REA response to:

BEIS Consultation on the design of a business model for low carbon hydrogen

The Association for Renewable Energy & Clean Technologies (REA) is pleased to submit this response to the above call for evidence. The REA represents industry stakeholders from across the whole bioenergy sector and includes dedicated member forums focused on green gas, biomass heat, biomass power, renewable transport fuels and energy from waste (including advanced conversion technologies). Our members include generators, project developers, fuel and power suppliers, investors, equipment producers and service providers. Members range in size from major multinationals to sole traders. There are over 500 corporate members of the REA, making it the largest renewable energy trade association in the UK.

Section 2

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

Yes, we agree with the overall approach set out in this section and the general design principles set out in the following section.

The REA strongly supports the development of a producer-led subsidy to support low carbon hydrogen production and help establish the market for low carbon hydrogen in the early years of market development.

However, in the following sections we have made comments on the detail (or lack of detail in some cases) of the proposed revenue scheme.

Overall, we consider that the proposed mechanism has significant merits but also significant complexity. Added complexity risks adding market entry barriers for new and smaller players in the market. We believe the approach adopted is more suited to large scale projects, or companies that have the financial and human resources to deal with this level of complexity – in particular, those complexities associated with the contract. This may deter smaller projects, or companies with less resources, from applying.

We think a wide range of scales and types of projects is required in the UK to build a functioning hydrogen economy. This includes smaller scale, decentralised projects which are key to kick start the hydrogen market and can be deployed relatively rapidly with the right support from Government.

For this reason, we think simpler options such as a fixed premium or a fixed price should be kept on the table or considered as an interim, bridging solution before moving to a more complicated approach such as a contractual arrangement.

Even with a fixed price approach that offers the simplicity and predictability of a non-contractual, accreditation type mechanism, a variable element could still be included linked to the market price. This could lead to a similar outcome for BEIS to that of a variable premium. Please see more detailed comments in our response to question 3.

If a simpler bridging solution is not possible, BEIS may wish to consider developing a parallel **'decentralised business model'** that is more suited to support the deployment of distributed, smaller scale projects, alongside the proposed 'centralised' model (more geared toward large scale projects).

For smaller projects BEIS should not rely solely on the support available under the Renewable Transport Fuel Obligation, as there are other applications for hydrogen that are not mobility related (and for additional reasons detailed in our response to question 11). These include the displacement of grey hydrogen in existing markets (for example, in refineries) and power to gas systems that convert variable renewable energy sources to hydrogen via electrolysis. These systems can provide grid balancing services and long-term storage to manage the variation in power supply from renewable sources such as wind and solar.

Finally, as highlighted in our response to the consultation on the low-carbon hydrogen standard, several members are in favour of a mechanism that differentiates between different types of 'low-carbon' hydrogen ie provides higher incentives to production pathways that deliver higher carbon savings. We have further expanded on this issue in our response to the low-carbon standard consultation.

Other important measures to support the rapid development of low carbon hydrogen

Reducing the cost of grid electricity

As previously highlighted to BEIS, one of the key barriers to the deployment of electrolytic hydrogen projects connected to the grid remains operational costs. In addition to the cost of electricity itself, further costs are added by regulatory support levies and system fees applying to electricity bills. if Government wishes to see a high number of electrolytic projects being developed in the short and medium term, measures could be taken to reduce these costs so that electrolysers can access cheaper grid electricity. Such measures could be considered as part of the Heat and Buildings Strategy proposals (for example in the upcoming Government's Fairness and Affordability Call for Evidence) and we have discussed these in our response to question 11.

Flexible operation

Government should introduce measures to encourage flexible operation of electrolysers on the grid so that these are operated to improve grid utilisation and assist with integrating increasing shares of renewables. These include, for example, preferential electricity rates for electrolysers that operate in a flexible mode (e.g., time-of-use tariffs) or Power Purchase Agreements that insist on flexibility. Government should ensure that any additionality criteria introduced under the low carbon standard are pragmatic, don't disincentivises the business case for electrolysers connected to the grid by placing an unnecessary disproportionate burden. We have covered this in more detail in our response to BEIS low carbon hydrogen consultation.

