APPLICANT'S RESPONSES TO ISSUES RAISED AT DEADLINE 1

Drax Bioenergy with Carbon Capture and Storage

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APPENDICES

1. INTRODUCTION

1.1 PURPOSE OF THIS DOCUMENT

1.1.1 On 23 May 2022, Drax Power Limited ("the Applicant") made an application ("the Application") for a Development Consent Order (DCO) to the Secretary of State for Business, Energy and Industrial Strategy ("the SoS"). The Application was accepted for Examination on 20 June 2022.

1.1.2 This document provides the Applicant's response to the issued raised in various submissions made at Deadline 1. These submissions were from a number of Interested Parties and were published on the Planning Inspectorate website on 6th February 2023, as follows:

Table 1.1 – Interested Party Submissions Made at Deadline 1

Interested Party	Submission
Selby District Council and North Yorkshire County Council	Local Impact Report
	Statement on Local Government Reorganisation
	Summaries of Relevant Representations
	Cover Letter and Position Statement.
Just Transition Wakefield	Post-hearing submissions, including written summaries of oral submissions to the hearings.
Mr Hewitt	Post-hearing submissions, including written summaries of oral submissions to the hearings
Biofuelwatch	Post-hearing submissions, including written summaries of oral submissions to the hearings - Open Floor Hearing 1
	Post-hearing submissions, including written summaries of oral submissions to the hearings - Preliminary Meeting
	Post-hearing submissions, including written summaries of oral submissions to the hearings - Issue Specific Hearing 1

1.1.3 This report provides the Applicant's response to the key issues raised by Interested Parties in their Deadline 1 submissions.

1.2 THE USE OF BIOMASS

1.2.1 Concerns and issues relating to the use Biomass have been raised a number of times by the various Interested Parties.

1.2.2 As set out during the examination, Drax is seeking consent for implementing CCS at an already consented biomass power station. In accordance, sustainability conditions related to continued use of biomass sources should remain outside of the remit of the examination process.

1.2.3 Paragraph 2.1.5 of Chapter 2 of the ES (APP-038) confirms that Units 1 and 2 (as well as Units 3 and 4) are already operated using biomass, with operations controlled under the provisions of several Environmental Permits required by the Environmental Permitting (England and Wales) Regulations 2016 (paragraph 2.1.10). 2

1.2.4 As such the principle of using biomass is not within the scope of the application, which, as set out above, relates to the installation and use of carbon capture technology.

Table 2.1– North Yorkshire County Council and Selby District Council Local Impact Report, Position Statement and Statement on Local Government Reorganisation

Response Ref. (Location in Original Submission)	Comment	Applicant's Response
Submission Document: Local Impact Report		
Noise and Vibration		
2.1 (LIR Paragraph 14.6)	DCO requirement 14 allows a number of 'permitted preliminary works' to take place prior to the CEMP being agreed and implemented. There is uncertainty whether or not those permitted preliminary works would result in any harm, for example: (a) where will the temporary facilities for contractors be?; (b) what remedial works are required and using what equipment; (c) what construction techniques are involved in the laying of services; and (d) where is the enclosure for site security. Therefore, it is recommended that the CEMP is agreed and implemented prior to all permitted preliminary works.	It is considered that certain activities could progress prior to the production of the CEMP without causing harm. The Applicant has reviewed the list of permitted preliminary works and has identified those activities that could be progressed and these are as follows: • Environmental surveys; • The provision of temporary means of enclosure and site security for construction; and • The temporary display of site notices or advertisements. The Applicant has therefore updated the draft DCO to reflect that these activities could be done prior to the preparation and approval of the CEMP. Bearing this update in mind, the Applicant has responded to each point in turn below: a) For these preliminary works it would be anticipated that either the facilities already provided on site would be used for contractors, or that they would provide their own temporary welfare facilities. Given the scale of works this might include, for example, a self-contained welfare unit and it is therefore considered that this would not result in any harm or impact. b) As per the update to the dDCO, remedial works would not be carried out without an approved CEMP. c) As per the update to the dDCO, laying of services would not be carried out without an approved CEMP. d) Any temporary means of enclosure and site security would be provided within the Drax Power Station Site or the East Construction Laydown Area. It is not considered that provision of site fencing would result in harm.
2.2 (LIR Paragraphs 7.7 to 7.8)	Operational noise impacts are not adequately addressed / mitigated in the Application / draft DCO. DCO requirement 17 reflects the predicted noise rating levels LAr,Tr and so acceptance of the DCO requirement results in adverse noise impacts during the	Requirement 17 of Schedule 2 of the draft DCO requires a noise mitigation scheme to be submitted to and approved by the relevant planning authority containing details of how the design has incorporated noise mitigation measures for work nos. 1 (carbon capture

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	nighttime period at two residential receptors within the district. Contextual considerations are put forward at sections 7.9.15-7.9.20 of Volume 1, Chapter 7 of the Environmental Statement (document reference APP034), notably no exceedance of ambient LAeq,T values, widespread compliance with BS8233:2014 design criteria and use of conservative background LA90,T values. However, there is uncertainty regarding good acoustic design within this section in terms of efforts to incorporate noise mitigation measures as set out within section 7.5.53 of Volume 1, Chapter 7 of the Environmental Statement (document reference APP-034) when seeking to avoid adverse noise impacts at all sensitive receptors. In the absence of demonstrating good acoustic design, under DCO requirement 17, the 'Rating Level' against Receptor R6 (2 Forest Grove, Barlow) should be reduced from 34dB to 33dB, and against Receptor R14 (Low Farm) reduced from 35dB to 33dB.	plant), 2 (infrastructure to transport compressed CO2) and 3 (supporting works), to ensure that the operational noise rating levels will not be exceeded. This scheme will include measures to mitigate noise impacts on receptors R6 and R14 to ensure that the noise rating levels set out in Table 1 of Requirement 17 for those receptors are not exceeded. The Applicant is also obliged to implement the mitigation scheme, as approved. The relevant planning authority therefore has an opportunity to ensure that a good acoustic design is achieved during the detailed design stage. As such, it is considered that a suitable and robust mechanism for mitigating noise impacts during the operation phase is secured via the DCO.
2.3 (LIR Paragraph 8.3)	Policies and guidance relevant to the determination of the DCO include: a) A E Weddle. (1987). Drax Power Station Landscape Management Report, July, 1987.Revised July 1990. b) Green Infrastructure Framework – Principles and Standards for England c) Leeds City Region Enterprise Partnership. (2018). d) Leeds City Regional Green Infrastructure Strategy 2017-2036 - Version Draft Final e) Dales to Vale River Network Partnership (Dales to Vales River Network Catchment Partnership, 2021).	The LPA have identified a number of policies and guidance that they consider is relevant to the determination of the DCO. The Applicant has set out how these have been considered and responded below: a) A E Weddle. (1987). Drax Power Station Landscape Management Report, July, 1987. Revised July 1990. The Applicant notes the guidance provided in the Weddle report in relation to the setting of the power station, and its relationship with the green infrastructure. However, the Applicant does not consider that the document is relevant to the determination of the Application. The report is not policy and therefore should only be considered in its role as guidance and in so much as it can be adhered to within specific applications. In this case, the Application has sought to reinforce existing field boundaries and replace landscape features where they may be impacted directly by the Proposed Scheme or where improvements may be considered as mitigating impacts, such as the reinforcement of the existing hedgerow (to the east of the Construction Laydown Area boundary). The Applicant can only be expected to mitigate significant effects in relation to the Proposed Scheme, rather than replacing green infrastructure that has been removed in the past or for the management of the remainder of the Drax site and surrounding landscape which is not under its ownership. The Applicant therefore considers that it has committed to what is required to deliver the Proposed Scheme as part of the Application which is being considered. Nevertheless, through consultation with the LPA, the Applicant has considered some of the guidance provided within the Weddle report in developing the Design Framework (APP-195). This has included avoiding where appropriate low-level clutter, the use of on-site mitigation to provide screening, along with building materials and colour using lighter tones for taller structures and darker tones at a lower height. The

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		Applicant does acknowledge within the Design Framework (APP-195) that since the original design, there has been some erosion of the original symmetry, and widening of the original footprint with some visual coalescence, however within the context of the cooling towers and main building, the resulting effects of the Proposed Scheme are limited and are not considered significant, as described within Chapter 9 of the ES – Landscape and visual amenity (APP-195), the predicted impacts and residual effects, which are agreed upon, as recorded within item 4.10.6 and 4.10.8 of Table 4.10 - Design, landscape and Visual Impact within the Statement of Common Ground between Selby District Council, North Yorkshire County Council and Drax Power Limited (REP-018). The absence of significant landscape and visual effects in the operational phase means there is limited (if any) any justification for taking additional land for off-site landscape mitigation measures or enhancement. b) Green Infrastructure Framework – Principles and Standards for England. This was considered a guidance document within the Design Framework (APP-195).The Applicant does not consider that the document is relevant to the determination of the Application. The document is not policy and therefore should only be considered in its role as guidance and in so much as it can be adhered to within specific applications. The Applicant has within the Design Framework set out how the Proposed Scheme has sought to retain the existing green infrastructure within the Order Limits through vegetation retention, provided woodland enhancement measures as part of off-site habitat provision (Arthurs Wood and Fallow Field) and proposed the reinforcement of the existing hedgerow (to the east of the Construction Laydown Area boundary). The Design Framework sets out in Section 4.2, how the retention of green infrastructure and its potential further development within the Site has been considered, including specific measures set out within the Outline Landscape and Biodiversity Strategy (AS-094), and secured through items E1 and LVIA1 of Table 1.1 Register of Environmental Actions and Commitments, within the Register of Environmental Actions and Commitments 04 (REP-015). c & d) Leeds City Region Enterprise Partnership (2018) and the Leeds City Regional Green Infrastructure Strategy 2017-2036 Comprising strategy documents which do not form statutory planning documents, these seek to expand green infrastructure to enable everyone within the region access to green infrastructure. The Applicant has in Section 5.5 Regional Strategies of the Design Framework (APP-195) set out how the Proposed Scheme contributes to a number of the strategy aims with increased provision of hedgerow and woodland enhancement. e) Dales to Vale River Network Partnership (Dales to Vales River Network Catchment Partnership, 2021). As an organisation the Dales to Vale River Network Partnership seeks to bring together organisations and individuals with an interest in preserving and enhancing the benefits provided by rivers and wider catchments. The Site lies within the Ouse Catchment

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		Management Plan; however, the Applicant does not consider that the document is relevant to the determination of the Application. Nevertheless, the Applicant has in Section 5.5 Regional Strategies of the Design Framework (APP-195) set out how the Proposed Scheme contributes to addressing some of the issues raised by the partnership within the Ouse Catchment Management Plan, specifically delivering a net-gain in biodiversity and selecting suitable woodland species, suited to the floodplain environment. The Applicant has committed to delivering a 10% biodiversity net gain as detailed in the Biodiversity Net Gain Assessment ((AS-196) an updated version of which will be submitted at Deadline 2). Appropriate species of trees including riparian species suitable for locations within the floodplain are identified in 4.2.22 of the Design Framework (APP-195) and secured through Requirement 7 of the Draft DCO ((AS-076) an updated version of which will be submitted at Deadline 2).
2.4 (LIR Paragraph 8.5)	Notwithstanding the above and statements of whether effects are defined as ‘significant’ in EIA terms, there is concern that there are no clearly identified landscape mitigation proposals or other landscape design proposals or commitments set out within the Application which would demonstrate ‘good design’ and to help reduce adverse landscape and visual effects and potential adverse cumulative effects in conjunction with other planned developments.	The Design Framework (APP-195) was prepared in consultation / liaison with the LPAs and sets out to stakeholders what represents ‘good design’ in the context of the Proposed Scheme. It provides an overview of the historic landscape vision for Drax Power Station and the evolving design context in terms of new and ancillary infrastructure on the Site as a whole. Where necessary and/or required, aspects identified within the Design Framework that represent good design, e.g. massing, colour, materials, lighting design, landscape design have been, or will be, applied. Specifically, the design principles, including the colour palette in relation to the height of structures/buildings which is secured via the Requirement 6 (Detailed Design) of the Draft DCO ((AS-076) an updated version of which will be submitted at Deadline 2). The Applicant’s response to ExA’s first written question DLV.1.1 sets out in detail how the Proposed Scheme complies with good design requirements, and also highlights the limitations in this respect given the engineering design requirements and constraints. In relation to siting, the north option (as compared to the southern option) for the Proposed Scheme was chosen for a number of reasons, one of these being that it achieved a good fit within the existing site and made use of existing green infrastructure, reflecting the ‘good design’ principles outlined in paragraph 4.1.2 of the Design Framework (APP-195). The LIR states “notwithstanding the above and statements of whether effects are defined as “significant” in EIA terms”, however, the need for mitigation cannot be divorced from the effects of the Proposed Scheme. It is agreed with NYCC/SDC that no significant adverse effects have been identified for landscape during the operational phase of the proposed development, including the cumulative assessment. This is confirmed as being agreed with NYCC/SDC within item 4.10.6 and 4.10.8 of Table 4.10 - Design, landscape and Visual Impact within the Statement of Common Ground between Selby District Council, North Yorkshire County Council and Drax Power Limited (REP-018). Consistent with that agreement, the LIR does not identify significant adverse effects to any landscape

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		character or viewpoint. In the absence of significant landscape or visual effects in the operational phase, the Applicant considers that it has already provided reasonable and appropriate mitigation, proportionate to the level of effects predicted to result from the Proposed Scheme, and as a result has minimised harm to the landscape resulting from the Proposed Scheme (in accordance with paragraph 5.9.8 of NPS EN-1). Further green infrastructure improvements would be considered as enhancements to the existing baseline, and would not directly relate to the impact of the Proposed Scheme, nor would they be required in order to make the Proposed Scheme acceptable in order to be granted development consent (and the Applicant does not understand NYCC/SDC to suggest otherwise). All essential landscape mitigation proposals have been set out in the Outline Landscape and Biodiversity Strategy (AS-094) which is secured via Requirement 7 of the Draft DCO ((AS-076) an updated version of which will be submitted at Deadline 2).
2.5 (LIR Paragraph 8.6)	The original landscape mitigation strategy for the power station has been notably eroded over a number of years and with ongoing redevelopment pressures on and around the Application Site. Landscape tree and shrub planting has been generally removed or reduced due to redevelopment on the site or though management of landscape infrastructure, particularly within and around the main operational area of the site. This erosion is particularly noticeable around boundaries to the site where structure planting has been removed along New Road fronting the main electricity connections and substation (circa 2016), and along the main entrance / access road to allow construction of the new contractor's compound (circa 2019).	The Applicant does acknowledge within the Design Framework (APP-195) that since the original design, there has been some erosion of the original symmetry, and widening of the original footprint with some visual coalescence. However, the erosion of specific boundaries has arisen as a result of previous planning applications (some entirely outside of Drax's control) that were subject to scrutiny by the relevant planning authorities at the time. In relation to the Proposed Scheme, the Application has sought to reinforce existing field boundaries and replace landscape features where they may be impacted directly by the Proposed Scheme or where improvements may be considered as mitigating impacts, such as the reinforcement of the existing hedgerow (to the east of the Construction Laydown Area boundary). The Applicant has carried out an assessment of the potential impacts from the Proposed Scheme and identified appropriate measures to mitigate likely significant effects in this respect. The identified mitigation did not include replacing green infrastructure that has been removed in the past or for the management of the remainder of the Drax site and surrounding landscape which is not under their ownership. Assessment of the Proposed Scheme and the existing baseline landscape determined there would be no significant adverse effects during operation, and therefore no further mitigation is proposed beyond that which is in the Design Framework and secured via the REAC and Draft DCO Requirement 7 (Provision of Landscape and Biodiversity Mitigation and Enhancement). In the absence of significant landscape or visual effects in the operational phase, the Applicant considers that it is has done all that is required to deliver a scheme that avoids or reduces significant effects. Further green infrastructure improvements would be considered as enhancements to the existing baseline and are not a requirement in relation to the determination.

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		The Applicant understands the point being made by the Councils, however, as the impacts it is concerned with are not a result of the Proposed Scheme (and are therefore not required to be mitigated in order to make the Proposed Scheme acceptable), there are limits (in line with NPS policy requirements and the NPPF tests relating to requirements and obligations) as to what the Applicant can do in the context of this Application.
2.6 (LIR Paragraph 8.7)	All ongoing reduction of the original landscape mitigation will erode the original landscape baseline by which subsequent Applications are assessed and inevitably increase overall visibility of the site and that of any subsequent development. There is little evidence overall that the main site landscape or the wider structural landscape is being strengthened or improved through ongoing landscape management.	Although it is acknowledged that some necessary vegetation clearance has been undertaken in certain locations around the perimeter of Drax Power Station, for operational safety and security reasons, this vegetation removal would not have provided significant screening of the Proposed Scheme, due to its location. It should also be noted that, irrespective of the acknowledged vegetation removal, the main site has been visible to varying degrees from the surrounding landscape since the site was developed as a power station. Whether there is evidence that the main site landscape or the wider structural landscape has been strengthened or improved, is not relevant to the current application. Furthermore, these expectations or requirements do not relate to the Proposed Scheme and, as a result, do not meet the legal tests in the NPPF for requirements. The points made above in response to LIR paragraph 8.6 are also relevant in this respect.
2.7 (LIR Paragraph 8.8)	There is concern that each individual development Application (including this Application) is justifying the non-provision of supporting landscape on the basis that the development is 'low adverse' and 'not significant'.	Although this concern is acknowledged, the assessment of landscape and visual effects, presented in Chapter 9 of the ES – Landscape and visual amenity (APP-195) does not identify significant effects in the operational phase. This is confirmed as being agreed with NYCC/SDC within item 4.10.6 and 4.10.8 of Table 4.10 - Design, landscape and Visual Impact within the Statement of Common Ground between Selby District Council, North Yorkshire County Council and Drax Power Limited (REP-018). This is also the case for the assessment of cumulative effects presented in Chapter 18 Cumulative Effects (APP-054 an updated version of which is submitted at Deadline 2) and agreed as being appropriate in item 4.10.9 of Table 4.10 - Design, landscape and Visual Impact within the Statement of Common Ground between Selby District Council, North Yorkshire County Council and Drax Power Limited (REP-018), potentially arising from other schemes that were assessed in combination with the Proposed Scheme. It is entirely appropriate that mitigation is provided when there is a justification for it, or requirement to do so (in line with the requirements of the NPSs, and relevant NPPF tests). In this instance, mitigation beyond that which has been identified within the Design Framework (APP-195) and secured via Requirements 6 (Detailed Design), 7 (Provision of Landscape and Biodiversity Mitigation and Enhancement) and 14 (Construction Environmental Management Plan) (in relation to timing of planting as detailed in LVIA7
2.8 (LIR Paragraph 8.9)	This is relevant given that there are increasing and ongoing pressures for redevelopment within the site and in proximity to the site reflected in the current number of current planning applications relating to power infrastructure, renewable energy and mineral extraction (as considered within Chapter 18 Cumulative Effects of the Environmental Statement (document reference APP-054) and listed in Appendix 18.21 Short List of Other Developments (document reference APP-114).	

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		within the Register of Environmental Actions and Commitments (REP-015 an updated version of which will be submitted at Deadline 2)) of the Draft DCO ((AS-076) an updated version of which will be submitted at Deadline 2) is not necessary in order to mitigate impacts directly resulting from the Proposed Scheme nor to make it acceptable in the context of relevant NPS policy with respect to landscape and visual effects. Assessment of the Proposed Scheme alone, and in combination with other schemes, within the context of the existing baseline landscape, determined there would be no significant adverse effects during operation. Therefore, no further mitigation is proposed beyond that which has already been identified (see paragraph above). Although it is possible that some additional design considerations or planting proposals would provide 'enhanced' mitigation for the Proposed Scheme, this has not been proposed because it is not a requirement to implement 'enhanced' mitigation. Furthermore, it should be emphasised that the assessment was undertaken regarding the landscape baseline at the time of the Proposed Scheme application. As the LVIA finds no significant landscape effects during operation, there is no requirement to strengthen or improve the Drax Power Station Site landscape, nor the wider structural landscape, through ongoing landscape management. Any perceived reduction of the 'original landscape mitigation' and erosion of the 'original landscape baseline' has therefore not formed the basis for any proposed mitigation.
2.9 (LIR Paragraph 8.10)	Given the scale of the existing Drax Power Station site and the significant changes that have taken place since the original landscape design, the Authorities recommend that the Applicant should continue to develop the Design Framework (document reference APP-195) and the Lighting Strategy (document reference APP-184) together with clearly defined mitigation proposals which can be secured through the DCO.	The Councils reference the scale of the existing Drax Power Station Site and significant changes that have already occurred, as being the impetus to develop the documents referred to. However, in the context of this Application, the Applicant can only be expected to mitigate significant effects in relation to the Proposed Scheme, rather than replacing green infrastructure that has been removed in the past or for the management of the remainder of the Drax site and surrounding landscape which is not under their ownership. The Applicant considers that it has committed to reasonable and appropriate mitigation in order to minimise harm to the landscape caused by the Proposed Scheme, and is required to deliver an acceptable scheme as part of the Application which is being considered. Nevertheless, through consultation with the LPA, the Applicant has considered some of the guidance provided within the Weddle report in developing the Design Framework (APP-195). This has included avoiding, where appropriate, low-level clutter, the use of on-site mitigation to provide screening, along with building materials and colour (using lighter tones for taller structures and darker tones at a lower height), the latter being secured via Requirement 6 (Detailed Design) of the Draft Development Consent Order ((AS-076) an updated version of which is submitted at Deadline 2). The Applicant does acknowledge within the Design Framework (APP-195) that since the original design, there has been some erosion of the original symmetry, and widening of the original footprint with some visual coalescence. However within the context of the cooling towers and main

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		building, the resulting effects of the Proposed Scheme are limited and are not considered significant. This is described within Chapter 9 of the ES – Landscape and visual amenity (APP-195), the predicted impacts and residual effects having been agreed upon, as recorded within item 4.10.6 and 4.10.8 of Table 4.10 - Design, landscape and Visual Impact within the Statement of Common Ground between Selby District Council, North Yorkshire County Council and Drax Power Limited (REP-018). In the absence of significant landscape and visual effects in the operational phase there is no justification for broadening the scope of the Draft Lighting Strategy (APP-184) beyond that which is necessary to mitigate the Proposed Scheme and reduce or avoid significant landscape and visual effects which it has done. It should be noted that the Design Framework (APP-195) has been developed in consultation with the LPA. The Design Framework looks to provide an approach by which the Proposed Scheme is considered within the context of the Drax Power Station. Those elements that are applicable to the Proposed Scheme are appropriately secured via the Draft Development Consent Order ((AS-076) an updated version of which is submitted at Deadline 2), in particular via Requirements 6, 7 and 14 as detailed above. The preceding responses to the LIR are also relevant, in relation to the scope of proposed mitigation as relevant to the Proposed Scheme (as opposed to more broadly).
2.10 (LIR Paragraph 8.11)	The Authorities also recommend that the Design Framework is updated to include a clear commitment for ongoing maintenance and management of existing and proposed landscape within and around Drax Power Station in order to minimise ongoing erosion, including a commitment to minimise and reduce lighting levels.	The Outline Landscape and Biodiversity Strategy (AS-094) sets out a clear management strategy for key measures required to mitigate and compensate for effects on sensitive ecological and landscape receptors as identified in the Environmental Statement, specifically Chapter 8 (Ecology) (APP-044) and Chapter 9 (Landscape and Visual Amenity) (APP-045) as a result of the Proposed Scheme. It covers a period of 30 years which is considered appropriate as this would see any planting achieve maturity and effectively deliver the required mitigation measures. Requirement 8 of the draft DCO requires that a Lighting Strategy is approved and implemented, and that it is in substantial accordance with the Draft Lighting Strategy. The aim of the Draft Lighting Strategy is to provide a framework within which the future exterior lighting design of the Proposed Scheme shall be designed to ensure that International, National and Local standards and guidance documents are embedded within the design process to ensure a compliant and balanced approach to exterior artificial lighting to balance the health and safety needs of Drax Power Station Site operatives and environmental aspects. The following specific design requirements to mitigate the impact of lighting are included in the Draft Lighting Strategy (refer to paragraph 5.3.4): a) The extent of lit sections should be constrained to the minimum required for safety; b) Selected lighting levels should be reduced to the minimum required for safety;

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		c) LED luminaires should be specified so that light distribution is easily controllable to reduce spill light and other obtrusive parameters; d) Luminaires to be specified so that no light is emitted directly upward above the horizontal where practicable; e) Luminaires with a minimum luminous intensity class of G4 (refer to (BSI, 2015) Table A.1) should be utilised, to remove any light emission above the horizontal and to reduce source intensity over greater distances where practicable; f) Luminaires should be installed at 0° to the horizontal to preserve their luminous intensity class; g) Luminaires with maximum colour temperatures of 3,000 Kelvin (K) should ideally be used, to minimise the blue-light component and the Proposed Scheme's impact on fauna populations; h) Other colour temperatures up to 5,000 K where higher colour rendering is required for specific visual tasks, can be utilised but should be kept to a minimum where practicable; i) A more limited range of spectral power distribution is used, with predominance in the longer wavelength end of the spectrum, to aid environmental mitigation; j) A system of control and operation should be considered that allows; Dimming of lighting to a lower level during periods of low use or switch-off when areas are not in use; The use of detection-operated lighting should be considered where appropriate and / or zonal switching i.e., lighting is only operational when tasks are being performed and is activated locally by the operative or via the Site control room; k) Shield and baffles to be used where levels of Obtrusive Light cannot be limited through good design and where issues may arise post-installation; and l) The choice of luminaire with the right distribution at the right height is critical to minimising light spill and Obtrusive Light effects yet providing the right lighting performance on the task area. It should be noted that a lower mounting height is perhaps not better as can be seen from Plate 5.1 below. A lower mounting height can create a higher level of light spill and require more columns. In conclusion the intensity of lighting on site will be governed by the appropriate design standards as detailed in the Draft Lighting Strategy (APP-184) and the Lighting Strategy that will be approved by the LPA. The Applicant has already set out in the preceding responses why it is not appropriate for such mitigation to go beyond what is required in connection with the effects resulting from

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		the Proposed Scheme, and to apply more broadly "within and around Drax Power Station".
2.11 (LIR Paragraph 8.15)	The Viewpoint photography (document reference APP-103) illustrates the Proposed Scheme Maximum Design Parameters as a red line, often to much larger extents than the photorealistic image shown of proposed buildings. It is unclear what parameter has been taken into account within the LVIA and the Authorities would question whether this presents a misleading or confusing representation of what might be developed through detailed design, secured by the DCO.	The photomontages are accurate as they are fully compliant with the standards required for Photomontages as identified by the Landscape Institute (Visual Representation of Development Proposals – Technical Guidance Note 06/19, 17th September 2019). These have been prepared in accordance with the highest level of accuracy required by the guidance, as Type 4. The red line indicates the maximum parameters which are provided in Section 2.6 of Chapter 2 (Site and Project Description) of the Environmental Statement (ES) (APP-038) (and Schedule 14 of the draft DCO), i.e. the Rochdale Envelope, which provides for some deviation to allow for design/technology changes. It is these maximum parameters which were assessed within Chapter 9 Landscape and visual effects (APP-045). This is in line with PINS Advice Note Nine (Rochdale Envelope) (PINS, 2018). The photomontages include a rendered version of the 3-d model of the Proposed Scheme as assessed.
2.12 (LIR Paragraph 8.24)	The LVIA identifies potential for a number of significant Moderate Adverse landscape and visual effects during the construction phase. The assessment of Cumulative Effects identifies potential for a number of significant Moderate Adverse landscape and visual effects during the construction phase. Neither the LVIA or the assessment of Cumulative Effects have identified the potential for significant adverse landscape and visual effects during either the operational or construction phases. However, there are a notable number of minor adverse landscape and visual effects within both the LVIA and the assessment of Cumulative Effects. No notable landscape or visual mitigation is proposed.	Chapter 9 of the ES – Landscape and visual amenity (APP-045) identifies that the Proposed Scheme will give rise to a significant effect during the construction phase and this extends to the assessment of cumulative effects. In the interest of avoiding effects (the first step in the mitigation hierarchy), the Applicant has sought to retain the existing green infrastructure within the Order Limits through vegetation retention (which is considered key to limiting the predicted impacts), refer to Outline Landscape and Biodiversity Strategy - Volume 2 - Figure 3: Existing Retained Vegetation (APP-183). As detailed within the chapter, Landscape mitigation planting, for the purpose of visual screening is proposed along the eastern boundary of the East Construction Laydown Area. The existing hedgerow would remain in place and be enhanced along its length, to include the thickening and gapping up of the hedge and the planting of frequent broadleaved tree species. The intention is to provide additional filtering of views towards the East Construction Laydown for footpath users east of the Drax Power Station Site and for occupiers of nearby residential properties during construction. Measures to achieve this mitigation are provided within the OLBS. As stated in Ref ID LVIA7 of Table 1.1 Register of Environmental Actions and Commitments within the REAC (REP-015) these works will be undertaken prior to the commencement of the construction phase, as part of the construction of the East Construction Laydown Area, at the appropriate time of year (tree planting season runs between November and March). This will mean that the planting will be implemented during the winter prior to construction commencing, at the latest. - Planting stock of a suitable age and size will be used to ensure initial reasonable mitigation of the visual impact of the construction site. It should be noted that advanced planting stock provides better immediate screening but establishes less successfully and grows more slowly,

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		whereas younger planting stock establishes more successfully and grows more quickly – it is proposed that some older / larger planting stock be used to provide immediate screening, but that the majority of the planting stock be younger / smaller to ensure successful establishment and relatively quick growth, to deliver the necessary environmental function of visual screening. Reference to the enhancement of the existing hedgerow along the eastern side of the East Construction Laydown is identified in 3.3.12 of the Outline Landscape and Biodiversity Strategy [AS-095] and is also secured within item LVIA1 of Table 1.1 Register of Environmental Actions and Commitments of the REAC, meaning that pursuant to Requirement 14, the commitment will be included in the Construction Environmental Management Plan. Further mitigation measures that will be implemented during construction are included in the REAC (and secured as detailed in the paragraph above) as follows: 1) Fencing will be erected prior to construction activities and will remain in place for the entire construction period; 2) No works (including temporary) will be carried out within the canopy of the spread of existing retained trees; and 3) Where existing vegetation is removed by the construction of the Proposed Scheme, appropriate planting in the form of hedgerows, arable field margins and tree planting will be planted in line with the landscape mitigation design (refer to Landscape Mitigation Plan) in order that the vegetative framework of the landscape is replaced / restored. This planting will be carried out in March to minimise the potential effects of loss and disturbance of FLL on wintering/passage SPA and Ramsar bird species. The OLBS which is secured by Requirement 7 (Provision of Landscape and Biodiversity Mitigation and Enhancement) of the Draft DCO ((AS-076) an updated version of which is submitted at Deadline 2) sets out measures for the reinstatement / replacement of existing vegetation removed during construction: a. Existing vegetation identified for removal in order to facilitate construction works b. Any additional loss of vegetation within Works Plan Areas (subject to detailed design progression). No significant effects were identified during operation for the Proposed Scheme, as reported in ES Chapter 9: Landscape and Visual Amenity. The absence of significant landscape and visual effects in the operational phase coupled with the Applicant having proposed reasonable and appropriate mitigation to minimise harm, proportionate to the effects identified as resulting from the Proposed Scheme, limits the justification for additional landscape and visual mitigation (assuming there is further mitigation of those effects which would be possible, which the Applicant does not accept), including taking

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		additional land for off-site landscape mitigation measures or enhancement. However, the Applicant has sought to retain the existing green infrastructure within the Order Limits through vegetation retention (which is considered key to limiting the predicted impacts) and has provided woodland enhancement measures as part of the Off-Site Habitat Provision Area (Arthurs Wood and Fallow Field); provision of new hedgerow planting to the north of the Power Station Site and proposed the reinforcement of the existing hedgerow (to the east of the Construction Laydown Area boundary) which will help contribute to wider landscape character integration. The predicted impacts, residual effects and cumulative effects for both construction and operational phases are agreed upon, as recorded within item 4.10.6, 4.10.8 and 4.10.9 of Table 4.10 - Design, landscape and Visual Impact within the Statement of Common Ground between Selby District Council, North Yorkshire County Council and Drax Power Limited (REP-018).
2.13 (LIR Paragraph 8.28)	The Application does not explain how the site hard and soft landscape, wider green infrastructure and public amenity benefits would be incorporated and supported.	Hard and soft landscape measures will be secured via Requirement 7 of the Draft DCO ((AS-076) an updated version of which is submitted at Deadline 2), the detail of which will reflect the principles and palettes outlined in the Design Framework (APP-195). In relation to wider green infrastructure and public amenity benefits, the absence of significant landscape and visual effects, including those associated with public footpaths and amenity corridors/spaces in the operational phase limits the justification for further measures beyond that which is necessary to mitigate the Proposed Scheme (as explained in the preceding responses). In accordance with Section 4.2 of the Design Framework (APP-195) the Applicant has sought to retain where possible the existing vegetation within the site and on the boundary to the Application Site, being cognisant of the existing green infrastructure. This includes off-site habitat provision (Arthurs Wood and Fallow Field) and proposed the reinforcement of the existing hedgerow (to the east of the Construction Laydown Area boundary). The Design Framework sets out in Section 4.2, how the retention of green infrastructure and its potential further development within the Site has been considered, including specific measures set out within the Outline Landscape and Biodiversity Strategy (APP-180).
2.14 (LIR Paragraph 8.30)	While these broad principles for landscape and green infrastructure are welcome, they are not clearly defined commitments that can be secured through the DCO (other than vegetation retention and reinstatement of amenity planting if temporarily lost to facilitate the works).	The Applicant considers that the measures appropriate to the Proposed Scheme have been secured via Requirements 6 (Detailed Design), 7 (Provision of Landscape and Biodiversity Mitigation and Enhancement) and 14 (Construction Environmental Management Plan) (in relation to timing of planting as detailed in LVIA7 within the Register of Environmental Actions and Commitments (REP-015 an updated version of which is submitted at Deadline 2)) of the Draft DCO (AS-076 an updated version of which is submitted at Deadline 2). Measures for the retention of existing vegetation are detailed within the Outline Landscape and Biodiversity Plan (AS-094) and illustrated on Figure 3 (Vegetation

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		Retention) (APP-183). Areas of existing amenity planting will be retained, unless directly impacted by the Proposed Scheme. Where the loss of such planting is unavoidable, the detailed design will seek to reinstate those landscape elements that are temporarily lost, or to incorporate new amenity planting measures in-keeping with the original aspirations as set out within the Weddle Strategy for Drax Power Station. This is secured through the DCO, Schedule 2, Requirement 7 (Provision of Landscape and Biodiversity Mitigation and Enhancement) (AS-076 an updated version of which is submitted at Deadline 2).
2.15 (LIR Paragraph 8.31)	Elsewhere in the Application there is a general lack of certainty to protecting existing vegetation on the site using statements such as “*Where practicable, the Proposed Scheme intends to retain existing natural habitats*”. This is equally reflected in the DCO.	Measures for the retention of existing vegetation are detailed within the Outline Landscape and Biodiversity Plan (AS-094) and illustrated on Figure 3 (Vegetation Retention) (APP-183). Areas of existing amenity planting will be retained, unless directly impacted by the Proposed Scheme. Where the loss of such planting is unavoidable, the detailed design will seek to reinstate those landscape elements that are temporarily lost, or to incorporate new amenity planting measures in-keeping with the original aspirations as set out within the Weddle Strategy for Drax Power Station. This is secured through the DCO, Schedule 2, Requirement 7 (Provision of Landscape and Biodiversity Mitigation and Enhancement) (AS-076 an updated version of which is submitted at Deadline 2).
2.16 (LIR Paragraph 8.33)	The Lighting Strategy document includes general good guidance and design recommendations for minimising lighting within this Application. However, this is set against a general presumption that additional lighting will be needed (thereby adding to the accumulation of adverse effects on the site). The Lighting Strategy does not consider the wider Application Site, only the new buildings and structures. There is no consideration of how lighting levels of the wider Power Station could be reduced to ensure no net increase in adverse night-time visual effect, to minimise wider cumulative adverse effects.	As outlined in paragraph 5.1.1 of the Draft Lighting Strategy (APP-184), “artificial lighting would be used during the hours of darkness to adequately illuminate the Proposed Scheme for the safety of site personnel undertaking complex tasks during the hours of darkness and site security.” Requirement 8 of the Draft Development Consent Order requires that a Lighting Strategy is approved and implemented, and that it is in substantial accordance with the Draft Lighting Strategy. The aim of the Draft Lighting Strategy is to provide a framework within which the future exterior lighting design of the Proposed Scheme shall be designed to ensure that International, National and Local standards and guidance documents are embedded within the design process to ensure a compliant and balanced approach to exterior artificial lighting to balance the health and safety needs of Drax Power Station Site operatives and environmental aspects. The assessment of lighting has been undertaken in the context of the existing night-time baseline, which is in accordance with the methodology, agreed with NYCC as evidenced in item 4.10.4 Table 4.10 - Design, landscape and Visual Impact within the Statement of Common Ground between Selby District Council, North Yorkshire County Council and Drax Power Limited (REP-018). The approach to the night-time assessment including the locations to be assessed using night-time photography has been agreed with NYCC/SDC, as evidenced in Table 9.1 - Consultation Summary Table, Chapter 9 of the ES – Landscape and visual amenity (APP-045). Night-time photomontages showing the

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		impacts of night-time lighting are provided in relation to viewpoints 2 and 7 Environmental Statement - Volume 2 - Figure 9.6: Viewpoint Photography (APP-103). The Draft Lighting Strategy includes a number of specific design requirements to mitigate the impact of lighting (refer to paragraph 5.3.4) as follows: a) The extent of lit sections should be constrained to the minimum required for safety; b) Selected lighting levels should be reduced to the minimum required for safety; c) LED luminaires should be specified so that light distribution is easily controllable to reduce spill light and other obtrusive parameters; d) Luminaires to be specified so that no light is emitted directly upward above the horizontal where practicable; e) Luminaires with a minimum luminous intensity class of G4 (refer to (BSI, 2015) Table A.1) should be utilised, to remove any light emission above the horizontal and to reduce source intensity over greater distances where practicable; f) Luminaires should be installed at 0° to the horizontal to preserve their luminous intensity class; g) Luminaires with maximum colour temperatures of 3,000 Kelvin (K) should ideally be used, to minimise the blue-light component and the Proposed Scheme's impact on fauna populations; h) Other colour temperatures up to 5,000 K where higher colour rendering is required for specific visual tasks, can be utilised but should be kept to a minimum where practicable; i) A more limited range of spectral power distribution is used, with predominance in the longer wavelength end of the spectrum, to aid environmental mitigation; j) A system of control and operation should be considered that allows; Dimming of lighting to a lower level during periods of low use or switch-off when areas are not in use; The use of detection-operated lighting should be considered where appropriate and / or zonal switching i.e., lighting is only operational when tasks are being performed and is activated locally by the operative or via the Site control room; k) Shield and baffles to be used where levels of Obtrusive Light cannot be limited through good design and where issues may arise post-installation; and l) The choice of luminaire with the right distribution at the right height is critical to minimising light spill and Obtrusive Light effects yet providing the right lighting performance on the task area. It should be noted that a lower mounting height is perhaps

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		not better as can be seen from Plate 5.1 below. A lower mounting height can create a higher level of light spill and require more columns. The assessment of lighting has therefore taken into account the existing lighting levels in the site which are driven by operational and regulatory requirements, in addition to other developments as part of the cumulative assessment provided in Chapter 18 Cumulative Effects (APP-054). The predicted impacts, residual effects and cumulative effects for both construction and operational phases are agreed upon, as recorded within item 4.10.6, 4.10.8 and 4.10.9 of Table 4.10 - Design, landscape and Visual Impact within the Statement of Common Ground between Selby District Council, North Yorkshire County Council and Drax Power Limited (REP-018). Whilst the lighting levels of the wider site are not relevant given the findings of the night-time assessment, , the lighting levels of the Drax Power Station are driven by operational and regulatory requirements. In the absence of a significant night-time effect, the Applicant considers that it has committed to what is required to deliver the Proposed Scheme as part of the Application which is being considered within this dDCO.
2.17 (LIR Paragraph 8.35)	There are no meaningful landscape proposals within the Outline Landscape and Biodiversity Strategy (OLBS) which would help reduce or offset the likely adverse landscape and visual effects identified in the LVIA, other than retention of existing vegetation ‘where practicable’, reinstatement of temporary construction laydown areas and related hedgerows.	The Applicant has carried out a landscape and visual impact assessment for the Proposed Scheme in accordance with the EIA Regulations and accepted good practice methodology and has identified appropriate mitigation to address significant effects in relation to the Proposed Scheme. Through consultation with the LPA, the Applicant has also considered the guidance provided within the Weddle report in developing the Design Framework (APP-195). This has comprised a good approach to design through the retention of existing vegetation, avoiding where appropriate low-level clutter, the use of on-site mitigation to provide screening, along with building materials and colour (using lighter tones for taller structures and darker tones at a lower height) as summarised below: • The inclusion, where reasonably practicable, of landscape elements which reinforce the original intents of the Weddle Strategy for the Drax Power Station Site, notably: - To create an attractive and positive working environment for site users within the confines of the Power Station; and - To provide a landscape structure capable of incorporating continuing development of ancillary industry. • Improving the biodiversity value of amenity planted areas within the Power Station Site: - Increasing species-rich grassland areas, with reduced amenity grassed areas (subject to function); - Incorporating species-rich amenity hedges where introduced; and

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		- Reducing the use of ornamental shrub species in favour of species selection for biodiversity and habitat creation, while maintaining an amenity function. • Enhancement opportunities resulting from any necessary replacement of aged, over-mature amenity planting, where its appearance and function is now heavily compromised. • Design principles, described within Section 4 of the Design Framework (APP-195) for the colour palette associated with the Proposed Development that will be followed in the detailed design, are set out below (Work No.s 1D and 1E): - 'Goosewing Grey' (BS10A05) will be used for storage tanks and pipework; - 'Ash Grey' BS9093 will be used for buildings over 15 m. - 'Dark Camouflage Brown' (BS381C-436) will be used for buildings up to 15m in height. Landscape mitigation planting, for the purpose of visual screening is proposed along the eastern boundary of the East Construction Laydown Area. The existing hedgerow will remain in place and be enhanced along its length, to include the thickening and gapping up of the hedge and the planting of frequent broadleaved tree species. Some older planting stock will be used to provide more immediate screening, alongside younger stock to ensure successful establishment and relatively quick growth. Feathered trees (planted as transplants) will also be used as these will be trimmed back to encourage growth. The intention is to provide additional filtering of views towards the East Construction Laydown for footpath users east of the Drax Power Station Site and for occupiers of nearby residential properties during construction. Measures to achieve this mitigation are provided within the Outline Landscape and Biodiversity Plan (APP-180). As a result of the approach taken to the siting, massing and appearance and taking into account the mitigation measures as set out in the OLBS, no significant operation effects have been identified in relation to landscape and visual, as described within Chapter 9 of the ES – Landscape and visual amenity (APP-195). The predicted impacts and residual effects have been agreed upon, as recorded within item 4.10.6 and 4.10.8 of Table 4.10 - Design, landscape and Visual Impact within the Statement of Common Ground between Selby District Council, North Yorkshire County Council and Drax Power Limited (REP-018).
2.18 (LIR Paragraph 8.36)	The OLBS sets out the maintenance and management requirements for the final LBS. The management timeframe is limited to 30 years to satisfy biodiversity Net Gain requirements and does not support a longer-term landscape need.	The Outline Landscape and Biodiversity Strategy (AS-094) sets out the management strategy for key measures required to mitigate and compensate for effects on sensitive ecological and landscape receptors as identified in the Environmental Statement,

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2.19 (LIR Paragraph 8.37)	Clarity is needed on how a sufficient detailed landscape and green-infrastructure scheme could be delivered through the DCO, together with commitment for long-term maintenance and management.	specifically Chapter 8 (Ecology) (APP-044) and Chapter 9 (Landscape and Visual Amenity) (APP-045) as a result of the Proposed Scheme. It covers a period of 30 years which is considered appropriate as this would see any planting achieve maturity and effectively deliver the required mitigation measures in relation to biodiversity and secondary benefits associated with landscape. This is generally regarded within the landscape industry as a suitable period of time and also aligns with the requirements for Biodiversity Net Gain (BNG) set out in the Environment Act 2021, where it states that BNG is to be managed for at least 30 years.
2.20 (LIR Paragraph 8.38)	ID Reference D1 (REAC) This makes reference to the Design Framework. There are no specific commitments set out in the Design Framework to explain the overall scope of works. Similarly, D1 provides no specific commitment of overall scope and what is likely to be achieved, using terms “The inclusion, where reasonably practicable, of landscape elements which reinforce the original intents of the Weddle Strategy for the Drax Power Station Site”. Potential proposals which might not be described in the original ‘*Weddle Strategy*”, might be excluded and limit wider options outlined in the Design Framework. There are no links to the Lighting Strategy where coordination of screen planting might have benefit, not specifically for bat mitigation.	The approach to hard and soft landscape design is set out in Section 4.2 of the Design Framework (APP-195); the detail of this will be subject to agreement with the LPA pursuant to the DCO, Schedule 2, Requirement 7 (Provision of Landscape and Biodiversity Mitigation and Enhancement) (AS-076 an updated version of which is submitted at Deadline 2).
2.21 (LIR Paragraph 8.39)	ID Reference D1 (REAC) There is no requirement for further approved of the detailed design or to justify retrospectively what has been achieved or how this will comply with the achievement criteria ‘This will be recorded on as built drawings’. The achievements criteria only uses the LBS as a benchmark and does not consider the Design Framework, or other landscape design proposals. The LBS is focussed on biodiversity, not wider landscape issues.	The approach to hard and soft landscape design is set out in Section 4.2 of the Design Framework (APP-195); the detail of this will be subject to agreement with the LPA and is secured via the DCO, Schedule 2, Requirement 7 (Provision of Landscape and Biodiversity Mitigation and Enhancement) (AS-076 an updated version of which will be submitted at Deadline 2). Pursuant to Requirement 6, details of the detailed design are required to be approved by the LPA, and must be in accordance with the design principles in the Register of Environmental Actions and Commitments, specifically item D1 in Table 1.1, that relates to the Design Framework (APP-195).
2.22 (LIR Paragraph 8.40)	ID Reference D4 (REAC) This makes reference to the Draft Lighting Strategy in which there is a general presumption that additional lighting will be needed. The Lighting Strategy does not consider the wider Application Site, only the new buildings and structures. There is no consideration of how lighting levels of the wider Application Site / Power Station could be reduced to ensure no net increase in adverse night-time visual effect, to minimise wider cumulative adverse effects.	In relation to the Draft Lighting Strategy and the lighting associated with the wider site – the Applicant would refer to item 2.16 above.
2.23 (LIR Paragraph 8.41)	ID Reference D4 (REAC) The achievements criteria only uses the approved Lighting Strategy LBS as a benchmark and does not consider the Design Framework, or other landscape design proposals. The LBS is focussed on biodiversity, not wider landscape issues. No requirement for a final strategy to be produced.	The requirement for a final Landscape and Biodiversity Strategy is based on the Outline Landscape and Biodiversity Strategy (AS-094). This document identifies, within paragraph 3.3.8, that the planting design should reflect the design principles described within Chapter 9 - Landscape and Visual Amenity (APP-045) of Volume 1 of the ES and referenced within the Design Framework (APP-195) and will be agreed in consultation with the Planning Authority. All new planting measures would be included as part of the LBS as it is progressed.

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2.24 (LIR Paragraph 8.43)	ID Reference G7 (REAC) This makes provision for a Landscape and Biodiversity Strategy. Comments similar to D1, no specific landscape commitments. No commitment for long-term maintenance and management for wider landscape benefit beyond 30 years to demonstrate biodiversity Net Gain. Clarity needed about stages and phasing – delivery of landscape related specific to each stage / phase. No specific timing requirement for implementation and initial maintenance establishment period, replacement of planting defects.	The requirement for a final Landscape and Biodiversity Strategy is based on the Outline Landscape and Biodiversity Strategy (AS-094). This document identifies within paragraph 3.3.8 that the planting design should reflect the design principles described within Chapter 9 - Landscape and Visual Amenity (APP-045) of Volume 1 of the ES and referenced within the Design Framework (APP-195) and will be agreed in consultation with the Planning Authority. All new planting measures would be included as part of the LBS as it is progressed. The approach to hard and soft landscape design is set out in Section 4.2 of the Design Framework (APP-195), and is secured via the DCO, Schedule 2, Requirement 7 (Provision of Landscape and Biodiversity Mitigation and Enhancement) (AS-076 an updated version of which is submitted at Deadline 2). Requirement 7 sets out the initial maintenance period of 5 years during which time any planting which fails will be replaced within the first available planting season. Section 5 of the Outline Landscape and Biodiversity Strategy (AS-094) sets out the timing of annual inspection visits and their purpose.
2.25 (LIR Paragraph 8.44)	ID Reference LVIA 1 (REAC) This makes provision for reinstatement of the east Construction Laydown Area. There is no reference to ground conditions or reinstatement to achieve specific ALC grade. No requirements for long-term maintenance beyond those for net gain via the LBS.	Measure GC2 of the REAC details that a Soil Handling Management Plan, which will be included in the CEMP, will be produced prior to any enabling or construction works commencing. This will include best practice measures to reduce impacts to soil during handling and will be informed by site-specific soil and climatological data. Appropriate measures in the SHMP will include: 1) Site specific soil management considerations which will be informed by the detailed ALC Survey (refer to Appendix 11.2, (APP-158)) and available Post-1988 ALC survey information; 2) The SHMP will demonstrate the sustainable, beneficial soil re-use of potential surplus soil resources; 3) The SHMP will include the principles outlined within the DEFRA Construction Code of Practice for the Sustainable Use of Soils on Construction Sites; 4) The SHMP will include the type and volume of each soil type to be handled and stockpiled and the location of soil storage and restoration. These activities will be determined by the nutrient status of the soils and the ALC grade. 5) For areas of temporary development, the SHMP will outline actions for appropriate methods for the stripping, handling and storage of the soils. 6) The methods which will be used to restore affected areas to agricultural use after works will be outlined using the ALC survey as a baseline and will aim to return the soil to the same quality as far as practicable to minimise potential loss.

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		7) Land to be restored for agricultural use after construction will require an agreed aftercare plan with the landowner / farmer and aim to return the land to the same agricultural capability as before construction. 8) The SHMP will be prepared in consultation with Natural England. The SHMP, which will form part of the CEMP, will be approved by the LPA following consultation with Natural England. This measure is secured via DCO, Schedule 2, Requirement 14 (Construction Environmental Management Plan) which requires a CEMP to be produced, that will be approved by the LPA, that is substantially in accordance with the register of environmental actions and commitments.
2.26 (LIR Paragraph 8.45)	ID Reference LVIA 2 (REAC) This makes provision for the CEMP and tree protection. This makes no provision for an arboricultural method statement and tree protection to BS5837, to be approved by the LPA prior to construction. Makes reference to 'Landscape Mitigation Plan' for tree reinstatement but not clear what this is.	Measure G5 within the REAC details that trees and their roots that are within or enter the construction areas will be protected in accordance with BS5837:2012 Trees in relation to design, demolition and construction, and the National Joint Utilities Group (NJUG) Guidelines for the Planning, Installation and Maintenance of Utility Apparatus in Proximity to Trees. Fencing will be erected prior to construction activities and will remain in place for the entire construction period. This measure is secured via DCO, Schedule 2, Requirement 14 (Construction Environmental Management Plan) which requires a CEMP to be produced, that will be approved by the LPA, that is substantially in accordance with the register of environmental actions and commitments. BS5837: 2012 identifies that where existing vegetation is likely to be affected by proposals that an appropriately detailed Arboricultural Impact Assessment is carried out that 'evaluates the direct and indirect effects of the proposed design and where necessary recommends mitigation'. The Outline Landscape and Biodiversity Strategy (AS-094) and its accompanying figures (6.6.2.1 Outline Landscape and Biodiversity Strategy - Volume 2 - Figure 1: Landscape and Biodiversity Mitigation Plan (APP-181) and 6.6.2.3 Outline Landscape and Biodiversity Strategy - Volume 2 - Figure 3: Existing Retained Vegetation (APP-183)) include measures for the retention of existing vegetation . The Landscape and Biodiversity Strategy for the Proposed Scheme, which is substantially in accordance with the outline landscape and biodiversity strategy and would be approved by the LPA is secured via Requirement 7 of the dDCO (AS-076 an updated version of which will be submitted at Deadline 2).
2.27 (LIR Paragraph 8.46)	ID Reference LVIA 4 (REAC)This makes reference to soil protection. No requirement for a Soil Resource Management Plan or reference to recognised standards for soil protection.	Measure LVIA 4 in Table 1.1 Register of Environmental Actions and Commitments, within the Register of Environmental Actions and Commitments 04 (REP-015) does not refer to soil protection. Measure GC2 details that a Soil Handling Management Plan, which will be included in the CEMP, will be produced prior to any enabling or construction works commencing. This will include best practice measures to reduce impacts to soil during handling and will be

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		informed by site-specific soil and climatological data. Appropriate measures in the SHMP will include: 1) Site specific soil management considerations which will be informed by the detailed ALC Survey (refer to Appendix 11.2, (APP-158)) and available Post-1988 ALC survey information; 2) The SHMP will demonstrate the sustainable, beneficial soil re-use of potential surplus soil resources; 3) The SHMP will include the principles outlined within the DEFRA Construction Code of Practice for the Sustainable Use of Soils on Construction Sites; 4) The SHMP will include the type and volume of each soil type to be handled and stockpiled and the location of soil storage and restoration. These activities will be determined by the nutrient status of the soils and the ALC grade. 5) For areas of temporary development, the SHMP will outline actions for appropriate methods for the stripping, handling and storage of the soils. 6) The methods which will be used to restore affected areas to agricultural use after works will be outlined using the ALC survey as a baseline and will aim to return the soil to the same quality as far as practicable to minimise potential loss. 7) Land to be restored for agricultural use after construction will require an agreed aftercare plan with the landowner / farmer and aim to return the land to the same agricultural capability as before construction. 8) The SHMP will be prepared in consultation with Natural England. The SHMP, which will form part of the CEMP, will be approved by the LPA following consultation with Natural England. This measure is secured via DCO, Schedule 2, Requirement 14 (Construction Environmental Management Plan) which requires a CEMP to be produced, that will be approved by the LPA, that is substantially in accordance with the register of environmental actions and commitments.
2.28 (LIR Paragraph 8.47)	ID Reference LVIA 1 (REAC) This makes provision for tree planting, but is based on 30yr net gain requirements, not longer-term landscape management.	The Outline Landscape and Biodiversity Strategy (AS-094) sets out the management strategy for key measures required to mitigate and compensate for effects on sensitive ecological and landscape receptors as identified in the Environmental Statement, specifically Chapter 8 (Ecology) (APP-044) and Chapter 9 (Landscape and Visual Amenity) (APP-045) as a result of the Proposed Scheme. In relation to LVIA1, the proposed planting associated with the eastern boundary of the East Construction Laydown Area, is included within the OLBS which covers a period of 30 years, this is considered appropriate as it would see any planting achieve maturity and effectively deliver the required mitigation measures.

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		The Landscape and Biodiversity Strategy for the Proposed Scheme, which is substantially in accordance with the outline landscape and biodiversity strategy and would be approved by the LPA is secured via Requirement 7 of the dDCO (AS-076 an updated version of which is submitted at Deadline 2).
2.29 (LIR Paragraph 8.48)	ID Reference LVIA 6 (REAC) This makes provision for maintenance inspections. Makes reference to 'Landscape Management Plan', but not clear what this is as not defined.	Measure LVIA6 within the REAC should make reference Outline Landscape and Biodiversity Strategy (AS-094). LVIA6 of Table 1.1 within the Register of Environmental Actions and Commitments, within the Register of Environmental Actions and Commitments 04 (REP-015) has been updated at Deadline 2 to make this clear.
2.30 (LIR Paragraph 8.49)	DCO Schedule 1 Works No. 3 page 34 – no provision for soils, landscape maintenance and management.	In relation to soils, landscape maintenance and management, these are not secured via Schedule 1 but rather Schedule 2 Requirements (Schedule 1 is setting out the authorised development consented by the Scheme). In relation to soils, [GC2] of the REAC details that a Soil Handling Management Plan, which will be included in the CEMP, will be produced prior to any enabling or construction works commencing. This will include best practice measures to reduce impacts to soil during handling and will be informed by site-specific soil and climatological data. The SHMP, which will form part of the CEMP, will be approved by the LPA following consultation with Natural England. This measure is secured via DCO, Schedule 2, Requirement 14 (Construction Environmental Management Plan) which requires a CEMP to be produced, that will be approved by the LPA, that is substantially in accordance with the register of environmental actions and commitments. In relation to landscape maintenance and management, the Applicant has submitted an Outline Landscape and Biodiversity Strategy (Doc Ref AS-094). Table 5.1 of this document confirms that will be a five year period in which to establish the landscape and habitat creation works, including soils, followed by a maintenance programme to cover the period up to 30 years. The Landscape and Biodiversity Strategy for the Proposed Scheme, which is substantially in accordance with the outline landscape and biodiversity strategy and would be approved by the LPA, is secured via Requirement 7 of the dDCO (AS-076 an updated version of which is submitted at Deadline 2).
2.31 (LIR Paragraph 8.50)	DCO Schedule 2 Works No. 3 page 38 – no provision for the long-term retention maintenance and management of landscape (being part of the wider mitigation strategy for the site).	The Outline Landscape and Biodiversity Strategy (AS-094) sets out the management strategy for key measures required to mitigate and compensate for effects on sensitive ecological and landscape receptors as identified in the Environmental Statement, specifically Chapter 8 (Ecology) (APP-044) and Chapter 9 (Landscape and Visual Amenity) (APP-045) as a result of the Proposed Scheme. It covers a period of 30 years which is considered appropriate as this would see any planting achieve maturity and effectively deliver the required mitigation measures in relation to biodiversity and landscape.

