H2Teesside Project

Environmental Permit Application Reference: [EPR/AP3328SQ/A001]

Land at and in the vicinity of the former Redcar Steel Works site, Redcar and in Stockton-on-Tees, Teesside

Document Reference: [AP3328SQ-APP-SS] Environmental Permit Application Supporting Statement

Environmental Permitting (England and Wales) Regulations 2016

Applicants: H2 Teesside Ltd

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GLOSSARY

Abbreviation	**Description**
AGI	Above Ground Infrastructure
AMP	Accident Management Plan
AOX	Adsorbable Organically Bound Halogens
Applicant/Operator	H2 Teesside Ltd
AQAL	Air Quality Assessment Level
ASU	Air Separation Unit
ATR	Auto Thermal Reformer
BAC	Booster Air Compressor
BAT	Best Available Techniques
BATc	BAT Conclusions
BAT-AEL	BAT- Associated Emission Level
BFW	Boiler Feed Water
BGS	British Geological Society
BRef	BAT Reference
CCRO	Closed Circuit Reverse Osmosis
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Usage and Storage
CCRA	Climate Change Risk Assessment
CEM	Continuous Emissions Monitor
COD	Chemical Oxygen Demand
CO_2	Carbon dioxide
CO	Carbon Monoxide
COMAH	Control of Major Accident Hazards
Cr	Chromium
CSM	Conceptual Site Model
Cu	Copper

CW	Cooling Water
DAF	Dissolved Air Flotation
DCO	Development Consent order
DCS	Distributed Control System
DMW	Demineralised Water
EA	Environment Agency
EMS	Environmental Management System
EPC	Engineering Procure and Construction
EPR	Environmental Permitting Regulations
ERMP	Emergency Response Management Plan
ES	Environmental Statement
ETP	Effluent Treatment Plant
FEED	Front-End Engineering Design
FID	Final Investment Decision
GHG	Greenhouse Gas
GHR	Gas Heated Reformer
GWP	Global Warming Potential
GWth	Giga Watt Thermal
H_2	Hydrogen (gaseous)
HP	High Pressure
HRA	Habitats Regulations Assessment
IED	Industrial Emissions Directive
IP	Intermediate Pressure
ISO	International Standards Organisation
ITS	Isothermal Shift
JM	Johnson Matthey
LCH	Low Carbon Hydrogen
LCP	Large Combustion Plant
LDAR	Leak Detection and Repair
LHV	Lower Heating Value
LNR	Local Nature Reserve
LP	Low Pressure
LTS	Low Temperature Shift
MAC	Main Air Compressor
MCERTs	UK Monitoring Certification Scheme
MCPD	Medium Combustion Plant Directive
MLD	Minimalised Liquid Discharge
MP	Medium Pressure
MWth	Meg Watt Thermal
N_2	Nitrogen
NEP	Northern Endurance Partnership
NG	Natural Gas
NH_3	Ammonia
Ni	Nickel

NNR	National Nature Reserve
NSR	Noise Sensitive Receptor
NWL	Northumbrian Water Limited
NZT	Net Zero Teesside
O_2	Oxygen
O&M	Operations and Maintenance
OTNOC	Other Than Normal Operating Conditions
PEC	Predicted Environmental Concentration
PCSW	Potentially Contaminated Surface Water
ppb	Parts Per Billion
PPE	Personal Protective Equipment
SuDS	Sustainable Drainage Scheme
RBT	Redcar Bulk Terminal
RO	Reverse Osmosis
SAC	Special Area of Conservation
S:C	Steam : Carbon Ratio
SCR	Selective Catalytic Reduction
SMR	Steam Methane Reformer
SO_2	Sulphur Dioxide
SPA	Special Protection Area
SPZ	Source Protection Zone
SSSI	Site of Special Scientific Interest
STDC	South Tees Development Corporation
TAR	Turnaround
TN	Total Nitrogen
TOC	Total Organic Carbon
TSS	Total Suspended Solids
UF	Ultra Filtration
WwTW	Wastewater Treatment Works
Zn	Zinc

CONTENTS

TABLES

PLATES

1.0 NON-TECHNICAL SUMMARY

1.1.1 This document presents the supporting information for an Environmental Permit application for H2 Teesside, a 1.2-Gigawatt Thermal (GWth) Lower Heating Value (LHV) Carbon Capture and Storage (CCS) enabled Hydrogen Production Facility ('proposed Installation') on land in the Teesside industrial cluster area in Redcar, Stockton-on-Tees ('the Site').

1.1.2 The proposed Installation will have a design capacity of 1.2 GWth LHV, across two phases of development (600 Megawatt thermal (MWth) per phase). This equates to the capacity to produce up to 37.3 t/hr (phase 1 + 2) of hydrogen at peak production. The proposed Installation is designed to deliver a carbon capture rate of 95% in accordance with current BAT guidance and has the potential capacity to further increase the capture rate to meet potential future regulatory changes. The proposed Installation has the capacity to continuously export up to 2.54 megatonnes (Mt) of CO_2 per year once both phases are operational (100% utilisation). A number of service connection corridors for H_2 and CO_2 export, natural gas and compressed oxygen (O_2) and nitrogen (N_2) import, electrical supply and water supply are integral to the operation function and intended purpose of the proposed installation as a whole, but will sit outside the proposed Installation boundary. The Site location is shown on Figure 1 in Appendix A.

1.1.3 This application is made in connection with the application for a Development Consent Order (DCO) that has been submitted to the planning inspectorate. The Environmental Statement for the DCO (Ref: EN070009) application is provided in Appendix M.

1.1.4 The captured CO_2 will be transported via the Northern Endurance Partnership (NEP) pipeline infrastructure for secure storage within the Endurance saline aquifer, located approximately 145 km offshore from Teesside, under the North Sea. This project can therefore make a significant contribution toward the UK reaching its net zero greenhouse gas (GHG) emission target by 2050.

1.1.5 The NEP onshore CO_2 compression and export infrastructure, as well as offshore CO_2 transportation and geological storage, are subject to separate consents and are outside of the proposed Installation boundary.

1.1.6 The proposed Installation will be operated by the Applicant - H2 Teesside Ltd ('the Operator'), a bp company. Once commissioned and operational, the proposed Installation will be designed to operate twenty-four hours a day, seven days per week until decommissioning, with brief exceptions for planned outages such as for maintenance and repair.

1.1.7 The proposed Installation will be located on the previous Redcar Steelworks site on the south bank of the River Tees (0.9 km west), approximately 1.3 km west of Warrenby, and 680 m to the south of the North Sea shoreline. The area of the former steelworks site where the proposed Installation will be constructed will be cleared of redundant plant, levelled and appropriately remediated prior to construction. The Site Condition Report, taking account of the proposed remedial works, is provided in Appendix B.

1.1.8 The Teesmouth and Cleveland Coast Site of Special Scientific Interest (SSSI) is immediately adjacent to the proposed Installation northern boundary. A further three European designated sites are within 15 km of the Site.

1.1.9 The development of the hydrogen production plant from concept to full commercial scale must proceed alongside the emerging Best Available Technique (BAT) regulatory positions. An initial assessment has been conducted against available BAT standards, but further assessment will be conducted against emerging BAT as the Front-End Engineering Design (FEED) process develops.

1.1.10 At this stage of project development, while the technology provider for the hydrogen production with CCS processes has been selected, the Installation is currently in FEED and therefore an approach to the derivation of BAT has been applied which is driven by:

- The technology licensors requiring commercial confidentiality of some of their process aspects to be maintained;
- To allow the FEED process to progress without limiting options for later technology selections; and
- To determine indicative BAT and BAT Associated Emission Levels (BAT-AELs) for the plant which are consentable, taking into consideration the environmental sensitivities and conditions at the site.

1.1.11 The proposed Installation will utilise Johnson Matthey's (JM's) Low Carbon Hydrogen (LCH) blue hydrogen technology which is a combination Gas Heated Reformer (GHR) – Autothermal Reformer (ATR) process. The LCH technology surpasses the efficiency of the conventional ATR process thereby requiring comparatively lower natural gas feed to achieve the design hydrogen export capacity. This process receives natural gas feedstock and reforms it with steam and oxygen (O_2) to produce hydrogen gas product (H_2), evolving carbon dioxide gas (CO_2) in the process. This CO_2 is absorbed in an amine-based solvent, then is stripped from the solvent and sent off-site for geological storage.

1.1.12 The term 'blue hydrogen production' is used throughout this document to refer to hydrogen production with carbon capture.

1.1.13 The design and operation of the proposed Installation is intended to meet the indicative requirements of BAT as defined for blue hydrogen production, large combustion plant (LCP), cooling, emissions management and energy efficiency as summarised in this document and described in full in Appendices C1 to C5.

1.1.14 During normal operation, the Auxiliary Steam Boiler stacks would be the primary source of atmospheric emissions from the proposed Installation. Emissions from the proposed Installation include NO_x, carbon monoxide (CO), particulate matter and sulphur dioxide (SO_2). There will be no emissions to air of amines and amine degradation products during normal operation, as the carbon dioxide capture process is a closed loop system. Emissions will be monitored and minimised in accordance with BAT through use of selective catalytic reduction (SCR) for the auxiliary steam boilers during normal operations when H_2-rich tail gas is used as fuel . Emissions for the auxiliary boilers will meet the emission limits for LCP under the Industrial Emissions Directive.

1.1.15 In relation to the fired start-up heaters on each phase the net rated thermal input means they are classed as medium combustion plant (MCP). However, as they only operate during start-up, the overall annual runtime of each will be <500 hours and as such no emission limit values will be applied. Additionally each phase will be supported by a separate diesel emergency back-up generator and a separate firewater pump and these also qualify as MCP which will operate for <500 hours per year.

1.1.16 The stack height and emission levels required to minimise impacts on air quality receptors to 'insignificant' have been determined through an air quality impact assessment, undertaken in accordance with EA guidance. The assessment includes dispersion modelling of maximum emission parameters, prediction of maximum process contributions, and existing air quality baseline conditions to determine the worst-case predicted environmental concentrations. These have been compared with air quality standards and the impact assessment is presented in Appendix F.

1.1.17 The FEED stage will refine the proposed energy efficiency measures, which are likely to include optimised heat and water recovery measures and integration, as far as practicable, of electrical, steam, steam condensate and water circuits throughout the plant. The proposed measures for efficient use and recovery of energy within the Installation are described in this document, and in Appendix C4.

1.1.18 Cooling for the proposed installation is expected to be achieved through use of wet cooling towers, with make-up raw (non-saline) water to the towers (and to other minor uses) obtained via the Northumbria Water Limited (NWL) raw water supply either through the existing South Tees Development Corporation (STDC) supply or via a new connection to the existing supply. The use of wet cooling for the proposed Installation has been determined as BAT for this site through an assessment process which considered a number of options. The full cooling BAT assessment is presented in Appendix C3 and is summarised in this document.

1.1.19 Continuous wastewater streams from the proposed installation will include process condensate from the reforming process, cooling tower blowdown, and demineralisation plant rejects (water treatment). Process condensate will be treated in the Bio-treatment Plant comprising a Membrane Bioreactor (MBR) while the other wastewater streams will be treated in the Effluent Treatment Plant (ETP). Both treatment plants will be located on site. The treated water from the biological treatment plant will be recycled back to the raw water treatment plant. The treated water from the Effluent treatment plant will be discharged via the NZT outfall to Tees bay. Disposal of degraded amine will be via tanker and sent off site for disposal at a suitably permitted waste facility.

1.1.20 In addition to the ETP and Bio-treatment plant (MBR), other supporting infrastructure and plant to the proposed installation will include either an Air Separation Unit (ASU) in phase 2 or third party oxygen supply (O_2) in phase 1, the auxiliary steam boilers, water supply infrastructure, chemical storage, cooling infrastructure, flares, instrument air, fire water system, and infrastructure for natural gas import and conditioning and CO_2 conditioning and export.

1.1.21 Other than wastewater, wastes from the proposed Installation are expected to be minimal, and will be appropriately disposed of via a licensed third party.

1.1.22 The site will be operated under an ISO14001 attested Environmental Management System (EMS) including operating procedures to manage the various aspects of the operation of the plant, including but not limited to emissions monitoring, accident management, waste minimisation and management, and infrastructure maintenance.

2.0 INTRODUCTION TO THE PROPOSED INSTALLATION

2.1 Project Summary

Background

2.1.1 This document has been prepared by AECOM Ltd ('AECOM') on behalf of H2 Teesside Limited ('the Applicant), a company with bp and ADNOC as shareholders, in support of an Environmental Permit application for the proposed H2 Teesside 1.2-Gigawatt Thermal (GWth) Lower Heating Value (LHV) Carbon Capture and Storage (CCS) enabled Hydrogen Production Facility ('proposed Installation') on land in the Teesside industrial cluster area in Redcar, Stockton-on-Tees ('the Site'). The Site location is shown on Figure 1 in Appendix A.

2.1.2 The application is made under the Environmental Permitting (England and Wales) Regulations 2016 (as amended) ('the EP Regulations'). The Operator has made an application for a DCO (Ref: EN070009), for the project to the Secretary of State for the Department of Energy Security and Net Zero (DESNZ) under section 37 of the Planning Act 2008, and this application for an Environmental Permit is submitted in parallel to the DCO application and will be twin tracked

2.1.3 The Environment Agency (EA) is a statutory consultee to the DCO application and must provide assurance to the Planning Inspectorate that the proposed Installation would be granted an Environmental Permit to operate, in order that the Examining Authority gain confidence that there is no impediment to the granting of Development Consent. It is therefore recognised that the permit application is being made before detailed design of the proposed Installation has been completed; a variation to the permit or response to pre-operational and improvement conditions is therefore likely to be required closer to the commissioning date to reflect design changes that may have occurred.

2.1.4 The proposed Installation will have a design capacity of 1.2 GWth LHV, across two phases of development (up to 600 Megawatt thermal (MWth) per phase). This equates to the capacity to produce 37.5 t/hr of hydrogen at peak production. The proposed Installation will be supported by electricity and water connections along with pipelines to export the hydrogen (H_2) gas and carbon dioxide (CO_2). The proposed Installation is designed to deliver a carbon capture rate of 95% in accordance with current BAT guidance and has the potential capacity to further increase the capture rate to meet potential future regulatory changes. The proposed Installation will have the capacity to continuously export 2.54 megatonnes (Mt) of CO_2 per year once both phases are operational (100% utilisation).

2.1.5 The captured CO_2 will be transported via the Northern Endurance Partnership (NEP) pipeline infrastructure for secure storage within the Endurance saline aquifer, located approximately 145 km offshore from Teesside, under the

North Sea. This project can therefore make a significant contribution toward the UK reaching its net zero greenhouse gas (GHG) emission target by 2050.

2.1.6 The proposed Installation will be designed to optimise H_2 production and CO_2 capture, while minimising emissions and waste generation and maximising energy efficiency. While individual BAT assessments have been prepared to address BAT for Hydrogen Production with Carbon Capture, LCP, Cooling, and Energy Efficiency, the system will be integrated to address multimedia effects across the Installation as a whole.

2.1.7 The term 'blue hydrogen production' is used throughout this document to refer to hydrogen production with carbon capture.

The Operator

2.1.8 The proposed Installation will be operated by the Applicant, i.e. H2 Teesside Ltd ('the Operator'), a company with bp and ADNOC as shareholders.

2.1.9 The Operator will be responsible for the proposed Installation so far as it relates to the construction and operation and decommissioning of the proposed Installation. These are the activities that will be regulated (by the EA) through an Environmental Permit.

2.1.10 Geological CO_2 storage and offshore CO_2 transportation will be managed and operated by NEP and is subject to separate consents.

The Proposed Installation

2.1.11 The proposed Installation comprises the development of a 1.2 GWth (LHV) CCS-enabled Hydrogen Production Facility. CCS-enabled hydrogen production is referred to as 'blue hydrogen' production. The proposed Installation is to be sited on land in the Teesside industrial cluster area in Redcar and Stockton-on-Tees. A high-level process flow diagram for the proposed installation is shown in Plate 2.1.

2.1.12 The proposed Installation will utilise Johnson Matthey's (JM's) Low Carbon Hydrogen (LCH) blue hydrogen technology which is a combination Gas Heated Reformer (GHR) – Autothermal Reformer (ATR) process. The LCH technology surpasses the efficiency of the conventional ATR technology thereby requiring comparatively lower natural gas feed to achieve the design hydrogen export capacity.

2.1.13 The application for the environmental permit is therefore for a hydrogen production facility comprising:

- A new Above Ground Installation (AGI) on the Site to receive natural gas, which is common for both Phase 1 and Phase 2;
- A new AGI on the Site at the point of export of CO_2 which is common for both Phase 1 and Phase 2;

- A Hydrogen Production Unit in each phase, where the main process of reforming occurs. Reforming is the reaction of hydrocarbons with water (steam) to produce hydrogen. Each Hydrogen Production Unit also includes the following components:
  - Pre-treatment to remove sulphur species;
  - Saturator to raise steam;
  - GHR-ATR to reform methane (CH_4) and larger hydrocarbons to syngas;
  - Shift reactors for water-gas-shift reaction to convert carbon monoxide (CO) in syngas to CO_2 and H_2, and heat recovery and recycle of separated condensate back to the saturator to raise steam;
  - CO_2 absorber to separate the CO_2 from the syngas mixture to achieve the carbon capture rate (the proposed Installation is designed to deliver a carbon capture rate of 95% in accordance with current BAT guidance and has the potential capacity to further increase the capture rate to meet potential future regulatory changes);
  - Compressors to increase the pressure of the CO_2 prior to drying (dehydration);
  - A Pressure Swing Adsorber (PSA) where raw H_2 is further purified and dehydrated and prepared for export to the pipeline networks, after passing through a compressor to achieve a minimum required pipeline pressure of 40 barg and cooled to 32°C for export; and
  - Tail gas compressor unit.
- Ancillary infrastructure, including:
  - **Air Separation Unit (ASU)** for the compression and separation of air for Phase 2, which is passed through a rectification column to produce O_2 and N_2 for use in the GHR – ATR combination process. It also includes provision of liquid N_2 storage on site for back up. As an alternative for Phase 1, an option to utilise O_2 and N_2 from a nearby supplier, which would remove the requirement for an onsite ASU has been selected.
  - **Cooling Water Circulation System** including cooling water towers, pumps and circuit piping to supply cooling water where it is needed throughout the proposed Installation. This will require topping up with water due to losses from evaporation, drift and blowdown.
  - **Auxiliary Steam Boiler** to raise steam using an H_2 rich fuel fitted with SCR and in continuous operation.

- **Raw Water Pre-treatment Plant** will be used to treat water from the NWL raw water supply, treated water from the biological treatment plant, steam blowdown and recycled clean stormwater prior to the demineralisation stage and will include coagulation and flocculation, clarification, Dissolved Air Flotation (DAF), Ultrafiltration (UF) (for removal of fine solids), or other suitable pre-treatment technologies. Any solids will be sent off site for disposal.

- **A Demineralisation plant** to be used to treat water supplied to the Hydrogen Production Facility and steam condensate from MP blowdown drum. This process comprises two stages of reverse osmosis (RO) for removal of ions and an electro-deionisation stage which would produce demineralised water (DMW) which will be pumped to all locations where it is required within the Hydrogen Production Facility, including for boiler feed water; therefore, this water will be used to produce H_2 and make up losses from the steam system. The liquid RO concentrate will be taken off site for further treatment and disposal.

- **A Biological-treatment plant** comprising a membrane reactor (MBR) which will treat process condensate and flare knockout drum liquid to reduce methanol and ammonia concentration using nitrification and denitrification. The treated process condensate will then be reused as makeup water in a Raw Water Treatment Plant. Sludge produced will be dewatered and solids will be sent off site for disposal.

