Long Duration Energy Storage (LDES) Service Provision

Procurement Mechanism Recommendations

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Executive Summary

Long Duration Energy Storage (LDES) can play an important role in supporting the transition to a highly renewable electricity system and the delivery of Ireland's Climate Action Plan (CAP)[1] electricity system related targets. LDES capability and targeted service delivery can support the management of increasing volumes of variable renewable generation by providing the electricity system with a source of flexibility to manage the variability of indigenous renewable generation, reduce dispatch requirements and contribute to secure system operation.

EirGrid's Call for Evidence on LDES,[2] published in October 2023, gathered initial views from industry on:

- the need for LDES in Ireland and the benefits it could offer;
- the need for a procurement mechanism to incentivise LDES and address barriers to investment;
- various proposed procurement mechanisms that could be introduced; and
- risks of various procurement mechanisms.

The Electricity Storage Policy Framework (ESPF),[3] published by the Department of Climate, Energy and the Environment (DCEE) in July 2024, established a policy framework supporting the integration of long duration energy storage (LDES), and in Action 6, highlighted a requirement to facilitate an immediate procurement of up to 500 Megawatt (MW) of LDES services. LDES in the context of Action 6 refers to a storage duration of equal to or greater than 4 hours discharge of electricity back to the Transmission System.

In line with this policy framework and following detailed engagement with the Commission for Regulation of Utilities (CRU), EirGrid published a consultation on a proposed procurement mechanism and operational considerations for LDES service provision in Ireland and conducted an industry webinar. The consultation closed on 24 November 2025 and received 38 responses.

While there was broad support for the introduction of a procurement mechanism, stakeholders raised a range of views on key design elements, including procurement volume, contract structure, operational constraints, and the balance between investor certainty and market participation.

This Recommendations Paper sets out EirGrid's final position on the immediate procurement of an LDES service, reflecting consideration of stakeholder feedback and the TSO's assessment of system requirements that LDES services can help meet. The proposed approach is intended to meet the TSO's requirements, provide certainty to industry on the initial procurement volume, while recognising that further development of a separate and more enduring LDES framework may be required over the coming years.

EirGrid's final position retains the core elements of the original consultation proposal, with refinements introduced to improve clarity, transparency and deliverability. The recommended procurement framework includes:

- A phased, technology-neutral approach, enabling delivery of an initial tranche of LDES service provision while allowing potential future rounds to reflect market, policy and system evolution.
- A service-based contract structure incorporating a Trading Envelope (TE), revenue floor and revenue-sharing mechanism, designed to balance investment certainty with efficient market participation and consumer value.
- Procurement of up to a maximum volume of 500 MW (minimum of 4-hour duration capability) of service provision
- Requirement for LDES service providers to progress relevant LDES eligible assets through the normal ECP connection processes (i.e. no dedicated LDES connection process will be enabled), with a

[1] https://www.gov.ie/en/department-of-climate-energy-and-the-environment/publications/climate-action-plan/
[2] LDES Call for Evidence EirGrid.pdf
[3] DCEE - Electricity Storage Policy Framework

Connection Offer required at Qualification stage and Connection Agreement required at Tender stage.

- Tender weighting criteria that provide greater weighting to connection types that maximise the utilisation of existing connection points, and to projects that can mitigate dispatch down and provide energy arbitrage at their proposed connection locations.
- Clear eligibility and procurement criteria aiming to achieve contract award to successful LDES service providers in 2028 (Target Scheme Go-Live date to be confirmed).
- Deliverability assessment undertaken by EirGrid during the tender assessment process that will determine whether LDES service providers due to connect to the network can feasibly meet the Target Scheme Go-Live Date

The proposed Trading Envelope (TE) model (renamed from the original Operational Envelope terminology) is a central component of the service, intended to align LDES operation with system needs by introducing ex-ante limits to traded positions at certain times, with the objective of minimising the need for redispatch. While this approach introduces trading restrictions for participating assets, it is designed to ensure that LDES delivers measurable system benefits in return for revenue support.

The revenue mechanism combines a competitively determined revenue floor with an upside sharing arrangement, providing a level of revenue certainty while maintaining incentives for efficient market participation. The design seeks to balance the need to support investment in LDES with the requirement to protect consumer value.

This paper is submitted to the CRU for consideration, alongside a detailed LCOS methodology paper prepared by independent consultants that underpins the revenue floor limit.

Following the publication of the CRU decision on this Recommendation Paper, and informed by the CRU decisions, EirGrid will issue a second consultation document that will address detailed contractual arrangements for the procurement of LDES in Ireland, which will lead to a further Recommendation paper submission to the CRU. Once the contractual arrangements are finalised by CRU decision EirGrid will progress toward procurement. It is anticipated that procurement will commence in 2027.

Overview of TSO Recommendations

Table 1 provides an overview of the recommendations which are contained in this paper.

Table 1 Overview of recommendations

Section	Category	TSOs' Recommendations	Change from Consultation Proposal
3.3	Procurement design	Implement a phased, technology-neutral procurement framework. Initial procurement up to a maximum of 500 MW. A qualification system approach will be used.	Overall procurement design relatively unchanged from the original proposals. Volume range increased from min 201-300MW to a max of 500MW See section 6.3 for more details.
4.3	Eligibility criteria	Retain ≥ 4-hour duration, MEC/MIC 1:1 ratio, minimum/maximum capacity thresholds, Connection Offer at qualification, Connection Agreement at tender stage, full planning	Connection requirement refined; other core eligibility criteria retained.

Section	Category	TSOs' Recommendations	Change from Consultation Proposal
4.3	Benefits of co-locating LDES	Recognise and incentivise co-location of LDES with existing connections due to benefits including Improved delivery times by building on existing connections, relieving network constraints and curtailment by locating LDES closer to renewables and more efficient use of connection bays The required minimum volume of co-located renewable generation that would enable qualification as a co-located LDES site is 30MW of transmission connected renewable generation, in line with existing ECP processes.	No change. Clarification provided.
4.3	Connection location	Evaluate and incentivise LDES capability based on pre-existing ECP nodal constraint and dispatch down assessments, whereby tendering LDES assets will be assessed based on their proposed MW and MWh capability on their proposed location within ECP analysed nodes and projected levels of wind and solar re-dispatch.	Clarification and more detail on methodology provided.
4.3	The Trading Envelope model	Proceed with a TE design as it offers the greatest value to consumers in a market led system with a single unconstrained market price, while also maintaining market access and revenue stacking opportunities for LDES contracted assets.	Further clarification provided on implementation and obligations.
5.3	Trading envelope - Definition	Define TEs as dynamic, time-based import/export limits set at D-1 to align LDES operation with system need and minimise redispatch. The TSO will set individual TEs for each LDES asset at 10 am D-1 covering a 24-hour horizon of the Trading Day, D, allowing LDES service providers to trade in day-ahead markets to align with the time-specific LDES energy import/export limits. The TSO expects to set TEs that, for example, ensure LDES assets do not discharge during periods in which wind is being curtailed, or charge during periods of peak demand or system scarcity.	No change.
5.3	Service payment / compensation: Revenue floor	Implement a revenue floor determined through competitive bidding, capped by a Levelised Cost of Storage (LCOS)-based limit with annual ex-post assessment and true up. Revenue floor: Defined through pay-as-bid submissions during bidder selection. There will	Further detail will be provided in the LCOS methodology paper - to be published separately.

Section	Category	TSOs' Recommendations	Change from Consultation Proposal
		be a bid limit placed on all bids informed by an LCOS assessment, undertaken by independent consultants. It is proposed that duration specific bid caps will apply to tendering assets. Revenue floor bidding limit: Bidding limit placed below LCOS. Ex-post true up: The revenue floor will be assessed on an annual basis.	
5.3	Service Payment / Compensation: Revenue Sharing	A revenue sharing ratio will be applied to revenues that exceed the revenue floor level set at 70:30 (LDES service provider: TUoS).	No change.
5.3	Service Payment / Compensation: Non-compliance charges & Trading Non-activity Scalar	Contracted LDES service providers will be subject to non-compliance charges for breaching TE dynamic export/import limits. A trading non-activity scalar will be applied and reduce the revenue floor where asset cycling falls materially below expected levels.	Further clarification provided.
5.3	Scheme Duration	Set scheme duration at ten years, reflecting the immediate procurement requirement and anticipated evolution of market arrangements (e.g. EU integration post Celtic). Early service delivery can be facilitated if projects are operational before the scheme go-live date, further detail will be provided in the contractual consultation.	No change.
5.3	Provision of other services and revenue stacking opportunities	Retain full access to all SEM markets subject to TE compliance.	No change. Additional clarification on compliance checks and service interactions provided.
6.3	Qualification criteria	Pass/Fail approach against company-specific criteria and project-specific technical requirements.	Further clarification provided.
6.3	Tender criteria	Tenderers will be assessed against a series of Pass/Fail eligibility requirements and then scored against Cost (50%), Impact (30%) and Connection Method (20%) criteria. Scoring will assess revenue floor bids, the potential reductions in renewable dispatch down and availability to do energy arbitrage (based on ECP 2.5 hourly dispatch down modelling), and the efficiency of the proposed connection arrangement.	Amended following consultation feedback. See details in Section 6.

Section	Category	TSOs' Recommendations	Change from Consultation Proposal
6.3	BAFO, grid connection assessment and deliverability	The highest-ranked projects will proceed to BAFO stage, where EirGrid will undertake a grid connection deliverability assessment and determine a feasible Target Energisation Date for each shortlisted project. Projects that have been evaluated to have a feasible target energisation date that can meet the final target scheme go -live date will be invited to submit a BAFO, which will determine the final project rankings and selection outcome.	This step has been introduced to ensure that successful tenderers are able to submit final bids based on a realistic and deliverable energisation date, to ensure timely service delivery.

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Abbreviations

Abbreviation	Definition
BAFO	Best and Final Offer
BESS	Battery Energy Storage System
BM	Balancing Market
CBA	Cost Benefit Analysis
CAP	Climate Action Plan
COD	Complex Offer Data
CRU	Commission for Regulation of Utilities
DAM	Day Ahead Market
DASSA	Day-ahead system service arrangements
DCEE	Department of Climate, Energy and the Environment
DD	Dispatch Down
DSO	Distribution System Operator
DTUoS	Demand Transmission Use of System charges
ECP	Enduring Connection Policy
ESPF	Electricity Storage Policy Framework
ESPS	Energy Storage Power Station
EU	European Union
FASS	Future Arrangements for System Services
FPN	Final Physical Notification
FSR	Foreign Subsidies Regulation
GFM	Grid Forming
IRT	Investment Rate Threshold
LCIS	Low Carbon Inertia Service
LCOS	Levelised Cost of Storage
LDES	Long Duration Energy Storage
LTESA	Long-Term Energy Service Agreement (Australia)
LTS	Long-Term Scheduling
MEC	Maximum Export Capacity
MIC	Maximum Import Capacity
MW	Megawatt
MWh	Megawatt-hour
NZIA	Net-Zero Industry Act
OBA	Open Book Accounting

Abbreviation	Definition
PPA	Power Purchase Agreement
PN	Physical Notification
QEX	Ex-post Quantity
RA	Regulatory Authority
RED III	Renewable Energy Directive III
RES	Renewable Energy Source
RTC	Real Time Commitment
RTD	Real Time Dispatch
RTE	Round Trip Efficiency
SDP	Schedule and Dispatch Programme
SEM	Single Electricity Market (Ireland and Northern Ireland)
SOC	State of Charge
SoH	State of Health
TE	Trading envelope
TOD	Technical Offer Data
TSO	Transmission System Operator

1 Introduction

1.1 EirGrid

EirGrid is the Transmission System Operator (TSO) in Ireland, managing the electricity transmission network and the flow of power from generators to consumers. Electricity is generated from renewable and fossil fuel sources at sites across the island of Ireland and is also imported and exported through interconnection with other jurisdictions. The high-voltage transmission network transports electricity to high demand centres, such as cities, towns, and industrial sites.

EirGrid is at the forefront of the integration of high volumes of non-synchronous renewables into the transmission system. In line with government ambitions, we have a responsibility to facilitate the transition to a low-carbon energy system while continuing to ensure that the electricity transmission system operates securely and efficiently.

1.2 Consultation on the Procurement Mechanism

The purpose of our consultation on the procurement mechanism for LDES was to seek industry views on our proposed approach to:

- The key services that LDES is intended to deliver;
- The proposed qualification system framework;
- The proposed pre-qualification requirements;
- Operational considerations to maximise the value of the contracted service capability; and
- Market interaction considerations for LDES service providers.

1.3 Structure of the Recommendations Paper

This paper addresses feedback received from stakeholders and sets out EirGrid's recommendations for the LDES procurement mechanism.

It is structured as follows:

- **Section 2 – Responses to the consultation** provides a list of respondents to the consultation and an overview of general feedback received.
- **Section 3 – Key drivers and stakeholder engagement** summarises respondents' views and the TSO's response on the key drivers for LDES procurement, the proposed procurement design approach and engagement to date.
- **Section 4 – LDES considerations** provides an overview of responses and TSO recommendations on eligibility criteria, co-location considerations, locational benefits, market integration, and the proposed Trading Envelope (TE) (previously referred to as an Operational Envelope) model.
- **Section 5 – LDES service detailed considerations** provides an overview of responses and TSO recommendations on scheme duration, notice periods, operational obligations, and the floor-and-share mechanism.
- **Section 6 – LDES procurement arrangements** provides an overview of responses and TSO recommendations on procurement design, qualification and award criteria, scoring, and alignment with wider EU frameworks such as the NZIA.
- **Section 7 – Operational considerations** provides an overview of responses and TSO recommendations on implementation, TE parameters and system operation issues.
- **Section 8 – Additional considerations** presents any additional points raised for consideration by the TSO.
- **Section 9 – Next steps** provides an overview of next steps.

2 Responses to the consultation

The consultation on the LDES procurement mechanism closed on 24 November 2025. In total, 38 responses were received. The non-confidential respondents are listed below:

- Aer Soleir
- Amarenco Solar
- Aughinish Alumina
- Bord Gais Energy
- Bord na Mona
- Cian Murtagh
- EAI
- EDF Power
- Elgin
- Energia
- Energy Dome
- Energy Storage Ireland
- Engineers Ireland
- EP Dublin Energy Ltd
- ESB Generation & Trading
- ESB Networks
- Flexible Power Solutions
- Form Energy
- FuturEnergy
- HydroStor
- IESA
- Invinity Energy Systems
- LDES Council
- Lirion Power
- NTR Asset Management Europe
- PWC
- Siga Hydro
- Solar Ireland
- SSE

Note that all non-confidential responses have been published on the EirGrid consultation portal.[4]

[4] Long Duration Energy Storage (LDES) Procurement Mechanism Consultation - Submissions | EirGrid Consultation Portal

3 Key drivers and stakeholder engagement

3.1 Summary of consultation

3.1.1 Key drivers influencing LDES procurement

As electricity systems evolve and integrate larger volumes of renewable and weather dependent electricity generation there is an increasing recognition of the need to capture renewable generation that is either in excess of demand requirements or that cannot be accommodated onto the relevant system for technical reasons. Long duration energy storage technologies can help to minimise the loss of such generation by consuming electricity during high levels of renewable output and exporting electricity back to the grid and displacing the need for conventional generation at times of lower renewable output.

Existing EU Directives[5], relevant Irish Statutory Instruments[6], the Irish Climate Action Plan[7], the Irish Government Electricity Storage policy framework[8] all provide guidance on the development of services that support TSOs in the management of increasingly complex, diverse and dynamic power systems. The Renewable Energy Directive III[9] (RED III) outlines that "…To that end, Member States should establish a framework that includes market-compatible mechanisms to tackle the remaining barriers to having secure and adequate electricity systems fit for a high level of renewable energy, as well as storage facilities fully integrated into the electricity system."

However, TSOs are currently restricted in their capability to directly operate storage assets as per Article 54 of the 2019/943 Electricity Market Directive (and updated version[10]) and Article 23 of S.I. No 20/2022[(2)]. Additionally, Article 40 of the proposed Network Code on Demand Response[11] will also prohibit direct operation of such assets by TSOs, with clear requirements clearly that energy storage services shall be market based and competitive, and storage assets must be able to fully participate in wholesale and ancillary service markets only with derogation and regulatory authority approval (also required under the Electricity Market Directive) shall Member states allow system operators to own, develop, manage or operate energy storage assets.

Therefore the European and Irish policy context is clear, EirGrid as TSO is not permitted to own, develop or directly operate energy storage assets, but should ensure that appropriate service design and market compatible mechanisms are utilised to tackle barriers that exist to the integration of adequate energy storage capabilities to manage increasing levels of renewable energy and complex system operations. Procurement of services such as that proposed under this LDES scheme needs to be targeted to service delivery by long duration storage assets.

In addition, there are also technical system requirements that can be supported by the integration of LDES assets. As EirGrid progresses its Operational Policy Roadmap[12] we are moving towards a system that can accommodate up to 100% non-synchronous generation, but there are several significant milestones required before we can securely operate the system without the technical system supports that we currently rely on from conventional synchronous generators. This means that at times we have to reduce non-synchronous renewable generation to ensure we can maintain sufficient technical support services from conventional

[5] EU) 2024/1711[5] (amending Directives 2018/2001 and 2019/944) and Regulation (EU) 2024/1747[5], (amending Regulations (EU) 2019/942 and (EU) 2019/943),
[6] S.I. No. 20/2022 - European Union (Internal Market in Electricity) Regulations 2022
[7] https://www.gov.ie/en/department-of-climate-energy-and-the-environment/publications/climate-action-plan-2025/
[8] https://www.gov.ie/en/department-of-climate-energy-and-the-environment/publications/electricity-storage-policy-framework/
[9] EU 2023/2413 Renewable Energy Directive
[10] DIRECTIVE (EU) 2019/944 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU
[11] ACER_Recommendation_01-2025_DR_NC-Annex1_Amended_DR_NC.pdf
[12] Operational Policy Roadmap 2025-2035 | EirGrid

generation. The introduction of LDES on to the system could help to offset that reduced renewable output and also help manage occasions of local network congestion.

One other main driver of this procurement approach is to ensure investment certainty is provided to industry for LDES development. The majority of responses to the Call for Evidence from 2023 indicated that there is a missing money issue regarding the development of new long duration energy storage projects. Respondents indicated that a lack of certainty of revenue from current markets results in a shortfall of LDES development. Therefore, this initial procurement process of LDES with its proposed TE model, revenue floor and revenue sharing remuneration mechanism should help to provide the revenue certainty LDES investors have requested.

3.1.2 Stakeholder engagement to date on the Procurement Recommendations

As mentioned above the Shaping our Energy Future Roadmap was published in July 2023, prompting a Call for evidence on LDES in October. A summary of responses received was published in March 2024[13].

The Consultation paper on the Procurement Approach was launched in October 2025, with an online webinar on the Consultation paper held in November 2025.Over 170 participants joined the webinar and subsequently EirGrid issued a Questions and Answers document responding to questions and feedback received during the webinar[14].

Separate stakeholder engagement to date has been conducted including interaction with departments and regulatory authorities, the Irish DSO, industry representative bodies, peer TSOs in the UK, Canada and Australia, and industry participants.

3.2 Summary of consultation responses

The following questions were asked in relation to key drivers influencing LDES procurement and stakeholder engagement to date:

Q1: Do you agree with our assessment in Section 1.2 of key drivers that support the procurement of LDES assets?

Q2: Do you support the overall procurement design approach and opportunities for engagement and industry feedback through this and future consultations?

3.2.1 Q1: Do you agree with our assessment in Section 1.2 of key drivers that support the procurement of LDES assets?

31 stakeholders responded to this question. The majority of respondents agreed with the TSO's assessment of key drivers that support the procurement of LDES assets, with a large number of respondents stating that reducing dispatch down of renewables is one of the most important drivers of LDES procurement. Many respondents also stated that LDES procurement will be beneficial for system security and flexibility. A number of respondents highlighted that decarbonisation and increased integration of renewable energy are also drivers for LDES procurement; and that a procurement mechanism for LDES is necessary given the 'missing money' issue for storage.

While the majority of respondents agreed with the provided assessment, some expressed concerns that there was a lack of quantified economic analysis supporting the assessment, and requested further evidence to justify LDES procurement, including detailed forecasts for the volume of renewable surplus in the future. One respondent cautioned that trading limitations at this early stage could risk distorting natural market evolution given the regulatory and system changes underway and requested that EirGrid provide further justification.

[13] https://cms.eirgrid.ie/sites/default/files/publications/EirGrid-Response-Call-for-Evidence-on-Long-Duration-Energy-Storage-LDES-Mar-24.pdf
[14] Long Duration Energy Storage (LDES) Procurement Mechanism Consultation | EirGrid Consultation Portal

3.2.2 TSO response

The TSO welcomes the strong engagement from respondents and notes the broad recognition of the need to procure LDES assets. The TSO also acknowledges the concerns raised and will seek to address them in more detail throughout this paper.

3.2.3 Q2: Do you support the overall procurement design approach and opportunities for engagement and industry feedback through this and future consultations?

Eight stakeholders generally agreed with the overall procurement design, noting that a procurement mechanism is necessary given the 'missing money' issue and acknowledging the urgency. Many stakeholders agreed and suggested additional scope items or made additional recommendations, including:

- adding an investment rate threshold to target projects in early stages of development,
- aligning the definition of hybrid assets with CRU's definition,
- recognising the higher value of LDES of >8 hours duration,
- including climate targets in the objectives,
- including all flexibility types and ensuring criteria do not undermine technology neutrality,
- considering locational incentives based on an assessment of grid curtailment,
- selecting eligibility criteria that reflect whole-of-system benefits.

Nine stakeholders agreed in principle with need for a procurement mechanism but felt more ambition is required in terms of both volume (i.e. 500 MW) and storage duration (i.e. +8hrs) in meeting the ESPF objectives. Stakeholders highlighted the risks of relying on a small number of projects and proposed that a greater number of projects would enhance resilience.

Many stakeholders expressed concerns that the proposed mechanism is not a suitable enduring regime. Some stakeholders supported the mechanism on an interim basis for an initial procurement phase. Noting that it is generally positive that LDES is progressing, several stakeholders felt LDES procurement must accelerate to ensure delivery in a timely manner and to ensure that the process is fit for system needs. Stakeholders were concerned that the procurement mechanism is overly concerned with short-term issues and risks locking in short duration assets. Some stakeholders strongly felt that the opportunities for learning from an initial procurement round is limited in the timeframe, and delivery of an enduring solution should be prioritised. While some stakeholders felt that a more sophisticated procurement approach would be required on an enduring basis, other stakeholders felt that the proposed design approach could be acceptable if significant clarifications and refinements were made.

Most stakeholders expressed opposition to the proposal to procure 201 MW in an initial phase of procurement. Stakeholders across segments raised similar concerns. Most stakeholders queried the rationale behind the initial procurement of 201 MW. Many stakeholders noted that the delivery schedule does not permit lessons learned to be applied in time for subsequent procurement rounds before 2030. Stakeholders submitted that the proposed pace and scale do not reflect the urgency of the need or the realities of lead time required for projects. Many stakeholders strongly supported increasing the minimum auction volume from 201 MW to the 500 MW guide volume from the ESPF. Stakeholders felt that procurement of 201 MW is insufficient to achieve the target emissions reductions by 2030.

Stakeholders requested timelines for further procurement after 2030 and an indication of EirGrid's approach after procurement of the initial 500 MW in order to facilitate investor confidence and project pipelines.

One stakeholder suggested strategic procurement of LDES would be better served by a tolling arrangement. One stakeholder felt that under the current proposal, 4hr batteries would score more highly in constraint locations where they would serve the least benefit. Some stakeholders noted the need for the procurement to be technology neutral in order to maximise competition.