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		The Landscape and Biodiversity Strategy will be developed at the detailed design stage, and will contain measures detailed within the Outline Landscape and Biodiversity Strategy. The Landscape and Biodiversity Strategy for the Proposed Scheme, which is substantially in accordance with the outline landscape and biodiversity strategy and would be approved by the LPA, is secured via Requirement 7 of the dDCO (AS-076 an updated version of which will be submitted at Deadline 2). As stated in item 2.13, the Application has considered how the Proposed Scheme is cognisant of the existing green infrastructure as set out in Section 4.2 of the Design Framework (APP-195).
2.32 (LIR Paragraph 8.51)	Requirement 7 of Schedule 2 of the Draft DCO provides that the written landscape and biodiversity strategy can be brought forward in parts as each of the numbered works are commenced. This has the potential to result in 8 strategies that would need to be discharged. The Authorities believe that it would be very difficult to discharge the strategy in this way, without being able to assess the full scope of the mitigation strategy. The approach will also lead to increased resource pressure. The Authorities would therefore welcome the Applicant reconsidering the approach to develop the written landscape and biodiversity strategy in its entirety, covering all works, that can be discharged once.	Please refer to item 2.34 in response to LIR paragraph 9.25, below.
2.33 (LIR Paragraph 9.22)	The Authorities are of the opinion that whilst the majority of mitigation, compensation and enhancement measures for impacts have been detailed within the Environmental Statement and the OBLS, net gain for riverine habitats has still to be demonstrated and secured. It is noted that a s106 is proposed to secure the off-site BNG and in principle this approach is supported.	The Applicant has identified an opportunity for the delivery of the required river units, through supporting habitat enhancement and restoration measures to be delivered by the Calder and Colne Rivers Trust (CCRT). The Applicant is supporting CCRT in carrying out work to confirm the exact number of river units that can be delivered. Based on an initial review of the habitat enhancement and restoration proposed by the River Trust, the Applicant expects these measures to be more than able to deliver 10% BNG for the Rivers, Ditches and Streams component of BNG. This will be reflected in an update to the BNG Report for the Proposed Scheme, which the Applicant anticipates will be ready for submission into the Examination at Deadline 3. The Applicant is currently also in the process of drafting appropriate wording for the S106 agreement, to secure the delivery of CCRT's proposed habitat enhancement and restoration measures and their allocation to the Proposed Scheme's BNG allocation.
2.34 (LIR Paragraph 9.25)	Requirement 7 of Schedule 2 of the Draft DCO provides that the written landscape and biodiversity strategy can be brought forward in parts as each of the numbered works are commenced. This has the potential to result in 8 strategies that would need to be discharged. The Authorities believe that it would be very difficult to discharge the strategy in this way, without being able to assess the full scope of the mitigation strategy. The approach will also lead to increased resource pressure. The Authorities	The Applicant considers that it is important for Requirement 7 (Provision of landscape and biodiversity mitigation and enhancement) to include provision for the Requirement to be discharged in parts. This is necessary in order to retain flexibility for the detailed design, site clearance and construction works to proceed in phases. This reflects the likelihood that detailed design (and subsequent implementation) will proceed in phases, and hence work may need to start on parts of the Proposed Scheme prior to detailed design being

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	would therefore welcome the Applicant reconsidering the approach to develop the written landscape and biodiversity strategy in its entirety, covering all works, that can be discharged once.	completed for the entire Scheme. Under such circumstances, it may not be possible to produce detailed ecology and landscape proposals for the entirety of the Proposed Scheme, as these would necessarily be informed by, for example, the detailed design of earthworks, other engineering features, and site clearance footprints. Under such circumstances, it would be necessary to produce a Landscape and Biodiversity Strategy covering those parts of the Proposed Scheme for which detailed design was available, and for that Strategy to be approved by the relevant planning authority. Without such approval, the parts of the Proposed Scheme for which detailed design was available could not proceed. In addition, until site and vegetation clearance requirements and subsequent habitat reinstatement for the entirety of the Proposed Scheme are finalised, the final Biodiversity Net Gain (BNG) to be delivered cannot be calculated. It is therefore also necessary to retain flexibility for the phased discharge of Requirement 7 in order to allow refinement of habitat creation proposals to achieve the scheme wide 10% BNG in response to the actual habitat loss and disruption that will occur as part of the Proposed Scheme.
2.35 **(LIR Paragraph 10.4)**	Paragraph 10.6 states "*A 10 km study area around the Order Limits and Off-site Habitat Provision Area was agreed during consultation with HE and NYCC and has been applied for the assessment of medium to high value designated HAs (Figure 10.1 (Designated Heritage Assets)) (document reference 6.2.10.1) (therefore only Grade I and II* Listed Buildings were considered).*" If Grade II listed buildings are described as being both medium and high value and they are assessed medium to high value heritage assets in the study area, then Grade II listed buildings should have been identified and assessed within the 10km study area. At present, Grade II listed buildings have not been identified within Figure 10.1 (document reference APP-105) which includes maps of designated heritage assets.	While paragraph 10.6.1 of Chapter 10 of the ES (APP-046) states that the 10km study area "has been applied for the assessment of medium to high value designated HAs (Figure 10.1 (Designated Heritage Assets)) (document reference 6.2.10.1) (therefore only Grade I and II* Listed Buildings were considered)", this includes an error. It should have stated that only high value designated assets were considered, notably Grade I and II* listed buildings. As stated in the Historic Environment Desk-Based Assessment, Appendix 10.1 to the ES (APP-154), in paragraph 3.2.1, "Only Grade I and II* Listed Buildings were considered for the 10 km study area". This is reiterated in Paragraph 6.1.3. This was not clarified within Chapter 10 (APP-046). This is why the Grade II listed buildings are not shown on Figure 10.1 (APP-105).
2.36 **(LIR Paragraph 10.8)**	Chapter 10 of the Environmental Impact Assessment (document reference APP-046) should have identified the relevant built heritage such as listed buildings and conservation areas. The listed buildings within the 1km and 10km study areas should have been described within the Environmental Statement and then the impact of the proposed development assessed against them.	There are 447 Grade II listed buildings within the 10 km study area (see Chapter 11 of the scoping report in Appendix 1.1 to the ES (APP-115)). As only significant effects need to be reported, and because there are no significant effects on Grade II listed buildings, the ES chapter has limited the assessment of effects to Grade I and Grade II* listed buildings, as detailed in the Historic *Environment Desk-Based Assessment, Appendix 10.1 to the ES (APP-154), in paragraph 3.2.1, "Only Grade I and II* Listed Buildings were considered for the 10 km study area*". This is reiterated in Paragraph 6.1.3. Conservation areas are detailed in in the Historic Environment Desk-Based Assessment, Appendix 10.1 to the ES (APP-154) and the effects assessed in Table 6.2. Those which are affected (Airmyn, Snaith and Brayton) are discussed in paragraphs 6.2.33-6.2.54 of APP-154.

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2.37 (LIR Paragraph 16.2)	The site is located within a minerals safeguarding area. The Application constitutes 'exempt development' Policy having reference to Policy S02 of the Minerals and Waste Joint Plan as it involves 'Redevelopment of previously developed land not increasing the footprint of the former development.' So minerals safeguarding does not apply for this site, but this still needs to be identified in the report.	The Applicant agrees with NYCC that the application site is within the Mineral Safeguarding Area. The Applicant also agrees with the Authorities that the Proposed Scheme comprises 'exempt development' for the purposes of that policy and that this position is recorded in the Local Impact Report.
2.38 (LIR Paragraph 17.9)	DCO requirement 12 states "*No part of numbered works 1,2,3 and 5 must commence (including permitted preliminary works comprising demolition of existing structures, environmental surveys, geotechnical surveys and other investigations for the purpose of assessing ground conditions only)…*". This appears to have been drafted incorrectly. It would be acceptable for permitted preliminary works (a) to occur before requirement 12 is discharged, as requirement 12 cannot be fulfilled until site investigation work has been completed. However, it would be unacceptable for permitted preliminary works (c) and (d) to occur before requirement 12 is discharged, as contamination risks would yet have been assessed.	The Applicant notes and agrees with this comment. The draft Development Consent Order submitted at Deadline 2 has been revised to read: *'No part of numbered works 1,2,3, 5 and 7 is to commence (including permitted preliminary works comprising demolition of existing structures, remedial work in respect of any contamination or other adverse ground conditions or the diversion and laying of services) ...'*
2.39 (LIR Paragraph 18.3)	The Authorities are in discussion with the applicant as to the adequacy of the timescales set out within schedule 11 and will seek to resolve the issue through the statement of Common Ground and further drafts of the DCO.	The Applicant has agreed with the Authorities to increase the timescales in Article 40 and Schedule 11 of the dDCO from six to eight weeks and this amendment is made in the dDCO submitted for Deadline 2. Agreement on this issue will be captured in future iterations of the Statement of Common Ground between The Applicant and the Authorities (the most recent version of which was submitted at Deadline 1 (REP-018)).
2.40 (Letter Paragraphs 1 to 5)	The following is a joint statement made on behalf of North Yorkshire County Council and Selby District Council. It is not considered that Local Government Reorganisation in North Yorkshire will have an impact on the examination process for the Drax BECCS scheme. Local Government Reorganisation (LGR) is the process by which the two-tier system of County Council and District Councils will become one unitary council. On the 1st April 2023 (vesting day), North Yorkshire Council (NYC) will be created. North Yorkshire County Council (NYCC) and Selby District Council (SDC) will cease to exist as they are now. The new Council is required to put in place a new Local Plan within 5 years of the vesting date. Until such time, the existing local policies of the current Local Planning	The Applicant is aware of the forthcoming Local Government Reorganisation, and agrees with the Authorities that it will not have an impact on the Councils' response to the application and participation in the examination. The Applicant has amended the draft Development Consent Order being submitted at Deadline 2 to refer to the 'Relevant Planning Authority' as being the unitary council. The Requirements in Schedule 2 have been amended to remove specific reference to consultation being required with NYCC (which reflects discussions with NYCC's lawyer). Separately, NYCC's lawyer is reviewing the dDCO to propose any further amendments that are required as a result of the Local Government Reorganisation, and the Applicant will make any further amendments in a future iteration of the dDCO.

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	Authority (Selby District Council) will be the prevailing local policies for the area. The local policies against which the application is being considered in the Local Impact Report will remain in place throughout the examination and beyond. Throughout the process, the two Councils (NYCC and SDC) have adopted an approach of responding to the application jointly as ‘the Authorities’. As such, a project team has been established across both Councils. At present, there are no plans in place to alter staff roles after vesting date and participation of officers will remain unchanged throughout the examination. It is therefore not considered that LGR will have an impact on the Council’s response to application and participation in the examination.	
2.41	Appendix A is a tabled summary of written representations submitted by North Yorkshire County Council and Selby District Council (The Authorities) on 5th September 2022.	The Applicant notes the summary of the issues provided by the Authorities, and does not consider that it raises any new issues that would require an additional response over and above that provided in the Applicant's Response to Relevant Representations and Additional Submissions (PDA-002) that was submitted at Procedural Deadline A.

Table 3.1– Just Transition Wakefield

Response Ref. (Location in Original Submission)	**Comment**	**Applicant's Response**
3.1 (Section 1, Paragraph 1)	Drax Power is keen for discussion of the climate impacts of biomass to be excluded, but the scientific understanding of the climate impacts of the biomass industry has developed considerably over recent years, and it makes no point to discuss the climate impacts of the plant without including the supply chain. I will also raise evidence specifically about the climate impacts of BECCS technology.	The biomass generation units that are the subject of the Proposed Scheme are already fully consented and in current operation. The Proposed Scheme is seeking consent only to retrofit a carbon capture plant to those biomass units. As such this comment is not considered by the Applicant to be relevant to the merits of the Proposed Scheme. In any event, supply chain has been accounted for in the emissions calculations, as set out in Chapter 15 of the Environmental Statement [APP-051].
3.2 (Section 1, Paragraph 6)	Briefly, even assuming that all clear-felled forests are replanted, the carbon emitted from Drax's smokestack will not be re-sequestered until well after 2100, if at all. Therefore, within the timescale of the UK's legally binding net zero targets, the burning of woody biomass cannot be carbon neutral and as a consequence, BECCS cannot be carbon negative within the same timeframe (if at all). Emissions from forest soil, timber drying, pellet manufacture and pellet transport (road, shipping and rail) all need to be added to the smokestack emissions, because they all end up in the atmosphere. Drax claim that their pellet manufacture is carbon neutral because it too is powered by biomass, but this claim also clearly falls based on the above arguments. Further, Drax receives pellets from a number of manufacturers, including Enviva in the US, and it is on public record that they use methane to dry the wood not biomass.	The biomass generation units that are the subject of the Proposed Scheme are already fully consented and in current operation. The Proposed Scheme is seeking consent only to retrofit a carbon capture plant to those biomass units. As such this comment is not considered by the Applicant to be relevant to the merits of the Proposed Scheme. Notwithstanding that the DCO application is for the fitting of carbon capture units, the accounting principles that apply to the project are laid out in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. These require that biogenic carbon emissions are calculated through changes in land carbon stock in the Agriculture, Forestry and Other Land Use (AFOLU) sector, not at the point of final emission (e.g. combustion or respiration). Permanent capture of carbon from biomass (which has already assumed to be emitted in the land sector) therefore delivers negative emissions: *"If the [CCS] plant is supplied with biofuels, the corresponding CO_2 emissions will be zero (these are already included in national totals due to their treatment in the AFOLU sector), so the subtraction of the amount of gas transferred to long-term storage may give negative emissions. This is correct since if the biomass carbon is permanently stored, it is being removed from the atmosphere."* (IPCC, 2006 Guidelines for National Greenhouse Gas Inventories, Chapter 2 Stationary Combustion, Section 2.3.4, Carbon Dioxide Capture, page 2.37).
3.3 (Section 1, Paragraph 7)	Further, even if we accept Drax Power's confident assertion that they will successfully and continually capture 95% of CO_2 emissions, there is still considerable uncertainty concerning the permanence of storage in saline aquifers and old oil and gas wells, which is why we believe that this DCO should be considered alongside the Humber Low Carbon Pipeline application and the undersea storage application. They are not only related – Drax Power's dDCO is completely dependent on these two following DCO applications (although they are not dependent on Drax's DCO). Therefore we argue that either the consideration of this dDCO is delayed, or any decision is contingent on	The CO_2 released from the combustion process will be captured and the technology is designed to capture rate approximately 95%. This is in line with other applications applying CCS technologies to combustion processes associated with power generation and was taken into account in the decision on Keadby3. The Applicant does not accept that there is a policy test that would require the consent of the current application to be linked to other schemes. The Overarching National Policy Statement for Energy (NPS EN-1) specifically accepts that the CCS chain has three links - capture of carbon; transport; and storage – but does not contain a

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	permission being granted for BOTH the pipeline AND the undersea storage, and that no work should start until both related permissions are granted. We believe that in seeking licence to start construction, there is a risk that Ministers might be "*encouraged*" into agreeing the two outstanding DCOs (pipeline and storage) with less than full consideration of the merits and problems	requirement that CCS schemes should only be approved where the entire chain has been consented. As discussed at the Hearings, the Government is considering the CCS chain in full in developing its commercial and regulatory models for CCS over the coming years. It is also noted that in EIA terms, there are no cumulative impacts of the Proposed Scheme and the storage facility, given the distance involved and the very different receptors involved. The Applicant in its ES, supplemented by its other Deadline 2 submissions, has done what is required in EIA terms to cumulatively assess the impacts of the Proposed Scheme with the Low Carbon Humber Pipeline The successful delivery of a working CCS plant is a desirable objective in its own right, consistent with the aim of the NPS, and the Applicant considers the current DCO application should be determined on its own, consistent with the approach taken to the recent Keadby 3 Carbon Capture Power Station DCO Decision. Further discussion on any linkage being made between the Proposed Scheme and the rest of the T+s infrastructure through the DCO Requirements is set out in the Schedule of Changes to the DCO document also submitted at Deadline 2.
3.4 (Section 1, Paragraphs 9 to 16)	Detailed evidence about the payback time for replanted trees to recapture the combustion and other emissions can be found in Sterman et al from 2018. (John D Sterman et al 2018 Environ. Res. Lett. 13 015007.) In this paper, Sterman and colleagues evaluate existing evidence about the emissions from burning wood, making clear that the climate impacts of burning wood to replace coal depends on multiple factors, specifically: "*The climate impact of biofuels therefore depends on CO2 emissions from combustion of biofuels versus fossil fuels, the fate of the harvested land and dynamics of NPP*" (Net Primary Production). Skipping to their conclusions, Sterman et al draw 7 separate conclusions from their data. First, yet contrary to the policies of the EU and other nations, biomass used to displace fossil fuels injects CO2 into the atmosphere at the point of combustion and during harvest, processing and transport. Reductions in atmospheric CO2 come only later, and only if the harvested land is allowed to regrow. Second, the combustion and processing efficiencies of wood in electricity generation are lower than for coal (supplementary material). Consequently, the first impact of displacing coal with wood is an increase in atmospheric CO2 relative to continued coal use, creating an initial carbon debt. Third, after the carbon debt is repaid, atmospheric CO2 is lower, showing the potential long-run benefits of bioenergy. However, before breakeven, atmospheric CO2 is higher than it would have been without the use of bioenergy, increasing radiative forcing and global average temperatures, worsening climate	The DCO Application relates to the installation and operation of CCS technology and the principle of using biomass to generate electricity is not within the scope of the Application. The sustainability credentials of biomass are not a relevant consideration to the question of whether or not it is acceptable for CCS technology to be applied. The approach to carbon accounting in relation to biomass is an approach that has been agreed by IPCC and the international scientific community. One paper does not counteract the national and international policy support for biomass production - as set out in the Overarching NPS for Energy (EN-1). Paragraph 3.4.3 of this document states that biomass is a '*significant'* source of renewable and low carbon energy and that '*biomass is considered to be low carbon, providing that the biomass has been cultivated, processed and transported with due consideration of sustainability. Its combustion also displaces emissions of carbon dioxide ordinarily released using fossil fuels.'* The Applicant also considers that the combustion efficiency of biomass is not lower than coal. Drax thermal efficiency is above average coal plant efficiency in the UK for all years dating back to 1997 (Digest of UK Energy Statistics (DUKES) and notes that the EU does not assume biomass to be carbon neutral, but rather recognises the accounting principles laid out in the 2009 and 2019 IPCC Guidelines for National inventories, which require biomass emissions to be accounted for in the land sector.

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	change, including potentially irreversible impacts that may arise before the long-run benefits are realized. Fourth, biofuels are only beneficial in the long run if the harvested land is allowed to regrow to its preharvest biomass and maintained there. Natural forests have high carbon density compared to pasture, cropland, developed land and managed tree plantations. (Our emphasis) Fifth, counter to intuition, harvesting existing forests and replanting with fast-growing species in managed plantations can worsen the climate impact of wood biofuel. Although managed loblolly pine grows faster than hardwood, speeding the initial recovery of forest biomass, the equilibrium carbon density of managed plantations is lower than unmanaged forest, so carbon sequestered in plantations never offsets the carbon taken from the original forest. This is true even if the managed plantation is never reharvested, and worse if the plantation is periodically reharvested. Further, typical plantations require periodic fertilization, increasing N2O emissions and worsening their climate impact beyond what we report here (Schulze et al 2012). Sixth, growth in wood harvest for bioenergy causes a steady increase in atmosphericCO2 because the initial carbon debt incurred each year exceeds what is repaid. With the US forest parameters used here, growth in the wood pellet industry to displace coal aggravates global warming at least through the end of this century, even if the industry stops growing by 2050. Seventh, using wood in electricity generation worsens climate change for decades or more even though many of our assumptions favor wood, including: wood displaces coal (the most carbon intensive fossil fuel); all harvested land is allowed to regrow as forest with no subsequent conversion to pasture, cropland, development or other uses; no subsequent harvest, fire or disease; no increase in coal demand resulting from lower prices induced by the decline in coal use for electric power; no increase in N2O from fertilization of managed plantations; and no increase in CO2 emissions or methanogenesis from disturbed land. Relaxing any of these assumptions worsens the climate impact of wood bioenergy. Sterman et al summarise thus: In sum, although bioenergy from wood can lower long-run CO2 concentrations compared to fossil fuels, its first impact is an increase in CO2, worsening global warming over the critical period through 2100 even if the wood offsets coal, the most carbon-intensive fossil fuel. Declaring that biofuels are carbon neutral as the EU and others have done, erroneously assumes forest regrowth quickly and fully offsets the emissions from biofuel production and combustion. The neutrality assumption is not valid because it ignores the transient, but decades to centuries long, increase in CO2 caused by biofuels	

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3.5 (Section 1, Paragraph 19)	In fact, we have seen evidence that a CO2 capture rate of 60% is more typical, and to consistently achieve capture rates of 90-95% will cause a significant additional energy debt. This technology is not the silver bullet it is portrayed as, but an unproven distraction from genuine emissions reduction strategies. This will be expanded on in detail in our submission at deadline 2, by which time we will have been able to collate all of the research papers that we have accessed. However, in the meantime, the Examining Authority would be justified in asking Drax to evidence their confidence in their predicted capture rates. This should include clarity over whether 95% is the average capture rate over time, or the peak capture rate when the system is working as planned (meaning that the average will be lower). This is significant in assessing the actual climate impact of the retrofitted CCS unit(s). The ExA would also be justified in asking Drax for detailed figures for the energy penalty through CCS operation, and how that varies with capture rate. Whether this information and data is given in private or public, the ExA needs to be confident of both the accuracy and reliability of this data.	The Carbon Capture rate of the technology used for the Proposed Scheme has been designed to capture approximately 95% of all CO_2 from two biomass units. This figure is considered to be achievable based on the use of Best Available Techniques. The Applicant is currently pursuing an Environmental Permit that will be issued by the Environment Agency. Under the terms of any license that is granted, Drax will be required to use Best Available Techniques in order to prevent or minimise emissions and impacts on the environment. It is expected that an Environmental Permit granted will establish the figure of 95% (and how it should be tested), which is a rate of capture that is broadly consistent with the position set out in 3.6.4 of the NPS EN1 that: *‘Carbon Capture and Storage (CCS) has the potential to reduce carbon emissions by up to 90%’.* Ultimately the achievement of the 95% figure is a matter not for this DCO Application, but is rather a matter that the Environment Agency will control under the terms of the Environmental Permit. Nevertheless the Applicant consideres that the figure of 95% is acchievable. A recent article posted on LinkedIn from Professor Jon Gibbins, Professor of Carbon Capture and Storage Technology at Sheffield University included the following statements; “*For at least two decades the conventional wisdom has been – largely because it was a ‘standard’ baseline used in studies comparing costs – that capturing 90% of the CO_2 in a flue gas stream was both good enough and the best that could be done. Based on more recent experience, this generally-accepted limit has been pushed up to 95% capture, but this is obviously still short of net zero*”. The article is titled, “*How amine post-combustion capture can trap 100% of fossil CO_2 before it enters the atmosphere*.” and is included as Appendix 1.
3.6 (Section 2, Paragraphs 1 to 4)	Irrespective of the historic flood patterns around Drax and the surrounding villages and farmland, the 2022 Climate Change Risk Assessment (CCRA 2022.3) advises that climate change adaptation needs to be integrated effectively into all new infrastructure, and to prepare for warming up to 4oC. The dDCO predates this advice, and so we contend that the flood risk assessments must be re-modelled in accordance with CCRA 2022.3. Using the available open-source coastal flooding projection tools available at Climate Central.org it is clear that the Drax site is at serious risk of future flooding. By altering the parameters to assume a mid-range temperature rise of 3.2oC by 2100, it is anticipated that the power station site may well be below the 10 year flood level by 2050 and below the tideline by 2050. The models also predict that even if global heating is constrained to 1.5oC, which seems increasingly unlikely, Drax	Whilst the dDCO predates the advice within the 2022 Climate Change Risk Assessment, the design standards for flood risk assessments (which were adopted for use within the Flood Risk Assessment (FRA) (AS-088 and 090) for the Proposed Scheme) have been developed by the Environment Agency based upon RCP8.5, which is the high-emissions global warming scenario and would equate to a 3.3 ºC warming for North Yorkshire. As the FRA has already assessed the impacts of RCP8.5 through site specific models (which are more refined than the open source projection tools), there is no requirement to undertake further assessment. These impacts are suitably mitigated within the FRA (AS-088) for the design life of the Proposed Scheme.

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	Power Station is likely to be permanently below sea level in the long term (this would be well into the next century).	The FRA has been approved by the Environment Agency in their role as statutory consultee for flood risk, as such there is no requirement for the ExA to request new and independent analysis of the flood risk to the Proposed Scheme.
3.7 (Section 2, Paragraph 8)	Late 2022 has seen a series of reports about ice sheet and glacier melting, all indicating that this is happening faster than previously predicted and that sea level rises will further accelerate as a result. Therefore, it is clear that the Climate Change Risk Assessment advice to plan for a 4oC temperature rise is timely. Whilst it is not the fault of Drax Power that their flood risk assessment has been overtaken by disturbing new evidence, it is within the power of the ExA to ask for new and independent analyses of flood risks over the operation and dismantling phases of the plant at Drax, using a variety of scenarios to adequately assess actual risk.	
3.8 (Section 3, Paragraph 1 to 6)	There has been increasing scrutiny of the biomass industry throughout 2022, including documentaries in both the UK and Canada about biodiversity losses from logging and wood pellet operations in British Columbia. There is also intense scrutiny on the biomass industry in the Southern US where Drax Power sources much of its wood pellet from, and in Estonia. The debate on this matter highlights the gap between Drax's assertion that its operations and purchases are legally compliant and licenced, which I am sure is the case, and the actual impact on naturalised, biodiverse forests. The think tank, Ember, has reported that it believes that some imported pellets from Estonia are in breach of UK sustainability criteria through: • *logging in protected areas (including those protected under Estonian law and those designated as Natura 2000 reserves);* • *damage to watersheds around rivers and streams; • damage to carbon-rich peat soils;* • *logging in ways that harm biodiversity (including clearcutting and other types of harmful logging in habitat for species protected under EU and/or Estonian law due to their imperilled status); and logging culturally significant trees.* It is clear from evidence on the ground that whether or not wood pellet production uses whole trees or waste, much of the timber provided to wood pellet manufacturers, including Drax itself, is derived from clear felling and from mature, biodiverse forest, not monoculture plantations. There are recorded concerns in all supplying nations about risks to specific protected species including Caribou in Canada. The South Eastern coastal	The biomass generation units that are the subject of the Proposed Scheme are already fully consented and in current operation. The Proposed Scheme is seeking consent only to retrofit carbon capture units to those units. As such and as set out above, this comment is not relevant to the merits of the Proposed Scheme. Notwithstanding this, the Applicant agrees that much of the sustainable biomass associated with the biomass units to which the Proposed Scheme will be fitted will be imported from outside the UK. The Applicant responded to points of this nature in section 10 of its Response to Relevant Representations document [PDA-002].

Response Ref. (Location in Original Submission)	Comment	Applicant's Response
	forests of the US have in excess of 1500 endemic species that are under increasing pressure as natural swamp forests are cleared as being of "*no commercial value*", completely discounting their biodiversity value. These examples could all fall foul of UK sustainability regulation.	
3.9 (Section 3, Paragraph 7 to 8)	This is at a time when it is recognised that biodiversity is collapsing globally, threatening human life to at least the same extent as global heating. As awareness increases, and following COP15 in December, it is highly likely that the regulatory framework for harvesting biomass from biodiverse forests will tighten incrementally over coming years, alongside international agreements on deforestation. This will threaten the global supply of "*affordable*" wood pellet and undermines the business case for an expanding biomass industry. It may be that the narrowness of UK Planning Law puts these overseas biodiversity considerations outside of the planning process, but there is emerging evidence that biomass sourcing is NOT aligned with the UK sustainability regulation, which we believe justifies raising the questions here. This in itself could make such a project non-viable.	The biomass generation units that are the subject of the Proposed Scheme are already fully consented and in current operation. The Proposed Scheme is seeking consent only to retrofit carbon capture units to those units. As such and as set out above, this comment is not relevant to the merits of the Proposed Scheme. The biomass sector is highly regulated. The Applicant works actively with national and state regulators and complies with complying with the relevant local environmental standards and in accordance with the relevant environmental permits and regulatory requirements (including in relation to biodiversity). The Applicant agrees that these matters are not relevant to the consideration of the Application as any future change in law is not a valid consideration for the ExA to take into account when it is essentially unknowable. In any event. the viability of the project is for the Government and Applicant to consider.

MR HEWITT

Table 4.1– Mr Hewitt

Response Ref. (Location in Original Submission)	**Comment**	**Applicant's Response**
4.1 (Paragraphs 1a to 1b)	1a) The Preliminary Meeting heard that the applicant is negotiating with government concerning the likely CO_2 capture rate of the proposed works. The 95% minimum proposed (presumably referring to an annual average rather than an occasional maximum) does not reflect the very poor performance hitherto obtained by carbon capture facilities worldwide within the power sector, despite large subsidies. Facilities which compress captured CO_2 at those unsuccessful power stations have not all performed as expected. 1b) 95% may have been chosen for cosmetic, presentational purposes, for example, to boost the apparent credentials not only of the proposal itself but also of the project downstream (to which the captured CO2 would be supplied and perhaps permanently stored). 95% may also have been chosen to help maximise the likelihood and amount of subsidy (if any) which the UK government provides to the applicant for doing no more than have an "*oven-ready*" scheme which might never be built let alone operate at an annual average capture rate anywhere near 95% (regardless of whether demand for electricity from one or both units is intermittent or continuous).	1a) The Carbon Capture rate of the technology used for the Proposed Scheme has been designed to capture approximately 95% of all CO_2 from each biomass unit. This figures is considered to be achievable based on the use of Best Available Techniques, and is broadly consistent with the figure of 90% that is used in paragraph 3.6.4 of the NPS EN1. 1b) The use of Best Available Techniques will be a requirement of any Environmental Permit that is granted by the Environment Agency. Ultimately the acheivement of the 95% figure is a matter not for this DCO Application, but is rather a matter that the Environmnt Agency will control under the terms of the Environmental Permit. Nevertheless the Applicant considers that the figure of 95% is achievable.
4.2 (Paragraphs 2a to 2b)	2a) If current carbon accounting rules deem that emissions from the applicant's power station occur in the countries which supply its woody biomass fuel, then it would be absurd for the applicant (and UK government) to claim that any captured and subsequently stored CO_2 from that power station should be credited to the UK or applicant as negative emissions. That CO_2 (net of leakage) should be deducted *pro rata* from the carbon accounts of the supplying countries. *This negates the (ostensible) purpose of the proposal.* 2b) Failing to take this into account might reflect a prevalent view - independent of the industry and its partners - that BECCS projects of the sort and size proposed are unlikely to be plausible or socially acceptable in the foreseeable future.	The Proposed Scheme is seeking consent only to retrofit a carbon capture plant to those biomass units. As such this comment is not considered by the Applicant to be relevant to the merits of the Proposed Scheme. Notwithstanding that the DCO application is for the fitting of carbon capture units, the accounting principles that apply to the project are laid out in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories which states, "*If the [CCS] plant is supplied with biofuels, the corresponding CO_2 emissions will be zero (these are already included in national totals due to their treatment in the AFOLU sector), so the subtraction of the amount of gas transferred to long-term storage may give negative emissions. This is correct since if the biomass carbon is permanently stored, it is being removed from the atmosphere*". This is also set out and discussed further in the Applicant's Summary of Oral Submissions at ISH1 [REP-028]
4.3 (Paragraphs 3a to 3c)	3a) The applicant's business is sustained by the subsidy which it receives for burning carbon other than fossil fuel at its Drax power station. Most of that subsidy is due to end in 2027, implicitly making continued operation of that power station commercially unviable. 3b) The proposed works might not need to commence until the latest date necessary to ensure that completion is sufficiently in advance of when the store commences operation.	3a) The commercial viability of the Proposed Scheme and the time at which the works are carried out is a matter for the Applicant and not an important and relevant consideration in the determination of the DCO Application. Given the well-established need for dispatchable renewable energy and the commercial expectations of the Government, the Applicant would not expect that commencement of the Proposed Scheme will be delayed until the latest possible date as the Applicant would seek to maximise the commercial return available to it from capturing carbon.

Response Ref. (Location in Original Submission)	Comment	Applicant's Response
	3c) The applicant itself recognises that the downstream project is likely not to be operational until 2040. 2040 is five years after government policy requires the closure of all unabated (carbon burning) power stations except those whose emissions are outsourced.	3b) The Overarching National Policy Statement for Energy (NPS EN-1) specifically accepts that the CCS chain has three links - capture of carbon; transport; and storage – but does not contain a requirement that CCS schemes should only be approved where the entire chain has been consented. The Applicant does not accept that there is a policy test that would require the consent of the current application to be linked to other schemes. The successful delivery of a working CCS plant is a desirable objective in its own right, consistent with the aim of the NPS, and the Applicant considers the current DCO application should be determined on its own, consistent with the approach taken to the recent Keadby 3 Carbon Capture Power Station DCO Decision. 3c.The Applicant does not recognise an operational date of 2040. The most recent dates for the delivery of Humber Low Carbon Pipeline provided by National Grid are for the start of construction in 2024, with an earliest date for completion of construction given as 2026.
4.4 (Paragraphs 4a to 4b)	4a) As such, it seems reasonable to regard the proposal as if for a new power station (not a going concern) - despite the power station already being elderly (units 1 and 2 implicitly being two of the oldest). 4b) As with the performance of the carbon capture facility (and the readiness of the technology currently proposed), the applicant offers no guarantee that the proposed timelines would be met.	The Applicant considers that the nature of the DCO Application is clear, for retrofitting of CCS technology to existing power generation units. Paragraph 2.1.4 of Chapter 2 of the Environmental Statement ('Site and Project Description') (Document Reference APP-038) confirms that: *'Drax Power Station was originally built, owned and operated by the Central Electricity Generating Board. It had a capacity of just under 2,000 megawatt ('MW') when Phase 1 was completed in 1975, increasing to 4,000 MW from six coal-fired units after the construction of Phase 2 in 1986.'* As such and the Applicant does not accept that the Proposed Scheme should be regarded as if it were for a new power station. Whilst inevitably there must be some degree of uncertainty over any major construction project, the Applicant is confident that the proposed times lines for delivery of the Proposed Scheme that are set out in Part 2.4 of Chapter 2 are robust and achievable. The Applicant does not consider that a guarantee needs to be in place as to when the works will commence, given the minimal amount of harm that is caused by the construction phase of the Scheme with mitigation measures in place – that will be a commercial decision for the Applicant.
4.5 (Paragraph 5)	5) The applicant has a clear interest in setting aside such considerations in order to accelerate the approval process, so as to lock in its recovery of costs and foregone profit should the proposed works not proceed. Doing so would also help give capital markets and legislators the view that both "*BECC without the S*" and the "S" are both already bankable.	The timelines for the approval of a DCO Application are set out in the 2008 Planning Act and there is no opportunity for acceleration within the Applicant's control. It is for the Government to decide if commercial support is to be given to the East Coast Cluster of which BECCS forms part – in doing so it has sought reassurances that all parts of the system, including capture, are delivered as soon as possible. The Applicant responds to that expectation.
4.6 (Paragraphs 6a to 6b)	6a) The contractual aspects of the proposal would be complex. Amongst other matters, they would include the integration of the proposed works with the downstream network and the "complete and permanent" store. The law is at an early stage of evolution concerning CO2 storage.	The costs of access and use of the CO_2 transport and storage (T&S) network have not yet been confirmed by BEIS / NEP. However, the Applicant is using an estimated cost (£/tCO_2) within its economic modelling.

Response Ref. (Location in Original Submission)	Comment	Applicant's Response
	6b) The price at which the owners of those facilities accept CO2 from the proposed works would reflect the extent to which the applicant accepts future liability for that CO2. As the Preliminary Meeting heard, the applicant does not propose to accept any such liability – further undermining the viability and credentials of the proposal.	However, whatever the payment mechanism and structure between Drax Power Station Site and the pipeline and storage operator, this is an issue for the Applicant's consideration in determining whether or not to proceed (and the Government in considering its business submission). The Government is setting up the commercial business models for each part of the system, where each part will be subject to its own incentives and risks, including in relation to matters such as leakage. That is for the Government and those parties to deal with. However, the fundamental position is that the Government is setting up a carbon capture, transport and storage system as part of national government policy. Each part is necessary to make the system work and to ensure that the UK's net zero target is met, including the Proposed Scheme. This will involve commercial and contractual matters, but that is not relevant to planning consideration of the Proposed Scheme.
4.7 (Paragraphs 7a to 8)	7a) The proposal is predicated on the evermore urgent need to reduce greenhouse gas emissions to zero and maximise CO2 sequestration. Carbon (especially carbon debt), not sustainability or renewability, is central to the rationale for the proposed works. 7b) However, government policy (currently in flux and perhaps influenced by the industry - even the opposition is receiving donations and sponsorship from Drax) is inconsistent with the climate and biodiversity emergencies. 7c) Government acceptance does not guarantee sustainability or carbon neutrality. As the Preliminary Meeting heard, the applicant deems such acceptance as sufficient. 8) The applicant is having difficulty explaining to parliament and the public that burning imported woody biomass to generate electricity is a climate change "solution" and, crucially, without carbon debt. It is an especially inefficient way of maximising exploitation of the embodied energy in that wood. The application does not seek to capture and sell heat.	Chapter 4 of the Needs and Benefits Statement that is submitted with this DCO Application identifies the national, international and local policies that support the use of CCS technology. Government support for the use of biomass as a significant source of renewable and low carbon energy is confirmed at paragraph 3.4.3 of NPS EN-1 the use of CCS at paragraph 3.6.4. The need for CCS is reconfirmed in the emerging Draft EN-1. The need for biomass with or without CCS is established as urgent. The government also states that new CCS infrastructure will be needed to ensure the transition to a net zero economy (Draft EN-1, 2021, paragraph 3.5.1). Draft EN-1 clarifies why new CCS infrastructure will be needed to ensure the transition to a net zero economy: *"It will be difficult to completely decarbonise all sectors of the economy, with aviation and agriculture viewed as particularly challenging. Where sectors are not completely decarbonised, we will need negative emissions to offset the residual emissions in those sectors. Capturing and storing emissions from bioenergy or directly from the air using CCS infrastructure provides a source of negative emissions. There are other sources of negative emissions, such as afforestation, but all of these are limited in some way and negative emissions using CCS infrastructure are viewed as essential for delivering our net zero target" (Draft EN-1, 2021, paragraph 3.5.7)* The Applicant does not accept that there is any inherent conflict between the drive to zero carbon and meeting the climate and biodiversity emergencies. Chapter 1 of the Government's Biomass Strategy identifies the: '. Bioenergy with Carbon Capture and Storage (BECCS) can provide net Negative emissions because the carbon captured in plant growth is captured, stored and removed from the atmosphere' and that the Net Zero Strategy has outlined that greenhouse gas removals (GGRs), which include BECCS, are '*essential to compensate for residual emissions from the hardest to decarbonise sectors, such as aviation, agriculture, and heavy industry.'*

Response Ref. (Location in Original Submission)	**Comment**	**Applicant's Response**
		The Proposed Scheme is considered to be consistent with Government Policy, including the Net Zero Strategy. .
4.8 (Paragraphs 9a to 9c)	9a) The applicant relies on government acceptance of a certification scheme (Sustainable Biomass Program) established by the industry for the industry, despite that scheme's neglect of carbon debt. 9b) When considering regional certification, that scheme is particularly weak concerning forest fragmentation, soil carbon, ad hoc sources of supply, the small percentage of supply chains field-audited, subsequent restoration (like-for-like or otherwise) after clear felling, ecosystem services and other parameters crucial to the carbon balance). 9c) Chatham House estimates that CO2 emissions attributable to *"lost forest growth and decay of residues*" in USA add between 19% and 44% to the amount of CO2 which Drax power station emitted during 2019 when burning woody biomass from its sources in USA. The applicant pays no compensation either for these losses or for subsequent matching sequestration.	The biomass generation units that are the subject of the Proposed Scheme are already fully consented and in current operation. The Proposed Scheme is seeking consent only to retrofit carbon capture units to those units. As such and as set out above, this comment is not relevant to the merits of the Proposed Scheme. Notwithstanding this, the Applicant agrees that much of the sustainable biomass associated with the biomass units to which the Proposed Scheme will be fitted will be imported from outside the UK. The sourcing of biomass for the Power Station is currently subject to strict regulations and standards set by the UK Government, including through the Renewables Obligation Order 2015. These requirements are unique in that they are stricter and more onerous than what is required for other energy generation technologies or other sectors of the bioeconomy (e.g. solid wood products).Updated sustainability standards will apply to the biomass to be sourced for the Proposed Scheme and set out in any subsidy contract relating to the same. An update Biomass Strategy is expected to be announced later in 2023 which will provide clarity on these requirements. The vast majority of biomass sourced for the existing generation units also complies with a number of voluntary certification schemes, such as the Sustainable Biomass Program (SBP), FSC and SFI, and third parties provide oversight to ensure the material meets the required sustainability regulations. All biomass sourced without certification undergoes additional due diligence and third party auditing. The Applicant publishes a comprehensive overview of this data in its Annual Reports.
4.9 (Paragraph 10)	10) The extent to which assessing this application should take such upstream considerations into account given that almost all of them pertain outside the UK is unclear.	The Applicant considers that the nature of the DCO Application is clear, for retrofitting of CCS technology to existing power generation units. Although not part of the scheme that is applied for, as explained in Chapter 15 of the ES [APP-051], The supply chain emissions have been accounted for in the assessment of GHG impacts and are clearly defined in Appendix 15.2 (APP-169), Table 1.1 – Proposed Scheme GHG Emissions.
4.10 (Paragraph 11)	11) Consideration should be given as to whether Chinese-owned British Steel should be allowed to manufacture strategically valuable items for the proposed works.	The Applicant does not consider this a matter relevant to the determination of the DCO Application.

Table 5.1– Biofuelwatch

Response Ref. (Location in Original Submission)	**Comment**	**Applicant's Response**
	Submission Document: Post-hearing submission – Open Floor Hearing 1	
Health impacts relating to use of amine solvents and impurities in the flue gas		
5.1 (Section 1, Paragraph 1)	The proposal is not a sustainable development as defined in the National Planning Policy Framework, since it is not compatible with supporting communities' health due to concerns about the health impacts of the chemicals that will be used.	The Proposed Scheme would support the achievement of sustainable development by supporting the UK's transition to zero carbon, by delivering negative emissions associated with electricity generation to offset the sectors which it is more difficult to decarbonise (e.g., agriculture and aviation). The Environmental Statement also concludes that there are no likely significant effects to health arising from the Proposed Scheme. It would generate employment opportunities in North Yorkshire during construction and operation which would, therefore, contribute positively to socio-economic wellbeing of people in North Yorkshire and beyond. The Proposed Scheme constitutes sustainable development in the context of the NPPF, delivering economic, social and environmental benefits. It therefore accords with the main principles of the NPPF and in applying the NPPF approach to decision-making, there would be no adverse impacts which would significantly and demonstrably outweigh the benefits, when assessed against the policies in the NPPF taken as a whole.
5.2 (Section 1, Paragraph 2)	There are no real-world examples on which to assess the release of amine degradation products from BECCS using woody biomass as Drax itself admits this is the first project of its kind globally.	As detailed in the Applicants Response to Relevant Representations (PDA-002), response reference 16.4. In relation to amines and degradation products, the assessment has been undertaken conservatively and the increase in ground level concentrations represents a small proportion of the Environment Agency environmental assessment level (EAL) for nitrosamines (as NDMA) and the EALs for emitted amines, proposed by the Applicant (which are more stringent than the EALs set by the Environment Agency). Impacts on amines can be screened as negligible. Impacts from nitrosamines have been assessed to be negligible on basis that the EAL has been derived by the Environment Agency on the basis of a negligible cancer risk and the Proposed Scheme's process contribution is a factor of 10 lower than the level assessed to represent a negligible cancer risk i.e. significantly lower again (see response in 5.3 below above for more information). There is, therefore, a negligible lifetime cancer

		risk from exposure to amine degradation products that may arise from the Proposed Scheme. Should the performance of the plant, when operational, differ from that in the permit variation application (which is consistent with the material before the Examination), then this would be dealt with through the permitting and regulatory regime by the Environment Agency.
5.3 (Section 1, Paragraphs 3 to 5)	The flue gases are different to those of fossil fuel CCS. Drax is demolishing its flue gas desulphurisation plant because the lower sulphur levels released to the atmosphere from biomass flue gases are within legal limits. However, they are at a greater level than with desulphurised fossil emissions, which will lead to different degradation products within the carbon capture system. The presence of increased sulphur and other particles mean a direct comparison with CCS cannot be made in terms of the release of harmful amine degradation products (nitrosamines, nitramines and others). Drax acknowledges in its application that existing toxicological data indicates that most nitrosamines are carcinogenic. Moreover, although there is commercially available modelling software, these results cannot be validated due to there being no real world examples on which to test it.	The air quality impact assessment set out in Chapter 6 (Air Quality) (APP-042) and supporting appendices are based on the emissions limits from the biomass units, comparing future scenarios with and without carbon capture. Comparisons to fossil fuel CCS are not appropriate or relevant. The modelling of amine degradation products is based on the biomass plume characteristics and uses the ADMS v5.2 software package. The theory behind the degradation of amines is well established, the model software has been validated by the developers and the reaction rates used for the amine degradation are specific to the technology (provided by the technology suppliers from literature values). Any model, or indeed monitoring, has associated uncertainties. This is taken into account in the assessment through the employment of highly conservative assumptions that ensure that impacts are not underestimated. Specifically, in the case of the modelling of amines and their degradation, it has been assumed that all degradation products (nitrosamines and nitramines) have the same toxicity as NDMA and act in combination, and the photolytic degradation of products has been neglected as has the time delay between the release of amines and the onset of degradation. Further information is provided below but reference should be made to response reference 5.34 and 16.1 of the Applicant’s Response to Relevant Representations [PDA-022]. The installation will be regulated by the Environment Agency under the Environmental Permitting Regulations; these regulations will control the emissions to air from the plant and these emissions will include compounds associated with acid deposition including but not limited to Sulphur Dioxide. The application for a variation to the permit has been submitted to the Environment Agency and this variation includes a decrease in concentrations of Sulphur Dioxide from the units associated with BECCS (units 1 and 2). The assessment undertaken is based on the permit limits which have been applied for as a realistic worst-case scenario. The BECCS technology includes a quencher system (a recirculating water spray system removing condensable components in the flue gas) which reduces the Sulphur load which enters the absorber system and which eventually is emitted to atmosphere. In addition, biomass has a low sulphur content. All of these data are monitored, recorded and reported to the regulator. The Environmental Permit will be in place prior to the commercial operation of the installation and will remain in place unless varied during the lifetime of the plant.

		The assessment reported in the ES Chapter 6 (Air Quality) (APP-042) has fully accounted for the emissions of amines and the formation of nitrosamines and nitramines. Moreover, the assessment, as presented in the ES and subsequent additional information (AS-10), has been undertaken on a highly conservative basis, as outlined below. Extensive research is available on the impacts of amines, nitrosamines and nitramines on health, and this has been used by the Environment Agency to derive Environmental Assessment Levels (EALs) for MEA (an amine) and NDMA (a key nitrosamine). Finally, it is worthwhile reinforcing that the assessment is based on worst case, conservative, assumptions. In particular, the BECCS units are assumed to operate at full load continuously, with emissions at their permitted levels at all times and impacts assessed for the worst year of 5 years tested. Furthermore, the risk relates to the combined impacts from nitrosamines and nitramines whereas it is widely accepted that nitramines, which form the majority of the total nitrosamines + nitramines, have lower toxicity than nitrosamines (Gjernes, 2013. Health and environmental impact of amine based post combustion CO_2 capture. Energy Procedia Volume 37, 735-742). Actual risks will therefore be considerably lower than 1 in 1,000,000.
5.4 (Section 1, Paragraph 6)	BEIS's Biomass policy statement 2021 states that research and updated regulation will also be required to understand and address any air quality impacts from BECCS, including emissions associated with carbon capture solvents. This was published in November of that year which was after levels were set for monoethanolamine (MEA) and N-Nitrosodimethylamine (NDMA) in September of that year following a consultation by the Environment Agency.	Please refer to the previous answer (5.3) above. The assessment of impacts has been based on the specific amine compounds and biomass exhaust parameters specified by technology suppliers. Furthermore, the assessment has used conservative assumptions to ensure that uncertainties are taken into account and impacts will not be underestimated. The regulation of carbon capture and the use of amine solvents is an area of ongoing development. Notwithstanding this, the operation of Drax BECCS will be in accordance with the applicable Environmental Permit and all applicable regulations at the time of operation. This will respond to the emerging regulatory picture as the regulator undertakes further work on this issue.
5.5 (Section 1, Paragraphs 7 to 9)	The Environment Agency say in next steps: "*We will also consider the need to develop British Standards for monitoring of emissions from carbon capture systems and in ambient air because, as to date, there are no certified standards for continuous emission monitoring (CEMS), periodic monitoring or ambient air quality monitoring*". This is not yet in place. In addition, there is a lack of transparency from Drax as to the particular solvents it intends to use with reasons of commercial confidentiality cited. There is a paucity of research on the health impacts of amines and their degradation products when released into the environment and given their limited use and monitoring there is a total lack of epidemiological data.	Monitoring will be undertaken in accordance with the applicable Environmental Permit as per the standards that are set by the EA. Drax are working closely with the EA to provide required information to gain the Environmental Permit and will be monitored against that permit. Drax will comply with those requirements as they develop as it has done since construction of the power station and as other successful applications have noted e.g. Keadby 3. Please refer to previous Response Reference 16.1 of the Applicant's Relevant Representations Response Document (Document Reference PDA-002) and previous answers (5.3 and 5.4) in relation to uncertainty around impacts of nitrosamines.
5.6 (Section 1, Paragraph 10)	There is a widely-accepted principle of using the reasonable worst-case scenario in models - given all of the above it is difficult to have confidence that Drax's figures represent such a scenario.	In accordance with the Environment Agency 'Air emissions risk assessment for your environmental permit' (2021) guidance, both the short-term (hourly / daily) and long-term (annual) assessments are carried out and the processed model outputs comprise concentration data for each pollutant. In accordance with the guidance, for the long-term assessment the worst case year, out of a five year period, is assessed.

		The assessment considers the baseline along with the "*with Proposed Scheme*" and the "*with Proposed Scheme and Other Projects*". As detailed in ES Chapter 6: Air Quality (APP-042), section 6.5.55 (b), in the core model scenarios, the non-BECCS Biomass Units at Drax Power Station are assumed to operate at full load for up to 4,000 hours per annum (i.e., a 'mid-merit' operating regime), representing a robust and realistic projection for future baseline operation. The BECCS units are assumed to operate continuously at baseload for all hours of the year. However, further sensitivity model scenarios have been completed, as reported in ES Appendix 6.3 (APP-127), whereby the non-BECCS units also operate continuously at baseload for all hours of the year which represents the "*worst case emissions profile*" profile from the Proposed Scheme. In relation to future baseline without the Proposed Scheme it is anticipated that air quality would remain unchanged or would slightly improve (due to the expected reduction in vehicle emissions as older, more polluting vehicles are replaced by cleaner vehicles). However, no improvement in air quality in the future baseline has been assumed for the assessment which makes it inherently conservative.
5.7 (Section 1, Paragraph 11)	It is also of note that there is no reference in Drax's application to occupational exposure to amine degradation products.	Drax Power Limited received notice of legal action from the Health and Safety Executive in relation to wood dust from operations at Drax Power Station prior to 2017. We have pleaded not guilty. As this legal case is ongoing, we cannot provide any further information at this time. Since the commencement of large-scale biomass operations in 2013, the Company has been committed to continuous improvements of its facilities. The health, safety and wellbeing of colleagues has been and continues to be a priority for Drax Power Limited. An integral part of the design and engineering of the project will include a series of HAZIDS and HAZOPS conducted with the design and construction teams. These meetings and the output of them will ensure that hazards are identified and addressed as part of the integral design and operation of the plant.
5.8 (Section 1, Paragraph 12)	This is concerning given Drax is currently being taken to court by the Health and Safety Executive regarding exposing its workers to wood dust.	
5.9 (Section 2, Paragraphs 1 to 6)	According to the Ecology Report [redacted], the proposed development is likely to lead to the disturbance and degradation of vital habitats and it risks harming a wide range of protected species. Drax's non technical summary of the Environmental Statement notes that: 'Likely effects from construction and decommissioning include disturbance and clearance of habitats, disturbance of protected species, and the risk of release of water-borne pollutants from plant and other machinery" [redacted] p.32) The proposed development will adversely impact nationally- and internationally-designated areas that cannot be adequately mitigated or compensated for. Areas close to the site that are likely to be impacted include ten international and 12 national statutory designated sites within 15 km of Drax Power Station and nine non-statutory designated sites of county importance within 2 km of the Proposed Scheme.	As set out in the Ecology chapter of the ES (APP-144), the Applicant's assessment of ecological effects is that there will be short term adverse effects on some ecological receptors as a result of unavoidable construction phase impacts. Mitigation measures have been proposed to minimise these and operational effects (and avoid them completely in a number of cases), and in the medium to long term, effects are expected to be not significant or beneficial. No significant adverse effects on internationally and nationally designated sites are expected. The Applicant would also like to clarify that the River Ouse only forms part of the Humber Estuary SAC, SPA, and Ramsar site several kilometres downstream from the Site of the Proposed Scheme. The River Ouse closer to the Site is however considered to provide functionally-linked habitat for fish and bird species, and for otter, associated with the Humber Estuary, River Derwent, and Lower Derwent Valley designations. The River Derwent SAC is located upstream of the River Ouse

	These include the River Ouse which forms part of the Humber Estuary Ramsar Site, Special Conservation Area (SAC), Special Protection Area (SPA) and Site of Special Scientific Interest (SSSI) and the River Derwent which is a Special Conservation Area close to the Power Station. [redacted] It is therefore not a sustainable development as defined by the National Planning Policy Framework because it fails to protect the natural environment or enhance biodiversity by 'minimising impacts on and providing net gains for biodiversity, including by establishing coherent ecological networks that are more resilient to current and future pressures.' [redacted] 174,d)	and approximately 0.7 km north of the Proposed Scheme Order Limits. It therefore also provides a habitat linkage for migratory fish between the Humber Estuary and the River Derwent. The Proposed Scheme includes a series of measures to avoid and minimise the risk of water-borne pollution and sediment release, during both the construction/decommissioning and operational phases of development. NE have agreed that subject to securing of the necessary measures via the DCO, they do not consider water-borne sediment or chemical releases would lead to adverse effects on integrity of European Sites/SSSI including in relation to functionally-linked land used by otters that may form part of the River Derwent SAC populations. No concerns have been raised in relation to sediment and chemical water-borne pollution risk by the NYCC Ecology Team. The Environment Agency also agrees with the measures in the REAC (REP-015) and considers that they will be sufficient to mitigate the impacts of the Proposed Scheme. In addition to incorporating avoidance, reduction, mitigation, and compensation measures as per the 'mitigation hierarchy', the Proposed Scheme includes measures to deliver Biodiversity Net Gain. On the basis of the Proposed Scheme's landscape and biodiversity measures and recent engagement with the Calder and Colne Rivers Trust, the Applicant expects to be able to deliver 10% BNG for Area habitats, hedgerows, and rivers and streams; this will deliver enhancement for biodiversity through the measures proposed in the Habitat Provision Area, Off-Site Habitat Provision Area, and through the Applicant's intended support of river habitat enhancements to be delivered by the Calder and Colne Rivers Trust. The Proposed Scheme is therefore considered to constitute sustainable development in ecological terms.
5.10 (Section 2, Paragraphs 7 to 9)	Moreover, the proposed development is incompatible with: a) Commitments made in the Environment Act 2021 to support the "*conservation and enhancement of biodiversity in England*" b) The aims of the Defra Nature Recovery Green Paper (March 2022) *"to address the drivers of nature's decline including habitat deterioration, loss and fragmentation*".	In addition to incorporating avoidance, reduction, mitigation, and compensation measures as per the 'mitigation hierarchy' and set out in the OLBS, the Proposed Scheme includes measures to deliver Biodiversity Net Gain. On the basis of the Proposed Scheme's landscape and biodiversity measures and recent engagement with the Calder and Colne Rivers Trust, the Applicant expects to be able to deliver 10% BNG for Area habitats, hedgerows, and rivers and streams; this will deliver enhancement for biodiversity through the measures proposed in the Habitat Provision Area, Off-Site Habitat Provision Area, and through the Applicant's intended support of river habitat enhancements to be delivered by the Calder and Colne Rivers Trust. The Proposed Scheme is therefore not incompatible with the Environment Act 2021 or the Nature Recovery Green Paper.
5.11	Drax's environmental statement also states that a large number of protected and notable species have been identified within 2 km of the proposed project site, including bats, badgers, otters, water voles, breeding and wintering birds, reptiles, fish and plants. •	In relation to Point A, the scope of surveys including reliance on previous survey data from the Drax Repower scheme was agreed with the NYCC Ecology Team during pre-application discussions and has subsequently been agreed with Natural England. This is set out in the Statements of Common Ground for NYCC (REP-018)

(Section 2, Paragraphs 10 to 19)	Moreover, Drax's Ecology Report notes that habitats within and close to the project site are suitable to support protected and notable species and these areas will be impacted. The Government Circular 'Biodiversity and Geological Conservation - 06/2005' stipulates that: "*The presence of a protected species is a material consideration when a planning authority is considering a development proposal that, if carried out, would be likely to result in harm to the species or its habitat*". paragraph 98). The application for consent is deficient in that: A) It relies on some outdated species surveys from 2018 and therefore does not properly assess the impact on biodiversity of the proposed development. • The surveys that were only conducted in 2018 include the Reptile survey , the otter and water vole survey the Breeding Bird Survey , the Bat building emergence survey and the Bat tree roost Assessment survey. • It is concerning that Assumption C of the Environmental Statement states that: 'Unless otherwise stated, the ecological baseline pertaining to protected and notable species has not changed significantly since the ecological impact assessment within the Drax Repower Environmental Statement in 2018.' • We believe that more evidence is required to prove that new surveys are not required, particularly as the worsening climate crisis means that the environmental conditions for species may have changed since 2018. • As many of these species are mobile, there are concerns that the development could impact in some cases on populations of local or county value and the mitigation proposed may not be sufficient for all species. B) it does not pay sufficient attention to the potential for damage to watercourses by sediment and accidental release of chemicals. • Given that there are multiple important sites for biodiversity, this should be taken into account when considering the applicant's request to begin construction before the relevant permits have been granted.	and Natural England (REP-020). An extended Phase 1 habitat survey was completed of the Site prior to submission of the application and is reported within the Preliminary Ecological Appraisal (APP-136), in order to assess which further surveys may be needed. This allowed an appropriate scope of further surveys to be completed (as detailed below) based on an updated assessment of the habitats present and with consideration to the extent and location of the Proposed Scheme, which covers a smaller extent of land compared to the Drax Repower project. Surveys completed between 2021 – 2022 include extended Phase 1 habitat survey and UK Habitat Classification Surveys ('UKHab') which included assessments for badgers, otters, water voles, potential for roosting and foraging/commuting bats, green-winged orchid, terrestrial invertebrates, great crested newts and other amphibians, and breeding and wintering birds. An extended UKHab survey has also been completed for the Proposed Change areas associated with undergrounding of overhead power lines and telecommunication lines. In addition, targeted surveys for terrestrial invertebrates (APP-139), great crested newts and other amphibians (APP-137), wintering and passage birds (APP-138), and badgers (APP-140 – confidential) were also completed within and adjacent to the Order Limits at the Drax Power Station Site. Assumption C in the Ecology chapter of the ES (which follows paragraph 8.5.26) states: '*Unless otherwise stated, the ecological baseline pertaining to protected and notable species has not changed significantly since the ecological impact assessment within the Drax Repower Environmental Statement in 2018 (Drax Power Limited, 2018). This is because the habitats within Drax Power Station Site have by and large not changed significantly since then and this has been reconfirmed through the updated PEA (document reference 6.3.8.1) (as per CIEEM's guidance on the lifespan of ecological reports and surveys (CIEEM, 2019)). The surveys undertaken specifically for the Proposed Scheme (great crested newts, wintering birds, and terrestrial invertebrates) were carried out as a result of habitats becoming more suitable for these species in localised areas within and in proximity to Drax Power Station Site, or due to differences in the Order Limits for the Proposed Scheme relative to the Drax Repower scheme'*. The Applicant considers that the scope of surveys completed for protected and notable species is robust, proportionate and proportionate to the specific characteristics of the Proposed Scheme. In relation to Point B, the Proposed Scheme includes a series of measures to avoid and minimise the risk of water-borne pollution and sediment release, during both the construction/decommissioning and operational phases of development. NE have agreed that subject to securing of the necessary measures via the DCO, they do not consider water-borne sediment or chemical releases would lead to adverse effects on integrity of European Sites/SSSI including in relation to functionally-linked land used by otters that may form part of the River Derwent SAC populations. No concerns have been raised in relation to sediment and chemical water-borne pollution risk by the NYCC Ecology Team. The Environment Agency also agrees

		with the measures in the REAC (REP-015) and considers that they will be sufficient to mitigate the impacts of the Proposed Scheme.
5.12 (Section 3)	We are aware Drax has no intentions to expand wood sourcing from within the UK. This makes them reliant upon importing wood pellets to burn and continuing reliance upon imported fuel. This is contrary to government policy which aims to increase domestic supply of fuel due to issues of fuel security.	It is noted that the Proposed Scheme does not itself ‘rely’ on fuel from abroad as the Proposed Scheme does not seek to consent biomass operation – it seeks to consent the application of CCS to that operation. In any event, the Applicant sources biomass from trusted, democratic countries with strict forestry regulations and which the UK has strong relationships with. In addition, biomass pellets are typically purchased on long-term contracts with fixed prices. NPS EN-1 recognises that there are benefits of having a diverse mix of all types of power generation and hence this reduces the dependence on any one type of fuel or power ensuring greater security of supply.
5.13 (Submission Pages 1 to 2)	GHG emissions ● Due to the energy penalty, installing carbon capture and storage at Drax power station will significantly reduce electricity output. Based on Drax’s own figures, this will remove 371 MW net electrical capacity from the National Grid. ● Biomass electricity is classified as renewable and low carbon by the UK government. Biofuelwatch strongly disagrees with this, however, we are focussing here on whether the proposal is in line with government energy and planning policies. ● While the amount of wood burned by Drax would remain unchanged, this project would leave a 371 MW gap in UK electricity generation. There is a realistic prospect that the loss of 371 MW capacity in what is classed as renewable electricity generation will be compensated for by increased fossil fuel burning. ● This would contradict the UK’s climate change obligations and also the requirements under the Climate Change Act to reduce carbon emissions. ● Non-biogenic emissions: supply chain emissions will not be ‘neutralised’ by the proposed carbon capture process and due to the energy penalty (or reduction in energy output due to the adding of CCS) the carbon footprint for supply chain emissions increases per MWh. Energy Penalty points The effect of the proposed scheme on the output capacity of the power station Significant loss of net electric capacity contrary to government energy policy ● According to Drax’s Environmental Statement Volume 3, Appendix 15.2, the carbon capture development will reduce the combined net capacity of the two biomass units to 931 MW, i.e. 465.6 MW per unit. ● According to Drax’s website (tinyurl.com/nbvdr4zh), the current biomass capacity is 2.6 GW across four units, i.e. 650 MW per unit.	The ‘energy penalty’ of operating a Carbon Capture system is acknowledged in the NPS EN-1: ‘*the process of capturing, transporting and storing carbon dioxide also means that more fuel is used in producing a given amount of electricity than would be the case without CCS*.’ Nevertheless, the use of CCS is an aim of Government policy. The Applicant does not agree that it is a ‘realistic prospect’ that loss of capacity will be compensated for by increased fossil fuel burning, given the net zero pathway of the UK, however, in any event this is not relevant to the ExA or Secretary of State – that will be something for National Grid to decide, and no assumption can be made as to where that capacity will come from. The energy penalty is the amount of energy utilised to operate the additional CCS infrastructure and if CCS is not operated then the units will still be able to generate at their current output without capturing carbon. The Proposed Scheme would allow the Applicant to deliver flexible electricity generation as it does currently, and to offer carbon capture in addition to electricity generation dependant on UK needs. As set out in the Needs and Benefit Statement, it responds to Government policy, including in both the existing and proposed National Policy Statements. The Proposed Scheme delivers two vital products which are electricity generation and carbon dioxide removal, as opposed to a single product which Drax Power Station currently delivers. Chapter 15 of the Environmental Statement (Document Reference APP-051) confirms at Paragraph 15.11.15 that: *‘With the Proposed Scheme, operational emissions are anticipated to total minus 7,975,620* tCO_2e */ year of. However, certain assessed GHG emissions, such as supply chain emissions, are likely to reduce over time (such as transport as presented in Plate 15.1) therefore increasing the carbon savings achieved by the Proposed Scheme.’*

