

H2Teesside Project

Planning Inspectorate Reference: EN070009

Land within the boroughs of Redcar and Cleveland and Stockton-on-Tees, Teesside and within the borough of Hartlepool, County Durham

The H2 Teesside Order

Document Reference: 8.11.3 Response to ExQ1 Air Quality and Emissions

Planning Act 2008



Applicant: H2 Teesside Ltd

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1.0 INTRODUCTION

1.1 Overview

1.1.1 This document has been prepared on behalf of H2 Teesside Limited (the 'Applicant'). It relates to an application (the 'Application') for a Development Consent Order (a 'DCO'), that was submitted to the Secretary of State for Energy Security and Net Zero ('DESNZ') on 25 March 2024, under Section 37 of 'The Planning Act 2008' (the 'PA 2008') in respect of the H2Teesside Project (the 'Proposed Development').

1.1.2 The Application has been accepted for examination. The Examination commenced on 29 August 2024.

1.2 The Purpose and Structure of this document

1.2.1 The purpose of this document is to set out the Applicant's responses to the Examining Authority's ExQ1 on Air Quality and Emissions, which were issued on 4 September 2024 [PD-008]. This document contains a table which includes the reference number for each relevant question, the ExA's comments and questions and the Applicant's responses to each of those questions, and is followed by Appendix 1 in response to Q1.3.1.

Table 1-1: Applicant’s Responses to ExQ1 Air Quality and Emissions

EXQ1	QUESTION TO:	QUESTION:	RESPONSE
Q.1.3.1	Applicants	<p>Clarification/ Update sought.</p> <p>Paragraph 8.2.16 of ES Chapter 8 (Air Quality) [APP-060] states that, as the Proposed Development is an emerging technology, there is currently no finalised European Best Available Techniques Reference Documents (BRefs) or Best Available Technique (BAT) guidance documents available for a Hydrogen Production Facility with associated Carbon Capture, and therefore no BAT-Associated Emission Levels (AEL) have been defined for the activity to date.</p> <p>Guidance on Emerging techniques for hydrogen production with carbon capture has been released (EA, 2023) and this has formed the basis for discussions with the EA to agree appropriate BAT and AELs. Bearing this in mind, please provide:</p> <p>Confirmation on whether an appropriate approach to the BAT and AEL has been agreed with the EA, if not please provide an update on the current position regarding the Applicant’s discussions with the EA in this regard.</p> <p>Provide an update on the current position regarding discussions with the EA in respect of the incorporation of BAT and AEL within the EP.</p>	<p>The Applicant understands from pre-application engagement that BAT and AELs as set out in the Guidance for Emerging Techniques (GET) noted at Appendix 1 of this document and other associated BREF documents will be applied by the EA within the EP. All appropriate BAT and AEL standards have been considered by the Applicant in preparing the Environmental Permit application, which was submitted in June 2024.</p>
Q.1.3.2	Applicant/EA	<p>Clarification/ View(s) sought.</p> <p>Paragraph 8.2.17 of ES Chapter 8 (Air Quality) [APP-060] states part of the technology used, such as the auxiliary boilers, will need to comply with the Large Combustion Plant BRef, as the aggregated thermal input is predicted to be over 50 MW. However, as the boilers will run on a hydrogen rich tail gas during normal operations, the natural gas Emission Limit Values (ELVs) cannot be used directly and will be updated to take the hydrogen content of the tail gas into account.</p> <p>Can the Applicant provide a further explanation as to why it considers the natural gas ELVs cannot be used directly.</p> <p>Please confirm whether the EA agrees with the Applicant’s approach and assessment, and whether it is considered the approach has any implications for the air quality assessment.</p>	<p>The use of fuel that includes some hydrogen will generate a larger emission of NOx than would have occurred with 100% natural gas. With 100% hydrogen, the NOx emissions are approximately 37% higher than would have occurred with 100% natural gas. Therefore, natural gas ELVs are set at too low a level unless the hydrogen content of the tail gas is taken into account.</p> <p>The Air quality assessment has considered scenarios when the fuel is natural gas and when the fuel contains hydrogen. The Applicant’s approach is based on an emerging guidance note (see WQ1.3.1) that the EA has drafted and consulted the industrial sector on and therefore is entirely consistent with EA methodology.</p> <p>The EA will make their assessment as part of the EP determination process. It is understood that the EA agrees with the Applicant’s approach and that there are no implications for the air quality assessment.</p>
Q.1.3.3	Applicants	<p>Clarification.</p> <p>Paragraph 8.2.18 of ES Chapter 8 (Air Quality) [APP-060] states other BRef documents such as the Common Wastewater and Waste Gas Treatment/ Management Systems in the Chemical Sector will also be considered where relevant.</p> <p>Please confirm whether any of the above BRef documents have now been assessed/ considered? If the answer to this question is yes, please provide a detailed explanation of the outcome(s).</p>	<p>As part of the Applicant’s EP application a BAT assessment has been carried out and submitted with the Environmental Permit application. The approach to BAT was agreed with the Environment Agency (EA) during the pre-application discussions.</p> <p>The Applicant can confirm that an assessment of BAT against all relevant BREF documents including against the Large Combustion Plant and Common Waste Water BRef were completed and submitted with the Environmental Permit application. The assessments concluded that the proposed technology and processes met the relevant</p>

EXQ1	QUESTION TO:	QUESTION:	RESPONSE
			<p>BAT standards. The Proposed Development will be in accordance with these documents, and the EA will be able to ensure this through the EP process.</p> <p>As an example, the Common Wastewater and Waste Gas Treatment/ Management Systems in the Chemical Sector BRef document, section 4.5.3, BAT 17, identifies the use of flare to combust gaseous emissions as being BAT during start-up and shut-down but not for continuous use.</p> <p>The above has been considered in designing the Proposed Development and we are adopting flaring as an embedded control measure during start-up and shut down.</p>
Q.1.3.4	NE, the EA and relevant LAs (HBC, RCBC and STBC, together with any other relevant Authority/ Body	<p>Views sought.</p> <p>Paragraph 8.3.1 – 8.3.2 of ES Chapter 8 (Air Quality) [APP-060] states that the Study Area for construction dust and construction Non-Road Mobile Machinery emissions has been applied in line with the IAQM guidance 2024 extending:</p> <p>up to 250 m beyond the Proposed Development Site and 50 m from the construction traffic routes (up to 250 m from the Proposed Development Site entrances), for human health receptors; and</p> <p>up to 50 m from the Proposed Development Site and construction traffic routes (up to 250 m from the Proposed Development Site entrances) for ecological receptors.</p> <p>The ExA would ask the EA, NE and LAs to confirm whether they consider the Study Area distances assessed by the Applicant and set out above, are appropriate and acceptable in respect of the air quality study areas.</p>	n/a
Q.1.3.5	NE, the EA and relevant LAs (HBC, RCBC and STBC) together with any other relevant Authority/ Body	<p>Views sought.</p> <p>Paragraph 8.3.4 of ES Chapter 8 (Air Quality) [APP-060] states the Study Area or the operational Proposed Development point source emissions extends up to 15 kilometres (km) from the emission sources to assess the potential impacts on ecological receptors. This is in line with the EA Risk Assessment Methodology (Defra and EA, 2016, as updated in 2023) but also includes additional sites requested by the Proposed Development biodiversity specialists:</p> <p>Special Protection Area(s) (SPA), Special Area(s) of Conservation (SAC), Ramsar sites and Sites of Special Scientific Interest (SSSIs) within 15 km of the Proposed Development Site; and</p> <p>Local Nature Sites (including ancient woodlands, Local Wildlife Sites and National and Local Nature Reserves) within 2 km of the Proposed Development Site.</p> <p>Paragraph 8.3.5 of ES Chapter 8 (Air Quality) [APP-060] lists the additional sites to include the North York Moors SPA and SSSI, the North Cumbria Coast SPA, Durham Coast SAC, Northumbria Coast Ramsar, Cliff Ridge SSSI, Durham Coast SSSI and National Nature Reserve, Hart Bog SSSI, Langbaugh Ridge SSSI, Loe Hill Pools SSSI, Roseberry Topping SSSI and Saltburn Gill SSSI. Please state whether the EA, NE and LAs, together with any other relevant Authority/ Body, considers the Study Area of 15 km to be satisfactory to assess the potential impacts on ecological receptors.</p>	n/a

