LOCATIONAL MARGINAL PRICING – IMPLICATIONS FOR COST OF CAPITAL

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Introduction and summary of analysis

During 2022, there has been a significant increase in interest in the possibility of implementing locational marginal pricing (LMP) in the GB power market. Most significantly:

- following its Net Zero Market Reform (NZMR) project, NG ESO is recommending LMP as the wholesale market model best suited to support the transition to Net Zero. NG ESO has published an initial report setting out the rationale for its preference;
- Ofgem is carrying out its own comprehensive study which is expected to report in the Autumn; and
- BEIS is consulting on LMP as part of its wider Review of Electricity Market Arrangements (REMA).

A move to LMP may have important implications for investor cost of capital during any transition period (which would be expected to last for at least 5 years). It may also have an effect on an ongoing basis. Given the significant amount of investment that will be required to achieve decarbonisation in the GB electricity sector up to 2035 and the further investment required for Net Zero, it is important that any such implications of LMP for investors are considered thoroughly as part of a comprehensive assessment.

As it stands there has been limited evidence presented of the potential cost of capital impacts:

- As part of its NZMR, NG ESO stated that they did not receive from stakeholders any 'firm evidence to suggest that nodal pricing would raise the cost of capital for investment in key technologies'; and
- While Ofgem is currently still undertaking its assessment, its proposed framework for assessing the impact on the cost of capital does not appear to consider all of the relevant factors, and it also refers to analysis which does not appropriately consider the counterfactual (e.g. evidence that nodal markets continue to attract investment).

More broadly, although there is extensive literature related to the relative benefits of LMP versus zonal or national pricing alternatives, it has tended to focus on issues of operational and investment 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.

SSE, RWE and Greencoat Capital have commissioned Frontier Economics to consider in more detail the potential enduring implications for the cost of capital (i.e. beyond those relating to the transition process) in order to feed into the assessments of LMP being undertaken by BEIS and Ofgem.

The key findings from this study are briefly summarised below.

Although we know from recent GB experience that uncertainty created by the volatility in TNUoS charges has presented challenges to investors, the introduction of an LMP regime may be expected to lead to investors facing an even greater risk around their expectations of earnings. Two key reasons for this are that:

- In contrast to the TNUoS regime, under an LMP regime, investors receive no compensation if the network cannot physically accommodate their production. Investors will therefore have to forecast the likely extent of such curtailment over the investment horizon, and will be exposed to errors in their forecasts. The level of curtailment will be highly sensitive to delays in the commissioning of new transmission lines, or shifts in the spatial pattern of generation and demand relative to expectations and therefore may have a material impact on returns.
- Relative to the TNUoS locational signal, the value of the LMP locational signal is likely to be more volatile, as it is impacted by a greater number of factors which are difficult for investors to predict, and more likely to be in flux in coming years. These include the level and location of spare capacity on the system, which itself is likely to be driven by a wide variety of non-market factors such as government energy policy, the application of marine and land spatial planning regulations, and the rate of build out of the transmission network etc

Our analysis of historic data from GB and the US confirms that LMP locational signals can indeed be significantly more volatile than those in today's TNUoS regime.

As a result of the increased risk, investors are likely to seek a higher return on their capital. Our analysis tries to place some quantitative bounds on the scale of such a potential increased cost of capital. It suggests that the expected return demanded by investors may increase by 2-3 percentage points as a result of a move to LMP (the lower end of this range is consistent with the single piece of academic literature we have found looking at this topic). While it is important to recognise that any quantitative exercise is only likely to be able to provide an indication of the possible impact, and we note a number of caveats that may increase or decrease this estimated range, this indicates there is at least the potential for a substantial increase in the WACC as a result of any move to LMP.

In the remainder of this report we:

- first, provide an overview of the role of locational signals and explain the approach taken under the current regime and under LMP;
- second, consider conceptually the differences in investor risks that arise under the two approaches that could lead to differences in the required cost of capital for investment; and
- finally, examine historic data from GB and two US markets to provide an indication of the potential magnitude of differences in the volatility of the locational signal under the different regimes and hence potential differences in the cost of capital.

Overview of locational signals

An efficient locational signal should reflect the forward looking costs (or benefits) that users impose on (provide to) the network based on where they connect and how they use the system. In other words, a locational signal is a cost reflective charge that should result in users of the system internalising into their own investment or operational decisions the incremental societal costs or benefits that they cause.

Locational transmission charges currently used in GB (i.e. TNUoS) and LMPs are both different forms of locational signal. For a generation plant the locational signal is the relative cost of one location relative to others:

- *Under the current system*, because the locational signal is embedded in locationally varying transmission charges (TNUoS) determined annually, it can be expressed as the spread between the zonal TNUoS charge paid by the generator and the average generation TNUoS charge. The component of TNUoS charges which varies locationally is a form of long-run marginal cost (LRMC) signal, because it reflects the cost of incremental network expansion triggered by additional network use at a particular location.
- *Under LMP,*[1] because the locational signal is embedded in wholesale prices, the locational signal can be expressed as the spread between the nodal price received by the generator and an average (or 'traded hub') wholesale price. This is a short-run marginal cost (SRMC) signal as the price signal is based on today's network capacity (i.e. it is not based on the cost of new investment).[2]

Although the signals are very different in nature, SRMC and LRMC signals could result in the same locational signal over time if the network is developed optimally. This is illustrated in Figure 1. Intuitively, this is because optimal expansion of the network would entail investing in capacity up to the point where the cost incremental investment (i.e. the LRMC) is expected to equate to the benefit society derives from the investment, which is in turn related to avoiding the costs of congestion resulting from lack of capacity (i.e. the SRMC).

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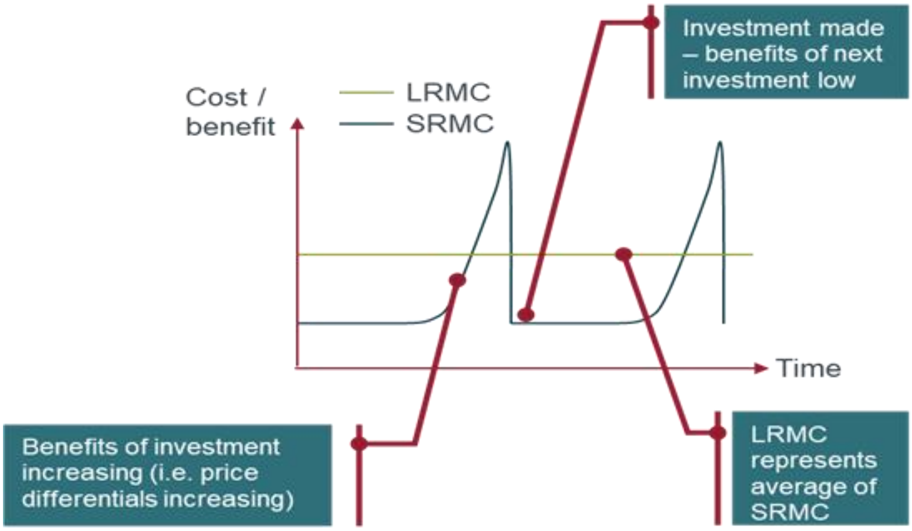
1 We focus on the congestion component of LMP rather than that associated with transmission losses. GB already has arrangements in place to send locational signals in relation to transmission losses.

