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Report

Locational Pricing Assessment – Frequently Asked Questions			
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Version	2.0		

Ofgem published a Call for Input (CfI) on 1 June 2022[1] asking for stakeholder views to inform our assessment of locational wholesale pricing ("locational pricing assessment"). Alongside responses to the CfI, we have received questions from stakeholders largely related to the economic modelling commissioned from FTI Consulting ("FTI").

This document aims to provide further clarity to stakeholders by answering a set of Frequently Asked Questions (FAQs) that have been collated from responses to the CfI and questions asked at a stakeholder session on 30th May.

Version 2.0

This is an updated version of the document originally published 26th August 2022, to reflect:

1. A subset of additional questions, based on two subsequent stakeholder workshops (30th August and 20th October 2022); and
2. Updates to the original FAQs where the modelling approach has either been amended, or otherwise finalised (and was previously uncertain).

[1] Locational Pricing Assessment | Ofgem

We welcome all stakeholder engagement to date and note the high-level of interest in this project. As it is not practicable for this document to cover all questions raised by stakeholders, we have concentrated on a select number of questions which are commonly asked by multiple-stakeholders or where we think clarification would aid general understanding of the project and work to date.

Note that these responses are correct at the time of publication, and are subject to change as the Locational Pricing Assessment progresses.

Please get in touch with WMReform@ofgem.gov.uk should you wish to engage further with us on our work.

Contents

FAQs related to Ofgem’s Locational Pricing Assessment

1. How does Ofgem’s assessment of locational pricing fit with the UK Government’s Review of Electricity Market Arrangements (REMA) programme?

The UK Government’s REMA programme is considering a wide range of options[2] for updating GB electricity market arrangements to ensure the UK’s commitment to a decarbonised and secure electricity system by 2035, at least possible cost to consumers, can be delivered. Ofgem supports the scope of the REMA programme and is working closely with the Department for Business, Energy and Industrial Strategy (BEIS) to consider the full range of incremental and radical options considered as part of the first REMA consultation.[3]

In parallel to this, Ofgem is undertaking a targeted assessment of locational pricing options (specifically zonal and nodal wholesale market designs) that would see the GB wholesale electricity market provide locational signals in both investment and operational timescales. The need for more accurate locational signals was identified as a key cross-cutting issue within the REMA consultation, with BEIS considering a range of options for addressing the significant locational challenge the GB energy system faces. Ofgem’s assessment of zonal and nodal pricing intends to inform BEIS’s short-listing of options for and, if relevant, BEIS’s reform packaging process.

2. Will Ofgem’s Locational Pricing Assessment consider the case for change to market arrangements?

As referenced in the REMA consultation, the REMA case for change was developed as part of a collaborative process between BEIS, Ofgem and National Grid Electricity System Operator (NGESO). The REMA consultation sets out a range of challenges facing the GB energy system and a vision for future market arrangements that we will use to inform our technical assessment of locational pricing option.

3. Why is the scope of the project limited to locational pricing? Why are Ofgem not considering a broader range of options?

As mentioned, the UK Government’s REMA programme is considering a wide range of options for updating GB electricity market arrangements. Ofgem supports the scope of the REMA programme and is working closely with BEIS to consider the full range of incremental and radical options considered as part of the first REMA consultation.

As part of REMA, BEIS have identified a range of options for delivering stronger locational signals including:

[2] The BEIS REMA programme is considering a broad range of options, from medium-term changes to existing arrangements that can be delivered from the mid-2020s, to longer-term transformational reforms, as well as low regret ‘quick wins’ which could be pursued on accelerated timelines and implemented regardless of the end package of reform.
[3] [Review of electricity market arrangements - GOV.UK (www.gov.uk)](https://www.gov.uk)

- Moving to zonal or nodal wholesale pricing;
- Introducing locational signals to renewables support schemes and/or capacity markets;
- Locational imbalance pricing; and
- Network access and/or charging reform.

These options are not mutually exclusive.

