Department for
Business, Energy
& Industrial Strategy

Llywodraeth Cymru
Welsh Government

Decarbonisation Readiness

Joint call for evidence on the expansion of the 2009 Carbon Capture Readiness requirements

Closing Date: Wednesday 22 September 2021

July 2021

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

Executive summary

The 2009 Carbon Capture Readiness (CCR) requirements[1] have ensured that new build combustion power plants sized at or above 300 MW in England and Wales have only been granted planning consent if they can demonstrate it is technically and economically feasible to retrofit carbon capture technology to the plant within its lifespan. As noted in the December 2020 Energy White Paper (EWP),[2] the 300 MW threshold means only a small proportion of new build combustion power plants are captured by the requirements. Furthermore, the UK Government and Welsh Government believes the threshold is creating a market distortion which is constraining the deployment of new build gas-fired power plants larger than 300 MW. The CCR requirements also ignore the possibility of conversion to firing low carbon hydrogen and so limit the decarbonisation options available to combustion power plants.

This call for evidence follows the commitment announced in the EWP for the government to consult on an expansion to the CCR requirements. In this call for evidence, we are seeking initial views on how to expand the scope of the CCR requirements to ensure that all new build combustion power plants have a viable route to decarbonisation. Additionally, we are seeking views on how to make the requirements more flexible, to keep pace with the evolving nature of decarbonisation technologies, including low-carbon hydrogen and carbon capture. As part of this expansion, we have renamed the CCR requirements to the "Decarbonisation Readiness" requirements, to reflect their expanded scope.

We are seeking views and evidence in the following areas:

- Removing the 300 MW minimum capacity threshold at which the requirements apply. This should remove the market distortion for plants sized over 300 MW and support the rapid decarbonisation of the electricity system.

- Moving the Decarbonisation Readiness requirements from the planning consent process to the environmental permitting process. This should allow the requirements to be amended more readily to respond to future market or technical developments. The Environment Agency (EA) and Natural Resources Wales (NRW) would be responsible for the implementation of the requirements in England and Wales respectively.

- Introducing the option to comply with Decarbonisation Readiness through hydrogen conversion, in addition to the retrofitting of carbon capture and storage (CCS) technologies. This should provide a decarbonisation option more suitable for smaller combustion plant and/or 'peaking' combustion power plants (i.e. plants with a lower load factor) for which CCS conversion would be potentially impractical due to either economic or technical constraints. The option would also be available for larger sized plants where CCS may be possible, but hydrogen conversion could also be a cost-effective option. This will require the development of new assessments for hydrogen conversion readiness.

- Expanding the scope of Decarbonisation Readiness to include some technologies which were previously excluded from CCR; for example, heat generation, biomass, energy from waste (EfW) and combined heat and power (CHP). This should support the rapid

[1] https://www.gov.uk/government/publications/carbon-capture-readiness-ccr-a-guide-on-consent-applications
[2] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future

decarbonisation of the electricity system and complement existing technology-specific decarbonisation policies.

- Ensuring that the economic and technical feasibility assessments are updated to reflect developments including, for example, the recent consultation on how to sequence industrial clusters,[3] as well as the forthcoming UK Government's Hydrogen Strategy, which was announced in the EWP. This will ensure that the assessments fit with wider government policy.

- Allowing developers the flexibility to choose between CCS, hydrogen conversion and any other decarbonisation technologies which may come forward in the future. This should enable developers to respond to emerging market or technical developments and make effective business decisions which also support decarbonisation efforts.

- Ensuring that the assessments for Decarbonisation Readiness are achievable for developers and do not limit investment in firm dispatchable generation, whilst also being meaningful in ensuring combustion power plants have a viable route to decarbonisation.

[3] https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-market-engagement-on-cluster-sequencing

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1. Introduction

1.1 Background

Carbon Capture Readiness (CCR) requirements[4] were introduced in 2009 to ensure that planning consent in England and Wales was only granted to fossil fuel combustion[5] power plants where developers could demonstrate it was technically and economically feasible that carbon capture technology could be retrofitted within the lifetime of the plant. This requirement only applied to prospective power plants sized at or above 300 MW and covered by (at the time) the Large Combustion Plant Directive. Large power plants are expected to have an operational life of around 25 years,[6] during which time it was recognised that the government might take action to decarbonise the electricity system which could affect the operation of these plants. The intent of the CCR requirements was, therefore, to reduce the risk of generation assets becoming uneconomic before the end of their operational lifetime because of unanticipated changes in their operation, due to action to decarbonise the electricity system.

Since the original CCR requirements were introduced, GB's electricity sector has changed dramatically. Renewable capacity has increased fivefold since 2010, with around 50% of the UK's power now coming from low-carbon technologies, and the government recently confirmed its intention to accelerate the closure of unabated coal power generation units in GB, bringing forward the closure date to 1 October 2024.[7]

We are only part way through the energy transition, with more change still to come. In 2019, the UK became the first major economy to commit in law to reducing national carbon dioxide (CO_2) emissions to net zero by 2050.[8] The Energy White Paper[9] (EWP), published in December 2020, highlighted that the UK will need to go further in its efforts to decarbonise the power sector, particularly as it underpins the decarbonisation of other sectors and, therefore, delivery of our net zero target. For example, the electrification of cars and vans, and the anticipated increase in electric heating, will support decarbonisation efforts but will also increase electricity demand.[10]

In March 2021, Wales also set its statutory target for greenhouse gas emissions to be net zero by 2050. This is particularly challenging given the high proportion of emissions from the hard to decarbonise industrial and agricultural sectors, and the disproportionate amount of gas-fired power generation capacity located in Wales.

We expect that a large amount of new capacity will need to be built over the next decade and beyond to meet increased demand, but also to replace aging capacity that closes. In addition to the closure of the last remaining coal plant by 2024, a large proportion of the UK's existing nuclear fleet is coming to the end of its operational life and a number of Combined Cycle Gas Turbines (CCGTs) are also expected to reach the end of their operational life within the coming decade.

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[4] https://www.gov.uk/government/publications/carbon-capture-readiness-ccr-a-guide-on-consent-applications
[5] Combustion power plants burn fuel to generate electricity.
[6] https://www.gov.uk/government/publications/leigh-fisher-and-jacobs-2016-electricity-generation-cost-update
[7] https://www.gov.uk/government/consultations/early-phase-out-of-unabated-coal-generation-in-great-britain
[8] https://www.gov.uk/government/news/uk-becomes-first-major-economy-to-pass-net-zero-emissions-law
[9] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future
[10] BEIS modelling suggests that overall demand for electricity could double by 2050 as more areas of the economy electrify.

Much of this demand for new capacity will be met by low carbon capacity. However, some of this new capacity will need to be dispatchable,[11] in order to be available when renewable output is lower. Whilst we expect dispatchable low carbon options such as long-duration storage, low carbon hydrogen and carbon capture and storage (CCS) to provide peaking capacity in the future, these technologies are not presently deployed at scale. Therefore, we expect that, in all likelihood, there will continue to be a need for new build gas-fired generation, supported by the Capacity Market, to come forward in the mid-2020s to fill the capacity gap left by closing plants and increasing demand, and so ensure security of supply.