The role of Guarantees of Origin

For producers to get the best market price and therefore minimise the amount of subsidy provided – producers must be able to give a consumer the highest level of confidence of the product characteristics, in particular its GHG intensity. To do this, a robust and recognised Guarantees of Origin system must be put in place. Recognition of such a system must be built into the UK gov rules on Energy and Carbon reporting and within any carbon taxation system (currently the UK ETS). The REAL's Green Gas Certification Scheme (GGCS) is planning to expand to include Guarantees of Origin for clean hydrogen.

Support scheme for hydrogen injection into the gas grid via the GGSS and post-GGSS support

Low carbon hydrogen should be supported in the Green Gas Support Scheme (GGSS) and under any policy for greening the gas grid that will come after it. This could provide an important route to market for smaller scale projects if BEIS decides to introduce a variable price support mechanism that is more geared towards large scale production. The REA is working with its members on more detailed policy proposals related to this suggestion and will submit this to BEIS in due course.

Injecting low-carbon hydrogen into the gas grid to displace natural gas and selling it at the wholesale price [p/kWh] of natural gas will not provide a viable business case on its own. Power to gas and low carbon hydrogen injection into the gas grid will require a financial support mechanism, similar to the GGSS. This scheme could be adapted to include support for injection of clean hydrogen based on the equivalent CO_2 savings compared to biomethane.

In practice the hydrogen molecules would be blended in the gas grid, but green gas certificates associated with each kWh of hydrogen injected could be linked to I&C customers, who are aiming to reduce their natural gas use. Guarantees of Origin for clean hydrogen awarded under the GGCS or other equivalent schemes will create opportunities to drive a market value for this gas, thereby reducing the direct subsidy required over time.

The combination of commodity value, GGSS type support and certificate value could make injection of hydrogen into an economic option which would help to develop the supply chain in 2022-25, in the same way the original Renewable Heat Incentive did in successfully creating the biomethane supply chain in 2012-16. The low carbon hydrogen injected into the gas grid and used to displace natural gas could also be considered a hydrogen storage project (the kWhs of hydrogen are stored in the same way as natural gas). As such and as highlighted in our response to question 11, electricity loads that are used to produce this hydrogen should be exempt from use of system fees (as they are for battery storage).

The advantage of injecting low carbon hydrogen into the gas grid is that on day one all the hydrogen can find a market (e.g. the I&C customer). For example, making green hydrogen to use as a bus fuel requires the buses to be available on day one and this does not happen in practice as it is more likely to need a three year build up. Having a low carbon hydrogen 'sink' of the gas grid can also facilitate the use of low carbon hydrogen into trucks and buses.

Note on Implementation

The GGSS uses the same primary legislation as the RHI, which allows support to producers of biomethane, which must be made from biogas – where biogas is defined in section 100(3) of the 2008 Act as gas produced by the 'anaerobic or thermal conversion of biomass'. Although the GGSS has chosen to limit eligibility within the scheme to gas produced from anaerobic conversion, this was a policy choice to keep the scheme relatively simple – it remains within the scope of the primary legislation to include biomethane produced from thermal conversion as well.

Arguably, hydrogen made from gasification of biomass already falls within this definition – or would be if otherwise met requirements for injection to the gas grid. The legislation also allows the biogas definition to be 'modified'.[1] It should be possible to modify the definition to include hydrogen made from electrolysis – and a similar approach has been taken to the RTFO, where such fuels are known as Renewable Fuels of Non-Biological Origin.

