BUSINESS MODELS FOR LOW CARBON HYDROGEN PRODUCTION

A report for BEIS

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EXECUTIVE SUMMARY

Low carbon hydrogen[1] could have a significant role to play in meeting the UK's Net Zero target: the Committee on Climate Change (CCC) estimates that up to 270TWh of low carbon hydrogen could be needed in its 'Further Ambition' scenario. However, at present, there is no large-scale production of low carbon hydrogen in the UK, not least as it is more costly than most high carbon alternatives. For hydrogen to be the viable option envisaged by the CCC, projects may need to be deployed from the 2020s.

BEIS has commissioned Frontier Economics to develop business models to support low carbon hydrogen production. This report builds on the earlier Carbon Capture, Usage and Storage (CCUS) business models consultation[2] and develops business models for BEIS to consider further. This report is a milestone in BEIS' longer term process of developing hydrogen business models. It forms a part of BEIS' wider research into a range of decarbonisation options across the economy. Further analysis will be required before a final decision is made.

Scope

Our work focusses on near term investments to incentivise largescale low carbon hydrogen production for supply to industry. We recognise that demand side policies may be required alongside the business models discussed in this report.

- **Largescale.** Our focus is on investments in hydrogen production with capacity greater than 100MW.
- **Near term**. The ultimate aim is to move to a subsidy-free net zero economy. However, our focus is on investments in the near term where low carbon hydrogen technologies and markets may be less mature.
- **Industry.** The business models have been developed primarily to support the use of low carbon hydrogen in industry. This is because, based on current evidence, industrial end users are likely to have fewer cost-effective alternative decarbonisation options than other end user groups. Therefore, the decarbonisation value of low carbon hydrogen may be higher in industry.
- **Other sectors.** While the focus of this work is on industry, alternative sources of demand such as blending, power, and transport may also be important.
  - Blending could provide a reliable source of baseload demand to support early low carbon hydrogen producers. This could be a more stable source of demand than industrial users.
  - Transport could be used to complement other sources of demand. In contrast to industrial and blending end users, the retail price of fuel is already higher than the cost of low carbon hydrogen.[3] This means there is

[1] Hydrogen produced through a low carbon process.

[2] BEIS, (2019), *Business Models for Carbon Capture, Usage and Storage* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819648/ccus-business-models-consultation.pdf

[3] BEIS, (2019), *Business Models for Carbon Capture, Usage and Storage* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819648/ccus-business-models-consultation.pdf

a higher economic incentive for users to switch. But other barriers exist, most importantly the lack of refuelling infrastructure.

- Power could also be a source of demand, for example, hydrogen could be used as a fuel in dispatchable peaking plants.

We look across five main technologies (Figure 1). While these technologies do not form an exhaustive list of low carbon hydrogen production technologies, these technologies are diverse in terms of their cost structure and level of maturity. Designing business models with a focus on these technologies should allow the resulting business models to be applied to other emerging production technologies as well.

Figure 1 Technology characteristics summary table

Group	Technology
Methane reformation	Steam Methane Reforming (SMR) with carbon capture and storage (CCS)
	Autothermal Reforming (ATR) with CCS
Bioenergy with carbon capture and storage (BECCS)	Biomass Gasification with CCS
Electrolysis (with grid electricity and dedicated renewables)	Alkaline
	Proton exchange membrane (PEM)

Source: Frontier Economics

Aims of business models

The aims of the business models are to provide an incentive to invest in low carbon hydrogen production, while limiting costs to consumers and taxpayers. The models should deliver against the six criteria set out in Figure 2.

Figure 2 Criteria for business models

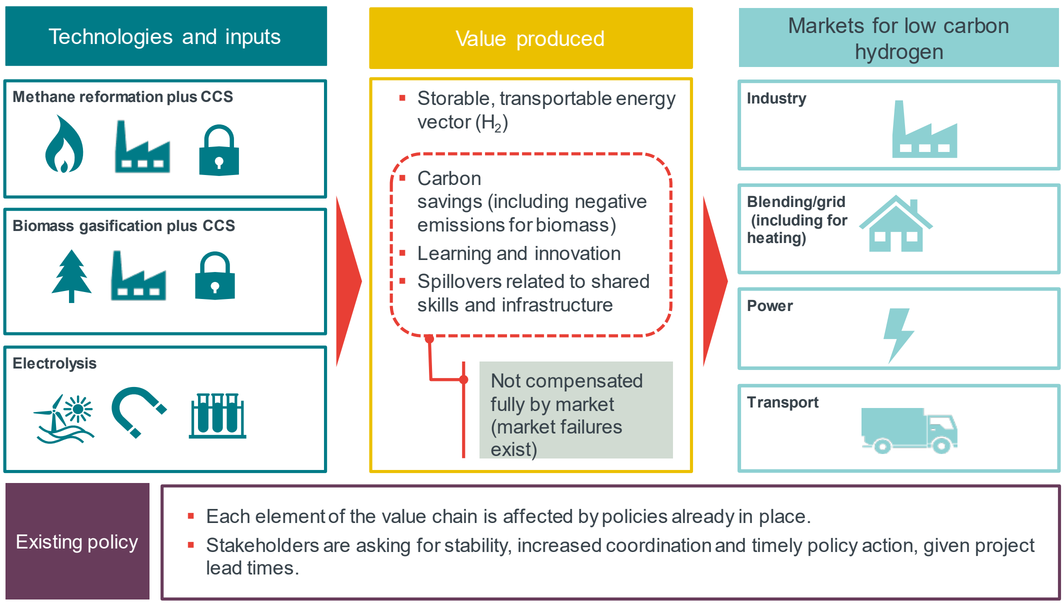
1 Incentivise producers to provide value to the economy	▪ Drive decarbonisation ▪ Direct low carbon hydrogen where it provides the highest decarbonisation value ▪ Provide valuable service to low carbon hydrogen consumers ▪ Incentivise efficient management of production costs (capex and opex) ▪ Incentivise efficient production levels
2 Instil confidence among investors	▪ Allocate **risks** in way that attracts investment and finance at the appropriate cost of capital
3 Limit costs to tax payers and bill payers	▪ Allocate **risks** in a way that limits costs to consumers and billpayers ▪ Avoid over-paying, or paying for production that is not required ▪ Compatibility with fair and practical cost distribution
4 Be practical and simple	▪ Administrative ease for government ▪ Practicality and simplicity for investors ▪ Limited complementary policy requirements ▪ Potential for timely implementation
5 Be compatible with the wider value chain	▪ Compatibility with lead options for CCUS and H2 T&S ▪ Interaction with existing and planned policy support in other parts of the value chain ▪ Interaction with the carbon price
6 Be compatible with a path to a subsidy free world	▪ Ease of reducing payments for future investments ▪ Potential for technology neutrality ▪ Ease of moving to a subsidy free world over time

Source: Frontier Economics

Priorities for business model design

Through a literature review, stakeholder interviews and case studies, we first assessed risks and barriers associated with the technologies, value produced, markets and existing policies associated with the low carbon hydrogen production sector (Figure 3).

Figure 3 Framework for considering risks and barriers



Source: Frontier Economics

Based on this analysis, we have identified nine key considerations that should be taken into account in the design of business models to meet the aims described in Figure 2 above.

1. Subsidy to cover externalities

Multiple externalities (particularly associated with carbon and learning) mean that low carbon hydrogen cannot generally compete with the incumbent carbon-intense fuel, particularly in industry. Allowing low carbon hydrogen to compete with carbon-intense alternatives can be most practically achieved by providing a subsidy. The alternative (to tax the externalities associated with the alternative fuel) is unlikely to be practical in the near term, given risks of industrial offshoring. Ideally the level of the subsidy will be determined through a competitive allocation process (e.g. an auction), however, the level may need to be administratively set for some of the first investments.

2. Focus on uses where the decarbonisation value is highest

The decarbonisation value of hydrogen will be highest where viable and cost-effective alternative decarbonisation options are not available. In the near term, while the quantity of low carbon hydrogen produced is still limited, the intention is to aim for the use of low carbon hydrogen in industry, since based on current evidence, alternative cost-effective abatement options are less readily available.

3. Technology-specific support (in the near term only)

Low carbon hydrogen production technologies differ currently in terms of their costs and their level of maturity. If the same support was provided to all technologies, it is likely that the more mature technologies would dominate. This may not be optimal given learning externalities, and the potential benefits from ensuring that a diverse set of production technologies is available in the UK over the next decades. This means that technology-specific support may be needed in the near term, although technology-neutral support (which takes account of differences in carbon-intensity) will be more efficient as the market matures.

4. Transfer of demand risk away from investors

Given the presence of multiple externalities, demand for low carbon hydrogen will depend on policies to tackle market failures and to drive action on climate change. It would be difficult for investors to manage policy-driven risks around demand for low carbon hydrogen through market means (e.g. long-term contracts). For example, industrial customers could go out of business, or policies to encourage switching to low carbon hydrogen may be amended or may not turn out to be effective. Investment may be limited unless demand risk is transferred away from investors.

5. Reduce risk of policy change

Low carbon hydrogen production facilities are long-lived assets, with expected economic lives of 25 years or more. Before sinking investment into such assets, investors will require confidence that support payments for the specific investment will not be adjusted in unforeseen ways over its lifetime. This means that business models should be designed so that support for a given investment is not open to ongoing unilateral adjustments. This does not preclude adjusting support levels for subsequent investments.

6. Separate switching support for users

The upfront costs associated with switching should be covered separately through a payment to end users. This is because end users face additional switching costs and additional risks in switching to low carbon hydrogen. Without a separate end user subsidy, demand for low carbon hydrogen may be limited even where low carbon hydrogen can compete on price with the incumbent carbon-intense alternative fuel. Allocation of this end user support could be done by identifying the users that will have the highest decarbonisation value associated with switching to low carbon hydrogen, for example industrial processes that are difficult to electrify.

7. Reductions in support for successive investments

Some elements of low carbon hydrogen production technologies are relatively mature. For example, SMR technologies are widely used to produce hydrogen in industry already. However, these technologies have not been applied at scale with carbon capture and storage. The lack of full value chain deployment of low carbon hydrogen production technologies means that the first producers will face higher risks associated with first-of-a-kind projects. This may require additional compensation relative to future projects that would occur once the technologies are proven. The expectation of falling costs for subsequent investments means that business models should allow support to be reduced for successive investments.

8. Compatibility with existing policy

Low carbon hydrogen production facilities are part of a wider value chain that includes transport and storage of hydrogen and input fuels, as well as energy consumers across the economy. Support mechanisms should be designed to be compatible with existing sectoral policies – for example to avoid double subsidies under the Renewable Transport Fuels Obligation (RTFO) or under the contracts for difference system for low carbon electricity generation. Support mechanisms must also be compatible with the leading options for support of CCS and hydrogen networks.

9. Reduce risk of market power

Low carbon hydrogen is not a direct substitute for the incumbent carbon-intense fuels. Separate transport networks are required, and in many cases, users will need to make upfront investment (for example, in new boilers) in order to be able to use low carbon hydrogen. In the near term, there may not be a liquid, well-functioning market for low carbon hydrogen. This could lead to a risk of market power, if the number of users or producers in a given area is small, and a national or regional transport network is not in place. Consideration of risks around market power in the very early stages of the market should be taken into account when designing the business models.

Business model categories

We have considered four broad categories of business models that could potentially deliver on these priorities. These are summarised in Figure 4.

Figure 4 Summary of model categories

Business model category	High level description
Contractual payments to producers	The hydrogen producer receives a subsidy which covers the incremental cost of low carbon hydrogen above the carbon-intensive alternative fuel. Examples include premium payment models or Contracts for Differences (CfDs).
Regulated returns	Regulated returns models allow the hydrogen producer to earn a regulated return on costs.[4] Examples include Regulated Asset Base (RAB) and Cap and Floor models.
Obligations	An obligation is imposed on parties outside the hydrogen production sector (e.g. fuel suppliers or end users) to supply or consume a certain quantity of low carbon hydrogen.
End user subsidies	An ongoing technology-neutral subsidy is provided to end users for carbon abatement.

Source: Frontier Economics

Considering these business model types, we first assessed them against their ability to deliver on the nine priorities identified above. We found that all of the business models could be designed to meet five out of the nine priorities.

- **Subsidy to cover externalities.** All of the business models could provide a subsidy to over externalities.
- **Focus on uses where the decarbonisation value is highest.** All of the business models can be designed so that the low carbon hydrogen is diverted to industry, where the decarbonisation value is likely to be highest, for example by using certification and metering to verify end uses.
- **Separate switching support for users.** Switching costs for industrial customers can be supported separately across all business models**.**
- **Compatibility with existing policies.** Policies can be designed to avoid double subsidies, for example by ensuring any future support under the Renewable Transport Fuels Obligation or Contracts for Differences in the power sector is not available to producers already receiving separate support.
- **Reduce risk of market power.** The risk of market power as the first plants are developed can be considered in all models, for example through application of license conditions.

However, the business models differ in their ability to meet the remaining four priorities (Figure 5).

[4] The model could be implemented by providing separate payments to the producer and shipper, as described in Annex F.

Figure 5 Business model category filter

	Contractual payments to producers	Regulated returns	Obligations on suppliers	End user subsidies
Technology-specific support (in the near term only)	**Yes** – support can be allocated separately to different technologies	**Yes** – support can be allocated separately to different technologies	**Yes** – obligation certificates can be banded[5]	**Difficult** – while an end user subsidy could be designed to be technology specific, this would add significant complexity
Transfer of demand risk away from investors	**Yes –** support payments can be made regardless of demand (either through a backstop or split payment)[6]	**Yes –** returns on fixed and capital costs can be gained regardless of demand	**Difficult** - A 'split' payment is not possible. While a backstop could be applied, this would be very complex[7]	**No** – demand for low carbon hydrogen is driven partly by availability of alternative abatement options and by the level of the subsidies (which could be adjusted or removed)
Reduce risk of policy change	**Yes** – contracts cannot be changed by policy-makers ex post	**Yes –** length of price control or cap and floor periods can be set to a level that reduces this risk	**No** – obligations can be adjusted over time by policy-makers	**No** – end-user subsidies can be adjusted over time by policy-makers
Reductions in support for successive investments	**Yes** – support payments can be reduced over time for successive investments	**Yes –** regulated returns can be reduced over time for successive investments	**Yes** – obligation certificates can be banded by vintage	**Difficult**– while an end user subsidy could be designed to reward plants of different vintages separately, this would add significant complexity

Source: Frontier Economics

This analysis suggests that while it would be possible to deliver the priorities through either contractual payments to producers or regulated returns models, it would be more difficult to do this via obligations or end user subsidies. This is mainly driven by the following:

- **Investors will continue to be exposed to policy uncertainty under an obligation model.** Before investing in production plants, investors will seek confidence that support levels for a given investment will not be adjusted in unforeseen ways over the lifetime of their investment. However, it is difficult to

[5] Banding would involve allowing some technology types to generate more obligation certificates per unit of hydrogen produced than others. It is discussed in detail in Annex F.

