

## The Future of local energy institutions and governance

Closing date: 10<sup>th</sup> May 2023

British Hydropower Association response

The British Hydropower Association (BHA) is the leading trade membership association solely representing the interests of the UK hydropower industry and its associated stakeholders in the wider community.

Our Mission is to drive growth in the sector by engaging, influencing and promoting Hydropower, Tidal Range and Pumped Storage Hydro, as firm, renewable power, providing critical infrastructure for achieving Net Zero and Energy Security.

*Table 1 – The BHA 'Asks' to Government*

	<b>Hydropower:</b>	<b>Pumped Storage Hydro:</b>	<b>Tidal Range:</b>
<b>Potential deployable capacity</b>	1GW	15GW`	13GW
<b>What is the BHA calling for?</b>	Move to 'Enhanced' Levelised Cost of Energy inc whole systems benefits. Replace 1 GW of coal with 1GW Hydropower. CfD tweak for AR6: <ul style="list-style-type: none"> <li>– Strike price £140/180MWh.</li> <li>– Reduce &gt;5MW to &gt;1MW.</li> <li>– Ring fence and aggregation potential for Capacity Market inclusion</li> </ul>	A cap and floor, to enable delivery of the <b>15GW</b> called for in this <a href="#">CCC report</a>	Regulated Asset Base, used for Nuclear, to enable delivery of <b>13GW</b>
<b>What are the main barriers to support?</b>	Hard to raise relevance (see as, too small, can't scale, too expensive)	Geographically constrained, market can deliver batteries	Too expensive (ie, Swansea Bay)

<b>Why are these technologies important?</b>	Resource adequacy, hydropower is cheaper than gas peakers (Reservoir hydro currently provides 900GWhs of storage and load follows)	Storage, reduced curtailment and balancing costs, grid stability/ flexibility (pumps and generates) currently 29GWhs, pipeline 135GWhs	Non-weather dependent, generation near increasing demand centres (circumvents transmission constraints), flood defence , socio economic value.
<b>The counter points:</b>	<p><b>Longevity:</b> All these technologies are intergenerational assets that will deliver well beyond 2050 – true energy security.</p> <p><b>Resource adequacy:</b> What's the answer to 3 week Low wind period in 2035?</p> <p><b>Energy sovereignty:</b> Gas interruption, interconnector failure, French nuclear fleet refurbishment.</p> <p><b>Reliability:</b> Hydro/ PSH/ TR are all proven, reliable, long lasting &amp; deliverable</p> <p><b>Cost:</b> LCOE: cheapest kWhs will not deliver a stable grid. Lowest cost is not always best value. We need to move to 'Enhanced' LCOE and account for Non price factors.</p> <p><b>Path to net zero:</b></p> <ul style="list-style-type: none"> <li>• Fraught with delivery risk and time slippage</li> <li>• To mitigate risk, we need diversity.</li> <li>• We need all technologies being progressed rather than a favoured few.</li> </ul> <p><b>Grid:</b> How can we deploy localised energy solutions that will not be hampered by Transmission constraints.</p>		

## Questions:

- Q1. Do you agree with our proposal to introduce Regional System Planners as described, who would be accountable for regional energy system planning activities? If not, why not?
- Q2. What are your views on the detailed design choice considerations described?
- Q3. Do you have views on the appropriate regional boundaries for the RSPs?
- Q4. Do you agree that the FSO has the characteristics to deliver the RSPs role? If not, what alternative entities would be suitable?
- Q5. Do you agree with our proposal for a single, neutral expert entity to take on a central market facilitation role? If not, why not?
- Q6. Do you agree with the allocation of roles and responsibilities set out in Table 2? If not, why not?
- Q7. Are there other activities that are not listed in Table 2 that should be allocated to the market facilitator or other actors?
- Q8. What are your views on our options for allocating the market facilitator role?
- Q9. Are there other options for allocating the market facilitator role you think we should consider? If so, what advantages do they offer relative the options presented?
- Q10. Do you agree that DNOs should retain responsibility for real time operations? If not, why not?

Q11. What is your view on our proposed approach to the undertaking of an impact assessment as outlined in Appendix 1?

Q12. What is your view on the most appropriate measure of benefits against the counterfactual?

Q13. How should we attribute these benefits between the governance changes in the proposed option, and other changes required to achieve the benefits? We particularly welcome analysis from bodies that have undertaken an assessment of benefits, specifically how those benefits might be attributed to different policy reforms that are required to achieve those benefits.

