smartenergy@beis.gov.uk

28 September 2021

To whom it may concern,

Large scale and long duration energy storage (LLES): call for evidence

Scottish Renewables is the voice of Scotland's renewable energy industry. Our vision is for Scotland leading the world in renewable energy. We work to grow Scotland's renewable energy sector and sustain its position at the forefront of the global clean energy industry. We represent over 260 organisations that deliver investment, jobs, social benefits and reduce the carbon emissions which cause climate change.

Our members work across all renewable energy technologies, in Scotland, the UK, Europe and around the world. In representing them, we aim to lead and inform the debate on how the growth of renewable energy can help sustainably heat and power Scotland's homes and businesses.

Scottish Renewables convenes the UK Pumped Storage Hydro Working Group (comprising SSER, Drax Power, ILI Group, Buccleuch, Dorothea Pumped Hydro, CCSQ and the British Hydro Association) and we are pleased to provide a response to this call for evidence on behalf of the group.

We welcome that BEIS is examining the need for LLES and the case for more fundamental market intervention to support the deployment of large scale, long duration storage and that a decision will be made by early next year.

Our members are currently developing some 5GW of LLES in the UK that can make a major contribution to providing flexibility needed to enable an affordable, secure net zero energy system.

The need for LLES

Future FES and CCC scenarios for a net zero energy system all forecast significant increases in variable wind and solar generation. This major growth in renewable generation will have important effects upon the future electricity system and drive the need for LLES and the benefits it can provide.

6th Floor, Tara House, 46 Bath Street,
Glasgow, G2 1HG
0141 353 4980 @ScotRenew
www.scottishrenewables.com

Scottish Renewables Forum Limited.
A company limited by guarantee in Scotland No.200074
Registered office: c/o Harper Macleod,
The Ca'd'oro, 45 Gordon Street, Glasgow G1 3PE

The BEIS 2021 Smart Systems and Flexibility Plan1 proposes that 30GW of flexible capacity will be required by 2030 to meet current net zero pathways. It suggests that some £10 billion per annum may be saved by 2050 by the introduction of flexible electricity technologies. The ESO's Future Energy Scenarios (FES)2, also forecasts vast increases in LLES deployment to enable the widescale rollout of intermittent renewables. By 2030 up to 13GW of new electricity storage could be required.

We agree flexible capacity is urgently needed when renewables are not available. Currently, fossil-fuel generators mainly provide this support, but they will need to be displaced by low-carbon alternatives over time.

Also, non-synchronous, intermittent renewables do not currently provide the critical security of supply ancillary services, such as inertia, voltage flexibility and restoration. These will have to be predominantly provided by dispatchable flexible resources, such as long duration storage, but again there are currently no long- term price signals for this capability.

Furthermore, renewables located far from demand centres will drive an increase in network constraints. These constraints increase the potential for curtailment of renewables and additional balancing costs, which could be mitigated by long duration storage.

The benefits of LLES

LLES can make a major contribution to a net zero electricity system, both enabling the rapid growth in variable wind and solar renewables and accelerating the displacement of fossil fuelled generation. It will enable the following benefits to be realised:

1. Meeting variable system demand: flexible low-carbon electricity capacity will be needed when variable renewables are not available. Currently, fossil-fuel generators mainly provide this flexibility, but they can be displaced by low-carbon dispatchable resources such as LLES to complement renewable generation.

2. Maintaining system stability: non-synchronous, variable renewables do not currently provide the dispatchable system ancillary services, such as inertia, voltage flexibility and restoration, all of which are essential to maintain security of supply. Again, these

1 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1003778/smart-systems-and-flexibility-plan-2021.pdf

2 https://www.nationalgrideso.com/document/202851/download

services are currently mainly provided by fossil fuel generators, but they can be replaced by low carbon dispatchable resources such as LLES.

3. Lower system costs: renewables located far from demand centres will drive an increase in network costs and balancing costs from curtailment of renewables to manage network constraints. These costs could be mitigated by LLES sited in appropriate locations on the electricity system.

4. Reducing renewable electricity curtailment: LLES can also provide additional flexible demand on the system at times of low consumer demand. If this demand was not added, then renewable generation may need to be curtailed, thus increasing the system carbon intensity.

Introducing a new market mechanism

We have provided our response to the call for evidence, highlighting that:

- 5GW of pumped storage hydro projects can be operational by 2030 if suitable market frameworks are available
- The key barrier to investment is long-term revenue risk, which may best be addressed by the proven cap and floor mechanism
- This cap and floor mechanism would need to be adapted for LLES to ensure that market optimisation incentives are retained
- This approach would address some of the existing market distortions i.e., absence of long-term prices for flexibility or low carbon
- A window-based application approach would allow the policy to be reviewed over time to ensure barriers were not created for nascent technologies such as CCUS and hydrogen

The most significant barrier is the lack of revenue certainty in the markets where LLES technologies will compete, this includes wholesale market, balancing market, ancillary services markets, and the capacity market. In our view, the introduction of a cap and floor mechanism is necessary to overcome this revenue uncertainty and enable investment in LLES.

In summary, a cap and floor mechanism would give confidence to investors that revenues will underpin an efficient level of debt financing. The similar mechanism used for interconnector projects has successfully attracted investment into several projects, delivering significant benefits to consumers. Introducing a cap and floor regime for LLES would bring several benefits:

- It is relatively simple to introduce as the existing interconnector regime can be used as a blueprint.
- It will deliver services consistent with the system's needs as operators will be incentivised to participate in balancing services for the ESO and will be able to compete with other technologies.
- The cap and floor mechanism appropriately apportions risk by providing reasonable certainty of servicing debt without consumers underwriting all costs, while the cap provides protection to consumers.
- It incentivises efficiency as operators are exposed to market opportunity between the cap and the floor. This mitigates any market distortion by incentivising the provision of services in response to market price signals from multiple competitive markets (wholesale, balancing, ancillary and capacity markets).
- If the cap and floor is open to multiple LLES technologies, this can introduce competitive pressure and further avoid market distortions as multiple technologies could bid for support.
- The support for LLES technologies under a cap and floor would also advance the low-carbon economy, maintain security of supply, and deliver value for money.

We trust these comments are helpful and would be pleased to discuss further and engage as needed to help quickly develop the detail of new regulatory arrangements. We believe the need for LLES flexibility is becoming increasingly urgent and look forward to the next steps in bringing this to a reality.

Scottish Renewables would be keen to engage further with this agenda and would be happy to discuss our response in more detail.

Yours sincerely,

M Watson

Morag Watson | Director of Policy

Scottish Renewables

Annex: Response to LLES call for evidence questions

This annex addresses the specific questions raised in the LLES call for evidence consultation. We have addressed our comments in relation to the following key areas raised in the call for evidence:

A. Strategic context: The role and value of LLES in a net zero energy system

B. Current market: Understanding the storage landscape

C. Current market: Potential barriers to LLES development

D. Market reforms: Current routes to market and potential reforms

E. Rationale for further intervention to de-risk LLES: Considering approaches

F. Understanding risks

A. Strategic context: The role and value of LLES in a net zero energy system

1. Do you agree with our definition of LLES as storage technologies that can store and discharge energy for over 4 hours and have a power capacity of at least 100 MW? If not, what alternative definition would be more suitable? Please provide supporting evidence where possible.

We see strong merit in increasing the duration to at least 6 hours[3], up from 4 hours, to better reflect the growing system need. Over the last 10 years the growing volumes of renewables has meant that CCGT generation plant load factors have decreased as they have moved from baseload generation to more flexible operating patterns, resulting in two or three shifting generation/shutdown patterns daily. The 2021 ESO FES reports that the load factor of all gas generation in 2020 was 29.4%, producing 91TWh from 35GW of installed capacity.

Such operating patterns will reduce CCGT generator efficiency and increase generation costs, increase CO_2, SO_2 and NOx emissions, and reduce plant life. These impacts may be expected to increase as the proportion of renewable generation increases.

We consider that LLES is well placed to replace this evolving CCGT generating pattern and satisfy the system flexibility need without these disadvantages. This could require LLES flexibility from periods as short as 1 to 2 hours to meet peak demands, or up to 7 hours e.g., from 7am to 2pm to meet the morning peak demand periods.

