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/YP3133LL
The Applicant / Operator is:	Keadby Generation Limited
The Installation is located at:	Keadby Power Station, Trentside, Keadby, Scunthorpe, DN17 3EF

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 applications the reference numbers EPR/YP3133LL/V011, EPR/YP3133LL/V012 and EPR/YP3133LL/V013. We refer to the applications as "the **Application**" in this document in order to be consistent.

The number we have given to the Permit is EPR/YP3133LL. We refer to the Permit as "the **Permit**" in this document.

The Applications were duly made on 20/06/2022 (V011) and 30/01/2024 (V012 & V013).

Variation V011 is a substantial variation comprising of the addition of a new CCGT power plant, a post-combustion amine-based (Monoethanolamine, MEA) carbon capture plant (CCP) for permanent geological storage and their ancillary requirements. The new plant will be referred to as Keadby 3.

Variation V012 is a normal variation that introduces a ‘one-pump scenario’ for a thermal plume discharge from Keadby 1 via emission point W1 when just one of the two pumps for Keadby 1 is in operation. This scenario is to account for planned maintenance of the pumps. The variation includes differential temperature limits for this ‘one-pump scenario’ into table S3.2 of the Permit.

Variation V013 incorporates differential temperature limits into table S3.2 of the Permit, for normal operations from emission point W1, that have been proposed as a result of IC3 and the re-routing of cable pull-pit effluent from emission point W11 to W10 (and ultimately W1).

The Applicant is Keadby Generation Limited. We refer to Keadby Generation Limited as “the **Applicant**” in this document. Where we are talking about what would happen after the Permit is granted, we call Keadby Generation Limited “the **Operator**”.

Keadby Generation Limited’s proposed facility is located at Keadby Power Station, Trentside, Keadby, Scunthorpe, DN17 3EF. We refer to this as “the **Installation**” in this document.

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Glossary

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
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
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
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.
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 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 Applications were duly made on 20/06/22 (V011) and 30/01/24 (V012 & V013). This means we considered that they were in the correct form and contained sufficient information for us to begin our determination but not that they 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 (V011) 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 (V011) 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.

We made a copy of the Application (V011) and all other documents relevant to our determination (see below) available to view on our Citizen space 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 (UKHSA)
- The Director of Public Health
- The Health and Safety Executive
- The Food Standards Agency
- Local Authority – Environmental Health

- Fisheries and Aquaculture Sciences
- National Grid

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 Applications duly made, we did in fact need more information in order to determine variation V011 and issued information notices on **07/03/2023 and 21/12/2023 (Schedule 5 Notice, 2nd issue)**. Additional information was also requested via emails on 30/01/2024, 23/02/2024, 22/05/2024 and 25/05/2024.

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

3. Chapter III of the Industrial Emissions Directive

Chapter III of the 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 large combustion plant.
- 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 ≥50MW making the CCGT proposed in Variation V011 an LCP.

Chapter III lays out special provisions for LCP and mandatory maximum ELVs 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.

4. Large Combustion Plant(s) description and number

The Permit uses the DEFRA LCP reference numbers to identify each LCP. The LCP Permitted, as proposed in Variation V011, is as follows: LCP689.

This LCP consists of one 1,500 MWth CCGT which vents via a single stack on the heat recovery steam generator (HRSG) (A106), when unabated, or via two carbon dioxide absorber stacks (A105a and A105b) when abated. The unit burns natural gas.

5. Net thermal input

The net thermal input of LCP689 is 1,500 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 an improvement condition, requiring the operator to provide this information within 12 months of the plant completing commissioning.

6. 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 and improvement condition, requiring the operator to provide this information within 12 months of the plant completing commissioning. Table S1.5 in the Permit has also been completed to reflect this.

7. Large Combustion Plant Best Available Techniques reference document conclusions

We have reviewed the Permit Application against the revised BAT Conclusions (BATc) for the LCP sector published on 31st July 2017.

BAT conclusions 1 – 17 applicable to all sites and 40, 42 & 44 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 13 of this decision document.

The BAT AELs have been set as discussed in section 10 of this decision document.

8. 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.

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 stacks (Emission Points A105a and A105b). When CO_2 is not being abated, combustion gases from the CCGT HRSG will be released from the HRSG stack (Emission Point A106).

The Applicants assessment states that emissions from release point A2 (equivalent to A106) would be released at a much higher temperature compared with emissions from release point A1 (A105a and A105b). 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 (A105a and A105b)) represent worse case, and the assessment detailed below presents the findings of this assessment.

8.1 Assessment Methodology

8.1.1 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 PC primarily for screening purposes and for estimating process contributions 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 process contributions calculated are likely to be an overestimate of the actual maximum concentrations. More accurate calculation of process contributions can be achieved by mathematical dispersion models, which take into account relevant parameters of the release and surrounding conditions, including local meteorology.

8.1.2 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 a very small number of cases, e.g. for emissions of Lead, the National EQS is more stringent that the EU EQS. 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** process contribution is less than **1%** of the relevant EQS; and
- the **short-term** process contribution is less than **10%** of the relevant EQS.

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

- spatial and temporal conditions mean that short term process contributions are transient and limited in comparison with long term process contributions;
- 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 contributions from other existing or planned developments, where relevant 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 of 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.

8.2 Assessment of Impact on Air Quality

The Applicant's assessment of the impact of air quality is set out in *Appendix F – Air Quality Impact Assessment'* dated July 2021. 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 and human health.

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 8.4.

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, for NO, CO, ammonia, amines, N-amines (nitrosamines and nitramines), acetaldehyde, formaldehyde and ketones which is a commonly used computer models for regulatory dispersion modelling. The model, for NO_x, CO and N-amines used 5 years of meteorological data collected from the weather station at Doncaster Robin Hood Airport which is 21km west 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 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 (nitrosamines and nitramines). 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 air impact assessments, and the dispersion modelling upon which they were based, employed the following assumptions.

For NO_x, CO, ammonia, amines, N-amines, acetaldehyde, formaldehyde and ketones emissions:

- First, the applicant has assumed that the ELVs in the Permit, for NO_x and CO, would be Permitted to BAT AEL levels outlined within the LCP BAT Conclusions or the IED ELV. These substances and levels are:
    - Oxides of nitrogen (NO_x), expressed as NO_2 – monthly concentration of 50 mg/m^3, hourly concentration of 100 mg/m^3, annual concentration of 30 mg/Nm^3 and daily concentration of 40 mg/Nm^3
    - Carbon monoxide (CO) – daily concentration of 110 mg/m^3, monthly concentration of 100 mg/m^3, hourly concentration of 200 mg/m^3, annual concentration of 100 mg/Nm^3

- Second, the applicant has assumed that the ELVs in the Permit for ammonia, total amines, acetaldehyde, formaldehyde and ketones at the following levels:
    - Ammonia – yearly concentration of 1.0 mg/m^3
    - Total amines - monthly concentration of 5.5 mg/m^3
    - Acetaldehyde – monthly concentration of 5.3 mg/m^3
    - Total nitrosamines - monthly concentration of 0.002 mg/m^3
    - Formaldehyde - monthly concentration of 0.5 mg/m^3
    - Ketones - monthly concentration of 5.0 mg/m^3
- Third, the applicant has assumed that the Installation operates at a worst case of up to 8,760 hours (constantly) in any given year.
- Fourth, the applicant produced the Air Quality Assessment at pre-Front-End Engineering Design (pre-FEED) stage. The applicant has made several assumptions about the plant design, as a result, the following key parameters (in which the consultant has based the AQA) will be subject to final FEED:
    - Absorber stack and building locations – modelled 4 possible locations. We have considered these in our checks
    - Stack configuration – height (105m) and diameter (6.8m)
    - Building configuration – height (90m) and the other dimensions that may affect downwash
    - Ammonia emission concentration – the AQA mentions that “until the licensor is chosen at FEED stage there is some uncertainty in the level of NH_3 emissions from the absorber stack”
    - Monoethanolamine (MEA) emissions concentration – 5.5 mg/Nm^3
    - N-nitroso-dimethylamine (NDMA) emissions concentration – 0.002 mg/Nm^3

The assumptions underpinning the model have been checked and are reasonably precautionary. We agree with the Applicant’s conclusions.

The Applicant used the values from the DEFRA background mapping system as background concentrations. Background concentrations from the Defra 2018-based background maps have been taken for the grid square in which the proposed Installation is located (National Grid Reference (NGR) 482500, 411500) for NO_x and NO_2). Background concentrations for CO are not available for the most recent Defra maps, but data for 2001-based background concentrations are available and this has been adjusted for 2018 using the Defra published year adjustment factors. Data for 2018 has been used for the assessment to represent a conservative approach, as the typical trend shown in the Defra background mapping is that over the projected time period, concentrations of NO_2 and NO_x are decreasing. This corresponds to a reduction overtime of vehicle emissions as newer, cleaner vehicles replace older ones. Therefore, assuming no reduction occurs until the opening year of the proposed Installation (earliest data 2026), is considered to represent a conservative approach. Amines, nitrosamines and nitramines are not routinely monitored in the UK, therefore, in the absence of data the applicant assumed background concentrations of these pollutants to be zero. We agree with this approach.

The Applicant provided us with modelled output showing the concentration of key pollutants at a number of specified locations within the surrounding area. We used our Air Quality Screening tool to audit these outputs and confirm the likely predicted peak ground level concentrations for nitrogen dioxide as well as auditing predicted concentrations at the receptors.

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.

8.2.1 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. 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, taken from Table 11 of the submitted Air Quality Assessment (AQA).

Table 1 – Process Contributions to Emissions to air from Keadby 3

Pollutant	EQS / EAL (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	Insignificant?
NO_2 Annual	40	1.3	3%	No – PC as a % of EAL > 1%
NO_2 Hourly mean	200	24.6	12%	No - PC as a % of EAL > 10%
CO 8-hour mean	10,000	190	2%	Yes - PC as a % of EAL < 10%
CO 1-hour mean	30,000	459	2%	Yes - PC as a % of EAL < 10%
NH_3 1-hour mean	2,500	7.8	0.3%	Yes - PC as a % of EAL < 10%
NH_3 annual mean	180	0.15	0.1%	Yes - PC as a % of EAL < 1%
Total Amines (as MEA) 1-hour mean (as the 100th percentile)	400	25.2	6%	Yes - PC as a % of EAL < 10%
Total Amines (as MEA) 24 hour mean	100	4.9	4.9%	No – PC as a % of EAL > 1%
Acetaldehyde 1-hour mean (as the 100th percentile)	9,200	24.3	0.3%	Yes - PC as a % of EAL < 10%
Acetaldehyde Annual Mean	370	0.21	<0.1	Yes - PC as a % of EAL < 1%
Formaldehyde 1-hour mean (as 100th percentile)	100	2.3	2.3	Yes - PC as a % of EAL < 10%
Formaldehyde Annual Mean	5	0.02	0.4	Yes - PC as a % of EAL < 1%

Pollutant	EQS / EAL (µg/m^3)	Process Contribution (PC) (µg/m^3)	PC as % of EQS / EAL	Insignificant?
Ketones 1-hour mean (as the 100th percentile)	89,500	22.9	<0.1	Yes - PC as a % of EAL < 10%
Ketones Annual Mean	6,000	0.2	<0.1	Yes - PC as a % of EAL < 1%

From the table above the following emissions can be screened out as insignificant, at maximum ground level concentration, in that the PC is <1% of the long term EQS/EAL and <10% of the short term EAQ/EAL. These are:

- Short-term carbon monoxide
- Short and long-term ammonia
- Short-term amines
- Short and long-term acetaldehyde
- Short and long-term formaldehyde
- Short and long-term ketones

From the table above the annual mean NOx PC is over 1% of the long-term EAL and the hourly mean NOx PC and 24 hour mean Total Amines PC are over 10% of the short-term EAL, so we also considered the NOx background levels and Total Amines (as MEA) contributions from local existing or planned sites to evaluate cumulative impacts:

Table 2a – Process Environmental Contributions (PECs) to Emissions to air from Keadby 3 (long-term)

Pollutant	EQS / EAL (µg/m^3)	Process Contribution (PC) (µg/m^3)	PC as % of EQS / EAL	PEC (µg/m^3) (Background + PC)	PEC as % of EQS	Insignificant?
NO_2 Annual	40	1.3	3	10.8	27%	Yes - PEC as a % of EAL < 70%
Total Amines (as MEA) 24 hour mean (maximum PC anywhere from Keadby 3 (K3) and including maximum anywhere PC from DRAX - VP3530LS/V022)	100	4.9	4.9	4.9 + 0.07 = 4.97	4.97%	Yes - PEC as a % of EAL < 70%
Total Amines (as MEA) 24 hour mean (maximum PC anywhere				4.9 + 0.1 = 5.00	5.00%	Yes - PEC as a % of EAL < 70%

Pollutant	EQS / EAL (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	PEC (µg/m³) (Background + PC)	PEC as % of EQS	Insignificant?
from K3 and including maximum anywhere PC from VPI - BJ8022IZ/V014)						
Total Amines (as MEA) 24 hour mean (maximum PC anywhere from K3 and including max anywhere PC from Phillips 66 - UP3230LR/V021				4.9 + 0.06 = 4.96	4.96%	Yes - PEC as a % of EAL < 70%

Table 2b - Process Environmental Contributions (PECs) to Emissions to air from Keadby 3 (short-term)

Pollutant	EQS / EAL (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	Background Concentration (BG)	PC as % of EAL – (2 x BG)	Insignificant?
NO_2 Hourly mean	200	24.6	12	19	15.2%	Yes – PC as % of EAL – (2 x BG) < 20%

When taking these 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 either of these pollutants at maximum ground level concentration.

Therefore, we consider the Applicant’s proposals for preventing and minimising the emissions of these substances to be BAT for the Installation subject to the audit of BAT considered later in this document.

N-Amines Assessment

The Environment Agency Risk Assessment Guidance includes Environmental Assessment Levels 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 12 to 18 of the Air Impact Assessment (Appendix F – Air Quality Impact Assessment, dated July 2021) submitted with the Application. The following table shows the predicted maximum (anywhere) NDMA PC (combined direct and indirect) when the solvent is assumed to be MEA. If a solvent other than MEA is used, a variation to re-assess these emissions is required:

Table 3 - N-Amine Process Contributions – Keadby 3 alone

Direct N-Amine Release PC (ng/m³) Keadby 3	Indirect N-Amine Release PC (ng/m³) Keadby 3	Combined N-Amine PC (ng/m³) Keadby 3	Total N-Amine EAL (ng/m³)	Combined PC as % EAL
0.08	0.022	0.102	0.2	51%

Table 4 - N-Amine Process Contributions from K3 (maximum anywhere) with the addition of local existing/planned contributions (maximum anywhere)

Pollutant	EQS / EAL (ng/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	PEC (µg/m³) (Existing/Planned site contributions + PC)	PEC as % of EQS	Insignificant?
Total N-Amines (as NDMA) annual average (including worst-case receptor PC from DRAX - VP3530LS/V022)	0.2	0.102	51%	0.102 + 0.02 = 0.104	52%	Yes - PEC as a % of EAL < 70%
Total N-Amines (as NDMA) annual average (including worst-case receptor PC from VPI - BJ8022IZ/V014)				0.102 + 0.195 = 0.297	148.5%	No - PEC as a % of EAL > 70%
Total N-Amines (as NDMA) annual average (including worst-case receptor PC from Phillips 66 - UP3230LR/V021				0.102 + 0.057 = 0.159	79.5%	No - PEC as a % of EAL > 70%

As Table 4 shows the cumulative impacts with VPI and Phillips 66 using maximum PCs anywhere, we have carried out a less conservative cumulative assessment of the PCs at receptors that are closest together from Keadby 3 and VPI/Phillips 66. The results of this assessment are shown in Table 5 below.