- **A Stormwater system** which will consist of an oily water separator, neutralisation sump (for flows from the chemical drains), storm water attenuation pond and daily retention sump. All oily water produced by the proposed Installation will be sent to the oily water separator. Clean water will be recycled back to raw water treatment plant, with excess discharged to Tees Bay via NZT outfall.

- **An Effluent Treatment Plant (ETP)** which will treat demineralisation plant rejects and cooling water blowdown. This effluent will be treated using media filtration to an appropriate level in accordance with BAT-AELs and be disposed of via the NZT outfall that is to be built as part of Net Zero Teesside. . Sludge formed will be dewatered and solids will be sent for disposal offsite.

- **Flares**, any flammable gas released from the proposed Installation during an emergency will be collected in the flare header system and sent to the flare drum where any liquid associated with the gas is separated. The gas from the flare drum will be sent to the flare system where it will be safely disposed by combustion. The liquid collected in the drum will be pumped by the flare pump to the bio-treatment plant.

- **A Fire Water System** consisting of fire water store on site (supplied by treated raw water), pumps and firefighting system.
- **Emergency Diesel Generator** for each phase which would be operated in the event of emergency to support safe shutdown of the plant and will be intermittently energized for periodic testing purpose. This will require on-site diesel storage. Storage quantities will be confirmed post-FEED when the final design for the proposed installation is known.
- **Chemical Storage** for additives, solvents and fuel such as aqueous ammonia (NH_3), amines, anti-foaming agent for the carbon capture unit, chemical dosing for water treatment and diesel, which are imported by tanker.
- **Above ground pressurised H_2 storage** shared between each phase, including high pressure compression and let down facilities.

2.1.14 The electrical, steam, steam condensate and water circuits will be integrated as far as is technically practicable in order to reduce energy use.

2.1.15 The proposed Installation boundary (green line) is shown on Figure 1 in Appendix A and typical flow diagram for the process is shown in Plate 2-1 on the following page.

<u>Outside the Proposed Installation Boundary</u>

2.1.16 A number of service connection corridors for H_2 and CO_2 export, natural gas and compressed oxygen (O_2) and nitrogen (N_2) import, electrical supply and water supply are integral to the operation function and intended purpose of the proposed Installation as a whole, but sit outside the proposed Installation boundary.

2.1.17 The overall proposed development Site, as per the DCO application, encompasses an area of approximately 1,746 hectares (ha) including all the connection corridors. The proposed Installation boundary, as per the Environmental Permit application, covers an area of approximately 91 ha and only encompasses the listed prescribed activities and its Directly Associated Activities (DAA).

2.1.18 The NEP onshore CO_2 compression and export infrastructure, as well as offshore CO_2 transportation and geological storage, are subject to separate consents and are outside of the proposed installation boundary.

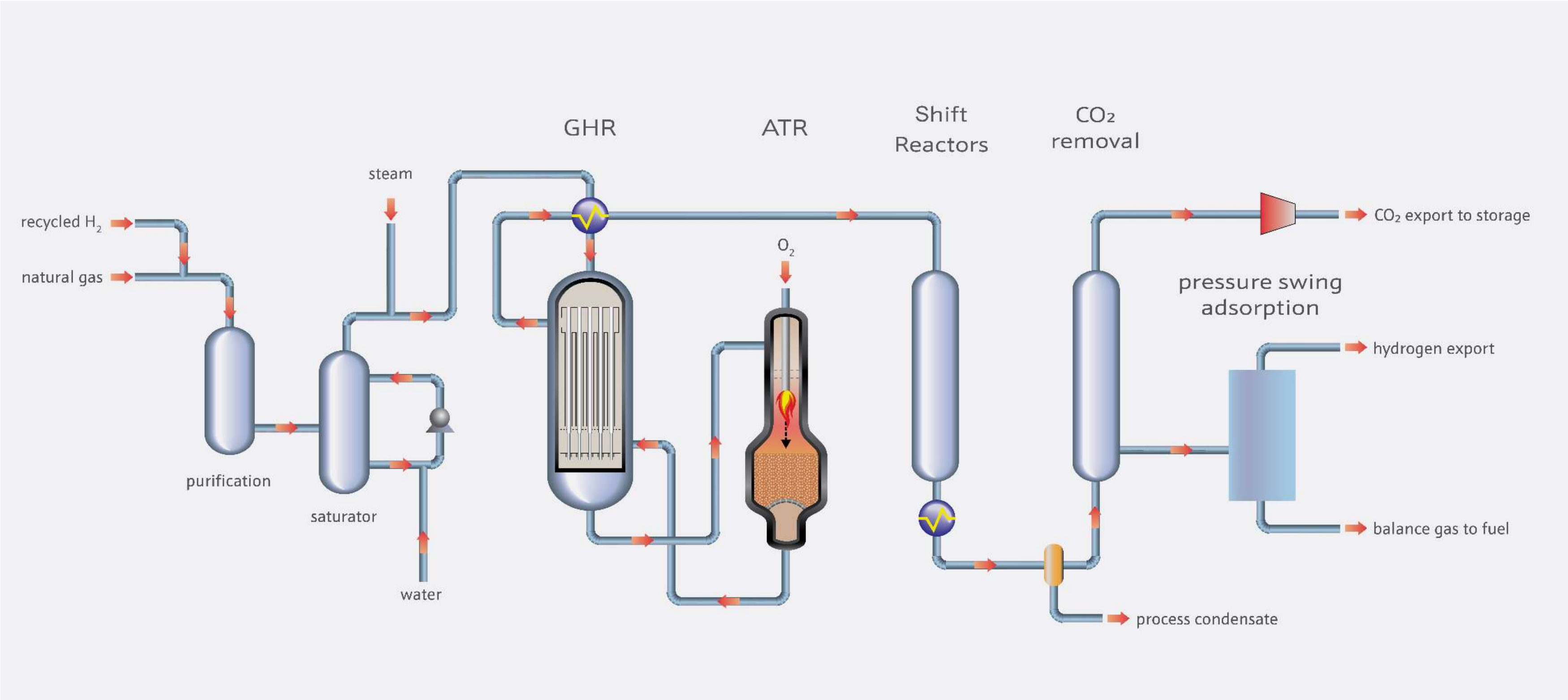


Plate 2.1: Simplified Flow Diagram for the Installation

The GHR pre-heats and reforms purified natural gas before it enters the ATR reactor. In the GHR's initial stage, 30% of total hydrocarbons react with steam, producing synthesis gas (a mixture of carbon monoxide (CO) and hydrogen (H2)). In the subsequent ATR stage, oxygen is introduced to combust some partially reformed gas, elevating the process gas temperature to approximately 1,000°C. The resulting gas then undergoes further reforming within the same reactor using a steam reforming catalyst. Operating at high temperature and steam flows is crucial for minimising methane content and, consequently, reducing overall carbon dioxide emissions. The hot gas exiting the ATR circulates back to the GHR, supplying the heat needed for the reforming reaction in the GHR tube side.

2.2 Permitting Strategy for the Proposed Installation

2.2.1 The development of the hydrogen production plant from concept to full commercial scale must proceed alongside the emerging BAT regulatory positions for hydrogen production. An initial assessment has been conducted against available BAT standards, but further assessment will be conducted against emerging BAT as the Front-End Engineering Design (FEED) process develops.

2.2.2 At this stage of project development, while the technology provider for the hydrogen production with CCS processes has been selected, the Installation is currently undergoing FEED and therefore an approach to the derivation of BAT has been applied which is driven by:

- The technology licensors requiring commercial confidentiality of some of their process aspects to be maintained;
- To allow the FEED process to progress without limiting options for later technology selections;
- To determine indicative BAT and BAT Associated Emission Levels (BAT-AELs) for the plant which are consentable, taking into consideration the environmental sensitivities and conditions at the site.

2.2.3 The techniques described in this report and the associated BAT assessments are therefore based on the currently anticipated approaches to optimising both hydrogen production and carbon capture efficiencies.

2.2.4 The approach to BAT has been agreed with the Environment Agency (EA) during the pre-application discussions.

2.3 Listed Activities

2.3.1 This application is made for the following activities listed under Schedule 1 of the EP Regulations, and a number of directly associated activities (DAA) associated with the proposed Installation, which are also included in Table 2.1 on the following page.

Table 2.1: Schedule 1 Listed Activities

Activity Ref	SCHEDULE 1 – PART 2 REFERENCE	DESCRIPTION OF ACTIVITY	LIMITS OF SPECIFIED ACTIVITY	DETAILS OF THE ACTIVITY
A1	Section 4.2, Part A (1)(a)(i): Production of Inorganic Chemicals (Hydrogen) – Phase 1	Operation of a blue hydrogen production facility by means of JM LCH technology (GHR-ATR combination process). Design capacity of 1.2 GWth LHV, across two phases of development (600 Megawatt thermal (MWth) per phase). This equates to the capacity to produce 37.3 t/hr (phase 1 + 2) of hydrogen at peak production, once both phases are operational.	From receipt of natural gas to the discharge of hydrogen product.	Blue hydrogen production process involving the conversion of natural gas feedstock into hydrogen product, using the JM LCH technology (GHR-ATR combination).
A2	Section 4.2, Part A (1)(a)(i): Production of Inorganic Chemicals (Hydrogen) – Phase 2			
A3	Section 6.10 Part A(1): Carbon Capture and Storage	Operation of a blue hydrogen production facility by means of JM LCH technology (GHR-ATR combination process). Carbon capture rate of 95% in accordance with current BAT guidance and has the potential capacity to further increase the capture rate to meet potential future regulatory changes. Capacity to continuously export 2.54 megatonnes (Mt) of CO_2 per year once both phases are operational (100% utilisation).	From receipt of CO_2 process emissions in the CO_2 removal unit to the treatment of CO_2 prior to export from the Installation.	The absorption of CO_2 generated in the hydrogen production process using an amine-based solvent, followed by compression and dehydration of the treated CO_2 for off-site transportation and long-term storage.
A4	Section 1.1 Part A(1)(a): Burning of any fuel in an appliance with a rated thermal input of 50MW or more.	Operation of : • auxiliary steam boilers for each phase. With a capacity of up to 71.87 MW per boiler. • fired startup heaters for each phase with a combined capacity of 36.6MW.	From receipt of fuel gas (natural gas during startup and process tail gas and H_2 rich gas during normal operations) to discharge of exhaust gases.	Auxiliary steam boilers to satisfy the steam demand of the hydrogen production facility. Continuously fired during normal operations by process tail gas and fired by natural gas during startup.

Activity Ref	SCHEDULE 1 – PART 2 REFERENCE	DESCRIPTION OF ACTIVITY	LIMITS OF SPECIFIED ACTIVITY	DETAILS OF THE ACTIVITY
		• Emergency back-up generators for black start with an 8.86 MW input capacity per generator, and diesel driven fire water pumps with a 1.3 MW input capacity per pump.		Fired startup heaters using natural gas to facilitate plant start-up periods only. Boilers are SCR-enabled to abate emissions of oxides of nitrogen (NO_x) to the atmosphere during normal operation.
A5	Section 5.4, Part A (1)(a) (ii) Disposal of non-hazardous waste with a capacity exceeding 50 tonnes per day involving physico-chemical treatment.	Effluent Treatment	From receipt of wastewater to point of discharge to NZT outfall	Onsite treatment of wastewater through effluent treatment plant and offsite discharge to the Tees Bay.
A6	Section 5.4, Part A (1)(a) (i) Recovery of non-hazardous waste with a capacity exceeding 50 tonnes per day involving biological treatment.	Biological Treatment via membrane bioreactor	From receipt of condensate and other effluents through denitification and anionic nitrification stages to recycle treated water back to the raw water treatment plant.	Onsite biological treatment of process condensate and other process wastewaters.
A7	Section 5.4, Part A (1)(a) (ii) Disposal of non-hazardous waste with a capacity exceeding 50 tonnes per day involving physico-chemical treatment.	Oily Water Treatment	From receipt of stormwater or potentially contaminated surface water to point of discharge to NZT outfall.	Onsite treatment of stormwater or potentially contaminated surface water.
Directly Associated Activities				
A8	Directly associated activity	Raw Water Treatment Plant	From receipt of the incoming water supply through the primary/secondary treatment processes to production of water for use in the hydrogen production facility	Treats supplied water for use in the hydrogen production process.

Activity Ref	SCHEDULE 1 – PART 2 REFERENCE	DESCRIPTION OF ACTIVITY	LIMITS OF SPECIFIED ACTIVITY	DETAILS OF THE ACTIVITY
A9	Directly associated activity	Dewatering of raw water sludge.	From receipt sludge from clarifier to disposal of solids.	Dewatering of clarifier sludge (0.04 m^3/hr) and disposal of the resulting sludge.
A10	Directly associated activity	Demineralisation Plant	From receipt of the treated raw water supply through the reverse osmosis and electro-deionisation processes to produce DMW for use in the hydrogen production facility	Treats supplied water for use in the hydrogen production process.
A11	Directly associated activity	Dewatering of sludges from the MBR or backwashes from the ETP processes.	From receipt of bio-sludges from the membrane bioreactor and backwash from the effluent treatment plant.	Dewatering of biosludges and backwash by dewatering (<0.002 m^3/hr) and subsequent disposal of the resulting sludge.
A12	Directly associated activity	Production of or import of oxygen and nitrogen	Production of oxygen / nitrogen (ASU) and storage onsite prior to use in process or import and storage onsite prior to use	ASU and storage or pipeline for import of oxygen and nitrogen for use in the hydrogen production process.
A13	Directly associated activity	Raw materials handling and storage	From receipt of raw materials to their point of use.	Storage, handling, distribution, and use of raw materials including water, liquid (water treatment chemicals) and gaseous (N_2) materials
A14	Directly associated activity	Process Cooling Plant	From receipt of cooling water to discharge of cooling water blowdown to effluent treatment plant.	Operation of process cooling plant.
A15	Directly associated activity	Surface Water Drainage	From receipt of surface water to point of discharge.	Operation of systems for the collection, reuse, and discharge of uncontaminated surface water.
A16	Directly associated activity	Product storage	From point of hydrogen production to its export	Storage, handling, and export of hydrogen.

Activity Ref	SCHEDULE 1 – PART 2 REFERENCE	DESCRIPTION OF ACTIVITY	LIMITS OF SPECIFIED ACTIVITY	DETAILS OF THE ACTIVITY
A17	Directly associated activity	Process Water Closed Drainage System	Closed drain systems: a) From separate collection of amine drain drum to either reuse or disposal via tankers. b) From separate collection of process condensate from syngas plant to a closed drain drum to the biological treatment plant and reuse in raw water treatment.	Operation of separate closed drainage system for collection and handling of amine containing process waters and separate closed drainage system of process condensate for treatment and reuse in raw water treatment plant.
A18	Directly associated activity	Emergency flare	From receipt of waste gas into the flare to the release of combustion gases	Operation of a flare for the safe disposal of flammable off-gases in startup, shutdown, process upset and emergencies
A19	Directly associated activity	Gas compression	Compression of hydrogen and carbon dioxide gases prior to export.	Operation of the gas compression systems.

3.0 ENVIRONMENTAL SETTING AND SITE CONDITION REPORT SUMMARY

3.1 Site Setting

3.1.1 The proposed Installation will be located within approximately 91 ha of land (known as the 'The Foundry' site) previously within the Redcar steelworks site. The land was used for iron and steel manufacture, together with associated ancillary development. The former steelworks shut in October 2015 and much of the existing infrastructure including industrial buildings, conveyors, tanks, and overhead pipes have been either demolished or are in the process of being dismantled by the landowner as part of the decommissioning of Redcar Steelworks, to prepare the site for future. A combination of hardstanding, road networks and railway tracks remain, surrounded by informal vegetation (primarily grass, with occasional shrubs and small trees). Prior to construction of the proposed Installation, the relevant areas of the Site within the Installation boundary will be levelled and remediated.

3.1.2 Appendix A (Drawings and Plans) shows the proposed Installation boundary, within the immediate setting:

- The operational Redcar Bulk Terminal (RBT) is located immediately adjacent to the west of the site, on the south bank of the River Tees;
- To the south lies the NWL Bran Sands sewage treatment plant, operational land of PD Ports Teesport and the Wilton International industrial complex;
- West of the Site, on the North bank of the River Tees, similar industrial complexes are present (at Seal Sands);
- The town of Dormanstown is located approximately 1.3 km southeast of the Site, whilst Redcar is situated approximately 2.6 km to the east of the Site;
- The Site is located approximately 680 m south of the North Sea shoreline.

3.1.3 There are no residential receptors within 500 m of the site. The closest residential properties (individual receptors) to the site are those at Marsh House Farm, in Warrenby approximately 1.3 km to the east.

3.1.4 The Cleveland Golf Links course is situated approximately 1.2 km east of the site. Tingdene Beach Caravan Park is situated approximately 1.8 km east of the site.

3.1.5 A number of nationally designated ecological sites are situated within close proximity to the Site; including the Teesmouth and Cleveland Coast Site of Special Scientific Interest (SSSI)/ Special Protection Area (SPA)/ Ramsar site located immediately north of the Site.

3.1.6 A further three European designated sites are located within 15 km of the Site:

- Northumbria Coast SPA/ Ramsar site (approximately 13.5 km northwest);
- Durham Coast Special Area of Conservation (SAC) (approximately 13.5 km northwest); and

- North York Moors SAC/ SPA/ National Park (approximately 12.2 km southeast)

3.1.7 There is one Local Nature Reserve (LNR) within 5 km of the Installation, that being Seaton Dunes and Common LNR, located approximately 3.1 km north-west.

3.1.8 The River Tees flows approximately 0.9 km to the west of the Site and is tidal at that point, with the normal tidal limit approximately 14 km upstream (at the Tees Barrage).

3.1.9 There are also a number of surface water features in the vicinity of the Site, including the Dabholm Gut which flows into the River Tees approximately 0.7 km south of the Site. The Dabholm Gut is tidal and accepts water from other 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).

3.2 Site Condition Report

3.2.1 The Site Condition Report for the proposed Installation, including a Conceptual Site Model (CSM) and a baseline for the Site, is presented in Appendix B.

3.2.2 The area is predominantly industrial in nature, as described above. It is understood that prior to the construction of the iron and steel making facilities in the 1970s, the Site principally consisted of reclaimed marshland with some ancillary industrial development.

3.2.3 The environmental sensitivity of the Site is considered to be as follows:

- Groundwater – Moderate/High sensitivity – The underlying Merica Mudstone and Penarth Group bedrock strata are classified as Secondary B aquifers, and the Redcar Mudstone deposit is classified as a Secondary Undifferentiated aquifer. The superficial deposits consist of Secondary A, Secondary Undifferentiated, and Unproductive strata. The sensitivity of the secondary superficial deposits is classified as moderate to high.
- Surface water – Moderate sensitivity – River Tees, located circa 840 m to the west of the Site, the North Sea is situated approximately 680 m to the north, and there are a number of drains feeding into the tidal Dabholm Gut which flows to the River Tees approximately 0.7 km south of the proposed installation site.
- Land use – Low sensitivity – the Site is surrounded by industrial and agricultural land and no significant land uses have been identified.

