Connections Reform Consultation

Closing date: 28th July 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

	Hydropower:	**Pumped Storage Hydro:**	**Tidal Range:**
Potential deployable capacity	1GW	15GW`	13GW
What is the BHA calling for?	Move to 'Enhanced' Levelised Cost of Energy inc whole systems benefits. Replace 1 GW of coal with 1GW Hydropower. CfD tweak for AR6: – Strike price £140/180MWh. – Reduce >5MW to >1MW. – Ring fence and aggregation potential for Capacity Market inclusion	A cap and floor, to enable delivery of the **15GW** called for in this CCC report	Regulated Asset Base, used for Nuclear, to enable delivery of **13GW**
What are the main barriers to support?	Hard to raise relevance (see as, too small, can't scale, too expensive)	Geographically constrained, market can deliver batteries	Too expensive (ie, Swansea Bay)

Why are these technologies important?	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.
The counter points:	**Longevity:** All these technologies are intergenerational assets that will deliver well beyond 2050 – true energy security. **Resource adequacy:** What's the answer to 3 week Low wind period in 2035? **Energy sovereignty:** Gas interruption, interconnector failure, French nuclear fleet refurbishment. **Reliability:** Hydro/ PSH/ TR are all proven, reliable, long lasting & deliverable **Cost:** 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. **Path to net zero:** • Fraught with delivery risk and time slippage • To mitigate risk, we need diversity. • We need all technologies being progressed rather than a favoured few. **Grid:** How can we deploy localised energy solutions that will not be hampered by Transmission constraints.		

1. Do you generally agree with our overall initial positions on each of the foundational design options and key variations? Are there any foundational design options or key variations that we should have also considered?

The complexity of a decarbonised grid needs a flexible approach that will be nuanced across different areas. The BHA agrees that fundamental changes must be made, and the approach taken will be useful, but an additional Foundational Design option could include the Regional System Planners who should have a deeper understanding of what is needed on the grid and where, for it to decarbonise and remain operatable, stable and secure.

A gated approach is useful, but this approach should have huge amounts of flexibility in it to allow the RSP to bring forward generation, demand or flexibility where it is needed and in sufficient amounts.

There needs to be an 'override' to allow technologies that will enable security, stability and operability to be prioritised within the queue.

2. Do you agree with our initial view that the current issues with the connections process could potentially be addressed on an enduring basis through other, less radical, and lower risk means than the introduction of capacity auctions?

Bringing forward more generation to compete on the grid is not the priority and therefore capacity auctions are unlikely to resolve the issue that we face, which is there is too much queued to get connected, and the queue is not being prioritised? The biggest priority is reinforcing and connecting the generation that is queued?

3. Do you agree with our initial view that the reformed connections process should facilitate and enable efficient connection under either a market-based (i.e. locational signals) or 'centralised' deployment approach (or an approach somewhere between the two), but not mandate which approach to follow?

Renewable energy needs to be deployed where there is the most resource creating the most efficient generation. Although this means a more heavily reinforced transmission and distribution system, the electrical grid and the generation plant is likely to be in place for the next 60 years, as repowering existing plant is still likely to take place where there are the most natural resources for renewable generation. Power transfers to centres of demand is always going to be a necessity for a grid based on renewable energy generation.

As with the answer to question 2, the Regional System Planner should be key to how, what and why generation needs to be added and prioritised for connection.

A closer overview of generation profiles must be utilised to allow better planning of what will be generating and when.

4. Do you agree with our initial recommendation that TMA A to TMA C should all be progressed, irrespective of the preferred TMO?.

Yes – there should be routes and processes to allow good communications between developers wanting to connect and the TO/ DNO and ESO. This will improve the rates of innovation as developers are more likely to try and be compatible with the needs of the grid.

5. Do you agree with our initial recommendation on the introduction of a nominal Pre-Application Stage fee, discounted from the application fee for customers which go on to submit an application within a reasonable time period?

