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Low Carbon Hydrogen Business Model: Consultation Response

Scottish Renewables is the voice of Scotland's renewable energy industry, working to grow the sector and sustain its position at the forefront of the global clean energy transition. We represent around 260 organisations across the full range of renewable energy technologies in Scotland and around the world, ranging from energy suppliers, operators and manufacturers to small developers, installers, and community groups, as well as companies throughout the supply chain.

Scottish Renewables welcomes the opportunity to provide our view on the proposals outlined in this consultation.

In summary, we would like to highlight the following points:

- We are concerned that having one model that covers both blue CCUS-enabled hydrogen and green electrolytic renewable hydrogen may not provide the specific support that electrolytic hydrogen needs, especially the smaller-scale, 'stepping-stone' projects that are needed to grow the supply chain.
- We consider it extremely important to have a different "pot" for electrolytic hydrogen, so electrolytic projects are not directly competing against Carbon Capture Utilisation and Storage (CCUS) enabled projects.
- There needs to be clarity around whether the RTFO will be available for those in receipt of the business model.
- Linking the reference price to the gas price creates an investment risk for electrolytic hydrogen production because it exposes the producer to volatility.

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

Yours sincerely,

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1. Do you agree with our overall approach to introduce a contractual, producer-focused business model covering the proposed scope?

The Government's minded-to position of providing revenue support through a producer-led incentive model which can work across a range of different production technologies and end use sectors is a very ambitious proposal. We are concerned that having one model that covers both blue CCUS-enabled hydrogen and green electrolytic renewable hydrogen may not provide the specific support that electrolytic hydrogen needs, especially the smaller-scale, 'stepping-stone' projects that are needed to grow the supply chain. We are concerned at the 'one size fits all' approach the Government is employing. Both electrolytic and CCUS hydrogen are different journeys and will require different approaches, separate allocation processes, separate quality standards. We have concerns that CCUS hydrogen will crowd out electrolytic hydrogen – therefore, industry feels an electrolytic hydrogen target is essential.

However, despite this, we agree broadly with the overall approach. One concern is the issue of demand application, that whatever producer subsidy is agreed as a result of this consultation, will go hand-in-hand with other obligations, for example, the Renewable Transport Fuel Obligation (RTFO). There needs to be clarity around whether the RTFO will be available for those in receipt of the business model.

We agree that this should be a contractual approach. The consultation document states that early stage will be a bilateral agreement progressing to an eventual aim of an auction, however a great deal of work is needed to get to this stage.

Contracts for Difference (CfD) worked very well for power, however applying a similar mechanism to an emerging market is a different issue. The idea of picking and choosing an offtaker will not work in the early days of the hydrogen economy.

We do think that eventually electrolytic hydrogen should be subsidised under the business model, but, as said above, this needs a lot of work to get to that point.

The consultation does correctly raise the "chicken and egg" challenge of supply and demand, but it is not clear to industry that this is being resolved yet. More is needed to demonstrate how BEIS expects to support demand-side. For example, how will BEIS ensure low carbon hydrogen is cost competitive in steel manufacturing and how will it ensure infrastructure is where it is needed to support demand.

It is important to ensure that business model applications and Net Zero Hydrogen Fund (NZHF) applications can be made in parallel and determined together, as outcomes are interdependent, and it is also important to avoid a cliff edge when subsidies are stopped.

2. Do you agree with our approach to business model design?

No, we do not agree with the set out approach to business model design. Different market mechanisms will be needed at different points in the development of hydrogen. Project developers will need to choose between two mechanisms: Power Purchase Agreements (PPA) or trading with Contracts for Difference (CfD) and hoping they do not overlap.

There is concern about the subsidy reducing over time, as this could impact the commercial viability of latter stages of the project lifetime and so would require careful design. For example, it may be that for a particular project, hydrogen production costs remain fairly constant while market prices drop, in which case the gap to be met by subsidy could widen rather than narrow over time.

We do agree that price risk and volume risk are two of the critical elements that need to be addressed for low carbon hydrogen projects.

3. Do you agree with our minded to position for a variable premium for price support? Please provide arguments to support your view.

We partly agree with the minded to position, if we find a good reference price and a fixed premium, similar to the RTFO. However, a variable premium has historically worked very well with the CfD.

