Department for Energy Security & Net Zero

Annexes

Guidance on greenhouse gas emissions and sustainability criteria under the UK Low Carbon Hydrogen Standard

Version 2

April 2023

Any enquiries regarding this publication should be sent to us at:
hydrogenproduction@beis.gov.uk

Contents

Annex A: Hydrogen production pathway - Electrolysis

1. Electrolysis Process Description

A typical water electrolysis cell consists of an anode and a cathode separated by a membrane immersed in an electrolyte (a conductive solution). When the electrodes are connected to a direct current power supply, electricity flows through the electrolyte and causes the water to split into hydrogen at the cathode and oxygen at the anode. Each electrolyser system consists of a stack of electrolysis units, a gas purifier and dryer, compression, and an apparatus for heat removal.

There are currently three main electrolyser technologies, distinguished by the electrolyte (and associated production temperatures): alkaline electrolyser, polymer electrolyte membrane (PEM) electrolyser and solid oxide (SOEC) electrolyser. The methodology discussed in this Annex may be applied to any other electrolysis technologies.

Hydrogen and oxygen gas products must be purified, dried, and cooled prior to storage and/or delivery to market, subject to required product specifications.

The oxygen gas must be safely vented to the atmosphere or recovered and utilised.

2. Electrolysis overview

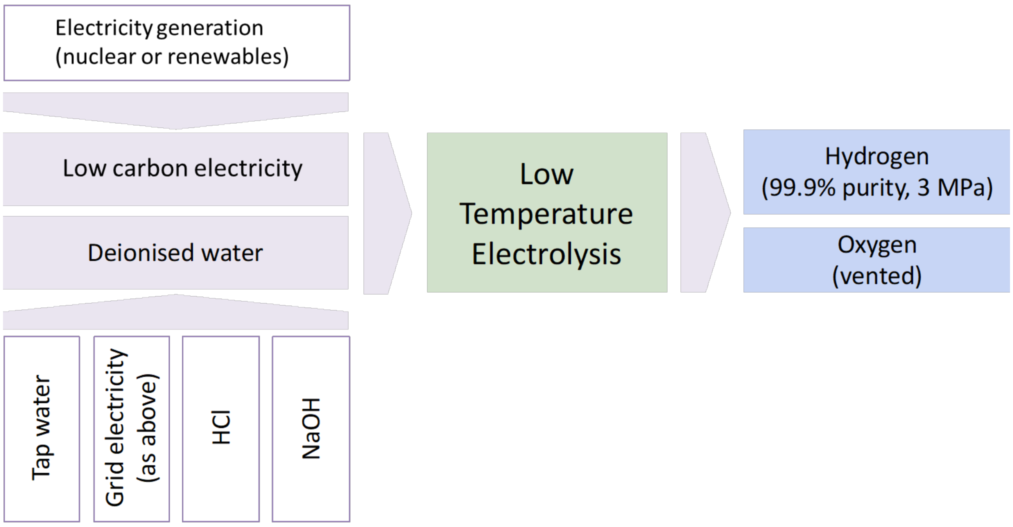
Electrolytic hydrogen production varies in GHG emissions intensity according to the primary electricity inputs, and the production process used.

For indicative purposes, simplified flow diagrams are shown in the figures below for three different hydrogen production processes using electrolysis via low carbon electricity, using grid electricity, and high-temperature electrolysis using nuclear generated electricity.

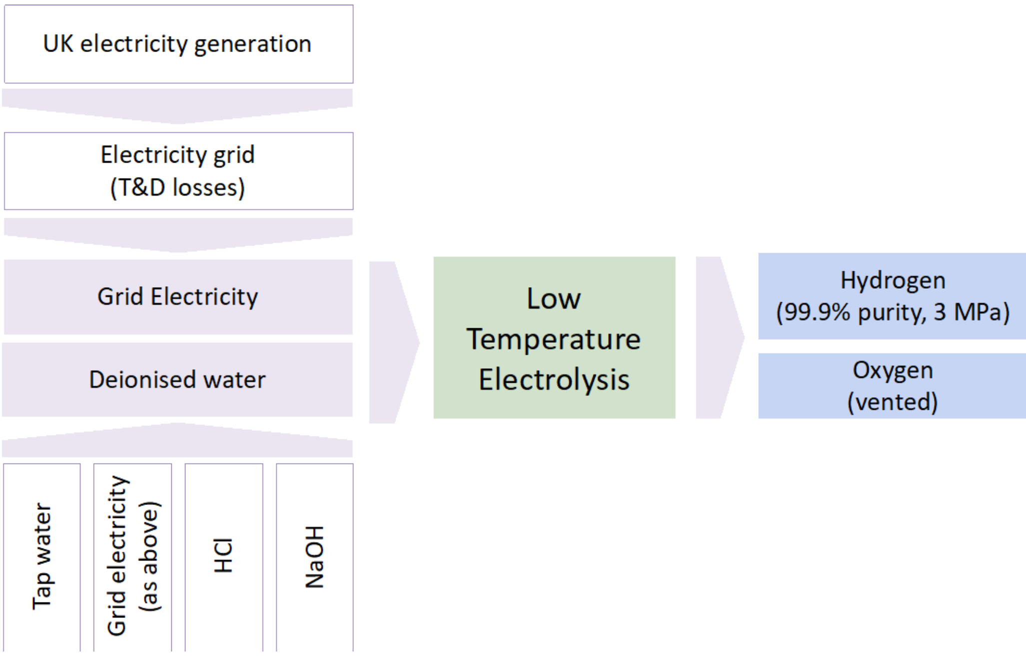
These provide information on the primary inputs used in electrolytic hydrogen production processes, and the resulting primary outputs. These are detailed to provide context for the below section on emission sources in electrolysis and the evidence requirements for low carbon hydrogen production via electrolysis.

