Email to: energy.security@beis.gov.uk

18 October 2021

To whom it may concern,

Capacity Market: Improving delivery assurance and early action to align with net zero - 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.

The UK Pumped Hydro Storage Working Group (convened by Scottish Renewables and comprising SSER, Drax Power, ILI Group, Buccleuch, Dorothea Pumped Hydro, CCSQ and British Hydro Association) is pleased to provide a response to this call for evidence. Our members are currently developing a pipeline of some 5GW of pumped storage hydro in the UK – this capacity can make a major contribution to providing firm capacity needed to enable an affordable, secure net zero energy system.

We welcome that this call for evidence is seeking views on potential early actions to align the Capacity Market with net zero and to address increasing security of supply challenges. We agree with the key concern raised by the consultation that the Capacity Market plays a key role in ensuring security of supply, but the current design incentivises unabated gas generation to provide firm flexible generation when renewable output is low.

The key point we would wish to stress in our response is that the current Capacity Market design does not incentivise long duration electricity storage (LLES) technologies such as pumped storage hydro that can provide firm flexible generation.

In this cover letter, we have highlighted the current status of pumped storage hydro projects and the key benefits they can bring to ensure security of supply. We have also summarised our responses to the consultation and our detailed responses to individual questions is included in an annex.

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INVESTORS IN PEOPLE

The UK pumped storage hydro pipeline

Pumped storage hydro is a proven LLES technology, with around 160GW installed and operational worldwide. Future ESO FES and CCC scenarios for a net zero energy system all forecast significant increases in variable wind and solar generation. This major growth in renewables will have important effects upon the future electricity system and drive the need for LLES and the benefits it can provide.

The BEIS 2021 Smart Systems and Flexibility Plan[1] 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), 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.

Some 3GW is already constructed and operational in the UK, as shown in table 1 below. All the 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**	

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 2.5GW 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
Corrivarkie	2023 (est)	2029	600	19	ILI

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

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

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:

- **Meeting system demand:** providing flexible zero-carbon electricity capacity when renewables are not available, displacing fossil fuel generation.
- **Maintaining system stability:** providing flexible system stability services, such as inertia, voltage flexibility and restoration.
- **Meeting system locational needs**: reducing network and balancing costs by siting LLES close to renewables located far from demand centres.
- **Reducing renewable electricity curtailment:** providing additional demand at times of low consumer demand, thereby reducing renewable curtailment.

We have separately replied to the BEIS call for evidence on LLES, setting out detailed evidence to support the benefits that pumped storage hydro can bring to enable net zero, and supporting the introduction of a cap and floor mechanism to enable investment in these projects.

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. A cap and floor mechanism would give confidence to investors that revenues will underpin an efficient financing structure.

Our response to the Capacity Market consultation

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

- **Low carbon definition –** we propose this should be a ‘zero-emissions’ definition if net zero targets are going to be met.
- **Enabling projects with long construction times** – auction timetables and capital expenditure delivery windows should enable 5–7-year pumped storage hydro construction periods.
- **Incentivising firm delivery** – we agree that incentives for delivery of firm capacity should be enhanced.
- **Incentivising flexibility** – we suggest that future Capacity Market auctions should widen the scope of the services being sought. In addition to provision of firm capacity at times of system stress and net zero emissions, we suggest the auctions should include:
    - Provision of flexibility i.e., MW ramp up/down, and system stability services

- Location of assets and how they contribute to localised electricity system stress

New pumped storage projects are well placed to deliver all these additional system through the Capacity Market and help ensure that security of supply may be maintained for net zero.

We trust these comments are helpful and would be pleased to engage further to help develop new market arrangements. We believe the need for pumped storage hydro in the UK 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,

Angeles Sandoval

Policy Manager | Networks & Markets

Scottish Renewables

Annex: Capacity Market: Improving delivery assurance and early action to align with net zero - Call for Evidence

Question 1 - Could 'low carbon capacity' in the context of the Capacity Market be defined in terms of an emissions limit? If so, what should form the basis of this limit – for example, would it be better to base a limit on carbon intensity or overall annual emissions, and what types of capacity should be captured by this emissions limit?

