



University of  
**Strathclyde**  
Engineering

# Exploring market change in the GB electricity system: the potential impact of Locational Marginal Pricing

Simon Gill, Callum MacIver and Keith Bell

Department of Electronic and Electrical Engineering  
University of Strathclyde

February 2nd, 2023

**Simon Gill** runs the independent consultancy The Energy Landscape and is an associate of Regen.

**Callum MacIver** is a Research Fellow in the Department of Electronic and Electrical Engineering at the University of Strathclyde.

**Keith Bell** holds the ScottishPower Chair in Future Power Systems in the Department of Electronic and Electrical Engineering at the University of Strathclyde.

The authors have worked together on this review of evidence and perspectives on what Locational Marginal Pricing would mean for the British electricity sector. The project has two main outputs – this main report and a record of findings from stakeholder engagement. The Executive Summary from this report is also available as a standalone document.

This project has been supported by the University of Strathclyde's [Scottish Low Carbon Power and Energy Partnership](#), funded by SSE and ScottishPower. However, Dr Gill, Dr MacIver and Professor Bell have full editorial independence and take full responsibility for any errors and omissions.

The documents are archived at the following links:

Main Report & Standalone Executive Summary: <https://doi.org/10.17868/strath.00083869>

Stakeholder Insight Report: <https://doi.org/10.17868/strath.00083868>

## Table of contents

Table of contents.....	3
Acronyms & abbreviations .....	5
Executive summary .....	7
Introduction.....	7
Structure of LMP markets .....	8
Learning from the LMP experience around the world.....	9
Challenges of introducing LMP in GB .....	11
Stakeholder views on LMP .....	13
Conclusions.....	14
Recommendations.....	19
1 Introduction.....	21
1.1 Methodology .....	21
1.2 Structure of the report .....	21
1.3 Why are LMPs being discussed in the GB context?.....	22
1.4 Objectives of the GB electricity system.....	24
1.5 The GB context – a decarbonised electricity system in 2035.....	26
1.6 Flexibility on a power system .....	29
2 The structure and operation of LMP markets .....	38
2.1 High level characteristics of an LMP market .....	39
2.2 What is LMP and what is it not?.....	39
2.3 The LMP algorithm .....	41
2.4 Day ahead market .....	44
2.5 Reliability unit commitment.....	44
2.6 Real time market .....	45
2.7 Self-dispatch .....	45
2.8 Financial transmission rights (FTRs) .....	45
2.9 Bilateral trading.....	48
2.10 Virtual trading.....	50
2.11 Market power mitigation .....	51
2.12 Market monitoring .....	51
2.13 Dispatch and real time balancing .....	52
2.14 Settlement.....	52
3 Case studies of existing LMP markets .....	54

3.1	PJM .....	54
3.2	California ISO (CAISO) .....	57
3.3	ERCOT .....	61
3.4	Ontario.....	65
3.5	New Zealand .....	66
3.6	Australia (National Electricity Market) .....	68
3.7	Experience of negative prices and renewable curtailment in LMP markets.....	71
4	Challenges of introducing LMP into the GB system .....	74
4.1	Very high penetration of wind and solar.....	74
4.2	Managing risks.....	76
4.3	Financial transmission rights in the GB system .....	86
4.4	Limited transmission capacity .....	88
4.5	Designing a coordinated LMP / CfD system .....	92
4.6	Legacy generators.....	98
5	Stakeholder evidence and discussion of the potential impact of LMP in GB.....	102
5.1	How might a move to LMP affect siting, investment and operation of renewable generation and flexibility in GB?.....	102
5.2	Assessing the costs and benefits of LMP.....	108
5.3	Interaction between LMPs and transmission development .....	112
6	Conclusions and recommendations .....	116
6.1	Discussion .....	116
6.2	Conclusions.....	126
6.3	Final comments and recommendations.....	131
	References.....	133

## Acronyms & abbreviations

<b>AC</b>	Alternating Current
<b>AEMO</b>	Australian Electricity Market Operator
<b>AGC</b>	Automatic Generation Control
<b>AR</b>	Allocation Round (in the GB CfD process)
<b>ARR</b>	Auction Revenue Rights
<b>BaU</b>	Business as Usual
<b>BM</b>	Balancing Mechanism
<b>BSUoS</b>	Balancing Service Use of System
<b>CAISO</b>	California Independent System Operator
<b>CBA</b>	Cost Benefit Analysis
<b>CCC</b>	Climate Change Committee
<b>CCGT</b>	Closed Cycle Gas Turbine
<b>CCS</b>	Carbon Capture and Storage
<b>CfD</b>	Contract for differences
<b>CM</b>	Capacity Market
<b>CMM</b>	Constraint Management Model (Australia)
<b>COAG</b>	Council of Australian Government
<b>CONE</b>	Cost of New Entry
<b>CPM</b>	Capacity Procurement Mechanism (California)
<b>CPP</b>	Critical Peak Pricing
<b>CREZ</b>	Competitive Renewable Energy Zones (Texas)
<b>CRR</b>	Congestion Revenue Rights (California and Texas)
<b>DC</b>	Direct Current
<b>DDM</b>	Department of Market Monitoring (California)
<b>DNO</b>	Distribution System Operator
<b>EMR</b>	Electricity Market Reform
<b>ERCOT</b>	Electricity Reliability Council of Texas
<b>ESC</b>	Energy System Catapult
<b>ETYS</b>	Electricity Ten Year Statement
<b>FERC</b>	Federal Energy Regulation Commission (USA)
<b>FES</b>	Future Energy Scenarios
<b>FiT</b>	Feed in Tariff
<b>FSO</b>	Future System Operator
<b>FTR</b>	Financial Transmission Rights
<b>HND</b>	Holistic Network Design
<b>HOPE</b>	Hourly Ontario Energy Price
<b>HVDC</b>	High Voltage Direct Current
<b>IESO</b>	Independent Electricity System Operator (Ontario)
<b>ISO</b>	Independent System Operator
<b>LCoE</b>	Levelised Cost of Energy
<b>LMP</b>	Locational Marginal Pricing
<b>LSE</b>	Load Serving Entity (US markets)

<b>MFC</b>	Market Floor Price
<b>MISO</b>	Midcontinent Independent System Operator
<b>MO</b>	Market Operator
<b>NEM</b>	New Electricity Market
<b>NGESO</b>	National Grid Electricity System Operator
<b>NOA</b>	Network Options Assessment
<b>NYISO</b>	New York Independent System Operator
<b>O&amp;M</b>	Operation and Maintenance
<b>OCGT</b>	Open Cycle Gas Turbine
<b>PJM</b>	Pennsylvania, New Jersey and Maryland interconnection
<b>PPA</b>	Power Purchase Agreements
<b>PUCT</b>	Public Utility Commission of Texas
<b>RAB</b>	Regulated Asset Base
<b>REMA</b>	Review of Electricity Market Arrangements
<b>REZ</b>	Renewable Energy Zones (Australia)
<b>ROC</b>	Renewable Obligation Certificate
<b>RTO</b>	Regional Transmission Organisation
<b>SO</b>	System Operator
<b>SRMC</b>	Short Run Marginal Cost
<b>TEC</b>	Transmission Entry Capacity
<b>TNUoS</b>	Transmission Network Use of System
<b>TO</b>	Transmission Owner
<b>TOU</b>	Time of use
<b>TSO</b>	Transmission System Operator
<b>WACC</b>	Weighted Average Cost of Capital
<b>ZMC</b>	Zero Marginal Cost

## Executive summary

### Introduction

Decarbonising the electricity system is a key stepping stone towards net zero greenhouse gas emissions across the economy, and doing so by the middle of the 2030s is both a recommendation of the Climate Change Committee and an ambition of the UK Government. This will require a major change in how electricity is generated and consumed with National Grid ESO's (NGESO) 2022 Future Energy Scenarios (FES) suggesting that up to 80% of electricity will need to come from wind and solar. The need to reliably meet demand for electricity in spite of the variability of renewable resources is stimulating a focus on 'flexibility' in managing the balance between supply and demand.

Questions are being asked by many in and around the electricity supply industry and government about whether existing market arrangements will drive enough investment in the right mix of resources such that a sufficiently reliable supply of low carbon electricity will be delivered to energy users at least cost. The UK Government has set up a Review of Electricity Market Arrangements (REMA) aiming to "identify reforms needed to transition to a decarbonised, cost effective and secure electricity system". This is considering a wide range of options for reform of both the wholesale market for electrical energy and a number of related areas including support schemes for low carbon power, capacity adequacy, operability and ancillary service markets.

One option that has attracted significant interest is that of energy trading based on Locational Marginal Pricing (LMP). LMP markets exist in jurisdictions around the world including several in North America. They operate on the principle that electricity is priced at each individual location on the network and the price there reflects the short run marginal cost of meeting demand at that location.

Several reviews and work programmes, including recent and ongoing work by National Grid ESO (NGESO), Ofgem and the Energy Systems Catapult, are investigating the potential benefits of moving the GB wholesale market from its current arrangements to an LMP market. They argue that a move to LMP and the associated centralised dispatch process would help reduce the increasingly burdensome and costly re-dispatch requirements linked with managing system constraints as well as providing the necessary price signals to drive more investment in, and efficient operation of, sources of generation and flexibility.

To date, these studies have focussed on the high-level principles of LMP and have not described the detail of how these markets operate in practice. Whilst this is a reasonable first step, it is possible that theoretical benefits may not be fully achievable in practice and that the very different context in GB compared with existing LMP systems means that experiences from other countries should be interpreted with caution.

This review explores LMP, how it might be applied in Britain and how the risks faced by different market participants might change were it to be introduced. It describes some key features of existing LMP markets and, through review of existing literature and interviews with industry experts, attempts to draw lessons from them and highlights the challenges of implementing LMP in GB. It also explores the links between LMP and other aspects of a market framework, notably support for low carbon generation delivered through Contracts for Difference (CfDs), and the provision of hedging arrangements for market participants through the sale of Financial Transmission Rights (FTRs). It reveals key details of the design of LMP and FTRs that vary between existing markets and would need to be addressed before any implementation in GB.

A key conclusion is that the design of electricity markets must be matched to the characteristics of the systems in which they are applied. Rigorous assessment of the *interaction* between different mechanisms is crucial. While some reforms might promise lower direct costs to consumers than others, there is the

potential for higher costs to other market participants with the associated risk that one or more of the overall objectives of reform are missed.

We highlight the significant increase in risk that a GB LMP implementation could place on market participants, and identify important differences between a decarbonised GB system and existing LMP markets that would drive the need for major innovation in the underlying LMP frameworks in order to operate in GB. It is likely that attempting to implement an ‘off-the-shelf’ LMP market along the lines of existing systems simply would not work, whilst designing, testing and implementing the changes needed to make LMP suitable for GB would be extremely challenging on the timescales proposed for decarbonising the GB electricity system.

The rest of this Executive Summary provides a synopsis of the key sections of the report together with a detailed list of [15 conclusions](#) and [6 recommendations](#).

### Structure of LMP markets

The high-level tenet that electricity prices should reflect the local short run marginal cost of meeting demand at each location on a network conceals a wider set of principles, assumptions and processes that make up a real-world LMP market. Figure ES1 shows the elements of a typical LMP framework. This is based around *two* separate LMP markets: a day ahead and a real-time market. Together these markets constitute a centralised dispatch of all supply and demand for electricity. However, they sit within a much wider framework typically designed to ensure security of supply, provide hedging opportunities for market participants and ensure markets run in a fair and competitive way. The main part of this report provides a description of each of the elements shown in the Figure ES1 and a discussion of its relevance for GB market design.

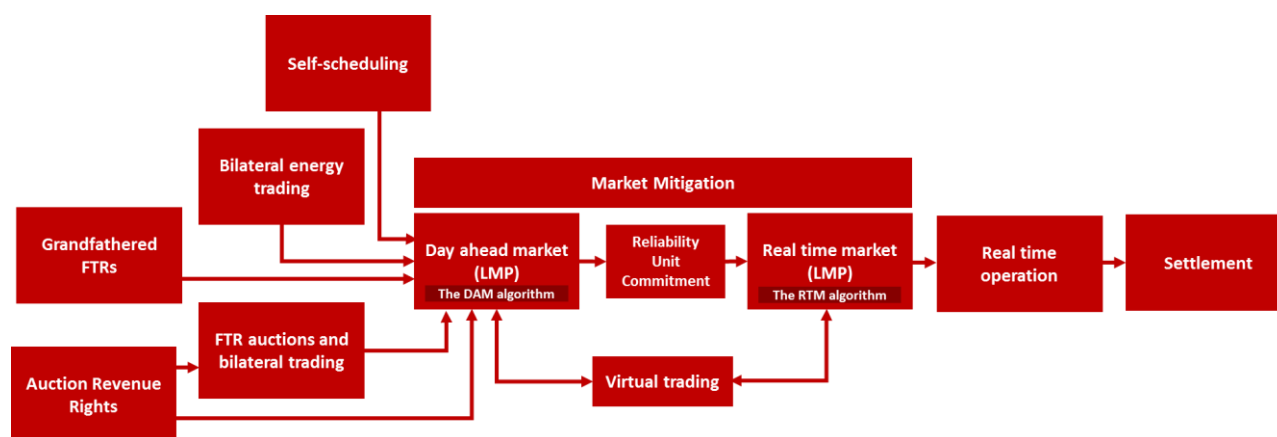


Figure ES1: Key elements of a typical LMP market

The individual elements laid out in Figure ES1 are underpinned by a number of principles or market design choices several of which would represent a significant a departure from existing GB arrangements. These are:

- **Dispatch of resources to meet demand is done centrally:** LMP markets operate using centrally managed optimisation tools to determine ‘cost optimal’ (within the limits of the algorithms used and data fed into them) dispatch of generator outputs and settings of flexible demand and storage based on bids and offers submitted by all market participants.
- **There is a requirement to participate in central dispatch:** although there are options to opt-out of economic bidding and ‘self-schedule’, it is mandatory for all participants above a certain size to participate in the central dispatch and to receive or pay the LMP clearing price for their energy. Bilateral trading arrangements are used in LMP markets but must work around this requirement.

- **System access rights are non-firm:** unlike current GB arrangements, generators and flexibility providers in LMP-based markets do not receive firm rights to access the system. Rather, the right to inject or withdraw power is granted temporarily only when participants are dispatched 'on' by the central algorithm either in the day-ahead or real time market.
- **Day ahead dispatch is financially firm:** if dispatched 'on' in the day-ahead market the financial commitment is firm. However, participants can buy their way out of that obligation in the real-time market which typically closes around one hour before delivery.
- **Congestion rent accrues to the System Operator (SO) and needs to be redistributed:** when networks are congested in an LMP market, demand pays more to the SO, than the SO pays out to generation. The residual is known as congestion rent. LMP markets generally specify mechanisms to return that rent to consumers.
- **Market designs should normally incorporate financial tools for hedging risk within the centralised structure:** in most LMP-based markets these include FTRs which pay out the difference in price between two nodes if there is congestion between them, and virtual trading which provides a route to hedge differences in price between the day ahead and real time markets.
- **LMP markets can dispatch reserve as well as energy:** in addition to prices for the generation or consumption of energy, market participants can submit bids and offers to provide reserve services together with the technical parameters to describe their capabilities. The LMP algorithm can then solve to optimise dispatch of reserve as well as energy. Other ancillary services such as voltage support and black start provision remain as separate markets.

One aspect of design of an LMP-based market that is likely to be important for the GB debate is the use of Financial Transmission Rights (FTRs). These can play multiple roles in an LMP market. They can be used: to return excess revenue accrued by the SO to consumers; to provide a means for market participants to hedge their locational risk; as compensation to market participants who lose rights or revenue streams when an LMP market is implemented; and for speculation.

It is important to differentiate each of these roles when discussing FTRs.

A key finding of this report is that FTRs, in the form used in many existing markets, are unlikely to be suitable for use in a GB system dominated by variable renewables and experiencing extensive network congestion.

The structure of LMP markets is discussed further in [Section 2](#) of this report

### Learning from the LMP experience around the world

The concept of LMPs has been used in major market designs since the mid-1990s in New Zealand and across an increasingly large part of the US since the turn of the century. There is evidence that many of these markets have operated successfully over many years in a way that is largely competitive. However, there have been challenges, particularly with the use in the US of so called 'long term' FTRs (that is, up to three years ahead).

Although successful in fossil fuel dominated systems and in some systems that have partially decarbonised, no existing LMP market approaches the level of penetration of variable renewable generators that is expected in GB in the mid-2030s. Whilst California and Texas have significant capacity of wind and solar – 27% and 29% of total generation capacity respectively, levels that are similar to GB today – none are currently embarking on the scale or speed of decarbonisation proposed for GB. Successful use of LMP in systems where the majority of electricity is generated from schedulable, fuel-based power stations, does not, by itself, provide proof it would be equally successful in systems with very different characteristics.

The key markets reviewed here are PJM in the North Western US, CAISO in California, ERCOT in Texas, New Zealand, Ontario and the SEM in Eastern Australia.

**PJM (North West US):** the first US LMP market has operated for over 20 years but has a low penetration of variable renewables. It has experienced issues with its FTR markets, with a major scandal in recent years that cost consumers \$179 million and, separately, a recommendation made by its independent market monitor that 'long term' FTRs are removed from its market structure.

**CAISO (California):** the introduction of LMP in California came in 2009. Solar and wind capacity have grown considerably over the past decade and, in recent years, battery capacity has also grown quickly. However, California has experienced summer blackouts with insufficient capacity available to meet early-evening peaks once solar stops generating. The implication is that the combination of the wholesale energy market and capacity adequacy mechanisms has not worked together to ensure sufficient firm capacity is available when needed.

**ERCOT (Texas):** Texas is often cited as an LMP system which has seen significant development of wind generation with its introduction in 2009 being followed by a period of strong growth in wind capacity. Proponents of LMP have argued, firstly, that LMP did not act as a blocker to the development of wind and, secondly, that LMP provided important signals to the siting of new developments. However, the connection of wind to the network was chiefly enabled by strategically planned, state-funded development of new transmission corridors to the areas with the greatest wind resource coinciding with the move to LMP. Investment has since come in waves based on the availability of transmission capacity to resource rich areas with little evidence that LMP has driven siting decisions for wind in Texas.

**New Zealand:** the first country in the world to operate under an LMP system, New Zealand is unusual in that for more than a decade it operated without FTRs and exposed the demand side to nodal pricing rather than applying a zonal or system-wide average price to demand. Prior to the introduction of FTRs the New Zealand electricity market was structured around vertically integrated utilities largely generating and supplying at the same node in order to avoid locational risk. More recently, FTRs have enabled greater financial hedging. Although New Zealand operates a highly decarbonised system the vast majority of renewable generation comes from hydro rather than variable, weather dependent sources.

**Ontario:** is in the process of moving from a centralised pool market with no locational elements to an LMP system. There was widespread acceptance that the legacy system was not fit for purpose and failed to dispatch the existing fleet – mainly fossil fuel generators – effectively.

**NEM (Eastern Australia):** The Eastern part of Australia currently operates a zonal market but has considered moving to a fully nodal LMP market in recent years. Conversion to a full US-style LMP market was recently rejected, and market participants remain nervous about LMP-like options. Some of the challenges facing Australia mirror issues in GB, particularly around multiple renewable generators being caught behind the same network constraint. Options being considered for managing these challenges may be highly relevant to GB.

The learning from international LMP case studies is discussed further in [Section 3](#) of this report.

## Challenges of introducing LMP in GB

Looking ahead to the 2030s the GB context is one where electricity production will be dominated by variable, Zero Marginal Cost (ZMC) renewable generators: wind and solar. It is also one where transmission constraints will remain a major feature of the system – although the optimal amount of transmission will have some constraints, the new network capacity necessary to reach that optimal level will struggle to catch up with the development of renewable generation that is needed. No matter what wholesale market solution is implemented, the need to build new transmission capacity at speed to increase the ability to transfer electricity from areas with greatest potential for low carbon generation to areas with highest demand will be critical to decarbonising the electricity system.

There are a number of theoretical advantages to a market based on LMP. However, our exploration has identified the following challenges for a GB market based on LMP.

**The level of variable renewable penetration required is unprecedented in any LMP-based market:** this will create challenges for any market design and will drive wholesale market prices to zero or below for large parts of the year making investment in any form of generation capacity challenging. This would be exacerbated by a move to LMP where areas such as Scotland, with significant growth potential for renewable generation but a lack of transmission capacity, could see zero or negative prices the majority of the time.

**Very high levels of network congestion and need for network investment:** interviewees with experience of existing LMP markets suggest that these markets work most effectively where transmission capacity is close to optimal with some, but not too much, congestion. The level of network constraints in some parts of the GB system is a major challenge in itself. Introducing an LMP market would not change the fundamental nature of this issue. There is currently a need for significant levels of investment in additional GB network capacity, a need that a switch to LMP is unlikely to reduce in the short to medium term even if, in principle, LMP would reduce need in the longer term.

Operation of an LMP market in the face of excessive congestion would, on its own, likely lead to reduced investment in generation behind constraints. It may, however, fail to deliver increased generation investment elsewhere as limits imposed by planning, space and resource levels (wind and solar) are likely to restrict increased development in all but the very long term.

LMPs can provide a mechanism, at least in theory, to support flexibility in relieving network constraints including by incentivising location specific investment in storage and new forms of flexible demand like hydrogen electrolysis. In practice, there may be limitations on how flexible the location of such demand can be, depending, for example, on the market for hydrogen that develops and the need for infrastructure to transport or store it. Further, if levels of congestion remain high it may well limit the ability of some flexibility providers, particularly energy storage, to benefit from locational price signals and make a significant contribution to constraint management.

**Dispatch risk:** the loss of firm network access creates a new and significant form of risk for individual market participants. ‘Dispatch risk’ is where generators face the risk of failing to be dispatched by the LMP algorithm and are unable to access the electricity market during that settlement period. The LMP market design concentrates risk onto individual generators in ways that are challenging to manage or mitigate.

An example is seen where multiple ZMC generators are caught behind a single constraint. In this situation dispatch would become relatively arbitrary, set either by very small differences in minor variable operating costs, by small variations in overall system losses, or by bidding incentivised by support mechanisms. There is risk of a ‘winner takes all’ outcome with generators falling into a

largely fixed and arbitrary merit order. Where within that merit order a generator sits would be hard to predict in advance and would have significant impact on its revenue.

The consequences could include a higher cost of capital, or worse, a significant hiatus in investment caused by increased and poorly understood risks.

**Financial transmission rights may fail to match market needs:** existing FTR products tend to be of significantly shorter duration than investments in generation capacity and experience from the US suggests potential issues with the competitiveness of FTRs more than one year ahead. In addition, fixed-profile FTRs, whilst suitable for baseload and other schedulable generation with relatively predictable operating cycles, do not match the variable, uncertain characteristics of wind and solar.

**Coordination with renewable support schemes:** GB's existing CfD support scheme has been successful in supporting investment in low carbon generation. However, it is closely integrated into the wholesale market using market prices as a reference to pay or draw back support. Introducing an LMP market opens up myriad potential arrangements relating to how auctions are cleared, what constitutes the reference price, how 'negative pricing rules' should be designed, and the interaction with FTR arrangements. We show, for a small number of examples, how each combination of choices leads to a unique set of incentives on generators. The lesson is that this is a highly complex area; as it is central to getting investment in low carbon generators, it must not be ignored. The need for wholesale market arrangements to be well-aligned with support for low carbon generation applies whether current CfD arrangements are continued in broadly the same way as today or if alternative approaches to supporting low carbon generation are considered.

**Removal of access rights for legacy market participants:** moving to LMP would remove existing market participants' firm access rights to the system. In order to avoid any potential legal challenge, there would be a need to think carefully about how to compensate generators and to integrate the LMP market with existing support arrangements including the Renewables Obligation and existing CfD contracts. This would have implications for how these participants bid and offer into the LMP markets.

**Implications for consumers:** although the focus of the work reported here is on generation and flexibility, it is essential for any market review to consider the impact on consumers. LMP removes some costs and risks, such as those associated with congestion, from consumers (at least directly) and places them on generators. Depending on the precise form of LMP, consumers in some locations may benefit through lower electricity prices in comparison to others. Overall, it is not yet clear how changes in allocation of system costs and overall risks would flow back through to consumers.

The challenges of introduction of LMP into the GB system are discussed further in [Section 4](#) of this report.

## Stakeholder views on LMP

As part of this review we undertook semi-structured interviews with ten electricity market experts. This included specialists with experience in regulation and market design in the US and Australia as well as a number of key participants in the GB debate. The cohort included a mix of views on the value of LMPs for GB. Some of the key themes that emerged from these discussions were as follows.

**How might a move to LMP affect siting and investment?** There was significant disagreement on the extent to which LMP would improve siting decisions. Stakeholders with experience of existing LMP markets were unconvinced that locational signals from wholesale energy prices significantly changed siting decisions and highlighted that non-price factors such as the availability of resource and the ability to obtain permissions and consents to get a project built were likely to be more important. This appeared to many to be a greater concern for GB than in the US due to more limited space and the restriction of favourable planning policy to particular areas of the country. Whilst some interviewees highlighted the potential for more offshore wind in the southern part of GB including some delivered through floating projects, this is likely to be, at best, a long-term solution due to a lack of an existing pipeline of surveyed and consented sites.

In terms of resources offering particular flexibility services, whilst LMP would in principle incentivise efficient siting of storage, electrolysis and other forms of flexibility, interviewees were aware of very little evidence to show whether it would deliver flexible capacity in practice. An important implication of this is the need for more detailed in-depth studies of the likely operation of flexibility, any dependencies on other infrastructure (such as for hydrogen) and the relative importance of wholesale energy markets, ancillary services and other flexibility revenue streams for different forms of flexibility in LMP and other market designs.

**Impact on cost of capital:** interviewees highlighted a number of pieces of evidence on the potential impact of LMP on cost of capital, some anecdotal and some more formalised. This evidence suggests that increases in the range of two to three percentage points are credible and arise from the significant increase in risk faced by individual market participants, and the limited opportunities for mitigating that risk. Other interviewees emphasised the interaction between LMPs and CfDs or alternative low carbon support mechanisms and noted that the cost of capital would ultimately depend on the overall risk associated with the combination of market structure and support mechanisms. This is an important point and highlights the need to explore in detail the interaction between each element of a market framework. Overall, our conclusions from the interviews are that there is an urgent need for more quantitative evidence on this point, and that there is the real potential for cost of capital increases to offset any operational cost savings that LMP may deliver.

**Consumer savings:** a key argument for LMP is that it would lead to lower prices for consumers overall. Interviewees were aware that LMP markets can transfer the burden of costs away from consumers and onto other market participants. However, they also highlighted the importance of understanding how those costs and risks would end up being recycled. Whilst some may be directly absorbed by generators through reduced profit, interviewees also highlighted the potential that they are passed to consumers through higher CfD strike prices or PPA contracts struck alongside the LMP market.

A more detailed discussion of Stakeholder views forms [Section 5](#) of this report.

## Conclusions

Our review has led us to reach the following conclusions.

### **1. Moving to LMP could increase the risk of failing to deliver decarbonised power by 2035.**

Introducing an LMP market would create significant short-term disruption, increase the allocation of costs and risks to individual generators and require significant innovation to adapt the existing LMP standard model to suit a GB system. This risks turning GB's wholesale electricity market into a national experiment at a time when certainty is needed to deliver significant investment in the sector. One result could be a delay in our ability to deliver a decarbonised electricity system due to a hiatus in investment.

There will be risk associated with any significant change in market arrangements. Some of that risk stems from the fact of change itself and the uncertainty that it creates, and some will be down to the nature of the particular set of changes. Any implementation of LMP should be part of an appropriate and complementary package of reforms spanning ancillary services, capacity markets and low carbon support mechanisms. These elements interact and combine to impact the potential profitability of different investments. There is little time to carry out the necessary analysis, design, consultation and implementation at the pace required to impact on how the electricity system looks and is operated in the mid-2030s.

The difficulty of solving this challenge should not be underestimated and exploring at least some of the complexities involved needs to be a central part of the evidence base used to make decisions on future wholesale market arrangements.

### **2. LMP could significantly increase the cost of capital for generators, but that depends on the interaction between the wholesale energy market framework and the wider package of market reform including mechanisms to support investment in new low carbon generation.**

In addition to the risk of delaying a decarbonised electricity system, there is a risk that market reform will result in a more costly system than expected. A key part of that risk comes from the cost of capital. There is anecdotal evidence that markets that price energy on a nodal basis increase the cost of capital for merchant investment relative to those that do not, but there is limited published analysis of the effect. Our review suggests that, relative to today and dependent on the implementation of a wider package of reforms, LMP would place additional revenue risk on GB investors and create a situation where risk is hard to forecast and difficult to control for individual market participants (e.g. the risk to a generator of a competing generator connecting at the same node or of a major demand customer closing).

Participants in an LMP market face both price and dispatch (or volume) risk. For ZMC renewables, in particular, it is important that these risks can be quantified and managed in advance for a significant fraction of a project's operating life. Mechanisms do exist in LMP markets to manage price risk. These include FTRs and bilateral PPAs. However, evidence from existing markets suggests that these mechanisms are likely to be limited to a timespan of no more than a few years, much shorter than the typical lifespans of generation assets. Dispatch risk relates to the lack of firm access rights in a conventional LMP market and uncertainty over whether a market participant will be scheduled by the LMP algorithm which mean, without dispatch by the algorithm, a participant cannot participate in the market. In contrast to price risk, there are limited mechanisms in place in existing LMP markets to mitigate dispatch risk. In principle, generators might self-schedule but they will then be exposed to the energy price at their connection node which, in a wind dominated area under windy conditions, could turn negative leading to them losing money.

There are ways that wider market design can reduce and reallocate some of the risk on particular market participants through other arrangements, particularly support mechanisms for low carbon generators.

Continued use of CfDs could absorb some of the price risks associated with network constraints while adoption of something akin to a 'deemed generation' CfD would be required to mitigate generator dispatch risks, a potentially bigger factor for GB. However, the extent to which such measures are utilised and their detailed design would have direct consequences on the level of consumer welfare benefits that LMP could deliver.

**3. LMP markets are in use in some parts of the world; some of them have a reasonable level of ZMC renewable (wind and solar) penetration but not to the extent that GB expects to have by 2035.**

LMP markets have existed in their modern form for at least 20 years in parts of the US and elsewhere and are generally considered by those who work within them to be efficient, effective and competitive overall, although there are some important caveats with certain aspects of those markets such as long-term FTRs.

Other markets also provide evidence that it is possible to operate LMP markets with moderate penetration of variable, zero marginal cost renewables. In 2020 CAISO had a 28% penetration of wind and solar (as a proportion of total electrical energy production) and ERCOT 41%. Investment in renewables continues to be made in those systems although it is unclear whether this investment is made 'because of' or 'in spite of' LMP. However, there is no experience world-wide of introducing LMP into a system that is undergoing the level of change currently being experienced in GB, nor one that has ambitions on such a short time scale to convert fully to decarbonised electricity system, a process that will potentially require an increase in the penetration of variable, zero marginal cost renewables to provide 80% of electricity.

**4. LMP has the potential to improve the efficiency of dispatch of system resources including generation and flexibility.**

The locational signals delivered through LMP markets on day ahead and operational timescales have the potential to improve the efficiency of dispatch. This includes the dispatch (or not) of ZMC renewables. The benefit comes largely in terms of driving efficient dispatch of interconnectors, storage and fuelled, schedulable generators. This has the potential for operational savings through the burning of less fuel. However, the significance of such savings in a system in which most energy comes from ZMC generation should be assessed. However, the significance of such savings in a system in which most energy comes from ZMC generation should be assessed.

The design of the algorithm is critical to successful dispatch, and needs to reflect the underlying physical characteristics of the system. For a decarbonised electricity system, the way the algorithm deals with multi-period constraints would be particularly important as this would be central to efficiently dispatching energy storage and demand flexibility.

**5. LMP is likely to be limited in its ability to drive more efficient siting in GB.**

Evidence from this review suggests that LMP would likely have limited impact on the siting of ZMC renewables. We have come across little evidence of locational price variations affecting the siting of renewables in existing LMP markets and several interviewees highlighted that non-price factors such as availability of resources (wind or sun) and the ability to get planning permission are more likely to drive siting decisions.

The experience of Texas suggests that renewable investment is likely to come in waves in line with availability of new transmission capacity to areas with the best resource rather than being redirected to other locations which already have more network capacity available. These factors are likely to have a strong impact in GB where space is at a premium, planning and consenting is difficult and time consuming, and resource availability is concentrated in particular parts of the country.

**6. LMP markets do not, on their own, solve the problem of planning, designing, building and operating an efficient and effective transmission network.**

An LMP market is largely about efficiently managing access to a given quantity of network capacity. There is limited evidence that moving to LMPs leads to less need for transmission network in practice.

Comments made by interviewees highlight that LMP markets are most effective where there is a close-to-optimal level of transmission network, with some (but not too much) network congestion.

**7. There are significant concerns in existing LMP markets with ‘long term’ Financial Transmission Rights for hedging.**

In US markets FTR products are often available for no more than three years in advance, and market monitors in two systems (CAISO and PJM) have advocated the removal of so called ‘long-term FTRs’ with terms from one to three years ahead, citing poor consumer value and the potential for manipulation. Long-term FTRs often sell at auction for significantly less than the value they realise suggesting a lack of competition for these products. Despite significant resource given to market monitoring FTR markets have been subject to major scandals. One prominent example in PJM saw costs of US\$179 million associated with what FERC ruled as manipulative FTR trading.

**8. An ‘off-the-shelf’ LMP market solution does not exist for GB – we would need to adapt existing processes and develop new ones.**

If LMP were chosen for GB there would be a need to significantly adapt the ‘standard model’ of LMP design in potentially complex ways to reflect both the physical characteristics of the system and wider market structures, particularly CfDs. (See further points below). No existing LMP market operates on a system where ZMC generation is the price setter across much of the network for a significant part of the year. And, whilst the theory of LMP markets can still work in such a system, it is clear that it would raise specific and new challenges. One example of innovation that will be needed is to develop ways of ensuring that the system can always be balanced even with the very high ramp rates of residual demand that can be expected in future. These innovations would take time to develop, test and demonstrate making proposed implementation before the end of the decade challenging. Introducing a period of policy uncertainty risks an investment hiatus that could impact on 2035 targets for decarbonisation of electricity.

**9. A new form of FTR suitable for variable renewables would need to be developed.**

Whilst FTRs are argued by many to be critical to the effective functioning of an LMP market, we believe there are significant risks associated with relying on them in the context of a decarbonised GB electricity system either to hedge long-term risk or act as compensation for the loss of firm access rights that existing generators would face. FTRs currently in use in US markets involve fixed, pre-defined profiles, and therefore do not match the time-varying nature of wind and solar generation, nor do they have the flexibility to adapt to the uncertainty in future output inherent in weather dependent renewables. A new form of FTR suitable for variable renewables would need to be developed and tested robustly.

**10. Integration of LMP and centralised CfD renewable support would be a world first (with associated risk of trying something new).**

Whilst existing LMP markets have been run with support for renewables based on fixed or near fixed payments per MWh, they have not been run with arrangements similar to Britain’s Contract for Difference arrangements where the uplift payment depends on the difference between a strike price determined in an auction and a market reference price for each wholesale market settlement period. There would be a number of important choices to be made in co-designing a joint LMP and CfD system for GB such as how to set the reference price, and how to deal with negative wholesale prices.

**11. An LMP market may not efficiently dispatch a large number of generators caught behind the same network constraint.**

All ZMC generators caught behind a constraint would have the same short run marginal cost: zero. Bidding in an LMP market may be influenced by very small differences in variable operation and maintenance costs, small impacts on overall system losses, and arrangements related to support payments.

Given these small differences, there would be a significant degree of arbitrariness around which ZMC generators are dispatched 'on' and which are not. Even if the relevant locational price is zero, this can lead to significantly different revenue outcomes across the ZMC fleet due to the different forward contracting and low carbon support arrangements that market participants have, the majority of which are likely to depend on dispatch and physical production.

**12. Without additional arrangements, a move to an LMP market might fail to deliver capacity adequacy.**

LMP has the potential to reduce revenue available for some schedulable generators including peaking plant and increase the importance of a robust capacity adequacy mechanism. As with other elements of the overall market package, it is critical to ensure that the energy and capacity adequacy arrangements work effectively together.

Ensuring a secure low carbon system requires significant capacity of schedulable low carbon energy sources such as hydrogen peaking plant, gas generation combined with CCS, storage, or access to reliable imports. Many market designers, including those in CAISO, PJM (and GB), have made the judgment that a wholesale energy market needs to be combined with some form of capacity adequacy mechanism in order to ensure sufficient capacity to meet peak demand. Others markets such as ERCOT rely on the energy market alone, through scarcity rents, to support capacity adequacy.

A significant quantity of ZMC renewables is likely to impact on revenues not just for peaking plant but also for 'mid-merit' schedulable generation which will have limited running hours in a system with a high level of variable renewable generation capacity. These generators will almost certainly require a strong capacity market or other non-wholesale market-based revenue streams, and this requirement would likely be stronger in a market with LMP than in one without.

Evidence from the rolling blackouts experienced in California in recent years suggests that poor coordination between their LMP market, where day-time revenues have been eroded through the growth of solar power, and the Capacity Procurement Mechanism was one factor leading to insufficient generation available in the early evening after the sun had set.

**13. The impact of a move to LMP on the demand side is unclear.**

In principle, LMP would reduce the total cost of dispatch. Depending on the extent to which locational prices are passed through to energy users there is the potential for consumers to benefit in areas where the marginal price is very low. On the other hand, LMP could expose energy users in import constrained areas to higher energy prices. The overall extent of benefits to the demand side depends on negative effects of LMP – e.g. on cost of capital to investors in new generation and the impact of that on cost of energy – not outweighing the benefits.

At present there appears to be little evidence to help understand the potential real-world impact of LMP on the demand side and little consensus on the extent to which the demand side should be exposed to locational prices. In most US LMP markets, for example, the demand side is only exposed to locational price difference at the zonal rather than nodal level. However, some markets, such as in New Zealand, do apply nodal prices to the demand side.

The prospect of highly variable energy prices for consumers based on location leading to a ‘postcode lottery’ has the potential to raise significant distributional as well as political concerns. Most energy users in Britain buy their electricity through Suppliers who could be charged for demand on a nodal basis but regulated in the degree to which time and locational variation can be passed through to end consumers.

**14. In the US significant attention is paid to Market Monitoring to identify the degree of efficiency and competition in LMP markets and to spot potential breaches of market rules. We should be ready to devote similar levels of attention here.**

The effort placed on market monitoring in US LMP markets is significantly greater than is seen in GB. This provides detailed analysis and insight into the operation and effectiveness of each element of the market structure. Market monitoring is carried out independently of the regulator with monitors given the power to make recommendations to the Market Operator and to the regulator, and to refer potential breaches of market rules for formal review. We see significant value in adopting similar approaches to the GB market regardless of decisions over the form of that market.

**15. While there are major questions to be resolved in the design of LMP and complementary arrangements as part of an overall package, any alternative set of arrangements must address similar issues.**

The final suite of reform options that is brought forward from the ongoing review process should be the package that best addresses the overarching objective of the power system, which this report suggests to be:

*Ensure that, by 2035, net production of greenhouse gases on the GB electricity system is negligible while supplying electrical energy with sufficient security and resilience at lowest total cost to energy users over the medium to long term.*

*In achieving this objective, reform of energy markets should consider their interaction with a wider set of economic, social and environmental policies and how development of the energy system makes the most of opportunities for the whole economy, ensures fair access to and affordability of energy, supports regional development across GB and provides appropriate protection for natural capital and ecosystem services.*

This raises significant challenges associated with coordinating the siting and dispatch of resources.

These challenges will grow under any set of market arrangements.

Whilst there are significant risks and challenges associated with moving to an LMP market, many of the fundamental issues will be common to any market system and there are areas where current GB arrangements are poorly aligned with the changing needs of the system. In particular, any form of electricity market arrangements needs to:

- Manage the cost and risk created by ZMC generators connecting where strong non-price locational signals dictate.
- Incentivise flexibility – storage, flexible demand and schedulable sources of energy – to be made available in the right places, at the right times and ensure that it is used efficiently within the constraints of the system.
- Provide signals to interconnectors to connect in the most effective locations in GB and to dispatch them in a way that supports the GB system without exacerbating network constraints.
- Influence the development of the transmission network to better anticipate where market participants will connect, ensuring that there is sufficient transmission capacity in the right parts of the network at the right times.

## Recommendations

Based on our review of existing LMP markets and the discussions we have had with interviewees we make a number of recommendations for action related to market reform and informing policy.

1. Further analysis and critical appraisal of market reform options, including LMP, should take clear and detailed account of the package of measures that LMP would be implemented within. This should include, but is not limited to:
  - the likely level of innovation needed in LMP structures and in the coordination between LMP and other GB market arrangements and system objectives;
  - how LMP and CfDs might be co-designed to deliver desired outcomes including appropriate splits of cost and risks between market participants, mitigating risks associated with LMP without undermining the main objectives;
  - the need for new FTR arrangements to support variable ZMC renewables and the limitations of FTRs as long-term hedging mechanisms that have been identified in existing LMP markets;
  - consideration of how an LMP algorithm would dispatch multiple ZMC generators behind the same constraint.
2. Cost Benefit Analysis (CBA) should be carried out for LMP as part of a package for reform (rather than for LMP in isolation) and against counterfactuals reflecting that the appropriate comparison is not just with current GB arrangements but with other options for reform.
3. To inform CBAs, robust quantitative evidence is required on the impact of moving to LMP on the cost of capital for different types of market participant. This needs to be supplemented with significant sensitivity analysis considering the impact of the wider package and context for all market reform options. Sensitivities should include:
  - the risk implications of different forms of CfD or alternative low carbon support mechanisms in combination with LMP;
  - the impact of delays in transmission development and of network outages;
  - constraints on siting for new network users.
4. Undertake a detailed study of the size and allocation of risk under different market proposals. This should review any changes to risk, including the risk of failing to achieve a decarbonised electricity system by 2035 and of insufficiently secure supply. It should consider how risk is allocated across market participants. It is important that those undertaking this work fully understand the nature of risk under an LMP market combined with a fully decarbonised electricity system. This report highlights that dispatch risk would become increasingly important with a scale significantly larger in GB than in existing LMP markets.
5. Develop a longer-term plan for transmission network development beyond the period covered in the ‘holistic network design’ that exists at the time of writing, giving the sector an indication of what transmission capacity across major boundaries could be in 2035 and 2040. This should be assessed for a number of scenarios rather than just a central pathway (much like FES does for generation and demand) and for boundaries expected to experience significant and costly congestion over the coming decades.
6. Review the approach to market monitoring in US LMP markets and consider funding and implementing similar, independent monitoring of GB markets, regardless of the form of those markets.

# Introduction

## 1 Introduction

There is growing interest in exploring the potential to move the GB wholesale electricity energy market to a more centralised arrangement using Locational Marginal Pricing (LMP). In a market based on LMP, electricity is priced separately at each location on the transmission network in each trading period. Prices at each location reflect the marginal cost of electricity at that location. This contrasts with the existing wholesale market design in GB which relies on a national market price and a decentralised dispatch process whereby owners of generation plant (of a certain minimum size) inform the system operator of their intention to run based on bilateral trading positions. The system operator then uses the centralised balancing mechanism (BM) to re-dispatch the system to ensure supply and demand are met in real time whilst adhering to the physical constraints of the system.

It is claimed by its proponents that an LMP market would bring efficiency benefits to the GB system<sup>1</sup>. However, clarity is needed on the nature of these efficiencies and whether they would be realised in practice. Further, the introduction of LMP to GB would present a number of practical challenges and could have significant implications at a time when major change is needed to deliver net zero. Careful consideration needs to be given to the interaction between LMPs and existing structures in the system and between LMPs and the wider package of market and system change before a final decision is reached.

There are two main forms of LMP: zonal and nodal. In the latter, typically, marginal prices are computed at each node of the transmission network. However, variations can be imagined in which prices are also calculated at nodes within the distribution networks. A nodal market is distinct from a zonal one in which pricing is determined at a sub-national regional scale and can be thought of as a middle ground between nodal and national pricing.

The version of LMP that has received most attention in Britain in recent times is nodal. Throughout this report the term LMP market is used in the context of a nodal market unless otherwise stated, however we return to the question of zonal locational markets in Section 6. This report seeks to explore the potential impact that the proposed move to LMP could have on market participants in GB, with a focus on generators and flexibility providers, and assess the specific challenges that would be associated with implementation in the context of a GB electricity system seeking to make a rapid transition towards deep decarbonisation.

### 1.1 Methodology

The authors have undertaken an extensive literature review and conducted a series of semi-structured interviews with expert stakeholders<sup>1</sup> in GB, the US and Australia to understand experiences and learning points from existing LMP markets, elicit informed opinion on LMP as an option for future market reform in GB, and identify the key challenges for implementation. The resulting combination of literature review and expert interviews, reported here, is intended to bring a new level of detail to the public debate on electricity market reform in GB.

### 1.2 Structure of the report

The remainder of this report is laid out as follows.

- The rest of Section 1 expands on the reasoning for LMP being considered in GB, outlines key objectives for the GB market and provides further context on what is required to deliver a decarbonised power system operation by 2035.
- Section 2 provides a review of how LMP markets typically operate and their main features.

---

<sup>1</sup> Ten interviews were undertaken with expert stakeholders including representatives with current or previous experience spanning market design, regulation, investment in generation and storage, system operation, research, consultancy and government.

- Section 3 discusses a series of case studies reflecting on LMP implementations in some particular jurisdictions and the insights that can be gained from their experiences.
- Section 4 then considers the specific challenges that would be associated with implementation of an LMP market in GB including the potential impact on market participants in terms of risk, interactions with other market mechanisms such as renewable support schemes and the treatment of legacy generators with contracts and business models aligned with the market design that exists today.
- Section 5 provides some detailed discussion and evidence from the stakeholder interviews that address some of the key claims around LMP, such as its impact on the investment in siting and operation of renewable generation and ‘flexibility’ (including storage and flexible demand), the potential benefits to consumers and the dependency of those benefits on transmission investment.
- Section 6 then offers a concluding discussion that reflects on both the insights gained with respect to LMP and the wider challenges that need to be addressed by market reform in GB. It also includes the report’s key conclusions and recommendations.

In addition to the main report, there is a separate Stakeholder Insight report which includes a summary of the responses that were given as part of the stakeholder interviews.

### 1.3 Why are LMPs being discussed in the GB context?

The design of the GB wholesale electricity market will be important in delivering net zero. The urgency of market reform has grown over the past year due both to the UK Government’s commitment to a fully decarbonised electricity system by 2035 (subject to security of supply)<sup>2</sup> and the energy price crisis. The recent *Review of Energy Market Arrangements* (REMA) consultation states that “Our future market arrangements will deliver a step change in the rate of deployment of low carbon technologies (both on the supply and demand side); continue decarbonising whilst meeting the rapidly growing demand for electricity; and reduce our reliance on fossil fuelled generation.”<sup>3</sup>

In this context, LMP is being explored as one of the options for change under REMA. Significant work has also been carried out by several organisations, a number of which advocate nodal pricing as a potential solution to some of the challenges of delivering a decarbonised electricity system. This includes work by National Grid ESO (NGESO)<sup>4</sup>, Ofgem<sup>5</sup>, and the Energy Systems Catapult (ESC)<sup>6</sup> <sup>ii</sup>.

A key driver of the LMP debate has been the market reform work carried out by NGESO<sup>7</sup>. The company argues that there are four problems that current market arrangements create for the delivery of net zero:

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; and
4. current market design does not unlock the full potential of flexibility from both supply and demand.

NGESO’s report concludes: “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.”

Ofgem has also been reviewing the challenges of achieving net zero. In *Net Zero Britain*<sup>8</sup> they highlight three groups of challenges for the energy system to overcome:

---

<sup>ii</sup> The ESC work was commissioned by Octopus Energy. In addition, all three parties - NGESO, Ofgem and ESC - have used FTI consulting to perform their modelling of LMP for GB.

- 1. the need for coordination** which highlights the scale of the investment needed and the importance of combining strategic planning with market-driven outcomes and particularly the challenge of finding the right balance between network capacity and flexibility;
- 2. optimisation of the energy system** which focuses on the need to deal with the marginal price challenge (that even a small quantity of gas sets the price for much of the time in today's system) and the lack of locational and sufficiently granular time-varying market signals; and
- 3. challenges facing consumers** highlighting unaffordable bills and the potential value to consumers of being flexible.

Ofgem's proposed reforms to deal with the first two issues include greater strategic planning and significant market reform. Whilst noting that more work is required, they specifically highlight the ideas of 'market splitting' and locational pricing as possible ways to deal with the challenges. Ofgem has also commissioned consultants FTI to carry out a detailed cost benefit analysis of moving to LMP. This work is expected to report in Q1 2023<sup>9</sup>.

The facilitation of 'flexibility' looms large in the apparent thinking of NGESO and Ofgem on electricity market reform. Specifically, it is argued that present day market arrangements provide insufficient incentives to flexibility being made available and used optimally. We provide a more detailed discussion of flexibility in Section 1.6.

When considering the role that LMP could play in GB it is important to set it in the context of wider market reform options. The REMA review sets out a vast array of reform options being considered by the Government. These are summarised in Figure 1. The diagram shows that the choice of whether to move to LMP is only one element of many potential reforms that could be made to the wholesale market, although, as highlighted, it would also dictate a move to central dispatch and pay-as-clear price formation. REMA also covers reform options for the market that support delivery of mass low carbon power, flexibility, capacity adequacy and system operability. If the Government chose to implement an LMP market, the package of reform options that went along with it would be crucial to determining outcomes and implications for wholesale market participants and end users of electricity.

