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Net Zero Teesside Power Limited

Environmental Permit Variation

Main Supporting Document

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List of Abbreviations

Abbreviation	Description
ADMS	Atmospheric Dispersion Modelling System
APIS	Air Pollution Information Service
AQS	Air Quality Standard
AST	Above-ground Storage Tank
BAT	Best Available Techniques
BAT-AEELs	Best Available Techniques-Associated Energy Efficiency Levels
BAT-AELs	Best Available Techniques-Achievable Emission Levels
BATc	Best Available Techniques Conclusions document
BGS	British Geological Survey
BRef	BAT Reference document
CAPEX	Capital Expenditure
CATS	Central Area Transmission System
CBA	Cost Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CEM	Continuous Emissions Monitor
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Chemical Oxygen Demand
CSW	Clean Surface Water
DAA	Directly Associated Activity
DCC	Direct Contact Cooler
DCS	Distributed Control System
DIN	Dissolved Inorganic Nitrogen
DLN	Dry-low NOx
DPA	Dispatchable Power Agreement
EA	Environment Agency
EAL	Environmental Assessment Level
EDG	Emergency Diesel Generator
EE	Electrical Efficiency
EED	Energy Efficiency Directive
EGR	Exhaust Gas Recirculation
ELV	Emission Limit Value
EMS	Environmental Management System
EPCC	Engineering, Procurement and Construction Contract
EP Regulations	Environmental Permitting (England and Wales) Regulations 2016 (as amended)
EQS	Environmental Quality Standard
ER	Electrical Resistance
ETP	Effluent Treatment Plant

Abbreviation	Description
FEED	Front-end Engineering Design
FTIR	Fourier Transform Infra-red
FOAK	First of a Kind
GHG	Green House Gas
GET	Guidance on Emerging Techniques
GT	Gas turbine
Ha	Hectare
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IC	Improvement Condition
IED	Industrial Emissions Directive
IP	Intermediate Pressure
kPA	Kilo Pascal
LCP	Large Combustion Plant
LOD	Limit of Detection
LP	Low Pressure
LWS	Local Wildlife Site
MCP	Medium Combustion Plant
MEA	Monoethanolamine
MVR	Mechanical Vapour Recompression
MWe	Megawatt electrical
MWth	Megawatt thermal
MP	Medium Pressure
NDMA	N-Nitrosodimethylamine
NIA	Noise Impact Assessment
NH_3	Ammonia
NO_2	Nitrogen dioxide
NOx	Oxides of nitrogen
NPL	National Physics Laboratory
NTS	National Transmission System
NWL	Northumbrian Water Limited
NZT	Net Zero Power
O_2	Oxygen
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
OTNOC	Other Than Normal Operating Conditions
PCC	Post-combustion Carbon Capture
PCWS	Potentially Contaminated Surface Water
PID	Proportional Integral Derivative
PO	Pre-operational Condition
ppm	Parts per million
ppb	Parts per billion
PTR-ToF-MS	Proton-Transfer Reaction Time of Flight Mass Spectroscopy

Abbreviation	Description
RO	Reverse Osmosis
SAC	Special Area of Conservation
SCR	Selective Catalytic Reduction
SO_2	Sulphur Dioxide
SOx	Oxides of sulphur
SPA	Special Protection Area
SSSI	Site of Special Scientific Interest
ST	Steam Turbine
STDC	South Tees Development Corporation
TCM	Technology Centre Mongstad
TOC	Total Organic Carbon
T&S	Transmission and Storage
UF	Ultra Filtration
UPS	Uninterruptible Power Supply
VOC	Volatile Organic Compound
wt%	Percentage by weight
WEE	Waste Electronic Equipment
WESP	Wet Electrostatic Precipitator
WFD	Water Framework Directive
WLC	Weight Loss Coupon
WwTP	Wastewater Treatment Plant

1. Non-Technical Summary

This Main Supporting Document presents the supporting information for an Environmental Permit variation application under the Environmental Permitting (England and Wales) Regulations 2016 (as amended) (the EP Regulations), submitted on behalf of Net Zero Power Limited (NZT) to vary the existing Environmental Permit for the Net Zero Teesside Power Station and Carbon Capture Plant (the Installation), reference EPR/PP3501LR. The Installation's location and existing Installation Site Boundary is provided in Figure 1 (Appendix A).

The Installation will be the UK's first commercial scale, Carbon Capture and Storage (CCS) gas-fired power station and is designed to capture up to 2.44 million tonnes of carbon dioxide (CO_2) emissions per year, although the actual capture will depend upon utilisation. In addition, it provides the anchor project for the Teesside cluster, providing the initial CO_2 feed into the adjacent Net Zero North Sea Storage Limited's High Pressure Compression site (the operation of which is covered under a separate Directly Associated Activity (DAA) Permit (EPR/FP3143QN)) and then underground storage. As such, the NZT project will lead the way in decarbonising industry in Teesside, make a significant contribution toward the UK Government's Clean Power 2030 ambition and in reaching its net zero greenhouse gas emission target by 2050. The Installation is planned to start commissioning in Quarter 3 2027 and commercial operation is planned to commence in 2028.

At the time of the original Environmental Permit application for the Installation, the final detailed technology selection for the Combined Cycle Gas Turbine (CCGT) power plant and the post-combustion carbon capture (PCC) plant was still in progress. The application was therefore made on the basis of a generic high efficiency CCGT and a PCC plant based on the generic monoethanolamine (MEA) carbon capture solvent.

As the Installation now enters construction, final design details are available, and therefore this Environmental Permit variation is being made in order to align the permitted Installation with the updated design and specific plant details, which mainly involves the use of a proprietary amine carbon capture solvent, rather than the generic MEA solvent included in the original Environmental Permit application.

This Environmental Permit variation application is therefore for a normal variation to the existing Section 1.1 Part A(1) (a) burning of any fuel in an appliance with a rated thermal input of 50 MW or more activity and a substantial variation to the Section 6.10 Part A(1): Capture of carbon dioxide streams from an installation for the purposes of geological storage, as discussed with the Environment Agency (EA) in pre-application discussions.

The Installation is being constructed within approximately 45 hectares (Ha) of land previously within the Redcar steelworks site, which shutdown in October 2015. Since the original Environmental Permit application, the Site has been remediated and a development platform created prior to construction commencing.

Since the original permit application was made, the Site layout has been revised, such that the Installation Site Boundary has increased in size. There is therefore a change required to the existing Installation boundary from the original Environmental Permit application (shown in Figure 1, Appendix A), to the new Installation Boundary indicated in Figure 2 Appendix A.

A Site Condition Report was submitted with the original Permit application, however due to the change to the Installation Boundary, this has been revised and resubmitted with this variation to include the additional land now to be included in the Installation Boundary, and also to take into account updated information that is available about the Site. The Site Condition Report is provided in Appendix B.

The Installation will comprise a gas-fired CCGT power station, with integral Post-combustion Carbon Capture (PCC) plant. The CCGT will comprise a H-Class gas turbine capable of generating 815 MWe of electricity with a thermal input of approximately 1,400 MWth. Natural gas from the National Grid's National Transmission System (NTS) or the Central Area Transmission System (CATS) Terminal will be mixed and combusted with compressed air in the Gas Turbine (GT). The hot combustion gases will expand, rotating the GT blades at high speed, driving an electrical generator to produce electricity. The hot exhaust gases from the GT will then be passed through a Heat Recovery Steam Generator (HRSG) to produce high-pressure (HP), intermediate-pressure (IP) and low-pressure (LP) steam, which is used to drive a ST also connected to the generator; thereby maximising electricity generation from the fuel being combusted. The power produced will be supplied to the national power grid via a Dispatchable Power Agreement (DPA).

The PCC plant will use the CANSOLV DC-103 amine-based solvent to strip CO_2 from the flue gas from the CCGT power plant, in a packed absorber column, via a weak acid-base reaction. The CO_2-depleted flue gas will then pass through emissions abatement equipment (a water wash and mist eliminator) prior to its release to atmosphere via dedicated stack on top of the PCC plant absorber tower (Emission Point A1).

The CO_2 will be removed from the CO_2-rich solvent in a CO_2 stripper (or regeneration column) by heat, using steam provided by the HRSG, enabling the lean amine-solvent to be recycled back into the absorption process for reuse.

The CO_2 gas will undergo LP compression, with dehydration and de-oxygenation also carried out. It will then be transferred to the adjacent HP compression site, operated by NEP to be compressed to dense phase before being exported off-site to the Transport and Storage (T&S) network for transport to permanent underground storage.

Over time, the amine-based solvent can accumulate impurities, and these will be removed via a solvent thermal reclaiming process which will be carried out continuously within the PCC plant. A slip stream of solvent from the absorber will be fed to the thermal reclaimer unit, and will be heat treated to remove any solvent degradation products to prevent their build up.

The capture of CO_2 using amine-based solvents is a proven technology, used for many years in oil refineries and gas processing plants. More recently, it has been employed at a number of power stations worldwide, although its use in the UK is still very much in the early phase of deployment.

A review of the Installation against the Best Available Techniques (BAT) for Large Combustion Plant (LCP) has been carried out and is provided in Appendix C. In addition, an assessment against the Guidance on Emerging Techniques for Post-Combustion Carbon Capture has been carried out and is provided in Appendix D.

The main PCC plant emissions from Emission Point A1 will comprise pollutants from the CCGT power plant, including combustion emissions of oxides of nitrogen (NOx), carbon monoxide (CO) and ammonia from the Selective Catalytic Reduction (SCR) system. There will also be trace pollutants within the flue gas, including trace levels of amine from the solvent and amine break-down products from within the PCC plant.

An air quality impact assessment has been undertaken which includes an assessment of background air quality conditions, identification of human and ecological receptors and an assessment of the air quality impacts from the PCC plant. The assessment used the latest ADMS atmospheric dispersion model (version 6) to determine the worst-case predicted environmental concentrations which were then compared with relevant Air Quality Standards (AQS) or Environmental Assessment Levels (EALs). The Air Quality Impact Assessment is provided in Appendix E.

The results of the air quality assessment of the indicative emissions from the PCC plant demonstrate that it is unlikely that any exceedances of the relevant AQS or EALs at identified human health receptor would occur.

For ecological receptors impacts against the relevant critical levels (CLs) have been demonstrated to be acceptable, with the depositional impacts at all but the closest ecological receptor also being insignificant. Adjacent to the north of the Installation is the Teesmouth and Cleveland Coast Special Protection Area (SPA)/ Ramsar and Site of Special Scientific Interest (SSSI), which incorporates and area known as Coatham dunes. Whilst the impacts of nitrogen deposition on the dune habitat cannot be screened out as being insignificant for the extreme worst case normal operation of the PCC plant (i.e. assuming that emissions are at the maximum emission concentrations, with operation assumed to be for 365 days a year 24 hours a day), when a more likely worst case normal operation is assessed (i.e. envisaged long term emission concentrations and a more likely operating profile of approximately 6,094 hours per year), the nitrogen deposition at the dues is under the 1% threshold to demonstrate insignificance of the impacts.

In addition to the main PCC plant emission point, there will also be a stack associated with the HRSG (Emission Point A2), which would only be used when the CCGT power plant is operational and the carbon capture unit of the PCC plant is off-line. Combustion emissions from this source have therefore also been modelled to demonstrate that impacts associated with this mode of operation are also acceptable.

There will be a number of emergency diesel generators at the Installation to enable safe shut-down of equipment in the event of a power outage. Emissions from these sources have also been included in the Air Quality Impact Assessment.

The risk of odour being released as a result of the operation of the Installation is low as the CANSOLV DC-103 solvent has a low vapour pressure. The NH_3 storage tank will be nitrogen blanketed and will have vapour balancing for unloading operations. The vent to atmosphere will be fitted with carbon filters to prevent ammonia emission and potential odour issues.

The existing Environmental Permit contains two Emission Points to water, W1 and W2. Emission Point W1 represents the final discharge point for all waters collected in the onsite Outfall Retention Pond, which will discharge via a pump into Tees Bay via a new outfall to be constructed for the Installation, discharging approximately 1.1 km from the shore.

Waters collected in the Outfall Retention Pond will comprise surface waters from areas of the Site that are unlikely to be contaminated and Reverse Osmosis (RO) concentrate from the water demineralisation plant. Surface water from process areas, and therefore potentially could be contaminated, will be collected in an attenuation pond and be tested to ensure that they are suitable for release before being transferred to the Outfall Retention Pond.

There will also be process effluents from the Direct Contact Cooler (DCC) and Exhaust Gas recirculation (EGR) condensate waters, which will be treated in the Wastewater Treatment Plant (WwTP), before being reused within the cooling water circuit. Cooling tower and HRSG blow down will be monitored at Emission Point W2 before being released into the Outfall Retention Pond for discharge via Emission Point W1.

W2 therefore is effectively a compliance point for waters that will be treated through the WwTP and cooling water and HRSG blowdowns, as detailed in Table 5.2.

The PCC plant will have a hard piped, closed drainage system for amine containing wastewaters and for both glycol containing closed cooling water and fuel gas condensate drums to ensure that these are not released into the Installation's drainage system.

An assessment of the releases from Emission Point W1 has been carried out and is provided in Appendix F. The assessment concludes that there is no risk of any Environmental Quality Standard (EQS) being exceeded as a result of the operation of the Installation.

There will be no process emissions to sewer or land from the Installation.

The main waste generated by the PCC plant will be the waste from the thermal reclaimer. This will be collected and stored onsite prior to disposal off site via a licensed 3rd party waste contractor. Other than thermal reclaimer waste, wastes from the PCC plant are expected to be minimal, and will be appropriately disposed of via a licensed 3rd party in line with Installation procedures.

The existing Environmental Permit includes a Pre-operation Condition (PO4) to provide an updated Noise Impact Assessment (NIA) following completion of final design and at least 6 months prior to the commencement of commissioning. As the final design is not yet available, with regards to the confirmed equipment noise levels and the mitigation measures required to ensure that noise impacts at receptors are not experienced, an updated NIA has not been provided as part of this Environmental Permit variation application. This will be provided to the EA in line with the existing PO4 requirement.

A Combined Heat and Power (CHP) Cost Benefit Analysis (CBA) Assessment was caried out for the original Permit application and it is considered that there have been no changes that would materially affect the potential for heat recovery or the feasibility of CHP integration since the original assessment was carried out, and therefore this assessment has not been revisited as part of this variation.

The Installation will produce an ISO14001:2015 compliant Environmental Management System (EMS). The EMS will detail operating procedures and manage the various aspects of the operation of the Installation, including but not limited to emissions monitoring, accident management, waste minimisation and management, and infrastructure maintenance.

In addition to the changes to the Installation, this variation also addresses a number of the Pre-operational Conditions (PO) that are included in the existing Environment Permit, namely:

- PO3 - requiring a comprehensive review of the options available for utilising the heat generated by the combustion process and PCC plant in order to ensure that it is recovered as far as practicable.
- PO5 – in relation to the number, size, location and impacts of Emergency Diesel Generators (EDGs).

- PO6 – requiring an updated Water Quality Assessment for the final design.
- PO7 – requiring the provision of a drainage plan.
- PO12 – requiring an updated air quality assessment for the final design.

In addition, in light of recent discussions with the EA and Natural England, proposed new wording for the existing Environmental Permit PO15 (relating to nitrogen deposition), has been included.

2. Introduction

Net Zero Power Limited (NZT) is currently constructing the Net Zero Power Station and Carbon Capture Plant (the Installation), at Redcar, Cleveland, TS10 5QW. The Installation has an existing Environmental Permit, reference EPR/PP3501LR, which was issued in May 2024. The Installation's location and existing Site Installation Boundary is shown in Figure 1 (Appendix A).

The Installation will be the UK's first commercial scale, Carbon Capture and Storage (CCS) gas-fired power station and is designed to capture up to 2.44 million tonnes of carbon dioxide (CO_2) emissions per year, although the actual capture will depend upon utilisation. In addition, it provides the anchor project for the Teesside cluster, providing the initial CO_2 feed into the adjacent Net Zero North Sea Storage Limited's High Pressure Compression site (the operation of which is covered under a separate Directly Associated Activity (DAA) Permit (EPR/FP3143QN)) and then underground storage. As such, the NZT project will lead the way in decarbonising industry in Teesside, make a significant contribution toward the UK Government's Clean Power 2030 ambition and in reaching its net zero greenhouse gas emission target by 2050. The Installation is planned to start commissioning in Quarter 3 2027 and commercial operation is planned to commence in 2028.

At the time of the original Environmental Permit application for the Installation, the final detailed technology selection for the Combined Cycle Gas Turbine (CCGT) power plant and the post-combustion carbon capture (PCC) plant was still in progress. The application was therefore made on the basis of a generic high efficiency CCGT and a PCC plant based on the generic monoethanolamine (MEA) carbon capture solvent.

As the Installation is currently in construction, final design details are now available, and therefore this Environmental Permit variation is being made in order to align the permitted Installation with the updated design and specific plant details, which mainly involves the use of a proprietary amine carbon capture solvent, rather than the generic MEA solvent included in the original Environmental Permit application.

This Main Supporting Document presents the supporting information for an Environmental Permit variation application made under the Environmental Permitting (England and Wales) Regulations 2016 (as amended) (the EP Regulations), and is submitted on behalf of NZT to enable a normal variation to the existing Section 1.1 Part A(1) (a) burning of any fuel in an appliance with a rated thermal input of 50 MW or more activity and a substantial variation to the Section 6.10 Part A(1): Capture of carbon dioxide streams from an installation for the purposes of geological storage, as discussed with the Environment Agency (EA) in pre-application discussions.

2.1 Proposed Operations

2.1.1 Listed Activities under Schedule 1 of the EP Regulations

There are two activities in the existing Environmental Permit for the Installation which fall under Schedule 1 of the EP Regulations, as detailed in Table S1.1 of the Installation's Environmental Permit. This variation application will vary the existing the Section 1.1 Part A(1) (a) combustion activity and the existing Section 6.1 Part A(1) activity of capture of carbon dioxide streams from an installation for the purpose of geological storage. In addition, the Environmental Permit contains a number of DAAs. The changes requested to the Schedule 1 Table S1.1 of the existing Environmental Permit in this variation, are shown in Table 2.1.

Table 2.1: Table S1.1 Schedule 1 Listed Activities

Activity listed in Schedule 1 of the EP Regulations	Description of Specified Activity	Limits of Specified Activity	Changes Detailed in this Variation
Section 1.1 Part A(1) (a) Burning of any fuel in an appliance with a rated thermal input of 50 MW or more.	LCP687 (CCGT mode): Operation of a combined cycle gas turbine power plant (CCGT) burning gas to produce electricity (approximately 1400MWth)	From receipt of natural gas to discharge of exhaust gases (emission points A1 and A2) and wastes, and the generation of electricity and steam for use in the Heat Recovery Steam Generator (HRSG), steam turbine and carbon capture plant.	Inclusion of Exhaust Gas Recirculation (EGR) for the CCGT plant.

Activity listed in Schedule 1 of the EP Regulations	Description of Specified Activity	Limits of Specified Activity	Changes Detailed in this Variation
	Emergency gas oil generators to provide electrical power in the event of interruption of fuel supply and/or simultaneous loss of power generation and external power failure to the site. Schedule 25A – Medium Combustion Plant (MCP) and Specified generator that is excluded.	Emergency generators, as approved in response to pre-operational condition PO5, operated for the purpose of testing for no more than 1 hour per month per engine and no more than 500 hours operation per year in an emergency. Only one generator shall be tested at a time unless otherwise agreed in writing with Environment Agency. From receipt of gas oil to discharge of exhaust gases to emission point A3, and generation of electricity for emergency use at the installation only.	Confirmation of the emergency generators to be installed: 2 x ~5 MWth 2 x ~4 MWth 1 x ~3.2 MWth 1 x ~2.5 MWth
Section 6.10 Part A(1): Capture of carbon dioxide streams from an installation for the purposes of geological storage	Operation of a carbon capture plant involving the treatment of exhaust gas from the HRSG into the capture plant using an amine-based solvent to extract CO_2 followed by compression, oxygen removal and dehydration of the CO_2 for off-site transportation and long-term storage, and release of CO_2-abated flue gas to atmosphere.	From receipt of exhaust gases from the HRSG in the carbon capture plant to the treatment of exhaust gas prior to export of CO_2 from the installation; release to atmosphere of treated exhaust gases from emission points A1; or venting of CO_2 from emission point A4.	Change to the carbon capture solvent from MEA to CANSOLV DC-103.
Directly associated activity	Storage of gas oil for use in emergency gas oil generators.	From receipt of raw materials to dispatch for use.	No change
Directly associated activity	Water treatment – The pumping, filtering and chemical treatment of raw water from 3rd party supply for use in the cooling water circuit, capture plant and boiler (steam cycle).	From receipt of raw materials to dispatch to chemical effluent and dirty water system.	No change
Directly associated activity	Electric auxiliary boiler providing steam/ heat for use within the carbon capture plant.		No change
Directly associated activity	Discharge to Tees Bay of cooling water blow-down, steam condensate, treated direct contact cooler effluent and surface water run-off.	From collection of effluents and surface water run-off to discharge at emission point W1.	No change
Directly associated activity	Treatment of effluent from the direct contact cooler using reverse osmosis.	From the receipt of effluent from the direct contact cooler to treatment and release at W2 to emission point W1.	No change

2.2 Environmental Setting

The Installation is being constructed within approximately 45 hectares (Ha) of land previously within the Redcar steelworks site, which shutdown in October 2015. Since the original application the Site has been remediated and a development platform created prior to construction commencing. Figure 1 (Appendix A) shows the Site location and existing Site Installation Boundary.

The Installation is located approximately 400 m to the south of the North Sea shoreline and the town of Dormanstown is located approximately 1.4 km to the southeast of the Installation, whilst Redcar is situated approximately 1.8 km to the east. There are no residential receptors within 500 m of the Site, and the closest residential property to the Site is Marsh Farm in Warrenby, approximately 600 m to the east, and on Broadway West in Dormanstown, approximately 1.5 km to the south-east.

The land use in the immediate setting of the Installation incudes:

- North - Teesmouth and Cleveland Coast Special Protection Area (SPA)/ Ramsar and Site of Special Scientific Interest (SSSI) and the North Sea shoreline;

- West – Land associated with the former Redcar Steelworks, set for potential further industrial development. The operational Redcar Bulk Terminal is beyond, on the south bank of the River Tees. Beyond, on the north bank of the River Tees, industrial complexes present (at Seal Sands);
- South - Northumbrian Water Ltd (NWL) Bran Sands sewage treatment plant, operational land of PD Ports Teesport and the Wilton International industrial complex;
- East – Warrenby, Cleveland Golf Club and Redcar Beach Caravan park.

There are a number of European and Internationally designated ecological sites situated within close proximity to the Installation; this includes the Teesmouth and Cleveland Coast SPA and Ramsar and the nationally designated SSSI, which is located adjacent to the north of the Site (at its nearest point).

In addition, a further three European/ Internationally designated sites are located within 15 km of the Installation:

- Northumbria Coast SPA/ Ramsar site (approximately 14.6 km northwest);
- Durham Coast Special Area of Conservation (SAC) (14.6 km northwest); and
- North York Moors SAC/ SPA/ National Park (11.5 km southeast).

There are six SSSIs located within 15 km of the Site:

- Lovell Hill Pools (approximately 6.3 km southeast);
- Saltburn Gill (approximately 10.3 km southeast);
- Hart Bog (approximately 14.9 km northwest);
- Roseberry Topping (approximately 12.1 km south)
- Cliffe Ridge (approximately 12.6 km south); and
- Langbaurgh Ridge (approximately 13.2 km south).

There are also a number of Local Wildlife Sites (LWS) with 2 km of the Installation:

- Coatham Marsh LWS (which is part of the Teesmouth and Cleveland SSSI) (approximately 1.3 km east); and
- Eston Pumping Station LWS (approximately 1.2 km south).

The River Tees flows approximately 1.6 km to the west of the Installation and is tidal at that point, with the normal tidal limit approximately 14 km upstream (at the Tees Barrage).

There are also a number of surface water features in the vicinity of the Installation, including the Dabholm Gut which flows to the River Tees approximately 0.8 km south of the Site. The Dabholm Gut is tidal and accepts water from smaller streams, namely the Fleet (that runs from Coatham Marsh to the west of Redcar), the Mill Race (from east of the Wilton International complex); and Dabholm Beck (from the west of the Wilton International complex).

Further detail on the environmental setting and local receptors is presented in Section 7.

3. Site Condition Report

Since the original Environmental Permit application was made, the Site layout has been revised, such that the Installation Site Boundary has increased in size. There is therefore a change required to the existing Installation boundary from the original Permit application (Figure 1, Appendix A), to the new Installation Boundary indicated in Figure 2 Appendix A.

A Site Condition Report was submitted with the original Permit application, however due to the change to the Installation Boundary, this has been revised and resubmitted with this variation to include the additional land now to be included in the Installation Boundary, and also to take into account updated information that is available about the Site.

The revised Site Condition Report is provided in Appendix B.

A brief summary of the sensitivity of the Installation area is provided here:

- **Groundwater -** Low to Very High sensitivity - The underlying Sherwood Sandstone Group – Sandstone bedrock deposit is classified as a Principal Aquifer whilst the Redcar Mudstone deposits are classified as Secondary Aquifer – B. The underlying superficial deposits consist of Secondary Aquifer - A and Unproductive Strata. The sensitivity of the underlying deposits is therefore classified as varying from low to very high.
- **Surface water -** Moderate sensitivity – River Tees, located circa 1.6 km to the west of the Site, the North Sea is situated approximately 0.4 km to the north, and there are a number of drains feeding into the tidal Dabholm Gut which flows to the River Tees approximately 0.8 km south of the Installation site;

  The Installation is approximately 1 km from the mouth of a Water Framework Directive (WFD) coastal waterbody named Tees Coastal. The site is in a Flood Zone 1 (less than 1 in 1,000 annual probability of river or sea flooding).
- **Land use -** Low sensitivity – the Installation is surrounded by industrial land and no significant land uses have been identified.

The existing Environmental Permit includes a number of pre-operational (PO) conditions concerning the Site Condition Report, namely:

- PO9 – requiring an updated report on the baseline conditions of soil and groundwater at the Installation;
- PO10 – requiring a written protocol for a monitoring and maintenance plan for the monitoring of soil and groundwater; and
- PO11 – requiring submission of a report detailing how redundant historic and current ground investigation boreholes have been decommissioned

Whilst an updated Site Condition Report is provided with this application, due to the change in the Installation Boundary, the requirements of PO9, PO10 and PO11 will be dealt with outside of this Environmental Permit variation application. This was discussed and agreed with the EA during pre-application discussions.

4. Operating Techniques

4.1 Technical Standards

The following technical standards are considered to be applicable to this Environmental Permit variation application:

- Best Available Techniques (BAT) Reference (BRef) Document for Large Combustion Plant (LCP) (LCP BRef)[1]; and
- BAT Conclusions for Large Combustion Plants (LCP BATc)[2].
- Develop a management system: environmental permits[3]
- Guidance on Emerging Techniques on how to prevent of minimise the environmental impacts of post-combustion carbon dioxide capture (PCC GET)[4].
- Emergency backup diesel engines on installations: best available techniques[5].

A review of the CCGT plant against the LCP BATc has been provided in Appendix C, with a review of the PCC plant against the PCC GET provided in Appendix D. It should be noted that the EA PCC GET does not have the same legal status as BRefs published under the Industrial Emissions Directive (IED) and does not provide specific regulatory requirements but rather identifies important environmental issues to address and best practice.

BAT for PCC is evolving and will continue to do so until the UK has operational experience gained over a number of years. Compliance with the PCC GET is therefore not explicitly required where it can be demonstrated that the important environmental issues identified in the guidance have been addressed.

4.2 Process Description

4.2.1 Overview

As detailed in the original Environmental Permit application for the Installation, the Installation will comprise a gas-fired CCGT power station, with integral PCC plant.

The CCGT will comprise a H-Class gas turbine (GT) capable of generating 815 MWe of electricity with a thermal input of approximately 1,400 MWth. The power produced will be supplied to the national power grid via a Dispatchable Power Agreement (DPA). The CCGT will comprise:

- a GT;
- a Heat Recovery Steam Generator (HRSG);
- a Steam Turbine (ST);
- Exhaust Gas Recirculation (EGR); and
- Selective Catalytic Reduction (SCR).

Natural gas from the National Grid's National Transmission System (NTS) or the Central Area Transmission System (CATS) Terminal will be mixed and combusted with compressed air in the GT. The hot combustion gases will expand, rotating the GT blades at high speed, driving an electrical generator to produce electricity. The hot exhaust gases from the GT will then be passed through a HRSG to produce high-pressure (HP),

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[1] Best Available Techniques (BAT) Reference Document for Large Combustion Plant, under Directive 2010/75/EU of the European Parliament and of the Council, European IPPC Bureau, December 2017

[2] Commission Implementing Decision of 30 November 2021 establishing best available techniques (BAT) conclusions, under Directive 2010/75/EU of the European Parliament and of the Council, for large combustion plants, November 2021

[3] https://www.gov.uk/guidance/develop-a-management-system-environmental-permits

[4] Post-combustion carbon dioxide capture: emerging techniques - GOV.UK

[5] Emergency backup diesel engines on installations: best available techniques (BAT) - GOV.UK

intermediate-pressure (IP) and low-pressure (LP) steam, which is used to drive a ST also connected to the generator; thereby maximising electricity generation from the fuel being combusted.

The PCC plant will tie into the flue ducting from the HRSG. On entering the PCC plant, the exhaust gases from the HRSG will first pass through a pre-treatment stage of quenching via a direct contact cooler (DCC) before passing to the main PCC plant for CO_2 abatement. The PCC plant will contain a solvent-based unit, utilising the CANSOLV DC-103 solvent, designed to selectively remove the CO_2 from the flue gas feed and vent treated flue gas to atmosphere.

Once cooled in the DCC, the exhaust gas will pass to the PCC plant, where it will travel up through a counter-flow, packed absorption column against a falling solvent, into which the majority of the CO_2 content within the flue gas will be absorbed. The treated flue gases (CO_2-abated flue gas) will then pass through solvent retention and air emissions mitigation stages and will subsequently be released to atmosphere via a stack located on top of the absorption column (Emission Point A1).

The CO_2-rich solvent will leave the bottom of the absorption column and be routed to the top of the CO_2 stripper, via a crossflow heat-exchanger, where it will pass down a packed column, counter-current to hot rising vapour from the reboiler at the CO_2 stripper base, releasing the absorbed CO_2. The CO_2-lean solvent at the bottom of the CO_2 stripper will then return to the solvent system via the cross-flow heat-exchanger, and the CO_2 from the top of the CO_2 stripper will pass to onsite LP compression and de-watering facilities. The CO_2 will then be transferred to the HP Compressor Station Compression Site, which will be operated by Net Zero North Sea Storage Limited under a separate DAA Environmental Permit (EPR/FP3143QN) for further compression and transfer to storage.

The PCC plant has been designed to capture at least 95% of the CO_2 emissions from the CCGT power station during normal operation, designed to capture up to 2.44 million tonnes of CO_2 annually, dependent on utilisation.

