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OTHER DEADLINE 3 SUBMISSIONS
THE APPLICANT'S RESPONSE TO GREAT EXPERT REPORT ON THE STATEMENT OF NEED - REFERENCE 4

August 2019
Revision A

Document Reference: 11.4.10.4
Submitted: Deadline 3

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CLEVE HILL
SOLAR PARK

Department for
Business, Energy
& Industrial Strategy

RAB MODEL FOR NUCLEAR

Consultation on a RAB model for new nuclear projects

Closing date: 14 October 2019

July 2019

INDUSTRIAL
STRATEGY

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

Contents

General information

Why we are consulting

The purpose of this consultation is to set out the basis for our assessment of a Regulated Asset Base (RAB) funding model for nuclear and to seek views from stakeholders on a nuclear RAB model and its high-level design principles.

Consultation details

Issued: 22 July 2019

Respond by: 14 October 2019

Enquiries to:

Electricity and RAB Strategy Team
Department for Business, Energy & Industrial Strategy,
3rd Floor Victoria 309
1 Victoria Street,
London,
SW1H 0ET

Email: RABconsultation@beis.gov.uk

Consultation reference: Consultation on a Regulated Asset Base (RAB) Model for Nuclear

Territorial extent:

This consultation applies to the energy markets in Great Britain. Responsibility for energy markets in Northern Ireland lies with the Northern Ireland Executive's Department for the Economy.

How to respond

Respond online at: https://beisgovuk.citizenspace.com/energy-strategy-networks-markets/regulated-asset-base-rab-model

Email to: RABconsultation@beis.gov.uk

Write to:

Electricity and RAB Strategy Team

Department for Business, Energy & Industrial Strategy,

3rd Floor Victoria 309

1 Victoria Street,

London, SW1H 0ET

When responding, please state whether you are responding as an individual or representing the views of an organisation.

Your response will be most useful if it is framed in direct response to the questions posed, though further comments and evidence are also welcome.

Confidentiality and data protection

Information you provide in response to this consultation, including personal information, may be disclosed in accordance with data protection Laws.

If you want the information that you provide to be treated as confidential please tell us but be aware that we cannot guarantee confidentiality in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not be regarded by us as a confidentiality request.

We will process your personal data in accordance with all applicable UK and EU data protection laws. See our privacy policy.

We will summarise all responses and publish this summary on GOV.UK. The summary will include a list of names or organisations that responded, but not people's personal names, addresses or other contact details.

Quality assurance

This consultation has been carried out in accordance with the government's consultation principles.

If you have any complaints about the way this consultation has been conducted, please email: beis.bru@beis.gov.uk

Executive summary

For new nuclear projects to be successful in a more competitive energy market, it is essential that there is a sustainable funding model that can attract private finance at a cost that represents value for money to consumers. In his statement to Parliament in June 2018, the Secretary of State for Business, Energy and Industrial Strategy said that the Government would review the viability of a 'Regulated Asset Base' (RAB) model for new nuclear projects and in January 2019 confirmed the Government's intention to publish an assessment of this model by the summer.

RAB models, typically used for funding UK monopoly infrastructure, involve an economic regulator who grants a licence to a company to charge a regulated price to users of the infrastructure. RAB-funded infrastructure has attracted significant investment from private sector capital over the last 20-30 years, with total value of RAB assets in 2018 of c.£160bn.

Our assessment has concluded that, by providing regulated returns to investors, a RAB model has the potential to reduce the cost of raising private finance for new nuclear projects, thereby reducing consumer bills and maximising value for money for consumers and taxpayers.

To deliver these benefits, we believe that a RAB model for new nuclear projects would need to have the following features (described in further detail in this consultation):

a) Government protection for investors and consumers against specific remote, low probability but high impact risk events, through a Government Support Package (GSP);

b) A fair sharing of costs and risks between consumers and investors, set out in an Economic Regulatory Regime (ERR);

c) An economic regulator (the 'Regulator') to operate the ERR; and

d) A route for funds to be raised from energy suppliers to support new nuclear projects, with the amount set through the ERR, during both the construction and operational phases (the 'Revenue Stream').

The purpose of this consultation is to seek views from stakeholders on a nuclear RAB model and its high-level design principles, including risk sharing arrangements.

This consultation will run until 14 October 2019. Responses should be submitted to RABconsultation@beis.gov.uk and will be published unless respondents request confidentiality.

Introduction

1. Nuclear power plays an important role in our current energy mix, with eight nuclear power stations – spread across the country, from Dungeness to Torness – providing around 20% of our total power needs[1]. We have a world-leading civil nuclear sector, covering the full lifecycle of fuel production, construction, generation, decommissioning, waste management and research. Industry estimates that the civil nuclear sector supports 46,000 jobs across the civil nuclear supply chain[2]. In 2016, the government gave the go ahead to the construction of the first nuclear power station in a generation at Hinkley Point C (HPC), and in 2018 signed an ambitious sector deal with the nuclear industry to reduce costs, drive innovation and increase diversity across the sector [3].

2. The United Kingdom recently became the first major economy to legislate for a target of net zero greenhouse gas emissions by 2050[4]. This decision was taken following advice from the independent Committee on Climate Change that a net zero 2050 target was feasible, deliverable, and can be met within the same cost envelope of 1% to 2% of GDP in 2050 as the 80% target when that was set[5].

3. Reaching this target will require ambitious action across the economy to reduce emissions while keeping energy costs low and supplies secure. To ensure that we achieve the transition to net zero in a way that works for households, businesses and the public finances, HM Treasury will be leading a review into the costs of decarbonisation.

4. Meeting net zero will require emissions from the power sector to be reduced to low levels and the deployment of negative emissions technology to offset emissions from those sectors that cannot be completely decarbonised. It is likely that electricity demand will grow significantly by 2050 as other sectors of the economy such as transport and heat are electrified, potentially nearly doubling (or more) from today's levels.

5. To meet this increasing demand, whilst reducing emissions to low levels, there will need to be a substantial increase in low carbon generation – the Committee on Climate Change estimate a four-fold increase may be needed. This is at a time when seven out of eight of our existing nuclear power plants – important contributors to our low carbon generation – are due to come offline by 2030 as they reach the end of their operational lives.

6. As the cost of renewable technologies such as offshore wind and solar continues to fall[6], it is becoming clear that they are likely to provide the majority of our low carbon generating capacity in 2050. However, there will still be a crucial role for low-carbon 'firm' (i.e. always available) power in 2050 – the Committee on Climate Change includes 38% firm low carbon in their further ambition scenario[7] – to meet net zero while maintaining security of supply and keeping costs low.

[1] https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2018-main-report
[2] https://www.nssguk.com/media/1316/publication-nuclear-workforce-2017-exe-summary.pdf
[3] https://www.gov.uk/government/publications/nuclear-sector-deal
[4] https://www.gov.uk/government/news/pm-theresa-may-we-will-end-uk-contribution-to-climate-change-by-2050
[5] https://www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/
[6] https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016
[7] https://www.theccc.org.uk/publication/net-zero-technical-report/#technical-annexes

7. The technologies currently available to provide this large-scale firm, low-carbon power in 2050 are nuclear and gas with carbon capture, usage and storage (CCUS)[8]. While advances in technologies, system flexibility and energy storage may eventually provide additional options for fully decarbonising the power sector, it is clear that a significant capacity of new nuclear power stations and gas-fired power plants with CCUS, alongside renewables, will also be required.

8. To ensure we have a credible plan for delivering our climate targets while maintaining security of supply and keeping costs low, we must take the necessary enabling steps to deliver the required firm low-carbon capacity based on the current set of options available to us.

9. In that context, the Government believes that we should be prepared to support further new nuclear projects in the years ahead, if they can be delivered at a competitive price and each individual project represents value for money.

10. The first step in driving down costs was the signing of an ambitious sector deal with the nuclear industry which focuses on lowering the cost of new nuclear projects by 30% to ensure nuclear remains competitive with other technologies. Industry is leading work – as part of the implementation of the Nuclear Sector Deal[9] – to establish how that target can be achieved by 2030. This will involve thinking about how, for example, innovative approaches to advanced manufacturing, construction and materials can reduce costs in a range of products and services across the nuclear industry, including for future nuclear technologies.

11. As the Secretary of State for Business, Energy and Industrial Strategy made clear in his statement to Parliament on 17 January 2019, the next major challenge is how new nuclear projects are financed going forward.

12. HPC is being financed by EDF and CGN, with a Contract for Difference (CfD) providing long-term price stability for the generator once the plant begins generating (but leaving construction and operating risk with the investors)[10]. The CfD model was appropriate in this instance as HPC was the first new nuclear project to begin construction in the UK for a generation. At the point the decision was taken to enter into the CfD contract, the European Pressurised Reactor (EPR) technology was not operational anywhere in the world, and similar projects in France and Finland had suffered from significant delays and cost overruns. It was therefore right that all construction and operational risk should sit with the project investors.

13. The context will, however, be different for future new nuclear projects. HPC is now under construction, providing employment opportunities and helping to rebuild the supply chain for new nuclear projects across the UK, providing valuable knowledge and skills[11]. Furthermore, on 24 June this year HPC reached a significant construction milestone with the completion on schedule of the concrete base for the reactor buildings, helping to build confidence in the delivery of further new nuclear projects in the UK. The EPR technology

[8] Bioenergy is another source of firm, low carbon capacity and currently provides around 10% of total electricity generation. It will continue to have an important role in 2050 – particularly in combination with CCUS to provide 'negative emissions' – but supplies of sustainable, low carbon biomass are likely to limit the scale to which this can be deployed in the power sector.
[9] https://www.gov.uk/government/publications/nuclear-sector-deal
[10] https://www.gov.uk/government/news/hinkley-point-c-contract-signed
[11] https://www.gov.uk/government/publications/hinkley-point-c-wider-benefits-realisation-plan (Source: NNB HPC)

has now started commercial operations in China[12], and other technologies that have been proposed for deployment in the UK are either already operational elsewhere or are expected to be operational before they would be deployed in the UK.

14. Despite the progress at HPC, the challenges facing the global nuclear industry have meant that replicating a CfD model for further new nuclear projects has proved very challenging[13]. Few project developers have a balance sheet that can accommodate the £15-20bn cost of delivering a new nuclear project, and financial investors have been unwilling to invest during the construction phase given the long construction period and risk of cost increases and delays. We are therefore looking to work with the sector to develop an alternative funding model for new nuclear projects that can attract private finance at a cost that represents value for money to consumers and are considering its wider applicability to other firm low carbon technologies.

15. This is consistent with the National Audit Office (NAO) report on HPC[14], which recommended that Government consider whether alternative funding models for future new nuclear projects could improve value for money and reduce cost to consumers.

16. In light of the NAO's recommendations, the Government announced[15] in June 2018 that it was willing to consider direct investment into Horizon's proposed Wylfa Newydd nuclear project, alongside investment from Hitachi, Japanese Government agencies and other parties. At the same time, the Secretary of State made clear that it remained the Government's objective in the longer term that future new nuclear projects beyond Wylfa should be financed by the private sector, and that Government would review the viability of a Regulated Asset Base (RAB) model (see box 1) as a sustainable funding model based on private finance, which could deliver the Government's objectives in terms of value for money, fiscal responsibility and decarbonisation. Such a model could ensure taxpayers' money could be invested in vital public services, while continuing to reduce public sector net debt.

17. Despite a concerted effort by all parties involved, Hitachi announced in January 2019 that it was suspending development of the Wylfa Newydd nuclear project. Following Hitachi's announcement, the Secretary of State made a statement to Parliament[16] in January 2019, stating that Government was continuing to review the viability of a RAB model and assessing whether it could deliver value for money for consumers and taxpayers. He confirmed the Government's intention to publish this assessment by the summer.

18. Our assessment has concluded that a RAB approach could present a sustainable and value for money model for funding new nuclear projects. It has the potential to attract significant investment for new nuclear projects at a lower cost to consumers, enabling low carbon power to be delivered at scale. However, there remain significant challenges to delivery of a RAB model for new nuclear projects. These include raising the scale of capital required and establishing an appropriate risk sharing arrangement between the project company, the supply chain, investors, taxpayers and energy suppliers and consumers.

19. The purpose of this consultation is to set out the basis for our assessment and to seek views from stakeholders on a nuclear RAB model and its high-level design principles,

[12] https://www.edfenergy.com/media-centre/news-releases/taishan-1-connected-to-grid
[13] https://commonslibrary.parliament.uk/science/energy/mind-the-gap-challenges-for-future-uk-energy-policy/
[14] https://www.nao.org.uk/report/hinkley-point-c/
[15] https://www.gov.uk/government/speeches/statement-to-parliament-on-horizon-project-at-wylfa-newydd
[16] https://www.gov.uk/government/speeches/statement-on-suspension-of-work-on-thewylfa-newyddnuclear-project

including risk sharing arrangements. We are consulting on the basis that this model would be introduced alongside our existing model for delivering new nuclear projects, the CfD model, rather than as a replacement. A decision on which model was most appropriate for a particular project would be made on a case-by-case basis. There could be further consultations on specific design features if the Government decides to proceed with implementing the framework for a nuclear RAB model following this consultation.

20. We are also considering whether a RAB model could be applied to other firm low carbon technologies, such as transport and storage infrastructure for carbon dioxide. This is included in a separate consultation on business models for Carbon Capture Usage and Storage (CCUS)[17].

Box 1: What is a Regulated Asset Base (RAB) funding model?

A RAB model is a type of economic regulation typically used in the UK for monopoly infrastructure assets such as water, gas and electricity networks. The company receives a licence from an economic regulator, which grants it the right to charge a regulated price to users in exchange for provision of the infrastructure in question. The charge is set by an independent regulator who holds the company to account to ensure any expenditure is in the interest of users. In the case of a nuclear RAB, suppliers would be charged as users of the electricity system and would be able to pass these costs onto their consumers who also use the electricity system.

In 2016 the model was applied successfully for the first time to a single asset construction project – the £4.2bn Thames Tideway Tunnel (TTT) sewerage project[18]. Much of the c.£1bn of private sector equity finance that was raised to deliver the project came from UK pension funds, representing 1.7 million pensioners, or a quarter of the UK's largest 25 pension funds[19].

RAB-funded infrastructure has received significant quantities of investment from private sector players over the last 20-30 years. As of 2018 the total RAB value across the UK electricity, gas, water and airport sectors is c.£160bn (2018 prices).

Under economic regulation, the cost of transporting a unit of electricity around Britain has fallen by 17% since the mid-1990s, relative to the retail price index[20]. Since 2015 there have been significant improvements in distribution network reliability, currently standing at 99.99%[21]. Customer interruptions have fallen by 11%, and the duration of interruptions has fallen by around 9%[22]. In 2009-10 the average duration of distribution network power cuts was 97 minutes, in 2017-18 it was 36 minutes[23].

[17] https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-ccus-business-models
[18] https://www.gov.uk/government/publications/thames-tideway-tunnel-strategic-and-economic-case-costs-and-benefits-2015-update
[19] https://www.nic.org.uk/publications/review-infrastructure-financing-markets-report-nic/
[20] https://www.ofgem.gov.uk/news-blog/our-blog/tougher-price-controls-energy-networks
[21] https://www.ofgem.gov.uk/publications-and-updates/riio-electricity-distribution-annual-report-2017-18
[22] https://www.ofgem.gov.uk/publications-and-updates/riio-electricity-distribution-annual-report-2017-18
[23] https://www.ofgem.gov.uk/publications-and-updates/riio-electricity-distribution-annual-report-2017-18

A RAB model for new nuclear projects

Introduction to a nuclear RAB model

Objectives of a nuclear RAB model

21. Government believes that additional nuclear capacity will be required to ensure a low cost, stable, reliable, low carbon system.

22. Since financing costs are a major component of the price of new nuclear projects, lower financing costs could have a significant impact in driving down the total costs that suppliers and their consumers pay for this power.

23. Recent years have seen the emergence of large volumes of private sector capital looking to invest in infrastructure projects. Governments around the world are seeking ways to access this capital[24], which in the UK primarily comprises pension funds and insurers[25]. This is potentially a major source of the investment required to meet our decarbonisation objectives. For new nuclear projects to attract this capital, it is necessary that the investment proposition is comparable to the other types of infrastructure projects available for investment. This requires the creation of a more typical infrastructure investment profile where investor exposure to risks and their returns are bounded.

24. On this basis, the primary objective of a nuclear RAB model would be to enable the delivery of new nuclear projects and reduce the cost of this additional nuclear capacity. This would be achieved through:

    a) attracting private capital to finance new nuclear projects in the UK;

    b) incentivising the private sector, through robust regulatory mechanisms and competition where possible, to deliver new nuclear projects on time and to budget; and

    c) enabling a financing structure and cost of capital which is as efficient as possible in order to reduce the total financing costs of new nuclear projects to consumers.

Elements of a nuclear RAB model

25. A large-scale new nuclear project bears some similarities with the Thames Tideway Tunnel (TTT) project, in that it is a complex single asset construction project with a significant upfront capital expenditure requirement, long construction period and a long asset life. In developing a potential nuclear RAB model, we have taken the model used for TTT, which was also developed under a RAB, as a starting point, whilst recognising that new nuclear projects are greater in scale and face specific challenges that were not relevant to TTT.

[24] https://www.oecd.org/pensions/private-pensions/institutionalinvestorsandlong-terminvestment.htm

[25] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/520086/2904569_nidp_deliveryplan.pdf

26. We envisage that in order to attract low cost capital at the scale required, a nuclear RAB model would have the following key elements:

    a) Government protection for investors and consumers against specific remote, low probability but high impact risk events, through a set of contractual arrangements (the 'Government Support Package' or 'GSP');

    b) A fair sharing of costs and risks between consumers and investors, established through an 'Economic Regulatory Regime' (ERR);

    c) An economic regulator (the 'Regulator') to operate the ERR; and

    d) A route for funds to be raised from energy suppliers to support new nuclear projects, with the amount set through the ERR, during both the construction and operational phases (the 'Revenue Stream').

These are described further in the following sections.

Government Support Package

27. In order to raise the amount of finance required, Government would need to provide a GSP offering protection to investors for specified low probability but high impact risks that the private sector would not be able to bear – either at all or at an efficient price (as was the case for TTT). The GSP would also protect consumers from exposure to these risks.

28. Examples of specific risks that might be protected by a GSP are: (a) risk of cost overrun above a remote threshold, (b) disruption to debt markets, (c) certain risks for which insurance is not available in the market, and (d) political risks.

29. For the protection described in (a) above, it is envisaged that the threshold capital expenditure amount (the 'Funding Cap') would be identified prior to the GSP being issued and set by Government at a level at which there was only a remote chance of construction costs reaching this level. The Funding Cap would be set based on robust project diligence and global benchmarking of comparable projects.

30. Options for dealing with the remote risk of cost overrun beyond the Funding Cap would be developed. It is proposed that, in the event capital expenditure beyond the Funding Cap was required, the Regulator would have the option of deciding whether further financing would be reflected in higher regulated charges. Similarly, whilst investors would not be committed to finance capital expenditure beyond the Funding Cap, they could choose to do so. If investors decided not to provide finance beyond the Funding Cap, Government could choose to either provide the finance required to complete the project (in return for commensurate ownership and governance rights), or to discontinue the project and make a discontinuation payment to investors.

Economic Regulatory Regime

The Economic Regulatory Regime and Allowed Revenue

31. It is envisaged that a nuclear RAB model would require an ERR in which a licence was granted to a project company entitling it to charge nuclear RAB payments (the 'Allowed

Revenue') in exchange for performing its functions (the construction and operation of a nuclear plant). The amount of Allowed Revenue would be determined by the Regulator, and this would effectively govern the way in which risk was shared between investors and users of the electricity system (suppliers and their consumers).

32. The Allowed Revenue would be expected to be based on a set of 'building blocks' that would enable the project company to recover its costs (if approved by the Regulator) and to generate a return on capital invested to finance those costs. Indicative building blocks are set out below:

Figure 1: Allowed Revenue building blocks

33. The 'Weighted Average Cost of Capital' (WACC) would be the cost of capital allowed by the Regulator (see paragraphs 45 – 48 below).

34. The 'RAB' (also referred to as the Regulatory Capital Value or RCV) would be the total cumulative capital expenditure as incurred and approved as being efficient by the Regulator, as adjusted for indexation and Depreciation (for more detail, see paragraph 35 below).

35. The 'Depreciation' building block would allow repayment of the initial capital cost of the RAB value during its operational life so that, by the end of operations or earlier, all capital invested in the plant and approved as efficient by the Regulator would be paid back to investors. There are several options to shape the profile of the RAB repayment over its lifetime i.e. the profile of Depreciation.

36. Below is an illustrative figure showing the RAB balance during construction and the operational life of the plant, assuming that it is depreciated on a 'straight line' (real) basis down to zero.

