

Response to Ofgem's Open Letter on Long Duration Energy Storage (LDES) (January 2024)

About Energy UK

Energy UK is the trade association for the energy industry with over 100 members – from established FTSE 100 companies right through to new, growing suppliers, generators and service providers across energy, transport, heat and technology. Our members deliver nearly 80% of the UK's power generation and over 95% of the energy supply for 28 million UK homes as well as businesses. The sector invests £13bn annually and delivers nearly £30bn in gross value - on top of the nearly £100bn in economic activity through its supply chain and interaction with other sectors. The energy industry is key to delivering growth and plans to invest £100bn over the course of this decade in new energy sources. The energy sector supports 700,000 jobs in every corner of the country. Energy UK plays a key role in ensuring we attract and retain a diverse workforce. In addition to our Young Energy Professionals Forum, we are a founding member of TIDE, an industry-wide taskforce to tackle Inclusion and Diversity across energy

Contact: for any questions on this response, please contact Naomi Baker, Senior Policy Manager - naomi.baker@energy-uk.org.

Context

This is Energy UK's response to Ofgem's Open Letter [here](#)¹ (December 2024) on Long Duration Energy Storage (LDES). The Open Letter sets out Ofgem's initial views on:

- the LDES programme and delivery timeline;
- the approach to selecting eligible LDES projects in the first allocation window,
- the expected approach to assessing whether eligible projects should receive cap and floor support
- the approach to setting the cap and floor

Background: In January 2024, Government published [Designing a policy framework to enable investment in long duration electricity storage](#)², which identified LDES as a potential building block of the future system, and proposed a Cap and Floor scheme to support investment storage technologies of 6 hours duration and higher. It proposed streams for established (TRL 9; minimum capacity of 100MW) and less mature technologies: TRL 8, minimum capacity of 50MW). Energy UK supported this proposal (response [here](#)³).

In October 2024, Government [confirmed](#)⁴ its intention to introduce a cap and floor regime for LDES and announced Ofgem as the regulator. It noted that Ofgem and DESNZ would publish a joint Technical Decision Document (TDD) in Q1 2025 outlining application window timelines, eligibility criteria, the approach to setting the cap and floor, and the potential LDES

¹ https://www.ofgem.gov.uk/sites/default/files/2024-12/Dec_OpenLetter_LDES_0.pdf

² <https://assets.publishing.service.gov.uk/media/659bde4dd7737c000ef3351a/long-duration-electricity-storage-policy-framework-consultation.pdf>

³ https://www.energy-uk.org.uk/wp-content/uploads/2024/03/EnergyUK_LDES_March2024_Final.pdf

⁴ <https://assets.publishing.service.gov.uk/media/670660eb366f494ab2e7b57a/LDES-consultation-government-response.pdf>

capacity needed. Ofgem's Open Letter provides additional information to the industry ahead of the Q1 2025 TDD. Ofgem will finalise as many aspects as possible in the TDD and then move forward with implementation in Q3 2025.

Energy UK has previously published the following responses on LDES:

- Energy UK [response](#)⁵ (March 2024) to [Designing a policy framework to enable investment in long duration electricity storage](#) (DESNZ, 2024)
- Energy UK [response](#)⁶ (September 2023) to the [House of Science and Technology Committee inquiry](#)⁷ Long-duration energy storage.
- Energy UK [response](#)⁸ to Government Call for Evidence into [Facilitating the deployment of large-scale long duration energy storage](#)⁹, BEIS (2021)

Summary of Energy UK response

We thank the Ofgem and DESNZ teams for their work in this space and for setting out the timeframes for the next steps. We support the need for pace but note that the two-week timeframe over Christmas has made it challenging to adequately discuss the proposals with association members.

The Cfl includes proposals that would have a significant impact on Window 1 applications, and are being introduced at a late stage in the design (with less than 4 months before the Window 1 opens). We do not support significant changes for Window 1 at this stage.

On the potential prioritisation of projects for 2030, whilst we support the government's ambition of CP2030, LDES projects are costly and complex so it is important that the focus is on an enduring scheme to deliver the best outcome for the system and for consumers. An over-focus on 2030 (which in practice few projects will meet) could detract from this.

