THE IMPLICATIONS OF LOCATIONAL MARGINAL PRICING FOR THE COST OF CAPITAL

REFLECTIONS ON THE CURRENT DEBATE AND EVIDENCE

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Summary

Locational marginal pricing (LMP) remains a hotly debated topic in GB. A move to LMP would transfer network related risks to investors, and so a key question in its assessment relates to implications for investor cost of capital. While there is a little evidence on this issue in the literature, given the scale of investment required for Net Zero it is not credible to ignore it. Even a small increase would materially worsen any cost benefit assessment.

Our first report aimed to help fill this evidence gap in the GB context. We concluded that for supported wind investments i) investors will face greater earnings uncertainty under LMP, and ii) this increased uncertainty is likely to translate into a material cost of capital increase. We estimated this could be by 2-3 percentage points, although, we recognised any quantitative exercise can only provide an indication of the possible impact.

Since the publication of our report, we have received a number of questions and challenges. In relation to earnings uncertainty:

- we were clear that the findings in our first report were constrained by available data and hence our quantification was uncertain. That said, we have not seen new evidence to challenge our underlying conclusion. In particular, FTI has analysed short term volatility in wholesale prices rather than the long term volatility of locational signals (the relevant question for investors); and
- our first report focused on supported wind as a key technology for the transition. We agree the impact may vary by technology, and that there may be investors who face reduced risks under LMP. In this report we consider drivers of such variations, in particular the importance of “constrained on” actions for individual investors and technologies. We conclude the risk of increase is likely highest for supported wind, and that it is not possible, a priori, to dismiss negative impacts for other technologies.

FTI has suggested that, because investors will be able to diversify away any increased risk, there would be no impact on cost of capital. This argument is based on the most common theoretical framework for determining cost of capital. However, FTI ignores the fact that the theory’s assumptions are unlikely to apply in the context of the Net Zero transition. There are numerous examples, in the energy sector and beyond, of GB policymakers recognising such shortcomings. These include the original introduction of CfDs in EMR, and new transition related support policies (e.g., in relation to hydrogen production and industrial carbon capture business models). All these policies aim to remove risks from investors to reduce their cost of capital without verifying whether the risks in question are diversifiable or not by the investors concerned. Similarly, based on FTI’s logic, there would be no rationale for policies which try to attract new sources of finance into specific sectors, something which the government is actively pursuing.

In this second report, we responded to challenges raised and extended our previous analysis to other technologies. However, at least in relation to supported wind, we maintain the conclusions from our first report.

Introduction

Frontier published our study considering the implications of LMP for investor cost of capital in October 2022. We concluded that for wind assets:

- first, it is likely that investors would face greater risk around their expectations of earnings under LMP; and
- second, that this increased uncertainty is likely to translate into an increase in the cost of capital.

We then presented an indicative quantitative assessment focussing on wind assets which suggested that the expected return demanded by investors may increase by 2-3 percentage points as a result of a move to LMP.

Over the past 10 months there has continued to be considerable debate across the industry looking at the case for LMP, in particular in Ofgem, NGESO and in DESNZ as part of its REMA programme. As part of its own LMP assessment, Ofgem has also commissioned FTI Consulting to conduct a wide-ranging analysis of the costs and benefits of introducing LMP.

The implications for the cost of capital have remained an important area of debate. Since the publication of our report, we have engaged in several discussions about our study with interested parties. Through these discussions and the work of FTI, we have identified some common questions relating to the original Frontier report. Frontier Economics has been commissioned by SSE to review our original conclusions in light of these questions.

First, there were a number of comments that challenged our conclusion that investors were likely to face greater risk under LMP, which we briefly summarise below:

- **Impacts on different technologies** - feedback questioned whether we had fully taken account of the risks faced by plants under the current arrangements, pointing to uncertainty related to Balancing Mechanism (BM) revenues for system balancing in particular, and questioning whether we were overestimating the impact of LMP. For wind plants, which was the focus of our study, this issue is of less relevance. However, this may not be the case for other dispatchable technologies, and therefore in this report we develop a framework for considering a broader range of technologies to understand the differential impacts of LMP. While we highlight the fact that there will be differences, we show that consideration of "constrained-on" payments does not mean that concerns about increased uncertainty due to LMP can be dismissed for other technologies.
- **Changes in uncertainty due to LMP** - given its importance to our overall conclusions, there has been surprisingly little commentary on the underlying conceptual arguments put forward in our report that compared the drivers of uncertainty under the TNUoS signal and the LMP locational signal. However, without reference to the arguments that we set out, it has been argued that the locational signal in a nodal market is market driven and therefore subject to less regulatory risk. In response, in this report we explain that even

though the LMP locational signal is the outcome of a market-driven process, changes in the signal are heavily dependent on policy/regulatory risks, and the exposure of producers to these risks is potentially greater than for TNUoS. This is important given they are difficult to predict, as demonstrated by historic forecasts of congestion costs. Difficulty in forecasting congestion is not surprising as it relies on accurate forecasts of the spatial distribution of demand and generation growth, and network expansion, which are highly uncertain. However, it does demonstrate that investors – who are likely to have substantially less data available to them than the ESO – are unlikely to be able to forecast the future level of system congestion with any narrower a margin of error.

- **Indicative quantitative volatility assessment** - there have been a number of specific questions as to whether the volatility of locational signal and investor returns in the US markets analysed is as great as we estimated. We respond to these directly in this report. While it is important to recognise that any quantitative exercise using historical data is only likely to be able to provide an indication of the possible impact, and we noted several caveats that may increase or decrease this estimated range, we maintain our view that there is a high potential for a substantial increase in the WACC as a result of any move to LMP.

Second, there has been a significant challenge (most notably from FTI) regarding the **implications of increased uncertainty for cost of capital.** Putting aside whether or not a move to a nodal market increases volatility, FTI has suggested that a change in investor risk would not increase an investor's cost of capital. This is because according to FTI's interpretation of the Capital Asset Pricing Model (CAPM) framework (at least for their "base case"), any additional risk can be diversified away as part of a market-wide portfolio eliminating any impact on the cost of capital. In this report, we argue that this interpretation is a purist view of the CAPM which does not sufficiently consider the limitations and underlying assumptions behind the CAPM framework. Neither does it consider the way in which policymakers make decisions in practice, which often does not strictly rely on the conclusions of CAPM. We do not therefore consider this to be a robust basis for asserting that a transition to LMP will not impact cost of capital for generation investment.

Finally, we note that a general lack of evidence on the issue of the impact of LMP on investor cost of capital has often been cited as a reason to dismiss concerns entirely. We would agree that although there is extensive literature related to the implementation of LMP, it has tended to focus on issues of operational efficiency, liquidity, and market power. Relatively little attention has been given to the implications for investors and the cost of capital, and even less to any quantitative estimation. However, we dispute that this means it should be dismissed as an issue. In our first report, we identified important investor impacts from the introduction of LMP that have the potential to increase the cost of the significant investment needed to achieve Net Zero. Given the scale of investment required and so the potential impact of a material change in cost of capital, it is not credible simply to ignore it.