4.0 OPERATING TECHNIQUES

4.1 Technical Standards

4.1.1 The proposed Installation will be operated in accordance with the conditions of the Environmental permit and also applicable EA Sector Guidance and BAT standards:

- EPR 4.03: How to Comply with your Environmental Permit, Additional Guidance for: The Inorganic Chemicals Sector (1)
- Environment Agency's Guidance on Emerging techniques for hydrogen production with carbon capture(2)
- Best Available Techniques (BAT) Conclusions for Large Combustion Plants(3) (LCP BATc)
- EU Reference Document on the application of Best Available Techniques to Industrial Cooling Systems(4)
- Environment Agency: Risk assessments for your environmental permit(5)
- Best Available Techniques (BAT) Reference Document for Common Waste Water and Waste Gas Treatment/Management Systems in the Chemical Sector(6)
- Best Available Techniques (BAT) Reference Document for Waste Treatment(7)

4.1.2 The proposed Installation will be regulated under EPR 2016, as amended as a Section 4.2, Part A (1)(a)(i) – Production of Inorganic Chemicals (Hydrogen) activity. The proposed Installation will be carbon capture enabled (blue hydrogen production) and the carbon capture aspect of the plant will be regulated under EPR 2016, as amended as a Section 6.10 Part A(1)(a) - Capture of carbon dioxide streams from an Installation for the purposes of geological storage pursuant to Directive 2009/31/EC of the European Parliament and of the Council on the geological storage of carbon dioxide.

4.1.3 The proposed Installation will include auxiliary steam boilers (71.87 MW for each phase) fired by natural gas during startup and by process tail gas and H_2 rich gas produced in the process, continuously fired during normal operations to meet the steam demand of the plant. The Installation will also operate medium combustion plant including natural gas fired start-up heaters, and emergency back-up generators (including those associated with diesel driven fire water pumps when required and these plant and the auxiliary steam boilers will be regulated under EPR 2016 permit, as a Section 1.1 Part A(1)(a) – Burning any fuel in an appliance with a rated thermal input of 50 or more megawatts.

4.1.4 The proposed Installation will be compliant with the Industrial Emissions Directive (IED), and relevant BAT Conclusions (BATc) (as available); and a summary of compliance against the current BATc is provided in Appendix C, with more detailed discussion presented in the following sections. As there is currently no BAT Reference (BRef) documents or BATc for blue hydrogen production, BAT has been assessed in accordance with the Environment Agency's 'Guidance on Emerging techniques for hydrogen production with carbon capture'. BAT assessments have also been conducted for LCP, Cooling, Emissions Management and Energy Efficiency using the corresponding BRef and BATc for these aspects.

4.1.5 The proposed Installation will develop a management system prior to commencement of operations in accordance with the EA guidance – 'Develop a management system: Environmental Permits'(8) as a good practice measure.

4.2 Operational Modes of the proposed installation

4.2.1 Hydrogen production is expected to increase during the initial 12 to 18 months of operation in line with increasing offtaker demand. The peak H_2 export rate for each Phase is expected to be 600 MWth LHV (or approximately 18.65 tonnes/hour at 98% H_2) with the associated peak CO_2 export rate being approximately 160,000 kg/hr. For Phase 1 and 2 combined this would equate to approximately 1.2 GWth LHV (37.3 T/hr) peak H_2 production and export and 320,000 kg/hr CO_2 export.

4.2.2 Once Phase 1 is commissioned and operational, the Hydrogen Production Facility will be designed to operate twenty-four hours per day, seven days per week (including when Phase 2 is under construction, commissioned and in operation) until decommissioning, with brief exceptions for planned outages such as for maintenance and repair.

4.2.3 Any other operational modes which may occur are other than normal operating conditions (OTNOC) and would only be temporary until normal operation is restored. This includes the temporary use of the natural gas fired heater at start-up, temporary use of the emergency diesel generators during emergency or upset conditions, venting of CO_2, flaring of CO_2 when NEP is offline and abnormal use of the flare during emergency or upset conditions

4.3 Process Description

4.3.1 The following section describes the anticipated process description for the proposed Installation, at the current stage of design (i.e. FEED). A simple process flow diagram for the proposed Installation is provided in Figure 3 along with more detailed process flow diagrams (PFD) (see Appendix A).

Natural Gas Metering, Compression and Pre-treatment

4.3.2 Metered natural gas (NG) is pre-heated before pressure letdown to avoid condensation. The organic sulphur species in the heated feed gas are converted to hydrogen sulphide in the presence of a nickel-metal oxide (Ni-Mox) catalyst in the feed gas hydrogenator and then the H_2S is adsorbed on to the zinc oxide beds in the feed gas desulphuriser reactor. The feed gas desulphuriser reactor contains two bed types. The hydrogenation of sulphur species and adsorption on the ZnO bed take place according to the following reactions:

$$RSH + H_2 \rightarrow RH + H_2S \text{ (hydrogenator)}$$

$$R_2S + 2H_2 \rightarrow 2RH + H_2S \text{ (hydrogenator)}$$

$$H_2S + ZnO \rightarrow ZnS + H_2O \text{ (desulphuriser reactor)}$$

4.3.3 The final step of feed gas purification takes place in the bottom bed of the feed gas desulphuriser reactor, to reduce sulphur slip). Reducing sulphur to ultra-low levels benefits the downstream catalyst systems, since sulphur species severely poisons the catalyst if present in the feed gas.

Reforming

4.3.4 The desulphurised feed gas is passed through the feed gas saturator column in which it flows upwards against a downflow of hot circulating condensate. Some of the condensate evaporates into the feed gas to provide part of the steam required for natural gas reforming. The saturator provides the ability to the process to utilise relatively low grade heat in raising process steam as well as recycling more than 90% of the process condensate directly without treatment.

4.3.5 A small purge from the circulating condensate from the saturator is transferred to the biological waste water treatment package before sending it to the raw water treatment plant package. Intermediate pressure (IP) steam and superheated medium pressure (MP) steam are also used to supplement the total required steam to satisfy the Steam to Carbon ratio (S:C) in the feed gas sent to the GHR-ATR reforming section. The mixed feed gas is then heated in the GHR Feed/Effluent interchangers which is recovering heat from the mixed effluent from the shell side of the GHRs.

4.3.6 The preheated feed gas is reformed in the GHR before entering the ATR reactor. In the first reaction step in the GHR, some of the total hydrocarbon is reformed by reaction with steam to form syngas, according to the following reactions:

$$C_nH_m + nH_2O \rightarrow nCO + \left(n + \frac{1}{2}m\right)H_2$$

$$CH_4 + H_2O \leftrightarrow CO + 3H_2$$

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

4.3.7 The hot partially reformed gas from the GHR is sent to the ATR vessel after mixing with preheated oxygen from the outlet of the O_2 preheater, which uses saturated MP steam as heating medium.

4.3.8 The heat required for the reforming reaction to take place in the ATR is provided by the partial oxidation of methane and hydrogen of the partially reformed gas, carried out in a proprietary burner where the gas is mixed with the oxygen in the combustion zone at the top of the ATR. These compounds combust as per the following reactions:

$$CH_4 + \frac{3}{2}O_2 \rightarrow CO + 2H_2O$$

$$H_2 + \frac{1}{2}O_2 \rightarrow H_2O$$

4.3.9 After the combustion zone, the hot gas flows downwards through the ATR vessel across a nickel-based catalyst bed where the following endothermic reforming reaction is carried out:

$$CH_4 + H_2O \leftrightarrow CO + 3H_2$$

4.3.10 In addition, a small amount of the CO is converted to additional H_2 and CO_2 according to the water-gas shift reaction:

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

4.3.11 The hot syngas exiting the shells of GHRs is first passed to the GHR Feed/Effluent interchangers and then a saturator water heater where it is cooled by heating the GHR feed and circulating water in the saturator water circuit, respectively, before entering the isothermal shift (ITS) converter. The ITS inlet temperature is selected to provide both optimum reaction rate and also a good final equilibrium conversion position for the shift reaction so as to meet the carbon capture requirements of the plant.

CO Conversion and Heat Recovery

4.3.12 The syngas from the reforming unit passes to the CO conversion section where the CO in the syngas selectively converts to H_2 and CO_2 according to the water gas shift reaction. As the water gas shift reaction is exothermic, IP steam is raised in the reactor to keep the temperature profile approximating a pseudo isothermal system. The IP steam generated in this reactor is used as process steam, added upstream of the GHR-ATR reforming section.

4.3.13 The shifted syngas exists the ITS reactor and is cooled in a saturator water heater before entering the low temperature shift (LTS) reactor. The effluent from the Shift Converter is then cooled in process condensate heaters, water heaters and the CO2 stripper syngas reboiler. Process condensate is removed in the various knockout pots. The cooled dry syngas then passes to the CO_2 Removal Unit.

4.3.14 As the syngas is cooled in the syngas cooling train exchangers, the liquid process condensate obtained from the syngas is collected in several drums. All the liquid is transferred to the process condensate drum from where most of it is pumped back to the base of the saturator column where the water and soluble hydrocarbons are carried over with the natural gas by direct contact in the saturator column before entering the reforming section. The rest of the process condensate is transferred to the biological waste water treatment package before sending it to the raw water treatment plant package.

CO_2 Removal

4.3.15 The syngas enters the CO_2 absorber within the CO_2 removal unit. CO_2 is absorbed into the amine and raw hydrogen exits the CO_2 absorber at the top of the column, to be further purified in the pressure swing adsorption (PSA) unit. A small flow of hydrogen-rich gas from the unit is used as fuel in the auxiliary steam boiler. Rich amine solution is fed to the top of the CO_2 Stripper, where the vapour and liquid parts are separated. A major part of the absorbed CO_2 is stripped off by heat generated in the CO_2 Stripper Syngas Reboiler and CO_2 Stripper LP Steam Reboiler. The regenerated solution leaves the CO_2 Stripper bottom with a very low residual CO_2 Loading and is recycled back to the CO_2 absorber. The Stripped CO_2 exits from the top of the stripper and is sent for compression and dehydration.

CO_2 Compression and Dehydration

4.3.16 The CO_2 gas from the stripper is routed to a CO_2 compressor suction separator where any residual liquid is knocked out of the gas before feeding the gas to the CO_2 compressor package. The compressor package increases the pressure of the CO_2 to the required export pressure of ~20 bara.

4.3.17 The compressed CO_2 is dried in a silica gel dryer package located at the discharge of the fourth stage. The package consists of three absorber vessels containing packed beds of desiccant, which operate on a fixed cycle; two vessels are in drying duty and one in regeneration, involving heating and cooling. The regeneration is achieved by using part of the dried outlet gas flow rate, which is recycled back to the dryer inlet. The regeneration gas is first preheated in the Regeneration heater to the required regeneration temperature by using MP steam. The hot and dried regeneration gas is directed in counter-current flow through the adsorber and is directed through the Regeneration Cooler, where the regeneration gas is cooled down. All condensate is removed in the water separator downstream the regeneration cooler. The condensate is routed to the CO_2 compressor suction separator, from where the liquids will be returned to process condensate drum. The dry CO_2 gas, with a purity of ~ 99.8% mol% CO_2. is fed to the gas after filters followed by the CO_2 Fiscal Meter before routing to export.

Hydrogen Purification, Distribution and Export

4.3.18 The H_2 product from the CO_2 removal unit is fed to a PSA unit to remove any traces of impurities in accordance with the H_2 product specification. In the PSA unit, H_2 is purified to >98 vol % H_2. The residual gas (PSA Tail Gas) passes through the PSA tail gas compressor package. The discharge is split: a stream used as fuel in the auxiliary steam boiler, and a proportion used to provide H_2 for the front end system to improve overall efficiency.

4.3.19 The remaining H_2 product is then routed to the H_2 compressor, where it is compressed to the required delivery pressure, cooled and sent to the fiscal meter before routing to export.

4.3.20 On-site H_2 storage will be provided and will be used only in the event of a plant trip that can impact the export of hydrogen. The hydrogen will be compressed prior to storage and stored in multiple pressurised vessels.

Steam System

4.3.21 MP steam is raised at the auxiliary boiler, which uses tail gas from the PSA tail gas compressor package and HP flash gas from the HP Flash reabsorber as fuel. MP steam is used for: heating duty in a purification pre-heater, heating duty in a saturator water heater, heating duty in the ATR oxygen pre-heater and in a regeneration heater.

4.3.22 IP saturated steam is raised in the shift reactor and fed to the GHR-ATR reforming section for steam to carbon ratio control.

4.3.23 Continuous blowdown from the IP saturated steam drum is sent to the MP blowdown drum and sent to a DMW plant package. Continuous blowdown from the auxiliary steam boiler is also sent to the DMW plant package. LP steam is generated in the MP condensate flash drum and MP blowdown drum. The majority of LP steam is used in the CO_2 stripper reboiler, with portion of it used in natural gas letdown heater and deaerator.

4.4 Ancillary Equipment and Structures

4.4.1 A number of ancillary operations are required to support the operation of the blue hydrogen production facility, including:

- Air Separation Unit (ASU) and liquid N_2 and O_2 storage (in the event the third party O_2 and N_2 supply is not available).
- Power Generation and Auxiliary Boiler
- Water Preparation and BFW Treatment and Supply
- Chemical Storage
- Cooling Water
- Wastewater Treatment
- Flare
- Instrument Air / Plant Air
- Fire Water

Air Separation Unit

4.4.2 The ASU unit has been substituted with a third party supply of O_2 and N_2 for phase 1.

4.4.3 For Phase 2 an ASU will be used whereby atmospheric air is compressed by the main air compressor (MAC) to a supply pressure of approx. 6 bar where the air is dried. A part of the dry compressed air is taken and compressed further in the booster air compressor (BAC). The air from the BAC is then expanded through a turbine before being fed to the main cryogenic HP rectification column along with the air from the MAC. Following separation, the oxygen liquid product is pumped at high pressure as a cryogenic liquid and vaporised against a stream of condensing high-pressure air within the ASU main heat exchanger.

4.4.4 The gaseous O_2 product is preheated to 250°C and then is consumed in the ATR. LP nitrogen is also obtained as a product and used to satisfy the plant purging and inerting requirements. Storage for liquid N_2 and O_2 will be provided onsite.

Power Generation

4.4.5 Power is not generated onsite, and all electrical power will be imported.

4.4.6 The site will be supported by a backup emergency diesel driven generator on each phase to provide black start capability.

Water Preparation and BFW Treatment and Supply

4.4.7 Raw Water will be sufficiently available for water makeup.

4.4.8 Raw water will be treated in the raw water treatment package to meet the quality required for makeup water. Raw water will be supplied by Northumbrian Water and will be supplemented by water recirculating from:

- Clean storm water;
- Recycled water from the biological treatment plant;
- Steam blowdown;
- Various recycles from within the raw water treatment plant such as dewatering filtrate; ultrafiltration filtrate and GAC water.

4.4.9 The specific details of the raw water treatment plant will be finalised at FEED but is anticipated to include a number of physio-chemical treatment stages including:

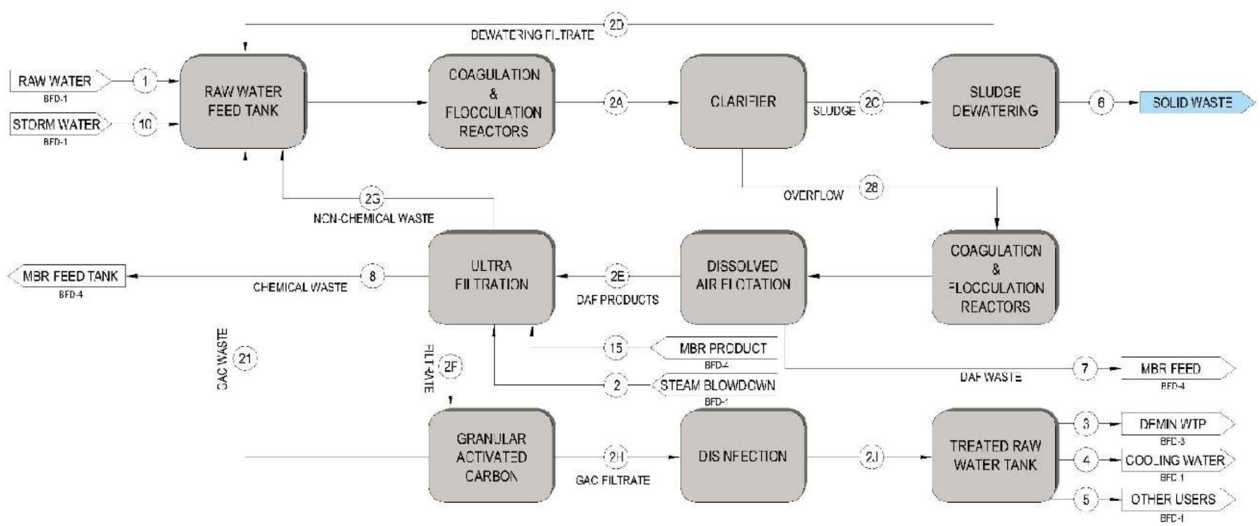
- Coagulation and flocculation reactors followed by a clarifier stage to remove suspended solids which results in the dewatering filtrate being recirculated back to the raw water feed tank, overflow passing to a second stage of coagulation and flocculation and the dewatered solid waste being removed for third party offsite disposal.
- Following the second coagulation and flocculant stage, the output passes to a dissolved air floatation (DAF) unit for further separation. The DAF waste stream is sent for biological treatment in the membrane bioreactor (MBR) and the product stream is passed to an ultra-filtration stage.
- The ultrafiltration unit receives the DAF product, the treated MBR product and steam blowdown product and produces three streams. Non-chemical 'waste' stream is returned to the raw water feed tank for recirculation back

through the process, the filtrate passes to a granulated activated carbon (GAC) filter and the chemical ‘waste’ stream passes to the MBR.

- The GAC is an additional filtration stage which recirculates GAC waste to the raw water feed tank and sends the filtrate for disinfection.
- Following disinfection the water is passed to the treated raw water tank before being distributed to the cooling system and other process users and to the demineralisation treatment plant.

4.4.10 A process flow of the proposed feed water treatment process is shown in Plate 4.1 on the following page.

Plate 4.1: Feedwater Treatment Flow

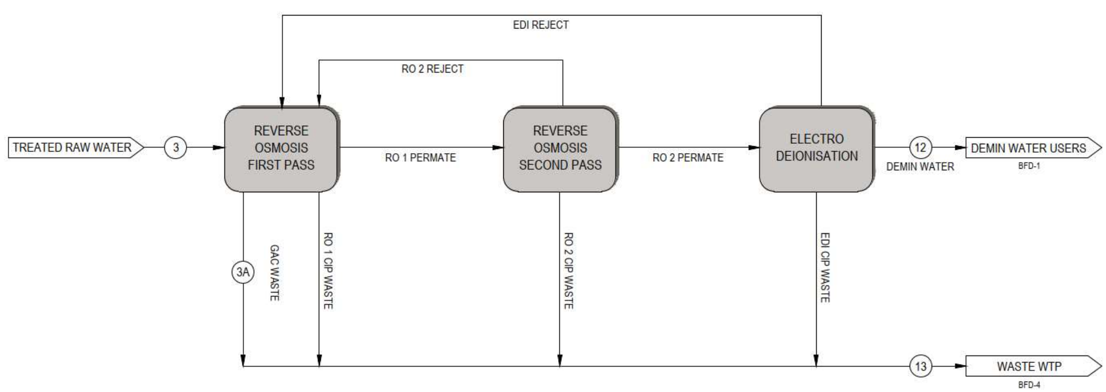


4.4.11 A demineralised water (DMW) treatment plant is a physico-chemical process which will receive treated raw water which will pass through a double reverse osmosis arrangement (RO) followed by electro-deionisation (EDI). The incoming treated raw water feed will pass through the first RO stage with the permeate passing to the second RO and the permeate then passing through EDI to produce DMW which is passed to the process users such as for boiler feedwater. The RO and EDI units will be equipped with a 'clean in place' (CIP) cleaning system.

