Department for
Business, Energy
& Industrial Strategy

Government response to the consultation on a Low Carbon Hydrogen Business Model

April 2022

Any enquiries regarding this publication should be sent to us at: hydrogen.businessmodels@beis.gov.uk

Disclaimer

This government response sets out our current proposals on a business model for low carbon hydrogen production. The proposals are indicative only and do not constitute an offer by government and do not create a basis for any form of expectation or reliance.

The proposals are not final and are subject to further development by government, as well as the development and Parliamentary approval of any necessary legislation, and completion of necessary contractual documentation. We reserve the right to review and amend all proposals set out within the document, in particular to ensure that proposals provide value for money and are consistent with the current subsidy control regime.

This government response takes into account responses to the consultation on a low carbon hydrogen business model in August 2021[1], as well as feedback that has been provided by stakeholders through engagement that has taken place since publication of the consultation.

BEIS will continue engaging with the devolved administrations to ensure that the proposed policies take account of devolved responsibilities and policies across the UK.

[1]The consultation on a low carbon hydrogen business model can be found at: https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen

Contents

Section 1: Introduction

Executive summary

In this publication, we summarise the responses received to each of the 21 questions in the consultation on a business model for low carbon hydrogen and outline our proposed policy and current thinking on each area.

In sections 2 and 3 on key design parameters and approach, we outline the wide support from respondents for a contractual, producer focused business model and confirm that we will proceed with this proposal. We confirm that the business model will be applicable to a range of hydrogen production pathways, though is not intended to support existing producers looking to retrofit using carbon capture, usage and storage (CCUS) technology nor the production of by-product hydrogen. The volumes of hydrogen produced will need to meet the proposed UK Low Carbon Hydrogen Standard (LCHS) to qualify for support. We will proceed with our proposal for the business model to facilitate hydrogen use in a broad range of sectors. We set out the following proposals for some specific offtake cases, subject to compliance with subsidy control and other public law principles:

- *Own consumption*: allowing business model subsidy where the producer and user are the same entity. We are considering options for model design to accommodate this.
- *Intermediaries*: considering any potential challenges to the business model created by sales to intermediaries.
- *Blending hydrogen into the gas grid*: considering whether and how to support blending through the business model to achieve the intended role of blending as a demand-sink for hydrogen producers. Given the timescales for wider policy decisions on blending, we anticipate that support for blending hydrogen into the gas grid will not be included in initial business model contracts. We will consider a contractual reopener, which could enable support for blended volumes in future.
- *Exports*: exports of hydrogen would be permitted for projects benefitting from business model support, but the specific volumes exported would not be eligible for support payments.

We note the strong support from respondents for our key design principles and our approach to considering price and volume risk separately, and will continue with this overall approach.

In section 4 on price support, we confirm our intention to proceed with a variable premium, with strong support from respondents. We note there is reasonable support for the proposed reference price approach and will proceed with developing its detailed design, based on the achieved sales price with a floor at the natural gas price combined with a price discovery mechanism to enable the true price of hydrogen to emerge over time. We will integrate a market benchmark price into the reference price at the earliest opportunity for future projects. We consider indexation of the strike price to be an important aspect of the business model in providing protection to producers against unmanageable and uncontrollable changes to input costs and government from over subsidy, while providing end users with security of supply. We indicate the further analysis we are carrying out. We intend to allow hydrogen producers to receive subsidy for sales of hydrogen to feedstock users and are assessing the options for addressing the risk that sales at the natural gas price to feedstock users could cause distortions in downstream markets.

In section 5 on volume support, we note there is reasonable support from respondents for our proposal to provide volume support via a sliding scale and we will continue to develop the detailed design of this approach. We do not see a compelling case for providing additional volume support in the business model contract beyond the sliding scale approach. We will continue to take forward wider measures (beyond the business model) to unlock greater use of hydrogen.

In section 6 on applicability of the business model across different types of project, we acknowledge that some respondents considered that a separate, simpler scheme for small (or potentially all) electrolytic projects is needed. Following careful consideration, we do not see a compelling case for introducing a separate scheme for smaller scale projects. We confirm that we will continue to develop our proposed model so that it can work across different project scales and technologies. We will consider different approaches for different technologies within the overall model design, for example on strike price indexation, as well as running separate allocation processes.

In section 7, we set out our thinking on additional considerations for the preferred model. On contract duration, our starting point is a contract between 10 to 15 years and we do not currently see a reason to vary this by technology. On options for producers to scale up volumes, we are considering the case for producers to increase the volume of hydrogen produced within an existing plant above any level defined in their contract. Building a new plant or a new module would not be subsidised under the existing contract and would require application to a new allocation process. On allocation of risks, we consider that the proposals we set out in the consultation remain appropriate. On accommodating different sources of support (alongside the business model), we confirm the principles we will use to determine specific rules and conditions for how the business model will interact with other sources of support.

In section 8 on allocation, we set out our plans for allocation including alignment with the Net Zero Hydrogen Fund (NZHF) and ambition to move to price competitive allocation by 2025 as soon as legislation and market conditions allow. Work is underway on the design of this process, which may be subject to further consultation.

In section 9 on funding the business model, we set out that we are minded to introduce a levy to fund revenue support provided through the business model, subject to consultation and legislation, with the first electrolytic hydrogen projects supported through the 2022 allocation round being funded through general taxation until the levy is in force.

In section 10 on hydrogen transportation and storage (T&S), we set out that we propose to allow some small scale T&S to be supported through the business model, where it is necessary, subject to affordability and value for money considerations. We recognise the importance of larger scale hydrogen T&S infrastructure and provide an update on our wider review of requirements in the 2020s and beyond. As set out in our new Energy Security Strategy, we have committed to designing, by 2025, new business models to support the development of hydrogen T&S infrastructure.

Background

The Prime Minister's *Ten Point Plan for a Green Industrial Revolution* [2] committed to focus on driving innovation, boosting export opportunities, and generating green jobs and growth across the country to level up regions of the UK. To build on this, government published the Net Zero Strategy[3] in October 2021 to set out a long-term plan to deliver our decarbonisation ambitions. Our new Energy Security Strategy sets out our ambition for up to 10GW of low carbon hydrogen production capacity by 2030, subject to affordability and value for money, with at least half of this coming from electrolytic hydrogen.

The UK's skills, capabilities, assets and infrastructure mean that we have the potential to excel in both CCUS (carbon capture, usage and storage)-enabled and electrolytic low carbon hydrogen production. Alongside the scale of production that CCUS-enabled hydrogen can bring, our renewables can support the growth of electrolytic hydrogen, bringing down costs and increasing production capacity whilst new production technologies such as hydrogen from nuclear and biomass are developed.

In August 2021, alongside the UK Hydrogen Strategy[4], we published a consultation on a proposed hydrogen business model to overcome one of the key barriers to deploying low carbon hydrogen: the higher cost of low carbon hydrogen compared to high carbon counterfactual fuels. The hydrogen business model is one of a range of government interventions intended to facilitate the deployment of low carbon hydrogen projects that will be necessary to meet Carbon Budget 6 and net zero targets.

In October 2021 the Net Zero Strategy[2] announced the setting up of the Industrial Decarbonisation and Hydrogen Revenue Support (IDHRS) scheme, which will fund the allocation of hydrogen business model contracts to both electrolytic and CCUS-enabled projects from 2023. We announced that IDHRS would provide up to £100 million to award contracts of up to 250MW of electrolytic hydrogen production capacity in 2023 and we have announced a second allocation round opening next year. Our new Energy Security Strategy sets out our ambition for up to 1GW of electrolytic hydrogen production projects to be in construction or operational by 2025. We aim to run annual allocation rounds for the hydrogen

[2] The Ten Point Plan can be found at: https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution/title
[3] The Net Zero Strategy can be found at: https://www.gov.uk/government/publications/net-zero-strategy
[4] The UK hydrogen strategy can be found at: https://www.gov.uk/government/publications/uk-hydrogen-strategy

business model for electrolytic hydrogen, moving to price competitive allocation by 2025 as soon as legislation and market conditions allow. We will also announce a funding envelope that will enable us to award the first contracts to CCUS-enabled hydrogen production projects from 2023 through the Cluster Sequencing process, to deliver up to 1GW of CCUS-enabled hydrogen by the mid-2020s.

We have been working with stakeholders through the Hydrogen Advisory Council, the Hydrogen Business Model Expert Group and directly with interested parties. This engagement has supported the development of the hydrogen business model since the consultation was published. We set out the progress that has been made in this document and identify areas for further work.

The consultation on the hydrogen business model closed in October 2021. We received 121 responses through the online response tool and by email. We held 28 stakeholder meetings to discuss the consultation as well as three roundtables and a Q&A event. We also presented on the consultation at six trade body events.

We are publishing this response to the hydrogen business model consultation alongside several other documents:

- **Indicative Heads of Terms for the hydrogen business model**[5]: this sets out a preliminary and indicative framework for the principal terms and conditions that are expected to be included in the contract underpinning the hydrogen business model – the **Low Carbon Hydrogen Agreement (LCHA).**
- **Net Zero Hydrogen Fund (NZHF) government response**[6]: this sets out the proposed scope, design and delivery of the £240 million NZHF, which will make grant funding available to support the capital costs of developing and building low carbon hydrogen production projects.
- **Low Carbon Hydrogen Standard government response**[7]: this sets out key policy positions on an emissions standard that will underpin the deployment of low carbon hydrogen for use across the economy. One of the objectives of the standard is to ensure that hydrogen projects supported by government are consistent with our net zero ambitions.
- **The UK Low Carbon Hydrogen Standard guidance document**[8]**:** this sets out in detail the methodology for calculating the emissions associated with hydrogen production and the steps producers are expected to take to prove that the hydrogen they produce is compliant with the standard. The document also sets out sustainability criteria that biomass hydrogen producers will need to meet and how to put a risk mitigation plan in place for

[5]The indicative Heads of Terms can be found at: https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen
[6] The Net Zero Hydrogen Fund government response can be found at: https://www.gov.uk/government/consultations/designing-the-net-zero-hydrogen-fund
[7] The Low Carbon Hydrogen Standard government response can be found at: https://www.gov.uk/government/consultations/designing-a-uk-low-carbon-hydrogen-standard
[8]The UK Low Carbon Guidance document can be found at: https://www.gov.uk/government/publications/uk-low-carbon-hydrogen-standard-emissions-reporting-and-sustainability-criteria

fugitive hydrogen emissions in production. Further detail on the criteria for specific hydrogen production pathways can be found in Annexes A - E. The guidance document should be used by hydrogen producers seeking support from government schemes and policies that apply the standard.

- **Electrolytic Allocation Market Engagement document**[9]: this seeks views on a proposed approach to allocating hydrogen business model and NZHF support to electrolytic hydrogen projects in the 2022/23 round.
- **Hydrogen Investor Roadmap**[10]: this showcases the UK's hydrogen offer and the scale of our ambition for the role of the hydrogen economy in meeting net zero. It spotlights the exciting investment opportunities across the hydrogen value chain – from production, through transmission and storage to the range of potential end uses, including power, transport and heating.

Working with the devolved administrations

BEIS will continue to work with the devolved administrations (DAs) to ensure that the proposed policies take account of devolved responsibilities and policies across the UK to facilitate successful deployment.

Next steps

The government is grateful to those who took the time to respond to our consultation and participate in our stakeholder engagement events. We understand the need for clarity on a range of elements and will continue to develop the business model design with input from stakeholders. We aim to finalise the business model in 2022, enabling the first contracts to be allocated from 2023.

Analysis of responses received to the consultation

This government response outlines the consultation position, a summary of the responses to the consultation and the government's response to these, organised under each consultation question.

In reporting the overall response to each question, we have used a number of terms:

- 'majority' indicates the clear view of more than half of respondents to that question.
- 'minority' indicates the clear view of fewer than half of respondents to that question.

The following terms have been used in summarising additional points raised in the responses:

[9] The market engagement document can be found at: https://www.gov.uk/government/consultations/hydrogen-business-model-and-net-zero-hydrogen-fund-market-engagement-on-electrolytic-allocation
[10] The Hydrogen Investor Roadmap can be found at: https://www.gov.uk/government/publications/hydrogen-investor-roadmap-leading-the-way-to-net-zero

- ‘some respondents’ means any number between 3 and 20 respondents.
- ‘many respondents’ indicates between 20 and 60 respondents have shared this view.
- ‘strong agreement’ indicates that upwards of 60 respondents have shared this view.

We have thematically analysed each response as a whole based on the themes set out in the consultation and identified via stakeholder engagement.

Responses which did not explicitly express their support or disapproval for the specific question were logged but classified as neither supportive nor non-supportive. When summarising responses to the consultation, all accompanying written text was analysed for each question. Where information provided by a respondent related to a different question, we have summarised it under that other question. Where relevant, we have interpreted ‘blue’ hydrogen as CCUS-enabled methane reformation and ‘green’ hydrogen as electrolytic hydrogen from low carbon / renewable electricity.

Government response to the consultation

Section 2: Rationale for a production-focused business model and key design parameters

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

Consultation position

The consultation proposed that the preferred overall approach for the hydrogen business model is to provide revenue support to low carbon hydrogen producers. We set out that the business model is intended to be applicable on a UK-wide basis to a range of hydrogen production technologies and possible end users, and that we intend to require the volumes of hydrogen produced to meet a future UK LCHS to qualify for support. We set out our minded to position to support new production, while existing producers may be eligible to apply for funding through the Industrial Carbon Capture (ICC) Business Model. We also set out that the business model is intended to support domestic production and consumption of hydrogen, and that volumes of hydrogen exported would not be eligible for support. The consultation also noted that the preferred delivery mechanism would be a contractual approach.

Summary of stakeholder responses to consultation

Response summary	
Agree with overall approach	84
Responded with 'maybe'	14
Did not agree with overall approach	2
Not answered or unclear	21

Key points

A majority of respondents to this question agreed that a contractual, producer focused revenue support is the most appropriate approach to implement the hydrogen business model.

Reasons for strong agreement were:

- A producer focused model would be a faster, relatively simpler way of supporting the deployment of low carbon hydrogen.
- A producer focused model incentivising production can support a wide range of different users and production technologies.
- Directing revenue support to hydrogen producers rather than hydrogen users reduces the risk of investing in the production side.
- A private law contract is a well-understood delivery mechanism and is best suited to provide investor certainty and lower costs of capital.

Two respondents disagreed with the proposed approach. One noted that an end-user model would be preferred for the reason that hydrogen producers may have a monopolistic position locally in the early stages of market development and may not pass through the benefits of a producer subsidy to the end user. The other noted that using a producer model would mean there is supply but demand is not sufficiently incentivised.

A few respondents also asked for clarity on who the government counterparty would be.

Need for broader policies to complement the hydrogen business model

While a producer focused business model was supported by the majority of respondents, many respondents recognised the need for measures to stimulate the demand for hydrogen, in order to minimise volume risk and to incentivise end users to switch to low carbon hydrogen. Some respondents pointed out that additional support for investment in hydrogen T&S and CO2 T&S would play an important role in stimulating production and demand and unlocking the hydrogen economy.

Support for smaller scale projects

Some respondents suggested that more support is needed for smaller scale projects as those projects could provide the geographical spread and range of scale to help decarbonise throughout the country. A respondent also noted that supporting smaller scale projects could generate demand away from hydrogen clusters and help overcome high costs of hydrogen transportation. A few other respondents commented that the current model is not likely to be suited for smaller scale projects and suggested considering a separate model for smaller projects. This issue is covered in more detail under question 12 on whether a separate revenue support scheme should be introduced for projects of a smaller scale.

Hydrogen production pathways in scope of the business model

Of the respondents who provided specific views on the production pathways that should be in scope of the business model, opinions were mixed.

Some respondents commented that the business model should be neutral and non-discriminatory to encourage early-stage production pathways, increase competition and lower costs. Some respondents recommended that more focused support is needed for electrolytic hydrogen (of those, two respondents emphasised that the focus should be *only* on electrolytic) and that the long-term vision must be to prioritise electrolytic hydrogen. Some other respondents said that a mix of both CCUS-enabled and electrolytic is required to achieve deployment at scale.

Some respondents expressed concern with one business model covering both CCUS-enabled and electrolytic hydrogen, noting that smaller electrolytic projects may be crowded out without additional support. Some responses suggested further consideration is needed to accommodate a range of production technologies within the business model, reflecting the specific features and limitations of different technologies. This issue is covered in more detail under question 11 on the applicability of the proposed business model for different technologies and operating patterns.

A few suggested, given differences in cost structure and scale, it would be beneficial to ringfence separate allocation pots for CCUS-enabled and electrolytic. This issue is covered in more detail under question 18 on allocation.

<u>End users</u>

Some respondents provided views on the types of end use that hydrogen producers supported by the business model should be allowed to supply. There were contrasting views on which end uses should be eligible. On the one hand, some respondents emphasised the importance of allowing a wide range of end users to be supplied by hydrogen producers, ensuring diversity of end uses and allowing early deployment of low carbon hydrogen to occur naturally, especially as there is some uncertainty as to which hydrogen applications will be viable in the long term.

On the other hand, some respondents commented that government should prioritise hydrogen use where no other alternative decarbonisation pathways are viable or readily available, with a few suggesting that targeted use of hydrogen should be encouraged through the business model design or through separate policies. One respondent noted that hydrogen could be targeted at the 'easiest' industries first, focusing on more developed projects, to help bring down the cost of hydrogen for the harder to reach sectors in the longer term.

A few respondents who specifically mentioned exports as one of the possible end uses of hydrogen supported the proposal not to subsidise exports, but suggested that government should consider the role of exports as a way to mitigate the demand risk (for example, allowing exports when volumes of hydrogen produced cannot be placed with domestic end users) and as a means to facilitate international trade. A question was also raised as to whether the business model would support hydrogen used in the manufacturing of products that are themselves exported.

Government response

The primary objective of the business model is to incentivise the production and use of low carbon hydrogen through the provision of ongoing revenue support in order to overcome the cost gap between low carbon hydrogen and cheaper higher carbon counterfactual fuels. We consider that a contractual, producer focused business model is the most effective approach to deliver this policy objective, with the design of the model enabling producers to deliver a price incentive for end users to switch. We will proceed with this proposal.

We recognise that measures beyond the business model are needed to support hydrogen deployment and that the business model forms part of a wider, holistic approach as set out in the UK Hydrogen Strategy. This includes measures to incentivise and secure demand for hydrogen in key sectors such as in industry and to unlock investment in hydrogen T&S and CO2 T&S assets needed to develop a thriving hydrogen economy.

<u>Hydrogen production pathways in scope</u>

We confirm that the business model will be applicable to a range of hydrogen production pathways to facilitate the growth of the nascent hydrogen economy. The technologies in scope of each round of allocation to award business model support will continue to be guided by the UK Hydrogen Strategy.

We will proceed with our minded to position to stimulate investment in new low carbon production capacity through the hydrogen business model. This will be defined as newly constructed facilities built for the specific purpose of producing hydrogen that can meet the requirements outlined in the UK LCHS. We will also proceed with our proposal to require the volumes of hydrogen produced to meet the UK LCHS in order to qualify for and receive hydrogen business model funding.

Existing producers of hydrogen looking to retrofit using CCUS technology will not be eligible for support through the hydrogen business model, but may be eligible to apply for support through the ICC business model.

We do not intend to support new build industrial facilities generating hydrogen as a by-product through the hydrogen business model. We have not seen evidence that by-product hydrogen pathways require revenue support to sell hydrogen at a competitive price. In some cases, supporting by-product pathways may also pose a risk of indirectly incentivising industrial processes used to manufacture a carbon intensive product, even if the process (and by-product hydrogen) itself is low carbon. We consider this to be inconsistent with achieving government’s decarbonisation ambitions.