[6] The backstop and the split model are discussed more in the next section.

[7] See Annex F for a discussion of this.

design an obligation model to be robust to the risk of policy change. Support for a given investment would be open to ongoing unilateral adjustments. This is because the obligation certificate price will be in part determined by detailed rules of the scheme, such as the level of the obligation, the buyout provisions and any banding. These detailed rules can be changed over time by policy-makers. While investors may in some cases be happy to invest under an obligation, their cost of capital (and therefore the subsidy they require to make the investment) will be higher than under business models that provide more certainty.

- **Investors will be exposed to demand risk under the end user subsidy model.** A technology-neutral end user subsidy may not support an emerging low carbon hydrogen market (though this type of intervention may be economically efficient in the longer term). Since the subsidy is applied for abatement, rather than for low carbon hydrogen consumption, demand risk for low carbon hydrogen would remain with the producer. In the context of a sector where long-term contracts may be difficult to secure, this demand risk is likely to be difficult for producers to manage. In addition, because the end user subsidy is technology-neutral, it would not allow technology specific subsidies to be applied in the near term. It would also not allow differentiation between vintages of investment, and so would not allow support to be reduced over time for successive investments. Therefore, while a technology-neutral end user subsidy may be optimal in the longer term, it is unlikely to bring on the required diverse mix of investments in the near term.

In contrast, contractual and regulatory models can both be designed to accommodate a range of detailed design features aimed at meeting the nine priorities identified above. They mainly differ in terms of the certainty they can give to investors and to the new institutional capability required.

Once again, there are trade-offs:

- The contractual approach may have an advantage over the regulatory approach as it could be perceived to give more certainty to investors. Regulated returns models are generally administered through license agreements, where appeal rights may be to the Competition and Market Authority or, in limited circumstances, to the Courts. These models work well in established parts of the energy sector, where there is a large amount of precedent to draw on to provide certainty about the model being used. In a new area, such as low carbon hydrogen production, investors may consider that covering off eventualities in a contract provides greater certainty.
- On the other hand, the regulatory model may be easier to set up. The contractual model would require further development of institutional capability for assessing the level of payments to cover fixed and capital costs. This institutional capability is already well-developed in the regulatory system.

BEIS analysis in the context of nuclear investment has also highlighted benefits of hybrid models that combine regulatory and contractual approaches. Contractual and regulatory approaches should not be considered to be mutually exclusive and hybrid approaches should also be considered.

We conclude that both contractual and regulatory models, as well as hybrid approaches, are worth investigating further.

Key design features

We consider three key design features of the business models, which can all be delivered either through contractual payments to producers or regulatory means.

Managing downside demand risk: Backstop vs split payment

Unless downside risks around demand for low carbon hydrogen are managed, investors may face a very high cost of capital, or insufficient investment may come forward. Downside demand risk can be managed for producers by applying either a backstop or applying a split subsidy structure which would result in payments being provided even when outturn demand is lower than expected.

- Under a backstop[8], there would be a role for a Government counterparty to be a 'buyer of last resort' for low carbon hydrogen, to provide demand certainty for producers, as the market develops
- Under the split structure, separate support payments would be given to cover fixed and capital costs regardless of demand, but variable costs would only be covered where low carbon hydrogen is being produced.

We assess these options against the criteria in Figure 6. This illustrates that the split payment model has several key advantages over the backstop. In particular, it is less likely to over incentivise production and to lead to higher than necessary subsidy costs for taxpayers/billpayers.

Figure 6 Backstop vs split payment

	Backstop	Split payment
Incentivise producers to provide value to the economy	Over-incentivisation is a risk as producers are paid regardless of demand levels	Producers are incentivised to produce efficiently, when there is demand
Instil confidence among investors	Demand risk is transferred from investors	
Limit costs to taxpayers and bill payers	Taxpayer/billpayers cover fixed and variable costs of low carbon hydrogen production, where demand falls below expected levels	Taxpayer/billpayers cover only fixed costs of low carbon hydrogen production, where demand falls below expected levels
Practical and simple	Would involve complex contractual terms	Requires separate estimation of fixed and variable costs
Compatible with the wider value chain	There is no conflict with existing and planned policies in the wider value chain	
Compatible with a path to a subsidy-free world	Support for subsequent investments can be reduced and removed over time	

Source: Frontier Economics

Premium payment vs revenue stabilisation

Under a premium model, producers receive a subsidy on top of market revenue from the sale of low carbon hydrogen. In contrast, a revenue stabilisation model aims to provide a guaranteed return to producers by topping up the revenue

[8] Backstop arrangements could also include provisions for buyout. There may be extreme circumstances beyond investor control, under which the Government (or a party acting on its behalf) is obligated to buyout the production facilities.

received through sales in the market (valued at an agreed reference price) to an agreed level (the strike price). Under both models, the subsidy could be set at a level that allows the investor to break even, given its revenues and costs and including its cost of capital. Both could be applied to either a contractual payment model or a regulated return model.

Figure 7 sets out our assessment of the choice between these models. This illustrates that both models could be designed to efficiently incentivise investment, but that the key difference relates to their ease of application to technologies with different cost structures.

In particular, a split premium model could be difficult to apply to technologies with capital-intense cost structures such as electrolysis with dedicated renewables (EDR). EDR technologies have very low ongoing costs, and these ongoing costs are likely to be below the price of low carbon hydrogen in the market. Under the split premium design, the fixed component of the subsidy would cover the EDR capex, and it is likely that the market revenue would exceed variable costs. Therefore, the support to cover their fixed and capital costs would need to be adjusted, to subtract the value of the market revenue they would be likely to achieve. This would require either forecasting the future revenue of the producer (to subtract the correct amount from the fixed payment) or a periodic true-up (to adjust the level of the fixed payment in recognition of revenue received). This would add significant complexity to the model. Under the revenue stabilisation model, a fixed payment is received on an ongoing basis, and revenues are topped up or paid back up to the level of an agreed strike price. No forecasting or true up is required. Instead, when revenue is higher than the strike price, producers pay back to billpayers/taxpayers under the standard terms of the CfD or its regulatory equivalent.

Figure 7 Premium versus revenue stabilisation

	Premium	Revenue stabilisation
Incentivise producers to provide value to the economy	Can be designed to provide an incentive to produce efficiently and seek sales	
Instil confidence among investors	Can be designed to transfer policy and demand risk from investors	
Limit costs to taxpayers and bill payers	Can be designed to limit costs	
Practical and simple	Different models may be required for capital-intense investments such as EDR	Can be applied across technologies with different cost structures
Compatible with the wider value chain	There is no conflict with existing and planned policies in the wider value chain.	
Compatible with a path to a subsidy-free world	Support for subsequent investments can be reduced and removed over time.	

Source: Frontier Economics

Managing input price risk: Fixed or indexed support.

Support could be provided on a fixed basis per unit of low carbon hydrogen produced or indexed to input fuel costs.

- The revenue stabilisation model allocates input price risk to producers, while removing any natural hedge that might result from the sale price of low carbon hydrogen tracking the input price.
- Producers may face less input price risk where support is paid as a premium over the low carbon hydrogen sales price, to the extent that the low carbon hydrogen sale price is driven by the input price.

Our assessment of the choice between fixed or indexed support is set out in Figure 8 below.

This suggests that if a revenue stabilisation mechanism like a CfD is applied, it may make sense to index the strike price to input prices. The decision for indexing a premium is less clear cut. Indexing support places input price risk on consumers. However, if transferring this risk to them results in a lower cost of capital, consumers may gain. Producers may be better placed than taxpayers/consumers to bear some natural gas price risk. The decision on whether to index may depend on the impact that leaving input price risk with producers could have on their cost of capital.

Figure 8 Fixed or index support

	Fixed support	Indexed support
Incentivise producers to provide value to the economy	Can be designed to provide an incentive to produce efficiently and seek sales	
Instil confidence among investors	Fixed support leaves input cost risk with investors. However, investors are relatively well placed to manage this risk, and under a premium model, there may be a natural hedge against sales revenue	Indexed support transfers input price risk away from investors. This may be particularly helpful to investors under a revenue stabilisation model, where there is no natural hedge
Limit costs to taxpayers and bill payers	Fixed support may result in a higher cost of capital and therefore higher support costs. However, in return, taxpayers/billpayers will bear lower risks of increased subsidy payments	Indexed support may result in a lower cost of capital and therefore lower support costs. However, in return, taxpayers/billpayers will bear higher risks of increased subsidy payments
Practical and simple	Fixed support leads to a simpler model	Indexing input fuel costs marginally increases the complexity of the model
Compatible with the wider value chain	There is no conflict with existing and planned policies in the wider value chain	
Compatible with a path to a subsidy-free world	Support for subsequent investments can be reduced and removed over time	

Source: Frontier Economics

Summary of conclusions and issues for further consideration

We have considered four categories of business models that could potentially be used to bring on low carbon hydrogen production in the near term, with a focus on supply to industrial clusters. Our analysis suggests the following:

- Of the four categories of business models considered:
  - Contractual payments to producers or regulatory returns models could be designed to deliver low carbon hydrogen production in the 2020s. Contractual models may give more certainty to producers, while regulatory models may be easier to implement, given existing institutional capabilities.
  - In contrast, it would be more difficult to incentivise low carbon hydrogen using end user subsidies or obligations in the near term. This is because these models leave significant, policy-driven risks with producers.
- In designing the contractual payments or regulatory returns models, we assessed three key design features.
  - To manage demand risk, we conclude that a split structure is likely to be preferable to applying a backstop (or guaranteed purchase of low carbon hydrogen). This is because under the backstop approach, consumers are exposed to potentially very high payments per unit of hydrogen produced.
  - The support could be provided through either a revenue stabilisation model (such as a CfD) or paid as a premium to sales revenue. Both models have merits, but if applying the same model across different technologies is a priority, then revenue stabilisation models would be easier to deploy across all technologies.
  - Indexing support payments to the input fuel price should be considered further, as depending on the impact on producer's cost of capital, it could reduce support costs. Indexing may be particularly helpful if a revenue stabilisation approach is taken, to avoid placing excessive input cost risk on investors. The decision for indexing a premium is less clear cut and will depend on the impact that leaving such a risk with producers could have on their cost of capital.

A summary of the models that we recommend are considered further is provided in Figure 9.

Figure 9 Summary of models to be considered further

Source: Frontier Economics

1 INTRODUCTION

BEIS has commissioned Frontier Economics to help Government understand and compare potential business models that could enable largescale[9] low carbon hydrogen production to be deployed at scale from the 2020s with a focus on supply to industrial customers. This builds on the CCUS business models consultation of 2019.[10] Our report is a milestone in BEIS' longer term process of developing hydrogen business models and further analysis will be required before a final decision on business models is made.

BEIS defines business models as the systems of actors, infrastructure, financing for development and operation costs, use of revenues and profits, and risk ownership required for hydrogen production infrastructure to be developed and operated. Business models aim to address the key risks and barriers that prevent low carbon hydrogen from developing without policy support.

Hydrogen is a transportable and storable energy vector. It can be produced in a low carbon way using several technologies, some of which require carbon capture, usage and storage (CCUS). The CCC projects that up to 270TWh of low carbon hydrogen could be produced and used alongside other decarbonisation options in the UK by 2050 under its 'Further Ambition' scenario presented in its Net Zero analysis.[11] At present, hydrogen is only produced on a small scale in the UK[12] mainly for direct use in industry such as petrochemicals. In addition, only a fraction of current production is low carbon.

There are several major barriers and risks associated with deployment of low carbon hydrogen production technologies, including the relative cost of low carbon hydrogen compared to more carbon-intense alternative fuels and the uncertainty over future policies that could incentivise demand for low carbon hydrogen. This report develops several business models which could address these barriers and risks, and evaluates them against a set of criteria. It is structured as follows:

- Section 2 describes the focus of this work. We consider five key technologies for low carbon hydrogen production, with industry as the main end user.
- Section 3 develops nine priorities for business model design. This is informed by a systematic literature review and interviews with a range of industry stakeholders.
- Section 4 describes four categories of business models and filters them based on the priorities. It then describes and assesses design features that could help deliver low carbon hydrogen efficiently.
- Section 6 sets out our conclusions.

Further detailed analysis and background is set out in the annexes to this report.

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9 Largescale is defined as greater than 100MW. We note that there may be a case for including parallel mechanisms for incentivising smaller scale plants.

10 BEIS (2019) *Business models for Carbon Capture, Usage and Storage* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819648/ccus-business-models-consultation.pdf,

11 Further Ambition scenario. CCC, (2019), *Net Zero: The UK's contribution to stopping global warming* - https://www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/

12 10 – 27 TWh, Energy Research Partnership, (2016), Role of hydrogen in the UK Energy System - http://erpuk.org/wpcontent/uploads/2016/10/ERP-Hydrogen-report-Oct-2016.pdf

2 AREA OF FOCUS

Our focus is on developing business models for low carbon hydrogen production that will enable investments in the 2020s.

Low carbon hydrogen can be produced using a range of technologies, and has the potential to be deployed in a number of sectors (Figure 10). This report focuses on largescale (>100MW HHV)[13] hydrogen production for industrial end use. This approach follows guidance from BEIS and is in line with the Low Carbon Hydrogen fund announced in August 2019, innovation activity and the Industrial Clusters Mission. It also reflects the potential for hydrogen to deliver abatement in industrial sectors.

We focus on three technology groups[14]:

- Methane reformation with CCUS, either via steam methane reformation (SMR) or autothermal reformation (ATR);
- Biomass gasification with CCUS;
- Electrolysis using proton exchange membrane (PEM) or alkaline.

While these technologies do not form an exhaustive list of low carbon hydrogen production technologies, these technologies are diverse in terms of their cost structure and level of maturity. Designing business models with a focus on these technologies should allow the resulting business models to be applied to other emerging production technologies as well.