Some members feel that the key issue is in the setting of the strike price and suggested that this is agreed privately between industry and Government and not via an auction, so as not to discriminate against first of a kind (FOAK) demonstration projects who may not be able to compete under auction conditions alongside larger scale facilities.

4. Do you agree with our minded to position for setting the reference price? Please provide arguments to support your view.

<u>Natural Gas Price</u>

It is important to recognise that there are several issues associated with using the natural gas price with the reference price.

The minded-to position for setting the reference price is overly complex. Some members have strong reservations regarding the inclusion of a floor structure linked to the gas price.

Gas price volatility is problematic under the proposed reference price. If gas prices spike above the fixed offtake price for hydrogen, the top-up received under the model would not be enough for the producer to recuperate all its costs. For example, assume an electrolytic hydrogen producer needs a revenue of £175MWh. While gas prices are stable, the same producer agrees to a long-term offtake contract priced at £50MWh. This producer would need a subsidy of £125MWh to make the project financially viable. If, however, gas prices were to spike to £75MWh (as they did in October 2021) then the producer would only receive a subsidy of £100MWh - creating a revenue shortfall of £25MWh.

Linking the reference price to the gas price therefore creates an investment risk for electrolytic hydrogen production because it exposes the producer to volatility. As well as this, users will be less incentivised to switch to electrolytic hydrogen because the benefit of not being exposed to gas price volatility is lost. This would imply the model is naturally geared towards helping CCUS hydrogen projects (which have an input of natural gas) remain competitive against electrolytic hydrogen projects.

Using natural gas as the reference price also implies that the scheme is prioritising (CCUS) hydrogen that will be located near and injected into the existing gas system as a blend. Most electrolytic producers, however, are located close to demand centres and will not use this infrastructure as it could contaminate the final product. Again, the implication here is that the model has been designed for CCUS hydrogen production first and electrolytic hydrogen second which is inconsistent with the government's twin track approach.

It is worth noting that with gas price as the reference price this only encourages switching where off-takers are exposed to the UK ETS so the UK-ETS needs to be broadened in scope to ensure switching in all sectors.

Achieved Sales Price

There are a few issues with an 'achieved sales price' mechanism as a reference price, some members state that it is not necessary if there is a competitive subsidy allocation process driving producers to increase prices. In addition, there is no motivation for the offtaker to pay or for the producer to fix the price. Some members feel there is merit to the inclusion of a gainshare mechanism being used in the structure and we think that it could provide the right incentives for producers to secure the highest price for the hydrogen being sold, however more clarity is needed on this mechanism.

The achieved sales price may be commercially sensitive so will need to be appropriately handled. It will also be administratively burdensome for projects and will incur additional costs.

We recommend that the market benchmark price is set by electrolytic hydrogen but need clarity on how this would work in practice. Some members also strongly agree with BEIS' approach not to use market benchmarks for initial projects.

We suggest that BEIS engage further with industry on this aspect of the consultation given that it is so fundamental to the mechanism and therefore to the success in driving electrolytic hydrogen deployment.

5. Does our minded to position create any other specific risks, incentives or disincentives which we have not already stated above? If so, what are they and how could the related risks be addressed – either within the model or outside of the model?

There are risks associated with the associated sales price, for example, project development risk, with a lack of certainty of support. There is a risk to the development of the supply chain; in fact, could end up pushing applications that do not help build indigenous supply chain and affect the potential economic gains. There needs to be a smooth transition. A risk is that sensitivity to fine, raw materials could create pressures on the supply chain. In addition, there is a lack of detail on the gainsharing mechanism option. Some members do not feel that £/MWh or £/tCO2 (mentioned in this section of the consultation document) are appropriate measures for cost of hydrogen production. Members would prefer £/kg of hydrogen produced.

There is a risk that larger CCUS hydrogen projects will outbid smaller electrolytic projects that may not have the resources or experience to competitively bid in auctions. We consider it extremely important to have a different "pot" for electrolytic hydrogen, so electrolytic projects are not directly competing against Carbon Capture Utilisation and Storage (CCUS) enabled projects. A separate pot should be backed with a GW deployment target for electrolytic production, as said above, as it would provide a clear trajectory for the technology and boost investor confidence.

There are also uncertainties around the prices used in the business model and so it may be appropriate to include a price review option that can be activated if these prices prove to be outdated.

