Determination of an Application for an Environmental Permit under the Environmental Permitting (England & Wales) Regulations 2016

Decision document recording our decision-making process

The Permit Number is:	EPR/PP3501LR
The Applicant / Operator is:	Net Zero Teesside Power Limited
The Installation is located at:	Net Zero Teesside Power Station and Carbon Capture Plant, Redcar, Cleveland

What this document is about

This is a decision document, which accompanies a permit.

It explains how we have considered the Applicant's Application, and why we have included the specific conditions in the permit we are issuing to the Applicant. It is our record of our decision-making process, to show how we have taken into account all relevant factors in reaching our position. Unless the document explains otherwise, we have accepted the Applicant's proposals.

We try to explain our decision as accurately, comprehensively and plainly as possible. Achieving all three objectives is not always easy, and we would welcome any feedback as to how we might improve our decision documents in future. A lot of technical terms and acronyms are inevitable in a document of this nature: we provide a glossary of acronyms near the front of the document, for ease of reference.

Preliminary information and use of terms

We gave the application the reference number EPR/PP3501LR/A001. We refer to the application as "the **Application**" in this document in order to be consistent.

The number we have given to the permit is EPR/PP3501LR. We refer to the permit as "the **Permit**" in this document.

The Application was duly made on 30/06/2022.

The Applicant is Net Zero Teesside Power Limited. We refer to Net Zero Teesside Power Limited as "the **Applicant**" in this document. Where we are talking about what would happen after the Permit is granted (if that is our final decision), we call Net Zero Teesside Power Limited "the **Operator**".

The Applicant's proposed facility is located at Redcar, Cleveland, TS10 5QW. We refer to this as "the **Installation**" in this document.

Glossary

AQ	Air quality
Baseload	means: (i) as a mode of operation, operating for >4000hrs per annum; and (ii) as a load, the maximum load under ISO conditions that can be sustained continuously, i.e. maximum continuous rating
BAT	best available techniques
BAT-AEEL	BAT Associated Energy Efficiency Level
BAT-AEL	BAT Associated Emission Level
BREF	best available techniques reference document
CCGT	combined cycle gas turbine
CCP	carbon capture plant
CEM	continuous emissions monitor
DLN	Dry Low NOx burners
DLN-E	Dry Low NOx effective
Emergency use	<500 operating hours per annum
ELV	emission limit value set out in either IED or LCPD BAT Conclusions
FEED	Front End Engineering Design
GT	gas turbine
IED	Industrial Emissions Directive 2010/75/EC
LCP	large combustion plant – combustion plant subject to Chapter III of IED
MCR	Maximum Continuous Rating
MSUL/MSDL	Minimum start up load/minimum shut-down load
NE	Natural England
NOx	Oxides of nitrogen (NO plus NO_2 expressed as NO_2)
OCGT	open cycle gas turbine
Part load operation	operation during a 24 hr period that includes loads between MSUL/MSDL and maximum continuous rating (MCR). Also referred to as low load operation.
PC	Process Contribution
PCC	Post-combustion carbon capture
SCR	selective catalytic reduction
SNCR	selective non catalytic reduction

1. Our decision

We have decided to grant the Permit to the Applicant. This will allow them to operate the Installation, subject to the conditions in the Permit.

We consider that, in reaching that decision, we have taken into account all relevant considerations and legal requirements and that the Permit will ensure that a high level of protection is provided for the environment and human health.

This Application is to operate an Installation which is subject principally to the Industrial Emissions Directive (IED).

The Permit contains many conditions taken from our standard Environmental Permit template including the relevant Annexes. We developed these conditions in consultation with industry, having regard to the legal requirements of the Environmental Permitting Regulations (EPR) and other relevant legislation. This document does not therefore include an explanation for these standard conditions. Where they are included in the Permit, we have considered the Application and accepted the details are sufficient and satisfactory to make the standard condition appropriate. This document does, however, provide an explanation of our use of “tailor-made” or installation-specific conditions, or where our Permit template provides two or more options.

2. How we reached our decision

2.1 Receipt of Application

The Application was duly made on 30/06/2022. This means we considered it was in the correct form and contained sufficient information for us to begin our determination but not that it necessarily contained all the information we would need to complete that determination: see below.

The Applicant made no claim for commercial confidentiality. We have not received any information in relation to the Application that appears to be confidential in relation to any party.

2.2 Consultation on the Application

We carried out consultation on the Application in accordance with the EPR and our statutory Public Participation Statement. We consider that this process satisfies, and frequently goes beyond the requirements of the Aarhus Convention on Access to Information, Public Participation in Decision-Making and Access to Justice in Environmental Matters, which are directly incorporated into the IED, which applies to the Installation and the Application. We have also taken into account our obligations under the Local Democracy, Economic Development and Construction Act 2009 (particularly Section 23). This requires us, where we consider it appropriate, to take such steps as we consider appropriate to secure the involvement of representatives of interested persons in the exercise of our functions, by providing them with information, consulting them or involving them in any other way. In this case, our consultation already satisfies the Act’s requirements.

We advertised the Application by a notice placed on our website, which contained all the information required by the IED, including telling people where and when they could see a copy of the Application. The advertising period ran between 02/09/2022 and 30/09/2022. An advert detailing the consultation and how to view the Application and submit comments was placed in The Gazette on 02/09/2022.

We made a copy of the Application and all other documents relevant to our determination (see below) available to view on our Citizenspace web-based consultation portal and the public register. Anyone wishing to see these documents could also do so and arrange for copies to be made.

We sent copies of the Application to the following bodies, which includes those with whom we have “Working Together Agreements”:

- UK Health Security Agency
- The Director of Public Health
- The Health and Safety Executive
- Northumbria Water Limited

- National Grid
- Redcar and Cleveland Council – Planning and Environmental Department

These are bodies whose expertise, democratic accountability and/or local knowledge make it appropriate for us to seek their views directly. Note under our Working Together Agreement with Natural England, we only inform Natural England of the results of our assessment of the impact of the Installation on designated Habitats sites.

Further details along with a summary of consultation comments and our response to the representations we received can be found in Annex 2. We have taken all relevant representations into consideration in reaching our determination.

2.3 Requests for Further Information

Although we were able to consider the Application duly made, we did in fact need more information in order to determine it and issued an information notice on 15/11/2022. We also requested additional information via email as follows:

Date of email	Details of request
24/01/2023	Request for additional Information to support site condition report.
02/02/2023	Request for additional information on viability of heat recovery from Direct Contact Cooler; and a Sankey Diagram.
15/02/2023	Request for additional information on proposed effluent treatment plant.
28/03/2023 & 04/05/2023	Request for additional information on proposed discharge to Tees Bay.
09/05/2023	Request for additional information on key features of the CO_2 venting systems.
16/05/2023	Request for confirmation of proposed use of SCR.
08/06/2023	Request for additional information on CO_2 venting
05/07/2023	Request for additional information relating to proposed effluent treatment plant.
26/09/2023 & 14/11/2023	Requests for additional information relating to CO_2 venting air dispersion modelling assessment.

A copy of each information notice, email and the response was placed on our public register.

3. The installation

3.1 Description of the installation and related issues

The Installation is subject to the EPR because it carries out activities listed in Part 1 of Schedule 1 to the EPR:

- Section 1.1 Part A(1)(a) – Burning any fuel in an appliance with a rated thermal input of 50 megawatts or more.
- Section 6.10 Part A(1): capture of carbon dioxide steams from an installation for the purpose of geological storage.

An installation may also comprise “directly associated activities”, which at this Installation includes:

- Storage of diesel for use in emergency diesel generator.
- Discharge to Tees Bay of cooling water blowdown, steam condensate, treated direct contact cooler effluent and surface water runoff.
- Water treatment – The pumping, filtering and chemical treatment of raw water from 3rd party supply for use in the colling water circuit, capture plant and boiler (steam cycle).
- Electric auxiliary boiler providing steam/heat for use with the carbon capture plant (CCP)
- Treatment of effluent from the direct contact cooler using reverse osmosis

Together, these listed and directly associated activities comprise the Installation. Note that the Installation also includes a high-pressure compressor which has been permitted separately. The compressor is Operated by Net Zero North Sea Storage Limited and is permitted as a Directly Associated Activity, permit number EPR/FP3143QN.

3.2 The Site

The Applicant submitted a plan which we consider is satisfactory, showing the site of the Installation and its extent. A plan is included in Schedule 7 to the Permit, and the Operator is required to carry on the permitted activities within the site boundary.

3.3 Key issues in the Determination

The key issues during the determination were emissions to air and their impact on human health and the environment.

3.4 The site and its protection

The Operator proposes a number of techniques for the prevention of pollution to ground and groundwater, these include:

- Impermeable surfacing across the site.
- Areas handling chemicals will be paved and kerbed/bunded to ensure that spillages and /or leaks in those areas are contained, manually cleaned up and removed for treatment off site.
- Road tanker unloading areas will have kerbed /bunded areas sized to hold the full inventory of the tanker in the event of a full loss of containment.
- Secondary containment will be provided for all primary storage containers, including bulk tanks and IBCs, in line with the appropriate legislation and regulatory guidance. All bunds and bunded pallets shall be sized to accommodate a minimum of 110% of the maximum storage vessel volume located in the bund. Containment bunds would be provided around tanks where there is risk of spillage, and would be designed and constructed according to the requirements of CIRIA C736, API 650 and relevant Eurocodes.
- Emergency isolation valves will be in place to minimise the risk of discharges off-site from any spillages entering the site's surface water drainage system.
- Spill kits will be available in suitable locations.

Under Article 22(2) of the IED the Applicant is required to provide a baseline report containing at least the information set out in paragraphs (a) and (b) of the Article before starting operation.

The Applicant has not submitted a baseline report but has committed to carry out a survey prior to construction of the Installation. We have therefore set a pre-operational conditions (PO9 – PO11) requiring the Operator to provide information for approval on the site condition in line with Environment Agency (including a baseline report) prior to the commencement of operations.

The baseline report is an important reference document in the assessment of contamination that might arise during the operational lifetime of the Installation and at cessation of activities at the Installation

3.5 Closure and decommissioning

Pre-operational condition (PO1) and condition 1.1 in the permit requires the Operator to implement and operate in accordance with an Environmental Management System and this will include a site closure plan.

At the definitive cessation of activities, the Operator has to satisfy us that the necessary measures have been taken so that the site ceases to pose a risk to soil or groundwater, taking into accounts both the baseline conditions and the site's current or approved future use. To do this, the Operator will apply to us for surrender of the Permit, which we will not grant unless and until we are satisfied that these requirements have been met.

4, Operation of the Installation – general issues

4.1 Administrative issues

This is a multi-operator installation. Net Zero Teesside Power Limited is the Operator of this permit and Net Zero North Sea Storage Limited are the Operator of the High Pressure CO_2 compressor which forms the other part of the installation under permit EPR/FP3143QN.

We are satisfied that the Operator is the person who will have control over the operation of the Installation after we grant the Permit; and that the Operator will be able to operate the Installation so as to comply with the conditions included in the Permit.

4.2 Management

The Operator has stated in the Application that they will implement an Environmental Management System (EMS) to cover operation of the Installation. A pre-operational condition (PO1) is included requiring the Operator to provide a summary of the EMS prior to commissioning of the plant and to make available for inspection all EMS documentation.

We are satisfied that appropriate management systems and management structures will be in place for this Installation, and that sufficient resources are available to the Operator to ensure compliance with all the Permit conditions.

4.3. Accident management

The Operator has not submitted an Accident Management Plan. However, having considered the other information submitted in the Application, we are satisfied that appropriate measures will be in place to ensure that accidents that may cause pollution are prevented but that, if they should occur, their consequences are minimised. An Accident Management Plan for the proposed installation will form part of the EMS and must be in place prior to commissioning as required by a pre-operational condition (PO1).

4.4 Operating techniques

We have specified that the Operator must operate the Installation in accordance with the following documents contained in the Application:

Description	Parts Included	Date received
Part B3 of the application form and Appendix 1 Non-technical summary, Supporting document and appendices Response to request for information for duly making dated 22/04/2022	All parts Response to questions 2, 4, 5 and 6	Duly made 30/06/2022

Response to Schedule 5 Notice issued on 15/11/2022	Response to questions 1, 2, 3, 4, 5, 8, 9, 10, 11, 12, 13, 14, 16, 17, 18, 19, 20, 21, 22, 24, 25, 26, 27 and 28 CO_2 Venting Modelling Assessment V4	31/03/2023 & 18/10/2023
Request made on 02/02/2023 via email	Additional information on viability of heat recovery from Direct Contact Cooler; and a Sankey Diagram.	31/03/2023
Request made on 15/02/2023 via email	Additional information on proposed effluent treatment plant.	31/03/2023
Request made on 28/03/2023 & 04/05/2023 via email	Additional information on proposed discharge to Tees Bay.	29/03/2023 & 08/05/2023
Request made on 09/05/2023 via email	Additional information on key features of the CO2 venting systems.	24/05/2023
Request made on 16/05/2023 via email	Clarification on proposed use of Selective Catalytic Reduction (SCR).	16/05/2023
Additional Information	Technical Note to the Environment Agency on CO_2 Capture Rates	11/07/2023
Response to information request made on 05/07/2023 via email	BAT Assessment for Effluent Treatment	29/08/2023
Additional Information	Updated Technical Note to the Environment Agency and Natural England on Nitrogen Deposition – Dated 18/03/2024	18/03/2024

The details set out above describe the techniques that will be used for the operation of the Installation that have been assessed by the Environment Agency as BAT; they form part of the Permit through Permit condition 2.3.1 and Table S1.2 in the Permit Schedules.

We have also specified the following limits and controls on the use of raw materials and fuels:

Raw Material or Fuel	**Specifications**	**Justification**
Gas Oil	< 0.1% sulphur content	As required by Sulphur Content of Liquid Fuels Regulations.
Monoethanolamine (MEA)	Diethanolamine (DEA) not exceeding 0.2% content (unless otherwise agreed with the Environment Agency).	DEA is s known secondary amine contaminant in the production of MEA, due to the higher likelihood of degradation product formation from secondary amines in this process we have set a specification for the maximum amount of DEA present that we understand is achievable.

5. Large Combustion Plant

5.1 Chapter III of the Industrial Emissions Directive

Chapter III of the Industrial Emissions Directive (IED) applies to new and existing large combustion plants (LCPs) which have a total rated thermal input which is greater or equal to 50MW. Articles 28 and 29 explain exclusions to chapter III and aggregation rules respectively.

The aggregation rule is as follows:

- A LCP has a total rated thermal input ≥50MW.
- Where waste gases from two or more separate combustion plant discharge through a common windshield, the combination formed by the plants are considered as a single LCP.
- The size of the LCP is calculated by adding the capacities of the plant discharging through the common windshield disregarding any units <15MWth.

A “common windshield” is frequently referred to as a common structure or windshield and may contain one or more flues.

The Combined Cycle Gas Turbine (CCGT) on this site consists of an individual combustion unit with a total rated thermal input of approximately 1400MWth making it an LCP.

Combustion plant on the installation that do not form part of an LCP and so do not come under chapter III requirements, are still listed within the Section 1.1 Part A(1)(a) activity listed in Schedule 1 of the EPR. In this instance the site is likely to have 2- 3 standby diesel generators (<6MWth each) and have therefore been listed within the Section 1.1 activity. The generators are also within the scope of the Medium Combustion Plant Directive (MCPD) and have been listed as MCP in the Permit.

Other than for testing the generators will only operate to provide emergency power to the installation in the unlikely event that electrical power is unavailable from the installations CCGT; and the national grid connection; and the South Tees Development Corporation (STDC) site power. Therefore, the generators are very unlikely to ever be required for their intended purpose. They will all operate for less than 50 hours per year for testing and will not be tested concurrently. In line with MCPD, no emission limits have been specified. Note that the Operator has stated that the type and location of the generators cannot be confirmed at this stage therefore a pre-operational condition has been included in the permit (PO5) requiring the Operator to confirm this and to provide an air quality risk assessment for approval that confirms the generators will not have a significant impact on air quality. Note that they will not be able to operate the emergency generators until we have approved their proposal.

Chapter III lays out special provisions for LCP and mandatory maximum emission limit values are defined in part 2 of Annex V for new plant, however it is worth noting that best available techniques (BAT) requirements may lead to the application of lower ELVs than these mandatory values. Mandatory ELVs cannot be exceeded even if a site specific assessment can be used to justify emission levels higher than BAT.

5.2. Large Combustion Plant(s) description and number

The Permit uses the DEFRA LCP reference numbers to identify each LCP. The LCP permitted is as follows: **LCP687.**

This LCP consists of one 1400MWth CCGT which vents via a single stack. The unit burns natural gas.

5.3. Net thermal input

The Applicant has stated that the net thermal input of LCP687 will be approximately 1400 MWth.

The Applicant has not provided sufficient information to demonstrate the net thermal input of the LCP as the plant has not been built yet. Consequently, we have set improvement condition IC2, requiring them to provide this information within 12 months of the plant starting up.

5.4. Minimum start-up and minimum shut-down load

The Applicant has not provided sufficient information to set the minimum start-up and minimum shut-down load (MSUL/MSDL) as the plant has not been built yet. Consequently, we have set improvement condition

IC1, requiring them to provide this information within 12 months of the plant starting up. Table S1.5 in the Permit has also been completed to reflect this.

6. The Installation's environmental impact

Regulated activities can present different types of risk to the environment, these include noise and vibration, accidents, fugitive emissions to air and water; as well as point source releases to air, discharges to ground or groundwater, global warming potential and generation of waste and other environmental impacts. Consideration may also have to be given to the effect of emissions being subsequently deposited onto land (where there are ecological receptors). The key factors relevant to this determination are discussed in this and other sections of this document.

For an installation of this kind, the principal emissions are those to air, although we also consider those to land and water.

The next sections of this document explain how we have approached the critical issue of assessing the likely impact of the emissions to air from the Installation on human health and the environment.

The Operator based their assessment on the use of monoethanolamine (MEA) as the amine-solvent used in the carbon capture process. If in the future the Operator decides to use a different solvent they will be required to apply for a variation to the permit and submit a new air quality risk assessment which we would need to approve before permitting its use.

The Applicant's Air Quality assessment explains that there will be two modes of operation, CO_2 abated and CO_2 unabated. Normal operation for the Installation will be in CO_2 abated mode, when combustion gases are released from the CCP absorber stack (Emission Point A1). When CO_2 is not being abated combustion gases from the CCGT heat recovery steam generator (HRSG) will be released from emission the HRSG stack (Emission Point A2). The Applicants assessment states that emissions from release point A2 would be released at a much higher temperature compared with emissions from release point A1. At higher stack temperatures the thermal buoyancy is improved, and consequentially the dispersion, resulting in a level of impact for the CO_2 unabated CCGT operation that is no worse than for the CO_2 abated mode of operation and initial modelling has confirmed that this is the case. Therefore emissions from the CCP absorber stack (Release Point A1) represent worse case, and the assessment detailed below presents the findings of this assessment.

6.1 Assessment Methodology

6.1.1 Application of Environment Agency Web Guide for Air Emissions Risk Assessment

A methodology for risk assessment of point source emissions to air, which we use to assess the risk of applications we receive for permits, is set out in our Web Guide and has the following steps:

- Describe emissions and receptors;
- Calculate process contributions;
- Screen out insignificant emissions that do not warrant further investigation;
- Decide if detailed air modelling is needed;
- Assess emissions against relevant standards;
- Summarise the effects of emissions.

The methodology uses a concept of "process contribution (PC)", which is the estimated concentration of emitted substances after dispersion into the receiving environmental media at the point where the magnitude of the concentration is greatest. The guidance provides a simple method of calculating PCs primarily for screening purposes and for estimating PCs where environmental consequences are relatively low. It is based on using dispersion factors. These factors assume worst case dispersion conditions with no allowance made for thermal or momentum plume rise and so the PCs calculated are likely to be an overestimate of the actual maximum concentrations. More accurate calculation of PCs can be achieved by mathematical dispersion models, which take into account relevant parameters of the release and surrounding conditions, including local meteorology.

6.1.2 Use of Air Dispersion Modelling

For LCP applications, we usually require the Applicant to submit a full air dispersion model as part of their application, for the key pollutants. Air dispersion modelling enables the PC to be predicted at any environmental receptor that might be impacted by the plant.

Once short-term and long-term PCs have been calculated in this way, they are compared with Environmental Quality Standards (EQS).

Where an EU EQS exists, the relevant standard is the EU EQS. Where an EU EQS does not exist, our guidance sets out a National EQS (also referred to as Environmental Assessment Level - EAL) which has been derived to provide a similar level of protection to Human Health and the Environment as the EU EQS levels. In such cases, we use the National EQS standard for our assessment.

National EQSs do not have the same legal status as EU EQSs, and there is no explicit requirement to impose stricter conditions than BAT in order to comply with a national EQS. However, national EQSs are a standard for harm and any significant contribution to a breach is likely to be unacceptable.

PCs are considered **Insignificant** if:

- the **long-term** PC is less than **1%** of the relevant EQS; and
- the **short-term** PC is less than **10%** of the relevant EQS.

The **long term** 1% PC insignificance threshold is based on the judgements that:

- It is unlikely that an emission at this level will make a significant contribution to air quality;
- The threshold provides a substantial safety margin to protect health and the environment.

The **short term** 10% PC insignificance threshold is based on the judgements that:

- spatial and temporal conditions mean that short term PCs are transient and limited in comparison with long term PCs;
- the threshold provides a substantial safety margin to protect health and the environment.