Wholesale Market	Location	National pricing		Zonal pricing		LMP / Nodal pricing			
	Technology	Unified Market			Split by Characteristic				
	Balancing	National			Local then national				
	Price formation	Pay-as-clear			Pay-as-bid				
	Dispatch	Self-dispatch			Central Dispatch				
	Mass low carbon power	Existing CfD	CfD – more price exposure	Deemed generation CfD	Supplier obligation	Revenue cap and floor	Dutch subsidy	Equiv. firm power auction	
	Flexibility	Optimised capacity market	CM with flex enhancements	Supplier obligation (inc CPS)		Revenue cap and floor	Dutch subsidy	Equiv. firm power auction	
	Capacity adequacy	Optimised capacity market	Capacity payment	Centralised reliability option	Decentralised reliability option	Targeted tender	Strat. reserve	Equiv. firm power auction	
	Operability	BAU	BAU+	Local markets	Changes to CfD/BM design	Co-optimisation	Dedicated support scheme		

Figure 1: Options for electricity market reform in the REMA consultation with LMP and associated options highlighted - adapted from [10]

Whilst REMA’s scope is extensive, it excludes a number of areas critical to delivering decarbonised electricity. These areas include retail market design and the need to invest in new transmission capacity at significant scale and speed.

## 1.4 Objectives of the GB electricity system

Whilst the work by NGENSO and others highlight what they see as problems with current market arrangements and provide a list of benefits that they argue LMPs could deliver, they often neglect to clearly align their discussion to an overall objective for our electricity or wider energy system.

One important framing of electricity system objectives is the trilemma of security of supply, sustainability (most usually focused on decarbonisation) and low cost. The REMA consultation bases its overall objectives on an articulation of the trilemma along with separate points for its vision and assessment criteria (see Table 1).

*Table 1: Objectives, Vision and Assessment criteria proposed for UK Government’s review of electricity market arrangements.*

Objectives	Vision	Assessment Criteria
<ul style="list-style-type: none"> <li>• Support full decarbonisation by 2035</li> <li>• Maintain security of supply</li> <li>• Cost-effectiveness</li> </ul>	<ul style="list-style-type: none"> <li>• Deliver a step change in the rate of deployment of low carbon technologies and reduce our dependence on fossil fuelled generation.</li> <li>• Provide the right signals for flexibility across the system.</li> <li>• Facilitate consumers to take greater control of their electricity use by rewarding them through improved price signals, whilst ensuring fair outcomes.</li> <li>• Optimise assets operating at local, regional, and national levels.</li> <li>• Ensure that the security of the system can be maintained at all times.</li> </ul>	<ul style="list-style-type: none"> <li>• Least cost.</li> <li>• Deliverability.</li> <li>• Investor confidence.</li> <li>• Whole system flexibility.</li> <li>• Adaptability.</li> </ul>

A more fundamental view of the objectives of the GB power system is given in the legislation underlying operation of the system. The 1989 Electricity Act<sup>11</sup> lays out the objectives that the UK Secretary of State for Energy and Ofgem are required to meet. The high-level objective is “to protect the interests of existing and future consumers in relation to electricity” and it describes those interests as including both the “reduction of electricity-supply emissions of targeted greenhouse gases” and “the security of the supply of electricity”. Included within these objectives are two important points. Firstly, the need to ensure that “licence holders are able to finance [their] activities” and that direct consideration should be given to named groups of vulnerable customers: those who are chronically sick, pensionable, on low incomes and living in rural areas. These objectives reflect the importance of electricity in the economy and society. Similarly, the 2022 *British Energy Strategy* begins by stating that “Energy is the lifeblood of the global economy” and the Scottish Government’s 2019 vision for *Scotland’s Electricity and Gas Networks* states that “access to affordable and reliable energy underpins our society and economy”<sup>12</sup>. An effective electricity system is also important in delivering regional ambitions, both in terms of harnessing regional energy strengths – such as wind resources in Scotland, solar in Southern England and carbon storage potential off the east coast – and beyond the energy sector, for example in supporting regional economic strengths and opportunities. This has been recognized in recent work, for example a collaboration between Scottish Government, Ofgem, NGENSO and each of the energy network companies operating in Scotland in producing a set of principles for the development of Scotland’s gas and electricity networks<sup>13</sup>.

Box 1 gives an example of an overall objective statement for the electricity system. It remains focused on the energy trilemma through delivery of decarbonised electricity, security of supply and minimisation of cost in the medium to long term. However, the statement goes beyond cost to articulate various elements of wider

societal value such as the impact of the electricity system on the economy and natural capital, highlighting its role in delivering economic growth, fairness and support of regional strengths.

**Box 1: The articulation of GB electricity system used in this report**

Ensure that, by 2035, net production of greenhouse gases on the GB electricity system is negligible while supplying electrical energy with sufficient security and resilience at lowest total cost to energy users over the medium to long term.

In achieving this objective, reform of energy markets should consider their interaction with a wider set of economic, social and environmental policies and how development of the energy system makes the most of opportunities for the whole economy, ensures fair access to and affordability of energy, supports regional development across GB and is appropriately aligned with protection for natural capital and ecosystem services.

In setting out a broad overall ambition for electricity it is also important to note that these outcomes cannot be achieved only through electricity policy and regulation but need to work hand-in-hand with wider government, regulatory and investment levers well beyond the sphere of electricity. It is beyond the scope of this report to comment on wider tax, economic and social policy. However, it should be remembered throughout that these will remain important for delivering wider ambitions.

The target date of 2035 in the objective statement is an important part of the context for discussion of market reform. In their analysis of the Sixth Carbon Budget the CCC recommended that “the UK’s electricity production is zero carbon by 2035”<sup>14</sup> and in the accompanying analysis showed a Balanced Pathway that “very largely decarbonises electricity generation by 2030, and decarbonises it completely by 2035, with action thereafter focused on meeting rising demand with low-carbon generation.”<sup>15</sup> UK Government broadly accepted this recommendation in the 2021 Net Zero strategy committing to “fully decarbonise our power system by 2035, subject to security of supply.”<sup>16</sup> Thereafter, both the Government’s Net Zero Strategy and the CCC’s Balanced Pathway show a significant expansion of the electricity system to satisfy growing demand due to the electrification of much of our end use of energy.

The date of 2035 is important in that electricity production is seen as one area that can feasibly be substantially decarbonised by then, indeed, the IEA recommend that advanced economies should overall have net zero electricity by 2035<sup>17</sup>. Failure to meet this goal will mean that emissions must be reduced more quickly in other, more challenging sectors in order to comply with the 6<sup>th</sup> Carbon Budget. Also, although it is controversial and the capacity to do it without impacting on other aspects of land use is limited, the power sector offers the potential for negative emissions via biomass used in combination with carbon capture and storage to produce hydrogen or electricity.

There are many reforms that could help deliver a decarbonised electricity system by a later date but may struggle to deliver it in just 13 years. For example, part of the discussion about the potential benefits of LMP which are discussed in Sections 4 and 5 hinges on whether it is feasible to move significant capacity of on and offshore wind from Scotland to England or Wales. In terms of offshore wind, for instance, arguments have been made that the development of floating wind opens significant areas of seabed in the southern part of GB, although there will be significant constraints to overcome<sup>18</sup>. This may be true in the longer term, but the ability to deliver it by 2035 is likely to be limited.

## 1.5 The GB context – a decarbonised electricity system in 2035

Decarbonising the GB electricity system in line with current ambitions means moving from Britain’s current level of renewable contribution, around 37% of domestic electricity production in 2021, to around 80%<sup>iii19</sup> by 2035. This will need between 130 GW and 180 GW of installed capacity of wind and solar which implies an annual increase in capacity of between 7.5 GW and 10.5 GW per year. In addition to this, installation rates will also need to cover recommissioning or replacement of existing capacity that closes, both for variable renewable and schedulable generation. Figure 2 compares the installed GB generation fleet and peak demand of the system in 2021 with 2035 under the four NGENO Future Energy Scenarios (FES) published in 2022.

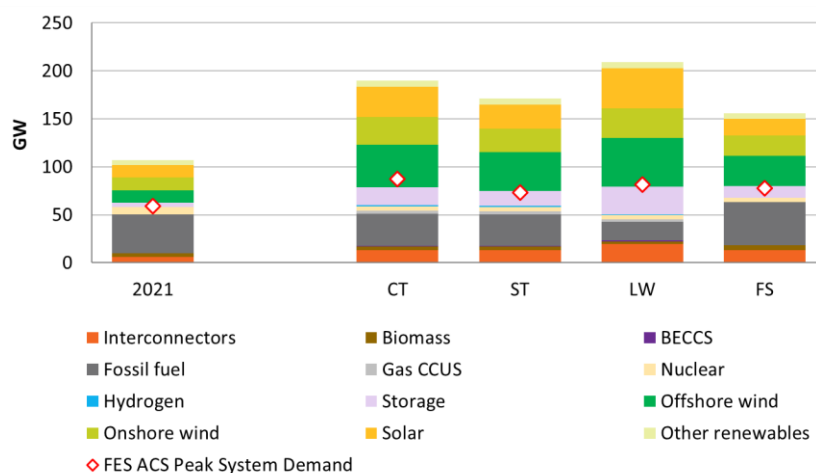


Figure 2: GB peak demand and installed generation capacity in 2021 and 2035 under the FES 2022 scenarios.<sup>20</sup>

Figure 3 breaks down the implied installation rate for renewable technologies by year and compares this with the historical trend. These two charts make clear the scale and pace implied by the 2035 target and the need to grow renewable capacity at a rate significantly faster than has been achieved historically. The historic trend peaked in 2015 with around 5 GW of new capacity added and has fallen significantly since (although emerging data for 2022 shows an upturn<sup>21</sup>).

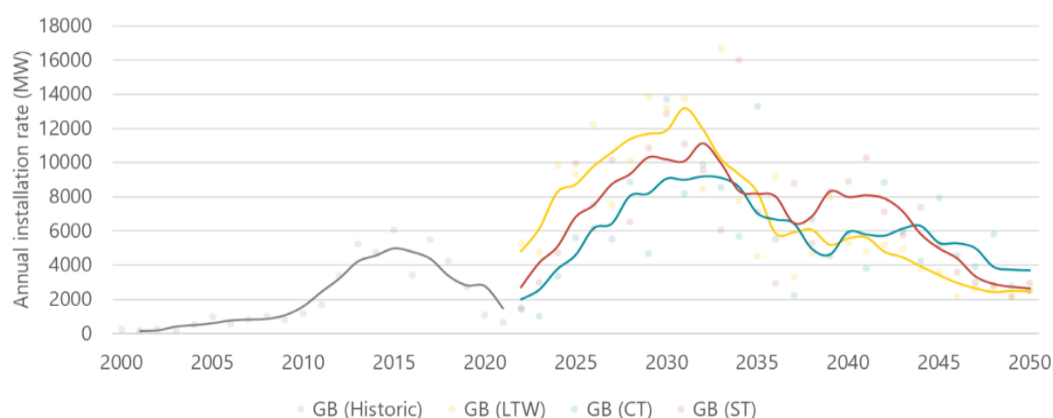


Figure 3: Installation rate of renewable technologies implied by FES 2022 scenarios and compared with the historic trend.<sup>iv 22</sup>

<sup>iii</sup> Data based on FES 2022 Data sheet ES. E07 – net zero compliant scenarios in 2035 range from 78 to 82% contribution from wind and solar to domestic generation.

<sup>iv</sup> Graph taken from Regen REMA response: Underlying data is (a) analysis of FES 2022 installed capacities and (b) Renewable energy planning database.

In the context of LMPs, the regional picture is also important. Understanding the potential balance between generation capacity, demand, ‘flexibility’ and transmission capacity is important in identifying the likely impact of transmission congestion. The border between Scotland and England represents the most important area of congestion both today and over the coming decade. A recent report showed that 3.5 TWh of wind generation was curtailed in 2020 and 2.3 TWh in 2021 – equivalent to 5% and 2% respectively of the total available. Scottish wind farms accounted for 94% of that curtailment in 2020 and 80% in 2021 due to network constraints<sup>23</sup> v. Table 2 lays out peak demand and installed capacities in Scotland in 2035 under the three net zero compliant FES 2022 scenarios. It shows a significant excess of generation capacity over demand and reflects the expected continued growth of on and offshore wind in Scotland.

Table 2: Scottish peak demand and generation capacity in 2035 under the net zero compliant FES 2022 scenarios.

	Leading the Way	Consumer Transformation	System Transformation
<b>Wind (GW)</b>	56.1	54.5	49.5
<b>Solar (GW)</b>	3.5	3.1	2.3
<b>Other renewables (GW)</b>	1.9	2.1	2.0
<b>Schedulable generation (GW)</b>	2.1	4.5	3.3
<b>Interconnection to other markets (GW)</b>	2.6	1.2	0.5
<b>Storage capacity (GW)</b>	7.0	5.7	3.1
<b>Peak Demand (GW)</b>	8.2	8.2	7.3

It is important to note that the FES modelling does not take account of transmission constraints, nor has it modelled the potential impact of LMP; rather, it reflects the potential development of the electricity system under current market arrangements and takes account of the existing pipeline of projects and locational factors outside beyond power system operation and planning. Many of the arguments for LMP explored below focus on finding an optimal mix of location for generation, demand and flexibility for a given configuration of transmission network. However, as discussed in the following sections, many stakeholders expect that, in order to deliver a decarbonised power system by 2035, the majority of wind capacity in Scotland postulated in the FES will still need to be located there. One interviewee for this report commented on the limited timescale noting that “the wind resource is where it is and where it's been possible to get planning. We need to mostly have decarbonised power by 2035. We've got a 10-year development timescale, so if you change your mind today, you might [just] possibly affect a wind farm being located to come on in 2035” whilst another indicated that “I expect that you will still need that capacity in Scotland”.

A further important part of the context is to understand how the operation of different market participants will work together. For example, in understanding the characteristics we need from flexibility, it is important to have a view of the structure of periods of excess and shortfall of renewables relative to demand at those times. To help the reader understand this Figure 4 gives an illustrative comparison of demand with solar and wind availability for GB across a full year in 2035 under the Leading the Way FES 2022 scenario. It shows that available renewable generation will exceed demand for significant periods of the year. That excess can be exported (GB interconnection capacity is 24.6 GW in the Leading the Way FES 2022 scenario and NGENSO models peak coincident export flow to be 16.3 GW) or used by flexibility (battery storage, time-shifted

<sup>v</sup> Absolute curtailment levels were taken from the LCP report referenced and total available GB wind generation was calculated from BEIS Energy Trends database.

demand, or new flexible demand such as electrolysis). It also shows the total demand for electrical energy in the course of a year and the total energy available from wind and solar generation<sup>vi</sup>.

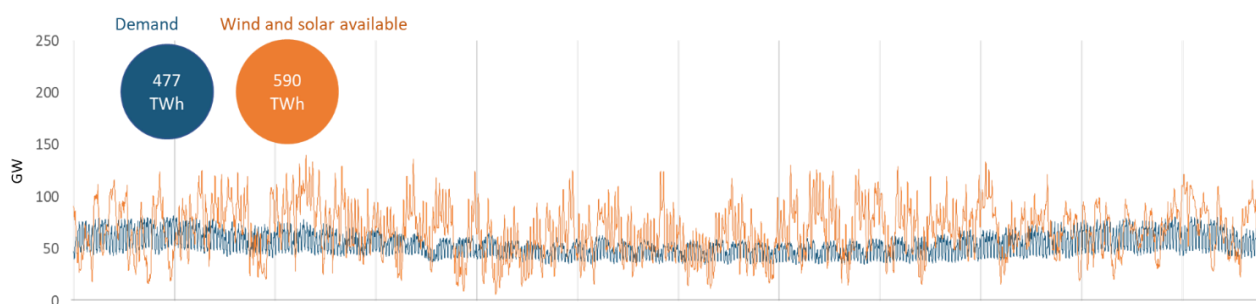


Figure 4: Illustrative time series for availability of power from GB variable renewables and underlying electric power demand in 2035 under the Lead the Way scenario from FES 2022. The circles indicate the annual demand for electrical energy and the energy available from wind and solar.

Figure 5 provides an equivalent graph for Scotland and highlights the significant level of excess generation over and above Scotland's own demand. Use of any excess depends on the ability to export power from Scotland to the rest of the GB market or to other, interconnected markets. The 2021 *Electricity Ten Year Statement*<sup>24</sup> estimates that, based on plans laid out in the 2020/21 *Network Option Assessment*<sup>25</sup> (NOA), the ability of the transmission network to export power to England and Wales would be around 16 GW in the mid-2030s. This value is expected to rise reflecting the 2022 NOA Refresh report<sup>26</sup> along with the Holistic Network Design<sup>27</sup>. As with the GB-wide case, there remains significant excess generation which could be used by interconnection, storage, time-shifted demand and electrolysis.

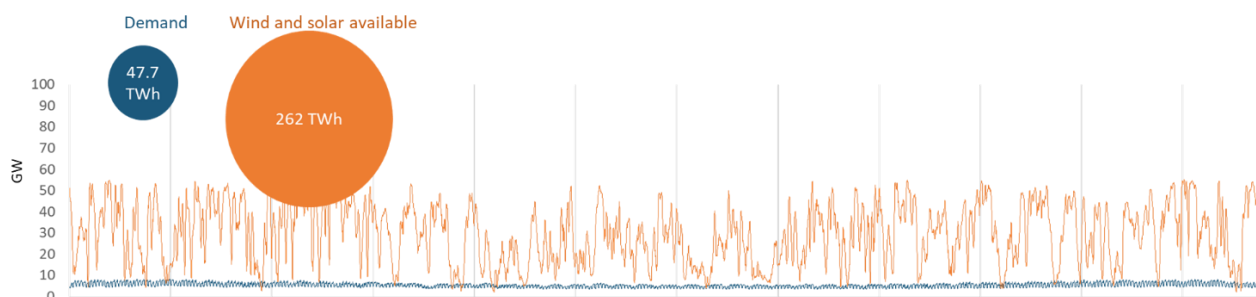


Figure 5: Illustrative time series of renewables availability and electricity demand in Scotland in 2035 under the Leading the Way scenario.

Figure 6 gives an illustration of the potential pattern of excess renewable availability in Scotland in 2035 considering the time series shown in Figure 5 and expected transmission capacity. Any period of excess generation represents an opportunity for flexibility and new demand. It will be important to consider the degree to which it is physically, technically and commercially feasible for flexibility to deliver. For example, the profile in Figure 6 suggests that there could be limited opportunity to discharge renewables when constraints are not binding.

<sup>vi</sup> The time series presented in Figures 4 and 5 are illustrative. They are derived as follows. **Demand:** Half hourly historical 2019 (pre-pandemic) demand is scaled to match FES scenarios' peak demand and total energy demand. **Generation:** hourly wind farm and solar farm capacity factor time series were extracted from modelled data published by researchers at Imperial College London and ETH Zurich through renewables ninja. Data for multiple sites across England, Wales and Scotland were combined to give an aggregate generation time series. This was then scaled to match the installed capacity in the FES scenarios.

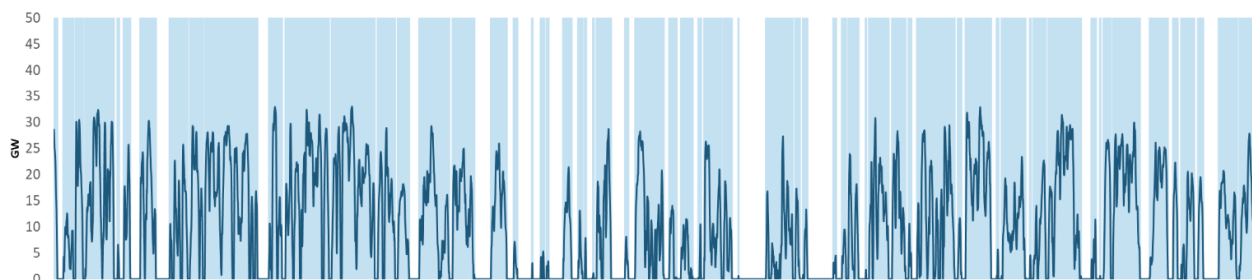


Figure 6: Illustrative time series of excess Scottish renewable generation for 2035 under Leading the Way. Excess generation is defined as renewable availability remaining after meeting Scottish demand, export to England and Wales within transmission constraint limits (16 GW export boundary capability) and export over interconnection. Excess is either available for use by storage and flexible or new demand, or would need generation production to be curtailed.

One of the key drivers for the development of renewables ahead of transmission capacity was the introduction of ‘connect and manage’ for transmission access on an interim basis in 2009 and an enduring basis in 2010. This moved away from the preceding ‘invest and connect’ model under which generators had to wait for relevant reinforcement of the wider network to be completed leading to a substantial queue of prospective generators. The UK Government’s objectives in making this decision were threefold: provide sustained, commercially viable connection with firm data to support investment in new generation; support security of supply; and help meet renewable aspirations for 2020<sup>28</sup>. Under connect and manage generators can connect before wider works are completed, it in effect allows generation to connect ahead of transmission build out. The Government response to the 2010 Connect and Manage consultation also highlighted the expectation that new transmission capacity would continue to be delivered in a timely and efficient manner.

## 1.6 Flexibility on a power system

The case for changing wholesale market arrangements made by UK Government, NGENSO, Ofgem and others often cites the importance of ‘flexibility’ as a key enabler of a zero-carbon electricity system. As part of that, the anticipated growing importance of flexible demand and energy storage is often emphasised. However, in many cases, the discussion fails to define ‘flexibility’, the variety of roles that it will play or the full range of different sources and their respective characteristics. This section discusses flexibility and what it means for a power system.

### 1.6.1 Why are we now so interested in flexibility?

Flexibility in an electricity system based largely on variable renewables is extremely important. Wind droughts – periods with low wind speeds and wind fleet capacity factors of less than around 10% – and the potential for them to occur at times of high demand and last for a number of days are a key challenge for the design of electricity sector commercial and regulatory arrangements. Long wind droughts give rise to a need for, on a GB-wide scale, tens of TWh of energy during such conditions from somewhere other than wind production. Historically, flexibility on the GB system has largely been provided by fossil fuelled generators, particularly mid- and low-merit Combined Cycle Gas Turbines (CCGTs) and coal plant. Low efficiency peaking plant such as Open Cycle Gas Turbines (OCGTs) has provided additional capacity margin. Schedulable low carbon generation such as nuclear power or use of natural gas with carbon capture and storage (CCS) can play a part. However, neither gas with post-combustion CCS nor nuclear plant are typically expected to provide flexibility. Inflexible plant increases the surplus of low carbon energy available during windy periods and has limited ability to ramp up and down to match demand during wind droughts.

As the use of unabated fossil fuels is reduced, the electricity system will need new sources of flexibility. Flexible uses of electricity, such as EV charging, could offer a significant body of demand that can vary controllably in time. However, flexible sources of energy and energy storage are also likely to be essential.

Potential new energy sources include interconnector imports and flexible, schedulable generators using sustainable sources of biomass. The stored forms of energy could include new long duration storage technologies and hydrogen manufactured from low carbon sources, such as electrolysis during periods of surplus power availability.

The key point is to have enough of such resources, and for them to be sited in places that can utilise surpluses, have access to suitable stores, and can be made use of from a range of locations across the electricity network.

### 1.6.2 What is flexibility and how can it be accessed?

Flexibility could be seen broadly in terms of

- (i) scheduling of energy production to match forecast variations of demand, or scheduling of demand to match variations in the availability of generation; and
- (ii) use of spare power capacity – active or reactive power – to respond to unexpected variations in system balance<sup>vii</sup>.

It might also be seen in terms of the flexibility to locate a particular resource in any given location. However, although ‘flexibility’ is often framed as an alternative to network capacity, network capacity has the potential to provide access to resources in different places that are able to change generation or consumption and contribute to whole system balancing, i.e. to facilitate ‘flexibility’.

‘Efficient’ scheduling of production and consumption has normally been expected to be determined or incentivised through energy markets with adjustments through balancing mechanisms. Spare power capacity – ‘headroom’ or ‘footroom’ to allow responses to variations in system frequency or voltage – has been procured by system operators as ancillary services.

Proponents of wholesale energy market reform believe that signals in today’s largely decentralised British wholesale market are insufficient to provide enough offering of flexible energy production or use in the right locations, or to ‘efficiently’ utilise the flexibility that is on the system.

Present day GB wholesale market arrangements do provide opportunities for flexibility of energy production and use. Portfolio operators of generation can schedule thermal plant within their portfolio to complement the availability of, in particular, variable renewable generation in meeting their forward bilateral contracts and power exchange trades. In respect of those contracts, parties might also trade with each other, making use of resources outside of their portfolio, to provide an overall best fit with the availability of zero marginal cost generation and obligations to provide specific volumes of energy in particular periods. Most remaining imbalances in the last 60-90 minutes before physical delivery are corrected by the System Operator’s acceptance of offers of or bids for energy in the Balancing Mechanism, the rest being dealt with through frequency regulation or containment ancillary services. However, it might be argued that a more efficient overall scheduling and utilisation of resources – and, thus, lower overall cost of electrical energy and electricity system related infrastructure – could be achieved through centralised scheduling and dispatch arrangements.

---

<sup>vii</sup> ‘Power’ is the rate of production, conversion or use of energy. ‘Active power’ concerns energy that can finally be converted into useful services such as heat, light, motion or the powering of electronic devices. ‘Reactive power’ is a concept developed by power systems engineers to represent the effect of any element on or connected to an AC (alternating current) power system in causing current to ‘lead’ or ‘lag’ voltage. This results in the ‘active power’ available for use from a current of a particular magnitude being reduced, and either a demand for or surplus of ‘reactive power’. This must be balanced by sources or sinks of reactive power appropriately distributed across the system. Moreover, there must be a minimum provision of flexible sources or sinks as the demand for reactive power can change considerably across the system and in specific locations as conditions change, such as due to changes in active power flows or faults on the network. Such flexible sources or sinks include synchronous machines used as generators in thermal and hydro power plant, ‘voltage source converters’ used in newer HVDC interconnectors, modern wind turbines and ‘static VAR compensators’, ‘synchronous compensators’, and switchable banks of capacitors or inductors.

### 1.6.3 Demand-side flexibility

A criticism often made of present-day market arrangements in GB is that there is too little participation in both forward and real-time balancing by the demand side. There are several reasons why this could be the case: a lack of strong price signals, an inability to measure – and, hence, reward – flexibility, or a lack of demand that is able to flex in time.

Different forms of flexibility from demand can be envisaged, involving planned shifts in time, responses to unplanned events or reductions of demand (sometimes referred to as ‘demand destruction’ through foregoing a particular service provided by energy). We suggest a taxonomy of different ways of managing demand, shown in Figure 7.

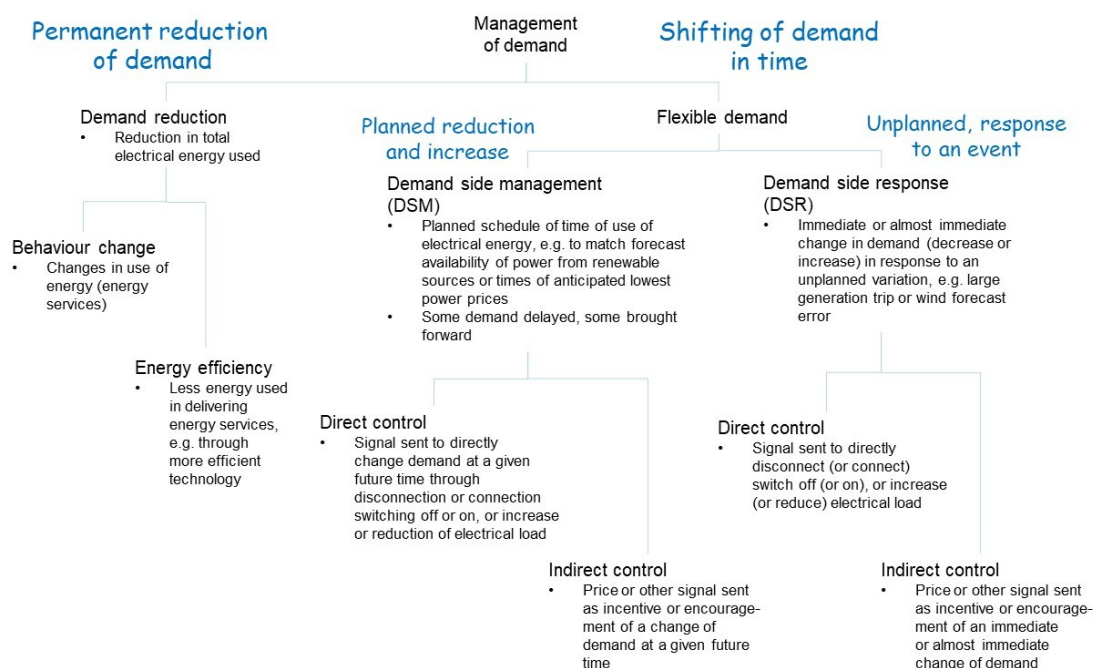


Figure 7: A taxonomy of ways of managing demand for electricity

The introduction of market-wide half-hourly metering (expected by 2025<sup>29</sup>) is likely to be an important enabler for demand side flexibility. Such metering may be sufficient to measure the relevant changes in demand from a baseline pattern and make it possible for increasing amounts of demand to offer and be rewarded for flexibility. The growing use of electric vehicles and electrified heat in well-insulated buildings should bring more demand onto the system that is capable of being flexed with minimal adverse impacts on energy users.

### 1.6.4 Flexibility over different timescales

The need for flexibility can be seen over different timescales from seconds and milliseconds in responses to loss of infeed or loss of demand events, through to minutes and hours as demand and the availability of generation change, and days to years in meeting daily or annual peak demand. As demand and availability of generation change, the prices at which the marginal source of energy is bought and sold changes. In principle, any energy market that articulates distinct prices for different periods of time can encourage ‘flexibility’ and provide incentives for production, imports or discharging of storage to be moved in time to exploit high prices, and demand, exports and charging of storage to move to take advantage of lower prices.

In addition to the wholesale energy market there is an important role for procuring flexibility through ancillary services. This covers situations where it is not possible for the wholesale market to articulate prices, deliver an energy balance and ensure continuous operability of the system. This can happen when either the

time-granularity for flexibility is smaller than is possible to achieve in the wholesale market, the notice period of the need is very short, there is a highly non-linear relationship between energy production and operation of the system, such as in the case of voltage control and reactive power, or the particular energy service is used so rarely that a competitive price is difficult to discover, such as in the case of support for system restoration.

In order to incentivise the tracking of demand variations down to timescales of minutes, there is the potential to reduce GB's current half-hour settlement period, such as following Australia's example of moving to a 5-minute settlement period. Adjustments on the scale of seconds will likely still require ancillary services such as automatic frequency regulation reserve<sup>viii</sup>. However, there is also the need for flexibility to respond following a fault such as the disconnection of a large power station, interconnector or consumer. In this situation sufficient flexibility – frequency containment and restoration reserves – must be available and capable of responding with a very short notice period (automatically and within tens of milliseconds in the case of frequency containment reserve).

### 1.6.5 Capacity adequacy – a specific type of flexibility

Over investment timescales, a key concern for policy makers, regulators and system operators has been what is commonly referred to in the US as 'generation adequacy', i.e. is there enough generation available at time of peak demand to meet that demand sufficiently reliably? In practice, it is not just generators that can meet peak demand and contribute to adequacy but also discharging of energy stores, imports via interconnectors and shifting or reduction of demand. Thus, in this report we tend to refer to 'capacity adequacy' rather than 'generation adequacy'<sup>ix</sup>. Although often separated from other flexibility considerations, capacity adequacy is an important element of long-term flexibility procurement. 'Scarcity pricing' has a particular role to play in encouraging capacity adequacy

### 1.6.6 Dimensions of 'flexibility'

A variety of different resources, including low carbon resources, might provide 'flexibility'. We summarise a number of these in Table 3 in relation to some key characteristics:

- **Agility:** the ability to adjust production or consumption quickly and at short notice.
- **Schedulability:** the extent to which the resource can be scheduled, with confidence, to produce or consume power at any given time on a given day up to a few weeks in the future.
- **Persistence:** a particular level of production or consumption can be sustained for a period of time, i.e. energy not just power can be relied on.

It should be noted that variable renewable generation is able to provide some of the required features listed in Table 3.

'Locatability' – the degree to which the developer of a particular resource can choose to locate it anywhere – might be regarded as a further key feature. However, all but a few of the resources listed in Table 3 face comparable challenges. For example, all depend on there being sufficient network capacity for the resource to be usable; all require planning permission, which is always uncertain. Particular natural resources are

<sup>viii</sup> Reserves that respond automatically to variations in frequency are often called 'frequency response' in Britain.

<sup>ix</sup> In 2018, CIGRE Working Group C1.27 on "The Future of Reliability" defined 'adequacy' as "A measure of the ability of a power system to meet the electric power and energy requirements of its customers within acceptable technical limits, taking into account scheduled and unscheduled outages of system components, where: power system includes all elements of the generation, transmission and distribution systems, and customer facilities that supply or use power and energy, or provide ancillary services; customers include all parties that supply power and energy or ancillary services, as well as those who consume them; requirements of customers include their basic power and energy needs, and agreed use of customers' ability to vary power supply, adjust demand and provide ancillary services; acceptable technical limits and scheduled and unscheduled outages are those specified in the applicable planning criteria and standards; and system components include all elements of the supply, delivery and utilization systems regardless of ownership or control."

required that are available to varying extents in different places: high wind speeds, high solar radiation; access to cooling water; high rainfall. And many of the resources depend on other infrastructure: a supply of natural gas, biomass or hydrogen; transport and storage of CO<sub>2</sub>; the nature of electricity production in another country. The amount of flexible demand that is available is also very location specific. However, network capacity can reduce the overall system's location dependency by providing access to flexible generation, demand, storage or interconnection connected in different places.

Table 3: Dimensions of flexibility for different low carbon resources

	<b>Agile?</b>	<b>Schedulable?</b>	<b>Persistent?</b>
<b>Wind</b>	If it's windy, yes	No	Sometimes
<b>Solar</b>	If it's sunny, yes	No	Sometimes, but limited to daylight hours for solar PV.
<b>Nuclear</b>	No, not really	Yes, for the most part	Yes
<b>CCGT burning blue or green hydrogen, or biomass from sustainable sources</b>	Yes	Yes, for the most part	Yes, if fuel is available
<b>CCGT burning natural gas with CCS</b>	Perhaps, but at a cost	Yes, for the most part	Yes, if fuel is available
<b>Batteries charged using low carbon energy</b>	Yes	Yes, for the most part	To an extent, if power is rationed
<b>Pumped hydro</b>	Yes	Yes, for the most part	Only if power is rationed
<b>Flexible demand</b>	Yes	Depends on what it is	Not beyond a few hours?
<b>Interconnection with low carbon resources in other countries</b>	Yes	Yes, for the most part	Yes, depending on conditions at the far end

### 1.6.7 Low carbon provision of ancillary services

The different resources included in Table 3 are also able to provide different ancillary services which, as discussed above, are used to provide flexibility and maintain operability of the system where the wholesale energy market itself fails to provide adequate signals.

We provide a summary of our understanding the capability of each flexible resource to deliver key ancillary services in Table 4.

Income for the provision of these services can be an important complement to revenues from production or trading of energy for many market participants. These revenue streams should be considered alongside broader wholesale market reform options such as LMP. In many cases, delivery of ancillary services depends on agility, in respect either of active or reactive power, sustained over only short periods of time.

Of the various ancillary services, the value of frequency management reserves is not generally location specific. However, network constraints might prevent it from being used in certain places. The value of all the others is location specific. Revenues from location-specific services might go some way to offsetting risks arising from locational pricing of energy, though this cannot be guaranteed.

As can be seen from Table 4, low carbon resources – including wind and solar – do have the ability to provide a number of both system-wide and location-specific ancillary services. However, if wider energy market arrangements disincentivise them from siting at particular places, they would obviously not be able to provide location-specific ancillary services there.

The concept of 'residual demand', i.e. the demand remaining to be met after utilisation of the power available from variable renewables, can be useful in framing a discussion on flexibility. One issue concerning flexibility that should not be overlooked is the potential for significant ramps of residual demand, e.g. if demand is increasing at the same time as wind output is reducing. Energy trading settlement periods of an hour or 30 minutes – in which trades are made based on the total energy produced or consumed in that period, with little or no reference to the time series profile of power within that period – might not be sufficiently short to encourage close matching of the rate of change of schedulable energy production or consumption to changes in the residual demand. Shorter settlement periods, such as 5 minutes as used in the National Electricity Market in Australia, or a specific ramping ancillary service product such as has been proposed for the market on the island of Ireland<sup>30</sup>, might be required.

Table 4: Ancillary service capability of different resources

	<b>Frequency regulation reserve</b>	<b>Frequency containment reserve</b>	<b>Fast frequency containment reserve</b>	<b>Frequency restoration reserve</b>	<b>Voltage regulation and reactive power</b>	<b>Short circuit current</b>	<b>Blackstart capability</b>	<b>Contribution to later stages of a restoration process</b>
<b>Wind</b>	Only under windy conditions; requires deloading* and some of the available energy being unutilised	Only under windy conditions; some kinetic energy can be extracted from the rotating mass to provide some response without initial deloading. For larger response, requires initial deloading and some of the available energy being unutilised	Only under windy conditions; some kinetic energy can be quite quickly extracted from the rotating mass to provide some response without initial deloading. For larger response, requires deloading and some of the available energy being unutilised	Only under windy conditions; requires initial deloading and some of the available energy being unutilised	Can contribute; the extent of capability is inversely proportional to the level of wind power production at the time.	To no significant extent unless designed with an over-sized converter	No practical capability	Only under windy conditions.
<b>Solar</b>	Only under sunny conditions; requires deloading and some of the available energy being unutilised	Only under sunny conditions; requires deloading and some of the available energy being unutilised	Only under sunny conditions; requires deloading and some of the available energy being unutilised	Only under sunny conditions; requires deloading and some of the available energy being unutilised	Can contribute; the extent of capability is inversely proportional to the level of wind power production at the time.	To no significant extent unless designed with an over-sized converter	No practical capability	Only under sunny conditions.
<b>Nuclear</b>	With appropriate design and deloading with some of the available energy being unutilised, some can be provided	With appropriate design and deloading with some of the available energy being unutilised, some can be provided	Provides an inertial response	Requires initial deloading and some of the available energy being unutilised	Can be provided if the plant is synchronised.	Can be provided if the plant is synchronised.	No capability	No capability
<b>CCGT burning blue or green hydrogen</b>	Can be provided with appropriate deloading.	Can be provided with appropriate initial deloading.	Provides an inertial response	Can be provided with appropriate initial deloading.	Can be provided if the plant is synchronised.	Can be provided if the plant is synchronised.	Can contribute	Can contribute
<b>CCGT burning natural gas with CCS</b>	With appropriate design, can be provided with appropriate deloading.	With appropriate design, can be provided with appropriate initial deloading.	Provides an inertial response	With appropriate design, can be provided with appropriate initial deloading.	Can be provided if the plant is synchronised.	Can be provided if the plant is synchronised.	No capability	Unlikely to be any capability

	Frequency regulation reserve	Frequency containment reserve	Fast frequency containment reserve	Frequency restoration reserve	Voltage regulation and reactive power	Short circuit current	Blackstart capability	Contribution to later stages of a restoration process
<b>Batteries</b>	Can be delivered provided there is an appropriate initial state of charge.	Can be delivered provided there is an appropriate initial state of charge.	Can be delivered provided there is an appropriate initial state of charge.	Can be delivered provided there is an appropriate initial state of charge.	Can contribute; the extent of capability is inversely proportional the level power charging or discharging at the time.	To no significant extent unless designed with an over-sized converter.	Can be delivered provided there is an appropriate initial state of charge.	Can be delivered provided there is an appropriate initial state of charge.
<b>Pumped hydro</b>	Can be delivered provided there is an appropriate initial water level.	Can be delivered provided there is an appropriate initial water level.	Provides an inertial response if the machine is synchronised.	Can be delivered provided there is an appropriate initial water level.	an be provided if the plant is synchronised.	Can be provided if the plant is synchronised.	Can be delivered provided there is an appropriate initial water level.	Can be delivered provided there is an appropriate initial water level.
<b>Flexible demand</b>	Not so far tested.	Low frequency response can be readily provided via suitable automatic actuation.	In principle, fast low frequency response can be readily provided via suitable automatic actuation.	Can only be provided via 'demand destruction'.	No capability	No capability	No capability	With suitable control, can be provided
<b>Interconnection</b>	Can be provided with appropriate deloading.	Can be provided with appropriate initial deloading.	Can be provided with appropriate initial deloading.	Can be provided with appropriate initial deloading.	Can contribute; the extent of capability is inversely proportional the level of power import or export at the time.	To no significant extent unless designed with a voltage source converter and an over-sized converter.	Can be provided by a voltage source converter with appropriate deloading.	Can be provided by a voltage source converter with appropriate deloading.
<b>Synchronous compensators</b>	Cannot be provided.	Cannot be provided.	Can be provided only through inertial response.	Cannot be provided.	Can be provided.	Can be provided.	Energy cannot be provided; can help with voltage control.	Energy cannot be provided; can help with voltage control.

\* Deloading here means that the set point of power production is lower than the maximum output that could be delivered at that time.

# The structure and operation of LMP markets

## 2 The structure and operation of LMP markets

This section describes and discusses the main components and concepts associated with LMP markets. The importance of each element varies between systems, however there is enough commonality that a 'standard model' has been identified with most components appearing in some form in current LMP markets around the world. A version of such a standard model is shown in Figure 8. It is based around two LMP markets: one a day ahead forward and financially firm market, the other a real time physically firm market.

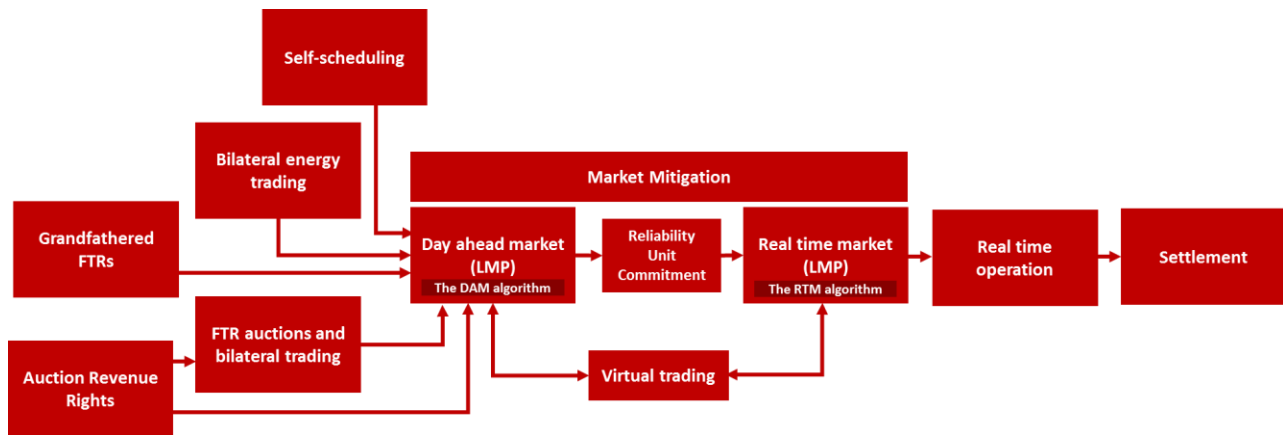


Figure 8: Key elements of a typical LMP market

The underlying principle of LMP markets is well known: the market sets prices at each individual location on the network separately, with those prices reflecting the marginal price of meeting demand at each location. Therefore, as well as capturing the system-wide marginal cost of generation LMPs also reflect the cost of electrical losses and congestion on the network, which may mean that additional demand at a certain place cannot be served by the cheapest available generation on the system. Whilst the high-level concept is simple, as with all electricity markets, the design of a real-world LMP-based market is complex. When considering the pros and cons of each market structure it is important to have an appreciation of how they operate in practice.

Complexity in electricity markets is, to some degree, inevitable. Firstly, electricity markets need to be resilient against a wide range of credible but unexpected events and to do so in the face of uncertainties in forecasting conditions across timescales of minutes, hours or days. At the same time markets need to support investment in a diverse mix of technologies and infrastructure, much of which takes years to deliver and has significant up-front capital cost which can take decades to recover. A related point is that any market structure inherits a legacy mix of generation technologies, network topologies, existing long-term contract commitments and expectations. New market frameworks rarely, if ever, have the ability to wipe the slate clean and start with a brand-new set of rules and regulations.

The day ahead and real time LMP markets might be described as aiming to deliver an economically efficient dispatch of generation, ensuring that demand is met at lowest marginal cost in line with standard economic theory about commodity trading. However, surrounding these two linked markets are a range of structures which help support other objectives equally important for the operation of electricity systems: adequate and secure supplies and the need for longer term (longer than day ahead) contracts to support investment and hedge risk for the longer-term system. This includes the use of Financial Transmission Rights (FTRs), discussed later in this report, in Section 2.7.

The remainder of this section lays out the key concepts important in an LMP market and describes each of the elements shown in Figure 8. This is not intended to be an LMP textbook, rather it provides a high-level

explanation and a short discussion highlighting aspects that may be important when considering the potential for LMPs in the GB context<sup>x</sup>.

## 2.1 High level characteristics of an LMP market

Before describing the detailed components of an LMP market, it is worth considering some of their wider characteristics. These set the framework within which market participants operate and how they aim to combine energy operation and revenues with their wide business cases:

- **Dispatch of resources to meet demand is done centrally:** LMP markets operate using centrally managed optimisation tools to determine ‘cost optimal’ (within the limits of the algorithms used) dispatch of generator outputs and settings of flexible demand and storage based on bids and offers submitted by all market participants.
- **There is a requirement to participate in central dispatch:** although there are options to opt-out of economic bidding and ‘self-schedule’, it is mandatory for all participants above a certain size to participate in the central dispatch and to receive or pay the LMP clearing price for their energy. Bilateral trading arrangements are used in LMP markets but must work around this requirement.
- **System access rights are non-firm:** unlike current GB arrangements, generators and flexibility providers in LMP-based markets do not receive firm rights to access the system. Rather, the right to inject or withdraw power is granted temporarily only when participants are dispatched ‘on’ by the central algorithm either in the day-ahead or real time market.
- **Day ahead dispatch is financially firm:** if dispatched ‘on’ in the day-ahead market the financial commitment is firm. However, participants can buy their way out of that obligation in the real-time market which typically closes around one hour before delivery.
- **Congestion rent accrues to the ISO and needs to be redistributed:** when networks are congested in an LMP market, demand pays more to the ISO, acting as the central market operator, than the ISO pays out to generation. The residual is known as congestion rent. LMP markets generally specify mechanisms to return that rent to consumers given that they have, in most existing LMP markets, paid the costs of the transmission infrastructure through network charges.
- **Market designs should normally incorporate financial tools for hedging risk within the centralised structure:** in most LMP-based markets these include FTRs which pay out the difference in price between two nodes if there is congestion between them, and virtual trading which provides a route to hedge differences in price between the day ahead and real time markets.
- **LMP markets should dispatch reserve as well as energy:** in addition to prices for the generation or consumption of energy, market participants submit bids and offers to provide reserve services together with the technical parameters to describe their capabilities. The LMP algorithm can then solve to optimise dispatch of reserve as well as energy. Other ancillary services such as voltage support and black start provision remain as separate markets.

## 2.2 What is LMP and what is it not?

In addition to the high-level statement given above, there are several ways in which a locational marginal price can be described:

1. As the dual variables (or shadow prices) of the energy balance constraints in an energy optimisation problem. Values of the dual variables reflect how the objective function – typically, the total cost of meeting total demand, subject to various pre-defined constraints – alters with a change in the value

---

<sup>x</sup> For a more extensive textbook introduction to LMP-based markets, see, for example, Stoft, S., *Power System Economics*, Wiley-IEE, 2022,

of a particular main (primal) variable. The optimisation could be a single ‘snapshot’ optimal power flow based on a full ‘AC’ representation of the network or a ‘DC’ approximation, a multi-period optimal power flow or a more complex optimisation that includes elements of unit commitment<sup>xi</sup>. Although technical, this is an important conceptual point as the prices used in LMP markets are derived directly from the optimisation algorithms used and so depend on how exactly those algorithms are set up.

2. Instead of a single value, an LMP is often decomposed into three components:
  - **Energy component:** the marginal system price if there were no network constraints or losses
  - **Losses component:** the marginal cost of meeting additional losses created by serving the next MW of demand at each node. The losses component can be negative if additional demand reduced system losses
  - **Congestion component:** the variation in LMP caused by limits on the transmission network meaning that out-of-merit generation is needed to meet demand at some location.

This decomposition is useful in making clear what is driving costs at a particular node, and it is important in some specific market mechanisms, notably FTRs, which pay out based on price differences between nodes; these are usually defined based on the congestion component of the LMP but not the losses.