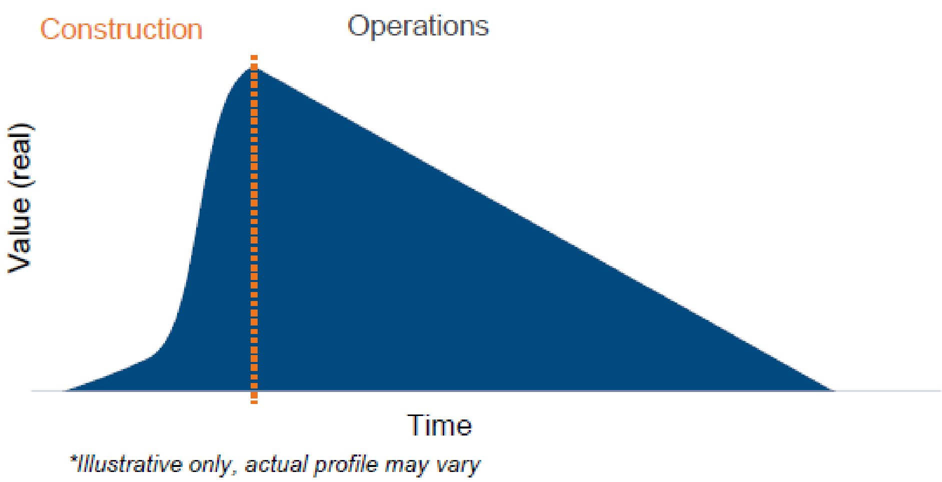


Figure 2: Evolution of RAB balance over project life

37. The 'Funded Decommissioning Programme' (FDP) building block would make provision for the decommissioning and waste management costs associated with a new nuclear project. It is envisaged that this building block would apply from the point of nuclear operation for the remainder of the period in which a regulated Allowed Revenue was charged, with incentives placed on costs within the project company's control.

38. The Allowed Revenue would be charged during both the construction and operational period, with charges increasing over the construction period in line with the cumulative project spend, as illustrated in the figure above. Such an approach would both reduce the scale of the financing challenge and the cost of financing (and so, increase deliverability of the financing, whilst reducing total cost to suppliers and their consumers). A potential challenge with this approach is that it would expose suppliers and their consumers to the risk that they provide construction-phase funding for a plant that is never completed. However, a robust due diligence process (see paragraphs 70-74 below) would be used to ensure that only projects where the risk of non-completion was highly remote would be granted a nuclear RAB licence and GSP.

39. The right to charge the Allowed Revenue set through the ERR could run for the construction phase and an operational phase similar to the design life of a plant (for example, 50 or 60 years). However, it would also be possible under a nuclear RAB model to set the ERR over a shorter period than the expected life of the plant (e.g. 35 years, the length of the CfD for HPC). A decision on this would be made as part of the overall design of the ERR for each new nuclear project, with regard to factors likely to enable best value for money for consumers, including affordability for suppliers and consumers, the expected cost of capital, the expected life of the plant and financing considerations.

Construction cost risk

40. The ERR would need to govern how construction cost overruns would be accounted for in the RAB model and how the project would be incentivised to remain efficient. The objective for any RAB model in setting this incentivisation and risk sharing approach would be to put maximum incentive on investors (and minimum risk on consumers and taxpayers) subject to ensuring that the project could be financed at an efficient cost of capital, with the overall objective of achieving best overall value to consumers. There are two potential approaches to achieving this in RAB models:

    a) **'Ex post' cost settlement**: At set periods, the Regulator could review the costs actually incurred by the project company and decide on a discretionary basis, in accordance with regulatory principles, which costs should be allowed as part of the RAB in the Allowed Revenue calculations. This would enable the Regulator to penalise the project company for inefficient spending by preventing it from accruing to the RAB; or

    b) '**Ex ante' cost settlement:** A target total construction cost would be set for the project company which would be used as the Baseline for incentivisation and risk sharing. If construction costs increased above the Baseline, a portion of the additional costs would be added to the RAB, such that the impact would be shared between investors and suppliers (and through them, their consumers). It would also operate the other way – if costs came in below the Baseline, suppliers and their consumers would share the benefits with investors. An additional tool could involve the reduction or suspension of investor returns in delay scenarios (which are closely correlated with cost overrun scenarios). The Baseline costs would be set at the point the nuclear RAB licence was granted, following a robust due diligence process carried out by Government and the

Regulator. This was the approach adopted by TTT. More detail on the ex ante approach is set out in Box 2.

41. Our initial analysis indicates that the ex ante approach is likely to be more appropriate for new nuclear projects because it could both:

a) incentivise investors to bring to bear their collective experience in project diligence and oversight to prevent risks materialising; and

b) provide clarity and certainty to investors, suppliers and consumers, which is particularly important for a large single-asset project with a complex and relatively long construction period. Combined with the GSP provisions for Government finance above the Funding Cap (see paragraphs 27-30 above), this would enable Government to estimate maximum potential exposure for suppliers and their consumers before additional/increased regulatory discretion. It would also enable investors to calculate the maximum impact that cost overruns could have on their returns and therefore to price their investment efficiently, which in turn should reduce overall cost to suppliers and their consumers and ensure value for money.

42. A final decision would be taken on this as part of the detailed design of the ERR for a particular project. This would be subject to further development.

Box 2: Overview of potential RAB risk sharing in construction

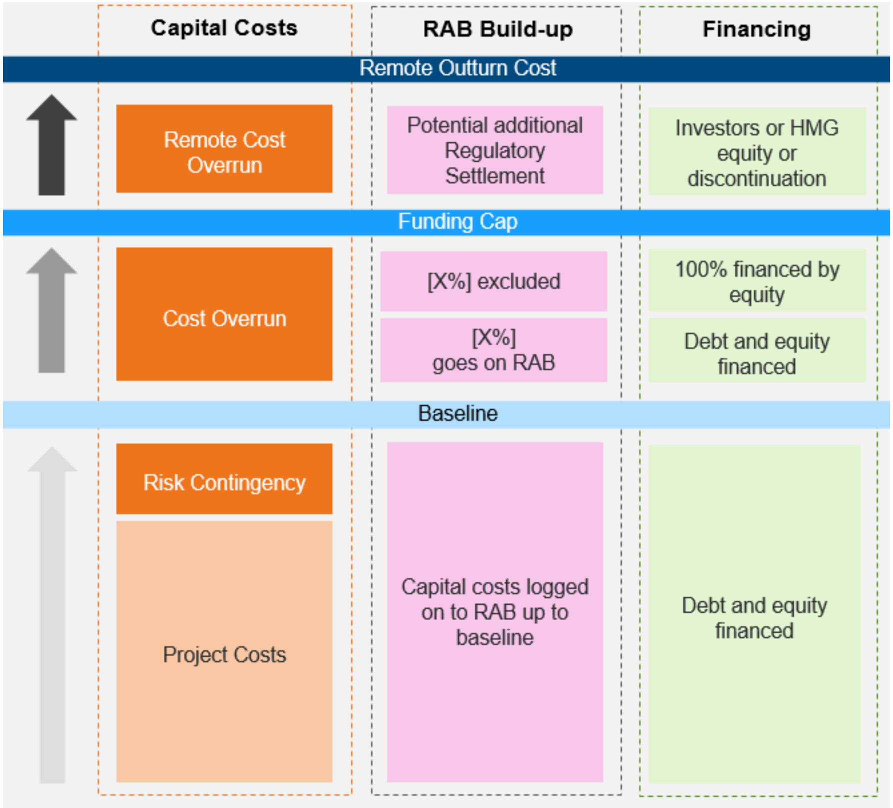


Figure 3: Illustration of how an ex ante risk sharing approach could work during the construction phase. This is based on the approach used on TTT.

A Baseline construction cost would be set at the point the RAB licence is granted, for the purposes of establishing regulatory incentives under the ERR. It would be the forecast cost of the project with a provision for reasonable risk contingency.

If project costs exceeded the Baseline, some of the additional costs would be borne by contractors through the supply chain or by insurers, depending on circumstances. Any extra costs that fell to the project company would be assessed and scrutinised by the Regulator or independent technical assessor. In limited circumstances, such costs could be entirely excluded from the RAB (e.g. where the costs were not justified by accounts and records or arose due to fraud or gross negligence or imposed by fine). Otherwise, under the ex ante model, cost overruns that fell to the project company would ultimately be shared between investors and consumers (through their suppliers).

The precise ratio of risk sharing would be subject to calibration when the ERR was set for a particular project.

Other project risks

43. Construction cost risk is one of the main risks associated with a new nuclear project. However, there are a number of other risks in a new nuclear project, some of which apply to any infrastructure project. Examples include financing costs (e.g. risk of a rise in interest rates), performance risk (e.g. risk that the plant generates less electricity than expected), regulatory risk (e.g. change in safety standards) and 'end-of-asset-life risk' (e.g. changes in the cost of decommissioning). Other than those risks of the kind identified in paragraph 28, to be protected by a GSP, the allocation of the above risks between consumers (through suppliers) and investors could be determined and calibrated on a project specific basis.

44. It is likely that, in line with existing economic regulatory practice in networks, a risk that investors were unable to control would in most cases sit with consumers, but where investors could control a risk, they would be incentivised as far as possible to minimise that risk.

Cost of capital and yield to investors

45. Generally, the WACC for RAB assets is determined administratively by the relevant economic regulator through benchmarking of the cost of capital based on their specific sector knowledge. However, the TTT project took a different approach and used a competition between capital providers to set the initial WACC, to apply during the construction phase and the early years of the operating phase. The WACC for TTT will then be re-set by Ofwat (The economic regulator of the water sector in England and Wales) at regular intervals during the operating phase. A mechanism to set the WACC competitively might also be an appropriate approach for a nuclear RAB model but would need further consideration, given the amount of capital required to finance a new nuclear project.

46. Regardless of the approach taken, the intention would be to establish a WACC that was the minimum needed to raise sufficient capital for the project, so as to keep the overall cost to suppliers and their consumers as low as possible.

47. It is expected that the ERR and GSP could enable a return to investors to be paid out on a regular basis, including during the construction phase. This would:

    a) enable the project to attract the capital required from, for example pension and insurance funds (who need to ensure that assets match liabilities), and

    b) reduce overall cost to suppliers and their consumers by reducing the total amount of finance required to be raised (by avoiding the compounding of interest and equity returns).

48. Returns to shareholders would likely be capped during construction to incentivise project performance, and we would need to consider whether they should be suspended during a delay / cost overrun scenario.

Electricity consumers

49. As described in the Introduction, delivering net zero while maintaining security of supply and keeping costs low is likely to require a significant amount of firm low carbon power, such as nuclear, as part of a diverse generation mix. The cost of electricity to consumers is made up of several components aside from costs of building and operating power plants,

including the networks that transport electricity from where it is generated to where it is used, and the cost of ensuring that reliable electricity is available at all times. This means that it is not possible to work out the cheapest overall system simply by comparing the costs of different generation types – it is necessary to model all the elements of the system under a range of different scenarios to understand what generation mixes are likely to be lowest cost.

50. The cost to consumers and taxpayers of a nuclear project is affected by the cost of building (i.e. the ‘overnight’ capital cost) and operating the project, and the cost of financing the project (i.e. the WACC). Reducing these costs is important in ensuring a minimised overall cost to consumers.

51. As set out in the Introduction (see paragraphs 1–19), industry and Government committed in the Nuclear Sector Deal to seek to drive down construction costs, and the nuclear RAB model would be intended to reduce the cost of financing nuclear projects.

52. The final WACC achieved for a new nuclear project under a nuclear RAB model would be determined at financial close (see paragraphs 45-48). It would depend on various factors such as market conditions at the time (e.g. the cost of debt), alternative investment opportunities for investors, the quality of the project itself and the risk sharing arrangements under a RAB model, including the terms of the ERR and GSP. However, we believe it is likely that a RAB model would allow a significant reduction in WACC to be achieved, due to the reduction in risks to which investors would be exposed.

53. The RAB would also reduce overall financing costs through the payment of Allowable Revenues during construction (see paragraph 38), which should further reduce consumer bills.

54. As these reductions would be achieved by sharing risks with consumers and taxpayers, it would be important we take the probability and impact of these risks into account when assessing value for money.

55. Our initial view, consistent with NAO analysis in their report on Hinkley Point C[26], is that a nuclear RAB model has the potential to significantly reduce the £/MWh price and that these consumer savings would be robust to significant cost overruns or construction delays[27]. A detailed value for money assessment (see paragraph 74), factoring in the probability and impact of different potential outturn scenarios, would be carried out prior to any decision to grant a RAB licence and GSP to a specific project.

56. It would also be crucial to minimise the likelihood of risks materialising. We would envisage this being done by:

    a) Subjecting proposed new nuclear projects to a robust assessment through a structured diligence process (paragraphs 70-73) before the granting of a nuclear RAB licence and GSP.

    b) Placing strong incentives on investors through the ERR to build the plant on time and to budget and to operate it efficiently. The Regulator would play a key role in protecting the interests of consumers throughout the regulated life of the plant.

[26] https://www.nao.org.uk/report/hinkley-point-c/
[27] NAO found that for a project with a WACC of 6% (nominal), costs could overrun by between 75% - 100% before consumers costs would be equivalent to that of a project with a WACC of 9% (nominal).

c) Ensuring that appropriate risk was taken by the contractors supplying equipment and services to the project company under the key project contracts.

Role of the Regulator

57. The Regulator would be responsible for economically regulating a new nuclear project.

58. We currently consider that the Regulator should have responsibility for protecting the interests of consumers, whilst having regard to the ability of the project company to finance the project i.e. construction and operation of the plant.

59. Several regulatory functions would interface in the operation of a nuclear RAB model, including environmental, safety and security regulation as well as the economic regulation discussed here. The Regulator would work with the Environment Agencies and the Office for Nuclear Regulation (ONR, the safety and security regulator for the nuclear industry in the UK) to ensure that safety and environmental protection were paramount in decision making. The intention would be to draw on existing experience of cooperation between economic, safety and environmental regulators in other regulated businesses, whilst also taking account of any considerations specific to the nuclear sector. Each regulator would retain its complete statutory independence.

60. No entity currently carries out the role of Regulator in the nuclear sector, and so a new body or existing entity would need to be appointed to carry out this role. This entity would need to build capability to effectively fulfil the remit, and to gain consumer, supplier and investor confidence in the expertise and independence of the entity. We anticipate that Government, the Regulator and other relevant regulators would need to work closely together as their respective functions were established.

Consultation Questions

Question 1: Have we identified a model which could raise capital to build a new nuclear power station and deliver value for money for consumers and taxpayers?

Question 2: Do you have any comments on the components of the Economic Regulatory Regime as described?

Question 3: Do you have views on how consumer interests are protected under the proposed approach? What else should be considered to protect consumer interests?

Question 4: Do you agree that consumer risk sharing could be value for money for consumers if it achieves a lower expected overall cost for consumers compared to a Contract for Difference model?

Revenue stream

61. Whilst the regulatory regime would set the amount of Allowed Revenue that a new nuclear project could charge, a nuclear RAB model would need a route for funding to flow from suppliers to the project company – a **'revenue stream'**. We would expect suppliers to decide how best to reflect these costs in their consumer tariffs.

62. There are important differences between existing revenue streams and the characteristics of a nuclear RAB model that could require a bespoke revenue stream:

    a) under a nuclear RAB model, revenue would likely be channelled to the project company in both the construction and operational period; and

    b) a nuclear RAB model would entail a variable £/MWh price (calculated by reference to the Allowed Revenue from time to time) allowing for the revenue stream to be adjusted by the Regulator as circumstances change. This is different to the CfD where the "strike price" is fixed.

Design considerations for a revenue stream

63. We think that a revenue stream for a nuclear RAB model would likely need to:

    a) give investors confidence that the revenue stream was a reliable way to channel funding so that the project company is able at all times to meet its financing, construction and operating costs;

    b) take account of how current electricity markets function (both the retail and wholesale markets) and how they might change in the future;

    c) ensure that those who make payments for a new nuclear project should directly benefit from doing so;

    d) avoid significant fluctuations to the revenue stream; and

    e) incentivise the project company to respond to appropriate price signals in the market.

64. In order to achieve these objectives, one way that the revenue stream could be designed would be as follows:

    a) An intermediary body collects payment from suppliers and passes this onto the project company.

    b) In *construction*, the project company is not yet selling power into the wholesale market and therefore participating suppliers are charged their share of the **total** Allowed Revenue, according to their share of the market at that time.

    c) In *operation*, the project company sells its power into the wholesale market, and suppliers are charged their share of the Allowed Revenue minus the revenue the project company would expect to receive if power was sold in the wholesale market at a specified reference price.

d) The difference payment could be based on generation output, as is the case under CfDs for renewables and HPC; however, alternative models (e.g. payment based on availability such as the one adopted in the Capacity Market) would be considered as part of the design process.

e) Suppliers could pass the cost of the payment obligation onto their consumers, as they do with other regulated costs and could likewise reimburse their consumers (as happens under a CfD) in periods where suppliers receive payments from the project company (e.g. when the Allowed Revenue is lower than the project company's revenue from power sales). The design process would need to consider how these charges could be made in more detail, in consultation with suppliers and consumer representatives.

f) The mechanism to determine a participating supplier's proportion of the charge would need to be decided. Ofgem's Targeted Charging Review[28] would likely be considered as part of the design process.

g) It is likely that the project company would need credit arrangements to be in place to ensure the revenue stream was a reliable means of channelling funding.

h) The project company should be incentivised to behave commercially during operation and maximise its market revenues, including being incentivised to respond to the pattern of energy demand (for example carrying out refuelling and planned maintenance in low-demand periods).

Intermediary body

65. If a version of the model described above were to be used, a revenue stream would need an intermediary body to charge and collect payment from suppliers, and to pass this onto the project company. Both suppliers and the project company would need to have confidence that the organisation which took on this function had the capability to do so effectively.

66. This would likely mean that, as a minimum, an intermediary body would need to be able to carry out the following activities:

    a) billing and settlement with suppliers and the project company;

    b) forecasting of supplier payment obligations in advance of payment, to allow for suppliers to reflect these costs appropriately in their consumer tariffs; and

    c) implementation of appropriate credit support/collateral mechanisms.

67. It is not currently envisaged that the intermediary body would play the role of Regulator or exercise any regulatory or contractual authority over the project company.

68. Given its importance to the effectiveness of the revenue stream, it is likely that an intermediary body would be expected to have the following characteristics:

[28] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/targeted-charging-review-significant-code-review

a) be insolvency-remote (and there would be mechanisms in place to swiftly replace the intermediary in the unlikely event of its insolvency);

b) have credibility with market participants and investors;

c) have the capacity and capability to carry out the required activities;

d) be able to access the data required to carry out its billing, settlement and forecasting functions; and

e) be fully compliant with the relevant Financial Conduct Authority (FCA) rules and guidance.

69. Following our analysis of responses to this consultation, should we decide to proceed with introducing a nuclear RAB model, we would continue to work though the design considerations of the revenue stream. We would envisage revisiting revenue arrangements on a project by project basis.

Consultation Question

Question 5: Do you have views on the potential way to design a revenue stream for a nuclear RAB model that we describe, and are there alternative models we should consider?

A nuclear RAB assessment process

70. It would be important for the Regulator and Government to carry out a robust process of structured diligence to assess whether a new nuclear project should be granted a nuclear RAB licence and GSP. This would help to ensure that project risks were fully understood, limited and minimised. Equally, taking a structured approach to the project assessment would be valuable for potential developers who felt their project was appropriate to be considered for a nuclear RAB.

71. The assessment framework would need to draw together the activities of the Regulator, Government and the project company into a consistent and coherent process. These activities would be specific to the granting of a nuclear RAB licence and associated GSP and would remain separate from other regulatory processes such as the Development Consent Order (DCO)[29] and granting of the Nuclear Site Licence (NSL)[30]. That said, we would expect the granting of a nuclear RAB licence to be informed by the granting of, or substantive progress towards, the DCO and NSL.

72. The framework could be structured over a number of key 'decision gates' at which point Government and the Regulator would consider whether they had sufficient confidence in a project to allow it to proceed to the next stage. For a decision granting the project a nuclear RAB licence, and for the Government to agree to contractual provisions for a GSP, a project would need to have successfully passed through the relevant decision gate(s).

73. Such an assessment framework would allow Government and the Regulator to:

    a) assess the deliverability of a project and its applicability to be granted a nuclear RAB licence and GSP;

    b) assess project risk in order to calibrate the ERR incentive regime and GSP appropriately, ensuring that, for each new nuclear project, the right balance was being struck between financeability and consumer/taxpayer protection;

    c) assess the value for money of a project to consumers and taxpayers (see below);

    d) assess broader strategic and societal considerations; and

    e) make the grant of a nuclear RAB licence and GSP conditional on a demonstration that the project was amongst other things, value for money, compatible with applicable State aid rules and following industry best practice in areas such as engineering, project management, governance arrangements etc.