2 In economic terms, "short run" costs assume the capital stock is constant.

Figure 1 Chart or graph etc



Source: Frontier Economics
Note: [Insert Notes]

In practice, implementation of the signals may always be sub-optimal, and optimal development of the network is unlikely. Therefore, to understand the implications of the different approaches for investors and the cost of capital, it is most meaningful to focus on:

- the actual way locational signals are, or could be, implemented under the two approaches; and
- real-world network investment conditions.

Before we go on to consider these differences in detail, it is important to note that the impact of the different approaches to locational signals on investors will also depend on the wider market design, as mechanisms within that design may impact which parties are left facing locational risks:

- Under the current CfD design:
  - With regard to TNUoS, locational risk is left with the investors in that strike prices do not adjust in response to annual changes in the TNUoS charge i.e. investors must make a forecast of expected TNUoS costs over the life of the investment in determining their CfD bid price.
  - With regard to LMP, it is not clear where locational risk would sit. It could remain with the investor in a similar way to today if the reference price is set as a system average price. Alternatively, the investor could be significantly insulated from locational risk if the reference price is set as the nodal price.
- The risk profile for renewable investments could also be more fundamentally changed if a materially different alternative to today's CfD mechanism were adopted. For example, if payments were based on deemed output (instead of actual output as is currently the case), then depending on the precise design locational risks could be reduced even further.

There is also no single blueprint for an “LMP market”, although there are clearly features which are central to the design. There are many aspects to the specific design of a GB LMP market which will have (potentially significant) impacts on its implications for investors. As an example, there are a number of key design questions related to Financial Transmission Rights (FTRs), an important tool for hedging locational risks for investors, such as what volume of contracts will be available, the extent to which product shape and size will match with generator profiles, the allocation method of contracts, and time horizon over which products are available.

Our approach in this paper is to assume a design of an LMP market, combined with a broader market design, that exposes investors to the full locational signal, as would be the case under a pure form of LMP. For example, we recognise that an FTR market is likely to be developed alongside a GB LMP market, and we assume a full competitive process to allocate FTRs (i.e. no grandfathering).

We recognise alternative policy decisions could be taken to reduce risks for investors, in which case, any impact on cost of capital identified in this paper might also be reduced.

Impact of locational signals on investors

When considering the implications for the enduring cost of capital of a switch to LMP, we are primarily concerned with assessing the implications of the change in the nature of the locational signal (i.e. TNUoS to LMP) on the distribution of expected returns for a generation, storage or demand side response investment decision. The distribution of returns is an indicator of the riskiness of an investment, which in turn will influence the cost of capital required by investors.

We know from recent GB experience that uncertainty created by the volatility in TNUoS charges has presented challenges to investors and may have led to increases in cost of capital relative to an alternative more stable set of charges. The key questions that we explore in this section are (i) whether conceptually there are reasons to believe that the distribution of returns is likely to be wider or narrower (and hence risk higher or lower) under LMP than TNUoS, and (ii) based on that, what conclusions can be drawn in principle in relation investors' cost of capital.

We separate this discussion into three steps:

- First, we review each of the approaches in more detail to understand what drives changes in each locational signal;
- Second, taking into account the drivers of change, we assess the implications of a move to LMP for risk, as measured by the distribution of expected returns of an investment; and
- Finally, we consider the implications of differences in the distribution of expected returns on the cost of capital.

Drivers of change in locational signals

We start by identifying the key drivers of change in the locational signals over time under each methodology.

At the outset, it is worth noting that while LMP signals vary over the very short term (e.g. hour to hour), we are not interested in this volatility. We are principally concerned with risk for which investors may seek to be compensated via an increased cost of capital, and it is reasonable to assume that investors will see that for the assets on which we are focused (e.g. generation plant, battery or other storage assets), short term variations in the locational signal will be averaged over an investment time horizon. Our starting point is therefore to consider factors which drive risk in TNUoS and LMP locational signals over the longer term (e.g. at least year to year).

