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Business, Energy
& Industrial Strategy

Hydrogen Business Model: Expert Group meeting

Hydrogen Business Model Team
3rd March 2022

Note: The content in the following slides does not represent BEIS policy, but provides ideas for discussion

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Meeting etiquette

Please can you:

- ✓ Turn off your video when not speaking
- ✓ Mute your microphone when not speaking
- ✓ Raise questions via the chat function or put your hand up

This meeting will be recorded for BEIS internal use only.

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Agenda

	Item	Approx time	Lead
1	**Welcome**	12:30 – 12:35	Will Lochhead
2	**Update on progress**	12:35 – 12:45	Carolyn Campbell
3	**Payment mechanism:** metrics and measurement periods	12:45 – 13:25	Shabana Jamil
4	**Qualifying volumes:** Feedstock users, own consumption, intermediaries, blending	13:25 – 14: 25	Neil Atterbury, Nat Shaughnessy
5	**AOB and close**	14:25 – 14:30	Will Lochhead

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Hydrogen Business Model: Update on progress

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Hydrogen business model consultation - reminder of the key components

The objective of the hydrogen business model is to incentivise the production and use of low carbon hydrogen, and help us achieve our 5GW ambition by 2030. It is designed to provide hydrogen producers with revenue support to overcome the operating cost gap between low carbon hydrogen and fossil fuels in order to unlock private investment in hydrogen projects.

Approach to model design

Primary focus on mitigating two key risks:

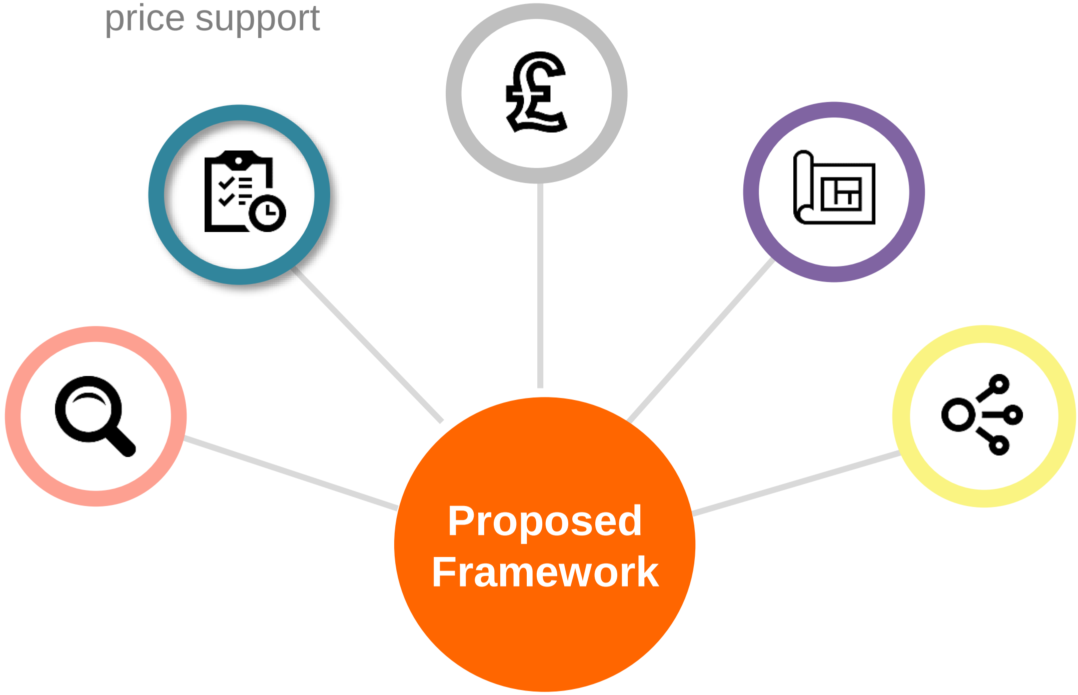
- Market price risk
- Volume risk

Scope and delivery mechanism

- New production that meets the 'low carbon hydrogen standard'
- Producers as recipients of subsidy
- Open to different production technologies and project sizes
- Open to range of end users
- Private law contract