We support a 'low carbon capacity' definition that is based on a zero or almost zero emissions intensity limit. This should provide an appropriate incentive for the development of zero emission technologies. Pumped storage hydro generation will emit zero carbon emissions and would be incentivised to participate in capacity market auctions defined in this way.

If a definition is used to enable unabated gas generation to operate for a few hours per year at times of system stress, then this could cannibalise the capacity market revenues available for zero carbon generation such as pumped storage hydro. This could disincentivise investment in these zero carbon technologies.

Question 2 - Are there alternative approaches to defining low carbon capacity in the context of the Capacity Market? Please provide justifications.

We note that the consultation considers opportunities for incentivising technology developments such as hydrogen blend by including them within the low carbon capacity definition. We consider that using variations to the definition for the purpose of incentivising nascent technologies could have the effect of disincentivising proven technologies such as pumped storage hydro.

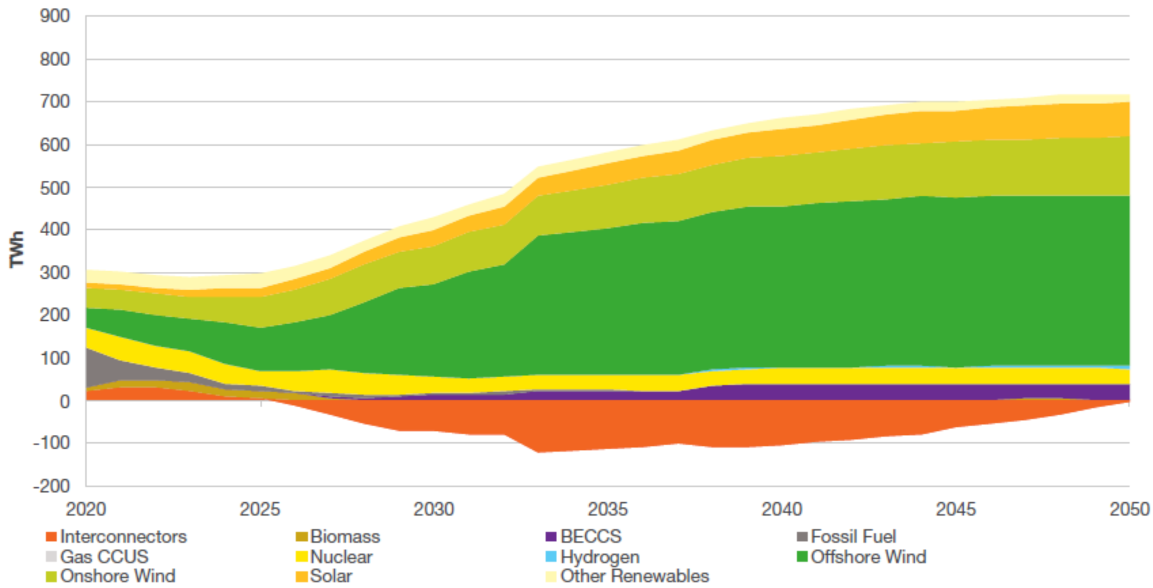
We suggest it may be more appropriate to use other incentive mechanisms e.g., direct development grants to support such technologies rather than add uncertainty and complexity to a capacity market that is targeted at a net zero outcome.

Question 3 - What are your views on the benefits or challenges of linking future long-term Capacity Market agreements to a new carbon emissions limit? Do you have any suggestions regarding an appropriate approach to setting such an emissions limit, and how could we best account for 'lower' rather than 'low' carbon technologies in determining eligibility for multi-year agreements?

We agree that long-term capacity market agreements should be linked to a carbon emissions limit. We suggest this should be a zero emissions limit if net zero targets are to be met.

To illustrate this, the following chart from the ESO 2021 Future Energy Scenarios shows the potential energy mix for their view on the fastest credible way of reaching net zero targets. This indicates that unabated fossil fuel generation output should be minimal after 2030.

Figure 1: 2021 ESO FES Electricity output by technology (Leading the Way scenario)



A goal of eliminating unabated fossil fuel generation by 2030 would support a future approach where long term capacity market contracts should only be awarded to zero emissions technologies.

