The voice of the energy industry

Energy UK Response to Dispatchable Power Agreement business model consultation

10th June 2022

About Energy UK

Energy UK is the trade association for the GB energy industry with a membership of over 100 suppliers, generators, and stakeholders with a business interest in the production and supply of electricity and gas for domestic and business consumers. Our membership covers over 90% of both UK power generation and the energy supply market for UK homes. We represent the diverse nature of the UK's energy industry – from established FTSE 100 companies right through to new, growing suppliers and generators, which now make up over half of our membership.

Our members turn renewable energy sources as well as nuclear, gas and coal into electricity for over 27 million homes and every business in Britain. Over 680,000 people in every corner of the country rely on the sector for their jobs, with many of our members providing long-term employment as well as quality apprenticeships and training for those starting their careers. The energy industry invests over £12.5bn annually, delivers around £84bn in economic activity through its supply chain and interaction with other sectors, and pays £6bn in tax to HMT.

Executive Summary

Energy UK welcomes the opportunity to respond to the Government's consultation on the Dispatchable Power Agreement business models for Carbon Capture Usage and Storage (CCUS). There is widespread consensus across industry, experts and policymakers that CCUS will be crucial if the UK is to meet its legislated target of net-zero emissions by 2050 at the lowest cost. Carbon capture has consistently been identified as an integral part of a least-cost portfolio of technologies needed to support the energy transition. This is particularly true in the UK where fossil-based power generation is likely to retain an important role to ensure security of supply. We are therefore very pleased to see important progress on the development of the Dispatchable Power Agreement business model to facilitate the deployment of this technology.

Should you have any questions regarding this consultation response then please do not hesitate to get in touch via the details below.

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Response to Consultation Questions

1. Do you agree that the proposed Availability Payment component of the DPA Contract incentivizes efficient decarbonisation and best in class carbon capture technology selection? If not, what changes do you think are necessary to facilitate this?

Energy UK agrees that an Availability Payment component can incentivise effective decarbonisation, however, the availability of generation rate (which will be determined by the generator) and the availability of capture rate (set at a minimum 85% level) are currently disproportionate and do not establish the foundation for a proper Availability Payment calculation. It is imperative for the availability of generation and availability of capture rate to be assessed independently. If a common factor has the effect of reducing the availability of capture rate and the availability of generate rate, the generator will suffer a disproportionate reduction in Availability Payments creating some inefficiency. Further clarity will be needed about how the availability payment rate will be set and negotiated.

One of the key issues relating to the Availability Payment is the amount of merchant risk the generator will be required to take on (setting a low APRi in cases where the generator assumes most risk and setting a high APRi where the generator assumes less merchant risk). This will be key to financing decisions, where lenders are expecting high APRi payments in order to make the DPA financeable. In order to incentivise efficient decarbonisation, the Availability Payment must provide sufficient coverage over all fixed costs. Expecting an unreasonably low APRi will undermine bankability.

At present, the availability of capture mechanism is overly complex. The Deemed Rate mechanism appears to compound past performance issues through averaging and applies a disproportionate penalty to periods where the station is not required but is fully available. The use of Deemed Rate also disincentivises operation when the capture plant is underperforming as there will be an ongoing impact for the subsequent 12 months. This does not encourage efficient decarbonisation as the Power CCUS plant may still be the lowest carbon generator on the margin.

There is also a challenge with introducing high average capture rates requirements for first-of-a-kind (FOAK) projects. This is particular concern because of the proposed termination arrangements which are very severe for failing to achieve the high rate. High rates could be harder to achieve for plants more frequently starting up. Energy UK think they should be some flexibility as further engineering work is undertaken on each project.

An alternative approach to measure the capture performance of the plant, which would offer a strong incentive to maximise capture rate and be simpler to understand and manage, would be to use a combination of achieved capture rate when in operation and declared capture rate when not. The DPA counterparty could then retain rights of audit and testing to ensure the declared rate is accurate.

2. Do you agree that the proposed Availability Payment and Variable Payment in the DPA Contract will ensure that a power CCUS Facility reacts to electricity market price signals and provide dispatchable output without incentivising it to generate at all times thereby displacing lower cost and lower carbon generation sources such as renewables and nuclear? If not, what amendments do you consider necessary to achieve this objective?