As such, we consider that LLES could potentially be defined as having longer operational periods than 4 hours, so that the storage volumes in MWh are valued as much as peak capacity for short periods. In this context, we would suggest that an amended definition that LLES technologies should be able to store and discharge energy continuously for at least 6 hours should be considered. This means that they should be better able to deliver the flexibility and other power system functions currently delivered by CCGT power stations.

3 We note that capacity market de-rating factors are currently set at 5.5 hours and the STOR availability window is 5 hours. A 6 hour duration would accommodate both of these existing duration specifications.

We would suggest that the volume of the storage capacity might be an important factor to also include. In line with our suggestion above, it may be more appropriate to define storage capacity in both MW and MWh terms, so an appropriate threshold for application of the LLES regime might be 100 MW for 6 hours, so only facilities able to deliver a continuous output in excess of 600MWh might be defined as LLES.

As far the 100MW threshold definition for LLES is concerned, we consider this should largely be determined by the associated capital cost and whether financing can be obtained on a merchant revenue and risk basis. A key factor associated with pumped storage hydro investments is that will have a high up front capital costs for very long-life assets. The 100MW threshold appears appropriate. We would expect most pumped storage hydro projects have sufficient storage capacity so they could be designed with MW capacity well in excess of this level.

2. ***Do you agree that the electricity system requires, and will benefit from, LLES delivering the services outlined above? Are there any other important services that LLES can provide that are not covered here? Please provide supporting evidence where possible.***

The GB electricity system will be at the centre of the energy transition to Net Zero as the transport and heat sectors are increasingly electrified. But electricity systems must continually match power supply and customer demand. They must have essential operational resources continually available (and in reserve) to ensure the stability of the system. These resources are critical in ensuring security of supply, which is becoming more critical in a society dependent on the digital world.

These essential operational resources are often referred to as flexibility or ancillary services and are managed by the ESO through balancing services markets. They are:

- Power flexibility – capacity for ramping up or ramping down power output as needed to meet highly variable levels of demand, including holding output for use in reserve. Power flexibility is normally managed through wholesale market trading, but the ESO will manage real-time imbalance markets and ensure sufficient flexible output is always available,
- Frequency flexibility – providing frequency response through rapid changes in output, including holding capability in reserve,
- Stability flexibility – providing sufficient levels of system inertia, dynamic voltage control, and short circuit management to maintain stability, including holding capability in reserve,
- Voltage flexibility – providing the capability to generate or absorb reactive power to manage voltage levels, including holding capability in reserve,
- Restoration – black start capability to restore the power system.

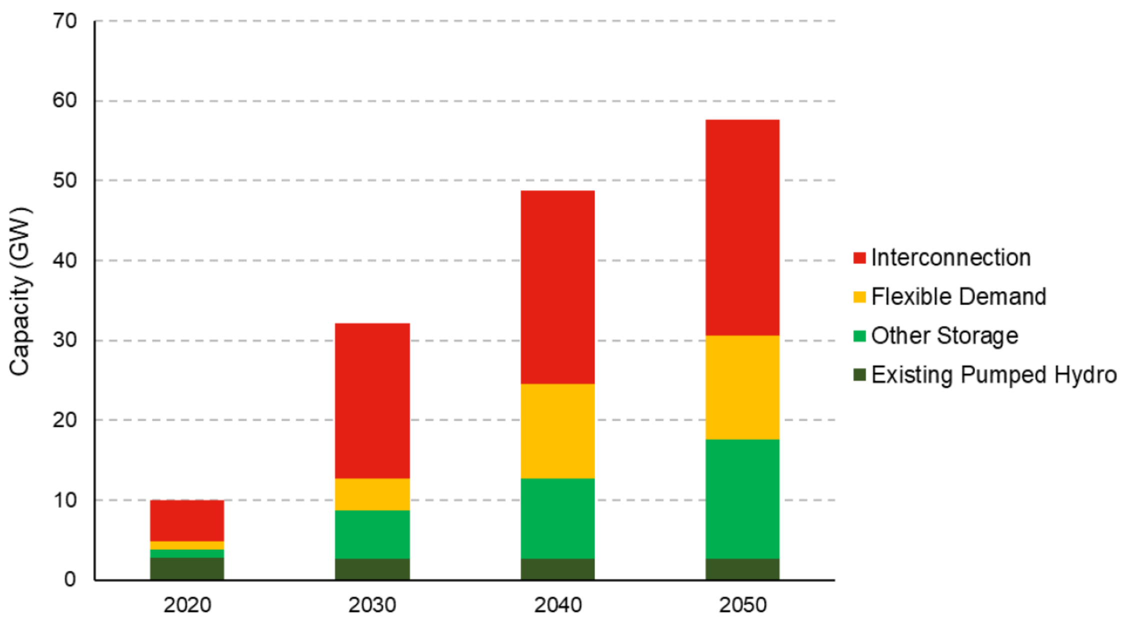
Historically, power systems have been designed around fleets of large fossil-fuel synchronous generators that were obliged to provide many of these essential system services, normally without additional payment. These are being replaced by renewable generators that do not have the same requirements and capabilities. This creates a flexibility gap, both in terms of the operational resources and payment for these services.

Pumped storage hydro can provide all the necessary resources for continuous stable operation of the electricity system, and security of supply. These will include the critical system resources for flexibility, inertia, frequency response, reserve, voltage support and system restoration to displace those currently provided by fossil-fuel generators. Also, rather than deploying technologies for individual benefits, such as for inertia or for constraint management, a single LLES asset could be deployed and provide multiple services, for a lower overall cost. This is evidenced by recent study carried out by Imperial College London, showing that an additional 4.5GW of long-duration PHS, with 90GWh of storage could save up to £690m per year in electricity system cost savings by 2050.4

3. ***Do you think there will be a need for a range of different LLES technologies, alongside other technologies that may be able to deliver similar system benefits, such as hydrogen production and generation, and carbon capture, usage and storage?***

Yes, we agree there should be a range of technologies available to deliver flexibility benefits, we believe a range of LLES technologies will likely be required alongside other technologies such as hydrogen and CCUS. As set out in the Government's recent Smart Systems and Flexibility Plan, these flexibility resources may include distributed energy resources, interconnectors, low carbon flexible generation, and storage, as illustrated in the chart below.

Figure 2: Smart Systems and Flexibility Plan: Illustrative deployment of flexibility technologies (high flexibility, high demand scenario)



This diagram suggests that the mix of additional flexibility resources for 2050 could be split between new storage, flexible demand, and interconnection. We agree that different technologies can deliver these benefits but would suggest the following factors should be considered:

- Interconnector flexibility capacity may be limited by the volumes of variable renewables connected in neighbouring countries. The UK will be interconnected with other European countries that are also expected to substantially increase their solar and wind resources over the next decade, increasing the risk that neighbouring countries face common periods of low renewable output and high flexibility requirements.

---

4 https://www.imperial.ac.uk/energy-futures-lab/reports/Whole-System-Value-of-Long-Duration-Energy-Storage-in-a-Net-Zero-Emission-Energy-System-for-Great-Britain/

- New low carbon flexible generation such as CCUS and Hydrogen are emerging technologies which remain to be proven at scale, or in flexible operation modes. They may not be able to reliably displace gas generation for flexibility purposes.
- Demand flexibility has significant potential, but the delivery of these resources is unproven. For example, reliance of electric vehicles to provide flexibility resources will require significant behavioural shifts in society.
- Storage technologies – while evidence is growing of lithium-ion battery capabilities, other technologies such as flow batteries and liquid/compressed air are yet to be proven at scale. These technologies may be less economic than pumped storage hydro as discussed below.

