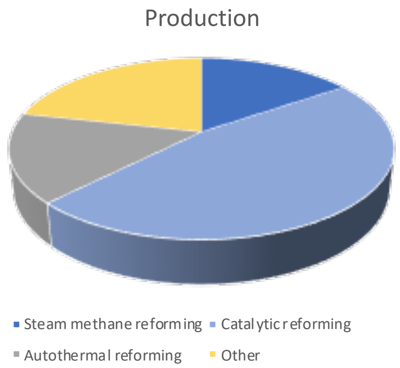
UKPIA Response to the Consultation on a Business Model for Low Carbon Hydrogen

Introduction

As outlined in the BEIS Hydrogen Strategy, low carbon hydrogen (LCH) has an essential role to play in delivering a Net Zero UK[1]. Whilst hydrogen is already used in many industrial processes as either a feedstock or energy vector, it is normally produced at the same site with currently a negligible market in place.

The UK downstream sector is currently the largest hydrogen-producing sector in the UK, responsible for almost half of UK production. The production processes are currently a mix of steam methane reforming (SMR), autothermal reforming (ATR), and as a by-product from catalytic reforming (CR) – the latter of which accounts for approximately half of all hydrogen production in the sector (see Figure 1).[2]



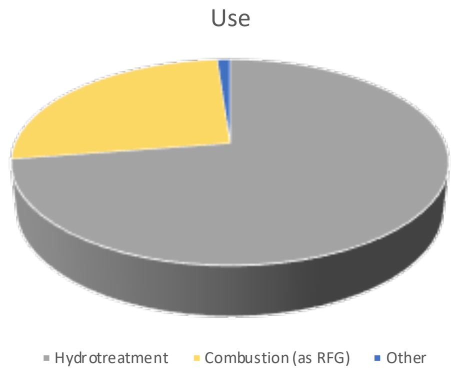


Figure 1: Proportions of hydrogen production methods and consumption processes in the UK refining sector

The vast majority of hydrogen used by a refinery is for the hydrotreatment of intermediate streams – the primary means by which sulphur is removed from the products. Hydrogen is also present in refinery fuel gas (RFG) in varying quantities, lowering the carbon content of the RFG used for firing/heating processes.

As such an integral part of the refining process, the downstream sector has decades of experience in producing and handling hydrogen and is already beginning to utilise this expertise for the deployment of LCH. Our sector is also experienced in providing hydrogen as a fuel to the consumer, with members such as Shell taking a leading role in the early deployment of hydrogen refuelling stations (HRS) in the UK.[3]

Accordingly, the downstream sector is ideally placed to support the proliferation of LCH in the UK and looks forward to close partnership with the UK government in helping to deliver a LCH economy in the UK. UKPIA welcomes the UK Hydrogen Strategy and the opportunity to engage via the accompanying consultations. It is essential that the right policy foundations are laid in the early 2020s to support the rapid scale-up of the nascent LCH market.

[1] UK Hydrogen Strategy, BEIS, August 2021
[2] UKPIA and BEIS data
[3] http://www.ukh2mobility.co.uk/stations/ and https://www.shell.co.uk/a-cleaner-energy-future/hydrogen.html

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

Any LCH business model should support the range of production, distribution, and off-take paradigms that will emerge as the LCH market develops. These may be more simply summarised as:

1. *One-to-one*: where one site/entity produces hydrogen for either another site/entity or consumes the produced hydrogen at the same site. For example, a refinery producing hydrogen for use in a hydrotreater or for combustion. There is unlikely to be a distribution party/entity in this case and only an internal market for the hydrogen. However, such cases should be covered by the proposed business model, as these provide an important means of decarbonising existing hydrogen production.
2. *One-to-many*: where one site/entity produces hydrogen for multiple off-takers (which may include itself as one). Distribution may be managed between the parties or possibly via an intermediate distribution entity. There is a limited market with off-takers reliant on one hydrogen source.
3. *Many-to-many*: where multiple sites/entities produce hydrogen for multiple off-takers. Distribution may be managed between the parties or possibly via an intermediate distribution entity for some or all of the distribution network. This would form a competitive market.