In the longer term, decarbonising the electricity sector means replacing – as far as it is possible to do so – fossil fuels with clean electricity generation technologies. That said, we recognise the essential role that unabated gas generation currently plays in ensuring security of supply. Furthermore, as outlined in the EWP, some scenario analysis suggests that an amount of unabated gas generation on the system in 2050 may be consistent with net zero, provided it has lower load factors.

As new unabated combustion power plants constructed during the next decade could be expected to be operational into the 2040s and 2050s,[12] it is likely that at some point, during the lifespan of these assets, the government will need to act, to achieve net zero by 2050, by restricting carbon emissions and staying within the trajectory set by our carbon budgets. This could be directly, for instance, through a carbon emissions limit; indirectly, such as, through limiting operational hours; economically, through carbon pricing or through supporting greater amounts of low carbon, zero marginal cost flexible assets which displace gas; or a combination of these. At present, we have not confirmed which option, or combination of options, we are likely to pursue.

To reduce the risk that such policy actions prevent these plants from earning an economic return on their investment (i.e. becoming “stranded assets”), it is important that developers put plans in place to ensure that these assets can be decarbonised in the future, through the low-carbon technologies which are expected to be available by retrofitting CCS or converting to hydrogen-firing. The government is planning to support the deployment of CCS and hydrogen for power through separate mechanisms, including through the Dispatchable Power Agreement (DPA) for power CCS and a hydrogen business model to stimulate investment in new hydrogen projects. Furthermore, hydrogen and CCUS-enabled plants can already compete in the Capacity Market (CM), and we intend to come forward with a call for evidence on how the CM can better align with our net zero commitment. These mechanisms will create opportunities for unabated plants to retrofit to low carbon in future, but this will only be relevant for sites where it is economically and technically feasible to do so.

Therefore, we are undertaking an expansion of the CCR requirements, to ensure that all new build combustion power plants, regardless of size, have a viable route to decarbonisation. The requirements will continue to apply in England and Wales[13] only. We note that, in their report on the UK’s 6th Carbon Budget, the Climate Change Committee highlighted an update to CCR as one of their key recommendations for driving the net-zero agenda forward in the early 2020s.

[11] Dispatchable generation is electricity generation that can be turned on, off, up or down as needed.
[12] New build gas turbines can be expected to have an operational life of around 25 years and new build reciprocating engines may be in operation for more than 15 years https://www.gov.uk/government/publications/leigh-fisher-and-jacobs-2016-electricity-generation-cost-update
[13] This matter is devolved. Northern Ireland and Scotland have their own arrangements.

1.2 Summary of areas covered by the call for evidence

This call for evidence seeks evidence and feedback on our expansion of the CCR requirements, as trailed in the EWP. The requirements will be expanded to capture smaller plants and allow for an assessment of not just the feasibility of retrofitting carbon capture equipment but also conversion to hydrogen-firing. To reflect the expanded scope, we are renaming the requirements to "Decarbonisation Readiness" (DR) requirements.

The primary aim of the DR requirements is to minimise the risk of creating stranded assets and, therefore, minimise the costs associated with decarbonising the power sector. The DR requirements will support developers with their plans for maximising the potential to decarbonise their new build assets in the future. We expect that developers will already be doing this planning, given the net-zero imperative. The DR requirements will support and standardise this process across the energy industry, as well as to give the government transparency and confidence on how industries are planning to decarbonise sites.

The EWP, which announced the government's intention to expand the CCR requirements, highlighted a number of issues to be addressed through the review. Specifically:

- The 300 MW threshold means the requirements only apply to a small proportion of new build power plant. For example, around three quarters of new build gas-fired capacity which secured long-term agreements in the Capacity Market since 2017 have been sized below 300 MW.[14]
- The 300 MW threshold is creating a market distortion by preventing the deployment of peaking plants larger than 300 MW,[15] as peaking plants are unable to pass the economic and/or technical feasibility tests for CCS.
- The current CCR requirements do not reflect technological advances and alternative options for decarbonising power plants, including conversion to firing low-carbon hydrogen.

We are seeking evidence and views on the following:

- Removing the 300 MW minimum capacity threshold at which the requirements apply. This should remove the market distortion for peaking plants and support the rapid decarbonisation of the electricity system.
- Moving the Decarbonisation Readiness requirements from the planning consent process to the environmental permitting process. This should allow the requirements to be amended more readily to respond to future market or technical developments. The Environment Agency (EA) and Natural Resources Wales (NRW) would be responsible for the implementation of the requirements in England and Wales.
- Introducing the option to comply with Decarbonisation Readiness through hydrogen conversion, in addition to the retrofitting of carbon capture and storage (CCS) technologies. This should provide a decarbonisation option more suitable for smaller combustion plant and/or 'peaking' combustion power plants (i.e. plants with a lower load factor) for which CCS conversion would be potentially impractical due to either economic

[14] Source: Capacity Market Registers as at April 2021, https://www.emrdeliverybody.com/CM/Registers.aspx
[15] In the T-4 auction for Delivery Year 2024/25 seven Capacity Market Units sized at 299-299.9 MW prequalified for the auction (about a quarter of pre-qualified new build gas capacity).
Source: Capacity Market Registers as at April 2021, https://www.emrdeliverybody.com/CM/Registers.aspx

or technical constraints. The option would also be available for larger sized plants where CCS may be possible, but hydrogen conversion could also be a cost-effective option. This will require the development of new assessments for hydrogen conversion readiness.

- Expanding the scope of Decarbonisation Readiness to include some technologies which were previously excluded from CCR; for example, biomass, energy from waste (EfW) and combined heat and power (CHP). This should support the rapid decarbonisation of the electricity system and complement existing technology-specific decarbonisation policies.

- Ensuring that the economic and technical feasibility assessments are updated to reflect developments including, for example, the recent consultation on how to sequence industrial clusters,[16] as well as the forthcoming Hydrogen Strategy, which was announced in the EWP. This will ensure that the assessments fit with wider government policy.

- Allowing developers the flexibility to choose between CCS, hydrogen conversion and any other decarbonisation technologies which may come forward in the future. This should enable developers to respond to emerging market or technical developments and make effective business decisions which also support decarbonisation efforts.

- Ensuring that the assessments for Decarbonisation Readiness are achievable for developers and do not limit investment in firm dispatchable generation, whilst also being meaningful in ensuring combustion power plants have a viable route to decarbonisation.

The feedback from this call for evidence will form the basis of further consultation on specific proposals for DR and the legislative changes necessary to implement them. We anticipate issuing this consultation by the end of 2021.

This call for evidence complements the UK Government's ongoing review of the National Policy Statements for energy infrastructure (NPS). Our intention is to update the NPS sections pertaining to CCR as part of this review and in line with the introduction of any new DR requirements.

1.3 How to Respond

This call for evidence will be open for 10 weeks from 14 July 2021 until 22 September 2021. Please submit your response to this consultation by 11:59pm on 22 September 2021. When responding, please state whether you are responding as an individual or representing the views of an organisation. Your response will be most useful where it is framed in direct response to the questions posed, though further comments are also welcome.

Email to: energy.security@beis.gov.uk

[16] https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-market-engagement-on-cluster-sequencing

1.4 Confidentiality and data protection

This call for evidence is being undertaken on behalf of the Department for Business, Energy and Industrial Strategy (BEIS) and the Welsh Government. Information you provide in response to this consultation, including personal information, may be shared between these bodies, and 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.