Where an emission is screened out in this way, we would normally consider that the Applicant's proposals for the prevention and control of the emission to be BAT. That is because if the impact of the emission is already insignificant, it follows that any further reduction in this emission will also be insignificant.

However, where an emission cannot be screened out as insignificant, it does not mean it will necessarily be significant.

For those pollutants which do not screen out as insignificant, we determine whether exceedances of the relevant EQS are likely. This is done through detailed audit and review of the Applicant's air dispersion modelling taking background concentrations and modelling uncertainties into account. Where an exceedance of an EU EQS is identified, we may require the Applicant to go beyond what would normally be considered BAT for the Installation or we may refuse the application if the applicant is unable to provide suitable proposals. Whether or not exceedances are considered likely, the Application is subject to the requirement to operate in accordance with BAT.

This is not the end of the risk assessment, because we also take into account local factors (for example, particularly sensitive receptors nearby such as Sites of Special Scientific Interest (SSSIs), Special Areas of Conservation (SACs) or Special Protection Areas (SPAs). These additional factors may also lead us to include more stringent conditions than BAT.

If, as a result of reviewing the risk assessment and taking account of any additional techniques that could be applied to limit emissions, we consider that emissions **would cause significant pollution**, we would refuse the Application.

6.2 Assessment of Impact on Air Quality

The Applicant's assessment of the impact of air quality is set out in *Air Impact Assessment* dated June 2021 of the Application. The assessment comprises:

- Dispersion modelling of emissions to air from the operation of the installation.
- A study of the impact of emissions on nearby sensitive conservation sites.

This section of the decision document deals primarily with the dispersion modelling of emissions to air from the Installation and its impact on local air quality. The impact on conservation sites is considered in section 6.3.

The Applicant has assessed the Installation's potential emissions to air against the relevant air quality standards, and the potential impact upon local conservation sites and human health. These assessments predict the potential effects on local air quality from the Installation's stack emissions using the ADMS (Atmospheric Dispersion Modelling System) dispersion model, which is a commonly used computer model for regulatory dispersion modelling.

The ADMS model developers, CERC, have generated a specific amine chemistry module for use with ADMS software, for assessment of emissions of amines and their atmospheric degradation products. The ADMS amine chemistry module is the only commercially available software that can be used to evaluate potential impacts on air quality from amines and amine degradation. The model calculates the rate of amine degradation taking into account the reaction of amines with other species present in the exhaust gas (i.e. nitrogen dioxide (NO_2)) and also with hydroxyl radicals in the atmosphere. Whilst the ADMS model itself has been validated, the specific amines module has not been, and therefore the results should be regarded as indicative rather than definitive.

The model used five years of meteorological data between 2015 and 2019 collected from the weather station at Durham Tees Valley Airport, which is 22km southwest of the installation between 2015 and 2019. The impact of the terrain surrounding the site upon plume dispersion was considered in the dispersion modelling.

The Applicant's air impact assessments, and the dispersion modelling upon which they were based, employed the following conservative assumptions.

  - Emission concentrations for the process are calculated based on the use of IED limits, BAT Associate Emission Level (AEL) concentrations, or maximum envisaged emission rates from licensors; in practice annual average rates would be below this to enable continued compliance with environmental permit requirements;
  - Conservative assumptions on the amine and N-amine species likely to be emitted (assumes total N-amine (Nitrosamine and nitramine) is the most toxic species);
  - Maximum annual operation for the plant configuration assessed (8,760 hours, assuming the plant is used for baseload as a worst case);
  - Reporting of the worst case results from the five years of meteorological data modelled;
  - Maximum absorber building height;
  - Presentation of the worst-case impacts from assessment of the absorber stack being in four locations within installation boundary defined for the CCP; and
  - Conservative estimates of background concentrations for the commencement of operation at the receptor locations.

We are in agreement with this approach. The assumptions underpinning the model have been checked and are reasonably precautionary.

The Applicant provided us with modelled output showing the concentration of key pollutants at a number of specified locations within the surrounding area.

The way in which the Applicant used dispersion models, its selection of input data, use of background data and the assumptions it made have been reviewed by the Environment Agency to establish the robustness of the Applicant's air impact assessment. The output from the model has then been used to inform further assessment of health impacts and impact on habitats and conservation sites.

Our review of the Applicant's assessment leads us to agree with the Applicant's conclusions.

The Applicant's modelling predictions are summarised in the following sections.

6.2.1 Assessment of Air Dispersion Modelling Outputs

The modelling predictions are summarised in the tables below.

The modelling predicted maximum pollutant concentrations.

The table below shows the maximum ground level concentrations of pollutants. Where emissions screen out as insignificant, the background pollutant levels are not considered within the assessment in accordance with our H1 screening process. Where we take the background levels into account, we combine these with the PC to determine the Predicted Environmental Concentration (PEC) and assess the headroom between the PEC and the EQS as shown below.

Pollutant	EQS / EAL (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	PEC (µg/m³) (Background + PC)	PEC as % of EQS
Nitrogen dioxide (NO_2) Annual	40	0.8	2	15.5	39
NO_2 Hourly mean	200	7.0	<10	-	-
Carbon monoxide (CO) 1-hour mean	30,000	84.9	<10	-	-
CO 8 – hour mean	10,000	75.2	<10	-	-
Ammonia (NH_3) Annual	180	0.2	<1	-	-
NH_3 1-hour mean	2,500	1.7	<10	-	-
Amines (as MEA) 1-hour mean	400	4.5	<10	-	-
Amines (as MEA) 24-hour mean	100	2.8	2.8	2.8	2.8
Acetaldehyde 1-hour mean	9,200	4.8	<10	-	-
Acetaldehyde annual mean	370	0.2	<1	-	-
Formaldehyde ½ -hour mean	100	0.4	<10	-	-
Formaldehyde annual mean	5	0.02	<1	-	-

Pollutant	EQS / EAL ($\mu g/m^3$)	Process Contribution (PC) ($\mu g/m^3$)	PC as % of EQS / EAL	PEC ($\mu g/m^3$) (Background + PC)	PEC as % of EQS
Ketones 1-hour mean	89,500	4.8	<10	-	-
Ketones annual mean	6000	0.2	<1	-	-
Acetic acid 1-hour mean	3,700	1.0	<10	-	-
Acetic acid annual mean	250	0.04	<1	-	-

From the table above the following emissions can be screened out as insignificant in that the PC is <1% of the long term EQS/EAL or <10% of the short term EQS/EAL. These are:

- NO_2 hourly mean at maximum grid concentration.
- CO 1-hour mean or 8-hour mean
- NH3 annual or 1-hour mean
- Amines (as MEA) 1-hour mean
- Acetaldehyde annual or 1-hour mean
- Formaldehyde annual or 1-hour mean
- Ketones annual or 1-hour mean
- Acetic acid annual or 1-hour mean

From the tables above the annual mean NOx was over 1% of the long-term EQS so we also considered the background NO_2 levels. When taking this into account there is adequate headroom between the PEC and EAL to indicate that it is unlikely that there will be an exceedance of an EQS for this pollutant. The 24-hour annual mean PC of amines that occurs anywhere as a result of the proposed installation represents 2.8% of the relevant EQS for MEA. As the background concentration is considered to be 0 µg/m3, the PEC is also 2.8% of the EQS and therefore can also be considered to be insignificant.

<u>N-Amines Assessment – Nitrosamines and Nitramines</u>

The Environment Agency Risk Assessment Guidance includes EALs for MEA (a primary amine) and NDMA (a stable nitrosamine). Amines, nitrosamine and nitramines are not routinely monitored in the UK, therefore in the absence of data the Operator assumed background concentrations to be zero. The Operator's 'direct' and 'indirect' PCs are shown in tables 7.1 to 7.6 of the Air Impact Assessment submitted with the Application. The following table shows the predicted maximum NDMA PC (direct and indirect):

Direct Amine Release PC as % EQS/EAL	**Indirect Amine Release PC as % EQS/EAL**	**Combined PC as % EQS/EAL**
35%	46%	81%

The results above are based on the following assumptions:

- Any nitrosamine and nitramine formed in ambient air will be NDMA and any directly emitted nitrosamine will be NDMA. This likely to be conservative based on toxicological evidence for NDMA.

- There are no EALs for nitramines (such as that formed from DMA, dimethynitramine) or any other nitrosamine that may be directly released.

- NDMA ‘indirect’ predictions are based on the maximum highest concentration formed from reactions of direct MEA and DMA releases. The Operator’s NDMA numerical predictions indicate that NDMA predictions are lower from MEA reactions. As MEA is a primary amine and unlikely to form stable nitrosamine this is likely to be a conservative assumption.

6.2.2 Consideration of key pollutants

(i) Nitrogen dioxide (NO_2)

The impact on air quality from NO_2 emissions has been assessed against the EU EQS of 40 $\mu g/m^3$ as a long-term annual average and a short-term hourly average of 200 $\mu g/m^3$. The model assumes a 70% NO_x to NO_2 conversion for the long term and 35% for the short-term assessment in line with Environment Agency guidance on the use of air dispersion modelling.

The above tables show that the grid maximum long-term PC is 2% of the EU EQS and the short term PC is less than 10% of the EU EQS. Short-term impacts can be screened out as insignificant. For longer term impacts we consider that there is adequate headroom between the PEC and EQS to indicate an exceedance is unlikely. Therefore we consider the Applicant’s proposals for preventing and minimising the emissions of these substances is likely to be BAT for the Installation, however we address this in further detail in sections 7, 11 and 12 of this decision document.

(ii) Dust

Natural gas is an ash-free fuel and high efficiency combustion in the gas turbine does not generate additional particulate matter. The fuel gas is always filtered and, in the case of gas turbines, the inlet air is also filtered resulting in a lower dust concentration in the flue than in the surrounding air. Thus, for natural gas fired turbines dust emissions are not an issue.

(iii) Sulphur dioxide

Natural gas, that meets the standard for acceptance into the National Transmission System, is considered to be a sulphur free fuel. Hence, sulphur dioxide emissions from burning natural gas, were not considered to be significant and were not modelled by the Applicant. We agree with this approach.

(iv) CO

The above table shows that for CO emissions, the 8-hourly and 1-hourly means are predicted to be less than 10% of the EAL/EQS and so can be screened out as insignificant. Therefore we consider the Applicant’s proposals for preventing and minimising the emissions of these substances to be BAT for the Installation.

(V) Ammonia

The above table shows that for ammonia emissions, the peak long term PC is less than 1% of the EAL/EQS and the peak short-term PC is less than 10% of the EAL/EQS and so can be screened out as insignificant. Therefore, we consider the Applicant’s proposals for preventing and minimising the emissions of these substances to be BAT for the Installation.

(v) N – amines (Nitrosamines and Nitramines)

The above results of the N-amines assessment show that direct and indirect PCs of N-amines are unlikely to result in an exceedance of the available EQS/EALs.

6.3 Impact on Habitats sites, SSSIs, non-statutory conservation sites etc.

6.3.1 Sites Considered

The following Habitat (i.e. Special Areas of Conservation (SAC), Special Protection Areas (SPA) and Ramsar) sites are located within 15 km of the Installation.

- Teesmouth and Cleveland Coast SPA and Ramsar
- North York Moors SPA and SAC

- Northumbria Coast SPA and Ramsar
- Durham Coast SAC

The following sites of special scientific interest (SSSI) are located within 2 km of the installation:

- Teesmouth and Cleveland SSSI
- North York Moors SSSI
- Durham Coast SSSI
- Lovell Hill Pools SSSI
- Saltburn Gill SSSI

The following non-statutory local wildlife (LWS) and conservation sites are located within 2 km of the Installation:

- Coatham Marsh LWS
- Eston Pumping Station LWS

6.3.2 Habitats Assessment

We have assessed the impact from the proposed Installation on the Habitat sites that are within the relevant screening distance. As required under the Habitats Regulations we have completed a Habitats Regulation Assessment (HRA). This is a two stage process. The Stage 1 HRA is where it is identified whether PCs will have a likely significant effect on the integrity of the habitat site. For any habitat site where we are unable to conclude that there will be no likely significant effect on the integrity of the site a detailed 'appropriate assessment' of the impacts is carried out under the Stage 2 HRA to determine if the impacts will have an adverse effect on the habitat site.

The following details the results of the Applicant's Air Quality modelling assessment on the relevant habitat sites:

- Teesmouth and Cleveland Coast SPA and Ramsar; and SSSI

Pollutant	EQS / EAL ($\mu g/m^3$)	Back-ground ($\mu g/m^3$)	Process Contribution (PC) ($\mu g/m^3$)	PC as % of EQS / EAL	Predicted Environmental Concentration (PEC) ($\mu g/m^3$)	PEC as % EQS / EAL
Direct Impacts[1]						
NO_x Annual	30	19.43	1.2	3.9%	20.20	67%
NO_x Daily Mean	75	29.15	17.2	22.9%	44.6	60%
Ammonia Annual	3	0.89	0.05	1.5%	0.95	32%
Deposition Impacts[1]						
Nutrient Nitrogen Deposition (kg N/ha/yr)	10	10.5	0.39	3.9%[Note 2]	10.9	109%

Pollutant	EQS / EAL (µg/m^3)	Back-ground (µg/m^3)	Process Contribution (PC) (µg/m^3)	PC as % of EQS / EAL	Predicted Environmental Concentration (PEC) (µg/m^3)	PEC as % EQS / EAL
Acidification - Nitrogen Dep (Keq/ha/yr)	Min CL Min N – 0.856 Min CL Max N – 4.856 Min CL Max S – 4.00	N = 0.75 S = 0.25	0.025	<1%	-	-
Note 1: Direct impact units are µg/m^3 and deposition impact units are kg N/ha/yr or Keq/ha/yr. Note 2: The process contribution from Nutrient Nitrogen Deposition calculated by the Applicant did not take into account the contribution from amines. Environment Agency air quality modelling specialist predicted that the contribution from amines could potentially increase to 8.6% of the Nutrient Nitrogen Deposition critical load.						

- North York Moors SPA and SAC; and SSSI

Pollutant	EQS / EAL (µg/m^3)	Back-ground (µg/m^3)	Process Contribution (PC) (µg/m^3)	PC as % of EQS / EAL	Predicted Environmental Concentration (PEC) (µg/m^3)	PEC as % EQS / EAL
Direct Impacts[1]						
NO_x Annual	30	-	0.06	<1%	-	-
NO_x Daily Mean	75	-	1.0	<10%	-	-
Ammonia Annual	3	-	0.004	<1%	-	-
Deposition Impacts[1]						
N Deposition (kg N/ha/yr)	10	-	0.03	<1%	-	-
Acidification - Nitrogen Dep (Keq/ha/yr)	Min CL Min N – 0.499 Min CL Max N – 0.792	-	0.002	<1%	-	-

Pollutant	EQS / EAL (µg/m³)	Back-ground (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	Predicted Environmental Concentration (PEC) (µg/m³)	PEC as % EQS / EAL
	Min CL Max S – 0.150					
Note 1: Direct impact units are µg/m³ and deposition impact units are kg N/ha/yr or Keq/ha/yr.						

- Northumbria Coast SPA and Ramsar

Pollutant	EQS / EAL (µg/m³)	Back-ground (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	Predicted Environmental Concentration (PEC) (µg/m³)	PEC as % EQS / EAL
Direct Impacts[1]						
NO_x Annual	30	-	0.04	<1%	-	-
NO_x Daily Mean	75	-	0.8	<10%	-	-
Ammonia Annual	3	-	0.003	<1%	-	-
Deposition Impacts[1]						
N Deposition (kg N/ha/yr)	8	-	0.02	<1%	-	-
Acidification - Nitrogen Dep (Keq/ha/yr)	Min CL Min N – 0.223 Min CL Max N – 0.786 Min CL Max S – 0.420	-	0.001	<1%	-	-
Note 1: Direct impact units are µg/m³ and deposition impact units are kg N/ha/yr or Keq/ha/yr.						

- Durham Coast SAC and SSSI

Pollutant	EQS / EAL (µg/m³)	Back-ground (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	Predicted Environmental Concentration (PEC) (µg/m³)	PEC as % EQS / EAL
Direct Impacts[1]						
NO_x Annual	30	-	0.05	<1%	-	-
NO_x Daily Mean	75	-	0.7	<10%	-	-
Ammonia Annual	3	-	0.003	<1%	-	-
Deposition Impacts[1]						
N Deposition (kg N/ha/yr)	15	-	0.02	<1%	-	-
Acidification - Nitrogen Dep (Keq/ha/yr)	Min CL Min N – 0.223 Min CL Max N – 1.03 Min CL Max S – 0.81	-	0.001	<1%	-	-
Note 1: Direct impact units are µg/m³ and deposition impact units are kg N/ha/yr or Keq/ha/yr.						

From the tables above we concluded ‘no likely significant effect’ as result of emissions to air from the proposed installation at all the Habitat sites with the exception of Teesmouth and Cleveland Coast SPA, Ramsar and SSSI.

We completed a stage 1 and stage 2 Habitat Risk Assessment (HRA) and this was sent to Natural England for consultation. The HRA detailed the relevant impacts on the habitat sites listed above from the proposed installation.

Natural England responded to the consultation and stated that ‘*Natural England considers that the current proposal is likely to damage Teesmouth and Cleveland Coast SSSI and that further mitigation is required’*. It was subsequently clarified with Natural England that the proposed installation would not have an adverse effect on the integrity of the Teesmouth and Cleveland Coast SPA and Ramsar and it was the impact on the features of interest of the Teesmouth and Cleveland Coast SSSI that could be damaged specifically from the predicted process contributions of Nutrient Nitrogen Deposition on the Cobham Dunes area of the SSSI. This is discussed further below.

We are therefore satisfied that based on the information provided in the Application that emissions to air from the proposed installation will have no likely significant effect on the Habitat sites listed that are within the relevant screening distance of the installation. However, with respect to Teesmouth and Cleveland Coast SSSI we were unable to conclude that the predicted impact would not damage the SSSI, therefore further assessment was required this is discussed further in section 6.3.3 below.

A copy of the stage 1 and stage 2 Habitat Risk Assessment (HRA) and Natural England's response is available to view on Public Register.

6.3.3 Assessment of Sites of Special Scientific Interest (SSSI)

We have assessed the impact from the proposed Installation on the four SSSIs that are within the relevant screening distance.

The result of the Operator's air quality modelling assessment is as follows (note that the results of the assessment for Teesmouth and Cleveland Coast SSSI, North York Moors SSSI and Durham Coast SSSI are shown above):

- Lovell Hill Pools SSSI

Pollutant	EQS / EAL ($\mu g/m^3$)	Back-ground ($\mu g/m^3$)	Process Contribution (PC) ($\mu g/m^3$)	PC as % of EQS / EAL	Predicted Environmental Concentration (PEC) ($\mu g/m^3$)	PEC as % EQS / EAL
Direct Impacts[1]						
NO_x Annual	30	-	0.11	<1%	-	-
NO_x Daily Mean	75	-	1.7	<10%	-	-
Ammonia Annual	3	-	0.01	<1%	-	-
Deposition Impacts[1]						
N Deposition (kg N/ha/yr)	No comparable habitat with established critical load for estimate available					
Acidification - Nitrogen Dep (Keq/ha/yr)	No critical loads assigned for the features present.					
Note 1: Direct impact units are $\mu g/m^3$ and deposition impact units are kg N/ha/yr or Keq/ha/yr.						

- Saltburn Gill SSSI

Pollutant	EQS / EAL (µg/m³)	Back-ground (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	Predicted Environmental Concentration (PEC) (µg/m³)	PEC as % EQS / EAL
Direct Impacts[1]						
NO_x Annual	30	-	0.06	<1%	-	-
NO_x Daily Mean	75	-	0.8	<10%	-	-
Ammonia Annual	3	-	0.01	<1%	-	-
Deposition Impacts[1]						
N Deposition (kg N/ha/yr)	15	-	0.05	<1%	-	-
Acidification - Nitrogen Dep (Keq/ha/yr)	Min CL Min N – 0.142 Min CL Max N – 2.639 Min CL Max S – 2.448	-	0.004	<1%	-	-
Note 1: Direct impact units are µg/m³ and deposition impact units are kg N/ha/yr or Keq/ha/yr.						

The tables above for Lovell Hill Pools SSSI, Saltburn Gill SSSI, North York Moors SSSI and Durham Coast SSSI show that the PCs are below the critical levels or loads and can be considered insignificant in that the PC is <1% of the long term critical load/critical level and <10% of the short-term critical load/critical level. These are:

- NO_2 annual mean, NO_2 daily mean, nitrogen deposition and acidification.

We are satisfied that the Installation will not cause significant pollution at the sites.

As discussed in section 6.3.2 above, following consultation with Natural England we were initially unable to conclude that the predicted impact from nutrient nitrogen deposition would not damage the Cobham Dunes area of the Teesmouth and Cleveland Coast SSSI.

In response the Applicant highlighted that the AQ assessment submitted with the Application was based on a number of worst-case assumptions as the project was in a very early stage of development. So in order to reflect a more realistic assessment of the impact on the SSSI they updated their assessment to reflect up to date design information and operational profile. The assessment showed that the nutrient nitrogen deposition PC at the SSSI would be significantly less than originally predicted at <1% of the critical load, this was based on the assumption that the installation would be operational for 62% of the time which would be reflected in the permit via a limit on hours of operation. As required under the Countryside and Rights of Way Act (CRoW) we completed an Appendix 4 notice which detailed our assessment and conclusions and this was sent to Natural England for consultation. Natural England's response was to agree with our conclusions.

