Low Carbon Hydrogen Business Model: Consultation on a business model for low carbon hydrogen

25 October 2021

About Energy UK

Energy UK is the trade association for the energy industry with over 100 members spanning every aspect of the energy sector – from established FTSE 100 companies right through to new, growing suppliers and generators, which now make up over half of our membership.
We represent the diverse nature of the UK's energy industry with our members delivering over 80% of both the UK's power generation and energy supply for the 28 million UK homes as well as businesses.
The energy industry invests £13bn annually, delivers £31bn in gross value added on top of the £95bn in economic activity through its supply chain and interaction with other sectors, and supports 738,000 jobs in every corner of the country.

Energy UK welcomes the opportunity to respond to this consultation, we provide comments to the questions below:

Section 2

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

Yes, Energy UK supports this approach, which is similar to the existing well established CfD framework and has the potential to support investment in production facilities for the development of a hydrogen economy. It is suitable for the large-scale production technologies.

Further consideration is needed on:

- the interaction of the UK and Scottish 5GW production targets by 2030
- the alignment of demand in parallel with production and infrastructure development. Co-ordination with capacity market development for generation and industrial decarbonisation deployment is needed
- support for smaller scale de-centralised electrolytic projects, say <15MW[1]
- support for projects before the business model is in place
- the desired balance between 'blue' and 'green' hydrogen by 2030, including implementation of ringfenced pots at the outset to deliver these targets.

[1] This level is not precise there are a range of views

- pathways beyond 2030, including a ‘green’ hydrogen target.
- timing of steps beyond the consultation and whether these are consistent with delivering 1GW production by 2025.
- Co-ordination of planning and permitting processes to support projects to FID
- Appropriateness of green levies on electricity for electrolysis
- Appropriateness of introducing natural gas price risk into electrolytic projects
- Support for end use synchronised with production to boost early market growth
- Support for the development of transport and storage infrastructure

<u>Section 3</u>

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

Energy UK broadly supports the approach, to support hydrogen production, including the design principles and key risks. However, we note there are a number of elements of the business model that are yet to be decided, the detail of these is needed as soon as possible for developers to fully understand the framework proposed. Definition and understanding of strike price indexation, sliding scale approach and application to a range of sectors will all be key.

It will also be important to fully understand how all the policy measures fit together including the low carbon hydrogen standard and the net-zero hydrogen fund. Linkages to demand support measures to encourage transition will also be important in terms of timelines and alignment with production.

We also have some reservations about whether this is the best approach for small electrolytic projects, due to the complexity and timescale before the model can be applied to support FID for projects.

Key issues for small electrolytic:

- Some early adopters of hydrogen technology are willing to pay more than they would for the counterfactual fossil fuel. They place a high value on hydrogen now. They also expect the cost of production from electrolysers will fall over time and hence the price of hydrogen. The business model assumes a rising ‘value’ of hydrogen which is the opposite.
- In some cases, they also value the stability of knowing the cost of hydrogen up front and avoiding the volatility of the price of natural gas. They will install renewables for a known capital cost, thus fixing the cost of input electricity. The variable premium model is unhelpful to these customers as it re-introduces a variable element and one that has no relation to their project.
- The first projects that use the new business model will need to educate investors and lenders on the model. This is possible where the projects are large, and the ticket size justifies the first-of-a-kind effort. However, it will be a significant burden on early smaller projects. Experience with wind CfDs is that only once large projects show

the way, investors will get comfortable to work with CfD type contracts on smaller projects

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.

Energy UK agrees that for the enduring model there is merit in utilising the variable premium model for price support, and that there is merit in the way the mechanism evolves with evolution of the hydrogen market and price discovery.

We also suggest that a simpler model for early projects will allow the UK to start to build local capability before the long-term model is available. A simple fixed premium approach may be useful here.

We consider that it may be useful to retain the simpler option as a 'back-up' approach, if delivery of the preferred approach becomes too challenging. A competitive award process will ensure value for money for customers.

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

Energy UK agrees that setting the reference price is a key parameter that could determine the successful development of the hydrogen economy. Ideally it should be based on a hydrogen market benchmark, but until this is available, linking it to the natural gas price as and the achieved sales price seems to be a reasonable approach for most early projects. However, this is not without challenges, particularly for electrolytic producers as the costs of electrolytic hydrogen do not relate directly to the natural gas price and it introduces unwanted volatility and risk which could impact strike prices, sales prices and risk perverse incentives.

Whilst the achieved sales can impact the allocation process, as producers will already be incentivised to maximise the hydrogen sale price to offer a lower strike price. Some members consider only one reference price should be used, and consideration should be given to what happens if the natural gas price exceeds the achieved sales price as this would result in reduced subsidy jeopardising project viability.