'Minded to' positions for payment mechanism:

- Price support via variable premium, with sales price as reference price and natural gas price floor
- Volume support provided indirectly via sliding scale of price support



Seeking views on options for further design features with potential variations for different production technologies, including:

- Indexation of strike price
- Duration of support
- Scaling of future production volumes

Allocation to vary for:

- Projects eligible to CCUS-cluster sequencing process
- Projects not eligible to cluster sequencing (e.g. electrolytic projects)

HBM payment mechanism - reminder of the key components

CORE COMPONENTS

STRIKE PRICE: reflects the price the producer needs to achieve to cover their costs of production and return on investment; strike price level and cost components could vary for different production technologies

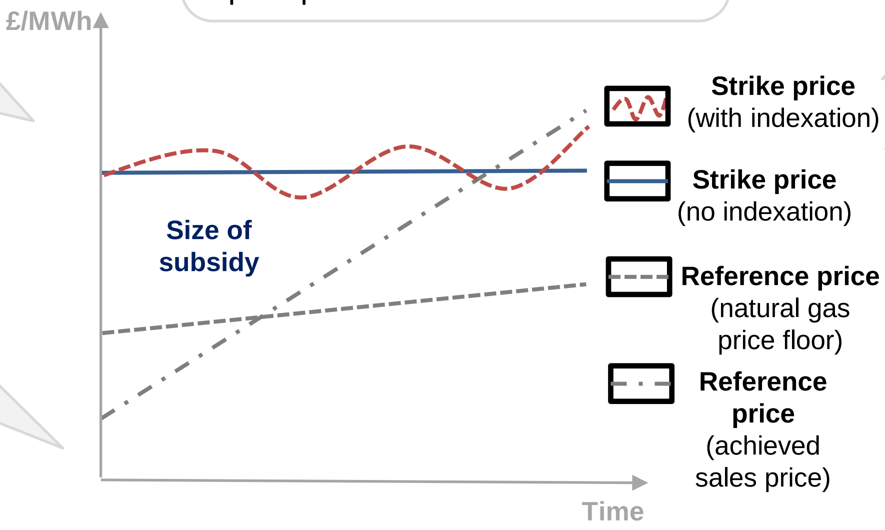
REFERENCE PRICE: intended to represent the market price received by the producer; for initial projects, proposed reference price is achieved sales price with a floor at natural gas price

PRICE DISCOVERY: potential contractual measure to incentivise producer to increase achieved sales price

MARKET BENCHMARK: propose to integrate into the reference price at the earliest opportunity for future projects

CONTRACT DURATION

SCALING FUTURE VOLUMES: open questions in consultation



ALLOCATION OF OTHER RISKS:

- Construction, technology and decommissioning risk – with developer
- Change in law, policy or regulatory framework risk – producer protected from unforeseeable and material changes
- Input fuel supply disruption risk – with developer
- H2 and CO2 T&S – developing position

ADJUSTMENTS

INDEXATION: potential adjustment to strike price to reflect changes in production costs; approach could vary for different production technologies

SLIDING SCALE OF STRIKE PRICE: variation of strike price in response to lower offtake volumes in order to help manage volume risk

QUALIFYING VOLUMES: any variations to subsidy calculation for particular volumes of hydrogen, including: propose no payments for volumes exported; open question in consultation on options to constrain support for volumes used as feedstock; consideration of situations where volumes are for producer's own use or sold to an intermediary

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Expert Group meeting forward look for March and April

	Date	Topics
1	3 March	▪ Payment mechanism – metrics and measurement periods ▪ Qualifying volumes – Feedstock users, own consumption, intermediaries, blending
2	15 March	▪ Strike price indexation ▪ Defining reference price (achieved sales price, natural gas price floor, implications for two-way payment) ▪ Future production volumes (scaling question in consultation) ▪ Overview of indicative Heads of Terms
3	TBD April	▪ Overview of government response to consultation ▪ Presentation of Heads of Terms by Ashurst