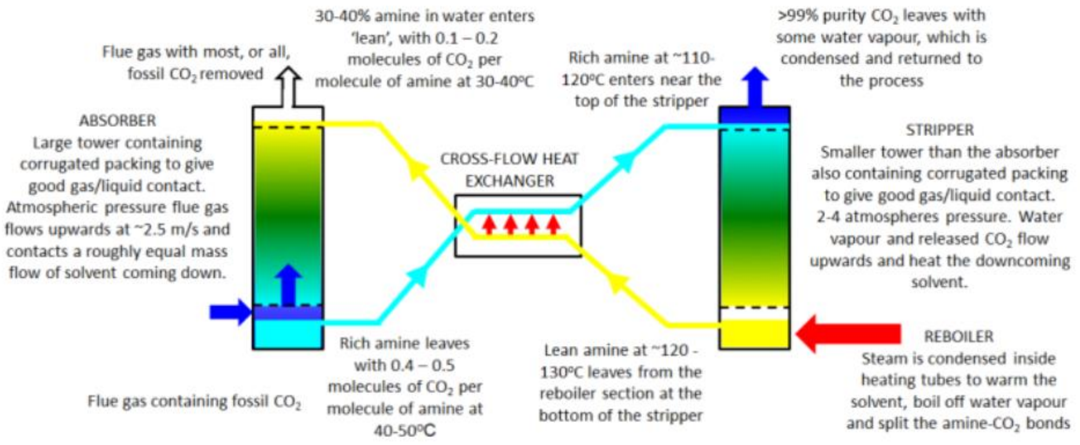
	● This means that the proposed development will reduce the biomass units' net capacity by 28.4%, and overall electric capacity by 369 MW. This reduction is due to the energy required to capture and compress CO2 . We believe that this reduction in electric capacity is not compatible with: ● Overarching National Policy Statement on Energy (EN-1), 2011: As highlighted in paragraph 3.3.10 in particular, "*as part of the UK's need to diversify and decarbonise electricity generation, the Government is committed to increasing dramatically the amount of renewable generation capacity*." ● Draft Overarching National Policy Statement for Energy (EN-1), 2021: Similar to the current EN-1, this draft policy emphasises the "*need to dramatically increase the volume of energy supplied from low carbon sources and reduce the amount provided by fossil fuels*" (2.3.4). ● Drax's application, on the other hand, will, if approved, allow for a reduction in renewable generation capacity by 369 MW. ● Evidence that efficiency and net output could be reduced further comes from the world's only current commercial-scale carbon capture project at a coal unit, Boundary Dam in Canada. There, 30-31% of the unit's energy is required to capture and compress CO2 (tinyurl.com/5p7wdpku).	The Applicant does not accept that this reduction in Greenhouse Gases is incompatible with the National Policy Statements even where there is an energy 'penalty' of what goes to the grid. As Government policy recognises (including in current and emerging EN-1), the UK needs to <u>both</u> urgently de-carbonise <u>and</u> increase renewable generation capacity.
5.14 (Submission Page 2)	Support for CCS from biomass in the draft EN-1 National Policy Statement is based on ensuring security of supply & Drax's proposed reduction in electricity does not comply with this policy ● The Draft EN-1 does support carbon capture and storage, including from bioenergy (3.3.34). ● However, this support is qualified in paragraph 3.3.43: "*All the generating technologies mentioned above are urgently needed to meet the Government's energy objectives by: • providing security of supply (by avoiding concentration risk and not relying on one fuel or generation type*)". ● In our view, Drax's proposed significant reduction in biomass electricity is not compatible with this policy.	The compatibility of the Proposed Scheme with the policies of the draft National Policy Statements is set out in Appendix C of the Planning Statement (Document Reference APP-032) that accompanies this DCO Application. The Applicant does not accept that the use of CCS is incompatible with the policies of the draft EN-1. Part 3.5 of the draft EN1 is entitled: '*the need for new nationally significant carbon capture and storage infrastructure*', with Paragraph 3.5. confirming that: '*New carbon capture and storage infrastructure will be needed to ensure the transition to a net zero economy. The Committee on Climate Change Committee states CCS is a necessity not an option.'*
The effectiveness and reliability of the proposed technology for the capture of CO_2		
5.15 (Submission Pages 2 to 4)	At the hearing, the ExA asked the applicant if it could provide evidence of the carbon capture rate it claims it will achieve being demonstrated anywhere else in the world. We provided oral evidence regarding the longest-running and world's only operating commercial carbon capture facility at a coal-fired power plant which is Boundary Dam, run by Sask Power. The figures we provided were that that facility's carbon capture rate in 2021 was less than 37% of the official target of 90%. We provide more information here in the hope that this will further assist the ExA: In this more recent article [redacted] it states that the world's sole carbon capture project on a large power plant (again Boundary Dam) caught 43 percent fewer metric tons of carbon dioxide in 2021 compared with the year before, according to new data from the	According to the IEA there are 35 large scale CCUS facilities operating globally and they are capturing around 45Mt of CO_2 per annum. In 2030, based on planned projects, the number of CCUS plant will increase to around 200 which would result in 230Mt of captured CO_2. The need for this type of Greenhouse Gas Removal Technology (GGR) is clear and is supported by the CCCs 6th Carbon budget which identified 'BECCS Power' as one of the technologies necessary to meet Government targets. The Applicant has successfully tested the solvent which will be utilised within the BECCS Proposed Scheme on the expected flue gas composition generated by the

	Canadian utility company operating the project. This was said to be because a compressor failed. According to this article [redacted], SaskPower has apparently downsized its ambitions for Boundary Dam 3. Instead of capturing 90 percent of the CO2 it produces, which was the original goal for Boundary Dam 3, the company is now settling for a target of only 65 percent. This paper [redacted] published in November 2018 is less recent but examines Boundary Dam in more depth: Holy Grail of Carbon Capture Continues to Elude Coal Industry, David Schlissel, Director of Resource Planning Analysis Dennis Wamsted, Associate Editor Institute for Energy Economics and Financial Analysis. To assist the ExA we have copied a particularly relevant section here: SaskPower, the state-owned utility in Saskatchewan, has spent C$1.5 billion to retrofit Unit 3 at its Boundary Dam generation station with CCS technology. Of that total, 50%, or roughly C$750 million, went to CO2 capture equipment and C$440 million was spent to upgrade and modernise the ageing plant so that it would be able to run long enough to recover the carbon capture investments. SaskPower spent an additional C$293 million on related emission controls and efficiency improvements. In its 2014 annual report, the company touted the project as "*the first commercial-scale post-combustion project of its kind at a coal-fired power station*" and one that would be able to capture 1 million metric tons of CO2 annually—roughly 90% of the plant's CO2 output. Much of the captured CO2 was to be used in enhanced oil recovery efforts (EOR) at an oil field in southern Saskatchewan. The rest was to be stored underground. Given its first-of-a-kind status, it is no surprise that little has gone well. The project was over budget and behind schedule when it began operating in October 2014. Its overall CO2 capture rate during its first year of operation hovered at about 40%, a dismal performance, as David Jobe, SaskPower's director of carbon capture and chemical services, acknowledged in an interview with The Chemical Engineer in May of this year. "*Let's just say that out of the box, the plant didn't work as designed*," Jobe said. Nor is the plant working now as promised. Boundary Dam has never hit its CO2 sequestration goal of 1 million metric tons a year, having captured a total of only 2.2 million metric tons in the four years since its carbon capture system came online. Meanwhile, the utility has had to pay millions of dollars for temporary units that boost the capacity of the system's thermal reclaimer, the unit that purifies the amine solution used to strip CO2 and sulphur dioxide from the plant's flue gases. The amine solution has been degrading faster than anticipated, overwhelming the plant's installed reclaimer and forcing the utility to bring in mobile units. The fix has worked, but according to a report prepared for SaskPower, it is "*not economically sustainable*." The amount of CO2 captured at Boundary Dam is not likely to increase anytime soon either, as the entire plant has been online only approximately 50% of the time from August 2015 to August 2018.	combustion of biomass. This demonstrated that the solvent was capable of capturing CO_2 from flue gas generated from biomass combustion. A recent paper cited as follows: Gibbins, J., Lucquiaud, M. (2022) BAT Review for New-Build and Retrofit Post-Combustion Carbon Dioxide Capture Using Amine-Based Technologies for Power and CHP Plants Fuelled by Gas and Biomass and for Post-Combustion Capture Using Amine-Based and Hot Potassium Carbonate Technologies on EfW Plants as Emerging Technologies under the IED for the UK, Ver.2.0, December 2022, provides the following statement on CO_2 capture rates; '*PCC can be applied to remove up to around 95% of the* CO_2 *from any flue gas, so, given that net-zero Green House Gas (GHG) emissions must be achieved, it has widespread applications in a range of industries as well as in power plants*.' Section 4.5 of the paper focuses on the CO_2 capture level and provides the following statement; '*instantaneous capture levels of 95% and above are routinely achievable, and clearly desirable given the UK's target of net zero emissions.*' It is worth noting that this paper, which is included as Appendix 2, was originally published in December 2022.

	Capturing the CO2 from Boundary Dam Unit 3 also is very expensive, averaging about C$60 per metric ton (US$42 per short ton), doubling the overall cost of producing power at the Plant. SaskPower said this summer that its costly experience with Unit 3 prompted it to decide against retrofitting two other units at Boundary Dam with carbon capture technology. Instead, the two 1970s-era units will be shuttered, perhaps as early as next year.	
Overall GHG emissions		
5.16 (Submission Page 4)	These factors clearly need to be considered together: the energy penalty and likely offset by baseload supply from other generators - in all likelihood coming from fossil gas; supply chain emissions; the likely carbon capture rate; and the question which was raised by others in the hearing of the carbon neutrality of woody biomass due to the carbon payback period being too long for any relevance in meeting our current climate commitments. For these reasons we do not believe the application complies with either the spirit or the letter of EN-1 and EN-3.	As discussed above: • no assumptions can be made about the off-set of supply to the National Grid from the installation of the CCS; • supply chain emissions have been captured in the ES and large scale negative carbon emissions are still recorded; • the Applicant will be incentivised and regulated to maximise capture rate; • CCS is recognised by policy to be necessary as well as new renewable energy; and • the sustainability of biomass is not relevant, subject to separate regulation, and is in any event recognised as a renewable resource in EN1. As such for all these reasons, it is considered that it cannot be possible to say that the application is not compliant with EN-1 or EN-3. .
Submission Document: – Preliminary Meeting		
5.17 (Submission Page 3)	A number of government policies which are pertinent to this planning application are currently under review. We believe that the examination timetable of this application should be delayed until they have been published in order to assess the application against the most up to date policy framework. 1) The Overarching National Policy Statements for Energy are under review The Rule 6 letter states that the Overarching National Policy Statement for Energy (EN-1) and the National Policy Statement for Renewable Energy Infrastructure (EN-3) apply to decision-making relating to this application. However, in order to achieve the Government's long-term energy policy to reach net zero emissions by 2050, the Government determined that its existing National Policy Statements for Energy required to be updated following the publication of the Energy White Paper, 'Powering our net zero future' in December 2020. These policy statements, including EN-1 and EN-3, are still under review. We request that the examination timetable be delayed until these updated policy statements have been published.	The Planning Statement assesses the Proposed Scheme against the emerging EN-1 and EN-3 and agrees that they should be considered as important and relevant considerations. As such, it is appropriate that the Examination has commenced with these policies under consideration.

5.18 (Submission Page 3)	2) The application refers to the Government's Net Zero Strategy which was ruled to be unlawful by the High Court The Rule 6 letter states that the Planning Inspectors will consider: "*The applicability of the Net Zero Strategy in assessing the need for the Proposed Development*." However, the Government's Net-Zero Strategy – 'Build Back Greener', which was published in October 2021, was ruled to be unlawful by the High Court last year. ([redacted]) The High Court judgement stated that the strategy does not meet the Government's obligations under the Climate Change Act on how to meet the carbon budgets. The net zero strategy is due to be revised by the Government before the end of March 2023 to show how the legally-binding climate targets will be met. [redacted] We believe that the examination of the proposed development should be considered with reference to the revised Net Zero Strategy.	In the case of R (on the application of Friends of the Earth Ltd) v BEIS (2022), Holgate J concluded that the NZS breached the detail and reporting requirements of ss. 13-14 of the Climate Change Act 2008 ("**CCA 2008**"), insofar as the NZS itself lacked sufficient explanation of how the government's plans would achieve CB6, and BEIS' report on NZS did not account for a carbon shortfall of 5% in the NZS. The ruling was therefore that the NZS was unlawful as currently drafted – however, rather than quashing the NZS altogether (not least because the claimants in the case did not seek for it to be quashed), the court at the end of its judgment ordered BEIS to instead publish an updated report by the end of March 2023 under s.14 of the CCA 2008 that would set out an improved NZS. Therefore, given that the NZS remains in place and will still be in place (albeit via an improved version of the strategy) at the time of determination, the Applicant considers that it remains applicable in assessing the need for the Proposed Development.
5.19 (Submission Page 3)	3) The Government's biomass strategy has not yet been published Moreover, the biomass strategy, which was expected in autumn 2022, has not yet been published. This strategy will presumably inform policy and the role of biomass in UK energy policy going forward, making it highly pertinent to the issue of BECCS from woody biomass.	The use of biomass is outside of the scope of this DCO application, which relates to the retrofitting of CCS technology. The role of BECCS is clearly set out in various government policy documents, including the biomass policy statement. Whilst the Biomass Strategy may be published in due course, there is sufficient policy support at the current time for BECCS and for biomass.

APPENDIX 1



The basic principles of a post-combustion capture system: Numbers shown are typical ranges for monoethanolamine (MEA) but they will vary between different amines/amine mixtures and depend on how the PCC system is designed and operated

The basic principles of a post-combustion capture system: Numbers shown are typical ranges for monoethanolamine (MEA) but they will vary between different amines/amine mixtures and depend on how the PCC system is designed and operated

How amine post-combustion capture can trap 100% of fossil CO2 before it enters the atmosphere

Jon Gibbins

Professor of Carbon Capture and Storage at University of Sheffield

23 articles

Following

December 20, 2022

‘Net zero’ is a frequently used phrase these days but what it means and how it is delivered is perhaps not as well understood as it should be. Of course, the meaning is what it says on the tin – the net consequence for the climate of a net zero emissions activity must be no additional warming impacts due to greenhouse gas emissions. All CO2 emissions are either captured at source or recaptured from the atmosphere and permanently stored, plus any associated emissions of other greenhouse gases, such as methane from the natural gas supply chain, are compensated for by additional removals of atmospheric CO2.

When the alternative to capturing CO2 at source is the removal of an equal amount of CO2 from the atmosphere using Direct Air Carbon Capture and Storage (DACCS) then point-source CCS project developers will obviously start to look hard at every bit of fossil CO2 they emit. For at least two decades the conventional wisdom has been – largely because it was a 'standard' baseline used in studies comparing costs – that capturing 90% of the CO2 in a flue gas stream was both good enough and the best that could be done. Based on more recent experience, this generally-accepted limit has been pushed up to 95% capture, but this is obviously still short of net zero. For 100% capture of fuel carbon, with just the CO2 that came in with the combustion air leaving at the top of the absorber, around 99% capture is needed for a gas turbine flue gas containing ~4% CO2 and up to ~ 99.7% capture for flue gases from biomass and coal.

One of the reasons why lower capture levels have seemed acceptable, even though some fossil CO2 is still emitted, is that the cost of capturing the last few percent with the widely applied amine post-combustion capture (PCC) technology has been estimated to be extremely expensive in studies that used inappropriate design conditions. More recently there have been some suggestions that net zero PCC is feasible, but that only special technologies can achieve this. However, in an ongoing programme of work to improve and open up PCC by the UK CCS Research Centre at the University of Sheffield and its Translational Energy Research Centre, we have been able to demystify the process of achieving high capture levels and suggest how it can be done with the industry-standard monoethanolamine (MEA) solvent. Similar principles probably apply with at least some other amines, provided they can be reclaimed (i.e. be kept very clean) effectively.

The key to achieving high capture levels is to contact very 'lean' solvent, with only around 1 molecule of CO2 for every 10 MEA molecules (0.1 loading), with the flue gas in the absorber. Such lean solvent is able to draw down the exiting flue gas CO2 concentration to the ~400 ppm required to match that of the incoming air. Starting with a lean solvent also means that it continues to attract CO2 strongly all the way down the absorber, avoiding CO2 transfer virtually stopping as temperatures rise in the descending solvent due to the heat generated when CO2 reacts with it. This makes the best use of the contact area provided by the internal corrugated packing, even without looping the solvent out and in partway down the absorber for 'intercooling' with cold water, and ensures that the rich solvent leaving at the base of the absorber is loaded close to the maximum of 1 molecule of CO2 for every 2 MEA molecules (0.5 loading). It was thought that obtaining such lean solvent would require impossibly large amounts of energy but, as a recent paper with Stavros Michailos shows, this need not be the case if slightly higher pressures and temperatures are used in the reboiler and stripper where the CO2 is removed to regenerate the solvent (and also provided that the rich loading is kept high). Because a leaner solvent is more thermally stable these higher temperatures may not increase degradation rates significantly, provided the solvent can be kept very clean by thermal reclaiming (distilling pure solvent out of a mix with corrosion and degradation products) to avoid catalytic effects.

So, 100% fossil CO2 capture using amine PCC is within reach, without excessive energy use or equipment sizing, but there is the practical consideration that the PCC plant absorber has to operate at its optimum design point all of the time to achieve it. There simply is not scope to run with significantly lower capture levels when operational or ambient changes occur and catch up later by running with higher capture levels, as would be the case with a lower target. Fortunately this can readily be addressed by the 'agricultural engineering' (i.e. unsophisticated and robust) approach of using lean and rich solvent storage, to ensure that the absorber always receives the optimum flow of solvent at the required lean loading. With this arrangement the stripper can catch up later if it is not immediately ready to provide the solvent that the absorber requires. But supplying too little, or insufficiently lean, solvent to the absorber is not the only problem; using too much solvent will capture slightly higher levels of CO2 in the flue gas but will also give a lower rich loading and hence higher reboiler energy requirement. So solvent storage is essential not only for start/stop situations, when heating steam for the reboiler may not be available, but also for continuous real-time control of the solvent flow to the absorber to deliver simultaneously both the optimum rich loading and a high capture level.

However, not all emission sources need to, or should, have 100% capture fitted to achieve net zero, even where technically feasible. For amine PCC plants it should be possible – with modest design changes – to achieve 100% fossil capture and in the future it may also be possible to add separate direct air capture facilities using the amine to get >100% capture. So it makes sense to use, or at least not to preclude the use of, the full capabilities of PCC units that are built. But, for transport applications, small distributed sources and for any size plant that only operates infrequently, capturing CO2 at source and transporting it to permanent storage, even if technically feasible, can be more expensive than DACCS. As noted at the start, the 'net' in net zero just means that any and all fossil CO2 emissions to atmosphere have to be recaptured by DACCS. But, once DACCS is deployed at scale and therefore defines the true cost of CO2 emissions, expect a rapid increase in PCC performance!

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APPENDIX 2

BAT Review for New-Build and Retrofit Post-Combustion Carbon Dioxide Capture Using Amine-Based Technologies for Power and CHP Plants Fuelled by Gas and Biomass and for Post-Combustion Capture Using Amine-Based and Hot Potassium Carbonate Technologies on EfW Plants as Emerging Technologies under the IED for the UK

Ver.2.0, December 2022 (including EfW)

Prepared by Jon Gibbins and Mathieu Lucquiaud

University of Sheffield

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Contents

Glossary

1-MPZ	1-Methyl Piperazine
2-MPZ	2-Methyl Piperazine
Abs	Absolute (for pressure)
AD	Anaerobic Digester
AFS	Advanced Flash Stripper
AMP	Aminomethyl Propanol
bara	Bars Absolute (absolute pressure in bars, i.e. units of 10^5 Pa)
barg	Bars gauge, pressure in relation to atmospheric pressure
BAT	Best Available Technology
BD3	Boundary Dam power plant, Unit 3; the first power plant fitted with PCC
BEIS	Department for Business, Energy & Industrial Strategy
BECCS	Biomass Energy with Carbon Capture and Storage
BPT	Back Pressure Turbine
BREF LCP	The BAT Reference Document (BREF) for Large Combustion Plants (BREF LCP, 2017)
CCGT	Combined Cycle Gas Turbine power plant
CCR	Carbon Capture Ready – the installation was permitted without CCS but with provisions, including location, to facilitate the retrofit of CCS in the future
CCS	Carbon (dioxide) Capture and Storage
CCSA	Carbon Capture and Storage Association [redacted]
CCU	Carbon (dioxide) Capture and Utilisation, not involving permanent storage of the CO_2
CCUS	Carbon (dioxide) Capture, Utilisation and Storage (overwhelmingly EOR at present)
CDR	Carbon Dioxide Removal from the air
CEGB	Central Electricity Generating Board
CFB	Circulating Fluidised Bed boiler/steam power plant
CHP	Combined Heat and Power plant
CO_2	Carbon dioxide
COP	Conference of the Parties, see [redacted]
COPx	The Coefficient Of Performance for (steam) e**x**traction; ratio of heat supplied to a PCC plant by steam extracted from a steam cycle to the reduction in work (electricity) output from that steam cycle
DAP	1,2-Diaminopropane
DCC	Direct Contact Cooler; brings the flue gas into contact with water upstream of the absorber, possibly with added caustic to neutralise acid gases
DECC	Department of Energy & Climate Change, became part of Department for Business, Energy & Industrial Strategy in July 2016
DEA	Diethanolamine
DGA	Di-Glycolamine
DIPA	Diisopropanolamine
DORA	Dissolved Oxygen Removal Apparatus (from the rich solvent)
EAL	Environmental Assessment Level
EDA	Ethylene Diamine

EfW	Energy from Waste
EGR	Exhaust Gas Recirculation
ELV	Emission Limit Value
EOP	Electricity Output Penalty
EOR	Enhanced Oil Recovery
EPSRC	Engineering and Physical Sciences Research Council
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulphurisation plant
FWH	Feed Water Heater (in a steam boiler)
GE	General Electric
GHG	Greenhouse Gas
GT	Gas Turbine
HAZID	Hazard Identification study
HAZOP	Hazard and Operability study
HHV	Higher Heating Value (also known as gross calorific value)
HP	High Pressure, the highest pressure cylinder in a steam turbine
HRSG	Heat Recovery Steam Generator (sometimes pronounced “hersig”)
HSS	Heat Stable Salts
HT	Heat Transfer
ICE	Internal Combustion Engine
IED	The Industrial Emissions Directive
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate Pressure, the intermediate pressure cylinder in a steam turbine
IRCC	Integrated Reforming Combined Cycle
IX	Ion exchange reclaimer unit
LC MS QQQ	Liquid Chromatography with triple-Quadrapole Mass Spectrometry
LDAR	Leak Detection And Repair
LHV	Lower Heating Value (also known as net calorific value)
LP	Low Pressure, the lowest pressure cylinder in a steam turbine
MAPA	3-Methylamino Propylamine
MCERTS	The Environment Agency's Monitoring Certification Scheme
MDEA	Methyl Diethanolamine
MEA	Monoethanolamine
MHI	Mitsubishi Heavy Industries
MIT	Massachusetts Institute of Technology
MMEA	Monomethylethanolamine
MSG	Minimum Stable Generation
MTPA	Megatonnes (of CO_2 in the context of this report) *Per Annum*
MTU	Mobile Test Unit
NCCC	National Carbon Capture Center [redacted]
NETL	National Energy Technology Laboratory [redacted]
NG	Natural Gas

NGCC	Natural Gas Combined Cycle
NH_3	Ammonia
NOx	Oxides of Nitrogen
NPC	National Petroleum Council [redacted]
O_2	Oxygen
OEM	Original Equipment Manufacturer
Pa	Pascal, unit of pressure, $1N/m^2$
PCC	Post-combustion (CO_2) capture
PIPA	Piperazine (see also PZ)
ppm	parts per million
ppmv, ppbv	parts per million by volume; parts per billion by volume
PTR-TOF-MS	Proton-transfer-reaction time-of-flight mass-spectrometer. Used to measure VOCs. Similarly, QMS = quadrupole-mass-spectrometer
PZ	Piperazine (see also PIPA)
RAMO	Reliability, Availability, Maintainability, Operability
RH	Reheat(er) (in a steam boiler)
SCPC	Supercritical Pulverised Coal power plant
SCR	Selective Catalytic Reduction (of NOx)
SEPA	Scottish Environment Protection Agency
SO_2	Sulphur dioxide
SO_3	Sulphur trioxide (with water, forms sulphuric acid)
SOx	Oxides of Sulphur (unspecified mix of SO_2 and SO_3)
ST	Steam Turbine
STG	Steam Turbine Generator
T&S	(CO_2) Transport and Storage
TCM	Technology Centre Mongstad [redacted]
TERC	Translational Energy Research Centre, University of Sheffield [redacted]
TONO	Total nitrosamines
tpd	tonnes per day
TPY	Tonnes Per Year
TRU	Thermal Reclaimer Unit
UNFCCC	United Nations Framework Convention on Climate Change
VLE	Vapour Liquid Equilibrium
VOC	Volatile Organic Compounds
XFHE	The cross-Flow Heat Exchanger, transferring heat from the hot lean solvent leaving the stripper to the cooler rich solvent coming from the absorber

1. Introduction

1.1 *Document purpose and scope*

This document addresses Best Available Techniques (BAT) under Article 14.6 of the Industrial Emissions Directive (see Annex 1), in the context of which post-combustion carbon (dioxide) capture (PCC) is an 'Emerging Technique' for which there is no relevant existing BAT reference document.

PCC plants will be new facilities deployed to enable the UK to meet its Net Zero 2050 target. These installations will be permitted under the Environmental Permitting Regulations (England and Wales) 2016 and the Pollution and the Prevention and Control (Scotland) Regulations 2012. PCC will be a Part A (1) 6.10 activity in its own right or a Directly Associated Activity to a combustion activity installation. Permits include all plant within the installation boundary, including carbon dioxide (CO_2) compression.

The scope for the second issue of this document is limited to:

a) power, and combined heat and power (CHP), plants where the fuel is gas or biomass, using amine solvent PCC - these PCC installations may be on new-build plants or retrofitted to existing combustion plants, with retrofits being either to plants that were permitted as carbon capture ready (CCR) or older units there were not;

b) energy from waste (EfW) plants.

BAT for PCC on flue gases from other applications and for additional CCS technologies will be developed in the future.

This document will briefly review a range of PCC technologies, but BAT discussions will focus on those using amine solvents, since these are immediately available for deployment and are also the only class of solvents for which significant information on such large-scale applications is available. In addition, for EfW applications, the use of post-combustion capture from pressurised flue gas by hot potassium carbonate will be considered (separately, in Section 9).

PCC on power plants is an emerging technology with very few large-scale (~ 1 $MtCO_2$/yr and above) examples in service (one operating, one currently shut down), plus extensive under-reporting of a wide range of aspects of technology configuration and performance because of stated commercial confidentiality associated with proprietary solvents, the literature does not offer reliable examples of what 'Best Available Technology' performance is or will be. At the time of writing, there is also only one small-scale example of post-combustion capture using amine PCC in operation on an EfW plant. In the absence of sufficient information from multiple successful technology implementations that would allow best performance metrics to be estimated, this review has therefore, in a number of areas, highlighted where practitioners have considered that things either went well or could have been improved. Discussions of these areas for improvement are important, since they serve to suggest approaches that may not be BAT and which would therefore need careful consideration before being included in the UK CCS deployment programme. Experience so far has shown that BAT should be technology that is based on evidence from practical experience, with some unexpected outcomes being observed from that practical experience in projects to date.

It is also obvious that many of the design features that will be needed on PCC installations will not have been demonstrated in service, because they were not previously needed in the few PCC projects that have been developed in detail so far. Actual PCC power plant installations to date have been on coal plants designed for baseload operation and there is one EfW PCC plant; other PCC applications have been in the process industries. But where appropriate PCC design approaches can be based on established engineering principles, their use can clearly be considered. There is also scope to further support and de-risk appropriate UK PCC designs through realistic piloting.

This BAT Review has been the subject of extensive consultation with the UK regulators, and with industry CCS practitioners through the kind support of the CCSA and other organisations (see Annex 4). All contents are, however, the responsibility of the authors. As CCS is currently a fast-moving field, it is also inevitable, and welcome, that further material will become available that is relevant to the contents of this report. Please contact info@ukccsrc.ac.uk with any suggestions or comments.

1.2 Technology introduction

Post-combustion capture (PCC) of CO_2 from the products of fuel combustion in air (also known as 'flue gases') using amines has been in use since the 1930s (Bottoms, 1930), but so far almost exclusively for the separation of CO_2 for use in beverages, chemical production and Enhanced Oil Recovery (EOR). Only in this century has it received significant attention for capturing CO_2 for permanent storage to avoid CO_2 emissions to atmosphere, with the 2005 Gleneagles Conference (G8, 2005) being a landmark in the recognition of the role of CCS in tackling climate change.

Amine removal of acid gases in natural gas sweetening and other applications is, however, widely used and has many similarities, although differing in the nature of the gas streams being processed. For a discussion of solvents, corrosion and reclaiming in these types of applications see e.g. (Nielsen, 1997).

The basic principle of amine capture in power plants is to 'wash' the CO_2 out of the flue gases flowing upwards in a tall 'absorber' tower, where it is typically present in the range of 4-15% by volume, using a solution of amine in water that trickles down over extended-surface-area packing. The amine reacts with CO_2 at low temperatures ranging from 30 to 70°C and then releases it at high temperatures, so the CO_2 can be recovered in a pure form by heating the solvent up to around 120°C in a smaller 'stripper' tower, typically using low-pressure steam taken from the power plant after it has already done most of the work it can in generating electricity, after which the solvent is cooled and recycled back to the top of the absorber. The CO_2 released in the stripper is typically at 1-3 atmospheres in pressure and has to be compressed to 100-200 atmospheres (possibly with the final compression stages remote from the power plant) and to be thoroughly dried to avoid pipeline corrosion before transportation to storage.

PCC can be applied to remove up to around 95%[1] of the CO_2 from any flue gas, so, given that net-zero Green House Gas (GHG) emissions must be achieved, it has widespread applications in a range of industries as well as in power plants. Prior to the Paris Agreement in 2015 (UNFCC, 2015) when this net-zero target developed, the main application envisaged for PCC was on coal power plants, and much of the global experience is for this application. PCC on biomass power plants can be expected to have many similarities to coal, but Combined Cycle Gas Turbine (CCGT) power plants have different steam cycles and produce larger volumes of flue gases per unit of CO_2 with lower CO_2 concentrations and higher O_2 concentration, the latter being known for causing oxidative solvent degradation. Thus, there is less closely relevant large-scale experience (~1MtCO_2/yr) for PCC applications on CCGT plants; however, the fuels used are inherently cleaner, and there is extensive experience of capture from natural-gas-derived steam reformer flue gases for urea production at large scale (e.g. MHI, 2020) and Fluor successfully ran a 330tCO_2/day unit on GT flue gas for 14 years (Fluor, 2008).

Amine solvent PCC is often considered to be less attractive than more novel CO_2 capture techniques, principally because it uses a lot of energy, in absolute terms, to regenerate the solvent. In practice, though, this energy is required at a temperature (e.g. 120°C) only a little above that of a domestic kettle and can therefore be produced by condensing steam that was going to be condensed anyway as part of the normal operation of a power or CHP plant, after being produced at much higher peak temperatures and pressures and being expanded to produce electricity in a steam turbine, with typically four or more times as much energy being supplied to the PCC plant as the electrical energy that is lost from the plant output (see Annex 3). PCC has therefore been assessed as competitive

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[1] See Section 4.5 for a detailed discussion of capture levels.

compared to other CO_2 capture options in theoretical studies, e.g. as shown in the comparison below from a study for BEIS (Wood, 2019), where PCC is assessed as giving the lowest levelised cost of electricity for each of the three fuels (natural gas, coal, biomass). PCC has also already been deployed commercially on coal power plants at >1MtCO_2/yr scale (Preston, 2015; Petra Nova, 2017) and has been assessed in detailed FEED studies as suitable for use on natural gas power plants (e.g. Bechtel, 2009; Peterhead, 2016). PCC may also be the preferred option for retrofitting CO_2 capture to existing plants, both those that were designed to be capture ready (DECC, 2009) and those that were not (e.g. Bechtel, 2018).

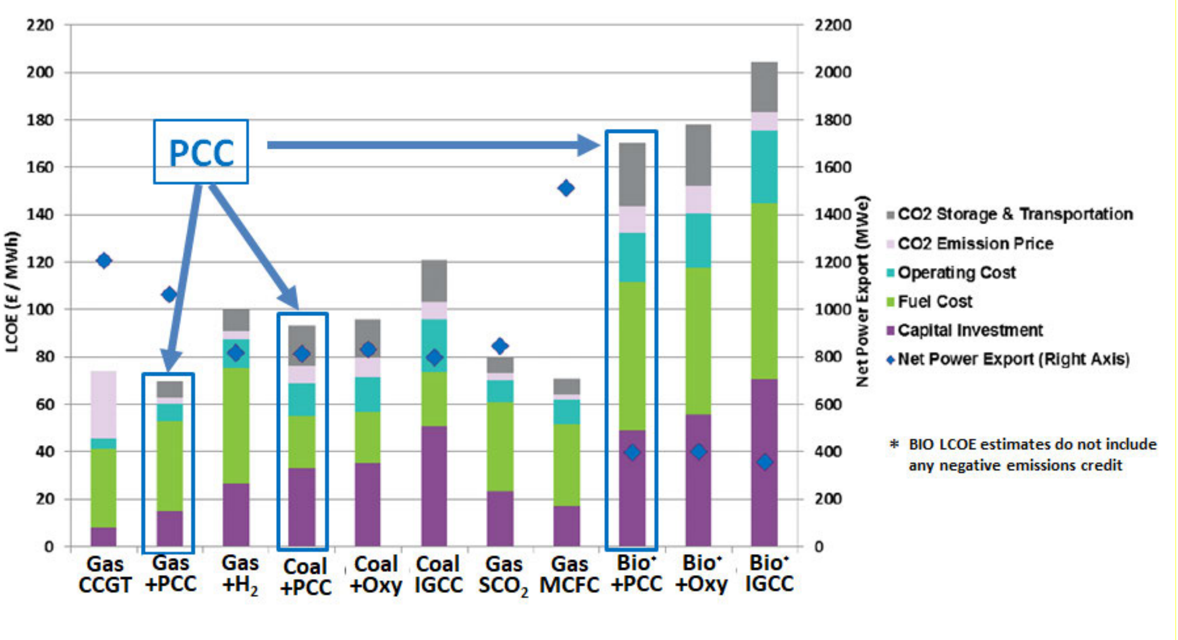

Fig 1.1 UK capture technology cost estimates for a range of fuels and technologies (Wood, 2019)
(reproduced with permission from Wood)

Brief technology key – see reference for further details:

Gas CCGT	Natural Gas CCGT without capture
Gas+PCC	Natural Gas CCGT with amine solvent PCC
Gas+H_2	Natural Gas IRCC with Pre-Combustion Carbon Capture
Coal+PCC	Coal SCPC with amine solvent PCC
Coal+Oxy	Coal SCPC with Oxy-Combustion Carbon Capture
Coal IGCC	Coal IGCC with Pre-Combustion Carbon Capture
Gas SCO_2	Oxy-fired Supercritical Gas Power Generation with Carbon Capture
Gas MCFC	Natural Gas CCGT with MCFC Power Generation and Carbon Capture
Bio+PCC	Biomass Fired CFB Boiler with amine solvent PCC
Bio+Oxy	Biomass Fired CFB Boiler with Oxy-Combustion Carbon Capture
Bio IGCC	Biomass IGCC with Pre-Combustion Carbon Capture

A detailed report and cost spreadsheet are also available for download using the link provided under (Wood, 2019) in the reference section. The absolute cost values quoted depend on the assumptions made in this study, for the power plant technology but also, and very importantly, for the assumed cost of capital, fuel and carbon emission prices and availability factors.

PCC on EfW plants has been pioneered at Duiven by AVR (Wassenaar, 2022), with a 12 tCO_2/hr plant in operation since 2019[2] and now by other sites in the NL (Twence, 2021).

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[2] [redacted]

2. Overview of power plants with post-combustion capture amine technology and BAT considerations

2.1 Introduction

This section gives an overview of whole power plant plus PCC systems as a framework for the detailed discussion of BAT issues in subsequent sections.

2.2 Overview of Gas and Biomass Power Plants and EfW Plants with PCC

2.2.1 Gas-fired Power Plants with PCC – general considerations

CCGT gas power or CHP plants have much higher thermal efficiencies than gas-fired boiler power plants using a steam cycle alone. Thus in the short term the UK is likely to deploy NG-fired CCGT with PCC and so this is the focus of this study. Proposals may also be made in the future for gas power plants using reciprocating engines[3], particularly if small in size or operated at low load factors, but this option will not be considered in this review.

The main fuel for UK CCGT+PCC power plants is expected to be natural gas, but waste gases (e.g. from refining or steel-making) and Anaerobic Digester (AD) gas may also be used. Being able to fire waste gases is important, not only to save cost but also to have the CO_2 from them captured; fuel switching to hydrogen without also having CCS applied to the combustion of the displaced carbon-based fuel obviously gives no net climate benefit. Use of AD gas would achieve net CO_2 removal from the air (a form of Bio-Energy with Carbon Capture and Storage (BECCS)), given the biogenic origin for the methane. If AD gas is fed directly to a CCS application, still containing CO_2 and other carbon-containing gases, rather than as a purified methane feed via the gas grid, there could be further carbon dioxide removal from the air (CDR).

A simple block flow diagram for one configuration of a CCGT+PCC power plant is shown in Fig 2.1 below. Variations on the configuration, which will be discussed in more detail in Sections 3-5, could include venting the exhaust gases directly from a stack on the carbon capture unit, supplying Low Pressure (LP) steam for solvent regeneration from a new CHP unit, also with CCS, and having a second, high pressure, CO_2 compression and drying stage remote from the power plant.

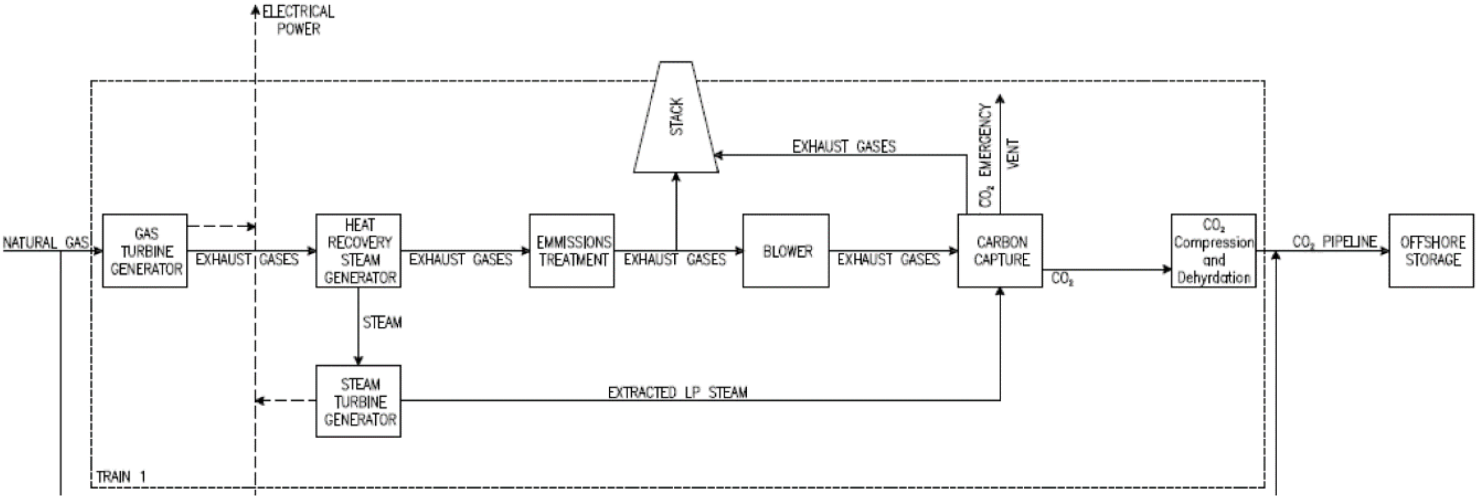

Fig 2.1 Simple Block Flow Diagram of a CCGT+PCC power plant scheme (SNC-LAVALIN, 2017)

This diagram shows exhaust gases from the carbon capture unit going to a common stack; they may also be vented from a stack on top of the absorber (not shown in this figure) in the carbon capture unit.

(These materials are taken from a project funded and commissioned by the ETI. Further details of the Project (including the parties who delivered the project) can be found at [redacted]

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[3] There is little experience of PCC use on gas engines, but anecdotal experience in the UK suggests that the scope for fine particulate matter in the engine exhaust (Ristovski, 2000) to nucleate amine aerosols in the absorber should be considered.

A more detailed flow diagram for the same plant, shown in Fig 2.2, gives a high-level representation of further details of the system components and how they are interconnected. It is worth noting that the use of a gas/gas cooler is linked to the decision to bring the absorber exhaust back to ground level to go into the main stack. Alternative means for exhaust heating would have been required if the exhaust were to be vented through a stack on top of the absorber. Two units for the critical purpose of removing impurities accumulating in the amine solvent, and amine solvent degradation products, are shown: a Thermal Reclaimer Unit (TRU) and an ion exchange unit (IX). The latter might not be required with some solvents. Not shown, however, is a key heat exchanger, the 'cross-flow heat exchanger' (XFHE) between the rich solvent coming from the absorber and the hot lean solvent leaving the stripper.

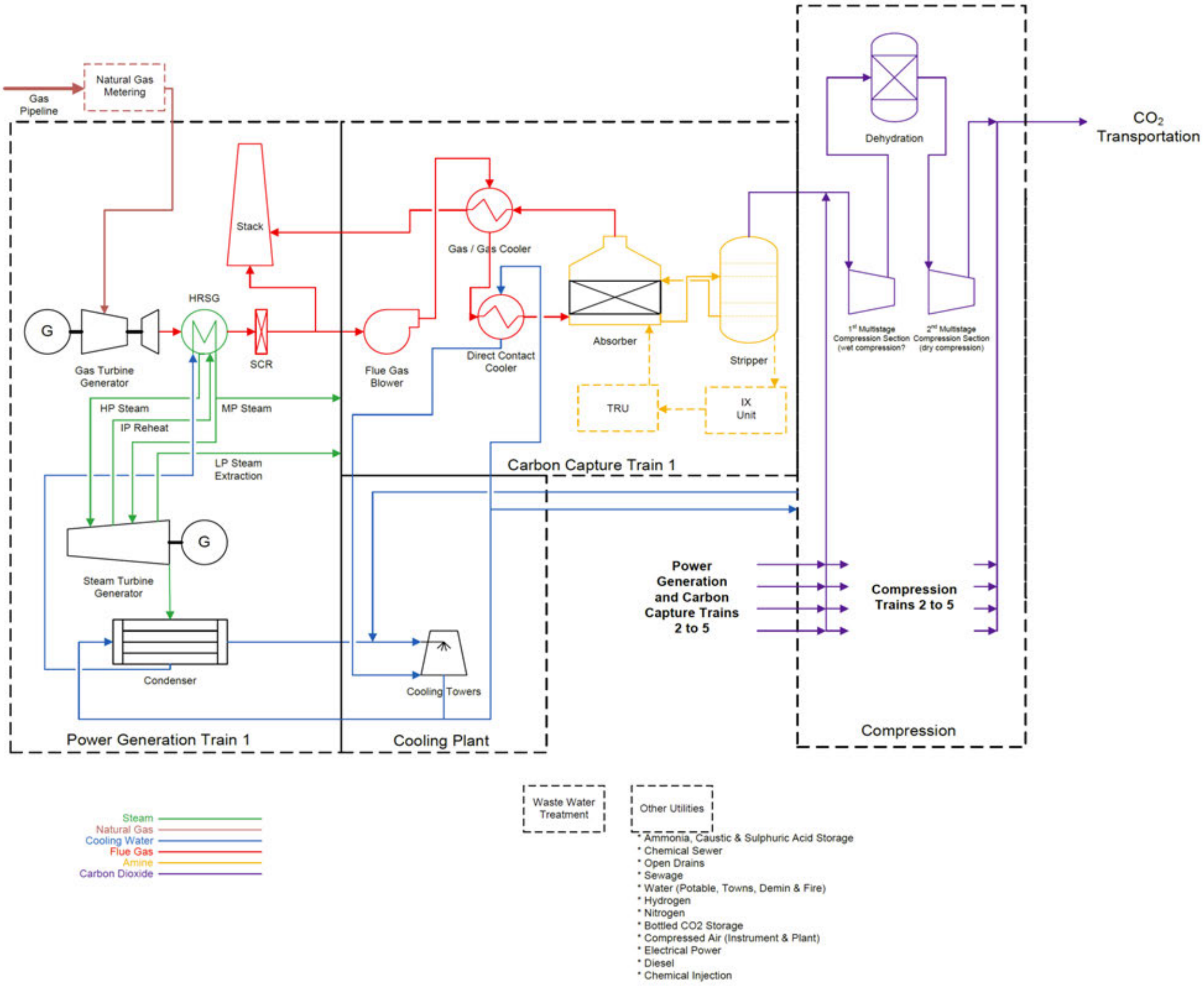

Fig 2.2 Flow diagram of a CCGT+PCC plant, taken from SNC-LAVALIN, 2017

(TRU = solvent Thermal Reclaiming Unit, IX = Ion-exchange solvent cleaning unit)

(These materials are taken from a project funded and commissioned by the ETI. Further details of the project (including the parties who delivered the project) can be found at [redacted] The document contains materials protected by copyright licensed under this ETI Open Licence, se [redacted]

A site with five parallel CCGT+PCC trains is pictured in Fig 2.3. A block of forced-draught cooling towers is in the foreground. The gas turbine of the nearest train is shown without its enclosure, to the left of which is the Heat Recovery Steam Generator (HRSG) and the obvious circular stack to vent the GT flue gases when the PCC unit is not in operation. Ductwork containing blowers and the gas/gas cooler connects to the prominent adjacent absorber/stripper units on the left. In this design concept the absorber vessel is rectangular in cross section and constructed from concrete, with a polymer liner and beds of conventional structured packing made from corrugated and perforated stainless steel sheets inside.

Fig 2.3 View of a five-train CCGT+PCC new-build power plant concept (SNC-LAVALIN, 2017)

The arrangement shown in Fig 2.3 is for a new-build 5 x 750 MW CCGT “clean power station” with a 90% capture rate, corresponding to 5 x 2 MTPA CO_2 being captured, processed and compressed for offshore storage (so 10 MTPA of CO_2 stored). A scaling of the Peterhead engineered solvent post combustion amine plant (Peterhead, 2016) based on publicly available information was used for the carbon capture units in this design.

The arrangement in Fig 2.3 can be contrasted with that shown in Fig 2.4 below. This FEED study, for a retrofit on a 420 MW CCGT using an open-art MEA design with 85% capture, corresponding to ~1 MTPA (Bechtel, 2009), uses cylindrical stainless steel vessels for the absorber (two units) and stripper (single smaller unit) in the upper centre of the image. With two absorber towers, these are small enough to be manufactured offsite and shipped in to save on-site construction costs. A less compact layout is shown here; the original power plant block was not optimised for PCC retrofit and the PCC plant had to be sited in an adjacent area separated by an access road. Partly because of the second long duct that would have been needed to get back to the main stack (far left, next to the HRSG, the GT enclosure is partly off-image), the warmed exhaust gas was vented from stacks on top of the absorbers. An updated version of this configuration has also been developed in a recent FEED study for a CCGT in Texas (Elliott, 2021).

While different in appearance, both of these PCC plants, and many other possible permutations of layout, vessel type, etc., are all undertaking the same basic functions and are capable of being BAT for the particular conditions applying to a given site and project.

Fig 2.4 View of a PCC retrofit concept for a single CCGT using two absorbers and a shared stripper
(Bechtel, 2009 – reproduced with permission from Bechtel)

2.2.2 Gas-fired Power Plants with PCC – new-build vs. retrofit

UK CCGT plants may have been built to be CO_2 capture-ready (CCR). The most significant consideration for implementing CCS is likely to be access to CO_2 transport and storage infrastructure, with CCR plants having been permitted on the basis that there is a suitable area of offshore deep geological storage available for the CO_2 which could be captured at the proposed power station and that it is technically feasible to transport the captured CO_2 to the proposed storage area.

The main consequence of retrofitting PCC is expected to be possible additional expense due to the increased difficulty in making flue and steam connections to the main power plant and locating the PCC power plant and its ancillary equipment, including extra cooling towers if required, and also constructing the majority of the PCC plant while the CCGT plant continues to operate. Only on very 'tight' sites, however, is PCC addition likely to be effectively impossible. Some likely constraints and solutions are detailed below:

(a) Flue gas connections may be longer and more difficult if space for the absorber has not been reserved near the stack; contrast the layout and flue gas duct lengths between Fig 2.3 (new-build) and 2.4 (retrofit, non-CCR). Retrofit ducting may therefore cost more and also involve higher fan power requirements, although this additional fan power will still be a minor part of the overall PCC Electricity Output Penalty (EOP) (i.e. compared to total new-build fan power, compression power and lost output due to steam extraction). Tie-ins to the stack may also be constrained for some retrofits, although Fig 3.3 shows an example that was deemed to be feasible. Flue gas connection issues are discussed in more detail Section 3.2.

(b) Steam extraction from the IP/LP crossover in the Steam Turbine (ST) may be more difficult in a non-CCR retrofit, but extraction at reheat pressures (i.e. upstream of the IP ST cylinder) and subsequent expansion to reboiler pressures in a new back-pressure ST is much more likely to be possible, even though not originally designed for, since there are more possible access points, the IP/LP crossover pressure is not an issue and the steam line itself will have a smaller diameter. While possibly slightly costlier, a properly designed RH extraction system is likely to have comparable efficiencies to other extraction options that achieve good reversibility (e.g. Gibbins, 2009; Lucquiaud, 2012; Bechtel, 2018) and could also have advantages for flexible operation (see Section 7). If steam extraction from the retrofitted plant is not to be used, then only another CCGT with PCC, or other high-efficiency CCS power plant as appropriate for the additional fuel type, would give efficient use of fuel, but this would result in a significant increase in electrical output from the site as well as requiring increased space and CAPEX (IEAGHG, 2011). See also Section 3.3.1 and Annex 3.

2.2.3 Biomass Power Plants with PCC – general considerations

Biomass power plants with PCC may use pulverised fuel burners, fluidised beds or fixed grate boilers, depending on their scale and the types of fuel they are intended to burn. To date, little information on full-scale BECCS power plants is available; new biomass power plants in the UK have so far been below the 300MW (electrical) threshold at which capture-ready regulations apply (BEIS, 2009) so no capture-ready studies have been required or undertaken.

As already noted, there are likely to be many similarities between PCC for coal boilers, which has already received significant attention, and PCC for biomass boilers. There will also be differences, though:

- Biomass plants do not generally have a Flue Gas Desulphurisation (FGD) plant, since sulphur levels are usually low
- Ash properties and composition for biomass are very different from coal; overall quantities are lower for biomass but fine particle loadings may be more comparable
- New biomass plants intended for PCC (or capture-ready) may have a baghouse for particle removal, to capture finer particles and in particular any very small aerosols that could cause very high levels of solvent entrainment, but a baghouse could be a problem if there were carryover of large, and hence still burning, particles; the alternative would be an ESP, but aerosols from SO_3 injection to improve conductivity may be a problem; a wet ESP would be an alternative but more costly
- Common practice seems to be for purpose-built biomass power plant sizes to be smaller than for coal (the example below assumes 2 x 250MW biomass power plants before capture), perhaps because of expectations regarding fuel availability at a particular site or because of a wish to use fluidised bed boilers for better fuel flexibility rather than the larger pulverised fuel boilers commonly used for modern coal plants.

A block diagram for a new-build circulating fluidised bed power plant with PCC is shown in Fig 2.5 below. In this case baghouses are assumed to be used on the boilers, to remove most particulates and any sulphur trioxide (SO_3) mist present, and caustic soda is added to the pre-scrubber (also known as a Direct Contact Cooler or DCC) to remove the low levels of sulphur dioxide (SO_2) that would be expected from a biomass fuel (rather than using a Flue Gas Desulphurisation Unit as would be normal with coal firing).

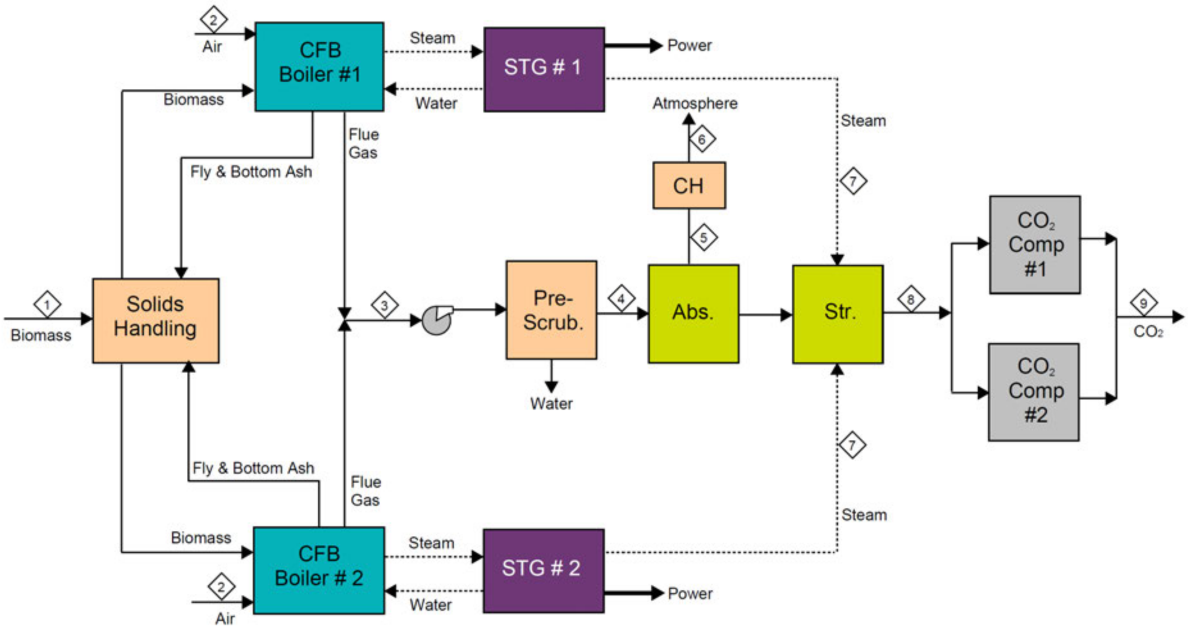

Fig 2.5 Block Diagram for a new Biomass Post-Combustion Capture for Power Generation (Wood, 2018) based on 2 x 250MW Circulating Fluidised Bed steam boilers
(reproduced with permission from Wood)

CFB = Circulating Fluidised Bed, STG = steam turbine generator; Pre-scrub. = pre-scrubber to cool the flue gas and remove, particularly, SOx and fine ash; Abs. = absorber; Str. = stripper; Comp = compressor, CH = condensate heater to warm exhaust gases from the absorber above the water dewpoint and give plume buoyancy

A diagram for a proposed PCC retrofit to a large brown coal power plant is shown in Fig 2.6. This has some similarities to a retrofit on a biomass power plant. The fuel is a very young brown coal and its properties are somewhat similar to biomass, including a low ash content that is high in alkali earth metals and a low sulphur content; the brown coal water content is high at around 60% w/w. No FGD unit is fitted. As on many coal power plants, electrostatic precipitators (ESPs) are used to remove fine fly ash from the flue gas before the stack.

The PCC retrofit approach used in this case is described in an open-access feasibility study report (Bechtel, 2017). Addition of an FGD was not considered practicable because of lack of space on site, in addition to the cost. Instead, it was planned to remove sulphur oxides (SOx) in the DCC using the alkalinity in the fly ash and added caustic if necessary. Observed occasional fluctuations in flue gas SOx levels might, however, exceed the DCC capabilities at times so, in addition, a low-cost solvent was proposed, monoethanolamine (MEA) at 40% w/w concentration, coupled with semi-continuous thermal reclaiming to achieve rapid removal of any Heat Stable Salts (HSS) formed by the SOx reacting with the MEA (an inevitable acid/base reaction with all amines), other solvent degradation products and ash constituents (soluble and insoluble). This approach effectively also allowed SOx neutralisation by adding alkali in the reclaimer, when necessary.