Ofgem's targeted assessment intends to directly support BEIS and wider stakeholders' consideration of zonal and nodal wholesale pricing options by assessing and providing high quality information on the potential benefits, costs, distributional impacts and implementation requirements associated with these reform options.

4. Ofgem have engaged FTI to support the locational pricing project. FTI have previously worked with NGESO on their Net Zero Market Reform project[4]. How is Ofgem ensuring that the analysis remains independent, and how it is bringing new insights and mindsets to the work?

FTI were awarded the contract through a transparent procurement process in accordance with Civil Service rules. FTI scored the highest based on several factors, including their modelling expertise and their extensive practical experience working in and designing international zonal and nodal markets.

We did not perceive any conflicts of interest stemming from FTI's work with NGESO, nor have any been identified since they began their contract with Ofgem. A key part of our process is open and transparent engagement with stakeholders to enable scrutiny of the approach, assumptions and inputs that will shape FTI's final outputs.

5. Can Ofgem publish dates and expectations on stakeholders for events ahead of time?

We will share invites, agendas and any pre-read with stakeholders as far ahead of the relevant workshop as possible. We anticipate facilitating a final session on the modelling outputs in Q1 2023.

FAQs related to the quantitative modelling

[4] Net Zero market reform | National Grid ESO

1. **Using the status quo market arrangements (ie, a single national price) as the reference risks overestimating the benefits of locational pricing designs as any potential incremental changes to current market design made in advance of/as part of REMA could deliver some of the benefits associated with zonal or nodal pricing. Therefore, can an enhanced status quo option be used as the counterfactual (eg, by considering a more granular Transmission Network Use of System (TNUoS) charge, or a reformed Contract for Difference (CfD) scheme)?**

   The scope of this project is intentionally focused on zonal and nodal pricing options and does not include an assessment of other options being considered as part of REMA, such as more medium-term changes to the CfD regime and TNUoS. This is a reflection of the distinct scopes of Ofgem's targeted assessment and the BEIS REMA programme.

   There are also limitations in terms of what is practicable within project timelines, both in terms of establishing a reasonable counterfactual and developing an approach to modelling an enhanced counterfactual. Given this, the long-term forecasts of capacity deployment based on NGESO's Future Energy Scenarios (FES)[5] 2021 are considered an appropriate counterfactual for the analysis, as they reflect an extensive industry-wide consultation process and represent a credible envelope of possible outcomes for the GB power market.

2. **Will the assessment be conducted on a system cost or a consumer cost basis?**

   The assessment will consider both and clarify which outcomes result from system efficiency gains and which are the result of welfare transfers. For example, the analysis will consider the potential changes to consumer welfare (from changes in wholesale power prices, constraint costs, and CfD support costs), as well as changes to the producer surplus resulting from changes in wholesale power prices. We will also consider the impact of new revenue sources being created, notably intra-GB congestion costs.

   We aim to undertake a distributional analysis on the raw results of the modelling, which will seek to quantify the potential impact on consumer bills, looking at differential implications on multiple consumer categories (both geographically and in terms of consumption profiles).

3. **Will the modelling assumptions and methodology be independently reviewed?**

   At this time, we do not plan to have the modelling assumptions and methodology independently reviewed as:

   - We are using a series of stakeholder workshops held throughout the project to explain and provide transparency on the methodology, assumptions and

[5] Future Energy Scenarios 2022 | National Grid ESO

initial findings. Materials are available to all interested stakeholders and a summary of each workshop will be published online.

- For example, stakeholder feedback (both from the first workshop and in response to our June CfI) has been used as part of this external 'challenge and review' process, with refinements and amendments to the methodology and assumptions made in line with responses received to date.
- FTI will provide a report to Ofgem, which we intend to publish, and which will contain as much information as possible on the assumptions, input data and modelling methodology (whilst respecting commitments to confidentiality).
- In conducting our assessment, we intend to use exogenous inputs whenever possible (eg, FES, the Electricity Ten Year Statement (ETYS)[6], the Network Options Assessment (NOA)[7]) as these are well understood by stakeholders and have been subject to stakeholder scrutiny and subsequent refinement.

