# Market Facilitator Governance Consultation Response Form

Publication date: 18 September 2025

Please use this response form to respond to the Market Facilitator Governance Consultation which was published on Thursday 18 September 2025.

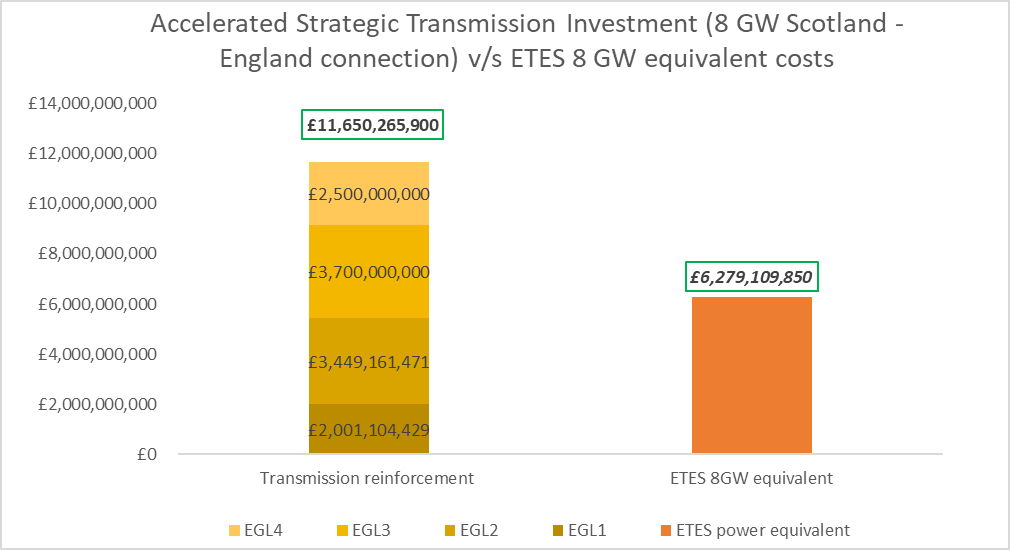
Please submit your response to [flexibility@ofgem.gov.uk](mailto:flexibility@ofgem.gov.uk) by 5pm on Thursday 16 October 2025.

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| Respondent details |
| Company name: Exergy3 |
| Company type (e.g. DNO, flexibility service provider): OEM/Flexibility service provider |
| Date of submission: 15/10/25 |