2. Scope of Decarbonisation Readiness

2.1 Territorial Scope of Decarbonisation Readiness

The current CCR requirements apply in both England and Wales. Our intention is to retain this territorial scope with Decarbonisation Readiness. If DR were to be implemented, it would be administered through environmental permitting rather than the current planning consent process. The regime would be, therefore, primarily implemented in England by the Environment Agency, and in Wales by Natural Resources Wales. For some specific sites, local authorities may manage environmental permits rather than the regulator. This matter is devolved; therefore, Scotland and Northern Ireland have their own arrangements.

2.2 The 300 MW threshold

As announced in the EWP, a key change to CCR that we would like to make is the removal of the 300 MW threshold. This would ensure that as many build combustion power plants, as possible are covered by the requirements. The requirements would continue to apply in England and Wales only, as did the CCR requirements. The matter is devolved. Scotland and Northern Ireland have their own arrangements.

A significant proportion of capacity on the system is small-scale combustion generation, particularly natural gas-fired reciprocating engines, and this volume is growing. For example, in Capacity Market auctions since 2017, around three quarters of new-build natural gas-fired capacity which secured agreements was sized below 300 MW.[17]

As with larger assets, small scale combustion generation can be expected to have an operational life of around 15 years (reciprocating engines) to 25 years (gas turbines). To meet net zero in a way which minimises the risk of creating stranded assets, it is vital that new build smaller scale combustion power plants also provide themselves with the option and ability to adopt decarbonisation measures during their lifespan. The removal of the 300 MW threshold should help achieve this outcome.

In practice, if the DR requirements were to be implemented through environmental permitting (see Section 3), then DR could be applied to all power plants that require an environmental permit. Currently, almost all new build combustion power plants must obtain a environmental permit, although a small number are not covered (e.g. plants sized below 1 MW which are not a Specified Generator[18]).

To date, 'peaking' plants have struggled to demonstrate, according to the current CCR requirements, that it would be technical or economically feasible to retrofit carbon capture equipment in the future. This is evidenced by the number of 'peaking' plants consented at 299 MW. In relation to technical feasibility, plants equipped with post-combustion CCS are not expected to be suited to providing fast-start peaking capacity, due to the amount of time that it takes for capture equipment to reach its maximum capture rate. In relation to 'economic feasibility', the avoided carbon costs over typical running hours for peaking plants from any

[17] Source: Capacity Market Registers as at April 2021, https://www.emrdeliverybody.com/CM/Registers.aspx
[18] As defined in Defra's guidance: https://www.gov.uk/guidance/specified-generator-when-you-need-a-permit#definition-of-a-specified-generator

captured carbon may not be sufficient to cover the scale the investment in the carbon capture equipment.

To ensure removal of the 300 MW threshold does not lead to a cessation of the development of peaking plant of all sizes, the development of the new DR requirements needs to strike a careful balance between making the tests meaningful (to ensure they meet their stated objective of supporting decarbonisation and reducing the risk of stranded assets) whilst still being achievable. The new assessments which are designed to test the potential for future conversion to hydrogen-firing will be critical in this (see Section 6), as will our proposed updates for carbon capture and storage technologies (see Section 7).

Removing the 300 MW threshold will eliminate the market distortion between smaller and larger plants, and ensure developers bring forward optimal sized plant which can provide for a more cost-efficient system overall.

Question 1 (Background)

What type of organisation are you answering on behalf of? (e.g., generation, interconnector, demand side response, storage, investor, developer, trade association, consultant, individual, other)

Question 2 (Background)

Which technologies is your organisation mainly involved with? (e.g. gas turbines, combined heat and power, reciprocating engines, nuclear, interconnector, coal plant, demand side response, storage, wind, solar, energy from waste, hydropower, batteries, other)

Question 3

What are your views on the 300 MW threshold, and what challenges might the removal of the threshold present to developers?

2.3 Combustion power plants covered by Decarbonisation Readiness

2.3.1 New and refurbishing combustion power plants

We are inclined to include both refurbishing and new build combustion power plants in the scope of DR. Existing combustion power plants would not be included in DR. Including refurbishing plant within scope will eliminate the risk of unintentionally incentivising developers to pursue refurbishing existing projects as a way of avoiding the DR requirements, which would undermine the delivery of our policy objectives. As part of this, we would need to consider how to identify refurbishing power plants within scope, as there may be a grey area between routine maintenance and refurbishment which extends the lifetime of a plant. We note that 'substantially refurbished' already has a specific meaning in the context of the requirements set out in Schedule 24 of the Environmental Permitting (England and Wales) Regulations 2016[19]. This could provide a useful starting point for the definition in DR.

[19] https://www.legislation.gov.uk/uksi/2016/1154/contents/made

Question 4

What are your views on the inclusion of refurbishing plant in DR? how could we best define refurbishing plant in this context?

2.3.2 Types of combustion power plant

The 2009 CCR guidance applies to applications for power stations of a type covered by the EU Large Combustion Plant Directive (LCPD). The LCPD was superseded by the Industrial Emissions Directive (IED) in 2013. The secondary legislation which implements the IED (the Environmental Permitting Regulations) continues to operate by virtue of the Withdrawal Act 2018 and subordinate legislation.[20] Therefore, as the legislative context has shifted significantly since 2009, we need to consider how power plants subject to the DR requirements should be defined.

In addition, the mix of technologies in GB has changed significantly since 2009. For example, there is no longer the prospect of new coal-fired and oil-fired power plants being built. Furthermore, given the net zero imperative, it is necessary to consider whether additional types of combustion power plant should be captured by the DR requirements e.g. heat, energy from waste, biomass and CHP. These plant types were previously implicitly excluded from the scope of the CCR requirements due to their size and improved environmental performance compared to unabated fossil fuel combustion power plants. Going forward, we are minded to include them in the DR requirements, because when considered in the context of our ambitious decarbonisation targets for the electricity system, they may still emit significant amounts of carbon. We also need to consider whether combustion plants used only for heat should be covered by DR.

Implementing DR through environmental permitting (see Section 3), would provide an avenue for capturing new and refurbishing combustion power plants in the requirements, as well as the additional types of combustion power plants discussed in the previous paragraph. The large majority of combustion power plants are already captured by the environmental permitting regime, including (but not limited to):

- Combustion power plants sized over 50 MW that were previously covered by the IED.
- Combustion power plants sized between 1-50 MW that were previously covered by the Medium Combustion Plant Directive (MCPD)[21].
- Specified Generators[22] sized below 1 MW if they have a Capacity Market Agreement or[23] participate in the Balancing Mechanism.
- Combustion power plants below 1 MW which are not Specified Generators but are associated with other activities that require an environmental permit.
- Combined heat and power (CHP) plants.

[20] https://www.gov.uk/guidance/industrial-emissions-standards-and-best-available-techniques
[21] https://www.gov.uk/guidance/medium-combustion-plant-when-you-need-a-permit
[22] As defined in Defra's guidance: https://www.gov.uk/guidance/specified-generator-when-you-need-a-permit#definition-of-a-specified-generator
[23] https://www.gov.uk/guidance/specified-generator-when-you-need-a-permit

- Plants which combust waste in order to produce energy (referred to as incineration plants in the environmental permitting regime).
- Combustion plants which produce heat rather than electricity.

Question 5

What are your views on the potential inclusion of technologies such as heat, energy from waste, biomass and CHP in DR? Are there are any additional technologies to these which could be included?