Furthermore, regarding flexibility contributions by interconnectors, there are additional factors that we think should be considered:

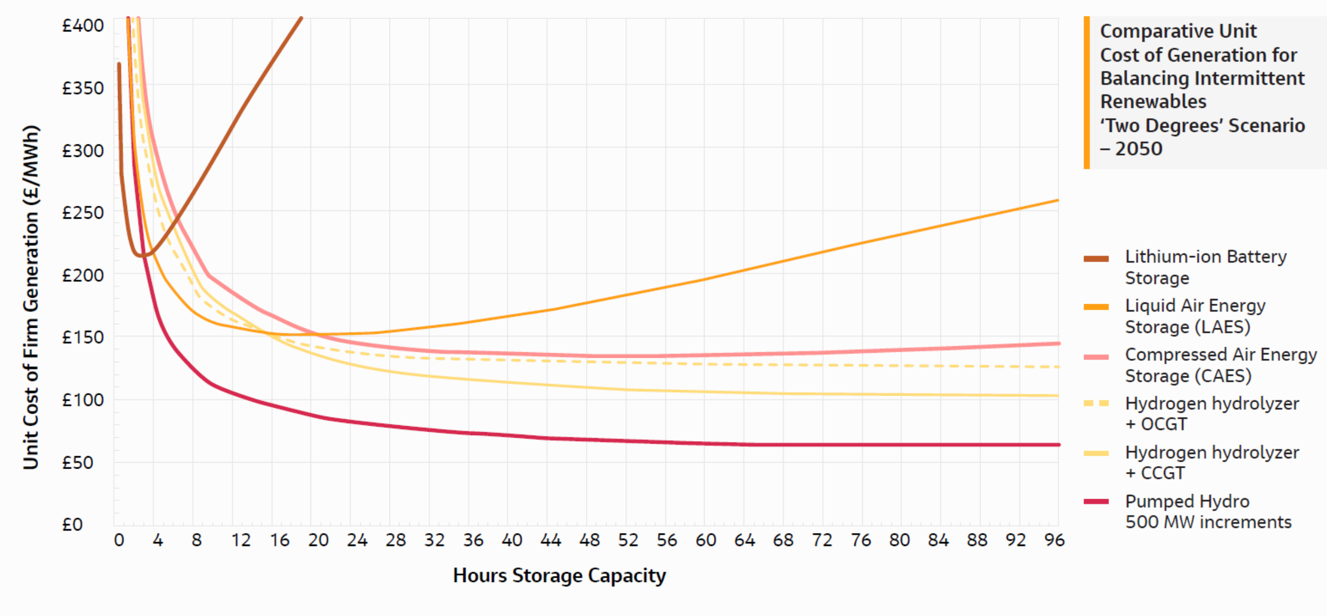
- the real carbon content (not just certificate-based) of imported electricity must be reflected in its cost otherwise carbon neutral LLES will be disadvantaged.
- in the longer-term GB is expected to be a net exporter of low cost, low carbon electricity. But imports will be at higher cost at times of low renewables output. This results in net value being exported from GB system. LLES will allow value of low-cost renewable generation to be retained in GB and reduce higher cost import requirements.

In their 2020 energy storage report, Jacobs[5] compared the unit costs of several energy storage technologies with the equivalent unit cost of generation from other net zero carbon generation. The energy storage technologies examined were lithium-ion batteries, liquid and compressed air storage, and pumped storage hydro. These are compared with equivalent cost curves for green hydrogen OCGT and CCGT technologies, which provide equivalent flexibility services.

Figure 3 shows cost curves derived using the outputs from the daily balancing of baseload plant and intermittent renewable generation predicted for 2050. It combines the capital and operating costs for each technology to derive an approximate levelised unit generating cost against storage capacity.

Figure 3: Unit costs of generation and storage for different storage durations

5 https://www.jacobs.com/sites/default/files/2020-10/Jacobs-Strategy-for-Long-Term-Energy-Storage-in-UK-August-2020.pdf



The comparative unit cost of generation by technology type, for a typical plant of 500 MW installed capacity at a range of different storage durations from 1 hour to 4 days

The above chart shows that lithium-ion batteries have the lowest cost of storage for durations of less than 4 hours, but that for longer durations there is a marked reduction in storage cost for the other technologies such as pumped hydro, hydrogen generation, compressed air, and liquid air. Pumped hydro has the lowest cost for durations of greater than 4 hours.

National Grid ESO in its 2021 Future Energy Scenarios (FES)6 has outlined some illustrative power sector pathways to net zero. Under these scenarios up to 13 GW of new electricity storage could be required in 2030 to balance intermittent renewables deployment. The FES is clear that "immediate action on deployment is required for CCUS, hydrogen, and long duration storage technologies".

B. Current market: Understanding the storage landscape

4. ***Please provide details of specific LLES projects that could begin development in the next 5 years. These details should include technology type (including intended use of fuel generated through sector coupling), MW and MWh, the business model or route to market, efficiency and expected development, capital, operational costs and expected lifetime of projects.***

The question invites comments on LLES projects that could begin development in the next 5 years. However, given the scale of the challenge in replacing fossil-fuel flexibility resources we believe the question should focus on identifying the LLES projects that can commence construction within this timescale. In our response below, we have provided details of pumped storage hydro LLES projects that will be able to commence construction in the next 5 years.

Pumped storage hydro is a proven LLES technology, with around 160 GW installed and operational worldwide. Some 3 GW is already constructed and operational in the UK, as shown in table 1 below. All the

6 https://www.nationalgrideso.com/document/202851/download

existing UK pumped storage plants were constructed when the industry was state-owned and the projects were commissioned with Government backing. No projects have been constructed since the industry was privatised in 1990, after markets were created to enable trading in wholesale electricity and ancillary services.

Table 1: UK pumped storage hydro in operation

Site	Date commissioned	MW capacity	GWh capacity	Owner
Dinorwig	1983	1728	10.4	First Hydro
Foyers	1974	300	6.4	SSER
Ffestiniog	1963	360	1.8	First Hydro
Cruachan	1966	440	7.6	Drax Power
Total		**2828**	**26.2**	

With regard to new pumped storage hydro development, the pre-construction development works involve a process of site identification and acquisition, technical and environmental feasibility studies, followed by planning consent and grid connection applications.

Our members are currently developing around 5GW of new pumped storage hydro projects that will be ready to commence construction within the next 5 years. About 2.5 GW of these are well advanced with the necessary planning consents and grid connections already in place, and the remainder expect their consents to be available by 2023.

The following table shows the status of individual projects. All sites are in Scotland unless stated.

Table 2: Pumped storage hydro projects under development

Site	Consent date	Target operation date	MW capacity	GWh capacity	Owner
Coire Glas	2020	2028	1500	30	SSER
Red John	2021	2027	450	2.9	ILI
Glenmucklock	2016	2027	400	1.5	Buccleuch
Glyn Rhonwy (Wales)	2017	2027	100	0.7	Quarry Battery
Cruachan extension	2023 (est)	2030	600	TBC	Drax Power
Balliemeanoch	2023 (est)	2029	1000	45	ILI

Site	Consent date	Target operation date	MW capacity	GWh capacity	Owner
Corrivarkie	2023 (est)	2029	600	19	ILI
Dorothea (Wales)	2023 (est)	2029	450	2.1	Dorothea Pumped Hydro
Halviggan	2024 (est)	2027	150	1.2	SSER
CCSQ (Wales)	2025 (est)	2032	100	0.6	CCSQ
Total			**5350**	**94.0**	

These new pumped storage hydro projects are all expected to have the following characteristics:

- Round trip generating/pumping efficiency – 80%,
- Construction capital expenditure and development costs estimated at £800-£1500/MW, totalling some £5-6 billion of investment for the above project pipeline, average construction timescales are expected to be 5-7 years depending on the scale of the project,
- Project lifetimes – in excess of 60 years,
- Operating costs – the major operating cost will be purchase of electricity for pumping (which can be netted off against generation revenues); other costs will include site costs (including business rates), operation & maintenance staff costs, TNUoS tariffs and BSUoS charges,
- Annual average availability – in excess of 90%,
- Carbon intensity – all electricity generated will have zero emissions.

Further details about specific projects are provided in the submissions by individual developers.

<u>Business model and route to market</u>

The main sources of revenue currently available to pumped storage hydro are from wholesale market revenues, ancillary service and balancing markets, and the capacity markets.

While these routes to market are available for operational pumped storage hydro, the route to market for new investments is currently blocked because future market design and long-term price signals are uncertain. No long-term price signals are provided specifically for flexibility. The most significant barrier faced is revenue certainty.