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Milestones for the hydrogen business model in 2022

- We aim to **publish the government response** to our consultation on the design of a business model for low carbon hydrogen
- We aim to **finalise the design** of the hydrogen business model
- We plan to develop **legislation** for an enduring HBM regime and progress the proposed hydrogen production levy to pay for deployment
- We propose to **launch an allocation round** for electrolytic (green) hydrogen developers to apply for a HBM and award up to 250MW contracts (up to £100 million) with further allocation in 2024 to get up to 500MW online or in construction by 2025
- We aim to **shortlist the CCUS-enabled (blue) hydrogen projects to enter into bilateral negotiations with** (received through Phase 2 of cluster process) and announce a funding envelope for CCUS-enabled hydrogen, to deliver up to 1GW of CCUS-enabled hydrogen capacity by the mid-2020s

Hydrogen Business Model: Payment mechanism

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Breakdown of payment mechanism
Q: Are there any missing components?

Focus of today*

Measurement periods
- Settlement period
- Billing period
- Billing Statement
- Payment Period

Defining parameters
- Low Carbon Hydrogen Standard
- Defining trigger for payment
- Units for payment

Core components
- Strike price
- Reference price (Achieved sales price)
- Reference price floor (Natural gas price)
- Price discovery mechanism

Adjustments
- Indexation of strike price
- Sliding scale of strike price
- Qualifying volumes

Role of counterparty
- Role in subsidy calculation
- Low Carbon Hydrogen Standard compliance
- Quality assurance

Formula for payment mechanism

* The Low Carbon Hydrogen Standard component was discussed at the 15th February Expert Group and will not be on the agenda for today.

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Units for payment

What units will be used within the payment calculation?

Preferred option: £/MWh HHV (pounds per megawatt hour in higher heating value)

- Different components of payment calculation (strike price, achieved sales price of hydrogen, and natural gas price) need to be converted into consistent units to ensure accurate calculation. MWh chosen to compare different components like for like.

- HHV (which, unlike LHV, takes into account the energy content of water vapour produced during combustion) was chosen to align with the way natural gas is reported in the UK – familiar to industry.

- **Note:** Units different to that proposed in the Low Carbon Hydrogen Standard consultation (gCO2e/MJ LHV). Conversions are straight forward, and units for each reflect what is typical for energy contracts (in the case of the HBM) or for similar schemes (e.g. gCO2e/MJ LHV commonly associated with low carbon schemes).

- Possibility of publishing a unit conversion table for user convenience.

Trigger for payment – payment conditional on sale of hydrogen to offtaker
Q: Does this approach cause any concerns?

What is the trigger for payment of the subsidy to the producer?

The key design principles most relevant for assessment of options are:

- 'promotes market development' and 'value for money'

Options	Considerations
1. Production of hydrogen **only**	▪ No guarantee producers develop sources of demand for use of h2 ▪ Risk HMG does not achieve objective of end users replacing high carbon counterfactual fuels by switching to hydrogen
2. Production and storage of hydrogen	▪ If h2 produced goes into storage, there is no guarantee of it being sold in future to offtakers ▪ Whilst in storage, the h2 is not being used for decarbonisation purposes so no benefit for HMG
3. Production and sale of hydrogen (Preferred option)	▪ If producers are paid when offtakers physically take the h2 this should incentivise producers to develop sources of demand and sell their h2 ▪ HMG achieves objective of developing a hydrogen market through both the production and use of hydrogen

Preferred option:

- Payment conditional on sale of the h2 to an offtaker, i.e. volumes have to be accepted by offtakers
- No payment for only producing the h2 or moving it into storage

Measurement periods to set out in the payment mechanism

Why are measurement periods important?