2.3.3 Exemptions and transitional arrangements

We acknowledge that our proposals for an expansion in scope of DR, and the move to apply the requirements via the Environmental Permitting Regime (see Section 3), may cause some concern amongst developers of assets that were previously out of scope. In particular, given that the hydrogen conversion readiness assessments are as-of-yet unspecified, there will inevitably be a degree of uncertainty about whether individual projects will be able to meet these assessments. In the short term, we recognise that this has the potential to create a hiatus in investment of some types of new build combustion power plants. Given the potential security of supply and consumer cost implications of such a scenario, we do not wish to restrict unnecessarily new build combustion power plant coming to market. That said, the overarching objective of this policy is to reduce the risk of future stranded assets, and therefore we expect that there will be some limited instances where the new requirements will lead to decisions to slow or drop the development of specific projects.

As part of the decision-making process on an expanded scope, we will carefully consider the impact of applying the DR requirements to a broader range and number of combustion plant (see Section 8). We are also considering whether it is necessary to introduce exemptions and/or transitional arrangements.

2.3.3.1 Exemptions

A limited range of exemptions for certain emergency back-up plants[24] already exists within the Environmental Permitting Regime. Such plants are expected to run very infrequently and so it should be suitable for them to be excluded from DR too.

We are also considering whether there are any other plants which it would be suitable to exclude from DR, for example, plants which are expected to have very low load factors (e.g. less than 50 hours per year) or produce very low total annual emissions, either from the point of starting commercial operations or by a specified future date. An exclusion on either basis could be consistent with our net zero ambitions – as noted earlier, some scenario analysis presented in the EWP suggests that an amount of unabated gas generation on the system in 2050 may be consistent with net zero provided it is limited to running very few hours per year – and would effectively provide developers a way of opting out of the DR requirements. Further analysis is required to determine what limit on annual emissions / running hours would be appropriate. If such a limit was set to bite from a future date, it may be necessary to request developers provide some form of assessment to help demonstrate economic feasibility of operating under such conditions.

[24] https://www.gov.uk/guidance/specified-generator-when-you-need-a-permit#definition-of-a-specified-generator

Power plants that are built to be low-carbon (e.g. those fitted with CCS on their total capacity) from their first day of operation should also be exempted from DR. We would need to consider how to define ‘low-carbon’ in this instance, whether it would be appropriate to exempt plants using, for example, a blend of hydrogen and natural gas. We welcome views on whether there are any additional exemptions that could be appropriate for DR.

2.3.3.2 Transitional arrangements

If we were to implement DR through environmental permitting, then we would aim to have this completed by 2023. This would allow time to consult on and develop the appropriate legislation and guidance, in partnership with the EA and NRW. We would not apply DR to any plants that secured an agreement in a Capacity Market auction held prior to the date of implementation. This would minimise threats to security of supply, by ensuring that affected developers have sufficient clarity and confidence to continue progressing with previously awarded Capacity Market agreements and/or participate in upcoming auctions whilst the DR requirements remain under development.

Question 6

What are your views on potential exemptions from DR? Would it be suitable to exclude plant which operate below a certain level of annual carbon emissions and/or running hours?

Question 7

Beyond grandfathering of Capacity Markets agreements, is there anything more that we could do to ensure that the DR requirements do not affect the Capacity Market?

3. Moving Decarbonisation Readiness to Environmental Permitting Regime

3.1 Summary of current implementation route

Currently the CCR requirements are applied through the Development Consent Order (DCO) process for Nationally Significant Infrastructure Projects (NSIPS). The Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013[25] ("CCR Regulations 2013") establish that new combustion power plants at or above 300 MW must demonstrate that it will be technically and economically feasible to retrofit carbon capture technology within the lifetime of the plant as a condition of receiving their DCO. The NPS then replicates these principles, in chapters EN-1 and EN-2[26]. The 2009 CCR guidance[27] supplements the principles of CCR, as set out in the NPS and the CCR Regulations, with details of how technical and economic feasibility should be assessed by developers, the detailed requirements of CCR reports, and how CCR reports are assessed by BEIS with support from the Environment Agency (EA) and Natural Resources Wales (NRW) as part of the consenting process.

3.2 The benefits of implementation through environmental permitting

There are many advantages to applying the DR requirements through the environmental permitting regime, compared to the DCO process:

- If we continued to apply the DR requirements through the DCO process it could take many years before the changes to policy had any practical effect. There are many projects below 300 MW which have already been consented and may not have a plan for decarbonisation. Implementing through environmental permitting will mitigate this delay by allowing us to capture previously consented projects in the DR update and make sure they are only built if they are decarbonisation ready. As noted in Section 2.3, we are considering a range of exemptions and transitional arrangements to ensure that developers, particularly those with consented projects that were previously out-of-scope, can continue to develop their projects.
- Planning consents for plants below 50 MW in England and 10 MW in Wales are dealt with by local authorities. Therefore, if the 300 MW threshold is removed from DR, local authorities would become responsible for reviewing and approving DR demonstration. This could create issues for some local authorities depending on their capabilities, resourcing and expertise, particularly as there may be a large number of planning applications for smaller combustion power plants. In comparison, the environmental agencies are already involved in the assessment of CCR requirements and have the technical expertise to assess DR demonstration. At present, when a planning consent

[25] https://www.legislation.gov.uk/uksi/2013/2696/made
[26] https://www.gov.uk/government/publications/national-policy-statements-for-energy-infrastructure
[27] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/43609/Carbon_capture_readiness_-_guidance.pdf

application is made it goes to the Planning Inspectorate, who then request views from the EA or NRW on the CCR element of the overall application.

- It opens up the opportunity to apply DR to refurbishing combustion power plants, which could otherwise be used as a loophole to avoid DR requirements. See Section 2.3 above.

- Most new build power plants in the UK are already required to have environmental permits in place in order to operate. Operators and investors are therefore well versed in the Environmental Permitting process, making a transition from planning easier.

- Environmental Permitting is a more flexible regime than planning and so will allow the EA and NRW to update and amend the requirements more readily, as technology and policy develops. Tried and tested systems are already in place for compliance monitoring, inspection & audit, reporting & enforcement, and paying permitting fees & charges.

Due to these advantages, we are considering moving the application of the DR requirements out of the planning regime and into environmental permitting. Note that if DR were to be implemented through permitting, it would be used as a tool to ensure that developers have a plan for decarbonisation, **but it would not be used a tool to regulate conversion to hydrogen or CCS as and when infrastructure is available.**

Implementation through environmental permitting would require amendments to the CCR Regulations 2013 and the Environmental Permitting Regulations 2016.

3.3 Potential issues with implementing DR through environmental permitting

Despite the numerous benefits of implementing through EPR, there are some drawbacks which we would need to consider how to mitigate:

- There is no requirement for an environmental permit to be granted before a DCO is granted for a site. Moving the DR requirements to environmental permitting may therefore create a risk whereby developers must decide, for example, how much space should be set aside to accommodate additional equipment needed for carbon capture or hydrogen-firing in the future and lock this in through their DCO, before having formal confirmation from the EA or NRW that this is sufficient to meet their DR requirements. However, similar risks already exist (e.g. decisions on stack height linked to air quality requirements) and developers are encouraged to pursue such considerations linked to their applications for an environmental permit and planning consent in parallel, in order to minimise issues around alignment.