4.4.12 The RO reject from the second RO stage and the reject from the EDI are recirculated back through the first RO stage. The reject from the first RO stage and the CIP waste from each RO and the EDI are passed to the wastewater treatment plant for further treatment.

4.4.13 A process flow of the proposed DMW treatment process is shown in Plate 4.2 below.

Plate 4.2: DMW Treatment Flow



4.4.14 Demineralised water from the tank will be pumped to the deaerator trayed top head via the demin water heater. Condensate from the LP condensate drum is injected at the lower section of the deaerator. The water is dosed with chemicals, and it is deaerated with LP steam before being pumped to the pressure required for LP boiler feed water (BFW) users.

4.4.15 LP BFW is used to provide cooling water to the GHR and ATR jackets.

4.4.16 MP BFW is preheated in the boiler feed water pre-heater. Preheated MP BFW enters the MP steam drum from the auxiliary boiler where MP steam is produced. In addition, preheater MP BFW is used to produce IP steam in the IP steam boiler at the isothermal shift reactor.

Chemical Storage

4.4.17 Chemical storage includes storage facilities for aqueous ammonia, antifoam, chemical dosing for water treatment and diesel, which are all imported by road tanker.

Cooling Water

4.4.18 Cooling water (CW) will be supplied by a cooling water tower and is circulated across the plant. There will be losses from the cooling water tower due to evaporation, blowdown, and drift losses. Therefore, treated raw water is used to supply cooling water makeup. A cooling water dosing package is required to prevent scale and corrosion.

4.4.19 Cooling water blowdown will be sent to the ETP before sending as final effluent.

Wastewater Treatment

4.4.20 Wastewater from the blue hydrogen plant is treated in two separate waste water plants: Biological treatment plant and Effluent Treatment Plant (ETP). Each of them will b described separately in the following sections.

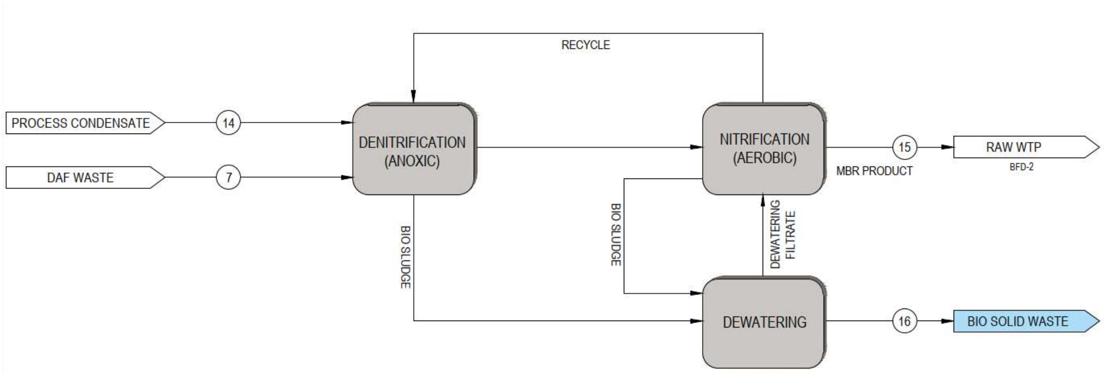
4.4.21 The biological treatment stage comprises a membrane bioreactor (MBR) which will receive feed water from the following:

- Process condensate from the syngas plant;
- DAF waste;
- Filtration waste;
- Flare Liquid KO Drum Liquid.

4.4.22 The process is a biological treatment stage which initially involves an anoxic denitrification stage followed by an aerobic nitrification stage with the MBR product being recirculated back to the raw water feed tank. The overflow from the nitrification step is recycled back to anoxic denitrification for further treatment while the sludge from each stage is passed through a dewatering unit. The solid waste from dewatering is removed for third party waste disposal while the dewatered liquid is either passed back through the nitrification stage or to the wastewater treatment plant.

4.4.23 A process flow of the proposed MBR treatment process is shown in Plate 4.3 on the following page.

Plate 4.3: MBR Treatment Flow



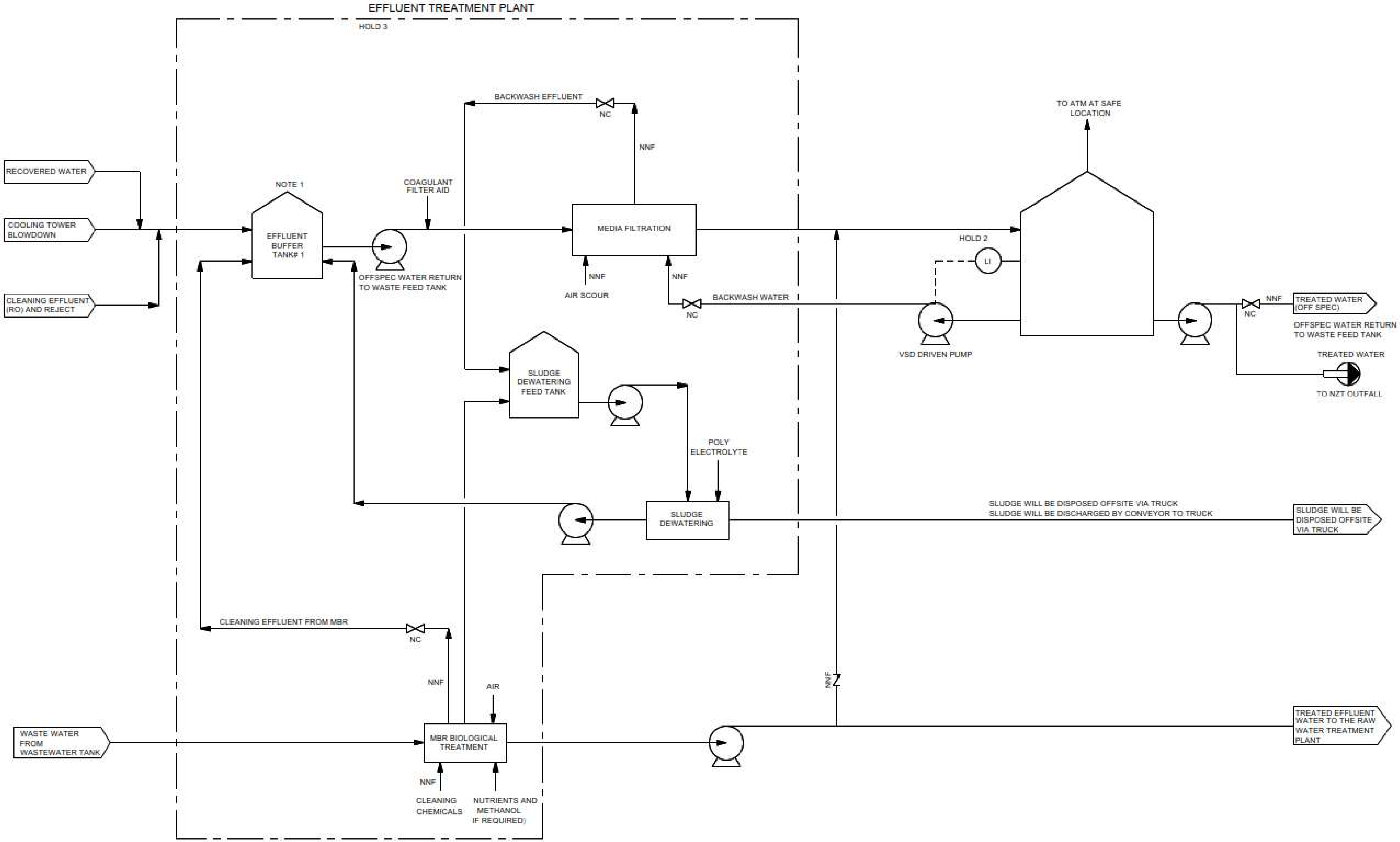
4.4.24 The wastewater or effluent treatment plant (ETP) treats water from the following sources:

- Cooling tower blowdown;
- Demineralization plant rejects; and
- Dewatering filtrate.

4.4.25 The wastewater is collected at wastewater treatment plant feed tank. The water passes through a media filtration stage which passes backwash into the dewatering stage and final effluent to the NZT outfall for discharge to the Tees Bay. The solid waste from dewatering is removed for third party waste disposal while the dewatered liquid is either passed back through the nitrification stage or to the wastewater treatment plant.

4.4.26 A process flow of the proposed treatment process is shown in Plate 4.4 on the following page.

Plate 4.4: ETP Treatment Flow



4.4.27 The stormwater system consists of an oily water separator, neutralisation sump (for flows from the chemical drains), storm water attenuation pond and daily retention sump. All oily water effluents produced by the plant are sent to the oil water separator. Clean water will be recycled back to raw water treatment plant, with excess discharged to Tees Bay via NZT outfall.

4.4.28 Waste grey/black water will be disposed of offsite via the NWL Bran Sands Wastewater treatment plant.

Flare

4.4.29 The flare system consists of a flare drum, flare drum pump and flare package. Any flammable gas released from any high operating pressure part of the plant during an emergency is collected in the flare header system and sent to the flare drum where any liquid associated with the gas is separated. The gas from the flare drum is sent to the flare system where it is disposed of by burning. The liquid collected in the drum is pumped by the flare pump to the bio-treatment package.

4.4.30 The flare will be operated in pilot mode using natural gas during normal operations.

Instrument Air / Plant Air

4.4.31 The air compressor package consists of a number of units. The system consists of a wet receiver, an air dryer package, and an instrument air receiver. The wet air receiver and dry air receiver are directly cooled with cooling water.

Fire Water

4.4.32 The fire water system consists of fire water storage, three pumps (two motor driven and one diesel driven), a jockey pump and a firefighting system.

4.5 Drainage

Surface Water Drainage System

4.5.1 A suitable surface water drainage network and management system will be provided for the proposed Installation, to segregate uncontaminated surface waters from those that could be potentially contaminated. The drainage network will provide appropriate interception, conveyance, treatment and attenuation of surface water run-off.

4.5.2 The clean surface water drain system will collect rainwater run-off from uncontaminated areas including building roofs, paved process areas identified as 'clean' and roads. Clean surface water run-off may be sent to an attenuation pond and either recycled back to the raw water treatment plant or discharged to the NZT outfall without treatment.

4.5.3 The potentially contaminated (non-amine) system will collect run-off from areas which are potentially contaminated with oil including run-off from potentially contaminated paved areas, firefighting water and miscellaneous sources such as vehicle maintenance facility or workshop. This drainage system will be designed such that run-off per zone can be collected in bunds and kerbs and routed via gravity through an underground network. This drainage system shall be provided with a passive diversion chamber and a local off-line interceptor pit. Interceptors will be tested prior to discharge to the potentially contaminated surface water (PCSW) attenuation pond. Any contaminated water will be sent for oily water treatment package for cleaning prior to cleaning before being routed to the retention pond for discharge.

4.5.4 The proposed drainage scheme is presented on Figure 4 in Appendix A (Drawings and Plans).

Carbon Capture Area Drainage System

4.5.5 The Carbon Capture area shall be paved and kerbed/bunded with controlled discharges to help avoid uncontrolled surface run-off and contain spillage and leakages from equipment.

4.5.6 Amine contaminated water shall not be discharged to any open drain systems or outfall. A connection from the kerbed / bunded area to the PCSW system shall be provided with normally closed valve to enable pooled rainwater not contaminated with chemicals to be drained to the PCSW system manually following inspection of the water contained in the bunded area. The operator shall sample the pooled water for laboratory analysis to confirm that levels of chemicals and amine do not exceed relevant thresholds before it is allowed to drain to the PCSW system.

4.5.7 Contaminated water with amine will be taken offsite to an appropriate third party facility.

Contaminated Wastewater Drainage System

4.5.8 Wastewater management includes treatment of process condensate from the syngas plant, DAF waste, filtration waste and flare KO drum liquid c in the MBR followed by recirculation to the raw water treatment plant and treatment of cooling water blowdown, DMW plant rejects and dewatering filtrate in the ETP (as described above) followed by discharge via the NZT outfall to Tees Bay.

4.5.9 The foul water sewer shall collect the domestic wastewater, which is not chemically contaminated from toilets, sinks, showers (except safety showers) from administration and control building, workshop and warehouse building, and gatehouse. Sanitary sewers shall not receive discharges from other sources.

4.5.10 Domestic wastewater will be drained via conventional foul sewer sumps and be pumped off-site via South Tees Development Corporation (STDC) infrastructure.

4.6 Management Systems

4.6.1 The proposed Installation will be operated in line with appropriate standards and the operator will implement and maintain an Environment Management System (EMS) which will be attested to International Standards Organisation BS EN (ISO) 14001. The EMS will outline requirements and procedures required to ensure that the proposed Installation is operating to the appropriate standard.

4.6.2 In summary, the management system identifies 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 proposed Installation.

4.6.3 The management system and procedures will be available for inspection at the Site and will be applicable to all staff, contractors and visitors to the facility. The management system is developed to enable compliance with the Environmental Permit and other legislative requirements for the protection of the environment and human health.

4.6.4 Written procedures clearly describing responsibilities, actions and communication channels will be available for operational personnel dealing with emergencies.

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

4.6.6 Internal audits will be undertaken to ensure conformance with the management system, 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 management system and improvement measures implemented will be recorded for reference and inspection purposes.

4.6.7 Staff competence and training will be maintained as part of the EMS. In-house training services or a local training contractor will be contracted to provide all the necessary plant training for maintenance and operation. The provider will also manage a COMAH compliant competency system for all agency and staff workers at technician and safety critical role level.

4.6.8 An Emergency Response Management Plan (ERMP) will be maintained as part of the EMS. The ERMP will detail the procedures for managing emergencies and reducing the impacts of abnormal events and accidents on the workers, asset and the environment.

4.7 General Maintenance

4.7.1 Routine maintenance will be planned and scheduled via the maintenance management system with major overhauls occurring approximately once every four years on each unit and last for approximately 28 days. These maintenance activities will require additional Engineering, Procurement and Construction (EPC) contractors to work on-site. The EPC contractors will access the Main Site via the main entrance.

4.7.2 It is anticipated that an integrated Operations and Maintenance (O&M) team will have responsibility for daily operations, including troubleshooting and effecting minor repairs on the proposed installation. Major O&M interventions are likely to be outsourced, whilst major equipment items will be serviced by original equipment manufacturers.

4.7.3 All major maintenance activities requiring significant equipment outages will be coordinated to occur during the planned routine turnaround (TAR). TAR is a planned period of regeneration in a plant. During this time, part of the operation is taken offline whilst the plant is inspected and revamped.

4.8 Raw Materials

4.8.1 The main feedstock for the Installation is natural gas. Natural gas will be supplied to Main Site from the wider gas supply network, via the Natural Gas Supply Connection which will be a tie in point to infrastructure constructed by NZT Power as part of the NZT development.

4.8.2 Other raw materials required for the Installation are N_2 and O_2, which will either be supplied by the ASU for phase 2 (which uses ambient air as raw material) or by offsite sources for phase 1.

4.8.3 The carbon capture system will use an amine-based solvent for capture of CO_2, which will be stored, conditioned, regenerated and re-conditioned for subsequent re-use, in accordance with licensor recommendations. The amine-based solvent is likely to be hazardous. Materials of construction will be appropriate to avoid degradation of the solvent during storage and use.

4.8.4 Amine storage and dilution tanks, pipework materials and operating conditions will be confirmed during FEED stage, however it is anticipated that this is likely to include stainless steel tanks, with heat tracing to maintain the amine at a useable temperature, and atmospheric fixed roof with N_2 blanketing.

4.8.5 It is typical practice to include a breather vent in the storage tank to allow for vapour maintenance/ displacement during tank filling, fire exposure relieving rate from the tank and/ or N_2 purging when unloading road tankers or cleaning lines. The tanks for amine will have a N_2 blanket. Due to the potential toxicity and odorous nature of emissions associated with the venting of amine, it is considered that abatement may be required on the breather vent for the storage tank. These requirements, with full consideration of BAT, will be considered at FEED stage.

4.8.6 Bulk storage of chemicals in above ground bulk storage tanks may include NH_3 for use in the SCR plant, the amine solvent for the carbon capture system, and various cooling water conditioning/ treatment chemicals, chemicals for use in the water treatment plant, and other chemicals for use in the carbon capture system and compression unit. Such tanks will be designed and constructed to appropriate industry standards for the material being held.

4.8.7 Chemicals required for the operation of the proposed Installation will need to be stored and used at the Site. Some of these materials may be classed as hazardous. Where any substance could pose a risk to the environment through its uncontrolled release (e.g. through the surface water drainage system) appropriate containment facilities will be used including (but not limited to) bunds and concrete surfaces appropriately designed and sized for their intended use. An inventory of materials to be stored on the Site will be finalised through the detailed design.

4.8.8 An emergency generator, and diesel fuelled fire water pump are required, that will also require on-site diesel storage for fuel.

4.8.9 Table 4.1 summarises the main raw materials anticipated to be used at the proposed installation, based on initial engineering information. Quantities where provided are based on pre-FEED data and all volumes and consumption rates will be confirmed post-FEED when the final design for the proposed Installation is known.

Table 4.1: Raw Materials for the Proposed Installation (indicative quantities)

Material	Use on Site	Annual Usage	Comment
KATALCO™ 61-2F	Hydrodesulphurisation Catalyst	-	Held in a catalyst bed (26m^3) with expected lifetime of 4 years
KATALCO 32-4	Desulphurisation Absorbent	-	Held in a catalyst bed (43.9m^3) with expected lifetime of 1 year per bed
KATALCO 79-1	Ultra-Purification	-	Held in a catalyst bed (3.7m^3) with expected lifetime of 1 year per bed
KATALCO 23-4HMQR	Gas Heated Reformer (GHR) Catalyst	-	Held in a catalyst bed (12.9m^3) with expected lifetime of 4 years
KATALCO 23-4HMQ	Gas Heated Reformer (GHR) Catalyst	-	Held in a catalyst bed (10.3m^3) with expected lifetime of 4 years
KATALCO 23-4HQ	Gas Heated Reformer (GHR) Catalyst	-	Held in a catalyst bed (2.6m^3) with expected lifetime of 4 years
KATALCO 28-4Q	Autothermal Reformer (ATR) Catalyst	-	Held in a catalyst bed (29.4m^3) with expected lifetime of 4 years
KATALCO 83-5	Isothermal Temperature Shift (ITS) Catalyst	-	Held in a catalyst bed (29.4m^3) with expected lifetime of 4 years
KATALCO 89-9GQ	Autothermal Reformer (ATR) Catalyst	-	Held in a catalyst bed (2.3m^3) with expected lifetime of 4 years
KATALCO 83-3X	Low Temperature Shift (LTS) Catalyst	-	Held in a catalyst bed (125.6m^3) with expected lifetime of 4 years
KATALCO 59-4	Chloride Guard	-	Held in a catalyst bed (8.7m^3) with expected lifetime of 1 year per bed
OASE White	CO_2 absorption solvent	6.2 m^3/y	760 m^3 (b)
Natural gas	Hydrogen production	986,026 t/y	Storage not proposed – maximum use for both phases/
Nitrogen	Purging equipment to free it from flammable / toxic material; blanketing amine storage and other storage tanks, compressor seals and sump vessels Non-continuous demand for safe shutdown of the plant (non-continuous demand will be supplied by on-site liquid N2 storage)	17,520 t/y	TBC at FEED
Oxygen	ATR	813,103 t/y	Storage proposed up to 600T per phase if ASU option selected.
Diesel	Emergency diesel generator	TBC at FEED	TBC at FEED
Raw water	Reagent, cooling and steam makeup	~6 Mt/y (phase 1 + 2)	TBC at FEED
Nalco Elim-Ox	Boiler Water Treatment – O2 scavenger	TBC at FEED	TBC at FEED
Sodium Phosphate	Boiler Water Treatment Chemicals	TBC at FEED	TBC at FEED
Morpholine (20% solution)	Boiler Water Treatment Chemicals	17.3 m^3/y	TBC at FEED
Hydrochloric Acid	Cooling Water Treatment Chemicals	83 m3/y	TBC at FEED
Aqueous ammonia	SCR	600 m3/yr (Phase 1)	TBC at FEED
Caustic	Cooling Water Treatment Chemicals	<1 t/year	TBC at FEED
Sodium Hypochlorite	Cooling Water Treatment Chemicals	530 m^3/y	TBC at FEED
Bromine water	Cooling water treatment Chemicals	6.5 t/y	TBC at FEED
Corrosion inhibitors	Cooling water treatment Chemicals	39.2 t/y	TBC at FEED
Scale Inhibitor	Cooling Water Treatment	23.6 t/y	TBC at FEED

Material	Use on Site	Annual Usage	Comment
Foam	Firefighting foam	TBC at FEED	TBC at FEED

(a) All site storage volumes to be confirmed at FEED.
(b) MSDS for water treatment and firefighting systems are linked to the final vendor selected and will be confirmed at final design.
(c) All annual consumption values to be confirmed at FEED – where volumes are provided these are the current estimates.

