ANNEX C

DPA Detailed Explanation and Examples

Note: this Annex is subject to the "Disclaimer" section at the front of the update document to which it is annexed.

Legal and Contractual Framework

We set out below our current thinking on the key commercial and structural principles for the Dispatchable Power Agreement (the "DPA"). As outlined in Section 4 of the main document, the DPA will be the key tool used to encourage low carbon electricity generation by bringing forward investment in power CCUS plants initially in GB where there is an existing Contract for Difference (CfD) regime, but potentially across the UK, and to incentivise such facilities to operate in dispatchable mode at the appropriate place in the merit order.

Where relevant, we have commented below on potential similarities and differences between the DPA and the Standard CfD Terms and Conditions for Allocation Round 3 (the "AR3 CfD"). While it is intended that this section will be capable of being reviewed on a stand-alone basis, the reader may find it useful to refer to the detailed provisions of the AR3 CfD, along with the detailed heads of terms for the DPA (the "DPA HoTs") found at Annex D (Power CCUS DPA HoTs) which builds on the summary set out below.

Unless stated otherwise in this section, terms not defined in this section will have the same meaning given to them in Annex D.

Overview and Parties

Form of and parties to the DPA: The DPA will be a private law, commercial contract made between the Generator and the DPA Counterparty. As set out in Section 4 of the main document, it is proposed that the Low Carbon Contracts Company Ltd will act as the DPA Counterparty and that the DPA will be entered into following an applicable contract allocation or negotiation process established under the Energy Act 2013. However, these matters are subject to further consideration by BEIS.

Eligibility Criteria: It is expected that either prior to or shortly after (pursuant to the "Initial Conditions Precedent" under the DPA, discussed further below) the execution of the DPA, the Generator will have satisfied certain eligibility criteria relating to the allocation of the DPA. We currently consider, as a minimum, that such criteria will include: (i) a grid connection offer; (ii) a real property agreement or lease; (iii) planning permission; (iv) corporate approvals; and (v) a supply chain plan.

Term, Milestone and Conditions Precedent

Term of the contract

Our initial assumption has been that the DPA should have a 15-year contract term (for both new build and retrofit), following the successful precedents from standard CfD contracts and Capacity Market (CM) agreements. We are considering whether a term length for retrofit projects could be shorter than this, dependent on expected capital expenditure incurred. A term length of 15 years or longer may be appropriate for new build projects. The specific contract lengths could be set based on analysis of likely project costs. We will continue to conduct further work to define the appropriate DPA term length.

We have considered that the contract term length should be the same for both the Availability Payment and Variable Payment. As carbon prices are expected to rise over time, the saved carbon cost for power CCUS plant relative to unabated plant will increasingly provide the dispatch decision for abated plant. In addition, the term length for the DPA would seem to provide reasonable clarity to investors on the profile for the recovery of fixed costs. However, if carbon prices do not rise as expected, the dispatch risk for Power CCUS projects could increase significantly if they become less competitive against unabated generators.

Commencement: The DPA will commence on the earlier to occur of the "Start Date" and the last day of a specified "Target Commissioning Window" of [X] months which will be adjusted day-for-day for any delays that occur due to "Force Majeure" (discussed in further detail below). Therefore, if the Generator fails to commission the Facility (being both the power plant and the capture plant) by the end of the Target Commissioning Window, the term of the DPA will commence and the [X] year term will start to reduce. However, payments under the DPA will not commence unless and until the Start Date occurs. This is to incentivise the relevant Generator to commission the Facility as soon as reasonably practicable following the execution of the DPA.

Initial Conditions Precedent: It is envisaged there will be two sets of conditions precedent, the "Initial Conditions Precedent" and the "Operational Conditions Precedent", similar to the AR3 CfD. The "Initial Conditions Precedent" are designed to ensure that the Generator meets certain legal/regulatory requirements and conditions relating to the DPA immediately following the date of the Agreement. This may include the Generator's entry into certain key project documents, such as the T&S connection agreement. As mentioned above, we may also include the eligibility criteria requirements as part of the Initial Conditions Precedent.

Milestone Requirement: The Generator will be required to demonstrate within a certain period of time that it is committed to the Project by evidencing: (i) actual spend of at least a minimum percentage (to be determined) of "Total Project Commissioning Costs"; or (ii) fulfilment of specified "Project Commitments", both similar to the AR3 CfD requirements. This is to deter speculative or underdeveloped projects from applying for a DPA (over and above any primary checks prior to this point), and to ensure that budget remains committed only to projects that demonstrate sufficient progress. The DPA Counterparty will be responsible for determining the robustness of the evidence submitted by the Generator.

Operational Conditions Precedent and the Start Date: For the Start Date to occur, the Generator will be expected to satisfy a number of "Operational Conditions Precedent". The form of such Operational Conditions Precedent will be based on the AR3 CfD, and importantly will not only include conditions relating to the electrical output of the Facility but also the gas input and CO_2 export of the Facility, and will be appropriately tailored to reflect the technical and regulatory differences between these additional inputs and outputs. For example:

a) evidence that a "Net Dependable Capacity" equal to or exceeding a specified percentage of the "Initial Net Dependable Capacity Estimate" has been demonstrated at commissioning of the Facility;

b) evidence that an "Achieved CO_2 Capture Rate" equal to or exceeding a specified "Minimum CO_2 Capture Rate" has been demonstrated at commissioning of the Facility;

c) evidence that the Generator is complying with electricity metering obligations, relevant CO_2 metering obligations, and gas supply metering obligations; and

d) a date and time stamped copy of the electrical schematic diagram for each of the electricity metering equipment, CO_2 metering equipment, and gas supply metering equipment.

Expiry Date: Where the Generator achieves the Start Date before the end of the relevant Longstop Date, the DPA will expire on the date which falls [X] years after the date referred to above in ‘Commencement’, above, unless it is terminated earlier in accordance with its terms. Please see below for a discussion on early termination.