- Implementing through EPR may increase investors perception of risk, due to the possibility of changes to future permit requirements, thus making projects more expensive. Any additional cost would ultimately fall to consumers, due to increased prices in the Capacity Market and other energy markets.

- Environmental permits already contain a variety of requirements which operators must meet, such as Best Available Techniques, which focuses on minimising industrial emissions. Including DR in environmental permitting creates a risk of cutting across or interfering with these requirements, in a way which could create confusion and additional burdens for both the regulator and operators. We would therefore need to ensure that DR was implemented in a way which fits around existing permit requirements.

Question 8

What are your views on implementing DR through environmental permitting rather than the planning consent process?

Question 9

If we were to implement DR through environmental permitting, how can developers be given confidence that their site will be compliant with DR prior to construction?

4. Reviewing Decarbonisation Readiness

4.1 Reviewing Decarbonisation Readiness assessments

Under the 2009 CCR guidance, developers are required to submit a review report within three months of the commercial operation date of the plant and every two years thereafter, continuing until such time as the developer retrofits carbon capture technology to their plant. Developers are required to submit the reports outlining whether it remains technically feasible to retrofit carbon capture technology to the plant and to inform government of any technical barriers to retrofitting which may have emerged since the original consent was granted.

If DR was to be implemented through environmental permitting, then our preference would be to retain the requirement for a two-yearly update report but remove the need to produce a report within three months of commercial operations. We anticipate, then, that as a result of environmental permits being issued closer to the point of plant operations commencing rather than closer to the original planning consent, the three-month report would become redundant. The two-yearly report could be reviewed by the EA or NRW.

If the two-yearly review identifies a barrier to retrofitting the developer's chosen decarbonisation technology, we do not believe this should necessarily be treated as non-compliance with the permit. Both hydrogen and CCS are evolving technologies and a technical solution may emerge in time. Developers, however, should consider any identified barrier carefully and explore solutions accordingly. The review would only lead to a developer being considered in breach of their permit if any action they had taken had led to the emergence of the barrier, for example, if they fail to maintain control of the space set aside for carbon capture equipment or equipment associated with hydrogen storage or transport.

Developers would be able to use the review as an opportunity to justify a reduction in the amount of space set-aside for carbon capture technology, with reference to evidence. The EA or NRW should consider such justifications and may allow appropriate modifications. They would also be able to use the review to inform the EA or NRW of a change of decarbonisation technology, and evidence demonstrating that the DR requirements for the alternative technology have been met.

Question 10

What are your views on the two-yearly review of DR requirements? Should this be retained and is the frequency suitable?

4.2 Reviewing Decarbonisation Readiness Guidance

Both hydrogen and CCS are evolving in terms of technology, economics and how they sit within the energy policy landscape. These changes will likely have an impact on how the proposed DR assessments can be applied, and indeed, additional decarbonisation technologies may emerge which could offer alternative routes for power plants to decarbonise in future, e.g. ammonia as a fuel. We therefore propose that the DR guidance should be periodically reviewed to assess its effectiveness, to account for technical, economic and policy changes in hydrogen and CCS, and to assess if new decarbonisation technologies have emerged.

It will be important to balance the need for guidance which keeps pace with technical and economic developments against a desire for regulatory stability and resource considerations of undertaking the review. A requirement to periodically review the DR guidance could be added to the legislation e.g. every five years. We anticipate the review should include a public consultation.

Question 11

How frequently should the DR requirements be reviewed? Should this be made a legislative requirement?

Question 12

How can we future proof DR again further technological development, e.g. new decarbonisation technologies and/or simplify the process for adding new techs to DR?

Question 13

Are there any alternative decarbonisation options, beyond low-carbon hydrogen and CCS which are already developed enough to be included in Decarbonisation Readiness? If so, then please include details on how their readiness could be assessed for a combustion power plant.

5. Design Principles of Decarbonisation Readiness

The primary objective of the DR requirements is to encourage developers to consider how their projects could be decarbonised at a point in the future, thereby reducing the risk of stranded assets and enabling continued investment in a rapidly evolving power sector. Therefore, the update to the DR technical and economic feasibility assessments will be informed by the following principles:

- **The assessments have to strike a careful balance between being meaningful but also achievable.** There are benefits to making the assessments tougher, as this would limit the chances of a developer being overly optimistic about the prospects of decarbonising their plant and, therefore, minimising the risk of stranded assets. However, more stringent assessments would also carry risks, such as limiting innovation or preventing certain technologies from coming forward. We believe that, given the nascency of both CCS and hydrogen infrastructure and policy, it would be appropriate for the tests to be less rigorous at the outset but to become more rigorous over time, as certainty around the technology and policy context increases. A periodic review of the DR requirements should facilitate this (see Section 4.2).

- **The assessments should be based upon a "no barriers" approach.** The 2009 CCR guidance establishes a "no barriers" approach where developers were asked to demonstrate there were no known technical or economic barriers which might prevent the installation or operation of their chosen carbon capture technology. The government did not prescribe which carbon capture technology should be adopted in individual cases, but allowed developers to utilise the best information available at the time and provide a reasoned justification for their choices and conclusions. Our preference is to maintain this approach for DR requirements to facilitate innovation and flexibility in how developers meet the tests to strike the balance between making the tests meaningful but achievable.

- **Developers should be able to change their chosen decarbonisation technology prior to implementation.** The uncertainty around how hydrogen and CCS policy and technologies will evolve in the future can make it difficult for developers to decide which route will be best for decarbonising their project. Therefore, developers should be permitted to change their decarbonisation technology after having passed the DR requirements, if they can meet the requirements for the alternative technology. To maximise flexibility, developers should therefore endeavour to ensure that their projects meet the DR requirements for both CCS and hydrogen. We note, however, this approach may not always be possible, and that siting and layout choices may 'lock-in' a certain technology. To assist developers with this dual planning, we are considering whether to require a contingency plan to be produced and assessed as part of DR. The contingency plan would set out details of how the site would be decarbonised if the preferred route was not available in the future. The contingency plan would also set out what would happen if the site could not be decarbonised at all and therefore, for example, the implications if the site had to restrict its running hours to meet tight annual limits on carbon dioxide emissions.

- **Passing the assessments should be mandatory, with the exception of the economic feasibility assessment and, in the short term, the hydrogen fuel access**

test. The economics of hydrogen conversion and retrofitting of carbon capture equipment are highly uncertain at the moment, as they will depend on how government policy and hydrogen technologies evolves over the next decade. Therefore, whilst we propose that an assessment of economic feasibility assessment is still required, it would not be necessary to "pass" this assessment. It would, however, be necessary to demonstrate there are no technical barriers to future decarbonisation. Given the limited deployment of UK hydrogen infrastructure to date, our view is requiring developers to demonstrate access to a hydrogen cluster or supply source (e.g. production or storage site), could be a barrier to entry in the short term. We are minded therefore, to make passing this test non-compulsory in the short-term to reflect this. Our preference is for the first periodic review of DR to be used to assess whether UK hydrogen infrastructure has, or expected to have, expanded to strengthen the test and to make it passing it compulsory.