The GB system is moving towards a centrally planned system in which scarce grid connection capacity will be prioritised for assets best fitting pre-determined system need. There is a mismatch between this trajectory and the C&F's combination on high entry requirements (planning application, grid connections) but lack of sight on the system needs against which the application will be assessed (or how relative benefits will be weighted), Together these factors present a high-level of regulatory risk for developers. This will be challenging for projects which are not already well advanced and for less developed or FOAK technologies.

We recommend that entry requirements (full FEED study, planning and grid connection) are reduced with staged checks used to filter out unsuitable or speculative projects/ locations/ and developers. This would avoid developers incurring a high level of DevEx risk for projects that might not address an undisclosed system need, and should broaden project diversity.

We understand that the C&F is now intended to be technology-agnostic. However, some ambiguity remains on lithium-ion battery storage projects and whether these are required to be 'a novel iteration' as mentioned in the government response published in October 2024 "*novel iterations of Li-ion batteries which are specifically developed for longer-duration electricity storage*" (and what this would mean in practice).

⁵[EnergyUK_LDES_March2024_Final.pdf](#)

⁶[LDES_SciTechCommittee_EnergyUK_responseFinal.pdf](#)

⁷<https://lordslibrary.parliament.uk/long-duration-energy-storage-house-of-lords-committee-report-and-plans-for-a-new-scheme/>

⁸[Energy UK response to BEIS CfE on Facilitating the Deployment of LDES - Energy UK](#)

⁹[Call for Evidence \(CfE\) on Facilitating the deployment of large-scale long duration energy storage. BEIS](#)

Response to Consultation Questions

Q1: We have outlined an ambitious timeline for Window 1. Do you have any comments or suggestions on how we can streamline application submissions by developers and our project assessment process to make it more efficient?

Timeline for Window 1 spans now to 2026, with key milestones and deadlines by quarter:



Figure 1: Timeline for LDES Window 1 approval

Timeline: We welcome Ofgem’s ambitious timeline with Window 1 opening in Q2 2025 and the first projects being approved with preliminary Cap and Floor levels set by Q2 2026. The timelines are ambitious but we generally support them as necessary.

Whilst we expect few projects to be operational for 2030, pumped hydro storage projects (PHS) have a six-year lead time, therefore projects on the 2033 track would need their Final Investment Decision (FID) by 2026/7. This means that the proposed timeline of awarding contracts from Q2 2026 will be necessary for 2033 delivery.

We would highlight however that major design changes (such as increasing the minimum duration to 10 hours), or requiring too much information/ evidence upfront (for example, a full FEED assessment in Window 1) would create delays potentially making the timeline unfeasible for some projects.

Regulatory risk: significant questions still remain about both the design (for example, minimum duration), and how applications will be assessed/ benefits weighted. The asymmetry of information between Ofgem/ NESO conducting the CBA and the developer who, in advance of the publication of the NESO’s Strategic Spatial Energy Plan (SSEP) will need to make their own assessment on system need, exacerbates this regulatory risk. Whilst the need for pace makes some of this inevitable, the following changes could help to provide a fairer balance of risks:

- ❖ For Ofgem to set out the planned frequency of rounds in advance (in a parallel approach to that proposed for offshore wind) along with the approach to setting indicative capacities in each round.
- ❖ For NESO to provide greater clarity on the system needs for LDES by location (ahead of the full SSEP) to support developers address specific system needs, identify gaps

and better understand where to deploy in strategic locations to maximise grid benefits. There is currently no publicly available spatial analysis for LDES system-need for investors to refer to.

- ❖ For Ofgem to continue engagement with all market participants (not just Window 1 projects), to ensure the detailed design and contract is fit for purpose for range of technologies. This should build on the finding of international LDES procurement.

These changes would support more of a partnership approach to developing the best projects, avoiding developers having to second guess NESO analysis at risk (and Ofgem needing to assess unsuitable projects at bill payer expense).