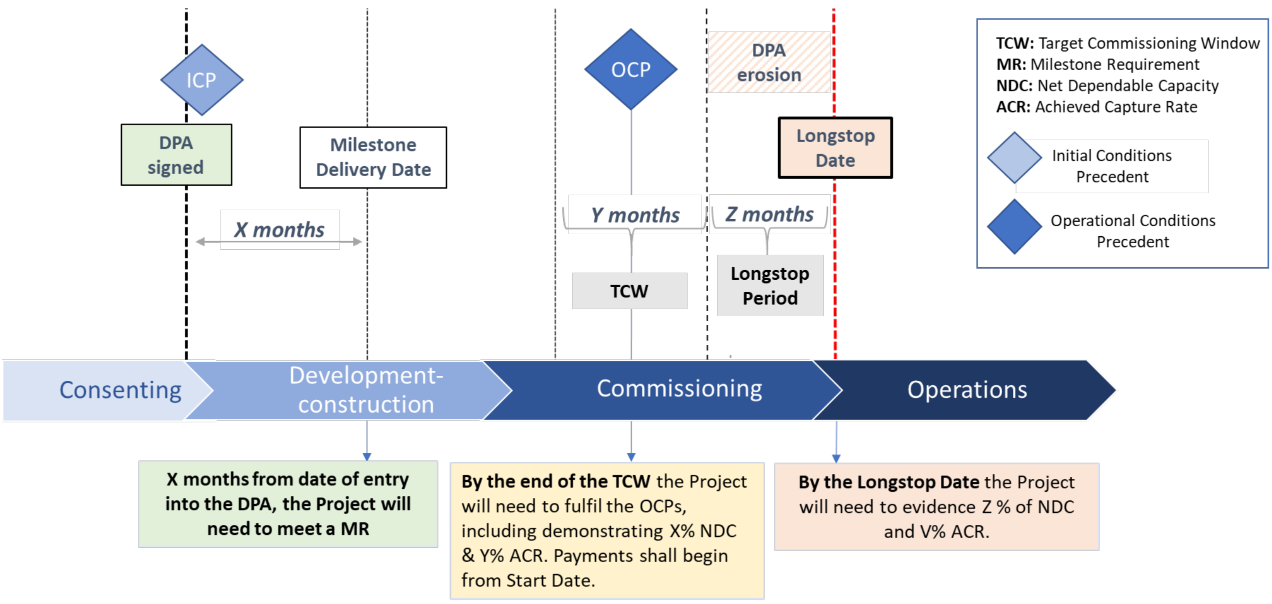

Figure 1: Indicative timeline of DPA milestones

Termination and Consequences of Termination

Pre-Start Date Termination: Similar to the AR3 CfD, the DPA will contain various rights for the DPA Counterparty to terminate the DPA prior to the occurrence of the Start Date. Such rights will ensure that DPA funding that has been committed to support the deployment of carbon capture infrastructure for power generation facilities is not tied up indefinitely in a project that has no realistic prospect of being commissioned. The DPA will include a right (but not the obligation) for the DPA Counterparty to terminate where:

a) initial Conditions Precedent: the Generator fails to fulfil the Initial Conditions Precedent within the specified time after the date of the Agreement (subject to any waiver by the DPA Counterparty), similar to the position under the AR3 CfD;

b) milestone Requirement: the Generator fails to fulfil the Milestone Requirement before the Milestone Delivery Date. The Milestone Delivery Date will be adjusted day-for-day for any delays that occur due to Force Majeure; and

c) longstop Date: the Generator fails to satisfy the Operational Conditions Precedent by a specified "Longstop Date" which, similar to the AR3 CfD, is likely to be 12 months after the expiry of the Target Commissioning Window. The Longstop Date will be adjusted day-for-day for any delays that occur due to Force Majeure.

Consequences of Pre-Start Date Termination: A Pre-Start Date termination could be on a no-liability basis under the DPA.

Termination for Prolonged Force Majeure: We may include a DPA Counterparty right to terminate the DPA where, prior to the commencement of the Target Commissioning Window, the Generator is significantly delayed in achieving the Start Date due to a continuing, unresolved Force Majeure. This is to ensure that committed DPA funding is not tied up indefinitely in a project that has no realistic prospect of being commissioned. If BEIS requires such a right, termination may be on a no-liability basis due to the non-fault nature of the event.

Termination for Generator Stranded Asset event (T&S Unavailability): Where a non-fault event prevents the Facility from accessing the T&S network for a continuous period (with such period to be determined), BEIS is considering whether to give the DPA Counterparty the right to terminate the DPA. In such circumstances, it may be reasonable for the relevant Generator(s) to be compensated in an amount to be determined.

Default termination: The default termination provisions in the DPA are likely to follow the AR3 CfD by giving the DPA Counterparty the right to terminate the DPA for Generator events of default comprising (a) insolvency; (b) non-payment which is not rectified within a specific cure period; (c) breach of key obligations relating to ownership of the Facility, no assignment and fraud; and (d) breach of key obligations relating to the fuel, carbon and electricity meters. In addition, BEIS is considering whether to include an event of default similar to the final installed capacity requirement found in the AR3 CfD, if the Generator fails to demonstrate a " Net Dependable Capacity" equal to or exceeding a specified percentage of the "Initial Net Dependable Capacity Estimate" has been commissioned. It may be appropriate to include a similar requirement/termination right in respect of the "Achieved CO_2 Capture Rate".

Consequences of Default termination: BEIS is currently considering whether compensation should be payable by the Generator to the DPA Counterparty following a default termination. Such compensation may also cover forgone T&S fees.

No Generator termination right: We note that, similar to the AR3 CfD, the Generator will not be entitled to terminate the DPA unilaterally before the Expiry Date.

Termination or Penalties for Poor Performance: BEIS is currently considering introducing penalties and/or a further termination event, in cases where the Generator's performance is poor for a prolonged period of time and particularly during the last years of the DPA. This could ensure that generators have incentives to continue maintaining their plant at an acceptable level. Consideration is also being given as to whether differing requirements should apply between initial and subsequent DPA projects.

Representations, Warranties and Undertakings

Representations, Warranties and Undertakings: BEIS is currently considering following the AR3 CfD in respect of the representations, warranties and undertakings that both the Generator and the DPA Counterparty are required to provide each other.

Generator's Metering Undertakings: BEIS intends to include the AR3 CfD electricity metering undertakings in the DPA, with such undertakings mirrored in respect of the gas input and CO_2 export of the relevant Facility.

Qualifying Change in Law

Scope of and Carve-Outs from Qualifying Changes in Law: The DPA may largely replicate the Qualifying Change in Law ("QCiL") provisions of the AR3 CfD, providing a level of cost and revenue protection for the Generator in respect of QCiLs that constitute "Discriminatory Changes in Law" (i.e. that discriminate against the Generator/the Project), "Specific Changes in Law" (i.e. that specifically apply to facilities with a DPA/a particular technology) and "Other Changes in Law" (i.e. that have an undue and discriminatory effect on a Generator's out-of-pocket costs in comparison with certain comparator groups). The intention is for the DPA QCiL provisions to have similar carve-outs, such as for "Foreseeable Change in Law". BEIS is still considering the details of such provisions, including whether the Generator will be protected in respect of QCiLs which only impact the "Power Plant" (as opposed to the "Capture Plant") and what are the most appropriate comparator groups for Specific Changes in Law and Other Changes in Law.