Other financial measures

- Business Rates should also be reduced or removed for early adopters, to speed adoption.
- The rules for EIS and VCT schemes should be changed so that hydrogen production from renewables is eligible.
- VAT should be waived on renewable hydrogen for transport applications until 2030 or charged at the lower rate of 5% (as applied to Energy Saving Materials), to encourage take up of hydrogen in the transport sector (some members have said they could sell H_2 to transport for £10/Kg, but they are forced to sell it at £12.Kg because of the VAT. Waiving this charge would encourage uptake of hydrogen in transport applications). This sort of approach would also be consistent with the likely shape of EU taxation. Commission's proposals on revisions to the Energy Taxation Directive recommend minimum tax levels that are in a hierarchy based on the environmental harm they cause. So, petrol and diesel would pay the full rate, sustainable first-generation biofuels and biogas would pay 50% of the minimum rate and advanced technologies and RFNBOs would pay very little (just over 1%).

Storage

Hydrogen storage is likely to be required, along with other types of long duration energy storage, if we are to meet our decarbonisation targets, as it provides flexibility and resilience. See our response to question 21 for further detail on our suggestions on how to support hydrogen storage.

[1] S100(5) of the Energy Act 2008

Mobility

A number of measures are likely to be needed to encourage deployment and unlock potential in different segments of the transport sector e.g., trucks, buses, railway and aviation, but we have not detailed these in this response.

Section 3

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

Overall, we agree with the principles set out in this section of the consultation.

Section 4

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

Some members of the REA have highlighted that financeability of any producer-led subsidy is key: it is paramount that the structure of the revenue scheme gives investors and developers enough predictability on the project's overall returns over the length of the contract and sufficient upside for equity investments.

Other members have raised concerns about the significant complexity of the proposed variable premium mechanism, which is regarded as having 'too many moving parts'. These members are concerned that such complexity may deter smaller projects, or companies with more limited financial and human resources, from applying. This is mostly due to the contractual complexity ie the significant administrative costs and burden associated with preparing, applying, bidding for, negotiating and meeting the terms and conditions/managing the contract under the proposed scheme, which may mean that the scheme is not affordable for these types of projects.

These members feel that other, simpler options should be kept on the table and perhaps be introduced as an introductory or an early regime to support early projects.

Some members are very supportive of a fixed premium price which would function in a similar way to a variable premium, but it would be much simpler and could still be allocated on a competitive basis if the price discovery element is seen as critical by the Government. This would simplify the process especially for smaller projects, and it would be much lighter in terms of bureaucracy and contract management. This option should be kept on the table as an introductory or an early regime to support early projects.

Alternatively, BEIS should at least consider the merit of introducing a fixed price initially (like a feed-in tariff), set administratively, but combined/topped up with a variable amount directly related to gas or energy prices which would act like the CfD. The merits of this option in comparison to a fixed price or fixed premium approach on their own are set out below:

- It would provide an element of bankability to investors;

- It would avoid the overcomplexity of a CfD/contractual type of approach, which would make the scheme unaffordable for smaller scale projects and is premature at a point where the market is only just beginning, and
- It would also address Government concerns of windfall profits when energy prices are high as the variable element is adjusted to reflect these.

In a few years (e.g., five years), the Government could then transition to a more conventional CfD type of approach (or variable premium), when there is a more established market for hydrogen and a benchmark price that can be used as a reference price. **In summary, the REA calls for an interim, bridging simpler mechanism that avoids the overcomplexity of the proposed revenue scheme in the early years, when the market is still immature but with the aim of transitioning to a more conventional CfD mechanism once the market is more established.**

If a simpler bridging solution is not possible, BEIS may wish to consider developing a parallel **'decentralised business model'** that is more suited to support the deployment of distributed, smaller scale projects, alongside the proposed 'centralised' model (more geared toward large scale projects).

Members that are developing large scale projects feel that the proposals are broadly appropriate at this stage, but highlighted that, in addition to the complexity associated with defining an appropriate reference price and understanding it, the greatest challenge of the business model proposed will be to understand in detail what is the process for determining the strike prices and the exact allocation process. This level of detail is not yet covered in the BEIS consultation - there is no methodology provided for a strike price and how the allocation process works, so more clarity needs to be provided on this feature of the proposed revenue scheme.

