Permitting Decisions- Variation

We have decided to grant the variation for Stanlow Manufacturing Complex operated by Essar Oil (UK) Limited.

The variation number is EPR/FP3139FN/V013.

The variation is to include the operation of a new Hydrogen Production Plant (HPP) on land formerly used by the Alcohols Plant at the Stanlow Refinery. The new HPP is being developed as part of the wider HyNet Project and will consist of reforming of natural gas and refinery off-gas (ROG), followed by a carbon capture and storage (CCS) plant. The CCS plant captures the carbon dioxide (CO_2) generated by the process. The captured CO_2 is compressed and exported from the installation for offsite geological storage (beyond the scope of this variation) through the infrastructure that is part of the wider HyNet Project. The variation application covers production of 100,000 Nm^3/h of hydrogen, with a design CO_2 capture rate of 97%, corresponding to approximately 75 tonnes/hour of CO_2.

We consider in reaching that decision we have taken into account all relevant considerations and legal requirements and that the permit will ensure that the appropriate level of environmental protection is provided.

1. Purpose of this document

This decision document provides a record of the decision-making process. It

- highlights key issues in the determination
- summarises the decision making process in the Decision considerations section to show how the main relevant factors have been taken into account
- explains why we have also made an Environment Agency initiated variation
- shows how we have considered the consultation responses

Unless the decision document specifies otherwise we have accepted the Applicant’s proposals.

Read the permitting decisions in conjunction with the environmental permit and the variation notice.

2. Key issues of the decision

2.1 Outline description of the proposal

The variation application covers the following new Environmental Permitting Regulations (EPR) scheduled activities:

- Section 4.2 Part A(1)(a)(i) - Producing inorganic chemicals such as gases (hydrogen)
- Section 6.10 Part A(1)(a) - Capture of carbon dioxide for geological storage
- Section 5.3 Part A(1)(a)(i) Disposal or recovery of hazardous waste with a capacity exceeding 10 tonnes per day by biological treatment
- Section 5.3 Part A(1)(a)(ii) Disposal or recovery of hazardous waste with a capacity exceeding 10 tonnes per day by physio-chemical treatment

The following existing permitted activity is amended as a result of this variation application:

- Section 1.1 Part A (1) (a) Burning any fuel in an appliance with a rated thermal input of 50 or more megawatts

The following existing permitted activities are removed from the permit, through this variation:

- Section 4.1 Part A(1)(a)(i) Producing organic chemicals such as hydrocarbons (linear or cyclic, saturated or unsaturated, aliphatic or aromatic) - Higher Olefins SHOP, including LCP 143 - serving this activity but part of activity Section 1.1 Part A(1)(a).
- Section 4.1 Part A(1)(a)(ii) Producing organic chemicals such as organic compounds containing oxygen - Alcohols (Neodol and Linevol) including Syngas production.
- Section 4.1 Part A(1)(a)(ii) Producing organic chemicals such as organic compounds containing oxygen - Epoxy resins

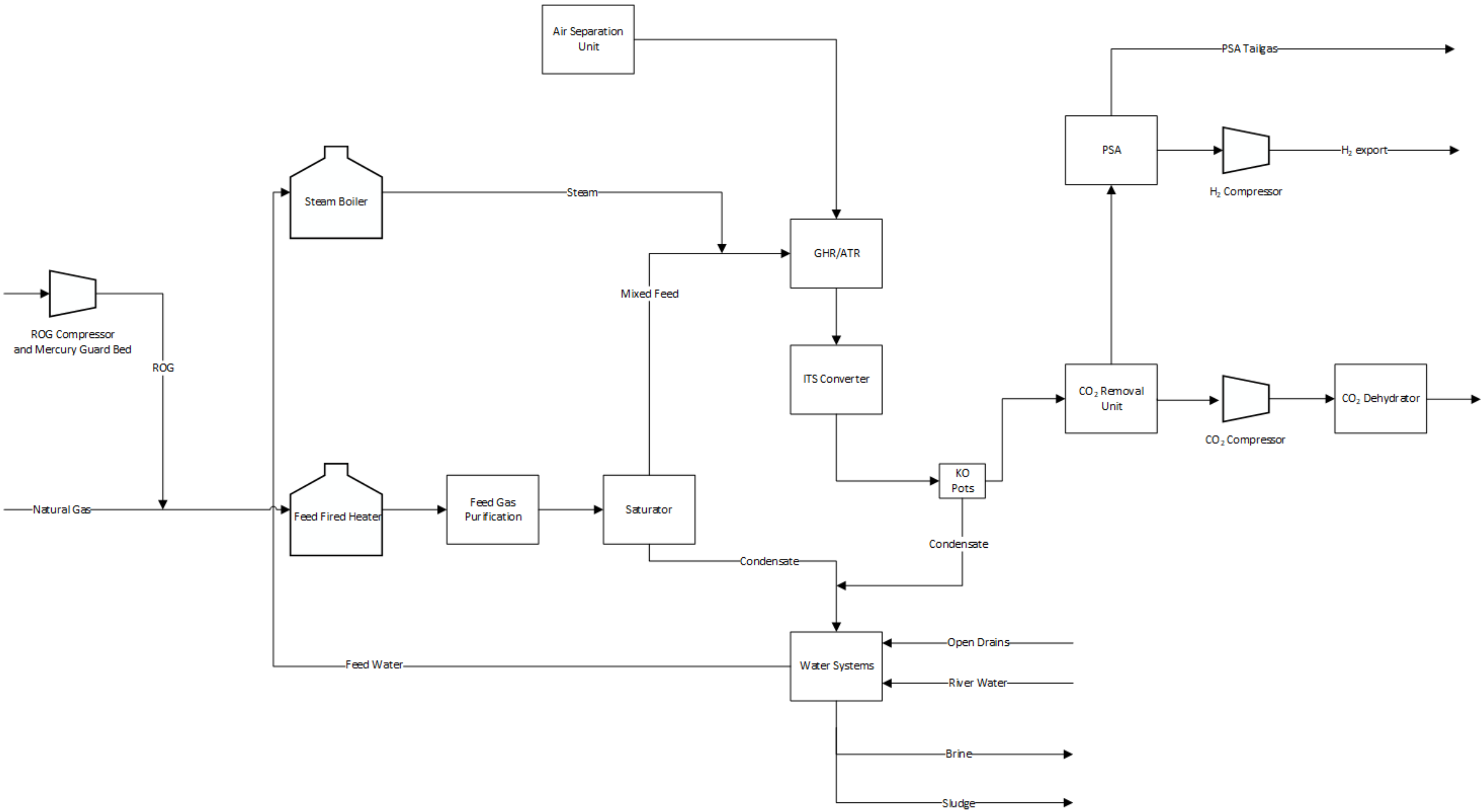
However, the land associated with the activities being removed is retained within the permitted installation boundary and will be occupied by the new proposed activities, therefore the above-mentioned activities are removed from the permit through a variation mechanism. References to the alcohol, SHOP and resins plants have been retained in the permit issue log, for the purpose of future surrender of the land associated with these activities.

The HPP is designed to produce a compressed hydrogen product, of greater than 99.9% purity by volume, from a feedstock of natural gas, ROG, water and oxygen and to capture the CO_2 produced by the reforming process. The captured CO_2 is compressed and dehydrated to a specification suitable for routing to subsea geological sequestration via a CO_2 pipeline (the CO_2 sequestration infrastructure is beyond the boundaries of the installation).

The overall process for the production of hydrogen and the separation of CO_2 is carried out in a sequence of stages:

- Feed gas delivery and purification;
- Feed gas saturation;
- Gas reforming;
- Isothermal Shift (ITS) conversion;
- CO_2 removal, compression and export; and
- Hydrogen purification, compression and export.

A short process description of each stage is provided in the following paragraphs, along with a block flow diagram reproduced from the application documents:


Air Separation Unit
PSA Tailgas
PSA
H_2 export
H_2 Compressor
Steam Boiler
Steam
GHR/ATR
Mixed Feed
ROG Compressor and Mercury Guard Bed
ROG
ITS Converter
CO_2 Removal Unit
CO_2 Compressor
CO_2 Dehydrator
KO Pots
Natural Gas
Feed Fired Heater
Feed Gas Purification
Saturator
Condensate
Condensate
Water Systems
Open Drains
River Water
Feed Water
Brine
Sludge

Delivery and purification

The feed gas stream comprises either natural gas (NG) (on start-up and shut-down) or a mixture of up to 55% natural gas and 45% ROG. The natural gas is sourced from the UK National Transmission System (NTS), and the ROG piped from the refinery. The incoming gas stream is heated in the Feed Fired Heater and goes through a process to remove any chloride or sulphur compounds to prevent the deactivation of down-stream catalysts. The Feed Fired Heater is fired on tail gas from the downstream pressure-swing-adsorption (PSA tail gas) process (or NG on start-up and shut-down) a desulphurised process off-gas, comprising mostly hydrogen, nitrogen and methane, from the hydrogen product purification process. Products of combustion are exhausted to atmosphere via a stack (emission point HPP-A-1).

Saturation

The purified and heated feed gas is passed to the Saturator and is contacted with hot water and steam to saturate the gas stream (this is required to achieve the reforming process reaction). The water-saturated gas (now termed the ‘mixed feed’) is then heated further in the Feed Fired Heater and routed to the Gas Heated Reformer. Steam is generated in a Steam Boiler fired on PSA tail gas. Products of combustion are exhausted to atmosphere via a second stack (emission point HPP-A-2).

Reforming

The mixed feed is passed through two reformers, a Gas Heated Reformer (GHR) and an Autothermal Reformer (ATR) both of which contain proprietary nickel-based catalysts. The reformers promote the conversion of the mixed feed into synthesis gas (or ‘syngas’), consisting of a mixture of oxides of carbon – carbon monoxide (CO) and carbon dioxide (CO_2) – hydrogen and residual methane.

Isothermal Shift

The syngas leaving the reforming process passes to the Isothermal Shift (ITS) Converter, which comprises tubes containing a copper-based catalyst, surrounded by a water jacket. The catalyst promotes the reaction of carbon monoxide with water to produce hydrogen and CO_2. The heat of the water gas shift reaction is recovered for steam generation and is also used for heat exchange against other process streams (optimising the energy efficiency of the HPP). The cooled reacted gas is routed to the CO_2 Removal Unit.

CO_2 Removal

The CO_2 Removal Unit uses an amine solution to adsorb CO_2 from the syngas; the amine solution is then passed to a lower pressure stripper column where the adsorbed CO_2 is released, and the lean amine solution is then returned to absorb more CO_2 from the syngas. The process operates continuously to produce two separate product gas streams:

- a high purity CO_2 product stream (with a CO_2 concentration in excess of 95% mol) which is then sent for compression, dehydration and export in a dedicated CO_2 pipeline for sequestration; and

- a CO_2-free syngas (with a CO_2 concentration of less than 0.1% mol) which is sent to a Pressure Swing Adsorption (PSA) unit for further purification.

The carbon capture process consists of process removal, as opposed to post-combustion carbon capture, meaning that the CO_2 is separated from syngas process stream instead of being separated from a flue-gas stream post-combustion.

Hydrogen purification

The CO_2-free syngas is passed through the PSA Separation Unit where remaining carbon monoxide, methane and nitrogen are removed from the hydrogen. The hydrogen product is then compressed and cooled. A proportion is used in the refinery as a fuel (the hydrogen is essentially a decarbonised replacement for the ROG used as HPP feedstock). The remainder is exported via the hydrogen pipeline (outside of the installation).

The gases separated from the hydrogen product stream in the PSA Separation Unit (comprising a portion of hydrogen gas as well as carbon monoxide, methane and nitrogen) is the PSA tail gas, used as a fuel in the Feed Fired Heater and Steam Boiler.

There are a range of utilities and services required to serve the HPP process. These include:

Water Supply and Treatment

Water used in the plant is primarily sourced from an existing United Utilities raw water supply drawn from the River Dee. However, water usage has been optimised by augmenting this supply with re-used process water and harvested rainwater.

The water process includes: clarification; oil separation; biological treatment of process effluents; filtration and demineralisation. The demineralisation plant will generate a demineralised water stream and a reject effluent, which will be discharged to the existing refinery drainage system for eventual discharge at existing discharge point W3.

The water clarification, filtration and membrane bio-reactor (MBR) process generate sludges which are dewatered and sent for off-site disposal.

Steam System

Steam is generated in the Steam Boiler (a fired boiler using PSA tail gas as a fuel) and in the iso-thermal shift (ITS) Converter (using recovered process stream heat). Boiler Feed Water is demineralised water treated with a Boiler Feedwater Package.

Air Separation Unit

A single cryogenic air separation unit (ASU) supplies oxygen to the ATR and nitrogen, which will be used as a process purge gas in start-up and shut-down, and for inerting.

Cooling System

Cooling is provided by an air-cooled closed-circuit system using a propylene glycol/water mix as the cooling medium.

Emergency Power Generation
The facility has a diesel engine-driven emergency power generator (2.9 MWth input) to allow safe shut-down and maintenance of the facility in the event of loss of power (emission point HPP-A-4). Under normal circumstances, the emergency generator will only be operated for regular routine testing, amounting to less than 50 hours per year.

Flare
A flare is provided for emergency and maintenance purposes (emission point HPP-A-3). It comprises a single raised flare stack with a common header. The flare is designed to provide a safe disposal route for the HPP's flammable gases under start-up, shut-down, abnormal and emergency conditions only.

2.2 Operating techniques and BAT assessment

The assessment of the operating techniques proposed for the installation against Best Available Techniques (BAT) is set out in the application document titled 'HyNet Hydrogen Production Plant Environmental Permit Application Supporting Document', received on 31/08/2021. Further information on how the proposed operating techniques compare against BAT was provided by the Applicant in response to the Schedule 5 Notice served on 17/03/2022 (responses received on 24/06/2022, 15/07/2022, 18/07/2022, 09/08/2022, 26/09/2022, 25/11/2022, 28/11/2022 and 09/12/2022). We have included the relevant application documents and responses to the request for additional information in table S1.2 of the environmental permit.

It should be noted that, although the production of hydrogen by thermal conversion of hydrocarbons is a well-established process and the individual technologies identified in the application can be considered mature, the thermal production of hydrogen coupled with carbon capture for geological storage is a novel concept that has not seen commercial applications at an industrial scale yet. Hence, we consider the application to consist of emerging technologies.

Our BAT determination is therefore based on our current understanding of these emerging technologies and takes into account the fact that this is the first project developed in the UK for this type of installation. Our position on the determination of BAT for hydrogen production with carbon capture and storage is subject to change and development as we receive more applications for similar plants, and we develop and consolidate our positions on specific BAT issues. This may also happen as the result of the continuous exchange of information and engagement with industry and other key stakeholders, the review of received applications and the regulation of the permitted sites brought into operation.

We have determined BAT for the proposed installation with reference to the following guidance: 'Emerging techniques for hydrogen production with carbon capture'. This is published on our website. The BAT criteria referred to in the guidance are those set out in Annex III of the Industrial Emissions Directive (IED), as read in accordance with Schedule 1A to the Environmental Permitting (England and Wales) Regulations 2016.

The application is discussed in the following against the key requirements set out in the guidance on emerging techniques. Reference is also made to the Refining of Mineral Oil and Gas BAT Conclusions (also referred to as REF BAT Conclusions in the following), which are relevant to the type of activities carried out at the installation.

2.2.1 Environmental management system, staffing and resourcing

The existing installation currently operates according to an Environmental Management System (EMS) that was previously determined to meet all the applicable requirements of BAT conclusion 1 of the Refining of Mineral Oil and Gas BAT Conclusions (variation application EPR/FP3139FN/V009). The existing EMS is certified to ISO standard 14001:2015. The Applicant has committed to updating the EMS to incorporate the proposed HPP prior to start of operations, including any plant specific emissions controls, management techniques and operating procedures. This update will include a review and update of the Accident Management Plan. We have set a pre-operational condition requiring the Operator to submit to us a report confirming the extension of the existing EMS to cover the activities introduced by this variation.

According to the information provided in the application, Essar Oil (UK) Limited, will be the legal operator of the proposed new facilities, with overall control and responsibility for the operations and activities, including management of emergencies, resourcing and staff management, investment and financial decisions. They will operate the facilities in the scope of the application by virtue of a contract with Vertex Hydrogen Ltd which will be the owner of the assets.

In the response to the Schedule 5 Notice received on 24/06/2022 the Applicant confirmed that the operations of the HPP in the scope of the application will be adequately staffed with a new asset team consisting of 19 additional qualified operational full-time employees (FTE), above the existing headcount employed at the Stanlow Manufacturing Complex. A separate maintenance organisation sub-structure will be set up within the Operator's maintenance department consisting of a team leader, and one technician for each of the rotating equipment, electrical and instrumentation and general mechanical disciplines, liaising with subject matter experts for technical support. An engineering assurance team, independent from the operational asset team, will be established for the HPP, consisting of qualified engineering personnel including: technologist (1 FTE), rotating equipment engineer (0.25 FTE), inspection engineer (1 FTE), electrical and instrumentation engineer (1 FTE) and mechanical engineer (1 FTE).

The staffing levels stated in the application documents and responses to requests for further information have been included in the operating techniques as minimum requirements that the Operator is expected to comply with (table S1.2 of the permit).

2.2.2 Technology selection

Our guidance on emerging techniques requires applicants to demonstrate their technology selection considers the overall environmental performance of the plant, including energy efficiency, resource efficiency, CO_2 capture efficiency and emissions to the environment.

The application includes a justification for the technology selected for the proposed plant. This will consist of the 'Low Carbon Hydrogen' (LCH™) process, licensed by Johnson Matthey. The core of the LCH™ flow sheet consists of a sequence of gas-heated reforming (GHR) and auto-thermal reforming (ATR).

According to the application, the proposed technology offers lower cost, higher CO_2 capture rate and scalability advantages over the reference alternative technology, Steam Methane Reforming (SMR), when coupled with carbon capture and storage. SMR is the established reference technique for hydrogen production internationally today. However, whilst the SMR approach is suited to a proportion of CO_2 capture, it has a CO_2-containing stream which is at lower partial pressure compared to the proposed LCH™ process.

Therefore, according to the explanation set out in the application, achieving acceptable levels of capture is more expensive and energy-intensive than with the proposed LCH™ process.

The LCH™ technology, comprising a GHR coupled with an oxygen blown ATR, has a single process stream with a higher partial pressure of CO_2. This makes it more cost-effective and efficient to deliver a higher CO_2 capture rate of around 97%. The combination of a GHR and ATR offers increased gas process efficiency compared to SMR, and the production of hydrogen at pressure results in reduced compression costs.

According to the application, the LCH^{TM} technology is inherently more efficient than SMR with CCS, as the heat required for the reforming reactions is not provided by external heat, as is the case in the SMR process.

Our guidance on emerging techniques includes a review of the following technologies:

- Steam methane reforming (SMR);
- Autothermal reforming (ATR);
- Gas heated reforming (GHR); and
- Partial oxidation (POX).

At present, our approach to permitting thermal production of hydrogen with carbon capture is technology neutral as we think that there is not enough evidence to conclude that one of the technologies listed above is preferrable to the others. This is subject to change as we develop further our BAT position on these emerging technologies.