4. Market participants are exposed to a variety of signals through markets and administered schemes. The degree to which they respond to each signal depends on the specific attributes of each participant and their assets.

a. What assumptions have been made on the locational siting elasticity of generation?

For the purposes of the modelling, assumptions have been made regarding the degree to which different technologies can choose to delay/cancel projects in certain locations and accelerate/develop new projects in other locations. As set out in table 1, technologies have been assigned diverse levels of mobility to reflect real-world constraints and assumptions on their ability to respond to wholesale power price signals when making siting decisions.

These constraints are applied to both the nodal and zonal market designs, though with lesser granularity in the zonal market.

<table>
<tr><th>Technology</th><th>Assumed locational siting constraint(s) in response to forecast wholesale electricity prices</th></tr>
<tr><td>Nuclear</td><td rowspan="2">Do not respond (neither in terms of timing nor in terms of location)</td></tr>
<tr><td>Fossil fuel</td></tr>
<tr><td>Biomass</td><td>Do not respond (fixed as per FES '21)</td></tr>
<tr><td>Carbon Capture and Storage (Biomass)</td><td>Location optimised within the clusters and nodes identified in the government strategy.</td></tr>
<tr><td>Hydrogen</td><td>Location optimised around nodes as defined in FES '21 and/or as within Hydrogen clusters</td></tr>
<tr><td>Offshore wind</td><td>Does respond, limited by:
• Historic CfD Allocation Round results; and
• Differences in resource availability (ie, wind speeds)
• Current seabed leases or the capacity in FES until 2030. Increases beyond 2030 are limited to twice the currently leased amount, or the capacity in FES.</td></tr>
<tr><td>Onshore wind</td><td>Does respond, limited by:</td></tr>
</table>

[6] Electricity Ten Year Statement (ETYS) 2021 | National Grid ESO
[7] Network Options Assessment (NOA) | National Grid ESO

	• New onshore wind in England as indicated in FES21; and • New onshore wind in Scotland and Wales can locate on any node with onshore wind capacity in FES '21 • Maximum additional capacity per node in Scotland and Wales set at twice that of FES '21 forecast • Differences in resource availability (ie, wind speeds)
Solar	Does respond, limited by: • Maximum additional capacity per node set at twice that of FES '21 forecast; and • Differences in resource availability
Battery storage	Does respond and new capacity can locate on any node with battery capacity in FES '21
Hydro and Pumped Storage	Does not respond
Interconnectors	Do not respond – capacity and location as per FES '21

Table 1: Key generation locational siting constraints used in the modelling

b. What is the approach to modelling the expansion of the generation mix? Will the model decide this internally?

In the single national price model (ie, the counterfactual), the expansion of the generation mix is defined by the FES scenarios and is fully exogenous.

In the zonal and nodal market designs, the location of assets is optimised endogenously, as described in the answer to question 4.a, above. Capacity is kept nearly constant between the national and zonal/nodal designs such that the modelling results focus on the re-siting of technologies, rather than a more comprehensive change in the technology mix.

In practice, a potential benefit of a zonal or nodal market design could be a rebalancing of the generation mix (ie, changing the relative capacities of different technologies). Therefore, the approach employed to optimise capacity (as described above) may underestimate the benefits of zonal or nodal pricing.

c. The benefits of introducing locational pricing will depend heavily on participants' ability to react to the price signals. How is the flexibility of the demand side being modelled?

First, Demand Side Response (DSR) is modelled as a technology that participates in the wholesale power market. This includes several elements:

- 'Baseline' DSR: In discussion with NGESO, two-tiers of DSR are included in the model, then activated at different price levels. The capacity of DSR and price levels are based on FES '21.
- Heat pumps and cooling: In the modelling, only heat pump demand defined as flexible in FES '21 is allowed to optimise its electricity consumption within the day to minimise cost.
- Electric vehicles (EVs): A proportion of EVs is allowed to optimise consumption within a day to minimise cost. This proportion is based on the percentage of households taking part in smart charging, as defined in FES '21. The remaining proportion of EVs follow a fixed demand profile peaking late at night (ie, most charging happens overnight).