<u>Qualifying offtakers and end uses</u>

We will proceed with our proposal to facilitate hydrogen use in a broad range of sectors, while developing the business model design to address challenges linked to specific hydrogen end uses or ‘offtakes’. We have set out below the key areas where further work is needed to accommodate these use cases or where hydrogen supply will not qualify for business model support. All of these positions are subject to compliance with subsidy control and public law principles and we will keep them under review as the hydrogen market develops.

Own consumption: we have considered the applicability of the business model to different potential commercial arrangements between producers and users of hydrogen. In some projects, the hydrogen producer may manufacture hydrogen for its own consumption (i.e. the producer and end user may be the same entity or closely affiliated). We intend to allow business model subsidy for own consumption hydrogen projects. We are considering options for the model design to accommodate this type of market arrangement between producer and offtaker project where there may be little or no commercial incentive for the producer to increase their achieved sales price and facilitate price discovery.

Intermediaries: we are considering whether and how we could address any potential challenges to the business model created by sales to intermediaries, particularly where they intend to take ownership of the hydrogen produced. This includes considering any reporting that may be required about the destination and value of sales to end users, to ensure subsidised hydrogen is sold to qualifying end uses, as well as any measures required to avoid creating perverse incentives or over subsidisation if intermediaries are used.

Feedstock users: we intend to allow hydrogen producers to receive subsidy for sales of hydrogen to feedstock users. However, we recognise the potential for sales to feedstock users to cause market distortions and are therefore considering whether additional measures are needed to address this risk. We have set out further detail in our response to question 7.

Blending hydrogen into the existing gas grid: hydrogen is currently limited to 0.1% (by volume) in Great Britain's (GB) natural gas networks, as outlined in the Gas Safety (Management) Regulations 1996. We have not yet decided whether to enable blending of up to 20% hydrogen (by volume)[11] into GB gas networks, and are targeting a policy decision in 2023, subject to the outcomes from ongoing economic and safety assessments and wider strategic considerations. We are working closely with Ofgem, the Health and Safety Executive (HSE), the Devolved Administrations, GB natural gas network operators and wider industry to understand the case for hydrogen blending.

There may be significant value in having blending available to support the early development of the hydrogen economy. However, BEIS currently views blending as a transitional option only. If enabled, it will have a limited role in heat decarbonisation as we move away from use of natural gas for heat. Hydrogen is expected to play a more valuable role in other parts of the economy, such as industry, heavy transport, or power generation. Blending may also be able to support a potential future transition to 100% hydrogen in heating, but our decision on the role of hydrogen in heating does not depend on any future decision on blending. Trials to explore 100% hydrogen for heating are in preparation, enabling strategic decisions in 2026 on the role of hydrogen for heat decarbonisation.

As set out in our Hydrogen Strategy, use of hydrogen is most valuable where other routes to decarbonisation do not exist or are limited, particularly where direct electrification is not an option. This will be a consideration if government decides to take steps to enable blending. While we recognise the value of blending as a demand-sink for hydrogen producers facing volatile, or temporarily unavailable demand, we will be looking to ensure that blending does not displace supply of pure hydrogen to those end users who require it to decarbonise. This is likely to be reflected in the design of any potential financial support that is available for hydrogen producers for blended volumes.

Support for blending through the hydrogen business model is one possible commercial option for delivering its potential role as a demand-sink for producers. We are currently assessing different potential market and trading arrangements to deliver blending. When we have completed this assessment, we will determine whether and how to support blending through the hydrogen business model to achieve its intended role as a demand-sink for hydrogen producers. We anticipate that this will not be done in time for the award of initial hydrogen business model contracts, which would mean that support for blended volumes is not included within these initial contracts. We will consider including a contractual reopener for these initial contracts, which could enable support for blended volumes in future.

Exports: given the primary objective of the business model is to kickstart the UK's low carbon hydrogen economy, we will proceed with our position to support domestic production and

[11] Due to the lower calorific value of hydrogen relative to natural gas, blends of 20% hydrogen by volume are estimated to generate around 7% carbon-savings on current gas consumption, resulting from the lower energy content of hydrogen-blended gas.

consumption of hydrogen. While exports of hydrogen would be permitted for projects benefiting from business model support, the specific volumes exported would not be eligible for support payments. We do however recognise the role of exports in supporting trade and managing volume risks. We also note the considerations raised in relation to hydrogen used in the manufacturing of industrial products which may themselves be exported. We will consider this in the next stage of design.

Counterparty

The contractual model will require a counterparty to manage the contracts. We are assessing options for the most appropriate organisation to perform that role.

Section 3: Our approach to design of the business model

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

Consultation position

In the consultation, we considered the needs of the main parties involved in a hydrogen project, defined our objectives for what a 'good' hydrogen business model looks like, and set out key design principles for considering the advantages and disadvantages of each design option. We identified the two key risks for producers – market price risk and volume risk – and our approach to addressing those risks in the business model design.

Summary of stakeholder responses to consultation

Response summary	
Agree with our approach	71
Responded with 'maybe'	16
Did not agree with our approach	3
Not answered or unclear	31

<u>Key points</u>

The majority of respondents to this question agreed with our approach to business model design, with only three respondents disagreeing. There was strong agreement on the design objectives set out in the consultation, as well as our proposal to address price and volume risk separately. Some respondents raised concerns about whether the proposed business model design would achieve the objectives set out, or highlighted issues that should be considered. Given the general nature of this question, respondents commented on a range of aspects of business model design and where appropriate we have discussed these comments under relevant questions later in this document (e.g. comments on hydrogen T&S are discussed under question 20 and question 21).

<u>Needs of the main parties</u>

Some respondents agreed with our identification of producers, government, and end users as the three main parties involved in hydrogen projects and our assessment of their needs. One respondent added that there is another impacted party and that is the general public who will fund the business model and who are affected in other ways, including impacts on jobs and any risks such as localised pollution.

In discussing the needs of end users, respondents built on points raised under question 1, highlighting the need for broader policies to complement the business model. They highlighted that a greater focus is needed to support potential users to switch to low carbon hydrogen to both reduce volume risk and allow for faster market development. Specific points included:

- Significant end user capital investment is needed to enable hydrogen fuel switching.
- There will be considerable difference between first of a kind (FOAK) and nth of a kind (NOAK) in relation to end-user confidence in adopting hydrogen technology.
- In some sectors, such as industry, it is unclear how well aligned the different support packages are across the full hydrogen value chain. In other sectors, such as heavy-duty transport, there may be gaps in the support available from government.

Key design principles

Respondents raised a number of considerations for the design principles and the objectives for a 'good' business model, including:

- Some respondents said they did not want support to 'taper off' too quickly as this would pose risks, or they noted this would require careful design as it could impact the commercial viability of the later stages of the project lifetime for investors. The design of the mechanism must provide sufficient comfort for funders to take the risk of committing to large scale and long-term investments. If the level of perceived risk is too great for the appetite of financial investors and funders, development of the hydrogen production market would be restricted to existing strategic participants, which would limit the growth of the market and the volume of projects that can proceed. One respondent suggested that tapering should start only once sustainable levels of demand are realised.
- One respondent believed that the reference to compatibility (with other subsidy schemes) is not ambitious enough and that government should look to align mechanisms across policy objectives.
- One respondent noted that price transparency is key for both producers and consumers. Another suggested that the principles should consider market price formation.
- One respondent proposed that the definition of 'what good looks like' should be expanded to include: only producing high marginal cost hydrogen when there is insufficient low marginal cost hydrogen; and only producing electrolytic hydrogen when the electricity supply is saturated with low carbon electricity (with limited exceptions).

Key risks: market price and volume

Many respondents agreed with our approach of considering price and volume risks separately. Some respondents explained that we illustrated reasonable mitigation strategies for both risks. For example, one respondent stated that 'revenue support will mitigate price and (some) volume risk to make investment acceptable.'

Barriers and suggestions for delivering the objectives

Some respondents raised concerns about whether the proposed business model would achieve the objectives set out, or they highlighted issues that ought to be considered in order to deliver the objectives. Individual points raised included:

- Concerns regarding the relative complexity of the business model compared to the early stages of other subsidy support such as renewable electricity and heat. Some respondents considered that these were relatively simple, clear about the level of support available and easy for operators, both large and small, to take part in.

- Whether the model would sufficiently address all market archetypes, for example projects where there are many producers selling to many consumers, including via intermediaries like shippers, and producers who consume their own volumes.
- Consideration for both how the initial hydrogen projects will develop associated hydrogen T&S infrastructure and how wider T&S infrastructure will be developed. These issues were raised by a number of respondents and are discussed in more detail under questions 20 and 21.
- The minded to position not promoting effective competition between projects or fully recognising the benefits of some production methods which could result in misallocation of significant funds and a delayed transition to genuine zero carbon hydrogen.
- A risk of information asymmetry between hydrogen producer and hydrogen user that may create adverse outcomes during the contract negotiation.
- Consideration for how the business model design affects the specification that projects are built to and their operation once they are built.
- Optionality ought to be maintained for further project support towards the end of the contracts.

Clarifications requested

Several respondents asked for greater clarity on the proposed business model design, including the following specific issues:

- Support for hydrogen for feedstock (discussed under question 7).
- Business model interactions with the NZHF (discussed under questions 17 and 18).
- The approach to addressing volume risk and the mechanism for volume support (discussed under questions 9 and 10).
- Transparency on the timing and frequency of allocation rounds for support with a ramp up in support to GW-scale electrolytic hydrogen in the late 2020s (also covered under question 18).
- Clarity that the more carbon intensive forms of hydrogen are transitional, how the carbon intensity of the hydrogen mix is expected to decline over time towards net zero, and the role of the hydrogen business model in achieving this aim.
- Eligibility including whether public sector organisations could be eligible for support.

Evolution of business model design

Some respondents commented on how business model design might change over time and suggested that different market mechanisms will be needed at different points in the development of hydrogen. One respondent said that it may be necessary to adopt a different approach for FOAK projects to ensure they are deliverable within the timeframes required. One respondent explained that, initially, there is a need for both price and volume support, but this may change to a price support-only model as the hydrogen market develops and options such as blending into the gas grid are clarified. Providing volume support has some merit but should not detract from the wider objective of building volume in the hydrogen market as soon as possible.

Government response

We note the strong support from respondents for our approach to business model design, including the key design principles and our approach to considering price and volume risk separately, and will continue with this overall approach. We note some concerns raised about whether the proposed business model achieves all the objectives we have set out. We address some of these concerns in more detail under later questions and will continue to take this feedback into account as we develop the model design. We will seek to provide further clarity to stakeholders on the questions raised as we move through this next stage of development.

Section 4: Price support

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

Consultation position

The consultation provided the rationale for mitigating price risk – the risk that the price the producer is able to achieve for selling hydrogen does not cover the cost of producing it, as it is unable to compete against counterfactual fuels, such as natural gas or diesel. Based on the assessment of the price support options presented in the consultation against the key principles, we set out the variable premium option as our minded to position. The premium is calculated as the difference between a 'strike price' (to enable producers to cover costs) and a 'reference price' (price received by the producer) for each unit of hydrogen sold.

If the producer is able to sell hydrogen for a higher price as the value of hydrogen increases (for example as the carbon price increases and it becomes more expensive to use higher carbon fuels), then the subsidy paid through the variable premium can reduce. We considered this to be the most advantageous of the options presented as it gives the price support intervention flexibility and adaptability that the fixed price and fixed premium approaches do not provide, in the absence of a hydrogen benchmark price. In particular, it enables the possibility that the level of subsidy can reduce over the length of the contract as the market evolves, rather than only across allocation rounds.

Summary of stakeholder responses to consultation

Response summary	
Agree with variable premium for price support	75
Responded with 'maybe'	18
Did not agree with variable premium for price support	4
Not answered or unclear	24

<u>Key points</u>

Most respondents agreed with our minded to position for a variable premium for price support. The main reasons were that it is an investable proposition because it enables producers to cover costs with certainty, helps to reduce costs of capital and is a proven approach as exemplified by the success of the low carbon electricity generation Contract for Difference (CfD) scheme. Value for money for government, flexibility across technologies and the ability to adjust the premium for different end uses were also cited as key reasons to support the minded to position.

Some respondents responded with ‘maybe’. These respondents generally felt that although the variable premium would work for large, CCUS-enabled projects, it would be too complex for small, electrolytic projects and therefore these respondents would prefer a fixed premium or fixed price for early projects. Responses from trade associations generally reflected that CCUS-enabled producers broadly supported the variable premium while electrolytic producers raised more concerns around the proposed mechanism. Several of these respondents however mentioned that the variable premium is likely to be better suited for future electrolytic projects. A few respondents gave conditional support for the variable premium provided the reference price design is workable.

A small number of respondents opposed the variable premium, mainly because they would prefer a fixed price or fixed premium to provide more certainty for small, electrolytic or FOAK projects. One mentioned they would like a fixed premium for all electrolytic projects below 100MW.

Arguments in support of the variable premium providing price support

Most respondents supported our minded to position of variable premium for price support, with the main reasons as below:

- It is similar to the CfD approach for low carbon electricity generation across technologies which has been in place for years. It is a proven approach and well understood. The CfD and the Dutch SDE++ scheme[12] provide good evidence and experience for those involved in the low carbon hydrogen market to draw on.
- It provides sufficient revenue certainty for producers to cover their costs with certainty and reduces price risk and therefore addresses investor concerns which can attract private capital and drive down costs.
- It enables the size of the variable premium to adjust as the market evolves, reflecting what producers need, whereas with the fixed price or fixed premium options, it could be difficult for government to set the price at a level which justifies the investment by producers.
- It is advantageous for government as the size of subsidy changes to reflect market changes. If the price of hydrogen increases, then it reduces the premium and secures value for money for government and fairness to the taxpayer as it does not over subsidise producers.
- It provides more flexibility than the fixed price or fixed premium approaches to enable deployment of large scale projects that target hydrogen offtake from multiple sectors. It allows the reference prices to vary to reflect the different sales prices for each end use sector.

Concerns raised

There were some concerns that the variable premium relies on the reference price approach to be effective. The main concerns with the variable premium centred around respondents’ views that it would not suit all projects, with some respondents preferring subsidy support to be in the

[12] Information on the Netherlands SDE++ variable premium mechanism can be found at: https://english.rvo.nl/subsidies-programmes/sde/features-sde

form of a fixed price or fixed premium instead. There were three main reasons for wanting an alternative approach:

- The variable premium approach would be too slow to implement, and it would be preferable to adopt an alternative approach that could support early projects more quickly. Some of the concerns expressed about speed of implementation related to the allocation process (e.g. the time to set up an auction) rather than the approach to price support, and this is covered in more detail under question 18 on allocation. Some respondents have suggested this alternative support could be time limited ahead of transitioning to the variable premium which would be better for NOAK projects when the market matures and is more established.
- For small projects, unintended barriers could arise from the complexity and associated administrative burden. There were a few suggestions of having a parallel model to the variable premium to help deploy smaller scale projects. This issue is covered in more detail under question 12 on whether a separate revenue support scheme should be introduced for projects of a smaller scale.
- Where hydrogen is produced and consumed within the same facility, the variable premium would not be appropriate as the variable premium is predicated on a producer to end user relationship. An alternative approach of a feed-in-tariff or return on revenue approach was suggested to recognise this scenario.

Government response

We note the strong support from respondents for the minded to position of providing price support via the variable premium mechanism, and will proceed with this proposal. We note the concern that this model could be slow to implement although we do not consider that we could deliver an alternative approach to price support, such as a fixed premium approach, on a faster timetable. We consider designing two schemes in parallel would increase complexity and result in longer timelines for implementation. We have also considered speed of implementation in developing our proposals for allocation, which we set out under question 18. We acknowledge the concerns raised that some small electrolytic projects could face unintended barriers from the relative complexity of a variable premium model and we respond to this further under questions 11 and 12. We also note the concerns of producers who are producing their own hydrogen to consume in the same facility - more detail on our approach has been set out in question 1.

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

Consultation position

The consultation set out how crucial the selection of the reference price is to the effectiveness of the variable premium price support approach. In the absence of a market benchmark, we set out a number of reference price options with consideration for the advantages and disadvantages of each.

Individually, each option had drawbacks which could undermine its effectiveness as a reference price. For initial projects therefore we presented a minded to position for the reference price with three components. First, the producer's achieved sales price. This would give pricing power to the hydrogen producer to incentivise end users to switch, but on its own it would not reward the producer for any effort in developing higher value sales, features no floor and may encourage over reliance on government subsidy. It could also create wider distortions in other energy markets. To address these issues, the second component proposed was a price floor at the natural gas price. This is the most common fuel from which end users would switch so they are likely to be willing to pay at least that price for hydrogen. The natural gas price floor would prevent the producer from receiving additional support for sales below that price, improving value for money for government and reducing wider market distortions. Finally, to incentivise producers to increase the achieved sales price and avoid sales remaining at the natural gas price floor for the duration of the contract, we proposed a contractual price discovery mechanism. This last component would enable the subsidy to reduce over time.

We also set out that the variable premium would integrate a market benchmark into the reference price at the earliest opportunity for future projects.

Summary of stakeholder responses to consultation

Response summary	
Agree with approach to reference price	53
Responded with 'maybe'	23
Did not agree with approach to reference price	13
Not answered or unclear	32

Key points

A majority of respondents to this question agreed with our minded to position for the reference price. The main reasons were:

- It is a logical approach in the absence of a hydrogen market benchmark price.
- The achieved sales price is transparent and enables producers to vary the price of hydrogen for different end users.
- Natural gas is the most common and lowest cost counterfactual fuel and therefore an appropriate reference price floor.

Respondents agreed with our proposal to combine the minded to position for the reference price with additional contractual measures to incentivise producers to negotiate higher sales prices and therefore reduce subsidy over time.

A smaller but significant number responded with 'maybe', with a variety of reasons given. Respondents raised concerns about the natural gas price floor, including the volatility of gas prices which introduces risk for those seeking to enter into fixed price offtake contracts, and the applicability of the floor at natural gas for electrolytic producers. They also raised the risk of introducing complexity, as well as lack of clarity on calculation of the achieved sales price and the design of the price discovery mechanism to minimise gaming. A few suggested a different reference price for transport end uses to avoid over-subsidy from hydrogen being available at the natural gas price.

Some respondents did not agree with the approach, for the same main reasons as above. A few were concerned about how achieved sales price combined with a price discovery mechanism would work for those who produce and use their own hydrogen. Risk of over-subsidy and gaming potential from using the achieved sales price were also mentioned.

<u>Arguments in support of the reference price approach</u>

Many respondents recognised that setting the reference price is not simple, with a few stating that incorporating the market benchmark in initial projects when it emerges would create too much risk for investors. Most stated the approach to be logical for initial projects in the absence of a market benchmark, with the market benchmark adopted only for future projects (rather than applied retrospectively).

The main reasons for supporting the reference price approach were:

- Achieved sales price:
    - It fairly reflects the value of the hydrogen sold.
    - It enables producers to price hydrogen differently across end users, with the negotiated achieved sales price likely to end up at the level of counterfactual fuel plus carbon.
    - There could be wider benefits if achieved sales prices are published in summary form.
- Price floor at natural gas price:
    - It is an appropriate price floor below which subsidy support should not be provided and a preferable proxy for the price of hydrogen in the absence of a market benchmark as it is the most common and lowest cost counterfactual fuel, which would encourage fuel switching.
- Advantages of excluding the carbon price from the price floor:
    - An incentive would be created for end users to switch to hydrogen as they would not pay the carbon price.
    - One respondent flagged that pricing at natural gas does not give the domestic heating sector an incentive to switch but that this is beneficial as hydrogen ought to be adopted in the ‘hard to treat’ sectors first.
- Overall reference price approach:
    - The approach avoids distortions in the market and does not favour one technology over another. One prospective electrolytic producer stated they were indifferent to the reference price as long as it is at a price that the majority of offtakers are willing to pay.

- The achieved sales price with a price floor at natural gas alone would not incentivise producers to seek the highest sales price for hydrogen and the price discovery mechanism is therefore important.
- The price discovery mechanism would play a role in supporting a market benchmark price for hydrogen to emerge.
- Respondents requested more information on how the price discovery mechanism would work, including associated incentives and risks.