The current 5GW pipeline of pumped storage hydro projects would be able to replace the system security benefits currently provided by unabated fossil-fuels. A zero-emissions eligibility definition would provide a strong incentive to support these developments.

Question 4 - Is it necessary and appropriate for carbon intensive generation to continue to access shorter multi-year agreements, until such a time as low carbon dispatchable generation is more widely available?

We recognise that there must be a transition from the existing capacity market arrangements which include incentives for unabated fossil fuel to provide security of supply. However, shorter multi-year agreements should be designed so as not to impact the incentives available to zero carbon generation such as pumped storage hydro. It would appear appropriate to retain incentives for unabated generation up to 2030, but to phase these out as new zero carbon alternatives are commissioned.

Question 5 - Would you expect these suggested changes to agreement lengths to affect your decision to participate in the Capacity Market, your bidding behaviour, or the costs of and access to finance? If so, how? Can you suggest any alternative approaches to ensuring agreement lengths offered in the Capacity Market are consistent with the delivery of net zero targets?

We suggest that new pumped storage hydro projects should be able to access long-term (e.g., for 20 years), capacity market agreements to deliver firm zero carbon capacity at least cost.

Pumped storage hydro is the primary technology used worldwide to provide grid-scale electricity storage with over 160GW of installed global capacity and many new projects in development. It is a proven technology, but projects require significant civil engineering works and have a high upfront capital cost. The main barrier to investment in new pumped storage hydro is the lack of long-term revenue certainty. Investors in these projects need revenue certainty before investing and long-term revenue certainty will enable access to low-cost finance.

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. No long-term price signals are provided specifically for flexibility. Prices in future high renewable electricity markets will be uncertain due to near-zero marginal costs when renewables are available and unknown and increased price volatility when renewables are unavailable.

Despite the potential attractiveness of the future market landscape, the route to market for new investments is currently blocked because future market design and long-term price signals are uncertain. The inconsistent approach to contract terms and application regimes across these markets add to uncertainty about future revenues.

As such, we consider that reform to the capacity market alone will not incentivise the development of pumped storage hydro projects. We support the development of a cap and floor regime like that currently used for interconnectors. Our recent reply[2] to the BEIS LLES consultation has set out our evidence to support this approach. In our response we propose that the capacity market will comprise one source of revenue available to pumped storage hydro projects, alongside other revenue streams.

Question 6 - Is it still appropriate to maintain the link between capital expenditure thresholds and multi-year agreements? If not, what other criteria could we consider using to assess eligibility for multi-year agreements (other than the new lower emissions limit discussed in section 2.3.2.1)?

The capital cost for the potential 5GW pipeline of new pumped storage hydro projects is expected to be around £5-6 billion in total, with construction capital expenditure and development costs estimated to be £0.8m-£1.5m/MW. If capital expenditure thresholds are still to be applied, we suggest they should be designed to ensure they do not restrict the development of these projects.

Question 7 - Should we revise the applicable capital expenditure thresholds? If so, what data could we base them on, and do we still need to have two different thresholds? Should low carbon DSR be able to access shorter multi-year agreements on the basis of emissions limits rather than capital expenditure thresholds?

Please see our answer to Q6.

Question 8 - Should we review the 77 month window for new builds?

Yes, we consider that the 77 month capital expenditure window for new builds should not act as a barrier to projects such as pumped storage hydro.

A typical pumped storage hydro project may have a construction period of 5-7 years depending on the scale of the project. This may be preceded by several years of pre-construction development and planning before reaching financial close and start of construction for the project. Due to the significant amount of civil engineering and tunnelling works, projects are likely to need to build in delay contingencies to their delivery timescales.

[2] https://www.scottishrenewables.com/publications/909-final-response-long-duration-storage-call-for-evidence

We suggest that the capacity market rules are designed such that the specific circumstances and construction of each of these individual large capital projects may be considered. This should ensure that there is an agreed delivery commitment to ensure that the project is incentivised for timely delivery, but which reflects realistic delivery timescales.

Question 9 - What are the benefits of maintaining the Extended Years Criteria?