The justification provided in the application is satisfactory and we consider the proposed technology meets the requirements of our guidance on emerging techniques.

Further detail on the energy efficiency, carbon capture efficiency, resource and emissions performance for the proposed plant are discussed in the following sections and support the conclusion that the proposed installation meets BAT for these emerging technologies.

2.2.3 Overall CO_2 capture efficiency

Our guidance for emerging techniques requires the design to maximise the carbon capture efficiency and as a minimum achieve an overall CO_2 capture rate of at least 95%, although it acknowledges that this may vary depending on the operation of the plant.

The overall carbon capture rate or efficiency is defined as the mass of CO_2 equivalent captured for use or storage as a percentage of the mass of CO_2 equivalent in feed gas or as the mass of carbon captured as a percentage of the mass of carbon in the feed gas.

According to the application, the design CO_2 capture rate for the proposed plant is 97%. The capture rate is defined in table 3-4 of the application document titled 'HyNet Hydrogen Production Plant Environmental Permit Application Supporting Document' as the percentage ratio between the carbon captured by the process and the carbon in the feed gas, in a way that is consistent with the definition set out in our guidance.

Based on the information available in the application, we are therefore provisionally satisfied that the proposed plant meets the requirements of our guidance on emerging techniques for the overall CO_2 capture efficiency.

As the carbon capture parameter stated in the application is a design performance, and the actual operation of the plant ‘as built’ may diverge from its design specification when taking into account transient and abnormal operations, we have set an improvement condition requiring the operator to assess and confirm whether the actual carbon capture performance of the operating plant is consistent with its design specification over an extended period of time (i.e. one year of operation). Should the actual capture performance fall short of the minimum capture performance of 95% stated in our guidance, the Operator shall carry out an analysis of the issues affecting the performance of the plant and propose remedial actions for our approval to improve the capture efficiency performance.

Annual reporting requirements for the carbon capture performance have been specified in the consolidated variation notice.

It is noted the proposed plant imports approximately 24 MWe of electric power (reference: amended figure provided in Response to Schedule 5 Notice, received on 24/06/2022), whose indirect CO_2 emissions are not accounted for in the capture efficiency definition specified by our guidance. However, the electricity import is not expected to significantly contribute to the overall carbon footprint of the proposed operations, because, according to the operating techniques stated in the application, this will be sourced as green electricity, under a guarantee of origin, from renewable energy sources.

2.2.4 Feed gas quality and treatment

The HPP is designed to process a gas stream comprising natural gas (NG) taken from the National Transmission System and refinery-off-gas (ROG) from Stanlow refinery. Depending upon the operating case the feed gas can compromise 100% NG to a 55/45% mol NG/ROG mix. The refinery produces a number of sources of ROG of varying qualities and consistency, but, according to the application, only the best quality and most reliable of these streams will sent for reforming in the HPP.

The ROG has a design H_2S concentration of 13.6 ppmv. The HPP includes a desulphurisation stage designed to remove impurities in the gas of up to 20 ppmv total sulphur (and 3.5 ppmw chlorides and 5 ppmv organo-sulphur). According to the operating techniques stated in the application, if the impurities exceed these levels for any appreciable time, the ROG will not be imported.

The feed gas desulphurisation will result in beneficial effects on emissions to air, as the two principal sources of combustion gases on the HPP are the Feed Fired Heater and the Steam Boiler, which will be fired on PSA tail gas (under all operating scenarios except during start-up and shut-down when NG is used as the fuel). This is a desulphurised gas stream the combustion of which will not result in atmospheric emissions of sulphur dioxide (SO_2).

There will be pre-treatment of the ROG to remove mercury which can poison the HPP catalysts. The up-stream ROG Compressor will therefore be provided with a mercury guard bed to remove any traces of mercury before the ROG is transferred to the HPP.

The HPP will be provided with desulphurisation catalyst/ adsorbent inventories with a design life of 4 years for single vessels (consistent with the major maintenance turnaround for the HPP) and 2 years where twin vessels are used.

The ROG delivered to the HPP has an ethane content of 18% mol. However, according to the application, a pre-reforming step is not necessary and therefore it has not been provided in the HPP design. This is because the proposed reforming process already consists of two stages:

- The GHR (which operates at a temperature of around 700ºC) is effective at breaking down the heavier hydrocarbons.
- The second stage reforming of the resulting gas mix is then carried out in the ATR at a higher temperature (of around 1,020ºC).

We are satisfied that the proposed feed gas treatment process meets requirements set out in our guidance on emerging techniques.

2.2.5 Reforming process

Our guidance for emerging techniques requires applicants to select, design and operate the reforming reaction in order to reduce risk of carbon deposition on catalyst, which would result in reduced reaction efficiency; and minimise catalyst change frequency and the need for recycling/waste disposal.

According to the application, the risk of soot formation within the LCH™ technology is reduced by the selection of a low inlet temperature of the purification stage of the plant and for the ATR the high level of hydrogen and the high steam to carbon ratio. The formation of soot will be detected through the presence of solid carbon particles in process condensate (i.e. through water analysis) and, should this happen, appropriate action would be taken promptly to prevent impacts on the performance of the plant.

The metals employed in the reformer catalysts can be recovered and recycled: according to the application, the expectation, in the current and likely economic climate, is that the spent catalysts will be reclaimed/recycled and so not go to landfill. The Applicant proposed that the arrangements for the management of spent catalysts will be formalised at the project detailed engineering stage through the development of a catalyst care programme. We have set an improvement condition to confirm the arrangement of this programme.

We are satisfied that the proposed reforming process meets the requirements of our guidance on emerging techniques.

2.2.6 CO shift process

Our guidance on emerging techniques requires that a CO shift process is used to convert methane to hydrogen, carbon monoxide and CO_2, while minimising unreacted methane. The carbon monoxide conversion to CO_2 should be optimised considering the overall CO_2 capture requirement and the impact on downstream processing stages to meet the hydrogen product specification.

According to the proposed operating techniques stated in the application, the HPP is configured to maximise the heat recovery from the ITS process. The heat of reaction from the water gas shift reaction is transferred to ITS Steam Drum to generate steam. Heat from the resulting syngas (H_2/CO_2/water mix) is transferred to process fluids in a highly heat integrated process flow sheet.

We are satisfied that the proposed reforming process meets the requirements of our guidance on emerging techniques.

2.2.7 Process CO_2 capture from hydrogen product

The technology for CO_2 capture (CO_2 removal unit) from hydrogen product consists of absorption in a circulating amine-based solvent, with regeneration of the solvent through reduction of pressure and heating to liberate CO_2.

The objective of the unit is to remove CO_2 from the syngas downstream of the ITS Converter such that concentration of CO_2 in the treated gas sent to the PSA will be less than 0.1% mol, and the concentration of the CO_2 in the gas sent to the CO_2 Compression Unit is greater than 95% mol. This will be achieved by an absorber using an amine-based solvent.

Our guidance requires applicants to select the solvent, process design and operating conditions to maximise energy efficiency and capture performance, and to minimise the waste and effluent treatment required.

In response to a request for additional information, the Applicant has explained that the selection of the solvent was determined by gas composition and pressure of the feed gas. The solvent consists of activated methyl diethanolamine (MDEA) which speeds up the chemistry of the CO_2 capture unit process. According to the Applicant, the solvent was optimised for:

- The defined gas composition and CO concentration.
- A low CO_2 slip: to achieve high purity hydrogen in the treated gas stream.
- The limited amount of energy available from the upstream process: used for solvent regeneration and hence reboiler duty.
- Implementation of a low-pressure flash: this reduced energy consumption by using process conditions to improve CO_2 loading.

- The use of welded plate and frame heat exchangers for heat recovery: this reduces energy consumption by allowing smaller approach temperatures.

According to the application, typical energy consumption for similar CO_2 capture units using a single stage absorption column is in the region of 3MJ/tonne of CO_2. This plant achieves approximately 1.6MJ/tonne of CO_2, which provides the lowest possible energy consumption design for the plant using a single stage absorber design.

The design of the CO_2 Removal unit has a number of features aimed at optimising its environmental and process performance:

- The CO_2 Absorber has been provided with a down-stream Treated Gas Knock-out Drum to reduce losses of amine to the PSA unit. A downstream charcoal filter has also been recommended to further reduce amine carry-over. The benefits of this charcoal filter and its operational setup will be fully evaluated at the detailed engineering stage of the project. This charcoal filter (activated carbon) is expected to be installed downstream of the CO_2 capture unit, i.e. upstream of the PSA unit. The charcoal filter shall be installed as a lead/lag system to allow continuous operations of the plant. The charcoal filter shall be highlighted as a requirement to the preferred PSA supplier.

  Preventing losses not only reduces the amine solvent's consumption, but also prevents its transfer to the Feed Fired Heater and Steam Boiler (via the PSA Unit and its tail gas production), and thus limits NOx production through amine combustion.

  According to the application, the current calculated levels of active solvent (amine) within the treated gas stream exiting the CO_2 capture unit are in the range of 0.0000229 mol%, but it is expected that the charcoal filter shall bring any amine carry over down to virtually nil concentration, and hence no amines shall enter the PSA system and therefore not be present within the PSA tail gas/ combustion flue gas as oxides of nitrogen.

- Heat used in the amine reboiler is recovered from the syngas instead of using steam for this heating duty. This represents beneficial heat transfer between two technology packages (the reformer and the CO_2 removal system), compared with raising steam for this service.

- A smaller driving temperature in the heat exchangers (5ºC compared with 10ºC) maximises the heat exchange between the lean and the rich amine (albeit at the expense of the physical size of the heat exchanger).

- High pressure amine flashing (in the HP Flash Column) has been incorporated to maximise hydrogen recovery.

- The regenerator overhead condenser is a main heat sink in the overall process. It is included to minimise water and amine losses to the CO_2 stream. The CO_2 capture unit design has opted for an air-cooled condenser instead of a quench type condenser, to reduce and minimise amine losses which would be associated with a quench type condenser. According to the Applicant, using a quench type condenser would lead to higher concentration of amines to be found in the quenched looped system.

- The design of the CO_2 capture unit also includes the implementation of a back wash tray system which minimises the carry-over losses to the CO_2 stream.

- The HyNet CO_2 transport and storage network will have strict specifications for amine carryover into the capture CO_2 stream, to control liquid drop-out in the pipeline. Therefore, this will also be closely monitored (either by routine sampling or online analysis (to be confirmed) as part of the commercial offtake agreement with the transport and storage operator. Therefore, the CO_2 capture unit has been designed with several sampling locations. There is a sample point on the outlet of the LP flash column reflux drum. This is to monitor any possible amine carry over to the captured CO_2 stream.

We are satisfied that the proposal meets the requirements of our guidance on emerging techniques in regard to process CO_2 capture from the hydrogen product.

2.2.8 Hydrogen product

Our guidance on emerging techniques requires applicants to purify and compress hydrogen so that it is fit for purpose after it is separated from the CO_2 in the CO_2 capture stage. The purification process should consider the use of pressure swing adsorption (PSA) to remove impurities from the hydrogen; and consideration of whether methanation to convert CO into CH_4 is appropriate, depending on the specification of hydrogen to ensure hydrogen is fit for purpose.

In line with our guidance on emerging techniques, the proposed plant includes a PSA stage: according to the application, the PSA has been designed to remove the impurities from the product hydrogen stream and bring it to export specification for a range of operating cases, designed taking into consideration the hydrogen product specification and the composition of the hydrogen rich gas leaving the CO_2 absorber.

According to the application, the hydrogen product is specified to consist of greater than 99.9% purity by volume and the concentration of CO in the gas from the CO_2 removal process is too low to make methanation a practical consideration.
The process technology used for the reforming allows production of hydrogen at higher pressure, saving on product compression requirements.

We are satisfied that the proposal meets the requirements of our guidance on emerging techniques regarding the purification of the hydrogen product.

2.2.9 Carbon dioxide product

Our guidance on emerging techniques requires applicants to design the process to meet the required CO_2 quality specification, temperature and pressure as required for transport to permanent geological storage; to design the overall process to minimise power required for compression to achieve the user specification; to maximise recovery of waste heat from compression.

Section 2.2.7 addresses the features of the design of the CO_2 Removal Unit to minimise carry over of amines to the CO_2 stream.

The CO_2 product stream separated in the CO_2 Removal Unit is mixed with a recycle stream from the CO_2 Dehydration Package and then compressed to the CO_2 pipeline pressure by the electric motor driven CO_2 Compressor. The compression is carried out in multiple stages with interstage cooling.

Any process condensate removed in interstage knockout pots will be sent to the HPP's Waste Water Treatment Plant for effluent treatment.

The compressed CO_2 product stream is dehydrated in the CO_2 Dehydration Package, where the dehydration is achieved by means of a recirculating solution of triethylene glycol (TEG). Downstream of the package the dehydrated CO_2 is routed for export in the new CO_2 pipeline. The pipeline is not part of the HPP project. Water removed by the lean TEG is flashed off in the TEG Regeneration skid through the application of heat and vented to atmosphere.

The dehydration process is of particular importance as it reduces the water content in the CO_2 stream to prevent internal corrosion within the downstream systems.

Our guidance on emerging techniques requires applicants to consider heat recovery from the compression of CO_2. According to the proposal, which is based on the front-end engineering design stage, waste heat from the compression of CO_2 is not recovered. However, The Applicant has committed to undertaking a cooling optimisation study at the next phase of the design for this and other compressors, the outcome of which will support the evaluation of heat integration and waste heat recovery from the CO_2 and Hydrogen compressor systems. We have accepted the proposal to follow up on heat recovery options. Refer to section 2.2.11 for further details.

2.2.10 CO_2 capture from residual gas from hydrogen purification

The Applicant has provided a justification for not capturing the CO_2 emissions associated with the combustion of residual gas separated in the hydrogen purification process (i.e. the PSA tail gas): this gas will comprise predominantly hydrogen with low concentrations of methane, oxides of carbon, and other hydrocarbons. Post combustion, the concentration of CO_2 in the flue gases emitted to the atmosphere will thus be of the order of 2% (by volume). Thus, the Applicant has explained that the capture of CO_2 from the flue gases would not be economically practicable and environmentally significant.

Since the overall design carbon capture efficiency of the proposed plant meets and exceeds the minimum capture efficiency of 95% set out in our guidance, we have decided to accept the justification provided by the Applicant. However, we note that our approach might change for future determinations of similar applications, as in the future we may set out new carbon capture readiness requirements for combustion equipment, as the result of the expected changes to the Environmental Permitting Regulations implementing decarbonisation readiness.

Whilst at present we agree with the Applicant that the capture of the small amount of CO_2 associated with the combustion of the hydrogen rich PSA tail gas is unlikely to be economically feasible or environmentally significant, we note that the significance of this carbon-capture might change over the likely operational life of the proposed installation, potentially spanning up to the UK net zero target in 2050. We have therefore advised the Applicant that they should consider how they would comply with any potential future requirements for increased CO_2 capture efficiency, for example by making decarbonisation readiness provisions for the emission points emitting the flue gas from the combustion of PSA tail gas, such as leaving space for future retrofitting.

2.2.11 Energy and process efficiency

The Net Feed Gas Energy Conversion Efficiency figure initially presented in table 3-4 of the Permit Application Supporting Document was 74.1%. This figure was defined in the application as the ratio between:

- the net energy content of the hydrogen product; and
- the net energy content of the feed gas plus the energy content associated with the electrical power imported by the scheme.

However, we considered that the above definition was not thermodynamically accurate as it added up inconsistent energy figures at the denominator of the ratio (i.e. a thermal energy figure and an electrical energy figure). As such, this figure was not suitable for meaningful benchmarking against different technologies for the thermal production of hydrogen with CCS, that might also entail electrical power generation (such as the SMR technology, producing excess high-pressure steam that can be expanded in a steam turbine to generate electric power).

In response to our request (Schedule 5 Notice served on 17/03/2022), the Applicant recalculated the Net Feed Gas Energy Conversion Efficiency figure as 72.19%, using an amended definition of this figure that we consider more accurate. According to the amended definition, the Net Feed Gas Energy Conversion Efficiency is defined as the ratio between:

- the net energy content of the hydrogen product; and
- the net energy content of the feed gas plus the power import figure expressed as the equivalent net energy content of the hydrogen product that would be necessary to generate the electrical power input required by the HPP, at an assumed typical net electrical efficiency of 58.5%.

This figure is consistent with the benchmark Net Feed Gas Energy Conversion Efficiency reported in Table 20 of the Environment Agency's 'Review of emerging techniques for hydrogen production with carbon capture', for the process configuration entailing GHR + ATR, with a PSA based hydrogen purification stage.

We therefore consider that the proposed energy efficiency figure is consistent with BAT for these emerging technologies.

According to the operating techniques stated in the application, the primary energy efficiency feature of the proposed HPP consists of the selection of the process technology, since in the GHR + ATR process configuration the heat required for the reforming reactions is not provided by external heat but is released from the oxygen driven autothermal process and exchanged at the highest possible thermal level, hence maximising the heat transfer and its efficiency.

Further energy efficiency and heat integration features of the proposal, as described in the application, include:

- The design has adopted a smaller driving temperature in the heat exchangers (5ºC compared with 10ºC). This smaller temperature approach maximises heat recovery albeit at the expense of the physical size of the heat exchangers.
- Heat integration between key process streams is provided in the following units:
    - **GHR/ATR**: Heat exchange between hot reformed gas leaving the ATR to the mixed feed in the GHR.
    - **Steam Boiler**: Pre-heating boiler feed water with flue-gases (economiser)
    - **ITS Converter**: Steam is generated in the ITS Steam Drum from the heat of reaction from the water gas shift reaction.
    - **Saturator Water Heater No.1**: Water is heated against the hot syngas exiting the ITS Converter.
    - **Saturator Water Heater No.2**: Water is heated against the hot reformed gas from the GHR.
    - **Process Condensate Pre-Heater**: Heating the water condensate removed from upstream of the CO_2 Removal Unit prior to its return to the Saturator. Heat is exchanged against the hot syngas downstream of Saturator Water Heater No.1.

- **Syngas CO_2 Regeneration Reboiler**: Heating the reboiler liquids circulated from the CO_2 Removal Unit. Heat exchange against hot syngas downstream of Process Condensate Pre-Heater.
- **Demin Water Heater:** Heating the demineralised water prior to the Deaerator and entry into the steam system. Heat exchange against hot syngas downstream of Syngas CO_2 Regeneration Reboiler.

The proposed hydrogen production plant will produce sufficient steam for its requirements, but will not produce excess high-pressure steam, hence it will not generate electrical power from the operation of a steam cycle.

The Applicant confirmed that the adoption of a combined heat and power (CHP) generation system was considered and excluded from HPP design in early development. They provided a qualitative justification as to why they did not include a CHP to generate electrical power and, at the same time, to raise the steam needed by the scheme (which is raised in a dedicated steam boiler in the proposed configuration). The justification included:

- The need to avoid increased engineering systems complexities, given that the HPP represents a first-of-a-kind plant in terms of its overall processing objectives and combination of systems.