Uncertainty in future high renewable electricity markets is expected to result from near-zero marginal costs when renewables are available and unknown and increased price volatility when renewables are unavailable. Capacity and balancing markets do not provide adequate long-term price signals either.

Uncertainty about future market design and available revenues is deterring large scale investments such as pumped storage hydro.

C. Current market: Potential barriers to LLES deployment

5. Do you agree that the issues outlined above are barriers to the deployment of LLES? Please comment on any issues that are particularly significant in your view.

The call for evidence identifies the following main barriers to LLES deployment. We have provided our comments on each of these below:

a) ***High upfront capital costs and long construction lead times.*** *Technologies such as pumped storage hydro require significant civil engineering works which can increase investment risk.*

We agree that the high upfront capital cost and long construction times can present a risk for LLES projects such as pumped storage hydro. However, major civil engineering projects are constantly being successfully designed and managed in the UK, with the successful construction of new onshore and offshore wind installations being a good example. These projects face a very challenging offshore construction environment, deploying increasingly advanced wind farm technologies.

While construction risk is a challenge for all such projects, the construction of onshore pumped storage hydro offers a less challenging construction environment and is able to use proven technologies. The key challenge for pumped storage hydro LLES is revenue certainty rather than construction risk.

b) ***Lack of track record****. Novel technologies face additional investment challenges compared to more mature technologies.*

We agree this can present an additional investment challenge, but technology risk is accepted by investors in all types of business as an opportunity to achieve a competitive advantage. While Government has an important strategic role to play in supporting innovation through research and development funding, there is a risk that Government picks technology winners rather than using competitive market forces.

While technology risk will be higher for novel technologies, the benefits may also be higher as a result thereby encouraging investors to take greater risk than with more mature technologies. We would suggest that the critical way to encourage innovation is to provide greater revenue certainty across all LLES technologies.

Pumped storage hydro is a mature, proven technology in GB and worldwide that does not face these technology challenges.

c) ***Revenue certainty*** *is weak. The current market design for stacking revenues across different contracts and terms mean that cash flows are not visible before investment.*

This is a key challenge for LLES. Investors and lenders for these projects will wish to see certainty of revenue including:

- the percentage of contracted revenue throughout the operational life of the project,
- the type of contracted revenue e.g., the creditworthiness of the counterparty,
- that revenue contracts are agreed before start of construction

Currently this is just not possible to secure in advance meaning that, if they wish to commence construction, LLES projects are faced with a significant revenue risk. To attract finance, LLES projects with high development and construction costs and long asset lifetimes will need to provide investors with confidence that future revenues will recover these costs and provide a return. Future revenue uncertainties will either increase the cost of capital or block investment altogether.

d) ***Market signals*** *do not capture the full value of LLES projects. Currently the market tends to value short-duration storage; also, carbon emissions are not fully valued in flexibility markets*

We agree with this, particularly that neither flexibility nor low carbon flexibility is directly valued through market price signals. In recent years, new generation and storage projects with lower development and construction costs and shorter asset lifetimes (such as batteries, gas engines, and diesel generators) have been able to attract new investment from investors willing to accept significant merchant risk. But these risks are offset through fast development and construction times accompanied by greater confidence about near term market dynamics and price signals.

The ESO has embarked on a strategy of enhancing volumes and liquidity in short-term markets to improve competition, but while this strategy has the effect of increasing competition short-term markets it does not provide clear price signals to encourage long-term investment in LLES. In addition, the ESO NOA process is biased towards identifying network solutions rather than potential non-network solutions that could be met by LLES.

High value, long development timescale projects such as long duration storage cannot only rely on these near-term price signals for investment. Given their much longer lifetimes they are also much more exposed to future market design changes. Furthermore, by capturing market share, merchant projects with shorter asset lifetimes and/or high carbon output will cannibalise the available revenue for lower cost resources such as LLES.

A longer-term whole system planning approach is needed from independent ESO which clearly includes developers (not just network TO's) in the input and review process. Type, quantity and estimated value of flexibility services are needed for 2030's and beyond to ensure developers include these capabilities within their designs given the 50 years plus life of the assets.

A critical function of LLES is to provide balancing and stability services to market and the network. LLES are not net MWh generators, but they are defined as generators and therefore the balancing and stability benefits (and cost savings from reduced network investment) are not reflected in the way their connection application to the grid is assessed. LLES is considered as just another generator and are connected on first come first served basis behind other generators. We consider that grid connections for LLES should be prioritised based on the wider benefits they bring. Connection queue delays are a significant barrier to the deployment of LLES. Network operators will always prefer to build out more network assets as solutions which increase the cost burden to consumers.

In addition to clearer market price signals, reforms to connection processes and network charging are needed to recognise the net benefits that LLES can bring to heavily generation congested areas.

6. Are there any other barriers impacting the deployment of LLES?

Despite an evident need for LLES such as pumped storage hydro, and favourable long-term economics, these projects are not currently able to attract investment from capital markets. For potential storage investors, it comes down to two main and interrelated uncertainties, namely:

- uncertainty about future project revenues as described above. We consider that construction and technology risk can be managed by developers if there is greater confidence about revenues.

- uncertainty about the future market landscape. Revenue confidence cannot be gained unless there is also confidence about the future market design and associated regulatory and policy framework.

These factors make it difficult for investors to gain the confidence necessary to raise and allocate large capital sums. This is not specific to LLES, it also applies to other high-value projects such as interconnectors, nuclear, CCUS and hydrogen generation.

The evidence that 3 GW of existing pumped storage hydro projects in Great Britain are all able to operate successfully in today's electricity markets demonstrates their economic viability. These were all commissioned when the industry was state-owned – that no further projects have been built illustrates the challenges involved in realising this kind of investment on an entirely merchant basis.

A key issue concerns the certainty around future system needs, specifically the amount of storage capacity and system support services that will be required. Whilst indications of future system need have been provided through projections such as National Grid ESO's FES, there is considerable uncertainty around areas such as the decarbonisation of heat, the decarbonisation of transport, and the role of interconnectors. This uncertainty makes it difficult to forecast potential revenue streams for LLES technologies further hindering their deployment.

Furthermore, there is much uncertainty around medium to long-term network charging arrangements given the potentially significant change underway in this area. Clarity over these future arrangements would help in forecasting the future costs that an LLES project may incur.

In summary, we consider the additional the issues that investors in long duration storage will want to be addressed are:

- **Policy confidence** – consistent policy support for LLES, which recognises the value and the need for this resource, including for low carbon resources . We think that targets for LLES GW or GWh capacity, similar to those set for offshore wind, would give confidence about policy intent, and encourage early stage development.
- **Market confidence** – consistent future electricity market designs to enable LLES to compete equally with other technologies.

7. What types of capital are available for LLES and from what types of investors?

Currently there is no, or very limited investment capital available for LLES investment.

This is set against a background where, internationally and in the UK, the infrastructure investment sector is buoyant with a wide range of investors and lenders seeking long-term investments in high quality infrastructure assets. In particular, the rapid growth of ESG-targeted investments has led to an increased appetite for low carbon infrastructure investments.

Large infrastructure projects such as LLES could very well into this investment landscape, and we envisage a wide range of potential sources for investment capital if a viable route to market in GB is established. These include:

- Strategic investors seeking to own and operate LLES assets,
- Infrastructure funds, pension investment funds, or other financial institutions seeking long term investments in infrastructure assets,

- Commercial or development banks offering short- or long-term debt, or potentially project bonds with groups of institutional investors

Many of these finance providers are likely to be interested in providing either equity or debt, although the financing structure for individual projects may change as they move from development to construction to operation, and risk profiles change accordingly.

While both equity and debt are technically available in principle, the current barriers to the deployment of LLES and the high degree of uncertainty make the required rates of return unaffordable.

We suggest that each project will need to be capable of being financed on a project finance basis. This means that the providers of finance for each project will only have recourse to the project company in the event of a default and not to the shareholders of the project company, or their ultimate parent companies. This structure will both allow access the widest pool of capital and allow cost of capital to be reduced using senior debt and equity.