The integration of business models will be crucial to the successful deployment of the technology and particularly important to ensure that CCUS facilities react to market price signals in the correct merit order. Energy UK believes that incorporating carbon price support could serve as a means to ensure the CCS plant is dispatched ahead of an interconnected unabated plant. It is possible that the benefits that a Generator obtains from saved/reduced UK ETS costs is greater than the cost of gas and other operating costs of the carbon capture unit and in this scenario, the Generator would retain the full upside of such benefits under the proposed DPA commercial structure, and no payments would be made by the Generator to the DPA Counterparty.

Whilst we note that the Gain Share Mechanism is designed to prevent over remuneration of a Generator, the mechanism as currently proposed only applies above a threshold IRR level. In addition, the timing of the Gain Share Mechanism means that any over compensation above the threshold IRR level may only be returned several years later.

The Availability Payment, if set at an appropriate level, will incentivise the development of desired capacity. The issue of dispatch and response to signals is determined by the Variable Payment. So long as the reference plant metrics are always set at a level that represents best in class of unabated plants at any given time, we believe the Variable Payment mechanism does incentivise the right outcome (i.e. only displacing all unabated CCGT, whilst not displacing lower carbon alternatives).

The Generator is exposed to a risk premium (i.e. Generators assessment of risk including the potential for plant failure measured against future earnings potential) that outweighs that of the reference unabated plant as part of the Availability Mechanism under the current proposals of the DPA. This could lead to scenarios where the unabated plant can set a lower price than the DPA supported Generator and dispatches ahead.

An alternative approach would be to allow for an availability target over an aggregated period, which would give the Generator the same positive signal to make the Facility available, whilst also reducing the associated risk premium. The DPA could also consider including start up costs in the variable payment to avoid the plant not dispatching for short peak time periods.

Further consideration should also be given to the merit order interaction with new technologies such as hydrogen coming onto the system.

3. The objective of the Variable Payment is to incentivise a power CCUS Facility to dispatch ahead of an unabated reference Plant. Do you agree that the proposed Variable Payment mechanism achieve this? If not, what further amendments do you consider necessary to achieve this objective? Please provide your reasoning.

Energy UK agrees that a Variable Payment is required to incentivise a Power CCUS facility to dispatch ahead of unabated gas plants. The Variable Payment does not necessarily result in a sufficient payment to the Generator to ensure priority dispatch in all scenarios, as it currently compensates the CCS plant based on the difference between design parameters and the reference plant. In practice, the unabated plant could end up having a lower short-run marginal cost for several reasons, including the effect of start-up costs. Thus, the variable payment should account for actual additional costs over the reference plant using the metered information ex-post. The deemed rate calculation serves as a disincentive to running the plant when there is a capture underperformance.

An alternative approach, to ensure priority dispatch for the CCS plant, would be to ensure the contract has a cost advantage that enables abated operations to be below the cost of unabated. This additional margin could reduce the impact of any risk premium.

The DPA needs to strike the right balance for effective pricing of the DPA to enable dispatch ahead of interconnected unabated plant. The DPA does not do this currently as interconnected unabated plants avoid carbon price support costs, which are not taken into account as part of the Variable Payment formula.

4. Are there any additional hurdles to a power CCUS Facility retaining the flexibility to respond to market conditions and consumer needs over the term of the DPA Contract considering foreseeable evolution of the power generation composition and demand profile over this time?

Power-CCS plants will be flexible in terms of their technical/ and operating capabilities and this flexibility would be maintained across the plant’s lifetime.

Access to a flexible CO_2 network and store is a prerequisite of a CCS plant being able to operate flexibly. Further consideration is required on network access and network codes, particularly in network constraint scenarios where the plant is ready to dispatch but unable to have certainty on network access. This must be time critical to allow generators to understand the interaction between this and the DPA.

5. Do you agree that the standard terms and those project specific terms in the Front End Agreement of the DPA Contract are capable of equally incentivising investment in new build, re-powering and retrofit Projects alike? Alternatively, are there particular provisions which you consider require modification to facilitate investment in a particular type of Project (please explain why this is the case in your response)?

The front end agreement terms (and to a lesser extent the standard terms) contain the key parameters that BEIS should consider in selecting preferred projects. By definition, new builds will outperform in the variable payment metric (given their higher efficiencies) whilst retro-fit will outperform in the availability payment (given their lower capex profile). These are fundamentals that should not be mitigated or influenced under the DPA and we believe the current construct will ensure that the best projects will be awarded support contracts.

We don't believe that incentivising investments in all different projects should be a goal. If, for example, retrofit projects represent the best overall value for money, we don't believe the DPA should be seeking to ensure an equal deployment of alternative configurations. It is important that retrofit projects are properly considered here.