- The fact that the LCH™ heat and material balance is optimised in such a way that no fuel or heat import is required for either process heating or steam generation; the PSA tail gas, produced by the purification of product hydrogen, contains precisely the fuel required by the Steam Boiler and Feed Fired Heater and the beneficial use of this process coproduct improves the overall process efficiency.
  Whilst steam could be supplied or imported from an additional CHP scheme, producing at the same time the electrical power required by the HPP in a way that might be thermodynamically more efficient compared to the proposed configuration, this solution would likely result in excess PSA tail gas. Continuously flaring this excess PSA tail gas would be a process inefficiency, compared to the proposed configuration, that would not be consistent with BAT. An additional consideration supporting this argument is that, given the current technological development, the excess PSA tail gas can be beneficially used in static combustion equipment such as fired heaters and boilers, but, due to its high hydrogen content, at the present it would not be suitable for combustion in machinery able to generate electrical power, such as gas engines or gas turbines, with a sufficient level of technological maturity.

- The Applicant explained that they are exploring options for the repowering of the existing refinery CHP to hydrogen fuelled. Those plans have not yet been finalised. Once 100% hydrogen fuelled gas engines and gas turbines of a suitable size, with robust emissions controls become commercially available, hydrogen-fired power generation plant will be considered to provide power to industrial power consumers in the region including the HPP. This approach will unlock generation efficiencies, by including HPP's load in a larger base-load generation plant, versus a standalone power generation solely for HPP. The option to send HPP PSA tail gas to the new Stanlow Manufacturing Complex CHP for combined steam and power generation is being considered and will be further investigated if the plans for the hydrogen-fuelled complex CHP materialise.

The Applicant provided a qualitative justification as to why Feed Fired Heater and Steam Boiler waste heat rejected to the atmosphere are not considered suitable for further heat recovery: this is because the heat recovery has been maximised for internal use within the installation. According to the response to a request for further information received from the Applicant on 24/06/2022, the Feed Fired Heater and Steam Boiler have been specified to achieve energy efficiency levels that are consistent with BAT: the guaranteed design efficiencies are respectively 92% for the Feed Fired Heater and 95% for the Steam Boiler. Additional technical and economic factors considered in the justification provided by the Applicant, included the absence of any nearby users, the elevation above grade at which heat exchangers would need to be installed, and the high water content of the exhaust gases (a consequence of burning gas with a high concentration of hydrogen) which would bring corrosion and materials selection issues.

Given that the heat recovery has been maximised for internal use within the proposed process to the extent that it has been deemed economically viable by the process designer, we have agreed to the justification presented by the Applicant in support of their proposal that a cost-benefit analysis for the feasibility of district heating under Article 14 of the Energy Efficiency Directive was not required for this application.

The Applicant has provided the following **justification for the selection of the dry air-cooling system** proposed for the HPP: this system was selected due to the limited availability of raw water make-up for direct cooling or evaporative cooling; to avoid the discharge of a concentrated cooling tower blowdown stream; to better manage and reduce the risk of potential leakages of toxic or flammable process fluids from higher pressure process to lower pressure cooling medium. In response to the Schedule 5 Notice served on 17/03/2022 (response received on 24/06/2022), the Applicant reported an electrical power consumption for the air-cooling based cooling medium system of 818 kW and noted that there would be a potential to reduce the power requirements using an evaporative cooling system.

Taking into account the relatively small potential gain in terms of reduced electric power consumption from using an evaporative cooling system or direct cooling system, the environmental sensitivity of the surface water receptor to where the discharge of cooling water would take place if a direct cooling or hybrid system was to be selected - i.e. the Mersey Estuary Special Protection Area (SPA) /Site of Special Scientific Interest (SSSI) /Ramsar-, and the limited water availability, we have decided that the proposed use of air cooling is acceptable for this specific application. However, we have specified a pre-operational condition requiring the Operator to investigate further opportunities to reduce the energy demand of the proposed plant during the detailed engineering design of plant.

The proposed hydrogen production plant does not include the following energy efficiency features:

- **Heat integration between the ASU and the wider HPP**. This has been justified by the Applicant on process safety grounds. Liquid oxygen is very reactive and pure oxygen can react violently with hydrocarbons and combustible gases resulting in fire and / or explosion.

  The Applicant reported that there have been a number of documented explosions on ASUs. A common cause is accumulation of hydrocarbons in liquid oxygen which can take place in the main condenser unit.

  To prevent the process plant feeding combustibles such as hydrogen and natural gas to the ASU, these areas of the plant are not integrated. The process systems are generally at a higher pressure than the cooling and heat transfer medium systems meaning in that any leaks have the potential to enter those systems. Any combustible leaks in cooling and heat transfer medium systems could potentially find their way to the ASU; with a mixture of oxygen and combustibles leading to a catastrophic explosion. The safest way to design is to ensure no potential mixing of ASU and process systems.

  Therefore, according to the application, significant consideration was given in the design to segregating hydrocarbon and oxygen containing systems as far as possible. This included reviewing the design of the flare / drains systems to ensure that flammable atmospheres will not be formed within pipework / vessels. This same principle applies to the heating / cooling medium systems and separation of heating / cooling systems for the HPP and ASU is considered the safest option to prevent the potential formation of flammable atmospheres. Segregation of these inventories constitutes part of the inherently safer design of the process.

- **Waste heat recovery from the compression of hydrogen or CO_2**. For the CO_2 compressor system, interstage cooling is required, as is cooling on the outlet of the last stage. For the hydrogen compressor, there is no interstage cooling, it is a single stage compressor but cooling is required on the compression outlet. In response to the Schedule 5 Notice served on 17/03/2022, the Applicant confirmed that there are possibilities for using heat from compression in the CO_2 and hydrogen compression for heating colder process streams. This will be investigated at the next phase of engineering during which cooling system optimisation will be evaluated. The Applicant therefore committed to undertaking a cooling optimisation study for these compressors, the outcome of which will support the evaluation of heat integration and waste heat recovery from the CO_2 and Hydrogen compressor systems.

Although not all the energy efficiency features described in our guidance for emerging technologies have been included in the proposed design, we are satisfied that the proposal meets the essential energy and process efficiency requirements.

We have achieved this decision taking into account and balancing factors including:

- The high level of heat integration achieved between the reforming process, the isothermal shift conversion and the CO_2 Removal Unit;
- The favourable energy conversion efficiency benchmarking for the proposed technology against competing technologies for the production of hydrogen with carbon capture and storage (e.g. SMR with post-combustion carbon capture);
- The justifications provided by the Applicant for energy efficiency options that have been considered but have not been implemented;
- The fact that this is the first project developed in the UK for this type of installation;
- The overall environmental objective of the project to produce a decarbonised fuel; and
- The commitment made by the Applicant to carry out a cooling system optimisation study to look at the options of recovering waste heat from the compression of hydrogen and CO_2. We have reflected this commitment in the requirement of a pre-operational condition.

We consider that the Applicant has satisfactorily demonstrated they have applied an appropriate combination of the techniques stated in BAT conclusion 2 of the Refining of Mineral Oil BREF including heat integration, pinch analysis, process optimisation and use of energy benchmarks against similar processes:

BAT conclusion 2*. In order to use energy efficiently, BAT is to use an appropriate combination of the techniques given below.*

(i) Design techniques
(ii) Process control and maintenance techniques
(iii) Energy-efficient production techniques

We have accepted the Applicant's proposal to demonstrate the overall energy efficiency of the HPP at the commissioning stage through a methodology to be approved by the Environment Agency and we have set a pre-operational condition accordingly. We have set a process monitoring requirement to monitor and report the Net Feed Gas Energy Conversion Efficiency (averaged over the time).

2.2.12 Flexible operation

Our guidance for emerging techniques requires applicants to consider whether the hydrogen production plant needs to operate on a flexible basis to balance variations in demand from hydrogen users; to consider whether this need for flexibility will affect the design, operation and maintenance of the plant; and to identify flexible operating scenarios where environmental performance could be affected, or where additional emissions are expected, such as rapid changes in capacity or start-up following enforced shut-down.

The application explains that the HPP is expected to operate at steady state operation at high throughputs in order to get return for the CAPEX invested and therefore it is optimised for this operating scenario. However, the design takes into account flexibility features to match the market requirements. These include:

- The configuration of the plant in relation to the phased development of the project. The HPP will be developed in two phases: Phase 1 involving the construction and subsequent operation of facilities to produce 100,000 Nm^3/h of hydrogen, and Phase 2 which will increase the hydrogen production capacity by a further 200,000 Nm^3/h through the installation of further plant. This variation application covers Phase 1 of the development only.
- The plant will be capable of turning down to 40% of maximum hydrogen output.
- The plant is designed to operate under different operational scenarios, including Natural Gas Case - Beginning of Life (BOL); Natural Gas + ROG Case – BOL; Natural Gas Case – End of Life (EOL); and Natural Gas + ROG Case – EOL. Life is defined as the operational life of the principal catalysts between catalyst change (i.e. 4 years).
- The plant is specified to achieve a ramp up rate of at least 1%/minute and a ramp down rate of between 2%/minute and 5%/minute. According to the application, these rates are a balance between needing flexibility on hydrogen production whilst having a rate of variation of CO_2 production that can be accepted by the transport and storage system.
- The plant will be operated on natural gas only in start-up and shut-down, moving to a mixture of natural gas and ROG in routine operation.
- According to the application, the flare is designed to provide a safe disposal route for the HPP's flammable gases under start-up, shut-down, abnormal and emergency conditions only. Hence, emissions from flaring operations are only expected during these transient scenarios.
- According to the application, during the operation the PSA hydrogen recovery will be increased from BOL to EOL to ensure that there is not an overproduction of tail gas which might otherwise be sent to flare.
- The application identifies CO_2 venting as abnormal emissions during start-up and shut-down transient operation and emergency depressurisations.

We are satisfied that the proposal meets the requirements of our guidance on emerging techniques in relation to consideration given by the design to the flexibility of operation.

2.2.13 Reliability and availability

Our guidance for emerging techniques requires applicants to identify equipment and systems that are critical to avoiding emissions. These need to be designed, operated and maintained to ensure they are reliable and available, including providing installed back-up equipment, where necessary.

According to the application, the HPP has a design availability of at least 93.5% averaged over its lifetime calculated with respect to hydrogen production as a proportion of total requested hydrogen production assuming 8760 hours/year operation. The availability takes account of both planned and unplanned maintenance and includes the reliability of all utilities and services (including the electricity supply). The plant is designed so that no planned outage is greater than 30 days from hydrogen off to hydrogen on (full load to full load).

In response to our request for further information received on 24/06/2022, the Applicant identified the following environmentally critical systems to avoid emissions during other than normal operating conditions:

- **Control systems** required to ensure the plant control responds to other than normal operation to protect the environment. The HPP plant is operated and controlled by an Integrated Control and Safety System, consisting of Distributed Control System (DCS) for process control, with an independent Safety Instrumented System (SIS) performing automated shutdown and Emergency Shutdown (ESD) functions. The design availability specification for the DCS is 99.99%.

  In order to meet the required system availability, redundancy and / or fault tolerant technology is specified in the design.

- **Fire and Gas (F&G) System**, detecting fire or gas release in order to safely shut down the HPP. The minimum performance standard for the F&G System includes the following: Detection of fire and flammable / process gases; Provide plant operations and personnel with warning if fire or gas is detected and relay fire or gas warning from other plants within the Stanlow Manufacturing Complex; Continuously monitor all areas where either the presence of a fire hazard may exist, or an accumulation of flammable or process gases may occur; alert personnel at the control room and fire station of presence, location and nature of the fire, gas leak or emergency; Provide automatic and operator-initiated activation of fixed fire protection systems, i.e. fire water monitors, fusible plug and deluge spray enclosure protection where applicable; Reduce the risk to personnel by implementing executive actions to turn on protection equipment and/or initiate shutdown events of process equipment.

  The Fire & Gas detectors to be used are: Fire (Flame) detectors; UV/IR detectors with integral CCTV; Flammable gas detectors (for hydrocarbon gases, H_2 and O_2); Process gas detectors (for CO_2 , CO and N_2); Smoke detectors (including high sensibility smoke detectors); Heat detectors; Gas leak detectors.

- **Electrical systems** required to power the plant. The power connection to the HPP is a dual 100% redundancy supply via cables connecting to the site main switchboard. Each connection can provide the full site power requirement.
  The 100% redundancy philosophy is continued throughout the network for the transformers and switchboards distribution.
  The Emergency Generator provides power to safely shut down the facility on loss of external power supply.

  The Uninterruptable Power Supply (UPS) system, with battery backup, provides power to essential power consumers (e.g. control system) following to loss of external power in order to safely shut-down the plant.

- **Instrument Air** required to provide motive force to operate control and blow down valves. Emergency Instrument Air Compressor provided to supply air on loss of ASU supplies. The Instrument Air Receiver contains an inventory of air for the activation of valves in an emergency. Valves that are important for process safety and plant shut-down are designed to fail in a safe position (e.g. fail open, fail closed) on loss of control or instrument air. The valve positions are considered in design safety reviews such as Hazard and Operation (HAZOP) studies.

- **Flare and blowdown** system to safely combust flammable gas inventories in case of emergency. The majority of the equipment is static and therefore spare equipment items are not generally required. The exception is the flare knock drum pumps which are spared due the lower reliability inherent with some rotating machinery.

According to the response to the Schedule 5 Notice served on 17/03/2022 and received on 24/06/2022, the water treatment packages, including the MBR **wastewater treatment plant** are designed for the high availability target of 2 weeks shutdown every 4 years. All pumps in wastewater treatment systems are spared. A high-level availability review was carried out for the wastewater treatment plant (MBR) based on historical project data, indicating an availability level of 99.9%. The Applicant stated that a detailed Reliability, Availability & Maintenance (RAM) study will be carried out during the execution phase of the project on this system.

We are satisfied that the proposal meets the requirements of our guidance on emerging techniques in relation to consideration given by the design to the reliability and availability of the assets.

2.2.14 Emissions to air

2.2.14.1 Combustion processes

Our guidance for emerging techniques requires applicants to maximise energy efficiency and heat integration so that the need for combustion processes and resultant CO_2 and other combustion products is minimised; to maximise the capture of CO_2 from combustion processes taking account of the overall carbon capture requirement. If applicants decide that carbon capture from a combustion process is not appropriate, they must justify their decision based on BAT.

Applicants should consider NOx primary measures and abatement techniques including burner design, flue gas recirculation, heat exchange with fuel/air, selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR).

Applicants are also required to consider the overall impact of using residual gas from the hydrogen purification process as a supplementary fuel for fired equipment to balance overall heat requirements, while considering the impact of the additional emissions of combustion products to air; for ATR, whether the relatively smaller additional heat need can be supplied by combustion of hydrogen-rich residual gas or combustion of hydrogen product; the impact on emissions to air due to variability in fuel gas composition or any need to switch between fuel gas sources, for example, at start-up when residual PSA gas for fuel is not available and some feed gas may need to be combusted.

The proposed HPP will have two principal combustion units, the Feed Fired Heater (net thermal input of 20.2 MWth) and the Steam Boiler (net thermal input of 27.6 MWth), both of which will be fired on sulphur-free PSA tail gas under normal operating conditions and natural gas during start-up and shutdown, in line with the requirements of our guidance.

The PSA tail gas is a decarbonised, de-sulphurised, hydrogen rich residual gas, whose combustion in support of the pre-heating and steam generation represents a process efficiency feature of the proposed plant configuration. Refer to section ‘Energy and process efficiency’ for a discussion of how the proposed activities comply with BAT requirements for energy efficiency.

The proposal does not include post-combustion carbon capture on the small concentration of CO_2 resulting from the combustion of the PSA tail gas. The Applicant’s justification for this proposal and our consideration of their justification is set out in the section 2.2.10 above.

A full BAT justification, against the requirements of the BAT conclusions for the combustion units set out in the Refining of Mineral Oil and Gas BAT Conclusions is discussed in the application and summarised in the following (note: only the potentially applicable techniques stated in the BAT conclusions are reproduced).

BAT conclusions 34 – *In order to prevent or reduce NO_X emissions to air from the combustion units, BAT is to use one or a combination of the techniques given below*

Primary or process-related techniques:

Selection of fuel - Use of gas to replace liquid fuel

Combustion modifications – Staged combustion, Optimisation of combustion, Flue-gas recirculation, Use of low-NOx burners (LNB)

Secondary or end-of-pipe techniques:

Selective catalytic reduction (SCR), Selective non-catalytic reduction (SNCR)

The PSA tail gas is a low-carbon fuel, and the beneficial use of a process coproduct improves process efficiency. The fuel is a clean gaseous fuel which has low impurity levels. Amine carry-over from the CO_2 Removal Unit, potentially resulting in NOx emissions due to their nitrogen content, is removed using a knock-out pot at the top of the CO_2 stripper, followed by a carbon filter (to be confirmed during the detailed engineering design).

The burners specified for both the Feed Fired Heater and Steam Boiler are modern low NOx burners which provide combustion air mixing and staging.

Process controls will include monitoring and management of combustion process parameters to ensure efficient combustion (optimisation of combustion).

The application justifies that SCR/SNCR are not considered necessary techniques for this process because the manufacturers of the combustion equipment consulted during the design process have confirmed that both combustion units included in the HPP will be able to meet a NOx emissions limit of 80 mg/Nm^3 during the sampling period (at 3% oxygen, dry basis), with the primary techniques stated above. This emission level is more stringent than the BAT-AEL range of 30-100 mg/Nm^3 (monthly average) set out for new gas-fired combustion units (other than gas turbines) in table 10 of the Mineral Oil and Gas Refining BAT Conclusions.

This emission level has been proposed as the emission limit by the Applicant. According to them, SCR and SNCR would determine increased process complexity, increased space requirements, increased capital and operating increased risks associated with raw materials storage and potential spills/release of ammonia or urea; and would present a risk of ammonia slip in air emissions.

BAT conclusion 35 - *In order to prevent or reduce dust and metal emissions to air from the combustion units, BAT is to use one or a combination of the techniques given below.*

Primary or process-related techniques

Selection or treatment of fuel: use of gas to replace liquid fuel, use of low sulphur refinery fuel oil (RFO)

Combustion modifications: optimisation of combustion, atomisation of liquid fuel

Secondary or end-of-pipe techniques

Electrostatic precipitator (ESP), Third stage blowback filter, Wet scrubbing, Centrifugal washers

According to the application, the PSA tail gas is a clean gaseous fuel which has low impurity levels with a low potential to generate particulates from combustion. Particulate emissions are therefore inherently controlled by the nature of the fuel.

Combustion controls will ensure efficient combustion and control particulate emissions. Primary measures to control the nature of the gaseous fuel and combustion controls are considered BAT, no further measures are required for gas-fired plant. No BAT-AELs for particulates apply to the combustion of gas.

BAT conclusion 36 - *In order to prevent or reduce SOx emissions to air from the combustion units, BAT is to use one or a combination of the techniques given below.*

Primary or process-related techniques:

Selection of fuel - Use of gas to replace liquid fuel, Treatment of refinery fuel gas (RFG), Use of low sulphur refinery fuel oil (RFO) e. g. by RFO selection or by hydrotreatment of RF.