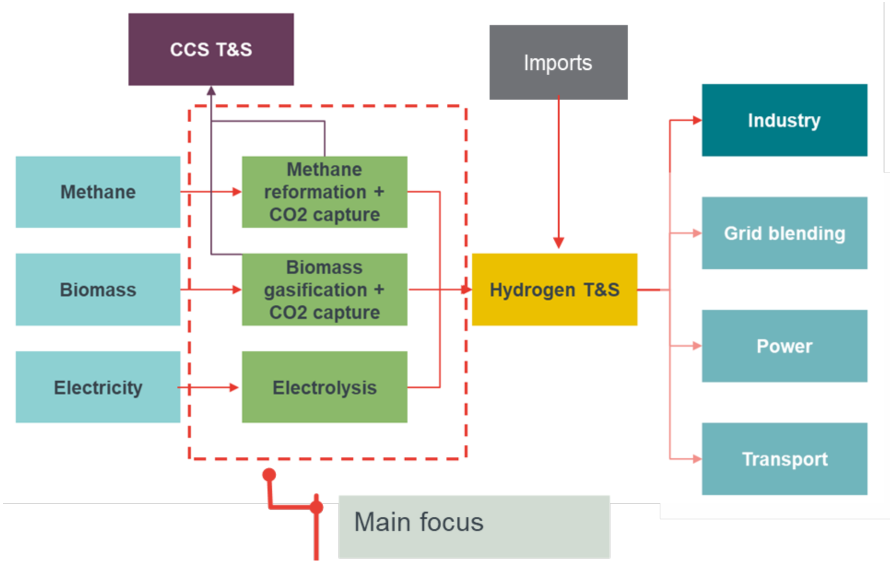
BEIS is separately undertaking work to look at other aspects of the value chain. This includes ongoing work to consider the interactions with current and potential future policy frameworks around:

- options to support carbon transport & storage (T&S);
- options to support hydrogen distribution;
- ongoing support for renewables through Contracts for Difference (CfD) mechanisms in the power sector; and
- existing and planned policy frameworks, including the renewable transport fuel obligation (RTFO), support for CCUS in power, and support for industrial CCUS.

[13] It may be appropriate to deploy separate business models in parallel to deploy smaller scale hydrogen production.

[14] We have not considered how these business models would be applied to imports. The question of cross border participation is out of scope for this study.

Figure 10 Low carbon hydrogen value chain



Source: Frontier Economics

Although we focus on production for industrial users, business models must be developed in the context of the value chain as a whole. We therefore use a set of assumptions about other parts of the value chain throughout our business model design (Box 1). We also evaluate interactions with CCUS T&S, hydrogen T&S, and other existing policies as part of our assessment.

BOX 1: KEY ASSUMPTIONS ON THE REST OF THE VALUE CHAIN

Assumptions are based on the BEIS 2019 CCUS Business model consultation.[15]

- Each carbon capture project will be charged a T&S fee on a £/tonne CO_2 basis for use of a regional CO_2 T&S network
- The first carbon capture project is charged all the CO_2 costs initially, with costs being shared as more capture plants join the network
- There would be flexibility for plants with carbon capture to operate unabated, if the T&S network is temporarily unavailable
- The EU ETS or a similar carbon pricing mechanism will remain in place
- Other policy frameworks will be in place to support different technologies across end users, in particular to support fuel switching and industrial CCUS

2.1 Timeline

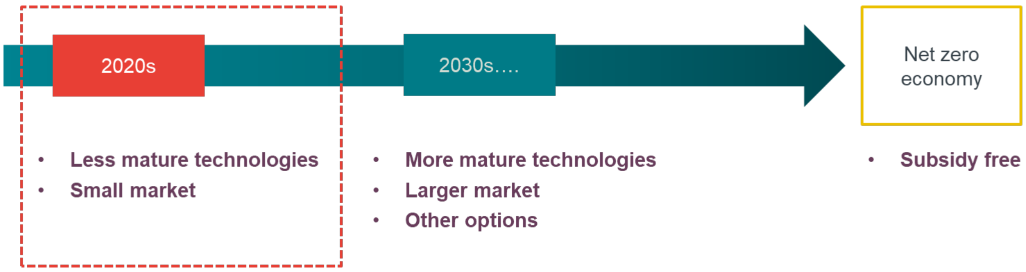
Moving to a net zero economy by 2050 will involve several phases (Figure 11). During each phase, the type of business model required to support low carbon hydrogen may need to change as the technologies and market context develop. In this report, we focus on developing business models that will enable low carbon hydrogen production to be deployed in the 2020s. We also consider which models

[15] BEIS (2019) *Business models for Carbon Capture, Usage and Storage* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819648/ccus-business-models-consultation.pdf

could be most applicable and transferable to a longer-term arrangement as part of our evaluation criteria.

- In the 2020s, technological learning on the supply and demand side is likely to be particularly important for low carbon hydrogen and alternative abatement options. The market for low carbon hydrogen may be small, with low levels of demand, limited liquidity, and a small number of producers and consumers. During this phase, low carbon hydrogen will require business model support which takes into account the low level of technology maturity and the small market.
- In later years, technologies are expected to start reaching maturity as we move towards net zero. Learning externalities will be smaller. The market for low carbon hydrogen may become more liquid and competitive, with more producers and consumers, and a larger and more diverse demand base. This means the type of business model support required in this phase may be different from the earlier phase. In addition, business model design should recognise that low carbon hydrogen may not turn out to be the optimal abatement option.
- The ultimate destination is a net zero economy where carbon externalities have been consistently internalised and regulation is stable. This is expected to be a subsidy-free world where low carbon hydrogen does not need specific business model support.

Figure 11 Timeline



Source: Frontier Economics

2.2 End users

There are four main groups of end users for low carbon hydrogen: industry, grid blending, transport, and power (Figure 12). BEIS has asked us to focus on industry as the main end user for low carbon hydrogen. This is because:

- Hydrogen may have the greatest decarbonisation value in industry, at least in the near term: industrial users are likely to have fewer alternative practical and cost-effective decarbonisation options than other end user groups.[16] The CCC recommends that hydrogen is best used selectively, where it adds more value alongside widespread electrification. This means using hydrogen where there

[16] Element Energy & Jacobs, (2018), *Industrial Fuel-Switching Engagement Study* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/764058/industrial-fuel-switching.pdf

are limits to feasible electrification,[17] utilisation of CCUS cannot be implemented, or the alternative is continuing to burn unabated fossil fuels.[18]

- Industrial users tend to be geographically clustered and can provide large baseload demand for early projects without the need for large-scale hydrogen transport infrastructure.

Figure 12 End users

Industry	Grid blending	Transport	Power
▪ Large baseload demand profile could provide an anchor for early projects ▪ Fewer cost-effective alternative decarbonisation options than other end uses ▪ Switching cost and complexity for natural gas users ▪ Risk that plants close down or move offshore	▪ Stable and reliable source of demand could support early projects ▪ Regulatory limits to blending are a barrier ▪ Customer acceptability is unproven ▪ Safety testing for blending and end appliances is needed	▪ Retail cost gap between blue / green hydrogen and petrol is smaller than other fuels ▪ Refuelling infrastructure is not in place ▪ Switching cost for users who must purchase new vehicles ▪ Smaller scale and unpredictable demand near term	▪ Could be cost-effective for dispatchable peaking plants, because hydrogen + CCUS will have higher utilisation of CCUS than a dispatchable plant with post-combustion capture ▪ Less cost-effective than post-combustion capture for baseload electricity generation

Source: Frontier Economics

While our focus is on industry, alternative sources of demand such as blending, power and transport may also be important.

- **Blending** could provide a reliable source of baseload demand to support early low carbon hydrogen producers. This could be a more stable source of demand than industrial users, although there may be some seasonal variation that needs consideration, given seasonal patterns of heat demand.[19] Further safety testing is required to test the feasibility of this approach.
- **Transport** could be used to complement other sources of demand. In contrast to industrial and blending end users, the retail price of fuel is already higher than the cost of low carbon hydrogen.[20] This means there is a higher economic incentive for users to switch. But other barriers exist, most importantly the lack of refuelling infrastructure. In the near term, some local fleets could be used as a source of transport demand that does not require a national refuelling network.
- **Power** could also be a source of demand, for example, hydrogen could be used as a fuel in dispatchable peaking plants.

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17 Committee on Climate Change, (2018), *Hydrogen in a low carbon economy* - https://www.theccc.org.uk/wp-content/uploads/2018/11/Hydrogen-in-a-low-carbon-economy.pdf

19 Seasonal changes in gas demand may impact the amount of hydrogen that producers are able to inject into the grid. Since hydrogen is storable, it may be possible for producers to efficiently plan around the seasonal variation.

20 BEIS (2019) *Business models for Carbon Capture, Usage and Storage* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819648/ccus-business-models-consultation.pdf

2.3 Technologies

Our focus is on five hydrogen production technologies (Figure 13).[21] We focus on these technologies as illustrative examples in this report, however other technologies that are not listed here could also be potential recipients of support.

Figure 13 Technology characteristics summary table

Group	Technology	Maturity	Scale	Carbon capture	Other constraints
Natural gas reformation	SMR with CCS	SMR mature but CCS not	150 - 1000 MW	70-90%	Best placed near CCS T&S
	ATR with CCS	ATR has high TRL but has not been tested at scale; CCS is not mature	300 – 1000 MW	95-98%	Best placed near CCS T&S
BECCS	Biomass Gasification with CCS	Biomass gasification has not been demonstrated at scale; CCS is not mature	50 – 500 MW	Negative emissions	Availability and sustainability of biomass – dependent on waste policies
Electrolysis with dedicated renewables, or with grid connection	Alkaline	Reasonably mature	No minimum scale	N/A	Production may be intermittent
	PEM	Demonstration level but has not been tested at scale	No minimum scale	N/A	

Source: Frontier Economics

Note: Information taken from:

Carbon Connect, (2018), Producing Low Carbon Gas – Future Gas Series: Part 2 – https://www.policyconnect.org.uk/research/producing-low-carbon-gas-future-gas-series-part-2 ;

Element Energy & Jacobs, (2018), Hydrogen supply chain evidence base – https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf ;

The Royal Society, (2018), Options for producing low-carbon hydrogen at scale – Policy Briefing – https://royalsociety.org/topics-policy/projects/low-carbon-energy-programme/hydrogen-production/.

2.4 Criteria

The business models aim to incentivise investment in low carbon hydrogen production, while limiting costs to consumers and taxpayers. To achieve this, our intention is to design business models that would meet the six criteria set out in Figure 14 below, recognising that there are trade-offs between these criteria.

These criteria are based on those developed by BEIS for the CCUS Business Model consultation.

[21] See Annex A for further details.

Figure 14 Model assessment criteria

	Criterion	Description
1	**Incentivise producers to provide value to the economy**	▪ Drive decarbonisation ▪ Direct low carbon hydrogen where it provides the highest decarbonisation value ▪ Provide valuable service to low carbon hydrogen consumers ▪ Incentivise efficient management of production costs (capex and opex) ▪ Incentivise efficient production levels
2	**Instil confidence among investors**	▪ Allocate **risks** in way that attracts investment and finance at the appropriate cost of capital
3	**Limit costs to tax payers and bill payers**	▪ Allocate **risks** in a way that limits costs to consumers and billpayers ▪ Avoid over-paying, or paying for production that is not required ▪ Compatibility with fair and practical cost distribution
4	**Be practical and simple**	▪ Administrative ease for government ▪ Practicality and simplicity for investors ▪ Limited complementary policy requirements ▪ Potential for timely implementation
5	**Be compatible with the wider value chain**	▪ Compatibility with lead options for CCUS and H2 T&S ▪ Interaction with existing and planned policy support in other parts of the value chain ▪ Interaction with the carbon price
6	**Be compatible with a path to a subsidy free world**	▪ Ease of reducing payments for future investments ▪ Potential for technology neutrality ▪ Ease of moving to a subsidy free world over time

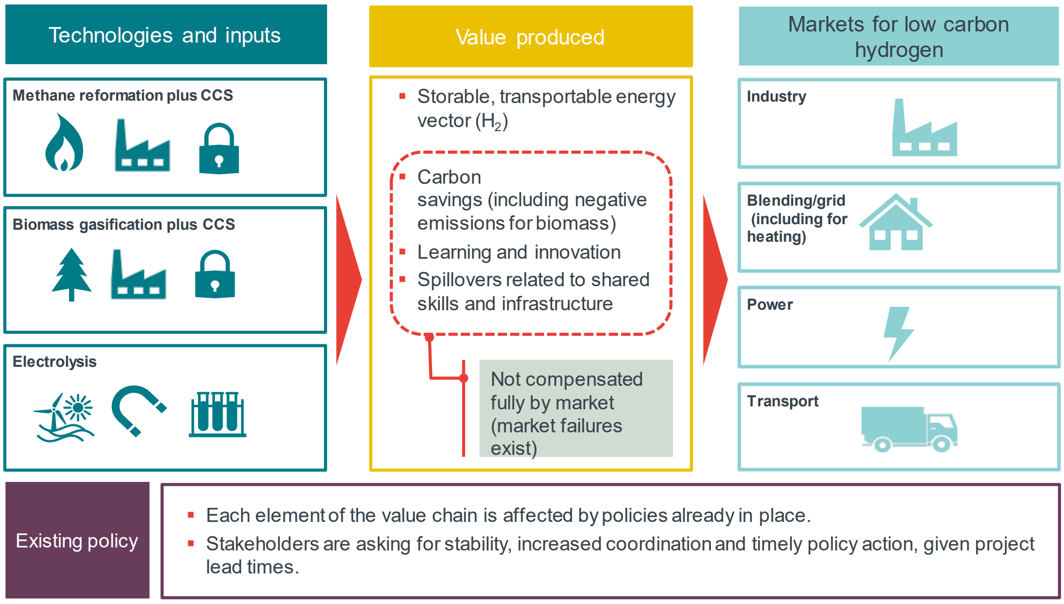
Source: Frontier Economics

3 KEY ISSUES FOR BUSINESS MODELS TO RESOLVE

We have investigated the key risks and barriers for low carbon hydrogen production through a review of the literature and consultation with stakeholders.[22] We summarise our findings in four inter-related categories (Figure 15).

Business models must address barriers across these categories to incentivise the production of low carbon hydrogen in a way that meets the criteria set by BEIS, described in Section 2 above.

Figure 15 Framework for considering risks and barriers



Source: Frontier Economics

We now consider each area in turn.

3.1 Value produced

The output of low carbon hydrogen production is an energy vector with a market value. In addition, there are three types of externality in the near term:

- **Carbon emission savings** (and potential negative emissions for BECCS) are not currently rewarded by an effective carbon price. This means that low carbon hydrogen cannot compete on cost with high carbon alternatives.
- **Learning and innovation** externalities exist because low carbon hydrogen production technologies have not been demonstrated at scale in the UK. In addition, learnings are likely to vary by technology in the near term because the technologies have different levels of maturity. Investment in less mature technologies will be associated with higher learning externalities.
- **Spillovers** related to shared skills and infrastructure could be provided. Recent research commissioned by BEIS found that business opportunities associated with hydrogen infrastructure could reach up to £1.5 billion in Gross Value Added

[22] For more detail on the methodology see Annex E.

(GVA).[23] In particular, hydrogen production facilities help harness the economies of scale associated with carbon transport and storage networks.