EXQ1	QUESTION TO:	QUESTION:	RESPONSE
		<p>have any comments and observations on the additional areas included by the Applicant as the ecological receptors for the Study Area.</p> <p>have any other observations to make in respect of Paragraph 8.3.5 – 8.3.6 of ES Chapter 8 (Air Quality) [APP-060].</p>	
Q.1.3.6	Applicants	<p>Clarification.</p> <p>Paragraph 8.3.6 of ES Chapter 8 (Air Quality) [APP-060] states, in terms of human health receptors, based on similar modelling studies and EA guidance, impacts from the operational Proposed Development become negligible within 2 km and therefore sensitive receptors for the human health impacts are concentrated within a 2 km Study Area.</p> <p>Please signpost where the evidence to support this conclusion is provided within the submitted Application documentation; or if not included please provide the relevant evidence to support this conclusion.</p>	<p>The air quality impact assessment is undertaken as an iterative process. The initial dispersion model study area for human health was set to be 15km from the point of release and these results are used to identify the part of the study area requiring more assessment effort. As with many schemes, for this study it was within 2 km of the Main Site and a greater concentration of representative receptors were selected within 2 km of the sources. This is demonstrated in Figures 8-6, 8-7, 8-8 and 8-9 [APP-101, APP-102, APP-103, APP-104]</p>
Q.1.3.7	LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body	<p>Views sought.</p> <p>It is stated in paragraph 8.3.10 of ES Chapter 8 (Air Quality) [APP-060] that there may be a period following opening of Phase 1 where Phase 1 will be operational and Phase 2 in construction. There may be construction traffic pollutant emissions from Phase 2 construction at the same time as operation point source emissions from Phase 1 with two different types of emissions sources (road traffic emissions typically extending up to 200 m from the source with emissions released near ground level whilst operational emissions are released over a broader area, from height). This means, that typically, the greatest pollutant contributions at receptors in the Study Area will be very different for the two emission types.</p> <p>For completeness, the predicted contributions at receptors that may experience impacts from both sources have been combined to demonstrate the total pollutant contribution from the two emission sources. It is noted that this is a very precautionary approach as it combines the peak construction traffic pollutant contributions with the combined pollutant contributions from Phase 1 and 2 operations.</p> <p>Bearing the above in mind, please confirm whether the EA and LAs, together with any other relevant Authority/ Body:</p> <p>Agree with the approach adopted by the Applicant in paragraphs 8.3.9-8.3.10 of ES Chapter 8 (Air Quality) [APP-060].</p> <p>Have any comments or observations in relation to the assessment methodology adopted by the Applicant in ES Chapter 8 (Air Quality) [APP-060] and the Applicant's conclusions on the impacts and LSE set out in Paragraph 8.6 of the same document.</p>	n/a
Q.1.3.8	Applicants	Clarification.	i)/ii) Any impacts on air quality from developments becoming operational after 2023 cannot have been captured within measurement data generated by the project-specific

EXQ1	QUESTION TO:	QUESTION:	RESPONSE
		<p>Paragraph 8A.2.3 of ES Appendix 8A (Air Quality – Construction Assessment) [APP-190] states that the cumulative impacts from existing sources of pollution in the area are accounted for in the adoption of site-specific background pollutant concentrations from archive sources and a programme of project-specific baseline air quality monitoring in proximity to the Proposed Development Site. However, it was also recognised that there is a potential impact on local air quality from emission sources which were not present at the time of the survey.</p> <p>Please provide details of the emission sources with a potential impact on air quality which were not present at the time the cumulative impact survey was undertaken.</p> <p>Please explain whether these non-present emission sources are likely to be present during construction and operational phases of the Proposed Development.</p>	<p>baseline air quality monitoring. Paragraphs 23.5.7 and 23.5.8 of ES Chapter 23: Cumulative and Combined Effects (Document reference 6.2.23) [APP-076] lists out developments with the potential to impact air quality, that were not present at the time of the survey. The assessment of effects considered potential cumulative effects with several committed but as yet undeveloped schemes – these are screened in or out of the cumulative impact assessment accordingly based on their locations, nature and size. Those developments screened in for further consideration (e.g. NZT) were then appraised qualitatively or quantitatively (through dispersion modelling) as appropriate.</p>
Q.1.3.9	NE, the EA and relevant LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body	<p>Clarification/ Views sought.</p> <p>Paragraphs 8B.2.14 and 8B.2.15 of ES Appendix 8B (Air Quality - Operational Phase) [APP-191] sets out a list of cumulative developments which are either consented or about to receive planning consent but yet to come into operation and which have potential operational air quality impacts. The details of the cumulative assessment is presented at 8B.11 (Annex B: Cumulative Assessment Inputs and In-Combination Results) of that document.</p> <p>Bearing in mind the above:</p> <p>Please confirm whether the LAs, together with any other relevant Authority/ Body, are satisfied with the list of consented, or soon to be consented, cumulative development included in that list.</p> <p>Should any of the Interested Parties (IPs) listed in the question above not be satisfied, please provide full details of those consented or about to be consented development it believes are missing from the list.</p> <p>When providing such details please provide a statement confirming the status of the planning application (ie Planning permission granted, resolution to grant subject to the prior completion of a legal agreement, undetermined, on appeal, etc, as well as details of the planning application, including, but not limited to, the planning application number, a description of and location of the Development, a copy of the planning permission granted or resolution to grant planning permission, etc).</p> <p>Please advise whether the LAs, together with any other relevant Authority/ Body, have any observations or comments on the cumulative assessment set out in 8B.11 Annex B (Air Quality - Operational Phase) [APP-191].</p>	n/a