- **The two sets of separate assessments (i.e. the hydrogen conversion readiness assessments and the carbon capture readiness assessments) should be broadly equivalent and mirror one another as far as possible.** We believe this is important to avoid making one decarbonisation route artificially more attractive than the other.
- **Where possible, the robustness of the demonstration of decarbonisation readiness should be proportionate to the capacity of the plant under development.** Once the 300 MW threshold is removed, the number of DR assessments carried out each year will increase significantly. Many of these will be for smaller plants, which may be under the ownership of Small and medium-sized enterprises (SMEs). It is therefore important that assessments for smaller plants are not disproportionately burdensome. This could be achieved by reducing the robustness of demonstration and evidence required for smaller plants, as compared to larger plants.

Question 14

What are your views on our suggested design principles?

6. Hydrogen Readiness

6.1 Introduction

We intend to update the 2009 CCR requirements to include conversion to hydrogen-firing. Allowing for the option of conversion to hydrogen supports the removal of the 300 MW threshold as it provides peaking plant with a viable route to decarbonisation.

Developers of power plants will be able to demonstrate that they are “hydrogen ready” through meeting a series of assessments akin to those currently in place for CCR. To avoid favouring one form of decarbonisation route over another, we intend to ensure equivalency between the assessments for demonstrating hydrogen readiness and carbon capture readiness.

We propose the following four assessments to demonstrate hydrogen readiness:

- that sufficient space is available on or near the site to accommodate any equipment necessary to facilitate hydrogen conversion;
- the technical feasibility of conversion to 100% hydrogen-firing;
- that the site’s location enables the transport of hydrogen to the site and/or that hydrogen can be produced and potentially stored at the site; and
- that it is likely to be economically feasible, within the power station’s lifetime, to convert to hydrogen combustion.

The specifics for each assessment are outlined in the following sections

In addition, we are considering requiring all plants which are deemed “hydrogen ready” to also be technically capable of burning a blend of hydrogen fuel from the first day that they are put into operation. The proportion of hydrogen required would vary depending on the date of construction (see Section 6.2).

Question 15

What are your views regarding the four proposed assessments for demonstrating hydrogen readiness? Are there additional assessments which would be beneficial?

6.2 Hydrogen firing capability

We are considering requiring all plants which are deemed “hydrogen ready” to also be technically capable of burning a blend of hydrogen fuel from the first day that they are put into operation. They would still be permitted to use 100% natural gas as a fuel, the equipment would simply need to be *capable* of handling a blend of hydrogen and natural gas, were this to be available (assuming that this wouldn’t affect the ability of the plant to operate on 100% natural gas). The purpose of this would be to send a strong market signal to Original Equipment Manufacturers (OEMs) to develop generation equipment capable of firing a blend of hydrogen, and to ensure that operators are on the front foot with their conversion to hydrogen-firing. The proportion of hydrogen blend required would vary depending on the date of construction, for example it could be:

- if built before 2030, technically capable of burning at least 20% hydrogen with natural gas.
- if built after 2030, technically capable of burning 100% hydrogen (at this point, the assessment of technical feasibility would no longer be relevant for assessment whether a plant is “hydrogen ready’, as the plant would have to be technically capable of firing 100% hydrogen from the first day of operation).

When setting the dates for these requirements, we need to be cognisant of two factors. Firstly, that the dates are in line with when hydrogen combustion units (turbines/engines) are likely to be available from manufacturers. Secondly, that the dates are in line with the expected increase in the availability of hydrogen fuel itself. Based on early industry engagement, our view is that the majority of gas turbine engines and engines currently available could be capable of firing a blend of 20%-30% hydrogen with modest modifications.

We anticipate this requirement could be met through a declaration from the generation equipment manufacturer certifying the percentage of hydrogen the generation unit is capable of firing. This may be available in the manufacturer’s warranty.

Question 16

What are your views on the suggested requirements for hydrogen ready plants to demonstrate hydrogen blend capability from the point of construction, including the example of 2030 as a cut-off for 100% hydrogen?

6.3 Hydrogen space requirements

Developers will need to set aside space to accommodate any additional equipment needed for hydrogen combustion, for example, the fuel transport infrastructure, fuel lines and storage. Additionally, hydrogen has more safety requirements than natural gas, which may create a need for additional safety equipment which in turn needs additional space.

Therefore, as is already the case with respect to the CCR assessments, we are considering whether to place a requirement on developers that plan to decarbonise through conversion to hydrogen to set aside space for these pieces of equipment.

Specific space requirements will be determined through future consultations. For now, we are seeking views on whether there is a requirement for additional space and, subsequently, what the magnitude of this requirement might be.

As explained in Section 5, our preference is that developers who can decarbonise their site through their either hydrogen or CCS to plan for both. In this regard, it may be beneficial for the space requirement for such sites to be determined whichever technology has the largest space requirement (either hydrogen or CCS), even if the site has chosen the smaller-sized technology as their preferred option for meeting DR requirements. This may require us to specify a capacity threshold above which this would apply.

Question 17

We would welcome views on if there are any additional and/or necessary items for hydrogen combustion that might have space requirements (e.g. NOx abatement equipment) and what their specific requirements might be?

Question 18

Would it be suitable to require plants that have a choice between hydrogen and CCS to set-aside enough space for whichever technology requires the most space, even if they are planning to meet the DR requirements through hydrogen? How could we ensure that this would only apply to sites which are likely to be able to retrofit CCS as well as to convert to hydrogen?

6.4 Hydrogen technical feasibility

It is important that new build combustion plants are configured in such a way that future technical works to convert to hydrogen are as straightforward as possible and there are no known technical barriers. The works required may vary depending on the combustion technology, e.g. a boiler, engine or turbine and the manufacturer of the equipment.

Below we have listed some examples of technical issues that developers may need to take into consideration. We would appreciate your views on these issues, including whether there are any we have overlooked, and how we can best ensure that developers consider all the relevant technical issues as part of their DR assessment:

- Hydrogen fuels have the potential to produce significant emissions of oxides of nitrogen, requiring additional modifications and / or abatement technology.
- Depending on the combustion process, hydrogen may burn hotter than natural gas. Therefore, the metals and materials used in the combustion process may need to be more resistant to heat.
- Hydrogen combustion may require amendments to the operational routines or combustion systems to ensure flame stability.
- Hydrogen may need higher pressures than natural gas due to greater volume flow.
- Hydrogen molecules can be more prone to leakage than natural gas. Therefore, additional safety and measurement process may be needed.
- Hydrogen has the potential to embrittle some material more than natural gas does, therefore piping may need to be modified or managed.
- The flow rate and air fuel ratio of the combustion process may need to be altered.
- Redesign of the combustion controls and software may be needed.
- The low lubricity and viscosity of hydrogen can cause additional problems in fuel systems.

- Additional safety measures may be needed for hydrogen combustion, compared to natural gas.
- Hydrogen combustion may lead to greater amounts of water vapour in flue gases, creating knock-on issues which require management e.g. more rapid corrosion of exhaust equipment.

In addition to this call for evidence, we intend to commission a study on hydrogen readiness, to understand what this means from a technical and cost perspective.

Question 19

We would appreciate your views on these issues, including whether there are any we have overlooked, and how we can best assure/assess that developers have considered all the relevant technical issues.

6.5 Hydrogen fuel access

Ensuring a plant is located so that it is likely to have a sufficient and reliable access to a source of hydrogen supply in the future, either directly from on-site production or via a supply network/storage, will be fundamental to ensuring hydrogen conversion is viable.