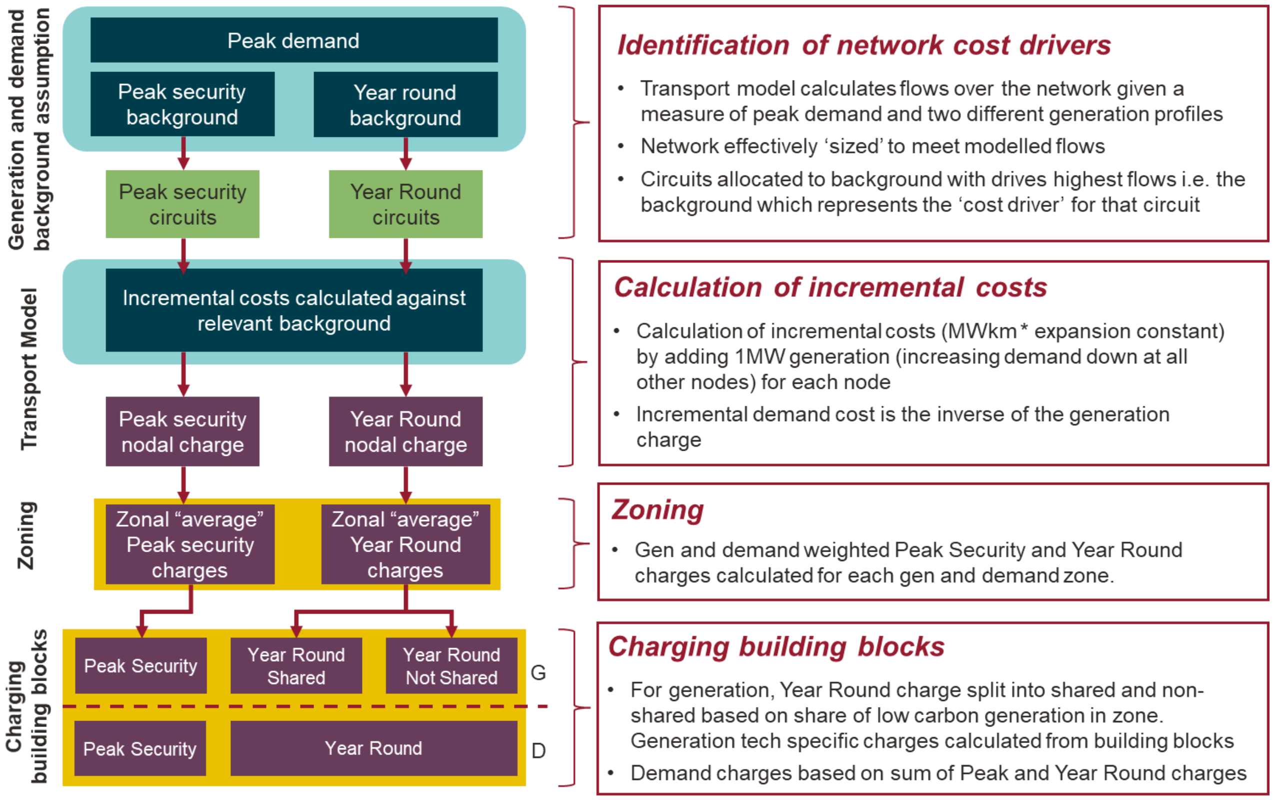
Locational TNUoS

Locational TNUoS is currently under review by the TNUoS taskforce, which may lead to reforms with implications for cost of capital. Ultimately, the cost of capital implications of LMP should be compared to the future reformed version of TNUoS. However, in this section we focus our discussion on locational TNUoS as it exists today, on the grounds that at this stage we do not know what the reforms may be, and our quantitative analysis in the next section is based on historic TNUoS data.

The locational TNUoS charges are set annually based on the outputs of a DC load flow model covering all nodes on the GB transmission network (the "Transport Model"). A description of the methodology is set out in Figure 2. Some of its key features are that:

- Within the Transport Model, base flows across the network are set according to two different backgrounds in order to find the mix of generation and demand that results in the highest flows for each network element (i.e. the "cost driver"):
  - *Peak security background*, intended to reflect a mix of generation and demand more likely to exist in peak periods and therefore identify those network elements whose dimensioning is more driven by peak security; and
  - *Year Round background*, intended to reflect a mix of generation and demand that causes flow on network elements whose dimensioning is driven more by an economic assessment of constraint costs rather than by peak security considerations.
- The network is assumed to perfectly accommodate these flows with no spare capacity.
- Incremental costs are calculated for each node based on an assumed incremental 1MW injection, matched by a 1MW increase in demand spread across all nodes weighted by demand.
- The cost of accommodating the additional flows across the network is calculated assuming a cost of additional MWkms of network.
- Incremental costs for all nodes in GB (roughly 900) are averaged across (currently) 27 generator and 14 demand zones.
- Finally, generation charges are calculated for specific technologies, with Year Round charges varying based on the share of low carbon capacity in the zone.

Figure 2 Overview of approach to estimating locational TNUoS charges



Source: Frontier Economics

There are a number of aspects of the methodology that are important to highlight in relation to what drives changes year to year:

- **Charges will be sensitive to the actual spatial distribution of generation and demand**. If the balance of generation and demand changes, then the flows that are implied by each of the backgrounds will also change, and if the change is sufficient to alter the direction of flow over individual network elements then measured incremental costs over those elements could flip from being positive to negative, impacting nodal cost estimates.

- **Changes to the actual physical capacity of the network do not directly influence charges.** Charges are calculated assuming that the network is sized to perfectly accommodate the flows that are implied based on the backgrounds. Therefore, if network reinforcements to existing network elements are completed in a particular year, or delayed to future years, there is not a direct effect on the calculation of charges[3]. However, changes to overall network topology (e.g. addition of new routes) may affect charges.

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[3] Although changes to the configuration may affect future generation and demand investment decisions, which may then result in changes to charges

Since TNUoS is determined by a regulated methodology, changes to the methodology or its regulated inputs over time may also result in volatility. For example:

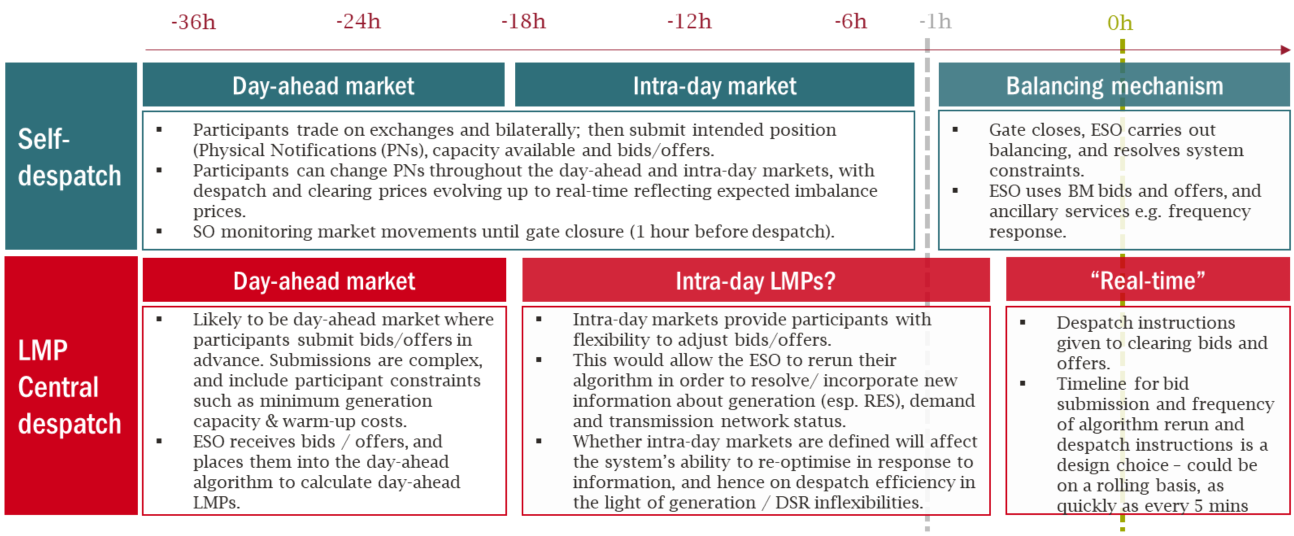
- **Variability in charges is likely to be limited by zoning, but may be induced by changes to zones.** The approach to zoning may smooth out a lot of the underlying variability in incremental costs that would be identified within the Transport Model at the nodal level, and therefore significant changes year to year at individual nodes are also likely to be smoothed out. However, periodic changes to zonal boundaries may, for some nodes, create significant volatility when and if they occur.