Anything to improve the time resource invested in the above Q and A will be welcomed. The current system can be opaque and slow and does not precipitate innovation and adaptability that will be required if we are to have a flexible, decarbonised grid.

6. Do you agree with the importance of the TMA A 'Key Data'? Please provide suggestions for any other key data that you suggest we consider publishing at Pre-Application Stage.

As stated in the answer to Q3, generation profiles will be key as we look at intermittent generation meeting flexible demand. An understanding of how this will be configured within a future grid should be part of this 'Key Data'. For example, the case study in appendix A highlights that even when there is no wind and therefore, there will be available head room on the grid, the Alt Ne Moine scheme is still not allowed to generate as it is inflexibly curtailed at 50kW. This is not only a problem of 'visibility' and lack of active network management, but also a lack of planning utilising generation profiles and meteorological data.

As we are working towards a Smart grid, the availability of future datasets should be highlighted alongside an estimation of when that data will be available and where. Different areas of grid will have this data at different times, but as soon as it is available, this will be useful for developers looking to be agile and work within the constraints or availability of head room available.

Appendix A highlights that the grid is still hugely under utilised and the overall asset is not being 'sweated' to reach its full potential. Digitalisation will be key as we increasingly need the ability to have flexible generation and demand. As this comes on line, this data must be made available.

7. Do you agree with our initial recommendation with regard to TMA D (requirements to apply)?

Yes. For an abstraction licence to be submitted to the Environment Agency for a Hydropower project, there must be a letter of consent from the landowner, alongside environmental studies and a design of the scheme. This ensures that the developer is within their rights and has already committed resource to the project for it to be considered.

8. Do you agree with our initial recommendation with regard to TMA E (determination of enabling works), including that it is right to wait until the impact of the 5-Point Plan is known before forming a view on whether further changes to TMA E are required?

No. There is too much urgency to wait for the impact of the 5 point plan to be known before looking at whether further changes to the TMA E are required.

There is not enough of a dynamic, innovative and/or a flexible approach across the TOs and DNOs to ensure that this process is speeded up. Currently there are huge delays in information flows between the TOs/DNOs and the developers, this must be addressed and resolved if there is to be a speeding up of connection processes. Much of the delay is around uncertainty as to what enabling works will be needed and the inability to build ahead of need. Better planning around Local energy area plans looking at what total decarbonised energy demand will be needed could help resolve some of this uncertainty.

There is a reticence from the TOs/DNOs to make decisions on a timescale that can assist developers, or decarbonise the grid at speed as this is not their mandate, protection of the grid and assets is their mandate and adding distributed generation is complex and is still seen as damaging to the overall resilience of a historically centralised grid. Each decision made by the TO and DNO is seen as a risky decision and people do not like to take risky decisions, they are easier left to someone else. This leads to prevarication, uncertainty for developers and long wait times.

9. Do you agree with our initial recommendation with regard to TMA F (criteria for accelerating 'priority' projects)?

Yes, the BHA agree that there should be the ability to bring forward 'priority' projects. This should not be done through an ability to pay more, but should be done according to the benefits of decarbonising the grid and enabling stability and operability. This should be done on a technology and locational basis. Ie, a hydro storage project with active network management that can be brought on when the wind isn't blowing, or co-located solar next to wind that will complement the overall generation profile. These projects should be considered on a case by case basis and a Regional Systems Planner could be useful to enabling this decarbonised grid priority process.

10. Do you agree with our initial recommendation with regard to TMA G (queue management)?

The word 'capacity' needs to be reviewed. Capacity brought forward by different technologies must start to be considered differently rather than homogenously. The capacity of an offshore wind, hydro (with storage) and solar are very different and have very different generation profiles. Lumping everything together as 'capacity' misses the nuances required for a decarbonised grid.