[29] https://infrastructure.planninginspectorate.gov.uk/application-process/the-process/
[30] http://www.onr.org.uk/licensing.htm

Value for money assessment

74. We envisage that new nuclear projects would not be granted a nuclear RAB licence or GSP unless they could be shown, at the time the licence was granted and GSP signed, to offer value for money for consumers and taxpayers. When assessing value for money of new nuclear projects, Government would be focussed in particular on whether the project was expected to contribute to the target of net zero emissions by 2050 and deliver security of supply, at a lower total electricity system cost for consumers than alternatives without the project. It is currently envisaged that the value for money test would take into account:

    a) the cost of the project, having regard to safety and environment protection and risk transfer to suppliers (and, therefore, their consumers) and to taxpayers;

    b) overall cost of the electricity system to consumers over time under different scenarios (including with and without the plant);

    c) wider benefits, specific to the project, which would influence a decision as to whether, on balance, proceeding was in the interests of consumers and taxpayers.

Consultation Question

Question 6: Do you have views on our proposed approach to assessing a new nuclear project under a nuclear RAB model and determining whether it is value for money for consumers and taxpayers?

Next steps

75. The consultation period will last for 12 weeks and close on 14 October 2019.

76. We will be engaging with interested stakeholders during the 12 week consultation period so that we can capture a range of views on the principles of a RAB model and its applicability to finance future new nuclear projects, alongside the existing CfD model.

77. Following our analysis of responses, should we decide to proceed with introducing a RAB model to facilitate delivery of new nuclear projects, there could be further consultations on the specific design features of a nuclear RAB model.

Annex 1: Consultation questions

Question 1: Have we identified a model which could raise capital to build a new nuclear power station and deliver value for money for consumers and taxpayers?

Question 2: Do you have any comments on the components of the Economic Regulatory Regime as described?

Question 3: Do you have views on how consumer interests are protected under the proposed approach? What else should be considered to protect consumer interests?

Question 4: Do you agree that consumer risk sharing could be value for money for consumers if it achieves a lower expected overall cost for consumers compared to a Contract for Difference model?

Question 5: Do you have views on the potential way to design the revenue stream for a nuclear RAB model that we describe, and are there alternative models we should consider?

Question 6: Do you have views on our proposed approach to assessing a new nuclear project under a nuclear RAB model and determining whether it is value for money for consumers and taxpayers?

Annex 2: Glossary

Defined Term	Definition
Allowed Revenue	A regulated revenue amount (in £) which the project company would be entitled to receive under its economic licence in return for constructing and operating a nuclear power plant.
Baseline	The baseline project capex costs set for the purposes of establishing regulatory incentives under the ERR.
Capacity Market	A market-based mechanism that incentivises reliable generating capacity to be available to ensure security of electricity supply.
Capex	Capital Expenditure.
CCUS	Carbon Capture, Usage and Storage
CfD	Contract for Difference.
CGN	China General Nuclear Power Group.
Consumers	The consumers in the UK who receive electricity from energy suppliers.
Cost of capital	Cost of finance, being the return that investors (equity and debt) expect for providing capital to a company
DCO	Development Consent Order. A statutory instrument granted by the Secretary of State to authorise the construction and development of a Nationally Significant Infrastructure Project, such as a new nuclear power plant.
Depreciation	The allocation of the cost of assets to periods in which the assets are used.
EDF	Électricité de France
ERR	Economic Regulatory Regime. This is the regime that would be put in place for economic regulation of the nuclear power plant.
EPR	A third-generation pressurised water nuclear reactor.
FDP	Funded Decommissioning Programme. A programme which makes financial provision for the costs of decommissioning, waste management and disposal associated with a new nuclear project.
Funding Cap	A threshold capital expenditure amount, set at a level such that there was only a remote chance of construction costs reaching this level
GDA	Generic Design Assessment. An assessment process that allows the Environment Agency and Office for Nuclear Regulation to scrutinise new nuclear power stations before they are built.
GSP	Government Support Package.
Horizon	Horizon Nuclear Power. A UK nuclear energy company and a subsidiary of Hitachi Ltd.
HPC	Hinkley Point C nuclear power plant currently under construction in Somerset.
MW	Megawatt (1,000,000 Watts)
MWh	A MW of electricity used for an hour.

NAO	The National Audit Office
Negative emissions technology	Technology that removes emissions, such as Biomass carbon capture and storage.
Net Zero	The commitment by the Government to legislate to reduce greenhouse gas emissions to net (i.e. including the use of negative emissions technology) zero by 2050.
NSL	Nuclear Site Licence
Nuclear Sector Deal	A Sector Deal set-up between the Government and the nuclear industry, published in 2018 as part of the Industrial Strategy.
Ofgem	The Office of Gas and Electricity Markets. The regulator for gas and electricity markets in the UK.
Ofgem's Targeted Charging Review	Ofgem review into the way in which costs of the network used to transport electricity to homes, public organisations and businesses are recovered.
ONR	The Office for Nuclear Regulation. The safety regulator for the nuclear industry in the UK.
RAB	Regulated Asset Base. The total cumulative capital expenditure as incurred and approved as being efficient by the Regulator.
RAB model	A type of economic regulation typically used in the UK for monopoly infrastructure assets such as water, gas and electricity networks, the application of which to nuclear power plants is considered in this consultation.
Revenue Stream	A route for funds to be raised from energy suppliers (and indirectly their consumers) to support new nuclear projects, with the amount set through the ERR, during both the construction and operational phases
Regulator	The economic regulator of a project company under a RAB model.
RIIO-1	Revenue + Incentives + Innovation + Outputs. The network price controls set by Ofgem.
TTT	Thames Tideway Tunnel project
WACC	Weighted Average Cost of Capital
Wholesale Market	The UK wholesale electricity market, where electricity is traded between suppliers, generators, traders and customers.
Wylfa Project	The proposed new nuclear power plant at Wylfa Newydd, in Anglesey, North Wales.

This consultation is available from: www.gov.uk/government/consultations/regulated-asset-base-rab-model-for-nuclear

Department for
Business, Energy
& Industrial Strategy

BUSINESS MODELS FOR CARBON CAPTURE, USAGE AND STORAGE

A consultation seeking views on potential business models for carbon capture, usage and storage

Closing date: 16 September 2019

July 2019

Contents

General information

Why we are consulting

The purpose of this consultation is to set out the emerging findings from our work on possible new business models for carbon capture, usage and storage (CCUS), and to seek views from stakeholders.

Consultation details

Issued: Monday 22 July 2019

Respond by: Monday 16 September 2019

Enquiries to:

ccusbusinessmodelsconsultation@beis.gov.uk

or

Carbon Capture Usage and Storage Policy Team

Department for Business, Energy and Industrial Strategy

3rd floor, Spur

1 Victoria Street

London

SW1H 0ET

Consultation reference: Consultation on business models for carbon capture, usage and storage (CCUS).

Territorial extent:

This consultation applies to the energy markets in Great Britain. Responsibility for energy markets in Northern Ireland lies with the Northern Ireland Executive's Department for the Economy.

With regard to industrial carbon capture, depending on the specific industrial process in question, some matters covered by this consultation may be devolved to Scotland, Wales and Northern Ireland. In general however, we anticipate that the incentive mechanism will apply to the relevant sectors in the whole of the UK.

How to respond

Your response will be most useful if it is framed in direct response to the questions posed, and with evidence in support wherever possible. Further comments and wider evidence are also welcome. When responding, please state whether you are responding as an individual or representing the views of an organisation.

We encourage respondents to make use of the online e-consultation wherever possible when submitting responses as this is the Government's preferred method of receiving responses. However, responses in writing or via email will also be accepted. Should you wish to submit your main response via the e-consultation platform and provide supporting information via hard copy or email, please be clear that this is part of the same consultation response.

Respond online at: https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-ccus-business-models

Email to: ccusbusinessmodelsconsultation@beis.gov.uk

Write to:

Carbon Capture Usage and Storage Policy Team
Department for Business, Energy and Industrial Strategy
3rd floor, Spur
1 Victoria Street
London
SW1H 0ET

Confidentiality and data protection

Information you provide in response to this consultation, including personal information, may be disclosed in accordance with UK legislation (the Freedom of Information Act 2000, the Data Protection Act 2018 and the Environmental Information Regulations 2004).

If you want the information that you provide to be treated as confidential please tell us, but be aware that we cannot guarantee confidentiality in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not be regarded by us as a confidentiality request.

We will process your personal data in accordance with all applicable data protection laws. See our privacy policy.

We will summarise all responses and publish this summary on GOV.UK. The summary will include a list of names or organisations that responded, but not people's personal names, addresses or other contact details.

Quality assurance

This consultation has been carried out in accordance with the government's consultation principles. If you have any complaints about the way this consultation has been conducted, please email: beis.bru@beis.gov.uk.

List of consultation questions

Consultation questions	
Introduction – overarching questions	
1	Have we identified the right parameters to guide the development of CCUS business models?
2	Bearing in mind our emerging findings on CCUS business models, do you have any views at this stage on how the business models might be integrated?
CCUS-specific risks	
3	Do you have proposals to mitigate CCUS-specific risks?
4	Are there any other CCUS-specific risks that need to be considered? If so, what are your proposals for mitigating them?
Carbon dioxide transport and storage (T&S)	
5	Have we identified the most important challenges in considering the development of CO_2 networks?
6	Do you agree that a T&S fee is an important consideration for any CO_2 T&S network? In your view, what is the optimal approach to setting the T&S fee?
7	Of the models we have considered for CO_2 T&S, do you have a preference, and why?
8	Are there any models that we have not considered in this consultation which you think should be taken forward for CO_2 T&S, and why?
Power CCUS	
9	Have we identified the most important challenges in considering the development of CCUS power projects?
10	Of the models we have considered for power CCUS, do you have a preference, and why?
11	In your view, should any potential funding model(s) be applicable across all power CCUS technologies (including but not necessarily limited to CCGT with post-combustion capture, BECCS, and pre-combustion capture or hydrogen turbines)?
12	Are there any models that we have not considered in this consultation which you think should be taken forward for power CCUS, and why?
Industry CCUS	
13	Have we considered the most important challenges in considering the development of CCUS for industry?
14	Of the models we have considered for industry CCUS, do you have a preference, and why?

15	Are there any other models that we have not considered in this consultation which you think should be taken forward for industry CCUS, and why?
16	In your view, are there any models which best work across all industrial sectors where CCUS could have a role to play?
17	What actions should Government and industry take to help establish demand for low-carbon industrial products?
CCUS for hydrogen production	
18	Do you agree that a future business model should focus on hydrogen production costs? If not, what are the benefits of considering other parts of the hydrogen value chain in the next phase of our work?
19	Do you have views on whether the model should seek to support both CCUS-enabled hydrogen production and renewable production methods? If so, how might this work?
20	Have we identified the most important challenges in considering the development of a business model for hydrogen production?
21	What reflections do you have on the approaches we have identified to address the main challenges in designing the model?
22	Do you have views on which business models we should evaluate in the next phase of our work?
Delivery capability	
23	What capabilities are needed for the delivery of CCUS in the UK?

Introduction

Context

There is global consensus that carbon capture usage and storage (CCUS) will be essential to successfully tackling climate change and meeting the ambitions of the Paris Agreement. The UK sees an opportunity to become a global leader in CCUS and create significant new opportunities for UK business domestically and globally.

Domestically, CCUS is likely to play an essential role in meeting our net zero target, as was outlined recently by the Committee on Climate Change, which described carbon capture and storage as "a necessity, not an option."[1]

This is because CCUS can play a critical role across the UK economy, helping to decarbonise industry; generate low carbon power; and enable the production of low carbon hydrogen at scale, which can enable decarbonisation across the energy system. CCUS can also provide a pathway towards the development of bioenergy (BECCS) and Direct Air Capture and Carbon Storage (DACCS), key technologies in the delivery of greenhouse gas removals or GGRs (which are also referred to as negative emissions).

CCUS is likely to be vital to the low carbon transformation of the UK's industrial base and the Government's Industrial Clusters Mission, announced at COP24 in December 2018, which sets out the ambition to establish the world's first net-zero carbon industrial cluster by 2040, and at least one low-carbon cluster by 2030.

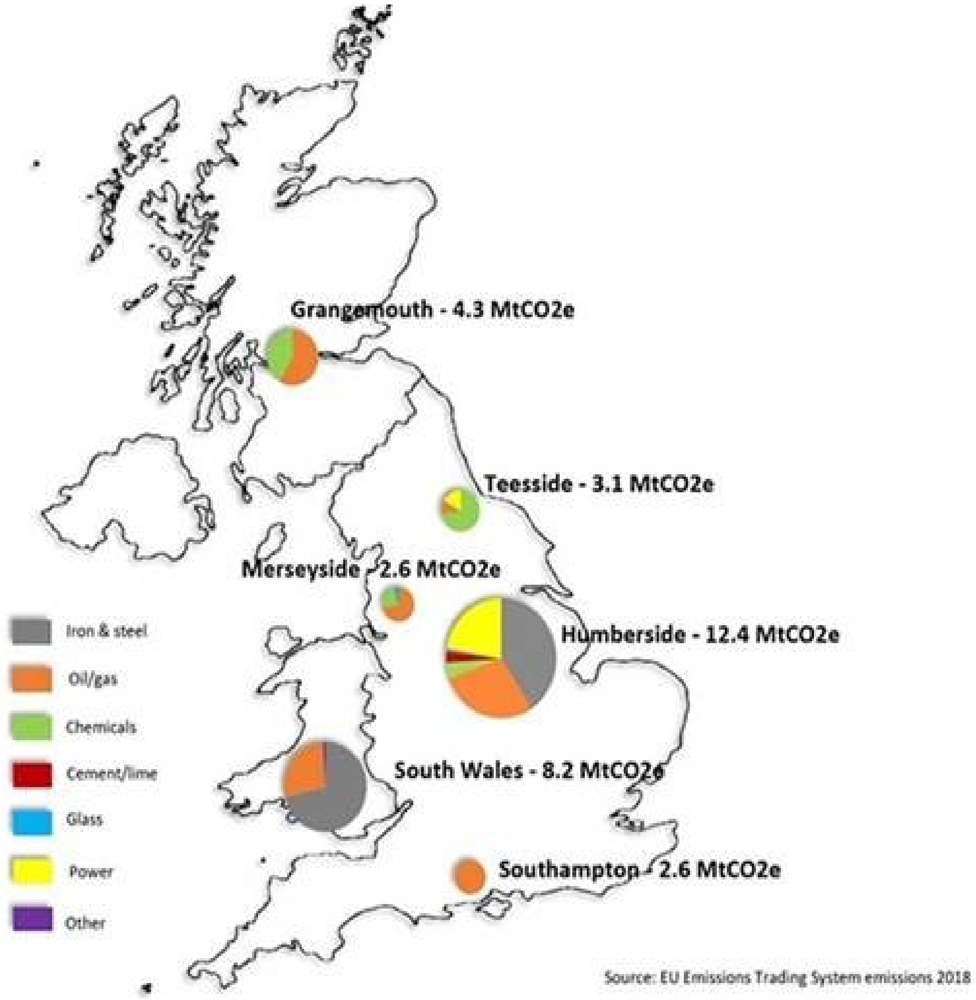
This is important as energy intensive industries have a value of around £160 billion to the UK economy (GVA), secure around 1.7 million jobs, and export goods and services worth approximately £332 billion.[2] However, industry also currently accounts for around one quarter of UK emissions, with more than two thirds of industrial emissions coming from a small number of energy intensive industries.[3] CCUS could help strengthen the long-term competitiveness of the UK's industrial regions, in Scotland, South Wales, Humberside, Merseyside and Teesside.

[1] Committee on Climate Change, Net Zero – the UK's contribution to stopping global warming, May 2019, https://www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/

[2] Office for National Statistics, Annual Business Survey 2017, https://www.ons.gov.uk/businessindustryandtrade/business/businessservices/bulletins/uknonfinancialbusinesseconomy/previousreleases

[3] Office for National Statistics, Annual Business Survey 2018, https://www.ons.gov.uk/businessindustryandtrade/business/businessservices/bulletins/uknonfinancialbusinesseconomy/previousreleases

Figure 1: Largest industrial clusters by emissions



CCUS opportunities

The development of CCUS provides an opportunity for the UK to develop a domestic supply chain, utilising the expertise of our existing oil and gas industry and new UK-based innovative carbon capture technologies.

We are in a strong position to grasp the opportunities from becoming a global technology leader on CCUS. Deployment of CCUS could create new markets for UK businesses both domestically and internationally. For example, CCUS exports could potentially be worth multiple billions of pounds per year for the UK in 2050, particularly in engineering, procurement and construction services, helping to support tens of thousands of jobs.

With the potential to store more than 78 billion tonnes of carbon dioxide (CO_2)[4], the UK can be a world leader in CO_2 storage services. In addition, innovative companies across the UK are developing cutting edge CCUS technologies; there are world leading academic institutions in the UK focused on driving cost reductions; and our existing industries have the skills and capability required to deploy CCUS at scale.

Innovation case study: C-Capture at Drax

C-Capture is a Leeds University spin-out technology company developing chemical-based systems to remove carbon dioxide from power plants, steel works, and cement factories, supported by £2.2m funding from the UK Government.

C-Capture is working with Drax Power Station in North Yorkshire on a Bioenergy Carbon Capture and Storage pilot plant, which will remove carbon dioxide from emissions produced by generating electricity from sustainable biomass.

If the pilot project is successful, Drax could become one of the world's first negative emissions power stations - meaning the electricity it produces would help reduce the amount of carbon dioxide in the atmosphere. The project is the first of its kind in Europe.

The UK Carbon Capture Usage and Storage deployment pathway: An Action Plan

The Clean Growth Strategy established an ambition to have the option to deploy CCUS at scale during the 2030s, subject to the costs coming down sufficiently. As a vital first step to meeting this ambition, the CCUS Action Plan is designed to enable the UK's first CCUS facility to be commissioned from the mid-2020s.

Commissioning the UK's first CCUS facility from the mid-2020s will help establish our domestic supply chain and capabilities, enabling deployment to be ramped up in the 2030s and keeping the UK on a low cost pathway to net zero.

This will also support a cost reduction trajectory, allowing the UK to take advantage of the cost reductions already seen in CCUS since 2015. Important to this will be the implementation of business models that can unlock investment across a broad range of investors and support cost reductions.

[4] Energy Technologies Institute LLP, Taking stock of UK CO_2 Storage, 2017, https://www.eti.co.uk/insights/taking-stock-of-uk-CO2-storage

Government support for CCUS

Innovation

The Government announced over £50 million of innovation funding in 2018, to drive down the cost of CCUS and support the development of the technology. This includes:

- A £20 million CCU Demonstration Programme to fund design and construction of CCU demonstration plants in the UK, including £4.2 million to support a CCU plant at Tata Chemicals in North West England;
- A £24 million CCUS Call for Innovation, supporting a new CCUS international testing centre near Rotherham and supporting engineering studies and planning for projects in Scotland, Yorkshire, Merseyside and Teesside;
- £6.5 million of UK funding to the second international call of the Accelerating Carbon Technologies research programme, a €30 million fund supporting CCUS research across 11 countries that can lead to safe and cost-effective development of CCUS technology.

We are investing up to £108m in a range of innovation programmes to explore and develop the potential of hydrogen:

- A £20m Hydrogen Supply programme to reduce the costs of bulk low carbon hydrogen production;
- A £20m Fuel Switching Competition to support the switch to lower carbon fuels in industry, including hydrogen;
- A £20m Storage at scale competition to demonstrate large scale energy storage, including power-to-gas;
- A £23m Hydrogen for Transport programme to support deployment of hydrogen vehicles and growth of refuelling infrastructure; and
- A £25m Hy4Heat programme to ensure the safe use of 100% hydrogen in buildings.

International collaboration

We have developed new partnerships with other leading countries on CCUS:

- The UK brought together 50 world energy leaders, with the International Energy Agency, for the world's first dedicated CCUS Summit in November 2018.
- We are co-leading the CCUS initiatives under Mission Innovation and the Clean Energy Ministerial and strengthening our bilateral work on CCUS with countries including Norway, Japan, Saudi Arabia and the United States.
- We are the largest donor of Official Development Assistance on CCUS globally, providing £70 million since 2012 to support CCUS activities in emerging and developing countries including Indonesia, Mexico and South Africa.
- There is an increasing international focus on the role of low carbon and renewable hydrogen in meeting the Paris Agreement. The UK is an active participant across a range of international initiatives.

Review of CCUS Delivery and Investment Frameworks

The CCUS Cost Challenge Taskforce identified the need for a long-term supportive policy environment and viable business models to support the delivery of CCUS. In the CCUS Action Plan, the Government confirmed it will undertake a review of CCUS Delivery and Investment Frameworks, working closely with industry, to identify the parameters for investable commercial models and establish market-based frameworks for bringing forward CCUS.

Since the publication of the Action Plan, we have been working with industry through groups such as the CCUS Advisory Group (CAG). This has helped develop our understanding of the challenges and barriers to deploying CCUS in the UK. Our discussions have been wide ranging, covering such matters as cost structures, risk sharing arrangements and market mechanisms which will take full advantage of innovation and competition.

The CCUS Advisory Group (CAG)

The CCUS Advisory Group (CAG) is an industry-led group considering the critical challenges that face CCUS, and providing insight into potential solutions. The CAG brings together experts from across the CCUS industry, finance and legal.