In the remainder of this report, we discuss:

- consideration of revenue risk across technologies;

- our conceptual assessment of LMP price uncertainty and volatility;
- our quantitative assessment of LMP price uncertainty and volatility; and
- how changes in investor revenue risks affect the cost of capital.

Consideration of revenue risk across technologies

It has been noted that our analysis failed to consider the additional uncertainty in a national price regime that arises due to constrained on and off payments to generators in the balancing mechanism.

In our previous report, we focussed on the impacts of a move to LMP for windfarm investments supported by CfDs on the grounds that all pathways to Net Zero include very significant new investment in wind, and therefore changes in the cost of capital for this technology will have significant implications for total system costs. We note that this assumption is supported by the capacity mix in the National Grid ESO's Future Energy Scenarios. Taking its *Leading the Way (Holistic Network Design)* scenario as an example, wind capacity is expected to double between 2025 and 2030, implying an addition of some 30 GW. Between 2030 and 2040, total wind capacity is expected to double again, with an expected 120GW of installed wind capacity by 2040.

Supported windfarms will typically be exposed to constrained-off risk. The impact of balancing market (constrained-off) revenues on overall revenue uncertainty for a supported windfarm is likely to be low, given it can mitigate any curtailment risk by bidding in the balancing mechanism at the value of its lost support payment.

However, this may not be the case for other technologies outside of the scope of our original analysis, particularly if they are more heavily reliant on constrained-on payments. From our discussions there has clearly been an appetite to understand the implications for technologies other than wind, and therefore in this section, we set out a conceptual framework for analysis of the implications of LMP for different technologies and in doing so, consider the implications of balancing mechanism risk.

To describe this conceptual framework, it is helpful to first consider a stylised example of two plants in the current national market: a plant that only generates if constrained-on in the balancing market – 'Plant A'; and a plant which generates all its revenue by selling output in the national day ahead market – 'Plant B'.

Considering Plant A, the volatility of revenues under a national market and under LMP could be described as follows:

- under a national market, Plant A is out of merit in the wholesale market but has its offer accepted in the balancing market, with the clearing locational price in the balancing market expected to be at the same level as the nodal price; and

- under LMP, Plant A receives the nodal price, which rises to a level that is sufficiently high to ensure the plant is running during periods of network congestion.

In this example, there is the same level of volatility in Plant A's wholesale revenues under the national market (consisting of combined energy revenue – which in this case is zero – plus the balancing market revenues) as under LMP. Since LMP may also remove the additional uncertainty around TNUoS charges, it is possible that Plant A experiences an overall reduction in the uncertainty of returns under LMP.

In contrast, Plant B is analogous to the example windfarm discussed in our previous report:

- under a national market, Plant B generates all its revenue by selling in the day ahead market and is therefore exposed to locational risk through the spread between the zone-specific TNUoS charge and the average TNUoS charge across all zones; and
- under LMP, Plant B receives the nodal price and experiences locational risk as the difference between the nodal price and the average price across all nodes.

We concluded in our previous report that a plant of this nature is likely to have greater volatility in the locational signal (and consequently in returns) under LMP than under a national market with TNUoS charges. Table 1 summarises the impact on the volatility of the locational signal of a move to LMP for the two stylised examples described above.

Table 1 Stylised example of locational risk under a national market and under LMP

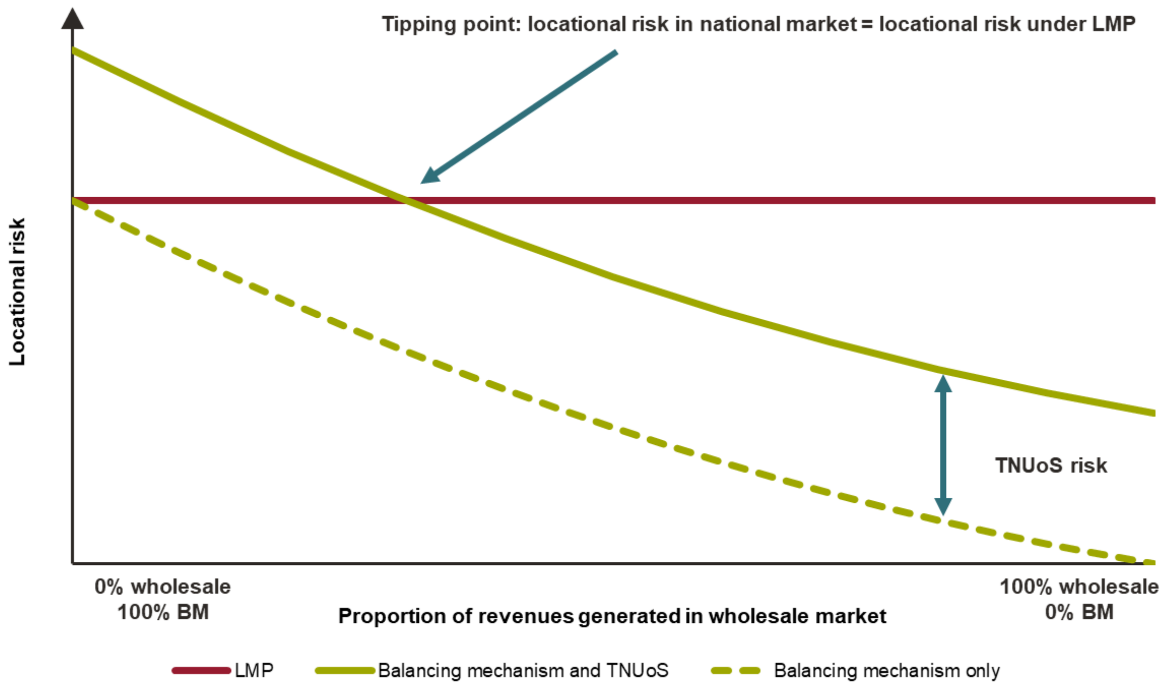
'Stylised' plant	National wholesale market	LMP	Likely impact of move to LMP
Plant A (all output sold through BM)	Locational risk embedded in clearing locational price in Balancing Mechanism and in TNUoS charges.	Locational risk embedded in nodal price (and equal to locational risk in BM). No TNUoS locational risk.	Reduction in locational risk.
Plant B (all output sold through day ahead market)	Locational risk embedded in TNUoS charges.	Locational risk embedded in nodal price. No TNUoS locational risk.	Increase in locational risk.

Source: Frontier Economics

From these two 'extreme' examples, it is evident that the extent to which LMP increases or decreases volatility in returns depends on how much of a plant's revenues comes from constrained-on payments through the balancing mechanism. As the balance shifts away from constrained-on revenues towards wholesale (national price) revenues, any move to LMP is more likely to increase risk.

At some point there will be 'tipping point' where the level of uncertainty in the national market equals the uncertainty from the LMP locational signal. This is illustrated as a more generalised framework in Figure 1 below. Plants with a balance of revenues to the left-hand side of the tipping point are likely to experience a reduction in risk under LMP, and plants located to the right-hand side are likely to experience an increase. Wind plants that we analysed in our first report, are likely to be located to the far right-hand side, motivating a comparison between the LMP locational signal and LMP alone.

