Summary of the discussion from Locational Pricing Assessment Workshop #1

Background

Ofgem is undertaking an assessment of the potential benefits, costs and implementation requirements associated with transitioning to a zonal or nodal wholesale market design. This assessment will evaluate several key design options in a GB context and assess the potential distributional impacts associated with different design options. It will also consider key risks and mitigations associated with such a move, including potential impacts on market liquidity and investment. This will report in Autumn 2022.

Regular stakeholder engagement is being used to help evaluate design options, including via a series of targeted stakeholder workshops. The workshops have been designed to facilitate discussions in small break-out groups, with attendees selected to reflect a diverse range of stakeholder interests.

The first workshop was held on 26th May 2022 and focused on project objectives, modelling assumptions and methodology and potential wider policy impacts. Subsequent workshops will focus on different elements, including outputs from economic modelling, implementation, and transitional measures.

This note provides a summary of the key discussion points captured during the session. Please contact WMReform@ofgem.gov.uk if you would like a copy of workshop materials.

Session 1: Overview of modelling approach

Stakeholders provided feedback on the **impacts of transitioning to a zonal or nodal market** that will be considered quantitively or qualitatively. Attendees generally supported the impacts identified to date but typically emphasised the need to consider potential impacts on market liquidity and investor confidence. Several attendees cautioned that the potential benefits of nodal pricing could be overstated in the modelling, given wider impacts associated with a wealth transfer from generators to consumers. For example, while nodal pricing could deliver significant consumer savings as consumers would no longer pay generators "constrained off" compensation payments, additional costs could materialise elsewhere in the system, for example, in higher CfD payments. FTI confirmed the modelling approach intends to calculate the impact of zonal and/or nodal designs on the CfD top-up payments (i.e., the increased or decreased quantum of support that may be required as a result of the wholesale power price changes).

Several participants highlighted the need to consider the impact of moving to a zonal or nodal market on reaching net zero, specifically in terms of the potential impact on investment and cost of capital. Several participants also highlighted the importance of understanding the impact of a zonal or nodal market at transmission-level on distribution-connected assets.

Stakeholders generally agreed that it would be helpful to further disaggregate the **consumer categories being considered**. Notably, the 'consumer' category should differentiate impacts on domestic and non-domestic consumers, flexibility providers and aggregators.

Stakeholders were generally supportive of the proposal to **model a seven-zone zonal market design** and identify '**nodes' at transmission sub-station level**. No stakeholder signalled disagreement with the proposal to use the FES Leading the Way and System Transformation **scenarios**. However, it was suggested that the Consumer Transformation scenario could provide insight into the impact of locational pricing on consumer behaviour.

Some participants asked for clarification on whether the boundary of the zones would evolve as part of the modelling. This may be included as part of FTI's modelling at appropriately distant intervals to reflect how, in reality, definition of zones may evolve (i.e., not every year). This would be an appropriate approach if the assumption of 'static' zones turns out to lead to very high within-zone transmission constraints.

Session 2: Key assumptions

Stakeholders provided feedback on the key assumptions to be used in modelling transmission capacity, electricity demand, generation capacity build-out and commodity prices.

The options for **modelling transmission capacity post-2041** were considered, given a lack of data. While some attendees were sceptical of the assumptions required to model out to 2050, several believed this time horizon was necessary, and the use of some dynamic assumptions could be used to improve outputs. There was no clear consensus on how the transmission capacity post-2041 should be treated, given the inherent uncertainties involved. Options discussed included extrapolation from expected network build before 2041, and optimising network build based on constraints. Both approaches, however, inevitably struggle to take account of real-world constraints on planning and technical feasibility.

There was broad support for the approach to defining the evolution of **demand levels** for each node, an hourly demand pattern, and flexibility assumptions by demand type. Some participants suggested looking at how demand profiles differ locationally. There was also a challenge to consider demand portability within the modelling and not just as a sensitivity. NB: Given the complexities of estimating long-term price-elasticity of industry siting decisions (and the key role of other factors, rather than just wholesale electricity prices), it seems most appropriate to treat demand portability as an exogenous sensitivity. This should help in understanding the potential system impacts of sources of demand changing their siting decisions in response to differing wholesale price signals.