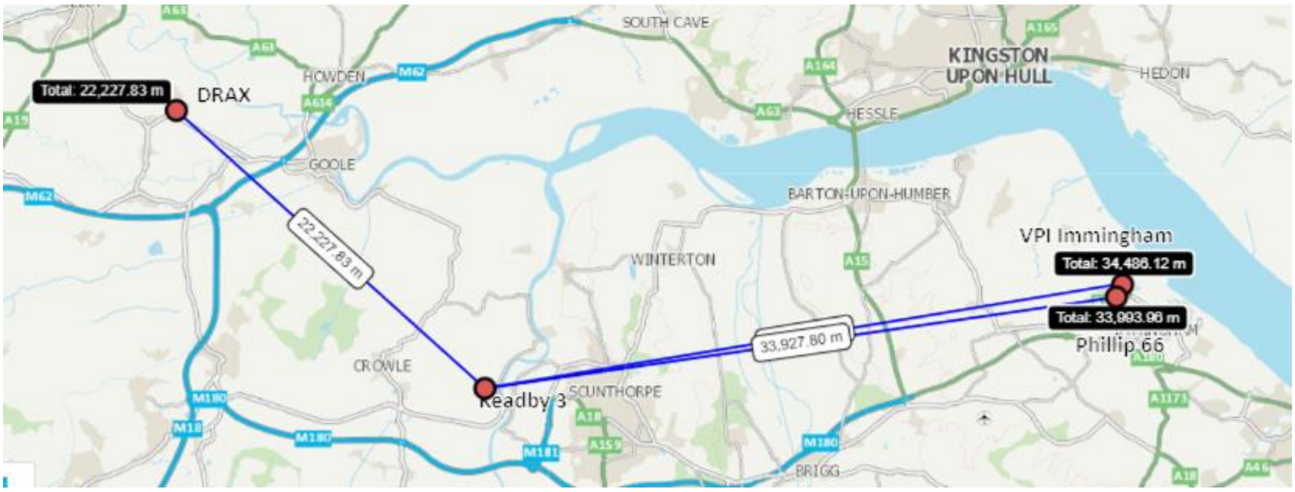
Table 5 - N-Amine Process Contributions from MEA with the addition of local existing/planned site PCs (closest receptors to one another from Keadby and from existing/planned site)

For the Keadby 3 contributions the direct emissions are taken from a screening assessment and the indirect emissions from ADMS modelling

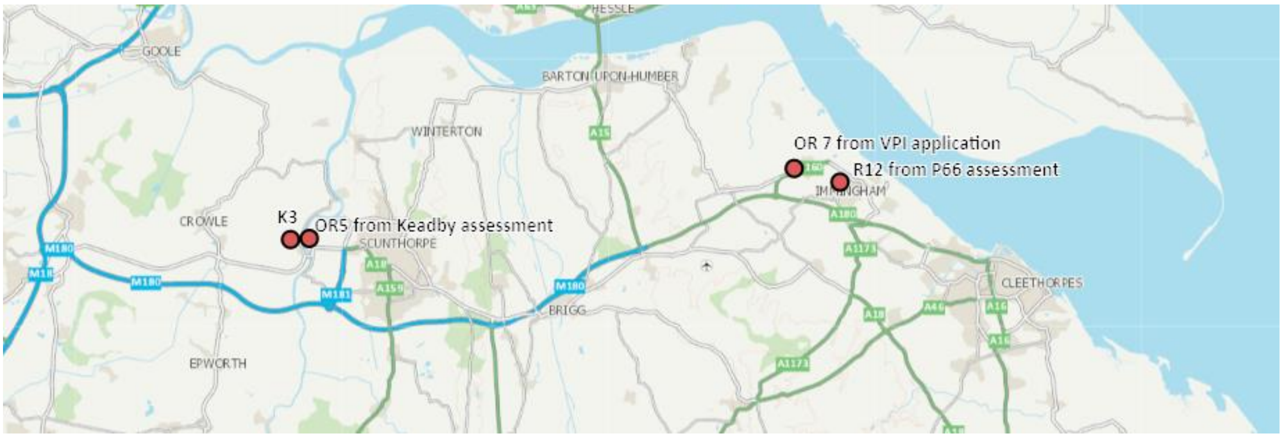
Pollutant	EQS / EAL (ng/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	PEC (µg/m³) (Existing/Planned site contributions + PC)	PEC as % of EQS	Insignificant?
Total N-Amines (as NDMA) annual average (including closest receptor PC from VPI - BJ8022IZ/V014)				(OR5 in Keadby assessment) 0.032 + (OR10 in VPI assessment) 0.012 = 0.044	22%	Yes - PEC as a % of EAL < 70%
Total N-Amines (as NDMA) annual average (including closest receptor PC from Phillips 66 - UP3230LR/V021				(OR5 in Keadby assessment) 0.032 + (OR12 in P66 assessment) 0.011 = 0.043	21.5%	Yes - PEC as a % of EAL < 70%

The receptor locations in relation to Keadby 3, VPI and P66 are shown in Plans 1 and 2 below:

Plan 1



Plan 2



The results for indirect N-Amine PCs (used in the assessment in Table 5) when using the mid-point of the reaction rate constants for MEA and including the dilution and entrainment option (as advised by CERC) are shown below:

Table 6 – Indirect N-Amine Process Contributions for MEA from K3 (including mid-point conversion reaction rate constants for MEA and including dilution and entrainment as advised by CERC).

AQ/EAL (ng/m^3)	Nitrosamine PC (ng/m^3)	Nitramine PC (ng/m^3)	Combined PC	Combined PC as % EQS/EAL
0.2	0.014	0.0073	0.022	11%

The results above are based on the following assumptions:

- The mid-point rate constant values with dilution and entrainment have been used in the assessment.

The results in Tables 1 - 6 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.

- This assessment assumes that all the N-amine (nitrosamine and nitramine) emission occurs as the nitrosamine NDMA, when this may only make up a small proportion (if any) of the direct release, with the total release comprising a number of nitrosamines and nitramines that are likely to be less toxic than NDMA. It is therefore considered that the PCs presented represent a worst-case assessment of the potential impact from the direct N-amine releases.

- NDMA ‘indirect’ predictions are based on the maximum highest concentration formed from reactions of direct MEA and NDMA releases and reactions. 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.

- During our audit of the modelling and report, we discovered that most of MEA reaction kinetic parameters differ significantly between the consultant’s and the Carbon Capture & Storage Association (CCSA) suggested list. It is understood that MEA is a primary amine and will not lead to stable nitrosamines. We have undertaken sensitivity to the parameters suggested by CCSA (and assuming nitrosamine formation) and note that they lead to significantly lower formation of nitrosamines and nitramines than using the consultant’s kinetic parameters. This indicates that the consultant’s kinetic parameters for MEA lead to conservative NDMA concentrations.

- During our audit of the modelling and report, we discovered that the consultant’s kinetic parameters for NDMA reactions are indicatively in the same order of magnitude to those suggested by the CCSA, except for the reaction rate constant for amino radical with O2 to form imine (i.e., k2), which is approximately 14 times higher than that suggested by the CCSA. The consultant refers to this parameter as a “significant uncertainty in the assessment”. We have undertaken sensitivity to varying k2 individually, assuming the CCSA value.

8.2.2 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 μg/m^3 as a long-term annual average and a short-term hourly average of 200 μg/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 1, 2a and 2b show that the long-term PC is 3% of the EU EQS and the short-term PC is 12% of the EU EQS at sensitive receptors, however 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 section 8.5 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 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) Emissions to Air of CO

The above table 1 shows that for CO emissions, 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) Ammonia

The above table 1 shows that the annual and hourly mean PCs of ammonia as a result of the proposed Installation represent less than 1% and 10% of the relevant long and short-term AQALs and therefore can be considered insignificant at the first level of screening at all receptor locations.

(vi) Total Amines (As MEA)

The above table 1 shows that the 24 hour mean PC of amines as a result of the proposed Installation represents 4.9% of the relevant AQAL for MEA. As it is assumed that the background concentration is 0 ug/m^3, however we have included an assessment of the process contributions from local existing or planned sites to evaluate predicted cumulative impacts (table 2 a); the PECs are as follows:

- The maximum PC anywhere from Keadby 3 and the maximum PC anywhere from DRAX is 4.97% and therefore can be screened out (<70% of the EAL) at the second level of screening.
- The maximum PC anywhere from Keadby 3 and the maximum PC anywhere from VPI is 5.00% and therefore can be screened out (<70% of the EAL) at the second level of screening.
- The maximum PC anywhere from Keadby 3 and the maximum PC anywhere from Phillips 66 is 4.96% and therefore can be screened out (<70% of the EAL) at the second level of screening.

The hourly mean PC at the maximum impacted location is 25.2 ug/m^3, representing 6% of the AQAL, and is therefore less than the 10% threshold for insignificance for short term impacts.

(vii) Amine degradation products (aldehydes and ketones)

The above table 1 shows that the annual mean PCs of acetaldehyde, formaldehyde and ketones that occur anywhere as a result of the proposed Installation, represent less than 1% of the relevant AQALs at all locations and therefore can be considered to be insignificant at the first stage of screening.

The hourly PCs are all less than 10% of the relevant AQALs at all locations and therefore can be considered to be insignificant at the first stage of screening.

(viii) Nitrosamines and Nitramines – N-Amines

The results, shown in the above tables 3, 4, and 5, of the N-Amines assessment show that the combined direct and indirect process contributions of N-amines from Keadby 3 alone are 51% of the EAL and so are not insignificant. As a result, we have included an assessment of the combined direct and indirect N-Amine process contributions from local existing or planned sites to evaluate predicted cumulative impacts; the PECs are as follows:

- The combined maximum PCs anywhere from Keadby 3 and DRAX is 52% and therefore can be screened out (<70% of the EAL) at the second level of screening.
- The combined maximum PCs anywhere from Keadby 3 and VPI is 148.5% of the EAL and therefore cannot be screened out (>70% of the EAL) at the second level of screening. An assessment of the PCs at the discrete receptors closest to each other from Keadby 3 (OR5) and VPI (OR7) was carried out. The PCs from Keadby at OR5 and the PCs from VPI (OR7) were combined to assess the cumulative impact. The PEC is 22% of the EAL and can be screened out (<70% of the EAL) at the third level of screening.
- The combined maximum PCs anywhere from Keadby 3 and Phillips 66 is 79.5% of the EAL and therefore cannot be screened out (>70% of the EAL) at the second level of screening. An assessment of the PCs at the discrete receptors closest to each other from Keadby 3 (OR5) and Phillips 66 (OR12) was carried out. The PCs from Keadby at OR5 and the PCs from Phillips 66 (OR12) were combined to assess the cumulative impact. The PEC is 21.5% of the EAL and can be screened out (<70% of the EAL) at the third level of screening.

Therefore, we consider the Applicant's proposals for preventing and minimising the emissions of these substances is likely to be BAT for the Installation and the emissions of N-Amines are unlikely to result in an exceedance of the available EALs at discrete receptors.

(iv) Acetic Acid

The applicant has not included acetic acid in their assessment. Since acetic acid may be released as a potential amine-based solvent degradation product, we have considered this in our audit of the submitted modelling. Emissions of acetic acid are unlikely to result in an exceedance of the relevant EAL.

8.3 Assessment of acute impacts of CO_2 venting

The Applicant's assessment of the acute impacts of CO_2 venting is set out in *Appendix B – CO_2 Toxic Dispersion Risk Assessment* dated February 2024 of the Application.

The aim of the CO_2 Toxic Dispersion Risk Assessment is to evaluate the hazard ranges associated with toxic gas dispersion for specified CO_2 vent and venting scenarios, with respect to the potential to reach and create hazardous (toxic) atmospheres for operators and the public outside the facility's boundaries.

This section of the decision document deals primarily with the dispersion modelling of emissions to air from CO_2 venting from the Installation and its impact on human health.

The Applicant has assessed the Installation's potential emissions to air against the relevant air quality standards (UK HSE Workplace Exposure Limit (WEL)), and the potential acute impacts upon human health. These assessments predict the potential effects on human health from the Installation's stack emissions using the Phast™ (Process Hazard Analysis Software Tool) v8.9 dispersion model, for CO_2, which is a comprehensive consequence modelling tool, which is applicable to all stages of design and operation across a wide range of process industries. Phast™ was specifically validated for full scale releases of CO_2.

The model used 4 years of meteorological data collected from the weather station Doncaster Robin Hood Airport, which is 21km west 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 acute human health impact assessments, and the dispersion modelling upon which they were based, employed the following assumptions:

For CO_2 venting emissions:

1. The main ‘worst case’ scenario used in the CO_2 venting assessment assumes that the compressed and chilled CO_2 is routed via the Carbon Capture Absorber Stacks without the influence of the hot flue gas on the CO_2 plume, and thus this is not accounted for in the venting assessment. This is expected to be a more conservative approach since it is assumed that the hot flue gases could warm up the CO_2 plume, thereby making it less dense, due to the combined effect of temperature increase and dilution, and less likely to slump back towards the ground.
2. The stream is composed of 100% CO_2.
3. The vent tip is assumed to be directed vertically.
4. The total venting flowrate (provided by Aker [7] SHE-ASL-DOC-CCP-MS-KEAD3-00001 Rev 01 - Keadby 3 Safety Studies Scope of Work (EI-048 Addendum for Absorber CO2 Venting)) is equally split between the two vents.
5. Weather conditions are constant during the entire release duration (i.e., 90 minutes).
6. The presence of equipment / obstacles in the area around the release is neglected.
7. Receptor height is set at 2 m from ground level.
8. The release flowrate is assumed to be constant over time during the entire discharge phase (i.e., constant release rate of 83.2 kg/s between 0 and 30 minutes then constant release rate of 77.8 kg/s between 31 and 90 minutes).
9. The calculated diameter refers to the internal diameter of the piping (i.e., the one defining the cross section).

The assumptions underpinning the model have been checked and are reasonably precautionary. We agree with the applicant’s conclusions.

There are several country-wide annual average databases representing buoyant CO_2 background concentrations (e.g., approximately 400 ppm in the UK in 2016). However, CO_2 is not routinely monitored at a local level representing similar conditions to those releases in scope. This indicates uncertainty and variability in the representation of background concentrations. The applicant did not consider background concentrations. We agree with this approach at the time of writing this document.

The Applicant provided us with modelled output showing the concentration of key pollutants at a number of specified locations within the surrounding area. We conducted check modelling based on consultant’s Phast™ (version 9.0) modelling file and our own indicative modelling in ADMS (version 6.0.1).

Provided CO_2 venting is minimised and under the conditions modelled, we consider that exceedances of the proposed assessment criteria of 5,000 ppm at sensitive receptors are unlikely. As a result of our checks, we found that although we do not necessarily agree with the applicant’s approach, we agree with the conclusions in the scope of the limitations of the assessment. However, we cannot rule out exceedances of the alternative 2,000 ppm threshold.

The Applicant’s modelling predictions are summarised in the following section.

Key considerations of emissions of carbon dioxide from venting

The modelling has shown that at no point is a concentration of 0.5% CO_2 predicted to occur at receptor height, noting that conservative assumptions have been included within the modelling methodology.

It was also found that toxic impact from the absorbers is limited and the occurrence of low (0.2% / 2000ppm) CO_2 concentrations reaching the ground is highly unlikely and is not in the direction of human receptors

Guidance published by the HSE (‘Assessment of the major hazard potential of carbon dioxide’), reports a concentration of 3% CO_2 for 1 hour exposure as the concentration responsible for headaches. Furthermore, PHE/UKHSA guidance (‘Compendium of Chemical Hazards: Carbon Dioxide’) indicates a 2-5% CO_2 concentration as the indicative reported effect level associated with symptoms such as headaches, dizziness, sweating, shortness of breath for inhalation of CO_2.

The applicant has used concentration thresholds an order of magnitude lower than the above concentrations, therefore, the risk assessment is much more conservative and has demonstrated that the impacts on human health from short-term duration venting are not predicted to be significant.

We agree with the applicant’s conclusions, noting the limited scope of applicability of the CO_2 venting assessment:

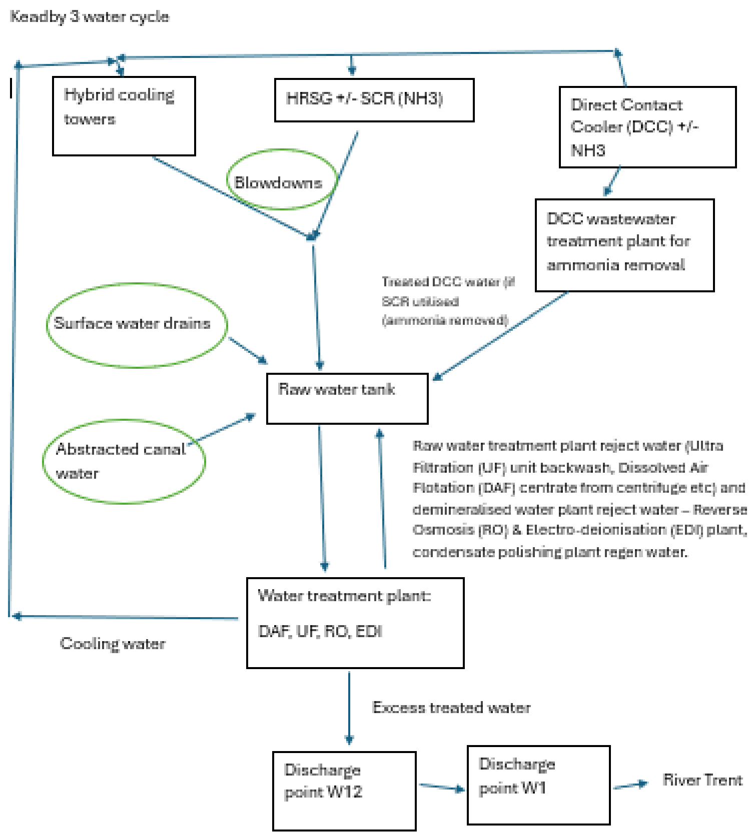
1. Maximum release duration of 90 minutes at any one time (scenario 2).
2. CO_2 at release is fully expanded gas at a maximum of 83.2 kg/s and minimum exhaust temperature of 23°C (scenario 2).
3. Vent heights are 92m with indicative combined diameters of 51” or 36”.
4. Modelling may not be representative with a 50m vent height if surrounding structures affect downwash.

Pre-operational condition PO7 has been included in the Permit to validate assumptions made in the submitted CO_2 venting emissions to air risk assessment.