Secondary or end-of-pipe techniques

Non-regenerative scrubbing, Regenerative scrubbing, SNOX combined technique

The feed gas is treated to remove sulphur compounds, meaning the PSA tail gas is essentially sulphur-free. Un-odorised natural gas used during start-up and shut-downs has also low levels of sulphur. When primary measures to control the sulphur content of the fuel are regarded as BAT, no further measures are required. Since the PSA tail gas is not expected to contain sulphur, we consider it will meet the SO_2 BAT-AEL of 5-35 mg/Nm^3 (monthly average) set out for combustion units (other than gas turbines) in table 13 of the Mineral Oil and Gas Refining BAT Conclusions.

BAT conclusion 37 - *In order to reduce carbon monoxide (CO) emissions to air from the combustion units, BAT is to use a combustion operation control.*

The BAT-AEL for carbon monoxide emissions to air from a combustion unit specified in table 15 of the Mineral Oil and Gas Refining BAT Conclusions is 100 mg/Nm^3 (monthly average).

According to the application, CO emissions will be minimised through the use of combustion control measures to ensure efficient combustion.

Based on the information provided in the application, we agree that the proposed operating techniques for combustion processes will be compliant with the applicable requirements of the Mineral Oil and Gas Refining BAT conclusions 34, 35, 36 and 37 and the requirements of our guidance for emerging techniques.

As the Feed Fired Heater and the Steam Boiler are also new Medium Combustion Plant, we have also considered the relevant emission limits specified by the Medium Combustion Plant Directive. These are:

Pollutant	Natural Gas	Gaseous Fuel Other than Natural Gas (i.e. PSA tail gas)
SO_2	-	35 mg/Nm^3
NOx	100 mg/Nm^3	200 mg/Nm^3
At 3% oxygen, dry gas, temperature of 273.15 K, pressure of 101.3 kPa		

On review of the proposal made by the Applicant, we have set the emission limits for NOx, CO and SO_2 at emission points HPP-A-1 and HPP-A-2 that are consistent with, or more stringent than, the BAT-AELs set out in the Mineral Oil and Gas Refining BAT Conclusions and the ELVs specified by the Medium Combustion Plant Directive:

- NOx – 80 mg/Nm^3 at 3% oxygen, dry gas, temperature of 273.15 K, pressure of 101.3 kPa

- CO - 100 mg/Nm^3 at 3% oxygen, dry gas, temperature of 273.15 K, pressure of 101.3 kPa

- SO_2 – 35 mg/Nm^3 at 3% oxygen, dry gas, temperature of 273.15 K, pressure of 101.3 kPa

For NOx and SO_2 we have specified annual periodic monitoring with EN standards, according to BAT conclusion 4 of the Mineral Oil and Gas Refining BAT Conclusions, for combustion units below 50 MWth input. For carbon monoxide we have specified 6-monthly monitoring with EN standards, according to BAT conclusion 4 of the Mineral Oil and Gas Refining BAT Conclusions, for combustion units below 50 MWth input.

We have not specified monitoring of particulates emissions since no BAT-AEL applies to this parameter for combustion of gaseous fuels and their emissions are not anticipated to be a key risk for this process.

A third source of combustion gas emissions is the diesel emergency generator (2.9 MWth input), which will be a new medium combustion plant. However, this unit is not considered to be a significant source of emissions on the basis of its capacity and infrequent operation. This emergency generator will be operated for less than 50 hours per year for testing. Since it will operate for less than 500 hours per year, it won't be subject to the emission limits set out in the Medium Combustion Plant Directive. The limit to the operational hours of this combustion unit has been specified in the variation notice.

The Application states that low-sulphur diesel fuel will be selected as this provides a diverse and self-contained fuel source for emergency operation in the event of a loss of electrical power to the plant. Whilst we agree that the use of diesel fuel is an appropriate selection for standby generation, we have specified in the permit the use of ultra-low sulphur gas oil for this generator, as opposed to low-sulphur gas oil, as we consider ultra-low sulphur gasoil is widely available and represents BAT for this operation.

According to the application and the response to the Schedule 5 Notice received on 24/06/2022, the selected engine will be a new, modern diesel generator unit equipped with an Electronic Control Unit (ECU). The emergency generator will be specified to meet BAT standards for emissions from standby generators (i.e. TA-Luft 2g, or US EPA Tier 2 standard or equivalent) and will consist of a vertical, elevated stack with unimpeded emission point (no cowls and caps).

For the emergency generator, we have specified periodic monitoring of carbon monoxide and NOx emissions according to standards compliant with https://www.gov.uk/government/publications/monitoring-stack-emissions-low-risk-mcps-and-specified-generators/monitoring-stack-emissions-low-risk-mcps-and-specified-generators. We have specified a monitoring frequency of once every 1500 hours of operation or once every five years (whichever comes first) for the emergency generator, in line with the Medium Combustion Plant Directive. This monitoring has been included in the permit in order to comply with the requirements of Medium Combustion Plant Directive, which specifies the minimum requirements for monitoring of carbon monoxide emissions, regardless of the reduced operating hours of the plant. We have also specified monitoring of emissions of nitrogen oxides from this new medium combustion plant, with the same frequency specified for the monitoring of carbon monoxide emissions. In setting out this requirement, we have applied our regulatory discretion, as we consider that this limited monitoring for NOx, to happen in concurrence with the statutory required carbon monoxide monitoring, is proportionate to the higher risk associated with emissions of NOx, than that associated with emissions from carbon monoxide.

2.2.14.2 Height of stacks

The Applicant carried out a sensitivity study to determine BAT stack height for the Feed Fired Heater and Steam Boiler. The assessment modelled NOx emissions from the Feed Fired Heater and Steam Boiler at a range of stack heights at 5 m increments between 30 and 55 m. The maximum predicted ground level concentrations at each stack height were plotted. This illustrated that at stack height of 40 m and above there was a noticeable reduction in the rate at which ground level concentrations of NOx decreased with each additional 5 m of stack height.

The Applicant therefore selected stack heights of 40 m for both these combustion units, as representing BAT for dispersion given the insignificant process contributions of oxides of nitrogen. We agree with the conclusions of this assessment, refer to 2.3.1.2.

2.2.14.3 Post combustion carbon capture

As the HPP does not involve post-combustion CO_2 capture, instead using a closed process capture and recovery system, the potential for amine emissions and any degradation products are significantly reduced and are confined to fugitive releases (i.e. loss of containment).

We agree the proposed plant configuration meets the requirements of our guidance on emerging techniques for this process.

2.2.14.4 Flaring and venting

In relation to flaring, our guidance for emerging techniques requires applicants to design and operate their plant to minimise the need for continuous or intermittent flaring or venting of gases, including methane/refinery fuel gas, hydrogen and CO_2. The requirements relevant to flaring include:

- flaring rather than venting, where emissions cannot be eliminated and where practicable, to minimise emissions of higher global warming potential gases such as methane and hydrogen
- plant design to maximise equipment availability and reliability
- avoidance of routine flaring for waste gas destruction
- minimising emissions under start-up, shut-down, and abnormal operations
- managing production of off-gas and balance against requirements for fuel gas using advanced process control
- using procedures to define operations, including start-up and shut-down, maintenance work and cleaning

- robust commissioning and handover procedures to ensure that the plant is installed in line with the design requirements
- robust return-to-service procedures to ensure that the plant is recommissioned and handed over in line with the operational requirements
- designing flaring devices to enable smokeless and reliable operations and to ensure an efficient combustion of excess gases when flaring under other than normal operations
- monitoring and reporting of gas sent to flaring and associated parameters of combustion

Reference is made to BAT Conclusions 55 and 56 of the Refining of Mineral Oil and Gas BREF:

BAT conclusion 55. *In order to prevent emissions to air from flares, BAT is to use flaring only for safety reasons or for non-routine operational conditions (e.g. start-ups, shutdown).*

According to the operating techniques described in the Application, flaring operations will be minimised and only used for off-spec operational and emergency conditions, in compliance with the requirements of BAT conclusion 55.

BAT conclusion 56. *In order to reduce emissions to air from flares when flaring is unavoidable, BAT is to use the techniques given below.*

(i) Correct plant design
(ii) Plant management
(iii) Correct flaring devices design
(iv) Monitoring and reporting

According to the operating techniques described in the Application:

- The HPP flare system has been designed with sufficient capacity for all normal, abnormal and emergency operating conditions arising from Phase 1 and 2 combined, although the production of hydrogen in Phase 2 is not in the scope of the application. The worst-case flaring scenario corresponds to full simultaneous blowdown via all Phase 1 and 2 blowdown valves due to an emergency event. According to the additional information provided by the Applicant on 26/09/2022 all flaring scenarios entailing the combustion of high purity hydrogen have been added to the specification of the flare.
- The HPP is specified to achieve designed availability of at least 93.5%, see section above on ‘Reliability and availability’.
- The HPP flare will be designed, fabricated and tested according to the latest of editions of international standards API Standard 521: ‘Pressure-Relieving and Depressurizing Systems’ and API Standard 537: ‘Flare Details for Petroleum, Petrochemical, And Natural Gas Industries.
- In operation, the PSA hydrogen recovery will be increased from BOL to EOL to ensure that there is not an overproduction of tail gas which might otherwise be sent to flare. Between BOL and EOL the hydrogen

recovery will increase by up to 1 % to balance the fuel requirements of the process.

- The flare is designed for smokeless operation without steam assist. Smokeless operation to Ringelmann 1 or less will be achieved for the given gas compositions for all flowrates, due to the low carbon concentration in the waste gas.

In response to the Schedule 5 Notice served on 17/03/2022 (response received on 24/06/2022), the Applicant provided a justification for not including in the design a flare gas recovery system. This is because the flare will be used only during start-up, shut-down, emergency and maintenance operations. According to the Applicant, flare gas recovery would not be appropriate for the application to emergency flaring as any disruption to gas flows due to the potential failure of the additional equipment required by the gas recovery system could have negative process safety impacts and any escalation of an incident could potentially determine worse environmental consequences.

Whilst the Applicant acknowledged that flare gas recovery might be appropriate for planned commissioning, start-up, and shut-down activities, they claimed that, since these operations are intended to be intermittent and infrequent, there would be a risk that the machinery required for flare gas recovery would not be available on demand. This is because the reliability of positive displacement type compressors (such as rotary lobe or screw machines) suitable for this service, decreases with lack of use because of the contact between rotor tips and casing.

The Applicant confirmed that a design work stream has been identified to maximise the use of start-up / shut-down / abnormal operation waste gas from HPP within the Stanlow Manufacturing Complex. Where possible, hydrogen product gas which is out of specification for 3rd party customers will still be used within the Stanlow Manufacturing Complex, either through specific hydrogen converted burners, or by recovery into the Fuel Gas Main. This will be feasible when there is a positive demand of energy from the operations of the Complex, or, in other words, when the energy requirements are not in balance.

We are satisfied with this approach.

Flow measurement and reporting instruments will be installed on the flare headers. These will be upstream of the flare stack. This will enable measurement and monitoring of the quantity of flared gases. Composition of the flared gas will be monitored either by sampling and lab analysis that will allow calculation of specific emissions factors or by an approved calculation methodology based on plant inventories.

The safety relief valves to be used for this project will have applicable Safety Integrity Level (SIL) rating. That will ensure the high integrity of relief valves installed.

We consider that the proposed operating techniques meet the requirements of our guidance for emerging techniques and are compliant with BAT conclusion 56.

In the Schedule 5 Notice served on 17/03/2022 (response received on 24/06/2022), we requested the Applicant to explain / implement process monitoring measures and controls available upstream or at the inlet of the hydrogen production plant, to prevent feeding off-spec ROG to the hydrogen plant, potentially leading to flaring of gas with high sulphur concentration from the proposed new flare.

The Applicant confirmed that an analyser package is currently contained within the design, which consists of a gas chromatography analyser. On review, the Applicant proposed to add also a dedicated fast-response sulphur species analyser as part of the next engineering design phase. Both of these analysers shall have a 2 out of 3 voting system. According to the operating techniques stated by the Applicant, the gas chromatography analyser will operate on a 5-minute cycle time and the sulphur species analyser will operate with a 1 second cycle time. According to the application, the duration of an off-specification ROG stream with higher sulphur content entering the pipelines feeding the ROG compressor would be approximately 2 seconds.

We included the requirement for this analyser in Table S3.5(b) 'Process monitoring requirements' of the variation and consolidation notice.

In relation to venting, our guidance for emerging techniques requires applicants to quantify and assess harm from other routine venting and purging requirements, identifying any pollutants that are expected to be present.

Venting and purging are suitably identified in the application. These include:

- Steam vents (GHR steam jacket vent and ATR Steam jacket vent, operated continuously) and pressure relief valves on the steam system (only operated during abnormal operation to reduce pressure in steam systems), giving rise to emission of demineralised water with very low concentrations of boiler treatment chemicals);
- Vent on the TEG Still Column. The off-gases from the TEG still column comprises steam, with CO_2 (23.4 mol %) and methanol (9.5 mol%); there is no residual TEG carry-over as the TEG is removed in the TEG regeneration system. The concentration of methanol in the off-gases will be minimised before venting through use of a condenser and knock-out drum, that will remove the methanol in a liquid phase, as opposed to emitting it to the atmosphere through the venting point; the use of this condenser was not confirmed in the initial proposal submitted by the Applicant, but it was subsequently included in the design, in response to our request to implement BAT for minimisation of VOC emissions, provided in the Schedule 5 Notice served on 17/03/2022 (response received from the Applicant on 24/06/2022). This measure is now one of the binding operating techniques to be followed by Operator and referred to in table S1.2 of the variation and consolidation notice;
- Steam system deaerator vent (vents incondensable gases from steam system);
- Vents on the amine, TEG storage and diesel fuel tanks (the latter supplying the emergency generator) comprising low levels of emissions from tank

breathing losses. The amine and TEG tanks are contained under a nitrogen blanket with pressure relief valves. Breathing losses are further minimised as the tanks are only filled or emptied occasionally.

- Emission points venting CO_2 during abnormal operations. These include:
    - Emergency depressurisation / blowdown of CO_2 pipeline;
    - Maintenance venting of CO_2 metering package;
    - Emergency pressure relief from the TEG Regeneration Skid;
    - Venting from the CO_2 Capture Unit through pressure control valve PCV-0014 associated with balancing, start-up and turndown;
    - Emergency depressurisation scenarios from the CO_2 Capture Unit (including CO_2 Compressor Package C-103)

There are three Above Ground Installations (AGIs) pipelines that will be connected to HPP to import feedstock and export product across the installation's boundaries:

- Natural Gas Import pipeline from National Grid National Transmission system (NTS)
- Hydrogen export pipeline
- CO_2 export pipeline (exporting pressure 7.5-35 barg, gas phase).

The blowdown philosophy for the interface pipelines was explained by the Applicant in their response to Schedule 5 Notice provided on 26/09/2022:

Each AGI operator is responsible for blowdown/depressurisation of the pipeline and equipment on their side of the interface; the contents will not be sent to the HPP for flaring or venting. There will be remotely operated shut-down/trip valves and manual double block valves and spade points at the installation's side of each battery limit. This description is taken as one of the binding operating techniques to be followed by Applicant and referred to in table S1.2 of the variation and consolidation notice.

Refer to section 2.3.1 for the risk assessment of emissions to air.

2.2.15 Water supply, use and treatment

Our guidance for emerging techniques requires applicants to minimise water use, segregate, treat and re-use water where possible and to choose cooling methods taking account temperature impact on process performance, energy efficiency and environmental impact on the receiving medium.

The conformance of the HPP with the Common Waste Water and Waste Gas Treatment/Management System in the Chemical Sector and Refining of Mineral Oil and Gas BAT Conclusions documents in relation to waste water collection and treatment is set out in Tables 3-18 and 3-19 of the application document titled 'HyNet Hydrogen Production Plant Environmental Permit Application Supporting Document', received on 31/08/2021.

Taking into account the activities in the scope of this variation and their interaction with the existing refining activities carried out the installation and its infrastructure, we consider that the following BAT conclusions from the Refining of Mineral Oil BREF are the most relevant to assess the BAT compliance of the proposal:

BAT conclusion 10. *BAT is to monitor emissions to water by using the monitoring techniques with at least the frequency given in Table 3) [of the Refining of Mineral Oil and Gas BAT Conclusions] and in accordance with EN standards. If EN standards are not available, BAT is to use ISO, national or other international standards that ensure the provision of data of an equivalent scientific quality.*

BAT conclusion 11. *In order to reduce water consumption and the volume of contaminated water, BAT is to use all of the techniques given below.*

- *(i)* *Water stream integration*
- *(ii)* *Water and drainage system for segregation of contaminated water streams*
- *(iii)* *Segregation of non-contaminated water streams (e.g. once- through cooling, rain water)*
- *(iv)* *Prevention of spillages and leaks.*

BAT conclusion 12. *In order to reduce the emission load of pollutants in the waste water discharge to the receiving water body, BAT is to remove insoluble and soluble polluting substances by using all of the techniques given below.*

- *(i)* *Removal of insoluble substances by recovering oil*
- *(ii)* *Removal of insoluble substances by recovering suspended solids and dispersed oil*

Removal of soluble substances including biological treatment and clarification.

BAT-associated emission levels for direct waste water discharges are specified in Table 3 of the Refining of Mineral Oil and Gas BAT Conclusions.

Given the hydrogen production activity at the core of the Application, the Applicant also considered applicable to the effluent directly discharged to the environment from the HPP, the BAT-AELs set out in tables 1, 2 and 3 of the Common Waste Water and Waste Gas Treatment/ Management Systems in the Chemical Sector (CWW) BAT conclusions. We note this approach is conservative and we have therefore agreed to it in setting the relevant emission limits and monitoring requirements.

BAT conclusion 13. *When further removal of organic substances or nitrogen is needed, BAT is to use an additional treatment step.*

According to the operating techniques stated in the application, water used in the plant is primarily sourced from an existing United Utilities raw water supply drawn from the River Dee. However, water usage has been optimised by augmenting this supply with re-used process water and harvested rainwater.

Raw water is clarified to remove suspended solids before storage in the Clarified Water Tank for use in the process.

Process effluent streams, rainwater draining from potentially contaminated areas and clean rainwater runoff will be collected in segregated catchment systems and routed to the appropriate point for treatment and reuse in a highly integrated process configuration that maximises water reuse and minimises water usage.

Rainwater falling on areas of the HPP at low risk of contamination will be collected in the uncontaminated drains system and transferred to the existing refinery drainage system for discharge and treatment to the existing United Utilities treatment plant, through the existing emission point S1. This indirect discharge is not subject to any applicable BAT-AEL.

Process effluent streams (from blow-down and condensate returns, sludge dewatering, and the CO_2 removal system) are collected and routed to a Membrane Bioreactor (MBR) for biological treatment, to remove soluble contaminants. The treated effluent from the MBR is then routed to the Clarified Water Tank, where it joins the clarified raw water stream.

Rainwater draining from potentially contaminated areas (runoff from hardstanding in process areas) will drain to a corrugated plate interceptor (CPI) to remove oil and will then be mixed with the process water steam and routed to the MBR for treatment and re-use.