- Need to know what we are paying for, when the actual payment will be made and provide transparency to producers
- Measurement periods need to enable the payment mechanism to work for all projects in the pipeline and in future. We expect a variety of projects to come forward for support:
  - Ranging from CCUS-enabled projects running baseload to electrolytic producing on an intermittent basis
  - Capacity of projects could range from as small as 5-10MW
  - Developers could be small or new

Key design principles

- Promote market competition
- Investable
- Technology agnostic
- Size agnostic
- Avoids unnecessary complexity

Measurement periods to set out in the payment mechanism:

- **Settlement period** – minimum period over which hydrogen production is measured
- **Billing period** – frequency with which producer receives payments & comprises all settlement periods in billing period
- **Billing statement** – issued by counterparty to producer after h2 is produced outlining information used to calculate subsidy
- **Payment period** – delay from when hydrogen is produced and producers receive subsidy

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Precedents for measurement periods have been set by existing policies and policies in development – namely CfD and ICCBM

	Renewable elec CfD	ICC business model (under development)
Settlement period	- **30 mins** over which electricity generation is measured - Carbon intensity varies across the day, so narrow window enables precise prices for when electricity is generated[1]	- **24 hours** over which amount of carbon captured by emitter is recorded - Settlement window enables daily adjustments to be made in case of e.g. CO_2 T&S outages
Billing period	- **Daily** payment to generators - Each half hour settlement period is added over 24 hrs - Where the RP is above the SP, daily billing period also requires generators to make payments daily to LCCC	- **Monthly** payment to emitters - Includes every settlement period in a calendar month - Standard commercial billing arrangement
Billing statement	- Statements issued **7 business days** after the generation of electricity, on a daily basis, based on metered volume data - Outlines info used to calculate the daily payments to generators, inc. any payments generators owe to LCCC	- Capex, opex and T&S billing statements issued no later than **7 business days** after the end of the relevant billing period - Outlines info used to calculate capex, opex and T&S payments, capture rates, outage events, other details
Payment delay	- **28 day delay** from when electricity is generated and generators receive subsidy. i.e. 28 business days in arrears after the electricity is generated	- Payment to the emitter is made no later than **28 business days** after the end of the relevant billing period

1. Duck Curve depicts power production over the course of a day and shows the timing imbalance between peak demand and renewable energy production. For example, daily peak demand occurs when solar power is no longer available, therefore the power for peak demand must be generated using sources other than solar

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Minded to positions for HBM measurement periods, with key considerations
Q: Does this approach cause any concerns?

Settlement period

Preferred option: Half hourly across technologies

- Granularity for assessing carbon intensity of hydrogen produced is consistent with CfD and would accommodate Low Carbon Hydrogen Standard
- Consistency across technologies
- Future proofing in case of more granular gas prices or changes in the Low Carbon Hydrogen Standard
- Data collection for analysis of scheme performance

Billing period

Preferred option: Monthly

- Sufficient cashflow period to help producers manage working capital positions, with manageable borrowing costs
- Reduced admin burden compared with CfD billing period
- Aligns with commercial standards for financing of projects and ICC BM

Billing Statement

Preferred option: Issued 7 business days after relevant billing period

- Gives certainty as fast as possible to producer of info used to calculate subsidy and size of payment
- Aligns with CfD and ICC process

Payment period

Preferred option: 28 days, in arrears

- Payment received by producer as fast as possible after billing period ends
- Aligns with commercial standards, including CfD and ICC payments

Hydrogen Business Model: Qualifying volumes

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Context on project eligibility and qualifying volumes

1. Eligibility – pass / fail; which projects are eligible to apply for funding and can bid into different HBM allocation rounds?

2. Qualifying volumes – should all volumes produced by a project qualify for support? Are adjustments to the HBM payment mechanism needed for specific volumes?

Key considerations in eligibility and qualifying volumes

- Ensuring alignment with HMG strategic objectives
- Providing clarity on requirements to receive support
- Ensuring value for money
- Mitigating unintended consequences and avoiding overcompensation
- Avoiding creating any unnecessary complexity

Eligibility and qualifying volumes may be reviewed ahead of different allocation rounds and as the hydrogen market develops.