EXQ1	QUESTION TO:	QUESTION:	RESPONSE
Q.1.3.10	Applicant, EA, UK Health Security Agency (UKHSA) and relevant LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body	<p>Clarification/ Views sought.</p> <p>Paragraph 8.3.35 of ES Chapter 8 (Air Quality) [APP-060] states that there will be no emissions to air of amines and amine degradation products during normal operation, as the CO₂ capture process is a closed loop system.</p> <p>Can the Applicant explain how the close loop system for the carbon capture process ensures that there will be no emission of amine and amine degradation products during normal operation.</p> <p>Are the UKHSA, EA and LAs, together with any other relevant Authority/ Body, content with the approach adopted by the Applicant in respect of amine and amine degradation products emission during normal operations.</p>	<p>The carbon capture system to be installed on the hydrogen production facility is closed loop, meaning that the amines and associated degradation products are kept in a closed system and not discharged to atmosphere. The amine solution is recycled through a reclaiming system and returned for reuse. This is possible in chemical production processes such as the hydrogen production process, but is not possible in, for example, post combustion carbon capture on a power station, since the flue gas from the power station has to eventually be discharged to atmosphere and therefore can carry some amine and amine degradation products entrained in that flue gas.</p> <p>There is therefore no emission of amine and amine degradation products to atmosphere during normal operation.</p> <p>The Environment Agency, will also review this as part of the Environmental Permit determination process.</p>
Q.1.3.11	EA	<p>View(s) sought.</p> <p>Please could the EA:</p> <p>Confirm whether it is satisfied that the approach adopted in Paragraphs 8B 2.2 - 8B 2.4 of ES Appendix 8B (Air Quality - Operational Phase) [APP-191], in regard to the assessment of operational process emissions, is considered to be a reasonable “worst case” scenario.</p> <p>Comment, if required, on the approach used in the dispersion modelling assessment set out in paragraph 8B.2.9 of ES Appendix 8B (Air Quality - Operational Phase) [APP-191].</p> <p>Confirm you are content with the approach adopted to the modelling of the emissions, as set out in paragraphs 8B.3.4 - 8B.3.7 of ES Appendix 8B (Air Quality - Operational Phase) [APP-191].</p> <p>Provide any observations in relation to Tables 8B-2 and 8B-3 of ES Appendix 8B (Air Quality - Operational Phase) [APP-191], as you may consider necessary.</p>	n/a
Q.1.3.12	Applicant	<p>Response sought.</p> <p>In RR [RR-026] NE raises a number of issues related to Air Quality. These, in particular include:</p> <p>Impacts from ammonia not considered in assessment of traffic emissions (Construction and Operation).</p> <p>Impacts of acid deposition from aerial emissions (Construction and Operation).</p> <p>In-combination impacts of nitrogen deposition from aerial emissions (Operation).</p> <p>Impact of amines from aerial emissions (Operation).</p>	<p>The Applicant would direct the Examining Authority to the Applicant’s Comments on Relevant Representations and Additional Submissions [REP1-007] RR26, Ref Nos. NE10, NE11, NE12, NE14, NE15, NE17, NE18 and NE19 for the Applicant’s position on the issues raised by Natural England.</p>

EXQ1	QUESTION TO:	QUESTION:	RESPONSE
		<p>Consideration of sites used to inform in-combination assessment, and resulting conclusion being unclear (Construction and Operation).</p> <p>Potential sources of air emissions appear to be excluded from the assessments (Construction and Operation).</p> <p>Clarification required regarding scope of emissions from main site (Construction and Operation).</p> <p>Impact from emissions during 4-year major overhaul.</p> <p>Please provide a detailed and reasoned response in respect to the issues raised by NE in regard to air quality.</p>	
Q.1.3.13	Applicant	<p>Clarification.</p> <p>Please explain why the Coastal Dune Grasslands (Grey Dunes) feature of the Durham Coast SAC was considered in the air quality modelling for nutrient nitrogen deposition in ES Appendix 8B (Air Quality - Operational Phase) [APP-191] (Table 8B-31] but not in the Report to Inform Habitats Regulations Assessment (HRA) [AS-016].</p>	<p>The Applicant has reviewed the citation for the Durham Coast SAC which lists the qualifying features as “H1230 Vegetated sea cliffs of the Atlantic and Baltic coasts”. Coastal Dune Grasslands are not a qualifying feature of the Durham Coast SAC and therefore it was not included in the Report to Inform HRA (Document reference 5.10) [AS-016]. However, this was included in the modelled air quality assessment presented in Appendix 8B (Document reference 6.4.8) [APP-191] because it is listed as an interest feature on the Air Pollution Information System (APIS).</p>

APPENDIX 1: HYDROGEN PRODUCTION WITH CARBON CAPTURE: EMERGING TECHNIQUES

Guidance

Hydrogen production with carbon capture: emerging techniques

Emerging techniques on how to prevent or minimise the environmental impacts of industrial hydrogen production from methane or refinery fuel gas with carbon capture for storage.

From: **Environment Agency**
([/government/organisations/environment-agency](https://www.gov.uk/government/organisations/environment-agency))

Published 3 February 2023

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You can produce hydrogen from methane or refinery fuel gas and capture the carbon dioxide (CO₂) which is also produced in this process.

The hydrogen can be:

- used within the installation

- exported as a product

The CO₂ can be:

- transported by pipeline or other means and stored in permanent underground geological storage facilities
- used as a product (not covered in this guidance)

These environmental regulators (referred to as ‘the regulators’) worked with industry stakeholders to develop a ‘[review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture)’ on which this guidance is based:

- Environment Agency
- Natural Resources Wales
- Northern Ireland Environment Agency (an executive agency of the Department of Agriculture, Environment and Rural Affairs)
- Scottish Environment Protection Agency

Except where existing regulations apply, this guidance on emerging techniques is not a regulatory requirement but identifies best practice to address important environmental issues.

The regulators expect operators to follow this guidance, or to propose an alternative approach to provide the same (or greater) level of protection for the environment.

1. Who this guidance is for

This guidance is for:

- operators when designing their plants and preparing their application for an environmental permit
- regulatory staff when determining environmental permit applications
- any other organisation or members of the public who want to understand how the environmental regulations and standards are being applied

This guidance covers large-scale industrial plants:

- producing hydrogen using methane (for example, from natural gas) or refinery fuel gas
- capturing the CO₂ produced within the process, carbon capture (CC), or using post-combustion carbon capture (PCC) to make it ready for permanent geological storage – this is known as carbon capture and storage or sequestration (CCS)

The guidance covers both new plants and retrofits to existing plants.

It does not cover downstream permanent geological storage or using the captured CO₂.

Large-scale means typically greater than 100 tonnes a day of hydrogen which is around 140MW of hydrogen energy at its lower heating value.

Smaller plant should use this guidance until further guidance is available.