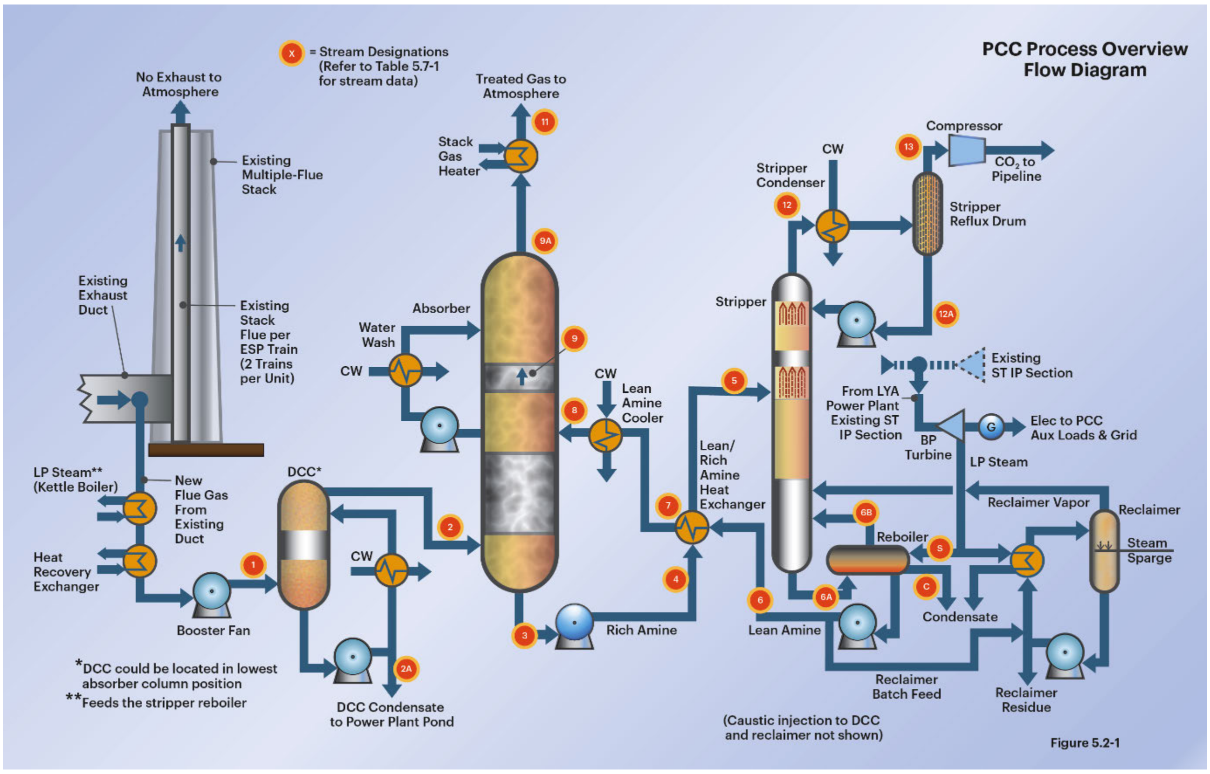

Fig. 2.6 Brown coal power plant PCC retrofit proposal. This is obviously not a biomass plant but the PCC retrofit had to address possibly similar conditions
(CW=caustic wash, to remove acid gases in the DCC)
(Bechtel, 2018 - reproduced with permission from Bechtel).

2.2.4 *Biomass Power Plants with PCC – new-build vs. retrofit*

Biomass power plant retrofits face similar challenges to those on CCGT plants: possibly challenging tie-ins to the stack and existing ducts, longer connecting ducts to the PCC plant and tight sites overall.

Biomass retrofits and new-build also face additional challenges because of the impurities in the flue gas. While these will be at acceptable levels for emission to atmosphere, they may cause unacceptable consequences in the PCC unit, i.e. from particulates, SOx and NOx.

Enhanced particulate removal, including aerosols, may be achieved on new plants using baghouse filters (although baghouses are vulnerable to carryover of larger biomass particles that are still alight), whereas existing biomass plants are likely to have ESPs. The presence and effect of aerosols will need to be verified by pilot-testing to assess the need for any aerosol countermeasures in retrofits.

As discussed above, adding (or re-instating possibly, for coal-to-biomass conversions) an FGD to remove SOx requires significant additional space and cost and may be seen as 'overkill' given the small amounts of SOx that can be expected from biomass. Instead, both retrofit and new-build may use alkali addition to the DCC if necessary. The ash from a biomass plant will also be rich in alkali species and will contribute to SOx reduction in the process and also if fly ash enters the DCC.

As discussed above, some biomass plants have been built non-CCR, so access to CO_2 transport and storage infrastructure will vary between different sites. For retrofitting PCC, the main consequence is expected to be possible additional expense due to the increased difficulty in making flue and steam connections to the main power plant and locating the PCC plant and its ancillary equipment, and also constructing the majority of the PCC plant while the biomass plant continues to operate. Only on very ‘tight’ sites, however, is PCC addition likely to be effectively impossible. As for CCGT plants, some likely constraints and solutions are as detailed below:

(a) Retrofit ducting for flue gas connections to the PCC unit may cost more than new-build and also involve higher fan power requirements, although these will still be a minor part of the overall PCC EOP. Tie-ins to an existing stack may also be more constrained for some retrofits.

(b) Steam extraction from the IP/LP crossover in the ST may be more difficult in a non-CCR retrofit, but extraction at reheat pressures (i.e. upstream of the IP ST cylinder) and subsequent expansion to reboiler pressures in a new back-pressure ST is much more likely to be possible, even though not originally designed for, since there are more possible access points, the IP/LP crossover pressure is not an issue and the steam line itself will have a smaller diameter. While possibly costlier, a properly designed RH extraction system is likely to have comparable efficiencies to other extraction options that achieve good reversibility (e.g. Gibbins, 2009; Bechtel, 2018) and could also have advantages for flexible operation (see Section 7). If steam extraction from the retrofitted plant is not to be used, then only a high-efficiency CCS power plant would give efficient use of fuel, but this would result in an approximate doubling of electrical output as well as giving increased space and cost (IEAGHG, 2011). See also Section 3.3.1 and Annex 3.

2.2.5 EfW combustion plants with amine PCC - general considerations

The Energy Systems Catapult (Gammer & Elks, 2020) have undertaken *A Preliminary Assessment of Their Potential Value to the Decarbonisation of the UK* for EfW plants coupled to CCS. The summary of their main findings is quoted below:

Energy from Waste (EfW) plants currently emit around 11 Mte CO_2 per year in the UK, with proposed and under-construction facilities potentially adding another 9 Mte CO_2 per year. Reducing these emissions would have a material impact on the UK’s low carbon energy transition. Preliminary analysis of the potential of fitting carbon capture (CCUS) equipment to the growing number of EfW plants in the UK as a means of CO_2 reduction has therefore been undertaken.

The key conclusion from this analysis is that the cost of EfW-CCUS technology as a means of emissions abatement is competitive with other industrial abatement options, but that its uptake would require policies reflecting its ability to generate “negative emissions” as a consequence of using the biogenic content of part of the carbon in waste.

The analysis has also shown that:

- *Many EfW plants are geographically well located for CCUS, being in industrial clusters near to accessible CO_2 storage locations*
- *A significant proportion of the UK’s EfW fleet is relatively new compared to other industrial facilities, and they therefore have a long life ahead of them in which to benefit from a CCUS retrofit investment*
- *CCUS significantly improves the sustainability of EfW facilities and can therefore mitigate many of the system level environmental issues that threaten the long-term sustainability of EfW in the UK*
- *On a lowest system transition cost basis, fitting CCUS to EfW plants could lead to 20% of all captured CO_2 in the UK being derived from EfW plants by 2050, with a corresponding 20% overall increase in CO_2 being captured in the same timeframe compared with the case without EfW-CCUS being available*

The range of operational EfW facility sizes, by approximate CO_2 emissions based on permitted capacity, is shown in Fig. 2.7 below (data from Tolvik, 2022).

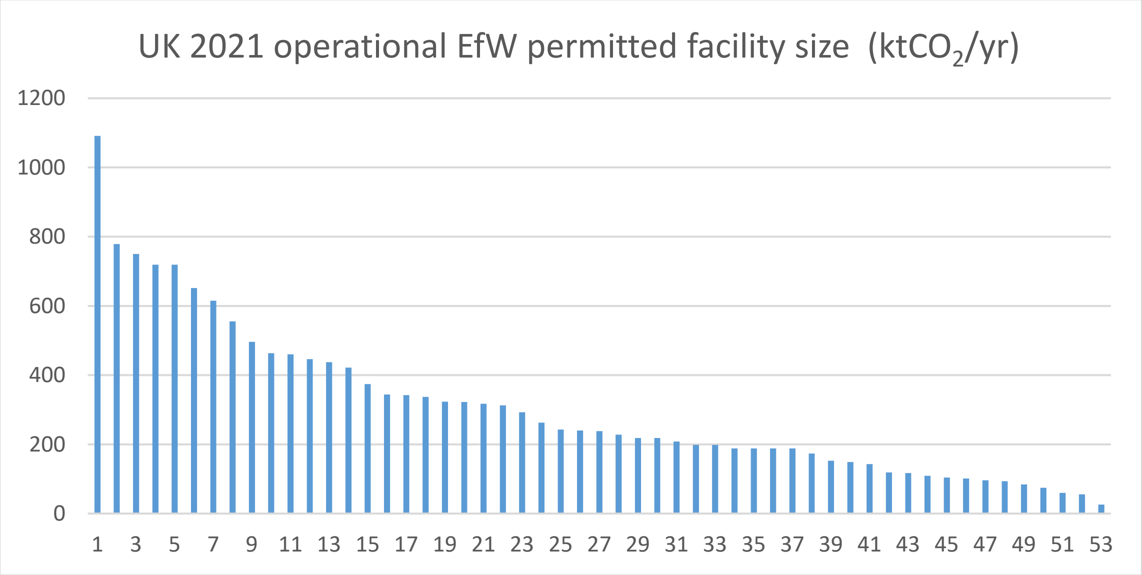

Fig. 2.7 Ordered histogram of UK 2021operational EfW facilities by permitted size (converted to approximate ktCO$_2$/yr[4] - data from Tolvik, 2022)
note this is significantly lower in most cases than for power plants (>1 MtCO$_2$/yr)

The 53 operational facilities had an average age of 10.7 years in 2021. Availability for most plants is high (see Fig. 2.8), in excess of 90% in many cases, so capture plants would also be fully utilised. On average the UK fleet exported 591 kWhe/t of waste and 126 kWhth/t of waste in 2021, but this heat export was from just 12 facilities (out of 53), so actual electricity and heat outputs vary significantly by site and many sites have no heat output at all.

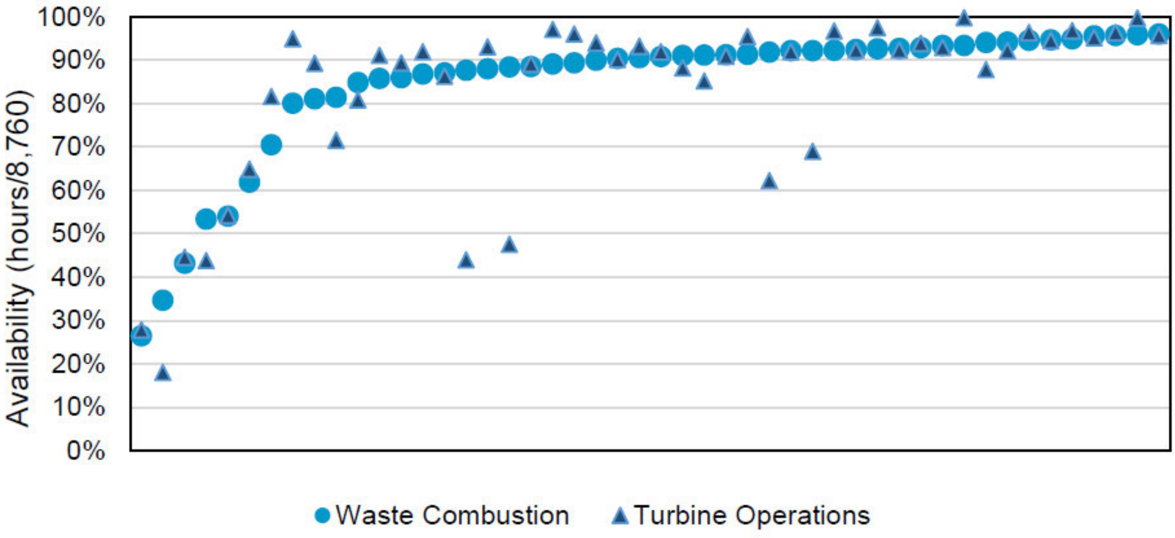

Figure 2.8: 2021 UK EfW Availability – Hours (Source: Tolvik analysis, 53 records)

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[4] Based on permitted capacity in kt waste/yr and average emissions of 0.992 tCO$_2$/t of waste

Personal communications during the consultation on EfW (in particular from P. James) also raised a number of other aspects regarding the application of PCC and associated CO_2 transport and storage on EfW plants:

- It was stated that EfW plants are often not in planned CCS clusters, although there is also evidence of EfW plants in the West Coast Cluster at the time of writing, possibly one more plant in the East Coast Cluster – T&S may be a problem for existing plants not in clusters (although out of scope for this review). For new capacity, it is currently likely that Decarbonisation Readiness guidelines (BEIS, 2021) will be updated to included EfW, including consideration of T&S.
- Space on site may be an issue – some are urban and may have PCC permitting issues as a result
- The main purpose of an EfW plant is the combustion of waste, followed by the supply of heat, if contracted to do so. This must take priority over the supply of steam required for CO_2 capture
- Fuel composition: it is much more variable with waste than fossil fuels or most biomasses and contains much greater variety of contaminants. Some impact on the PCC can be expected

The capture level that could be achieved on EfW plants was also queried, although no evidence has been found that values considered to be achievable on power plants (i.e. 95% or above) could not also be implemented on EfW PCC plants. See Section 4.5 for a detailed discussion on capture levels, also recently Su et al (2023) published a theoretical study that predicted that 100% fuel CO_2 capture, equivalent to a 99.7% absorber capture fraction, is possible with open-art 35% w/w MEA.

2.2.6 EfW combustion plants with amine PCC – new-build vs. retrofit

Apart from issues associated with facilitating CO_2 transport and storage, which are outside the scope of this review, new-build EfW combustion plants can select sites that include scope for erecting CCS equipment and can ensure that steam cycles are designed for steam extraction.

2.2.7 EfW gasification/pyrolysis plants with amine PCC – general considerations

No such plants are currently operating in the UK and no public domain information on the application of PCC to flue gas streams from such plant has been identified.

2.2.8 EfW gasification/pyrolysis plants with amine PCC – new-build vs. retrofit

Given that no plants are yet operating, it would be expected that new plants are built at least capture ready. For new decarbonisation ready guidelines see (BEIS, 2021).

2.3 Post-combustion capture amine technology

2.3.1 Basic PCC amine cycle

Amine solutions are basic (alkaline) and so undergo reversible, exothermic reactions with acidic CO_2 in a PCC absorber. The maximum, equilibrium, extent of reaction is a function of CO_2 partial pressure and temperature, as shown in Fig 2.7. CO_2 partial pressures are determined by its concentration in the flue gas, since all PCC absorbers operate at near atmospheric pressure; higher values tend to increase the CO_2 loading of the amine. Lower temperatures also favour higher CO_2 equilibrium loading but, because lower temperatures also reduce chemical reaction rates (and may cause some amine solutions to freeze or precipitate), liquid and gas temperatures entering the absorber are usually not lower than 20-40^{o}C.

A typical amine CO_2 capture and release cycle for MEA is shown in Fig 2.9, labelled ABCD. Amine solvent will generally be close to, but not quite in, equilibrium with the flue gas entering and leaving the absorber, as some out-of-equilibrium driving force is needed to make the solvent absorb CO_2. At A, lean solvent is distributed across the top of the packing in the absorber and then flows down, picking up CO_2, while the flue gas flows up from the bottom of the absorber, losing CO_2 as it rises. The reaction of CO_2 with amine is exothermic so the performance may be improved if heat is removed from the solvent in the absorber by intercooling: taking solvent out partway through the absorber and passing it through a heat exchanger before redistributing it over another bed of packing. This will stop the absorption rate slowing because the solvent loading is approaching the thermodynamic limit (see section 4.3), particularly for higher inlet CO_2 concentrations as with biomass.

After leaving the absorber (B), at typically 30-60°C, the 'rich' amine is heated in the cross flow heat exchanger (XFHE) and then passes into the top of the stripper (C). As it trickles down the packing in the stripper it is further heated by warmer vapour and gas passing upwards and starts to release its CO_2. CO_2 release is fully completed (for the system considered in this example – typically there will still be 0.15 – 0.35 moles of CO_2 per mole of amine in the lean MEA leaving the stripper[5]) in the sump of the stripper (D) where the solvent reaches its maximum temperature, typically around 120°C for MEA but possibly higher or lower for other amines, as it is recirculated through external reboilers (or heat exchangers) heated by condensing low-pressure steam. Generally, higher reboiler temperatures would be favoured, since they increase the pressure that the stripper can be operated at, so reducing compression work and also allowing lower lean loadings and hence reduced absorber height. But solvents also experience increased thermal degradation at higher temperatures, so a trade-off is required.

'Lean' amine from the stripper sump is pumped through the XFHE, where it is cooled and the rich solvent warmed and then is further cooled to the required inlet temperature before going back to the top of the packing in the absorber, A, to collect more CO_2.

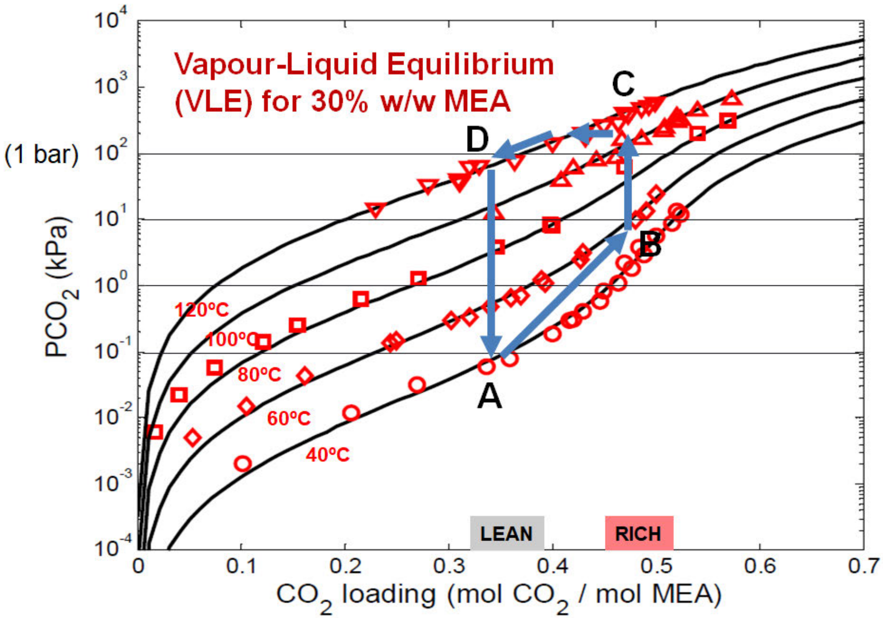

Fig 2.9 MEA vapour-liquid equilibrium data and a typical PCC amine cycle

(data from Ugochukwu, 2010)

In the system shown in Fig 2.6 a small slip-stream of lean amine is also sent to the reclaimer. Caustic is added to neutralise heat stable salts (HSS) formed by the amine and other acid gases such as SOx,

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[5] Capture plants using other solvents may have lower lean loadings after stripping, although specific values do not appear to be stated often in the literature. In NETL (2015) it was stated, in connection with a commercial BASF solvent, that '*Aminocarboxylic or aminosulfonic acids, which become significantly more acidic with temperature may also be used to increase the cycle capacity (lower lean loading)*'. NETL also noted that '*Lower molar CO_2 loading (i.e., mol CO_2/mol amine) ….. does not translate to lower weight-based or volumetric CO_2 loading. The molecular weight and density of the amine [or other solvents]….are important parameters affecting these measures.*'. Lean loadings for CESAR 1 are reported in Benquet (2021).

and then the whole mixture is heated to boil off water, CO_2 and amine and, ideally, to leave all solvent impurities and degradation products behind. The vapour is also ideally sent to the stripper to recover heat, which means that reclaiming must be done while the plant is operating[6] (although reclaiming may be done only at intervals, as required to maintain solvent cleanliness). These ideal conditions are largely met for reclaiming MEA; as discussed in more detail in Section 4, the reclaimer can be operated in the region of 150-160°C at stripper pressure with amine recoveries in excess of 90%. Limited information on thermal reclaiming is available in the public domain for other solvents, but a similar reclaimer arrangement, venting into the stripper, is reported at Petra Nova (Petra Nova, 2020) and by Fluor (Fluor, 2004) – see Section 4.1.

2.3.2 Absorber design

The purpose of the absorber in a PCC plant is to provide adequate surface area for CO_2 mass transfer from the flue gas to the solvent and sufficient solvent hold-up time in the packing for liquid phase reactions to chemically bind (reversibly) the CO_2 to the amine[7]. To achieve this, very large vertical columns containing beds of structured packing are employed. These columns may be round or rectangular and use metallic or lined concrete construction, depending on supplier experience and preference, and site characteristics (e.g. scope to ship in assembled columns or column sub-assemblies). No differences in environmental performance arising from the basic design and construction methods appear to exist, with one possible exception as described below.

The absorber (and amine flue gas desulphurisation (FGD) unit column) at Boundary Dam unit 3 (BD3) was constructed from reinforced concrete poured behind ceramic tiles (i.e. not slip-formed). The same, or a similar, construction method was used for an amine storage tank (Power, 2015), which was found to leak in service, could not be repaired and was replaced with a stainless steel vessel that was shipped to site (CBC, 2015).

Overall CO_2 absorption rates are solvent-specific, with some variation in the height of the packed section to be expected between solvents. In general, taller packing beds give higher capture levels and lower energy requirements, i.e. there is a trade-off between capital and operating costs. There appears to be, however, rapidly diminishing returns for increased bed height above a certain value. Significant extra overall height is needed in the column for packing supports, liquid distributors (Fig 2.10) and re-distributors, and also for the sump, flue gas inlet connection, washing sections and spray/mist removal beds (see Fig 2.11). As well as increased costs, visibility considerations may weigh against bed heights significantly in excess of design requirements, although some additional margin might be included to allow for uncertainty, loss in solvent effectiveness during service, or to allow for subsequent use of a replacement solvent that has slower overall absorption kinetics but other desirable properties.

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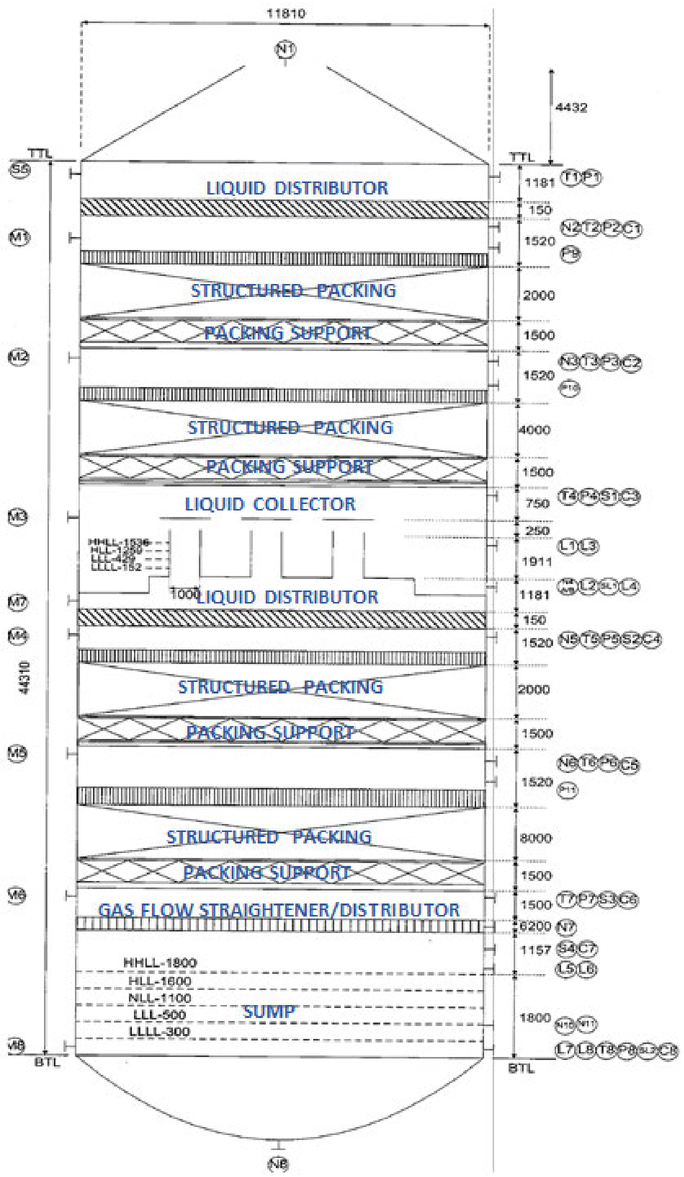
[6] Batch reclaiming with the plant off-line is also possible. In this case less solvent has to be processed than when using a slip-stream but the heat cannot be recovered – and the PCC plant cannot be used at the same time unless a duplicate solvent inventory is available.

[7] Predominantly as a carbamate.

Fig 2.10 Liquid flow distributor

(Sulzer, 2008: all copyrights with Sulzer Chemtech AG, reproduced with permission)

"Liquid distributors must spread solvents evenly across the cross-sectional area of large columns. At Sulzer Chemtech, test rigs allow for full-scale testing with water prior to installation in columns."



DIMENSIONS SHOWN

BUT NOT DRAWN TO SCALE

[redacted]

Fig 2.11 Absorber column internal arrangements
(Bechtel, 2009 - reproduced with permission from Bechtel)

Other important features of the plant are the wash sections at the top of the absorber, which use recirculated water with a small make-up of fresh water and blowdown to the circulating amine solution (which recycles captured amine and also serves as a water make-up, if required). Water washes are intended to re-dissolve trace amine vapour and other volatile components in the flue gas leaving the top of the absorber packing sections. The effectiveness of a water wash is enhanced if multiple stages are used. A wash stage using acid (usually dilute sulphuric acid) to react with ammonia (which cannot be controlled using water washes alone, since ammonia concentrations build up to the point where rates of release match rates of production), and with residual amine vapour and other basic species, can also be employed. An acid wash will, however, require more complex arrangements to catch and recycle the liquid and will also require acid (typically sulphuric) top-up and give rise to a reject stream.

The reject stream from an acid wash could possibly be used for its ammonium sulphate content rather than being treated as a waste, but this would have to be verified for each project because of the specific solvent-derived compounds it may contain – no published experimental work appears to exist on this topic. It was concluded for the Peterhead FEED study that '*the possibility to treat the acid wash effluent containing quantities of amine was also investigated but the resultant water treatment plant design was highly complex, expensive, operator intensive and would have most likely have suffered from poor reliability. It was therefore decided at the end of the Execution Preparation phase to transport the acid wash effluent to a licensed offsite disposal facility for incineration*' (Peterhead, 2016), but it is not stated whether or not this was based on practical trials.

Wash sections are not, however, effective at removing fine aerosol droplets; if these are present, special demisters or flue gas heating would be required, but these measures may still not be effective enough – avoidance or possible removal of the aerosol at source is likely to be preferable. See Section 4.6.3 for more details on these absorber exit measures.

Flue gases leaving the absorber are released to air, so may require reheating to aid plume dispersion and to minimise plume visibility. To achieve this, flue gases exiting the top of the absorber may be returned to ground level to be reheated (possibly using a gas-gas heater) and then be returned to the main or a separate stack (e.g. Peterhead, 2016). Probably more conveniently, the flue gases can be vented from a shorter stack directly on top of the absorber, again with reheating but using steam or a heat transfer fluid (e.g. as in Bechtel, 2018) rather than a gas/gas heater. Stack height on top of the absorber will still be a consideration, for dispersion and also for sampling, to give adequate settling lengths before sampling points and to protect operators from the main plume.

The EfW+PCC plant at Duiven returns the flue gas from the absorber to a separate stack with much greater elevation than the top of the absorber – see Fig 2.12 below.

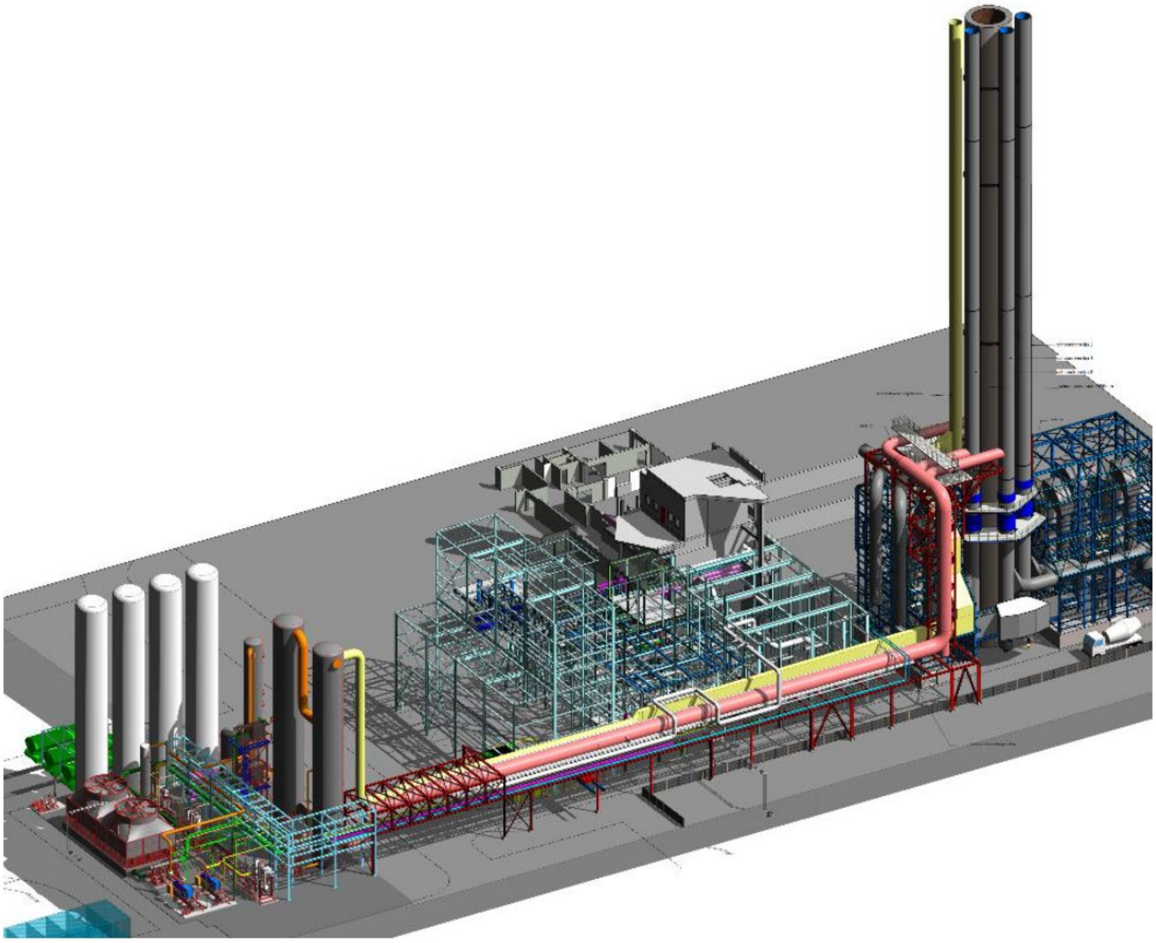


Fig. 2.12 AVR Duiven PCC retrofit plant – note incoming flue connections from existing stacks (red) and flue gas vent line and new stack (yellow) (Wassenaar, 2020).

2.3.3 Solvent regeneration and compression, and effect on power plant performance

In a typical arrangement (alternatives are discussed in Section 4.3), rich solvent (i.e. loaded with CO_2) collects in the sump of the absorber and is pumped to the XFHE for pre-heating before it enters the stripper for regeneration.

Regeneration heat energy requirements arise mainly from three causes:

a) Heat of reaction	The energy required to break the reversible chemical bond between the amine and the CO_2.
b) Heat of evaporation	The CO_2 leaving the stripper in a gaseous form contains water vapour produced from the liquid water in the rich solvent; evaporating this vapour requires relatively large amounts of energy. The stripper pressure and the temperature of the CO_2/water mixture leaving the stripper are key factors, since they determine the composition of the (fully-saturated) mixture and hence the thermal energy associated with the heat of evaporation.
c) Sensible heat	The difference between the heat content of the lean solvent exiting the stripper and the rich solvent entering it. For a given solvent, this is largely a function of the XFHE performance, so these are usually designed for close approach temperatures, typically around five to ten degrees. There is

nonetheless an inherent sensible heat loss if the incoming rich solvent is heated only by the leaving hot lean solvent, because of the higher heat capacity of the former. In some configurations some of the rich solvent is therefore diverted before the XFHE and heated by other mean (e.g. waste heat from the compressor intercoolers).

Solvent regeneration heat is required at temperatures typically around 120-130°C (but can be up to 150°C for PZ), limited by thermal degradation of the solvent, and this can be supplied by condensing steam taken from the power plant. Most of this heat would have otherwise been rejected in the power plant condenser (as an entirely necessary consequence of running a thermodynamic cycle to generate electricity) and the only loss in power plant electricity output due to using it in the PCC plant is due to the higher temperature at which the steam is now condensed. The ratio between heat to the PCC process from low pressure steam extraction and the loss in electric power output from the power plant depends on the cooling water, and hence condenser, temperature (with higher cooling water temperatures giving a higher ratio) but a factor of up to five is a typical value (Lucquiaud, 2011). There is also scope for some of the heat supplied to the PCC unit subsequently to be recovered at lower temperatures after use in the PCC plant and then be employed in the steam cycle for condensate heating in steam power plants (e.g. biomass power plants) but not typically in CCGT power plants (since CCGT plants usually have an excess of heat available at temperatures below the temperature pinch for the LP evaporator). See Annex 3 for more details.

2.3.4 Solvents

Solvent issues are covered in more detail in a report by the Scottish Environment Protection Agency (SEPA), last updated in 2015 (SEPA, 2015), from which the text below is taken:

'The group of chemicals known as organic amines are typified by substitution of one or more of the hydrogen atoms in ammonia (NH_3) by an organic group (Lawrence, 1994). This can be expressed in chemical notation as N-(R1,R2,R3). Primary amines are the group of compounds where one hydrogen atom has been substituted by one organic group, secondary amines have two hydrogen atoms substituted by two organic groups and so on. The typical amine solvents that have been used in carbon capture scrubbing systems tend to be the generic group of amines referred to as alkanolamines. These are primary or secondary amine compounds consisting of hydroxyl (alcohol) and amino functional groups on an alkane backbone [also tertiary alkanolamines, most notably MDEA]. *Most reported work has concentrated on the use of 2-aminoethanol (often referred to as monoethanolamine, MEA). This solvent is normally used as a baseline when comparing the performance of other types of amine solvents or mixtures of solvents.*

Other alkanolamine compounds (either alone or in blended mixtures) have been proposed as carbon capture solvents include 2-(2-hydroxyethylamino)ethanol (often referred to as diethanolamine or DEA), 2-(2-hydroxyethyl(methyl)amino)ethanol (referred to as methyldiethanolamine or MDEA), 1-(2-hydroxypropylamino)propan-2-ol (referred to as di-isopropanolamine or DIPA) and 2-(methylamino)ethanol (referred to as monomethylethanolamine or MMEA). Other amine compounds have also been investigated as potential carbon capture solvents including cyclic and glycol amines such as 2-amino-2-methyl-propanol (referred to as aminomethylpropanol or AMP), the cyclic compound 1,4-diethylenediamine (universally referred to as piperazine or PIPA [or PZ] *) and 2-(2-aminoethoxy)ethanol (referred to as di-glycolamine or DGA). A wide range of other, more highly substituted alkanolamines and polyamines are also being investigated at the laboratory scale (Lepaumier et al 2009). Proprietary solvents and solvent mixes are also being developed however information on the composition of these solvents is in some cases confidential.'*

In general, amine solvent characteristics for PCC can be summarised as follows:

Table 2.1 Classes of amines and relevant characteristics for PCC
(summary for amines in aqueous solution, as typically used in PCC applications and pilot tests, based on amine-related references cited in this review)

Type of amine	**Examples in use**	**Relevant characteristics for PCC**
Primary	MEA	Widely used for other purposes, rapid kinetics, low CO_2 capacity, moderate volatility and can form mists with aerosols, moderate to low stability and resistance to thermal degradation, pure material will not form stable nitrosamines, liquid at all relevant temperatures, easy to reclaim thermally. Proposed for use at increasing concentrations in water (now 35-40% w/w, was 30% w/w) to partially overcome lower CO_2 loading capacity and hence higher regeneration energy requirements than secondary and tertiary amines/blends.
Secondary/ secondary blends	PZ Piperazine	Rapid kinetics, moderate CO_2 capacity, lower volatility compared to MEA but can still form mist with aerosols, good thermal and oxidative stability, as secondary amine the pure material forms nitrosamines, can 'freeze' at lower temperatures so often used as an accelerator in blends with 'slower' amines, reported to be reclaimable thermally (Sexton, 2014) but limited practical evidence available at the time of writing.
	PZ + AMP blends	AMP is a sterically-hindered amine with higher capacity and PZ an accelerator in this blend. Non-proprietary version known as CESAR1, with public domain information available (e.g. Brúder, 2011). More toxic, rapid kinetics, high CO_2 capacity, low volatility but can still form mist with aerosols, good thermal and oxidative stability, readily forms nitrosamines, limited published evidence on reclaimability to date, precipitation reported for CESAR1 blend at low flue gas temperatures (30°C vs 40°C) (Languille, 2021).
Tertiary/tertiary blends Good capacity but slow kinetics so used in blends	PZ + MDEA blends	PZ is an accelerator for the slower, tertiary amine MDEA in this blend. Rapid kinetics, high CO_2 capacity, lower volatility than MEA but can still form mist with aerosols, good thermal and oxidative stability, forms nitrosamines, liquid at all relevant temperatures, may not be easily reclaimable thermally due to the difference between the boiling points of MDEA of 246.1°C and that of PZ of 146°C.

With respect to a ranking of amines, CSIRO (2012) has suggested, since the compounds that have the greatest health and environmental risk are the nitrosamines and the risk for their formation is highest with secondary amines, lower with tertiary amines and the lowest with primary amines, that one could rank the solvents from greatest to lowest environmental and health risk as:

PZ > MDEA > AMP = MEA

However, based on their propensity for degradation to alkylamines, secondary amines (that may eventually form nitrosamines) and volatile products (principally ammonia), the CSIRO ranking would be:

MEA > MDEA > PZ=AMP

A CSIRO combined ranking, giving more weight to the risk of nitrosamine formation, was:

PZ > MDEA > MEA > AMP

And adding in amine volatility, based on increased volatility increasing emissions in normal operation and in the event of accidents, the following overall ranking was suggested by CSIRO :

PZ > AMP > MEA > MDEA

The following generalised statements were also made (CSIRO, 2012):

a) *Secondary amines have highest risk of nitrosamine formation, followed by tertiary amines, while primary amines have the lowest risk of nitrosamine formation.*

b) *All other things being equal, solvents with low vapour pressure are safer than solvents with high vapour pressure*[8]*.*

c) *All other things being equal, a more stable solvent that will resist degradation is safer than a less stable one since the more stable solvent will have lower emissions of degradation products.*

NETL (2015) also gives a summary of solvent properties relevant for commercial use (see below), as well as some information on generalised composition details and overall performance for specific commercial solvents (including BASF OASE Blue Solvent, MHI KS-1 and Cansolv DC-103, DC-103B and DC-201), based on the NETL test programme:

> *Primary and secondary amines typically have higher rates of reaction with* CO_2 *compared to tertiary amines. Among various primary amines, MEA has the highest reaction rate, and blends of MEA and other tertiary or hindered amines are typically used to exploit this feature while maintaining relatively-low reboiler loads. Primary/secondary (mono)amines with a 1:2 stoichiometry have lower* CO_2 *carrying capacity compared to tertiary amines which bind 1:1 with* CO_2*. Further, polyamines such as piperazine have a higher carrying capacity because they have two amine groups per molecule. Tertiary amines have higher* CO_2 *capacities but the reaction kinetics with* CO_2 *are significantly slower than primary and secondary amines. Because the* CO_2 *carrying capacity is expressed in wt%* CO_2 *in the solvent, or the quantity of solvent circulated to capture a unit quantity of* CO_2*, the molecular weight and density of the solvent also play a role in determining its volumetric or weight-based CO2 carrying capacity.*
>
> *From a health and environmental safety perspective, MEA is highly biodegradable, and has no direct adverse effects on human health, animals, and vegetation. Other amine solvents such as AMP, MDEA and PZ are toxic and are not easily biodegraded compared with MEA. The reaction of amines with NOx in the flue gas leads to the formation of nitrosamines, which are carcinogenic. The reactivity with NOx varies with the amine structure.*

MEA is typically available at much lower cost than other amines, not least because it is already widely used for other purposes. The global market capacity and its size in relation to the quantity of amine required for initial charge and consumption in a large PCC project are obviously important considerations for project developers and operators.

There are many amines, with an infinite scope for variety in the range of amine-containing blends initially fed into the plant. Further complexity is introduced as amine inventories degrade and accumulate possible additives and impurities as they approach long-term equilibrium compositions, with the additional modifying effects of reclaiming and other solvent maintenance during commercial

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[8] Nguyen (2011) ranks volatility for amines in aqueous solution (i.e. as used in PCC), as (lowest volatility first) MDEA < DGA < PZ < 2-MPZ < MAPA < EDA < MEA < DAP < 1-MPZ < AMP (see Glossary for full names).

service. Reclaiming and solvent management are often omitted from pilot tests undertaken for solvent development or comparison, but are obviously absolutely essential if pilot tests results are to represent those on an actual commercial plant, where some form of reclaiming and other solvent management techniques can be expected to be deployed[9].

It cannot be too strongly emphasised that it is this long-term, equilibrium composition and solvent behaviour that will determine the solvent-related environmental performance of the plant, not the behaviour observed in tests starting with relatively fresh solvent and with little or no reclaiming or other solvent maintenance to remove impurities, as would be required in commercial operation. It is self-evident that the average long-term concentration of any given impurity in the solvent will be the value at which, for that specific impurity, average removal rate matches average formation rate (for degradation products) or average addition rate (for flue gas impurities or corrosion products). Thus, tests that do not include the use of the impurity removal procedures that will be used in full-scale applications can never match the solvent composition (and therefore behaviour) that will be observed in practical commercial applications.

The critical difference that can exist between initial operation with fresh solvent, even during formal acceptance trials, and subsequent long-term operation is evidenced by reported experience at SaskPower's Boundary Dam Unit 3 (BD3) PCC retrofit project, as quoted below.

After construction and less than a year of operation, the following assessment was made (Preston, 2015). Note the term 'technology' as used here appears to imply mainly choice of amine solvent, but all amine solvents are expected to be using very similar PCC hardware configurations and process conditions. It appears that Fluor's Econamine FG Plus was also examined (Fluor, 2009) for use at BD3, but Shell's Cansolv DC-103 solvent was selected (NETL, 2015):

> *'SaskPower learned some important lessons during the design and engineering phases of the BD3 retrofit:*
>
> - *A technology must be piloted at a level that allows for meaningful engineering scale-up to commercial size.*
> - *The technology chosen must be commercially viable at the time it is selected NOT when operation begins. There will be a lag of 3–5 years between those dates.*
> - *Commercial proposals for each technology are required before the costs of implementing each one can be understood.*
> - *A fully-engineered cost estimate with a detailed process design is essential to be certain of the required capital investment and operating costs, as well as the associated environmental and operating implications.*
> - *Simple and predictable are the best indicators for technology and equipment selection when required to expend significant capital funding.*
> - *Plan for the time required to build confidence by the key stakeholders in the project. This would include the time required to conduct a third-party investment review.'*

The 2015 BD3 report then went on to add:

> *'This list of anticipated and unanticipated issues is surprisingly short given the immaturity of the CO_2 capture technology installed at BD3, and the low level of associated engineering*

---

[9] Accelerated degradation testing has been used to pre-evaluate solvent stability and eliminate the worst solvents before undertaking larger-scale and longer pilot test campaigns on them (e.g. Helgesen, 2016), but this is a different application than verifying satisfactory operation of a solvent and solvent management regime over extended periods (i.e. multiple years) in commercial service.

> *knowledge and operating history related to integrating that technology with modern coal-fired power generation.*
>
> *Combined with the pre-conditioning of the flue gas before entry to the capture plant, the new flue gas emitted from the stack at BD3, as designed when the capture plant is in operation, shows significant improvement in the quality of all air emissions compared to BD3's pre-retrofit emission performance.'*

Table 2.2 BD3 characteristics before and after PCC retrofit (Preston, 2015)

CONSTITUENT	PRE-CCS	POST-CCS DESIGN VALUES	CHANGE
Power	139 MW	120 MW	13.60%
CO_2	3604 tonnes/day	354 tonnes/day	90%
SO_2	7 tonnes/day	0 tonnes/day	100%
NO_x	2.4 tonnes/day	1.05 tonnes/day	56%
PM_{10}	190 kg/day	15 kg/day	92%
$PM_{2.5}$	65 kg/day	7 kg/day	70%

A rather different assessment was made in 2018 (Preston, 2018), after nearly four years of operation (with two extended outage periods):

> *'The capture facility at Boundary Dam has been operating since 2014, almost four years. During this time, there have been difficulties with the plant being able to supply the contracted* CO_2 *to its off-taker. There were a significant number of design deficiencies and construction quality issues to manage. In addition, the Capture Plant continues to experience significant issues with the amine absorbent chemical that is fundamental to the process.*
>
> *These issues were, and continue to be, tackled in order of priority: 1) safety, 2) reliability, and 3) efficiency and cost-effective operation. As SaskPower implemented projects to correct the issues of which it was aware, the process was further complicated by the emergence of previously undetected issues that required further corrective action. At times, this involved long lead times to procure and install specialized equipment. This, coupled with amine-related issues, has contributed to lengthy outages and underperformance of the plant.*
>
> *Since the facility entered service, major work has been undertaken to:*
> - *Address safety issues and construction deficiencies;*
> - *Mitigate unanticipated reactions of the fly ash with the amine process;*
> - *Investigate and in some cases improve the systems designed to remove fly ash from the plant;*
> - *Increase thermal reclamation capability;*
> - *Mitigate increased degradation of the amine solvents;*
> - *Improve temperature control on various process units to meet design specifications;*
> - *Implement ongoing measures to clean fouling from heat exchangers;*
> - *Add isolation valves and selected redundancy and capacity increases on heat exchangers and process units to enable "on the-fly" cleaning of fouling; and*
> - *Incorporate instrumentation to measure fouling within the process control system.'*

Annual costs for solvent replacement alone were reported to a government committee as $17.3 million in 2015, $14.6 million in 2016 (SaskPower, 2016) and stated by the SaskPower chairman as $13.6 million in 2017 (SaskPower, 2018), against initially-predicted annual costs of $5 million. These solvent replacement costs would be consistent with the level of variable operation and maintenance (O&M) costs reported for BD3 in Fig 2.10, which also shows reported values for Petra Nova and predicted values from a study undertaken for Shand, another coal plant in Saskatchewan.

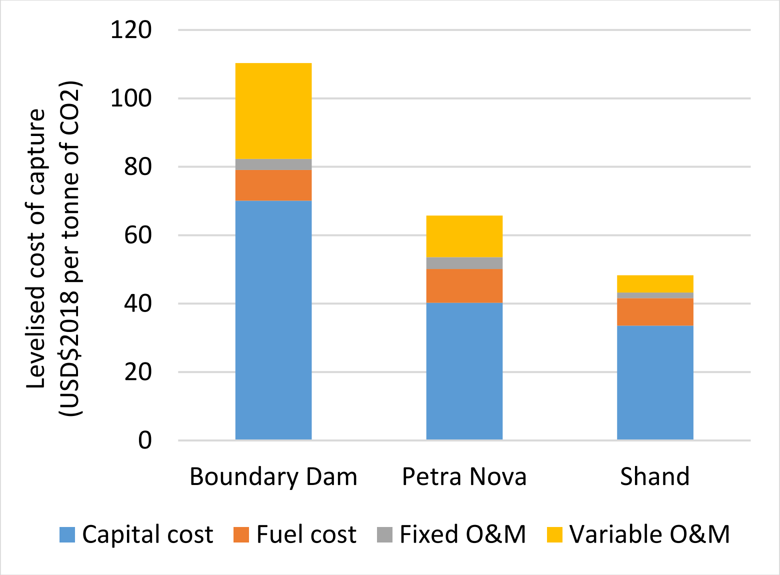

Fig 2.10 GCCSI analysis of levelised cost of capture for BD3, Petra Nova and a proposed retrofit plant at Shand (data from GCCSI, 2019)
'Variable O&M' costs are likely to be predominantly for solvent management and replacement. Results based on 8% discount rate, 30 years' project life, 2.5 years' construction time, capacity factor of 85%. Cost data are normalised to 2017 values. Stated expected accuracy range: Boundary Dam and Petra Nova: -10% to +15%, Shand: -25% to +40%.

More recently (CCSKC, 2020a), based on experience at BD3, it was stated that:

> *'……. the research currently available on post-combustion amine-based carbon capture is insufficient for adequately understanding interactions between amines and flue gases.*
>
> *"Long-term testing of amines was quite often limited in duration around the time that BD3 was built. The data we have on the behaviour of the amine used on this particular facility does not reflect the accelerated degradation that occurred closer to 3,000 or 4,000 hours of run time."*
>
> *In the presence of the common components and undesirable particulates present in a flue gas stream, amines degrade and must be replaced with fresh amine solution for the capture process to continue optimally. Degradation products and operational challenges are unique to each of the different amines in combination with various flue gas streams. As such, piloting must adequately emulate the conditions of the final, full-scale process.*
>
> *To address this research gap, the Knowledge Centre is considering the development of a skid – a portable testing apparatus. One of the main objectives of the skid would be to conduct longer-term monitoring of amine behaviour that will emulate an equivalent environment on a smaller scale. Knowledge Centre Chemist, Colin Campbell, explains how the project has a completely different focus and approach to how carbon capture systems have traditionally been studied.*
>
> *"A lot of the test skids have been used for years to study the energy efficiency of a particular solvent system, but what we're interested in is how the amine reacts, how it degrades, and how it will behave, in contact with the gas stream."*
>
> *Long-term testing of an amine solution for carbon capture typically occurs after the product is selected at a pilot-scale facility, which is a rather large and costly process. The ability to test multiple amines prior to selection – targeting expected amine health on specific applications and flue gas streams – is the central purpose of the Amine Validation Program.*

> *A key design feature will allow the skid to be connected to a variety of carbon dioxide-containing gas streams beyond coal-fired plants as CCS technology is easily applicable to other heavy-emitting industries.*
>
> *"If we can predict amine behaviour on a given application because of learnings from running these test skids or from building a database of contaminants vs. amine types – ultimately, that information can go into either selecting the type of amine for a particular project or the size of the amine reclamation equipment," says Campbell.'*

A further comment on solvent performance at BD3 was provided in an IEAGHG report (IEAGHG, 2020): *'Shell Cansolv reported that solvent consumption costs had indeed been higher than anticipated at Boundary Dam. While the amine recovery efficiency had operated better than design, with higher than anticipated CO_2 capture and lower energy consumption, the degradation rate of the absorbent had been higher than expected. It was emphasised that these results were particular to Boundary Dam. For other plants, the absorbent used may not be the same, operating conditions may differ and the design of the reclaimer may also differ.'*

While there is a shortage of independent information in the public domain for proprietary solvent performance, what there is suggests that the impacts of regeneration energy consumption on the power plant electricity output penalty and hence specific capital costs and operating costs for different (fresh) proprietary, and non-proprietary, amine solvents are quite similar, as shown in the following figures. To help explain this, Fig 2.14 shows illustrative relative changes in power plant electrical output for CCGT+PCC and BECCS with PCC for a typical range of solvent regeneration energies. As can be seen, the relative change is of the order of 3% in output and hence electricity revenue for CCGT+PCC. The change is larger, at 10%, for BECCS with PCC, but it is possible that, with biomass flue gases, other solvent-related effects that have to be taken into account, such as solvent make-up amounts, can also be larger, as shown in Fig. 2.10.

Table 2.3 shows estimated cost breakdowns for CCGT plants using 30% w/w MEA (a primary amine) and CESAR-1 (blend of a secondary – PZ – and a sterically-hindered amine – AMP) from a theoretical study informed by pilot testing (Manzolini, 2015; Sanchez, 2014).

In addition, in actual commercial projects, other factors, such as health and safety issues, environmental performance, commercial availability, solvent cost, investor confidence and proven viability in long-term use, are also likely to be differentiating factors.

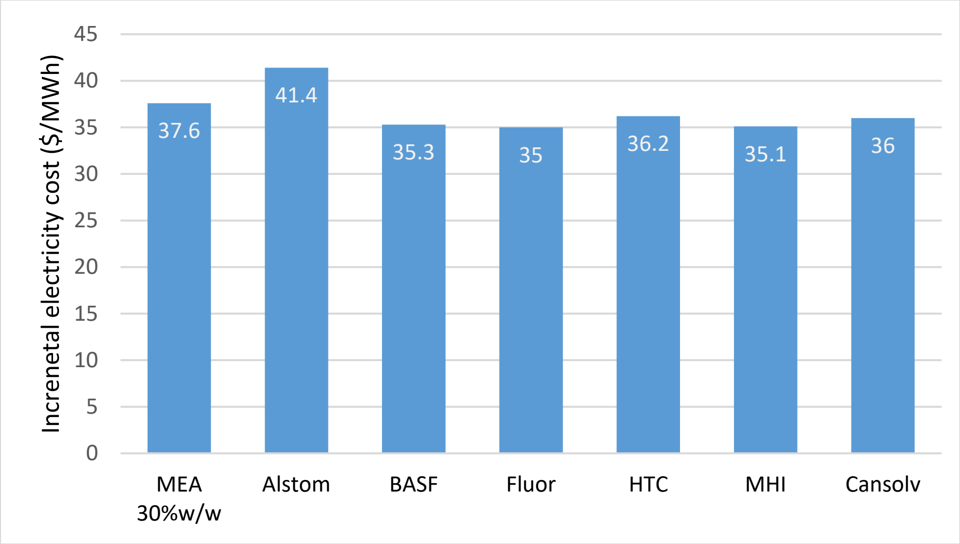

Fig 2.11 Estimated variation in additional electricity cost for a retrofit to a natural gas combined cycle power plant, for 30% w/w MEA and named proprietary solvents (data from Nexant, 2016)

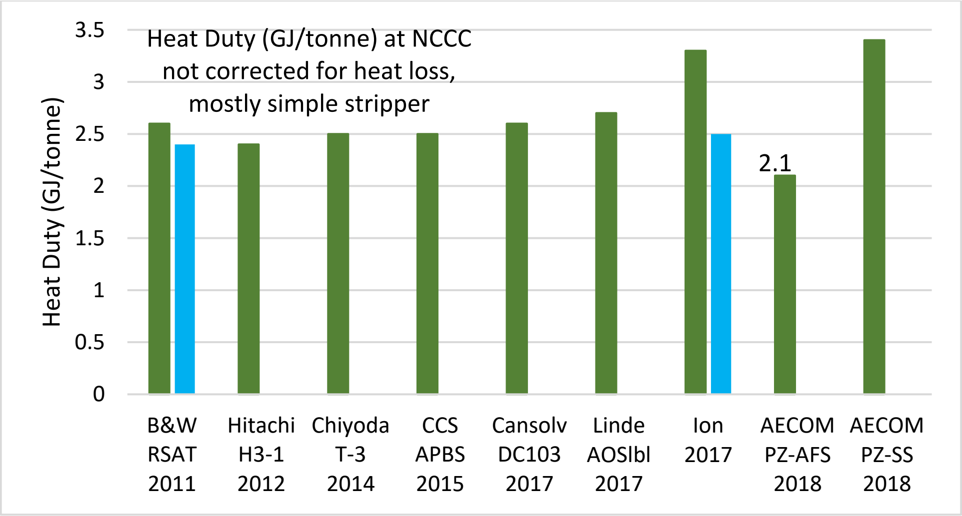

Fig 2.12 Estimated performance of proprietary solvents and piperazine in NCCC trials, from DOE Project FE0005654 (data from Rochelle, 2018)

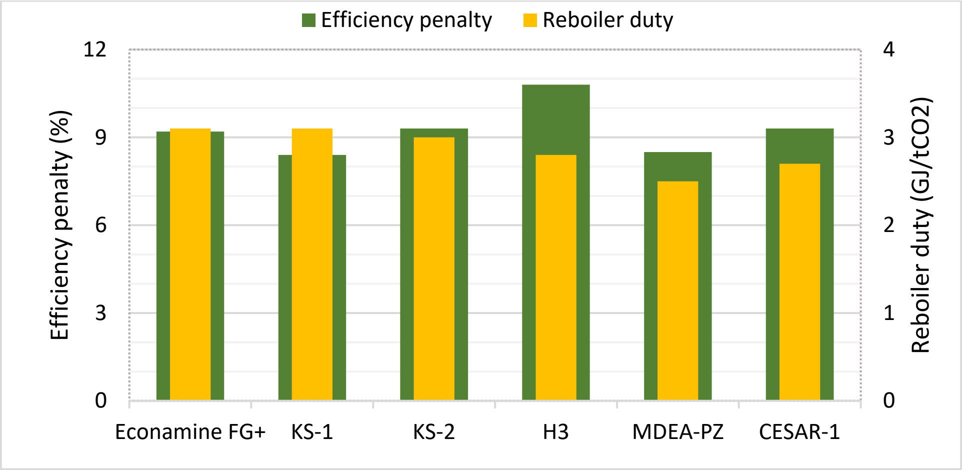

Fig 2.13 Estimated performance of PZ-AMP blend CESAR-1 (12 wt% PZ, 23wt% AMP) for coal flue gas, compared to other solvents (data from Fernandez, 2014)

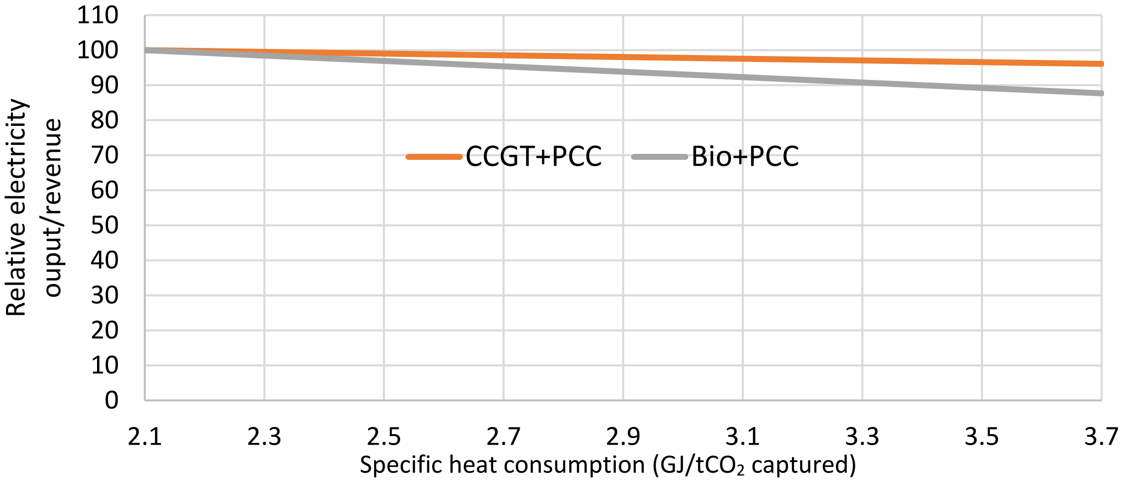

Fig 2.14 Illustrative effect of solvent regeneration energy on relative electricity output and electricity revenue that would need to be offset against other cost savings and benefits
(Assumptions: Heat input/power output ratio=4; LHV efficiency with PCC at min regeneration energy, CCGT=54%; bio(mass)+PCC/BECCS=30%; CO_2 captured=95%; Fuel LHV CO_2 emissions: Natural gas=0.2tCO_2/MWh.th, biomass=0.35tCO_2/MWh.th)

Table 2.3 Estimated comparison of 30% w/w MEA and CESAR (12% w/w PZ, 23% w/w AMP) for a natural gas CCGT application (Manzolini, 2015; Sanchez, 2014)

Principle details summarised below; see references for further information.