The main simplified block flow diagrams for electrolysis are described below:

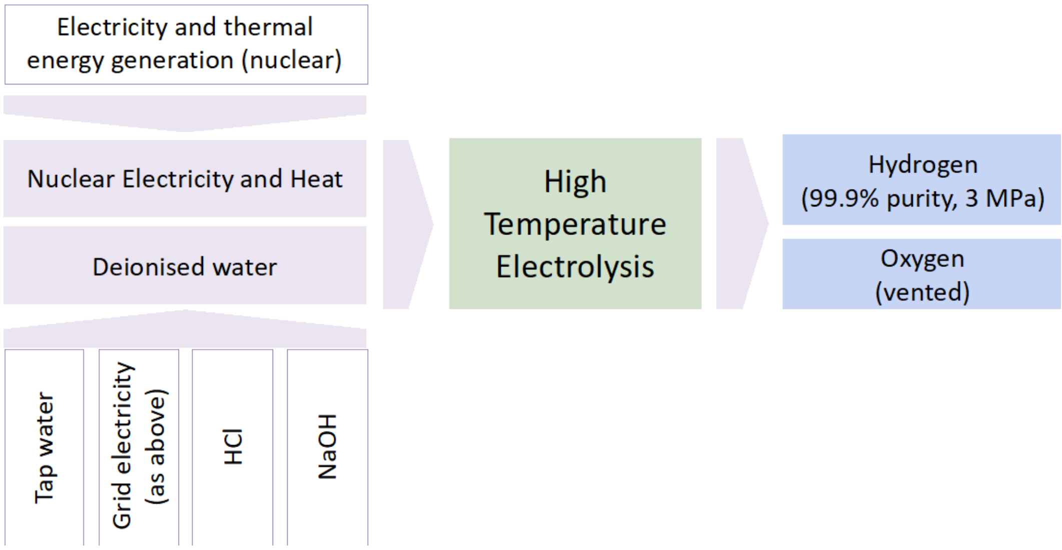
Low temperature electrolysis using low carbon electricity



Low temperature electrolysis using grid electricity



High-temperature Electrolysis with Nuclear Electricity and heat



High temperature electrolysis is illustrated here as being near to a nuclear power plant, taking nuclear electricity as well as heat from the power plant.

Note the diagrams above are illustrative examples. Inputs and outputs may vary (e.g. oxygen may be utilised, electricity used for deionisation may vary, water input sources may vary and not all electrolysers will require chemical inputs for water ionisation).

3. Emissions sources in electrolysis

GHG emissions associated with electrolysis are primarily subject to the nature of the associated electricity supply for electrolysis as electricity can be sourced from different routes with different GHG emissions; for example on site low carbon generation (off-grid); grid import via sleeved Power Purchase Agreement (PPA) or via wholesale/retail grid import.

Each process unit or stage in the electrolysis process contains emissions sources outlined in Table 1, although this is not an exhaustive list of emissions sources.

Table 1: GHG emissions summary for electrolysis

Process unit/stage	Key emissions sources	Other emissions sources
Water supply and treatment	Electricity for purification and filtration	Chemicals use e.g. salts, solvents, acids and bases for water purification

Hydrogen production	Electricity for electrolyser units	Steam and heat (where purchased) Liquid, solid and/or gaseous fuels for power or steam generation
Hydrogen compression, purification, drying and cooling	Electricity for relevant units	Steam and heat (where purchased) Solid, liquid and/or gaseous fuels for relevant units and/or steam generation

4. Electrolysis – Evidence Requirements for Low Carbon Electricity Input

4.1 Sources of Low Carbon Generation in the UK and Overview of Requirements

This section defines how an operator using low carbon electricity, such as renewable or nuclear electricity, should account for this, and the evidence that should be required to demonstrate standard compliance of the hydrogen produced . The GHG emissions associated with the low carbon electricity input must be monitored and accounted for when calculating the overall GHG emissions of the hydrogen produced.