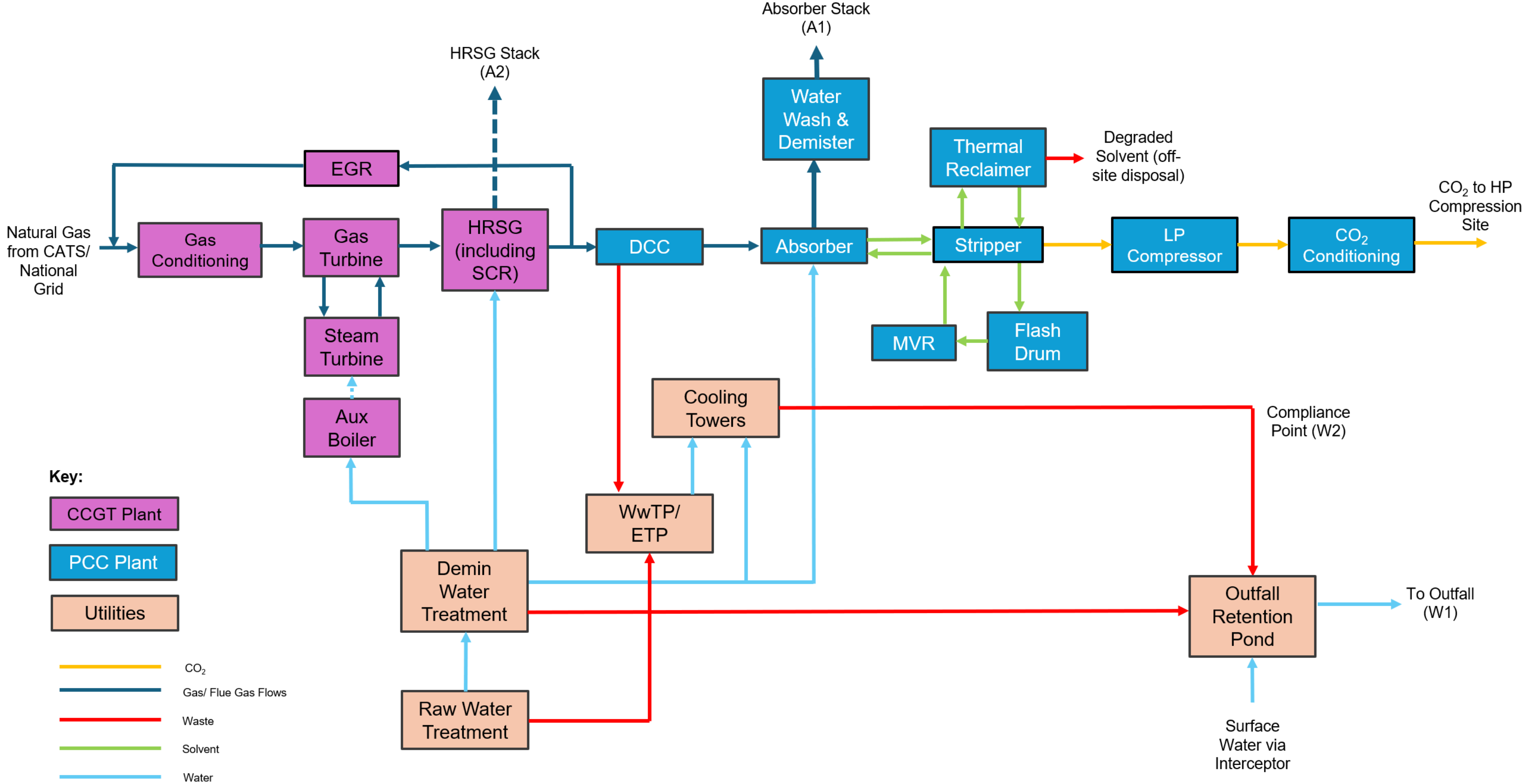
To ensure that degradation products do not build up in the solvent, a slip stream of solvent will be constantly fed to a thermal reclaimer which heat treats the solvent to break down heat-stable salts formed in the PCC plant’s process. This recovers solvent and removes degradation products, prior to returning the solvent to the PCC plant.

The PCC plant will include the following components:

- a DCC;
- CO_2 absorber column, water wash section and stack;
- CO_2 stripper column;
- A thermal solvent reclaimer unit; and
- LP compression, oxygen (O_2) removal and dehydration;
- CO_2 metering and pipelines connecting the PCC plant to the Net Zero Teesside High Pressure Compressor Station Compression Site.

A high-level Process Flow Diagram is provided in Plate 1.

Plate 1: Typical Flow Diagram for the Installation



The operation of the Installation will also require the following activities:

- Raw water treatment of water from NWL for use as process/ cooling water
- Cooling via hybrid cooling towers;
- Wastewater Treatment Plant (WwTP) for the treatment of waste process waters from the PCC and EGR DCCs and an Effluent Treatment Plant (ETP) that will dewater solids from the raw water treatment plant and the WwTP;
- Chemical storage facilities for the CANSOLV DC103 and others such as ammonia (NH_3);
- Drainage, including closed drainage for amine and glycol containing wastewaters.

4.2.2 Operating Regime

As detailed in the original Environmental Permit application, the Installation has been designed to be able to operate in either baseload or in a flexible (dispatchable) mode. Baseload mode power refers to power generation that generally runs continuously at high levels of power output throughout the year and whereby the CCGT plant is operated at stable power output levels. Dispatchable mode generation refers to highly flexible operation when the Installation will be on demand and dispatched according to market conditions and requirements. As such, operating in dispatchable mode could involve multiple start-up/ shutdown cycles per year and the PCC plant design is such that CO_2 capture during these times is maximised (see Section 4.2.4.8).

Operations in baseload mode are considered the worst-case in terms of environmental impacts (although carbon capture efficiencies may be more stable during baseload operations) and therefore this is the basis for the impact assessments carried out in support of this variation and for raw material and waste quantities detailed.

As stated previously, the commercial operation of the Installation is controlled through a DPA. The Installation will respond to electricity market prices, operating when prices are high (typically when renewable energy is low) and pausing when prices are low (when renewables are abundant). The DPA includes a “Variable Payment” mechanism that ensures NZT is financially incentivised to run ahead of traditional gas-fired power stations that do not include capture carbon. This payment covers the extra costs of running a low-carbon plant, such as the CO_2 capture and transport element, so that NZT can compete fairly in the market. This ensures that NZT will typically dispatch before higher-emission alternatives when the electricity grid needs power.

4.2.3 Power Plant – CCGT

Natural gas from the National Grid’s NTS or CATS terminal will enter the Installation at HP and will be let-down to the required pressure within the gas receiving area. There will be no storage of natural gas on Site.

The received gas will be metered and pass through mechanical and coalescing filters and be heated to counter the Joule-Thomson effect from pressure reduction, and heating of the gas to optimise combustion in the CCGT by reducing the fuel required to reach turbine firing temperatures. Heating will be provided by two heaters; an electrical dew-point fuel gas heater to prevent liquid drop out in the GT at start up and a performance heater which uses IP condensate to heat the gas to approximately 300°C during normal operations.

Within the GT, the heated gaseous fuel will be mixed and combusted with ambient air. Note that combustion air will not be pre-heated as if the air is too hot, it can cause damage to the turbine and decrease its efficiency. The GT will have dry low NOx (DLN) combustion technology to minimise the production of oxides of nitrogen (NOx) during combustion.

The fuel-air mixture combustion results in high temperature combustion gases that expand across the blades of the GT causing them to turn and produce mechanical energy used to drive a generator to produce electricity.

The GT system will have equipment to reliably monitor the fuel flow rate, temperature, pressure and shaft speeds of the system, with the control system being temperature and power based in order to ensure safe and efficient operation. The control system will include emergency fuel shut off systems.

The hot exhaust gases from the GT will then be passed through a HRSG to produce HP, IP and LP steam, which would otherwise be lost through the exhaust stack, (i.e. as in an open cycle gas turbine). The resulting steam is used to drive a ST, also connected to a generator; thereby maximising electricity generation from the fuel being combusted.

The ST will be a three pressure reheat ST. There will be a HP turbine, supplied by the HRSG HP steam system, an IP turbine supplied by the HRSG reheater (which is supplied by the HP turbine exhaust and IP superheater discharge, the combination of which is commonly called "Cold Reheat" steam), and the LP turbine, which is fed by IP turbine exhaust through crossover pipe.

The arrangement is a single-shaft configuration in which the GT is connected to the ST on the same shaft.

The control systems of the ST will monitor and regulate its operation, ensuring optimal performance. These control systems will monitor the steam flowrates, temperature, and pressure of the system. Furthermore, the ST will be fitted with safety mechanisms such as emergency stop systems, steam isolation, overspeed protections, and vibration monitoring systems.

The steam exhausting from the ST will be condensed with the condensate returned to the steam-water cycle of the HRSG for continued reuse. Water used within this steam/ water cycle will need to be treated to be of extremely high purity to regulate the build-up of residual dissolved solids in the pipework arising from the continuous evaporation and condensing of water within the cycle. It will be dosed to control pH and dissolved O_2. To further manage this, it will be necessary to intermittently purge a small amount of the boiler water (known as 'blowdown') to the cooling tower basin. Any blow-down removed from the cycle will need to be made up with fresh demineralised water.

The condensation of steam exiting the ST will be achieved using a separate circuit of cooling water that will be recirculated through hybrid cooling towers.

A portion of the flue gas from the HRSG will be recirculated back to the GT inlet compressor to provide an Exhaust Gas Re-circulation (EGR) loop. Further information on EGR is included in Section 4.2.3.1.

Control systems will be employed to monitor and regulate the HRSG's operation. These control systems will manage the flow of feedwater, steam, and exhaust gases, maintaining the desired temperature and pressure levels within the HRSG. Safety mechanisms, such as safety valves, and pressure relief valves shall be integrated to protect against overpressure and overheating.

The HRSG will have a stack (Emission Point A2) from which emissions will only occur in the event that the CCGT operates in unabated mode (i.e. when the PCC plant is not operational). It is anticipated that this mode of operation would mainly occur at times when the CCGT is required to provide electricity for the National Grid but the Transport and Storage (T&S) network is not available (see Section 4.2.4.9).

The CCGT is also designed to be Combined Heat and Power (CHP) Ready; however, CHP is not proposed to be installed from the outset of commercial operation. The potential for using the CCGT plant as a CHP plant will be assessed periodically (at least every 4 years), as per regulatory requirements. A CHP Cost-Benefit and Readiness assessment was carried out as part of the original Environmental Permit application, and it is considered that there have been no material changes that could affect the potential for heat recovery or the feasibility of CHP integration to the Installation since it was carried out. This approach was discussed and agreed with the EA during pre-application discussions on 28th July 2025.

4.2.3.1 CCGT Exhaust Gas Re-circulation

As stated above, the EGR loop enables the recirculation of a proportion of the HRSG exhaust flue gas to the GT inlet compressor and mixing of this stream with the incoming combustion air, after cleaning, cooling and condensing out the moisture. This increases the CO_2 concentration from approximately 5% to approximately 7% prior to treatment though the PCC plant and therefore increases the CO_2 capture efficiency. The EGR system will enable up to 30% exhaust gas recirculation based on the flue gas flow from the HRSG exhaust into the GT inlet.

The CCGT will be able to operate with or without EGR, by the opening/ closing of the inlet/ outlet dampers on the EGR loop. Normal operation will be to operate with EGR, with a slip stream of the exhaust gas exiting the HRSG being diverted to the EGR loop prior to the PCC plant's DCC. The EGR loop itself will consist of an enhanced DCC with an integrated Wet Electrostatic Precipitator (WESP) and chemical dosing to reduce the re-circulated flue gas temperature and remove any impurities, prior to the conditioned flue gas being routed to the inlet static mixer. The static mixer will be part of the GT air inlet system and will distribute the conditioned recirculated flue gas into the inlet air stream.

The EGR DCC water will be cooled in a heat exchanger fed by the site cooling water system and the quality of the EGR DCC water will be monitored to determine the rate of water removal, in order to ensure the quality is kept within the required specification. Water removed from the system will be sent to the onsite WwTP Additionally, the WESP will need to periodically flushed with water to remove entrained particulates, and this water will also be sent to the onsite WwTP.

On initial start-up of the CCGT, the GT will be started with the generator running in reverse, as a motor, which initiates a flow of air through the GT and HRSG to purge any hydrocarbons within the system. At this time the dampers to the HRSG stack and PCC plant will be closed and therefore the air purged from the plant will be released via a vent on the EGR loop. The GT will then be fired and the damper to the PCC plant will be opened. This step would only be required on the initial start-up sequence of the Installation, or in the event that the CCGT had been offline for extended periods, such as for maintenance.

For every start-up sequence, in order for the EGR DCC to achieve effective cooling of the flue gas prior to reintroduction into the GT, a small slip stream of the HRSG exhaust gas will be fed through the EGR loop and be vented from the EGR vent. Once effective cooling is achieved the EGR vent damper will be closed, and the EGR loop will be fully opened to allow full operation of the EGR.

On shut-down the EGR vent will be opened prior to the GT ceasing firing, the GT will then be shut off and the damper to the PCC plant closed. Any flue gas remaining in the plant will be purged from the EGR vent to ensure that there are no remaining hydrocarbons, facilitating the quick start of the CCGT on next operation.

4.2.3.2 Exhaust Gas Treatment Prior to the PCC Plant

The optimisation of natural gas combustion within a GT is well understood, such that the emissions are carefully controlled by design and typically through the implementation of primary control measures such as burner design, DLN burners and staged combustion. Additional (secondary) abatement of NOx will be required to achieve the required BAT-Achievable Emission Levels (AEL) from new CCGT plant (daily average of 40 mg/Nm^3 and an annual average of 30 mg/Nm^3 (with the energy efficiency correction factor applied)).

SCR is a secondary abatement technique typically involving the injection of NH_3 into the exhaust gas to react with any NOx present in the presence of a catalyst to produce nitrogen and water. The SCR system will be located within the HRSG, at the optimum catalyst temperature zone and will comprise:

- SCR housing as an integral part of the HRSG;
- SCR catalyst;
- NH_3 injection system;
- NH_3 flow control unit (skid based); and
- Instrumentation and control.

The required amount of NH_3 will be pumped via the feed control valve to the vaporiser where it will be mixed with hot dilution air and be vaporised. The vaporised NH_3 will then be mixed with the flue gas in the HRSG, upstream of the SCR catalyst via the NH_3 injection grid, which will ensure homogeneous mixing of NH_3 with the flue-gas. Any unreacted ammonia in the SCR will remain within the exhaust gas (NH_3 slip) from the HRSG.

The flue gas NOx concentration at the outlet of the SCR will be analysed and a Proportional Integral Derivative (PID) control loop will modulate the NH_3 feed control valve, regulating the NH_3 flow against the required level of NOx reduction in the flue gas leaving the SCR to ensure that the required NOx BAT-AEL is achieved, and that NH_3 slip is minimised.

It is anticipated that NH_3 slip from the SCR will be in compliance with the required LCP BAT-AEL of < 3 - 10 mg/Nm^3 as a yearly average, or average over the sampling period (noting that the lower end of the range is applicable to SCR, with the upper end applicable to Selective Non-Catalytic Reduction).

Opportunities for the re-use of the catalyst from the SCR unit will be investigated and wherever possible utilised, however at this stage of the project this cannot be confirmed. Any opportunity for re-use would include the consideration of suitable waste preparation for re-use, where specific quality criteria are requested, in line with LCP BAT No. 16.

Carbon monoxide (CO) emissions are controlled through primary combustion controls, with no requirement for secondary abatement.

4.2.4 PCC Plant

The PCC plant will be an amine-based solvent, post-combustion carbon capture plant that is designed to capture at least 95% of the CO_2 from the pre-treated flue gas received from the DCC. The specified CO_2 capture efficiency is set out in the Functional Specification (part of the Engineering, Procurement and Construction Contract (EPCC) documents entered into with the facility designer) and detailed design is targeted to achieve this capture rate.

The CANSOLV DC-103 system is based on a unique class of amines that optimally balance the ability to absorb and regenerate CO_2. CANSOLV DC-103 is a binary mixture comprised of 50wt% water and 50wt% amine.

4.2.4.1 PCC Plant DCC

As the natural gas for the CCGT would either come directly from the NTS or CATS it will not be odourised (only LP systems going to non-industrial customers are odourised), and therefore the sulphur content will be very low. The PCC plant design accounts for the possibility of 10mg/m^3 of sulphur dioxide (SO_2) in the fuel gas to the CCGT, which is considered conservative based on operational experience of CATS gas. It is therefore considered that there would be negligible amounts of SO_2 and particulate matter in the exhaust gas from the HRSG, and therefore secondary abatement of these species going into the PCC plant is not considered to be necessary for the purpose of reducing the potential for degradation products to form in the PCC plant's solvent.

The flue gas from the HRSG will pass through the PCC plant DCC and then into the main PCC plant. The DCC water will be dosed with caustic to maintain an appropriate pH, and this would also remove any SO_2 from the flue gas, if present.

The DCC will saturate and cool the flue gas prior to the CO_2 absorber column, to ensure optimum conditions for CO_2 absorption and to prevent excessive water evaporation from the solvent solution occurring within the absorber. The flue gas will be cooled to the required temperature for the carbon capture process by direct contact with recirculating water within the DCC. The recirculating water will be cooled against air in the DCC water cooler.

Water condensed from the flue gas in the bottom section of the DCC may contain NH_3 from the SCR and therefore this will be sent to the onsite WwTP.

The original Permit application stated that a booster fan (blower) would be needed to overcome the pressure loss through the exhaust gas path to the PCC plant stack, however the final design is such that the GT supplies the necessary pressure for the flue gas from the CCGT to flow through the PCC plant and to the atmosphere without needing an additional blower between CCGT and DCC.

4.2.4.2 CO_2 Absorption

The cooled CO_2-rich flue gas from the DCC will enter at the bottom of the PCC plant CO_2 absorber column, where it will contact the cooled lean amine solvent that will remove the CO_2 from the flue gas. The CO_2-rich flue gas will pass up through the absorber column, with the lean solvent flowing down, counter-current, through the multi-level packed-bed absorber, to ensure good contact efficiency is maintained throughout the column. The CO_2 will become chemically bound by the amine solvent as the alkaline nature of the solvent will mean that it selectively absorbs acidic gases such as CO_2.

The equilibrium limit for the reaction will be reached at the top of the absorber column where the leanest lean solvent contacts the exhaust gas with minimum CO_2 concentration. The overall carbon capture efficiency is given by the difference in exhaust gas inlet and outlet CO_2 concentrations.

Typical operating temperatures in the absorber column range from 40°C to 55°C, depending on the process design parameters such as the compositions of the solvent and exhaust gas, as well as the presence of any intercooling arrangement in the absorber column. The reaction between the solvent and the CO_2 is exothermic, as such the flue gas temperature is increased through the main packed bed of the absorber column.

The absorber column will have a water wash section at the top, which will remove entrained solvent in the CO_2-lean flue gas prior to its release, in order to minimise solvent carry-over into the waste gases discharged from the PCC plant stack (see Section 4.2.4.3). The treated flue gas leaving the top of the absorber column will finally pass through a mist eliminator and will be reheated against steam condensate to ensure sufficient gas buoyancy for effective dispersion before being released to the atmosphere via Emission Point A1.

The water used in the water-wash section is continuously recycled and cooled in the water-wash cooler. As such, water is condensed from the flue gas in the water wash section, and any excess water is drained to the solvent loop to prevent solvent build-up in the water wash section and to minimise both solvent and water consumption.

The proportion of water in the recirculating amine solvent needs to be managed to ensure that this does not accumulate due to condensation of the flue gas. The amine solvent will be routinely sampled and analysed to determine whether excess water requires purging from the system.

The CO_2 rich solvent will be removed from the bottom of the absorber column and will be sent for CO_2 stripping (see Section 4.2.4.4).

4.2.4.3 Exhaust Gas Treatment Post PCC Plant

A single stage water wash will be located at the top of the absorber column to remove any amines present in the flue gas being released from the absorber stack (Emission Point A1). It is recognised that the PCC GET states that:

> *"an acid or other chemically active wash or scrubber after the water wash will react with amines, NH_3 and other basic species and reduce them to very low levels (for example, 0.5mg to 5mg per m^3 per species or lower)."*

It goes on to say that:

> *"You should implement an acid wash as it is considered to be 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".*

It is not considered that an acid wash is required for the Installation, as the proposed water wash will achieve the 'acid wash levels' specified in the PCC GET at Emission Point A1.

CANSOLV DC-103 is composed of low volatility amines compared to other technologies available in the industry, and its degradation pathways favour the formation of low volatility degradation products (including organic acids, amides, formamides and nitrosamines and nitramines (collectively referred to as N-amines). The resulting low primary emissions of amines and degradation products for a CANSOLV PCC plant therefore leads to much lower accumulation in the water-wash system than for other amine systems, including MEA systems. Combined with the intrinsically low volatility, this leads to negligible equilibrium partial pressure of amines and degradation products exerted by the circulating water, and low residual concentrations in the gas exiting from a water wash. As such, the low equilibrium concentration at the outlet of the water wash means that a second wash stage would result in minimal further reduction, provided the packing height in the first stage is sufficient.

The above considerations also mean that generation of NH_3 from CANSOLV DC-103 is very limited for clean gas applications, such as the Installation (i.e. where the flue gas does not contain contaminants such as iron, which could favour degradation pathways leading to increased ammonia generation), typically of the order of a few parts per million (ppm) or lower, as indicated in the emission limit values (ELVs) proposed for Emission Point A1 (see Table 5.1). Achievement of the low NH_3 ELV indicated in Table 5.1 is therefore reliant on the inherently low primary emissions of the overall CANSOLV system in clean gas applications. It is recognised the presence of the water wash will not reduce NH_3 emissions further, as the captured NH_3 is returned to the amine loop with the water wash overflow.

The use of a single stage water wash is supported by the experience of the two existing CANSOLV plants in operation (Boundary Dam and the Brothers CISA unit), which have been operational since 2014 and 2013 respectively. Both have single stage water wash sections and no acid wash. Further, long-term pilot tests carried out by the solvent provider have shown that outside of contaminated applications (i.e. where iron and/ or aerosols are present), a single stage water wash achieves the proposed ELVs detailed in Table 5.1 for NH_3, amines and other listed degradation products. The findings of several of these pilot tests have been reported in public presentations and/ or articles[6], which have often used advanced monitoring instrumentation to respond to an increasing demand for data on emissions with ppb level sensitivity.

It is therefore considered that the data for CANSOLV DC-103 supports the conclusion that a simple water wash, in the absence of an acid wash, will be sufficient to abate amines and solvent degradation products such that the ELVs in Table 5.1 can be met. As such, the proposed ELVs from the Installation are considered to be *"at acid wash levels with a water wash"*, as they are below the *"very low levels"* specified in the PCC GET without the requirement for an acid wash.

Although this is considered a first of a kind project (FOAK) for the UK, there are similar operational applications using the CANSOLV DC-103 solvent, and substantial pilot plant trial information to reduce the level of uncertainty. As such, the proposed emissions from the Installation are based on performance guarantees that have been agreed with NZT; no licensor would offer a performance guarantee for their technology without having confidence that such a guarantee would be met.

The wash water is circulated counter-currently to the flue gas through a packed bed in the water wash section of the absorber column. The wash water is drawn from a chimney tray at the base of the water wash section at approximately 50°C and is recirculated to the top of the packed bed via the water wash coolers, by pumps. The wash water cooler reduces the temperature of circulating wash water from approximately 50°C to 30°C, which minimises water loss and enhances capture efficiency of the solvent and degradation product. Water condensed from the flue gas in the water wash packed bed falls into the chimney tray and is recycled through to the water wash pumps.

The water wash return temperature is controlled to maintain the amine loop's overall water balance, through its effect on water loss through the absorber stack. This is achieved by adjusting the cooling water flowrate in the water wash coolers. In design operating conditions, a water wash return temperature of 30°C will be required to keep the absorbent water fraction in the PCC plant constant.

The absorber wash water level control is provided to maintain an adequate level of wash water in the section, such that the volatile or entrained solvent mist is captured, the water carried over by the flue gas is condensed and the water balance within the system is maintained. The excess water condensed will flow to the base of the absorber column to maintain the required level within the wash water section.

A mist eliminator will be present at the top of the water wash section of the absorber column to minimise liquid droplet entrainment. It is recognised that this mist eliminator will not efficiently capture aerosols (submicron droplets), however due to very low concentration of dust and oxides of sulphur (SOx) (specifically sulphur trioxide) in the flue gas, the potential for aerosol formation is considered to be very low, and therefore no specific aerosol capture system is considered to be required.

Prior to release from the absorber stack, the flue gas will be reheated using LP condensate from the stripper reboiler flash drum. This will heat the flue gas from approximately 45°C to 65°C and therefore aid the dispersion of emissions and reduce the potential for visible plumes to occur.

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[6] Oslo Klemetsrud piloting campaign – 2019. Reported in J. Fagerlund et Al. (2020). Performance of an amine-based CO_2 capture pilot plant at the Fortum Oslo Varme Waste to Energy plant in Oslo, Norway. International Journal of Greenhouse Gas Control 106 (2021) 103242.

Oslo Klemetsrud piloting campaign – 2021. Reported in Karl Stephenne, Rajiv Srinivasan, Saravanan Venkatesan, Paul-Emmanuel Just. (2022). Pilot campaigns and Cost Reduction in the CANSOLV CO_2 Capture Process. 16th International Conference on Greenhouse Gas Control Technologies, GHGT-16. 23rd -27th October 2022, Lyon, France and A. Wisthaler et al. *PPB-level monitoring of amines and NO_2 at the Klemetsrud CO_2 capture pilot plant.* 16th International Conference on Greenhouse Gas Control Technologies, GHGT-16. 23rd-27th October 2022, Lyon, France.

TCM demonstration campaign – 2023. This campaign, performed from February to August 2023, aimed at testing operation with several DC-103 formulations (including the formulation to be used in the Installation) with the two flue gas sources available at the TCM test centre (catalytic cracking off-gas and the CHP from the co-located refinery).

Although the results have not been publicly presented, they confirm low emission levels, and in clean gas conditions (corresponding to processing of the TCM CHP flue gas), at the same levels predicted for the Installation.

4.2.4.4 CO_2 Stripper

The CO_2-rich solvent, collected in the sump of the absorber column, will be pumped to the CO_2 stripper for solvent regeneration and CO_2 recovery via the lean/ rich solvent heat exchangers, which will warm the incoming CO_2-rich solvent.

The CO_2 stripper will consist of a stripping section with a collector tray below the packing and a reflux section on top of the column to maximise the solvent-CO_2 separation. The rich solvent will enter the CO_2 stripper on top of the stripping section of the column and the CO_2 will be removed from the solvent by steam rising up through the column which breaks the CO_2-amine bond.

Lean absorbent flowing to the bottom packing section of the CO_2 stripper will be collected on a chimney tray and gravity fed to the reboilers. The solution will be heated in the reboilers by LP steam and a mixture of water vapour and lean solvent will flow from the reboilers back to the CO_2 stripper sump underneath the chimney tray by thermosyphon effect. The flashed vapours will be separated from the liquid and the vapour will re-enter the stripping section to strip out any remaining CO_2 from the solvent. Water vapour will flow upwards through the chimney tray to strip the solvent of CO_2 while the lean absorbent will be collected in the bottom sump.

Flashed LP condensate will be directed to the lean absorbent flash drum to provide suction pressure to the Mechanical Vapour Recompression (MVR) compressors. The MVR is used to recover energy from water saturated vapor, increasing its pressure and using it as a heating medium in the CO_2 stripper, hence reducing the steam requirement for the system.

The lean solvent will then be passed through a heat exchanger to be cooled before the solvent re-enters the absorber column for reuse.

The gas containing the CO_2 from the stripping section will pass through the reflux section of the CO_2 stripper and will be routed to the reflux condenser. The residual steam will be condensed, and the liquid separated from the gas in the reflux drum. The bulk of the liquid will be returned to the top of the reflux section of the CO_2 stripper.

The removed CO_2 will be routed from the top of the CO_2 stripper column, where a portion of the vapour will be condensed by recycled reflux to enrich the overhead CO_2 gas stream. The CO_2 stripper overhead gas will be partially condensed by cooling in the CO_2 stripper condenser. The partially condensed two phase mixture will flow under gravity to the CO_2 stripper reflux drum where the two phases will separate. The reflux water will be collected and returned via the CO_2 stripper reflux pumps to the CO_2 stripper rectification section. In addition, a connection is also provided at the reflux pump discharge to provide reflux make-up to the CO_2 absorber wash water section, if required.

The CO_2 will flow from the CO_2 stripper reflux drum to the CO_2 LP compressors (see Section 4.2.4.5).

The efficient management of the solvent is fundamental to the maximisation of efficiency of the PCC plant. The recirculating solvent can accumulate insoluble contaminants entrained within the flue gas. In addition, oxidative degradation, where amines react with O_2, nitrogen dioxide (NO_2) or SO_2 to form corrosion products including NH_3, can occur at temperatures between 40 - 55°C and particularly in the presence of particulate impurities.

Thermal degradation of the solvent will be minimised by ensuring the temperature of the regeneration process is optimised for the CANSOLV DC-103 solvent to be used within the PCC plant. The selection of appropriate materials of construction is also necessary to minimise this risk.

The use of solvent management techniques specific to the CANSOLV DC-103 solvent will minimise waste generation and ensure optimum capture performance in accordance with the PCC GET. However, despite good solvent management controls, the lean solvent may pick up dust or other insoluble contaminants as it flows through the PCC plant. To prevent the build-up of such contaminants, a filtration system comprising a mechanical filter and a carbon bed filter will be in place to process a slip stream of the lean solvent (approximately 5%) being returned to the absorber column. Once filtered, the majority of solvent will return to the PCC plant for reuse, however a portion will be sent to the thermal reclaimer to remove solvent degradation products, to prevent these from building up within the process (see Section 4.2.4.6).

4.2.4.5 CO_2 Compression

Wet CO_2 from the CO_2 Stripper will first pass through a knock-out drum and then go through four stages of compression. O_2 will then be removed by reacting with hydrogen to form water, and the CO_2 will then pass through a dehydration filter containing desiccant and dehydration dryers before being finally filtered and metered. The limit of the Environmental Permit is at the tie-in to the DAA High Pressure Compressor Station Compression Site.

The quality of the CO_2 from the CO_2 Stripper will be continuously monitored for compliance with export specification. The following parameters will be measured as part of normal operations:

- temperature;
- pressure;
- water content;
- O_2 content;
- hydrogen content;
- CO content;
- hydrogen sulphide content;
- SOx;
- NOx; and
- amines.

There will also be a requirement for sampling and analysis of other components that are included in the export specification including the following:

- NH_3;
- Formaldehyde;
- Acetaldehyde;
- Methanol and ethanol (combined)
- Mercury;
- Cadmium;
- Thallium; and
- Total sulphur).

In addition to quality monitoring, fiscal flow metering is to be provided for custody transfer of CO_2 sent to the export pipeline.

4.2.4.6 Thermal Reclaimer

Thermal reclamation will be carried out on a continuous basis. A solvent slip stream from the filtration unit (approximately 0.1% of the PCC plant inventory) will be dosed with caustic to ensure the correct pH is achieved and then fed to a preheater, where it will be heated by IP steam prior to entering the thermal reclaimer.