QCiL Compensation: The form of the QCiL Compensation provisions in the DPA may be based on the AR3 CfD and may broadly follow the 'no better, no worse' principles of the AR3 CfD (i.e. to place the parties in the position they would have been in had the QCiL not occurred). BEIS is still considering how such QCiL compensation should be calculated.

Qualifying Shutdown Events: For shutdown events, BEIS intends to follow the AR3 CfD, providing a level of compensation for a Generator if a "QCiL Construction Event" (i.e. a change in law which by its nature prevents a Project which is still in construction from reaching the Start Date) or a "QCiL Operations Cessation Event" (i.e. a change in law which renders it illegal for a Project to continue operating) occurs. BEIS is still considering how such compensation should be calculated.

Generator Credit Standing

BEIS is considering whether to require each Generator to have and maintain an "Acceptable Credit Standing", which will be defined in the DPA. This is being considered on the basis that payments might flow from the Generator to the DPA Counterparty in certain instances (e.g. under a possible gainshare mechanism or termination/ penalties for poor performance). A failure to maintain an "Acceptable Credit Standing" could give the DPA Counterparty the right to suspend payments under the DPA, with such suspended payments to be repaid to the Generator (without interest) after such failure is rectified.

Other Provisions

Reporting and Confidentiality: The form of the reporting and confidentiality provisions in the DPA will likely be based on the AR3 CfD. However, in respect of reporting under the DPA, BEIS is likely to require more detailed and frequent reporting, with the Generator being required to keep the DPA Counterparty fully informed on its progress during the construction, completion, testing and commissioning of the Facility and in satisfying the Operational Conditions Precedent. This is in recognition of the importance the first Power CCUS DPA projects may have to the wider CCUS cluster of which they are part.

Force Majeure: In respect of Force Majeure, it likely that BEIS will largely follow the provisions of the AR3 CfD, whereby the Generator is afforded an extension of time (pre-Start Date) and relief from performance of its DPA obligations where a Force Majeure occurs which is beyond the Generator's control.

Dispute Resolution Procedure: BEIS' intention is to follow the dispute resolution procedure detailed in the AR3 CfD, with disputes escalated to a meeting of senior representatives followed by resolution by expert determination or arbitration.

EU and UK Transition Provisions: BEIS has reserved its position in respect of the DPA provisions referring or related to European Law and subsidy control rules in light of the UK's exit from the European Union on 31 January 2020.

Limited recourse Arrangements: It is currently intended that provisions of the DPA will follow the limited recourse provisions set out in the AR3 CfD. In summary, this will include:

a) a requirement for the DPA Counterparty to make appropriate requests of Electricity Suppliers under the Supplier Obligation for the purpose of ensuring that it is in sufficient funds to meet its liabilities under all DPAs;

b) a provision clarifying that the liability of the DPA Counterparty under the DPA will not exceed the amounts received and held by the DPA Counterparty pursuant to the Supplier Obligation; and

c) certain specific remedies for the Generator where the DPA Counterparty fails to pay an amount on the due date under the DPA where such amount has been obtained pursuant to the Supplier Obligation, namely equitable relief and the right to recover default interest from the DPA Counterparty.

Payment Mechanism

The proposed DPA consists of two payments: an Availability Payment for low carbon generation capacity and a Variable Payment to adjust the position of the power CCUS plant (referred to as the ‘Facility’ in Annex D) in the merit order relative to unabated CCGTs.

Availability Payment

The DPA will incorporate an Availability Payment for low carbon electricity generation capacity. This will be linked to performance requirements for the power CCUS plant. The Availability Payment is intended to provide investors with certainty through a stable regular payment based on the availability of low carbon generation capacity. The Availability Payment Rate on which the Availability Payment is based will be set through either a negotiated or competitive allocation process.

The proposed formula is based on a constant monthly Availability Payment Rate, with settlement adjusted to reflect the availability of generation and availability and performance of capture that the power CCUS plant is able to achieve in any given month.

Calculation of Availability Payment

$$AP = (AG \times AC \times NDC \times APR) + TSCF$$

Where:

Calculation of Availability of Generation

$$AG^{1} = 1 - \frac{\sum((NDC - NAC_i) \times (\Delta T_{Event_i} \div 60))}{NDC \times \Delta T_{PH}}$$

Calculation of Availability of Capture

$$AC^{2} = \frac{ACRph \times \Delta T_{OP} + \sum DCR_i \times \Delta T_{NOP_i}}{\Delta T_{PH} \times TCR}$$

[1] Note to reader: AG shall be limited to a maximum value of 1.
[2] Note to reader: BEIS is considering a maximum limit value for the Availability of Capture.

Calculation of Achieved CO_2 Capture Rate

$$ACRph = \frac{CO2_{exp}}{CO2_{gen} - CO2_{gen\_TS}}$$

Term	Definition	Source
AP	Availability Payment in the AP Billing Period (£)	Calculated (see first formula)
AG	Availability of Generation in the AP Billing Period (%)	Calculated (see second formula)
AC	Availability of Capture in the AP Billing Period (also referred to as the CO_2 Capture Rate) (%)	Calculated (see third formula)
APR	Availability Payment Rate (£/MW)	Agreed in DPA and [fully/ partially] indexed to inflation
$TSCF$	T&S Capacity Fee in the AP Billing Period (£)	Defined in T&S Connection Agreement
NDC	Net Dependable Capacity (MW)	Measured through the OCP Acceptance Test or (where relevant) by the Longstop Acceptance Test
NAC_i	Net Available Capacity (during any Power Plant Outage Event in the AP Billing Period) (MW)	Declared on REMIT forms
ΔT_{Event_i}	Power Plant Outage Event Duration (includes a derating event) (minutes)	Declared on REMIT forms
ΔT_{PH}	Period Hours in the AP Billing Period (h)	Calculated

