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

Submission to BEIS, October 2021

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

In general, yes, this approach is appropriate.

However, small-scale production needs to be supported also and could facilitate cost reductions in electrolysis through deployment. A modest fixed payment scheme could be a way to address this part of the market.

However, Business models for other parts of the hydrogen value chain (transport, storage, industrial equipment investment, domestic conversion) are needed, together with a full consideration of business models for negative emissions (given the importance of negative emissions to achieving net zero). This needs to be supplemented by policy support and other interventions including:

1. A robust **carbon pricing** mechanism that will transparently increase over time to encourage early decarbonisation of industry.
2. **Demand-side policies** to encourage uptake of low-carbon industrial products including mandates, product standards and public procurement mechanisms that create a favourable environment for procurement of these products, recognising that on a purely economic basis, low-carbon products may not be the cheapest option. We should be advocating for global alignment on these policies, to prevent offshoring of industry.
3. **Carbon Contracts for Difference (CCfD)** could help to provide a sufficiently reliable, "investible" carbon price to underpin the business case for commercial scale industrial deep decarbonisation deployment. [19]
4. **Adaptation of the existing market structures and system operation rules** are necessary to enable transparent pricing structures for decarbonised gases to develop.
5. **A certification framework to ensure that the residual carbon content for different decarbonised gases is understood** - RED II is an EU objective that extends the existing Guarantees of Origin (GoOs) scheme to include decarbonised gases. It encourages investment and facilitates cross-border trade, which will drive competition and ultimately drive down prices, in the decarbonised gas market.

Further consideration should be given to exports, in the cases where it can be used as a mitigation of demand risk, particularly when volumes cannot be placed with domestic off-takers for reasons outside the Producers' control. These exports may contribute to stimulate a global market for low-carbon hydrogen in which the UK can take a leading role.

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

Yes. A revenue support model is the most effective way to stimulate the low carbon hydrogen sector while achieving value for money for Government. The Governments minded to position should sufficiently mitigate price and (some) volume risk for the private sector to an acceptable level for investment, whilst Government takes on the risks others cannot, safeguarding the emerging low-carbon hydrogen economy.

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

Yes. Industry is well accustomed to subsidy adjustments as markets evolve, reducing the financial burden for Government as supply and demand price expectations reach alignment.

Using a fixed premium or fixed price may not incentivise a competitive pricing landscape for hydrogen in the fulness of time, potentially requiring more subsidies, and thus eroding value for money for the UK taxpayer.

Even so, there is a risk that a variable premium model would be less likely to make hydrogen attractive across the broad spectrum of end-use cases, unless further market-specific reference prices were introduced.

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

Yes, subject to caveats. Setting the reference price at the higher of the achieved sales price or the natural gas price is the most effective option as natural gas is the most common and lowest cost counterfactual fuel. This means that producers can sell low carbon hydrogen at the same cost as natural gas to incentivise switching particularly in sectors that face increasingly prohibitive carbon pricing. Producers are also incentivised to sell hydrogen at a higher price through the gainshare mechanism or periodic payment linked to achieving or exceeding a defined pricing threshold or benchmark. However, the gainshare mechanism must be appropriately designed to incentivise sales into higher value markets.

With the recent spike in gas prices, there is some concern with setting the reference price at the price of natural gas. This is of particular importance in end use sectors where natural gas isn't the counterfactual fuel. For example, if a hydrogen producer is selling hydrogen into the transport sector and the price of natural gas increases to a level above the achieved sales price, then the size of the subsidy the producer receives falls with no increase in sales revenue and potentially an increase in cost (depending on production method). There is also some concern in sectors where natural gas is the counterfactual fuel that with very high gas prices (and therefore hydrogen prices), industries may be forced to cease production, if they cannot afford hydrogen. The DGA believe that there needs to be a mechanism to mitigate this risk such as a ceiling on the reference price or a contractual reopener in the situation that natural gas prices hit a certain pre-determined threshold.

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?