4.9 Solvent Selection

Initial Solvent Selection

4.9.1 Initial solvent selection was undertaken with an engineering contractor during the early feasibility stage of the project as part of the technology screening process to evaluate carbon capture technology available on the market including pre-combustion chemical solvent, post-combustion chemical solvent, physical solvent, cryogenic process and pressure swing adsorption.

4.9.2 This initial screening process included ranking the technology according to their:

- technology readiness,
- scalability,
- efficiency,
- performance,
- effluent,
- waste,
- safety,
- cost,
- operability and
- flexibility.

4.9.3 The conclusion of this initial assessment was:

- Pre-combustion chemical solvent (i.e. amine) scored the highest. Pre-combustion carbon capture with amine maximises energy efficiency for H2Teesside blue hydrogen plant as it utilises the waste heat from the syngas for the amine stripper reboiler and flashes the solvent to lower pressure to minimise energy consumption. The pre-combustion amine itself is highly energy efficient as there is no huge compressor power demand. Pre-combustion amine processes can be designed to capture almost all the carbon dioxide in the process stream; the only waste stream from the process is the flash gas which can be used to raise steam in the syngas process and no liquid effluent treatment is required during normal operation. The risk of amine degradation is low due to the absence of oxygen and low carbon monoxide in the feed gas

- Post combustion chemical solvent is not applicable to this project as all the carbon dioxide is in the process stream during normal operation.
- In the case of cryogenic process, physical solvent and pressure swing adsorption process these had a huge compressor power demand which made them less energy efficient.

4.9.4 Given that H2Teesside is a standalone blue hydrogen plant (i.e. no benefit to export steam) and carbon dioxide export is in gaseous phase, and that pre-combustion amine technology is field proven as it is widely used to remove carbon dioxide from natural gas and ammonia plants worldwide; this technology was deemed to be the BAT for the project at this stage.

Second Stage Solvent Selection

4.9.5 At the next stage of the project development further assessment of potential pre-combustion amine based solvents was undertaken which considered aspects such as the maturity of the systems and associated real world operation, the related energy demand, the lifecycle of the solvent and the environmental impact of the operation.

4.9.6 The review recognised that options could include:

- Single solvent options using amines classed as primary, secondary, or tertiary depending on whether one, two, or three of the hydrogen atoms of ammonia are replaced by organic functional groups. Some of the single amines most commonly used in CO2 capture are monoethanolamine (MEA), methyldiethanolamine (MDEA), 2-Amino-2- methylpropanol (AMP), Piperazine (PIPA), diglycolamine (DGA), diethanolamine (DEA), and di-isopropanolamine (DIPA). MDEA is typically selected over primary (such as MEA, DGA) and secondary amines (such as DEA) due to its lower corrosivity potential (lower reactivity). This is counter-acted by adding an activator to promote the reaction with CO2.
- Cutting-edge proprietary solvent blends that are being used new technologies. These solvents used for CO2 capture are often a mixture of several different amines. As per the OASE White MSDS, which is the BASF supplied amine comprising a mixture of amine solvents.

4.9.7 Bids were received from a number of pre-combustion solvent suppliers, with their proposal and solvent selection made based on bp’s defined plant requirements. The technical evaluation was undertaken, and BASF was selected and was deemed to be BAT based on the following advantages:

- It had the largest number of installed reference plants (in the order of hundreds) in syngas and natural gas applications.

- It was proven on operating plants at 1.5 times the capacity required for H2Teesside.
- It is a proven solvent for large CO2 removal from syngas stream (similar to H2Teesside).
- There was multiple references for split flow schemes
- It had the lowest amine circulation rate
- There was experience working with knowledgeable contractors to provide the Process Design Package (PDP)
- Previous history; and
- As BASF own in-house solvent will be used there is potential ongoing improvement with BASF continuous R&D programme.

4.10 Waste

4.10.1 Small quantities of operational waste will be generated from the operation and maintenance of the proposed Installation, in addition to minor amounts of general waste from plant staff.

4.10.2 All waste generated on site will be managed in line with the waste hierarchy and disposed of by licenced waste contractors where necessary. Waste quantities and appropriate treatment or disposal routes will be determined at FEED.

4.10.3 Catalyst waste will be disposed of, recycled or reclaimed in accordance with TAR frequency, i.e. approximately once every four years. Sulphur removal beds may need to be disposed of annually.

4.10.4 Chemical containers (e.g. sodium hypochlorite for cooling tower dosing) may be collected by chemical suppliers, who will handle the containers for re-use. If suppliers do not collect chemical containers, these may need to be washed out on site to remove trace chemicals.

4.10.5 There may be some waste amine if it is needed to bleed any material from the system due to quality issues. However, this will be infrequent. Most amine will be kept in the process, as any amine drained for maintenance activities will be drained via a closed system to a sump vessel before returning to the process.

4.10.6 Other contaminated materials which may require disposal during plant operation may include, but not be limited to:

- Spent filter cartridges
- Contaminated PPE
- Contaminated lagging material
- Scrap wood and metal from maintenance activities

- Waste oils/greases from maintenance activities (including spent oil and empty oil containers)
- Aerosols
- Waste lab chemicals, packaging and sample bottles (will be re-used where possible)

4.10.7 There may be waste generated from heat exchanger cleaning which may be unsuitable for normal effluent streams and therefore require separate disposal, but this is likely to mainly occur during TAR events.

4.11 Energy Use

4.11.1 There is a hydraulic turbine at the rich amine outlet of the CO_2 absorber which generates 2MW for consumption by the process. The balance of the electrical power requirements will be imported.

4.11.2 Steam is utilised as an energy carrier throughout the process. The steam demand of the process will be met by the auxiliary steam boilers. The auxiliary steam boilers will use NG during start-up only and otherwise will run continuously using tail gas and H_2-rich gas produced in the process as fuel.

4.11.3 Diesel will be consumed in emergency diesel generators/pumps/compressors only when necessary i.e. in case of emergency energy supply, or during testing of the generators.

4.11.4 A breakdown of energy consumption is provided in Table 4.2.

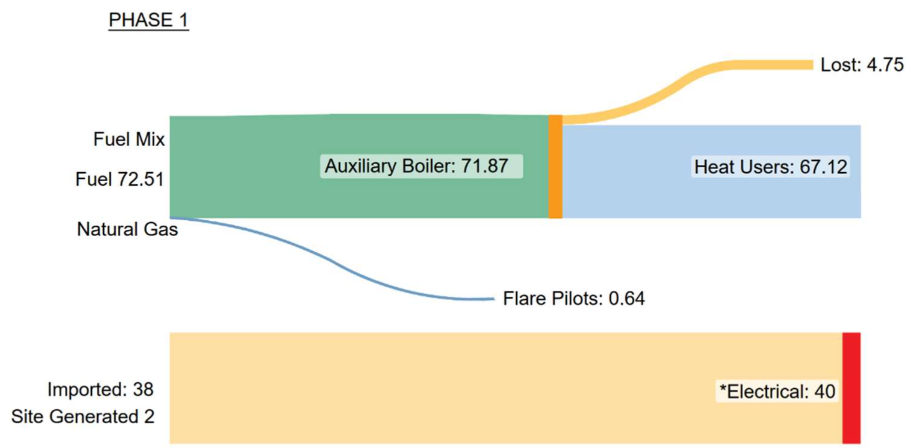
Table 4.2: Breakdown of energy consumption per phase

CONSUMER	TYPE	RATE	LHV	INTAKE	
		kg/hr	**MJ/kg**	**MJ/h**	**MW**
Fired Start-up Heater	Natural Gas	1435.2	45.90	65,880	18.3
Auxiliary Boiler	Fuel Mix	4770	54.241	258,729.57	71.87
Flare and Boiler Pilots	Natural Gas	50.00	45.90	2,295.08	0.64
Grid Import	Electricity[(a)]				68
Site Generated	Electricity				2
TOTAL					**142.51**[(b)]

(a) Table shows the electricity usage per phase including operation of an ASU. The option to provide O_2 from a third party for phase 1 means, means electricity would reduce to a total of 40MW for this phase.

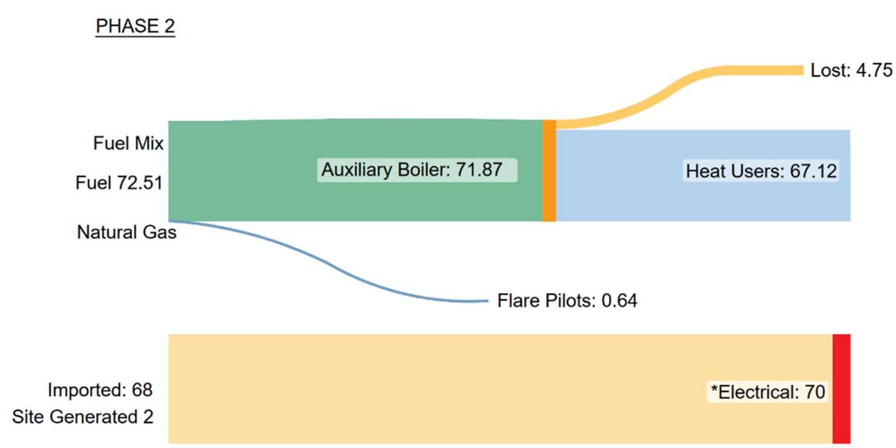
(b) Total excludes the MW for the fired start-up heater as this is not a continuous supply and only used during start-up periods.

4.11.5 The energy breakdown is illustrated in a Sankey diagram in Plate 4.1. The Sankey diagram is presented in MW.



Notes:

A. Oxygen and nitrogen supply by third party in phase 1.
B. This diagram represents normal operations excluding start-up.



Note:

A. Oxygen produced on site by ASU for Phase 2.
B. This diagram represents normal operations excluding start-up.

Plate 4.5: Sankey Diagram of Energy Consumption

4.12 Energy Efficiency

4.12.1 The overall performance of the hydrogen production and carbon capture plant for optimised energy efficiency is dependent on, as far as practical, electrical, steam, steam condensate and water circuits along with optimised integration of utilities.

4.12.2 A small amount of power is generated by a hydraulic turbine in the CO_2 removal section and consumed by the process.

4.12.3 During normal operation the auxiliary steam boilers will be operated with tail gas from the PSA as the fuel.

4.12.4 The LCH technology requires a significant amount of steam to be added to the natural feed gas – approximately 80% of this is raised and recovered for use from the process. The remaining 20% is generated in the auxiliary boilers.

4.12.5 Using the steam from the saturator and shift convertor is more efficient in terms of quality, when compared to a steam methane reformer (SMR) which typically uses the 860°C stream at the exit of the reformer to raise medium pressure steam thereby degrading the quality of the heat. The LCH technology is therefore more efficient with an energy efficiency than an SMR.

4.12.6 The use of the GHR allows heat to be recovered at significantly higher temperatures than an SMR which allows the LCH technology to use around 10% less natural gas for every unit of H_2 produced.

4.12.7 The LCH technology utilises a GHR-ATR combination which reduces the combustion requirements of ATR in isolation. This maximises the energy within the process and due to reduced combustion requirements requires less O_2. This improved feedstock and O_2 utilisation therefore provides a process with higher thermal efficiency.

4.12.8 In terms of heat integration, the process is designed using engineering techniques to evaluate the process heat flows and optimise the overall energy use.

4.12.9 Further details of the energy efficiency measures for the proposed Installation are provided within the Energy Efficiency BAT assessment provided in Appendix C4.

<u>CHP Readiness</u>

4.12.10 CHP readiness requirements do not apply to Installations that do not include power generation, however, as the proposed combustion units exceed 20 MW thermal input, the requirements of Article 14 of the Energy Efficiency Directive are applicable.

4.12.11 At this current stage, external heat integration is not considered in the design, and will be assessed further during the FEED stage. The design currently focuses on recovering heat internally for better process efficiency, as described in Section 4.12.8 above. There is no opportunity to export power from the site as the site consumes any power generated by a hydraulic turbine in the CO_2 removal section.

5.0 EMISSIONS TO AIR, WATER AND LAND

5.1 Emissions to Air

5.1.1 During normal operation, the Auxiliary Boilers stacks (one stack per phase) would be the primary sources of emissions from the hydrogen generation process associated with the proposed Installation.

5.1.2 In addition, there would be a stack associated with the flare (used during normal (pilot and purge) and emergency operations, for phase 1 and 2), two stacks for the Fired Heaters (start-up only, one for each phase) and two stacks for the emergency diesel generators (one for each phase).

5.1.3 The main reported emissions for the Proposed Development have been modelled at a release height of 70 m above finished ground level for the Auxiliary Boilers, with an internal stack diameter of 1.65 m. This release height is based on the results of the Stack Height Assessment, provided in the Air Quality Assessment in Appendix F. It is considered that this represents a conservative assessment, and the higher release height would result in lower impacts at modelled receptor locations. Following the same approach, the Fired Startup Heaters have been modelled at a release height of 35 m above finished ground level, with an internal stack diameter of 0.55 m.

5.1.4 For the flare, effective release heights and equivalent stack diameters have been calculated for each of the operational scenarios. The final release height of 66.4 m is based on the results of the Stack Height Assessment, as well as consideration of the minimum release height required for safety and design reasons. The release height of 66.4 m is assessed as a minimum release height and at any increased release height, lower pollutant concentrations would be anticipated.

5.1.5 Emissions to air from the proposed Installation are summarised in Table 5.1 and Table 5.2

5.1.6 H_2 will be flared to air during commissioning, start-up and Low Carbon Hydrogen Agreement (LCHA) performance tests.

Table 5.1: Emissions Inventory

PARAMETER	UNIT	FIRED HEATER (START-UP)	FLARE (NORMAL OPERATION[1])	FLARE (EMERGENCY/UPSET) SCENARIO 1	FLARE (EMERGENCY/UPSET) SCENARIO 2	FLARE (EMERGENCY/UPSET) SCENARIO3	AUXILIARY BOILER (START UP)	AUXILIARY BOILER (NORMAL OPERATION)	EMERGENCY DIESEL GENERATORS
Stack Position	M (Easting, Northing National Grid)	Phase 1 – 456360, 525375 Phase 2 – 456558, 525792	Phase 1 – 456477, 525580 Phase 2 - 456588, 525536	Phase 1 – 456558, 525536 Phase 2 - 456588, 525536	Phase 1 – 456558, 525536 Phase 2 - 456588, 525536	Phase 1 – 456558, 525536 Phase 2 - 456588, 525536	Phase 1 – 456421, 525325 456634, 525765	Phase 1 – 456421, 525325 Phase 2 – 456634, 525765	Phase 1 – 456542, 525209 Phase 2 – 456441, 525830
Release Height (above ground level)	m	35	66.4*	99.9*	97.7*	106.6*	70	70	10
Effective internal stack diameter	m	0.9	0.9	11.5	10.8	11.8	1.9	1.9	0.92
Flue temperature	°C	200	1,000	1,000	1,000	1,000	259	155	600
Flue H_2O content	%	18	-	0.0045	-	-	-	29.3	n/a
Flue O_2 content (wet)	%	1.6	0	0.05	0.05	0.05	-	1.6	n/a
Stack gas exit velocity	m/s	16.6	20	20	20	20	16.5	16.1	15.0
Stack flow (actual)	Am^3/s	10.5	1.0	-	-	-	46.7	45.7	10.0

[1] Flare normal operation is pilot and purge only

Table 5.2: Emissions Concentrations and the Assessed Emission Rates

POLLUTANT	FIRED HEATER (START-UP)		FLARE (NORMAL OPERATION)		**FLARE (EMERGENCY/UPSET) SCENARIO 1**		**FLARE (EMERGENCY/UPSET) SCENARIO 2**		**FLARE (EMERGENCY/UPSET) SCENARIO 3**		AUXILIARY BOILER (START UP)		AUXILIARY BOILER (NORMAL OPERATION)		EMERGENCY DIESEL GENERATORS	
	EMISSIONS CONCENTRATION (MG/NM^3)	EMISSIONS RATE (G/S)	EMISSIONS CONCENTRATION (MG/NM^3)	EMISSIONS RATE (G/S)	EMISSIONS CONCENTRATION (MG/NM^3)	EMISSIONS RATE (G/S)	EMISSIONS CONCENTRATION (MG/NM^3)	EMISSIONS RATE (G/S)	EMISSIONS CONCENTRATION (MG/NM^3)	EMISSIONS RATE (G/S)	EMISSIONS CONCENTRATION (MG/NM^3)	EMISSIONS RATE (G/S)	EMISSIONS CONCENTRATION (MG/NM^3)	EMISSIONS RATE (G/S)	EMISSIONS CONCENTRATION (G/KW-HR) (TIER 2))	EMISSIONS RATE (G/S)
Oxides of Nitrogen	200	1.02	-	0.01-	-	21.97-	-	19.23	-	23.0	100	1.69	75	1.61	6.4	5.51-
Carbon monoxide	100	0.51	-	0.048	-	100.17	-	87.66	-	104.85	100	1.69	-	-	3.5	3.01
Particulate Matter	-	-	-	0.0009[4]	-	87.2	-	7.63	-	9.13	-[2]	0.14	-[2]	-	0.2	0.17
Sulphur Dioxide	3.9	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ammonia	-[3]	-	-	-	-	-	-	-	-	-	-[3]	0.2	3	0.0646	-	-

[1] Negligible emissions from Hydrogen. [2] Negligible emissions from Hydrogen/Natural gas. [3] No SCR at start up. [4] Negligible emissions

5.2 Emissions to Water

5.2.1 The process effluent streams produced at the proposed Installation are listed in Section 4.5.

5.2.2 As discussed in 4.5, effluent treatment is followed by discharge to the NZT outfall . Discharges to Tees Bay have been modelled for the DCO application and the water quality modelling report is provided in Appendix L.

Surface Water Drainage

5.2.3 A new surface water drainage network and management system will provide adequate interception, conveyance and treatment of surface water runoff from buildings and hard standing, with foul systems for welfare facilities and process wastewater generated by the site operations.