Pumped storage hydro assets are expected to have lifetimes of 80-100 years and can provide firm security of supply benefits over these extended periods. It will be important that the capacity market fairly considers these benefits alongside other assets that are only expected to provide security of supply benefits for shorter periods. As such we think it is important that there continues to be an assessment that new capacity market assets can provide the required capacity for several years.

Question 10 - What are your views on the introduction of a declared later delivery year as a way of addressing the challenges experienced by projects with long build times seeking to enter the Capacity Market? Would this affect your decision to participate in the Capacity Market, and if so, how? Are there other approaches we could take to removing barriers to participation for technologies and projects with long build times?

We welcome that the review is seeking to ensure that technologies such as new build pumped storage hydro, with long build times, can compete in the market on a fair and level basis with no unintended barriers to entry.

This is not currently possible under the current market design, where new build CMU's that successfully secure capacity agreements in a T-4 auction are incentivised to deliver four years from securing their agreement to deliver, with the potential for an additional 12-month extension until a Long Stop date.

This timescale is unsuitable for new build pumped storage hydro projects which have typical construction timescales of 5-7 years. We request that the capacity market redesign allows for these longer construction timescales, allowing the capacity market incentives to be provided to these technologies.

We note that the consultation is considering arrangements that effectively provide a maximum of up to seven years to deliver capacity in the event a CMU has a declared later delivery year of two delivery years after the start of the T-4 delivery year. If this approach is adopted, it should be flexible enough to ensure that it does not inhibit the development of large-scale pumped storage projects that may have longer construction periods.

The consultation states that the government is separately considering whether new build pumped storage hydro should be able to benefit from cap and floor arrangements. If this is the case, the consultation suggests that rules may be introduced so new build pumped storage hydro projects in receipt of cap and floor benefits will only be allowed access to one-year agreements, as is the case for interconnectors.

As previously outlined, we have responded separately to the LLES call for evidence and support the cap and floor approach. We would suggest that the design of the cap and floor regime for LLES is likely to be different from that for interconnectors. In our response, we suggest that LLES projects must be incentivised to compete in wholesale, balancing/ancillary service and capacity markets through a profit-sharing incentive. Otherwise, the projects will be disincentivised to operate in response to market signals once regulatory capped returns have been realised.

The capacity market consultation does not provide evidence to support the conclusion that pumped storage hydro should be excluded from long-term capacity market contracts. These contracts would form an important part of the revenue stack for pumped storage hydro projects alongside revenues from other electricity markets. Long term capacity market contracts for pumped storage hydro projects would reduce reliance on a cap and floor mechanism for revenue certainty, and commensurately reduce risks to consumers.

Also, exclusion from these contracts may distort the market incentives available for the operation of pumped storage hydro projects or may distort the operation of the capacity market by excluding a zero-carbon resource with a low lifetime cost. The addition of pumped storage hydro projects in the capacity market would improve liquidity and competition in this market.

We suggest this issue should be carefully considered alongside the design of a cap and floor mechanism, such that neither the incentivisation of pumped storage hydro nor the operation of the capacity market is negatively impacted.

Question 11 - Do you agree with our suggested approach to determining and verifying eligibility for a declared later delivery year? Are there other approaches we could consider?

We agree that CMUs wishing to qualify for a declared later delivery year should provide suitable supporting evidence which identifies why it is not possible to construct and deliver the new build CMU within the standard four-year lead in time, verified by an Independent Technical Expert.

We agree the evidence provided should take the form of an evidenced project timeline with key development and build milestones, as part of a construction plan.

Question 12 - How can we best mitigate any security of supply risks arising from this approach? Can you identify any additional risks and/or disbenefits related to the introduction of a declared later delivery year?

Please see our answer to Q11. Supply risks should be mitigated by the provision of supporting evidence, verified by an Independent Technical Expert.

One possible way to mitigate supply risks could be assigning 0MW capacity to the longer lead time CMU, for the purposes of the auction. Once procured, these MWs can then be considered in the target setting process for future delivery years.

Question 13 - What are your views on the benefits and challenges of introducing an auction design splitting auctions between new build and refurbishing low carbon capacity and existing capacity? Would this affect your decision to participate in the Capacity Market or your bidding behaviour, and if so, how?