8. Do the financing challenges LLES projects face primarily concern raising debt, or also equity?

As set out above, the financing challenges concern both raising debt and equity. The current market framework means that it is neither possible to finance new LLES projects on an equity nor equity and debt basis. We believe it is important that the LLES regime should be designed such that project finance structures can be used and therefore raise lower cost debt as well as equity, thereby reducing project costs and reducing ultimate costs to consumers.

The key challenge to securing debt for project finance projects is about obtaining pre-construction certainty about the revenues available to service debt payments.

As an example of the need to provide ex-ante revenue certainty to enable finance of similar high value projects We would point to the example of interconnectors, where Ofgem7 has designed a cap and floor regime suitable for project financing.

By way of background, prior to the cap and floor regime in GB there were four interconnectors providing the GB electricity market with 4GW of cross-border capacity. Despite attractive commercial opportunities, the only route to market was through a merchant approach which means the developer was fully exposed to downside risk. The inherent revenue risks chilled investment in GB interconnection. Consequently, Ofgem introduced the cap and floor regime to offer a predictable and stable framework which could attract investment in interconnectors.

Ofgem has recently concluded that if all planned projects go ahead, a total of 10.9GW of additional capacity will be brought forward under the cap and floor regime, compared to 4GW of pre-cap and floor capacity. Ofgem state that the projects approved under the cap and floor regime are expected to deliver substantial socio-economic benefits to GB consumers by lowering electricity bills, supporting decarbonisation and enhancing security of supply.

7 https://www.ofgem.gov.uk/publications/interconnector-policy-review-working-paper-workstream-1-review-cap-and-floor-regime

D. Market reforms: Current routes to market and potential reforms

9. To what extent will the reforms outlined above support the investability of LLES? Please comment on any specific reforms that, in your view, hold potential to support the investability of LLES significantly.

The call for evidence outlines a number of potential routes to market for LLES and also some new opportunities that may emerge from current reforms. We have set these out below, together with our comments:

<u>Current routes to market</u>

1. *Wholesale market – arbitrage opportunities and merchant risk*

Wholesale market revenues are difficult to forecast with confidence over the long payback periods required by investors in high-value projects. Future wholesale market prices are expected to become more volatile in a high renewable high flexibility energy system, with many of the key demand and cost drivers being impacted by as yet unspecified Government policies e.g., support for electric vehicles, hydrogen, etc.

Potential funders of major capital projects find it challenging to gain confidence in a merchant revenue stack underpinned by wholesale market revenues that is out of step with the longer funding, construction, and operational timescales of large-scale LLES projects.

The absence of long-term price signals means that larger scale storage is being crowded out of these markets by short-term storage or flexibility solutions which have lower up-front capital costs but higher lifetime costs than long duration storage. This will lead to higher overall energy prices for consumers.

2. *Power purchase agreement – potential for revenue floors being offered by suppliers*

We agree there is some market evidence of PPA's being offered by suppliers for some flexibility resources, but there is no evidence that PPA's will be available at the volumes or contract durations necessary to underwrite the revenues necessary to support the financing of high value projects such as LLES. The uncertainties about the future of wholesale and balancing markets will also impact the availability of PPA's.

The use of corporate or supplier PPA's will also create additional counterparty credit risks and will require a stack of PPA's to be combined before start of construction to secure financing. This is very similar to the problem that merchant interconnectors faced before the cap and floor regime in that they were unable to attract sufficient long-term capacity purchasers before start of construction because these counterparties were unable to enter into long-term contracts.

3. *Balancing mechanism/Ancillary services – various contracts, mostly short-term*

Balancing and ancillary service markets should provide a valuable future revenue stream for LLES projects. However, these markets are essentially designed to provide short-term price signals and do not provide the long-term revenue confidence needed by new LLES. There are significant market distortions due to cross subsidisation from other markets, and competition is focused on short term marginal costs rather than providing capacity incentives.

The market is highly fragmented into different products and services, and contract are generally short term. This makes it very difficult for a high value project such as LLES to gain a stack of contracts before the start of construction to secure financing. Again, this is a similar situation faced by interconnectors before the cap and floor mechanism was introduced.

4. *Capacity market – 15-year contracts for new assets (with 5-year max delivery period)*

The capacity market should provide a valuable future revenue stream for high-value LLES projects. However, the current design of the capacity markets means that this is unlikely to make a significant contribution. LLES projects with longer construction times e.g., 6-7 years, will not qualify for the regime. Furthermore, the current capacity market does not target and value the assets that the system needs. In addition to targeting MW capacity, the electricity system needs capacity that is low carbon, provides flexibility capabilities, and in located where it will reduce network and balancing costs.

We think the redesign of the capacity market could seek to target the benefits from LLES projects of different sizes and lead times, as well as their system benefits. We will provide further suggestions in our response to the separate capacity market consultation.

Overall, we consider that the current routes to market will not enable new LLES projects to be financed and constructed.

Current policy reforms

1. Stability pathfinders

The ESO has identified system need in certain regions of the country and run competitive tenders to find solutions. While the introduction of Stability Pathfinders by the ESO is welcome, we note that these are still at the pilot stage with many teething problems yet to be resolved. The pathfinders have tended to look at one issue and find a solution in isolation rather than a holistic whole system approach, which allows revenues for different services to be stacked. This disadvantages LLES technologies that can provide multiple services at the same time as commercial rules are developed for each pathfinder in isolation.

The key challenges that seem to be emerging are that while the tenders have attracted significant interest, the tender process appears complex and slow, with potential bidders facing challenges such as gaining land rights at the ESO's target locations, having to apply for grid connections, and the contract terms potentially prioritising smaller scale early delivery solutions which may be less economic overall.

While in principle the stability pathfinder process could be extended to tender for LLES solutions, this would require a radically different approach from that currently adopted by the ESO, also requiring changes to its approach to design of transmission networks and the design of balancing markets, taking a longer term view of the most cost-effective solutions for consumers. The current approach favours short term solutions from existing assets without giving the investment signals to longer term capacity and capability. This will lead to higher costs to consumers in the longer term.

However, if the ESO was willing and able to enter long-term contracts for its services (e.g. 15 years or more) for a package of LLES services from a particular project, this could provide further revenue certainty which might strengthen the case for investment.

We consider that such a change is likely to take several years to design and implement such that contracts could be agreed with LLES developers that would provide revenue certainty about balancing revenues. Even if these were to be agreed, the LLES developers would also need to have sufficient certainty about capacity market and wholesale revenues in order to secure financing.

2. UK investment bank

While investment by a national infrastructure bank could make a valuable contribution, this is only likely to partially fund a new LLES project and would not provide Government backing to other investors in the event of default. Private capital would still need to gain assurances about the revenue certainty associated with the project.

3. Capacity market (CM)

As set out above, the capacity market can provide a valuable contribution to future revenue certainty for LLES projects. We have responded separately to the Capacity Market consultation. In our response, we agree that the qualifying time periods should be extended such that pumped storage hydro LLES projects may be included. In addition, we propose that the capacity market reforms should be extended to consider electricity system needs for a) flexible resources, b) low carbon, and c) their location.

We would however highlight, that while CM reforms proposed are generally positive, they are unlikely to support the deployment of LLES on their own. The Capacity Market clearing price has cleared at a low price in several of the recent auctions and consequently would make up only a small proportion of the overall revenue needed for LLES. For the CM to be sufficient on its own to make LLES investable, the clearing price would have to be significantly higher than recent levels. Reforming the CM alone is unlikely to support LLES deployment at the scale required.

4. Network and LLES competition

We welcome that the network competition policy could include development of non-network solutions such as LLES. However, this regime has been under development for several years and is unproven. For the tenders to be successful, there will need to be a fair competition between alternative solutions, requiring a process for identifying the need, qualifying bidders, process governance and decision making, etc.

From a policy perspective, it would need to be clear whether the LLES project was competing as an alternative regulated asset, or whether it would still seek merchant revenues and participate in balancing and wholesale markets. Creating additional regulated flexibility assets may cause wider market distortions.

This regime is likely to take some time to develop and runs the risk of delay and uncertainty, thereby chilling investment until the regime has been proven. If a solution such as cap and floor were to be introduced, then perhaps such a competitive approach might be developed as an enduring solution.