Concerns about the reference price approach

There were a range of concerns raised by respondents about the reference price approach:

- Complexity:
  - While the need for the constituent parts of the minded to position for the reference price is understood, each part introduces complexity.
  - It would be simpler to adopt only one reference price out of natural gas and achieved sales price.

- Achieved sales price might introduce administrative complexity and confidentiality issues:
  - It is difficult and onerous to provide achieved sales price data, and to have the data audited, especially where producers have multiple contracts with multiple offtakers over different contract periods.
  - Providing commercially sensitive achieved sales price information could cause problems with confidentiality.

- Achieved sales price might not result in prices above the natural gas price:
  - Producers will encounter difficulty finding offtakers willing to pay an achieved sales price which is higher than natural gas unless there is a differentiated quality of hydrogen (arguing that the UK LCHS should differentiate between low carbon hydrogen and zero carbon hydrogen, and therefore the zero carbon hydrogen could attract a higher price). Government will need to consider how to motivate offtakers to pay more but there is a risk that this ends up being poor value for money for government if the price discovery mechanism is not sufficient to provide an adequate incentive for producers to seek higher value sales. From an end user's perspective, it is problematic if producers raise their prices in the early years of market development when there are no alternative producers.
  - If hydrogen prices stay at the natural gas price, the hydrogen business model could price out potential new hydrogen producers.

- Achieved sales price could lead to gaming behaviour:
  - Producers could set prices purposely low and cross-subsidise hydrogen within a vertical supply chain or to partner companies.

    - If offtakers do not participate in price discovery they could capture premiums for themselves and not enable the true market value of hydrogen to be realised.

- Recent high/volatile natural gas prices could cause instability:

    - Linking the reference price to the natural gas price could cause instability. One respondent flagged that there could potentially be further instability in the gas price with increasing amounts of renewable gas and hydrogen blended into the gas supply.
    - Including natural gas as the price floor could negate the incentive to switch for end users as they would be exposed to volatile natural gas prices which are out of their control.
    - If the natural gas price increases above the achieved sales price, this could result in producers decreasing or stopping production. A few producers reflected that a way to manage this risk would be to link their offtake agreements to the natural gas price.
    - Respondents have suggested government 'stress-test' gas prices to check affordability across end user sectors, and that high or volatile gas prices should trigger a contractual review of the reference price with adjustments made if necessary.
    - Respondents requested more information on whether producers are expected to pay back if the natural gas price floor exceeds the strike price.

- Natural gas could be a less suitable floor price for non-CCUS-enabled projects:

    - It introduces unwanted volatility and risk for electrolytic projects as natural gas is not used as a feedstock (i.e. it is not the main cost driver).
    - Natural gas might be less appropriate for electrolytic hydrogen for mobility end uses as natural gas is not the counterfactual fuel.
    - Electrolytic projects are likely to have long-term fixed price contracts and no indexation to the gas price. This is especially the case for those linked to dedicated renewable sources. Introducing a link to natural gas in offtake contracts could increase the cost of capital and/or reduce end users' incentive to switch.

- There could be potential for the natural gas price floor to result in over-subsidy:

    - If achieved sales price is lower than the cost of counterfactual fuel plus carbon, this could cause distortions in downstream sectors since some market players would have access to cheaper fuel costs compared to others.
    - If producers sell hydrogen at the natural gas price to higher value end users such as those in the mobility sector, then the hydrogen price could remain at the natural gas price, resulting in higher costs for government.
    - For producers selling to hydrogen intermediaries there could be a risk of over-subsidy if intermediaries buy at the natural gas price but sell for a higher amount. There may need to be restrictions to ensure that transactions are occurring at arms-length.

- Alternative suggestions for the reference price:

- Power price for renewable hydrogen projects.
- The lower of power prices and natural gas prices to provide the floor price.
- Counterfactual fuel for the end use sector in question or the dominant end use.
- Have two reference prices – diesel price for transport end uses and natural gas for all other end uses.
- The primary energy input for each type of production should be taken into account as natural gas and electricity are likely to be less closely linked in the future.

- Pricing challenges and potential distortions:

  - The achieved sales price with the price discovery mechanism does not support a partnership approach between a single producer and end user. This approach would inhibit joint ventures unless they become complex in nature.
  - Price discovery might not be possible where producers and offtakers are isolated and there are no other producers or offtakers. For example, at a refinery or petrochemical plant, where hydrogen represents one of many input costs and is utilised as a feedstock and source of energy.

Government response

Overall, we note there is reasonable support for the proposed reference price approach. We will proceed with developing the detailed design of this proposed approach, based on achieved sales price, with a floor at the natural gas price, and a contractual mechanism to enable price discovery.

We acknowledge that this price support approach has moved away from the low carbon electricity CfD due to the nascent nature of the hydrogen economy in comparison with the electricity market and its well-established wholesale price benchmark. We consider that a different approach is needed given the nascent hydrogen market and to achieve the objectives of the hydrogen business model in the absence of a hydrogen price benchmark. As and when a benchmark is available, we expect many of these challenges to fall away.

We recognise the concerns raised by respondents, including the administrative burden and confidentiality issues associated with the achieved sales price and the risks created by the potential volatility of the natural gas price floor. We are working with the counterparty for the CfD (the Low Carbon Contracts Company) to understand how a future counterparty for hydrogen contracts could support producers to minimise these burdens.

We will consider the issues raised and the detailed suggestions put forward by respondents for the next stage of design and will continue to work with stakeholders. It remains one of our key design principles to minimise complexity where possible.

Question 5 - Does our minded to position create any other specific risks, incentives or disincentives which we have not already stated above? If so, what are they and how could the related risks be addressed – either within the model or outside of the model?

Consultation position

The consultation set out the risks, incentives and disincentives created from our minded to positions on the price support mechanism and the reference price approach. We asked stakeholders to respond with any additional points not already considered.

Summary of stakeholder responses to consultation

The main points raised by respondents were:

Additional risks and incentives to consider

- Having a separate UK LCHS for CCUS-enabled and electrolytic hydrogen production could enable different prices to emerge and encourage sales prices above the natural gas price.
- If the reference price floor were to include the carbon price, it could reduce the incentive for producers to sell to intermediaries at a lower price, which could in turn reduce the risk of government over-subsidy, as outlined under question 4.
- The UK Emissions Trading Scheme (UK ETS) should be expanded to end use sectors that are currently not exposed to it otherwise the business model does not give them an incentive to switch to hydrogen. The model also needs to account for what happens to free allocation of allowances under the UK ETS when customers buy hydrogen.
- The possibility that a producer can earn higher revenues from supplying hydrogen as diesel or gasoline substitute may boost fuel cell vehicle (FCV) uptake at the expense of battery electric vehicles (BEV). From an energy efficiency point of view this is negative because the 'well-to-wheel' efficiency of a FCV is much worse than that of a BEV.
- There is a risk of CCUS-enabled hydrogen having a significantly lower capture rate than expected by BEIS. Because the initial subsidies will be higher than the carbon price, there is little to no incentive for the CCUS-enabled hydrogen producer to minimize carbon dioxide emissions. An emissions penalty is therefore likely required to disincentivise emissions.

Additional design considerations

- The measurement of the strike price and achieved sales price needs to be considered as it will impact the size of the subsidy support. A few respondents suggested quantifying hydrogen production in £/kg or £/mega-joule.
- The final design needs to be suitable for non-recourse debt finance as well as balance sheet financing.

Government response

We will take into account the additional points raised by respondents in the next stage of design. For example, we will continue to design a business model that requires all projects to be able to meet the UK LCHS and also consider any potential challenges to the business model created by sales to intermediaries (see question 1).

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

Consultation position

In the consultation, we explained that indexation is a method to link the value of payments to changes in production costs which are outside of the producer's control. Indexing the strike price protects the producer from having their returns impacted from input costs being higher than expected, while also protecting government against the possibility of the producer making higher-than-expected profits due to falling input costs. We invited views on the most appropriate option for indexation of the strike price.

For this question, when we refer to CCUS-enabled we mean a reformation and/or gasification low carbon hydrogen production plant using natural gas as fuel and feedstock, reflecting the focus of respondents who answered this question. However, we recognise that CCUS-enabled production plants could use different inputs from natural gas, such as biogas, and we are considering the most appropriate approach to indexation for these inputs.

Summary of stakeholder responses to consultation

Response summary	
Agree with a single indexation option for all costs of all technologies	14
Agree with an indexation of the main input fuel/energy costs to a technology specific benchmark and some discussed indexation of other production costs to inflation	62
Support indexation without stating a preference	6
Not answered or unclear	39

Key points

When considering the most appropriate approach to indexation, the majority of respondents considered the strike price as being split into two production cost categories:

1. Main input fuel/energy costs.
2. Other (non-fuel/energy) production costs.

On main input fuel/energy costs, the majority of respondents proposed that CCUS-enabled and electrolytic projects should be protected from changes to these costs. The main reason for this was investment risk to projects from changing fuel/energy costs, which respondents noted would be particularly challenging for CCUS-enabled projects.

On other production costs, the majority of respondents proposed inflation protection with no consensus on the inflation benchmark that government should use.

While the majority of respondents proposed a technology-specific approach to indexation, reflecting different input fuel/energy costs for different production technologies, some respondents proposed using a single indexation option for all technologies.

<u>A single indexation option for all costs of all technologies</u>

Indexation of all production costs to an inflation benchmark for all technologies was the option most discussed by those proposing a single indexation option. Others discussed not providing any indexation protection, using an unspecified natural gas benchmark, or using an unspecified electricity benchmark.

Respondents proposed an inflation benchmark for three main reasons:

- Government should not take on energy price risk. Instead, the potential volatility in input fuel costs (e.g. natural gas in the case of CCUS-enabled producers) should be reflected in the project's strike price.
- Electrolytic producers should not be protected from electricity price changes through indexation to an electricity price benchmark as this may see these projects use grid electricity at times of high carbon intensity. This should be considered alongside the provisions in the UK LCHS.
- Indexing to an inflation benchmark would be simple and familiar to investors as it is consistent with existing UK energy policy. This would be a consistent approach across all technologies and allow government to compare the relative cost of these technologies.

One respondent who discussed an inflation benchmark in respect of electrolytic producers suggested that an additional upward adjustment of the strike price to a pre-set threshold would be necessary at times of high gas prices to protect the producer's returns.

<u>Indexation of the main input fuel/energy costs to a technology specific benchmark and some discussed indexation of other production costs to inflation</u>

Indexation of the main input fuel/energy costs

Many respondents discussed that providing no indexation or only providing inflation protection for input fuel/energy costs would pose a high investment risk and lead to higher financing costs for producers. This would leave producers exposed to energy market volatility and not reflect the characteristics of the natural gas and electricity markets. CCUS-enabled producers would be particularly exposed to short-term natural gas price rises as there are no long-term, fixed-price natural gas contracts available in the UK gas market. Electrolytic projects would be able to manage this risk by securing long-term, fixed-price contracts.

Some respondents proposed indexing the main input fuel/energy costs to the actual input energy costs faced by each producer as this would reduce investment risk most compared to the other indexation options. Some respondents noted the complexity this would add to the business model as government would have to consider each producer's energy purchasing strategy in turn, as well as the disadvantages outlined in the consultation (e.g. risk of transfer pricing distortions and potential for inefficient use of energy/fuel). For these reasons, some respondents suggested that indexation to actual input energy costs should not be taken forward.

The majority of respondents proposed indexing the main input fuel/energy costs to a technology specific benchmark.

For CCUS-enabled projects, respondents proposed indexing this cost to a natural gas benchmark. Some respondents discussed the different options (e.g. short- or long-term benchmarks) that could be used. A long-term benchmark would reduce government's exposure to volatility in the short-term market, reduce the likelihood of subsidy distortions, and incentivise producers to carefully manage their energy purchasing strategy to meet the long-term benchmark. One respondent also proposed that producers using autothermal reformation (ATR) technology should be provided with indexation to an electricity price benchmark to reflect the amount of electricity used in this production process.

For electrolytic projects, respondents differentiated between two electrolytic archetypes when discussing the most appropriate indexation option for the main input energy cost: (1) projects purchasing grid electricity, and (2) projects purchasing electricity from dedicated renewable generator(s). They didn't consider projects that may use multiple sources of electricity.

(1) Electrolytic projects purchasing grid electricity

- Respondents proposed an electricity price benchmark and discussed a range of options for the benchmark: day to multi-day, week, month, and year. Several respondents proposed long-term benchmarks for the reasons explained above for CCUS-enabled projects. Other respondents proposed other benchmarks: low carbon electricity generation CfD strike prices, low carbon/renewable energy PPAs, or a low carbon electricity price benchmark.
- Respondents discussed other considerations for electrolytic projects purchasing grid electricity:
    - While some thought that electrolytic producers should be allowed to run baseload to reflect the most efficient operating pattern and enable producers to make the necessary returns, others proposed restrictions on running during periods of high carbon intensity for the grid.
    - The relationship with the minded to reference price (i.e. achieved sales price, with a floor at the natural gas price, and a contractual mechanism to enable price discovery) may impact the producer's returns. One producer proposed, as a solution, indexing a portion of the strike price to natural gas prices.

(2) Electrolytic projects purchasing electricity from dedicated renewable generator(s)

- Respondents noted that the electricity price would be largely fixed and proposed only indexing production costs to an inflation benchmark.

Indexation of other production costs to inflation

Respondents proposed a variety of inflation benchmarks (retail price index (RPI), consumer price index (CPI) and producer price index (PPI)) for other production costs, such as other utility and labour costs. One respondent proposed an alternative approach: a fixed percentage increase in strike price over the length of the contract to manage the change in these costs. Respondents highlighted that inflation protection of other production costs would be consistent with existing UK energy policy.

Some respondents discussed the cost of CO2 T&S and proposed that the cost should be a pass through with producers protected from any changes in fees.

<u>Other considerations for indexation</u>

Respondents discussed other considerations.

- The subsidy could look like a fixed premium for CCUS-enabled producers should their strike price be indexed to a natural gas benchmark and this strike price move in tandem with a reference price comprised of a natural gas price floor.
- Some suggested that the proportion of the strike price protected through each indexation approach (e.g. energy price benchmark for fuel/energy costs and inflation-linked for other costs) should be tailored to the specific production costs breakdown of each producer, whereas other respondents proposed that the proportion of the strike price protected under each cost category should be standardised across different production pathways to reduce complexity.
- The frequency of the strike price adjustment (e.g. once a day, week, month, year) would be important for the producer's cash flow.
- The potential future developments of the hydrogen market should be factored into the decision on indexation: the relative hydrogen cost of existing hydrogen producers and new hydrogen producers; and the viability of producers when the contract finishes.

Government response

In light of the responses, we consider indexation of the strike price to be an important aspect of the business model in protecting producers against unmanageable and uncontrollable changes to input costs and government from over subsidy, while providing end users with security of supply.

Moving into the next stage of design, we are using the cost categories and the technology archetypes used in the Hydrogen Production Cost Report 2021[13], published alongside the

---

[13] Report found at: https://www.gov.uk/government/publications/hydrogen-production-costs-2021. The report uses the following archetypes: 300MW/1000MW SMRs with CCUS, ATRs with CCUS, and ATR + GHR with CCUS; and grid electricity (industrial retail price/industrial LRVC), dedicated offshore, and curtailed electricity Alkaline, PEM and SOE electrolysers.

consultation, as a foundation for further analysis of costs. As we develop a preferred indexation approach, we are considering how it interacts with other parts of the business model, in particular the reference price and the UK LCHS. We are considering whether different approaches to indexation for different production technologies is appropriate and provide an update on our minded to approach in the indicative Heads of Terms. Additionally, we are considering the make-up of the strike price and the treatment of the different production costs in the business model. We are currently analysing the treatment of:

- Policy costs on electricity faced by hydrogen production pathways.
- Network costs faced by hydrogen production pathways for the different utilities used in the different production processes.
- Hydrogen T&S costs, which we discuss in question 20.
- UK ETS liability faced by CCUS-enabled producers for uncaptured carbon from the production process. We are minded to leave this liability with producers to incentivise industry to design hydrogen plants that achieve higher capture rates and reduce residual emissions in line with our net zero objectives.
- UK ETS free allocation of UK allowances (or free allowances) to CCUS-enabled hydrogen producers.
- CO2 T&S cost faced by CCUS-enabled producers for inserting and storing the captured carbon. We are minded to take a similar approach to the Dispatchable Power Agreement (DPA) and the ICC business models and protect producers from any changes to this cost via a pass through (funded via the hydrogen business model). We are considering how the CO2 T&S fees will be treated in the hydrogen business model and how to treat these fees where producers breach the terms of the connection agreement with the CO2 T&S company (CO2 T&SCo), ensuring alignment with ongoing CO2 T&S policy development.[14]

Question 7 - What are your views on whether price support for low carbon hydrogen should be constrained for applications using hydrogen as a feedstock to mitigate potential risks of market distortions? Please explain your rationale, including any suggestions both within and outside the business model to mitigate these risks.

Consultation position

In the consultation we set out that, while our preferred reference price mechanism is intended to accommodate all end use sectors, we are considering the risk of overcompensation where hydrogen is used as a feedstock (e.g. chemical sector, ammonia production). Users of carbon intensive hydrogen already place a relatively high value on hydrogen and pay a higher price associated with using it. If users of hydrogen as a feedstock were to receive low carbon hydrogen benefiting from the same level of subsidy as end users switching from other counterfactual fuels, it could lead to over subsidy and create distortions in the downstream markets they compete in. We did not set out a preferred position on this question but welcomed views on the potential need to limit the proposed price support where hydrogen is

[14] Carbon capture, usage and storage business models found at: https://www.gov.uk/government/publications/carbon-capture-usage-and-storage-ccus-business-models.

directed to these end users, and on potential measures which could be considered to counteract any risk of over subsidy.

Summary of stakeholder responses to consultation

Response summary	
Exclude from HBM	8
No constraints	24
Acknowledge some measures may be needed to avoid market distortion / apply on a case by case	30
Not answered or unclear	59

Key points

There was no clear consensus over this question, although most respondents were against fully excluding existing feedstock users from accessing subsidised hydrogen. The main reason for this was the benefits of selling low carbon hydrogen to existing carbon intensive hydrogen users (e.g. easy target market, clear carbon reduction benefit). Some of these respondents did acknowledge the risk of market distortions posed by sales to users of hydrogen as a feedstock and suggested measures to address this risk through the business model. These suggestions included a well-designed price discovery mechanism, a separate reference price or other contractual measures.

Some respondents were against any constraints to price support. A key reason for this was the added complexity that these constraints would bring to the model.

A small minority of respondents supported excluding existing users from accessing subsidised hydrogen.

Reasons not to exclude price support for applications using hydrogen as a feedstock:

A majority of respondents to this question were against excluding hydrogen feedstock users from accessing subsidised hydrogen. A wide range of stakeholders, including producers, consumers, investors and trade bodies responded this way. Respondents highlighted four main benefits that would be realised if we allow price support for feedstock users.

First, a little under half of respondents said that selling low carbon hydrogen to feedstock users would lead to a more efficient scale up of the hydrogen economy. The most common reason given for this was that they offer immediate sales opportunities to producers, as they have lower barriers and costs to switch to low carbon hydrogen. A less common reason given was that these users could provide constant, baseload demand for low carbon hydrogen in the early days of the market, and therefore serve as an ‘anchor’ customer for producers and mitigate the need to access volume support.

Second, some respondents said that switching existing carbon intensive hydrogen users to low carbon hydrogen could result in substantial carbon savings. These respondents emphasised that the current production of carbon intensive hydrogen emits large quantities of CO_2 in the UK, and that the hydrogen business model should aim to reduce this.