The bulk process effluent recycled via the closed drains was characterised and the biological treatment process (MBR) was specified to cope with the levels of chemical oxygen demand, ammonia, methanol and amine that are predicted in the incoming effluent.

The biological treatment will include nitrification / denitrification stages to remove nitrogen from the effluent as gaseous elemental nitrogen, in compliance with BAT conclusion 13.

The potential for emissions of volatile organic compounds (VOC) from the operations of the waste water treatment facilities will be minimised in that process waste waters, potentially containing organics will be drained to the closed drain drum. This system is closed, with no atmospheric venting. The closed drains drum is connected to the flare header and volatile components that evaporate here will be routed to the flare system for combustion.

Water in the Clarified Water Tank will be passed through a Dual Media Filtration Plant to produce filtered water. The filtered water, arising from raw water treatment and wastewater treatment, will be fed to the Demineraliser plant to meet demineralised water demand.

The Demineralisation plant will generate a demineralised water stream and a reject effluent. The reject effluent will be discharged to the existing refinery drainage system at point T1 at the existing CT2 open sump, already included in the existing permit). This will then flow from CT2 to discharge through point N38 to existing permitted discharge point W3 to the Manchester Ship Canal. This is the only wastewater stream proposed to be directly discharged to the environment from the HPP. The total discharge flow rate permitted at emission point W3 will remain unchanged, after including the new demineralisation effluent generated by the HPP operations. Given the highly integrated flow scheme of the water treatment and reuse facilities, this effluent is the resultant of the treatment of the process wastewater arising from the operations of the HPP.

The Applicant stated that, were the HPP to incur a serious outage such that the MBR could not process the recycled effluents to the necessary specification, the HPP would be shut down and the waste waters tankered off site for treatment.

The Applicant has justified the proposed use of dry air cooling for the HPP with the aim of reducing the water usage for the plant, albeit at the expense of a small energy penalty (refer to the section above on ‘Energy and process efficiency’ for further discussion on the determination of BAT for cooling).

We are satisfied that raw water and wastewater treatment facilities are highly integrated to minimise the water usage and maximise its reuse. We consider that the proposal meets the relevant BAT requirements concerning water treatment and reuse.

We have specified the following emission limits and monitoring requirements for the effluent resulting from the integrated water and wastewater treatment facilities (i.e. the demineralisation effluent emitted through the intermediate emission point point T1). These are based on:

- BAT-AELs set out in table 3 of the Refining of Mineral Oil and Gas BAT Conclusions; and
- BAT-AELs set out tables 1, 2 and 3 of the CWW BAT Conclusions.

Since this effluent is emitted to the environment through the existing final emission point W3 and the combined effluent at this emission point is subject to the emission limit values specified in the permit according to the REF BAT-AELs, we have only specified new emission limits at the intermediate process monitoring point T1.

These limits are for the parameters that don’t already have an emission limit at the final emission point W3, or for which a more stringent emission limit is required, as the result of the comparison between the REF BAT-AELs and the CWW BAT-AELs that we consider applicable to this application.

In line with Defra IED Guidance, where the BAT AELs are expressed as a range, the ELV has been set on the basis of the top of the relevant BAT AEL range (the highest associated emission level). Additional, or more stringent emission limits and/or monitoring requirements may need to be specified according to the results of the risk assessment required by a pre-operational condition. Refer to section 2.3.2 of this document for additional information.

Parameter	Expected emission level [Note 1]	REF BAT-AEL [mg/l] [Note 3]	CWW BAT-AEL [mg/l] [Notes 3, 4]	Current ELV at W3 [mg/l]	ELV at T1 [mg/l]	Reference period	Monitoring frequency	Monitoring standard
Flow rate	14.1 m^3/hr (normal) 17.0 m^3/hr (design)	-	-	90,000 m^3/d (normal) 100,000 m^3/d (abnormal)	408 m^3/d	Continuous	Continuous [Note 3]	MCERTS performance requirements
Hydrocarbon Oil Index (HOI)	Nil	0.10 – 2.5	-	2.5	N/A [Note 2]	-	-	-
TSS	Nil	5-25	5-35	25	N/A [Note 2]	-	-	-
COD	8.03	30-125	30-100	125	100	Yearly	Daily (24 hour flow proportional)	BS 6068-2.34 Same as ISO 6060 or BS ISO 15705 [Note 6]
Total N	Nil	1-25	5-25	20	N/A [Note 2]	-	-	-
Lead	Nil	0.005- 0.03	-	0.02	N/A [Note 2]	-	-	-
Cadmium	Nil	0.002-0.008	-	0.002	N/A [Note 2]	-	-	-

Nickel	≤ 0.02	0.005-0.1	0.005-0.050	0.02	N/A [Note 2]	-	-	-
Mercury	Nil	0.0001-0.001	N/A	0.0002	N/A [Note 2]	-	-	-
Benzene	Nil	0.001 – 0.05	-	0.05	N/A [Note 2]	-	-	-
Chromium	≤ 0.025	N/A	0.005-0.025	-	0.025	Yearly	Monthly [Note 5]	BS EN ISO 11885
Copper	≤ 0.05	N/A	0.005-0.050	-	0.05	Yearly	Monthly [Note 5]	BS EN ISO 11885
Zinc	≤ 0.3	N/A	0.02 – 0.3	-	0.3	Yearly	Monthly [Note 5]	BS EN ISO 11885
Total phosphorus	≤ 3	N/A	0.5-3	-	3	Yearly	Daily [Note 5]	BS EN ISO 15681

Notes:

1. Reference: Table 6-3 of 'HyNet Hydrogen Production Plant Environmental Permit Application Supporting Document', received on 31/08/2021 as supplemented by the responses to the Schedule 5 Notice served on 17/03/2022 and responded on 24/06/2022.
2. Not required as an ELV compliant with the BAT-AEL is already specified at the final emission point W3.
3. The BAT AELs refer to yearly averages. This means, the average of all daily averages obtained within a year, weighted according to the daily flows. For this reason we have specified continuous monitoring requirements for the flow rate of the effluent from the demineralisation plant.
4. BAT-AEL for Adsorbable organic bound halogens (AOX) from the CWW BAT conclusions is not deemed applicable considering the type of effluent and the applicability threshold of 100 kg/year relevant to this parameter.
5. Monitoring frequencies may be adapted with written agreement from the Environment Agency, if the data series clearly demonstrate a sufficient stability.
6. Measurement of TOC and application of a correlation factor may be used as a surrogate for COD. Parallel monitoring of TOC and COD shall be undertaken over a period of 1 year (to allow for seasonal variance) to determine the applicable correlation factor. The TOC correlation factor shall be agreed in writing with the Environment Agency before parallel monitoring of COD can cease.

2.2.16 Oxygen production

Oxygen is required for the autothermal reforming (ATR). It is produced by an air separation unit (ASU), which is a relatively large energy user.

Our guidance for emerging techniques requires applicants to consider heat recovery from the heat generated by the air compression system and whether it can be used within the rest of the hydrogen production process to maximise energy efficiency. BAT considerations relevant to oxygen production include:

- Overall energy consumption depends on the design of the ASU and its air compressor.
- Energy required will be a balance between oxygen purity, oxygen pressure needed to supply the hydrogen production process and energy needed to purify the hydrogen.
- Higher oxygen purity will increase the energy required for oxygen production but reduce the amount needed for hydrogen purification to remove residual argon and nitrogen.
- Co-production of argon and nitrogen can be used for export or on site.
- Heat energy needed to dry and purify the compressed air.
- Options to increase the compressor exit temperature to improve options for heat recovery should be explored, balanced with compressor design and higher power requirement.
- Safe and reliable operation of both the ASU and hydrogen production plant where heat integration is used.
- High availability of oxygen supply and backup supply or liquid storage is important to avoid potential environmental impacts of emergency or frequent shut-down and startup of the plant.

According to the operating techniques stated in the Application documents, the HPP (Phase 1) will be provided with a single dedicated cryogenic ASU capable of providing oxygen at a purity of 99.5 mol%. The unit will also supply nitrogen (99.9 mol% purity), and plant and instrument air.

Energy efficiency for the ASU has been taken into account: the Applicant has benchmarked the electrical power demand for this unit among different vendors, who have quoted consistent figures averaging at 14.4 MWe and comparable demands for cooling.

According to the proposal, the ASU will not be integrated with the wider HPP and will occupy a geographically separate area from the main process plant for safety reasons (to eliminate the potential for the mixture of flammable gases). Refer to 'Energy and process efficiency' section above for further details of the justification provided by the Applicant and how we have made our decision in relation to this justification.

The ASU will be provided with a back-up liquid oxygen and nitrogen supply. This is in line with the requirement of our guidance to avoid potential environmental impacts of emergency or frequent shut-down and start-up of the plant.

We are satisfied that the proposal has given sufficient consideration to the requirements guidance on emerging techniques and is acceptable to us.

2.2.17 Waste management

Our guidance for emerging techniques requires applicants to eliminate or minimise wastes and treat them, where appropriate. This is consistent with the requirements of the following REF BAT Conclusions, which are applicable to this application:

BAT conclusion 14. *In order to prevent or, where that is not practicable, to reduce waste generation, BAT is to adopt and implement a waste management plan that, in order of priority, ensures that waste is prepared for reuse, recycling, recovery or disposal.*

BAT conclusion 15. *In order to reduce the amount of sludge to be treated or disposed of, BAT is to use one or a combination of the techniques given below.*

- *(i) Sludge pretreatment (Prior to final treatment (e.g. in a fluidised bed incinerator), the sludges are dewatered and/or de-oiled (by e.g. centrifugal decanters or steam dryers) to reduce their volume and to recover oil from slop equipment)*
- *(ii) Reuse of sludge in process units. Certain types of sludge (e.g. oily sludge) can be processed in units (e.g. coking) as part of the feed due to their oil content*

BAT conclusion 16. *In order to reduce the generation of spent solid catalyst waste, BAT is to use one or a combination of the techniques given below.*

- *(i) Spent solid catalyst management*
- (ii) *Removal of catalyst from slurry decant oil* (not applicable to this process)

Table 3-39 of the Application document titled 'HyNet Hydrogen Production Plant Environmental Permit Application Supporting Document', received on 31/08/2021, provides a preliminary waste inventory, which identifies the recovery, reuse and disposal options for the wastes generated by the proposed HPP. According to the operating techniques stated in the Application, prior to commissioning, the Operator will review the waste management proposals identified in the Application for their continued suitability and to ensure wastes are prevented or managed as high up the waste hierarchy as possible and proposed a pre-operational condition as follow-up.

As part of the site's environmental management system, the Operator will review and record at least every four years whether changes to waste management measures should be made and take any further appropriate measures identified by a review. Sludges generated in the HPP waste treatment system (from the CPI, Backwash Settlement Tanks, Clarification Plant and MBR) will be pre-treated by dewatering in the Dewatering Centrifuge Plant which reduces the volume of sludge to be removed by tanker for off-site disposal. The HPP sludges do not require de-oiling and there is no opportunity to re-use sludges in the HPP process.

Catalysts and absorbents will be changed out according to a catalyst management plan. The change-out and recharging with new catalyst and absorbents will be carried out by a specialist contractor. The catalysts and absorbents will be sent for metals recovery, subject to prevailing metals market conditions. Catalysts and adsorbents will not mix with oils in the HPP process.

We agree that the stated operating techniques for waste management are provisionally compliant with BAT, pending the follow up on waste management required by the relevant improvement condition we have specified in the permit .

2.2.18 Monitoring CO_2 capture performance

Our guidance for emerging techniques requires applicants to identify how the CO_2 capture performance of the plant will be monitored.

CO_2 capture performance is expected to be monitored according to standards that are recognised under the UK Emissions Trading Scheme (UK ETS). Measurements required to monitor CO_2 emissions to atmosphere may, for example, include direct measurement of the flow and composition of fuel gas to combustion systems.

This, together with measurement of the flow and composition of feed gas, hydrogen product (including methane content where applicable) and CO_2 product streams, will allow monitoring of the CO_2 capture rate and CO_2 quality (considering any impurities that could impact downstream systems).

According to the operating techniques stated in the Application and in response to the Schedule 5 Notice served to the Applicant, the CO_2 capture performance will be determined through a carbon balance over the HPP plant that will be based on the process monitoring of the following parameters:

- Temperature, pressure and flow rate of the export of CO_2 will be measured
- Composition of the exported CO_2
- The relief gas flow to flare (actual and totalised)
- CO_2, SO_2, NOx and CO monitoring in the Feed Fired Heater and Steam Boiler exhaust stacks.

We have set the following process monitoring requirements:

- Feed gas mass flow, composition and calorific value (natural gas and ROG)
- Electrical power import
- Exported CO_2 mass flow
- Hydrogen production mass flow
- Net Feed Gas Energy Conversion Efficiency (%)
- Emissions of CO_2 from venting operations to UK ETS standards
- Emissions of CO_2 from Feed Fired Heater and Steam Boiler exhaust stack to UK ETS standards
- Flared gas (actual and totalised), including CO_2 emissions from flaring to UK ETS standards
- Carbon Capture Efficiency (%)
- Diesel usage
- Water usage
- Fugitive emissions of VOCs and hydrogen.

These process monitoring requirements have been specified in order to monitor and report on the overall efficiency of the HPP and CCS plants.

We have set a pre-operational condition requiring the Operator to submit for approval by us, a methodology detailing the monitoring parameters, their standards and the frequency in order to carry out the carbon balance over the HPP and monitor the carbon capture efficiency of the plant and the energy efficiency of the plant (instantaneous and averaged over the time).

2.2.19 Unplanned emissions, soil and groundwater protection

Fugitive emissions to air

Our guidance for emerging techniques requires applicants to propose a leak detection and repair (LDAR) programme that is appropriate for the fluids and their composition. This should use industry best practice to manage releases, including from joints, flanges, seals and glands. This requirement is consistent with BAT conclusion 18 of Refining of Mineral Oil and Gas BAT Conclusions, which is relevant to the type of activities carried out at the Installation:

BAT Conclusion 18. *In order to prevent or reduce diffuse VOC emissions, BAT is to apply the following techniques:*

- *i) limiting the number of potential emission sources,*
- *ii) maximising inherent process containment features,*
- *iii) selecting high integrity equipment,*
- *iv) facilitating monitoring and maintenance activities by ensuring access to potentially leaking components,*
- *v) well-defined procedures for construction and assembly,*
- *vi) robust commissioning and hand-over procedures to ensure that the plant is installed in line with the design requirements, and*
- vii) *Use of a risk-based leak detection and repair (LDAR) programme in order to identify leaking components, and to repair these leaks*.

According to the operating techniques stated in the Application, fugitive emissions will be well controlled by design and regular inspection and maintenance measures. The operator operates a LDAR programme on the existing installation, that will be extended to cover the HPP. We have specified an improvement condition to follow up on the successful extension of this programme to the activities in the scope of this variation.

The Application states that the HPP will be designed to relevant industry design standards to limit potential sources of volatile organic compounds (VOC) emissions by minimising potential sources of leaks, including minimising the number flanged joints and setting valve performance specifications. Feed and process gas pressure relief valves or vents are routed to the flare system, which will minimise venting emissions.

According to the Application, the HPP equipment layout has been designed to enable access for regular inspection and planned maintenance during normal operations, as well as major overhaul in shutdown periods.

The Applicant has committed to developing a Commissioning Plan, containing procedures to manage HPP commissioning. Commissioning procedures will include measures to control fugitive emissions, including pressure testing and other leak detection monitoring, and regular checks of equipment during commissioning. The Commissioning Plan will include the production of formal hand-over documentation between the engineering/procurement/commissioning (EPC) contractor and the Operator and Operator's training. We have set a pre-operational condition requiring the operator to submit the Commissioning Plan for our approval before the start of the commissioning activities.

Whilst VOCs are the primary focus of BAT conclusion 18, these are not the only potential fugitive emissions of concern from the proposed plant. The intent of our guidance for emerging techniques is to cover also potential fugitive emissions of hydrogen. We have therefore specified within an improvement condition that the extension of the LDAR programme to the activities in the scope of this variation application shall also cover fugitive emissions of hydrogen.

Fugitive emissions to water, groundwater, land

The Application includes a statement of compliance and a review against the requirements of our web guidance Control and monitor emissions for your Environmental Permit on emissions to waters and leaks from containers.
In particular, the following techniques are proposed:

- Process areas and utilities areas will be surfaced with high quality reinforced concrete hardstanding with spill containment kerbs and sealed construction joints. Roads and parking areas will have concrete or tarmac surfacing with concrete kerbs. Areas outside the processing areas and roads will have gravel surfacing to aid infiltration as part of the Sustainable Drainage System (SUDS) design.
- The Applicant has an existing inspection and maintenance programme which includes tanks, secondary containment, and surfacing; this will be extended to cover the HPP.
- There will be no subsurface bulk storage tanks. The Amine Drain Drum, TEG Drain Drum and Closed Drains Drum are sub-surface, but they will be designed to ensure that they are water-tight and, according to the additional information provided by the Applicant on 26/09/2022, within reinforced concrete bunds.
- The only other sub-surface structures will be the open drains pipework and sealed drainage pits which collect clean and potentially contaminated surface water run-off. The as-built location of drains and sumps and interceptors will be recorded on a site drainage plan. Interceptors will be fitted to areas of the open drainage system that could be contaminated by oils.
- All HPP storage tanks are above-ground. Tanks that contain potentially polluting materials will be bunded. The application document titled 'Technical Note – Secondary Containment', received on 07/12/2021 in response to a request for further information. This document includes a list of storage tanks foreseen in the scope of the HPP project, provides a review of storage inventories and identifies the tanks that will be provided with

secondary containment according to the hazardous characteristics of the stored materials. The design philosophy states that where a bund is specified, it shall hold at least 110% of the maximum inventory, to provide a margin for rainwater and that the margin should be increased if it is foreseeable that there be additional liquids (e.g. fire water) which could lead to an overflow beyond the secondary containment.

Bunds will be designed, constructed and managed to meet the further requirements relating to capacities, containment, connections and management identified in EA Guidance ‘Control and monitor emissions for your Environmental Permit’.

In the response to the Schedule 5 Notice received on 24/06/2022, the Applicant confirmed that the bunds will be constructed of reinforced concrete, lined with an impermeable polymeric liner.

- All sumps, drainage drums and bunds will be waterproof and resistant to the materials stored in them.
- The Amine Storage Tank, TEG Storage Tank, Cooling Medium Storage Tank, Waste Water Blending Tank, Sludge Blending Tank, and Thickened Sludge Holding Tank will be fitted with high and low level controls connected to the Distributed Control System (DCS) alarms and Safety Instrumented System (SIS) trips.
- Delivery and offloading areas will be purposely designed areas, with in-built containment which can be isolated from the site drainage system. Material deliveries, storage and handling will be undertaken in accordance with site procedures; this includes supervision of deliveries.
- Raw materials and wastes will be stored in appropriate containers resistant to the substances contained. Intermediate bulk containers (IBCs) and drums and other containers will be stored in clearly marked, designated storage areas with identified capacities. They will be provided with bunded containment and will be situated on areas of hardstanding. Any incompatible materials will be identified and stored separately, where required.

