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Battery and Hybrid Projects in Ireland: Regulatory progress and key challenges that remain

The Irish energy storage sector is moving in the right direction. In April and June 2026, the Commission for Regulation of Utilities ("**CRU**") made two important decisions that improve the investment signals for storage projects: sharing a single contracted Maximum Export Capacity ("**MEC**") to unlock hybrid co-location and replacing Demand Transmission Use of System charges ("**D-TUoS**") on charging volumes with Generation TUoS ("**G-TUoS**") for Energy Storage Units ("**ESUs**"). These are meaningful steps forward. Yet structural challenges remain, including on Integrated Hybrid Project regulation, operational restrictions placed on Battery Energy Storage Systems ("**BESS**") assets and the risk of trading storage in a centrally dispatched market like Ireland's. Resolving these challenges will be just as important as the progress already made.

The importance of storage to Ireland's energy transition is well established. The Government's Electricity Storage Policy Framework for Ireland recognises that an increased deployment of electricity storage systems is critical to maximising the integration of renewable electricity onto the grid while maintaining security of supply. With over 1 GW of electricity storage systems already operational and peak renewable electricity generation already above 5,800 MW and growing, the policy framework identifies BESS as a central tool for achieving Ireland's 2030 Climate Action Plan targets: 80% of electricity from renewable sources, a System Non-Synchronous Penetration ("**SNSP**") ceiling raised to 95% and dispatch-down of renewables limited to below 7%. Alongside the launch of full wholesale market participation for BESS in November 2025, EirGrid's Long Duration Energy Storage ("**LDES**") procurement scheme and ESB Networks' Demand Flex programme, the CRU's reforms described in this article sit within that broader policy ambition.

Sharing Maximum Export Capacity

The CRU's decision of 15 April 2026 (CRU202643) removes one of the long-standing structural barriers to hybrid project development in Ireland. Multiple generation and storage technologies at a single grid connection point will, once fully implemented, be able to dynamically share a single contracted Maximum Export Capacity ("**MEC**"). This means that a developer with a 70 MW MEC can co-locate 70 MW of solar and a 50 MW BESS without requiring 120 MW of separate export capacity. Each participant must manage the allocation of MEC between the technologies.

The decision has significance well beyond greenfield development. As a grid strategy, MEC sharing allows existing contracted grid capacity to work harder. It can allow for utilising headroom that would otherwise sit idle during periods when the primary generation asset is not operating at full output. For operational wind and solar projects, this creates a compelling case for retrofitting BESS onto existing sites. Given the current pressure on grid connection queues and the cost and timescales associated with new connection applications, the ability to add storage value behind an existing connection point is a material commercial and infrastructure benefit. From a system perspective, it also supports more efficient use of existing network assets, potentially deferring or avoiding costly grid reinforcement.

The decision applies to "Hybrid Co-located Projects", which are projects where separately sub-metered and registered generation and storage units operate independently for market, settlement and dispatch purposes. Co-located wind, solar and BESS all fall within this framework. Integrated Hybrid Projects, where technologies operate as a single registered market unit, are out of scope. The policy applies to onshore projects with a single legal entity behind the connection point. Offshore developments are out of scope. Arrangements for multiple legal entities will follow legislative changes arising from the Private Wires Bill.

The recently published Implementation Roadmap sets out a 24-month programme of workstreams required to facilitate MEC sharing. There will be a short preparatory ramp-up period before the formal start of these workstreams and delivery of the MEC sharing programme is expected to last beyond 24 months. The first 12 months focus on preparatory, assessment, design and scoping work, which will inform regulatory processes including code modifications and regulatory authority decisions in the second 12-month period. Developers should engage with the implementation process early to have input into the regulatory reforms.

However, one significant issue that the roadmap does not resolve (and which is likely to be a material consideration for existing renewable projects evaluating whether to pursue MEC sharing) is the interaction between dynamic MEC sharing and priority dispatch. Certain qualifying renewable generators benefit from priority dispatch status, meaning they are scheduled and dispatched ahead of conventional non-renewable generation.