5.2.4 The proposed surface water drainage system is to include the use of sustainable drainage systems (SuDS) to provide treatment of runoff where there is a low risk of contamination by any chemicals to ensure potential adverse effects on water quality and habitat of receiving water bodies are avoided. The drainage system will be designed to be inherently safe and protect the local environment from urban diffuse pollutants that may be present. Clean surface water runoff will be segregated from contaminated/potentially contaminated water, which will be directed to the to oily water separation or ETP or in the case of amine contaminated water for off-site disposal. Gravity drainage will be used wherever practicable. The indicative surface water drainage plan (Figure 4) is provided in Appendix A.

5.2.5 The drainage system consists of the following:

- clean surface water runoff;
- potentially contaminated surface water (PCSW) runoff (non-amine contaminated);
- production plant surface water drainage;
- common utilities area surface water drainage; and
- diesel generator, tankage area and central chemical storage area surface water drainage.

5.2.6 Process operations on site will require the storage and use of a range of potentially polluting chemicals such as amine and ammonia. Wastewater may also have low pH, be contaminated with high levels of total suspended solids (e.g. iron corrosive products) and have the potential to exert a chemical oxygen demand on receiving watercourses. The surface water drainage system for areas of site drainage that may contain chemical pollutants from minor leaks and spills (i.e. surface water drainage near chemical storage tanks or overlying pipework etc.) will therefore need to be separated from the main 'clean' surface water drainage system using appropriate methods such as kerbs, bunds, sumps. Some areas may also be covered with rain shelters to reduce the ingress from rainfall to minimise the volume of potentially contaminated runoff that needs to be managed on the site. Where water is contaminated, this will be directed to the on-site effluent treatment plant.

5.2.7 In addition to the above sources of surface water, under exceptional circumstances firewater may be generated. Therefore, the surface water drainage system will include suitable measures for fire-fighting water to be diverted from the existing surface water SuDS system to a dedicated storage facility (which may be a basin or tank system) where the contaminated fire water can be stored prior to being pumped out for appropriate off-site disposal at a licenced waste facility. The storage requirements and the method by which fire-fighting water is diverted (i.e. an automatic or manual operated system) will be determined during detailed design.

Process Wastewater Drainage

5.2.8 Process waste waters may be generated on Site from the following operational activities including:

- process condensate from reforming process;
- raw water treatment rejects such as DAF and filtration wastes;
- flare KO drum liquids;
- cooling tower blowdown; and
- demineralisation plant rejects.

5.2.9 Wastewater management includes two separate wastewater treatment processes. The first involves the treatment of process condensate from the syngas plant, DAF waste, filtration waste and flare KO drum liquid in the biological treatment plant followed by recirculation to the raw water treatment plant. The second involves treatment of cooling water blowdown, DMW plant rejects and dewatering filtrate in the ETP followed by discharge via the NZT outfall to Tees Bay. Disposal of degraded amine will be via tanker and off-site disposal at a suitably permitted waste facility. Surface water runoff from uncovered external paved areas containing amine equipment, which during normal operation is expected to result in chemical drips, leaks and minor spill and which could be contaminated, shall be located within minimised local kerbed areas and be routed to the amine drain vessel for off-site disposal.

5.2.10 All relevant hazardous substances will be stored within bunded areas or internally within buildings with sealed drainage. Standard Operating Procedures will be in place detailing actions to be taken in the event of a spill or a leak, detailing how to contain and clean-up the release before it reaches the drainage system. Spill kits will be present at various locations to ensure prompt clean-up in case of a spill.

5.3 Emissions to Sewer

5.3.1 Sanitary waste water from welfare facilities in the administration and control building, workshop and warehouse building, and gatehouse will be drained via conventional foul sewer sumps and be pumped off-site to the NWL foul sewer connection and treated at Brans Sands WwTW.

5.3.2 Due to the nature of the discharge (i.e. domestic sewage, non-process emission) it does not fall within the Environmental Permit.

5.4 Emissions to Land

5.4.1 All areas on site, with the exception of any landscaped areas (which will be located away from process areas), will be covered in hardstanding. There are no soakaways on the site. Consequently, no direct emissions to land will occur as a result of the operation of the proposed Installation.

5.5 Odour

5.5.1 Storage of ammonia for the SCR plant, and storage and use of amines within the capture unit may have the potential to generate odour.

5.5.2 It is typical practice to include a breather vent in the storage tank to allow for vapour displacement during tank filling, fire exposure relieving rate from the tank and/ or nitrogen purging when unloading road tankers or cleaning lines.

5.5.3 If identified through FEED studies as being required, the amine storage tanks will have atmospheric fixed roof construction with appropriate abatement installed on breather vents, and suitable equipment to employ back-venting to tankers during filling, to minimise fugitive emissions and mitigated any odour emissions. This will be confirmed during FEED stage.

5.6 Noise

5.6.1 The proposed Installation will include several key plant and equipment which could lead to noise emissions from the site without appropriate mitigation. An assessment of the potential noise impacts has been completed as part of the Environmental Statement submitted with the DCO application and is provided in Appendix H.

5.6.2 Operational noise at residential noise sensitive receptors (NSR) has been assessed, including where relevant distinctive sound character correction, and consideration of other industrial sound sources that are closer to the NSRs than the proposed Installation will be, and other ambient sound levels.

5.6.3 The operational assessment has assumed that potential sound of a tonal, impulsive or intermittent nature (according to BS4142: 2014) will be designed out of the proposed Installation during the detailed design phase through the selection of appropriate plant, building cladding, louvres and silencers/ attenuators as necessary.

5.6.4 The noise assessment concludes that predicted change in the existing daytime and night-time ambient sound levels at NSRs would be just perceptible as a worst case, although the assessment will be refined at FEED.

5.6.5 Noise generation from the proposed Installation is therefore not anticipated to result in significant impacts at NSRs.

5.6.6 It is proposed that confirmation of the specific mitigation measures to be applied and their impact is provided to the EA upon completion of the FEED, prior to commencement of operation of the proposed Installation, to demonstrate compliance with the requirements of the EP Regulations.

6.0 MONITORING

6.1 General

6.1.1 An environmental monitoring plan will be implemented at the proposed Installation, which will demonstrate and provide ongoing assurance to site management and other stakeholders that mitigation measures are being applied and are effective. Suitable and sufficient sampling systems shall be provided for effective monitoring.

6.1.2 The environmental monitoring plan includes monitoring of atmospheric emissions, waste, water, and noise.

6.1.3 The environmental monitoring plan will be informed by guidance including:

- Best Available Techniques (BAT) Conclusions for Large Combustion Plants(3) (LCP BATc)
- Best Available Techniques (BAT) Reference Document for Common Waste Water and Waste Gas Treatment/Management Systems in the Chemical Sector(6)

6.2 Emissions to Air

6.2.1 There are potentially eight (four in each phase) new Release Points to air associated with the proposed Installation and equipment covered by this application, comprising:

- A1 & A3: Fired Start-up Heaters
- A2 & A4: Auxiliary Steam Boilers
- A5 & A6: Flares
- A7 and A8: Emergency Diesel Generators; and
- Firewater pumps

6.2.2 The hydrogen production plant will be maintained to seek to optimise thermal and electrical efficiency and minimise emissions generation.

6.2.3 To verify compliance with the AELS, Continuous Emission Monitoring Systems (CEMS) will be fitted to the stacks of the auxiliary steam boilers to monitor the flue gas parameters. The CEMS equipment will be certified by the UK Monitoring Certification Scheme (MCERTS).

6.2.4 Periodic monitoring will be used to monitor the fired heaters, emergency generators and fire pumps. This is consistent with monitoring requirements for MCP which operate less than 500 hours per annum.

6.2.5 The list of the emission points at the proposed Installation and the proposed monitoring to be carried out is shown below in Table 6.1.

6.2.6 Limits are not proposed for SO_2, HCl, HF, VOCs and PM since the combustion fuels are gaseous and very low in sulphur content and contain no chlorinated substances.

6.2.7 Limits are not proposed for the flare as it is only lit on pilot gas during normal operation.

6.2.8 Limits are not proposed for the fired heaters, emergency generator or firewater pump due to their limited operation in start-up or in testing and emergency. This is in line with the requirements of the Medium Combustion Plant Directive (MCPD) set out in EPR16 Schedule 25A.

Table 6.1: Proposed Preliminary Emission Levels and Monitoring

RELEASE POINT	PARAMETER	SOURCE	LIMIT (mg/Nm^3)	REFERENCE PERIOD	MONITORING FREQUENCY	MONITORING STANDARD OR METHOD	COMMENT
A1	NO_x	Fired heater (Phase 1)	-	-	Every 1500 hours of operation or once every 5 years (whichever comes first)	In line with Monitoring Stack Emissions: Low risk MCPs and Specified Generators	No limit as operating less than 500 hours per year
			-	-			
	CO		-	-			
A2	NO_x	Auxiliary boiler (Phase 1)	80	Yearly average	Continuous	BS EN 14181	Limit based on LCP BRef.
			110	Daily average or average over the sampling period	Continuous	BS EN 14181	
	CO		30	Yearly average	Continuous	BS EN 14181	Limit based on LCP BRef.
A3	NO_x	Fired heater (Phase 2)	-	-	Every 1500 hours of operation or once every 5 years (whichever comes first)	In line with Monitoring Stack Emissions: Low risk MCPs and Specified Generators	No limit as operating less than 500 hours per year
			-	-			
	CO		-	-			
A4	NO_x	Auxiliary boiler (Phase 2)	80	Yearly average	Continuous	BS EN 14181	Limit based on LCP BRef.

RELEASE POINT	PARAMETER	SOURCE	LIMIT (mg/Nm^3)	REFERENCE PERIOD	MONITORING FREQUENCY	MONITORING STANDARD OR METHOD	COMMENT
			110	Daily average or average over the sampling period	Continuous	BS EN 14181	
	CO		30	Yearly average	Continuous	BS EN 14181	Limit based on LCP BRef.

6.3 Emissions to Water

6.3.1 Measures will be taken that are designed to prevent accidental emissions such as fuel/chemical spillages and firewater entering the surface water drains. Such measures will be confirmed with the Environment Agency for approval as part of the final design prior to commencement of proposed operations, and are likely to include isolation valves such as penstocks, or source control measures such as booms or absorbent systems.

6.3.2 Wastewater management includes two separate wastewater treatment processes. The first involves the treatment of process condensate from the syngas plant, DAF waste, filtration waste and flare KO drum liquid in the biological treatment plant followed by recirculation to the raw water treatment plant. The second involves treatment of cooling water blowdown, DMW plant rejects and dewatering filtrate in the ETP followed by discharge via the NZT outfall (release point W1) to Tees Bay.The emission limits for the discharge point are provided in Table 6.2. These emission limits are derived from the BAT-AELs for Common Waste Gas and Wastewater.

Table 6.2: Emission limits for emissions to water

PARAMETER	LIMIT	UNITS	REFERENCE PERIOD
Total organic carbon (TOC)	33	mg/L	Yearly average
Chemical oxygen demand (COD)	100	mg/L	Yearly average
Total suspended solids (TSS)	35	mg/L	Yearly average
Total nitrogen (TN)	25	mg/L	Yearly average
Total inorganic nitrogen (N_{inorg})	20	mg/L	Yearly average
Total phosphorous (TP)	3	mg/L	Yearly average
Adsorbable organically bound halogens (AOX)	1	mg/L	Yearly average
Chromium (expressed as Cr)	25	µg/L	Yearly average
Copper (expressed as Cu)	50	µg/L	Yearly average
Nickel (expressed as Ni)	50	µg/L	Yearly average
Zinc (expressed as Zn)	300	µg/L	Yearly average

6.3.3 Clean stormwater may be recirculated to the raw water treatment plant or could be discharged either to the NZT outfall discharging into Tees Bay.

6.3.4 Continuous Water Monitoring Systems (CWMS) will be in place at the point to carry out automatic measurements. An indicative list of parameters to be considered for continuous monitoring regime and online analysing at the final discharge point is as follows:

- Flow rate
- pH

- Temperature
- Total Nitrogen
- Nitrate
- Conductivity
- Ammonia

6.3.5 Trace contaminants that may be present in water treatment chemicals such as sodium hydroxide, will be controlled through specification of raw materials.

6.3.6 The proposed Installation will be controlled and managed via a central Distributed Control System (DCS) for all operations. The DCS at the plant will provide the site operator with alarms should an operating parameter approach or exceed its set-point/ control value. The DCS will continuously monitor various parameters of the process water, and will use interlocks and trips if they are deemed necessary by Hazard and Operability (HAZOP) / Layer of Protection Analysis (LOPA) to prevent water of unacceptable quality from being discharged into surface water.

7.0 ENVIRONMENTAL RISK ASSESSMENT (IMPACT ASSESSMENT)

7.1 Introduction

7.1.1 This section discusses the potential impact on sensitive receptors and the surrounding area and shows how the emissions from the proposed Installation have been assessed and minimised.

7.1.2 Guidance contained in the EA guidance – 'Risk assessments for your environmental permit', has been used to scope and assess the emissions from the site.

7.1.3 Where necessary baseline impact assessments have been completed to ensure that any predicted significant effects on sensitive receptors can be avoided/ mitigated.

7.2 Site Location and Sensitive Receptors

Human Receptors

7.2.1 The town of Dormanstown is located approximately 1.3 km southeast of the Site, whilst Redcar is situated approximately 2.6 km to the east of the Site

7.2.2 There are no residential receptors within 500 m of the site. The closest residential properties (individual receptors) to the site are those at Marsh House Farm, in Warrenby approximately 1.3 km to the east.

7.2.3 The receptors listed in Table 7.1 are selected to be representative of residential dwellings, recreational areas and schools in the area around the proposed installation.

Table 7.1: Human Receptor Locations

RECEPTOR REFERENCE	RECEPTOR DESCRIPTION	DISTANCE AND DIRECTION FROM THE OPERATIONAL SITE
O1	Marsh Farm House, Warrenby Road, Coatham, Redcar	1.3 km east
O2	Cleveland Golf Links, Coatham, Redcar	1.2 km east
O3	South Gare Fishermans Association, Redcar	1.3 km north
O4	Marine Club, Redcar	1.3 km north
O5	Tingdene Beach Caravan Park, Coatham, Redcar	1.8 km east
O6	120 Broadway W, Dormanstown, Redcar	1.8 km south-east
O7	68 York Rd, Coatham, Redcar	2.2 km east
O8	Dormanstown Primary Academy, Redcar	2.2 km south-east

RECEPTOR REFERENCE	RECEPTOR DESCRIPTION	DISTANCE AND DIRECTION FROM THE OPERATIONAL SITE
O9	Coatham Church of England School, Coatham, Redcar	2.5 km east

Sensitive Environmental Habitats

7.2.4 EA 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 15 km for European designated sites and up to 2km for nationally designated sites.

7.2.5 Statutory designated sites listed in Table 7.2 have been identified through a desk study of the Defra Magic mapping website, which identifies Sites of Special Scientific Interest (SSSIs), RAMSAR sites, Special Protection Areas (SPAs) and Special Areas for Conservation (SACs).

Table 7.2: Ecological Receptor Locations

RECEPTOR IDENTIFICATION	ECOLOGY SITE	DESIGNATION	DISTANCE AND DIRECTION FROM THE OPERATIONAL SITE
OE1	Teesmouth and Cleveland Coast Ramsar, SPA, SSSI	Ramsar, SPA, SSSI	150 m north
OE2	Teesmouth and Cleveland Coast SPA, SSSI	SPA, SSSI	0 m adjacent north
OE3	Coatham Marsh LWS and Teesmouth and Cleveland Coast SPA, SSSI	LWS, SPA, SSSI	1.2 km east
OE4	Eston Pumping Station LWS	LWS	1 km south
OE5	Teesmouth NNR	NNR	1.78 km north-west
OE6	Teesmouth and Cleveland Coast SSSI	SSSI	0 m adjacent north
OE7	North York Moors SPA and SSSI	SPA, SSSI	12.5 km south-east
OE8	North Cumbria Coast SPA, Durham Cost SAC, Northumbria Coast Ramsar	SA, SAC, Ramsar	13.6 km north-west
OE9	Cliff Ridge SSSI	SSSI	13.2 km south

RECEPTOR IDENTIFICATION	ECOLOGY SITE	DESIGNATION	DISTANCE AND DIRECTION FROM THE OPERATIONAL SITE
OE10	Durham Coast SSSI and Durham Coast NNR	SSSI, NNR	12.6 km north-west
OE11	Durham Coast SSSI	SSSI	12 km north-west
OE12	Hart Bog SSSI	SSSI	14.3 km north-west
OE13	Langbaurgh Ridge SSSI	SSSI	12.5 km south
OE14	Lovell Hill Pools SSSI	SSSI	6.6 km south
OE15	Roseberry Topping SSSI	SSSI	12.2 km south
OE16	Saltburn Gill SSSI	SSSI	11 km south-east

7.2.6 The Teesmouth and Cleveland Coast SPA, SSSI and Ramsar site is located to north, adjacent to the proposed Installation). It includes a range of coastal habitats (sand and mud-flats, rocky shore, saltmarsh, freshwater marsh and sand dunes) on and around the Tees Estuary. The site was recently extended to include Coatham Dunes.

7.2.7 A Habitats Regulations Assessment was prepared for the DCO this is presented at Appendix J.

7.3 Hydrology

7.3.1 The River Tees flows approximately 0.9 km to the west of the proposed Installation boundary. The River Tees is tidal at the location, with the normal tidal limit approximately 14 km upstream (at the Tees Barrage).

7.3.2 The North Sea is located approximately 680 m to the north of the proposed Installation.

7.3.3 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 0.7 km south of the proposed 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).

7.3.4 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.

7.3.5 The EA ‘Flood map for planning’ indicates that the whole of the proposed 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.”

7.3.6 The proposed Installation site is not located within any Groundwater Source Protection Zone.

7.4 Geology

7.4.1 Artificial Ground is widespread across the site. The Artificial Ground is associated with the reclamation of land from the Tees Estuary from dredged materials and slag and the long historical industrial use of the site.

7.4.2 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.

7.4.3 The BGS maps show the bedrock geology underlying the Site to be Redcar Mudstone Formation, Penarth Group Mudstone underlain by both the Mercia Mudstone Group and Sherwood Sandstone Group.

7.5 Hydrogeology

7.5.1 The EA Groundwater Protection Policy adopts aquifer designations consistent with the Water Framework Directive. According to this system the Redcar Mudstone Formation is classified as a mixture of Secondary B and Secondary (undifferentiated) aquifers. The Mercia Mudstone Group and Penarth Group are mudstones and classified as Secondary aquifers B. The Sherwood Sandstone Group however is classified as Principal aquifer; these are layers of sedimentary rock deposit that have high intergranular and/ or fracture permeability; meaning they usually provide a high level of water storage. They may support water supply and / or river base flow on a strategic scale. In most cases, principal aquifers are aquifers previously designated as major aquifers. There are 2 licensed water abstractions within 1 km of the proposed Installation for industrial, commercial and public services (Sahaviriya Steel Industries UK Ltd, Cleveland Potash Ltd).

7.5.2 EA Groundwater Maps show that the proposed Installation site falls outside any Groundwater Source Protection Zones.

7.5.3 The proposed Installation site is also identified to be located on a Secondary (undifferentiated) Aquifer with the groundwater vulnerability classified as High.

7.5.4 The proposed Installation site is indicated to be outside the Groundwater and Surface water Safeguard Zones for Drinking Water.