Subsequently, the Applicant informed us that they did not want to have a limit on operational hours. This meant that were required to provide an updated assessment of the impact of Nutrient Nitrogen Deposition based on the installation operating 100% of the time. The Applicant provided an updated assessment (Updated Technical Note to the Environment Agency and Natural England on Nitrogen Deposition – Dated 18/03/2024) which as well as being based on operating 100% of the time also reflected further updated installation design. The updated predicted nutrient nitrogen deposition PC on the Teesmouth and Cleveland Coast SSSI is as follows:

Pollutant	Critica load (µg/m³)	Back-ground (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	Predicted Environmental Concentration (PEC) (µg/m³)	PEC as % EQS / EAL
Deposition Impacts						
N Deposition (kg N/ha/yr)	10	12.3	0.14	1.4%	12.44	124%

The table above shows that the updated predicted nutrient nitrogen deposition PC is below the nutrient nitrogen deposition critical load, however the impact is not considered insignificant in that the PC is >1% of the critical load at a small area of the Cobham Dunes area of the SSSI. As discussed above, the advice from Natural England is that an impact >1% of the critical load may lead to damage to the features of interest within the Cobham Dunes area of the SSSI. Whilst the predicted impact of 1.4% is only marginally above 1% we consider it necessary for the Operator to reduce their annual emissions of pollutants that contribute to Nutrient Nitrogen Deposition to al level that will result in a PC of 1% or below at Cobham Dunes. In order to ensure this we have included the following pre-operational condition in the permit (PO15 in table S1.4):

PO15	Emissions to Air Following the completion of the final design of the Installation and at least 6 months prior to the prior to the first combustion of a fuel or first firing the Operator shall submit to the Environment Agency for approval in writing a report proposing annual mass emissions limits or operating techniques, with associated calculation and reporting methods for parameters which could contribute to nutrient nitrogen deposition at the Coatham Dunes area of the Teesmouth and Cleveland Coast Site of Special Scientific Interest (SSSI). Compliance with the limits or operating techniques shall ensure that nutrient nitrogen deposition rates at this receptor do not exceed 1% of the lower end of the critical load range for nutrient nitrogen deposition.

Compliance with the pre-operational condition will ensure that the proposed installation will not damage the SSSI. Note that the conclusions in the Appendix 4 Notice which has been sent to NE remain unchanged and therefore further consultation with Natural England was not required.

6.3.4 Assessment of other conservation sites

Conservation sites are protected in law by legislation. The Habitats Directive provides the highest level of protection for SACs and SPAs, domestic legislation provides a lower but important level of protection for

SSSIs. Finally the Environment Act provides more generalised protection for flora and fauna rather than for specifically named conservation designations. It is under the Environment Act that we assess other sites (such as local wildlife sites) which prevents us from permitting something that will result in significant pollution; and which offers levels of protection proportionate with other European and national legislation. However, it should not be assumed that because levels of protection are less stringent for these other sites that they are not of considerable importance. Local sites link and support EU and national nature conservation sites together and hence help to maintain the UK's biodiversity resilience.

For SACs SPAs, Ramsars and SSSIs we consider the PC and the background levels in making an assessment of impact. In assessing these other sites under the Environment Act we look at the impact from the Installation alone in order to determine whether it would cause significant pollution. This is a proportionate approach, in line with the levels of protection offered by the conservation legislation to protect these other sites (which are generally more numerous than Natura 2000 or SSSIs) whilst ensuring that we do not restrict development.

Critical levels and loads are set to protect the most vulnerable habitat types. Thresholds change in accordance with the levels of protection afforded by the legislation. Therefore, the thresholds for SAC SPA and SSSI features are more stringent than those for other nature conservation sites.

Therefore we would generally conclude that the Installation is not causing significant pollution at these other sites if the PC is less than the relevant critical level or critical load, provided that the Operator is using BAT to control emissions.

The Operator's assessment shows that the PCs at the non-statutory local wildlife and conservation sites listed above will be below the critical levels or loads. We are therefore satisfied that the Installation will not cause significant pollution at the sites. The Operator is required to prevent, minimise and control emissions using BAT, this is considered further in Sections 7, 11 and 12.

6.4 Impact of abnormal venting of carbon dioxide (CO_2)

The release of highly concentrated CO_2 under pressure from the installation has the potential to cause harm to human health. It is recognised that for installations of the type proposed that venting to atmosphere of concentrated CO_2 may be required during operation of the installation. For this reason, the Applicant was required to provide an assessment of the risk of the vented concentrated CO_2 causing harm to health at nearby sensitive receptors. The Applicant provided an assessment which presented a number of operational scenarios under which CO_2 may be vented to atmosphere and they have used air dispersion modelling (ADMS) to predict impacts on nearby receptors. The scenarios include venting of CO2 during commissioning of the CCP. The impacts have been compared to exposure assessment criteria detailed in the CO_2 incident management document (Compendium of Chemical Hazards: Carbon Dioxide. Public Health England (PHE) publications gateway number: 2014790. PHE, 2015) from the former Public Health England (PHE), now UK Health Security Agency (UKHSA), which provides incident management guidelines for assessing and managing the potential effects from exposure to CO_2.

Environment Agency air quality specialists have audited the Applicants assessment and are satisfied that the concentrations of CO_2 are likely to be below the Applicant's proposed lowest assessment criteria at sensitive human receptor locations. Therefore, we are satisfied that that there is no significant risk to human health.

A pre-operational condition (PO8) has been included in permit requiring the Operator to provide an updated assessment for approval following completion of the final design of the proposed installation. Also included in this condition is a requirement for the Operator to submit to the Environment Agency for approval a management plan detailing operating techniques to minimise potential CO_2 phase changes, solid effects and dense gas behaviour when venting CO_2 atmosphere. This is included because the Applicant's assessment assumes that CO_2 releases are (fully expanded) gas with no phase change, we therefore require the Operator have plans in place to minimise the CO_2 phase changes, dense gas behaviour or incidents that could occur during the proposed venting operation.

6.5 Other Emissions to the Environment

6.5.1 Emissions to water and sewer

The Applicant amended their proposals for discharges to surface water and sewer during the determination of the permit. It was originally proposed for there to be a discharge to Tees Bay and a discharge to Bran Sands waste water treatment works (WwTW). However, during the determination the Applicant informed us that they would be changing their proposals and no longer discharging effluent to Bran Sands WwTW. They explained to us that this was due to the potential dissolved inorganic nitrogen content of the discharge adversely impacting on the developments ability to demonstrate Nutrient Neutrality within the Teesmouth and Cleveland Coast Special Protection Area (SPA)/ Ramsar catchment. This discharge, which comprised of effluent from the Direct Contact Cooler will now be treated on site to remove ammonia, with the resulting treated effluent either being re-used on site or discharged to Tees Bay via emission point W1.

The discharge to emission point W1 will comprise of cooling water blow-down, steam condensate, treated direct contact cooler effluent and surface water run-off. It is proposed in the application that condensate and dehydration water from the compression plant and flue gas wash water will be recovered within the amine solvent system so will not be included in the discharge. Waste from solvent reclamation will be neutralised prior to transport off-site for treatment.

The Operator did submit a Water Quality Risk Assessment with the Environment Permit Application. The assessment modelled the discharge to Tees Bay and assessed the impact on water quality including the thermal impact. Environment Agency Marine Water Quality Specialists reviewed the modelling assessment and were satisfied that it was appropriate and agreed with their conclusions. However, as discussed above the discharge proposals have changed since this assessment was submitted and therefore the assessment no longer reflects the discharge arrangements now proposed by the Applicant. They confirmed that whilst the existing Water Quality Assessment is now out of date, it provides a worse-case assessment of the discharge into Tees Bay. In order to verify this, we have included a pre-operational condition (PO6) in the Permit requiring the Operator to submit an updated Water Quality Risk Assessment that reflects the final design and discharge arrangements of the installation. When submitted this assessment will be reviewed by Environment Agency Marine Water Quality Specialists to ensure that impacts on Tees Bay are not significant. The Operator will be unable to begin operations on site until the assessment has been approved by the Environment Agency.

Note that the Stage 1 and Stage 2 HRA completed for this determination includes details of the assessment of the impact of the proposed discharge to Tees Bay on the interest features of the Teesmouth and Cleveland Coast Special Protection Area (SPA)/ Ramsar, copies of the assessments are available to view on our public register. As stated earlier in this document, the HRA concludes that emissions (including the discharge to Tees Bay) will not have a significant impact on the Teesmouth and Cleveland Coast SPA/ Ramsar. We consulted Natural England on our assessment and they agree with our conclusions.

6.5.2 Fugitive emissions

The IED specifies that Operators must be able to demonstrate that the plant is designed in such a way as to prevent the unauthorised and accidental release of polluting substances into soil, surface water and groundwater. In addition storage requirements for waste and for contaminated water of Article 46(5) must be arranged.

The Applicant has proposed the following key measures to control fugitive emissions:

- Impermeable surfacing across the site.
- Areas handling chemicals will be paved and kerbed/bunded to ensure that spillages and /or leaks in those areas are contained, manually cleaned up and removed for treatment off site.
- Road tanker unloading areas will have kerbed /bunded areas sized to hold the full inventory of the tanker in the event of a full loss of containment.

- Secondary containment will be provided for all primary storage containers, including bulk tanks and intermediate (IBCs), in line with the appropriate legislation and regulatory guidance. All bunds and bunded pallets shall be sized to accommodate a minimum of 110% of the maximum storage vessel volume located in the bund. Containment bunds will be provided around tanks where there is risk of spillage, and will be designed and constructed according to the requirements of CIRIA C736, API 650 and relevant Eurocodes.
- Primary and secondary surface water attenuation basins including all the mechanisms will be designed and constructed to control the flow of clean discharge to the Tees Bay in accordance with the requirements described in the Development Consent Order (DCO) application document and the CIRIA C736.
- Emergency isolation valves will be in place to minimise the risk of discharges off-site from any spillages entering the site's surface water drainage system.
- Spill kits will be available in suitable locations.
- Provision for containment of contaminated firewater on site.
- The concrete lined retention/attenuation pond will be designed as water retaining structure to BS EN 1992-3 and tested in accordance with BS 8007.

6.5.3 Odour

Based upon the information in the Application we are satisfied that the appropriate measures will be in place to prevent or where that is not practicable to minimise odour and to prevent pollution from odour.

The Applicant has stated that the proposed amine solvent will have a low vapour pressure at ambient temperatures and therefore consider the risk of amine odour to be low. Amine storage will be in closed tanks so under normal operation there would be no direct breathing to atmosphere from the storage tanks. Aqueous ammonia will be stored in closed tanks. During filling operations of the amine and ammonia/urea tanks displaced air will be back vented to the delivery tankers to minimise fugitive emissions. In addition the they have stated that a leak detection and repair (LDAR) program will be implemented at the proposed Installation.

With regards to odour risk from the amines released to atmosphere from the absorber stack, we are satisfied that ground level concentrations of amines will not cause significant odour at sensitive receptors.

The permit includes condition 3.3.2 which requires the Operator to submit an odour management plan for approval if notified by the Environment Agency that the activities are giving rise to pollution outside the site due to odour.

6.5.4 Noise and vibration

Based upon the information in the Application we are satisfied that the appropriate measures will be in place to prevent or where that is not practicable to minimise noise and vibration and to prevent pollution from noise and vibration outside the site.

The Applicant has stated that noise mitigation will be included through the choice of plant location and design. This may include appropriate stack design, use of cladding and shielding where appropriate and where practical siting equipment away from site boundaries and receptors.

The Application contained a noise impact assessment which identified local noise-sensitive receptors, potential sources of noise at the proposed plant and noise attenuation measures. Measurements were taken of the prevailing ambient noise levels to produce a baseline noise survey and an assessment was carried out in accordance with BS4142:2014 to compare the predicted plant rating noise levels with the established background levels.

The Applicants assessment concluded that for operational noise the effects at all noise sensitive receptors (NSR) are expected to be minor adverse or less, so therefore unlikely to be significant at any NSR. However, it is acknowledged that the Applicant's assessment is not based on the final design of the Installation, so for this reason we have set a pre-operational condition (PO4) in the Permit requiring the Operator to submit to us for approval a new Noise Impact Assessment based on the final design of the Installation. This will include consideration of noise impacts when venting CO_2 to atmosphere. At this point we can review the noise impacts from Operator's final plant design and we will not approve the proposals unless we are satisfied that noise impacts will not be significant.

7. Application of Best Available Techniques

7.1 Scope of Consideration

In this section, we explain how we have determined whether the Applicant's proposals are the Best Available Techniques (BAT) for this Installation.

- We address the fundamental choice of combustion technology and carbon capture technology;
- We consider energy efficiency, and options for Combined Heat and Power, and compliance with the Energy Efficiency Directive;
- We consider the cooling system proposed.

Chapter III of the IED specifies a set of maximum emission limit values. Although these limits are designed to be stringent, and to provide a high level of environmental protection, they do not necessarily reflect what can be achieved by new plant. Article 14(3) of the IED says that BAT Conclusions shall be the reference for setting the permit conditions, so it may be possible and desirable to achieve emissions below the limits referenced in Chapter III. The BAT Conclusions were published in 2021 so BAT Associated Emission Levels (AELs) are specified alongside Chapter III limits from the IED within the Permit.

Operational controls complement the emission limits and should generally result in emissions below the maximum allowed; whilst the limits themselves provide headroom to allow for unavoidable process fluctuations. Actual emissions are therefore almost certain to be below emission limits in practice, because any Operator who sought to operate its installation continually at the maximum permitted level would almost inevitably breach those limits regularly, simply by virtue of normal fluctuations in plant performance, resulting in enforcement action (including potentially prosecution) being taken. Assessments based on Chapter III ELVs or BAT AELs are therefore "worst-case" scenarios.

We are satisfied that emissions at the permitted limits would ensure a high level of protection for human health and the environment in any event.

7.2 Consideration of Combustion Plant and Carbon Capture Plant

The operator has chosen to operate a CCGT plant. The plant will comprise one H-Class gas turbine having a nominal output of up to 860 MWe (CO_2 unabated).

CCGTs operate with a heat recovery steam generator (HRSG) and therefore have a greater efficiency when compared with an Open Cycle Gas Turbine (OCGT).

Operation of gas turbines in combined cycle is considered BAT due to increased energy efficiency and reduced pollutants released to air in comparison to operating gas turbines in open cycle mode.

During combined cycle operation the turbines will only burn natural gas and the main pollutant of concern will be NO_2. Within the gas turbine the gas will be mixed and combusted with compressed air. The hot combustion gases will expand, rotating the turbine blades at high speed, driving an electrical generator to produce electricity.

The hot gases from the GT will then be passed through a heat recovery steam generator (HRSG) to produce high-pressure steam, which is used to drive a steam turbine also connected to the generator, thereby maximising electricity generation from the fuel being combusted.

A portion of the steam will be extracted from the GT and used in the CCP for separation of CO_2 from solvent (regenerator), solvent conditioning (reclaimer) and CO_2 conditioning during low pressure compression (oxygen removal unit).

The exhaust gases that have passed through the HRSG will then pass through pre-treatment stages, including selective catalytic reduction (SCR) to reduce oxides of nitrogen (NOx) in the gas and direct cooling of the gas using water, before passing through to the CCP. The CCP uses an amine -based solvent (Monoethanolamine (MEA) is currently proposed) to strip CO_2 from the exhaust gas within a packed column, via a weak acid-base reaction. The CO_2 depleted exhaust gas then passes through emissions abatement stages and is released to atmosphere via a stack. Whilst it is anticipated that the CCGT will operate in CO_2 abated mode at all times on the occasions where the CCP is not operational gases from the CCGT will be emitted to atmosphere via the HRSG exhaust stack.

The CO_2 is removed from the CO_2-rich solvent by heat, using steam taken from the HRSG. The solvent is recirculated within the plant, whilst the CO_2 gas passes to a low-pressure compressor where it is compressed to a liquid and impurities (moisture, oxygen) are removed before the CO_2 is exported off-site via pipeline. The solvent can accumulate impurities over time, and these are removed via a solvent reclaiming process which comprise of a thermal or ion-exchange process, either continuously via a slip-stream or as a batch process. The main CCP plant stack emissions will be residual pollutants from the combustion and treatment processes.

7.3 Consideration of emission control measures

We have reviewed the techniques used by the Operator and compared these with the relevant guidance notes. The CCGT will be fitted with dry low NOx burners and Selective Catalytic Reduction (SCR) to minimise emissions of NOx. The SCR equipment will be installed following the HRSG and will be in use in both CO_2 abated and un-abated mode. When in CO_2 abated mode the minimisation of NO_x content of the exhaust gas is important as NO_2 can preferentially react with the amine solvent within the CCP, causing degradation of the solvent, which can reduce levels of carbon capture.

SCR uses ammonia (NH_3) or urea injection, as a result ammonia slip from the SCR process is likely. It is anticipated that the NH_3 will be stripped from the exhaust gas by a direct cooling water stage and water scrubber stages. It is acknowledged that further NH_3 abatement maybe necessary so the Applicant has stated that an acid wash stage may be used if deemed necessary following final installation design.

We are satisfied that the proposed abatement for emissions to air is BAT for this Installation.

7.4 Large Combustion Plant Best Available techniques reference document conclusions

We have reviewed the Application against the revised BAT Conclusions (BATc) for the large combustion plant published Nov.2021. BAT conclusions 1 – 17 applicable to all sites and 40 – 45 applicable to plant combusting gaseous fuels (but excluding those relating to iron and steel and chemical industries) have been considered. The response to each is set out in section 11 of this decision document.

The BAT AELs for emissions of NOx and CO have been included in tables S3.1 and S3.1a of the permit.

7.5 Post- combustion carbon dioxide capture best available techniques.

We have reviewed the Application against the Post Combustion carbon dioxide capture: Best available techniques (BAT) guidance Post-combustion carbon dioxide capture: best available techniques (BAT) - GOV.UK (www.gov.uk) .

The response to each is set out in section 12 of this decision document.

7.6 Energy efficiency

7.6.1 Consideration of energy efficiency

We have considered the issue of energy efficiency in the following ways:

1. The use of energy within, and generated by, the Installation which are normal aspects of all EPR permit determinations. This issue is dealt with in this section.
2. The applicability of the combined heat and power ready (CHP-R) guidance to the Installation.
3. The extent to which the Installation meets the requirement of Article 14(5) of the Energy Efficiency Directive which requires new thermal electricity generation installations with a total thermal input exceeding 20 MW to carry out a cost-benefit assessment to "*assess the cost and benefits of providing for the operation of the installation as a high-efficiency cogeneration installation*".

   Cogeneration means the simultaneous generation in one process of thermal energy and electrical or mechanical energy and is also known as combined heat and power (CHP)

   High-efficiency co-generation is cogeneration which achieves at least 10% savings in primary energy usage compared to the separate generation of heat and power – see Annex II of the Energy Efficiency Directive for detail on how to calculate this.

4. The extent to which the Applicant has demonstrated energy efficiency in line with the BAT AEELs set out in the LCP BAT Conclusions.

7.6.2 Use of energy within the Installation

The primary considerations of energy efficiency for this site relates to the initial selection of combustion plant as set out in section 7.2 above.

7.6.3 Combined Heat and Power Ready

Our CHP Ready Guidance - February 2013 considers that BAT for energy efficiency for new combustion power plant is the use of CHP in circumstances where there are technically and economically viable opportunities for the supply of heat from the outset.

The term CHP in this context represents a plant which also provides a supply of heat from the electrical power generation process to either a district heating network or to an industrial / commercial building or process.

In cases where there are no immediate opportunities for the supply of heat from the outset, the Environment Agency considers that BAT is to build the plant to be CHP Ready (CHP-R) to a degree which is dictated by the likely future opportunities which are technically viable and which may, in time, also become economically viable.

The Applicant has proposed that the hot exhaust gases from the gas turbine will be passed through a heat recovery steam generator (HRSG) to produce high-pressure steam, which is used to drive a steam turbine. A proportion of the steam will be extracted from the steam turbine and used in the CCP for separation of CO_2 from solvent (regenerator), solvent conditioning (reclaimer) and CO_2 conditioning during low-pressure compression (oxygen removal unit). Also, waste heat may also be used to re-heat flue gas to aid dispersion. This means a significant proportion of the of the available waste-heat from the process will be unavailable for export off site as it is not envisaged that the CCGT would operate in isolation from the CCP. As a consequence the Applicant's CHP Ready Assessment considers the utilisation of waste heat from the CCP rather than direct low pressure steam offtake from the CCGT. With two potential areas of waste heat availability considered for off-site use during the integrated operation of the CCGT and CCP. These comprise:

- Extraction from the CO_2 stripper overhead stream;
- Extraction from the low pressure condensate leaving the CO_2 stripper re-boiler.

The location of the Installation largely determines the extent to which the waste heat can be utilised, and this is a matter for the planning authority. The Applicant carried out a feasibility study and provided a CHP-R assessment as part of their Application, the assessment provided a review of potential heat demands within a 15km radius of the proposed Installation. The review considered known and proposed future developments that may require heat and identified any major heat consumers. The assessment did identify a number of potential heat demand clusters, however none these were considered suitable (technically and/or economically). They have therefore not proposed CHP to be installed from the outset, however they have stated that the proposed Installation will be built CHP ready with sufficient space allocated for future retrofit of a heat offtake within its footprint should viable opportunities to supply heat be identified in the future. We are satisfied that this is BAT.