The DGA would like to be confident that Government have stress tested the design of these business models against very high gas prices, such that a protection mechanism can address gas price exposure. This mechanism could either be a contractual reopener if gas prices hit a certain threshold or a reference price ceiling. More detail on this risk can be seen in the response to Q4.

There is also a risk that without effective design of the gainshare mechanism, producers will not be adequately incentivised to achieve the maximum sales price for hydrogen. Making the gainshare mechanism generous to producers may reduce the financial burden of the business model as without a proper incentive to achieve the highest possible sales price it is likely that producers will simply sell at the natural gas price and be awarded maximum subsidy from Government. Incentivising a higher sales price will reduce the size of the subsidy paid by Government and allow hydrogen to be deployed in the sectors that value it most.

Furthermore, without correct design of the gainshare mechanism, price discovery of low carbon hydrogen will be impacted as producers won't have enough of an incentive to sell above the price of natural gas and that price may prevail.

This model seems to be based on the principle of a production facility selling to a small number of off-takers. Whilst this may be the case for the first train of ATRs planned at Stanlow Refinery in Cheshire, producing hydrogen for on-site refinery use, the Government should consider the expansion cases for production companies to sell to hydrogen distributors in the future. If this occurs the distributor will be purchasing the hydrogen at a cost and then selling it to a higher value market. If for example a distributor purchases hydrogen at a price between the reference price and the strike price and then sells the hydrogen into a market which values hydrogen above the strike price, then the Government is providing subsidy that is not necessary to the market.

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

A blend of a natural gas benchmark, an electricity benchmark and inflation has merit as an option for indexation as this mixture would most accurately reflect costs and mitigate some of the risk of natural gas price increases. However, there may need to be differences in the relative weighting of this indexation hybrid for different production methods to reflect different costs structures and different market risks.

There is some concern that a benchmark will not be able to react quickly enough to changing prices, particularly in the current climate and could become overly complex. As a simpler alternative worth considering is Actual Energy Input Cost, coupled with inflation.

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.

Hydrogen used as a feedstock is an important application that is currently very carbon intensive (due to the principle use of the SMR production route). The CCC estimate there is currently 27 TWh of hydrogen production in the UK- of which a very small proportion is low carbon. Applying average emissions factor of grey hydrogen from a BEIS literature review of 273.5 gCO2e, we have estimated that 7.4 MtCO2e of emissions are produced as a result. It is vital, therefore, that future production routes for hydrogen are decarbonised both to reduce emissions and improve public perception of hydrogen.

It is expected that existing hydrogen production plants capable of adopting CCS can be decarbonised through the Industrial Carbon Capture Business Models. However, the DGA believes new low carbon production should not be excluded from targeting these sectors while acknowledging the risk of over-reward.

The best solution to this risk is effective design of the gainshare mechanism, which will incentivise firms to achieve the maximum possible sales price of hydrogen and minimise the risk of over-reward.

If Government are still concerned about the risk of over-reward in these sectors, the DGA would advocate for a separate price floor where hydrogen is used as a feedstock, this could be based on:

- A benchmark of the cost of carbon intensive hydrogen
- Increment to the natural gas price to reflect the costs of manufacturing feedstock hydrogen

However, this would increase the complexity of the business models.

The use of low carbon hydrogen as a feedstock, for example in ammonia, should be supported as an important part in building up a hydrogen value chain and would provide an additional customer to make the investment case for production projects more robust, would support the decarbonisation of other sectors and would kick-start a broader low carbon products market in which the UK can take a leading role

8. Do you agree with our overall minded to position for price support? Please provide arguments to support your view.
Yes. Overall, the Government minded position is the most effective at both stimulating production and achieving value for money for Government. However, the devil is in the detail and the DGA would like to reiterate the risks of:

- Natural gas prices increasing significantly
- Ineffective design of the gainshare mechanism
- Different markets emerging where the current proposal may lead to over reward

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

In principle we agree with that a sliding scale mechanism can be used to provide volume support, however it will depend on how the supporting curve will actually been defined during design phase. Hydrogen infrastructure and storage will be required to balance production (running at steady state for blue hydrogen projects for optimised carbon capture) and variations in demand from off takers, some of which may not be co-located with production. This also provides wider resilience by managing volume risk. Without this, projects will require additional support through the business model

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.