Streamlining the application process - a data portal would facilitate the information submission and assessment process. We would also support the allowance of reasonable movement in costs between the PA and PCR stage to reflect the uncertain nature of some of the cost elements.

2030: An over-focus on 2030 risks incentivising developers to overstate how quickly they can deliver a project. This could reduce outcomes for consumers if it means that a less beneficial project is selected based partly on a (potentially) overstated scope for early delivery.

Q2: Do you have any comments on our proposed approach to split Window 1 into two distinct delivery tracks?

Yes - members are generally supportive of the approach.

However, we seek further clarification around contract start dates and agreement lengths for projects in Track 2, i.e. delivery in 2033. Specifically, we are keen to ensure that these projects are not precluded from operating earlier than 2033 if they are able to (or that projects should be disadvantaged via its contractual arrangements if it is able to start operating before 2033). We also note that there will be projects capable of achieving a 2033 date (i.e. with a construction period of 4 years) that do not need to have satisfied the prequalification criteria set out by Q2 2025 when the scheme opens to deliver by 2033.

As in our response to Q1, we highlight that 2030 delivery will be very challenging and the design should focus on addressing system need/ outcomes for consumers rather than early delivery. System benefits for a 2030 start should already be covered via the CBA. Applying an additional weighting risks double counting this benefit (which could undermine the selection of the most optimal projects).

It is important that Ofgem mitigates the risk of projects gaming the pre-qualification criteria by overstating their ability to reach COD by 2030 – phased projects with a more developed first phase, could use this to secure cap and floor support for less progressed subsequent phases. The penalties suggested in subsequent questions could be used to mitigate this risk. It is also important that the 2030 track does not force projects to rush into the construction stage to deliver by the required date, without sufficient preparatory works completed in advance, thus resulting in an escalation of the construction risks and consequential delays and cost overruns.

Q3: Any comments on the proposed approach to assessing deliverability?

In general, we support the approach though we do not support the requirement to have a full FEED study in place at application (Q2, 2025) as this will not be feasible for some complex projects. We would however, support a new requirement to assess developer's capability to deliver the projects and investors ability to finance it (in addition to the proposed approach to assess project readiness).

The FEED study for PSH projects can be very complex with the civil works running up until the start of the construction. It would not be reasonable to expect developer to have full FEED study complete before the criteria were set, and at such an early stage in the project. Whilst we agree that the FEED study would need to be completed before the cap and floor could be awarded, a more reasonable requirement would be to require either that the developer had contracted the FEED survey or for a phased approach.

In Australia, New South Wales's (NSW) Long-Term Energy Services Agreement ("LTESA") procurement, which shares many commonalities with the UK's C&F scheme assesses projects using merit criteria including:

- Pathway to commercial operation: Demonstrate ability to meet key project development milestones critical for construction and financing. Development milestones included securing approvals, network connections, and site control, as well as understanding project risks. Applicants had to furnish evidence of capital-raising efforts to further Financial Close.
- Organisational capacity to deliver the project: Demonstrate a track record of delivering comparable energy storage projects and detailed procurement plans, including key delivery partners, advisors, and resource availability.

Q4: Do you agree with our approach of requiring planning consents before starting project assessment, and of asking for evidence of submitted planning applications and expected decision dates to avoid speculative projects?

As highlighted in earlier questions, the pre-qualification criteria represent a sizeable barrier to entry for new entrants and many market players. This requires developers to put significant development expenditure at risk prior to the pre-qualification stage (before the overall rules and design of the scheme are fully known) and for projects which are unlikely to be viable without a C&F contract.

Planning applications and grid connections require a substantial financial outlay from developers. The proposed approach represents a far higher level of DevEx risk than comparable international processes (for example NSW LTESA) and the Power CCS process in the UK. A member has estimated that the pre-qualification cost under the proposed C&F proposals would cost £40 million compared to £5 million under the Australian ETESA equivalent scheme.

Similarly, one of the principal reasons for the success of the UK Power CCUS business model was the pre-FID capital expenditure recovery support (which LDES projects do not have access to). Compared to the C&F proposals, the CCUS cluster process set more achievable eligibility criteria to reflect the technology maturity, revenue uncertainty and development risk – and the relative detail of the support scheme contracts available at the time of bidding.