The thermal reclaimer will be a single column with a reboiler heated by IP steam at the column base. The column will operate at vacuum and will separate out of most of the water and reclaimer lean solvent (overheads) from the degradation products (bottoms). Steam sparging will be available at the base of the thermal reclaimer column to reduce viscosity and aid solvent reclamation.

The overheads will be partially condensed in the thermal reclaimer condenser and the resultant two-phase mixture will then be separated in the thermal reclaimer reflux drum. The vapour will then be sent to the thermal reclaimer vacuum system.

The degradation products will build up in the thermal reclaimer until they reach a specified level when they will be collected at the bottom of the thermal reclaimer column and pumped to the degraded solvent drum for storage, prior to disposal offsite via a 3rd party licenced waste contractor.

Ongoing solvent management techniques, such as maintaining the concentrations of degradation products below a target value, will ensure that they do not have adverse effect on the process performance. Lab sampling of solvent will be periodically carried out to monitor the concentration of degradation products present. Normal operation of the thermal reclaimer will maintain an efficient operating profile such that degradation products are kept under control (preventing an increase to levels which would reduce solvent performance or further accelerate degradation). Their concentration is therefore monitored through regular (weekly to monthly in early operation, monthly to quarterly once demonstration of stable operation has been confirmed) solvent analysis, and the solvent processing rate of the thermal reclaimer adjusted as required to correct the contaminants removal rate. This means optimum operation of the reclamation process to minimise generation of degradation products with minimum energy usage.

It is considered that thermal reclamation is a mature technology, capable of removing non-ionic heavier molecular weight degradation products, including metals and polymeric compounds all formed via thermal degradation. In applications with low flue gas contamination, such as the Installation, the amounts of ionic degradation products (low molecular weight acids) and heat stable inorganic salts is considered to be relatively low, and therefore the use of ion-exchange resins is not considered appropriate. These species are also removed via thermal reclamation and therefore it is considered that this is the best method overall for removing all types of potential degradation products.

In addition, reclamation via ion-exchange resins is not considered to be a mature technology, and there are a number of disadvantages to its use, including:

- Ion-exchange resins have a limited life expectancy, and therefore will require replacement over time, increasing waste generation;
- Ion-exchange resins can be contaminated or have their performance affected by the presence of trivial anions such as carbonate and bicarbonate;
- Ion-exchange resins do not remove polymeric (uncharged) material and have a limited performance in the removal of metals; and
- Ion-exchange resins might produce more effluent than thermal reclamation, as the resins need to be recovered by flushing with dilute caustic.

Thermal reclamation is also considered to be more energy efficient than ion-exchange, utilising steam available from the CCGT. The steam requirements for reclamation are much lower than for solvent regeneration and therefore represent a comparatively small loading on the CCGT. In addition, the vapour produced during reclamation would be fed directly into the CO_2 Stripper, thus recovering the energy employed for reclaiming back into the carbon capture process.

Thermal reclamation is proven technology for the CANSOLV DC-103 solvent to be used in the PCC plant, whereas other methods of reclamation have not been validated for this solvent.

N-amines and other degradation products only tend to accumulate in the absence of reclaiming, or if the reclaiming rate is insufficient to compensate for the degradation products generation rate. The method to limit accumulation to design levels – typically 1-2% in a commercial plant – is the use of the thermal reclaimer (which has built-in spare capacity to account for unexpectedly high degradation rates).

In addition, N-amines tend to degrade in the CO_2 stripper, due to the high temperatures present, and as such, their accumulation rate will be slowed, and may reach a steady-state plateau, even in the absence of reclamation.

4.2.4.7 Solvent Selection – Technology Review

NZT carried out a technology review of available carbon capture technologies prior to the selection of CANSOLV DC-103. In addition, a dual Front-end Engineering Design (FEED) with two technology providers was carried out before the final selection of CANSOLV DC-103. The key reasons for selecting CANSOLV DC-103 were:

Energy Demand of the Regeneration Process

Detailed information on the energy efficiencies and performance of individual licensors' technologies is commercially confidential, and subject to Non-Disclosure Agreements. However, this information was obtained and used by NZT to compare and appraise the different solvents for a number of criteria including capture efficiency, energy efficiency, solvent degradation and safety.

CANSOLV DC-103 was found to have a lower reboiler duty, typically requiring 2.4–3.2 GJ/tonne CO_2. This is significantly lower than traditional solvents like MEA, which requires 3.5–4.2 GJ/tonne CO_2, and therefore the energy consumption and operating costs for CO_2 regeneration are significantly lower.

Proven Industrial Track Record

CANSOLV DC-103 was selected largely due to the ability of the licensor to demonstrate scale-up of the technology and ability to back-up its high scoring performance data with performance guarantees.

CANSOLV DC-103 has been successfully deployed in commercial-scale projects such as SaskPower's Boundary Dam (Canada) and Brothers CISA in Newcastle (South Africa), demonstrating its reliability and scalability. A such, there is significant operational experience of the technology and solvent, which have been commercially deployed since 2013 and data on pilot plant for similar flue gas types. This provided NZT with reassurance that the details provided on CANSOLV DC-103 are based on actual performance data rather than concept data or aspirational performance.

The PCC GET states that solvent performance must be based on 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. Several thousand hours of testing of CANSOLV on various flue gases has been accumulated, including commercial scale operation of the CANSOLV D-103 solvent, which is summarised in Table 4.1.

Table 4.1: CANSOLV Pilot Trials Information

Flue Gas Stream	Industry	DC-103 solvent	Trial Duration	Inlet CO_2 (%v)
Natural Gas Boiler	Pulp & Paper	-	Mar – Jun 2004	12
Coal Fired Boiler	Pulp & Paper	-	Nov 2005	12
Coal Fired Boiler	Steel	-	Feb 2006	22
Coal Fired Power Plant	Power	-	July- Sept 2006	12
CCGT	Test Centre	Yes	May - Sept 2007	4
Blast Furnace	Steel	Yes	April 2007	22
Cement Kiln	Cement	Yes	Jan – Feb 2008	22
Natural Gas Fired	Test Centre	-	May 2012	-
Blast Furnace	Steel	-	November 2011	22.5 / 13.5
Coal Fired Power	Power/ Test Centre	-	Aug – Oct 2012	13
Coal Fired Power (simulated CCGT)	Power/ Test Centre	-	2013	4

Flue Gas Stream	Industry	DC-103 solvent	Trial Duration	Inlet CO_2 (%v)
Coal Fired Power	Power/ Test Centre	Yes	2014	10
Natural Gas Cogeneration	Test Centre	-	2014 - 2016	4
Municipal Waste Boiler	Waste-to-Energy	Yes	Mar – Dec 2019	9
CCGT	Test Centre	Yes*	Jan – Aug 2023	4
Catalytic cracker	Test Centre	Yes*	Jan – Aug 2023	15
Municipal Waste Boiler	Waste-to-Energy	Yes*	Aug – Dec 2021	9
Acid plant tail gas	Mining and metals	Yes	Dec-July 2024	6
Cement kiln	Cement	Yes	July – 2026	13

* Standard DC103 formulation and new formulations tested during the trial period

From 2014, more focus was placed on the PCC plant emissions and since 2019 most campaigns include the use of advanced instruments like Proton-Transfer Reaction Time of Flight Mass Spectroscopy (PTR-ToF-MS) for continuous, low limit of detection (LOD) monitoring of emissions of amine and degradation products. The measurements performed allowed validation of the supporting emission prediction models used for projects under development (i.e. the contributions taken into account such as component volatility, liquid entrainment, aerosols induced emissions). Note that tests performed with other variants of CANSOLV are still relevant to the validation of the supporting emission prediction models.

The pilot campaigns have dealt with different types of applications, which differ from the Installation's flue gas in terms of:

- Inlet CO_2 concentrations (as shown in Table 4.1); and
- Contaminants in the flue gases.

The contaminants present in the flue gases are relevant in terms of the resulting emissions, where flue gases with higher contaminants can lead to acceleration of solvent degradation (particularly where iron is present), or aerosol-promoted emissions.

The tests most representative of the Installation's flue gas with regards to emissions are those performed on CCGT off-gas (Risavika 2007 and at Technology Centre Mongstad (TCM) 2023), although all tests with gases exempt of aerosols are also considered relevant.

Reported historic issues with CANSOLV applications, such as those that have occurred at Boundary Dam, relate to the impact of gas contaminants on rates of solvent degradation along the different degradation pathways, resulting in an increase in emissions. While the Boundary Dam 3 unit is in compliance with its operating permit – notably with regards to amine/ N-amine emissions, accumulation of contaminants such as iron results in higher NH_3 emissions than for clean gas applications, such as the Installation.

Subsequent comparison with clean gas applications and other contaminated gas applications has allowed the licensor to:

- Demonstrate that clean applications resulted in low emissions; and
- Confirm (Licensor and public) model predictions of the impact of the different contaminants.

This has been taken into account in the assessment of the Installation's flue gas quality and potential content of specific contaminants. The accumulation of degradation products beyond the design concentrations, with potential impact on emissions has been accounted for in the NZT design with an appropriate margin in the reclaimer processing capacity.

The reclaiming method to be used at the Installation is the same as used in the Boundary Dam and Brother CISA commercial units. The Brother CISA plant operates on a gas boiler plant and therefore has a flue gas which is analogous to the Installation's flue gas in composition. The thermal reclaimer has maintained the solvent working composition since start-up in 2014, i.e. for 10 years.

The Boundary Dam unit has also demonstrated its capacity to separate amine and degradation products over the 10+ years of operation, although due to the coal-fired nature of the power station, degradation rates were much higher than the design and exceeded its processing capacity. Additional reclaiming capacity – operating on the same principle had to be added. Learning from this has been taken into account in the design for new CANSOLV-based projects by including sufficient spare capacity in the design of the reclaimer

Performance Guarantees

CANSOLV DC-103 is backed by performance guarantees on the capture rate achievable. This is not available when using generic products such as MEA.

Other considerations also include:

Degradation and Chemical Stability of the Solvent (including formation of N-amines and heat stable salts)

Proprietary solvents, such as CANSOLV DC-103 are considered to offer significant benefit over the single solvent option of MEA, due to their lower volatility leading to lower amine emissions and solvent degradation rates, improved capture rates and better energy efficiencies.

The CANSOLV DC-103 solvent is considered to have very good thermal and oxidative stability compared to MEA, which degrades at lower temperatures and with oxygen. For example, MEA would need to be stored under a nitrogen blanket to prevent oxidative degradation, whereas this is not required for CANSOLV DC-103.

It is recognised that the PCC GET states that solvent formulations including secondary amines or other species may have lower regeneration heat requirements and may readily form N-amines with NOx in the flue gases. However, it is considered that the reclamation process included in the PCC plant design will enable any N-amines generated to be removed at the rate of generation, thereby minimising potential emissions. This is demonstrated by the very low ELV proposed (Total N-amines 0.003mg/Nm^3).

Toxicity Profiles of the Solvent Components and their Degradation Products

It is considered that the N-amines associated with the CANSOLV DC-103 solvent are significantly less mutagenic than the N-amines used to derive the Environmental Assessment Level (EAL) currently applied to the assessment of impacts of generic N-amines (i.e. that of N-Nitrosodimethylamine (NDMA)). Further evidence to support this conclusion is detailed in the Wagner *et al.* (2014), which details the testing of a number of nitrosamines for their mutagenicity, including one of those associated with the CANSOLV DC-103 solvent and found that it was not mutagenic.

Further information on the toxicity profiles of the amines and N-amines associated with CANSOLV DC-103 has also been provided in the Air Quality Impact Assessment (Appendix E).

It is therefore considered that the significant benefits of the lower energy demand, higher stability and ease of reclamation, outweigh the potential generation of N-amines that are more stable than those generated by MEA, especially when considering that the N-amines that may be generated are considered to be significantly less mutagenic than NDMA.

4.2.4.8 Maximising CO_2 Capture Rates During Start-up and Shut-down

NZT have prioritised dispatchable requirements for the Installation from the outset of the project, having completed pilot plant testing and extensive techno-economic analysis to inform the design. Optimising CO_2 capture rate during start-up, minimising CO_2 losses and keeping the parasitic loads as low as practical require careful CAPEX/ OPEX trade-off to achieve the optimal design.

The Installation will be designed to be dispatchable meaning that it will start-up and shut-down regularly in response to changing requirements for supply to the UK Grid. The dispatch requirements will be driven by both user power demand and the variable supply from intermittent renewable sources of energy such as wind and solar. Unabated gas fired power plants (meaning those without PCC plants) commonly play the role of balancing these swings in supply and demand and ensuring availability of power.

Demonstration of optimised start-up time and capture rate is also a key item within the DPA which will be agreed on and tested as part of the contract (refer to "Annex 2, Testing Requirements" in the published DPA Terms and Conditions).

In 2020, NZT completed a two-week test campaign at TCM using a non-proprietary solvent to test the capture plant start sequence and optimise for dispatchability. The data obtained supported simultaneous start sequencing, and maximising capture during transients (simulating heat retention, fast start steam and amine buffer capacity), all of which are important in maximising CO_2 capture rate on start-up.

It is envisaged that the PCC plant would remain on hot standby enabling it to initiate operations seamlessly after receiving the flue gas from the CCGT, with no delays in solvent regeneration caused by energy losses to the environment.

The general principle of the hot standby mode includes passive techniques (e.g. increased insulation and maintaining thermal mass) and active techniques (e.g. electric auxiliary boiler for steam production to keep the amine warm by countering the heat losses from the system, bypassing of cooling water exchangers etc.). Auxiliary steam may also be used to keep the steam lines from the CCGT to the CO_2 stripper reboilers warm and ready to receive steam on start-up further reducing start-up times.

While heat for solvent regeneration can be provided by the Auxiliary Boiler during start-up, its capacity is limited compared to the main CCGT thermal output. To maximise CO_2 capture efficiency without solely relying on auxiliary steam, a lean solvent tank has been integrated. This provides an immediate supply of lean amine during the initial start-up phase until the CCGT produces sufficient heat for a sustainable, high-volume regeneration rate.

In addition, ensuring that the compressor dehydration beds are ready in dry condition and that the LP compressor is depressurised with dry CO_2 will minimise delays in start-up of the compression process.

This allows:

- Retention of heat of the CO_2 stripper for as long as possible;
- Flexible start-up of the CO_2 stripper independently of the availability of steam from the CCGT, by using the electric auxiliary boiler. Without segregation, energy from steam in the hot CO_2 stripper loop would be lost to cooling exchangers in the cold absorber loop;
- Use of the significant volume of lean absorbent in the absorber column and associated pipework as a CO_2 sink. This allows for the possibility of earlier absorption of CO_2 (before the CO_2 stripper is fully operational) thus allowing more a flexible plant restart. The ability to absorb some CO_2 without CO_2 stripper operation (albeit at low flue gas rates) means that the use of power from electrical import (running the auxiliary boiler) and heating from the CCGT can be optimised to achieve minimum CO_2 slippage during start-up with minimum energy cost; and
- Minimisation of thermal cycling of equipment.

4.2.4.9 Other Than Normal Operating Conditions (OTNOC)

The PCC plant has been designed and optimised for dispatchable operation with CO_2 capture taking place. Under normal operation the PCC plant is expected to operate at 100% load, however in order to operate in the UK electricity market, the PCC plant will need to be capable of operating for extended periods according to the Grid's load requirements in either Abated or Unbated mode and at any load between the following load setpoints:

- Base Load;
- Minimum Stable Generation – unabated mode; and
- Turndown – abated mode.

It is therefore considered that these modes of operation will not represent OTNOCs, and that OTNOC would also not include periods of start-up and shut-down due to the dispatchable nature of the Installation.

The PCC plant will also be designed to enable a Partial Abatement Mode, for times when the T&S entry capacity is curtailed. This mode will require the operation of the Installation with the PCC plant in service and capturing CO_2 from the CCGT flue gas, with a portion of the captured CO_2 being vented via the CO_2 Absorber Column.

The existing Environmental Permit for the Installation has a pre-operational measure to develop an Other than Normal Operating Conditions (OTNOC) management plan (PO13) 6 months prior to the commencement of commissioning.

NZT are currently discussing the requirements of the OTNOC management plan with the EA, and this will be provided to the EA when complete, and prior to commissioning activities, as required by PO13.

The OTNOC management plan will:

- Set out any potential OTNOC for the PCC plant, taking into consideration both internal and external causes of OTNOC;
- Detail measures to (i) minimise the occurrence of OTNOC that are within operator control except for periods of start-up and shut-down associated with dispatchable power generation; and (ii) reduce the impact of all OTNOC events; and
- Set out proposals for measuring and reporting carbon capture performance during periods of start-up and shut-down; and proposals for reviewing and optimising capture performance periodically so capture rates are as high as reasonably practical during these periods.

4.3 Ancillary Equipment and Utilities

To support the operation of the CCGT and PCC plant, a series of ancillary equipment and structures will be required and are outlined in the following sections.

4.3.1 Auxiliary Boiler

An auxiliary boiler package will be provided to provide steam for the following uses:

- CCGT start-up operation;
- CO_2 stripper reboiler (LP steam) during start-up; and
- Thermal reclaimer reboiler (IP steam) to allow independent operation of the thermal reclaimer without steam coming from the CCGT.

The auxiliary boiler will be electric and therefore there are no combustion emissions associated with its use.

4.3.2 Emergency Diesel Generators

Emergency power to the Installation would be required in the event of an electrical power cut for; Heating, Ventilation and Air Conditioning (HVAC), telecoms, emergency lighting and plant control systems and for recharging the Uninterruptible Power Supply (UPS) battery. The original Permit application (responses provided for Additional Information for Duly Making) provided details of 2 - 3 Emergency Diesel Generators (EDGs) to enable safe shut-down of the plant in the event of loss of power to the Site.

The Installation's design now includes six EDGs, with a thermal input capacity of approximately 24 MWth and an electrical output of approximately 12 MWe.

There will be two approximately 5 MWth, two approximately 4 MWth, one approximately 3.2 MWth and one approximately 2.5 MWth EDGs. Diesel fuel for the EDGs will be stored in individual day tanks for each unit, which will be made of carbon steel and be of double walled design. The smaller units (i.e. the 2.5 MWth generator and 3.2 MWth generator) will have approximately 3,000 l diesel day tanks mounted within the package enclosure. The larger units (i.e. the two 5 MWth EDGs and two 4 MWth EDGs will have approximately 5,000 litre tanks each, which will be mounted outside of the diesel enclosure, due to its larger size.

The day tanks will be sized for 8 hours of continuous operation. Filling of the day tanks will be by truck unloading.

The EDGs are the last resort in the event of a power loss at the Installation and subsequently are very unlikely to ever be required for their intended purpose, as, if possible, power would be provided by the CCGT, the national grid or South Tees Development Corporation (STDC) site power in order of preference before the EDGs.

In order to ensure that the EDGs remain fit for purpose, they will be subject to routine testing, likely to comprise of less than one hour of operation per month per generator. A total maximum of 12 hours of operation per EDG per year would therefore be required.

As the EDGs are for emergency purposes with annual operations of less than 50 hours per year, they would be exempt from ELVs imposed through the EP Regulations Specified Generator requirements, additionally as they will be operated for less than 500 hours per year they would be exempt from the Medium Combustion Plant (MCP) ELVs.

The EDGs will comply with the EA's BAT guidance on EDGs and will be optimised to reduce emissions ('emissions optimised') with NOx emissions meeting the 2g TA Luft and United States Environment Protection Agency (EPA) Tier 2 (or equivalent) standards. The EDGs have yet to be selected and therefore datasheets for the EDGs are not available at this time. It is anticipated that the EA will require the submission of EDG datasheets as a PO measure in the varied Permit, to demonstrate compliance with BAT.

The existing Permit includes a Pre-operational Condition (PO5), which requires NZT to:

> *Following the completion of the final design of the installation and at least 6 months prior to the commencement of commissioning the Operator shall submit a report for assessment and written approval by the Environment Agency for the emergency gas oil generators. The report shall include:*
>
> - *the number, size (MWth) and emission point locations;*
> - *an updated emissions to air risk assessment (including air dispersion modelling), for emissions of combustion gases from the proposed generators based on the final design of the installation.*
>
> *In the event that the assessment shows that impacts will lead to the exceedance of an environmental standard for air quality and/ or relevant critical level or critical load at a relevant conservation/ habitat site then the Operator shall submit proposals for approval for appropriate emissions abatement.*

The number and size of the EDGs has been confirmed in the information provided above. The allocated Emission Points will be A3 to A8 and the emission point locations are provided in Figure 3 and Figure 4 (Appendix A).

Emissions from the EDGs have been included in the Air Quality Impact Assessment provided in Appendix E, and have been demonstrated to not lead to any exceedance of an environmental standard, critical level or critical load. It is therefore considered that PO5 has been completed as part of this Environment Permit variation application.

4.3.3 Diesel Firewater Pump

There will be a diesel firewater pump onsite, which will be approximately 550 kWth, and therefore does not fall under the MCP Regulations.

4.3.4 Raw Water Treatment Plant and Demineralisation Water Package

Water will be sourced from NWL for sanitation, drinking water, safety showers and eye baths etc from their River Tees abstraction, therefore, prior for use at the Installation the raw water will require treatment in the Raw Water Treatment plant.

Specifically, the Raw Water Treatment plant will include:

- Two 100% dual media filter trains including dual media filter and their associated pretreatment, including coagulation, flocculation and clarification.
- All ancillary equipment (backwash tank, backwash pumps, air blowers, chemical dosing sets, backwash effluent collection pit/ tank and pump transfer).

Media carry-over and sludges generated from treatment will be sent to the ETP for dehydration treatment prior to discharge from the Site, or sent for off-site disposal via a licensed 3rd party waste contractor as appropriate.

Treated raw water will be stored in a treated water storage tank and used directly for:

- Cooling tower make-up water;
- Hose washing in process areas;
- Feed to the fire water storage tank and circuit; and
- Feed to the demineralisation water package.

The demineralised water package will include:

- Guard strainers;
- Ultrafiltration (UF);
- Reverse Osmosis (RO) membrane skid mounted equipment; and
- Electro de-ionisation demineralisation equipment.

All chemical dosing systems will have duplicate dosing/ supply pumps. Each system will include all necessary equipment and features for safe and reliable operation. A sodium bisulphite system will be provided to de-chlorinate the RO feed stream. An antiscalant system will dose anti-scalant into the RO feed stream to reduce scaling potential. Chemical dosing will be provided to adjust the pH of the RO feed stream as required.

The demineralised water will be used for the following purposes:

- Feed water to the HRSG;
- Feed water for the auxiliary boiler;
- Make up of solvent for the PCC plant;
- Within the closed loop water cooling system across both the CCGT and PCC plant;
- For flushing of various sampling lines within the Installation; and
- As make up water for chemical dosing e.g. within the SCR.

4.3.5 Wastewater Treatment Plant (WwTP) and Effluent Treatment Plant (ETP)

The WwTP will treat the wastewaters produced by the PCC plant DCC, the EGR DCC and cooling tower backwash. The plant will comprise:

- Process effluent buffer tank;
- Three x 50% UF units;
- First and second pass RO units; and
- Filtration.

The system will be able to detect when a treatment train is not achieving the required treatment specification and automatically switch to the spare train or have enough buffer to allow operator switchover in order to not cascade to a trip.

In the RO process, high hydraulic pressure (20 - 100 bar), in excess of the osmotic pressure of the feed stream, is applied across the membranes. This leads to the separation of the water molecules from the feed stream, and their subsequent transfer across the membrane. The purified water (permeate) is collected, while the impurities (e.g. the dissolved inorganic nitrogen) are retained in a concentrate stream. The concentrate stream would require further treatment and disposal offsite by a licenced 3rd party waste contractor. However, the treated wastewater will be re-used as cooling water make-up in the first instance to minimise raw water usage, or be directed to the Outfall Retention Pond for discharge via Emission Point W1, when the re-use system is unavailable. The flow of wastewater will be metered either back into the process and or into the Outfall Retention Pond.

The ETP will treat wastewaters from the raw water treatment plant and demineralisation water package, in order to dewater the solids for disposal and recover water to return to the process.

Re-using the treated wastewater as raw water makeup, will reduce the overall raw water demand for the Installation by up to 10%.

4.3.6 Cooling

A BAT assessment of the proposed cooling technology was carried out for the original Environmental Permit application and concluded that mechanical draught wet cooling towers represented BAT for the Installation on the basis that they provided:

- Much lower water demand and thermal discharge compared to once-through systems;
- Lower energy consumption than other alternatives considered;
- Comparable net efficiency to once-through cooling – given the site-specific nature increasing auxiliary pumping loads to a level largely negating the increased gross output likely to be achieved with once-through cooling;
- Lower noise emissions than hybrid plume-abated cooling towers; and
- Availability of raw (non-saline) water within current supplies from NWL, with better heat-transfer characteristics and lower maintenance and chemical requirements than estuarine water.

The use of hybrid (plume abated) cooling towers would be indicative BAT if visible plume impacts were a material consideration. However, the Site location was not considered to be particularly sensitive to visual impacts from thermal plumes given the industrial landscape and the distances to sensitive receptors and therefore mechanical draught cooling towers were considered to represent BAT for the Installation. There has been no change to the design since the original BAT assessment which would require the assessment to be revised for this Environmental Permit variation.

4.3.7 Steam

The PCC plant will require LP steam for the operation of the CO_2 stripper reboilers and the thermal reclaimer column. IP steam will be required for the thermal reclaimer reboiler.

The steam requirements for the PCC plant will be met by the CCGT plant or the auxiliary boiler.

4.3.8 Instrument Air, Nitrogen and Hydrogen

The Installation will require instrument air, nitrogen and hydrogen.

As the continuous flow rate of required nitrogen is relatively low, it will be generated onsite via a package nitrogen plant. Redundancy or storage will be incorporated to ensure availability of operations is maintained, with buffer tanks for pressure stability.

Nitrogen will be used for blanketing of demineralised water tank, the NH_3 storage tank, and other tank/ drums used in the process that require blanketing, as well as for maintenance purging.

Hydrogen will be required for O_2 removal from the CO_2 going to the LP compressors. Hydrogen will be provided by tank trailer. Via a dedicated tank trailer loading station..

4.4 Process Control

The operation of the Installation will be highly automated, with a site wide Distributed Control System (DCS) providing monitoring and control. The design philosophy of the DCS will be to provide the maximum possible level of automation for all systems installed on the Site and the plant will generally operate automatically under operator supervision during normal operation.

Semi-automatic sequences and manually requested actions will also be available via the DCS when required, for instance operator intervention may be required to maintain minimum utility flows by the opening of equipment by-passes or shutting down unnecessary equipment (e.g. cooler fans, circulation pumps, amine pumps). Generally, plant operations will be carried out from the control room. The DCS will allow items, systems and the entire plant to be started, operated and stopped in a safe manner.

The DCS will display and record the plant operating parameters required for best practice process control and minimisation of environmental impacts. For example, the cooling tower purge system will provide information to the operators covering flow, temperature, pH, residual chlorine etc. This information will be available online to the operator via the plant operating screens as instantaneous values, with historical data available via trend screens. The DCS will also include typical CEMs information. CEMs at site will comprise monitoring of parameters applicable to the Installation and may include received gas quality, exhaust gas concentrations of O_2, CO and CO_2 (in the exhaust gas from the HRSG and that being sent to the compression unit), air flow, moisture content, and plant efficiency. This information will also be available for offline analysis by operators and site engineering.

The plant operational data will allow the plant processes and maintenance procedures to be reviewed and optimised. The data available via the DCS will also allow reporting of plant performance and environmental compliance.

Furthermore, the DCS will alert operators through a series of alarms if any operating parameter approaches, or exceeds, its defined normal operating envelope. These alarms will be displayed on the appropriate plant operating screen as well as a dedicated alarm screen for operator review and timely action. For example, discharge of cooling tower purge would be prevented if any of the monitored parameters exceeded permitted levels.

In addition to the DCS, a separate safeguarding system is expected to be employed which will use interlocks and trips to prevent an undesirable situation from occurring or continuing.

4.5 Management Systems

The existing Environmental Permit has a PO requirement (PO1) to provide a summary of the Environmental Management System (EMS) to the EA prior to commencement of commissioning. As the Site will not become operational until late 2027 at the earliest, the EMS has yet to be developed, however the Site will be operated in line with an EMS compliant with the requirements of ISO14001, the EA Guidance on Developing a Management System[3] and the LCP BATc (BAT 1).

The EMS will be developed to enable compliance with the Environmental Permit and other legislative requirements for the protection of the environment and human health. Implementation of the EMS will enable NZT to systematically identify, prevent, and mitigate environmental and social impacts and risks, protecting natural resources, respecting internationally recognised human rights and complying with all relevant, applicable legal and regulatory requirements. This also identifies and helps maximise opportunities for NZT, stakeholders and surrounding communities, to deliver continuous improvement in environmental and social performance.

In summary, the EMS will identify the systems and procedures that minimise the risk of pollution and harm to human health; which may arise from the operation, maintenance, accidents, incidents and non-conformances specific to the Installation.

Written procedures clearly describing responsibilities, training, communication, actions, monitoring, document control, maintenance programmes and emergency preparedness and response will be available for operational personnel.

Internal audits will be undertaken to ensure conformance with the EMS, relevant legal requirements, environmental and management performance and to identify preventative/ corrective actions to minimise the risk of breach/ non-compliance. The findings of any such review and audits will be communicated to staff and relevant external contractors and where appropriate improvement works/ corrective actions will be implemented. Internal reviews, audits, amendments to the EMS and improvement measures implemented will be recorded for reference and inspection purposes.

The systems and procedures will be externally audited and contingency plans written in preparation for any unexpected complications. Internal review of the EMS (or relevant parts therein) will be undertaken at least on an annual basis or in the event of a change in operations/ site processes.

The EMS and procedures will be available for inspection by the EA upon request, and will be applicable to all staff, contractors and visitors to the Installation.

4.6 General Maintenance

The objective of plant maintenance is to ensure that the Installation operates safely and reliably. In addition, maximising the availability of the Installation through the implementation of an effective operational and maintenance strategy is key to the commercial success of the Installation's operation.

Inspection and maintenance activities have been considered in the Installation's design and layout during the design process. The design is such that equipment with high inherent levels of integrity and minimum requirements for intrusive work whether for maintenance or inspection will be sought to:

- Minimise shutdown, inspection, and maintenance requirements. A high planned maintenance to corrective maintenance ratio will be prioritised to mitigate against unplanned breakdowns.
- An inspection plan in accordance with the relevant regulations will be implemented.
- Eliminate the need for intrusive inspection ensuring appropriate inspection techniques and equipment are available to provide an equivalent or better method for validation of system integrity.
- Minimise the need for active corrosion management (use of inhibitors, etc.), inspection, repair, and fabric maintenance over field life. High quality coatings, corrosion protection and corrosion allowances will be provided to render the requirement for fabric maintenance to low criticality.
- Eliminate the need for shutdown maintenance (wherever possible). Where periodic shutdown maintenance is required the design of these items will ensure that maintenance can be achieved in the minimum time and on an opportunistic basis - i.e., by providing local high integrity isolation in accordance with minimum isolation requirements, good access, and design for unit handling and changeout.