- Hydrogen electrolysers: Total demand from electrolysers and their capacity is taken from FES '21. The electrolysers' consumption profile is then optimised by Plexos® [8] to minimise the cost.
- Power to Gas ("P2G") and storage: All demand is price-responsive within the Plexos® model and optimised to maximise their revenue

Second, it is possible that locational pricing would result in a certain degree of demand portability, ie, a large energy consumer connecting to the network in a different region of GB under the zonal/nodal design compared to where they would have connected under a national pricing design. This could be estimated using a stylised set of assumptions. This type of analysis would recognise that only some types of large energy users can exhibit demand portability (eg, data centres), as factors other than wholesale electricity price would also affect the location choice. This has not been included in the quantitative analysis as it was deemed too subjective. Therefore, this could be said to represent a conservative assumption in the analysis.

5. The Plexos® modelling software used in this assessment can endogenously build out the transmission network. Will this assessment make use of that?

We will not allow the model to endogenously build-out the transmission network as part of the assessment. An endogenous build-out of transmission risks not incorporating many "real world" constraints (e.g., the consenting and planning process) and may lead to an over optimistic transmission build out relative to what in practice might be feasible. Our approach is therefore, to use the information provided by Transmission Owners in the NOA process, combined with NGESO's assessment (including the recent Holistic Network Design[9]). Given the limitations on the information available regarding the transmission network post-2040, our approach is to only perform power market modelling up to and including 2040. For the period post-2040, we are planning to deploy a simplified extrapolation approach, to provide an order-of-magnitude comparison of the different locational pricing options under assessment.

6. Will the benefits, costs and risks of Financial Transmission Rights (FTRs) be included in the modelling?

Using the modelling results, an estimate of the total value of FTRs in a locational market will be generated. Any risks and benefits associated with introducing FTRs to the market will not be modelled but assessed qualitatively. The total volume of intra-GB congestion rents will be linked to the total volume of FTRs, and we will also illustrate different options for allocating/auctioning FTRs, based on international examples.

The qualitative assessment of FTRs will feed into analysis being undertaken on possible cost of capital effects, to investigate how market participants may be able to manage price risk in different market designs.

[8] Plexos® is the software platform being used to perform the modelling in this locational pricing assessment.
[9] The Pathway to 2030 Holistic Network Design | National Grid ESO

7. How will potential impacts on liquidity be assessed? Will this form part of the modelling?

International evidence on liquidity in other nodal and zonal market designs will be used to help inform the analysis, as well as from third party engagements. The power market modelling itself does not provide any insights on the volumes of liquidity.

8. How will a potential impact on the cost of capital be assessed? How will this be accounted for in the modelling?

As indicated in the stakeholder workshops presented to date, FTI will consider a three-pronged approach to evaluating the potential impact of different locational pricing designs on the cost of capital for market participants. This will include a theoretical assessment of potential risks, international evidence, and evidence collated from stakeholders through the CfI process.

As presented in the October workshop, a change in the cost of capital (which may be an increase or a decrease depending on the technology/region) will be reflected in the costs of a new build of relevant resources, as part of a sensitivity.

9. For the zonal model, what is the rationale for the number of zones and boundaries? Will the modelling consider evolutions overtime?

In line with the core modelling principle being used, the choice of a zonal market to model has been based on the publicly available information. In this case, NGESO's forecasts of constraints across relevant boundaries between 2022 and 2032. On this basis, the six most significant boundaries have been identified (giving rise to seven zones), which are appropriate for the modelling of 2025 and 2030. These are also consistent with historical volumes of constraints observed in GB.