There is a risk that setting the bar unnecessarily high for pre-qualification, will inadvertently restrict the range of technologies and developers able to participate, and limit the private investment flowing into development of LDES projects. Instead, the aim should be to set criteria that serve as a reasonable filter for projects that can realistically deploy within the timeframes required, recognising that all projects will continue development during the long assessment and contract award process.

There are so many challenges for developers in the planning and grid connection space currently - pragmatism here would better support the industry to move at pace. A staged approach with more limited requirements at the pre-qualification stage, supplemented by a number of conditions precedent that would need to be met by successful projects prior to any C&F taking effect could be more proportionate especially for less mature technologies.

Example of a staged approach that could be used instead:

Key pre-qualification criteria	Required at cap and floor pre-qualification stage	Cap and floor contract conditional on
Grid Connection Agreement	Grid connection application submitted	Grid Connection Agreement obtained
Planning permission	Scoping Report submitted to the Planning Inspectorate	Planning permission obtained
Environmental permit	Engagement with regulators to confirm permit / licence requirements taken place	Environmental permits obtained
Generation licence		Generation licence obtained

We do agree though that projects should only progress where they can demonstrate that they can obtain the relevant consents and connection agreements in time – to avoid slowing down the administration of the allocation process.

Q5: For stream 1 only, if your project would be affected by an increase in the minimum duration requirement to 10 hours, would you re-scope the project to meet the new requirement or discontinue it?

Whilst some/ many relevant projects could be rescope to meet the longer duration by reducing the capacity or other design changes, this would require additional resources and could require additional (or completely new) planning permission. This could incur a delay of 18-months to application/ operation, and could result in PSH projects (average 6-year lead time) or other complex/ FOAK projects missing the 2033 delivery date.

Q6: Do you have views on the potential differences in system and consumer benefits between longer and shorter minimum duration requirements, including how these differences might affect LDES asset operation?

Energy UK’s [response](#)¹⁰ to the DESNZ C&F consultation (March 2024) supported extending the minimum duration to 8 or 10-hours. Members felt that this would help to create a clearer distinction between the kind of LDES projects the C&F scheme seems to be aiming to encourage and the wider existing storage market which is focussed on shorter durations. This we felt would better fit with the longer periods of excess/ shortfall identified in the LCP Delta supporting analysis (which suggested that over 50% of TWhs are projected to occur in shortfall/excess events lasting more than 24 hours). We suggested that an approach here

¹⁰ https://www.energy-uk.org.uk/wp-content/uploads/2024/03/EnergyUK_LDES_March2024_Final.pdf

could be via set 'ambitions' expressed as capacity ranges and split by different durations. For example, if 6-hours were retained as the minimum threshold:

- between 'x' GW to 'y' GW capacity of 6-10hr duration technologies by 2035/2050
- between 'x' GW to 'y' GW capacity of 10-16hr duration technologies by 2035/2050
- between 'x' GW to 'y' GW capacity of 16-24hr duration technologies by 2035/2050
- between 'x' GW to 'y' GW capacity of 24hr+ duration technologies by 2035/2050

Members would still welcome this clarity on system-need from the NESO (whilst noting that it need not preclude the initial procurement of some volume ahead of this output).

However, most members now view it as too late in the design process to change the minimum duration for projects in Window 1. Instead, we recommend that the relative benefits of longer durations would be better picked up in the CBA process (where relevant).

Changing the duration at this stage is likely to result in the same projects being submitted for Window 1 but with lower capacity to meet the duration threshold. Much of the value to the system and consumers will be LDES capacity to absorb surplus power. This will remain the same and be unaffected by the projects ability to deliver power over a longer period.

If a decision is made to change the minimum duration for subsequent windows, this should be based on system-need, evidenced by the NESO.