It is also important to understand what the LMPs do not include. In standard LMP markets, the prices bid and offered by market participants tend to be based only on marginal *energy* cost rather than on other operating costs such as start-up and shut down costs or no-load costs. As such there are often significant additional costs that some generators face which might not be covered by the revenues and infra-marginal rents flowing from the LMP market. The conventional way of covering these costs is through bilateral ‘make whole’ payments from the Market Operator to the generator. These can be opaque and are not published as individual transactions as to do so would effectively make public the private costs of individual generators.

More recently, attempts have been made to introduce mechanisms to improve cost reflectivity of the LMP markets themselves, for example by making adjustments to the algorithm or allowing start-up costs to be included within energy offers for multiple time periods (See Section 2.3). Box 2 lays out an example.

---

<sup>xi</sup> The term ‘unit commitment’ refers to the process of determining which generation units to commit as operational and therefore available to meet demand. A committed unit has to operate within its own physical constraints, for example above a minimum output level, and committing a unit involves specific costs such as start-up costs that are not related to its energy output.

**Box 2: Non-energy costs and uplift payments**

In the real time market four generators are dispatched to run to meet demand as shown in Figure 9. Units 1 and 2 are dispatched at their full output as the cheapest generators. Without any limitations caused by minimum output levels Unit 3 would also be fully dispatched and Unit 4, partially dispatched, would be the marginal generator.

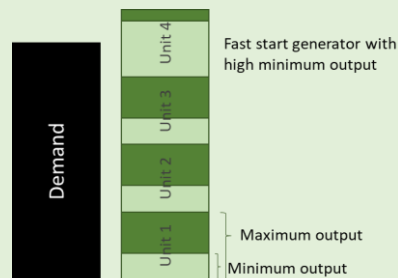


Figure 9: unit dispatch with minimum output constraints.

Unit 4 offers energy based on its marginal energy cost, consisting mainly of fuel cost and some variable operation and maintenance (O&M). However, it has a minimum generation level that is higher than the additional energy that is needed to balance supply and demand if Unit 3 is fully dispatched.

To balance supply and demand, Unit 4 is dispatched 'on' at its minimum generation level and the next-most expensive generator that has flexibility has its output reduced to balance supply and demand. This leads to a situation where:

1. Unit 4 is the most expensive unit on the system, but it is not the marginal unit. An additional unit of demand would be met by an increase in the output of Unit 3 which has been dispatched lower than its maximum output to make headroom for Unit 4.
2. As Unit 3 is the marginal generator, its offer sets the price and the market revenue to Unit 4 is below its marginal energy costs.
3. In addition, the start-up costs incurred by Unit 4 (which were not included in its offer) are not covered.

The result is that the LMP does not cover legitimate costs associated with the operation of Unit 4. LMP market arrangements tend to allow these costs to be recovered from the market operator through private payments often referred to as make-whole or uplift payments.

Alternative strategies for LMP market design which have been trialled include:

1. **A separate pricing run:** Re-running the LMP algorithm without generator 'minimum generation level' constraints would lead to a situation where, within the LMP model, Unit 4 is the marginal plant and sets the LMP. Whilst the dispatch would be 'wrong' because it doesn't respect real-world physical constraints, the prices are a more intuitive match for the real-world situation with the most expensive plant (rather than the marginal plant) setting the price.
2. **Allow start-up costs to be included in the energy offers:** In addition to minimum output levels, Unit 4 will also likely specify a minimum-run time. Rules in LMP markets could be updated to encourage start-up costs to be included separately alongside energy offers. These costs can be split across each settlement period within the minimum-run time and added on to the energy offers made by the generator. This would ensure that the generator's final offer in the market takes account of both energy and start-up costs. Assuming that the generator is dispatched for at least its minimum run time (which an effective multi-period optimisation should deliver) it will have recovered all of its start-up costs.

### 2.3 The LMP algorithm

As noted above, optimisation algorithms are central to the working of an LMP market. However, it is rarely as straightforward as choosing 'an' optimisation approach. Rather the algorithms used tend to include a multi-stage workflow which lead to the final dispatch and prices of both energy and reserve. Different

approaches may be used in optimisations and the workflows used are often significantly different between the day ahead and real time markets.

Design choices for the algorithm or algorithm workflow include:

- How is the network represented: through a DC or AC model? And if using a simplified DC model, how are voltages managed in the final dispatch?
- How is 'unit commitment' considered? For example, is a separate generation unit commitment run first to define which units are available to pass to the algorithm which sets the dispatch and prices, or is the main algorithm itself extended to include unit-commitment variables within the main optimisation?
- How are multi-period constraints such as ramp rates and minimum run times managed? Is the algorithm inherently 'multi-period' in which case it optimises for multiple settlement periods at once, or is a single-time step algorithm used with separate processes for checking the consistency between time steps?
- Are prices set by the same optimisation as dispatch? Or, as is applied in a number of LMP algorithms, is a 'relaxed' run used to set prices and a 'constrained' run used to set the dispatch, the difference being that the relaxed run may provide a better intuitive indicator of the price but would not be consistent with all real constraints that the physical dispatch must constrain. (See Box 2).

Each market has its own bespoke algorithm and optimisation workflow which reflects its history, the preferences of market participants and the physical characteristics of the system. For example, the need to dispatch energy storage, a technology which inherently needs a 'multi-period' optimisation to be dispatched appropriately, is driving several market operators to revisit their approach to dealing with multi-period constraints.

To the extent that the algorithm used in an LMP market determines the setting of frequency containment and restoration reserves and voltage and reactive power targets it addresses significant aspects of ancillary services needs. If only a DC approximation of the network is used the optimisation of voltage and reactive power cannot be an inherent part of the algorithm.

Algorithms used today also don't optimise against uncertainty, although there is the potential in future to build in stochastic optimisation approaches. These could dispatch the system not just to minimise the objective function for a given set of input variables, but also minimised the *expected* value of the objective function subject to the uncertainty in those input variables.

Figure 10 shows an outline of the process used in the PJM market in the Eastern US to dispatch the Day ahead Market and real time markets. This shows how PJM relies on several modules for solving both markets which interact in different ways. For example, at the day ahead stage a unit commitment algorithm is first run which identifies which units to dispatch as 'available' for each of the 24 hours of the following day. Secondly, an optimisation equivalent to a DC optimal power flow is used to set an initial dispatch and, thirdly, this is tested in the equivalent of an AC power flow which considers contingencies (outages) which the system needs to be secure against. The second and third stages are then repeated until the results respect all post contingency network constraints as well as generator limits.

This process is used to define both a dispatch run and a pricing run. Under the dispatch run all generation constraints are binding, whilst in the pricing run certain generator constraints (such as minimum generation levels – see above) are removed.

At the real time stage, a different set of modules is used to dispatch the generation and reserve provision of available resources for each 5-minute period. Given the need for continuous smooth operation, this includes

not just an optimisation for the 5-minute period itself but both (a) a state estimator to determine the current state of the system and (b) a look ahead with appropriate consideration of upcoming multi-period constraints.

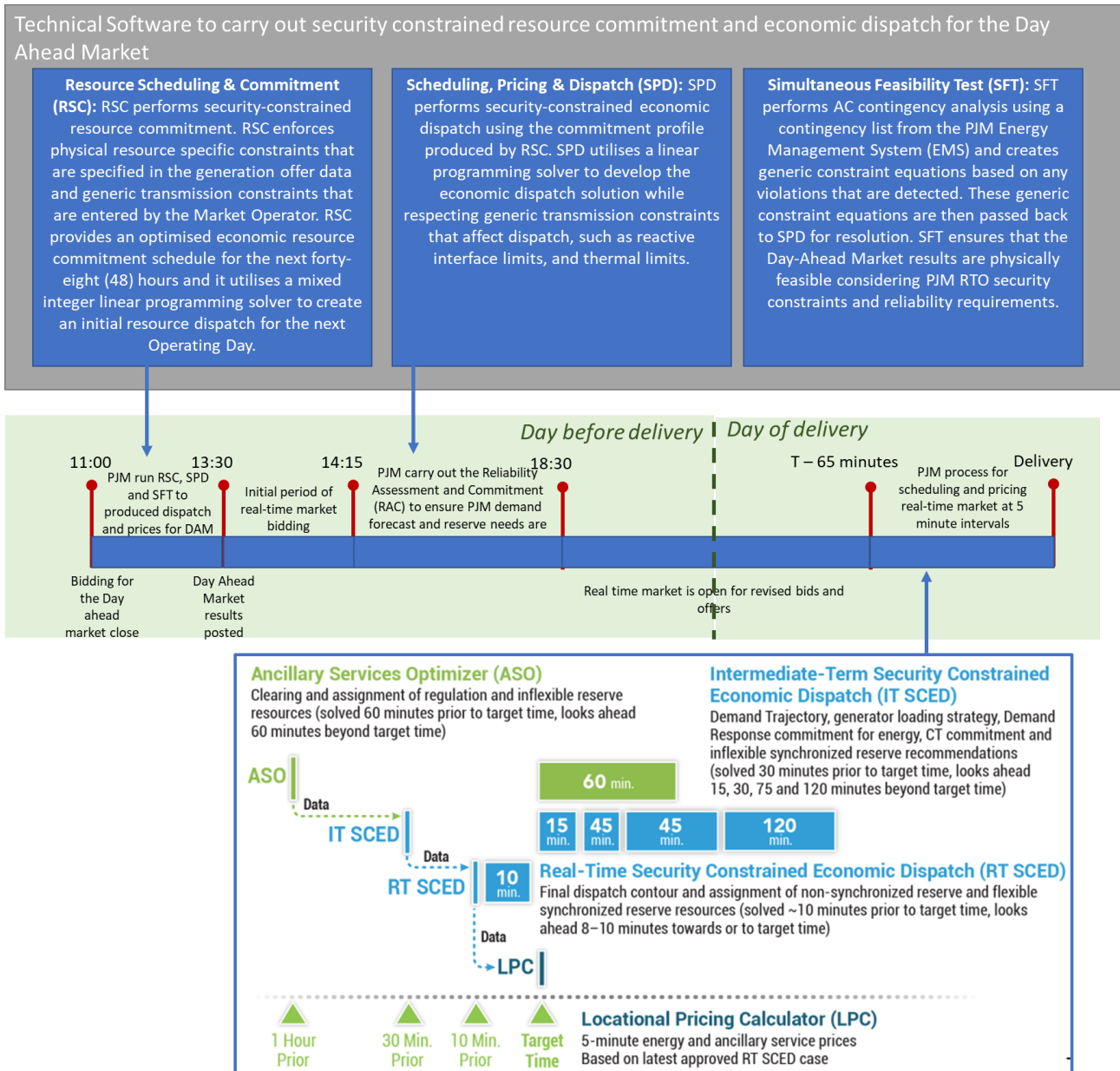


Figure 10: Example of the timeline and algorithms used to solve the PJM day ahead and real time markets – details from [31]

The algorithms used in PJM and other existing LMP markets have been designed and tuned to reflect the characteristics of their markets. For example, in markets with large coal plants, adaptations are made for plants with very long start-up times which need to be committed to generate more than 1 day in advance. In a similar way, we would expect the need to adapt algorithms for a high penetration of variable and zero-marginal cost generators. Also, as we integrate energy storage into the system, the look-ahead period for optimisation may need to change as dispatching energy storage in charge or discharge mode will have knock-on implications for what happens several hours later.

**LMP algorithms are not simple, and all have evolved over time to deal with the specific characteristics of the systems that they optimise. It is unlikely that a near ‘off-the-shelf’ product exists suitable for use in a**

**power system with very high levels of variable, uncertain, and zero-marginal cost generation. Detailed consideration would need to be given to how the algorithms should be designed.**

## 2.4 Day ahead market

The day ahead market is typically run for 24 one-hour trading periods for the following day resulting in dispatch instructions and prices for each hour-long trading period. Although day ahead markets are sometimes colloquially referred to as ‘spot markets’ it is better to describe them as day ahead forward markets which award financially binding contracts but are not physically binding. In that sense, any party with a contract in the day ahead market can buy their way out of the obligation in the real time market, effectively paying real time prices to reverse their position. The energy required tends to be set by the quantity of demand bids received (rather than by the Market Operator’s independent estimate of what demand will be).

Inputs required include **offers and bids** from generators, Load Serving Entities (LSEs)<sup>xii</sup>, flexibility providers and non-physical traders. It may include resources outside the market (equivalent of GB interconnector trading). The Market Operator will specify the **reserve requirements** defined against reliability standards. In addition to the availability and marginal energy prices, market participants submit a range of technical data including start-up costs, no-load costs, minimum up times. The Market Operator will also use the most up-to-date information on availability of transmission capacity.

A key consideration for analysis of the day ahead market is the degree of certainty which market participants have of their likely capabilities the next day. In all power systems there are significant uncertainties, for example around faults which may make a generating unit unavailable for delivery. However, in a system with a high dependence on weather conditions through wind and solar farms, there is likely to be significant uncertainty 24 hours in advance as to the profile of available generation. It will be important to consider how this would manifest in the market, for example whether the market design encourages wind or solar farm operators to be long or short in the day ahead market. The first LMP systems began as real time only markets before adding a day ahead market later which provided clear financial commitment from both sides sufficiently early for most generators to manage their start up and shut down scheduling.

## 2.5 Reliability unit commitment

Most LMP markets have an intermediate phase between the day ahead and real time markets designed to ensure that sufficient capacity is committed and available for generation to meet reliability and security of supply standards. A key difference in some markets between the day ahead market commitment and the reliability unit commitment is the use of an independent load forecast from the Independent System Operator (ISO). For example, in the California system, the day ahead market clears based on load offers submitted to the market regardless of whether these add up to the California ISO’s (CAISO’s) expectations of demand at that time. The reliability unit commitment may well commit further units, beyond those committed by the day ahead market.

**In a GB decarbonised electricity system, it will be important to consider how reliability unit commitment is developed. The dependence on variable renewables and the exposure this creates to forecast risks, particularly when made 24 hours or more ahead of delivery, is likely to increase the importance of reliability unit commitment.**

---

<sup>xii</sup> The term ‘supplier’ is ambiguous when discussing US markets as it is often used to refer to the entity supplying electricity to the system i.e. a generator. The term ‘Load Serving Entity’ can apply to a Supplier in the GB meaning of the term (usually akin to an actor in the energy retail market) or to a virtually integrated utility that may be responsible for both the final supply and billing of customers as well as owning and / or operating parts of the network.

## 2.6 Real time market

The real time market is effectively a market based on deviations from day ahead contract positions. Trading and dispatch periods can vary typically from 5 to 30 minutes. Real time markets open once the day ahead market, and any reliability unit commitment results are made known. The markets generally accept bids and offers continually up to around 1 hour before delivery. Unlike the day ahead market, the contracted position after the real time market dispatch will be physically firm with penalties for market participants that deviate. As the positions of market participants evolve between the day ahead market and delivery, the real time market effectively allows them to buy or sell for under or over generation or for additional or reduced demand. Once the market closes, the algorithm (such as those described above) takes information on the current state of the system and the likely trajectory up until delivery, along with the standard market information to arrange a final dispatch of reserve and energy.

The process of dispatching participants in the real time market can vary significantly between different markets. It needs to take account of the detailed unit commitment and multi-period constraints including generator ramp rates and start up times. The algorithms used include multi-period optimisations which look ahead across several settlement periods to ensure not just that supply and demand can be met in one specific trading period, but that it is possible to transition between trading periods given the resources available. Figure 10 provides illustrates the stages used by PJM to dispatch the real time market. Here real time trading periods of 5 minutes are dispatched through a process that operates between 60 minutes ahead and 10 minutes ahead. Longer lead time decisions such as decisions to start up new generators will be taken earlier in the hour and indicative dispatch shapes and prices will be produced several times up to the final dispatch run which is made around 10 minutes before delivery.

## 2.7 Self-dispatch

Market participants can choose to self-dispatch rather than to submit economic bids into the market. A self-dispatch offer or bid is one where a generator states the quantity but doesn't submit a price and agrees to accept the clearing price, however low that is. Non-flexible demand is also effectively 'self-dispatched' with LSEs on behalf of consumers agreeing to pay whatever the nodal clearing prices are for generation.

Submitting a self-dispatching bid or offer will guarantee dispatch as long as there are no physical constraints which mean that accepting all self-dispatched capacity is infeasible. Self-dispatch is often used by large baseload generators such as nuclear with significant shut-down and start-up costs and timescales and so an incentive to ensure continuous dispatch. It is also used in conjunction with bilateral trading where a combination of a private CfD contract between generator and LSE and an FTR can fully hedge against price variations. See Section 2.8 and Figure 11 for further explanation.

## 2.8 Financial transmission rights (FTRs)

### 2.8.1 What are FTRs?

FTRs are financial instruments which require the ISO acting as the market operator to pay the holder the difference in price between two specified nodes. FTRs are defined by a pair of locations on the network - a source node and a sink node - a capacity, the profile (for example baseload, on-peak or off-peak) and the term (for example 1 year or 1 month). FTRs have limited duration, typically with a maximum term of 1-3 years.

Standard FTRs, also called FTR obligations, are bidirectional: they pay the holder when the price is higher at the sink node than at the source but require the holder to pay when the price is higher at the source node than at the sink. FTR obligations are most common, but some markets also allow FTR options which only require payments in one direction.

FTRs pay out regardless of other activity. That is, they do not require a holder to generate or consume electricity or otherwise participate in the market. FTRs can be allocated, often to LSEs who hold them on behalf of electricity consumers, auctioned by the ISO or sold in secondary trading markets either bilaterally or in ISO managed marketplaces specifically designed for the purpose.

Where FTRs have been either allocated or sold, the ISO faces an ongoing cost when congestion occurs on the network. However, in these circumstances the variation of LMPs will always lead to consumers paying more to the Market Operator than the Market Operator pays to generators. The resulting difference is referred to as congestion rent. An important issue for the ISO is to determine the quantity of FTRs that should be either allocated or offered for auction. Most LMP markets limit the quantity to be no more than a 'feasible set'. A feasible set is one where, if all FTRs were matched by physical generation and demand at the source and sink nodes, the power flows on the network would remain within limits. It is a well-established result that, for a feasible set, the payments to FTR holders will never be more than the congestion rent collected<sup>32</sup>. This provides revenue security for the ISO.

Whilst this might hold in theory, in practice there remains the risk that because of changing system conditions such as an outage on an important transmission line, the capability of the system to transfer power falls below what was assumed when FTRs were issued, so some risk remains with the ISO which is usually passed through to bill payers who ultimately make up any shortfalls.

It is also worth noting that different names are used for FTRs in some markets. For example, CAISO uses the term congestion revenue rights (CRRs).

### 2.8.2 What are the functions of FTRs?

There are several distinct objectives that FTRs can be used to help meet. When discussing their use, it is important to consider which of these objectives is being considered.

**FTRs should return congestion rent to consumers<sup>33</sup>:** FTRs are one mechanism that can be used to return that congestion rent to market participants. In most LMP systems it is largely consumers who have paid the costs of the transmission network through their bills, therefore in most LMP systems it is considered appropriate to return congestion rent to consumers.

Many market frameworks include an allocation of FTRs to LSEs as a mechanism to achieve this.

Note that this is not the only mechanism that can achieve this. For example, the losses component of an LMP leads to an analogous 'losses rent' accruing with the Market Operator. However, this is usually re-distributed to consumers purely on a pro-rata basis.

**FTRs should provide a hedge to market participants against congestion costs and basis risk<sup>34 xiii 35</sup>:** there can be a significant risk to a generator or a demand customer at a specific location associated with congestion. For a generator, if congestion occurs between its location and the main load centres of the system it will no longer be able to receive market prices that reflect what demand is willing to pay. Likewise, for demand customers, a constraint between their location and that of cheap generation means that they have to pay more than they would otherwise have done if transmission capacity had been higher. If the level of congestion was precisely known in advance this would still be a cost but a certain one.

In reality, congestion levels are often highly uncertain and therefore, as well as a straightforward cost, represent a risk. Therefore, market participants may be willing to buy an FTR to hedge that risk. In a competitive market for FTRs, the price to purchase an FTR today would be equal to its expected return, i.e.

---

<sup>xiii</sup> CAISO's department of market monitoring separates out allocated CRRs as meeting the congestion rent return objectives and auctioned CRRs as meeting the hedging mechanisms, describing it as a price swap.

equal to the expected level of congestion cost across the term and profile of the FTR. Once purchased, and assuming it is combined with a generation or demand profile which exactly matches the profile of the FTR (see the example in Figure 11 below), the congestion cost is now completely fixed at today's expected value. The limited duration, and typically fixed shape, of traditional FTR contracts raises questions around their ability to provide an effective hedging mechanism for a future GB system dominated by variable output resources. This is explored further in Sections 2.8.3 and 4.3.

It is worth reiterating the difference between this objective and the first: returning congestion rent to consumers is achieved by allocating a set of FTRs to LSEs at no cost; hedging is achieved by allowing market participants to purchase additional FTRs at a competitive price.

**FTRs can be used to compensate generators for loss of access rights to the system<sup>36</sup>:** Unlike in current GB arrangements, generators and flexibility providers in LMP-based markets do not receive firm rights to access the system. Rather, instead of having the right to compensation when lack of network capacity intervenes, the right to inject or withdraw power is granted temporarily only when participants are dispatched 'on' by the central algorithm either in the Day Ahead or Real Time market. When moving from market arrangements with firm access rights to an LMP market without them, FTRs can be grandfathered to generators as a form of compensation. This is not without its issues but could provide a replacement for the curtailment payments that generators in GB receive today (See Section 4.6 below). As with the first objective, this outcome is achieved by allocated FTRs to certain generators at no cost.

**FTRs can be used to speculate:** most markets which provide FTRs allow participation from non-physical participants. These organisations are not trying to hedge risk, but rather to speculate on which FTRs may increase in value between purchase and outturn. We discuss this in more detail in relation to PJM and CAISO's FTR market below where there is evidence that longer term FTRs regularly sell at auction for significantly less than their outturn value which allows non-physical traders to successfully speculate and make money. As the mechanism of FTR allocation, auction and potential for secondary trading are, at least in part, designed to return congestion rent to consumers overall, a systematic undervaluing of FTRs at auction has led to consumers receiving substantially less revenue returns than the congestion rent collected by the ISO.

Despite the centrality of FTRs to LMP markets there is a significant amount of disagreement between knowledgeable stakeholders as to their role and how it should be fulfilled. As discussed below in the PJM case study, the Market Monitor for PJM argues for the primacy of the objective to return congestion rent to consumers. This point was backed up by two interviewees, both with detailed knowledge of US LMP and FTR markets. For example, one stated that "FTRs were designed to get rid of the congestion rent [from the market operator] and return it to customers". However, PJM and FERC explicitly disagree with this interpretation stating that "FTRs were designed to serve as the financial equivalent of firm transmission service and play a key role in ensuring open access to firm transmission service by providing a congestion-hedging function"<sup>37</sup>.

### 2.8.3 Auction revenue rights

The concept of an auction revenue right (ARR) is used in some markets to represent the initial allocation of the right to congestion rent to some market participants, in particular those who have paid for the transmission network. For example, in PJM, LSEs are allocated ARRs which give them the right to receive a portion of the revenue which comes from the auction PJM then runs to sell FTRs. The holder of an ARR has two options: either to retain the ARR and receive the auction revenue, or to convert the ARR into an FTR and to receive the direct return from that FTR. In a competitive market the two options would correspond, respectively, to (a) receiving the expected value of congestion rent on the date the auction is held, versus (b) receiving the outturn value of congestion rent.

## 2.9 Bilateral trading

Although LMP markets are centrally dispatched and all energy must go through the day ahead and real time markets, priced at the relevant LMP, bilateral trading is also common. One of the original US objectives for the design of LMP markets was that they remain compatible with bilateral trades.

Bilateral trading in LMP markets is significantly different from current practice in GB. In a bilaterally traded, self-dispatched market such as GB, bilateral trades are effectively standard contracts to buy and sell electricity. The key parameters are simply the price or the formula to calculate the price, and the quantity (or, as is common with PPAs with variable renewables, the agreement to buy whatever is available). In this system it is relatively easy to see the mechanisms by which prices are fixed or the risks of uncertain future prices are shared between buyer and seller.

In LMP markets, by contrast, bilateral trading involves agreeing how to arrange bilateral cash flows around the centralised market cashflows to get the desired result, such as a fixed price. The exact nature of bilateral contracts will differ between markets, but needs to consider the following issues:

- All energy must be bought and sold through the centralised LMP market either at day ahead or real time prices. Therefore, there is a 'market' cashflow that is inherent in any generation or consumption of electricity. Bilateral contracts need to work around these 'mandatory' market cashflows.
- As demand and generation are, in general, at different network locations, bilateral trading often includes a 'basis risk' on one or both of the parties. Basis risk here is, effectively, the risk of congestion between the generation and demand location and would lead to the demand paying more than the generator is paid in the LMP market. Managing this to deliver a true –fixed-price bilateral agreement requires Financial Transmission Rights (FTRs) which are described in detail below.
- Because LMP markets are dispatched for each day based on received bids and offers, generators involved in a bilateral contract might not be dispatched on, despite their bilateral contract position.

There are two common ways of managing the first two issues: one is to use a private Contract for Difference<sup>xiv</sup> where the offtaker agrees to pay or be paid an additional sum to or from the generator equal to the difference between the LMP price and a pre-agreed strike price. If the market price is lower than the strike price the offtaker pays the generator the difference whilst if the market price is higher than the strike price the generator pays the offtaker the difference. This requires reference to the LMP at a specific location (as all locations could have different prices) and therefore needs to be combined with an FTR to give a fixed price outcome (see Figure 11 for an example).

The second option is to allow responsibility for the generation and demand payments in the centralised market to be taken by one party to the bilateral trade. For example, the offtaker make take responsibility for both paying for demand to the Market Operator and being paid for generation at the relevant nodal prices. The bilateral element of the contract would involve a separate payment, outside the market, between offtaker and generators. Where there are no losses or congestion the market cash flows for the offtaker would net-out to zero and the bilateral trading cash flow would deliver the agreed fixed price. With losses and congestion, the LMP-market cashflows do not net out to zero and the bilateral arrangements would need to manage these discrepancies, for example by including an FTR.

---

<sup>xiv</sup> Note that it is important to differentiate private CfDs, which are common in many forms of commodity trading simply as a way of hedging risk, from the GB system of centralised Feed in Tariff CfDs which were introduced as a way of providing support to specified technologies.

The final issue raises different questions for forward contracts with defined quantities compared with typical PPA contracts for wind and solar farms. For contracts that define quantity (e.g. a contract to supply 1 MWh of energy between 6pm and 7pm on the 1<sup>st</sup> of March), the contract is one to *supply* energy rather than a requirement to *generate*. If the generator doesn't get dispatched in the LMP market because the LMP is below the generator's marginal cost, it will be cheaper for the generator to meet its contractual obligation by buying sufficient energy from the market rather than generating itself and bilateral contracts are likely to reflect this.

By contrast, for a variable renewable generator on a PPA based on a 'buy everything generated' clause, a failure to get dispatched leads to a situation where it simply gets nothing: no market revenue and no bilateral trading revenue. Therefore, this generator faces significant dispatch risk. (We discuss dispatch risk in detail in relation to the GB context in Section 4.2.)

**Bilateral contracting is often a critical component of gaining the confidence needed to invest in new generation capacity, particularly zero marginal cost (ZMC) generation. However, the form of bilateral trading will be significantly different in an LMP market from that under current GB arrangements. A key component of that is the loss of firm access rights to the system and the significant increase in risk this places on the generator. The degree to which this can be managed through bilateral trading is highly context dependent.**

The example in Figure 11 shows how, in theory, a combination of an FTR and a private CfD can be a so-called perfect hedge. However, the perfection of the hedge is not something that can be reproduced in the real world due to the nature of the products being bought and sold.

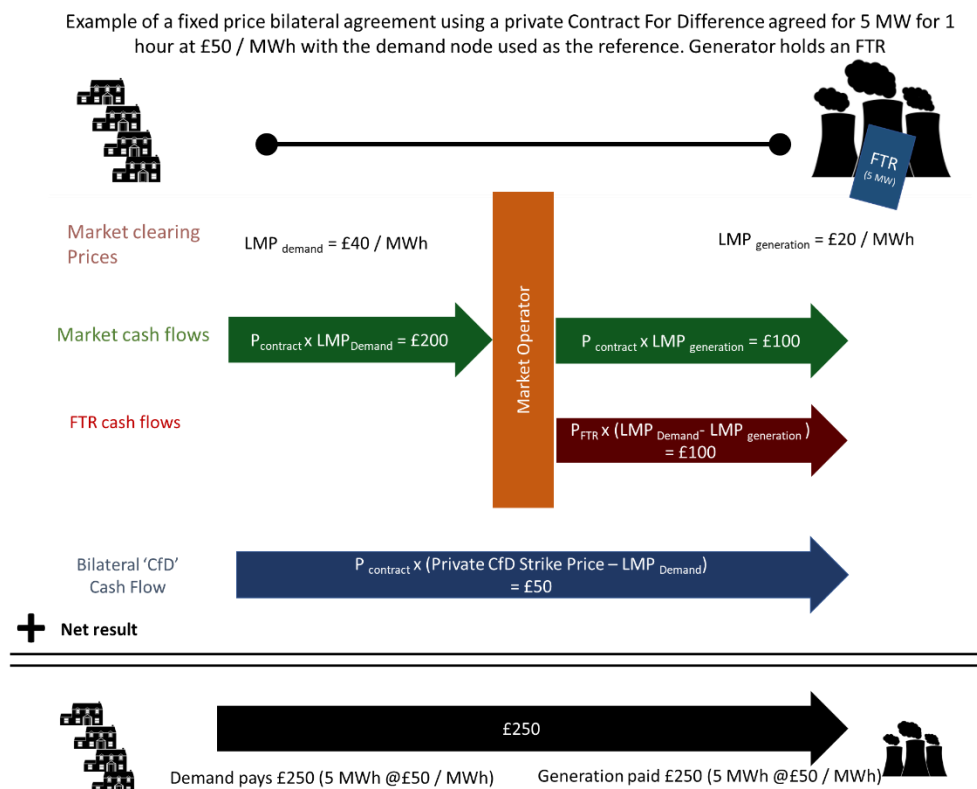


Figure 11: Cash flow example for an LMP market. Electrical losses are ignored. Note that this only shows revenue flows associated with the electricity element itself. To get a full picture of the costs it is important to consider (a) the generators variable operational costs including fuel costs; and (b) the money spent to purchase the FTR which, in a competitive market, would be equal to the expected return to the holder over the FTRs term.

Firstly, FTR products tend to be of a limited and predefined shape. For example, in the PJM market, FTRs are for either 24 hours (baseload), off-peak or on-peak. If bought in the annual auction this provides an FTR at the specified capacity for either every hour of the year or every on/off peak hour of the year (on and off-peak hours are predefined by the Market Operator). To provide perfect hedging, the profile of the bilateral contract needs to exactly match the profile of the FTR. This may be possible when agreeing a bilateral forward baseload or on-peak contract but is not possible when agreeing a PPA with a wind or solar plant based on taking what is generated.

If the example in Figure 11 is adjusted to consider a wind farm rather than a schedulable power station, there is immediately a question of what capacity of FTR should be bought. Assuming a baseload FTR, options could include:

- **FTR capacity equal to wind farm capacity:** an FTR equal to the capacity of the wind farm will regularly have a capacity greater than the available generation. During these periods the wind farm will effectively be over hedged and the FTR revenue will be ‘too much’ compared to output. In purchasing such a large FTR the contracting parties will have overspent in the FTR auction
- **FTR capacity lower than wind farm capacity, for example an ‘energy equivalent’ FTR:** for example, if the capacity factor of the wind farm was expected to be 40%, then purchasing a baseload FTR at 40% of the wind farm capacity might be considered ‘energy equivalent’. This fails to hedge the owner against risk in two directions: firstly, when wind output is higher than the FTR capacity the wind farm is over hedged and when wind output is lower than FTR capacity it is under hedged. For a system with a significant quantity of wind generation connected, the likelihood of congestion will be more prevalent when wind availability is high. This asymmetry would suggest that an energy equivalent FTR would, overall, under-hedge.

The conclusion is that the fixed profile FTRs available in current markets will not lead to perfect hedging of wind or other variable renewable output.

One possible way to manage this is to define a new FTR product type with a profile designed to match that of the relevant generation technology. One report explores the potential for a “Wind FTR” under which the capacity of the FTR varies from period to period and follows a measure of the local or regional wind speed<sup>38</sup>. This would allow the profile of the ‘right’ to closely follow the profile of the output generation and produce something much closer to a perfect hedge. This is an interesting idea to explore further. However, to date this has only been discussed in an academic context and hasn’t been demonstrated or trialled in practice.

**If FTRs were used in the GB power system context specifically as a tool to allow market participants to hedge their risk of facing congestion costs it will be important to consider how these FTRs were designed, and it is likely that radically new forms of FTRs would be required. In particular, if FTRs were considered as a way to manage congestion risk across heavily constrained parts of the transmission network for either wind or solar generation, it is unlikely that any FTR products used in existing markets would be suitable and new products, such as wind or solar specific FTRs may be required.**

## 2.10 Virtual trading

Virtual trading is where traders buy and sell equal and opposite quantities of energy in the day ahead and real time market. The process effectively arbitrages between the two markets. For example, a virtual trade may consist of the purchase of 30 MWh in the Day ahead Market and the sale of 30 MWh in the real Time Market. If prices in the two markets are the same, the two trades will net out at zero revenue. However, if, for example, the price in the real Time Market is higher the trades will net out with a positive return.

There is some evidence that virtual trading allows the market to penalise the ISO for poor unit commitment, e.g. if the ISO is regularly over committing units DA, this will lead to lower prices in RT than in DA. A virtual trader can then sell energy at DA and buy in RT giving a positive return. The virtual trade effectively inserts a 'virtual' generator into the dispatch at DA stage which can force the ISO to reduce the number of real units its commits leading to a more efficient overall dispatch.

However, there are risks with allowing unregulated virtual trading in certain circumstances. For example, on radial feeders, virtual trades can have a significant impact on clearing prices and there is a risk that FTR holders could use virtual trades to manipulate the day ahead market, against which FTRs are settled, in ways that potentially lose them money on the virtual trade in return for significant gains on their FTR. To manage these risks, markets tend to allow virtual trades only at predefined and relatively liquid locations and disallow FTR holders from virtual trading against locations to which their FTR is tied.

### 2.11 Market power mitigation

There are real concerns over the ability of individual market participants to exert market power. This becomes more acute because of two reasons: first, congestion within an LMP market has the potential to split the market potentially leaving an area with low levels of liquidity and few active market participants, separated from the wider system. Second, a set of LMP market arrangements typically includes several linked markets where actions in one market can have direct impacts on others. For example, the value of an FTR is directly linked to the LMPs at its source and sink nodes. Therefore, conditions can easily arise where a holder of an FTR can affect an LMP, potentially losing money in the day ahead LMP market, but to their own benefit in terms of FTR returns.

Market power tests often use a 'pivotal supplier' test which examines bids, offers and dispatch to identify if one particular supplier (this is the US terminology for energy producer, what would be called a generation in GB) will be required to relieve a constraint. A recent analysis of the ERCOT system identified that "Pivotal suppliers existed 18% of all hours in 2021, compared to 22% in 2020. Under high-load conditions, a supplier was pivotal in more than 70% of the hours, since competing supply is more likely to already have been fully utilized."<sup>39</sup>

To address these issues, all US markets have some form of automatic mitigation procedure for local market power built into their LMP software as a key component. This operates every hour before market clearing, automatically determining conditions when a supplier's offer is worthy of mitigation based on perceived market power and reduces payment to a pre-determined reference level. A recent paper provides an overview of the range of market power mitigation tools implemented in US markets and asserts that the potential for market power becomes an increasingly prominent issue in highly decarbonised power systems (for example single units setting the price in renewable dominated areas at times of low output) which may increase the challenges already faced by market power mitigation mechanisms<sup>40</sup>.

**Evidence suggests that an LMP implementation on a GB system dominated by variable ZMC generation could face potentially significant challenges associated with exploitation of market power. This may give rise to a need for new and bespoke market power mitigation solutions.**

### 2.12 Market monitoring

There appears to be significant value from the market monitoring function carried out across US markets. FERC's original Order 2000 set out market monitoring as one of the minimum requirements of a Regional Transmission Organisation (RTO)<sup>41</sup>. RTOs or ISOs have over time submitted market monitoring plans for approval by FERC. Some, such as PJM, have entered into a long-term contract with an independent company to deliver market monitoring on their behalf<sup>42</sup>. Other such as CAISO have established a Department of

Market Monitoring (DMM) within the ISO organisation itself<sup>43</sup>. However, even in this case, the DMM is set up to have independence and <sup>44</sup>.

Market monitors generally carry out several roles. FERC identifies these as<sup>45</sup>:

- To identify ineffective market rules and tariff provisions and recommend proposed rule and tariff changes to the ISO/RTO that promote wholesale competition and efficient market behaviour.
- To review and report on the performance of wholesale markets in achieving customer benefits.
- To provide support to the ISO/RTO in the administration of Commission-approved tariff provisions related to markets administered by the ISO/RTO (e.g. day ahead and real time markets).
- To identify instances in which a market participant's behaviour may require investigation and evaluation to determine whether a tariff violation has occurred, or may be a potential Market Behaviour Rule violation, and immediately notify appropriate Commission staff for possible investigation.

A key part of their role is in producing ongoing quarterly and annual reports which provide significant detailed analysis of the operation of the markets. Each market monitor produces recommendations for the RTO or ISO and potentially to others such as FERC. Whilst these recommendations are non-binding, in most cases the Market Monitor and the RTO / ISO agree to inform FERC of any disagreement over recommendations<sup>46 47</sup>.

**A key value of dedicated market monitoring appears to be the focus placed on reviewing and understanding (a) what market rules are in place, what they aim to achieve and whether they are driving those outcomes or others, and (b) how market participants are behaving within the rules and identifying occasions where they step outside those rules. The requirements for a regulator-approved market monitoring plan and the market monitoring functions that are derived from them focus significant resources on understanding the market and thinking of how to improve it. We believe there will be value in introducing a similar function in GB regardless of what market reform options are taken forward.**

### 2.13 Dispatch and real time balancing

Once dispatched in the real time market, for consumption, to generate energy or to provide availability for response or reserve, commitments become firm with a penalty associated with failing to deliver. Final balancing is provided in much the same way as it would be in other market structures, through a combination of automatic response to system parameters such as frequency, to other automatic signals such as Automatic Generation Control (AGC) mechanisms commonly used in the US, or through manual control-room dispatch.

### 2.14 Settlement

The Market Operator is also responsible for settling the market. All contracts within an LMP market are with the Market Operator itself. Participants don't buy or sell energy with each other, rather than sell to the Market Operator or buy from the Market Operator. Therefore, the Market Operator has a major role to play in the timely and accurate settling of market transactions both at day ahead and real time stages and with FTR markets. Finally, the Market Operator has to ensure that its operations are revenue neutral. For example, rent – where consumers pay more than is paid to generators - associated with the losses component of the LMP needs to be distributed back to consumers according to a predefined set of rules, often based on a pro-rata split in the rent to LSEs based on their underlying share of demand.

# Case studies of existing LMP markets

### 3 Case studies of existing LMP markets

The standard model for an LMP-based market described in Section 2 has been used in several major markets around the world. Much of North America is now served by LMP markets broadly in this form as well as markets in Singapore and New Zealand. Ontario is in the process of introducing LMPs as part of its market reform process and the National Electricity Market in Australia, currently a Zonal market, has considered several forms of LMPs over the past decade.

This section provides some high-level case studies from some existing LMP markets which aim to illustrate some of the points described in Section 2. The case studies do not provide a comprehensive review of existing LMP markets, but rather aim to draw out examples of points which the GB market debate should be aware of. The majority of this section is based on short discussions of particular markets; however, we also provide a discussion on negative prices across multiple US LMP markets as well as a summary of key points for GB.

#### 3.1 PJM

##### 3.1.1 Background

Area covered	Thirteen states in the central-east coast region of the US including all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. <sup>48</sup>
Size of market	65 million People Peak demand 149 GW 810 TWh Annual energy demand
Date of implementation of LMP	Between 1998 and 2002
Wind and solar penetration	3.1% of electrical energy demand
How is the supply side exposed to locational signals?	Nodal
How is demand side exposed to locational signals?	Zonal
FTRs	<ul style="list-style-type: none"> <li>• Auction Revenue Rights allocated to LSEs</li> <li>• LSEs either convert ARR directly to FTRs or claim revenue from the FTR action.</li> <li>• FTRs sold in monthly, annual and 'long term' auctions. Long term FTRs are for up to three years after the current year.</li> </ul>
Security of supply	PJM Capacity market

PJM was the first US market to introduce LMPs, a process which it carried out over the period from 1998 to 2002. In 1998 it introduced a single real time cost-based locational market, which it updated to a bid-based market in 1999 and expanded to a two-settlement Day ahead and Real time market in 2002. It also introduced FTRs in 2000 against the real time market, later adjusting them to settle against the day ahead market once introduced.

The most recent annual assessment of PJM by Monitoring Analytics, the independent Market Monitor, published in 2021<sup>49</sup> concludes that "The PJM markets work, even if not perfectly ... The PJM markets bring customers the benefits of competition." It concludes that the energy market performance is competitive and the FTR market is partially competitive.

The context of PJM is one of relative stability in terms of the electricity system. Between 2007 and 2020 there was a turnover of 42 GW generation capacity on a system with a peak demand of around 150 GW<sup>50</sup>.

Whilst some variable renewables were added, this only accounted for 2.4 GW of additions over that period. Ambitions in the PJM region, set by individual states, suggest that by 2035 around 22%<sup>51</sup> of annual demand for electricity will need to be served by renewable sources, compared with up to 80% in GB<sup>52</sup>.

**PJM provides evidence that an LMP market can operate effectively under particular circumstances over multiple decades. This is a conclusion backed up by independent market monitoring. However, the context of the PJM system is very different from that of Great Britain today and from the expected GB power market in 2035.**

### 3.1.2 Long term FTRs in PJM

The PJM Market Operator currently provides FTRs for up to three years in the future with further ahead than the next year referred to as 'long term FTRs'. As discussed in Section 2.7, FTRs are considered critical to the successful operation of an efficient LMP market, and experience from New Zealand which operated for more than a decade without FTRs has been argued to show the inefficiencies that can develop without the potential to hedge between locations<sup>53</sup>. Long term FTRs in the US were introduced in response to a FERC order, which itself was a response to generator preference for arrangements which were similar (in financial terms) to physically firm connection agreements<sup>54</sup>.

However, experience in PJM has highlighted some potential pitfalls of long term FTRs, at least in the framework operated by PJM. These include low prices achieved by auctions for long term FTRs reflecting high levels of uncertainty inherent in future congestion, the quantity which ultimately sets the value of FTRs, and the potential for significant and potentially fraudulent trading the cost of which ultimately has to be covered by consumers.

The first issue with long term FTRs is that the return an investor is likely to receive from holding an FTR is hard to forecast at the point of auction. The value of an FTR is directly linked to the level of congestion that will be seen in outturn across the term of the contract. However, the level of congestion is highly uncertain as it depends heavily on decisions made by generators, consumers and transmission owners and operators. Risks include: the potential for an existing generator to close or the development of a new generator to be delayed, the potential for large consumers to close, delays to the commissioning of new transmission capacity and the risk that the level of outages on the transmission network differs from expected.

For these reasons long term FTRs have tended to sell at auction for significantly less than the revenue they result in, reflecting the high level of risk represented by the investment. This has led the PJM Market Monitor to recommend that the long term FTR product is eliminated. It notes that "in a competitive market the price of Long Term FTRs would be expected to converge with the prices of Annual FTRs, but there has been a persistent, wide divergence that has made the purchase of Long Term FTRs persistently very profitable"<sup>55</sup> and in turn this undermines the ability of FTRs to return congestion rent to consumers through auction revenues.

However, PJM disagree with this finding<sup>56</sup> highlighting that the fraction of congestion rent returned to consumers depends on the decisions by LSEs around whether to convert allocated ARR into FTRs, a process which gives LSEs the freedom to reflect their risk appetite. PJM also point to a FERC statement in 2017 on the objectives of FTRs: "We reject the arguments that the sole purpose of FTRs is to return congestion revenue to load, and the market should therefore be redesigned to accomplish that directive."<sup>57</sup>

**In conclusion: Revenues from the sale of long term FTRs in PJM auctions have tended to be significantly lower than the outturn value of those FTRs. The PJM Market monitor argues that this means the framework fails on the objective of returning congestion revenue to consumers whilst PJM argue that this is acceptable as this is not the sole objective of FTRs. It is clear that even in a mature LMP / FTR market**

**there are different interpretations of objectives and outcomes between even experienced market stakeholders.**

### 3.1.3 Manipulation in FTR markets: The case of GreenHat Energy

In June 2018 GreenHat Energy defaulted on paying the first loss on a multimillion-dollar portfolio. FERC concluded that GreenHat's trading was manipulative<sup>58</sup> and had resulted in GreenHat's owners taking \$13 million in unjust profits and to approximately \$179 million of losses which had to be recovered from PJM members.

Between 2014 and 2018 GreenHat had traded in the FTR market, putting together the largest FTR portfolio in PJM's history primarily in what is referred to in the PJM market as long term FTRs (which, in practice, have 3-year durations). The FERC decision describes how GreenHat identified which FTRs to buy based only on minimizing PJM credit requirements rather than on any consideration of likely network congestion and therefore the ultimate value of the FTRs in their portfolio. This allowed GreenHat to purchase large capacities with very limited collateral. Although this led to a largely loss-making portfolio, it did include a few profitable FTRs. GreenHat's owners sold these bilaterally before they became due for settlement and moved the profits out of GreenHat's bank accounts before the company defaulted.

The full scale of the default only emerged as the terms of each FTR in GreenHat's portfolio expired, a process which finished in May 2021. In late 2021 FERC found that GreenHat had engaged in manipulative behaviour and ordered that the \$13 million in profits be disgorged and assigned civil penalties of \$180 million<sup>59</sup>.

Since GreenHat, PJM and other Market Operators have significantly tightened their collateral requirements following criticism of PJM including from one FERC commissioner<sup>xv</sup> and from an independent expert report commissioned by PJM. These documents highlight that PJM's process of setting the levels of collateral and managing risk was flawed. This was partly due to inaccurate assessment of the likely worth of some FTRs: PJM required very low levels of collateral for certain FTRs because they forecast that those FTRs would likely have a positive value. These assessments, according to Danley's Dissenting statement were "*wildly inaccurate*" (original italics) and "used an FTR Credit Requirement Calculator that seriously underestimated the risks of its FTRs". But it was also because PJM was not clear in its duties as a manager of risk on behalf of its members. Many recommendations of the independent review focus on the importance of explicitly considering the role that PJM plays in understanding and managing financial risk. For example, recommendations include: "PJM bolsters how aggressively it views its role as manager of risk; Establish the position of a Chief Risk Officer and a Risk Oversight Committee"<sup>60</sup>. The report also highlights the importance of in-depth knowledge related to the management of financial markets, highlighting that this is "sorely needed".

**The GreenHat Scandal highlights the significant risk-management activities that a Market Operator undertakes on behalf of consumers, and the major impact on market participants that can result from a failure to appropriately assess risk and manage potentially manipulatory behaviour. GreenHat was not a physical participant in the PJM electricity market, and it also highlights the role of non-physical FTR traders that were speculating on FTR values rather than using them as a hedge.**

---

<sup>xv</sup>The FERC decision was a majority decision with one commissioner, James Dalny, dissenting and arguing that while he "remained deeply sceptical of GreenHat's explanation's" the "enforcement failed to provide the proof necessary to meet its burden." <https://www.ferc.gov/news-events/news/commissioner-james-dalny-dissent-regarding-greenhat-energy-llc-et-al>

## 3.2 California ISO (CAISO)

### 3.2.1 Background

Area covered	80% of electrical load in California and a small part of Nevada
Size of market	32 million consumers Peak demand: 46 GW <sup>61 62</sup> 225 TWh annual demand
Date of implementation of LMP	2009
Wind and solar penetration	27% of electricity demand in 2021
How is the supply side exposed to locational signals?	Nodal
How is demand side exposed to locational signals?	Zonal
FTRs	FTRs are called congestion revenue rights (CRRs). Allocated CRRs given to LSEs on behalf of consumers and others who pay transmission access charges Auctions CRRs are available for hedging
Security of supply	Mandatory resource adequacy requirement <sup>63</sup>

After instigating a zonal real time centralized market design during the 1990s California moved to the standard LMP design using both day ahead and real time markets and nodal pricing in 2009. Market reform in California at this time was significantly influenced by the 2000 crisis which involved both market manipulation by several market participants (of which Enron is the most well-known) and failures of market design which left LSEs forced to buy wholesale electricity significantly above a cap at which they were allowed to sell to consumers.

Today, the California Independent System Operator (CAISO) runs three LMP markets: a day ahead, and two real time markets with 15 minute and 5-minute dispatch and prices. The day ahead market closes at 10:00 the day before delivery with results published at 13:00. At that point the real time market opens with market participants able to submit bids and offers up until 75 minutes before the start of a trading hour. The 15-minute market and the 5-minute markets both use the same bids and offers. A number of tools including a combination of security constrained unit commitment and economic dispatch (all with network constraints included) are run over a predefined timeline up to and across the trading hour. Real time unit commitment and fifteen-minute market algorithms are run every 15 minutes. The final physically binding 5-minute dispatch instructions are issued following the final run of an economic dispatch algorithm around 7.5 minutes ahead of the start of each 5-minute period. This issues both a binding dispatch for the coming period and advisory dispatches for up to the following 12 periods (up to 1 hour ahead)<sup>64</sup>.