We believe it is important for Government to retain as much flexibility as possible in agreeing the contractual terms for projects across both the Front-End Agreement and the DPA Contract. The FOAK nature of these projects warrants less onerous performance requirements, testing regime, and termination events as currently drafted, with flexibility being key in agreeing thresholds with early projects.

The approach to supply chain emissions should also be considered here as the benefits and therefore the renumeration of the Power CCS projects are not adjusted for the impact of supply chain emissions. This approach should be consistently adopted across all CCUS sectors including engineered GGRs, with GGR projects being renumerated for gross carbon capture quantities, and where appropriate, thresholds applied to supply chain emissions. This should be consistently counted and adjusted for all GGR's and Power CCUS projects.

6. Do you consider risk is appropriately allocated to enable investment in Projects and value for money for consumers? If not, please indicate the aspects of the contract where you believe risk is not appropriately allocated and why.

Energy UK agrees that operational risks should sit with the generator and that cross-party risk and the risk of changes in law should sit with government, this allocation of risk under the DPA is appropriate. However, we have identified several other elements of risk which we believe are disproportionate and will require further review:

Gain share mechanism – The gainshare mechanism creates a disproportionate risk profile for investors and seems to be misaligned with the intention of the DPA as it doesn't reflect the appropriate risk balance of a CCS project. We believe that a gainshare mechanism could also make availability payments more expensive.

Merchant risk - when it comes to merchant risk regarding the dispatch profile of an unabated plant and the market price of electricity, carbon and natural gas - if all of this rests with the generator - then a very high availability payment will be required (this risk will be priced into the availability payment regardless of whether the risk materialises to the downside). If BEIS assumes some of this risk, perhaps working this into the gainsharing mechanism where loss-sharing is also considered, then this will result in a lower availability payment rate and perhaps better value for money.

Cross-chain risks – The way the fees are set will create further issues for plants. If the intention of the DPA is to allow a plant to run as an unabated plant in the event of T&S unavailability, this appears to be a restriction. The Generator is currently exposed to T&S underperformance. If the T&S fee is comparatively lower than the cost to emit as expected, this will increase the cost of running in unabated mode where there are any outages, derating or constraints on the T&S system. This risk is also currently difficult to assess given the lack of T&S infrastructure currently, so there are no performance standards to base analysis and judgement on. The framework needs to set a very clear requirement for the T&S to interact effectively with the generator. It is also worth noting the discrepancy in the commissioning window which is currently 31st December 2027, and not appropriate for generators unable to connect to T&S until late 2027.

Operating in unabated mode – related to the above, the DPA assumes the Generator will be able to operate in unabated mode. However, it is unclear whether environmental permitting and the planning process will allow this.

Termination rights – The DPA does not currently provide for any formal appeals process or opportunity to correct a breach once a termination notice has been issued. This is overly onerous and there should be appropriate avenues for a generator to seek a remedy should a termination notice be issued. There should also be alignment between the DPA contract and the T&S contract to ensure that the DPA takes account of liabilities such as an ICC plant termination. The Force Majeure rights should recognise that contractors includes T&S operators. At the moment there is a risk that the generator is held liable for issues arising for T&S availability.

Interaction with the Capacity Market for retrofit projects – existing Generators retrofitting with CCUS will face a commercial risk due to the interaction with the Capacity Market. The Capacity Market year runs from October to September, and this may not align with the Generator's Start Date. An option to address this could include the introduction of a "choice of scheme" rule could be implemented to enable a Generator to hand back a Capacity Market agreement early. The choice of scheme rules would need to reflect that the capacity of the CCUS retrofit generator would be lower than the original unabated generation unit, due to the parasitic load / steam requirements of the carbon capture unit. The timing of any allowable capacity market agreement hand back would need to allow for procurement of replacement capacity in respect of the parasitic load of a retrofit CCUS generator. Similarly, the expiry of the DPA may not align with the start of the Capacity Market year and a mechanism will be required to ensure a seamless transition between the DPA expiry and Capacity Market support mechanisms

7. Power CCUS projects will be part of a wider CCUS network. A T&S Prolonged Unavailability Event would have a significant impact on any project connected to the network, including those projects holding DPA Contracts. We need to consider how to best manage this interface risk. We have set out an initial minded to position on the termination right where there is a T&S Prolonged Unavailability Event, which seeks to balance the risk held by investors in the power CCUS project and investors in transport and storage and the wider network.