6. What do you think is the most appropriate option (or options) for indexation of the strike price? Please explain your rationale.

The most appropriate option for indexation of the strike price is that it should be linked to the electricity price over the year as this is the actual input energy cost for electrolytic hydrogen projects. It should also be linked to inflation to cover other variable elements of producers' operating expenditure.

Indexation through the Consumer Price Index is most appropriate. This has been proven to effectively incentivise investment in renewable energy while at the same time driving down strike prices over successive subsidy periods.

However, BEIS should avoid being too prescriptive with the index design because different projects will have different characteristics, particularly between electrolytic and CCUS technologies. Along with Renewable UK, we recommend an “over the counter” model which offers separate indexation routes based on a project’s main operating costs.

There are many ways to produce hydrogen with different energy inputs. For CCUS hydrogen this is natural gas, and for electrolytic hydrogen it is electricity. In most cases these input costs will make up a significant portion of the overall levelised cost of hydrogen; this should be reflected in the model.

The offtake agreement is also important. Inflation-based indexing could be used for projects that have fixed Power Purchase Agreements (PPA), while the actual energy input-indexed approach could be used for projects that purchase power on a merchant basis. Using the CPI is beneficial because it is well understood and can be easily modelled by investors.

That said, BEIS should be clear as to what extent it wants the indexation to support cost recovery and the level of subsidy they are planning for CCUS and electrolytic hydrogen. Does the index, for example, represent 100% of price movements or a lower amount? Also, the consultation is unclear over the costs associated with waste disposal for CCUS-enabled production, which of course is not a cost for electrolytic production.

7. What are your views on whether price support for low carbon hydrogen should be constrained for applications using hydrogen as a feedstock to mitigate potential risks of market distortions? Please explain your rationale, including any suggestions both within and outside the business model to mitigate these risks.

The main hydrogen currently in play is grey hydrogen so replacing its use wherever it is, would be very useful, including in feedstock. This would support the decarbonisation of other industries such as agriculture, that use products derived from hydrogen as a feedstock, and thus help the UK (and other markets) achieve their climate targets. Any risk of market distortions could be addressed through a price review process (see Q5).

Users of hydrogen as a feedstock represent a significant share of the current market for hydrogen and present some of the best opportunities for early roll-out of low carbon hydrogen production. The conversion of these users to low carbon hydrogen will be crucial in achieving the interim target of 1GW of low carbon electrolysers by 2025 and the 2030 target of 5GW. They should be encouraged as much as possible rather than discouraged through the proposed constraint.

8. Do you agree with our overall minded to position for price support? Please provide arguments to support your view.

Subject to points raised in our answers to questions 6 and 7, we agree with the overall minded-to position for price support. We would question BEIS' assumption that the market price for hydrogen will increase over time (see Ref price in graph in P48). Based on discussions with offtakers, this is not a widely held view within the market, where supply is expected to increase and costs reduce, which will lead to downwards pressure on prices.

BEIS is not clear about what the pathway for green hydrogen projects will be.

The policy framework for a pipeline of CCUS hydrogen projects seems far more developed and robust than it does for electrolytic hydrogen production. BEIS has set out cluster sequencing for CCUS deployment; Carbon Capture and Storage (CCS) Infrastructure Fund; Transport & Storage (T&S) Business Models; and Industrial; Power CCUS Business Models; and a roadmap for CCUS supply chains. £171mn was awarded under the Industrial Strategy Challenge Fund to nine CCS and CCUS hydrogen projects. Against this backdrop, specific funding for electrolytic hydrogen production is largely absent. Nonetheless, we fully support the recent ring-fencing of funding for electrolytic production under the Industrial Decarbonisation and Hydrogen Revenue Support (IDHRS) scheme, set out in the Net Zero Strategy, and we would like to see more of this.

We recommend that BEIS sets out a clear roadmap for electrolytic production with particular emphasis on setting a target for its deployment. Failing to do this is a missed opportunity because the UK has an abundance of renewable energy and electrolysis can enhance our grid and further our net zero ambitions.

9. Do you agree with our minded to position of sliding scale for volume support? Please explain your rationale.

This is difficult to answer at this point as much more detail is needed in the proposals. Industry would want to see early payback of CAPEX. Some members suggest the sliding scale should apply over the life of the project, that curves will be different for different technologies, that curves should be known before applications are made, that the payback point for electrolytic hydrogen should be low reflecting the intermittent nature of the power source and that early payback of CAPEX is desirable.