The consultation suggests that a new auction design is introduced to target low carbon capacity. We would support an approach for an auction for zero carbon capacity with sufficiently long timescales to allow for pumped storage hydro construction.

Currently, new build pumped storage hydro is unable to compete in capacity markets but has the capability to provide a valuable contribution to security of supply and support the main purpose of the capacity market.

Pumped storage hydro not only can provide MW of capacity at times of system stress but is also able to provide system services of flexibility, voltage support and inertia, together with locational benefits to the electricity system from sites in Scotland and Wales. All of these attributes can provide a valuable contribution at times of system stress. We suggest that future capacity auction design should take account of these factors.

Question 14 - What are your views on the potential split auction designs considered in sections 2.5.2 and 2.5.3? Are there alternative designs we should consider? And what approach could we take to setting targets for a separate low carbon auction?

As set out above, we would support a low carbon auction that would allow pumped storage hydro to compete. The addition of pumped storage hydro could increase market liquidity and provide a lower clearing price across all the low carbon technologies.

We consider that the benefits that should be assessed in an auction should extend beyond MW or zero carbon MW to other system security attributes such as location, flexibility, system stability services.

A single auction with price/benefit assessments would appear to be most appropriate for this purpose, but this may be more complex to administer and assess multiple clearing prices. Alternatively, a split auction could be used to specifically target factors such as low carbon.

On balance, we suggest that a single auction with multiple clearing prices for different types of capacity is the most appropriate design. This would allow the auction to assess not just on price but also on the benefits that are offered by the bidding CMU's.

Question 15 - What are your views on expanding the scope of the Price Taker Threshold to potentially make it a price cap for Price Taker Capacity? Would this impact bidding behaviour? What changes to the Price Maker Memorandum might be necessary to ensure any changes to the Price Taker Threshold would be effective?

We do not have any comments on this question.

Question 16 - What are your views on the potential benefits or challenges of amending the Net Welfare Algorithm to calculate to next lowest bid, rather than by the round floor price? Would this have an impact on bidding behaviour?

We do not have any comments on this question.

Question 17 - How might the changes to auction design considered in section 2.5 interact with other design possibilities explored in Chapter Two concerning agreement lengths (2.3) and projects with long build times (2.4)?

As set out in our earlier responses, we consider that auction design should be compatible with pumped storage projects that may have construction timescales of some 5-7 years.

In addition, we suggest that auction design should be focused on valuing the following key characteristics:

- Provision of firm capacity at times of system stress
- Net zero emissions
- Provision of flexibility services
- Provision of system stability services
- Location of assets and how they contribute to localised electricity system stress e.g., location in Scotland with limited synchronous generation and transmission capacity

Question 18 - What are your views on changing the figure used in calculating the penalty rate (for example, from 1/24 to 1/8 or 1/4)? Should the penalty rate be linked to the Value of Lost Load rather than the auction clearing price? Please provide supporting reasons/evidence.

Capacity Market providers are required to deliver their capacity obligation during stress events or face financial non-delivery penalties. We note that BEIS propose to strengthen the measures to incentivise capacity providers appropriately to deliver during system stress events in all circumstances.

We support this approach as pumped storage hydro projects are designed to be extremely reliable and versatile in delivering their output to support electricity systems. We agree with proposals for strengthening the penalty mechanism to prevent gaming while at the same time ensuring that the penalties are not so onerous as to inhibit efficient investment and operation.

We note that the value of lost load is proposed as a way of determining a penalty mechanism which seems an appropriate alternative metric. However, it will be important that investors have certainty about the likely penalties over the lifetime of their project so we suggest that the penalty mechanisms should be designed such that ex-ante confidence can be provided.

Question 19 - What are your views on the changes we consider in relation to the annual and monthly penalty caps?

We agree that penalty caps should be strengthened to disincentivise under delivery. But it will be important to retain caps to provide certainty for investors. These should be proportionate to the ability of the providers' ability to manage the delivery risk.

Question 20 - What are your views on the options we consider for improving the coordination of capacity during a stress event?

The consultation recognises that there is a need to consider the coordination of capacity during a stress event in more detail. Options may include better information on the likely nature of the stress event in the run-up to an actual event, amendments to the calculations and/or sensitivities within the Capacity Market Notice, or removal of the four-hour notice period.