It must be noted that the energy input required for cooling and compressing hydrogen will always present a technoeconomic 'hurdle' when considering the distribution of hydrogen. Until a national distribution network is established (such as a pipeline system), this hurdle will result in geographic pockets of hydrogen production and use and therefore a series of isolated LCH markets.

The hydrogen off-takers/end-users may also be categorised according to their product/process demands:

i. Fuel use/energy source
ii. Ammonia and other chemicals production where hydrogen is an essential feedstock (usually produced via on-site SMR) or accounts for the major proportion of feedstock costs)
iii. Complex chemical processing (such as a refinery or petrochemical plant) where hydrogen is one of a suite of feedstocks and also a fuel/energy source

With these considerations briefly summarised, the suitability of the proposed business model may now be explored.

UKPIA agrees with the overall approach outlined by BEIS to the LCH business model. A producer-focused business model offers the most appropriate means of supporting producers with the greater cost of producing LCH. For clarity, this should not preclude demand-side measures also being implemented in due course to encourage LCH adoption and ensure sufficient demand for supported supply.

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

Yes, in principle, with the design likely to work effectively for market paradigms 2 and 3 and off-takers i and iii outlined under question 1.

The proposed business model appears to be designed assuming a fungible product market such as electricity. Whilst hydrogen may eventually become such a market, depending on the establishment of a national distribution system as outlined above, this is currently not the case and will not be for decades – there will be a transition period where regional markets emerge.

The business model design is suitable for these multiple party regional markets and also provides support under the ‘one-to-one’ paradigm, however for this latter case there may be challenges regarding pricing requiring further policy development (see question 3). The downstream sector would welcome continued engagement with BEIS on the business model to seek clarity for these cases.

As there is a high degree of uncertainty on how the UK LCH market will develop over the next decade, and therefore what the supply and demand conditions may be towards the latter stages of the CfD contracts, UKPIA would encourage BEIS to maintain optionality for further project support towards the end of the contracts.

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

Yes, a variable premium for price support will provide flexibility for different end-use cases and is also likely to provide the most cost-effective means for the government to support the development of the new LCH market.

It should be noted that a contracts for difference (CfD) approach may present pricing challenges for isolated producers and off-takers as price discovery may not be possible. For example, at refinery or petrochemical plant, where hydrogen represents one of many input costs and is utilised as a feedstock and source of energy.

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

Yes, as recognised in the consultation document, a LCH reference price is not feasible as the market does not (yet) exist. A reference price based on the natural gas price for a variable premium price support mechanism will provide incentive for potential producers to switch to LCH by removing the cost increase relative to solely natural gas-derived production.

This approach to the reference price will incentivise producers to maximise their LCH sale price with off-takers by entering into a gain share model. This will naturally drive increases to the LCH sales prices for off-takers along the duration of the CfD contract thereby minimising the level of subsidy provided to the producer by the government while ensuring commercial viability for the producer. The reference price proposed will also incentivise off-takers not subject to UK Emissions Trading Scheme (ETS) CO_2 allowances and incentivise them to switch through other existing support mechanisms.

For off-takers obligated under UK ETS, this approach will provide a ‘premium’ by enabling a saving on a portion of their CO_2 costs while also incentivising them to invest in ‘hydrogen-ready’ technology to further save CO_2 costs under UK ETS.

As aforementioned, single producer and off-taker contracts will not be driven by the same dynamic and price discovery may not be possible when producer and off-taker are the same entity. This risks an outcome where the mechanism is limited to only multi-party markets (as per 2 and 3 in question 1), however further clarity/flexibility will be needed under this production-use paradigm.

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 business model is rightly seeking to support all forms of LCH that qualify under the low carbon hydrogen standard (LCHS) currently being consulted on in parallel. However, it should be noted that different production methods - predominantly electrolysis utilising low carbon electricity (green) and carbon capture of CO_2 from thermochemical production (blue) - have differing capital expenditure (capex) and operational expenditure (opex) dependencies (e.g. methane price vs electricity price). Capex and opex as a proportion of total life costs also differs greatly for LCH production compared to the fungible electricity market that the proposed CfD approach is broadly mirroring.