In order to ensure that the Operator reviews the viability of CHP in the future we have included the following condition in the permit;

1.2.2 The operator shall review the viability of Combined Heat and Power (CHP) implementation at least every 4 years, or in response to any of the following factors, whichever comes sooner:

(a) new plans for significant developments within 15 km of the installation;

(b) changes to the Local Plan;

(c) changes to the BEIS UK CHP Development Map or similar; and

(d) new financial or fiscal incentives for CHP.

The results shall be reported to the Agency within 2 months of each review, including where there has been no change to the original assessment in respect of the above factors.

7.6.4 Compliance with Article 14(5) of the Energy Efficiency Directive

In addition to the requirements of the CHP-R guidance, Article 14(5) of the Energy Efficiency Directive require operators of certain combustion installations to carry out a cost benefit analysis (CBA) where opportunities for ‘High Efficiency Co-generation’ are identified. ‘High Efficiency Co-generation’ is where the CHP scheme will achieve a minimum of 10% primary energy savings (PES). The Operator has calculated the PES as <10%. For this reason, a CBA is not required.

(i) Permit conditions concerning energy efficiency

The Operator is required to report energy usage and energy generated under condition 4.2 and table S4.2 in Schedule 4. This will enable us to monitor energy efficiency at the Installation and take action if at any stage the energy efficiency is less than proposed.

There are no site-specific considerations that require the imposition of standards beyond indicative BAT, and so the Environment Agency accepts that the Applicant’s proposals represent BAT for this Installation.

7.6.5 Compliance with energy BAT AEELs set out in BAT Conclusions

An energy efficiency level associated with the BAT-AEEL refers to the ratio between the combustion unit's net energy output(s) and the combustion unit's fuel/feedstock energy input at actual unit design. The net energy output(s) is determined at the combustion unit boundaries, including auxiliary systems (e.g. flue-gas treatment systems), and for the unit operated at full load.

The table below sets out the BAT-AEELs specified in the LCP BAT Conclusions for the LCP on the site and the energy efficiency levels proposed in the Application.

BAT AEELs (%)			Plant efficiency (%)		
Net electrical efficiency	**Net total fuel utilisation**	**Net mechanical efficiency**	**Net electrical efficiency**	**Net total fuel utilisation**	**Net mechanical efficiency**
CCGT Operating in CO_2 unabated mode					
57 – 60.5%	**None**	**None**	**>61%**	**NA**	**NA**

Based on the information in the Application the net electrical efficiency when the CCGT is operating in CO_2 un-abated mode will exceed the BAT AEEL. However, when operating in CO_2 abated mode, the net electrical efficiency of the plant will be reduced to approximately 53%. There is currently no BAT AEEL for combustion plant operating in carbon capture mode as carbon capture is still a relatively new technology on this scale.

7.7 Choice of Cooling System

The Applicant has proposed mechanical draught cooling towers as their chosen cooling method. The application contained a BAT assessment justifying the use the mechanical draft cooling over other methods including once through cooling, dry air cooling condensers (ACC) and hybrid (wet-dry) cooling. The BAT assessment included a costs and benefits assessment of the cooling options. The assessment compared a number of parameters including parasitic load, net thermal efficiency, noise, water demand, capital costs, operating costs. It concluded that once-through cooling using estuarine water is usually identified as indicative BAT for the type of installation proposed, however for specific geographical and technical conditions (including the CCP elements) for the proposed Installation in this case once through cooling is not considered BAT. We have reviewed the Applicant’s BAT assessment and we agree, based on the information contained in the Application, that for this proposed Installation the proposed mechanical draft cooling towers are BAT for cooling.

7.8 Choice of effluent treatment method

The Applicant has proposed to treat effluent from the direct contact cooler using reverse osmosis. The Applicant provided a BAT assessment and options appraisal which justified the choice of reverse osmosis. The Assessment included a review of the proposed operating techniques against the waste treatment BAT conclusions (2018), this assessment confirmed that the process will be operated in accordance with the relevant BAT conclusions and BAT AELs for treatment process. We are therefore satisfied that reverse osmosis is BAT for the treatment of this effluent stream.

8. Emission limits

8.1 CO_2 Unabated mode – emission limits to air

The Operator has proposed limits in line with part 2 annex V of the IED and BAT AELs set out within the BAT Conclusions for LCP, when operating in CO_2 unabated mode. As discussed in section 6 above, emissions at these limits will not cause significant pollution. Consequently we have accepted the proposed limits and incorporated them into table S3.1a of the Permit. Annex V of the IED is a backstop and these limits are included where there is no tighter limit specified within the BAT Conclusions.

The BAT Conclusions specify that the AELs will apply when dry low NOx (DLN) is effective. We have specified an improvement condition IC8 requiring the operator to define an output load or operational parameters and provide a written justification for when the dry low NO_x operation is effective. The report shall also include the NO_x profile through effective dry low NO_x to 70% and then to full load.

The Operator is also required to propose achievable emission limit values (ELV) for NO_x and CO expressed as a daily mean of validated hourly averages from Minimum start-up load (MSUL) to baseload through improvement condition IC9.

The annual AEL for CO from the BAT Conclusions is indicative. At this stage the Applicant did not have adequate information to demonstrate whether the selected plant can meet the CO AEL. We have included improvement condition IC9 specifying that the Operator is required to propose an achievable ELV for CO expressed as an annual mean of validated hourly averages within 6 months following commissioning. If the proposed ELV deviates from the indicative BAT AEL for CO of 40mg/m^3 then an associated BAT justification will need to be submitted to the Environment Agency as a written report.

Parameter	**Reference Period**	**Annex V mg/m^3**	**BAT AEL**	**Permit limit mg/m3**
NO_x	95%ile of hourly averages	100	-	100
	Monthly averages	50	-	50
	Daily average or average over the sampling period	-	44.4*	44.4
	Yearly average	-	33.3*	33.3
CO	95%ile of hourly averages	200	-	200
	Monthly averages	100	-	100
	Daily average or average over the sampling period	110	-	110
	Yearly average	-	33.3*	33
* In accordance with the BAT AEL as the plant has a energy efficiency greater than 55 %, a correction factor has been applied to the higher end of the BAT-AEL range, corresponding to [higher end] x EE / 55, where EE is the net electrical efficiency of the plant which is predicted to be 61%				

8.2 CO_2 abated mode – emission limits to air

We have set emission limits to air for when the plant is operating in CO_2 abated mode in table S3.1 of the Permit. The limits will apply to emissions of treated exhaust gases from the Absorber Stack on the CCP. It is noted that with reference to the limits set out within the BAT Conclusions for LCP, that the limits have been normalised to take into account the reduction in volume of the gas from the removal of CO_2 and therefore the limit is referenced to a standard 0.5% dry v/v CO_2 (comparable to referencing for O2 at 15% dry v/v for gas turbines. This means that it has been assumed that emissions from CCP absorber stack will be at the annual average BAT-AEL, corrected for CO_2 abatement.

Parameter	**Reference Period**	**Permit limit mg/m3**
NOx	Yearly average	34 mg/m^3
	Monthly averages	51.7 mg/m^3

	Daily average or average over the sampling period	45.8 mg/m^3
	95%ile of hourly averages	103.3 mg/m^3
CO	Yearly average	34.4 mg/m^3
	Monthly average	103.3 mg/m^3
	Daily average or average over the sampling period	113.7 mg/m^3
	95%ile of hourly averages	206.7 mg/m^3
Ammonia	Annual Average	3mg/m^{3*}
Total Amines (as MEA)	Average over the sampling period	1mg/m^{3*}
Total Amines (as NDMA)	Average over the sampling period	0.002 mg/m^{3*}
Acetaldehyde	Average over the sampling period	5.3 mg/m^{3*}
Formaldehyde	Average over the sampling period	0.5 mg/m^{3*}
* No BAT AELs apply to these parameters, therefore emission limits reflect the emission concentrations proposed by the Applicant and used in the AQ Risk assessment.		

8.3 Emission limits for discharge to water

We have set emission limits and monitoring for the discharge of treated direct contact cooler effluent from the reverse osmosis treatment plant (emission point W2). The limits and monitoring are set in accordance with the requirements and BAT AELs as required by BAT5 and BAT15 of the LCP BAT Conclusions, which are set for emissions to water from flue-gas treatment.

For emissions from point W1 we have not set emission limits. However, in order to ensure that emission are as predicted in the approved water quality risk assessment (submitted in response to pre-operational condition PO6) we have set improvement condition IC6 in the permit which requires the Operator to carry out monthly monitoring of the final effluent discharge to Tees Bay for a minimum of 12 consecutive months. The monitoring will reflect the list of pollutants modelled in the approved water quality risk assessment. The Operator will be required to submit a review of the Water Quality Modelling Assessment using the pollutant concentrations derived from the 12-month monitoring exercise, in order to verify the conclusions of the assessment.

9. Monitoring & Reporting

9.1 Emissions to air

For both CO_2 un-abated and abated mode sulphur dioxide emissions from natural gas firing of gas turbines and boilers will be reported as six-monthly concentrations on the basis of the fuel sulphur content without continuous or periodic monitoring since only trace quantities of sulphur are present in UK natural gas.

For gas turbines we have not required any reporting for dust as the dust emissions will always be reported as zero. This is because natural gas is an ash-free fuel and high efficiency combustion in the gas turbine does not generate additional particulate matter. The fuel gas is always filtered and, in the case of gas turbines, the inlet air is also filtered resulting in a lower dust concentration in the flue than in the surrounding air.

When operating CO_2 abated mode the Permit requires the Operator to monitor final emissions to air from the absorber stack for a range of pollutants based on MEA and the degradation products that may be formed following chemical reactions resulting from the CO_2 abatement of the flue gas within the CCP.

The Operator is also required to periodically monitor emissions from the emergency diesel generator in accordance with the requirements of the medium combustion plant directive and specified generator regulations.

9.2 Carbon Capture Plant Performance

We have included process monitoring requirements in the Permit covering the operation of the CCP. The monitoring concentrates on ensuring that solvent quality is monitored and maintained to ensure that CO_2 capture rates are optimised and degradation products (e.g. amines, nitrosamines and nitramines) are minimised. Iron and stable salt build up in the solvent can give an indication of plant corrosion and can lead to amine solvent degradation which may affect carbon capture performance, we have therefore required the Operator to routinely monitor for iron content, heat stable salts and colour changes in the amine solvent. There is evidence of yellowing of amine solvents as iron levels build up and as the solvent ages.

With regard to carbon capture efficiency, the purpose of a post combustion carbon capture plant is to maximise the capture of CO_2 emissions. Operators should aim to achieve a design CO_2 capture rate of at least 95%, although operationally this can vary, up or down. The Applicant has stated in their application that the installation has been designed to capture 95% of the CO_2 in the flue gas from the CCGT during steady state (normal) operation. In order to assess whether CO_2 capture is maximised, monitoring and reporting requirements have been included in the permit. Pre-operational condition PO2 includes a requirement for the Operator to provide a methodology for approval to demonstrate the carbon capture efficiency of the plant. This approved methodology will then be used to measure carbon capture efficiency as required in table S3.3 of the permit.

We have also included improvement condition IC10, requiring the Operator to provide a report on carbon capture efficiency under normal operations. As well as under normal operating conditions the Operator is also expected to maximise carbon capture during periods of start-up and shut-down. Pre-operational condition PO13 requires the Operator to include proposals in their PCC OTNOC management plan to monitor carbon capture performance during these periods.

9.3 Emissions to water

The Permit requires monitoring of emissions of aqueous discharges to Tees Bay, as shown in Table S3.2 of the Permit and discussed in section 8.3 above.

9.4 Standards

Standards for assessment of the monitoring location and for measurement of oxygen, water vapour, temperature and pressure have been added to the Permit.

A row has been included in tables S3.1 and S3.1a which requires the operator to confirm compliance with BS EN 15259 in respect of monitoring location and stack gas velocity profile in the event there is a significant operational change (such as a change of fuel type) to the LCP.

9.5 Resource efficiency metrics

A more comprehensive suite of reporting metrics has been added to the permit template for Electrical Supply Industry (ESI) plant. Table S4.2 “Resource Efficiency Metrics” have been added requiring the reporting of various resource parameters, as this is an ESI power plant. This table is being used for all ESI plant.

10 Meeting the requirements of the IED

The table below shows how each requirement of the IED has been addressed by the permit conditions.

IED Article Reference	IED requirement	Permit condition
30(6)	If there is an interruption in the supply of gas, an alternative fuel may be used and the permit emission limits deferred for a period of up to 10 days, except where there is an overriding need to maintain energy supplies. The EA shall be notified immediately.	N/A – plant runs on natural gas only
32(4)	For installations that have applied to derogate from the IED Annex V emission limits by means of the transitional national plan, the monitoring and reporting requirements set by UK Government shall be complied with.	N/A – applies to existing plant only
33(1)b	For installations that have applied to derogate from the IED Annex V emission limits by means of the Limited Life Derogation, the operator shall submit annually a record of the number of operating hours since 1 January 2016.	N/A – applies to existing plant only
37	Provisions for malfunction and breakdown of abatement equipment including notifying the EA.	2.3.7, 4.2.5 and 4.3.1(d)
38	Monitoring of air emissions in accordance with Ann V Pt 3	3.5, 3.6
40	Multi-fuel firing	N/A – no multi fuel firing
41(a)	Determination of start-up and shut-down periods	2.3.5 Schedule 1 Table S1.5
Ann V Pt 1(1)	All emission limit values shall be calculated at a temperature of 273,15 K, a pressure of 101,3 kPa and after correction for the water vapour content of the waste gases and at a standardised O2 content of 6 % for solid fuels, 3 % for combustion plants, other than gas turbines and gas engines using liquid and gaseous fuels and 15 % for gas turbines and gas engines.	Schedule 6, Interpretation
Ann V Pt 1	Emission limit values	3.1.2 Schedule 3, Tables S3.1/S3.1a
Ann V Pt 1	For plants operating less than 500 hours per year, record the used operating hours	N/A
Ann V Pt 1(6(1))	Definition of natural gas	Schedule 6, Interpretation
Ann V Pt 2	Emission limit values	3.1.2 Schedule 3, Tables S3.1/S3.1a
AnnV Pt 3(1)	Continuous monitoring for >100MWth for specified substances	3.5, 3.6 Schedule 3, Tables S3.1/S3.1a
AnnV Pt 3(2, 3, 5)	Monitoring derogations	N/A
AnnV Pt3(4)	Measurement of total mercury (NA for natural gas)	N/A

IED Article Reference	IED requirement	Permit condition
AnnV Pt3(6)	EA informed of significant changes in fuel type or in mode of operation so can check Pt3 (1-4) still apply	2.3.1 Schedule 1, Table S1.2
AnnV Pt3(7)	Monitoring requirements	3.5.1 Schedule 3, Tables S3.1/S3.1a
AnnV Part 3(8,9,10)	Monitoring methods	3.5, 3.6
AnnV Pt 4	Monthly, daily, 95%ile hourly emission limit value compliance	3.5.1 Schedule 3, Tables S3.1/S3.1a
AnnV Pt7	Refinery multi-fuel firing SO_2 derogation	N/A

11 Meeting the requirements of the LCP BAT Conclusions

This annex provides a record of decisions made in relation to each relevant BAT Conclusion considered potentially applicable to the installation. This table should be read in conjunction with the Permit.

The conditions in the permit through which the relevant BAT Conclusions are implemented include but are not limited to the following:

BAT Conclusion requirement topic	Permit condition(s)	Permit table(s)
Environmental Management System	1.1.1	S1.2
BAT AELs	3.1.2 and 3.5.1	S3.1, S3.1a
Monitoring	2.3, 3.5 and 3.6	S1.2, S1.6 (DLN effective,start-up and shut-down thresholds), S3.1/S3.1a.
Energy efficiency	1.2 and 2.3	S4.2
Noise	2.3 and 3.4	S1.2
Other operating techniques	1.1	S1.2

The overall status of compliance with the BAT conclusion is indicated in the table as:

NA Not Applicable

CC Currently Compliant

FC Compliant in the future where plant not built yet but will be in compliance once operational

NC Not Compliant

PC Partially Compliant

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
General			
1	**In order to improve the overall environmental performance, BAT is to implement and adhere to an environmental management system (EMS) that incorporates all of the following features:** i. commitment of the management, including senior management; ii. definition of an environmental policy that includes the continuous improvement of the installation by the management; iii. planning and establishing the necessary procedures, objectives and targets, in conjunction with financial planning and investment; iv. implementation of procedures (a) Structure and responsibility (b) Training (c) Communication (d) Employee involvement (e) Documentation (f) Efficient process control (g) Maintenance programmes (h) Emergency preparedness and response (i) Safeguarding compliance with environmental legislation v. checking performance and taking corrective action, paying particular attention to: (a) monitoring and measurement (see also the Reference Document on the General Principles of Monitoring) (b) corrective and preventive action (c) maintenance of records (d) independent (where practicable) internal and external auditing in order to determine whether or not the EMS conforms to planned arrangements and has been properly implemented and maintained; vi. review of the EMS and its continuing suitability, adequacy and effectiveness by senior management; vii. following the development of cleaner technologies; viii. consideration for the environmental impacts from the eventual decommissioning of the installation at the stage of designing a new plant, and throughout its operating life; viii. consideration for the environmental impacts from the eventual decommissioning of the installation at the stage of designing a new plant, and throughout its operating life; ix. application of sectoral benchmarking on a regular basis. Etc - see BAT Conclusions	FC	An EMS will be in place at the installation.

<table>
<tr><th>BAT Concn. Number</th><th>Summary of BAT Conclusion requirement</th><th>Status NA/ CC / FC / NC</th><th>Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement</th></tr>
<tr><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td></td><td>Applicability. The scope (e.g. level of detail) and nature of the EMS (e.g. standardised or non-standardised) will generally be related to the nature, scale and complexity of the installation, and the range of environmental impacts it may have.</td><td></td><td></td></tr>
<tr><td>2</td><td>BAT is to determine the net electrical efficiency and/or the net total fuel utilisation and/or the net mechanical energy efficiency of the gasification, IGCC and/or combustion units by carrying out a performance test at full load (1), according to EN standards, after the commissioning of the unit and after each modification that could significantly affect the net electrical efficiency and/or the net total fuel utilisation and/or the net mechanical energy efficiency of the unit. If EN standards are not available, BAT is to use ISO, national or other international standards that ensure the provision of data of an equivalent scientific quality.</td><td>FC</td><td>A process monitoring table specifies that the Operator shall determine the net electrical efficiency after commissioning.</td></tr>
<tr><td>3</td><td>BAT is to monitor key process parameters relevant for emissions to air and water including those given below.
<table>
<tr><th>Stream</th><th>Parameter(s)</th><th>Monitoring</th></tr>
<tr><td rowspan="3">Flue-gas</td><td>Flow</td><td>Periodic or continuous determination</td></tr>
<tr><td>Oxygen content, temperature, and pressure</td><td rowspan="2">Periodic or continuous measurement</td></tr>
<tr><td>Water vapour content ([3])</td></tr>
<tr><td>Waste water from flue-gas treatment</td><td>Flow, pH, and temperature</td><td>Continuous measurement</td></tr>
</table></td><td>FC</td><td>Monitoring parameters specified within the permit emissions table S3.1 and S3.1a.</td></tr>
<tr><td>4</td><td>BAT is to monitor emissions to air with at least the frequency given below and in accordance with EN standards. If EN standards are not available, BAT is to use ISO, national or other international standards that ensure the provision of data of an equivalent scientific quality.
<table>
<tr><th>Substance/Parameter</th><th>Fuel/Process/Type of combustion plant</th><th>Combustion plant total rated thermal input</th><th>Standard(s) ([4])</th><th>Minimum monitoring frequency ([5])</th><th>Monitoring associated with</th></tr>
<tr><td>NH_3</td><td>— When SCR and/or SNCR is used</td><td>All sizes</td><td>Generic EN standards</td><td>Continuous ([6]) ([7])</td><td>BAT 7</td></tr>
</table></td><td>FC</td><td>Continuous NOx and CO monitoring specified in Table S3.1 and S3.1a for the gas turbine. Also, continuous NH_3 (due to use of SCR) and annual SO_2 monitoring is required.</td></tr>
</table>

BAT Concn. Number	Summary of BAT Conclusion requirement						Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
	NO_X	— Coal and/or lignite including waste co-incineration — Solid biomass and/or peat including waste co-incineration — HFO- and/or gas-oil-fired boilers and engines — Gas-oil-fired gas turbines — Natural-gas-fired boilers, engines, and turbines — Iron and steel process gases — Process fuels from the chemical industry — IGCC plants	All sizes	Generic EN standards	Continuous (6) (8)	BAT 20 BAT 24 BAT 28 BAT 32 BAT 37 BAT 41 BAT 42 BAT 43 BAT 47 BAT 48 BAT 56 BAT 64 BAT 65 BAT 73		
		— Combustion plants on offshore platforms	All sizes	EN 14792	Once every year (9)	BAT 53		
	N_2O	— Coal and/or lignite in circulating fluidised bed boilers — Solid biomass and/or peat in circulating fluidised bed boilers	All sizes	EN 21258	Once every year (10)	BAT 20 BAT 24		
	CO	— Coal and/or lignite including waste co-incineration — Solid biomass and/or peat including waste co-incineration — HFO- and/or gas-oil-fired boilers and engines — Gas-oil-fired gas turbines — Natural-gas-fired boilers, engines, and turbines — Iron and steel process gases — Process fuels from the chemical industry	All sizes	Generic EN standards	Continuous (6) (8)	BAT 20 BAT 24 BAT 28 BAT 33 BAT 38 BAT 44 BAT 49 BAT 56 BAT 64 BAT 65 BAT 73		