We recognise that most of the hydrogen production in the UK is currently limited to relatively small volumes of hydrogen that is not low carbon and is produced by steam methane reformation.[28] We anticipate that low carbon hydrogen supply will expand over the coming decade as hydrogen has the potential to provide low-carbon alternatives not only to power, but also to industry, transport, and heating. The Prime Minister's Ten-Point Plan for a Green Industrial Revolution[29] published in November 2020 announced the government's ambition to generate 5 GW of low carbon hydrogen production by 2030. In the 10 Point Plan, we also confirmed our intention to develop business models to overcome the cost gap between low carbon hydrogen and higher carbon counterfactual fuels. The UK Government will consult shortly on our preferred hydrogen business model to bring through low carbon hydrogen projects. Similarly, the EWP highlights that we will ensure that the existing gas networks and markets evolve in a way which promotes the use of low carbon options wherever possible. In April 2020, we announced the five successful projects from the Hydrogen Supply Competition Phase 2[30] which will support the development of UK hydrogen production.

It may be possible in the long term that the existing gas network, or new network infrastructure, could carry hydrogen in sufficient quantities to adequately supply hydrogen-fuelled power plants over long distances. In the short to medium-term, however, we anticipate the majority of hydrogen production to be focused around industrial clusters, and to be supported by dedicated small-scale hydrogen pipelines connecting hydrogen producers to users.[31] Moreover, bearing in mind that due to the current limited infrastructure for transporting

[28] Hydrogen produced from fossil fuels without capture of CO_2 emissions.
[29] https://www.gov.uk/government/news/pm-outlines-his-ten-point-plan-for-a-green-industrial-revolution-for-250000-jobs
[30] https://www.gov.uk/government/publications/hydrogen-supply-competition/hydrogen-supply-programme-successful-projects-phase-2
[31] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/803086/industrial-clusters-mission-infographic-2019.pdf

hydrogen over long distances and the likelihood that large production sites will be clustered in hubs, this will likely mean that the initial geographical scope of hydrogen fired plants could be limited compared to the locational options for existing natural gas fired plants.

That said, the production of hydrogen could also occur on sites where hydrogen fired plants are located. For example, low carbon hydrogen could potentially be manufactured on-site via electrolysis from renewables or nuclear and used to supply a hydrogen fired plant also on-site. We anticipate such a model would require electrical and/or hydrogen storage to provide grid flexibility.

Supply could potentially also come by methods other than pipeline e.g. rail or road provided there are hydrogen storage facilities at the site. We anticipate that non-pipeline distribution may be appropriate for smaller sized "peaking" plants, which may have sufficient on-site hydrogen storage capacity to meet the plant's demand for limited running hours.

The purpose of the hydrogen fuel access assessment will be to ensure developers critically assess the viability of the options available for securing an adequate supply of hydrogen fuel to their site in future. Potential approaches to this assessment could include developers considering whether their plant is located sufficiently close to an actual or anticipated hydrogen supply cluster, or whether there is a feasible route for a supply network to connect to their site. This style of assessment could replicate the design principles of the current CCR CO_2 transport and storage assessment with which currently requires developers to identify a 'way out' narrow corridor 1 km wide within a 10 km radius from the plant which can accommodate a future hydrogen supply pipeline, and then a wider 10 km wide corridor to known or anticipated industrial cluster or production or storage location.

We anticipate the first CCUS-enabled hydrogen plants are likely to come forward through the CCUS cluster sequencing process launched on 7 May 2021.[32] This will identify at least two CCUS clusters across the UK. In phase two of this process, projects will have the opportunity to be considered for government support, including a hydrogen business model. This could support developers in identifying suitable sites to demonstrate potential connection to.

As the hydrogen economy becomes established and hydrogen infrastructure expands, the hydrogen fuel access assessment could be strengthened with a requirement to be located within a specified distance from a hydrogen supply point (e.g. cluster or production site). This would reduce the challenges of transporting hydrogen over long distances and minimise the risk the plant becomes stranded because it was unable to access a suitable hydrogen supply. The regular review of DR requirements outlined in Section 4 could provide a suitable mechanism to review and add to this assessment.

An alternative option for some developers could be demonstrating viable plans to either produce the hydrogen fuel on site, or transport to their site via methods other than a pipeline such as road or rail (both options would rely on the provision of sufficient onsite fuel storage). Furthermore, certain mobile generators may be able to relocate their equipment, in order to access hydrogen fuel. We recognise this option may not be suitable for all plants.

In the medium term, we anticipate it will likely be challenging for developers to anticipate future connection and to meaningfully demonstrate compliance with a hydrogen fuel access assessment due to the limited UK hydrogen supply and production infrastructure.

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[32] https://www.gov.uk/government/publications/cluster-sequencing-for-carbon-capture-usage-and-storage-ccus-deployment-phase-1-expressions-of-interest

Bearing in mind the developing nature of hydrogen infrastructure, we welcome views on "passing" the hydrogen fuel access assessment non-compulsory to obtain a permit in the short-term (as is currently the case with CCR and unlike the proposed hydrogen space and technical feasibility assessments). This approach would still require developers to consider hydrogen fuel access in the short to medium-term, but it would not act as a barrier to entry due to the uncertainties of hydrogen infrastructure locations. As the hydrogen economy develops and more infrastructure becomes available, it will be easier for developers to meaningfully demonstrate connection and so "pass" the test.

We propose that the hydrogen fuel access assessment be non-compulsory in the short-term, with a review of the assessment undertaken as part of the proposed periodic review of DR requirements outlined in Section 4.2 to assess if hydrogen infrastructure has expanding or is on course to have developed sufficiently to make passing the hydrogen fuel access assessment mandatory.

Our design intention outlined in Section 5 is to ensure the assessment for hydrogen readiness and carbon capture readiness are broadly equivalent and mirror one another as far as possible, however, our view is that the transport and storage / fuel access assessments for the separate assessments should reflect their corresponding technologies and so be disparate. Our intention, therefore, is to retain the CCR CO_2 transport and storage assessment as mandatory to reflect the differences in how developers can demonstrate connection to the two technologies infrastructure. The limited UK hydrogen infrastructure makes it challenging for developers to identify a suitable fuel source connection. The CCR CO_2 transport and storage assessment requires developers to identify a potential deep geological offshore storage area. These are well known to industry, and so developers opting for CCR would remain able to demonstrate their plant's connection to one of these areas or to a known or anticipated CCS cluster. We expect CCS clusters to develop around the UK, and so if a suitable CCS cluster or CO_2 transport and storage network is built closer to the plant, developers could modify their approach to connect to the closer infrastructure in future.

Question 20

We welcome your views on how to design a meaningful assessment for hydrogen fuel access.

Question 21

We welcome your views on our likely position to make the hydrogen fuel access assessment non-compulsory in the short-term, with a view to making "passing" it mandatory in future to reflect the anticipated development hydrogen economy.

Question 22

We appreciate your views on the viability of on-site hydrogen supply and/or storage for hydrogen-fuelled peaking plants.