The sliding scale methodology does not provide protection to small, FOAK producers in the event that volumes fall to zero, for example, if there was a major wind turbine, electrolyser, or hydrogen export infrastructure failure, which could not be fully recouped through the warranty or O&M contract. For FOAK projects this could be a significant risk for investors. A backstop where the project receives enough revenue to pay for OPEX whilst the fault is being rectified would be preferred to largely eliminate this risk.

Furthermore, the consultation document implies that the volume support provided early on would not be sufficient to meet investor return requirements, only to cover costs, which introduces investor risk.

Additionally, in a similar way to the discussion of Strike Price above, the proposed approach would disadvantage integrated electricity to hydrogen production projects. These projects add to the overall renewable network capacity (gas or electric) and so should not be put at a disadvantage.

10. Do hydrogen plants need any further volume support in addition to the sliding scale? Please explain your response, including what kind of additional volume support and under what circumstances it would be needed.

There is an element of risk here, this is a very different market from the electricity market. Hydrogen producers need to be able to look at the entire system and see where they will make a profit – therefore far more clarity is urgently needed. For example, how much of their volume becomes a bilateral agreement for those early projects. If it is too risky, companies are less inclined to look at the UK to invest.

It is difficult to give a full response due to the lack of detail on how the mechanism will operate and interact with the premium.

We agree that the model will help projects sell hydrogen at a price that is attractive to demand which should encourage uptake. But the pace and extent of hydrogen offtake will depend on policy intervention outside the scope of this consultation which is designed to stimulate initial demand. This demand-side policy must be coordinated alongside supply-side policy so that consumers can afford to switch and make the necessary equipment changes

11. Do you consider our preferred options on price and volume support outlined in sections 4 and 5 can work across different production technologies and operating patterns? If not, what difference in payment mechanisms might be required between different technologies and how should any downsides associated with that be managed?

No, see points above on indexing the strike price for CCUS and electrolytic hydrogen production. A variation in the indexation of the strike price is necessary to ensure the model is fit for purpose for multiple technologies.

We would like to reemphasise our point about having separate allocation pots for CCUS and electrolytic hydrogen and the need to have commitments around volumes and frequency of rounds. Some members suggest separate pots within the electrolytic pot for self-powered electrolysis by incumbent (such as fixed offshore wind and solar PV) and emerging renewables (floating offshore wind). Emerging technologies – specifically FLOW – are necessary if targets are to be achieved. Existing renewable sites are saturated and insufficient alone.

If operating intermittently, this uses less power than operating continuously. There are issues around downstream applications in terms of capital expenditure and the size of the electrolyser. All these are interlinked so needs to be as flexible as possible so that anything can be considered.

12. Do you agree with our proposal not to introduce a separate revenue support scheme for projects of a smaller scale? Please give arguments to support your response.

No, the consultation implies a one size fits all solution for all hydrogen production and ignores the disproportionate challenges faced by "smaller" electrolytic hydrogen projects. There needs to be a route to market for those smaller-scale, more demonstration-like projects. Smaller scale projects could benefit from a simple revenue support scheme. There is a need here to contract with an offtaker and think about what happens to the hydrogen produced.

The scheme proposed will be legally complex, with contracts running to many hundreds of pages, as well as the bilateral negotiations that may take place. It is difficult to envisage how smaller projects will navigate this process and complexity (e.g., through legal costs as DEVEX) versus large hydrogen production plants that have more resources at their disposal.

First-of-a-Kind (FOAK) electrolytic hydrogen projects are not yet at a stage where they can enter these lengthy negotiations but are in a process of upscaling to ensure electrolysis can be deployed at large-scale by the end of the decade. Taking a technologically neutral stance ignores these crucial distinctions and automatically puts electrolytic hydrogen production at a disadvantage.

In the early stages, smaller-scale producers should be able to establish a strike price via bilateral negotiations with reduced administrative burdens. There also needs to be stronger alignment between the NZHF and the business models because smaller projects will need the revenue certainty provided by both these schemes.