5. Network charging

We agree that network charging is a key factor to consider in the policy regime for the development of LLES. It will be important that the transmission charges appropriately reflect the value that these flexibility resources provide to the electricity system, both as demand and generation.

We consider that the flexibility and locational benefits of LLES should specifically be taken into account in the design of transmission charges, recognising and thereby incentivising the value that these assets provide. This could include a locational benefit for dispatchable demand for example.

6. Transmission constraint licence condition

We note the latest developments in this policy area, targeted at optimising balancing costs through the use of storage in constrained areas of the electricity system. While this is a welcome policy from a LLES perspective, we consider that it will not have a significant impact on the investment case for LLES, given the need for significant long term revenue certainty before construction.

7. Smart Systems and Flexibility Plan

We welcome the update to flexibility policies set out in the Smart Systems and Flexibility plan, and its prioritisation of low carbon flexibility (30 GW needed by 2030) to achieve net zero. We note that the paper highlights that it will be very difficult to achieve the deep power sector decarbonisation needed to achieve the sixth Carbon Budget without significantly higher levels of system flexibility.

We also welcome the commitment to decide on the future regulatory regime for LLES in early 2022.

Overall, we recognise that these current market reforms could each help support the development of LLES. However, the need for this resource is becoming increasingly urgent and these reforms will take time. Also, until the reforms are completed, none are certain to deliver the revenue confidence needed to ensure LLES can be constructed.

10. Do you have any views on further reforms that could take place in current markets to improve the investability of LLES?

We have considered a potential option for a new flexibility obligation for renewable generators:

<u>A new flexibility obligation for renewable generators</u>

This approach addresses the decline in flexibility resources that are currently mandated from fossil-fuel generation by requiring these services to be provided by renewable generators. This could be enabled through an obligation on either energy suppliers or on generators, requiring them to provide flexibility services for power output, frequency, inertia, and voltage. This could be applied to all, or only to new renewable generation.

All other market mechanisms would continue unchanged. The balancing market would optimise these flexibility resources in the short-term markets. Key disadvantages would be that:

- this approach is reliant on suppliers and generators being able to commit to long-term investment contracts for long duration flexibility. This is unlikely to be possible. Suppliers will seek to contract on a short-term basis and generators will seek contracts that align with their individual revenue horizons. This approach may lead to increased procurement of less economic short-duration storage, resulting in higher overall energy prices for customers,
- this would distort the market signals for renewable generation. By mandating a requirement for all renewable generation (existing and new) this will impose an additional unexpected cost that could undermine confidence in renewable generation investments,
- a market-wide mechanism is likely to lead to an excess of flexibility resources being procured with an associated cost penalty being passed to investors and consumers,
- a market-wide mechanism may not be efficient, as it will not signal the location or type of flexibility resources that are needed,
- the impact of this intervention across balancing, wholesale and capacity markets, and across technologies would be unclear, adding to market and revenue uncertainty,
- it will require significant change to existing market arrangements which will be complex and take time to implement.

In theory, this obligation could directly replace the flexibility capabilities currently provided by fossil fuel generators through contracts with flexibility providers. But it will be difficult for suppliers or generators to make long-term commitments for long duration storage. Overall, it will be complex and difficult to implement and may lead to higher costs for consumers and may undermine incentives to develop renewable generation.

11. Are you aware of any proposed market changes (and/or system changes) that could make it more difficult to finance LLES within current markets?

As set out in our answers above, we don’t think that changes to existing markets are likely to change the investability of LLES for several years. In principle, any of the changes could make improvements, but the key underlying requirement is to gain certainty over longer term revenues.

Indeed, we consider that the potentially slow progress of current market reforms, which do not specifically value the economic and system benefits from LLES will lead to cannibalisation of the future potential LLES revenues by less economic solutions, thereby making it less likely that large scale LLES projects can be developed in future.

Recent proposals from Government have indicated that co-located storage assets may be supported under the Contracts for Difference scheme in future allocation rounds. Since LLES technologies will be too large to deploy as co-located assets, the proposed support could disproportionately benefit short-duration small-scale technologies such as batteries which could deploy to the system through support under the CfD.

12. Considering your answers to questions 9, 10 and 11, do you think further intervention is needed to de-risk investment in LLES?

As set out above, we do not think that current market reforms will provide additional revenue certainty and improve the investability of LLES, and that a cap and floor mechanism is the most appropriate way of achieving this as it builds upon an existing proven approach.

One initiative that could potentially improve the confidence of investors in LLES assets would be if there was a clear market signal for purchase of flexibility resources alone. This could potentially lead to the ESO, or suppliers, having to purchase these essential system flexibility services on a stand-alone basis.

However, this would require all existing flexibility services (currently provided without charge by flexible generators) to be valued and provide short- and long-term pricing signals for new LLES investments. While this could potentially be another option to consider, we think this would cause significant disruption to existing market signals, be difficult to measure and implement, and may not provide the desired signals until LLES investors were confident that this approach was working. Such an approach to specifying flexibility resources and opening them to competition might be attractive in principle but may give rise to greater market uncertainty and volatility.

In conclusion, we think that key market interventions to support LLES should address the following:

1. the introduction of a cap and floor approach to provide revenue stability
2. changes to capacity market rules to allow projects with long construction timescales to participate
3. changes to the way the ESO seeks pathfinder and non-network solutions through LLES options
4. changes to the way in which the ESO gives LLES the opportunity to participate in flexibility markets

The first two of these are the most important to give revenue certainty. The ESO reforms should enable LLES to compete fairly against other technologies and deliver the lowest cost flexibility for consumers.

We consider it is important that reforms to enable LLES take place quickly to ensure the benefits are realised, and that the reform scope does not become overly complex, or risk being delayed by vested interests. As such, we think the priority cap and floor and capacity market reforms should be prioritised through BEIS/Ofgem leadership of this initiative.

E. Rationale for further intervention to de-risk LLES: Considering approaches

13. Do you think that it is necessary to try to accelerate the deployment of LLES, even if stronger signals for longer duration storage may not develop until the late 2020s / 2030s?

Yes, we consider the need for LLES is becoming more urgent and the deployment should be accelerated in the same way that the deployment of interconnectors was accelerated a decade ago. LLES technologies typically have long lead times both in terms of development, where securing development consent can take several years and cost millions of pounds, and in construction, which can take in excess of 5 years. If the UK is to deploy the level of storage and flexibility as outlined in the FES by 2030, creating the framework to enable the deployment of these technologies must start now.

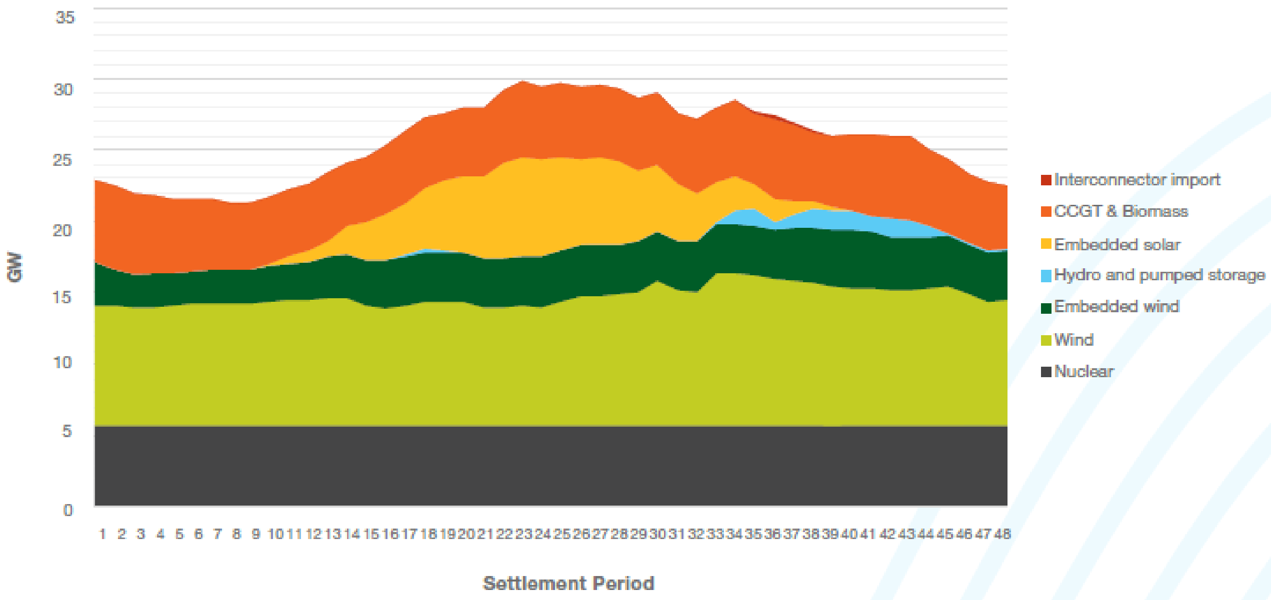
The electricity system is currently facing increasing challenges to meeting security of supply and an associated rapid growth in balancing costs. As an example, the ESO's 2021 Future Energy Scenarios report8