Q14. What additional costs might arise from our governance proposals? We welcome views both on the activities that may arise and cause additional costs to be incurred, as well as the best way to estimate the size of the costs associated with those activities.

Q15. What additional costs may arise from sharing functions with several interacting organisations? We welcome views on set up cost, lost synergies, and implementation barriers.

## Introduction

The grid poses the biggest challenge and threat to the transition to Net Zero. The situation we find ourselves in currently, has been in the making for a number of years and the inability to build ahead of need has been one of the biggest issues. Even when reinforcements are undertaken, the future need, is still not recognised. However, with the ASTI and HND, this is now changing.

The biggest challenge we now have, is how do we continue to build towards our NZ ambition without the Transmission constraints meaning that nothing can be connected at Transmission or distribution without significant curtailment.

The case study below is a good example of where the failures lie. This mostly lies in the lack of 'visibility' between the distribution and transmission networks which are separated in their operations and the inability to 'see' what is happening across Grid Supply points. This may well be circumvented with digitalisation and more active network management, but until delivery of technology is speeded up and deployed, we are left with a blanket approach that means transmission constraints will stop any deployment at distribution level.

## Case Study: Allt na Moine Hydro

### Summary

- Allt na Moine is a recently completed 2 Megawatt storage hydro scheme, located to the north of Applecross in Wester Ross.
- The final Feed in Tariff scheme to be completed, Allt na Moine has the capacity to generate more than 10,000,000 kilowatt hours of renewable electricity each year – equivalent to the annual consumption of more than 2,500 homes.
- The reservoir allows 150MWhs of storage, meaning the scheme can be responsive to the needs of the grid and local wind farms.
- Due to protracted delays in upgrading the Transmission network between Fort Augustus and Broadford, Allt na Moine is only permitted to export 50 kilowatts of electricity until such time as these works are completed. As things stand, this restriction will apply until the end of 2026 at least.
- The UK urgently needs to get additional renewable electricity on to the grid to address short-term energy security issues and to get back on track to achieve the declared ambition of Net Zero by 2035.

- Storage hydro represents the ideal technology to complement other renewables, most notably onshore and offshore wind.
- The opportunity exists for all parties to achieve a win by enabling Allt na Moine hydro to make use of the considerable 'dynamic headroom' that is understood to exist, but this will require a shift in approach from the rigid policies and procedures of the past to a much more flexible approach that utilises the latest grid management technology.

## Background

Allt na Moine is a 2 megawatt storage hydro scheme, 6 miles north of Applecross. The scheme completed construction in summer 2022 and has now been energised and G99 certified in conjunction with SSEN but is unable to export more than 50 kW due to a grid constraint that was originally due to be removed in 2021 but is now scheduled for late 2026....at the earliest.



*Figure 1 – Reservoir with 150MWhs storage*

Developments such as Allt na Moine have for many years been actively encouraged by UK and Scottish Governments in the critical drive to reduce carbon emissions. The introduction of Feed in Tariffs by the UK Government in 2010 was specifically intended to stimulate the construction and commissioning of renewable electricity generating schemes such as this. In order to qualify for Feed in Tariffs, applicants required to have full planning consent, a CAR licence from SEPA, and a grid connection offer from the relevant DNO. All three of these items placed demanding obligations on the developer, however in the case of the grid connection offer, the arrangement was very one-sided, with no obligation on the DNO or Transmission counterparts to adhere to quoted timescales or costs, as so clearly demonstrated in the case of Allt na Moine.

The table below details the extent to which the cost of connection and the projected connection dates have moved in the past 5 years. It should be noted that the costs shown in the table do not include any amounts for attributable transmission works (c. £265k) or wider cancellation charges.

*Table 2 – Grid connection cost escalation and time slippage*

<b>Offer date</b>	<b>Connection costs (Distribution) exc. VAT</b>	<b>Connection date (Distribution)</b>	<b>Connection date transmission</b>
April 2017	£829,806	31 August 2020	31 October 2022
September 2019	£1,455,685	31 December 2020	31 October 2024
March 2022	£2,155,187	15 December 2022	31 December 2025

September 2022 Additional substation costs of c. £336,000	£2,491,177		31 October 2026
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Since the original grid connection offer was made to Innogy (now RWE) in April 2017, the overall costs, excluding transmission related payments, have trebled from £830k to £2,491k. And there is no guarantee that the costs will not increase further.