**Questions**

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| Annex A – Draft Governance Framework Document |
| Q1. Do you agree that the Draft Governance Framework Document clearly defines the scope, roles & responsibilities and deliverables of the Market Facilitator? If not, what would you change and why? |
| No, would add explicit scope for industrial demand turn-up via Electro-thermal energy storage (ETES). The Market Facilitator’s remit should explicitly cover enabling ETES to:   1. Provide high-temperature (up to 1200 °C) process heat. 2. Act as flexible, dispatchable demand to absorb surplus renewable generation. 3. Act as a flexible asset for demand turn down across the full spectrum of flexibility services 4. Relieve binding transmission constraints, particularly B6 and B8.   Coordination with TSOs and DNOs Network Options Assessment (NOA) should be mandatory so that demand turn-up is assessed as an alternative to reinforcement as a “network option.” While laying cables increases the delivery capacity of a system, this doesn’t necessarily translate into improved capacity or utilisation of that capacity. This coordination should also consider cost allocation, including options that enable capital investment and recovery by industrial users or flexibility providers where this delivers better value for consumers than transmission reinforcement alone.  Enable large industrial participation: The Market Facilitator should provide streamlined registration, metering and dispatch so industrial users can participate without prohibitive transaction costs.  Operational transparency at key boundaries: Publish boundary-specific operational signals (e.g. day-ahead B6/B8 flows) to enable automated ETES response, avoiding and reducing skip rates.  Deliverables to add:   1. A plan to develop standard products (including LCM expansion) for constraint-driven demand turn-up. 2. An annual report on constraint-cost savings attributable to demand-side solutions. 3. A means of capital reallocation where in the customer’s interest via NOA, allowing capital to be invested in flexibility affording maximum utilisation and capacity (rather than soley energy delivery capacity). 4. A time-bound proposal for a “Demand for Constraints” product to formalise payment for demand increases in constrained zones. |
| Q2. Do you agree with the appeals process and the proposed performance arrangements for Elexon as the Market Facilitator? If not, what would you change and why? |
| No, specific adjustments to ensure industry participation delivers value to consumers. KPIs should include:   1. Constraint-cost reductions attributable to demand-side measures (reported by boundary, including B6/B8). 2. Industrial participation metrics (registered sites; delivered MW/MWh of demand turn-up). 3. Onboarding efficiency: end-to-end registration lead time and standardised participation charges per site. 4. Timely, reliable publication of boundary signals (e.g. day-ahead B6/B8). |
| Q3. Do you have any other comments on the Draft Market Facilitator Governance Framework Document? |
| 1. Ensure participation of technologies on equal terms such as batteries or Hydrogen, with ETES explicitly recognised in eligibility, baselining and settlement. 2. Publish boundary-specific operational signals and settlement data via open, machine-readable APIs so ETES sites can automate response. 3. Formalise joint working with NESO and DNOs focused on relieving constraints at B6/B8 (and other binding boundaries). 4. Reflect ETES in the government’s low-carbon flexibility roadmap and undertake a targeted awareness programme so ETES can participate on equal terms and at scale. |
| **Annex B – Draft Market Facilitator Impact Assessment** |
| Q1. Do you agree that we have, to a reasonable extent, identified and understood the potential costs and benefits of implementing the Market Facilitator? |
| No. We recommend the final Impact Assessment includes:   1. A scenario where 20–30% of current constraint volumes are absorbed by industrial ETES demand turn-up and the value of incentives required to achieve this. 2. A direct comparison of capacity and constraint-management savings through the adoption of flexible assets such as ETES (hundreds of millions per year) versus capital reinforcement costs (billions, with long lead times). 3. An assessment of employment and competitiveness benefits of industrial participation.   This would provide a fuller view of the net benefit to GB consumers and the economy and is aligned with Ofgem’s statutory objective to protect the interests of existing and future consumers. |
| Q2. Do you agree that we have, to a reasonable extent, identified and understood the potential impacts of the introduction of the Market Facilitator? Are there any unintended consequences of implementing the Market Facilitator that we have not identified? |
| No, add analysis of employment and industrial competitiveness, including retaining operations in Scotland and northern England (often anchor employers) and improving UK industry’s international competitiveness by accessing surplus, low-cost, green electricity.  To address barriers to industrial electrification and ETES uptake, the UK should:   1. Explore expanded exemptions from policy costs for ETES users (e.g. CCL, RO, FiT, CfD “supercharger”, and future potentially crippling costs from Nuclear and Transmission charges. 2. As a short term solution, give industry exemption from levies for any consumption over 2GWh/per annum where flexible assets are installed. Do not limit this to EII users where 20% of revenue is spent on energy, this would be cleaner and easier to implement. 3. Introduce time-limited bridging mechanisms (per-unit support for heat storage) until electricity/gas policy costs are rebalanced.   Additionally, assess the consumer impact of enabling capital cost recovery by flexibility providers (e.g. ETES providing constraint relief) in place of, or alongside, transmission reinforcement, where this reduces total system cost and near-term constraint spend. |
| **Annex C – Licence Changes** |
| Q1. Do you agree with the updated proposed Definitions to be added to the Standard Conditions of the Electricity Distribution Licence and the ESO Licence? Are any changes required? |
| No, agree broadly, with two clarifications:   1. Electro-thermal energy storage (ETES) and industrial demand turn-up should be explicitly included in the definitions of flexibility services and assets. 2. Clarify that “constraint management” includes demand increases in constrained export zones (not only demand reduction or curtailment). |
| Q2. Do you agree with the updated proposed licence condition clauses for Flexibility Market Rules to be added to both licences? Does the current drafting deliver the policy intent? Do you have any suggested changes? |
| No, while agree with adding Flexibility Market Rules duties, to deliver the policy intent, the licence should require the Market Facilitator to:   1. Develop standard products for constraint-driven demand turn-up, including LCM expansion, with ETES explicitly eligible and participation on at least equal terms with batteries. Noting that ETES has lower degradation and higher reliability. 2. Publish boundary-specific operational signals (e.g. day-ahead B6/B8 flows) to enable automated industrial response. 3. Expand the LCM to all constrained zones as alternative/replacement to balancing mechanism. 4. Coordinate with NESO’s NOA so demand turn-up is assessed alongside reinforcement as a “network option.”   Streamline registration, metering and dispatch for large industrial consumers to cut transaction costs and reduce time to first dispatch. |
| Q3. Do you agree with the updated proposed licence condition clauses for implementation monitoring to be added to both licences? Does the current drafting deliver the policy intent? Do you have any suggested changes? |
| No, add the following minimum metrics:   1. Annual constraint-cost savings from demand-side solutions (boundary-level). 2. Industrial participation (number of sites/locations; MW/MWh of demand turn-up). 3. Publication performance of boundary signals (accuracy, timeliness and availability). 4. Onboarding metrics (registration lead time; indicative transaction costs). |
| Q4. Do you agree with the updated proposed licence condition clauses for Market Facilitator input into NESO service design to be added to the ESO Licence? Does the current drafting deliver the policy intent? Do you have any suggested changes? |
| No. Strengthen to require service design that explicitly procures demand turn-up for constraint relief/curtailment avoidance and aligns qualification, baselines and dispatch across local and national services to cut industrial transaction costs. Prioritise B6/B8 pilots. |
| Q5. Do you have any additional comments or suggestions? |
| 1. Establish a “Demand for Constraints” product to formalise payments for demand increases in constrained zones. 2. Publish a multi-year roadmap for constraint-driven flexibility that includes ETES pilots and scale-up. 3. Work with government to reflect ETES in the national low-carbon flexibility roadmap and run a targeted awareness programme for industrial ETES participation. 4. Support rebalancing of policy costs: consider expanded exemptions for ETES users (e.g. CCL, RO, FiT, CfD “supercharger”) and time-limited, per-unit support for heat storage until electricity/gas policy costs are rebalanced. 5. Enable appropriate cost allocation and capex recovery for flexibility providers/industrial users where this lowers whole-system costs relative to transmission reinforcement. |