In any zonal market it is likely that there would be potential for these zones to change over time. It is not possible for us to model all sensitivities of interest. As such, we are not planning to undertake any analysis of a different zonal configuration, but we intend to comment qualitatively on the evolution of constraint costs within specific zones, and on the potential implications and practical limitations of any re-zoning process.

10. Does the model assume perfect foresight, or does it account for uncertainty?

Perfect foresight is common in power dispatch models. The model being used in this study assumes that a central System Operator has the correct information (in terms of costs, technical parameters, etc) to schedule and dispatch the system in the most efficient manner possible to meet demand. The model is not set up to reflect additional deviations (eg, unexpected changes to weather or demand) that would inevitably arise in real-world.

In terms of long-term capacity development (under zonal and nodal designs), the model will optimise the location of the new build based on a simplified forecast of future power prices (and within the constraints highlighted in question 4.a), which are aggregated to larger blocks of average prices (ie, not hourly).

We are aware of the limitations of this approach and the impacts it may have on the outputs, and as such, we will consider this as part of our evaluation of the modelling outputs.

11. How will the model predict any CfD prices to be determined for future projects?

The structure and design of future support mechanisms for different types of technologies is within the responsibility of Government, and is not within the scope of this project. However, for the purposes of this Cost Benefit Analysis, a methodology has been developed for estimating possible CfD top ups, which is based on a following equation:

$$CfD\ payment = (Strike\ price - Reference\ price) * Generation\ volume$$

The assumptions adopted on the future CfD regime design are:

- *Strike price* - based on either the strike price that has been set already (e.g. where known), or, for future new build, the BEIS estimates of the Levelised Cost of Energy (LCOE)[10] for electricity generation technologies. For each technology type we assumed the same LCOE, and used a simple average across the range provided in BEIS report.[11]
- *Reference price* – we assumed the reference price would be based on the individual nodal or zonal price. This assumption implies that resources are not exposed to any locational price risk. We recognise that in practice, the reference price could be defined in several alternative ways (e.g. as a hub price, or national price with an FTR to the local node).
- *Generation volumes* - based on an unconstrained (ie, prior to ESO re-despatch) output from the Plexos® model

Our assessment includes the following known projects with (or which will use) CfDs:

- Existing projects with CfD contracts;
- All proposed offshore wind projects awarded CfDs in AR1-4; and
- Hinkley Point C

The assessment further takes into account the potential for future, unknown projects to be operating with CfDs as follows (and based on technology specific capacities forecast in FES):

- All future offshore wind projects;
- 50% of future solar projects; and
- 50% of future onshore wind projects

For the avoidance of doubt, this methodology should not be interpreted as a recommendation of a future CfD policy design, or indeed as an indication of a likely

[10] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/911817/electricity-generation-cost-report-2020.pdf

[11] In practice, this might differ based on capacity factors and constraint risk

future Government position on the matter. It has been developed purely for illustrative purposes.

12. How does the modelling account for the impact on interconnectors? Does this include the Multi-Regional Loose Volume Coupling (MRLVC) methodology?

The location and volume of interconnection are exogenous in the model and are based on FES '21.

The flows on interconnectors will be based on the relative wholesale power prices in GB and the connecting countries, in a given hour, considering the technical loss factor on the relevant cable. These flows will respect the economic signals and flow in the 'correct' direction.

The MRLVC methodology has not yet been finalised, so this cannot be considered. The implicit assumption in the modelling is that any form of market coupling will give rise to economically efficient trades taking place (ie, avoid flows taking place against the direction of the power prices).

13. What assumptions are being used for new interconnector capacity?

The assumptions for new interconnector capacity are based on FES '21 forecasts for the relevant scenarios. They are fully exogenous in terms of location and capacity, and remain the same under all market design options considered in this study.

14. Why are NGESO's FES '21 scenarios being used, as opposed to other available scenarios (eg, FES '22, or those produced by BEIS or the Climate Change Committee (CCC))?