It is anticipated that an integrated Operations and Maintenance team will have responsibility for daily operations, including troubleshooting and effecting minor repairs on the Installation. The Maintenance programme will be designed to ensure the Installation's long-term integrity and operational availability and will include the CCGT Original Equipment Manufacturer (OEM) and the PCC plant licensor.

The Maintenance and Inspection strategy encompasses all aspects of maintaining the integrity and reliability of the facilities to ensure the Installation is fit for continued service and safe operation by using the combined best practice of operations, maintenance, inspection, and process chemistry.

Routine maintenance will be planned and scheduled via a maintenance management system, including major overhauls. Maintenance routines will follow a cycle, as shutdowns are required after a set number of GT operating hours or start-ups (whichever comes earliest). Routine maintenance will be undertaken annually with major maintenance events undertaken less frequently. Periodically the GT will be taken off-line and washed with a high concentration detergent solution as recommended by the OEM.

Material selection is key to managing the risk of corrosion of plant materials used to store and transfer amine solvent, appropriate stainless steels would be used in the amine systems to minimise corrosion.

The Plant Inspection strategy will be developed during the EPCC phase of the project. It will take into account all systems involved in the handling and transfer of amine solvent given that some solvents have potential to create corrosive environments when saturated with water in the presence of CO_2.

It is envisaged that stress-relief (normally post weld heat treatment) of all carbon steel equipment, cold drawn bends, piping and welds in contact with the amine solvent would be carried out, to ensure they can endure the potential for amine stress corrosion cracking. In addition, corrosion monitoring methods will be employed.

Rotating equipment auxiliaries such as filters, pumps and heat exchangers will be arranged with sufficient redundancy so that failure or outage of a single component will not lead to a reduction in the CCGT electrical output or PCC plant capture rate.

Common services, plant control and instrumentation, and electrical systems will be provided with sufficient redundancy so that failure or outage of a single component will not lead to a reduction in the CCGT electrical output or PCC plant capture rate.

4.7 Raw Materials

The use of hazardous materials within the Installation will be eliminated by design where possible, and minimised where it is not practical to eliminate them. In areas where chemicals are being handled, the flooring will be paved and kerbed/ bunded to ensure that spillages and/ or leaks in those areas are contained, manually cleaned up and disposed of appropriately, in line with the existing Installation's spillage management procedures. Any liquid chemicals stored will be kept in appropriately bunded and segregated areas.

Bulk storage of chemicals in new above-ground storage tanks (ASTs) will include NH_3 for the SCR, the amine solvent for use in the PCC plant, various other chemicals for use in the PCC plant, water treatment plant and RO plant and diesel for the EDGs and the diesel fire pump.

4.7.1 Amine Storage

The principal raw material to be used in the PCC plant will be the amine-based solvent, CANSOLV DC-103. There will be an initial quantity (first fill) of amine-based solvent and after which the PCC plant will include equipment for recovering and reclaiming the used solvent for reuse within the process, as described in Section 4.2.4.6, thereby minimising solvent usage.

There will be a lean solvent tank, which will receive fresh solvent coming onto Site and will receive lean solvent from the CO_2 stripping process for reuse in the PCC plant. The tank will have trace heating to maintain the bulk fluid at 65°C and will be sized to have sufficient volume so it can contain the entire solvent inventory (lean and rich) for the whole PCC plant for in the event that the entire solvent loop is required to be drained, for example during maintenance activities. Therefore, whilst the total storage capacity of the tank is approximately 5,600m^3 the majority of the time the tank will be less than 10% full.

The amine solvent to be used in the PCC plant has a low volatility. Its boiling point is 105°C, i.e. higher than water, and it has a very low vapour pressure of <0.013 kPa at 20°C. Although it is described as having a 'sweet' odour, it is considered that due its low volatility there is minimal potential for odour issues to arise from storage or delivery operations. As such, it is not considered that abatement is required on the breather vent for the storage tank, nor that back venting for tanker deliveries will be required.

The vapour pressure of CANSOLV DC-103 is only just over 0.01 kPa, which is used for the definition of a Volatile Organic Compound (VOC) in the Industrial Emissions Directive (IED). The vapour pressure of CANSOLV DC-103 is therefore much lower than that of MEA (0.05 kPa at 20°C). Unlike MEA, CANSOLV DC-103 does not degrade/ decompose when exposed to atmospheric O_2 and therefore does not need to be stored under nitrogen to prevent degradation.

The tank will be designed to relevant industry codes (API 650) and standards (BSEN 14015). The tank will be an atmospheric pressure fixed roof tank, constructed of stainless steel with 40 mm of external insulation and will be painted white, which is considered BAT in the Emissions from Storage BRef for tanks where nitrogen blanketing is not required.

The tank will be located in a bund that will have sufficient capacity to allow for tank failure and firewater management. This will be designed in accordance with CIRIA C736 guidance and will normally either hold 110% of the capacity of the largest tank within a bund or 25% of the total capacity, whichever is the greater. It will be constructed of impermeable materials on impermeable ground and all pipework will be routed over the bund and not through it.

Additionally, it is considered that there are no specific fire and gas detection requirements for the storage area.

4.7.2 Ammonia Storage

The NH_3 storage for the SCR will be provided in an approximately 180m^3 atmospheric pressure fixed roof tank, sized tank designed to relevant industry codes (API 650) and standards (BSEN 14015).

The tank will be nitrogen blanketed and will have vapour balancing for unloading operations. The vent to atmosphere will be fitted with carbon filters to prevent ammonia emission and potential odour issues.

The tank will be located in a bund that will have sufficient capacity to allow for tank failure and firewater management. This will be designed in accordance with CIRIA C736 guidance and will normally either hold 110% of the capacity of the largest tank within a bund or 25% of the total capacity, whichever is the greater. It will be constructed of impermeable materials on impermeable ground and all pipework will be routed over the bund and not through it.

NH_3 gas detectors will be provided and located in the bund area and close to pumps handling aqueous Ammonia due to the toxicity of this product.

4.7.3 Diesel Storage

Diesel fuel for the EDGs will be stored in individual day tanks for each unit, which will be made of carbon steel and be of double walled design. The 3.2 MWth and 2.5 MWth EDGs will each have approximately 3,000 litres diesel day tanks mounted within the package enclosure. The two 5 MWth and 4 MWth EDGs will have 5,000 litre tanks each, which will be mounted outside of the diesel enclosure, due to the larger tank size.

4.7.4 Other Chemicals

All other chemical tanks (e.g. water treatment chemicals such as sodium hydroxide, sulphuric acid, biocide and antiscalants etc) will be installed within a dedicated bund. The capacity of the bund will be 110% of the capacity of the corresponding chemical storage tank or 25% of the total capacity of tanks within the bund, whichever is the greater.

Other raw materials for use at the Installation will be stored in appropriate containers, within suitable spill protection including bunds, on bunded pallets, on drip trays, in specifically designed cabinets and cupboards or other appropriate storage units and areas. Additional hazardous materials will be supplied, stored and used in containers of $1m^3$ or less.

A Stage 1 – 3 Hazardous Substances Assessment has been carried out and is presented in Annex B of the Site Condition Report (Appendix B).

The EMS will comprise procedures for controlling raw material delivery including for transfer operations, and spill response procedures. Spill kits will be available at various locations at the Installation, including the designated area for material delivery.

All other raw materials and their predicted storage volumes are detailed in Table 4.2.

Table 4.2: Raw Materials

Material	Purpose	Estimated Maximum Storage Quantity	Estimated Annual Consumption[1]
Natural gas	Fuel source	No storage	12,264,000 MWh
CANSOLV DC-103 Fresh solvent	100% solvent delivery to site - CO_2 scrubbing solvent.	5,600 m^3	850 tonnes
24.5%wt. Ammonia	SCR	180 m^3	6,600 tonnes
99.95%wt Anhydrous Ammonia	Water-steam cycle dosing	10 m^3	18 tonnes
47% Sodium hydroxide (caustic)	DCC wastewater stripper dosing, Thermal Reclaimer pH control, WwTP	15 m^3	270 tonnes
Sodium hypochlorite	Raw Water Treatment plant	15 m^3	225 tonnes
Coagulant ($FeCl_3$)	Raw Water Treatment plant, WwTP	20 m^3	150 tonnes
Flocculant	Raw Water Treatment plant, WwTP	5 m^3	20 tonnes

Material	Purpose	Estimated Maximum Storage Quantity	Estimated Annual Consumption[1]
Sulphuric acid	Demin water plant and WwTP	2 m^3	10 tonnes
Antifoam agent	Added to the re-circulating amine to prevent foaming in the CO_2 Absorber.	5 m^3	2 tonnes
Activated carbon	Solvent reclaiming	10 tonnes	45 tonnes
Diesel	Emergency generators and firewater pump	20m^3	7 tonnes
Hydrogen	Compression (water removal)	420 kg	10 tonnes
Corrosion Inhibitor	Cooling water system (closed loop circuit)	3 m^3	Product is intended to compensate accidental losses from closed circuits losses. Normally no consumption.
Biocide	Cooling water system (closed loop circuit)	3 m^3	
Propylene glycol	Cooling water system (closed loop circuit)	5 m^3	
Lubrication oil	Turbine oil for the GT and ST, hydraulic oil for valves	44 m^3	15,000 litres
Biodispersant	Cooling water system (closed loop circuit)	0.3 m^3	1.6 tonnes
Sodium metabisulphite	Auxiliary boiler	5 m^3	54 tonnes
[1] Based on baseload operation. Quantities for dispatchable operation would be lower.			

4.7.5 Water Use

Raw water for process purposes will come from NWL and will be treated on site prior to use.

In order to minimise water usage, water from the onsite WwTP and ETP will be returned to the treated raw water tank for reuse in the cooling water circuit prior to eventual discharge. Re-using the treated wastewater as raw water makeup, will reduce the overall raw water demand for the Installation by up to 10%.

Where possible, HRSG blowdown will be used as cooling tower water make-up and condensate streams and water from knock-out drums and the LP compression facilities will also be reused onsite to maximise water reuse where possible.

Waters that may contain traces of the amine solvent will be used as dilution waters for the solvent, to maintain the solvent make up of 50% water, 50% solvent.

The Site will also have the capability to pump water back from the attenuation pond (where the potentially contaminated surface water (PCSW) drains are directed) to the inlet of the raw water treatment plant. Water from the attenuation pond will be tested to determine whether it is suitable for re-use.

It is therefore considered that the potential for water reuse on Site has been maximised through the design.

4.8 Waste

The Installation's EMS will include procedures to manage raw material and water use, in order to minimise waste generation in accordance with existing procedures and indicative BAT requirements (LCP BATc, BAT 14).

Waste from the thermal reclaimer (degraded amine) will be collected and contained within the PCC plant in the degraded solvent drum, which when full will be discharged to a tanker and transported offsite for treatment and disposal by a registered 3rd party waste contractor.

Other waste generated onsite will be managed via the waste management hierarchy such that it is, in order of preference, avoided or minimised, reused, recycled or recovered, treated or disposed of.

Storage will be provided in the waste storage area (location shown in Figure 3, Appendix A), which will have an open non-hazardous waste section and an enclosed hazardous waste section. The waste storage area will be on impermeable servicing and will be kerbed/ bunded as appropriate. All liquid wastes greater than 220 litres will be within bunds with 110% of the largest storage container or 25% of the total storage capacity (whichever is greater).

All wastes will be stored in appropriate, labelled containers and stored in designated areas within the waste storage area. The waste storage area will be regularly inspected and spill kits will be available.

Non-hazardous wastes generated onsite will include uncontaminated plastic, metals, glass, paper and cardboard, wood etc, which will be segregated to aid recycling. Hazardous wastes will include Waste Electronic Equipment (WEE), oily rags, lube oil, filter elements and catalysts.

The wastes anticipated to be generated by the operation of the Installation, including estimated quantities and generation frequency i.e. continuous/ intermittent/ occasional, are shown in Table 4.3.

Table 4.3: Wastes

Waste Stream	Estimated Annual Quantity	Generation frequency	Disposal Route
Thermal reclaimer waste (degraded solvent)	2,000 tonnes	Continuous	Discharged to degraded solvent drum prior to disposal. Likely to be stored in batches of 10 - 15m^3 prior to collection for offsite disposal as hazardous waste by licenced 3rd party waste contractor.
Solvent from solvent drain vessel	Solvent will be re-used in the process wherever possible, and only disposed of if cannot be re-used, therefore disposal quantity unknown.	Intermittent	Collection and disposal by licenced 3rd party waste contractor.
Activated carbon and filters from CO_2 absorber	45 tonnes	Intermittent, expected to be every 6 - 12 months depending on filter performance	Mechanical filter elements and activated carbon from the filtration systems are likely to be hazardous in nature and will require disposal offsite by licenced 3rd party waste contractor.
Water from GT blade washing	40 tonnes	Intermittent maintenance	Collection and disposal by licenced 3rd party waste contractor.
SCR catalyst	1 – 2 tonnes	Intermittent every 3 - 5 years.	Returned to vendor on change out for recycling or disposal.
Spent filter elements from the CCGT air intakes	1,000 filters	Intermittent, expected to be every 3 – 24 months	Collected and stored prior to offsite by licenced 3rd party contractor.

Waste Stream	Estimated Annual Quantity	Generation frequency	Disposal Route
		depending on filter type and performance	
Waste lubricants	5 tonnes	Intermittent	Stored in the waste storage area in drums, disposed of or recycled offsite by licenced 3rd party waste contractor.
Spent filter cartridges from water treatment	100 – 500 cartridges	Intermittent, expected to be every 6 – 12 months depending on filter type and performance	Stored in waste storage area in containers, disposed of offsite by licenced 3rd party waste contractor.
Spent desiccant from LP compression	30 tonnes	Intermittent, expected to be every 6 – 12 months	Stored in waste storage area in containers, disposed of offsite by licenced 3rd party waste contractor.
Dehydrated sludge from WwTP	2,000 tonnes	Continuous	Stored in waste storage area in containers, disposed of offsite by licenced 3rd party waste contractor.
Oily water from Installation interceptors	0 – 2 tonnes	Intermittent every 12 months	Disposed of/ recycled offsite by licenced 3rd party waste contractor.

4.9 Energy Efficiency and Energy Use

4.9.1 Energy Efficiency

Under Article 14 of the Energy Efficiency Directive (2012/27/EU) (EED), operators of certain types of combustion installations >20 MWth are required to undertake an assessment of opportunities for cogeneration (also known as CHP) or supplying a district heating or cooling network. It requires that a cost-benefit analysis in accordance with Part 2 of Annex IX of the EED is carried out in order to assess the cost and benefits of providing for the operation of a new installation as a high-efficiency cogeneration installation. A Cost Benefit Assessment (CBA) and CHP-Readiness report was provided with the original Environmental Permit application and it was agreed with the EA, during pre-application discussions, that there was no need to update the assessment as part of this Permit variation.

The PCC plant, represent a parasitic load on the CCGT and therefore optimised integration of utilities for energy efficiency is paramount to maximising the overall CO_2 reductions of the Installation as a whole. Opportunities for maximising thermal energy efficiency have been explored and integrated in the design of the PCC plant as much as practicable. In addition, the CANSOLV DC-103 solvent and associated process configuration was selected to maximise energy efficiency (as discussed in Section 4.2.4.7).

The existing Environmental Permit includes PO requirement PO3, which states:

> *Prior to the commencement of commissioning, the Operator shall submit a report for assessment and written approval by the Environment Agency. The report shall contain a comprehensive review of the options available for utilising the heat generated by the combustion process and carbon capture plant in order to ensure that it is recovered as far as practicable. The review shall*

detail any identified proposals for improving the recovery and utilisation of waste heat and shall provide a timetable for their implementation.

The main ways in which the Installation recovers heat is using waste heat from the CCGT to regenerate the solvent in the CO_2 stripper. This heat could otherwise be lost and therefore capturing it minimises the overall energy consumption associated with operating the PCC plant.

The optimisation of heat recovery is complex and needs to balance with other factors including maximising the power generation from the GT generator, the potential use of the waste heat recovery to provide additional power generation using a ST (or other means) and the impact of the heat recovery on the start-up and shutdown times for the GT.

The main ways in which the Installation optimises heat utilisation is through the use of the MVR system, which recovers heat from the hot regenerated lean solvent. Reduction of the pressure of this stream in a flash vessel results in its partial vaporisation; the vapours generated are compressed back to the stripper operating pressure and can then provide part of the stripping effect and latent heat required for solvent regeneration. This heat could otherwise be lost (ultimately to cooling water) and therefore capturing it minimises the overall energy consumption associated with operating the PCC plant.

Further heat recovery is achieved by also recovering heat from the condensate exiting the stripper reboilers in the MVR system. Flashing the condensate at lower pressure allows generation of additional stripping vapours, and reduces the condensate return temperature to the power block, which is beneficial for overall thermodynamic efficiency of the CCGT.

As heat to regenerate the solvent is only available during periods that the CCGT is running, this heat is not available on start-up. Therefore, to maximise CO_2 capture on start-up, a lean solvent tank has been integrated into the design to provide a supply of lean amine during start-up until a sustainable rate of amine regeneration can be achieved. This optimises capture during start-up whilst minimising the requirement for additional heat energy from an imported source.

Boiler blowdown would be minimised due to use of a condensate polishing plant. It is therefore considered that, due to the dispatchable operation of the Installation and the small volume of low-grade heat that would be available from the blowdown, heat recovery from boiler blowdown is not viable for the Installation.

DCC process water is cooled from approximately 48°C to 40°C and the cooling water heated from approximately 25°C to 35°C depending on the ambient conditions. Waste heat generated from the DCC process is therefore very low-grade. There are no viable options for the reuse of such low-grade waste heat generated in this process within the PCC plant. An end user would have to accept heat at 10°C - 20°C with extremely large heat exchangers and external users of such low-grade heat do not exist in the area.

The lower heating value efficiencies of the proposed CCGT are anticipated to be 61%. This is greater than the ≥60% stated in the PCC GET. When a CCGT is optimised to operate without CO_2 capture, the ST would be appropriately sized to maximise the electrical power generated from the available steam. If the CCGT was built to operate without CO_2 capture it would potentially achieve a value of 63%.

However, for the Installation (i.e. a new build CCGT operating with CO_2 capture) the ST has been sized to provide maximum efficiencies under CO_2 capture conditions, as this will be the normal mode of operation. During CO_2 capture operation, a portion of steam is diverted back to the PCC plant to provide heat for the process, and as such, the ST is smaller than would be utilised for a new build CCGT without CO_2 capture. This has the knock-on effect that if the Installation were to be operated without CO_2 capture, the lower heating value efficiencies would be slightly negatively impacted.

Having a larger ST to provide maximum efficiency during unabated operation would negatively impact abated operation. The lower heating value efficiency of the Installation operating in CO_2 capture is anticipated to be 54%, and if this optimisation had not been included in the design, it would have been lower than 54%. It is therefore considered that as the normal mode of operation is to be with CO_2 capture, the design of the Installation represents BAT.

The key interfaces for energy efficiency within the PCC plant, are considered to be:

- exhaust-gas pre-treatment including cooling, prior to the PCC plant, utilising the DCC;

- use of steam supplied from the HRSG for solvent stripping (CO_2 stripper reboiler) and solvent recovery (thermal reclaimer);
- implementation of an MVR scheme to reduce steam demand by the PCC plant;
- steam condensate recovery from the PCC plant;
- integration of cooling water between the CCGT and the PCC plant to allow for variations in cooling loads across the system; and
- electricity supply to the PCC plant from the CCGT (parasitic load).

General measures to maximise energy efficiency across the Installation plant include:

- the plant components will be sized appropriately for the design capacity of the plant in abated mode, so that each element is operating optimally and efficiently;
- use of high efficiency motors and variable speed drives to minimise parasitic load;
- the effective insulation of hot surfaces; and
- regular planned maintenance in order to maximise the efficiency of the equipment and plant, with performance monitoring and audits to optimise the maintenance schedule.

The information provided above is considered to provide the information required by PO3.

4.9.2 Energy Use

A CCGT of nominal output of up to 820 MWe would be expected to use circa 1,400 MWth (LHV) of natural gas, at maximum load.

The total internal electricity auxiliary load (parasitic) of the Installation is estimated to be around 70 MWe per hour, including consumption of the power plant, the utilities and general users (buildings) and the LP compression plant.

A Sankey Diagram for the Installation is provided in Figure 5, Appendix A.

5. Emissions

5.1 Emissions to Air

5.1.1 Point Source Emissions

The emissions associated with all the Emission Points to air from the Installation are detailed in Table 5.1 and an Air Quality Impact Assessment has been carried out to determine the predicted impacts from the emissions. The Air Quality Impact Assessment is detailed in Appendix E and the results summarised in Section 7.3.2.

There are a number of changes to the final plant design from those presented in the original Environmental Permit application. The auxiliary boiler detailed in the original Environmental Permit application will now be an electrical boiler and therefore will have no emissions to air associated with it. Additionally, two EDGs were originally proposed, however the final design now includes six EDGs.

There are also some changes to the amine and amine degradation product emissions from the CO_2 absorber (Emission Point A1) as a result of the use of the CANSOLV DC-103 solvent for the PCC plant.

The locations of all the Emissions Points to air associated with the final design are shown in Figure 3 and Figure 4 (Appendix A).

The existing Environmental Permit includes PO requirement, PO12 which states:

> *Following the completion of the final design of the installation and at least 6 months prior to the commencement of commissioning the Operator shall submit an updated air quality assessment (for emission points A1 and A2) for assessment and written approval by the Environment Agency.*
>
> *The assessment shall review and update the air quality risk assessment submitted with the permit application and be carried out in accordance with environmental risk assessment methodology*

As stated above, an updated Air Quality Impact Assessment for the operation of the Installation, based on the use of the CANSOLV DC-103 solvent and the proposed ELVs detailed in Table 5.1 has been carried out and is provided in Appendix E. The assessment also considers the abnormal operation of the emissions occurring from the HRSG stack (Emission Point A2), in the event that the PCC plant is not operational. It is therefore considered that PO12 has been completed through this Environmental Permit variation application.

5.1.1.1 Emission Point A1 – CO_2 Absorber Stack

The main emission point during normal operation will be the CO_2 absorber stack (Emission Point A1), which will release the combustion emissions from the CCGT (NOx and CO) and NH_3 from the SCR. Additional emissions of amines will occur due to small quantities of solvent that may become entrained in the exhaust gas from the CO_2 absorber. Additionally, due to degradation of the solvent in the PCC plant, there may be small emissions of amine degradation products (NH_3, N-amines, acetaldehyde, formaldehyde, and amides).

Combustion emissions will be released at the LCP BAT-AELs, which can have an uplift applied where the electrical efficiency (EE) of the CCGT is greater than 55%. As with the original Environmental Permit application, it is considered that the ISO baseload conditions recognise the efficiency of the CCGT technology without the application of carbon capture, and therefore it is considered appropriate to apply the correction factor to the NOx and CO concentrations without consideration of the operation of the PCC plant. The EE correction factor has therefore been applied based on an EE of 61%, as applied in the original Environmental Permit application, in order to not compromise the ability of the CCGT to meet the BAT-AEL as a result of the application of carbon capture.

Furthermore, the normalisation of the LCP BAT-AELs for CO_2-abated flue gas must take into account the reduction in volume of the gas from removal of CO_2 (comparable to referencing for O_2 at 15% dry for gas turbines). It is proposed that this calculation is based on an assumed 3.4% of CO_2 in the flue gas (based on stoichiometric calculations) and that this is corrected to account for CO_2 removal of at least 95%. A methodology and example calculation for this was provided in the original Environmental Permit application. Whilst it is recognised that the EGR will increase the CO_2 in the flue gas from approximately 3.4% to approximately 7%, the calculation applied on the basis of the stoichiometric assumed 3.4%, as per the original Permit application.

An annual CO emission at the IED ELV of 100mg/Nm^3 (with the EE and CO_2 correction factors applied) has been included in Table 5.1. The LCP BATc states that indicative yearly average CO emissions for a new CCGT ≥50MW of < 5 – 30mg/Nm^3 are achievable, and therefore a yearly ELV of 30mg/Nm^3 (with the EE and CO_2 correction factors applied), is included in the existing Environmental Permit. Unlike other ELVs which are considered to be mandatory, the BATc specifically states that yearly CO emissions are indicative.

NZT agree that a yearly ELV of 30mg/Nm^3 can be achieved for a baseload CCGT operating conventionally, however due to the dispatchable nature of the Installation and the potentially limited operational hours and reduced loads associated with dispatchable power generation mode of operation, the indicative yearly CO ELV may not be attainable. In addition, the application of EGR to increase the CO_2 in the flue gas to maximise the CO_2 capture, also has the potential to increase the CO present in the flue gas.

Although implementation of EGR is not considered to be new technology, as the individual components are proven, it has not yet been demonstrated at scale and therefore long-term (i.e. yearly) achievable CO emission concentrations when operating with EGR are not yet fully understood. This could therefore further compromise the ability of the Installation to achieve the yearly average ELV for CO.

These things considered, the CCGT OEM has proposed the following guarantees for CO emission concentrations for CO_2 unabated mode.

- 100mg/Nm^3 at all loads; and
- 30mg/Nm^3 at full load.

It should be noted that Air Quality Standard (AQS) and Environmental Assessment Level (EAL) for CO are set for 8-hour rolling averages and for hourly averages respectively. The impact assessment carried out to support this Environmental Permit variation application (provided in Appendix E) demonstrates that impacts of CO assessed at the higher IED ELV of 100mg/Nm^3 results in impacts that can be considered to be insignificant. There are no standards to protect human health for CO based on an annual averaging period and therefore it is considered that there is no specific driver to require the LCP BATc indicative value to be met.

In addition, this issue has been discussed with the EA following the issue of the original Environmental Permit and was summarised in a note issued to the EA on 21st October 2024. Following the discussions, the EA issued a Compliance Assessment Report (CAR) form on 22nd October 2024 which stated that the EA would undertake a review of the annual average CO emission limit value as part of this Environmental Permit variation application.

The proposed NH_3 ELV has been based on emissions of NH_3 that are considered to be achievable from the PCC plant process. The PCC plant DCC will remove most of the NH_3 present in the flue gas coming from the CCGT before it enters the absorber. Some additional NH_3 may be generated in the absorber as an amine breakdown product. NH_3 emissions are minimised by utilising a water wash and demister, but some trace emissions can be present in the final flue gas.

The amines within CANSOLV-DC103 are considered to have good thermal and oxidative stability and therefore although degradation products; aldehydes, formaldehyde, amides and N-amines can form in the solvent, the continual reclaiming of the solvent prevents the build-up of these species and consequently reduces their potential release to air.

There are currently no BAT-AELs relating to the PCC process itself, and although the EA has provided the PCC GET guidance it does not include any specific ELVs at this time, as it is intended that these will be developed once PCC plants become operational in the UK, and collated monitoring data can confirm suitable levels for which the BAT-AELs should be set. Emissions of these species from the PCC plant are therefore based on levels that have been advised by the solvent supplier, as achievable annual emissions from their PCC process. The very low ELVs that have been proposed for the Absorber stack (Emission Point A1) for these species are detailed in Table 5.1.

The CANSOLV DC-103 Amines present in the emission from the PCC plant have been referenced as Amine 1 and Amine 2, to simplify the complex naming system of the individual amines. Further detail of this is provided in the Air Quality Impact Assessment (Appendix E).

5.1.1.2 Emission Point A2 – HRSG Stack (only during periods of PCC plant shut-down)

During periods of operation of the CCGT without the PCC plant, emissions from the CCGT will occur from the HRSG stack (Emission Point A2).

As above, the combustion emissions will be released at the LCP BAT-AELs, which can have an uplift applied due to the EE of the CCGT being greater than 55%. The uplift has been calculated on the basis that the CCGT will achieve an EE of 61%.

CO emissions are again assumed to be at the IED ELV of 100mg/Nm^3 (with the EE uplift applied) as detailed in Section 5.1.1.1.

NH_3 emissions from the CCGT are assumed to be at the lower end of the LCP BATc BAT-AEL.

5.1.1.3 Emission Points A3 - A8 – Emergency Diesel Generators

The EDGs are for emergency purposes only, with annual operations of less than 50 hours per year. As such, they are exempt from ELVs imposed through the EP Regulations Specified Generator requirements. Additionally, as they will be operated for less than 500 hours per year they are exempt from the MCP ELVs.

The EDGs will meet the required BAT guidance for EDGs and will be optimised to reduce emissions ('emissions optimised') with NOx emissions meeting the 2g TA Luft and United States Environment Protection Agency Tier 2 (or equivalent) standards.

In order to ensure that the EDGs remains fit for purpose, they will be subject to routine testing, likely to comprise of less than one hour of operation per month per EDG. A total maximum of 12 hours of operation per EDG per year would therefore be required.

It is recognised that the existing Environmental Permit contains a requirement that only one EDG shall be tested at a time unless otherwise agreed in writing with EA. This has therefore been taken account of in the Air Quality Impact Assessment (Appendix E).

Table 5.1: Emissions to Air Inventory

Emission Point	Description	Stack height[1] (m)	Stack Diameter (m)	Temp (°C)	Actual flow rate (Am/s)	O_2 Content (%)	H_2O Content (%)	Normalised flow[2 & 3] (Nm^3/s)	Efflux velocity (m/s)	Pollutant	Emission Conc$^{\underline{n}}$ (mg/Nm^3)	Release rate (g/s)
A1	Absorber stack (normal operation)	128	7.0	65	698	8.8	9.9	1,006	18.2	Oxides of nitrogen (annual average)[2]	34.4	34.6
										Oxides of nitrogen (daily average)[2]	45.8	46.0
										Carbon monoxide[2]	114.6	115.3
										Ammonia	3	3.0
										Amine 1	0.9	0.91
										Amine 2	0.1	0.10
										Total nitrosamines	0.003	0.003
										Formaldehyde	0.5	0.50
										Acetaldehyde	5.3	5.3
										Total Amides	0.03	0.03
A2	HRSG (only when PCC plant not operational	78	9.0	88	1,116	12.2	9.5	1,133	17.5	Oxides of nitrogen (annual average)[2]	33.3	37.7
										Oxides of nitrogen (daily average)[2]	44.4	50.3
										Carbon monoxide[2]	111	125.6
										Ammonia	3.0	3.4
A3 & A4	5MWth EDGs	5	0.7	370	9.4	11.5	12	5.6	24.3	Oxides of nitrogen	750	4.2
A5 & A6	4MWth EDGs	5		370	7.5	11.5	12	4.5	38.2	Oxides of nitrogen	750	3.3

Emission Point	Description	Stack height[1] (m)	Stack Diameter (m)	Temp (°C)	Actual flow rate (Am/s)	O_2 Content (%)	H_2O Content (%)	Normalised flow[2 & 3] (Nm^3/s)	Efflux velocity (m/s)	Pollutant	Emission Concn (mg/Nm^3)	Release rate (g/s)
A7	3.2MWth EDG	5	0.35	370	6.0	11.5	12	3.6	62.3	Oxides of nitrogen	750	2.7
A8	2MWth EDG	5	0.3	370	3.7	11.5	12	2.2	53.0	Oxides of nitrogen	750	0.8

[1] Stack heights provided as height above ordnance datum.