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement

	— IGCC plants				
	— Combustion plants on offshore platforms	All sizes	EN 15058	Once every year (9)	BAT 54
SO_2	— Coal and/or lignite incl waste co-incineration — Solid biomass and/or peat incl waste co-incineration — HFO- and/or gas-oil-fired boilers — HFO- and/or gas-oil-fired engines — Gas-oil-fired gas turbines — Iron and steel process gases — Process fuels from the chemical industry in boilers — IGCC plants	All sizes	Generic EN standards and EN 14791	Continuous (6) (11) (12)	BAT 21 BAT 25 BAT 29 BAT 34 BAT 39 BAT 50 BAT 57 BAT 66 BAT 67 BAT 74
SO_3	— When SCR is used	All sizes	No EN standard available	Once every year	—
Gaseous chlorides, expressed as HCl	— Coal and/or lignite — Process fuels from the chemical industry in boilers	All sizes	EN 1911	Once every three months (6) (13) (14)	BAT 21 BAT 57
	— Solid biomass and/or peat	All sizes	Generic EN standards	Continuous (15) (16)	BAT 25
	— Waste co-incineration	All sizes	Generic EN standards	Continuous (6) (16)	BAT 66 BAT 67
HF	— Coal and/or lignite — Process fuels from the chemical industry in boilers	All sizes	No EN standard available	Once every three months (6) (13) (14)	BAT 21 BAT 57
	— Solid biomass and/or peat	All sizes	No EN standard available	Once every year	BAT 25
	— Waste co-incineration	All sizes	Generic EN standards	Continuous (6) (16)	BAT 66 BAT 67

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement

Dust	— Coal and/or lignite — Solid biomass and/or peat — HFO- and/or gas-oil-fired boilers — Iron and steel process gases — Process fuels from the chemical industry in boilers — IGCC plants — HFO- and/or gas-oil-fired engines — Gas-oil-fired gas turbines	All sizes	Generic EN standards and EN 13284-1 and EN 13284-2	Continuous (6) (17)	BAT 22 BAT 26 BAT 30 BAT 35 BAT 39 BAT 51 BAT 58 BAT 75
	— Waste co-incineration	All sizes	Generic EN standards and EN 13284-2	Continuous	BAT 68 BAT 69
Metals and metalloids except mercury (As, Cd, Co, Cr, Cu, Mn, Ni, Pb, Sb, Se, Tl, V, Zn)	— Coal and/or lignite — Solid biomass and/or peat — HFO- and/or gas-oil-fired boilers and engines	All sizes	EN 14385	Once every year (18)	BAT 22 BAT 26 BAT 30
	— Waste co-incineration	< 300 MW_{th}	EN 14385	Once every six months (13)	BAT 68 BAT 69
		≥ 300 MW_{th}	EN 14385	Once every three months (19) (13)	
	— IGCC plants	≥ 100 MW_{th}	EN 14385	Once every year (18)	BAT 75
Hg	— Coal and/or lignite including waste co-incineration	< 300 MW_{th}	EN 13211	Once every three months (13) (20)	BAT 23
		≥ 300 MW_{th}	Generic EN standards and EN 14884	Continuous (16) (21)	
	— Solid biomass and/or peat	All sizes	EN 13211	Once every year (22)	BAT 27
	— Waste co-incineration with solid biomass and/or peat	All sizes	EN 13211	Once every three months (13)	BAT 70
	— IGCC plants	≥ 100 MW_{th}	EN 13211	Once every year (23)	BAT 75
TVOC	— HFO- and/or gas-oil-fired engines	All sizes	EN 12619	Once every six months (13)	BAT 33 BAT 59

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement

	— Process fuels from chemical industry in boilers				
	— Waste co-incineration with coal, lignite, solid biomass and/or peat	All sizes	Generic EN standards	Continuous	BAT 71
Formaldehyde	— Natural-gas in spark-ignited lean-burn gas and dual fuel engines	All sizes	No EN standard available	Once every year	BAT 45
CH_4	— Natural-gas-fired engines	All sizes	EN ISO 25139	Once every year (24)	BAT 45
PCDD/F	— Process fuels from chemical industry in boilers — Waste co-incineration	All sizes	EN 1948-1, EN 1948-2, EN 1948-3	Once every six months (13) (25)	BAT 59 BAT 71

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
5	BAT is to monitor emissions to water from flue-gas treatment with at least the frequency given below and in accordance with EN standards. If EN standards are not available, BAT is to use ISO, national or other international standards that ensure the provision of data of an equivalent scientific quality.	NA	There is an emission of effluent from the direct contact cooler. The effluent is treated on site by reverse osmosis.

Substance/Parameter		Standard(s)	Minimum monitoring frequency	Monitoring associated with
Total organic carbon (TOC) (26)		EN 1484	Once every month	BAT 15
Chemical oxygen demand (COD) (26)		No EN standard available		
Total suspended solids (TSS)		EN 872		
Fluoride (F^-)		EN ISO 10304-1		
Sulphate (SO_4^{2-})		EN ISO 10304-1		
Sulphide, easily released (S^{2-})		No EN standard available		
Sulphite (SO_3^{2-})		EN ISO 10304-3		
Metals and metalloids	As	Various EN standards available (e.g. EN ISO 11885 or EN ISO 17294-2)		
	Cd			
	Cr			
	Cu			
	Ni			
	Pb			
	Zn			

<table>
<tr><th>BAT Concn. Number</th><th>Summary of BAT Conclusion requirement</th><th>Status NA/ CC / FC / NC</th><th>Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement</th></tr>
<tr><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td></td><td>
<table>
<tr><td></td><td>Hg</td><td>Various EN standards available (e.g. EN ISO 12846 or EN ISO 17852)</td><td rowspan="3"></td><td></td></tr>
<tr><td colspan="2">Chloride (Cl^-)</td><td>Various EN standards available (e.g. EN ISO 10304-1 or EN ISO 15682)</td><td>—</td></tr>
<tr><td colspan="2">Total nitrogen</td><td>EN 12260</td><td>—</td></tr>
</table>
</td><td></td><td></td></tr>
<tr><td>6</td><td>
In order to improve the general environmental performance of combustion plants and to reduce emissions to air of CO and unburnt substances, BAT is to ensure optimised combustion and to use an appropriate combination of the techniques given below.
<table>
<tr><th colspan="2">Technique</th><th>Description</th><th>Applicability</th></tr>
<tr><td>a.</td><td>Fuel blending and mixing</td><td>Ensure stable combustion conditions and/or reduce the emission of pollutants by mixing different qualities of the same fuel type</td><td rowspan="2">Generally applicable</td></tr>
<tr><td>b.</td><td>Maintenance of the combustion system</td><td>Regular planned maintenance according to suppliers' recommendations</td></tr>
<tr><td>c.</td><td>Advanced control system</td><td>See description in Section 8.1</td><td>The applicability to old combustion plants may be constrained by the need to retrofit the combustion system and/or control command system</td></tr>
<tr><td>d.</td><td>Good design of the combustion equipment</td><td>Good design of furnace, combustion chambers, burners and associated devices</td><td>Generally applicable to new combustion plants</td></tr>
<tr><td>e.</td><td>Fuel choice</td><td>Select or switch totally or partially to another fuel(s) with a better environmental profile (e.g. with low sulphur and/or mercury content) amongst the available fuels, including in start-up situations or when back-up fuels are used</td><td>Applicable within the constraints associated with the availability of suitable types of fuel with a better environmental profile as a whole, which may be impacted by the energy policy of the Member State, or by the integrated site's fuel balance in the case of combustion of industrial process fuels.</td></tr>
</table>
</td><td>FC</td><td>
(a) N/A Natural gas use only.
(b) Operator has stated that all plant equipment at the site will be regularly maintained, including the combustion system by qualified maintenance contractors.
(c) Operations will be monitored and operated by suitably trained site personnel and managed via an automated control system such as Distribution Control System (DCS) to continuously monitor the operation of the plant and equipment at the site. Any non conformance or deviation in normal operating parameters shall be identified by the DCS to allow operators to take action to avoid a breach of permitted emission levels.
(d) Operation of the CCTG units will be controlled by trained site operators using an automated control system, which will incorporate controlling the operation of the plant and also recording data on the plant performance.
</td></tr>
</table>

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
	For existing combustion plants, the type of fuel chosen may be limited by the configuration and the design of the plant		(e) Only natural gas will be used including for start-up.
7	In order to reduce emissions of ammonia to air from the use of selective catalytic reduction (SCR) and/or selective non-catalytic reduction (SNCR) for the abatement of NO_X emissions, BAT is to optimise the design and/or operation of SCR and/or SNCR (e.g. optimised reagent to NO_X ratio, homogeneous reagent distribution and optimum size of the reagent drops). **BAT-associated emission levels** The BAT-associated emission level (BAT-AEL) for emissions of NH_3 to air from the use of SCR and/or SNCR is < 3–10 mg/Nm^3 as a yearly average or average over the sampling period. The lower end of the range can be achieved when using SCR and the upper end of the range can be achieved when using SNCR without wet abatement techniques. In the case of plants combusting biomass and operating at variable loads as well as in the case of engines combusting HFO and/or gas oil, the higher end of the BAT-AEL range is 15 mg/Nm^3.	FC	The Installation is expected to comply with the NOx ELV without the use of additional abatement. However, the Installation will include the operation of a SCR plant for NOx control, either to ensure compliance with the NOx ELV or for the purpose of optimum carbon capture solvent performance, using ammonia as a reagent. The SCR plant will be appropriately designed to maintain optimum ammonia injection rate. An ELV of 1 mg/Nm^3 of NH3 has been included in the permit.
8	In order to prevent or reduce emissions to air during normal operating conditions, BAT is to ensure, by appropriate design, operation and maintenance, that the emission abatement systems are used at optimal capacity and availability.	FC	The emissions abatement systems will be designed, operated and maintained to ensure use at optimal capacity and availability, as described for BAT6 and BAT 4 above.
9	In order to improve the general environmental performance of combustion and/or gasification plants and to reduce emissions to air, BAT is to include the following elements in the quality assurance/quality control programmes for all the fuels used, as part of the environmental management system (see BAT 1): (i) Initial full characterisation of the fuel used including at least the parameters listed below and in accordance with EN standards. ISO, national or other international standards may be used provided they ensure the provision of data of an equivalent scientific quality; (ii) Regular testing of the fuel quality to check that it is consistent with the initial characterisation and according to the plant design specifications. The frequency of testing and the parameters chosen from the table below are based on the variability of the fuel and an assessment of the relevance of pollutant releases (e.g. concentration in fuel, flue-gas treatment employed); (iii) Subsequent adjustment of the plant settings as and when needed and practicable (e.g. integration of the fuel characterisation and control in the advanced control system (see description in Section 8.1)).	FC	As natural gas supplied by the National Grid is required to meet a standard we consider acceptable environmentally we have decided that plants fuelled on natural gas from the grid will not require characterisation or testing.

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
	Description Initial characterisation and regular testing of the fuel can be performed by the operator and/or the fuel supplier. If performed by the supplier, the full results are provided to the operator in the form of a product (fuel) supplier specification and/or guarantee.		

Fuel(s)	Substances/Parameters subject to characterisation
Biomass/peat	— LHV — moisture
	— Ash — C, Cl, F, N, S, K, Na — Metals and metalloids (As, Cd, Cr, Cu, Hg, Pb, Zn)
Coal/lignite	— LHV — Moisture — Volatiles, ash, fixed carbon, C, H, N, O, S
	— Br, Cl, F
	— Metals and metalloids (As, Cd, Co, Cr, Cu, Hg, Mn, Ni, Pb, Sb, Tl, V, Zn)
HFO	— Ash — C, S, N, Ni, V
Gas oil	— Ash — N, C, S
Natural gas	— LHV — CH_4, C_2H_6, C_3, C_4+, CO_2, N_2, Wobbe index
Process fuels from the chemical industry [27]	— Br, C, Cl, F, H, N, O, S — Metals and metalloids (As, Cd, Co, Cr, Cu, Hg, Mn, Ni, Pb, Sb, Tl, V, Zn)
Iron and steel process gases	— LHV, CH_4 (for COG), C_XH_Y (for COG), CO_2, H_2, N_2, total sulphur, dust, Wobbe index
Waste [28]	— LHV — Moisture — Volatiles, ash, Br, C, Cl, F, H, N, O, S

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
	— Metals and metalloids (As, Cd, Co, Cr, Cu, Hg, Mn, Ni, Pb, Sb, Tl, V, Zn)		
10	In order to reduce emissions to air and/or to water during other than normal operating conditions (OTNOC), BAT is to set up and implement a management plan as part of the environmental management system (see BAT 1), commensurate with the relevance of potential pollutant releases, that includes the following elements: — appropriate design of the systems considered relevant in causing OTNOC that may have an impact on emissions to air, water and/or soil (e.g. low-load design concepts for reducing the minimum start-up and shutdown loads for stable generation in gas turbines), — set-up and implementation of a specific preventive maintenance plan for these relevant systems, — review and recording of emissions caused by OTNOC and associated circumstances and implementation of corrective actions if necessary, — periodic assessment of the overall emissions during OTNOC (e.g. frequency of events, duration, emissions quantification/estimation) and implementation of corrective actions if necessary.	FC	The Operator's proposals are that the plant and associated control systems will be designed to minimise the potential for OTNOC events to occur. The installation will be operated using an automated control system to continuously monitor the operation of the plant and equipment at the site. Any non-conformances or deviation in normal operating parameters is expected to be identified by the automated control system to allow operators to take action to avoid OTNOC events. Site Operators shall be trained to monitor plant operation and take appropriate actions(s) in the event of a potential OTNOC event being identified. Start-up and shut-down procedures will be put in place with the aim to minimise the time during which the plant is operating at non-optimal conditions and operators shall be trained in the appropriate actions required should the potential for an OTNOC event be identified. All plant and equipment at the site will be regularly maintained including those systems provided to minimise the potential OTNOC conditions to occur. The Installation will also have an accident management plan and emergency response procedures for the management of spills, fire

<table>
<tr><th>BAT Concn. Number</th><th>Summary of BAT Conclusion requirement</th><th>Status NA/ CC / FC / NC</th><th>Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement</th></tr>
<tr><td></td><td></td><td></td><td>water, and the blocking of any discharge outlet to the river.</td></tr>
<tr><td>11</td><td>BAT is to appropriately monitor emissions to air and/or to water during OTNOC.
Description
The monitoring can be carried out by direct measurement of emissions or by monitoring of surrogate parameters if this proves to be of equal or better scientific quality than the direct measurement of emissions. Emissions during start-up and shutdown (SU/SD) may be assessed based on a detailed emission measurement carried out for a typical SU/SD procedure at least once every year, and using the results of this measurement to estimate the emissions for each and every SU/SD throughout the year.</td><td>FC</td><td>The Operator’s proposals are that the flue gases from the site will be monitored using MCERTS certified CEMs in accordance with BS EN 14181. This system will capture emissions during OTNOC situations and can be used to inform subsequent incident investigation.</td></tr>
<tr><td>12</td><td>In order to increase the energy efficiency of combustion, gasification and/or IGCC units operated ≥ 1 500 h/yr, BAT is to use an appropriate combination of the techniques given below.
<table>
<tr><th colspan="2">Technique</th><th>Description</th><th>Applicability</th></tr>
<tr><td>a.</td><td>Combustion optimisation</td><td>See description in Section 8.2.
Optimising the combustion minimises the content of unburnt substances in the flue-gases and in solid combustion residues</td><td rowspan="4">Generally applicable</td></tr>
<tr><td>b.</td><td>Optimisation of the working medium conditions</td><td>Operate at the highest possible pressure and temperature of the working medium gas or steam, within the constraints associated with, for example, the control of NO_X emissions or the characteristics of energy demanded</td></tr>
<tr><td>c.</td><td>Optimisation of the steam cycle</td><td>Operate with lower turbine exhaust pressure by utilisation of the lowest possible temperature of the condenser cooling water, within the design conditions</td></tr>
<tr><td>d.</td><td>Minimisation of energy consumption</td><td>Minimising the internal energy consumption (e.g. greater efficiency of the feed-water pump)</td></tr>
<tr><td>e.</td><td>Preheating of combustion air</td><td>Reuse of part of the heat recovered from the combustion flue-gas to preheat the air used in combustion</td><td>Generally applicable within the constraints related to the need to control NO_X emissions</td></tr>
</table></td><td>FC</td><td>a. The specific control settings for the combustion units shall be pre-set in the control system to achieve efficient combustion and optimise plants efficiency.
b. Performance tests of the Power Station shall be undertaken periodically in accordance with applicable BS EN standards.
c. The efficiency of the plant will be driven by the design of the CCGT including HRSG. The plant will be designed to exploit optimum steam pressure and temperature settings to maximise the overall efficiency.
d. All plant and equipment will be designed or specified and maintained to ensure optimal operation.</td></tr>
</table>

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
	f. / Fuel preheating / Preheating of fuel using recovered heat / Generally applicable within the constraints associated with the boiler design and the need to control NO_X emissions g. / Advanced control system / See description in Section 8.2. Computerised control of the main combustion parameters enables the combustion efficiency to be improved / Generally applicable to new units. The applicability to old units may be constrained by the need to retrofit the combustion system and/or control command system h. / Feed-water preheating using recovered heat / Preheat water coming out of the steam condenser with recovered heat, before reusing it in the boiler / Only applicable to steam circuits and not to hot boilers. Applicability to existing units may be limited due to constraints associated with the plant configuration and the amount of recoverable heat i. / Heat recovery by cogeneration (CHP) / Recovery of heat (mainly from the steam system) for producing hot water/steam to be used in industrial processes/activities or in a public network for district heating. Additional heat recovery is possible from: — flue-gas — grate cooling — circulating fluidised bed / Applicable within the constraints associated with the local heat and power demand. The applicability may be limited in the case of gas compressors with an unpredictable operational heat profile j. / CHP readiness / See description in Section 8.2. / Only applicable to new units where there is a realistic potential for the future use of heat in the vicinity of the unit k. / Flue-gas condenser / See description in Section 8.2. / Generally applicable to CHP units provided there is enough demand for low-temperature heat l. / Heat accumulation / Heat accumulation storage in CHP mode / Only applicable to CHP plants. The applicability may be limited in the case of low heat load demand		e. Combustion air will be pre-treated via a pre-heater package utilising recovered heat, to optimise combustion. f. The natural gas used as a fuel will be pre-heated via a pre-heater package utilising recovered heat within the steam system, to optimise combustion. g. Operation of the CCGT unit will be controlled by trained site operators using an automated control system, which will be used to control the operation of the plant and also records data on the plant performance, and which can be used by the operations team to identify potential issues. The specific control settings for the combustion units shall be pre-set in the control system to achieve efficient combustion and optimise plant efficiency. h. Once steam energy has been used, the remaining energy will be recovered by condenser and transferred to the feed-water system. i. The plant has the potential to supply heat to other users; and an appraisal of CHP opportunities will be undertaken. However, the steam demand for the CCP would take precedence over off-site users. j. The plant has the potential to supply heat to other users and will be designed to be CHP ready. k. The plant does not operate as a CHP; hence no flue gas condenser is installed on site.

BAT Concn. Number	Summary of BAT Conclusion requirement				Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
	m.	Wet stack	See description in Section 8.2.	Generally applicable to new and existing units fitted with wet FGD		l. This is applicable when CHP is installed. The technique is therefore not applied. m. N/A n. N/A o. N/A p. N/A q. The site will be a new low carbon power station, and will be designed using suitable materials available at the time of construction to optimise operations. r. A three-pressure steam cycle (HP, MP and LP) with appropriate turbine configuration and HRSG will be implemented as part of the overall plant design. s. the steam circuit at the CCGT plant will incorporate steam interstage re-heating systems and include evaporator/economiser and superheated steam; the final design will be established during the Front End Engineering Design (FEED) stage.
	n.	Cooling tower discharge	The release of emissions to air through a cooling tower and not via a dedicated stack	Only applicable to units fitted with wet FGD where reheating of the flue-gas is necessary before release, and where the unit cooling system is a cooling tower		
	o.	Fuel pre-drying	The reduction of fuel moisture content before combustion to improve combustion conditions	Applicable to the combustion of biomass and/or peat within the constraints associated with spontaneous combustion risks (e.g. the moisture content of peat is kept above 40 % throughout the delivery chain). The retrofit of existing plants may be restricted by the extra calorific value that can be obtained from the drying operation and by the limited retrofit possibilities offered by some boiler designs or plant configurations		
	p.	Minimisation of heat losses	Minimising residual heat losses, e.g. those that occur via the slag or those that can be reduced by insulating radiating sources	Only applicable to solid-fuel-fired combustion units and to gasification/IGCC units		
	q.	Advanced materials	Use of advanced materials proven to be capable of withstanding high operating temperatures and pressures and thus to achieve increased steam/combustion process efficiencies	Only applicable to new plants		
	r.	Steam turbine upgrades	This includes techniques such as increasing the temperature and pressure of medium-pressure steam, addition of a low-pressure turbine, and modifications to the geometry of the turbine rotor blades	The applicability may be restricted by demand, steam conditions and/or limited plant lifetime		
	s.	Supercritical and ultra-supercritical steam conditions	Use of a steam circuit, including steam reheating systems, in which steam can reach pressures above 220,6 bar and temperatures above 374 °C in the case of supercritical conditions, and above 250 – 300 bar and temperatures above	Only applicable to new units of ≥ 600 MW_{th} operated > 4 000 h/yr. Not applicable when the purpose of the unit is to produce low steam temperatures and/or pressures in process industries.		