8 https://www.nationalgrideso.com/document/202851/download

showed the challenge a decarbonised electricity system might face. During the first COVID-19 lockdown in summer 2020, with sunny weather and low levels of electricity demand, UK electricity generation had a record low carbon intensity. This resulted in low inertia and flexibility on the system. Despite having sufficient renewable electricity, the ESO needed to use natural gas power stations to respond quickly to demand changes and provide the inertia required to ensure security of supply.

The following chart shows the generation mix on May 23, 2020, highlighting that LLES in the form of pumped storage was already making a valuable contribution to meeting variable demand. In future, LLES can increasingly substitute for the flexible CCGT output, both in summer and winter periods.

Figure 1: Generation mix on Saturday, May 23, 2020



14. Are other reforms needed to markets to ensure long-duration storage assets are providing the maximum value to the system? If yes, please provide detail of what reforms could be needed.

As described in our answers above, we consider that market reforms are needed so that the value of LLES to the electricity system is fully recognised. This includes MW of capacity, volumes of ancillary/balancing services, low-carbon benefits, and locational benefits.

If these attributes are to be recognised, then the breadth and depth of these reforms would need to be captured across all markets in a non-discriminatory way.

The market reforms would need to deliver long-term as well as short-term price signals to enable LLES investment.

15. Which intervention, in your view, has the most potential to be appropriate for addressing barriers to help bring forward investment in LLES, including novel storage technologies? Are there any other mechanisms which might be appropriate to consider? Please provide evidence to support your response where possible.

In our view the Cap and Floor mechanism is the most appropriate mechanism to address the barriers and bring forward investment in LLES.

The Cap and Floor mechanism would provide sufficient certainty to investors that the income will underpin an efficient level of debt financing. This would unlock the finance required for new projects to go ahead. The Cap and Floor regime has been highly successful in attracting private sector investment in interconnectors.

a) RAB model as used by Ofgem for regulated energy networks

If applied to LLES, the RAB model could give a guaranteed return on investment assuming that operational performance obligations were met. It could also mitigate construction risk.

However, it will be difficult to design a regulatory regime that appropriately incentivises the asset owner to optimise performance, ensuring efficient dispatch e.g., an operator may seek to optimise against regulatory rate of return incentives instead of optimising performance through competing in the different electricity markets.

While a RAB model should provide revenue certainty and should attract investment capital for the development of LLES, it may distort competition in balancing markets by limiting incentives for the LLES asset to seek performance improvements to enhance returns.

b) Cap and floor model as used by Ofgem for interconnectors, potentially with a variation for setting a floor without a cap

We think this option has the greatest potential for application to LLES projects and should provide investor confidence.

The Cap and Floor regime currently used for interconnectors guarantees a long term regulated revenue floor and a cap on investor return. The cap and floor levels are derived by Ofgem from capital and operating costs and allowed return. We consider that a similar cap and floor mechanism (with a 20–25-year term) should be appropriate for pumped storage hydro LLES. Similar to interconnectors, we think there are merits in considering periodic reviews or annual adjustments that seek to ensure optimum operation and value for consumers.

There is a significant difference in the characteristics of interconnectors and LLES projects in that LLES assets such as pumped hydro will purchase electricity for pumping and receive revenues from electricity sales and flexibility services. Interconnectors essentially provide only import or export capacity for their customers. A cap and floor model for LLES should incentivise the asset owner to participate in existing markets to optimise costs and revenues in the most efficient way and deliver these benefits to consumers.

Because of the complexity involved in designing a revenue stabilisation mechanism that accounts for the variability and unpredictability of the costs involved in operating storage assets, stabilisation based on income after electricity purchases[9] appears most appropriate for LLES assets. i.e., the cap and floor should be designed to include electricity purchases as a normal operating cost.

The cap is in place to protect consumers from the risk of excessive outturn profits from this ex-ante regime but the wholesale and balancing market would optimise these resources in short-term markets. But a cap could disincentivise the optimisation of the asset and cause market distortions. e.g., once the cap was

9 **Annual revenues from electricity markets less electricity purchases (or cost of sales).**

reached in any regulatory cap period, there is no incentive to continue operating the asset, and the benefits would be lost.

The alternatives to a fixed cap would either be to have no cap and rely on market competition to optimise LLEs prices, or to have a gain share arrangement in place where a proportion of profits above a specified level could be returned to customers. We think both these approaches have merits in that they will maintain a profit incentive for the LLES plant to optimise its operation and costs, and will reduce potential market distortions from a revenue cap.

If a gain share mechanism is to be used, then it will be important that this is set at a level where it can still encourage investment taking account of the potential construction, technology, market, and regulatory risks that investors will face. For example, investors would need to be able to predict the impact of a gain share mechanism and how it deals with fluctuations in revenues and profits over time due to differing market and operational conditions. The design of a gain share mechanism might be more complex that the benefits it is likely to deliver.

Beyond unlocking the finance required to invest in LLES, we believe that the introduction of a Cap and Floor can have multiple other benefits over alternative support mechanisms, such as:

- It is relatively simple to introduce as the existing interconnector regime can be used as a blueprint.
- It will deliver services consistent with the system's needs as operators will be incentivised to participate in balancing services for the ESO and will be able to compete with other technologies.
- The Cap and Floor appropriately apportions risk by providing reasonable certainty of servicing debt without consumers underwriting all costs, while the cap provides protection to consumers.
- It incentivises efficiency as operators are exposed to market opportunity between the cap and the floor. This mitigates any market distortion by incentivising the provision of services in response to market price signals from multiple competitive markets (wholesale, balancing, ancillary and capacity markets).
- If the Cap and Floor is open to multiple LLES technologies, this can introduce competitive pressure and further avoid market distortions as multiple technologies could bid for support.
- The support for LLES technologies under a Cap and Floor would also advance the low-carbon economy, maintain security of supply, and deliver value for money.

c) C) Contract for difference framework used to support low-carbon generation.

The current CfD regime procures long-term contracts during regular tender rounds. They enable a renewable generator to stabilise its revenues at a pre-agreed floor level (the Strike Price) in £/MWh for the contract duration. CfD top-up payments above wholesale market prices are funded by electricity suppliers and ultimately by customers.

The challenge in applying a similar CfD regime to LLES is that it does not recognise that the value of storage will quite often be from providing availability of capacity to be held in reserve i.e., for not producing output.

LLES will also face difficulty in determining an accurate strike price for its CfD bid because it must also estimate the costs of procuring electricity to create the storage capacity.

The CfD approach appears unlikely to be suitable for storage investments as it would incentivise an inefficient outcome i.e., the storage asset could seek to maximise output rather than respond to all the different electricity market signals in an efficient manner. It would also create investment uncertainty because of the difficulty in estimating the electricity purchase costs needed to determine a strike price for a CfD bid.

d) Reformed capacity market

Capacity market redesign could provide a long-term price signal for LLES flexibility projects such as pumped storage hydro. But, for pumped storage hydro projects to participate in capacity market auctions the market mechanism would first of all need to reflect the longer construction times of these assets, potentially up to 8 years depending on the project scale.