Administrative strike prices for the CfD contacts for power, for example, have been determined through an extensive process of calculating standard Internal Rates of Returns (IRRs) applied across different technologies, researching into the cost of each technology, and working backward from that. We would imagine a similar approach would need to be adopted by BEIS for the hydrogen business model, but this needs to be set out in detail and clearly upfront to provide visibility to developers on what the process is.

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

As mentioned below, the approach used is very complex and some members have questioned whether the reference prices suggested are appropriate for green (electrolytic) hydrogen producers. For these projects the subsidy should not be calibrated against the natural gas price since this is not the main cost driver. The key cost for green hydrogen projects is the cost of input electricity and electricity system levies and charges.

Some members of the REA have also highlighted that considering recent fluctuations in gas pricing, the linkage to an unstable gas price is not sensible.

Reference price makes sense for power sales as almost everyone will be selling their power onto the open market. So, it is a minor detail whether the prices achieved contractually by a generator match the market ones – they are not going to be far out over time.

However, there is currently no hydrogen market with a dominant end use. Over time, we might reach a stage where most of the hydrogen goes to a single usage, or where if other offtakers fail, the producer will always be able to get a particular end use to take it off their hands. At that point, the dominant end use could set the reference price. If that was injection to the gas network, then there is not a problem with price volatility – the producer will not get a windfall when gas prices are high, and he will not make a loss when they are low.

Under the current situation, however, the economics of the hydrogen production plant could have no connection with gas prices at all (and might well have a much greater connection to electricity prices) so the support the producer receives could change wildly in a way that may makes little sense.

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?**

To reiterate, there is a risk of the CfD mechanism creating unintended barriers to entry for smaller, independent and new market entrants, that could be mitigated by adopting the proposal above.

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

There seems to be general support from members on inflation-linked indexation because it is simpler – inflation is an economy-wide measure which is well understood, and consistent with other energy policies. Developers will have to include an inflation number in their financial models, whilst other measures (e.g. input energy costs or natural gas prices) are unpredictable. Everyone understands the nature of inflation as an economy-wide measure.

The strike price represents the total sales value that a project needs, and it would make no sense to vary this by far more volatile indices (and with a far greater variation) such as gas or electricity prices.

Some members have pointed out that the right type of indexation will depend on what technologies/pathways are being used to produce low carbon hydrogen. For example, a natural gas benchmark would work better for blue hydrogen and electricity would be more suited to electrolytic hydrogen projects. However, in our view these points would be better focussed on picking an appropriate reference price.

BEIS will need to strike a balance between trying to reflect different potential pathways in the policy and ensuring the policy doesn't become too complex at the risk of undermining its credibility.

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.**

If the mechanism is about stimulating new sources of production and supporting new markets, then we agree that existing applications using hydrogen should be excluded from support.

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

Comments already made above. Although we agree this is the right structure for a revenue scheme in the longer term, the REA believes a simpler, bridging, or interim mechanism would be more suited for the initial years of hydrogen development, until the market becomes more established. An interim mechanism could either be a fixed premium, or a fixed price with a variable element connected to the energy prices which would protect Government from overcompensating projects. See our recommendations above.

Section 5

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

Generally, the proposals related to the sliding scale approach are seen as the least clear proposals in the consultation, both conceptually and directionally.

It is unclear what these proposals really mean for investors and developers, in particular the following is very unclear:

- how the sliding approach is linked to the variable premium price/ how it interacts with the pricing support
- how it leads to predictability and financeability
- how the price will be reduced: is this a continuous reduction, or is it in buckets / bands?

There needs to be much more detail on the sliding scale approach for industry to understand the implications.

In addition, some members have expressed strong concerns with a business model that tries to regulate both price and volume simultaneously, as this may end up encouraging speculative or semi-speculative applications. On the provision the Government has signalled its strong support for hydrogen and has set the right pricing framework to encourage fuel switching from end users, a pattern of demand will emerge which should be able to support strong offtake contracts. No investors would finance the development of a plant without clear demand and agreed robust offtakers.