The CAG has examined a range of business models focusing on industrial CCUS, power production, CO_2 transport and storage, and hydrogen production. It has considered how the proposed business models interact, in order to minimise issues such as cross-chain risk, and has considered issues such as delivery capability.

The CAG's Final Report, Investment Frameworks for Development of CCUS in the UK, can be read in full at the following link: http://www.ccsassociation.org/ccus-advisory-group.

We are grateful to the members of the CAG for their work.

Through this ongoing work we are seeking to better understand the critical deployment challenges, focusing on CCUS for industry; CCUS for power; and CO_2 transport and storage infrastructure. More broadly we are seeking to understand how a core set of CCUS specific cross-cutting risks which have been presented as an intractable problem for some previous CCUS projects might best be mitigated through the development of appropriate business models.

We have also begun to explore business models for low carbon hydrogen production, recognising the increased focus on the potential role of hydrogen in meeting net zero. This thinking is at an earlier stage than the rest of the CCUS landscape, and through this consultation we seek to develop a shared understanding of the challenges that a model needs to address, and a framework for evaluation of specific models in the next phase of our work.

The Government does not have a preference at this stage on which business models to take forward. The purpose of this consultation is to gather a range of views and evidence – both on the models explored in detail in this consultation, as well as on any other business models which respondents think are viable.

To help frame our considerations of business models we have established a number of parameters, outlined in the table below. These parameters are aligned with the principles for the power sector, set out by the Secretary of State for Business, Energy and Industrial Strategy in November 2018.[5]

The parameters are not designed to be prescriptive; we recognise that there may be trade-offs, and an appropriate business model may not accord with every parameter. However, we would like those responding to this consultation to consider these when answering the questions we have posed.

Overarching parameters to guide the development of CCUS business models:

- The models should be market based and incentivise CCUS to **provide value to the economy.** They should drive decarbonisation and be compatible with market operation and existing market frameworks.
- The design of the models **should instil confidence among investors** and should attract innovation and new entrants to the market.
- The models should be **cost efficient** – providing value for money for taxpayers and bill payers, driving cost reductions and attracting new investment.
- There should be **appropriate and fair cost sharing** between the Government and CCUS developers, being mindful of impacts on taxpayers and bill payers.
- There should be an **appropriate allocation of risk** between the Government and CCUS developers, that evolves as the CCUS industry matures.
- The models should have the **potential to become subsidy free**.

Next steps

The purpose of this consultation is to seek a broad range of views on the emerging findings from the ongoing Review of CCUS Delivery and Investment Frameworks. We will use responses to this consultation to help us progress and complete the Review. The consultation will allow us to move to considering the detailed implementation of preferred business models, including issues such as liabilities on Government, public finance considerations, State aid and the regulatory framework that business models might operate under. The consultation will also provide evidence for the next phase of our work on low carbon hydrogen production.

As part of our further work we will consider the interaction with the development of GGRs, including whether a separate business model is required to support GGR deployment.

As we progress this work on business models for CCUS, a key consideration will be the integration of the business models and their interactions with each other and other markets.

[5] Speech by the Secretary of State for Business, Energy and Industrial Strategy: *After the trilemma: Four principles for the power sector*, 15 November 2018: https://www.gov.uk/government/speeches/after-the-trilemma-4-principles-for-the-power-sector

Overarching consultation questions

1. **Have we identified the right parameters to guide the development of CCUS business models?**

2. **Bearing in mind our emerging findings on CCUS business models, do you have any views at this stage on how the business models might be integrated?**

Chapter 1: CCUS-specific risks

Overview

As set out in the introductory chapter of this consultation, the benefits and opportunities of CCUS are widely acknowledged. However, as a first of a kind technology, there are likely to be CCUS-specific risks that can have an impact on both the cost of CCUS and whether positive final investment decisions can be made on projects. Ignoring or not taking account of these risks when considering the design of business models may result in the models not delivering the intended outcomes.

For example, the Public Accounts Committee concluded that the Government did not allocate the risks appropriately between Government and developers in the previous CCS Competition.[6] The Committee highlighted "full chain" risk, which created problems for sharing risks between investors in different parts of a CCS project. It recommended that the Government should test at the outset which risks the private sector could feasibly bear.

Similarly, the National Audit Office (NAO) highlighted that many CCUS stakeholders think the Government should bear more risk, particularly over stored CO_2, for CCUS to be built in the UK. [7] The National Audit Office concluded that the Government taking a greater share of the risk could reduce delivery costs, as developers and investors require lower returns when they carry less risk, but the NAO noted this would expose taxpayers to losses in the event of risks materialising.

The Cost Challenge Taskforce sought to identify "the irreducible core of CCUS specific risks", defined as low probability but high impact risks which the private sector, at least initially, cannot price or take, or where the risk premium attached to them may increase the costs of CCUS projects.[8] These risks need to be appropriately managed and allocated in order to initially deploy CCUS in the UK. The Taskforce also reported that as finance and insurance markets mature, alongside the CCUS industry, some of these risks may reduce or disappear, so any risk that the Government might bear would reduce as the industry evolves.

The irreducible core set of risks identified include CO_2-related cross-chain risk, stranded asset risk, and insurability of CO_2 storage liability, given the risk (albeit very low) of CO_2 leakage and the lack of an insurance market to cover the specific CO_2 leakage risks.

As part of the Review, we have assessed previous evidence and worked with industry including through the CAG, to consider CCUS-specific risks in more detail, as well as options for mitigating them.

CCUS-specific risk 1: mitigating CO_2-related cross-chain risks (CO_2 T&S assets not operating, or capture plant not operating)

[6] House of Commons Committee of Public Accounts, Carbon Capture and Storage, 24 April 2017, https://www.parliament.uk/business/committees/committees-a-z/commons-select/public-accounts-committee/inquiries/parliament-2015/carbon-capture-storage-16-17/
[7] National Audit Office, Carbon Capture and Storage: the Second Competition for Government Support, 20 January 2017, https://www.nao.org.uk/report/carbon-capture-and-storage-the-second-competition-for-government-support/
[8] CCUS Cost Challenge Taskforce, Delivering Clean Growth: CCUS Cost Challenge Taskforce Report, 19 July 2018, https://www.gov.uk/government/publications/delivering-clean-growth-ccus-cost-challenge-taskforce-report

Cross-chain risks are associated either with CO_2 transport and storage (T&S) assets not operating, or the capture plant not operating, with implications for other users of the network.

CO_2 T&S assets could become unavailable either in the transport segment of the chain, or in storage, and the duration of the assets' unavailability could vary.

Equally, a capture plant could fail to deliver CO_2 to a CO_2 T&S developer for a number of reasons, including for example, an unexpected outage in the capture plant or an unexpected issue with the capture technology.

The potential impact of the risk of these sorts of events occurring is an increased pricing of risk on both the CO_2 T&S asset and the carbon capture asset, where developers are concerned about the impact on their revenue of the unavailability of one asset. While this is less of an issue for "full-chain projects" where one entity is the developer of the capture plant and of the CO_2 T&S asset, this risk may become more pronounced when operating a CCUS cluster.

CCUS-specific risk 2: stranded asset risk

A consequence of different developers owning and operating different parts of the CCUS chain is the increased risk of stranded assets, where one part of the CCUS chain becomes permanently unavailable (or its construction is delayed or stopped) and it causes another part of the chain to lose revenue as a result. This can be illustrated by, for example, a capture plant being built but the CO_2 T&S being delayed, meaning the capture plant's operation start date is similarly delayed.

CCUS-specific risk 3: long-term CO_2 storage liability and leakage

The risk of a CO_2 leak is very low – the CAG notes that no reported leakage of any significance has occurred of any of the 250 million tonnes of CO_2 that has been stored underground in the last 47 years.[9]

However, while it is a very low risk, it is a potential cost risk that needs to be mitigated. Under the EU Emissions Trading Scheme (EU ETS), any leak would have to be paid for with EU ETS permits (at the price of the €t/CO_2 under the ETS at the time of a CO_2 leak). The lack of certainty over the price at a point in the future if a leak were to ever occur makes the financial risk unquantifiable. As a result, a risk premium can be placed on this low probability, high impact risk, which in turn has an impact on the project cost.

The National Audit Office assessed that CO_2 storage risk is "the most challenging element of investing in CCS" because it is a risk that has to be managed over the long term.[10] This is because the EU's CCS Directive requires a CO_2 storage site owner to continue to provide a financial security for potential CO_2 leakage from its store for at least 20 years after the site has finished injection, before responsibility is handed back to the State.

The CCUS Cost Challenge Taskforce assessed that industry is able to bear a proportion of CO_2 leakage risk, and that self-insurance can be supplemented by additional cover from insurance markets. However the Taskforce highlighted limitations in the current insurance market, including the capacity of the market (which nonetheless could be expected to respond

[9] CCUS Advisory Group, Investment Frameworks for the Development of CCUS in the UK: CAG Final Report, July 2019, http://www.ccsassociation.org/ccus-advisory-group
[11] CCUS Cost Challenge Taskforce, Delivering Clean Growth: CCUS Cost Challenge Taskforce Report, 19 July 2018, https://www.gov.uk/government/publications/delivering-clean-growth-ccus-cost-challenge-taskforce-report

over time) and the short term nature of insurance policies, which could mean that obtaining insurance, in the Taskforce's assessment, proves "impossible or exorbitantly expensive."[11] The Taskforce therefore concluded that while storage liability could be insurable by the private sector in the medium to long-term as the CCUS industry matures, in the short-term this risk may need to be shared between the CCUS developer and the Government. This was a similar conclusion to that reached by the National Audit Office previously.

CCUS Advisory Group (CAG) view

The CAG notes that each investor is likely to need protection against failure of other parts of the chain, but that CO_2 cross-chain risk is likely to decline when new capture and T&S assets (or even shipping options) are incorporated, or the original assets are expanded to create multiple options for capture and storage. The CAG's proposals on risk mitigation are therefore applicable to initial projects only.

When considering CO_2 cross chain risks, the CAG recommends that the design of business models considers allowing for sufficient revenue protection when elements of the chain are not operating.

The CAG regards the possibility of stranded assets as "an extremely remote" risk. It proposes, for example, allowing flexibility for a capture plant to operate unabated if the T&S network is unavailable. If intervention is required to stop or reduce a CO_2 leak, the CAG view is that considerations for CCUS business models could include allowing for the T&S operator to amend T&S fees to cover the costs of CO_2 store leakage. Another option might be to establish a remediation fund to pay for costs associated with leakage.

For the CCUS-specific risks identified, the CAG suggests use of risk transfer instruments like insurance where available, and where appropriate, consideration of a "funder of last resort" model.

Consultation questions on CCUS-specific risks

3. **Do you have proposals to mitigate CCUS-specific risks?**
4. **Are there any other CCUS-specific risks that need to be considered? If so, what are your proposals for mitigating them?**

[11] CCUS Cost Challenge Taskforce, Delivering Clean Growth: CCUS Cost Challenge Taskforce Report, 19 July 2018, https://www.gov.uk/government/publications/delivering-clean-growth-ccus-cost-challenge-taskforce-report

Chapter 2: Carbon Dioxide Transport and Storage

Overview

Central to deploying CCUS is putting in place carbon dioxide (CO_2) infrastructure to transport and permanently store the CO_2. This CO_2 infrastructure is vital to enabling the UK to scale up CCUS deployment as required, supporting the delivery of both net zero and our Industrial Clusters Mission.

Developing transport and storage (T&S) infrastructure for CO_2 will require large upfront capital expenditure, to construct carbon dioxide offshore and onshore pipelines and develop CO_2 storage sites and wells, alongside associated infrastructure including compressor stations and injection equipment. Whilst these initial construction costs are likely to be relatively high, once built, operating costs are relatively low. Figure 1 provides an indicative estimate of these costs based on a number of current and past CCUS projects.

CCS Project	Transport Costs (£m, 2019)[12]	Storage Costs (£m, 2019)	Offshore Pipeline Capacity (Mt per year)[13]	Storage Capacity (Mt)[14]
White Rose	£600	£350	17	Endurance (520)
Peterhead	£80	£160	4	Goldeneye (30)
Kingsnorth	£540	£260	10	Hewett (200)
Longannet	£320	£240	4	Goldeneye (30)
Hynet	£65	£60	10	Hamilton (125)
Acorn	£25	£145	5	Acorn (153)

Figure 1: Table of estimated CO_2 T&S capex costs

[12] Transport and storage costs have been inflated to 2019 prices using the Department's Green Book supplementary guidance https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal. Transport and storage costs have also been rounded to the nearest £5m. Hynet and Acorn cost estimates are Pre FEED and are therefore subject to more uncertainty than the post FEED estimates for the other sites.
[13] Figures for Acorn are based on maximum flow rates, rather than pipeline capacity. Capacity figures do not necessarily correspond to 100% utilisation rates.
[14] Source: ETI Storage Appraisal Project https://onedrive.live.com/?authkey=%21ANk4zmABaDBBtjA&cid=56FC709A2072366C&id=56FC709A2072366C%211573&parId=56FC709A2072366C%211559&o=OneUp, with the exception of the Acorn storage site, which have been provided by Pale Blue Dot. The exact storage capacity of the individual site is subject to uncertainty, due to engineering factors around how a site is developed.

In certain circumstances, it may be possible to reduce costs through the re-use of existing oil and gas assets for CCUS projects. We have launched a separate consultation on this which can be found at the following link: https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-ccus-projects-re-use-of-oil-and-gas-assets. In the future there is also the possibility of transporting CO_2 via shipping.

The UK has one of the largest potential carbon dioxide storage capacities in Europe, with an estimated storage capacity of more than 78 billion tonnes of CO_2[15], which is likely to be critical to enabling the UK to meet its net zero ambition by storing CO_2 emissions from industry, from power, from low carbon hydrogen production and certain negative emission technologies. The Energy Technologies Institute estimates that the UK's total storage capacity is equivalent to over 150 $MtCO_2$ per year, (which could support 50 GW of gas CCS plant running all year, for 500 years).[16]

Deploying CO_2 T&S will require an effective business model to cater for:

- Mitigation of the CCUS-specific risks discussed in the previous chapter;
- Multiple users of a specific CO_2 T&S, for example within a specific industrial region, but also potentially from CO_2 captured and transported (for example, by ship) in other locations in the UK and/or from Europe; and
- Providing sufficient certainty to investors in CO_2 T&S of revenue and transparency of the T&S fee to carbon capture projects.

This will be challenging given that users of the CO_2 T&S are likely to be from across different sectors, supported by a range of different carbon capture business models.

T&S fee

Central to the development of a CO_2 T&S network across the UK and within specific industrial regions will be determining how a "T&S fee" can be developed that is fair, transparent and equitable to all potential users of a regional CO_2 T&S network. The T&S fee will be an important element of any proposed CO_2 T&S business model.

The Parliamentary Advisory Group, CCUS Cost Challenge Taskforce and the CAG have all proposed that each CO_2 capture project will be charged a T&S fee (on a £/tCO_2 basis) for use of a regional CO_2 T&S network. This T&S fee will form part of the cost of a carbon capture project and be paid to the T&S operator, ensuring certainty of revenue.

In determining the level of fee, the following needs to be considered:

- Whether 100% of all CO_2 T&S costs are charged to the first capture project utilising a T&S network, and costs are subsequently shared when more capture projects join a network (on the basis of how much each capture project utilises the network). This needs to take into account cost impacts for the first capture project; **or**

[15] Energy Technologies Institute LLP (2017) Taking stock of UK CO_2 Storage, https://www.eti.co.uk/insights/taking-stock-of-uk-CO_2-storage
[16] Energy Technologies Institute (2016) Strategic UK CCS Storage Appraisal, https://www.eti.co.uk/programmes/carbon-capture-storage/strategic-uk-ccs-storage-appraisal

- Whether capture projects are charged a T&S fee based on each project's utilisation of a CO_2 T&S network. This would mean that until a network is fully utilised by multiple projects, the additional costs of running a T&S network may need to be provided by other means.
- Whether an alternative funding formula to £/tCO_2 for the T&S fee is required to ensure certainty of revenue, due to potential variability in the amount of CO_2 being supplied by the capture project, for example from a CCUS power plant operating flexibly. This could take the form of a separate fixed capacity fee and volume-based variable payment.

The Cost Challenge Taskforce favoured the approach where the first capture project is charged all the CO_2 T&S costs initially, with costs being shared as more capture plants join the network (based on each project's utilisation of the CO_2 T&S). The Taskforce proposed the following formula for T&S fees under a Regulated Asset Base (RAB) model (Figure 2).

Figure 2: Formula for T&S fees proposed by the Cost Challenge Taskforce

T&S fees = (RAB x WACC) + Opex + Depreciation + FCA + Tax + Decommissioning + Additional T&S Fees + Adjustments

This formula would include:

- **RAB**: the regulated asset base, being the forecast capital cost of the project incurred by the T&S licensee in creating the assets during the construction period;
- **WACC**: the weighted average cost of capital for the T&S licensee, made up of the weighted average cost of the debt and the equity, to the extent possible determined by competition (to ensure attraction of providers with operational expertise) or, in the operational periods, as determined by the regulator;
- **Opex**: the costs incurred by the T&S licensee for the operation of the T&S assets, including operating, maintenance and management costs, costs of regulatory compliance, insurance costs and other similar costs associated with the operation of T&S in the operational phase such as monitoring;
- **Depreciation**: a sum to account for the depreciation of the closing value of the RAB following construction over the useful economic life of the assets, which creates a revenue stream for the amortisation of any financing of the capital cost;
- **FCA**: a financing cost adjustment to protect against movements in the market cost of debt during the construction period; during the operation period embedded debt would be taken into account by the Regulator;
- **Tax**: an allowance for the tax liabilities of the T&S provider, including business rates;
- **Decommissioning**: an allowance for the costs of decommissioning the assets after the closure of the store;
- **Additional T&S Fees**: additional capex to be logged onto the RAB for expansions of the system (for example the drilling of additional wells for injection, additional capacity, pipeline spurs to new Feeder projects, or shipping for development of overseas services); and
- **Adjustments**: including a reconciliation adjustment to update the RAB for actual expenditure such that T&S Licensee's revenues are corrected from the amount earned on the forecast RAB to the amount which should have been earned on the actual RAB and to implement any of the incentivisation mechanism (if any).

Figure 2: Formula for T&S fees proposed by Cost Challenge Taskforce

Given the importance of a T&S network to both the CO_2 T&S operator and individual capture plants, we are keen to understand respondents' views on the approach to setting the fee and how costs should be allocated.

Potential CO_2 T&S Business Models

The only business model for CO_2 T&S that exists currently is the "full chain" model, as was developed under the last Government CCS Competition (2012-2015), supported by a Contract for Difference for both the power capture and CO_2 T&S element of the project. The intention was that future power and/or industry capture projects would join the CO_2 T&S infrastructure, paying a T&S fee.

Under this 'fixed price' model a project is funded based on a strike price paid when there is operation of both a power capture plant and a CO_2 T&S network for the duration of a contract – in the case of the CCS Competition, this would have likely have been for 15 years. The strike price is fixed at the start and must be sufficiently attractive to investors to provide comfort that the project can absorb any risks which crystallise across the value chain. Under this model all construction and significant operational risks sit with the project investors.

Following the end of the CCS Competition in 2015, this "full-chain" model was assessed by a number of bodies including the National Audit Office[17], Parliamentary Advisory Group on CCS[18], and CCUS Cost Challenge Taskforce[18]. Each broadly concluded that the full chain, fixed price model under the CCS Competition was not capable of absorbing the different risk appetites of different organisations involved in the full chain (for example the capture plant owner was different to the CO_2 T&S operator). The result was an increase in cost of the CCUS project. As such, each of these bodies concluded that a separate CO_2 T&S business model should be established.

Most recently, BEIS Select Committee[19] took evidence from a range of stakeholders who said that CCUS costs could be substantially lowered by separating the business model for carbon capture at individual facilities from that for carbon dioxide transport and storage infrastructure. The Committee therefore recommended that the Government separates the funding models for these activities, a position consistent with a range of other evidence put forward to Government including from the Committee on Climate Change[20].

These bodies, and others, also underlined the unique risks associated with CO_2 T&S, which a CO_2 T&S business model will have to address. These are:

- unfixed costs (for example offshore, particularly sub-surface, operations);
- unknown liabilities (for example, a CO_2 leak from the storage site), which are particularly difficult to price and share across the full CCUS supply chain, and would increase the cost of the entire CCUS project; and
- cross-chain interdependence risks, such as the impact on the wider chain when one component – either in transport, storage, or capture – is not operating. These risks are examined detail in this consultation, in the chapter on CCS-specific risks.