Term	Definition	Source
ACR_{PH}	Achieved CO_2 Capture Rate in the AP Billing Period (%)	Calculated (see fourth formula)
ΔT_{OP}	Total Operational Period (duration of all periods of CO_2 export to the T&S network occurring in the AP Billing Period) (h)	Calculated from CO_2 metering data on entry to T&S network
DCR_i	Deemed CO_2 Capture Rate (during a Non-Operational Period, being no CO_2 export to the T&S network) (%)	TBC
ΔT_{NOPi}	Total Non-Operational Period (duration of period of no CO_2 export to the T&S network occurring in the AP Billing Period) (h)	Calculated from CO_2 metering data on entry to T&S network
TCR	Target CO_2 Capture Rate (%)	Agreed in DPA
$CO2_{exp}$	Metered CO_2 Output in the AP Billing Period (tCO_2)	Metered on entry to T&S network at the CO_2 Delivery Points
$CO2_{gen}$	Calculated CO_2 Generated in the AP Billing Period (tCO_2)	Calculated from Total Metered Fuel Consumption and the Fuel Composition using JEP[3] methodology
$CO2_{gen\_TS}$	Calculated CO_2 Generated with T&S Outage in AP Billing period (tCO_2)	Calculated from Total Metered Fuel Consumption and the Fuel Composition using JEP methodology

[3] Joint Environmental Programme

Key components of the Availability Payment formula are explained in further detail below:

Availability Payment Rate (APR)

The Availability Payment Rate, or the value in £/MW that is paid by the DPA Counterparty to the Generator on the basis of its low carbon availability, will be agreed in the DPA through either a negotiated or competitive process. The Availability Payment Rate will be either partially or fully indexed to inflation. Further work is necessary to identify the appropriate price index, and we will consider relevant examples such as the AR3 CfD (which is fully indexed to CPI).

Availability of Generation

This is the Net Dependable Capacity less any Power Plant Outage Events. The impact of the Power Plant Outage Event is calculated as the Net Dependable Capacity less Net Available Capacity (declared in REMIT forms) multiplied by the Power Plant Outage Event Duration (declared in REMIT forms).

This term links the level of Availability Payment to be paid to the availability of generation capacity. This is intended to reduce the level of the Availability Payment in line with any outages on the generation unit (referred to as the ‘Power Plant’ in Annex D). Reductions will be proportionate to the length of any outage and will be applied in the billing period or month in which they occur. The availability of the generation unit could be determined on the basis of its declarations through the REMIT framework, which is used to document planned and unplanned availability in the electricity market. Whilst this framework is concerned more with market manipulation, it would reduce the need to create an additional administrative burden for the Generator. There are existing penalty mechanisms in place that give confidence over REMIT data, including the threat of criminal prosecution for misrepresentation of operational data in REMIT submissions or the failure to make adequate submissions.

We have considered alternative options for applying reductions to the payment, such as increasing or decreasing reductions for increasing length of outages, and for reductions to be spread across a multiple number of billing periods. However, these changes would add significant complexity to the formula and could have unintended consequences.

We are also considering options for whether and how to reward the Generator for improving the efficiency of capture over the lifetime of the DPA. There may be merit in allowing the Net Dependable Capacity in the DPA to be increased if the same CO_2 Capture Rate can be maintained with a higher electrical output (this would require a reduced energy requirement for the CO_2 capture process).

Availability of Capture

This term is intended to link the Availability Payment to the availability and performance of the capture unit (referred to as the ‘Capture Plant’ in Annex D) in capturing CO_2. There is no existing framework for reporting Availability of Capture (also referred to as the CO_2

Capture Rate) which could form the basis for this part of the Availability Payment formula. In order to measure this, it is necessary to consider both periods where the power CCUS plant is capturing CO_2 and periods where it is not because, to avoid distorting incentives to generate, the Availability Payment should be predicated on the availability of low carbon generation, rather than actual generation output.

During Operational Periods, CO_2 capture availability (the Achieved CO_2 Capture Rate in the formula) is measured simply by metering CO_2 on entry to the T&S network and comparing to the total CO_2 that would be generated by combusting the metered volume of gas used.

During Non-Operational Periods, we are considering two primary options:

1. Generators to declare CO_2 capture availability/ non-availability using an expanded REMIT framework or parallel declaration framework; or

2. the Deemed CO_2 Capture Rate to be equal to an average over a previous period (duration to be defined), subject to any declarations by the Generator that show a lower CO_2 Capture Rate (i.e. taking whichever is lower).

We will carry out further work to assess these options in more detail. We will also consider whether the DPA counterparty should have the right to request validation of any declared CO_2 Capture Rates through tests.

We are also considering options for whether and how to reward power CCUS plants for improving their CO_2 Capture Rate over the lifetime of the DPA. With technological improvement, they may be able to increase the proportion of CO_2 captured, which should result in further savings on carbon cost, but could also be incentivised through the Availability of Capture component of the Availability Payment formula. This term has been presented above as the Achieved CO_2 Capture Rate relative to the Target CO_2 Capture Rate, as defined in the DPA, which could apply for a scalar to the Availability Payment exceeding 100%. Allowing for the Availability of Capture scalar to exceed 100%, could provide an appropriate mechanism to incentivise improved CO_2 Capture Rate, which would ultimately lead to further decarbonisation of electricity generation. However, this could encourage Generators to under-estimate their respective Target CO_2 Capture Rate in the DPA, and may have wider impacts, including on the capacity required in the T&S network by the power CCUS plant, and on budget control. We are also considering whether the Target CO_2 Capture Rate would then have to be amended to reflect the power CCUS project's new capabilities following annual testing.

Net Dependable Capacity

Net Dependable Capacity is determined by the power CCUS plant's capacity at the time the DPA is signed and demonstrated at commissioning, the OCP Acceptance Test (or, if relevant, Longstop Date Acceptance Test). For a retrofit plant, this would be at the point of commissioning of the capture unit. This capacity will be fixed in the Availability Payment formula. It will not decrease over time in line with any degradation in capacity experienced by the power CCUS plant.

In developing this proposal we have considered whether the Net Dependable Capacity should be updated on a regular basis, perhaps by annual capacity tests. Our current view is that, while this may provide some protection to Generators from risk of degradation in plant capacity, Generators are best placed to manage this risk. Furthermore, including regular capacity tests would increase the administrative burden for these contracts and may add further complexity to the mechanism overall.

Indexation

Options for indexing the Availability Payment Rate have been explored and there are relative advantages and disadvantages for both full and partial indexation.

Partial indexation could be implemented for any negotiated FOAK projects but would be difficult to implement for competitively allocated contracts. This is because partial indexation is reliant on visibility of the underlying cost drivers of projects in order to identify what proportion of costs are appropriate to index to inflation. This proportion is likely to differ by project and an estimated allocation could be inaccurate and could lead to either windfall gains or losses for Generators.