When you apply for an environmental permit for this activity, you must tell your regulator whether you are going to follow this guidance. If not, you must propose an alternative approach which will provide the same or greater level of protection for the environment.

In the UK, these installations are permitted under the:

- Environmental Permitting (England and Wales) Regulations 2016
- Pollution Prevention and Control (Scotland) Regulations 2012
- Pollution Prevention and Control (Industrial Emissions) Regulations (NI) 2013

For environmental permitting purposes, the hydrogen production plant is a Part A (1) 4.2 (a)(i) inorganic chemicals activity.

A CC or PCC plant is a Part A (1) 6.10 (a) carbon capture and storage activity when the CO₂ is being captured from an installation for geological storage.

The existing best available techniques (BAT) reference documents (BREFs) for [Large Volume Inorganic Chemicals – Ammonia, Acids and Fertilisers](https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers) (<https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers>) and [Refining of Mineral Oil and Gas](https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0) (<https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0>) do not include hydrogen production with CC, other than as an intermediate product for ammonia production.

The [large combustion plant BREF](https://eippcb.jrc.ec.europa.eu/reference/large-combustion-plants-0) (<https://eippcb.jrc.ec.europa.eu/reference/large-combustion-plants-0>) identifies carbon capture as an emerging technique but does not address all the potential environmental effects of carbon capture.

Where BAT is not covered in existing BREFs or where all the potential environmental effects are not addressed, the regulator must follow [Article 14\(6\) of the Industrial Emissions Directive \(IED\)](https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32010L0075#d1e1666-17-1) (<https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32010L0075#d1e1666-17-1>).

This means that your regulator must set permit conditions covering emission limit values (ELVs), together with other permit conditions. These conditions must be based on the regulator's own assessment of emerging techniques using the criteria listed in [Annex III of the IED \(https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e32-57-1\)](https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e32-57-1). They should also consult with operators before setting these conditions. The regulators consulted potential technology providers and operators when developing the [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture) on which this guidance is based.

Permits must protect the environment by setting conditions to make sure operators do not breach any environmental quality standards ([Article 18 of the IED \(https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e1918-17-1\)](https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e1918-17-1)).

Your regulator may grant a [temporary derogation \(https://www.gov.uk/guidance/best-available-techniques-environmental-permits\)](https://www.gov.uk/guidance/best-available-techniques-environmental-permits) of BAT- associated emission levels (BAT AELs) for up to 9 months, on the basis that hydrogen production with carbon capture for permanent storage is testing and using an emerging technique (see [Article 15\(5\) of IED \(https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e1802-17-1\)](https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e1802-17-1)). You should discuss this with your regulator if this is likely to apply.

Your regulator will make a decision on the emission limits and other permit conditions that will apply on a case-by-case basis. They will do this based on the elements outlined in this guidance and the most appropriate source of reference.

The [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture) summarises the available evidence to support this guidance. We refer to the relevant sections of the review in this guidance.

You may [request advice before applying for your permit \(https://www.gov.uk/guidance/get-advice-before-you-apply-for-an-environmental-permit\)](https://www.gov.uk/guidance/get-advice-before-you-apply-for-an-environmental-permit).

For further advice from your regulator, in:

- England, contact the Environment Agency: enquiries@environment-agency.gov.uk
- Scotland, contact the Scottish Environment Protection Agency: ppc@sepa.org.uk

- Wales, contact Natural Resources Wales:
enquiries@naturalresourceswales.gov.uk
- Northern Ireland, contact the Northern Ireland Environment Agency:
IPRI@daera-ni.gov.uk

2. Technique selection

When choosing hydrogen production and CC plant configuration, you should consider its overall environmental performance, including:

- energy efficiency
- resource efficiency
- CO₂ capture efficiency
- emissions to the environment

These are the hydrogen production methods the regulators considered when producing this guidance:

- steam methane reforming (SMR)
- autothermal reforming (ATR)
- gas heated reforming (GHR)
- partial oxidation (POX)

They also considered combinations of these such as GHR plus ATR and GHR plus SMR.

All of these methods will need to separate out, capture and prepare hydrogen and CO₂ ready for:

- using hydrogen product within the installation
- transporting hydrogen product for use off-site
- transporting CO₂ for permanent geological storage off site

These activities are outside the scope of this guidance.

3. Plant design and operation

3.1 Flexible operation

You must consider whether your hydrogen production plant may need to operate on a flexible basis to balance variations in demand from hydrogen users.

You should consider whether this need for flexibility will affect the design, operation and maintenance of the plant.

You should identify flexible operating scenarios where environmental performance could be affected, or where additional emissions are expected. For example, these could be as a result of rapid changes in capacity, or start-up following enforced shutdown.

You should describe measures you would take to minimise the environmental impact of these scenarios, which could result in, for example:

- reduced CO₂ capture rates
- reduced energy efficiency
- increased emissions to air, venting and flaring
- increased effluent or wastes produced
- increased risk of accidents in non-steady state conditions

3.2 Reliability and availability

You will need to identify equipment and systems that are critical in avoiding emissions. You will need to design, operate and maintain these to make sure they are reliable and available, including providing installed back-up equipment, where necessary.

You should implement a risk-based other than normal operating conditions (OTNOC) management plan, which identifies potential scenarios, mitigation measures, monitoring and periodic assessment.

3.3 Overall CO₂ capture efficiency

You should design plant to maximise the carbon capture efficiency. As a minimum, you should achieve an overall CO₂ capture rate of at least 95%, although this may vary depending on the operation of the plant. You can base this on average performance over an extended period (for example, a year).

Overall carbon capture rate or efficiency is defined as ‘the mass of CO₂ equivalent captured for storage as a percentage of the mass of CO₂ equivalent in all feed gas, including methane or refinery fuel gas (or both) used in combustion plant’.

For clarity, this is the same as ‘the mass of carbon captured as a percentage of the mass of carbon in all feed gas’.

This should be achievable for the hydrogen production and CO₂ capture routes considered for new plant.

You will need to provide justification if you are proposing a design CO₂ capture rate of less than 95%.

You should consider how you would comply with future requirements for increased CO₂ capture efficiency by making your plant decarbonisation ready.

You should plan to allow for space and technical retrofit within the design for additional carbon capture plant. This will allow for the capture of residual emissions of CO₂, for example, from combustion of any hydrogen purification residual gas.

This is to future-proof the plant so you can comply with any future requirements for carbon capture ready for emissions of CO₂ and the likely changes to CO₂ capture efficiency required.

You should note that any carbon-containing compounds as allowed by the hydrogen product specification will be emitted to the environment in downstream uses, such as combustion. You should aim to minimise these where feasible.

For more detail, see the [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture):

- section 5.7 Carbon capture efficiency
- section 6.3, Table 22: Carbon capture key performance parameters

3.4 Process CO₂ capture from hydrogen product

Technology for CO₂ capture from hydrogen product will typically be through absorption in a circulating solvent, with regeneration of the solvent through reducing pressure and heating to liberate CO₂.