According to the Application document titled ‘Technical Note: Surface Water Drainage’, four retention pits serving the contaminated drainage system have been designed with adequate capacity to provide tertiary containment for spent firewater in the case of a fire.

In response to our request for further information on the design of containment systems, the Applicant responded that the specification for the primary, secondary and tertiary containment systems is yet to be finalised. The containment systems will be designed and specified by suitably qualified and experienced engineers to comply with the requirements of CIRIA 736, addressing the key elements which include:

- Updating the risk assessment (in addition to ENVID and HAZOP studies that have already been carried out) and classification to identify the class of containment required;

- Developing the specification and design of the primary, secondary and tertiary containment appropriate to the class of containment, taking into account CIRIA 736 guidance on bunding, further containment and transfer systems;
- The design will take into account the capacity requirements, including the capacity of the inventory to be contained, allowance for rainfall, and firefighting and cooling water provision.

The Applicant proposed a pre-operational condition as follow-up.

In response to our requests for further information (received on 24/06/2022 and 26/09/2022), the Applicant confirmed the following design changes, which are now taken as binding operating techniques to be followed by the Applicant and referred to in table S1.2 of the variation and consolidation notice:

- The double walled Emergency Generator Diesel Tank will be provided with an interstitial leak detection system, initially not included in the design.
- The design was updated to include a secondary containment bund around the Thickened Sludge Holding Tank and Sludge Blending Tank, initially not included in the design.
- The design was updated to include a secondary containment bund designed to CIRIA 736 standard around Waste Water Blending Tank, initially not included in the design.

We are satisfied that the general design principles stated in the Application are consistent with BAT and meet the requirements of our guidance. However, since the design still needs to be finalised, we have specified a pre-operational condition requiring the Applicant to submit for approval by us the details of the final design of secondary and tertiary containment systems and their isolation philosophy, to be developed according to CIRIA 736 guidance.

Our guidance for emerging techniques also requires applicants to assess and mitigate the risks of accidental releases to the environment. Refer to section 2.3.3 for accident risk assessment and abnormal emissions.

2.2.20 Emissions of noise and vibration

Our guidance for emerging techniques requires applicants to consider sources that have high potential for noise and vibration. In particular, CO_2 and H_2 compression, pumping and fan noise could be significant additional sources. Once the main sources and transmission pathways are identified, applicants should consider using common noise and vibration abatement techniques and mitigation at source, wherever possible.

The Applicant submitted a Noise Impact Assessment based on preliminary noise plant data available at the front-end engineering stage of the design. We audited the Applicant's assessment and, based on the information available at this stage, we agree with the conclusion that adverse or significant adverse impacts at nearby receptors from the activities proposed in the scope of this variation are unlikely.

At this stage, the application included generic commitments on noise mitigation measures, such as locating equipment away from site boundary, installing noisy equipment within acoustic enclosures and mounting rotating machinery items on appropriately specified anti-vibration supports. The application sets out the noise mitigation hierarchy for the project and included a commitment from the Applicant to further mitigating the minor adverse impacts predicted at the 'Stables travellers' site' as part of the detailed design process, through the further application of noise mitigation measures, including equipment selection, noise abatement and screening. These provisions are adequate to the development of the project and notionally consistent with BAT, however it was not possible to audit detailed information on the noise emissions data from equipment manufacturers and to review detailed information on the design of acoustic mitigation measures included in the design as these will only become available as the detailed engineering design of the project is progressed.

We have therefore set a pre-operational condition requiring the Applicant to update the Noise Impact Assessment submitted with the application according to noise emissions data provided by equipment manufacturers during the detailed engineering design of project and noise mitigation measures demonstrated to be compliant with BAT. Refer to section 2.3.4 for further details.

2.2.21 Prevention of odorous emissions

Our guidance for emerging techniques requires applicants to use best practice containment methods for odour and notes that the handling, storage and use of some amines may result in odorous emissions.

The application states that odour is not anticipated to be an issue as the process is not inherently odorous and identifies the following measures:

- The feed gas is desulphurised, and potential odorous materials are contained and subject to regular maintenance checks.
- None of the process gases are released directly to atmosphere: sulphur containing feed gas, if it is relieved from the process, is combusted at the flare tip and discharged to atmosphere at a height of 60 m, ensuring good dispersion.
- Process absorbents – amine and TEG – are under nitrogen blanket and are not open to the atmosphere but are fitted with pressure valves (operating at a low pressure). These are only used occasionally (for initial filling and storage for plant drain-down) and thus displacement losses are only occasional.
- Diesel is stored in a tank with an open vent. This is a small storage tank, diesel fuel has low volatility and the tank will only be filled infrequently.

We consider that the proposed measures are adequate to the nature and risks of the proposed operations and consistent with BAT. Should unanticipated odour issues arise during the operation of the proposed activities, the Operator will be required to submit and implement an odour management plan, according to condition 3.3.2 of the permit.

2.3 Environmental risk assessment

Regulated activities can present different types of risk to the environment. For the activities in the scope of the Application, the principal risks identified in the Application include emissions to air and water; risk associated with accidents; risks associated with noise and vibration; risk associated with flooding; global warming potential. Consideration may also have to be given to the effect of emissions being subsequently deposited onto land (where there are ecological receptors). The key factors relevant to this determination are discussed in this and other sections of this document. In the following, we explain how we have approached the critical issue of assessing the likely impact from the activities in the scope of the application on human health and the environment.

2.3.1 Emissions to air

2.3.1.1 Assessment Methodology

Application of Environment Agency Web Guide for Air Emissions Risk Assessment

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

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

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

Use of Air Dispersion Modelling

For emissions that don’t screen out as insignificant, we require the Applicant to submit a full air dispersion model as part of their application, for the key pollutants.

Air dispersion modelling enables the PC to be predicted at any environmental receptor that might be impacted by the plant.

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

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

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

PCs are considered **Insignificant** if:

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

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

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

The **short-term** 10% process contribution insignificance threshold is based on the judgements that:

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

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

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

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

This is not the end of the risk assessment, because we also take into account local factors for example:

- Statutory protected ecological receptors nearby, i.e. Sites of Special Scientific Interest (SSSIs), Ramsar sites, Special Areas of Conservation (SACs) or Special Protection Areas (SPAs).
- Non-statutory protected ecological receptors, such as local nature sites

The insignificance criteria for statutory protected ecological receptors are:

- the short term PC is less than 10% of the short term environmental standard for protected conservation areas
- the long term PC is less than 1% of the long term environmental standard for protected conservation areas

If the long term PC is greater than 1% we look at the background concentration and calculate the predicted environmental concentration (PEC). If the PEC at the statutorily protected ecological receptor is less than 70% of the long term environmental standard for protected conservation areas, the emissions are considered insignificant.

The insignificance criteria for non-statutory protected ecological receptors are:

- the short-term PC is less than 100% of the short-term environmental standard for protected conservation areas
- the long-term PC is less than 100% of the long-term environmental standard for protected conservation areas

These additional factors may also lead us to include more stringent conditions than BAT.

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

2.3.1.2 Assessment of impact on air quality

The Applicant's assessment of the impact of air quality is set out in the Application document titled 'HyNet Hydrogen Production Plant - Air Quality Assessment Phase I' dated 17/06/2021. The assessment comprises:

- Dispersion modelling of emissions to air from the operation of the major combustion sources in the scope of this variation (Feed Fired Heater and the Steam Boiler).
- A qualitative risk assessment for emissions to air from minor intermittent combustion sources and emergency flare.
- A study of the impact of emissions on nearby sensitive conservation sites.

This section of the decision document deals primarily with the dispersion modelling of emissions to air from the installation and its impact on local air quality. The impact on conservation sites is considered in section 2.3.1.5.

The Applicant has assessed potential emissions to air against the relevant air quality standards, and the potential impact upon local conservation sites and human health. These assessments predict the potential effects on local air quality from the stack emissions using the US EPA AERMOD dispersion model, which is a commonly used computer model for regulatory dispersion modelling. The model used 5 years of meteorological data collected from the weather station at Speke (formerly Liverpool John Lennon Airport) which is 6 km to the north-west of the installation, between 2016 and 2020. The impacts of buildings and terrain surrounding the site upon plume dispersion were considered in the dispersion modelling.

The air impact assessments, and the dispersion modelling upon which they were based, employed the following assumptions:

- A single operational scenario for emissions from the Feed Fired Heater and Steam Boiler was modelled. This represents the normal operational conditions for the concurrent operation of the Feed Fired Heater and the Steam Boiler. For the purpose of the assessment, it was assumed that both sources operate continuously and at full load throughout the year, ignoring temporary shut-down periods for maintenance.

- Consideration of emissions from other sources at the refinery were excluded from the scope because the air dispersion modelling demonstrated that process contributions (PC) were environmentally insignificant at all human and ecological receptors (i.e. contribute less than 1% of applicable long term standards and 10% of applicable short term standards). In addition, it was demonstrated that the annual emissions from the new HPP introduced by this variation, are lower than those arising from the equipment proposed to be removed from the permit by the same variation application (i.e. combustion equipment serving the Higher Olefines and Alcohol plants).

- The Feed Fired Heater and the Steam Boiler each discharge through individual stacks and were therefore modelled as separate point sources. Each emission source was modelled to discharge at a height of 40 metres above ground (the height having been determined from a stack height sensitivity study that was presented in the same application document).

- The Feed Fired Heater and the Steam Boiler operating as part of the HPP will be continuous sources of NOx, which would arise from the combustion of PSA tail gas (and natural gas on start-up). NOx emissions were modelled at the proposed emission limit of 80 mg/m^3 at 3% oxygen and reference conditions.

- Natural gas, which may be used infrequently at start-up, has a very low sulphur content of less than 5 ppm total sulphur, so would not materially contribute to emissions. Also, sulphur will be removed from the feed gas through a desulphurisation process to comply with a maximum limit. The HPP project has currently agreed a limit on the sulphur content of feed gas equivalent to 13.6 ppm H_2S. If the ROG content of H_2S increases, it would reduce the equipment performance and lifetime thus the plant is designed against this, although occasionally there could be peaks above the design level. If this happened, the ROG would be diverted elsewhere within the Stanlow refinery and is outside the scope of this Application. For these reasons, sulphur dioxide emissions have been anticipated to be negligible.

  According to the application, there could occasionally be flaring of some sulphur containing gas but this would be very infrequent and for short durations. The flare emissions would be discharged at a height of 60 m above ground level at high temperature and thus dispersion would be very effective for both NOx and SO_2 emissions. In the Schedule 5 Notice served on 17/03/2022 (response received on 24/06/2022), we requested the Applicant to explain / implement process monitoring measures and controls available upstream or at the inlet of the hydrogen production plant, to prevent feeding high-sulphur off-spec ROG to the hydrogen plant, potentially leading to flaring of gas with high sulphur concentration from the proposed new flare. The Applicant confirmed that there will be a dedicated fast-response sulphur species analyser installed with a 2 out of 3 voting system. This sulphur species analyser will operate with a 1 second cycle time. The duration of an off-specification ROG stream with higher sulphur content entering the pipelines feeding the ROG compressor would be 2 seconds, based on the 2 out of 3 voting system for the sulphur species analyser. Assuming a margin of 5 seconds for the sulphur species analyser, would lead to approximately 15kg of off specification ROG entering the pipelines network upstream of the ROG compressor. This quantity is considered insignificant, and the 5 second time margin allows sufficient time to close an isolation valve and divert the off-specification ROG back to the Stanlow Manufacturing Complex preventing the risk of emissions of SO_2 from the new flare.

- The stack diameters were estimated in order to provide a value in the range 10-15 m/s for the exhaust gas velocity, a suitable assumption for both the heater and the boiler.

- The standby diesel generator and firewater pump are only expected to operate for very limited periods throughout the year, for testing and emergency use. For these reasons, their impacts were considered negligible and these three sources were not included in the detailed modelling study.

The Applicant used the values from the Cheshire West and Chester Council's Air Quality Annual Status Report (ASR) published in 2019, to inform the study with background concentrations.

The way in which the Applicant used dispersion models, its selection of input data, use of background data and the assumptions it made have been reviewed by the Environment Agency's Air Quality Modelling and Assessment Unit (AQMAU) to establish the robustness of the Applicant's air impact assessment.

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

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

2.3.1.3 Assessment of air dispersion modelling outputs at human receptors

The table below shows the ground level concentrations at the most impacted receptor. Where emissions screen out as insignificant, the background pollutant levels are not considered within the assessment in accordance with our H1 screening process.

Table 1 -air dispersion modelling outputs at human receptors

Pollutant	EQS / EAL (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL
NO_2 Annual	40	0.2 [Note 1]	0.5% [Note 1]
NO_2 Hourly mean	200	3.2 [Note 2]	1.6% [Note 2]
Notes: 1. PC at discrete receptor referred to as D22 - The Stables, Thornton Le Moors – in the application 2. PC at discrete receptor referred to as D26 - Commonside, Alvanley – in the application			

From the table above the emissions can be screened out as insignificant in that the PC is <1% of the long term EQS/EAL and <10% of the short term EAQ/EAL.

2.3.1.4 H1 Assessment of emissions of methanol from TEG still column vent.

The Applicant submitted a screening assessment for the emissions to air associated with venting from the TEG still column, carried according to the methodology described in our web guidance [Air emissions risk assessment for your environmental permit - GOV.UK (www.gov.uk)] and made use of the Environment Agency's H1 tool software. The off-gas from this still column will consists of water, carbon dioxide and methanol. Methanol emissions to air are minimised through the use of a condenser and knock-out vessel, as described in section 2.2.14.4. The table below shows the results of the H1 risk assessment for emissions of methanol:

Number	Substance	Long Term EAL	Short Term EAL	Long Term PC	Long Term % PC of EAL	Long Term > 1% of EAL?	Short Term PC	Short Term % PC of EAL	Short Term > 10% of EAL?
		µg/m3	µg/m3	µg/m3	%		µg/m3	%	
1	Methanol	2,660	33,300	9.52	0.358	**No**	182	0.546	**No**

- The long-term PC of methanol is environmentally insignificant in that it is <1% of the long-term EAL.
- The short-term PC of methanol is environmentally insignificant in that it is <10% of the long-term EAL.

We agree with the conclusions of this assessment and we therefore consider the proposed operating techniques to be BAT.

2.3.1.5 Impact on habitats and conservation sites

The following statutory protected habitats sites are located within relevant screening distance:

- Mersey Estuary Special Protection Area (SPA), Ramsar and Site of Special Scientific Interest (SSSI);
- River Dee and Bala Lake Special Areas of Conservation (SAC)

The following non-statutory local wildlife sites (LWS) and conservation sites are located within relevant screening distance:

- Station Road Railway Site
- Frodsham and Helsby and Ince Marshes LWS
- River Gowy LWS
- Gowy Meadows and Ditches LWS
- Shelway Road Pond South LWS

- Wervin Meadows LWS
- Hoblane Ponds LWS

We consider that the only pollutants relevant for the ecological assessment are NOx, which are potentially responsible for toxic impacts, nutrient nitrogen deposition and acidification. The activities proposed in the scope of this variation will reduce the potential for emissions of SO_2, compared to the current operations of the installation, as a result of the desulphurisation of the refinery off-gas fed to the HPP, resulting in a desulphurised gaseous fuel (PSA tail gas) fired in the main combustion equipment introduced by this variation. Therefore, we have agreed that SO_2 emissions are not of concern.

The Applicant's modelling predicted NOx concentrations and deposition parameters at the most impacted statutory ecological receptor (Mersey Estuary SPA/SSSI/Ramsar) and at the most impacted non-statutory local ecological receptor are shown in table below. Where emissions screen out as insignificant, the background pollutant levels are not considered within the assessment in accordance with our H1 screening process.

Table 2 - Air emissions impacts at Mersey Estuary SPA/SSSI/Ramsar

Pollutant	EQS / EAL (µg/m³)	Back-ground (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	Predicted Environmental Concentration (PEC) (µg/m³)	PEC as % EQS / EAL
Direct Impacts[1]						
NO_x Annual	30	N/A	0.07	0.2%	N/A	N/A
NO_x Daily Mean	75	N/A	<1.4	<1.9%	N/A	N/A
Deposition Impacts[1]						
N Deposition (kg N/ha/yr)	5	N/A	0.01	0.2%	N/A	N/A
Acidification - Nitrogen Dep (Keq/ha/yr)	0.498	N/A	0.001	0.2%	N/A	N/A

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

Table 3 - Air emissions impacts at Gowy Meadows and Ditches LWS

Pollutant	EQS / EAL (µg/m³)	Back-ground (µg/m³)	Process Contribution (PC) (µg/m³)	PC as % of EQS / EAL	Predicted Environmental Concentration (PEC) (µg/m³)	PEC as % EQS / EAL
Direct Impacts[1]						
NO_x Annual	30	N/A	0.16	0.5%	N/A	N/A
NO_x Daily Mean	75	N/A	1.4	1.9%	N/A	N/A
Deposition Impacts[1]						
N Deposition (kg N/ha/yr)	20	N/A	0.02	0.1%	N/A	N/A
Acidification - Nitrogen Dep (Keq/ha/yr)	5.701	N/A	0.002	0.03%	N/A	N/A
Note 1: Direct impact units are µg/m³ and deposition impact units are kg N/ha/yr or Keq/ha/yr.						

Table 2Table 1 -air dispersion modelling outputs at human receptors above show that the PCs at the most impacted statutory protected ecological site are below the critical levels or loads and can be considered insignificant in that the process contribution is <1% of the long-term critical load/critical level and <10% of the short-term critical level.

We are satisfied that this variation will not cause likely significant effects at the Mersey Estuary SPA/Ramsar, River Dee and Bala Lake SAC and will not be likely to cause damage to the qualifying features of the Mersey Estuary SSSI.

Table 3 above show that the PCs at the non-statutory ecological sites are below the critical levels or loads and can be considered insignificant in that the process contribution is <100% of the long and short-term critical load/critical level.

We are satisfied that this variation will not cause significant pollution to any local nature site.

The Applicant is required to prevent, minimise and control emissions using BAT, this is considered further in section 2.2. No further assessment of impact on conservation sites is required.

2.3.2 Emissions to water

Rainwater falling on areas of the HPP at low risk of contamination, such as roads and building roofs, will be collected in the uncontaminated drains system and transferred to the existing refinery drainage system for discharge and treatment to the existing United Utilities treatment plant, through the existing emission point S1. The environmental risk associated with uncontaminated rainwater is expected to be low and, in the unlikely scenario that low-level contamination was present in this effluent, this will be treated by the United Utilities treatment plant.

The Demineraliser plant will generate a demineralised water stream and a reject effluent. The reject effluent will be discharged to the existing refinery drainage system at point T1 at the existing CT2 open sump, already included in the existing permit). This will then flow from CT2 to discharge through point N38 to existing permitted discharge point W3 to the Manchester Ship Canal. This is the only wastewater stream proposed to be directly discharged to the environment from the HPP.

The total discharge flow rate permitted at emission point W3 will remain unchanged, after including the new demineralisation effluent generated by the HPP operations.

The permitted flow rate at W3 is 90,000 m^3/day during normal operations (up to 100,000 m^3/day during abnormal operations when S1 emission point is not available).