	No capture	MEA	CESAR-1
Net power output (MW)	829.86	709.92	722.61
Net electric efficiency (%LHV)	58.34	49.90	50.76
Capture level (%)		90	90
Solvent regeneration energy (GJ/tCO2)		3.95	3.39
Total plant cost (M€)		683	672
Total fixed O&M costs (M€/yr)		12.50	11.94
Variable O&M - raw materials[a] (M€/yr)		3.17	10.54
Variable O&M - utilities[b] (M€/yr)		6.35	0.95
Total variable O&M (€/MWh.net)		0.63	1.43
LCOE (€/MWh.net)		69.26	68.59

[a] Includes solvent make-up (1.5 kg/tCO_2 for MEA, 0.5 kg/tCO_2 for AMP, 0.05 kg/t CO_2 for PZ) and activated carbon (0.075 kg/tCO_2 for MEA solvent and 0.0375 kg/tCO_2 for CESAR-1 solvent).

[b] Includes cooling water and process water.

2.4 Noise

The Large Combustion Plant Best Available Techniques Reference document, termed LCP BREF, already cover noise impacts for the main power plant, so only additional process steps in PCC technology that have high potential for noise and vibration need to be considered here. In particular, CO_2 compression could be an area of concern. Once the principal sources and transmission pathways have been identified, the use of common noise and vibration abatement techniques and mitigation at source wherever possible should be considered, e.g.:

- the use of embankments to screen the source of noise
- the enclosure of noisy plant or components in sound-absorbing structures
- the use of anti-vibration supports and interconnections for equipment
- the orientation and location of noise-emitting machinery
- a change in the frequency of the sound

Health and safety risks of the embankments and enclosure options should also be considered.

2.5 Main BAT considerations and trade-offs

2.5.1 Emissions to atmosphere

Environmental impacts due to emissions of substances (leaving aside residual CO_2) to atmosphere from the PCC plant should be avoided wherever practicable and minimised to an acceptable Environmental Assessment Level (EAL) where not[10]. A critical factor here is the choice of the amine(s)

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[10] See https://www.gov.uk/government/collections/risk-assessments-for-specific-activities-environmental-permits for more details.

to be used, with direct consequences also for the types and amounts of degradation products they will form in the PCC system over time and the further products that emitted substances may form by reactions after they are released. Countermeasures against unwanted emissions will also be important, including under other-than-normal operating conditions, on the power plant as well as in the PCC plant itself. Countermeasures, following the prevent, minimise, render harmless hierarchy, are likely to include equipment for pre-treating the flue gas, equipment to manage solvent 'hygiene', modifications to operating parameters to reduce the formation or release of emissions, plus washes and filters at the point of release of the flue gases, to trap emissions before they enter the atmosphere. Flue gas height of release and release temperature, to provide adequate dispersion, are also important.

2.5.2 Combined optimisation of electricity output and residual CO_2 emission

The absolute amount of power plant electricity output lost due to operation of a PCC plant (including CO_2 compression and preparation for transportation and storage) is likely to rise continuously (although not linearly) as residual CO_2 emissions are reduced, so optimisation reflects a balance between the relative importance of maximising electricity output and minimising CO_2 emissions. The environmental impact of CO_2 emissions depends on average emissions over long periods (i.e. many years) while the importance of producing more or less electricity varies continuously with time (as frequently as half-hourly scheduling periods). Exploitation of the inherent flexibility of post-combustion capture is important when working out this optimisation averaged over an extended period (i.e. daily, weekly, yearly), by reducing capture levels at certain times (even to the extent of stopping to provide energy for the capture system under certain circumstances, e.g. impending power cuts), increasing capture levels at others, and possibly also storing solvent or energy for short periods of operation (see Section 7 for a more detailed discussion). A given amine solvent's intrinsic properties cannot be varied, but a range of options for PCC system design and operation should be considered for this optimisation. It is worth noting that modifications and improvements may be intrinsically more feasible for appropriately-designed PCC plants than for some other CO_2 capture technologies where incremental improvements may not be so feasible, e.g. oxyfuel, membranes.

2.5.3 Minimisation of environmental impacts from waste streams

PCC plant operation will result in the production of waste streams from, e.g., solvent management equipment and water washes. There are likely to be trade-offs between the amount and nature of these waste streams, but environmental impacts can be addressed by choices in solvent selection, plant operation and design, as well as by selecting appropriate on-site treatment and disposal methods. If waste stream compositions and hence treatment options are not already well understood (e.g. from relevant commercial plant operation) for a particular solvent and flue gas combination, then long-term pilot tests are obviously a good opportunity to develop environmentally robust, and cost-effective, recycling, use and disposal options.

2.5.4 Water usage (cooling and process)

While noting the water use hierarchy described in Section 4.7, EfW plants may present site-specific issues for water use in respect of retrofits to plants that use air cooled condensers, ACCs, on the steam cycle. No specific evidence has been identified, but consideration from first principles would suggest that additional cooling capacity will be required as steam is diverted to the PCC reboiler and the consequent heat rejection shifts from the ACC to the PCC unit, principally the lean amine cooler, the CO_2 reflux condenser and the CO_2 compressor intercoolers. In principle all of these duties could also use dry air cooling, either directly or indirectly, to avoid increased water use, but achievable temperatures may be higher than desirable, particularly during extreme weather periods. A compromise, based on the water hierarchy, might be the use of hybrid cooling options with water use reserved for periods of high ambient temperatures if water supplies are limited. Alternatively, PCC plant performance, in particular achieved CO_2 capture fraction, may need to be derated during periods of elevated ambient temperatures to allow for increased lean solvent temperatures and higher CO_2 inlet temperatures to compressor stages unless sufficiently large air cooling capacity is provided to achieve a fixed performance standard even under ‘abnormal’ operating conditions.

Depending on the water dewpoint of the incoming flue gas, PCC operation is likely to result in a net water loss or gain, since the outgoing flue gas is necessarily fully saturated with water after the final water or acid wash stage and temperatures here are constrained by other factors (i.e. available cooling temperatures, need to control amine volatility, need to avoid water dilution in an acid wash). Again no evidence has been located in the public domain, but it is evident that if water can be added to the PCC system via evaporation in a direct contact cooler than a lower purity source can be used than if water is added to the amine circuit directly (likely via makeup to a water wash). In general, process water management is likely to follow similar approaches to that for normal EfW plant operation under water-constrained conditions (e.g. Gardoni, 2015).

3. Power/EfW plant integration

Power plant integration issues include:

- Flue gas connection, pre-treatment and venting
- Energy for solvent regeneration, CO_2 compression and ancillaries
- Cooling options – scope to shift cooling load from condenser to PCC plant

These issues cannot be considered independently of the PCC system when developing an effective overall CCS power plant concept. They will be dealt with in two sections in this report, with cross-references where appropriate. Some of the issues are common to CCGT+CCS and BECCS power plants and EfW plants; others are more specific to a particular technology. These will be discussed first.

3.1 Power-technology-specific issues

3.1.1 CCGT + PCC

a) Exhaust Gas Recycling

Gas turbines are standard pieces of equipment and there are a limited number of suppliers for the largest scale units. No modifications appear to be available at the time of writing specifically to accommodate CCS, but one that has been discussed is Exhaust Gas Recycling (EGR) to give a higher CO_2 content in the flue gas [the term 'exhaust gas' is used in the gas turbine (GT) industry, but 'flue gas' will be retained for gas going through the PCC system throughout this review]. Unlike boilers, which use relatively little excess air in combustion, gas turbine combustors require significant amounts of excess air (order 200%) for cooling purposes, in the combustor itself and to limit gas temperatures going into the first set of blades. Flue gas CO_2 concentrations are then typically of the order of 5% v/v and oxygen levels around 15% v/v, instead of perhaps 10% v/v CO_2 and 1-3% oxygen for near-stoichiometric combustion of natural gas in air in a natural gas boiler. By recycling cooled exhaust gas to the GT inlet, the flue gas going into the PCC unit would reach some intermediate CO_2 concentration, closer to that for stoichiometric combustion, with the following advantages:

- the flue gas volume would be decreased, reducing the cross-sectional area of ducts, flue gas conditioning equipment prior to the absorber, and the absorber
- the CO_2 would be at a higher partial pressure, and so require less energy and less solvent to capture
- O_2 levels would be lower, so oxidative degradation levels and O_2 carryover in the captured CO_2 would be reduced

EGR at 40-50% has been proposed by Siemens for part load efficiency improvement (Jonshagen, 2016) and at 27% at full load by Mitsubishi Heavy Industries Limited (MHI) for nitrogen oxide (NOx) reduction (Tanaka, 2013); General Electric (GE) has also proposed EGR for NOx reduction (ElKady, 2009; Evulet, 2009). The LCP BREF document discusses EGR for NOx reduction in boilers and reciprocating engines, but apparently not for GTs. A detailed discussion on the application of EGR for PCC is available in Herraiz (2016).

Higher CO_2 concentrations and reduced oxygen levels (with no increase in flue gas volume) also result when duct firing is employed. Duct firing is used in the UK on gas turbine CHP plants (VPI, 2020), and more widely in the US on CCGT power plants to increase output at periods of peak demand (Gülen, 2018). The use of very heavy duct firing with PCC is modelled by González-Díaz (2016). By increasing the concentration of CO_2 in the flue gas the size of the PCC absorber is reduced, by up to a factor of two in the case studies where firing is assumed to proceed up to the limit of the flue gas oxygen content. The PCC EOP is reduced due to the higher CO_2 content, but the marginal efficiency for fuel fired in the HRSG is lower than in a GT (as also discussed in Gülen, 2018), so the overall plant efficiency with CCS falls compared to normal operation. But, if duct firing effectively provides additional generation capacity with CCS at reduced capital costs - and this will have to be verified for specific installation details - the boost in CCGT plant output from duct firing could offer advantages for CCGT+PCC power plants at times of higher demand (i.e. duct firing can be viewed as a peaking plant with CCS). Duct firing could also confer benefits because of reduced O_2 content in the flue gas and hence reduced amine degradation and also reduced O_2 carryover into the captured CO_2. But, especially for continuous use, these benefits of duct firing would have to be set against the reduction in overall thermal efficiency.

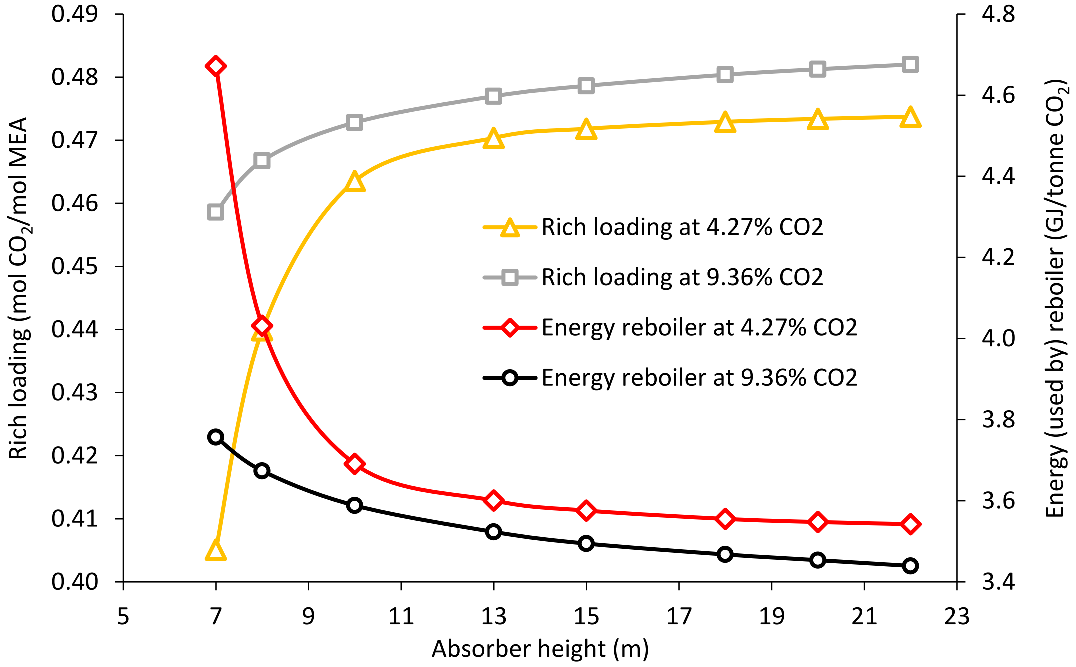

Fig 3.1 Calculated effect of CO_2 concentration in the flue gas on solvent energy of regeneration for 30% w/w MEA at a range of absorber column heights (data from González-Díaz, 2016)

The capture rate is 90%. The lean loading and pressure in the reboiler are, respectively, 0.27 and 1.9 bar for the unfired CCGT configuration and 0.26 and 1.9 bar for the maximum duct firing configuration. Similar trends might be expected for other solvents, but with different absolute values.

b) Fast-start CCGT plant

Fast-start has become increasingly valuable for unabated CCGT power plants as electricity markets contain more intermittent renewable power sources and average load factors for thermal plants decrease; multiple options are being offered by the major Original Equipment Manufacturers (OEMs) (e.g. Varley, 2016; Van der Biest, 2018; Siemens, 2020; GE, 2020). This technology can readily be combined with PCC to give full capture throughout starts and stops.

Fast-start capability and robustness when operating with multiple starts per year depend on both the GT and steam cycle design. PCC performance and the ability to capture CO_2 during the whole start and stop sequence is also facilitated by suitable steam cycle design and specific modifications. As detailed in a recent study for BEIS (AECOM, 2020), which is summarised in more detail in Section 7: '….. *fast starting steam cycle technology ….. would significantly reduce the time lag before steam can be extracted to the PCC plant.*

Fast-starting steam cycle technologies include:

- *Operational procedures such as carrying out the combustion path purge at shut-down instead of start-up*

- *Feedback control and automatic adjustment of the gas turbine inlet guide vanes at start-up*
- *Once-through high-pressure boiler technology such as the Benson Boiler equipment (as originally installed in the UK at Cottam*[11]*)*

Fast steam cycle starting technologies have the potential to impose extra fatigue on the steam cycle, with the connection between the high-pressure drum (for a fast drum boiler) and its steam riser being the component at most risk of failure in work by Foster Wheeler America (Power, 2013). The same report also proposed advanced plant controls to mitigate the impact on component life. Another report by VPI (Power, 2010) proposed a full inspection and monitoring program based on condition modelling for fast starting and cycling CCGT based on adapting sub-critical HRSG for fast starts. Sufficient measures to mitigate any impact on steam cycle lifetime are therefore expected to be available such that the net penalty in plant life for fast starting would be likely to be negligible. Note that a […] once-through boiler such as the Benson technology would avoid the high-pressure drum and therefore stress issue altogether, albeit imposing stricter water quality and operating procedure requirements than drum boilers.

Alternative means of improving the steam cycle response and therefore PCC plant start-up time particularly during the cold start include diverting bypass steam into the amine reboiler. The bypass steam is normally dumped into the condenser and the heat rejected until steam quality is acceptable to use in the ST. However, the amine reboiler minimum requires only LP-grade steam. Therefore, the PCC plant can utilise heat that would otherwise be wasted into the condenser during start-up, completing the PCC start-up significantly sooner particularly in a cold start scenario. However, the diverted steam will be of continuously increasing quality during start-up, imposing requirements on let-down to LP to protect against introducing supercritical steam into a low-pressure system. The steam must also be appropriately de-superheated to avoid overheating the reboiler and amine inventory.

The steam diversion option would connect by a take-off valve on the HP bypass line and require controls to be put in place for the rising upstream steam quality during start-up. Measures could include multiple parallel control valves of dissimilar trim sizes to cover the range of conditions encountered or other split-range control measures. This option would require rigorous analysis to ensure adequate safeguarding measures are put in place to protect the low-pressure equipment in the amine plant.

Once the steam cycle start-up is complete, steam extraction should progressively switch over to the normal operating extraction point i.e. the IP/LP cross-over as prolonged operation on HP steam let-down would be inefficient for the plant.

Alternative means could be an arrangement with an intermediate back-pressure turbine such as investigated by Bechtel for Loy Yang A (Bechtel, 2018)*. Under such an arrangement, steam extraction for the PCC plant would always be via the main ST HP bypass, with the intermediate back-pressure turbine also bypassed during start-up, with expansion through the back-pressure turbine once start-up is complete. Clearly, an additional turbine and generating equipment would be required in this scenario compared to the standard configuration and any other improvement configuration which would introduce cost and complexity. However, the incremental costs would likely be partly offset by less onerous extraction connection works required. In particular, the HP bypass line is more likely to be easily accessible on existing plants than the IP/LP cross-over. Existing plants considering retrofit of PCC may see more benefit from this option (providing suitable location can be provided for the back-pressure turbine).'*

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[11] Reported UK sites with Benson Boilers include: Cottam; Langage; Severn Power; Keadby 2 [redacted]

c) Selective Catalytic Reduction (SCR) to remove NOx
NOx can contribute to nitrosamine formation in amines (see Section 6 for more details), so SCR is expected to be installed on new CCGT plants with PCC if this is an area of concern with the solvents being used. The use of SCR raises the issue of ammonia (NH_3) slip, but NH_3 will be removed in either the DCC before the absorber or, if necessary, in an acid wash provided at the top of the absorber. If SCR is not fitted, then the HRSG or boiler can be built 'SCR-ready' to allow it to be implemented in the future (e.g. the Peterhead HRSG units were SCR-ready and would have had SCR added had PCC been retrofitted (Snow, 2014; Peterhead, 2016)).

d) Other flue gas impurities
Natural gas is not expected to give rise to any further impurities in the flue gas, except possibly very low levels of SOx from the odorant (unless removed), but in some cases combined cycle units may also use at least some fuel gas from other sources (e.g. anaerobic digester gas, or 'waste' fuel gases from steelmaking or refineries). High levels of sulphur species removal are also expected for these sources, but residual levels and possible plant upsets need to be considered. One possibility is the addition of alkali to the DCC, but this may not be feasible if sudden and infrequent changes occur (or if no DCC is used). If the main consequence is temporarily-increased Heat Stable Salt (HSS) formation, then it is possible that normal solvent maintenance measures will correct the problem – in effect it would be post-event alkali addition in the thermal reclaimer. If, however, there is SO_3 aerosol formation then there is a possibility of unacceptable levels of seeded amine mist carryover from the absorber, when the only option might be to stop capture. This would register as high amine levels on continuous monitoring instruments connected to the stack by a heated line, although isokinetic sampling plus proper sample handling (Shah, 2018) would be needed to get an exact value.

3.1.2 Biomass power plants

a) Flue gas impurities and emission control systems
Impurities of concern for biomass power plants are NOx, SOx and particulates, with reasonably well-understood consequences in terms of HSS formation from SOx, but less accurately predictable impacts on solvent degradation and nitrosamine formation from NOx and particulates. NH_3 in the flue gas, including from SCR slip, will also report in the DCC or PCC wash section.

Chlorine and other impurities found in biomass may be largely removed in a DCC, but if not will have to be removed by suitable solvent management techniques (e.g. thermal reclaiming) and may cause corrosion and degradation issues if allowed to accumulate.

Any aerosol presence, from SO_3 if present but perhaps alternatively from fine particulates, would also be of major concern, as it has the potential to cause solvent mist carryover from the absorber and is hard to correct either by subsequent flue gas treatment or by measures at the absorber outlet. Solvent mist formation would be evidenced by increased amine losses measured using iso-kinetic sampling that would capture both amine vapour and fine droplets. Ideally this would not be identified for the first time in full-scale operation though, but would have been observed during pilot trials using the actual amine and flue gas and, importantly, with realistic liquid and gas temperatures along the flue gas path in the pilot plant absorber column. Since serious amounts of aerosols may only occur at certain times, e.g. when firing a fuel with higher S content, extended trials where the full range of potential plant fuels are fired are also important.

For NOx and SOx, the LCP BREF gives guidance for emission reduction technologies to be applied to biomass. Selective Non Catalytic Reduction (SNCR) or SCR may have to be considered if lower NOx levels are required. Aerosols, and to some extent all SOx, may be addressed by the use of baghouses, with added absorbent injection if the alkalinity in the fly ash is not sufficient (Beaudry, 2018).

Gas/gas rotary air heaters are also reported to be effective in avoiding SO_3 mist formation (Mertens, 2015; Reddy, 2017)

For all impurities, though, a satisfactory level of flue gas treatment can be verified only by long term testing (pilot trials or actual operation) on the actual plant flue gas. As well as the major role for solvent maintenance methods in determining the response to impurities, actual fuel variations, operational variations etc. will all affect actual outcomes.

b) Boiler type and steam conditions (see also LCP BREF (2017) guidance)
For new BECCS plants, operators are likely to be interested in achieving fuel flexibility, with fluidised bed boilers generally expected to offer the most scope. Supercritical steam conditions should also be examined for increased efficiency, although the operability of the plant may also have to be considered, since even for BECCS plants baseload operation may not be an option in the future (National Grid, 2020). In addition, the ability to provide primary response frequency stabilisation, facilitated by stored energy in steam drums, as well as by the option to stop steam extraction to the PCC reboiler, is likely to be valuable. Supercritical steam conditions are also not expected to be feasible for smaller size units; the first supercritical CFBC plant using coal (at Lagisza, Poland, commissioned in 2009) had an output of 460 MWe (Burnard, 2011).

3.1.3 EfW combustion and gasification/pyrolysis plants with amine PCC

a) Flue gas impurities and emission control systems
On PCC capture plants retrofitted to existing EfW plants a recent study by AECOM for BEIS (AECOM, 2022) stated that:

> *….. it is important that the composition of the flue gas is understood and the interface with the existing plant is appropriately designed. The level of additional treatment required will be site specific and depend on factors including the feedstock used, the emissions abatement system already in place and the requirements of the proposed capture technology.*
>
> *For contaminants including particulates, heavy metals and volatile organic compounds, it has been assumed that the abatement measures included in the host process plant will be relied upon. The long-term impact of trace contaminants on solvent performance is an area of uncertainty and the subject of ongoing research.*
>
> *Two important parameters to consider in relation to flue gas pre-treatment are NOx and SOx. These are discussed in more detail below.*
>
> ***Oxides of Nitrogen – NOx*** [but see additional comments below, at the end of this quotation]
> *Oxides of nitrogen react with amine solvent and cause the solvent to degrade. Of particular concern is NO_2, which reacts to form nitric acid and subsequently heat stable salts, and nitrosamines if secondary amines are present. It has been suggested that the concentration of NO_2 in flue gas should be restricted to approximately 20 ppmv at 6% O_2 for economic post-combustion capture using amine* (IEAGHG, 2004). *Converting to the reference O_2 concentration for EfW flue gases gives a guidance figure of 13 ppmv at 11% O_2, or 27 mg/Nm^3.*
>
> *The reference flue gas for the EfW benchmark has a NOX concentration of 150 mg/Nm^3. If 10%* (EA, 2007) *of the NOX is NO_2 this gives a NO_2 concentration of 15 mg/Nm^3. On this basis no further NOx control would be needed prior to an amine capture plant based on this input gas specification. However, it is noted that some projects that are developing carbon capture for EfW plants assume that additional SCR will be installed as part of the capture plant retrofit, based on specific flue gas conditions and proprietary solvent performance.*
>
> ***Oxides of Sulphur – SOx***
> *Oxides of sulphur also react with amine solvent causing it to form heat stable salts. It has been suggested that the concentration of SO2 in flue gas should be restricted to approximately 10 ppmv at 6%O2 for economic post- combustion capture using amine* (IEAGHG, 2004). *Converting to the*

reference O2 concentration for EfW flue gases gives a guidance figure of 7ppmv at 11%O2, or 20mg/Nm^3*.*

The reference flue gas for the EfW benchmark has a SOX concentration of 20 mg/Nm^3*. If 95%* (Green, 2016) *of the SOX is SO2, this gives a SO2 concentration of 19 mg/Nm*^{3}*. On this basis no further SOX control would be needed prior to an amine capture plant based on this input gas specification. If reduced SOX levels are required, it may be possible to meet them by making changes to the operation of the acid gas abatement system.*

When considering the above AECOM recommendations on NOx and SOx for EfW applications it is, however, necessary to reflect that these NOx and SOx level recommendations can be traced back to sources that referred specifically to MEA, as below:

a) a paper on the Fluor Econamine FG process (Chapel, 1999),

b) a study by Fluor for IEAGHG (Fluor, 2004).

It cannot be emphasised too strongly that different recommended limits may apply for other solvents, noting in particular that NO_2 may be able to form nitrosamines directly with some solvents as discussed in Sections 2.3.4 and 6, not just form heat-stable salts as described for MEA below.

Chapel (1999) on NOx for MEA: *Thus far, oxides of nitrogen have never created problems in Econamine FG units, however they have led to corrosion of steel and amine degradation in other plants. The Bridgeport* CO_2 *recovery plant did not eliminate some corrosion problems until the NOx was reduced to less than 1 ppmv in the absorber feed. NOx is best controlled though control of the peak flame temperature in the boilers. Also, any boiler NOx reduction (SCR) equipment will benefit the absorption process. The chief culprit in NOX is* NO_2*, which reacts to form nitric acid in the amine solvent and ultimately heat stable salts. However, typically only 10% of the NOx is* NO_2 *and only a fraction of the* NO_2 *gas is absorbed in the solvent. NOx can be a problem in the* CO_2 *product if it is to be used in the food and beverage industry and steps must be taken in the liquefaction unit for its removal.*

Fluor (2004) on NOx for MEA and MHI: *The flue gas input to a solvent scrubbing unit has to have low concentrations of SOx and* NO_2*, as these substances result in loss of solvent. The SOx limit is set at 10ppm(v) by Fluor and 1 ppm(v) by MHI. Such low concentrations can be achieved by current FGD technologies. The* NO_2 *limit set by Fluor is 20 ppm(v) but the selective catalytic reduction (SCR) unit included in the coal fired plants in this study produces a flue gas with a* NO_2 *concentration to 5 ppm(v).*

Chapel (1999) on SOx for MEA: *Flue gases can contain significant concentrations of SOx unless natural gas or very low sulfur fuels are being fired. SOx reacts irreversibly with MEA to produce non-reclaimable corrosive salts that are very detrimental to plant operation. For MEA-based processes, it is less expensive to install a SOx scrubber than to accept the solvent losses when the flue gas contains more than 10 ppmv* SO_2*. Coal fired boilers produce the highest concentrations of SOx, often 300 to 5000 ppmv before flue gas desulfurization (FGD), but even oil firing can produce 100 ppmv SOx. The limestone or wet lime FGD systems in large power boilers today achieve SOx reductions in the 90-95% range. Therefore, even the flue gas from a low-sulfur liquid or solid fuel, or from a limestone FGD system needs further* SO_2 *removal. The 10 ppmv* SO_2 *requirement is met by using the active alkali metal neutralizing agents, caustic soda or soda ash, in a relatively inexpensive spray scrubber.*

Sulfur trioxide, SO_3*, presents additional problems.* SO_3*, like* SO_2*, leads to solvent losses due to the formation of non-reclaimable heat stable salts, but it also forms a corrosive* H_2SO_4 *aerosol in wet scrubbers. Furthermore, less than one-third of the* SO_3 *may be removed by the* SO_2 *scrubbing system unless a special mist eliminator is used. Therefore, most of the remaining* SO_3 *will form heat stable salts in the absorber. The fraction of SOx which forms* SO_3 *is a function of combustion, fuel*

> *composition, and flue gas processing factors, but SO_3 typically accounts for a few percent of the total sulfur. Minimization of SO_3 is a boiler design issue preferably handled upstream of the SO_2 scrubber.*

b) Steam supply

Steam supply for PCC retrofits on EfW plants shares the problem common to all power plants of extracting large amounts of steam from steam turbines that were not designed for it. In addition, a number of EfW plants (in the UK, 12 of 53 in the 2019 fleet, as noted in Section 2.2.5) are committed to supplying heat for district heating or industry. As discussed in Section 3.3.3, experience outside the UK, where heat supply is more commonly applied to EfW plants, suggests that the latter constraints are overcome using a combination of steam cycle modifications and installation of heat pumps.

The scope to extract steam from the steam cycles of existing EfW is discussed at a general level in a recent study for BEIS (AECOM, 2022):

> *If a carbon capture plant is being retrofitted to an existing EfW facility, a certain amount of steam will be available from the existing EfW plant with limited modifications required. The mass of steam that is easily available will depend on the design of the steam turbine and steam system installed. If sufficient steam is readily available, then the cost of steam would be proportional to the reduction in electrical output that results from extracting steam from the turbine. This was the assumption made for cost of steam in the gas fired power plant scenarios.*
>
> *The capture plant requires a significant thermal energy input relative to the total energy flow in the steam cycle of the host EfW plant. At many facilities it may not be possible to easily extract the required volume of steam from existing equipment due to limitations in the design of the installed steam turbine. For example, the diameter of extraction nozzles. Even if the steam system at an existing EfW plant could provide the required volume of steam with limited modifications, then there may be efficiency or operational flexibility penalties associated with extracting this volume of steam.*
>
> *For the purposes of this study the unit cost for steam in any given year of the model has been assumed to be the wholesale electricity price for that year divided by 2 for the EfW scenarios. This value for the unit cost of steam includes contributions from both capital and operational costs associated with providing the steam. It is based on the value of lost electrical generation plus a nominal uplift to account for the fact that extensive steam system modifications could be required, and efficiency or operational flexibility penalties could occur depending on how the existing steam system is modified. The actual cost of thermal energy provision will vary between sites and there may be instances when plants are able to access steam with a lower unit cost than that assumed. When carbon capture projects are being investigated at specific EfW sites, the provision of thermal energy to the capture plant should be considered at an early stage of the design process.*
>
> *EfW plants may also need to consider the provision of thermal energy to existing, or proposed future, district heating networks. Supply of heat to a district heating network is a highly effective and relatively low-tech way of increasing the efficiency of an unabated EfW plant. The export of heat from EfWs decreases CO_2 emissions per unit of energy recovered and should be encouraged for both existing and proposed new EfW plants. New-build EfW plants should seek to be co-located with industrial heat users where possible.*

As described in Section 3.3.3, detailed site-specific studies may, however, be able to achieve better energy performance than might be inferred from the generic, high-level AECOM modelling assumptions although, given that new or additional equipment may be required in these approaches, the AECOM assumption of taking steam cost per unit energy (i.e. this is not the ratio of steam energy to electricity lost) as half the corresponding electricity price is still qualitatively consistent.

A recent modelling study (Su, 2023) also reported that, with enhanced heat recovery methods, district heating output could be maintained after PCC retrofit and also that high CO_2 capture fractions (>99%) could be achieved.

c) Gasification/pyrolysis EfW plants with PCC

No examples have been identified in the public domain literature for gasification/pyrolysis EfW plants that incorporate PCC. Nonetheless there are examples of such plants with flue gas streams vented to the atmosphere that contain significant amounts of CO_2 and overall plant capture levels will be significantly reduced if PCC is not applied to these streams. It is anticipated that these streams will be no ‘dirtier’ than normal EfW flue gases and possibly, in some cases, will be cleaner due to upstream processing for the fuel used.

3.2 Flue gas connections to and from the PCC unit

CCS power plants are currently expected to retain a conventional stack to allow operation without the PCC unit in service, although this may not always be considered necessary.

With a conventional stack the question then arises whether to attempt to use dampers to close off the possibility of flow up or down the conventional stack when the PCC plant is operational. An open stack reduces the risk of under- or over-pressurisation but also increases the probability of a flow imbalance, with small amounts of air entering the PCC unit or small amounts of flue gas entering the stack. If there are multiple stacks then, given the possibility of leakage even if dampers are fitted, they will all require continuous monitoring.

With or without a stack damper, close matching of the PCC fan system is required, possibly augmented by dampers controlling flow to the PCC plant. Rapid response is likely to be more easily controlled using variable pitch (for axial fans) or variable guide vanes rather than motor speed control alone.

The very large duct sizes required may make connections and routing difficult for retrofits to existing plant, particularly on sites with multiple boiler units sharing an existing stack.

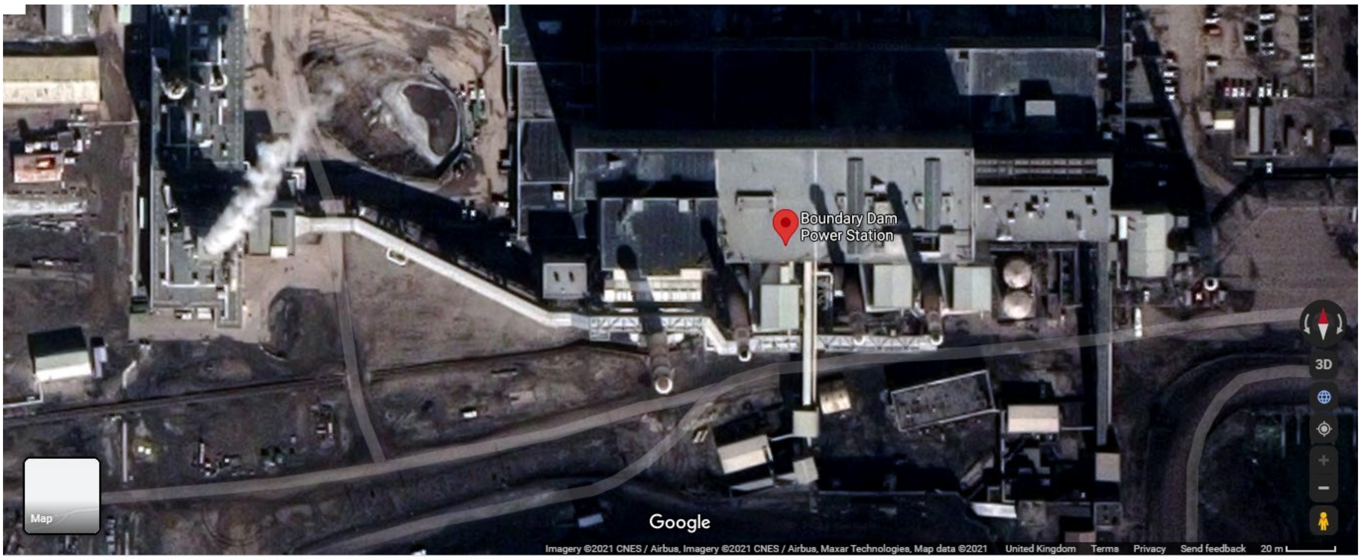

Fig 3.2 BD3 with PCC in Google Maps satellite view – the light-coloured flue gas duct runs from the base of the stack on the right of the power plant to the PCC on the left; a vapour plume is visible from the top of the absorber (image from Google Maps)

For CCGT units, if the existing or planned stack is based at ground level at the end of the HRSG with a horizontal gas path (i.e. rather than on top of an HRSG with a vertical gas path) then the location for duct connections should be relatively easy to access (unless hindered by other plant), although mechanical and flow issues will obviously still need attention. The stack connection planned for a CCGT unit is shown in Fig 3.3.

Fig 3.3 Proposed tie-in to existing, ground-based CCGT stack
(Bechtel, 2009 - reproduced with permission from Bechtel)

Flue gases leaving the absorber will be saturated with water and at the final wash temperature. They need to be vented at a suitable height and temperature to give satisfactory plume dispersion and also to minimise plume visibility. This can be from a stack on top of the absorber or from a separate stack based at ground level. A slipstream flue gas flow was proposed to be returned to the same duct at Maasvlakte (ROAD, 2019), but one of the principal advantages of this, heat addition from mixing with the remainder of the flue gas, would not be realised in a plant with full CCS and also the risk of flue gas recirculation would likely be much higher. A separate duct, in the same, or a separate, stack, might therefore be preferred if the flue gas is not vented directly from the absorber.

If heating is found to be necessary and the flue gases are vented at the top of the absorber, the heating will need to take place in gas heaters using heat removed from the incoming flue gas or heat recovered from the steam cycle or from the PCC or compression plant, via heat transfer fluid or steam. This was proposed for flue gas reheating to 75°C in a brown coal PCC retrofit study (Bechtel, 2018), see Fig 2.6. In contrast, a flue gas cooler was installed at BD3 and is used for feed water heating (Preston, 2015).

If the flue gases are returned to ground level then a gas/gas heater can be used to transfer heat directly from the incoming flue gas (e.g. see Herraiz, 2016 for analysis) before sending to a stack. This was proposed for the Peterhead PCC project (Peterhead, 2016), again for flue gas reheating to 75°C.

Alternatively, it might in principle be possible to vent the unheated absorber flue gases through a natural draft cooling tower, as is done with the flue gas leaving the FGD unit in some coal power plants (e.g. Glamser, 1989), but this type of cooling tower might not be selected for new plants in the UK.

The EfW+PCC plant at Duiven (Wassenaar, 2020) returns the flue gas from the absorber to a separate stack with much greater elevation than the top of the absorber – see Fig 2.10.

3.3 *Energy integration and steam sourcing*

3.3.1 PCC heat and electricity supply without integration

Using separate facilities to provide steam for the routine operation of a PCC plant attached to a power plant will always introduce increased system complexity and interdependence, and hence reduced RAMO (Reliability, Availability, Maintainability, Operability) is an obvious drawback.

The separate facilities must also include CO_2 capture to avoid excessive overall CO_2 emissions. For 'conventional' additional facilities also using PCC (see IEAGHG, 2011 for a more complete discussion), the only satisfactory way to achieve best available thermal efficiencies (i.e. to produce as much electricity as possible for the additional fuel burnt, as well as also providing the necessary heat) in separate facilities used to provide steam for PCC is:

a) if using the same fuel, to add another unit of roughly similar size and type (except using the latest technology), so approximately doubling fuel use and electricity output;

b) if using natural gas to support PCC on a biomass power plant, to add a large and high-efficiency combined cycle CHP plant also with PCC, with an electricity output that would probably exceed that of the biomass plant, i.e. the installation effectively turns into a fossil plant with an add-on biomass unit.

Petra Nova is <u>not</u> a good example of BAT for UK conditions, since it used a small GT and a duct-fired HRSG generating low-pressure steam only, i.e. it did not produce as much electricity as possible from the fuel before producing low-pressure steam to use in the reboiler (Petra Nova, 2017; 2020). Moreover, this ancillary unit did not have CO_2 capture.

As discussed below and elsewhere in this report, since satisfactory efficiencies can be obtained using steam extracted at IP inlet pressures, from the hot or cold reheat, even if there are difficulties in using steam from the IP/LP crossover or similar extraction point, there should be no insuperable obstacle to using integrated solutions for PCC steam provision in retrofits, and obviously none in new-build plants.

Some examples of the poor performance for the use of boilers compared to integrated steam extraction in PCC retrofits to CCGT plants are shown below (Gibbins, 2009).

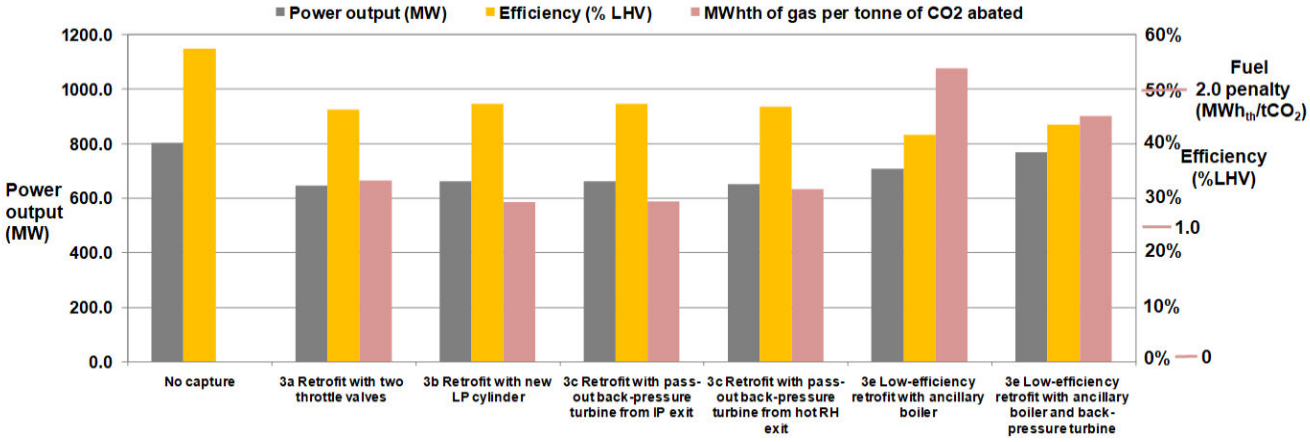

Figure 3.4 Comparison between post-combustion retrofit options for natural gas-fired CCGT plants
(data replotted from Gibbins, 2009)

3.3.2 PCC heat and electricity supply with integration

PCC and compression requires energy in the form of heat and electricity but, when assessing the energy performance of PCC plants integrated with the main power plant, the only relevant measure for power plants is the Electricity Output Penalty (EOP), the overall loss in electricity output from the power plant as a result of capturing and compressing CO_2 compared to a defined unabated counterfactual plant configuration, with kWh/tCO_2 captured being convenient units and the flue gas CO_2 concentration also being a relevant factor. Less comprehensive metrics that are sometimes quoted, e.g. 'steam consumption', 'overall energy' (i.e. equating heat and electricity), GJ/tCO_2 captured, parasitic steam consumption, parasitic power etc. can give only a partial overview of the multiple integrated and interdependent effects that together determine the overall result and, because they give incomplete information, are open to gaming when used to, e.g., indicate the performance of different solvents and technology options. Even measures that quote 'percentage of plant output lost' or similar, are also dependent on the original efficiency of the power plant, so two identically-effective PCC systems could appear to give different results depending on whether they are used in a new-build or a retrofit application. Quoting percentage points difference in thermal efficiency between unabated power plants and those with PCC is more robust, but still gives different results for the same overall PCC performance depending on fuel composition and hence flue gas composition. A discussion of EOP is given in Lucquiaud (2011).

Provided power plant integration is conducted in accordance with reasonable thermodynamic principles that seek a 2nd Law optimisation, where work (i.e. electricity) output is maximised as far as possible, it is likely that a range of different integration options will give similar overall results for a given solvent and for similar constraints, e.g. peak reboiler temperatures, on the use of the solvent.

An example of similar results for different options is in steam extraction for solvent heating. Usually most of this heat is required at a single temperature (i.e. for a reboiler) and this is obviously supplied most reversibly by condensing steam. The principle then is that this steam should be expanded to the pressure at which it is supplied to the PCC system in a turbine producing work (though in a CCGT plant possibly some steam is also produced in an LP evaporator run at the appropriate pressure). This expansion is often envisaged to all take place in the main power plant turbine, with steam extracted at the IP/LP crossover, but similar (and possibly even more reversible) results may alternatively be obtained by expansion from the hot or cold reheat through a Back Pressure Turbine (BPT). The latter option, as noted above in Section 3.1.1, may, with a BPT bypass, facilitate starts and stops, and also allow steam to be delivered at full pressure to the PCC plant at part load, when the IP/LP crossover pressure would tend to fall due to reduced steam flows. It can also be more convenient for supplying higher-pressure steam for a reclaimer. The alternative, for a IP/LP steam extraction point for reboiler steam supply during part-load power plant operation, could include running with reduced reboiler temperatures, and possibly impaired PCC plant operation or excessively low LP steam turbine cylinder flowrates, or the use of a lower flow of higher-pressure steam in a steam ejector to raise the pressure of steam from the IP/LP crossover, as proposed for partial capture from a coal plant at Maasvlakte (ROAD, 2019) and analysed for a CCGT plant by Apan-Ortiz (2018).

If, as is likely, the temperature of the extracted steam for the reboiler is significantly above the saturation point after this expansion in a turbine then it will need to be desuperheated, not least to avoid excessive thermal degradation of the solvent. The most reversible way to do this is to use a desuperheating Feed Water Heater (FWH), but this may not always be feasible, especially in CCGT plants without a FWH train. Spray desuperheating with reboiler condensate is then a good alternative option (Gibbins, 2004) but spray desuperheating with cold water is obviously not (unless this cold water can be pre-heated using 'waste' heat recovered from somewhere else in the plant).

Heat from PCC system coolers (e.g. a dry flue gas cooler and compressor intercoolers) may be at a high enough temperature to be used in the reboiler but, since it is available across a range of temperatures, this will inevitably involve irreversibilities. Other heat (e.g. from the stripper reflux condenser) will be at a lower temperature than the reboiler. For BECCS plants it may be better applied in the condensate/FWH train of the main steam cycle or for other liquid heating duties (including possibly for PCC stack heating). For CCGT plants, no use can be made of heat in the main steam cycle at temperatures below the LP evaporator pinch, although recovery for other purposes such as flue gas heating after the absorber may be worthwhile.

Although various heat recovery concepts may theoretically be viable (i.e. consistent with the 2nd Law of Thermodynamics), capital cost and RAMO considerations will constrain what is reasonably worth doing, as well as the characteristics and hence detailed heat requirements of the PCC unit. Of particular concern is the quality of the condensate return from the PCC plant or heat recovery units. As noted above, supercritical once-through boilers are likely to be preferred for efficiency and rapid response, but this places very high demands on feed water purity. For normal operation, this means that returning condensate will at least need to re-enter the main steam cycle before the deaerator (see CCSKC, 2018 for a discussion of steam cycle adaptation for PCC retrofit). For tolerance to leaks, steam/water from the main steam cycle should also always be at a higher pressure than the fluid on the other side of the heat exchanger so leaks are in the 'right' direction; otherwise an intermediate circuit could be used or, if the engineering team is confident it can achieve the desired level of security, continuous conductivity monitoring and fast-acting isolation/diverter valves might be employed on the PCC condensate return.

While this discussion establishes that integration schemes will be differentiated in their details, the overall performance of the specific integration components can be assessed by the equivalent overall coefficient of performance:

COPx = Heat supplied / Electricity output lost excluding compressor work

While evidence from actual full-scale applications is still emerging into the public domain, theoretical analysis e.g. (Lucquiaud, 2011; Sanchez Fernandez, 2012) suggests that a value of up to 5 may be achievable. See Annex 3 for a simplified analysis and worked examples.

3.3.3 EfW PCC heat and electricity supply options

Electricity supplies for the PCC plant would usually be expected to come from the EfW power plant. Steam would also most effectively be extracted for the EfW power plant steam turbine, but this may not always be feasible, even for plants which do not already have steam extraction committed for a CHP heat load. As noted in the Next Generation Capture study (AECOM, 2022d):

> *If a carbon capture plant is being retrofitted to an existing EfW facility, a certain amount of steam will be available from the existing EfW plant with limited modifications required. The mass of steam that is easily available will depend on the design of the steam turbine and steam system installed. If sufficient steam is readily available, then the cost of steam would be proportional to the reduction in electrical output that results from extracting steam from the turbine (and/or proportional to te reduction in heat output for up to 12 UK plants). This was the assumption made for cost of steam in the gas fired power plant scenarios.*
>
> *In this benchmark scenario, the capture plant uses approximately 66% of the thermal input to the steam turbine at the base EfW plant. At many facilities it may not be possible to easily extract this volume of steam from existing equipment due to limitations in the design of the installed steam turbine. For example, the size of extraction nozzles. Even if the steam system at an existing EfW plant could provide the required volume of steam with limited modifications, then there may be efficiency or operational flexibility penalties associated with extracting this volume of steam.*
>
> *For the purposes of this study, a steam cost of £28/MWh has been assumed for the EfW scenarios. This value for the unit cost of steam includes contributions from both capital and operational costs associated with providing the steam. It is based on the value of lost electrical generation plus a nominal uplift to account for the fact that extensive steam system modifications could be required, and efficiency or operational flexibility penalties could occur depending on how the existing steam system is modified. The actual cost of thermal energy provision will vary between sites and there may be instances when plants are able to access steam with a lower unit cost than that assumed.*

> *When carbon capture projects are being investigated at specific EfW sites, the provision of thermal energy to the capture plant should be considered at an early stage of the design process.*
>
> *EfW plants may also need to consider the provision of thermal energy to existing, or proposed future, district heating networks. Supply of heat to a district heating network is a highly effective and relatively low-tech way of increasing the efficiency of an unabated EfW plant. The export of heat from EfWs decreases CO2 emissions per unit of energy recovered and should be encouraged for both existing and proposed new EfW plants if they cannot be retrofitted with CCS. New-build EfW plants should seek to be co-located with industrial heat users where possible, to the extent that heat is still available after CCS is applied to the EfW plant.*

Some detailed site-specific studies that address these issues are described below (see also Su, 2023). These are able to achieve better energy performance than might be inferred from the generic, high-level AECOM modelling assumptions above although, given that new or additional equipment may be required in these approaches, the AECOM assumption of taking steam cost per unit energy (i.e. this is not the ratio of steam energy to electricity lost) as half the corresponding electricity price may still qualitatively consistent.

a) Klemetsrud FEED study (FOV, 2020a)

In a FEED study undertaken for PCC retrofit to the Klemetsrud EfW plant (FOV, 2020a) the interaction between steam supply issues and other heat demands was handled as described below:

> *All results presented so far have been aiming for maintaining the current district heating production at Klemetsrud, i.e. to be able to recover a heat effect from the capture plant equal to the heat effect lost by the steam extraction. As the CC plant has a large amount of low quality waste heat the most feasible solution found is using a heat pump to boost the low quality to levels sufficient for use in the internal district heating network. Unfortunately the heat pump is only able to produce hot water at temperatures of 85 °C, so the remaining heat needed to reach the district heating supply temperatures is to be supplied by the plant. However, in case the district heating network supplied by the plant could be expanded there is more waste heat available within the capture plant that potentially could be utilized for increasing the district heating production.* [Table 3.1] *below shows the maximum district heating production that can be produced by maximizing the amount of heat the plant can receive from the capture plant heat pump while still being able to further increase the district heating water temperature to the supply temperature set-point from the 85 °C produced by the heat pump.*

Table 3.1 Evaluation of maximum district heating production by capture plant
(based on FOV, 2020a, Table 5-7, not including lines for redacted information; for the maximum district heating output case the scrubber heat recovery pump output is restricted to 13 MWe)

Heat integration solution		Updated plant,	Technip Solution 3a	Technip Solution 3a	Difference
Operational mode		Winter	Maintained DH production	Max DH production	
Plant flows	**Units**				
Plant output	MWe	24.210	20.315	20.315	0.0
Steam turbine K1K2	MWe	13.351	9.489	9.489	0.0
Steam turbine K3	MWe	10.858	10.825	10.826	0.0
District heating output	MWth	111.773	111.871	131.722	19.8
District heating output K1K2	MWth	31.409	31.487	42.975	11.5
District heating output K3	MWth	80.364	80.383	88.747	8.4
DCC heat pump recovery	MWth	-	33.968	53.241	19.3
Condensate heat recovery	MWth	-	0.0	0.0	0.0

The approach to delivering integration, based on a new steam turbine is shown in Fig. 3.5 below.

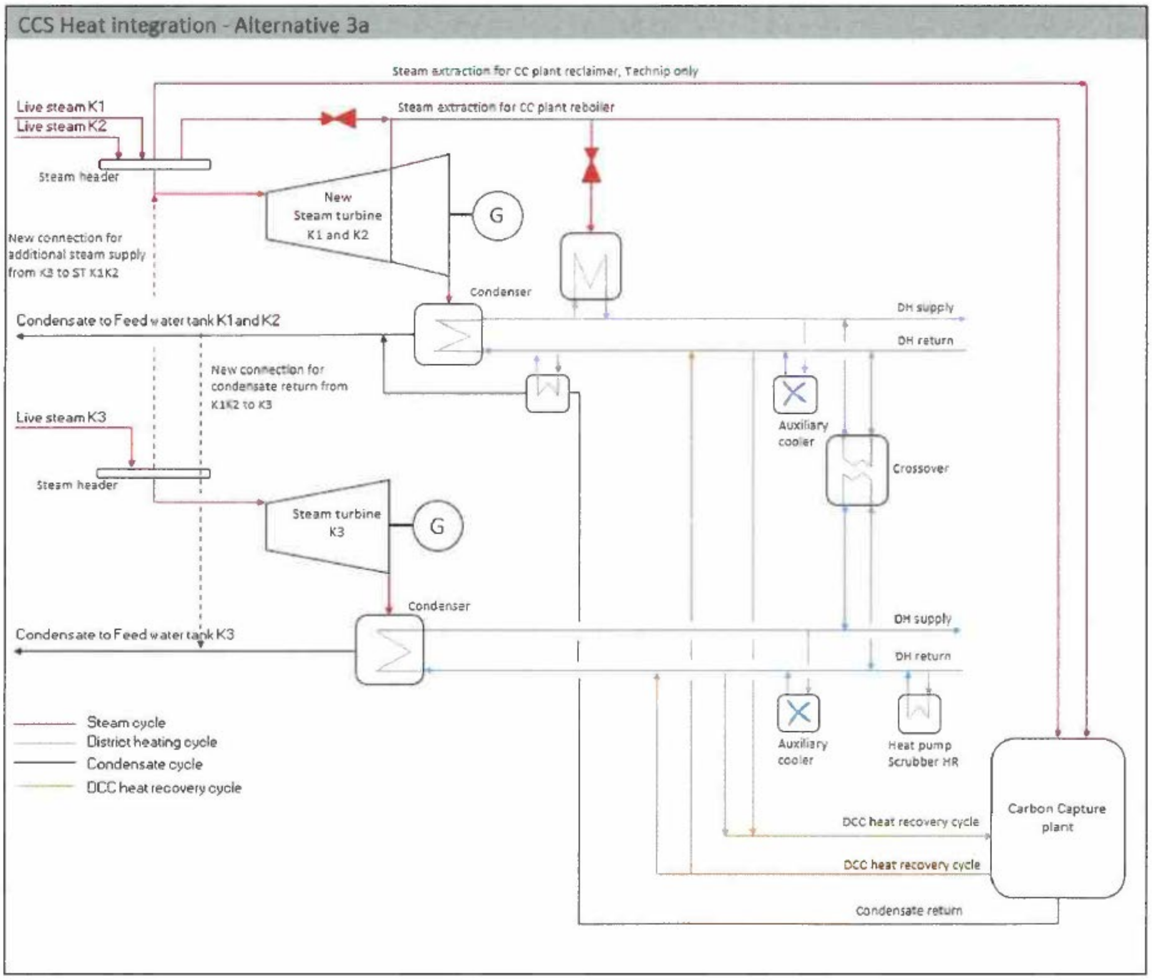

Fig. 3.5 Simplified illustration of heat integration scheme 3a proposed for Klemetsrud retrofit (FOV, 2020a)

b) Retrofit to Returkraft WtE plant in Kristiansand, Norway

Magnanelli *et al* (2021) examined options for supplying heat for MEA PCC integrated to the Returkraft WtE plant in Kristiansand, Norway. It was noted that "*While the study is specific to a real WtE plant, its characteristics are typical for many Europe WtE plants and its results will be relevant to many grate-fired CHP (Combined Heat and Power) WtE plants. The plant started operation in 2010 and it incinerates 130 000 t of household and industrial solid waste every year (in proportion approximately 60/40%) to produce heat and power. The plant has a nominal thermal power capacity of 54 MW and produces approximately 90 GWh electricity and 120 GWh district heat per year.*"

The cases shown in Table 3.2 were examined, with summary results shown in Table 3.3. Significant additional heat needed to be supplied if an external boiler was used, but a number of alternative ways were found to operate without any heat addition and to minimise the impact on the plant. As noted "*When the two plants are considered separately, the heat requirement of the capture plant corresponds to 27% of the nominal thermal capacity of the WtE plant. When integrating the two plants, steam extraction from the boiler drum to provide the heat necessary to the capture plant reduces the power and district heat production of the WtE plant by 30% and 6% respectively, while extraction from the turbine causes a reduction of 8% and 12%. By modifying the condensers' temperature, it is possible to maintain 96% of the original district heat production. By performing carbon capture only when* *excess heat is available, it is possible to capture 47% of the CO2 emitted by the WtE plant, while reducing the power production by only 5%."*

Table 3.2 Steam supply options examined by Magnanelli et al (2021)

CASE 0: the flue gas from the WtE plant cleaning system is sent to the capture plant. The heat necessary for amine regeneration in the reboiler is provided by an external source. Therefore, the operation of the capture plant does not affect the operation of the WtE plant and its heat and power delivery (base case).

CASE 1a: the heat necessary for the amine regeneration process is provided by steam extracted from the WtE plant boiler. The other WtE plant process parameters are kept constant. Steam extraction from the boiler will have an impact on both heat and power delivery of the WtE plant.

CASE 1b: the heat necessary for the amine regeneration process is provided by steam extracted from the turbine. The other WtE plant process parameters are kept constant. Similar to Case 1a, there will be an impact on both heat and power delivery of the WtE plant.

CASE 2: the heat necessary for the amine regeneration process is provided by steam extracted from the boiler drum. The heat delivery to the district heating network is kept as equal as possible to the base case by modifying some key process parameters such as condensers' temperature. This will cause a further impact on the power delivery of the WtE plant.

CASE 3a and 3b: the capture plant is operated only when excess heat is available at the WtE plant. Steam extraction from the boiler drum and the turbine will have a different impact on the CO2 capture efficiency of the CCS plant, as well as on the power production of the WtE plant. It should be noticed that while in the other cases 85% capture will be achieved over the year, in Case 3 the overall capture efficiency will be lower.

Table 3.3 Comparison of scenarios for retrofit to Returkraft WtE plant, for Case 3 based on conditions in 2018 (based on Magnanelli et al (2021), Table 3)

Case	External heat	Power production (GWh)		District heating production (GWh)		CO_2 capture efficiency (%)	
	GWh	GWh	Red'n	GWh	Red'n	%	Red'n
Case 0	125.8	91.7	Base	124.9	Base	83.9	Base
Case 1a	None	63.9	-30.3%	116.9	-6.4%	83.9	-0%
Case 1b	None	84.1	-8.2%	109.6	-12.2%	83.9	-0%
Case 2	None	63.5	-30.8%	119.5	-4.3%	83.9	-0%
Case 3a	None	75.8	-17.3%	124.9	-0%	47.1	-43.9%
Case 3b	None	87.3	-4.9%	124.9	-0%	46.7	-44.4%

c) Thermal integration of post-combustion CO_2 capture into a WtE plant

Su et al (2023) uses operating data from literature and operating data from an unspecified WtE UK plant to examine configurations '*representative of the WtE facilities in operation in Europe'*. They report power and heat output for a power-only WtE plant and CHP WtE plant before and after the addition of open art 35%wt MEA CO_2 capture. Two capture rates are examined: a 95% capture rate and a 99.7% capture, corresponding to 100% capture of fuel CO_2.