The level of detail that is required for the input data to any nodal modelling requires that we use a source of information that provides adequate locational granularity of demand and supply. FES '21 is therefore the most appropriate source of such information as it provides information on demand and generation by each relevant node on the network. By contrast, neither BEIS nor CCC scenarios provide any information on the node-specific location of new generation. The use of these scenarios would require a manual allocation of new capacity across hundreds of nodes across GB, which would require a large degree of judgement, increasing the subjectivity of any results. Further, it would not be practicable in the timescales of this assessment.

In addition, the FES '21 data is consistent with the ETYS and the NOA. This enables a consistent dataset to be constructed, which includes both the future development of the transmission network and the location of demand and supply across that network.

FES '22 has not been used as the Locational Pricing Assessment project started in April 2022, and FES '22 was not available until July 2022. Moreover, some of the detailed underlying datasets that are required for the nodal modelling are not available for FES '22.

We aim to consider the extent to which any differences between FES '21 and FES '22 would impact the results of our study.

15. Will the modelling consider extreme scenarios, such as commodity price shocks, extreme weather events, etc, to test the resilience of a new market design? If not, why?

Unfortunately, it is not possible for us to model all sensitivities of interest, hence we will not be taking this forward.

16. Will the modelling include the potential impact of delayed investment because of uncertainty faced by market participants?

We are not currently planning to model the potential impact of delayed investment.

17. How will the impact of locational pricing on Government Net Zero targets and security of supply be considered within the modelling?

Total expected carbon dioxide (CO_2) emissions will be an output of the modelling runs for the three market designs. This will allow a comparison of the degree to which the specifics of the wholesale electricity market design may impact achievement of Net Zero targets. However, we note that under all three designs the model seeks to achieve Net Zero by 2050. While dispatch of different technologies is expected to vary across the designs, this is unlikely to drive a significant difference in the outturn CO_2 emissions.

As per question 4.b, the security of supply requirement is an input constraint for the model, ie, Plexos® builds sufficient generation capacity to ensure there is a minimum amount of reserve capacity relative to peak load. Hence, there is limited benefit in comparing security of supply levels. The model will output the total volume of Expected Energy Not Served (EENS).

18. How do you consider distribution network constraints in looking at resource location?

The modelling is no more granular than Grid Supply Points (GSPs). Under the status quo (national model) all the resources are connected as per information provided by FES, in terms of siting. For any re-siting that occurs in the zonal or nodal models, with the exception of solar capacity, it is assumed that it is possible for the necessary connections to be made. For solar capacity we have adopted a constraint to re-site capacity only onto the nodes where solar already exists in the FES forecasts, and the change can not be more than double the capacity suggested by FES (see question 4.a).

It is not feasible to include further network granularity, or additional exogenous constraints (such as the availability of the land), given both the amount of data that this would require and the limitations of the project timeline.

19. Can you provide more information on the assumptions on how batteries are treated?

The FES (both '21 and '22) includes five kinds of electrical storage technologies: Battery (split for domestic and non-domestic), Liquid Air, Compressed air, Pumped hydro, Vehicle-to-Grid (V2G). For the purposes of the modelling being undertaken in this project, only the capacity and the storage capacity of electric storage technologies are considered. As a result, there are four kinds of storage in the Plexos® model: Pumped storage – same as pumped hydro in FES;

- Behind the meter battery – Domestic batteries and V2G in FES;
- One-hour battery – Everything from the other categories with one to two hours of storage duration;
- Four-hour battery – Everything from the other categories with three to six hours of storage duration (including all compressed air and liquid air);

We are also excluding any batteries which are incorporated in FES ’21, and with storage duration of less than one hour, from the modelling.

The location of behind the meter and V2G capacity is fixed with only grid-connected storage (primarily short- and medium-duration) allowed to re-allocate. Battery demand/generation output is optimised to maximise profit.

20. For all new capacity the model assumes is built, do you check they are economic and adjust if necessary? If not, how do you justify the build?