- **Variability in parameter inputs**. There are a number of inputs to the methodology (including, for example, the estimated cost of investment per MWkm, the increment in costs associated with redundancy in the transmission network), which may be subject to periodic updates. Changes in these parameters could create material volatility in charges.

Locational Marginal Prices

In an LMP market, the market is despatched based on the ESO running an optimisation algorithm that takes into account parameters including bids and offers from generation and demand, plant technical constraints, and possibly reserve requirements. A comparison of the central despatch process under LMP and the current self-despatch system is set out below in Figure 3.

Figure 3 Comparison of central despatch under LMP and self-despatch



Source: Frontier Economics
Note: [Insert Notes]

LMPs are derived from this optimisation process. They reflect the short run marginal costs of generation in different locations, and the short run cost of congestion on the network. The way in which LMPs are calculated based on the central despatch is complex. It has been described in many recent reports as part of the on-going debate[4] and so we do not go further into the details here.

As a result of the way they are derived, nodal prices – and so the locational signal – will respond immediately (i.e. in the half-hour in which the change occurs) to both:

- changes in the level and spatial distribution of generation and demand; and
- the extent and location of spare capacity on the network, and so to changes in network availability and physical reinforcements on the network.

For example, at a constrained exporting node, a reduction in the nodal price and an increase in the strength of the locational signal may be brought about by:

- a new unit of low cost generation, which will immediately affect the balance of supply and demand at that location, and all else equal, lead to a reduction in the nodal price; and
- a reduction in network availability in elements facilitating exports form that node, which will again immediately change the balance of supply and demand at that location, and lead to a reduction in the nodal price.

LMPs (and hence the locational signal) are driven by relativities in the marginal costs of generation located on different parts of the system (put another way, the price spread between a generator's local nodal price and the average or hub price is a function of the marginal costs of the local price setting generators and those located at the hub). This means that the locational signal may be affected by changes in commodity prices. For example, in a system with unabated gas setting the prices in an import constrained zone and abated gas setting prices in an export constrained zone, a change in the carbon price can drive changes in the locational signal even if the spatial distribution of generation does not change.

Furthermore, the opportunity cost of new generation will also be relevant to the locational signal, which means that the nature of support contracts may be important. For example, if a renewables generator with a high strike price CfD connects at an export constrained node, the price at that node at times of high production may move to be more strongly negative (as the generator will have a strong incentive to wish to continue generating) than if the renewables contract had a low strike price.

It is sometimes argued that the allocation of FTRs, which provide a hedge against volatility in the LMP locational signal, act to reduce risks for investors. However, this will only be the case in very specific conditions:

- if FTRs are not allocated via a competitive process – if they are, then while the FTR may hedge short term LMP volatility, the investor is exposed to variations in prices in that competitive process (e.g. an FTR auction);
- if FTRs are allocated over a long time horizon – if only short term FTRs are available, then investors will remain exposed to LMP volatility after the term of available FTRs ends; and

[4] Operation Market Design: Dispatch and Location, National Grid ESO, Net Zero Market Reform Project, Phase 3

- if FTRs are allocated sufficiently in advance to remove risk at FID – if they are not, then at the point at which investors are making investment decisions in new long lived assets, they may be faced with a mixture of FTR price and LMP volatility.

In any case, the impact of FTRs will also be limited by the volume of contracts issued.

Finally, it is important to note that while LMPs are in the first instance set by a market process, the rules for that market are essentially a regulatory construct. Just as has been the case in GB to date (e.g. in relation to changes in the calculation of cashout prices over time), changes in market rules (for example, changes in the specification of the despatch algorithm, or changes in the way the transmission network is represented in the algorithm) have the potential to have an impact on the locational signal, in the same way as for TNUoS signals.

Summary of comparison of drivers of change for TNUoS and LMP

We summarise in Table 1 the key drivers of the locational signals discussed above.

Table 1 Comparison of drivers of locational signals

Driver	Impact on TNUoS locational signal	Impact on LMP locational signal
Changes in level of connected generation and load in a given location	**Yes**, if change results in flip in base direction of flow of network elements	**Yes**, if change results in change in extent and location of spare capacity / network congestion
Changes in technology of connected generation in a given location	**Yes,** via assumptions within backgrounds and calculation of final charges	**Yes,** via changes in marginal costs and likely load factors and so market prices
Changes in spatial distribution of energy produced and consumed	**No**	**Yes**, if change results in change in extent and location of spare capacity / network congestion
Changes in terms of support for connected generation in a given location	**No**	**Yes,** via changes in opportunity costs and so market prices
Changes in commodity prices	**No**, at least not directly (may change network build or imply changed expansion constant)	**Yes,** via changes in market prices
Change in spare capacity on existing network paths	**No**	**Yes**
Creation of new transport paths	**Yes**	**Yes**
Changes in estimated network investment costs	**Yes**, directly via expansion constant	**Yes**, as may change optimal network investment build

Driver	Impact on TNUoS locational signal	Impact on LMP locational signal
Changes in methodology / rules	**Yes**, via methodology and input parameters	**Yes**, via market rules and input parameters

Source: Frontier Economics
Note: [Insert Notes]

From this comparison, there are a number of high level conclusions which can be drawn:

- First, and perhaps not unexpectedly, there is a degree of commonality between the drivers of change in the two types of locational signals;
- Second, there are more uncertain factors which influence the LMP locational signal, and therefore more sources of potential risk to investors;
- Third, some of the differences are likely to be more important than others – for example, the fact that LMPs are sensitive to the level and location of spare capacity is likely to be particularly important in a period of major change in the location of generation on the system and a period with a need for major transmission reinforcement (and hence a greater risk of delay associated with network investment programmes); and
- Fourth, some apparent similarities may mask important differences – for example, while both locational signals can be affected by increasing levels of generation connection in a given location, TNUoS signals may be more likely to change gradually (as some network elements flip their base direction), whereas LMP signals may change more quickly (as each MW of additional generation may lead to more hours of congestion at key boundaries).

Implications for expected returns

Having identified drivers of risk under different approaches to sending locational signals, we now consider how these differences might affect investors' perceptions of the distribution of returns around an expected level.

Under either a TNUoS regime or LMP, investors will have to make forecasts of locational signals as part of deciding whether and where to invest. However, the more unpredictable locational signals are, as a result of being driven by unpredictable inputs, the greater the probability that the expectations on which investments are based turn out to be misplaced – or put another way, the greater the risk to which investors are exposed.