This means that without any intervention, the level of investment in low carbon hydrogen production will be too low because investors are not compensated by the market for these externalities.

Implications for business models

The presence of multiple externalities has the following consequences:

- **A carbon price alone would be insufficient to address all externalities.** A long-term credible carbon price would address the carbon emission externality. However, this would be insufficient to deliver an optimal investment outcome for society as it would not address the learning, innovation, and spillover value that is gained by developing new decarbonisation technologies.
- **Technology-specific support may be needed (in the near term only).** Less mature technologies like PEM electrolysis that currently have higher costs (see Section 3.3 below) will struggle to compete with more established technologies such as SMR. Technology-neutral support therefore risks picking more established technologies which may not be the best decarbonisation options in the long run. To address this issue, it may be necessary to provide technology-specific support in the near term, while recognising that a move to technology-neutral support would be optimal over the longer term. In the longer term, technology neutral support should take into account the different carbon intensities of different technologies.

3.2 Markets

Focussing on industrial uses, the main near-term barrier to production is the lack of an established market for low carbon hydrogen. This is driven by two important features of low carbon hydrogen:

- **Low carbon hydrogen is more costly than the carbon-intense alternative of natural gas for industrial users**.[24] It will also be more costly than hydrogen feedstock produced in a carbon intense way (generally SMR without CCS). This is because externalities described in Section 3.1 are not properly rewarded by the market through an effective carbon price. The presence of these externalities means that demand for low carbon hydrogen will be determined by policy. This in turn means that investors face policy-driven demand risk, something that is very difficult for them to manage.
- **Low carbon hydrogen is not a direct substitute for natural gas** Most industrial customers use natural gas as their incumbent fuel. Switching to hydrogen generally requires investment in new equipment such as boilers.

These two features lead to risks and barriers for customers and investors.

[23] Vivid Economics, (2019), *Energy Innovation Needs Assessment - Sub-theme report: Hydrogen and fuel cells* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/845658/energy-innovation-needs-assessment-hydrogen-fuel-cells.pdf

[24] Reformation technologies with CCUS will always be more expensive than natural gas because they apply an additional process to natural gas (by converting it to hydrogen), and grey hydrogen (through the CCUS process).

- For industrial customers, the high cost of low carbon hydrogen is a barrier to take up. Industry cannot pass on this higher cost by charging a higher price for products produced using low carbon fuels because as low carbon attributes are not currently fully rewarded in the market. So, there is no incentive for them to take up the low carbon fuel. This barrier requires policy support to take low carbon hydrogen to at least price parity with the carbon-intense alternative in order to make it an economic option for industrial users.
- In addition to the ongoing higher cost of low carbon hydrogen relative to alternative fuels, the process of switching from natural gas to low carbon hydrogen is costly because equipment such as boilers must be converted. There is also a disruption cost, for example where continuous production processes must be disrupted to make changes. Policy support may be needed to address this cost as well as the ongoing cost difference between fuels.
- Switching also entails risks for consumers, because production will be concentrated among relatively few producers in the near term, and regional or national transport networks are unlikely to be in place. This could lead to a risk of supply interruptions or local market power. Dual fuel operations may help manage this risk for some consumers but may not be possible or optimal for all consumers.[25]

Figure 16 summarises the risks and costs for customers who switch from natural gas to low carbon hydrogen.

Figure 16 Switching costs for industrial customers

Methane	Low carbon hydrogen
▪ Liquid, well-established and competitive supply market. ▪ No upfront capex for switching. ▪ Option remains open to switch in the future when carbon price gets higher. ▪ Option remains open to take up other abatement options in the future (electrification, post combustion capture).	▪ Illiquid, new market, with potential for supply interruptions and market power among relatively few producers. ▪ Upfront capex required for switching, as well as period of outage/interruptions and potential for new operational risks. ▪ Risk that carbon price will not rise, or that other abatement options turn out to be less expensive.

Source: Frontier Economics

Other end user groups face different barriers, which are outlined in Figure 17. As discussed in Section 2.2 above, based on current evidence, the decarbonisation value of low carbon hydrogen is thought to be highest in industry, at least in the near term. This is because industrial users are likely to have fewer alternative practical and cost-effective decarbonisation options than other end user groups.[26]

However, the fact that the decarbonisation value is highest in industry is not reflected in the prices of fuels that customers actually face. For example, once taxes are taken into account, low carbon hydrogen could potentially compete with the retail cost of diesel in the transport sector[27]. In contrast, low carbon hydrogen

[25] An import market may reduce the switching risks for industrial customers by providing increasing market liquidity. At the same time, it would increase the demand risks faced by producers, as discussed below.

[26] Element Energy & Jacobs, (2018), *Industrial Fuel-Switching Engagement Study* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/764058/industrial-fuel-switching.pdf

[27] BEIS (2019) *Business models for Carbon Capture, Usage and Storage* - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819648/ccus-business-models-consultation.pdf

is much more costly to users than natural gas, which will often be the incumbent fuel in industry. This means that additional policy intervention may be required to divert hydrogen for use in the sectors where its decarbonisation value is highest.

Figure 17 Customer demand features

	Demand patterns in the near term	Demand locations	Switching costs and barriers	Long term contracts
Industry	Large baseload demand profile could provide an anchor for early projects	Clustered demand, located near to CO2 T&S networks	Upfront capex/disruption required for current methane users to switch over. Dual fuel unlikely to be practical in most cases	Plants can close down, offshore or switch fuels. May be unwillingness to sign long term contracts
Blending (inc. heat)	Stable and reliable source of demand but feasibility at scale still being tested. If successful could be backstop customer	Anywhere there is a gas grid connection (noting that issues with T&D are different)	Current regulatory limits to blending Requirement for safety testing in some applications	Long term contracts likely to be possible. Potential exposure to consumer acceptability issues
Power	Intermittent demand- main role is likely to be in peaking plant. Low carbon power gets CfDs and avoids ETS	Relatively flexible	Up front capex required for switching Storage needs may be significant	Long term contracts may be possible, depending on capacity market developments
Transport	Small scale demand in near term. Taxes mean that retail cost of counterfactual fuel is very high	Distributed across the country and at ports and train depots, driven by refuelling needs	Refuelling infrastructure is not in place Switching cost for users where H_2 vehicles are more costly	Possibility of long term contracts

Source: Frontier Economics

Investor risks and barriers

At present, the lack of demand for low carbon hydrogen makes it unprofitable to invest in low carbon hydrogen production.

Because part of the value of hydrogen relates to non-market goods, policy intervention is required for demand to increase to its efficient level. This means that even if policy support is in place to overcome the customer barriers and create demand for low carbon hydrogen, investors will still face significant ongoing policy-driven risks around demand for their product. For example, there is a risk that the government may decide to stop supporting low carbon hydrogen as a decarbonisation option. These types of policy risks are difficult for investors to manage and given their importance to the business case for investment, it may make sense for them to be transferred from investors. In fact, several stakeholders stated that unless these risks are managed by the business model, investment could not go ahead.

In addition to policy risks around demand, industrial customers could close down, move offshore or switch back to carbon-intense fuels. The potential for imported low carbon hydrogen to enter the market further increases the demand risk for domestic producers.

Implications for business models

In summary, these market issues have six main implications for business model design.

- **Support is required to allow low carbon hydrogen to compete with the incumbent carbon-intense fuels.** In the absence of this support, a market for low carbon hydrogen is unlikely to develop. To achieve the best value for taxpayers and billpayers, support should be allocated using market mechanisms such as auctions, where possible. However, initially, where the numbers of potential projects are low, support levels could be set administratively. In developing the support mechanism, it will be important to ensure that the governance of the framework is transparent.

- **Policy intervention may be required to divert hydrogen for use in the sector (industry) where its decarbonisation value is likely to be highest.** The fact that the decarbonisation value is highest in industry is not currently reflected in the prices of fuels faced by customers.
- **Industrial customers are likely to require additional support for switching.** Hydrogen is not a direct substitute for natural gas. The costs and risks for industrial users who switch from natural gas to low carbon hydrogen are a key barrier to take-up. This means that complementary support to end users will be required to support switching.
- **Demand risk may need to be transferred away from investors.** Demand for low carbon hydrogen is highly uncertain and largely policy-driven because it relies on policy support to make it an economic option for end users. Investors therefore are not well placed to manage this risk, and so business models should help to insulate investors from uncertainty around demand.
- **Market power risks.** In the near term, market power may be a risk, given there may be a small number of producers and consumers in each area and wider transport networks may not be in place.
- **Complexity of the low carbon hydrogen value chain.** Many different elements are involved in the value chain including CCUS T&S, hydrogen T&S, and carbon capture technologies. Although our focus is on industrial users, business model design should take into account the interactions of support mechanisms across the value chain, and the potential for complexity if support mechanisms of different forms are introduced in different parts of the value chain.

3.3 Technologies

Two key aspects of technologies should inform business model design:

- technology maturity
- technology cost structure.

3.3.1 Technology maturity

Stakeholder feedback suggests that technology barriers are low, as many components of the technologies are relatively mature. However, some technologies are at different stages of maturity. And even for more mature technologies, there are risks associated with the lack of full-scale deployment in the UK.

The maturity levels of each technology are outlined in Figure 18. The less mature technologies will have greater learning externalities associated with them, as set out in Section 3.1. Business model design should take into account these differences to avoid the risk that technologies that are less mature now are not available as part of the future portfolio of low carbon hydrogen production technologies. However, we note that in the longer run, a move to technology-neutral support is likely to be preferable.

Figure 18 Technology maturity

Technology	Maturity
SMR with CCS	SMR is mature but not when combined with CCS
ATR with CCS	ATR has not been tested at scale CCS combined with ATR is not mature
Biomass gasification with CCS	In development but has not been demonstrated at scale CCS combined with biomass gasification is not mature
Alkaline electrolysis	Reasonably mature technology
PEM electrolysis	At demonstration phase but has not been tested at scale

Source: Based on stakeholder interviews and literature review

The lack of deployment at scale as part of a full low carbon value chain impacts investor perception of risk. This increases costs through combination risk and construction risks.

- Combination risk arises from uncertainty around how well the technologies can be integrated throughout the value chain.
- Construction risks is associated with complex production facilities requiring multiple contractors for the different elements. These risks tend to be complex to manage and may entail a mismatch in contractual arrangements on liability. The investor will not be able to cover all construction risks and will have to incur the costs of managing these. Some construction risks can be mitigated through contracting, but this will come with a risk premium on costs.
- Outage risk arises if producers are unable to supply committed volumes of hydrogen. Producers may also face liability issues for damages, penalties or higher supply costs under their supply contracts if this occurs.

3.3.2 Cost structures

Figure 19 illustrates how the cost structure of the key technologies varies. For illustrative purposes, we have assumed in this case that Alkaline electrolysis is combined with dedicated renewables, while PEM electrolysis is combined with grid electricity. However, both technologies could be combined with either dedicated renewables or grid electricity.

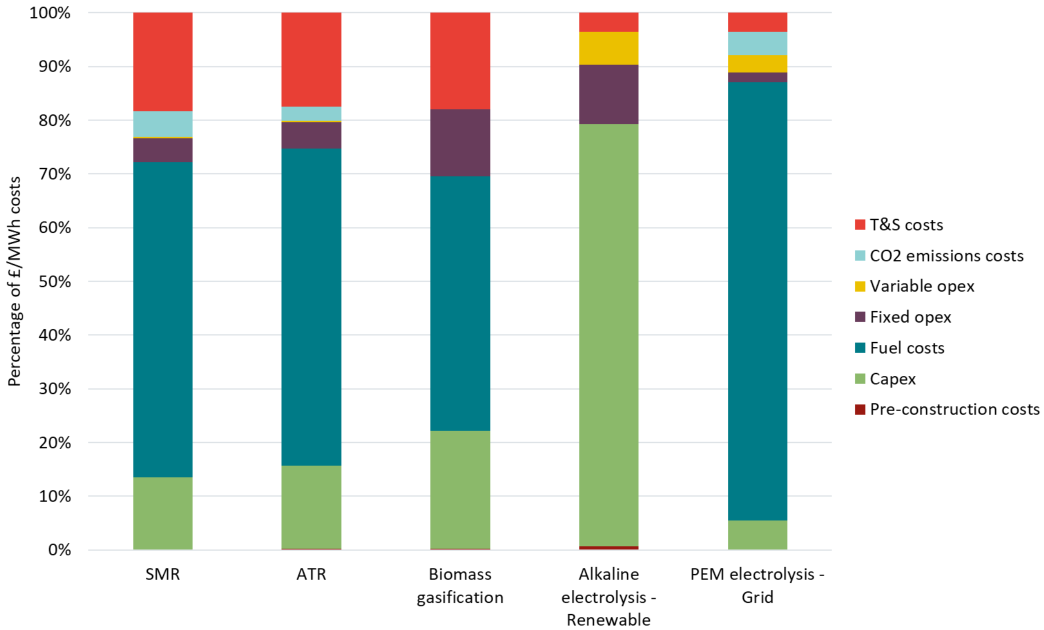
This illustrates that for all technologies apart from electrolysis with dedicated renewables, fuel costs dominate, accounting for at least 60% of total costs for these technologies. In the case of electrolysis with dedicated renewables, capex replaces fuel costs as the dominant cost, accounting for almost 80% of all costs.

Biomass gasification has higher capex and fuel costs than either methane reformation technology, however when combined with CCUS the negative CO_2 emissions could potentially be a significant source of revenue, if remunerated.[28] In

[28] This estimate assumes that hydrogen producers using biomass gasification are rewarded for negative emissions at the current carbon price.

all the business models we have explored, BECCS producers would need to be compensated for these negative emissions in order to be cost competitive.

Figure 19 Comparison of cost structure across technologies[29]



Source: Frontier Economics

Notes: The above chart omits negative carbon costs from BECCS. If negative emissions are valued at the carbon price specified in the Green Book Supplementary Guidance[30], this could offset more than 70% of costs.

Implications for business models

Technology-related issues have three main implications for business model design:

- **Technology specific support may be required due to maturity differences.** A technology-neutral policy could see production from SMR or ATR dominate in most locations. Given the potential for the costs of less mature technologies to fall over time, it may make sense to allocate funding separately for different technologies.
- **Support levels should fall over time for new investments.** The lack of full value chain deployment means that the first producers will face high risks associated with first of a kind projects. This may require additional compensation relative to future projects once the technologies are proven.
- **Technologies have different cost structures.** Running costs dominate for most technologies. The fact that electrolysis with dedicated renewables has a different cost structure to the other technologies may imply that different business models are appropriate.

[29] The aim of this work was not to determine new estimates for the costs of hydrogen production technologies. We therefore used existing estimates in the literature as our input assumptions. Technology cost inputs are mainly based on research by Element Energy. The sourced input assumptions used for each technology are in Annex E.