The capacity allocation is based on the Plexos® Integrated Energy Model platform, which considers economic, environmental and security of supply criteria to determine the optimal location and the optimal evolution of capacity (MW). The siting of the generation represents the lowest-cost combination of generation plants (of all technologies) that meets the minimum capacity margin and constraints on emissions. The model is, in its essence, a least-cost model, and it therefore implicitly assumes that a resource is least-cost to meet the relevant constraints. We acknowledge that this does not necessarily mean a resource is economically viable on the basis of wholesale electricity market revenues, and therefore that a financially compensating mechanism (which we are agnostic about) might need to be in place to ensure any new forecast resource is built.

21. Does "new" capacity include repowering? Is there an assumption about how much capacity will not be repowered or extended as a result of the new market implementation?

New capacity is based on the information contained within the FES ‘21 and we do not assume re-powering nor extension as a part of our analysis.

22. How is the European network taken into account? What assumptions are made?

FTI’s European power market model covers the EU-27 countries, plus GB, Switzerland, Norway, the Balkans and Turkey. Countries connected to Europe beyond this scope are modelled at an aggregate level. The model's long-term capacity forecast achieves net zero in Europe by 2050, and is kept constant between all modelled scenarios, such that a movement from national to zonal or nodal pricing in GB does not affect European capacity deployment.

The European long-term capacity deployment is guided by national energy policies and third-party benchmarks, primarily countries' National Energy and Climate Plans (to 2030) and the Global Ambition scenario of ENTSO-E's Ten-Year Network Development Plan (TYNDP) 2022 (to 2050). The final capacity mix is optimised within the Plexos® model to minimise system cost while meeting a number of constraints, namely national security of supply through minimum reserve margins, coal and nuclear phase-down plans, and emission reduction targets. Cross-border transmission and interconnectors (excluding those connecting to GB) are as forecasted in the TYNDP 2022 Global Ambition scenario.

23. Do you treat interconnectors as a generator or a transmission line?

Interconnectors are treated as a two-way asset that can serve either as a source of demand or supply to GB and not as a generator. The model covers the European power markets and the transfer via interconnectors is determined by the price differential between connected markets.

24. Can you confirm where your gas and carbon cost forecasts have come from?

Commodity price forecasts are based on future curves and long-term projections in the World Economic Outlook.

More specifically, the sources are:

- Gas - World Economic Outlook 2021 and Bloomberg (TTFGDAHD[12])
- Carbon - World Economic Outlook 2021 and Bloomberg (UK CO2)

25. How do you model CfD payments in the case that a generator is curtailed? Or in the nodal market, when the nodal capture price drops below the Short Run Marginal Cost?

Under the national market design, CfD payments are calculated based on the unconstrained model runs (ie, before action is taken by the ESO in the BM).

Under the nodal market design, the model does not account for any CfD payments in the case that the market participant is not generating. See question 11 for more on how we try to account for the CfD mechanism in the modelling.

26. Are Capacity Market costs (or other subsidy schemes) being considered in the modelling?

No, we are only considering impacts on CfDs. For clarity, the CfDs are only included as part of the cost-benefit analysis, but they are not a feature of the Plexos® model itself.

[12] TTF Gas Day-Ahead

27. Is it realistic to assume that benefits can accrue from 2025? Can you explain how you are taking into account the time for implementation within the modelling results?

The data used in our modelling starts from 2025 and therefore that was used as a starting point in presenting the raw results in the workshops. The implementation timeline will be considered as part of the post-processing of the modelling results, considering information provided by the ESO, stakeholders and experiences from other jurisdictions that underwent a similar change.

For the avoidance of doubt, whilst the modelling period begins in 2025 our final report will provide a view on the benefits which might accrue over a period in which it is realistic to implement locational pricing.

28. The results shared in the workshops on 30th August and 20th October show that capacity is relocating in 2025. Can you explain this result?