The impacts of a move to LMP are likely to vary by technology. For the purposes of this discussion we focus on the implications 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 costs.

For a windfarm, annual revenue can be divided into two, as shown in Figure 4.[5] The first component relates to "valuable production", by which we mean production which is eligible to receive a support payment. This component is then either added to or reduced by a component providing a locational signal. From this annual revenue, other fixed and operating costs (which can be assumed to be invariant to this aspect of market design) are subtracted to determine profit.

Figure 4 Expected revenues of illustrative windfarm

Source: Frontier Economics
Note: [Insert Notes]

Under the TNUoS regime:

- valuable production can be assumed to be the total renewable infeed available less that which occurs during periods in which day ahead national energy prices are at or below zero.[6] If there are local transmission network constraints which imply that this energy cannot be physically accommodated, investors can bid into the balancing mechanism in a way which will ensure that they still receive their strike price despite not producing at full capability;[7] and
- the locational signal relates to the locational TNUoS charge.

Investors are therefore exposed to risk in relation to (i) their forecasts of production during times of positive energy prices, and (ii) their forecasts of TNUoS charges. Importantly, this means that:

- investors are not exposed to errors in their forecasts of local congestion; and
- investors are only exposed to errors in their forecasts of the volume and pattern of new generation and new load connection in their area to the extent that (i) they have an influence on national price formation, or (ii) they influence TNUoS charges.

This contrasts to the situation faced by an investor under an LMP regime, for whom:

- valuable production will additionally be constrained by the relative levels of low cost generation and transmission capacity in their local area. As we note above, under LMP there is a direct relationship between the local price and the local level of generation related to transmission

5 For the purposes of this illustration, we assume the wind farm sells power on the reference market for the CfD. For simplicity of exposition, we have also ignored other potential sources of revenue.

6 This reflects changes to the time periods in which support payments are provided from AR4 onwards.

7 They can inform ESO of an intention to generate, and submit negative price bids to the balancing mechanism. In the event the transmission network cannot accommodate their energy, they would agree to "buy back" their energy provided ESO pays them and be paid for so doing.

capacity. In areas with high (low cost) generation relative to network capacity, the local price will fall, become negative, and in the limit prevent the generator from generating profitably;[8] and

- the locational signal will be defined by the level of their local nodal price relative to the average system price.

Therefore, under an LMP regime there are two important areas of increased risk for investors.

The first relates to the changed definition of valuable production. Under both regimes, if local low cost generation is too high relative to the available transmission capacity, the network may not physically be able to accommodate their production. However, in contrast to the TNUoS regime, under an LMP regime, investors will receive no compensation. In other words, they will not earn their strike price on such “curtailed” volumes.

Investors will therefore have to forecast the likely extent of such curtailment over the investment horizon, and will be exposed to errors in their forecasts. The level of curtailment will be highly dependent on the location of other parties’ investments and production relative to the pace of network and local load development. As a result, delays in the commissioning of new transmission lines, or shifts in the spatial pattern of generation and demand relative to expectations may have a material impact on returns.

While such factors will also influence TNUoS charges, as we note above, the impact may be much more gradual. The LMP regime may result in investors being exposed to a much wider distribution around expected earnings.

The second relates to the locational signal. As we noted above, relative to TNUoS, the LMP locational signal:

- is impacted by a greater number of factors which are difficult for investors to predict;
- is directly impacted by factors which are more likely to be in flux in the coming years and which are difficult to predict with accuracy (such as the level and location of spare capacity on the system, which is likely to change materially with the changing pattern of generation and load, and which will be driven by a wide variety of non-market factors such as government energy policy, the application of marine and land spatial planning regulations, the rate of build out of the transmission network etc.); and
- may change more quickly in response to changes in the dispersion of generation and load and the development of the transmission network.

Again, an LMP regime may therefore be expected to lead to investors facing a greater risk around their expectations of earnings. This is likely to lead to investors seeking a higher return on their capital, which we discuss in more detail in the next section.

8 Because the absolute size of the negative price is greater than the absolute size of their (positive) strike price.

Implications for cost of capital

Having identified reasons to believe that risks for investors will be higher in an LMP regime, the final question is whether investors are likely to demand a higher cost of capital in order to bear these increased risks.

The Capital Asset Pricing Model (CAPM) suggests that investors do not need to be compensated for risks which can be mitigated through diversification within a portfolio. Under CAPM logic, investors only require additional return to hold risks which cannot be diversified via other investments. Diversification, in the context of CAPM, relates not just to other investments in the energy sector (such as investments in other locations on the grid) but also to investments across the economy. If the additional risks to which investors are exposed as a result of a move to LMP are capable of diversification, it would follow that they should not lead to an increased cost of capital.

We note that some studies have suggested, albeit with limited evidence, that congestion related risks may be diversifiable under the CAPM logic[9]. However, when the assessment of investor risk was considered as part of EMR, DECC commissioned a report by NERA[10] which noted a number of weaknesses in the CAPM model. The report in particular suggested that the CAPM framework did not address fully two aspects of real world risk for which investors do require compensation:

- the existence of material asymmetric risks; and
- the existence of real option value (where investors need to be compensated for investing now, because in doing so they give up the opportunity to "wait and see", in order to inform forecasts using improved information sets).

A full assessment of the extent to which the risks we highlight here can be considered to be non-diversifiable is beyond the scope of this report. However, particularly in light of the first limitation highlighted by the NERA report as part of EMR, it is worth noting that there are material risks referred to above which are (either by definition or in all likelihood) asymmetric in nature. These include, for example:

- the risk associated with the loss of the strike price in the event of curtailment; and
- some of the key drivers of price risk and physical curtailment risk, such as delays in transmission investment (i.e. in practice, transmission investment is unlikely to be delivered early).

Based on NERA's analysis in their EMR report, this increases the likelihood that these aspects of risk do result in a requirement for an increased cost of capital. We also note that a number of the risks (such as the rate of connection of renewables and some new loads, the direction of carbon prices)

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9 Costs and Benefits of Access Reform. Prepared for the Australian Energy Market Commission. March Update, NERA, March 2019

10 Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime, NERA, December 2013

are driven to a significant extent by government policy. This may make them less capable of diversification.

Quantitative comparison of LMP and TNUoS risk

Having identified qualitatively why it is likely that investors under an LMP regime are exposed to higher risk than under a TNUoS regime, and why that additional risk may result in investors requiring a higher cost of capital, we now turn to placing some quantitative bounds on the scale of such a potential increased cost of capital in GB.