13. What do you think is an appropriate length of contract? Please explain your rationale.

The length of contract should be 20 years; having this for hydrogen would align it with other renewables projects such as the Renewables Obligation scheme. A 15-year contract may not be long enough to support the second stack replacement of electrolytic projects and so the cost of the scheme will have to increase.

14. Should the length of contract vary for different technologies? Please explain your rationale.

The length of the contract should be the same. Pragmatically, if the Government carries out large-scale deployment of CCUS hydrogen to get to electrolytic hydrogen, it makes sense that the process of support should cover both.

15. What are your views on the most appropriate option for scaling up volumes?

None of the options are appropriate for scaling up volumes. Failing a new approach, the accordion option would suffice up to a point, but for projects that wish to scale up further, they should be able to enter new CfD auctions with less of an administrative burden.

16. Do you agree with our minded to allocation of the risks presented? Please explain your arguments, including if any other key risks have not been identified and how they should be allocated.

We agree with the allocation of the risks identified in *Table 4: Risks relating to hydrogen production projects,* however, would suggest that construction risk can happen due to national issues such as the coronavirus pandemic, so measures to alleviate this should not just be on the hydrogen production plant developer.

We also want to reiterate the risks that some members see relating to the gas price floor and further suggest that this needs further development with industry before a decision is made.

The risk for not producing qualifying hydrogen should be elaborated. Support for CCUS projects that are relying on complex T&S scenarios to dispose CO2 or those that are relying on networks to be built on time for when they start production should be carefully considered.

There is a public perception risk that may impact the future success of building a market for hydrogen in the UK. The public perception can be influenced by several factors (i.e., safety considerations, the chosen funding scheme, scrutiny from media, environmental impact etc.). Communication from government and producers to potential off-takers and end users will be important to mitigate negative perception in the society, by raising knowledge and awareness. Collaborative efforts and public support will be key to reach the UK government's overall climate ambitions as well as building a market for hydrogen. The business model should keep this in mind to ensure that support enables producers to comply with standards given and contribute to a positive public perception.

Another risk is ensuring safety in design and operation within the low carbon hydrogen value chain. Any incidents, big or small, will impact the credibility of in the industry. We see a risk that players of different sizes and experience may have different approaches to safety.

Hence, there is a need for establishing appropriate standards for designing systems with appropriate engineering controls and guidelines to ensure the safe handling and use of hydrogen

17. Do you agree with our approach to seek to accommodate different sources of support? Please explain your arguments, including any considerations of unintended consequences linked to revenue stacking, and how might they be mitigated.

We agree with BEIS's approach to accommodate existing support policies across the hydrogen value chain, but more clarity is needed on how the scheme will interact with other schemes such as the Renewable Transport Fuel Obligation. BEIS should ensure this scheme does not encourage or discourage the use of hydrogen in transport compared to other potential uses due to its design. Revenue stacking could lead to unintended consequences such as not receiving the RTFO, so there needs to be a way for these to work together.

As mentioned, other subsidy mechanisms in the value chain are needed and should be developed alongside each other. Some members believe BEIS has been focusing too much on production-side and, consequently, has ignored demand.

Hydrogen producers do not want to lose options for the offtake of the sale of their hydrogen. How can this be made to work in this circumstance? Business models are supportive for CCUS hydrogen in transport but is that then directly competing with the RTFO? CCUS hydrogen would then be powering transport with different carbon intensities – is that over and above the obligation to provide a certain amount of renewable fuels certificates for that?

It is not clear how this would work for electrolytic hydrogen and what happens when the hydrogen economy mixes CCUS and electrolytic hydrogen. An RTFO for electrolytic hydrogen may be 8 – 10 years away.

18. What are your views on the most appropriate allocation mechanism for the hydrogen business model contract, both near term (for projects outside the CCUS cluster sequencing process) and longer term (for all technologies/projects)?

We support the idea of bilateral negotiations for the near term. Longer term, we support an auctions process.

19. What are your views on the possible approaches to funding the proposed hydrogen business model?

This is a difficult question to answer at the moment in terms of rising gas prices and householders facing potential gas levies on their energy bills. Any additional indirect costs being passed onto consumers through household bills would be deeply unpopular.

Funding should not come from consumers' bills but from general taxation. Using levies to fund the CfD scheme in the power sector makes sense because the demand users are consumers. However, demand for hydrogen will be industrial and transport sectors in the short-term (subject to a UK Government decision on heat in 2026). We do not think it appropriate that domestic consumers subsidise these sectors directly.