We would support more consideration on how the supported assets are used on the system to provide the greatest benefit to the system and bill payers. Whether designed as a 6-hour or 8-hour project, the asset will still be responding to market signals. Instead of the focus on the minimum duration, we would prefer a stronger focus on ensuring that these market signals coordinate assets in the most appropriate way (for example, sharper market signals through incremental reforms to the BM). There is a similar need to ensure that as more storage enters the Capacity Market (CM), that it charges and discharges at appropriate times in the run-up/ during a stress event to support rather than exacerbate the potential issue. There are differences between the membership here but for some, part of the justification for the C&F is to ensure sufficient income so that assets can provide support at times of system stress rather than operating on a purely merchant basis. Whereas other members believe that developers will be incentivised to obtain a long-term CM contract as it will make up a significant part of the stacked revenues and will increase their chances of receiving a C&F contract. Therefore, these projects will become subject to CM obligations and penalties and will provide necessary support during the periods of stress events.

The focus on duration risks overstating the role of LDES. None of the projects (6-hr or 10-hr) will be able to deliver for prolonged periods of low wind output. A Dunkelflaute (wind drought) will require gas-fired generation to back-up the system (whether hydrogen power, gas CCUS or unabated gas). The role of LDES is to support periods of imbalance that are longer than may be cost effective with lithium-ion batteries but which may not require the additional cost or carbon associated with gas back-up required for prolonged periods. We would support further clarity from DESNZ, Ofgem and the NESO on how very long duration imbalances will be managed to avoid this confusion.

Q7: Do you agree with initial view to not require detailed evidence for TRL9 projects?

Yes. The TRL levels are somewhat arbitrary and have not been clearly defined across international practice so we agree that it is best to leave this to the assessment process.

Q8: If you are a potential Stream 2 applicant, what information do you think you would need to provide to demonstrate TRL 8 status?

Given that views here will vary, members would support Ofgem setting out a clear view on what it considers eligible evidence as part of its Technical Decision Document. Some members working in this space would prefer more focus on commercial readiness (as with equivalent schemes in NSW and California) than on TRL level.

Q9: How might we include significant refurbishments that expand the capacity or change the purpose of existing LDES assets? What criteria and processes would ensure these provide comparable benefits to new projects?

We recommend Ofgem apply the same criteria as used in the Capacity Market – that the proposed refurbishment creates an asset that lasts as long as a new asset.

Member support major refurbishment through the cap and floor only where the project can demonstrate that it cannot be funded via the current or reformed Capacity Market

There is a mix of views amongst members on the requirement for additionality – whether the refurbished asset should result in additional LDES capacity rather than supporting the continuation of existing system services.

In general, our view is that if the project would result in beneficial capacity which would not be there without the intervention, and at a lower cost than for an equivalent new build asset, then we agree that it represents good value and should be supported.

Q10: What are your views on proposed CBA approach for LDES cap and floor regime? Are there additional factors/ impacts that should be considered?

We support the overall approach of using multiple criteria and assessing projects on both an individual and collective basis. We highlight however, that the benefit assessment process for LDES projects, which are heterogeneous with very different financing structures, locational differences and project lifetimes, will be *significantly* more complex than the same exercise for interconnectors (which are relatively homogeneous).

This heterogeneity may lend itself better to collective assessment under an ‘optimised mix of projects’ approach (to assess which mix can deliver the greatest collective benefit) as opposed to the ‘marginal addition’ method proposed (which could amount to comparing ‘apples with pears’).

A further complication with the ‘marginal addition’ method would be the two tracks for Window 1 (2030 and 2033). We would support projects in the 2033 track beginning operations as soon as they are ready (where there is sufficient system need) rather than waiting until 2033 to start. It is unclear how early starts could be accounted for in the ‘marginal addition’ method.

We recommend that Ofgem allows time to develop the C&F analysis and adequate time to thoroughly assess the input from developers, as well as contracting external support for this.