Third, some respondents mentioned the opportunity for the UK to support new green industries by subsidising the switch from high to low carbon hydrogen among existing feedstock users. Supporting the decarbonisation of certain industrial sectors, for example the ammonia sector, could help drive growth and potentially enable UK-based businesses to command a 'green premium' for their low carbon products. One respondent pointed out that these industries do not have an alternative to hydrogen, and ultimately will require support from somewhere to decarbonise.

Fourth, a minority of respondents said that feedstock users offer a high-value market to sell into. This was viewed as a positive for price discovery, which is essential to the establishment of a market benchmark price for low carbon hydrogen. In addition, one respondent indicated that selling to high value end users could lead to lower strike prices, and better value for money for government.

There was a split between those that acknowledged a potential need for some constraints to mitigate the risk of market distortions, and those that advocated for no constraints at all. Slightly more respondents felt there may be a need for some constraints.

Out of those that advocated for no constraints, the key reason for this was the added complexity it would bring to the business model. These respondents said that introducing multiple approaches to price support for different users would complicate the contractual arrangements, and so government should be careful to balance any benefits against this additional complexity. Some respondents also said that it would be difficult to enforce different approaches in practice, as feedstock users might look to buy low carbon hydrogen from third parties, or purchase hydrogen for use as both a feedstock and a fuel.

<u>Reasons to exclude price support for applications using hydrogen as a feedstock</u>

A minority of respondents were in favour of excluding feedstock users from price support entirely. The main reason for this was the risk of market distortions caused by overcompensation from the hydrogen business model. There was no clear agreement as to the precise extent and nature of these market distortions. Other reasons given for excluding feedstock users included:

- The business model should target and help develop new markets for hydrogen, rather than existing ones.
- A business case can already be made for those using carbon intensive hydrogen as a feedstock, so a subsidy is not required.
- Switching these users to low carbon hydrogen is potentially of limited carbon reduction benefit.

It was suggested by some of these respondents that producers in receipt of a business model should still be able to sell unsubsidised hydrogen to feedstock users.

<u>Options for constraining price support</u>

Several options for constraining price support for feedstock hydrogen users were given by respondents. These included relying on the price discovery mechanism (e.g. a gainshare mechanism), setting an alternative reference price, reporting requirements, contract review clauses and limiting sales of hydrogen to fuel use only.

The preference of some prospective producers was to rely on the price discovery mechanism to limit over subsidy. It was suggested that feedstock users should be able to pay more for low carbon hydrogen than the natural gas price (as they already pay the price of carbon intensive hydrogen). According to these respondents, an effectively designed price discovery mechanism would provide the necessary incentive for producers to seek a higher price from this type of end user.

Some large prospective producers also suggested that, if we were to require additional constraints, then a separate (higher) floor reference price for feedstock hydrogen users would be the best option. The aim of this would be to ensure the cost of low carbon hydrogen could not be much below the cost of carbon intensive hydrogen. Two main alternatives were suggested. One was to use a market benchmark price for carbon intensive hydrogen as the floor price for existing users. The second alternative was to use the natural gas price plus an uplift, such as the carbon price. These suggestions came with the caveat that they would increase the complexity of the business model.

A small minority of respondents suggested we include specific review clauses in the business model contract. If over subsidy occurred, these clauses would enable either rectifying changes to the contract to be made or require the producer to pay back subsidy if excess profits were being made.

Several respondents emphasised that, if we were to constrain price support for feedstock users through the business model, then it would be vital to ensure they have adequate alternative means of decarbonising and that existing carbon intensive hydrogen production assets are not stranded. The main suggestion was to provide separate funding for producers of carbon intensive hydrogen to retrofit CCUS.

A small number of respondents suggested that we limit sales of subsidised hydrogen to use cases where hydrogen is used as a fuel, with one also suggesting allowing the use of hydrogen as a biofuel feedstock. This would effectively only enable sales of unsubsidised hydrogen to feedstock users. The risk of market distortion, and lack of alignment with government objectives, were the main reasons given for this. Most of these respondents did caveat their answers to say that producers should be allowed to sell excess low carbon hydrogen to feedstock users, but that it should not be subsidised.

Government response

Subject to compliance with subsidy control and public law principles, we intend to allow hydrogen producers to receive subsidy for sales of hydrogen to feedstock users. In our view, there are clear benefits to allowing these end users to access low carbon hydrogen, including carbon savings, the higher value they place on hydrogen and the potential for them to offer flexible and reliable demand as they have the option to blend low carbon hydrogen with their existing supplies if necessary.

However, we recognise the potential for sales of low carbon hydrogen at the natural gas price to feedstock users to lead to overcompensation and cause market distortions. We are therefore working through whether additional measures are needed to address this risk, including gathering further evidence to understand the scale of the risk posed, assessing what, if any, proportional constraints could be applied to these sales and considering the best way to enforce them. Options currently under consideration include, but are not limited to:

- Relying on the price discovery mechanism to incentivise sales at a higher price to feedstock users.
- Using an alternative reference price (such as a different benchmark index or a bespoke formula to calculate the floor price).

Our key considerations when assessing these options will include value for money for government and minimising complexity where possible for all parties.

Our position remains that existing hydrogen producers, including those for feedstock uses, will not be eligible for support through the hydrogen business model, but may be eligible to apply for the ICC business model, as set out under question 1.

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

Consultation position

The consultation set out a minded to position for the key components of the business model, as already outlined under questions 3, 4, 5, 6, and 7 relating to price support. The aim of this question was to give respondents an opportunity to consider the overall package for price support in its entirety including any interactions between components. Some of the issues raised under this question related to specific price support questions and therefore have been included in the summaries to those questions.

Summary of stakeholder responses to consultation

Response summary	
Agree with our overall position for price support	66

Agree with some components but not all or agreed on a conditional basis	13
Did not agree with our overall position for price support	7
Not answered or unclear	35

Key Points

Most respondents agreed with the overall minded to position for price support. There were some respondents who agreed with some components of it but not all, as well as a small minority who did not agree with most of the positions set out.

Government response

Overall, there is good support for our price support proposal in its entirety, with the key arguments that were raised for and against individual components summarised in previous questions. In conclusion we will proceed with the price support approach set out in the consultation:

- Variable premium as our preferred mechanism for price support. It gives the price support intervention flexibility and adaptability that the fixed price and fixed premium approaches do not provide and enables the possibility that the level of subsidy can reduce over the length of the contract as the market evolves, rather than only across allocation rounds.
- Producers' achieved sales price, with a price floor at natural gas, as our preferred option for the reference price for initial projects. The reference price is key for ensuring the variable premium mechanism is a workable solution and realises the benefits we outlined.
- An additional contractual measure to incentivise producers to seek higher priced sales and aid price discovery. We propose that this will be in the form of an amount linked to the increment by which the reference price exceeds the price floor for each unit of hydrogen sold. We are also considering whether to constrain the amount for sales prices which exceed a certain level to ensure hydrogen remains affordable for offtakers and to protect government from over subsidy.
- Integration of a market benchmark price into the reference price at the earliest opportunity for future projects. We will use evidence from initial projects and other countries, as well as working with price reporting agencies, to understand how government can best support the emergence of the market benchmark price.
- Indexation of the strike price to protect producers against unmanageable and uncontrollable changes to input costs and government from over subsidy, while providing end users with security of supply. We are considering different approaches for different production technologies.
- No exclusion of business model support for sales of hydrogen to feedstock users. The next steps are to gather further evidence to assess if any constraints should be applied to address any overcompensation risk.

Section 5: Volume support

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

Consultation position

The consultation document provided the rationale for mitigating volume risk – the risk that the producer is unable to sell enough volumes of hydrogen to offtakers to cover costs with reasonable confidence – through the business model. Based on the assessment of the volume support options presented in the consultation against the key principles, we set out the sliding scale as our minded to position. This manages volume risk through paying a higher level of price support on low offtake volumes, with the level of price support tapering off as volumes increase. We consider this option best balances investability from the perspective of producers and value for money from the perspective of government, while minimising the risk of distortions and unintended consequences.

Summary of stakeholder responses to consultation

Response summary	
Agree with sliding scale for volume support	50
Agree with sliding scale for volume support, with caveats	8
Responded with ‘maybe’	12
Did not agree with sliding scale for volume support	15
Not answered or unclear	36

Key points

The majority of respondents to this question agreed with our minded to position of the sliding scale for volume support. Although many caveated their response with needing to know further details of the design, they outlined it to be the most appropriate of the options presented. Reasons included minimising distortions from government intervention and providing the right incentives for producers to secure offtake.

A small minority agreed only if certain conditions are met in the next stage of design. Conditions included the design accounting for technology turndown limitations, debt and capital obligations adequately being met, supporting low offtake volumes ahead of the decision to enable gas blending, and additional support being provided alongside the sliding scale if offtake falls to zero.

A larger minority did not agree. Half of these respondents suggested that government take a more interventionist role in the market and buy hydrogen or provide availability payments for producers in the event offtake volumes fall to zero, instead of using a sliding scale.

A similar number responded with a ‘maybe’. The main reasons for this were broadly two-fold:

- More design detail is needed to make a decision either way, or
- Additional support is needed if offtake volumes fall to zero.

One CCUS-enabled developer asked for clarity that a project would earn a minimum economic return with certainty at low volumes.

Arguments in support of the sliding scale providing volume support

Most respondents to this question were in support of the sliding scale to mitigate volume risk. They outlined that it would help producers to manage volume risk, and be a logical way to reduce the support as offtake volumes increase. There were three main reasons in favour of the sliding scale:

- It would give confidence to investors by providing a stable revenue profile and allow producers to raise capital and reduce the cost of loans.
- The design of the sliding scale would provide the right incentives for producers to secure more offtake volumes. It promotes production over capacity as there are no incentives to create capacity for which there is no offtake, with producers (rather than government) being best placed to find and build more offtake volumes.
- The sliding scale is the least interventionist option as it avoids the negative distortions and complexity arising from government acting as an offtaker. The sliding scale has been highlighted as best balancing what producers need with securing value for money for government.

Concerns about the sliding scale providing volume support

There were four key concerns raised by respondents.

First, respondents outlined that the approach is a complex way to provide volume support. Specific complexities raised were:

- Each producer would have their own volume risk and therefore a standardised approach would not be practical, while a project-specific sliding scale would be too burdensome for the government to administer.
- It would be difficult to calculate an appropriate level for the strike price, let alone tapering the strike price as that requires understanding the costs of production for each producer.

Second, respondents said the sliding scale introduces investor risk as the approach only covers fixed and marginal costs for low volumes. If projects are unable to earn an equity return in the event of insufficient volumes or meet their debt obligations at low volumes then it would make the model a less investable proposition for them.

Third, respondents flagged the sliding scale being challenging in circumstances where offtake volumes fall to zero as no support would be provided. This was a concern raised in general as well as a specific point about projects with a single offtaker who could fall away with no alternative offtakers nearby. Producers still incur plant running costs and debt service even if there is no hydrogen being produced. Solutions to this problem were suggested by some respondents:

- Government to offtake hydrogen instead to get projects started as sliding scale alone would not derisk projects and mitigate volume risk sufficiently. Specific suggestions by respondents for how government could mitigate volume risk, such as government allowing hydrogen to be blended into the gas network, are set out in question 10.
- Availability payments instead to stimulate the market for initial rounds of contracts, which would be better for smaller projects.
- A floor for payments, recognising that certain types of plant would not operate effectively if they have to ramp down in the event of losing their offtake volumes.

Finally, one respondent argued the sliding scale would reduce the incentive for producers to locate where there is the lowest likelihood of loss of volume and that this could potentially impede the spread of electrolytic projects throughout all areas of the UK.

There was only one respondent who did not agree with any form of volume support as they considered the volume risk is already reduced by the price support mechanism, and if the producer receives no volume support, they would have a stronger incentive to manage counterparty risk.

Design details for the next stage

Many respondents flagged they need more information on the design of the sliding scale. The most important aspect was how the sliding scale would link to components of the variable premium price support, and how it would lead to predictability of revenues and ultimately attract investors.

There were also many suggestions for government to consider as part of the next stage of design, including the type of volume risk the sliding scale should accommodate and the incentives it should create. There were specific components of the sliding scale which respondents would like the model to set out: how it would apply to different project archetypes, how the technological restrictions around the ramping up and down of technology would be taken into account, when the sliding scale would be triggered, the shape and slope of the reprofiled strike price, administrative aspects and interactions with scaling up of future production volumes.

Government response

We note there is reasonable support from respondents for the minded to position of providing volume support via the sliding scale. The majority agree with it, while some respondents want the next stage design detail before confirming their position. Using information collated from consultation responses, we have provided the Hydrogen Business Model Expert Group with more detail on defining those risks which the sliding scale mechanism can mitigate and those which it cannot, how the sliding scale mechanism will be delivered and the parameters which the design of the mechanism should take into account.

We acknowledge the concerns raised by those respondents who want a mechanism which provides additional protection if offtake volumes were to fall to zero. However, we consider that the alternative options identified, many of which were previously considered in the consultation, are likely to give less value for money as they could result in significant budget being spent on non-production of hydrogen.

We therefore remain of the view that the sliding scale is our preferred mechanism for mitigating volume risk. We will continue to develop the detailed design, drawing on the information provided by respondents.

Question 10 - Do hydrogen plants need any further volume support in addition to the sliding scale? Please explain your response, including what kind of additional volume support and under what circumstances it would be needed.

Consultation position

In the consultation we asked whether further volume support is needed in addition to the sliding scale. Once market price risk and volume risk are mitigated via the variable premium and sliding scale, respectively, we want to understand whether any volume risk that remains with the producer would be a barrier for investment decisions. We asked for information on the detail of outstanding volume risks not sufficiently mitigated by the proposed sliding scale mechanism. Specifically, we want to understand the circumstances under which they might occur and what further support may, as a result, be necessary.

Summary of stakeholder responses to consultation

Key points

Although some respondents said they do not require further volume support in addition to the sliding scale and have outlined reasons why, most respondents said they do want further support. The additional support required falls broadly into two categories. First, additional support for producers if offtake volumes fall to zero, in the form of availability payments, government offtake and minimum pay-outs. Second, for government to play a role in stimulating demand in the form of both funding support and non-monetary support. Examples given of ways in which government could do this included reducing the costs of switching for end users, support for storage, enabling blending into the gas grid and communicating a clearer strategy around which hydrogen end uses and sectors should be targeted.

Reasons why no further volume support is necessary

Some respondents said no further support was needed, with one respondent explaining their reasoning as government should not be supporting less thought-through projects through the provision of certainty of demand.

A few said further volume support would not be necessary if the sliding scale design:

- Provides sufficient risk mitigation.

- Provides sufficiently robust and effective support for hydrogen T&S.
- Includes the use of hydrogen as a feedstock.
- Can deliver no/minimal loss guarantee.

One respondent said government should monitor whether additional volume support is needed and amend the approach to add further intervention as necessary.

Reasons why further volume support is necessary

A much larger number said they do want government to provide support in addition to the sliding scale, for a variety of reasons.

There were several respondents who would like additional support in the form of availability payments, government offtake or minimum pay-outs to cover fixed costs. The reasons given included:

- At zero offtake volumes, producers are still incurring costs including financing costs.
- Producers are exposed to an individual end user's market risk, which is outside of their control.
- Producers need time to find another offtaker if their one end user falls away.
- CCUS-enabled plants are not easily able to reduce or cease production if offtake volumes fall away and therefore need to be producing at minimum production levels before the plant is turned off. In the event the plant is turned off, energy efficiency and costs associated with maintenance of the plant would be adversely affected.
- Producers might not be able to find alternative offtakers as no transport networks are yet up and running so offtakers need to be located where the hydrogen can be delivered to them.
- Small electrolytic producers find it difficult to find offtakers and negotiate contracts with them.
- Small, FOAK electrolytic projects face the risk of major wind turbine or electrolyser failure.

Most respondents to this question want government to play a bigger role in the demand-side of the value chain to stimulate demand in end use sectors. This has been identified as reducing volume risk for producers, and there would be less need for producers to call on the volume support provided in the hydrogen business model. Suggestions by producers on ways in which government could do this either involve more funding or are non-monetary, with further information below.

Funding support for demand-side policies:

- Provide revenue support in the form of grants to reduce the costs of switching to hydrogen for end users. Some specific sectors which face significant up-front costs such as steel were mentioned by a few respondents as key industries which need help with switching.
- Provide support for hydrogen storage as it would increase supply resilience for offtakers and reduce volume risk.

Non-monetary support for demand-side policies:

- Communicate a clearer strategy around end uses where hydrogen should be targeted and sector specific areas. This would be helpful for stakeholders as hydrogen is only one way to decarbonise.
- Provide clarity and transparency on what incentives are in place for end users to switch.
- Provide clarity on the phasing out of carbon intensive hydrogen.
- Coordinate the demand-side interventions alongside supply-side policy so that consumers can afford to switch and make the necessary equipment changes.
- Allow blending into the gas grid in due course to provide a default backstop market.
- Set quotas or sector-specific abatement targets, mandate the use of hydrogen in industry and increase emissions standards for vehicles.
- Put in place anchor loads to stimulate offtake (e.g. consumers of well-established utilities).
- Use hydrogen in areas which the public sector delivers – such as hospitals, military vehicles and refuse vehicles.
- Require low carbon product standards on the average carbon intensity to produce each key material or product to decline across the economy, and permit regulated entities to trade compliance credits. Similar schemes of (tradable) credits/standards could also be applied in heavy-duty transport and domestic heating.
- Public procurement of green steel/cement for government buildings and encourage adoption of materials with lower carbon intensity.

Government response

We do not see a compelling case for providing additional volume support in the business model contract beyond the sliding scale approach. We consider the business model to be an investable proposition without additional volume support and would like to encourage producers to play an active role in promoting market development by seeking and helping to develop sources of demand for hydrogen. Suggestions made by respondents have been for availability payments or minimum pay-outs and government offtake. We considered these options in the consultation and remain of the view that these should not be taken forward primarily due to their potential to distort the market and use up available budget without incentivising the production of hydrogen or delivering carbon savings.

We recognise a holistic approach is needed to support hydrogen deployment. Securing demand in key end use sectors will be critical to achieving our legally binding Carbon Budget 6 and net zero commitments and developing a thriving hydrogen economy. We are taking forward a range of commitments to unlock greater use of hydrogen as set out in the UK Hydrogen Strategy. This includes the Industrial Energy Transformation Fund, which supports hydrogen fuel switching and launched its latest application window on 31 January[15]. We also launched a call for evidence on enabling hydrogen-ready industrial boiler equipment[16] and are considering future hydrogen network and storage requirements.

[15] Industrial Energy Transformation Fund – How to Apply.

[16] The consultation on enabling or requiring hydrogen-ready industrial boiler equipment can be found at: https://www.gov.uk/government/consultations/enabling-or-requiring-hydrogen-ready-industrial-boiler-equipment-call-for-evidence

Section 6: Applicability of the business model across different types of projects

Question 11 - Do you consider our preferred options on price and volume support outlined in sections 4 and 5 can work across different production technologies and operating patterns? If not, what difference in payment mechanisms might be required between different technologies and how should any downsides associated with that be managed?

Consultation position

We noted throughout the consultation that hydrogen projects can vary substantially in terms of production technology, operating mode and size (or capacity). In this chapter, we considered whether different business models would be required for CCUS-enabled and electrolytic projects, and/or for larger and smaller scale projects. We set out our view that the business model can work across different production technologies and operating patterns. It is possible to incorporate different design features into the basic model, notably indexation, and different support requirements can be reflected in strike prices and managed via separate allocation processes and/or separate funding pots.

Summary of stakeholder responses to consultation

Response Summary	
Agree that our preferred options on price and volume support can work across different techs and operating patterns	23
Agree, with caveat that variable model features are needed	27
Responded ‘maybe’	19
Did not agree with our preferred options on price and volume support (cannot work)	9
Not answered or unclear	43

Key points

The majority of respondents to this question considered the preferred options set out on price and volume support can work across different production technologies and operating patterns. Around a third of respondents to this question added a caveat that certain features would need to be applied differently across technologies, such as different strike prices or indexation approaches.