8.4 Emissions to Water

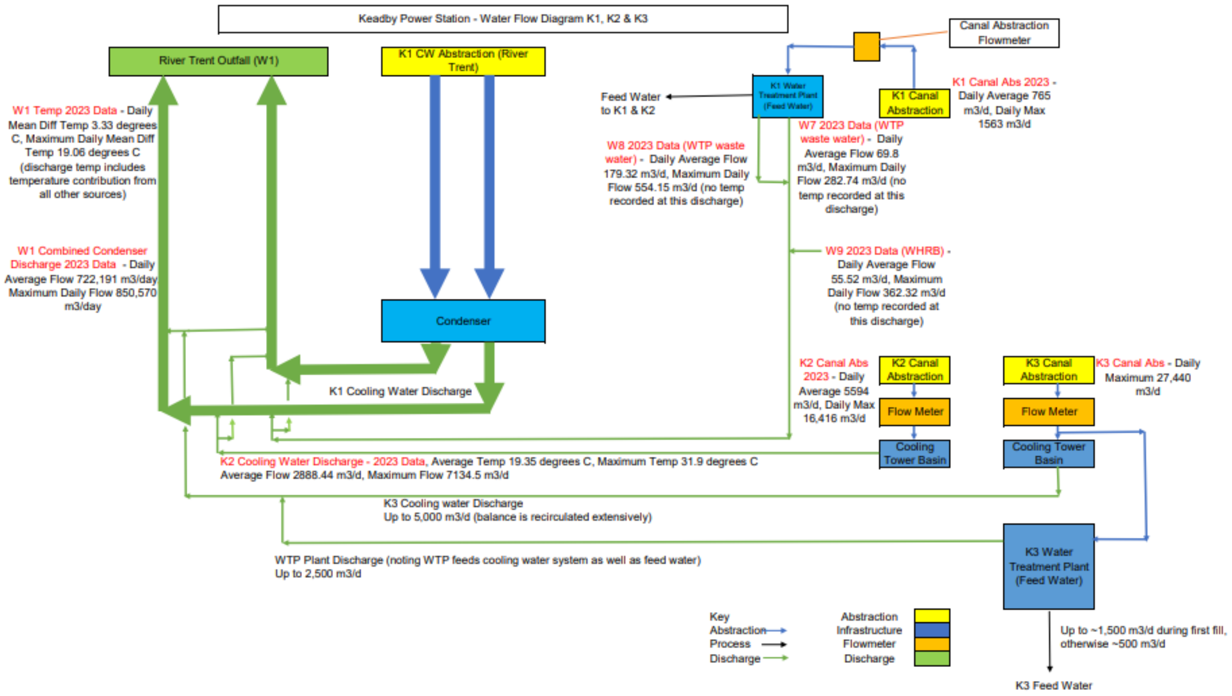
Water and Wastewater Cycle at Keadby

The make-up of the raw water used on site is simplified in the following diagram:



Potential impacts of thermal plume discharge (V011)

The combined thermal plume emissions from the Keadby site consists of the following sources:



The combined effluent discharge from W12 (via W1) has been assessed for impact significance with all parameters found to be insignificant in the H1 screening tests with the exception of the following which required modelling:

- Keadby 2 and Keadby 3 Thermal plume (V011) – the combined discharge of cooling water from Keadby 2 and Keadby 3 operating concurrently was modelled using the CORMIX hydrodynamic modelling software. The results of the modelling show that the thermal plume temperatures at the edge of the mixing zone do not exceed the thresholds for thermal discharges into European Marine Sites designated under the Habitats Directive under the Water Framework Directive, nor does the temperature uplift of 2°C in the mixing zone occupy more than 25% of the cross section of the Estuary for more than 5% of the time (UKTAG 2008) and should not form a barrier to migration across the whole estuary or block areas of the estuary through which fish are likely to pass.
- Keadby 2 and Keadby 1 (one-pump scenario) Thermal plume (V012) – the combined discharge of cooling water from Keadby 2 and Keadby 1 – one pump scenario, operating concurrently was modelled using the CORMIX hydrodynamic modelling software. The results of the modelling show that temperatures at the edge of the mixing zone do not exceed the thresholds for thermal discharges into European Marine Sites designated under the Habitats Directive under the Water Framework Directive, nor does the temperature uplift of 2°C in the mixing zone occupy more than 25% of the cross section of the Estuary for more than 5% of the time (UKTAG 2008) and should not form a barrier to migration across the whole estuary or block areas of the estuary through which fish are likely to pass.

  The intention of these mixing zone boundaries is to maintain an open corridor for fish migration. An estuary's cross section should not have an area larger than 25% with a temperature uplift above 2°C, for more than 5% of the time.

  As a result, we do not expect there to be an adverse effect on site integrity and so to the migratory species found in the designated site.

The Applicant employed a consultant to undertake a data collection exercise including; river cross-section profiles, hydrodynamic model from EA, sampling for ambient temperature and concentration, discharge characteristics and wind conditions at Keadby. The study identified the pollutants released from the proposed

Installation and a H1 screening assessment was carried out to identify species requiring further modelling. Detailed water quality dispersion modelling has then been carried out using CORMIX software for the thermal plume discharge.

The emission to water discharges from Keadby 3 of cooling water from the hybrid cooling towers will be released via emission point W12, into the Keadby 1 cooling water culvert before final discharge to the River Trent at W1. It is considered that all the contaminants present within the release (except for ammonia) are associated with the concentration up of existing contaminants present in the abstracted canal water utilised for cooling water make-up. The H1 tool therefore examines the discharge of Keadby 3's cooling water in the absence of the Keadby 1 cooling water flow, as this represents the worst case for dispersion. The total volume of substances discharged remains the same regardless of the presence or absence of Keadby 1's cooling water discharge. There is no readily available river flow data for the River Trent near to Keadby, and therefore river flow data for the upstream river monitoring station 28022 River Trent at North Muskham. This is the last upstream flow monitoring station on the River Trent, and has been collated from the National River Flow Archive. The river monitoring station, North Muskham, is located approximately 40 miles upstream of the location of W1, and hence may underestimate the flow in the river at the W1 discharge point. A Q95 river water flow rate of 28.9m^3/s has been used in the assessment. The details of the calculated K2 and K3 cooling water discharge that have been assessed are provided in Table 2.1:

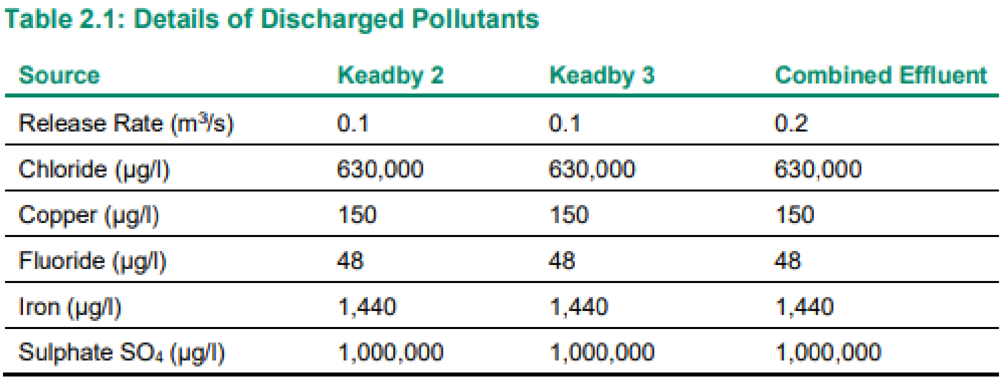


Table 2.1: Details of Discharged Pollutants

Source	Keadby 2	Keadby 3	Combined Effluent
Release Rate (m^3/s)	0.1	0.1	0.2
Chloride (µg/l)	630,000	630,000	630,000
Copper (µg/l)	150	150	150
Fluoride (µg/l)	48	48	48
Iron (µg/l)	1,440	1,440	1,440
Sulphate SO_4 (µg/l)	1,000,000	1,000,000	1,000,000

All of the above pollutants are found to be insignificant in H1 screening tests and so ELVs have not been set in the Permit.

Emissions of un-ionized ammonia in the thermal plume discharges

If the site will utilise SCR on the proposed Keadby 3 CCGT, the operator will carry out additional treatment of the Direct Contact Cooler (DCC) wastewater to recover and remove ammonia (this is explained further in the 'cooling water' section below). There will still, however, be residual ammonia in the effluent which will be discharged into the sites cooling water discharge.

In general, the un-ionized form of ammonia is more toxic than the ionized form. At higher pH values, un-ionized ammonia represents a greater proportion of the total ammonia concentration. Temperature increase also raises the relative proportion of un-ionized ammonia, but this effect is much less marked than for pH change. A greater percentage of ammonia will also be in the un-ionized form when the salinity is lower. The concentration of un-ionized ammonia can therefore be derived from knowledge of the total ammoniacal nitrogen concentration (i.e. NH_4 as N), the salinity, the pH and temperature. The EQS for un-ionized ammonia is 21 µg/l expressed as an annual average.

Keadby 3 power station is proposing to discharge cooling waters with elevated temperature and this will in turn affect the Ammoniacal nitrogen:un-ionized ammonia ratio, increasing the un-ionized element. The applicant has modelled un-ionized ammonia concentration using peak summertime river temperatures of 19.1 ºC and therefore a discharge temperature of 47.1 ºC degrees with mean values of pH, 8.01 and ammoniacal nitrogen 0.0653 mg/l. The results show initially high values of 12 ug/l which then drop as the temperature decreases away from the discharge. There are no predicted values above 21 ug/l, thus the EQS is not predicted to be exceeded.

The applicant has proposed a 6 – 9 pH emission limit for the Keadby 3 emissions to water discharge (W12) to account for seasonal variations in the pH of the abstracted cooling water (occasionally >9). As both temperature and pH variations affect the Ammoniacal nitrogen:un-ionized ammonia ratio, increasing the un-ionized element, we have assessed two worst case scenarios

- the ambient summer temperature and maximum differential temperature and associated average pH levels, and
- the maximum effluent pH and associated seasonal ambient and differential effluent temperature levels

Table 7 - Un-ionized ammonia levels using the ambient summer temperature and maximum differential temperature and associated average pH level

pH	7.85	**summer average - June, July, Aug**
max ambient T and ΔT	47	ambient 19.1 **(summer - June, July, Aug)**, ΔT 28 deg C (one-pump scenario)
mean salinity	0.13	ppt
ammoniacal N	0.0715	mg/l - **(summer average - June, July, Aug)**
un-ionized ammonia	12.7	ug/l

Table 8 - Un-ionized ammonia levels using the maximum effluent pH and associated seasonal average ambient and differential effluent temperature levels

max pH	9.13	**March average**
max ambient T and ΔT	18.2	ambient 5.6 **(Winter Average)**, ΔT 12.6 deg C (winter normal operation differential)
mean salinity	0.13	ppt
ammoniacal N	0.042	mg/l - **(March average)**
un-ionized ammonia	16	ug/l

The resulting un-ionized ammonia concentrations in both (worst case) scenarios is less than the un-ionized ammonia EQS (21 ug/l).

We agree with the conclusion that the discharge of un-ionized ammonia can be classed as unlikely to cause pollution during normal or one-pump scenario operations.

Emissions of total ammonia in the thermal plume discharges

The Keadby discharge is to a TraC (Transitional and Coastal) waterbody. There is no total ammonia class for TrAC waterbodies in the Water Framework Directive and so there is no need for a total ammonia assessment for this discharge.

Rerouting of cable pull pit effluent from Keadby 2 (V013)

A H1 screening assessment has been undertaken to determine whether the addition of the re-routed discharge of cable pull pit water from the site to emission point W10 represents a potential risk to the river Trent. Rainwater from the Keadby 2 cooling tower roofs that is included in this variation application, was not included in the assessment on the assumption that this is clean, uncontaminated surface water that should not result in harmful emissions to the environment.

The proposed effluent discharge of W10 has been assessed independently of mixing/the addition of effluent flows of Keadby 1 W1 cooling water flow. Therefore, the H1 assessment did not take into account the additional dilution from W1 effluent stream which W10 ultimately combines with before discharging to the environment. The results of the highly conservative H1 assessment indicate that all substances screen out in the TRAC Riverine water tests.

The following parameters were taken through the H1 assessment:

- Dissolved Arsenic
- Dissolved Barium
- Dissolved Boron
- Dissolved Copper
- Dissolved Nickel
- Dissolved Selenium
- Dissolved Vanadium
- Dissolved Zinc
- Dissolved Mercury
- Sulphate (SO_4)
- Naphthalene
- Phenanthrene
- Carbazole
- Chloride
- Fluoride
- Iron
- Dissolved Iron

Wastewater Treatment

The key sources of waste waters generated at Keadby 3 originate from:

- Clean surface water run-off from non-process areas
- Blow down from the hybrid cooling towers and HRSG
- Waste water Direct Contact Cooler (DCC) (from the wastewater treatment plant to remove ammonia, if necessary) reused in the cooling towers/HRSG prior to discharge with the blow down detailed above
- Demineralisation plant and condensate polishing plant regeneration; and
- Rejected wastewater stream from the raw water treatment plant

There will be no emission of amine solvent/solvent breakdown products to process waters. Any water contaminated with amine solvent/solvent breakdown products will be taken off-site for treatment at an authorised facility (acid wash water) or returned to the solvent loop (water wash water and CO_2 conditioning wastewater).

Cooling water

To reduce the abstracted water volume required for cooling, a water treatment plant will receive water from a raw water tank, which is made up of abstracted canal water, surface water drainage, treated DCC water, centrate water from the Dissolved Air Flotation (DAF) centrifuge, backwash from the UltraFiltration (UF) units, cooling tower blowdown, and other wastewaters on site suitable for reuse.

The water treatment plant will include Dissolved Air Flotation (DAF) units (to remove suspended solids and algae from the abstracted canal water), Ultrafiltration (UF) units, Reverse Osmosis (RO) units and an electro-deionisation (EDI) plant.

The sludge from the DAF plant will be centrifuged to remove water, with the solids being collected for offsite treatment and disposal. The centrate water will be recycled back through the water treatment plant via the raw water tank.

The DCC wastewater will be reused in the process (e.g. cooling water makeup) via additional treatment (to remove ammonia (slip) from the use of SCR, if necessary), any excess treated DCC water will be discharged in combination with the water treatment plant water and cooling water directly to the River Trent via compliance point W12 to the existing Keadby 1 discharge point (W1).

It is undecided whether the quench water (from the HRSG) will be treated, this decision depends on whether the operator will utilise Selective Catalytic Reduction (SCR), if it is decided that SCR will be utilised for Keadby 3, the applicant proposed that:

Additional treatment to remove ammonia may be required prior to onward use. There are a number of ways in which this could be achieved, however the current proposed method is by the addition of sodium hydroxide solution to increase the pH, and warm air stripping within a small column absorber.

The ammonia in the DCC wastewater will be recovered as follows:

- *Granulated Activated Carbon (GAC) filter for solids removal.*
- *The filtered water will then be pumped under high pressure to a Reverse Osmosis (RO) unit. The high pressure is required to overcome the osmotic potential of the water to remove 95% of the ammonium salts present in the wastewater.*
- *Concentrate from the RO will be higher in ammonium salts and will flow to a second pass RO unit for further concentration and water separation. The treated RO permeate (now low in ammonium) will flow to the Raw Water tank and be combined with incoming canal water for reuse within the cooling water circuit.*
- *The concentrate from the second pass RO will be treated in the ammonia scrubber. The ammonia scrubber will separate ammonium from the concentrate from the second pass RO, targeting a removal efficiency of 85% of the ammonium from the wastewater. A first packed column will convert the ammonium solution back to ammonia gas. The scrubbed water will go back to the DCC Water Tank for re-use.*
- *The ammonia gas from the first scrubber column will flow into the second column where it will react with sulphuric acid and make-up water to create a high strength (35%w/w) ammonium sulphate solution. The ammonium sulphate will be pumped from the base of the second column to a holding tank for tankering off-site to be sold to a chemical distributer for use as fertiliser. An air blower will recirculate air from the second column back through the first column to extract the ammonia gas.*
- *The stripping air, containing ammonia, would then enter a separate absorption section against a counter-flow of sulphuric acid to generate ammonium sulphate. The stripping air would then be recycled within the process, avoiding the need for venting to atmosphere, and there would be no emissions to atmosphere from the DCC wastewater treatment system under normal operation. In the event that there is excess DCC water for reuse, there will be a discharge directly to the River Trent via a compliance point (W12) to the existing Keadby 1 discharge (W1).*

Pre-operational condition PO4 has been included in the Permit which requires the operator to confirm whether SCR will be utilised and thus whether the above DCC wastewater treatment and recovery process will be undertaken.

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

8.5.1 Sites Considered

Emissions to air

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

- Humber Estuary – SAC/Ramsar
- Humber Estuary (at Blacktoft Sands) – SAC/SPA/Ramsar
- Thorne Moor – SAC
- Thorne and Hatfield Moors - SPA

The following Sites of Special Scientific Interest (SSSIs) are located within 2km of the Installation:

- Humber Estuary

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

- Stainforth and Keadby Canal Corridor – Local Wildlife Site (330m)
- Keadby Wetland - Local Wildlife Site (695m)
- Keadby Wet Grassland - Local Wildlife Site (710m)
- Three Rivers - Local Wildlife Site (1.1km)
- Ash Tip - Local Wildlife Site
- Keadby Boundary Drain – Local Wildlife Site
- South Soak Drain – Local Wildlife Site
- Keadby Warping Drain – Local Wildlife Site

Emissions to water

The following Habitats (i.e. Special Areas of Conservation, Special Protection Areas and Ramsar) sites are located downstream of the point source emission to surface water from the Installation:

- Humber Estuary – SAC/Ramsar

The following SSSIs are located downstream of the point source emission to surface water from the Installation:

- Humber Estuary

The following protected species are located downstream of the point source emission to surface water from the Installation:

- Smelt Osmerus: eperlanus migratory route
- European Eel: Anguilla migratory route
- Atlantic Salmon: Salmo salar migratory route
- Twaite shad alosa: fallax migratory route
- Allis shad alosa: alosa migratory route
- River lamprey: lampetra fluviatilis migratory route
- Sea lamprey: Petromyzon marinus migratory route

8.5.2 Habitats Assessment

We have assessed the impact from the proposed combustion plant on the four Habitats 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 process contributions 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.

Emissions to air

The Applicant's modelling predicted pollutant concentrations at ecological receptors. The tables below show the ground level concentrations from the installation at the most impacted ecological receptors:

- OE1-5 – Humber Estuary – SAC/Ramsar/SSSI – NO_x (annual and daily mean), NH_3 (long term annual critical level) and Nutrient Nitrogen Deposition (annual critical load),
- OE21 – Scotton and Laughton Forest Ponds – SSSI – Acid Deposition (annual critical load)

Where emissions screen out as insignificant, the background pollutant levels are not considered within the assessment in accordance with our H1 screening process.

The Applicants modelling did not include emissions of total amine releases into the nutrient nitrogen deposition predicted pollutant concentrations at ecological receptors, however we have included this in our sensitivity checks and have concluded that the addition of these emissions will not change the conclusions of the assessment.

The result of the modelling assessment are as follows:

Humber Estuary - SAC, Ramsar and SSSI

Table 9 - Keadby 2 and Keadby 3 impacts - OE1-5 - Humber Estuary SAC, Ramsar and SSSI;

Pollutant	EAL/critical level/critical 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
Direct Impacts[1]						
NO_x Annual	30	13	1.3	4.2%	14.3	48%
NO_x Daily Mean	75	19.5	17.7	24%	37.3	50%
Ammonia (critical level)	3	2.3	0.11	3.6%	2.41	80%
Deposition Impacts[1]						
N Deposition (critical load - kg N/ha/yr)	20	19.7	0.67	3.35%	20.4	102%
Note 1: Direct impact units are µg/m³ and deposition impact units are kg N/ha/yr or Keq/ha/yr.						