Capex represents approximately 5-10% of the total "business model contract life" costs for both green and blue hydrogen production plants. This is markedly different from renewable electricity generation such as solar or wind, where capex represents approximately 90% of the total lifetime costs and where the government has most experience with CfD business models. There is an inherent long-term cost uncertainty consideration remaining for hydrogen producers that is not present for electricity producers. Whilst efforts can be made to fix significant opex costs as far as possible during the contract period, a greater number of input dependencies (i.e. potential risks) exist than for electricity producers.

This does not necessarily present a risk specific to the policy as proposed, but does highlight two key considerations for BEIS as part of its broader LCH policy framework:

- There is likely to be a difference in policy efficacy relative to the electricity market, demonstrating the need for demand-side measures/policies to support LCH adoption.
- There is a reduced degree of 'opex predictability' post-contract relative to electricity production, demonstrating the potential need for continued CfD support post-contract should the market not justify the opex costs (and therefore ceasing operation of the LCH asset).

The proposed business model appears to offer scope for future legislative changes mid-contract. As outlined in the consultation document, providing investment certainty is a key objective of the policy, therefore any future changes should not be considered without consultation with industry years ahead of any potential changes. UKPIA note that changes in law have been considered in design of the Industrial Carbon Capture Utilisation and Storage (ICCUS) business model and are specifically addressed in the Industrial carbon Capture Contract Heads of Terms[4]. UKPIA believe a similar approach would also be applicable under the Hydrogen Business Model.

As bilateral negotiation with BEIS for projects is likely to be the only viable means of appropriately indexing strike price, there will also need to be clarity of how the differential credit would apply in joint ventures. For example, would this be negotiated contractually within the investing parties, or would BEIS have some expectation of the credit distribution.

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

Indexation should be based on the true energy cost for the applying producer as it would cater for specific risk exposure relevant to the full suite of technologies being proposed to produce the LCH – which will vary by project. Costs to the producer are unique to the

[4] BEIS Carbon capture, usage and storage (CCUS): business models.

technologies they utilise. Therefore, contracts should be agreed bilaterally with BEIS on a project-by-project basis. UKPIA does not believe this creates an additional administrative burden for BEIS as any project will need to be assessed on any energy input basis for eligibility under the CfD (and potentially the Net Zero Hydrogen Fund (NZHF)).

It may be challenging to link the strike price to natural gas for a CfD mechanism when there are significant variations in monthly price. This will be even more challenging for on-grid green hydrogen production as electrolyser input energy will be tied to electricity prices rather than natural gas prices.

Indexation to input energy costs would not inadvertently incentivise producers to be less careful with energy use in their LCH production process as this would still result in increased cost/reduce profit for the producer. Indexing to input energy would mean that the portion of the price of LCH allocated to input energy (e.g. electricity by X%) is fixed from the outset of the CfD contract and indexed year on year accordingly. Such an approach would cover the risk of an increase in cost of the energy input but not the quantity of the energy input. Therefore suitable drivers for increasing energy efficiency remain.

In the case of electricity and natural gas, there is minimal scope for price distortion even energy is supplied by the same provider, as these can be indexed based on live/existing market prices. This is not possible in the case of hydrogen as there is no established market, therefore an internal transfer price can arbitrarily set by any individual company thus necessitating a true input energy cost approach.

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 scope for price support for LCH as a feedstock must be considered within the context of a plant's feedstock slate (summarised in i - iii in question 1). Price support should be provided for industries/sectors where the counter-factual input fuel is natural gas – i and iii.

For industries where hydrogen is the sole feedstock, and therefore are already operating profitable businesses based on a hydrogen-dominated high feedstock cost, price support will effectively act as a government subsidy for these businesses increasing their profits whilst not stimulating a LCH market. Furthermore, such support would not necessarily significantly reduce the GHG emissions of these businesses – thereby not fulfilling the policy objectives.

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

Yes, as per questions 6 and 7 above, with a policy enhancement to drive further GHG emissions reductions. UKPIA suggests that the price support mechanism provide additional credit for producers of LCH that exceeds the sustainability criteria prescribed by the LCHS. For example, the award of a premium above the strike price for additional tonnes CO_2e saved beyond the LCHS. This would incentivise LCH producers to implement GHG savings beyond the LCHS threshold, rather than simply meet the GHG saving threshold.