The steam supply options considered are:

- Power-only Configuration: '*the WtE plant produces only electricity and the steam turbine train comprises a condensing steam turbine (ST) where superheated steam expands from 60 bar to a condenser pressure of 0.1 bar, considered in this work for an air cooling system. This configuration is representative of WtE plants which are not connected to a District Heating (DH) network including, but not limited to, plants that are built as DH ready (i.e. they will provide DH in the future) or CHP WtE plants currently connected to a DH network operating during summer time when the DH demand is expected to be zero'*.
- CHP Configuration #1: '*the WtE plant produces electricity and thermal energy for the DH system. The steam turbine train consists of a high pressure (HP) ST cylinder and a condensing low pressure (LP) ST cylinder connected to an air-cooler condenser. Superheated steam expands from 60 bar to 4 bar in the HP steam turbine cylinder, a fraction of steam is then extracted to supply thermal energy to the DH system, and the remaining steam expands in the LP steam turbine cylinder from 4 bar to the condenser pressure (i.e. 0.1 bar). A constant steam extraction to the DH system is assumed with and without PCC and, thus, additional steam extraction for CO_2 capture will only penalise the electricity output. It is assumed that the minimum flow rate through the LP steam turbine cylinder is 15 % of the nominal flow rate at full load, to cool down the blades and avoid overheating by churning'*.
- CHP Configuration #2: '*the WtE plant produces electricity and thermal energy for the DH system. The steam turbine train consists of a HP ST cylinder and a back pressure LP ST cylinder. Superheated steam expands from 60 bar to 4 bar and it is then sent to the DH system. When PCC is implemented, part of the steam is sent to the reboiler of the CO_2 capture plant. In reality, the steam turbine train can be designed with a Synchro-Self-Shifting (SSS) clutch, which could be used to decouple the HP and the LP cylinders so that no minimum steam flow rate is required through the LP cylinder [5]. This operation scenario is representative of WtE plants with high DH demand during the whole year and particularly CHP WtE plants located in regions with long cold winters'*.

Su et al. also examine the recovery of excess heat from the compressor intercoolers, the stripper overhead condenser and the Direct Contact Cooler into feedwater heaters for power-only configuration, or the district heating network for CHP configurations.

Table 3.4: Comparison of steam supply options in Su et al (2023) for 95% capture

Configuration	Power only		CHP#1 Condensing turbine		CHP#2 Back pressure turbine	
	Power output (MW_e)	Heat output (MW_{th})	Power output (MW_e)	Heat output (MW_{th})	Power output (MW_e)	Heat output (MW_{th})
No capture	15.3		12.5	14.1	8.1	37.3
95% capture	10		7.2	14.1	6.2	19.9
95% capture with heat recovery	10.6		5.0	32.2	4.1	38.0

4. PCC system issues for BAT

The fact that a wide range of known and also proprietary amines has been tested successfully at pilot units such as Technology Centre Mongstad (TCM) and National Carbon Capture Center (NCCC) using conventional absorber and stripper arrangements indicates that there are a number of common shared PCC system factors affecting the following main environmental issues for power plants with CCS:

1. Emissions to atmosphere
2. Combined optimisation of electricity output and residual CO_2 emissions
3. Minimisation of environmental impacts from waste streams

These common factors will be modified by constraints and characteristics imposed by the choice of solvent, with some further adjustments due to the way that operating parameters and solvent management methods affect the long-term composition of the solvent as actually used in a commercial plant.

There is also at least one pilot-scale study (Rochelle, 2018) that suggests that a modified solvent regeneration system based on multiple flashes rather than a conventional stripper would give reduced energy consumption for piperazine, but the extent to which this modified arrangement would also impact the performance of other amine solvents (and other characteristics of this arrangement when implemented commercially) has yet to be resolved. It appears unlikely that anything other than conventional absorber/stripper PCC systems, with some relatively minor modifications for incremental improvements in performance, will be deployed at scale in the UK in the immediate future.

4.1 Solvent and solvent management selection

4.1.1 Reclaimability, reclaiming, degradation, emissions and solvent hygiene management

As already noted, solvent and solvent management need to be considered as a package, since what matters for environmental impacts is the long-term solvent composition, and hence performance, that can be maintained under working conditions.

Rates of degradation and accumulation of impurities from the flue gas will be affected by flue gas pre-treatment and operating conditions but, especially since the presence of degradation products and impurities may also promote further degradation reactions, the solvent management system needs to be able to get rid of everything that is added, or formed, in the solvent at high enough rates to maintain their concentrations at levels at which satisfactory operation can be maintained.

Reclaimability means that the solvent can be separated from all impurities in a reclaimer and returned to its original composition, or an entirely satisfactory modified composition, when required and without undue difficulties. It is an essential qualifying requirement for viable commercial use of a solvent, and low rates of degradation measured in pilot tests starting with fresh solvent samples cannot be a substitute for reclaimability.

In-line mechanical filters are widely used for removing solid impurities in solvents. Activated carbon filters have also been found useful in reducing foaming (e.g. Jacobs, 2017), although changing them generates additional waste. Ion exchange, coupled with alkali dosing to break down HSS, has also been used for selective removal of unwanted chemical species, but it appears likely to be infeasible to remove all of the impurities that will accumulate using ion exchange alone (e.g. see Peterhead, 2016 example below).

Thermal reclaiming is therefore widely used. Simple thermal reclaiming involves release of solvent locked up in HSS by reaction with added alkali, followed by evaporation of the solvent with water in a single recovery stage. This will result in all species with lower volatility than the solvent largely being rejected. Simple thermal reclaiming is known to work with MEA (e.g. Reddy, 2008; Flø, 2017) and is reported to work using MHI's KS-1 solvent; the published process flow diagram for the Petra Nova PCC unit appears to show a simple thermal reclaimer venting into the stripper (Petra Nova, 2017). This arrangement recovers the extra-lean solvent, CO_2 and steam released in the reclaimer, so avoiding much of the electricity output penalty (EOP) that would otherwise arise from the use of the steam in the reclaimer. While operation appears to have been satisfactory, with stated solvent consumption '*within the expected consumption rate*', the reclaimer steam tube bundle has been reported to have suffered from corrosion-induced leaks after just over two years in service (Petra Nova, 2020). Construction materials and other relevant details do not appear to have been reported, however, and it is also possible that a diversion of condensate containing corrosion products to the reclaimer from a compressor intercooler is involved in the failure.

It was reported that, for a Fluor solvent containing >30% w/w MEA tested at pilot scale with reclaiming (Reddy, 2017), '*Corrosion coupons at all locations (except for the Reclaimer) indicated no visible corrosion under Scanning Electron Microscopy on the base metal and corrosion rates were between 0.01 and 1.0 µm/yr. Only 304L and 316L coupons in the Reclaimer exhibited a marked material loss, each losing nearly 1 mm/yr. The corrosion rate of Duplex 2205 in the Reclaimer was roughly 1,000-fold lower.*'

Singh (2014) described a thermal reclaimer unit that used a vacuum distillation unit to remove ionic and non-ionic degradation products from Cansolv DC-103 as part of a PCC unit capturing 170 tCO_2/day from a gas boiler. The unit was operated in semi-batch mode with lean solvent feed for 15-20 days followed by a final boil-off period without further amine input to maximise solvent recovery. At this final stage steam sparging was also used, which '*promotes mixing and dissolution of the degraded products and crystals.*' Recommended operating bottom temperatures for the reclaimer were '*close to 190-200^oC*'. It was reported that '*An average amine recovery of 99.75%, with a maximum of 99.8% of amine recovery*' was achieved, but details of the period over which these measurements were made were not given. However, it was stated that the plant had started operation in Q3, 2013 and the paper was presented at GHGT-12 in October 2014.

More complex, multi-stage reclaiming arrangements may be employed where simple thermal reclaiming is not possible, due to solvent and degradation product properties, or where it offers improved technical or economic performance. For example, the Peterhead NGCC retrofit project (Peterhead, 2016) proposed to use an ion-exchange reclaimer combined with a three-stage thermal reclaimer train, operating at 105°C and 1.23 bara, 75°C and about 0.1 bara and 162°C and 0.12 bara respectively, to reclaim Cansolv DC-201, although this arrangement was not subsequently built and tested.

Batch reclaiming of the whole inventory with the PCC plant offline is also technically possible, rather than processing a slipstream, although published examples where this is proposed for full-scale PCC applications have not been identified. In this case, less solvent has to be processed than when using a slip-stream, but the heat cannot be recovered and the PCC plant cannot be used at the same time unless a duplicate solvent inventory is available. This approach would be most applicable in applications where a solvent could not have a reclaimer venting to the stripper anyway, and especially if the solvent degraded and picked up impurities slowly enough, perhaps with assistance from in-line cleaning arrangements, to require full reclaiming only during scheduled outages.

It goes without saying that reclaimability must be demonstrated in pilot plant operation, or as part of equipment acceptance trials, using degraded solvents that are as close to those that will be encountered in service as possible. As an example, a solvent with a blend of piperazine (PZ, boiling point 146 °C) and MDEA (boiling point 247 °C) may be able to be evaporated successfully in a simple thermal reclaimer as a fresh mixture, possibly utilising a vacuum to reduce the reclaimer temperatures required, but it could prove challenging to recover MDEA without also evaporating any higher-boiling-point PZ degradation products, if these are present in a degraded solvent mixture after a period of use. In general, as this example illustrates, amine blends are obviously more likely to have the potential for complex thermal reclaiming behaviour than single amines.

Reclaimer residue composition and amounts will obviously depend on many factors, including the solvent, flue gases, plant operation and reclaimer type and operation. An example for Fluor Econamine FG plus MEA-based solvent is shown in Table 4.1. The copper is reported to come from a corrosion inhibitor used to protect carbon steel elements of the plant (Mariz, 1999).

Table 4.1 Analysis of Typical Reclaimer Waste from Bellingham PCC plant (Fluor, 2004)

pH	10.29
Water	33.9 Vol %
API gravity	0.7 (SG=1.0703)
Composition	
Cr	less than 2 ppm total
Cu	855 ppm (coming from added corrosion inhibitor; Fluor)
Fe	129 ppm
Ni	less than 2 ppm
Na	7500 ppm
MEA	6000 ppm

It was stated (Fluor, 2004) that '*waste disposal companies charge about $1.0 per US gallon to dispose of this waste. These companies process the waste by removing the metals and then incinerating the remainder. This waste can also be disposed of in a cement kiln where the waste metals become agglomerated in the clinker.*' Trials with amine reclaimer waste injection for NOx reduction in a cement plant have also been reported (Botheju, 2013).

A theoretical analysis of reclaimer waste properties and disposal, comparing thermal reclaiming, ion exchange and electrodialysis, has also been undertaken (IEAGHG, 2014a).

Key properties for the long-term solvent composition (i.e. including all degradation products plus any collected flue gas impurities) are:

i) Volatility of all solvent mixture components (to determine emissions to air in normal operation) with (a) countermeasures in place and (b) under fault conditions and (c) with countermeasures for faults

ii) Toxicity (relevant for operators' health and for leakage)

iii) Thermal and oxidative stability, i.e. degradation resistance (also indirectly impacts on regeneration and reclaiming, see below)

iv) Multiple effects on the plant physical design and operation (e.g. absorber height, liquid to gas mass flowrates (L/G) ratio, need for intercooling, stripper pressures etc.)

v) Overall EOP and capture level constraints that are consequential on the choice of solvent – with the physical design of the plant also having a significant influence

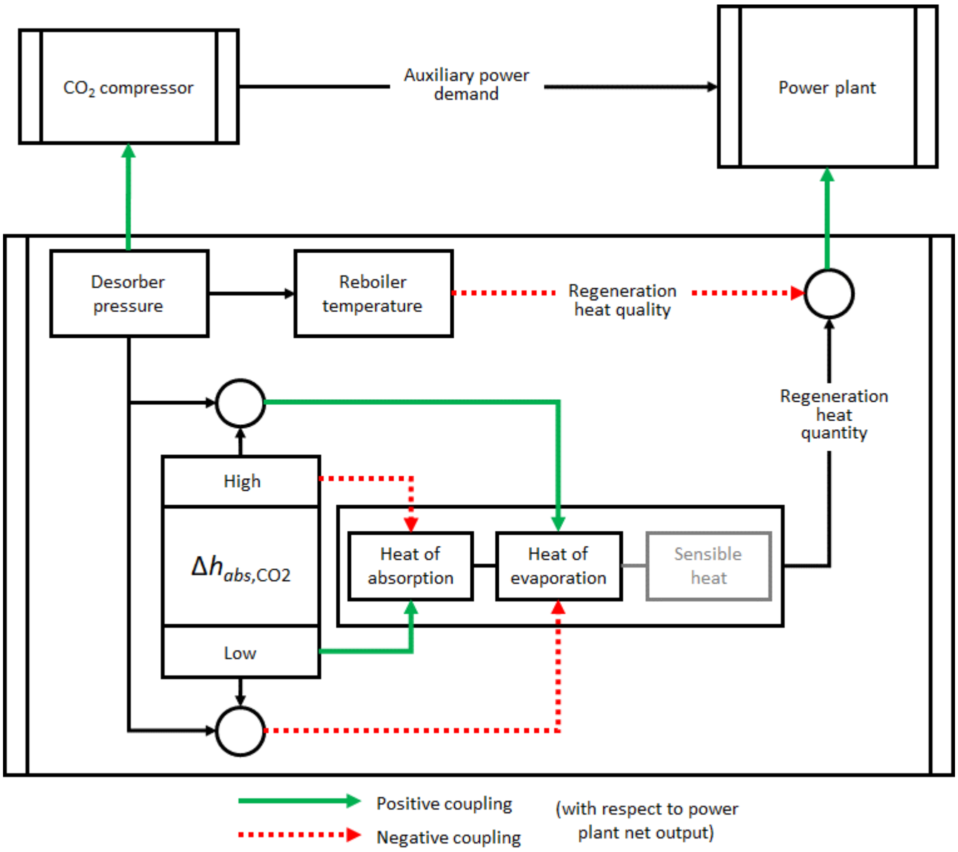

Fig 4.1 Components in energy demand for a conventional amine PCC system
(based on Oexmann, 2010)

4.1.2 Impact of solvent properties on electricity output penalty (EOP)

A breakdown of the factors affecting EOP is shown in Fig 4.1 from Oexmann (2010). This paper makes the point that the heat of absorption, also equal to the energy to release the CO$_2$ from the amine in the stripper, is only one factor in the EOP. The heat of evaporation of the water vapour in the CO$_2$ leaving the top of the stripper and the pressure of the CO$_2$/vapour mixture, and hence compression power, are also important, and Oexmann stated that these would tend to be increased by a reduction in the heat of absorption, counteracting its effect.

The stoichiometry of the reaction between the amine and CO$_2$, plus how high amine concentrations in water[12] can be without causing excessive corrosion rates and viscosities, are also important in determining how much 'dead weight' there is in the liquid flow through the stripper.

These multiple effects demonstrate that there are no simple metrics for evaluating solvents, even just for EOP; the overall performance of a realistic aged solvent mixture in the actual system of interest is what matters, with the presence of degradation products also likely to reduce performance. When other solvent properties are taken into account it appears likely that no single solvent offers the 'best' characteristics in all aspects, although some solvents may be ruled out if they fail to meet acceptable standards on basic requirements.

4.2 Flue gas pre-treatment

SCR, particulate removal and FGD (if required) have been considered as part of the power plant configuration in Section 3. Further pre-treatment will, however, usually take place in a DCC upstream of the absorber.

Variations have been envisaged in which the DCC is incorporated in the base of the absorber (Bechtel, 2018) or even omitted altogether in GT flue gas applications, with cooling being effected by water

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[12] Non-aqueous amine mixtures have also been proposed, but are not explicitly covered in the current report due to lack of data in the public domain for any solvent proposed for commercial use.

fogging in the flue gas transfer duct (Bechtel, 2009). Fogging is already widely used for cooling GT inlet air, and the principles and spray hardware are proven in this application (e.g. GE, 2000) but have not yet been demonstrated in a PCC application, so should be included in future pilot testing prior to deployment. If fogging gave rise to aerosols and this promoted droplet nucleation in the absorber leading to carryover, it would obviously be undesirable. Some mitigating aspects are:

- Stripper reflux condenser water can be used for the fogging spray, so solids should be very low
- With a GT flue gas, peak absorber temperatures will be lower than with e.g. coal flue gases

A DCC can, however, be an important trap for dust in the flue gas if a conventional limestone slurry FGD is not fitted upstream (as may well be the case in biomass plants). BD3 was originally planned to have only dry cooling, used for heat recovery to maximise efficiency, but a water 'curtain spray' was added to wash out particulates after problems were identified with fly ash in the flue gas entering the unique amine FGD located before the amine absorber (SaskPower, 2017).

A major function of the DCC is also to remove heat from the flue gas before it enters the absorber. If the flue gas, and hence amine, temperature is too high then the rich amine loading will be limited by the Vapour Liquid Equilibrium (VLE).

The flue gas may also be cooled by heat transfer to low pressure steam, heat transfer fluids or in a gas/gas heater, as already discussed. This recovered heat may be used to offset some of the solvent regeneration energy (although temperatures will limit the scope for this), to reheat the flue gases after the absorber and, for steam plant (but not CCGT), for condensate and feed water heating.

In a CCGT plant, and also a biomass plant without FGD, the flue gas will typically not be saturated and significant amounts of water will be picked up in the DCC. In plants with a wet limestone FGD the flue gas will be saturated with a dew point well above the DCC temperature, with water evaporated in the FGD, and significant amounts of this water will be condensed in the DCC (and subsequently disposed of).

In all cases, water accumulation in the circulating solvent is undesirable, if there are concerns about treating water collected in the stripper reflux condensers, so slightly more water needs to leave in the flue gas exiting the absorber than enters in the flue gas leaving the DCC. Given that the partial pressure and hence the volume of water vapour is reduced by removal of the CO_2, the temperature of the flue gas leaving the absorber must therefore be higher than the temperature of the flue gas entering it. The only way to avoid this constraint is by the removal and treatment of water from the reflux (overhead) condenser after the stripper (desorber). The use of this water is actually suggested, combined with intentional addition of water to the solvent via forward osmosis from a saline source, as a way to generate useful process water in a theoretical study from Australia (Feron, 2017) but as noted, '*an important parameter is the quality of the water recovered in the desorber overhead. At the maximum water recovery, the process modeling indicated that the levels of monoethanolamine were negligible (≪1 ppm), with dissolved CO_2 being the main impurity (1750 ppm). Under realistic process conditions, the water might contain volatile degradation products such as ammonia and products that are carried over as droplets. This can only be evaluated in practical trials, for example, carried out in pilot plants.*'

Alkali additions to the DCC may be used to remove small amounts of SO_2 in the flue gas. This could be important for both CCGT and biomass applications where an FGD would probably not be fitted but small amounts of SOx might arise from the fuel. Reported recommended maximum levels for SOx in flue gases are between 1 and 10 ppmv (Adams, 2010), with lower levels apparently applying to more expensive solvents, although these cannot be rigid limits as the effect is progressive (Chapel, 1999)and the formation of HSS is reversible. Hence tolerance of SOx depends on the effectiveness of reclaiming and the cost of the solvent (e.g. see discussion in Bechtel, 2018). SO_3 aerosols may not be removed in the DCC, however, and, as noted elsewhere, can cause mist formation and excessive amine carryover.

Sodium sulphite additions to a DCC have also been reported to be effective in pilot-scale trials at NCCC for NO_2 removal (Selinger, 2017), and sodium sulphite additions to a wet limestone FGD have also been proposed for the same purpose (Sexton, 2017).

4.3 Absorber and regenerator modifications proposed for reduced EOP

The design and operation for the main solvent circulation system need to achieve the following objectives:

1. Result in process conditions that, with reasonable additional solvent management and flue gas washing/filtering equipment, give:
    - acceptable levels of solvent degradation
    - acceptable levels of emissions to atmosphere
2. Can be operated flexibly enough to meet the needs of the overall power plant while continuing to capture CO_2
3. Produce waste streams (e.g. collected water) for which environmental impacts are minimised, and reduce environmental impacts generally
4. Achieve a combined optimisation of electricity output and residual CO_2 emissions
5. Minimise capital and operating costs as far as feasible

While the same basic arrangements can be used for all amine solvents, some details will have to differ depending on the properties of the solvent being used, and some more specialised alternative systems have been proposed that are stated to possibly favour a particular solvent more than others (e.g. see the Flash Regeneration System described below).

In general, there will tend to be a conflict between the first three essential requirements and the fourth and fifth, desirable but variable, optimisation objectives. Examples are:

- Lower temperatures in the stripper reduce solvent degradation but higher temperatures increase stripper pressures and reduce compressor work, while also giving leaner solvent to allow higher capture rates
- More complex solvent regeneration schemes reduce irreversibilities in the overall process and hence energy requirements and EOP, but will tend to reduce operability and may increase capital costs more than the corresponding reduction in operating costs
- Taller absorbers (up to a certain point) will tend to increase capture levels and reduce thermal energy requirements but will also increase capital costs (non-linearly with increasing height) and visual impact
- Absorber inlet and exit temperatures selected to achieve a satisfactory water balance may require additional cooling or tend to increase solvent evaporation in the flue gas

The resulting PCC plant design is therefore a compromise; it is not likely to be possible to achieve the 'best' result in every aspect of the performance simultaneously.

Some of the following features may, however, be generally of value in conventional PCC systems, although not all of them could be used together, or be effective in combination:

a) Close approach temperatures in the XFHE

b) Measures to match the heat capacities in the XFHE by diverting some of the rich solvent upstream of the XFHE (the following are alternatives):
  - Split feed into the stripper (e.g. Neveux, 2013), see Fig 4.2
  - Rich slipstream flash and semi-lean solvent return to the absorber (e.g. Fluor, 2004) (this also provides an intercooling effects – see 'Absorber Intercooling' below

c) Lean vapour recompression (e.g. Fluor, 2008) (although this may expose solvents to elevated temperatures and hence cause excessive degradation)

d) Absorber intercooling (e.g. Fluor, 2008), most likely to offer benefits with higher-CO_2 flue gases, i.e. biomass but probably not CCGT on natural gas without duct firing

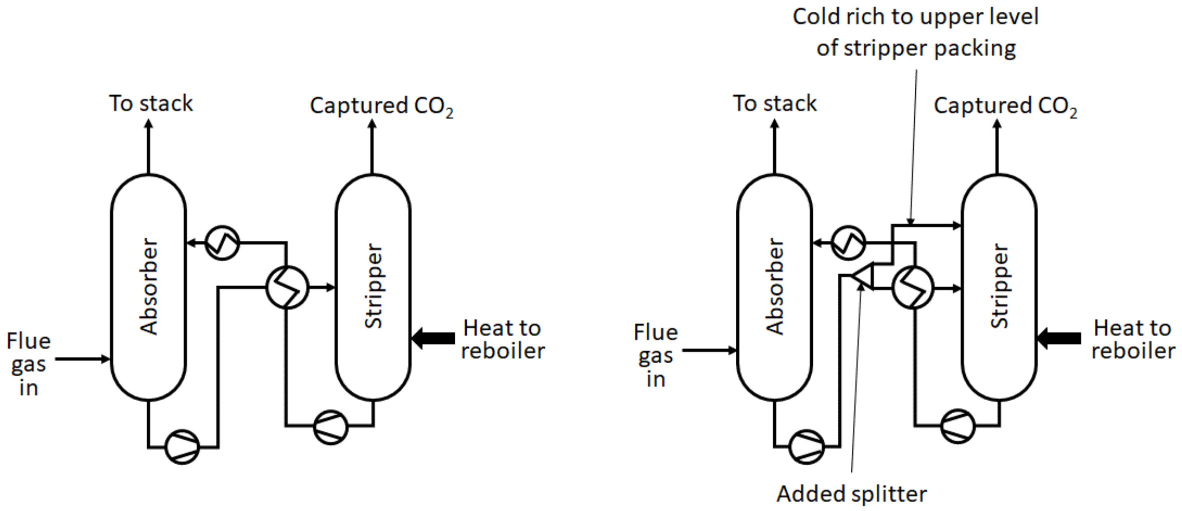


Fig 4.2 Normal stripper feed (left) and split feed (right) into the stripper
(based on Neveux, 2013)

An alternative 'Advanced Flash Stripper' (AFS) multi-stage flash regeneration system that has been tested at pilot scale (Rochelle, 2014) is shown in Fig 4.3 as an example of a less conventional solvent regeneration proposal. This arrangement acts by reducing vapour losses and sensible heat in the final exiting CO_2, also a feature of the split feed into the stripper modification, see b) above.

It was reported that the AFS (see Fig 2.11) gave improved thermal energy performance using piperazine but the viability with other solvents is unclear since it uses high temperatures after the steam heater, and solvents that are less thermally-stable than piperazine might have unacceptable levels of degradation. Operability also needs to be considered and final results when integrated with a power plant have still to be reported. Corrosion problems have been reported with piperazine (Chen, 2019): *'The most problematic location was in the hot rich, two-phase solvent between the steam heater and the stripper sump; both stainless steel and carbon steel usually had unacceptable corrosion at this location. The steam heater and hot cross exchanger should be opened and inspected for evidence of corrosion. After confirmation with further corrosion testing, these locations may need to be constructed with other alloys.'*

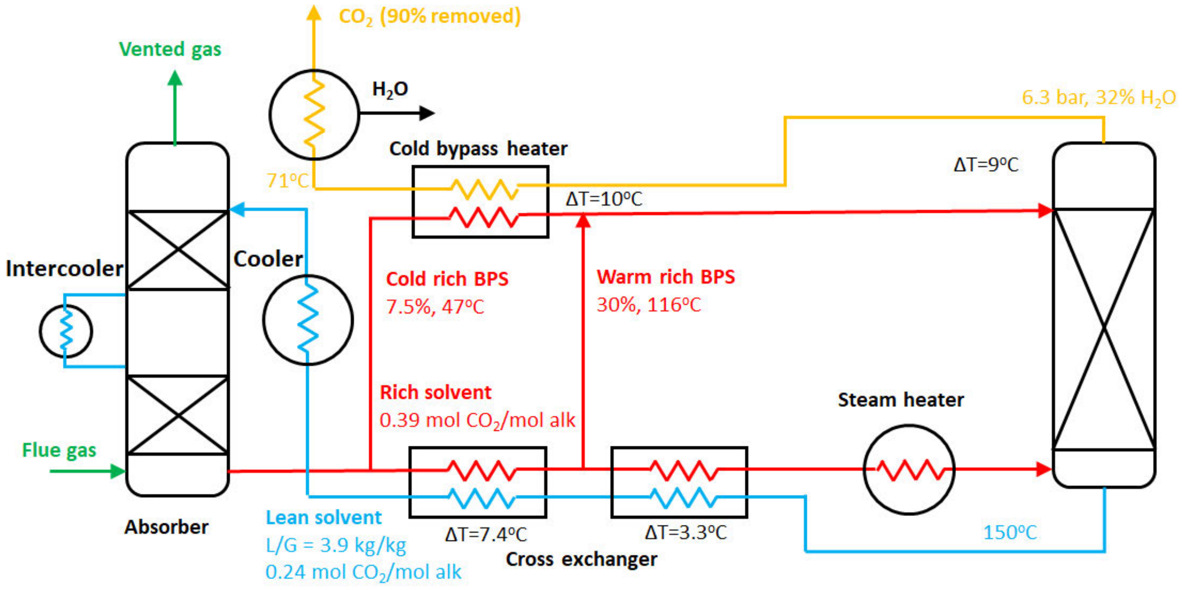


Fig 4.3 'Advanced Flash Stripper' (AFS) multi-stage flash regeneration system
(based on description in Rochelle, 2014)

4.5 CO_2 capture level

Long-term (averaged annually or longer) CO_2 emissions is what matters for climate impacts (as opposed to instantaneous values). There is therefore no satisfactory threshold level of CO_2 emissions; instead CO_2 emissions need to be as low as reasonably possible at any and every time the plant is operating. In practice, , instantaneous capture levels of 95% and above are routinely achievable, and clearly desirable given the UK's target of net zero emissions. When coupled with the ability to maintain 95% capture (i.e. the normal operating capture level) during start-up and shut-down (see Section 6) and to increase capture levels beyond 95% when conditions are favourable (see discussion below) this means that very low levels of residual CO_2 emissions are feasible.

Since a tonne of CO_2 entering the atmosphere from any source has exactly the same impact on achieving UK net zero targets, it makes economic sense to capture CO_2 wherever the cost of doing so is less, and this includes aiming for high capture rates at biomass power plants as well as fossil fuel ones.

On capture levels, Errey (2018), calculated that relatively little increase in EOP would be incurred by operating at 95% capture rather than a lower level (see Fig 4.4 below), implying that high capture levels are feasible if permitted by the plant design. Similar results were obtained by Feron and co-workers in a study for IEAGHG (Feron, 2019; IEAGHG, 2019). A 95% CO_2 capture case for a modern CCGT+PCC configuration has also recently been reported by AECOM (2020).

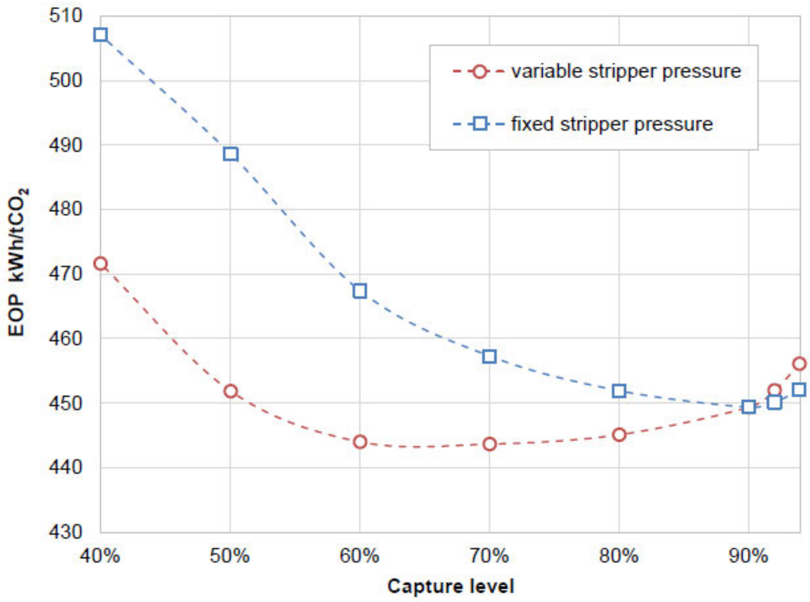


Fig 4.4 Total Electricity Output Penalty of CO_2 capture and compression at different capture levels under variable and fixed stripper pressure operation (Errey, 2018)

Plant design will affect achievable CO_2 capture levels. Shorter absorber packing heights may preclude high capture levels without excessive EOP values. The design characteristics of the plant, e.g. fluid flows, CO_2 compressor capacity, etc., must obviously also be able to accommodate higher capture levels. This trade-off is well-illustrated for cases using MHI's KS-1 solvent in Tables 4.1 and 4.2 and Fig 4.5 below.

Table 4.1 Relative utility and solvent consumptions as a function of capture rate and packing height (Hirata, 2020) (NB – values below are actually % of base case, not units shown, see Fig 4.5)

Utility and solvent consumptions (scale against base value: 100).

	Base case			Sensitivity cases				Near zero emissions case
Capture ratio (%)	90	95	99	99.5	99.5	99.5	99.5	99.5
Absorption packing height (m)	100	100	100	100	125	175	200	150
Lean solvent rate (kg/tonne CO_2)	100	104	114	125	108	101	99	103
Reboiler steam (kg/tonne CO_2)	100	102	109	115	105	100	99	102
Electricity (kW/tonne CO_2)	100	99	99	100	99	98	98	98
Cooling water (kg/tonne CO_2)	100	98	101	105	99	95	95	96
KS-1^{TM} make-up (kg/tonne CO_2)	100	100	100	100	100	100	100	100
OPEX ($/tonne CO_2)	100	101	103	106	101	100	99	100

Table 4.2 Design specifications of major equipment as a function of capture rate and packing height (Hirata, 2020) (NB – values below are actually % of base case, not units shown)

		Base case	Sensitivity cases						Near-zero emission case
Capture ratio (%)		90	95	99	99.5	99.5	99.5	99.5	99.5
Flue gas quencher	Diameter (m)	100	100	100	100	100	100	100	100
CO_2 absorber	Diameter (m)	100	100	100	100	100	100	100	100
	Absorption packing height (m)	100	100	100	100	125	175	200	150
Regenerator	Diameter (m)	100	105	110	114	109	105	105	106
Reboiler	Heat duty (MW)	100	108	119	127	116	111	110	113
Lean/rich solvent exchanger	Heat duty (MW)	100	111	128	139	119	110	107	113
Lean solvent pump	Flow rate (m^3/hr)	100	109	126	138	119	111	110	114
Rich solvent pump	Flow rate (m^3/hr)	100	110	126	139	119	112	110	114

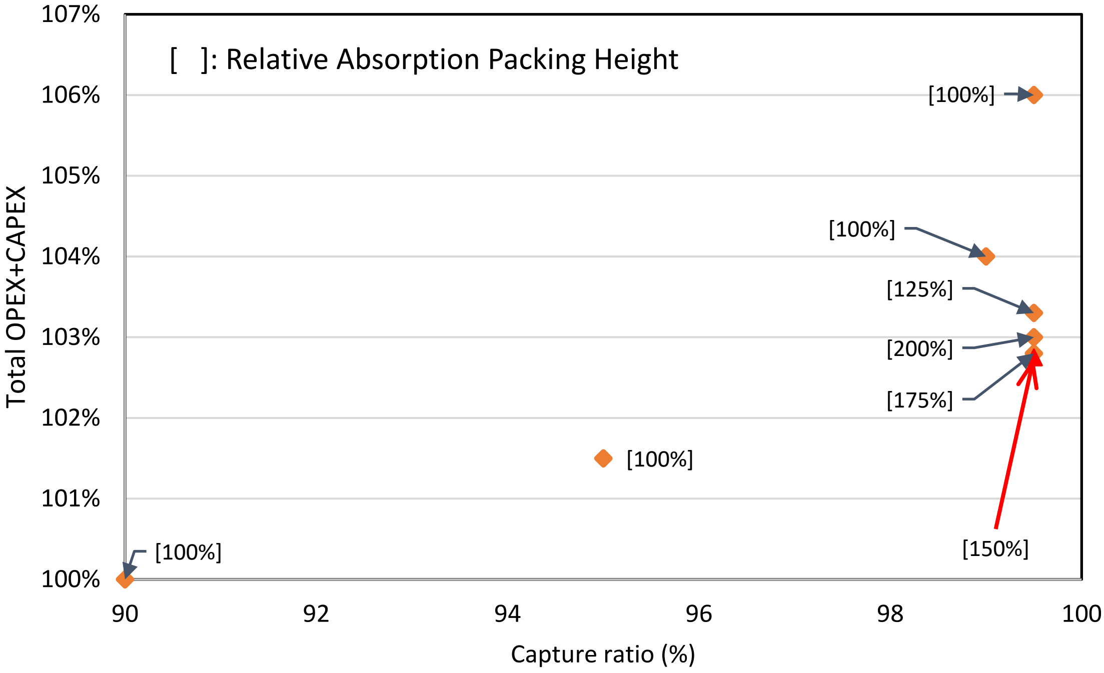


Fig 4.5 Aggregated relative specific cost of capture (i.e. cost per tonne of CO_2 captured) as a function of capture rate and packing height (data from Hirata, 2020)

Another proprietary solvent supplier, Shell, has advertised (Just, 2020), '*Download the Cansolv CO_2 Capture System Fact Sheet to Learn How to Capture Up to 99% of the CO_2 from Low-Pressure Streams*'; the linked datasheet (Shell, 2019) states '*Systems can be guaranteed for bulk CO_2 removal of over 90%.*' For pilot testing of Cansolv at Klemetsrud, Jemtland (2019) reported, '*during the 5,500-hour test that we conducted, the test facility has proven that the technology can provide the intended capture rate of 90 per cent. But, we have seen numbers as high as 99 per cent and a stable 95 per cent capture rate of the CO_2 from the flue gas.*'

Pilot tests at NCCC using piperazine (Gao, 2019) also observed capture rates up to 99% using 12m of absorber packing, with minimal effect of energy requirements per tonne of CO_2 captured (<5% increase).

Capture levels in the range 95-99% were also observed in pilot-scale tests at TCM using both MEA (Shah, 2021) and CESAR1 (Benquet, 2021).

Operation at high capture levels obviously must be appropriately supported financially. For a given plant configuration that has been designed to accommodate high capture levels there will still always be a continuous trade-off between increasing EOP and CO_2 capture level, with the balance being affected by ambient conditions as well as plant operating conditions. In all cases, though, even though the EOP may be fairly constant, capturing more CO_2 will obviously decrease electricity output. Those seeking to make CCS power plant look as 'good' as possible from a limited perspective focusing on maximising electricity production, or to maximise revenues under CO_2 price arbitrage inconsistent with zero emission targets, will therefore obviously look to capture the <u>minimum</u> amount of CO_2 that is required, if such an arbitrary threshold exists, to minimise superficial capital and operating costs per MWh of electrical output. At a societal level, however, the cost of dealing with residual CO_2 emissions (or, in the case of BECCS, of losing the opportunity for additional negative emissions) from PCC plants needs to be taken into account when determining the way that power generation with CCS is regulated and incentivised by subsidies.

So, in particular, for optimised environmental impact it is imperative that artificial constraints are not placed on the upper capture level at which power+PCC plants operate. Any arbitrary minimum capture level thresholds in regulations, or other constraints applied through any financial incentive support scheme, should not be applied in such a way that this minimum also becomes the *de facto* maximum capture level. Enabling and encouraging progressive and flexible incentives to achieve the highest reasonable capture level is likely to be the best way to avoid 'lock-in' of unnecessary residual emissions that will then have to be dealt with externally to achieve UK climate targets.

4.6 Emissions control countermeasures for PCC systems

4.6.1 Flue gas impurities and possible upstream countermeasures

a) SO_2 and SO_3 may arise from biomass impurities and from odoriser in natural gas (in low quantities) or from waste gases fired in CCGT plant. SO_2 will react with amines to form heat stable salts (HSS). SO_3 will also form HSS but, more seriously, a fine sulphuric acid mist aerosol can cause severe amine carryover (as discussed elsewhere). To date neither biomass nor CCGT plants have usually had FGD plants fitted, but this, or countermeasures in the DCC such as alkali addition, is obviously an option, prior to the PCC plant, if fuel compositions and PCC system sensitivities merit it.

Within the PCC system, any SO_2 that enters will generally need to be neutralised using added alkali, either in the DCC or the solvent reclaimer. The alkali consumption for SO_2 neutralisation will be approximately the same by either route, so other factors, including solvent cost and reclaimability, will affect the approach used.

SO_3, if captured by the solvent, will also need to be neutralised, but amine mist formation in the absorber is a more serious risk. Removal using Brownian diffusion filters has been at deployed at pilot scale at TCM (de Cazenove, 2017). SO_3 removal by acid condensation on surfaces in a power plant gas/gas heater has been reported (Mertens, 2015) and presumably similar gradual cooling in a flue gas cooler might have the same effect, provided the flue gas is above the acid dew point beforehand. Rapidly quenching a flue gas in a wet DCC can be expected to form aerosols if SO_3 is present, and this is unlikely to be sufficiently removed in the DCC (Mertens, 2017). As noted elsewhere, SO_3 and other aerosols may be present only intermittently, and possibly also unpredictably, in flue gases entering a PCC system, and their presence may not be known. Extended (i.e. order 1 year) pilot testing using actual flue gases and realistic conditions throughout, and over the full range of operating conditions, may be necessary to ensure that potential problems are adequately assessed and that satisfactory management methods are (and can be) implemented.

b) NOx removal may be desirable, particularly for amine systems that are susceptible to nitrosamine and nitramine formation. Apart from measures during combustion and downstream SCR on the plant, final removal using sulphites and thiosulphates in a DCC that also uses alkali addition for SOx polishing has been reported (Selinger, 2017; Sexton, 2017). But again, extended piloting under realistic conditions would be required to verify satisfactory operation.

c) Other biomass impurities and trace elements, e.g. chlorine, iron, alkali earth metals, may also be entrained in the flue gas. These flue gas impurities will be significantly different than for coal (Finney, 2018), so satisfactory operation of a solvent on a coal or other 'dirty' flue gas cannot be taken as confirmation of satisfactory operation on biomass. Some removal can be expected in a wet DCC, but actual levels can be expected to vary significantly over time as biomass feed and plant operation varies, and also possible impacts on solvent degradation and corrosion may take extended periods to develop, so acceptable performance can only be verified by extended and realistic piloting.

4.6.2 Thermal and oxidative degradation

Emissions countermeasures that can be implemented by the design and operation of the PCC system are mainly linked to reductions in solvent degradation rates or removal of any solvent degradation products that are the precursors for unwanted emissions, but the relative importance of these countermeasures in the overall emission control strategy will depend on the properties of the solvent and its degradation products.

Thermal degradation is known to be a strong function of reboiler temperature, although higher reboiler temperatures usually also favour slightly lower EOP values and higher CO_2 capture levels so a trade-off is needed. Locally elevated temperatures due to any residual superheating in the reboiler steam might also be expected to cause elevated thermal degradation.

Oxidative degradation can take place in the absorber or through dissolved oxygen in the rich solvent as it is being heated but before the O_2 is released in the stripper, or through reactions at elevated temperatures in the stripper involving oxygen-containing precursors formed in the absorber and rich solvent hold-up locations. One possible countermeasure, particularly for CCGT applications, is to reduce the oxygen level in the flue gas by burning additional fuel, as discussed in Section 3.11, with duct firing being a proven option.

Another possibility in the future may be removal of dissolved oxygen from rich solvent through a membrane to an oxygen scavenger (Dissolved Oxygen Removal Apparatus, DORA – Monteiro, 2018) or other means, but this is still under development and impacts are uncertain (since oxygen will still be present in the absorber). Oxygen has a higher solubility in water than amine solution and, in trials at TERC, significant spikes in dissolved oxygen measurements were observed in a pilot-scale absorber sump at times when liquid from the water wash was drained into it (Akram, 2020).

4.6.3 Potential aerosol/mist problems related to design and operation of the PCC system, including upstream and exit countermeasures

Mist formation problems can also occur within absorbers. As already noted, aerosols or very small particles present in the flue gas can nucleate condensation of solvent mist in the absorber, which subsequent wash sections are not able to capture. In the context of this report, biomass power plants are expected to offer a higher risk of aerosols than CCGT power plants but, if duct firing is used, especially with unconventional fuels, then particulates in a CCGT flue gas could be an issue. The presence of aerosols and particles may be intermittent and mist problems might then only become evident with long-term piloting. As discussed in Section 2.3.2, the best countermeasure is probably to avoid aerosol presence in the incoming flue gas to the absorber altogether. Aker Solutions claimed (Aker, 2015) that the problems of mist emissions can be addressed by countermeasures that act both within the absorber and at the absorber exit, described as follows:

(a) having a lean amine temperature (e.g. 60 to 85°C) at the top of the column that is equal to, or no more than 5° C below, the maximum temperature in the absorption section of the absorber;

(b) using two or more water washes, with the water in the first stage that the flue gas passes through at a temperature that is equal to or higher than the wet bulb temperature of the flue gas;

(c) adding an acid wash section downstream of the warm water wash in order to remove alkaline gaseous compounds such as volatile amines and ammonia from the exhaust gas.

Results for emissions from tests using this approach are described in Section 4.6.4 below. The consequences for other aspects of PCC system design (e.g. absorber height) and operation (e.g. CO_2 capture level, energy requirements, water balance) do not appear to be available in the published literature for the Aker system but are discussed for operation with MEA in the TCM system by Shah (2018). It was noted that having warmer lean solvent would reduce aerosol growth but, because in the configuration used this resulted in less heat transfer in the XFHE, the required regeneration energy increased.

MHI (Hirata, 2020; Hirata, 2014; Kamijo, 2013) report successfully controlling amine emissions caused by SO_3 aerosols apparently using absorber exit measures only. Background information on the MHI system (IEAGHG, 2010) is:

'*In 1994 MHI introduced an optimized packing and demister technology in the absorber column washing section. In the period 1999 to 2008, MHI installed nine commercial plants with this technology, all of them running with the proprietary KS-1 solvent. In 2003, an improved proprietary washing system was developed. They are able to reach 1 ppmv of amine emission, 1.5 ppmv of degradation products and no mist emission with this technology. Also other emission compounds are low. MHI have, however, seen the need for further reduction of amine emissions and have under development a new technology where they introduce a special reagent in the final washing stage in the top of the absorber. A liquid stream subject to waste water treatment is then produced. The target for this new technology (MHI zero amine emission system), which has been tested in pilot scale since 2009 and is expected to be commercial within two years, is to fall below 0.1 ppmv amine and 0.2 ppmv degradation products in the treated off gas. MHI also informed that they have under construction a 500 tonne per day demo plant in the US*.'

After trials at Plant Barry, using artificially-added SO_3, it was stated that, '*the amine emission clearly increased with SO_3 concentration at the quencher inlet, especially in the case of conventional washing and demister system.* [A graph showed approximately 75 ppm of KS-1 solvent emitted with ~1.5 ppm of SO_3 at the absorber inlet – see similar trends for MEA in Table 4.3 below.] *MHI amine emission reduction technology was tested and amine emissions were significantly reduced to less than 1/10 compared with the conventional system.*'

Table 4.3 Effect of SO_3 aerosols on MEA vapour and aerosol emissions from a 1 tpd pilot test unit (Kamijo, 2013)

SO_3 concentration at absorber inlet (ppm, dry)	MEA vapour and aerosols emission at absorber outlet (ppm, dry)
0	0.8
1	29.8
3	67.5

The MHI technology was also reported to be effective at an un-named MHI commercial plant, as shown in Table 4.4, with a clearly-visible aerosol plume shown as almost entirely disappearing.

Table 4.4 Effect of MHI special type multi stage washing system on amine vapour and aerosol emissions from a commercial unit (Kamijo, 2013)

Item	Before modification	After modification
SO3 concentration at quencher inlet (ppm, dry)	2.1 – 2.7	2.3 – 2.6
Amine emissions (ppm, dry)	12 – 35	0.7 – 3
Solvent consumption	Base	25%

4.6.3 Other countermeasures at the absorber exit

(For a discussion of plume heating methods to aid dispersion see Section 3.2; for emissions monitoring see Section 6)

Amine emissions can be moderated by reducing lean solvent and water wash temperatures, but NH_3 emissions are set by the NH_3 formation rate from solvent breakdown (plus any ammonia slip from the main power plant that has passed through the rest of the system). Any temporary reductions in NH_3 emissions due to cooling will be offset by an increase in NH_3 concentration in the water wash until no more ammonia is absorbed. For meaningful cuts in ammonia emissions an acid wash after the water wash is required, to allow the NH_3 to be removed from the PCC system as an ammonium salt. An acid wash will also react with any amine carryover and possibly with some of the degradation products present in the flue gases leaving the absorber.

For an example of an acid wash on a PCC pilot plant, for which data is available, see (Khakaria, 2014). TNO's 6 tCO_2/day /0.65 m diameter capture plant then in place at Maasvlakte had an acid wash column added using 1.26 m of Sulzer Mellapak 250 structured packing with a liquid distributor followed by a demister (KnitMesh - Sulzer Chemtech) to prevent carryover of droplets. The demister was capable of removing droplets of 2 µm with 96.4% efficiency, and above 10 µm with 100% efficiency. Overall increase in column height required for the acid wash was estimated to be 4.7 m for a full-size column design.

Typical NH_3 emissions at the water wash outlet were in the range of 15−20 mg/Nm^3 under normal operation with MEA, but additional ammonia (up to 150 mg/Nm^3) was added for test purposes. Experimental results showed ammonia emissions below 5 mg/Nm^3 at a pH of 6 for both normal and added NH_3 conditions. MEA emissions after the acid wash were in the range 1−3 mg/Nm^3, mostly below 1 mg/Nm^3, from water wash outlet values of 1.2−26.8 mg/Nm^3 (but generally below 10 mg/Nm^3).

The use of an acid wash to capture ammonia and alkyl amines from a novel Aker solvent was reported by Knudsen (2013). Sulphuric acid at 10% w/w was added to the wash, which was maintained below pH 5. Table 4.5 shows the emissions of simple (i.e. volatile) alkyl amines measured at the MTU operating respectively with and without acid wash. Ammonia was also significantly reduced, to 1 ppmv or lower.

Table 4.5 Emissions of simple alkyl amines (mg/Nm^3) with and without acid wash (Knudsen, 2013)

	Date & Time	Acid wash	Dimethylamine	Methylamine	Ethylamine	Diethylamine
Test 1	14. Nov 15.45	N	0.0027	0.0031	0.0054	0.0031
Test 2	15. Nov 9.30	N	0.0018	0.0021	0.005	0.0029
Test 3	15. Nov 15.40	N	0.0025	0.0058	0.012	0.0058
Test 4	16. Nov 14.10	Y	<0.0013	<0.0022	<0.0004	<0.0004
Test 5	16. Nov 16.5	Y	<0.0011	<0.0019	<0.0004	<0.0004

The effect of emission controls that include an acid wash is also indicated in Table 4.6 for tests on a pair of Aker proprietary solvents, but note that these were undertaken in different pilot units and also appear to have incorporated additional measures as described in Section 4.6.3.

Table 4.6a Measured emissions from the Technology Centre Mongstad (TCM) amine unit with a double water wash and Aker Solutions' Mobile Test Unit (MTU) with 'Aker Solutions' ACC^{TM} emission control design, which includes the Aker Solutions' anti mist system and acid wash polishing step' for Aker S21 solvent (Gorset, 2014)

		TCM DA amine plant S21 Campaign				**MTU with ACC^{TM} Emission Control System S21 Campaign**					
		20/11-12	**22/11-12**	**29/1-13**	**31/1/13**	**29/11-12**	**29/11-12**	**24/1-13**	**24/1-13**	**11/3-13**	**20/3-13**
Solvent amines	mg/Nm^3	0.5	0.5	0.4	0.5	<0.023	0.020	<0.019	0.023	<0.012	<0.031
NH$_3$	mg/Nm^3	2.7	2.7	3.1	2.9	0.14	0.02	<0.01	<0.01	0.14	0.3
Sum primary alkyl amines (MA, EA)	mg/Nm^3	0.015	0.010	0.009	0.013	0.0005	0.0002	0.0006	0.0003	0.0007	0.0011
Sum secondary alkyl amines (DMA, DiEA)	mg/Nm^3	0.0005	0.0003	0.00014	0.00015	<0.0002	<0.0002	<0.0001	<0.0001	<0.0001	0.0004
Sum solvent specific nitrosamines	µg/Nm^3	<0.10	<0.11	<0.06	<0.06	<0.3	<0.2	<0.12	<0.19	<0.18	<0.10
Sum generic nitrosamines (EPA mix + NMOR)	µg/Nm^3	<0.39	<0.40	<0.08	<0.08	<0.2	<0.2	<0.17	<0.73	<2.17	<0.14
TONO (total nitrosamine content)	µmol/Nm^3	<0.33	<0.34	<0.33	<0.32	<0.76	<0.83	<0.69	<0.62	<0.16	<0.16
Converted to mass for Mw=130 for this report	µg/Nm^3	<42.9	<44.2	<42.9	<41.6	<98.8	<107.9	<74.45	<80.6	<20.8	<20.8
Sum solvent specific nitramines	µg/Nm^3	<0.01	<0.01	<0.01	<0.01	<0.1	<0.1	<0.20	<0.18	<0.08	<0.09
Sum generic nitramines (NO$_2$-MA, NO$_2$-DMA)	µg/Nm^3	<0.07	<0.08	<0.07	<0.07	<0.7	<0.7	<0.15	<0.14	<0.88	<0.17
Sum aldehydes	mg/Nm^3	0.34	0.44	0.10	0.18	0.4	0.6	0.8	-	0.8	1.0
Sum ketones	mg/Nm^3	0.47	0.68			3.9	4.4	4.7	-	4.0	4.3

Table 4.6b Measured emissions from the Technology Centre Mongstad (TCM) amine unit with a double water wash and Aker Solutions' Mobile Test Unit (MTU) with 'Aker Solutions' ACC^{TM} emission control design, which includes the Aker Solutions' anti mist system and acid wash polishing step' for Aker S26 solvent (Gorset, 2014)

		TCM DA amine plant S26 Campaign 16/6-14	MTU with ACC^{TM} Emission Control System S26 Campaign 12/2-14
Solvent amines	mg/Nm^3	1.8	0.09
NH$_3$	mg/Nm^3	1.9	<0.01
Sum primary alkyl amines (MA, EA)	mg/Nm^3	0.10	0.0004
Sum secondary alkyl amines (DMA, DiEA)	mg/Nm^3	0.006	<0.0001
Sum solvent specific nitrosamines	µg/Nm^3	<0.005	<0.010
Sum generic nitrosamines (EPA mix + NMOR)	µg/Nm^3	not analysed	not analysed
TONO (total nitrosamine content)	µmol/Nm^3	<0.02	<0.05
Converted to mass for Mw=130 for this report	µg/Nm^3	<2.6	<6.5
Sum solvent specific nitramines	µg/Nm^3	<0.05	<0.010
Sum generic nitramines (NO$_2$-MA, NO$_2$-DMA)	µg/Nm^3	<0.07	not analysed
Sum aldehydes	mg/Nm^3	2.95	1.2
Sum ketones	mg/Nm^3	0.22	0.2

An acid wash was also planned for use at Peterhead on the proposed Cansolv amine capture unit (Peterhead, 2016), as described below:

An acid wash packed bed section is included above the water wash section to capture mainly light amine components but also other entrained amine containing mist and potentially evaporated amine from the water wash section to minimise the emission level to the 170 m tall stack. The acid wash pH is maintained at 3 to maximise the light amine components capture. An acid and water mixture drawn from a chimney tray at approximately 30°C and 1.033 bara is re-circulated to the top of the packed section, by the Acid Wash Pumps (P-2001 A/B) at 30°C and 1.028 bara. Captured amine and other volatile components will be converted into salts by the sulphuric acid, which will suppress the vapour pressure and minimise the emission of amine to the environment. The amine salt will be purged by a take-off from the chimney tray located at the base of the acid wash section of the absorber and routed to the waste water treatment system. The flue gas leaving the acid wash will be reheated to approximately 70°C preventing plume formation and enhancing dispersion of light amine components and other amine degradation product emissions, before being released to atmosphere.

As already noted in Section 2.3.2, an acid wash will, however, require more complex arrangements to catch and recycle the liquid than a water wash and will also require acid (typically sulphuric) top-up and give rise to a reject stream. This reject stream could possibly be used for its ammonium sulphate content rather than being treated as a waste, but this would have to be verified for each project because of the other solvent-derived compounds it may contain – no published work appears to exist on this topic.

4.7 Cooling options

Generally, the best power and capture plant performance will be achieved by using the lowest-temperature cooling available, so the hierarchy of cooling methods is as follows:

- Direct water cooling (e.g. seawater)
- Wet cooling towers
- Hybrid cooling towers
- Dry cooling – direct air-cooled condensers and dry cooling towers

Power plants that are retrofitted with PCC using steam extraction, or are intended to be able to operate intermittently without capture, can share water cooling between the power plant and the PCC system, since the cooling load on the main steam condensers falls with increased steam extraction rate. But this shift away from condenser cooling will obviously not apply for systems with direct air-cooled condensers.

It may also be possible to re-use cooling water after the main condensers for higher-temperature cooling applications in the PCC plant, although water rejection temperature limits may obviously be an issue for direct cooling.

A feature of PCC is that heat generally has to be removed from a flue gas stream that was originally not cooled. Rejection of heat to atmosphere can still be achieved by heating the flue gas leaving the absorber using heat from the incoming flue gas, either directly (e.g. using a rotary gas/gas heater) or indirectly (e.g. using a heat transfer fluid or low-pressure steam).

Lean/rich solvent storage may also help to achieve satisfactory PCC performance during peak cooling stress periods.

5. CO_2 compression, drying and pipeline specification

5.1 CO_2 compression in context

Fig 5.1 shows approximate EOP for compression as a function of stripper pressure and Fig 5.2 shows illustrative EOPs for a range of reboiler heat duties and stripper pressures (IEAGHG, 2013). Based on these trends, compression is around a third of overall EOP for conventional PCC solvents at ~120ºC, e.g.

MEA and KS1, and maybe a quarter for high-stability solvents operated at elevated temperatures, e.g. piperazine.

The work input for CO_2 compression is also path-dependent, with options to combine compression, cooling an liquid pumping to optimise work input and also to facilitate any CO_2 purification processes (e.g. drying) taking place at intermediate pressures during the compression process e.g. (GE, 2010).

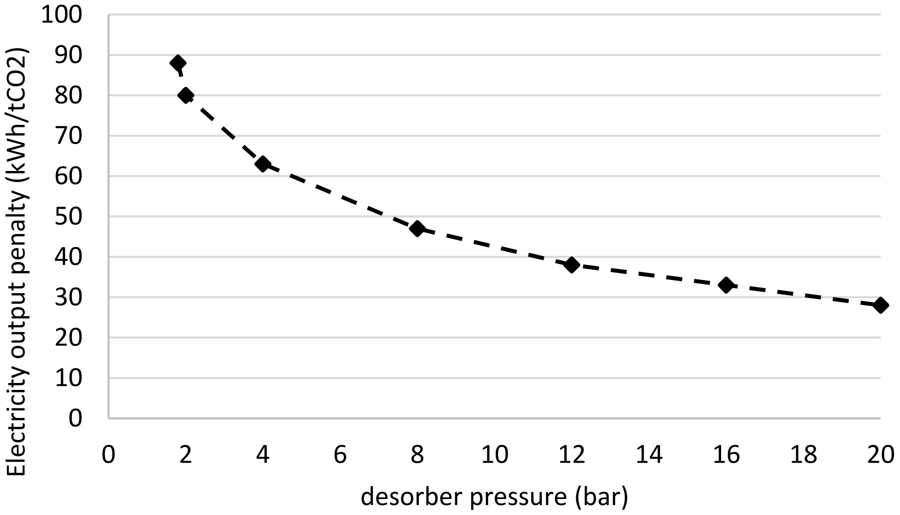
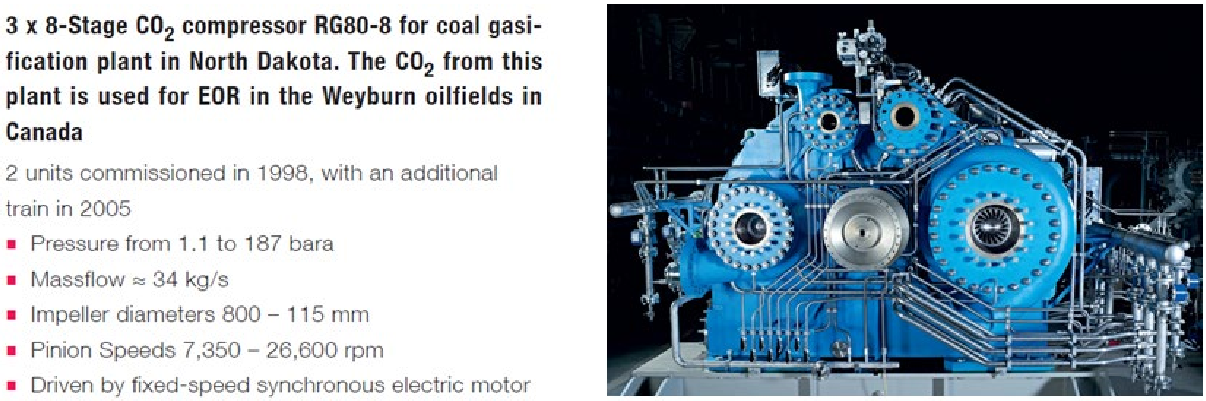


Fig 5.1 Approximate EOP for compression to 100 bar as a function of desorber pressure, with the assumption that the compression train operates with intercooling (data from IEAGHG, 2013**)**

5.2 Types of CO_2 compressors for CCS applications

At the 1 $MtCO_2$/yr scale centrifugal machines would generally be used. To date, integrally-geared machines have been used on the PCC projects at BD3 and Petra Nova. These are stated to have higher efficiencies and lower capital costs than barrel configurations. An example is shown in Fig 5.2.