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?
Do we need something in here to account for differences in load factors and ramp up/down times for electrolysis vs reforming?

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.

13. What do you think is an appropriate length of contract? Please explain your rationale.
10–15-year contract possibly with the option to extend by 5 years if carbon prices haven't met a certain threshold would be broadly appropriate. This is broadly in line with offshore wind CfDs.

14. Should the length of contract vary for different technologies? Please explain your rationale.
While electrolysers generally have shorter lifetimes than CCUS enabled projects, the energy input may not have a shorter lifetime e.g., electrolytic production with dedicated wind power. Furthermore, stacks can swapped out at the

end of life, so electrolysers don't necessarily have short lifetimes. Therefore, we believe the contract length should be consistent between different hydrogen production technologies.

15. What are your views on the most appropriate option for scaling up volumes?
Not answered

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.
Yes, subject to caveats. The DGA generally agrees with the allocation of these non-price or volume risks. However, as previously stated, more needs to be done to stress test these business models against very high natural gas prices.

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.

Yes. The Government is correct to recognise the differing requirements for projects and across the hydrogen value chain. These different requirements lend themselves to specific support mechanisms. It is therefore important that different sources of support can be combined such as the business models for production and the Industrial Energy Transformation Fund (IETF) for industrial end users. Considering hydrogen production in isolation would create a severe risk of oversupply of hydrogen without adequate demand from off-takers resulting in poor value for money for Government and delays to decarbonisation through hydrogen.

Furthermore, the Government is correct to be concerned with over subsidy and the DGA agrees with the approach to not support the same costs twice.

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)?

The DGA agrees that different funding pots will be essential to drive down costs of electrolytic hydrogen, which is likely to be more expensive than CCUS-enabled hydrogen in the near term and therefore would not be deployed if the two production methods are compared solely on costs.

In the near term, auctioning may not be an appropriate allocation mechanism for the hydrogen business models, due to the nascent nature of the low carbon hydrogen sector. While still in price discovery phase and before costs are accurately known a bi-lateral negotiation is more appropriate. This also allows Government and industry to trial different terms and conditions and establish the most effective set up for future auction rounds.

In the medium term, auctioning should be used to allocate business models where the lowest strike price wins the contract. We have witnessed the success of this set-up at driving down costs in the offshore wind sector. In an auction situation, we believe the funding pots between electrolytic and CCUS enabled hydrogen should remain separate as they are different technologies with different merits.

There are lessons learnt from the low carbon electricity CfD rounds such as clarifying of some of the auction details in the medium term. For example, industry knowing the number of auctions, in which years auctions will occur and how much funding is available would significantly improve the ability for hydrogen companies in the UK to build out domestic supply chains.

It would be beneficial for the sector to gain clarity on the counterparty in these contractual negotiations, for example is it the Low Carbon Contracts Company? Additionally, understanding whether there is a need for new legislation for either of these allocation methods would help give confidence to the sector.

19. What are your views on the possible approaches to funding the proposed hydrogen business model?
The hydrogen business models are for the public good as they will help to decarbonise a wide range of sectors across the economy as well as reducing air pollutants. The DGA therefore believes these should be funded through general taxation and not increasing energy prices, particularly at a time where energy prices and fuel poverty are of such high concern.

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. Small scale distribution and storage costs are critical to production projects in the absence of large-scale storage and hydrogen networks; Without these elements, production firms cannot get their hydrogen to market. If these costs are not factored into the business model support, then firms are being required to spend on infrastructure that they will not be financially compensated for.

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, a different model will be required for larger scale shared hydrogen networks and storage.