Table 9 above show that the PCs **cannot** be considered insignificant for all pollutants, in that the PC is greater than 1% of the long-term EQS, critical level or critical load and 10% of the short-term EQS.

So, we also considered the background levels.

When taking the background levels 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 or critical level for the following:

- NOx annual mean and NOx daily mean,
- Ammonia (critical level).

When taking the background levels into account there is **not** adequate headroom between the PEC and EAL to indicate that it is unlikely that there will be an exceedance of an EQS for nutrient nitrogen deposition, and therefore an appropriate assessment (habitats) was required for the features that directly or indirectly depend on the habitat for the following:

- Nutrient nitrogen deposition

Table 10 - Keadby 3 alone impacts - OE1-5 - Humber Estuary SAC, Ramsar and SSSI;

Pollutant	EAL/critical level/critical 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[1]						
N Deposition (critical load - kg N/ha/yr)	10	19.7	0.09	0.9%	-	-
Note 1: Deposition impact units are kg N/ha/yr or Keq/ha/yr.						

The Applicant's Air Quality Assessment (AQA) assessed the combined emissions from the Keadby 2 and Keadby 3 CCGT plants. The variation applied for is only for the addition of Keadby 3; the Keadby 2 Permit was issued in 2020 and therefore emissions from that plant are considered part of the baseline. A review of the AQA for Keadby 2 shows nitrogen deposition PCs from Keadby 2 are 0.58 kgN/ha/yr and so it is estimated that actual Keadby 3 PCs would be 0.09 kgN/ha/yr. According to EA data, upper marsh is present at or nearby the receptor locations, and so it is appropriate to apply a critical load (CL) of 10 kgN/ha/yr. The PC from Keadby 3 would then equate to 0.9% of the critical load and would mean the nutrient deposition results for Keadby 3 screen out as insignificant.

We are therefore satisfied that the Installation will not cause significant pollution at the sites. The Applicant is required to prevent, minimise and control emissions using BAT, this is considered further in Section 9.

Scotton and Laughton Forest Ponds – SSSI

Table 11 - Keadby 2 and Keadby 3 impacts - OE21 - Scotton and Laughton Forest Ponds – 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
Deposition Impacts[1]						
Acidification - Acid Dep (Keq/ha/yr)	Min Cl Min N – 0.321 Min Cl Max N - 0.484 Min Cl Max S – 0.163	1.5	0.006	1.87%	1.506	469%
Note 1: Deposition impact units are kg N/ha/yr or Keq/ha/yr.						

Table 11 above show that the Acid Deposition PC **cannot** be considered insignificant in that the process contribution is greater than <1% of the long-term critical load and the PEC is greater than <100% of the long term critical load.

Table 12 - Keadby 3 alone impacts - OE21 - Scotton and Laughton Forest Ponds – 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
Deposition Impacts[1]						
Acidification - Acid Dep (Keq/ha/yr)	Min Cl Min N – 0.321 Min Cl Max N - 0.484 Min Cl Max S – 0.163	1.5	0.001	0.31%	-	-
Note 1: Deposition impact units are kg N/ha/yr or Keq/ha/yr.						

However, the Applicant's Air Quality Assessment (AQA) assessed the combined emissions from the Keadby 2 and Keadby 3 CCGT plants. The variation applied for is only for the addition of Keadby 3; the Keadby 2 Permit was issued in 2020 and therefore emissions from that plant are considered part of the baseline. A review of the AQA for Keadby 2 shows acid deposition PCs from Keadby 2 are 0.005 Keq/ha/yr and so it is estimated that actual Keadby 3 PCs would be 0.001 Keq/ha/yr. Applying the lowest critical load (CL) of 0.321 Keq/ha/yr for the site. The PC from Keadby 3 would then equate to 0.31% of the critical load and would mean the acid deposition results for Keadby 3 screen out as insignificant in that the PC from Keadby 3 is <1% of the long-term critical load.

We are therefore satisfied that the Installation will not cause significant pollution at the sites. The Applicant is required to prevent, minimise and control emissions using BAT, this is considered further in Section 9.

No further assessment of impact on conservation sites is required.

Emissions to water

The Applicant employed a consultant who has undertaken an effluent dispersion modelling study to assess the impacts on water quality in the River Trent for the development of Keadby 3 power plant.

A H1 assessment has been completed. Screening tests determined the pollutants such as Chloride, Fluoride, Iron and Sulphate are insignificant. However, the total ammonia within the wastewater should be considered for detailed water quality modelling study.

We (the Environment Agency) provided a regional hydrodynamic model to inform the water level and flow speed information for CORMIX model inputs. The model review showed that the tidal levels over spring-neap tidal cycles are well reproduced, and the model shows a reasonable simulation of the Keadby site.

The discharge velocity of 1.32m/s and existing invert level of pipe at -3.05mAOD have been used as inputs for the modelling study. It requires pumped outfalls if the required velocity is not achievable for gravity systems.

CORMIX water quality modelling was carried out for the total ammonia and thermal discharge. 6 model scenarios were identified, total ammonia for Keadby 3 - Option 1 and Keadby 3 – Option 2, thermal discharge for Keadby 3 - Option 1, Keadby 3 - Option 2 and Keadby 3 - Option 2 + Keadby 2, one-pump scenario for Keadby 2.

Modelled plume extents were explored for the specified concentration, 0.3mg/l for the total ammonia and 2.0°C excess for temperatures. The results provide the maximum plume width across the channel and plume length along the channel downstream/ upstream from the outfall location.

None of plumes in five established scenarios is predicted to cross the entire channel. All plume widths are within 25% of total channel width.

For the one-pump scenario the model has used the SAC imposed limits of 21.5°C at the edge of the mixing zone

- For the total ammonia, the widths are 19.6m for Scenario 1 and 37.4m Scenario 2 as the worst cases, which are equivalent to 10% and 20% of total channel width (190m).

- For the thermal dispersion, the maximum predicted extents of 2°C above the ambient water temperature were 1.2m, representing only <1% of the total channel width.

- For the total ammonia, predicted maximum plume length along the riverbank was 163.1m (scenario 1). For the thermal dispersion the maximum length was 14.5m (2°C) in Scenario 4. The thermal dispersion simulations show that the excess temperature in the plume drops substantially within the first 50m from the outfall point.

- Results from the modelling confirm that it is unlikely that both total ammonia and thermal plumes are attached to the left riverbank (looking downstream) in a confined small area. The thermal effects are expected to be localised and an excess temperature of 2.0°C is achieved in a range of 5m to 15m.

- Un-ionized ammonia can be toxic to fish. The concentration of un-ionized ammonia is a function of the total ammoniacal nitrogen concentration (i.e. NH_4 as N), the salinity, the pH and temperature. The EQS for un-ionized ammonia is 21 µg/l expressed as an annual average. The power station cooling water does not discharge increased ammonia, however the increased temperature can increase un-ionized ammonia concentrations. Results of the modelling indicate that the predicted discharge is unlikely to exceed the EQS.
- The oxygen content of the river is generally good with values in excess of 8 mg/l. The concern of increasing temperature is not therefore that it will lead to be significantly reduced oxygen, but that the hot discharge may be supersaturated and could become detrimental to fish health. The results of the modelling indicate that values in excess of 120% should only occur in the near vicinity of the discharge and only at the surface, with oxygen concentration at 100% saturation within 500m for most scenarios.
- For the one-pump scenario the analysis indicates that most scenarios occupy only a small fraction of the river cross section above 2°C. The only exception to this is at low water slack when the cross section in excess of 2°C reaches up to 19%, though still less than the 25% criteria. It should also be noted that the period of low water slack is only approximately 20 min every 12 hrs, i.e. 2.8% of the time, less than the Environment Agency 5% criteria.

We do not have any concerns with the proposals of the Application and the potential impact from emissions to surface water.

We sent the HRA Stage 1 and Stage 2 to Natural England for consultation. Natural England have not raised any concerns with the proposals of the Application.

We have audited the submitted modelling and we are satisfied that the Installation will not cause significant pollution at the habitats sites or cause harm to the protected species downstream of the emission point. The Applicant is required to prevent, minimise and control emissions using BAT, this is considered further in Section 9.

No further assessment of impact on conservation sites or protected species is required.

8.6 Noise impacts

The following measures were proposed to minimise noise impacts:

- Reducing the breakout noise from the plant through use of enhanced enclosures, or potentially containing them within a building;
- Reducing air inlet noise emissions by addition of further in-line attenuation;
- Reducing stack outlet noise emissions by the addition of silencers or sound proofing panels;
- Reducing fin fan cooler noise emissions by screening, re-sizing, fitting low noise fans or attenuation;
- Screening or enclosing the compressors or other equipment;
- Use of screening or bunding to shield receptors from noise sources; and
- Orientation of plant within the site to provide screening of low-level noise sources by other buildings and structures, or orientating fans and the air inlets away from sensitive receptors.

The Application contained a noise impact assessment (NIA) which identified local noise-sensitive receptors, potential sources of noise at the proposed plant and potential 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.

We audited the Applicant’s assessment.

Conclusions from our audit of the submitted NIA

Following sensitivity check modelling we found slightly higher specific sound emissions from the Keadby 3 power station compared to the consultant. The outputs of the modelling files submitted to the Environment Agency, with no changes made, output higher predictions than those stated within the noise impact assessment.

We have found that significant adverse impacts are likely at the noise sensitive receptor (NSR) at Vazon Bridge, however this impact is caused by the existing Keadby 2 power station. In the long-term the site should be working to reduce sound levels at Vazon Bridge from the Keadby site, we have included an improvement condition to ensure a report is submitted. We agree that the proposed variation (the addition of Keadby 3 CCGT and associated CCP) is unlikely to increase the sound rating at Vazon Bridge by a noticeable amount.

At NSRs Hawthorne House and The Grange, we found that the proposed variation is likely to increase the sound rating level and that there is likely to be an adverse impact at these locations. Therefore, the operator should be working to best available techniques and have an updated noise management plan (NMP). The BAT assessment submitted for the proposed variation suggests that Keadby 3 will be BAT compliant however specific measures to be applied to the proposed Installation for mitigating noise emissions from the site will be confirmed during the detailed design phase and be provided to us for approval prior to commencement of operations. **A pre-operational condition has been included in the Permit to confirm any mitigation via the submission of a revised NIA and NMP in order to validate that the currently predicted impacts do not increase as the detailed design is completed**.

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 if the pre-operational condition is completed satisfactorily.

9. Application of Best Available Techniques

9.1 Scope of Consideration

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

- We address the fundamental choice of combustion 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;
- We address the design and operational choices of the post combustion carbon capture and storage plant.

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 and a revised BREF for LCP were published in July 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.

9.2 Consideration of Combustion Plant against LCP BAT conclusions

The proposed Installation assumes the use of high efficiency CCGT, with efficiency to be confirmed with final technology selection. This is explained more in response to LCP BAT conclusions point 12 and the submitted ‘Appendix D4 – BAT assessment for energy efficiency’.

9.3 Consideration of emission control measures

We have reviewed the techniques used by the operator and compared these with the relevant guidance notes.

Emissions of oxides of nitrogen are either considered insignificant (at discrete receptors) or are considered to have adequate headroom between the PEC and EQS to indicate that an exceedance of the EQS is unlikely (maximum grid and in combination assessment).

We consider that the emission limits included in the Installation Permit reflect the BAT for the sector.

9.4 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 the iron and steel and chemical industries) have been considered. The response to each is set out in section 13 of this decision document.

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

9.5 Post-combustion carbon dioxide capture: emerging techniques

We have reviewed the Application against the Post-combustion carbon dioxide capture: emerging techniques guidance: Post-combustion carbon dioxide capture: emerging techniques - GOV.UK (www.gov.uk).

The response to each is set out in section 14 of this decision document.

9.6 Energy efficiency

9.6.1 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 Installation 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 BAT Conclusions.

9.6.2 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 9.2 above.

9.6.3 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 site has submitted a CHP ready assessment and is designed to be CHP ready, to enable the use of heat from the plant and thus increase efficiency. Condition 1.2.2 of the permit requires the operator to 'review the viability of Combined Heat and Power (CHP) implementation at least every 4 years…'

Heat Extraction Options

One primary factor contributing to the high efficiency of modern CCGTs such as the model evaluated is re-use of large amounts of the 'waste' heat within the plant itself. Useful heat is recovered from the gas turbine's exhaust gas through the Heat Recovery Steam Generator (HRSG). This heat is used to produce steam, at various pressures, which generates further power via a separate steam turbine.

The carbon capture process uses steam from the steam turbine. Most of the steam provision required in the CCP is used to generate the heat necessary to separate the captured carbon dioxide from the rich amine within the carbon dioxide stripper.

Some reheat of the treated flue gas may also be required to aid dispersion and this would therefore use some additional waste heat within the proposed development, further reducing availability for export.

This results in a significant amount of heat from the CCGT already being utilised within the proposed development. This CHP-R Assessment takes into account the steam requirement for the CCP and its provision from the CCGT before any residual waste heat is then appraised for CHP purposes. It is not envisaged that the CCGT would routinely operate in isolation from the carbon capture plant, although there are circumstances that this could be necessary (refer to paragraph 3.2.6 of the CHP-R assessment, dated May 2021).

In order to reduce the loss in available power in abated mode, waste heat from the CCGT would be used as a priority within the CCP where feasible. As a consequence, the CHP readiness assessment appraises opportunities to use heat rejection at a suitable temperature from the CCP, rather than using direct low pressure (LP) steam offtake from the CCGT. It is noted that licensors will optimise heat recovery within the CCP to minimise parasitic loads and this will be undertaken at the detailed design stage. As a consequence, available heat for CHP may be further reduced accordingly. However, two potential options for extracting heat from the proposed development have been considered during full operation with both the CCGT and CCP running (i.e. abated operation). These comprise:

- extraction from the carbon dioxide stripper overhead stream; and
- extraction from the low-pressure condensate leaving the carbon dioxide stripper reboiler.

During normal (abated) operation, the flue gases will enter the integrated CCP. However, during outages of the CCP, it will be possible to discharge exhaust gases through a dedicated stack above the HRSG building, which will be fitted with CEMS instrumentation. As the proposed development is expected to operate with the CCP for the majority of its design lifetime, the following sections and CHP-R Assessment Form (Appendix A) have only considered the CHP potential from the abated CCGT (operating with carbon capture).

Carbon Dioxide Stripper Overhead Stream

From analysis of the stream temperatures across the CCP within heat and material balance calculations, the carbon dioxide stripper overhead stream was identified as a potential source of heat extraction.

The carbon dioxide overhead stream exits the top of the carbon dioxide stripper column at a temperature of around 109°C before transferring into the carbon dioxide stripper condenser where the temperature of the stream is reduced to 26°C using the site cooling water. At this elevated temperature, it is possible to heat hot water using the available waste heat to approximately 90°C, the typical requirement for district heating.

With the use of a suitable heat exchanger, heat from the carbon dioxide overhead stream can be extracted by reducing the temperature of this stream before the carbon dioxide stripper condenser. Assuming the carbon dioxide overhead stream temperature exiting the heat exchanger is 70°C, there is approximately up to 62MWth of heat available from the proposed development running at maximum electrical power (full load).

During minimum electrical power operation (part load), the heat available will be reduced due to the reduced flow rate of the carbon dioxide overhead stream. For this operating mode, there is approximately up to 30MWth of heat available in the form of 90°C hot water.

Carbon Dioxide Stripper Reboiler Condensate Return

After supplying heat to the rich amine within the carbon dioxide stripper reboiler, the LP steam condenses within the reboiler, leaving at a temperature that could be up to approximately 144°C based upon a generic design. This LP condensate requires further cooling before returning to the CCGT's condenser.

Therefore, there is potential to utilise this available excess heat from the LP condensate to heat water for district heating using a water-water heat exchanger before the condensate cooler.

Based on the model's condensate cooler duty, approximately up to 18MWth of heat can be extracted when running at full load and used to supply 90°C hot water for district heating.

During part load, the CCP requires a lower demand of LP steam and therefore the amount of heat which can be extracted is lower than at full load. For this operating mode, there is approximately up to 9MWth of heat available in the form of 90°C hot water.

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 Operator carried out a feasibility study and provided a CHP-R assessment as part of their Permit 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). The Operator has 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 are 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.

9.6.4 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' is 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 the Environment Agency 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.

9.6.5 Compliance with energy BAT AEELs set out in BAT Conclusions

An energy efficiency level associated with the best available techniques (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 large combustion plant 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 for Keadby 3 operating in CO2 unabated mode					
57 – 60.5%	**50-60**	**None**	**>61%**	**NA**	**NA**

Based on the information in the application, that 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 55%. There is currently no BAT AEEL for combustion plant operating in carbon capture mode.

9.6.4 Choice of Cooling System

The proposed Installation will be serviced by a close loop cooling system with hybrid cooling towers, where the majority of the cooling water will be recycled.

As a hybrid cooling system, the amount of water used is lower than that for fully wet cooling systems. As such, only a nominal amount of water treatment chemicals is expected to be used, primarily for prevention of scaling and corrosion, and biofouling. The cooling system also recirculates the cooling water. Therefore, the proposed Installation is anticipated to comply with LCP BAT 13 – Water recycling.

The Application contained a BAT assessment for cooling options justifying the use the hybrid cooling towers over other methods including once through cooling. The BAT assessment included a costs and benefits assessment of the cooling options. The assessment considered both carbon abated and unabated modes, for the design reference case, under summer, winter and minimum flow operations. It also considered two potential cooling water temperature rises and maximum temperatures at discharge outfall and compared a number of parameters including water consumption, water source and necessary treatment, parasitic energy load, net thermal efficiency, noise, water demand, capital costs for equipment, pipework and intake and outfall upgrades and operating costs.

It concluded that although 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 hybrid cooling towers are BAT for cooling.