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

UKPIA agrees if the sliding scale applies to sale volumes above the minimum turndown capacity of the producing plant. For example, if this is 50% (depending on technology), then the sliding scale should apply to volumes above that, but the UK government should cover the fixed cost plus a portion of the total variable cost below the minimum turndown point. This will ensure plants are in a continued state to meet demand – especially in the early stages of market development when regional market demand may be volatile.

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.

Yes, as per question 9, the sliding scale provides no support below the turndown point as the plant becomes unviable and therefore unable to produce any LCH on spec for off-takers. The UK government should cover the fixed cost plus a portion of the total variable cost below the minimum turndown point. Such a situation should be reported daily to ensure costs for the producer are covered when incurred whilst ensuring the producer is under scrutiny to maximise sales/supply of LCH.

For clarity, producers must be able to demonstrate to BEIS that any lack of sales below the minimum turndown point is due to lack of demand and not due to internal inefficiencies or avoidable plant downtime - the obligation of operational risk should still remain with the producer.

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?

UKPIA agrees in principle that the business model may be suitably adapted for a range of technologies and associated expenditure options. However, given the infancy of the market and these type of projects, there remains a myriad of uncertainties that may not yet have been considered by industry or government in development of the business model.

BEIS may wish to consider means of offering flexibility and/or risk mitigation for producers. This would include indexation agreed/calculated on a project-by-project basis as outlined in question 6, and could also include market-based mechanisms such as hedging.

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.

Yes, the proposed business model, whilst requiring some clarity in some production-supply paradigms, should be appropriate for the range of production scales. Indexation and establishment of a strike price as outlined above should cater for specific projects according to their technology and scale.

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

Contract duration should be at least 15 years to provide enough time for the nascent LCH market to develop and have a chance to self-sustain without continued UK government fiscal support. As highlighted in question 5, there may be need for continued CfD support post-contract should the market not justify the opex costs and therefore require ceasing operation of the LCH asset.

It will take at least 10 years for pipeline distribution systems to develop across regional clusters (longer to establish national linkages) with such a distribution system essential for the market to mature.

UKPIA considers the proposed capital repayment period of 5 years to be adequate.

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

No, the length of contract should be dictated by the time it will take to develop the nascent LCH market to the point that it becomes subsidy-free and can live on its own merit. This will occur only when there are enough producers and users interconnected. That is independent of the technologies employed to produce the LCH. Differences in technology lifetime of the asset is irrelevant as factored in the Business Model and reflected in the negotiated strike price under CfD.

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

Scaling-up is possible in one of two ways: i) addition of another plant or ii) increasing output from an existing plant. For i), new assets in the ground means a new project however it is important that this is proportionate – a new bilateral negotiation for each extra 'clip' of capacity must be avoided. For ii), additional LCH produced should be supported. The differing production routes for blue and green hydrogen may result in a mismatch in support for the technologies as the latter has a more linear capex-production relationship than blue hydrogen once all infrastructure is in place (as it broadly scales with electrolyser capacity). A 'contingent commitment' approach for green hydrogen projects may support scale-up in these cases.

For example, should an existing asset be optimised to produce additional LCH via improved CO_2 capture, these additional volumes should be supported under the business model. This will meet the policy objectives of accelerating the growth of a LCH market further in a most cost-effective manner to the UK government. UKPIA would suggest that the sliding scale proposal for the strike price would ensure that producers are incentivised to produce and sell the additional LCH without risk of UK government 'over-crediting' the additional production.

However, if material additional volumes of LCH are produced due to additional assets being built such as new cells added to existing electrolyser(s) or a larger autothermal reforming reactor added to debottleneck an existing blue hydrogen plant, etc then this should be considered a new project requiring application for CfD support like any new plant.

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.

UKPIA agree with the 'minded to' position on allocation of key risks identified in Section 7.3 of the consultation document. Broadly speaking, the risks are similar to those identified by the BEIS ICCUS Expert Group in development of the ICCUS CfD model and for which more detail is available on proposed allocation and mitigation. A number of risks have not been specifically addressed including (but not limited to):

Operational Risks

- Energy and electricity volume.