Opportunities for engagement and industry feedback

Twelve stakeholders provided feedback on the opportunities for engagement. Feedback on the engagement approach was positive. Stakeholders generally appreciated the outreach and engagement, but some issues with platforms used were raised including regarding the Slido character limit and the formality of consultation portal.

3.2.4 TSO response

The TSO welcomes the comments and views of industry. The Irish Government Electricity Storage Policy Framework[15] is provides a supportive policy context for the procurement of up to 500 MW of 4 hours duration LDES; "*This policy framework is mindful of the challenge that bringing a first of kind electricity storage 'route to market' presents for both the RA and the TSO. In order to expedite matters this policy framework fully supports through Action #6 the procurement of up to 500 MW of (long duration*) electricity storage on to the transmission grid system, with the potential for subsequent procurement round(s) pending a review process to ensure the proper functioning of the transmission grid system. The development of this electricity storage product is a high priority for this Government and the DECC will, through the Accelerating Renewable Electricity Taskforce, promote the rapid progress of this product throughout 2024 and 2025*". [16] EirGrid has been cognisant of the ESPF objectives in designing and proposing the approach outlined in the consultation.

We welcome the detailed responses in regard to our proposals and have addressed the aspects called out above in more detail throughout the paper. In particular we understand the concerns that several industry participants have in relation to the establishment of a procurement mechanism that may not be tailored to achieving a more enduring framework for >4 hr duration energy storage assets, and also, energy storage assets (e.g. thermal storage) that may support the reduction of dispatch down but not deliver electricity return to the transmission system. However, to advance an immediate procurement EirGrid considers that the service-based procurement and the main features of our original proposals remain valid.

We recognise the concerns raised by several stakeholders that the TE approach may somewhat limit wider and future market participation, however we consider that within the current wholesale market design there is no specific ability for the TSO to signal locational constraints. It is for this reason that we propose that successful LDES contracted assets will be required to comply with a location and LDES asset specific TE in the delivery of the LDES service. We remain committed to ensuring revenue stacking capability across all services.

In relation to the 201 MW minimum, we take on board the concerns that many respondents raised in relation to the overall objective of the procurement and the ability to incorporate learnings into any subsequent phase of procurement. This was included in the original proposal as a means of minimising the risk of introducing an inefficient cost to the consumer and of introducing opportunities for market manipulation. However, based on the overarching need to ensure we have sufficient flexible capacity to mitigate dispatch down events, the strong industry feedback and with the overall structure of the LDES procurement design we are now recommending that we procure up to 500MW.

In relation to the stakeholder engagement, we welcome the positive feedback and accept the suggestions for improvements.

3.3 TSO recommendation

EirGrid's recommendations in relation to the overall procurement approach for this immediate procurement phase are as follows:

We recommend:

- A procurement process that aims to deliver

[15] Irish Government Electricity Storage Policy Framework
[16] See Action 6, Section 3.7.4

    - An LDES service-based approach – i.e. the procurement approach will select those providers that are the most efficient in providing the service; an investment rate threshold will not be a consideration for this procurement
    - 500 MW maximum volume procured of 4-hour minimum duration LDES service provision (no max duration specified – i.e. final MWh volume will be determined as a result of the tender procedures).
    - A robust examination of deliverability of tendering projects to ensure the delivery of the LDES service in a timely manner (see Section 6 for more details)
- Establishment of a Qualification system to help determine eligible projects that have met all relevant initial milestones and ensure only viable projects can proceed to tender.
- A technology-neutral approach, where qualified providers have been deemed to meet the minimum requirements.
- Facilitation and encouragement of revenue stacking across all available markets and revenue streams, within the bounds of the TE.

4 LDES considerations

4.1 Consultation proposal

4.1.1 Eligibility criteria

The eligibility criteria proposed in the consultation for phase 1 of LDES procurement are summarised in Table 2.

Table 2 Proposed eligibility criteria

Criteria	Description
Duration of import and export capability	The storage asset must be capable of discharging ≥4 hours of electricity continuously at its nameplate power capacity rating (and in line with its contracted MEC) over the length of the scheme duration. Similarly, the asset must be capable of charging for ≥4 hours of electricity continuously at its nameplate power capacity rating (and in line with its contracted MIC).
MEC / MIC ratio	1:1 MEC=MIC
Minimum capacity	Hybrid connection: 20 MW minimum Standalone connection 75 MW minimum
Maximum capacity	100 MW (both hybrid and standalone connections)
Grid connection	A grid connection offer accepted at qualification stage will be required.
Planning permission	Final Grant of Planning Consents for the Facility and Grid Connection will be required, as well as Evidence of Land Owner Consents, Key Map and AutoCAD of the Grid Infrastructure
Deliverability	Target scheme go-live to be defined following the next consultation process on the contractual arrangements.

4.1.2 Benefits of co-locating

The consultation paper highlighted the benefits that co-locating LDES with wind and/or solar can bring compared to standalone LDES are:

1. Improved delivery times: building at existing connections is expected to lead to faster connection of LDES assets.
2. Relieving network constraints: LDES located closer to wind and/or solar units are expected to provide greater opportunities to reduce curtailment and network constraint events.
3. Connection opportunities: allocation of scarce substation space to standalone connections comes at an opportunity cost, meaning that future connections for renewables, reinforcements, or supplying the distribution system may not be possible. Co-location of LDES mitigates the saturation of valuable bay connection opportunities.

4.1.3 Connection location

EirGrid proposed to evaluate and incentivise LDES capability based on pre-existing ECP constraint analysis. Tendering LDES assets would be assessed on their proposed location within ECP analysed nodes and projected levels of redispatch of wind and solar. It is important to note that this approach was proposed as only relevant for tender evaluation. There would be no subsequent contractual reliance on the ECP analysis or predicted redispatch at a nodal level, and the application of envelopes and associated operational requirements would not be directly linked to such analysis.

4.1.4 Scheduling and dispatch updates

The concepts set out in the consultation proceeded with the understanding that the Follow PN enabled by SDP02 would be fully operational. SDP 02 went live in Nov 2025[17] . [18]

4.1.5 Operational Signals

In periods of temporary, location-specific transmission constraints, it may better support the reduction of dispatch down if it is possible to disincentivise LDES exporting. This may not be reflected by market signals alone and so more distinct, ex-ante operational signals would be required to inform such behaviour, with such signals not available currently through any other ex-ante market mechanism. At other times for other system reasons, there may be an increased system benefit from limiting the import by LDES assets, for example, during tight system conditions or system alert periods. Currently the TSO's optimisation engine and dispatch processes will redispatch generation and storage away from their traded positions to ensure system security during network constraint or curtailment events. The costs of redispatching the relevant units for this are based on their submitted Inc and Dec bids and offers and captured in dispatch balancing costs (i.e. imperfections costs).

4.1.6 LDES Trading Envelope Model

To maximise the availability of the time-specific capability of such assets, EirGrid considered three potential options for an LDES operational model:

- Option 1: Unfettered Market Access
- Option 2: Full TSO Control
- Option 3: Trading Envelope (Operational Envelope) Model

Option 3 was proposed as it offers the greatest value to consumers while maintaining market access and revenue stacking opportunities for LDES contracted assets. Option 3 envisages that the TSO issues dynamic, time-based import and export limits for each LDES asset to manage congestion and reduce dispatch. Assets would be required to trade within these defined limits, with non-compliance charges applied where limits are breached. LDES assets would participate under a service contract that includes a revenue floor and a revenue-sharing mechanism for revenues gained in excess of the required revenue floor.

4.2 Summary of consultation responses

The following questions were asked in relation to LDES considerations:

Q3: Do you agree or disagree with the above eligibility criteria? Please explain your rationale.

Q4: Are there any other eligibility criteria that EirGrid should consider in relation to the procurement of LDES services?

Q5: Do you agree with the outlined benefits from co-locating LDES? Please explain your rationale.

Q6: Are there any additional benefits or drawbacks from co-locating LDES that have not been captured here? Please explain your rationale.

Q7: Do you agree with the outlined benefits of locating LDES in areas experiencing high levels of dispatch down of wind and solar? Please explain your rationale.

Q8: Are there additional benefits or drawbacks from locating LDES in areas experiencing high levels of dispatch down of wind and solar that have not been captured here? Please explain your rationale.

[17] https://cms.eirgrid.ie/sites/default/files/publications/Future_Power_Markets_Design_Authority_Newsletter-Issue_26-November_2025.pdf

Q9: Do you have any concerns or comments with regards to the integration of LDES in future market timeframes, post-Celtic?

Q10: Do you agree the operational envelope model delivers both sufficient investment signals to industry and value to the TSO? Please explain your rationale.

Q11: Do you believe the operational envelope model can help align LDES operations with real-time, locational TSO system needs? Please explain your rationale.

Q12: Are there other methods by which you believe the TSO could further improve LDES market operations with real-time, locational TSO system needs, while ensuring LDES asset capability to trade to required positions? Please explain your rationale.

4.2.1 Q3&4: Do you agree or disagree with the above eligibility criteria? Please explain your rationale. Are there any other eligibility criteria that EirGrid should consider in relation to the procurement of LDES services?

33 stakeholders responded to Q3. The majority of respondents either fully or partially disagreed with the proposed eligibility criteria, while five respondents were in agreement with the criteria.

Many respondents stated that the requirement for an accepted grid Connection Offer is overly stringent and may act as a barrier to new entrants. Many respondents also stated that the requirements for an RTE greater than 75% and a MEC/MIC ratio of 100% are overly restrictive. Some respondents also expressed the opinion that standalone projects below 75 MW should not be excluded, and that the minimum capacity requirement should be reduced. Some respondents stated that a 4-hour duration for LDES assets is too short. One respondent stated that the go live date is too aggressive for projects not built or currently under construction.

22 stakeholders responded to Q4, suggesting additional eligibility criteria that EirGrid should consider in relation to the procurement of LDES services, as detailed in Table 3 below

Table 3 Additional criteria suggested by respondents

Industry suggested criteria	Additional Detail	EirGrid comment
Include an investment rate threshold	LDES providers must demonstrate that they are investing more than an applicable IRT	Conflicts with the provision of a service and a technology and provider agnostic approach to procurement. This procurement is not designed to screen and rank capital investments by developers, and aims to instead value the delivery of a service to reduce redispatch from assets that can technically provide this service.
Grid connection acceptance not required at qualification phase	Requirement for an accepted grid connection should be moved from the qualification phase to the tender phase	EirGrid recognises that requiring a transmission grid Connection Offer acceptance for entry into the qualification phase would limit the participation of potentially valuable service providers. Therefore, the requirement to have accepted a Connection Offer now moves to become a pre-requisite of the tender entry phase. Projects currently have a 60 day acceptance period once issued a Connection Offer. Greater certainty of connection delivery is provided once a project has a Connection Agreement and is progressing through the normal connection process timelines. Potential LDES providers are encouraged therefore to seek to progress connections expediently, as the BAFO

Industry suggested criteria	Additional Detail	EirGrid comment
		process outlined in Section 6 highlights the importance of having a connection delivery timeframe that meets the Target Scheme Go-Live date.
Consider asset degradation and cycling requirements	Asset oversizing may be required to ensure sufficient duration at end of life	Will be accounted for in the LCOS and asset health management criteria. See Section 4.2.2 for more details
Change Round Trip Efficiency requirement	Suggestion of an RTE of 75%	EirGrid is incentivising assets to participate in all available markets and gain revenue streams that are feasible within their trading envelopes. A lower RTE would mean that an LDES asset would require a greater price spread between import and export for cost-effective utilisation, which could lead to lower utilisation. In turn, this may limit the asset's ability to absorb excess generation and efficiently convert it into usable output, reducing its effectiveness in lowering dispatch down and weakening the core system benefits of LDES.
Follow a similar approach to Italy's MACSE scheme	New or incremental capacity resulting from repowering or expansion only should qualify	As per above response to investment rate threshold
Longer duration threshold	Minimum duration should be longer than 4 hours, i.e., 6-12h	EirGrid is structuring this initial LDES procurement in line with the policy context in Ireland. There are no restrictions to maximum duration
Skills and workforce development	Skills and workforce development commitments, to support Ireland's engineering capability	EirGrid committed to ensuring sufficient resourcing to deliver within its remit.
Prioritise made in Europe clean tech	Introduce a minimum EU local content requirement of 30% for LDES assets, to support the domestic clean technology industry	EirGrid will follow relevant procurement law in relation to procurement requirements, including the EU Net Zero Industry Act (NZIA) and the Utilities Directive
Carbon reduction; minimisation of dispatch down	Analysis made available to assess how a proposal would reduce GHG emission during periods of renewable dispatch down	Part of the tender assessment will assess the theoretical capability of a tendered asset at a particular node in achieving a reduction in dispatch down volumes. Detailed explanation has been provided.
Widen scope of potential providers	Consider providers from the electrification of	EirGrid are designing this procurement in line with the ESPF definition of energy storage that requires import, storage and re-export of electricity back to the

Industry suggested criteria	Additional Detail	EirGrid comment
	heat and transport sectors	transmission system for this immediate procurement requirement.
Prefer co-located projects	Co-located projects which avail of the MEC sharing should be preferred	MEC sharing is not considered for this initial procurement. Co-located projects are incentivised but will require separate metering and market registration from co-located RES
Grid forming capabilities	Recognise grid forming "GFM" capability as a scored attribute	A Grid forming strategy and roadmap to future requirements has been published by EirGrid,[19] which outline roadmap relevant to the integration of grid forming capabilities to the power system. GFM will not be a specific requirement under LDES, but participants are encouraged to make themselves familiar with future requirements that will be incorporated in to Grid Code for GFM capability.

4.2.2 TSO response

The TSO considers that, on balance, having reviewed all detailed responses received, and considering the need to ensure delivery of the LDES service in line with policy objectives, the eligibility criteria set out in the consultation remain appropriate and should be retained; as detailed in Table 2.

- EirGrid has undertaken some analysis of different theoretical MEC/MIC ratios e.g. 1.2 and 0.8 utilising the impact criterion assessment of avoided dispatch down and blocked hours, which has demonstrated highly heterogenous outcomes (i.e. whether an asymmetric MEC/MIC ratio is beneficial or detrimental is very dependent on the connecting node). If the TSO was to allow for a generic tolerance of MEC/MIC around 1 across the network, there is no evidence this would provide system-wide benefits. Therefore, the requirement for a MEC/MIC ratio of 1 will be maintained in order to equally prioritise import and export capability that can help to minimise the need for redispatch, and ensure that such assets are able to revenue stack across multiple markets in line with their technical capability.
- Similarly, the minimum capacity threshold for standalone projects will be upheld, with a minimum of 20 MW for a co-located hybrid project, with an additional clarification that the renewable element of such a project will be required to be of a minimum capacity of 30 MW. See Section 4.2.4 for more details. For a standalone project, the minimum capacity will remain at 75 MW.
- The need for a potential LDES service provider to hold a Connection Agreement at time of qualification will be reduced to requiring the service provider to have received a Connection Offer at the Qualification Stage. This should enable wider participation at qualification stage, but it is important to note that EirGrid requires all projects to have a Connection Agreement at time of entry to the tender phase. This is required to ensure projects are advanced and able to support the urgent delivery timescale. This represents a change from the consultation proposal.
- Additionally recognising that there are significant volumes of connections and network enhancements to advance across the network (for capacity market contracted units, RESS supported assets, LCIS projects, new network upgrades, maintenance etc) LDES project developers are advised to progress connection processes expediently to be able to meet delivery timelines.
- The minimum 4-hour duration requirement remains unchanged, to avoid creating inconsistency with government policy.

[19] https://cms.eirgrid.ie/all-island-grid-forming-strategy-february-2026

Several respondents highlighted the importance of appropriately accounting for asset degradation over the operational lifetime of LDES facilities. EirGrid recognises that degradation is an inherent technical characteristic of storage technologies and has therefore incorporated degradation assumptions within the LCOS assessment, while placing responsibility for degradation management with the asset operator. It is the responsibility of the asset owner to ensure that the asset meets its contracted power and duration capability throughout the lifetime of the contract. This approach provides operators with flexibility to adopt their preferred asset management strategies, including oversizing, augmentation, component replacement, or operational optimisation, to ensure continued compliance with contractual obligations.

To ensure fairness between newly commissioned and existing storage assets participating in the scheme, each system will be required to demonstrate its capability to deliver its contracted power and energy at the start of its contract, establishing a clear baseline for performance. Depending on the technologies successfully awarded LDES contracts, this will be verified using an LDES specific test, which shall be an evolution of the Energy Storage Power Station (ESPS) test protocol[20] or other testing procedures as determined appropriate by the EirGrid Testing team.

Following contract award, ongoing compliance will be verified on an annual basis. The primary mechanism for annual verification will be operational evidence, whereby the asset demonstrates, through delivery and agreed metering and reporting, its ability to provide the full contracted power continuously for the full contracted duration. In assessing compliance, a reasonable tolerance will be applied to account for measurement uncertainty and operational variability. Delivery will be considered compliant where the achieved output is within an appropriate tolerance of the contracted power level for the contracted duration, with the specific tolerance to be defined and detailed within the contract. Where such evidence is provided and validated, additional performance testing will not be required for that year.

Where an asset is unable to demonstrate compliance through operational delivery, or where there is evidence of non-performance, the TSO may require the asset at the time of their choosing to undertake an ESPS performance test to prove capability. The same tolerance will apply in the assessment of performance test results to ensure consistency between operational verification and testing. Annual performance verification will be required with an appropriate minimum interval between tests to avoid undue operational burden.

Until the asset successfully re-demonstrates compliance, EirGrid may reduce, withhold or adjust floor payments and any other relevant contract payments to reflect the asset's most recently demonstrated capability. This does not remove the LDES service provider's ongoing obligation to restore and maintain the originally contracted power and duration capability.

If an asset cannot demonstrate, maintain, or re-demonstrate its contracted import capability, export capability, power output and/or duration capability, and this is identified through operational performance, metering and reporting data, performance testing, or any other verification method set out in the contract, this will be treated as a breach of contract where the shortfall is outside the allowed tolerance or otherwise shows that the asset cannot provide the contracted service.

In such circumstances, and without prejudice to any other rights or remedies available to EirGrid under the contract, at law or in equity, EirGrid shall retain the contractual right, acting reasonably and with reference agreed verification methodology, to determine whether the failure is isolated, recurring or material. EirGrid can the LDES service provider to submit and implement, within a defined period, a corrective action plan to EirGrid’s satisfaction and to re-demonstrate full compliance within the remediation period specified under the contract.

If the operator does not resolve the issue within the applicable remediation period, or if the issue is repeated, persistent or material, EirGrid may exercise any additional rights or remedies available under the contract. These may include requiring further testing at the operator's expense, applying non-compliance charges or other payment reductions, suspending floor payments, calling on any contractual security arrangements, suspending the contract, and/or terminating the contract in line with its terms.

[20] https://www.eirgrid.ie/grid/grid-codes-and-compliance-overview/grid-code-compliance-testing/power-park-modules-ppm

This approach is intended to provide operational flexibility while ensuring that contracted LDES capability remains deliverable and enforceable throughout the contract term, with clear consequences where the contracted service is not provided.

The proposed framework is intended to balance system assurance and fairness with operational flexibility, while maintaining strong incentives for asset availability and performance throughout the contract life.

Several respondents proposed the introduction of an Investment Rate Threshold (IRT) as several respondents proposed its inclusion as part of the eligibility criteria, whereby LDES providers would be required to demonstrate that the investment exceeds a defined minimum level in order to qualify for the scheme.

The TSO does not propose to introduce an Investment Rate Threshold (IRT) as part of the eligibility criteria. The scheme is designed as a competitive procurement of a defined LDES service, open to all assets capable of delivering the required technical and operational performance. Introducing an investment-based eligibility requirement would shift the design away from a service-based framework towards one that screens for capital expenditure levels, which is not the purpose of this procurement.

From a regulatory and legal perspective, particularly in the context of the Utilities Directive any eligibility criterion must be objective, transparent, and non-discriminatory, and must not have the effect of artificially narrowing competition. An IRT could risk disproportionately disincentivising otherwise technically capable assets, thereby restricting participation in a manner that may be difficult to justify under the procurement principles of equal treatment, proportionality, and maintaining adequate competition. The proposed eligibility framework already includes several technical and operational requirements that appropriately limit participation to assets capable of providing the LDES service. Adding an IRT could further constrain the competitive field without a clear service-related justification, potentially reducing competitive tension and value for consumers. For these reasons and given that the objective of the procurement is to secure the delivery of a system service rather than to incentivise specific levels of capital investment, the TSO considers that an IRT is neither necessary nor appropriate as part of the eligibility criteria.

TSO position

Having considered the consultation responses, the TSO confirms that the eligibility criteria set out in Table 4 below.

Table 4 Final eligibility criteria for LDES procurement

Criteria	Description
Duration of import and export capability	The storage asset must be capable of discharging electricity continuously at its nameplate power capacity rating for the contracted MWh duration at the start of the contract (minimum of 4 hr) and in line with its contracted MEC over the length of the scheme duration. Similarly, the asset must be capable of charging for the contracted duration continuously at its nameplate power capacity rating (and in line with its contracted MIC).
MEC / MIC ratio	1:1; MEC=MIC
Minimum capacity	Hybrid connection: 20 MW minimum (renewable element of hybrid connection must be a minimum of 30 MW) Standalone connection 75 MW minimum
Maximum capacity	100 MW
Round Trip Efficiency (RTE)	75%
Asset Health Management	The asset must be able to demonstrate, on an annual basis, its ability to deliver its full contracted power and duration, either through verified operational delivery and reporting or, where required, through performance testing.

Grid connection	A Connection Offer received at qualification stage and a Connection Agreement at tender stage will be required. A connection programme will also be required at Tender submission stage and will be assessed by the TSO during the BAFO process. The outcome of this assessment will be that the assessed Unit Energisation Date will need to be four months before the Target Scheme Go-Live Date to pass the deliverability criterion. Further details are provided in Section 6. The Target Scheme Go-Live Date for the provision of LDES will be determined in the consultation on the contractual arrangements.
Planning permission	Final Grant of Planning Consents for the Facility and Grid Connection will be required, as well as Evidence of Land Owner Consents, Key Map and AutoCAD of the Grid Infrastructure
Deliverability	The Target Go-Live Date will be further defined in the next consultation as a number of months from LDES contract execution. Early delivery will be incentivised by provision of a longer scheme duration for projects able to deliver the contracted LDES service ahead of the Target Scheme Go-Live Date.

4.2.3 Q5&6 Do you agree with the outlined benefits from co-locating LDES? Please explain your rationale. Are there any additional benefits or drawbacks from co-locating LDES that have not been captured here? Please explain your rationale.

31 stakeholders responded to Q5. Several respondents were fully in agreement with the outlined benefits of co-locating LDES. These respondents emphasised that co-location improves delivery time and efficiency while also optimising land use and therefore is highly beneficial.

Approximately half of the respondents agreed with the outlined benefits of co-location, but also expressed concerns about ignoring the benefits standalone assets can provide, and requested a change to the definition of co-location adopted in the paper. Some respondents were of the opinion that co-location of LDES is beneficial, but that since standalone assets can also confer benefits, they suggested that both co-located and standalone assets should be facilitated. Several respondents also stated that the definition of co-location in this paper is overly narrow, as it only allows for co-location with renewable energy sources. These respondents suggested that the CRU definition of co-location, which does not restrict co-location to assets that are co-located with renewable energy, should instead be adopted. Some respondents also suggested including MEC sharing in this round of procurement, following CRU's future decision on MEC sharing. One respondent suggested that an LCIS-style approach is adopted, requesting the TSO to conduct modelling to indicate where best to locate LDES on the grid.

