Autumn Markets Forum

Slido Questions

13/10/22

nationalgridESO

Contents

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FAQ

Introduction

This document responds to the unanswered questions submitted via Slido at National Grid ESO (NGESO)'s Autumn Markets Forum and is correct at the time of publication.

Short Term Priorities

1. **If you initially use £0/MWh for the Coal assets, that will cause SIP to initially be artificially low obscuring the true SIP to market participants.**

   We are working with Ofgem and Elexon to address this with changes to the BSC where the coal contracts are dispatched.

   When the ENCC needs to despatch the coal plant the units will have a PN of £0/MWh to indicate they will not receive any revenue through the settlement processes for the energy they provide, the PN will also indicate to the ENCC the time and duration of the run that will be available. When the units are dispatched the BSAD system will amend the price for the unit to £99999.00/MWh, this would ensure that the SIP is unaffected by the initial £0/MWh PN that was used to trigger the dispatch of the unit. To enable these changes, a BSC mod is being raised to allow NGESO to amend the BSAD numbers which will then flow through the normal Elexon settlement processes.

   We have an open consultation on this pricing methodology. Please direct comments and feedback into that route. https://www.elexon.co.uk/mod-proposal/p447/

2. **Coal-If NGESO withdraw the BOA post event it will remove the vols from offer stack & will affect the calc of NIV. NGESO still risk setting a unrepresentative cashout**

   Post dispatch NGESO will raise a BSCP18 form to allow Elexon to remove the action from settlement, then NGESO will amend the BSAD/ABSVD to include the dispatched volume, system flagged and priced at £99,999. This flows through to Elexon and through their normal process be removed as a high priced system action cannot set cash out

   We have an open consultation on this pricing methodology. Please direct comments and feedback into that route. https://www.elexon.co.uk/mod-proposal/p447/

3. **Interconnector principles-are you exploring flexible allocation of Response & reserve on interconnectors? This could be a "win-win" in capacity for us and EU TSO**

   As part of the BEIS Smart Flexibility plan we have an action to explore removing barriers to entry for different technology types, this will include looking at how Interconnectors can potentially participate.

4. **How quick is very quick on changing the price of the coal units? Will it be done before the first SIP estimate comes out?**

   The BSCP18 process can take multiple days so it is unlikely that this change will be in place before the first SIP estimate comes out. We are looking at all options to expedite this process.

   We have an open consultation on this pricing methodology. Please direct comments and feedback into that route. https://www.elexon.co.uk/mod-proposal/p447/

5. **Re Interconnectors, do the other TSO's have the same approach that they will pay anything to have power flow to them?**

   We are working closely with TSOs to understand their operational concerns and risks and are ensuring we have the right processes and procedures in place to manage a range of scenarios. We have no visibility of what limitations on trading other TSOs have in place.

6. **How will the market know what conversations have been held with other TSO's? Will capacity holders be bound to the same constraints? (if imposed by TSOs)**

   NGESO is engaging with all market parties equitably, including connected EU TSOs, to discuss NGESO's winter and forward plans. Capacity is allocated in accordance with the relevant regulations and protocols which considers the impacts on capacity holders. NGESO does not directly interact with interconnector capacity holders, therefore we suggest contacting the relevant interconnector owners for further information.

7. **Coal is priced at £99,999 (the highest possible in the market) so all interconnector trades will be less than this and therefore should be taken first.**

   The Order of Action slide shows interconnector actions in the everyday actions and therefore these would be taken in advance of the enhanced action of the winter contingency units.

8. **Can you publish written information on how coal units will be instructed and feed into cash out price?**

   We will update once the consultation is closed and Ofgem decision has been made. Updates will be published here: https://www.nationalgrideso.com/winter-operations

9. **How does the cost of coal contracts being recouped through BSUoS work with the capping of BSUoS?**

   BSUoS coal calculations will take account of the Winter Contingency costs from 1st October 2022 until 31st March 2023, the costs are due to be recovered fully within this period. The BSUoS cap will be unaffected by the winter contingency costs, the cap of £40/MWh will be retained. There is no certainty that the cap will be breached with the inclusion of these costs, but ESO will update the market on the utilisation of the cap through the next six months. There is a total facility cost limit of £250m associated with the BSUoS cap, beyond that limit BSUoS will not be capped.

Medium Term Priorities

1. **We've stated in the demand flex service that we can override the EBR article 18 T&Cs – EBR T&Cs are law, we cannot override this**

   NGESO recognises that A18 T&C have to be complied with.

2. **How quickly will Accepted VoIs be fed as DISBSAD into cashout calcs? Will they be part of the indicative cashout calcs, i.e. 20mins past hour?**

   We will be using the assessment data for BSAD, so it is based on forecast rather than outturn. This aligns to the process for other balancing services. BSAD data will be published post event. We will endeavour to do this as soon as possible and will likely be the following day.