It is still unclear what factors will be assessed in the CBA or how they will be weighted. It is disappointing that the letter did not include detail on the assessment criteria, metrics and weighting. Developers need to understand the assessment criteria and weighting as soon as possible so they can continue to create projects with a high chance of success

We would support a stronger weighting for system-benefits (based on NESO's insights), as well as a focus on lifetime costs (to support with assessing heterogeneous projects) and a focus on the additional value of the LDES project versus the counterfactual. This would compare the cost/ value with that of alternative technologies would be required to balance the system if the LDES asset were not built (for example, as reduction in LOLE with and without LDES asset). This analysis would also support Ofgem to assess the cost of delays

Other factors include diversity of location (i.e. beyond thermal constraints which is important from a security of supply and system services cost perspective) and reduction in curtailed renewables for consumers.

Q11: Do you have views on the proposed approach to project cost assessment?

We support the proposal for performance-based incentives and penalties for cost over-runs in principle, however, industry needs more detail on how this could be applied / potential impact (percentage increase to cap or floor level?) to comment further. There is concern with the proposed loss of cap and floor support altogether beyond this 2 year period as this presents a cliff-edge risk that would deter investors. An alternative route that could be considered at this point would be for the contract term to be eroded until the project is operational. The approach will need to be implemented in a way that avoids gaming (for example, developers setting initial targets that are overly conservative) but with sufficient flexibility to allow extensions that are available for reasons outside the developers control.

PSS projects, with the layers of EPC contracting and the civil works required, involve more cost/ delivery uncertainty which cannot always be avoided. FOAK projects are likely to be similar, so it will be important to strike a reasonable balance between flexibility and using the incentive structure to drive pace/ ambition and incentivise developers to set accurate delivery timescales. Given this, we would encourage Ofgem to carefully review the evidence and recognise the need for a reasonable movement in costs between the PA and PCR stage to deliver an investable LDES Cap and Floor.

Performance assessment - Ofgem will need to be clear what counts as 'operational'. Any new complex project will have initial issues which then level out ([the bathtub effect](#)). Performance in the initial six months before performance levels out could look very different from settled performance after two years of continuous operation. Ofgem will therefore need to determine when in the 'bathtub curve' to start measuring performance.

Q12: What are your views on calibration of the cap and floor levels? Do you consider setting the floor at, for example, 80% of projects' costs is a viable model for LDES assets, potentially alongside a higher cap?

We do not support the proposal to set the project floor at 80 percent of project costs. As per our response to the DESNZ C&F proposal (March 2024), we support the floor being set above the hurdle rate to ensure that projects are viable.

We highlight here that new LDES projects have not been built in the UK for 50 years due to both the high capital cost and the uncertainty of future revenue stack. If investors do not have confidence that the floor or future revenues will provide a reliable return, then either investors will increase the cost of the finance (cost of debt or equity) or projects will not get built/ built in sufficient quantity. Both of these outcomes (higher finance cost or insufficient LDES requiring higher cost alternatives) would increase costs for bill payers.

LDES technologies, such as PSH and FOAK projects, are exposed to significantly higher design, construction, delivery and revenue risks compared to interconnectors. We are concerned that Ofgem may be underestimating the differences between the technology classes.

Q13: Do you support exploring methods to lower consumer costs, including more use of competitive mechanisms when setting cap and floor rates? Any suggestions on how Ofgem can improve the cap and floor setting using a competitive process?

On the specific proposal, we note that it is a relatively new change to the interconnector scheme and not a well understood process for industry yet.

It feels like unnecessarily complexity for early stage given the heterogeneous projects and different financing structures. It may be more feasible for subsequent rounds when there is more comparator data from earlier rounds and capital markets become more familiar and comfortable with the C&F mechanism.

In general members would be more supportive of other proposals (such as introducing reopeners or more revenues sharing at the cap) which have a better potential to benefit consumers.

If Ofgem were to pursue this option, it would need to ensure that developers that are electing for balance sheet financing providing evidence of the ultimate market debt at the corporate level rather than the intercompany transfer between the corporate entity and the project company.

More competition could be introduced by ensuring that vendors, contracted by the project, are via a competitive process (as opposed to single sourcing of services).

Q14: Do the potential benefits of allowing assets to be managed by in-house trading teams outweigh potential risks? How can we effectively mitigate any potential risks of gaming, such as manipulating trade bookings or market manipulation?