Queues must be reviewed with the mindset of what each project 'capacity' will bring to the grid in terms of generation profile matching a future decarbonised demand profile, whether there is storage co-located or how flexible the generation can be (or how costly to curtail?)

A much more flexible approach is needed with a view to what each project will bring over the next 20 or 30 years to the grid. Curtailment of wind is a massive and costly issue and one that was entirely predictable. We have weather data and we can predict what generation will look like into the future, better forecasting of what the impact of projects will be on the grid over the long term must be taken into account when looking at project queues.

A **matrix of benefits** for the grid and for consumer costs should be applied to project queues, this could include deliverability of a project, but also criteria that look at the benefits it will bring to operability and stability for a long term decarbonised grid.

11. Do you agree these four TMOs present a reasonable range of options to consider for a reformed connections process?

12. Do you think any of the four TMOs could be materially improved e.g. by adding, removing or changing a specific aspect of the TMO? If so, what and why?

13. Are there any important TMOs we have missed?

A **matrix of benefits** would be a useful addition that highlights what projects need to be prioritised and be brought forward to archive a decarbonised, operable and stable grid.

Projects are currently market led (ie brought forward due to perceived commercial gain due to the incentive mechanisms available) Therefore competition for connections has been driven by a market led (skewed by incentive mechanisms) process, not a utility led process.

The ESO has the ability to add in utility based priorities that will enable the objective of a decarbonised, stable and operable grid. A transparent matrix that will enable priority projects to move up a queue would not distort this market, but would reduce the overall cost that consumers face for congestion, curtailment and reinforcing the grid that is the consequence of the market distortion currently in place from FITs and CfD incentive mechanisms. This would not be a 'locational price signal' but would encourage developers to look more closely at what is queued and what is likely needed on the grid at particular points and therefore more likely to leapfrog their own projects. Projects that co-locate storage would be given higher points in a matrix and therefore look to move up a queue – this would encourage developers to look at how they could gain additional points in the matrices by adding features that will be beneficial to creating a decarbonised, stable and operable grid. This would encourage developer led innovation, something that at present doesn't happen as there is no perceived need by the developer to do so.

14. Do you think 'Submit Consent' is too early for Gate 2 in TMO2 to TMO4? If so, what milestone should be used instead and why?

15. Do you agree that TMO4 should be the preferred TMO?

16. Do you agree with our design criteria assessment of the four TMOs? If not, what would you change any why?

As stated above, a matrix scoring system to prioritise projects should be brought forward.

With the large queues for grid connection, ESO has a huge opportunity to use the queue as a way to develop and design a decarbonised grid that will be stable and operable.

Projects are put forward that are designed to maximise generation and therefore profit. Developers could be encouraged to design their project to become more 'grid friendly' and therefore cost the consumer less downstream in terms of curtailment/ congestion/ reinforcements. Co-location of storage, active network management, consideration of Smart grid measures and even smart local energy systems could all be additional 'add-ons' that the developer could think through to ensure their project met higher criteria in the grid queue prioritisation.

This would push developers into becoming a bigger part of the grid solution rather than a more passive connection that is not being innovative or enabling the future smart grid.

The current 'passive' queue system is not leveraging the finance/ innovation or motivation of developers to be part of the solution. ESO should work harder and better with these developers to bring forward solutions that many developers will be keen to adopt, if they know it will get their project higher up the queue.

There are a lot of projects queued, but not enough for a small team to have all the details at their finger tips. A small team should be in constant dialogue with developers creating an active and co-creative solution environment.

An element of competition already exists within the queue, but it has been the competition of first come first served. This needs to be reconsidered and competition should be brought into the queue, but the competition should be which project will **'best serve'** the overall ambition of a decarbonised, stable and operable grid.

First ready, first served is compounding the issues that are already there. A hydro project will take longer than a solar project but will offer a very different generation profile and will also be there for 80 years. First ready approach fails to look at the next 20 years and what will be most useful on the grid? A 'best serve' approach should be replace 'first ready'.