A minority of respondents said the model could ‘maybe’ work across different technologies and operating patterns, and the smallest group responded ‘no’. The key concerns raised by these groups were the administrative burden of the business model for small producers and the wide variation in technologies rendering a single model unworkable.

Reasons the model should be applied across different technologies and operating patterns

The main reason given to support the application of the model across different technologies and operating patterns was avoiding unnecessary complexity. These respondents felt that introducing a single business model would be simpler for industry and would provide investors with greater certainty. Several respondents also expressed their view that the model should be technology agnostic. One respondent indicated that this would ensure no bias between technologies is introduced, which would stimulate competition and innovation. Another respondent felt that the model should focus on carbon outcomes rather than technology inputs.

Concerns raised that the model cannot work across technologies and operating patterns

The main concern raised by respondents about the applicability of the model across different technologies and operating patterns was the administrative burden for smaller, most likely electrolytic, projects. Some suggested that the use of a private law contract, and the variable premium price support, would be too expensive and complicated for smaller projects to manage, meaning these projects would be unable to bid for a business model contract. The knock-on impact of this would be a bias in allocation of support towards larger, mostly CCUS-enabled hydrogen projects. The issues in relation to smaller scale projects are discussed in more detail under question 12.

A small number of respondents said that a single, inflexible business model would not work, due to wide variations in hydrogen production technologies. The main differences noted were:

- Cost structures and capital requirements depend on the technology employed. For example, input energy costs between CCUS-enabled and electrolytic hydrogen differ. It was pointed out that, over time, the correlation between gas and electricity prices is expected to weaken. A reference price, or approach to indexation, linked purely to natural gas was highlighted as inappropriate for electrolytic projects by a small number of respondents.
- Ability to ramp production up and down depends on the technology. A small number of respondents pointed out that CCUS-enabled hydrogen facilities are unable to start and stop producing hydrogen quickly without impacting costs and the integrity of the facility. It was emphasised that we should consider this when designing the sliding scale volume support mechanism.
- Whether projects require hydrogen transport or not. One respondent pointed out that projects which are co-located with end users may be at an advantage if they are competing with projects that need to recoup hydrogen transport costs through their strike price. It was suggested that this risk be addressed via different strike prices for different categories of project.
- Unforeseen differences that only become apparent in future once technologies have had more time to develop. It was stressed that the model should remain flexible to deal with this risk.

Suggestions made to address concerns

Many respondents suggested we implement different model features to ensure the model works for different production technologies. The suggested features to vary were:

- Allocation pots and processes. This was the most common suggestion, with a mixed group of energy companies, consumers, trade bodies and others backing separate pots of money for allocation of support to different technologies.
- Strike prices. This was another popular suggestion, with respondents keen to see different technology costs reflected in different strike prices.
- Indexation. This was also a common suggestion, with respondents supporting separate approaches to indexation to reflect different input costs. It was further suggested that natural gas would not be suitable indexation for electrolytic projects, that indexation could be negotiated on a project-by-project basis and that electrolytic projects should not be indexed to a short-term power market as this could incentivise production at peak times on the grid.
- Volume support. This was a less common suggestion. However, a small number of companies felt that volume support should reflect the different turndown capabilities of certain technologies.
- Carbon savings. Several respondents suggested that electrolytic projects should be able to benefit commercially if they achieve greater carbon savings than CCUS-enabled projects. One pointed out that this would encourage grid-linked electrolytic projects to procure electricity when the grid is supplied by mostly renewable power.
- Reference price. One respondent explicitly suggested having different reference prices for different technologies.

Several respondents highlighted a desire for the model, and contract, to remain flexible. This is so it can adapt to issues that might arise in future, for example innovations in technology. Two respondents suggested keeping the terms and conditions flexible, especially for FOAK projects, to reflect lower levels of technology readiness.

We also noted a small number of respondents expressly urged us not to overcomplicate the model. In particular, these respondents were keen that we do not try and address all possible risks – which would lead to overcomplexity – and instead identify the key risks that it is appropriate for government to mitigate through the business model.

Finally, a small number of the respondents to this question suggested we develop a separate model for electrolytic projects. They suggested this should take the form of a simpler fixed premium and would enable electrolytic projects to move forward quicker. More respondents raised this suggestion in answer to question 12, and it is discussed further there.

Government response

We note that the majority of respondents to this question considered that the proposed business model can work across different production technologies and operating patterns. We acknowledge the concerns raised by others that a single, inflexible model would not work due to wide variations between technologies, for example around different cost structures, operating flexibility, transport requirements and future unknowns.

Our view is that these concerns can be reasonably mitigated within the overarching design of the current business model proposal, for example by considering different approaches to strike price indexation and running separate allocation processes. We are progressing with the next stage of design on this basis, and will consider how our approach, particularly in relation to indexation, agreeing strike prices, and allocating contracts, should vary across technologies and operating patterns.

We respond to the suggestion of a separate model for smaller projects under question 12.

Question 12 - Do you agree with our proposal not to introduce a separate revenue support scheme for projects of a smaller scale? Please give arguments to support your response.

Consultation position

We set out our view that most smaller projects would be able to proceed without a separate business model, for a few reasons. First, many (but by no means all) smaller scale projects we are aware of are intending to supply hydrogen to transport applications. They are therefore potentially eligible to apply to the existing Renewable Transport Fuel Obligation (RTFO) revenue support scheme. More generally, some smaller scale projects may, depending on their specific circumstances, be able to make a business case with support via other policy mechanisms including grant funding through the NZHF. Furthermore, the low carbon electricity CfD scheme has demonstrated that private law contracts can enable investment in relatively smaller scale projects. We also set out that administering multiple schemes would be more challenging for government to deliver and increase the complexity of the policy landscape for industry.

Summary of stakeholder responses to consultation

Response summary	
Agree not to introduce separate model	40
Responded with ‘maybe’	11
Did not agree with our position not to introduce a separate model	21
Not answered or unclear	49

Key points

A majority of respondents to this question supported our proposal not to introduce a separate business model for projects of a smaller scale. From this group, several felt that the proposed business model was not well suited to smaller scale projects, but that introducing multiple schemes would be too complex and could distort competition, or that government should focus on developing large scale hydrogen projects to begin with. A small number of respondents gave no clear ‘yes’ or ‘no’ response to this question.

Just under a third of respondents to this question disagreed with our proposal. The main reasons given were that the business model is too complex for small producers, and that the RTFO would not be a suitable alternative. Some respondents supported the idea of a simpler, fixed premium model for smaller projects.

<u>Reasons for supporting government minded to position</u>

A majority of respondents to this question supported our proposal not to introduce a separate business model for projects of a smaller scale. From this group, several felt that the business model was not well suited to smaller scale projects, but they did not support the introduction of a separate model.

Several respondents said that introducing more than one business model would increase the complexity of the policy landscape for industry. In addition, multiple models could distort competition or create perverse incentives and lead to suboptimal or inefficient plant design to meet ‘arbitrary’ model thresholds. They cited other policies, including the electricity Feed-in-Tariff and Renewable Obligation Certificates being examples of models encouraging plants to change their design purely to fit support scheme thresholds. Having multiple schemes would also increase administrative costs for government and be less clear for investors.

Several respondents considered that government support should be targeted at larger projects initially, to achieve quicker scale up of the hydrogen economy, and therefore did not feel a separate model for smaller projects should be introduced. Additional reasons for this view included that encouraging new end uses for hydrogen would require rapid scale and that all technologies should aspire to achieve large scale production, with policy measures designed primarily to support this.

There were several other reasons given to support the minded to position, including:

- Alternative schemes are available and can support small projects, for example RTFO and/or NZHF.
- Taking different approaches to indexation and setting strike prices can accommodate different sizes of project.
- The private-law, CfD-style mechanism proposed is now well understood by the energy industry, meaning administrative costs have fallen.
- Smaller projects are likely to supply higher value end uses and so may not require business model support.
- Small scale hydrogen production will often be a by-product, and this production route should not receive revenue support.

<u>Reasons for not supporting government minded to position</u>

Some respondents felt that the proposed business model is too complex and administratively burdensome for small scale, electrolytic projects. These respondents said that the complexity of a private-law, variable premium contract is likely to be an issue for projects with less resource – which will be the case for many small scale projects. One respondent highlighted the potential requirement to bilaterally negotiate a contract, and in future the potential for periodic auctions, as particularly burdensome.

The interpretation of small scale differed between respondents, with some stating the business model would be too burdensome for projects under 10MW. Others said it depends more on the size of the company than project, and that they would expect the business model to be become worthwhile in the 20-40MW region for a larger company, while a smaller company with a smaller legal team would need to be working on a project of around 100MW.

A group of several respondents also felt that the RTFO is not suitable to support small scale projects in place of a targeted hydrogen business model. This group said that the RTFO is not bankable and so is not sufficient to be the core revenue stream for most projects. Several specific issues with the RTFO for hydrogen production were noted, including:

- It does not offer volume support and the existing market for Renewable Transport Fuel Certificates (RTFCs) is limited, which presents uncertainty over the price and value of certificates.
- It does not support hydrogen produced by nuclear electricity and has demanding and complex additionality requirements for hydrogen produced by renewable electricity.
- Government is effectively requiring small projects to sell into the transport market by only offering revenue support through the RTFO.

Some respondents commented that not providing adequate and early support for small scale projects would be detrimental to the development of the hydrogen economy and slow the pace of learnings for the entire industry. Small scale projects are seen as vital to early scaling of hydrogen demand and progressing from FOAK to NOAK production projects. An early pipeline of small projects could also help secure important early supply chain investment in the UK. Furthermore, distributed electrolysis sites could play a valuable role in the electricity market by providing demand side response services.

Suggestions made to address problems for small scale projects

Some respondents felt that a separate, simpler scheme for small, or potentially all electrolytic, projects is needed. The most common suggestion was a fixed premium mechanism for these types of projects. It was suggested by a few respondents that the funding pot and length of time this model was available for could be smaller than for that of larger projects but that it should be developed sooner to enable early projects to get started. A fixed premium of around £2/kg was said to be sufficient for many small project developers to commence.

Several options for supporting smaller projects through the existing business model design were also suggested, including:

- Having an alternative allocation pot for smaller projects so they would not have to compete directly with larger ones.

- Continuing bilateral negotiations for longer to avoid smaller projects being outbid by larger projects in a competitive auction.
- Supporting smaller projects through the process of claiming a business model subsidy, for example providing flexible support to address their specific issues, streamlining processes and providing dedicated administrative support.
- Designing the business model to enable the modular scale up of initially small projects.

Some respondents also suggested amending other subsidy schemes to better support smaller projects. This included:

- Widening access to the RTFO, for example by including hydrogen produced with nuclear power.
- Giving small projects preferential access to the NZHF or better aligning the NZHF with the business model to give small projects revenue certainty.

Government response

Following careful consideration of the evidence provided, we do not see a compelling case for introducing a separate scheme for smaller scale projects. We note that most respondents to this question agreed with our proposal not to introduce a separate scheme, even if they did not all agree that the proposed model is suitable for smaller projects. Government has a limited budget to support low carbon hydrogen and aims to maximise the impact of spending, which we consider is best achieved through the variable premium design set out in Section 4. Introducing multiple business models would add complexity to the policy landscape, could create market distortions, and potentially delay implementation and therefore deployment of all types of projects that require business model support.

In our market engagement document on a proposed approach to allocating hydrogen business model and NZHF support to electrolytic hydrogen projects, our proposed eligibility criteria include a minimum production capacity of 5MW. This proposed criterion would bring forward larger projects to support scale up and maximise impact.

We recognise the benefits that smaller scale projects (below 5MW) can bring to the hydrogen economy, including providing decentralised supply and supporting local economies. Such projects will have the option to apply to ‘strand 2’ of the NZHF, which is intended to support projects that can deploy on the basis of capital expenditure alone.

We intend to continue developing the hydrogen business model and allocation processes so that they can work across a range of project scales and technologies. This includes streamlining allocation processes where possible.

For future allocations, we may consider whether it would be appropriate to allow smaller projects to aggregate and submit a joint bid for business model support. We do not propose to consider project aggregation for initial contracts, as the complexities of this approach for both the allocation process and business model design would require further analysis which would put at risk the proposed allocation timescales.

Section 7: Additional considerations

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

Consultation position

We did not set out a minded to position in the consultation regarding contract duration but invited views from stakeholders on the appropriate length. We set out several factors that would need to be considered. These included the lifetime of the asset, financing of the capital asset, net present value of support and evolution of market conditions. We also set out precedents created by other energy sector policies, specifically the CfD for renewable electricity and the proposed ICC business model.

Summary of stakeholder responses to consultation

Response Summary	
20+ years	9
15 years, including: 15-20 years 15 minimum 15 with option to extend 15 maximum	49
10 years, including: 10-15 years 10 minimum 10 for electrolytic projects	20
<10 years, including: 5-10 years 6 years 5 minimum	3
Not answered or unclear	40

<u>Key points</u>

Over half of those that responded to this question felt that the most appropriate length of contract was around 15 years, with some subtle variation between those saying exactly 15 years and others '15-20 years' or 'maximum / minimum 15 years'. The main reasons cited for choosing this length of contract were the precedent set by the low carbon electricity CfD, this being the relevant capital repayment period and this giving enough time for the hydrogen market to sufficiently mature.

Some respondents said that a contract length of around 10 years was most appropriate, again with some variation between those saying '10-15 years' or '10 years minimum'. The main reasons for choosing this length of contract were confidence in the pace of hydrogen market development and a desire for carbon emitting technologies not to be locked in for the long term. A small number of respondents preferred even shorter contract durations, ranging from five to 10 years.

Some respondents preferred longer contracts of 20 years and over. The main reasons given for this were the precedent set by the Renewables Obligation (RO), the need to match contracts to asset lifetimes and the ability to lower strike prices if handed longer contracts.

Key considerations raised in the consultation

Many respondents agreed that the factors we set out in the consultation are important to consider when determining contract duration. First, the length of time needed to finance capital expenses was raised as a key consideration by a range of stakeholders. Some respondents emphasised that a longer contract duration would lower the cost of capital for hydrogen production projects as it provides lenders and investors with greater confidence in the plant operating over its full lifetime. In turn, this could lead to lower strike prices being negotiated with government. One respondent said that aligning the contract duration with the typical length of an offtake contract would also make sense, as financing will be secured against these contracts.

Second, some respondents said that the lifetime of the production asset is a key consideration in determining contract duration. There was a variety of views as to how long this should make the contract, including ‘half the asset’s life’ and ‘75%’ of the asset’s lifetime. A small number of respondents also mentioned that asset lifetime, and therefore the need for a longer contract, was more pertinent for FOAK projects, because they would be taking additional risk and to reduce the risk of stranded assets. It was suggested that contract duration could be reduced for NOAK projects. Finally, the need for contracts to be long to support electrolyser stack replacement was raised by some respondents. It was suggested that a typical electrolyser stack lasts for 10 years but that an electrolytic project could last 20. This was used to argue for a greater than 15-year contract, to enable a stack replacement.

Third, some respondents flagged the importance of contracts being long enough for market conditions to sufficiently evolve so that low carbon hydrogen could be sold without subsidy. The key indicators mentioned to determine whether the market has evolved were a liquid market, decreasing production costs, demand growth, an increasing value of low carbon hydrogen, a higher carbon price and the availability of hydrogen T&S infrastructure. There were varying predictions as to how long this would take but the general view was that it would be at least 10 years.

Fourth, a small number of respondents referenced the net present value (NPV) of support as an important factor. It was suggested that this favoured a contract duration of around 15 years, as this would effectively ‘front load’ the support for projects expected to last longer than 15 years. Any subsidy would need to be very large to impact the NPV of a project beyond 15 years, as the private sector discount applied would be so high.

Finally, the precedent of a 15-year contract, provided to offshore wind and other low carbon electricity generators through the CfD, was cited by many respondents. It was suggested that, given industry's familiarity with, and acceptance of, the term of the CfD, matching the hydrogen business model with it would make sense.

Further considerations raised by respondents

Many respondents suggested including a reopener or extension trigger in the contract, which would build some flexibility into its duration and reflect the unknown nature of the future hydrogen market. There were some different options suggested for how this could work:

- The most common suggestion was for an extension of five or 10 years to be triggered if the carbon price has not hit a pre-specified level after a certain date (for example after 10 years), or the hydrogen market has not sufficiently developed based on another metric. A higher carbon price is seen as vital to making low carbon hydrogen cost competitive with fossil fuels.
- Having a break clause in case the market changes unexpectedly and the contract needs to be renegotiated.
- Rolling contract extensions if the hydrogen market price does not warrant operation without subsidy.
- Shorter (ten-year) contracts covering capital costs with options for extension if the plant remains economically unviable to run without support but is still cheaper than supporting a new project (as the capital costs have already been recovered).
- Review milestones or reopeners after set periods to assess if the hydrogen market has sufficiently developed.

Several respondents mentioned other subsidy schemes they felt set a relevant precedent for the duration of the hydrogen business model contract. The RO, which was set at 20 years, was said by some to be a better precedent that the CfD, as it was introduced when the renewable electricity market was less mature. The Non-Domestic Renewable Heat Incentive was also raised as a relevant precedent by a small number of respondents, and it too was set at 20 years. A small number of respondents also mentioned that 15-year contracts are common in the industrial gases market, and so will be familiar to many involved in the hydrogen market.

Other, less commonly raised suggestions and considerations included:

- Electrolytic contracts could be determined by running hours rather than years, as their lifetimes are more closely based on this.
- Consider having a shorter capex repayment period, or design the sliding scale on a time basis, so that larger payments are made in early years to cover capital costs.
- Do not lock the UK into set technology pathways by awarding very long contracts.
- Consider hydrogen T&S commitments and dependencies for producers, as these assets will last longer than the production assets.
- The risk of over subsidy from long contracts can be mitigated by the producer paying back in periods where the reference price exceeds the strike price.

- Consider contract duration in the context of projects with a phase-to-phase design (e.g. building three separate plants over three phases). It may not be suitable for a contract to expire for one phase of a project whilst another is still under contract.

Government response

Our starting point is for contract duration to be set between 10 to 15 years. Based on responses to this consultation, the precedents set by the low carbon electricity CfD and proposed ICC business model, as well as the factors set out in our consultation, we consider that this would be an appropriate period and would have broad support.

However, we have not made a final decision and will continue to consider the relevant factors outlined in the consultation and stakeholder responses. In our view, while we can consider provisions relating to running hours, contracts will also need to have an end date for the purpose of budget control.

As part of our ongoing work on contract duration we will consider the implications of including a mechanism to extend or reopen the contract. Our initial view is that this will add unnecessary complexity to the contract, create potential challenges for budget control and we have not identified a clear need for it. However, reflecting the consultation responses that argued for this, we do not at this stage rule out the possibility of projects receiving further revenue support after the initial contract end date, through a contract extension or a new contract.

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

Consultation position

We did not set out a minded to position in the consultation on whether the length of contract should vary for different technologies. We set out several factors that would need to be considered when determining the length of the contract. These included the lifetime of the asset, financing of the capital asset, net present value of support and evolution of market conditions. We also set out precedents created by other energy sector policies, specifically the CfD for low carbon electricity and the proposed ICC business model.

Summary of stakeholder responses to consultation

Response summary	
No, the length of contract should not vary for different technologies	39
Yes, longer for electrolytic	6
Yes, longer for CCUS-enabled	6
Yes, with the caveat that it should be based on key factors (e.g. asset lifetime and financing)	12

Responded with ‘maybe’	17
Don’t know yet	2
Not answered or unclear	39

Key points

Just under half of respondents to this question said that contract lengths should not vary, the main reason being to create a level playing field and avoid market distortions by favouring one technology over another. A small number of respondents suggested contracts should be longer for electrolytic projects, mainly to reflect greater carbon savings. Conversely, a small number of respondents said that contracts should be longer for CCUS-enabled projects, to reflect longer asset lifetimes and payback periods. Some respondents felt there ‘may’ be a case to vary contract durations between technologies, for the same reasons as above.