One respondent expressed the opinion that the outlined benefits of co-located assets can equally apply to standalone assets, and that co-location does not necessarily provide additional benefits. This respondent stated that standalone projects with an accepted grid Connection Offer have the capability to deliver fast connection of LDES, and that standalone projects in areas of high dispatch down equally have the potential to alleviate constraints.

It is important to note that the primary aim of the proposed tender scoring criteria is to identify projects with the greatest potential to deliver the required value to the electricity system and consumers, while using project maturity and deliverability as differentiating factors. The relevant preference for connection types will be reflected in the tender scoring methodology, as set out in Chapter 6 (see Table 14).

20 stakeholders responded to Q6. Additional benefits and drawbacks from co-locating LDES were proposed, and points raised in response to Q5 were emphasised. A summary of key points raised is presented in Table 5 below.

Table 5 Benefits and drawbacks from co-locating LDES

Details	TSO initial response
Benefits	
Improved delivery times	Acknowledged. Co-location can accelerate delivery times.
Maximising grid utilisation	Acknowledged. Co-location can improve utilisation of existing infrastructure and bay capacity.
Relieving network constraints;	Acknowledged. Co-located LDES can help reduce constraint related dispatch down.
Enhance resilience through diversified energy assets	Acknowledged, this initial procurement is focused on the delivery of assets that can provide a minimum of 4 hour energy import and export duration. The procurement is technology neutral, where technologies can meet the minimum technical criteria. A different approach may be taken for a more enduring procurement approach to LDES.
Streamlining of permitting and planning processes	We are targeting the procurement of assets that have advanced grid connection and permitting processes to ensure service delivery as early as possible.
Delivery of system-wide flexibility and resilience	Acknowledged, the LDES procurement should deliver enhanced flexibility to the system and support resilience in a changing energy generation landscape
Drawbacks	
CRU definition of co-location would be preferred by industry; to allow co-location with non-renewables	The CRU definition will not be applied, further clarification is provided in the text later in this paper.
Full benefits of co-location will not be realised without MEC sharing or ability to have multiple legal entities behind the same connection point	MEC sharing is not considered in this procurement, as it would not be possible to facilitate TEs for an MEC shared connection.
Contractual compliance contradictions: do RESS commitments for generation or TE requirements take precedence?	Energy storage technologies are not supported independently under RESS (RESS 5 requirements facilitated energy storage assets where located on site with a RESS supported renewable asset). RESS 5 contracted providers did not include any energy storage elements. RESS 6 terms and conditions are still in development. For LDES the requirements are clear that co-located renewable assets and LDES assets will be required to be separately metered and market registered. Behind the meter charging of the LDES asset from a RESS supported asset will not be possible. TEs will apply to the LDES asset.
Behind the meter charging if MEC regulations are changed	MEC sharing and behind the meter charging are not considered in this procurement.
Drawbacks of co-locating LDES behind a heavily constrained node	Acknowledged. The TSO recognises that constraint conditions may limit LDES operation in some locations and will assess this in the impact criteria assessment.
Increased complexity in site operations and maintenance	Developers are able to submit tender bids for standalone assets. Co-location weighting aims to ensure efficient utilisation of existing standalone or renewable connections. Appropriate site design to

Details	TSO initial response
	accommodate operations and maintenance of assets is not within the remit of the TSO to determine.
Security risks when integrating multiple systems	Assets will be required to comply with applicable cybersecurity obligations, including those arising under NIS2 Directive, as implemented in Irish law, where applicable, and any associated requirements imposed through licence, regulatory or contractual arrangements applicable to TSO connected infrastructure.
Need to consider the overall effect of co-location on system costs	Co-location can reduce overall system cost through lower connection costs and more efficient utilisation of existing network infrastructure. These benefits are reflected in the procurement design through the connection method scoring.
Need to consider areas where LDES would be beneficial but additional wind or solar would be problematic	The impact criteria nodal assessment (see Section 6.2.4) will take account of the proposed LDES assets in relation to predicted dispatch down of ECP relevant renewable generation. The LDES approach does not intend to identify sites where further wind or solar may be problematic.
Co-location may concentrate market participation among existing renewable developers and large utilities	Co-location weighting aims to ensure efficient utilisation of existing standalone or renewable connections. Additionally, this initial procurement requires planning consent progress and Connection Offer at the time of procurement qualification which will require early commitment to development funding. All projects that meet the pass/fail eligibility and pre-qualification criteria will be assessed objectively using the outlined tender assessment process.
Greater market coupling could increase revenue uncertainty for storage	Acknowledged, but it could also bring greater trading liquidity and opportunities for market participation.

4.2.4 TSO response

The TSO acknowledges the broad support recognising the system benefits that co-located LDES can deliver and the concerns relating to the definition of co-location. Following consideration, the TSO does not propose any change to the definition of co-location for this procurement phase. As outlined above in Table 4 the TSO proposed to grant the highest weighting to both an existing standalone LDES asset, and an LDES asset that is locating at an existing renewable generation site.

Following industry engagement, the TSO would like to provide clarification in relation to the volume of renewable generation required to meet the definition of a relevant TSO connected renewable installation.

With regard to the LDES approach the TSO clarifies that in line with existing ECP policy and node assignment rules,[21] applications for a project that is defined as hybrid (co-located with renewable generation) will be assessed on the basis that a minimum of 30 MW of installed renewable capacity will be required for a site to be considered a transmission connected renewable installation. The site MEC must always equal the summation of all technology MECs at the site. The detailed approach to transmission connection assessments as outlined in the node assignment rules document indicates that the TSO will approach the assessment on the basis of the following:

- A single application with a total MEC equal to or larger than 40 MW, will first be assessed by the TSO for a connection at transmission level. This will be reviewed in conjunction with the node assignment's principles and considerations.

[21] https://cms.eirgrid.ie/sites/default/files/publications/Node-Assignment-Rules-ECP-2.pdf

- Applications below 50 MW may subsequently be considered for transfer to distribution level, where appropriate. If these connections are acceptable to the DSO then the application will be transferred to the DSO.
- If an applicant of less than 50 MW has a specific request for a transmission connection, this will be considered on a case-by-case basis. As a rule, this will not be facilitated for generators less than 30 MW or in scenarios where a relevant substation has less than three available spare bays. In addition, for a hybrid site the site MEC must be equal to the sum of the renewable generation MEC and the LDES MEC.

Consistent with these node assignment rules, EirGrid clarifies that any proposed transmission connecting LDES hybrid project that has a renewable generation capacity of less than 30 MW will not qualify for entry into the LDES procurement as a hybrid project. Projects with less than 30 MW of renewable generation capacity can be considered as standalone projects if they meet the 75 MW minimum/100 MW maximum requirements and comply with separate metering and market registration requirements, while holding a site MEC that is equal to the sum of all technology MECs at the site.

We acknowledge stakeholder views on the potential benefits of standalone LDES assets, and therefore as originally proposed will provide a higher tender weighting to those standalone projects that are in existence at the time of procurement. Further detail is provided in Section 6.2.4.

All other issues raised by respondents in relation to the benefits and drawbacks of co-location are addressed in Table 5 above.

TSO position

The TSO confirms that no change will be made to the definition of co-location and LDES hybrid for this procurement phase. Only sites with ≥30 MW of transmission connected renewable generation will qualify as co-located. The site MEC must equal the sum of all technology MECs at the site, and all units must be separately metered and market registered. MEC sharing will not feasible for LDES tender participants.

4.2.5 Q7&8: Do you agree with the outlined benefits of locating LDES in areas experiencing high levels of dispatch down of wind and solar? Please explain your rationale. Are there additional benefits or drawbacks from locating LDES in areas experiencing high levels of dispatch down of wind and solar that have not been captured here? Please explain your rationale.

30 stakeholders responded to Q7 and 23 to Q8. The majority agreed that locating LDES in areas with high levels of renewable dispatch down can deliver system benefits. Respondents highlighted that LDES could alleviate curtailment, and improve local grid stability, supporting Ireland's wider decarbonisation and flexibility objectives.

However, many offered conditional agreement, emphasising that the benefit depends on accurate, forward-looking modelling of constraints. A few stakeholders cautioned that relying on historic constraint data may not reflect future realities, particularly with new interconnectors, reinforcement works and changing renewable patterns. Differences between solar driven and wind driven constraint profiles were raised, with some noting that multi-hour storage may be insufficient in wind dominant locations.

A recurring theme was the preference for a zonal assessment rather than nodal assessment approach, which respondents felt would better capture system needs and broaden participation. Respondents highlighted that zonal assessment may better reflect the wider constraint patterns that influence redispatch costs, avoid overreliance on historic node specific modelling, and broaden participation by ensuring viable projects within constrained regions are not excluded due to narrow node level assumptions.

Three respondents cautioned that co-location benefits may be overstated where LDES assets would themselves face import/export limitations behind highly constrained nodes, and that prioritising shorter duration assets (4-hour) in these locations could inhibit connection opportunities for longer duration technologies, given limited transmission capacity.

Stakeholders also emphasised their preference to align with the CRU definition of co-location, noting that aligning with the CRU definition would enable wider participation and competition.

4.2.6 TSO response

Having considered the feedback on nodal assessment versus a zonal assessment approach, the TSO maintains that a nodal assessment is necessary to accurately evaluate the potential of LDES assets to reduce dispatch down, taking account of location specific constraints.

While the aim of the LDES service is to support system operations, both in addressing system wide and nodal challenges, to support this tender evaluation, EirGrid will apply a impact criteria assessment that considers the extent to which the proposed MW and MWh capability of each tendered asset could reduce predicted levels of dispatch down at the relevant node under modelled conditions (using ECP 2.5 hourly dispatch down results), and the extent to which asset size, curtailment event duration or constraint conditions at the node could restrict the asset's ability to charge or discharge.

A zonal assessment would not sufficiently assess the value of dispatch down avoidance at nodes with high levels of dispatch down, as it would not be able to determine the potential restrictions on the asset based on the node it is connecting to.

TSO Position

The TSO confirms that a nodal approach for tender assessment will be retained for this procurement phase for locational assessment. This will be supported by enhanced modelling using ECP 2.5 hourly dispatch down forecasts. A zonal approach is considered insufficiently granular to assess the system value of dispatch down reduction.

4.2.7 Q9: Do you have any concerns or comments with regards to the integration of LDES in future market timeframes, post-Celtic?

23 stakeholders responded to this question. The majority of respondents expressed concerns about how LDES will integrate into future market timeframes post Celtic, noting that increased interconnection is expected to raise levels of dispatch down and is likely to influence LDES revenues and operational behaviour. Several respondents stressed that full market assessment and clearer modelling assumptions (e.g., interconnector flow assumptions, constraint projections, treatment of LDES in the BM) are required to accurately understand the future value of LDES.

Many respondents also noted that Celtic will introduce additional complexity across market timeframes, with one respondent highlighting that the TSO and CRU must be adequately resourced to ensure successful implementation. A recurring theme among responses was that future market design must allow LDES to participate effectively in balancing, capacity and system services markets, with many calling for clear operational rules, predictable TEs, and improved integration of storage into the BM to avoid distorting price signals or limiting LDES flexibility.

While most respondents acknowledged the importance of LDES in a more interconnected, decarbonised system, many raised concerns that the proposed TE model may constrain LDES trading and increase revenue uncertainty. Several respondents suggested that in cases where the TSO requires actions contrary to market signals, compensation and clear reconciliation mechanisms must be defined to protect investors.

A number of respondents argued that a separate enduring solution should move toward market-based optimisation, with some suggesting that a tolled model or alternative support structure may be more appropriate if TEs significantly restrict LDES market participation.

4.2.8 TSO Response

The TSO notes the feedback received in relation to future market developments, including concerns regarding the impact of forthcoming system changes on LDES operation and value.

The focus of this procurement is on the immediate procurement of an LDES service. Our proposals are based on our assessment of the most appropriate approach to deliver this procurement and integrate with existing market structures and delivering value to the consumer. Full market participation within the bounds of the TE will be possible for contracted LDES service providers.

Any future LDES procurement mechanism will need detailed consideration and more bespoke modelling, along with necessary evolutions in scheduling and dispatch processes and capability to enable effective utilisation of very long duration assets.

Specifically in relation to the impact of Celtic flows on dispatch down, these are evident in the published ECP 2.5 results. More broadly, full transparency on Celtic integration and wider EU market timing developments continue to be provided through the Future Power Markets Fora[22] and other industry publications.

TSO Position

The TSO confirms that this procurement is focused on the immediate procurement of an LDES service. The TSO will contractually reserve the right to update the TE as necessary post DAM gate closure, however this will be consulted on further, in advance of any introduction of such update processes.

4.2.9 Q10: Do you agree the operational envelope model delivers both sufficient investment signals to industry and value to the TSO? Please explain your rationale.

27 stakeholders responded to Q10. The majority of respondents expressed mixed or negative views of the proposed TE approach. However, some did agree that the TE model delivers sufficient investment signals to industry and value to industry, though the majority of these respondents also stated that more information would be needed as to how the TE will be implemented, and one respondent suggested periodic review of the TE.

Several respondents asked for further clarity on the details of the TE, stating that the proposed approach is complicated. One respondent expressed concern that the operational complexity introduced by the TE approach could deter new private investors from participating. Some respondents also expressed that it is difficult to say whether the TE model will provide sufficient signal, without further details as to how to it will be implemented in practice. One aspect that a respondent requested further clarity on is how LDES operators will be expected to respond to changes in the TE, and how operators can avoid penalisation when the TE changes following gate closure. One respondent requested further justification as to why EirGrid requires ability to define TEs, and expressed concern that EirGrid being able to issue ex-ante TEs will influence prices in the wholesale electricity markets.

Respondents also stated that the TE will result in uncertainty in revenue forecasting, and the TE approach alone will not provide sufficient investment signal to industry. Two alternative approaches for how the TE model can be utilised by the TSO were proposed by industry: the first suggested that the TE model be used initially but not as an enduring solution, with a move towards a market-based solution at a later date; the second suggested that since the TE model alone is insufficient, and that it instead be incorporated as one part of a larger package.

Several respondents stated that LDES participants should be allowed unconstrained access to other markets, such as the Ex-ante, Day-Ahead and Intraday markets, and expressed that this would be better for the participants.

Respondents also expressed concern regarding the proposal that EirGrid will have the ability to change the TE following gate closure.

Respondents expressed concern of the breadth of the envelope, and encouraged the use of a wider envelope, as narrower envelopes would be overly restrictive for the providers.

[22] https://www.eirgrid.ie/shaping-our-electricity-future/electricity-markets#future-power-markets-industry-workshops

4.2.10 TSO response

The TSO remains committed to introducing TEs and considers this approach justified for a service specifically designed to support the reduction of dispatch down and that provides revenue floor commitments to the contracted service providers.

Respondents have questioned whether BM participation alone could resolve curtailment and constraint issues. It is recognised that the TE approach will introduce an element of ex-ante constraint recognition into market trading through defined operational limits, something which cannot be achieved within the current unconstrained market design and BM activations. Therefore, by placing ex-ante limits on contracted LDES providers, the TE is intended to reduce the likelihood that traded positions exacerbate curtailment or constraints, thereby reducing the need for subsequent redispatch. Lower redispatch volumes ex-ante will in turn reduce associated redispatch actions and dispatch balancing costs incurred by the TSO.

As a result, for a floor-price supported service, the TSO considers the TE approach appropriate and necessary. There are no other existing mechanisms which would enable the TSO to apply trading restrictions on an LDES asset. If we were to consider a revenue floor model without any additional service or trading restrictions such as option 1 outlined in the consultation paper, this would lessen the value of LDES service delivery and could exacerbate redispatch requirements and related costs to consumers. Furthermore, the TE model ensures that, in return for security of a floor price, participating LDES service providers are free to trade within defined import and export limits, enabling revenue maximisation in a manner that aligns trading behaviour with system needs and reduces redispatch volumes.

In response to concerns about the possibility of changes to the TE after GC2 gate closure, the TSO confirms that the TE is an ex-ante mechanism and will not be altered post GC2 gate closure. All LDES assets will be obliged to submit their standard BM data – availability, Technical Offer Data (TOD), Complex Offer Data (COD) and Final Physical Notification (FPN) / Ex-post Quantity (Q_{EX}) positions etc. Any TSO instructed movement away from the TE restrictions will be determined based on system need and the COD of the LDES asset, as per existing operational practices.

As outlined in 5.3 the TSO will issue at 10 am D-1 the TE. The TSO reserves the right to in the future provide updated TEs (but only following further detailed consultation) after the DAM gate closure but before GC2 gate closure as market liquidity increases and there is enhanced technical capability to assess potential envelope amendment requirements after D-1 gate closure.

With respect to the TE dimensions, it is envisaged that the envelope will restrict the units trading positions only during periods that relate to the provision of the LDES service to minimise redispatch requirements, or during system tightness events. Envelope parameters will be informed by available system data, including but not limited to, renewable forecasts, outage schedules, network conditions, most of which will also be available to market participants. These are intended to reflect expected system conditions rather than prescribe specific operational outcomes.

As outlined previously, LDES assets will retain access to all other SEM markets, and revenue across these markets will be accounted for under the open book accounting framework, which is further detailed in 5.2.10.

TSO Position

The TSO confirms retention of the TE model as the core framework for contracted LDES assets. The TE is justified to manage ex-ante constraint-driven behaviour, minimise redispatch, and ensure system value where a revenue floor is provided.

4.2.11 Q11: Do you believe the operational envelope model can help align LDES operations with real-time, locational TSO system needs? Please explain your rationale.

23 stakeholders responded to Q11 with broadly mixed views. The comments generally reflect that while the TE model may help align LDES operations with TSO system needs in some circumstances, most respondents expressed significant concerns regarding its practicality, predictability, impact on investment decisions, and

readiness for implementation. There were also several requests for further detail and worked examples on how TE parameters would work in practice.

While a few respondents support the concept, highlighting its potential to prevent LDES exacerbating local system constraints, the majority stated that the TE is overly prescriptive, risks distorting market signals, and may not be compatible with long duration asset optimisation.

Several responses indicated that the TE should be treated as an interim measure, used only to support early operability, with a longer-term transition to a market-based approach once storage is fully integrated into the BM. One respondent expressed a preference for LDES to be provided as a "tolled asset" to afford an opportunity for it to be used in the ways that benefit the consumer most.

Several responses highlighted that insufficient detail on TE implementation makes it difficult to assess investment viability. Multiple stakeholders emphasised that without predictable TE behaviour, financing and revenue modelling become materially more challenging.

Stakeholders expressed concern regarding how losses resulting from TE compliance will be treated. Without clarity on compensation mechanisms, respondents indicated that they would need to apply a risk premium to floor price bids.

Stakeholders also called for transparency on the LCOS methodology, including input assumptions, calculation logic, and how TE driven costs feed into the LCOS reconciliation.

4.2.12 TSO response

The TSO acknowledges stakeholders concerns regarding the TE model, and notes that additional detail on the scope and limitations of the envelope will help provide the clarity being sought by respondents.

The TSO confirms that the envelope will remain non-prescriptive, in order to preserve market participation and allow assets to determine their own trading strategies within defined envelope limits and will be issued each day before D-1 market closure and will not force an asset to take a position. While the TSO will retain the ability to update envelopes post 10 am D-1, which could include a change to import/export restrictions. The initial issuance timing of 10 am D-1 reflects current operational capabilities and market processes. As operational experience develops, the TSO may review this timing, including consideration of earlier issuance of envelopes where this is shown to improve usability and participant decision-making. Evolution of envelope issuance would only be considered if intraday liquidity improves and if operational needs justify more frequent updates. Any such developments would take place following sufficient industry engagement including potentially a public consultation and would be subject to regulatory oversight.

The requirement to comply with TEs will apply for the full duration of the LDES contract. There is no minimum required time of restriction, and if system conditions evolve such that envelope restrictions are no longer required to support reductions in dispatch down volumes and unrestricted market access of LDES unit is considered the best solution, the TSO may issue a full range envelope with no restrictions. The TSO will continuously monitor the outcomes of the TE throughout the contract period to ensure it continues to provide system value.

EirGrid will publish a detailed LCOS methodology paper prepared by independent consultants setting out the input value sources, and calculation methodology used to produce the LCOS values, providing transparency to stakeholders regarding the definition of the revenue floor.

TSO Position

The TSO confirms that the TE will remain non-prescriptive, imposing only maximum import and export limits, with no minimum requirements and no forced crossing of zero. TE will be issued at 10 am D-1 and will not be amended after this time at the outset of the scheme. The TSO will monitor the use of envelopes throughout the contract period, evolving market dynamics and may, following industry consultation and regulatory engagement, introduce envelope updates post DAM gate closure.

4.2.13 Q12: Are there other methods by which you believe the TSO could further improve LDES market operations with real-time, locational TSO system needs, while ensuring LDES asset capability to trade to required positions? Please explain your rationale.

There were 23 responses to Q12. Most suggested that refinement and clarification would be needed to ensure the TE approach would work effectively. Respondents stressed that the current proposal lacks sufficient detail to allow developers to assess how the TE would work in practice.

Several respondents reiterated concerns that TE restrictions undermine efficient market operation, limiting LDES participation in energy markets and reduce commercial efficiency. Several suggested that improved BM integration should ultimately replace TE based dispatch controls.

A strong theme across responses was the need for clarity on compensation where TE driven dispatch requires LDES to act against market signals. Many stressed that operators should not be exposed to imbalance charges, redispatch losses, capacity market penalties, or other non-compliance costs arising from TSO initiated TE changes. Several noted that without defined compensation and reconciliation arrangements, the scheme would introduce material financial risk.

Several respondents reiterated that the TE should be an interim mechanism, appropriate only until improved BM arrangements and broader market reforms allow LDES to be fully integrated. Stakeholders emphasised that enduring system design should enable LDES to participate fully in scheduling, dispatch and system services markets.

Some respondents highlighted that TE development must be considered in parallel with network charging (e.g. DTUoS), firm access arrangements, and rules for hybrid or MEC shared connections.

4.2.14 TSO response

The TSO notes respondents feedback regarding the potential impact of the TE model on market operations. The TSO acknowledges concerns but is of the view that wholesale unconstrained market signals and ex-ante market trading can result in market participating LDES service providers having a traded position that may exacerbate local constraints and increase redispatch requirements of the unit itself or of renewable generation. The LDES service and implementation of the TE intends to mitigate this and deliver savings to the end consumer.

While service providers will not be required to act in a specific direction or mandate trading to certain positions against market signals, they may be restricted at times from taking advantageous market positions to remain in compliance with the envelope. Non-compliance charges will apply where units' trades are in breach of the envelope. It is understood that potential profit-making opportunities could be forgone in exchange for certainty of a revenue floor. The envelope aims to anticipate periods of constraint, curtailment etc and restrict trading to export or import (dependant on the circumstances) during certain hours where such trading by the LDES unit could exacerbate the need for redispatch actions and increase dispatch balancing costs. As previously stated, any future development that would allow for envelopes to be updated after DAM gate closure would only be implemented following sufficient industry engagement.

In relation to concerns on compensation, the TSO confirms that remuneration will not compensate for imbalance charges or redispatch losses, as the TE is designed such that traded positions remain at the discretion of the asset. The LDES asset is not subject to additional risk of imbalance charges or redispatch losses as a result of this scheme. As with other market facing assets, alignment of traded position with actual delivery is assessed and the appropriate penalties or charges will be applied where the asset has not delivered against its traded position. Normal BM rules apply, so where an asset is moved by the TSO away from its traded position the relevant normal BM requirements apply. Interactions between TSO actions in the BM timeframe and subsequent market positions taken by the asset will be considered in terms of state-of-charge impacts of TSO actions outside the envelope restrictions will be assessed within the Trading Day.