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
	<table><tr><td></td><td></td><td>580 – 600 °C in the case of ultra-supercritical conditions</td><td>Not applicable to gas turbines and engines generating steam in CHP mode. For units combusting biomass, the applicability may be constrained by high-temperature corrosion in the case of certain biomasses</td></tr></table>		
13	In order to reduce water usage and the volume of contaminated waste water discharged, BAT is to use one or both of the techniques given below. <table><tr><th colspan="2">Technique</th><th>Description</th><th>Applicability</th></tr><tr><td>a.</td><td>Water recycling</td><td>Residual aqueous streams, including run-off water, from the plant are reused for other purposes. The degree of recycling is limited by the quality requirements of the recipient water stream and the water balance of the plant</td><td>Not applicable to waste water from cooling systems when water treatment chemicals and/or high concentrations of salts from seawater are present</td></tr><tr><td>b.</td><td>Dry bottom ash handling</td><td>Dry, hot bottom ash falls from the furnace onto a mechanical conveyor system and is cooled down by ambient air. No water is used in the process.</td><td>Only applicable to plants combusting solid fuels. There may be technical restrictions that prevent retrofitting to existing combustion plants</td></tr></table>		a. The installation will be serviced by an open loop wet cooling system with mechanical draught cooling towers, where the majority of the cooling water will be recycled, with only a small amount of water (<2% of the cooling demand) required for cooling water make-up. There will be a continuous aqueous stream from the LCP will be cooling water blow-down. Quantities of cooling water blow-down will be limited, due to recirculating cooling water, and it would not be possible to reuse in the LCP due to the build-up of contaminants over time in the recirculated water. This will therefore be discharged directly to Tees Bay via the new proposed outfall at Emission Point W1. Both designs include provision for the re-use of un-contaminated surface run-off, which will be considered further during FEED optimisation and detailed design. Volumes of surface water run-off are however extremely low in comparison to overall water usage and

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
			opportunities for optimisation are limited, due to the water quality requirements for on-site processes. Treated effluent from the direct contact cooler will be treated via reverse osmosis and will be re-used where possible within the installation. b. The Installation will not produce any ash from the combustion process; therefore, the techniques for dry bottom ash handling are not applicable to the Installation.
14	In order to prevent the contamination of uncontaminated waste water and to reduce emissions to water, BAT is to segregate waste water streams and to treat them separately, depending on the pollutant content. ***Description*** Waste water streams that are typically segregated and treated include surface run-off water, cooling water, and waste water from flue-gas treatment. ***Applicability*** The applicability may be restricted in the case of existing plants due to the configuration of the drainage systems.	FC	Waste water streams generated at the installation will comprise of surface water run-off, DCC efflunet, boiler blowdown, cooling water blowdown, demin backwash and a small amount of cooling water purge blowdown; all waste water streams will be appropriately segregated, treated and disposed of.
15	In order to reduce emissions to water from flue-gas treatment, BAT is to use an appropriate combination of the techniques given below, and to use secondary techniques as close as possible to the source in order to avoid dilution. **Technique** / **Typical pollutants prevented/abated** / **Applicability** **Primary techniques** a. Optimised combustion (see BAT 6) and flue-gas treatment systems (e.g. SCR/SNCR, see BAT 7) / Organic compounds, ammonia (NH_3) / Generally applicable **Secondary techniques** [29] b. Adsorption on activated carbon / Organic compounds, mercury (Hg) / Generally applicable	FC	Flue gas treatment includes SCR. The SCR plant will be appropriately designed to maintain optimum ammonia injection rate. The proposals also include a direct contact cooler (DCC), to cool the exhaust gases before they enter the CCP. As discussed earlier in this document effluent from DCC will be treated by reverse osmosis before being either reused on site or discharged to

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
	(see tables below)		Tees Bay. The Applicant has confirmed that the pollutant concentrations in the treated discharge will be below the upper range of the BAT AELs and these have been set as emission limits in the permit (table S3.2)

c.	Aerobic biological treatment	Biodegradable organic compounds, ammonium (NH_4^+)	Generally applicable for the treatment of organic compounds. Aerobic biological treatment of ammonium (NH_4^+) may not be applicable in the case of high chloride concentrations (i.e. around 10 g/l)
d.	Anoxic/anaerobic biological treatment	Mercury (Hg), nitrate (NO_3^-), nitrite (NO_2^-)	Generally applicable
e.	Coagulation and flocculation	Suspended solids	Generally applicable
f.	Crystallisation	Metals and metalloids, sulphate (SO_4^{2-}), fluoride (F^-)	Generally applicable
g.	Filtration (e.g. sand filtration, microfiltration, ultrafiltration)	Suspended solids, metals	Generally applicable
h.	Flotation	Suspended solids, free oil	Generally applicable
i.	Ion exchange	Metals	Generally applicable
j.	Neutralisation	Acids, alkalis	Generally applicable
k.	Oxidation	Sulphide (S^{2-}), sulphite (SO_3^{2-})	Generally applicable
l.	Precipitation	Metals and metalloids, sulphate (SO_4^{2-}), fluoride (F^-)	Generally applicable
m.	Sedimentation	Suspended solids	Generally applicable
n.	Stripping	Ammonia (NH_3)	Generally applicable

The BAT-AELs refer to direct discharges to a receiving water body at the point where the emission leaves the installation.

BAT-AELs for direct discharges to a receiving water body from flue-gas treatment

Substance/Parameter		**BAT-AELs**
		Daily average
Total organic carbon (TOC)		20–50 mg/l (30) (31) (32)
Chemical oxygen demand (COD)		60–150 mg/l (30) (31) (32)
Total suspended solids (TSS)		10–30 mg/l
Fluoride (F^-)		10–25 mg/l (32)
Sulphate (SO_4^{2-})		1,3–2,0 g/l (32) (33) (34) (35)
Sulphide (S^{2-}), easily released		0,1–0,2 mg/l (32)
Sulphite (SO_3^{2-})		1–20 mg/l (32)
Metals and metalloids	As	10–50 µg/l
	Cd	2–5 µg/l

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
	<table><tr><td rowspan="6"></td><td>Cr</td><td>10–50 µg/l</td></tr><tr><td>Cu</td><td>10–50 µg/l</td></tr><tr><td>Hg</td><td>0,2–3 µg/l</td></tr><tr><td>Ni</td><td>10–50 µg/l</td></tr><tr><td>Pb</td><td>10–20 µg/l</td></tr><tr><td>Zn</td><td>50–200 µg/l</td></tr></table>		
16	In order to reduce the quantity of waste sent for disposal from the combustion and/or gasification process and abatement techniques, BAT is to organise operations so as to maximise, in order of priority and taking into account life-cycle thinking: (a) waste prevention, e.g. maximise the proportion of residues which arise as by-products; (b) waste preparation for reuse, e.g. according to the specific requested quality criteria; (c) waste recycling; (d) other waste recovery (e.g. energy recovery), by implementing an appropriate combination of techniques such as: <table><tr><th colspan="2">Technique</th><th>Description</th><th>Applicability</th></tr><tr><td>a.</td><td>Generation of gypsum as a by-product</td><td>Quality optimisation of the calcium-based reaction residues generated by the wet FGD so that they can be used as a substitute for mined gypsum (e.g. as raw material in the plasterboard industry). The quality of limestone used in the wet FGD influences the purity of the gypsum produced</td><td>Generally applicable within the constraints associated with the required gypsum quality, the health requirements associated to each specific use, and by the market conditions</td></tr></table>	FC	The installation will develop a Waste Management Procedure (WMP) prior commencement of site operations, detailing waste storage and handling procedures on site. The Installation will apply the waste hierarchy for the management of any waste produce on site. The site will only produce minor quantities of waste which will be sent off site via licensed contractors. a. No generation of gypsum on site. b. No generation of residues. c. No acceptance of waste. d. Opportunities for re-use of catalysts from the SCR unit will be investigated and wherever possible utilised, however at this stage of the project this cannot be confirmed. Any opportunity

<table>
<tr><th>BAT Concn. Number</th><th>Summary of BAT Conclusion requirement</th><th>Status NA/ CC / FC / NC</th><th>Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement</th></tr>
<tr><td></td><td>
<table>
<tr><td>b.</td><td>Recycling or recovery of residues in the construction sector</td><td>Recycling or recovery of residues (e.g. from semi-dry desulphurisation processes, fly ash, bottom ash) as a construction material (e.g. in road building, to replace sand in concrete production, or in the cement industry)</td><td>Generally applicable within the constraints associated with the required material quality (e.g. physical properties, content of harmful substances) associated to each specific use, and by the market conditions</td></tr>
<tr><td>c.</td><td>Energy recovery by using waste in the fuel mix</td><td>The residual energy content of carbon-rich ash and sludges generated by the combustion of coal, lignite, heavy fuel oil, peat or biomass can be recovered for example by mixing with the fuel</td><td>Generally applicable where plants can accept waste in the fuel mix and are technically able to feed the fuels into the combustion chamber</td></tr>
<tr><td>d.</td><td>Preparation of spent catalyst for reuse</td><td>Preparation of catalyst for reuse (e.g. up to four times for SCR catalysts) restores some or all of the original performance, extending the service life of the catalyst to several decades. Preparation of spent catalyst for reuse is integrated in a catalyst management scheme</td><td>The applicability may be limited by the mechanical condition of the catalyst and the required performance with respect to controlling NO_X and NH_3 emissions</td></tr>
</table>
</td><td></td><td>for re-use would include the consideration of suitable waste preparation for re-use, where specific quality criteria are requested, in line with this BAT Conclusion.</td></tr>
<tr><td>17</td><td>In order to reduce noise emissions, BAT is to use one or a combination of the techniques given below.
<table>
<tr><th colspan="2">Technique</th><th>Description</th><th>Applicability</th></tr>
<tr><td>a.</td><td>Operational measures</td><td>These include:
— improved inspection and maintenance of equipment
— closing of doors and windows of enclosed areas, if possible</td><td>Generally applicable</td></tr>
</table>
</td><td>FC</td><td>The site will have a maintenance schedule in place to ensure optimum operation of all plant and equipment. The gas turbine will be situated within an enclosure, and all outdoor equipment will have noise attenuation enclosures, where required. Any maintenance work will be undertaken during daylight hours.
All equipment being installed is new and designed to generate low levels of noise, below applicable lowest observed adverse effect level (LOAELs), and all process areas are enclosed</td></tr>
</table>

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
			and not expected to lead to significant noise emissions.

		— equipment operated by experienced staff — avoidance of noisy activities at night, if possible — provisions for noise control during maintenance activities	
b.	Low-noise equipment	This potentially includes compressors, pumps and disks	Generally applicable when the equipment is new or replaced
c.	Noise attenuation	Noise propagation can be reduced by inserting obstacles between the emitter and the receiver. Appropriate obstacles include protection walls, embankments and buildings	Generally applicable to new plants. In the case of existing plants, the insertion of obstacles may be restricted by lack of space
d.	Noise-control equipment	This includes: — noise-reducers — equipment insulation — enclosure of noisy equipment — soundproofing of buildings	The applicability may be restricted by lack of space
e.	Appropriate location of equipment and buildings	Noise levels can be reduced by increasing the distance between the emitter and the receiver and by using buildings as noise screens	Generally applicable to new plant

Combustion of gaseous fuels

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
40	In order to increase the energy efficiency of natural gas combustion, BAT is to use an appropriate combination of the techniques given in BAT 12 and below.	FC	The electrical efficiency of the CCGT plant at ISO conditions will be 53 – 54% after carbon capture, or greater than 61% for the CCGT

	Technique	Description	Applicability
a.	Combined cycle	See description in Section 8.2	Generally applicable to new gas turbines and engines except when operated < 1 500 h/yr.

<table>
<tr><th>BAT Concn. Number</th><th>Summary of BAT Conclusion requirement</th><th>Status NA/ CC / FC / NC</th><th>Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement</th></tr>
<tr><td></td><td>
<table>
<tr><td></td><td></td><td></td><td>Applicable to existing gas turbines and engines within the constraints associated with the steam cycle design and the space availability.
Not applicable to existing gas turbines and engines operated < 1500 h/yr.
Not applicable to mechanical drive gas turbines operated in discontinuous mode with extended load variations and frequent start-ups and shutdowns.
Not applicable to boilers</td></tr>
</table>

BAT-associated energy efficiency levels (BAT-AEELs) for the combustion of natural gas

<table>
<tr><th rowspan="3">Type of combustion unit</th><th colspan="6">BAT-AEELs (136) (137)</th></tr>
<tr><th colspan="2">Net electrical efficiency (%)</th><th rowspan="2">Net total fuel utilisation (%) (138) (139)</th><th colspan="2">Net mechanical energy efficiency (%) (139) (140)</th></tr>
<tr><th>New unit</th><th>Existing unit</th><th>New unit</th><th>Existing unit</th></tr>
<tr><td>Gas engine</td><td>39,5–44 (141)</td><td>35–44 (141)</td><td>56–85 (141)</td><td colspan="2">No BAT-AEEL.</td></tr>
<tr><td>Gas-fired boiler</td><td>39–42,5</td><td>38–40</td><td>78–95</td><td colspan="2">No BAT-AEEL.</td></tr>
<tr><td>Open cycle gas turbine, ≥ 50 MWth</td><td>36–41,5</td><td>33–41,5</td><td>No BAT-AEEL</td><td>36,5–41</td><td>33,5–41</td></tr>
<tr><td colspan="6">Combined cycle gas turbine (CCGT)</td></tr>
<tr><td>CCGT, 50–600 MW_{th}</td><td>53–58,5</td><td>46–54</td><td>No BAT-AEEL</td><td colspan="2">No BAT-AEEL</td></tr>
<tr><td>CCGT, ≥ 600 MW_{th}</td><td>57–60,5</td><td>50–60</td><td>No BAT-AEEL</td><td colspan="2">No BAT-AEEL</td></tr>
<tr><td>CHP CCGT, 50–600 MW_{th}</td><td>53–58,5</td><td>46–54</td><td>65–95</td><td colspan="2">No BAT-AEEL</td></tr>
<tr><td>CHP CCGT, ≥ 600 MW_{th}</td><td>57–60,5</td><td>50–60</td><td>65–95</td><td colspan="2">No BAT-AEEL</td></tr>
</table>
</td><td></td><td>operating independently. See section 7.6.5 above.</td></tr>
<tr><td>41</td><td>In order to prevent or reduce NO_X emissions to air from the combustion of natural gas in boilers, BAT is to use one or a combination of the techniques given below.

<table>
<tr><th colspan="2">Technique</th><th>Description</th><th>Applicability</th></tr>
<tr><td>a.</td><td>Air and/or fuel staging</td><td>See descriptions in Section 8.3.
Air staging is often associated with low-NO_X burners</td><td rowspan="2">Generally applicable</td></tr>
<tr><td>b.</td><td>Flue-gas recirculation</td><td>See description in Section 8.3</td></tr>
</table>
</td><td>NA</td><td>Not applicable</td></tr>
</table>

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
	(continued table below)		

c.	Low-NO_X burners (LNB)		
d.	Advanced control system	See description in Section 8.3. This technique is often used in combination with other techniques or may be used alone for combustion plants operated < 500 h/yr	The applicability to old combustion plants may be constrained by the need to retrofit the combustion system and/or control command system
e.	Reduction of the combustion air temperature	See description in Section 8.3	Generally applicable within the constraints associated with the process needs
f.	Selective non–catalytic reduction (SNCR)		Not applicable to combustion plants operated < 500 h/yr with highly variable boiler loads. The applicability may be limited in the case of combustion plants operated between 500 h/yr and 1 500 h/yr with highly variable boiler loads
g.	Selective catalytic reduction (SCR)		Not applicable to combustion plants operated < 500 h/yr. Not generally applicable to combustion plants of < 100 MW_{th}. There may be technical and economic restrictions for retrofitting existing combustion plants operated between 500 h/yr and 1 500 h/yr

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement
42	In order to prevent or reduce NO_X emissions to air from the combustion of natural gas in gas turbines, BAT is to use one or a combination of the techniques given below.	FC	a. Operation of the CCGT units will be controlled by trained operators using an automated control system, which will be used to control the operation of the plant and also record data on the plant performance, which be used by the operations team to identify potential issues.

Technique		Description	Applicability
a.	Advanced control system	See description in Section 8.3. This technique is often used in combination with other techniques or may be used alone for combustion plants operated < 500 h/yr	The applicability to old combustion plants may be constrained by the need to retrofit the combustion system and/or control command system

<table>
<tr><th>BAT Concn. Number</th><th>Summary of BAT Conclusion requirement</th><th>Status NA/ CC / FC / NC</th><th>Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement</th></tr>
<tr><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td></td><td>
<table>
<tr><td>b.</td><td>Water/steam addition</td><td rowspan="2">See description in Section 8.3</td><td>The applicability may be limited due to water availability</td></tr>
<tr><td>c.</td><td>Dry low-NO_X burners (DLN)</td><td>The applicability may be limited in the case of turbines where a retrofit package is not available or when water/steam addition systems are installed</td></tr>
<tr><td>d.</td><td>Low-load design concept</td><td>Adaptation of the process control and related equipment to maintain good combustion efficiency when the demand in energy varies, e.g. by improving the inlet airflow control capability or by splitting the combustion process into decoupled combustion stages</td><td>The applicability may be limited by the gas turbine design</td></tr>
<tr><td>e.</td><td>Low-NO_X burners (LNB)</td><td rowspan="2">See description in Section 8.3</td><td>Generally applicable to supplementary firing for heat recovery steam generators (HRSGs) in the case of combined-cycle gas turbine (CCGT) combustion plants</td></tr>
<tr><td>f.</td><td>Selective catalytic reduction (SCR)</td><td>Not applicable in the case of combustion plants operated < 500 h/yr.
Not generally applicable to existing combustion plants of < 100 MW_{th}.
Retrofitting existing combustion plants may be constrained by the availability of sufficient space.
There may be technical and economic restrictions for retrofitting existing combustion plants operated between 500 h/yr and 1 500 h/yr</td></tr>
</table>
</td><td></td><td>b. Water/stream addition for NOx control is not applied at the plant as dry low NOx burners and SCR are used for NOx control.
c. The CCGT will have dry low NOx burners in place.
d. Not applicable as this is limited by the turbine design. Operational efficiency characteristics of the plant vary according to the load.
e. The CCGT will have dry low NOx burners in place to minimise emissions of NOx, therefore LNBs are not considered to be required.
f. SCR is proposed.</td></tr>
<tr><td>43</td><td>In order to prevent or reduce NO_X emissions to air from the combustion of natural gas in engines, BAT is to use one or a combination of the techniques given below.
<table>
<tr><th>Technique</th><th>Description</th><th>Applicability</th></tr>
</table>
</td><td></td><td>Not applicable – relevant to gas engines.</td></tr>
</table>

<table>
<tr><th>BAT Concn. Number</th><th>Summary of BAT Conclusion requirement</th><th>Status NA/ CC / FC / NC</th><th>Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement</th></tr>
<tr><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td></td><td>
<table>
<tr><td>a.</td><td>Advanced control system</td><td>See description in Section 8.3.
This technique is often used in combination with other techniques or may be used alone for combustion plants operated < 500 h/yr</td><td>The applicability to old combustion plants may be constrained by the need to retrofit the combustion system and/or control command system</td></tr>
<tr><td>b.</td><td>Lean-burn concept</td><td>See description in Section 8.3.
Generally used in combination with SCR</td><td>Only applicable to new gas-fired engines</td></tr>
<tr><td>c.</td><td>Advanced lean-burn concept</td><td rowspan="2">See descriptions in Section 8.3</td><td>Only applicable to new spark plug ignited engines</td></tr>
<tr><td>d.</td><td>Selective catalytic reduction (SCR)</td><td>Retrofitting existing combustion plants may be constrained by the availability of sufficient space.
Not applicable to combustion plants operated < 500 h/yr.
There may be technical and economic restrictions for retrofitting existing combustion plants operated between 500 h/yr and 1 500 h/yr</td></tr>
</table>
</td><td></td><td></td></tr>
<tr><td>44</td><td>In order to prevent or reduce CO emissions to air from the combustion of natural gas, BAT is to ensure optimised combustion and/or to use oxidation catalysts.
Description - See descriptions in Section 8.3.
BAT-associated emission levels (BAT-AELs) for CO emissions to air from the combustion of natural gas in gas turbines
<table>
<tr><th rowspan="2">Type of combustion plant</th><th rowspan="2">Combustion plant total rated thermal input (MW_{th})</th><th colspan="2">BAT-AELs (mg/Nm^3) [142] [143]</th></tr>
<tr><th>Yearly average [144] [145]</th><th>Daily average or average over the sampling period</th></tr>
<tr><td colspan="4">Open-cycle gas turbines (OCGTs) [146] [147]</td></tr>
<tr><td>New OCGT</td><td>≥ 50</td><td>15–35</td><td>25–50</td></tr>
<tr><td>Existing OCGT (excluding turbines for mechanical drive applications) — All but plants operated < 500 h/yr</td><td>≥ 50</td><td>15–50</td><td>25–55 [148]</td></tr>
<tr><td colspan="4">Combined-cycle gas turbines (CCGTs) [146] [149]</td></tr>
<tr><td>New CCGT</td><td>≥ 50</td><td>10–30</td><td>15–40</td></tr>
</table>
</td><td>FC</td><td>The relevant BAT AELs are specified in Table S3.1 and S3.1a of the Permit.</td></tr>
</table>

BAT Concn. Number	Summary of BAT Conclusion requirement	Status NA/ CC / FC / NC	Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement

Existing CCGT with a net total fuel utilisation of < 75 %	≥ 600	10–40	18–50
Existing CCGT with a net total fuel utilisation of ≥ 75 %	≥ 600	10–50	18–55 [150]
Existing CCGT with a net total fuel utilisation of < 75 %	50–600	10–45	35–55
Existing CCGT with a net total fuel utilisation of ≥ 75 %	50–600	25–50 [151]	35–55 [152]
Open- and combined-cycle gas turbines			
Gas turbine put into operation no later than 27 November 2003, or existing gas turbine for emergency use and operated < 500 h/yr	≥ 50	No BAT-AEL	60–140 [153] [154]
Existing gas turbine for mechanical drive applications — All but plants operated < 500 h/yr	≥ 50	15–50 [155]	25–55 [156]

As an indication, the yearly average CO emission levels for each type of existing combustion plant operated ≥ 1 500 h/yr and for each type of new combustion plant will generally be as follows:

— New OCGT of ≥ 50 MW_{th}: < 5–40 mg/Nm^3. For plants with a net electrical efficiency (EE) greater than 39 %, a correction factor may be applied to the higher end of this range, corresponding to [higher end] × EE/39, where EE is the net electrical energy efficiency or net mechanical energy efficiency of the plant determined at ISO baseload conditions.