Figure 1 below highlights the main commercial routes available to contract access to electricity in the UK. Whilst the GHG emissions associated with these different routes varies, all of these routes may be eligible to demonstrate low enough GHG intensity electricity input for hydrogen production to meet the UK low carbon hydrogen standard, provided the evidence requirements are met (see Table 3 for specific evidence requirements).

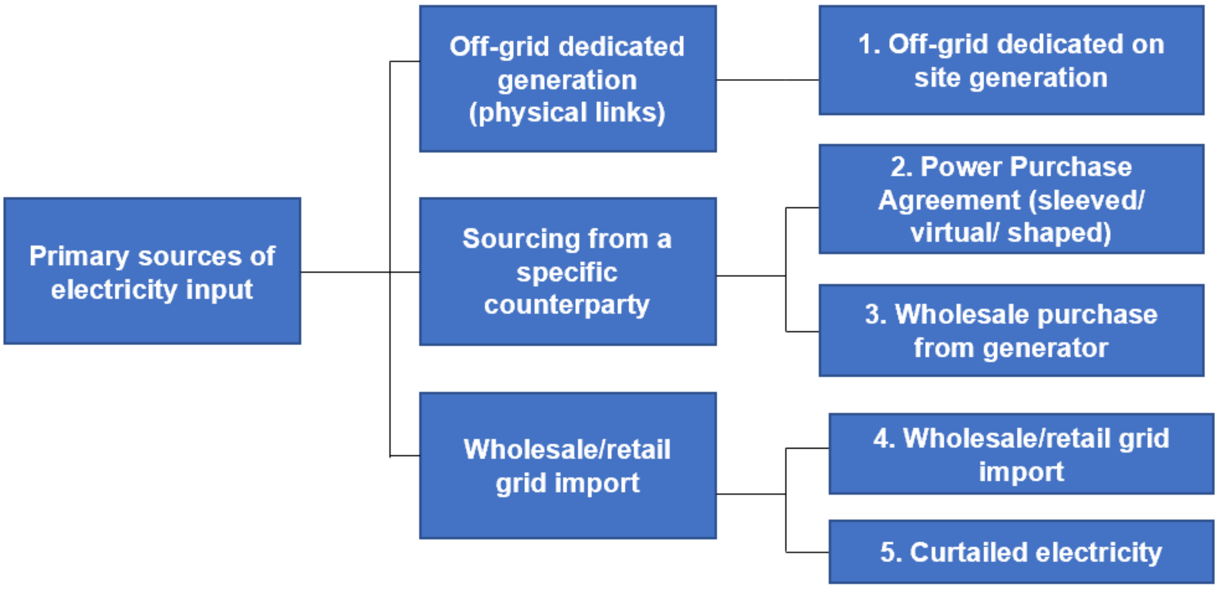


Figure 1: Primary Sources of Low Carbon Electricity Input for Hydrogen Production

*This may not cover all electricity input routes, but is an indication of all primary electricity input routes available in the UK today.

A hydrogen producer must be able to accurately account for the low carbon electricity consumed in hydrogen production, and must be able to provide sufficient evidence the electricity used will allow or has allowed the hydrogen produced to meet the emissions compliance threshold of $20gCO_2e/MJ_{LHV}$ hydrogen (after any allowed weighted averaging at the end of the calendar month). To ensure accurate calculation of the overall GHG emissions of the hydrogen produced, the GHG emissions associated with all electricity inputs must be monitored per 30-minute settlement period.

For low carbon electricity inputs, if the technical requirements can be met (links to low carbon generation, temporal correlation) the actual emissions intensity of the low carbon generation source in real time may be claimed (disallowing negative values). For grid connected electrolysers seeking to use grid imported electricity not linked to a specific generation source, actual national grid average emissions data per 30-minute electricity settlement period will be required in order to calculate the emissions intensity of the grid imported electricity used in hydrogen production.

4.2 General Requirements

Across all electricity inputs for hydrogen production, evidence needs to be provided that the hydrogen producer has exclusive ownership of the low carbon attributes of the electricity consumed to cover the amount of electrolytic hydrogen produced. This is to ensure that low carbon electricity used in hydrogen production is accounted for, avoiding the risk of the same electricity attribute information being claimed by another user on the system. This is expected to be a monthly reporting requirement, but further detail on exact reporting and audit requirements will be provided for any government scheme that applies the standard. This is in recognition that the current regime facilitates annual retrospective renewable energy matching. Examples of evidence requirement to meet this requirement are listed in Table 3 below, and include purchase, registration and retiring of Renewable Energy Guarantees of Origin (REGOs), or for non-renewable sources such as nuclear, suitable provisions in contracts to demonstrate electricity has been purchased and consumed and not onward sold. At regular review points we will continue to review the requirements for energy attribute information reporting, including options to increase the frequency of this reporting and the different evidence requirements across electricity input routes.