Contract duration should not vary between technologies

Just under half of respondents to this question said that contract lengths should not vary between technologies. The main reason given was the desire to avoid creating artificial advantages for one technology over another, which could lead to market distortions. These respondents felt that a consistent approach to contract duration would ensure a fairer competitive environment and enable the market to determine the best route forward. In addition, some respondents suggested that:

- The focus should not be on technology but on the contract lasting until a liquid, subsidy-free market for low carbon hydrogen has developed.
- Technology lifetimes will be factored into strike prices and so should not impact contract duration.
- It would be less complex to have a standard contract duration.

A small number of respondents emphasised that there is no need for CCUS-enabled hydrogen to receive longer contracts than electrolytic, for the following reasons:

- Electrolyser stacks can be replaced to extend project lifetimes to near those of CCUS-enabled hydrogen, and this should be allowed through the subsidy.
- Dedicated renewable energy supply has a longer lifetime than the electrolyser stacks and will continue to require offtake. One respondent also mentioned that nuclear plants have longer lifetimes, and so electrolytic hydrogen projects relying on nuclear electricity should not receive shorter contracts.
- A longer contract for CCUS-enabled projects would unfairly shield them from falling electrolyser costs.

Contract duration should be longer for electrolytic projects

Some respondents suggested that contract duration should be longer for electrolytic projects. The main reason given to support this view was that electrolytic projects can deliver greater carbon savings than CCUS-enabled, making them net zero compliant. It was also suggested that electrolytic technologies are less mature and so will require support over a longer period.

Contract duration should be longer for CCUS-enabled projects

Some respondents said that contracts should be longer for CCUS-enabled projects. The reasons given for this were to:

- Reflect the longer lifetime of CCUS-enabled projects. One respondent emphasised that this was especially important for FOAK projects to support investor confidence and reduce the risk of stranded assets, but that it could be reviewed for NOAK projects.
- Reflect the longer payback period required for larger CCUS-enabled projects.
- Reflect the greater scope for cost reductions in electrolytic technologies and enable cheaper NOAK projects to receive support sooner.

Other reasons to vary contract duration

A number of respondents suggested that varying contract durations may be necessary but did not specify which technology should receive a longer contract. The factors to consider included:

- Level of technology risk involved, with less mature technologies needing longer.
- Projected running hours of an electrolyser.
- Size of project, with smaller projects perhaps being for demonstration and so requiring shorter contracts.

Finally, several respondents said that contract duration should 'maybe' vary by technology. The reasons given were the same as those outlined in the previous sections, such as asset lifetime and carbon intensity. It was also suggested that projects could be asked to propose a contract length as part of the negotiation process.

Government response

As set out in the government response to question 13, our starting point is a contract length of between 10 to 15 years. We do not currently see a compelling reason to vary this by technology. We acknowledge respondents' views that introducing different contract lengths would add complexity and potentially distort competition between technologies. We also consider that there are other factors, independent of technology type, to consider when setting contract duration, including evolution of market conditions, which we set out in the consultation. However, we have not made a final decision and will continue to consider all relevant factors raised in the consultation and engage with industry and other stakeholders.

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

Consultation position

In the consultation, we set out that hydrogen producers, including both CCUS-enabled and electrolytic, may wish to have the ability to increase the volume of hydrogen produced at a plant[17] above the capacity defined in their contract to respond to increased demand. We outlined three potential options and asked for views on the most appropriate option for scaling up production volumes.

We defined the three options as:

- No scaling – the volumes of hydrogen produced above the capacity in a contract would not qualify for additional support.
- Grandfathering – a producer is able to apply to government on an ad-hoc basis to increase the capacity at a plant and receive the same terms as under their existing contract.
- Accordion – a producer is able to increase capacity of a plant up to a pre-agreed maximum level.

Summary of stakeholder responses to consultation

Response summary	
Did not agree with any scaling up of volumes	10
Agree with grandfathering	8
Agree with accordion	40
Agree with volume scaling but did not specify the mechanism	17
Not answered or unclear	46

Key points

Respondents provided mixed views on the most appropriate option for scaling of future production volumes. The majority of respondents who answered the question proposed the accordion as it provided the best balance between value for money to government and certainty to producers and investors. Some respondents preferred no scaling, grandfathering, or supported volume scaling but did not specify the mechanism.

No volume scaling

[17] In this sub-section, 'a plant' refers to the hydrogen producer's project that is allocated a business model support contract. We have referred to 'a plant' as hydrogen producers, including both CCUS-enabled and electrolytic, may build up a roster of plants in the future, all potentially under different contract terms.

Some respondents proposed no volume scaling and focused on the following points:

- No scaling would allow government to benefit from reduction in cost of future hydrogen production projects as no budget would need to be held back to fund any volume scaling of existing projects.
- Scaling of any type would unfairly benefit incumbents, would be difficult to administer and would be a departure from existing UK energy policy.

One respondent concluded that increasing capacity would not be possible for electrolysers as they have a fixed capacity. One respondent noted that the rationale for scaling was not clear. Some respondents suggested that any capacity increase should be done through a new allocation process.

However, if government decided to allow volume scaling, two respondents who proposed no volume scaling noted the accordion should be used as it provided better value for money than grandfathering.

<u>Grandfathering</u>

Some respondents proposed this option as it would reduce government's administrative burden and be better value for money for government as it was the most capital efficient way of increasing capacity. Producers would need less capital to increase the capacity of an existing plant than that needed to build a new one. Two respondents suggested that grandfathering would be needed by projects with a phase-to-phase design (e.g. building three separate plants over three phases) to provide certainty to producers and investors that the whole project will be supported. All phases could be included in the initial contract.

Some respondents who supported the grandfathering option nonetheless considered there should be a limit on the amount of volume scaling allowed. For example, one respondent suggested up to 50% increase in existing plant capacity and any increase above this level should face a competitive allocation process.

<u>Accordion</u>

The majority of respondents proposed the accordion for the following reasons:

- It would provide the right balance between value for money and certainty to investors, offering the opportunity for more capital efficient expansion, while avoiding local monopolies due to the limit on the amount of volume scaling.
- It would enable government to more quickly meet its hydrogen ambitions (in comparison with no volume scaling) by incentivising producers to seek, up to a limit, more demand around the area of the plant.
- It could provide security of supply to end users of hydrogen with access to only a single source of hydrogen as an increase in demand could be met by the existing supplier.
- It would support the development of wind farms and help to deliver the government's wind generation ambitions by enabling electrolysers to scale and provide demand for new wind assets.

Respondents discussed the amount of volume scaling that should be allowed in the accordion, with suggestions including:

- Some respondents proposed small increases in capacity, through efficiency/technology improvements or capital expenditure to respond to demand, while others proposed allowing larger phase-to-phase increases through adding new units alongside existing plants.
- The limit should be a set percentage increase, ranging from 20% up to 200% increase in capacity.
- The limit should reflect future local demand growth or, in the case of electrolysers, the availability of low carbon electricity.
- Any capacity increase should not limit government support for future projects with lower production costs.

Respondents discussed the level of subsidy any new capacity should receive, with suggestions including:

- It should be the same level of subsidy as existing capacity.
- It should exclude the fixed costs and capital repayments for the existing production capacity.
- It should be benchmarked against the level of subsidy provided through the hydrogen business model to new projects at the time when the accordion is accessed.
- It should be integrated into the sliding scale approach to volume support as this would limit support for the new capacity.
- It should consider the carbon reduction of the new capacity, the speed of deployment and the cost of hydrogen produced.

Other considerations

Some respondents did not propose an option for volume scaling and instead discussed the factors government should consider when making a decision on the most appropriate option. Most of these factors are discussed above, with some additional points made:

- Any approach should be fair to all technologies by considering their different options for increasing capacity and the associated costs.
- While phase-to-phase expansion should be subject to a competitive allocation process, the administrative burden should be proportionate.
- The frequency of future competitive allocation rounds should dictate the level of volume scaling.

Government response

In light of the responses, we would like to clarify the scope of this question as we move through the next stage of work.

We are considering the case for producers to increase the volume produced within an existing plant above any level defined in their contract. However, any increase in volume produced above any defined level through a new plant or a new module will not be subsidised under the existing contract, including new modules/units being added to an ATR or SMR plant and new electrolyser modules being added to electrolytic facilities. While we acknowledge that some respondents supported allowing contract capacity to be increased through a new plant, we believe that this approach may not represent value for money to government and should be subject to open and fair competition with new production projects in future rounds of contract allocation.

In considering the case for supporting scaling up production volumes within an existing plant, we are carrying out further work to understand how the different hydrogen production technologies are able to increase production capacity, including whether capital is required or not. This information will be considered alongside the design principles outlined in the consultation and related aspects of the payment mechanism, including the sliding scale of volume support. This will enable us to progress to a minded to position on whether the contract should support producers to scale up production volumes at the plant above any level defined in the contract and, if so, by how much and what level of subsidy should be payable.

Question 16 - Do you agree with our minded to allocation of the risks presented? Please explain your arguments, including if any other key risks have not been identified and how they should be allocated.

Consultation position

In the consultation, we considered a number of risks faced by initial hydrogen production facilities (aside from market price risk and volume risk discussed earlier), with the aim of achieving the right incentives for initial projects. We set out our minded to position on allocation of these risks.

Summary of stakeholder responses to consultation

Response summary	
Generally agree with risk allocation proposals	58
Maybe agree with risk allocation proposals	9
Did not agree with risk allocation proposals	5
Not answered or unclear	49

CO2 T&S cross-chain and qualifying hydrogen risk

Many respondents agreed with our inclusion of cross-chain risk associated with the CO2 T&S infrastructure, and the risk of hydrogen volumes not qualifying for support if this infrastructure is not in place at the beginning of operation.

A range of respondents believed it is not appropriate for hydrogen producers to pick up risk relating to the CO2 T&S being unavailable and hydrogen plants therefore not meeting the UK LCHS and qualifying for support. However, there were different views on who should carry this risk. Some investors believed hydrogen producers would have insurance to cover this possibility. Hydrogen producers believed there is a role for government to pick up this risk as proposed in the ICC and DPA business models. Other groups believed the risk could be picked up through the CO2 T&S business model.

Hydrogen transport and storage

A large number of respondents believed that a risk not initially included is the lack of hydrogen T&S infrastructure. They felt that more clarity on this infrastructure could reduce volume risk and remove a barrier to the development of the hydrogen market.

Many respondents believed that the construction and delivery of the hydrogen T&S infrastructure poses a high risk for hydrogen producers. Many believed that government has a role to play to set the direction for the future of this infrastructure to ensure there are no blockers to its timely delivery.

Change in law, policy and regulations

All respondents who specifically mentioned this risk agreed it sat best with government. A large proportion of these responses asked that it be clarified that, if a regulation or the new UK LCHS were to change during the lifetime of the contract, the hydrogen producer would not be required to meet these new changes.

Construction, technology and decommissioning risk

Where mentioned in responses, the vast majority agreed that construction, technology and decommissioning risks should sit with the hydrogen producer as they are best placed to manage them. A number of respondents asked for flexibility around construction timelines (as with the low carbon electricity CfD) due to potential supply chain delays. Two respondents flagged the role that NZHF capex funding could play in reducing construction risk for producers.

Other risks not covered in the initial consultation

- Public acceptance / perception – a number of industry groups and trade bodies highlighted the risk of negative public perception of hydrogen from the possibility of a health and safety incident. They believed there is a role for government, alongside other parties, to promote the positive role hydrogen has to play in delivering government's net zero ambitions in the public domain.
- High gas prices – a number of prospective CCUS-enabled and electrolytic producers, as well as industry groups, asked that government considers the risk posed by high gas prices.
- International risk – two respondents flagged a risk relating to the UK LCHS, reflecting that it could impact how UK producers interact with international hydrogen markets.

Government response

In light of the responses, we consider that the risk allocation set out in the consultation remains appropriate. We summarise the proposed risk allocation in the table below and will continue to review this allocation as we further develop the business model.

Risk	Description	Proposed risk allocation
Change in law, policy or regulatory framework	Risk that any change in law, policy or regulation impacts hydrogen production or consumption. This could be where a change impacts on the cost of producing and/or using hydrogen, the uptake of hydrogen, or on the feasibility of delivering the necessary infrastructure for carbon capture and/or future hydrogen infrastructure development.	The business model contract will set out the appropriate provisions to protect the hydrogen producer from certain unforeseeable and material changes. We are considering this in further detail. For the UK LCHS specifically, the contract itself will not require producers to comply with any future amendments to the UK LCHS after the contract is signed. Subject to the final contract terms and conditions, we expect that producers will be able to follow, where relevant, future changes to the UK LCHS, should they choose to do so. BEIS is also considering how the business model may interact with a potential future hydrogen certification scheme; the detailed design of any such scheme would be subject to further consideration.
Qualifying hydrogen risk	Risk that hydrogen produced does not meet the LCHS and therefore may not qualify for support payments. This could happen in a number of situations. One example would be where the CO_2 T&S network is unavailable due to a temporary outage and CCUS-enabled producers are unable to inject CO_2 into the network. Another example is where electricity input for electrolytic hydrogen producers is not sufficiently low carbon to meet the LCHS.	We are continuing to consider how to manage this risk across a number of scenarios for both CCUS-enabled and electrolytic hydrogen production.

Construction risk	The risk of construction overruns and, as a result, an increase in capital costs. This includes the construction of the hydrogen plant and associated hydrogen T&S infrastructure.	The developer of the hydrogen production plant is best placed to manage construction risk through effective risk and financial management, including sufficient allocation of contingency within their budget. However, we acknowledge the risk of construction delays and are developing milestone requirements in the Heads of Terms for the contract, which we propose will be similar in structure to the low carbon electricity CfD, to provide sufficient flexibility on build timescales, as well as suitable Force Majeure provisions.
New risk: Hydrogen T&S risk	The risk that there is not enough capacity in hydrogen T&S facilities for FOAK projects, restricting the growth of supply and demand.	The hydrogen producer is primarily responsible for considering what hydrogen infrastructure is required and proportionate to support initial and future offtakers of hydrogen. There is also a role for government to establish any necessary regulatory frameworks and, where appropriate, support as the hydrogen economy develops. This is discussed further under questions 20 and 21.
Decommissioning risk	Risk that decommissioning costs are higher or lower than originally forecasted, or where the hydrogen producer is unable to carry out the decommissioning process.	The hydrogen producer is responsible for decommissioning the hydrogen plant in line with the relevant industry standards.
Technology risk	Risk that technology related to low carbon hydrogen production fails or does not behave predictably.	The hydrogen producer is responsible for procuring technology with a high level of confidence, and ensuring there are contingency plans if it were to fail.
Input fuel supply disruption risk	Risk that an energy network supply mismatch, unplanned	The hydrogen producer is responsible for managing this risk to ensure they

	outage, high prices or inconsistent input fuel supply means that hydrogen producers are unable to fulfil offtaker contracts.	have a supply of input fuel to produce low carbon hydrogen. However, we recognise that the scenario of high gas prices needs to be factored into policy design, and this is discussed further in Section 4.

We have not discussed public acceptance and international risk in the allocation table above as these are related to wider hydrogen policies, and we do not see a need to address them through the hydrogen business model. The risks flagged by respondents are being considered as part of the development of relevant policies.

Question 17 - Do you agree with our approach to seek to accommodate different sources of support? Please explain your arguments, including any considerations of unintended consequences linked to revenue stacking, and how might they be mitigated.

Consultation position

The consultation noted that the business model should be compatible with other existing support policies. We set out that we are minded to accommodate a combination of different sources of support across the value chain to help drive demand and reduce cost of production, while ensuring that this does not result in paying twice for the same costs and minimising complexity. We also sought views on the benefits of subsidy cumulation (or 'stacking') for hydrogen producers which might be eligible to access other subsidy schemes and how risks of perverse outcomes could be mitigated.

Summary of stakeholder responses to consultation

Response summary	
Agree to seek to accommodate different sources of input	65
Responded with 'maybe'	17
Did not agree to seek to accommodate different sources of input	2
Not answered or unclear	37

Key points

The majority of respondents to this question agreed with the proposal to seek to accommodate different sources of support. Respondents highlighted that combining support across the hydrogen value chain could maximise the prospects of developing successful projects and encourage demand, production and the development of enabling technologies and infrastructure in parallel, particularly in early stages of deployment. A few also noted that it is highly unlikely that a single model would be able to provide appropriate support for all elements of the value chain without making the model too complicated.

While there was generally strong support to explore and allow interactions with other schemes, many respondents noted the following caveats:

- Overcompensation should be avoided.
- Complexity should be minimised. Interactions should not introduce unnecessary complications.
- Careful design and robust control measures will be essential to mitigate risks of unintended outcomes.
- Clarity and further details on how subsidy cumulation could be implemented in practice is needed.
- Schemes across the value chain should be aligned and progressed in parallel to help address the coordination challenge that hydrogen projects face if they require multiple sources of support.
- Access to multiple subsidy streams should not create uneven competition across different production technologies, or create skewed incentives.

Two respondents were not supportive of the proposed approach. One noted the need for clarity on the purpose of different support schemes and that different sources of support could 'cloud' development. The other suggested that allowing producers to cumulate subsidies to support hydrogen production could add unnecessary complexity and could increase administrative costs for both projects and government. This respondent noted that additional support would be better aimed at hydrogen transportation, storage and use. One further respondent suggested that each 'energy vector' should only have one form of government support.

Some respondents proposed that electrolytic projects receiving business model support should be allowed to procure low carbon electricity from both subsidised and unsubsidised electricity generation. They noted that the use of subsidised electricity should be allowed as there are two 'energy vectors' involved (i.e. electricity and hydrogen) and as these subsidies are serving different purposes. The production of renewable hydrogen using electricity supported by the CfD, being eligible for RTFCs under the RTFO was noted as an example of existing precedent.

Some respondents stated that they would welcome clarity on how the business model would interact with other government schemes. The specific schemes highlighted included the NZHF, RTFO, CfD, Industrial Energy Transformation Fund (IETF), Capacity Market, DPA, and cross-cutting policies such as UK ETS.

Hydrogen producers cumulating other subsidies with hydrogen business model support

Some respondents specifically mentioned that they are in favour of producers being able to cumulate subsidies where they are able to access support from other schemes. Reasons for this were mostly similar to the reasons provided for supporting the approach to accommodate different sources of funding across the value chain (as outlined in the first paragraph of this section). A few respondents commented that accessing different subsidies could be important in enabling electrolytic projects to compete against other technologies, such as CCUS-enabled projects.

Some respondents, however, emphasised that allowing subsidy cumulation should be designed carefully to ensure it does not lead to over-subsidisation, create confusion between schemes or skewed incentives that may encourage or discourage specific end uses or hydrogen production pathways. For example, if business model support could be cumulated with the RTFO, this may encourage more hydrogen production to be directed to the transport sector at the expense of hydrogen use in other sectors. A few respondents also commented that given transport has other routes to decarbonisation, such as electrification, hydrogen use should be focused elsewhere.

A few respondents noted that subsidy cumulation could provide some projects with a competitive advantage and emphasised the importance of taking into account other subsidies to ensure a level playing field, including when comparing projects at allocation stage and when determining the level of support provided under the business model.

Some respondents who mentioned the RTFO were generally in favour of allowing business model and RTFO cumulation. A few argued that cumulation should be allowed as the two schemes have different purposes. One respondent suggested eligible producers should have the option of accessing both schemes, and the producers could choose to be supported by the RTFO for RTFO-supported end uses and by the business model for other end uses.

Government response

The majority of respondents supported our proposal and agreed with the broad set of principles set out in the consultation. We will continue to use the following principles when determining any specific rules and conditions for how the business model will interact with other sources of support, including to determine where subsidy cumulation may be allowed:

- Maximising benefits of government intervention, while avoiding the risk of perverse outcomes.
- Avoiding double subsidisation and/or over subsidisation, including by ensuring support is only received once for the same costs.
- Minimising policy and administrative complexity.
- Being adaptable to the potential future introduction of complementary subsidies across the value chain.