In time the approach could evolve to adopt a hydrogen market price benchmark. Consideration will need to be given to the parameters used to determine when any benchmark is sufficiently robust and how its introduction can avoid negative impacts between production facilities or existing Business Model contract holders. The proposed approach provides some 'headroom' for sales to be achieved above the natural gas price, in sectors where a carbon price applies, but this will be dependent on a wide range of factors including the presence of localised markets and direct contracts for the provision of hydrogen by non-networked hydrogen production assets with centres of demand.

Further consideration will need to be given to the reporting and disclosure requirements in relation to the achieved sales price, including; confidentiality concerns, frequency and audit requirements without this becoming too burdensome. It should also be recognised that low carbon hydrogen production facilities are likely to have contracts with multiple offtakers at different prices and over different contract durations. Establishing a single achieved sales price metric will not therefore be straightforward. BEIS will also need to consider whether there could be benefits in publication of a price summary in some form.

A gainshare mechanism or some kind of incentive mechanism to sell hydrogen above the natural gas price, is desirable in principle but is yet to be developed, along with other features. If it is to be used, it should be developed at pace with further engagement and consultation, to achieve clarity at the earliest opportunity to avoid adding to the time to delivery of the business model package with consequent risk for project delivery timescales and government production targets.

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?**
    - Delivery timescales, especially for 1GW of production capacity by 2025
    - Complexity of the business model may deter smaller electrolytic projects. Although we note and welcome the commitment to £100M for upto 250MW of electrolytic hydrogen production in 2023 with a further allocation beyond this in the Net Zero Strategy[2]
    - Both these factors could lead to longer term consequences if other countries deploy such projects more rapidly, leverage learning and develop supply chains. The UK could lag behind in the development of supply chains for electrolysers
    - Future disconnect between natural gas reference price and hydrogen market price. In particular reflecting on previous oil indexation of long term gas contracts that led to renegotiation when they decoupled.
    - Co-ordination of investment across the supply chain
    - Risk that hydrogen production may not be eligible for export, which could limit investment.

[2] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1026655/net-zero-strategy.pdf

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

Energy UK understands indexation is a complex topic that it will be important to get right to avoid inappropriate incentives or remuneration. We agree that different types or indexation or a basket of indices are likely to be needed for different production archetypes; gas reforming, grid connected electrolysers and electrolysers connected to dedicated renewable generation. Indexation should as much as possible be set to reflect energy input costs for each technology plus an allowance for indexation, some consideration of end use may be appropriate, risks are created if inappropriate indexation is applied. The indexation structure may need to evolve over time for new projects, based on experience.

Thought will also need to be given to the granularity of indexation periods, eg day, week, month, year and how frequently the strike price is updated. This will impact hedging strategies for the gas or electricity input costs. The mechanism should be stress tested against the recent gas and electricity price increases.

If gas price indexation is provided, it is critical that the risks of gas price volatility are taken into consideration when assessing the strike prices of CCUS-enabled gas reforming projects, so that a robust comparison can be made with the strike prices of other hydrogen projects that don't require this type of indexation. This would provide a fairer representation of the real costs of those types of hydrogen production that have natural gas as an input fuel.

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.**

Energy UK considers it is important to encourage all sectors to utilise low carbon hydrogen to displace 'grey' hydrogen and a significant fraction of demand will come from industry for feedstock. We also appreciate the understand the concerns about over reward and distortions in downstream markets and would like to understand this further. if the natural gas reference price benchmark were used. The proposed framework should be implemented for hydrogen used as feedstock and amended, for example on the basis of contractual review clauses, only if the risks actually materialise.

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

No additional comments

Section 5

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

Energy UK recognises volume risk is an issue that may impact FID for production and welcomes consideration of options to help producers in the event that offtake volumes fluctuate or are lower than expected.,. However, if blending into networks is available then this should be utilised ahead of reduced production and Government should ensure that blending into networks and development of hydrogen storage become available as quickly as possible to help manage demand side risk, although it is not expected to fully eliminate this risk.

Energy UK agrees that the sliding scale approach conceptually has merits over the other options considered. It has merit in helping to manage volume risk, and capex payback although not if an offtaker is simply late in commissioning its hydrogen capable equipment, this is a risk producers have limited ability to manage. It also adds considerable complexity to the business model, and it needs to be more fully defined considering;

- Whether it is part of every contract or when needed
- Interactions with the indexation approach
- The duration of any enhanced support
- Whether it is prospective or retrospective at the end of a period
- Whether there is an end of period adjustment
- Is there an impact on the support across the lifetime of the project?
- Whether arrangements are bespoke or standardised by technology type
- Consequences for the funding approach
- If it creates risk of sub-optimal project location

Worked examples would be useful to aid understanding

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.