[2] Normalised conditions: standard temperature (0°C) and pressure (101.3kPa), dry gas, 15% O_2. CO_2 correction applied to A1 for the removal of 95% of CO_2 from an assumed flue gas content of 3.4% CO_2 (i.e. ELV x (1-0.0017)/(1-0.034).

[3] For plants with a net EE greater than 55%, a correction factor may be applied to the higher end of the BAT-AEL range, e.g. for the NOx annual average AEL - $30mg/m^3$ x 61 / 55 = $33.3mg/Nm^3$.

5.1.1.4 Emission Point A9 – CO Vent

The existing Environmental Permit includes PO requirement PO8 which states:

> *Following the completion of the final design of the Installation and at least 12 months prior to the commencement of commissioning the Operator shall submit a report for assessment and written approval by the Environment Agency. The report shall include:*
>
> - *An updated assessment of the impact of CO_2 emissions on human health from the short duration venting that may be required during the start-up sequence of the carbon capture plant, during other than normal operating conditions and plant commissioning. The assessment shall be carried out in accordance with the environmental risk assessment methodology with impacts compared with CO_2 acute exposure levels to humans.*
> - *A management plan detailing operating techniques to minimise potential CO_2 phase changes, solid effects and dense gas behaviour when venting CO_2 atmosphere.*

Since the original Environmental Permit application was made, the EA have changed their guidance on the requirement to carry out CO_2 venting assessments, rather requiring applications to address the following:

- *Describe the different potential venting scenarios, including where the whole inventory is vented*
- *Show how modelling has been or is intended to be used to inform the process design and manage risks associated with CO_2 venting.*
- *Confirm that the design will be in line with industry best practice, such as that produced by the Energy Institute, or other equivalent guidance.*
- *Describe the operating techniques that will minimise the risks associated with venting CO_2 to atmosphere*
- *Develop a venting management plan prior to the commencement of operation – likely that this will be a pre-operational condition and the EA will include details for this when they have decided what should be included*

A range of venting scenario were assessed using ADMS dispersion modelling during the determination phase of the original Environmental Permit application and the previous assessment is currently being reviewed in line with the finalised detailed design. It is intended that the assessment will be updated to include any additional or changed venting scenarios to address the first two points of the CO_2 venting assessment guidance.

Once the assessment has been revised, this will be provided to the Environment Agency together with the information required to address the final three points of the CO_2 venting assessment guidance. It is intended that this work will be provided to the EA during the determination phase of this Environmental Permit variation.

5.2 Emissions to Water

The existing Environmental Permit includes a Pre-operational Condition PO7 which requires NZT to:

> *Following the completion of the final design of the installation and at least 6 months prior to the commencement of commissioning the Operator shall submit to the Environment Agency a drainage plan based on the final design of the installation.*

A drainage plan is provided in Figure 6 (Appendix A) for the Installation's final design. It is therefore considered that PO7 is complete.

5.2.1 Point Source Emissions

The existing Environmental Permit contains two Emission Points to water, W1 and W2.

Emission Point W1 represents the final discharge point for all waters collected in the onsite Outfall Retention Pond, which will discharge via a pump into Tees Bay via a new outfall to be constructed for the Installation, discharging approximately 1.1 km from the shore.

Waters collected in the Outfall Retention Pond will comprise surface waters from areas of the Site with no potential for contamination (Clean Surface Water (CSW)) and RO concentrate from the water demineralisation plant. Surface water from process areas, and therefore potentially could be contaminated (PCSW), will be collected in an attenuation pond and be tested to ensure that it is suitable for release before being transferred to the Outfall Retention Pond.

There will also be process effluents from the DCC and EGR condensate waters, which will be treated in the WwTP, before being reused within the cooling water circuit. Cooling tower and HRSG blow down will be monitored at Emission Point W2 before being released into the Outfall Retention Pond for discharge via Emission Point W1.

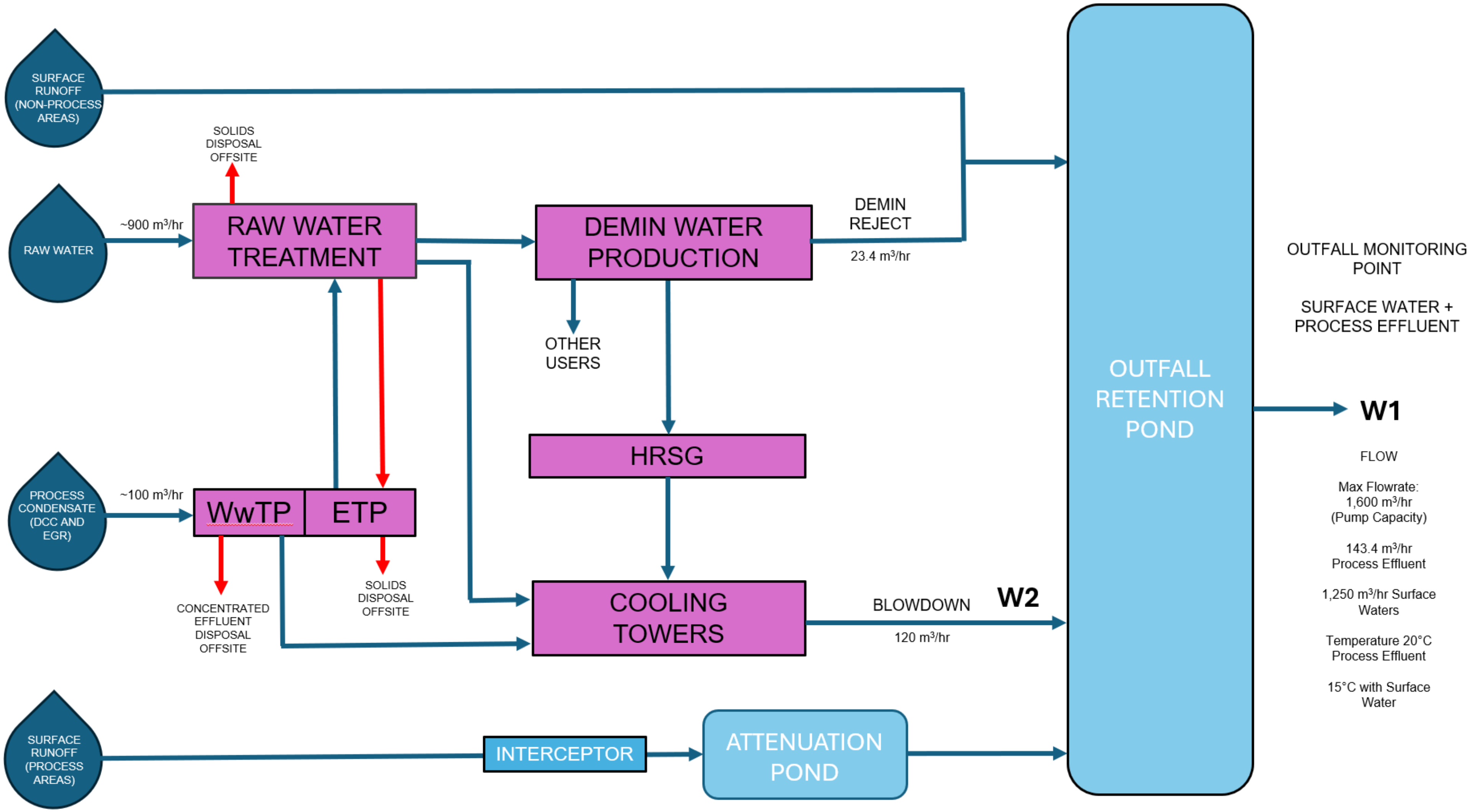
W2 therefore is effectively a compliance point for waters that will be treated through the WwTP and cooling water and HRSG blowdowns, as detailed in Table 5.2.

The PCC plant will have a hard piped, closed drainage system for amine and glycol containing wastewaters to ensure that these are not released into the Installation's drainage system.

A flow diagram of the wastewater streams to be generated at the Installation is provided in Plate 2 and further detail on each of the individual wastewater streams is provided in the following Sections.

.

Plate 2: Flow Diagram of Wastewater Streams



Note: Evaporative losses from the system occur from the HRSG and Cooling Towers

5.2.1.1 *Surface Water Drainage – Clean Surface Waters*

The CSW drainage system will collect clean surface water from non-process areas, or areas where Site plant is protected by buildings or appropriate rain shelters to ensure that no contamination can occur. The drainage will be routed directly to the Outfall Retention Pond, prior to discharge to Emission Point W1.

5.2.1.2 *Surface Water Drainage – Potentially Contaminated Surface Waters*

Process areas will be surfaced with watertight concrete to ensure that oil and chemicals are prevented from infiltrating the ground. PCSW from process areas will be contained within containment bunds around tanks and appropriate kerbing where there is risk of spillage, designed and constructed according to the requirements of CIRIA C736, API 650 and relevant Eurocodes.

PCSW would be routed via an oil/ water interceptor to an attenuation pond (in accordance with the Development Consent Order (DCO) Conceptual Drainage Strategy Report and with reference to CIRIA C736), so that such waters can be tested, and neutralised where required, prior to being released to the Outfall Retention Pond for discharge to Emission Point W1.

Where there is potential for amine to be present in water collected in bunds or kerbed areas, collected waters will be tested for amine content and if possible, reused within the process.

Where such waters contain amines and cannot be reused in the process, offsite disposal via a licenced 3rd party waste contractor will be carried out. Where such waters can be demonstrated to not contain amines, they will be sent to the Outfall Retention Pond prior to draining to Release Point W1.

5.2.1.3 *Process Effluents*

A summary of the process effluent streams generated at the Installation and the routes for treatment and/ or disposal are detailed in Table 5.2.

Table 5.2: Summary of Wastewater Streams Generated and Proposed Treatment

Wastewater Stream	Potential Contaminants	Proposed Disposal/ Treatment Method
Process water from the PCC plant DCC and EGR	Ammonia	Treated in the WwTP. The treated waters will then be used as cooling tower make-up water before being released to the Outfall Retention Pond as cooling tower blowdown prior to draining to Release Point W1. The WwTP system will achieve a Dissolved Inorganic Nitrogen (DIN) concentration of <20 mg/l in the treated waters.
Blowdown from the cooling towers	Only the concentration up of chemicals within the raw water feed	Chemical dosing for pH control, if required, before being released to the Outfall Retention Pond prior to discharge to Release Point W1.
Blowdown from the HRSG	None	Used as cooling tower make-up water before being released to the Outfall Retention Pond as HRSG blowdown prior to draining to Release Point W1.
Reject water from the Demineralisation Water Package	Elevated dissolved minerals from source water	No treatment of Demineralisation Water Package reject water is necessary. The stream is discharged to the clean water surface drains and directed to the Outfall Retention Pond for discharge via W1.
Process water from CO_2 compression and dehydration	Weak carbonic acid	Reused within the process as cooling tower make-up water and subsequently released to the Outfall Retention Pond and W1 via cooling water blow down.

The existing Environmental Permit includes a Pre-operational Condition PO6 which requires NZT to:

Following the completion of the final design of the installation and at least 6 months prior to the commencement of discharges of effluent and surface water run-off to Tees Bay from emission point W1, the Operator shall submit an updated Water Quality Assessment for assessment and written approval by the Environment Agency.

The anticipated composition of the process effluents (based on the cooling tower blowdown (which will contain treated water from the WwTP, blowdown from the HRSG, and compression waters)) and the reject water from the demineralisation water package) from the Installation are shown in Table 5.3. The combined flow of the process effluents is anticipated to be a maximum of 344m^3/hr (average flow rate of 143m^3/hr).

Table 5.3: Composition of Process Effluent Stream

Parameter	Concentration
Total Organic Carbon	41.8 mg/l
Chemical Oxygen Demand	125.5 mg/l
Total Suspended Solids	26.7 mg/l
Calcium	271.9 mg/l
Magnesium	64.4 mg/l
Iron (total)	2.3 mg/l
Manganese	0.3 mg/l
Chloride	245.6 mg/l
Sulphate	538.0 mg/l
Sodium	135.1 mg/l
Fluoride	1.5 mg/l
Cadmium	0.3 µg/l
Chromium	6.4 µg/l
Copper	10.1 µg/l
Nickel (Ni)	7.4 µg/l
Lead (Pb)	83.7 µg/l
Zinc (Zn)	170 µg/l
Total phosphorus (as P)	3.8 mg/l
DIN	20 mg/l

A H1 screening assessment of the emission of process effluents to water has been carried out and is presented in Appendix F and summarised in Section 7.3.3. The assessment takes into account all of the species identified in Table 5.3, where Environmental Quality Standards (EQS) are available, and at the maximum effluent flow rate of 344m^3/hr. A more realistic assessment of the average flow rate has also been carried out. In order to ensure a worst-case assessment is carried out, it has been assumed that there is no dilution of the process effluents from surface water despite the fact that this will be combined with CSW within the Outfall Retention Pond prior to release via Emission Point W1.

Due to the River Tees being identified as a Nutrient Neutrality Catchment, an assessment of DIN was carried out as part of the DCO determination process. The assessment considered an emission of DIN at 20mg/l at a maximum flow rate of 344m^3/hr in a worst-case scenario where there was no additional discharge of surface water from the site, which would provide further dilution to the effluent. Near and far field models were carried out, and the results showed that there would be no measurable impact in the River Tees.

As there is no change to the DIN emission concentration and the maximum flow rate since this assessment was carried out, it is considered that no further assessment of DIN is required.

It is therefore considered that PO6 has been completed through this Environmental Permit variation application.

5.2.1.4 Closed Drain System

The PCC plant will have a hard piped, closed drainage system for amine containing wastewaters. The closed drain will route absorbent drained from vessels during maintenance activities to an absorbent drain vessel, which will be located below ground in a concrete pit. The contents of the absorbent drain vessel will be tested and pumped back into the process where possible, to allow for recovery of solvent. Where not possible, this will be disposed of off-site via a licensed 3rd party waste contractor and will not be discharged to water.

Glycol containing wastewaters for both closed cooling water systems and fuel gas condensate will also be collected in individual closed drainage systems, as will oily water from the LP compressor system. All these waste streams will either be recycled back into the process, where appropriate, or be disposed of via a licensed 3rd party waste contractor for off-site treatment and disposal.

5.2.2 Fugitive Emissions

All pipework will be fully welded and to minimise the risk of leaks. Any below ground pipework will be contained within a concrete trench.

Areas handling chemicals will comprise hardstanding and be kerbed/ bunded to ensure that spillages and/ or leaks in those areas are contained, manually cleaned up and removed for treatment off-site. To minimise rainwater collection (and therefore inventory), these areas will be located indoors or be provided with rain shelters, where practicable and safe to do so.

5.3 Emissions to Sewer

There will be no process emissions to sewer as a result of this Environmental Permit variation. There will be a connection to the sewage system for domestic waste waters, which will be sent to the Bran Sands Treatment Works.

5.4 Emissions to Land

There will be no emissions to land as a result of this Environmental Permit variation.

5.5 Odour

The potential for odour to occur from the PCC plant is dependent on the volatility of the CANSOLV DC-103 solvent. CANSOLV DC-103 has a low volatility. Its boiling point is 105°C, i.e. higher than water, and it has a very low vapour pressure of <0.013 kPa at 20°C, which is only just over 0.01 kPa, which is used for the definition of a VOC in the IED.

Although it is described as having a ‘sweet’ odour, it is considered that due its low volatility there is minimal potential for odour issues to arise through its use and therefore no specific controls on storage tanks are considered necessary.

The ammonia tank will be nitrogen blanketed and will have vapour balancing for unloading operations. The vent to atmosphere will be fitted with carbon filters to prevent ammonia emission and potential odour issues.

5.6 Noise

The existing Environmental Permit includes PO4 relating to a Noise Impact Assessment (NIA), which states:

> *Following the completion of the final design of the Installation and at least 6 months prior to the commencement of commissioning, the Operator shall submit and updated NIA for assessment and written approval by the Environment Agency. The NIA shall be in accordance with BS4142:2014 (Rating industrial noise affecting mixed residential and Industrial areas) or other methodology*

as agreed with the Environment Agency. The assessment shall be based on the final design of the installation and include consideration of CO_2 venting as a noise source.

As the final design is not yet available, with regards to the confirmed equipment noise levels and the mitigation measures required to ensure that noise impacts at receptors are not experienced, an updated NIA has not been provided as part of this Environmental Permit variation application. This will be provided to the EA in line with the existing PO4 requirement at least 6 months prior to the commencement of commissioning.

6. Monitoring

6.1 Emissions to Air

The PCC absorber stack (Emission Point A1) will have CEMS in place for the following species:

- NOx;
- CO;
- NH_3;
- O_2;
- Water vapour
- Pressure; and
- Temperature.

Additional monitoring for pollutant species related to the operation of the PCC plant will include amines, N-amines and other degradation products. Monitoring of these species will be carried out by extractive (manual) isokinetic sampling, as detailed in Table 6.1 and in the existing Environmental Permit.

Whilst it is recognised that FTIR and PTR-ToF-MS monitoring for amine and nitrosamine emissions is being investigated, as it is capable of measuring down to parts per trillion levels, it is not widely established nor commercially available at this time.

PTR-ToF-MS has been trialled on several CANSOLV DC-103 pilot plant campaigns, and it has been found to bring significant benefits in terms of limit of quantification of emissions (ppb level), as well as the range of contaminants that can be monitored, with the possibility to perform full spectrum monitoring. However, at present PTR-ToF-MS cannot yet be used for real-time monitoring, as the instrument output data must be analysed and validated by specialised third parties. It is however understood that the instrument OEM are developing commercial versions that may become available in the .

CEMS will be in place on the HRSG stack (Emission Point A2) for the following species:

- NOx;
- CO;
- NH_3;
- O_2;
- Water vapour;
- Pressure; and
- Temperature.

Emissions, and therefore monitoring, at Emission Point A2 will only occur when the Installation is operating without the PCC plant being operational.

ELVs for NOx and CO are only applicable from when the effective DLN threshold is achieved to baseload. Effective DLN can only be determined following commissioning and therefore the existing Permit includes an Improvement Condition (IC8) for effective DLN to be defined within four months of completion of commissioning. Until then the ELVs are applicable from 70% to baseload.

Table 6.1: Proposed Emissions to Air and Monitoring (for update in the Permit)

Emission Point Reference	Parameter	Source	Limit [1]	Reference Period	Monitoring Frequency	Monitoring Standard or Method
A1 [2]	Oxides of nitrogen [3] (NO and NO_2 expressed as NO_2)	Absorber stack	34.4 mg/Nm^3	Yearly average	Continuous	BS EN 14181
			51.7 mg/Nm^3	Monthly mean of validated hourly averages		
			45.8 mg/Nm^3	Daily mean of validated hourly averages		
			103.3 mg/Nm^3	95% of validated hourly averages within a calendar year		
	Carbon monoxide		103.3 mg/Nm^3	Monthly mean of validated hourly averages		
			114.6 mg/Nm^3	Daily mean of validated hourly averages		
			206.7 mg/Nm^3	95% of validated hourly averages within a calendar year		
	Ammonia		3 mg/Nm^3	Annual average		
	Total amines		1 mg/Nm^3	Average over the sampling period	Monthly until the requirements of IC11 have been agreed, then biannual.	EN ISO 21877
	Total nitrosamines		0.003 mg/Nm^3			Isokinetic impinger based on EN ISO 21877
	Formaldehyde		0.5 mg/Nm^3			Isokinetic CEN TS 17638
	Acetaldehyde		5.3 mg/Nm^3			
	Total amides		0.03 mg/Nm^3			Isokinetic impinger based on EN ISO 21877
A2	Oxides of nitrogen [3] (NO and NO_2 expressed as NO_2)	HRSG Stack	33.3 mg/Nm^3	Yearly average	Continuous	BS EN 14181
			50 mg/Nm^3	Monthly mean of validated hourly averages		
			44.4 mg/Nm^3	Daily mean of validated hourly averages		

Emission Point Reference	Parameter	Source	Limit [1]	Reference Period	Monitoring Frequency	Monitoring Standard or Method
			100 mg/Nm^3	95% of validated hourly averages within a calendar year		
	Carbon monoxide		100 mg/Nm^3	Monthly mean of validated hourly averages		
			110.9 mg/Nm^3	Daily mean of validated hourly averages		
			200 mg/Nm^3	95% of validated hourly averages within a calendar year		
	Ammonia		3 mg/Nm^3	Annual average		
A3 – A8	Oxides of nitrogen (NO and NO_2 expressed as NO_2)	Emergency Diesel Generators	No limit	Periodic	First monitoring measurements shall be carried out within four months of the issue date of the permit or of the date when the MCP is first put into operation, whichever is later. Then after 500 hours operation and no less frequent than every 5 years.	MCERTS BS EN 14792
	Carbon monoxide		No limit			MCERTS BS EN 15058
A9	CO_2	CO_2 Vent	No limit	-	-	-

[1] Normalised conditions: standard temperature (273.15K) and pressure (101.3kPa), dry gas, 15% O_2.

[2] 0.34% v/v CO_2 correction applied to A1 only.

[3] For plants with a net EE greater than 55%, a correction factor may be applied to the higher end of the BAT-AEL range, e.g. for the NOx annual average AEL - 30mg/m^3 x 61 / 55 = 33.3mg/Nm^3.

6.2 Emissions to Water

As previously stated, the only Emission Point to water from the Installation will be W1, which will discharge waters from the Installation's Outfall Retention Pond to Tees Bay via a new outfall constructed for the Installation. In the existing Environmental Permit there are no monitoring requirements assigned to W1, rather they are subject to two Improvement Conditions (IC6 and IC7) which are included in the Environmental Permit. IC6 requires NZT to carry out a monitoring exercise on the final discharge to Tees Bay at Emission Point W1 when the Site is fully operational for a period of 12 consecutive months. IC7 then requires NZT to use the discharge monitoring results to review and verify the conclusions of the existing Water Quality Risk Assessment.

Table S3.2 of the existing Environmental Permit provides emission parameters and associated ELVs and monitoring requirements for the emissions from Emission Point W2. This is replicated in Table 6.2. It is noted that the existing emission parameters with limits defined in Table 6.2 have been set in accordance with BAT15 (Table 1) of the LCP BAT Conclusions, which are defined for emissions to water from flue-gas treatment systems. As such, it is considered that a number of these parameters have been incorrectly applied to the Installation, given that they are largely associated with LCP that would have flue gas treatment such as Flue Gas Desulphurisation plant, hence the inclusion of sulphite, sulphides, fluoride, chloride and heavy metals that could result from the burning of coal. Table 1 of BAT15 has a footnote that specifically states that the BAT-AELs for Total Organic Carbon (TOC), Chemical Oxygen Demand (COD), fluoride, sulphide and sulphite only apply to wastewater from the use of wet Flue Gas Desulphurisation.

Table 6.2: Existing Environmental Permit Emissions to Water Monitoring (from Table S3.2)

Emission Point Reference and Location	Source	Parameter	Limit	Reference Period	Monitoring Frequency	Monitoring Standard or Method
W1 on site plan emissions to Tees Bay	Waste water emission from site – includes cooling water blowdown, steam condensate, treated direct contact cooler effluent and surface water runoff.	Requirement as agreed in accordance with IC7 in table S1.3 of this permit.				
W2 emission from effluent treatment plant to W1 and then to Tees Bay	Treated direct contact cooler effluent.	Flow	-	-	Continuous	MCERTS self-monitoring of effluent flow scheme
		pH	-	-		BS6068-2.50
		Temperature	-	-		
		Total organic carbon (TOC)	50 mg/l	24-hour flow proportional sample	At least once every month	EN 1484
		Chemical oxygen demand (COD)	150 mg/l			BS ISO 15705
		Total suspended solids (TSS)	30 mg/l			EN 872
		Fluoride (F^-)	25 mg/l			BS ISO 10304-1

Emission Point Reference and Location	Source	Parameter	Limit	Reference Period	Monitoring Frequency	Monitoring Standard or Method
		Sulphide, easily released (S^{2-})	0.2 mg/l			-
		Sulphite (SO_3^{2-})	20 mg/l			BS ISO 10304-1
		Arsenic (As)	50 µg/l			EN ISO 11885 or En ISO 17294-2
		Cadmium (Cd)	5 µg/l			
		Chromium (Cr)	50 µg/l			
		Copper (Cu)	50 µg/l			
		Nickel (Ni)	50 µg/l			
		Lead (Pb)	20 µg/l			
		Zinc (Zn)	200 µg/l			
		Mercury (Hg)	3 µg/l			EN ISO 12846 or EN ISO 17852
		Chloride (Cl^-)	-			EN ISO 10304-1 or EN ISO 15682
		Total nitrogen	-			EN 12260

The process effluents generated at the Installation come from the DCC, cooling towers and HRSG blowdown and therefore would only contain NH_3 contained within the flue gas from the SCR, which does not have a limit applied under BAT15, and trace contaminants from water treatment chemicals. There would be no source of any of the other chemical or metal species that have been included in the existing Environmental Permit, other than from the raw water that is abstracted from the River Tees for use at the Site and therefore are not considered to be present as a result of flue gas treatment.

It is considered that NH_3 is subject to control through the proposed monitoring of DIN, as detailed in Section 5 of the Nutrient Nitrogen Safeguarding scheme (provided in Appendix F, Annex A). This has been agreed with Natural England and the Environment Agency to meet the requirements of nutrient neutrality for the Tees. The Nutrient Nitrogen Safeguarding scheme proposed monitoring of DIN for a 12 month period, running parallel with the requirements of IC6, and confirmation of actual emissions of DIN are consistent with the model input parameters. The proposed DIN limit is to be applied at the point of discharge (Emission Point W1) and therefore there is no further requirement to further control this at W2.

It is also considered that the inclusion of the monitoring for the listed metals species in the existing Environmental Permit is not in line with other installation's that use abstracted raw water for cooling water purposes and raw water treatment processes, where the only source of such species is from the raw water and due to the cycles of concentration that occur in the cooling water circuit, where these have been demonstrated to not lead to exceedances of EQS. The H1 assessment carried out and provided in Appendix F demonstrates that all parameters assessed will not have an adverse impact of the quality of the receiving waters.

A review of Environmental Permits issued to LCP sites in England has shown that no other LCP installation has all the BAT15 metal emission parameters applied, with only a few requiring monitoring of Cd and Hg. In some cases, emission of Cd and Hg are controlled via a requirement to limit the concentration in the water treatment chemicals used onsite, rather than through specific ELVs within the permits.

In order to protect the receiving surface waters it is therefore considered that the only monitoring required for the Installation is shown in Table 6.3, and therefore it is requested that the Environmental Permit is updated accordingly.

Table 6.3: Proposed Emissions to Water Monitoring

<table>
<tr><th>Emission Point Reference and Location</th><th>Source</th><th>Parameter</th><th>Limit</th><th>Reference Period</th><th>Monitoring Frequency</th><th>Monitoring Standard or Method</th></tr>
<tr><td>W1 on site plan emissions to Tees Bay</td><td>Waste water emission from site – includes cooling water blowdown, steam condensate, treated direct contact cooler effluent, raw water treatment plant reject and surface water runoff.</td><td colspan="5">Requirement as agreed in accordance with IC7 in table S1.3 of this permit including the monitoring of DIN, in accordance with the requirements set out in Section 5 of the Nutrient Nitrogen Safeguarding scheme.</td></tr>
<tr><td rowspan="7">W2 emission from effluent treatment plant to W1 and then to Tees Bay</td><td rowspan="7">Treated EGR and PCC direct contact cooler effluent.</td><td>Flow</td><td>-</td><td>-</td><td rowspan="3">Continuous</td><td>MCERTS self-monitoring of effluent flow scheme</td></tr>
<tr><td>pH</td><td>-</td><td>-</td><td>BS6068-2.50</td></tr>
<tr><td>Temperature</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Total organic carbon (TOC)</td><td>50 mg/l</td><td rowspan="4">24-hour flow proportional sample</td><td rowspan="4">At least once every month</td><td>EN 1484</td></tr>
<tr><td>Chemical oxygen demand (COD)</td><td>150 mg/l</td><td>BS ISO 15705</td></tr>
<tr><td>Total suspended solids (TSS)</td><td>30 mg/l</td><td>EN 872</td></tr>
<tr><td>Chloride (Cl^-)</td><td>-</td><td>EN ISO 10304-1 or EN ISO 15682</td></tr>
</table>

6.3 Emissions to Sewer

There will be no process emissions to sewer as a result of this Environmental Permit variation and therefore no monitoring is required.

6.4 Emissions to Land

There will be no emissions to land as a result of this Environmental Permit variation and therefore no monitoring is required.

6.5 Infrastructure

Monitoring of all Installation infrastructure will be undertaken as part of the Installation's EMS, operational protocols and practices.

Regular inspection of all Installation infrastructure will be undertaken including routine operational checks and infrastructure audits, likely to comprise identification of issues relating principally to:

- minor leaks;
- equipment degradation;
- standing water in bunded/ kerbed areas; and
- storage areas.

Any issues identified during operational checks or inspections will be recorded and actions assigned to relevant personnel and closed out once they have been actioned.

Process monitoring will be undertaken at key stages of the process for a suite of parameters, including flow rates, temperatures and pressures.

6.6 Solvent Process Monitoring

PO14 in the existing Environmental permit states that:

"Following the completion of the final design of the installation and at least 6 months prior to the commencement of commissioning the Operator shall submit to the Environment Agency for assessment and written approval methodologies for the following process monitoring requirements for absorber amine solvent quality as required in table S3.3 of this permit:

- *percent active amine (MEA)*
- *carbon dioxide loading (rich amine)*
- *heat stable salts*
- *soluble iron concentration (rich and lean amine)*
- *colour"*

It is proposed that PO14 be updated to remove reference to MEA in the varied Permit.

Written methodologies for the monitoring of the solvent quality will be formally agreed with the EA in line with the requirements of PO14.

6.7 CO_2 Monitoring

As stated previously, the PCC plant is designed to achieve a capture rate of at least 95% for baseload operation. The following parameters will be monitored to assist the demonstration of the capture rates:

- CO_2 mass balance;
- CO_2 in fuel combusted;
- total capture level (as a percentage);
- CO_2 released to the environment; and
- CO_2 quality.

As well as ensuring compliance with the pipeline specifications, it is also a requirement of the PCC GET and the UK-ETS scheme that these parameters are monitored.

7. Environmental Risk Assessment (Impact Assessment)

7.1 Introduction

This section discusses the potential impact on sensitive receptors and the surrounding area and shows how the emissions from the Installation have been assessed. The EA document – 'Risk assessments for your environmental permit'[7] ('EA Risk Assessment guidance'), has been used to scope and assess the emissions from the Installation.

Where necessary, baseline impact assessments and appropriate modelling has been completed to ensure that any predicted significant effects on sensitive receptors can be avoided/ mitigated.

The impact assessments are reported in the relevant sections or Appendices of this Main Supporting Document:

- Air Quality Impact Assessment (Appendix E);
- Water Impact Assessment (Appendix F)
- Qualitative Risk Assessment (Appendix G).