17. What are your views on the stated benefits and key challenges in relation to TMO4?

See above

18. Do you think that there is a better TMO than TMO4? Whether that be TMO1 to TMO3, as presented, a materially different option, or a refined version of one of the four TMOs we have presented?

See above

19. Do you agree with our views on DNO Demand in respect of the TMOs?

20. Do you have any views on the appropriate mechanism to incentivise accurate forecasting of requirements and avoid more RDC than is necessary being requested by DNOs?

21. Do you agree with our views on the process under which DNOs apply to the ESO on behalf of relevant small and medium EG which impacts on or uses the transmission system, including that(underTMO4):

i.DNOs should be able to request RDC via application windows to allow them to continue to make offers to EG inter-window; and
ii.resulting offers should be for firm access until relevant EG has reached Gate2 (at which point they can request advancement and an earlier non-firm connection date)?

19,20 & 21

The current issue with visibility across the TO/DNO and Grid supply points is a huge problem for connections for embedded generation. So much focus is on Transmission, however, electrification of heat, transport and industry and the new demand that will create is all at Distribution, including the weak rural grid. Currently the constraints at Transmission are leading to many delays for connections at distribution where much of the work needs to happen to decarbonise communities. This is causing huge delays for Net Zero ambitions.

Regional System Planners could become key in resolving these issues, however, this needs to happen much faster than it currently is.

Solutions that are Smart, local and flexible that will allow balancing at Distribution are not 'seen' at transmission must be brought forward, but so often, this is not trusted by TO as it is not 'visible' across the GSP. Appendix A case study highlights this issue. Active Network Management could be engaged in this instance but this needs to have sign off at Distribution and Transmission, and there is perceived 'risk' that people are not willing to take.

Priority will be protection of assets in the here and now, rather than moving to a decarbonised grid which is inherently got more risk as it's no longer a centralised systems and will be more dependent on smart technologies.

22. Do you agree that directly connected demand should be included within TMO4 and that the benefits and challenges are broadly similar as for directly connected generation?

23. Do you agree that TMO1 to TMO3 would require a separate offshore process, and that this would result in material disbenefits?

24. Do you agree that TMO4 is the most aligned to the direction of travel for offshore projects? If not, why?

25. Other than the Letter of Authority differences are there any other TMAs which have specific offshore considerations?

26. Do you agree with our views on network competition in the context of connections reform, including that TMO4 is the option which is most aligned with network competition as it includes the most design time at an early stage in the end-to-end process? .

27. Do you agree with our initial recommendation related to each of the TMAs within this chapter? If so, why? If not, what would you change and why?

28. Do you agree with our current views in respect of the implementation period?

Speed is key. The grid is the biggest barrier to Net Zero and as we slow down, investment will head to areas with more opportunity, ie USA with the Inflation Reduction Act.

The solutions don't have to be perfect, it's the direction of travel that's important. The solutions can be tweaked to ensure they are getting the right outcomes.

29. Do you agree with our current views in respect of transitional arrangements? What are your views on how and when we should transition to TMO4?

Moving away from the current system is key. A transparent system where developers can access well qualified advisors is key, this needs to happen quickly.

30. What further action could Government and/or Ofgem take to support connections reform and reduce connection timescales, including in areas outside of connections process reform?

Regional System Planners need to be brought in to help enable the issues across the T/D GSPs. There is not enough resource (time and money) going into innovation and Smart systems utilisation. DNOs must be given more resource and developers better access to routes forward for innovations. The Case study highlights this point. Large institutions like the DNOs are less well equipped to be innovative, however, developers are. They are not being encouraged to be innovative and ESO needs to help enable this innovation to come forward through better grid queue competition.

1. 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 requires 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

Offer date	Connection costs (Distribution) exc. VAT	Connection date (Distribution)	Connection date transmission
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

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 bulldozer the infrastructure, leaving the gird 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.