Energy UK recognises and supports the production led approach for the business model but thinks from the wider strategy perspective more attention needs to be given to ensuring the demand side develops in parallel, this is essentially a type of volume support.

Whilst explicit support linkage, may be a step too far there needs to be an overview that recognises the linkages and helps to expedite processes to align development of demand. Project discussions often occur in parallel but then have different application processes.

For example; changes to the capacity mechanism are being considered that may support hydrogen generation, but will these timescales work alongside hydrogen production business models processes? There will also be planning and permitting issues, that could lead to a mismatch in production and demand if not considered in a co-ordinated manner.

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?

Energy UK considers that the proposed options are broadly suitable across a range of hydrogen production technologies with appropriate parameters, allocation processes and funding pots.

However, we share the concern articulated for smaller scale projects, in that the private law contract with variable payment mechanism may be too complex for some. We do not believe these are limited to transport related projects.

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, we think there would be merit in revenue support, for small electrolytic projects to ensure early deployment and provide opportunities for learning by doing to support growing the scale of electrolysers during this decade. A simple mechanism like the premium FIT would be relatively simple to establish and administer, given experience with the existing mechanisms and importantly would aid early and rapid deployment. Some members think, this would likely support the development of local supply chains and employment that may otherwise be established overseas.

Section 7

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

Energy UK considers that in principle the contract duration should reflect the asset life, particularly for the FOAK projects that will have no knowledge about what the market will look like after the end of the contract. A clear pathway set out by government, which sets out what needs to change at policy level to develop a liquid traded market and a hydrogen backbone or local network is needed to enable a hydrogen economy to develop in a timely manner.

For investors revenue certainty over a longer time period will enable lower initial prices and enable learning for the FOAK projects. A starting point should be 15-20 years for all technologies. For subsequent projects we recognise the need to drive efficiency and this may be reviewed.

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

We consider the starting point should be 20 years for all technologies, whilst noting that linking the contract duration to asset life will potentially be more important to those that have no prospect of connecting to a network.

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

Energy UK can see the case for allowing some limited volume scale up being allowed, but this should be limited to marginal efficiency improvements. Future projects are expected to be lower cost so anything other than a limited approach could undermine competition for funding for future projects in future rounds / allocation processes.

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.

Our initial view is that the risks are allocated appropriately, subject to previous responses, whilst recognising understanding will develop overtime.

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.

Energy UK agrees with the principles outlined when considering how the business model interacts with other sources of support.

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)?

Energy UK considers a pragmatic approach is needed for initial projects within the cluster sequencing process and for other projects approaching FID to ensure early deployment of hydrogen production technologies to contribute to the 2030 5GW target. Bilateral negotiation is therefore suitable for early projects.

We also consider auctions, with separate pots by archetype will be appropriate if there is a sufficient pipeline of projects to ensure a competitive process.

Section 9

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

The cost targeting approach needs to reflect and be consistent with BEIS wider approach to affordability and fairness across fuels and different customer groups. We note that BEIS is shortly due to publish a call for evidence on this topic and is looking to make policy decisions in 2022. More broadly, Energy UK have long been of the opinion that levying costs on energy bills is a regressive mechanism A more progressive options would be to recover costs by general taxation, especially given the wider societal benefits of de-carbonisation. We also note that the levies currently placed on electricity bills already represent a significant barrier to customers making decisions to decarbonise how they heat their homes and businesses. A consistent approach to the management of levies is required across government energy policy.

If our preference for general taxation is not applied then costs should be socialised to all users of gas. This will act as an incentive to reduce the use of unabated carbon based fuels. Costs should not be applied to clusters as this will remove any incentive to de-carbonise.

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.

It seems reasonable to accommodate this for initial projects that are progressed and agreed by bilateral negotiation as this may lower cost through efficient and optimised plant size choice, it is more difficult to see how this can be accommodate in a price-based auction as comparison between projects would be more difficult.

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 consider a more tailored approach will be needed for larger scale networks and storage including exploration of re-purposing options to ensure efficient outcomes and to minimise stranded assets in the future. We assume that a more detailed assessment of regulatory models will be undertaken, taking account of the latest estimates, and ensuring any model developed was in line with best regulatory practices and in the interests of consumers.

For further information contact:

Julie Cox
Senior Policy Advisor, Gas Transition
Energy UK
26 Finsbury Square
London EC2A 1DS

Tel: +44 1782 615397
julie.cox@energy-uk.org.uk
www.energy-uk.org.uk