[30] https://www.gov.uk/government/collections/the-green-book-supplementary-guidance

3.4 Existing policy

In addition to the policy risks covered in Sections 2.1 to 2.3, stakeholders also highlighted the following risks around the existing policy framework:

- Stakeholders view the future direction of policy as uncertain. Decarbonisation targets are insufficient incentives without supporting policies. Business models should have sufficient contractual arrangements in place to give long-term confidence to investors.
- Co-ordination across different public sector organisations is important because the full value chain extends across multiple sectors.
- Regulation and standards will need to be changed to support low carbon hydrogen deployment. For example, current limits on grid blending will need to be reviewed if the trials prove the case for blending.
- Slow progress on support for decarbonisation options is problematic because of the length of time projects need to get started. Timely action is required to get the first projects off the ground in the 2020s.
- There is the potential for support for hydrogen producers to interact with existing policy, such as the Renewable Fuel Transport Obligation (RTFO).

Implications for business models

- **Support should not be open to ongoing adjustments.** Investors require confidence that changes to government policy will not reduce the level of support (for example, through changes to the strike price) leaving them unable to make a return.
- **Complementary policy will also be required.** This should ensure that regulation and standards enable low carbon hydrogen production, and interact effectively with other policy frameworks e.g. the RTFO. Additional support for industry switching will also be required.
- **Low carbon hydrogen support may have an impact on other low carbon policies.** This could include a successor to the EU ETS scheme, following Brexit. The impact of low carbon hydrogen support on the emissions from sectors covered by this scheme should be taken into account when the cap level is set.

3.5 Key priorities for business models design

Based on the above, we identify nine priorities for business model design (**Figure 20**).

Figure 20 Priorities for business model design

	Priority	Explanation
1	Subsidy to cover externalities associated with production of low carbon hydrogen	The required support level needs to enable investors in low carbon methods of hydrogen production to compete with the incumbent carbon-intensive fuel. The alterative (to tax the externalities associated with the alternative fuel) is unlikely to be practical in the near term, given risks of industrial offshoring. Ideally the level of the subsidy will be determined by competition, however for some of the first investments the level may need to be administratively set.
2.	Focus on uses where the decarbonisation value is highest	The decarbonisation value of hydrogen will be highest where viable and cost-effective alternative decarbonisation options are not available. In the near term, while the quantity of low carbon hydrogen produced is still limited, the intention is for policy to aim for the use of low carbon hydrogen in industry.
3	Technology-specific support (in the near term only)	Without separate support, it is likely that the more mature technologies would dominate given the difference in technology maturity. This may not be optimal given learning externalities. This means that technology-specific support may be needed in the near term, although technology-neutral support (which takes account of differences in carbon-intensity) will be more efficient as the market matures.
4	Transfer of demand risk away from investors	We find that there is a significant, and mainly policy-driven, uncertainty around demand for low carbon hydrogen. It would be difficult for investors to manage risks around this through market means (e.g. long-term contracts). For example, industrial customers could go out of business, or policies to encourage switching to low carbon hydrogen may not turn out to be effective. Unless demand risk is transferred away from investors investment may be limited.
5	Reduce risk of policy change	Investors require confidence that support levels will not be adjusted in unforeseen ways over the lifetime of their investment. Support for a given investment should not be open to ongoing unilateral adjustments.
6	Separate switching support for users	The upfront costs associated with switching should be covered separately through a payment to end users. Otherwise, demand for low carbon hydrogen may be limited, even where low carbon hydrogen can compete on price with the incumbent carbon-intense alternative fuel. Allocation of this support could be done on the basis of which users will have the highest decarbonisation value associated with switching to low carbon hydrogen, for example industrial processes that are difficult to electrify.
7	Reductions in support for successive investments	The lack of full value chain deployment means that the first producers may face higher risks associated with first-of-a-kind projects. This may require additional compensation relative to future projects that would occur once the technologies are proven. Business models should allow support to be reduced for successive investments.
8	Compatibility with existing policy	Support mechanisms should be designed to be compatible with existing sectoral policies – for example to avoid double subsidies under the Renewable Transport Fuels Obligation (RTFO).
9	Reduce risk of market power	In the near term, there may not be a liquid, well-functioning market for low carbon hydrogen. Consideration of risks around market power in the very early stages of the market should be addressed by the business models

Source: Frontier Economics

4 BUSINESS MODELS

BEIS defines business models as the systems of actors, infrastructure, financing for development and operation costs, use of revenues and profits, and risk ownership required for hydrogen production infrastructure to be developed and operated.

Business models aim to address the key risks and barriers that prevent low carbon hydrogen from developing without policy support, which are set out in Section 3.

In this section:

- We first present a longlist of business models and describe key features that they have in common.
- Based on the nine key priorities identified in Section 3, we then apply an initial filter.
- Focussing on the models that pass this filter, we then consider key choices around the design features for each of these models.
- Finally, we assess these key design choices against the six criteria agreed with BEIS (presented in Figure 14 above).

4.1 Business model longlist

Based on the literature review, case studies and stakeholder interviews we focus on four categories of support mechanisms. Examples of these models are described and assessed in detail in the annexes to this report. We summarise the categories in Figure 21:

Figure 21 Categories of support mechanisms

Business model category	High level description	Key features
Contractual payments to producers	The hydrogen producer receives a subsidy which covers the incremental cost of low carbon hydrogen above the carbon-intensive alternative fuel. The level of the subsidy (per unit of output or per year) is contracted between the recipient and a Government party.	We consider six design variants based on providing support in a number of ways: ▪ Standard payment with backstop or split payment. The payment could be based on outputs (with a backstop purchase arrangement in place), or as a ‘split’ payment (covering capital and fixed costs regardless of demand) and a variable payment covering running costs. ▪ Premium or revenue stabilisation mechanisms (CfD). Payments can be provided on top of the low carbon hydrogen price (premium) or the output price achieved can be stabilised through a CfD. ▪ Fixed or indexed. The premium payment, or strike price can be fixed, or indexed to the input price (for natural gas, biomass or grid electricity).
Regulated returns	Regulated returns models such as a Regulated Asset Base (RAB) model or a Cap and Floor model allow the hydrogen producer to earn a regulated return on costs.	Regulated returns models could be designed to provide the same structure and level of payments to the producer as under the six variants considered for contractual payments. The key difference is that the payments will be regulated rather than contractual.
Obligations	An obligation is imposed on parties outside the hydrogen production sector (e.g. fuel suppliers or end users) to supply or consume a certain quantity of low carbon hydrogen. This obligation is policy-based rather than contractual, and can be adjusted over time.	We consider an obligation on suppliers to supply a certain quantity of low carbon hydrogen. ▪ Parties could meet the obligation either by consuming or supplying low carbon hydrogen or by submitting certificates provided by others who have exceeded their obligation. ▪ Low carbon hydrogen producers sell tradeable obligation certificates along with the low carbon hydrogen and receive additional income from this.
End user subsidies	Abatement subsidy is offered to industrial emitters.	We consider an end user subsidy for industrial customers ▪ The subsidy is offered on an ongoing basis, per tonne of carbon abatement by industrial customers, relative to a defined baseline. ▪ The subsidy is technology-neutral (can be used to fund any abatement).

Source: Frontier Economics

4.1.1 Common features of business models

In Section 3, we identified nine priority considerations for business model designs:

Five of these priorities are compatible with all categories of business model, and therefore are common feature across all of the business models we consider. The priorities that can be delivered by all business models are as follows.

- **Provide a subsidy to cover externalities.** Across all models, support can be provided at a level that aims to cover externalities and to allow investors to gain a required return. Support can be set at a level that allows the producer to break even, given its technology costs, the revenue it can gain from the sales of hydrogen, and its cost of capital. This means that the support enables the low carbon hydrogen to compete with the main incumbent fuel (see Box 2 below). For all models, except the end user subsidy, support would be allocated based on an assessment of low carbon hydrogen production needs and an application process. Alternatively, a competitive auction process could be used. The competitive auction would be specific to particular technologies or technology groups in the near term.[31]

[31] In the longer term, as technologies mature, it would be optimal to move to a technology-neutral auction.

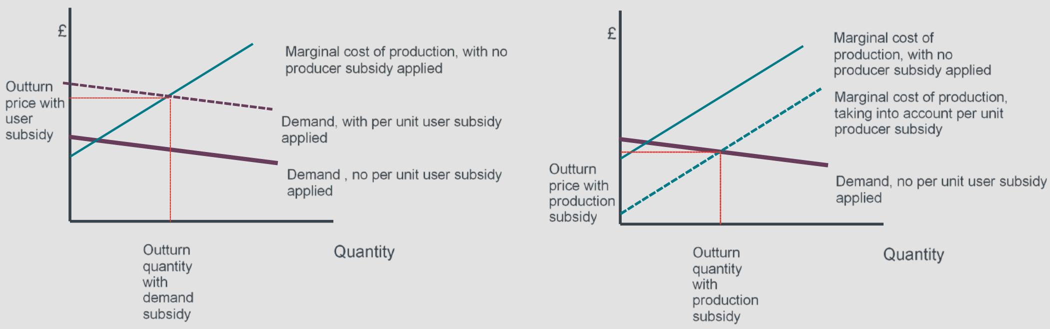
BOX 2: IMPACTS OF BUSINESS MODELS ON THE PRICE OF LOW CARBON HYDROGEN

An intervention involving the application of a subsidy will increase demand for low carbon hydrogen. It will do this by either increasing the price that users are willing to pay for low carbon hydrogen (through the application of an end user subsidy) or by reducing the price of low carbon hydrogen (through a production subsidy). This is illustrated in Figure 22 which shows how price would be formed in a well-functioning market with subsidies applied (the cost and demand curves are purely illustrative in this figure).

- **End user subsidy.** In this case, the price will reflect the marginal cost of production of low carbon hydrogen.
- **Other business models.** Where a subsidy is applied per unit of low carbon hydrogen produced, the price of low carbon hydrogen and the quantity consumed will be determined by the marginal cost of production, minus the per unit producer subsidy.

All of the business models considered therefore will have a direct impact on the price of low carbon hydrogen, assuming a well-functioning market.

Figure 22 Price formation where a subsidy is applied



Source: Frontier Economics

- **Focus on uses where the decarbonisation value is highest.** All of the business models can be designed so that the low carbon hydrogen is diverted to industry, where the decarbonisation value is likely to be highest. For contractual payments, and regulated returns models, the model could be designed to provide a subsidy only where the low carbon hydrogen is sold on for industrial uses. These uses could be verified through certification and metering. For the obligation model, the model could be designed so that obligation certificates would only be provided where the low carbon hydrogen is sold on for industrial uses. For the end user subsidy, this could be provided only to industrial users.
- **Separate switching support for users.** Switching costs for industrial customers could be supported separately across all business models. The upfront costs to users of low carbon hydrogen associated with switching are covered separately through a payment to end users. This allows the business models to focus on reducing ongoing costs.
- **Compatibility with existing policies.** Business models can be designed to avoid double subsidies. This could mean for example, that low carbon

hydrogen from producers receiving subsidies would not also be entitled to generate Renewable Transport Fuel Certificates under the RTFO.[32] Similarly, eligibility for support under the CfD mechanism in the electricity sector introduced to encourage low carbon generation using hydrogen could be restricted so that it does not apply where subsidies have received upstream through these mechanisms.[33,34] It is also important to recognise that there are a range of business models in place across the value chain, and that introducing new and different business models could increase complexity.

- **Reduce risk of market power.** The risk of market power as the first plants are developed can be considered in all models. In the near term, there may not be a liquid, well-functioning market for low carbon hydrogen. Box 3 describes some options for managing this risk.

BOX 3: MANAGING THE RISK OF MARKET POWER IN THE NEAR TERM

The risk that there will not be a liquid, well-functioning market for low carbon hydrogen in the near term also needs to be explored. This is because in the early years:

- markets will be local, as a regional or national transport network for low carbon hydrogen is unlikely to be in place; and
- in any local area there is likely to be a small number of low carbon hydrogen producers to choose from, as the market builds up.

Producers or consumers could have market power in this situation.

This could be managed by:

- **Relying on market forces.** While there is a risk of producer market power, each producer is likely to be relying on demand from a small number of large industrial customers. In this case, the producer's pricing is constrained by the risk of industrial customers offshoring or converting back to natural gas (especially where dual fuel is possible or switching costs are limited).
- **Existing policy around competition law could be strengthened by additional licence conditions.** We assume that the hydrogen production facility would require a licence. Competition law already provides for protection against abuse of dominance, but this could be further strengthened by additional licence conditions to address the specific risks from this situation.
- **Price regulation in the near term.** This is a more substantial intervention that would reduce the risk that industrial customers would face excessive prices for low carbon hydrogen. Once a liquid market was established, price regulation could be removed. However, regulating the price has several major downsides:
  - It would make it harder to allow producers to offer different prices to different consumers, depending on their cost to serve (which may be impacted by

[32] Under the RTFO suppliers of transport fuel in the UK must be able to show that a percentage of the fuel they supply comes from renewable and sustainable sources by submitting Renewable Transport Fuel Certificates (RTFCs). Source: https://www.gov.uk/guidance/renewable-transport-fuels-obligation

[33] For example, detailed technical eligibility requirements are already in place for the participation of ACT technologies in the CfD. See: https://www.gov.uk/government/publications/advanced-conversion-technologies-act-technical-guidance-contracts-for-difference-allocation-round-3

[34] Support under the Capacity Mechanism would not constitute double counting, since the Capacity Mechanism is not providing a reward for carbon reductions.

demand patterns, scale etc). Regulation could be designed to allow different pricing strategies, but this would add complexity.

- Depending on the complexity of its design, it could be very administratively burdensome, for producers, consumers and regulators.
- It potentially exposes consumers and producers to ongoing policy risk, if the regulated price can be adjusted over time.
- The requirement (or not) for any price regulation of hydrogen is one that will require further analysis and consultation as part of the future work that BEIS is due to undertake.

4.2 Filtering based on key features of models

Five of the nine priorities identified in Section 3 can be delivered using any business model. However, Figure 23 illustrates that the four remaining priorities cannot be delivered easily under an obligations model or with end user subsidies:

- technology-specific support cannot be delivered via end user subsidies;
- demand risk remains with investors under the end user subsidies;
- the risk of ongoing policy adjustments remains with investors under end user subsidies and obligations;
- support cannot be reduced under end user subsidies.