[17] National Audit Office, Carbon Capture and Storage: the Second Competition for Government Support, 20 January 2017, https://www.nao.org.uk/report/carbon-capture-and-storage-the-second-competition-for-government-support/

[18] Parliamentary Advisory Group on Carbon Capture and Storage, Lowest Cost Decarbonisation for the UK: The Critical Role of CCS, September 2016, http://www.ccsassociation.org/news-and-events/reports-and-publications/parliamentary-advisory-group-on-ccs-report/

[18] CCUS Cost Challenge Taskforce, Delivering Clean Growth: CCUS Cost Challenge Taskforce Report, 19 July 2018, https://www.gov.uk/government/publications/delivering-clean-growth-ccus-cost-challenge-taskforce-report

[19] BEIS Select Committee, Carbon capture usage and storage: third time lucky?, April 2019, https://publications.parliament.uk/pa/cm201719/cmselect/cmbeis/1094/109402.htm

[20] Committee on Climate Change, Net Zero – The UK's contribution to stopping global warming, May 2019, https://www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/

Work to date

In considering whether (a) a new business model for CO_2 T&S is required; and (b) the possible business model that might be most suitable to support CO_2 T&S in the UK, we have considered evidence from a range of sources and against the key parameters set out in the introductory chapter.

In our CCUS Action Plan we set out that we would explore whether a business model, different from the fixed price model of the previous CCS Competition, could be an investable proposition for the transport and storage element of CCUS. We committed to explore whether there were alternative options that could reduce risk and support a sustainable commercial model for CCUS in the UK. This exploration has included evidence provided by sources outlined in Figure 3 below.

Parliamentary Advisory Group's review on CCS (September 2016)[21]	This report recommended establishing a government owned CO_2 transport and storage company "T&SCo" to deliver CO_2 T&S, as part of the Government owned CCS Delivery Company. The T&SCo would be regulated as a publicly owned network on a rate of return basis, consistent with other regulatory structures for gas and electricity networks, with long-term storage risk residing with the company. The report recommended that a regulated return approach was most likely to attract cost-effective private investment at scale. Central to the recommendation was that the T&SCo could be privatised in the future.
CCUS Cost Challenge Taskforce (July 2018)[22]	The CCUS Cost Challenge Taskforce recommended a privately financed Regulated Asset Base (RAB) model for CO_2 T&S, with a usage fee shared by those projects using the infrastructure, with 100% of the costs allocated initially to the first carbon capture project using the infrastructure. The infrastructure would be funded by a combination of electricity and/or gas bill payers and taxpayers, depending on the types of projects using the CO_2 T&S.
Phase 1 study on the CO_2 transport and storage produced by Pale Blue Dot Energy Ltd (January 2018)[23]	This study considered potential business models for CO_2 T&S infrastructure development and key challenges involved.

[21] Parliamentary Advisory Group on Carbon Capture and Storage, Lowest Cost Decarbonisation for the UK: The Critical Role of CCS, September 2016, http://www.ccsassociation.org/news-and-events/reports-and-publications/parliamentary-advisory-group-on-ccs-report/
[22] CCUS Cost Challenge Taskforce, Delivering Clean Growth: CCUS Cost Challenge Taskforce Report, 19 July 2018, https://www.gov.uk/government/publications/delivering-clean-growth-ccus-cost-challenge-taskforce-report
[23] Pale Blue Dot Energy Limited conducted a study, 'CO2 transport and storage: Review of business models Phase 1, January 2018 https://www.gov.uk/guidance/uk-carbon-capture-and-storage-government-funding-and-support

	The range of business models it identified included: full public ownership; mainly public ownership; a public private entity; and a fully private venture. Key challenges identified in terms of the development of T&S infrastructure included guaranteeing CO_2 supply, cross-chain interdependence risks, uncapped leakage liability and allocation of risk.
BEIS Select Committee (April 2019)[24]	Recommended that Government should consider the suitability of a RAB model for CCUS and focus on costs, risk and consumer protection.

Figure 3: Sources used to consider potential CCUS T&S business models

Challenges to address

Our review so far would suggest that splitting the CCUS chain and establishing a new, separate, business model for CO_2 T&S could be a viable option. Under this approach a T&S operator would be responsible for developing and managing the T&S infrastructure in a specific region, with different users of the infrastructure charged a T&S fee.

This would enable the CO_2 T&S infrastructure to be considered as a different asset class with its own investors and would enable T&S operators to focus on their core business function (i.e. transporting and storing CO_2 emissions from capture projects, whether industry, power, hydrogen, BECCS or direct air capture), while also looking for new commercial opportunities (for example from emissions in Europe).

Of the models reviewed by a number of organisations and bodies, including the CCUS Cost Challenge Taskforce, the BEIS Committee and the CAG, there is a consensus that due to the characteristics of a CO_2 T&S network, a Regulated Asset Base (RAB) type model might be appropriate and should be considered in more detail.

[24] BEIS Select Committee, Carbon capture usage and storage: third time lucky?, April 2019, https://publications.parliament.uk/pa/cm201719/cmselect/cmbeis/1094/109402.htm

What is a Regulated Asset Base (RAB) funding model?

A RAB model is a type of economic regulation typically used in the UK for monopoly infrastructure assets such as water, gas and electricity networks. The company receives a licence from an economic regulator, which grants it the right to charge a regulated price to users in exchange for provision of the infrastructure in question. To prevent monopolistic disadvantages, the charge is set by an independent regulator who holds the company to account to ensure any expenditure is in the interest of users.

In 2016 the model was applied successfully for the first time to a single asset construction project – the £4.2bn Thames Tideway Tunnel (TTT) sewerage project[25]. Much of the almost £1bn of private sector equity finance that was raised to deliver the project came from UK pension funds, representing 1.7 million pensioners, or a quarter of the UK's largest 25 pension funds.[26]

RAB-funded infrastructure has received significant quantities of investment from private sector players over the last 20-30 years. As of 2018 the total RAB value across the UK electricity, gas, water and airport sectors is almost £160bn (2018 prices).

A RAB model is being considered in detail by the Government for new nuclear projects. You can access this consultation at the following link:
https://www.gov.uk/government/consultations/regulated-asset-base-rab-model-for-nuclear

A regulated approach has been put forward by a number of organisations because uncertainty over costs in the operational period can make it difficult and expensive to raise finance under a fixed price model. Under a fixed price model, investors will need to be comfortable that they are adequately protected against such risks and will look to price these into the fixed price in case they materialise, pushing up the price of the project, or not invest at all. However under a RAB model, certain risks can be shared with or transferred to the consumer. For example, the payment could be adjusted if a risk materialises and returns are affected, but consumers will not pay if the risk does not occur. This approach can improve the investment and lower the cost of capital of the project, reducing costs to the consumer. However, as these reductions are achieved by sharing risks with consumers, it is important that steps are taken to minimise the likelihood of risks materialising.

The difference in cost of capital of a RAB model compared with a fixed price model will depend on a number of specific factors such as market conditions (for example the cost of debt), alternative investment opportunities for investors, the quality of the project itself, and risk sharing arrangements between consumers and investors. Investor appetite for a RAB-based mechanism will also depend on the level of confidence in the regulator to set fair prices (for example, the cost of capital allowance). Investors who are comfortable with the specifics of the technology and project type may prefer a RAB model as this offers more long-term visibility of project returns and less risk of regulatory intervention during the operating period.

As indicated by the CAG and others, a RAB model for CO_2 T&S would require an independent function to regulate companies and ensure that the interests of those meeting the costs of the

[25] Thames Tideway Tunnel Strategic and Economic Case Costs and Benefits 2015 update (October 2015) https://www.gov.uk/government/publications/thames-tideway-tunnel-strategic-and-economic-case-costs-and-benefits-2015-update
[26] National Infrastructure Commission Review of Infrastructure Financing Markets https://www.nic.org.uk/publications/review-infrastructure-financing-markets-report-nic/

regulated asset base are considered. Were a RAB model to be considered an appropriate business model for CO_2 T&S, the nature of such an organisation to undertake this function would need to be considered further. This is important as the identity of the regulator could affect investor and consumer confidence in the arrangements.

Additionally, a RAB model requires a revenue stream which will likely come from capture projects for accessing the CO_2 T&S. This T&S fee and revenue stream will be important to the investability of a RAB-based model, with the T&S fee also forming an important consideration within each capture business model (for example, as a pass through cost).

There are also other variants of a RAB model that have been used for pricing of other energy assets and would need to be considered in more detail. For example, a Cap and Floor mechanism, which has been applied in the electricity interconnector market, sets a maximum and minimum level of revenue that an asset can earn. Another example is the Offshore Transmission Owner (OFTO) model, where an OFTO provides electricity infrastructure between offshore wind generation assets and onshore electricity networks. An offshore transmission licence is obtained through a competitive tender process in accordance with the relevant regulations, which allows companies to bid for a licence to be the OFTO of particular offshore networks. This entitles them to earn a regulated rate of return on the costs of building and operating those networks.

In considering a RAB model, the following factors would need to be taken into account:

- The need to identify a long term, credit worthy customer base and revenue stream, noting that under the clusters model, T&S users could be a mix of different industrial emitters, hydrogen production facilities and power plants with different financing structures;
- The need to identify, set and review what will be classed as allowed revenue;
- Consideration of establishing an appropriate new regulatory structure and environment for an infrastructure project which is not directly comparable to existing utility RAB models;
- The ability to manage remote risks such as the storage risks described in Chapter 1 of this consultation on CCUS-specific risks;
- The extent to which a government support package is required;
- The extent to which a RAB is needed, for example, for smaller scale T&S projects and/or the re-use of existing infrastructure;
- How the model could be adapted over time as regional networks develop; and
- An appropriate economic regulator.

Potential models considered

CO_2 T&S under a Regulatory Asset Base (RAB) model

A RAB model aims to give investors certainty on investment and a fair return on the capital and includes clear allocation of risks between investors in the project, consumers and taxpayers.

All investments made are valued and costs are recoverable in accordance with regulations, in order to support network development, control tariffs and to pay investors.

Such a model would provide for a CO_2 T&S service whereby revenues are periodically reviewed by a regulator with the regulator setting the return for review period and updating for actual capital expenditure. The regulator would issue licenses for operating a CO_2 T&S network and set the T&S fee (£/tCO_2).

Depending on the design of the RAB, companies may be able to recover their upfront investment early in the project lifespan, through for example a fixed-period price control mechanism, in which opex incurred can be recovered during the time period, and capex is added to the growing RAB and remains in the RAB for the length of the depreciation age. The company can therefore earn a return on this capital via the allowed weighted average cost of capital for the CO_2 T&S network.

The private sector led CO_2 T&S model financed by a RAB was proposed by the CCUS Cost Challenge Taskforce Report and has also been examined in further detail by the CAG, as set out on page 28 of this consultation.

An alternative to this privately financed approach was proposed by the Parliamentary Advisory Group on CCS, who recommended that the Government establish a new, Government-owned, regulated T&SCo to develop, deliver and manage CO_2 T&S. The Parliamentary Advisory Group recommended that the T&SCo should be subsequently privatised as the CCUS market matures (for example, in the 2030s) and as such, should be operated with a RAB framework. The Parliamentary Advisory Group advised that the T&S Co would have a UK-wide remit.

CCUS Advisory Group (CAG) view

The CAG has considered three viable options for CO_2 T&S: a private sector financed CO_2 T&S under a RAB model; a private sector financed CO_2 T&S under a RAB model but with an upfront capital grant from Government; and a Government-owned T&S model regulated by a RAB framework. Further details on these models can be found here.

A private sector financed CO_2 T&S RAB model

The CAG's lead option is for CO_2 T&S to be privately financed, under a RAB model. In this model the private sector will have two roles: 1) as a service provider to the T&SCo; and 2) as an investor, as the private sector will fund the T&S with debt and equity.

A new RAB, specifically designed for enabling the deployment of CO_2 T&S will be established in law, designed to enable the T&S developer's investments and operations to be low risk and earn a low return with debt financing contributing to keeping post-tax costs down.

The T&S developer will be permitted by a regulator to charge fees which allow it to make a return commensurate with the risk it is incurring. All costs can be recovered under the RAB, provided they are properly incurred, and a return made on the capital invested.

Private sector financed RAB with Government grant

The CAG also proposes a variant to the Private sector financed RAB, which includes the addition a Government grant. Under this variant a T&S developer receives a grant for the capital investment in the T&S developer's first T&S assets in a specific area. This is designed to reduce cross-chain risk.

The T&S developer will raise finance for all required working capital; and prudent contingency funding, which will be restored promptly if used.

Government owned T&S

The CAG considers, similar to the Parliamentary Advisory Group on CCS, that another viable option might be for the T&S assets to be owned and financed by the Government through an HMG Transport and Storage Company (T&SCo). The CAG consider that this option has the potential to simplify the initial cross chain risk allocation and management. The T&SCo would be set up in the same way as if it were owned by a private sector owner, in preparation for eventual privatisation, and as such a RAB framework would govern the operation of the T&S, as if it were privately financed.

Other models considered

Other models for CO_2 T&S have also been considered, although not to the level of detail of the options we have discussed above. We welcome views on other potential options for CO_2 T&S, including but not necessarily limited to those in the table below (Figure 4).

Model	Description
Public and privately owned entity	Potentially a combined ownership model between the public and private sector. It relies on the recognition that public and private sectors each have certain advantages relative to each other in performing specific tasks and managing risk. The responsibilities of the private sector could entail finance, design, construction, operation, management and maintenance of the project.
Cost Plus Open Book	Direct operational payments from government to cover all properly incurred costs annually, on an open book basis, with an addition of agreed profit margins and return on investment. Widely used in transport and infrastructure projects.
Waste sector type contractor	Payment of a fee per unit of CO_2 injected and stored. An arrangement could be established where funding from local authority budgets can be supported by private finance credits.
Hybrid	A combination or evolution of various models could be adapted to incorporate positive traits of some models and minimise negative aspects of others.

Figure 4: Descriptions of other models considered

Consultation questions on carbon dioxide transport and storage

5. **Have we identified the most important challenges in considering the development of CO_2 networks?**

6. **Do you agree that a T&S fee is an important consideration for any CO_2 T&S network? In your view, what is the optimal approach to setting the T&S fee?**

7. **Of the models we have considered for CO_2 T&S, do you have a preference, and why?**

8. **Are there any models that we have not considered in this consultation which you think should be taken forward for CO_2 T&S, and why?**

Chapter 3: Power CCUS

Overview

There is consensus that electricity generation with CCUS (or power CCUS) can support the low cost decarbonisation of the UK's electricity system, alongside the expansion of other forms of low-carbon generation. This has been demonstrated in work conducted by a wide variety of institutions, ranging from the Energy Technology Institute, to the National Grid, to the Committee on Climate Change (CCC)[27],[28],[29].

A mix of technologies will be needed to decarbonise the power sector at low cost. Combined cycle gas turbines (CCGTs) with post-combustion carbon capture, BECCS, hydrogen-fired power generation (or pre-combustion capture) and oxy-fuel technologies (such as the Allam Cycle configuration being developed by NET Power) could all play a role in supporting decarbonisation of the power sector.

The role of gas-fired power CCUS facilities may evolve over time, from initially providing low carbon, firm baseload power to a 'mid-merit' role in the longer term, providing low carbon, firm dispatchable power. For example, during the 2020s and potentially longer, with moderate levels of intermittent renewable generation in the electricity system, CCUS facilities could be expected to provide baseload capacity (i.e. running at high load factors), particularly when considering BECCS and the potential need for greenhouse gas removal. This could mean that early, first-of-a-kind power CCUS plants are able to operate for long hours, which could contribute to technological and operational improvements. As greater capacity of intermittent generation is added, gas-fired power CCUS facilities could operate in the longer term as mid-merit plants, running at lower load factors. We refer to this type of operating behaviour in this publication as "dispatchable generation".

Therefore, it may be that over time power CCUS technologies will need to provide dispatchable generation, and consequently developers and technology providers should ensure that power CCUS plants are capable of performing this role. Recent work has shown that performing this role is within the capability of existing technology[30],[31].

A similar conclusion was reached by the CCC in their recently published Net Zero report. The Committee highlighted that power CCUS could play a role in providing firm low-carbon generation, alongside nuclear. In addition, the Committee highlighted the role which power CCUS and hydrogen-fired turbines may be required to play in providing mid-merit power, and the need to build in this requirement to the design of plants and business models.

While we recognise the strategic value of bringing forward power CCUS, this should be done in such a way as to protect consumers and taxpayers, and which ensures that we continue to decarbonise the power sector at low cost. Any potential model for power CCUS should

[27] Energy Technology Institute, Still in the Mix? Understanding the System Role of Carbon Capture, Usage and Storage, 2018, https://www.eti.co.uk/insights/still-in-the-mix-understanding-the-system-role-of-carbon-capture-usage-and-storage

[28] National Grid, Future Energy Scenarios, 2019, http://fes.nationalgrid.com/fes-document/

[29] Committee on Climate Change, Net Zero – the UK's contribution to stopping global warming, May 2019, https://www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/

[30] Flexibility of Low-CO_2 Gas Power Plants: Integration of the CO_2 Capture Unit with CCGT Operation. Ceccarelli et. al. 2014.

[31] Dynamic operation and modelling of amine-based CO_2 capture at pilot scale. Bui et. al. 2018.

therefore adhere to the overarching parameters set out in the Introduction of this document. In addition, with regard to the development of power CCUS, funding models will only be considered where they bring forward projects that are led and financed primarily by the private sector, and are consumer funded.

Work to date

Work reviewed and undertaken to date suggests that CCUS can play a role in decarbonising baseload and mid-merit generation, enabling further integration of renewable technologies into the UK electricity mix and achieving low cost decarbonisation of the power sector. We have considered a range of sources of evidence and commissioned studies and have tested this with the CCUS industry.

Author and report	Summary
Wood: Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology (July 2018)[32]	Wood assessed the cost reduction potential and competitiveness of novel (next generation) UK carbon capture technologies, and to develop the benchmark cases for current state-of-the-art natural gas, coal and biomass technologies. Wood concluded that a 'Nth-of-a-kind' (NOAK) natural gas-fired CCGT with post-combustion carbon capture could have a levelised cost of electricity (LCOE) of £69.9/MWh[33].
Uniper Technologies Ltd.: CCUS Technical Advisory report on assumptions (November 2018)[34]	Uniper Technologies Ltd. carried out a review and update of the technology and cost data used in BEIS internal modelling[35]. Uniper drew on a range of publications, including the Wood report. Based on this review, BEIS analysis showed that the LCOE for a first-of-a-kind (FOAK) CCGT with post-combustion CCUS could be around £77/MWh[36], for a plant commissioning in 2025.

32 Wood, Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology, 2018, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/730562/BEIS_Final_Benchmarks_Report_Rev_3A__2_.pdf
33 LCOE in 2017 prices.
34 Uniper Technologies Ltd., CCUS Technical Advisory report on assumptions, 2018, https://www.gov.uk/government/publications/power-carbon-capture-usage-and-storage-ccus-technologies-technical-and-cost-assumptions
35 This report was published in November 2018: https://www.gov.uk/government/publications/power-carbon-capture-usage-and-storage-ccus-technologies-technical-and-cost-assumptions
36 LCOE in 2012 prices.

CCUS Cost Challenge Taskforce: Delivering Clean Growth (July 2018)[37]	The CCUS Cost Challenge Taskforce recommended that power CCUS be taken forward under the existing CfD business model, adapted for CCUS.
Cornwall Insight and WSP: Market-based frameworks for power CCUS (July 2019)[38]	Cornwall Insight and WSP conducted a review of potential market-based frameworks for power CCUS. This included how the Contract for Difference (CfD) could be adapted for CCUS in power, alongside a high-level assessment of other potential market-based frameworks. This report is published alongside this Consultation.

Figure 1: Sources used to consider potential power CCUS business models

Challenges to address

Whilst recognising the strategic value of bringing forward power CCUS, understanding the roles which power CCUS plants will play in decarbonisation of the electricity system is important. The primary factors which we have considered through our Review is how to ensure that:

- Any proposed business model can incentivise and enable power CCUS to play the role that is required of it by the electricity system, balancing the inherent uncertainty of this role with the provision of sufficient certainty to investors to ensure deployment can proceed; and
- How any funding model can minimise the cost to consumers, with as much revenue as possible coming from the wholesale market.

In addition, we have considered the challenge of how proposed business models may incentivise generators and technology providers to reduce costs and improve capture rates from power CCUS technologies. In particular, improving capture rates for both baseload and dispatchable operation of power CCUS could be important in meeting a net zero emissions target.

We have considered at a high level how any potential funding models could be developed and consider that any potential contracts should be awarded competitively where possible. This

CCUS Advisory Group (CAG) view

The CAG determined that CCUS is well placed to provide low carbon dispatchable electricity generation capacity. The CAG recommended that projects be brought forward under private ownership and finance, through a new ‘Dispatchable CfD’ with fixed payment and variable payment (e.g. a top up and cap). This would be funded by electricity consumers through the Low Carbon Contracts Company (LCCC).

[37] CCUS Cost Challenge Taskforce, Delivering Clean Growth: CCUS Cost Challenge Taskforce Report, 19 July 2018, https://www.gov.uk/government/publications/delivering-clean-growth-ccus-cost-challenge-taskforce-report
[38] Cornwall Insight and WSP for BEIS, *Market based frameworks for power CCUS*, 2019. https://www.gov.uk/government/publications/market-based-frameworks-for-carbon-capture-usage-and-storage-ccus-in-the-power-sector

may mean that, in future, power CCUS contracts could be awarded through a competitive process such as the allocation framework used for renewable generators. This could further drive cost reduction and attract new investment.