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Challenges linked to specific offtake and end users

Focus of today

Offtaker/User	Benefits	Key considerations and potential risks for the HBM
Feedstock	High-value market; potential demand flexibility; technology readiness	Value for money (VfM) and potential distortions in end use markets
Own consumption	Potentially lower volume risk; common in today's hydrogen market	VfM; reduced effectiveness of HBM incentives (e.g. price discovery mechanism) and potential market distortions
End use intermediaries	Improve liquidity and diversity of offtake; de-risk production; improve deliverability	Risks to payment calculation (e.g. what is included in achieved sales price) and of information asymmetry; reduced ability to enforce other limits to price support
Blending into gas grid	Demand flexibility; could help manage volume risk; could open up access to large scale, infrastructure supported market	Limited ability to test suitability of HBM incentives due to lack of existing regulatory / market framework; unclear who will be offtaking blends; relative lower value market and relative lower decarbonisation value
Exports	Not eligible for HBM funding – outstanding questions: enforcement mechanisms; treatment of exported products manufactured with hydrogen	
Storage	Treatment of volumes stored on-site and off-site	
Transport	Interactions with RTFO support in transport sector	

Key questions

- What are the risks and opportunities arising from subsidised hydrogen being sold to the above offtakers? How can risks be mitigated and opportunities realised?
- Are potential adjustments to the HBM payment mechanism needed to address the challenges identified?

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Feedstock users, own consumption and intermediaries

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Hydrogen sold to feedstock users (i.e. hydrogen is not used for its energy value)

Context

We are considering the risk of overcompensation where carbon intensive hydrogen is used as a feedstock (e.g. chemical sector, ammonia production). These users may not require the same level of subsidy as others because we expect they:

- have a higher willingness to pay (based on price of carbon intensive hydrogen)
- are likely to have lower switching costs than others

As such, if feedstock users were to access LCH*at the natural gas price floor, it could lead to **over subsidisation and potential distortions in their end use markets (i.e. an ability to undercut competitors).** The risks posed by over- subsidy appear greater for feedstock users than other end uses (see table on right).

Initial view

Subject to compliance with subsidy control and public law principles, our preferred option is to allow producers to claim subsidy for sales of hydrogen to feedstock users. However, we recognise the potential for sales of LCH at the natural gas price to lead to overcompensation and market distortions. We are therefore considering whether additional measures are needed to address this risk.

End user	Relative cost of counterfactual[1]	Switching costs (financial and operational)[2]	Risk of market distortions?[3]
Feedstock	High (grey H_2)	Low	Possibly
Transport	High (diesel)	High	Less likely
Industrial heat	Low (natural gas)	High	Less likely
Power	Low (natural gas)	High	Less likely

[1]End users with a cheaper counterfactual fuel need a greater incentive to switch, and therefore likely require a higher level of subsidy
[2]End users with a lower cost of switching to LCH (e.g. cost of buying new equipment) should be able to pay more for it
[3]Possible risk of creating distortions in end use markets by overcompensating an end user and enabling them to undercut competitors. This may be more likely in feedstock sectors (e.g. ammonia) than in end use markets that are more localised and constrained by infrastructure (e.g. transport). These are our initial views but they are subject to further analysis

*LCH: Low carbon hydrogen

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Hydrogen used for own consumption (producer and consumer are the same or closely affiliated)