Figure 23 Business model category filter

	Contractual payments to producers	Regulated returns	Obligations on suppliers	End user subsidies
Technology-specific support (in the near - term only)	**Yes** – support can be allocated separately to different technologies	**Yes** – support can be allocated separately to different technologies	**Yes** – obligation certificates can be banded[35]	**Difficult** – while an end user subsidy could be designed to be technology specific, this would add significant complexity
Transfer of demand risk away from investors	**Yes –** support payments can be made regardless of demand (either through a backstop or split payment)[36]	**Yes –** returns on fixed and capital costs can be gained, regardless of demand	**Difficult** - A 'split' payment is not possible. While a backstop could be applied, this would be very complex[37]	**No** – demand for low carbon hydrogen is driven partly by availability of alternative abatement options and by the level of the subsidies (which could be adjusted or removed)
Reduce risk of policy change	**Yes** – contracts cannot be changed by policy-makers ex post	**Yes –** length of price control or cap and floor periods can be set to a level that reduces this risk	**No** – obligations can be adjusted over time by policy-makers	**No** – end-user subsidies can be adjusted over time by policy-makers
Reductions in support for successive investments	**Yes** – support payments can be reduced over time for successive investments	**Yes –** regulated returns can be reduced over time for successive investments	**Yes** – obligation certificates can be banded by vintage	**Difficult**– while an end user subsidy could be designed to reward plants of different vintages separately, this would add significant complexity

Source: Frontier Economics

At this stage, we filter out the obligation and end user subsidy models.

Based on the analysis in Figure 23, we believe that the obligations and end user subsidy models are less promising than the contractual payments and regulatory return models. The reasons for our view are as follows:

35 Banding would involve allowing some technology types to generate more obligation certificates pre unit of hydrogen produced than others. It is discussed in detail in Annex F.

36 The backstop and the split model are discussed more in the next section.

37 See Annex F for a discussion of this.

- **Investors will continue to be exposed to policy uncertainty under an obligation.** As described in Section 3, because of the externalities associated with low carbon hydrogen production, and because low carbon hydrogen in the near-term expected to be significantly more expensive than the alternative carbon-intense fuels, investors will be reliant on policy support in order to gain their required returns. Before investing in production plants, investors will seek confidence that support levels for a given investment will not be adjusted in unforeseen ways over the lifetime of their investment. However, it is difficult to design an obligation model to be robust to the risk of policy change. Support for a given investment would be open to ongoing unilateral adjustments. This is because the obligation certificate price will be in part determined by detailed rules of the scheme, such as the level of the obligation, the buyout provisions and any banding. These detailed rules can be changed over time by policy-makers. While investors may in some cases be happy to invest under an obligation, their cost of capital (and therefore the subsidy they require to make the investment) will be higher than under business models that provide more certainty.
- **Investors will be exposed to demand risk under an end user subsidy model.** A technology-neutral end user subsidy may not support an emerging low carbon hydrogen market (though this type of intervention may be efficient in the longer term). Since the subsidy is applied for abatement, rather than for low carbon hydrogen consumption, demand risk for low carbon hydrogen would remain with the producer. In the context of a sector where long term contracts may be difficult to secure, this demand risk is likely to be difficult for producers to manage. In addition, if the end user subsidy is designed to be technology-neutral, it would not allow technology specific subsidies to be applied. It would not allow differentiation between vintages of investment, and so would not allow support to be reduced over time for successive investments. Subsidies specific to technology types and vintages could be designed, but this would add significantly to the complexity. Therefore, while an end user subsidy may be optimal in the longer term, it is unlikely to bring on the required diverse mix of investments in the near term.

Because of this, we focus on the contractual payments and regulatory return models in the rest of this section. However, the obligations and end user subsidy models are described in detail and assessed against criteria the annexes to this report.

4.3 Model design principles

The rest of this section discusses the advantage and disadvantages of key design choices for contractual and regulatory returns models:

- options for managing downside demand risk;
- the choice between premium or revenue stabilisation models; and
- options for managing input cost risk.

We also discuss options for implementation (contractual or regulatory approach)

We set out the options for each choice, and then go on to assess the options against a set of criteria in Section 4.4.

4.3.1 How can downside demand risk be managed?

As described in Section 3, downside demand risks would be generally very difficult for investors to manage. This is because demand for low carbon hydrogen is largely driven by policy.

Unless downside demand risk is managed, it may result in a very high cost of capital for investors, or it may result in limited investment coming forward. For example, if investors see the investment decision as binary, they may consider that there is insufficient protection from demand risk for investment to go ahead at all, regardless of the potential return.

The options for managing demand risk for producers are:

- apply a backstop; or
- apply a split support structure.

Backstop

One option is to continue to pay the producer[38] full support even when demand is lower than expected. This could be implemented through a backstop mechanism (Box 4) whereby a Government counterparty steps in as a 'buyer of last resort' in the event that industrial demand fluctuates, for example due to offshoring or recession.[39]

This will protect producers' revenue if demand is low. However, it would also expose taxpayers or bill payers to paying the full subsidy for low carbon hydrogen even if it is not needed. We present analysis on the potential impact of this on support payments per unit of low carbon hydrogen in the detailed annexes accompanying this report.

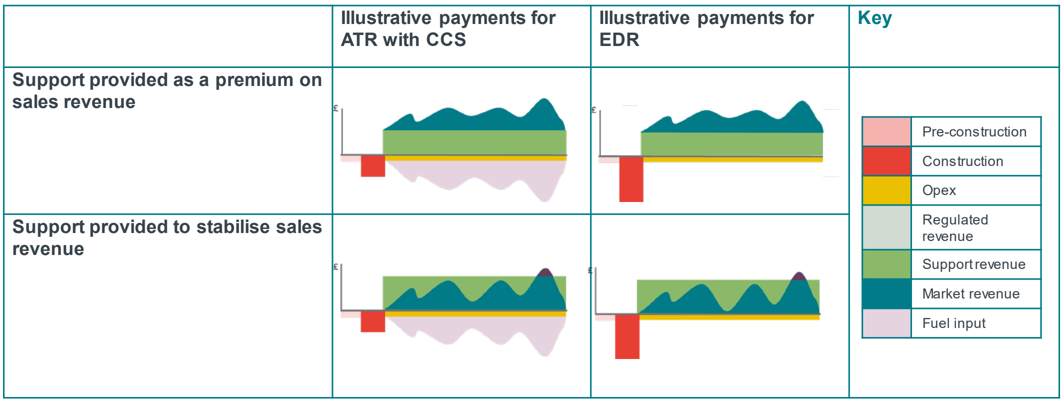
Figure 24 shows illustrative payments where a backstop is applied. Throughout, we use the examples of ATR plus CCS and electrolysis with dedicated renewables (EDR) to illustrate the profile of costs and revenue under each model. These represent the two main types of cost structure across the technologies considered[40]:

- ATR with CCS has very high running costs, with fuel input costs making up 60% of overall costs.
- In contrast, EDR is highly capital-intense, with very low running costs. This is based on the assumption that the dedicated renewables are wind, and that no grid connection is in place.

[38] Under the regulated returns models, support may be paid to the shipper rather than the producer. However, the net effect on producer revenues would be the same.

[40] The cost structure of BECCS is different in that it includes negative emissions. We assume throughout that negative emissions can be covered through an additional payment.

Figure 24 Illustrative payments profiles where a backstop is applied



Source: Frontier Economics Note: These figures assume a backstop is applied.

BOX 4: BACKSTOP PURCHASE AGREEMENTS

A **backstop** would involve a role for Government to be a 'buyer of last resort' to provide demand certainty for producers, as the market develops. For example, a Government counterparty (an organisation like the LCCC) commits to buying hydrogen and using it for grid blending, in the event that industrial demand fluctuates, for example due to offshoring, or recession. Conditions would need to be set that determine when the Government counterparty steps in such as a material volume reduction in sales, due to customer closures.

To ensure the backstop was a last resort measure, T&Cs could be negotiated as part of allocation. Therefore, producers could opt for less of a backstop in return for a higher support payment.

Incentives for the producer to find new customers could be maintained by providing less than full compensation – for example, producers may have to bear a three-month interruption to sales before the backstop kicks in.

The backstop would be subject to time limits and the producer would have to renew arrangements periodically with the Government, providing evidence that commercial buyers were not available.

Buyout

There may also be extreme circumstances beyond investor control, under which the Government (or a party acting on its behalf) is obligated to buyout the production facilities. For example, this may occur if support for low carbon hydrogen is withdrawn (e.g. because an alternative abatement option emerges or because something such as an accident turns the public against low carbon hydrogen). The triggers for, and conditions attached to, such a buyout should be part of the support contract.

Split support structure

An alternative way of managing demand risk, would be to provide support under a split payment structure. Instead of paying producers the full subsidy for each unit of production, the support payments could be designed to have two components.

- One payment covers capital and fixed costs. This would be paid to producers on an annual basis, even if outturn demand was lower than that projected. This payment would be constant over time.
- One payment covers variable costs. This would only be paid to producers proportionate to the level of low carbon hydrogen that is actually demanded, and would be focussed on covering running costs. This payment would be constant over time on a per unit basis, but the quantity received by the producer would vary according to production.

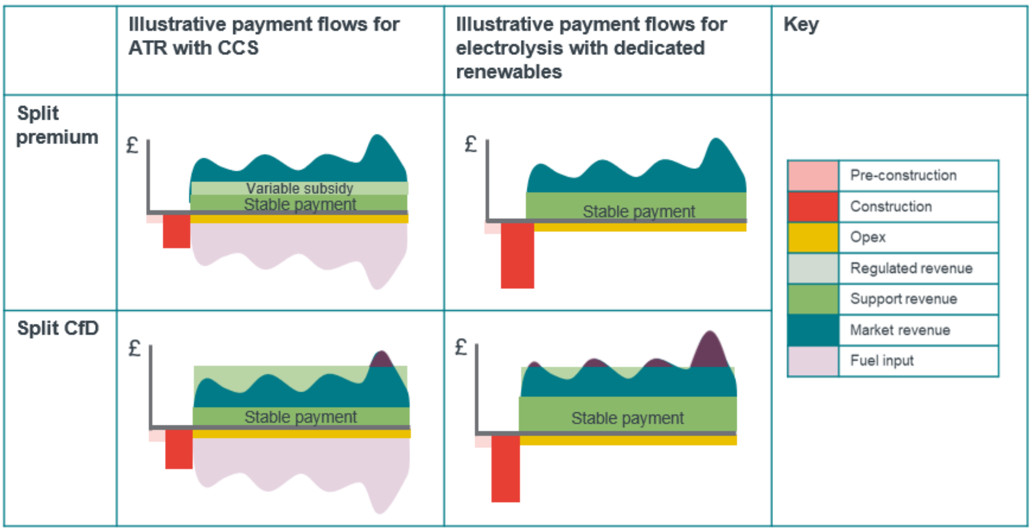
To ensure producers have an incentive to maintain availability and to seek sales, the payment covering capital and fixed costs could be set slightly lower than that required to give full compensation to producers (with a corresponding slight increase in the variable payment, relative to what would be required to cover running costs).

This feature could be incorporated into contractual options and regulated returns designs.

- Contractual options could include fixed payments which are made regardless of demand, and a separate variable payment which is paid in line with the amount demanded.
- Regulated options could allow producers to earn a return on their capex and fixed costs, which would be paid even if demand was low. The variable payment could be paid only when there is demand for hydrogen. Regulatory models that include separate compensation for fixed and operating costs have been used in the networks sector.

Illustrative payment structures under the split models are shown in Figure 25.

Figure 25 Illustrative payments under split models



Source: Frontier Economics.

Note: In this illustrative example, we assume that for the EDR split premium model, the stable payment has been adjusted to take into account expected sales. See discussion in Section 4.3.2 below.

We note that splitting the subsidy in this way could increase administrative complexity over and above setting one subsidy which is not split, under both a regulatory and contractual option. In both cases, the level of the fixed and variable subsidy payment needs to be determined, either administratively or via auctions.

However, the split support design has a major advantage over the backstop, because it manages demand risk for producers but does not leave taxpayers exposed to paying the full price for hydrogen that isn't needed. We assume that this measure is in place when discussing the next choices.

4.3.2 The choice between premium and revenue stabilisation models

Under a premium model, producers receive a subsidy on top of market revenue from the sale of low carbon hydrogen. In contrast, a revenue stabilisation model aims to provide a guaranteed return to producers by topping up the revenue received through sales in the market (valued at an agreed reference price), to an agreed level (the strike price). Under both models, the subsidy could be set at a level that allows the investor to break even, given its revenues and costs and including its cost of capital. Both could be applied to either a contractual payment model or a regulated return model.

These models have different implications in two areas:

- allocation of upside demand risk; and
- ease of applicability to technologies with different cost structures.

Allocation of upside demand risk

We assume that support is set at a level that allows producers to sell low carbon hydrogen at the price of the carbon-intensive alternative fuel (see Box 2 above). Investors can be protected from downside demand risk by the backstop or the split structure. If the price was to fall below a level that covers the running costs, due to lower than expected demand, the producer could stop production, and still receive compensation for its fixed costs under the split model or it could sell via the backstop if a backstop is in place. But if demand is higher than expected, the low carbon hydrogen price could rise above the price of natural gas. The impact of this on producers will depend on the model.

- **Premium payments would allocate the upside demand risk to producers** Figure 25 above illustrates the flow of costs and revenues from the investor perspective. This shows that under a premium model, the investor remains exposed to variation in the low carbon hydrogen sales price as the subsidy is paid on top of sales revenue. As the price of low carbon hydrogen increases, producers receive more sales revenue and continue to receive the premium payment. This has the advantage of providing the producer with an incentive to seek sales at times when the value of low carbon hydrogen is highest. However, it also means that billpayers or taxpayers do not gain from lower subsidy costs, where market revenue from low carbon hydrogen is higher than expected.
- **It may be possible to allocate upside demand risk to billpayers or taxpayers under the revenue stabilisation models, but this may not be**

practical in the near term.[41] Revenue stabilisation mechanisms such as the CfD could allow billpayers/taxpayers to make a saving if the outturn low carbon hydrogen price is higher than expected, but only if a reference price based on the low carbon hydrogen price can be set. Setting such a reference price is unlikely to be possible in the near term, given the absence of a liquid market for low carbon hydrogen.

- If it is possible to set a reference price based on a low carbon hydrogen price, the level of the subsidy would adjust upwards or downwards as the low carbon hydrogen price changes. This would pass demand upside on to taxpayers or billpayers, as they would pay a lower subsidy when the low carbon hydrogen price is higher.
- Where the reference price is based on the natural gas price, producers will receive the difference between the reference price and the pre-determined strike price, and will gain if the low carbon hydrogen price is higher than the reference price. Under these conditions, producers would also have an incentive to seek sales at times when the value of low carbon hydrogen is highest. However, as with the premium, billpayers/taxpayers would not gain from lower subsidy costs, where market revenue from low carbon hydrogen is higher than expected.