7.6 Pathways for Pollution

7.6.1 In order for a pollution risk to occur, there has to be a source – pathway – receptor (S-P-R) linkage.

7.6.2 Pathways to sensitive receptors primarily include, but are not limited to, the following:

- Chemicals and fuel (diesel) required for the operation of the proposed Installation might leach into the ground and be washed into surface water or groundwater through the underlying soils.
- Chemicals required for the operation of the proposed Installation could be accidentally released and discharged into surface water via the outfall at W1.
- Emissions to air from the proposed Installation will be dispersed in the air to sensitive receptors.

7.6.3 In order to prevent and minimise the risk of pollution, the proposed 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.

7.6.4 The detailed description provided in Section 4.0 of this supporting document demonstrates how BAT have been applied to prevent pollution from the proposed Installation.

7.7 Impact Assessment

7.7.1 The following sections provide an assessment of the impact of releases from the proposed 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.

7.7.2 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;
- Present the assessment as detailed in the EA's Guidance 'Risk assessments for your environmental permit'[(5)].

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

7.8 Amenity and Accidents

7.8.1 A qualitative risk assessment has been undertaken for the proposed Installation and is included in Appendix D of this document.

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

Odour

7.8.3 Storage of ammonia for the SCR plant, and storage and use of amines within the capture unit may have the potential to generate odour.

7.8.4 In order to minimise the potential for odour to occur, fixed roof storage tanks will be used and if identified through FEED studies as being required, breather vents on the tanks will be fitted with suitable abatement, and tanks will back-vent to tankers during filling.

7.8.5 It is considered that through the FEED studies, potential for odour to result during the operation of the proposed Installation will be considered, and appropriate mitigation measures will be implemented.

7.8.6 Odour is assessed in the qualitative environmental risk assessment in Appendix D. Odour is not deemed significant at this time and no odour management plan has been proposed. A Leak Detection and Repair Plan (LDAR) will be maintained in the EMS which will prevent escape of odour.

Noise and Vibration

7.8.7 A copy of the noise assessment undertaken for the site is included in the ES and provided in Appendix H. The noise assessment included inherent mitigations and concluded that the operation of the proposed Installation will not result in any significant noise and vibration effects. Therefore, no noise management plan is proposed at this time.

7.8.8 Specific measures to be applied to the proposed Installation for mitigating noise emissions from site will be confirmed during the detailed design phase, and will be provided to the EA for approval.

Fugitive Emissions

7.8.9 CO_2 gas may be vented during start-up or scenarios such as inspections and testing if CO_2 purity is not suitable to be fed to the CO2 pipeline. It is not anticipated that such venting would include entrained solvent. These periods of venting will be infrequent and only as required for safe operation for the plant. A preliminary assessment of the venting scenarios has been completed and provided as Appendix P. The venting scenarios will be finalised during the detailed design and a further assessment of impact will be completed at that time.

7.8.10 H_2 will be directed to the flare during emergency scenarios, inspections and testing.

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

Visible Plumes/Flares

7.8.12 The risks associated with visible plumes and flares is discussed in Appendix D.

7.8.13 There is potential for visible plumes to occur from the mechanical draft cooling towers. Plume visibility will be considered as part of BAT during FEED.

7.8.14 The flare may be visible at night. Flare visibility will be considered as part of BAT during FEED.

Accidents

7.8.15 An assessment of major accidents and disasters has been carried out for the ES (Appendix M), which details the main hazards within the proposed Installation and identifies appropriate precautionary actions, to prevent or mitigate potentially significant risks.

7.8.16 For the management of accidents with lower environmental risk, an Accident Management Plan (AMP) will be developed to include the proposed Installation and all associated equipment. The AMP will meet the requirements of Hazardous Substances Consents and COMAH requirements.

7.8.17 A number of environmental protection measures will be implemented on site via the Environmental Management System (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 and all site personnel will be trained in their use. 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, oil storage regulations and CIRIA C736 requirements.
- Incorporation of interceptors into the drainage system to prevent spilled fuel entering the surface water drainage system or local water bodies.

7.8.18 In line with BAT requirements , a management plan will be developed as part of the EMS in order to reduce emissions to air and/ or to water during other than normal operating conditions (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.

7.9 Flood Risk Assessment

7.9.1 The EA Long term flood risk information[(9)] show that the site location is in an area at very low risk of flooding. The Detailed flood risk information for this area[(10)] identifies the flood risk from rivers or the sea, and surface waters as being very low at the proposed Installation site. 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.

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

- Flood resistance and resilience measures;
- Flood Emergency Response Plans;
- Flood Warnings and Alerts;
- Emergency access and egress; and
- Design capacity exceedance.

7.9.3 A copy of the flood risk assessment undertaken for the site is included in the ES and provided in Appendix I.

7.10 Emissions to Water

7.10.1 There will not be any direct discharges to the ground/ groundwater from the activities proposed by this application.

7.10.2 A summary of the emissions from the proposed Installation to surface water is provided in Section 5.2, including details of potential process water discharges and controls which will be applied to them. Wastewater treatment will be required for process effluent prior to discharge to the environment. Wastewater management includes two separate wastewater treatment processes. The first involves the treatment of process condensate from the syngas plant, DAF waste, filtration waste and flare KO drum liquid in the biological treatment plant followed by recirculation to the raw water treatment plant. The second involves treatment of cooling water blowdown, DMW plant rejects and dewatering filtrate in the ETP followed by discharge via the NZT outfall to Tees Bay.

7.10.3 Clean stormwater could be discharged either to the NZT outfall discharging into Tees Bay.

7.10.4 A water quality assessment has been completed on discharges to the Tees Bay and is presented in Appendix L.

7.10.5 All discharges to the Tees Bay from the proposed Installation will be continuously monitored to verify compliance with the Environmental Permit. It is therefore considered that the impact of the discharges to surface water will be insignificant.

7.10.6 There are no proposals to discharge any contaminated wastewater from the proposed Installation into the foul sewer (only domestic sewerage).

7.10.7 On this basis it is considered that the risk of impact to controlled water from treated and uncontaminated wastewaters from the proposed Installation will be very low.

7.11 Emissions to Air

7.11.1 An air dispersion modelling exercise has been undertaken to:

- Assess the impact on local air quality as a result of the anticipated emission levels identified in Table 5-1 and Table 5-2 above.
- Confirm the heights of the exhaust stacks so as to ensure adequate dispersion, and therefore ensure acceptable impacts at receptors.

7.11.2 A copy of the air quality assessment is included in Appendix F and the key findings are summarised below.

Appropriate Stack Heights

7.11.3 The selection of an appropriate stack release height requires a number of factors to be taken into account, the most important of which is the need to balance a release height sufficient to achieve adequate dispersion of pollutants against other constraints such as the visual impact of tall stacks. The analysis considers each stack individually first, then together to confirm the combined impacts are acceptable.

7.11.4 The main reported emissions for the proposed Installation have been modelled at a release height of 70 m above finished ground level for the Auxiliary Steam Boilers, with an internal stack diameter of 1.9 m. This release height is based on the results of the Stack Height Assessment in Appendix F. It is considered that this represents a conservative assessment, and the higher release height would result in lower impacts at modelled receptor locations. Following the same approach, the Fired Start-up Heaters have been modelled at a release height of 35 m above finished ground level, with an internal stack diameter of 0.9 m.

7.11.5 For the flare, effective release heights and equivalent stack diameters have been calculated for each of the operational scenarios. This final release height of 66.4 m is based on the results of the Stack Height Assessment, as well as consideration of the minimum release height required for safety and design reasons. The release height of 66.4 m is assessed as a minimum release height and at any increased release height, lower pollutant concentrations would be anticipated.

Impact on Local Air Quality

7.11.6 The proposed Installation will be designed such that combustion plant emissions to air comply with the emission requirements specified in BAT (i.e. BAT-AELs).

7.11.7 Where BAT-AELs are not available, the emissions have been assumed to be at the maximum concentrations provided from all technology licensors, in order that that a worst-case assessment can be carried out.

7.11.8 Detailed dispersion modelling has been used to calculate the concentration of pollutants at identified sensitive receptors and these have been compared with National Air Quality Strategy objectives, and Critical Levels and Critical Loads for ecosystems, with consideration for the baseline air quality and ecological deposition rates, in accordance with the EA's methodology.

7.11.9 The assessment has been based on the worst-case operational scenarios with respect to potential air quality impacts, employing operational design parameters for the alternative technologies and configurations under consideration for the proposed Installation. A number of other conservative assumptions have been made in combination, including:

- The use of the worst-case year of 5 years of meteorological data modelled.
- The use of maximum building sizes within the concept design.
- Annual operation of 100% utilisation, as a worst case for annual average impacts.
- Operation of the plant at proposed emission limits, when in reality annual average emissions are likely to be below these.
- Conservative estimates of background concentrations of pollutants at the sensitive receptors.

Detailed Dispersion Modelling Results

7.11.10 An H1 screening assessment of emissions to air was conducted using the Environment Agency's H1 tool (Appendix E). This assessment considered normal operation only. NO_x, particulate matter and CO emissions fail the H1 screening assessment, and therefore detailed modelling has been conducted. This detailed modelling is presented in Appendix F and the summary results are presented in Table 7.3 and discussed below.

7.11.11 The impact of point source emissions at human health receptors has been determined from model outputs at discrete receptor locations.

7.11.12 The maximum hourly, daily and annual mean predicted concentrations at human health receptors for normal operations have been compared with the relevant Air Quality Assessment Levels (AQALs), as summarised in Table 7.3. Any inconsistencies between the Predicted Environmental Concentration (PEC) (i.e. the process contribution, existing background concentration and the process contributions of other committed developments) and the predicted changes combined with the future year without development concentrations are due to rounding only.

7.11.13 The results have been initially presented as the maximum concentration that occurs at sensitive receptors. The predicted concentrations at locations within the Study Area have been reported in Appendix F.

7.11.14 The impacts of all pollutants released from the Proposed Installation are predicted to result in negligible adverse effects at all human health receptors within the study area, and these are considered to be Not Significant.

Table 7.3: Results of Operational Impact Assessment for Human Health Impacts

SPECIES	LOCATION	AQAL ($\mu G/M^3$)	PC ($\mu G/M^3$)	PC/AQAL (%)	MAGNITUDE OF IMPACT	BACKGROUND (BC) ($\mu G/M^3$)	FUTURE YEAR WITHOUT PROPOSED DEVELOPMENT WITH BC ($\mu G/M^3$)	PEC ($\mu G/M^3$)	PEC/AQAL (%)	SIGNIFICANCE OF EFFECT ACCORDING TO THE H1 ASSESSMENT CRITERIA
Maximum NO_2 hourly mean (as the 99.79^{th} percentile) – Normal Operation	Most affected sensitive receptor (O2 and O3)	200	1.0	0.5%	**Negligible**	26.6	31.3	32.2	16.1%	**Not Significant**
	Maximum anywhere outside site boundary		3.1	1.5%	**Negligible**	26.6	29.0	32.1	16.11%	**Not Significant**
Maximum SO_2 15 min mean (as the 99.9^{th} percentile) – Normal Operation	Most affected sensitive receptor (O6)	260	0.1	<0.1%	**Imperceptible**	4	11.7	11.8	4.5%	**Not Significant**
	Maximum anywhere outside site boundary	260	0.6	0.2%	**Imperceptible**	4	34.7	35.3	13.6%	**Not Significant**
Maximum SO_2 hourly mean (as the 99.73^{rd} percentile) – Normal Operation	Most affected sensitive receptor (O1)	350	0.1	<0.1%	**Imperceptible**	4	6.9	7.0	2.0%	**Not Significant**
	Maximum anywhere outside site boundary	350	0.5	0.2%	**Imperceptible**	4	28.6	29.2	8.3%	**Not Significant**
Maximum SO_2 24- hour mean (as the 99.18^{th} percentile) – Normal Operation	Most affected sensitive receptor (O6)	125	<0.1	<0.1%	**Imperceptible**	4	5.6	5.6	4.5%	**Not Significant**
	Maximum anywhere outside site boundary	125	0.3	0.1	**Imperceptible**	4	14.3	14.6	11.6%	**Not Significant**
Maximum PM_{10} 24 Hour Mean (as the 90.41^{th} percentile) – Normal Operation	Most affected sensitive receptor (O2)	50	0.1	0.1%	**Negligible**	19.2	19.2	19.4	38.7%	**Not Significant**
	Maximum anywhere outside site boundary		0.2	0.4%	**Negligible**	19.2	19.2	19.3	38.6%	**Not Significant**
Maximum CO 8-hour rolling average –	Most affected sensitive receptor (O1)	10,000	0.1	<0.1%	**Negligible**	221.8	250.3	250.4	2.5%	**Not Significant**

SPECIES	LOCATION	AQAL (µG/M³)	PC (µG/M³)	PC/AQAL (%)	MAGNITUDE OF IMPACT	BACKGROUND (BC) (µG/M³)	FUTURE YEAR WITHOUT PROPOSED DEVELOPMENT WITH BC (µG/M³)	PEC (µG/M³)	PEC/AQAL (%)	SIGNIFICANCE OF EFFECT ACCORDING TO THE H1 ASSESSMENT CRITERIA
Normal Operation	Maximum anywhere outside site boundary		0.3	<0.1%	**Negligible**	221.8	242.8	243.1	2.4%	**Not Significant**
PC = Process Contribution, AQAL = Air Quality Assessment Level, BC = Background Concentration, PEC = Predicted Environmental Concentration										

7.11.15 Operational air quality results for the worst affected ecological receptor (Teesmouth and Cleveland Coast SPA, SSSI and Ramsar site, located adjacent to the Main Site) are presented in Table 7.4. Results at all other ecological receptors are presented in Appendix F.

7.11.16 The annual average impacts of NO_x can be considered Not Significant, given that the PEC remains below 70% of the minimum relevant critical levels.

7.11.17 The daily NO_x concentration can also be considered Not Significant, given that the PC is less than the 10% screening criteria.

7.11.18 As the change in nitrogen deposition is predicted to be less than 1% of the minimum relevant critical load at the designated sites assessed, this is considered to be Not Significant.

7.11.19 Similarly, the change in acid deposition is predicted to be less than 1% of the minimum relevant critical load at the designated sites assessed, this is considered to be Not Significant.

Table 7.4: Results of Operational Impact Assessment for Designated Habitats

SPECIES	AQAL ($\mu g/m^3$)	PC ($\mu g/m^3$)	PC/AQAL (%)	BC ($\mu g/m^3$)	FUTURE YEAR WITHOUT PROPOSED DEVELOPMENT WITH BC ($\mu G/M^3$)	PEC ($\mu g/m^3$)	PEC/AQAL (%)	SIGNIFICANCE OF EFFECT
Worst case receptor NO_x daily mean (as the 100th percentile)	75	2.9	3.8%	34.0	33.0	35.8	47.8%	**Not Significant**
Worst case receptor NO_x annual mean	30	0.3	1.1%	17.0	18.9	19.2	64.1%	**Not Significant**
Worst case receptor NH_3 annual mean	3	0.01	0.4%	1.2	1.2	1.2	40.4%	**Not Significant**
Worst case receptor Nitrogen Deposition	10	0.11	1.1%	12.5	12.8	12.9	126.7%	**Not Significant**

SPECIES	AQAL (µg/m^3)	PC (µg/m^3)	PC/AQAL (%)	BC (µg/m^3)	FUTURE YEAR WITHOUT PROPOSED DEVELOPMENT WITH BC (µG/M^3)	PEC (µg/m^3)	PEC/AQAL (%)	SIGNIFICANCE OF EFFECT
Worst case receptor Acid Deposition	0.856 Min CL Min N/ 4.856 Min CL Max N / 4 Min CL Max S	0.008	<0.1%	1.0	1.01	1.03	5.5%	**Not Significant**

7.12 Site Waste

7.12.1 The details of anticipated waste streams generated at the proposed Installation are provided in Section 4.10.

7.12.2 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.

7.12.3 It is therefore considered that further assessment of the waste from the proposed site operations is not required.

7.13 Global Warming Potential (GWP)

7.13.1 This section is based on guidance presented in the EA guidance – "Assess the impact of air emissions on global warming"[(11)].

7.13.2 The proposed Installation is designed to deliver a carbon capture rate of 95% in accordance with current BAT guidance and has the potential capacity to further increase the capture rate to meet potential future regulatory changes. Therefore, the global warming impact of the emissions to air from the hydrogen production facility is significantly reduced.

7.13.3 The main global warming impact of the proposed Installation will arise from the remaining 5% of unabated process CO_2 emissions. The anticipated greenhouse gas (GHG) emissions of the proposed Installation is summarised in Table 7.5 (Phase 1 only) and Table 7.6 (Phase 1 and Phase 2). Scope 1 and 2 emissions are the operational emissions. Scope 3 emissions are presented to demonstrate that these have been considered.

Table 7.5: Average Annual GHG emissions (Phase 1)

ITEM	ACTIVITY/EMISSION SOURCE	EMISSIONS (TCO_2E/YEAR)
Scope 1	Flare pilots, flue gas, vent and seal leakage	4,357
	Uncaptured CO_2 emissions (5% that is not captured at 95% capture rate)	67,980
Scope 2	Imported electricity (average of 2028 to 2029)	64,223
	TOTAL Scope 1 and 2	**136,560**
Scope 3	Upstream emissions (well to tank methane extraction)	224,422

ITEM	ACTIVITY/EMISSION SOURCE	EMISSIONS (TCO_2E/YEAR)
	Downstream emissions (combustion of methane in output H_2 product)	132
	Worker transport	412
	Maintenance	36
	Uncaptured CO_2 during transport and storage unavailability	83,956
TOTAL Scope 1, 2 and 3		**445,518**

Table 7.6: Average annual GHG emissions (Phase 1 + Phase 2)

ITEM	ACTIVITY/EMISSION SOURCE	EMISSIONS (TCO_2E/YEAR)
Scope 1	Flare pilots, flue gas, vent and seal leakage	8,713
	Uncaptured CO_2 emissions (5% that is not captured at 95% capture rate)	135,960
Scope 2	Imported electricity (average of 2030 to 2055)	31,006
TOTAL Scope 1 and 2		**175,679**
Scope 3	Upstream emissions (well to tank methane extraction)	448,843
	Downstream emissions (combustion of methane in output H_2 product)	263
	Worker transport	412
	Maintenance	36
	Uncaptured CO_2 during transport and storage unavailability	167,911
TOTAL Scope 1, 2 and 3		**793,147**

7.14 Climate Change Risk Assessment

7.14.1 The Environment Agency's "*Adapting to Climate Change: Risk Assessment for Your Environmental Permit*"[(12)] guidance identified that a climate change risk assessment should be completed for a bespoke installation which Is expected to operate for more than 5 years.

7.14.2 The guidance also outlines the general approach to completing the risk assessment which comprises:

- Complete a screening assessment which is normally completed at the time of application;
- Where the screening score is greater than 5 then a full risk assessment is required – this involves completion of the relevant EA climate change risk assessment worksheet associated with the river basin area in which the site is located (the completed risk assessment worksheet is presented in Appendix K); and
- Identification of the controls and management measures that will be applied for potentially any significant risks that may be identified.

Screening Assessment

7.14.3 The screening assessment is summarised in Table 7.7 below. A site score of 5 is obtained, which is above the threshold for screening out a climate change risk assessment. Since a climate change risk assessment has been developed for the DCO submission (Environmental Statement Chapter 19, Appendix M), this climate change risk assessment is included to demonstrate that this has been considered.