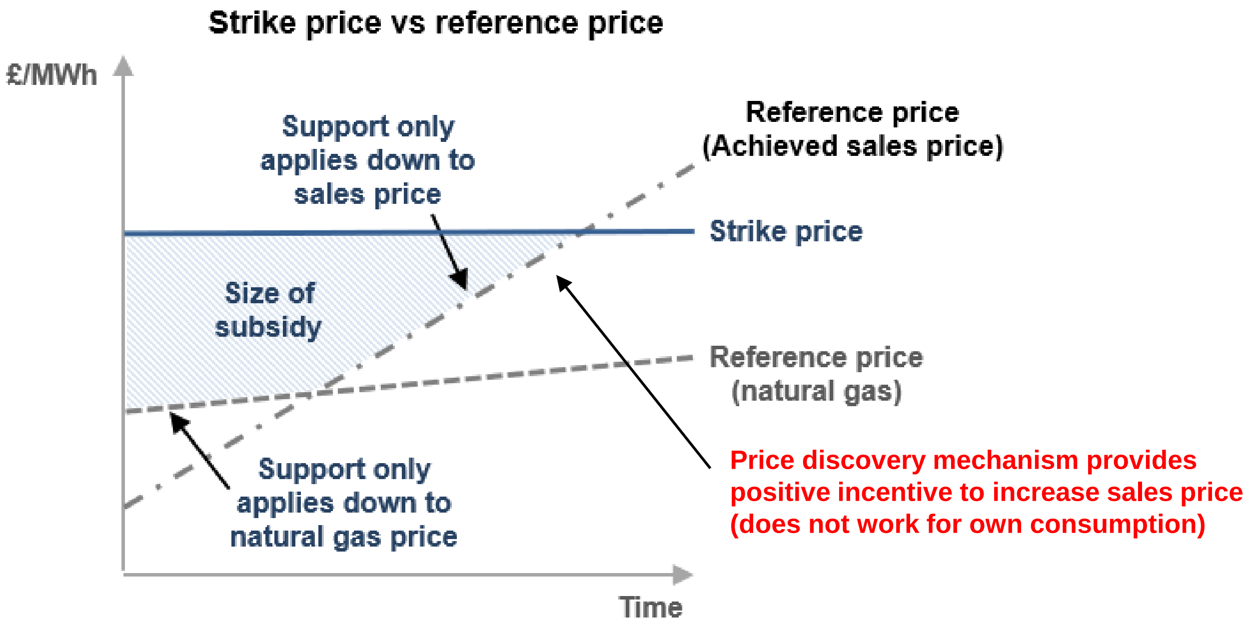
<u>Context</u>

The variable premium, and the price discovery mechanism (PDM) that has been discussed with the Expert Group can provide an incentive to the producer to expend effort to maximise the reference price. There may be little or no commercial incentive to do this in cases of captive hydrogen production for own consumption – because the producer and consumer are the same entity (or closely affiliated) and so have no incentive to agree a higher price. This could lead to:

- Over-subsidisation of own consumption projects
- Distorted market price formation as there would be no price discovery process for own consumption projects

<u>Initial view</u>

Subject to compliance with subsidy control and public law principles, our preferred option is to allow subsidy for own consumption hydrogen projects. However, we are considering options for the model design to accommodate this type of market arrangement.



We have discussed introducing a price discovery mechanism (PDM) to incentivise producers to increase their achieved sales price, and therefore reduce the subsidy paid. The PDM would enable producers to share the additional revenue generated from sales above the natural gas floor price. However, in the case of own consumption, that additional revenue would be coming out of their own pocket. As such, they would have no incentive to increase their achieved sales price.

Please note: many existing hydrogen feedstock users currently produce their own hydrogen. We therefore expect feedstock users to make up a core part of future low carbon hydrogen own consumption. However, own consumption could also be relevant for other sectors e.g. power, industry and transport and so we are considering it as a separate qualifying volume question to feedstock.

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Hydrogen sold via an intermediary

Context

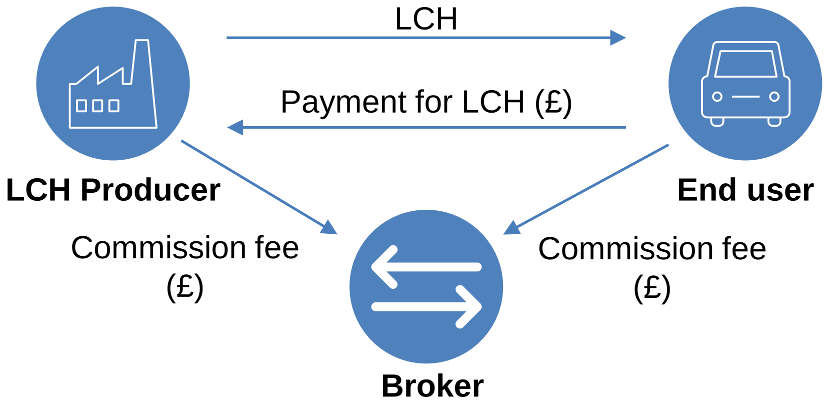
Intermediaries are entities that sit between a producer and end user, and facilitate the transaction in multiple ways. We expect to see different types of intermediary emerge, as is the case in other commodity markets. Our main concern is "risk-taking" intermediaries, meaning those that physically or financially take ownership of subsidised hydrogen and look to sell it on. Our concerns include:

- Reduced ability to enforce other limits to price support on intermediaries (e.g. no exports, constraints on feedstock subsidy etc.)
- Challenges in determining the appropriate reference price and strike price when intermediaries are involved (e.g. if intermediaries provide sales/administrative support, where would these costs be reflected?)
- These problems may be exacerbated if an intermediary is part of the same company as the producer e.g. lack of incentive from price discovery mechanism (similar to own consumption)

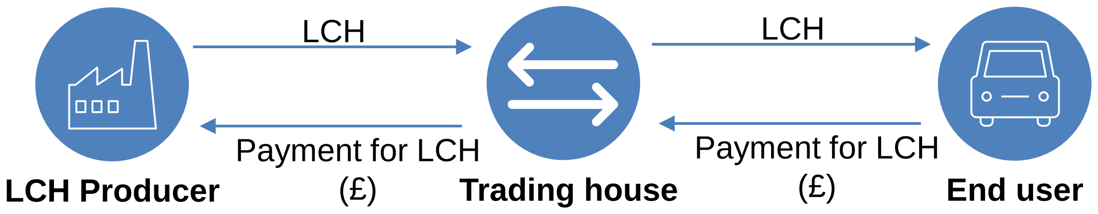
Initial view

We are further considering any potential challenges to the business model created by sales to intermediaries, and options for the model design to accommodate these sales as far as possible.

Non risk-taking intermediaries e.g. agents or brokers



Risk-taking intermediaries e.g. trading houses, hydrogen suppliers



Risk-taking intermediaries may pose the greatest challenges for HBM design, such as:

- Which "payment for LCH" should be used as the reference price?
- Is the intermediary incentivised to extract value from the end consumer?
- How can government ensure the intermediary sells to a qualifying end user?

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Potential mitigation options

We are developing a set of options to explore how the risks discussed above could be mitigated. Our key considerations are ensuring value for money as well as limiting the complexity and administrative burden of the model for producers and government. This includes identifying cross-cutting solutions that can address multiple concerns.

As part of our further policy design work, we will also consider the need for:

- Additional reporting requirements: such as volumes sold to specific offtakers
- Contractual definitions: the definition of what does/doesn’t constitute a certain user (e.g. own use, intermediary)

Longlist of potential mitigation options
Do nothing: allow sales of subsidised LCH to these users as normal
Constrain reference price: use an alternative reference floor price to address risk of over-subsidy
Cumulative cap on variable premium payments[1]: put a cumulative total cap on subsidy payments in a contract, to encourage producers to seek out higher value sales
Strike price adjustment: adjust strike price to reflect appropriate level of variable premium payment
Variable premium clawback: similar to strike price adjustment but involves claiming back subsidy from final invoiceable premium rather than adjusting the strike price that calculates the premium
Restrictions on offtake contract structure: e.g. enforced price escalation, regular rebasing to market rates, requirement to offer the same terms to other parties, restriction on volumes sold to X party
Restrictions on project structuring: production must be legally ringfenced and independent from consumption, with restrictions on info sharing

Questions for the Expert Group

- What are your views on the challenges posed by each potential offtaker/end user?
- Do you agree actions are needed to mitigate these challenges, including potential variations to the HBM design?
- Do you have any views on the pros and cons of the options under consideration?
- Do you think there are alternative options worth considering?