3. **Will the tests also feed into cash out?**

   The tests were due to feed into cash out, with the original proposed Guaranteed Acceptance Price (GAP) not due to have a material impact. We are currently working through our options to find the best solution.

4. **How many households are you aiming to get to sign up for the demand flexibility service? Is there a minimum number you need to make it worthwhile?**

   We're aiming to achieve a specific demand reduction of 2GW. The make up of that can come from a mix of domestic, business and industrial consumers. It's not specifically about achieving a set number of households involved but they will play an important role.

5. **Why would people not just sign up on the off chance they have less demand (maybe they are out) but actually take no deliberate action?**

   We are requiring providers who sign-up to have specific Initiation Measures in place which prove end users have signed up to participate for that specific event. On the day of the requirement providers must submit an updated forecast based on end users confirmations.

6. **How are you defining the operational time windows of the real time markets for example in seconds minutes?**

   30 minute Settlement Periods

7. **Can we have an update on where you are with the ABSVD calculations in regards to the R2 reporting?**

This question is in the process of being answered directly with the individual to understand further the background to their question. Once answered, this will be updated in this document.

Long Term Priorities

1. **How do you address -ve resid demand? i.e. net export GSP periods. not just market problem but stability and voltage reg. challenge-which should constrain which?**

   In the first instance, we are proposing nodal pricing be implemented at the transmission level only, with distribution flexibility markets playing a crucial role. We see this question as part of the whole system challenge, requiring effective coordination between ESO and DNOs/DSOs in markets and operations. In our BP2 published this year, we stated our priority to drive towards a whole system approach.

2. **How will NGESO protect the consumer from volatile and extreme price variations within the nodal pricing regime?**

   There exist multiple options open to policymakers in how consumers experience regional wholesale price variation. Very few jurisdictions implementing nodal pricing expose residential consumers to their nodal price, and instead choose zonal pricing and/or to differentiate by type of demand to mitigate consumer distributional concerns. A weighted average zonal price or "opt-in" pricing could effectively mitigate the distributional impact of nodal pricing on GB consumers. Exposure could also be limited to the supply side or be applied to specific demand segments such as I&C. Whilst this would reduce the total potential benefits, we believe that nodal pricing could be justified due to more efficient supply side dispatch and siting alone, as it has been elsewhere. A compelling option that warrants further investigation is to expose consumers to an accurate within-day nodal price profile that reflects local generation output through the day, without exposing the consumer to systemic locational differences in power prices.

3. **How can you level off bills across the market? are you talking about a standard price for all?**

   A compelling option that warrants further investigation is to expose consumers to an accurate within-day nodal price profile that reflects local generation output through the day, without exposing the consumer to systemic locational differences in power prices. This could be achieved via the application of an adjustment factor to bring weighted average power prices in each area to a national average level. The adjustment factor would be negative in higher average nodal price areas and positive in lower average nodal price areas. This option potentially offers a "best of both worlds" solution, whereby the demand-side is incentivised to harness low-carbon, low-cost energy when and where it is available or to reduce system costs, whilst avoiding major distributional impacts for domestic consumers.

4. **A zonal or local spot market of flexibility can end up incentivising time shifts in unavoidable inflexibility, and herded behaviour-how are these being addressed**

   Greater temporal granularity of price signals plays an important role in preventing herded behaviour, which can be achieved in spot markets by introducing shorter settlement periods (e.g. 5 minutes). Greater transparency and information in forward markets (day-ahead market and intraday auctions), which can be improved through central dispatch, along with efficient coordination between ESO and DNOs/DSOs, will play a crucial role in ensuring efficient optimisation of flexibility resources. As the system decarbonises with renewables and DER, and also with digitalisation and growth in data, we expect to be able to evolve market design to effectively address such issues.

5. **In other markets with central dispatch and nodal pricing it is difficult to trade positions intraday which could undermine flexibility. What are the ESOs views?**

   Other markets with central dispatch and nodal pricing tend to have a ‘two settlement’ approach, with a financially binding day-ahead market and a physically binding ‘real time’ spot market. This construction has proved effective for integrating flexible resources, but the timing still reflects the needs of traditional fossil fuel plant, which need to be warmed up at day-ahead stage. We see opportunity in a GB context for reconsidering what the optimal timing for the various wholesale market auctions would be in the context of high renewables penetration and flexible demand. This could, for example, mean increasing the number of intraday auctions or implementing continuous trading. We believe the structure of intraday trading is an area for significant potential innovation in REMA and would welcome your thoughts/ input.