10. Emission limits

10.1 CO_2 unabated mode

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 Large Combustion Plant, when operating in CO_2 unabated mode. As detailed in section 8 above, emissions at these limits will not cause significant pollution. Consequently, we have accepted the proposed limits and incorporated them into table 3.1 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 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. This has been included as Keadby 3 is a new gas turbine where the final specifications of the plant have not been confirmed and therefore an appropriate ELV for MSUL to baseload is not confirmed prior to Permit issue.

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 an improvement condition.

The annual AEL for CO from the BAT Conclusions is indicative. The operator has supplied information that annual emissions of CO from Keadby 2 (similar CCGT to Keadby 3) can be closer to 100 mg/m^3 in order to mitigate NO_x emissions when entering Compliance Mode. Therefore, annual CO emissions were modelled at 100 mg/m^3. An assessment of CO PCs against short term EALs (1 hour mean and 8-hour rolling mean) screen out at the first stage at <10 % of the relevant EAL and so can be screened out as insignificant. This will be kept under review as a part of the annual reporting submission.

At this stage the Operator did not have adequate information to demonstrate whether the selected plant can meet the CO AEL. We have included an improvement condition specifying that the Operator is required to propose an achievable ELV for carbon monoxide 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 30mg/m^3 then an associated BAT justification will need to be submitted to the Environment Agency as a written report.

Table 13 – Permit ELVs for Keadby 3 emissions to air (in unabated mode)

Parameter	Reference Period	Annex V mg/m^3	BAT AEL mg/Nm3	Permit limit mg/m^3
NO_x	95%ile of hourly averages	100	-	100
	Monthly averages	50	-	50
	Daily average or average over the sampling period	-	40	40 To be confirmed under improvement condition IC15
	Yearly average	-	30	30
CO	95%ile of hourly averages	200	-	200
	Monthly averages	100	-	100
	Daily average or average over the sampling period	110	-	110 To be confirmed under improvement condition IC15

	Yearly average	-	30 indicative	100
Ammonia (NH_3)	Annual average		3-10	1

10.2 CO_2 abated mode

We have set emission limits to air for when the plant is operating in CO_2 abated mode. 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 NOx BAT AEL set out within the BAT Conclusions for Large Combustion Plant, that this limit has been normalised to take into account the reduction in volume of the gas from the removal of CO_2, as described in Note 9 of Table S3.1 of the permit. This means that it has been assumed that emissions of NOx from CCP absorber stack will be at the annual average BAT-AEL, corrected for CO_2 abatement.

Table 14 – Permit ELVs for Keadby 3 emissions to air (in abated mode)Parameter	**Reference Period**	**Permit limit mg/m^3**
NOx	95%ile of hourly averages	112.7
	Monthly averages	56.4
	Daily average or average over the sampling period	45.1 To be confirmed under improvement condition IC15
	Yearly average	33.8
CO	95%ile of hourly averages	225.5
	Monthly averages	112.7
	Daily average or average over the sampling period	124.0 To be confirmed under improvement condition IC15
	Yearly average	112.7
Ammonia (NH_3)	Annual Average	1
Total Amines (expressed as MEA)	Periodic average over sampling period	5.5
Acetaldehyde	Periodic average over sampling period	5.3
Total N-Amines (as NDMA)	Periodic average over sampling period	0.002
Acetaldehyde	Periodic average over sampling period	5.3
Formaldehyde	Periodic average over sampling period	0.5
Ketones	Periodic average over sampling period	5

11. Monitoring & Reporting

11.1 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.

The IED Annex V ELVs and BAT Conclusions AELs for NO_x and CO apply to CCGTs.

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. This monitoring shall be carried out as specified in table S3.1 of the Permit.

In addition to this the Operator will also be required to carry out an intensive amine monitoring exercise, as agreed in accordance with pre-operational condition PO2. The Operator will then be required using the results of the monitoring exercise to propose a suitable monitoring regime, for approval with the Environment Agency, which once agree will eventually supersede the amine monitoring requirements in the Permit.

11.2 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 CO2 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 CO2 emissions. Operators 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 in their application that the installation has been designed to capture 95% of the CO2 in the flue gas from the CCGT during steady state (normal) operation. In order to assess whether CO2 capture is maximised, monitoring and reporting requirements have been included in the permit. A pre-operational condition that 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 an improvement condition, 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. We have included a pre-operational condition that requires the Operator to include proposals in their PCC OTNOC management plan to monitor carbon capture performance during these periods.

11.3 Emissions to water

The Permit requires monitoring of emissions of aqueous discharges to the River Trent, as shown in table S3.2 of the Permit.

This variation includes V011, V012 & V013 which affect the emissions to water from the site in the following ways:

V011 – addition of a cooling water discharge from a hybrid cooling system associated with CCGT & Carbon Capture Plant, Keadby 3

V012 – include increased cooling water discharge temperature from Keadby 1, to account for a ‘one-pump scenario’

V013 – inclusion of differential temperature limits for emission from W1 (whole site emission point – normal operations) that have been proposed as a result of IC3, and the re-routing of ‘cable pull-pit effluent’ from emission point W11 to W10 (and ultimately W1) to allow for pH correction before discharge.

11.4 Monitoring location assessment

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 table S3.1 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.

12. 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.	2.3.10, 3.1.3, 3.6.7, 4.2.2, 4.2.5, 4.3.1(d) and schedule 5
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	2.3.7 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, Table S3.1
Ann V Pt 1	For plants operating less than 500 hours per year, record the used operating hours	N/A for Keadby 3 LCP689
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, Table S3.1

IED Article Reference	IED requirement	Permit condition
AnnV Pt 3(1)	Continuous monitoring for >100MWth for specified substances	3.5, 3.6 Schedule 3, Table S3.1
AnnV Pt 3(2, 3, 5)	Monitoring derogations	N/A for Keadby 3 LCP689
AnnV Pt3(4)	Measurement of total mercury (NA for natural gas)	N/A for Keadby 3 LCP689
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, Table S3.1
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, Table S3.1
AnnV Pt7	Refinery multi-fuel firing SO_2 derogation	N/A for Keadby 3 LCP689

13. 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	3.1.1 and 3.5.1	S3.1
Monitoring	2.3, 3.5 and 3.6	S1.2, S1.5, S1.6 (start-up and shut-down thresholds and DLN effective), S3.1, S3.2, S3.3, S3.4.
Energy efficiency	1.2 and 2.3	S3.3
Noise	2.3 and 3.4	S1.2
Other operating techniques	2.3.1	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 (within 4 years of publication of BAT conclusions) or where plant not built yet but will be 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	CC	The proposed new activities to the Installation will be operated under the existing BAT compliant ISO14001:2015 accredited Environmental Management System (EMS) for the Keadby Power Station, as amended to include Keadby 3 operations. The EMS comprises an environmental policy and other relevant management documents. The site-specific procedures define the roles and responsibilities for applicable site personnel. The EMS includes all elements listed under BATc 1 items as required under ISO14001:2015.
	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; **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.	CC	a. Monitoring and Measurement the applicant has confirmed that the proposed new activities to the Installation will have an operational procedure document describing the monitoring of emissions to air (as required by the LCP BRef) and water, including monitoring emissions to air during periods of abnormal operation.

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
			b. Corrective and Preventative Actions the applicant has confirmed that the proposed new activities to the Installation will be controlled and operated via a Distributed Control System (DCS) to continuously monitor the operation of the plant and equipment at the site. Any nonconformance or deviation in normal operating parameters will be identified by the DCS to allow the operator to take action to avoid a breach of Permitted emission levels. c. Records The EMS clearly defines the requirements for maintaining and storing records. d. Auditing The EMS is subject to periodic review and update and will be subject to internal audits as well as external certification audits.
	vi. review of the EMS and its continuing suitability, adequacy and effectiveness by senior management;	CC	Regular Management Review of the EMS is undertaken at the site in line with procedure MS-SHE-015.
	vii. following the development of cleaner technologies;	CC	See ix. below

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
	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;	FC	The proposed new activities to the Installation will be regulated under the Environmental Permitting Regulations 2016 (as amended) which requires sites to have a decommissioning plan in place to manage such considerations. As an existing power station operating two power plants (Keadby 1 and Keadby 2), the site has an existing BAT compliant decommissioning plan. This plan will be amended prior to commencement of operations at the proposed new activities to the Installation and will be subject to regular reviews to ensure that correct site operations are reflected in the plan. As such, the proposed Installation will be designed with consideration to decommissioning aspects. A pre-operational condition has been included into the Permit which requires the decommissioning procedure to be updated to reflect the variations (V011/12/13).
	ix. application of sectoral benchmarking on a regular basis.	CC	The proposed new activities to the Installation will be regulated under the Environmental Permitting Regulations 2016 (as amended), which requires the application of

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
			BAT for the operation of the Installation; this includes the requirement to undertake sectoral benchmarking as and when revised sector guidance is issued (e.g. BRef documents) and to implement compliance with the sector guidance within 4 years of issue. This is implemented through the Regulation 61 notice process.
	x. quality assurance/quality control programmes to ensure that the characteristics of all fuels are fully determined and controlled (see BAT 9);	CC	See response under BATc 9.
	xi. a management plan in order to reduce emissions to air and/or to water during other than normal operating conditions, including start-up and shutdown periods (see BAT 10 and BAT 11);	CC	See response to BATc 10 and 11.
	xii. a waste management plan to ensure that waste is avoided, prepared for reuse, recycled or otherwise recovered, including the use of techniques given in BAT 16;	FC	The applicant has confirmed that the proposed Installation will include dedicated appropriate waste storage areas; additionally, a waste procedure that includes the implementation of the waste hierarchy will be developed prior to commencement of operations. A pre-operational condition has been included into the Permit which requires the waste management plan to be developed.
	xiii. a systematic method identify and deal with potential uncontrolled and/or unplanned emissions to the environment, in particular:	FC	The applicant has confirmed that the potential for fugitive emissions

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
	(a) emissions to soil and groundwater from the handling and storage of fuels, additives, by-products and wastes (b) emissions associated with self-heating and/or self-ignition of fuel in the storage and handling activities;		will be regularly reviewed as part of the EMS environmental aspect and impact identification procedure and will have a site-specific emergency preparedness and response plan and accident management plan to cover management of potential uncontrolled and/ or unplanned emissions to the environment and accidents.
	xiv. a dust management plan to prevent or, where that is not practicable, to reduce diffuse emissions from loading, unloading, storage and/or handling of fuels, residues and additives;	NA	The applicant has confirmed that due to the inherent nature of the site operations, the potential for dust generation at the site will be minimal. Therefore, no specific dust management plan is proposed to be developed for the Installation.
	xv. a noise management plan where a noise nuisance at sensitive receptors is expected or sustained, including; (a) a protocol for conducting noise monitoring at the plant boundary (b) a noise reduction programme (c) a protocol for response to noise incidents containing appropriate actions and timelines (d) a review of historic noise incidents, corrective actions and dissemination of noise incident knowledge to the affected parties;	NA	The applicant has submitted an assessment of potential noise sources at the proposed Installation and impact on the sensitive receptors in the vicinity of the site has been undertaken as part of the Environmental Impact Assessment for the proposed Installation and the environmental Permit variation application. The assessment concluded that no significant noise or vibration effects are expected to occur at any identified sensitive

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
			receptor from the operation of Keadby 3. We agree with this conclusion, however as the Keadby 3 project is currently in the early design stage, the consultant has not been able to determine the specifications of all of the equipment that will be used on site. Additionally, our audit of the submitted Noise Impact Assessment concludes that there are significant adverse impacts at Vazon Bridge noise sensitive receptor due to existing emissions from Keadby 2. As a result we have included an pre-operational condition that requires the operator submit a revised NIA and NMP to validate the assumptions made in the NIA submitted for variation V011, once the finalised design parameters have been ascertained for Keadby 3, and to ensure that adequate mitigation measures are installed on-site to address existing emissions from Keadby 2.
	xvi. for the combustion, gasification or co-incineration of malodourous substances, an odour management plan including:	NA	The applicant has confirmed that the CCGT at the proposed Installation is likely to use

<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>(a) a protocol for conducting odour monitoring
(b) where necessary, an odour elimination programme to identify and eliminate or reduce the odour emissions
(c) a protocol to record odour incidents and the appropriate actions and timelines
(d) a review of historic odour incidents, corrective actions and the dissemination of odour incident knowledge to the affected parties.</td><td></td><td>deodorised natural gas directly from the National Transmission System (NTS) as a fuel, therefore is not likely to generate odour.
The requirement to confirm this ‘pre-FEED’ assumption has been included into the permit as a pre-operational condition.</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>The applicant has confirmed that Periodic Operational Performance tests measuring the load, fuel used, and power output will be undertaken in accordance with applicable BS EN standards.
The site has existing procedures for monitoring and reporting of fuel consumption (both natural gas and other fuels used on site), and the energy output from the site, which will be amended as required to include the proposed new activities to the Installation.</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>CC</td><td>The applicant has confirmed that the CCGT plant at the proposed Installation will be able to achieve the required BAT-AELs by the use of primary abatement measures and potentially with the use of secondary flue-gas treatment such as Selective Catalytic Reduction</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
			(SCR) for the control of emissions of nitrogen oxides (NOx). The HRSG will have a dedicated stack for emissions to air from the CCGT plant, in the event that the CCP is not operational. This will operate as a bypass stack. The emissions from the CCP (Carbon Capture Plant) are described within the separate CCS BAT assessment. When the bypass stack is operational, the flue gases from the CCGT will be monitored using MCERTS certified Continuous Emissions Monitoring system (CEMs) in accordance with BS EN 14181. To facilitate the conversion of measured CEMS pollutant emissions data to standard reference conditions, continuous monitoring of stack temperature, pressure, oxygen and water vapour will be provided, as required for the type of CEMS systems installed. Continuous flow monitoring will be provided, or as per the EA agreed JEP IED/ BRef Monitoring Protocol for Large Combustion Plants, an

<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>agreed calculation method may be used instead.
Continuous monitoring of emissions to wastewater will be carried out for flow, pH and temperature, and as required under the Permit.</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>
<tr><td>NO_X</td><td>— Natural-gas-fired boilers, engines, and turbines</td><td>All sizes</td><td>Generic EN standards</td><td>Continuous (6) (8)</td><td>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</td></tr>
<tr><td>CO</td><td>— Natural-gas-fired boilers, engines, and turbines</td><td>All sizes</td><td>Generic EN standards</td><td>Continuous (6) (8)</td><td>BAT 20
BAT 24
BAT 28
BAT 33
BAT 38
BAT 44
BAT 49
BAT 56</td></tr>
</table></td><td>CC</td><td>The applicant has confirmed that the flue gases from the CCGT will be monitored using MCERTS certified Continuous Emissions Monitoring systems (CEMs) in accordance with BS EN 14181.
This system will continuously monitor NOx, CO and NH3 (associated with SCR if used).</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></td><td>
<table>
<tr><td></td><td></td><td></td><td></td><td></td><td>BAT 64
BAT 65
BAT 73</td></tr>
<tr><td rowspan="2">TVOC</td><td>— HFO- and/or gas-oil-fired engines
— Process fuels from chemical industry in boilers</td><td>All sizes</td><td>EN 12619</td><td>Once every six months (13)</td><td>BAT 33
BAT 59</td></tr>
<tr><td>— Waste co-incineration with coal, lignite, solid biomass and/or peat</td><td>All sizes</td><td>Generic EN standards</td><td>Continuous</td><td>BAT 71</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>
</td><td></td><td></td></tr>
<tr><td>5</td><td>
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.
<table>
<tr><th colspan="2">Substance/Parameter</th><th>Standard(s)</th><th>Minimum monitoring frequency</th><th>Monitoring associated with</th></tr>
<tr><td colspan="2">Total organic carbon (TOC) (26)</td><td>EN 1484</td><td rowspan="13">Once every month</td><td rowspan="13">BAT 15</td></tr>
<tr><td colspan="2">Chemical oxygen demand (COD) (26)</td><td>No EN standard available</td></tr>
<tr><td colspan="2">Total suspended solids (TSS)</td><td>EN 872</td></tr>
<tr><td colspan="2">Fluoride (F^-)</td><td>EN ISO 10304-1</td></tr>
<tr><td colspan="2">Sulphate (SO_4^{2-})</td><td>EN ISO 10304-1</td></tr>
<tr><td colspan="2">Sulphide, easily released (S^{2-})</td><td>No EN standard available</td></tr>
<tr><td colspan="2">Sulphite (SO_3^{2-})</td><td>EN ISO 10304-3</td></tr>
<tr><td rowspan="6">Metals and metalloids</td><td>As</td><td rowspan="6">Various EN standards available (e.g. EN ISO 11885 or EN ISO 17294-2)</td></tr>
<tr><td>Cd</td></tr>
<tr><td>Cr</td></tr>
<tr><td>Cu</td></tr>
<tr><td>Ni</td></tr>
<tr><td>Pb</td></tr>
</table>
</td><td>CC</td><td>The applicant has confirmed that the proposed Installation may use SCR for the control of NOx emissions in the flue gas for optimised operation of the CCP.