5.3 Experience with CO_2 compressors in service: BD3, Petra Nova, Gorgon



3 x 8-Stage CO_2 compressor RG80-8 for coal gasification plant in North Dakota. The CO_2 from this plant is used for EOR in the Weyburn oilfields in Canada

2 units commissioned in 1998, with an additional train in 2005

- Pressure from 1.1 to 187 bara
- Massflow ≈ 34 kg/s
- Impeller diameters 800 – 115 mm
- Pinion Speeds 7,350 – 26,600 rpm
- Driven by fixed-speed synchronous electric motor

Fig 5.2 CO_2 compressor for the North Dakota – Weyburn pipeline; a similar unit is used on BD3
(MAN, 2013 - Reproduced with permission from MAN Energy Solutions)

The integrally geared compressor used for the North Dakota to Weyburn pipeline is shown in Fig 5.2; the BD3 unit is reported to be similar. The suppliers, MAN, stated that (MAN, 2013):

For most CO_2 and N_2 compression applications, integrally geared centrifugal compressors have emerged as state of the art. This technology offers several clear advantages:

- *Optimum impeller flow coefficient, since the optimum speed can be selected for each pair of impellers*
- *Axial inflow to each stage*
- *Shrouded or unshrouded impellers can be used*
- *Intercooling possible after each stage (impeller)*
- *External connection after each stage results in more flexibility in selecting the pressure level for the dehydration system, if applicable*
- *Practically no limit to the possible number of stages in one machine (pressure ratio of 200 possible on a single frame)*
- *Can be direct-driven by a 4-pole electric motor on the bull-gear, or a steam turbine on one of the pinions*
- *Inlet Guide Vane (IGV) for flow control*

The following experience in service has been reported for the BD3 compressor:

- *The compressor used at BD3 is similar to those that have been in service at DGC* [Dakota Gasification Company] *in Beulah, North Dakota since 2000. It is an eight stage, integrally geared centrifugal compressor, with a capacity of 55 mm scf/d (1.58 million m3/d) and electricity driven by a 14.5 MW fixed speed motor.*[13]

- July 2017: *The previously communicated planned outage at the carbon capture facility is continuing. Additional work included replacing packing in the stripper tower and work to repair vibration issues on the CO_2 compressor. The capture facility will be brought back online and resume normal operations once work is complete.*[14]

- August 2017: *The extra time* [>4 weeks for total 3 months' outage] *was required to complete the installation of new coolers on the CO_2 compressor used on site. This involved modifying the existing piping to accommodate the connection of the new coolers to compressor. The CCS CO_2 compressor is one of the largest high speed compressors produced by the manufacturer; therefore, the process to attach the piping to the compressor requires precise movement and suspension of the piping so that the mechanical stresses transferred to the compressor due to the weight and position of the pipe are minimized as much as possible. This precision necessitated technical assistance from the manufacturer in Germany and the overall process took some time.*[15]

More recently the following was also reported for the Petra Nova project, which uses a Mitsubishi eight stage integrally geared compressor with a triethylene glycol dehydration system located between the 4th and 5th stages of the compressor for CO_2 water removal (Petra Nova, 2020):

- *Each of the first four stages of the CO_2 compressor are equipped with intercoolers (shell and tube heat exchangers) with the compressor dehydration system providing CO_2 drying between the 4th and 5th stages. Early in Phase 3, heat transfer performance issues were detected in the CCS reflux system plate and frame heat exchanger. During an inspection, scaling was found in the heat exchanger, the reflux system piping, and intercooler drains. An investigation revealed that the CO_2 compressor intercoolers were fabricated with materials not conducive to the environment. The parties developed a plan to replace the required intercooler components during the 2018 planned outage.*

- *During the 2018 outage, Petra Nova discovered that the 1st stage scroll casing flow diffuser in the CO_2 compressor suffered leading-edge failures on most of the diffuser vanes. An RCA* [root cause analysis] *revealed that flow induced resonance caused the damage on the leading edges. A new design was completed, and a replacement diffuser was fabricated and delivered for future*

---

[13] [redacted]

installation. The original diffuser was repaired and reinstalled with an expected minor loss in 1st stage performance. No issues were found in the other diffusers.

- *The compressor operated without any measurable performance loss until mid-summer 2019 when a slight drop in performance was detected in the operating data. The OEM suggested fouling in one of the stages might be occurring. Petra Nova completed a compressor power use evaluation and determined that the power use was on a small, but steady rate of increase since early 2019. In September, the OEM informed Petra Nova that operating data is indicating performance loss in two additional stages. A reason for the performance degradation is not readily known until an inspection can be done – which is scheduled for 2020.*

The following arguments led to the choice of a barrel compressor in preference to an integrally-geared machine for the Gorgon CCS project (Musardo, 2012; TMI, 2017):

> *To allow the use of a carbon steel high pressure pipeline, the Gorgon CO_2 injection facility has been designed to control the 3rd stage discharge pressure to within the range of 725-943 psi (50-65 bar) to allow the maximum dropout of liquid water.*
>
> *During a shutdown, the pipeline will remain liquid water free even if the pipeline pressure is blown down to atmospheric pressure and the site is at minimum ambient temperature.*
>
> *The compressor, however, will have saturated gas mixing from the first 3 stages (prior to the water removal) and therefore the entire compressor has been designed with corrosion resistant materials suitable for free water and CO_2 during a shutdown event.*
>
> ***Comparison with integrally geared compressors***
> *During the early phases of the project, a review was made to determine the appropriate compressor design for the Gorgon CO_2 compressors. The two types of compressors found to be applicable for this service were conventional beam type compressors and integrally geared compressors.*
>
> *The following considerations were made in determining the final selection.*
>
> - *Safety aspects with CO_2 and H_2S, specifically with regard to the available sealing technologies.*
> - *Maintainability and maintenance access (ergonomics).*
> - *Machine complexity.*
> - *Intercoolers using air coolers instead of water coolers.*
> - *Nozzle loads with cyclonic wind conditions.*
> - *Overall power consumption for CO_2 injection.*
>
> *Relevant characteristics are then:*
>
> - *Seal leakage during shutdown – cannot vent seals to lower-pressure stages*
> - *Fast depressurization is a concern for CO_2 because of the formation of solid CO_2 (dry ice).*
> - *The conventional beam type compressor arrangement consists of two compressor bodies and therefore 4 dry gas seals*
> - *Integrally geared option requires a minimum of 8 compressor stages and therefore 8 DGS.*
> - *Barrel type compressor arrangement selected does not require the process piping to be removed for normal maintenance activities.*
> - *Integrally geared compressors require removal of suction piping, head covers and impellers to access DGS* [dry gas seal]*, and removal of discharge piping, stage casing and upper half of the gear box casing to access journal bearings.*
> - *From a safety standpoint, the HP barrel compressor has been designed with only one head-cover (3rd suction side) while the 4th stage head-cover is integral with casing and avoids the risk of high pressure leakage. The integrally geared option needs head-covers with relevant sealing gaskets on all 8 stages.*

5.4 BAT considerations for compression

As discussed in e.g. IEAGHG (2011b), CO_2 compression and drying technology selection will involve trade-offs between cost, efficiency and RAMO, particularly for units that may not be operated at baseload. Flexibly-operating PCC plants, on CCGT in particular, may need to employ multiple trains or different types of compressor for different stages in compression to achieve satisfactory operation, with some reduction in baseload performance and increase in capital costs.

Integrally-geared compressors have been used on the only two PCC projects, but with some problems. They are expected to be more efficient and cheaper, particularly for baseload operation.

A barrel centrifugal compressor was, however, chosen for a project in a more remote site. The stated reasons for this have been presented.

All the three overseas projects for which details are presented compressed the CO_2 to supercritical, dense phase conditions from stripper pressure. In contrast, UK projects may use gas-phase transport onshore with compression to dense phase for offshore transport at the beach crossing; this lower discharge pressure for the PCC installation will obviously affect the nature of the compressor (and it may allow some measure of line packing for flexible operation). Smaller installations, perhaps producing liquid CO_2 for ship, rail or road transport, will also have different requirements.

For the above reasons, compression and drying technology solutions for UK projects may be different from experience to date.

5.5 Pipeline CO_2 specification and oxygen removal

A recommended CO_2 pipeline specification from National Grid Carbon (NGC) (2019) is given below. Additional details of CO_2 specifications used in other studies and projects (including Northern Lights) are given in an ACT ALIGN project report (Dugstad, 2020).**Table 5.1 NGC CO_2 quality specification**

This represents the maximum allowable levels of components in the CO_2 stream based on safety, asset integrity and hydraulic efficiency, taking account of factors identified which require further investigation. The main driver for this specification is the development of safe, cost effective and efficient assets at all points in the CCUS/CCS chain.

Component	Limiting Criterion % Vol (ppmv values quoted for minor components)		
	Safety Maximum	Integrity Maximum(See note 3)	Hydraulic Efficiency + Fracture Control
Carbon dioxide (CO_2) (See note 6)	100	100	100
Water (H_2O)		0.005 (50 ppmv)	
Hydrogen sulphide (H_2S)		0.008^1 (80 ppmv) 0.002^2 (20 ppmv)	
Carbon monoxide (CO)	0.02 (200 ppmv)		
Oxide of nitrogen (NOX)	0.01 (100 ppmv)		
Oxide of sulphur (SOX)	0.01 (100 ppmv)		
Nitrogen (N_2)			See note 3
Oxygen (O_2)			≤ 10 ppmv (See note 5)
Hydrogen (H_2)			≤ 2% (see note 4)
Argon			See note 3
Methane (CH_4)			See note 3

Notes:

1. Limit for gaseous phase CO_2 at a total pressure of 38 barg (specified to avoid requirement for sour service).
2. Limit for dense phase CO_2 at a total pressure of 150 barg (specified to avoid requirement for sour service materials).
3. The allowable concentration of non-condensable components in the dense phase is subject to confirmation of the saturation pressure of the mixture. The saturation pressure shall not exceed 80 barg.
4. Due to the significance of H_2 on saturation pressure, the maximum concentration is limited to 2 mol.%.
5. Level set to maintain the integrity of storage site well bore materials.
6. The allowable minimum concentration of CO_2 is:
   gaseous phase $CO_2 \geq 91$ mol.%.
   dense phase $CO_2 \geq 96$ mol.%.

The same oxygen concentration limit is also proposed in the recent NPC report on CCUS deployment (NPC, 2019), '*Oxygen concentration should generally be below 10 parts per million by volume to avoid conflicts with the reservoir.*'

More detailed explanation of the effects of oxygen is given by NETL (2013) (refer to the original for supporting references):

'*Oxygen is another non-condensable species requiring additional compression work and a concentration limit of less than 4 volume% for most applications. The BAM Federal Institute for Materials Research and Testing conducted testing on pipe material with O_2 concentrations up to 6,600 ppm (0.66% vol) and found no negative pipeline effects when SO_2 concentration was kept to a minimum. However oxygen in the presence of H_2O can increase cathodic reactions causing thinning in the CO_2 pipeline. Because of this,* *the typical standard found for pipeline designs is 0.01 volume%; however, operating pipelines tend to be even more conservative in the 0.001 to 0.004 volume% range. The maximum oxygen content was set by specification (see Cole, 2011), which is also used by the AEP Mountaineer project. Preliminary conclusions from an ongoing NETL study indicate that the cost of a CO_2 purification system used to lower O_2 content doesn't vary significantly based on final O_2 concentration (10, 100 or 1,000 ppmv).*

Oxygen can also cause the injection points for EOR to overheat due to exothermic reactions with the hydrocarbons in the oil well. In addition, high oxygen content can cause aerobic bacteria to grow in the reservoir and at the injection points.

In sequestration applications, O_2 can react with SO_2 forming H_2SO_4, and NO forming NO_2, which in water could form HNO_2. Dissolved O_2 can also react with the cap rock if it contains iron, manganese, and other metals. If dissolved ferrous ions are present in water within the formation, ferric oxide-hydrate, or ferric hydroxide, could form potentially plugging pore space as well.'

Proposals for oxygen removal in PCC plant are described in two FEED study reports. The Peterhead FEED study (Peterhead, 2016) reported:

'*To meet the required O_2 specification of the sequestered CO_2, it is necessary to condition the captured CO_2 to remove oxygen. The oxygen concentration of the captured CO_2 is estimated to be approximately 19 ppm mol.*

The oxygen specification of the exported CO_2 was <1 ppmv in the FEED. A single, 1 x 100 % oxygen removal unit is proposed in the FEED design for oxygen removal. The required catalyst volume is 10 m^3 (based on Johnson Matthey Puraspec 2712), with a reactor diameter defined as 2.1 m which results in a bed height of 2.9 m. The bottom head of the reactor vessel is assumed to be filled with different layers of ceramic balls. The catalyst bed would also be retained by a layer of 19 mm balls. A distance between bottom of catalyst layer and TL [tangent line] *of 200 mm was assumed. The proposed FEED reactor design has been confirmed with a catalyst vendor.*

Further work to consider the effects of pitting corrosion of the stainless well tubing was done in the Execution Preparation Phase, after FEED was completed. The work has allowed the relaxation of the O_2 content design limit to < 5 ppmv.'

The Klemetsrud EfW Concept Study report (FOV, 2018) states that:
'*After the final stage of compression, the* [CO_2] *stream is passed to an oxygen removal reactor in which Hydrogen (in excess) is used. An actuated control valve will be used to control hydrogen injection rates. The Hydrogen dose rate will be very small thus even if a valve fails the injection is unlikely to create an issue. The specification of the liquefied CO_2 indicates that only minor quantities* [preliminary information: "H_2 content after the reactor will be about 50 ppm molar"] *of H_2 will be present in liquid CO_2 product.'* But then adds: '*An oxygen removal package was put on hold to gain further understanding of its requirement - therefore, it was not included within the scope.*' Elsewhere in the report it was noted, '*Hydrogen introduces fire and explosion risks, and possibilities for accident escalation. In* [an alternative] *design flue gas treatment* [unspecified] *is introduced to avoid the oxygen removal reactor, and introducing hydrogen is not found necessary.'* In the FEED study (FOV, 2020a) it was confirmed that a hydrogen-based oxygen removal system was included, but no further details were published.

5.6 Water removal

The IEAGHG commissioned a study of drying techniques by AMEC in 2014 (IEAGHG, 2014). Target water contents varied from 600 ppmv to < 10 ppmv, with a focus on TEG (triethylene glycol) and molecular sieve systems. The study included the effects of CO_2 flow rates, pressure and other CO_2 stream constituents.

Øi (2014) reported HISYS modelling of TEG and molecular sieve dehydration systems for CO_2. Process options for CO_2 dehydration down to water levels below 5 ppm were simulated.

Water removal experience at the Quest CCS project has been reported in detail (Quest, 2020). The basic details of the dehydration system at Quest (IEAGHG, 2019b) are:

- Design content in the CO_2 product gas is 102 mg H_2O/Nm^3 to meet pipeline specifications.

- The TEG drying unit operates at 5 MPa(g).
- CO_2 captured in the TEG absorber is flashed from the water-rich TEG and returned to first-stage compression.
- TEG is regenerated in a stripper reboiler to remove water vapour.

Lessons learned from operation of the TEG unit include:

- *Carryover of TEG into the CO_2 stream to the pipeline was very low when compared with design. The estimated losses for 2016, 2017, 2018 and 2019 were roughly 6,900 kg, 5,800 kg, 8,700 kg and 11,100 kg annually vs the design makeup rate of 46,000 kg annually. The losses are <10 ppmw of the total CO_2 injection stream for 2019, compared to the 27 ppmw expected in design.*
- *When running at design process conditions for temperature, stripping gas and TEG flows, the CO_2 moisture content was below 20ppm. This allowed an optimization on stripping gas to reduce N_2 usage for the unit from design of 37.7 sm^3/m^3 TEG to ~3 sm^3/m^3 TEG. After making this adjustment, the average for moisture content of the outlet remains below spec.*
- *One of the CO_2 moisture content analyzers on the outlet of the TEG unit experienced some reliability issues in December 2015. The issues were associated with scale buildup on the highly polished stainless steel reflective mirror. Scale buildup was found to be related to low temperatures on the mirror and the issues were rectified via improving heat containment in the enclosure. Operation of the device has been stable ever since.*

5.7 Planned and accidental releases of CO_2 from the compression system

Limited public domain information on practice in this area has been identified. Generic guidance on pressurised CO_2 safety is provided in the DNV RISKMAN reports (DNV, 2021) and the outline plans to use an earlier DNV-provided approach in the 'Dispersion Modelling Strategy' for unplanned CO_2 releases is given in a coal plant PCC FEED study by E.ON (E.ON, 2011).

An example of planned CO_2 venting methods for PCC plants is provided in (Bechtel, 2022), with dilution in the PCC flue gas used to assist dispersion:

'*The venting carbon dioxide is to be routed to the absorber stacks to mix with the exiting flue gases to ensure buoyancy necessary to disperse the carbon dioxide. Assuming a supercritical carbon dioxide volume of 20m3 (CO_2 Surge Drum ullage between NLL and LLL) depressured over 15 minutes results in a carbon dioxide vent flow of 8 kg/ s, in the order of 1% of the flue gas flow, so the flue gas exit temperature should not be significantly reduced. CFD analysis should be conducted in the next project stage to confirm this routing is acceptable when the flue gas flow has stopped, or whether the dry gas vent should be separately vented.*'

6 Air Emissions: PCC emissions triangle, emissions monitoring for environmental impact assessment

6.1 Background – public domain data

There is only limited information available in the public domain at present that would be relevant for permitting a new PCC project in the UK. All available measurements of emissions from PCC plants (with the exception of Table 6.1. below) arise from pilot tests, which do not usually include the full range of solvent management and emissions controls that could be expected on a plant designed and operated under UK conditions, and which also were not run until stable, average solvent composition were achieved with these measures. In addition, most tests are not on the actual flue gases of interest, with the partial exception of natural gas combustion products (i.e. NOx will still be plant-specific and trace components may differ). Note also that in most cases when pilot plant emission data for proprietary solvents is reported not all details are presented.

There are no large-scale CCGT or BECCS power plants with PCC running anywhere in world. Fluor's unit at Bellingham (Fluor, 2008) was the closest example for CCGT, but this has now been closed.

Even for operating commercial coal power plants with PCC published data on emissions is very limited; see Table 6.1 below and also Table 2.2 (with the latter being only design, not actual measured, values).

Table 6.1 Reported absorber emissions metrics for Petra Nova project from final technical report (Petra Nova Parish Holdings, 2020)[16]

ABSORBER EMISSIONS METRICS (AT 100% LOAD)		
ITEM	**PERMIT LIMITS**	**PHASE 3 RESULTS (3-YEAR AVG)**
Volatile Organic Compounds (VOC)	24.53 TPY	2.84 TPY
Ammonia (NH_3)	1.35 TPY	0.318 TPY

6.2 Factors affecting emissions to air from a PCC plant

Fig 6.1 summarises the factors affecting emissions from a PCC plant as the three apexes of a PCC emissions triangle:

A. Determine the possibilities for environmental impacts from emissions by solvent selection

B. Reduce degradation and impurity addition rates, and accelerate degradation product and other impurity removal rates (all additions must be balanced by removals)

C. Trap potential emissions at the absorber exit

This triad can be viewed as a hierarchy for action. Although, to some extent, preventative actions in subsidiary areas can compensate for deficiencies at higher levels, this will be accompanied by less robust assurance of satisfactory performance under fault conditions or even in normal operation when encountering unforeseen operating conditions or fuels.

Overall, the factors across the three areas will have to be adjusted so that emissions performance of the PCC plant, when coupled with atmospheric dispersion and reaction models that also include

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[16] During the 3-year demonstration period, the PCC facility captured 3,904,978 short tons of CO_2.
Assuming the flue gas averages 12% v/v CO2 dry, average capture rate is 92% and a kmol of flue gas is 22.4 m^3: Three year flue gas dry volume = 3.905×10^6 short tonx907.18 kg/short ton/44.1 kg/kmolx22.4 m^3/kmolx(100-0.92x12)/(0.92x12) = 14.50×10^9 m^3 ; VOC concentration =3 yr x2.84.10^9 mg/yr/14.50 x 10^9 ~ 0.6 mg/m^3; NH_3 ~ 0.066 mg/m^3 (Petra Nova, 2020)

atmospheric reaction processes, will yield environmentally acceptable impacts. There remains the potential to reheat the flue gases after the absorber to aid dispersion, as well as the stack geometry. However, further discussion of dispersion and atmospheric chemistry modelling is beyond the scope of this PCC BAT review.

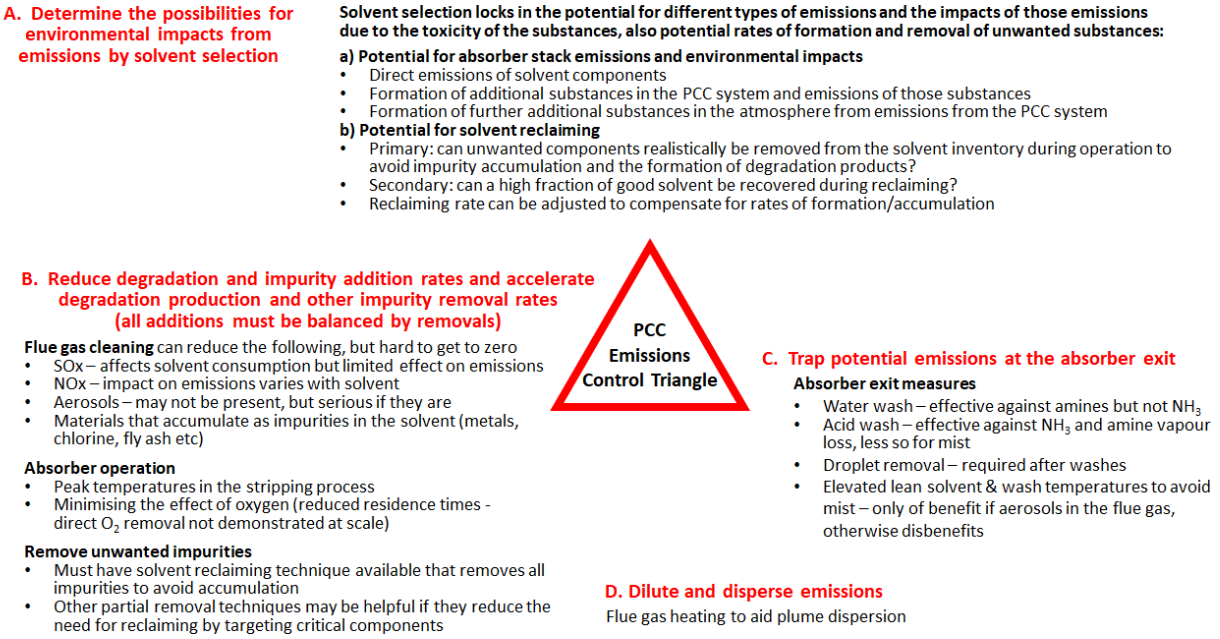
Given the complex nature of the processes involved and the emerging nature of PCC technology, as already discussed, pilot studies under thoroughly realistic conditions are required for reliable indications of the dispersion, reaction and deposition modelling inputs, and these inputs will still need to be verified by monitoring of the full-scale plant for an extended period after construction, with remedial action as necessary to ensure that satisfactory environmental impacts are actually being achieved.

When permitting PCC plants the general approach should therefore be to:

a) Assess the probability of acceptable emissions performance, with higher probabilities of acceptability being assigned to PCC emission triangle combinations that have been demonstrated as giving satisfactory atmospheric dispersion modelling software inputs in representative pilot trials, and also to systems that minimise the scope of the risks and to systems that give flexibility in the mitigation measures that can be applied to compensate for uncertainties in actual performance.

b) Measure actual plant performance when in service and recalculate atmospheric dispersion modelling software results as necessary to verify satisfactory performance. Measurements would be undertaken at more frequent intervals initially, with the frequency dropping as continuing satisfactory operation is confirmed.

Emissions monitoring, at both pilot and full scale, is therefore a critical aspect of the environmental performance of PCC technology; this will be discussed in the remainder of this section.



A. Determine the possibilities for environmental impacts from emissions by solvent selection

Solvent selection locks in the potential for different types of emissions and the impacts of those emissions due to the toxicity of the substances, also potential rates of formation and removal of unwanted substances:

a) Potential for absorber stack emissions and environmental impacts
- Direct emissions of solvent components
- Formation of additional substances in the PCC system and emissions of those substances
- Formation of further additional substances in the atmosphere from emissions from the PCC system

b) Potential for solvent reclaiming
- Primary: can unwanted components realistically be removed from the solvent inventory during operation to avoid impurity accumulation and the formation of degradation products?
- Secondary: can a high fraction of good solvent be recovered during reclaiming?
- Reclaiming rate can be adjusted to compensate for rates of formation/accumulation

B. Reduce degradation and impurity addition rates and accelerate degradation production and other impurity removal rates (all additions must be balanced by removals)

Flue gas cleaning can reduce the following, but hard to get to zero
- SOx – affects solvent consumption but limited effect on emissions
- NOx – impact on emissions varies with solvent
- Aerosols – may not be present, but serious if they are
- Materials that accumulate as impurities in the solvent (metals, chlorine, fly ash etc)

Absorber operation
- Peak temperatures in the stripping process
- Minimising the effect of oxygen (reduced residence times - direct O_2 removal not demonstrated at scale)

Remove unwanted impurities
- Must have solvent reclaiming technique available that removes all impurities to avoid accumulation
- Other partial removal techniques may be helpful if they reduce the need for reclaiming by targeting critical components

C. Trap potential emissions at the absorber exit

Absorber exit measures
- Water wash – effective against amines but not NH_3
- Acid wash – effective against NH_3 and amine vapour loss, less so for mist
- Droplet removal – required after washes
- Elevated lean solvent & wash temperatures to avoid mist – only of benefit if aerosols in the flue gas, otherwise disbenefits

D. Dilute and disperse emissions

Flue gas heating to aid plume dispersion

Fig 6.1 The PCC Emissions Control Triangle

6.3 Measuring PCC stack emissions

6.3.1 Overview

Given the apparent lack of a requirement for detailed emissions monitoring on full-scale PCC projects to date, only pilot-scale experience for amine capture plant emission measurements is available.

This is also not a fully mature area. SEPA (2015) concluded that:

> *'There has been limited stack emission monitoring of amine compounds from carbon capture pilot plants and no standard reference method exists for nitrosamines, nitramines or for the combination of substances anticipated in flue gas. Consideration needs to be paid to targeting both the aerosol and gas phases, the issue of 'fogging' and the risk of formation/degradation of substances during monitoring. Indeed, the variation in emissions measurements results between laboratories for the same analyte at the same sampling site of a facility has been shown to be significant.'*

Some examples for stack emission measurements from Test Centre Mongstad (TCM) in Norway (see Fig 6.1), which has consistently led in this area, for pilot tests using MEA are reported below in Table 6.2 (see also Table 4.1 for TCM measurements for pilot tests using Aker solvents). These measurement examples may be suitable as a basis for satisfactory measurements in other systems but, given differences will exist in the nature of the plant or the potential substances being emitted in future implementations of PCC, project-specific measurement and monitoring schemes will need to be proposed, ideally based on realistic pilot-scale tests, as part of initial permitting, and then be verified in service, e.g. by cross-comparison between independently-obtained sets of measurements.

Similarly, the substances that need to be measured will be application-specific, depending in particular on the solvent used.

As an example, for MEA only, the substances shown in Table 6.2 were measured in trials at TCM.

Table 6.2 Substances measured in TCM trials on MEA: Degradation products and measurements in solvent, emission to air from the amine plant absorber stack and in ambient air (Morken, 2017)

Component	Abb	CAS No	Mw	Solvent	Emission to Air	Ambient Air
Monoethanolamine	MEA	141-43-5	61	X	X	X
Ammonia	NH_3	7664-41-7	17	X	X	
Formaldehyde	FA	50-00-0	30	X	X	
Acetaldehyde	AA	75-07-0	44	X	X	X
N-Nitroso-diethanol-amine	NDELA	1116-54-7	134	X	X	
N-(2-hydroxyethyl) acetamide	HEA	142-26-7	103	X		
1-hydroxyethane 1, 1-diphosphonic acid	HEDP	2809-21-4	206	X		
N-(2-hydroxyethyl)ethylenediamine	HEEDA	111-41-1	104	X		
N-(2-hydroxyethyl)formamide	HEF	693-06-1	89	X		
N-(2-hydroxyethyl)glycine	HeGly	5835-28-9	119	X		
N-(2-hydroxyethyl)-2-(2-hydroxyethylamino)acetamide	HEHEAA	144236-39-5	162	X		
Pyrazine	-	290-37-9	80	X	X	
N-(2-hydroxyethyl)imidazole	HEI	1615-14-1	112	X		
N-(2- hydroxyethyl)imidazolidinone	HEIA	3699-54-5	130	X		
4-(2-hydroxyehyl)piperazin-2-one	HEPO	23936-04-1	144	X		
Dimethylamine	DMA	124-40-3	45	X	X	X
Methylamine (Monomethylamine)	MA (MMA)	74-89-5	31	X	X	X
Ethylamine	EA	75-04-7	45	X	X	X
Diethylamine	DiEA	109-89-7	73	X	X	X
Morpholine	Mor	110-91-8	87	X	X	
Trimethylamine	TMA	75-50-3	59	X	X	X
4,4-dimethyl-2-oxazolidinone	4.4-DMO	26654-39-7	115	X	X	
N-Nitroso(2-hydroxyethyl)glycine	NO-HeGly	80556-89-4	148	X	X	
2-(Nitroamino)ethanol	NO2-MEA	74386-82-6	106	X	X	
N-methyl,N-nitroso-methanamine	NDMA	62-75-9	74	X	X	
N-nitro-N-methyl-methanamine	DMNA	4164-28-7	90	X	X	
N-Nitrosomethylethylamine	NMEA	10595-95-6	88	X	X	
N-Nitrosodiethylamine	NDEA	55-18-5	102	X	X	
N-Nitrosodi-n-propylamine	NDPA	621-64-7	130	X	X	
N-Nitrosodi-n-butylamine	NDBA	924-16-3	158	X	X	
N-Nitrosopyrrolidine	NPYR	930-55-2	100	X	X	
N-Nitrosopiperidine	NPIP	100-75-4	114	X	X	
N-nitrosodiethanolamine	NDELA	1116-54-7	134	X	X	
2-Oxazolidone	OZD	497-25-6	87	X	X	
Alkylpyrazine	-			X	X	
NN’-Bis(2-hydroxyethyl)oxamide	BHEOX	1871-89-2	176	X	X	
Diethanolamine	DEA	111-42-2	105	X	X	

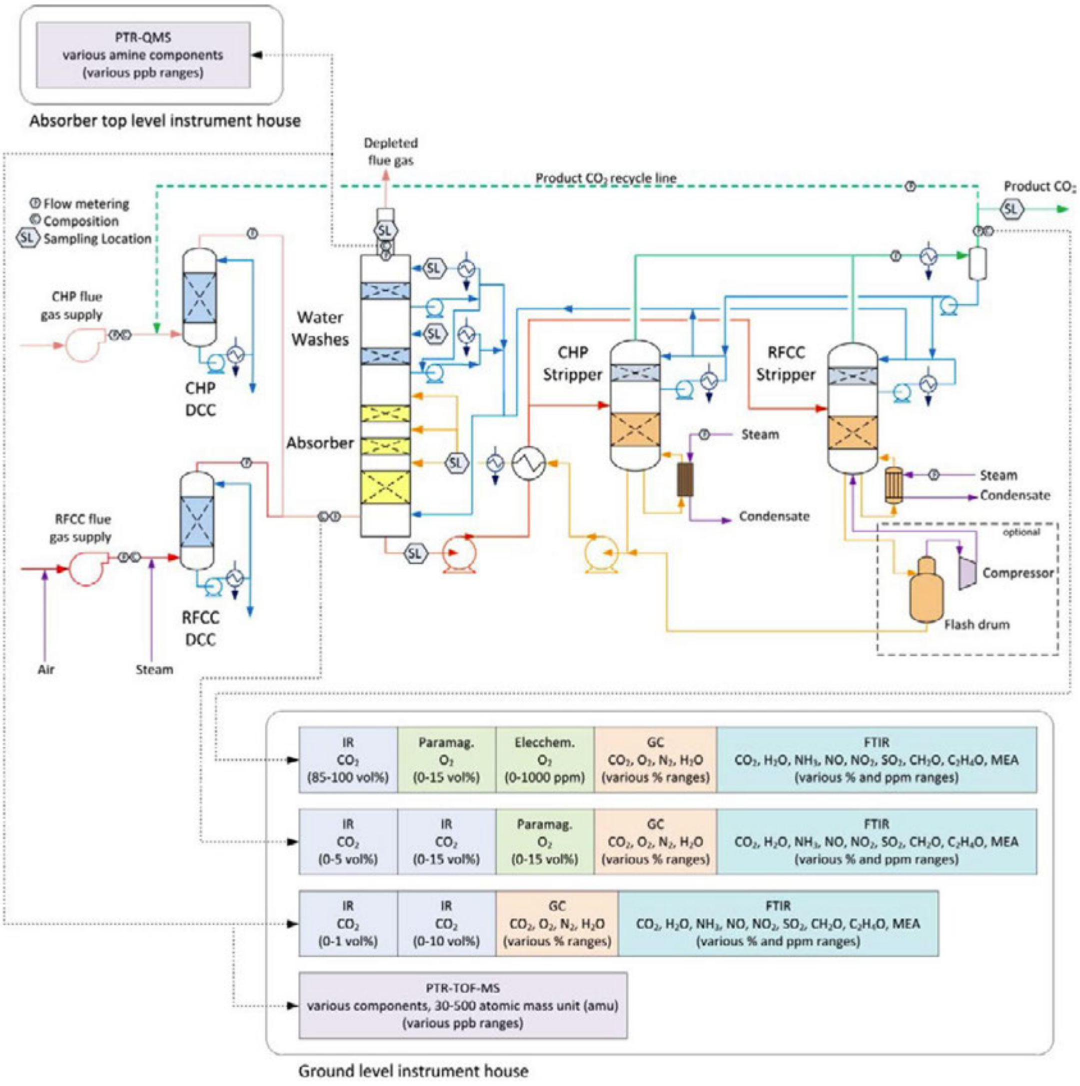


Fig 6.2 Process flow diagram for TCM, including locations of online equipment and manual sampling (Morken, 2017) (Reproduced with permission from TCM). *Note that TCM is a test plant with added flexibility and scope with regards to the instrumentation. In particular the PTR-TOF-MS is not a permanent installation, it is part of a continuous collaboration with the University of Oslo and required highly trained specialists to maintain and operate.* (TCM, 2021, personal communication)

Stack emissions will need to be measured continuously to verify, as far as possible, satisfactory plant operation, but components of interest that are present in quantities that are below the detection limits for continuous monitoring instruments can only be assessed by collecting a sample, which is then analysed offline, from the flue gases over an extended period. Since this will be a relatively infrequent measurement, reliance has to be placed on its being undertaken at representative times. It is also important that indicators of plant emissions performance that can be continuously monitored are used to indicate that ‘normal’ performance with respect to undetectable emissions to air is likely to be occurring. These indicators will depend on the details of the PCC plant, but might include:

- Amine and other emissions that can be measured by online instruments
- Absorber exit flue gas temperature and relative humidity
- Water wash temperatures
- Water wash pH values
- Water wash circulating flows
- Incoming flue gas properties, including NOx

If these parameters vary, e.g. because of absorber wash topping-up and draining cycles, as well as during flexible operation such as load changes, it is obviously important that sampling periods are selected so that emissions over the full range of operating conditions are assessed.

A procedure for 'Sampling and analytical procedures for potentially harmful components related to amine based CO_2-capture' has been defined by Statoil (2014 – expired Jan 2020). Continuous online and sampling emission measurement methods in use at TCM are described by Morken (2017).

6.3.2 Online stack emissions monitoring methods at TCM

Online TCM instrumentation for monitoring absorber stack emissions is shown in Table 6.3. These instruments are located at ground level, except for the PTR-QMS that is housed in the absorber top level instrument house.

As noted by Morken (2014):

> '*The sampling line bundle installed at TCM DA is 101 meters long. It consists of 3 separate lines made from the following materials, respectively:*
>
> - *PFA Teflon™*
> - *Electro-polished stainless steel*
> - *Sulfinert™-treated passivated stainless steel*
>
> *All lines can be heated to 140 °C. Sample transfer via a heated sampling line has several benefits over placing the equipment at the top of the absorber:*
>
> - *Easy access to the analyzer for maintenance and calibration and to utilities such as power, gas supplies, etc.*
> - *Increased physical space for the analyzer*
> - *Safer operations*
>
> *Some negative aspects are however:*
>
> - *Delayed analyzer response*
> - *Potential degradation reactions and adsorption effects in the sampling line*
>
> *Potential sample line effects are rarely reported in open literature. It is generally accepted is that the sample path should be kept as short as possible, and that the line temperature should be well above the dew point. However, increasing the temperature too much may lead to unwanted decomposition, to potential formation of nitrosamines, and to other sampling artefacts. Switch between different sample lines should be avoided due to memory effects.*'

Table 6.3 Online instrumentation for emission monitoring at TCM (Morken, 2017)

Instrument	Gasmet FTIR FCX	FTIR Anafin2000	PTR-TOF-MS	PTR-QMS
Supplier	Gasmet Technomogies Oy	Analect	Ionicon	Ionicon
Temp	Cell 180°C	Cell 85°C	Drift tube 100°C	Drift tube 100°C
Cell path length	5m	7m	-	-
Resolution	8cm^{-1}	2cm^{-1}	$(\Delta(m/z))/((m/z)) > 3000$	$\Delta (m/z) = 1$
Flow rate	120 – 600 L/h	100 L/h	30 L/h	30 L/h
Range	900-4200cm^{-1}	500-7000cm^{-1}	10-200	20-200
LOD	0.5-1ppmv*	0.5-1ppmv*	0.0001ppmv	0.001ppmv
SD	*	*	±20%	±20%
Inlet Flue Gas		x		
CO_2-Stack	x		x**	
Absorber	x	x**	x	X

*Limit of detection (LOD) value depends on compound, level of compound, the way of calculation and measurement time.

**Occasionally measurements on these streams for QA/QC and comparing different instruments.

6.3.3 Stack emissions sampling methods at TCM

A flue gas sampling system for use when aerosols are not present is shown in Fig 6.3. Shah (2018) describes additional heating measures that have been found necessary to achieve satisfactory operation when flue gases with aerosols are being sampled at TCM. Sample analysis methods are shown in Table 6.4 and sample results for an MEA test in Table 6.5.

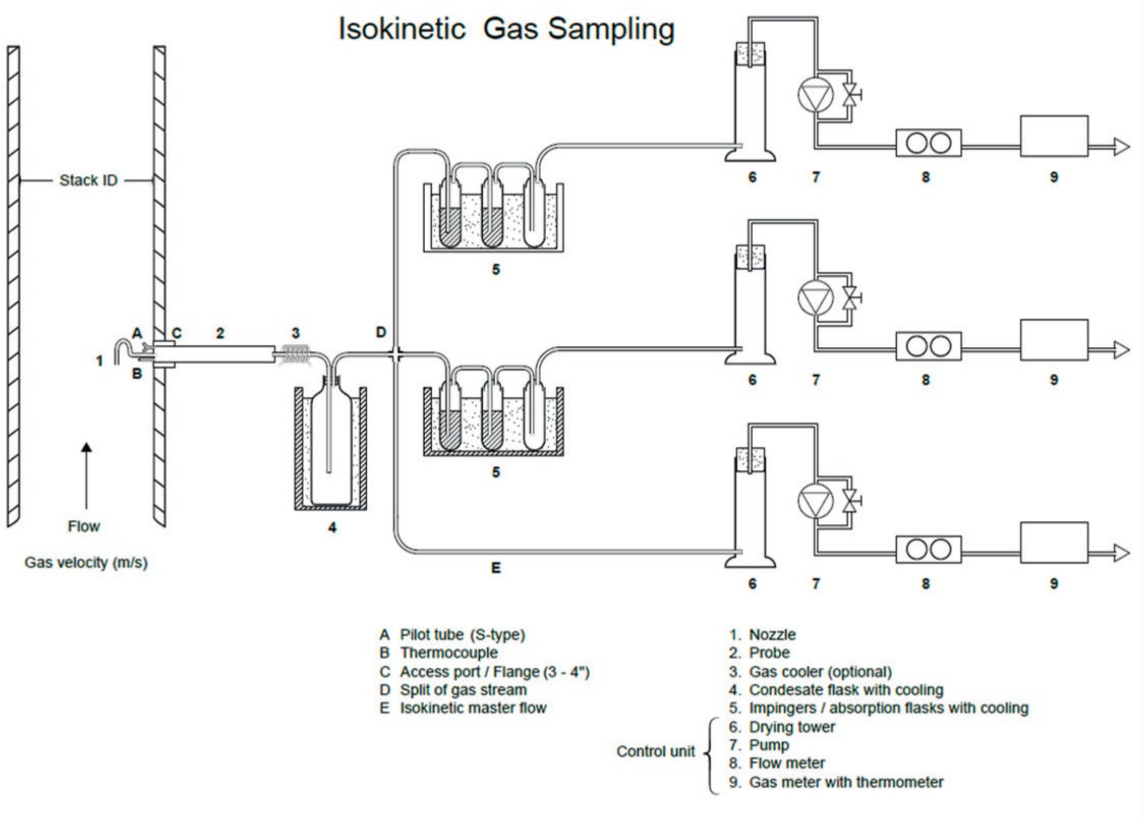


Fig 6.3 Gas sampling equipment for use at the absorber exit, suitable for flue gases without aerosols (Statoil, 2014; Morken, 2014) (Reproduced with permission from TCM)

Table 6.4 Analysis methods used for samples
(Morken, 2014); (for TONO method see Statoil, 2014)

Parameters/component groups	Sampling	Analysis
Amines (solvent)	Condensate + 2x 0,05M sulphuric acid impingers + empty flask	LC MS QQQ
Amines (alkyl)	Condensate + 2x 0,05M sulphuric acid impingers + empty flask	UPLC-MS/MS (Ramboll [7])
Ammonia	Condensate + 2x 0,05M sulphuric acid impingers + empty flask	Cation chromatography, IC-ECD
Aldehydes	Condensate + 2x DNPH cartridges	LS MS QQQ
Nitrosamines* (Specific, generic and TONO)	Condensate + 2x 10g sulfamic acid impingers + empty flask	See* (Ramboll [7])
Nitramines	Condensate + 2x 10g sulfamic acid impingers + empty flask	UPLC-MS/MS or GC-HRMS (Ramboll [7])
pH**	-	pH-paper [7]
Nitrate (NO_3^-)**	-	Anion chromatography, IC-ECD

*Specific; CLLE extraction followed by UPLC-MS/MS or GC-HRMS. Generic; LLE followed by analysis on GC-HRMS. TONO; Quench of soluted nitrate followed by break of N-NO bond in a reaction chamber. Total NO released from the N-nitroso groups detected by chemiluminscence analyser ; **For sample preservation and work-up.

Table 6.5 Example measurements of MEA degradation components in flue gas out of absorber from gas emission measurements (Morken, 2014)

Compound	04.02.2014 µg/m³	04.02.2014 ppbv	10.02.2014 µg/m³	10.02.2014 ppbv
Methylamine	2.6	2	3.6	3
Dimethylamine	<1.1	<1	<1.1	<1
Ethylamine	<1.1	<1	<1.1	<1
Diethylamine	<1.1	<0.3	<1.1	<0.3
Ethylmethylamine	<2.2	<1	<2.1	<1
MEA	13	5	17	6
DEA	<1.1	<0.2	<1.1	<0.2
Morpholine	<2.2	<1	<2.1	<1
MEA-NO2	<0.01	<0.002	<0.01	<0.002
Dimethylnitramine	<0.002	<0.0006	<0.002	<0.0006
Diethylnitramine	<0.004	<0.001	<0.004	<0.001
NDMA	<0.001	<0.0003	0.001	0.0004
NMEA	<0.001	<0.0003	<0.001	<0.0003
NDEA	<0.001	<0.0002	<0.001	<0.0003
NDPA	<0.001	<0.0002	<0.001	<0.0002
NPYR	<0.001	<0.3	<0.001	<0.3
NMOR	<0.002	<0.0004	<0.002	<0.0004
NPIP	<0.001	<0.0002	<0.001	<0.0002
NDBA	<0.001	<0.0002	<0.001	<0.0002
NDELA	<0.01	<0.002	<0.01	<0.002
TONO*	<0.2	<0.04	<0.2	<0.04

The isokinetic sampling results shown in Table 6.6 come from commercial trials by Fluor at Wilhelmshaven (Reddy, 2017) using Econamine FG Plus, reported to contain >30% w/w MEA (Reddy, 2008).

Table 6.6 Absorber overhead gas isokinetic test results (n.d. = not detected) (Reddy, 2017)
(†VDI methods would not be used in the UK)

Parameter	Value	Units	Method†
Amine	0.3	mg/Nm$_3$ (dry)	VDI 2467-1
Ammonia	1.7	mg/Nm^3 (dry)	VD1 3496-1
Aldehydes, Ketones	0.2	mg/Nm^3 (dry)	VDI 3862-2
Total Nitrosamines	n.d. (<3.2)	µg/Nm^3 (dry)	Amidosulfonic acid
Total Organic Carbon	n.d. (<0.1)	ppmv (dry)	EN 12619
SO_2	1.0	mg/Nm^3 (dry)	EN 14791
NO_x	98.4	mg/Nm^3 (dry)	EN 14792

6.3.4 Emissions monitoring experience at EfW + PCC plants

No public domain information has yet been identified.

6.4 Other emissions to air

Experience at the Petra Nova plant (Petra Nova, 2020) to ensure compliance with Leak Detection and Repair (LDAR) VOC regulations is that, in addition to attention to piping joints, flanges, and drain valves, all open-ended lines needed caps or secondary valves to properly seal each line. There were over 2000 LDAR monitoring points in total. With these provisions, Petra Nova was permitted to reduce LDAR monitoring frequency to semi-annually since emissions were below the permitted threshold.

6.5 BAT considerations

The PCC plant must also have acceptable environmental risks through the prevention or minimisation, or rendering harmless, of emissions. It is expected that Environmental Standards for air emissions from the PCC plant and their subsequent atmospheric degradation products (including e.g. nitrosamines and nitramines) must be achieved; see reference: https://www.gov.uk/guidance/air-emissions-risk-assessment-for-your-environmental-permit. This will need to be confirmed using atmospheric dispersion, reaction modelling tools and specific site parameters which will define plant-specific emission limit values (ELVs).

Reliable air emissions data for a PCC plant can finally be verified from measurements taken on the actual plant only after an extended period in service to ensure that the solvent inventory has reached its long-term composition range and that all operational effects (e.g. variations in flue gas compositions and operating requirements) are also taken into account.

Methods to undertake continuous monitoring of a range of emissions to atmosphere from PCC plant have been reported, but the effectiveness will depend on details of the installation and operation (e.g. sampling line arrangements), and performance will have to be checked and verified on an individual basis and for the specific substances of interest.

Some substances of interest (e.g. nitrosamines) that are potentially present in PCC absorber stack gases can be measured accurately only by sampling and trapping, with subsequent analysis off-line. It is important that this sampling is timed, and the plant operated, to give representative measurements. It is also important that attention is given to how parameters that can be monitored continuously are used to assess that satisfactory emissions performance for these substances is likely to be being achieved.

All of these considerations will need to be included in a Monitoring Plan for the PCC plant. This plan should also take into account what preliminary data is available, or will become available before operation, from representative pilot testing. If limited evidence is available (i.e. there is no representative long-term pilot plant data) then the operator should propose precautionary limits to ensure no harm occurs.

7 Plant Operation and Flexibility

7.1 Expected operating modes

CCGT+PCC and BECCS PCC power plants, and CHP plants, might be expected to operate in the following ways in the future UK electricity system:

- PCC power plants could be expected to dispatch in the merit order behind zero-marginal-cost sources (i.e. nuclear and renewables) when energy is the only requirement, but ahead of unabated fossil. BECCS, as also providing net CO_2 removal from the air, could also be expected to run ahead of low-carbon power such as biomass without CCS and gas power with CCS.
- This implies that the ability to undertake planned starts and stops with minimal extra CO_2 emissions is important, particularly for CCGT+PCC plants. Unplanned starts are less of an issue because they would be infrequent.
- PCC power plants may also need to operate at minimum stable generation for periods when the electrical output is not valued because of an oversupply of intermittent renewables, but either the grid services supplied by the PCC power plants are valuable or the period until the plant is predicted to be required again is too short to justify stopping and starting.
- CHP plants (biomass or gas) with PCC have to satisfy a more continuous heat load so will likely need to continue operating irrespective of electricity market conditions. In this case, the ability to reduce electricity output at least temporarily is likely to be a useful option, also to continue to provide grid services as far as possible.
- Both power and CHP plants should be able to provide grid services as far as possible – spinning reserve and response for frequency support. Since steam can be temporarily diverted from the PCC plant and, with more disruptive consequences, electric power can be cut for compression and other duties, PCC is capable of providing a rapid and sustained increase in output in response to falling grid frequency.
- PCC plants may also be able to offer electricity storage services, through storing heat or lean solvent at times of excess power in the market and using it to allow more electricity output when other generation sources are unavailable.

7.2 Power plant and PCC features for starts and stops

In a recent study for BEIS by AECOM (AECOM, 2020) it was shown that CCGT PCC power plants could be expected to maintain normal capture levels during planned starts and stops with some relatively straightforward design provisions. These are summarised below; readers should refer to the study report for more details:

Power plant

a) Steam that would normally be bypassed to the condenser during start or stop sequences because it cannot be used in the steam turbine should be made available for use in the PCC reboiler – this steam is automatically available if CO_2 is being produced, with a relatively short delay for heating up metal and liquid in the boiler.

b) For CCGT, fast-starting steam cycle designs are becoming common for new unabated plants due to market conditions and will both provide steam quickly as above and reduce the overall power plant start and stop times.

(It is also obvious that, in multi-unit stations, if some units are already operating then steam from them may be available to support the start-up of other units).

PCC unit

c) Arrangements should be made to segregate the solvent inventory during start-up, with separate solvent circuits around the absorber and stripper; see Fig 7.1 below.

d) Buffer storage should be provided for lean and rich amine; alternatively, for start-up, heat storage could be used to cover periods when steam is not available, but this would not be of as much value as amine storage in supporting other transitions in PCC operation.

Suitable process control is also a key consideration, with a recognition that, during starts and stops as well as in normal operation, there may be a trade-off between maximising electricity output and maximising CO_2 capture.

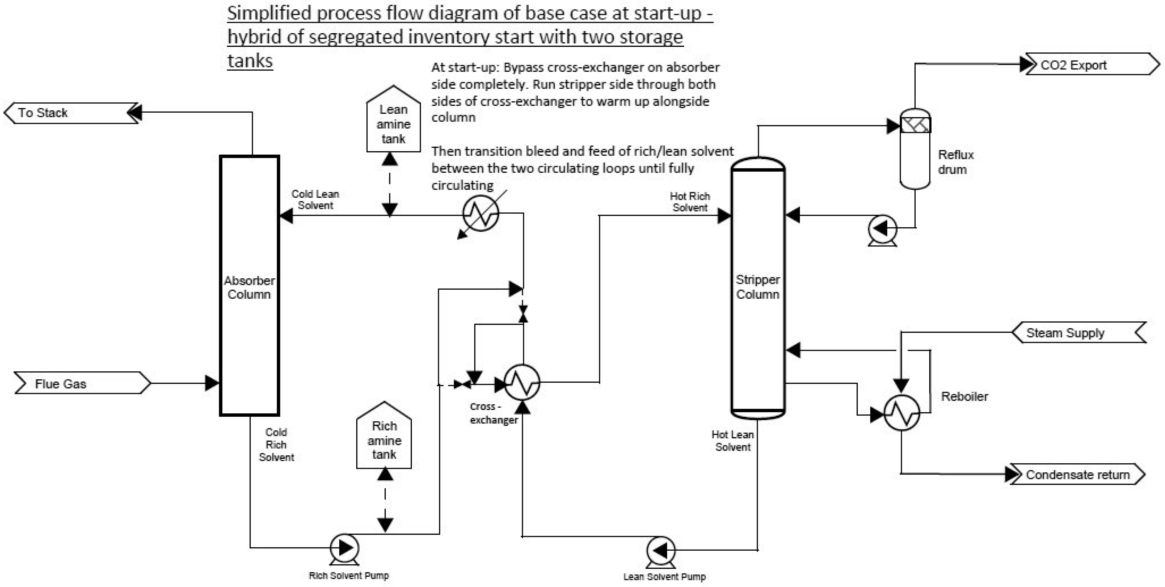


Fig 7.1 Post-combustion capture with segregated solvent inventory and lean and rich solvent storage (AECOM, 2020 - reproduced with permission from AECOM)

An auxiliary gas boiler venting into the absorber and using circulating solvent for PCC, or an electric boiler, could obviously potentially reduce start-up times by pre-warming steam lines. This requires limited thermal energy.

Auxiliary heating might also be useful for heating/maintaining temperature in the stripper when the plant is offline, although the stripper is also likely to retain heat for shorter periods. If this involves CO_2 emissions, then these would obviously have to be taken into account.

Starting arrangements

When not in baseload operation, CCGT+PCC plants will normally start up and run to full power to meet expected demand for a network dispatch period (typically a multiple of 30 minutes), defined by grid operational needs. This will be an entirely predictable event, against supply and demand requirements estimated around a day ahead and usually based on a bid to supply at a given price. In this case a full-scale PCC plant can be prepared in advance to receive flue gases and capture CO_2 using methods that the operators can fine-tune by experience. This means there is almost no need for feedback control of key parameters during start-up nor for the delays that this imposes; feed-forward control can be used to set operational parameters, including taking into account the state of the PCC plant prior to start-up (e.g. solvent inventory loadings, stripper temperatures), that are known to give near-optimal results.

Note that a CCGT+PCC plant will not usually be asked to make an un-forecasted rapid start, but if this was required it would normally only be in response to a fault condition and so would take place infrequently; therefore an immediate start to capture would not be required. Nonetheless, it would be feasible to initiate capture quickly using the same start-up process described below, if necessary, sending untreated flue gases to the stack until the PCC unit is fully operational.

It is expected that for maximum flexibility the PCC plant would be connected via an open-stack arrangement during start-up, remaining in this condition (i.e. either with no stack damper installed, or, if present, with the stack damper open) until a baseload stable operating condition has been reached.

In this case, any imbalance of flow between CCGT and PCC is matched by flow up (or down) the stack, and so back pressures on the HRSG and GT are maintained within acceptable values.

With these appropriate design considerations, the solvent and wash flows in the absorber are initiated before the GT starts firing and CO_2 starts to be produced. As might be expected, the level of CO_2 capture for flue gas entering the absorber would then be the same as, or higher than, for normal operation during the start-up phase. Minimal electrical power is required to operate pumps, blowers, etc., prior to capture. The compressor will not be required until the stripper is operational; prior to this CO_2 will be stored in rich solvent.

As already noted, for well-established plants, an operating map for the PCC unit will be available to cover all CCGT and PCC loads, ambient operating conditions etc., and this will allow rapid feed-forward control of the PCC unit to the optimum operating point.

It is possible that the GT will be emitting higher levels of NOx and CO in the flue gas at times during start-up. Since water and, if present, acid washes can be instated before any flue gas enters the absorber, instantaneous emissions to atmosphere, even if elevated, could still be expected to be reduced. If additional degradation products were formed then a compensatory increase in reclaiming, with associated solvent consumption, would be required. The importance of these effects will depend on the solvent chemistry and the way in which it can be maintained, and therefore would need to be considered in solvent selection.

Solvent storage can also be used to continue capture until the GT shuts down. If rich solvent storage is to be avoided because of a risk of enhanced degradation then the solvent inventory can alternatively be made over-lean beforehand to absorb GT CO_2 after steam ceases to be available for the stripper (AECOM, 2020).

Of course, CO_2 production rate, delivery pressure and possibly temperature from the stripper will also vary during start/stop and other changes in plant output, and the CO_2 compression system and CO_2 transport and storage (T&S) system must be designed to accommodate this if flexible operation is required. This obviously may incur additional costs (e.g. through multiple, smaller compressor units) and require a compromise on compressor efficiency (e.g. more off-design operation, different compressor type). CO_2 T&S characteristics will be site-specific; in general, as multiple CO_2 sources arise in a cluster then it could be expected to be easier to vary CO_2 flows from individual sources.

7.3 Load changes and minimum stable generation (MSG)

If solvent storage is installed, then any transient effects during load changes that would otherwise lead to increased CO_2 emissions can be offset by drawing on stored lean solvent or temporarily storing rich solvent. But it is obviously necessary to be able to maintain stable long-term PCC operation across the required range of power plant outputs. The principle potential problems here are expected to be the availability of reboiler steam at a suitable pressure and the ability of the CO_2 compression system to operate effectively at lower flows.

Steam extraction characteristics will be plant-dependent, but in general if steam is extracted at the hot or cold reheat stage and expanded using a BPT then any part-load condition should be able to be accommodated with bypassing etc. (possibly using facilities that will also support early steam supply to the reboiler for start-up). An alternative that was proposed for Maasvlakte (where only partial capture was to be implemented) was a steam ejector to raise the pressure of steam extracted from the IP/LP crossover using a smaller flow of high-pressure steam in a 'steam jet booster', also known as a steam jet ejector (ROAD, 2016). The use of steam from the HP drum in a steam ejector on a CCGT+PCC plant has also been analysed for improving part-load performance by Apan-Ortiz (2018).

7.4 Frequency response

As already discussed, capturing and compressing CO_2 requires energy. In the context of grid services, rather than PCC performance, it is relevant to note that, for typical modern UK power plants with steam extraction, this will correspond to between approximately an eighth (for gas) and a quarter (for biomass) of the power plant's electricity output without CO_2 capture, that part or all of this output can be restored as quickly as the primary response from sub-critical steam plants (EON, 2008) and that, unlike unabated conventional power plants that need to be run at part load to maximise the primary response capability, this response is available when the CCS power plants are running normally at full load. Furthermore, not only would this extra power be available rapidly but, if needed, it could subsequently be supplied almost indefinitely, qualifying as high-frequency response[17].

Thus, post-combustion capture offers a valuable capability to stabilise the grid and avoid power cuts like the one that occurred in the UK in August 2019, when rapid frequency response and reserve power were needed (E3C, 2020).

For shorter periods and responses that only involve stopping reboiler steam extraction rather than stopping electrical equipment (i.e. blowers, CO_2 compressors, pumps), CO_2 delivery to the T&S system would probably not even need to be interrupted. Capture could continue at normal levels for even longer if solvent storage was provided for starts and stops. Pilot plant trials (Akram, 2021) showed that interrupting heating to the reboiler for short periods (e.g. seconds to a few minutes) did not immediately halt CO_2 release, due to stored heat energy in the system. For longer periods of additional power output, one option to avoid possible disruption to T&S facilities would be to reduce steam extraction, and hence compression power, to MSG values. But in real emergencies obviously all CO_2 capture loads could be stopped. In all cases, since total long-term CO_2 emissions are what matters for climate change, the relatively small extra amounts of CO_2 that would be released can be made up by additional capture at other times, when electricity is abundant, to meet the required annual targets.

7.5 Component outages and system trips

Environmental aspects of unplanned outages need to be considered as part of HAZID/HAZOP analyses, in particular the need to minimise emissions of CO_2 and other pollutants while closing down safely. The expectations for operation without CCS (other than for grid support) also need to be examined and possible countermeasures to minimise this (e.g. having multiple key components with spares to allow planned and unplanned maintenance) should be discussed.