This will align with the principles applied within the Scheduling and Dispatch Programme, where for battery units, post redispatch impacts are evaluated within the same trading day timeframe.[23]

Specifically, for capacity market charges, the non-performance difference charge will only be compensated where the shortfall is directly caused by the TE. This applies in situations where, following TSO scrutiny following the individual event, it is clear that an asset has had an insufficient state of charge to meet their contracted Capacity Market obligations directly as a result of TE that did not allow adequate import time in the eight hours before the Capacity Market event, and an insufficient state of charge was held at the start of the eight hour period before the CM event. To receive this compensation, assets must have accurately declared their availability levels.

TSO Position

The TSO confirms that the remuneration framework will not compensate for imbalance charges or redispatch losses, as trading positions remain at the discretion of the asset and all standard market rules apply. Capacity market non-performance difference charges will only be compensated, where a shortfall is directly caused by TE and related state-of-charge limitations. Any compensation will only be possible after TSO scrutiny of applied TE restrictions and resultant state of charge impacts. All LDES service providers that hold capacity market contracts will be obliged to submit accurate availability declarations.

4.3 Summary of TSO recommendations

Our main recommendations in relation to the overall procurement approach are relatively unchanged from the original proposals.

We recommend:

- **Retention of the core eligibility criteria, with refinement of the grid connection requirement** as these remain necessary to ensure a valid LDES service and to meet timely procurement objectives. These are outlined in more detail in Table 4.
- **No introduction of any additional eligibility criteria**. Some of the suggestions may conflict with a technology-neutral service-based procurement, could risk constraining participation, or introduce regulatory complications. See Table 3 for more detail.
- **Retention of the TSO definition of LDES co-location**, confirming alignment with ECP existing approaches. Only sites with ≥30 MW of transmission connected renewable generation will qualify as co-located. MEC sharing is not feasible for this procurement.
- **Maintaining a nodal approach to locational assessment**, supported by enhanced modelling using ECP 2.5 hourly dispatch down forecasts. A zonal approach is considered insufficiently granular to assess the system value of dispatch down reduction.
- **Retention of the TE model** as the core framework for contracted LDES assets. The TE is justified to manage ex-ante constraint-driven behaviour, minimise redispatch, and ensure system value where a revenue floor is provided.
- **The TE will**:
  - Be issued at **10:00 D-1** ahead of Day-ahead market closure;
  - Apply **only maximum import /maximum export limits**, with no minimum requirements and **no forced crossing of zero**;
  - Remain fixed after it is issued at 10:00 D-1, at the beginning of the contract
  - The TSO will contractually reserve the right to update the TE as necessary post 10:00 D-1, however this will not be introduced without further consultation, with industry input to be assessed in advance of any introduction of such update processes.
- The **TE approach will remain in place for the duration of the LDES scheme**, though restrictions may be reduced over time if system conditions or market evolution allow for less intervention.

[23] Overview of SDP Solution for Battery Units V2.pdf

- Retention of unrestricted access to the SEM markets provided the asset remains compliant with the TE. Revenue stacking remains a core design feature.
- No compensation for imbalance charges or redispatch losses arising from TE compliant traded positions. Assets maintain autonomy over trading and associated risks. Capacity non-performance charges will be compensated only where shortfall is directly caused by TE-restricted state-of-charge limitations (and following TSO scrutiny of relevant capacity market events).

5 LDES service detailed considerations

5.1 Consultation proposal

This initial iteration of the LDES TE will be defined by dynamic variation of export/import limits, to align with system need. The TSO will set individual TEs for each LDES service provider at D-1 covering a 24-hour horizon of the Trading Day, D, allowing LDES asset operators to trade in day-ahead markets to align with the time-specific LDES energy import/export limits. The TSO expects to use asset-specific TEs that, for example, ensure LDES assets do not discharge during periods in which wind is being curtailed or due to local constraints, or similarly to not charge during periods of peak demand or network outage where this would exacerbate local or system constraints.

The TSO will issue dynamic import and export TEs before day-ahead gate closure to participating assets. MIC (Maximum Import Capacity) and MEC (Maximum Export Capacity) outlined in connection contracts govern the maximum power flow of a transmission connected asset during import (MIC i.e. take from the network) or export (MEC i.e. flow onto the network). During periods of constraint, the TSO may limit the export capability of an asset to prevent the asset discharge from overloading constrained grid assets. During periods of tight capacity margin, the TSO may limit the import capability of an asset to prevent an asset charging in a manner that could exacerbate system tightness.

The LDES TE will define periods in time during which the LDES asset must trade within specified export/import limits, which will vary from the asset's generic MEC/MIC as defined in its Connection Agreement, while remaining within the absolute limits of asset MEC/MIC. Between these defined windows where TE limits are imposed, the asset is free to trade its full capacity as it sees fit in other markets. The TSO intends that dynamic export and import limits will be issued during relevant periods, in response to periodic local constraint or system wide curtailment. By setting import/export envelopes, the TSO aims to prevent LDES assets from exacerbating constraint or curtailment events and ensure that the assets are available to support the system. TEs will be aligned as much as possible with predicted constraints and curtailment events to support system operations and help ensure system security while minimising redispatch.

The TSO will continue to monitor the effectiveness of LDES TEs and retains the right to further develop the TE definition parameters, as operational experience of LDES assets increases and operational requirements develop. This may involve TEs being defined or refined closer to real time (following further consultation) as outlined in Section 4.3 and 7.2.4.

5.2 Summary of consultation responses

The following questions were asked in relation to LDES service detailed considerations:

Q13: Do you believe that the operational envelope model proposed in this consultation is compatible with LDES asset operations and investment decisions?

Q14: Do you believe that 10 am D-1 is sufficient notice to achieve a desired market position?

Q15: Do you wish to add any further comments on the operational envelope model?

Q16: What is your view on the proposed 10-year contract length? Please provide rationale to explain this.

Q17: Do you have feedback on the proposed floor and share mechanism as outlined in Chapter 3 Section 3.3? Do you have concerns or a potential alternative you would suggest?

Q18: What cadence of revenue floor payments will be necessary to finance LDES projects?

5.2.1 Q13: Do you believe that the operational envelope model proposed in this consultation is compatible with LDES asset operations and investment decisions?

22 stakeholders responded to Q13. Fifteen stakeholders believed that the operational envelope model proposed in the consultation is not compatible with asset operations and investment decisions. Stakeholders generally felt that the uncertainty of the TE model will lead to higher floor price bids, as the complexity of the model leads to difficulty forecasting project revenues, which increases financing costs. Stakeholders had concerns about trading at a loss if TEs are narrow and queried how this will be recompensed. Stakeholders also expressed concerns that responding to a system security direction may cause the TE to be breached and queried how this will be treated.

Summary of 'incompatible' responses

Responses from the 15 stakeholders who felt the TE is not compatible with asset operations and investment decisions included concerns about:

- Trading at a loss for period where the operating envelope is narrow, in particular how this would be recompensed if losses are incurred as a result of TE changes.
- Penalties for envelope breaches, in particular, if penalties are incurred as a result of TSO-initiated redispatch instructions.
- Project finance and increased financing costs. Stakeholders emphasised how uncertainty weakens the bankability of long-duration projects by increasing the cost of capital and increases floor levels.
- The complexity of the model and the impact on providers' ability to forecast revenues and optimise market positions
- Operational considerations, including when and how assets will be required to charge and discharge. Stakeholders requested more detail on expectations of asset cycling and the proposed approach to accounting for asset degradation.
- The restrictiveness of the operating regime, impacting the ability to participate in the market. Some stakeholders queried how a provider would 'declare unavailability to the capacity market' without affecting other market availability.
- Clarity of the open book reconciliation, specifically what costs (not just revenues) would be included. Stakeholders requested clarity on TE changes after gate closure and the impact on open book reconciliation.
- The focus of the model on curtailment mitigation and local constraint management, rather than delivery of strategic system services. Some stakeholders suggested including multi-day TEs to address this.

Of these 15 stakeholders, two stakeholders specifically noted that the TE model is not necessary in the LDES context and is not an enduring solution. Many stakeholders raised or reiterated these issues in their responses to Q15. These stakeholders:

- Noted that while TEs make sense in the ESBN DFP context, in the LDES context the use of trading envelopes reduces the incentive for the TSO to build comprehensive solutions of BM participation by BESS and RE-E.
- Proposed a time limit on the use of TEs and a move towards a market-based approach in the long-term
- Felt that the TE model is not required, as full flexibility of all battery units will be available to the TSO via BM once an enduring solution for battery participation in the BM is deployed.

Summary of 'compatible' responses

Six stakeholders (including one confidential response) felt the TE model would be compatible and appropriate for creating revenue certainty, but noted that:

- it would not be sufficient on its own to provide adequate investment signals

- allowances should be made for benefits that come from reduced deployment timeframes
- transparency regarding dispatch signals and timelines will be critical
- compatibility depends on whether limited intra-day updates are allowed and LDES cycle/degradation limits are recognised
- the TE must reflect the technical capabilities of assets and not require assets to operate outside limitations.

5.2.2 TSO response

The TSO acknowledges the range of concerns raised by stakeholders regarding compatibility of the TE with LDES asset operations and investment decisions. A number of these issues are addressed across different sections of this paper in more detail but the TSO would like to reiterate that the TE remains a necessary element of the proposed service design.

In response to concerns regarding the need for a clear mechanism that aligns LDES operation with system needs during periods of constraint, the TSO consider the TE should deliver ex-ante recognition of system constraints, and therefore does not consider their removal feasible over the duration of the contract in the absence of alternative measures to prevent ex-ante trading-based behaviour exacerbating dispatch down events. Further rationale for maintaining the TE for the scheme duration is set out in 4.2.12.

The TSO acknowledges concerns raised around revenue impacts, including the potential effect of operational and market uncertainty on project financing and restates that while the TE may restrict trading in certain periods, the revenue floor provides mitigation against having to trade contrary to market signals and to reduce revenue uncertainty for investors. A detailed explanation of the floor setting, open-book accounting and reconciliation is provided in 5.2.10.

BM participation remains fully facilitated as the TE operates only as an ex-ante limitation. All LDES assets will continue to submit BM data in line with existing arrangements. The TSO provides further information in 4.2.12 and 4.2.14

Relevant non-compliance charges will apply only where an asset has traded outside the envelope restrictions i.e. have breached the required trading envelope. Where a TSO redispatches an asset and thereby alters the asset's ability to meet its traded position within the envelope, this will be assessed in accordance with SDP 002 Follow PN ruleset, reflecting stakeholder concerns relating to TSO dispatch triggering penalties. Clarification on treatment of BM driven deviations is provided in 4.2.14

Stakeholder concerns regarding fairness and technical feasibility in how TE breaches are assessed, including the impact of TSO redispatch actions, are addressed in 4.2.14. The methodology used to assess nodal dispatch down benefits is provided as part of the scoring assessment in 0.

Relating to concerns on the impact of TE complexity on long-term revenue forecasting and the implications for financing, the TSO is adapting the TE design to provide sufficient clarity to industry to make investment decisions (see 7.3 for further detail).

Further clarity on operational expectation, including cycling patterns and degradation, will be provided in the LCOS methodology paper. In addition further detail on requirements for compliance with contracted MW and MWh volumes are outlined in Section 4.2.2.

TSO position

The TSO confirms that the application of a TE remains a necessary element of the LDES service design to deliver ex-ante recognition of system requirements that include locational constraints that are not evident through ex-ante market structures. EirGrid does not consider that the removal of this will be feasible over the duration of the scheme in the absence of alternative measures to prevent ex-ante trading-based behaviour exacerbating dispatch down events.

5.2.3 Q14: Do you believe that 10 am D-1 is sufficient notice to achieve a desired market position?

19 stakeholders responded to this question. The majority of stakeholders submitted that 10 am D-1 provides insufficient notice to achieve a desired market position. In general, these stakeholders felt that 9am D-1 would be preferable, noting that 10 am D-1 is too close to real time and does not provide enough time to process data, mitigate contingency or prepare ex-ante market strategies. Stakeholders broadly felt that 9am D-1 would allow sufficient time to formulate strategy and submit bits in the event of technical difficulties. Two stakeholders supported longer notice periods, one suggesting 10 am D-2 (i.e. 25 hours before closure of DAM), and one suggesting notice be given in contractual arrangements, not at a day-ahead stage.

One stakeholder agreed that 10 am D-1 provides sufficient notice. One stakeholder conditionally agreed, noting that 10 am D-1 could provide sufficient notice if accompanied by transparent congestion forecasts, firm DA TE parameters, and updates ahead of gate closure. Two stakeholders felt that while 10 am D-1 could be acceptable on a daily basis, it poses difficulties in the long-term, especially regarding forecasting long-term revenues over the life of the asset and for technologies that require longer operational planning horizons. In general, stakeholders who conditionally agreed with 10 am D-1 proposal felt that the broader complexity of the TE proposal remains challenging.

5.2.4 TSO response

The TSO acknowledges the potential challenges introduced by issuing TE at 10 am D-1 and the complexity it adds to trading strategies. The proposed timing aligns with the publication of the reposed DASSA volume forecast and therefore should allow LDES participants to evaluate their D-1 wholesale market bids in line with both their DASSA bidding strategy and their TE envelope requirements. The trading envelope determination will be a new TSO task, with additional resourcing requirements which needs detailed examination in the wider context of operational enhancements. A potential move to an earlier issuance time may be possible but is currently pending based on other internal operational developments The TSO proposes that the 10 am D-1 issuance time remains for the initial implementation of the service, noting that further capability to issue an earlier envelope may be determined before LDES operational go-live. A move to an earlier issuance time carries the risk of reduced forecast accuracy. This will be considered by the TSO as part of the development of the TE determination process.

The TSO has provided a provisional list of intended inputs into the TE, most of which will be available to market participants to allow them to conduct their own analysis and predict incoming envelopes prior to the 10 am D-1 issuance time. The characteristics of the TE have been further clarified in 4.2.12. As outlined, the TE will not include minimum import or export requirements and will instead define maximum import and export limits only.

At the outset of the LDES service, once issued at 10 am D-1, envelopes will not be amended which is designed to provide certainty for participants close to gate closure. Additionally, as outlined in Section 4.3 the TSO reserves the right to, following further industry consultation, provide updated TEs to assets after 10 am D-1 if this is deemed necessary in future.

TSO position

The TSO confirms the TEs will be issued at 10 am D-1 for the initial implementation of the LDES service. At service outset, once issued the TE will not be amended which is designed to provide certainty for participants close to gate closure. Additionally, as outlined in Section 4.3 the TSO reserves the right to provide updated TEs to assets after 10 am D-1 if this is deemed necessary in future, following further industry consultation and regulatory oversight.

5.2.5 Q15: Do you wish to add any further comments on the operational envelope model?

19 stakeholders responded to Q15. The themes generally align with concerns set out under Q13, 5.2.1, where respondents questioned the compatibility of the TE with investment decisions and long-term operational planning. A short summary of how these concerns arise in the context of Q15 is provided below.

Concept of TE

Many respondents reiterated the concerns raised in Q13, where stakeholders questioned the applicability of an TE based design and highlighted that it may be overly restrictive, with one stakeholder suggesting that the TE model will result in significant intervention by the TSO, with another suggesting that LDES should be provided as a 'tolled asset'.

Lifespan of TE

Stakeholders again expressed concern that the TE will be required for the full scheme duration, voicing preference for a time limited approach as market-based systems better align with real-time requirements. Stakeholders also suggested phased implementation of the TE, with optional enhancements available for participants willing to accept additional complexity in exchange for additional revenue.

TE amendments

Stakeholders requested clarification regarding changes to the TE and the possibility of real-time changes, and that breaches arising from TSO action should not trigger penalties, reflecting concerns raised under Q11, 4.2.11.

Revenues and costs

Feedback on revenue and costs linked to broader concerns rais in Q13 and Q17, particularly the need for clarity around cycling expectations and the basis on which revenue floors would be calculated, stating that the revenue floor mechanism be applied to net revenues, not gross to better reflect operational costs and support investment.

Stakeholders noted that uncertainty over how TE related losses will be treated could affect bid formation, mirroring concerns raised under Q12 and Q17. Stakeholders called for detail on the LCOS methodology (including input assumptions), noting that transparency and engagement on LCOS calculation would support investor confidence.

Scope of TE

A number of stakeholders questioned whether the TE design might limit participation from certain technologies or business models, suggesting that design should be expanded to LDES projects seeking a route to market through PPAs. Stakeholders felt additional detail on data transparency, regulatory governance, environmental metrics, and financial predictability would enhance the credibility and scalability of the TE model.

5.2.6 TSO response

Concept of TE

The TSO considers the TE concept strikes a balance between providing value to the end consumer, a sufficient investment signal to industry and contributing towards climate targets along with the provision of support tool to the TSO in managing complex system operations in a timeline that meets policy objectives. The rationale for maintaining the TE is further detailed in 4.2.10.

Lifespan of TE

The TSO maintains the TE model as outlined in this paper will remain in place for the duration of the scheme. The TE will be used as long as it continues to provide value to the TSO and end consumer. See 4.2.12 for more information.

TE amendments

The TSO does not intend to issue updated envelopes after the initial issue time of 10 am D-1 at the outset of the contract. The TSO retains the right to issue updated envelopes after 10 am D-1 but will only do so after sufficient industry engagement, consultation and with regulatory oversight. See 4.2.12 for more information.

Revenues and costs

The TSO continues to propose that the revenue floor be assessed on the basis of gross market revenues, rather than net revenues. See 5.2.10 for more information.

The TSO acknowledges the TE may, at times, limit access to potential revenue-earning opportunities. The purpose of the revenue floor mechanism is to provide a degree of protection to LDES investors against revenue uncertainty arising from TE restrictions. The TSO has provided further clarity in 4.2.14.

Further details on the LCOS methodology used to limit the revenue floor will be set out in the LCOS methodology paper to be published separately.

Scope of TE

The scope of the procurement has been designed to ensure valuable delivery of LDES services to the TSO in line with policy objectives. Wider concerns regarding eligibility and technology neutrality were addressed under sections 4.2.2 and 4.2.4 where the TSO clarified the rational for maintain the proposed eligibility criteria.

TSO position

The TSO confirms that the TE requirement will apply for the full duration of the LDES scheme that will be issued to successful tenderers from this procurement process. The TSO does not intend to issue updated envelopes after the initial issue time of 10 am D-1 at the outset of the scheme. Further detail is provided in Section 5.2.10 on the definition of gross and net revenues and the context of energy charging costs for LDES assets.

5.2.7 Q16: What is your view on the proposed 10-year contract length? Please provide rationale to explain this.

For clarity, terms such as contract length and contract duration used in the Consultation paper refer to the proposed duration of the LDES scheme and the period for LDES service payment eligibility. The actual contract that will be signed by successful LDES providers will cover the length of relationship between the TSO and the contracted provider from contract signature through project delivery and start of service delivery to the end of the scheme duration (i.e. could be longer than 10 years). We have attempted therefore, to ensure that in this paper we refer to scheme duration and scheme length to reflect the concept of the duration of the LDES scheme and revenue support eligibility.

27 stakeholders provided views on the proposed 10-year scheme duration. The majority considered 10 years too short, with 17 advocating for a scheme duration of at least 15 years, noting this would better reflect asset lifetime and support investment certainty.

4 stakeholders supported the proposed 10-year scheme duration, with an additional 4 stakeholders in conditional support, stating that a 10-year term would only be acceptable if accompanied by measures such as an investment rate threshold.

5.2.8 TSO response

The TSO acknowledges stakeholder views that a longer scheme duration could provide additional investment certainty. However, the purpose of the LDES procurement is not simply to support the deployment of storage assets, but to procure a service that delivers system benefits through the reduction of dispatch down and redispatch. The proposed Trading Envelope framework is intended to align asset behaviour with

these system needs, while the locational assessment criteria seek to incentivise projects in areas where they can provide the greatest value.

The TSO notes that while the technical lifetime of LDES assets may extend beyond 10 years, system needs and the value of specific locations will evolve over time as the network develops, generation patterns change and additional flexibility resources connect to the system. The TSO therefore considers it appropriate to strike a balance between providing sufficient contractual certainty to support investment decisions, procurement of a relevant and necessary service provision and maintaining the ability and flexibility to reassess future procurement requirements and locational needs in a rapidly evolving power system

5.2.9 On this basis, the TSO considers that a 10-year contract term is appropriate for the service being procured and reflects a reasonable balance between investment certainty and the evolving nature of system requirements.Q17: Do you have feedback on the proposed floor and share mechanism as outlined in Chapter 3 Section 3.3? Do you have concerns or a potential alternative you would suggest?

25 stakeholders provided feedback on the proposed floor and share mechanism. Overall respondents were broadly supportive of the concept but identified several areas for clarification or refinement.

Overall support for the mechanism

Most stakeholders support the proposed floor and share mechanism, noting that the upside revenue sharing would incentivise efficient asset operation. The proposed 70/30 split was broadly acceptable to stakeholders, although a few stakeholders suggested a 50/50 to better reflect the operational complexity and regulatory risk of the mechanism.

Some stakeholders expressed concerns that the strict eligibility requirements, short scheme duration, bias towards hybrid projects and focus on congestion means the mechanism is unlikely to procure a mix of LDES durations. It was proposed that a 'diversity metric' be introduced to the mechanism.

Basis of the revenue floor

Stakeholders reiterated a preference for the revenue floor to be assessed on a net revenue basis, concerned that a gross revenue floor fails to account for operating costs and does not provide a credible investment signal.

Floor limit and LCOS methodology

Stakeholders reiterated the need for clarity on how the limit on the floor price would operate, with some suggesting it be higher or removed entirely. Many supported using LCOS but requested transparency on assumptions and methodology. Some respondents expressed concern that setting the revenue floor below Long run marginal cost (LRMC) or LCOS will not provide incentives for investment in new storage, and that LCOS based capping may favour established technologies over innovative solutions.

A number of stakeholders proposed indexation of the floor in line with either inflation or an agreed benchmark, noting that this approach aligns with international examples (UK, NSW).

Others echoed commentary regarding increased financing costs due to administrative complexity submitted elsewhere in responses.

Charging and cost allocation

Stakeholders requested clarity on the treatment of non-compliance charges. One stakeholder noted that the current approach to network charging limits trading opportunities for batteries and submitted that trading opportunities would be further limited if the upside revenue is shared without wholesale charging and other costs.

Open book accounting requirements

Some stakeholders raised concerns about the administrative burden and commercial sensitivity risks associated with full OBA across multiple revenue streams. One stakeholder recommended a more

streamlined approach focussed on market-visible revenues, which could reduce administrative burden without compromising oversight.

Annual adjustment

Stakeholders requested clarity on EirGrid's position regarding annual adjustment of the revenue floor. Stakeholders generally do not support annual adjustment, with some suggesting allowing multi-year averaging to smooth market volatility.

International comparisons

Stakeholders suggested considering international examples and potential applicability in the Irish context. One stakeholder referenced the Australian Energy Market Operator's (AEMO) approach to setting contractual obligations for successful bidders regarding asset operations. Stakeholders also referred to the NSW LTESA offering annuity-based options for developers seeking predictable cash flows, with optional repayment if the upside is realised.

5.2.10 TSO Response

Approach to the revenue floor and share mechanism

The majority of respondent expressed support for the proposed revenue floor and upside sharing mechanism, recognising that the sharing of upside revenues can incentivise efficient asset operation. Having considered stakeholder feedback, the TSO does not propose any changes to the overall structure of the procurement approach at this time.

While concerns were raised regarding eligibility criteria, scheme duration and the potential impact on the diversity of LDES technologies, the TSO considers that the current design appropriately balances operational feasibility, system needs and value for consumers. These aspects will continue to be kept under review as the mechanism develops.