**Appendix A: Deployment costs comparison of 8 GW capacity grid extension v/s 8 GW ETES**



EGL1 & EGL2 Projects in development (to be delivered by 2028-2029).

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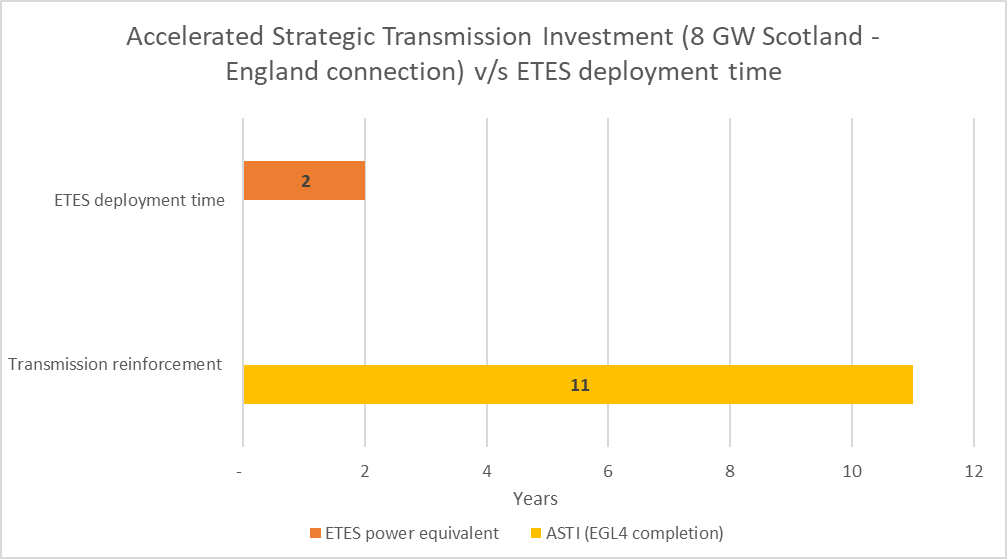
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*\*Indicative price for EGL3 (Hitachi Energy) and EGL4 (Siemens Energy).*

*Figure 1: Deployment costs comparison between ASTI and ETES alternative.*

Cost comparison of the deployment costs of the ASTI project (EGL1, EGL2, EGL3, and EGL4 components) versus the equivalent of 8 GW of industrial ETES.

**Appendix B: Deployment timeline comparison of 8 GW capacity grid extension v/s 8 GW ETES**



2033: EGL4 deployed and operational

*Figure 2: Deployment time comparison between ASTI and ETES alternative.*

Comparison between deployment time of ASTI and the Industrial ETES solution. For this comparison, ASTI considers its kickoff date to be the 15th of December 2022 (the publication date of the ASTI decision) and is considered finished when the EGL4 has reached its deterministic delivery date (the 13th of December 2033). ETES deployment time is based on historical data plus assumed economies of scale.