Potential models considered

We have considered a range of potential funding models which could be used to support power CCUS, outlining examples below. In examining these, we have considered the needs of and impacts on a wide range of stakeholder groups, including consumers, investors and developers. Further detailed design and analysis of the funding implications of different models will be necessary before the Government considers which option may be preferable.

Standard Contract for Difference for CCUS

This would provide a power CCUS generator with a fixed strike price, where a difference payment tops up the revenue to the generator above the wholesale electricity price. This strike price would incorporate the levelised cost of electricity (LCOE) of the generation and capture of the plant, the fee payable to the transport and storage operator, and any associated decommissioning costs. A fuel price adjustment could be required in order to ensure that generators were incentivised to dispatch at times of high fuel prices, and to protect consumers in the event of a significant fuel price decrease after a contract has been signed. Payments would be made on the output of low carbon electricity generation only. The remaining generation could be sold by the generator at wholesale market value.

Dispatchable Contract for Difference

This models is an adapted CfD mechanism which aims to enable CCUS to play both a baseload and mid-merit role in meeting electricity demand. It would aim to adjust the merit order characteristics of a gas-fired power CCUS facility, positioning it ahead of equivalent unabated gas plant.

In order to implement such a model, a mechanism to identify the economics of a plant without operating CCUS equipment would need to be developed. This ‘reference plant’ would need to be robust enough to establish an understanding of pricing signals, against which the CCUS plant would be remunerated. It would also need to be established in such a way as to provide confidence to the market.

Payments to the CCUS facility could consist of a fixed payment, a variable payment, and the fee payable to the transport and storage operator. The fixed payment could be paid based on the availability of firm low carbon electricity generating capacity and the cost of the of the CCUS equipment. Conditions and penalties related to any fixed payment could be set to ensure availability of firm low carbon electricity generating capacity when required. This fixed payment may be important in ensuring that this model presents an attractive proposition to investors.

The generator would earn variable revenues on the output of low carbon electricity for the periods when the plant is generating, using a reference plant to establish pricing. As much revenue as possible should come from the wholesale market, however, a variable payment may be needed to incentivise the generator to dispatch ahead of unabated fossil thermal generation, and behind zero marginal cost technologies. Calculation of the pricing using the ‘reference plant’ would have to be undertaken on a regular basis to take account of changes in the fuel price relative to electricity prices.

One proposal for how this variable payment could work is set out in more detail in the Cornwall Insight and WSP report ‘Market-based frameworks for power CCUS’. This would involve a variable payment to a power CCUS plant up to a strike price, available when wholesale market prices rose above the level at which a reference plant would dispatch.

Another proposal is where a fixed top up is available to the plant at all times. A maximum margin which the power CCUS plant is able to earn from variable revenues could be applied reducing the exposure of consumers in return for the certainty provided by the fixed payment.

Other models considered

Other models for power CCUS have also been considered, although not to the level of detail of the CfD options discussed. We welcome views on other potential options for power CCUS, including but not necessarily limited to those in the table below.

Model	Description
Hybrid CfD	Contract for Difference designed to compensate a project based on a scaled payment system, with lower £/MWh top-up payment rates with each 'band' of higher output levels. This is designed to ensure generator is incentivised to lower output when prices are low (e.g. very high renewable generation) and vice versa.
Regulated Asset Base	Regulatory valuation of asset in relation to provision of electricity and setting tariffs to pass costs on to consumers.
Cost-plus open book	Direct operational payments from government to cover all properly incurred costs annually, on an open book basis, with an addition of agreed margins to the project. Widely used in transport and infrastructure projects. Adjustments to the model to allow for incentives on plant operation would be required to ensure the plant remains flexible in the market.
CCUS Certificates	Tradeable CCUS certificates combined with an obligation to decarbonise. Proposal is to award per tonne of CO_2 abated. An obligation to decarbonise could be placed on specified groups to purchase CCUS certificates covering a portion of their emissions. This system could work across sectors including power CCUS and industrial CCUS, and is described in more detail in Chapter 4: Industrial CCUS.
Cap and floor	Provides a minimum 'floor' of revenue to which asset owners/ operators will be 'topped up' if earnings fall below a set threshold. In reverse, assets are capped in revenues and must return earnings over a set threshold to the consumer.

Figure 2: Description of other models considered for power CCUS

Consultation questions on power CCUS

9. **Have we identified the most important challenges in considering the development of CCUS power projects?**

10. **Of the models we have considered for power CCUS, do you have a preference, and why?**

11. **In your view, should any potential funding model(s) be applicable across all power CCUS technologies (including but not necessarily limited to CCGT with post-combustion capture, BECCS, and pre-combustion capture or hydrogen turbines)?**

12. **Are there any models that we have not considered in this consultation which you think should be taken forward for power CCUS, and why?**

Chapter 4: Industrial CCUS

Overview

CCUS is fundamental to the decarbonisation of energy intensive industries (EIIs), such as steel, cement, oil refining and chemicals, some of which lack alternative options for achieving deep decarbonisation. Successfully decarbonising these sectors in line with our Industrial Clusters Mission and our net zero commitment is likely to require industrial carbon capture, or low carbon hydrogen production, which is reliant on the ability to capture and store CO_2.

CCUS has the ability to secure the future and long-term competitiveness of these industries in an increasingly carbon-constrained world. CCUS can support clean industrial growth, both generating new economic opportunities and securing industrial competitiveness. In the Committee on Climate Change's recent net zero report, they stressed the importance of CCUS in decarbonising industry, stating that it is essential to meeting our goals.

However, for the majority of industrial sectors, CCUS is not currently a viable investment. As well as challenges with capital financing repayment periods and revenue uncertainty, the cost of industrial carbon capture is, for sectors such as cement and steel, much greater than can be supported (or incentivised) at current EU Emissions Trading Scheme (EU ETS) allowance values. In addition, there is presently minimal premium attached to low carbon products. Therefore, an additional mechanism to supplement the ETS incentive in the short-medium term to provide financial support to make carbon capture in industry investible.

There is currently no business model in place to support CCUS in industry. This chapter considers possible models which could be used to incentivise deployment of carbon capture from industrial facilities.

Work to date

As part of the CCUS Review of Delivery and Investment Frameworks, the Government has considered evidence from a range of sources and has tested this evidence with the CCUS industry and investors.

CCUS Cost Challenge Taskforce (July 2018)[39]	The CCUS Cost Challenge Taskforce report recommended the Government investigates supporting industrial CCUS through a new tax credit scheme, similar to the US 45Q tax credit for CCUS[40]. It also suggested the possibility of enhancing the competitiveness of low carbon industrial products through developing a decarbonised product mark, with the ability for this to reduce the level of support provided via

[39] CCUS Cost Challenge Taskforce, Delivering Clean Growth: CCUS Cost Challenge Taskforce Report, 19 July 2018, https://www.gov.uk/government/publications/delivering-clean-growth-ccus-cost-challenge-taskforce-report

[40] 45Q refers to Section 45Q, a tax credit system in the US used to support CCUS deployment. Under a new bill, 45Q will provide a tax credit of \$50/tCO_2 stored by 2026. It also provides a tax credit for CO_2 utilisation, at the lower rate of \$35/tCO_2.

	tax credits in line with the value attributed to these low carbon products by the consumer.
Industrial carbon capture business models report by Element Energy (November 2018)[41]	In 2018, BEIS commissioned a report from Element Energy to analyse the barriers to industrial carbon capture, and develop a series of business models to incentivise its deployment. The report recommended three models to take forward for further consideration: a contract for difference based on a CO_2 strike price; a tax credit-based model; and a CCUS Certificates plus obligation model. The report also recommended three further models which had more limited applicability, including Cost Plus Open Book for early projects; a Regulated Asset Base (RAB) for incentivising carbon capture for hydrogen production only; and exploring the development of low carbon product markets as a long-term ambition to develop a consumer-funded business model for industrial carbon capture.
BEIS Select Committee (April 2019)[42]	The committee recommended an 'Industrial Capture Contract' to facilitate the deployment of CCUS in UK industry. This would be a contract regulated and funded by the UK Government, which was frontloaded such that a higher price was given in the early period in order to deliver capital repayment across a timescale consistent with industry horizons.

Figure 1: Sources used to consider potential CCUS industry models

Challenges to address

The parameters for CCUS business models are set out in the introductory chapter. Accordingly, an ideal mechanism for industrial carbon capture seeks to provide an appropriate financial incentive which can drive efficiency and cost reductions; and is relatively quick to implement. The mechanism will also need to share risk appropriately between Government and industrial participants. Ideally, the business model can be adapted over time as the CCUS market develops, to provide an incentive for early projects as well as to function as a sustainable, cost-efficient and subsidy-free mechanism for the enduring regime.

The costs of carbon capture vary considerably between different industrial sectors (see Figure 2) and the ability for each sector to pay for carbon capture also varies. A successful model will therefore need to be flexible so that it can be appropriate to all relevant industrial sectors; we expect that the degree of incentive will also need to vary across industrial sectors.

[41] Element Energy, Industrial carbon capture business models, October 2018, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/759286/BEIS_CCS_business_models.pdf
[42] BEIS Select Committee, Carbon capture usage and storage: third time lucky?, April 2019, https://publications.parliament.uk/pa/cm201719/cmselect/cmbeis/1094/109402.htm

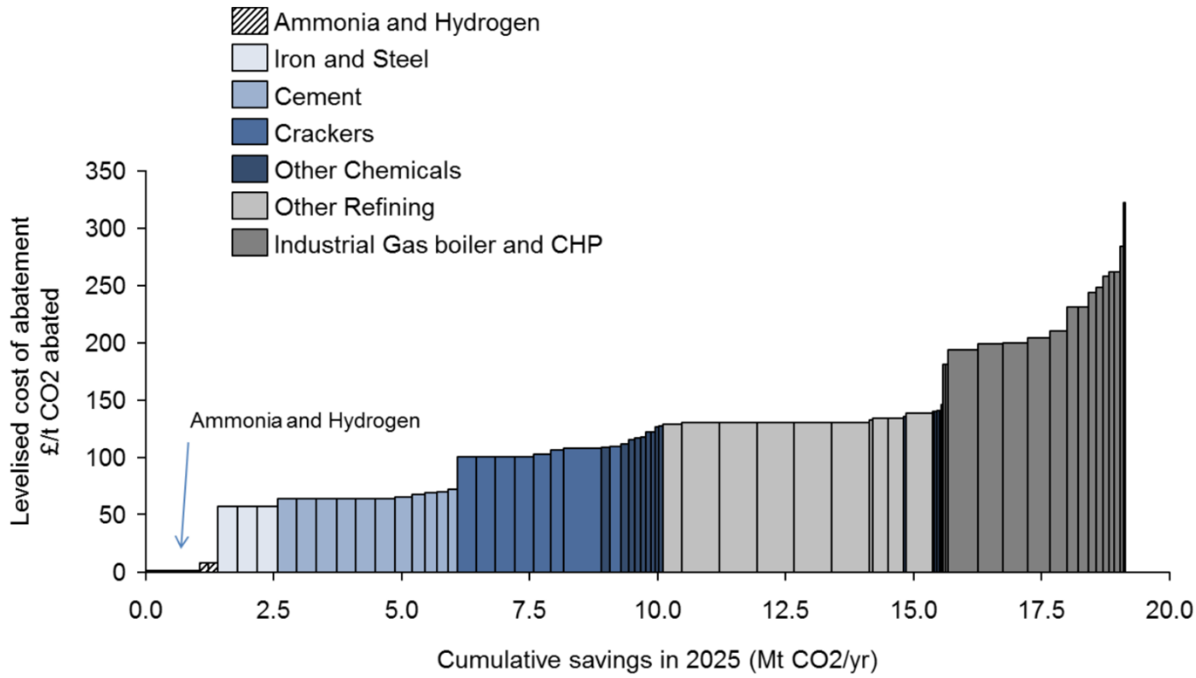


Figure 2: Marginal abatement cost curve for different subsectors for projects operational by 2025 (Element Energy, 2014), excluding the cost of compression, financing and T&S.

The cost of transporting and safely storing CO_2 will need to be accounted for within the support for the overall cost of carbon capture and model selected.

Another consideration is the long-term nature of the investment of industrial carbon capture. This creates multiple risks: as referred to in Chapter 1 of this consultation, there may be a risk that assets become stranded in the event that the industrial facility ceases to operate, or there is no longer sufficient support or incentive to cover the costs of operating the capture plant following the end of any mechanism that supports its initial deployment and operation.

Enabling emitters to obtain capital for the construction of the capture plant is an important priority. High upfront costs have been identified as a risk preventing the deployment of carbon capture in industry, and the business model will need to be designed to enable capital to be raised.

The incentive for carbon capture deployment in industry should become subsidy-free over time. To develop a long-term sustainable regime, in parallel with the deployment of early projects, a market could be developed for low carbon products. As well as reducing reliance on Government support, creating demand for low-carbon industrial products in the UK could reduce the risks of carbon leakage. Over time, the development of this market, in addition to potential factors such as rising carbon prices and falling costs of carbon capture, will enable carbon capture to become cost-effective.

CCUS Advisory Group (CAG) view

The CCUS Advisory Group (CAG) has considered a range of business models for industrial carbon capture. In particular, the CAG has evaluated a variety of options for the revenue model, and the mechanism for delivering revenue support, among other considerations.

The CAG has recommended two different potential approaches for the revenue model: the first is a 'Hybrid Grant/ CO_2 Contract for Difference' approach, where capital costs are covered by partial government grant, potentially under an open book contract structure, and ongoing operating costs are covered by a CO_2 contract for difference. The second is a regulated "decarbonisation service company". This involves establishing a new company which would raise private sector finance to invest in CO_2 capture projects on industrial sites and provide a "decarbonisation service" to industrial emitters. This company could operate the capture plant, or it could be run by their customers (i.e. industrial emitters) on the company's behalf. Revenue support would flow from Government to the service company, which eliminates the need for industrial producers to invest directly in the capture plant.

The CAG's suggested mechanism for delivering revenue support is direct award of payments. Alternative mechanisms including a Contract for Difference (based on a CO_2 reference price), accelerated depreciation, tax credits, and others were considered.

Potential models considered

Contract for Difference (CO_2 reference price)

One option for industrial CCUS is a contract for difference (CfD), which is a contract between an investor and a counterparty, in which the counterparty guarantees a set price for an asset (e.g. a unit of electricity), and which stipulates that the counterparty will pay to the investor the difference between the current value of an asset and the agreed price (the 'strike price'). If the difference is negative, the payment flows from the investor to the counterparty.

For this model, a CfD strike price will be agreed, per tonne of CO_2 abated, based on expected costs of installing and operating the industrial carbon capture assets. The strike price could be fixed throughout the lifetime of the contract for an agreed period, or it could be front-loaded to facilitate rapid capital amortisation. The emitter will partly fund the cost of capture by selling any excess CO_2 certificates (EU ETS or equivalent certificates) to another emitter at market price. The emitter will also be paid the difference between the CfD strike price and a defined, prevailing market CO_2 certificate price by a Government-backed entity. If the market CO_2 certificate price exceeds the strike price, the emitter would be obligated to return the difference; alternatively, the CO_2 price the emitter is exposed to could be capped or limited in some way.

The CfD strike price will vary between industrial carbon capture sectors, and potentially within sectors, if needed. It is anticipated that the mechanism will evolve over time, e.g. contracts may be awarded bilaterally initially, and could be awarded via competitive auctions over time. It is expected that strike prices will reduce as the market matures, technology improves, and risks reduce. Subsidy is also likely to decrease with time, perhaps eventually becoming subsidy free, as it is expected that the CO_2 price will increase (see Figure 3). To establish such a mechanism, a detailed, standardised contract would need to be developed. In addition, a delivery body would need to be designated or established to manage and deliver contracts.

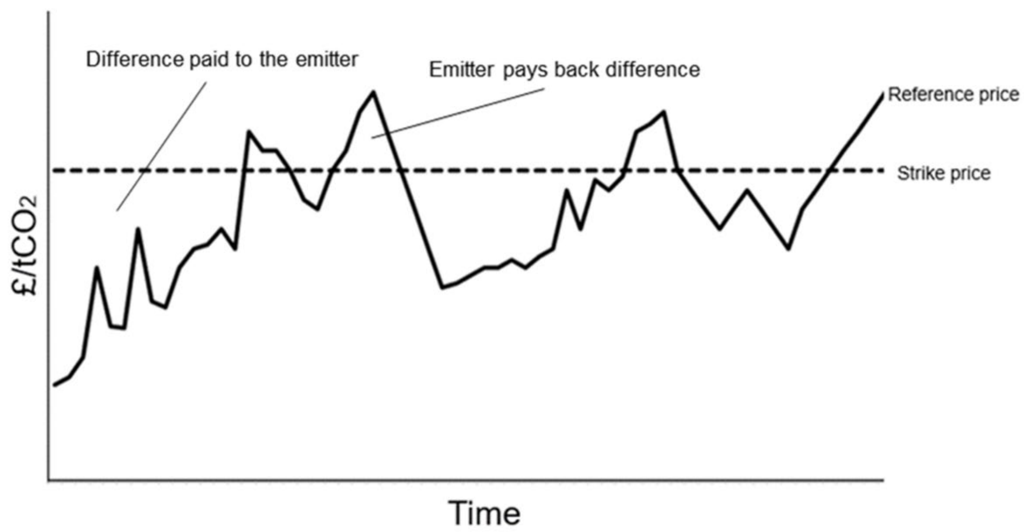


Figure 3: Illustration of a Contract for Difference based on an ETS allowance reference price.

Tradeable CCS certificates plus obligation

Under this model, CCS certificates are awarded per tonne of CO_2 abated, relative to an industry benchmark. An obligation is created and would require the specified parties to ensure a certain amount of CO_2 is captured and stored, with the obligations increasing over time to result in a long-term decarbonisation trajectory and provide certainty to investors. The certificates may be used to meet the obligation or traded freely, so that those emitters have a choice as to whether to invest in CCUS or purchase cheaper certificates via a CCS certificates market. Such a market may involve auctions and bilateral trading of certificates.

The price of certificates would be determined by the market, so is uncertain. However, the Government may provide a buyout price, creating a floor price for certificate value; and penalties for not meeting the obligation may create a price ceiling. The price floor and ceiling could be index linked to the CO_2 price, so that while CO_2 price is low, the floor price is higher, giving emitters more financial compensation certainty. It is expected that the market would function as an effective, self-sustaining mechanism only once there is a significant industrial CCUS presence in the UK, due to the need for liquidity in the certificates market.

Who the obligation is placed on is a fundamental consideration within this model. If placed on industrial emitters, an additional incentive (e.g. CfD) may be required to prevent carbon offshoring.

Cost plus open book

Under cost plus open book, the emitter is directly compensated by the Government for all properly incurred operational costs[43] and the emitter's capital investment is paid back with agreed returns. The contract is agreed bilaterally and is bespoke to each capture project. Each project would require ongoing evaluation by the Government on an annual basis. Repayments may be shaped such that the majority of the emitter's capital outlay is recovered by the EII in the first few years, but the EII would earn a higher return on capital only if it continues to operate the plant for the full contract period.

To incentivise efficiency and drive cost reductions, payments could be made against a combination of forecast and actual costs, so that returns to the emitter are higher if they can drive cost reductions (a 'pain-gain sharing' mechanism), although this could increase administrative complexity. In addition, it is envisaged that this model would need to account for avoided carbon costs, e.g. by reducing compensation levels with greater CO_2 prices.

Consultation questions on industrial CCUS

13. Have we considered the most important challenges in considering the development of CCUS for industry?

14. Of the models we have considered for industry CCUS, do you have a preference, and why?

15. Are there any other models that we have not considered in this consultation which you think should be taken forward for industry CCUS, and why?

16. In your view, are there any models which best work across all industrial sectors where CCUS could have a role to play?

17. What actions should Government and industry take to establish demand for low-carbon industrial products?

[43] 'Properly incurred' costs are those deemed appropriate and proportionate, based on an 'efficient' use of resources, as defined by a bilaterally agreed contract. This would include capital costs, operational costs, fuel costs, and a transport and storage fee. A benchmark may be required to define 'efficient' use of resources.

Chapter 5: CCUS for hydrogen production

Context

Hydrogen is an energy carrier with potential to support the UK's efforts to transform and decarbonise the energy system in line with our new 2050 net zero target. Solutions and technologies that offer flexibility and optionality will be highly valuable in the transition to net zero. This is why we have seen a rapid upswing of interest in the role of hydrogen in a clean energy future, both here in the UK and internationally.

Hydrogen delivers gaseous energy that can be stored for long periods of time and in large volumes. It can be deployed flexibly and responsively across the energy system, and combusts in a similar way to natural gas, without emitting carbon at the point of use.

Hydrogen can be produced from a range of energy inputs, including fossil fuels, electricity, biomass and waste, and can be used across multiple end use sectors. If hydrogen production can be wholly switched to low carbon methods, its particular characteristics position it as an important, and cost effective, decarbonisation option, particularly in hard-to-electrify sectors and processes. However, low carbon hydrogen is more expensive than high carbon alternatives, suggesting action will be required to address costs.