Thorough scrutiny of Generators' costs is possible for a negotiated allocation, in which the Availability Payment Rate is based on project costs and those costs can be justified to government. However, it would be considerably more difficult to apply an appropriate partial indexation for an allocation process in which developers compete on the value of their Availability Payment Rate and do not share underlying project costs with government for assessment. In a liquid competitive allocation, it is unlikely that government or the Counterparty would have access to underlying project costs and, as a result, it would be difficult to assess the appropriate proportion of costs to be indexed.

Therefore, it is likely that the Availability Payment Rate would be fully indexed to inflation in line with existing electricity market support mechanisms to protect investors from inflationary pressure. We are considering which measure of inflation would be most appropriate to use for indexation.

T&S Capacity Fee

As noted in Section 3 of the main document, the T&S fees may comprise both a capacity fee and a volumetric fee. The treatment of the volumetric fee – linked to the volume of CO_2 captured – within the DPA is discussed later, but here we discuss the treatment of the T&S Capacity Fee. The T&S Capacity Fee will be based on how much capacity the Generator will require in the T&S network, when capturing the maximum volume of CO_2 at full load. This fee will be payable regardless of the volume of CO_2 that is injected into the T&S network. To provide certainty for the Generator and recognise the cross-chain risks in the

T&S fees, the T&S Capacity Fee should be incorporated within the Availability Payment. Separating the T&S Capacity Fee as a specific component in the Availability Payment formula provides some certainty to Generators that those costs will be indexed to those set the Economic Regulator for T&S and that the Availability Payment Rate does not need to be altered substantially to account for changes to these costs, and would allow the Availability Payment Rate to be stable following negotiation or auction.

This would reflect that the T&S Capacity Fee is primarily a cross-chain risk and higher costs are unlikely to be the result of poor negotiation by the Generator, but instead as a result of higher than expected system costs, fewer customers over whom to spread those system costs, or lower than expected system CO_2 volume. This means that the Availability Payment Rate itself does not need to be amended to account for deviations from the expected T&S Capacity Fee.

Specifying a T&S Capacity Fee would also remove one of the most uncertain components of the Availability Payment Rate from indexation and is instead regularly updated to reflect real costs. This would reduce the inflation risk and uncertainty for Generators on the T&S Capacity Fee.

During periods of unavailability of the generation unit and/ or capture unit, the T&S Capacity Fee will still be payable to the T&Sco (referred to as the 'T&S Operator' in Annex D). We are considering whether the T&S Capacity Fee would continue to be paid by consumers in this event or whether it may be paid by the Generator without recourse to consumer levies.

Billing Period (Availability Payment)

Performance could be calculated by the settlement period (currently half-hourly) in line with market settlement and settled on a monthly basis, to allow for a fair assessment of average capture efficiency and availability.

Outages can be calculated on a higher granularity: we are considering using REMIT declarations which can be made on a minute-by-minute basis. The Availability Payment formula should therefore take into account the exact duration in minutes of any outage to ensure the accuracy of the calculation. This also avoids the complication of establishing a threshold at which point it becomes appropriate to consider a Generator to have been unavailable for a settlement period and risk of over- or under-compensation for availability.

Treatment of Outages

We recognise that the definition of outages and derating events (where capacity is reduced but not entirely unavailable) will be an important consideration in measuring performance under the Availability Payment. In principle, outages and derating events should only impact on the Availability Payment when they are within the control of the Generator. This gives the Generator the incentive to control outages where possible, while protecting the Generator from risks that it cannot easily mitigate.

Outages which are not in the control of the Generator and which should not have a bearing on the Availability Payment include those due to:

- T&S network construction delays or planned or unplanned temporary outages;
- Gas supply failures; and
- Electrical grid outages.

However, where the impact of outages is within the power CCUS plant's control, these should be directly proportional to their duration.

Where outages of power and capture plant are simultaneous, for that period the lowest of the availability of generation and availability of capture will be used in the formula, whereas the highest of the two will be set to equal 1. The purpose of this is to avoid the Generator being penalised twice.

The mechanics of the Availability Payment formula are demonstrated below in four worked examples, showing its performance where the power CCUS plant is fully available for a month, a scenario where an outage on the T&S network causes it to become unavailable (referred to as a 'T&S Outage Event' in Annex D), and scenarios with outages on the generation unit (referred to as a 'Power Plant Outage Event' in Annex D) and capture unit (referred to as a 'Capture Plant Outage Event' in Annex D).

Availability Payment – illustrative examples

The following illustrative examples show the calculation of the Availability Payment (not including the T&S Capacity Fee) using the below format:

$$\underbrace{1 - \frac{\sum ((NDC - NAC_i) \times (\Delta T_{Event_i} \div 60))}{NDC \times \Delta T_{PH}}}_{AG} \times \underbrace{\frac{ACRph \times \Delta T_{OP} + \sum DCR_i \times \Delta T_{NOP_i}}{\Delta T_{PH} \times TCR}}_{AC} \times \underbrace{NDC}_{NDC} \times \underbrace{APR}_{APR}$$

Illustrative example (i) – normal operation

A power CCUS plant has 1000MW capacity and a Target CO_2 Capture Rate of 90%. With full availability through a month and occasional generation that shows its achieved capture rate as meeting its Target CO_2 Capture Rate, its Availability Payment can be calculated as:

AG		AC		NDC		APR
$1 - \frac{\left(\left(1000MW - 1000MW \times 0h\right)\right)}{(1000MW \times 744h)}$	×	$\frac{(0.9 \times 744h)}{(744h \times 0.9)}$	×	$1000MW$	×	APR
= 1		= 1		= 1000		= APR

Illustrative example (ii) – T&S Outage Event

The same power CCUS plant as in illustrative example (i) above faces an unexpected outage on the T&S network for 5 days and is therefore unable to export CO_2. Given this outage is outside the control of the Generator, this outage should not count against its availability. For the periods in which it is non-operational as a result of the T&S Outage Event, the Achieved CO_2 Capture Rate should be replaced by a Deemed CO_2 Capture Rate, either on the basis of declarations by the power CCUS plant or on the basis of a historic CO_2 Capture Rate over a previous month. The example below assumes that the Deemed CO_2 Capture Rate is lower than the CO_2 Capture Rate achieved across the rest of the month. The lower CO_2 Capture Rate declared for those periods results in the Availability of Capture (i.e. the CO_2 Capture Rate for the applicable Billing Period) component falling to 98.21%.