Under any scenario consistent with UK decarbonisation targets there is likely to be a significant need for hydrogen storage for whole system flexibility and resilience. National Grid's Future Energy Scenarios state that 'despite a huge increase in electricity storage capacity in the net zero scenarios, the energy it stores is dwarfed by that of hydrogen storage, demonstrating the value of the latter to the whole energy system.' [1]

Plans for the development of hydrogen in the industrial clusters are dependent on the availability of a hydrogen network and significant hydrogen storage. The development of these assets will require a bespoke support mechanism, possibly with support for storage and networks decoupled. The lead times for their development means that this should be addressed with urgency.

Britain's Hydrogen Network Plan sets out the steps that the gas networks are taking to repurpose our world-leading gas network infrastructure. If all operational UK salt caverns for natural gas storage are converted to 100% hydrogen, it would provide 2.8 TWh of storage (based on a third of the current energy storage capacity, given hydrogen's lower volumetric energy density). Repurposing the Rough storage facility could provide 2- 10 TWh of storage and the cost of doing so could be offset against avoided decommissioning expenditure.

While there are considerable potential consumer benefits associated with hydrogen storage, many of these benefits are externalities – meaning the commercial revenues that would be earned would not fully reflect these benefits. Further, a key consideration for investment is the uncertainty regarding the pathway and timing of large-scale hydrogen use in the UK. As a result, there is likely to be under investment without some form of regulatory model.

To utilise geological formations as hydrogen storage facilities will incur significant investment costs. These include investments into the assets and purchasing cushion gas. There are several possible regulatory models that could be implemented to bring forward investment but based on our initial estimate of market revenues, our economic analysis concludes that the most appropriate form of such a regulatory backstop would be a Regulated Asset Base (RAB) model.

There are several benefits of implementing fully regulated model for large scale storage & networks. Due to the fixed nature of the revenue allowance, the model would not be dependent on the market for hydrogen and could therefore be easily implemented and adapted. Further, by providing certainty to investors, these assets could potentially be financed at lower financing rates. A RAB model is also well understood by industry. However, as we have seen in the gas sector this does not always lead to optimal outcomes and we are now in a situation with insufficient storage facilities.

It should be noted that the support of OFGEM will be crucial on any matters relating to network and storage investment.

[1] National Grid 2021 Future Energy Scenarios hydrogen storage data

About the DGA

The Decarbonised Gas Alliance (DGA) represents nearly 30 expert organisations who have come together to promote decarbonised gas as a stable pathway to help meet the UK's target of net zero climate emissions.

Our aim is to articulate a shared view on how decarbonised gas of all types can help the UK reach net zero effectively by both retaining funding for existing projects whilst shaping the future of the decarbonised gas industry.

The DGA offers a unique perspective to decarbonised gas markets including green, blue and other 'colours' of hydrogen, gaseous fuels from biomass and plastics as well as biogases and synthetic gas.

The development of attractive market structures and business models will be critically important in stimulating and underpinning decarbonised gas demand and supply side investment opportunity. The DGA is ready to help shape that process.

Since inception in 2017, the Secretariat and Alliance members have:

- Completed 18 responses to date on strategic government consultations
- Commissioned detailed public opinion research 'Getting net zero done' to understand consumer attitudes in detail to understand how domestic heating, transport and industry could be decarbonised (using gas), and worked with an external agency to produce a detailed report for government on how the sector could be supported https://www.dgalliance.org/wp-content/uploads/2020/05/DGA-Getting-Net-Zero-Done-final-May-2020.pdf
- Provided advice to BEIS through their Hydrogen Advisory Council Working Groups, and Business Model Expert Groups on Hydrogen and CCUS as well as cooperating with the Hydrogen Task Force
- Ensured representative responses to key BEIS, Treasury, All Party Parliamentary Groups, Climate Change Committee and Select Committee consultations
- Played a leading role in the design of the Industrial Decarbonisation Challenge, which secured £170 million of funding from the Industrial Strategy Challenge Fund.

The DGAs Primary Goal

Today, we remain focused on being a unified voice to support the deployment of low carbon gas solutions that make best use of our existing infrastructure and enable quicker and cheaper decarbonisation. We are committed to working with government and expert organisations of all levels to create a deliverable pathway net zero emissions.