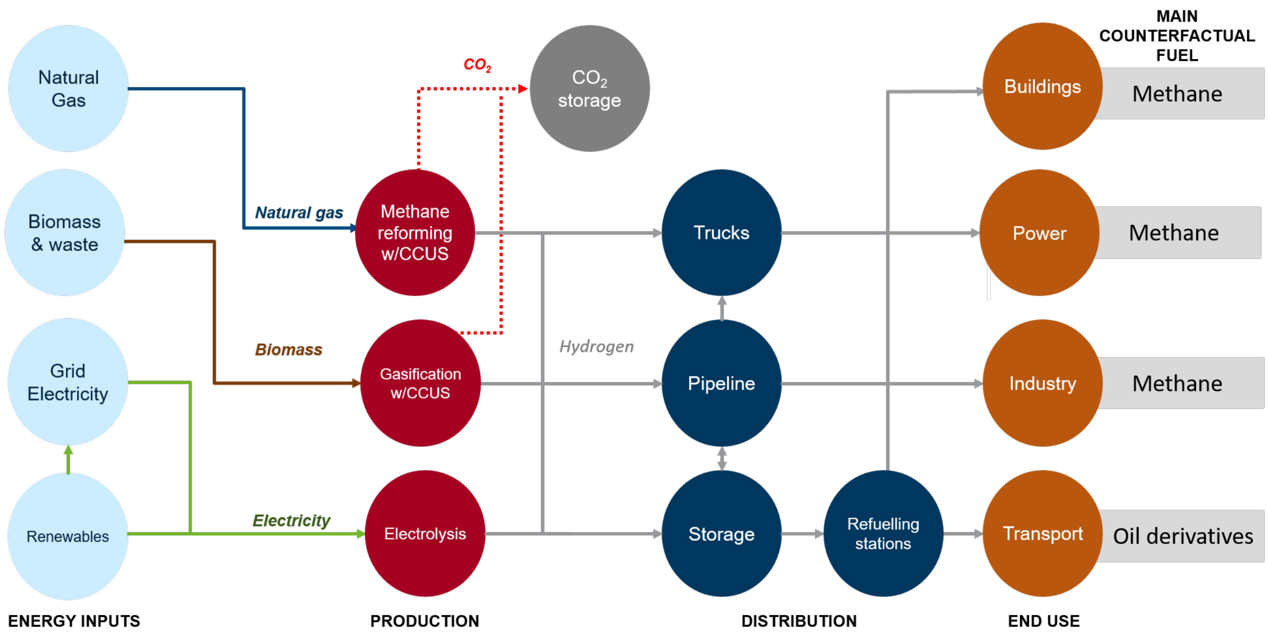


Figure 1: Representation of the hydrogen value chain

We are committed to exploring the option of hydrogen as a flexible and strategic decarbonised energy carrier for the UK, alongside electricity and other decarbonised gases. It is not possible to be certain of the precise role hydrogen will play in 2050, the applications it will be used in, or the scale of demand. That said, analysis from the Committee on Climate Change (CCC) suggests that a major increase in hydrogen production is required, with a complete switch to low carbon production methods.

The 'Further Ambition' scenario from the CCC's Net Zero report envisages up to 270TWh of low carbon hydrogen being produced and used in the UK by 2050. In this scenario, the Committee projects that over 80 per cent of low carbon hydrogen will come from production methods that require CCUS. These methods include methane reformation and biomass gasification (see Figure 2, on page 47).[44] CCUS is therefore a critical enabler for low carbon hydrogen production in the UK.

The current market for hydrogen in the UK is small. Production estimates range from 10-27TWh.[45] Only a fraction of current production is low carbon (the same is true internationally).[46] The main production methods are methane reformation and industrial processes which release hydrogen as a by-product. Neither method currently uses carbon capture. Demand for hydrogen is mainly from outside the energy system. The petrochemicals industry is the largest user of hydrogen, either as a feedstock (e.g. for fertilizer production) or for processing other fuels (e.g. in refining). A small amount of hydrogen is produced from electrolysis, primarily for use in transport.

To explore the potential of low carbon hydrogen as a component of a net zero energy system, we need to move towards commercial demonstration and deployment. We need to put the right building blocks in place to give confidence that low carbon hydrogen can be produced reliably and cost-effectively. As the CCC have recommended, hydrogen production could be an element of CCUS projects in some industrial clusters from the outset, complemented by retrofit of existing plant with carbon capture and renewable hydrogen from electrolysis.

We will work with partners to understand all the elements required to test low carbon hydrogen production and enable the option of deployment. This will include looking at the supply chain, skills requirements and how best to coordinate our efforts. Alongside this, it will be necessary to explore further the likely sources, scale and timing of future demand; and the Government's role in stimulating and supporting it.[47]

Action from a range of stakeholders will be required to deliver this ambition and any future ramp up. Key barriers to deployment across the hydrogen value chain need to be addressed: low carbon production at scale is still to be proven; the price of low carbon hydrogen is generally higher than high carbon alternatives (and expected to remain so out to 2030 (Figure 2)); and a new policy and market framework is needed to underpin long-term investment. In addition, appliances that could use hydrogen as a fuel[48] are not readily available in all sectors; and the safety, feasibility and consumer acceptability in novel use cases, such gas grid distribution and hydrogen for heat in buildings, needs to be proven.

[44] Committee on Climate Change, Net Zero Technical Report, May 2019, https://www.theccc.org.uk/publication/net-zero-technical-report/
[45] Energy Research Partnership, Role of hydrogen in the UK Energy System, October 2016: http://erpuk.org/wp-content/uploads/2016/10/ERP-Hydrogen-report-Oct-2016.pdf;
CCUS Advisory Group, Investment Frameworks for the Development of CCUS in the UK: CAG Final Report, July 2019, http://www.ccsassociation.org/ccus-advisory-group
[46] The International Energy Agency, The Future of Hydrogen, June 2019, https://www.iea.org/hydrogen2019/
[47] As one example of this, our Clean Maritime Plan includes a vision of clean maritime clusters being developed in the 2020s, including the bunkering of low or zero emission fuels such as hydrogen and/or ammonia, and a commitment to undertake a related study with the Clean Maritime Council: Clean Maritime Plan report: https://www.gov.uk/government/publications/clean-maritime-plan-maritime-2050-environment-route-map
[48] Such as domestic boilers and cookers, and industrial boilers, kilns and furnaces

As set out in the introduction, Government investment in a range of innovation programmes seeks to overcome some of these barriers and develop the potential of hydrogen. These programmes are complemented by a number of projects driven by academic, industry and regional partners that are testing and demonstrating a range of hydrogen applications in the UK.49 In addition, industry led studies such as HyNet North West and H21 North of England have explored the feasibility of projects using CCUS enabled hydrogen to deliver significant regional decarbonisation.[50]

We know from the development of other low carbon technologies that innovation is most effective when accompanied by supportive policy, including sustainable business models that can stimulate private investment. That is why we are complementing our increased investment in hydrogen innovation with inclusion of hydrogen production in the CCUS Review.

Work to date

The Parliamentary Advisory Group on CCS,[51] CCUS Cost Challenge Taskforce,[52] BEIS Select Committee[53], and HyNet project[54] have given consideration to business models for hydrogen production. By and large, that work has been guided by consideration of hydrogen's potential role in decarbonising heat; either blending into the gas grid, or full conversion of the gas grid to 100% hydrogen. As such, the potential for including production costs in existing Gas Distribution Network Operator (GDNO) Regulated Asset Bases (RABs), as part of the RIIO price control framework has been at the forefront of their thinking.

In support of this Review, the CCUS Advisory Group have looked again at the development of sustainable business models for hydrogen production, taking more of a whole system perspective. They have set out their view of the opportunity that low carbon hydrogen presents across the energy system, some of the open questions about hydrogen business models which need answering before a preferred model can be chosen, and have begun to discuss the effectiveness of a range of models, including options for sources of revenue and delivery mechanisms.

We have considered the findings of earlier work and the work of the CCUS Advisory Group, and tested our emerging thinking with CCUS and hydrogen stakeholders. There is consensus that more evidence is required before a full assessment of the suitability of business models to support hydrogen production for use across the energy system can be made. Responses to this consultation will help develop criteria that will guide future evaluation of different models, alongside the parameters set out in the introductory chapter.

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49 International Partnership for Hydrogen and Fuel Cells in the Economy, UK Country Update, 2019: https://www.iphe.net/united-kingdom

50 https://hynet.co.uk; https://www.northerngasnetworks.co.uk/h21-noe/H21-NoE-26Nov18-v1.0.pdf

51 Parliamentary Advisory Group on Carbon Capture and Storage, Lowest Cost Decarbonisation for the UK: The Critical Role of CCS, September 2016, http://www.ccsassociation.org/news-and-events/reports-and-publications/parliamentary-advisory-group-on-ccs-report/

52 CCUS Cost Challenge Taskforce, Delivering Clean Growth: CCUS Cost Challenge Taskforce Report, 19 July 2018, https://www.gov.uk/government/publications/delivering-clean-growth-ccus-cost-challenge-taskforce-report

53 BEIS Select Committee, Carbon capture usage and storage: third time lucky?, April 2019, https://publications.parliament.uk/pa/cm201719/cmselect/cmbeis/1094/109402.htm

54 Cadent, HyNet Project Report, 2018: https://hynet.co.uk/app/uploads/2018/05/14368_CADENT_PROJECT_REPORT_AMENDED_v22105.pdf

Scope of this chapter

The scope of this chapter is summarised in Table 1 and discussed in more detail below.

	In scope	**Out of scope**
Costs	Capital and operating costs of production	Capital costs of conversion Costs of distribution
Production method	Methane reformation with CCUS Biomass gasification with CCUS	Electrolysis
Relationship with wider CCUS	Hydrogen produced for fuel-switching from fossil fuels	Post-combustion capture on hydrogen production for industrial feedstock (in scope of ICC model)

Table 1: Summary of this chapter's scope

Costs

There are a range of costs associated with the deployment of low carbon hydrogen:

- **Production - capital costs:** Large-scale hydrogen production facilities come with high up-front construction costs. For example, a 300MW auto-thermal reformer (producing around 2.5TWh of hydrogen) could cost in the region of £250m.[55]
- **Production:**
    - **Operating costs:** Fuel costs - Hydrogen produced with CCUS is likely to come with higher fuel costs compared to directly using methane, in the region of 15-35% greater depending on production technology.[56]
    - **Operation and maintenance costs** - likely to be higher at least during scale-up as supply chains mature; will include the costs of using a T&S network for carbon.
- **Distribution costs,** including the costs of storage. For example, new hydrogen pipelines as needed across clusters; associated operation and maintenance costs, particularly as supply chains mature; purification costs where required (for use in some fuel cells).
- **End users' one-off conversion costs:** switching to hydrogen is likely to require additional capital expenditure on end use technologies (e.g. industrial boilers, buses),

[55] Assuming a 95% load factor; Element Energy, *Hydrogen supply chain evidence*, November 2018, https://www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base
[56] Element Energy, *Hydrogen supply chain evidence*, November 2018, https://www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base

particularly if switching does not align with existing replacement cycles and so could require an element of scrappage.

The scope of this consultation covers the capital and operating costs of a hydrogen production facility.

Distribution costs are not in scope because production and distribution are substantially different services, so an effective business model for hydrogen production may not be readily transferable to hydrogen distribution. Moreover, in line with current arrangements for energy production and distribution, it seems plausible that distribution assets could either be privately owned (particularly in the case of cluster projects, and as some existing hydrogen pipelines are), or could potentially be added to the Regulated Asset Base of Gas Distribution Network Operators.

End users' capital costs of conversion are not in scope because the additional costs are likely to be low relative to the cost of producing low carbon hydrogen. It is possible that these costs could be incorporated into the design of production business model at a later stage.

We would welcome views on whether our focus on hydrogen production at this stage is appropriate, or whether we should widen our focus to include a greater proportion of the hydrogen value chain.

Production method

Low carbon hydrogen can be produced through methods that do not require CCUS, mostly notably electrolysis.[57] We expect that in the near-to-medium term, methane reformation with CCUS will be the most cost-effective production method for low carbon hydrogen at scale. That said, electrolytic hydrogen could play a role by providing new routes to market for excess renewable electricity, and potentially provide substantial amounts of low carbon hydrogen in the longer term. This consultation focuses on CCUS-enabled hydrogen production, given its near-term opportunity for deployment at scale. We welcome views on whether and how a model could be designed to encompass a range of production methods.

Relationship with industrial carbon capture model

The focus of the industrial carbon capture (ICC) model is deployment of post-process capture on industrial processes. As set out above, some industrial processes include the production of hydrogen: the addition of post-process capture plant to this hydrogen production is in scope of the ICC model, so we do not consider it in this section.

[57] Royal Society, *Options for producing low-carbon hydrogen at scale*, January 2018, https://royalsociety.org/-/media/policy/projects/hydrogen-production/energy-briefing-green-hydrogen.pdf

Consultation questions on CCUS for hydrogen production

18. Do you agree that a future business model should focus on hydrogen production costs? If not, what are the benefits of considering other parts of the hydrogen value chain in the next phase of our work?

19. Do you have views on whether the model should seek to support both CCUS-enabled hydrogen production and renewable production methods? If so, how might this work?

Challenges to address

In line with our proposed scope, this section sets out some of the key challenges that a sustainable business model for hydrogen production will need to address. These challenges will inform the criteria by which specific business models are evaluated in our next phase of work. We welcome views on whether we have identified the most important challenges, whether we have characterised them (and potential mitigations to them) accurately, and whether there are other challenges that we should bear in mind as we evaluate specific business models.

Additional cost of hydrogen compared to high carbon alternative fuels

The key challenge that a business model needs to address is that, in the absence of a sufficiently high carbon price, low carbon hydrogen is expected to remain more expensive than methane in 2030, even as costs come down over the next decade (see Figure 2).

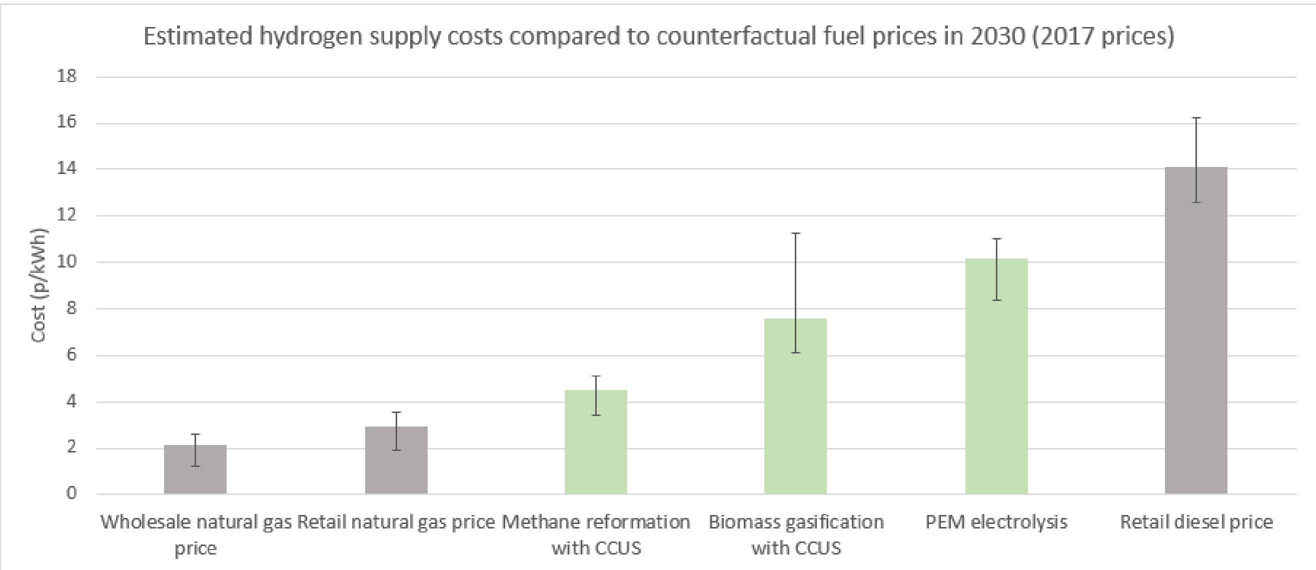

Figure 2: Estimates of hydrogen supply costs v fossil fuel counterfactuals[58]

[58] Source: BEIS analysis using Element Energy, Hydrogen supply chain evidence, November 2018, https://www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base and Valuation of Energy Use and Greenhouse Gas: Supplementary guidance to the HM Treasury Green Book on Appraisal and Evaluation in

The model will need to address the cost gap between low carbon hydrogen and methane, to ensure that hydrogen is competitive as a fuel-switching option for end users. In a sector such as industry, it will be important to have regard to the risk of carbon leakage, where emitters are incentivised to relocated overseas, rather than reduce their emissions if that comes with associated with increased energy costs.

In some sectors the main counterfactual fuel is not methane. Figure 2 shows that road diesel is expected to be more expensive than low carbon hydrogen, regardless of production method, in 2030.[59] We will need to monitor these fuel costs as they evolve to ensure that business models provide appropriate levels of support.

Ensuring that hydrogen production facilities are an investable proposition as demand grows and changes

The markets for low carbon hydrogen, particularly in potential lead applications like industry and heavy transport, are immature, and there is uncertainty around the sources, scale and timing of hydrogen demand in different sectors. This brings two related investment challenges:

- **Demand risk for investors, particularly in early projects**. New project developers may not be confident that there will be sustained future demand for hydrogen. Even if production facilities are built on the basis of supply contracts, credit risk could remain, as returns on investment would rely on the long-run viability of particular consumers. Unmitigated, this risk could mean higher interest rates on loans, which might make projects unattractive to investment.
- **Ensuring that new hydrogen production plants are appropriately sized.** A decision could be made to oversize production plants in anticipation of increases in future demand. However, future demand will be contingent on when users are willing and able to switch to hydrogen; and this in turn depends on a number of factors, including replacement schedules and lead-in times for equipment development. For investors, it may be less risky to size production plants based on more certain or nearer-term demand, but this might make production less cost-effective if there are smaller economies-of-scale.

Incorporating more established sources of hydrogen demand into the model for early projects could address these challenges. We have identified three existing markets that could provide reliable revenue for low carbon hydrogen produced in a commercial scale reformer:

- **Electricity generation** – though hydrogen is not currently used to generate grid electricity in the UK, the market for low carbon electricity is mature, and combusting

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Central Government, April 2019, https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal. Assuming plant sizes of 1GW for methane reformer, 10MW for PEM electrolyser, 250MW for biomass gasifier. Hydrogen supply costs only include the cost of the production technology, input fuels and an estimate of potential infrastructure costs. The counterfactual fuel price projections are shown for reference but are not directly comparable to the hydrogen costs: differing levels of taxation and duty are applied, and the efficiencies of end use technologies (like fuel cells) affects how much hydrogen is needed to replace a unit of fossil fuel. Costs do not include carbon prices, including for negative emissions, or the additional capital costs of fuel-switching.

[59] Figure 2 does not include a comparison with rebated diesel (so-called red diesel, as used in non-road applications, such as trains); but it is likely that, based on current duty rates, hydrogen produced via methane reformation with CCUS in 2030 could still be cheaper than red diesel.

hydrogen for this purpose could provide a stable revenue stream. Hydrogen-fired turbines, which are close to commercial readiness, would also need to be available.[60]

- **Petrochemicals** – this industry operates mature markets for hydrogen and hydrogen-derived products, including ammonia and methanol. Selling low-carbon hydrogen into these markets, which could include exports, could provide reliable revenue for hydrogen producers. The hydrogen is likely to be above market price (as there will be additional costs associated with capturing the carbon during production) but could command a premium for its low carbon content.

- **Decarbonisation of the gas grid** – blending hydrogen into the gas grid could provide a steady source of revenue. No additional physical demand-side activity is required to enable blending if it is at a sufficiently low level; and some (limited) decarbonisation benefit is derived from displacing natural gas. This will not be the long-term solution to the decarbonisation of heat, which will need to be almost completely decarbonised to meet our carbon targets, but it could play a role in de-risking early hydrogen projects.[61]

  Subject to the safety case for blending being proven (the objective of the Ofgem-funded HyDeploy projects), more evidence is needed about how much could be blended into the grid at one or a few injection points. This will affect the size of the potential revenue stream that could be relied on.[62]

There is an existing market for hydrogen in transport, with approximately 200 hydrogen fuel cell vehicles currently operating across the UK, including buses in London and Aberdeen.[63] While this number is set to increase, thanks in part to Government funding, the absolute size of this market is relatively small, and does not appear to have the potential to absorb substantial volumes of hydrogen in any one place before 2030. Increased future demand could come from heavy transport sectors, particularly buses, rail, shipping and some HGVs. However, we would not expect to see demand at scale before the 2030s. Transport therefore seems more likely to play a supplementary role in developing the business case for investment in low carbon hydrogen production facilities, particularly given the relatively high price hydrogen commands in this market.