Blending hydrogen into the natural gas grid

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Overview: Blending in the UK

What is hydrogen blending: Hydrogen is currently limited to 0.1% (by volume) in Great Britain's (GB) natural gas networks. Hydrogen blending refers to the proposal to raise this limit to 20% hydrogen into existing GB gas networks (mixed with natural gas). HMG has committed in the Energy White Paper to decide by 2023 whether to enable blending.

1. **Positive safety case** – due to be completed by early 2023
2. **Positive economic case** – due to be completed mid to late 2023
3. **Practical implementation** (e.g. legislative and regulatory changes to energy licences and codes) – unlikely to be finalised before 2024-2025

- Policy decision on blending targeted for 2023, subject to successful completion of economic and safety assessments.
- **Safety Case:** Safety trials ongoing, due to complete in early 2023. Formal safety assessment of evidence by UK Health and Safety Executive required following this.
- **Economic Case:** BEIS officials working to deliver economic case to ministers in early 2023. Will include options analysis of:
  - **Technical Models and market arrangements –** How should blending work in practice? (Injection points, billing & market arrangements, de-blending requirements)
  - **Funding Models –** What support, if any, should hydrogen producers receive for blending?
- **If decision is positive:** Legislative process to enable blending could begin in late 2023, and work on physical changes to network would follow. First commercial-scale blending anticipated no earlier than 2025.

The ‘backstop’ role of blending

Strategic Role:

The role of blending in the hydrogen economy should be primarily as a 'demand backstop' for hydrogen producers facing volatile, or temporarily unavailable demand, rather than being financially supported by the government as a long-term, majority offtaker.

Why?

- The Government currently views blending as a transitional option, as due to the limited role of natural gas in heating under net-zero, blending has less long-run decarbonisation potential compared with other end-uses for 100% hydrogen, such as industry, transport, or power generation.
- This approach allows blending to perform an important strategic role by helping producers to manage volume-risk during the early years of the hydrogen economy as the number of hydrogen-end users available grows, and transport and storage infrastructure develops, whilst ensuring that blending does not come ahead of preferred offtakers, such as industry, transport and power.

Implementation

- We are in the process of assessing different market arrangements and commercial support options to deliver blending, including how any potential financial support could be designed to deliver blending’s intended role as a backstop.
- We will conduct more detailed analysis of the costs and benefits of the any options identified that can deliver this role, in advance of a policy decision, targeted for 2023
- Beyond 2023, we may consider further technical and commercial blending options, subject to demonstration that these meet required safety standards, represent value for money, and are in line with the Government’s strategic objectives.

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Next steps

Options Analysis:

Technical models and market arrangements

- Where/how should injections occur (transmission vs distribution; centralised vs free market approach)?
- Which market actor (e.g. networks vs shippers) should buy the hydrogen from the producer for injection?
- How should billing methodologies be updated to ensure consumers who receive blended gas pay a fair price?
- Which users require de-blending infrastructure to be installed, and how should this be paid for?
- How should blending standards, such as ensuring hydrogen is low-carbon, be enforced/upheld?
- How should carbon savings arising from blending be allocated, and potentially rewarded?

Funding Models

- How, if at all, should producers be able to access commercial support for blending:
- How should blending be treated within existing/planned commercial support schemes (e.g. Hydrogen Business Model)?
- How can any potential commercial support be designed to ensure blending does not displace supply of hydrogen to higher-value end-users, such as industry, or power?
- How can blending be encouraged via the 'merchant route'/without receiving commercial support?

Q1-Q2 2022	Q3-Q4 2022	2023	2024-25
Strategic Case Development of commercial & technical model options Longlist options analysis	Shortlist Options analysis Value for Money assessment of leading option(s) Potential Call for Evidence	Completion of economic and safety case Recommendation to ministers & policy decision	Legislative changes to give effect to blending (if decision is positive)

Questions for the Expert Group

- We would welcome views on the suitability of blending as a backstop, to help manage potential 'volume risk' issues faced by prospective hydrogen producers and the nature and likelihood of these risks.

- We would welcome views on potential commercial support options to deliver the backstop strategic role of blending.