— Existing OCGT of ≥ 50 MW_{th} (excluding turbines for mechanical drive applications): < 5–40 mg/Nm^3. The higher end of this range will generally be 80 mg/Nm^3 in the case of existing plants that cannot be fitted with dry techniques for NO_X reduction, or 50 mg/Nm^3 for plants that operate at low load.

— New CCGT of ≥ 50 MW_{th}: < 5–30 mg/Nm^3. For plants with a net electrical efficiency (EE) greater than 55 %, a correction factor may be applied to the higher end of the range, corresponding to [higher end] × EE/55, where EE is the net electrical energy efficiency of the plant determined at ISO baseload conditions.

— Existing CCGT of ≥ 50 MW_{th}: < 5–30 mg/Nm^3. The higher end of this range will generally be 50 mg/Nm^3 for plants that operate at low load.

— Existing gas turbines of ≥ 50 MW_{th} for mechanical drive applications: < 5–40 mg/Nm^3. The higher end of the range will generally be 50 mg/Nm^3 when plants operate at low load.

In the case of a gas turbine equipped with DLN burners, these indicative levels correspond to when the DLN operation is effective.

BAT-associated emission levels (BAT-AELs) for NO_X emissions to air from the combustion of natural gas in boilers and engines

Type of combustion plant	BAT-AELs (mg/Nm^3)			
	Yearly average [157]		Daily average or average over the sampling period	
	New plant	Existing plant [158]	New plant	Existing plant [159]

<table>
<tr><th>BAT Concn. Number</th><th>Summary of BAT Conclusion requirement</th><th>Status NA/ CC / FC / NC</th><th>Assessment of the installation capability and any alternative techniques proposed by the operator to demonstrate compliance with the BAT Conclusion requirement</th></tr>
<tr><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td></td><td>
<table>
<tr><td>Boiler</td><td>10–60</td><td>50–100</td><td>30–85</td><td>85–110</td></tr>
<tr><td>Engine [160]</td><td>20–75</td><td>20–100</td><td>55–85</td><td>55–110 [161]</td></tr>
</table>
As an indication, the yearly average CO emission levels will generally be:
— < 5–40 mg/Nm^3 for existing boilers operated ≥ 1 500 h/yr,
— < 5–15 mg/Nm^3 for new boilers,
— 30–100 mg/Nm^3 for existing engines operated ≥ 1 500 h/yr and for new engines.
</td><td></td><td></td></tr>
<tr><td colspan="4">The remaining BAT Conclusions are not relevant to the proposed installation.</td></tr>
</table>

12. BAT guidance for Post-Combustion Carbon Capture (Post-combustion carbon dioxide capture: best available techniques (BAT) - GOV.UK (www.gov.uk))

This section provides a record of decisions made in relation to each relevant BAT guidance considered potentially applicable to the installation. This table should be read in conjunction with the permit.

The conditions in the permit through which the relevant BAT Conclusions are implemented include but are not limited to the following:

Ref	BAT Guidance	Applicants Proposals	BAT Y/N
1. Power Plant selection and integration with the PCC plant			
BAT for efficiency of fuel use in power and CHP plants with PCC.			
1.1	You must maximise the thermal energy efficiency of the power plant and of the supply of heat for the associated PCC plant. For natural gas power plants, lower heating value efficiencies of 60% or above without CO2 capture are reported in the LCP BREF to be achievable for large-scale new combined cycle gas turbine installations.	The Applicant has stated that the requirement to maximise thermal efficiency is integral to the CO_2 reductions of the installation as a whole. The lower heating value efficiencies of the proposed CCGT are anticipated to be ≥60%.	Y
Dispatchable Operation.			
1.2	In line with the needs of a UK electricity system with a large amount of intermittent renewable generation, all thermal power plants, including those with CO2 capture, are likely to be dispatchable. This means that the power plant operator can, within technical limits on rates of change in output and on minimum stable generation levels, operate the plant at any required output, up to its full load, at any time, and sustain this output indefinitely.	The Applicant has stated that the installation will be designed to be fully dispatchable.	Y

2. Supplying heat and power for PCC operation			
2.1	You will need to use low grade (for example 130°C) heat and electrical power to operate the PCC plant. You should work out the amounts needed based on factors that include the: • selected solvent • PCC plant configuration • CO2 capture level • CO2 delivery pressure You should supply this heat and electricity from the main power plant. Where not possible, this will need to be by fuel combustion in ancillary plants (with CO2 capture) that are then also treated as a power plant system for performance calculations.	The Applicant has stated that the requirement to maximise thermal efficiency is integral to the CO_2 reductions of the installation as a whole. During stable operation heat and electricity to the CCP would be provided by the CCGT. To assist CO_2 capture on start-up the use of an electrical auxiliary boiler is proposed, which would require electricity from the grid. This would be taken into account in the power plant system for performance calculations. As detailed in the Application heat and electricity used by the PCC will be supplied by the main power plant. The total internal parasitic load of the CCGT with operational CCP is expected to be around 60MWe (excluding power loss due to CCP steam demand), of which around 20Mwe is consumed by the CCGT power island and associated utilities. Flue gas transfer and CCP imposes an additional circa 12-15MWe, with additional utilities consumption of 5-6MWe. The parasitic load of the LP compression plant is estimated to be around 20MWe. The reduction in electricity generation capacity as a result of the steam extraction from the CCGT plant is circa 50MWe equivalent.	Y

	Typically, the best heat supplied to lost power ratio will exceed 4:1 for regeneration heat supplied at 130°C. It follows that if you use electricity instead of steam in PCC heating, for example to compress the vapour produced from flashing lean amine so that it can be fed back into the amine stripper, you should aim to achieve a similar ratio. This will ensure that the overall impact on plant electricity output is no higher than for steam extraction. You will achieve the best use of any additional fuel inputs when as much electricity as possible is also generated from the energy in the fuel before supplying the low grade heat. You can assess this based on: the thermal efficiency of a BAT baseload-capable power plant without capture using that fuel the ratio between heat supplied for PCC and the reduction in electrical power output from the relevant unabated BAT power plant output in the LCP BREF, which should exceed 4:1 for a typical amine regeneration heat supply at 130°C.	The Applicant has stated that the CCP is designed to use low pressure steam for regenerating the solvent. The design steam pressure has been chosen considering trade-offs between process requirements, sizing of reboiler and minimising parasitic load on steam turbine. Also, the final design will include additional technologies, which will provide energy saving at a higher efficiency than 4:1 ratio of heat to power loss.	
3. Purpose			
3.1	The purpose of the PCC plant is to maximise the capture of CO2 emissions for secure geological storage. You should aim to achieve a design CO2 capture rate of at least 95%, although operationally this can vary, up or down.	The Applicant has stated that the CCP will be designed to capture at least 95% CO_2 in the flue gas treated during stable operation.	Y
3.2	You should capture CO2 during start-up and shutdown as part of using BAT.	The Applicant has stated that the plant will be designed to maximise CO_2 capture rates during start-up and shut-down.	Y
3.3	You will need to deliver CO2: at local transport system pressures (gas phase such as 35 bar or dense phase such as 100 bar) with levels of water, oxygen and other impurities as required for transport and storage such as that for the system operator National Grid (NGC/SP/PIP/25 Dec.2019)	The Operator has stated that the onsite compression will remove oxygen and water from the CO_2 to meet the requirements of the Transport & Supply (T&S) network. The quality of the CO_2 would be monitored online for compliance with export specifications to ensure the required specification is met and fiscal flow metering would be provided for custody transfer of CO_2 sent to the T&S network.	Y
3.4	The PCC plant must also have acceptable environmental risks through preventing or minimising emissions, or render them harmless. You must achieve environmental quality standards for air emissions from the PCC plant and their subsequent atmospheric degradation products (including, for example, nitrosamines and nitramines). You should confirm this using: • atmospheric dispersion and reaction modelling tools	An air dispersion modelling assessment has been completed by the Applicant. We are satisfied that no Environmental Standards will be exceeded. The permit sets ELVs for relevant pollutants.	Y

	• specific site parameters which will define plant-specific ELVs		
3.5	Your PCC system design should aim to minimise the overall electricity output penalty on the power or CHP plants from all aspects of PCC plant operation, as much as possible. It should do this while meeting the CO2 capture requirements set out in this guidance	The Applicant has stated that the plant will be designed to maximise energy efficiency to ensure that CO_2 reductions for the project as a whole are as high as possible.	Y
4. Solvent Selection			
4.1	While the process design for the PCC plant is likely to be generally similar for all solvents, the amine solvent you select will determine details of the design and performance. Solvent types and published performance figures are described in the BAT review. There is particular concern about impacts on the environment from nitrosamines and other potentially harmful compounds formed by reaction of the amines and their degradation products with nitrogen oxides (NOx) in the flue gases. Check the environmental standards for air emissions for the protective environmental assessment levels. You have a choice between: • solvents using primary amines that may require more heat for regeneration but will not readily form stable nitrosamines in the PCC plant, especially if a high level of reclaiming is used to remove degradation products • solvent formulations including secondary amines or other species that may have lower regeneration heat requirements may readily form nitrosamines with NOx in the flue gases in the PCC plant - for controls, see section 3.3 on features to control and minimise atmospheric and other emissions The project-specific potential for absorber stack emissions and consequent environmental impacts will depend on the selected solvent. You should assess your plant design and operation, plus local environmental factors, based on: • 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	The Applicant has stated that the CCP would be designed with the specific solvent and degradation characteristics in mind. The solvent regeneration and reclamation process would minimise solvent degradation, in order to minimise emissions and potential environmental impacts, as demonstrated in the Air Impact Assessment provided in Appendix F of the Application. This assessment has taken into account both the direct and indirect impacts of N-amines resulting from anticipated amine and N-amine releases.	Y

4.2	The potential for solvent reclaiming and other cleaning methods is also an important factor in solvent selection. You should make sure it is practicable to remove all non-solvent constituents from the solvent inventory as fast as they are added during operation, to avoid accumulation. You should also make sure that you: • recover a high fraction of the solvent in the feed to the reclaimer during reclaiming. • Minimise reclaimer wastes and that they can easily be disposed of.	The Applicant has stated that the main aim of the solvent reclaiming is to ensure that a high fraction of the solvent can be used in the CCP, and the minimisation of waste. Until operation commences exact degradation rates and reclamation throughput is unknown. Solvent losses within the reclaimed waste are anticipated but it is expected that over 90% of the amine will be recovered from the reclamation process. In maximising solvent reuse on site, reclaimer wastes would be minimised as far as possible. Thermal reclamation will either be carried out on a batch or continuous basis. In either case, a slip stream of the lean amine would be removed downstream of the Lean Amine Pump and would be diverted into the Thermal Reclaimer. The liquid in the Thermal Reclaimer would be re-circulated, and heated with steam from the CCGT. The reclamation process achieves separation of most of the water and reclaimer lean absorbent (overheads) from the degradation products (bottoms). Caustic soda solution would be added to liberate and recover amine from the solution, if required. Once the reclamation process is over, the reclaimed waste would be discharged into either a holding tank prior to collection (continuous process), or straight into a road tanker for off-site disposal by a licensed 3rd party waste contractor (batch process). For the batch process, the Reclaimer would be sized such that the waste inventory of one reclamation batch can fit into one road tanker for disposal. In this case, the time required for processing the whole solvent inventory would be approximately 430 hours of continuous Reclaimer operation. More generally, it is envisaged that each reclamation campaign would take 200 hours, with a total of 1,600 hours of reclamation being carried out per year (i.e., 8 campaigns per year). For the batch process, the efficiency of solvent reclamation would be assessed directly through measurements of the contents of amines (e.g. heat stable salts, metals, etc.) in the Reclaimer waste stream, as well as its viscosity at the end of a reclamation batch. Indirectly, the efficiency of reclamation can be assessed through operational parameters such as vapour flow rates and temperatures.	

		For the continuous reclamation process, a material balance flow of 4.5 tonnes/hour means that, with the estimated inventory at FEED phase of 3,500 tonnes of solvent, the total inventory would turn over approximately every 32 days. For the continuous process, ongoing solvent management techniques, such as maintaining the concentrations of degradation products below a target value, would ensure that they do not have adverse effect on the process performance. Lab sampling of solvent would be periodically carried out to monitor the concentration of degradation products present. Normal operation of the Thermal Reclaimer would maintain an efficient operating profile such that degradation products are kept under control (preventing an increase to levels which would cause what is sometimes called auto-catalytic degradation). Their concentration is therefore monitored through regular (weekly to monthly) solvent analysis, and the solvent processing rate of the Thermal Reclaimer adjusted as required to correct the contaminants removal rate. This means optimum operation of the reclamation process to minimise generation of degradation products with minimum energy usage.	
	You must work out the solvent performance, including reclaiming requirements and emissions to atmosphere. Determine this through realistic pilot (or full scale) tests using fully representative (or actual) flue gases and power plant operating patterns over a period of at least 12 months.	The Applicant has stated that the amine solvent suppliers have extensive pilot plant and operational experience of their solvent performance on representative flue gases. The amine solvent will be stored in a closed tank, so no emission to atmosphere when stored. Amine emission to atmosphere from the absorber has been assessed see section 6 above.	
5. Flue gas cleaning			
5.1	Sulphur oxides (SOx) removal can be in the power plant flue gas desulphurisation unit or in the PCC direct contact cooler. SOx in the flue gas will readily react with amines to produce heat stable salts. These products are typically stable under reclaimer conditions, but the heat stable salt formation with SOx can be, at least partly, reversed by alkali addition in the solvent reclaiming process. SOx levels will therefore affect solvent consumption but are expected to have a limited effect on emissions. For most gas and biomass fuels that have intrinsically low S levels, adding more upstream SOx removal is likely to be primarily an economic decision. SOx levels in the exit flue gases from an amine PCC plant will be at extremely low levels.	The Applicant has stated that due to the use of un-odourised natural gas as a fuel, it is considered that SOx concentrations would not impact solvent performance or degradation, and therefore a desulphurisation unit/ caustic addition to the DCC is not considered necessary.	NA

5.2	The impact of NOx in the flue gas will vary significantly with the solvent composition. If the amine blend will form significant amounts of stable nitrosamines with NOx in the flue gas, then you must reduce NOx to as low a level as practicably possible (see LCP BREF) using selective catalytic reduction (SCR).	The Applicant has stated that SCR is being installed to reduce NOx concentrations in the flue gas from the CCGT plant to the CCP.	Y
	If necessary, it is expected that ammonia (NH_3) slip from the SCR unit could be addressed in a suitably designed PCC unit. In all cases, you must assess the effects of NOx in the flue gas on atmospheric degradation reactions and this may also affect the need for SCR	The dispersion modelling assessment included ammonia slip and degradation products from the CCP	
	If SCR is not fitted to a new build power plant, it is generally considered BAT to maintain space so it may be retrofitted in future, should this be considered necessary to meet ELVs.	Not applicable	
5.3	Sulphur trioxide (SO_3) droplets and fine particulates should not be present in the flue gas. If they arise in the PCC process they can cause significant amine emissions. The level of emissions (mainly solvent amines) are not directly related to aerosol measurements. Monitoring aerosols is difficult and aerosol quantities may also vary significantly over time. Aerosols might be present, for example, because of significant SOx in the flue gas. Where this is the case, you should carry out long-term testing on a pilot plant or the actual plant, with all planned countermeasures in place, to show satisfactory operation. You should also carry out regular isokinetic sampling in the operational plant to assess total vapour and droplet emission levels.	The Applicant has stated that a mist eliminator would be located after the water wash and acid wash (if required) section at the top of the Absorber column to minimise aerosol release.	Y
5.4	You may need to remove materials in the flue gas that would accumulate as impurities in the solvent (such as metals, chlorine and fly ash) to lower concentrations than is required under the LCP BREF. This is to ensure satisfactory PCC plant operation. Whether you need to do this will depend on the specific solvent properties and the effectiveness of the solvent management equipment (such as filtering and reclaiming).	Accumulation of metals, chlorine and fly ash in the solvent is unlikely due to use of natural gas.	Y

	You should assess the effects of flue gas impurities through realistic, long term pilot testing. In general, your PCC plant must abate these types of flue gas impurities before the residual flue gases are finally released to atmosphere.	The Applicant has stated that flue gas impurities have been considered in the plant design and it has not been deemed necessary to provide further abatement other than that discussed in the Application.	
6. PCC system operation			
Operating temperatures			
6.1	You must establish and maintain optimum temperature and appropriate limits in the solvent stripping process. Elevated temperatures can cause some thermal degradation of the solvent. But higher peak average temperatures during regeneration will also likely promote reduced energy requirements and higher CO_2 capture levels. You must balance both to ensure the right environmental outcome. Where feasible, you should avoid locally higher metal skin temperatures, such as from the use of superheated steam in heaters, as this provides no benefit and can result in degradation.	The Applicant has stated that CCP design is such that it would operate at optimised conditions for the solvent utilised.	Y
Solvent Degradation			
6.2	You should minimise oxidative degradation of the solvent by reduced solvent residence times in the absorber sump and other hold-up areas. Direct O2 removal from rich solvent may be developed in the future but has not yet been proven at scale.	The Applicant has stated that CCP design is such that it would operate at optimised conditions for the solvent utilised.	Y
7. Absorber emissions abatement			
Water wash			
7.1	You must use one or two water washes or a scrubber to return amine and other species to the solvent inventory. Capture levels are limited by vapour or liquid equilibria, with volatile amines captured less effectively. Any aerosols present will also not be captured effectively. Water washes alone are ineffective in preventing NH3 emissions, as concentrations will increase until the rate of release balances the rate of formation (and possibly addition from SCR slip).	The Applicant has stated that there will be either one or two water wash section in place, which would enable solvent reuse. They will also have a mist eliminator to reduce aerosols present in the flue gas.	Y

Acid wash			
7.2	An acid or other chemically active wash or scrubber after the water wash will react with amines, NH_3 and other basic species and reduce them to very low levels (for example, 0.5 to 5mg per m3 per species or lower). You should implement an acid wash as BAT, unless: • emission levels are already at acid wash levels with a water wash • you can show that the need to dispose of the acid wash waste outweighs the benefits of the additional reduction in emissions to atmosphere Depending on PCC system configuration, an absorber acid wash can also counteract NH3 slip from an SCR system. If an acid wash is not fitted, you should consider a second water wash as an acid wash if: • emissions performance is worse than expected • you wish to change to a more volatile solvent An acid wash is not likely to trap aerosols.	The Applicant has proposed a water wash stage and that an acid wash may be used if it is considered necessary to reduce ammonia/amine emissions from the CCP. They will also have a mist eliminator to reduce aerosols present in the flue gas.	Y
Droplet Removal			
7.3	You must prevent emissions of aerosols. To do this you could use standard droplet removal sections after washes. These will prevent droplet carryover from the wash. However, they are not effective against very fine aerosols arising from SO3 or other aerosol mists.	The Applicant has stated that a mist eliminator would be located at the top of the water wash section to prevent the entrainment of droplets into the waste gases.	Y
Stack Height			
7.4	Where modelling predicts that you may need to raise the temperature at the point of release to aid dispersion, you can: • increase the design stack height • add flue gas reheating Flue gas reheating can also reduce the plume visibility. Heat from cooling the flue gas before the PCC plant or waste heat from the PCC process should be used for flue gas reheating (see section 4 on cooling)	The Applicant has stated that the detailed dispersion modelling has shown that a stack height for the CCP would ensure that pollutants released would not result in exceedance of any air quality standards. Flue gas reheating would also be applied to increase dispersion and reduce plume visibility.	Y