Figure 1 Implications of balancing mechanism revenues for locational risk exposure



Source: Frontier Economics

While we can say that across the system there will be some plants to the left of the tipping point and some to the right, it is unlikely that this tipping point can be easily identified. It will depend on a range of factors, including the optimal level of congestion. The optimal level of congestion will depend on the cost of transmission investment relative to the cost of plants of different technologies – factors which are evaluated as part of the transmission planning process but are difficult to anticipate. If optimal congestion is relatively low, constrained on payments will become a less significant source of revenue across generation technologies and therefore the capacity for LMP to reduce uncertainty for constrained on plants would be relatively low, and vice versa.

To the extent that reliance on constrained-on payments is correlated with types of generation technology, then this framework allows us to consider the level of risk introduced by LMP to investors in different technologies. However, it may also be the case that reliance on constrained-on payments differs significantly for the same technology located on different parts of the network.

For example, consider a storage plant that has located behind an export constraint in order to benefit from helping to relieve congestion on the network. For a given level of congestion we would expect the storage plant to face similar arbitrage opportunities under LMP or the national market:

- Under a national market, it can benefit from low bid prices in the BM to charge during constrained periods, and high prices in the wholesale market or BM to discharge during unconstrained periods; and
- Under LMP, the storage plant can benefit from the spread between constrained and unconstrained prices at its node.

It is likely that such a plant would be positioned towards the left-hand side of Figure 1, and it may be that, depending on where it sits relative to the tipping point, its risks are increased or reduced under LMP. However, an alternative storage plant that did not locate near a systematic constraint and instead invested largely on the basis of inter-temporal arbitrage opportunities, would rely less on BM revenues and therefore would be more likely to experience an increase in risk.

This example demonstrates that it is not possible to be definitive about the precise impacts of LMP on all technologies. However, while it may be the case that risks are most likely to increase under LMP for technologies such as wind, this implies that concerns about increased revenue uncertainty due to LMP cannot be dismissed for other technologies.

Conceptual assessment of volatility

In our first report, we set out a detailed conceptual assessment of the drivers of volatility in the locational signal under TNUoS and under LMP. We concluded that:

- there is a degree of commonality between the drivers of volatility in the locational signal under TNUoS and LMP (e.g., in both cases, changes in the level of connected generation and load in a given location have the potential to impact the locational signal); but
- there are more uncertain factors which influence the LMP locational signal and therefore create additional sources of potential risk to investors (e.g., LMP locational signals are more sensitive to changes in the spatial distribution of energy produced and consumed, and to changes in the level and location of spare capacity, and hence revenues are more sensitive to these changes).

We have received relatively few comments on our conceptual assessment of the drivers of uncertainty in the locational signal in TNUoS charges and under LMP. However, it has been suggested that increased variation across all nodes is the purpose of LMP and that this variation is more easily modelled by investors (and hence is more predictable) than the variation under TNUoS. The principal argument advanced in support of this assertion is that the locational signal under LMP is market-driven, and therefore subject to less regulatory risk than TNUoS.

We explained in our first report that the locational signal under TNUoS and under LMP are each subject to regulatory and market risks. Even though the LMP locational signal is the outcome of a market-driven process, the nature of the signal is largely dependent on policy/regulatory decisions), and its sensitivity to those risks is demonstrably greater than for TNUoS. We identified several additional drivers of the locational signal under LMP which do not affect the TNUoS locational signal and which are clearly dependent on regulatory and policy decisions, for example:

- LMP locational signals are affected by the level and location of spare transmission capacity on the system and this is likely to be impacted by several non-market factors such as government energy policy, marine and land spatial planning regulations and transmission network build out; and
- LMP locational signals are affected by policy decisions to alter support mechanisms for connected generation since this would lead to changes in opportunity costs of generation (and so market prices) in a given location.

LMP's greater sensitivity to these factors is important given they are difficult to predict. In relation to the level and location of spare transmission capacity, the forecasting challenge is evident from the significant movements in the forecasts for congestion that have been made over time, and the significant deviations from outturn costs. For example:

- In 2015, NGET produced forecasts for two scenarios which predicted congestion costs would drop to 'nearly zero' in 2017/18 and in the more pessimistic scenario increase to around £180m in 2021/22, before dropping back to zero in 2023/24.[1] However, during this period outturn congestion costs amounted to approximately £420m in 2016 and rose year on year to over £2bn in 2022.[2]
- ESO's most recent congestion cost modelling carried out as part of the 2021/22 NOA Refresh, now suggests substantial and growing (structural) constraint costs over the next decade, potentially rising up to £3bn in 2028 for the Leading the Way scenario.[3] However,

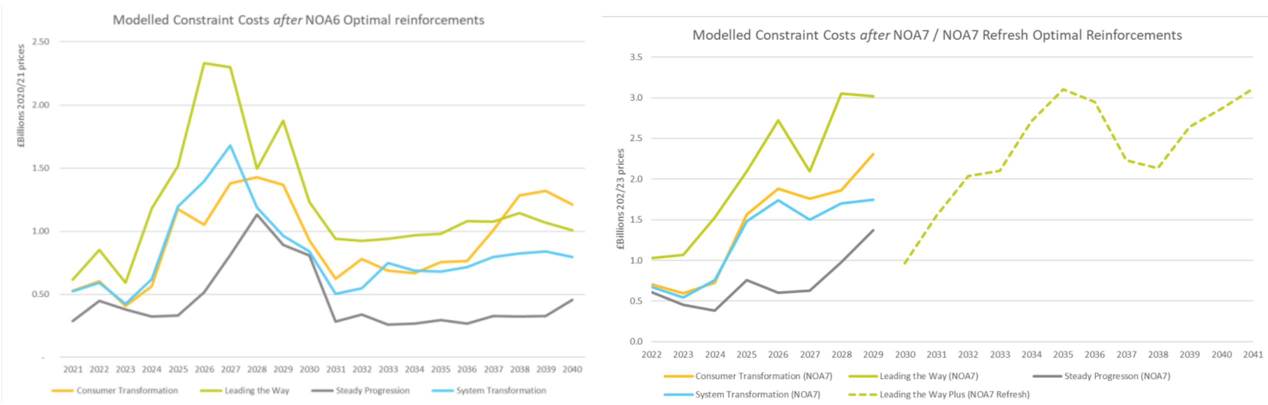
1 '*Monitoring the 'Connect and Manage' electricity grid access regime, Sixth report from Ofgem*', Ofgem, 14 December 2015, p.7.

2 '*Balancing Costs Strategy*', ESO, 2023, p.4.

3 *'Modelled Constraint Costs – NOA 2021/22 Refresh',* ESO, August 2022, p.3.

for a similar forecast published 14 months earlier, constraint costs were only estimated to be £1.5bn in 2028.[4] These forecasts are presented below in Figure 2.