With these principles in mind, we are developing our approach to hydrogen business model and NZHF allocation which will enable projects to access capital support from the NZHF and revenue support from the hydrogen business model. Further details can be found under question 18.

We will review the evidence and comments, particularly on specific scheme interactions and on the risk of creating uneven competition by allowing subsidy cumulation, and continue to work with stakeholders to provide more clarity on practical implementation.

Section 8: Allocation

Question 18 - What are your views on the most appropriate allocation mechanism for the hydrogen business model contract, both near term (for projects outside the CCUS cluster sequencing process) and longer term (for all technologies/projects)?

Consultation position

In the consultation we summarised two potential approaches to business model allocation:

- Bilateral negotiations – which could involve government and a project, or projects, negotiating to agree a contract.
- Auction – which could be a process where terms and conditions are standardised across all bidders and the allocation of support is determined by the lowest strike price.

We also considered a hybrid approach, for example a competitive process where projects earn the right to enter into a bilateral negotiation.

The consultation outlined government's plans for initial CCUS-enabled hydrogen projects to be allocated support as part of the CCUS cluster sequencing process[18], with more detail published in November 2021.

We sought views on the most appropriate allocation mechanism in the near term for projects outside this process (e.g. electrolytic projects). We proposed to run an allocation round for these projects in 2022, with projects assessed against defined eligibility and evaluation criteria, followed by a bilateral process.

We also set out that, in the medium term, we expect our preferred approach to be competitive allocation (e.g. auctions). We sought views on what stakeholders would consider the most appropriate allocation mechanism across all technologies in the longer term.

Summary of stakeholder responses to consultation

Response summary	
Agree with near term being bilateral approach (specified electrolytic)	67 (26)
Agree with a longer term competitive allocation (specified auction)	53 (44)
Need for separate pots	34
Not answered or unclear	37

<u>Near-term bilateral negotiations</u>

[18] Phase-2 of the cluster sequencing process will identify which CCUS-enabled hydrogen projects will be shortlisted for bilateral negotiations for a business model contract. For more information about this process and subsequent bilateral negotiations please refer to the Phase-2 guidance document.

The majority of respondents agreed that, in the near-term, bilateral negotiations are the most appropriate mechanism for allocating business model contracts. Of those respondents that agreed, just under half specified that their view applied specifically to projects outside the CCUS cluster sequencing process. Some respondents were not in support of bilateral negotiations and suggested competitive allocation, such as auctions, in the first instance because they are well understood by investors and there are perceived risks associated with negotiations, such as delays to projects and expense to government.

Bilateral negotiations were generally viewed by respondents as an important mechanism to kick start the hydrogen economy and support hydrogen market growth by enabling initial projects to take final investment decisions. The main reason given for this was the current stage of hydrogen market development, with the hydrogen market considered to be nascent and very much in the 'price discovery' phase.

Respondents who often represent smaller electrolytic projects were explicit about the need for bilateral negotiations for projects outside of the CCUS cluster sequencing process, rather than an auction which could result in lost strategic benefits. Respondents considered smaller projects to be at a disadvantage in an auction due to the resource and experience required to enter into an auction meaning the cost is disproportionately higher for smaller projects. In contrast, one respondent was of the view that a bilateral negotiations process, due to the volume of expected applicants, will disadvantage smaller projects because of the administrative burden to government of negotiating with a large number of smaller projects over a small number of large projects.

Respondents said that any bilateral allocation process should be both transparent and competitive, with objective and clearly defined technology-specific eligibility and assessment criteria, similar to a competitive tender. The criteria should be designed to support projects that are deliverable and aligned with government net zero objectives, resulting in a mix of projects being allocated support across a range of geographical locations.

<u>Medium term competitive allocation (e.g. auction)</u>

Many respondents agreed with the minded to position of transitioning to a more competitive allocation process such as an auction in the longer term. Some respondents supported transitioning as soon as possible, but the majority of those in support caveated the need for a more mature hydrogen market with a sufficient project pipeline before making a transition, with allocation based on a standardised set of terms and conditions. One respondent flagged that hydrogen produced from nuclear may not perform well in a competitive allocation process such as an auction, due to the lead times associated with developing nuclear so this technology may suit bilateral negotiations in the longer term.

Respondents shared a wide range of benefits associated with a more competitive process. In particular, they mentioned value for money and the potential for significant reductions in technology costs and supply chain improvements as demonstrated by offshore wind supported through the low carbon electricity CfD.

Beyond price there were several factors that respondents mentioned need to be taken into consideration when designing the future competitive allocation process. These included:

- How we account for demand to ensure projects are being developed where there is sufficient demand.
- At what stage of project development projects are expected to bid for support.
- How we ensure successful projects are deliverable including any mechanisms to ensure bidders are committed to delivering projects.
- Avoiding complexity to prevent market distortions.
- How to encourage projects to maximise emission reduction beyond compliance with the UK LCHS.
- How the process works for smaller projects who have less resources and need flexibility.

Different allocation pots for different technologies

Many respondents referenced the need to create different allocation pots for different technologies, for example separate pots for CCUS-enabled hydrogen production, electrolytic production and novel technologies. This is because technologies are at different stages of development and cannot compete on cost. For example, hydrogen produced through electrolysis is seen as being more expensive to produce but having a higher potential for cost reductions.

Instead of having technology specific pots, some respondents suggested pots should be defined based on the emissions reduction potential of technologies, to ensure alignment with net zero objectives and to encourage higher emissions reduction.

Additional points

One respondent suggested an alternative mechanism for allocation of hydrogen business model contracts based on the ‘Swiss challenge’ model for procurement. Under this model government would invite project proposals and those which government wants to support are then advertised to other developers who can bid to deliver the project at a more favourable rate.

Some respondents raised the need for clarity on future allocation phases and available pots to support the development of the project pipeline and build investor confidence. This includes having sight of the regularity of allocation rounds, their timing and the amount of funding that will be made available.

Respondents flagged the need to align the allocation process with the NZHF as there are likely to be interdependencies. They suggested considering the interfaces when designing an allocation round and reducing the administrative burden to projects of applying to two different schemes.

Government response

Phase-2 of the CCUS cluster sequencing process was launched in November 2021 and closed in January 2022. As set out in the NZHF government response[19], we intend for CCUS-enabled projects applying for a hydrogen business model through Phase-2 of the CCUS cluster sequencing process to have the opportunity to apply for NZHF capital co-funding (NZHF strand 4). We plan to launch a strand 4 NZHF Expression of Interest process following the announcement of the Phase-2 shortlisted projects, followed by a strand 4 application process in 2023. Further detail on the next phase of the CCUS cluster sequencing process will be provided in due course.

As outlined in the consultation, we intend to invite project applications in 2022 for projects outside of the CCUS cluster sequencing process which meet defined eligibility criteria. Having a separate process for these projects allows government to take into account the inherent differences in the technologies and enables projects with similar characteristics to compete against each other.

In response to stakeholder views on the need for alignment across the different support mechanisms available to hydrogen projects, we are proposing a joint allocation window where projects applying for business model support may also be able to apply for capex support from the NZHF. This is intended to ensure that the allocation process is streamlined for applicants who wish to access both sources of funding and delivers value for money for government.

Our proposal is for the 2022 allocation round to be open to initial electrolytic hydrogen projects. Further details about this process, including our proposed eligibility and evaluation criteria, are set out in the *Hydrogen business model and Net Zero Hydrogen Fund: Market Engagement on Electrolytic Allocation* document.[20] Following evaluation and possible application of portfolio factors, selected projects may then take part in bilateral negotiations to agree an offer of hydrogen business model support. Stakeholders can submit views on the design of the allocation process as part of the market engagement exercise by attending a workshop or online via Citizen Space.

We note there was broad support for a transition to a more competitive allocation process (e.g. auction) in the medium term. The Energy Security Strategy set out our ambition to move to price competitive allocation by 2025 as soon as legislation and market conditions allow. Work is now underway on the potential design of this competitive allocation process, noting this may be subject to further consultation. We note respondents' views that the transition to competitive allocation will require certain market conditions, and we will consider the points raised carefully when designing the process. We recognise the value of different allocation rounds/pots for different production technologies to account for different stages of commercial development.

[19] The NZHF government response can be found at: https://www.gov.uk/government/consultations/designing-the-net-zero-hydrogen-fund
[20] The market engagement document can be found at: https://www.gov.uk/government/consultations/hydrogen-business-model-and-net-zero-hydrogen-fund-market-engagement-on-electrolytic-allocation

We are minded to include different allocation rounds/pots for future competitive allocation. We will continue to engage with industry on the design of the process.

Section 9: Funding the hydrogen business model

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

Consultation position

How we pay for the transition to a net zero economy, and who should bear the costs, are key questions for government and society. Revenue support for low carbon electricity has been funded by passing on costs indirectly, for example through supplier obligations and suppliers passing costs onto energy bills. In the consultation we noted that we assume a similar approach would be taken for funding hydrogen production projects. We recognised that energy bills already bear various policy costs and that any costs passed onto consumers would need to fit into the wider policy landscape. We also noted that the funding mechanism would need to be sensitive to the specifics of the nascent hydrogen market.

Summary of stakeholder responses to consultation

Response summary	
Preference for general taxation	15
Preference for a levy	13
Preference for carbon pricing / UK ETS	6
Preference for a mixture of funding approaches	14
Offered views on the principles that should inform the government's approach, without expressing a preference for a specific funding mechanism	27
Not answered or unclear	46

Key points

Among the respondents who offered a single preferred option for funding the business model, most favoured general taxation or a levy, with some favouring carbon pricing. Some respondents preferred a mixture of funding approaches. This category includes respondents who were equally supportive of two alternative funding options (e.g. levy and general taxation), those who expressed clear first and second preferences, and those who favoured an approach whereby two options are used together. Some respondents did not express a preference for a particular funding mechanism, and instead provided views on the principles that should guide the government's approach to funding low carbon hydrogen production – for example, fairness, affordability, and the protection of certain consumers.

Considerations regarding a levy

A wide range of respondents favoured a levy to fund the hydrogen business model. These respondents cited reasons such as the following:

- Existing levies on energy bills have proved effective at providing revenue for renewables and decarbonisation policy, and a levy approach may support investor confidence.
- A levy approach may be used to encourage switching to low carbon alternatives, provided the levy is placed on high carbon fuels.
- Funding hydrogen production through consumer gas bills would provide a link with a large customer base who may ultimately be the beneficiaries of the development of hydrogen fuels and technology.

Respondents also highlighted several concerns regarding a levy, including:

- The potential impact of an additional levy on consumer incentives and government's decarbonisation objectives, noting that existing low carbon levies on electricity bills may incentivise consumers to use natural gas over electricity.
- The impact on consumer energy bills and fuel poverty.
- The possible need for exemptions/compensation for energy intensive industries at risk of carbon leakage, and vulnerable consumer groups.
- Uncertainty regarding hydrogen's future role in decarbonising the heating sector.

<u>Considerations regarding general taxation</u>

Respondents who favoured the use of general taxation to fund low carbon hydrogen production cited reasons related to affordability and fairness. Respondents noted the context of rising energy prices and the potential impact of a levy on fuel poverty. Respondents also highlighted that general taxation may provide a fairer option for funding low carbon hydrogen production, given the uncertainty regarding the future end users or beneficiaries of low carbon hydrogen.

<u>Considerations regarding carbon pricing</u>

Some respondents favoured funding by means of carbon pricing mechanisms, such as the UK ETS. Respondents in favour of this option noted potential advantages related to encouraging fuel switching to hydrogen and the acceleration of the production of, and markets for, electrolytic hydrogen. Others noted that carbon pricing may be an appropriate mechanism for funding hydrogen used in industrial settings.

<u>Consideration regarding a combination of two funding mechanisms</u>

Some respondents preferred a hybrid approach, whereby two options are used in conjunction with each other. A respondent noted that a combined general taxation/levy approach may be preferrable to a levy only approach, in terms of impacts on consumer energy bills. Similarly, a combined general taxation / carbon pricing approach was presented as an option that allowed for a progressive and fair approach to funding whilst also establishing an effective carbon-pricing environment. A hybrid approach was also presented as a potential transitional option, with one respondent noting that revenue from carbon dioxide certificates could be an initial funding source, before the adoption of an alternative funding approach.

Government response

The options identified by stakeholders in response to the consultation largely align with those that we have considered: a levy, general taxation, and carbon pricing. As set out in the Net Zero Strategy, we have set up the IDHRS scheme to fund our new hydrogen and ICC business models and give long-term certainty to investors and projects. This will be essential to helping us meet our hydrogen and CCUS ambitions. The Net Zero Strategy announced up to £100m of funding to award contracts of up to 250MW of electrolytic hydrogen production capacity in 2023. We will announce a further funding envelope in 2022 that will enable us to award the first contracts to CCUS-enabled hydrogen and industrial carbon capture facilities from 2023 through the Cluster Sequencing process. Our intention is for all revenue support for hydrogen production to be levy funded from 2025 at the latest, subject to consultation and legislation being in place.

We anticipate that a levy to fund the hydrogen business model will require new primary powers and we intend to legislate when Parliamentary time allows.

We are currently assessing options for the detailed levy design. This will reflect wider government priorities and policies to ensure affordability of consumer energy bills, that costs are distributed fairly, and that UK businesses remain competitive.

Section 10: Hydrogen transportation and storage

Question 20 - Do you agree with our proposal to allow projects to factor in small scale hydrogen distribution and storage costs as part of projects' overall costs of production when bidding for business model support? Please explain your arguments, including any considerations relating to avoiding market distortions and facilitating future expansion of the hydrogen economy.

Consultation position

In the consultation, we set out a proposal to allow projects to include small scale hydrogen T&S costs as part of the projects' overall cost of production when bidding for business model support. We set out that allowing projects to include these costs would reduce project costs (by reducing risk and therefore the financing cost), increase the viability of projects and meet the needs of their end users. This would help to encourage a flexible and resilient supply and demand of hydrogen, supporting the future expansion of the hydrogen economy.

Summary of stakeholder responses to consultation

Response summary	
Agree to including small scale costs in hydrogen business model support	75
Responded 'maybe' but need a definition first	9
Did not agree to including small scale costs in hydrogen business model support	3
Not answered or unclear	34

Key points

The majority of respondents agreed with the proposal to allow projects to include small scale hydrogen T&S costs as part of the projects' overall costs of production. The main reason for this was that, in the absence of large scale hydrogen T&S infrastructure, business model support for small scale costs would make projects viable.

Respondents discussed what costs should be supported, how they could be treated in the business model and how any infrastructure supported could be future proofed, with a wide range of views offered.

Business model should support small scale T&S costs

The majority of respondents agreed with the proposal that business model support could include small scale hydrogen T&S costs. This was for several reasons:

- Access to this infrastructure would make early projects financially viable as any business case would be based on access to demand.

- Large scale hydrogen T&S infrastructure would not be available in the early stages.
- Support for small scale infrastructure would kick start the development of the hydrogen economy through making a wider variety of projects investable by enabling projects to access end users in different locations. This would be particularly important for those projects without access to existing infrastructure.

Other points made by respondents included:

- Support should be carefully considered to avoid market distortions and avoid stranded assets as the hydrogen T&S network develops.
- Support for hydrogen infrastructure provided through other government schemes should be identified to avoid duplication.
- Support should be provided in limited circumstances where there is a genuine need.
- The process for assessing and allocating support for infrastructure through the business model should be integrated into strategic national/regional planning.

<u>Business model should not support small scale T&S costs</u>

Some respondents disagreed with the proposal that the business model should support small scale T&S costs. Respondents acknowledged the market barrier that limited T&S infrastructure presented to hydrogen producers, but explained that support should only be accessed through a strategic national/regional planning body and be funded through a separate scheme. One respondent noted that the business model would be complicated by the inclusion of these costs and that the NZHF would be more appropriate.

<u>What small scale T&S costs should be supported?</u>

Some respondents discussed what type of T&S infrastructure should be supported and made the following suggestions.

- Small scale pipelines should be supported to allow projects to connect to nearby offtakers, which would be particularly important for early projects.
- The use of tankers and tube trailers should be supported and be complemented by support for hydrogen refuelling infrastructure. On the other hand, one respondent noted that the business model should not support refuelling infrastructure as it could be indirectly supported through the RTFO.
- Small scale storage (i.e. above ground storage vessels) should be supported as it would enable producers to manage fluctuations in supply and demand, which would be particularly important for intermittent producers with offtakers requiring a baseload supply.

Respondents discussed whether support for small scale T&S should be limited, with the following views expressed:

- No limit should be put on support as a limit would introduce uncertainty for producers about where funding for infrastructure above the limit would come from. One respondent

proposed that producers should be able to decide on what costs are needed and should be supported.
- Support should be limited by distance to incentivise hydrogen production to be as near to demand as possible, though one respondent noted that any distance limit should be considered carefully to not rule out reaching offtakers in disparate locations. Other suggestions included: infrastructure up to the producer’s site boundary or just beyond site boundary if the end user occupies the adjoining land; or the infrastructure that is needed to connect to existing infrastructure.
- Support should be proportionate to the size of project.
- Support should be limited to a proportion of the producer’s overall production costs.
- Support should be limited to capital expenditure and/or operational expenditure.

<u>How should small scale T&S costs be treated in the business model?</u>

Two respondents proposed that the support projects need should be included in their strike price when bidding for business model support, while one respondent proposed these costs should be separate when bidding. Government would also need to consider the impact on the price of hydrogen if not all costs are supported and the consequent impact on offtakers’ incentive to switch from the counterfactual fuel.

<u>How could small scale infrastructure supported by the business model be future proofed?</u>

Some respondents discussed how infrastructure supported could be future proofed to enable a transition from early T&S infrastructure to a future network:

- The business model contract should include a mechanism to allow for a change in T&S costs.
- The contract should include provisions for third party access and monopoly risks to facilitate the transition.
- Common requirements and standards for this infrastructure would be needed to reduce market barriers for new operators and to ensure any infrastructure supported was compatible and interoperable with future networks.

Government response

We recognise that the majority of respondents support our proposal to allow small scale T&S infrastructure costs to be included as part of a project’s overall production costs when bidding for a business model contract. We also note the diversity of stakeholder views on the matter, which range from those that are fully supportive of our proposal, and offer views on how this might work, to those that caution about stranded asset risks, scheme complexity and the diversion of funding from its core focus of incentivising investment in low carbon hydrogen production capacity. While we recognise that a lack of T&S infrastructure could act as a barrier to the widespread use of low carbon hydrogen, we remain mindful that the primary focus of the business model is the production of cost competitive low carbon hydrogen.

With the above in mind, we intend to adopt a pragmatic approach when considering whether to support small scale T&S costs through the initial business model contracts awarded. We will assess whether to support these costs for both CCUS-enabled and electrolytic hydrogen projects by taking a number of factors into account, including necessity, affordability and value for money.

The next stage of policy development will seek to minimise any potential negative impacts from supporting these costs through the hydrogen business model. We will consider how these costs are treated in the business model and, taking into consideration the wider hydrogen economy, how this infrastructure can be future proofed to transition as smoothly as possible to a future hydrogen T&S network potentially supported by its own commercial framework.

Question 21 - Do you consider that bespoke funding model(s) might be needed to enable investments in larger scale, shared hydrogen networks and storage? If so, which model(s) might be best suited to bring forward projects? Evidence provided under this question will be used to inform our forthcoming reviews.

Consultation position

In the consultation, we set out our view that the hydrogen business model would not be appropriate to support the build-out of new hydrogen pipelines and new storage infrastructure as needs become greater in scale or where the required hydrogen pipelines become part of a larger, shared network. Hydrogen production facilities are substantially different asset classes compared to hydrogen T&S infrastructure. We also acknowledged that there is uncertainty, for example, it is unclear who may own and operate these assets in the future, and the pace of development currently remains unknown.