Actual data should be provided to demonstrate the electrolysis plant is consuming electricity at the same time (i.e. each 30 minute consignment) as the specified electricity generation source is generating electricity. This is required across all pathways that consume electricity, in order to provide certainty that the electricity consumed is linked across 30-minute electricity settlement period to the electricity generation.

4.3 Expected Eligibility Requirements for HMG Schemes Applying the Standard

Where electrolytic hydrogen production is not yet operational, hydrogen producers will be asked to provide evidence of planned sources of electricity input for low carbon hydrogen production, for example contracts with low carbon generation, and expected percentages of different input sources. Projected data (for further detail see section 10 of the main guidance) can be used to demonstrate how the hydrogen produced would meet the UK Low Carbon Hydrogen Standard e.g. with the use of projected national grid GHG intensity data for wholesale purchased grid electricity, and expected emissions intensities of low carbon generation sources, with evidence of how the technical requirements below will be met. For these purposes, projected or default data in the Data Annex can be used as a guide to calculate likely emissions. Further detail on exact reporting requirements will be provided for any government funding scheme that applies the standard.

4.4 Technical Requirements - Criteria for Low Carbon Electricity Input

Across all low carbon electricity inputs, the three criteria set out in Table 2 must be met in order to provide evidence the electricity used is low carbon. If all the three below criteria cannot be met, and where no evidence can be presented to demonstrate a direct link to electricity generation from identifiable low carbon electricity assets (e.g. temporal correlation and low carbon generation sourcing attributes), hydrogen consignment emissions should be calculated using actual average national grid electricity intensity data per 30-minute settlement period.

These criteria must be met to ensure producers can accurately calculate the emissions intensity of hydrogen produced via electrolysis, and to mitigate the risk of hydrogen production having negative impacts on the wider power sector, such as increasing emissions or causing constraints on the system. If these criteria are met, it is possible for a hydrogen consignment generated from a low carbon electricity source to use the actual emissions intensity for the low carbon electricity generation source (with a minimum intensity of zero) in its hydrogen emissions intensity calculations, factoring in any transmission/distribution losses.

Table 2: Technical Requirements to prove use of Low Carbon Electricity

Criteria	Description of Evidence / Accounting Requirements	Examples of Evidence Needed
1. Energy Attribute Information	• Hydrogen Producers must demonstrate exclusive ownership over the energy attributes of the low carbon electricity generated, to avoid the risk of double counting.	• Renewable Energy Guarantees of Origin (REGOs) registered and retired. • Where REGOs do not exist, e.g. for nuclear electricity, adequate provisions of ownership of electricity used in counterparty contractual information e.g. PPA or wholesale contract.
2. Low Carbon Electricity Generation Sourcing Attributes	• Hydrogen producers require evidence to prove that low carbon power has been sourced and consumed in the hydrogen production – proof of links to the claimed generation.	• Proof of links to a low carbon generation source, e.g. via Power Purchase Agreement (PPA), proof of internal sourcing, wholesale contract with a specific generator or other contractual arrangement.
3. Temporal Correlation Between Generation & Consumption	• Evidence low carbon electricity was consumed by the electrolysis plant matched to the 30-minute electricity settlement period of the electricity generation source.	• For on-site or wholesale/PPA linked low carbon generation; metering data is required linking the low carbon generator and hydrogen production facility per 30 minute settlement period.

4.5 Energy Attribute Information – Ownership

Energy Attribute Information for low carbon electricity should be verified where possible by a third-party verifier (e.g. evidence of registration and retiring of REGOs on the relevant register) to demonstrate exclusive ownership of the attributes of the electricity used, and demonstrating there has been no onward selling or other use of the energy attribute information used in hydrogen production. For nuclear electricity used in hydrogen production, given no REGO system exists, adequate provisions of ownership of the attributes of the electricity used will be required in counterparty contractual information e.g. PPA or wholesale contract demonstrating there has been no onward selling of energy attribute information used in hydrogen production. The reason this is required is to ensure there is no double counting of the low carbon attributes of electricity claimed in the system. As set out in 4.2, this is expected to be a monthly reporting requirement; but further detail on exact reporting and auditing requirements will be provided for any government scheme that applies the standard.

4.6 Low Carbon Electricity Generation Attributes

Evidence is required that low carbon electricity generation has been sourced or purchased and consumed in hydrogen production, to prove the hydrogen producer has a link to the low carbon source for the settlement periods being claimed. Hydrogen producers should be able to demonstrate evidence underpinning where the electricity used in hydrogen production has been sourced from, for example via a wholesale purchase agreement or PPA e.g. generator name, PPA in place and location.

4.7 Temporal Correlation

This is required across all low carbon electricity inputs to provide certainty that the electricity generation is linked across 30-minute electricity settlement period to the hydrogen production. This is expected to be able to be provided via appropriate metering during hydrogen production and low carbon electricity generation. Where tracing of physical low carbon electricity generation linked to a specific low carbon source is not possible through temporal correlation, the actual average GHG intensity of the national grid at the time the electricity was consumed must be used instead.