Figure 2 ESO congestion cost forecasts published in June 2021 and August 2022



Source: *'Modelled Constraint Costs NOA 2020/21', ESO, June 2021 (left), 'Modelled Constraint Costs NOA 2021/22 Refresh', ESO, August 2022 (right)*

Difficulty in forecasting congestion is not surprising as it relies on accurate forecasts of the spatial distribution of demand and generation growth, and network expansion, which are highly uncertain. However, it does demonstrate that investors – who are likely to have substantially less data available to them than the ESO – are unlikely to be able to forecast the future level of system congestion with any narrower a margin of error.

It is also worth noting that while LMPs are set by a market process, the rules for that market are the product of regulatory decisions and may equally be subject to change (for example, changes in the specification of the despatch algorithm or changes in the way the transmission network is represented in the algorithm).

We would also expect our conclusions about the unpredictability of the locational signal under a nodal market design (relative to a national market) to extend to a zonal design. A zonal market design may 'smooth out' some of the underlying variability in the drivers of the locational signal and therefore reduce uncertainty compared to a nodal design, although we would still expect the uncertainty to be greater than TNUoS. There are potential additional sources of risk compared to a nodal design related to regulatory decisions to alter the location of zone boundaries (although this re-zoning risk also applies to TNUoS) and any regulatory charges designed to transmit within-zone locational signals.

Overall, the main drivers of LMP outcomes cannot be decoupled from policy and regulatory decisions. It is therefore not reasonable to imply that because locational signals under LMP

4 *'Modelled Constraint Costs – NOA 2020/22',* ESO, August 2022, p.3.

are determined by a market-driven process, that they are therefore necessarily subject to lower regulatory risk.

Indicative quantitative volatility assessment

In our previous report we presented a quantitative assessment for windfarm investors of the potential size of the impact of implementing a LMP regime in GB on the cost of capital. This assessment consisted of two steps:

- first, we considered the extent of volatility in the locational signal under TNUoS and LMP regimes and the potential implications of such volatility for the distribution of returns for windfarm investors; and

- second, we translated the potential change in the distribution of returns for windfarm investors into an estimate of the impact on the cost of capital demanded by investors.

We noted in our report that there is considerable uncertainty about the design of any future GB LMP market and therefore the embedded LMP locational signal. On a practical basis, we looked to LMP markets operating internationally as a source of historical data on the potential volatility which may be introduced from the implementation of an LMP regime in GB. We collected data from two US nodal markets to inform our assessment: PJM and ERCOT.

We concluded from our quantitative assessment that the outer bounds of any cost of capital impact may be in the range of 1.8 to 4 percentage points, with a plausible cost of capital impact in the range of 2-3 percentage points.[5]

The intention of this quantitative exercise was to provide an indication of the possible impact on investor risk of implementing LMP. We noted that this evidence should be interpreted with care and listed several important assumptions and caveats:

- We assumed a 'pure LMP' market design which exposes investors to the full locational signal. Alternative choices around market design, including the specification of renewable support mechanisms, Financial Transmission Rights, and the granularity of the locational signal (i.e., nodal vs zonal pricing) could be taken. These might change the impact on risk for investors, although any such decisions would necessarily be balanced against the potential impact on the expected benefits of LMP.

- We assumed that the historic volatility in US LMP markets is informative of the future volatility in a potential GB LMP market. Specifically, we noted that:

[5] For the avoidance of doubt, the range presented reflects the incremental impact on cost of capital of the increased locational exposure under LMP, we are not saying that the only driver of the cost of capital is the size of the locational exposure. We note that there may have been some misinterpretation of our results on this point.

  - The mix of generation and demand, and the strength of transmission networks in such jurisdictions is unlikely to be a perfect match for that in GB.

  - Historic data, even from a well-matched jurisdiction, is not likely to be perfectly representative of the evolution of the GB system over the course of the journey to net zero.

- We only considered the volatility in the locational signal associated with LMPs over time. We did not fully reflect any differences in curtailment risk, which suggests that 2-3pp may underestimate the impact.

- We did not account for the possibility that some of the additional risk may be diversifiable, which suggests that 2-3pp may overestimate the impact.

In this section, we focus on specific questions raised in relation to the first step. We deal with issues on the second step in the subsequent section of this report. In particular we respond to specific questions relating to:

- our use of the *coefficient of variation* metric to measure the volatility in the locational signal in nodal and national markets; and

- our comparison of the *standard deviation of returns* across all nodes and TNUoS zones, rather than focussing on the comparison at individual nodes.

We also comment on recent alternative quantitative analysis carried out by FTI Consulting from which they conclude that there is no clear evidence that a nodal market would lead to more volatility than a national market.

Measuring volatility of the locational signal using a coefficient of variation

In the first step of our quantitative assessment, we compared historic differences in the volatility of the locational signal in US LMP markets to those under the TNUoS regime in GB.[6] We measured the volatility in the annual locational signal over time for each TNUoS zone and each node under LMP using a *coefficient of variation*. The coefficient of variation is a descriptive statistic that divides the standard deviation of the annual locational signal by the mean annual locational signal. This metric adjusts for differences in price levels and currency between GB and the US, allowing for cross-country comparison.

It has been noted that if the mean value of the locational signal for a given node or TNUoS zone (i.e., the denominator in the coefficient of variation calculation) is close to zero, then the coefficient of variation will be arbitrarily large.[7]

6 We presented the results of this analysis in Figure 5 and Figure 6 of our previous report.

7 Consider an illustrative example of two nodes each with a standard deviation of the annual locational signal of $10/MWh. One node has a mean locational signal of $1/MWh – implying a coefficient of variation of 10 – and the second node has a