Basis for assessing revenues

EirGrid retains the proposal that the revenue floor be assessed on the basis of gross market revenues[24], rather than net revenues[25]. Gross revenues provide a transparent and technology-neutral metric that can be applied consistently across diverse asset types. Assessing on a gross basis avoids the need to determine or verify individual asset-specific operational or commercial cost structures, which vary considerably. Using gross revenues therefore reduces administrative burden, avoids potential distortions associated with the treatment of individual cost categories, and supports a fair and consistent comparison across all participating technologies.

While the proposed revenue floor mechanism does not include an explicit allowance for charging costs, these costs are implicitly reflected within the revenue assessment framework. Specifically, both buy and sell positions associated with market participation are captured within the eligible revenue calculation. As a result, the cost of electricity purchased from the market for the purposes of charging is netted against market revenues and therefore taken into account when determining performance against the revenue floor. In this way, the economic cost of charging is inherently accommodated within the mechanism without the need for a separate or explicit charging cost compensation.

The LDES service and the TE is designed to allow assets to participate freely across all relevant markets. Assets will not be instructed to take specific operational positions and will retain full control over their charging behaviour, including the timing of charging for arbitrage opportunities and the management of

[24] Gross market revenues refer to the total revenues earned by the asset across all eligible market and contractual revenue streams, prior to any deduction of asset-specific costs or charges.

[25] Net revenues reflect revenues after deduction of asset-specific costs, including (but not limited to) network charges, operational costs and other commercial or financing costs.

associated costs. Given this operational flexibility, EirGrid considers that using gross revenues to assess performance against the revenue floor is appropriate. This approach avoids introducing market distortions and supports efficient participation in energy and ancillary services markets. Operational and commercial costs remain fully at the discretion of the asset owner and can vary over time based on individual strategies, technologies and contracting arrangements. It is therefore appropriate that such costs are borne by the asset owner rather than reflected in the revenue floor, ensuring that consumers are not exposed to rising operational costs or commercial decisions that lie outside the scope of the mechanism.

Non-compliance and non-trading activity based charges:

A non-compliance charge will apply whenever an asset takes ex-ante positions outside its defined TE, including any envelope breaches resulting from DASSA orders. LDES Service providers are expected to trade within their TE at all times for all relevant markets, and the mechanism will be designed on the basis that breaches should not occur under compliant operation. A breach is recorded whenever an asset's ex-ante position exceeds the envelope limits. The charge will reflect the magnitude of the deviation outside the envelope and will be linked to prevailing system and market conditions through a reference price. This ensures that non-compliance always results in a meaningful financial consequence and becomes particularly material during periods of system stress. A minimum non-compliance charge value will apply to maintain a consistent deterrent even in lower-price conditions. To reinforce expectations, multiple breaches within a six-month period will result in a higher charge multiplier, signalling that repeated non-compliance represents a serious departure from contract expectations. Overall, the mechanism will be structured to strongly deter any departure from the TE, ensuring that assets operate responsibly and reliably.

In addition to the non-compliance charge, a proposed non-trading activity scalar will apply to ensure that LDES service providers remain active participants in the market and do not remain persistently at zero or otherwise inactive. As the TE does not mandate specific positions or dispatch patterns, LDES service providers retain full discretion over their operation; however, there is an expectation that they will demonstrate a sufficient level of cycling to assist with redispatch mitigation across the year. The TSO intends to assess levels of participation in the markets and where an asset does not meet the expected level of participation, or is declaring as unavailable outside normal maintenance requirements, the revenue floor will be reduced on a proportional basis to reflect this non-activation.

The detailed methodology for determining the expected level of activity and the associated adjustments will be developed further, informed by experience from the implementation of SDP_02 since November 2025, and will be included for industry review in the contractual arrangement's consultation. EirGrid aims to ensure that such a non-activation charge is structured to be a fair, transparent and effective incentive to support meaningful operational participation, and is informed by industry comment.

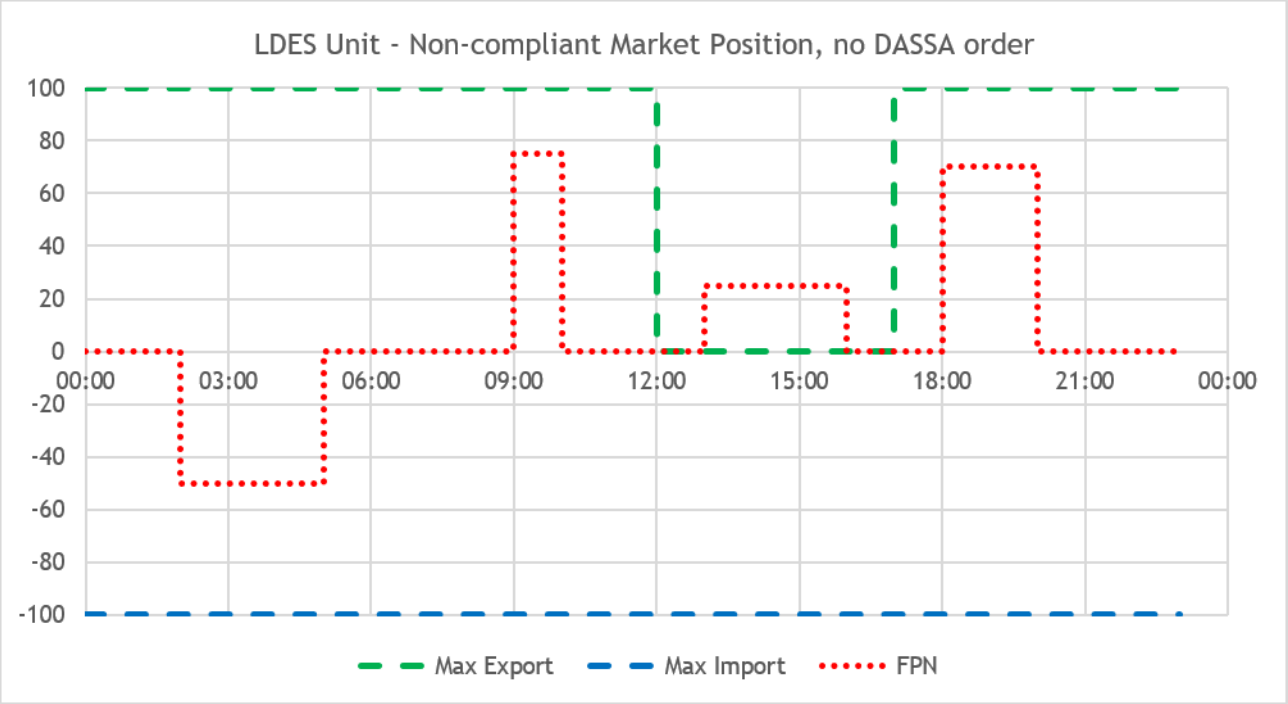
Illustrative example of non-compliance assessment and charge

Compliance with the Trading Envelope is assessed solely on a unit's ex-ante positions at gate closure (GC2) as defined in section D.2.1.2 in the Trading and Settlement Code. Any subsequent actions taken by the TSO to move a unit does not affect compliance. Units in breach of their Trading Envelope will be subject to a non-compliance charge which will be based on the maximum of revenue earned by the unit in that period or a minimum charge in cases where revenue is less. Given that TEs are limited to restrictions on maximum import or export only, a TSO action prior to gate closure cannot put a unit into a position of non-compliance with the TE that they were not already in themselves.

Participant's DASSA orders will be assessed when checking compliance with LDES envelopes. LDES units will be subject to non-compliance charges if their ex-ante DASSA position offers to provide a service that would put the units output in breach of the TE. Again, this would be an assessment of ex-ante positions only. DASSA positions will be assessed at secondary trading gate closure. DASSA reserve volumes will be calculated as the maximum reserve that would be required to be provided given the selection of orders for different services it has taken on in a period. More detail will be provided in the contractual arrangements consultation paper.

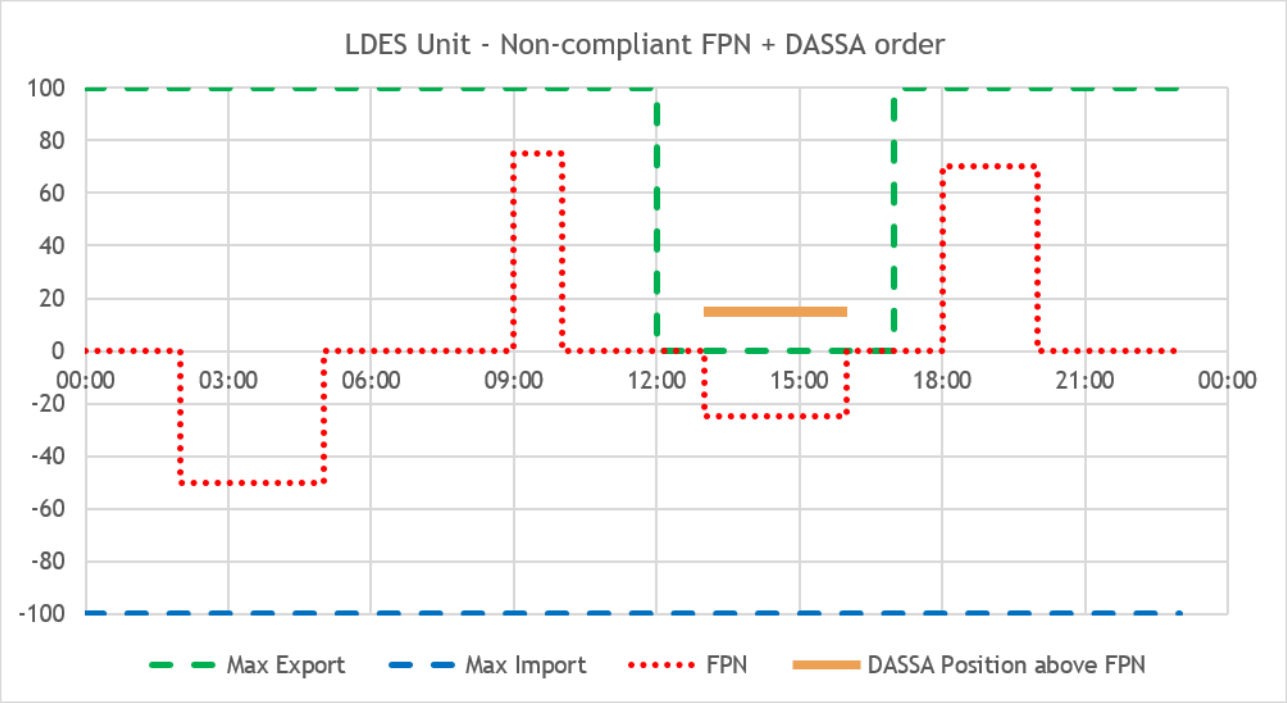
1. Unit has an export restriction of 0MW placed on it from 12:00 to 17:00. The unit has an FPN of 25 MW export from 13:00 to 16:00 and no DASSA orders. This unit is not compliant with the envelope for multiple periods as it has an FPN "%MW outside of the bounds of the envelope.

Figure 1 Scenario 1 Non-compliant FPN



2. Unit has an export restriction placed on if from 12:00 to 17:00. The unit has a FPN of -25 MW export from 13:00 to 16:00 and a DASSA order to be available to provide 40 MW of upward reserve in each period from 13:00 to 16:00. This unit is not compliant with the envelope in multiple periods as it has a DASSA order offering reserve service outside of the bounds of the envelope. The magnitude of the breach in this case is 15 MW. The volume of the breach caused by a DASSA order is considered in conjunction with the unit's FPN.

Figure 2 Scenario 2 Non-compliant FPN + DASSA position



The non-compliance charge will be applied in a manner that reflects both the magnitude of the breach and any history of repeated non-compliance. The charge will be linked to a reference price, the basis for which will be set out in the contractual arrangements consultation.

Where participants incur multiple breaches, the level of the charge will increase accordingly. In particular, where more than three breaches occur within a rolling six-month period, a higher multiplier will be applied to subsequent breaches within that period. This is intended to ensure that repeated non-compliance will result in stronger financial consequences. While further detail on the calculation of the MW breach and reference price to be utilised will be provided and consulted on in the Contractual Arrangement consultation, it is likely the non-compliance formula will be structured broadly as follows (subject to change):

$$\text{Non-compliance charge} = \alpha \times P_{ref} \times \text{Breach(MW)}$$

Where:

I. α is a multiplier – initial proposal of 1.5 with ability to increase to 2 if breaches are repeated

II. P_{ref} is the reference price

III. Breach (MW) is magnitude of the breach beyond the TE limit

Floor limit and LCOS methodology

Respondents were broadly supportive of the principle of using a LCOS to set the limit on the revenue floor level. In line with stakeholder feedback, EirGrid will publish separately a detailed methodology paper prepared by independent consultants setting out the input value sources, and calculation methodology used to produce the LCOS values, which will provide transparency to stakeholders regarding the definition of the revenue floor.

Open book accounting

As the mechanism provides a financial top-up where revenues fall below the agreed floor, it is necessary for the TSO to have sufficient visibility of the revenues received by participating assets. This is required to ensure the integrity of the scheme and to avoid the risk of over-compensation. The Open Book Accounting term refers to the process by which EirGrid, as TSO, will undertake to assess the revenue attributable to the LDES service provider across all relevant market and other financial streams, and determination of whether a revenue top up is required.

Accordingly, participation in the scheme will require asset owners to facilitate revenue data visibility and provision to the TSO. While the TSO acknowledges stakeholder concerns regarding administrative burden and commercial sensitivity, transparency in revenue reporting is considered essential to the effective implementation and governance of the mechanism. Appropriate confidentiality and information security considerations will be addressed as part of the contractual consultation.

To provide clarity on the scope of information to be reported, the assessment of revenues will include those earned through participation in the Day-Ahead Market, Intraday markets, DASSA, Capacity Market, BM, DASSA, RAD, and all other relevant revenue streams. Work is currently ongoing to determine future arrangements for the provision of non-reserve services; any potential revenue earned by LDES units for the provision of non-reserves will be included in the revenue assessment. These revenue streams will be aggregated and compared against the agreed revenue floor, with any shortfall addressed through a top-up payment, or where revenues exceed the floor, the agreed sharing mechanism will be applied. The mechanism will exclude any charges or adjustments arising from asset-specific operational behaviours such as uninstructed imbalance charges, generator performance incentives (GPIs), difference charges, testing-related charges or other similar behavioural or non-market-based settlement items. These categories of charges will not be eligible for top-up and will not be considered in the revenue assessment, with the final detailed list to be confirmed in the contractual arrangements' consultation.

While the proposed revenue floor mechanism does not include an explicit allowance for charging costs, these costs are implicitly reflected within the open book revenue assessment framework. Specifically, both buy and sell positions associated with market participation are captured within the eligible revenue calculation. As a result, the cost of electricity purchased from the market for the purposes of charging is netted against market revenues and therefore taken into account when determining performance against the revenue floor. In this way, the economic cost of charging is inherently accommodated within the mechanism without the need for a separate or explicit charging cost compensation.

In addition, with respect to use-of-system charges, the CRU has consulted on a proposal to reclassify the applicable Transmission Use of system charges (TUoS)for storage assets from Demand based TUoS (placed on volumetric demand) to Generation based TUoS G-TUoS) and has recently issued a Decision paper on Interim Transmission Network Charges for Energy Storage units (ESU)[26]. This decision facilitates a change from a volumetric based approach to a fixed locational transmission network charge. Under this approach, storage assets would be subject to the following

- Standalone ESUs and ESUs co-located with generation will be subject to G-TUoS charges per Schedules GTS-T or GTS-D of the Statement of Charges, consistent with generation units;
- ESUs will pay D-TUoS charges on energy volume and capacity only in respect of house load consumption, in line with the applicable G-TUoS Statement of Charges.

Consequently, the concerns on the application of DTUoS charges linked to charging volumes would no longer arise, further reducing the need for explicit treatment of charging-related network costs within the revenue floor mechanism.

To facilitate the OBA a portion of the relevant data is held by the designated NEMOs, the Market Operator, and the TSO. To facilitate the proposed remuneration mechanism, EirGrid will require timely access to this information, and will ensure provision of access to this is a contractual requirement. If it is necessary to

[26] https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU202696_Interim_Transmission_Network_Charges_for_Energy_Storage_-_Decision.pdf

ensure a formal requirement is placed on NEMOs or other market bodies or licensed entities to provide this data to the TSO, this will have to be mandated by the CRU in its' role as licensing and regulatory authority.

To ensure that the assessment of required revenue floor top up requirements takes account of all revenue streams accessible to the LDES contracted parties (based on the Unit ID) EirGrid will require that LDES contracted parties provide visibility of PPA revenue streams. This information will also be included in the revenue assessment. For clarity, only income attributable to the asset will be considered in the revenue floor assessment. Where a PPA arrangement results in a net payment outflow from the asset (i.e. the contracted party is paying out to a third party under the PPA), such amounts will not be eligible for compensation or top-up under the LDES scheme. Any additional revenue from PPA contracts will benefit TUoS customers through a net reduction in the revenue floor costs or an increase in funds returned through the applicable sharing mechanism.

EirGrid will therefore require submission of PPA revenue streams. A template will be developed to mandate and ensure the provision of standardised information for the Open Book assessment process. As part of contractual terms and conditions EirGrid will require a director's letter confirming the authenticity of the PPA declarations.

Illustrative Application of the Quarterly Revenue Floor, Revenue Sharing and Compliance Arrangements

This section provides an illustrative application of the proposed revenue floor mechanism on a quarterly settlement basis. The examples are intended to demonstrate the interaction between eligible market revenues, the revenue floor, the revenue sharing mechanism, and the treatment of non-compliance charges arising from breaches of the TE.

The Remuneration process will be carried out quarterly, with the annual revenue floor apportioned evenly across each quarter. At year-end, a retrospective review will be performed to ensure settlement against the revenue floor is appropriate on a full-year basis, and to reconcile any timing differences arising from quarterly top-up payments or periods where realised revenues exceeded the revenue floor. Normal market reconciliation processes will be accommodated within the LDES reconciliation processes. The comparison against the revenue floor will be made solely with reference to eligible revenues. Any non-compliance charges resulting from breaches of the TE are applied subsequent to the revenue floor assessment and are not eligible for top-up or inclusion within the revenue sharing calculation.

For the purposes of the illustrative examples set out below, it is assumed that the LDES unit has an agreed annual revenue floor of €8 million, corresponding to a quarterly revenue floor of €2 million. The agreed revenue sharing arrangement applies a 70:30 split to revenues above the revenue floor, with 30% of such revenues returned for the benefit of TUoS customers. In each illustration, the asset incurs a breach of the TE during the quarter, resulting in a non-compliance charge of €0.10 million.

Illustration A: Quarterly Revenues Above the Revenue Floor

In this quarter, the asset earns the following eligible revenues:

Table 6 Quarterly revenues above the revenue floor

Revenue Stream	Eligible revenue
Day-Ahead Market revenues	€1.2 million
Intraday Market revenues	€0.15 million
DASSA and RAD revenues	€0.35 million
Capacity Market revenues	€0.5 million
Balancing Market payments	€0.1 million
PPA revenues	€0.1 million
Total gross eligible revenues:	**€2.4 million**

When compared against the quarterly revenue floor of €2 million, gross eligible revenues exceed the floor by €0.4 million. As a result, no revenue floor top-up payment is due for the quarter. In accordance with the agreed revenue sharing mechanism, the surplus above the revenue floor is shared as outlined in Table 7 below:

Table 7 Surplus revenue

Revenue floor assessment	
Total revenue floor requirement	€2 million
Total gross eligible revenues	€2.4 million
Eligible Top-up	**€0**
Total revenue eligible for sharing mechanism	€0.4 million
TUoS customer returned share (30%)	**€0.12 million**
Asset owner retained eligible share (70%)	**€0.28 million**
Non Compliance charge	**€0.1million**

Following completion of the revenue floor and revenue sharing assessment, a non-compliance charge of €0.1 million is applied, arising from a breach of the TE during the quarter. This charge is not offset by the revenue floor or revenue sharing arrangements and reduces the net revenue retained by the asset owner.

Table 8 Revenue flows

Revenue flows	
Total returned by the asset	**€0.12 million TUoS share**
	€0.1million non-compliance charge
Total of revenue above revenue floor retained by the asset ((revenues gained above the revenue floor x70%) – applicable non-compliance charges)	**€0.18million**
Total Revenue for asset over the quarter (revenue below floor + share of revenue above floor – non-compliance charge)	**€2.18 million**

In this example, the asset would return €0.22 million to the TUoS pot (€0.12 million under the revenue share and €0.1 million from the non-compliance charge). The asset would retain €2.18 million over the quarter.

Illustration B: Eligible Revenues Fall Below the Quarterly Revenue Floor

In this quarter, the asset earns the following eligible revenues:

Table 9 Quarterly revenues below the revenue floor

Revenue Stream	Eligible revenue

Day-Ahead Market revenues	€0.85 million
Intraday Market revenues	€0.1 million
DASSA and RAD revenues	€0.25 million
Capacity Market revenues	€0.55 million
Balancing Market payments	€0.05 million
PPA revenues	€0.05 million
Total gross eligible revenues:	€1.85 million

When compared against the quarterly revenue floor of €2 million this results in a revenue shortfall of €0.15 million. In accordance with the remuneration mechanism, a revenue floor top-up payment of €0.15 million is made to bring total revenues for the quarter up to the level of the quarterly floor. As gross eligible revenues do not exceed the floor, no revenue sharing applies in this quarter.

As in illustration A, the asset incurs a breach of the Operational Envelope during the quarter, resulting in a non-compliance charge of €0.1 million. This charge is applied to the revenue floor top-up and is not eligible for compensation under the revenue floor mechanism.

The net effect is that the asset would receive a top-up payment of €0.05 million (€0.15 million top-up minus €0.1 million non-compliance charge).

Table 10 Revenue shortfall

Revenue floor assessment	
Total revenue floor requirement	€2 million
Total gross eligible revenues	**€1.85 million**
Eligible Top-up	**€0.15 million**
Total revenue eligible for sharing mechanism	€0
TUoS customer returned share (30%)	**€0**
Asset owner retained eligible share (70%)	**€0**
Non Compliance charge	**€0.1million**

Table 11 Revenue flows

Revenue flows	
Total returned by the asset	**€0.1 million non-compliance charge**
Total received by the asset (Top up payment)	**€0.15 million revenue top-up**
Net revenue received by asset	**€0.05 million (revenue top-up minus non-compliance charge)**

To provide clarity on the interaction between the quarterly application of the revenue floor mechanism and the annual assessment framework, this section sets out a simplified worked example covering a full year of operation. The illustration demonstrates how top-up payments, revenue sharing arrangements and non-compliance charges are applied on a quarterly basis, and how these interim financial flows are subsequently reconciled to ensure that the final outcome reflects the asset's performance against the revenue floor on an annual basis.

The illustration below first sets out the quarterly outcomes, including whether the asset is above or below the revenue floor in each period, and the resulting application of either top-up payments or revenue sharing. This is followed by a summary of aggregate in-year financial flows, before moving to the full-year assessment and final reconciliation.