4.8 Expected GHG intensity across different sources of electricity generation

Table 3 provides the expected GHG intensity of different sources of generation, provided the requirements in Table 2 are met.

Table 3: Requirements and expected GHG intensity of different sources of electricity generation

Case	Description	Energy Attribute Information[1]	Low Carbon Electricity Generation Attributes[2]	Temporal Correlation[3]	GHG Intensity
1	Off-grid dedicated generation (physical links)	Required: REGOs retired or other proof of ownership of attributes associated with the electricity consumed	Required: PPA or other behind the meter contract	Required: generation metering data matched to electrolyser consumption per 30 minutes	Depends on generation source but likely low carbon.
2	Power Purchase Agreement (Sleeved, Virtual or Shaped)	Required: REGOs retired or other proof of ownership of attributes associated with the electricity consumed	Required: PPA details proving links to the associated generation	Required: generation metering data matched to electrolyser consumption per 30 minutes	Sleeved PPAs – If these contracts provide adequate temporal correlation data e.g. on an as-produced basis - likely low carbon. Virtual PPAs – Where temporal correlation cannot be proven between generation assets and hydrogen production, an actual national grid average carbon intensity should be reported per settlement period. Shaped PPAs - Where tracing of physical power is not possible, the actual

[1] Energy Attribute Information is provided via REGOs or other contractual information demonstrating exclusive ownership & cancellation of energy attributes

[2] Low Carbon Generation Attributes are provided via contractual information e.g. contractual information such as a PPA, or wholesale contract

[3] Temporal Correlation data is provided via metering data from the generation assets and hydrogen production per 30 min settlement period

Case	Description	Energy Attribute Information[1]	Low Carbon Electricity Generation Attributes[2]	Temporal Correlation[3]	GHG Intensity
					national grid average intensity should be used. However, if low carbon generation/ consumption can be evidenced using metering data, it may be deemed low carbon. Where the grid is used, transmission and distribution losses should be factored into emissions calculations.
3	Wholesale purchase from a specific low carbon generator	Required: REGOs retired or other proof of ownership of attributes associated with the electricity consumed	Required: Contractual details covering ownership of the associated generation for the period/consignments being claimed as low carbon	Required: generation metering data matched to electrolyser consumption per 30 minutes	Depends on generation source but likely low carbon. Where the grid is used, transmission and distribution losses should be factored into emissions calculations.
4	Wholesale/ retail grid import	Required: REGOs cancelled to cover all grid import use	Not required[4]	Required: national grid average carbon intensity matched to electrolyser	Will reflect the actual average GHG intensity of the national grid per settlement period; transmission and distribution losses should

[4] For grid imported electricity not linked to a generation source, no links are required via contractual information, given this cannot be a tied to a specific generation asset.

Case	Description	Energy Attribute Information[1]	Low Carbon Electricity Generation Attributes[2]	Temporal Correlation[3]	GHG Intensity
				consumption per 30 minutes	be factored into emissions calculations.
5	Curtailed electricity	Required: REGOs or other proof of ownership of attributes associated with the electricity consumed	Required: Evidence requirements are set out on the right-hand side, with further detail provided for relevant schemes using the Standard.	Required: curtailed electricity matched to electrolyser consumption per 30 minutes	Can be deemed low carbon provided adequate evidence is provided electricity would have been wasted. Can be evidenced through emergency instruction from the National Grid ESO, relevant Distribution Network Operator or through contractual evidence in the balancing mechanism or ancillary services. Further detail may be provided on these evidence requirements in guidance related to relevant schemes applying the standard for government funding.

4.9 Treatment of consignments for electrolytic hydrogen production

As set out in section 8 of the main guidance, the Standard will have a consignment basis for the treatments of mixed inputs, allowing for either discrete consignments from a single measurable input or averaged consignments based on the average of multiple discrete consignments. To summarise:

- All electricity inputs shall have a discrete consignment size of 30 minutes.
- Real time tracking of generation and consumption (temporal correlation) is required across all 30-minute consignments
- Different types of discrete consignment will need to track GHG emissions intensities in different ways:

- Off-grid physical links must provide generation data matched to hydrogen production consumption per 30 mins
- Direct or sleeved PPA must provide generation data matched to hydrogen production consumption per 30 mins (accounting for all transmission and distribution losses)
- Wholesale grid import must provide actual national grid carbon intensity data per 30 minutes matched to consumption for hydrogen production (accounting for all transmission and distribution losses) using data provided by NGESO

  Where a mix of renewable, nuclear, other low carbon electricity and/or wholesale grid import are used this should be separated into individual discrete consignments within the 30-minute period with the % of each input clearly matched to hydrogen output volumes (and with all transmission and distribution losses factored in).