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The system operators have confirmed that priority dispatch configurations are not in scope of the current roadmap and will require further assessment before being considered in any future phase. For an operational wind or solar project weighing the merits of retrofitting BESS and entering a shared MEC arrangement, the risk of losing priority dispatch protection is a genuine commercial and contractual concern. If MEC sharing triggers a loss of priority dispatch for the renewable element, the economics of co-location may be materially affected, particularly for projects with existing offtake contracts or RESS support arrangements that are priced on the assumption of priority scheduling. This issue will need to be worked through as part of the regulatory process and developers considering MEC sharing for existing assets should seek clarity on their priority dispatch position before committing to a co-location structure.

Transmission Network Charges for Energy Storage

Following consultation on its minded-to position in April 2026 (CRU202645), the CRU published its final decision on 16 June 2026 (CRU202696). Effective from 1 October 2026, ESUs will be charged G-TUoS and will no longer pay D-TUoS on charging volumes.

Since 2020, BESS operating under an interim arrangement paid D-TUoS and not G-TUoS on the basis that dual charging may not have reflected BESS cost impacts and posed a barrier to entry. That interim position made some sense at the time. In the early years of grid-scale BESS deployment in Ireland, batteries operated almost exclusively as system services assets. Their revenue derived primarily from DS3 system services products (i.e., fast frequency response, inertia and voltage support) rather than from energy trading. In that context, a BESS asset was functionally more analogous to a demand-side participant absorbing and releasing energy in response to grid signals than to a conventional generator exporting into the wholesale market. The D-TUoS-only treatment reflected that operational reality.

The rationale for the interim arrangement eroded as the market evolved. The introduction of the Day-Ahead System Services Auction ("**DASSA**") framework and Initiative 2 of the Scheduling and Dispatch Programme ("**SDP-02**") in November 2025 changed the commercial landscape for BESS. SDP-02 enables BESS to trade more effectively in ex-ante wholesale markets by submitting negative physical notifications to signal charging activity as a market position. This improved the business case for energy arbitrage as a central component of the BESS revenue stack, alongside continued participation in system services and capacity market products. As BESS assets increasingly behave like active wholesale market participants rather than passive system services providers, the asymmetry in their network charging treatment relative to generators became increasingly difficult to justify. Continuing to apply D-TUoS on charging volumes effectively taxed each charging cycle at approximately €30/MWh, making frequent arbitrage cycling uneconomic and suppressing the very behaviour that market reform had been designed to enable. The move to G-TUoS corrects that misalignment. It treats BESS consistently with generation for network charging purposes, reflecting their evolving role as market participants whose value to the system lies precisely in their ability to cycle efficiently across wholesale and system services markets.

The 1 October 2026 commencement date is an interim measure. The CRU will address enduring charging arrangements for all storage assets through the multi-annual Electricity Network Tariff Structure Review, for which consultation is expected before 2027.

Key Takeaways and Remaining Challenges

For developers, investors and financiers active in battery and hybrid projects in Ireland, the direction of travel is encouraging. MEC sharing is decided. Developers with existing or planned co-located sites can now assess which configurations can be progressed under a shared MEC without requiring additional grid capacity. Removing the volumetric D-TUoS charge eliminates the ~€30 / MWh cycling cost that previously made frequent trading uneconomic, directly improving project revenue and bankability.

Taken together, these developments signal that Ireland is actively building the framework needed to attract and sustain large-scale storage investment. However, the regulatory agenda is unfinished. We believe there are at least three structural challenges require resolution before the full potential of BESS and hybrid projects can be realised in Ireland.

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Remaining Challenge 1: Integrated Hybrid Projects and timing for RESS 6 Hybrid Projects

The CRU's MEC sharing decision applies only to "Hybrid Co-located Projects" (i.e., developments where separately sub-metered and registered technologies operate independently for market, settlement and dispatch purposes). Integrated Hybrid Projects, where generation and storage operate as a single registered market unit, are expressly out of scope of the current framework. This distinction has taken on particular relevance in the context of the upcoming RESS 6 auction, scheduled to take place in the second half of 2026.