The DCC, where exhaust gas from the HRSG is quenched to lower the temperature, condenses some of the water present in the exhaust gas from the combustion process and therefore accumulates water, which may be used elsewhere in the process (e.g. cooling tower make-up). The water will also contain ammonia from the SCR treatment and small amounts of dissolved CO2 from the exhaust gas. Additional treatment to remove ammonia may be required prior to</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></td><td><table>
<tr><td rowspan="2"></td><td>Zn</td><td></td><td rowspan="4"></td><td rowspan="2"></td></tr>
<tr><td>Hg</td><td>Various EN standards available (e.g. EN ISO 12846 or EN ISO 17852)</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>onward use. There are a number of ways in which this could be achieved, however the current proposed method is by reverse osmosis, ultra filtration, the addition of sodium hydroxide solution to increase the pH, and warm air stripping within a small column absorber. The stripping air, containing ammonia, would then enter a separate absorption section against a counter-flow of sulphuric acid to generate ammonium sulphate. The stripping air would then be recycled within the process, avoiding the need for venting to atmosphere, and there would be no emissions to atmosphere from the DCC wastewater treatment system under normal operation.</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><th>Demonstration of BAT</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>Generally applicable</td><td>The proposed Installation will use the existing natural gas supply to the Keadby Power Station site, and will be subject to a fuel management and monitoring procedure. The site has a contractual agreement to receive natural gas from the NTS which includes the requirement for</td></tr>
</table></td><td>CC</td><td>See ‘Demonstration of BAT’ column in ‘Summary of BAT Conclusion requirement’ column of this table</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></td><td>
<table>
<tr><td></td><td></td><td></td><td></td><td>the gas to comply with specified quality criteria. Equipment such as a gas chromatograph (GC) will be put in place to periodically test the quality of the fuel if required and the parameters listed under BATc 9 for natural gas are recorded. Performance tests measuring the load, fuel used, and power output to calculate overall efficiencies shall be undertaken in accordance with applicable BE EN standards and existing site procedures (amended to include proposed Installation).</td></tr>
<tr><td>b.</td><td>Maintenance of the combustion system</td><td>Regular planned maintenance according to suppliers' recommendations</td><td></td><td>All plant and equipment at the site will be regularly maintained, including the combustion system, by qualified maintenance staff or contractors, as per site procedures.</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><td>The proposed Installation operations will be monitored and operated by suitably trained site personnel and managed via a Distributed 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.</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><td>The CCGT plant will be a new high efficiency unit offering leading performance in its class and compliant with all relevant and most</td></tr>
</table>
</td><td></td><td></td></tr>
</table>

<table>
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<tr><td></td><td><table>
<tr><td></td><td></td><td></td><td></td><td>recent regulatory requirements, in addition to design features to optimise performance in terms of emissions and efficiency</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.
For existing combustion plants, the type of fuel chosen may be limited by the configuration and the design of the plant</td><td>Natural gas from the NTS will result in minimal sulphur dioxide and particulate emissions from the CCGT.</td></tr>
</table></td><td></td><td></td></tr>
<tr><td>7</td><td>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.</td><td></td><td>The applicant has confirmed that the proposed new activities to the Installation <i>may</i> be able to comply with the NOx BATAEL without the use of secondary abatement. However, the proposed new activities to the Installation may include an SCR plant for NOx control, either to ensure compliance with the NOx BAT-AEL or for the purpose of optimum carbon capture solvent performance, using ammonia or urea as a reagent. The SCR plant will be appropriately</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
			designed and operated to maintain optimum ammonia injection rate and minimise ammonia slip emissions to air. Ammonia emissions from the CCP Absorber will be minimised by acid wash, if required, dependent upon the final solvent selection. The permit limits ammonia emissions to the emission concentration modelled by the applicant in their application air quality impact assessment (1 mg/m3). Ammonia emissions will comply with the annual BAT-AEL of 3 mg/Nm^3.
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.	CC	The applicant has confirmed that emissions abatement systems will be designed, operated and maintained to ensure use at optimal capacity and availability, as described in response to BAT 6 and BAT 4.
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;	CC	The applicant has confirmed that the proposed Installation will be subject to the existing Thermal Management procedure that covers the requirements of BATc 9.

<table>
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<tr><td></td><td>(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)).
<i>Description</i>
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.
<table>
<tr><th>Fuel(s)</th><th>Substances/Parameters subject to characterisation</th></tr>
<tr><td>Natural gas</td><td>— LHV
— CH_4, C_2H_6, C_3, C_4+, CO_2, N_2, Wobbe index</td></tr>
</table></td><td></td><td>Additionally, the site has a contractual agreement to receive natural gas from the NTS which will include the requirement for the gas to comply with specified quality criteria. Equipment such as a gas chromatograph (GC) would be put in place to periodically test the quality of the fuel if required and the parameters listed under BATc 9 for natural gas are recorded.
Performance tests measuring the load, fuel used, and power output to calculate overall efficiencies shall be undertaken in accordance with applicable BE EN standards.</td></tr>
<tr><td>10</td><td>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.</td><td>CC</td><td>The plant and associated control systems will be designed to minimise the potential for OTNOC events to occur.
The proposed Installation will be operated using an DCS to continuously monitor the operation of the plant and equipment at the site. Any non-conformance 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 will be trained to monitor</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
			plant operation and take appropriate action(s) in the event of a potential OTNOC event being identified. Start up and Shutdown procedures shall 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 system provided to minimise the potential for OTNOC conditions to occur. The proposed Installation will be managed according to the existing accident management plan (AMP) and emergency response procedures. Appropriate procedures will also be put in place to review any OTNOC events with periodic assessment of associated aspects. The records of OTNOC events will be retained on site. If the site is required to support a grid blackstart event to maximise generation/ response times/ grid support; this will be in accordance with the Black Start Response Plan.

<table>
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<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>CC</td><td>The applicant has confirmed 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 data 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>CC</td><td>The applicant has confirmed in their variation application submission ‘Appendix D4 – BAT assessment for energy efficiency’
<ol type="a">
the specific control settings for the combustion units will be pre-set in the control system to achieve efficient combustion and optimise plant efficiency.
Performance tests of the Power Station will be undertaken periodically in accordance with applicable BS EN standards
The efficiency of the plant will be driven by the design of the CCGT including the HRSG. The plant will be designed to exploit optimum steam pressure
</td></tr>
</table>

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<table>
<tr><td>f.</td><td>Fuel preheating</td><td>Preheating of fuel using recovered heat</td><td>Generally applicable within the constraints associated with the boiler design and the need to control NO_X emissions</td></tr>
<tr><td>g.</td><td>Advanced control system</td><td>See description in Section 8.2.
Computerised control of the main combustion parameters enables the combustion efficiency to be improved</td><td>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</td></tr>
<tr><td>h.</td><td>Feed-water preheating using recovered heat</td><td>Preheat water coming out of the steam condenser with recovered heat, before reusing it in the boiler</td><td>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</td></tr>
<tr><td>i.</td><td>Heat recovery by cogeneration (CHP)</td><td>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</td><td>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</td></tr>
<tr><td>j.</td><td>CHP readiness</td><td>See description in Section 8.2.</td><td>Only applicable to new units where there is a realistic potential for the future use of heat in the vicinity of the unit</td></tr>
<tr><td>k.</td><td>Flue-gas condenser</td><td>See description in Section 8.2.</td><td>Generally applicable to CHP units provided there is enough demand for low-temperature heat</td></tr>
<tr><td>l.</td><td>Heat accumulation</td><td>Heat accumulation storage in CHP mode</td><td>Only applicable to CHP plants.
The applicability may be limited in the case of low heat load demand</td></tr>
</table>
</td><td></td><td>and temperature settings to maximise the overall efficiency
d. All plant and equipment will be designed or specified and maintained to ensure optimal operation
e. Combustion air will not be pre-heated as if the air is too hot, it can cause damage to the turbine and decrease efficiency.
f. Fuel gas will be pre-heated (up to 230°C) via two pre-heater packages currently designed to run on natural gas, situated in the gas handling unit, to optimise combustion. An ongoing review is being undertaken to assess an additional waste heat recovery option from for pre-heating of the fuel, specifically using waste heat from the CCP's low-pressure (LP) condensate. Flue gas is not used for pre-heating of fuel gas.
g. Operation of the CCGT unit will be controlled by</td></tr>
</table>

<table>
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<table>
<tr><td>m.</td><td>Wet stack</td><td>See description in Section 8.2.</td><td>Generally applicable to new and existing units fitted with wet FGD</td></tr>
<tr><td>n.</td><td>Cooling tower discharge</td><td>The release of emissions to air through a cooling tower and not via a dedicated stack</td><td>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</td></tr>
<tr><td>o.</td><td>Fuel pre-drying</td><td>The reduction of fuel moisture content before combustion to improve combustion conditions</td><td>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</td></tr>
<tr><td>p.</td><td>Minimisation of heat losses</td><td>Minimising residual heat losses, e.g. those that occur via the slag or those that can be reduced by insulating radiating sources</td><td>Only applicable to solid-fuel-fired combustion units and to gasification/IGCC units</td></tr>
<tr><td>q.</td><td>Advanced materials</td><td>Use of advanced materials proven to be capable of withstanding high operating temperatures and pressures and thus to achieve increased steam/combustion process efficiencies</td><td>Only applicable to new plants</td></tr>
<tr><td>r.</td><td>Steam turbine upgrades</td><td>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</td><td>The applicability may be restricted by demand, steam conditions and/or limited plant lifetime</td></tr>
<tr><td>s.</td><td>Supercritical and ultra-supercritical steam conditions</td><td>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</td><td>Only applicable to new units of ≥ 600 MW_{th} operated > 4 000 h/yr.</td></tr>
</table>
</td><td></td><td>trained site operators using a DCS, which also records data on the plant performance, and will 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 others once the domestic requirements have been met; and a CHP-Readiness assessment was submitted as part of the Permit variation application
j. CHP readiness - See description in section 9.6.3
k. Flue-gas condenser - See description in section 9.6.3</td></tr>
</table>

<table>
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<tr><td></td><td><table><tr><td></td><td></td><td>580 – 600 °C in the case of ultra-supercritical conditions</td><td>Not applicable when the purpose of the unit is to produce low steam temperatures and/or pressures in process industries.
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></td><td></td><td>l. Heat accumulation - See description in section 9.6.3
m. n/a no wet FGD fitted
n. n/a no wet FGD fitted
o. n/a not combustion of biomass
p. n/a not a solid fuel fired combustion unit or gasification/IGCC units
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 will be implemented as part of the overall plant design.
s. The steam circuit at the CCGT plant will incorporate steam inter-stage reheating systems and include evaporator/economiser and superheated steam. The Applicant notes that the information to provide</td></tr>
</table>

<table>
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<tr><td></td><td></td><td></td><td>a response to this question will not be available until an Engineering Procurement and Construction (EPC) contract is placed. Therefore, information on this aspect will be provided by the confirmation of pre-FEED design assumptions required by a pre-operational condition in the permit and the Environmental Permit variation application. This will ensure that the Permit reflects the plant that will be installed and operated.</td></tr>
<tr><td>13</td><td>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>
</table></td><td></td><td>The applicant has confirmed that the proposed new activities to the Installation will be serviced by a close loop cooling system with hybrid cooling towers, where a majority of the cooling water will be recycled.
As a hybrid cooling system, the amount of water used is lower than that for fully wet cooling system. As such, only a nominal amount of</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
	<table><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>		water treatment chemicals is expected to be used, primarily for prevention of scaling and corrosion, and biofouling. The cooling system also recirculates the cooling water. Therefore, the proposed Installation is anticipated to comply with this BAT requirement. The proposed Installation will not produce any ash from the combustion process; therefore, the techniques for dry bottom ash handling are not applicable.
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.	CC	The applicant has confirmed that waste water streams generated at the proposed Installation are anticipated to comprise surface run-off water and cooling water purge and cooling tower blowdown (containing process waste waters); all waste water streams will be appropriately segregated, treated (if required) prior to discharge. Waste water from the Direct Contact Cooler will have a dedicated waste water treatment plan to remove ammonia, prior to reuse within other processes on site. See response to LCP BAT 5 for further detail.

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<tr><td>15</td><td>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.
<table>
<tr><th colspan="2">Technique</th><th>Typical pollutants prevented/abated</th><th>Applicability</th></tr>
<tr><td colspan="4">Primary techniques</td></tr>
<tr><td>a.</td><td>Optimised combustion (see BAT 6) and flue-gas treatment systems (e.g. SCR/SNCR, see BAT 7)</td><td>Organic compounds, ammonia (NH_3)</td><td>Generally applicable</td></tr>
<tr><td colspan="4">Secondary techniques (29)</td></tr>
<tr><td>b.</td><td>Adsorption on activated carbon</td><td>Organic compounds, mercury (Hg)</td><td>Generally applicable</td></tr>
<tr><td>c.</td><td>Aerobic biological treatment</td><td>Biodegradable organic compounds, ammonium (NH_4^+)</td><td>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)</td></tr>
<tr><td>d.</td><td>Anoxic/anaerobic biological treatment</td><td>Mercury (Hg), nitrate (NO_3^-), nitrite (NO_2^-)</td><td>Generally applicable</td></tr>
<tr><td>e.</td><td>Coagulation and flocculation</td><td>Suspended solids</td><td>Generally applicable</td></tr>
<tr><td>f.</td><td>Crystallisation</td><td>Metals and metalloids, sulphate (SO_4^{2-}), fluoride (F^-)</td><td>Generally applicable</td></tr>
<tr><td>g.</td><td>Filtration (e.g. sand filtration, microfiltration, ultrafiltration)</td><td>Suspended solids, metals</td><td>Generally applicable</td></tr>
<tr><td>h.</td><td>Flotation</td><td>Suspended solids, free oil</td><td>Generally applicable</td></tr>
<tr><td>i.</td><td>Ion exchange</td><td>Metals</td><td>Generally applicable</td></tr>
<tr><td>j.</td><td>Neutralisation</td><td>Acids, alkalis</td><td>Generally applicable</td></tr>
<tr><td>k.</td><td>Oxidation</td><td>Sulphide (S^{2-}), sulphite (SO_3^{2-})</td><td>Generally applicable</td></tr>
<tr><td>l.</td><td>Precipitation</td><td>Metals and metalloids, sulphate (SO_4^{2-}), fluoride (F^-)</td><td>Generally applicable</td></tr>
<tr><td>m.</td><td>Sedimentation</td><td>Suspended solids</td><td>Generally applicable</td></tr>
<tr><td>n.</td><td>Stripping</td><td>Ammonia (NH_3)</td><td>Generally applicable</td></tr>
</table>
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
<table>
<tr><th>Substance/Parameter</th><th>BAT-AELs</th></tr>
</table>
</td><td></td><td>The applicant has confirmed that the need for flue gas treatment is minimised by primary combustion controls identified in BAT 6 and appropriate control of the SCR (if required) system identified in BAT 7 above. If SCR is required then BAT-AELs will apply.
Waste water from the Direct Contact Cooler will have a dedicated waste water treatment plan to remove ammonia, prior to reuse within other processes on site. See response to LCP BAT 5 for further detail.</td></tr>
</table>

<table>
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<tr><td></td><td>
<table>
<tr><th colspan="2"></th><th>Daily average</th></tr>
<tr><td colspan="2">Total organic carbon (TOC)</td><td>20–50 mg/l (30) (31) (32)</td></tr>
<tr><td colspan="2">Chemical oxygen demand (COD)</td><td>60–150 mg/l (30) (31) (32)</td></tr>
<tr><td colspan="2">Total suspended solids (TSS)</td><td>10–30 mg/l</td></tr>
<tr><td colspan="2">Fluoride (F^-)</td><td>10–25 mg/l (32)</td></tr>
<tr><td colspan="2">Sulphate (SO_4^{2-})</td><td>1,3–2,0 g/l (32) (33) (34) (35)</td></tr>
<tr><td colspan="2">Sulphide (S^{2-}), easily released</td><td>0,1–0,2 mg/l (32)</td></tr>
<tr><td colspan="2">Sulphite (SO_3^{2-})</td><td>1–20 mg/l (32)</td></tr>
<tr><td rowspan="8">Metals and metalloids</td><td>As</td><td>10–50 µg/l</td></tr>
<tr><td>Cd</td><td>2–5 µg/l</td></tr>
<tr><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>
</td><td></td><td></td></tr>
<tr><td>16</td><td>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:</td><td></td><td>The applicant has confirmed that the proposed Installation will develop a Waste Management Procedure (WMP) prior to commencement of site operations, detailing the waste storage and handling procedures on site. The WMP shall outline identification of waste streams and how they must be handled, including appropriate segregation and storage within designated waste storage areas on site.
The proposed Installation will apply the waste hierarchy for the</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></td><td><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>
<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>management of any waste produced on site. It is expected that due to the inherent nature of the site operations and fuel used, the site shall only produce minor quantities of waste, primarily from maintenance. The main waste stream generated from the site activities is likely to comprise used lubricating oil, which will be sent off site for appropriately management via licenced contractors. The operator will review and identify potential re-use of wastes on site, such as spent catalysts, in line with the waste hierarchy. Anticipated quantities of waste streams from the Installation are provided in Table 3 of the Main Supporting Document.</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:</td><td>Generally applicable</td></tr>
</table></td><td>CC</td><td>The applicant has confirmed that:
a. The site will have a maintenance schedule in place to ensure optimum operation of all plant and equipment. The gas turbine will be situated</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></td><td>
<table>
<tr><td></td><td></td><td>— improved inspection and maintenance of equipment
— closing of doors and windows of enclosed areas, if possible
— equipment operated by experienced staff
— avoidance of noisy activities at night, if possible
— provisions for noise control during maintenance activities</td><td></td></tr>
<tr><td>b.</td><td>Low-noise equipment</td><td>This potentially includes compressors, pumps and disks</td><td>Generally applicable when the equipment is new or replaced</td></tr>
<tr><td>c.</td><td>Noise attenuation</td><td>Noise propagation can be reduced by inserting obstacles between the emitter and the receiver. Appropriate obstacles include protection walls, embankments and buildings</td><td>Generally applicable to new plants. In the case of existing plants, the insertion of obstacles may be restricted by lack of space</td></tr>
<tr><td>d.</td><td>Noise-control equipment</td><td>This includes:
— noise-reducers
— equipment insulation
— enclosure of noisy equipment
— soundproofing of buildings</td><td>The applicability may be restricted by lack of space</td></tr>
<tr><td>e.</td><td>Appropriate location of equipment and buildings</td><td>Noise levels can be reduced by increasing the distance between the emitter and the receiver and by using buildings as noise screens</td><td>Generally applicable to new plant</td></tr>
</table>
</td><td></td><td>within an enclosure; and all outdoor equipment having noise attenuation enclosures, where required. Any maintenance work that is likely to cause significant noise that poses a nuisance risk will be undertaken during daylight hours, where feasible.
b. The proposed Installation will be a new plant, and all equipment will be selected to avoid noise impacts either via inherent design qualities, or where a noise risk exists, via the Installation of noise attenuation measures.
c, d & e. The gas turbine will be situated within an enclosure.
All equipment being installed is new and mitigation will be in place where necessary to ensure levels of noise below applicable lowest observed adverse effect level (LOAELs), so that residual effects are expected to be not significant.</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="4">Combustion of gaseous fuels</td></tr>
<tr><td>40</td><td>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.
<table>
<tr><th colspan="2">Technique</th><th>Description</th><th>Applicability</th></tr>
<tr><td>a.</td><td>Combined cycle</td><td>See description in Section 8.2</td><td>Generally applicable to new gas turbines and engines except when operated < 1 500 h/yr.
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 < 1 500 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="5">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>CC</td><td>The anticipated electrical efficiency of the CCGT plant will be circa 55% after carbon capture, or greater than 61% for the CCGT operating independently, which is compliant with or exceeds the required BAT-AEEL range of 57 – 60.5% for CCGTs having a thermal input of >600MWth.
The electrical output from the CCGT plant will also provide for the parasitic electrical requirements for the Capture plant and other utilities on site. A separate BAT assessment has been undertaken for the overall energy efficiency of the proposed Installation (Appendix D4).
We have included a pre-operational condition that requires a confirmation of the pre-FEED design assumptions.</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.</td><td>NA</td><td>No natural gas fired boilers on site.</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