Members are generally more supportive of:

1) An offtaker of last resort, like the model used in the CfD power scheme, as this is much simpler and more effective to protect developers if an offtake falls through driven by circumstances in the market, or
2) An availability - based payment, where the plant owner is compensated for making the capacity available rather than actual output. This would be even safer in a nascent market where you could conceivably not find any offtakers or the producer's only offtake could fall through due to circumstances outside their control, in this circumstance, under an there is no offtaker of last resort option and under the sliding scale, the producer might would not receive any support. The security of an availability payment, or similar measure may be required in these circumstances.

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.

Availability of storage infrastructure will help manage the inevitable fluctuations in production (especially for electrolytic hydrogen), and consumption (due to seasonality in demand), Measures to support storage are highlighted in our response to question 21.

In parallel, measures to facilitate blending of hydrogen into the gas grid should also be taken. These includes a review of the 0.1% hydrogen limit by widening the gas quality standard that sits under the Gas Safety Management Regulations.

Section 6

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?

The support scheme chosen by BEIS should certainly apply to different technologies / pathways (ie it should be technology agnostic), but it also needs to avoid overcomplexity. Potentially a variation in the strike prices could help bring forward investments in a wider range of technologies.

However, we would be concerned if the policy tries to address all possible risks, becomes overcomplicated and introduces significant level of uncertainty for developers and investors on the multiple factors / elements of the scheme. We believe BEIS should decide what risks it is appropriate for Government to take, and which risks can be left to developers before the policy becomes overcomplicated.

11. 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.

We believe this is an area for further development.

As previously highlighted, the overall undertaking associated with putting together, negotiating, and managing this type of contract is significant and should not be underestimated. We understand from industry that projects below 10 MW would likely struggle to apply for this type of mechanism, although it must be pointed out that the size of the project is not the only factor. The main challenge is the contractual complexity as opposed to the size of the projects: for example, a company developing several small-scale electrolysers may have the resources to enter into such a contractual agreement, while an individual company developing a larger-scale project may not. It is worth noting that the CfD for power has been taken up almost exclusively by larger projects.

Secondly, BEIS has stated in the consultation that they believe small scale electrolysers are likely to develop and be supported under the RTFO. This needs further consideration. The RTFO is a market-based mechanism – given that the value of the Renewable Transport Fuel Certificates (RTFCs) is volatile, this mechanism is often not seen by developers as bankable when looking to fund new plant. In other words, RTFCs are never used as the funding mechanism to build a plant but are often seen as an additional revenue source once the plant is operational (unless a long-term offtake contract can be signed with a counterparty which guarantees the value of the certificates for a long period of time).

We have experience of this in the biomethane sector, where no biomethane plant has been funded solely on the basis of the RTFO. All AD plants injecting biomethane into the grid have needed accreditation (called 'registration' for biomethane) under the Renewable Heat Incentive, which provides a guaranteed stable income for developers for twenty years. Many of these plants, however, are likely to boost their production to supply additional biomethane for use in transport under the RTFO and earn additional revenues. We would be happy to share further information with BEIS on this important point.

BEIS will need to decide in the first place whether they want to see these types of projects developed in the UK and not rely entirely on the RTFO policy to support them. In our view, as highlighted previously, distributed production from electrolysers can play an important and immediate role in demand side response, providing wider whole system benefits. Small scale electrolytic projects are key to kick start the market for low carbon hydrogen in the UK, can be developed much faster than larger plants and will be crucial to accommodate more renewables in the system and balance the power grid. Not only can they play an important part in building the UK low carbon hydrogen economy, but they also have an instrumental role in helping the UK reach its Net Zero target at a faster pace.

As mentioned at the beginning of this response, the greatest barrier to the deployment of electrolytic hydrogen is cost, largely due to the cost of renewable electricity via the grid. In addition to the cost of electricity itself, significant further costs are added by green levies and system fees applying to electricity bills.