Table 7.7: EA Screening Assessment

CATEGORY	SCREENING QUESTIONS	SCORE	SITE SCORE
Timescales	***How long will a permit be required for the facility?***		
	5 years or less (no need to complete rest of screening and no requirement for a risk assessment)	0	
	<20 years operation	1	
	Until between 2040 and 2060 (between 20 – 40 years from now.	3	✓
	Until 2060 or beyond (>40 years from now)	5	
Flooding	***What is your site's risk of flooding from the sea?***		
	Not in a flood-risk zone	0	
	Very low or low	1	✓
	Medium	3	
	High	5	
Water Use	***If you use water for your site operations or fire prevention, what is the source of the water.***		
	Water not required	0	
	Mains water	1	✓
	Surface water or groundwater abstraction	5	
TOTAL SCORE			**5**

Climate Change Risk Assessment Evaluation Criteria

Risk Assessment Scoring

7.14.4 Details of the scoring which applies to the risk assessment are summarised in the Table 7.8 below.

Table 7.8: Risk Assessment Scoring

DESCRIPTION	SCORE
Likelihood	
Unlikely : - circumstances are such that it is improbable the event would occur even in the long term.	1
Low likelihood : - circumstances are such that an event could occur, but it is not certain even in the long term that an event would occur, and it is less likely in the short term.	2
Likely : - it is probable that an event will occur, or circumstances are such that the event is not inevitable, but possible in the short term and likely over the long term.	3
Highly likely: - event appears very likely in the short term and almost inevitable over the long-term, or there is evidence of the event already happening.	4
Severity of Impact	
Minor impact : - short or long-term impact to operations resulting in additional measures for compliance.	1
Mild impact: - short-term, acute impact to operations resulting in single temporary compliance breach.	2
Medium impact: - short-term, acute impact to operations resulting in multiple temporary compliance breaches.	3
Severe impact: - short-term, acute impact to operations resulting in permanent compliance breaches.	4
Risk Categories	
Score is 1 to 3	Low
Score is 4 to 6	Low - Moderate
Score is 8 to 9	Moderate - High
Score is 12 to 16	High

Risk Scoring Matrix

7.14.5 The impacts are scored using the scoring matrix above and the risk is then scored using the risk scoring matrix (Table 7.9) by:

$$\text{Risk} = \text{Likelihood} \times \text{Severity}$$

Table 7.9: Risk Scoring Matrix

		SEVERITY			
		Severe Impact (score 4)	Medium Impact (score 3)	Mild Impact (score 2)	Minor Impact (score 1)
LIKELIHOOD	Highly Likely (score 4)	16	12	8	4
	Likely (score 3)	12	9	6	3
	Low Likelihood (score 2)	8	6	4	2

	Unlikely (score 1)	4	3	2	1

Risk Assessment

7.14.6 The risk assessment considers how vulnerable the site is in current and future climates taking into consideration in site specific aspects. It has been completed on the EA risk assessment worksheet for the river basin where the site is located. The Proposed Installation is situated in the Northumbria river basin district and the completed risk assessment worksheet is presented in Appendix K.

Climate Adaptation Controls and Management Measures

Introduction

7.14.7 The Environment Agency's "*Adapting to Climate Change: Risk Assessment for Your Environmental Permit*"(12) guidance requires that where potentially significant risks are identified that appropriate climate adaption controls and management measures should be identified.

7.14.8 The Climate Change Risk Assessment should be embedded into the Management System and should take into consideration the issues specific to the site as well as having the flexibility to adapt to reflect the outputs of any reviews.

7.14.9 When developing these measures, consideration was given to the EA guidance for "*Chemicals: examples for your adapting to climate change risk assessment*" (13) which identifies the sector specific potential impacts and associated mitigation measures to consider when preparing the climate change risk assessment and developing the relevant adaption controls and management measures.

7.14.10 In general, the Operator will aim to manage the risk through existing control measures to address the climate hazard and its effect on operations or environmental impact. There are currently no plans to:

- transfer the risk, such as by taking out insurance; or
- to change the site processes which may terminate the risk.

7.14.11 These options will be kept under consideration when the climate change risk assessment is subject to its review although it should be noted that the Operator's adaptive capacity to mitigate the potential impacts through soft or hard changes will depend upon financial resources, human resources, technical resources and internal organisational capabilities.

7.14.12 The following sections review the relevant potentially changing climate change variables, potential impact and the relevant control and management measures to be employed, taking into consideration the sector specific guidance.

7.14.13 The impacts, mitigation measures and risk ratings correspond to the Climate Change Risk Assessment conducted in the ES (DCO, Environmental Statement, Chapter 19, Appendix M). Considering the mitigation measures embedded in the design of the Proposed Installation, no significant climate change risks are anticipated.

Variable 1: Summer Daily Maximum Temperature Increases

7.14.14 In respect of this variable, it has been identified in Climate Change Chapter DCO, Environmental Statement, Chapter 19, Appendix M) that daily maximum temperatures could be higher for summer and winter periods (see Table 7.10 below) and this can cause a number of impacts discussed below.

Table 7.10: Projected Changes in Temperature (^{O}C), 50% Probability (10% and 90% Probability in Parenthesis)

Climate Variable	Time Period		
	2020 to 2039	2030 to 2049	2050 to 2069
Mean annual air temperature anomaly at 1.5 m (°C)	+1.0 (+0.4 to +1.6)	+1.3 (+0.6 to +2.1)	+2.1 (+1.0 to +3.2)
Mean summer air temperature anomaly at 1.5 m (°C)	+1.0 (+0.2 to +1.8)	+1.3 (+0.3 to +2.3)	+2.4 (+0.7 to +4.2)
Mean winter air temperature anomaly at 1.5 m (°C)	+1.0 (0.0 to +1.9)	+1.3 (+0.1 to +2.5)	+1.9 (+0.5 to +3.5)
Maximum summer air temperature anomaly at 1.5 m (°C)	+1.1 (+0.2 to +2.1)	+1.5 (+0.3 to +2.7)	+2.6 (+0.8 to +4.6)
Minimum winter air temperature anomaly at 1.5 m (°C)	+1.0 (+0.0 to +2.0)	+1.3 (+0.2 to +2.4)	+1.9 (+0.5 to +3.3)

7.14.15 The mitigation measures embedded in the design of the Proposed Installation are listed below each impact.

- Overheating of electrical equipment, heat damage, deformation, cracking and thermal expansion of building surfaces and pavements.
  - In order to mitigate this, cabling will be buried underground, insulating against overheating during heatwaves; and

- All buildings will be designed to UK standards and specifications[13].

Considering these embedded mitigation measures, the associated risk is deemed Low – Moderate.

- Impacts on the thermal comfort of building users. Increase in ambient temperature of buildings, leading to higher air conditioning requirements. Poorer air quality from dust, wildfires. Commuting issues resulting from wildfires.
  - Detailed design of air conditioning units for offices would include an allowance for future rise in ambient temperature; and
  - All buildings would be designed to UK standards and specifications.
  - Considering these embedded mitigation measures, the associated risk is deemed Low.
- Reduced efficiency of Production Facility and operational plant.
  - The plant is designed to operate over a large range of ambient conditions and the plant efficiency difference is less than 1% in all temperatures. Temperature change unlikely to have noticeable impact.
  - Considering these embedded mitigation measures, the associated risk is deemed Low.

Variable 2: Winter Daily Temperature Changes

7.14.16 This could be 3.5°C more than the current average with the potential for more extreme temperatures, both warmer and colder than present. Monitoring and recording of meteorological data will be ongoing throughout the lifecycle of the site so that measures can be implemented when required by extreme winter temperatures although there is no anticipated impact.

Variable 3: Daily Extreme Rainfall

7.14.17 In respect of this variable, it has been identified in Climate Change Chapter DCO, Environmental Statement, Chapter 19, Appendix M) that annual precipitation can increase (see Table 7.11 below), and this can cause a number of impacts discussed below.

Table 7.11: **Projected Changes in Precipitation Variables (%) 50% Probability (10% and 90% Probability in Parenthesis)**

CLIMATE VARIABLE	TIME PERIOD		
	2020 TO 2039	2030 TO 2049	2050 TO 2069
Annual precipitation rate anomaly (%)	+4.5 (-1.5 to +11.2)	+1.5 (-3.5 to +6.9)	+0.8 (-6.0 to +8.3)

CLIMATE VARIABLE	TIME PERIOD		
	2020 TO 2039	2030 TO 2049	2050 TO 2069
Summer precipitation rate anomaly (%)	-2.0 (-16.8 to +14.7)	-5.1 (-19.9 to +11.3)	-16.4 (-36.6 to +5.5)
Winter precipitation rate anomaly (%)	+9.5 (-3.0 to +22.8)	+12.0 (-1.2 to +26.3)	+14.6 (-4.3 to +35.7)

7.14.18 The following potential impacts are associated with this variable:

- Surface water flooding and standing waters;
- Deterioration of structures or foundations due to increase in soil moisture levels;
- Damage to building surfaces/ exposed utilities from increased drying/wetting and increased frost penetration; and
- Damage to infrastructure through coastal erosion, storm surge and coastal destabilisation.

7.14.19 The following mitigation measures are in place:

- Installation of a suitable sustainable surface water drainage network and management system (SuDS) to protect to Site from high rainfall events. Supported by a Surface Water Maintenance and Management Plan;
- Flood Resistance and Resilience Measures (raised ground levels, SuDS, flood defence barriers) to be implemented for scenarios including increases in extreme rainfall, flood flow and flash flooding; and
- All buildings would be designed to UK standards and specifications[(13)].

Considering these embedded mitigation measures, the risk associated with this variable is deemed Low.

7.14.20 Further details on the Flood defence strategy, including the Flood Risk Assessment can be found in Appendix I.

Variable 4: Average Winter Rainfall Increases

7.14.21 Average winter rainfall may increase by over 35.7% of today’s averages and has the potential for increased site surface water and flooding. The impacts and mitigations associated with Variable 3 apply to this variable, and the risk is deemed Low.

Variable 5: Sea Level Rise

7.14.22 In respect of this variable, it has been identified in Climate Change Chapter DCO, Environmental Statement, Chapter 19, Appendix M) that sea level may increase (see Table 7.12 below).

Table 7.12: Sea Level Rise Projections

	YEAR			
	2022	2028	2056	2071
Sea level anomaly (m)	+0.08 (+0.06 to +0.11)	+0.11 (+0.08 to +0.14)	+0.26 (+0.19 to +0.33)	+0.39 (+0.29 to +0.53)

7.14.23 The impacts and mitigations associated with Variable 3 apply to this variable, and the risk is deemed Low.

Variable 6: Drier Summers

7.14.24 Summers could see potentially up to 36.6% less rain than now and a site may be subject to cooling water restrictions of temperature and volume. The following potential impacts are associated with this variable:

- Water shortages;
- Drying out of pavement structures;
- Deterioration of structures or foundations due to decrease in soil moisture levels; and
- Insufficient water for plant cooling.

7.14.25 The following mitigation measures are in place:

- Integration of water circuits;
- Buildings would utilise water efficient fixtures; and
- All buildings would be designed to UK standards and specifications.

7.14.26 Considering these embedded mitigation measures, the risk associated with this variable is deemed Low – Moderate.

Variable 7: River Flow

7.14.27 The flow in the watercourses could be 50% more than now at its peak, and 80% less than now at its lowest. It is anticipated that higher water levels in the River Tees would not affect the site operations. Up to 80% lower levels would however have the potential to affect the cooling water supply.

7.14.28 The site will review the cooling options applied on site. As such, since the water used for cooling at the Installation is not considered to be significant with respect to the catchment capacity. The site will have a Flood Management Plan to manage any flood risks.

7.14.29 Considering these embedded mitigation measures, the risk associated with this variable is deemed Low – Moderate.

Variable 8: Storms

7.14.30 Storms could see a change in frequency and intensity and could damage building and other site structures. The site buildings and infrastructure such as emission stacks are subject to inspection and maintenance.

7.14.31 Considering these embedded mitigation measures, the risk associated with this variable is deemed Low.

7.15 Nutrient Neutrality

7.15.1 On 16 March 2022, Natural England published advice (Natural England, 2022a) to a number of Local Planning Authorities (LPAs), including Redcar and Cleveland Borough Council (RCBC), Stockton-on-Tees Borough Council (STBC) and Hartlepool Borough Council (HBC) and the Inspectorate, to indicate that as a Competent Authority under the Habitats Regulations the LPA (or Secretary of State in the case of a Development Consent Order (DCO)), must carefully consider the nutrient impacts of any new plans and projects on habitats sites and whether those impacts may have an adverse effect on the integrity of a habitats site that requires mitigation, including through nutrient neutrality. In the case of RCDB, STBC and HBC, the affected habitats site is the Teesmouth & Cleveland Coast Special Protection Area (SPA) / Ramsar site, for which excessive nitrogen is contributing to unfavourable status.

7.15.2 The proposed Installation is located within the catchment of the Teesmouth & Cleveland Coast SPA / Ramsar site. Therefore, a Nutrient Neutrality Assessment was required to consider the potential nutrient impacts of the Proposed Installation, whether the issue of nutrient neutrality is invoked, and assesses whether the Proposed Installation is nutrient neutral.

7.15.3 The Proposed Installation has the potential to release nutrients via i) process water effluent discharge (where it introduces a new nitrogen load rather than just concentrating nitrogen already present in raw water and being returned to the habitats site); ii) surface water runoff; iii) foul water discharge; and iv) atmospheric deposition of nitrogen.

7.15.4 The Nutrient Neutrality Assessment was completed as part of the DCO and is presented as Appendix G. This concluded it was possible to screen out the above potential impacts and the proposed Installation was therefore considered nutrient neutral.

8.0 SITE CLOSURE

8.1.1 A plan for appropriate decommissioning and closure of the proposed 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.

8.1.2 The plan for decommissioning will be available after FEED or commissioning and will identify the controls and mitigations that will be in place to safely decommission and demolish the plant. The procedures will ensure that such activities will comply with the regulations in place at that time and will minimise the risk to the environment.

9.0 REFERENCES

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11. DEFRA and EA, published on: 1st February 2016, Assess the impact of air emissions on global warming, available at: https://www.gov.uk/guidance/assess-the-impact-of-air-emissions-on-global-warming, accessed on 25/07/2023
12. Environment Agency, April 2023, Climate change: risk assessment and adaptation planning in your management system.
13. The Building Regulations Approved Document Part H: Drainage and Waste Disposal 2010.

APPENDIX A: PLANS AND DRAWINGS

- Figure 1 – Site Location Plan
- Figure 2 – Indicative Site Layout
- Figure 3 – Indicative Process Flow Diagram
- Figure 4 – Indicative Surface Water Drainage Plan
- 00-PFD-PR-00001 – PFD -Natural Gas Treatment
- 00-PFD-PR-00002 – PFD – CO2 Compression
- 00-PFD-PR-00003 – PFD CO2 Dehydration and Metering
- 00-PFD-PR-00004 – PFD – H2 Compression, Distribution, Metering & Export
- 00-PFD-PR-00005 – PFD – Hydrogen Aboveground Storage
- 00-PFD-PR-00006 – PFD – Natural Gas Metering
- 00-PFD-PR-00007 – PFD – Preheat, Saturation, Pre-Reforming and ATR Reforming
- 00-PFD-PR-00011 – PFD – CO2 Removal and Amine Storage Make-up System
- 00-PFD-PR-00012 – PFD – CO Conversion & Heat Recovery
- 00-PFD-PR-00013 – PFD - Hydrogen Purification
- 00-PR-UFD-00001 – UFD - Water Preparation
- 00-PR-UFD-00002 – UFD – Wastewater Treatment 1
- 00-PR-UFD-00005 – UFD - Cooling Water
- 00-PR-UFD-00006 – UFD - Flare
- 00-PR-UFD-00007 – UFD – Instrument Air / Plant Air
- 00-PR-UFD-00008 – UFD – Fire Water
- 00-PR-UFD-00009 – UFD - Air
- 00-PR-UFD-00010 – UFD - Steam System
- 00-PR-UFD-00011 – UFD – Auxiliary Boiler
- 00-PR-UFD-00012 – UFD – BFW & Supply Treatment
- 00-PR-UFD-00013 – UFD - Emergency Diesel Generator

APPENDIX B: SITE CONDITION REPORT

APPENDIX C: BAT ASSESSMENTS

- C1 – BAT Assessment for Emerging Techniques for Hydrogen Production with Carbon Capture
- C2 – BAT Assessment for Large Combustion Plant
- C3 – BAT Assessment for Cooling
- C4 – BAT Assessment for Energy Efficiency
- C5 – BAT Assessment for Emissions Management

APPENDIX D: QUALITATIVE ENVIRONMENTAL RISK ASSESSMENT

APPENDIX E: H1 SCREENING

APPENDIX F: AIR QUALITY IMPACT ASSESSMENT

APPENDIX G: NUTRIENT NEUTRALITY ASSESSMENT

APPENDIX H: NOISE ASSESSMENT

APPENDIX I: FLOOD RISK ASSESSMENT

APPENDIX J: HABITATS REGULATIONS ASSESSMENT

APPENDIX K: CLIMATE ADAPTABILITY RISK ASSESSMENT

APPENDIX L: WATER QUALITY MONITORING ASSESSMENT

APPENDIX M: ENVIRONMENTAL STATEMENT

APPENDIX N: LIST OF RELEVANT PERSONNEL

H2 Teesside Limited

Company number: 14523230

Registered Office: Chertsey Road, Sunbury on Thames, Middlesex, England, TW16 7BP

Date Incorporated: 5 December 2022

Details of Company Directors (Active only)

DIRECTOR NAME (LAST NAME, FIRST NAME)	DATE OF BIRTH	APPOINTED ON
Agar, Thomas	November 1974	5 December 2022
De Oliveira, Shirley	October 1973	5 December 2022
Williamson, Matthew	July 1973	5 December 2022

Company Secretary: Sunbury Secretaries Limited

Registration number: 07158629

Registered Correspondence Address: 1 Chamberlain Square Cs, Birmingham, England, B3 3AX

Appointed on: 5 December 2022

APPENDIX O: APPLICATION CHECKLIST

QUESTION REFERENCE	DOCUMENT TITLE	DOCUMENT REFERENCE
Pt A, Q5c	List of relevant personnel	Appendix N, AP3328SQ-APP-SS
Pt B2, Q2b, Table 1; PtC3,Q1	Proposed operations	Section 4, AP3328SQ-APP-SS
Pt B2, Q3d	Management System	Section 4, AP3328SQ-APP-SS
Pt B2, Q5a	Site Plan	Appendix A, AP3328SQ-APP-FIG1
Pt B2, Q5b, Q5f	Site Condition Report, Baseline Conditions	Appendix B, AP3328SQ-APP-SCR
Pt B2, Q5c	Non-Technical Summary	Section 1, AP3328SQ-APP-SS
Pt B2, Q6	Qualitative Environmental Risk Assessment	Section 7 and Appendix D, AP3328SQ-APP-SS
Pt B3, Q2	Emissions to air, water, sewer and land	Section 5, AP3328SQ-APP-SS
Pt B3, Q3a	Technical Standards	Section 4 and Appendix C, AP3328SQ-APP-SS
Pt B3, Q3c	Raw Materials	Section 4, AP3328SQ-APP-SS
Pt B3, Q4a	Monitoring	Section 6, AP3328SQ-APP-SS
Pt B3, Q4a	Monitoring of emissions to air	Section 6, AP3328SQ-APP-SS
Pt B3, Q5a	Environmental Statement (EIA)	Appendix M, AP3328SQ-APP-ES
Pt B3, Q6a, Q6c	Energy efficiency	Section 4, AP3328SQ-APP-SS
Pt B3, Q6b	Energy use	Section 4, AP3328SQ-APP-SS
Pt B3, Q6d	Raw materials	Section 4, AP3328SQ-APP-SS
Pt B3, Q6e	Waste	Section 4, AP3328SQ-APP-SS

APPENDIX P: CO_2 VENTING ASSESSMENT