Funding via the wholesale gas price may be the chosen option to kick-start the hydrogen economy and encourage switching but is not sustainable in the longer term, nor is it relevant to electrolytic hydrogen production.

There are also risks bearing in mind small demonstrator producers, who may not be equipped to find offtakers at the market rate, associated with this approach.

Additionally, if relatively low cost CCUS hydrogen floods the market, bringing down the average market price of hydrogen, then electrolytic will be disadvantaged
and the development of electrolytic hydrogen will be curtailed before it is allowed to mature.

20. Do you agree with our proposal to allow projects to factor in small-scale hydrogen distribution and storage costs as part of projects' overall costs of production when bidding for business model support? Please explain your arguments, including any considerations relating to avoiding market distortions and facilitating future expansion of the hydrogen economy.

We believe storage and transport should be included where it is on the same parcel of land and/or adjoining land under the control of the hydrogen offtaker. The amount of storage required will depend on the operating regime which will in turn depend on the approach to additionality and temporal reconciliation set out in the Low Carbon Hydrogen Quality Standards. A more flexible approach to these reduces the relative need for smaller scale storage therefore reducing the cost of support in many cases.

21. Do you consider that bespoke funding model(s) might be needed to enable investments in larger-scale, shared hydrogen networks and storage? If so, which model(s) might be best suited to bring forward projects? Evidence provided under this question will be used to inform our forthcoming reviews.

Yes, we believe bespoke funding will be required. We suggest there is separate support for transmission and for storage. There are social benefits to all producers, off-takers and end-users as the hydrogen economy development. We would argue for further consideration on what is appropriate for hydrogen before proposing specific solutions.

It is also important to ensure that the rules applied facilitate access to supported hydrogen networks and storage by third parties.

Also, there is a need to think about the distortions the business can introduce to already built projects. These projects estimated a selling price for several years, and a sudden drop in market can lead them to close. For instance, if a refuelling station is built in 2024 next to a refuelling station built in 2022, one benefiting from the business model and the other not.

Electrolytic hydrogen volume support can also be supported by minimum obligations such as in California or, to a lesser extent, in the RTFO. Setting a higher target for renewable hydrogen would incentivise the demand and create conditions for the emergence of relevant projects. There should be a roadmap of the increase so that there are sufficient players to avoid undesired effect of monopoly in some sites – the producer then imposing the price – or cannibalization in others.

Also, apart from the definition of the mechanism, real thought must be made about the practical implementation of these policies. It is important that not too much time is spent between application and results. Large CCUS projects, with horizons 2027-2030, the process can take longer but for small electrolysis projects that only takes 1 to 1.5 years to implement, decision regarding financing should ideally be kept within 3 months. Likewise, there should be a reasonable time between the production of hydrogen and the transfer of the subvention, otherwise there might not be enough cash flow.

Last but not least, as mentioned in comment about the Hydrogen Standard, the renewable content of hydrogen is linked to the renewable content of electricity. Hydrogen production projects of few MW scale take around 1 to 2 years from initial development to commissioning. In comparison, wind developments can take 4 years. This limits the possibility of developing a new site from scratch, when the renewable capacity needs to be developed, and can lead to focus on the use of existing plants. If the government wants to foster the development of electrolytic hydrogen in the UK, then a key point is the support of the development of renewables in general. The additionality criteria, if adopted, needs to consider that this is connecting the development of electrolytic hydrogen to the development of renewable energies.

Research from Energy Network Association (ENA) says that UK renewables will have enough spare capacity between May and October to produce green hydrogen equivalent to 25 Hinkley Point C nuclear plants. ENA concludes that hydrogen could be stored to create a form of dispatchable power during the winter which could reduce the need for renewable generation by 76%. National Grid’s Future Energy Scenarios says that electricity storage is “dwarfed by that of hydrogen storage, demonstrating the value of the latter to the whole system”.

Large-scale storage is necessary to reduce curtailment of renewables, and therefore waste electricity, and will help reduce costs during periods of low wind but high demand. This decreases the total need of new infrastructure and increases the utilisation rates of existing infrastructure. In sum, hydrogen storage is very important to enable green electrons to be stored as green molecules which has significant whole-system benefits through increased flexibility and resilience.