In addition, to enable the whole system value of pumped hydro LLES to be recognised, and to enable fair competition against other technologies, it is suggested that any capacity market redesign would also need to address (and value) the following

- the low-carbon nature of LLES resources.
- That LLES can also provide inertia, frequency, and voltage flexibility as well as MW at peak.
- that LLES can provide additional system demand to reduce curtailment of renewables
- that LLES has a locational value to mitigate transmission constraint costs and reduce the need for additional transmission investment costs

Capacity market reform of this nature may be complex and take time to implement, and ultimately may not be sufficient to provide investment confidence. Even if this reform was established, revenues would still be obtained from stacking across different markets with different procurement timescales and different contract lengths.

Short- and long-term price signals from wholesale and balancing markets would still be subject to the volatility of market dynamics, with associated revenue uncertainty.

16. Please provide suggestions for how the most effective intervention, in your view, could be structured to ensure value for money and affordability.

As set out above, we consider a cap and floor mechanism has been demonstrated to be effective for interconnectors and in principle, a mechanism like that for electricity interconnectors should be effective for LLES technologies.

The minimum hurdle for an LLES project obtaining a Cap and Floor agreement should be to demonstrate a positive cost benefit assessment. This would ensure that projects provide a positive system impact such as reducing curtailment costs, reducing the need for network reinforcement, and reducing the need for high-carbon back-up technologies.

Value for money – a cap and floor mechanism will retain full merchant exposure for equity investors. Equity investors are highly incentivised to construct optimise the storage assets in a way that generates the most value, as they are exposed to returns falling to current costs of debt. This would include seeking the optimum technology and design solution to compete in and increase competition in existing electricity markets.

Affordability - the cost of the cap and floor to consumers should be minimal as the economics of individual projects should all demonstrate viability and should be assessed for positive cost benefits before they qualify for the regime. As such the risk to consumers of stranded assets should be low. Energy system customers would gain from the benefits of the projects which should result in lower electricity bills, greater security of supply and decarbonisation.

17. ***Do you think that hydrogen storage that will provide flexibility could face the same financing barriers discussed in relation to LLES above? Please provide evidence where possible.***

We think that the drivers for a cap and floor regime for LLES could also apply to hydrogen storage but the issues and timescales are different. Hydrogen is already a commercially produced gas that could be produced and stored at greater scale, but the future uses and volumes needed is still unclear.

We agree that this is a policy that could be considered in the future once these issues are clearer and consideration of a regime for hydrogen should not hold up LLES policy developments.

18. ***Do you agree that it is not yet appropriate for a Cap & Floor mechanism to be considered for hydrogen storage? If so, what other approaches might be appropriate to consider?***

Please see our answer to Q17.

F. Understanding risks

19. ***What are the key risks in intervening to support LLES, and what risks might arise from a Cap & Floor specifically?***

We consider that the main risks to customers in intervening to support LLES will be:

- <u>Higher costs from floor subsidy payments to stranded assets</u> – in this situation, LLES assets would not be able to operate economically in electricity markets and customers would be faced with higher bills as essential operating costs are recovered through the floor mechanism.

  This risk could be mitigated by only allowing economically viable projects to proceed into the cap and floor mechanism.

- <u>Distorting existing markets</u> – to distort existing markets, LLES projects would need to have an unfair advantage over other technologies or solutions that did not have a floor support mechanism.

Because LLES cap and floor projects would be seeking their revenues from the same wholesale and balancing markets as any other technology, then as long as these short and long-term markets are operating fairly and giving the correct price signals for the resources that are needed, then there should be no market distortion.

Again, the use of a qualification process for LLES projects to test their economic viability and benefits should allow the introduction of additional competitive pressure into electricity markets. In addition, the introduction of LLES which can replace the same technical characteristics from natural gas plant should help accelerate decarbonisation.

- <u>Cannibalising revenues from other technologies</u> – there is a risk that the introduction of LLES might cannibalise potential revenues for future hydrogen or CCUS generation.

  For the next decade, it would appear unlikely that other technologies would be capable of development at the scale needed to provide meet flexibility needs, and LLES would be best placed to fill this flexibility gap. We consider it unlikely that LLES will cannibalise BESS resources, given their different operating characteristics. Indeed, the capability of LLES to add demand during off-peak periods should enable additional operating hours for these technologies.

  Again, the use of a qualification process for LLES to test their economic viability would be able to test LLES solutions against the availability of these nascent technologies. A series of discrete LLES application windows would enable this policy to be kept under review.

- <u>Regulatory complexity and design failure</u> – there is a risk that a cap and floor regime becomes unduly complex, has a high administrative burden and is subject to challenge.

  This risk may be mitigated by keeping the design and operation of the regime as simple as possible, building on experience with interconnectors.

20. How might a Cap & Floor mechanism distort the market for short duration flexibility and nascent technologies? Please provide evidence where possible.

As set out above, we consider that the distortion to short term markets and nascent technologies is limited and is far outweighed by the benefits to consumers. Existing electricity wholesale and balancing markets already have effective competition between pumped storage hydro and short duration flexibility assets e.g., gas engines and lithium-ion batteries.

However, the current design of balancing markets strongly favours lower capital cost short-duration storage. These assets can construct quickly and take advantage of higher short-term prices because there is no competition from lower cost LLES. The absence of long-term price signals and 'crowding out' of LLES from current balancing markets is currently creating a market distortion which is causing higher costs to consumers as a result.

Furthermore, LLES that can provide non-network solutions instead of building new transmission lines also has no way of accessing these price signals, which is also a further market distortion.

We would suggest that the introduction of LLES will not create a significant new market distortion but instead will help to remedy two existing market distortions. The introduction of new LLES technologies should enhance competition and serve to replace natural gas power stations providing flexibility services.

21. How could any intervention, such as a Cap & Floor mechanism, be designed and implemented to enable the benefits to outweigh risks?

We consider that a cap and floor regime for LLES should be modelled on the interconnector regime and include the following key elements:

- Definition of system need
- Application windows, and
- Design of cap and floor regime

Definition of system need

The system need for flexibility resources should be defined to guide applications and project assessments. This should identify the system needs in terms of scope, location, and types of LLES flexibility services that the system requires. This information overall location These should assess which will assess eligibility for specific projects

Application windows

Given that there are expected to be a finite number of LLES projects due to siting and other development constraints, and that it will be important to understand the future pipeline of projects, it is suggested that application windows may be the most appropriate way of considering projects.

These windows would seek developer-led proposals and would require developers to submit their applications for a cap and floor for assessment against a set of eligibility criteria, designed to identify projects that have a strong probability of being constructed.

A developer-led model would have the advantage of speed, enabling the selection of advanced projects able to connect and operate before 2030.

These eligibility criteria could include

- Connection agreement
- Land rights
- Planning consents
- Generation licence

- Operational characteristics
    - Minimum import/export capacity of 100 MW
    - Compliant with Grid Code synchronous generation technical requirements
    - Minimum full load duration of 6 hours
- Project assessment information to determine value from the investment, including:
    - Cost benefit and social welfare modelling against a plausible range of scenarios
    - Assessment of risks and dependencies
    - Indicative costs
    - Justification of capacity and technical design
- Project delivery plans, including financing and supply chain plans

Cap and floor regime

We suggest the key terms should include:

- 20-25 year cap and floor period, with annual or periodic adjustments to reflect variable costs
- An annual availability target of 95%
- Floor is set at cost of debt and applies to 100% of the RAV
- If a cap is used then then it should be set at Cost of Equity (as calculated for a merchant project). If a sharing factor is applied at say 50%, then the cap would be applied to 50% of the RAV.
- Gross revenue calculations for the cap should be net of costs of electricity purchases needed to create storage capacity e.g., for pumping, and working capital financing costs.
- Non-controllable costs should be treated as pass through and included in the floor calculation. These should include land costs, business rates, licence fees, and corporation tax.
- Essential controllable costs should be included in the floor calculation. These should include insurance and other operation and maintenance costs.
- Cap and floor settings should be regularly updated to reflect outturn inflation, availability incentives and changes to opex and decommissioning costs.
- Regime should be designed to accommodate project finance lender requirements, similar to interconnectors
- Cap and floor payments should be recovered through TNUoS
- The regime should be implemented through the generation licence
- The regime should be administered by Ofgem