The REA believe it is paramount that, in addition to developing business models and providing capital grants, measures are taken to reduce the running cost of grid connected electrolysers by enabling them to access cheaper renewable electricity. This can be done by:

- Exempting electrolysers from 'green levies' on electricity bills – i.e. electrolysis could be on the list as energy intensive users (see EII Scheme), thereby qualifying such sites for exemption from the indirect costs of funding Contracts for Difference (CFDs), the Renewables Obligation (RO) and the small scale Feed in Tariff (FIT).
- Exempting electrolysers that provide grid services from use of system fees (on a time limited basis), or adopting an approach similar to the new rules for grid balancing charges borne by energy storage assets – i.e. on a net usage basis (exemption from final consumption levy double charging like storage devices[1]).

Government should also work with industry and energy suppliers to ensure Power Purchase Agreements are developed to help electrolysers take advantage of times when wholesale electricity prices are low, to help firm up the market for new renewables. At such times demand for electricity is at its lowest and there is surplus renewable power. This approach would therefore help the continued integration of renewables in the electricity system.

Similarly, economic incentives should be put in place to encourage the deployment and use of electrolysers to help reduce curtailment, because this provides an avoided-cost benefit for the system operator rebalancing the high-RES grid and reduces the wastage of renewable energy.

Measures to encourage flexible operation of electrolysers on the grid so that these are operated to improve grid utilisation and assist with integrating increasing shares of renewables. These include, for example, preferential electricity rates for electrolysers that operate in a flexible mode (e.g. time-of-use tariffs) or Power Purchase Agreements that insist on flexibility.

Section 7

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

For our members, 15 years is a good window – it is the relevant window for financing and for equity return calculations.

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

No, a 15-year contract length should be appropriate for most technologies.

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

[1] When charging and discharging from the grid, storage devices in the past were paying fees for both these activities on a gross basis. However, there have been grid modifications made that allow them to be charged only on a net usage basis. This recognises the fact these devices are aiding the electricity system flexibility. A similar approach needs to be applied to hydrogen electrolysers that are grid connected.

We would support the 'Accordion' option as it provides a better balance between the need for projects to have the flexibility to be able to expand if this delivers value for money, and the need for Government to minimise the risk of over subsidising plants.

Although not necessarily related to the question, it should be highlighted that as much flexibility as possible should be given to projects for commissioning. Especially for FOAK projects there is an element of uncertainty around the commissioning timescale and the mechanism would become unfinanceable if hard deadlines for commissioning are given, resulting in a penalty or the risk of losing the contract if the deadline is not met.

Under the power CfD some technologies such as ACT had significant issues due to the very strict commissioning deadlines set in the contract ie they need to commission a certain percentage of commissioning by certain dates and they may lose the contract if they can't. This has been a significant issue during ramp up when the output of ACT plants fluctuates, so it is paramount that flexibility is provided on commissioning windows.

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 broadly agree with the risks highlighted in this section.

However, the risk of an offtake falling through or of not finding any offtakers should also be included.

With regard to the risk related to a change in law, we are concerned about the wording used around 'unforeseeable changes'. Clarity on how unforeseeable and foreseeable are defined needs to be provided, this is set out for the power CfD policy, and it would be useful to understand if the hydrogen mechanism would follow the same system.

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 support the principle of allowing stacking of support, given the cross-cutting nature of hydrogen.

The interaction between the business model support and the RTFO should be fine in principle, especially given that the RTFO is not a subsidy for producing hydrogen, but for driving its use and supply of the fuel to the transport market. This should ensure it does not overlap and fits well with a business-led mechanism, if the risk for double counting is minimised. However, the interaction needs to be tested first to ensure it is workable.

For biomethane, Ofgem and DfT are putting in place some protocols to ensure it can be verified that for the same consignment of biomethane both RHI and RTFCs have not been claimed. These protocols have the potential to become quite complicated, so it is important that if interaction is allowed, a workable verification system is put in place.

It is also crucial that rules under the producer-led revenue scheme and the RTFO are aligned as much as possible. So, for example, additionality rules and requirements to account for the electricity used from electrolysers set out in the BEIS revenue scheme will need to be aligned with those in the RTFO (which come from the EU RED policy).

It is not clear whether Government has considered interaction with the UK ETS e.g. how the carbon price is factored in to ensure the producer is not double rewarded. This should therefore be clarified by BEIS.