This suggests that in the longer term, the revenue stabilisation model could have the potential to provide a better deal for consumers/taxpayers, by allowing subsidy costs to fall when the price rises. However, in the near term, both models will allocate upside demand risk to producers in a similar way.

Application to different cost structures

The split premium model and a split revenue stabilisation model would also differ in terms of their ease of application to technologies with different cost structures.

- **The split premium model would be difficult to apply to technologies with capital-intense cost structures such as EDR.** The split premium model shown in Figure 25 above could be applied to technologies with high running costs (such as the reformation technologies) by calculating a stable payment to cover fixed and capital costs and then calculating an additional variable payment to top up sales revenue so that running costs are covered. However, the premium model would be difficult to apply for EDR:
    - EDR technologies are capital-intense and have very low ongoing costs. These ongoing costs are likely to be below the price of low carbon hydrogen in the market.
    - Under the split premium design, the fixed component of the subsidy would cover the EDR capex and fixed costs (see Figure 25 above). Capex and fixed costs constitute the majority of costs for these producers.
    - At the same time, producers would receive market revenue. This revenue would be likely to exceed their variable costs, given the capital-intense cost structure of these investments.
    - To avoid overcompensation, the stable component of the subsidy would need to be adjusted, to subtract the value of the market revenue they are

[41] These instruments are not aimed at stabilising the low carbon hydrogen price for end users. In both cases, end users would continue to bear hydrogen price risk.

expected to achieve. This would require either forecasting the future revenue of the producer or a periodic true-up to adjust the level of the fixed payment for revenue received. These adjustments would add significant complexity and uncertainty to the system.

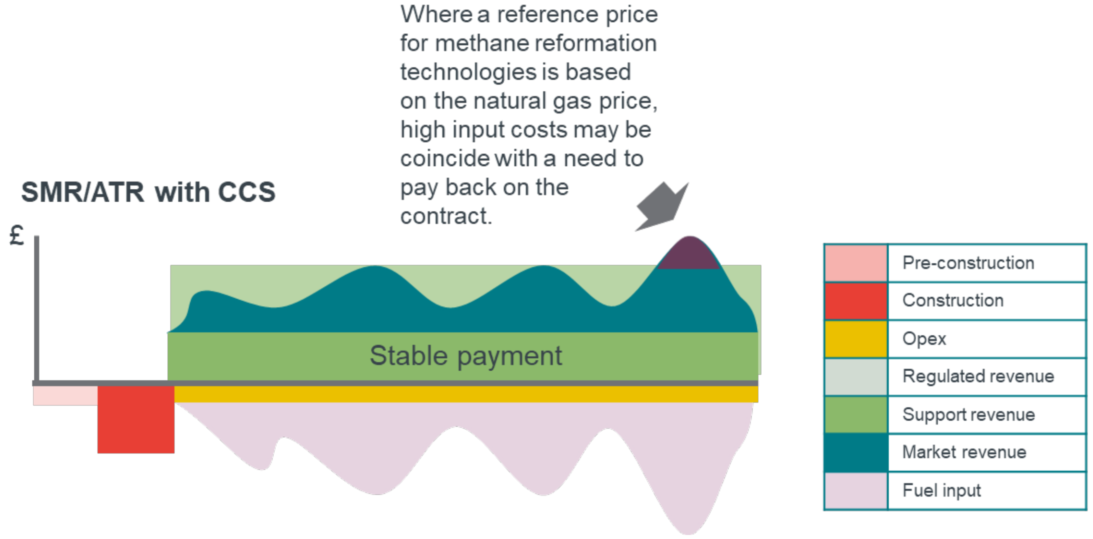
- **The split revenue stabilisation model can be applied to all technologies**. The split revenue stabilisation model is suitable for application to both capital-intense technologies and technologies with high running costs. Under this model, a fixed payment is received on an ongoing basis, and revenues are topped up or paid back up to the level of an agreed strike price (Figure 25). No forecasting or true up is required for EDR. Instead, when revenue is higher than the strike price, producers pay back to billpayers/taxpayers under the standard terms of the CfD or its regulatory equivalent.

Based on the above analysis, a revenue stabilisation model (such as a CfD, or a regulatory equivalent) may be preferable to a premium payment model because it can be applied to all the production technologies, including EDR.[42]

4.3.3 How should input risk be allocated?

One feature of the split revenue stabilisation model is that it allocates input price risk to producers, as it stabilises revenues, but leave input costs to fluctuate. This removes any natural hedge that there might be between input costs and the sales price of low carbon hydrogen. In particular, if a reference price based on natural gas is used, there may be situations where the reference price is above the strike price, meaning methane reformation producers must pay back on the contract, while at the same time facing higher input costs (Figure 26).

Figure 26 Paying back when input costs are high



Source: Frontier Economics

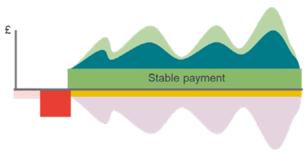
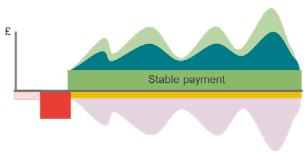
[42] Electrolysis with dedicated renewables producers would be set a very low strike price on the variable component to reflect their low ongoing costs. They would then mainly be paying back support as they generate because the reference sales price will generally be above the strike price.

Under a premium payment model, some of these price risks would be naturally hedged, to the extent that the low carbon hydrogen price is driven by the natural gas price (see Box 3 above). However, some input price risks would remain, given that a proportion of natural gas is used in the conversion process (and therefore the quantity of low carbon hydrogen produced is lower than the quantity of natural gas inputted to the process).

To manage this risk under the revenue stabilisation model, the strike price for reformation technologies could be indexed to the natural gas price so that when natural gas prices (and therefore ATR input prices) are high, the producers' subsidy payment also increases.[43] For BECCS technologies, indexing could be applied to the biomass price and for electrolysis with grid electricity, indexing could be to the electricity price. This indexation would not be required for electrolysis with dedicated renewables given there are no ongoing fuel costs.

The impact of indexing on illustrative revenue flows is illustrated in Figure 27.

Figure 27 Illustrative support flows under indexing for reformation technologies

	Illustrative payments for ATR with CCS	Illustrative payments for EDR	Key
Support provided as an indexed premium on sales revenue			Pre-construction Construction Opex Regulated revenue Support revenue Market revenue Fuel input
Indexed support provided to stabilise sales revenue			

Source: Frontier Economics

4.4 Assessment of design features

BEIS have identified six criteria against which the business models should be assessed.

1. **Incentivise producers to provide value to the economy.** The first criterion allows us to assess how well each business model incentivises producers to provide value to the economy, relative to the counterfactual intervention. This covers the aims of:

- directing low carbon hydrogen to where it best meets decarbonisation goals;
- providing an incentive to producers to seek sales;
- providing a high quality service to low carbon hydrogen customers;
- incentivising efficient management of production costs; and

[43] The split index model in Annex F describes this type of design in more detail.

- incentivising efficient production levels.

2. **Instil confidence among investors.** Using the second criterion, we assess the extent to which business models enable investment. To have the confidence to invest, investors must be able to manage the risks which are allocated to them. Where risks are very high and difficult to manage, investment may be extremely limited, even when there is the potential to gain high returns.
3. **Limit costs to taxpayers and billpayers.** Costs to taxpayers and billpayers could be limited by: designing business models so that they drive efficient investment and running of plants (as covered in criterion 1) and allocating risks in a way that limits costs to taxpayers and billpayers, and avoids paying for production that is not required (covered in this criterion). There are trade-offs here. Allocating risks to investors incentivises them to seek ways to manage these risks, potentially driving efficiency and reducing costs. However, such an allocation could also increase investors' cost of capital, which in turn would increase the level of subsidy required to deliver investment.
4. **Practical and simple.** Introducing a business model that is practical and simple is important for both the government and for investors.

- Business models should be as simple as possible to minimise the administrative burden on government.
- Models should also be practical and simple for investors. Familiar mechanisms for investors will increase investor confidence.
- Given the aim of achieving low carbon hydrogen production deployment in the 2020s, business models should be designed for implementation within this timeframe.

5. **Compatible with the wider value chain.** Low carbon hydrogen production is linked to the wider value chain both in terms of transport and storage and in terms of end use sectors (industry, transport, power and heating). It is important that the business models are designed to be compatible with lead options for transport and storage as well as existing and planned policies in end use sectors (such as the RTFO and CfDs for power). It is also important to consider the additional complexity that adding a new instrument to this part of the value chain could bring to the value chain as a whole.
6. **Compatible with a path to a subsidy-free world.** Our focus is on business models which will support investment in the 2020s. However, the models should be flexible over time to adapt as we move to net zero 2050. This means that they should be designed to allow:

- Reductions in subsidies for future investments to take into account the fact that as the technologies become more proven, the cost required to support low carbon hydrogen production may fall.
- Over time business models should support a transition to a technology-neutral world where different abatement options compete against each other.
- Business models should be compatible with a transition to a subsidy-free world.

In Figure 28 we describe how the options for each key design question meet the criteria agreed with BEIS. Further detail on how each specific examples of each model design meets the criteria can be found in the detailed annexes which accompany this report.

Figure 28 Model design assessment

	Managing downside demand risk: Backstop vs split payment	Premium payment vs revenue stabilisation model	Managing input price risk: Fixed or indexed support
Incentivise producers to provide value to the economy	Split model is better as under the backstop, producers are paid regardless of demand levels, which could lead to inefficient over-production	No difference (assuming the reference price is based on natural gas under the revenue stabilisation model)	No difference
Instil confidence among investors	No difference	No difference	Indexing support will reduce risks for producers.
Limit costs to taxpayers and bill payers	Split model is better as under the backstop, producers are paid regardless of demand levels, which could lead to inefficient over-production	No difference (assuming the reference price is based on natural gas under the revenue stabilisation model)	Indexing support places input price risk on taxpayers/billpayers. However, if transferring this risk results in a lower cost of capital, taxpayers/billpayers may gain
Practical and simple	Split model may be more complex, though backstop arrangements would also bring a degree of complexity	Premium payment would require different support design for EDR and ATR. This would introduce additional complexity into the value chain	Indexing support marginally increases the complexity of the instrument
Compatible with the wider value chain	No difference	No difference	No difference
Compatible with a path to a subsidy-free world	No difference	No difference	No difference

Source: Frontier Economics

Figure 28 illustrates the following:

- **Backstop vs split payment.** To manage downside demand risk, the split model is clearly preferable to the backstop in terms of its ability to incentivise producers to be provide value to the economy, and to limit taxpayers and billpayers.
- **Premium payment vs revenue stabilisation.** The revenue stabilisation model has the advantage of being simpler to apply to all technologies, regardless of their structure. This is because applying the premium payment to capital-intense technologies such as EDR may require forecasting of revenues or periodic true-ups.

- **Fixed support or indexed support.** There are advantages and disadvantages to providing indexed support. While it reduces risks for producers and therefore may reduce the cost of capital, it does this by placing input cost risk on taxpayers/billpayers.

4.5 Should the model approach be contractual or regulatory?

Contractual and regulatory models (both RAB and Cap and Floor models) can be designed to accommodate the different payment structures outlined above.

- In both cases, the contract could be awarded via administrative negotiation or, where there are sufficient numbers of potential bidders, via an auction. Both options for implementation are likely to be similarly complex both for investors and Government.
- In both cases, funding for capital costs could, if required, be provided as soon as construction commences (via the fixed element of the split payment, or via regulatory returns). However, we note that this is not likely to be a priority for hydrogen production investments, given their shorter lead times, compared, for example to nuclear development.
- While price controls in the network sector are generally undertaken periodically, it would also be possible to design a regulatory returns' model that fixed returns over the same period as a contractual instrument (e.g. for 15 years).

The main advantage of the contractual approach is that it could be perceived by investors to provide more certainty. Regulated returns models are generally administered through license agreements, where appeal rights may be to the Competition and Market Authority or, in limited circumstances, to the Courts. This model works well in established parts of the energy sector, where there is a large amount of precedent to draw on to provide certainty about the model being used. In a new area, such as low carbon hydrogen production, investors may consider that covering off eventualities in a contract provides greater certainty. In addition, most regulated models have a reasonably clear end user who ultimately bears the charge (e.g. water or energy consumers). The choice of 'who pays' is less clear for the case of low carbon hydrogen and allocating costs to parties other than network users may add complexity to the model.

On the other hand, the split contractual model would require a new institutional capability for assessing the level of payments to cover fixed and capital costs. This institutional capability already exists in the regulatory system. These issues should be tested further with the relevant stakeholders.

BEIS analysis in the context of nuclear investment has also highlighted benefits of hybrid models that combine regulatory and contractual approaches. Therefore, contractual and regulatory approaches should not be considered to be mutually exclusive and hybrid approaches should also be considered.

5 CONCLUSIONS

This report develops and assesses business models that could encourage investment in largescale low carbon hydrogen in the 2020s, with a focus on supplying to industrial customers.

The aims of the business models are to provide an incentive to invest in low carbon hydrogen production, while limiting costs to consumers and taxpayers. The models must best deliver against the six criteria set out in Figure 29.

Figure 29 Criteria for business models

1	**Incentivise producers to provide value to the economy**	▪ Drive decarbonisation ▪ Direct low carbon hydrogen where it provides the highest decarbonisation value ▪ Provide valuable service to low carbon hydrogen consumers ▪ Incentivise efficient management of production costs (capex and opex) ▪ Incentivise efficient production levels
2	**Instil confidence among investors**	▪ Allocate **risks** in way that attracts investment and finance at the appropriate cost of capital
3	**Limit costs to tax payers and bill payers**	▪ Allocate **risks** in a way that limits costs to consumers and billpayers ▪ Avoid over-paying, or paying for production that is not required ▪ Compatibility with fair and practical cost distribution
4	**Be practical and simple**	▪ Administrative ease for government ▪ Practicality and simplicity for investors ▪ Limited complementary policy requirements ▪ Potential for timely implementation
5	**Be compatible with the wider value chain**	▪ Compatibility with lead options for CCUS and H2 T&S ▪ Interaction with existing and planned policy support in other parts of the value chain ▪ Interaction with the carbon price
6	**Be compatible with a path to a subsidy free world**	▪ Ease of reducing payments for future investments ▪ Potential for technology neutrality ▪ Ease of moving to a subsidy free world over time

Source: Frontier Economics

5.1 Conclusions on business model categories

We considered four categories of business models that could potentially deliver on these criteria (Figure 30).

Figure 30 Summary of model categories

Business model category	High level description
Contractual payments to producers	The hydrogen producer receives a subsidy which covers the incremental cost of low carbon hydrogen above the carbon-intensive alternative fuel. Examples include premium payment models or CfDs.
Regulated returns	Regulated returns models allow the hydrogen producer to earn a regulated return on costs.[44] Examples include Regulated Asset Base (RAB) and Cap and Floor models.
Obligations	An obligation is imposed on parties outside the hydrogen production sector (e.g. fuel suppliers or end users) to supply or consume a certain quantity of low carbon hydrogen
End user subsidies	An ongoing technology-neutral subsidy to end users for carbon abatement.