The demineralisation plant effluent flowrate will be 338.4 m^3/day (normal flow), therefore corresponding to a minor percentage (0.4%) of the already permitted discharge during normal operations.

There will be no requirement to change the permitted flowrate limit to accommodate the HPP. Emission point W3 is currently permitted to discharge effluents from the existing demineralisation activities, that are likely to be qualitatively consistent with the effluent from the new demineralisation plant. Also, the combined effluent discharged at emission point W3 after this variation will meet the emission limits already set out according to the REF BAT-AEL in the current permit. Furthermore, the new discharge effluent proposed by this variation will also meet the CWW BAT-AELs, see section 2.2.15 of this document for additional information on how we have specified emission limits to take into account the applicable BAT-AELs.

As the determination of this variation application progresses, the Applicant has been carrying out a review of site effluents to address an existing permit Improvement Condition (IC38), which will result in changes to the effluents, flow rates and compositions discharged via the existing permitted discharge points. An assessment of the existing and the revised discharges (including those through W3) is currently being developed by Essar, using H1 or a more developed model, and is due to be submitted under this improvement condition. This assessment of existing and revised discharges will need to be completed first in order to provide a basis for the assessment of HPP discharges (which will be an additional element to the revised W3 discharges). Therefore, the Applicant has proposed adding the HPP discharges to the revised case assessment model, and to provide this assessment to us at the earliest opportunity, as part of a pre-operational condition, once the refinery-wide revised discharges assessment response to IC38 is completed.

Since the effluent proposed to be discharged:

- will not change the overall permitted discharge flow rate at emission point W3,
- will meet the existing emission limits set out in accordance to BAT; and
- constitutes a minor percentage of the already permitted discharge,

we consider the environmental risk associated with discharges to waters arising from this variation application is unlikely to be changed compared to the currently permitted operations.

We have therefore accepted the proposal of the Applicant and specified a pre-operational condition requiring the Operator to submit for approval by us a revised environmental risk assessment for emission point W3. This risk assessment shall be approved by us prior to beginning the commissioning operations of the proposed HPP. The pre-operational condition specifies that, if warranted by the outcomes of the risk assessment, the Operator shall propose amended operating techniques according to BAT, such as different design configurations of the water treatment activities, different disposal options, and/or emission limits more stringent than the BAT-AELs for the parameters of concern, due to their potential environmental impacts. Any amended operating techniques and emission limits proposed by the Operator shall be approved by the Environment Agency prior to the start of the commissioning operations of the hydrogen production and carbon capture plant.

2.3.3 Other than normal operating conditions (OTNOC) and accidents

2.3.3.1 Risk assessment for CO_2 venting during OTNOC

In response to our request for information (Schedule 5 Notice served on 17/03/2022), the Applicant provided a risk assessment for the abnormal emissions associated with venting operations of streams highly concentrated in carbon dioxide. The Applicant's response consisted of the following documents:

- A summary document in response to question 19 of the Schedule 5 Notice, titled '19. Risk assessment for abnormal CO_2 venting emissions', received on 25/11/2022.
- Appendix 1, an emission inventory detailing the emissions rates under all the foreseeable OTNOC conditions as informed by the process designer of the plant, received on 25/11/2022.
- Appendix 2, document titled 'Environmental risk assessment for abnormal emissions of carbon dioxide, Essar Stanlow Refinery', received on 25/11/2022.
- Appendix 3, describing the methodology for the risk assessment, received on 25/11/2022.
- A technical note explaining the derivation of the emissions parameters used in the air dispersion model, received on 09/12/2022.

The modelling was carried out to predict the resulting concentrations of carbon dioxide in the surrounding area, for comparison with acute exposure thresholds, which were determined, following a review of existing environmental and safety standards, and relevant guidance.

In humans, CO_2 is a normal component of blood gases at low concentrations, however if inhaled at high levels it can be harmful through toxicological impact. CO_2 has been shown to exhibit a level of toxicity related to the concentration and time of exposure.

CO_2 is normally emitted from combustion equipment fired on carbon containing fuels at concentration levels below 15% (depending on the fuel used and the combustion technology). At these concentration levels, considering the typical dispersion patterns of combustion flue gases, the concentrations of CO_2 after dispersions in the environment are not typically a concern for human health.

However, emissions of concentrated CO_2 streams, such those that may occur from the operation of carbon capture plant during other than normal operating conditions (OTNOC), may be such that levels of concern for human health could potentially be achieved in the environment. CO_2 is heavier than air, and releases involving pure CO_2, as well as those gas mixtures with an average molecular mass value significantly greater than that of air, may fall rapidly towards the ground after being released to air.

In the study submitted by the Applicant, modelled concentrations of carbon dioxide were compared with threshold values for public exposure. Sources of information in relevant thresholds included the former Public Health England's (PHE) (now UK Health Security Agency) 'Compendium of Chemical Hazards: Carbon Dioxide' and 'Assessment of the major hazard potential of carbon dioxide' published by the Health and Safety Executive (HSE).

The document published by Public Health England indicates a 2-5% CO_2 concentration as the indicative reported effect level associated with symptoms such as headaches, dizziness, sweating, shortness of breath for inhalation of CO_2.

The document published by the Health and Safety Executive reports a concentration of 3% CO_2 for 1 hour exposure (corresponding to 30,000 ppm) as the concentration responsible for headaches; and defines higher Specified Levels of Toxicity (SLOT) associated with different exposure times for land use planning, with the shortest exposure time being of 1 minute.

On a conservative basis, the Applicant used a 1-hour averaged threshold concentration of 2% of CO_2 (corresponding to 20,000 ppm), based on lower range of the figure reported by Public Health England, which is the lowest level reported between the two publications listed above.

The Applicant's assessment used the ADMS 5 dispersion model, which is a commonly used computer model for regulatory dispersion modelling. The model used 5 years of meteorological data collected from the weather station at Liverpool Airport, between 2016 and 2020.

The way in which the Applicant used dispersion models, its selection of input data, use of background data and the assumptions it made have been audited by the Environment Agency's Air Quality Modelling and Assessment Unit (AQMAU) to establish the robustness of the Applicant's air impact assessment.

As part of our audit of the Applicant's assessment, we requested additional information on the uncertainties of the modelling study (request for additional information served on 12/12/2022), in particular regarding the suitability of ADMS, which is gaussian air dispersion software, to model releases of CO_2 which have a potential to behave as a dense gas. A satisfactory response to our request was provided by the Applicant in the form of a revised environmental risk assessment study submitted on 30/01/2023. The revised version of the study submitted on

30/01/2023, confirmed the conclusions of the previous version submitted on 25/11/2022. Compared to the first version, the revised version of the study included:

- Sensitivity tests carried out to investigate the uncertainty in the high exit velocities associated with some of the release scenarios, and the associated high levels of turbulence.
- Further justification of the suitability of ADMS as dispersion model for the scenarios identified in the study.
- Test modelling using the dense gas model GASTAR for comparison against the predictions of ADMS. Plots of the plume centreline profiles for ADMS and GASTAR were presented, showing good general agreement for the two sets of plume centreline profiles for each modelled scenario.
- Prediction for the shortest exposure time of 1 minute, with reference to averaging times from the HSE publication referred to above.
- An additional, more conservative, scenario, considering the combined release of CO_2 from the CO_2 capture unit and Pipelines/AGI stack. The Applicant explained that the maximum rate from the CO_2 capture unit stack had already modelled as a single case at the total plant production rate. However, in response to our request, the Applicant added a further combined scenario, which is considered to represent a 'worst-case' scenario of combined releases from the Pipelines/AGI stack (with the remainder of the plant production rate emitted through the CO_2 capture unit stack).

The predictions of the Applicant's study are summarised in the following:

- The maximum 100th percentile offsite hourly average process contribution (PC) of CO_2 predicted by the Applicant is 4,474 ppm for the combined scenario, corresponding to 22.4% of the threshold value of 20,000 ppm, taken from the PHE publication referred to above. Including the background concentration, the maximum predicted offsite predicted environmental concentration (PEC) is 24% of the threshold.
- The maximum 100th percentile hourly average concentration of CO_2 predicted by the Applicant at a sensitive receptor is 1,981 ppm for the combined scenario, corresponding to 9.9% of the threshold value of 20,000 ppm. The Applicant concluded that these predictions can be screened out as insignificant when considering the Environment Agency short-term screening criteria of less than 10% of the environmental standard (refer to section 2.3.1).
- The maximum 100th percentile offsite 1-minute average process contribution (PC) of CO_2 predicted by the Applicant is 10,299 ppm for the combined scenario. The Applicant compared this prediction with the 1-minute SLOT of 105,000 ppm reported in the HSE publication referred to above, showing that this PC is below 10%. The Applicant concluded that these predictions can be screened out as insignificant when considering the Environment Agency short-term screening criteria of less than 10% of the environmental standard (refer to section 2.3.1).

- The maximum 100th percentile 1-minute average process contribution (PC) of CO_2 predicted by the Applicant at a sensitive receptor is 5,529 ppm for the combined scenario. The Applicant compared this prediction with the 1-minute SLOT of 105,000 ppm reported in the HSE publication referred to above, showing that this PC is below 10%. The Applicant concluded that these predictions can be screened out as insignificant when considering the Environment Agency short-term screening criteria of less than 10% of the environmental standard (refer to section 2.3.1).

On review of the predictions of the dispersion modelling study, the Applicant concluded that the proposed design would not cause any significant harm to persons off-site from the emissions of CO_2 during other than normal operating conditions.

We note that no scenario will entail exceeding the concentration of 2% of CO_2 (20,000 ppm), at any potential offsite receptors or under any of the exposure times considered in the study.

We audited the Applicant's assessment and reviewed their methodology and assumptions. We conducted our own check modelling and performed sensitivity analysis to our observations. As a result of our checks, we found that although we do not necessarily agree with applicant's numerical predictions, we agree with their conclusions.

We have included the emission points associated with CO_2 emissions during OTNOC in Table S3.1(f) 'Point source emissions to air during abnormal operation' of the permit. We have set monitoring and reporting requirements in the permit, requiring to identify and report venting events. In particular for each emission point the following information shall be reported:

- Number of events
- Duration of events
- Root cause analysis for each event and preventative / frequency reduction measures
- Total mass of CO_2 emissions (tonnes / event)

A pre-operational condition required the Operator to demonstrate that the duration and impacts of plant start-up operations are minimised, as part of the commissioning plan to be submitted for approval to the Environment Agency.

Table S3.5 (a) of the permit also specifies the requirement to monitor fugitive emissions of carbon dioxide as part of the Fire & Gas detection system.

2.3.3.2 Accidents risk assessment

Appendix A.4.0 to the Application document titled 'HyNet Hydrogen Production Plant Environmental Permit Application Supporting Document', received on 31/08/2021, provides the Accidents Risk Assessment for the project, along with the preventative and mitigation measures identified as part of the design or planned for the operation phase of the activities.

The potential accidents associated with the operation of the HPP were identified during the ENVID (ENVironmental impact IDentification) study undertaken as part of the front-end engineering design for the HPP plant.

The Accidents Risk Assessment identifies the accident hazards and risks associated with the operations of the HPP – for example, release of hazardous materials, or a fire – and against each accident hazard sets out the consequences of the accident happening; risk severity; measures which will be put in place to limit the likelihood of the accident's occurrence; and measures which will be put in place to respond to the accident were it to occur.

The key areas of risk identified for the operations of the HPP are:

- Release of hazardous material due to loss of containment
- Fire and explosion
- Collisions / dropped objects
- Adverse weather and climate change effects
- Process upset/ equipment failure
- Mishandling of materials or waste

The mitigations identified in the Accident Risk Assessment include technical, design and operational measures. The key measures to prevent and mitigate accidents include:

- Pressure relief valves and blowdown system
- Emergency flare
- Control systems and loops
- Anti-surge on compressors
- Secondary containment (bunding)
- Tertiary containment (firewater containment)
- Flood protection measures (see section 2.3.5 for more details)
- Adequate design of pressure equipment and pipework
- Materials compatibility, selection and provision of corrosion allowances for equipment and pipework
- Security features and measures to prevent cyber-attacks
- Operating and maintenance procedures implemented through the site Environmental Management System (EMS).

The Accidents Risk Assessment relies on the implementation of measures within the site's EMS. The Applicant provided a summary of the EMS currently implemented at the site, which we consider adequate for the permitting stage.

We consider that the correct implementation of the site's EMS is fundamental to prevent accidents and to mitigate and manage them should they occur. For this reason, we have set a pre-operational condition requiring the Operator to submit to us a report confirming the extension of the existing EMS to cover the activities introduced by this variation. This shall include relevant elements of the EMS, including an update to the Accident Management Plan, addressing all the accidents risks identified in the Application and, in particular, those with the highest severity (i.e. fire and explosion risks).

In addition to being regulated under the Environmental Permitting Regulations, the Installation is regulated by the Health and Safety Executive and the Environment Agency as a joint Competent Authority, under the Control of Major Accident Hazards Regulations 2015 (COMAH), as the installation is an upper tier COMAH site. The COMAH regulations places a general obligation on the duty holder (the Applicant in this case) to ensure all measures necessary are taken to prevent major accidents and to limit their consequences for human health and the environment.

COMAH Regulation 6(6)(c) requires that the Operator must submit a notification (prescribed information) to the COMAH Competent Authority in advance of any modification to an establishment which could have significant consequences for major accident hazards. Further information on this requirement can be found at http://www.hse.gov.uk/Comah/notification/index.htm#requirements.

COMAH Regulation 10(2)(d) requires that the Operator must, before making modifications to the establishment, review and where necessary revise their safety report where changes could have significant consequence for major accident hazards. Where this applies, a revised safety report, or revised parts of it, must be sent by the Operator to the Competent Authority in advance of the proposed modification. Therefore, the Applicant will need to update the safety report for the installation to address all the major accident hazards arising proposed operations of the HPP and CCS plant, including hazards associated with loss of containment, fire, explosion, toxic gas dispersion impacts.

In addition to the above, in response to the Schedule 5 Notice served on 17/03/2022, the Applicant has provided the following description of the safety studies undertaken as part of the design of the Installation or planned for the detailed design stage:

- Plot Plan Review - Systematic study of the 2D layout of the plant – includes review of safety features of the layout design to protect safety and environment.

- P&ID Review - Systematic study of the process design of the plant – includes review of safety features of the process design to protect safety and environment.

- 30% Model Review - Systematic study of the 3D design of the plant – includes review of safety features of the layout design to protect safety and environment.

- Plant Safety Review (HAZID / ENVID) - Systematic study to identify the safety and environmental hazards arising from the project.

- SIMOPS Review - Systematic study of simultaneous operations – risks arising of activities on different sites (e.g. construction of new plant next to an operating plant).

- HAZOP Review - Systematic study of process design of the plant using the piping and instrument diagrams. Study included an assessment of process safety and environmental hazards and risks arising.

- Quantitative Risk Assessment (QRA) - Calculation of risk was carried out using risk integration models to determine the potential scale and effect of the hazards identified in the HAZID study, in particular possible fire, blast and gas dispersion impacts. The QRA included assessment of both individual risk and societal risk for onsite and offsite populations.

Action tracking is used by the Applicant to ensure that actions arising from the safety studies are addressed in the design and build of the project. According to the Applicant, actions have either been addressed at the current stage of the project or have been communicated to future phases of the project. All actions generated in safety and design studies were entered into the project's Safety, Health, and Environment Action Management System (SHEAMS) register and tracked to completion. Process actions were reviewed in relation for their potential impact on the overall design to the project. These actions were addressed as a high priority where this was deemed to have a significant impact. According to the application, the systematic process of safety reviews will continue into the detailed design and build phase of the project. The following safety studies will be undertaken /updated in the future phases of the project (prior to the beginning of the operations):

- Update of safety and environmental engineering philosophy and plan
- Fire and explosion risk analysis
- Final QRA
- Human factors review
- Escape, Evacuation, and Rescue analysis
- Final HAZOP and SIL study
- Layer of Protection Analysis (LOPA)
- Maintenance of the SHEAMS system to ensure all actions are tracked to close out; and any residual hazards notified to the owner and operator of the plant
- Interface studies and reviews
- SIMultaneous OPerationS (SIMOPS) studies
- ALARP (as low as reasonably practicable) demonstration

The studies mentioned above are expected to inform the Safety Report required for the installation under the COMAH Regulations.

We consider the range of measures, studies and techniques described in the Application, when adequately implemented throughout the design, construction, commissioning, operations and maintenance of the proposed activities, are adequate and consistent with BAT. For major accident hazards, we refer to the regulation of the proposed activities under the COMAH regulatory regime and the updated Safety Report for the installation.

2.3.4 Noise emissions

The application contained a noise impact assessment which identified local noise-sensitive receptors (NSR), potential sources of noise at the proposed plant and generic noise attenuation measures and hierarchy (application document titled ‘HyNet Environment Agency Permitting Noise Assessment’, dated and received 15/07/2022). The noise assessment submitted by the Applicant was based on the plant noise data available at the current front-end engineering stage of the design and the Applicant stated that further information on noise levels from equipment will only become available during the detailed design phase, hence proposed to submit an updated noise impact assessment as a follow-up to a pre-operational condition after the detailed engineering design of the plant is completed.

Noise measurements were taken of the prevailing ambient noise levels to produce a baseline noise survey and an assessment was carried out in accordance with BS4142:2014 to compare the predicted plant rating noise levels with the established background levels.

The Applicant undertook baseline sound surveys in 2021 and 2022, which comprised short-term attended and long-term unattended measurements. The 2021 data included contributions from the existing operations of the Stanlow Manufacturing Complex site, so could not be used to determine a representative background sound level (LA90, dB) at the nearest NSR. We therefore requested the Applicant to undertake a new baseline sound survey (and to revise a previously submitted noise impact assessment), as part of a Schedule 5 Notice served on 17/03/2022. Several proxy locations were proposed by the Applicant, in accordance with BS 4142: 2014 +A1: 2019, Section 8.1.2. In particular, the Applicant proposed to use the measurements taken at proxy location P4 (Oakfield, Hapsford Lane, Helsby) for the assessment. This location is to the south-east of the site, at a similar distance from the dominant residual sound source (the M56 motorway) as the NSRs at Elton and Elton Green. On review, we agreed with the suitability of P4 as a proxy location to inform the assessment.

To inform the BS 4142 assessment, the Applicant identified a daytime background sound level of 51dB LA90 and a night-time background sound level of 45dB LA90 as being respectively representative of daytime and night-time conditions at P4.

The table below shows how the Applicant’s predicted rating level generated from the equipment in the scope of the variation compares to the background levels at the NSRs near to the installation. Impacts at receptors further away will be lower.

NSR	Rating level associated to the HPP compared to background (dB A)	
	Daytime	**Night-time**
The Stables travellers' site	-4	+2
Little Meadow Park travellers' site	-5	+1
Elton	-8	-2
Thornton Science Park	-9	N/A to this type of receptor
Thornton le Moors	-10	-4
St Mary's Church, Thornton le Moors	-13	N/A to this type of receptor
Elton Primary School	-16	N/A to this type of receptor
Ince	-19	-13

This comparison is obtained by subtracting the measured background sound level from the rating level. BS4142:2014 explains that, typically, the greater this difference, the greater the magnitude of the impact, and sets out the following impact assessment criteria:

- A difference of around +10 dB or more is likely to be an indication of a significant adverse impact, depending on the context.
- A difference of around +5 dB is likely to be an indication of an adverse impact, depending on the context.
- The lower the rating level is relative to the measured background sound level, the less likely it is that the specific sound source will have an adverse impact or a significant adverse impact. Where the rating level does not exceed the background sound level, this is an indication of the specific sound source having a low impact, depending on the context.