Assumptions:

- Annual revenue floor: €8.0m (€2m per quarter)
- Revenue sharing: 70:30 (LDES Asset:TUoS)
- Non-compliance charges: applied in Q1 and Q4 only (€0.1m each)

Quarter	Revenues	Position vs Floor	Top-up	TUoS Share (30%)	Non-Compliance	Net to Asset
Q1	€2.4m	Above (+€0.4m)	€0	€0.12m	€0.1m	€2.18m
Q2	€1.85m	Below (-€0.15m)	€0.15m	€0	€0	€2m
Q3	€1.7m	Below (-€0.3m)	€0.3m	€0	€0	€2m
Q4	€2.6m	Above (+€0.6m)	€0	€0.18m	€0.1m	€2.32m

- In Q2 and Q3, revenues fall below the floor and the asset receives top-up payments (€0.45m total)
- In Q1 and Q4, revenues exceed the floor and €0.3m is returned to TUoS customers through the revenue sharing mechanism
- These payments occur on a quarterly basis. However, these flows are interim and do not represent the final outcome under the mechanism

In year financial position:

Item	Amount
Total top-ups paid to asset(from TUoS)	€0.45m
Total share rebated to TUoS by asset	€0.3m
Non-compliance charges	€0.2m

During the year:

- The asset received support in lower-performing periods
- TUoS customers receive value when revenues exceed the floor

- These flows reflect quarterly variability, not the overall annual position

The mechanism is calibrated on an annual basis. Accordingly, performance is reassessed using full-year revenues with the eligibility for top up/ upside payments focused on the revenues minus any non-eligible non- compliance charges etc. TUoS Customer rebate requirements are based on the full revenues (i.e. non-compliance charges etc are not deducted when calculating this element to incentivise compliance with the envelope)

Item	Value
Total Revenues	€8.55m
Non eligible charges separately to be paid back to TUoS e.g. non-compliance charge etc)	€0.2m
Revenue floor	€8m
Surplus for TUoS rebate calculation	€0.55m
Top up payments received	€0.45m

On an annual basis, the asset has outperformed the revenue floor, indicating that overall support was not required.

TUoS Rebate and Top-up flows (Full-Year Basis):

Item	Value
TUoS rebate already received (in-year) – TUoS rebate entitlement = TUoS rebate adjustment	€0.3m
TUoS rebate entitlement (30% of €0.55m total revenues)	€0.165m
TUoS rebate reconciliation adjustment	**€0.135m**
TUoS Support provided i.e. top up payments	-€0.45m

- TUoS customers received €0.3m during the year, based on strong quarterly outcomes in Q1 and Q4
- However, when assessed over the full year, the correct TUoS entitlement is €0.165m
- TUoS based revenue top ups totalling €0.45m were paid in Quarter 2 and 3, that were in excess of the annual revenue requirements when assessed over the full year
- The difference arises because:
    - Quarterly payments are based on point-in-time performance, while
    - The final entitlement is based on aggregate annual performance over a calendar year

Final annual Reconciliation:

Final position TUOS customer year end reconciled	**€m**	**Final position LDES asset year end reconciled**	**€m**
Top ups paid (in year)	-0.45	Total top ups received-in year	0.45
Rebate Received (in year)	0.3	Total revenues	8.55

Year end position	-0.15	TuOS Rebate paid- in year	-0.3
TUoS share Rebate required	0.165	TuOS Reconciliation	-0.315
Reconciliation required (Year end position- Rebate required)	-0.315	Non-compliance charge	-0.2
		Reconciled revenues	8.185

On an annual basis, the asset's realised revenues give rise to a TUoS rebate entitlement of €0.165 million, consistent with the overall surplus of €0.55 million. Non-compliance charges (€0.2m total) are excluded from revenue floor calculations as they do not affect top-ups or sharing and are not reconciled at year-end. They apply as a standalone financial charge.

The reconciliation process therefore:

- Systematically nets all interim payments, including both top-ups and revenue sharing transfers; and
- Ensures that the final allocation of revenues is aligned precisely with the full-year outcome.

Accordingly, the asset is required to make a net repayment of €0.315 million, reflecting the extent to which in-year support exceeded that warranted by its annual performance. plus the charges of €0.2m are applied to the asset

Annual adjustment and indexation

For clarity, the revenue floor will not be re-set on an annual basis, The floor price established through the tender process will apply for the full duration of the scheme, subject only to any potential indexation arrangements (further detail on proposed indexation will be contained in the contractual consultation).

The reference to annual assessment relates solely to the settlement process, whereby all relevant asset revenues are assessed against the floor on an annual basis to determine whether a top-up payment or upside revenue applies for that period.

TSO position

The TSO confirms implementation of the revenue floor and upside sharing mechanism as consulted. Performance against the revenue floor will be assessed on the basis of gross market revenues, providing transparent and technology-neutral approach. The revenue floor will be established at tender stage and will not be re-set annually. Open book accounting will be required as a condition of participation to ensure appropriate visibility of revenues and to avoid over-compensation.

5.2.11 Q18: What cadence of revenue floor payments will be necessary to finance LDES projects?

22 stakeholders responded to Q18. Stakeholders generally felt that revenue floor payments should be made monthly, to match the cadence of capacity market payments. Five stakeholders proposed quarterly payments. Four stakeholders proposed alternative cadences including bi-annually and annually ("consider a fixed annuity option, as used in the New South Wales LTESA, which provides stable payments with optional claw back if upside is realised").

Stakeholders noted that resettlement would have to be factored into payments in n+4 and n+13, and proposed there be an annual adjustment to address any errors in monthly remuneration calculations. Some stakeholders emphasised that developers should not be disproportionately burdened by the cadence of floor payments, and the cadence should reflect the risks associated with the floor mechanism arrangements.

5.2.12 TSO response

Having considered stakeholder feedback and operational requirements, the TSO considers quarterly settlement with annual reconciliation to be the most appropriate payment cadence. Quarterly payments strike a balance between providing participating assets with sufficiently regular cashflows to support financing requirements, while also allowing adequate time for the accurate aggregation, validation and verification of revenue data across multiple market revenue streams. This cadence recognises the complexity of settlement under the floor mechanism.

The TSO acknowledges stakeholder concerns regarding administrative burden and financing risk and considers that quarterly settlement represent a pragmatic approach for initial implementation of the mechanism. The settlement frequency may be kept under review as operational experience with the scheme develops, but any change from the proposed quarterly settlement with an annual reconciliation process would need to be consulted on and gain regulatory approval.

TSO position

The TSO confirms quarterly settlements with annual reconciliation as the initial settlement schedule for the revenue floor mechanism.

5.3 Summary of TSO recommendations

Following consideration of stakeholder feedback, the TSO confirms the following final positions:

The TE model

- The **TEs will be issued at 10 am D-1.**

Revenue floor and upside sharing mechanism

- The **proposed revenue floor and upside sharing mechanism will be implemented** as consulted, with no changes to the overall structure.
- **Performance against the revenue floor will be assessed using gross market revenues**. Asset owner retains responsibility for its operating and commercial costs.
- The **revenue floor value will be established at the tender stage** and will remain unchanged for each asset over the duration of the contract, (**subject potentially only to indexation)**.
- The revenue floor **will not be re-set annually.**
- The **revenue floor limit will be set using an LCOS methodology** which provides a cost reflective ceiling for the floor value and ensures that contracted assets are not over-remunerated over the scheme duration. A detailed explanation of the LCOS methodology will be provided in the LCOS paper.
- **Open book accounting will be required** as a condition of participation to ensure appropriate visibility of asset revenues and to avoid over-compensation.

Settlement Arrangements

- Settlement against the revenue floor will be **assessed on an annual basis**, for reconciliation purposes only.
- **Quarterly payments** will apply to the revenue floor mechanism to balance predicable project cashflow with settlement accuracy and operational feasibility.
- These arrangements are considered appropriate for the initial implementation of the procurement and may be reviewed in future procurements as operational experience is gained.

Non-compliance and trading non-activity based charges:

- A non-compliance charge will apply where assets take ex-ante positions outside their defined Trading Envelope (TE), including deviations from DASSA orders; breaches will be measured against TE limits and incur charges proportionate to their deviation and linked to market conditions, with a

minimum charge applicable. For repeated breaches an escalation factor will increase the charge applied

- A trading non-activity scalar will also apply where assets fail to demonstrate sufficient market participation or remain persistently inactive, with reductions to the revenue floor applied proportionately. The detailed methodology for the structure of the non-compliance charge and trading non-activity scalar and expected activity levels, will be provided in detail and consulted upon in the upcoming contractual arrangements consultation.

6 LDES Procurement arrangements

6.1 Consultation proposal

This is a general overview of the proposed LDES procurement process as consulted upon and the key principles behind it.

Table 12 Overview of the proposed procurement approach

Qualification System publication (see section 4.2)

- EirGrid will establish a Qualification System that will allow shortlisting of projects eleigible for tender based procurement.

Qualification Phase (see section 4.3)

- To participate in the LDES Phase 1 Tender, applications must be submitted no later than 30 days after the Qualification System is published.
- To qualify candidates will need to meet a set of pass/fail criteria, including a minimum financial turnover and demonstration of previous experience, possessing an accepted connection offer for the LDES unit and meeting minimum technical requirements.

Tender Process (see section 4.4)

- Request for Tender to be issued to successful qualified participants.
- Tenderers will be subject to pass/fail criteria (including signed connection agreement, final grant of planning, evidence of land rights etc) and ranked based on cost, the grid connection method used and the location.

Notification of Preferred Bidders and Contract Award Process

- EirGrid will evaluate the tenders and issue the notification of preferred bidder status.
- Preferred bidders will have 20 business days to sign their contract and achieve all conditions precedent to contract execution.

6.2 Summary of consultation responses

The following questions were asked in relation to LDES procurement arrangements:

Q19: Do you agree with the proposed procurement strategy and qualification criteria? Are there additional factors for consideration?

Q20: Do you have feedback on the proposed award criteria as outlined in Section 4.4? Are there additional factors for consideration?

Q21: Do you have feedback on the scoring mechanism and proposed methodology to score the cost, the connection method and the location? Are there additional factors for consideration?

Q22: Do you have any feedback on what the application of the Net-Zero Industry Act to the procurement arrangements may mean for LDES investors?

6.2.1 Q19: Do you agree with the proposed procurement strategy and qualification criteria? Are there additional factors for consideration?

26 respondents provided feedback on Q19. While most agreed that a procurement process is necessary to enable LDES deployment, many raised concerns that some elements of the proposed design may be overly restrictive and could reduce participation. A number of respondents also commented that the proposed design was not suitable as an enduring framework.

A recurring concern was the requirement for an accepted grid Connection Offer at the qualification stage. Respondents described this requirement as “arbitrary” and warned that it could “exclude a great number of projects in development”. Others noted that this timing could reduce competition by limiting participation to projects already far advanced in the ECP process. A number of respondents recommended moving this requirement to the award stage, while others suggested adopting an LCIS-style approach where grid connections are allocated to successful projects after the tender.

Some respondents also stated that placing detailed technical and grid requirements at qualification would create “a repetitive PQQ type process”, and that a more workable approach would be to assess such requirements at the tender stage rather than during qualification. Some respondents emphasised that qualification should not require projects to have already reached milestones that depend on timelines outside developers’ control.

Several respondents noted that the framework would benefit from clearer information on how future procurement rounds will be structured, noting that the current proposal does not give visibility on timelines or volumes beyond the initial round. Others noted that the overall process would need to allow participation from a broad range of projects and avoid creating unnecessary administrative burdens.

Some responses also queried how project suitability, including locational considerations, would be determined, noting that the consultation did not fully explain the methodology or provide sufficient detail to allow applicants to assess how their projects would be evaluated. A few respondents specifically requested greater transparency on locational scoring methodologies, clearer definitions and worked examples demonstrating how different project configurations would be assessed.

6.2.2 TSO response

6.2.2.1 Grid Connection requirements and procurement process

The TSO acknowledges the concerns raised regarding the requirement for an accepted grid Connection Offer at Qualification Stage. The original intention of this requirement was to ensure that projects were sufficiently advanced in the connection process and that, by the time they progressed to Tender, enough information would be available to establish a realistic and credible energisation date.

However, following further assessment of the connection process and consideration of stakeholder feedback, EirGrid considers that holding an accepted Connection Offer at Qualification Stage does not provide the level of assurance required regarding project deliverability or the achievability of the proposed energisation date. In particular, the detailed review necessary to determine a realistic energisation date would need to be undertaken formally as part of the procurement process itself.

In addition, EirGrid recognises that requiring projects to have accepted a Connection Offer at Qualification Stage may reduce participation without materially improving EirGrid's ability to assess project deliverability at that stage. EirGrid therefore proposes that applicants are required only to have received a Connection Offer at Qualification Stage. The requirement to hold a Connection Agreement would move to Tender Stage, together with the submission of a connection programme.

This approach broadens access to the Qualification process while ensuring that connection deliverability remains a key consideration within the procurement. To support this, EirGrid proposes a formal assessment of each tenderer's connection programme during the Tender process to determine whether the proposed energisation date is credible, realistic and capable of meeting the procurement delivery timelines.

To facilitate this, EirGrid recommends amending the grid connection requirements and introducing a two-step Tender process, as outlined below:

Step 1 – Qualification System Questionnaire (QSQ)

Requirement for a Connection Offer received

As a Connection Agreement is required at the Tender Stage (Step 2.A), and Connection Offers typically have a three-month acceptance period, Connection Offers must be issued sufficiently in advance of the Tender closing date to allow applicants adequate time to review and accept their offer.

EirGrid therefore recommends, as a change from the consultation proposal, that projects are required to have received (but not necessarily accepted) a Connection Offer by the Qualification Stage. This approach helps avoid timing constraints, reduces pressure on the connection process, and supports a smoother procurement process, while ensuring that only projects which have progressed sufficiently through the grid connection process to receive a Connection Offer can proceed to the Tender Stage.

Step 2.A – Request for Tender (RfT) Submission

With regards to the Grid Connection requirements, tenderers would be required to meet the following Pass/Fail requirements and provide the relevant documentation for verification;

- A Connection Agreement
- Provision of a detailed Connection Programme for assessment by the TSO in Step 2.B.
- Grant of Planning Consent pertaining to both the Facility and Grid Connection
- Evidence of the Customer's Land Rights pertaining to the Grid Connection
- A Key Map and AutoCAD of the Grid Infrastructure
- A Revenue floor submission (€/MW/yr) that is below the relevant Revenue floor limit value

This ensures that all projects submitting an RfT have secured the fundamental prerequisites for delivery.

All tenderers passing the Pass/Fail criteria will be ranked based on their scored criteria (cost criterion, impact criterion, grid connection method criterion), as further described in section 6.2.4.

Step 2.B – Best and Final Offer (BAFO) / Connection Programme Deliverability Assessment and criteria

EirGrid recommends shortlisting the highest ranked tenderers and progressing only this shortlist to the Best and Final Offer (BAFO) stage. This two-step approach is considered the most efficient and least resource-intensive option for EirGrid while also providing increased certainty and transparency for developers

Shortlisting of Tenders

The purpose of the shortlisting stage is to ensure that a sufficient number of projects remain in the process to meet the procurement volume at contract award.

Projects will be ranked based on the evaluation criteria and a number of projects exceeding the procurement volume requirement will be shortlisted to progress to BAFO. This additional buffer recognises that projects will subsequently be subject to a deliverability assessment and that some may not meet the deliverability criterion.

During the BAFO phase, EirGrid will engage with each shortlisted tenderer to:

- Review the project's Connection Programme; and
- Determine an evidence-informed feasible Target Energisation Date.

The Target Energisation Date will reflect EirGrid's best estimate of the delivery timeline of the relevant LDES proposal at the point in time of the assessment. This will be used for the purposes of assessing whether the tenderer can meet the overall deliverability requirements in terms of meeting the Target Scheme Go-Live Date as set out in the LDES contractual arrangements, which will be consulted on later in 2026.

Additional Deliverability criterion (Pass/Fail) at this step:

At this stage, any project will fail this criterion if its Target Energisation Date falls after the point that is four months before the Target Scheme Go-Live Date. This is because we assume a four-month period is required after energisation to complete Grid Code testing and other relevant compliance requirements. The Target Scheme Go-Live Date will be further defined and consulted on as part of the next consultation on the Contractual Arrangements.

If EirGrid's estimated Target Energisation Date, following developer engagement, is determined not to be feasible within the required LDES Target Scheme Go-Live Date, then the project will not meet the Deliverability criterion and will be removed from the shortlist.

This approach allows bidders which have passed the Deliverability criteria with a feasible Target Energisation Date to submit a BAFO incorporating a discount (€/MW/year) which will apply to their initial revenue floor submission. Any discount submitted as a BAFO will determine the final revenue floor used for ranking and selecting preferred bidders. Where no BAFO discount is submitted, EirGrid will evaluate the offer by reference to the initial revenue floor.

Note that only the cost criterion will be updated following the submission of the BAFO. The score of the impact criterion and grid connection method criterion will remain unchanged.

The number of projects to be shortlisted will be defined at a later stage and will reflect the balance between maintaining sufficient competition at BAFO, ensuring enough projects pass the deliverability assessment, and supporting an ambitious delivery timeline.

Note that the Target Scheme Go-Live Date will be defined in the next consultation on the contractual arrangements.

Purpose of the Target Energisation Date

The Target Energisation Date will be used only for the purposes of the LDES Agreement. The Target Energisation Date serves as a form of commercial protection for developers. If this date is not achieved due to a delay attributable to the TSO, contractual provisions—such as the Target Scheme Go-Live Date or contract end date—may be adjusted to reflect the duration of the delay. Further information will be provided in the upcoming consultation on the Contractual Arrangements.

Broader concerns raised by respondents regarding competition, transparency of project assessment and the suitability of the procurement design beyond the initial phase are addressed elsewhere in this paper. In particular, regarding the scoring of the suitability of an LDES at the Node, the TSO's response is provided in 6.2.4.

TSO position

The TSO recommends moving to a Qualification Phase followed by a two-step Tender process. At the RfT stage, projects must hold a Connection Agreement, planning consent, land rights, and grid drawings, ensuring only mature projects enter the competition. The highest-ranked bidders would then progress to BAFO, where EirGrid would review each project's Connection Programme and determine an evidence-informed Target Energisation Date, which bidders may reflect in an updated offer.

A Deliverability criterion will apply at BAFO: projects with a Target Energisation Date falling later than four months before the Target Scheme Go-Live Date will not proceed, with the Target Scheme Go-Live Date to be further defined in the next consultation. The Target Energisation Date will also form part of the contractual framework, with protections for developers where delays are attributable to the TSO.

Figure 3 provides a high-level flowchart of the recommended process, highlighting the key grid connection arrangements.

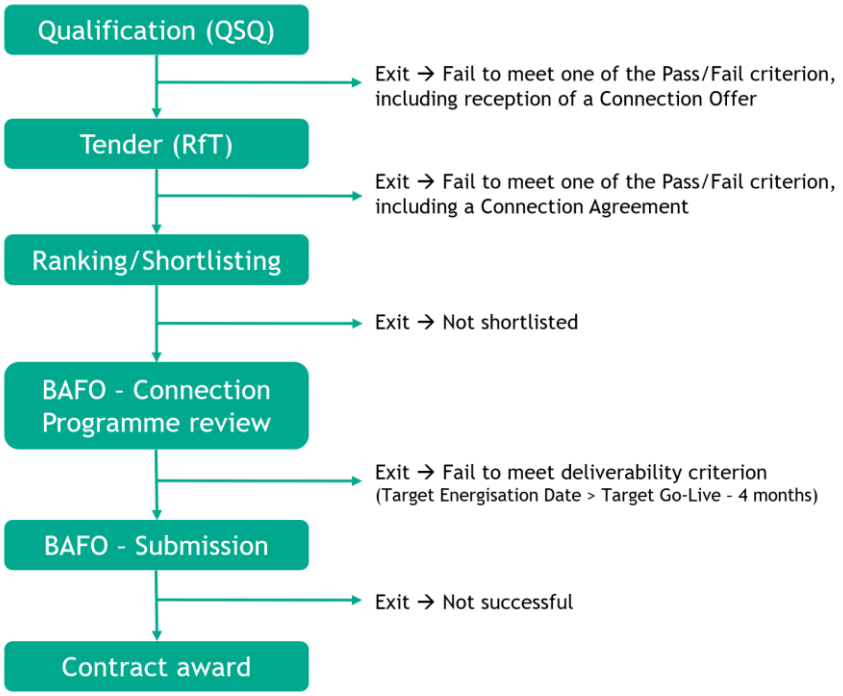


Figure 3: High-level flowchart of the recommended procurement process

6.2.3 Q20: Do you have feedback on the proposed award criteria as outlined in Section 4.4? Are there additional factors for consideration?

24 respondents provided feedback on Q20. Many commented that the proposed balance between price and non-price criteria, particularly the 50% weighting for non-price elements, was unusually high compared to other schemes and lacked sufficient justification. One respondent described the weighting as "a significant move away from prior support schemes", while others noted that it could have disproportionate effects on different types of projects. A number of respondents also felt that the weighting could introduce uncertainty for developers and requested clearer justification.

Several respondents expressed concerns that the scoring for connection method could disadvantage new standalone projects and that this could interact with cost differences already inherent between existing and new grid connections. Respondents also commented that existing grid connections already confer cost advantages and that awarding substantial additional scoring could amount to double counting. Some respondents suggested alternative approaches, such as capping the scoring or adjusting the weighting to avoid cost disparity between project types.

A number of respondents raised issues with the proposed locational scoring methodology, noting that the consultation does not clearly explain the calculation basis and that the approach could lead to "suboptimal outcomes." Concerns were also raised about assumptions used in the modelling, including the use of a one cycle per day assumption for evaluating impact on dispatch down.

Several respondents noted that the proposed scoring framework does not adequately reflect duration or the system value of long duration storage and requested worked examples and clearer explanations of how different characteristics would translate into scores. Some respondents shared concerns that the proposed approach may under reward technologies capable of addressing multi-hour or multi-day system needs and recommended refining the duration component.

6.2.4 TSO response

6.2.4.1 Scored criteria:

We acknowledge the feedback received regarding the proposed award criteria for this initial procurement phase, including the concerns raised by the respondents in relation to scoring weightages of the three scoring components and the request for further clarity on their calculation approaches.

With the proposed award criteria, we have attempted to reflect the potential value of an LDES unit while encouraging cost efficiency and optimised usage of grid infrastructure. As it is highly difficult to calculate the potential value of an LDES unit to the system, particularly due to its sensitivity to nodal placement, the award criteria are anchored in three sub-components and their scoring weightages, defined with the intentions to emphasize certain desired project characteristics.

For the initial procurement phase, we will adopt the following award criteria, with the recommended three scoring components:

Component 1: Cost criterion (50%)

It is important that the award criteria maximise value and encourage projects with efficient cost structures. This is achieved through a separate scoring component in the award criteria that prefers projects with lower Revenue Floor requirements compared to other projects in the tender. The key features of this component are:

- Separate assessment of the Revenue Floor bid submission in €/MW/yr.
- Maximum score available for this component will be 50 points.
- Only submissions received at or below the relevant Revenue Floor Bid Limit, will be accepted. (Bid limits will be set relevant to the duration of the asset and informed by the LCOS assessment (further detail provided in Sections 4.2,5.2, 5.3))
- The submission with the lowest price Offer for the Revenue Floor bid will receive the maximum score of 50.
- All other offers are scored in proportion to how close their price is to the lowest one.
    - **Points scored = cost of the lowest Offer price tender divided by the Offer price of the tender in question and multiplied by the maximum score achievable.**

With the above design, the TSO has shifted from their initial proposal of assessing the received Offer Price for Revenue Floor Price in € per MWh to € per MW of connection capacity. This change is made to align the cost component and the resulting incentives with the procurement target of this initial phase, expressed in MW (up to 500 MW).

Component 2: Impact criterion (30%)

The focus of this initial procurement phase of the LDES service is on reducing the redispatch by supporting projects that can appropriately import/charge, export/discharge, and store electricity as needed. Reflecting this in the award assessment criteria, the TSO initially proposed in the consultation paper the Suitability of the LDES unit at the Node criterion which scored submitted projects on their annual Charging Capability Estimate compared to the annual dispatch down at the node.