You should select the solvent, process design and operating conditions that maximise energy efficiency, capture performance, and minimise the waste and effluent treatment required. Where you have considered various options, you should provide the reasoning behind this to demonstrate that your chosen option uses overall BAT.

This could include, for example:

- maximising absorption for CO₂ capture
- optimising solvent regeneration to provide CO₂ at high pressure, but avoiding excessive degradation of solvent
- maximising heat exchange between lean and rich solvent streams

- minimising solvent carryover to minimise the need for downstream removal
- minimising wastes and effluent streams, while removing contaminant build-up in solvent

For more detail, see the [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture), section 5.4.

3.5 CO₂ capture for steam methane reforming

In SMR, heat for the reformer reaction is provided by external combustion in a furnace.

The fuel gas can be either:

- methane (usually from natural gas feed)
- refinery fuel gas
- hydrogen product
- a combination of these

All require post combustion capture to remove the CO₂ produced from the flue gas, except where pure hydrogen product is used as the fuel. Following consultation with industry, the regulators expect that more than 95% of CO₂ can be removed from the reformer flue gases.

The plant could be designed in such a way that no post combustion capture is needed if both of these apply:

- hydrogen is used as the fuel gas for the reformer
- there is in-process CO₂ removal prior to hydrogen purification

You will need to justify the best overall approach, considering all environmental impacts.

If post-combustion CO₂ capture is needed, you should use the guidance [post-combustion carbon dioxide capture: emerging techniques \(https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-emerging-techniques\)](https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-emerging-techniques) (referred to as PCC guidance).

You should take account of any differences between the flue gases considered in the PCC guidance and the flue gases from the SMR reformer furnace.

These differences could be, for example, oxygen and nitrogen content, potential for formation of nitrogen oxides (NO_x) and impact of requirement for flexible operation.

When optimising for environmental performance, you should consider:

- selecting appropriate solvents
- emissions to air of solvent and associated degradation products
- energy requirements
- effluents and wastes
- cooling requirements
- pump and fan noise
- flue gas pre-treatment
- treated flue gas dispersion

For more detail, see the [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture), sections 5.5 and 5.6.

3.6 CO₂ capture from residual gas from hydrogen purification

You should consider how to capture CO₂ produced by the combustion of residual gas, which results when hydrogen is purified.

You should aim to remove this CO₂ to maximise the overall carbon capture efficiency and to make sure you achieve at least 95%.

The residual gas may contain methane, carbon monoxide (CO) and CO₂ as well as hydrogen, nitrogen and argon. This is normally used as a fuel gas and any carbon containing compounds will be converted to CO₂.

The amount of carbon-containing compounds depends on the efficiency of conversion and removal before the hydrogen purification stage.

For more detail, see the [review of emerging techniques \(https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture\)](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture), section 5.9.

3.7 Energy efficiency, process efficiency, cooling

You should choose your hydrogen production process and design your plant to maximise:

- energy efficiency (minimise the energy needed to produce each tonne of hydrogen)
- process efficiency (minimise the raw materials, such as methane and water, needed to produce each tonne of hydrogen)

To decide on BAT, you will have to balance how you achieve these efficiencies in order to optimise the environmental and economic requirements.

You must explain how you have done this and what your considerations were.

This should take into account all of the chemical and physical processes within the installation boundary needed to produce hydrogen and capture carbon.

Main energy users will include:

- air separation unit (ASU) – for oxygen supply to ATR and POX
- hydrogen compressors
- CO₂ compressors
- hydrogen and CO₂ purification
- solvent recovery system
- pumping or fan systems

You should consider:

- electrical power needs and whether you will import or generate on site
- high pressure steam need and availability
- maximising any residual waste heat recovery
- cooling needs
- cooling type and medium

You should also consider heat integration optimisation, for example, heat recovery at:

- higher temperatures from compression systems including the ASU, CO₂ and hydrogen compression for power generation or drives
- medium temperatures for solvent recovery
- lower temperatures for boiler feed pre-heat

See also section 3.9 Water supply and use.

You should reference the BREF documents:

- [Industrial Cooling Systems](https://eippcb.jrc.ec.europa.eu/reference/industrial-cooling-systems)
(<https://eippcb.jrc.ec.europa.eu/reference/industrial-cooling-systems>)
- [Energy Efficiency](https://eippcb.jrc.ec.europa.eu/reference/energy-efficiency) (<https://eippcb.jrc.ec.europa.eu/reference/energy-efficiency>)

For further details, see the [review of emerging techniques](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture)
(<https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture>):

- section 5.10
- section 6.1 Table 20

3.8 Oxygen production

Oxygen is required for the ATR and POX processes. It is usually produced by an ASU, which is a relatively large energy user.

You must consider heat recovery from the heat generated by the air compression system and whether you can use it within the rest of the hydrogen production process to maximise energy efficiency. We expect you to explore all opportunities for waste heat recovery as the ASU will be considered part of the installation.

You should take the following into account when designing the oxygen production plant and optimise to show you are using BAT:

- 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 shutdown and start-up of the plant

For further details, see the [review of emerging techniques](https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture)
(<https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture>):

[hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture](#)), section 5.12.

3.9 Water supply and use

Water supply and its efficient use is an important aspect of BAT in hydrogen production plant.

The quality of the water supply will determine the pre-treatment needed before it can be used as a:

- raw material in hydrogen production
- heat transfer medium
- cooling medium

Water is consumed in the process as part of the hydrogen product.

Your choice of hydrogen production method will determine the ratio of hydrogen product that comes from water compared with that which comes from methane, or refinery fuel gas, or both.

For further details see Water consumption (process) in Table 20 of the [review of emerging techniques](#) (<https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture>).

You should:

- minimise the amount of water you use
- segregate, treat and reuse water where possible
- choose a cooling method that takes account of the temperature impact on process performance, energy efficiency and environmental impact on the receiving medium

For refineries, you should also comply with BAT conclusion 11 emissions to water from the [BAT conclusions \(BATC\) for refining of mineral oil and gas](#) (https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL_2014_307_R_0009).

3.10 Water treatment

Water and steam are used in the process.

Water is condensed both from steam systems and from process cooling. In most cases, this water can be reused without being treated. However, some water will need to be removed to avoid the build-up of contaminants. You

will need to treat it in an effluent treatment system before releasing it into the environment.

You should decide how much water to treat and how to treat it before it is:

- reused
- released to surface water or sewage undertaker
- disposed of

You should identify how much contaminant, such as methanol and ammonia, needs to be removed and design the treatment process accordingly.

You should identify any emissions to air or wastes that may result from the water treatment process, for example, emission of CO₂ from deaeration of boiler feed water.