We set out our intention to undertake a review to further understand hydrogen network requirements in the 2020s. To inform this review, we were interested in gathering stakeholder views on the potential need for bespoke funding mechanism(s) to facilitate investment in future larger scale hydrogen T&S.

Summary of stakeholder responses to consultation

Response summary	
Yes to a bespoke funding model	58
No to a bespoke funding model	1
Responded ‘maybe’ to a bespoke funding model	16
Not answered or unclear	46

<u>Key points</u>

The majority of respondents to this question felt that a bespoke funding model would be needed or would likely be needed to enable investments in larger scale, shared hydrogen transportation networks and storage. Many respondents answering positively set out the different types of funding models that could be used, based on experience from stimulating investment in similar assets.

Some respondents felt a bespoke funding model may be needed. Most respondents answering this way felt additional time was required to assess the potential growth of the hydrogen economy first before coming to a decision.

One respondent did not agree with the need for a bespoke funding model as it does not always result in a level playing field for UK businesses, directing government to consider unintended consequences in the offshore wind sector before making any decisions.

Importance to hydrogen economy

The importance of hydrogen transportation networks and storage to the wider hydrogen economy was raised by many respondents as a reason why bespoke funding was needed. Respondents said that this infrastructure supports both producers and end users, by mitigating against the supply and demand risk, as well as providing resilience and flexibility to the hydrogen system. Transportation networks and storage would be required for the UK to reach its ambition of a competitive, transparent, liquid, and resilient hydrogen market. The benefits of resilience and flexibility also apply to the wider energy system, especially in relation to storage which helps smooth out the intermittent supply of renewable electricity for electrolytic hydrogen production.

Building on this, a few respondents noted that providing a means to encourage the development of transportation networks and storage would complement the hydrogen business model and make it easier for these initial projects to come forward.

Potential funding models

Many respondents set out that a regulated asset base (RAB) or an approach similar to the existing natural gas network should be considered as a potential funding model. Respondents felt a RAB would be an effective way to recover investment costs in the presence of uncertain revenues due to the nascent nature of the hydrogen market. The majority of those mentioning a RAB felt it could be used for both transportation networks and storage.

Some respondents only suggested a RAB for transportation networks. This was because the most efficient outcome for the network would be a natural monopoly and a RAB was seen as being well suited to dealing with a natural monopoly as a regulator sets a fixed revenue allowance.

A few respondents felt that the existing RAB model for the natural gas transportation network could be used and expanded, although some tailoring would be needed. This would allow the experience of existing natural gas network licensees to be utilised. One of these respondents wanted clarity on existing licensees' role to be provided early to reduce risk of delay in developing this infrastructure, noting that roles and responsibilities need to be established to allow those accountable to take a lead.

One respondent suggested that a similar approach to funding of infrastructure installed in the North Sea to facilitate the expansion of the North Sea oil and gas industry could be used for hydrogen transportation networks.

A few respondents mentioned that a RAB would be suitable for storage. However, more respondents were able to suggest alternative funding models for storage, for example a cap and floor funding model or capital funding. A couple of respondents set out that, unlike natural gas, hydrogen storage could not adopt a merchant model given the uncertainties around net zero until, at least, a fully functioning hydrogen market had developed.

A few respondents felt an approach similar to developing infrastructure in offshore wind could be followed for both transportation networks and storage, with lessons to be learnt from that sector. A couple referred specifically to the Offshore Electricity Transmission (OFTO) regime. One respondent suggested a similar route to that taken for the development of High Voltage Direct Current transmission assets in Germany.

Hydrogen business model

A few respondents felt the hydrogen business model could be used to fund large scale transportation networks and storage, including in the near term, to support the future hydrogen system. One respondent noted the similar challenges for transportation networks and storage as for production, including high development expenditure and long lead times. A couple of respondents said that initial infrastructure should be future proofed to minimise the risk of stranded assets.

On the other hand, a larger number of respondents felt that a bespoke funding model was necessary, and the hydrogen business model could not be used. A few of these respondents noted the differences between production and transportation networks and storage, in terms of the actual assets, operation of those assets, and issues associated with those assets, meaning a different funding model was required. Others pointed to the major investment associated with this type of infrastructure, meaning a bespoke funding model would better ensure adequate funding is brought forward.

Regulatory regime

Some respondents mentioned the need for an appropriate regulatory regime along with any funding model. This would look at fair access, eliminate overcharging, and facilitate the right environment for efficient financing of transportation networks and storage. As such, rules should promote fair use, and any exemptions should only be in the short term.

One respondent suggested two phases for this regulatory regime, a transitional phase where the priority is to ensure investment is delivered promptly, and then an enduring phase where sub-optimal outcomes of the transitional phase are resolved. Arrangements would need to be included in the transitional phase to allow changes for the enduring phase.

One respondent suggested that owners of transportation networks and storage should be independent of producers.

Coordination

Some respondents cited the need for efficient build out of hydrogen transportation networks and storage, with the following points made:

- Coordination across the whole energy system is needed to reduce costs for consumers through a new regulatory regime enabled through gas and electricity regulatory reform. This would ensure effective long-term decisions on building new infrastructure as well as repurposing existing infrastructure.
- Exploration of re-purposing existing infrastructure is needed to ensure efficiency.
- Central planning of the build-out of infrastructure is needed to ensure optimum outcomes.
- Strategic thinking around any government intervention is needed to maximise the benefit for the UK economy. Lessons should be learnt from offshore wind, to avoid the hydrogen economy not being a consistent and level playing field for UK businesses.

Further time needed

Some respondents felt that more time would allow a better assessment of the required funding model(s) as well as the required infrastructure. They made the following points:

- There are too many uncertainties at the moment to assess the most appropriate funding model and building infrastructure now would lead to a greater risk of stranded assets.
- Central planning is needed to reduce the risk of wasted infrastructure in the future.
- The current priority should be to support hydrogen production.
- We should learn lessons from FOAK projects to feed into the assessment of an appropriate business model.
- More clarity is needed on how the hydrogen economy may evolve as it may take a decentralised approach. In that case, the hydrogen business model may be suitable, and a bespoke funding model would not be needed.
- A clear public use case for hydrogen at scale is needed first. Otherwise, it would be unfair on taxpayers or consumers to fund significant investment. As such, a bespoke model should only be suggested after the decision for the role of hydrogen in heating, for example.

Government response

The responses received to this question highlighted the importance that stakeholders attach to larger scale hydrogen T&S infrastructure as strategic assets in the growth of the hydrogen economy.

Stakeholders also highlighted the need for bespoke T&S business models to de-risk investment in such infrastructure. With this in mind, in the recent Energy Security Strategy government committed to designing, by 2025, new business models to support the development of hydrogen T&S infrastructure. It is government's intention that these business models will provide investors and developers with the reassurance they need to bring forward the T&S infrastructure that will be required to meet the government's renewed ambitions in this area.

In the Hydrogen Strategy, government committed to undertaking a review to better understand hydrogen T&S infrastructure requirements in the 2020s and beyond, including the need for financial support and economic regulation. This review is currently taking place and the responses that were received to this consultation will be used to inform the review. In addition, we will draw upon lessons from existing infrastructure from similar sectors to understand the most appropriate funding models available, as well as assessing unintended consequences associated with each model.

We committed to providing an update on our review in early 2022. In line with that commitment, we can report:

- We have commissioned consultants to undertake a research project to help us better understand hydrogen T&S infrastructure requirements. We expect this consultancy study to provide an assessment of the T&S infrastructure needs of the hydrogen economy as it evolves up to 2035 and beyond, the commercial arrangements attached to this infrastructure, likely costs, and barriers to investment.
- This consultancy study will be published later this year alongside either a call for evidence or a consultation which will seek stakeholders' views on hydrogen T&S infrastructure to support the design of the business models. We expect this engagement to include questions on high-level options for timings, funding, and wider economic regulation for this infrastructure.
- We are currently in the process of setting up a new Working Group under the Hydrogen Advisory Council. This Working Group will be used to progress policy on hydrogen T&S infrastructure, with a focus on funding and economic regulation. It will be made up of a representative group of stakeholders across the hydrogen value chain.
- As committed to in the Hydrogen Strategy, a hydrogen regulators forum has been established to help determine current and future non-economic regulatory responsibilities across the hydrogen value chain. It will focus on activity required across the 2020s to identify, prioritise and implement any changes to the existing non-economic regulatory framework, including addressing any gaps, to support the growth of a hydrogen economy.
- Within the same call for evidence or consultation mentioned earlier, we will seek stakeholder views on any initial outputs from the regulators forum.

We also acknowledge those respondents who indicated that, given the nascency of the hydrogen market, further analysis is needed to understand the evolution of the market before determining the most appropriate business models for large scale infrastructure. Given the potential for hydrogen to support the future integration of our energy system, this analysis will need to consider hydrogen's relationship with other infrastructure, energy carriers, and different end users. We will undertake this analysis as we design the hydrogen T&S infrastructure business models.

We will continue to engage with industry, non-governmental organisations and regulators as we undertake this work, and any learnings will feed into our high-level options within the call for evidence or consultation seeking views on hydrogen T&S infrastructure.

Ahead of the conclusion of our review, and as we design bespoke hydrogen T&S infrastructure business models, and in parallel with considerations of limited business model support for initial T&S infrastructure, we will work collaboratively with Ofgem to consider what work needs to happen now and what appropriate funding mechanisms could be used to support this, if necessary.

Acronyms

Acronym	Definition
CCUS	Carbon capture, usage and storage
CfD	Contract for difference
CPI	Consumer Price Index
DPA	Dispatchable Power Agreement
ETS	Emissions Trading System
FOAK	First of a kind
GGSS	Green Gas Support Scheme
GW	Gigawatt
ICC	Industrial Carbon Capture
IETF	Industrial Energy Transformation Fund
LCHS	Low carbon hydrogen standard
MW	Megawatt
NOAK	Nth of a kind
NZHF	Net Zero Hydrogen Fund
RTFC	Renewable Transport Fuel certificates
RTFO	Renewable Transport Fuel Obligation
T&S	Transport and storage
UK ETS	UK Emissions Trading Scheme

Glossary

Term	Definition
Achieved sales price	The value a hydrogen producer achieves selling hydrogen on the market
Allocation	The process of allocating revenue support through the hydrogen business model
Availability payments	A payment based on a hydrogen production facility's production capacity regardless of sales
Backstop	A financial arrangement where government acts as the buyer of last resort for unsold volumes of hydrogen
Balance sheet	The national balance sheet shows the market value of the financial and non-financial assets for the UK
Baseload	Operating continuously to meet a minimum level of demand
Carbon Budget 6	Limits the volume of greenhouse gases emitted over a 5-year period from 2033 to 2037, taking the UK more than three-quarters of the way to reaching net zero by 2050
Carbon Capture Utilisation and Storage	The process of capturing carbon dioxide from industrial processes, power generation, certain hydrogen production methods. The captured carbon dioxide is then either used or stored permanently
Carbon price	A cost applied to carbon emissions to encourage emitters to reduce the amount of greenhouse gases they emit into the atmosphere
CCUS cluster sequencing process	The process by which CCUS industrial clusters are chosen, with two anticipated by the mid-2020s, and a further two clusters by 2030 as outlined in the 10 Point Plan

CCUS-enabled hydrogen production	A process for producing low carbon hydrogen, and capturing, monitoring, metering and exporting CO2 generated in the production process[21]
Contract for difference	A Contract for Difference, as set out in the Energy Act 2013, is a contract between a generator and a counterparty to encourage the generation of low carbon electricity whereby the counterparty will pay an electricity generator the difference between the CfD reference price and the CfD strike price
Counterfactual fuel	The main fuel currently used in an end use sector, which a low carbon alternative could replace
Dispatchable Power Agreement	A mechanism to support power-CCUS projects
Electrolysis	A hydrogen production process which involves using electricity to generate hydrogen from water. Low carbon hydrogen is created when low carbon electricity is used as the input fuel.
Electrolytic hydrogen production	Hydrogen produced from electrolysis
First of a kind	The first low carbon hydrogen projects accessing revenue support through the business model, who take on first mover risk by entering an undeveloped low carbon hydrogen market
Fixed premium	When a producer is paid an additional fixed payment for every unit of hydrogen produced, on top of the price the producer achieves in the market
Fixed price	When a producer is paid a fixed price for every unit of hydrogen produced, with this price reflecting the anticipated cost of production
Carbon intensive hydrogen	Hydrogen that is produced from unabated methane-reformation, commonly used in industrial processes
Hydrogen business model	The objective of the hydrogen business model is to incentivise the production and use of low carbon hydrogen, and help us achieve our ambition of up to 10 GW by 2030, subject to affordability and value for money. It is designed to provide hydrogen producers with revenue support to overcome the operating cost gap between low carbon hydrogen and fossil fuels in order to unlock private investment in hydrogen projects.
ICC business model	Designed to incentivise the deployment of carbon capture technology for industrial users, the ICC business model is a private law contract, similar to a CfD, that provides the emitter with a payment per tonne of captured CO_2. Projects looking to retrofit carbon intensive hydrogen production may be eligible for support through this scheme
Indexation	Applied to the strike price to account for the varying cost of production inputs over time.
Low carbon hydrogen	Hydrogen that is produced with significantly lower greenhouse gas emissions compared to current methods of production – methods include methane reformation with CCUS and electrolysis using renewable electricity. The hydrogen produced will be subject to meeting the 20gCO2e/MJ LHV of hydrogen threshold set out in the proposed UK LCHS to be considered low carbon for the purpose of this scheme.

[21] The definition used in the consultation document was: 'Low carbon hydrogen produced from methane reformation with CCUS'. From analysing stakeholder feedback, we consider that the references to CCUS-enabled hydrogen usually intended to mean methane reformation with CCUS, though sometimes a wider range of technologies was discussed.

Low carbon hydrogen market	A future fluid market where hydrogen is established in the energy system and moves towards being more competitively priced
Low carbon hydrogen value chain	The low carbon hydrogen value chain covers; input fuels, production technologies, hydrogen and CO2 transportation and storage, end uses, and links with related economic activities
Market price risk	The risk that the price achieved for the selling of hydrogen into the market does not cover the cost of production, as it is unable to compete with the cost of high carbon counterfactuals
Methane reformation	A process for hydrogen production in which methane is the input fuel
Net zero	Legislation passed by the government to reduce greenhouse gas emissions to net zero by 2050
Net Zero Hydrogen Fund	A £240m fund to support low carbon hydrogen production
Non-ETS	Includes sectors such as transport, agriculture, waste, certain industrial emissions and the built environment who are not covered by the UK ETS
Nth of a kind	Low carbon hydrogen projects entering into a more developed hydrogen market using mature technologies and processes with less risk
Reference price	Reflects the price that the producer would receive for hydrogen in the market under a variable premium model
Renewable Heat Incentive	A fixed rate tariff designed to incentivise the use of renewable heat for both domestic and non-domestic properties
Renewables Obligation	An obligation on licenced electricity suppliers to source a proportion of the electricity they supply from eligible renewable sources
Renewable Transport Fuel Certificates	Suppliers of fuels, both renewable and non-renewable, totalling 450,000 litres or more in an obligation period have a responsibility under the RTFO. They can meet their obligation by claiming their RTFCs for the supply of renewable fuels. For every litre of renewable fuel, one certificate can be claimed. However, some fuels are incentivised and awarded double the RTFCs per litre (or kilogram) supplied, depending on specific wastes and residues.
Renewable Transport Fuel Obligation	Mechanism to support the production and use of renewable fuels based on obligation on suppliers of transport and non-road mobile machinery fuel in the UK to show that a percentage of the fuel they supply comes from renewable and sustainable sources
Revenue stacking	Common with battery storage business cases, revenue stacking is the combining of a variety of revenue streams to generate income to help pay for an asset
Revenue support	The funding provided on an ongoing basis, for an agreed term, which would cover a proportion of operating costs and an appropriate rate of return on private sector capital invested
SDE++	A Dutch subsidy scheme that subsidises the operating shortfall of renewable energy generation and other CO2-reducing technologies
Sliding scale	Volume support provided through a variation in the strike price. Higher levels of support are provided for low offtake volumes which are tapered downwards as volumes increase.

Strike price	Reflects the pre-agreed production cost of low carbon hydrogen under a variable premium model
Ten Point Plan	Sets out the approach government will take to build back better, support green jobs, and accelerate our path to net zero
Transfer pricing	A means of pricing transactions between connected parties to reduce cost burdens and maximise profits
UK Emissions Trading Scheme	Replacing the UK's participation in the EU ETS, the UK Emissions Trading Scheme applies to energy intensive industries, the power generation sector and aviation
Variable premium	A producer is paid a premium for the hydrogen produced. The premium is calculated as the difference between a strike price and a reference price for each unit of hydrogen sold
Volume risk	The risk that a hydrogen production facility is unable to sell enough volumes of hydrogen to cover costs with reasonable confidence

List of respondents to the Low Carbon Hydrogen Business Model Consultation

A total of 121 responses were received. 120 were from the organisations listed below with one personal response.

Organisation
Acorn Project (being developed by Storegga, Shell UK and Harbour)
Adynaton Asset Management LLP
Air Products
AMP Clean Energy
Anglo American plc
Arup
Associated British Ports
Association for Decentralised Energy
Assystem Energy and Infrastructure Limited
Bellona
BP plc
BPP Technical Services Limited
British Ceramic Confederation
British Glass
Brookfield
Cadent
Carbon Capture and Storage Association
Carlton Power/Trafford Green Hydrogen Ltd
Cemex
Centrica plc
Ceres Energy Limited
CF Fertilisers
CNG Services
Community Development of Community Energy
Confederation of British Industry

Conrad Energy
CR Plus ltd
Cudd Bentley
Dalton Nuclear Institute
Decarbonised Gas Alliance
Drax
DUGUUD/Amberside Capital
EDF Energy
Energy Networks Association
Energy Systems Catapult
Energy UK
Eneus Energy
Eni UK Limited
E.ON
Equinor
ERM Dolphyn
ESSAR OIL UK Limited
First Bus
First Hydrogen Limited
Gemserv (on behalf of Hydrogen Taskforce)
GeoPura
GFD
GHD
Gigastack Consortium
Global Infrastructure Investor Association
Green Alliance
Greenergy
GTIP
H2 Green
H2Transition Capital LLP
Helmsley Green Team
HiiROC Limited

Hydrologiq Ltd.
HyGen Energy, formerly Ryze Hydrogen Ltd
ICIS (a LexisNexis Risk Solutions Group business)
Industry Wales
INEOS
InterGen
Iogen Corporation
Kanay Energy Limited
Kellas Midstream Limited
Lloyds Banking Group
Lancashire LEP
Marprof Ltd
MCS Charitable Foundation
Menter Mon
Meridiam
Mutual Energy
National Nuclear Laboratory
National Grid
Neptune Energy
North West Hydrogen Alliance
Nuclear Industry Association
Octopus Renewables and RES Green Hydrogen Partnership
OGUK
OPIS
Orsted
OVO Energy
Phillips 66 Limited
Platts
Progressive Energy
REA
Regen
RenewableUK

RWE Generation
Scottish Power
Scottish Renewables
SGN
Shell
Shetland Island Council
Siemens Energy Limited
Simply Blue Group
Sizewell C
Skuunaq Energy
SSE plc
Statera Energy Limited
Statkraft
Summit E&P
Swindon and Wiltshire LEP
Tata Steel
Tate & Lyle Sugars
Tees Valley Combined Authority
The North Wales Economic Ambition Board
TotalEnergies E&P UK
Triton Power Ltd
Tyseley Energy Park
UK Hydrogen and Fuel Cell Association
UKPIA
Uniper UK
University of South Wales
URENCO Limited
Valero Energy Ltd
Wales Hydrogen Trade Association
Wood
Xodus Group Ltd

This publication is available from: https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen.

If you need a version of this document in a more accessible format, please email enquiries@beis.gov.uk. Please tell us what format you need. It will help us if you say what assistive technology you use.