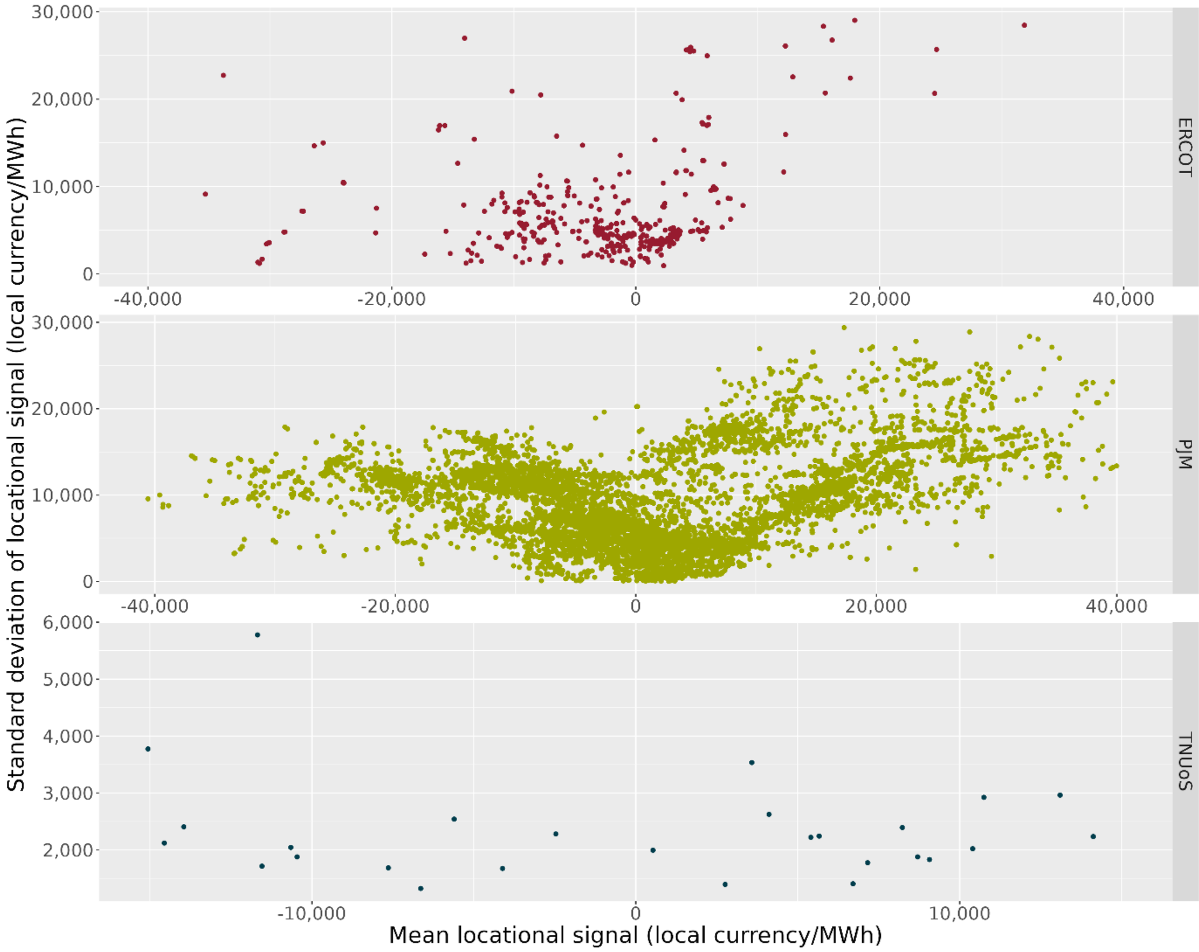
Because we compared the coefficients of variation for the locational signal in each TNUoS zone relative to those at each node, this would only affect our conclusions if it disproportionately affects the coefficients of variation we calculate for the LMP markets. Specifically, it would need to be the case that average locational signal for any given node under LMP is more likely to be close to zero than the mean locational signal for a TNUoS zone. In practice, this would mean that nodal prices are more likely to track the system average price than TNUoS charges track the average TNUoS charge.

Conceptually, we are not aware of a reason to expect any such structural difference in average locational signals between TNUoS and LMP markets. The data we used in our analysis also show that the average LMP locational signals are not obviously more likely to be close to zero than the TNUoS locational signal. We have illustrated this in Figure 3, which plots the standard deviation of the annual locational signal (the numerator in the coefficient of variation calculation) and the mean locational signal (the denominator) for all nodes and all TNUoS zones. The plots for the US LMP markets do not obviously show any clustering of the locational signal at or near zero.

In any case, we note that the coefficients of variation did not feed into our analysis of the expected investor *returns* under LMP and TNUoS and hence did not affect our conclusions on the cost of capital.

mean locational signal of $5/MWh – implying a coefficient of variation of 2. In this example, the absolute volatility of the locational signal (measured by the standard deviation) is the same across both nodes, but the differences in the average locational signal results in the first node having a larger coefficient of variation, implying greater volatility at this node.

Figure 3 Scatter plot of standard deviation and mean annual locational signal for all nodes and zones



Source: Frontier analysis of hourly LMPs in PJM, hourly settlement point prices in ERCOT and TNUoS charges.
Note: Data for PJM and TNUoS covers the period 2005 to 2021. Data for ERCOT covers the period 2010 to 2021

Measuring standard deviation of returns across all nodes

Our quantitative assessment considered the volatility of returns for an illustrative onshore windfarm under TNUoS and LMP (proxied using volatility in nodal prices from PJM). We presented the distribution of returns across all zones under TNUoS and all nodes under LMP and concluded that the volatility of returns was greater under LMP.[8]

Our analysis did not consider the volatility of returns at any *individual* location. It has been suggested that this is what individual investors are primarily concerned with.

8 We presented the results of this analysis in Figures 7 and 8 of our report.

We agree that it is reasonable to assume that an individual investor is primarily concerned with the distribution of potential returns at a particular investment node or nodes. This may be the set of nodes at which they are planning to invest, or if this is not yet clear or decided, at least the set of nodes at which they consider a wind investment to be feasible at a reasonable rate of return. The key question is therefore: what data should be used in an analysis to ensure a focus on such a set of nodes?

We were not able to source data from which to identify reliably any such set of 'investable' nodes in the US markets analysed. To avoid arbitrary selection of a subset of nodes, our analysis therefore looked at all locations.

In measuring the variation in equity return across all nodes, we assumed that investors could earn any of the returns observed in the historic data. We implicitly assumed therefore that there is no prior knowledge of the likely future balance of excess demand or supply at a particular location relative to network capacity over the course of an investment. In other words, we assumed that the volatility across all nodes on the system would be representative of the volatility at the set of 'investable' nodes, and that an investor's eventual return can be represented by a random draw from the whole distribution. Our approach is consistent between TNUoS and PJM.

Even if a different approach could be justified and tested, *a priori*, it is not possible to know whether taking a distribution from a smaller set of nodes would increase or decrease the standard deviation.[9] Furthermore, even when considering a smaller set of nodes, the extent to which the historic variation in supply and demand characteristics relative to network capacity would be a good representation of the possible future outcomes is unclear. Therefore, it may be reasonable for investors to look to a broader set of nodes from which to inform its distribution of possible returns i.e., they may still consider all nodes.

FTI's analysis of the impacts of LMP on average hour-to-hour price volatility

Ofgem has commissioned FTI Consulting, to produce a cost-benefit assessment of a more locational GB power market. The cost-benefit assessment involved a 'base case' assumption that introducing LMP would not result in any change to the cost of capital.

FTI supported its base case assumption with a review of the literature (including our own study) from which it concluded that there is limited evidence that moving to nodal or zonal pricing will impact the cost of capital. FTI also presented supporting modelling results which suggested a limited impact of locational pricing on average hour-to-hour price volatility. We present the results of FTI's analysis below in Table 2. The results show that for the years 2025,

9 It could be argued that for nodes which are more investable (i.e. those areas where significant investment in generation, demand or network is expected to support the Net Zero transition), the uncertainty is greater given it would be harder to predict the actual impact of investment on network spare capacity, compared to those areas where less investment is expected.