6.6 Hydrogen economic feasibility

Unabated combustion power plants will only convert to hydrogen fuel when it is economically feasible to do so. In principle, the assessment of the economic feasibility should involve comparing the increased capital and operating costs of hydrogen conversion with the potential for increased revenues following conversion due to avoided carbon costs. A range of factors will determine the economic feasibility of conversion to hydrogen-firing, including (but not limited to):

- the price of hydrogen fuel (which may include the cost of transporting the fuel) relative to the price of natural gas;
- the carbon price;
- the capital and opportunity costs (i.e. outages) of converting the plant to hydrogen firing; and
- any additional operational costs that may result from using hydrogen compared to natural gas, e.g. plant machinery, increased costs of leakage monitoring, NOx abatement equipment, increased safety requirements.

The costs of hydrogen conversion are highly uncertain at the moment, particularly the price of hydrogen fuel which will depend on the costs associated with the production and transport of hydrogen, which in turn will likely be dependent on government policy (e.g. potential support for hydrogen production and networks). Therefore, whilst we propose that an assessment of economic feasibility assessment is still required, it will not be necessary to “pass” this test (as is currently the case with CCR and unlike the other proposed hydrogen assessments).

Question 23

What factors are viewed as critical in determining whether conversion to hydrogen is economically feasible? What would be your economic considerations?

7. Carbon Capture Readiness

In expanding the DR requirements, we also wish to review the CCR requirements with a view to ensuring they remain fit for purpose and reflect the current policy, technical, and economic landscape of CCS.

We have reviewed the assessments relating to the space requirement and technical feasibility and believe the approach adopted remains fit for purpose and so do not have any plans to substantially amend these. That said, we are considering whether to remove some of the prescriptive detail from some of the current CCR assessments that can become rapidly out of date (for example, the table providing information on the minimum land footprint for carbon capture equipment).

In line with the approach proposed in relation to hydrogen readiness, and due to the inherent uncertainties associated with the economics of CCS, we propose that it will no longer be necessary to "pass" the CCR economic feasibility test. Developers will still be required to complete an economics assessment and to review this periodically as the context evolves and uncertainty reduces.

Following review of the current assessments, we are also minded to retain the current CCR CO_2 transport and storage assessment whereby developers identify a viable transport route from their plant to a suitable area of deep geological storage offshore. Given the increased ambition of deploying CO_2 transport and storage networks, which will be fundamental to the delivery of CCS clusters in the UK, we are however minded to change the emphasis of the current CCR CO_2 transport and storage assessment. Developers will need to either:

(a) identify a suitable area of deep geological storage offshore exists for the storage of captured CO_2 from the proposed power plant and demonstrate that a feasible route exists from the site to the storage area, or

(b) identify a suitable CCS cluster transport and storage network to connect with, to facilitate the onward transport and storage of CO_2 from the proposed power plant.

We expect, as CO_2 transport and storage networks around the UK develop, identification of how an unabated plant might connect to a CCS cluster transport and storage network would be the more appropriate approach for almost all plants in the future. The current CCR guidance "Transport Networks" section already signals this thinking[33]. Developers could update their chosen transport corridor and/or destination if a more economically or technically efficient alternative storage, CCS cluster or transport and storage solution becomes available.

To understand the technical feasibility of either transport and storage option, we expect developers to consider the technical operability of the chosen transport and storage solution, factoring in expected running patterns of the plant.

Our intent is to ensure parity in test requirements between hydrogen readiness and CCR to avoid distortions in making one decarbonisation route easier to demonstrate than the other. As with the hydrogen supply test, the test for connecting a combustion power plant to a CCS

[33] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/43609/Carbon_capture_readiness_-_guidance.pdf

transport and storage network needs to strike a balance between ensuring plants do not become stranded as they are unable to access the infrastructure necessary to decarbonise and limiting the burden the test places on developers and potentially creating a barrier to entry.

As noted in Section 6.5, the onus would be on the developer to ensure they have a viable transport route and we are also minded to retain the CCR CO_2 transport and storage assessment as mandatory. As outlined in Section 6.5, our view is demonstrating connection to an area of deep geological storage offshore, in addition to known or anticipated transport and storage infrastructure or CCS clusters, is a less burdensome test to meet than demonstrating connection to very limited hydrogen infrastructure in the short-term. Our intention would be to review the effectiveness of CCR CO_2 transport and storage assessment alongside the hydrogen fuel access assessment as part of the first five-year review of DR requirements.

We welcome feedback on the approach to the CCR transport test.

In conjunction with the EA, we will look to commission a study on carbon capture readiness to update our knowledge base on what this means both technically and economically, particularly for plants sized below 300 MW.

Question 24

What are your views on our proposed updates to the CCR requirements?

Question 25

What are your views on how the transport and storage test for CCR should be updated?

Question 26

Are there additional areas for change we have not identified? Please provide justifications.

8. Impacts

We would welcome evidence from stakeholders on the potential impacts of the changes to DR requirements under consideration. Information gathered through this call for evidence will be used to help inform the development of an Impact Assessment which will accompany the future consultation.

We would expect the proposed change in scope to increase businesses' administrative costs through additional staff time spent on familiarisation with the changes to the requirements and to provide the decarbonisation readiness assessments themselves. There will also be additional permitting costs in the permit application fee associated with DR, due to the increased burden on the environmental regulator. We would welcome any evidence on the magnitude of these costs and the main factors that influence them such as plant technology type and size, and whether demonstrating hydrogen or carbon capture readiness.

Applying the requirements to plant sized below 300 MW may disincentivise smaller generators and lead to fewer plant sized just below 300 MW. We welcome any evidence on the magnitude of this impact as well as how this measure may impact other businesses investment decisions, for example decisions on the type of technology and machinery used, space available on site and the site location.

We acknowledge that the DR requirements may reduce the number of new build projects coming forward. This is part of the intent behind the policy i.e. to ensure that projects which are not decarbonisation ready are not taken forward. We expect this impact to be limited, as prudent developers should be planning for decarbonisation anyway, and we are considering appropriate exclusions and transitional arrangements for the plants that would be most affected. We are interested in what additional administration and analysis is involved in meeting these decarbonisation requirements beyond what is already considered.

We may also need to consider implementing provisions to ensure that large numbers of plant do not retrofit to CCS or hydrogen all at once. We believe that signals from existing markets, in particular the Capacity Market, should be sufficient to prevent this. But we would welcome views on whether there are any additional controls which may be necessary, to avoid these outages creating security of supply risks.

Further, we need to consider the potential impact of DR on the electricity transmission and distribution networks, as CCS and hydrogen are likely to focus areas in where infrastructure will be available.

Please inform us of any other impacts not covered above, for example how the measure might change Capacity Market bidding behaviour.

Question 27

What impact could the changes discussed in this call for evidence have on your business's administrative costs for planning permission and environmental permitting? Please specify which of the proposed changes will have the most impact.

Question 28

We anticipate developers are already considering future decarbonisation options following the EWP. What impact are the changes discussed in this call for evidence likely to have on your investment decisions for new build plant? Please specify which of the proposed changes will have the most impact.

Question 29

How do you currently manage the long-term risks of decarbonisation in your investment decisions? What additional work will the proposed changes cause?

Question 30

Are there any specific impacts on small and micro businesses that are not covered above? If so, please provide details of the anticipated one-off and on-going costs.

Question 31

Please tell us if you think there are any other impacts not covered above, in particular wider impacts on the energy system and security of supply

This publication is available from: www.gov.uk/government/consultations/decarbonisation-readiness-call-for-evidence-on-the-expansion-of-the-2009-carbon-capture-readiness-requirements