We support the need to consider options for greater coordination as system stress events become more likely in a high renewable electricity system. The wide range of flexibility capabilities offered by pumped storage hydro plants would provide a valuable asset in such circumstances.

Question 21 - Do you agree with the idea of introducing an additional Satisfactory Performance Day for CMUs that fail to deliver in a stress event?

We agree with this proposal as a way of ensuring that delivery performance can be better assured.

Question 22 - What are your views on the options we set out regarding the recovery of unpaid penalties?

We note that the consultation proposes to maintain an approach to recover penalties from capacity market payments, instead of introducing a requirement for additional credit cover. We support this approach.

Question 23 - Would you expect any of these changes to the penalty regime to affect your decision to participate in the Capacity Market, your bidding behaviour, or the costs of and access to finance, and, if so, how?

We do not have any comments on this question.

Question 24 - What are you views on the benefits and challenges of the alternative model for a penalty regime set out in section 3.1.5? Are there other models we should consider?

We do not have any comments on this question.

Question 25 - What are your views on appropriate testing arrangements for wind and solar CMUs, distribution connected CMUs, and co-located CMUs?

We do not have any comments on this question.

Question 26 - Which is your preferred option of those proposed in section 3.2.5 relating to the timing of the connection capacity test? Are there alternative approaches we could consider?

We do not have any comments on this question.

Question 27 - Would it be beneficial for us to enable a third party (such as the Delivery Body) to re-auction capacity obligations in respect of CMUs that have been terminated during the delivery year, or between a capacity auction and the start of the relevant delivery year? If so, what are your views on the principles for such an arrangement (set out in section 3.3.2), and do you have any commercial considerations and/or concerns about the use of a third-party facilitator?

We do not have any comments on this question.

Question 28 - In your view, do the current de-rating methodologies remain appropriate and reflect a CMU's risk of non-delivery? If not, what alternative methodology could be applied and why? Please submit any evidence in support of your view.

We agree that it will be important to apply de-rating factors to ensure they continue to reflect a CMU's expected contribution to security of supply. We agree that historic data may not be the most appropriate way of doing this as backward-looking data may not be the best predictor of the capability of assets as they approach the end of their useful life. We agree that a more accurate forecasting methodology should be used to prevent market distortions.

We anticipate that pumped storage hydro will be able to maintain a high contribution to security of supply without degradation for many decades and this capability should be recognised appropriately.

Question 29 - Do you have initial views based on your experience on the Capacity Market's performance since its implementation that we should consider?

While the capacity market has provided a valuable service since its introduction in maintaining security of supply, the design of the regime appears to have resulted in some unintended consequences. For example, these include low and uneconomic capacity clearing prices due to generators cross subsidising their bids across revenue stacks, and rapid growth in small scale gas peaking capacity able to respond quickly to market signals.

We suggest that the future design of the capacity market should learn lessons from this experience such that it targets the right types of capacity needed for the future electricity system as well as seeking the lowest price.

Question 30 - What are your initial views on the Capacity Market as a continuing mechanism to address system adequacy? Is there a need for continued market intervention by the government to address electricity security? And should the Capacity Market (or alternative electricity security mechanism) also address wider system services such as flexibility and stability?

We welcome the proposal to consider future capacity market design, recognising that the future net zero electricity system will have a high proportion of renewables and distributed energy resources.

As set out in our earlier responses, we consider it essential that the capacity market also considers how it incentivises the development of flexible low carbon generation. In this regard, pumped storage hydro (together with other LLES technologies) can make a major contribution to a net zero electricity system, both enabling the rapid growth in variable wind and solar and accelerating the displacement of fossil fuelled generation. It will enable the following benefits to be realised:

1. <u>Meeting variable system demand</u>: 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. <u>Maintaining system stability</u>: 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 services are currently mainly provided by fossil fuel generators, but they can be replaced by low carbon dispatchable resources such as LLES.
3. <u>Location to reduce system costs:</u> 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. <u>Reducing renewable electricity curtailment:</u> 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.

Question 31 - Are there alternatives to the Capacity Market that may meet our current or future electricity security needs better, that we should consider? Please provide evidence to support your views.