- Energy and electricity price.
- Cost (which is as identified under the ICCUS Business Model for SMR+ICCUS).
- Performance, where the production efficiency may deteriorate after operation over a number of years.
- Leakage and safety risks, both for hydrogen itself and CO_2.
- Carbon policy and pricing, where changes to the UK ETS or free allowance allocation methodology may impact the commercial return. The UK ETS continues to use the EU ETS free allocation methodology for the refining sector; no alternative methodologies are currently available.

Cross-Chain Risks

- User stranded asset. If the T&S network fails to be constructed or is abandoned post commissioning, then H_2 production using SMR+ICCUS becomes stranded and inoperable. A similar situation may arise for H_2 production integrated with major offtake, for example in a refinery, where changes in configuration or closure may put the H_2 production facility at risk.
- T&S unplanned outage, timing mismatch and capacity constraints.

Mitigation measures for many of these operational and cross-chain risks have been addressed in the BEIS 'minded to' position on the ICCUS Business Model.

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, there is precedent for multiple forms of policy support such as producer/supply-side support combined with user/demand-side incentives. For example, in the UK, the production of green hydrogen from the electricity grid – which receives policy support via the renewable electricity CfD scheme[5] – is eligible for renewable transport fuel certificate (RTFC) reward under the renewable transport fuel obligation (RTFO) as a renewable fuel of non-biological origin (RFNBO) if deployed for some transport modes. A similar principle should be adopted for LCH, where demand-side incentives complement the new LCH business model support by BEIS to stimulate growth of the UK LCH market.

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)?

As outlined in question 6, bilateral negotiations with the UK government are the most appropriate mechanism for the allocation of contracts in the development of first-of-a-kind (FOAK) and Nth-of-a-kind (NOAK) hydrogen projects. LCH is a nascent market where there are few prospective producers based on few (effectively two) LCH production technologies. Competitive auction will be more appropriate when there is an established hydrogen market

UKPIA agrees that when there is an established LCH market – which is unlikely for 10-20 years – a competitive allocation/auction process will be most appropriate.

[5] https://www.gov.uk/government/publications/contracts-for-difference/contract-for-difference

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

UKPIA has no response for this question.

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, it will be essential that early LCH producers are able to distribute hydrogen to early off-takers to commence growth of a LCH network. This will require at least a limited level of distribution and storage infrastructure to be integrated and will be factored-in to the capex and opex costs of a LCH production asset when taking the final investment decision (FID).

The distribution and storage infrastructure could take the form of dedicated pipelines to early off-takers and/or tanker/tube-trailer loading. Given the level of uncertainty associated with FOAK LCH production, and potential uncertainty in end-user demand depending on demand-side policy interventions, dedicated pipeline/distribution operators are unlikely to invest in new supporting infrastructure. Therefore, such infrastructure must be considered part of LCH production projects (at least until a market is established) and factored-in to the bidding process.

For clarity, the inclusion of distribution and storage infrastructure costs in a LCH project should be assessed in the context of locally available infrastructure and adjacent/aggregated projects (such as at a cluster), rather than solely 'scale' as stated in the consultation document. It may be appropriate that a GW-scale LCH producer still includes distribution and storage infrastructure in their bid if they are geographically isolated and providing to one or two GW-scale off-takers (i.e. no distribution market forms).

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 bespoke funding model will be needed to fund large scale LCH networks and storage facilities for the reasons provided. Similar models to those used to incentivise expansion of networks across regulated markets in the UK such as water/sewage, natural gas or electrical distribution systems could be introduced.

22. Glossary

ATR	Autothermal Reforming
CfD	Contract for Difference
CR	Catalytic Reforming
ETS	Emissions Trading Scheme
FID	Final Investment Decision
FOAK	First-of-a-Kind
HRS	Hydrogen Refuelling Station
ICCUS	Industrial Carbon Capture, Utilisation and Storage
LCH	Low Carbon Hydrogen
LCHS	Low Carbon Hydrogen Standard
NOAK	Nth-of-a-Kind
NZHF	Net Zero Hydrogen Fund
RFG	Refinery Fuel Gas
RFNBO	Renewable Fuel of Non-Biological Origin
RTFC	Renewable Transport Fuel Certificate
RTFO	Renewable Transport Fuel Obligation
SMR	Steam Methane Reforming