As noted in the introduction there is very limited existing evidence related to the cost of capital effects of a switch to LMP. However, we did identify one study from Australia which surveyed 18 investors in electricity generation.[11] All of the investors noted that a switch from zonal to nodal pricing would increase their cost of capital in the range of 1.5–2pp, in particular citing an increase in revenue volatility driven by concerns about the firmness and short duration of FTRs. Although the estimates in the Australian study are not directly relevant to GB, they do provide some support to the conclusion of our conceptual analysis that investors risks are likely to increase, as well as providing a useful benchmark for the quantitative analysis in this section.

It is important to recognise that any quantitative exercise is only likely to be able to provide an indication of the possible impact. Important constraints on such an exercise include that:

- even were a potential GB LMP market design to be fully specified (which it is not), there would be no track record of its operation in GB, and hence no way to calibrate the individual risks to which investors may be exposed; and
- even were there an understanding of the likely level of volatility of LMPs (e.g. through simulation), and ignoring the limitations of the CAPM framework referred to above, there is no well-established framework through which quantitative assessments of revenue or cost volatility can be robustly translated into impacts on investor cost of capital.

Given these limitations, we have adopted a practical approach in order to arrive at some understanding of:

- the extent of volatility in the locational signal of TNUoS and LMP regimes respectively;
- the potential implications of such volatility for the distribution of returns for windfarm investors; and
- the potential implications of this for the cost of capital demanded by investors.

The extent of volatility in the locational signal of TNUoS and LMP regimes

While there is no easy way of understanding the nature of a locational signal associated with a future potential GB LMP market, there are LMP markets operating internationally. Historical data from these jurisdictions can shed some light on the volatility which may result from the implementation of an LMP regime in GB.

11 Financing costs and barriers to entry in Australia's electricity market, Rai & Nelson, 2021

Naturally such evidence has to be interpreted carefully. 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. Furthermore, 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. Nevertheless, in an environment with little or no other data to go on, international data at least provides some benchmark.

We have therefore examined the variation in the historic locational signal in GB relative to the historic locational signal in PJM and in ERCOT. To do this, we:

- captured data on TNUoS charges in each zone in the GB system[12] going back to 2005, and calculated a locational signal for each zone, defined by the annual spread per MW between the zonal generation charge faced by a windfarm with an estimated 40% load factor and the average of all TNUoS charges for the same windfarm;
- captured data on nodal prices on the PJM system going back to 2005, and calculated a locational signal for each node, defined by the annual per MW spread for a windfarm with the same estimated 40% load factor[13] between each nodal price and the average of all nodal prices for the same windfarm; and
- captured data on settlement point prices on the ERCOT system going back to 2010 and replicated the PJM analysis.

It is important to note that, in the ERCOT market, a settlement point price is calculated for a load zone rather than for each LMP, with the settlement point price being a load weighted average of LMPs assigned to the load zone.

We then assessed the volatility in each of the measured annual locational signals over the time period for which we had data. Given differences in price level and currency, we measured this volatility by calculating the coefficient of variation[14] of each nodes annual locational signal. The coefficient of variation is a unitless measure of the dispersion of a distribution. The higher the coefficient, the more the locational signal at the node varied over time.

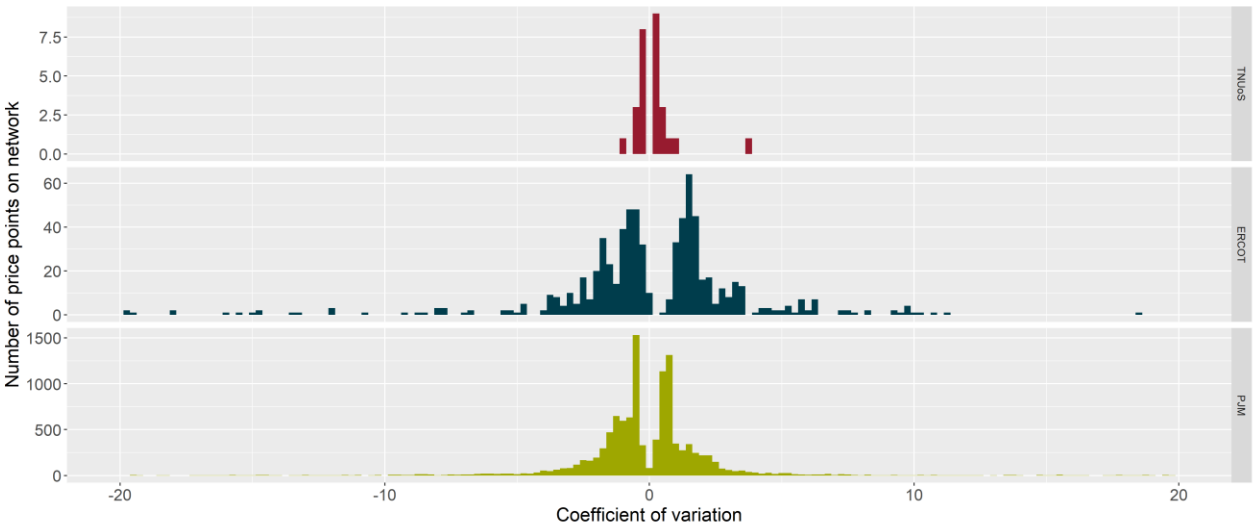
The results of this analysis are shown in Figure 5 and Figure 6.

12 Zonal definitions on the generation side have changed over time. We have attempted to map location data to the current generation TNUoS zones.