7.2 Installation Location and Sensitive Receptors

7.2.1 Human Receptors

The closest residential receptors to the Installation are situated to the east of the Installation. Table 7.1 lists the human receptors in the vicinity of the Installation.

Table 7.1: Human Receptors in the Vicinity of the Installation

ID	Receptor name	OS grid reference (m)		Receptor type	Distance and direction from the Installation
		x	y		
HH1	Houses off Tod Point Rd, Warrenby	457950	525045	Residential	600 m east
HH2	Cleveland Golf Links, Redcar	457835	525525	Recreational	380 m east
HH3	South Gare Fisherman's Association and Marine Club	455620	527345	Recreational	1.9 km north-west
HH4	Caravan Park, Redcar	458675	525415	Recreational	1.2 km east
HH5	Houses at Dormanstown	457895	523735	Residential	1.4 km south-east
HH6	Houses at Coatham	458900	525060	Residential	1.5 km east
HH7	Dormanstown Primary Academy School	458250	523585	School	1.7 km south-east
HH8	Coatham Primary School	459195	524980	School	1.8 km east

7.2.2 Ecological Receptors

EA Risk Assessment guidance requires that the effects of stack emissions on designated ecological sites be assessed where they fall within set distances of the source, up to 10 km (or 15 km for large emitters) for European designated sites and up to 2 km for nationally designated sites.

[7] Risk Assessments for your Environmental Permit, DEFRA and EA, Published on: 1st February 2016, Last updated on: 21st November 2023, accessed at: https://www.gov.uk/guidance/risk-assessments-for-your-environmental-permit

Statutory designated sites have been identified through a desk study of the Defra Magic mapping[8] website and the Air Pollution Information Service (APIS)[9] website, which both identify SSSIs, Ramsar sites, SPAs and SACs. In addition, non-statutory designated receptors have also been identified, including LWSs. Table 7.2 lists the ecological receptors in the vicinity of the Installation.

Table 7.2: Ecological Receptors in the Vicinity of the Installation

ID	Receptor	Designation	OS grid reference (m)		Distance and Direction from Installation (km)
			X	Y	
E1	Teesmouth and Cleveland Coast	Ramsar, SPA, SSSI	455680	526270	Adjacent north
E2	North York Moors	SAC, SPA, SSSI	461315	514190	11.5 km south-east
E3	Northumbria Coast	SPA, Ramsar	448260	537470	14.6 km north-west
E4	Durham Coast	SAC	448520	536190	14.6 km north-west
E5	Lovell Hill Pools	SSSI	459860	519100	6.3 km southeast
E6	Saltburn Gill	SSSI	467000	521265	10.3 km southeast
E7	Hart Bog	SSSI	445290	535380	14.9 km northwest
E8	Coatham Marsh	LWS	457860	524990	500 m east
E9	Eston Pumping Station	LWS	456370	523890	1.0 km south

The Teesmouth and Cleveland Coast Ramsar, SPA and SSSI is located immediately adjacent to the north of the Installation. It includes a range of coastal habitats (sand dunes, mudflats, saltmarsh, freshwater marsh etc) on and around the Tees Estuary.

There are three further SSSIs within 15 km of the Installation (Roseberry Topping, Cliffe Ridge and Lanbaurgh Ridge), which are designated for their geological features. It is therefore considered that these sites will not be affected by emissions from the Installation, as the Critical Levels and Critical Loads assigned to such sites are for the protection of vegetation and ecosystems only, and therefore they have been screened from further consideration.

7.2.3 Hydrology

The River Tees flows approximately 1.6 km to the west of the Installation boundary. The River Tees is tidal at the location, with the normal tidal limit approximately 14 km upstream (at the Tees Barrage). The North Sea is located approximately 0.4 km to the north of the Installation. There are a number of surface water features in the vicinity of the site, primarily comprising the Dabholm Gut, which flows to the River Tees approximately 0.8 km south of the Installation. The Dabholm Gut is tidal and accepts water from:

- The Fleet (that runs from Coatham Marsh, to the west of Redcar);
- The Mill Race (from east of the Wilton International complex); and
- Dabholm Beck (from the west of the Wilton International complex).

The NWL Bran Sands Wastewater treatment plant (to the immediate south of the site) discharges into the Dabholm Gut, as does effluent from the Wilton complex. The EA 'Flood map for planning' indicates that the whole of the Installation is located within Flood Zone 1 that is defined as, "land having a less than 1 in 1,000 (less than 0.1%) annual probability of river or sea flooding." The Installation site is not located within any Groundwater Source Protection Zone.

[8] Defra Magic mapping accessed at http://magic.defra.gov.uk/MagicMap.aspx

[9] APIS - Air Pollution Information System | APIS

7.2.4 Geology

Artificial Ground is widespread across the site. The Artificial Ground is associated with the reclamation of land from the Tees Estuary using waste materials (including slag) and the long historical industrial use of the site.

The published British Geological Survey (BGS) 1:50,000 scale maps ((Sheets 33 (BGS, 1987) and 34 (BGS, 1998)) show the Site to be underlain by two types of superficial deposits, Blown Sand and Tidal Flat Deposits.

The BGS maps show the bedrock geology underlying the Site to be Redcar Mudstone Formation and the Mercia Mudstone Group.

7.2.5 Hydrogeology

The EA Groundwater Protection Policy adopts aquifer designations consistent with the Water Framework Directive. Made Ground is not designated as an aquifer. The Tidal Flat Deposits and Blown Sands beneath the site are classified as Secondary A Aquifers.

The Redcar Mudstone Formation is classified as a Secondary (undifferentiated) aquifer whilst the Mercia Mudstone Group and Penarth Group are mudstones and classified as Secondary B Aquifers.

Groundwater monitoring indicates Made Ground and Tidal Flat Deposits are hydraulically connected and unconfined, with flow generally northeast toward the North Sea. The Redcar Mudstone Formation is confined and hydraulically separated from overlying deposits.

EA Groundwater Maps show that the Installation site falls outside any Groundwater Source Protection Zones. The Installation site is indicated to be outside the Groundwater and Surface water Safeguard Zones for Drinking Water.

7.2.6 Pathways for Pollution

In order for a pollution risk to occur, there has to be a source - pathway - receptor (S-P-R) linkage. Pathways to sensitive receptors primarily include, but are not limited to, the following:

- Chemicals and fuel (diesel) required for the operation of the Installation might leach into the ground and be washed into surface water or groundwater through the underlying soils.
- Treated process effluents will be discharged via Emission Point W1 to Tees Bay.
- Emission to air from the Installation will disperse in the air to sensitive human and ecological receptors.

In order to prevent and minimise the risk of pollution, the Installation will be designed and managed to isolate or reduce the effectiveness of these pathways, preventing contaminants from migrating off site other than through properly managed abatement systems.

The detailed description provided in Section 4 demonstrates how BAT in accordance with LCP BATc and the PCC GET has been applied to prevent pollution from the Installation.

7.3 Impact Assessment

The following sections provide an assessment of the impact of releases from the Installation, so as to underpin and justify the measures that will be put in place for their control and that will adequately protect the environment.

The risk assessment approach has been based on the following four sequential stages:

- identify risks from the activity;
- assess the risks and check that they are acceptable;
- justify appropriate measures to control the risks, if necessary; and
- present the assessment as detailed in the EA Risk Assessment guidance.

Activities with the potential to impact on the surrounding environment have been identified in line with guidance provided by the EA, and include the following assessments:

- Amenity and accidents;

- Emissions to air;
- Emissions to surface water;
- Site waste; and
- Global warming potential.

A short description of the key potential risks from the Installation is provided in the following subsections.

7.3.1 Amenity and Accidents

A Qualitative Risk Assessment covering potential minor accidents has been undertaken for the Installation and is included in Appendix G of this Main Supporting Document.

7.3.1.1 Odour

Storage of NH_3 for the SCR plant and storage and use of amines for the PCC plant have the potential to generate odour.

As detailed in Section 4.7.1, the amine solvent to be used in the PCC plant has a low volatility and very low vapour pressure. Although it is described as having a 'sweet' odour, it is considered that due its low volatility there is minimal potential for odour issues to arise from storage or delivery operations. As such, it is not considered that odour nuisance would occur as a result of the use and storage of the solvent on site.

The NH_3 storage will be nitrogen blanketed and will have vapour balancing for unloading operations. The tank will be suitably located so as to avoid direct sunlight, to minimise the potential for vaporisation. The vent to atmosphere will be fitted with carbon filters to prevent NH_3 emission and potential odour issues.

7.3.1.2 Noise and Vibration

As stated in Section 5.6, the final design of the Installation is not yet available, with regards to the confirmed equipment noise levels and the mitigation measures required to ensure that noise impacts at receptors are not experienced. As such, an updated NIA has not been provided as part of this Environmental Permit variation application. This will be provided to the EA in line with the existing PO4 requirement, at least 6 months prior to the commencement of commissioning.

7.3.1.3 Fugitive Emissions

Fugitive emissions have the potential to occur from flanges, seals, valves and equipment vents during transfer operations.

Based on the various controls placed on the Installation's plant and equipment, it is expected that fugitive emissions, particularly process emissions to air and water will be negligible.

All maintenance activities will be controlled under a permit to work system and will follow a Risk Assessment and Method Statement, which will define the necessary mitigating measures to minimise fugitive emissions from maintenance work.

7.3.1.4 Visible Plumes

During the original Environmental Permit application modelling of visible plumes from the Absorber stack was carried out both without and with flue gas reheat (flue gas at 35°C and 60°C respectively). The assessment demonstrated that a significant reduction in the potential for visible plumes to occur was associated with the application of reheat, with a visible plume being predicted for up to 40% of the time for the 35°C release, reducing to less than 1% of the time for the 60°C release.

The final design has flue gas reheat to 65°C, and therefore it is considered that the potential for a visible plume will be further reduced from that presented in the original assessment. As such, no further assessment of visible plumes has been carried out.

7.3.1.5 Accidents

An Accident Management Plan will be developed to include the Installation and all associated equipment.

A number of environmental protection measures will be implemented on site via the EMS to prevent and control spill events, including but not limited to:

- Plans to deal with accidental pollution and any necessary equipment (e.g. spill kits) will be held on Site. The EMS will incorporate details on how to appropriately deal with accidental spillages to ensure they are not released into any surface water system.
- Implementation of containment measures, including bunding or double-skinned tanks for fuels and oils. All chemicals will be stored in accordance with their COSHH guidelines.
- Incorporation of interceptors into the drainage system to prevent spilled fuel entering the surface water drainage system or local water bodies.

In line with the requirements of LCP BATc, a management plan will be developed as part of the EMS in order to reduce emissions to air and/ or to water during OTNOC that includes the following elements:

- 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.

In the event of a fire, a flow diversion value will control the flow of firewater run-off to a dedicated firewater run-off collection pond for storage testing and disposal. In the event that the firewater run-off collection pond capacity is exceeded, the firewater run-off collection pond would flow to the attenuation pond for PCSWs to provide additional storage. The drains on Site have been sized to deal with calculated maximum firewater run-off flows.

The discharge from the Outflow Retention Pond to Emission Point W1 is a pumped discharge and therefore this would be shut-off in the event of a fire.

7.3.1.6 Flood Risk Assessment

The EA's Flood Maps for Planning show that the Installation is in an area at very low risk of flooding. The detailed flood risk information identifies the flood risk from rivers or the sea, and surface waters as being very low. This level of risk implies that each year this area has a chance of flooding of less than 0.1%, taking into account the effect of any flood defences in the area. Such defences reduce but do not completely stop the chance of flooding, as they can be overtopped or fail.

The following mitigation measures have been considered to protect the Installation from flood, in accordance with the relevant legislative and regulatory requirements:

- Flood resilience measures;
- Flood emergency response plans;
- Flood warnings and alerts
- Emergency access and egress; and
- Design capacity exceedance

7.3.2 Emissions to Air

Air dispersion modelling has been carried out for the Installation and an Air Quality Impact Assessment is provided in Appendix E.

The assessment considered three operational scenarios:

- Scenario 1 – Extreme Worst Case Normal Operation of the PCC plant. Assumes that emissions are at the upper BAT-AELs for NO_x, the IED ELV for CO and at the design guarantees for amine and degradation products. Operation assumed to be for 365 days a year 24 hours a day;
- Scenario 2 – Abnormal operations of the Power Plant, with no carbon capture taking place; and

- Scenario 3 – Likely Worst Case Normal Operation of the PCC Plant. Assessment carried out to determine more realistic worst case impacts of nitrogen deposition specifically, in line with ongoing discussions carried out with the EA and Natural England. Based on envisaged long term emission concentrations as advised by the technology provider and a more likely operating profile of approximately 6,094 hours per year.

Scenario 1 shows that there are no significant effects for human receptors under extreme worst case operating conditions, for any of the pollutants assessed. Similarly for ecological receptors, there are no significant effects for any of the pollutants assessed, against the relevant Critical Levels or the acid deposition Critical Loads.

Impacts of nutrient nitrogen deposition could not be screened as insignificant for Scenario 1 at the Teesmouth and Cleveland Coast SSSI receptor, where impacts of up to 1.7% of the Critical Load were predicted to occur over the dune area. A review of the nitrogen deposition background data however shows that the predicted Process Contributions from the Installation are unlikely to be significant in terms of the interannual variations that occur in background nitrogen deposition concentrations in the area. Additionally, a more likely worst case normal operation (Scenario 3), indicates that the actual predicted impacts would be much lower, and represent only 0.9% of the Critical Load.

In relation to nitrogen deposition impacts, the existing Environmental Permit includes PO15 which states:

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

Discussions with the EA and Natural England have been ongoing on this issue since the original Environmental Permit was issued, and the nitrogen deposition impacts that are presented in Appendix E have already been shared and discussed with both parties. During these discussions, NZT have agreed with Natural England that compensation will be applied in line with the precautionary principle to reduce the potential for long-term nitrogen deposition impacts on the dune habitat. It is envisaged that the specifics of the compensation will be secured via a revised PO15 and an associated Improvement Condition within the varied Environmental Permit. Suggested wording for these conditions has been discussed with Natural England, as follows:

Pre-Operational Condition:

Prior to the commencement of the operational phase of the installation the operator will submit a plan for nutrient nitrogen deposition compensation measures to Natural England for approval to support the dune habitats (the "Nutrient Nitrogen Deposition Compensation Measures). Implementation of the Nutrient Nitrogen Deposition Compensation Measures will begin before the operational phase of the development commences and will continue to be implemented during the first three years of normal operation.

Improvement Condition:

An updated air quality assessment will be submitted to confirm if nutrient nitrogen deposition has exceeded 1% of the lower end of the critical load during the first three years from the start of operations. If deposition is less than 1%, the Nutrient Nitrogen Deposition Compensation Measures will be discontinued and this condition will no longer apply. If deposition is greater than 1% the measures agreed with Natural England will be reviewed and extended for a further period of three years and, if necessary, enhanced to ensure they remain adequate. The process outlined in this condition will be repeated until such time as deposition is less than 1%.

Scenario 2 was considered for the short-term averaging periods only, as abnormal operations are not planned to occur over long periods of time. No significant effects were identified for this scenario, for human receptors for any pollutants. In terms of ecological receptors, the NO_x daily Critical Level of 75µg/m^3 was exceeded at one location, however the Institute of Air Quality Management (IAQM) guidance for Nature Conservation outlines that a less stringent Critical Level of 200µg/m^3 can be used in areas where the SO_2 and ozone are likely to be low. When comparing the results with the 200µg/m^3 Critical Level, there are no exceedances or significant effects.

7.3.3 Emissions to Water

A summary of the emissions from the Installation to surface water is provided in Section 5.2 and a Water Impact Assessment of the process wastewater emissions to receiving waters has been undertaken in Appendix F.

The methodology set out in the EA's guidance 'Surface water pollution risk assessments for your environmental permit' were followed to determine the potential environmental impacts associated with the discharge to the "estuaries and coastal waters receiving water "type".

The assessment assumed no dilution from clean surface waters collected on site and discharged with the process wastewaters and therefore is considered to represent very much a worst case assessment.

The findings of the assessment confirm that all the parameters potentially released from the Installation will not have any adverse impact on the quality of the receiving waters. It is therefore considered that further detailed modelling is not required to support the Environmental Permit variation application.

7.3.4 Site Waste

The details of anticipated waste streams generated by the Installation are provided in Section 4.8.

All operational waste will be dealt with in accordance with the Site's waste management procedures, with appropriated designated storage areas for hazardous and non-hazardous wastes, and consigned via a registered waste carrier for treatment or disposal at a suitably licenced waste facility. It is therefore considered that further assessment of the waste from the Installation is not required.

7.3.5 Global Warming Potential

The EA's guidance 'Assess the impact of air emissions on global warming' was withdrawn on 23 July 2024 and therefore the Government conversion factors for company reporting of greenhouse gas emissions[10] have been used to assess the Global Warming Potential of the Installation, as advised by the EA.

The release of greenhouse gas emissions is anticipated primarily from the direct emissions produced or associated with energy and fuel use. These releases have been identified and their global warming potential calculated in Table 7.3.

The Installation will capture at least 95% of the CO_2 emissions resulting from the CCGT plant, therefore the global warming potential of the emissions to air from the Installation will be significantly reduced.

Table 7.3: Global Warming Potential

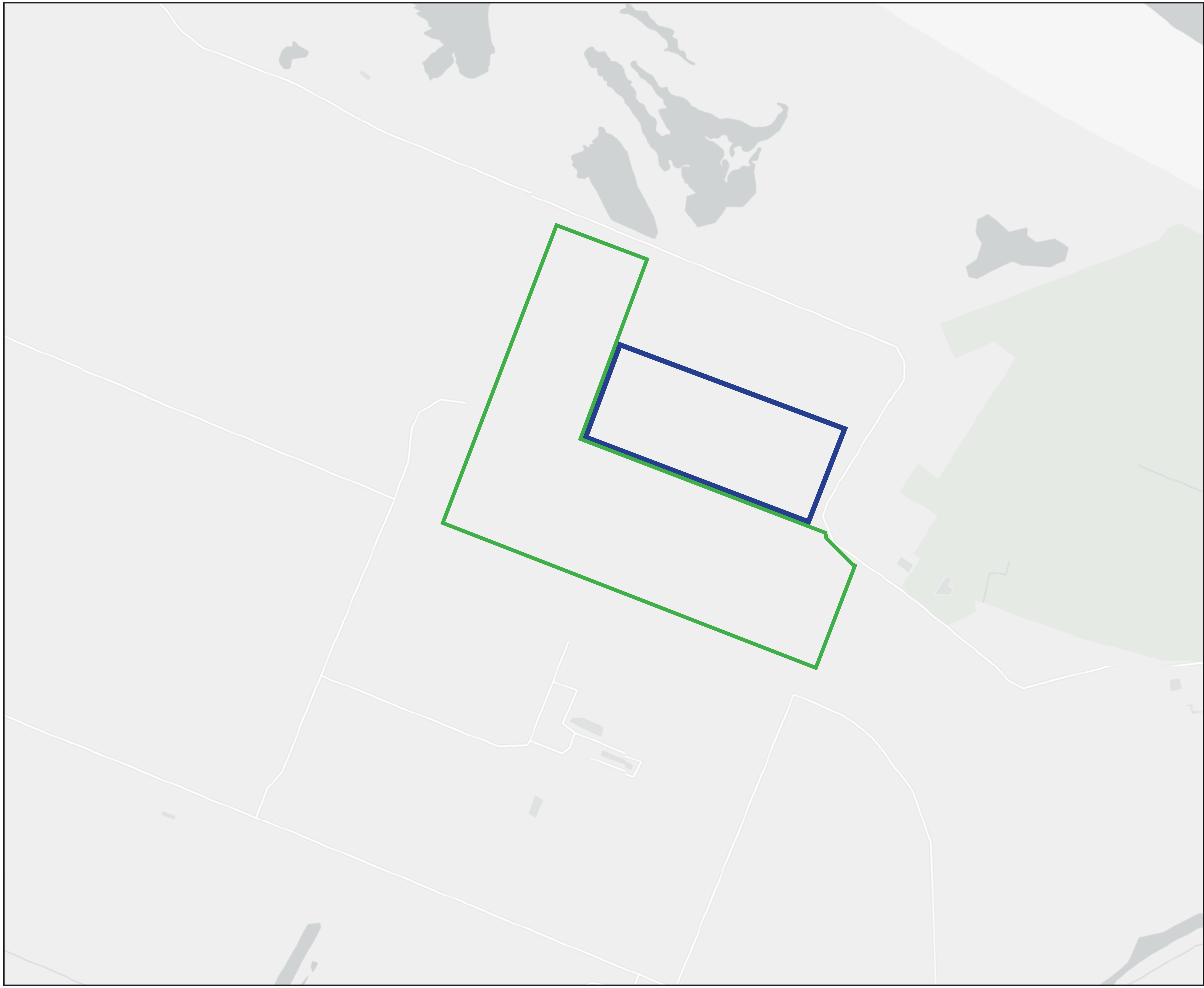
Energy Source	Energy Consumption Primary		
	At Primary Source	CO_2 Emission Factor (CO_2e/unit)	CO_2 (tonnes)
Natural Gas (CCGT) (no capture)[1]	12,264,000 MWh	0.202	2,447,328
Diesel	15,000 litres	2.63	40
CO_2 Capture			- 2,324,962
Annual CO_2 Emissions			**+ 122,406**
[1] Based on 1400MWth, 8760 hours per year			

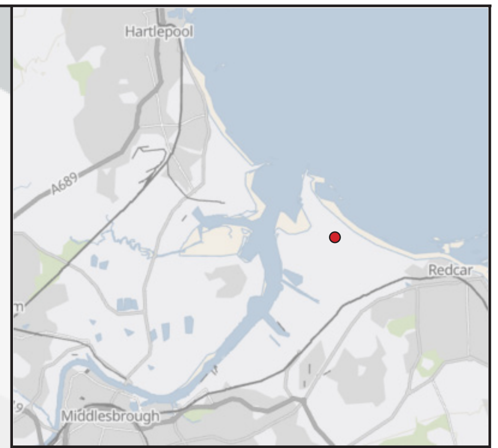
[10] Government conversion factors for company reporting of greenhouse gas emissions - GOV.UK

7.4 Site Closure

A plan for appropriate decommissioning and closure of the Installation at the end of its operating life will be developed. The plan will ensure that the Site is returned to the baseline condition, as outlined in this application.

Appendix A – Figures





Legend

- Environmental Permit Installation Boundary
- High Pressure Compressor Boundary

Rev	Date	By	Chkd	Appd
02	27/01/2026	IM	HW	

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Client
Net Zero Teesside Power Limited

Project Title
Net Zero Teesside Power Station and Carbon Capture Plant

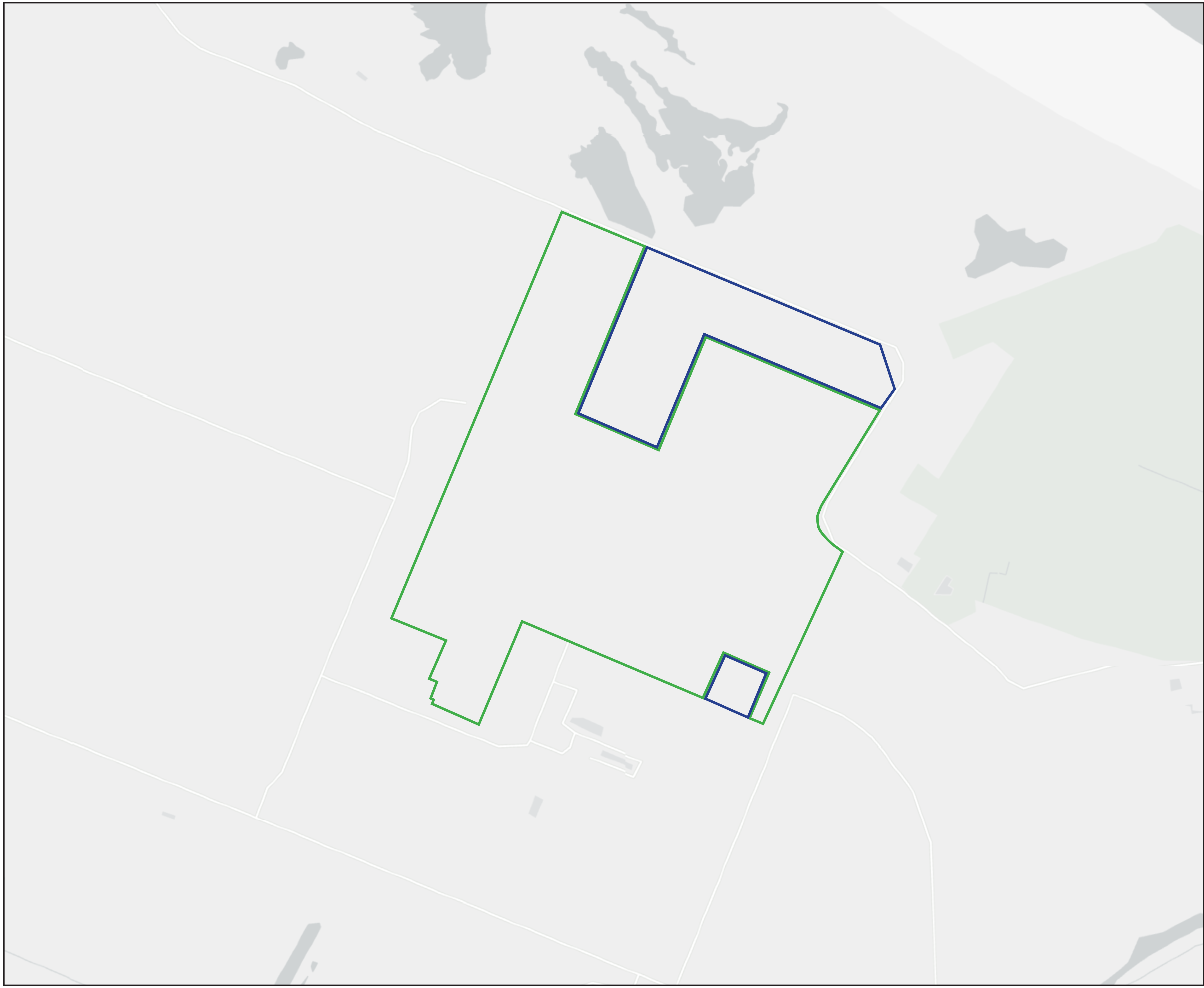
Drawing Title
Figure 1: Site Location Plan and Existing Installation Boundary

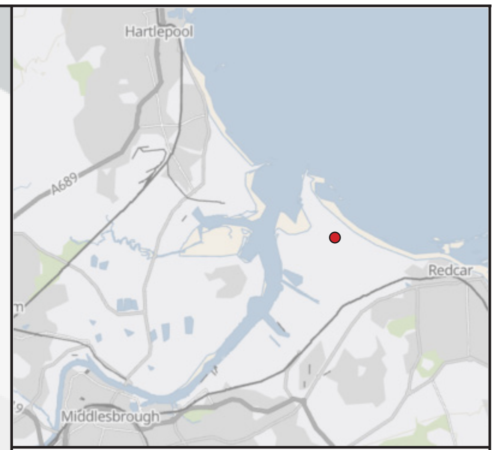
Role
Environmental Permit Variation

Arup Job No.
305719-70

Name
308822-ARP-NZT-EP-DR-0001

Scale
1:50,000 @ A3





Legend

- Environmental Permit Installation Boundary
- High Pressure Compressor Boundary

Rev	Date	By	Chkd	Appd
01	28/01/2026	IM	HW	

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Client
Net Zero Teesside Power Limited

Project Title
Net Zero Teesside Power Station and Carbon Capture Plant

Drawing Title
Figure 2: Revised Installation Boundary

Role
Environmental Permit Variation

Arup Job No.
308822-00

Name
308822-ARP-NZT-EP-DR-0002

Scale
1:50,000 @ A3

No.	PLANT DESCRIPTION
01	LER SUBSTATION 01
02	LER SUBSTATION 02
03	LER SUBSTATION 03
04	TURBINE HALL
05	FIREWATER PUMP SHELTER
06	ADMINISTRATION / CCR BUILDING
07	LABORATORY BUILDING
08	REFUGE BUILDING B30
09	REFUGE BUILDING C50
10	MIXED BED POLISHER PACKAGE
11	ULTRAFILTRATION & RO SYSTEM PACKAGE
12	PROCESS EFFLUENT TREATMENT PLANT No.1 PACKAGE
13	PROCESS EFFLUENT TREATMENT PLANT No.2 PACKAGE
14	WASTE WATER TREATMENT PACKAGE
15	RAW WATER TREATMENT PACKAGE
16	HAZARDOUS CHEMICAL STORAGE
17	GATE HOUSE
18	WORKSHOP WAREHOUSE

GENERAL NOTES

NOTES

LEGEND

- PROPERTY BOUNDARY FENCE
- BUILDING IDENTIFIER
- CURRENT PACKAGES
- TANKS
- INSTALLATION PERMIT BOUNDARY
- HIGH PRESSURE COMPRESSOR SITE BOUNDARY
- AIR EMISSION POINTS
- WATER DISCHARGE POINT

REFERENCE DRAWINGS

HOLDS

INDICATIVE SITE LAYOUT PLAN

	POWER PLANT INFORMATION
	PROCESS INFORMATION
	T.EN CONFIDENTIAL INFORMATION
	NOT APPLICABLE
	CONFIDENTIALITY

Rev.	Date DD/MM/YYYY	STATUS	WRITTEN BY (Name & visa)	CHECKED BY (Name & visa)	APPROVED BY (Name &visa)
A01	21/10/2025	IFR-ISSUED FOR REVIEW	ACH	MHE	CDI