Technique		Description	Applicability
a.	Air and/or fuel staging	See descriptions in Section 8.3. Air staging is often associated with low-NO_X burners	Generally applicable
b.	Flue-gas recirculation	See description in Section 8.3	
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

<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>42</td><td>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.
<table>
<tr><th colspan="2">Technique</th><th>Description</th><th>Applicability</th></tr>
<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>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.</td></tr>
</table></td><td>CC</td><td>a. Operation of the CCGT unit will be controlled by trained site operators using a DCS, which will be used to control the operation of the plant and also record data on the plant performance, which can also be used by the operations team to identify potential issues.
b. Water/ steam 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 to ensure minimum emissions of NOx.
d. Not applicable as this is limited by the turbine design. Operational efficiency characteristics of the plant vary according to the load. No supplementary firing is undertaken in the HRSGs.
e. The CCGT will have Dry Low NOx burners in place</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></td><td><table><tr><td></td><td></td><td></td><td>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>to ensure minimum emissions of NOx.
f. See Response BAT 7 of this table. The proposed new activities to the installation may be able to comply with the NOx BAT-AEL without the use of secondary abatement. However if needed SCR will be utilised.</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 colspan="2">Technique</th><th>Description</th><th>Applicability</th></tr>
<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.</td></tr>
</table></td><td>NA</td><td>No natural gas fired engines on site.</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></td><td>
<table>
<tr><td></td><td></td><td></td><td>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.
<i>Description</i> - See descriptions in Section 8.3.
BAT-associated emission levels (BAT-AELs) for NO_X 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>
<tr><td>Existing CCGT with a net total fuel utilisation of < 75 %</td><td>≥ 600</td><td>10–40</td><td>18–50</td></tr>
<tr><td>Existing CCGT with a net total fuel utilisation of ≥ 75 %</td><td>≥ 600</td><td>10–50</td><td>18–55 (150)</td></tr>
<tr><td>Existing CCGT with a net total fuel utilisation of < 75 %</td><td>50–600</td><td>10–45</td><td>35–55</td></tr>
<tr><td>Existing CCGT with a net total fuel utilisation of ≥ 75 %</td><td>50–600</td><td>25–50 (151)</td><td>35–55 (152)</td></tr>
<tr><td colspan="4">Open- and combined-cycle gas turbines</td></tr>
<tr><td>Gas turbine put into operation no later than 27 November 2003, or existing gas turbine for emergency use and operated < 500 h/yr</td><td>≥ 50</td><td>No BAT-AEL</td><td>60–140 (153) (154)</td></tr>
<tr><td>Existing gas turbine for mechanical drive applications — All but plants operated < 500 h/yr</td><td>≥ 50</td><td>15–50 (155)</td><td>25–55 (156)</td></tr>
</table>
</td><td></td><td>
The applicant has stated that:
NOx – the CCGT is expected to achieve the stated BAT-AELs, with energy efficiency uplifts applied as appropriate on confirmation of the CCGT supplier post FEED. However, these levels were not included in the emissions to air risk assessment, we have therefore set ELVs without the energy efficiency uplifts applied.
CO – performance to be confirmed following commencement of operation (requirement to submit included as an improvement condition in the permit). LCP indicative BAT ELV of 30 mg/m3 (for new CCGT) has been set in the permit subject to delivery of this improvement condition. IED Annex V ELVs and the JEP compliance daily ELV (MSUL/MSDL to baseload) have also been set in the permit for NOx and CO with an improvement condition for definitions of MSUL/MSDL
</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></td><td>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.</td><td></td><td></td></tr>
<tr><td>45</td><td>In order to reduce non-methane volatile organic compounds (NMVOC) and methane (CH_4) emissions to air from the combustion of natural gas in spark-ignited lean-burn gas engines, BAT is to ensure optimised combustion and/or to use oxidation catalysts.
<i>Description</i>
See descriptions in Section 8.3. Oxidation catalysts are not effective at reducing the emissions of saturated hydrocarbons containing less than four carbon atoms.
BAT-associated emission levels (BAT-AELs) for formaldehyde and CH_4 emissions to air from the combustion of natural gas in a spark-ignited lean-burn gas engine
<table>
<tr><th rowspan="4">Combustion plant total rated thermal input (MW_{th})</th><th colspan="3">BAT-AELs (mg/Nm^3)</th></tr>
<tr><th>Formaldehyde</th><th colspan="2">CH_4</th></tr>
<tr><th colspan="3">Average over the sampling period</th></tr>
<tr><th>New or existing plant</th><th>New plant</th><th>Existing plant</th></tr>
<tr><td>≥ 50</td><td>5–15 (162)</td><td>215–500 (163)</td><td>215–560 (162) (163)</td></tr>
</table></td><td>NA</td><td>No natural gas fired engines on site</td></tr>
</table>

15. Meeting the requirements of the Post-combustion carbon capture: guidance for emerging techniques

Ref	BAT Requirement	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 is proposing a gas fired CCGT capable of achieving electrical efficiency levels of >61% (LHV), this is within the efficiency range detailed in the LCP BReF.	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 proposed Installation will be designed to be able to operate in dispatchable mode.	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 • CO_2 capture level • CO_2 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.		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	Heat and electricity used by the CCP will be supplied by the main power plant. The Keadby 3 CCGT and CCP will also have an electrically powered auxiliary boiler each. The CCGT electric auxiliary boiler will be used to enable the safe shut-down during a power failure scenario and the CCP electrically powered auxiliary boiler will be used to provide heat/steam to the carbon capture plant during commissioning, start-up and shut-down, maintaining the CCP in a ‘hot’ or ‘warm’ standby state when the CCGT is offline. The anticipated electrical efficiency of the proposed CCGT plant will be >52% (LHV) after carbon capture and compression (CO_2-abated mode). The CCGT auxiliary power consumption is expected to be circa 15Mwe. The CCP steam extraction generation penalty is expected to be circa 15 – 20MWe. The post combustion CCP (including CO_2 compression plant and flue gas transfer energy penalty) also has an auxiliary electrical consumption of circa 40MWe . The CCP is designed to use LP steam for regenerating the solvent. The design steam pressure has been chosen considering trade-offs between process requirements, sizing of the reboiler and minimising parasitic load on steam turbine. For every 5.2 tonnes per hour (tph) of steam supplied to the CCP, about 1 MWe is lost. 5.2 tph of LP steam supplied to the reboilers is equivalent to 3.1 MW of heat. The ratio of heat supplied, relative to power lost, is therefore 3.12:1. As this ratio is below the heat supplied: power lost ratio of 4:1 described in the BAT guidance, our decision to	

		issue the permit recognises this is an emerging technique and the permit therefore includes requirements to maximise the energy efficiency of the carbon capture plant. This includes: a pre-operational condition requiring validation of pre-FEED design assumptions: an improvement condition requiring a commissioning report summarising the environmental performance of the installed plant; standard conditions requiring energy efficiency review(s); and resource efficiency monitoring and reporting.	

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 CC plant will be designed to be capable of capturing 95% of the CO_2 present in the exhaust gas from the CCGT, with an average capture rate of at least 90% (subject to completion of FEED studies and commercial agreement).	Y
3.2	You should capture CO2 during start-up and shutdown as part of using BAT.	The applicant has stated that at start-up there will be a delay in the CCP reaching operating temperature and during such times there may be unabated CO2 emissions from the proposed Installation. The length of the delay will be dependent on whether the plant was in a hot, warm or cold state prior to start-up. The CCP design is such that the targeted capture rates can be achieved as reasonably practicable after start-up, follow load variations of the CCGT keeping those capture	Y

		rates, and pursue a shutdown mode that again enables quick start-up operations. An amine buffer tank is proposed to prepare for quick start-ups. The tank will have enough solvent inventory to cover for the lag period where the reboilers are not receiving LP steam from the HRSG. In addition to amine storage, the “hot section” of the CCP will be kept warm, even while the plant is not capturing CO2. This is achieved through a hot-standby philosophy which enables the CCP 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.	
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 applicant has stated that the CO2 undergoes staged compression to dense phase (approximately 30 barg), and then passes through conditioning plant, which will include oxygen removal using bought-in hydrogen gas and platinum catalyst. The de-oxygenation package will require LP steam to preheat the CO2 product for the catalytic oxidation reaction. The onsite compression will remove oxygen and water from the CO2 to meet the requirements of the T&S network. The quality of the CO2 will be monitored online for compliance with export specifications to ensure the required specification is met and fiscal flow metering will be provided for custody transfer of CO2 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	An Air dispersion modelling assessment has been completed by the Applicant. We are satisfied that no Environmental Standards will be exceeded.	Y

	products (including, for example, nitrosamines and nitramines). You should confirm this using: - atmospheric dispersion and reaction modelling tools - specific site parameters which will define plant-specific ELVs	The Permit sets ELVs for relevant pollutants.	
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 Initial engineering studies suggest that the CC plant imposes approximately 10-12% penalty on the electrical efficiency of the CCGT, against a published value of 11% net electrical efficiency penalty (NETL, 2019). The penalty is incurred through a combination of direct electrical loads and indirect heat (as steam extracted from the steam cycle, equivalent to circa 10% of total heat). The Installation will comprise additional measures for recovering waste heat from various process equipment, balancing CO2 capture efficiency with energy efficiency optimisation. These are detailed in the Energy efficiency BAT assessment.	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 Applicant has stated that the selection of solvent will take into consideration a number of factors, including (but not limited to); the environmental impacts, process safety and the safety of storage implications (in terms of COMAH and COSHH), the energy requirement for solvent regeneration, the volatility of the solvent and expected losses to atmosphere, and the performance in long term, thermal and oxidative degradation tests. There are significant cost impacts associated with these elements, both capex and opex and so selection of the licensor is a critical aspect. The Operator will secure	Y

	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	performance guarantees from the licensor under the terms of contact during the FEED stage. For this determination we have assumed that the solvent for purposes of risk assessment is MEA. Any deviation from this would require a Permit variation application. Pre-FEED design assumptions include the use of a sealed/closed system with back venting for transfers of solvent received to storage, so there is no venting of solvent storage/transfer lines and so no requirement for monitoring emissions from storage. A pre-operational condition has been included into the permit to provide confirmation and validation of pre-FEED assumptions.	
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 solvent can accumulate impurities over time due to degradation, and these are assumed to be removed via thermal solvent reclaiming by a continuous process of a small slip-stream fraction of the hot lean amine from the bottom of the Regenerator. The main aim of solvent reclaiming is to ensure that a high fraction of the solvent can be reused in the CCP, and therefore minimise waste. Until operation commences it is not possible to confirm how much solvent can be reclaimed, although it is anticipated that up to 98% of solvent will be reclaimed. In maximising solvent reuse on site, reclaimer wastes will be minimised as far as possible.	Y

	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.	For the proposed proprietary solvent the applicant has stated: Extensive pilot plant and operational experience of the selected solvent performance on representative flue gases has been carried out. Additional information on this will be provided in an Environmental Permit variation to align the Permit with the final plant design.	
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.	Combustion gases from a typical CCGT plant contain negligible amounts of sulphur dioxide and the plant is likely to use deodorised natural gas from the National Transmission System (NTS) as a fuel, therefore abatement is not 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). If necessary, it is expected that ammonia (NH3) 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 applicant has confirmed the use of low NO_x burners and SCR is proposed (if required) for the reduction of NO_x. NO_x emissions have been assessed through air dispersion modelling and are not significant. The Applicant has stated that NH_3 slip from the SCR process is expected to predominantly to be stripped from the exhaust gas via dissolution in the DCC water, however a small proportion may be carried through into the Capture Plant. As such further abatement of the NH_3	Y

	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.	emissions from the flue gas may be necessary. The option of an acid -wash stage is therefore included in the current design which would have a continuous recirculation of concentrated sulphuric acid to abate NH_3 and act as a final amine removal polishing step. NO_x and ammonia emissions are limited by ELVs in the Permit.	
5.3	Sulphur trioxide (SO3) 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.	Combustion gases from a typical CCGT plant contain negligible amounts of sulphur dioxide therefore abatement is not necessary. A mist eliminator will be located after the water wash section at the top of the absorber columns to minimise aerosol release.	NA

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). 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.	Accumulation of metals, chlorine and fly ash in the solvent is unlikely due to use of natural gas. The Applicant has stated that exhaust gases pass through pre-treatment stages , including (if necessary) SCR to reduce NO_x in the gas and direct contact cooling of the gas using water (which will remove NH_3), before passing to the Capture plant. The Applicant has stated that solvent can accumulate impurities over time, and these are removed via a solvent reclaiming process which may be a thermal or ion exchange process, either continuously via a slip stream or as a batch process.	NA

6. PCC system operation

6.1	**Operating temperatures:** 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 CO2 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 specific heat requirement for solvent regeneration: The solvent reboilers are provided with steam at 3.5 bar and a maximum temperature of 160°C (about 21°C of superheat). In practice, steam temperatures will be slightly lower due to the heat loss en-route. Thermal degradation of the solvent is minimised by reduction in temperature of the regeneration process to circa 120-140^{o}C (solvent dependent). The CCP will be designed specific to the solvent to be used, with stainless steel being used where temperatures may lead to degradation of the solvent. Due to the reboiler bulk temperature of 123°C, skin temperatures are well below the values at which accelerated thermal degradation is a risk.	Y
6.2	**Solvent degradation:** 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.	Residence time in the absorber sump is not a significant contributor to oxidative degradation for two reasons: 1) The temperatures in the sump are relatively low (about 45°C). 2) The contact surface area is much smaller than the packing in the absorption section of the column, so any oxygen driven degradation will predominantly be in this part of the column. The solvent buffer tank (required for high capture during start-up) can lead to the solvent being exposed to some oxygen due to air in the tank. However, the contact surface area remains small compared to the tank volume. As such, nitrogen blanketing of the storage tank would have minimal benefit.	Y

7. Absorber emissions abatement

7.1	**Water wash:** 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 the CC plant design will employ a solvent retention system, to minimise droplet and vapour carryover, that minimises the solvent emissions to atmosphere. The system is expected to include one or two water-wash sections above the absorber to condense amine solvent in the CO_2 – lean flue gas, through direct water contact. The wash water is recycled into the solvent circulation system to minimise solvent and water consumption. The option of an acid -wash stage is included in the current design which would have a continuous recirculation of concentrated sulphuric acid to abate NH_3 and act as a final amine removal (polishing) step.	Y
7.2	**Acid wash:** An acid or other chemically active wash or scrubber after the water wash will react with amines, NH3 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.	The Applicant has stated that the option of an acid -wash stage is included in the current design which would have a continuous recirculation of concentrated sulphuric acid the abate NH_3 and act as a final amine removal polishing step. Trace nitrosamine and other degradation products entrained in the flue gas are also expected to be soluble within the acid wash and further abated. The acid wash effluent would be disposed of off-site via a licensed waste contractor. A pre-operational condition (P05) has been included into the Permit which requires the operator to submit a waste procedure to evaluate the fate of the acid wash effluent.	Y