CAISO differs from the standard design of LMP market due to the addition of the intermediate 15-minute market. As with the day ahead market, the 15-minute market is financially but not physically firm. It provides an opportunity for variable renewable generators to adjust their day ahead commitments to reflect much more accurate forecasts for generation and it provides sufficient time for at least some fast start generators to synchronize and generate.

California has been successful at integrating renewables into its electricity system and on the 8<sup>th</sup> of May 2022 for the first time succeeded in generating the equivalent of more than 100% of instantaneous energy demand from renewable sources with the vast majority coming from solar and wind energy<sup>65</sup>.

**Were LMP to be considered for GB it would be important to consider the importance of timescales. Whilst most LMP markets have chosen a day ahead and real-time market with 5-minute settlement periods (with dispatch often up to 5-minutes ahead), the introduction of a 15-minute market in California with results**

published just ahead of the trading hour, is an example of an innovation which supports CAISO in managing the variability introduced through solar. This is the type of innovation GB might have to make in order to manage forecast uncertainties from wind and solar.

### 3.2.2 Solar, the Duck Curve and ramping requirements

California provides an example of an LMP market which has seen significant development of renewables over the past decades. In 2020 33% of CAISO's electrical energy came from renewables with the vast majority (26% of total electrical energy) from wind and solar. California is particularly notable in terms of the development of solar and its impact on the net-demand profile seen on sunny days: the so called 'Duck Curve'. Figure 12 (a) shows the original forecast for the duck curve graph, published as a discussion point by CAISO in 2013. This estimated the potential for solar to reduce minimum net demand from around 21 GW in 2012 (when there was little solar capacity installed) to 12 GW in 2020 and the potential for ramping of net demand to reach 4.3 GW per hour.

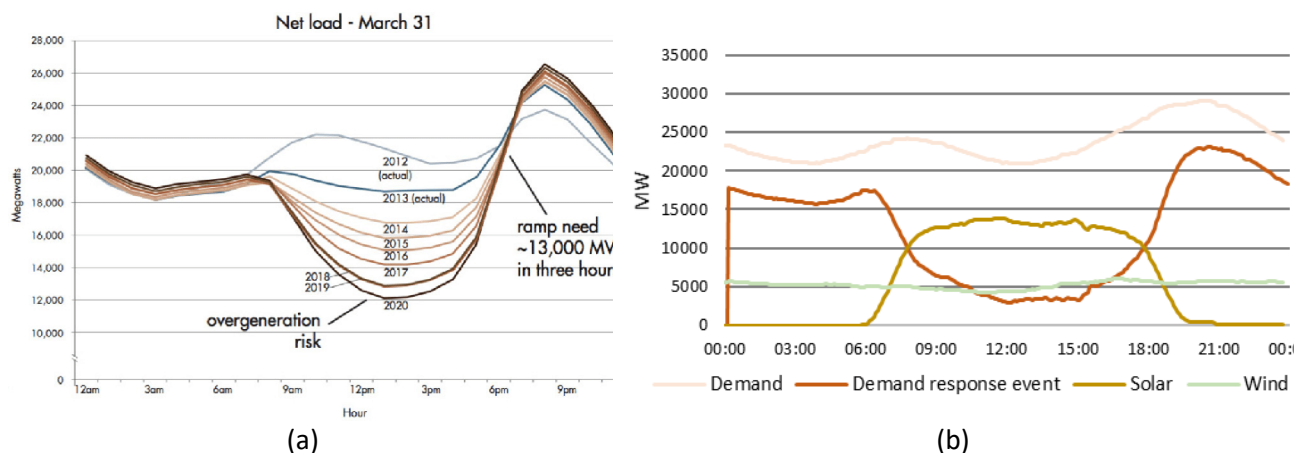


Figure 12: The California Duck curve. (a) Original Duck curve published in 2013 based on modelling of future development of solar<sup>66</sup> and (b) real-world data for 17th May 2022<sup>67</sup>

Figure 12 (b) shows outturn conditions for a typical day in May 2022. Solar has depressed net demand to less than 5 GW and the rate of ramping rises to a maximum of 8 GW / hour downwards during the morning and 10 GW / hour upwards during early evening. For comparison a 2017 report estimated that the maximum ramp rates for a putative UK system at the time would have been 10 GW/hour up and 11 GW/hour down<sup>68</sup> <sup>xvi</sup>. The same report suggested that ramp rates in a 2040 UK system could be as high as 21 GW/ hour up and 25 GW/ hour down.

CAISO introduced a specific ramping flexibility service into its market, the so called *Flexiramp* product, as early as 2011 noting that "The ISO has observed that in certain situations reserves and regulation service procured in the real time and units committed for energy in the fifteen-minute commitment process (RTPD) lack sufficient ramping capability and flexibility to meet conditions in the five-minute market interval"<sup>69</sup>. Although the impact of variable renewables was only one of many driving factors, the Flexiramp product has suffered some significant implementation issues over the decade since a first version was implemented<sup>70</sup>. Part of this is related not just to the need to procure sufficient flexibility to manage the expected ramp rate, but also the need to procure additional flexibility to cover uncertainty in the ramp rate.

**CAISO has had to significantly develop their LMP algorithms over the past decade to reflect the changing nature of their system, particularly, introducing and then adapting and improving a specific ramping product, and moving to a system with significant look ahead and multi-period linkage as part of the LMP**

<sup>xvi</sup> Note that the report states that the geographical coverage of its analysis was UK wide rather than GB.

**optimisation. This highlights the degree of adaption and upgrade required within existing LMP systems, particularly ones where the power system is going through significant physical change.**

### 3.2.3 Capacity crunch

In addition to ramping, the growth of solar has pushed the net demand peak to later in the evening and a significant capacity of schedulable generation has closed. Between 2017 and 2022 around 6 GW of schedulable generation capacity withdrew from the market. In addition, following rolling blackouts in 2020, CAISO took direct action to prevent a future 4 GW of schedulable capacity from leaving the market. Over the same period only 2 GW of firm capacity – in the form of gas generation – was added along with around 4 GW of batteries and 8 GW of variable renewables<sup>71</sup>. The growth of solar has been implicated by some commentators as one of the underlying reasons for the rolling blackouts, driving the lack of schedulable generation<sup>72</sup>. This, it is argued, is because solar generation reduces the quantity of demand available to firm generators such as gas turbines, and the price of electricity during daylight hours. This in turn affects the business case for investment in new firm capacity.

A key reason for the lack of new firm capacity is likely to be the relatively low revenue streams available through energy markets and resource-adequacy arrangements. The Department of Market Monitoring, using a number of scenarios, estimated that during 2020 and 2021 net revenue (energy market revenue minus operating costs) for a hypothetical CCGT could have been between \$20 and \$41 per kW whilst annualized fixed cost requirements would likely be around \$124 per kW. In combination with a soft cap on the Capacity Procurement Mechanism (CPM), currently set at \$76 / kW / year, revenues are likely to be less than required to cover fixed costs. The situation is even starker for combustion turbines with energy market net revenues and maximum CPM payments totalling between \$80 and \$100 per kW, whilst annualized fixed costs were about \$152 per kW<sup>73</sup>.

California provides evidence of the importance of ensuring the right *package* of market framework is implemented, but also of the challenges of aligning incentives and support from different elements of the framework. Whilst it has seen significant renewable growth (primarily solar) within an LMP system, it also provides evidence of the implications for schedulable plant, and ultimately reliability of supply, of reducing energy market revenues. The fact that LMP markets put downward pressure on prices and therefore lowers intramarginal rent means that where capacity is required for non-energy reasons – for example to provide firm capacity – addition markets or revenue streams specifically designed to pay for that service become more important. **In particular, in an LMP market, the importance of a well-designed capacity adequacy mechanism becomes more critical to ensuring security of supply.**

Even though many stakeholders had warned of the impending capacity shortage, the wider legislative, regulatory and market frameworks were unable to identify and adapt before major blackouts. One warning that GB policy makers might take from this is to avoid assuming that different elements of market reform can be implemented in isolation.

### 3.2.4 Energy storage

The capacity of energy storage connected to the CAISO system has grown significantly over recent years. Between 2017 and 2022 it rose by 4 GW, with 3.5 GW connecting since June 2020<sup>74</sup>.

Carrying out price arbitrage against its local nodal price is one revenue stream available to battery operators. However, analysis by the Department of Market Monitoring suggests that energy-market arbitrage is still a relatively small revenue stream compared with ancillary services. For example, the average ‘energy only’ annual revenue was \$12.78 / kW in 2021 compared with \$112.97 / kW when participating in both energy and ancillary service (regulation) markets.

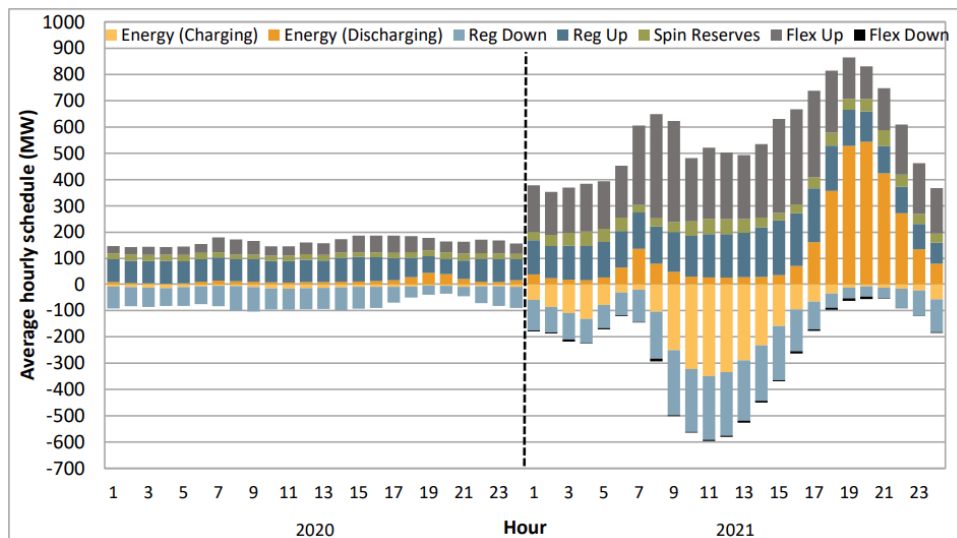


Figure 13: Average hourly battery schedule in 2020 and 2021. Installed capacity increased dramatically across the two years from around 500 MW in 2020 to 2,500 MW in 2021. The level of dispatch in the energy, rather than ancillary service market also increased significantly. Graph from CAISO Market Monitoring<sup>75</sup>.

**Whilst CAISO provides an example of a power system experiencing an explosion of battery storage capacity, it doesn't provide evidence that price arbitrage around LMPs is a significant driver of battery investment. Rather, ancillary services continue to provide the significant majority of revenues to battery storage despite increasingly volatile LMPs driven by diurnal generation patterns from solar.**

### 3.2.5 Congestion revenue rights in CAISO

California provides for both allocated and auctioned congestion revenue rights (CRRs). Allocated rights are passed to LSEs and return congestion rent to consumers. Consumers also receive the auction revenues from CRRs sold to other entities for hedging or speculation purposes. Similar to concerns raised by the PJM market monitor, the CAISO Department of Market Monitoring highlights that auction revenues are significantly lower than the pay out of the FTRs: "California ISO transmission ratepayers lost \$520 million in the congestion revenue right (CRR) auction from 2012 through 2015. For every dollar ratepayers paid to entities purchasing CRRs in the auction, ratepayers received only 46 cents in auction revenues. This consistent under-pricing of CRRs calls into question a fundamental assumption of the CRR auction design that competition will drive auction prices to equal the CRR's expected value."<sup>76</sup>

The Department of Market Monitoring has for several years recommended the removal of CRR auctions noting that "the current auction is unnecessary and could be eliminated, with all congestion rents being returned to transmission ratepayers."<sup>77</sup>

**This adds to the evidence from PJM that significant care should be taken when considering the role of FTRs and the development of competitive markets for FTRs as part of an LMP system.**

### 3.3 ERCOT

#### 3.3.1 Background

Area covered	90% of the Texas electricity load <sup>78</sup>
Size of market	26 million customers Peak demand: 75 GW 382 TWh in 2020
Date of implementation of LMP	2010
Wind and solar penetration	28% of energy generated from wind and solar in 2021
How is the supply side exposed to locational signals?	Nodal
How is demand side exposed to locational signals?	Zonal
FTRs	<ul style="list-style-type: none"> <li>- Allocated pre-assigned congestion revenue rights (PCCRs) to subset of market participants</li> <li>- congestion revenues rights (CRRS) made available in semi-annual auctions.</li> <li>- Auction revenues redistributed to load</li> </ul>
Security of supply	Texas is an 'energy only' LMP market – no capacity market

The Texas system is the closest analogy to GB in terms of renewable penetration. In 2021 it had 25 GW of wind installed along with 4 GW of solar. These resources contributed around 28% of total generation output. For comparison, in 2021 GB had 38 GW of installed variable renewables capacity which met around a quarter of electricity demand<sup>79</sup>. Texas also has limited interconnection with other systems.

#### 3.3.2 Development of wind and transition to LMP

Texas began developing wind power early, with more than 10 GW of installed capacity by 2010 and reached 20 GW in 2016<sup>80</sup>. The majority of installations were in the Northwest of the state where wind speeds are relatively high and there is limited competition for space. The initial boom in development slowed during the late 2000s and early 2010s as transmission capacity between the main areas of wind developments and the load centres in the south-east became congested.

This issue had been identified in 2005 when the Texas Senate passed a bill which both increased the Renewable Portfolio Standard – the mechanism for setting renewable capacity targets for Texas – and ordered the Public Utility Commission of Texas (PUCT) to set up Competitive Renewable Energy Zones (CREZ) “in which renewable energy resources and suitable land areas are sufficient to develop generation capacity from renewable energy technologies.” In addition, the bill required PUCT to plan the construction of new transmission network capacity to be “beneficial and cost effective at transporting electricity from the CREZs to customers.”<sup>81</sup>

The lag between the enactment of the Senate bill and the build out of transmission meant that by 2009 curtailment of available wind generation rose to 17% in 2009, by far the highest level of congestion seen in any US market at any time<sup>82</sup>. The commissioning of new wind capacity hit a peak in 2008 with 3 GW added to the system that year. However, the growing level of constraints along with the expected introduction of LMP in 2010 preceded a period of much slower growth over the following five years: commissioned capacity was around 500 MW or lower in 2010, 2011 and 2013.

The planning process for transmission lines related to CREZ took a total of four years with PUCT commissioning Transmission Service Providers to build around 12 GW of new transmission lines in Spring 2009. The build out took a further 5 years with all lines in service by January 2014. Following the build out of

the CREZ transmission lines wind capacity again grew quickly with annual capacity growth to 2 GW in 2014 and 3.5 GW in 2015; it has not fallen far below 2 GW since<sup>83</sup>.

**An important lesson from the early Texas experience is the need for coordinated between forward-looking transmission and generation investment influenced by the wholesale market structure. In ERCOT, and all other LMP markets, these are in fact separate processes. Delivering effective electricity system transformation means taking a strategic, centrally managed approach to both. Only by ensuring that sufficient transmission capacity was available did Texas manage to meet (and exceed its early renewable ambitions).**

The introduction of LMP in Texas in 2010 marked the end of a long process which began with a rule set by PUCT in 2003<sup>84</sup> to implement nodal pricing. The rationale laid out in the 2003 decision included the development of a more competitive market, reduced congestion, more transparent pricing and increased liquidity as well as improved siting of transmission and generation resources. A positive benefit case was set out in two CBA analysis in 2004 and 2008. The 2004 study found annual benefits of \$76 million and implementation costs of between \$108 million and \$157 million<sup>85</sup>. By 2008 it was clear that costs would be higher, and the 2008 CBA estimated total costs at \$222 million<sup>86</sup>. However, the cost benefit analysis was still positive and suggested that between 2009 and 2022 more efficient dispatch would lead to net savings of \$339 million with a further \$181 million from more efficient siting of generation.

Whilst Texas provides an example of an LMP market with a similar share of variable renewables to GB today, it is clear from the historical perspective that this has been driven by a combination of strong supportive renewable energy policies, appropriate levels of renewable support through federal tax credits, a strategic approach to spatially planning the development of renewable generation through the CREZ programme, and the related build out of significant transmission capacity outside the development of the LMP market. Whilst early cost-benefit analysis suggested savings in both dispatch and siting decisions for generators, for wind, siting has been determined more by other locational factors (land, wind speeds, supportive planning), whilst dispatch savings could be largely confined to swapping more efficient fuelled power stations for less.

### 3.3.3 Security of supply in ERCOT

Unlike other US LMP markets, Texas has chosen to avoid using a capacity market and relies on energy market revenues to deliver sufficient generation capacity. As the Texas market monitor puts it “The ERCOT market has seen many years of excess generation capacity, with revenues less than estimated costs of investing in new generation (known as the “cost of new entry” or CONE). If long-term expectations of revenues sufficient to support resource adequacy are to be met, revenues that far exceed the CONE must occur in some years as well.”<sup>87</sup>

Analysis carried out by the market monitor in 2021 show that between 2014 and 2020 energy market revenues (including those from ancillary services) were below the CONE value in all years except 2019 when they were broadly equal to the CONE. In 2021 revenues would have remained below the CONE except for the impact of a major Winter storm in February 2021. Between 15<sup>th</sup> and 19<sup>th</sup> February Storm Uri caused demand to increase to levels significantly in excess of the forecast winter peak and caused forced outages and fuel shortages across generators which, at the height of the storm, are thought to have reduced generation capacity by 52 GW<sup>88</sup>. In response the electricity price was between \$1,000 / MWh and the \$9,000 / MWh price cap for several days.

For schedulable generators which continued to be available to generate through Storm Uri, there was the potential to increase their annual revenues by nearly a factor of ten. For example, a combustion gas turbine would have earned around \$70 / kW in the south region of ERCOT without the effect of Storm Uri but nearly \$700 / kW with the effect of Storm Uri and these compare with a CONE of between \$95 / kW and \$110 / kW.

One naïve interpretation of Storm Uri might then be that the market provides sufficient occasional energy market revenues to support capacity build out. However, this would fail to reflect the causes and characteristics of the price crisis associated with Storm Uri.

Firstly, Texas is a system where peak demand is expected to occur in summer, driven largely by air conditioning load. Secondly the unavailability of generation was driven by an extreme event with a set of highly correlated failures rather than the situation that is often considered for system planning: the greatest level of *uncorrelated*, i.e. independent, failures that the system should be secure against. Thirdly, of course, the high annual revenues were only available to generators able to run throughout the storm. For those that were unable to operate due to technical faults the impact would have been substantial losses. According to one report “it has been reported that the state's four largest power producers – Vistra, Exelon Corp., NRG Energy Inc., and Calpine — collectively lost between \$2.5 billion and \$4 billion due to power plant performance problems, high natural gas prices, fuel supply constraints, and other problems.”<sup>89</sup>

New generators looking at an investment decision may look at Storm Uri as an example of an opportunity to gain very high revenues during an uncommon event, and they may choose to learn lessons from the event and ensure a design and fuel supply that is much more resilient against bad winter weather. However, it is in the nature of extreme events that the next one is unlikely to repeat the pattern of the last, and a more risk averse view would be to consider how much risk investors could be exposed to in the next extreme event in an energy only LMP market.

The complexity of the issue for generators – the interaction of an LMP centrally dispatched market, the use of hedging arrangements, technical failure and extreme weather – is highlighted in a lawsuit being brought by a Texas wind farm, the owner of which is attempting to avoid paying \$71 million to JP Chase which would usually be required through clauses in their fixed price contract<sup>90</sup>.

Finally, it is also important to consider the risk to consumers in an energy only LMP market: unhedged consumers faced bills two or more orders of magnitude higher than usual during Storm Uri and several LSEs filed for bankruptcy.

### 3.3.4 Stakeholder views on ERCOT

We spoke to several stakeholders with experience of investment in ERCOT. As part of the interview process, we asked for views, experience and evidence on what GB could learn from Texas.

In terms of overall efficiency of the ERCOT market one interviewee thought that “the reason that LMP could be said to have delivered more efficient dispatch is because it's delivered lower overall fuel costs compared to a counterfactual without it. This is because it enables you to dispatch particular types of (particularly thermal) plants more efficiently, especially anything that has a known ramp rate with efficiency penalties in it.” They went on to reflect that in the GB context these benefits will be hard to achieve: “we're going to be running a lot less thermal plant on the system as we get towards 2050 or even 2035 and it's difficult to see how in a nodal system you can more efficiently dispatch wind because wind is always going to be produced when the wind blows.”

One interviewee specifically said that “maybe [GB should] look at what they did with renewable energy zones in Texas” highlighting that the overall strategic system planning rather than the move to an LMP market has delivered the level of wind capacity in Texas. This was backed up with another, US-based interviewee with extensive experience of LMP markets: “I don't want to say LMP doesn't give signals to investment – you can use the LMP models to inform decision making – but ultimately there are other stronger forcing factors. - In the case of Texas this was the State policy [around development of CREZ zones]”. Another specifically highlighted the importance of the central planning and delivery of the transmission capacity noting that renewable investment happened in waves “the first time it happened was

in West Texas [then] transmission investment relieved a number of those constraints. It's now more intensely constrained in southern Texas”.

Finally, several interviewees commented on the risk profile faced by renewable developers in Texas. One key comment, which relates to unexpected consequences following Storm Uri: “[There are] sites in ERCOT where it leaves you incredibly vulnerable. The ice storm happened in early 2021 [and] the political consequences for Texas led to reviews of resilience across the piece, increased conservatism, and introduced safety cases and assessments of transmission capacity. That has caused them [ERCOT or the TOs] to dial back transmission capacity in several places. In some locations [it has resulted in] effectively six years zero or negative pricing for most of the year until transmission investment comes in to relieve that.”

The significant impact caused by extreme events such as Storm Uri is important to consider in the development of any centrally dispatched power system. In common with most emergency events, Storm Uri didn't play out in a way that led to the type of resource scarcity that system planners had allowed for and would have been hard to predict before the event whether a particular generator would have made a financial gain or loss. The market structure had an influence on the scale of the gains and losses and therefore on the scale of risk faced. **Events in GB are likely to be of a different nature but are equally likely to confound our planning assumptions. What happens to customers, suppliers, generators and others is then, in part, down to the way in which market rules interact with situations that they may not have been prepared for.**

### 3.4 Ontario

Area covered	Geographical footprint of the state of Ontario
Size of market	Population: 15 million Peak demand: 23 GW in 2021 Annual energy demand: 133 TWh in 2021
Date of implementation of LMP	Expected 2023
Wind and solar penetration	11% of energy generated from wind and solar in 2021
How is the supply side exposed to locational signals?	Nodal
How is demand side exposed to locational signals?	System-wide price for the majority of demand
FTRs	Included in market design
Security of supply	capacity Market

Ontario's current electricity market arrangements are based around a single real time national pool which was introduced in 2002. There is no day ahead market. The dispatch algorithm is run twice: once without imposing physical constraints such as transmission-limits and ramp rates, giving a solution that is used to set the state-wide hourly Ontario energy price (HOPE); and once with physical constraints included to set the physical dispatch.

However, in 2019 Ontario decided to move forward with the 'market renewable programme' which would transition to an LMP market broadly in line with the standard model used across north America.

The decision to reform the market and the benefit case for doing so were driven by the fact that electricity prices had risen much more than elsewhere in Canada – 71% between 2008 and 2016 in Ontario compared with 34% average growth across Canada<sup>91</sup>. A number of factors were described as having driven these high prices, including the mismatch between market dispatch and pricing and the underlying physical structure of the system<sup>92</sup>.

The market reform programme includes three key elements:

- **Single schedule design<sup>93</sup>**: this involves moving the existing real time market away from the two-schedule (separate price and dispatch runs) to a single schedule where prices and dispatch are set together. The two-schedule design reflects decisions made during market reform in the early 2000s to implement a single national price within a centralised dispatch model. The single schedule design is an implementation of LMP with physical network constraints involved in price and dispatch.
- **Day ahead market<sup>94</sup>**: the introduction of a financially binding day ahead energy market. The current Ontario market does not include a day ahead market although a day ahead commitment process was introduced in 2006 to deal with the need to schedule resources in advance. However, the 2006 reform does not lock in prices for participants and participation is not required for all market participants.
- **Enhanced real time unit commitment<sup>95</sup>**: This will implement a unit commitment process to be followed between clearing of the day ahead and real time markets. It will respond to changes between expected conditions at the day ahead stage and outturn conditions on the day. The project aims to improve on two limitations of current arrangements for unit commitment. Firstly, the current system optimises unit commitment based on energy costs alone and does not consider start-up and no-load costs. This leads to generators with greater overall costs being scheduled ahead of cheaper units. Secondly, the current process evaluates costs separately for each hour rather than optimisation across multiple periods and considering, for example, a unit's minimum run time.

A key piece of work which informed the decision to take forward reform was a 2017 study<sup>96</sup> which concluded that over ten years net benefits would be between \$2.2 Billion and \$5.2 Billion, including implementation costs of \$190 million. It quotes evidence from previous LMP reform programmes, for example the \$509 million cost of implementation in ERCOT in 2010. However around two thirds of the claimed benefits of reform in Ontario come from reform of the capacity adequacy mechanism and the introduction of a capacity auction rather than reform of the energy market. The energy market element of reform was estimated to deliver around \$500 million of benefits over ten years 2021 whilst the benefit of improved system operability was estimated at around \$600 million.

This piece of work led into a business case published in 2019 by IESO, the ISO for Ontario<sup>97</sup>, which quantified the benefits of the energy elements of market reform at between \$290 million and \$490 million with a cost benefit ratio of 2.7 - 4.3. The report highlights that this only quantifies a sub-set of benefits for which a reasonable degree of analytical certainty can be assumed. It highlights benefits such as “reliability risk and future opportunities for greater participation and new technologies, are essential to the IESO’s core functions and the long-term health of Ontario’s electricity markets”. However, many of these types of benefits are either highly uncertain or can only be considered on a qualitative basis and are therefore excluded from the CBA.

The experience of Ontario suggests that the existing national pricing framework with centralised dispatch and compulsory participation has been causing significant issues for the operation of the Ontario power system for many years. Combined with significantly rising prices driven in part by poor integration of the electricity market design with wider energy policies such as the Green Energy Act, a major overhaul of the electricity system was inevitable. Whilst savings associated with the move to LMP are seen to be significant, of the order of \$1 Billion (Canadian) over 10 years much of this could be put down to the deficit of the existing system rather than the benefits of LMP.

### 3.5 New Zealand

Area covered	Full geographical area of New Zealand
Size of market	Population: 5 million Peak demand: 7 GW Annual energy demand: 40 TWh
Date of implementation of LMP	1996
Wind and solar penetration	Around 2% of total demand for electricity (Other dispatchable renewables including hydro and geothermal account for around 70%)
How is the supply side exposed to locational signals?	Nodal
How is demand side exposed to locational signals?	Nodal
FTRs	Introduced in 2013 between two trading hubs and expanded since then
Security of supply	Energy only market, no capacity market

New Zealand was the first country in the world to introduce full nodal pricing. Annual energy production is dominated by hydro resources, contributing at least 50% of generation. New Zealand’s transmission network is characterised by a central backbone with local branches and loops. This has led, at times, to extreme local prices known as the ‘spring washer effect’. These are situations where parallel circuits and loop circuits with generators connected at remote locations can lead to very high price differences in close proximity available such as that shown in Figure 14. Two generators with very different short run marginal costs (SRMCs) are part of a network with two routes to supply power to two demands. The resulting LMPs at the demand

nodes show even greater variation than the SRMCs of the generators. This is because increasing demand at the left-hand demand node requires decreasing the output of the expensive generator as well as increasing the cheap generator in order to avoid overloading the network link already at capacity. Similarly, additional load at the right-hand demand node means reducing the output of the cheaper generator and replacing some of that generation with the expensive generator. A full explanation of the example is available here <sup>98</sup>.

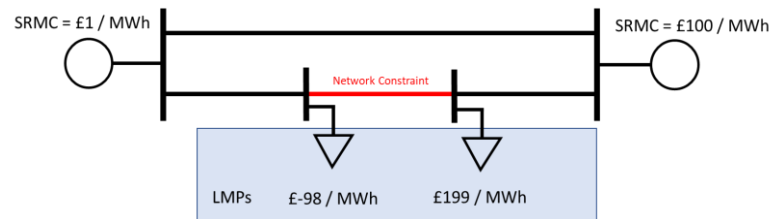


Figure 14: An example of the spring washer effect.

On introduction, the New Zealand LMP market did not include FTRs and offered limited ability to hedge basis risk. This led to the New Zealand regulator allowing previously unbundled generation and supply companies to be reintegrated with individual vertically integrated companies becoming dominant around particular nodes or demand hubs, of which there are only a small number. This created a difficult environment for smaller market participants away from the main trading hubs<sup>99</sup>.

FTRs were introduced in New Zealand in 2013 to help manage locational price risk following the 2010 Electricity Industry Act which required the introduction of mechanisms to help wholesale market participants manage price risks caused by constraints on the national grid. Trading is currently only allowed between designated hubs. The initial implementation began with two hubs and was specifically designed to manage basis risk between the North and South Islands and has grown to allow management of specific areas of constraint<sup>100</sup>.

Experience from New Zealand suggests that in regions with limited transmission network, and particularly regions with radial networks, there can be a risk of unintended price differentials that are driven by the particular design of the network and the connections to it, rather than by anything fundamental. In several areas GB has radial transmission branches or local loops, and increasingly widely dispersed generation is leading to situations where generators connect at the remote end of such circuits. Significant care will need to be taken to understand the mechanisms under which ‘spring washer’ type events can occur and weather specific elements of the LMP algorithm design can accentuate or help suppress them.

**On FTRs, whilst evidence from other markets suggests significant practical limitations in the FTR concept for hedging basis risks, the evidence of New Zealand also suggests significant negative consequences, lack of liquidity and inability to hedge risks, as a consequence of implementing LMP without FTRs.**

### 3.6 Australia (National Electricity Market)

Area covered	Eastern States of Australia
Size of market	Customers: 9 million Peak demand: 35 GW Annual energy demand: 200 TWh
Date of implementation of LMP	N/A – implemented a zonal market in 1998 and has considered LMP solutions several times over the past two decades
Wind and solar energy penetration	20%
How is the supply side exposed to locational signals?	Zonal
How is demand side exposed to locational signals?	Zonal
FTRs	No FTRs or equivalent between zones
Security of supply	Energy only market – no capacity market

Australia provides an interesting case study system as it has operated a zonal market since the late 1990s and has considered moving to a nodal system on a number of occasions in recent years. This section briefly summarizes existing arrangements and the outcomes of the most recent exploration of the idea of ‘LMP with FTRs’.

The National Electricity Market (NEM) was introduced in 1998 and adopts a zonal, centralized dispatch structure. Generators offer into the market; each zone clears at a regional reference price. Participation in the NEM is mandatory for most large types of generators. Settlement periods have recently been reduced from 30 minutes to 5 minutes. Wholesale market prices are capped at \$15,000 / MWh (in 2020, updated annually for inflation) and floored at \$-1000 / MWh.

#### 3.6.1 Recent reforms in Australia

In the context of discussions about LMPs an important point is that under the NEM generators do not have firm access rights and, in common with LMP markets, offer into a centralized auction for each settlement period in order to win temporary access to the system through dispatch. One aspect of the debate about market reform is therefore how risks faced by market actors change between a non-firm zonal system and a nodal one.

There have been a number of issues with the electricity market in Australia over recent years which have driven a lively discussion on market reform. There is a strong focus on security of supply, an issue which gained significant weight following the blackout in South Australia in 2016. In 2017 The Finkle Review led by Australia’s Chief Scientist concluded that: “Australia needs to increase system security and ensure future reliability in the NEM. Security and reliability have been compromised by poorly integrated variable renewable electricity generators, including wind and solar.”<sup>101</sup> It went on to make a number of recommendations about the improvement and integration of system planning through the development of a strategic energy plan.

Following these recommendations, the Australian Energy Market Operator (AEMO) published the first Integrated System Plan (ISP) in 2017 with the objective of describing “a least cost pathway for new transmission and Renewable Energy Zones (REZs) to meet the needs of the sizeable investment in variable renewable generation that is occurring.”<sup>102</sup> The ISP goes beyond the transmission planning approach used in GB where the development of energy scenarios in the FES happens separately from identification of network needs and the optimization of network investment. By contrast, the ISP is as an integrated *system* plan rather than an integrated *network* plan. The ISP will by necessity consider a wide spectrum of

interconnected infrastructure and energy developments including transmission, generation, gas pipelines and distributed energy resources. The ISP is a cost-based engineering optimisation plan that forecasts the overall transmission system requirements for the NEM over the next 20 years.”<sup>103</sup>

In 2019 the Council of Australian Government (COAG) Energy Council initiated a major post-2025 market project based on engaging with five areas of opportunity and challenge covering consumer benefit, investment signals, distributed resource, security of supply, and integrating variable renewables. The objective was to develop a long-term fit-for-purpose market framework to meet the needs of “diverse sources of non-dispatchable generation and flexible resources including demand side response, storage and distributed energy resource participation.”<sup>104</sup>

One of the options proposed through this framework was to move from zonal pricing to LMP with the addition of FTRs<sup>105</sup>. The case for change reflects the fact that congestion within zones was growing and that “all generators access the regional price for their physical dispatch, regardless of their location within the region”

The proposal included a move to full LMP for generation with demand continuing to be exposed to a zonal price. FTRs would have the following characteristics:

- 3 months in duration
- Available up to 10 years in advance
- Baseload or defined for specific hours of the day
- Only available for predefined node-pairs

The decision to offer such long term FTRs was based on stakeholder feedback suggesting that a longer tenure was needed in the NEM, given the forward contract market in Australia, and the dominance of longer term PPAs.

Stakeholder feedback suggested that the LMP / FTR model was not acceptable to market participants who were concerned about exposure to basis risk, high implementation costs and uncertainty arising from factors such as major change to market design<sup>106</sup>.

Instead, a number of design options have been taken forward including one referred to as ‘LMP approaches. A leading proposal is the Congestion Management Model which in effect starts from the zonal model but applies specific rules behind intra-zonal constraints. This aims to deal with two issues. At present, generators behind a constraint will, if dispatched, receive the zonal clearing price without being able to affect it. Therefore, they are incentivized to offer at the market floor (-\$1000 AU / MWh) a process referred to as ‘race to the floor bidding’. Where multiple generations are behind the same constraint this means a set of arbitrary ‘tie-breaker rules’ is required as the information available to the market, i.e., offer price, is insufficient to decide which generators to dispatch.

The Congestion Management model (described in more detail in Box 3) suggested is claimed to provide a route to (a) encourage generators to offer at their short-run marginal cost even when caught by a constraint and (b) provide a revenue stream to generators based on availability rather than dispatch.

In addition to the CCM model (described as a type of LMP model and leading to similar outcomes) there are a number of other models in consideration based on other principles. A consultation on these options issued in May 2022<sup>107</sup> elicited a response against the CMM model and towards a form of congestion relief trading which would see separate congestion markets opened after the initial dispatch and would allow market participants behind a constraint a way to trade congestion relief, that is turning up of consumption or down of generation.

There are a number of useful lessons for GB from the extended debate on market reform options.

- The near universal rejection of the LMP with FTRs proposal by market participants is consistent with some of the comments by interviewees for this report and concerns in GB about the impact of moving to LMPs on the rate of investment.
- The CCM model developed represents one of the few examples that we have come across where a market mechanism looks for ways of avoiding the ‘winner takes all’ issue with LMP markets, an issue that we believe has the potential to be particularly significant in the GB context. (See Section 4.4)
- The value in consideration of holistic system-wide scenario development such as that being carried out under the ISP approach and optimised networks along with generation, demand and wider energy system infrastructure.

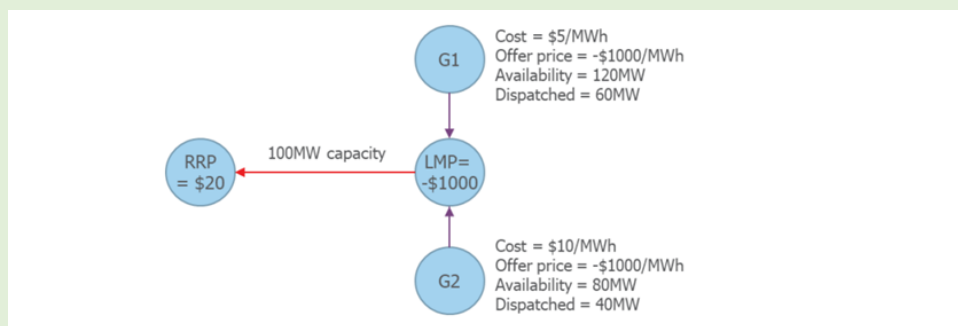
However, it is also important to note the different starting point for the Australian system compared with GB: the zonal system with non-firm access rights in the NEM creates a different environment for market reform compared with the largely self-dispatched financially firm access right system operation in GB.

**Box 3: Summary of the Australian Congestion Management Model**

- Generators continue to be paid the zonal clearing price if dispatched.
- Where intra-zonal constraints are binding, generators will also be charged a **congestion charge** equal to the congestion cost – the difference between the marginal generator behind the constraint and the zonal price.
- The revenue from the congestion charge would then be redistributed to generators via a **congestion rebate** behind the constraint according with a pre-determined allocation metric such as their availability as posted in their offers.

The result, as illustrated in the example below, is that generators are incentivized to offer at their short run marginal cost; to offer lower would risk a congestion charge that would exceed revenues. An availability-based allocation of the congestion rebate provides a way to manage dispatch risk which comes from a ‘winner takes all’ approach and will be particularly important where multiple ZMC renewable generators are behind the same constraint.

The following example shows two generators with differing costs behind a constraint that would under existing arrangements be incentivized to offer at the market floor. The introduction of the congestion charge which will be set equal to the difference between the local price and the zonal price, means they offer at their marginal cost. The rebate redistributes the full congestion charge on an availability basis meaning that generator 2 receives some revenue despite not being dispatched.



	Price received (\$/MWh) (A)	Cost incurred (\$/MWh) (B)	Congestion management charge (\$/MWh) (C)	Quantity generated (MW) (D)	Rebate (E) (\$/h)	Profit (\$/h) (A – B – C) x D + E
<b>Generator 1</b>	20	5	15	100	900	900
<b>Generator 2</b>	20	10	15	0	600	600

Figure 15: An example of the Congestion Management Model approach being considered as part of Australia's Post-2025 market reform work. (Example taken from the Energy Security Board Transmission access reform project initiation paper<sup>108</sup>)

### 3.7 Experience of negative prices and renewable curtailment in LMP markets

One of the challenges of operating any form of electricity market with high penetration of wind and solar is that their physical marginal costs are close to zero. As we discuss in Section 4, combined with support mechanisms that pay out per unit of electricity generated, there is an incentive for zero marginal cost (ZMC) generators to offer negative values into any electricity market. That is, they are prepared to be paid up to the level of their per MWh support to generate.

Market behaviour by ZMC generators with support mechanisms are not the only way in which negative prices might arise. Other examples include large generation units running on fossil fuel or nuclear power with long shut down and start up cycles. These generators may often be prepared to pay significant amounts to remain online and generating at their minimum output levels during a period of low demand overnight lasting several hours if this allows them to remain available for more lucrative periods during the following day. In this case, negative prices will reflect foregone shut down and start-up costs along with a component reflecting the expected opportunity value of remaining online.

The impact of both of these effects will be particularly noticeable in LMP markets. The importance of negative offers from nuclear and fossil fuel generation is evidenced by data going back until at least 2006 which shows negative prices for at least 2% of the time at major trading hubs<sup>109</sup>. However, in recent years ZMC renewables have increasingly set the marginal price behind certain network constraints. This effect can be seen particularly clearly in certain parts of the US, such as North Texas (ERCOT), Oklahoma and Kansas (Southwest Power Pool). Figure 16 shows that in 2017 negative pricing occurred at many nodes in these regions for at least a quarter of the year.

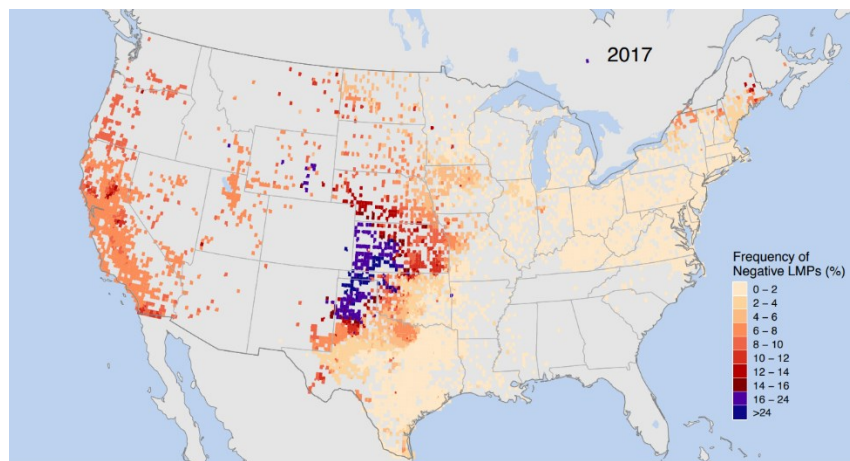


Figure 16: Frequency of negative real time power prices in 2017 (From work by Berkeley Lab)<sup>110</sup>

These negative prices, along with reduced positive prices at other times, are having a significant impact on the value of wind developments. According to a recent review by the US Department of Energy, wind's market value (capture price) was approximately 50% lower than average wholesale prices in SPP, ERCOT and MISO, approximately 40% lower in NYISO, and approximately 20% lower in CAISO, ISO-NE and PJM. The report noted that "these value reductions were primarily caused by a combination of transmission congestion and wind generation profiles that were negatively correlated with wholesale prices".<sup>111</sup>

The business case for wind in these markets depends on a combination of market value, potential adjustments to that value in PPA agreements with offtakers, any ancillary services / capacity payments, and support mechanisms such as the Federal Production Tax Credit which can pay out up to \$25 / MWh. The Department of Energy 2020 review suggests that the levelized cost of energy from wind is between \$29/MWh and \$35/ MWh depending on location, whereas recent PPA agreements tend to be around \$20 /

MWh in the centre of the country and \$30 / MWh in the west, although examples have been seen in the mid-teens. It is also interesting to note that wind PPAs have typically been very long-term ranging from 10 to 35 years.

PPAs have generally been slightly higher than the market value (the value that would have been achieved had the wind farm sold power in the LMP market without a PPA) which have ranged from \$11 / MWh in ERCOT to \$29 / MWh in CAISO. These figures show that the ability to finance a wind project depends on a combination of direct market revenues with or without a long term PPA, and support mechanisms, in particular the federal production tax credit. They also show the impact of wind on LMP market prices and the significant reduction in an area with high wind penetration, such as ERCOT, compared with other markets.

A related but separate issue is curtailment or non-dispatch of wind. As generation in an LMP market does not have firm access rights to the grid the meaning of the term curtailment differs from the usual GB meaning. Curtailment in this context can mean one of two things: either a failure of a wind farm to get dispatched in the market, or a redispatch by the System Operator (either through market mechanisms or other systems) to turn down wind<sup>xvii</sup>. The Department of Energy review found that curtailment of wind was around 3% nationally in 2020 and was highest in MISO at around 5%. The results are shown in Figure 17. The highest level of annual curtailment was seen in ERCOT in 2009 at 17%, where it fell to 0.5% in 2014 following significant transmission build out and has risen again since reaching 4.6% in 2020<sup>112</sup>.

If LMP were implemented, GB would immediately create significant areas where the prevalence of ZMC generation and transmission constraints impact on nodal prices to an even greater degree to that seen in the US. Although some ongoing GB work is looking at potential LMP prices in a GB system this work needs to be taken further with a specific focus on the potential ‘capture prices’ for different types of generators. It will also be important to understand the factors that affect the prices at which US style PPA agreements are stuck and how this might map onto wider trading arrangements in GB.

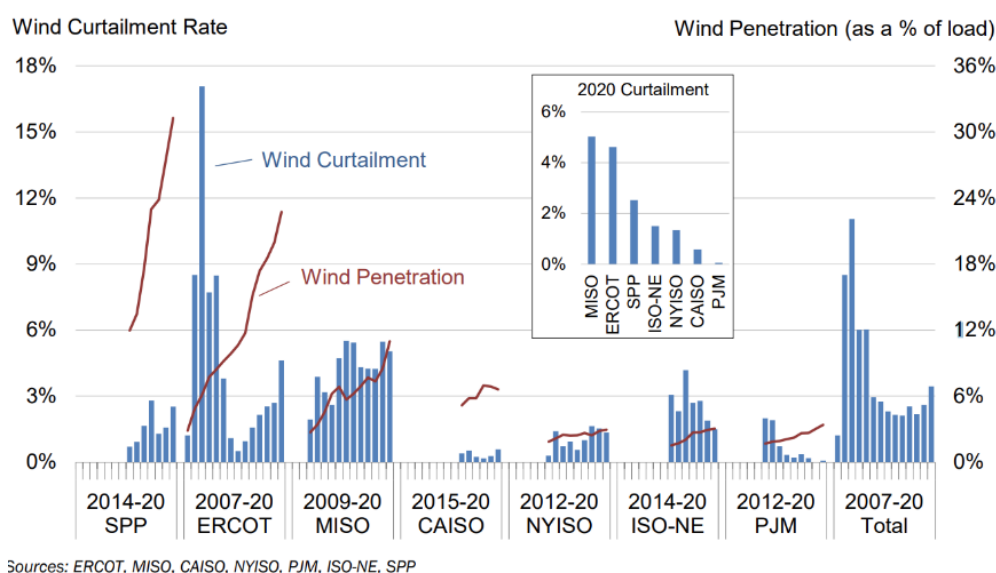


Figure 17: Wind curtailment and penetration rates in US ISOs up to 2020<sup>113</sup>

<sup>xvii</sup> For an example of a non-market-based curtailment mechanism used in the Southwest power pool see: [https://www.spp.org/documents/31797/fag\\_for\\_non\\_dispatchable\\_curtailments.pdf](https://www.spp.org/documents/31797/fag_for_non_dispatchable_curtailments.pdf)

# Challenges of introducing LMP into the GB system

## 4 Challenges of introducing LMP into the GB system

This chapter focuses on a number of specific challenges that would be associated with introducing LMPs into the GB system. The case studies in Section 3 have described the experience of existing LMP markets and have shown that they can be successful in the particular contexts in which they have been implemented. However, looking ahead to a decarbonised electricity system in GB offers a very different context to even the most decarbonised LMP systems today.

The differences between GB and existing LMP systems revolve around the scale and pace of installation of Zero Marginal Cost (ZMC), variable renewable generators, primarily on- and off-shore wind and solar. This section discusses the following challenges associated with implementing LMP in such a system:

- **Very high penetration of wind and solar**
- **Managing risk**
- **FTRs in the GB system**
- **Transmission constraints driven by zero marginal cost renewables**
- **Integrating LMP with the GB Contract for Difference support mechanism**
- **A large number of existing generators with legacy arrangements for connection, access to the system, support mechanisms**

In addition to these points, there are many considerations which are common between GB and markets using or considering using LMPs. These include the need to support flexibility, the coordination of transmission development with generation (beyond the specific challenges of the current GB transmission network), the impact of LMP on siting decisions for market participants, and the most appropriate way to compare costs and benefits when making decisions on market reform. These wider points are discussed further in Section 5.

### 4.1 Very high penetration of wind and solar

One of the biggest challenges of introducing LMP into the GB system is to consider how would the market operate when around 80% of generation is expected to come from wind and solar. This is significantly beyond the 20 – 30% penetrations seen in some existing LMP markets.

Wind and solar have a number of distinct but related characteristics, each of which may need to be considered separately within the design of an LMP market:

- **Zero Marginal Cost:** Both wind and solar have no fuel costs and very low variable operation and maintenance costs. The production of the next MWh (given that wind or solar resource is available) is close to zero.
- **Variable and correlated:** generators can only operate when the wind is blowing and the sun is shining. Variability can be highly predictable (tidal energy is a good example) or highly uncertain (such as with wind). However, the output of different generators, particularly those in close proximity to each other will be highly correlated: each generator will be experiencing similar weather. This correlation of output creates a situation where there is usually either an excess or a scarcity of available generation across a region or a whole system and it is less common to have an intermediate amount.
- **Uncertain:** The future availability of wind and solar is uncertain and the level of that uncertainty will vary depending on several factors including: the time interval over which predictions are made, and the form of weather system currently dominating (e.g. low or high pressure).

Each of these characteristics needs to be considered as part of the process of understanding the operation of an LMP market. Firstly, the ZMC nature of these generators means that in an efficient spot market they are likely to offer energy at or below zero price (depending on their support mechanisms). The correlated variability is the characteristic that will drive both national and regional excesses of renewables leading to more situations where they set the national or local prices. Finally, the uncertainty will drive the interaction between day ahead and real time markets as well as longer term bilateral trading. Throughout this and the following sections we refer to wind and solar generators as **ZMC renewables** unless one of the other characteristics is of particular importance to the point being made

Many commentators focus on the fact that the theory of LMP remains valid even with high penetration of ZMC renewables. For example, William Hogan a pioneer of LMP theory, stated in a 2021 paper that the “change to the green supply curve would not change the basic design principles ... the prices would change, and would be driven entirely by scarcity pricing, but the market design would be unchanged.”<sup>114</sup> Similarly Frank Wolak argues that “The basic features of an efficient short-term wholesale market design do not necessarily need to change to accommodate a significantly larger share of ZMC variable renewable energy from wind and solar resources”<sup>115</sup>.