13 Modelled as a baseload output across the year

14 The coefficient of variation is defined as the standard deviation divided by the mean.

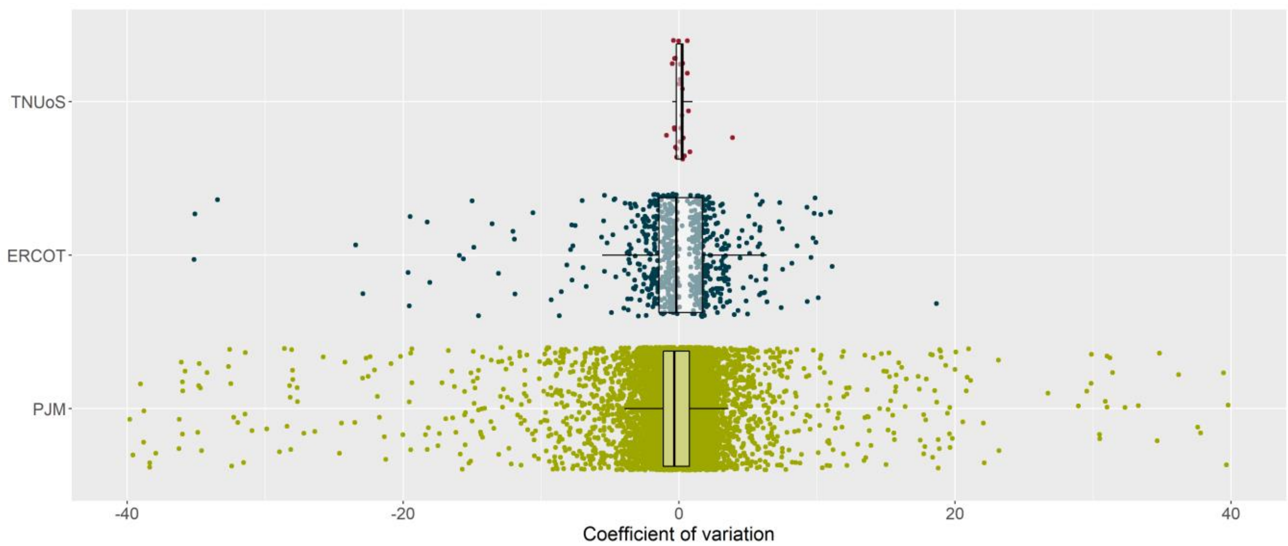
Figure 5 Histogram of the variation in annual locational signals for TNUoS, ERCOT and PJM zones



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

Note: 7 ERCOT outliers and 213 PJM outliers are clipped from this chart for presentational purposes

Figure 6 Jitter plot of the variation in annual locational signals for TNUoS, ERCOT and PJM zones



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

Note: 2 ERCOT outliers and 117 PJM outliers are clipped from this chart for presentational purposes. A jitter plot is similar to a single-axis scatter plot (strip plot), with dots randomly shifted along the second axis (here y-axis). This has no meaning in itself, other than allowing the dots not to overlap for visual purposes.

The graphs show that the variation in individual zonal TNUoS prices is relatively low compared to that in individual nodal or settlement point prices in PJM and ERCOT. The standard deviation is 0.80 for TNUoS, compared to 4.50 and 3.85 for ERCOT and PJM respectively.[15]

The jitter plot also shows that the locational signal in the US markets is more volatile than that in GB today. It also demonstrates that, while the interquartile range for ERCOT is higher than that for PJM[16], there are more examples of "extremes" of dispersion in the PJM data.

Taken together, the data from GB and from the two US jurisdictions appears consistent with our qualitative conclusion that investors are exposed to greater risk under an LMP market than under TNUoS.

It is also important to note that while this data captures volatility in the locational signal associated with LMPs over time, it does not fully reflect the differences in curtailment risk referred to above. It does not reflect the fact that if the network is unable to accommodate physically a windfarm's power under a TNUoS regime, the investor can continue to receive their strike price on the "curtailed" energy, but they do not receive such compensation under an LMP regime. In other words, the above analysis assumes that, at a 40% load factor, all of a windfarm's output is "valuable production" as defined above.

Implications of volatility for the distribution of returns for windfarm investors

From an investor point of view, it is not the locational signal which matters, but the potential variation in return from their investment as a result of this locational signal.

To estimate this, we used recent data from BEIS on the capital cost, operating cost, and cost of capital of an onshore windfarm in GB. We modelled a CfD strike price which would, for a plant in a zone with an average locational signal, secure BEIS' target rate of return on equity over a 10 year period[17]. We then calculated the return on equity which a plant with this price would achieve were it located in each other zone (effectively replicating variation in return as a result of the full range of theoretical locational choices which would be open to an investor, ignoring all other relevant factors behind siting decisions, including geographical differences in load factor).

In relation to the US markets, we focus our returns analysis on PJM data. We analyse returns looking over a 10 year horizon, but looking at rolling 10 year windows within our available dataset. Given our ERCOT dataset only runs back to 2011, this would have limited the number of 10 year windows available to analyse. As noted above, the ERCOT data also reflects settlement points (groups of nodes) rather than individual nodes as is the case in the PJM data.

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15 The 2 ERCOT outliers and 117 PJM outliers clipped from Figure 6 are also excluded from the calculation of the standard deviation.

16 The interquartile range for the TNUoS data is 0.48 while that for PJM is 1.91 and that for ERCOT is 3.14.

17 We modelled capital costs as an annual cost, calculated as an annuity at BEIS' stated rate of return, and then modelled the strike price which over the time horizon would ensure sufficient revenue to cover those "annualised" capital costs and operating costs.

The PJM data cannot be used directly in this analysis. PJM prices are denominated in a different currency (and the exchange rate changes over time), and the PJM market prices reflect generation technologies and costs which are unrelated to those in GB. Therefore, we used PJM data to proxy volatility arising from LMPs which a GB windfarm may see.

Using PJM market data, we derived proxy nodal prices for the GB system based on historic GB wholesale prices on one hand (to set the level) and the relativity between individual PJM nodal prices and an average PJM price on the other (to set variation across proxy nodes). As for TNUoS, we modelled a CfD strike price which would, for a plant in a zone with an average locational signal, secure BEIS' target rate of return on equity over a 10 year period. We then calculated the absolute top up or claw back due under the CfD relative to the historic GB wholesale price and then for each proxy GB node, we applied that absolute top up or claw back to the calculated proxy nodal price (essentially leaving locational risk with the investor).

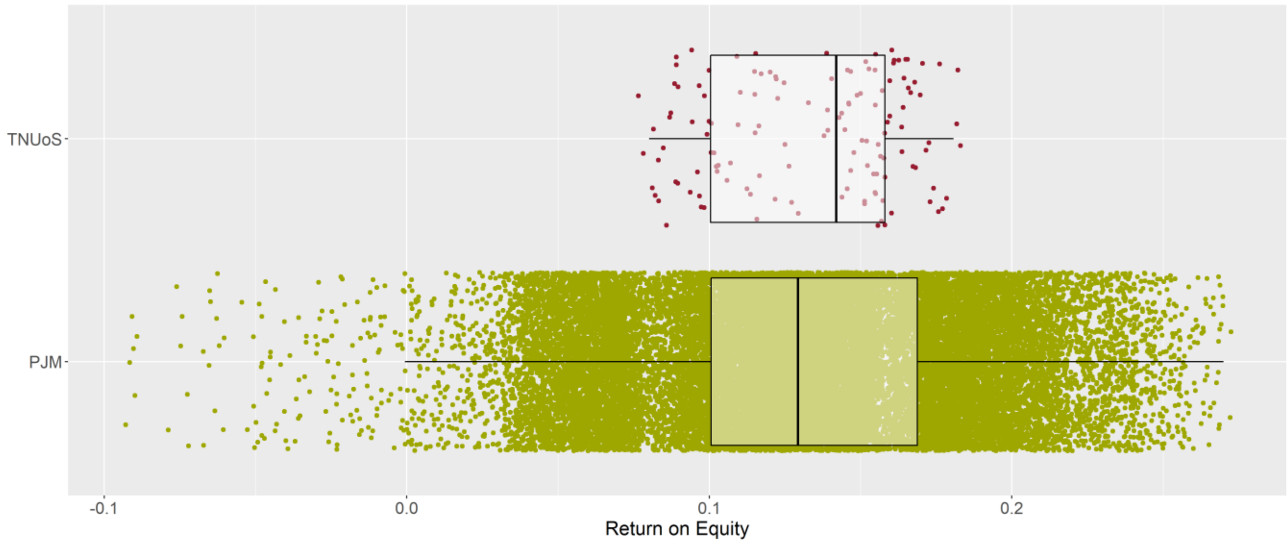
We have 14 years of GB wholesale price data, and therefore we calculated the return on equity which a plant at each proxy node would achieve over rolling 10 year periods.