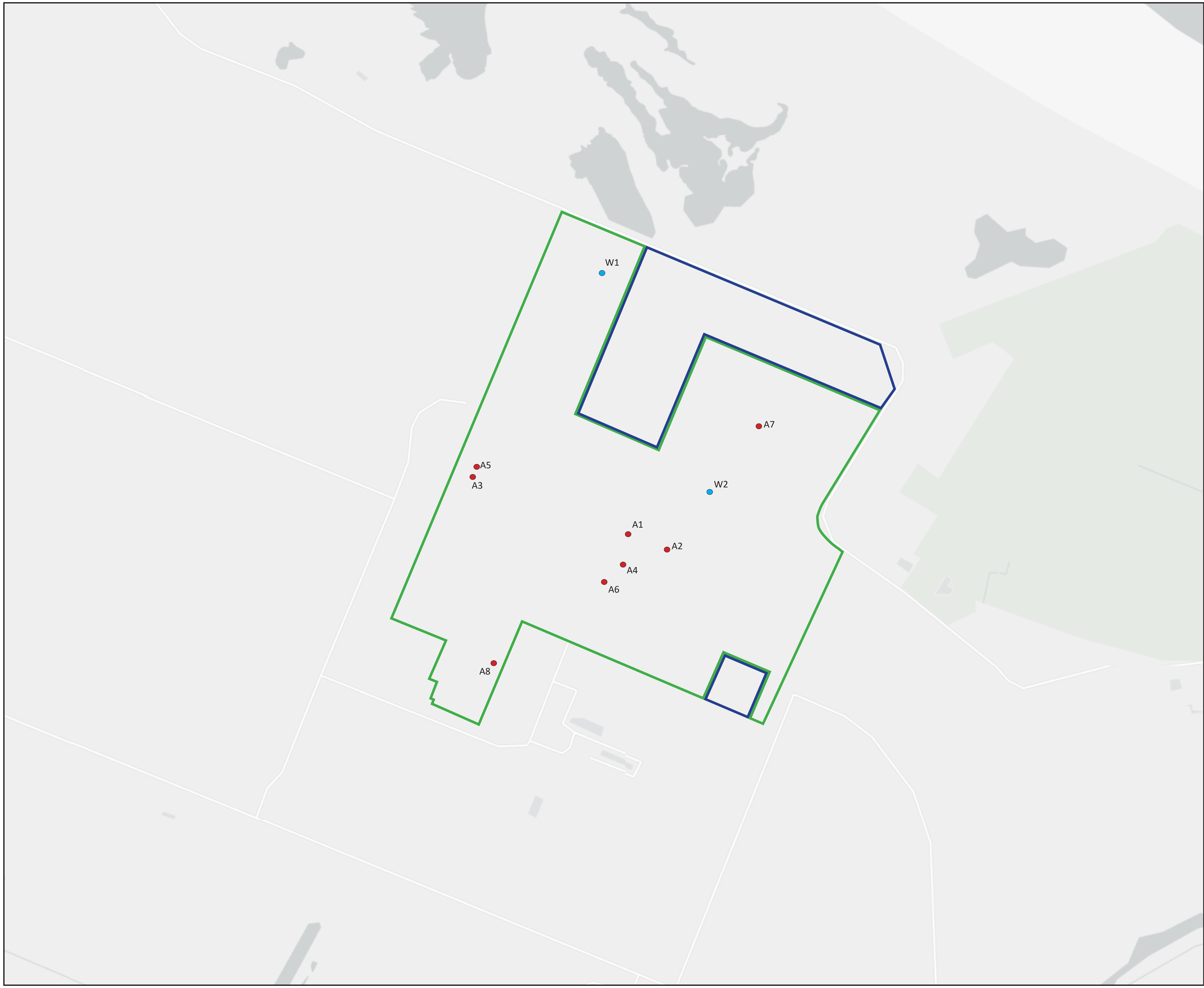
DOCUMENT REVISIONS

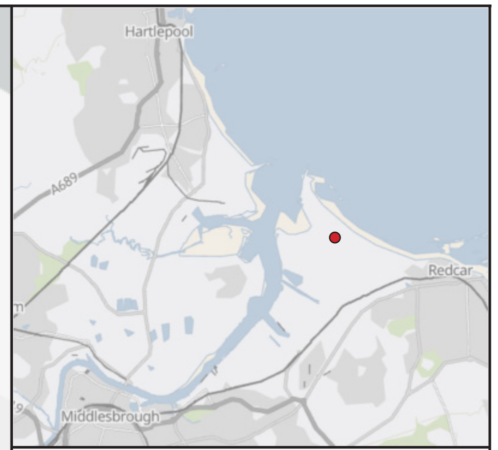
Net Zero Tesside

OVERALL PLOT PLAN
MAJOR FUNCTIONAL AREAS

SCALE: 1:1500	SHEET: 1 OF 1			REVISION	FORMAT
T.EN DOC. REF.	Project n° - Unit 217994C-A00	Doc. Type DW	Eng./Mat. Code xxxx	Serial n° xxxx	
CLIENT DOC. REF.	NS051-PI-PPL-xxx-xxx-xxxxx-xxx			A01	A0

FILE NAME:





Legend

- Environmental Permit Installation Boundary
- High Pressure Compressor Boundary
- Air Emission point
- Water Discharge Point

Rev	Date	By	Chkd	Appd
01	26/11/2025	IM	HW	

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Client
Net Zero Teesside Power Limited

Project Title
Net Zero Teesside Power Stationand Carbon Capture Plant

Drawing Title
Figure 4 - Installation Emission Points

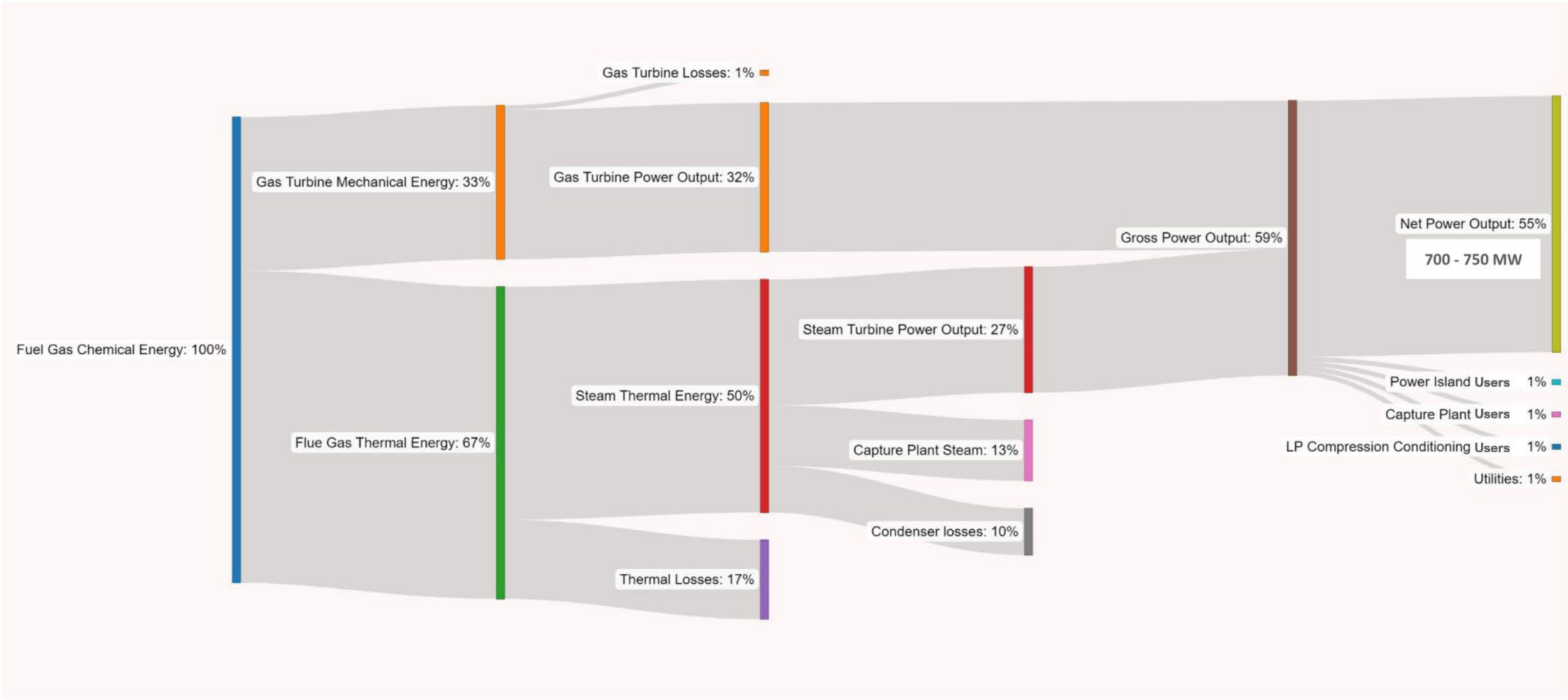
Role
Environmental Permit Variation

Arup Job No.
305719-70

Name
308822-ARP-NZT-EP-DR-0004

Scale
1:50,000 @ A3

Figure 5: Sankey Diagram



GENERAL NOTES

- PLANT DATUM = BRITISH NATIONAL GRID CO-ORDINATES E: 456594.418, N: 525094.095.
- GRADE HPP ELEVATION 100.000 = 7.5M ABOVE ORDNANCE SURVEY DATUM.
- ALL COORDINATES ARE IN METERS UNLESS OTHERWISE NOTED.
- ALL DIMENSIONS ARE IN MILLIMETERS (mm).
- FINISHED PAVING LEVEL FOR THIS AREA IS AS FOLLOW
  HIGH POINT PAVING (HPP): +100.000
- U/G PIPING AND OPEN DITCTH ARE NOT SHOWN ON THIS DRAWING.

NOTES

LEGEND

- ROAD AREA
- GRAVEL AREA
- BUILDING AREA
- PAVING AREA
- GREEN AREA

REFERENCE DRAWINGS

	POWER PLANT INFORMATION
	PROCESS INFORMATION
	T.EN CONFIDENTIAL INFORMATION
	NOT APPLICABLE
CONFIDENTIALITY	

Rev.	Date DD/MM/YYYY	STATUS	WRITTEN BY (Name & visa)	CHECKED BY (Name & visa)	APPROVED BY (Name &visa)
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DOCUMENT REVISIONS

TECHNIP ENERGIES · GE VERNOVA · NZT Power · Northern Endurance Partnership

Net Zero Tesside

Figure 6 - Drainage Plan

SCALE:	1:1500	SHEET:	1 OF 1
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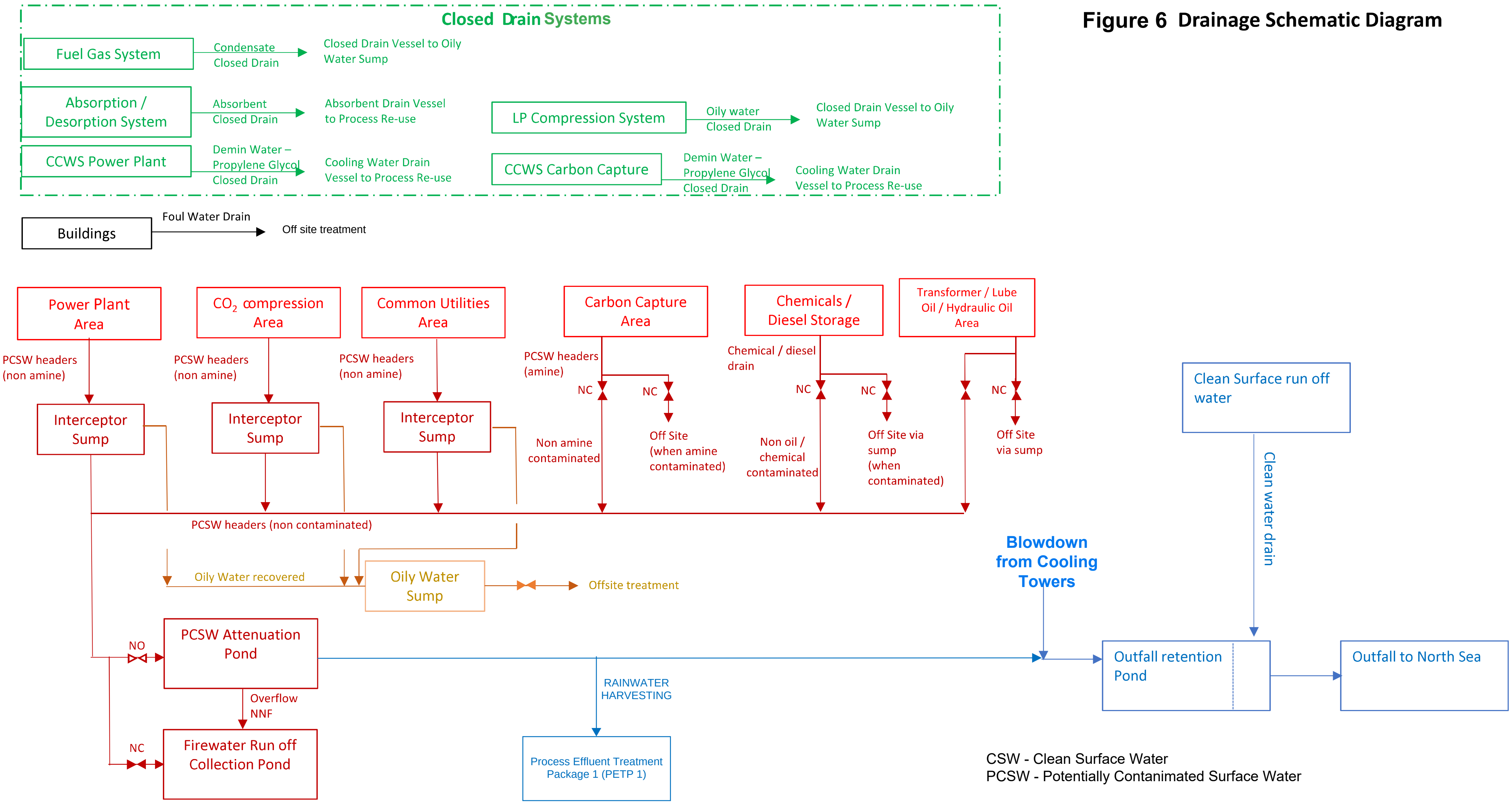
FILE NAME:

Figure 6 Drainage Schematic Diagram



CSW - Clean Surface Water
PCSW - Potentially Contanimated Surface Water

Appendix B – Site Condition Report

See accompanying report.

Appendix C – LCP BAT Assessment

Table C-1: BAT Conclusions for the LCP Process

BAT No.		BATc Requirements	Demonstration of BAT - Operator Response	Compliant with BAT?
1	**Environmental Management Systems** 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.	The Installation will be operated under an ISO14001:2015 accredited Environmental Management System (EMS). The EMS will comprise an environmental policy and other relevant management documents. The site-specific procedures will define the roles and responsibilities for applicable site personnel. The EMS will include all elements listed under BATc 1 items as required under ISO14001:2015.	Yes
	(ii)	Definition, by the management, of an environmental policy that includes the continuous improvement of the environmental performance of the installation.		
	(iii)	Planning and establishing the necessary procedures, objectives and targets, in conjunction with financial planning and investment.		
	(iv)	Implementation of procedures paying particular attention to: (a) structure and responsibility (b) recruitment, training, awareness and competence (c) communication (d) employee involvement (e) documentation (f) effective process control (g) planned regular maintenance programmes (h) emergency preparedness and response (i) safeguarding compliance with environmental legislation.		
	(v)	Checking performance and taking corrective action, paying particular attention to: (a) monitoring and measurement (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.	**a. Monitoring and Measurement** • Emissions to Air: The Installation will have an operational procedure document describing the monitoring of emissions to air. This procedure will also cover the procedures for monitoring emissions to air during periods of abnormal operation. The document will include the responsibilities of site personnel with regards to emissions monitoring, applicable daily, monthly and annual emission limits for each pollutant, control measures applied for each pollutant, and reporting methods and requirements. The operator will ensure that all equipment on site is appropriately maintained and calibrated as required to ensure monitoring and reporting of emissions for regulatory compliance and other requirements; including equipment used for the continuous and discontinuous monitoring of emissions to air and water. • Emissions to Water: The Installation operation will not include any direct discharge of untreated process waters that could be harmful to the environment to controlled waters. Any emissions to controlled waters will be treated, controlled and monitored appropriately, in line with written procedures developed prior to commencement of operations. • Maintenance Plan: All plant and equipment at the Installation will be regularly maintained by qualified maintenance staff and contractors. **b. Corrective and Preventative Actions**	Yes

BAT No.		BATc Requirements	Demonstration of BAT - Operator Response	Compliant with BAT?
			• 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 non-conformance 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 will clearly define the requirements for maintaining and storing records. **d. Auditing** • The EMS will be subject to periodic review and update and will be subject to internal audits as well as external certification audits (when certified).	
	(vi)	Review, by senior management, of the EMS and its continuing suitability, adequacy and effectiveness.	Regular management review of the EMS will be undertaken at the Site.	Yes
	(vii)	Following the development of cleaner technologies.	See 1ix. below.	-
	(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 including; (a) avoiding underground structures (b) incorporating features that facilitate dismantling (c) choosing surface finishes that are easily decontaminated (d) using an equipment configuration that minimises trapped chemicals and facilitates drainage or cleaning (e) designing flexible, self-contained equipment that enables phased closure (f) using biodegradable and recyclable materials where possible.	The Installation will be regulated under the Environmental Permitting Regulations 2016 (as amended) (EP Regulations) which requires sites to have a decommissioning plan in place to manage such considerations.	Yes
	(ix)	Application of sectoral benchmarking on a regular basis.	The Installation will be regulated under the EP Regulations, which requires the application of 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.	Yes
	Specifically for this sector, it is also important to consider the following features of the EMS, described where appropriate in the relevant BAT:			
	(x)	Quality assurance/ quality control programmes to ensure that the characteristics of all fuels are fully determined and controlled (see BAT 9).	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).	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.	The Installation will include dedicated appropriate waste storage areas on Site; additionally, a waste procedure that includes the implementation of the waste hierarchy will be developed prior to commencement of operations.	Yes

BAT No.		BATc Requirements	Demonstration of BAT - Operator Response	Compliant with BAT?
	(xiii)	A systematic method to identify and deal with potential uncontrolled and/or unplanned emissions to the environment, in particular: (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.	The potential for fugitive emissions will be reviewed as part of the EMS environmental aspect and impact identification procedure and on a regular basis through on-going site observations. The Site operations will include a procedure describing the processes to be followed with respect to the monitoring and reporting of emissions for regulatory compliance (outside of those required under the EP Regulations). Additionally, the Installation 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.	Yes
	(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.	Due to the inherent nature of the site operations, the potential for dust generation at the Installation will be minimal. Therefore, no specific dust management plan is proposed to be developed for the Installation.	Yes
	(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.	An assessment of potential noise sources at the Installation and impact on the sensitive receptors in the vicinity of the site will be carried out in line with the existing PO4 in the Environmental permit. Following completion of the noise impact assessment, a Noise Management Plan will be produced, should this be deemed appropriate.	Yes
	(xvi)	For the combustion, gasification or co-incineration of malodourous substances, an odour management plan including: (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.	The CCGT at the Installation will use unodorised natural gas directly from the NTS or CATS as a fuel, therefore is not likely to generate odour.	Yes
2		**Monitoring** 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, 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.	Periodic Operational Performance tests measuring the load, fuel used, and power output will be undertaken in accordance with applicable BE EN standards.	Yes
3		**Monitoring** BAT is to monitor key process parameters relevant for emissions to air and water including those given below.		
		(a) Flue gas – Flow – Periodic or continuous determination.		Yes

<table>
<tr><th>BAT No.</th><th colspan="4">BATc Requirements</th><th>Demonstration of BAT - Operator Response</th><th>Compliant with BAT?</th></tr>
<tr><td></td><td colspan="4">(b) Flue gas – oxygen content, temperature and pressure - Periodic or continuous determination.
(c) Flue gas – Water vapour content - Periodic or continuous measurement.
(d) Waste water from flue-gas treatment – Flow, pH, and temperature – Continuous measurement.</td><td>Flue gases 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 Joint Environmental Programme (JEP) IED/ BRef Monitoring Protocol for LCP, an 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 Environmental Permit.</td><td></td></tr>
<tr><td rowspan="6">4</td><td colspan="6">Monitoring
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.</td></tr>
<tr><td>Parameter</td><td>Standard</td><td>Minimum frequency</td><td>Monitoring associated with</td><td rowspan="5">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 NH_3 (associated with SCR use).
Further detail on the monitoring of emissions to air to be carried out at the Installation are provided in Section 6.1 of the Main Supporting Document.</td><td rowspan="5">Yes</td></tr>
<tr><td>NO_x</td><td>Generic EN standards</td><td>Continuous(1)</td><td>BAT 42, BAT 43</td></tr>
<tr><td>CO</td><td>Generic EN standards</td><td>Continuous(1)</td><td>BAT 49, BAT 56</td></tr>
<tr><td>NH_3</td><td>Generic EN standards</td><td>Continuous(1)</td><td>BAT 7</td></tr>
<tr><td colspan="4">(1) For gas turbines, periodic monitoring is carried out with a combustion plant load of >70 %.</td></tr>
<tr><td>5</td><td colspan="4">Monitoring
BAT is to monitor emissions to water from flue-gas treatment 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.</td><td>The Installation will use SCR for the control of NOx emissions in the flue gas to meet the BAT-AELs. There will be no emissions to water from the SCR, however the DCC will remove NH_3 from the flue gas prior to entering the PCC plant. DCC wastewaters will be treated onsite and reused in the cooling water circuit prior to release. Emissions to water will be monitored in accordance with relevant standards.</td><td>Yes</td></tr>
<tr><td rowspan="3">6</td><td colspan="5">General Environmental and Combustion Performance
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 an optimised combustion and to use an appropriate combination of the techniques given below:</td><td></td></tr>
<tr><td colspan="2">Technique</td><td>Description</td><td>Applicability</td><td></td><td></td></tr>
<tr><td colspan="2">Fuel blending and mixing</td><td>Ensure stable combustion conditions and/ or reduce the emission of pollutants by mixing different</td><td>Generally applicable.</td><td>The Site will have a contractual agreement to receive natural gas from either the NTS or CATs, which will include a requirement for the gas to comply with specified quality criteria. Equipment such as a gas chromatograph (GC) will be 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</td><td>Yes</td></tr>
</table>

BAT No.	BATc Requirements			Demonstration of BAT - Operator Response	Compliant with BAT?
		qualities of the same fuel type.		used, and power output to calculate overall efficiencies will be undertaken in accordance with applicable BE EN standards and site procedures.	
	Maintenance of the combustion system	Regular planned maintenance according to supplier's recommendations.	Generally applicable.	All plant and equipment at the Installation will be regularly maintained, including the combustion system, by qualified maintenance staff or contractors, as per site procedures.	Yes
	Advanced control system	The use of a computer-based automatic system to control the combustion efficiency and support the prevention and/ or reduction of emissions. This also includes the use of high-performance monitoring.	The applicability to old combustion plants may be constrained by the need to retrofit the combustion system and / or control command system.	The Installation's operations will be monitored and operated by suitably trained site personnel and managed via a DCS to continuously monitor the operation of the plant and equipment at the Site. Any non-conformance or deviation in normal operating parameters will be identified by the DCS to allow operators to take action to avoid a breach of permitted emission levels.	Yes
	Good design of the combustion equipment	Good design of furnace, combustion chambers, burners and associated devices.	Generally applicable to new combustion plants.	The CCGT plant will be a new high efficiency unit offering leading performance in its class and compliant with all relevant and most recent regulatory requirements, in addition to design features to optimise performance in terms of emissions and efficiency.	Yes
	Fuel Choice	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.	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.	Natural gas from the NTS or CATS will result in minimal sulphur dioxide and particulate emissions from the CCGT.	Yes
7	**General Environmental and Combustion Performance** 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 NOx emissions, BAT is to optimise the design and/or operation of SCR and/or SNCR (e.g. optimised reagent to NOx ratio, homogeneous reagent distribution and optimum size of the reagent drops).			The Installation will comply with the NOx BAT-AELs with the use of SCR secondary abatement using ammonia as a reagent. The SCR plant will be appropriately designed and operated to maintain optimum NH_3 injection rate and minimise NH_3 slip emissions to air. Further information on the control of NH_3 emissions is provided in Section 4.2.3.2 of the Main Supporting Document.	Yes

BAT No.	BATc Requirements	Demonstration of BAT - Operator Response	Compliant with BAT?
	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.	NH_3 emissions will comply with the annual BAT-AEL of 3 – 10 mg/Nm^3.	
8	**BAT Associated Emission Levels** 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.	The SCR will be designed, operated and maintained to ensure use at optimal capacity and availability, as described in response to BAT 7.	Yes
9	**BAT Associated Emission Levels** In order to improve the general environmental performance of combustion and/ or gasification plants and to reduce emissions to air, BAT is to include the following elements in the quality assurance/ quality control programmes for all the fuels used, as part of the environmental management system (see BAT 1): i. Initial full characterisation of the fuel used including at least the parameters listed below and in accordance with EN standards. ISO, national or other international standards may be used provided they ensure the provision of data of an equivalent scientific quality; ii. Regular testing of the fuel quality to check that it is consistent with the initial characterisation and according to the plant design specifications. The frequency of testing and the parameters 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). 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. Natural gas — LHV Natural gas — CH4, C2H6, C3, C4+, CO2, N2, Wobbe index	A contractual agreement to receive natural gas from the NTS or CATs will be in place, 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.	Yes
10	**General Environmental and Combustion Performance** 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	The plant and associated control systems will be designed to minimise the potential for OTNOC events to occur. The Installation will be operated using a 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.	Yes

BAT No.	BATc Requirements	Demonstration of BAT - Operator Response	Compliant with BAT?
	(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.	Site operators will be trained to monitor plant operation and take appropriate actions in the event of a potential OTNOC event being identified. Start up and shutdown procedures will be put in place with the aim to minimise the time during which the plant is operating at non-optimal conditions and operators shall be trained in the appropriate actions required should the potential for an OTNOC event be identified. All plant and equipment at the Site will be regularly maintained including those system provided to minimise the potential for OTNOC conditions to occur. The Installation will have in place an accident management plan and emergency response procedures. Appropriate procedures will also be put in place to review any OTNOC events. The records of OTNOC events will be retained on Site.	
11	**General Environmental and Combustion Performance** BAT is to appropriately monitor emissions to air and/ or to water during OTNOC.	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 all operating conditions, including OTNOC situations, and can be used to inform subsequent incident investigation.	Yes
12	**Energy Efficiency** 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. **Technique** / **Description** / **Applicability** Combustion optimisation / Optimising the combustion minimises the content of unburnt substances in the flue gases and in solid combustion residues / Generally applicable Optimisation of the working medium conditions / 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 NOX emissions or the characteristics of energy demanded Optimisation of the steam cycle / Operate with lower turbine exhaust pressure by utilisation of the lowest possible temperature of the condenser cooling water, within the design conditions	The anticipated electrical efficiency of the CCGT plant will be 61%, which is greater than the BAT-AEEL range of 57 – 60.5% for CCGTs having a thermal input of >600MWth. As detailed in Section 4.9.1, due to the optimisation of the ST for providing steam to the PCC plant, the efficiency of the CCGT is slightly lower than if it was optimised for power generation. Combustion air will not be pre-heated as if the air is too hot, it can cause damage to the turbine and decrease its efficiency. The fuel gas will be heated to counter the Joule-Thomson effect from pressure reduction and to optimise combustion in the CCGT by reducing the fuel required to reach turbine firing temperatures.	Yes

BAT No.	BATc Requirements			Demonstration of BAT - Operator Response	Compliant with BAT?
	Minimisation of energy consumption	Minimising the internal energy consumption (e.g. greater efficiency of the feed-water pump)			
	Preheating of combustion air	Reuse of part of the heat recovered from the combustion flue-gas to preheat the air used in combustion	Generally applicable within the constraints related to the need to control NOx emissions		
	Fuel preheating	Preheating of fuel using recovered heat	Generally applicable within the constraints associated with the boiler design and the need to control NOx emissions		
	Advanced control system	Computerised control of the main combustion parameters enables the combustion efficiency to be improved	Generally applicable to new units.		
	Feed-water preheating using recovered heat	Preheat water coming out of the steam condenser with recovered heat, before reusing it in the boiler	Only applicable to steam circuits and not to hot boilers. Applicability to existing units may be limited due to constraints associated with the plant configuration and the amount of recoverable heat		
	Heat recovery by cogeneration (CHP)	Recovery of heat (mainly from the steam system) for producing hot water/steam to be used in industrial processes/activities or in a public network for district heating. Additional heat recovery is possible from: • flue-gas • grate cooling • circulating fluidised bed			
	CHP readiness		Only applicable to new units where there is a realistic potential		

BAT No.	BATc Requirements			Demonstration of BAT - Operator Response	Compliant with BAT?
			for the future use of heat in the vicinity of the unit		
	Flue-gas condenser		Generally applicable to CHP units provided there is enough demand for low temperature heat		
	Heat accumulation	Heat accumulation storage in CHP mode	Only applicable to CHP plants. The applicability may be limited in the case of low heat load demand		
	Wet stack				
	Cooling tower discharge				
	Fuel pre-drying				
	Minimisation of heat losses				
	Advanced materials				
	Steam turbine upgrades	This includes techniques such as increasing the temperature and pressure of medium pressure steam, addition of a low-pressure turbine, and modifications to the geometry of the turbine rotor blades	The applicability may be restricted by demand, steam conditions and/or limited plant lifetime		
	Supercritical and ultra-supercritical steam conditions	Use of a steam circuit, including steam reheating systems, in which steam can reach pressures above 220,6 bar and temperatures above 374 °C in the case of supercritical conditions, and above 250 – 300 bar and temperatures above 580 – 600 °C in the case of ultra-supercritical conditions	Only applicable to new units of ≥ 600 MWth operated > 4000 h/yr. 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		

<table>
<tr><th>BAT No.</th><th colspan="3">BATc Requirements</th><th>Demonstration of BAT - Operator Response</th><th>Compliant with BAT?</th></tr>
<tr><td></td><td></td><td></td><td>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><td></td><td></td></tr>
<tr><td rowspan="4">13</td><td colspan="3">Water Usage and Emissions to Water
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.</td><td rowspan="4">The Installation will be served by a closed-loop cooling system with hybrid cooling towers, where a majority of the cooling water will be recycled. There will be some evaporative losses and blowdown - typically four cycles of concentration, meaning that the ratio of mineral concentration in the source water to that in the circulating water that must be maintained. It would not be possible to reuse the blowdown in the LCP due to the build-up of contaminants over time in the recirculated water.
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 water treatment chemicals is expected to be used, primarily for prevention of scaling and corrosion, and biofouling.
Water will also be reused from the HRSG blow down system and from the WwTP and ETP to minimise water use.
The volumes of surface water run-off are extremely low in comparison to overall water usage on site and opportunities for reuse on Site are limited due to the water quality requirements for on-site processes.
CCGTs do not produce any ash from the combustion process; therefore, the techniques for dry bottom ash handling are not applicable.</td><td rowspan="4">Yes</td></tr>
<tr><td>Technique</td><td>Description</td><td>Applicability</td></tr>
<tr><td>Water recycling</td><td>Residual aqueous streams, including run-off water, from the plant are reused for other purposes. The degree of recycling is limited by the quality requirements of the recipient water stream and the water balance of the plant.</td><td>Not applicable to waste water from cooling systems when water treatment chemicals and/or high concentrations of salts from seawater are present.</td></tr>
<tr><td>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.</td></tr>
<tr><td>14</td><td colspan="3">Water Usage and Emissions to Water
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.</td><td>Wastewater streams generated at the Installation are anticipated to comprise surface run-off water and cooling water blowdown (containing process waste waters); all wastewater streams will be appropriately segregated, treated (if required) prior to discharge.</td><td>Yes</td></tr>
<tr><td>15</td><td colspan="3">Water Usage and Emissions to Water
In order to reduce emissions to water from flue-gas treatment, BAT is to use an appropriate combination of the techniques, and to use secondary techniques as close as possible to the source in order to avoid dilution.</td><td>The need for flue gas treatment is minimised by primary combustion controls identified in BAT 6 and appropriate control of the SCR system identified in BAT 7 above.</td><td>Yes</td></tr>
<tr><td>16</td><td colspan="3">Waste Management
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:</td><td>The Installation will develop a waste management procedure prior to commencement of Site operations, detailing the waste storage and handling procedures on Site. The procedure will outline identification of waste streams and how they must be handled, including appropriate segregation and storage within designated waste storage areas on Site.</td><td>Yes</td></tr>
</table>

BAT No.	BATc Requirements			Demonstration of BAT - Operator Response	Compliant with BAT?
	(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 using appropriate techniques.			The Installation will apply the waste hierarchy for the 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 will only produce minor quantities of waste, primarily from maintenance activities. The main waste stream generated from the LCP at the Site 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, and spent catalysts, in line with the waste hierarchy. Anticipated quantities of waste streams from the Installation are provided in Table 4.3 of the Main Supporting Document.	
17	**Noise emissions** In order to reduce noise emissions, BAT is to use one or a combination of the techniques given below.				
	Operational measures	These include: • 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.	Generally applicable	The Site will have a maintenance schedule in place to ensure optimum operation of all plant and equipment. The GT and ST will be situated within an enclosure; and outdoor equipment will have 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.	Yes
	Low-noise equipment	This potentially includes compressors, pumps and disks.		The 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.	Yes
	Noise attenuation	Noise propagation can be reduced by inserting obstacles between the emitter and the receiver. Appropriate obstacles include protection walls, embankments and buildings	Generally applicable to new plants	The GT and ST 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, so that residual effects are expected to be not significant.	Yes
	Noise-control equipment	This includes: • noise-reducers • vibration or acoustic insulation, or vibration isolation • enclosure of noisy equipment • soundproofing of buildings	The applicability may be restricted by lack of space		

BAT No.	BATc Requirements			Demonstration of BAT - Operator Response	Compliant with BAT?
	Appropriate location of equipment and buildings	Noise levels can be reduced by increasing the distance between the emitter and the receiver and by using buildings as noise screens.	Generally applicable to new plants		

BAT 18 – 27 are associated with the combustion of solid fuels only, and therefore are not considered to be applicable to the Installation.