2030, 2035 and 2040, the average hour-to-hour volatility in the national wholesale price is similar to the average hour-to-hour volatility across zones/nodes under LMP.[10]

Table 2 Average hour-to-hour volatility of wholesale prices under national and locational pricing, presented by FTI Consulting

Average (min, max)	2025	2030	2035	2040
National	0.77	0.92	0.81	0.71
Zonal	0.66 (0.49, 1.08)	0.93 (0.92, 0.95)	0.87 (0.84, 0.90)	0.74 (0.71, 0.78)
Nodal	0.78 (0.04, 1.16)	0.92 (0.87, 1.03)	0.84 (0.77, 1.10)	0.70 (0.60, 1.06)

Source: *FTI Consulting, Locational pricing assessment in GB: Final modelling results, Presentation to stakeholder – Workshop 3, 6 June 2023, slide 55.*

Note: *Results presented are for FTI's Leading the Way (NOA7) scenario. Results in parentheses are the minimum and maximum values across all zones/nodes.*

FTI has provided very limited information regarding its calculations, so we are unable to verify the results. However, even taken at face value the analysis does not correctly measure the volatility which is relevant for assessing the impact on the cost of capital. In particular, FTI:

- focuses on the volatility of hourly prices in a particular year and therefore does not capture the uncertainty over the longer horizon that investors typically face when making an investment decision; and
- compares volatility of wholesale prices in a national and LMP market, rather than volatility of the locational signal (i.e. the volatility in TNUoS charges with the LMP locational signal).

With regard to the first point above, we explained in our previous report that for the assets on which we are focused (e.g. generation plant, battery or other storage assets), short term volatility, such as the within-year volatility considered by FTI, will be averaged over an investment time horizon. The risk for which investors may seek to be compensated through the cost of capital is the risk associated with changes to the locational signal over an investment time horizon. With respect to TNUoS, this is the risk that the spread in annual charges deviates significantly from expected levels over the life of the investment.[11] For LMP,

[10] FTI is not explicit about how it measures 'average volatility'. We assume this is the standard deviation of the national hour-to-hour volatility in a given year, and the average of the hour-to-hour standard deviations for each zone/node in a given year under LMP.

[11] Put differently, since TNUoS charges are determined annually, there is no within-year volatility of the locational signal under a national market design. This would imply that investors are not currently exposed to any locational risk through the TNUoS

the issue is not whether the nodal price deviates significantly hour to hour, but rather whether the average discount or increment to the average price deviates significantly from expected levels during the investment period. Therefore, it is more appropriate to consider factors which drive risk in TNUoS and LMP locational signals over the longer term (e.g. at least year to year).

With regard to the second point above, it is the volatility of the locational signal between a national and LMP market which determines the impact on locational risk, not the volatility of the wholesale price. The locational signal under the current system is embedded in the spread between the zonal TNUoS charge paid by the generator and the average TNUoS charge across all charging zones, and based on our earlier discussion, where relevant also relates to the value of constrained on and off payments. This differs to the locational signal under LMP, which can be expressed as the spread between the nodal price received by the generator and an average (or 'traded hub') wholesale price. The volatility of national wholesale prices under the current arrangements, and individual nodal/zonal prices are therefore not relevant comparators, as neither are directly measuring the locational signal.

In our view, it is therefore not possible to draw any robust conclusions on the impact of LMP on cost of capital from this analysis as it does not assess a relevant measure of volatility.

Implications of increased uncertainty for cost of capital

In the previous sections of this report, we have been focused on different aspects of the question as to whether introducing LMP would increase uncertainty for investors. However, putting aside whether or this would be the case, FTI has argued that, in any case, a change in risk would not increase investors' cost of capital. FTI's argument focuses on both the cost of debt and equity:

- With regard to the *cost of debt*, FTI argues that this is largely dependent on support mechanisms, such as CfDs for wind/solar and therefore that they expect any change in volatility of returns to have little impact; and
- With regard to the *cost of equity*, FTI argues that according to the CAPM framework, higher volatility of returns does not necessarily lead to a higher cost of equity as the increase in risk would not translate into higher *systematic risks* (i.e. those risks which cannot be diversified away as part of a market-wide portfolio).

As a result of these two positions, in its "base case" assessment of LMP, FTI assumes no impact on the cost of capital. FTI does carry out some sensitivity analysis with small increases in the costs of capital of 50 basis points for technologies supported by Contracts for Difference (wind, solar and Hinkley Point C), and they also calculate the increases in cost of capital

charge, which is clearly not the case. It is therefore more appropriate when assessing the impact of changes in locational risk on the cost of capital to measure that risk using the across-year volatility of the locational signal.

necessary to remove all of its estimated benefits. However, in its presentation of its key conclusions, FTI does not make any reference to cost of capital.

In this section we discuss in turn FTI's position in relation to cost of debt and cost of equity.

Cost of debt

In our first report, we did not focus our discussion directly on impacts on the cost of debt, although consideration of the cost of debt did inform some of the judgements we made regarding the range of possible cost of capital impacts implied by quantitative analysis.

It is true that we would expect any change in risk due to LMP to be largely borne by the equity holder. However, it is unrealistic to assume that lenders do not experience any change in risk. Although debt-holders are not directly exposed to changes in the profitability of an investment, the cost of debt is a function of the creditworthiness of a project or company, which is turn is affected by uncertainty of returns. If the returns of a project are expected to be more volatile or uncertain, this may increase default risk which would feed through into the cost of debt. This would arise due to lenders:

- increasing the cost of debt directly (and hence the overall cost of capital); and/or
- reducing the amount they are willing to lend (i.e. reducing the feasible gearing), which in turn would increase the reliance of the project on more expensive equity finance.

FTI appears to argue that under support arrangements such as CfDs, debt holders would be insulated from any change in uncertainty, and hence default risk, and therefore there would be no impact on the cost of debt. While it is true that the CfD was designed to offer greater stability of returns to investors in order to attract more debt finance into the sector, it does not remove all risks. CfD investors are exposed to the locational signal sent by TNUoS, and the working assumption in our analysis is that the CfD would also expose investors to the locational signal under LMP.[12]

Under these assumptions, incremental changes to locational risks would feed through to investors, and the cost of debt and gearing of investments may change. The effects cannot simply be ignored.

Cost of equity

FTI has suggested that our conclusion as to the impact of a move to LMP on the cost of equity is not correct because (at least as measured in their "base case") the increase in risk would be diversifiable, and so would not need to be compensated.

12 We note that FTI appears to assume that, through use of a nodal reference price, CfDs may insulate investors from some part of the locational signal. However, the current CfD is paid on volumes produced. Even with FTI's assumption of a nodal reference price, investors will be exposed to a greater risk than today, since projects would lose out on support payments if the network is unable to accommodate their potential output.

This argument is based on the conclusions of the CAPM framework and in particular assumes that it is safe for policymakers to assume that the assumptions behind this framework and its strict conclusions apply in this case.