However, there is a concern that a fully decarbonised system will accentuate many of the issues of existing LMP markets. Examples include the interaction between LMP energy markets and capacity adequacy mechanisms; the interaction between energy, response and reserve provision which are all dispatched through the LMP algorithm; the need to manage high ramp rates; and the importance of supporting investment in the face of transmission constraints which will drive prices to zero or negative values very regularly in some areas of the country.

Of course, there are also potential benefits. One of the features of LMP markets are that they involve central dispatch which provides a mechanism for the coordination of locational availability and constraints. There are questions about how a system without centralised dispatch can ensure efficient dispatch to meet demand.

Overall the following points related to the operation of markets with high ZMC renewable penetration need to be considered:

- At present there is no operational evidence of how an LMP market would work (or indeed, at a national level, any form of electricity market structure) with such high levels of ZMC renewables. Significant periods of very low or negative electricity prices system wide reflected by the energy component of the LMP when there is a national excess of ZMC energy available.
- Even more significant periods of very low or negative electricity prices behind network export constraints. This would be reflected in the congestion component of the LMP.
- Periods of very high prices when ZMC renewable resources are not available. During these times schedulable production including CCGTs or fuel cells using hydrogen, gas with CCS plant, discharging energy storage and demand-side flexibility will set the energy component of the LMP along with imports over interconnectors. As noted by Hogan in the quote above – this will likely lead to scarcity pricing for significant periods as schedulable generation aims to recover its sunk costs. The importance of scarcity pricing grows compared with its role in existing power systems as, without appropriate capacity or other availability-based payments, it is not just extreme and rare events which drive scarcity pricing but more regular low-renewable events.
- The above points will lead to significant short-term variability in the LMP price. There is an open question as to the degree to which the characteristics of the variability (mean, standard deviation etc.) will be easy to forecast in advance either at a national level (the energy component of LMP) or at a nodal level (including the congestion element) and allow market actors to quantify risk.

- Likely significant reliance on ancillary service and capacity market revenues for schedulable generators whose load factors will likely be reduced compared to today.

## 4.2 Managing risks

One of the key differences between current GB market arrangements and LMP is the management of risk: who takes it and what tools are available to manage it? NGESO articulated this in their recent REMA response, highlighting that, in their view, market design should not aim simply to minimise risk but to appropriately allocate it as well: “We believe that risks should be placed on market participants who are best placed to manage them. Minimising risks without considering appropriate risk allocation may lead to sub-optimal cost-effectiveness for the system overall, ultimately increasing consumer costs”<sup>116</sup>.

The current set of risk and cost allocations faced by market participants are a function of the decentralised, national, self-dispatch market design along with the machinery for re-dispatch through the Balancing Mechanism, and revenue streams received through the capacity market, CfDs and other support mechanisms. Both consumers and generators face price risk, but due to the firm financial access rights granted to generators, much of the risk (and cost) associated with transmission congestion, curtailment and re-dispatch was directed at consumers as a deliberate policy to accelerate renewable deployment.

Under an LMP market risk allocation changes. Market participants lose their financially firm access rights and have to win access to the system through the LMP auctions (see Section 2.1). Generators now face the risk of transmission congestions and the inability to get dispatched.

Beyond the risks faced by market participants, it is also important to consider wider societal risks associated with the overall objectives for the electricity system. Decisions over market frameworks can have significant impact on our confidence of delivering a decarbonised power system by 2035 and on the ability to ensure a reliable supply of electricity. Assuming both of these can be delivered, if decisions are made without sufficient testing of the likely cost outcomes, a choice that appears in a CBA to be lowest cost, may turn out in practice to be more expensive; therefore, society as a whole, as well as individual market participants, faces a price risk.

Discussing risk for electricity market arrangements is challenging: many individual risks overlap and the routes through which those risks are allocated can be complex. Figure 18 summarises the key risks and re-allocation of risk discussed in this section that might be argued to arise from the introduction of LMP. It covers both market participant risks (covered in Sections 4.2.1 – 4.2.7) and regulatory risks (covered in Section 4.2.8).

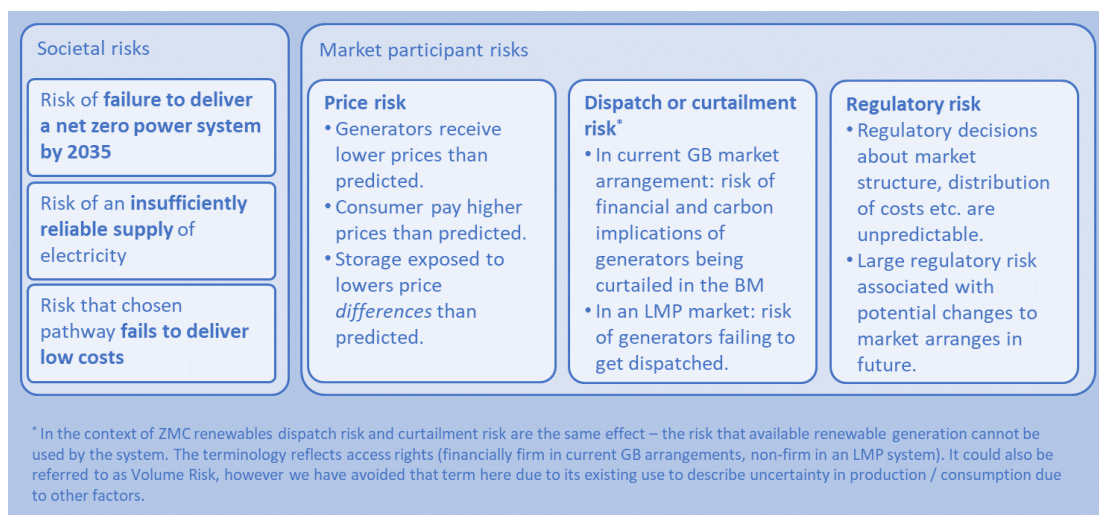


Figure 18: A description of key risks and re-allocation of risk arising from a move to LMP.

#### 4.2.1 Price risk

For generators price risk reflects the uncertainty in the unit-price they will receive for their energy in future and therefore a key part of their revenue stream. For consumers it is the uncertainty in the unit-price they have to pay.

In the current GB market both consumers (with suppliers<sup>xviii</sup> acting on their behalf) and generators are able to use bilateral contracting to help mitigate and manage that risk in the wholesale energy market. In general, both are exposed to and have options to manage price risk. The exception is renewable generators with CfD contracts where price risk is partially removed for the duration of the CfD (subject to negative pricing rules - See Section 4.5.2), and these generators are guaranteed a fixed price.

Currently market participants in GB do face a location-dependent net revenue risk through the Transmission Network Use of System (TNUoS) charging regime. This imposes network charges on consumers and generators based on the zone within which they are located. The aim of the regime is to apply forward looking cost-reflective charges on market participants through which to direct locational choices that help optimise the location of generation and the cost of transmission.

In an LMP system however significant locational risk is introduced through wholesale market prices themselves and it is expected that these will show significantly greater price volatility compared with the current GB TNUoS arrangement. Much of this risk will come through the congestion component of the LMP. Therefore, price risk in an LMP market encompasses much of what is discussed as congestion risk under current GB arrangements where it does not impact on wholesale prices.

A recent report has highlighted the significantly higher level of volatility, i.e. liability to change rapidly and unpredictably, that would potentially be faced by a wind farm in LMP markets (using ERCOT and PJM as case studies) compared with the volatility faced in GB under TNUoS<sup>117</sup>. Whilst prices are expected to be variable and difficult to predict far ahead of real time, particularly when there might be congestion, that does not automatically imply greater risk if there are the means to manage it. Indeed, one interviewee pointed out that volatility is actually a desirable feature for a future electricity system: “volatility is good and there will be more of it in future to provide useful signals to players to unlock flexibility. Anyone who can manage their demand should be able to get value out of that”.

<sup>xviii</sup> In the GB section the term ‘supplier’ is used with its usual GB meaning.

Whether or not nodal prices with high levels of variability are predictable depends on the underlying factors driving the variability. For a node experiencing significant congestion these underlying factors include transmission capacity linking that node to the main demand hubs, local demand, generation and flexibility levels, the short run marginal cost and bid / offer behaviour of other market participants.

These factors may be reasonably predictable over short timescales. A good understanding of the current system could provide reasonably high confidence of: near-term demand levels; generation outputs tomorrow or (subject to weather conditions) next week or month; and market intelligence will allow participants to develop reasonable estimates of costs and prices. Similarly, the level of transmission capacity is likely to stay relatively constant in the short term (although the risk of reductions due to fault or maintenance outages is an issue).

However, in the long term there is increasing uncertainty. It is difficult to predict today what other generation may be operating behind a constraint in five- or ten-years' time, and it will be difficult to predict the level of transmission capacity available. This has the potential to leave market participants behind a constraint at significant risk. For example, demand developed at a particular location to take advantage of energy that would otherwise be curtailed might suddenly find itself competing with other consumers for that energy. Conversely, generation in an import constrained area that subsequently sees network reinforcement might suddenly see the value of its supply fall considerably.

The next question is whether those market participants are best placed to manage those risks over medium to long term time scales. Taking three of those factors:

- **Managing the risk associated with changes to the local generation and demand portfolio:** an individual market participant has very little, if any, ability to influence the wider generation and demand balance behind a particular constraint. This will depend on the commercial decisions of other generators and consumers.
- **Use of flexibility to mitigate risk:** individual market participants could invest in physical flexibility in order to mitigate some short-term variations in marginal price, however the cost of some forms of flexibility such as battery storage could make this an expensive risk mitigation measure.
- **Managing risk of changes to transmission capacity:** this can be partially mitigated through the allocation or purchase of FTRs. However, there are significant limits on this in existing markets: As discussed elsewhere in this report FTRs tend only to be available for up to 3 years with significant concerns in some markets about the effectiveness and value of FTRs beyond 1 year into the future. (See discussion on PJM and CAISO in Sections 3.1 and 3.2).

Several interviewees touched on the issue of price risk and the ability to find counterparties willing to trade. One interviewee, commenting on experience in Texas, said, "You can't get anyone to take long-term risk. Maybe you can get a couple of years, or [maybe] three [through a bilateral contract]; but these are 30-to-35-year assets."

They highlighted the impact of the 2021 ice storm on the transmission owners' policy on defining operational line ratings: "this [The storm] caused them to dial back transmission capacity in several places and it's left us, for example, in some locations with effectively six years zero or negative pricing for most of the year, until transmission investment comes in to relieve that."

Decisions such as this suggest that price risk in an LMP market can often be set by events that are beyond the power of individual market participants to control, and without long term FTRs available they are unable to mitigate it. The interviewee concluded that the risk faced by developers can be characterised by: "when you get it wrong, you'll get it really, really, seriously wrong. So that's what you have to price in up front: I need to make sure that when it goes right [I capitalise on it]"

Another interviewee with extensive experience of US markets highlighted the importance of sufficient transmission capacity before price risk becomes manageable: “I would not be in favour [of an LMP market] if I were a Scottish generator” and if one were introduced, “I would be saying build me transmission or give me all the congestion revenue in [between Scotland and] London”.

**This discussion shows that there is the potential for significant increases in medium to long term price risk faced by developers in an LMP market compared with current GB arrangements. It is also far from clear that those risks can be managed or mitigated by individual developers. If unmanaged or unmitigated, it could risk reducing investment and increasing risk premiums.**

#### 4.2.2 Dispatch risk (or curtailment risk)

Dispatch risk is a risk faced by generators and relates to the risk of failing to get physically dispatched and generate electricity due to physical limits of the system. The term ‘curtailment risk’ is more intuitive in the current GB system as generators currently self-dispatch on and are then curtailed off by the system operator if required. The term ‘dispatch risk’ is more suitable for discussion of LMP markets where generators do not have firm access rights to the system. In this case the risk relates to whether or not they can get dispatched on. However, it is important to remember that, in practice, the terms dispatch risk and curtailment risk relate to the same effect – wind or solar generators being unable to export to the system when the wind is blowing or the sun shining.

It is also worth clarifying the two major causes of dispatch risk. The first source of risk comes from the probability that at certain times a generator’s offer will be more expensive than the system-wide marginal cost of generation. For ZMC generators this is likely to happen when there is a *system-wide* excess of must-run synchronous / baseload generation and ZMC renewables over demand.

The second source of dispatch risk is related to transmission congestion. It is the risk that there is more generation available behind a constraint offering lower prices into the market than there is local demand and transmission capacity across the constraint.

We deal with these two sources of dispatch risk in the next two sub-sections below.

#### 4.2.3 System-wide excess renewables risk

An excess of renewables nationally means a situation where there are more ZMC renewables over and above the sum of demand and interconnector export flows less output from must-run generation. When there is an excess of renewables it is likely to create a situation where national prices are close to zero or below. Although this may attract an increase in demand, e.g. from charging of storage or manufacture of hydrogen, reducing the excess of available generation, this will generally lead to some renewable generation failing to get dispatched. For generators this creates both price risk and dispatch risk.

In current GB market arrangements, the costs and risk associated with excess renewables are managed through a number of mechanisms. Firstly, generators must find a buyer for their output in order to self-dispatch on against either a bilateral contract or a contract won through a power exchange or an agreement with NGENSO to provide balancing services. Without this, if they still choose to generate, they will be entitled or exposed to only the BM system price for energy imbalance, which, on some occasions may be negative<sup>xix</sup>. However, many ZMC renewables have PPAs where the offtaker agrees to buy all output from the generator. The share of risk between generator and offtaker will depend on the terms of the PPA. For example, if the PPA has a fixed price with no separate provision for dealing with periods of negative prices, the price risk is passed to the offtaker, and the generator doesn’t face a dispatch risk. However, for PPAs index linked to wholesale electricity market indicators like the day ahead power exchange prices, the generator still faces

<sup>xix</sup> Even in today’s GB system, negative system prices in the BM have sometimes been seen

the risk of negative prices and may choose to manage this by self-curtailing generating during those periods. This might be described as the generator facing price risk but not dispatch risk (as the generator can be self-dispatched on if it chooses, but only in return for paying to generate).

The risk for ZMC generators is then further modified by their support mechanism. As discussed below, generators entitled to Renewable Obligation Certificate (ROCs) or Feed-in Tariffs (FiTs) have the cushion of a fixed price support per MWh generated. CfD generators are exposed to this risk differently depending on their allocation round (AR). AR1 generators will not face this risk as they will be paid a CfD top up to their strike price even during periods of negative day ahead pricing. AR2 and AR3 generators will not face this risk unless the duration of the negative price period exceeds 6 hours. And AR4 generators will face this risk in its entirety as CfD uplift payments are not made during any period where the day ahead market price is negative.

In summary: in the present-day GB market, generators will generally **face some price risk** during periods of excess renewables, potentially shared with an offtaker, and potentially cushioned or hedged by their support regimes, **but not dispatch/volume risk**.

Moving to an LMP market means changing the allocation of risk. During periods of excess renewables, prices across the system are likely to fall to zero or negative and this will be seen at all nodes as it affects the energy component of the LMP (See Section 2.1). If trading only through the LMP market, without bilateral contracts or support mechanisms, generators will now face a mixture of price and dispatch risk: price risk associated with whether they have to generate at very low prices; and dispatch risk because they may not get dispatched by the LMP algorithm at all.

However, it is likely that bilateral trading and support mechanisms will exist. As discussed in Section 2.8.3, it is feasible that generators may have signed up to private CfD arrangements<sup>xx</sup> with an offtaker which mean that the price element of risk can be hedged, depending on what terms offtakers are willing to sign up to. Any future centralised CfD arrangements also have the potential to significantly affect the share of risk. These are discussed in detail in Section 4.5.

**A general conclusion, though, is that bilateral contracts and support mechanisms could in theory mitigate and hedge price risk associated with periods of excess renewables but not dispatch risk. Therefore, a move to LMP is likely to increase the risk faced by generators during periods of system-wide excess of renewables.**

#### 4.2.4 Congestion risk

In GB today, most generators do not face a financial risk associated with network congestion in the short-term<sup>xxi</sup>. Larger generators gain firm financial access to the system through their connection agreement and their ongoing payment of Transmission Network Use of System (TNUoS) charges. The mechanism for ensuring financial firmness even when the system is not capable of taking their generation (i.e. they are not *physically* firm) is via the BM where those generators submit offers at a negative price to recoup any revenue losses associated with curtailment<sup>xxii</sup>.

The consequence of a system which does not place congestion risk on the generator is that the risk is placed with those who pay the cost of congestion. The process of paying for redispatch to manage congestion in the

<sup>xx</sup> Readers are reminded of the important distinction between private CfD arrangements agreed as bilateral contracts between two individual market participants and centralised low carbon support CfDs between a generator and a centralised organisation, on behalf of all consumers.

<sup>xxi</sup> To the extent that network congestion leads to investment in additional network capacity and, as a result, higher TNUoS charges, it could be argued that generators are exposed to long-term financial risk arising from congestion.

<sup>xxii</sup> Smaller distribution connected generators not participating in the BM normally have a firm physical connection with a Distribution Network Operator (DNO), although a minority of these smaller generators operating under active network management schemes may be on non-firm connection agreements which does place some dispatch risk on the generator.

current GB system is through Balancing Service Use of System (BSUoS) charges. Today BSUoS costs are split approximately equally between demand customers and generators. However, a recently approved code modification will, from April 2023, change this so that 100% of these costs are recovered directly from the demand side<sup>118</sup>. Therefore, it is end consumers who directly face the overall cost and risk associated with transmission congestion.

Under an LMP market this situation changes. As market participants don't have financially firm access rights to the network - rather, they are allocated those rights only when they are dispatched in the day ahead or real time markets - they face the financial cost of not getting dispatched and it is the generators themselves that face that risk. The risk comes in the form of both price risk (where local nodal prices fall to zero or negative but generators are still dispatched) and dispatch risk (where generators caught behind constraints do not get access to the network in the particular settlement period).

Access to the system is required for any revenue stream (except, potentially, behind-the-meter activity)<sup>xxiii</sup> and reducing that access means reducing the potential for any project revenue. Whilst it could be argued to be appropriate that generators face the cost and risk of failing to get dispatched, questions remain as to what the impact of this will be on investment and operation, how much control generators have over the risk and what mitigation measures are available to generators to manage the risk. Going through each of these:

- **Impact on investment and operation – potentially high:** where congestion leads to failure to get dispatched on a regular basis or exposed to very low prices, this removes the ability of the generator to carry out its core business as it does not have access to its markets (either for energy or ancillary services).
- **Control over risk – likely to be low or zero:** where the risk is caused by the actions of the transmission owner or investment in, and operation of, the assets of other market participants the potential for controlling that risk is likely to be negligible. For example, a network owner can introduce congestion through its actions, such as the taking of outages for maintenance. The example quoted above in Section 4.2.1, where the network owner reduced transmission ratings in Texas following storm Uri, illustrates the lack of control market participants can have over this type of risk.
- **Options to mitigate risk – may exist in principle but may not in practice:** options to mitigate price risk include agreeing bilateral contract agreements such as private CfDs and the use of FTRs. However, it is unlikely that counterparties, equally aware of the risks faced, would be willing to sign up to contracts which shield generators fully from congestion risk. Again, evidence quoted early and relating to Texas shows the difficulty in signing long term PPAs and as discussed elsewhere in this report, FTRs are generally only available for a maximum of three years.

One way in which a generator could manage congestion risk and other contributions to price risk is through investment in flexibility, either in the form of energy storage or flexible demand such as electrolyzers. These provide a physical hedge. When prices are low or dispatch to the system is not available, generation can be dispatched along with charging of storage or electrolysis. It is important that our future market model supports the development of flexibility, and this is one way in which LMP could support it. However, the degree to which flexibility can mitigate risks faced by market participants is an empirical rather than a theoretical question: it depends on the characteristics of the technology and the patterns of low price, renewable resources, demand and congestion. For example, the 'excess generation' graph in Figure 5 shows the potential pattern of excess generation in Scotland in 2035. One characteristic of this is the relatively long periods of excess generation punctuated occasionally by relatively short periods without excess generation.

<sup>xxiii</sup> Behind-the-meter connections would allow generation to be used by demand without flowing onto the public system.

This pattern does not suit the business case of battery storage; it may better suit the business case for electrolysis. However, the siting of electrolysers is likely to face constraints not faced by batteries: the need for access to a store of hydrogen and the ability for a buyer of hydrogen to transport it.

**In summary a move to LMP is likely to place significant additional congestion risk on generation developers compared with the current GB market. Much of this risk is likely to be due to changes in transmission capacity, and investment in and operation of other generators, flexibility assets and demand customers (i.e. under the control of those other market participants). The risks will manifest as both price and dispatch risk. It may be theoretically possible to mitigate price risk to some degree, although this will be more challenging in practice. However, dispatch risk is hard to manage.**

#### 4.2.5 Transmission upgrade delays and transmission outages

This is a component of overall congestion risk already discussed. It provides a concrete example of the type of risk faced by market participants trading in an LMP market. It is the risk faced by market participants when they have assumed that a particular level of transmission capacity will be available from a particular date.

An example of where this risk will be pertinent is the delivery timescale for upgrading of the transmission network between Scotland and England. For example, an Eastern HVDC link first was proposed a number of years ago but only recently has the Network Options Assessment (NOA)<sup>119</sup> indicated a firm commitment to it with capacity of 2 GW and a planned commissioning date of 2027<sup>120</sup>. Market participants aiming to connect before or around 2027 will need to take a view on how likely it is to be completed on time and how they are exposed to the risk of delay. There is some historical evidence to help: some major transmission projects have been completed on time, for example the Caithness Moray link<sup>121</sup>, whilst others such as the Western HVDC link have been significantly delayed<sup>122</sup> and suffered major outages since commissioning.

Under existing GB arrangements<sup>xxiv</sup> consumers will pay the full cost of network congestion through BSUoS until new transmission capacity is commissioned. It is consumers, therefore, who face this risk. The risk might be mitigated by, for example, improvements to the process for identifying and approving network investment or imposing penalties on the Transmission Owners if they do not meet agreed commissioning dates.

A closely related issue is the operation of the transmission network including the management of outages of parts of the network due to faults, ongoing maintenance and the need to upgrade capacity. This is a challenging risk to quantify as there is a lack of transparency over the operating capability of the transmission network and the occurrence and duration of faults and maintenance outages. Even with an understanding of individual outages it would be challenging to estimate the impact as there is not a simple MW-to-MW relationship between the components' capacity and boundary transfer capability.

Figure 19 shows how the operational boundary transfer capability of key system boundaries can fall significantly below the nominal values quoted in annual assessments and which are often used in impact studies.

<sup>xxiv</sup> Following BSUoS rule changes scheduled for April 2023

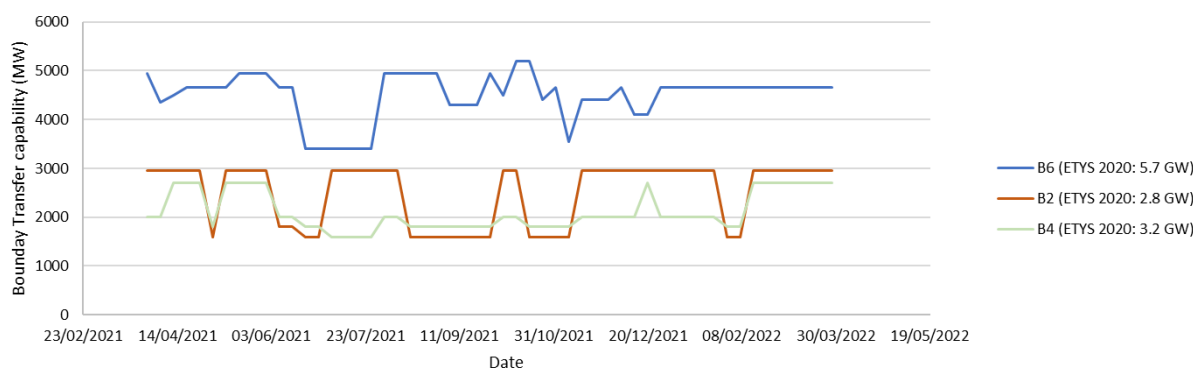


Figure 19: Forecast operation boundary limits for three key Scottish boundaries for the financial year 2021 – 22. The graph legend notes the nominal boundary capacity transfer listed in ETYS 2022 and shows that operational capacities were expected to fall significantly below nominal for much of the year for all three boundaries. Additional un-planned outages would have reduced this further<sup>123</sup>.

The data in Figure 19 shows forecast operating capability but, unlike generation outages, outturn transmission outages are not made public. One option to improve the understanding of this risk, valuable in any set of market arrangements, is to require NGESO to publish network congestion maps on a regular basis, and possibly in real time. This would include information about the current boundary capability of each of the major system boundaries, current transfer levels, and a live list of network outages. NGESO does report planned and outturn boundary capability each week in their transparency forum. However, due to the occurrence of unplanned outages or changes outage schedules, actual capability is often different from that which had been planned. Moreover, a good indication of daily boundary capability over a number of years would be required to inform investment decisions by network users exposed to dispatch risk.

Under an LMP market the market costs and risk caused by transmission delays and outages will fall directly on the market participants affected. In export constrained regions that will be generators. These are risks that cannot be controlled by those market participants and few options exist to mitigate them.

One argument put forward by an interviewee was that “moving to an LMP market will create a motivated group of market participants willing to spend effort highlighting and lobbying against inefficient operation of the transmission network”.

Much of the framing of debate around LMP and network constraints in Britain has concerned regions where there is, for much of the time, a surplus of available generation relative to demand. For generators, dispatch depends on there being sufficient network export capability. As the interviewee notes, these network users have a strong interest in the network being reinforced. However, the flip-side of this argument could occur in an importing area in which certain generators are needed to run because the network’s capacity is insufficient to import all the power needed to meet all demand in the area otherwise. Generators in the area benefit from lack of network capacity and may have the opportunity to exercise market power. They might therefore be expected to lobby against network reinforcement<sup>xxv</sup>.

#### 4.2.6 Capacity adequacy risk

Consumers face the risk that demand exceeds available generation capacity leading to a loss of supply to at least some customers. This can manifest as very high wholesale and balancing market prices as well as the need to disconnect customers. In GB generation adequacy risk is mitigated on behalf of consumers through

<sup>xxv</sup> In contrast, demand users of the network in an exporting area where they benefit from low marginal prices might be expected to lobby against network reinforcement while demand in an importing area might lobby for it if they think their security of supply is threatened or marginal prices in the area are excessive.

the Capacity Market which aims to maintain sufficient generation capacity to ensure a maximum 3-hour loss of load expectation.

An LMP market is compatible with a capacity market and most existing LMP markets combine nodal pricing with some form of capacity adequacy support. This becomes increasingly important where inframarginal and scarcity rents are limited<sup>xxvi</sup>. LMP markets are more likely than national markets to squeeze inframarginal rents in exporting areas as market prices behind a constraint will be set by the locally marginal generator rather than the nationally marginal one. This is generally argued to be a positive for consumers who avoid paying the inframarginal rent which, if it exceeds long-run costs, accrues to generators as profit. However, in a competitive market with prices set by generators with very low short-run costs, it is difficult for generators with significant up-front investment to pay off debt and reward equity. This is the well-known ‘missing money’ problem, and it is a problem that is becoming more significant in renewable dominated systems.

Experience with Texas in 2021 and California in 2020 show that an LMP market doesn’t guarantee generation adequacy and can lead to extreme and inappropriate outcomes during periods with low or negative generation margins. Texas’s energy-only market (it does not have a separate capacity market and relies on scarcity rents to entice investment) failed to deliver sufficient reliable capacity to meet high levels of demand during unexpectedly cold weather. Whilst California's LMP market plus system resource adequacy programme failed to deliver sufficient capacity to avoid rolling blackouts during early evening in the summer of 2020.

In GB the role of some form of capacity market can be expected to grow substantially as we move towards a decarbonised electricity system even under a national wholesale energy market. Load factors for schedulable plant are expected to reduce and the number of start-ups and shutdowns may also increase. At the same time, achieving decarbonised power will require schedulable generators to become zero or low carbon, most likely either through the development of hydrogen generation or the combination of natural gas with CCS, both of which will lead to significantly higher capital cost compared with today’s load following CCGTs and gas peaking plants. The result could be that wholesale energy market revenues reduce whilst capital costs will increase.

The introduction of LMPs will squeeze energy market revenues for generators by reducing infra-marginal rent. This will be a particular issue for schedulable plants that locate in constrained regions alongside ZMC generators. For example, the proposed natural gas with CCS plant at Peterhead<sup>124</sup> will, under LMP, see a reduction in the prices it is able to command during at least some of its operating periods - those where a network constraint is binding. There may also be challenges for schedulable plant associated with dispatch risk. During periods where there is a significant excess of ZMC renewables available schedulable generators may face similar dispatch risk to those renewables, but there is the potential for additional implications associated with shut down costs, minimum down times and costs for restarting.

The value of an effective and efficient generation adequacy mechanism is likely to grow over the coming decade, and this will be even more important if an LMP market is introduced. Evidence from the US shows these two components can work together effectively. However, experience also provides examples of where they have not worked well. **The introduction of LMP may increase the importance of a well-designed capacity adequacy mechanism.**

---

<sup>xxvi</sup> Infra-marginal rents represent the revenue between the market clearing price and the price for which a generator offered its energy, normally its short run marginal cost. Infra-marginal rents allow high and mid-merit plant to recover their long-run costs. Scarcity rent is the additional revenue generators receive when the market clearing price rises above the short run marginal cost of the marginal generator during periods of very tight margins. Scarcity rents are important for peaking plants that may operate for a few tens or hundreds of hours a year and have limited opportunity to capture inframarginal rent.

#### 4.2.7 Regulatory risks

One interviewee described a move to LMP as an opportunity to significantly reduce regulatory risk which is inherently hard to manage or mitigate (they cited changes to TNUoS rules as an example), and substitute it for market risk which can be managed. They went on to highlight that LMP market designs – in their opinion – seem stable highlighting that no LMP market has moved away from the LMP concept. In the conversation that followed the interviewee acknowledged that the argument relies on appropriate mechanisms being available to hedge risk: FTRs, opportunities for bilateral trading and renewable support mechanisms.

This is ultimately an empirical point and depends on the specific market arrangements in place. Much of the discussion within GB appears to be focusing on the mitigation of price risk for generators, whereas the discussion above has highlighted the importance of the separate but related dispatch risk. It also highlights some doubts about the ability of existing mechanisms to mitigate price risk since, as with many elements of electricity market design, this will depend deeply on the details.

It may also be argued that, due to exposure to dispatch and congestion risk, network users in an LMP market will be more exposed to risks associated with regulatory decisions to approve or deny expenditure by network owners on network reinforcements.

#### 4.2.8 Societal risk

The discussion in the previous subsections have covered a variety of risks faced by individual market participants and how that risk is allocated across different participant groups. There is a further set of risks: those faced by society and related to the overarching objectives for the electricity system.

Society's objectives were laid out in Box 1 and include decarbonisation of electricity, security of supply and low costs. It also highlights the need to consider the value brought by the electricity system to wider social objectives including supporting economic growth, regional development across GB and fairness and affordability.

Market structures can themselves support or hinder these objectives, whilst the process of change itself can introduce risk. The ability to deliver societal objectives depends on market participants playing the part required of them:

- for renewable and other low carbon generators to invest, build and operate;
- for suppliers and generators to be able to strike contracts which share and manage participant risk appropriately and enable low costs to be passed to consumers;
- for flexibility providers to have access to the revenue streams needed to support their business cases;
- for government, regulator, system operator and the transmission owners to coordinate the provision of network capacity; and
- for the government and regulator to maintain an appropriate policy and regulatory environment for the generation and use of electricity.

The level of concentration of risk that LMP markets place on some market participants and the challenges to mitigating at least some aspects of that risk, suggest that one of the key components required to deliver societal ambitions – ZMC renewable generation – may be at significant risk. These generators are central to delivering two of the three key elements of overall ambition – decarbonisation and overall low levelised cost of energy (LCoE). In addition, where price risk combines with reduced levels of dispatch for schedulable plant, the additional risk faced by those generators could itself increase the risk that an appropriate level of reliability of supply is not delivered.

It is challenging to understand the exact impact of market reform on risk to societal objectives. However, it is important that the debate about risk across all market reform options considers this wider perspective as well as the more narrow participant-level risks.

The issue of societal risk is discussed further in Section 6.

### 4.3 Financial transmission rights in the GB system

The introduction of FTRs alongside LMPs has been presented as an important way of mitigating risk for market participants. This reflects experience in most, not all, existing LMP markets. In discussing FTRs it is important to be specific as to which of the four roles they can play is under consideration: returning congestion rent to consumers, compensation for lost access rights, hedging for market participants, or instruments for financial speculation. Compensation for lost access rights is discussed in Section 4.6.2. The other roles are addressed in the next three subsections. It is also important to remember that FTRs don't change system costs, rather they reallocate costs and risks between market participants.

#### 4.3.1 Returning congestion rent to consumers

The level of congestion seen on the current GB system will lead to significant levels of transmission rent with demand paying considerably more than is paid to generators. As in existing LMP jurisdiction congestion rent should most likely be returned to those who have paid the costs of the transmission network. Under current TNUoS arrangements demand pays around three quarters of the cost of transmission infrastructure and would, on this principle, receive the majority of transmission rent. This could be achieved through a system of FTR allocations to Suppliers. However, it could also be achieved through a simple pro-rata allocation of congestion rent back to consumers, or by contributing directly to the cost of the transmission network.

#### 4.3.2 Hedging

As discussed in the section on risk, given the large exposure that generators would face to congestion, it would be important to ensure that mechanisms were available to hedge that risk in order to avoid either a reduction in investment or significant risk premiums. FTRs are argued to provide those mechanisms. However, evidence from existing markets suggest that this is only a good mechanism in the short term (1 year) with so-called 'long term' (3 year) FTRs unable to effectively price congestion risk. FTRs tend not to be available beyond three years. Investors in new generation assets with an expected lifespan of potentially three or more decades are unlikely to view FTRs, as currently conceived, as an adequate long-term hedging solution.

A second issue with the ability of FTRs to hedge risk is their profile shape. FTR Products in existing markets follow predefined profiles – either baseload on-peak or off-peak for example – whilst the profile of generation from a wind or solar farm is highly variable. Although FTRs are sometimes presented as a perfect hedge, even in theory this is only true if the generation profile and FTR match perfectly. This is illustrated in Figure 20.

The key revenue streams to consider are:

- **FTR costs:** this is the cost of purchasing the FTR in an auction
- **LMP income:** this is the revenue received by a generator directly from the LMP energy market
- **Congestion costs:** the reduction in LMP income caused by network congestion. i.e. the difference between the actual LMP income and the income if there had been no congestion
- **FTR income:** revenue received by a holder of an FTR. i.e. the difference between the actual LMP income and the income if there had been no congestion.
- **Net revenue:** LMP plus FTR income minus FTR costs.

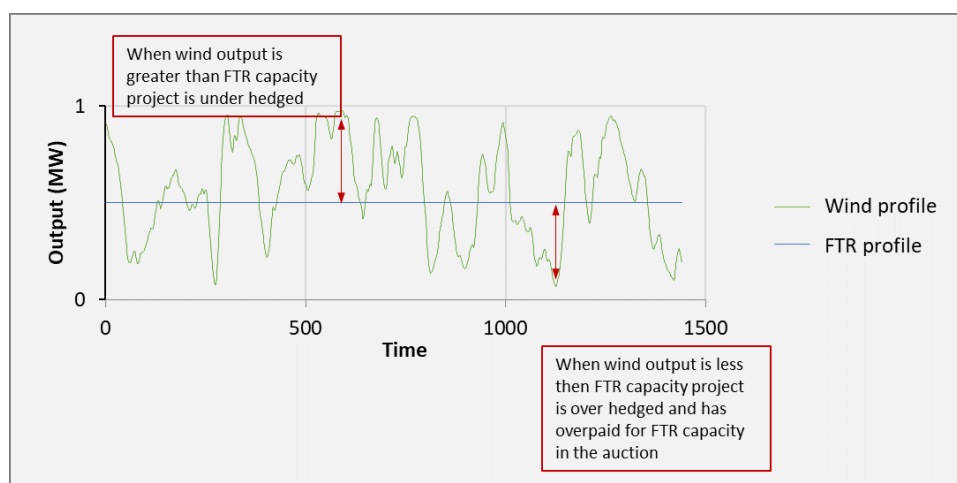


Figure 20: Illustration of under and over hedging of a wind farm using a standard baseload FTR.

The definitions above show that FTR income is equal to the congestion costs. With perfect foresight the FTR cost – the price at which a generator would be prepared to pay for an FTR in a competitive auction – will be exactly equal to the outturn cost of congestion and therefore FTR costs and income would perfectly balance out to zero.

However, without perfect foresight we have to analyse the situation where the generator buys an FTR at the *expected* level of constraint costs. If *outturn* congestion is *greater than expected*, then LMP revenues will be lower and FTR revenues will be higher. For a baseload plant where the generation perfectly matches the FTR profile these two impacts will perfectly cancel out. The situation reverses if outturn congestion is less than expected. This shows how, for a generator output closely matches the profile of its FTR, congestion risk can be effectively hedged.

For a wind farm this condition does not hold. The wind output will not match the FTR profile as its output is both variable and uncertain. For any FTR with a predefined profile, a wind farm will remain either under- or over-hedged for most settlement periods. Although it may be possible to explore different combinations of FTR capacity and profile to find the best pragmatic combination that can minimise uncertainty, it is not possible to hedge away the risk to the degree that is possible for a baseload plant.

If LMP markets with FTRs were to be introduced in GB it would be critical to explore this option in significant depth. One option, discussed in Section 2.8.3, is to consider the potential of FTRs designed specifically for the characteristics of different types of generation, e.g. ‘wind FTRs’ or ‘solar FTRs’. These would be FTRs with time-varying profiles which would be matched to wind or solar conditions in a particular area on a settlement-period by settlement-period basis.

#### 4.3.3 FTRs for speculation

Most FTR markets allow non-physical traders to participate, increasing liquidity and in theory improving competition. Those investors who buy FTRs on this basis are not hedging risk but developing an inherently risky portfolio for the purposes of speculation. International experience suggests that the majority of long term FTRs are bought at auction by large non-physical traders but can often be mispriced due to a lack of bidders and an inability to forecast price differences over longer timescales. They are then sold on closer to real time at which point market participants are more likely to be able to take a view as to their hedging value. There is the potential for this to happen in a future GB FTR market.

We spoke to two interviewees with an intimate working knowledge of US LMP markets, and neither were complimentary about how FTR markets have been operated. On the basis of the large regulatory burden involved in monitoring, enforcing and dealing with the potential for manipulation in FTR markets, one stated

that “I’m not sure I would endorse the way FTRs are done”. The other interviewee stated that “A large financial industry has grown up around FTRs. It has caused a lot of issues for ISOs. They have ended up running futures and derivatives markets and it becomes highly risky. Defaults have happened.”

**Coupling these views with the difficulties experienced in FTR markets in both PJM and CAISO and the recent rejection of a proposed move towards an FTR market in Australia, outlined in the earlier case studies, it is clear that any implementation of FTRs in GB would require much deeper thought as to the design of the market than has been evidenced in the GB debate so far and sophisticated regulatory models to mitigate risks as far as possible.**

#### 4.4 Limited transmission capacity

The interaction with the transmission network’s capacity is one of the defining factors of the LMP market design. Prices in an LMP market naturally respond to the capability of the network to transfer power between different locations. Locational pricing is argued to deliver an economically efficient dispatch of energy production along with response and reserve ancillary services given the existing network and set of market participants.

In spite of the importance of transmission capacity for operation of an LMP market, such a market does not place a direct incentive on transmission owners or the system operator to either build transmission or operate it efficiently. In a well-functioning market these incentives will exist; in the case of LMP, just as in the current GB market, they will need to be provided via other mechanisms<sup>xxvii</sup>. There will likely be interactions between these mechanisms. For example, it is clear that within an LMP market the existence of significant levels of congestion rent would suggest value in building more transmission capacity and, in such markets, it would make sense to use the level of congestion rent as one of the factors informing transmission investment. However, congestion rents should not be seen as a budget for transmission investment. For an optimal system, it is likely that congestion rents will be significantly lower than the cost of the transmission network. Furthermore, as previously discussed, the precise design of the LMP arrangements may require that congestion rent is passed directly back to consumers.

In the context of LMPs in GB there are several transmission related considerations. First is the fact that transmission capacity is currently far from optimal with significant congestion over key routes, in particular the corridor facilitating the transfer of renewable power between Scotland and England. Under all net zero compliant scenarios, this is envisaged to continue until at least the mid-2030s. The second is the fact that behind GB’s major transmission bottlenecks are tens or hundreds of variable ZMC generators – wind and solar farms – each of which will be offering power into the market at a level set by their physical marginal cost (almost zero) and the interaction between their support regime and the energy market. The third issue is the degree to which the wider electricity system and market participants can adjust around a limited capacity of transmission investment without impacting on the overall system objectives identified in Section 1.4.

##### 4.4.1 LMP markets with non-optimal transmission networks

One of the questions we asked of interviewees was their view of how LMPs would work in a system with very limited transmission capacity relative to generation in an area. The view expressed by several interviewees was that LMP markets work effectively at efficiently dispatching a system with close-to-optimal transmission network but are less efficient where the transmission network is not optimal: where the

<sup>xxvii</sup> In GB, it could be suggested that regulation of network utilities around their total expenditure, i.e. the sum of spending on investment in infrastructure and the cost of operation, provides a direct incentive to deliver an optimum amount of network capacity, provided the network owner is exposed to the cost of a lack of network capacity. It could be argued that this was the case for the integrated transmission owner and system operator (TSO) in England and Wales prior to April 2000, National Grid, for the period when it was exposed to a Balancing Services Incentive Scheme. Otherwise, ‘correct’ levels of development of transmission capacity depend on interpretation and enforcement of licence conditions.

transmission network is overbuilt and there is no congestion there is no additional value from locational prices (beyond minimising the cost of losses); where the transmission network is underbuilt the level of uncertainty and the cost this place on market participants is likely to lead to significant impacts either in terms of reduced investment or higher risk premium costs in capacity markets and support mechanisms.

#### 4.4.2 Multiple zero marginal cost generators caught behind a transmission constraint

Scotland provides an example of a situation where many ZMC generators are located behind a single and regularly binding network constraint. A recent report for Drax power highlights that in 2020 and 2021 Scottish wind generation accounted for 94% (3.3 TWh) and 80% (1.8 TWh) respectively of all GB wind curtailment<sup>125</sup>. Under current arrangements those generators do not face the costs and risks of network congestion. These arrangements are a result of a deliberate policy - a 'Connect and Manage' instead of 'Invest and Connect'<sup>126</sup> philosophy - to accelerate the development of renewable generation beyond that consistent with transmission development speed. This policy clearly incorporated removal of congestion related dispatch risk from generators. This is due to their firm financial system access rights and market arrangements that allow them to sell and settle energy production financially at BM gate closure, one hour ahead of the delivery settlement period. Balancing to maintain network constraints and to ensure a national energy balance is conducted through the BM in a way that doesn't penalise generators' gate-closure positions.

As discussed above, under an LMP market generators lose their firm access rights and face both price risk and dispatch/volume risk. The issues this could create with existing generators are discussed below in Section 4.6 on legacy generators. Here we discuss the challenge faced by investors in new generation in Scotland.

In order to invest in generation, where, especially for ZMC plant, the vast majority of costs are sunk before operation begins, investors need confidence over the long-term revenue streams they face. This involves developing commercial arrangements that manage both price and dispatch risk over time. Whilst bilateral contracting and CfDs provide a way to manage price risk, dispatch risk is a more challenging issue to solve.

In Britain's electricity system today, the available wind power regularly exceeds transmission capability; in 2035 the total power available from ZMC generation will also regularly exceed total GB demand. Under an LMP market generators will be dispatched based on prices offered and, assuming that the market is competitive, those prices should reflect underlying short run costs. Generator costs could include both **physical short run marginal cost** and the cost implication of dispatch on **support mechanism payments**.

The **physical** component of short run costs for ZMC generation will be, as the name suggests, close to zero. In practice, there are likely to be some costs such as variable O&M costs, which could push the physical short run costs slightly above zero, and costs related to the risk of turbine faults during shut down and start up, which could push the physical short run costs slightly below zero (i.e. generators may be prepared to pay a small amount to avoid shut down to reduce risk of turbine failure). These costs are likely to be small and, in regions with an excess of renewables this will lead to a close-to-flat supply curve.

Not only are the cost differences between generators small, but they are also likely to be largely fixed by the design of the generator. Therefore, whilst the cost difference may be only a few pence, the LMP market will choose to dispatch the cheapest generator. If the merit order is largely fixed this will lead to a **winner takes all** situation where the cheapest generators, even if only slightly cheaper, will always get dispatched whilst the most expensive will regularly fail to get dispatched.

**A key concern for investors would be that it would be exceptionally challenging to forecast in advance where their project is likely to land within a very flat supply curve whilst the implications of landing low**

**down the merit order would be substantial. This could result in a significant level of project risk which would be very hard to predict and model.**

The **support mechanism component** of an offer will depend on the exact market rules chosen and on the support regime for each generator. The support mechanism component for generators with FiT and ROC support is likely to be equal to negative the value of their support per MWh. For example, an onshore wind farm which receives 0.9 ROC / MWh and expects the value of each ROC to be £50 will be incentivised to offer energy at £-45 / MWh as the support mechanism component of its offer. The behaviour of CfD generators depends on a number of support regime design decisions and is discussed in detail in Section 4.5.

One observation about support mechanism components is that older generators tend to have higher price support mechanisms. This is true of FiT tariffs and it is also true for some technologies which receive ROCs – for example onshore wind allowances were reduced from 1 ROC per MWh to 0.9 ROC per MWh in 2013<sup>127</sup>. Also, the strike prices awarded for offshore wind in each consecutive CfD auction round have been lower than in the preceding round<sup>128</sup>. **Where generators are incentivised to offer close to the negative value of their support this would tend to favour old ZMC generators over new.** The ‘winner takes all’ logic discussed above in respect of physical costs applies to support mechanism ‘costs’ as well.

A third contributor to the issue of dispatch risk is losses. There is an argument that, all other things being equal, generators which lead to the lowest system losses would be dispatched first under the LMP algorithm. This is because additional losses mean the need to generate more electricity and, in general, this means increased system costs. However, if the additional energy needed for losses is being generated by ZMC generators, then their additional output doesn’t correspond to increased system costs: if there is spare headroom in the ZMC fleet – and the energy is being offered at exactly zero cost – any generator is as good as any other in terms of cost. In optimisation terms there is a redundancy in the solution – multiple solutions have the same overall system cost.

This logic can be extended to generators offering negative prices into the LMP market (due to the support component of their offer). Under these circumstances the LMP algorithm is likely to dispatch the generator that would lead to the *greatest* losses. From the perspective of the LMP energy market this leads to the lowest overall system cost (although, it would lead to increased support payments which would at least balance out any savings).

The previous paragraphs have argued that there is a risk of a ‘winner takes all’ situation emerging due to a fixed merit order which is either separated by very small price differences (relating to physical costs or losses) or factors which are related to support mechanisms rather than physical costs. Figure 21 illustrates the likely impact on dispatch levels of a fixed position in a merit order for wind farms in Scotland in 2035. The analysis assumes a 2035 demand profile scaled up from that in 2019, 16 GW of transmission export capacity and an overall capacity factor for the wind fleet in Scotland of 53%. The first 18 GW of wind capacity are able to achieve full dispatch making use of the transmission export capacity and meeting Scottish demand. Beyond 18 GW curtailment is required and the capacity factor begins to drop off. At 30 GW the capacity factor is around 36% and at 40 GW it is around 17%. **The outcome for a generator that falls within the first 18 GW of a ZMC merit order is very different in terms of dispatch compared with one that falls at 40 GW, this is a direct consequence of the potential winner takes all characteristic of LMP dispatch.**

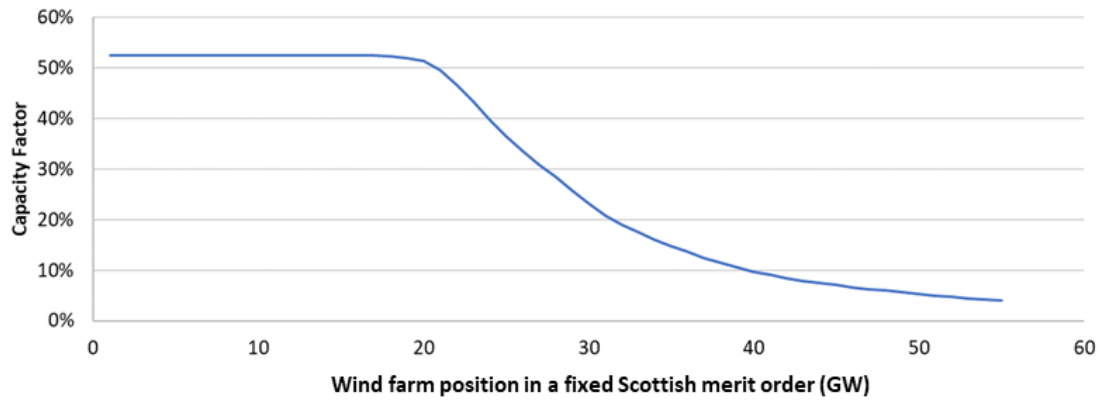


Figure 21: illustrative capacity factor that would be achieved for individual Scottish wind farm assuming a largely fixed merit order. Modelling assumes a 2035 Scottish demand profile and 16 GW of transmission export capability to the rest of GB.