Section 8

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)?

Our members overall agree that it would be sensible to start with a bilateral agreement and move to a competitive auction later.

However, there needs to much more clarity up front on what that bilateral process is and a set of clear, objective criteria for this process. Without objective criteria, there is a risk that bilateral contracts will go to the developers who are most successful in lobbying government. The bilateral process might also choose to target a range of technologies - or even other factors such as spread across geographical locations, size of plant etc.

The detail needs to be set out and be visible to developers up front. Developers shouldn't be invited to apply for a contract and then incur significant legal costs to learn down the line what the process and eligibility criteria are.

As an example, Government should include criteria such as Supply Chain sustainability and awarding contracts to projects illustrating added value to UK from local manufacturing. This can be adapted from the relatively successful Supply Chain Action Plans for the power CfD that has driven huge investment in offshore wind supply chains in the Humber and Tees valley.

Section 9

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

The REA recognises that there needs to be further debate about where policy costs currently sit on bills and what the costs will be in the longer term. These costs must be considered against impacts on the fuel poor.

The REA would encourage the Government to consider whether the cost of green levies (LCF, ECO, GGL and the Hydrogen Business Model) should be moved from energy bills to general taxation in the future, as this would be a more progressive system.

If it is decided that a levy is placed on gas bills, Government should ensure this is not regressive. The main criticism against the Green Gas Levy from consumers' perspective has been the fact that it will initially be a flat rate ie regardless of the volume of gas consumed, everyone will pay the same flat rate. Lessons from the Green Gas Levy should be learned to ensure any additional levy on gas bills is fair and doesn't disproportionately affect certain consumers.

It is worth pointing out that not all hydrogen will be supplied through the gas network, and unlike the Green Gas Support Scheme, the producer-led revenue scheme is not a scheme to encourage decarbonisation of the gas network, so it may be more problematic to place the cost on gas consumers.

Section 10

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.

Yes. Projects should be able to price storage in if it is part of their costs, especially in the early days of development. The events of recent months in the gas markets have highlighted the dangers of insufficient storage in the energy system.

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.

Pipelines and networks take a long time to develop and build so it would be difficult to capture this in the business model if we want this to be delivered quickly.

As previously mentioned, large scale hydrogen storage is likely to be required, in combination with other large scale storage technologies, to improve our energy system flexibility and resilience. Storage will help manage the increased shares of variable renewable sources in the power system grid and also the high seasonality of energy demand.

We understand from some members that repurposing of depleted gas fields and salt caverns are likely to represent the most attractive options for UK hydrogen storage from a geological, environmental and economic perspective, but the business case to support these types of projects is weak due to highly uncertain revenue streams.

These members strongly support the introduction of a Regulatory Asset Base (RAB) model to support investment in geological hydrogen storage. Under this model the regulator would set a fixed revenue allowance for the company, and any market revenues earned above (or below) this level are returned to (or topped up) by consumers. This means the model is not dependent on the market for hydrogen and provides certainty to investors which could potentially lead to lower financing rates.

It should be noted that the REA's Longer Duration Energy Storage Report, and response to recent Government call for evidnce, favours an income floor price for a more technology neutral large-scale and long-duration electricity storage (LLES technologies) support mechanism. This helps de-risk investments while incentivising efficient dispatch through price signals, while also incentivising operators to react to market signals according to the operational characteristics of their project. The report does also acknowledge the strength of a RAB model, if it is government's intention to create a bespoke funding model around hydrogen, recognising that '*the traditional RAB approach regulates returns fully, de-risking the investment more than the other mechanisms. Investors benefit from high levels of protection from risks, including during the construction phase. From an investor perspective, this is favourable when considering investment in technologies that are relatively new to the energy market. However, this means customers may face risks from cost overruns (depending on the detailed methodology set by the regulator).*'

Given the extremely uncertain revenues of hydrogen storage and current lack of a commodity market for hydrogen, RAB would probably be appropriate for hydrogen storage.

REA, 22/10/2021