4.10 Sources of data for tracing consignments' GHG intensity

As set out above, temporal correlation data is required per 30-minute settlement period across all electricity input routes. For grid imports, national grid average GHG intensity data is available from National Grid ESO[5] or can be provided using Elexon approved metering solutions, so hydrogen producers can provide actual carbon intensity data for each 30-minute consignment of hydrogen produced, to create a discrete grid imported consignment.

Further detail will be provided to hydrogen producers on the exact methodology and metering requirements for matching real time carbon intensity of electricity generation to hydrogen production consumption, including the types of metering and other evidence requirements for relevant schemes applying the standard for HMG funding.

For hydrogen produced via electrolysis, discrete consignments would be determined by the electricity input source(s) in question. For example, a discrete consignment of hydrogen may be produced by a directly connected wind farm, wholesale grid imported electricity, or a wind farm connected through to the grid via a PPA (assuming temporal correlation proves that supply is sufficiently low carbon). Further detail regarding consignments is set out in chapter 8 of the main guidance.

4.11 Additionality

The UK Low Carbon Hydrogen Standard will not include a mandatory 'additionality' requirement that hydrogen production must be linked to specific types of generation asset e.g. new build unsubsidised sites, or only using curtailed electricity. However, we recognise that projects that comply with additionality principles can bring electricity system benefits and

[5] Real time grid intensity data is provided through the National Grid ESO sources, e.g. Carbon Intensity Dashboard, and through other real time sources such as Energy Dashboard. Historic data is provided via National Grid ESO's Historic Generation Mix

emissions reductions compared to other projects. Therefore, we have developed a set of additionality principles that may apply to specific assessment criteria for government funding. Further details on these principles, and how they may be applied in criterion is provided in the UK Low Carbon Hydrogen Standard Consultation Response and via other relevant funding application eligibility and assessment documentation.

4.12 Accounting for electricity use in other hydrogen production pathways

Although not a feedstock, electricity can represent a relatively significant source of additional GHG emissions in other hydrogen production pathways. Therefore, for electricity used in non-electrolytic hydrogen production, there should be real time tracking of electricity inputs and consumption across all 30-minute intervals, in the same way as is set out for electrolytic hydrogen production.

If the technical requirements and evidence for low carbon electricity use can be demonstrated to have been met by non-electrolytic hydrogen producers (see above electrolytic requirements in this annex), the actual GHG intensity of the low carbon generation used in hydrogen production can be correlated to the electricity used. Otherwise, the average national grid intensity data per 30-minute settlement period should be used. 30-minute discrete consignments can be made based on the emissions of the electricity used in that 30-minute period.

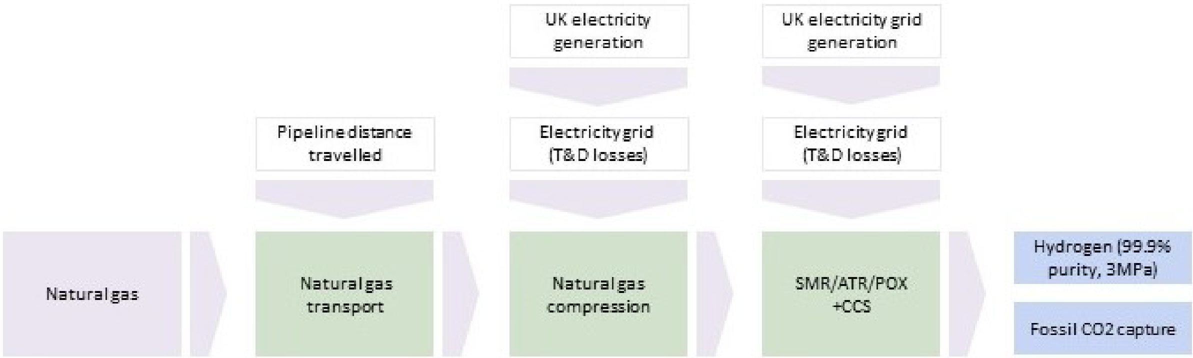
Where a non-electrolytic hydrogen production facility is not yet operational, illustrative data will be required e.g. average annual national grid GHG intensity data for wholesale grid imported electricity (using UK Green Book projections), and expected emissions intensity of low carbon generation sources, with evidence of how the technical requirements will be met, where relevant.

Annex B: Hydrogen production pathway – Fossil fuel reformation with CCS

1. Process Descriptions

There are several types of hydrogen production pathways producing hydrogen and CO_2 from a gas or fossil fuel source. The main current pathways, steam methane reformation (SMR), auto thermal reformation (ATR) and partial oxidation (POX) are described in the relevant sections below.

The main simplified block flow diagram for these three technologies can be found here:



1.1 SMR with CCS Process Description

A Steam Methane Reformer (SMR) is a mature production process in which an external heat source provides high-temperature steam for the endothermic reforming reaction that produces hydrogen and CO_2 from a gas source, such as methane, by using a catalyst.