AG		AC		NDC		APR
$1 - \frac{\left(\left(1000MW - 1000MW \times 0h\right)\right)}{(1000MW \times 744h)}$	×	$\frac{(0.9 \times 624h) + (0.8 \times 120h)}{(744h \times 0.9)}$	×	$1000MW$	×	APR
= 1		= 0.9821		= 1000		= APR

Illustrative example (iii) – Power Plant Outage Event

The same power CCUS plant faces an unexpected outage on the generation unit lasting five days. This outage is within the control of the Generator, so is deducted from the Availability of Generation component of the Availability Payment formula. For the periods in which the generation unit is unavailable the Deemed CO_2 Capture Rate of the power CCUS plant is judged to be 80%.

The unavailability of the generation unit for five days means that the plant receives 82.4% of its Availability Payment for the month owing to reductions in the Availability of Generation component as demonstrated in the example below.

AG		AC		NDC		APR
$1 - \frac{\left(\left(\begin{matrix}1000MW - \\ 0MW\end{matrix}\right) \\ \times 120h\right)}{(1000MW \times 744h)}$	×	$\frac{(0.9 \times 624h) + (0.8 \times 12}{(744h \times 0.9)}$	×	$1000MW$	×	APR
= 0.8387		= 0.9821		= 1000		= APR

Illustrative example (iv) – Capture Plant Outage Event

The same power CCUS plant as above faces a further five-day outage on the capture unit in addition to the Power Plant Outage Event. Given this outage is also within the control of the Generator, it is deducted from the Availability of Capture component of the Availability Payment formula. The complete unavailability of the power CCUS plant for five days means that the Generator receives 62% of its Availability Payment for the month owing to the reductions to both the Availability of Generation and Availability of Capture components as demonstrated in the example below.

AG		AC		NDC		APR
$1 - \frac{\left(\left(\begin{matrix}1000MW - \\ 0MW\end{matrix}\right) \\ \times 120h\right)}{(1000MW \times 744h)}$	×	$\frac{(0.9 \times 504h) + (0.8 \times 120h) + (0 \times 120h)}{(744h \times 0.9)}$	×	$1000MW$	×	APR
= 0.8387		= 0.7387		= 1000		= APR

Illustrative example (v) – Simultaneous Power Plant Outage Event and Capture Plant Outage Event

The same power CCUS plant as above experiences outages on both the generation and capture units for fifteen days each during the month. These outages are adjudged to be within the control of the Generator and so they are deducted from both the Availability of Generation and Availability of Capture components of the Availability Payment formula. However, these outages overlap by five days, for which period the Generator is able to claim relief from the reduction to the Availability of Capture term as a result of total generation outage. During this period, Availability of Capture term is set to 1. For purposes of the calculation, in order for the Availability of Capture to equal 1, during this period the capture rate is assumed to be the target capture rate of 90%.

As a result, the Availability of Generation is calculated to be 51.61%, while the Availability of Capture is calculated to be 67.74%. As a result, the Generator receives 34.96% of its monthly Availability Payment.

AG		AC		NDC		APR
$1 - \frac{\left(\left(1000MW - 0MW\right) \times 360h\right)}{(1000MW \times 744h)}$	×	$\frac{(0.9 \times 504h) + (0 \times 240}{(744h \times 0.9)}$	×	$1000MW$	×	APR
= 0.5161		= 0.6774		= 1000		= APR

Other Availability Payment mechanism components under consideration

Minimum performance thresholds

We are considering whether a minimum performance threshold should be imposed on the Availability Payment. Below a defined threshold of CO_2 Capture Rate, the Availability Payment could cease to have a proportionate relationship to performance, and instead be decreased to zero. This could, for example, mean that a power CCUS plant with a minimum performance threshold of 50% of the CO_2 emitted would receive no Availability Payments for periods in which its CO_2 Capture Rate is less than 50%. Further work will be necessary to understand whether imposing minimum performance thresholds is necessary and if so, at what level to set these.

Variable Payment

The DPA will also incorporate a Variable Payment that is designed to ensure the power CCUS plant dispatches ahead of an unabated equivalent plant. The Variable Payment will be calculated by considering the difference between the power CCUS plant as agreed in the DPA and a theoretical reference unabated plant (referred to as the 'Reference Plant' in Annex D).

The aim of this calculation is to isolate the impact of installing a particular CCUS technology from other differences between the power CCUS plant and an equivalent unabated plant (for example, an unabated CCGT) and would include the following:

- Gas Cost Differential;
- Carbon Cost Differential;

- T&S Volumetric Fee; and
- Other Extra Variable Costs.

The formula below sets out how the Variable Payment component of the DPA should be calculated:

Calculation of Variable Payment

$$VP = \sum (VPR_i \times MWh_i)$$

$$VPR_i = GC + CC + OC + TSVPR \text{ [Note]}^4$$

Where:

Calculation of Gas Cost Differential

$$GC = \frac{GP}{100} \times (GU_{CCUS} - GU_{Ref})$$

Calculation of Carbon Cost Differential

$$CC = CP \times (CO2E_{CCUS} - CO2E_{Ref})$$

Calculation of T&S Volumetric Payment Rate

$$TSVPR = TSVF \times \frac{CO2_{exp,i}}{MWh_i}$$

Term	**Definition**	**Source**
VP	Variable Payment in the VP Billing Period (£)	Calculated (see first formula)
VPR_i	Variable Payment Rate for day *i* in the billing period (£/MWh)	Calculated (see second formula)

[4] Note to reader: (i) BEIS is considering adding an adjustment factor to adjust VPR_i based upon the CO_2 Capture Rate for the relevant day; and (ii) VPR_i will be zero for periods of T&S Outage Events and/or Capture Plant Outage Events.

Term	Definition	Source
MWh_i	Metered Day Electricity Output for day *i* of the billing period (MWh)	Metered at entry to electricity transmission/ distribution network and reported by a BSC Company (or agent) to the DPA Counterparty
GC	Gas Cost Differential due to CCUS (£/MWh)	Calculated (see third formula)
CC	CO_2 Cost Differential due to CCUS (£/MWh)	Calculated (see fourth formula)
OC	Other Extra Variable Costs due to CCUS (£/MWh)	Agreed in DPA and indexed to inflation
$TSVPR$	T&S Volumetric Payment Rate (£/MWh)	Calculated (see fifth formula)
GP	Gas Price indicator (pence/therm)	TBD
GU_{CCUS}	Power Plant Gas Consumption (therms/MWh)	Calculated based on the power CCUS plant reference thermal efficiency agreed in DPA
GU_{Ref}	Reference Plant Gas Consumption (therms/MWh)	Calculated based on the Reference Plant thermal efficiency agreed in DPA
CP	Carbon Price indicator (£/tCO_2)	TBD
$CO2E_{CCUS}$	Power Plant CO_2 Emissions (t CO_2/MWh)	Calculated based on the power CCUS plant reference thermal efficiency agreed in DPA

Term	Definition	Source
$CO2E_{Ref}$	Reference Plant CO_2 Emissions (t CO_2/MWh)	Calculated based on the Reference Plant thermal efficiency agreed in DPA
$CO2_{exp}$	Metered CO_2 Output for day *i* of VP Billing Period (tCO_2)	Metered on entry to T&S network at the CO_2 Delivery Points
$TSVF$	T&S Volumetric Fee for captured CO_2 (£/tCO_2)	Defined in T&S Connection Agreement

Key components of the Variable Payment are detailed below.