You should use the following references to choose the most appropriate treatments:

- [BREF and BATC for common waste water and waste gas treatment/management systems in the chemical sector](https://eippcb.jrc.ec.europa.eu/reference/common-waste-water-and-waste-gas-treatmentmanagement-systems-chemical-sector-0)
(<https://eippcb.jrc.ec.europa.eu/reference/common-waste-water-and-waste-gas-treatmentmanagement-systems-chemical-sector-0>)
- [BREF and BATC for refining of mineral oil and gas](https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0)
(<https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0>)

For discharges to water, you should refer to the guidance [Surface water pollution: risk assessment for your environmental permit](https://www.gov.uk/guidance/surface-water-pollution-risk-assessment-for-your-environmental-permit)
(<https://www.gov.uk/guidance/surface-water-pollution-risk-assessment-for-your-environmental-permit>).

For further details on water treatment for re-use, see the emerging techniques review, section 5.13.

3.11 Feed gas quality and treatment

Your choice of supply of methane-containing feed gas will determine the type of gas treatment processes you will need prior to the main conversion reactions. It will also determine whether you will need to remove inert gases at the hydrogen purification stage.

If you use refinery fuel gas as your feed gas supply, where possible, you should remove contaminants such as sulphur and mercury in existing upstream refinery processes, taking account of BAT across the refinery installation.

You will need to take account of the possible range of gas composition so that you can design your processes to minimise the overall environmental impact, including substances such as:

- sulphur (S), typically as H₂S
- nitrogen (N₂)
- CO₂
- mercury
- other hydrocarbons

You will need to design your gas treatment and downstream processes in order to:

- minimise solid wastes (for example, catalyst) for recycling or disposal
- minimise sulphur dioxide (SO₂) emissions to air where feed gas is combusted
- maximise overall process reaction and energy efficiency
- minimise emissions to air associated with the removal of nitrogen or other inerts

You should consider removing sulphur compounds by hydrogenation and using catalyst adsorbent to avoid SO₂ emissions from combustion and catalyst poisoning.

You should consider removing other hydrocarbons by pre-reforming to avoid carbon deposition on catalysts.

You should consider the impact a pre-reforming step will have on the downstream reforming stage for an SMR. You may be able to optimise the energy efficiency and minimise NO_x emissions to air due to reduced gas fired reformer furnace duty. You will need to consider the impact on steam balance for the plant.

You should remove mercury to avoid catalyst poisoning and other downstream contamination.

Any CO₂ in the feed gas will be removed along with the CO₂ produced in the process. You should include this in the overall CO₂ balance and capture efficiency monitoring and reporting.

3.12 Reforming and CO shift

Hydrogen is produced in the reforming and CO shift stages of the plant.

You should convert methane to hydrogen, CO and CO₂ in the reforming stage, while minimising unreacted methane.

You should optimise CO conversion to CO₂ considering the overall CO₂ capture requirement and the impact on downstream processing stages to meet the hydrogen product specification.

3.13. Reforming

You should select, design and operate the reformer reaction in order to:

- reduce the risk of carbon deposition on catalyst, which would result in reduced reaction efficiency
- minimise catalyst change frequency and the need for recycling or waste disposal

If you choose ATR or POX technologies, carbon formation may be more likely due to the reducing atmosphere. You should choose operating parameters to minimise this risk.

3.14 CO shift

You should select, design and operate CO shift reaction in order to:

- maximise energy efficiency through, for example, heat integration with the overall hydrogen production and CO₂ capture processes
- minimise the duration of start-up operations and associated emissions to air from flaring
- minimise the production of wastes for recycling or disposal

You should consider a single step CO shift process rather than a more conventional high temperature or low temperature shift process, with isothermal conditions achieved through reactor cooling with recovery of heat.

By using this option, it may allow you to:

- increase overall heat integration and efficient use of recovered heat, as long as sufficient conversion of CO to CO₂ is achieved
- avoid using chromium catalyst needed for high temperature shift, therefore minimising hazardous waste
- reduce the potential for catalyst damage, methanation reactions, and Fischer-Tropsch reactions
- reduce the potential for the production of methanol which would condense out with water downstream and need to be treated by effluent

treatment

- consider the cost and environmental benefits of an isothermal reactor against a more complex multi-tube boiling water-cooled reactor

Refer to [BREF for large volume inorganic chemicals – ammonia, acids and fertilisers](https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers) (<https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers>) – section 2.4.14 Isothermal Shift Conversion.

3.15 Catalyst selection

When you choose which catalysts to use, you should consider the overall environmental performance, including, for example:

- any required pre-treatment to avoid poisoning, to minimise waste and associated treatment
- preventing any dust emissions, where applicable
- the ability to recover or recycle the solids or metals from the spent catalyst waste
- handling spent catalyst for environmentally safe recovery, recycling or disposal

3.16 Hydrogen product

You will need to purify and compress hydrogen so that it is fit for purpose after it is separated from the CO₂ in the CO₂ capture stage.

You should take account of hydrogen purification requirements. These will depend on:

- the hydrogen product quality specification
- impurities in the hydrogen following reforming, CO shift and CO₂ capture steps

The impurities may include:

- CO, which is not converted to CO₂ in the reforming or CO shift sections
- CO₂, which is not removed in the CO₂ capture section
- methane, which is not converted to CO in the reforming section
- nitrogen and argon – inert gases present in feed gas or oxygen supply
- water – the hydrogen is saturated with water following CO₂ capture

You should consider pressure swing adsorption (PSA) to remove impurities from the hydrogen. Treating residual gas containing the impurities is

considered in section 3.6 CO₂ capture from residual gas from hydrogen purification.

You should consider whether methanation to convert CO into methane is appropriate, depending on the specification of hydrogen, to make sure hydrogen is fit for purpose.

You should consider the impact on overall energy efficiency and the need for further treatment of hydrogen purification off-gas streams.

You should design the overall process to minimise the power required for compression to achieve the pressure required by the user. See section 3.7 energy efficiency, process efficiency, cooling.

3.17 CO₂ product

You should design the process to meet the required CO₂ quality specification, temperature and pressure as required for transport to permanent geological storage.

You should design the overall process to minimise the power required for compression to achieve the pressure required by the user. You should maximise recovery of waste heat from compression. See section 3.7 energy efficiency, process efficiency, cooling.

4. Emissions to air

You should eliminate, minimise or reduce any emissions to air that could cause pollution.

You should make sure that your process emissions can comply with all ELVs which are required under the relevant BATC.

You should carry out a risk assessment, including detailed air quality modelling, to assess the impact of these emissions.

4.1 Combustion processes

You should maximise energy efficiency and heat integration so you minimise the need for combustion processes, resultant CO₂ and other combustion products.

You should maximise the capture of CO₂ from combustion processes, taking account of the overall carbon capture requirement.

If you decide that carbon capture from a combustion process is not appropriate, you must justify your decision based on BAT. You must identify and minimise the continuous and periodic emissions of combustion products to air.