8. Process and emissions monitoring			
Role of monitoring			
8.1	The main purpose of monitoring the PCC process is to show that the emissions from the process, primarily to air, are not causing harm to the environment. You must also carry out monitoring to show that resources are being used efficiently. This includes: • energy and resource efficiency • capture efficiency • verification that the CO2 product is suitable for safe transport and storage Your permit application should include a monitoring plan for both a commissioning phase and routine operation. During the commissioning phase you will need to optimise the operating envelope for the process. When you have achieved this the process operation will then become routine, along with the monitoring.	The proposed Installation will be required to monitor and report energy and resource efficiency figures to demonstrate these are being used efficiently. The CCP operation would also be monitored continuously to report the resource and energy efficiency of the plant	Y
8.2	It's likely you'll need to do more extensive monitoring during commissioning than during routine operation. As PCC is an emerging technique, you will need to develop monitoring methods and standards. You should include proposals for this in your permit application.	CEMS for monitoring NOx, NH_3, CO_2 and CO will be in place. Provided appropriate CEMS can be identified for amines and N-amines monitoring, then these would also be in place. If not, extractive monitoring would be carried out. The requirement to implement a Commissioning Monitoring Plan has been included as a Pre-Operational Condition in the permit.	Y
8.3	Compliance with ELVs in the permit will provide the necessary protection for the environment, by monitoring emissions at authorised release points. You must also show that you're managing the process to prevent (or minimise) the formation of solvent degradation products.	Monitoring will be carried out for the requirements set in the Permit.	Y
8.4	Where degradation products are formed (and may be released), you must reduce these and any solvent emissions to the appropriate level. This process control monitoring will also be part of the permit conditions.	The Applicant has stated that process control monitoring to ensure that degradation products do not build up in the CCP would be carried out as part of the reclamation process as described in the Application.	Y

9. Point source emissions to air			
9.1	You must include monitoring to demonstrate compliance with the IED Chapter III ELVs and the LCP BREF BAT AELs at normalised conditions. You must also monitor for: • ammonia • volatile components of the capture solvent • likely degradation products such as nitrosamines and nitramines Your monitoring may be by either: • continuous emissions monitoring ('on line') • periodic extractive sampling ('off line') – where aerosol formation is expected, this must be isokinetic	Monitoring requirements and emissions limits have been set in the Permit.	Y
9.2	Emission sampling point must also comply with M1 sampling requirements for stack emission monitoring.	Improvement condition (IC5) has been included in the permit that will ensure the sampling point is compliant.	Y
10. Process control monitoring			
10.1	• You should use process control monitoring or periodic sampling with off-line analysis to control the CO2 capture and the quality of the solvent reclaiming. Parameters you can monitor include: • absorber solvent quality – percentage active solvent • CO2 loading both rich and lean solvent • maximum solvent temperature • heat stable solvent content	The Applicant has stated that the CCP would include instrumentation to monitor and record CO_2 capture rates and purity. Sampling points would be provided to collect fluid samples of the solvent to ensure the quality of solvent reclaiming	Y

	• solvent colour or opacity • soluble iron and other metals and degradation products • in water or acid washes and scrubbers – pH, conductivity, loading of abated substances, flow rate		
Monitoring of CO_2			
10.2	To meet the required specification, include: • CO2 mass balance • CO2 in fuel combusted • total capture level (as a percentage) • CO2 released to the environment • CO2 quality	The Applicant has stated that these parameters will be monitored as part of the CCP operation.	Y
Monitoring Standards			
10.3	The person who carries out your monitoring must be competent and work to recognised standards such as the Environment Agency's monitoring certification scheme (MCERTS). MCERTS sets the monitoring standards you should meet. The Environment Agency recommends that you use the MCERTS scheme where applicable. You can use another certified monitoring standard, but you must provide evidence that it is equivalent to the MCERTS standards. There are no prescriptive BAT requirements for how to carry out monitoring. Monitoring methods need to be flexible to meet specific site or operational conditions. You must use a laboratory accredited by the United Kingdom Accreditation Service (UKAS) to carry out analysis for your monitoring.	The Applicant has stated that any extractive monitoring carried out on the emissions from the CCP will be carried out by MCERTS accredited contractors. And where required and available, UKAS accredited labs will be used for analysis.	Y
11. Unplanned emissions to the environment			
11.1	You should propose a leak detection and repair programme that is appropriate to the solvent composition. This should use industry best practice to manage releases, including from joints, flanges, seals and glands.	The Applicant has stated that the Installation will have a maintenance programme and will include instrumentation to detect and monitor any leaks. Any leaks identified will be repaired by licenced contractors. A LDAR system	Y

	Your hazard assessment and mitigation for the plant must consider the risks of accidental releases to environment. This should also consider the actual composition of the fluids, gases and vapours that could be released from the plant after an extended period of operation. (Not only fresh solvent as initially charged.)	would be put in place for the CCP. HAZOPs would consider all potential risks of accidental releases to environment, as detailed in this BAT guidance.	
12. Capture level, including during flexible operation			
12.1	Capturing at least 95% of the CO_2 in the flue gas is considered BAT. You can base this on average performance over an extended period (for example, a year). To achieve this, you should make sure the design capture level for flue gas passing through the absorber equates to at least 95% of the CO_2 in the total flue gas from the power plant. If you process less than the full flue gas flow, your capture rate will have to be correspondingly higher. Over the averaging period, your capture level may vary up or down.	The Applicant has stated that the expectation is that the CCP will demonstrate 95% capture rates are achievable during steady state (normal) operation. The Permit includes a requirement to measure the capture rate, with the aim to achieve a 95% capture rate during normal operations.	Y
	As the fraction of intermittent renewable generation in the UK rises, CCS power plants will need to start and stop more often, and possibly also operate at variable loads. It is therefore important that CO_2 can also be captured at high levels during these periods, including during start-up and shutdown, to maintain high average capture levels. A method to maintain capture at normal rates or higher at all times using solvent storage has been identified in the BAT review. This, or alternatives that can achieve equivalent results, is considered BAT. If your PCC plant is	The Applicant has stated that they have prioritised dispatchable requirements for the proposed Installation from the outset of the project, having completed pilot plant testing and extensive techno-economic analysis to inform the design. Optimising CO_2 capture rate during start-up, minimising CO_2 losses and keeping the parasitic loads as low as practical require careful CAPEX/OPEX trade-off to achieve the optimal design. Demonstration of optimised start-up time and capture rate is also a key item within the DPA which will be agreed on and tested as part of the contract (refer to “Annex 2, Testing Requirements” in the published DPA Terms and Conditions). In 2020, NZT completed a two-week test campaign at Technology Centre Mongstad (TCM) using a non-proprietary solvent to test the capture plant start sequence and optimise for dispatchability. The data obtained supported	

	not initially constructed with this capability, your permit application should show how you may retrofit it.	simultaneous start sequencing, and maximising capture during transients (simulating heat retention, fast start steam and amine buffer capacity), all of which are important in maximising CO_2 capture rate on start-up. It is envisaged that the CCP would remain on hot standby enabling it to initiate operations seamlessly after receiving the flue gas from the CCGT, with no delays in solvent regeneration caused by energy losses to the environment. The general principle of the hot standby mode includes passive techniques (e.g. increased insulation and maintaining thermal mass) and active techniques (e.g. electric auxiliary boiler for steam production to keep the amine warm by countering the heat losses from the system, bypassing of cooling water exchangers etc.). Auxiliary steam may also be used to keep the steam lines from the CCGT to the CO_2 Stripper reboilers warm and ready to receive steam on start-up further reducing start-up times. The other aspect to maximising CO_2 capture during start-up shut down is the lean solvent inventory. The two consortia designs vary in their proposals; however it is considered that the techniques employed would enable the CCP to achieve required capture rates shortly after start-up, maintain the capture rates following load variations of the CCGT and also facilitate a shutdown mode that again will enable quick start-up of operations. In addition, ensuring that the dehydration beds are ready in dry condition and that the LP compressor is depressurised with dry CO_2 will minimise delays in start-up of the compression process.	
13. Compression			
13.1	You should select CO_2 compressors based on the expected duty. You should consider how any waste heat arising may be used.	The Applicant has stated that the CO_2 compressors are specified based on the expected duty. The potential for using waste compression heat is limited by the dispatchable nature of plant operation and assurance of system safety. Third and fourth stage LP compression heat would be utilised to raise the CO_2 above the oxygen removal reactor light off temperature ~150°C to allow the oxygen removal to work. It is also envisaged that any further waste heat would be low grade and therefore there is no viable use for it.	Y
13.2	For base load operation, you should use integrally geared units because they give the: • maximum full-load efficiency • minimum number of compression trains	The Applicant has stated that the Installation will be optimised for dispatchable operation rather than baseload operation, although integrally geared compressors are proposed for LP compression.	Y
13.3	For flexible and part-load operation, smaller compression trains (for example 2 at 50% compared to 1 at 100%) may be preferable. The use of different	The Applicant has stated that it is expected that the plant would operate at full load when its power is required by the grid. Nevertheless, the plant can	Y

	types of compressor or pump in series may also be preferable, to give greater flexibility at the expense of slightly lower full-load efficiencies.	operate at turndown, as such 2 x 50% low pressure CO_2 compression trains have been specified.	
14. Noise and odour			
14.1	The LCP BREF already covers noise impacts for the main power plant. You only need to consider additional process steps in PCC technology that have high potential for noise and vibration. In particular, CO_2 compression could be an area of concern. Once you've identified the main sources and transmission pathways, you should consider the use of common noise and vibration abatement techniques and mitigation at source wherever possible. For example, the: • use of embankments to screen the source of noise • enclosure of noisy plant or components in sound-absorbing structures • use of anti-vibration supports and interconnections for equipment • orientation and location of noise-emitting machinery • change of the frequency of the sound	A noise assessment was submitted as part of the Application and concluded no significant impact. However, a pre-operational condition has been included in the permit requiring a review of this noise assessment to be submitted following final design of the CCP.	Y
14.2	The handling, storage and use of some amines may result in odour emissions, so you should always use best practice containment methods. Where there is increased risk that odour from activities will cause pollution beyond the site boundary, you will need to send an odour management plan with your permit application	The Applicant has stated that the solvents have low vapour pressures at ambient temperatures and therefore are considered to have a minimal risk of generating odour. Solvent would be stored appropriately to ensure minimal odour emissions.	Y
15. Cooling			
15.1	You will be able to achieve the best power and CO2 capture plant performance by using the lowest temperature cooling available. You should use the hierarchy of cooling methods as follows: • direct water cooling (such as seawater) • wet cooling towers • hybrid cooling towers • dry cooling – direct air-cooled condensers and dry cooling towers	A Cooling BAT assessment was carried out in support of the Application which concluded that hybrid cooling towers represented BAT for the Proposed Installation. Use of direct cooling (heat rejection to wet cooling towers) has been maximised for the project. The use of dry cooling has only been implemented to ensure an inherently safe design - where use of a heat transfer fluid risks system boiling/ contamination/ freezing.	Y

15.2	Power plants that are retrofitted with PCC using steam extraction, or are intended to be able to operate without capture, can share water cooling between the power plant and the PCC system. This is because the cooling load on the main steam condensers falls with increased steam extraction rate. This shift away from condenser cooling will not apply for systems with direct air-cooled condensers. It may also be possible to reuse cooling water after the main condensers for higher-temperature cooling applications in the PCC plant. However, site specific water discharge temperature limits may be an issue for direct cooling.	The proposed system will provide cooling to both the power plant and the PCC.	Y
15.3	A feature of PCC is that you have to remove heat from a flue gas stream that was originally not cooled. You can still achieve rejection of heat to atmosphere by heating the flue gas leaving the absorber, using heat from the incoming flue gas. You can do this either: • directly – such as using a rotary gas-gas heater • indirectly – such as using a heat transfer fluid or low-pressure steam	The Applicant has stated that the maximum practicable recovery of heat from the flue gas is achieved to the steam cycle in the Heat Recovery Steam Generator. As such, the flue gas temperature is only 70°C by the time it reaches the CCP, and this temperature is too low for providing efficient flue gas reheating. The heat lost to cooling water in the DCC is also minimised by this method. As such, flue gas reheat would be carried out using steam condensate from the CCP.	Y
15.4	Lean and rich solvent storage may also help you achieve satisfactory PCC performance during periods of high cooling demand.	The Applicant has stated that the CCP is design to have the capacity to deal all levels of cooling demand as per the design envelope. Lean and rich solvent storage are currently considered for reasons of enabling dispatchable operations of the CCP.	Y
15.5	You should refer to the Environment Agency's evidence on cooling water options for the new generation of nuclear power stations in the UK when considering options for cooling. This gives an overview of UK power station cooling water systems in use in the UK and abroad.	The Operator has stated that this guidance was considered in the preparation of the Cooling BAT Assessment carried out for the Application.	Y
16. Discharge to water			
16.1	For discharges to water, you should refer to the guidance on surface water pollution risk assessment for your environmental permit.	The Applicant has stated that the Direct Contact Cooler water generated on site would contain ammonia from the SCR. Wastewaters will be treated on site via reverse osmosis.	Y

	For best practice in plume dispersal modelling, see the Joint Environmental Program report '[A protocol on projects modelling cooling water discharges into TrAC waters within power station developments]'.	The Applicant has submitted a WQ assessment that has been reviewed by us and we agree with the conclusions that the impact on WQ in tees Bay will not be significant. However, this assessment does not reflect the final design of the CCP. The Operator has confirmed that the submitted WQ assessment reflects a worst case impact and that impacts of emissions from the final design will be less. In order to verify this we have included a pre-operational condition in the permit for the operator to submit an updated WQ assessment based on the final design to confirm the impact on WQ in Tees Bay will not be significant. The plant will not be allowed to operate until this is confirmed.	
17. Climate change adaption			
17.1	You must complete an [adapting to climate change risk assessment] as part of your permit application.	Completed.	Y

Annex 1 Decision checklist

Aspect considered	Decision
Receipt of application	
Confidential information	A claim for commercial or industrial confidentiality has not been made.
Identifying confidential information	We have not identified information provided as part of the Application that we consider to be confidential.
Consultation	
Consultation	The consultation requirements were identified in accordance with the Environmental Permitting Regulations and our public participation statement. The application was publicised on the GOV.UK website. We consulted the following organisations: Public Health England The Director of Public Health The Health and Safety Executive The Food Standards Agency Local Council – Environmental Health The comments and our responses are summarised in the consultation section.
Operator	
Control of the facility	We are satisfied that the Applicant (now the Operator) is the person who will have control over the operation of the facility after the grant of the permit. The decision was taken in accordance with our guidance on legal operator for environmental permits.
The facility	
The regulated facility	We considered the extent and nature of the facility at the site in accordance with RGN2 'Understanding the meaning of regulated facility', Appendix 2 of RGN 2 'Defining the scope of the installation', Appendix 1 of RGN 2 'Interpretation of Schedule 1', guidance on waste recovery plans and permits. The extent of the facility is defined in the site plan and in the permit. The activities are defined in table S1.1 of the permit.
The site	
Extent of the site of the facility	The operator has provided a plan which we consider is satisfactory, showing the extent of the site of the facility. The plan is included in the permit.
Site condition report	See section 3.4 above.

Aspect considered	Decision
Biodiversity, heritage, landscape and nature conservation	The Application is within the relevant distance criteria of a site of heritage, landscape or nature conservation, and/or protected species or habitat. See section 6.3.2 above for details of our assessment. We have assessed the application and its potential to affect all known sites of nature conservation, landscape and heritage and/or protected species or habitats identified in the nature conservation screening report as part of the permitting process. We consider that the Application will not affect any sites of nature conservation, landscape and heritage, and/or protected species or habitats identified. We have consulted with Natural England, who agree with our conclusions.
Environmental risk assessment	
Environmental impact assessment	In determining the Application we have considered the Environmental Statement.
Environmental risk	We have reviewed the operator's assessment of the environmental risk from the facility. The operator’s risk assessment is satisfactory. The assessment shows that, applying the conservative criteria in our guidance on environmental risk assessment, all emissions may be categorised as environmentally insignificant. See section 6 above for further information.
Operating techniques	
General operating techniques	We have reviewed the techniques used by the operator and compared these with the relevant guidance notes and we consider them to represent appropriate techniques for the facility. The operating techniques that the applicant must use are specified in table S1.2 in the Permit.
Permit conditions	
Pre-operational conditions	Based on the information in the Application, we consider that we need to impose pre-operational conditions. See table S1.4 in the permit.
Improvement programme	Based on the information in the Application, we consider that we need to impose an improvement programme. See table S1.3 in the permit.
Emission limits	ELVs and equivalent parameters or technical measures based on BAT have been set. See section 8 above.
Monitoring	We have decided that monitoring should be added for the parameters detailed in tables S3.1, S3.1a and S3.2, using the methods detailed and to the frequencies specified in the permit.

Aspect considered	Decision
	These monitoring requirements have been imposed in order to meet requirements of Annex V of the IED and the AELs specified in the LCP BAT Conclusions document. We have also included monitoring of a range of amines specifically for when the plant is operating in CO_2 abated mode. We made these decisions in accordance with the SGN Combustion Activities (EPR1.01) and the monitoring methods are in accordance with the Monitoring of Stack Emissions to Air Technical Guidance Note (M2). Based on the information in the application we are satisfied that the operator's techniques, personnel and equipment have either MCERTS certification or MCERTS accreditation as appropriate.
Reporting	We have specified reporting in the permit. We have added reporting in the permit. The reporting requirements in the permit have been specified in order to comply with the requirements of the Industrial Emissions Directive. We made these decisions in accordance with the *JEP Electricity Supply Industry – IED Compliance Protocol for Utility Boilers and Gas Turbines. November 2022..*
Operator competence	
Management system	There is no known reason to consider that the Operator will not have the management system to enable them to comply with the Permit conditions. The decision was taken in accordance with the guidance on operator competence and how to develop a management system for environmental permits.
Relevant convictions	The Case Management System has been checked to ensure that all relevant convictions have been declared. No relevant convictions were found. The Operator satisfies the criteria in our guidance on operator competence.
Financial competence	There is no known reason to consider that the Operator will not be financially able to comply with the permit conditions.
Growth Duty	
Section 108 Deregulation Act 2015 – Growth duty	We have considered our duty to have regard to the desirability of promoting economic growth set out in section 108(1) of the Deregulation Act 2015 and the guidance issued under section 110 of that Act in deciding whether to grant this permit. Paragraph 1.3 of the guidance says: "The primary role of regulators, in delivering regulation, is to achieve the regulatory outcomes for which they are responsible. For a number of regulators, these regulatory outcomes include an explicit reference to development or growth. The growth duty establishes economic growth as a

Aspect considered	Decision
	factor that all specified regulators should have regard to, alongside the delivery of the protections set out in the relevant legislation.” We have addressed the legislative requirements and environmental standards to be set for this operation in the body of the decision document above. The guidance is clear at paragraph 1.5 that the growth duty does not legitimise non-compliance and its purpose is not to achieve or pursue economic growth at the expense of necessary protections. We consider the requirements and standards we have set in this permit are reasonable and necessary to avoid a risk of an unacceptable level of pollution. This also promotes growth amongst legitimate operators because the standards applied to the operator are consistent across businesses in this sector and have been set to achieve the required legislative standards.

Annex 2 Consultation

Advertising and Consultation on the Application

The following summarises the responses to consultation with other organisations, our notice on GOV.UK for the public and newspaper advertising and the way in which we have considered these in the determination process.

Responses from organisations listed in the consultation section

Response received from
UK Health Security Agency (11/10/2022)
Brief summary of issues raised
1. The Operator proposes modifying emission concentrations used in the risk assessment to reflect changes to the exhaust gas make-up by removal of CO_2 from the exhaust gas stream. The regulator should ensure this approach is appropriate. 2. The need for an air quality assessment of emissions from emissions point A2 when the plant is CO_2 unabated mode should be considered, or an appropriate condition limiting the operational duration of the plant in this mode considered. 3. The uncertainties in both the process design and subsequent abatement methodologies and effectiveness should be tracked and the regulator be satisfied that emissions levels proposed in the assessment can be met. 4. There is no assessment of emissions from start-up boilers or emergency power generators. Requirement for further assessment of these potential emissions should be considered. 5. An assessment of potential odour impacts from solvent emissions and degradation products is not submitted with applications. An assessment of odour based on ground level concentrations is recommended.
Summary of actions taken or show how this has been covered
1. We are satisfied that the approach is appropriate. The emissions limit values set for the CO_2 abated mode of operation take into consideration the removal of CO_2 from the emission gas stream. 2. The Operator has stated that higher stack temperatures of the release of flue gas from A2 means the thermal buoyancy is improved, and consequently the dispersion is also improved, this would result in a level of impact for the CO_2 -unabated CCGT operation that is no worse than for the CO_2 abated mode of operation. We agree with this assumption, therefore a separate air quality assessment for emissions from A2 is not required. 3. We are satisfied that emissions levels proposed in the Application and the limits and conditions set in the Permit will be met. Some aspects of the design are yet be finalised, however the Operator has stated that the risk assessment covering the key emissions (emissions to air and water) are worst case. Therefore it is likely that impacts when the installation is operational will be less than those predicted. The Operator has also described options for abatement that we consider appropriate. 4. The Operator has stated that the auxiliary (start-up) boilers will be powered by electricity so will have no significant emissions. The Applicant has not yet finalised the number and type of emergency generators, we have therefore set a pre-operational condition in the permit for the Operator to confirm this and provide an Air Quality Assessment to demonstrate that emissions will not result in significant pollution. They will not be able to operate until the assessment has been approved by the Environment Agency. Note that the generators are limited to <50 hours operation per year for testing and cannot be tested concurrently to minimise impacts.

5. We are satisfied that at the ground level concentrations predicted by the air quality assessment that odour will not be at a level likely to cause significant pollution at a sensitive receptor.

Response received from
Health and Safety Executive (HSE) (07/09/2022)
Brief summary of issues raised
The HSE have no comments to make.
Summary of actions taken or show how this has been covered
No action required

Representations from local MP, councillors and parish/town community councils

No responses received

Representations from community and other organisations

No responses received

Representations from individual members of the public.

No responses received.