The Applicant's assessment shows that the during daytime the rated sound levels will be below the current background level at all receptors; during night-time hours the rated level will exceed the background by +2dB at 'The Stables travellers' site and 'Little Meadow Park travellers' site only.

The Applicant's assessment therefore indicates that impacts from noise emissions form the proposed activities in the scope of this variation would generally be low at nearby noise receptors, and low to adverse at the nearest receptor (the Stables travellers' site). When considering the context, the area is a long established mixed industrial and residential area and the worst case affected receptors are also close to road traffic noise sources which are likely to be of a higher level than the operational noise from the refinery.

The Applicant's assessment also indicates that the cumulative impact from existing operations and the proposed variation will result in an adverse / significant adverse impact at the nearest receptors. However, the impact from existing operations alone is adverse / significant adverse and the proposed variation does not increase this, with the proposed variation only increasing overall site sound emissions by 1-2dB at the nearest residential receptors. A low impact is predicted at all NSR due to the operation of the HPP development in isolation. The cumulative impact of the existing operation of the Stanlow refinery and the operation of the proposed HPP development is expected to lead to a negligible increase in noise levels at nearby NSR. The Applicant therefore concluded that the HPP plant is not expected to lead to any further adverse impacts.

We audited the Applicant's assessment and, based on the information available at this stage, we agree with the conclusion that adverse or significant adverse impacts at nearby receptors from the activities proposed in the scope of this variation are unlikely. Since the proposed variation is predicted to increases the overall site sound emissions by only 1-2dB at the nearest residential receptors, we consider the proposed variation to be low risk in relation to noise.

However, the noise impact assessment submitted with the application was based on preliminary noise plant data available at the front-end engineering stage of the design. At this stage, the application included generic commitments on noise mitigation measures, such as locating equipment away from site boundary, installing noisy equipment within acoustic enclosures and mounting rotating machinery items on appropriately specified anti-vibration supports. The application sets out the noise mitigation hierarchy for the project and includes a commitment from the Applicant to further mitigating the minor adverse impacts predicted at the 'Stables travellers' site' as part of the detailed design process, through the further application of noise mitigation measures, including equipment selection, noise abatement and screening. These provisions are adequate to the development of the project and notionally consistent with BAT, however it was not possible to audit detailed information on the noise emissions data from equipment manufacturers and to review detailed information on the design of acoustic mitigation measures included in the design as these will only become available as the detailed engineering design of the project is progressed.

We therefore consider necessary to include a pre-operational condition specifying that, following the completion of the detailed engineering design, the Operator shall submit for approval by the Environment Agency a revised Noise Impact

Assessment informed by updated and final noise emissions data provided by equipment manufacturers during the detailed engineering design of the plant, taking into account the detailed noise attenuation measures included in the design according to BAT.

Based upon the information in the application we are satisfied that the appropriate measures will be in place to prevent or where that is not practicable to minimise noise and vibration and to prevent pollution from noise and vibration outside the site as long as the relevant pre-operational condition we have specified is completed satisfactorily.

2.3.5 Flood risk

The development site boundary is shown to lie partly within Flood Zones 2 & 3 (medium to significant risk) on the Environment Agency's flood risk map for planning. Extracts from the Environment Agency's most recent modelling carried out in 2019 show a much reduced area of the development site area to now be at significant risk. Given that only a very limited area of the site is now considered to be at tidal and fluvial risk, the application indicates that a strategy of 'flood avoidance' of any critical process or development in that specific area of the site has been undertaken and those activities located elsewhere (within Flood Zone 1 – low risk) within the site. Additional mitigation has been to provide surface water attenuation pits. We consider the proposal to be acceptable.

2.3.6 Global warming potential

The HPP's Global Warming Potential has been calculated as 17,405 teCO_2eq/year following our guidance and is presented in the Application.

Since the objective of the activities in the scope of the Application is to produce a decarbonised fuel and since the decarbonisation is achieved by making use of operating techniques and carbon capture performance levels that are consistent with BAT, we consider that the risks associated with the global warming potential (GWP) of the emissions from the proposed operation are not a key issue for this permit variation determination.

3. Decision considerations

3.1 Confidential information

A claim for commercial or industrial confidentiality has not been made.

The decision was taken in accordance with our guidance on confidentiality.

3.2 Identifying confidential information

We have not identified information provided as part of the application that we consider to be confidential.

The decision was taken in accordance with our guidance on confidentiality.

3.3 Consultation

The consultation requirements were identified in accordance with the Environmental Permitting (England and Wales) Regulations (2016) and our public participation statement.

The application was publicised on the GOV.UK website.

The application was advertised in the Liverpool Echo and in The Chester Chronicle on the 3rd of February 2022.

We carried out two rounds of consultations on the application: the initial consultation was held between the 03/02/2022 and the 03/03/2022; as part of the second round, we consulted between 30/12/2022 and 27/01/2023 on the responses received from the Applicant to the Schedule 5 Notice served on 17/03/2022.

We consulted the following organisations:

- Cheshire Fire and Rescue
- Local Planning Authority
- Environmental Health
- Health and Safety Executive
- Director of Public Health and UK Health Security Agency
- Civil Aviation Authority
- Food Standards Agency
- Sewerage undertaker (United Utilities)

We only received comments from the UK Health Security Agency. The comments and our responses are summarised in the consultation responses section.

No responses were received from members of the public, local MPs, assembly members, councillors and parish/town community councils, community or other organisations.

3.4 The regulated facility

We considered the extent and nature of the facilities at the site in accordance with RGN2 'Understanding the meaning of regulated facility', Appendix 2 of RGN2 'Defining the scope of the installation', Appendix 1 of RGN 2 'Interpretation of Schedule 1'.

The extent of the facilities are defined in the site plan and in the permit. The activities are defined in table S1.1 of the permit.

3.5 The site

The operator has provided plans which we consider to be satisfactory.

The plans show the location of the part of the installation to which this variation applies.

Since the variation does not entail a change of boundaries of the permitted installation, we did not amend the site plan included in Schedule 7 of the permit.

3.6 Nature conservation, landscape, heritage and protected species and habitat designations

We have checked the location of the application to assess if it is within the screening distances we consider relevant for impacts on nature conservation, landscape, heritage and protected species and habitat designations. The application is within our screening distances for these designations.

We have assessed the application and its potential to affect sites of nature conservation, landscape, heritage and protected species and habitat designations identified in the nature conservation screening report as part of the permitting process.

We consider that the application will not affect any site of nature conservation, landscape and heritage, and/or protected species or habitats identified. Refer to the key issues section for details.

We have not consulted Natural England and Natural Resources Wales on our Habitats Regulation assessment, however we have sent them our assessment for information.

The decision was taken in accordance with our guidance.

3.7 Environmental risk

We have reviewed the operator's assessment of the environmental risk from the facility.

The operator’s risk assessment is satisfactory.

The assessment shows that, applying the conservative criteria in our guidance on environmental risk assessment or similar methodology supplied by the operator and reviewed by ourselves all emissions are not environmentally significant. Refer to section 2.3 for details, in particular 2.3.1 (emissions to air), 2.3.2 (emissions to water), 2.3.3 (emissions of CO2 during OTNOC) and 2.3.4 (noise emissions).

3.8 General operating techniques

We have reviewed the techniques used by the operator and compared these with the relevant guidance notes and we consider them to represent appropriate techniques for the facility.

Refer to section 2.2 for our assessment of the proposed operating techniques against the relevant BAT conclusions and our guidance on emerging techniques.

The operating techniques that the Applicant must use are specified in table S1.2 in the environmental permit.

3.9 Operating techniques for emissions that screen out as insignificant

Emissions of oxides of nitrogen and methanol have been screened out as insignificant, and so we agree that the Applicant’s proposed techniques are Best Available Techniques (BAT) for the installation. Refer to section 2.3 for details.

We consider that the emission limits included in the installation permit as part of this variation reflect the BAT for the sector.

3.10 National Air Pollution Control Programme

We have considered the National Air Pollution Control Programme as required by the National Emissions Ceilings Regulations 2018. By setting emission limit values in line with technical guidance we are minimising emissions to air. This will aid the delivery of national air quality targets. We do not consider that we need to include any additional conditions in this permit.

3.11 Changes to the permit conditions due to an Environment Agency initiated variation

We have varied the permit as stated in the variation notice. In particular we have:

- Updated the status and progress of existing improvement conditions
- Deleted table S3.2(a) of the permit, since its applicability was time-limited to 31/01/2022, after which it was superseded by table S3.2(b)
- Amended table S3.2(b) of the permit, to include an emission limit value for concentration of phenols emitted through emission point W3. The emission limit value has been retained from the now deleted table S3.2(a).
  When table S3.2(b) was added to the permit as part of a previous variation (V009), the existing emission limit value for phenols at emission point W3 should have been retained on the basis of the principle of non-backsliding on environmental performance, even if there is no BAT-AEL for this parameter. However, this wasn't done. We have now corrected this historical mistake.

3.12 Raw materials

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

- Use of ultra-low sulphur gas oil in emission points HPP-A-4 (Emergency Gas Oil Generator) and HPP-A-5 (Firewater Pump fired on Gas Oil) – specified in Table S1.2 of the variation and consolidation notice
- Sulphur content of ROG < 20 ppm volume – specified in Table S1.2 of the variation and consolidation notice

3.13 Pre-operational conditions

Based on the information in the application, we consider that we need to include the pre-operational conditions, setting the requirements outlined below (refer to the variation and consolidation notice for the detailed wording of the pre-operational conditions):

- POC5 - Commissioning plan
  Requirement to submit a written commissioning plan including the timelines for the commissioning operations, risk assessment demonstrating that the environmental risks are not significant throughout all the phases of commissioning, minimisation of start-up impacts and duration, proposals for

a detailed methodology to calculate the overall energy efficiency and carbon capture efficiency of the plant. Refer to 2.2.11, 2.2.19 and 2.3.3.1 for further details.

- POC6 - Environmental Management System
  Requirement to submit a report confirming the extension of the installation's Environment Management System (EMS) to the hydrogen production and carbon capture plant, including the extension of the existing refinery plant and equipment inspection, testing and maintenance programme and the requirement to update to the existing refinery Accident Management Plan. Refer to 2.2.1 and 2.3.3.2 for further details.

- POC7 - Water discharges
  Requirement to submit an updated environmental risk assessment for the emissions to water from emission point W3, following approval of IC38, including the demineralisation effluent generated from the water treatment activities associated with the hydrogen production and carbon capture plant. Refer to 2.2.15 and 2.3.2 for further details.

- POC8 - Containment Infrastructure
  Requirement to submit an updated report including detailed information on the detailed design and construction specification of the primary, secondary and tertiary containment infrastructure associated with these activities. Refer to 2.2.19 for further details.

- POC9 - Noise impact assessment
  Requirement to submit a revised Noise Impact Assessment informed by updated and final noise emissions data provided by equipment manufacturers and to demonstrate that the detailed acoustic design of the plant is suitable to confirm the conclusions of the of the Noise Impact Assessment submitted with the variation application. Refer to 2.2.20 and 2.3.4 for further details.

- POC10 - Energy efficiency
  Requirement to submit an energy efficiency optimisation study, further reviewing options for reducing the energy demand of the plant including any options for recovering waste heat from the compression of hydrogen and CO_2. Refer to 2.2.11 for further details.

- POC11 – Commissioning compliance report
  Requirement to submit a report confirming that the environmental performance of the plant meets all the specifications stated in the permit application.

3.14 Improvement programme

Based on the information on the application, we consider that we need to include an improvement programme. We have included an improvement programme setting the requirements outlined below (refer to the variation and consolidation notice for the detailed wording of the improvement conditions):

- IC59 - Carbon Capture Performance
  Requirement to review the carbon capture performance over the first year of operations to demonstrate that the actual Carbon Capture Efficiency of the operating plant averaged over one year of operation is consistent with the design specification. Refer to 2.2.3 for further details.

- IC60 - Spent catalyst management
  Requirement to review the proposed waste management arrangements and the re-use, recycling, recovery and/ or disposal routes for wastes generated at the HPP and to develop a catalyst care programme. Refer to 2.2.5 for further details.

- IC61 - LDAR programme
  Requirement to extend of the refinery VOC LDAR programme to the HPP and CCS plants and to include fugitive emissions of hydrogen in the programme. Refer to 2.2.19 for further details.

- IC62 - Emission points HPP-A-1 and HPP-A-2
  Requirement to demonstrate compliance of air emissions monitoring locations with BS EN 15259.

3.15 Emission limits

Emission Limit Values (ELVs) have been added for the following substances and parameters:

- Emissions to air: NOx, CO and SO_2 from emission points HPP-A-1 and HPP-A-2. Refer to 2.2.14.1 for further details on the reasons and sources of these emission limits.

- Emissions to water: Flow Rate, COD, Chromium, Copper, Zinc and Total Phosphorus for the demineralisation plant effluent at process monitoring point T1. Refer to 2.2.15 for further details on the reasons and sources of these emission limits.

3.16 Monitoring

We have decided that monitoring should be added for the following parameters, using the methods detailed and to the frequencies specified:

- Emissions to air: NOx, CO and SO_2 from emission points HPP-A-1 and HPP-A-2. Refer to 2.2.14.1 for further details on the monitoring requirements set out for these parameters.

- Emissions to water: Flow Rate, COD, Chromium, Copper, Zinc and Total Phosphorus for the demineralisation plant effluent at process monitoring point T1. Refer to 2.2.15 for further details on the monitoring requirements set out for these parameters.

- Process monitoring: Feed gas mass flow, composition and calorific value (natural gas and ROG), electrical power import, exported CO_2 mass flow, hydrogen production mass flow, net feed gas energy conversion efficiency (%), emissions of CO_2 from venting operations, emissions of CO_2 from Feed Fired Heater and Steam Boiler exhaust stacks, flared gas (actual and totalised) including CO_2 emissions from flaring, Carbon Capture Efficiency (%), diesel usage, water usage, fugitive emissions of VOCs and hydrogen. Refer to 2.2.18 for further details.

We have specified improvement condition IC62 to demonstrate compliance of air emissions monitoring locations with BS EN 15259.

Based on the information in the application we are satisfied that the operator's techniques, personnel and equipment have either MCERTS certification or MCERTS accreditation as appropriate.

3.17 Reporting

We have added reporting in the permit for the following parameters:

Emissions to air: NOx, CO and SO_2 from emission points HPP-A-1 and HPP-A-2.

Emissions to water: Flow Rate, COD, Chromium, Copper, Zinc and Total Phosphorus for the demineralisation plant effluent at process monitoring point T1.

Other process and performance parameters: flaring events from HPP flare (emission point HPP-A-3); venting events from pipelines AGI, CO_2 Dehydration and CO_2 Capture Unit; diffuse emissions of methane and non-methane VOCs and hydrogen; natural gas usage (flow rate and net thermal based on Lower Heating Value); Refinery Off-Gas usage (flow rate and net thermal based on Lower Heating Value); Hydrogen production (flow rate and thermal based on

Lower Heating Value); energy usage (electrical power); exported CO_2; Net Feed Gas Energy Conversion Efficiency; Carbon Capture Efficiency; water usage.

We made these decisions in accordance with the following guidance: '[Emerging techniques for hydrogen production with carbon capture]'.

3.18 Management system

We are not aware of any reason to consider that the operator will not have the management system to enable it to comply with the permit conditions.

The decision was taken in accordance with the guidance on operator competence and how to develop a management system for environmental permits.

3.19 Growth duty

We have considered our duty to have regard to the desirability of promoting economic growth set out in section 108(1) of the Deregulation Act 2015 and the guidance issued under section 110 of that Act in deciding whether to grant this permit variation.

Paragraph 1.3 of the guidance says:

"The primary role of regulators, in delivering regulation, is to achieve the regulatory outcomes for which they are responsible. For a number of regulators, these regulatory outcomes include an explicit reference to development or growth. The growth duty establishes economic growth as a factor that all specified regulators should have regard to, alongside the delivery of the protections set out in the relevant legislation."

We have addressed the legislative requirements and environmental standards to be set for this operation in the body of the decision document above. The guidance is clear at paragraph 1.5 that the growth duty does not legitimise non-compliance and its purpose is not to achieve or pursue economic growth at the expense of necessary protections.

We consider the requirements and standards we have set in this permit are reasonable and necessary to avoid a risk of an unacceptable level of pollution. This also promotes growth amongst legitimate operators because the standards applied to the operator are consistent across businesses in this sector and have been set to achieve the required legislative standards.

3.20 Consultation Responses

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

3.20.1 Responses from organisations listed in the consultation section

Response received from UK Health Security Agency (UKHSA).

Brief summary of issues raised:

In the consultation response of 25/02/2022, the UKHSA commented that the emissions to air are not deemed to be significant and are not expected to contribute to air quality exceedances. In relation to emissions to surface water, the UKHSA advised us to clarify with the Applicant when they will be completing and submitting an updated risk assessment for these emissions. They also commented that Fire Management Plan or an Accident Management Plan were not provided and advised that both plans were requested from the Applicant.

In their response of 24/01/2023 to the consultation carried out on additional information received on the application, the UKHSA commented in relations to emissions of CO_2 to the atmosphere that these emissions are not deemed to be significant and are not expected to contribute to air quality exceedances. Based on the information contained in the application, the UKHSA confirmed they had no significant concerns regarding the risk to the health of the local population from the installation.

Summary of actions taken:

We have taken into consideration the comments raised from the UKHSA. No further action was required in relations to emissions to air and CO_2 venting emissions. Refer to sections 2.3.1 and 2.3.3.1 for details on our consideration of these risks.

Our considerations on the risk posed by emissions to surface water is addressed in section 2.3.2. Based on the information in the application, we consider the environmental risk associated with discharges to waters arising from this variation application is unlikely to be changed compared to the risk envelope of the currently permitted operations. However, we have specified pre-operational condition POC7, requiring the Operator to submit an updated environmental risk assessment for the emissions to water from emission point W3 for our approval, following approval of IC38 and including the demineralisation effluent proposed to be discharged from the operations of the HPP and CCS plants. Refer to 2.2.15 and 2.3.2 for further details.

We have set pre-operational condition POC6 requiring the Operator to update to the existing refinery Accident Management Plan. As this installation is part of an upper tier COMAH site, fire risks and associated management measure, along with other major hazards, are expected to be covered as part of the site's Safety Report beyond the scope of the environmental permit. For major accident hazards, we therefore refer to the regulation of the proposed activities under the COMAH regulatory regime and the Safety Report for the installation. Refer to section 2.3.3.2 for further details.

3.20.2 Representations from local MPs, assembly members, councillors and parish/town community councils

None received.

3.20.3 Representations from community and other organisations

None received.

3.20.4 Representations from individual members of the public

None received.