BAT 28 – 39 are associated with the combustion of liquid fuels only, and therefore are not considered to be applicable to the Installation.

Table C-2: BAT Conclusions for the Combustion of Gaseous Fuels

BAT No.	BATc Requirements		Demonstration of BAT - Operator Response	Compliant with BAT?
40	**Energy Efficiency & BAT-associated energy efficiency levels (BAT-AEELs)** 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 combined cycle for new gas turbines operating over 1,500 hours per year. New CCGT >600MW$_{th}$ BAT-AEEL = Net electrical efficiency 57 - 60.5%		The anticipated electrical efficiency of the CCGT plant will be 61% for unabated operation, which is greater than the BAT-AEEL range of 57 – 60.5% for CCGTs having a thermal input of >600MWth.	Yes
41	**NOx, CO, NMVOC and CH_4 emissions to air**			
	Only applicable to boilers and therefore not applicable to the Installation.			
42	In order to prevent or reduce NOx 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:			Yes
	Technique	**Applicability**		
	Advanced Control System	The applicability to old combustion plants may be constrained by the need to retrofit the combustion system and/or control command system.	Operation of the CCGT unit will be controlled by trained 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.	
	Water / Steam Addition	The applicability may be limited due to water availability.	Water/ steam addition for NOx control is not applied at the plant will have Dry Low NOx burners (DLN) and SCR for NOx control.	
	Dry Low NOx Burners (DLN)	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.	The CCGT will have DLN burners in place to ensure minimum emissions of NOx.	
	Low Load Design Concept	The applicability may be limited by the gas turbine design.	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.	
	Low NOx Burners (LNB)	Generally applicable to supplementary firing for heat recovery steam generators (HRSGs) in the	The CCGT will have DLN burners in place to ensure minimum emissions of NOx.	

BAT No.	BATc Requirements		Demonstration of BAT - Operator Response	Compliant with BAT?
		case of combined-cycle gas turbine (CCGT) combustion plants.		
	Selective Catalytic Reduction (SCR)	Not applicable in the case of combustion plants operated < 500 h/yr. Not generally applicable to existing combustion plants of < 100 MWth	See response to BAT 7	
43	Only applicable to natural gas engines and therefore not applicable to the Installation.			
44	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		CO emissions will controlled through primary combustion controls, with no requirement for secondary abatement.	Yes

Table C-3: BAT Associated Emission Levels (BAT-AELs) for the Combustion of Natural Gas in New CCGTs >50MWth

Pollutant	Yearly Average	Daily average or average over the sampling period	Demonstration of BAT - Operator Response
NOx	10-30 mg/Nm^3	15-40 mg/Nm^3	The CCGT is expected to achieve the stated BAT-AELs, with energy efficiency uplifts applied.
CO	5-30 mg/Nm^3 (indicative BAT-AEL)	-	Performance to be confirmed following commencement of operation. IED ELV of 100 mg/Nm^3 proposed in the Main Supporting Document and justified in Section 5.1.1.1

In the case of a gas turbine equipped with DLN, these BAT-AELs apply only when the DLN operation is effective.

For plants with a net EE greater than 55%, a correction factor may be applied to the higher end of the BAT-AEL range, corresponding to [higher end] x EE / 55, where EE is the net electrical efficiency of the plant determined at ISO baseload conditions.

Appendix D – PCC-GET Review

https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat

PCC GET Recommendation	Response
2. Power Plant Selection and Integration with the PCC Plant	
2.1 Energy efficiency in plants with PCC	
You must maximise the thermal energy efficiency of the plant and of the supply of heat for the associated PCC plant.	The requirement to maximise thermal efficiency is integral to the CO_2 reductions of the Installation as a whole. The CANSOLV DC-103 solvent and associated process configuration was selected to maximise energy efficiency (as discussed in Section 4.2.4.7). The main ways in which the Installation recovers heat is using waste heat from the CCGT to regenerate the solvent in the CO_2 stripper. This heat could otherwise be lost and therefore capturing it minimises the overall energy consumption associated with operating the PCC plant. As detailed in Section 4.9.1, the optimisation of heat recovery is complex and needs to balance with other factors including maximising the power generation from the GT generator, the potential use of the waste heat recovery to provide additional power generation using a ST (or other means) and the impact of the heat recovery on the start-up and shutdown times for the GT. The implementation of the MVR for heating the rich amine, in addition to a conventional ST for generating additional power from the turbine exhaust enables this balance to be achieved. As heat to regenerate the solvent is only available during periods that the CCGT is running, this heat is not available on start-up. Therefore, to maximise CO_2 capture on start-up, a Lean Solvent Tank has been integrated into the design to provide a supply of lean amine during start-up until a sustainable rate of amine regeneration can be achieved. This optimises capture during start-up whilst minimising the requirement for additional heat energy from an imported source. The key interfaces for energy efficiency within the PCC plant, are considered to be: • exhaust-gas pre-treatment including cooling, prior to the PCC plant, utilising the DCC; • use of steam supplied from the HRSG for solvent stripping (CO_2 stripper reboiler) and solvent recovery (thermal reclaimer); • implementation of an MVR scheme to reduce steam demand by the PCC plant; • steam condensate recovery from the PCC plant; • integration of cooling water between the CCGT and the PCC plant to allow for variations in cooling loads across the system; and

PCC GET Recommendation	Response
	• electricity supply to the PCC plant from the CCGT (parasitic load). General measures to maximise energy efficiency across the Installation plant include: • the plant components will be sized appropriately for the design capacity of the plant in abated mode, so that each element is operating optimally and efficiently; • use of high efficiency motors and variable speed drives to minimise parasitic load; • the effective insulation of hot surfaces; and • regular planned maintenance in order to maximise the efficiency of the equipment and plant, with performance monitoring and audits to optimise the maintenance schedule.
For natural gas power plants, lower heating value efficiencies of 60% or above without CO_2 capture are reported in the LCP BRef to be achievable for large-scale new combined cycle gas turbine installations.	The lower heating value efficiencies of the proposed CCGT are anticipated to be 61%. This is greater than the upper value of ≥60% stated in the PCC GET. When a CCGT is optimised to operate without CO_2 capture, the ST would be appropriately sized to maximise the electrical power generated from the available steam. If the plant were a new build CCGT without CO_2 capture, the lower heating value would be 63%. However, for the Installation (i.e. a new build CCGT operating with CO_2 capture) the ST has been sized to provide maximum efficiencies under CO_2 capture conditions, as the normal mode of operation. During CO_2 capture operation a portion of steam is diverted back to the PCC plant to provide heat for the process and as such, the ST is smaller than would be utilised for a new build CCGT without CO_2 capture. This has the knock-on effect that if the Installation were to be operated without CO_2 capture, the lower heating value efficiencies would be slightly negatively impacted.
2.2 Dispatchable Operation	
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 CO_2 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 Installation has been designed to be fully dispatchable.
2.3 Supplying Heat and Power for PCC Operation	
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	As detailed in the response to BAT 2.1 - The requirement to maximise thermal efficiency is integral to the CO_2 reductions of the Installation as a whole.

PCC GET Recommendation	Response
• 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 CO_2 capture) that are then also treated as a power plant system for performance calculations.	During stable operation heat and electricity to the PCC plant would be provided by the CCGT. To assist CO_2 capture on start-up the use of an electrical auxiliary boiler is proposed, which would require electricity from the grid. This would be taken into account in the power plant system for performance calculations.
The ratio between heat supplied as steam (or otherwise) and electricity output lost will depend on the: • temperature at which you need to supply heat • steam condenser cooling water temperature You should consider using a back-pressure turbine if it is not possible to supply enough steam to the PCC plant by extracting steam from a condensing turbine.	The PCC plant 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 reboiler and minimising parasitic load on ST. In addition, the MVR scheme will result in a reduction in total energy demand compared to a scheme without MVR.
3. PCC Plant Design and Operation	
3.1 Purpose	
The purpose of the PCC plant is to maximise the capture of CO_2 emissions for secure geological storage. You should aim to achieve a design CO_2 capture rate of at least 95%, although operationally this can vary, up or down.	The PCC plant will be designed to capture at least 95% CO_2 in the flue gas treated during stable operation.
You will need to deliver CO_2: • 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 onsite compression will remove oxygen and water from the CO_2 to meet the requirements of the T&S network. The quality of the CO_2 would be monitored online for compliance with NEP pipeline entry specification, to ensure the required specification is met and will include temperature, pressure, water content, oxygen content, hydrogen content, CO, hydrogen sulphide, SOx, NOx and amines. Fiscal flow metering would be provided for custody transfer of CO_2 sent to the T&S network.
The PCC plant must also have acceptable environmental risks through preventing or minimising emissions or render them harmless. You must achieve environmental quality standards for air emissions from the PCC plant and their subsequent atmospheric degradation products (including, for example, nitrosamines and nitramines). You should confirm this using: • atmospheric dispersion and reaction modelling tools	Dispersion modelling has been carried out to demonstrate that environmental quality standards for air emissions from the PCC plant and their subsequent atmospheric degradation products would not be exceeded as a result of the PCC plant operation. An updated Air Quality Impact Assessment has been provided in Appendix E of this Main Supporting Document.

PCC GET Recommendation	Response
• specific site parameters which will define plant-specific ELVs	
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 CO_2 capture requirements set out in this guidance.	The PCC plant has been designed to maximise energy efficiency to ensure that CO_2 reductions for the project as a whole are as high as possible. The design has optimised power demand through the selection of efficient equipment, implementation of energy recovery scheme (MVR), and selection of an energy efficient capture technology.
3.2 Solvent Selection	
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 PCC evidence 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. You have a choice between: • solvents using primary amines that may require more heat for regeneration but will not readily form stable nitrosamines in the PCC plant, especially if a high level of reclaiming is used to remove degradation products • solvent formulations including secondary amines or other species that may have lower regeneration heat requirements may readily form nitrosamines with NOx in the flue gases in the PCC plant - for controls, see section 3.3 on features to control and minimise atmospheric and other emissions The potential absorber stack emissions and resulting environmental impacts will depend on the selected solvent. You should assess your plant design and operation, plus local environmental factors, based on: • direct emissions of solvent components • formation of additional substances in the PCC system and emissions of those substances • formation of further additional substances in the atmosphere from emissions from the PCC system	The PCC plant has been designed with the specific solvent and degradation characteristics in mind. The solvent regeneration and reclamation process will minimise solvent degradation, in order to minimise emissions and potential environmental impacts, as demonstrated in the updated Air Quality Impact Assessment provided in Appendix E of this Main Supporting Document. The assessment has taken into account both the direct and indirect impacts of N-amines resulting from anticipated amine and N-amine releases of the CANSOLV DC-103 solvent. In addition, a BAT review of the solvent has been provided in Section 4.2.4.7.
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 demonstrate that you will: • 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 PCC plant will include a solvent filtration unit which will take a slip stream of the solvent from the absorber for continual cleaning. Most of the filtered solvent is routed to the lean solvent cooler for reuse in the CO_2 absorber, however a further slip stream of this will go to the thermal reclaimer, which will operate continuously.

PCC GET Recommendation	Response
	The aim of solvent filtration and reclaiming is to ensure that a high proportion of solvent can be reused in the process, without compromising either the CO_2 capture rate or the potential for emissions of degradation products to occur. Until operation commences it is not possible to confirm how much solvent can be reclaimed, although based on operating experience from plants utilising the same solvent, it is anticipated that > 99% of solvent will be reclaimed. In maximising solvent reuse on site, reclaimer wastes will be minimised as far as possible.
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. You do not need to do this for your plant if information on the solvent performance is already available from pilots, tests, or regular operation at a similar plant.	The solvent provider has accumulated several thousand of hours of testing on various flue gases and commercial scale operation of the CANSOLV D-103 solvent, including: 1. 5,000 hours of pilot scale testing at Fortum Oslo Varme AS (FOV) (in July 2018) to demonstrate that the CANSOLV DC-103 capture technology using solvent DC-103 is suitable for cleaning CO_2 from the exhaust gases of waste to energy (WtE) plant at Klemetsrud in Oslo, Norway – solvent reclaiming was not performed as part of this test 2. 10 years operational experience at Brothers Chemical, South Africa. Commercial scale plant at 60,000 tonnes per annum processing gas boiler flue gas which is analogous to VPI's flue gas in composition. Batch reclaiming of solvent is typically performed every second month. 3. Over 6 years operating experience at SaskPower's Boundary Dam coal power plant. 1MTPA commercial scale plant – batch reclaiming of solvent is performed. 4. Planned test campaign at TCM (Commencing Q1 2023). Target 5 months testing on CHP and refinery FCC flue gases. Further information on pilot plant testing of the CANSOLV DC-103 solvent is provided in Section 4.2.4.7.
3.3 Features to Control and Minimise Atmospheric and Other Emissions	
3.3.1 Flue Gas Cleaning	
Sulphur Oxides (SOx) Removal 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.	Due to the use of unodourised natural gas as a fuel, it is considered that the low SOx concentrations that may be present, would not require a desulphurisation unit. Caustic will be added to the DCC to ensure that SOx concentrations into the CO_2 absorber do not impact solvent performance or result in solvent degradation.

PCC GET Recommendation	Response
SOx removal can be in the power plant flue gas desulphurisation unit, flue gas treatment system or in the PCC direct contact cooler. SOx levels in the exit flue gases from an amine PCC plant will be at extremely low levels.	
NOx Removal 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 using selective catalytic reduction (SCR).	An SCR is being installed to reduce NOx concentrations in the flue gas from the CCGT plant to the PCC plant.
SCR can result in ammonia (NH_3) slip. If necessary, it is expected that (NH_3) slip from the SCR unit could be addressed in a suitably designed PCC unit. In all cases, you must assess the effects of NOx in the flue gas on atmospheric degradation reactions and this may also affect the need for SCR.	The dispersion modelling assessment included NH_3 slip and degradation products from the PCC plant.
If SCR is not fitted to a new build power plant, it is generally considered BAT to maintain space so it may be retrofitted in future, should this be considered necessary to meet ELVs.	Not applicable as SCR will be installed.
Aerosols Sulphur trioxide (SO_3) droplets and fine particulates should not be present in the flue gas. If they arise in the PCC process they can cause significant amine emissions. The level of emissions (mainly solvent amines) are not directly related to aerosol measurements. Monitoring aerosols is difficult and aerosol quantities may also vary significantly over time. Aerosols might be present, for example, because of significant SOx in the flue gas. Where this is the case, you should carry out long-term testing on a pilot plant or the actual plant, with all planned countermeasures in place, to show satisfactory operation. You should also carry out regular isokinetic sampling in the operational plant to assess total vapour and droplet emission levels.	SO_3 and fine particulates will not be present in significant quantities in the natural gas supply for the CCGT. A mist eliminator would be located after the water wash section at the top of the CO_2 absorber column to minimise aerosol release. In addition, an antifoam skid will be installed to mitigate foaming.
Other flue gas impurities You may need to remove materials in the flue gas that would accumulate as impurities in the solvent to lower concentrations than is required under the relevant BAT-AELs. 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).	Not applicable

PCC GET Recommendation	Response
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.	Flue gas impurities have been considered in the plant design and it has not been deemed necessary to provide further abatement other than that discussed in this Main Supporting Document.
3.3.2 PCC System Operation	
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 CO_2 capture levels. You must balance both to ensure the right environmental outcome. Where feasible, you should avoid locally higher metal skin temperatures, such as from the use of superheated steam in heaters, as this provides no benefit and can result in degradation.	The PCC plant design is such that it would operate at optimised conditions for the CANSOLV DC-103 solvent to be utilised.
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 O_2 removal from rich solvent may be developed in the future but has not yet been proven at scale.	The PCC plant design is such that it would operate at optimised conditions for the CANSOLV DC-103 solvent to be utilised.
3.3.3 Absorber Emissions Abatement	
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 NH_3 emissions, as concentrations will increase until the rate of release balances the rate of formation (and possibly addition from SCR slip).	There will be a single water wash section in place, which will enable solvent reuse. In addition, a mist eliminator will reduce aerosols present in the released flue gas.
Acid Wash An acid or other chemically active wash or scrubber after the water wash will react with amines, NH_3 and other basic species and reduce them to very low levels (for example, 0.5 to 5 mg per m^3 per species or lower). You should implement an acid wash as it is considered BAT, unless: • emission levels are already at acid wash levels with a water wash	An acid wash is not considered necessary to further reduce amine, ammonia or other pollutants from the process, based on the expected emission concentrations, as detailed in the justification provided in Section 4.2.4.3 and the proposed emission limits provided in Section 5.1. It is considered that the design uncertainties are limited for clean gas applications of the CANSOLV DC-103 carbon capture technology and therefore no further provision for future retrofit of additional wash stages is considered necessary.

PCC GET Recommendation	Response
• 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 NH_3 slip from an SCR system. If an acid wash is not fitted, you should consider a second water wash as an acid wash if: • emission performance is worse than expected • you wish to change to a more volatile solvent An acid wash is not likely to trap aerosols.	
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 SO_3 or other aerosol mists.	A mist eliminator would be located at the top of the water wash section to prevent the entrainment of droplets into the waste gases.
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).	Detailed dispersion modelling has shown that a stack height of 128m for the PCC plant would ensure that pollutants released would not result in exceedance of any air quality standards for the pollutants released. Flue gas reheating is included in the design to increase dispersion and reduce plume visibility.
3.4 Process and Emissions Monitoring	
3.4.1 Role of Monitoring	
You 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 • CO_2 capture rate • verification that the CO_2 product is suitable for safe transport and storage You will need to develop a monitoring plan for both a commissioning phase and routine operation.	The Installation will be required to monitor and report energy and resource efficiency figures to demonstrate these are being used efficiently. The PCC plant operation would also be monitored continuously to report the resource and energy efficiency of the plant.

PCC GET Recommendation	Response
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	
It is likely you will 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.	The existing Environmental Permit includes a Pre-operational Measure (PO2) to provide a Commissioning Plan at least 3 months prior to commissioning. The commissioning plan is to include monitoring requirements. CEMS for monitoring NOx, NH_3, CO_2 and CO will be in place. Provided appropriate CEMS can be identified for amines and N-amines monitoring, then these would also be in place. If not, extractive monitoring would be carried out.
You must demonstrate compliance with ELVs in the permit by monitoring emissions at authorised release points. You must also show that you are managing the process to prevent (or minimise) the formation of solvent degradation products.	Monitoring would be carried out in line with proposals in Section 6.1 of the Main Supporting Document.
Where monitoring shows that degradation products are being formed (and may be released), you must reduce these and any solvent emissions to the permitted level. This process control monitoring will also be part of the permit conditions.	Process control monitoring to ensure that degradation products do not build up in the PCC plant will involve a weekly sampling and testing schedule for degradation products, as advised by the solvent supplier based on their operational experience and detailed in Section 6.6.
3.4.2 Point Source Emissions to Air	
You must include monitoring to demonstrate compliance with the IED Chapter III ELVs and LCP BRef BAT-AELs at normalised conditions. You must also monitoring for: • Ammonia • Volatile components of the capture solvent • Likely degradation products such as nitrosamines and nitramines	CEMS for monitoring of combustion gases from the PCC plant would be installed to demonstrate compliance with LCP BRef BAT-AELs. It is intended that CEMs monitoring of these species would be included for the PCC plant, 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 would be monitored by periodic extractive monitoring.
Your monitoring may be either: • Continuous emissions monitoring (online) • Periodic extractive sampling (offline) – where aerosol formation is expected, this must be isokinetic Emission sampling points must also comply with M1 sampling requirements for stack emissions monitoring.	As described above. IC5 of the existing Environmental Permit requires the operator to submit a written report to the Environment Agency for assessment and written approval on the assessment of air emissions monitoring locations A1 and A2 during commissioning of the Installation, to confirm whether the air monitoring locations meet the requirements of BS EN 15259 and supporting Method Implementation Document (MID). This will be provided to the EA prior to commissioning.
3.4.3 Process Control Monitoring	

PCC GET Recommendation	Response
You should use process control monitoring or periodic sampling with offline analysis to control the CO_2 capture and the solvent reclaiming performance. Parameters you should consider monitoring include: • absorber solvent quality – percentage active solvent • CO_2 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 • Solvent usage	The PCC plant would include instrumentation to monitor and record CO_2 capture rates and purity, as detailed in Section 6.6. Sampling points would be provided to collect fluid samples of the solvent to ensure the quality of solvent reclaiming.
3.4.4 Monitoring of CO_2	
You should include: • CO_2 mass balance • CO_2 in fuel combusted • total capture level (as a percentage) • CO_2 released to the environment • CO_2 quality	These parameters would be monitored as part of the PCC plant operation as detailed in Section 6.7.
3.4.5 Monitoring Standards	
The person who carries out your monitoring must be competent and work to recognised standards such as the Environment Agency's MCERTS scheme. 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 UKAS to carry out analysis for your monitoring.	Any extractive monitoring carried out on the emissions from the PCC plant will be carried out by MCERTS accredited contractors. Where required and available, UKAS accredited labs will be used for analysis.
3.5 Unplanned Emissions to the Environment	

PCC GET Recommendation	Response
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. You must provide a hazard and mitigation assessment for the plant. This 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 Installation will have a maintenance programme and will include instrumentation to detect and monitor any leaks. Any leaks identified will be repaired by licenced contractors. A LDAR system would be put in place for the PCC plant. HAZOPs have been carried out as part of the detailed design process to consider all potential risks of accidental releases to environment, as detailed in this BAT guidance.
3.6 Capture Level, Including During Flexible Operation	
Capturing at least 95% of the CO_2 in the flue gas during normal operation is considered BAT. You can base this on average performance over an extended period (for example, a year). To achieve this, you should make sure the design capture level for flue gas passing through the absorber equates to at least 95% of the CO_2 in the total flue gas from the plant. Over the averaging period, your capture level may vary up or down.	The expectation is that the PCC plant will demonstrate at least 95% capture rates are achievable under normal operation.
You should set out any potential 'other than normal operating conditions' (OTNOC) for the CO_2 capture plant in your permit application. You should include a PCC OTNOC management plan in your management system to measure and minimise occurrence and impact of these periods. OTNOC includes periods of start-up and shutdown. Your PCC OTNOC management plan must compliment any OTNOC management plan for the facility it serves and consider internal and external causes of OTNOC. An example of OTNOC would be when the CO_2 transport and storage network is down.	Section 4.2.4.9 details the approach to OTNOC. In addition, the PO13 requires the provision of an OTNOC plan to the EA following final design and at least 6 months before commissioning. This will therefore be developed for the Installation.
As the fraction of intermittent renewable generation in the UK rises, many CCS enabled plants will need to start and stop more often, and possibly also operate at variable loads. It is therefore important, for current or future intermittent operation plant, that you aim to maximise CO_2 capture during these periods, including during start-up and shutdown, to maintain high average capture levels. You should therefore capture CO_2 during plant start-up and shutdown as part of using BAT. A method to maintain capture during start-up and shutdown using solvent storage has been identified in chapter 7 of the PCC Evidence Review. This, or alternatives that can achieve equivalent results, is considered BAT. You will need to provide justification and a cost benefit analysis if you are not proposing capture during start-up and shutdown. If your PCC plant is not initially constructed with this capability, your permit application should show how you may retrofit it.	As detailed in Section 4.2.4.8 NZT have prioritised dispatchable requirements for the Installation from the outset of the project, having completed pilot plant testing and extensive techno-economic analysis to inform the design. Optimising CO_2 capture rate during start-up, minimising CO_2 losses and keeping the parasitic loads as low as practical require careful CAPEX/OPEX trade-off to achieve the optimal design. Demonstration of optimised start-up time and capture rate is also a key item within the DPA which will be agreed on and tested as part of the contract (refer to "Annex 2, Testing Requirements" in the published DPA Terms and Conditions). It is envisaged that the PCC plant would remain on hot standby enabling it to initiate operations seamlessly after receiving the flue gas from the CCGT, with no delays in solvent regeneration caused by energy losses to the environment. To maximise CO_2 capture on start-up, a lean solvent tank has been integrated into the design to provide a supply of lean amine during start-up until a sustainable rate of amine regeneration can be achieved. This optimises capture during start-up whilst minimising the requirement for additional heat energy from an imported source.

PCC GET Recommendation	Response
	In addition, ensuring that the compressor dehydration beds are ready in dry condition and that the LP compressor is depressurised with dry CO_2 will minimise delays in start-up of the compression process.
Where the CO_2 is being captured for secure geological storage, the transport and storage system may not always be available. When it is not, it is not appropriate to capture CO_2. You will need to make sure the PCC plant is bypassed so that electricity generation can continue. You must not include these periods in any capture efficiency calculation, but you must keep a record of these, and CO_2 quantities emitted for reporting purposes. The CO_2 transport and storage system (including non-pipeline transfer) may sometimes need to be constrained – that is, it cannot take all the CO_2 you are producing. You should plan how you would meet this constraint as far as is practicable. You should detail both situations in your permit application. You must show how you will manage the plant to minimise emissions to the environment, including during start-up and shutdown.	In order to operate in the UK electricity market, the PCC plant will need to be capable of operating for extended periods according to the Grid's load requirements in either Abated or Unbated mode and at any load between the following load setpoints: When the T&S network is unavailable the CCGT will be able to operate in unabated mode with emissions to air existing via the HRSG stack (Emission Point A2). Emissions from the HRSG stack have been assessed in the Air Quality Impact Assessment (Appendix E). The PCC plant has also been designed to enable a Partial Abatement Mode, for times when the T&S entry capacity is curtailed. This mode will require the operation of the Installation with the PCC plant in service and capturing CO_2 from the CCGT flue gas, with a portion of the captured CO_2 being vented via the CO_2 absorber column.
3.7 Compression	
You should select CO_2 compressors based on the expected duty. You should consider how any waste heat arising may be used. For base load operation, you should use integrally geared units because they give the: • Maximum full-load efficiency • Minimum number of compression trains 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.	The CO_2 compressors are specified based on the expected duty. The potential for using waste compression heat is limited by the dispatchable nature of plant operation and assurance of system safety. Third and fourth stage LP compression heat would be utilised to raise the CO_2 above the oxygen removal reactor light off temperature ~150°C to allow the oxygen removal to work. It is also envisaged that any further waste heat would be low grade and therefore there is no viable use for it and a justification for this was provided with the original Environmental Permit application.
3.8 Noise and Odour	
Consider additional process steps in PCC technology that have high potential for noise and vibration. In particular, CO_2 compression could be an area of concern. Once you have 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: • 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	An updated Noise Impact Assessment will be carried out to fulfil the existing Environmental Permit's PO4. This will include an assessment of all potential sources of noise from the PCC plant, including the NEP DAA HP Compressor site.

PCC GET Recommendation	Response
• Change of the frequency of the sound	
The handling, storage and use of some amines may result in odour emissions, so you should always use best practice containment methods. Where there is increased risk that odour from activities will cause pollution beyond the site boundary, you will need to send an odour management plan with your permit application.	The CANSOLV DC-103 solvent has very low volatility and therefore is not considered to represent a particular odour risk.
4. Cooling	
You will be able to achieve the best power and CO_2 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 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.	A Cooling BAT assessment was carried out in support of the original Environmental Permit application which concluded that hybrid cooling towers represented BAT for the Installation, and no changes are proposed as a result of this variation. Use of direct cooling (heat rejection to wet cooling towers) has been maximised for the project. The use of dry cooling has only been implemented to ensure an inherently safe design - where use of a heat transfer fluid risks system boiling/ contamination/ freezing. All relevant guidance was considered in the preparation of the Cooling BAT Assessment carried out for the original Environmental Permit application.
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.	Not applicable.
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	It is considered that the maximum practicable recovery of heat from the flue gas is achieved to the steam cycle in the HRSG. As such, the flue gas temperature is only 70°C by the time it reaches the PCC plant, and this temperature is too low for providing efficient flue gas reheating. The heat lost to cooling water in the DCC is also minimised by this method. As such, flue gas reheat would be carried out using steam condensate from the PCC plant.
Lean and rich solvent storage may also help you achieve satisfactory PCC performance during periods of high cooling demand.	The PCC plant is design to have the capacity to deal all levels of cooling demand as per the design envelope.

PCC GET Recommendation	Response
	Lean and rich solvent storage are currently considered for reasons of enabling dispatchable operations of the PCC plant.
5. Discharge to Water	
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 DCC water generated on site would contain NH_3 from the SCR. The DCC wastewaters will be treated through a WwTP plant on site prior to reuse in the cooling towers and then discharge to Emission Point W1. An assessment of discharges to water has been carried out as part of this Environmental Permit variation application (Appendix F), which demonstrate that the discharge of process effluents will not result in an exceedance of any EQS within the receiving water. Thermal plume modelling was carried out for the DCO application and there are no changes proposed.

Appendix E - Air Quality Impact Assessment

See accompanying report.

Appendix F - Water Impact Assessment

See accompanying report.

Appendix G - Qualitative Risk Assessment

See accompanying report.

Appendix H - Company Information and Directors

Company name – Net Zero Teesside Power Limited

Registered office address – Chertsey Road, Sunbury on Thames, Middlesex, United Kingdom, TW16 7BP

Company number – 12473751

Incorporated on - 20/02/2020

Details of Company Secretaries

Secretary Name (Last name, First name)	Appointed on
N/A	

Details of Directors (Active only)

Director Name (Last name, First name)	Date of Birth	Appointed on
Cowan, Andrew	[redacted]	8 November 2024
Fosse, Inge	[redacted]	31 May2024
Holmgren, Tamara Nicola	[redacted]	29 May 2024
Tungland, Kjetil	[redacted]	31 May 2024