7.6 BAT PCC flexibility considerations

In general, allowing flexibility to maximise the level of capture from all CCUS installations rather than specifying uniform fixed levels is important to minimise overall UK CO_2 emissions and to reduce costs to consumers. For climate purposes CO_2 emissions can be averaged over decades. Yearly or longer averaging to allow optimisation of capture level (and initial plant design) to suit varying electricity market and weather conditions, with an equivalent adjustment in the assessed amount of 'clean' electricity output for payments, is therefore very important. Costs will be saved by not needing to over-invest to meet only occasional requirements, and CO_2 emissions will be reduced by encouraging higher levels of capture when conditions permit.

A key requirement to be able to maintain CO_2 capture levels during starts, stops and other flexibility events is an appropriate level of solvent storage. This needs to be backed up by steam extraction options that are also designed to support flexible operation, with priority being given to this as well as baseload efficiency and capital cost.

PCC system design also needs appropriate connections, controls and instrumentation to allow various modes of flexible operation, including being able to break the connections between absorber and stripper when appropriate.

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[17] There are three response speeds defined for UK frequency response (NG ESO, 2020). Providers may offer only one of these or a combination of different response times. Primary response - Response provided within 10 seconds of an event, which can be sustained for a further 20 seconds. Secondary response - Response provided within 30 seconds of an event, which can be sustained for a further 30 minutes. High frequency response - Response provided within 10 seconds of an event, which can be sustained indefinitely.

7.7 *EfW plant operation and flexibility considerations*

As shown in Section 2.2.5 EfW plants are operated with high load factors, so PCC plants can also be expected to operate in baseload mode only. Waste treatment, and the possible supply of heat, are, however, the priority, with several consequences:

- The operation of the EfW plant must be independent of, and take complete precedence over, that of the PCC plant and interconnection systems must be designed to accommodate this (the only exception may be EfW plants producing SAF, where low carbon is an integral part of the process).
- When an EfW plant is contracted to supply heat and uses steam extraction from the power cycle to do so, it would take precedence over steam extraction from the power supply for heat supply to a PCC plant
- Although the EfW plant will be operated continually the variability in the fuel may lead to fluctuations in power and steam output and/or flue gas flow and composition

Information on likely flue gas variation for design purposes and associated PCC plant performance impacts is likely to be best obtained by running a slipstream pilot plant for a period of a year (i.e. a full range of seasonal variations), as recommended in Annex 2 and elsewhere in this review.

In addition, the operation of the PCC plant will reduce the electricity and heat output from the EfW plant. It may be advantageous for UK energy security if capture (and possibly also CO_2 compression/liquefaction) can be paused, rapidly if necessary, to provide extra power when required, as discussed in more detail in 7.4 above.

8 Supporting scope for future changes

Economic lifetimes for power plants with CCS are expected to be at least 15 years while actual lifetimes in service might be of the order of 25 years. Thus even if a first tranche of UK power plants with PCC started operation as early as the mid-2020s they could still be operating in 2050, with current expectations of net zero GHG emissions then being required across the whole economy. It is also important that initial PCC projects, which are receiving additional support to enable relevant learning, support the development of best practice to meet net zero targets, both in their initial design and in their ability to apply improved techniques that will inevitably emerge as PCC technology is deployed for learning-by–doing, supported by R&D.

Requirements for future changes in PCC power plant operation and configuration are likely to arise because of the following:

a) Electricity market changes - reductions in average load factor and more erratic operation because of increased intermittent renewable generation capacity on the grid, in parallel with more demand for grid services from dispatchable plants that are operating; or some level of electrification of domestic heat supply resulting in a highly seasonal operation, with low demand for electricity-driven heating, e.g. via heat pumps, in the summer

b) Carbon market changes – as UK GHG emission targets are progressively reduced towards net zero there will be a growing need to achieve high capture rates to reduce residual emissions or to maximise negative emissions, and to use biomass-derived fuels for BECCS to replace fossil and possibly also to switch to biomass types with better lifecycle emissions.

c) Power plant and PCC technology changes – gas turbine, boiler and steam turbine upgrades for existing plants have historically been able to give some improvements in thermal efficiency and emissions performance. Upgrades for existing PCC technology can also be expected, e.g. additives and solvents that confer improvements in overall performance, through reduced toxicity and emissions, improved RAMO or reduced energy requirements; improved solvent management equipment; better instrumentation; improved waste management.

It is not expected that provisions to allow scope for future changes will involve major costs or disruption. The approach is similar in concept to Capture Readiness, where forethought to leave space in critical locations and to design equipment and pipework to facilitate necessary connections allows cheaper retrofits with less disruption in the future (e.g. IEAGHG, 2007; BEIS, 2021).

8.1 Potential power plant changes

Power plant changes could include:

a) For CCGT:

- GT upgrades, possibly with slightly increased flue gas volumes
- Duct firing for greater peak power, with similar flue gas volumes but more CO_2 and less O_2
- Possibly more fuel variation in some cases, as H_2 is used for fuel substitution for waste gases, or AD gases (possibly including CO_2) are fired for BECCS

b) For BECCS:

- More fuel variation, e.g. to use UK biomass, biogenic wastes

8.2 Potential PCC system changes

Potential PCC system changes could include:

- Alternative solvents and additives – operators may want to be able to take advantage of them as far as possible
- More solvent storage to cope with more stops and starts or off-line solvent regeneration
- Requirement for higher capture levels
- Requirement for improved solvent emissions performance

8.3 Potential EfW + amine PCC changes

As noted in the AECOM review of next generation capture technology for BEIS (AECOM, 2022) more advanced amine solvents than MEA may offer advantages, although these have to be confirmed by long-term service experience or, in the absence of this, representative pilot trials, as described in Annex 2.

A number of improvement areas for advanced amine solvents have been identified, leading to improved process performance. These improvements include reduced volatility reducing evaporative losses of solvent, increased thermal stability reducing thermal degradation of solvent, reduced oxidation rate reducing oxidative degradation of solvent, and reduced thermal regeneration energy reducing energy consumption of the absorption and desorption process cycle. These factors result in significant savings on both solvent consumption and energy consumption.

These advancements in solvent performance come at the cost of an increased solvent price, as required for a tailored, more complex, and most often proprietary chemical when compared to the standard generic amine of the benchmark.

After accounting for both a reduction in solvent use and increase in solvent price, an overall reduction in solvent cost is expected for the advanced amine process. A significant reduction in solvent use has been assumed and reduced solvent regeneration requirements contribute to lower energy consumption. The generation of solvent waste products is likewise anticipated to reduce.

9 EfW plants with hot potassium carbonate capture

CO_2 capture with hot potassium carbonate solution (HPC) is being considered for post-combustion capture from EfW and other applications as an alternative to amines for reasons that include:

- Low toxicity solvent
- Can be driven by electricity – no need to extract steam
- Pressurised capture process – smaller volumes
- Higher tolerance to oxygen

9.1 Hot potassium carbonate process description and history

Although not itself an EfW plant, the main recent evidence identified for this technology is review by AECOM for BEIS (AECOM, 2022) *CO2 Capsol* (formerly Sargas) *claim three successful pilot projects with more than 3,300 operating hours*. [Capsol, 2022], including a *lab-scale pilot plant at University of Paderborn as part of an EU funded project between 2011-2014 (scale and operational data not available)* (Hetland, 2008). *Stockholm Exergi has plans to build the largest BECCS (Bioenergy with Carbon Capture and Storage) plant in Europe using CO2 Capsol's technology. Stockholm Exergi aims to complete construction and start operations during the second half of 2025. The plant will be designed to capture up to 800,000 tpa CO_2 (~2,000 tpd CO_2 Capture)* (Capsol, 2021).

HPC has been used commercially as a solvent in gas processing applications. However, it has not been used for post combustion CO_2 capture.

There have been three pilot projects using CO2 Capsol process for post combustion capture, at scales of less than 2 tpd. Two of the projects were based at biomass-fired power plants and one at a coal-fired power plant. These projects may not have included all of CO2 Capsol's proposed energy integration system due to their limited scale.

A study was carried out in 2020 assessing the feasibility and economics of using the CO2 Capsol process on an EfW plant at a capture scale of 300 to 500 ktpa [16[18]]. There are also proposals for deployment at Stockholm Exergi's biomass-fired CHP plant in Värtaverket, Sweden at a capture scale of up to 800 ktpa of CO2 [17[19]].

As far as we [i.e. AECOM] *are aware there has not yet been any testing of the CO2 Capsol process using flue gases from an EfW plant.*

9.2 EfW hot potassium carbonate example(s)

Fig. 9.1 (AECOM, 2022) *shows a process block diagram of the process, with the dashed line representing the interface between the capture plant and the host power plant.*

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[18] CO2 Capsol, "A cost effective, energy efficient, carbon capture solution," [Online]. Available: [redacted]. [Accessed 18 March 2022].

[19] CO2 Capsol, "CO2 Capsol AS is well positioned in a fast-growing market with exciting opportunities," 22 September 2021. [Online]. Available: [redacted]. [Accessed 18 March 2022].

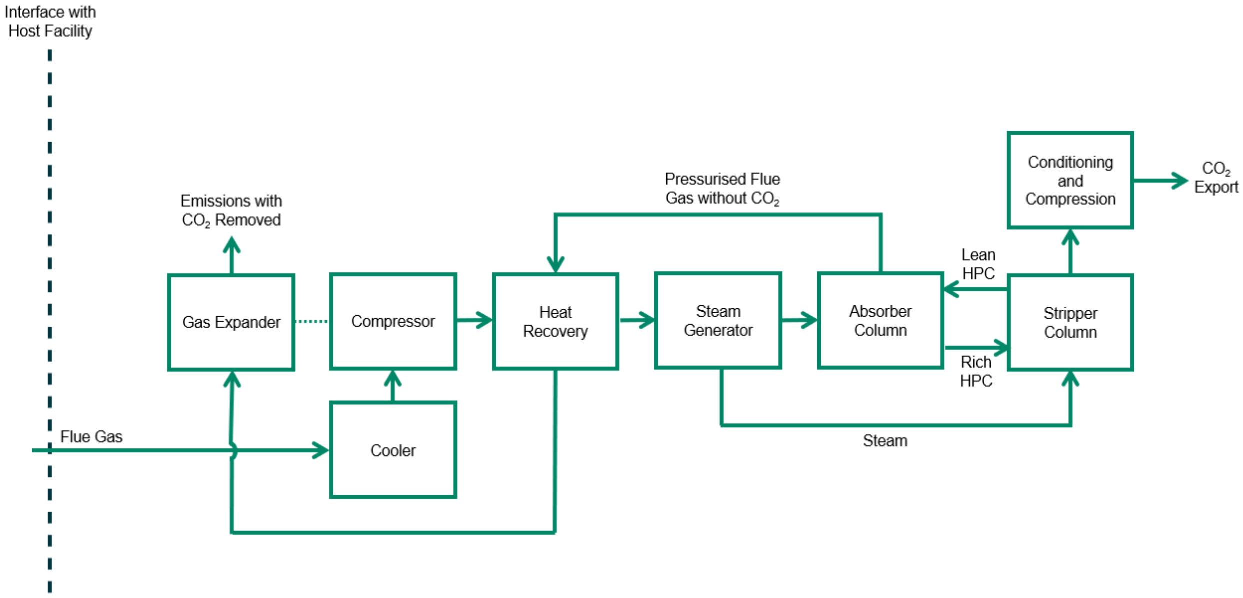


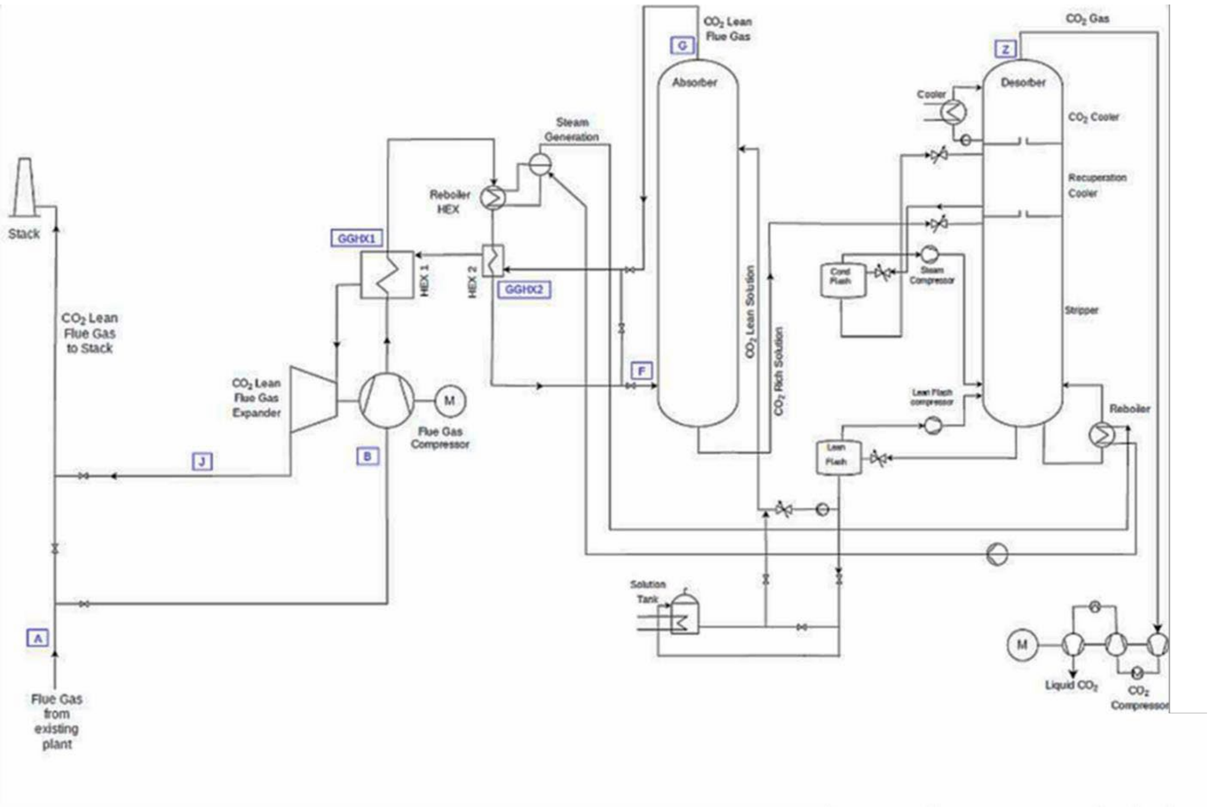
Figure 9.1 Block Diagram – CO_2 Capsol on EfW

One important process difference in comparison to [amine capture units] *is that the system uses pressurised flue gas in the absorber column. The solvent is then regenerated by passing it to a stripper column where the pressure is reduced and the CO_2 is released. This alternative method of solvent regeneration means that electrical energy requirements are increased (to compress the incoming flue gas) and thermal energy requirements are decreased. CO_2 Capsol offer a zero thermal energy input option where all thermal energy required for the stripper column is recovered from the process after the flue gas compression.*

The CO_2 Capsol process has following potential advantages:

- *HPC is relatively low cost and less hazardous than other solvents, although it should be noted that some HPC processes use potentially harmful chemicals such as amines or piperazine to aid solvent performance. It is understood that the CO2 Capsol process does not.*
- *Energy for the system can be provided fully, or partly in the form of electricity. Steam for the stripper is generated within the capture plant so there is a reduced requirement for imported thermal energy. This may be an advantage in relation to overcoming integration challenges with the host facility. In the modelled scenario only a small amount of steam is imported from the host plant for use in CO_2 conditioning.*

The following [more detailed] *diagram of a post combustion capture process using a hot potassium carbonate (HPC) solvent was provided by CO2 Capsol.*



9.2.1 Integration

(From AECOM, 2022) *The incoming flue gas requires to be cooled and then compressed to around 7 bara prior to entry into the absorber column. This compression would require a large size, high power, compressor unit. CO_2 Capsol's process diagram indicates that the compressor is directly coupled to both a motor and a gas expander that recovers energy from the pressurised exhaust of the absorber column.*

This process stage would require a specialised compressor/expander item of equipment. The availability and costs of this piece of equipment at the required scale would need to be investigated during the development of a project. If a single compressor/expander unit was difficult to procure, other equipment configurations could be used for compressing the flue gas to the required pressure. However, this may have cost or energy consumption implications.

Similar to the amine solvent in the benchmark case the HPC solvent will form heat stable salts and degrade when exposed to contaminants such SOX, NOX and other contaminants that may be present in the EfW flue gas. No additional treatment has been assumed in this scenario to remove flue gas contaminants prior to entry into the capture plant. However, it should be noted that information was not available on degradation rates for HPC solvent when used on EfW flue gas. Solvent testing under representative conditions would reduce uncertainty in relation to solvent management costs and the optimum level of flue gas pre-treatment required.

9.2.2 CO_2 capture level

A capture level of 95% is assumed in the AECOM review (AECOM, 2022). No published information on the ultimate limits on capture level for HPC processes appears to be available.

9.2.3 CO_2 compression, drying and quality

No specific CO_2 compression information for hot potassium carbonate systems has been identified. The CO2 Capsol example does, however, have additional flue gas compression, expansion and intercooling/recuperation processes, as identified in (AECOM, 2022):

Processes that use more complex energy integration systems are likely to have increased maintenance requirements because of additional equipment. The CO2 Capsol process contains a large size compressor and expander, mechanical vapour recompression systems and a greater number of heat recovery heat exchangers than other solvent based capture processes.

9.2.2 Impact on performance

(AECOM, 2022) *There is no requirement for large amounts of steam to be extracted from the main power plant in this scenario. Only a small amount of imported steam is required for CO2 conditioning. This is an advantage in that extensive steam system modifications at the existing EfW plant will not be required. It would also be an advantage in other sectors without easy access to steam.*

The plant uses electrical energy to operate the flue gas compressor and mechanical vapour recompression systems. Thermal energy is then recovered and exchanged at various points inside the CO2 Capsol process. There is a moderate degree of complexity associated with the energy integration systems at the plant. For example, after cooling and compression, the flue gases pass through a further three heat exchangers prior to entry into the absorber column.

Efficiency or cost savings may be possible if a limited quantity of additional thermal energy was provided to the process by the EfW plant to reduce reliance on heat recovery systems included in the design. A decision on whether to provide additional steam could be made based on the volume of steam readily available from the existing system at the EfW plant. At many EfW sites the extraction of limited quantities of steam will be relatively simple, and low cost, because significant modifications to the steam system would not be required.

When comparing energy consumption figures across capture technologies it is important to remember that more than one unit of thermal energy can be extracted from a steam turbine for every unit of electrical energy sacrificed. The ratio of useful heat exported to the reduction in electrical energy output from a steam turbine is referred to at the Z ratio and will vary between different steam turbines. Direct comparison of steam and electrical power consumption figures is usually not appropriate.

9.2.3 Environmental emissions

No public domain information has been identified. Because of the inorganic nature of the solvent low volatility is, however, to be expected.

9.2.4 Waste disposal

No public domain information has been identified.

9.3 BAT considerations, including energy impacts

The following observations on a commercial potassium carbonate process have been made in the study by AECOM (2022). A number of potential beneficial aspects are noted, but it is also evident that further practical evidence, i.e. from representative pilot tests if not full-scale plant operation, is needed to confirm these.

Measures that could be taken in relation to applying the CO2 Capsol technology to EfW flue gases include:

- *Testing the solvent on representative input flue gas to validate performance, understand degradation characteristics and understand reclaiming requirements.*

- *Construction of an intermediate scale demonstration project to validate costs, reliability, and energy performance predictions. To prove that energy performance based on modelled scenarios can be achieved in a working plant, the configuration of any demonstration facility would need to match the modelled configuration and include all thermal integration design features. In addition, the scale would need to be sufficient so that mass and heat transfer characteristics of the demonstration plant were representative of a larger commercial facility.*

- *Development of configurations of the technology designed to supply thermal energy to third parties. The use of a pressurised system may provide opportunities for the efficient recovery of additional heat for export. For example, latent heat recovery from moist flue gases could take place at a higher temperature if the gases are pressurised. Recovered heat could then be supplied to an external heat customer such as a district heating network.*

Due to the similarities between the processes, many of the areas for technology development in non-amine solvent capture systems are the same as those for amine systems on EfW plants ….

As the energy for the CO2 Capsol technology can be provided entirely from electrical power, there are potential advantages in developing the process for industries where steam is not readily available. This could include applications in the cement industry. Application of the CO2 Capsol technology to the cement industry was not assessed in this report due to limitations in the number of scenarios that could be evaluated.

Hazards

The hazards present in a HPC solvent capture plant will be like those in the benchmark amine case. However, the process is different, with different operating pressures and temperatures. Like all process plants structured hazard identification and mitigation measures would be required throughout the design and development of the process.

Replacement of an amine-based solvent with HPC will reduce the hazard associated with the solvent. Potassium carbonate is used in the food industry and poses lower risk towards the environment and people. Understanding and management of the hazards associated with solvent degradation products, or contaminants collected by the solvent, will still be required at an EfW facility using HPC.

Maintenance

The overall process concept in a non-amine capture plant is like the benchmark amine cases, so maintenance requirements will be similar. If a solvent is less corrosive or has lower levels of degradation this may result in reduced maintenance requirements.

Processes that use more complex energy integration systems are likely to have increased maintenance requirements because of additional equipment. The CO2 Capsol process contains a large size compressor and expander, mechanical vapour recompression systems and a greater number of heat recovery heat exchangers than other solvent based capture processes.

The CO2 Capsol energy integration process is different from other solvent capture processes in several areas, and it has not been demonstrated at scale. Construction and operation of a demonstration facility would reduce uncertainty in relation to availability, capital and maintenance costs.

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Annex 1 Parts of the Industrial Emissions Directive

Extracts from Industrial Emissions Directive 2010/75/EU: Article 5, 6 and Annexe III.

Article 5
Where the competent authority sets permit conditions on the basis of a best available technique not described in any of the relevant BAT conclusions, it shall ensure that:

(a) that technique is determined by giving special consideration to the criteria listed in Annex III; and

(b) the requirements of Article 15 are complied with.

Where the BAT conclusions referred to in the first subparagraph do not contain emission levels associated with the best available techniques, the competent authority shall ensure that the technique referred to in the first subparagraph ensures a level of environmental protection equivalent to the best available techniques described in the BAT conclusions.

Article 6
Where an activity or a type of production process carried out within an installation is not covered by any of the BAT conclusions or where those conclusions do not address all the potential environmental effects of the activity or process, the competent authority shall, after prior consultations with the operator, set the permit conditions on the basis of the best available techniques that it has determined for the activities or processes concerned, by giving special consideration to the criteria listed in Annex III.

ANNEX III
Criteria for determining Best Available Techniques:

1. *The use of low-waste technology;*
2. *The use of less hazardous substances for the environment;*
3. *The furthering of recovery and recycling of substances generated and used in the process and of waste, where appropriate;*
4. *Comparable processes, facilities or methods of operation which have been tried with success on an industrial scale;*
5. *Technological advances and changes in scientific knowledge and understanding;*
6. *The nature, effects and volume of the emissions concerned;*
7. *The commissioning dates for new or existing installations;*
8. *The length of time needed to introduce the best available technique – commissioning & optimisation*
9. *The consumption and nature of raw materials (including water) used in the process and energy efficiency;*
10. *The need to prevent or reduce to a minimum the overall impact of the emissions on the environment and the risks to it;*
11. *The need to prevent accidents and to minimise the consequences for the environment;*
12. *Information published by public international organisation*

Annex 2 Solvent post-combustion capture pilot testing for de-risking commercial applications

A2.1 Definition of this specific application

This annex covers experience with pilot-scale PCC solvent testing specifically to support commercial deployment directly by de-risking it through ensuring all critical aspects of performance have been demonstrated and found to be satisfactory.

This differs from most pilot-scale PCC plant operation to date, which has been for R&D purposes, or for estimating short-term solvent performance relative to other solvents as a stage in solvent development.

Pilot testing for commercial applications will usually happen after one, or a small number, of solvents and associated PCC plant configurations have been selected.

It is intended to de-risk deployment by reproducing all salient features of operation, including:

A. the flue gas and its variations during extended operation,

B. the long term time/temperature/gas composition histories that will be experienced by the solvent,

C. the ways that solvent degradation and the solvent reclaiming and other management techniques that will be used on the full-scale plant will interact to evolve the solvent inventory to something different, and probably much more complex, than the fresh solvent initial charge and make-up.

The inclusion of solvent reclaiming, successfully treating solvent that is fully 'dirty' rather than fresh solvent, is the key to having a relevant test for commercial deployment. Test periods therefore need to be long enough to allow this, and in particular to be able to demonstrate the ability to maintain a STABLE solvent composition that gives satisfactory PCC performance (i.e. with respect to foaming, corrosion etc. as well as capture level and energy consumption).

As discussed at some length in this report, particularly Section 2.3.4, it is self-evident that it must be possible to remove all degradation products and flue gas impurities at the rates at which they are formed in, or added to, the solvent in a PCC system and still have satisfactory performance. If this is not demonstrated, under realistic conditions, in pilot tests that are aimed at de-risking deployment then satisfactory performance in service for this, and related, aspects of PCC plant performance has not been fully assessed.

Examples of experience and pilot tests to de-risk commercial deployment are given in the rest of this annex.

It must be emphasized, however, that no comprehensive examination of correlation between pilot plant and long-term full-scale PCC behaviour for coal-fired power plants has yet been published, and also, since no full-scale plants are in service, cannot yet have been undertaken for either biomass or natural gas power plants.

A2.2 MHI Pilot Testing Experience

The philosophy for pilot-plant testing for post-combustion capture from coals (and, by inference, for other fuels with significant impurities such as biomass or gases from industrial processes) has probably best been described by MHI and is verified by their experience with 10 tpd and 500 tpd pilot-test units and subsequently the full-scale Petra Nova plant (Endo, 2010).

…… before offering commercial CO_2 capture plants for coal fired flue gas application, it is necessary to verify the influence of, and develop countermeasures for, related impurities contained in coal fired flue

gas. This includes the influence on both the absorbent and the entire system of the CO_2 capture plant to achieve high operational reliability and minimize maintenance requirements.

Preventing the accumulation of impurities, especially the build-up of dust, is very important when treating coal fired flue gas and MHI has undertaken significant work to understand the impact of impurities in order to achieve reliable and stable operating conditions and to efficiently optimize integration between the CO_2 capture plant, the coal fired power plant and the flue gas clean-up equipment.

To achieve this purpose, MHI constructed a 10 tpd CO_2 capture demonstration plant at the Matsushima 1,000MW Power Station and confirmed successful, long term demonstration following ~5,000 hours of operation.

…….. additional testing was undertaken to examine the impact of entrainment of higher levels of flue gas impurities (primarily SOx and dust by bypassing the existing FGD) and to determine which components of the CO_2 recovery process are responsible for the removal of these impurities. Following an additional 1,000 demonstration hours, results indicated stable operational performance in relation to the following impurities;

- *SO_2: even at higher SO_2 concentrations were almost completely removed from the flue gas before entering the CO_2 absorber.*
- *Dust: the accumulation of dust in the absorbent was higher, leading to an advanced understanding of the behavior of dust in the CO_2 capture plant and the dust removal efficiency of each component within the CO_2 recovery system. The data obtained is useful for the design of large-scale units and confirms the operating robustness of the CO_2 capture plant accounting for wide fluctuations in impurity concentrations.*

This important coal fired flue gas testing showed categorically that minimizing the accumulation of large concentrations of impurities, and to suppress dust concentrations below a prescribed level, is important to achieve long-term stable operation and to minimize maintenance work for the CO_2 capture plant. To comply with the above requirement, various countermeasures have been developed which include the optimization of the impurity removal technology, flue gas pre-treatment and improved optimization with the flue gas desulfurization facility.

In case of a commercial scale CO_2 capture plant applied for coal fired flue gas, its respective size will be several thousand tpd which represents a considerable scale-up from the 10 tpd demonstration plant. In order to ensure the operational reliability and to accurately confirm the influence and the behavior of the impurities in coal fired flue gas, it is necessary to gain further operational experience with coal fired flue gas at large scale. MHI's coal fired CO_2 capture experience and know how at 10 tpd scale aided in the design of the 500 tpd CO_2 capture demonstration plant to be deployed at Plant Barry Power Station in Alabama. …. an extensive test program is planned. Following successful demonstration of this plant, in relation to the effect of scale-up concerning the behaviour of impurities, it is envisaged that larger-scale commercial CO_2 capture plants can be designed and deployed for the coal fired power sector.

MHI stated goals in 2010 for Plant Barry testing (Endo, 2010) were:

- *Demonstration of 'Zero Amine Emission System'*
- *Demonstration of 'Online Solvent Analysing System' for automatic operational control - features optimum energy conservation*
- *Demonstration of 'Automatic CO_2 Capture and Plant Load Chasing System'-dynamic response testing for load following*
- *Confirm base Heat and Material Balance including*
    - *Material Balance on all major constituents and key trace elements*

    - *Heat Balance on all process equipment confirming performance relative to design*
- *Monitor all emission and waste streams*
- *Evaluate key scale-up technical issues*
- *Parametric testing on all process systems to develop predictive operating tools (for automatic control)*
- *Optimization of process enhancements*
- *Long term testing to validate equipment reliability*
- *High impurities coal testing*

In 2012 the goals for the remaining ~3 years of the 500 tpd Plant Barry test program (Iijima, 2012) were stated as follows:

> *(1) Acquisition of material and heat balance*
>
> *(2) Flue gas and wastewater component measurements*
> *Measurement of the trace components of treated flue gas and wastewater are planned.*
>
> *(3) Accuracy improvements*
> *Tests will be conducted with varied operating conditions to accumulate meaningful data with the aim of improving the accuracy of simulation tools.*
>
> *(4) Optimization of operation conditions*
> *In an effort to determine optimized conditions, the operational costs will be measured for various operational conditions.*
>
> *(5) Load-following operation test*
> *The system, which automatically controls the operating load of the CO_2 recovery plant in response to load fluctuations from the existing power plant, will be verified.*
>
> *(6) Long-term reliability of plant*
> *Through long-term operation, along with monitoring the effect of impurities contained in the flue gas from coal-fired power plant, the reliability of the impurity countermeasures that have been undertaken will be validated.*
>
> *(7) Test operation with high-particulate concentration*
> *The type of coal burned will be varied in order to change the particulate concentration in the feed gas flowing into the CO_2 recovery plant. The effect of high particulate concentration upon the CO_2 recovery plant will be investigated, and the effectiveness of countermeasures will be verified.*

A2.3 Examples of pilot testing specifically for de-risking commercial deployment

MHI pilot testing at Plant Barry was undertaken at a scale of 500 tpd (~25MWe equivalent) but such a large-scale capture pilot is the exception, possibly because in this case the CO_2 was also being used for a storage pilot. Most other pilot tests on PCC for coal undertaken as the intended precursor to full-scale commercial units have been of the order of 50-100 tpd - see Table A3.1 overleaf (and have vented the captured CO_2). It therefore seems that this scale has been considered to be an adequate compromise between cost and realism, although obviously it would still be necessary to ensure that flow passage dimensions, velocities, temperatures etc. match those planned for a full-scale plant. Tests for other applications have been at smaller scale.

Further details for some of the test campaigns (TCM/Peterhead, Brevik and Klemetsrud) are presented in the following sections.

Table A2.1 Examples of PCC pilot-scale testing to de-risk commercial projects

Solvent	User	Test Site name	Approx. CO_2 captured	Intended commercial project	Reclaiming	Approximate dates
MHI KS-1[20]	Southern	Plant Barry	500 tpd	Petra Nova	Repeated successful reclaiming reported	2011 – 2014 (>13,000 hrs)
HTC/Doosan[21]	SSE	Ferrybridge	100 tpd	Ferrybridge	Not known	2011-2012
Cansolv DC-103[22]	RWE	Aberthaw	50 tpd	Aberthaw	'Amine purification unit' included but no report of use	2013
Fluor[23]	Uniper	Wilmhelmshaven	70 tpd	Maasvlakte[24]	Thermal reclaimer integrated with stripper and vapour compression and use reported	2012-2015 (~7000 hrs)
Hitachi[25]	SaskPower	Shand	120 tpd	Shand	Thermal reclaimer venting to the stripper included but no report of use.	2015 – 2016? (8000 hrs planned)
Cansolv DC-201[26]	Shell	Technology Centre Mongstad	80 tpd	Peterhead	No report of reclaiming identified in public domain sources	November 2014 to May 2015; 2016
Aker S-26[27]	Norcem	Brevik	3.5 tpd	Brevik	Reclaiming predicted to have happened, but no report in public domain sources	May 2014, for 18 months
Cansolv DC-103[28]	Fortum Oslo Varme	Klemetsrud	3.5 tpd	Klemetsrud	No reclaimer fitted	March – December 2019 (>5,000 hrs)

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[20] (Endo, 2011; Hirata, 2013 & 2014; Hill, 2014

[21] (DECC, 2013)

[22] (Carlton, 2013; Hallerman, 2013)

[23] (Radgen, 2014; Reddy, 2013 & 2017)

[24] (ROAD, 2019)

[25] (Hitachi, 2012; MIT, 2013)

[26] (Campbell, 2016; Cotton, 2017)

[27] (Knudsen, 2014, Norcem, 2019a & 2019b)

[28] (FOV, 2020b; Fagerlund, 2021)

A2.3.1 Outline of Cansolv DC-201 testing at TCM and NCCC for Peterhead

(Cotton, 2017): *In addition, operational testing of the amine formulated for the PCCS project was undertaken at the world's largest* CO_2 *capture test plant, Technical Centre Mongstad (TCM). The testing campaign focused on the following elements:*

- *mimic the Peterhead process conditions;*
- *confirm the amine degradation rate;*
- *measure the amine emissions; and*
- *verify process performance including CO2 removal and energy consumption.*

Results from the TCM campaign confirmed that the PCCS project design was fit for purpose and no design change was required in terms of emissions as regulatory requirements would be met.

(Campbell, 2016): *Shell Cansolv and Technology Center Mongstad (TCM) have performed two testing campaigns in 2015 and 2016. For both testing campaigns the evaluated solvent was Cansolv DC-201, which is the latest generation solvent for* CO_2 *capture which has been developed and deployed by Shell Cansolv. The first TCM demonstration test occurred from November 2014 to May 2015. The objective of this campaign was to confirm scale-up of process performance (*CO_2 *removal, temperature profiles and energy consumption) from (1 – 8 tons* CO_2*/day) to (50 – 100 tons* CO_2*/day). This has been achieved and good model validation results have been presented at GHGT-12.*

Also, during the first demonstration campaign a focus was made to clearly understand the Cansolv DC-201 degradation rate and the amount of emissions (amine and degradation products) that enter the atmosphere. The test in 2015 was a benchmark or baseline test where no inhibitors of degradation have been added to the process. The emission results in the absence of degradation inhibitors were still below the acceptable emission levels according the TCM emission permit regulated by Norwegian authorities. Accurate measurements and calculations for degradation and emissions were only possible due to the good instrument and analytical capabilities of TCM and Shell Cansolv. All necessary instrument and lab quality assurance were confirmed prior to the start of the testing campaigns. The most important quality assurance checks performed were:

- CO_2 *gas analyzers (absorber inlet, absorber outlet and* CO_2 *product)*
- *Tank levels and solvent inventory throughout the plant*
- *Steam flowrate*
- *Liquid Chromatography Mass Spectrometry (LCMS) – used for monitoring amine and amine degradation product concentration in the solvent*
- *Proton Transfer Reaction Mass Spectrometry (PTR-MS) – used for monitoring amine and amine degradation product concentration in solution*
- *Fourier Transform Infrared Spectroscopy (FTIR) – used for online emission monitoring (amine and amine degradation product components)*
- *Proton Transfer Reactor Time-of-Flight Mass Spectrometry (PTR-TOF-MS) – used for online emission monitoring (amine and amine degradation product components)*
- *Extractive impinger gas sampling – used for emission monitoring (amine and amine degradation product components)*

In 2016 an additional demonstration campaign was planned and performed at TCM with a very effective degradation inhibitor for Cansolv DC-201. This inhibitor was identified by Shell Cansolv after performing carefully controlled laboratory experiments which mimicked real plant operation. Many inhibitors have been screened during these laboratory tests and Cansolv Inhibitor DC-A was identified as the best candidate for technology development at the larger scale. This inhibitor was not only *screened for performance (i.e. the reduction of degradation rate) but also cost, availability, health and safety and the by-products which are formed. This presentation will demonstrate the difference of degradation and emission levels when the Cansolv Inhibitor DC-A was added to the Cansolv DC-201 solvent at TCM. The operation conditions of testing with and without inhibitor were closely mimicked to ensure a relevant head to head comparison was possible.*

Prior to the TCM campaigns the DC-201 solvent was also tested at NCCC (Shell, 2017) with results summarized as follows. ‘*In 2013, Cansolv DC201 was successfully tested under simulated CCGT flue gas conditions for 1715 hours of operation at the NCCC piloting facility in Wilsonville, AL, US. 90 (+/- 5) % CO_2 capture was achieved and energy consumption requirements have not deteriorated before 1200 hours of operation, where the concentration of degradation products in the solvent hindered its performances (no bleed-and-feed or reclamation technology was used during the test).’*

‘The 2014 piloting campaign at NCCC was from July 23rd to August 15th 2014. …… Only 322 hours of operation were achievable due to flue gas supply short come. ……. At NCCC prescrubber unit treated flue gas before entering the absorber. Presence of SO_2 in flue gas causes side reactions which result in amine transformation. NOx can have similar effect however transformation products, involving NOx, may introduce environmental issues.’

‘Pre-scrubber did well by cooling down the flue gas to hot climate condition and removed significant amount of SO_2 and NOx. ……. Throughout the campaign CO_2 capture performance has not deteriorated and was stable.’

‘In general, in an amine-based post combustion CO_2 capture process, with no make-up added, it is expected that CO_2 capture declines over time. This is due to transformation of the main amine component to product(s) which do not have any CO_2 capture capacity. This deterioration was not observed during NCCC 2014 campaign. One reason was the length of the test, which was not long enough to build significant amounts of degradation products and/or contaminants and then not long enough to loose significant amount of amine. In addition, CANSOLV DC-201 transformation product maintains certain capacity for CO_2 capture.’

On solvent management it was also stated ‘*Depending on the flue gas composition, the solvent in the Cansolv CO_2 Capture System can accumulate non-regenerable salts (also called Heat Stable Salts) as well as various degradation products over time. These contaminants must be removed from the solvent in order to maintain the guaranteed system performance. During the design stage of the project, Cansolv engineers will design for the removal of these contaminants by circulating a small fraction of the lean solvent flow to an amine purification unit (APU). The APU can be a simple Ion-Exchange system designed to remove ionic species, or may be a thermal reclaiming stage, or a combination thereof. Validation and confirmation of this requirement is an optimization step to be done during an engineering phase of a project.*’

A2.3.2 Outline of Aker Norcem Brevik pilot testing

Details of pilot testing are given in (Knudsen, 2014), although it is reported by Aker that testing continued for approximately 18 months in total. For additional information on the full-scale plant design see (Norcem, 2019a; Norcem, 2019b). Summary information from (Knudsen, 2014) is as follows.

Aker Solutions’ Mobile Test Unit (MTU) was installed in Brevik in April 2014 and will be operated on a slip stream of flue gas from the cement kiln for a period of 6 months (end October 2014) [later extended to 18 months, but no public domain reports available – Aker, personal communication]. *This will be the first time amine based CO2 capture technology is extensively tested on real flue gas from a cement kiln. The overall objective of Aker Solutions test program at Brevik is to demonstrate the feasibility of Aker Solutions’ ACCTM amine process for the cement industry and determine key design and performance parameters.*

…………………

‘The design of the MTU is based on conventional amine absorption/desorption process with full packing height absorber and desorber columns. Several novel features are installed such as Aker Solutions’ ACCTM Energy Saver, Anti-Mist Design and Emission Control technology. Extensive instrumentation is implemented at the MTU and all on-line signals are logged in historical databases.’

Table A2.2 Reported MTU key design data and specifications

Parameter	Design value	Unit
Max flue gas capacity	1000	Sm^3/h
Co2 capture efficiency	~90	%
Absorber diameter	0.40	m
Absorber packing height	Up to 18	m
Desorber diameter	0.32	m
Desorber packing height	8.0	m
Solvent circulation	0 – 3.6	m^3/h
Number of washing stages	2 + 1 acid wash	

‘the overall objective of Aker Solutions test program at Brevik is to demonstrate the feasibility of Aker Solutions ACC^{TM} amine process for the cement industry and determine key design and performance parameters. Thus, the campaign will focus on determination of parameters such as:

- *Overall process stability and impact of cement plant operation conditions*
- *CO_2 capture efficiency and energy consumption*
- *Solvent degradation, consumption and reclamation*
- *Emissions and waste production*
- *Impact of flue gas pollutants on solvent degradation*
- *Performance of equipment and materials*
- *Equipment design’*

……………………………

‘only approx. 220 mg/l sulfur has been absorbed by the solvent after 1400 operating hours. The 220 mg/l sulfur is equivalent to approx. 0.014 mol/kg HSS. The ACC^{TM} process should operate safely with HSS levels up to 0.3 mol/kg before solvent reclaiming needs to be initiated. Hence, the current results indicate that operation can continue for years before the solvents’ sulfur content reach level where reclaiming is required. This illustrates that the SO_2 removal degree achieved in the MTU pre-scrubber is satisfactory. It is the plan to demonstrate the removal efficiencies concerning HSS, nitrosamines and other impurities with the ACCTM reclaiming technology before the end of the campaign in Brevik.’

Table A2.3 Reported results of manual emission measurements on 18.06.2014 and 19.08.2014 $^{++}$

Parameter	Unit	Test 18/6/2014	Test 19/8/2014
Solvent amines	mg/Nm^3	0.46	0.30
Ammonia	mg/Nm^3	4.0	3.1
Other volatile amines*	mg/Nm^3	0.04	0.06
Total nitrogen	mg/Nm^3	3.6	2.6
Total nitrosamine	$\mu mol/Nm^3$	<0.03	<0.03

*sum of 6 different amines: methy-amine, ethyl-amine, propyl-amine, dimethyl-amine, dipropyl-amine

A2.3.3 Outline of Cansolv DC-103 pilot tests at FOV Klemetsrud

(Text below is from Fagerlund (2021), see also (Jemtland, 2019; FOV, 2020b) for additional details)

Fortum Oslo Varme *'decided (in July 2018) to build a 1:350 scale pilot plant to demonstrate that the selected Cansolv capture technology is suitable for cleaning CO_2 from the exhaust gases of the Klemetsrud* [waste-to-energy] *plant, and in particular to show that the emissions of amines and solvent degradation products to air are within the set requirements. The duration for a successful demonstration of the first pilot campaign were decided to be at least 2000 operational hours, with total amine emissions lower than 0.4 ppmv on average over the last 500 h of testing (of the first test campaign).'*

'*Notable differences to the full-scale plant design* [(FOV, 2020)] *were that:*

- *No thermal reclaimer unit (TRU) was installed;*
- *No mechanical vapour recompression (MVR) system was installed;*
- *Steam supply was provided from a separate steam generator instead of from the* [waste-to-energy] *plant;*
- *No caustic was injected in the pre-scrubber;*
- *The cooling system was designed as a once-through system, i.e. no closed loops in the cooling system;*
- *All piping and vessels were made from stainless steel 316 (unlike in the full-scale design which consists of various materials optimized considering area of use)*

These differences are mostly linked to cost and complexity considerations and were accepted as they did not affect the relevance of the pilot plant results for the full-scale plant.'

………………

'Solvent purification

As mentioned above, the pilot plant is not equipped with a solvent reclaiming system. Starting with pure solvent, the degradation products concentration is left uncontrolled and allowed to progressively increase over the campaign. This allows to accurately estimate the degradation rate of the solvent, and also to compare performance at different concentrations of degradation products. The only solvent purification system in place is a mechanical / activated carbon filtration system that can be brought online if and when required'.

………………

'*The* [PCC] *pilot plant was in operation between March and December 2019 and the total number of successful pilot plant operational hours at Klemetsrud reached about 5100. The purpose of running the pilot plant beyond the original 2000 h was to obtain additional knowledge of operating the plant at higher concentrations of solvent degradation and various upset conditions. The average amine emissions to air remained well below the emission target concentration (0.4 ppmv) during the whole campaign. However, excursions were observed during upsets, intentional or unplanned, during which the pilot was pushed in abnormal and transient operating conditions. It has been shown that an amine emissions mitigation device helps to reduce amine emissions to air during these upset conditions (experienced between weeks 42 and 48), but that its effect during normal operation appears less pronounced due to very low aerosol and amine emissions. At the end of the campaign, the* [total degradation products – three individual degradation products were shown but not identified] *degradation product concentration in the solvent exceeded 5 wt% (i.e. around 10 % degraded solvent) without using a reclaimer. This is above the full-scale plant design envelope (1-2 wt% degradation products), where a thermal reclaiming unit (TRU) will maintain and control the degraded product concentration. The impact of a higher than design degradation product concentration has been negligible and indicates an opportunity to improve/ optimise the TRU/ full-scale CC plant design. An indication of a possible acceleration of degradation product build-up rate was only observed at the most elevated concentrations at the end of the campaign but would have needed continued operation to be confirmed.'*

Annex 3 Example calculations for heat supplied vs. electrical output lost for effective steam extraction

(based on BAT workshop discussions, 7 January 2021)

A simplified steam extraction diagram for a PCC application is shown in Fig. A7.1. A biomass or EfW plant might have similar extraction points but reboiler and reclaimer condensate would be returned at intermediate points in the condensate heating train and there would be heat recovery to the steam cycle (see e.g. Lucquiaud, 2011; CCSKC, 2018). Approximate pathways for LP turbine expansion and the steam extractions are shown in the enthalpy/entropy diagram in Fig. A7.2.

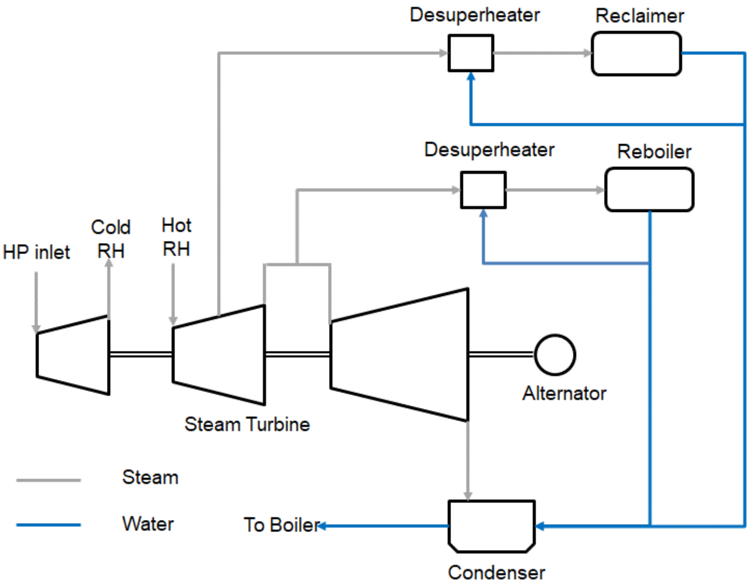

Fig. A3.1 Simplified steam extraction arrangements for reclaimer and reboiler for CCGT+PCC

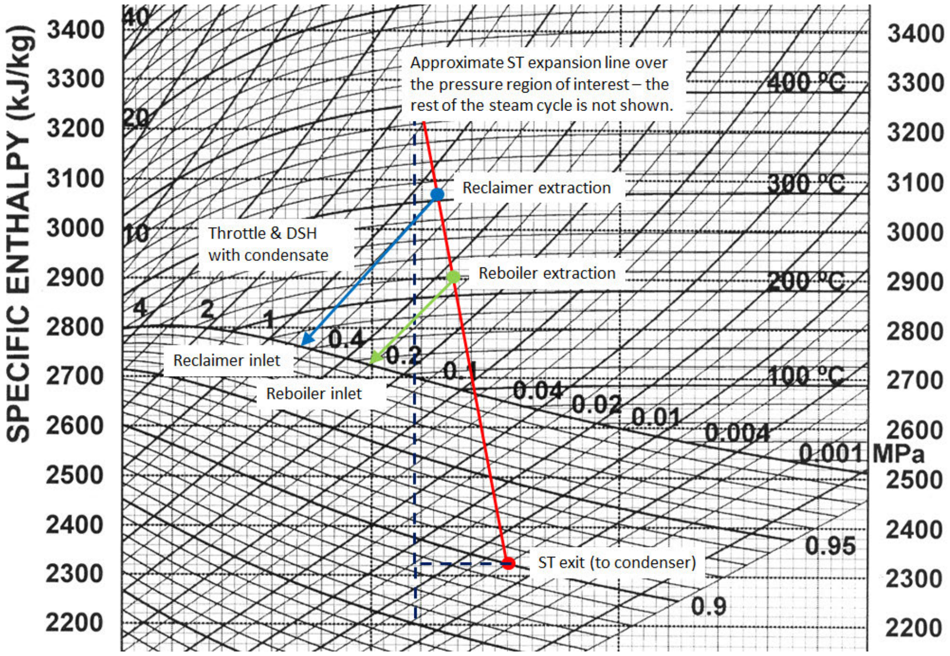

Fig. A3.2 Approximate steam extraction enthalpy-entropy (Mollier) diagram

Table A7.1 shows approximate calculations for the power lost per unit heat supplied, and hence the effective coefficient of performance, COPx, based on the h-s diagram in Fig. A3.2. This illustrates a COPx value of over 4 for the main reboiler steam extraction.

An approximate Sankey Diagram illustrating reboiler steam extraction, based on (Gülen, 2019), is shown in Fig. A3.3.

Table A3.1 Approximate heat recovered per unit of electric output lost for steam extraction
Note, for CCGT so no options to recover heat for condensate heating.
All kinetic energies ignored

Value	Units	Reclaimer steam	Reboiler steam
Extraction pressure	bar	8	3.5
Extraction enthalpy	kJ/kg	3090	2900
ST exit enthalpy (x=0.9, p=0.06 bar)	kJ/kg	2325.2	2325.2
Work lost per kg steam extracted	kJ/kg	764.8	574.8
Condensate pressure	bar	7	3.13
Saturated steam enthalpy, hg	kJ/kg	2762.7	2726.9
Condensate enthalpy, hf	kJ/kg	697.1	567.6
Steam extracted per kg sat steam (DSH with condensate)	kg/kg	0.863	0.926
Heat supplied per kg sat steam	kJ/kg	2065.6	2159.2
Elec output lost per kg sat steam (95% mech/elec eff'y)	kJ/kg	627.2	505.5
Electricity output lost per unit heat supplied	kJ/kJ	0.30	0.23
COPx (effective coefficient of performance for extraction)	kJ/kJ	3.29	4.27

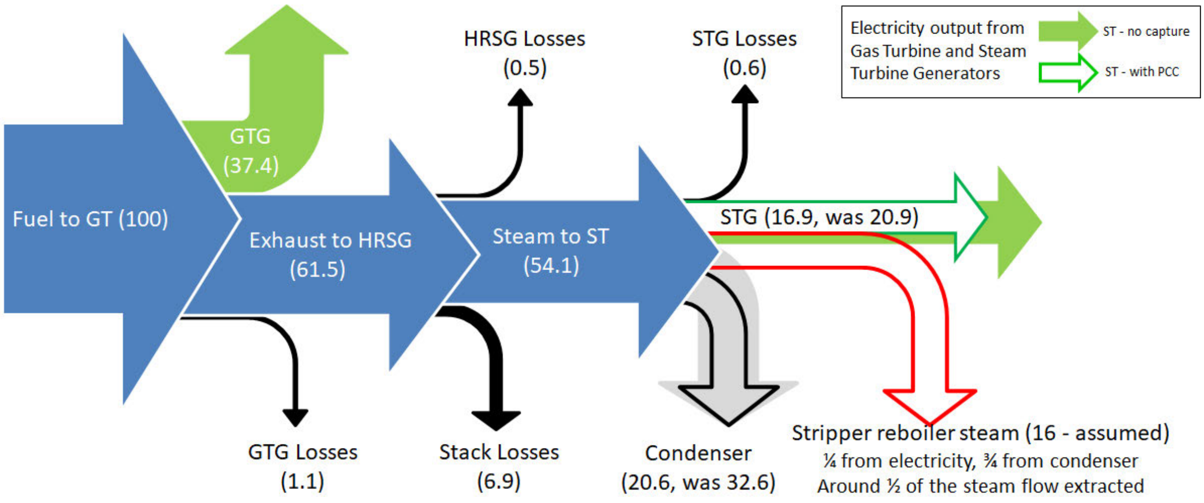

Fig. A3.3 Sankey diagram illustrating reboiler steam extraction (red) effects on steam turbine generator (STG) output (light green) and condenser heat rejection (grey/black); output from the gas turbine generator (GTG) is unaffected; power for PCC and heat rejection by PCC not shown. Possibility of some stack losses being recovered and re-applied for flue gas heating.
(based on Gülen, 2019)

Box A3.1 Examples for power plant efficiency impacts of PCC

Example 1 - CCGT consuming 1000 MWth LHV of natural gas, 0.2 tCO_2/MWh

PCC system requires 3 GJ/tCO_2 captured of heat at 120°C at a capture level of 95%, plus compression electric power of 70 kWh/tCO_2 plus electrical ancillaries of 30 kWh/tCO_2 (net additional thermal reclaimer heat requirement is relatively small and is neglected in these examples).

Expected plant performance:

Net output for H-class efficiency of 62% LHV net:	1000MWth.62% = 620.0 MW
CO_2 per hour (assumes 100% capture, will be less):	95%.1000MWth. 0.2 tCO_2/MWh = 190.0 t/hr
Reboiler heat requirement:	190 t/hr.3GJ/t = 570 GJ/hr = 158.3 MWth
Electricity output penalty for heat supply at 1:4 ratio	158.3MWth/4 = 39.6 MW(e)
Compression and ancillary power (values based on design)	190 t/hr. 100 kWh/t = 19MW
Net output with PCC and compression	620 – 39.6 – 19 = 561.4 MW
Efficiency with PCC and compression	561.4MW/1000MW = 56.1% LHV

Example 2 - Biomass power plant consuming 1000 MWth LHV of biomass, 0.3 tCO_2/MWh

PCC system requires 3 GJ/tCO_2 captured of heat at 120°C at 95% capture level, plus compression power of 70 kWh/tCO_2 plus ancillaries of 30 kWh/tCO_2.

Expected plant performance:

Net output for LCP BREF efficiency of 38% LHV net:	1000MWth.38% = 380.0 MW
CO_2 per hour:	95%.1000MWth. 0.3 tCO_2/MWh = 285.0 t/hr
Reboiler heat requirement:	285 t/hr.3GJ/t = 855 GJ/hr = 237.5 MWth
Electricity output penalty for heat supply at 1:4.5 ratio	237.5MWth/4.5 = 52.8 MW(e)
Compression and ancillary power (values based on design)	285 t/hr. 100 kWh/t = 28.5 MW
Net output with PCC and compression	380 - 52.8 – 28.5 = 298.7 MW
Efficiency with PCC and compression	298.7MW/1000MW = 29.9% LHV

Example 3 - Biomass power plant consuming 1000 MWth LHV of biomass, 0.3 tCO_2/MWh

Steam for CO_2 capture supplied by burning natural gas in a CCGT as efficiently as possible
PCC system requires 3 GJ/tCO_2 captured of heat at 120°C at 95% capture level, plus compression power of 70 kWh/tCO_2 plus ancillaries of 30 kWh/tCO_2.

Expected biomass plant performance:

Net output for LCP BREF efficiency of 38% LHV net:	1000MWth.38% = 380.0 MW
CO_2 per hour:	95%.1000MWth. 0.3 tCO_2/MWh = 285.0 t/hr
Reboiler heat requirement:	285 t/hr.3GJ/t = 855 GJ/hr = 237.5 MWth
Electricity output penalty for heat supply at 1:4.5 ratio	0 MW
Compression & ancillary power	285 t/hr. (70+30) kWh/t = 28.5 MW
Net output with compression and ancillary power	380 – 28.5 = 351.5 MW

Expected CCGT power plant performance (approximate size to match total PCC steam demand):

Net output for H-class efficiency of 62% LHV net:	1500MWth.62% = 930.0 MW
CO_2 per hour:	95%. 1500MWth. 0.2 tCO_2/MWh = 285.0 t/hr
Heat requirement for CCGT:	285 t/hr.3GJ/t = 855 GJ/hr = 237.5 MWth
Total PCC heat requirement (CCGT + biomass):	237.5 + 237.5 = 475 MWth
Electricity output penalty for heat supply at 1:4* ratio:	475MWth**/4 = 118.8MW(e)
Compression and ancillary power (values based on design):	285 t/hr. (70+30) kWh/t = 28.5 MW
Net output with PCC and compression	930 – 118.8 – 28.5 = 782.7 MW

* This ratio could, effectively, be improved by using PCC waste heat for condensate heating in the biomass plant
** This steam turbine might be designed a back-pressure unit, with no steam condensed

Annex 4 Summary of review preparation stages

A summary of the stages in the preparation of this review is given below.

Regulator reviews were undertaken with the Environment Agency, Scottish Environment Protection Agency, Natural Resources Wales and The Northern Ireland Environment Agency.

Industry reviews were undertaken with the help of the Carbon Capture and Storage Association and its members, who formed a BAT subgroup to the CCS Technical Working Group for the purpose. The Chemical Industries Association and a number of individual industrial and research organisations active in the field also participated.

Date	Activities
Jul 2020	Scope agreed and work started 2 Jul CCSA BAT subgroup meeting 6 Jul Stakeholder webinar ‘Public-domain evidence to inform BAT for PCC on natural gas and biomass’
10 Aug 2020	Regulators Review of draft BAT for post combustion carbon capture
12 Aug 2020	V3 draft released to industry for comment
13 Aug 2020	Discussions at CCSA BAT Subgroup meeting
Sep 2020	Feedback received from industry
2 Oct 2020	V4 draft discussed with regulators
21 Oct 2020	V5 draft released to industry for comment
28 Oct 2020	CCSA BAT subgroup meeting
30 Nov 2020	Regulators’ review
10 Dec 2020	‘Deep dive’ workshop on ‘Issues for achieving high capture levels’
17 Dec 2020	‘Deep dive’ workshop on ‘Emissions abatement measures, including provisions for acid wash as BAT’
7 Jan 2021	‘Deep dive’ workshop on ‘Steam supply options and effects on thermal efficiency with CO_2 capture for meeting the solvent thermal and electricity energy requirements’
Jan 2020	Final feedback on V5 draft received from industry (including discussions & clarifications)
23 Feb 2021	V6 draft released to industry for final comments
Mar-Apr 2021	Feedback on V6 draft received from industry (including discussions & clarifications)
July 2021	First published version released

EfW PCC consultation process

Date	Activities
18/11/2021	Initial meeting with the UK regulators and industry stakeholders to discuss the scope of the review and elicit initial input (~4 working weeks)
3/1/2022	Outline for the review and questionnaires circulated for comment by regulators (2 weeks)
17/1/2022	Send questionnaires to industry stakeholders (2 weeks)
1/2022 -4/2022	Industry stakeholder responses returned, analysis of responses, review updated.
15/6/2022	Review extended using information from BEIS Review of next generation carbon capture technology for industrial, waste and power sectors. https://www.gov.uk/government/publications/review-of-next-generation-carbon-capture-technology-for-industrial-waste-and-power-sectors and distributed to stakeholders, with draft guidance document.
17/6/2022	Meeting to discuss documents with industry stakeholders.
7/2022 – 8/2022	Inputs from industry stakeholders reviewed and review updated.
29/9/2022	Review circulated for final comments by regulators and industry stakeholders .
4/10/2022	Meeting to discuss documents with industry stakeholders.
10/2022	Review out for final comments
12/2022	Final draft of review ready for publication on UKCCSRC web site