You should consider NO_x abatement techniques where the combustion of hydrogen-rich gas with the potential for higher flame temperatures will increase thermal NO_x formation, including:

- burner design
- flue gas recirculation
- heat exchange with fuel or air

You should consider whether abatement of any of these emissions is required to comply with relevant BAT AELs or local air quality standards, for example, for NO_x. Where relevant, you should consider the following abatement techniques:

- selective catalytic reduction (SCR)
- selective non-catalytic reduction (SNCR)

You should 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 SMR, the requirement for post-combustion carbon capture for the reformer furnace emissions to air and any pre-treatment of combustion gases needed see the [PCC guidance \(https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat\)](https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat)
- for ATR, whether the relatively smaller additional heat need can be supplied by combustion of hydrogen-rich residual gas or combustion of hydrogen product
- for POX, the process is usually energy-balanced or produces excess heat and so combustion processes may not be needed
- 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

You could consider using excess oxygen, where available, to support oxy-combustion, in order to remove the source of nitrogen and therefore limit thermal NO_x formation.

Fuel NO_x may form from nitrogen in the residual gas from the PSA. There is limited experience of using oxygen, especially for hydrogen-rich gases and any such proposal would need to be fully justified with supporting data.

You should design combustion processes to comply with required emissions limit values (ELVs) from the existing sources of statutorily applicable emission limits and BAT AELs, including the following:

- [Medium Combustion Plant Directive \(https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32015L2193\)](https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32015L2193)
- [Industrial Emissions Directive Chapter III Annex V ELVs \(https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e32-59-1\)](https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e32-59-1)
- BAT AELs identified in the [Large combustion plant BREF \(https://eippcb.jrc.ec.europa.eu/reference/large-combustion-plants-0\)](https://eippcb.jrc.ec.europa.eu/reference/large-combustion-plants-0) and BATC
- [Refining of Mineral Oil and Gas \(https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0\)](https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0)
- [Large Volume Inorganic Chemicals – Ammonia, Acids and Fertilisers \(https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers\)](https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers)
- [Common Waste Water and Waste Gas Treatment/Management Systems in the Chemical Sector \(https://eippcb.jrc.ec.europa.eu/reference/common-waste-water-and-waste-gas-treatmentmanagement-systems-chemical-sector-0\)](https://eippcb.jrc.ec.europa.eu/reference/common-waste-water-and-waste-gas-treatmentmanagement-systems-chemical-sector-0)

You should consider the:

- type of combustion equipment
- fuels proposed to be combusted
- net rated thermal inputs
- BAT for control of emissions
- conclusions of an environmental risk assessment, considering the dispersion of pollutants into air and the sensitivity of the relevant receptors

4.2 Post combustion capture plant

Refer to the [PCC guidance \(https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat\)](https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat) – section 3.3 Features to control and minimise atmospheric and other emissions.

4.3 Flaring and venting

You must design and operate your plant to minimise the need for continuous or intermittent flaring or venting of gases, whether for operational or safety reasons, including:

- methane or refinery fuel gas
- hydrogen
- CO₂

This should 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 (see section 3.2 Reliability and availability)
- avoiding routine flaring for waste gas destruction
- managing production of off-gas and balance against requirements for fuel gas using advanced process control, for example
- using procedures to define operations, including start-up and shutdown, maintenance work and cleaning
- using commissioning and handover procedures to ensure that the plant is installed in line with the design requirements
- using 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

You must minimise emissions under start-up, shutdown, and abnormal operations. This can be achieved by:

- using a flare gas recovery system with adequate capacity
- routing gas that would be flared to alternative users
- using high integrity relief valves
- other measures to limit flaring to abnormal operation

If your activity is part of a refineries installation, you should refer to BAT conclusions 55 and 56 in [BATC for the Refining of Mineral Oil and Gas](https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL_2014_307_R_0009) (https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL_2014_307_R_0009).

You should quantify and assess harm from other routine venting and purging requirements, identifying any pollutants that are expected to be present, including, for example:

- CO₂

- hydrogen
- CO
- methane
- ammonia vapour
- methanol vapour

Requirements for continuous venting during normal operations may include, for example:

- water vapour from CO₂ dehydration systems using circulating tri-ethylene glycol
- deaeration of steam condensate or boiler feed waters
- gases from processing waste water streams
- purge of tanks, vent or flare headers

Requirements for intermittent venting may include, for example:

- CO₂ vented in abnormal conditions, such as when the downstream transportation and storage system is not available, or if the CO₂ does not meet the export specification
- venting needed as part of purging equipment for maintenance activities

5. Emissions to water

You must identify and eliminate, minimise, recycle or treat any emissions to water that could cause pollution.

You should carry out a risk assessment, including detailed modelling, where appropriate, to assess the impact of these emissions.

For discharges to water, you should refer to the guidance [Surface water pollution: risk assessment for your environmental permit](https://www.gov.uk/guidance/surface-water-pollution-risk-assessment-for-your-environmental-permit) (<https://www.gov.uk/guidance/surface-water-pollution-risk-assessment-for-your-environmental-permit>).

5.1 Effluent treatment discharges

You should identify continuous and periodic effluent streams from the process and determine whether effluent treatment is required. These streams may include process condensate containing contaminants, which may need treatment before discharge, for example:

- methanol
- ammonia
- CO₂

- amines
- degradation products

You should treat water for reuse as far as possible. See section 3.10 Water treatment.

You should refer to the appropriate BREF and BATC (where available) if the installation is considered to be part of a refinery or a chemicals installation:

- [Refining of Mineral Oil and Gas](https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0)
(<https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0>)
- [Common Waste Gas Management and Treatment Systems in the Chemical Sector](https://eippcb.jrc.ec.europa.eu/reference/common-waste-gas-treatment-chemical-sector)
(<https://eippcb.jrc.ec.europa.eu/reference/common-waste-gas-treatment-chemical-sector>)
- [Large Volume Inorganic Chemicals – Ammonia, Acids and Fertilisers](https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers)
(<https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers>)

6. Waste

You must eliminate or minimise wastes and treat, where appropriate.

You should consider how to deal with the following wastes that may be generated.

6.1 Liquid wastes

Liquid wastes such as:

- demineralised water production reject stream
- amine solvent – for example, from bleed or feed replacement
- dehydration solvent – for example, in case of tri-ethylene glycol dehydration
- amine reclaimer residue

6.2 Solid wastes

Solid wastes such as:

- depleted catalyst material – hydrogenation, reforming, CO shift
- spent adsorbent materials – gas treatment, dehydration, hydrogen purification
- solids from amine filtration
- soot (POX process)

7. Monitoring

The main purpose of monitoring is to demonstrate compliance with the permit and show that emissions from the process are not causing harm to the environment.

You must also carry out monitoring to show that resources are being used efficiently. This includes:

- energy and resource efficiency
- carbon capture efficiency
- verifying that the CO₂ product is suitable for safe transport and storage
- hydrogen product quality
- verifying (when applicable) compliance with low carbon hydrogen standards

Your permit application should include a monitoring plan for both a commissioning phase and routine operation.