The CAPM framework is probably the best coherent framework available for considering the relevant return on individual assets. However, the fact that it is the best we have does not mean that it is always accurate or applicable. Below we therefore:

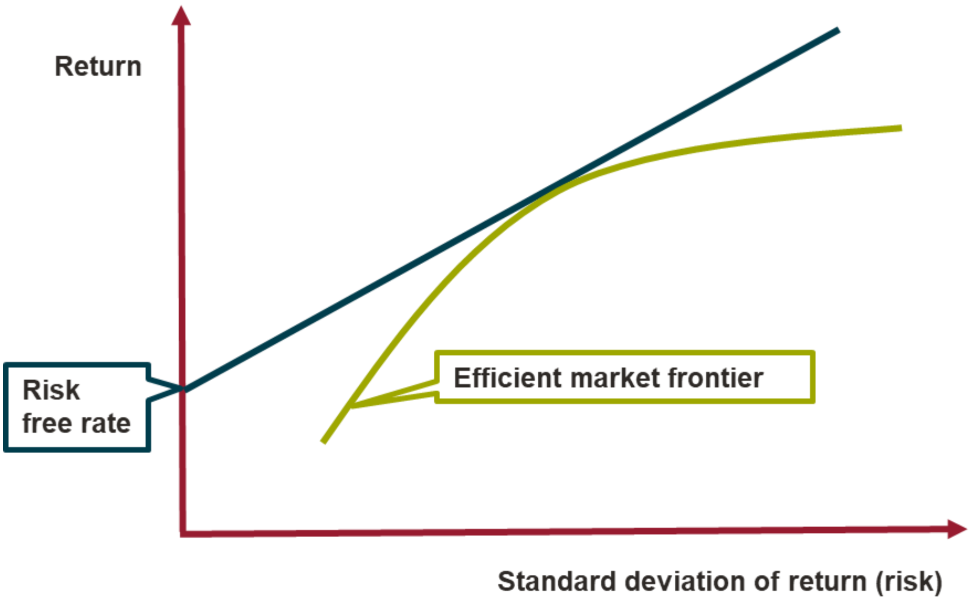
- summarise briefly the basis on which the CAPM concludes that diversifiable risk need not be compensated;
- consider if the assumptions underpinning CAPM are likely to apply in this case in the way required to support FTI's conclusions;
- consider examples of recent government policies which assume that the strict conclusions of the CAPM model do not hold; and
- draw conclusions on FTI's argument.

Basis of CAPM

Modern portfolio investment theory, first introduced by Harry Markowitz, characterises the risk and return relationship in the context of an efficient portfolio with the benefit of diversification.

In simple terms, if asset A and asset B have returns that are not perfectly correlated with each other, then holding a proportion of asset A and B together results in a better risk/return trade-off than holding either asset A or asset B independently. By extension, if investors hold diversified portfolios of assets, then for a given amount of risk (measured by the standard deviation of returns) there is a maximum level of expected return. This relationship is described as an efficient market frontier (the green line in Figure 4, where the horizontal axis measures the standard deviation of returns).

Figure 4 Risk and return in a diversified portfolio



If the return of any individual asset is below the market frontier, then the asset is over-priced (i.e. its expected return is too low for the given risk). If return is above the frontier it is under-priced. If market is working perfectly, prices will adjust such that all assets will be priced onto the frontier.

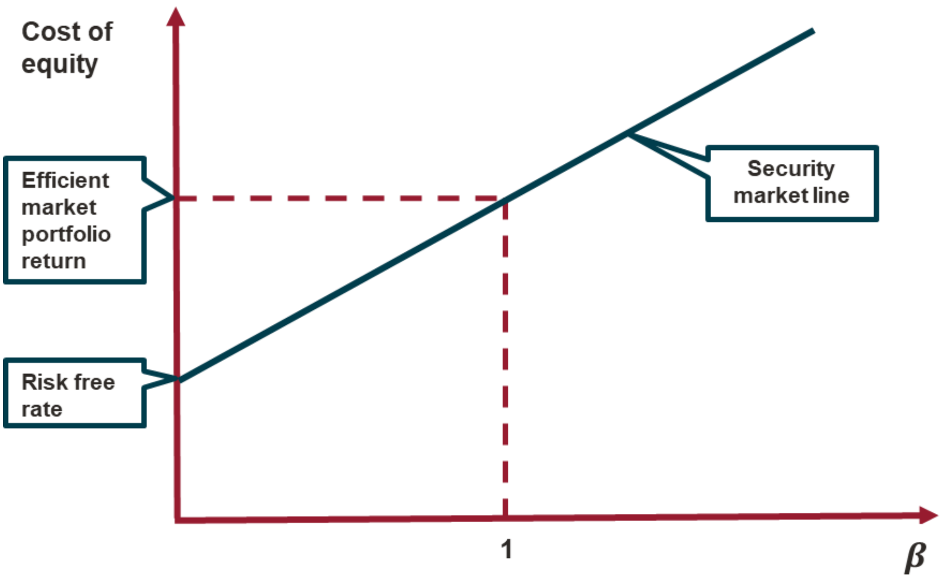
The introduction of a risk-free asset (with some positive level of return but no risk) allows the identification of a unique efficient market portfolio. Investors can hold any combination of the risk-free asset and points on the efficient market frontier, meaning that combinations shown by the straight blue line in Figure 4 are the most efficient (as other combinations below this line offer returns which are low for the level of risk being borne).

This implies that to achieve the maximum level of returns for any given level of risk, investors only need to invest in the correct proportions of the risk-free asset and the efficient market portfolio. Assuming *inter alia* unrestricted risk-free borrowing and lending, Sharpe et al. formalised this into the CAPM framework. They concluded that the expected return on any asset can be measured by the return on the risk-free asset plus the market risk premium times a factor which measures how correlated the return of the asset in question is to the efficient market portfolio.

Figure 5 presents this conclusion graphically. The factor (beta) is on the horizontal axis. Effectively the security market line shown in Figure 5 describes the investment strategy under which an investor buys the risk-free asset and the efficient market portfolio in differing proportions. When the investor holds only the efficient market portfolio, the beta of their portfolio is 1. When the investor holds only the risk-free asset, the beta is zero. The investor can secure a portfolio with a beta larger than 1 by borrowing money at the risk-free rate to buy the efficient market portfolio. Critically:

- there is no need for the investor to hold anything other than a combination of the risk-free asset and the efficient market portfolio; and
- the only risk measure that matters to pricing an asset is beta, as investors are all assumed to invest in the risk-free asset and the efficient market portfolio, and all assets in the market are priced onto the security market line.

Figure 5 Asset pricing within the CAPM framework



Formally, the assumptions underpinning this theory are that:

1. Investors are risk averse;
2. Rational investors seek to hold efficient portfolios, and as a result the portfolios they hold are fully diversified;
3. All investors have identical investment time horizon;
4. All investors have identical expectations about such variables as expected rates of return and how capitalisation rates are generated;
5. There are no transaction costs;
6. There are no investment-related taxes;
7. The rate received from lending money is the same as the cost of borrowing money; and
8. The market has perfect divisibility and liquidity (i.e., investors can readily buy or sell any desired fraction interest).

Applicability of CAPM to this analysis

The change in risk which is under consideration in this analysis relates to the potential introduction of LMP. Our previous analysis indicated that this would result in assets (windfarms) being exposed to increased risk. While some informative analysis of the extent of this risk can be performed (as per our previous report), a reliable evaluation of its extent and nature (including which other assets in the economy may be useful in diversifying the incremental risk) cannot be undertaken until investors have relevant data. In other words, it will only be possible after some years of operation of the new market.