The conclusion of this section is that (a) it is likely that ZMC generators caught behind a constraint will fall into a largely fixed merit order, (b) the impact of how far down the merit order a particular generator is will significantly affect its level of dispatch in an LMP market, and (c) factors affecting where within the merit order a generator sits are either very small and therefore hard to predict and model (physical costs and losses) or fixed by support levels.

## 4.5 Designing a coordinated LMP / CfD system

Existing LMP systems operate in conjunction with renewable support schemes which typically pay a fixed amount per MWh. For example, in the US, production tax credits pay up to 2.5 cents/kWh for wind generation<sup>129</sup> which incentivises ZMC generators claiming those tax credits to offer at down to \$-25 / MWh. GB Feed in Tariffs (FiTs) represent a similar arrangement and whilst the value of renewable obligation certificates (ROCs) does vary a little through the process of ROC trading and buy-out prices<sup>130</sup>, the variation is relatively limited and is on timescales of months or years, not between individual settlement periods. The current government backed centralised CfD support scheme provides a significantly different model, and one that has not yet, to our knowledge, been combined with an LMP market.

For generators in receipt of fixed subsidies, their bid / offer behaviour in an LMP market might be similar to the way that those generators currently bid to reduce their output in the BM; the same will not be true for CfD supported generators. The key difference for these generators is that, when bidding into the BM, a CfD generator already knows the value of the reference market price which was set by the clearing prices on day ahead power exchanges the previous day. In theory at least, CfD generators may choose to adjust their BM bids and offers during each period to reflect the varying but known CfD uplift value<sup>xxviii</sup>. By contrast, when bidding to sell energy in an LMP market, it is the outturn of that same auction that also sets the level of the CfD support payment; generators will be bidding whilst blind to the specific level of support it will receive.

One of the challenges of introducing LMP where renewables are supported by centralised CfDs is the number of different arrangements possible for coordinating the two schemes. The following subsections discuss some of the key design decisions that would need to be made.

### 4.5.1 What is the reference price?

In the current GB market, a reference price is defined based on the clearing prices of day ahead power exchanges. A key criterion for the reference price is that the generator is able to realize that price in the market. Only if this is possible can the generator practically hedge price risk and combine market trading with the CfD uplift payments in order to end up with a net-revenue equal to the strike price. One example of how CfD generators do that today is through the use of PPA agreements where an offtaker agrees to take all output available and pay the generators the market reference price for each settlement period. Another method is simply to sell their energy on the day ahead exchanges directly.

Under an LMP market several options exist for determining the reference price used in a CfD:

- **The generator's local nodal LMP:** this is the most obvious reference price to use, and it is one that is most easily realised by the generator as all that is required is that it sells its power into the LMP market. There is a choice as to whether day ahead or real time prices should be used. The choice would define the degree to which generators attempt to lock a good estimate of available generation at day ahead prices compared with waiting until the real time market.

An important challenge under a local LMP reference price model is that the uplift payment<sup>xxix</sup> to each generator will be different for each node. As discussed below that has consequences for the overall cost of the CfD scheme and the design of auctions to allocate new CfDs.

---

<sup>xxviii</sup> Evidence from one interviewee suggested that this has been tried by some CfD generators, in particular this year has seen some generators offering to pay to be turned down in the BM when the market reference price rises above the strike price. However, this has not become common practice with generators adapting their behaviour linked to a desire to avoid excessive curtailment which implies increased stress on turbines and increased difficulty in meeting obligations to provide certain consumers with 100% renewable electricity.

<sup>xxix</sup> The discussion in this section refers to 'uplift payments to generators', it should be remembered that whatever reference price is used, where the reference price rises above the strike price these payments become negative and reflect a revenue flow from generators back to consumers.

- **The LMP at a central reference node:** this has the advantage of setting a single level of uplift payment to all CfD generators. However, to realize the reference price generators would need to combine trading in the LMP market with either an appropriately structured PPA or an FTR between their own location and the reference node that was able to closely reflect the plant's output.

The PPA would set the bilateral price to the difference in price between the generator's local node and the reference node and would effectively transfer the congestion risk to the offtaker. (For a discussion and example of bilaterally trading cash flows in LMP markets see Section 2.8.3). This seems an unlikely arrangement for a commercial offtaker to be interested in unless it allowed them to develop a broad portfolio in a way that could allow risk to be managed more effectively than individual generators could. It may be a way the vertically integrated utilities would wish to manage their portfolio risk.

As we discussed in Section 4.3, the use of an FTR has a number of issues. Existing FTRs have predefined profiles and only offer a good hedge against congestion risk when the generator's output matches the FTR capacity. Secondly, either the FTR is allocated to the generator for free, which would blunt the locational signals that an LMP market aims to provide, or purchasing an FTR in the auction would represent an additional cost to the generator which would need to be covered by the developer, probably through an increase in the strike price offered in the auction. This last point may be in line with broader objectives of an LMP system in that it would provide a location-specific cost element in CfD bids similar to today's TNUoS charges. Finally, the lack of long term FTRs in existing markets raises concerns about their effectiveness on timescales over which renewable generation capacity is financed and CfD contracts are offered.

A final issue with this approach is that it involves a degree of arbitrariness in the choice of reference node and would be subject to the unique prices associated with it. If the reference node was poorly chosen, or if transmission outages lead to periods where the reference node LMP was not a good reflection of a 'central price', this would skew the transfers of costs and risks inherent in LMPs.

- **A national average price or the energy component of the LMP<sup>xxx</sup>:** these options would reflect a similar situation to GB today with, effectively, a national reference price. As with the previous option this has the benefit of providing the same reference price to all generators and it avoids the difficulties of picking a suitable reference node. However, it faces many of the same challenges as the central reference node and an additional one: they are fictitious price that no market participant is actually exposed to. As such they are hard for market participants to actually realise and doing so and may require new forms of trading arrangements.

#### 4.5.2 Negative Pricing Rules

In the first Allocation Round (AR1) of the UK's government backed CfD allocations the contract paid out regardless of the value of the market reference price. In AR2 a rule was introduced which meant that when the Intermittent Market Reference Price (the day ahead price on specified power exchanges) is below zero for six or more consecutive hours, no CfD difference payments are made to any generation during that period<sup>131</sup>. In 2021 the rules were updated again for AR4 with generators no longer paid for any period where the Intermittent Market Reference Price falls below Zero<sup>132</sup>. The UK Government's consultation on the AR4 rule change highlighted that paying generators when day ahead prices are negative "encourages CfD generators to keep generating during these periods despite oversupply in the day ahead market signalling that generation during these times is not beneficial." Furthermore, to pay out when prices were negative

---

<sup>xxx</sup> See section 2.1 for a discussion of the decomposition of LMPs into energy, congestion and losses

went against “the government’s view that generators should not be encouraged through the CfD to generate in ways that are unhelpful to the overall system.”<sup>133</sup>

Three broad options would exist for negative pricing rules in an LMP market: no limit on CfD top-up payments (similar to AR1); no CfD top up payments when the reference price is negative (similar to AR4); or CfD top up payments limited to no more than the strike price (in practice this means setting a floor for the reference price at zero for the purposes of calculating CfD top-up prices). In addition to this it is possible to imagine location-specific negative pricing rules combined with national reference prices. For example, it could be argued that if the UK Government’s view remained that “generators should not be encouraged through the CfD to generate in ways that are unhelpful to the overall system” and it were agreed that negative prices indicate a time when generation is unhelpful, then no CfD uplift payments should be made when a generator’s local LMP is negative even if a national reference price is being used.

In an LMP market any negative pricing rule would be connected to the decision on which reference price to use. The combination of the two would also significantly impact the likely bid / offer behaviour of generators offering into the day ahead market.

Box 4 provides a number of examples that illustrate a few of the large number of options and potential outcomes available to market designers when trying to coordinate the outcomes of an LMP market and CfD schemes. It shows that there is a trade-off between encouraging generators to offer at their real physical marginal cost and the degree of exposure generators would face to negative pricing risk. It is particularly interesting to consider example five which shows the case for a central reference node acting as the reference price along with a generator owning an FTR between its own node and the reference node. As discussed previously, within the theory of LMP markets, the ability for the generator to hedge risk with the FTR is seen as an important part of an effective LMP market. However, in combination with the CfD, it leads to a situation where the generator is no longer exposed to its own LMP and would be incentivised to offer at the market floor in order to maximize the likelihood of dispatch.

**Box 4: Examples of the impact of some combinations of reference price and negative pricing rules for CfDs operating in an LMP market**

The diagram accompanying each example shows the theoretically efficient bidding strategy for the generator to maximise revenue, and the cash flow assuming that the local nodal price for the generator in a particular settlement period clears at its offer price.

1. Local nodal LMP as the reference price; no negative pricing rule:
  - CfD uplift directly linked to local nodal clearing price.
  - If dispatched the generator is guaranteed to be paid an uplift payment equal to the full difference between its nodal price and its strike price (SP).
  - Therefore, if dispatched, the generator is guaranteed a net revenue flow equal to the SP.
  - If not dispatched the generator receives nothing.
  - **The generator is incentivised to offer at the market floor price (MFP), to maximise the chance of getting dispatched** (Case shown in Figure 22)
  - Generator is fully insulated from price risk but faces dispatch risk, with decisions on dispatch likely to require non-price tie breaker rules as other ZMC generators would likely behave in the same way.

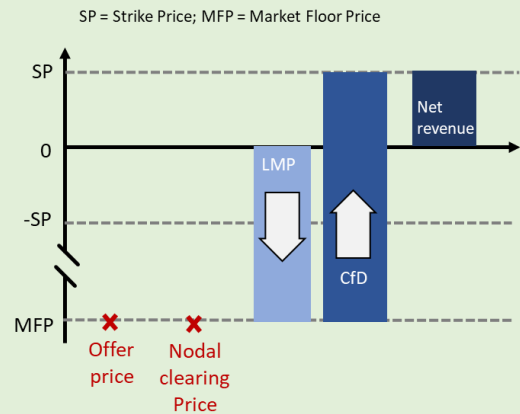


Figure 22: Optimal offer price and cash flows assuming this sets the nodal clearing price (example 1)

2. Local nodal price as the reference price; reference price floored at zero:
  - Similar to example 1 but with a negative pricing rule that places a maximum value on the CfD uplift equal to the SP.
  - If dispatched and its local nodal price is positive the CfD uplift will be the difference between the local nodal price and the SP, and the net revenue will be equal to the SP.
  - If dispatched and the local LMP is between zero and  $-1 \times SP$ , the generator pays to generate in the LMP market but receives a greater CfD uplift payment. Therefore, net revenue is positive but less than the SP.
  - If dispatched and the nodal price is  $-1 \times SP$  the generator will pay the SP to generate through the LMP market and be paid the SP through the CfD uplift. The net revenue will be zero (See Figure 23)
  - **The generator is incentivised to offer at  $-1 \times SP$  as this is the level at which its net revenue turns from positive to negative.** (Case shown in Figure 23).

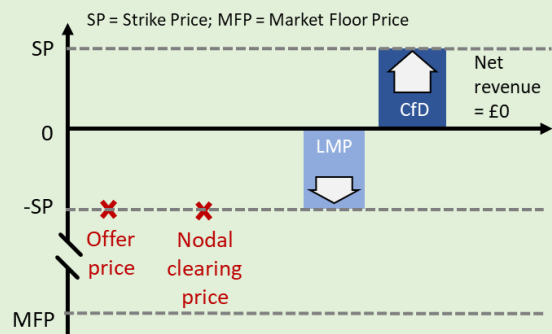


Figure 23: Optimal offer price and cash flows assuming this sets the nodal clearing price (example 2)

**Box 4 (continued)**

3. Local nodal LMP as the reference price with no payment when the reference price is negative:

- This is similar to example 1 but with a negative pricing rule that completely removes CfD uplift payments when the local nodal price (the reference price) turns negative.
- If dispatched and its local LMP is zero or positive, the generator net revenue will be equal to the strike price. (Case shown in Figure 24)
- If dispatched and its local LMP is negative, it will receive a negative net revenue (it will have to pay to generate and receive no CfD uplift).
- If not dispatched the generator receives nothing.
- **The generator is incentivised to offer at £0 / MWh as this maximizes its chance of getting dispatched but also avoids being dispatched if the price turns negative.**
- Generator faces no price risk whilst prices are positive but significant dispatch risk where there is an excess of ZMC generator. Dispatch risk will depend on minor O&M cost differentials, the treatment of losses or other non-price tie-break rules.

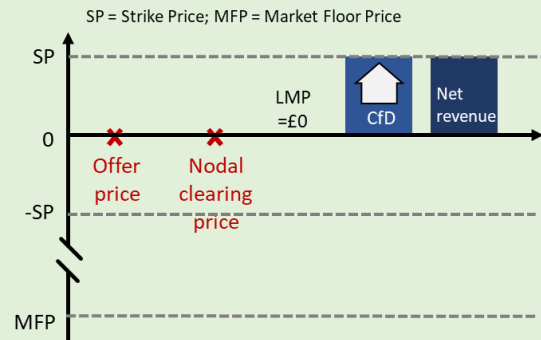


Figure 24: Optimal offer price and cash flows assuming this sets the nodal clearing price (example 3)

4. The LMP at a central reference node acts as the reference price<sup>xxxi</sup> with no negative pricing rule; no FTR available:

- In this case the price the generator receives in the market (its local nodal price) is not the same as the reference price which is set at a separate node.
- If dispatched, it will receive a net revenue equal to  $P_{\text{local\_LMP}} + (P_{\text{strike}} - P_{\text{ref\_LMP}})$ :
  - If the local LMP is the same as the reference node LMP, the generator net revenue is the SP.
  - If the local nodal price is less than the reference node LMP, the generator net revenue is below the strike price.
  - If the local LMP is equal to the negative of the difference between the strike price and the reference price, the generator net revenue is zero. (Third case illustrated in Figure 25)
- If not dispatched, the generator receives nothing.
- Offers depend on a **forecast of the reference price** made in advance and therefore involves uncertainty and risk. Strategies for setting offer prices will differ between an assumption of 'perfect foresight' and one where real-world uncertainty is included. It will also differ between generators with different risk appetites.
- **If the generator has high confidence of its Forecast Reference Price (FRP) it is incentivised to offer close to -1 x the difference between the FRP and SP. For example, if the expected reference node price were £40 / MWh (and the strike price is £50 / MWh) the generator is incentivised to offer at £-10 / MWh.**

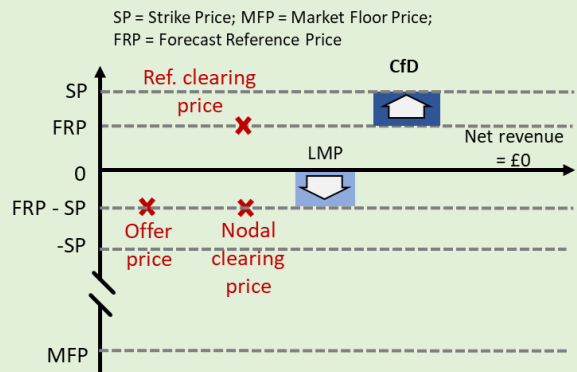


Figure 25: Optimal offer price and cash flows assuming this sets the nodal clearing price (example 4)

<sup>xxxi</sup> This also applies to a reference price based on a national average price or on the energy component of the LMP.

**Box 4 (continued)**

5. The LMP at a central reference node acts as reference with no negative pricing rule; generator owns an FTR that has a volume equal to output in the particular settlement period:

- This is the same as example 4 with the addition of an FTR owned by the generator.
- If dispatched, the generator is guaranteed a net revenue equal to its strike price
- If not dispatched, the generator receives its FTR revenue.
- A fully risk-averse generator may choose to bid at the market price floor to maximise potential for dispatch and certainty over revenue.
- However, as the FTR revenue does not depend on dispatch, if the local LMP clears low the generator could receive greater net revenue by foregoing the CfD uplift and the need to pay out for generating in the LMP market.

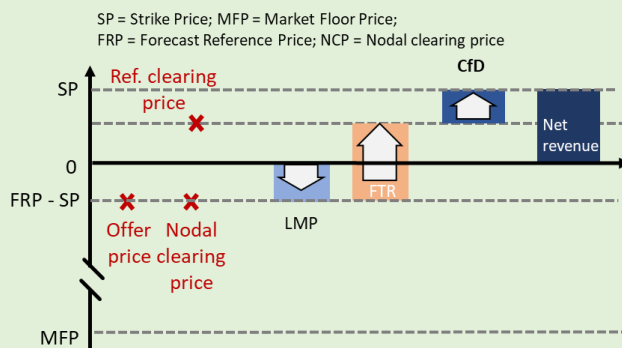


Figure 26: Optimal offer price and cash flows assuming this sets the nodal clearing price (example 5)

- Figure 26 shows the point at which net revenue from dispatch and non-dispatch is equal. It occurs when the nodal price is lower than  $-1 \times \text{FRP} - \text{SP}$ .
- However, as generators will be bidding into the LMP market based on a forecast of the reference price, it is likely that they will need to consider forecast uncertainty and risk tolerance. A full analysis of this scenario would also consider FTR purchase prices, FTR shape vs wind shape, and assumptions about strategies of other market participants.

### 4.5.3 Auction designs

The CfD scheme was part of the Electricity Market Reform process, introduced through the 2013 Energy Act. The objectives of EMR were threefold<sup>134</sup>:

- Ensure a secure electricity supply by providing a diverse range of energy sources;
- Ensure sufficient investment in sustainable low-carbon technologies to put us on a path consistent with our decarbonisation ambitions<sup>xxxii</sup>;
- Maximise benefits and minimise costs to the economy as a whole and to taxpayers and consumers.

The CfD scheme supports the delivery of the latter two objectives in particular. The approach taken has been to run a series of auctions for different technology pots. Prospective generators bid a strike price with bids ordered by strike price aiming, within each pot, to minimise the strike price agreed for generators and awarding all generators who win the auction contracts at the cleared strike price (a pay-as-clear mechanism).

Under an LMP market, if the objective remains to buy a certain amount of energy generation and to minimise the cost, the design of auction will depend on the choice of reference price and potentially on the choice of negative pricing rule.

- **For national reference prices (the LMP at a central reference node, the national average price, or the energy component of LMP):** under these models all generators would face the same reference price during the same period, and it could be argued that minimising strike prices remains an appropriate proxy for minimising costs to consumers for a given capacity. This would change if

<sup>xxxii</sup> The original EMA objectives referenced the EU2020 renewable targets and the then existing target of reducing carbon emissions by 80% by 2030.

location-specific negative pricing rules were introduced, such as a rule that removed CfD uplift payments if a generator's local nodal price went negative.

- **For a reference price based on the generator's local nodal LMP:** under this design each generator has its own reference price and the cost to consumers will differ considerably between those generators where LMPs are regularly low and those where they are not. Under these circumstances, if the objective remains to minimise the cost of CfD payments by consumers, a more suitable auction design would be one that awards contracts in a way that **minimises average uplift payments** rather than one that minimises strike prices.

Estimating average uplift payments in an LMP market for a prospective generator has the potential to be significantly more challenging and uncertain when compared to the current approach of comparing strike price.

Firstly, estimating average uplift payments requires the CfD awarding body to model the generator's local LMP over the full term of the CfD. Secondly, unlike a strike price approach, the decision on which generators to award a contract to depends heavily on this modelling. This would lead, for example, to a situation where the CfD awarding body's view of network congestion between Scotland and England five, ten, or fifteen years into the future (depending on the term of the CfD) would play a significant role in determining whether an English or a Scottish wind farm appeared better value for money.

Under current arrangements a forecast of future market prices is needed in order to calculate the total cost of a particular CfD auction. However, errors in that process affect different generators equally and even if there are significant errors in the price forecast, the auction should still produce the lowest cost for a given total capacity although the estimate of that cost may be wrong.

#### 4.5.4 Conclusions for designing a coordinated LMP / CfD scheme

The discussion above highlights the complexity of designing a CfD low carbon support mechanism to work with an LMP market. If developed it would represent a world first and would pose a significant design challenge. A key risk would be one of unintended consequences with the potential for multi-chain interactions between LMP prices, PPA agreements, FTR arrangements and the CfD itself. The examples given highlight the potential to set up situations which encourage 'race to the bottom bidding'. Whilst many of these risks can be bottomed out during the design phase it is important to note that there is unlikely to be a solution that perfectly matches objectives and incentives.

There will also be important issues associated with arrangements for generators that have CfDs in place before the move to LMP. We explore that next through a discussion on legacy generators.

#### 4.6 Legacy generators

Many of the issues affecting legacy generators have already been discussed in this report. However, it is important to consider these generators specifically. Existing generators have already signed up to binding long term agreements and a move to LMPs could require significant alteration to these agreements, albeit that the Renewables Obligation will begin to expire for some generators from 2027 and early CfD contracts will start to run down from 2033. Key among these are the agreements providing firm access to the transmission network, and contracts for support mechanisms i.e. FITs, ROCs or CfDs. Whilst arrangements for new generators allow investors, developers and potential operators to take clear decisions on whether to enter the market, existing generators do not have that opportunity, and many are in the process of recovering significant up-front capital expenditure.

It is therefore important to understand the degree to which existing contracts and arrangements need to be honoured (either legally, or from the perspective of maintaining investor confidence) and, where existing

arrangements are not meaningful in an LMP market (such as the concept of firm network access), what alternatives could be provided in return.

#### 4.6.1 The removal of firm system connection rights

Under existing arrangements transmission connected generators have firm ‘use of system’ rights. This means that, through their connection agreement, they will either be able to inject power into the transmission system up to their Transmission Entry Capacity (TEC) or have the right to payment in compensation for not being able to generate. The payments are usually delivered through the Balancing Mechanism with generators providing offers identifying the price the SO needs to pay, sometimes referred to as curtailment payments.

Under an LMP market no generator has a firm right of access to the network; instead, access is decided separately for each settlement period through day ahead and real time locational markets, based on the solution of the centralised market dispatch algorithm. Removal of firm network access and entitlement to curtailment payments would represent a significant change – one that might be subject legal challenge – to existing arrangements for generators, particularly those in export constrained areas such as Scotland. For example, in 2021 the volume of Scottish wind output curtailed off in the balancing mechanism was 2.2 TWh, or 13.3% of the available output of those wind farms<sup>xxxiii</sup>. This value is expected to increase significantly over the coming years as additional generation capacity connects<sup>xxxiv</sup>. Moving to an LMP model would therefore result in some existing renewable generators losing a substantial part of their revenue as a direct outcome of a change in the rights that they currently hold. We have described this above as ‘dispatch risk’ to differentiate it from the price risk associated with generating and receiving a lower or negative price for doing so.

In addition to the loss of revenue associated with curtailment, generators in constrained areas would expect to see market revenues per MWh produced fall. This is because the average nodal price in those areas will be significantly lower than the average national market price. For example, preliminary modelling by FTI for Ofgem suggests that under a ‘Leading the Way’ scenario in 2030 average annual wholesale prices could be £28.90 / MWh if a national market is retained but would fall to £12.90 / MWh in Scotland under nodal pricing<sup>135</sup>.

#### 4.6.2 The impact on existing renewable support mechanisms

The co-design of an LMP market and a CfD support system discussed above would also need to accommodate existing CfD contracts. As one interviewee put it, “Assuming you aren’t going to implement LMP much before 2030 then you have 50 GW of wind on the system with existing CfDs”. Section 4.5 described the options available for the choices of reference price and negative pricing rule which would likely influence prices offered in both future CfD auctions and the LMP market itself. However, for existing generators, it might be expected that existing strike prices and negative pricing rules would be honoured under whatever system is introduced alongside LMPs.

This principle can easily accommodate existing strike prices. However, some adjustment may be needed in order to integrate negative pricing rules. The examples in Box 4 show that under some arrangements, particularly where generators continue to be paid when the reference price turned negative, these generators may be incentivised to offer at the market price floor. For a relatively small number of generators this could be accommodated by self-scheduling. However, once the generation capacity begins to exceed network capacity, self-scheduling doesn’t solve the problem of transmission constraints. A further risk for existing generators is the increase and impact of dispatch risk under LMP arrangements. The loss of firm

<sup>xxxiii</sup> Calculated by: Bid Acceptance Volumes (BAV) / BAV + Metered output for all Scottish wind Balancing Mechanisms units.

<sup>xxxiv</sup> Reinforcement of the transmission network would allow the curtailment volume to be reduced. This is planned but will take time to be delivered.

access rights and the risk of failing to be dispatched in the market would lose generators support mechanism revenue as well as market revenue.

For renewable generators receiving ROCs or FiTs and who are therefore exposed directly to the wholesale market (although rewarded through their support schemes independently of the market), they could continue to strike bilateral PPA agreements using either fixed prices or prices pegged to the LMP at a particular node. However, it is likely that the PPA prices that wind farms in constrained areas could command would be lower than in current markets or in areas without constraints.

It is worth reiterating that, unlike in the current system, all existing renewable generators in an LMP market would lose all their revenue from the market and from support mechanisms during times where they are not dispatched by the centralised market. Although this will no longer be called 'curtailment', it will be physically identical: there is resource (wind or sun) available, but that resource remains unused.

### 4.6.3 Compensating existing generators for changing arrangements

Market reform may require some compensation for projects developed under current contractual arrangements. One option discussed briefly by NGENSO's work is to allocate FTRs to support the grandfathering of existing access rights and sustainability of the associated generation investments. In the context of grandfathering, FTRs provide a revenue stream based on the level of congestion between two locations and as such could provide an appropriate replacement for curtailment payments. In theory, FTRs will pay out more if congestion on the network is high and would therefore be correlated with current curtailment payments.

One challenge is that FTRs will pay out regardless of whether the holder generates, so whilst FTR payments may correlate with congestion it may not correlate with dispatch. Revenue outcomes for generators dispatched on and off are likely to be different. In addition to revenue from the FTR itself a generator dispatched on will likely receive revenue through bilateral contracts such as PPAs and through its support mechanism. So, although revenue from the LMP market could be zero (assuming the local LMP is zero), it could still receive a reasonable revenue. By contrast the generator which does not get dispatched nothing beyond the FTR income.

Any allocation of FTRs through a grandfathering process is therefore likely to either overcompensate generators regularly getting dispatched on or under compensate generators regularly failing to get dispatched. The market-designer therefore faces a significant challenge in deciding which generators to allocate FTRs to and what volume of FTRs to offer.

# **Stakeholder evidence and discussion of the potential impact of LMP in GB**

## 5 Stakeholder evidence and discussion of the potential impact of LMP in GB

The previous section discussed some of the specific challenges that would face market designers trying to implement LMP in Britain. Section 5 instead attempts to address some of the wider impacts that a move to LMP in GB could potentially entail. It draws on insights gained through a series of expert stakeholder interviews and provides a discussion around some of the key arguments for and against the introduction of LMP in GB. The key areas covered in this chapter include insights gathered in relation to investment, siting and operation of renewable and flexible assets, implications for risk and cost of capital, the extent of consumer benefits that LMP could expect to deliver as well as the interaction between LMP and transmission investment.

Interviews were conducted under Chatham House Rule such that any quotes are not attributed to individuals. The interview cohort consisted of ten electricity market experts spanning a range of disciplines including operators, traders and financiers. It also covered both GB and international experience and viewpoints including interviewees from the US who have significant experience in the design and operation of existing LMP markets. A full set of quotes together with more information on the interviews is given in the separate “Stakeholder Insight Report” document.

### 5.1 How might a move to LMP affect siting, investment and operation of renewable generation and flexibility in GB?

Proponents of LMP have argued that locational pricing would drive investment in new generation and flexibility to locations that are friendlier to the system given the existing transmission constraints. Separately they argue that once built, assets will be operated more efficiently from a system perspective as they are provided with price signals which reflect both the need for generation across the system and the ability of the network to transport their power. The overall results, it is argued, is lower total system costs and a minimising of the need for transmission infrastructure.

For example, one interviewee focused on the fact that in a system with a large capacity of ZMC renewables, “a certain level of constraints is going to be efficient and a certain level of constraints [that are] dynamically managed... by things like hydrogen [electrolysis demand] is going to lower system costs overall. I don’t see how you get that in the world of national pricing.” Another said, “I think locational signals have been too weak. I think we have implicitly, deliberately, taken the view that that was the right thing to do. The CfD mechanism has obviously been very successful in getting down the levelised cost of energy. But now I think we're moving into a different stage. We now need to start confronting the locational challenges and the system integration challenges. We really need to find ways of getting the mix of assets in the right places and operating in the right way. The flexible resources on the demand side need to have the right sort of signals to respond.”

Based on the broad range of stakeholder discussions it is clear there is substantial disagreement on the extent to which the stated benefits of LMP could be achieved in reality for GB with opponents raising a number of practical challenges that are discussed in the following sections. It is important to consider both suggested benefit streams – siting and operation – and how they interact with decisions on investment for generation, flexibility and potential demand. We address these issues further below with reference to stakeholder responses and wider evidence.

#### 5.1.1 Siting and investment in renewables generation

New generators connecting after a move to LMP would not be subject to existing agreements on connection and support arrangements, this places them in a different position to the legacy generators discussed in the

previous chapter. For these generators the important question is how the new arrangements would impact on investment decisions. In choosing to invest in a renewable generator under an LMP system, investors and developers would need to consider the following points:

- Acceptance of non-firm use of system rights.
- The need to participate in the LMP market which would entail either entering priced offers to the market or self-scheduling. In either case generators would receive the nodal clearing price if dispatched and have no network access if not dispatched.
- The need to build a business case around expected capture from the local nodal price whilst managing the potential significant uncertainty over those capture prices. For example, this would include consideration of the *expected* fraction of time that the local nodal price would be at or below zero but also the *risk that this fraction was higher than expected*.
- The potential to use bilateral contracts such as private CfDs, fixed price or price varying PPAs pegged to prices at other nodes. This would include considering the prices and terms that suppliers or other parties might be prepared to sign up to.
- The need to combine bilateral contracts with the purchase of FTRs to hedge the risk that outturn congestion differs from forecast and the need to factor in the cost of buying these FTRs.
- Consider the design of direct support contracts such as centralised CfDs including characteristics such as how is the reference price defined and whether uplift payments are made when the nodal price is zero or negative.
- Consider indirect support mechanisms put in place such as a Supplier obligation and take a view on whether these will be likely to add a market premium to zero carbon electricity and the opportunities and risks created.

In theory these factors should drive generation investment towards locations with higher expected returns from the local nodal price, typically those closer to demand centres. However, the extent to which this behaviour would be observed in reality is hotly disputed. Whilst some interview respondents did think there was some flexibility in siting decisions - “I would say now it is clear that we can build more offshore wind than we can economically use and so that does mean that there is some choice around that location” - a number of interviewees questioned whether there really is much flexibility in where renewables can site.

One interviewee said “I would argue that, for renewables, you actually have very little choice where you can site. It is a locational resource that's available offshore or wherever it might be and actually it's determined by leasing rounds that are led by government” while another suggested, “I would be more relaxed about nodal pricing if I thought we could deploy generation without any form of constraint”. One proponent of LMP even suggested that “it would be wrong to present LMP as doing most of the work, that all the decision making around where to build just gets organised through the LMP price differentials. I don't subscribe to that view, and I don't think that's the experience from the markets which have implemented LMP”. This was supported by a respondent in the US who said, “we like to say that LMP markets provide signals to investment in generation (and transmission), but I was hard pressed to find... an actual citation to a strong study that demonstrated that”.

The majority opinion of interview respondents and the weight of evidence from other LMP markets seems to suggest that other non-price locational factors such as the availability of resource, ability to secure land and planning consent and ability to obtain a grid connection remain the key influences on determining the location of investment in renewable energy. While sharper locational price signals may act as a deterrent to investment in renewables in remote parts of the network it remains unclear whether in practice there is significant scope to replace that investment either at alternative locations (closer to demand but with poorer resource potential on average) or via alternative low carbon options. A further important point is on timing: whilst it may be feasible to envisage tens of gigawatts of additional renewable capacity in currently

untapped areas such as the Celtic Sea, given the lack of supporting infrastructure, regional supply chains, and a well-developed pipeline of projects it is unlikely that significant capacity could be delivered ahead of 2035<sup>136</sup>.

An obvious further point is that, for any major market reform such as a move to LMP, it would likely take many years for the detail to be worked out and implemented which would inevitably increase uncertainty for generators. Before even considering the longer-term implications for investment there is a real risk that an investment hiatus is created in the interim at the very time investment in new capacity needs to ramp up to unprecedented levels. One interviewee commented that “In terms of an investment hiatus, I do think that is a real risk and if you go for wholesale reform you need to manage that somehow.”

While you risk an investment hiatus during periods of uncertainty, another scenario could arise in the period between design details of an LMP implementation being confirmed and the new arrangements becoming active. If, for example, investment conditions are perceived to be superior for projects that can connect before the transition is complete based on grandfathering arrangements, it is possible that there would be a rush to progress existing projects during the transition period, to the extent to which supply chains and planning processes would allow. A development dash might be seen as a good thing in general, but, when it comes to the time of the transition, greater volumes of 'existing' generation than expected would mean whatever projections were made about the cost to the consumer of the grandfathering arrangements would be wrong.

**In summary, our discussion about the impact of LMP on siting renewables, suggested that it is far from clear that the locational prices would outweigh the other non-price locational factors that drive siting decisions. Without the option of building sufficient capacity in less constrained regions and doing so within the timescale required for decarbonised power by 2035, there is a real risk to our decarbonisation ambitions.**

### 5.1.2 Siting and Investment in Flexibility

One of the main drivers behind proposals for a move to LMP is that it should give better operational signals to providers of flexibility including storage, interconnection and flexible demand to help alleviate system constraints and manage the variability of renewables across both time and space.

As outlined previously, in their case for support for LMP, NGENSO make two specific references to the current national pricing regime with regards to flexibility stating that it can (1) send perverse signals to flexible assets that can exacerbate rather than alleviate constraints and (2) that it does not unlock the full potential of flexibility. NGENSO claims that a nodal pricing market with centralised dispatch “ensures [the] most efficient resources are dispatched [while] taking into account network constraints, increases demand side flexibility and incentivises more efficient siting of assets”. They further claim it “removes compensatory payments from consumers to generators who are constrained off”<sup>137</sup> and it supports “avoiding the need for redispatch following Gate Closure [of the Balancing Mechanism] and ensuring the efficient use of interconnectors”<sup>138</sup>.

In both markets that make use of centralised dispatch and those – like in GB at present – that do not, flexibility of energy production and use is procured by system operators through a balancing mechanism or real-time market and ancillary services. Proponents of LMP typically argue that the volumes and costs of BM actions would be reduced in an LMP system. According to NGENSO, “efficient dispatch reduces balancing costs”, though quite what is ‘efficient’ here might be questioned. It is unclear whether an ‘efficient’ dispatch is one that minimises total cost of energy given an assumption of perfect foresight regarding what demand and the availability of generation (and network capacity) will really be. Alternatively, it could be one that minimises, over the long term, the *expected* total cost of an initial dispatch plus costs of balancing actions given uncertainties in demand and generation availability.

A strong example of national pricing delivering perverse outcomes is the case of system-wide national price differences driving interconnector import flows into a GB region that is already export constrained in relation to the rest of GB. Locational pricing would reflect the nature of that internal constraint, lowering prices in the region and so in theory would provide a signal for export flows on the interconnector instead which would act to alleviate the internal GB constraint. Similar issues may also arise with storage leading to inefficient utilisation of the assets based on national signals that don't necessarily reflect local constraint needs. Given the expected expansion and prominence of both of these sources of flexibility it seems clear that market reform will have to provide some form of locational signals to better manage the operation of these assets and what they do at different times.

Among interviewees there was also a unanimous acceptance that flexibility will play a key role in the delivery of net-zero policy ambitions and that signals are required to enable their efficient operation. However, there was a mix of opinions as to whether nodal pricing was the best solution for delivering investment in both flexibility and low carbon generation.

A number of interviewees were clear on the case for locational signals with one saying, "I strongly believe that flexibility does need locational signals, and it actually needs quite strong locational signals because you need them next to the renewables that are constrained." Another pointed to the need for regionally specific signals to drive demand flexibility that complements the local renewable resource which, for example, might be dominated by solar in some areas but wind in others - "let's say I have an electric car and I live in Cornwall, or I have an electric car and I live in Scotland. The only way that you will charge those differently at the moment is if those cars are in the BM. You get exactly the same signal if those cars are not in the BM so you're putting a huge burden on an energy supplier, for example, or a customer in order to get any locational value from doing something differently".

### *Storage*

Despite the above, a number of challenges were presented by some stakeholders that suggested more granular locational signals alone might not be sufficient to unlock the full potential of flexibility. The first of these is network access restrictions, particularly in relation to storage assets many of which are likely to be connected to the distribution rather than transmission network. As one stakeholder explained, "this is a problem, people are saying they want to connect in areas that are constrained, but you aren't going to get a connection agreement. So even if you've got LMP you need to be able to get a connection where LMP tells you and the current connection agreement regime won't allow that". Another offered a further example of this saying, "the network is planned without taking account of flexibility resources. For example, I'm involved with a local authority ... that is trying to develop their own local energy system but have been told by the DNO that due to transmission constraints they can't export anything from there until the mid-2030s". It is clearly an issue that storage, with the potential to help manage such constraints, is often unable to connect in export constrained areas because it has the *potential* to add to the constraint if operated in a certain way. This is an issue that needs to be addressed regardless of the structure of the wholesale energy market.

A move to an LMP market structure may do this naturally for transmission connected storage as connection doesn't provide firm network access and so Transmission Owners can offer unlimited connections without the need to guarantee that those network users can export or import power at any particular time. Moreover, it could be argued that a suitable LMP dispatch algorithm that couples time intervals would succeed in resolving it by ensuring rational use of the energy store's capacity through real time, locationally specific, price signals.

A second challenge, particularly for storage assets, is that even if you can get a connection agreement in an export constrained area and you were subject to sharp locational signals, it is not always obvious that you can act to significantly alleviate that constraint and so make the business case work in respect solely of

constraint management. One respondent explained that “it depends how long the constraint is active for” and that they’d been involved with studies for storage assets to help alleviate a particular constraint but “when you did the maths for contributing to that constraint, we couldn't get the power out ... The constraint is such that my battery sits full, and I can't get the power back out. What makes me money is cycling and volatility”. This presents further validation of the point raised earlier in Figure 6 (see section 2) showing the potential for export constraints out of Scotland to bite for large periods of the year based on current build-out projections. It suggests that either new transmission or flexible demand solutions are required to alleviate some constraints before any new signals to storage would be effective.

A third issue raised by interviewees is that flexible resources are not at present held back in development by a lack of locational signals. One interviewee pointed out that “I can make batteries profitable now” based on ancillary service revenue streams without any real locational signals while another suggested that “flexibility assets having [locational] signals behind a boundary would be powerful but at the moment the lack of those signals is not stopping things like battery storage and peaking capacity developing. They are developing regardless of whether there's an LMP signal or not.” This might be seen as sub-optimal as, without locational signals to guide siting decisions for flexible assets, they will not necessarily help to alleviate curtailment of renewables or minimise transmission investment needs. These insights coupled with the evidence presented in Figure 13 of Section 3.2 showing that revenues for storage assets in the CAISO LMP market come primarily from ancillary services suggest that there is not a strong evidence base that sharper nodal energy signals will drive increased investment in storage assets in GB. How ancillary service incomes evolve as the penetration of storage and other flexible assets grow remains to be seen. It is conceivable that these incomes could be squeezed through competition and cannibalisation such that wholesale price arbitrage becomes a more important driver for investment in future. In such a situation, it would be important that storage locates in places where the transmission network's capacity does not act as a barrier to such trading. The alleviation of network constraints might also become more important as a driver for investment in storage assets.

The increased complexity that would accompany a shift to nodal pricing was also raised as a potential issue. One operator of storage assets put it bluntly - “It's a hell of a lot more difficult to optimise my portfolio across [a large number of] different prices than it is across one price. If we can do this better than other people, then it's good for us but is it worth it for the amount of investment each company's going to have to do to manage this?” They were also conflicted overall on whether a shift to nodal pricing is the right move, citing the danger to investment in renewables – “a bit of me likes LMP because I love optimisation and I think I might make money out of it, but for me as a flex owner the thing that drives the value of flex the most is the growth of renewables on the system and if something slows down the growth of renewables, that is bad for my business and it's a very hard decision to make. This is a big change, so we need to know that it makes sense.”

One clear point that has emerged from our discussions is that there is very little evidence available on the impact of LMP or other market design options on investment in assets that provide electricity system flexibility. Whilst sharp locational price signals represent a theoretical mechanism to encourage geographically targeted investment in flexibility there is limited empirical evidence available to identify the size of likely revenue streams this would create. **It is critical that the sector and policy makers respond to this evidence gap and attempt to quantify likely arbitrage returns for storage and other forms of flexibility.**

### 5.1.3 Flexibility and the demand side

The response of demand to LMP depends on the degree to which it is exposed to locational price signals. Most LMP markets expose the majority of demand to zonal rather than nodal price signals in order to avoid major swings in prices across small geographical areas. However, different decisions could be made for different categories of demand and all demand could be offered the option of ‘opting in’ to full nodal pricing.

Assuming that at least some demand is exposed to nodal prices, Stakeholders were similarly conflicted in views towards the role LMP could have in encouraging flexible demand to locate optimally. In particular, hydrogen electrolysis is expected by many to play a significant role in the future power system as a new demand to utilise 'excess' renewables and potentially act as a seasonal-scale storage vector if used to fuel hydrogen power plants. One respondent was clear on the need case for locational pricing stating that "I think the bigger short-term impact that LMP would have on Scotland would be the amount of new sources of demand that you would build there, in particular, hydrogen electrolyzers. If we're going to have hydrogen in the power sector for balancing it should all be in Scotland" but at the moment, "the market refuses to tell it to be stuck in Scotland because we've dictated national pricing".

However, several stakeholders made the point that what is best for the electricity system in terms of demand location may not be optimal from a whole systems perspective as you need to account for where the demand for hydrogen would come from. One noted that "you can give the signal to hydrogen, but you then have to build the hydrogen infrastructure as well". Another made the similar point that you "have to transport that hydrogen to where it's needed and that's an additional cost on top of the cheap power". They argued that if you don't think carefully about the trade-offs in both systems at the same time you may end up "just outsourcing the challenge of transportation to another sector. It's a micro view of a macro issue in my opinion."

**Whilst there is significant potential for hydrogen electrolysis and potentially other forms of flexible demand to connect, the lack of clarity around the demand for hydrogen and the infrastructure that will be required to develop a hydrogen system is a critical gap in being able to fully evaluate *any* electricity market design that aims to influence the development of other energy vectors such as hydrogen.**

Hydrogen electricity is an example of industrial scale demand which can be specifically built to act flexibly. However, other forms of demand flexibility are less distinct. For example, EV charging and heat pump demand, both of which have the potential to provide a degree of flexibility, are hard to separate out from other forms of domestic and small scale industrial and commercial demand.

There are likely to be significant issues with exposing domestic demand to nodal prices, however one interviewee highlighted that "if you [do] have LMP with some element of it exposed at domestic level potentially then you get that behaviour [flexibility from EV charging and other domestic demand] without any contracting whatsoever – that behaviour just emerges." It would also allow suppliers to offer tariffs with meaningful locational differences: "at the moment they can't offer me that unless they somehow access locational value through the BM which is now administratively complex. Or through some defraying of network charges for a local solar farm through some bilateral contracts between the supplier and the solar farm which is even more complicated."

It is clear that some of the potential economic benefits from LMP could be blunted without exposing the demand side to locational signals although one interviewee suggested you could protect the consumer from overall price variations while still sending useful signals to aid system operation: "not fully exposing domestic households or their supplier to LMP will reduce the efficiency, but it will make it politically more viable... There can't be a postcode lottery [from a political perspective]. So, what you need to do is to expose suppliers to the variations in price shape at different nodes, but not the variations in average prices. The important thing is not the average differential in prices in different parts of the country because you don't want people to move house. The important thing is the price shape". Such a proposal would entail suppliers offering regionally bespoke time varying tariff schedules to allow the demand side to respond to regionally specific system constraints in a way that is not offered at present. How such a system could practically be operated whilst shielding consumers from wider differences in locational pricing would need careful design. Recent academic literature has proposed the increased use of time of use rates (TOU) and critical peak

pricing (CPP) as a step in that direction for US LMP markets that currently shield domestic consumers from nodal price variations<sup>139</sup>.

**A straightforward exposure of demand to LMPs could encourage a wider range of flexible demand to operate in ways supportive of the overall system. But, as with the hydrogen example above, there is limited evidence as to the degree of response. The downside is the potential for a post-code lottery with clear negative consequences in terms of fairness and political acceptability. Further work on alternative means of encouraging demand time shifting is needed to establish if locational pricing provides an effective and politically acceptable way of encouraging demand side flexibility.**

#### 5.1.4 Alternative reform options to support flexibility

While several stakeholders were sceptical with regard to the impact of or need for nodal pricing, there was consensus on the need for some form of locational signals going forward to unlock the value of flexibility. Some offered alternative options that might be able to deliver some of the proposed benefits of LMP. One stakeholder argued that “right now people are already starting to locate assets around network constraints because they can access the balancing market which acts as a proxy locational signal already. This begs the question of whether we really need to go all the way to nodal pricing to see the sorts of affects you want?” With regard to whether you can solve perverse signals to flexibility without nodal pricing, they suggested “zonal pricing solves that for you to a degree without losing some of the features of the wholesale market.”

Another stakeholder who was clear on the need case for strong locational signals of some form to flexibility was also emphatic that the same signals should not apply to renewables, suggesting that you need to “simply switch that off for renewable generation because it’s a tax they have no choice but to pay or you just make it cost pass through. The whole renewables industry is absolutely terrified about locational marginal pricing and the impact that it might have on existing and new investments because they do have very little choice, they have no way of managing that risk.”

Another stakeholder again pointed to the inherent trade-offs in designing a system that incentivises both flexibility and renewables and suggested that “there [are] other ways to incentivise flexibility than locational signals. I think you can have technology specific capacity markets. If the government wants electrolyzers or National Grid want electrolyzers, then effectively you could procure a certain amount of capacity through the capacity mechanism and it also allows for centralised planning. To get to net zero, you are going to need renewables, and you’re also going to need flex. But I think if you introduce a mechanism that may be good for flex, but disastrous for renewables, you’re never going to get to net zero.”

Another respondent suggested that “if we don’t do nodal pricing, I think there are other routes, especially around different ways of pricing congestion and thinking about the relationship between Suppliers and gate closure and the need to buy certain sorts of assets to balance closer to real time. These could give a greater sense of system visibility and provide forward schedules that do not rely on a central operator.”

**The above discussion highlights how crucial flexibility will be in future but also that there are huge variations in opinion around how best to deliver the right signals to deliver both investment and the correct operational signals to flexibility while at the same time protecting investment in renewable energy. This speaks to a lack of detailed analysis and evidence base for the impacts nodal pricing would have on the prospects for flexibility in a future GB market.**

## 5.2 Assessing the costs and benefits of LMP

The financial case for transitioning to LMPs is often portrayed as clear cut. It is argued that consumers would gain via more efficient operation of the system lowering costs and through the transfer of curtailment risk from consumer to producer and that these savings should outstrip any implementation costs within a short

period. Historic studies of LMP market implementations typically estimate operational efficiency gains in the range of around 1-4% of system running costs, for example a recent study estimated that Texas reduced operating costs by 3.9% in the first year of operation of their LMP market<sup>140</sup>. There was little in the way of refutation to the notion that as one stakeholder put it “LMP is a very efficient way of operating the existing assets that are already on the system.” One interviewee did however question whether the expected gains in GB would be significant on the premise that much of the historic savings from switching to LMP markets was based on delivering “lower overall fuel costs compared to a counterfactual without it” and their being less scope for improvement in a system dominated by renewables.

Constraint costs for GB are also projected to rise in the coming years. National Grid ESO released a short note<sup>141</sup> updating projections based on an updated assessment of Transmission build out via the Network Options Assessment (NOA) framework incorporating updates from the ongoing holistic network design (HND) process. The result of the analysis is shown in Figure 27 and shows rising constraint costs reaching as much as £3bn/yr by the late 2020s in the leading the way scenario under previous NOA7 transmission capacity expectations. The analysis shows that implementation of the updated optimal network reinforcements (from the NOA 2021/22 refresh process – ‘NOA 7 Refresh’ in the chart) reduces constraint costs under NGENSO’s 2021 view of the ‘Leading the Way Plus’ scenario.

In their interim analysis for Ofgem, FTI calculate consumer benefits of £55bn and total GB welfare benefits of £31bn under a nodal market design compared with the current market design for a modelled period of 2025 to 2040, assuming a background system with the Leading the Way generation background from FES 2021 and transmission capacity based on projections under NOA7. When the transmission background is enhanced to include the holistic network design (HND) the calculated consumer benefits reduce to £42bn and the total welfare benefits fall to £25bn over the period<sup>142</sup>. A large portion of the calculated consumer welfare benefit comes through the removal of constraint costs. As previously outlined, an LMP market would remove the need for largescale system re-dispatch through the balancing mechanism and in so doing, transfer the burden of curtailment payments from the consumer to producers in the form of dispatch risk. However, there are a number of question marks over the extent to which such reported savings can really be achieved including what a move to an LMP market could mean for cost of capital and whether constraint cost savings would really accrue to the consumer. These are explored in more detail below.