There are two main sources of CO_2 emissions: the CO_2 that is produced alongside hydrogen in the reforming reaction, and the CO_2 produced by the external heat source that provides the high-temperature steam for the reaction and the heat to the endothermic reforming reaction. In Steam Methane Reforming, methane reacts with steam and is converted to hydrogen and carbon monoxide by using a catalyst. The carbon monoxide produced as part of the methane steam reaction then reacts with steam (water-gas shift reaction) increasing the hydrogen yield and producing CO_2.

1.2 ATR with CCS Process Description

In Autothermal Reforming (ATR), methane is first partially oxidised by oxygen to produce hydrogen and carbon monoxide. Contrary to the steam methane reformer, the autothermal reactor does not require any heat from an external furnace (although other external heating operations may still be required, such as pre-heaters). The partial oxidation reaction is exothermic and provides the required heat to the steam reforming reaction in which methane and steam reacts to produce carbon monoxide and hydrogen in the reformer fixed catalyst bed.

Oxygen required for the partial oxidation reaction is separated from air in generated an air separation unit, typically cryogenically. The partial oxidation reaction occurs in the top section of the autothermal reformer. The top section is fitted with a burner where methane and oxygen are mixed in a diffusion flame.

1.3 POX with CCS Process Description

In partial oxidation, methane is first partially oxidised by oxygen to produce hydrogen and carbon monoxide. The partial oxidation reaction is exothermic. The heat produced through the reaction would normally be recovered through the downstream heat recovery process to generate steam from boiler feed water and to preheat other processes to maximise energy efficiency. As with ATR, POX typically requires oxygen for the partial oxidation step, generated in an air separation unit.

2. Emissions sources in SMR, ATR and POX with CCS

For steam methane reforming with CCS plants, the main source of GHG emissions onsite is likely to be the release of non-stored CO_2 through the conversion of natural gas (NG). Other likely significant emissions sources include the Scope 2[6] emissions of grid electricity input, CO_2 removal, CO_2 compression and transport for CCS, hydrogen compression and the air separation unit for ATR and POX. Each process unit or stage in the pathway contains emissions sources outlined in Table 4, although this is not an exhaustive list of emissions sources.

Producers should refer to Annex A 4.12 for the methodology for their electricity use accounting.

Table 4: GHG emissions summary for SMR, ATR and POX with CCS pathways

Process unit/stage	**Key emissions sources**	**Other emissions sources**
Upstream natural gas extraction and processing	Electricity and/or fuel combustion for NG extraction and processing Fugitive methane (venting, leaks) and/or carbon dioxide (flaring)	

[6] See definition in section 2 of the guidance document.

	from NG extraction and processing	
NG transport	Electricity and/or fuel combustion for materials movement Methane leakage	
Heat recovery and electricity generation	No significant emissions other than those covered under common emissions sources	
Auxiliary Heating Processes	Electricity and/or fuel combustion to provide auxiliary heat, e.g. in pre-heaters	
Air separation	Electricity or fuel combustion to separate oxygen from air to feed reformer (ATR and POX only)	
CO_2 and H_2 purification	Electricity and/or heat for operation of the relevant purification units	Exhaust CO_2 due to sulphur removal of exhaust gases (where applicable)
Hydrogen enrichment	Electricity and/or heat to supply water gas shift reactions occurring as part of hydrogen enrichment (if required)	
CO_2 capture and separation	Chemicals, electricity and/or heat for relevant separation units Residual CO_2 which is not captured for permanent storage	Changes in actual capture rate because of T&S network outages Fugitive carbon dioxide emissions prior to entry into T&S network

Compression and transportation of CO_2	Electricity for compression of CO_2 Electricity and/or gaseous fuel combustion for pipeline transport Liquid and/or gaseous fuel combustion for motive transport	Fugitive carbon dioxide from CO_2 compression and transportation prior to entry into the T&S network[7]
Storage of CO_2	Electricity and/or fuels for injection or transformation	
Hydrogen purification, compression and storage	Electricity for purification, compression and storage operations	*Fugitive hydrogen emissions*[8]
Input materials	Water, chemicals, replacement catalysts and oxygen if from third party supplier	

3. Natural gas upstream emissions

Hydrogen producers receiving their natural gas through direct connection to the UK gas network are required to use the average UK gas network value provided in the Data Annex section 3 to account for the emissions from the natural gas. This value will be updated regularly to maintain an accurate representation of the UK gas grid. Contractual arrangements with natural gas or other fossil fuel facilities will only be considered if the natural gas does not transit via the UK gas network. If hydrogen producers receive their natural gas through a contractual arrangement with a facility and that this gas does not transit via the UK gas network, they will be required to provide actual data.