During the commissioning phase, you will need to assess monitoring results and optimise the operation of the process. You will need to report on your commissioning phase monitoring results, your assessment of them and any changes you want to make to the operation.

It's likely you will need to do more extensive monitoring during the commissioning phase than during routine operation. As these production techniques for hydrogen with CCS are emerging techniques, you will need to develop monitoring methods and standards. You should include proposals for this in your permit application.

Complying with ELVs in your permit will provide the necessary protection for the environment, by monitoring emissions at authorised release points. You must also show that you are managing the process to prevent (or minimise) the formation of solvent degradation products.

Where degradation products are formed (and may be released), you must reduce these and any solvent emissions to the appropriate level. This process control monitoring will also be part of the permit conditions.

7.1 Monitoring point source emissions to air

You should provide a monitoring plan for monitoring emissions to air, based on expected pollutants such as:

- ammonia
- amine compounds

- SO₂
- NO_x
- CO
- methane
- hydrogen

You should do this using appropriate methods and measuring techniques.

Emissions of methane and hydrogen should be eliminated or minimised due to their global warming potential.

Your monitoring should consider, for example:

- NO_x and CO emissions from combustion
- SO₂ emissions from combustion where the fuel source contains sulphur
- ammonia emissions where SCR or SNCR is used
- amine or amine degradation products and other volatile solvent emissions, where relevant
- methane and hydrogen 'slip' from any combustion processes
- any other sources of methane or hydrogen emissions

For combustion plant, your monitoring plan should demonstrate compliance with the applicable emission limits described in section 4.1 Combustion processes.

Where you are using post-combustion CO₂ capture, for example, using amine solvent, your plan should include monitoring relevant emissions such as:

- ammonia
- volatile components of the capture solvent
- likely degradation products such as nitrosamines and nitramines

Specific pollutants arising from post-combustion capture may be monitored by continuous emissions monitors, if they are available, or by periodic extractive sampling. Where aerosol formation is expected, the sampling must be isokinetic.

7.2 Monitoring emissions to water

You must monitor emissions to water based on expected impurities (for example, ammonia, amine compounds, methanol, CO₂) using appropriate methods and measuring techniques.

You should use monitoring standards for discharges to water following:

- [BATC for common waste water and waste gas treatment/management system in the chemical sector \(https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1579188127132&uri=CELEX%3A32016D0902\)](https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1579188127132&uri=CELEX%3A32016D0902)
- [BATC for the refining of mineral oil and gas \(https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL_2014_307_R_0009\)](https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL_2014_307_R_0009)

7.3 Monitoring standards

The person who carries out your monitoring must be competent and work to recognised standards such as the Environment Agency's [monitoring certification scheme \(MCERTS\)](https://www.gov.uk/government/collections/monitoring-emissions-to-air-land-and-water-mcerts) (<https://www.gov.uk/government/collections/monitoring-emissions-to-air-land-and-water-mcerts>).

MCERTS sets the monitoring standards you should meet. The Environment Agency recommends that you use the MCERTS scheme, where applicable. You can use another certified monitoring standard, but you must provide evidence that it is equivalent to the MCERTS standards.

There are no prescriptive BAT requirements for how to carry out monitoring. Monitoring methods need to be flexible to meet specific site or operational conditions.

You must use a laboratory accredited by the [United Kingdom Accreditation Service \(UKAS\)](https://www.ukas.com/) (<https://www.ukas.com/>) to carry out analysis for your monitoring.

You should also refer to the [JRC Reference Report on Monitoring for IED Installations](https://eippcb.jrc.ec.europa.eu/reference/monitoring-emissions-air-and-water-ied-installations-0) (<https://eippcb.jrc.ec.europa.eu/reference/monitoring-emissions-air-and-water-ied-installations-0>).

7.4 Monitoring CO₂ capture performance

You should clearly identify how you will monitor the CO₂ capture performance of the plant.

The regulators expect you to monitor CO₂ capture performance according to standards that are recognised under the UK ETS. Measurements required to monitor CO₂ emissions to atmosphere may, for example, include directly measuring the flow and composition of fuel gas to combustion systems.

This, together with measuring the following, will allow monitoring of the CO₂ capture rate and CO₂ quality (considering any impurities that could impact downstream systems):

- flow and composition of feed gas
- hydrogen product (including methane content where applicable)
- CO₂ product streams

You will need to include:

- CO₂ equivalent mass balance
- CO₂ equivalent in feed gas
- total capture efficiency (CO₂ equivalent captured as a mass percentage of CO₂ equivalent in feed gas)
- CO₂ equivalent released to the environment
- CO₂ quality

7.5 Monitoring process performance

You should identify the main requirements for monitoring process operations where these ultimately impact on environmental performance, including, for example, for the CO₂ capture system:

- amine system performance, including monitoring of amine solvent quality such as amine concentration
- pH and presence of degradation or corrosion products
- amine temperatures
- amine and wash water circulation rates
- rich and lean amine CO₂ loading
- stripper reboiler steam rates

You should monitor energy efficiency in the hydrogen production and CO₂ capture processes by measuring feed and product gas flows and electrical power consumption to calculate overall energy consumption.

You should monitor the quality of the hydrogen product to ensure it is fit for purpose.

Requirements for process performance monitoring, either online or offline, will also be a condition of the permit.

8. Unplanned emissions and accidents

You should 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.

You should include how you will use LDAR to eliminate or reduce fugitive emissions of methane and hydrogen due to their global warming potential.

Your hazard assessment and mitigation for the plant must consider the risks of accidental releases to the environment. This should also consider the actual composition of the liquids, gases and vapours that could be released from the plant after an extended period of operation.

9. Noise and odour

You need to consider sources that have high potential for noise and vibration. In particular, CO₂ and hydrogen compression, pumping and fan noise could be significant additional sources.

Once you've identified the main sources and transmission pathways, you should consider using common noise and vibration abatement techniques and mitigation at source, wherever possible. For example:

- embankments to screen the source of noise
- enclosure of noisy plant or components in sound-absorbing structures
- anti-vibration supports and interconnections for equipment
- orientation and location of noise-emitting machinery
- changing the frequency of the sound

Please refer to [Noise and vibration management: environmental permits \(https://www.gov.uk/government/publications/noise-and-vibration-management-environmental-permits\)](https://www.gov.uk/government/publications/noise-and-vibration-management-environmental-permits).

Handling, storing and using some amines may result in odour emissions, so you should always use best practice containment methods. Where there is increased risk that odour from activities will cause pollution beyond the site boundary, you will need to send an odour management plan with your permit application.

In England, Wales and Northern Ireland please refer to [Environmental permitting: H4 odour management \(https://www.gov.uk/government/publications/environmental-permitting-h4-odour-management\)](https://www.gov.uk/government/publications/environmental-permitting-h4-odour-management). In Scotland refer to [Odour guidance 2010 \(https://www.sepa.org.uk/media/154129/odour_guidance.pdf\)](https://www.sepa.org.uk/media/154129/odour_guidance.pdf).

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