	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.		
7.3	**Droplet removal:** 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 it is generally considered that the propensity of aerosol formation from the exhaust gas from a gas-fired power plant is low risk, due to the low sulphur content within the exhaust gas. The primary method for avoiding aerosols/ mists that could be present in the emission is to avoid their formation in the first place. In addition, this will be achieved by ensuring that the lean solvent temperature in the absorber does not result in cooling of the flue gas below its water dewpoint. Temperature of the two-stage water wash process will also be controlled to ensure that the first wash section is the same as the flue gas temperature leaving the absorption packing. This allows the wash to remove gas phase solvent components without creating a mist. As such, once the flue gas reaches the upper water wash, where it is cooled to below the dewpoint to recover evaporated water, there are minimal solvent components present to dissolve into any mist/ aerosol droplets that do form. As additional safeguards in the current design, the absorber column will have an acid wash and a demister. The acid wash will help to remove gas phase solvent components, and the demister will minimise entrainment	Y

		losses from the acid wash and other parts of the absorber.	
7.4	**Stack height:** 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 confirmed that the stack heights for the CCP Absorber stack(s) have been optimised by the modelling with consideration given to minimising the ground-level air quality impacts, and the visual impacts of taller stacks. Dispersion modelling undertaken determined the optimum stack height for the CCP Absorber stack to be 105 m, through comparison of the maximum impacts at human health and ecological receptors. An evaluation of the release height for the main stack has shown that a release height of 105 m is capable of mitigating the short-term and long-term impacts of emissions to an acceptable level, with regard to existing air quality and ambient air quality standards at human health receptors. In addition, the temperature of the CCP Absorber(s) emission has not been finalised. The actual temperature of the release post CCP would be in the region of 35°C, however in order to improve the thermal buoyancy of the emission, there is an option for reheat to be included, which could increase the release temperature to 60°C. Whether or not reheat is required may depend on the actual NH_3 emission concentration once the final licensor is selected, in order to reduce the impacts of ammonia. At this stage in the design, it is assumed that reheat will be applied. **Once the amine solvent to be used has been finalised, the modelling will be revisited (Stage 2 of the Permitting process) to refine the assessment**	Y

		where possible, so that it is as representative of the actual solvent used as possible. This will be dealt with in a subsequent variation application.	
8. Process and emissions monitoring			
8.1	**Role of monitoring** 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 will also be monitored continuously to report the resource and energy efficiency of the plant. Pre-operational condition P02 and Improvement Conditions IC17, IC18, IC19 & IC20 have been included into the Permit which require the submission of commissioning and monitoring plans. Process monitoring table S3.3 in the Permit has also been updated to include energy efficiency, resource and amine solvent quality monitoring. See point 3.3 of this table regarding CO2 product monitoring.	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 NO_x, NH_3, CO_2 and CO will be in place. Provided appropriate CEMS can be identified for amines and N-amines monitoring, then these will also be in place. If not, extractive isokinetic monitoring will be carried out. The requirement for the provision of a Commissioning Monitoring Plan has been included into the Permit as a Pre-Operational condition (P02)	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.	The Applicant has stated that NO_2 can preferentially react with the amine solvent within the Capture Plant, causing degradation of the solvent. The use of SCR may lead to NH_3 emissions or slip but reduces solvent degradation and therefore improves overall performance and reduces solvent residue waste. Thermal degradation and oxidative degradation of the solvent will be minimised through application of appropriate process control measures, for temperature and exhaust gas trace species, as required by and specific to the licensor design. Selection of appropriate materials of construction is also necessary to minimise the risk of oxidative degradation and will be specified at the FEED stage once the specific solvent requirements are known. Monitoring will be carried out in line with proposals in Section 6.1 of the original Environmental Permit application document and as clarified in the response to Schedule 5 Notice Points 8 and 43.	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.	ELVs for likely amine solvent degradation products are set in the Permit. Process control monitoring to ensure that degradation products do not build up in the CCP will be carried out as part of the reclamation process.	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. Continuous monitoring proposed for NO_x, CO, CO_2, air flow, moisture content and ammonia. CEMS for monitoring of combustion gases from the CCP will be installed to demonstrate compliance with LCP BRef BAT-AELs. The applicant has stated that it is intended that CEMS monitoring of of Amines, Formaldehyde, Acetaldehyde, Ketones, Acetic Acid & N-amines will be included for the CCP, however the exact specification of equipment to monitor the amines and degradation products is yet to be confirmed. If no suitable equipment is available, these will be monitored by isokinetic, periodic extractive monitoring. of Amines, Formaldehydes & N-amines also proposed although no method stated. We have included specified methods in the permit which the operator must use or agree the use of another methodology with us in writing.	Y
9.2	Emission sampling point must also comply with M1 sampling requirements for stack emission monitoring.	The applicant has stated that sampling points will comply with M1, where practicable. We have also included an Improvement Condition which requires monitoring location validation to assess whether the air monitoring locations A105a, A105b and A106 meet the requirements of BS EN 15259 and supporting Method Implementation Document (MID).	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 • 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	The applicant has stated that the CCP will include instrumentation to monitor and record CO_2 capture rates and purity. Sampling points will be provided to collect fluid samples of the solvent to ensure the quality of the solvent reclaiming. Process monitoring table S3.3 in the Permit has also been updated to include energy efficiency, resource and amine solvent quality monitoring.	Y
10.2	**Monitoring of CO_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
10.3	**Monitoring standards:** 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).	The applicant has stated that any extractive monitoring carried out on the emissions from the CCP will be carried out by MCERTS accredited contractors. Where required and available, UKAS accredited labs will be used for analysis.	Y

	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.		
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. 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.)	The applicant has stated that the proposed 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 (Leak Detection and Repair) LDAR system will be put in place for the CCP, appropriate to the solvent to be used. HAZOPs will consider all potential risks of accidental releases to environment, as detailed in section 4 of this BAT assessment.	Y
12. Capture level, including during flexible operation			
12.1	Capturing at least 95% of the CO2 in the flue gas is considered BAT. You can base this on average performance over an extended period	The applicant has stated that the expectation is that the CCP will demonstrate 95% capture rates are achievable.	Y

	(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 CO2 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. 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 CO2 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 not initially constructed with this capability, your Permit application should show how you may retrofit it.	The Permit includes a requirement to measure the capture rate, with the aim to achieve a 95% capture rate during normal operations.	
13. Compression			
13.1	You should select CO2 compressors based on the expected duty. You should consider how any waste heat arising may be used.	The CO_2 compressors are specified based on the expected duty, however these comprise a vendor package that has yet to be finalised. The potential for using waste compression heat is limited by the dispatchable nature of plant operation and assurance of system safety. It is also envisaged that any waste heat would be low grade and therefore it is unlikely that there would be a viable use for it. The Rankine cycle is by nature a very inefficient system, especially below temperatures of 100°C, which would be the case. Low grade heat recovery at the Proposed Installation has limited uses due to a lack of heating requirements. The most efficient use of heat is within the CCGT which is	Y

		maximised to extract power. The main other users of heat are within the CCP, the reboilers and the de-oxygenation package, where the project reuses the heat of the LP condensate in the flue gas heater located in the top of the absorber column. The Proposed Installation utilises the heat of compression to meet the requirements of the CO_2 treatment plants and this reduces the need for additional heating sources. Our decision to issue the permit recognises this is an emerging technique and that the permit therefore includes requirements to maximise energy efficiency of carbon capture including: a pre-operational condition requiring validation of pre-FEED design assumptions: an improvement condition requiring a commissioning report summarising the environmental performance of the installed plant; standard conditions requiring energy efficiency review; and resource efficiency monitoring and reporting.	
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 proposed Installation will be optimised for dispatchable operation rather than baseload operation.	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 types of compressor or pump in series may also be preferable, to give greater flexibility at the expense of slightly lower full-load efficiencies.	It is expected that the CCP will operate at full load when its power is required by the grid. Nevertheless, the plant can operate at turndown; as such 2 x 50% low pressure CO_2 compression trains have been specified. CO_2 compressor will be 2 x 50% centrifugal compressors, each with efficient operation down to about 70% capacity by means of inlet guide vane control. If the load requirement is low then a single compressor train can be	Y

		switched off. The Compressor will mirror the CCP unit - if the CCP switches off one train then the compressor will also switch one train. With single compressor operation, efficient operation down to MEL will be possible. However, the bulk of operation is expected to be between 70-100% load.	
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, CO2 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 undertaken in support of the DCO application made for the Proposed Installation, and included an assessment of all potential sources of noise, including but not limited to the compressors. Attenuation of up to 20dB LAeqT is required to achieve a rating level no greater than + 3 dB above the defined representative background sound level (both daytime and night-time) and a range of sound reduction techniques have been identified including screening or enclosing the compressors or other equipment to achieve the criterion. During detailed design, an operational noise control scheme (including agreed noise limits) will be prepared to demonstrate use of BAT for the control of noise for the final Environmental Permit. Pre-operational condition P06 has been included into the Permit which requires the operator submit a revised Noise Impact Assessment and Noise Management Plan to validate assumptions made in the application.	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	Given the CCGT plant will use natural gas as a fuel, it is expected that odour from the proposed CCGT operations will not be a significant issue.	Y

		Storage of urea or ammonia for the SCR plant, and storage and use of amines with CCP plant may have the potential to generate odour. In order to minimise the potential for odour to occur, fixed roof storage tanks will be used and if identified through FEED studies as being required, breather vents on the tanks will be fitted with suitable abatement. The solvent has a low vapour pressure at ambient temperatures and therefore is considered to have a minimal risk of generating odour. Solvent will be stored appropriately to ensure minimal odour emissions by utilising a closed line and back venting during transfer.	
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	The applicant has confirmed that cooling for the proposed Installation is expected to be achieved through use of hybrid (wet-dry) cooling towers, with make-up fresh water to the towers (and to the HRSG boiler and other minor uses) obtained from the Stainforth and Keadby Canal. Alternatively, if such a licence cannot be granted, fresh water will be supplied from the River Trent under the existing Keadby 1 abstraction licence (which would fully accommodate the proposed abstraction). The use of fresh water hybrid cooling for the proposed Installation has been determined as BAT for this site through an assessment process which considered a number of options and the site-specific technical considerations for generational output, parasitic load and water quality impacts amongst others.	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 CCP	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 maximum practicable recovery of heat from the flue gas is considered to be achieved to the steam cycle in the HRSG. 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 will 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 proposed Installation is designed 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.	BAT assessment carried out. Relevant guidance including cooling water options for the new generation of nuclear power stations in the UK considered.	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. 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 completed an assessment of the impact of discharges to water (water quality and thermal impacts). We are satisfied that emissions will not result in a significant adverse impact on receiving waters.	Y
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: UK Health Security Agency (UKHSA) The Director of Public Health The Health and Safety Executive The Food Standards Agency Local Council – Environmental Health Fisheries and Aquaculture Sciences Natural England for consultation 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.

Aspect considered	Decision
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	The Operator has provided a description of the condition of the site, which we consider is satisfactory at this stage. The decision was taken in accordance with our guidance on site condition reports and baseline reporting under the Industrial Emissions Directive. The power station is unlikely to cause pollution of controlled waters, however, historical contamination could be mobilised, and the proposed drainage could be influenced by historic contamination. The Operator confirmed (other than the discharges assessed) only surface water run-off will be discharged and a drainage plan has been submitted. The Operator has confirmed that baseline conditions for the site will be collected as part of the detailed phase II ground investigation to be undertaken prior to construction of Keadby 3.
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. There are 3 Special Areas of Conservation, 1 Ramsar and 3 Special Protection Areas sites located within 15km of the Installation. There is 1 SSSI located within 2km of the Installation. There are 7 non-statutory local wildlife and conservation sites located within 2 km of the Installation. 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. See section 8 above for further information. We have consulted with Natural England on the Application who have not raised concerns with the variation proposals. The decision was taken in accordance with our guidance.
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.

Aspect considered	Decision
	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 8 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 environmental Permit.
Operating techniques for emissions that screen out as insignificant	Emissions to air of short-term carbon monoxide, short and long-term ammonia, short-term amines, short and long-term acetaldehyde, short and long-term formaldehyde and short and long-term ketones have been screened out as insignificant, and so we agree that the Applicant's proposed techniques are BAT for the Installation. Emissions to water of copper, unionised ammonia and a thermal plume have been screened out as insignificant, and so we agree that the Applicant's proposed techniques are BAT for the Installation. We consider that the emission limits included in the Installation Permit reflect the BAT for the sector.
Operating techniques for emissions that do not screen out as insignificant	The annual mean NOx PC is over 1% of the long-term EAL and the hourly mean NOx PC and 24 hour mean Total Amines PC are over 10% of the short term EAL, so we also considered the NOx background levels and Total Amines (as MEA) contributions from local existing or planned sites to evaluate cumulative impacts. When taking these 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 either of these pollutants at maximum ground level concentration. See 'N-Amines Assessment' of section 8.2.1 and Section 8.2.2 (viii) – 'Consideration of Key Pollutants: Nitrosamines and Nitramines – N-Amines' of the key issues. Emissions are therefore unlikely to risk significant impact.
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 on 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, as a result of variations V011, V012 & V013. See section 10 above.

Aspect considered	Decision
Monitoring	We have decided that monitoring of emissions to air and water should be added for the parameters detailed in tables S3.1 and S3.2, using the methods detailed and to the frequencies specified in the permit. See section 11 above. These monitoring requirements have been imposed in order to meet requirements of Annex V of the IED, the AELs specified in the Large Combustion Plant BAT Conclusions document and the Post-Combustion carbon dioxide capture: best available techniques (BAT). 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) and Monitoring discharges to water: guidance on selecting a monitoring approach (formally part of M18). 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. 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. February 2015.*
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:

Aspect considered	Decision
	“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 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 the way in which we have considered these in the determination process.

Responses from organisations listed in the consultation section

Response received from
UK HSA
Brief summary of issues raised
Based on the information submitted, it is understood that this is a variation application to install a new activity comprising a low carbon Combine Cycle Gas Turbine (CCGT) power station on land adjacent to the Keadby 2 power station, within the wider Keadby Power station site and will be added to the existing Permit. This will also comprise as post-combustion carbon capture and compression plant (CCP) and associated infrastructure. (1) Overall, there is insufficient information contained within the Permit application to be able to fully assess the impact of the Installation on public health. The main emissions of concern from this facility are those to air as a result of the carbon capture process, the operation of generators and boilers. It is acknowledged that whilst some initial modelling has been undertaken and submitted under stage one of this Permitting process, detailed design stages are yet to take place. It is expected that UKHSA will be consulted under of stage two of this Permitting process with updated modelling and assessments. This should be clarified by the Environment Agency. We would expect to see an Environmental Risk Assessment submitted with this and support the proposal for environmental monitoring during operation and the evaluation of the air quality assessment. (2) We request that the Environment Agency take into account the following concerns and areas for further consideration based on the information that has been supplied to date. **Recommendations** (2a) Receptors • It is noted that residential human receptors have been acknowledged in Main Supporting Document. We would recommend that recreational users of the canal and river, as well as users of foot and cycle paths also be taken into account when assessing public health risks of emissions from this facility. (2b) Air Quality • The Main Supporting Document advises that air quality assessment data is included in Appendix F. However, none of the submitted documents are entitled as such. It has been assumed that this relates to Chapter 8 of the Environmental Statement (including the corresponding appendices). It is recommended that the EA ensure that all cross-referencing between reports is accurate for documents submitted at stage - two of the Permit application. (2c) • It is recommended that air quality emissions modelling and assessment be undertaken for abnormal operations to help inform a worst-case assessment, as well as those under stable operation. This should comprise emissions from start-up and shut-down processes, as well as those from the HRSG stack (in unabated mode) and generators. In the absence of this, sufficient evidence and justifications for their exclusion are required. *(2d) Emissions from the CCP and CCGT* • It is acknowledged that the final licensor has not yet been selected, nor final design undertaken, and this will be addressed at stage two of this Permitting process

o We would expect the modelled emissions to be below the relevant Environmental Assessment Level (EAL) for all pollutants, these include all volatile components and aerosols from the chosen capture solvent and that a description of significance of effect be made. Mitigation measures should be implemented to minimise any identified significant effects.

o For amines and N-amines, it is recommended that their assessment against their EAL include the combined impact of both indirect and direct emissions. It is noted that no background data is available for these compounds. It is recommended that this uncertainty be accounted for in any assessment 3 (including consideration of other potential emission sources in the area) and clear justifications provided.

o Where the final design comprises two CCP absorbers or any changes to the stack height, we would expect the modelling and the assessment of emissions to be updated to reflect this change. It is noted that proposed changes to the Development Consent Order (DCO) in February 2022 (where UKHSA was a consultee) included a twin absorber CCP scenario.

(2e) Cumulative impacts

- Further clarifications are required as to whether NOx emissions that have been modelled also include cumulative impacts from the auxiliary boiler as well as emissions from Keadby 2 and other point sources in the wider area.
- It is recommended that cumulative impacts from particulate matter emissions from generators at this facility, Keadby 2 and others in the vicinity be modelled, including during abnormal operations.

(2f) Odour

- The potential for odour as a result from the amine storage and use, will require further assessment once detailed design has been undertaken.

This consultation response is based on the assumption that the Permit holder shall take all appropriate measures to prevent or control pollution, in accordance with the relevant sector guidance and industry best practice.

Summary of actions taken or show how this has been covered

Response to (1)

A Permit variation will be submitted with the final plant design and solvent selection. Revised risk assessments will be submitted and the UKHSA will be consulted.

A full impact assessment for the impact on public health using Monoethanolamine (MEA) as the solvent in the carbon capture process has been assessed and it has been determined the proposals in the variation will not have a significant negative impact on human health or the environment.

The Operator will have to apply for a Permit variation (including all relevant risk assessments) should they wish to use a solvent in the carbon capture plant that is not MEA.

Response to (2a)

We have carried out sensitivity checks and the process contributions (from all pollutant emissions) are below the significance criteria of the relevant Environmental Standards or Process Environmental Contributions (which include process contributions and background concentrations) are below the Environmental Standards at the maximum process contribution at any point on the grid, which will include the mentioned additional receptors. Please see section 8 of this decision document for further detail on the assessment.

Response to (2b)

All of the relevant documents were submitted as part of the Application and audited through the determination. The air quality assessment and modelling data was received either as part of the variation application or in response to schedule 5 and/or information requests.

Response to (2c)

Whilst it is recognised that during start-up and shut-down there may be short periods where emissions of amines and their degradation products are higher than those assessed, there is currently limited data on the duration and release concentration of these emissions from Keadby 3. It is anticipated that this information will become available during the FEED process and therefore these emissions will be assessed then, as part of Stage 2 of the Environment Permitting process.

Pre-operational condition PO13 has been included into the Permit which requires the submission of a post combustion carbon capture plant OTNOC (other than normal operating conditions) management plan.

Response to (2d)

Variation application V011 has assessed the proposed new CCGT plant with carbon capture using MEA as the capture solvent. The results and details of the risk assessment can be found in Section 8 of this Decision Document.

A Permit variation will be submitted to incorporate the final plant design (including CCP absorber stack locations) and solvent selection and include revised emissions risk assessments.

Pre-operational condition PO12 that requires the ‘confirmation of pre-FEED design assumptions’ to be submitted, and where the final design of the plant differs from those assumed in submissions for variation V011, the operator shall reassess any effects on emissions in accordance with the environmental risk assessment methodology set out in EA guidance.

Response to (2e)

The modelling submitted assessed the cumulative impact from Keadby 2 and Keadby 3 operating concurrently. Due to physical constraints Keadby 3 and Keadby 1 cannot operate concurrently.

The auxiliary boiler proposed for Keadby 3 is electric and so will not have a point source emission to air.

Combustion of natural gas is highly efficient and due to the nature of the fuel, the combustion gases from a CCGT plant contain negligible amounts of particulate matter. There are no proposals for a fuel fired backup generator in this variation.

Response to (2f)

A Permit variation will be submitted to incorporate the final plant design and solvent selection and include revised emissions risk assessments.