A successful model will therefore ensure that early projects are investable propositions and will incentivise oversizing of production facilities. We believe that incorporating reliable sources of revenue is one way to achieve this.

Ensuring hydrogen is deployed where it makes the greatest contribution to our decarbonisation goals, rather than where it commands the highest market price

One of the overarching parameters for CCUS business models, set out in the introduction to this consultation, is that CCUS should provide value to the economy; but there are a number of ways to conceptualise the 'value' of hydrogen.

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[60] The Nuom Magnum project in the Netherlands is seeking to have a hydrogen-fired gas turbine operational from 2023. See https://www.nsenergybusiness.com/projects/nuon-magnum-power-plant/

[61] Committee on Climate Change, Net Zero Technical Report, May 2019; there are a range of other considerations associated with introduction of blending of hydrogen into the gas grid, including consumer acceptance. These are not the subject of this discussion.

[62] The HyNet project has estimated that up to 380 MW could be blended into the Local Transmission System during winter months, though this could imply low, potentially uneconomic load factors for production facilities in summer: see *HyNet Project Report*, Cadent, 2018: https://hynet.co.uk/app/uploads/2018/05/14368_CADENT_PROJECT_REPORT_AMENDED_v22105.pdf

63 IPHE, UK Country update, 2019:https://www.iphe.net/united-kingdom

One kind of 'value' is market value, i.e. the price consumers are willing to pay. Because hydrogen has the potential to displace fossil fuels in a range of end use sectors and sub-sectors, and because the price of these fossil fuels varies (see Figure 2 above), the market value of hydrogen is different in each sector. There are several reasons for this variation:

- The counterfactual fuel itself varies by sector: in some (like industry) it is likely to be natural gas, whereas in others (like some heavy transport) the counterfactual fuel is diesel.
- The policy costs paid for these fuels also varies: some end users pay ETS costs when they burn fossil fuels, whilst others do not; and levels of fuel duty vary by end use.
- There is variation in terms of the third-party revenue opportunities associated with burning fossil fuels: in some sectors (like power) hydrogen is an intermediate step towards a final product, and so can command a price premium, whereas in others it is simply an input fuel.

A second kind of 'value' is how cost-effective a technology is at decarbonising a sector, when compared to the alternatives in that sector (its 'decarbonisation value'). Recent evidence suggests that hydrogen is likely to be among the most cost-effective options areas of industry, where alternative options are limited or more costly.[64] Even though hydrogen may have a higher absolute cost of abatement (on a £/t basis) in industry than, say, in baseload power generation, the availability of lower-cost alternatives for baseload power, and the scarcity of alternatives for some industrial fuel-switching, means that hydrogen's decarbonisation value is likely to be higher in industry.

The challenge is that those sectors in which hydrogen has the greatest market value may not be those sectors in which hydrogen has the greatest decarbonisation value. Simply determining the allocation of hydrogen with reference to its market value could therefore lead to unintended consequences: for example, this could lead to subsidised hydrogen being used to reduce the costs of fertiliser production, or crowding out the deployment of other power generation technologies, like gas turbines with post-combustion capture, nuclear or renewables, in the generation of baseload power.

A successful model will therefore need to ensure that hydrogen is deployed in those sectors and sub-sectors where it makes the greatest contribution to our decarbonisation goals. This will mean determining the use of hydrogen in a way that reflects its decarbonisation value. Potential approaches to this include:

- Incentivising take up by particular end users, based on hydrogen's market and decarbonisation values in the relevant sector or sub-sector;
- Creating differential pricing for hydrogen; and
- Allocating specific volumes of hydrogen to end use sectors.

Each of these approaches is likely to come with additional administration costs, particularly as market value and decarbonisation value could be challenging to calculate accurately and could change over time. Consideration will also need to be given to the risk of double subsidy in the model's interactions with other sources of support, such as the capacity market in the power

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

sector and the Renewable Transport Fuel Obligation (RTFO) in the transport sector. We welcome views on the applicability and attractiveness of these different approaches to address this challenge.

Considering these two challenges together suggests how the model's priorities might change over time:

- for early projects, the priority is likely to be minimising risk to investors, potentially through incorporating reliable revenue streams from existing markets like power, petrochemicals and blending;
- over time, the priority is likely to become deploying hydrogen in those sectors in which it has the greatest decarbonisation value, like industry and potentially heavy transport (including shipping, buses, rail and some HGVs), as well as providing the opportunity for hydrogen to expand into new sectors.

How to take account of the avoided carbon price

Emitters with obligations under the EU ETS who switch from fossil fuels to low carbon hydrogen would no longer have to pay a carbon price. There is a choice to be made about how to account for this avoided carbon price in a business model, particularly for early projects:

- A focus on having a route to becoming subsidy-free, and on cost-efficiency, might suggest that the level of support should be adjusted to take account of the full avoided carbon price. This would mean that an increase in the carbon price would lead to a reduction in support, and that the model would only support the take-up of hydrogen to the point of cost-effectiveness with counterfactual fuels. This offers a clear route to being subsidy-free, but could come with considerable administrative complexity, because the volume of carbon captured is not the same as the abated emissions, and because the fair counterfactual might change over time.
- A focus on simplicity might suggest that the level of support should not be adjusted to take account of the carbon price. This would avert the need to develop a methodology for calculating appropriate carbon prices and emissions intensities. This approach would provide certainty and protection from price volatility for users, which is likely to be crucial in early projects to incentivise take up. However, the complete absence of a carbon price would weaken the incentive provided by carbon pricing to switch from fossil fuels to hydrogen. As a result, this option would not offer a clear route to being subsidy-free and may not be the most cost-effective approach.
- An intermediate option might suggest that the level of support should be adjusted to take account of a stable carbon price, potentially using a form of emissions trading auction reserve price. This would avert the need to develop a methodology for calculating appropriate carbon prices but would still require a methodology for calculating appropriate emissions intensities. The model would work in one way for all users, and so would provide certainty and protection from price volatility for users and would come with some administrative complexity.

The design of the model will need to include specific consideration of the role of the carbon price, particularly how it might change over time.

Consultation questions on CCUS for hydrogen production

20. Have we identified the most important challenges in considering the development of a business model for hydrogen production?

21. What reflections do you have on the approaches we have identified to address the main challenges in designing the model?

Next steps

Following this consultation, our focus will be on detailed evaluation of specific business models for hydrogen, including consideration of both sources of revenue and delivery mechanisms for that revenue, using the parameters outlined in the introductory chapter and the challenges identified through this consultation as the basis for our assessment criteria. We welcome views on specific models that we should consider evaluating as part of this phase of our work. We will seek to consult on specific models in 2020, with a view to responding to the consultation by the end of 2020.

Consultation question on CCUS for hydrogen production

22. Do you have views on which business models we should evaluate in the next phase of our work?

Chapter 6: Delivery Capability

CCUS is likely to form a crucial part of the UK's pathway to achieving net zero emissions. This could involve the build-out of large-scale facilities across multiple sectors and regions, which could represent a significant delivery and coordination challenge.

In the CCUS Action Plan we committed to ensuring that we have the people and the delivery capability to deliver the CCUS infrastructure challenge, enabling the option to deploy CCUS at scale in the 2030s, and creating high value jobs for people across the UK.

Developing CCUS requires complex and large-scale infrastructure and technological advancement involving a wide number of actors including developers, investors, innovators and start-ups, local and central government and academia. There is action taking place across the entirety of the development lifecycle: R&D, capture facilities, utilisation and transport and storage. As we move to deploying CCUS in the UK, the supply chain will also need to gear up to maximise UK investment in the development of the technology. This includes transitioning the UK's existing skills base in the oil, gas and chemicals industries to support and service a CCUS industry.

The potential scale of CCUS deployment required to support net zero could mean a new industry is developed over a short timeframe. It will also involve interplay between different sectors (e.g. industry, power, transport) as well as different components of the CCUS chain, representing significant deliverability risk. Considering how to coordinate and reduce delivery risk will be important, particularly in the early phases of CCUS deployment in the UK.

As a nascent technology which has a potentially significant role in achieving net zero we want to consider the capabilities that might be required to deliver CCUS in the UK. This includes consideration of whether a co-ordinating body could help to ensure that all actors involved in CCUS work efficiently and effectively together.

Table 1 summarises some of the capabilities that might be needed to deploy CCUS and maximise the benefits to the UK.

Capabilities required	Rationale
Assessment of CO_2 storage sites	Storage appraisal activity will be needed to identify sufficient appropriate storage capacity to support CCUS deployment. Initial storage appraisal work has been conducted but further appraisal activity is likely to be needed.
Monitoring project pipeline	Maintaining a view of projects in feasibility, design, construction, operation and decommissioning stages.
Minimisation of risks	Project risks should be carefully considered and understood. The optimisation of projects across the CCUS chain can improve efficiencies and reduce costs of CCUS projects.
Coordination, planning and oversight of projects	Projects will need to be carefully planned and assessed to maximise the strategic benefit. Overseeing planning, coordination

	and delivery of projects, for example 'right-sizing' of CO_2 transport and storage infrastructure.
Technical assurance of projects	Ensuring projects meet technical standards required to ensure safe and effective capture, usage, transport and storage of CO_2.
Benefits realisation	Ensuring that strategic benefits of projects are secured, in particular ensuring that regional benefits such as jobs in the supply chain are realised and that regional populations have the opportunity to access these.
Oversight of the supply chain – skills, manufacturing, R&D	Oversight of the supply chain, including requirements for future projects. Identifying opportunities for maximising the benefit to UK companies.
Attracting external investment	Building investor confidence in deployment of CCUS technologies and securing increased direct investment in project deployment.
Disseminating knowledge to inform future projects	Maximising cost reductions in CCUS technology deployment from 'learning by doing' by ensuring knowledge spill over from initial projects.
Coordination of research to align with industry needs	Maximising impact of research through direct application to commercial projects which can drive down project costs.
Public engagement	Generating sustained support for CCUS across society is important if the sector is to be developed at the scale required to meet UK climate goals.

Table 1: Summary of possible capabilities needed for successful deployment of CCUS projects

The option of a CCUS co-ordinating body

Given the possible complexity of delivering CCUS across sectors as well as the coordination required between Government, industry, regions and academia, it has been suggested by the CAG and the Parliamentary Advisory Group on CCS[65] that a dedicated co-ordinating or delivery body for CCUS in the UK is needed.

The arguments put forward to Government for such a body are that, by representing the interests of multiple parties, it could better incorporate the views and needs of stakeholders in decision making processes. It could advise central Government while also working closely with regulators, potential CCUS projects and emitters, investors, trade unions, NGOs, research institutions and local authorities. Expertise around project delivery can be retained from one project to the next, supporting the transfer of 'learning by doing' knowledge to reduce costs of subsequent projects. This could be of increasing importance as the CCUS industry is scaled up. It should be noted though that, if a body were needed, we envisage its primary purpose to

[65] Parliamentary Advisory Group on Carbon Capture and Storage, Lowest Cost Decarbonisation for the UK: The Critical Role of CCS, September 2016, http://www.ccsassociation.org/news-and-events/reports-and-publications/parliamentary-advisory-group-on-ccs-report/

be supporting capabilities around delivery and co-ordination rather than owning or investment in CCUS projects (or elements of them).

Table 2 provides an assessment of some of the possible capabilities outlined in Table 1 and a high-level view on who might deliver them, including whether a delivery body could take them on.

Responsibility for:	Private sector	Local government	Academia	Future Co-ordinating/ Delivery Body
Assessment of storage sites	✓			✓
Monitoring project pipeline		✓		✓
Optimisation of CCUS chain	✓			✓
Coordination, planning and oversight of projects, including cluster development	✓	✓		✓
Technical assurance of projects	✓		✓	✓
Benefits realisation		✓		✓
Oversight of the supply chain – skills, manufacturing, R&D	✓			✓
Attracting external investment	✓			
Disseminating knowledge to inform future projects	✓	✓	✓	✓
Coordination of research		✓	✓	✓
Public engagement	✓	✓	✓	✓

Table 2: Assessment of existing capabilities within government, private sector, local government and academia and potential capabilities within a Delivery Body

We have also considered examples of CCUS bodies in other countries, in particular Norway and Japan (outlined in Table 3). Both have responsibilities for developing the technology, acting in an advisory capacity and supporting the development of CCUS projects.

We also recognise though that other countries such as the United States and Canada, who are deploying CCUS projects, do not have a specific CCUS body. The scale up of CCUS in these countries has been driven organically through industry, incentivised by demand for captured CO_2 in enhanced oil recovery and backed up by supportive policy, such as the 45Q tax credit and federal and state funding. This highlights that creating a specific CCUS body is a possible option, rather than a necessity.

Gassnova, Norway	Japan CCS
Gassnova[66] was established in order to effectively manage the risk of delivering CCS projects, with the Gassnova Board ultimately responsible for these projects, and accountable to the Minister for Petroleum and Energy. Responsibilities: • Technology development, including management of Technology Centre Mongstad.[67] • A full-scale CCS project. • Providing advice to Government on CCUS and climate issues.	Japan CCS[68] is a special purpose company, established in 2008 in response to the Japanese Government's call to develop CCUS technology. Japan CCS has five key business objectives: • Conduct studies and demonstrations for CCS projects in Japan. • Provide industry view on establishing legislation, regulations, and technical standards for CCS. • Conduct promotional activities. • Cooperate internationally to drive global deployment of CCS. • Collect and exchange information on CCS with international research organisations.

Table 3: Summary of Gassnova and Japan CCS, two CCUS delivery organisations

The CAG has developed a list of key capabilities and recommended the establishment of a specific CCUS body that would support the deployment of CCUS in the UK, which we have reflected above. Further detail on the CAG's recommendations for CCUS delivery capabilities can be viewed in their report which accompanies this consultation.

Consultation question on delivery capability

23. What capabilities are needed for the delivery of CCUS in the UK?

[66] https://www.gassnova.no/en
[67] https://www.gassnova.no/en/technology-centre-(tcm)
[68] https://www.japanccs.com/en/

Annex: Glossary of terms

Defined Term	Definition
Allam Cycle	An ‘oxy-fuel combustion’ technology which uses pure oxygen diluted with recycled CO_2 instead of air as the oxidant for the combustion process in a natural gas power plant. Pure ‘carbon capture ready’ CO_2 is produced as a function of the Allam Cycle.
Allowed Revenue	A regulated revenue amount (in £) which the project company is entitled to receive under its economic licence in return for constructing and operating a nuclear power plant.
Auto-thermal reformation (ATR)	A kind of methane reformation with the potential to achieve high carbon capture rates.
Baseload	The minimum level of demand on the electricity grid. The term is often ascribed to the type of power plants which typically service this demand, running at high load factors (e.g. Nuclear).
Biomass gasification	The production of gas (in this case hydrogen) from biomass.
BECCS	Bioenergy with Carbon Capture and Storage (BECCS) is the combination of biomass combustion or gasification with carbon capture and storage. BECCS can generate ‘negative emissions’ by capturing and storing the atmospheric CO_2 temporarily locked in plants after processing them to gain their energy.
Carbon capture, usage and storage (CCUS)	Carbon capture, usage and storage (CCUS) is the process of capturing carbon dioxide emissions from large-point sources (such as industrial facilities and power stations), and either transporting it in pipelines or via ships to very deep subsurface rock formations, where it can be safely and permanently stored; or using it, for example in the food and drink sector as a carbonating agent, or in the pharmaceutical industry, as a respiratory stimulant, or in the cement industry.
CCUS Advisory Group (CAG)	The CCUS Advisory Group (CAG) is an industry-led group, established in March 2019, which has been considering the critical challenges that face CCUS, and providing insight into potential solutions. The CAG brings together experts from across the CCUS industry, finance and legal.

	The views expressed by the CAG do not reflect Government policy, and they cannot be taken to represent the views of each or all members of the CAG. However, they do reflect a general consensus within the CAG.
Cap and floor mechanism	An incentive mechanism based on minimum (floor) and maximum (cap) revenues. Generators are 'topped up' to the floor if earnings fall below this threshold. If earnings exceed the cap, generators must return them.
Capacity Market	A market-based mechanism that incentivises reliable generating capacity to be available to ensure security of electricity supply.
Capex	Capital Expenditure.
CCGT	Combined cycle gas turbine.
Contract for Difference (CFD)	A Contract for Difference, as set out in the Energy Act 2013, is a contract between a generator and the Low Carbon Contracts Company, to encourage the generation of low carbon electricity.
Counterfactual fuel	The main fuel currently used in an end use sector, which a low carbon alternative could replace.
Cost of capital	Cost of finance, being the return that investors (equity and debt) expect for providing capital to a company.
Credit risk	The risk of a loss on a debt that may arise from a borrower failing to make required payments or meet contractual obligations.
Delivery Body	An entity that could coordinate and deliver several of the capabilities required for CCUS deployment.
Depreciation	The allocation of the cost of assets to periods in which the assets are used.
Dispatchable generation	Energy generation capacity which is typically available to increase or decrease output on demand, for example gas and biomass.
Electrolysis	A hydrogen production process which involves using electricity to generate hydrogen from water, with no CO_2 emissions at the point of production.
Emissions trading auction reserve price	A minimum price set at which allowances can be sold, set in advance of an emissions trading auction.
EU ETS	EU Emissions Trading Scheme.

First of a kind (FOAK)	A facility, technology, or process considered to be in some way novel or untested in the market.
GSP	Government Support Package.
GW	Gigawatts (1,000,000,000 Watts).
HGV	Heavy goods vehicle.
Industrial Clusters Mission	A mission announced in 2018 under the Clean Growth Grand Challenge, which aims to create the world's first net-zero carbon industrial cluster by 2040 and establish at least one low carbon bluster by 2030.
Intermittent generation	Energy generation which is typically not continuously available, for example wind and solar.
Levelised cost of electricity (LCOE)	A comparative measure of the cost of different generation sources. LCOE takes the total cost to build and operate a power generating asset over its lifetime and divides this by its total lifetime energy output.
Low Carbon Contracts Company	The LCCC is the counterparty for the Government's Contract for Difference (CfD) scheme. Its primary role is to manage CfDs with low carbon generators throughout their lifetime.
Methane reformation	A process for hydrogen production in which methane is the input fuel.
Mid-merit	The typical place in the 'Merit Order' of a load following power plant, which adjusts its power output as demand for electricity fluctuates throughout a day.
MW	Megawatt (1,000,000 Watts)
MWh	A MW of energy used for an hour
NAO	The National Audit Office
Negative emissions technology	Technology that removes greenhouse gases from the atmosphere (also known as negative emissions).
Net Zero	Legislation passed by the Government to reduce greenhouse gas emissions to net (i.e. including the use of negative emissions technology) zero by 2050.
Nth of a kind (NOAK)	A facility, such as a power plant, using mature technologies and processes.
Ofgem	The Office of Gas and Electricity Markets. The regulator for gas and electricity markets in the UK.

Opex	Operational expenditure.
Pass-through payment	In the context of this consultation, a "pass-through" payment is a fee paid by the funders of a capture plant, which the capture plant passes on in full to the CO_2 Transport and Storage operator, to cover the costs of CO_2 Transport and Storage.
RAB	Regulated Asset Base. The total cumulative capital expenditure as incurred and approved as being efficient by the Regulator.
RAB model	A type of economic regulation typically used in the UK for monopoly infrastructure assets such as water, gas and electricity networks, the application of which to carbon dioxide transport and storage is considered in this consultation.
Renewable Transport Fuel Obligation (RTFO)	A requirement on suppliers of transport and non road mobile machinery (NRMM) fuel in the UK to show that a percentage of the fuel they supply comes from renewable and sustainable sources.
Replacement schedule	The planned timing of replacing end use process equipment.
Revenue Stream	A route for funds to be raised from energy suppliers (and indirectly their consumers) to support new nuclear projects, with the amount set through the ERR, during both the construction and operational phases.
RIIO	Revenue = Incentives + Innovation + Outputs. The network price controls set by Ofgem.
Supply contract	A contract entered into by suppliers and customers governing the supply of a certain good for a certain period of time.
Short-run marginal cost (SRMC)	The cost of producing an additional unit of product. In this document SRMC is determined by a combination of technical characteristics of a CCUS facility, such as efficiency, fuel costs, carbon costs and fixed opex.
Strike price	The level of the fixed, pre-agreed price for the production of low carbon electricity under a CFD.
Third-party revenue	The potential revenue that can be gained by converting something (e.g. in this consultation, hydrogen) into something else, and selling the final product on.

T&SCo	A CCUS delivery company, responsible for delivering the transport and storage infrastructure for all sources of CO_2.
TTT	Thames Tideway Tunnel project.
TWh	Terawatt hour – 1,000,000 megawatt hours.
VfM	Value for Money.
Wholesale Market	The UK wholesale electricity market, where electricity is traded between suppliers, generators, traders and customers.
Zero marginal cost generation	Generation which carries zero (or almost zero) additional cost for each additional unit of energy produced. Renewable energy technologies are often described this way, whereas fuelled technologies carry a marginal cost.