Gas Cost Differential

A power CCUS plant faces higher gas costs than an equivalent unabated CCGT for the same volume of electricity generated, and these are likely to be the most significant contributor to the increase in variable costs incurred by a power CCUS plant above an unabated equivalent plant. This is as a result of the additional thermal energy required to operate the capture unit, which cannot then be exported. The additional load of the capture unit is apportioned across the electrical output of the generation unit, which results in an overall decreased thermal efficiency and higher gas consumption per unit of electrical output. Therefore, the formula considers the differential in gas use between the reference unabated plant and the power CCUS plant.

The term in the formula is based on thermal efficiency of the power CCUS plant under set conditions and, in comparison, the thermal efficiency of an unabated reference CCGT designed to reflect the best CCGT on the grid. The choice of Reference Plant is discussed further in this section.

The differential in thermal efficiency is then applied to an indicator for the wholesale cost of gas. Natural gas is currently a liquid commodity with reliable hub price indicators, which could be used as the input for gas cost in the short term. They provide an accurate depiction of the costs faced by wholesale purchasers of natural gas in GB in short-term and real-time markets.

In order to ensure that the Variable Payment accurately reflects the actual additional gas costs of power CCUS, the frequency of the gas indicator should reflect the granularity of the power CCUS plant's gas purchasing decisions. The most liquid market for gas is day-ahead, and this market is settled on a daily basis. It is expected that a flexible power

CCUS plant would buy gas day-ahead in response to price movements in the day-ahead electricity market. A daily gas price would therefore best reflect the likely commercial operation of the power CCUS plant. A daily gas price would also reflect the precedent of using day ahead prices from the AR3 CfD for intermittent renewable electricity generation.

The Generator may hedge against changing gas prices by buying most of its gas in advance, in which case day-ahead prices may not necessarily reflect the price paid. Unabated and abated gas plant might employ a similar hedging strategy for gas because gas is their key input cost and, particularly where power CCUS projects are operated by utilities, they will face similar risks in the natural gas market as their unabated competitors. This means that gas cost faced per unit should be similar and no specific arrangement needs to be made in the formula for hedging. Reflecting hedging strategies would also add significant complexity to the variable payment calculation while creating the risk of unduly limiting the Generator's commercial decisions and locking in sub-optimal hedging patterns.

Carbon Cost Differential

Carbon cost savings are likely to be the most significant contributor to the overall difference in short run marginal costs incurred by a power CCUS plant over the DPA term. Though dependent on the carbon price increasing over time, the saving in carbon cost for the power CCUS plant relative to an unabated plant is expected to significantly exceed the additional gas and other additional variable costs associated with running carbon capture equipment. As with gas costs, carbon savings are calculated on performance of the power CCUS plant under reference conditions, as agreed in the DPA, rather than the actual performance of the plant. This ensures a simpler, more consistent calculation of the differential in short run marginal cost between the power CCUS plant and the unabated equivalent reference plant. Calculating these on actual outturn performance would require a significantly more complex formula, with live data needing to be collected from both the power CCUS plant and the most efficient CCGT on the system. Instead, the use of a Reference Plant in the formula simplifies data collection and provides certainty of revenues to the Generator. As set out below, the unabated reference plant is to be kept under review and can be updated to reflect the deployment of new, more efficient CCGTs on the system.

The carbon price indicator to be included in the formula should be reflective of the effective carbon price faced by the Reference Plant. This will include a link to the UK Emissions Trading Scheme (ETS), which will be established to replace the UK's participation in the EU ETS. Details regarding the UK ETS were published by BEIS in the Energy White Paper[5].

[5] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future

T&S Volumetric Payment Rate

Power CCUS plants will pay T&S Fees for use of the T&S network. A proportion of this cost could be charged per unit of CO_2 as a volumetric fee. Incorporation of a T&S Volumetric Payment Rate in the Variable Payment formula (through calculation of the T&S Volumetric Payment Rate) ensures that power CCUS plants are not disincentivised from running due to these costs, which are in excess of those faced by an unabated equivalent plant.

The T&S Volumetric Payment Rate is accounted for in full in the Variable Payment formula by indexing to the fee set by the Economic Regulator for T&S, and the payment should be updated through an automatic process if this fee changes over time. They are assumed to be paid as part of the Variable Payment unless mitigated by sufficient carbon savings.

Any T&S fees faced by the power CCUS plant will not be faced by an unabated equivalent plant. These additional costs could impact the ability of the power CCUS plant to dispatch before other higher-carbon alternatives if they are not fully accounted for in the Variable Payment formula. Similarly, we expect that the T&S Capacity Fee will be indexed in the Availability Payment.

Other Extra Variable Costs

Additional variable operating costs associated with power CCUS plants, aside from gas, carbon emissions, and the T&S Volumetric Payment Rate, should be included in the formula as they affect dispatch decisions. These additional costs may vary depending on the technology used, however, this could include costs such as the cost of purchasing capture solvent inventory or oxygen, which may need to be replaced on a regular basis. For these, a constant term should be included to cover variable operating costs. These costs should be fully indexed to inflation. This ensures that all costs are represented accurately and that the power CCUS plant retains the appropriate place in the merit order. Plant dispatch should continue to be driven by commercial incentives driving efficiencies and by market conditions; so the DPA should only shift the position of the power CCUS plant in the merit order to the extent necessary to dispatch it ahead of unabated CCGTs. Although the Variable Payment is designed to cover the cost differential between a power CCUS plant and an unabated plant, it does so under reference conditions and the calculation should ensure that developers continue to have the correct commercial incentives to invest in high quality plant and employ efficient strategies, so as to participate in the market effectively.