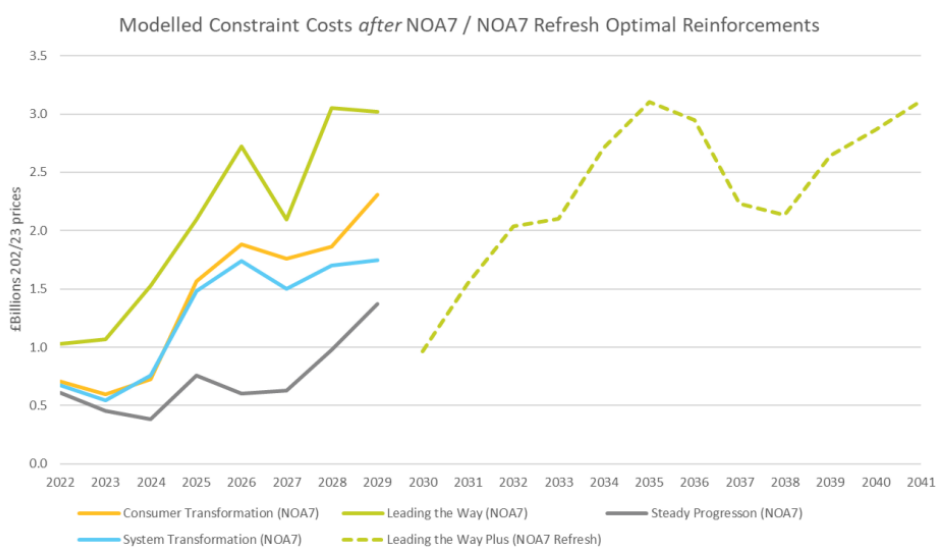


Figure 27: NGENSO modelled constraint costs after NOA 2021/22 Refresh optimal reinforcements included.

### 5.2.1 Impact on cost of capital

One of the key objections put forward against a move to LMP is that it has the potential to significantly increase risk, as outlined in detail in Section 4.2, for investors in new generation assets. In particular there is concern that wind generation which is expected to be a key driver of the decarbonisation effort and the ability to achieve decarbonised operation of the power system in 2035 would be heavily impacted. In their interim analysis for Ofgem, cited above, FTI undertook what they described as an “extreme sensitivity” analysis in which they sought to determine the level of increase in cost of capital that would negate all the welfare benefits that would accrue from a shift to nodal pricing. Their analysis suggests that a uniform increase in the weighted average cost of capital (WACC), for all technologies, of 240 basis points (or 2.4 percentage points) would be required to negate all consumer welfare benefits while an increase of 138 basis points would negate total GB welfare benefits. In comparison, their own sensitivity study assumes much lower impacts of 0 basis points for Regulated Asset Base (RAB) supported Nuclear and CCS projects, 25 basis points for CfD supported renewables and Cap and Floor supported interconnectors, and 50 basis points for merchant investment in renewables, storage and thermal assets.

While anecdotal evidence from investors points towards the potential for significantly higher increases in the WACC from a move to an LMP market design than FTI assume, there is little in the way of robust published evidence for this. One effort to address this comes from Frontier Economics who published a recent paper<sup>143</sup> that provided a numerical assessment of the potential cost of capital implications of LMP in GB. Their analysis focused on the increased volatility in locational pricing experienced in LMP markets like ERCOT and PJM compared with that experienced in GB through TNUoS charges. They conclude that “it would be reasonable to consider that this analysis is indicative of a range of impact on the WACC of 2-3pp [percentage points]”.

Commenting on the same analysis one interviewee remarked that “you have somewhere between four and six times the volatility in LMP markets that you have in GB [under TNUoS]. It's not 50% more, 20% more, 30% more, it's five times and that is what drives, in our view, a very significant increase in cost of capital.” Reflecting on situations like the case in Texas where increased conservatism in the wake of the fallout of Storm Uri caused the transmission owners to “dial back transmission capacity in several places”, the interviewee stated that “in some locations [it has resulted in] effectively six years of zero or negative pricing for most of the year until transmission investment comes in to relieve that. That is a totally different risk profile to underestimating TNUoS”. Analogous research conducted by UKERC<sup>144</sup> puts the implications of higher capital costs into further perspective. In assessing the impact of different risk exposure for offshore wind farms under different support schemes they estimate that “for every 1%-point increase in the cost of capital, the £15bn annual financing cost of offshore wind increases by £1bn per year”.

It is also possible to look to historical precedent for further instruction. In 2013 as part of the Electricity Market reform (EMR) process UK government commissioned a report by NERA Economic consulting<sup>145</sup> to assess the impact on hurdle rates (equivalent to WACC) of the move from the renewables obligation (RO) scheme to the Contracts for Difference (CfD) scheme. The analysis concluded that significant reductions in cost of capital could be expected mainly driven by the move from partial to full revenue certainty. The report estimated savings for offshore wind of 50-100 basis points with benefits for onshore wind (with a smaller fraction of total revenues covered by the RO scheme) expected to be even higher between 125-175 basis points. This analysis seems to have been proven largely correct with the CfD scheme widely seen to have reduced cost of capital – one interviewee stated that “CfDs have taken probably 75 to 100 basis points off the cost of capital”.

While acknowledging the risks one interviewee countered that “If we only focus on getting the cost of capital down we won't get investment to bring down system costs – we will get the wrong stuff located in the

wrong places. Then the whole system becomes more difficult to operate”. Another suggested that the risks to cost of capital will “completely depend on the support schemes that are available. If you have a 15-year CfD [then you remove much of the risk]”. They then followed “if you go for some sort of libertarian LMP energy only market then, yes, I would have thought the impact could be more than 150 basis points to be honest.”

If realised, the cost of capital increases suggested by some interviewees have the potential to counteract a significant portion of the savings that might be made through a move to LMP. The challenge for policy makers and industry is to assess the extent to which the various risks that an LMP market would impose on participants are manageable. Our analysis in Section 4.2 identifies some key risk areas attached to LMP like dispatch risk, price risk and transmission capacity risk for which it may be difficult or impossible at times for participants to manage effectively. The extent to which this is true will depend to a large degree on the package of market reforms that would accompany LMP. For example, implementation of something like a ‘deemed generation’ CfD scheme<sup>xxxv</sup> would remove dispatch risk from generators and so could act to significantly de-risk investment in new renewable capacity and mitigate against potential increases in WACC. However, it should be noted that this would entail the burden of dispatch risk passing back to the consumer and so result in a reduction in the potential consumer welfare benefits of LMP.

**Cost of capital is an important consideration. It is one of the many aspects of ‘cost’ which needs to be minimised within the overall objectives of electricity sector policy. Given the scale of investment required in ZMC renewables over the coming decade an increase in cost of capital can have a big implication for overall costs paid by consumers. Recent industry reports that have sought to produce indicative quantitative analysis and anecdotal numbers quoted by some interviewees both suggest that the implementation of LMP could have a significant impact on cost of capital. However, the precise impact of different reform packages on cost of capital remains a highly contested area which would greatly benefit from stronger evidence.**

### 5.2.2 Constraint costs and consumer savings

While constraint costs have become a significant problem and the removal of firm access rights nominally shifts this burden from the consumer back onto the producer, some stakeholders expressed doubts that this was a sensible approach and wondered whether it truly would represent a direct saving to consumers. One stakeholder agreed that the burden of costs would transfer away from consumer and “would transfer to generators or local demand under LMP – the trouble is that neither of those people can do anything about constraints so it places costs against something that they can’t manage”.

There was also a contention among some that costs associated with dispatch risk could simply resurface with the consumer via other mechanisms. If levels of curtailment for new investments are expected to be significant and the costs of that could not be recovered via specific market arrangements, then investors may seek instead to recover those costs through other means such as increased CfD strike prices or more costly corporate PPA arrangements – “In the investment case, we’d have to make up that shortfall elsewhere to effectively guarantee our return. To see it as a pure cost saving, I don’t think is correct because that shortfall would have to be made up to hit the returns”.

Quantifying the extent of such impacts is difficult but the example of Irish auctions for renewable capacity may be instructive at this point. In their latest RESS-2 capacity auction<sup>146</sup> the weighted average realised strike

<sup>xxxv</sup> A deemed generation CfD is one in which generators are paid based on their potential to generate, for example based on wind speeds, rather than their actual exported energy. It has been proposed as an option under REMA as a method of ensuring that ZMC renewables continue to receive support if they choose to forgo exporting energy to the network in order to participate in ancillary services or supply demand or charge storage connected behind their meter. It could also be used to continue rewarding ZMC generators where there is insufficient network capacity to allow them to export.

price for onshore wind and solar projects was a little under €98/MWh – far above the levels realised for equivalent projects in the latest GB round 4 CfD auctions. There are multiple factors which could go to explain this stark difference but two pertinent differences between the markets are, first, that Irish generators are not compensated for curtailment and, second, that the strike price in RESS-2 was not index-linked into future years unlike the GB CfD auction. These factors place significantly higher risks on developers in Ireland who were making their business case against a backdrop of rising global inflation. It is easy to see that increased cost of capital and the need to pass through expected curtailment costs could both be strong contributors to the difference.

The above could be taken as an argument for LMP as it would, for example, make wind farms behind constraints less competitive than those that were not but then we return to the question of how much potential for relocating assets there really is as well as how predictable constraints actually are. For example, in 2015 Ofgem outlined a prediction of constraint volumes and costs for 2021 that were significantly lower than the outturn constraint costs<sup>147</sup>. As one reading of Figure 27 above shows, constraint costs come back under control in 2030 if the network owners succeed in building new grid capacity. They only rise again through the 2030s under the assumption that renewables expansion continues but, at the time of writing, plans for transmission build out do not go beyond current NOA 2021/22 refresh levels.

### 5.3 Interaction between LMPs and transmission development

The development of an effective transmission network is a pre-requisite for any set of electricity market arrangements to work. Electricity can only be traded where network capacity exists to transport it. As shown in the stakeholder insight responses there was almost unanimous agreement that “significant transmission investment is needed in GB to move power from where it can be generated, to where it is needed”. Any market reform needs to consider carefully how the transmission network will be planned, delivered and utilised in an effective way. Incentivising and supporting the transmission network is of equal importance to incentivising the efficient behaviour of those who use it.

The move to an LMP market allows the limitations of the transmission network to be directly factored into market prices: where transmission capacity is limited, this is reflected in price differences between nodes. A relative lack of transmission network also leads to congestion rents which are revenues accumulated by the Market Operator because, when the network is constrained, payments to generators are lower than payments from demand. It is sometimes argued that these congestion rents can provide a useful signal to inform the development of the transmission network. While there was sympathy among interviewees for the idea that LMPs can increase the visibility of congestion and therefore transmission need there was a strong rejection of the notion that LMPs themselves would enable transmission investment. One respondent summed up the experience from the US by concluding, “LMPs don’t help transmission. They just don’t,” while another stated, “I think LMP provides more transparency about price differences making it easier for external players to access – what it doesn’t do is provide the right signals to market to build that capacity.”

In some situations, such as the development of merchant interconnectors between GB and neighbouring markets, the congestion rent itself delivers a return on investment. However, even in these cases, there is significant risk. In GB, interconnector developers are able to limit their risk through cap and floor arrangements, whilst previous attempts at merchant investment in interconnectors in Australia were unsuccessful with the assets subsequently taken over by a regulated utility<sup>148</sup>. On a wider scale, whilst excessive congestion rents would signal the need for additional network capacity, it seems unnecessary to instigate an LMP market and collect those congestion rents to identify the problem, as one interviewee put it “the transmission investment case is crystal clear” already.

Congestion rent should not be seen as the sole budget for development of transmission capacity. What experience from LMP markets does show is that central planning and policy incentives have been the route to investment in new transmission capacity. One respondent pointed to state policy around clean generation being the main driver saying, “in the case of Texas that was development of CREZ zones,” while other US states “have renewable portfolio standards that mandate X MW [of clean generation] in this place by this year. These standards can only be met by earmarking new transmission to facilitate more renewables.”

A second issue is that the revenues and costs for market participants are directly related to the availability of transmission capacity. This means that the extent to which new transmission capacity is effectively planned by the ISO, built in a timely way by the Transmission Owner, and operated and maintained efficiently (including outage scheduling and quick repairs) will have a significant impact on the prices paid by consumers and received by generators. The uncertainty that this will create for market participants is an additional risk and one that market participants do not control. One interviewee argued that signals from LMP congestion would “create a natural interest group [who would be thinking] how much effort do I put into advocacy around grid investment” suggesting that LMP could create the right environment to ensure efficient use of and investment in the network. However another respondent put forward the counter argument that LMP brings uncertainty to investment in generation which could increase the reticence of regulators to approve the build out of new transmission for fear of stranding assets – “the problem with the FTR plus LMP ‘leave it all to the market’ approach is invariably the regulator, who is signing off on the transmission investment, then says ‘it’s all too uncertain, I won’t sign off on anything’, so nothing gets built.”

Whether in a system of national pricing or locational pricing it seems clear that transmission planning needs to take place with a look-forward time of decades given the economic lifetime of the assets being constructed to meet energy policy objectives. Whilst congestion rent via LMP, which builds up through the operation of the day ahead and real time markets, could potentially provide a signal that more transmission network is needed today, that signal would come much too late. To inform network investment planning, the ISO will need to model future operation of the market, rather as they do today, albeit they will have to learn how to model a different market if we move to LMP.

Some respondents were of the opinion that we are going to be at the limit of transmission build out capability regardless of market model for the next decade or so. “The limiting factor is grid constraints and we are constrained on the build out rate of grid. Even in an LMP world the amount of wind and other stuff we would want in Scotland will still be constrained by the amount of grid that we can build so I don’t think we’ll have any less grid build out to Scotland in the next 10 years as a result of LMP. I think the amount of grid we will need by 2050 if we were to put it all in Scotland. That’s the bit that’s in play.”

The recent rise in GB curtailment costs, and particularly those associated with constraints between Scotland and England, is being driven by several factors: the growing capacity of renewable generation in Scotland, the significantly higher price of gas needed to turn up CCGTs in England to replace Scottish renewable curtailment, and the failure of transmission capacity to keep pace with the development of renewables.

This last point suggests a need to review GB’s current arrangements for planning (through NGENSO’s FES, ETYS, NOA process) and delivering transmission upgrades with a view to finding ways of accelerating network expansion. Such a review is currently under way, through the Ofgem-led Electricity Transmission Network Planning Review<sup>149</sup>, and through work being undertaken by the Electricity Networks Commissioner recently appointed by UK Government<sup>150</sup>. Some interviewees suggested alternative approaches to transmission development may be required with one advocating for increased access for merchant investment in transmission: “what you want to do to ensure efficient levels of construction is to not just rely on a single licensed entity to make that assessment but open it up to multiple perspectives with multiple different sorts of risk appetite.” Another stakeholder pointed to planning and consenting as a key challenge:

“the planning system does take a long time you could speed that up, I’m sure. Projects have been held in scoping for too long by Ofgem before being allowed to proceed. I would let the TOs consent a lot more infrastructure now even if they don’t necessarily plan to build it immediately.”

Another suggestion was to take lessons from elsewhere on development of transmission to specified development areas – “maybe look at what they did with renewable energy zones in Texas”. This also appears to be the latest thinking in Australia on how to manage transmission investment and constraints – “do we let congestion just develop and then try and manage it operationally or are you better off to put your time and energy into trying to get the grid built and encourage people to invest where the grid is and therefore have less congestion? That seems to be where we’re going in Australia at the moment... you might say that within that zone, we want a certain proportion of solar, a certain proportion of wind, a certain proportion of storage and then they will allocate rights according to that so the wind farm developers will all compete for the wind, and then once it’s all sold then it’s declined physical access until the next wave of transmission expansion occurs.” Such a move from an open access to closed access connection regime would mark a departure from the current connect and manage regime in GB.

**To conclude, it is clear that GB needs to significantly accelerate its transmission build out. However, a move to an LMP market would not inherently improve that process or make a significant difference to the needs case for new transmission in GB, certainly in the medium term.**

# Conclusions and recommendations

## 6 Conclusions and recommendations

### 6.1 Discussion

There is little doubt that some amount of market reform will be required to deliver a decarbonised power system. This is needed to align the physical characteristics of the electricity system with the arrangements for trading and balancing the system and for procuring the full range of non-energy services that are needed to keep the system operable, resilient and secure.

LMP is used extensively in the US and other parts of the world and it is sensible that it is one of the options under consideration. Centralised dispatch is a fundamental part of locational marginal pricing and is argued to allow the full set of resources – most particularly those that can be scheduled to complement variations in demand or the availability of power from the cheapest sources – to be utilised efficiently and avoids system-wide marginal prices being distorted by offers of energy that cannot be taken advantage of due to network constraints. And, in principle, pricing at a zonal or nodal level provides signals to investors in new generation, demand or storage to site their developments in ways that complement existing network capacity.

The available international evidence – mostly based on modelling before implementation of new market arrangements – seems to show that, once introduced, LMP provides an appreciable increase in the efficiency of system dispatch. Experience of LMP once it has been adopted shows a relatively stable market structure: existing markets have not moved away from the LMP concept. There is also evidence from California and Texas that it can be implemented in systems which have a significant penetration of zero marginal cost (ZMC) renewables, albeit modest relative to the levels expected for a decarbonised GB system.

There are, however, some important caveats. Firstly, whilst LMP has been proven to work in some markets, none of those markets has the characteristics of a decarbonised GB power system that the UK Government has committed to achieve by 2035.

Secondly, there have been significant issues with at least some of those markets: California and Texas have both had significant interruptions to supply in recent years and, although these should not be put down to LMP market structures alone, it is important to consider what role wholesale pricing arrangements played both directly and indirectly through a failure of coordination with other frameworks such as capacity adequacy mechanisms (or lack of those frameworks). Whilst FTRs are regularly described as essential to well-functioning LMP markets, experience from other markets highlights a number of challenges that would need careful consideration for any implementation in GB. These include proving compatibility with variable output renewables, determining suitable product durations and guarding against the potential for manipulation.

Thirdly, because a decarbonised GB electricity system is going to be very different physically from systems in existing LMP markets, there is no off-the-shelf version of LMP that can be implemented. Although there is a 'standard model' with common components that are used in most existing LMP markets, even within these markets the design and interaction of these elements are not the same. For example, each system has its own unique set of algorithms which reflect its physical make up: systems with high ramp rates pay greater attention to reflecting ramping in the dispatch and pricing algorithms, whilst systems with very long duration start-up units or cascade hydro schemes have specific adaptations to commit those units. There are also various fudge factors such as 'uplift' or 'make whole' payments that correct for the differences between simplified optimisation models and real-world operation. Each of the LMP markets also acknowledges that evolution and innovation in market set-up will be required to meet its own deep decarbonisation goals in the future.

Although 'the standard model' may provide an overarching template, significant and potentially first-of-a-kind adaptations would likely be needed in a GB implementation of LMP to manage the very high level of

congestion driven mainly by ZMC renewables. Significant levels of network reinforcement have already been indicated by Britain's system operator, NGESO, as being required to accommodate existing generation and new developments out to 2030. With the existing lag of network development and the potential for new transmission network projects to be delayed, the system will have large numbers of individual ZMC renewable generators located behind the same network constraints. These generators' strategies for pricing offers are likely to be influenced by decisions about the CfD support mechanism. At least some curtailment of ZMC generation will be necessary but our assessment suggests that existing LMP algorithms have limited ability to differentiate between those generators. This would create significant, potentially hard to control, risk for market participants. Finally, FTR products would likely need to be adapted to suit the needs of ZMC renewables rather than schedulable generation or demand.

Arguments can be made that each of these characteristics can be *theoretically* incorporated into an LMP market in an efficient way and, with time, *practical* methods to do so may well be developed. However, capturing all the necessary innovations in a new LMP market designed and implemented at speed over a few years would be a challenge. This risks turning GB's wholesale electricity market into a national experiment at a time when certainty over investment is needed to deliver a decarbonised electricity system on the ambitious timeline needed.

It is also clear that GB system change is not just, or even mainly, about wholesale market reform. Success depends primarily on fast-tracking investment in generation, flexibility and networks. Although an LMP market rewards or penalising market participants based partly on the availability, or lack of availability, of transmission capacity, if there is an intention that congestion rent is returned to consumers, transmission network owners are neither rewarded nor penalised through the LMP market. Whilst the market can signal the need for new investment through congestion rent, having an LMP market is neither a necessary nor a sufficient condition for clarity over future transmission needs and for ensuring that needs are met.

Other important points, beyond wholesale trading of electrical energy, include ensuring security of supply and delivering retail market reform. For security of supply the importance of capacity markets and ancillary services is likely to grow. These provide sources of revenue to generation in addition to income from energy markets and ensuring the various characteristics necessary for operation of the system and reliably meeting demand are provided. Retail markets, and the tariffs they offer to end users, will drive much of the demand side flexibility and the role of Suppliers within a decarbonised LMP market could be significantly different from their role today.

Whether or not to undertake a move to LMP in GB is only one part of a much wider debate and must be considered in relation to other potential reforms. This means understanding the *package* of reforms that would best accompany LMP but also ensure proper consideration is given to other potential packages of reform and not just the status quo when looking at counterfactual benefits.

This summary suggests four key questions which must be answered when considering LMP markets:

1. Are we confident that LMP can be well-adapted to the unique 'decarbonised GB power system' in practice as well as in theory? Can innovative arrangements be developed, tested and implemented within the accelerated timescale required for emissions reduction, and confidence given that major unintended consequences will be avoided?
2. What are the expected costs, benefits and risks faced by GB as a society and an economy, by market participants and other stakeholders in the electricity sector? These may include delay in reducing emissions, failing to provide sufficient reliability of supply, excessive cost, or unfair sharing of cost. Who is best placed to manage each of those risks?

3. How does a move to an LMP approach interact with transmission planning and investment? Is LMP an enabler of more efficient network utilisation and development, or might it distract from or obscure the need for network development? Is some level of network capacity expansion a pre-condition to success of LMP?
4. Could other reform options deliver the same benefits and to what extent do the costs and benefits depend on the package of reforms chosen?

### 6.1.1 Implementing an LMP approach well-adapted to GB's unique characteristics

GB today can be argued to be a unique case for market reform. Development of an LMP system that would fit with today's electricity system would require careful thought. However, the scale and pace of decarbonisation and the growing reliance on wind and solar generation – variable and uncertain as well as being ZMC and renewable – means that designing an LMP market for a 2035 decarbonised system and beyond will require significant innovation, adaption of existing processes and the development of new ones.

#### *The scale of ZMC renewables in a decarbonised GB system*

The scale of ZMC renewables will drive highly variable wholesale prices in any market design and a move to locational pricing is likely to increase that effect, exacerbated in GB in the near term by the lack of transmission capacity across key network boundaries. The variability will have particular characteristics: prices are likely to jump from zero / negative to very high between periods where ZMC renewables are in relative excess or scarcity. Given their correlated nature – which could be reduced by greater geographic diversity but only to a limited extent – this would mean ZMC generation would mostly only be able to access the lowest prices. This could deliver a price distribution that is bimodal. Whilst methods to hedge price risk would remain the same in outline, the practical design of hedging instruments would likely need to change significantly compared with those in use in existing LMP markets, and the sheer scale of ZMC renewables required is likely to mean that risk cannot be hedged for all market participants.

This report has identified the profiling of FTRs as one example: existing FTR profiles do not match the variability of ZMC renewables nor do they respond dynamically to changing wind and solar availability. The implication is that current FTRs cannot hedge risk for renewable projects in the way they can for baseload or even load-following generators. Hence, significant innovation on the FTR format, e.g. in the form of Wind or Solar FTRs, would be required to provide suitable hedging instruments for these generators.

#### *Coordinating LMP and CfD*

A second significant feature of the GB market that would require innovation is the integration of LMP with the centralised CfD arrangements used to support low carbon generation. Existing LMP markets interact with fixed 'per MWh' support payments leading to fixed negative offers from renewables. However, CfDs represent a support payment which varies depending on the clearing price of the energy market. Unlike today's GB energy market, a nodal market provides a range of choices for the reference price against which CfD uplift payments are made. These options in combination can incentivise an array of different behaviours. Implementing a CfD / LMP design would require careful and robust testing to reduce the risk of unintended consequences.

#### *Multiple ZMC renewables generators behind a constraint*

A point related to transmission congestion is the need to manage large numbers of ZMC renewables behind the same transmission constraint. This report has discussed how there is very little difference between individual wind or solar farms in their physical short run marginal costs. In an efficient market this leads to a very flat supply curve for locations behind a constraint with dispatch decided by very small effects such as minor differences in variable O&M costs or differences caused by network losses. These are points that are very hard for generators to predict in advance, but they are features that are likely to be consistent over

time leading to the same generators getting dispatched time and again: a winner-takes-all situation with the success or failure of individual projects depending on where within that flat merit order they fall.

Of course, prices offered by ZMC renewables are also likely to be affected by their support mechanisms. Whilst this may well add steps into the otherwise flat supply curve, it does not remove the ‘winner takes all’ issue with those generators able to offer the lowest price – perversely, those with the largest support payments – always dispatched first.

Scotland provides the most obvious, but not the only, example of where this could become a problem. Today, Scottish generation capacity exceeds the sum of demand and export capability by 5 GW<sup>151</sup>. The Scottish wind fleet includes 276 separate wind farms providing a total of 7.9 GW of capacity at an average of 28 MW per project. Each of these will face close-to-zero physical short run costs and will create different impacts on network losses. These impacts will generally increase the further north the generator is connected and the relative impacts will be similar across settlement periods. In terms of support mechanisms, older generators will receive ROC payments whilst newer ones will have CfDs with the CfD strike price generally lower for the most recent developments. Under an LMP market the Scottish wind fleet would likely fall into a fixed merit order with some generators always failing to get dispatched and therefore facing significantly lower revenue and increased risk.

There are routes that could be explored for managing this, such as applying ‘tie-breaker rules’ to generators whose offers into the market are the same or attempting to share dispatch across the fleet in non-market ways such as pro-rata network access. Alternative arrangements such as the Congestion Management Model approach proposed in Australia, which includes a constraint rebate to all available generators, could also be explored to ensure that non-dispatched generators are still able to receive some revenue.

#### *Introducing LMP into GB would have significant experimental elements*

The characteristics of a 2035 decarbonised GB electricity system would drive the need for significant levels of innovation relative to existing LMP frameworks to develop a working LMP model for GB. Whilst there are options for managing these innovations, these would need significant exploration both in their own right and, importantly, in terms of their interaction with each other and other market arrangements.

The conclusion has to be that introducing LMP at pace would carry the risk of unintended consequences. At least part of a GB LMP implementation would have to be treated as experimental, with the need for robust development and testing. However, as we discuss below, given the nature of change that we are trying to bring about in the physical nature of the GB power system, *any* package of changes to market and regulatory arrangements risks giving rise to unintended consequences. The best understood set of arrangements are those that prevail today which few commentators would argue to be perfect.

#### **6.1.2 Costs and benefits**

Existing estimates of the cost savings that a switch to LMP would bring about in GB are substantial. Analysis by FTI for Octopus Energy has been used by the Energy Systems Catapult to suggest a net saving of £30bn for consumers to 2035<sup>152</sup>. Modelling by FTI in ongoing work for Ofgem suggests consumer benefits could be as high as £55bn between 2025 and 2040 whilst total GB socioeconomic benefits, including both consumer and producer impacts, could be £31bn<sup>153,xxxvi</sup>. Estimates of net benefits for other systems that have moved to LMP have tended to be lower. For example, analysis of the Texas system in 2008, informing their 2010 transition to LMP, suggested net savings of the order of US\$0.5bn over 13 years (approximately US\$0.7bn in 2022 prices) for a system which today serves about 30% more energy than the GB system<sup>154</sup>. More recently, a 2019 study by Ontario’s System Operator suggested net benefits of up to CA\$0.5n over 10 years from the

<sup>xxxvi</sup> The FTI work is ongoing, and the results discussed here provisional and are expected to be updated ahead of a final report in early 2023.

wholesale electricity portions of their ongoing market reform for a system which serves around 45% of GB demand<sup>155</sup>.

One of the reasons for the apparently much higher level of benefits for the GB system is the level of overall investment needed to reach net zero and the potential, at least in theory, to locate that investment in places which make more efficient use of the electricity network.

Depending on the extent to which locational prices are passed through to energy users there is the potential for the demand side to benefit in areas where the marginal price is very low, i.e. areas with surplus low-cost energy. On the other hand, LMP would expose demand users in import constrained areas to higher energy prices than in an unconstrained dispatch. There is an additional argument that LMP could lower the overall cost of dispatch. However, that depends on negative effects of LMP, e.g. on cost of capital to investors in new generation and the impact of that on cost of energy, not outweighing the benefits.

A key area that is not incorporated in many cost-benefit analysis (CBA) outputs is the impact of adoption of LMP on the cost of capital. Anecdotal evidence from interviews and sector reports suggests that there is the potential for the introduction of LMP to cause a significant increase in the cost of capital. Interviewees quoted values of 1.5 percentage points whilst a recent report by Frontier Economics suggested between 2 and 3 percentage points. For comparison FTI's provisional CBA analysis for Ofgem suggests that an increase in cost of capital of 1.38 percentage points would negate the overall benefits while an increase of 2.4 percentage points would negate all consumer benefits in its modelling<sup>156</sup>.

The level of impact is not solely dependent on the implementation of LMP, but on the whole package of measures. Whilst quantitative analysis is limited, it would seem likely that packages which significantly reduce risk exposure would lead to lower cost of capital. For example, an LMP design combined with a very firm CfD such as a "deemed generation" CfD<sup>xxxvii</sup> with no limitation on paying out when the reference price is negative would deliver capacity at lower cost of capital than one without a CfD.

Estimates of the cost of transitioning to an LMP based market are also expected to be significant. The 2008 cost estimate for the ERCOT implementation in Texas was US\$560 million whilst the Ontario 2019 estimate was CA\$109 million. It might be expected that the overall cost for GB could be higher than those due to the large and growing number of participants, particularly generators and flexibility providers.

A further area of uncertainty is the degree of future transmission investment and the impact this would have on net benefits. This is discussed in Section 6.1.4.

In summary, some theoretical studies of LMP implementation appear to show very significant net benefits. However, that needs to be considered in light of three caveats: estimates need to include cost of capital impact and that they need an improved analytical evidence base; secondly, a critique is required of the degree to which analytical studies depend on overly optimistic assumptions on the availability of alternative locations for generation and speed with which they could be developed; and, thirdly, more effort needs to be given to showing how the distribution of costs and benefits is spread between consumers and generators and amongst both of those groups.

Estimates of the costs and benefits of any market reform need to be critiqued carefully. Modelling of a highly complex physical system, associated market mechanisms and how market actors would behave is extremely challenging. Most of the data are uncertain. The modelling depends, inevitably, on approximations and

---

<sup>xxxvii</sup> A deemed generation CfD is one in which generators are paid based on their potential to generate, for example based on wind speeds, rather than their actual exported energy. It has been proposed as an option under REMA as a method of ensuring that ZMC renewables continue to receive support if they choose to forgo exporting energy to the network in order to participate in ancillary services, or to supply demand or charge storage connected behind their meter. It could also be used to continue rewarding ZMC generators where there is insufficient network capacity to allow them to export.

judgements<sup>157</sup>. There are many elements of cost and any single analysis might not consider all of them, and might not treat them in a way that all stakeholders would regard as reasonable. Given the extent of dependency on judgement in the modelling, there is likely to be value in assessments being done by different parties and then comparing them. However, we note that published assessments of potential benefits of a switch to LMP in Britain seem to depend on a single party: FTI. Moreover, globally, we have seen a general lack of post hoc reviews of CBA for electricity market reforms, whether they accurately foresaw actual costs and benefits and whether the methods used were appropriate.

### 6.1.3 Risk

The importance of placing risk with those who are best able to manage and respond was a point raised by several interviewees throughout this project. However, there was also a significant divergence of views as to which market participants, or wider sector stakeholders, really are best placed to manage risk.

At a high level, a move from current GB arrangements to LMP is one that moves greater risk onto generators and away from consumers, at least in direct terms. It also reallocates risk across consumers and generators depending on their relationship to network constraints. It is argued by some that generators can respond: by choosing sites that minimise risk, through the purchase of FTRs, and by investment in or cooperation with owners of physical forms of flexibility such as storage. However, in exploring this area it has become clear that options for generators to manage these risks, especially in the context of a decarbonised GB power system, are limited.

Before discussing these options for management and mitigation, an important part of the debate is about the *concentration* of risk. Under LMP, a large fraction of a project's revenue can be subject to significant uncertainty. The level of exposure faced by parties in different locations would vary depending on their potential exposure to existing or future transmission constraints. An example was given by an interviewee familiar with Texas which highlighted how decisions outside the control of the generator, in that case decisions taken by the Transmission Owner in response to Storm Uri, led to a near complete collapse in market revenue for a generation project. Where there are multiple generators competing over limited network capacity, it is likely that arrangements would lead to a 'winner takes all' outcome with the same generators regularly failing to get dispatched.

Despite a concentration of generation in one location, it may still be possible to manage and mitigate revenue risk. The first option for doing so is for investors in new capacity to choose to invest in sites where congestion is likely to be limited over the lifetime of the project. Some interviewees and some reports argue that, for example, greater offshore wind capacity could be developed off the coast of England rather than Scotland. They highlight the extensive sea-space opened up by floating offshore wind and the ambition for up to 20 GW of offshore floating wind around the Celtic Sea. Whilst this argument may hold on timescales of 20 – 30 years it is hard to see significant movement of pipeline offshore wind capacity from Scotland to England before 2035. However, in a system with the scale of physical change that is expected in Britain – generation, network and storage capacity and, as time goes on, growth in demand for electricity – it is difficult to predict, with confidence, the location and extent of network congestion.

The second risk mitigation option often discussed is the use of FTRs to hedge congestion risk. This is an important short-term element of managing risk for participants in most existing LMP markets and attempts have been made in those systems to implement efficient longer term FTR markets. Long-term FTRs appear particularly important for ZMC renewable generators that need confidence over revenue streams over a large fraction of the lifetime of their asset in order to finance initial development. Although FERC rulings in the US have aimed to encourage the development of long-term FTRs, this has tended to extend only as far as three years into the future. Even over these timescales there are concerns: PJM and CAISO market monitors have recommended the removal of three-year FTR products for the purposes of hedging. The second issue,

already discussed above, is that traditional FTR products do not match the profile of ZMC renewable generation and cannot therefore provide the level of hedging they provide to schedulable generators. Whilst the introduction of new products could solve this, we highlight above that this would represent a significant innovation relative to existing processes.

Finally, there is the option of risk mitigation by investing in ‘physical hedges’ such as energy storage and hydrogen electrolysis located locally to the generator. These could both be viable strategies, but their success depends on wider considerations. Batteries will only have limited success in a highly congested network as congestion could extend over many days without a break. Discharging a battery at a worthwhile price will likely mean waiting until the network is not congested. If the cycles of congestion and non-congestion last several days at a time the ability of a battery to recover its investment costs will be limited. Of course, batteries are likely to continue to be valuable for other use cases such as the provision of ancillary services but may be of little value in terms of increasing the use of renewable power from constrained generators.

Pairing generation with hydrogen electrolysis can avoid these network issues as the potential use of hydrogen is not limited to the electricity system. However, the hydrogen itself only has value where infrastructure and markets exist for its offtake and eventual use. This is clearly an ambition of GB’s wider energy policy, but it is one where there is a need for an increased consideration of the interaction between the two systems.

#### 6.1.4 Transmission development

Much of the GB debate about the potential value of LMP is driven by the growing level of transmission congestion and the associated constraint costs. This itself is a consequence of what looks very much like a sub-optimal level of transmission capacity across key boundaries, particularly those in Scotland and the north of England. Constraint costs have risen sharply between late 2021 and the end of 2022, mainly due to the increase in fuel costs for gas power stations that are required when ZMC renewable output cannot be transported to demand further south. Regardless of fossil fuel costs, constraint costs are expected to stay high in the medium to long term if sufficient transmission reinforcement is not delivered. This will be driven by an increase in constraint volumes as generation, particularly wind, connects in areas in the north of Britain where resources are high and consenting regimes supportive. New transmission is being developed and the planned rate at which new network capacity will be added over the coming years is accelerating. There remain important questions, though: what is likely to be the ‘optimal’ transmission capacity for the GB system in 2035, 2040 and beyond? Is enough being done to plan and build sufficient capacity, or can more be done in the future? And what will the impact on market participants be of delays in transmission build out?

LMP is proposed as a mechanism for incentivising market participants to locate and operate in a way that makes efficient use of a given capacity of transmission. If this is successful it can reduce the need for additional transmission, although, as we discuss elsewhere in this report, it appears that evidence that LMPs would have a significant effect on siting is limited. Beyond its potential influence on market participants, it is important to remember that, aside from how revenues accruing from congestion rent might be treated, LMP markets do not directly incentivise and support the planning, delivery or operation of the transmission network. Transmission investment in existing LMP markets is undertaken based on strategic planning activities such as PJMs regional Transmission Expansion Plan<sup>158</sup> or ERCOT’s Competitive Renewable Energy Zones (CREZ) programme<sup>159</sup>.

LMP can signal a relative lack of transmission capacity in the prevailing market through the accumulation of congestion rent. There is the potential to use some of this to fund future network investment although in most LMP markets the majority of congestion rent is actually returned to consumers. However, even

attempting to make a direct link between the LMP market and transmission investment is likely to be flawed for two reasons. Firstly, the congestion rent is not solely a budget for transmission investment and its size is unlikely to correlate with that of the investment needed; and secondly, congestion rent is a signal about the current level of transmission, whilst, due to very long lead times for major transmission developments, decision making on investment in new capacity often need to be taken a decade or more in advance of delivery.

Although the LMP market does not necessarily directly influence transmission investment, it is also important that the two domains are not treated independently. The provisional CBA estimates produced by FTI for Ofgem<sup>160</sup> show that, within the assumptions of the study, the overall welfare benefits of moving from the current GB market to LMP fall by 18% – from £31.5bn to £25.7bn – simply by including plans for additional transmission capacity that have been brought forward since the start of 2022 (over the past 10 months). The current CBA estimates published at the time of writing for the period 2025 to 2040 only include proposed transmission, but current proposals for network upgrades only go out to the early 2030s, approximately 10 years into the future. The scale of expected development of variable renewables is such that it should be expected that additional network capacity will be proposed and built both within the period covered by the CBA and beyond it.

### 6.1.5 Considering alternative market arrangements

This report has provided an in-depth review of LMP as one option for GB wholesale market reform. It has identified that LMP could provide more efficient dispatch of resources on the system, but that its ability to impact on generation and energy storage infrastructure siting decisions may be limited and that there are significant uncertainties as to how it would work in practice. There are important implications associated with the transfer of risk between participants, and a need for substantial innovation in market mechanisms both with the LMP model itself and through the interaction between wholesale energy and other elements of the market.

Whilst an LMP approach is likely to present challenges, it is important to note that many comparable challenges exist in alternative approaches. These include the changing physical characteristics of the electricity system, the growing importance of flexibility and how to enable it, and the inherent risks and uncertainties associated with any kind of market reform. It is widely accepted that existing market arrangements are becoming increasingly unsuitable and that some form of change is required. This raises the question: if not LMP then what?

The REMA consultation and the electricity sector's responses to it have explored a variety of approaches to market reform, and discussion will continue throughout 2023. It has been beyond the scope of the work reported here to suggest alternatives to LMP or make recommendations on packages for reform. However, this section briefly highlights some of the key points which any market reform needs to address.

- **Generation needs to remain financeable:** The growth of ZMC generation will radically change the characteristics of the electricity wholesale market with significant implications for all participants. With prices likely to drop to zero or below on a regular basis even under a national market it will be important to consider how different types of generator will finance themselves. For ZMC renewables this will place greater weight on the need for long-term contracts, potentially a combination of private PPA arrangements and centralised CfD arrangements, to provide confidence that investment can be recovered.
- **A review of locational price signals under any set of market arrangements needs to be a priority.** Today's TNUoS charges are the major form of locational signal intended to influence investment by network users; however, these have previously been criticised for several reasons including being

hard to predict in advance, being over-sensitive to changes in single factors in the formulation, and being unreflective of the cost of transmission. One option for improving locational price signals is to overhaul TNUoS to better reflect the needs of the GB system. For example, this might consider how far in advance TNUoS is fixed.

- **The incentives given to flexibility** need to be a major focus of reform. Whilst an LMP market may increase opportunities for energy price arbitrage, it is likely that other revenue streams for dedicated providers of ‘flexibility’ will remain important, possibly dominant. Whatever market structure is chosen it is important to consider what each distinct form of flexibility is likely to be useful for and how best to incentivise that. To unlock the full potential of flexible assets like storage and flexible demand, time and location specific signals are required to direct both siting and efficient operation. LMP would be one way to deliver this but the extent to which other reform options, including adaptations to the Balancing Mechanism and capacity market, introduction of local balancing markets or adoption of zonal pricing as opposed to nodal pricing, could achieve the same outcomes should be thoroughly examined.
- **Managing interconnectors will become a growing challenge** as the capacity of interconnection increases over the next decade. Interconnectors are not currently exposed to TNUoS or BSUoS charges, a regulatory decision taken to implement EU regulations. They therefore do not receive a locational price signal to influence the siting of their connection to the GB system nor are they exposed to the costs they impose on the system. In addition, the market signal that currently governs interconnector flow direction at the day ahead stage does not account for internal GB system constraints and so has the potential to exacerbate rather than alleviate those constraints. Individual interconnectors have the potential to make a significant impact on power flows on the GB system. For example, a 2 GW interconnector can change the power balance in an area by 4 GW if turning from full import to full export.

This report has focused heavily on the implications of a fully nodal implementation of LMP. It should be noted that a zonal pricing model might be able to deliver many of the same purported system benefits while still retaining some of the features of existing market arrangements. Proponents of LMP who have been most vocal in GB in recent months heavily favour the nodal option. They put forward the need for frequent re-evaluation of the zonal boundaries and the continued need for system operator interventions to manage intra-zonal constraints as key arguments against the zonal model. However, a number of interviewees viewed zonal as a potential compromise option worth more consideration. The key questions are then: to what extent might zonal pricing achieve many of the benefits of LMP while reducing some of the risks? Could a zonal option potentially be better aligned with a more regional approach to the procurement and award of CfDs to renewable generation, something that would permit more strategic planning of resources and give an opportunity to engineer a degree of spatial diversity in the wind fleet? Or would a zonal approach still raise many of the same potential problems as nodal would? Answers to these questions should be considered by policy makers.

FTI’s interim analysis for Ofgem could provide some initial clues – the modelling suggests total societal welfare gains from a zonal pricing model could be around half of those delivered by a nodal model. However, the distribution of impacts between consumers and producers underlying this difference is varied. For the scenario modelled by FTI, a nodal approach produces consumer welfare gains of £55bn between 2025 and 2040 compared with national pricing while these benefits reduce to just £15bn for a zonal approach. In contrast the nodal approach implies a reduction in producer welfare of some £23bn compared with national pricing whereas total producer welfare under the zonal model is practically unchanged. A zonal model might therefore be viewed as carrying lower total risk for market participants, particularly investors. However, this

only reflects the outcome of a single modelling scenario – much more extensive analysis, including of the distribution of risk and impacts within each of the producer and consumer groups, is required to make a robust comparison.

Whilst consideration of LMP is one of the key features of the current market reform debate another hot topic at the time of writing, in light of the current cost of energy crisis, is the desire for consumers' final electricity bills to better reflect the cost of production of all the energy consumed rather than the costs of the marginal unit, often provided by gas in the present GB system. While gas prices remain steeply inflated compared with historic levels there is increasing concern as to the levels of inframarginal rents or excess profits that generation assets, including low carbon generation, might be able to extract from the present market arrangements. Policy makers could consider whether an LMP market might help to reduce the sum of inframarginal rent paid to generators; however, there is then the risk that it is reduced by too much to enable long-run costs to be recovered.

One of the challenges in electricity market design is that, while electricity as a commodity might be largely homogeneous in the form in which it reaches end users, it is not in terms of its production. Plant that are dependent on expensive fuels have very different cost structures from that using weather-dependent renewable forms of energy. Some market reform proposals seek to address the issue directly. The suggestion of split markets encapsulates a number of options which separate out the markets for production of 'firm power' whose cost structure is often dominated by short run marginal costs relating to fuel use, from those for zero marginal cost low carbon generation whose cost structure is dominated by long run costs associated with recovering capital expenditure. The existing centralised, government-backed CfD scheme can be argued to be a de-facto market splitting tool as it delivers revenue specifically to low carbon variable generators based on their long run costs.

Ascertaining the compatibility of an LMP market with any split market options or existing or future CfD arrangements is a key priority for policy makers – it is likely that some reform options under consideration may be mutually exclusive.

## 6.2 Conclusions

Our work results in the following recommendations for action related to market reform and informing policy.

### 1. **Moving to LMP could increase the risk of failing to deliver decarbonised power by 2035.**

Introducing an LMP market would create significant short-term disruption, increase the allocation of costs and risks to individual generators and require significant innovation to adapt the existing LMP standard model to suit a GB system. This risks turning GB's wholesale electricity market into a national experiment at a time when certainty is needed to deliver significant investment in the sector. One result could be a delay in our ability to deliver a decarbonised electricity system due to a hiatus in investment.

There will be risk associated with any significant change in market arrangements. Some of that risk stems from the fact of change itself and the uncertainty that it creates, and some will be down to the nature of the particular set of changes. Any implementation of LMP should be part of an appropriate and complementary package of reforms spanning ancillary services, capacity markets and low carbon support mechanisms. These elements interact and combine to impact the potential profitability of different investments. There is little time to carry out the necessary analysis, design, consultation and implementation at the pace required to impact on how the electricity system looks and is operated in the mid-2030s.

The difficulty of solving this challenge should not be underestimated and exploring at least some of the complexities involved needs to be a central part of the evidence base used to make decisions on future wholesale market arrangements.

### 2. **LMP could significantly increase the cost of capital for generators, but that depends on the interaction between the wholesale energy market framework and the wider package of market reform including mechanisms to support investment in new low carbon generation.**

In addition to the risk of delaying a decarbonised electricity system, there is a risk that market reform will result in a more costly system than expected. A key part of that risk comes from the cost of capital. There is anecdotal evidence that markets that price energy on a nodal basis increase the cost of capital for merchant investment relative to those that do not, but there is limited published analysis of the effect. Our review suggests that, relative to today and dependent on the implementation of a wider package of reforms, LMP would place additional revenue risk on GB investors and create a situation where risk is hard to forecast and difficult to control for individual market participants (e.g. the risk to a generator of a competing generator connecting at the same node or of a major demand customer closing).

Participants in an LMP market face both price and dispatch (or volume) risk. For ZMC renewables, in particular, it is important that these risks can be quantified and managed in advance for a significant fraction of a project's operating life. Mechanisms do exist in LMP markets to manage price risk. These include FTRs and bilateral PPAs. However, evidence from existing markets suggests that these mechanisms are likely to be limited to a timespan of no more than a few years, much shorter than the typical lifespans of generation assets. Dispatch risk relates to the lack of firm access rights in a conventional LMP market and uncertainty over whether a market participant will be scheduled by the LMP algorithm which mean, without dispatch by the algorithm, a participant cannot participate in the market. In contrast to price risk, there are limited mechanisms in place in existing LMP markets to mitigate dispatch risk. In principle, generators might self-schedule but they will then be exposed to the energy price at their connection node which, in a wind dominated area under windy conditions, could turn negative leading to them losing money.

There are ways that wider market design can reduce and reallocate some of the risk on particular market participants through other arrangements, particularly support mechanisms for low carbon generators. Continued use of CfDs could absorb some of the price risks associated with network constraints while adoption of something akin to a 'deemed generation' CfD would be required to mitigate generator dispatch risks, a potentially bigger factor for GB. However, the extent to which such measures are utilised and their detailed design would have direct consequences on the level of consumer welfare benefits that LMP could deliver.

**3. LMP markets are in use in some parts of the world; some of them have a reasonable level of ZMC renewable (wind and solar) penetration but not to the extent that GB expects to have by 2035.**

LMP markets have existed in their modern form for at least 20 years in parts of the US and elsewhere and are generally considered by those who work within them to be efficient, effective and competitive overall, although there are some important caveats with certain aspects of those markets such as long-term FTRs.

Other markets also provide evidence that it is possible to operate LMP markets with moderate penetration of variable, zero marginal cost renewables. In 2020 CAISO had a 28% penetration of wind and solar (as a proportion of total electrical energy production) and ERCOT 41%. Investment in renewables continues to be made in those systems although it is unclear whether this investment is made 'because of' or 'in spite of' LMP. However, there is no experience world-wide of introducing LMP into a system that is undergoing the level of change currently being experienced in GB, nor one that has ambitions on such a short time scale to convert fully to decarbonised electricity system, a process that will potentially require an increase in the penetration of variable, zero marginal cost renewables to provide 80% of electricity.