RESS 6 will, for the first time, include Energy System Integration ("**ESI**") as a non-price award criterion, on foot of Article 26 of the EU Net-Zero Industry Regulation. The Department of Climate, Energy and the Environment has proposed to assess ESI through temporal flexibility, specifically, a project's inclusion of BESS or a secondary renewable energy source.

The Department's stated rationale is that hybrid configurations incorporating storage are expected to support improved dispatch flexibility and reduce the impact of dispatch-down events on project revenue, improving the overall utilisation of available generation capacity. ESI is proposed to carry a weighting of up to 10% of the overall award score for projects, making it a potentially decisive factor in auction outcomes.

The core difficulty for RESS 6 bidders is one of timing and certainty. The Implementation Roadmap for MEC sharing extends beyond 24 months, with a start date only yet to be confirmed. As the system operators themselves acknowledged in the context of the RESS 6 process, the scope and duration of the roadmap impose real constraints on what bidders can credibly commit to. A developer seeking to score well on the ESI criterion by including BESS must bid on the basis of arrangements that will not be fully in place until the completion of the roadmap programme. That is a difficult position from which to bid with confidence, even where the RESS 6 framework accommodates separately metered co-located projects.

More fundamentally, the Department's stated goal in introducing ESI is to support improved dispatch flexibility and reduce the impact of dispatch-down events on project revenue and on overall system utilisation. Separately metered co-located projects, where generation and storage register and dispatch independently, can contribute to this goal. However, that contribution is likely to be more limited than the Department's ambition implies. It is Integrated Hybrid Projects, where generation and storage operate as a single registered market unit, responding in a coordinated way to dispatch signals, that are best placed to deliver the kind of flexible, system-responsive behaviour the ESI criterion is designed to incentivise. Until a regulatory pathway for Integrated Hybrid Projects is established, RESS 6's ESI objective will only be partially served and the full commercial and operational potential of hybrid projects will remain out of reach.

The absence of a regulatory pathway for Integrated Hybrid Projects also has direct consequences for the commercial structuring of corporate renewable energy procurement. Where a large energy user seeks to contract for renewable electricity from a hybrid project, for example one combining wind or solar with co-located storage, the inability to register the project as a single market unit creates significant complexity for Power Purchase Agreement ("**PPA**") design. A hybrid PPA that bundles firm or shaped renewable output with storage-backed delivery relies on the generation and storage assets being capable of operating as a coherent commercial unit. Under the current co-located framework, where each technology registers and dispatches independently, achieving that commercial coherence requires layered contractual arrangements that add cost, counterparty complexity and legal uncertainty.

Until an Integrated Hybrid registration model is available, the bankability and commercial attractiveness of hybrid PPAs in Ireland will remain limited. This is a missed opportunity in the context of Ireland's Large Energy User ("**LEU**") Connection Policy. The CRU's decision (CRU2025236) requires data centres with a Maximum Import Capacity ("**MIC**") of 10 MVA or above to provide dispatchable onsite or proximate generation and/or storage matching their MIC and to source at least 80% of their annual electricity demand from renewable energy generated in Ireland, with a six-year glide path from energisation.

Without a workable Integrated Hybrid Framework, the ability of LEUs to procure renewable electricity through a single coherent hybrid product, one that combines the renewable generation they need with the storage required to firm it up, is materially limited. Resolving Integrated Hybrid Project regulation will be an important option for Ireland's largest energy consumers to meet their regulatory obligations in the most commercially efficient way.

Remaining Challenge 2: Operational Restrictions on BESS Assets

Despite the positive reforms on charging and market participation, BESS assets in Ireland currently operate under binding system operator restrictions that directly limit their commercial utilisation. EirGrid imposes an aggregate cap of approximately 200 MW on simultaneous BESS charging across the all-island system, alongside an 85% maximum state-of-charge ("**SoC**") requirement. The primary rationale is system security. By capping aggregate charging and preserving headroom in batteries below full charge, EirGrid ensures that sufficient BESS response capability is available to absorb energy and arrest frequency rises during a high-frequency event on the grid.