Recognising the concerns highlighted in the received responses, discussed in detail in section 6.2.5, around the unsuitability of measuring the reduction of dispatch down volumes by LDES units using annual dispatch down volumes, we recommend a revised approach under this Impact Criterion component that:

- Values the potential DD reduction an LDES asset can potentially deliver at each node (core LDES procurement objective).
- Recognises the potential additional system value (energy arbitrage opportunities) of LDES assets that remain available and are not stuck behind dispatch down events unable to charge, discharge.

The key features of this component are:

- To consider the hourly dispatch down (DD) volumes and their event distribution to evaluate the impact of an LDES unit in reducing the DD volumes.
- The scoring assessment will be split into two subcomponents:

1. **Potential avoided dispatch down volumes**
    - The first subcomponent compares the theoretical potential avoided DD volumes of considered unit at its node with the max. avoided DD volumes from the projects being assessed for tender award.
    - The project with the highest avoided DD volumes at the node will receive the maximum score of 20
    - All other projects are scored in proportion to how close their avoided DD volume is to the highest one.
    - Points scored= avoided DD volumes at the node of the project in question divided by the highest avoided DD volume tender and multiplied by the maximum score of 20.
    - The potential avoided DD is determined for different battery capacity, duration and node based on our hourly analysis of ECP data as further described in section 6.2.6. These values can be found in the csv file attached along this recommendation paper and named "LDES Impact criteria – Dispatch down and blocked hours data"
    - Where a project configuration falls between the modelled MW capacity and duration categories, the avoided DD volume for the project will be determined using bilinear interpolation of the surrounding modelled values.
    - Where a project connects at a node with no renewable generation, the avoided Dispatch Down volume for that project will be assumed to be zero.

2. **Blocked hours**
    - The second subcomponent is introduced to emphasise the incentive for appropriately sizing LDES configurations (in terms of connection capacity and storage duration) to the volumes and duration of the DD events projected at the node. This incorporates the preference for a project with low number of hours blocked behind DD events between two projects with same potential avoided DD volumes. Assets with a lower number of blocked hours are more consistently able to charge and discharge when conditions allow and therefore are expected to deliver additional benefits by having greater energy arbitrage opportunities.
    - This subcomponent reflects the hours over which the considered LDES unit would be blocked behind a DD event unable to discharge or charge.
    - The project with the lowest number of blocked hours at the node will receive the maximum score of 10
    - All other projects are scored in proportion to how close their number of blocked hours is to the lowest one.
    - **Points scored= lowest number of blocked hours tender divided by the number of blocked hours of the tender in question and multiplied by the maximum score of 10.**
    - The number of blocked hours is determined for different battery capacity, duration and node based on our hourly analysis of ECP data as further described in section 6.2.6. These values can be found in the csv file attached along this recommendation paper and named "LDES Impact criteria – Dispatch down and blocked hours data"
    - Where a project configuration falls between the modelled MW capacity and duration categories, the number of blocked hours for the project will be determined using bilinear interpolation of the surrounding modelled values.

- Where a project connects at a node with no renewable generation, the avoided Dispatch Down volume for that project will be assumed to be 4654h as further explained in section 6.2.6.

The maximum score available for this component will be 30 points, with a 20 and 10 split between the Potential Avoided dispatch down Volumes and Blocked Hours subcomponents respectively.

The proposed weighting reflects the TSO's assessment of the relative importance of the two subcomponents. Potential avoided DD Volumes represent the primary objective of this procurement and therefore receive the greater share of the available score. The Blocked Hours subcomponent provides an additional assessment of how effectively an LDES configuration is matched to the duration and distribution of dispatch down events and recognises the additional value associated with assets that remain available for energy arbitrage and provide additional benefits when not constrained.

As noted above, we recommend increasing the maximum score available under the Impact Criterion from the original consultation proposal of 20 points to 30 points. This change reflects the central role of dispatch down reduction of this service procurement and ensures that the potential system impact of a project remains a key differentiator within the award assessment. The revised weighting also provides an appropriate balance relative to the Connection Method criterion, ensuring that connection-related considerations do not disproportionately influence tender outcomes at the expense of the primary procurement objective.

Furthermore, in conjunction with the Cost component, the Impact Criterion provides a strong incentive to appropriately configure LDES connection capacity and storage duration to the projected dispatch down volumes and event distribution at a given node. For example, increasing storage duration may reduce performance under the Cost criterion, but could be justified through improved performance under the Impact criterion if it allows the project to avoid a greater volume of dispatch down.

This interaction between the award assessment components is intended to allow tenderers to optimise project configurations and identify the most efficient balance between project cost and system benefit. Further details on the calculation approach of the above described two subcomponents are provided in section 6.2.6.

Component 3: Connection method criterion (20%)

The inclusion of the Connection Method criterion is intended to support the efficient integration of LDES projects onto the transmission system. The TSO considers that incentivising hybrid and existing connection arrangements promotes the efficient use of grid infrastructure and helps reduce the requirement for additional standalone transmission connections. In particular, hybrid connections are considered an efficient use of existing network infrastructure and support the co-location of storage and renewable generation.

Several respondents raised concerns that allocating a significant weighting to the Connection Method criterion could result in double counting, as projects benefiting from existing or shared infrastructure may also have lower project costs. The TSO acknowledges these concerns. However, connection method represents a developer decision and is assessed separately to recognise the system and infrastructure benefits associated with different connection arrangements.

While hybrid configurations may benefit from reduced effective connection costs depending on the specific connection design and commercial arrangements in place, these advantages should be inherently reflected in tendered bid prices. The TSO does not explicitly account for any assumed advantage within the Cost criterion and therefore does not consider that the Cost and Connection Method criteria result in double counting.

Having considered stakeholder feedback, the TSO recommends revising the Connection Method scoring as follows:

Score	Connection Method Type

20	• Hybrid (New and Existing): The LDES unit connects with a renewable generation installation (30 MW min of renewable generation). • Existing standalone: LDES unit connected independently & already energised by the Tender closing date.
0	• New standalone connection: LDES unit connecting independently, requiring a new transmission connection.

This revised scoring approach maintains an incentive for the efficient use of grid infrastructure while reducing the overall weighting of the criterion in response to stakeholder feedback. The TSO considers that the revised weighting appropriately recognises the benefits of hybrid and existing connection arrangements without allocating excessive weighting relative to the other award criteria.

TSO position:

The proposed award criteria for the initial LDES procurement phase are structured around three components—Cost (50%), Impact (30%), and Connection Method (20%)—each designed to incentivise specific project characteristics while supporting efficient system outcomes. The Cost Criterion rewards lower Revenue Floor bids assessed in €/MW/year, aligning incentives with the MW-based procurement target. While this approach may advantage shorter duration projects, the Impact Criterion is structured to counterbalance this by valuing the potential reduction in DD volumes and the availability of LDES assets to provide additional system value, using two subcomponents: avoided DD volumes and blocked hours.

The Impact Criterion weighting is increased from 20 to 30 points to reflect the central objective of reducing renewable dispatch down, encouraging developers to configure duration and capacity to match nodal DD patterns. The Connection Method Criterion supports efficient use of existing grid infrastructure, with revised scoring to avoid overweighting connection-related considerations relative to the Impact Criterion. Overall, the recommended criteria aim to balance cost efficiency, system impact, and grid utilisation, ensuring that procured LDES capacity delivers meaningful value to the power system.

The TSOs recommended approach for the Impact Criterion is expected to score longer duration projects higher, depending on DD event distribution at the considered node; thereby providing an incentive on the storage durations. This provides an opportunity for the project developers to optimise their project configuration between the, at times, competing incentives from the Cost and Impact Criterion to achieve the highest score in the award assessment. We believe that this approach achieves a balance between procuring long duration storage capacity that brings benefits to the system and reflects value to the end consumer through cost consideration. This is further discussed in detail under section 6.2.6, describing the calculation approach for the Impact Criterion.

6.2.5 Q21: Do you have feedback on the scoring mechanism and proposed methodology to score the cost, the connection method and the location? Are there additional factors for consideration?

There were 26 responses to Q21. Respondents provided a wide range of feedback, with many expressing concerns about the proposed locational scoring methodology. A recurring theme was that the nodal based approach may not accurately reflect real system behaviour. Several respondents argued that relying on single node analysis could lead to “suboptimal outcomes”, particularly because constraints and dispatch down patterns often span wider geographic areas rather than individual nodes.

Many respondents recommended replacing the nodal methodology with a zonal approach, noting that a zonal model would better capture systemwide constraints, provide more predictable investment signals, and align more closely with how EirGrid already assesses wider network conditions. They stated that the nodal method risks producing volatile or misleading scores that may not reflect the contribution projects could make to reducing dispatch down across an entire region.

A number of respondents also raised concerns that the proposed formula does not adequately reflect duration or the system value of long duration storage. Respondents noted that the methodology "rewards shorter duration storage equally to longer duration storage" up to the dispatch down limit, despite longer duration storage being more capable of addressing multi-hour or multiday surplus events. Several requested clearer explanations or worked examples of how duration would affect scores.

Some respondents questioned the assumptions underlying the calculation method, particularly the implied single cycle per day assumption used to calculate annual charging capacity. They suggested that this assumption oversimplifies real world operation and could distort comparisons between different technologies or durations. They recommended incorporating more realistic operational modelling to assess system value.

Several responses also highlighted that the current approach may unintentionally disadvantage certain technologies or project types. For example, respondents warned that the formula could favour short duration battery systems or hybrid configurations without adequately recognising the broader system value that other LDES technologies could deliver. They emphasised the need for a technology-neutral approach.

Finally, many respondents requested greater clarity on key elements of the scoring methodology, including the treatment of multiple projects at the same node, the impact of overbuild, and the input assumptions used in dispatch down forecasts. Respondents noted that without clear guidance and examples, it is difficult for developers to understand how their projects would be scored in practice.

6.2.6 TSO response

Suitability of the Node Scoring / Impact criterion (30%)

We acknowledge the extensive feedback received regarding the proposed locational scoring methodology, including the strong preference from many respondents for a zonal rather than a purely nodal one. As stated in Section 4.2.6 the TSO maintains that a nodal assessment is necessary to accurately evaluate the potential of LDES assets to reduce dispatch down, to take account of location specific constraints. A zonal assessment would not sufficiently assess the value of dispatch down avoidance at nodes with high levels of dispatch down, as it would not be able to determine the potential restrictions on the asset based on the node it is connecting to. For this initial procurement phase, we propose to continue using the ECP-derived nodal level dispatch-down results.

In relation to the treatment of duration and cycling assumptions, we note the concerns raised that our initial proposal does not sufficiently account for the duration or the distribution of dispatch down periods. In response to this feedback, we have undertaken additional analysis using the hourly dispatch-down data from the ECP 2.5 results.

We recommend the following approach:

- We recommend using the ECP 2.5 scenario, based on the 2030 Network assumptions that 50% of ECP wind and solar project capacity proceeds to connection and that 2.6 GW of offshore generation is delivered. This scenario includes only batteries expected to connect by 1 January 2028.
- Extract the hourly RES dispatch down results, assuming grandfathering, to assess the profile and magnitude of dispatch-down events at each node.
- For each node, we analyse the hourly RES dispatch down volumes (wind and solar) to determine the potential avoided dispatch down for LDES assets with different connection capacity (MW) and storage duration (hr).
- For each node, we also look at the potential availability of the unit to provide additional system benefits.
- This approach allows us to assess the relative efficiency of each proposed LDES unit in reducing RES dispatch down volumes at the node, rather than relying on an assumed single daily cycle.

Calculation approach:

1. Potential avoided dispatch down volumes
    - The potential avoided DD volume by a unit is calculated by taking the hourly dispatch down profile of wind and solar at the node in the ECP model year and assuming the considered unit to charge until there are no more nodal RES DD volumes available to absorb, or until 100% State Of Charge (SOC) is reached.
    - The charging rate is defined as the minimum of the hourly dispatch down volumes at the node and the maximum import capacity of the unit.
    - At 100% SOC, the unit sits idle for remaining hours of dispatch down and is considered as 'blocked' from discharging or charging. The unit can also find itself 'blocked' at any SoC when it can neither charge due to lack of nodal RES DD nor discharge due to an ongoing dispatch down event.
    - The approach distinguishes between system wide dispatch down events, i.e. surplus and curtailment, and location specific constraint-based dispatch down. The unit only charges with volumes of dispatch down at the node of its location, while it is restricted from discharging for all the hours with system wide or its location specific dispatch down events.
    - In any hour with no dispatch down, the unit discharges at the rate of its maximum export capacity until it is empty, i.e. 0% SOC. It is important to note that the unit only discharges in hours with no dispatch down at the node, and outside any system-wide dispatch down signals.
2. Blocked Hours
    - The blocked hours for a unit at the node is the count of hours for which the unit is stuck behind a dispatch down event (including surplus, curtailment and location specific constraint), unable to charge or discharge when minimising direct dispatch down of RES at the node.
    - LDES at nodes with no RES are, by definition, void of RES dispatch down however, we assume they are still subject to the same system-wide surplus and curtailment export restrictions (total of 4,654 hours). Due to LDES' inherent inability to reduce RES dispatch down at their node, these nodes are not reported under the impact criteria and are treated as follow:
        - Potential avoided dispatch down volumes at the node: 0 MWh
        - Blocked hours: 4,654

Assumptions and caveats:

- ECP models, assumptions and methodologies that inform forecasted dispatch down reports benefit from wide stakeholder engagement and are publicly available[27]
- We assume full alignment of LDES charging and discharging with nodal RES dispatch down events to calculate the avoided dispatch down volumes and hours blocked.
- No market wide price signals are taken into account to determine the potential avoided dispatch down for an LDES unit. This approach examines only the technical capability of the considered unit configuration (charging and discharging capacity and storage duration).
- The avoided dispatch down volumes are theoretical determinations, which may not reflect the real-world operation of these assets as that will be guided by various commercial and technical factors.
- The Trading envelope issued in D-1 at 10 am and market position that the LDES unit needs to take ahead of real time may not allow the full avoided dispatch down volumes to be realised.
- The assessment undertaken as part of the impact criteria will not inform actual envelope determination or be relied upon by the TSO to inform system operation.

[27] https://www.eirgrid.ie/industry/customer-information/ecp-constraint-forecast-reports

Example:

To provide further clarity on the calculation approach of the two subcomponents under the Impact Criterion, we present two examples. The inputs are for illustration purposes and do not reflect TSO expectation or ECP results.

1. Comparing the scoring for the same LDES unit at two different nodes

Unit Name	Storage Duration	Connection Capacity (import & Export)
Unit 1	5hrs	40 MW

Node Name	Dispatch Down Event Distribution (Constraint based events)	Dispatch Down Event volumes
Node A	• Occurs every day of the year • Duration of every event 19hrs	• 12.5 MW
Node B	• Occurs every day of the year • Duration of every event 3hrs	• 60 MW

Determined avoided dispatch down volumes and blocked hours for Unit 1 at nodes A and B are:

Node Name	Blocked Hours	Avoided Dispatch Down Volumes
Node A Dispatch down event of **12.5MW** occurs every day of the year and last **19hrs**	• Unit 1 takes 16 hours to charge and another 5 to discharge. • Based on the distribution of dispatch down events at node A, unit 1 completes 1 cycle, but is blocked for 3 hours every day. • Blocked hours = 3 * 365 = **1,095hrs**	• Unit 1 completes one cycle every day • Avoided dispatch down volumes = 12.5 * 16 * 365 = **73,000 MWh**
Node B Dispatch down event of **60 MW** occurs every day of the year and lasts **3hrs**	• Unit 1 charges for 3 hours and discharges for another 3. • Based on the distribution of dispatch down events at node B, unit 1 completes 0.6 cycles per day, and remains unblocked every day. Blocked hours = 0 * 365 = **0hrs**	• Unit 1 completes 0.6 cycles every day • Avoided dispatch down volumes = 3 * 40 * 365 = **43,800 MWh**

Despite being capable of avoiding greater volumes of dispatch down at node A (73 GWh vs. 43.8 GWh at node B), Unit 1 finds itself more 'blocked' (1,095 hours vs. 0 hours at node B). There is a compromise between both metrics and a dependency on the tender submissions, which as described in the calculation approach above will determine the preferred outcome of the procurement.

2. Comparing the scoring for two different LDES units at the same node

Unit Name	Storage Duration	Connection Capacity (import & Export)
Unit 2	6hrs	40 MW
Unit 3	4hr	40 MW

Node Name	Dispatch Down Event Distribution (Constraint based events)	Dispatch Down Event volumes
Node C	• Occurs every day of the year • Duration of every event 6hrs	• 40 MW

Determined avoided dispatch down volumes and blocked hours for Unit 2 & 3 at node C are:

Unit Name	Blocked Hours	Avoided Dispatch Down Volumes
Unit 2 Duration 6hrs Connection capacity 40 MW	• Unit 2 takes 6 hours to charge and another 6 to discharge. • Based on the distribution of dispatch down events at node C, unit 2 completes 1 cycle, and remains unblocked every day. • Blocked hours = 0 * 365 = **0hrs**	• Unit 2 completes one cycle every day • Avoided dispatch down volumes = 6 * 40 * 365 = **87,600 MWh**
Unit 3 Duration 4hrs Connection capacity 40 MW	• Unit 3 can only charge for 4 hours of dispatch down event. • Based on the distribution of dispatch down events at node C, unit 3 completes 1 cycle, but is blocked for 2hours in the day. Blocked hours = 2 * 365 = **730hrs**	• Unit 3 completes one cycle every day • Avoided dispatch down volumes = 4 * 40 * 365 = **58,400 MWh**

With a greater duration, Unit 2 provides both greater avoided dispatch down volumes and a reduction in hours blocked when compared to Unit 3, making it a more suitable candidate under the impact criterion. However, higher bid prices are expected to provide a counterbalance in the cost criterion, before arriving at final overall scores.

TSO position

The revised Impact Criterion (30%) retains a nodal approach because only nodal-level ECP dispatch down data is available and current ECP zones are not granular enough to meaningfully incentivise location. In response to feedback on duration and cycling assumptions, TSOs analysed hourly ECP 2.5 dispatch down data and developed a methodology that calculates each project's potential avoided dispatch down volumes and identifying hours in which the unit is "blocked." This assessment compares how effectively different

LDES configurations reduce dispatch down volumes and remain available for providing additional system value.

6.2.7 Q22: Do you have any feedback on what the application of the Net-Zero Industry Act to the procurement arrangements may mean for LDES investors?

21 respondents provided feedback on Q22, most were broadly supportive of the objectives of the NZIA, however concerns were raised about the practical application of requirements to this procurement.

A number of respondents noted that procurement must reflect the current reality of supply chains, stating that at present, it is not possible to source all relevant storage technologies within the EU at scale and within the expected timelines of this procurement. As a result, there is a concern that rigid or premature application of NZIA requirement could unintentionally restrict competition or delay project delivery.

Respondents also noted that not all storage technologies are covered by NZIA and do not trigger the same resilience requirements. Views differ on how this should be reflected, with one respondent cautioning against extending NZIA requirements beyond their formal scope, where a number of others emphasise that EirGrid must ensure that they are applied in a way that preserves a technology-neutral approach.

Several respondents recognised that NZIA requirements may not be fully applicable to this procurement round but emphasise the importance of future proofing the framework to accommodate NZIA for future procurement rounds.

A number of responses also highlighted the ongoing DCEE consultation on NZIA and RESS procurement, and requested that an consistent industry wide approach was applied. Stressing that LDES procurement should not diverge unnecessarily from the approach being developed elsewhere.

There was also a strong call for further clarity on how NZIA would be applied in practice. Respondents requested clearer information on elements such as; timing, scope, thresholds and exemptions. Without this clarity, respondents note that is difficult to assess risks or factor NZIA into bidding strategies. They also raised concerns that introducing NZIA requirements could results in additional procurement or qualification criteria, potentially slowing down the process.

6.2.8 TSO response

The Net-Zero Industry Act ("NZIA") (Regulation (EU) 2024/1735) entered into force on 29 June 2024, introducing certain non-price criteria in certain public procurement processes involving net-zero technologies.

EirGrid is considering whether it will, at its discretion, apply all three or fewer of the following three conditions:

(i) social or employment-related considerations;

(ii) compliance with cybersecurity requirements; or

(iii) contractual obligations relating to timely delivery.

EirGrid will ensure that any NZIA-related requirements are applied in a manner that is consistent with the Utilities Directive, and the relevant legislative framework.

Further detail on the application of NZIA requirements, including any resilience or sustainability considerations, will be specified in the forthcoming consultation on contractual arrangements.

Participants should familiarise themselves with NZIA and all participants should seek their own legal advice on provisions of NZIA and its application.

Foreign Subsidies Regulation

Participants should be aware of the Foreign Subsidies Regulation (Regulation 2022/2560) (the "**FSR**") which introduced a notification-based procedure to investigate bids in public procurement procedures involving financial contributions by non-EU governments, where the estimated contract value is at least €250 million and the bid involves a foreign financial contribution of at least €4 million per third country in the last three years.

In order to comply with the FSR, participants will be required to submit either a FSR notification or a FSR declaration. EirGrid is required to transmit this information to the European Commission, and the outcome of any review may impact contract award timelines or eligibility.

Participants bear sole responsibility for ensuring compliance with their obligations under the FSR and should be familiar with the FSR and the Implementing Regulation.

Participants will be expected to comply with all applicable legislative requirements, including NZIA and the Foreign Subsidies Regulation, as part of the procurement process.

6.2.9 Qualification and tender criteria summary

Table 13 Recommended qualification criteria

Qualification Criteria	TSOs' Recommendations	Change from Consultation Proposal
Financial Turnover	The candidate must have a minimum financial turnover in one of the last three financial years. This threshold will be proposed in the second consultation on contractual arrangements and may be calculated based on an estimated annual payment a typical LDES unit could receive under the floor price model described in section 5.3, multiplied by a factor of 1.5 to account for financial resilience and delivery risk.	No change. A minimum turnover figure will be provided in the second consultation on the contractual arrangements.
Previous experience	The Candidate must demonstrate that it has had a significant role in delivering 2 major projects for which the purpose is to generate electricity or provide system services through a connection to an Electricity Transmission System in the last 7 years. A significant role may include activities such as: • Project development • Engineering, procurement, and construction (EPC) • Ownership or investment • Operations and maintenance • Grid integration and commissioning Further details will be provided in the Pre-Qualification Questionnaire.	No change.
Cyber-Security insurance	Participant must demonstrate that they comply with relevant cyber security requirements and applicable NIS legislation (including but not limited to NIS certification, a	Minimum level of cyber insurance required specified. Note that by the

Qualification Criteria	TSOs' Recommendations	Change from Consultation Proposal
	minimum level of cyber insurance of €5,000,000 in the annual aggregate)	time of qualification, this number may be adapted.
Connection offer	Participants must have received a Connection Offer for an LDES relevant asset.	Connection Offer requirement changed from "accepted" to "received". See justification in 6.2.2
Technical requirements	**Connection:** To qualify, the project proposed by the Candidate must: • have received a Connection Offer from EirGrid for connection of the relevant LDES asset at 110kV or above to the transmission system • have separate market registration and submetering for any co-located assets. **MEC/MIC & Duration:** To qualify, the project proposed by the candidate must have a Maximum export capacity (MW), equal to an equivalent Maximum import capacity (MW), with a duration of at least 4 hours for both import and export capability in line with the proposed service definition **Technology Maturity:** To qualify, the candidate must demonstrate that the proposed technology is an established and commercially available technology, deployed in multiple grid-connected sites (in Ireland or other relevant jurisdictions) with demonstrated operational delivery of service delivery and/or market participation.	Connection Offer requirement changed from "accepted" to "received". See justification in 6.2.2 No changes to the other aspects.