CO_2 usage revenue could also be incorporated into the Variable Payment. If CO_2 usage is not taken into account, the power CCUS plant would have an incentive to export carbon for usage rather than storage. However, assuming that the Availability Payment calculation only takes CO_2 entering the T&S network into account when calculating Availability of Capture, then exporting CO_2 for usage would also negatively impact the Availability Payment, providing a disincentive. As the Variable Payment is likely to be much smaller than the Availability Payment, the reduction to the Availability Payment should be sufficient to outweigh the commercial benefits of usage, so it is not necessary to take CO_2 usage revenue into account in the Variable Payment.

CO_2 capture rate multiplier

The Achieved CO_2 Capture Rate (as detailed above) of the power CCUS plant is the captured CO_2 measured on entry to the T&S network, divided by CO_2 generated by the Generator determined using the JEP[6] methodology.

BEIS is likely to apply a CO_2 capture rate multiplier to the Variable Payment to avoid creating a perverse incentive for the power CCUS plant to capture less CO_2 and to ensure that subsidies are being paid out only where the power CCUS plant is meeting the objectives of the CCUS Programme.

Reference Plant

The Variable Payment formula should calculate the difference in costs between a power CCUS plant and an unabated plant based on a Reference Plant to simplify the formula. The Reference Plant should represent the best available CCGT technology when the DPA is agreed. The performance of the power CCUS plant should be calculated on the basis of reference characteristics of the power CCUS plant specified in the DPA. The Reference Plant may therefore need to be updated periodically to reflect improvements in CCGT technology. We are considering whether having an option to update this at 5-year intervals during the DPA term could be appropriate.

Ultimately, the DPA should protect the power CCUS plant by including a mechanism to ensure that the thermal efficiency and specific CO_2 emissions for the Reference Plant can only increase through this process.

Billing Period (Variable Payment)

Regarding billing periods, Variable Payments should be calculated half-hourly and could be settled on a daily basis, similar to the AR3 CfD payment mechanics. We are considering whether these could be settled on a monthly basis to match the Availability Payment settlement frequency. Dispatch decisions are currently made on a half-hourly basis because this is the current length of the market settlement period.

If the commodity costs comprising the inputs to the Variable Payment formula are collected day-ahead, it may be appropriate to calculate the differential between the CCUS plant and the Reference Plant daily and settle Variable Payments daily. Collecting the time variant inputs to the formula on a daily basis means there is little value in calculating payments and settling at a higher level of granularity than this.

[6] Joint Environmental Programme

Billing and settlement should be aligned with market practices and precedent from the AR3 CfD to avoid unnecessary burden for the DPA Counterparty.

Operating conditions

We do not think that varying operating conditions for the power CCUS plant or the Reference Plant need to be taken into account in the Variable Payment calculation. Incorporating dynamic reference efficiencies would make the Variable Payment formula significantly more complex. The performance profiles of power CCUS plant and unabated CCGTs is very similar across varying operating conditions, so holding both at the same reference condition in the formula should reflect overall differences in their costs regardless of outturn operating conditions.

Variable Payment – illustrative example

The Variable Payment Rate per MWh of Metered Day Electricity Output can be calculated using the following formula:

Gas Cost Differential + CO2 Cost Differential + Additional Variable Costs + T&S Volumetric Payment Rate = Variable Payment Rate

Where:

Gas Cost Differential

Gas Price		Gas Use Differential		Gas Cost Differential
Referenced to market indicator	×	$(GU_{CCUS} - GU_{Ref})$	=	*Calculated*

CO_2 Price Differential

Carbon Price: *Referenced to market indicator* × CO2 emissions differential: $(CO2E_{CCUS} - CO2E_{Ref})$ = CO2 Cost Differential: *Calculated*

Other Extra Variable Costs

Additional variable cost: *Agreed in DPA*

T&S Volumetric Payment Rate

T&S Volumetric Payment Rate: $TSVF \times \frac{CO2_{exp,i}}{MWh_i}$

Illustrative example (vi)

A power CCUS plant has 1000MW export capacity, a Target CO_2 Capture Rate of 90%, and an assumed net thermal efficiency of 56%. The Reference Plant is assumed to be a CCGT with export capacity of 1000MW and a net thermal efficiency of 62%. The power CCUS plant is also assumed to have an Other Extra Variable Cost of £2/MWh above the Reference Plant. The T&S Volumetric Fee is assumed to be £15/tCO_2.

The assumed Gas Price is 57p/therm and the assumed Carbon Price is £32.49/tCO_2. The carbon intensity of natural gas is assumed to be 5.4kgCO_2/therm. The Variable Payment Rate (per MWh) is calculated as:

Gas Cost Differential:

Gas Price		Gas Use Differential		Gas Cost Differential
$\frac{57}{100}$	$\times$	$(64.07 - 57.87)$	$=$	$Calculated$
0.57		= 6.20		= 3.53

CO_2 Cost Differential:

Carbon Price	CO2 emissions differential	CO2 Cost Differential
$Referenced\ to$ $market\ indicator$	$((0.3460 \times 0.1) - 0.3125)$	$Calculated$
32.49	= −0.2779	= −9.03

Other Extra Variable Costs

Additional variable cost
$Agreed\ in\ DPA$
= 2

T&S Volumetric Payment Rate

T&S Volumetric Payment Rate

$$15 \times \frac{\begin{pmatrix} 0.3460 \times \\ 0.9 \end{pmatrix}}{1}$$

= 4.67

The resulting Variable Payment Rate can then be calculated as:

$$\underset{3.53}{\text{Gas Cost Differential}} + \underset{-9.03}{\text{CO2 Cost Differential}} + \underset{2}{\text{Additional Variable Costs}} + \underset{4.67}{\text{T\&S Volumetric Payment Rate}} = \underset{1.17}{\text{Variable Payment Rate}}$$

The total costs associated with operating the power CCUS plant result in an additional cost of £1.17/MWh over the cost of operating the Reference Plant and this difference will be paid as the Variable Payment. If the T&S Volumetric Fee is assumed to be lower, at £10/tCO_2 the total T&S Volumetric Payment Rate is £3.09/MWh, and the Variable Payment falls to -£0.41/MWh. In this case, the floor of 0 is applied and no Variable Payment is made.

$$\underset{3.53}{\text{Gas Cost Differential}} + \underset{-9.03}{\text{CO2 Cost Differential}} + \underset{2}{\text{Additional Variable Costs}} + \underset{3.09}{\text{T\&S Volumetric Payment Rate}} = \underset{-0.41}{\text{Variable Payment Rate}}$$