This review aims to assess the Capacity Market against the additional criterion of 'net zero compatibility', and whether it is equipped to deal with the challenges posed by a system that is heavily reliant on intermittent renewables whilst also being consistent with net zero.

In the future, we consider that electricity markets should also value flexibility resources and provide price signals to incentivise its provision both in the long and short-term. Currently, flexibility must be provided as a mandatory service by large generators. While it could be advantageous for the capacity market to provide a price signal for flexibility, if the value is not recognised consistently in other electricity markets, this could lead to further distortions in the pricing signals.

For the development of pumped storage hydro projects, we consider that the best market intervention to support the development of this asset type would be a cap and floor regime. We have provided details of our suggested approach in response to the LLES call for evidence.

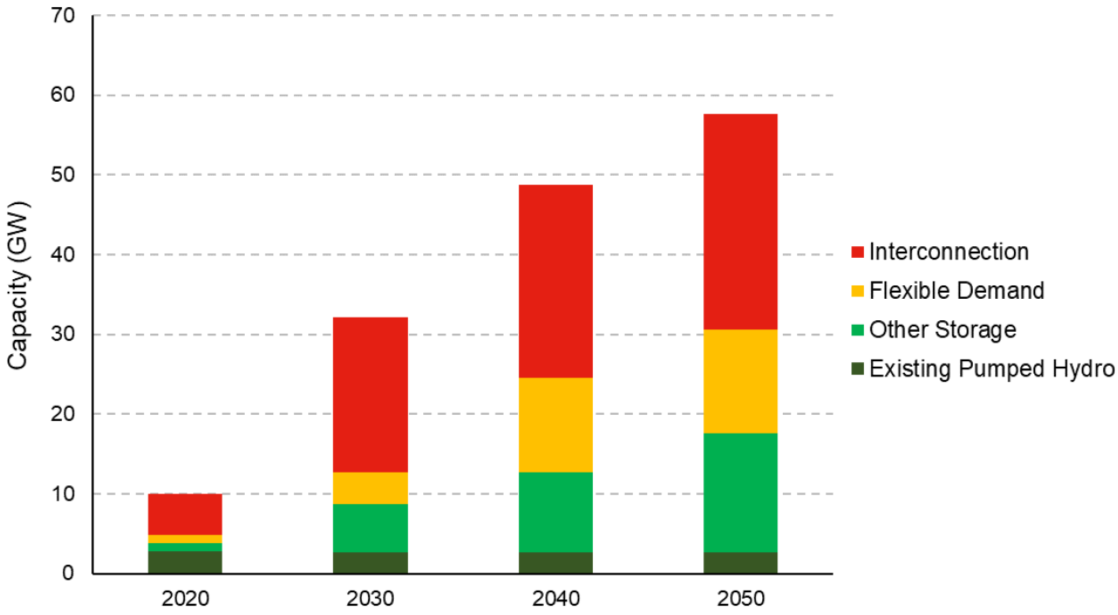
Question 32 - Should we continue to enable cross-border participation in the Capacity Market? If not, why not? In the absence of cross-border participation, how should target capacity calculations be altered to reflect the contribution of cross-border flows to security of supply?

In principle, we consider that there should be no restriction to cross-border participation in Capacity Markets. But the regime for this participation should ensure that cross-border resources compete on a level playing field with equivalent flexible, zero emission resources in the UK.

In a high renewable future, there will be a significant need for flexibility resources. 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[3]: Illustrative deployment of flexibility technologies (high flexibility, high demand scenario)

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



Regarding Interconnectors being used to provide flexibility and participating in the capacity market, we suggest the following factors should be considered:

- Interconnector 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.
- the real carbon content (not just certificate-based) of imported electricity must be reflected in its cost otherwise zero emission resources such as pumped storage hydro 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. Incentivising the development of LLES will allow value of low-cost renewable generation to be retained in GB and reduce higher cost import requirements.

Question 33 - If the CM continues to enable cross-border participation, what should be the preferred approach to cross-border flows – enabling direct participation of foreign generation, or continue with the existing indirect cross-border participation model (via interconnectors)? Please provide evidence to support your views.

We do not have any comments on this question.