Table 14 Recommended tender criteria

Tender Criteria	TSOs' Recommendations	Change from Consultation Proposal
Technical requirements (Pass/Fail)	Tenderers will be required to meet technical requirements relating to: • the unit size: - 20 MW to 100 MW for hybrid connections - 75 MW to 100 MW for standalone connections	

Tender Criteria	TSOs' Recommendations	Change from Consultation Proposal
	• The Round Trip Efficiency (RTE) of ≥75%	
Grid connection (Pass/Fail)	Tenderer must have a Connection Agreement and must provide a detailed connection programme that will be reviewed at BAFO stage. Additionally, tenderer shall have achieved: • Grant of Planning Consent pertaining to the Facility and Grid Connection, • Evidence of the Customer's Land Rights pertaining to the Grid Connection and • a Key Map and AutoCAD of the Grid Infrastructure	This is a change. See details in section 6.2.2.
Revenue floor Limit (Pass/Fail)	Tenderers shall provide a Revenue Floor bid in €/MW/year, not exceeding the applicable Revenue Floor limit.	This is a change from the consultation
Cost (50%)	Tenderer will bid a revenue floor in €/MW/year, and this will be assessed for all tenders (specific to each individual LDES asset characteristics) received based on €/MW/year	This is a change from the consultation proposal as further described in section 6.2.4
Impact criterion (30%)	Tenderer will be scored based on two subcomponents: • Potential avoided dispatch down (20%) • Blocked hours (10%)	This is a change from the consultation proposal as further described in section 6.2.4. The weighting has been changed from 20 to 30%.
Connection Method (20%)	**Score 20** • Hybrid (New and Existing): The LDES unit connects with a renewable generation installation (30 MW min of transmission connected renewable generation) • Existing standalone: LDES unit connected independently & already energised by the Tender closing date. **Score 0** • New standalone connection: LDES unit connecting independently, requiring a new transmission connection.	This is a change from the consultation proposal. The weighting has been changed from 30 to 20%. Note also that a threshold of 30 MW has been introduced on the Hybrid definition. See justification in Section 4.2.4.

Tender Criteria	TSOs' Recommendations	Change from Consultation Proposal
Deliverability criterion (Pass/Fail) – to apply at BAFO stage	Tenderer must have a Target Energisation Date falling no later than four months before the Target Scheme Go-Live Date[28].	This is a new criterion included at BAFO stage.

6.3 Summary of TSO recommendations

The TSO's recommended procurement arrangements are broadly consistent with the original proposals consulted upon, while incorporating targeted refinements in response to stakeholder feedback to improve deliverability, competition, and transparency.

1. Qualification System Publication

EirGrid will establish a Qualification System that will enable subsequent procurement phases. For this initial LDES Tender, participation will be through a Qualification System Questionnaire (QSQ).

The TSO recommends implementing a Qualification System under which participants must satisfy both company-level and project-level criteria.

- **Application window**

  To participate in this LDES Tender, applications to the Qualification System must be submitted no later than 30 calendar days following publication of the Qualification System.
- **Company-level criteria** require candidates to demonstrate:
  - A minimum financial turnover (to be confirmed in the next consultation on contractual arrangements);
  - Relevant experience in the development, delivery, ownership, or operation of large-scale electricity or system services projects; and
  - Compliance with cyber-security requirements, including minimum insurance provisions.
- **Project-level criteria** require that proposed LDES projects are at an advanced stage of development. In particular, projects must:
  - Have received a valid grid Connection Offer for an LDES asset of minimum four hours at 110 kV or above;
  - Meet minimum technical requirements, including at least four hours of export and four hours of import duration, have equivalent MEC and MIC values, separate market registration and sub-metering for co-located assets; and
  - Demonstrate technology maturity through the use of an established, commercially available technology deployed at multiple grid-connected sites with demonstrated operational delivery.

2. Tender Phase

The TSO recommends a two-step Tender process.

A. Request for Tender (RfT)

At the RfT stage, tenderers must meet all Pass/Fail requirements, including:

- A Connection Agreement;
- Grant of planning consent for the Facility and the Grid Connection;

[28] The Target Scheme Go-Live Date will be defined following the next consultation process on the contractual arrangements

- Evidence of land rights for the Grid Connection;
- Submission of Key Maps and AutoCAD drawings of the Grid Infrastructure;
- A detailed Connection Programme; and
- Submission of a Revenue Floor price in €/MW/year that does not exceed the defined Revenue Floor limit.

Tenderers meeting these requirements will be scored against three weighted award criteria:

- Cost criterion (50%): incentivises competitive Revenue Floor bids aligned with the MW-based procurement target.
- Impact criterion (30%): evaluates each project's ability to reduce renewable dispatch down and remain available to provide wider system value, using avoided dispatch down volumes and blocked hours derived from hourly ECP 2.5 data. See Sections 6.2.4 and 6.2.6 for further information.
- Connection Method criterion (20%): incentivises the efficient use of grid infrastructure. Projects utilising a hybrid connection arrangement (minimum 30 MW renewable generation) or an existing standalone connection at tender closing date receive the maximum score available under this criterion (20 points), while projects requiring a new standalone transmission connection receive a score of zero.

B. **Shortlisting and BAFO**

Following initial scoring, the highest-ranked tenders will be shortlisted. The shortlist size will be sufficient to meet the procurement volume, with an additional buffer to account for differences in individual project MW sizes and the risk that some projects may not meet deliverability requirements at the subsequent stage. See Section 6.2.2 for more information.

During the Best and Final Offer (BAFO) stage, EirGrid will:

- Review each shortlisted project's Connection Programme; and
- Determine a Target Energisation Date, representing EirGrid's best estimate of delivery timelines at this stage.

Deliverability Criterion

A Deliverability criterion will apply at BAFO stage on a Pass/Fail basis. Projects will not proceed where the Target Energisation Date falls later than four months before the Target Scheme Go-Live Date, reflecting the time required for Grid Code testing and compliance activities. The Target Scheme Go-Live Date will be further defined in the upcoming consultation on the contractual arrangements.

The Target Energisation Date will also form part of the contractual framework, providing appropriate protection where delays are attributable to the TSO.

Shortlisted tenderers that have passed the Deliverability criterion may submit a BAFO incorporating a discount (€/MW/year) to their initial Revenue Floor offer. Any BAFO discount will determine the final offer used for ranking and selection. Where no BAFO is submitted, the initial offer will be used. Only the Cost criterion will be updated following BAFO. Scores for the Impact and Connection Method criteria will remain unchanged.

3. Notification of Preferred Bidders and Contract Award

Following completion of the tender evaluation, EirGrid will issue notifications of Preferred Bidder status to the successful tenderers.

Preferred Bidders will be required to execute the LDES services contract and satisfy all conditions precedent to contract execution within 30 business days of notification (extended from 20 business days, reflecting

learnings from the Low Carbon Inertia Services procurement). Where a Preferred Bidder fails to do so within this period, EirGrid may withdraw Preferred Bidder status and consider the next-ranked tender.

7 Operational considerations

7.1 Consultation proposal

Before day-ahead gate closure, the TSO will issue an TE to each LDES asset which may contain periods in which dynamic energy import or energy export limitations are applied to the asset. It would be free to trade opportunistically in the ex-ante markets only within these constraints, including in the provision of other services, if its traded position stays within the relevant LDES dynamic energy import/export limits.

TE inputs

The following (non-exclusive) parameters will be included as inputs to the TE determination process:

A. RES forecasts and forecast error considerations
B. Asset MIC/MIC
C. Demand Forecast and forecast error considerations
D. Planned outages and risk of unplanned outages
E. Cycling restriction considerations
F. Min and max unit import/export restrictions
G. Interconnection forecasts
H. Firm access status
I. System wide redispatch forecasts (curtailment)
J. Locational constraint based redispatch forecasts

TE outputs

As part of this LDES procurement phase (i.e. the procurement of up to 500 MW, , the TSO will issue simple energy import/export TEs that define the maximum charge and discharge limits of an LDES asset for a specified time period. During periods of particular local or system-wide constraint or curtailment, the TSO may issue energy import/export limits that constrain the operation of the LDES asset to mitigate constraint or curtailment. During periods of low curtailment and constraint, the TSO may issue minimally prescriptive TEs.

TE implementation

The implementation of the TE will need further detailed consideration; this will be scoped out and detailed further in subsequent documentation and contractual agreements.

Assessment of compliance with TE

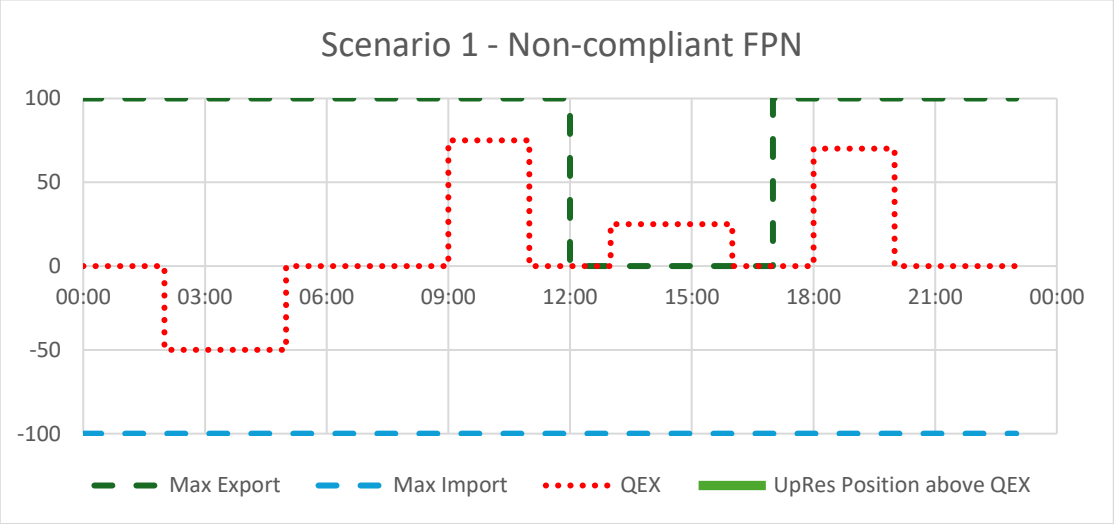
Assessment of compliance with LDES dynamic energy import/export limits will be assessed based on the LDES asset's final traded position, represented by its FPN and DASSA positions for each imbalance settlement (30 min) period. LDES asset operators will be liable for non-compliance charges if they do not trade TE within the bounds of the Trading Envelope. This approach allows for LDES asset operators to freely trade in all markets including day-ahead, intraday, system services and balancing so long as they trade within LDES dynamic energy import/export bounds.

Compliance with the Trading Envelope is assessed solely on a unit's ex-ante positions at gate closure (GC2). Any subsequent actions taken by the TSO to move a unit does not affect compliance. Units in breach of their Trading Envelope will be subject to a non-compliance charge which will be scaled to the magnitude of the breach and tied to a reference price to ensure that there are no circumstances where it would be beneficial for the unit to breach. Given that TEs are limited to restrictions on maximum import or export only, a TSO

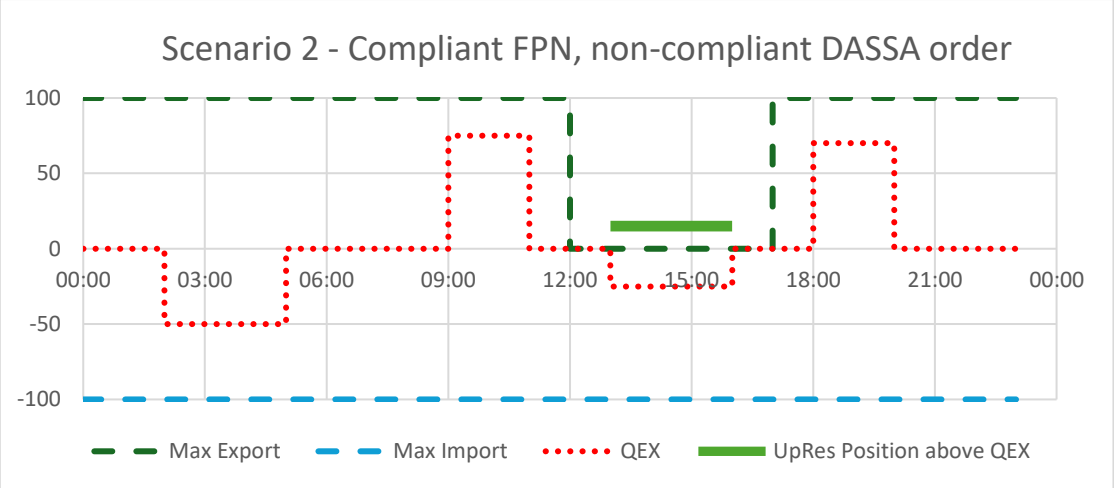
action prior to gate closure cannot put a unit into a position of non-compliance with the TE that they were not already in themselves.

Participant's DASSA orders will be assessed when checking compliance with LDES envelopes. LDES units will be subject to non-compliance charges if their ex-ante DASSA position offers to provide a service that would put the units output in breach of the TE. Again, this would be an assessment of ex-ante position. DASSA positions will be assessed at secondary trading gate closure. DASSA reserve volumes will be calculated as the maximum reserve that would be required to be provided given the selection of orders for different services it has taken on in a period. More detail will be provided in the contractual arrangements consultation paper.

3. Unit has an export restriction place on it from 12:00 to 17:00. The unit has an FPN of 50MW export from 13:00 to 16:00 and no DASSA orders. This unit is not compliant with the envelope as it has a FPN outside of the bounds of the envelope



4. Unit has an export restriction place on if from 12:00 to 17:00. The unit has a FPN of -25MW export from 13:00 to 16:00 and a DASSA order to be available to provide 40MW of upward POR reserve from 13:00 to 16:00. This unit is not compliant with the envelope as it has a DASSA order offering a reserve service outside of the bounds of the envelope.



The non-compliance charge calculation will likely take a form similar to that outlined below (may be be subject to change and will be further defined in the contractual consultation):

$$\text{Non-compliance charge} = \alpha \times \text{Breach(MW)} \times P_{ref}$$

TE summary

The benefits of the TE approach align with those highlighted in responses to the LDES Call for Evidence:

1) **Market-led:** LDES units under the TE Model would instead have full access to all markets they are eligible to participate in, provided they meet TE positions.
2) **Revenue certainty:** the proposed competitive process strikes a balance between the revenue certainty needed to attract investment and the market participation to ensure efficient operation of LDES assets.
3) **Revenue stacking:** responses to the Call for Evidence cited market participants' preference for revenue stacking facilitation and having the flexibility to operate in multiple markets.
4) **Reducing redispatch:** respondents to the Call for Evidence agreed that there was a need for LDES to support the management of renewable surplus, grid constraint, reducing generation costs and reaching our decarbonisation goals.

7.2 Summary of consultation responses

The following question were asked in relation to operational considerations:

Q23: Do you consider any other aspects need to be included in the inputs informing operational envelope development that have not been listed? Please explain your rationale.

Q24: Do you have any concerns on the initial outline of the proposed operational envelope outputs and implementation?

7.2.1 Q23: Do you consider any other aspects need to be included in the inputs informing operational envelope development that have not been listed? Please explain your rationale.

12 stakeholders responded to Q23. Respondents offered additional aspects that need to be included in the inputs informing TE development, key points of which are summarised in Table 15 below.

Table 15 Additional aspects suggested for inclusion in the operations envelope

Suggestion	TSO response
Clearer definition of hybrid sites	Clarity has been provided on hybrid sites in relation to MW requirement for renewable component of hybrid sites in Section 4.2.4
Higher scoring for connections that avail of existing infrastructure	This is an intrinsic component of our proposed scoring of the Connection element of the tender assessment
Time-limited use of the Operational; move to a market-based system later with LDES assets having unconstrained participation in the Day-Ahead market	Trading envelope application will be an essential component of the LDES service for the duration of the scheme, see Section 4.2.10 for further detail.

Provide worked examples of the TE model to provide clarity on investment	To be included
Explanation on how degradation will be accounted for	This is included in relation to asset performance requirements See 4.2.2 for more details.
Information on the difference in treatment and risk profile of firm versus non-firm batteries	Not applicable. This status does not directly impact the design or operation of the TE.
Consider intrinsic technical characteristics of each LDES technology type	Not applicable. The TE is designed as a technology-neutral mechanism based on system conditions. Technology-specific characteristics are reflected through asset performance and participant operational strategies.
Include inertia and frequency stability requirements, as well as system restoration and grid-forming capabilities	Not applicable. All assets will be required to meet minimum grid code requirements for their respective technology and will be incentivised to ensure they access revenue streams for all available reserve and non-reserve system services.
Inform the TE issuance based on real-time State of Charge and Asset Availability	The TE will be based on managing system conditions at the D-1 stage. It will be the asset owners responsibility to manage State of Charge, and to declare availability accurately. Updates to TE will need to take account of evolving LDES behaviour and system conditions.
Conduct forecasting for renewable build out and future constraint zones	Not applicable as part of this process.
Include market signals and interconnector flow information to inform the TE	All available and relevant data will be used to inform the development of the TE at D-1 stage.
Conduct consumer impact modelling	A Cost benefits assessment is underway
Safety and cybersecurity requirements	There will be mandatory cybersecurity and safety requirements placed on all tendering assets and maintained through the lifetime of the contract.
Set out how operational risks to do with the TE will be mitigated or compensated for	The TE will inform the trading behaviour of the asset. Operational strategies of the assets remain the responsibility of the asset owner.

7.2.2 TSO response

The TSO notes all feedback from respondents on inputs into the development of TEs. All inputs will be considered to ensure that the most accurate envelopes can be issued to ensure the minimisation of dispatch down. The TE will be in place for the duration of the contract and will be monitored throughout to ensure its use is providing value to the end consumer and the TSO.

7.2.3 Q24: Do you have any concerns on the initial outline of the proposed operational envelope outputs and implementation?

17 stakeholders responded to question 24. Respondents offered feedback on additional concerns on the proposed TE outputs and implementation, key points of which are summarised in Table 16 below. Respondents reiterated that communication between the TSO and operators is highly important; one respondent requested that the TSO engage directly with storage operators via in-person workshops, and to provide worked examples of how the TE will be implemented. One respondent reiterated their belief that

the TE framework is not required, and instead LDES assets should instead be available to the TSO through the BM once the enduring solution for battery unit participation in the BM is implemented.

Table 16 Additional concern on the TE outputs and implementation

Concerns
TEs could become overly restrictive; assets could have limited access to other markets
Lack of clarity on how units will be expected to respond to changes in the TE close to real time
Lack of clarity on TE timelines
Parameters for determining the envelopes need to specified in the service contract
TE should be made available to alternative routes to market
TE approach risks steering assets away from market price signals
Deviations from service contract must be compensated for

7.2.4 TSO response

TEs will not force action in a specific direction.

The TSO retain the right to introduce updated envelopes following the initial issuance at D-1 10 am if operational needs justify more frequent updates. The TSO commits to consult widely on the details of such a proposal to allow for full industry engagement. The issuance of closer to real-time envelopes will require the examination of the evolution of electricity markets, including changes to liquidity post Celtic go-live; and increased TSO capability to calculate envelopes within day.

7.3 Summary of TSO recommendations

Our main recommendations in relation to the operational considerations are relatively unchanged from the original proposals.

We recommend:

- That **TEs will only impose import and export maximum restrictions**. The envelopes will not impose minimum import or export requirements ensuring no specific traded positions are mandated at any time.
- Participants **DASSA orders will be assessed when checking compliance with LDES envelopes**. LDES units will be subject to non-compliance charges if their ex-ante DASSA position offers to provide a service that would put the units output in breach of the TE.
- Assets will be **free to bid into the DASSA RAD mechanism** and in line with the requirements to provide full availability data at BM gate closure this will allow full involvement in the RAD mechanism and potential RAD revenues if their RAD bids and availability are determined to have been successful in the RAD merit order assessed ex-post. RAD participation will not affect compliance with Trading Envelopes.

8 Additional considerations

8.1 LDES Connection Pathways

The final decision requires LDES applicants to have received a Connection Offer at qualification stage, and to have a Connection Agreement at Tender Stage. Based on these conditions, EirGrid identifies two possible pathways for LDES projects to meet the connection requirements set out in the LDES procurement process:

- LDES applicants with a Connection Agreement.
- LDES applicants without a Connection Offer or Connection Agreement from the TSO for access to the transmission network.

For both pathways, EirGrid identifies a set of scenarios and routes that will enable LDES projects to satisfy the required connection criteria.

8.1.1 LDES applicants with an existing Connection Agreement

This pathway covers applicants that already hold an executed Connection Offer, that is, a Connection Offer signed by both the applicant and the System Operator, forming a binding Connection Agreement. The different LDES configurations and their associated connection requirements allow existing contracted parties to utilise their Connection Agreement to participate in the LDES procurement process. However, in some cases the Connection Agreement may require modification in order to meet LDES requirements. Several scenarios may arise:

Applicants that already meet all LDES requirements. In this case, no modifications to the Connection Agreement are required. These applicants may access both the qualification and tender stages.

Applicants requiring regular modifications to the Connection Agreement. These amendments can be requested at any time and do not need to follow the ECP batch process. However, modifications must be completed and reflected in an updated Connection Offer in order to enter the qualification stage and an updated Connection Agreement to enter the tender. At this point of time the list of modifications are:

- Increase in storage duration.
- MIC/MEC decrease (with no significant expected change to shallow work).

Applicants requiring significant modifications. Certain substantial modifications may enable projects to become eligible for LDES procurement, but they must be processed through the ECP batches. Such modifications are assessed within the ECP batches, and must be completed and reflected in an updated Connection Offer in order to enter the qualification stage and updated Connection Agreement to enter the tender. The list of significant modifications are:

- MEC or MIC increase
- Repowering
- Change in technology type.

8.1.2 LDES applicants without a Connection Agreement

LDES projects must enter the ECP GSS offer process in order to obtain a grid Connection Offer. The ECP GSS is the current standard process for securing a grid connection and classifies projects into two categories: **RED III projects** and **non-RED III projects**. Interested parties are recommended to review the EirGrid Connection process information site[29] for more information.

Considering the LDES procurement process timelines, projects seeking a LDES contract and that do not yet hold a grid Connection Offer would need to be in receipt of an offer at qualification stage.

[29] https://www.eirgrid.ie/industry/becoming-customer/generator-connections

Furthermore, any type of Connection Offer modification request must be fully completed and reflected in an executed Connection Offer in order to enter the LDES qualification stage.

Other considerations

For clarification the following points are also relevant to some of the responses received

- Firm and non-firm :

  Some storage assets already operational may hold firm connection contracts. All recently connected or due to connect storage assets will be non-firm status in line with connection policy. This relates to their treatment in relation to balancing market revenues.

- Private wires, MEC sharing and multiple legal entities:

  As policy and regulatory processes evolve more complex considerations are emerging. For clarity for this immediate procurement of LDES we will only consider hybrid sites that have separate metering and market registration for the LDES asset and the renewable generation installation. Thereby we will not be able to accommodate MEC sharing proposals, or private wire arrangements. The multiple legal entities aspect is not yet clarified in terms of timelines for progressing of this, and we have not been able to examine the potential implications of this for LDES at this time.

9 Next Steps

This paper sets out the TSO recommendations to the CRU for the LDES Procurement Mechanism, taking into account the detailed responses received from industry during the LDES Procurement Mechanism consultation.

We will publish separately an independent consultant's report on the LCOS methodology. Also to be published separately and alongside this paper is the LDES Impact criteria – Dispatch down and blocked hours data document.

EirGrid will publish a second consultation document that will seek industry views on proposed detailed contractual arrangements for the procurement of LDES in Ireland later in 2026. It is envisaged that procurement will start in 2027. Further detail on anticipated timelines will be provided to industry through the Future Markets stakeholder engagement processes.