Source: Frontier Economics

Our assessment of the four business model categories against the six BEIS criteria is shown in Figure 28.

[44] The model could be implemented by providing separate payments to the producer and shipper, as described in Annex F.

Figure 31 Model design assessment

	Contractual	Regulated returns	Obligation	End User Subsidy
Incentivise producers to provide value to the economy	Models can be designed to direct low carbon hydrogen to where it best meets decarbonisation goals and also to provide an incentive to producers to seek sales, to incentivise efficient management of production costs and to incentivise efficient production levels.			May result in domination by those technologies that are currently most mature. This is unlikely to be optimal from a long-term perspective.
Instil confidence among investors	It may be easier to cover all eventualities in a contract rather than through design of a regulatory approach. However, both options have the potential to provide certainty to investors.		Investors will continue to be exposed to policy uncertainty.	Investors will be exposed to demand risk and policy uncertainty.
Limit costs to taxpayers and bill payers	Can be designed to allocate risks between investors and taxpayers/billpayers efficiently.		Higher policy risk will drive a higher cost of capital.	There is a risk that very limited investment occurs. Where it does occur, the cost of capital is likely to be higher.
Practical and simple	Models involve a degree of complexity for investors and for Government, though institutional capabilities to assess costs are already in place for regulatory models.		Detailed design features around banking, banding and buyouts will add complexity.	Involves a degree of complexity, for example abatement may need to be measured relative to a baseline.
Compatible with the wider value chain	All options could be designed to be compatible with the wider value chain.			
Compatible with a path to a subsidy-free world	Compatible with a path to a subsidy free world.		It is difficult to move away from an obligation without creating a 'cliff edge'	It is difficult to reduce the subsidy over time for subsequent investments, without affecting revenue for existing investments.

Source: Frontier Economics

Figure 31 shows that while investment could potentially be delivered in a way that meets the criteria via contractual means or via regulatory returns models, it would be more difficult to do this via obligations or end user subsidies. In particular these models may not instil sufficient confidence in investors, and may not limit costs to taxpayers/billpayers.

- **Investors will continue to be exposed to policy uncertainty under an obligations model.** It is difficult to design an obligations model to be robust to the risk of policy change. This is because the obligation price will be in part determined by detailed rules of the scheme, such as the obligation level, buyout provisions and banding. These detailed rules can be changed over time by policymakers.

- **Investors will be exposed to demand risk under the end user subsidy model.** Since the subsidy is applied for abatement, rather than for low carbon hydrogen consumption, demand risk for low carbon hydrogen would remain with the producer. In the context of a sector where long term contracts may be difficult to secure, this demand risk is likely to be difficult for producers to manage.

Contractual and regulatory models can both be designed to meet the criteria. However, there are trade-offs:

- The contractual approach may have an advantage over the regulatory approach in terms of instilling confidence in investors. In a new area, such as low carbon hydrogen production, investors may consider that covering off eventualities in a contract provides greater certainty than a regulated approach. In addition, most regulated models have a reasonably clear end user who ultimately bears the charge (e.g. water or energy consumers). The choice of 'who pays' is less clear for the case of low carbon hydrogen and allocating costs to parties other than network users may add complexity to the model.
- On the other hand, regulatory models may involve less complexity. The contractual model may require a new institutional capability for assessing the level of payments to cover costs. This institutional capability already exists in the regulatory system.

BEIS analysis in the context of nuclear investment has also highlighted benefits of hybrid models that combine regulatory and contractual approaches. Therefore, contractual and regulatory approaches should not be considered to be mutually exclusive and hybrid approaches should also be considered.

On this basis, we consider that contractual and regulatory models (and hybrids) would be more promising than end user subsidies and obligations in terms of delivering near term investment in low carbon hydrogen production.

CONCLUSIONS ON BUSINESS MODEL CATEGORIES

Of the four categories of business models considered, contractual payments to producers or regulatory returns models could be designed to deliver low carbon hydrogen production in the 2020s. These models should be considered further.

In contrast, it would be more difficult to incentivise low carbon hydrogen using end user subsidies or obligations in the near term. This is because these models leave significant, policy-driven risks with producers.

5.2 Conclusions on key design features

We consider three key design features of the models, which can all be delivered through contractual or regulatory means:

- Managing downside demand risk: Backstop vs split payment;
- Premium payment vs revenue stabilisation mechanisms; and

- Managing input price risk: Fixed or indexed support.

Managing downside demand risk: Backstop vs split payment.

Unless downside demand risk is managed, it may result in a very high cost of capital for investors, or it may result in limited investment coming forward. Downside demand risk can be managed for producers by applying a backstop or applying a split subsidy structure.

- Under a backstop[45], there would be a role for a Government counterparty to be a 'buyer of last resort' for low carbon hydrogen, to provide demand certainty for producers, as the market develops
- Under the split structure, separate support payments would be given to cover fixed and capital costs regardless of demand, but variable costs are only covered where low carbon hydrogen is being produced.

The split model has several advantages over the backstop:

- Under the backstop, producers are paid regardless of demand levels, which could lead to inefficient over-production and very high per unit support costs for taxpayers/consumers.
- While splitting support costs introduces complexity, applying the backstop would also increase complexity for both investors and Government.

We summarise our assessment against the BEIS criteria in Figure 32.

Figure 32 Backstop vs split payment

	Backstop	Split payment
Incentivise producers to provide value to the economy	Over-incentivisation is a risk as producers are paid regardless of demand levels	Producers are incentivised to produce efficiently, when there is demand
Instil confidence among investors	Demand risk is transferred from investors	
Limit costs to taxpayers and bill payers	Taxpayers/bill payers cover fixed and variable costs of low carbon hydrogen production, where demand falls below expected levels	Taxpayers/bill payers cover only fixed costs of low carbon hydrogen production, where demand falls below expected levels
Practical and simple	Would involve complex contractual terms	Requires separate estimation of fixed and variable costs
Compatible with the wider value chain	There is no conflict with existing and planned policies in the wider value chain	
Compatible with a path to a subsidy-free world	Support for subsequent investments can be reduced and removed over time	

Source: Frontier Economics

45 Backstop arrangements could also include provisions for buyout. There may be extreme circumstances beyond investor control, under which the Government (or a party acting on its behalf) is obligated to buyout the production facilities.

CONCLUSIONS ON MANAGING DOWNSIDE DEMAND RISK

To manage downside demand risk, we conclude that a split structure is likely to be preferable to applying a backstop (or guaranteed purchase of low carbon hydrogen). This is primarily because under the backstop approach, consumers are exposed to potentially very high payments per unit of hydrogen produced.

Premium payment vs revenue stabilisation

The split premium model and a split revenue stabilisation model differ most significantly in terms of their ease of application to technologies with different cost structures.

- **The split premium model would be difficult to apply to technologies with capital-intense cost structures such as EDR.** EDR technologies are capital-intense and have very low ongoing costs, and these ongoing costs are likely to be below the price of low carbon hydrogen in the market. Under the split premium design, the fixed component of the subsidy would cover the EDR capex, and it is likely that the market revenue would exceed variable costs. Therefore, the fixed part of the subsidy would need to be adjusted, to subtract the value of the market revenue these producers would be likely to achieve. This would require either forecasting the future revenue of the producer, in order to subtract the correct amount from the fixed payment or a periodic true-up to adjust the level of the fixed payment for revenue received. This would add significant complexity to the model.
- **The split revenue stabilisation model can be applied to all technologies**. The split revenue stabilisation model is suitable for application to both capital-intense technologies and technologies with high running costs. Under this model, a fixed payment is received on an ongoing basis, and revenues are topped up or paid back up to the level of an agreed strike price. No forecasting or true up is required for EDR. Instead, when revenue is higher than the strike price, producers pay back to billpayers/taxpayers under the standard terms of the CfD or its regulatory equivalent.

We assess the impact of this difference in Figure 33.

Figure 33 Premium versus revenue stabilisation

	Premium	Revenue stabilisation
Incentivise producers to provide value to the economy	Can be designed to provide an incentive to produce efficiently and seek sales	
Instil confidence among investors	Can be designed to transfer policy and demand risk from investors	
Limit costs to taxpayers and bill payers	Can be designed to limit costs	
Practical and simple	Different models may be required for capital-intense investments such as EDR	Can be applied across technologies with different cost structures
Compatible with the wider value chain	There is no conflict with existing and planned policies in the wider value chain	
Compatible with a path to a subsidy-free world	Support for subsequent investments can be reduced and removed over time	

Source: Frontier Economics

CONCLUSIONS ON PREMIUM PAYMENTS VERSUS REVENUE STABILISATION

Support could be provided through either a revenue stabilisation model (such as a CfD) or paid as a premium to sales revenue. Both models have merits, but if applying the same model across different technologies is a priority, then revenue stabilisation models may be easier to deploy across all technologies.

Managing input price risk: Fixed or indexed support

Support could be provided on a fixed basis per unit of low carbon hydrogen produced or indexed to input fuel costs (Figure 34).

One feature of the revenue stabilisation model is that it allocates natural gas price risk to methane reformation producers.[46] This is because when input prices are high, the producer must cover these costs while receiving a stable payment, even if the high input prices are reflected in a high market price for low carbon hydrogen. This is less of an issue where support is provided as a premium to the sales price, assuming some correlation between input costs and the sale price.

[46] This indexation would not be required for electrolysis with dedicated renewables given there are no ongoing fuel costs. For biomass gasification, the biomass price could be used as an index.

Figure 34 Fixed or index support

	Fixed support	Indexed support
Incentivise producers to provide value to the economy	Can be designed to provide an incentive to produce efficiently and seek sales	
Instil confidence among investors	Fixed support leaves input cost risk with investors. However, investors are relatively well placed to manage this risk, and under a premium model, there may be a natural hedge against sales revenue	Indexed support transfers input price risk away from investors. This may be particularly helpful to investors under a revenue stabilisation model, where there is no natural hedge
Limit costs to taxpayers and bill payers	Fixed support may result in a higher cost of capital and therefore higher support costs. However, in return, taxpayers/bill payers will bear lower risks of increased subsidy payments	Indexed support may result in a lower cost of capital and therefore lower support costs. However, in return, taxpayers/bill payers will bear higher risks of increased subsidy payments
Practical and simple	Fixed support leads to a simpler model	Indexing input fuel costs marginally increases the complexity of the model
Compatible with the wider value chain	There is no conflict with existing and planned policies in the wider value chain	
Compatible with a path to a subsidy-free world	Support for subsequent investments can be reduced and removed over time	

Source: Frontier Economics

CONCLUSIONS ON PREMIUM PAYMENTS VERSUS REVENUE STABILISATION

Indexing support payments to the input fuel price should be considered further, as depending on the impact on producer's cost of capital, it could reduce support costs. Indexing may be particularly helpful if a revenue stabilisation approach is taken.

5.3 Summary of conclusions

We have considered four categories of business models that could potentially be used to bring on low carbon hydrogen production in the near term, with a focus on supply to industrial clusters. Across these models, we have assessed three key design choices that could be implemented.

A summary of our conclusions on the model categories and design choices is set out in Figure 35.

Figure 35 Summary of assessment

	Criterion	Assessment
1	Incentivise producers to provide value to the economy	▪ All models have the potential to direct low carbon hydrogen to where it best meets decarbonisation goals. ▪ Application of a backstop has the potential to over-incentive production.
2	Instil confidence among investors	▪ The end user subsidy leaves demand risk with investors. ▪ Both the end user subsidy and obligation leave the risk with investors that policies could be adjusted in a way that affects an existing investment. ▪ All other models could instil a sufficient amount of confidence in investors.
3	Limit costs to tax payers and bill payers	▪ The split models limit costs to taxpayers and bill payers, without leaving all demand risk with investors. ▪ Application of a backstop could result in very high payments for consumers per unit of low carbon hydrogen produced, if demand for low carbon hydrogen is lower than expected.
4	Be practical and simple	▪ All models involve a degree of complexity for investors and for Government.
5	Be compatible with the wider value chain	▪ All models are compatible with the lead options for the wider CCUS value chain. ▪ Additional support is likely to be required to cover industrial switching costs in all models but the End User Subsidy.
6	Be compatible with a path to a subsidy free world	▪ All models are compatible with a path to a subsidy free world, though reductions in the subsidy for successive investments would be more difficult under the End User Subsidy model.

Source: Frontier Economics

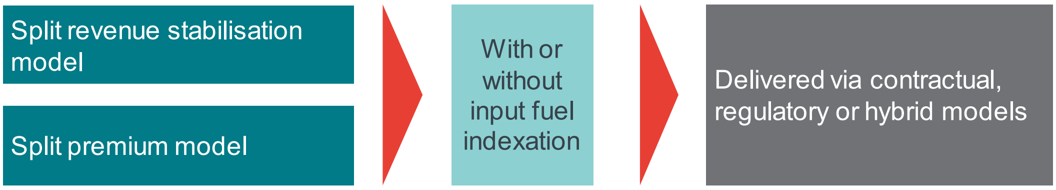
Our analysis suggests the following conclusions.

- Of the four categories of business models considered:
  - Contractual payments to producers and regulatory returns models could be designed to deliver low carbon hydrogen production in the 2020s. Contractual models may give more certainty to producers, while regulatory models may be easier to implement, given existing institutional capabilities.
  - In contrast, it would be more difficult to incentivise low carbon hydrogen using end user subsidies or obligations in the near term. This is because these models leave significant policy-driven risks with producers.
- In designing the contractual payments or regulatory returns models, we assessed three key design features.
  - To manage demand risk, we conclude that a split structure is likely to be preferable to applying a backstop (or guaranteed purchase of low carbon hydrogen). This is because under the backstop approach, consumers are exposed to potentially very high payments per unit of hydrogen produced.
  - The support could be provided through either a revenue stabilisation model (such as a CfD) or paid as a premium to sales revenue. Both models have merits, but if applying the same model across different technologies is a priority, then revenue stabilisation models would be easier to deploy across all technologies.
  - Indexing support payments to the input fuel price should be considered further. It could reduce investor cost of capital, though at the same time it would transfer additional risks to taxpayers and bill payers. Indexing may be particularly helpful if a revenue stabilisation approach is taken, to avoid placing excessive input cost risk on investors. The decision for indexing a

split premium is less clear cut, and will depend on the impact that leaving such a risk with producers could have on their cost of capital.

A summary of the models to be considered further is provided in Figure 36.

Figure 36 Summary of models to be considered further



Source: Frontier Economics

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