**4. LMP has the potential to improve the efficiency of dispatch of system resources including generation and flexibility.**

The locational signals delivered through LMP markets on day ahead and operational timescales have the potential to improve the efficiency of dispatch. This includes the dispatch (or not) of ZMC renewables. The benefit comes largely in terms of driving efficient dispatch of interconnectors, storage and fuelled, schedulable generators. This has the potential for operational savings through the burning of less fuel. However, the significance of such savings in a system in which most energy comes from ZMC generation should be assessed. However, the significance of such savings in a system in which most energy comes from ZMC generation should be assessed.

The design of the algorithm is critical to successful dispatch, and needs to reflect the underlying physical characteristics of the system. For a decarbonised electricity system, the way the algorithm deals with multi-period constraints would be particularly important as this would be central to efficiently dispatching energy storage and demand flexibility.

**5. LMP is likely to be limited in its ability to drive more efficient siting in GB.**

Evidence from this review suggests that LMP would likely have limited impact on the siting of ZMC renewables. We have come across little evidence of locational price variations affecting the siting of renewables in existing LMP markets and several interviewees highlighted that non-price factors such as availability of resources (wind or sun) and the ability to get planning permission are more likely to drive siting decisions.

The experience of Texas suggests that renewable investment is likely to come in waves in line with availability of new transmission capacity to areas with the best resource rather than being redirected to other locations which already have more network capacity available. These factors are likely to have a

strong impact in GB where space is at a premium, planning and consenting is difficult and time consuming, and resource availability is concentrated in particular parts of the country.

**6. LMP markets do not, on their own, solve the problem of planning, designing, building and operating an efficient and effective transmission network.**

An LMP market is largely about efficiently managing access to a given quantity of network capacity. There is limited evidence that moving to LMPs leads to less need for transmission network in practice. Comments made by interviewees highlight that LMP markets are most effective where there is a close-to-optimal level of transmission network, with some (but not too much) network congestion.

**7. There are significant concerns in existing LMP markets with ‘long term’ Financial Transmission Rights for hedging.**

In US markets FTR products are often available for no more than three years in advance, and market monitors in two systems (CAISO and PJM) have advocated the removal of so called ‘long-term FTRs’ with terms from one to three years ahead, citing poor consumer value and the potential for manipulation. Long-term FTRs often sell at auction for significantly less than the value they realise suggesting a lack of competition for these products. Despite significant resource given to market monitoring FTR markets have been subject to major scandals. One prominent example in PJM saw costs of US\$179 million associated with what FERC ruled as manipulative FTR trading.

**8. An ‘off-the-shelf’ LMP market solution does not exist for GB – we would need to adapt existing processes and develop new ones.**

If LMP were chosen for GB there would be a need to significantly adapt the ‘standard model’ of LMP design in potentially complex ways to reflect both the physical characteristics of the system and wider market structures, particularly CfDs. (See further points below). No existing LMP market operates on a system where ZMC generation is the price setter across much of the network for a significant part of the year. And, whilst the theory of LMP markets can still work in such a system, it is clear that it would raise specific and new challenges. One example of innovation that will be needed is to develop ways of ensuring that the system can always be balanced even with the very high ramp rates of residual demand that can be expected in future. These innovations would take time to develop, test and demonstrate making proposed implementation before the end of the decade challenging. Introducing a period of policy uncertainty risks an investment hiatus that could impact on 2035 targets for decarbonisation of electricity.

**9. A new form of FTR suitable for variable renewables would need to be developed.**

Whilst FTRs are argued by many to be critical to the effective functioning of an LMP market, we believe there are significant risks associated with relying on them in the context of a decarbonised GB electricity system either to hedge long-term risk or act as compensation for the loss of firm access rights that existing generators would face. FTRs currently in use in US markets involve fixed, pre-defined profiles, and therefore do not match the time-varying nature of wind and solar generation, nor do they have the flexibility to adapt to the uncertainty in future output inherent in weather dependent renewables. A new form of FTR suitable for variable renewables would need to be developed and tested robustly.

**10. Integration of LMP and centralised CfD renewable support would be a world first (with associated risk of trying something new).**

Whilst existing LMP markets have been run with support for renewables based on fixed or near fixed payments per MWh, they have not been run with arrangements similar to Britain’s Contract for Difference arrangements where the uplift payment depends on the difference between a strike price determined in an auction and a market reference price for each wholesale market settlement period.

There would be a number of important choices to be made in co-designing a joint LMP and CfD system for GB such as how to set the reference price, and how to deal with negative wholesale prices.

**11. An LMP market may not efficiently dispatch a large number of generators caught behind the same network constraint.**

All ZMC generators caught behind a constraint would have the same short run marginal cost: zero. Bidding in an LMP market may be influenced by very small differences in variable operation and maintenance costs, small impacts on overall system losses, and arrangements related to support payments.

Given these small differences, there would be a significant degree of arbitrariness around which ZMC generators are dispatched 'on' and which are not. Even if the relevant locational price is zero, this can lead to significantly different revenue outcomes across the ZMC fleet due to the different forward contracting and low carbon support arrangements that market participants have, the majority of which are likely to depend on dispatch and physical production.

**12. Without additional arrangements, a move to an LMP market might fail to deliver capacity adequacy.**

LMP has the potential to reduce revenue available for some schedulable generators including peaking plant and increase the importance of a robust capacity adequacy mechanism. As with other elements of the overall market package, it is critical to ensure that the energy and capacity adequacy arrangements work effectively together.

Ensuring a secure low carbon system requires significant capacity of schedulable low carbon energy sources such as hydrogen peaking plant, gas generation combined with CCS, storage, or access to reliable imports. Many market designers, including those in CAISO, PJM (and GB), have made the judgment that a wholesale energy market needs to be combined with some form of capacity adequacy mechanism in order to ensure sufficient capacity to meet peak demand. Others markets such as ERCOT rely on the energy market alone, through scarcity rents, to support capacity adequacy.

A significant quantity of ZMC renewables is likely to impact on revenues not just for peaking plant but also for 'mid-merit' schedulable generation which will have limited running hours in a system with a high level of variable renewable generation capacity. These generators will almost certainly require a strong capacity market or other non-wholesale market-based revenue streams, and this requirement would likely be stronger in a market with LMP than in one without.

Evidence from the rolling blackouts experienced in California in recent years suggests that poor coordination between their LMP market, where day-time revenues have been eroded through the growth of solar power, and the Capacity Procurement Mechanism was one factor leading to insufficient generation available in the early evening after the sun had set.

**13. The impact of a move to LMP on the demand side is unclear.**

In principle, LMP would reduce the total cost of dispatch. Depending on the extent to which locational prices are passed through to energy users there is the potential for consumers to benefit in areas where the marginal price is very low. On the other hand, LMP could expose energy users in import constrained areas to higher energy prices. The overall extent of benefits to the demand side depends on negative effects of LMP – e.g. on cost of capital to investors in new generation and the impact of that on cost of energy – not outweighing the benefits.

At present there appears to be little evidence to help understand the potential real-world impact of LMP on the demand side and little consensus on the extent to which the demand side should be exposed to locational prices. In most US LMP markets, for example, the demand side is only exposed to locational

price difference at the zonal rather than nodal level. However, some markets, such as in New Zealand, do apply nodal prices to the demand side.

The prospect of highly variable energy prices for consumers based on location leading to a ‘postcode lottery’ has the potential to raise significant distributional as well as political concerns. Most energy users in Britain buy their electricity through Suppliers who could be charged for demand on a nodal basis but regulated in the degree to which time and locational variation can be passed through to end consumers.

**14. In the US significant attention is paid to Market Monitoring to identify the degree of efficiency and competition in LMP markets and to spot potential breaches of market rules. We should be ready to devote similar levels of attention here.**

The effort placed on market monitoring in US LMP markets is significantly greater than is seen in GB. This provides detailed analysis and insight into the operation and effectiveness of each element of the market structure. Market monitoring is carried out independently of the regulator with monitors given the power to make recommendations to the Market Operator and to the regulator, and to refer potential breaches of market rules for formal review. We see significant value in adopting similar approaches to the GB market regardless of decisions over the form of that market.

**15. While there are major questions to be resolved in the design of LMP and complementary arrangements as part of an overall package, any alternative set of arrangements must address similar issues.**

The final suite of reform options that is brought forward from the ongoing review process should be the package that best addresses the overarching objective of the power system, which this report suggests to be:

*Ensure that, by 2035, net production of greenhouse gases on the GB electricity system is negligible while supplying electrical energy with sufficient security and resilience at lowest total cost to energy users over the medium to long term.*

*In achieving this objective, reform of energy markets should consider their interaction with a wider set of economic, social and environmental policies and how development of the energy system makes the most of opportunities for the whole economy, ensures fair access to and affordability of energy, supports regional development across GB and provides appropriate protection for natural capital and ecosystem services.*

This raises significant challenges associated with coordinating the siting and dispatch of resources.

These challenges will grow under any set of market arrangements.

Whilst there are significant risks and challenges associated with moving to an LMP market, many of the fundamental issues will be common to any market system and there are areas where current GB arrangements are poorly aligned with the changing needs of the system. In particular, any form of electricity market arrangements needs to:

- Manage the cost and risk created by ZMC generators connecting where strong non-price locational signals dictate.
- Incentivise flexibility – storage, flexible demand and schedulable sources of energy – to be made available in the right places, at the right times and ensure that it is used efficiently within the constraints of the system.
- Provide signals to interconnectors to connect in the most effective locations in GB and to dispatch them in a way that supports the GB system without exacerbating network constraints.

- Influence the development of the transmission network to better anticipate where market participants will connect, ensuring that there is sufficient transmission capacity in the right parts of the network at the right times.

### 6.3 Final comments and recommendations

The UK Government has set a goal of decarbonising electricity production, subject to security of supply considerations, in the next 12-13 years and then to grow the electricity system as we electrify increasing amounts of our end use of energy.

The final test of any package of market reforms is whether it succeeds in meeting the overall objectives of the power system. Options for reform should be considered in light of the main risks:

- that the total cost of electricity is higher than it needs to be;
- that the resilience and security of supply are less than is acceptable to society; or
- that emissions reduction targets – most notably in the short to medium term, the legislated carbon budgets – are missed.

Who faces the impacts of those adverse outcomes? And, if there is no perfect policy that mitigates all the risks to an acceptable level, how might policy be biased in order to avoid the worst of them?

Based on our review of the literature relating to implementation of existing LMP markets and the discussions we have had with interviewees, we make a number of recommendations.

1. Further analysis and critical appraisal of market reform options, including LMP, should take clear and detailed account of the package of measures that LMP would be implemented within. This should include, but is not limited to:
  - the likely level of innovation needed in LMP structures and in the coordination between LMP and other GB market arrangements and system objectives;
  - how LMP and CfDs might be co-designed to deliver desired outcomes including appropriate splits of cost and risks between market participants, mitigating risks associated with LMP without undermining the main objectives;
  - the need for new FTR arrangements to support variable ZMC renewables and the limitations of FTRs as long-term hedging mechanisms that have been identified in existing LMP markets;
  - consideration of how an LMP algorithm would dispatch multiple ZMC generators behind the same constraint.
2. Cost Benefit Analysis (CBA) should be carried out for LMP as part of a package for reform (rather than for LMP in isolation) and against counterfactuals reflecting that the appropriate comparison is not just with current GB arrangements but with other options for reform.
3. To inform CBAs, robust quantitative evidence is required on the impact of moving to LMP on the cost of capital for different types of market participant. This needs to be supplemented with significant sensitivity analysis considering the impact of the wider package and context for all market reform options. Sensitivities should include:
  - the risk implications of different forms of CfD or alternative low carbon support mechanisms in combination with LMP;
  - the impact of delays in transmission development and of network outages;
  - constraints on siting for new network users.
4. Undertake a detailed study of the size and allocation of risk under different market proposals. This should review any changes to risk, including the risk of failing to achieve a decarbonised electricity

system by 2035 and of insufficiently secure supply. It should consider how risk is allocated across market participants. It is important that those undertaking this work fully understand the nature of risk under an LMP market combined with a fully decarbonised electricity system. This report highlights that dispatch risk would become increasingly important with a scale significantly larger in GB than in existing LMP markets.

5. Develop a longer-term plan for transmission network development beyond the period covered in the 'holistic network design' that exists at the time of writing, giving the sector an indication of what transmission capacity across major boundaries could be in 2035 and 2040. This should be assessed for a number of scenarios rather than just a central pathway (much like FES does for generation and demand) and for boundaries expected to experience significant and costly congestion over the coming decades.
6. Review the approach to market monitoring in US LMP markets and consider funding and implementing similar, independent monitoring of GB markets, regardless of the form of those markets.

## References

- <sup>1</sup> NGESO: *Net Zero Market Reform, Phase 3 Assessment and Conclusions*, May 2022, <https://www.nationalgrideso.com/document/258871/download>
- <sup>2</sup> UK Government, *Net Zero strategy: Build back greener*, October 2021, <https://www.gov.uk/government/publications/net-zero-strategy>
- <sup>3</sup> Department for Business, Energy & Industrial Strategy, *Review of electricity market arrangements*, July 2022, <https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements>
- <sup>4</sup> NGESO, *Net Zero Market Reform, Phase 3 Assessment and Conclusions*, May 2022, <https://www.nationalgrideso.com/document/258871/download>
- <sup>5</sup> Ofgem, *Locational Pricing Assessment – call for input*, June 2022, <https://www.ofgem.gov.uk/publications/locational-pricing-assessment>
- <sup>6</sup> Energy Systems Catapult, *Locational energy pricing in the GB power market*, October 2021, <https://es.catapult.org.uk/report/locational-energy-pricing-in-the-gb-power-market/>
- <sup>7</sup> NGESO: *Net Zero Market Reform, Phase 3 Assessment and Conclusions*, May 2022, <https://www.nationalgrideso.com/document/258871/download>
- <sup>8</sup> Ofgem, *Net Zero Britain: Developing an energy system fit for the future*, July 2022, <https://www.ofgem.gov.uk/publications/net-zero-britain-developing-energy-system-fit-future>
- <sup>9</sup> Ofgem, *Locational Pricing Assessment – call for input*, June 2022, <https://www.ofgem.gov.uk/publications/locational-pricing-assessment>
- <sup>10</sup> Department for Business, Energy & Industrial Strategy, *Review of electricity markets*, July 2022, <https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements>
- <sup>11</sup> UK Government, *Electricity Act 1989*, July 1989, <https://www.legislation.gov.uk/ukpga/1989/29/contents>
- <sup>12</sup> Scottish Government, *Scotland's electricity and gas networks: vision to 2030*, March 2019, <https://www.gov.scot/publications/vision-scotlands-electricity-gas-networks-2030/documents/>
- <sup>13</sup> Scottish Government, *Gas and electricity networks: development principles*, March 2021, <https://www.gov.scot/publications/principles-development-scotlands-gas-electricity-networks/documents/>
- <sup>14</sup> CCC, *Recommendations of the Sixth Carbon Budget*, December 2020, <https://www.theccc.org.uk/publication/sixth-carbon-budget/>
- <sup>15</sup> CCC, *The sixth carbon budget. The UK's path to net zero*, December 2020, <https://www.theccc.org.uk/wp-content/uploads/2020/12/The-Sixth-Carbon-Budget-The-UKs-path-to-Net-Zero.pdf>
- <sup>16</sup> BEIS, *Net zero strategy: build back greener*, October 2021, [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/1033990/net-zero-strategy-beis.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1033990/net-zero-strategy-beis.pdf)
- <sup>17</sup> IEA, *Achieving Net Zero Electricity Sectors in G7 Members*, October 2021, <https://www.iea.org/reports/achieving-net-zero-electricity-sectors-in-g7-members>
- <sup>18</sup> Arup, ORE Catapult, AMP Mer for BEIS, Offshore Wind Evidence and Change Programme, The Crown Estate and The Crown Estate Scotland *Future offshore wind scenarios: an assessment of development drivers* April 2022, [https://www.futureoffshorewindscenarios.co.uk/assets/report/20220421\\_FOW\\_Final\\_Report.pdf](https://www.futureoffshorewindscenarios.co.uk/assets/report/20220421_FOW_Final_Report.pdf)
- <sup>19</sup> NGESO, *Future Energy Scenarios 2022 - Data workbook*, July 2022, <https://www.nationalgrideso.com/future-energy/future-energy-scenarios>
- <sup>20</sup> NGESO, *Future Energy Scenarios 2022*, July 2022, <https://www.nationalgrideso.com/future-energy/future-energy-scenarios>
- <sup>21</sup> BEIS, *Energy Trends UK, April to June 2022*, 29<sup>th</sup> September 2022, [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/1107456/Energy\\_Trends\\_September\\_2022.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1107456/Energy_Trends_September_2022.pdf)
- <sup>22</sup> Regen, *Review of Electricity Market Arrangements: Consultation Response from Regen*, October 2020, <https://www.regen.co.uk/publications/regens-rem-a-consultation-response/>
- <sup>23</sup> LCP, *Renewable curtailment and the role of long duration storage*, May 2022, <https://www.drax.com/wp-content/uploads/2022/06/Drax-LCP-Renewable-curtailment-report-1.pdf>

- 
- <sup>24</sup> NGE SO, *Electricity Ten Year Statement*, November 2021, <https://www.nationalgrideso.com/document/223046/download>
- <sup>25</sup> NGE SO, *Network Options Assessment*, January 2021, <https://www.nationalgrideso.com/document/185886/download>
- <sup>26</sup> NGE SO, *Network Options Assessment 2021/22 Refresh*, July 2022, <https://www.nationalgrideso.com/document/262981/download>
- <sup>27</sup> NGE SO, *Pathway to 2030: A holistic network design to support offshore wind deployment for net zero*, July 2022, <https://www.nationalgrideso.com/document/262676/download>
- <sup>28</sup> Department of Energy & Climate Change, *Government Response to the technical consultation on the model for improving grid access*, July 2010, [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/42979/251-govt-response-grid-access.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/42979/251-govt-response-grid-access.pdf)
- <sup>29</sup> Ofgem, *Electricity Retail Market-wide Half-hourly settlement: Decision Document*, 20<sup>th</sup> April 2021, <https://www.ofgem.gov.uk/publications/electricity-retail-market-wide-half-hourly-settlement-decision-and-full-business-case>
- <sup>30</sup> Jonathan O'Sullivan (Eirgrid), *New Systems Services Ramping Product: Industry workshop*, March 2022, [https://www.eirgridgroup.com/site-files/library/EirGrid/New-Ramping-Product-Workshop\\_310322.pdf](https://www.eirgridgroup.com/site-files/library/EirGrid/New-Ramping-Product-Workshop_310322.pdf)
- <sup>31</sup> PJM, *Manal 11: Energy & Ancillary Services Market Operations*, October 2022, <https://www.pjm.com/-/media/documents/manuals/m11.ashx>
- <sup>32</sup> W. W. Hogan, *Contract Networks for Electric Power Transmission. From Regulation to Competition: New Frontiers in Electricity Markets*, 1994, [https://link.springer.com/chapter/10.1007/978-94-011-1368-7\\_9](https://link.springer.com/chapter/10.1007/978-94-011-1368-7_9)
- <sup>33</sup> Monitoring Analytics, *2021 State of the market report for PJM - Section 13 FTRs and ARRs*, October 2022, [https://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2021/2021-som-pjm-sec13.pdf](https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-sec13.pdf)
- <sup>34</sup> PJM, *Financial Transmission Rights*, Accessed 30<sup>th</sup> January 2023, <https://www.pjm.com/markets-and-operations/fttr>
- <sup>35</sup> California ISO, *Shortcomings in the congestion revenue right auction design*, p4, November 2016, <http://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf>
- <sup>36</sup> Commission for Energy Regulation, *Overview of FTR instruments*, April 2003, <https://www.cru.ie/wp-content/uploads/2003/07/cer03098.pdf>
- <sup>37</sup> PJM, *Financial Transmission Rights Market Review*, April 2020, <https://pjm.com/~media/library/reports-notice/special-reports/2020/fttr-market-review-whitepaper.ashx>
- <sup>38</sup> Lawrence Berkeley National Laboratory, *Rethinking the role of Financial Transmission Rights in Wind-Rich Electricity Markets in the Midwest U.S.*, International Institute for Energy Economics (IAEE) webinar, Feb 2022, [https://iaee.org/en/webinars/webinar\\_kim.aspx](https://iaee.org/en/webinars/webinar_kim.aspx)
- <sup>39</sup> Potomac Economics, *2021 State of the Market Report for the ERCOT Electricity Market*, May 2022, <https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf>
- <sup>40</sup> Graf et al., *Market Power Mitigation Mechanisms for Wholesale Electricity Markets: Status Quo and Challenges*, April 2021, [https://fsi-live.s3.us-west-1.amazonaws.com/s3fs-public/mpm\\_review\\_gpqw.pdf](https://fsi-live.s3.us-west-1.amazonaws.com/s3fs-public/mpm_review_gpqw.pdf)
- <sup>41</sup> FERC, *Order No. 2000, P 11*, December 1999, [https://www.monitoringanalytics.com/company/Orders/FERC\\_Order\\_No\\_2000\\_19991220.pdf](https://www.monitoringanalytics.com/company/Orders/FERC_Order_No_2000_19991220.pdf)
- <sup>42</sup> Monitoring Analytics, *Our role as PJMs Market Monitor*, Accessed 30<sup>th</sup> January 2023, <https://www.monitoringanalytics.com/company/about.shtml>
- <sup>43</sup> California ISO, *Market Monitoring Overview*, Accessed 30<sup>th</sup> January 2023, <http://www.caiso.com/market/Pages/MarketMonitoring/Overview.aspx>
- <sup>44</sup> California ISO, *Fifth Replacement Electronic Tariff*, Appendix P, point 11.1.2, February 2021, <http://www.caiso.com/Documents/Conformed-Tariff-as-of-Sep1-2022.pdf>
- <sup>45</sup> FERC, *Policy statement on market monitoring units*, May 2005, <https://cms.ferc.gov/sites/default/files/2020-04/E-5.pdf>
- <sup>46</sup> California ISO, *Fifth Replacement Electronic Tariff*, Appendix P, point 5.1.7, February 2021, <http://www.caiso.com/Documents/Conformed-Tariff-as-of-Sep1-2022.pdf>
- <sup>47</sup> Monitoring Analytics, *PJM Market Monitoring Plan*, p6, June 2017 [https://www.monitoringanalytics.com/company/docs/Attachment\\_M\\_PJM\\_Market\\_Monitoring\\_Plan\\_20180112.pdf](https://www.monitoringanalytics.com/company/docs/Attachment_M_PJM_Market_Monitoring_Plan_20180112.pdf)

- 
- <sup>48</sup> PJM, *Territory served*, Accessed 30<sup>th</sup> January 2023, <https://www.pjm.com/about-pjm/who-we-are/territory-served>
- <sup>49</sup> Monitoring Analytics, *2021 State of the Market Report for PJM*, October 2022  
[http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2021/2021-som-pjm-vol1.pdf](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol1.pdf)
- <sup>50</sup> Monitoring Analytics, *2020 PJM Generation Capacity and Funding Sources*, September 2020,  
[https://www.monitoringanalytics.com/Reports/Reports/2020/IMM\\_2020\\_PJM\\_Generation\\_Capacity\\_and\\_Funding\\_Sources\\_20072008\\_through\\_20212022\\_DY\\_20200915.pdf](https://www.monitoringanalytics.com/Reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf)
- <sup>51</sup> PJM, *Energy Transition in PJM: Frameworks for Analysis*, p9, December 2021, <https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211215-energy-transition-in-pjm-frameworks-for-analysis.ashx>
- <sup>52</sup> National Grid ESO, *Future Energy Scenarios 2022*, July 2022, <https://www.nationalgrideso.com/future-energy/future-energy-scenarios>
- <sup>53</sup> Norwegian Water Resources and Energy Directorate, *Mapping of selected markets with Nodal pricing or similar systems*, February 2011, [https://publikasjoner.nve.no/report/2011/report2011\\_02.pdf](https://publikasjoner.nve.no/report/2011/report2011_02.pdf)
- <sup>54</sup> FERC, *Long-Term Firm Transmission Rights in Organized Electricity Markets*, July 2006,  
[https://www.ferc.gov/sites/default/files/2020-05/E-2\\_105.pdf](https://www.ferc.gov/sites/default/files/2020-05/E-2_105.pdf)
- <sup>55</sup> Monitoring Analytics, *2018 State of the Market Report for PJM*, p622, March 2019,  
[http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2018.shtml](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018.shtml)
- <sup>56</sup> PJM, *Financial Transmission Rights Market Review*, April 2020, <https://pjm.com/~media/library/reports-notices/special-reports/2020/ftm-market-review-whitepaper.ashx>
- <sup>57</sup> FERC, *Order on Rehearing and Compliance*, p11, January 2017,  
<https://www.pjm.com/directory/etariff/FercOrders/2048/20170131-el16-6-002,%20003,er16-121-001.pdf>
- <sup>58</sup> FERC, *Order on Assessing Civil Penalties*, November 2021,  
<https://elibrary.ferc.gov/eLibrary/filedownload?fileid=4ce51aac-f910-cbc3-95a4-7cf361a00000>
- <sup>59</sup> 177 FERC ¶ 61,073, *Order Assessing Civil Penalties - GreenHat Energy, LLC*, Nov 2021,  
<https://cms.ferc.gov/media/20211105-177ferc61073-in18-9-000-greenhat-order-assessing-penalty>
- <sup>60</sup> R. Anderson, N. Wolkoff, *Report of the Independent Consultants on the GreenHat Default*, March 2019,  
<https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.pdf>
- <sup>61</sup> CAISO, *2021 Annual Report on Market Issues Performance*, July 2022, <http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf>
- <sup>62</sup> CAISO, *Key Statistics*, August 2021, <http://www.caiso.com/Documents/Key-Statistics-Jul-2021.pdf>
- <sup>63</sup> California Public Utilities Commission, *Resource Adequacy Homepage*, Accessed 30<sup>th</sup> January 2023,  
<https://www.cpuc.ca.gov/ra/>
- <sup>64</sup> CAISO, *Business Practice Manual for Market Operations*, Dec 2022,  
<https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Operations>
- <sup>65</sup> CAISO, *Monthly renewables performance report*, Accessed 30<sup>th</sup> January 2023,  
<http://www.caiso.com/Documents/MonthlyRenewablesPerformanceReport-May2022.html>
- <sup>66</sup> National Renewable Energy Laboratory, *Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart*, November 2015, <https://www.nrel.gov/docs/fy16osti/65023.pdf>
- <sup>67</sup> CAISO, *Todays Outlook* Accessed 30<sup>th</sup> January 2023,  
<http://www.caiso.com/TodaysOutlook/Pages/default.aspx#section-net-demand-trend>
- <sup>68</sup> Bloomberg New Energy Finance, *Beyond the tipping point: flexibility gaps in future high-renewable energy systems in the UK, Germany and Nordics*, November 2017, <https://www.ceer.eu/documents/104400/-/-/13dcea6a-2575-a525-8c99-07e0d3988ff3>
- <sup>69</sup> CAISO, *Opportunity Cost of Flexible Ramping Constraint*, July 2011,  
<http://www.caiso.com/Documents/DraftFinalProposal-FlexibleRampingConstraint.pdf>
- <sup>70</sup> Market Surveillance Committee of the California ISO, *Opinion on Flexible Ramping Product Refinements*, September 2020 [http://www.caiso.com/Documents/MSC-OpiniononFlexibleRampingProductEnhancements-Sep8\\_2020.pdf](http://www.caiso.com/Documents/MSC-OpiniononFlexibleRampingProductEnhancements-Sep8_2020.pdf)
- <sup>71</sup> CAISO, *Annual Report on Market Issues Performance*, July 2022 <http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf>

- <sup>72</sup> Greentech Media, *California's Shift From Natural Gas to Solar Is Playing a Role in Rolling Blackouts*, Accessed 30<sup>th</sup> January 2023, <https://www.greentechmedia.com/articles/read/how-californias-shift-from-natural-gas-to-solar-is-playing-a-role-in-rolling-blackouts>
- <sup>73</sup> CAISO, *Annual Report on Market Issues Performance*, July 2022, <http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf>
- <sup>74</sup> CAISO, *Annual Report on Market Issues Performance*, July 2022, <http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf>
- <sup>75</sup> CAISO, *Annual Report on Market Issues Performance*, July 2022, <http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf>
- <sup>76</sup> CAISO, *Shortcomings in the congestion revenue right auction design*, November 2016 <http://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf>
- <sup>77</sup> CAISO, *Annual Report on Market Issues Performance*, July 2022, <http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf>
- <sup>78</sup> FERC, *Electric Power Markets: ERCOT*, Accessed 30<sup>th</sup> January 2023, <https://www.ferc.gov/industries-data/electric/electric-power-markets/ercot>
- <sup>79</sup> BEIS, *Energy Trends*, September 2022, <https://www.gov.uk/government/statistics/electricity-section-5-energy-trends>
- <sup>80</sup> U.S. Energy Information Administration, *Wind is a growing part of the electricity mix in Texas*, Accessed 30<sup>th</sup> January 2023, <https://www.eia.gov/todayinenergy/detail.php?id=45476>
- <sup>81</sup> Texas Senate, *An act relating to this state 's goal for renewable energy*, July 2005, <https://capitol.texas.gov/tlodocs/791/billtext/pdf/SB00020F.pdf#navpanes=0>
- <sup>82</sup> U.S. Department of Energy, *Land-Based Wind Market Report: 2021 Edition*, August 2021, [https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition\\_Full%20Report\\_FINAL.pdf](https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition_Full%20Report_FINAL.pdf)
- <sup>83</sup> U.S. Energy Information Administration, *Electricity: detailed data - workbook '3\_2\_Wind\_Y2021.xlsx'*, Accessed 30<sup>th</sup> January 2023, <https://www.eia.gov/electricity/data/eia860/>
- <sup>84</sup> Public Utility Commission of Texas, *Rulemaking Proceeding on Wholesale Market Design for the Electric Reliability Council of Texas*, May 2003, <https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.501/26376pub.pdf>
- <sup>85</sup> Norwegian Water Resources and Energy Directorate, *Mapping of selected markets with Nodal pricing or similar systems*, February 2011, [https://publikasjoner.nve.no/report/2011/report2011\\_02.pdf](https://publikasjoner.nve.no/report/2011/report2011_02.pdf)
- <sup>86</sup> CRA International for the Public Utility Commission of Texas, *Update on the ERCOT Nodal Market Cost-Benefit Analysis*, December 2008, [https://ftp.puc.texas.gov/public/puct-info/industry/electric/reports/31600/puct\\_cba\\_report\\_final.pdf](https://ftp.puc.texas.gov/public/puct-info/industry/electric/reports/31600/puct_cba_report_final.pdf)
- <sup>87</sup> Potomac Economics, *2021 State of the Market Report for the ERCOT Electricity Market*, May 2022, <https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf>
- <sup>88</sup> Potomac Economics, *2021 State of the Market Report for the ERCOT Electricity Market*, May 2022, <https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf>
- <sup>89</sup> C. W. King et al., *The Timeline and Events of the February 2021 Texas Electric Grid Blackouts*, July 2021, <https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%2020210714.pdf>
- <sup>90</sup> KLTV, *Lawsuit claims Tx Panhandle wind farm not financially responsible after winter storm causes frozen turbines*, Accessed 30<sup>th</sup> January 2023, <https://www.kltv.com/2021/03/12/lawsuit-claims-tx-panhandle-wind-farm-not-financially-responsible-after-winter-storm-causes-frozen-turbines/>
- <sup>91</sup> Fraser Institute, *Understanding the Changes in Ontario's Electricity Markets and Their Effects*, April 2018, [https://www.fraserinstitute.org/sites/default/files/understanding-the-changes-in-ontarios-electricity-markets-web-final\\_0.pdf](https://www.fraserinstitute.org/sites/default/files/understanding-the-changes-in-ontarios-electricity-markets-web-final_0.pdf)
- <sup>92</sup> The Brattle Group, *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project*, April 2017, [https://www.brattle.com/wp-content/uploads/2017/10/7193\\_benefits-case-assessment-market-renewal-project-clean-20170420.pdf](https://www.brattle.com/wp-content/uploads/2017/10/7193_benefits-case-assessment-market-renewal-project-clean-20170420.pdf)
- <sup>93</sup> IESO, *Single Schedule Market High-Level Design*, August 2019, <https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Single-Schedule-Market>

- 
- <sup>94</sup> IESO, *Day-Ahead Market High-Level Design*, August 2019, <https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Day-Ahead-Market>
- <sup>95</sup> IESO, *Enhanced Real-Time Unit Commitment High-Level Design*, August 2019, <https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Enhanced-Real-Time-Unit-Commitment>
- <sup>96</sup> The Brattle Group, *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project*, April 2017, [https://www.brattle.com/wp-content/uploads/2017/10/7193\\_benefits-case-assessment-market-renewal-project-clean-20170420.pdf](https://www.brattle.com/wp-content/uploads/2017/10/7193_benefits-case-assessment-market-renewal-project-clean-20170420.pdf)
- <sup>97</sup> IESO, *Market Renewal Programme Energy Stream Business Case*, October 2019, <https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Energy-Stream-Business-Case-2019.ashx>
- <sup>98</sup> TranspowerNZ (YouTube channel), *The Spring Washer Effect: section 3 - a spring washer scenario*, Accessed 30<sup>th</sup> January 2023, [https://www.youtube.com/watch?v=Yp2a7KY9pNY&list=PLXUccGn4ptEO5e0-MV37\\_vWPWerhB8yak&index=5](https://www.youtube.com/watch?v=Yp2a7KY9pNY&list=PLXUccGn4ptEO5e0-MV37_vWPWerhB8yak&index=5)
- <sup>99</sup> Norwegian Water Resources and Energy Directorate, *Mapping of selected markets with Nodal pricing or similar systems*, February 2011 [https://publikasjoner.nve.no/report/2011/report2011\\_02.pdf](https://publikasjoner.nve.no/report/2011/report2011_02.pdf)
- <sup>100</sup> Electricity Authority, *Overview of the FTR market*, Sept 2017, <https://www.ea.govt.nz/operations/wholesale/hedges/ftr-market/>
- <sup>101</sup> Commonwealth of Australia, *Independent Review into the Future Security of the National Electricity Market*, June 2017, <https://www.energy.gov.au/sites/default/files/independent-review-future-nem-blueprint-for-the-future-2017.pdf>
- <sup>102</sup> Energy Security Board, *Post-2025 Market Design Final advice to Energy Ministers - Part A*, July 2021, [https://www.energy.gov.au/sites/default/files/2021-10/Post%202025%20Market%20Design%20Final%20Advice%20to%20Energy%20Ministers%20Part%20A\\_0.pdf](https://www.energy.gov.au/sites/default/files/2021-10/Post%202025%20Market%20Design%20Final%20Advice%20to%20Energy%20Ministers%20Part%20A_0.pdf)
- <sup>103</sup> Energy Security Board, *Converting the Integrated System Plan into action*, September 2018, <https://www.aemc.gov.au/sites/default/files/2018-09/ESB-%20Converting%20the%20Integrated%20System%20Plan%20into%20action.pdf>
- <sup>104</sup> Energy Security Board, *Post-2025 Market Design Issues Paper*, September 2019, <https://www.energy.gov.au/government-priorities/energy-ministers/energy-ministers-publications/post-2025-market-design-issues-paper-september-2019>
- <sup>105</sup> AEMC, *Transmission access reform: Updated technical specifications and cost-benefit analysis*, September 2020, [https://www.aemc.gov.au/sites/default/files/2020-09/Interim%20report%20-%20transmission%20access%20reform%20-%20Updated%20technical%20specifications%20and%20cost-benefit%20analysis%202020\\_09\\_07.PDF](https://www.aemc.gov.au/sites/default/files/2020-09/Interim%20report%20-%20transmission%20access%20reform%20-%20Updated%20technical%20specifications%20and%20cost-benefit%20analysis%202020_09_07.PDF)
- <sup>106</sup> Energy Security Board, *Transmission access reform Project initiation paper*, November 2021, <https://www.datocms-assets.com/32572/1637195631-access-reform-project-initiation-document-nov-2021-final.pdf>
- <sup>107</sup> Energy Security Board, *Transmission access reform Project consultation paper*, May 2022, <https://www.energy.gov.au/sites/default/files/2022-06/Transmission%20access%20reform%20Consultation%20paper.pdf>
- <sup>108</sup> Energy Security Board, *Transmission access reform Project initiation paper*, November 2021, <https://www.datocms-assets.com/32572/1637195631-access-reform-project-initiation-document-nov-2021-final.pdf>
- <sup>109</sup> J. Seel et al., *Plentiful electricity turns wholesale prices negative*, *Advances in Applied Energy*, November 2021, <https://www.sciencedirect.com/science/article/pii/S2666792421000652>
- <sup>110</sup> A. D. Mills et al., *Impact of Wind, Solar, and Other Factors on Wholesale Power Prices: An Historical Analysis—2008 through 2017*, November 2019, [https://eta-publications.lbl.gov/sites/default/files/lbnl\\_-\\_wind\\_and\\_solar\\_impacts\\_on\\_wholesale\\_prices\\_approved.pdf](https://eta-publications.lbl.gov/sites/default/files/lbnl_-_wind_and_solar_impacts_on_wholesale_prices_approved.pdf)
- <sup>111</sup> U.S. Department of Energy, *Land-based wind market report: 2021 Edition*, 2021, [https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition\\_Full%20Report\\_FINAL.pdf](https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition_Full%20Report_FINAL.pdf)
- <sup>112</sup> U.S. Department of Energy, *Land-based wind market report: 2021 Edition*, 2021, [https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition\\_Full%20Report\\_FINAL.pdf](https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition_Full%20Report_FINAL.pdf)

- 
- <sup>113</sup> U.S. Department of Energy, *Land-based wind market report: 2021 Edition*, 2021, [https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition\\_Full%20Report\\_FINAL.pdf](https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition_Full%20Report_FINAL.pdf)
- <sup>114</sup> Hogan, W., *Electricity Market Design and Zero-Marginal Cost Generation*, October 2021, [https://scholar.harvard.edu/files/whogan/files/hogan\\_emd\\_102121.pdf](https://scholar.harvard.edu/files/whogan/files/hogan_emd_102121.pdf)
- <sup>115</sup> Wolak, F. A., *Market Design in a Zero Marginal Cost Intermittent Renewable Future*, October 2020, [https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/wolak\\_ieee\\_v6.pdf](https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/wolak_ieee_v6.pdf)
- <sup>116</sup> NGENSO, *REMA – ESO Response*, October 2022, <https://www.nationalgrideso.com/document/268781/download>
- <sup>117</sup> Frontier Economics, *Locational Marginal Pricing – Implications for Cost of Capital*, October 2022, <https://www.frontier-economics.com/media/5496/implications-of-cost-of-capital.pdf>
- <sup>118</sup> Ofgem, *CMP308: Removal of BSUoS charges from Generation*, April 2022, <https://www.ofgem.gov.uk/publications/cmp308-removal-bsuos-charges-generation>
- <sup>119</sup> NGENSO, *Network Options Assessment*, January 2021 <https://www.nationalgrideso.com/document/185886/download>
- <sup>120</sup> SP Energy Networks, *Eastern Link – Project Overview*, accessed 30<sup>th</sup> January 2023, [https://www.spenergynetworks.co.uk/pages/eastern\\_link\\_introduction.aspx](https://www.spenergynetworks.co.uk/pages/eastern_link_introduction.aspx)
- <sup>121</sup> SSEN, *Completion of Caithness-Moray transmission link*, January 2019, Accessed 30<sup>th</sup> January 2023, <https://www.sse.com/news-and-views/2019/01/completion-of-caithness-moray-transmission-link/>
- <sup>122</sup> Ofgem, *£158 million redress for two-year delay to major ‘Western Link’ subsea cable*, November 2021, Accessed 30<sup>th</sup> January 2023, <https://www.ofgem.gov.uk/publications/ps158-million-redress-two-year-delay-major-western-link-subsea-cable>
- <sup>123</sup> NGENSO, *Year Ahead Constraint Limit*, Accessed 30<sup>th</sup> January 2023, <https://data.nationalgrideso.com/constraint-management/year-ahead-constraint-limits>
- <sup>124</sup> SSE Thermal, *Peterhead Carbon Capture power stations – Powering on for a net zero Scotland*, Accessed 30<sup>th</sup> January 2023, <https://www.ssethermal.com/flexible-generation/development/peterhead-carbon-capture/>
- <sup>125</sup> LCP, *Renewable curtailment and the role of long duration storage*, May 2022, <https://www.drax.com/wp-content/uploads/2022/06/Drax-LCP-Renewable-curtailment-report-1.pdf>
- <sup>126</sup> Department of Energy & Climate Change, *Government Response to the technical consultation on the model for improving grid access*, July 2010, [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/42979/251-govt-response-grid-access.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/42979/251-govt-response-grid-access.pdf)
- <sup>127</sup> Department of Energy & Climate Change, *Renewable energy to bring £25Bn of investment into UK Economy – Davey*, July 2012, [https://webarchive.nationalarchives.gov.uk/ukgwa/20121217150421/http://www.decc.gov.uk/en/content/cms/new\\_s/pn12\\_086/pn12\\_086.aspx](https://webarchive.nationalarchives.gov.uk/ukgwa/20121217150421/http://www.decc.gov.uk/en/content/cms/new_s/pn12_086/pn12_086.aspx)
- <sup>128</sup> IPT Energised, *Contracts for Difference Explainer – Routes to market series*, Accessed 30<sup>th</sup> January 2023, <https://www.itpennergised.com/wp-content/uploads/2021/09/Contracts-for-Difference-Explainer-part-1.pdf>
- <sup>129</sup> United States Environmental Protection Agency, *Renewable Electricity Production Tax Credit Information*, Accessed 30<sup>th</sup> January 2023, <https://www.epa.gov/lmop/renewable-electricity-production-tax-credit-information>
- <sup>130</sup> Ofgem, *Renewables Obligation (RO) Buy-out Price, Mutualisation Threshold and Mutualisation Ceilings for 2021-22*, April 2021, Accessed 30<sup>th</sup> January 2023, <https://www.ofgem.gov.uk/publications/renewables-obligation-ro-buy-out-price-mutualisation-threshold-and-mutualisation-ceilings-2021-22>
- <sup>131</sup> BEIS, *Contracts for Difference: standard terms and conditions, version 2*, March 2017, [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/599098/FINAL\\_CFD\\_Standard\\_Terms\\_and\\_Conditions\\_V2-13\\_March\\_2017.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/599098/FINAL_CFD_Standard_Terms_and_Conditions_V2-13_March_2017.pdf)
- <sup>132</sup> BEIS, *Contracts for Difference: standard terms and conditions, version 4*, November 2021, [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/1046366/AR4\\_Standard\\_Terms\\_and\\_Conditions.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1046366/AR4_Standard_Terms_and_Conditions.pdf)
- <sup>133</sup> BEIS, *Contracts for Difference for Low Carbon Electricity Generation Consultation on proposed amendments to*

- the scheme, March 2020, [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/885248/cfd-ar4-proposed-amendments-consultation.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/885248/cfd-ar4-proposed-amendments-consultation.pdf)
- <sup>134</sup> BEIS, *Evaluation of the Contracts for Difference Scheme*, June 2019, [https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment\\_data/file/1075096/CfD\\_evaluation\\_phase\\_1\\_executive\\_summary.pdf](https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1075096/CfD_evaluation_phase_1_executive_summary.pdf)
- <sup>135</sup> FTI Consulting, *Presentation to stakeholders – Workshop 2b - Updated modelling results*, 20<sup>th</sup> October 2022, <https://www.ofgem.gov.uk/publications/locational-pricing-assessment>
- <sup>136</sup> The Crown Estate, *The Crown Estate announces areas of search to support growth of floating wind in the Celtic Sea*, July 2022, <https://www.thecrownestate.co.uk/en-gb/media-and-insights/news/2022-the-crown-estate-announces-areas-of-search-to-support-growth-of-floating-wind-in-the-celtic-sea/>
- <sup>137</sup> NGENSO, *Net Zero Market Reform: Phase 3 Conclusions*, Markets Forum 22nd March 2022, <https://www.nationalgrideso.com/document/247306/download>
- <sup>138</sup> NGENSO, *Net Zero Market Reform: Phase 3 Assessment and Conclusions*, May 2022, <https://www.nationalgrideso.com/document/258871/download>
- <sup>139</sup> T Schittekatte, D Mallapragada, P. L. Joskow, R Schmalensee, *Electricity retail rate design in a decarbonizing economy: An analysis of time-of-use and critical peak pricing*, October 2022, <https://www.nber.org/papers/w30560>
- <sup>140</sup> Triolo and Wolak, *Quantifying the benefits of a nodal market design in the Texas electricity market*, Energy Economics, August 2022, <https://doi.org/10.1016/j.eneco.2022.106154>
- <sup>141</sup> NGENSO, *Thermal constraint management projections*, August 2022, <https://www.nationalgrideso.com/document/266576/download>
- <sup>142</sup> FTI Consulting, *Presentation to stakeholders – workshop 2b: updated modelling results*, October 2022, <https://www.ofgem.gov.uk/publications/locational-pricing-assessment>
- <sup>143</sup> Frontier Economics, *Locational Marginal Pricing – Implications for Cost of Capital*, October 2022, <https://www.frontier-economics.com/media/5496/implications-of-cost-of-capital.pdf>
- <sup>144</sup> Blyth et al., *Risk and investment in zero-carbon electricity markets*, November 2021, <https://ukerc.ac.uk/publications/zero-carbon-electricity/>
- <sup>145</sup> NERA, *Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime*, December 2013, <https://www.gov.uk/government/publications/nera-economic-consulting-report-changes-in-hurdle-rates-for-low-carbon-generation-technologies>
- <sup>146</sup> Eirgrid, *Renewable Electricity Support Scheme 2 RESS 2 Final Auction Results*, June 2022, [https://www.eirgridgroup.com/site-files/library/EirGrid/RESS-2-Final-Auction-Results-\(R2FAR\).pdf](https://www.eirgridgroup.com/site-files/library/EirGrid/RESS-2-Final-Auction-Results-(R2FAR).pdf)
- <sup>147</sup> Ofgem, *Monitoring the ‘Connect and Manage’ electricity grid access regime Sixth report from Ofgem*, December 2015, [https://www.ofgem.gov.uk/sites/default/files/docs/monitoring\\_the\\_connect\\_and\\_manage\\_electricity\\_grid\\_access\\_regime\\_sixth\\_report\\_from\\_ofgem\\_0.pdf](https://www.ofgem.gov.uk/sites/default/files/docs/monitoring_the_connect_and_manage_electricity_grid_access_regime_sixth_report_from_ofgem_0.pdf)
- <sup>148</sup> Littlechild, S. C., *Regulated and merchant interconnectors in Australia: SNI and Murraylink revisited*, 2004, <https://doi.org/10.17863/CAM.5502>
- <sup>149</sup> Ofgem, *Consultation on our Minded-to Decisions on the initial findings of our Electricity Transmission Network Planning Review*, July 2022, <https://www.ofgem.gov.uk/publications/consultation-our-minded-decisions-initial-findings-our-electricity-transmission-network-planning-review>
- <sup>150</sup> BEIS, *New Electricity Networks Commissioner appointed to help ensure home-grown energy for Britain*, July 2022, <https://www.gov.uk/government/news/new-electricity-networks-commissioner-appointed-to-help-ensure-home-grown-energy-for-britain>
- <sup>151</sup> Scottish Government, *Scottish Energy Statistics Hub*, Accessed 30<sup>th</sup> January 2023, <https://scotland.shinyapps.io/sg-scottish-energy-statistics>
- <sup>152</sup> Energy System Catapult, *Location, Location, Location, Reforming wholesale electricity markets to meet net Zero*, May 2022 <https://es.catapult.org.uk/news/locational-pricing-could-save-30bn/>
- <sup>153</sup> FTI Consulting, *Presentation to stakeholders – Workshop 2b - Updated modelling results*, 20<sup>th</sup> October 2022, <https://www.ofgem.gov.uk/publications/locational-pricing-assessment>

- 
- <sup>154</sup> ERCOT, *Fact Sheet*, November 2021, <https://www.ercot.com/files/docs/2021/11/23/ERCOT%20Fact%20Sheet.pdf>
- <sup>155</sup> IESO, *Market Renewal Programme Energy Stream Business Case*, October 2019, <https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Energy-Stream-Business-Case-2019.ashx>
- <sup>156</sup> FTI Consulting, *Presentation to stakeholders – Workshop 2b - Updated modelling results*, 20<sup>th</sup> October 2022, <https://www.ofgem.gov.uk/publications/locational-pricing-assessment>
- <sup>157</sup> G. Hawker and K. Bell, *Making Energy System Models Useful: Good Practice in the Modelling of Multiple Vectors*, WIREs Energy and Environment, August 2019, <https://wires.onlinelibrary.wiley.com/doi/abs/10.1002/wene.363>
- <sup>158</sup> PJM, *Regional Transmission Expansion Plan (RTEP)*, Accessed 30<sup>th</sup> January 2023, <https://www.pjm.com/library/reports-notice/rtep-documents>
- <sup>159</sup> Jankovska, O., Cohn, J. A., *Texas CREZ Lines: how stakeholders shape major energy infrastructure projects*. Baker Institute, November 2020, <https://www.bakerinstitute.org/research/texas-crez-lines-how-stakeholders-shape-major-energy-infrastructure-projects>
- <sup>160</sup> FTI Consulting, *Presentation to stakeholders – Workshop 2b - Updated modelling results*, 20<sup>th</sup> October 2022, Available: <https://www.ofgem.gov.uk/publications/locational-pricing-assessment>