Figure 7 Histogram of estimated GB returns on equity under TNUoS and LMP (proxied using volatility in nodal prices from PJM)

Source: Frontier analysis of hourly LMPs in PJM and TNUoS charges for the period 2008 to 2021. These results also draw on Bloomberg's over-the-counter GB wholesale price data for the same period and BEIS data on capex, opex and capital costs for an onshore windfarm in GB.

Note: The histogram illustrates the results of the return on equity calculation for a 1MW investment in onshore wind generation at every potential point on the network (under the current TNUoS system, we model the investment in each of the current TNUoS generation zones, under the modelled LMP system, the investment is at each proxy node). We consider a rolling 10-year investment horizon, with investments beginning in each year between 2008 and 2012 (e.g. a 10 year investment beginning in 2008 and ending in 2017, beginning in 2009 and ending in 2018, and so on).

Figure 8 Jitter plot of estimated GB returns on equity under TNUoS and LMP (proxied using volatility in nodal prices from PJM)



Source: Frontier analysis of hourly LMPs in PJM and TNUoS charges for the period 2008 to 2021. These results also draw on Bloomberg's over-the-counter GB wholesale price data for the same period and BEIS data on capex, opex and capital costs for an onshore windfarm in GB.

Note: The chart presents the same set of results as shown in Figure 6. Each point represents an estimated return on equity for a 10 year investment at a particular TNUoS zone or proxy LMP node, for a given investment start year between 2008 and 2012. The jitter plot introduces random variation in y-axis to reduce the degree of overlap between points.

As can be seen in Figure 7 and Figure 8 below, the estimated variation in annual returns on equity for individual zonal TNUoS prices is relatively lower compared to that in the proxy nodes based on PJM data. The standard deviation is 0.03 for TNUoS, compared to 0.05 for the proxy nodes based on PJM prices.[18]

Implications for the cost of capital demanded by windfarm investors

Finally, we assessed what the implications of these differences in the standard deviation of returns might mean for the cost of capital demanded by investors. As context to this final part of the analysis, it is important to recall (as we noted at the outset) that there is no single, widely accepted framework which will allow translation of differences in the dispersion of returns into an implication for the cost of capital. As a result, any quantitative analysis can only be considered an illustration of the potential outcome.

One approach to the problem is to identify a metric which relates a level of return demanded by investors to the dispersion of expected returns, and to assume that investors may wish to keep this metric constant across any potential change in regime (i.e. from TNUoS to LMP). The Sharpe ratio is one such metric, originally proposed by one of the developers of the CAPM framework. It is a widely used method for measuring risk-adjusted relative returns. The Sharpe ratio is a measure of reward

[18] The interquartile range for the returns in the TNUoS system is 0.06 while that the LMP system based on PJM prices is 0.07.

(over and above the risk free rate) relative to risk (as measured by the standard deviation of returns). In its simplest form, it is defined as:

$$Sharpe\ Ratio = \frac{r - r_f}{\sigma}$$

where: r is the return on investment, r_f is the risk free rate, $r - r_f$ is defined as "excess" return above the risk free rate, and σ is the standard deviation of excess returns (above the risk free rate).

If we assume that investors wish to hold the Sharpe ratio of their investments constant, it means that faced with an increase in the standard deviation of excess returns, investors demand a proportional increase in excess returns. Therefore, given the increase in the standard deviation of equity returns that we estimated in the previous section, if faced with the increased volatility based on PJM data, investors could demand an increase in the cost of equity of 9 percentage points (pp). Based on the cost of debt and gearing assumption in BEIS's WACC, this increase in the cost of equity translates into a 1.8pp increase in the WACC.

This estimate of increase in WACC assumes that all of the additional risk is borne by the equity holder, with debt investors perceiving no increase in risk and hence no change in the cost of debt. While it is reasonable that equity holders are exposed to more of the change in risk, it is unrealistic that lenders do not experience any change in risk. In reality, the cost of debt and gearing of the investment would be likely to change.

We therefore considered an alternative extreme, in which the change in exposure to risk is borne by both the equity holders and lenders. To do this, we followed the same process above, but assumed that the starting WACC adjusts proportionally to the increase in the standard deviation of returns[19]. This analysis suggests investors could demand an increase in the WACC of 4pp.

These estimates of 1.8pp to 4pp are likely to represent outer bounds, as while it is unlikely that equity holders alone bear all of the change in risk, it is also unlikely that the risk is shared proportionately with debt holders. It is beyond the scope of this exercise to carry out an assessment of changes in cost of debt, equity and gearing. However, it would be reasonable to consider that this analysis is indicative of a range of impact on the WACC of 2-3pp. We note that the lower end of this range is consistent with the limited literature research from Australia cited above.

As noted earlier, it is important to recognise that any such quantitative exercise is only likely to be able to provide an indication of the possible impact. It is also important to note some caveats that may increase or decrease this estimated range:

- *On the one hand*, this estimate does not take account of the possibility that some of the additional risk may be capable of diversification, suggesting 2-3pp may overestimate the impact; and

19 In this second analysis, we used the increase in the standard deviation of project (rather than equity) returns to estimate the increase in cost of capital.

- *On the other hand*, this estimate does not take into account the difference in curtailment risk i.e. the fact that if the network is unable to accommodate physically a windfarm's power under a TNUoS regime, the investor can continue to receive their strike price on the "curtailed" energy, whereas they do not receive such compensation under an LMP regime. This suggests that 2-3pp may underestimate the impact.

To the extent that these two effects are offsetting, the result of this analysis indicates there is at least the potential for a substantial increase in the WACC as a result of any move to LMP.