In terms of **forecasting generation capacity**, clarification was requested in terms of whether demand and generation assumptions were dynamic or if the modelling will follow current NGESO projections. The modelling will be using NGESO's projections as detailed in the FES in the national market design of evolution of generation by location. By contrast, in the zonal and nodal market design, the modelling will allow some types of generation to re-locate in response to the observed wholesale power prices, albeit within pre-defined constraints. To reflect the partial flexibility of load, some proportion of demand will be permitted to vary in response to wholesale power prices under all three market designs (national, zonal, and nodal). Some stakeholders also asked for clarification on the assumptions underpinning generation portability, as it may not be sensible for all generation assets to site differently in response to location signals, e.g., limitation on nuclear plants and planning constraints that limit the ability of onshore wind to site in England as opposed to Scotland. FTI confirmed that (1) consideration will be given to the extent to which different types of generation can locate differently in response to locational signals, and (2) assumptions will consider real-world constraints such as planning, potential sites for nuclear generation and where seabed leases are available.

Overall, stakeholders were supportive of the **sources of data** for demand patterns, flexibility assumptions and capacity input.

There was broad support for the **approach to modelling CfD contract holders** and to the assessment more generally considering **how the CfD regime would be impacted** by a move to zonal or nodal markets and identifying changes that may be required**.** A question was raised regarding how the outcomes from Allocation Rounds 4-5 would be considered as part of the modelling, i.e., assumptions on who would receive contracts. Stakeholders also requested further detail on how we would model CfD contracts in the event that strike prices varied locationally.

Stakeholders were supportive of the approach to evaluating the potential impact of locational pricing on the **cost of capital**. Many participants highlighted the importance of assessing the long-run impact of locational pricing on uncertainty and the potential risk to investment decisions in the interim. Some stakeholders offered to provide evidence of the cost of capital impact in markets in which nodal pricing operates. One stakeholder did, however, question the importance of cost of capital impacts, given the significant reductions in the overall cost of renewables; this should mean that cost of capital has less effect on final bills than previously. Some participants pointed out that a key risk of implementing locational pricing is the **changes to price forecasting** – in their experience, price forecasting becomes more complicated with nodal pricing but less complicated with zonal. FTI will follow up to explore this further.

Session 3: Policy interactions

Stakeholders generally agreed with the **policies identified to date** and **initial prioritisation**. Some stakeholders raised the potential of considering impacts on future technologies or market changes, including CCUS Dispatchable Power Agreements, distributed energy generation or hydrogen business models. Consideration was also given to including potential impact on connection and connection charging regimes.

Clarification was sought on how any short-term changes to wholesale market arrangements will be considered as part of this assessment. It was confirmed that given timings, the status quo/counterfactual will assume no incremental changes to current wholesale and balancing mechanism. However, several in-flight Ofgem policies are now actively considering compatibility with future wholesale market designs. For example, Ofgem’s DUoS charging review will consider how distribution network charging will need to evolve to be compatible with any future wholesale market context, including locational pricing.

The assumptions required on the methodology for TNUoS charges under a zonal and nodal approach were also discussed. FTI explained that under a nodal approach, it would be reasonable to assume a "postage stamp" per MWh charge on demand for recovering the proportion of transmission costs that is not covered by the congestion surplus created in a nodal market – noting that in other jurisdictions roughly a third of the transmission costs are recovered through the congestion surplus. For a zonal approach, some form of hybrid between the current locational TNUoS charge and the postage stamp could be envisaged.

A suggestion was made that **all investment support schemes** may need to be considered in detail, especially as several LMP markets also have Capacity Mechanisms. Several stakeholders raised the possibility of splitting existing and future CfDs, as they could be treated very differently. This has been reflected in the FTI approach, and the modelling intends to maintain a distinction between legacy and future CFD contracts.