We think that Ofgem needs to be clearer about the potential risks it is concerned about and the measures it is proposing to mitigate which specific risk.

On gaming risk/ market manipulation: There is already sufficient regulation to ensure that developers operate their assets prudently and do not game the availability of those assets. These include competition law, market abuse regulation, REMIT, license conditions, Transmission Constraint License Condition (TCLC).

We do not support the proposal to mitigate a perceived risk here by requiring parties to require LDES assets to be traded via third parties. This would prescribe a certain business case (to outsource trading) at a late stage in the design process and could jeopardise investment by outsourcing a key part of the value chain.

It would be reasonable to increase transparency for in-house trading operations - for example by requiring a high-level view on how developers are planning to trade the asset and comply with existing law. The fast-moving nature of energy/ balancing markets would necessitate a 'snapshot' of potential revenue stacks based on current markets. Proposed mitigations beyond this, should be backed up by evidence that there are real risks that would warrant further action.

A potential risk with an in-house trading floor and a cap and floor scheme would be for the developer to apportion a greater share of these shared costs in the floor than might be warranted. However, the guidance on allowable costs and the need to demonstrate a highly competitive CBA means that gaming here would be unlikely (or counterproductive).

We would support a measured and justified mitigation approach, in the form of reporting requirements or additional transparency of trades, if there is sufficient evidence that these issues are likely to materialise.

Of the proposals, there was more support for specific metering points and appropriate allocations of shared infrastructure to the LDES project based on usage which could help with gaming risks around arbitrage (substituting assets).

On gaming/ withholding available capacity: we agree with this as a potential risk as highlighted in our March 2024 response to the DESNZ consultation

'As well as the risk of inaction/ delay, the main risk identified was the risk that assets funded by the scheme are not available to support the system when required since they may be able to earn better revenues by working across multiple, more frequent markets. An analogy was made here to 'huff and puff' gas storage where the costs of storing the gas are recovered by intraday cycling to capture the economic rent available rather than maintaining the store in case of a supply emergency. As we cannot judge whether future market signals will be sufficient, it was suggested that this risk could be managed by requiring supported assets to retain a contract with the CM to ensure the asset is available when required. However, there was not a consensus here (and it was noted that CM penalties max out after 4 hours). We would welcome more consideration on how to mitigate this risk'.

Most members would support a requirement that C&F-supported projects should hold a CM agreement to ensure that these assets are available at times of system stress.

There was not sufficient time to get a clear view from the membership on whether LDES assets in the CM should be 'price-takers'. Some members support this view as a means of preventing projects with the benefit of C&F revenue protections using that protection to unfairly out-compete unsupported assets in a CM auction.

Other members, however, noted that being price taker is likely to mean that the revenue stack is lower, thus increasing the risk of top-up requirements from consumers. They note that whilst interconnectors have 'price taker' status, this was a consequence of the technology only being eligible for 1-year CM contracts (to prevent a risk of withholding capacity and affecting either the clearing price or capacity adequacy). If C&F LDES can

access 15-year contracts (to supporting investment), they would be obliged to support system stress events (or face penalties for non-delivery) so this risk would not apply.

There are similar differences on whether CM fines and penalties should be taken account of when determining the revenue floor. Members who felt that the floor should not include these felt that this would ensure that LDES projects cannot avoid the financial impact of failing to be available for a CM event and that the costs of non-availability and termination fees are not paid by consumers.

Members concerned with the impact on unsupported short duration assets have suggested there might be a case for additional contractual requirements (or new NESO balancing and ancillary service products) to ensure that LDES-supported assets hold all or a certain proportion of their stored power in reserve, whenever an extended wind lull or comparable potential challenge to security of supply, is forecast. However, other members noted that these standalone requirements for LDES would be difficult to implement in practice as NESO's system needs are dynamic, evolving, and locationally dependent, stress events are difficult to forecast and technologies participating in the C&F are diverse making it difficult to impose the same set of requirements across all participants. These members also noted that introducing these stringent obligations could go be in conflict with some of the existing regulatory and licence requirements, thus, any interactions with existing market and policy frameworks need to be assessed carefully.