At a time of national and international energy crisis, when plans are being made for power cuts and old coal plants are being readied for use, there has to be a way of bringing the full generating potential of this renewable generation asset on to the national grid. The situation during week commencing 12 December 2022 confirmed the preposterous situation facing Allt na Moine. A prolonged spell of very cold, still weather resulted in power shortages, as neither wind nor solar was able to deliver any meaningful volumes of electricity. During this period, Allt na Moine hydro could have been running at full capacity, taking advantage of the 150 MWh storage capability of the scheme. However, due to the Transmission constraint, lack of active network management or visibility of the scheme for the Transmission operator, Allt na Moine was still constrained to deliver a meagre 50kWs to the Grid.



*Figure 2 – intake to penstock from Reservoir*

At such times when other sources of renewable generation are subdued, there will be capacity available on the grid to accommodate not just Allt na Moine, but other generators waiting for the Broadford Transmission upgrade.

A Derogation has been in place, covering the Broadford GSP, since 2010. When it was introduced, it was a positive initiative that enabled the early access to the grid for many renewable generators who would otherwise have had to wait for upgrades to the Transmission network. But over time, the same Derogation has become an obstacle to new development. With this Derogation in place, there would appear to have been less onus on completion of the otherwise required upgrades to the Transmission network.

It is evident that the Derogation achieved its original aim of getting more renewable generation on to the grid, but for the reasons stated above it has failed to optimise utilisation of available grid capacity. Because of the related obligation to make constraint payments to generators in circumstances when combined output exceeded physical capacity, it was wholly understandable that the Derogation only allowed for a fixed % of 'overselling', but the circumstances in 2023 are quite different, therefore the challenge is to find a way of getting more generation on to the grid, 365 days of the year, without increasing the financial exposure to constraint payments.

The solution proposed is for future beneficiaries of the Derogation not to be eligible for constraint payments. They will be the first generators to be temporarily excluded from grid access and will



receive no compensation in return. For generators with storage assets, such as Allt na Moine Hydro, this will impact the timing of output, but with little or no impact on overall generation.

Each scheme that operates under the G99 regime can be directly managed from the SSEN Control Centre in Perth, as was demonstrated during the G99 witness testing at Allt na Moine on 17 January 2023.

### Obstacles to connection

The primary obstacle to Allt na Moine being fully connected to the grid before the Broadford Transmission upgrade works are completed is the Derogation covering the Broadford GSP has been applied by SSEN Transmission. This states that no new connections of more than 50 kW can be added until further Transmission upgrades are completed.

There are two connected schemes in the vicinity currently restricted to 50kW which contracted prior to Allt Na Moine. They will increase their export to 90kW and 100kW (+90kW total) respectively upon completion of the Transmission reinforcements. Allt Na Moine is next in queue followed by an already connected scheme restricted to 50KW who will increase to 100kW, and a contracted scheme of 137kW.

In summary, the total extent of 'the queue' is less than 2.5 MW.



*Figure 3 – Turbine and power house, a low visibility, low impact scheme that will generate for 100+ years (true energy security)*

### Conclusion

As can be seen from the case study, trying to connect schemes to the grid is an expensive and moving feat, with no guarantees, moving goal posts and no obligation from the Grid operator, to the developer, to deliver on time, with the specified capacity. This scheme has the very real threat of going bankrupt and due to very high business rates, the cheapest option would be to bulldoze the infrastructure, leaving the grid minus a 2MW, storage scheme with flexibility, storage, inertia for what should be 100+ years.

As stated above, much of the issue lies with the inability of the grid operator to build ahead of need, however, there is also an inability to be innovative and work with developers to explore all options, often due to resourcing and finding constraints.

This scheme can be turned on and off within the distribution control room at Perth, however, as this is manual and not automatic, there is a risk that if there is a fault, the person watching the scheme may not be able to turn it off in time, this could be resolved if the process was automated.

## Conclusion

This response sets out to show the grass roots issues there are with the delivery of the Net Zero grid. The future of local institutions and governance must be able to understand and enable resolution of these issues. If there is a national body leading this work, there is a real danger that the nuances of each regional constraint and solution may be lost. It will be key that there is an understanding of the granular detail of schemes like this and pathways forward to resolve and solve these issues, if we are to have the best value solutions to Net Zero.