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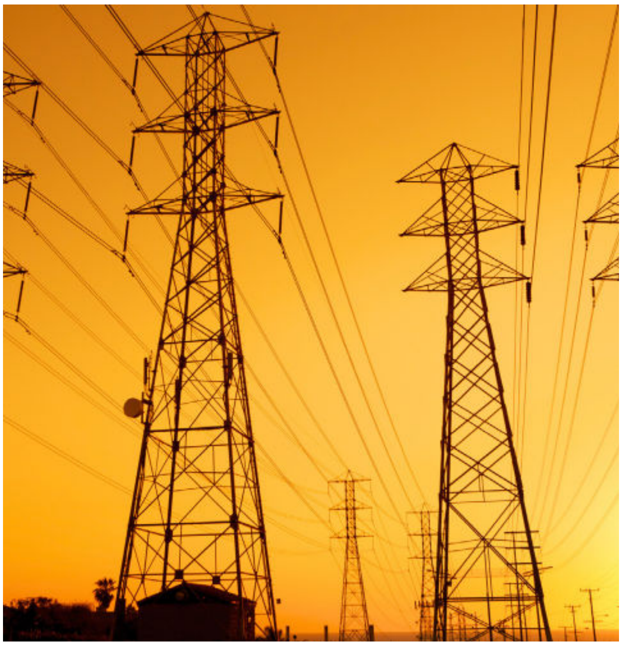
For example, a data centre may quickly drop load in response to a grid frequency event and then quickly re-connect to the system (instead of riding through faults).

The system operators are working on measures to address fault ride-through for large energy users. The expectation is that as fault ride-through compliance is demonstrated across large demand facilities, the basis for the aggregate charging restriction will reduce and the cap can be raised or removed. However, the criteria and timeline for achieving that outcome remain opaque. Developers and investors are pressing for clarity on what evidence or metrics EirGrid requires to conclude that sufficient fault ride-through capability has been achieved and what the governance mechanism is for reviewing and updating the operational constraints as fleet capabilities improve.



Remaining Challenge 3: Trading BESS in a Centrally Dispatched Market

Ireland operates a central dispatch model under the Single Electricity Market ("**SEM**"), in which EirGrid schedules and dispatches generation and storage assets in real time based on least-cost merit order principles. While the November 2025 reforms under SDP-02 enabled full wholesale market participation for BESS, including the ability to submit negative physical notifications, the central dispatch framework continues to create some risks for storage asset traders.

In a centrally dispatched system, BESS operators cannot independently execute their preferred charge or discharge strategy at the time of their choosing. Instead, dispatch instructions are issued by the system operator, who optimises across the full portfolio of market participants. This means that a BESS operator's commercial position, including hedging arrangements and optimisation strategies built around anticipated cycling, can be disrupted by dispatch instructions that deviate from their notified position.

Most energy storage units are 'non-firm' assets, meaning certain re-dispatch actions receive no compensation. This could expose the trader to imbalance costs that exceed revenues from executed trades. To the extent this risk is passed through to a BESS project owner, this risk could significantly impact the bankability of the project. Measures to reduce this risk include providing for compensation for dispatch-down and limited dispatch-down actions given the crucial role that BESS can play in managing system security (particularly at times of peak demand).

Conclusion

The regulatory environment for energy storage in Ireland is improving and the CRU's recent decisions demonstrate genuine commitment to unlocking the sector. The outstanding challenges are well understood and addressable. Developers and investors who engage proactively with the regulatory process will be best placed to benefit as these issues are resolved.

If you would like to know more, please contact our Energy Team.

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A very knowledgeable and dedicated team with a genuine interest in renewables and energy matters. The team at Philip Lee has built up cnsiderable sector specific expertise and they have the capacity and skills to provide swift and high- quality legal advice on a range of complex topics.

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