Under the modelling assumptions used, projects already in the pipeline remain in a fixed location. As per question 4.a, we allow that new projects can be shifted under some constraints. This degree of locational flexibility represents a pro-active approach of investors who might anticipate the impact of locational pricing, and re-site their projects in advance of any market re-design.

29. Why do you say that having fixed technology capacity budgets will lead to conservative results? Further, are these fixed in MW or MWh? If you fix MW, how do you propose to replace MWh (if the change in MW has different load factor)?

As described in our response to question 4.b and question 17, the total installed capacity (MW) is kept nearly constant.

The Plexos® model ensures that total demand (in MWh) is always served, and at the minimum cost given the resources available. Where the model is relocating (eg) wind capacity, and the load factor is lower in the new area, this may lead to a corresponding increase in production from another generator and/or increased demand response.

Nodal markets provide information on the incremental cost of serving demand in any location at a particular time. This price signal provides operational benefits, ensures efficient allocation of the transmission capacity, and provides a price investment signal for new generation capacity and demand response. In practice, a potential benefit of a zonal or nodal market design could be a rebalancing of the generation mix (ie, changing the relative capacities of different technologies) or different, more optimal transmission network development. Therefore, the approach employed to optimise capacity (as described above) is conservative as it may underestimate the benefits of zonal or nodal pricing.

30. The wholesale electricity price forecasts shared so far are lower than the BEIS Energy and emissions projections: 2021 to 2040 (as of 18 October 2022)[13]. How do FTI's forecasts relate to these?

BEIS' Energy and emission price forecasts are underpinned by a different scenario, underlying data and assumptions (fossil fuel prices, capacity projections, technology mix, interconnector capacity etc) than those assumed by FTI, and which currently are not in the public domain.

This project involves comparing all the market design options under an identical set of assumptions. Inevitably, under a different set of assumptions the outputs (including the electricity price forecast) will be different.

31. In an LMP market, when there are network constraints, how is it decided which wind/solar generators behind a constraint would get dispatched on and which would not?

Typically, LMP markets do not provide a financially firm access right for export energy to market participants. However, the price in each node reflects the locational value of energy and the cost of delivering it (considering network capacity and losses), at any point in time. The System Operator then uses this information to determine which market participants are dispatched. As such, market participants are not constrained by the action of the System Operator, but by whether they are an efficient resource available to meet demand at the time.

Any decision regarding which unit is being scheduled and dispatched, is determined using a least-cost Security Constrained Unit Commitment dispatch algorithm, which, in addition to price, considers a range of parameters such as the need for ancillary services, unit commitment constraints (minimum and maximum export levels, minimum downtime and minimum run time etc).

32. At the workshop on 20th October, FTI shared technology-specific increases to cost of capital[14]. How have these numbers been derived?

FTI have taken a three-pronged approach to evaluate the potential impact of moving to locational pricing on the cost of capital.

1. A consideration of how the various risks faced by market participants might change following a change in market design from national pricing to locational pricing, and how this may affect the components of the cost of capital.

2. An examination of the direct and indirect international evidence on how implementing a locational market has affected the cost of capital in other jurisdictions.

[13] Energy and emissions projections - GOV.UK (www.gov.uk)
[14] See slide 57: https://www.ofgem.gov.uk/sites/default/files/2022-11/Workshop%20Slides%2020th%20October.pdf

3. Quantitative evidence from stakeholders on the potential impact of locational pricing on their cost of capital.

The numbers presented at the 20th October workshop were based on a combination of these studies, and in FTI's central modelling, the cost of capital impact has been assumed to be nil.

However, for the purposes of the sensitivity analysis, FTI sought to illustrate a situation where there might be a change in risk faced by different technologies were locational pricing to be implemented. FTI therefore relied on the same three sources of information as described above, augmented with a qualitative evaluation of the relative changes in risks across different technology classes, as described in the presentation. The specific numbers used are not predictions, but simply a range of values used to test the sensitivity of the Cost Benefit Analysis to changes in Weighted Average Cost of Capital.