The need for new windfarm investment is part of the overall transition to Net Zero. As part of decarbonising the electricity sector, significant new investment is required before 2035. Critical to any assessment of the relevance of the conclusions of the CAPM is therefore time. FTI's argument implicitly assumes policymakers can be confident that the assumptions and conclusions of CAPM will hold in the short term and longer term.

It is clear that there are assumptions underpinning CAPM which are sufficiently unlikely to apply in practice that policymakers should find relying on its conclusions in the context of the decision on LMP unsafe. In particular:[13]

- **Rational investors hold fully diversified portfolios**: even if this assumption is assumed to hold in the long term, investors and potential investors cannot hold a perfectly diversified portfolio in the context of the new risks for windfarms in the short term. This is because by definition assets with these precise risk and return conditions do not currently exist. It will necessarily take time for investors to understand the changes in their portfolios which would be needed to diversify the additional risks, and then effect such changes (particularly given issues around liquidity, a point to which we return below);
- **the market has perfect divisibility and liquidity**: the ability of investors to construct and hold an efficient market portfolio requires it to be possible for investors to add or remove marginal amounts of individual assets from their portfolio. Were all assets traded on liquid public markets, it would be likely that this requirement would be satisfied. However, this is clearly not the case. Many assets, particular in the energy and infrastructure sectors of the economy, are held by entities whose equity is not traded, including smaller private company developers and larger funds (core infrastructure funds, private equity funds, sovereign wealth funds). This may mean that achieving "perfect" diversification via such assets is not possible, or at least takes a long time, as it includes bilateral transactions to acquire and possibly then sell down parts of the entities holding relevant assets; and
- **there are no transaction costs**: as a result of the above, because of the bilateral nature of potentially relevant diversification strategies, there are likely to be transaction costs to entering and exiting from many assets which are potentially relevant from a diversification

13 This list is not exhaustive – for example, it is not likely that all investors have the same investment time horizon. The renewable development landscape involves investors of different types – including those with solely a development focus, utility owners who may wish to invest for the development stage and hold some assets through their lives, and longer-term financial investors (e.g. pension funds) seeking reliable long term returns from operating assets.

perspective. Beyond this, regulatory measures often hinder the ability of some entities to invest in certain assets.[14]

It is not clear that these assumptions would hold in the longer term. Even if they did, there is even greater reason to believe that, in the short term, the inability of investors to assemble quickly a wide enough portfolio to diversify incremental risks associated with the implementation of LMP would mean that investors may be forced to demand additional return to cover risk factors besides market risk. This means that FTI's conclusion is unsafe.

Precedent from other policy decisions

That policymakers do not rely on the strict conclusions of CAPM is not new. In its Electricity Market Reform policy, the government:

- commissioned NERA to consider the implications of its policies on the cost of capital for investors, and NERA stated[15] that:
  - as a one-period model, the standard CAPM framework does not capture the resolution of uncertainty over time;
  - the CAPM assumes that the distribution of returns is symmetric, implying that investors are equally exposed to upside and downside risks, which need not be the case for all types of risks;
- concluded that "CfDs would make it cheaper to deliver low-carbon generation… because they will deliver cost of capital reductions that cannot be achieved through existing policy instruments";[16]
- noted that fixed payments (as a result of CfDs) "probably offer the greatest relative potential to attract new investors. Additional investment is likely to be required as … raising the required finance will prove a challenge and could stretch the Big 6 utilities to the maximum". As noted above, CAPM neither assumes a constraint on finance from particular sets of investors or the need to attract new investors;[17] and
- noted that there were important differences in the projects into which different sources of finance were likely to be attracted, noting that financial investors such as banks, pension funds, infrastructure funds and private equity were less likely to invest during the

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14 For example, the government recently made regulatory changes to allow pension scheme investors to smooth the incurrence of performance fees (often payable on illiquid investments) over a number of years, in order to encourage them to invest in sectors such as renewable energy projects. See: https://www.legislation.gov.uk/uksi/2023/399/pdfs/uksiem_20230399_en.pdf

15 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/267606/NERA_ReportAssessment_of_Change_in_Hurdle_Rates_-_FINAL.pdf

16 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/209276/EMR_Spending_Review_Announcement_-_FINAL_PDF.pdf

17 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/42637/1042-ia-electricity-market-reform.pdf

construction phase (even with market reforms) as the characteristics of greenfield energy generation (with high construction risk) do not suit their target investment criteria.[18]

The government is also following this logic in other aspects of its policymaking in relation to the energy transition. For example, in relation to the hydrogen production and industrial carbon capture business models, the government has stated that the policy will "*replicate much of the successful and highly investable CfD revenue regime and accompanying regulations which has enabled industry to cover costs with certainty and helped to reduce costs of capital*".[19]

It has been noted that the EMR decision (and more recent ones related to hydrogen) related to support arrangements for less mature technologies. It is also the case that the government has, as part of REMA, raised the prospect of exposing investors to more market risk, recognising that a higher cost of capital may be a price worth paying for reduced system costs as investors react more efficiently to price signals. This is a clear demonstration that government considers there to be a trade-off between insulating investors from market risk to reduce the cost of capital and exposing investors to more market risk to improve market efficiency but at the expense of a higher cost of capital. The relative merits of introducing greater market risk when making this trade-off may change over time, for example, exposure to more market risk may be more appropriate as technologies mature. However, taking a different perspective on the trade-off does not mean that there is no impact on cost of capital. It just reflects a view that the impacts on cost of capital are specific to the different contexts in which they are being considered. We expect government to also be considering this trade-off in the context of LMP.

Finally, there are examples beyond the energy sector in which the government is pursuing policies which are not consistent with the conclusion from CAPM that investors always hold a well-diversified efficient market portfolio. These include policies which aim to encourage particular types of investors to broaden their portfolio of investments in certain sectors, in order to ensure that companies in those sectors can secure appropriate funding. The governments "Long-term Investment for Technology and Science" (LIFTS) initiative is a recent example of such a policy, which aims to "crowd-in" investment from institutional investors (particularly defined contribution pension funds) to the UK's most innovative science and technology companies.[20] Both the notions that a sector may risk being starved of finance, and that investors need to be encouraged into some sectors run counter to the assumptions of CAPM.

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18 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/42637/1042-ia-electricity-market-reform.pdf

19 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1147391/hydrogen-production-icc-business-models-consultation.pdf

20 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1142755/lifts-initiative-request-for-feedback.pdf

Conclusions on FTI's argument

FTI's challenge that the risks we have considered can be diversified away ignores the fact that in the real world the assumptions and conclusions of CAPM theory do not necessarily apply. FTI has not shown that the risks which we highlight are diversifiable. However, even if they were, there are good reasons to believe that, particularly in the short term, simply trusting in the conclusions of the CAPM framework and ignoring them would be to understate the costs likely to arise from the implementation of LMP.

This means that the additional risks we identified are likely to need to be taken into account when assessing the appropriate level of return for projects in the real world. There is ample precedent from recent government policy in the energy sector and beyond of policymakers understanding that it is not safe to rely on the strict conclusions from CAPM.