   Do you consider that there is a fair allocation of risk between the different interests in relation to Termination for T&S Prolonged Unavailability Events? If not, please provide your rationale.

Energy UK believes that since the government is allocated T&S awards, it should be responsible (alongside the T&S provider) for any costs associated with failure relating to the T&S system (that aren't caused by the generator). Until such time as there are multiple options to choose from regarding T&S systems, the generator must be immunized from failures by T&S Co. If, for example, ECC/NEP doesn't have the capacity it suggests but BEIS has selected them to be the initial sole T&S system in the Humber, BEIS and ECC need to be responsible for all costs of non-performance.

There also needs to be consideration of events where only a fraction of the Generator's CO_2 is transported through the T&S system due to constraints on the T&S system. This may not be a full outage event, but will be caused by the T&S system and result in a customer receiving less CO_2 than purchased.

The testing regime may need to be developed differently for retrofit and new build projects Power CCS projects. For example, fuel supply system may be supplied by grid power and complete restrictions on electricity imports during a test period may not be achievable. For solid fuel generators such as biomass, the efficiency assessment is a combination of the fuel combustion system and turbine efficiency, which is not simple to assess and there are a limited and reducing number of specialist entities that can perform such assessments.

8. We have proposed testing requirements specified in annex 2 "Testing Requirements" of the draft DPA Contract to provide clarity on what is expected from Generators during the Performance Tests detailed in the DPA. We have sought to align these requirements with industry standards and expectations.

   Does the proposed Testing Requirements strike the right balance between robustly assessing the performance of a Facility and not being overly onerous on a Generator? If not, what amendments do you think are necessary to determine performance of the Facility against?

It is important that testing procedures accommodate for projects that have a staged development. At present, the testing regime in general requires a more pragmatic approach. We do not think the testing regime should be finalised at this stage as it is a highly novel area and it is not clear that what is being proposed will be workable in practice. Establishing a fixed regime now risks rendering the plant uninvestable if the regime and associated penalties are overly onerous.

9. 9. Do you consider the proposal to enable the publication of certain contractual information by the DPA Counterparty to be proportionate and reasonable in light of our policy objective? If not, please provide your reasoning and which elements should be published in the alternative.

We generally agree with the need for public money to be accompanied by public disclosure. The availability payment rate is derived from a number of factors some of which are based on highly sensitive information relating to market forecasts etc. Just need to give some thought to how this payment should be disclosed.

10. As outlined, do you agree that the inclusion of a gain share mechanism in the DPA Contract is a proportionate measure to mitigate the risk of overcompensation and to facilitate compliance with subsidy control principles? If you believe the inclusion of a gain share mechanism is a disproportionate measure to achieving our objectives, or could significantly inhibit investment in the DPA, please provide your rationale.

As mentioned above, we believe the gainshare mechanism creates a disproportionate risk profile for investors in its current design. The Gain Share mechanism is not consistent with the objective of incentivising the timely and cost-efficient delivery of Power CCS projects. A gain share mechanism is suited to projects and technologies with very high initial capex investment and low exposure to market risk such as nuclear projects where the potential gains would be obtained by efficiently managing the construction phase and ongoing maintenance spend. However, this is not the case in Power CCS Projects, where improving returns over the lifetime of the Project is heavily dependent on optimising performance to suit ongoing market dynamics.

To ensure value for money for consumers, the competitive processes of allocations inherent to the structure of Power CCS projects should be sufficient to mitigate any risk of overcompensation. It is also preferable from the perspective of value for money for the consumer for the applicable financial incentive structures to be negotiated and agreed on a project-by-project basis and at the time that contracts are actually awarded as part of the competitive process of allocations. By taking this approach, the parties will be able to take account of prevailing market conditions and the learned experience of any overcompensation or under-compensation from any earlier Power CCS projects which have been initiated.

11. The proposed gain share schedule would provide for two types of gain share, 'Project gain share' and 'sale gain share', in each case where such profits exceed a certain defined threshold.

    At what level of Equity Internal Rate of Return (Equity IRR) do you consider that gains should be shared under the gain share mechanism? Please provide context and evidence in your response.

See response to Q10 - we do not believe a gain share mechanism is a proportionate measure for Power CCS projects. Value for money and compliance with subsidy control measures should be achieved through the assessment of projects through a robust procurement process.

12. At what level of Equity IRR for a power CCUS Project do you consider that the risk of overcompensation under the DPA is low enough that the gainshare mechanism outlined here should not be required in order to mitigate that risk? Please provide context and evidence in your response.

See response to Q10 and Q11.