[7] Fugitive CO_2 from the T&S network and geological CO_2 storage sites are not accounted for as part of the hydrogen emissions calculation under the standard.
[8] The impacts of hydrogen as an indirect GHG have not been considered as part of produced hydrogen emissions calculations given current focus on (direct) GHG emissions accounting, and separate risk reporting.

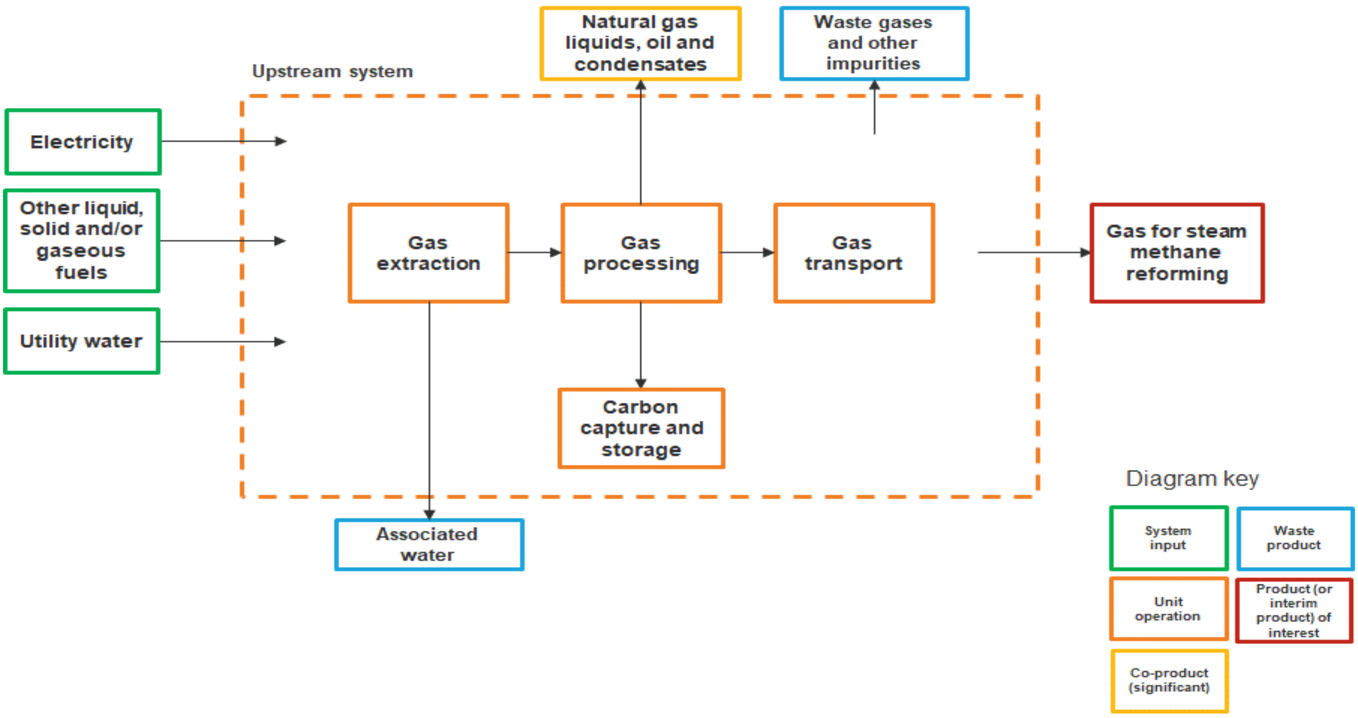
Where producers are receiving their natural gas through other means and not through the UK gas network (for example through direct pipeline or shipping) and have a contractual arrangement with a gas facility, they are expected to provide:

- the commercial arrangements of the supply of natural gas;
- the location of natural gas production;
- the planned route and mode(s) of delivery to the hydrogen production process from the point of natural gas production and associated emissions.

Producers providing actual data should report all of the emissions associated with the natural gas extraction, processing and transport from extraction point to the hydrogen production facility.

This includes:

- For the upstream natural gas extraction and processing: the electricity and/or fuel combustion for NG extraction and movement and the fugitive methane and/or carbon dioxide from NG extraction.
- For the natural gas transport: the electricity and/or fuel combustion for materials movement and methane leakage.
- Should natural gas from a facility enter the relevant UK gas network from the importing country, the grid average emissions should be accounted for (in line with the methodology set out below) rather than facility specific data. Emissions from compression and those associated with the transportation of the natural gas to the hydrogen production facility in the UK should also be accounted for.



3.1 Extraction and processing

When providing actual data, producers are expected to provide emissions from the following gases: CO_2, nitrogen oxides, N_2O, sulphur dioxide, carbon monoxide, CH_4 and volatile organic compounds.

Annual emission data for each of the gases listed in above must be submitted for each of the 3 emission types and associated sources, listed in Table 5 below, with the exception of PCF, SF_6, HFC, Halons, CFC and HCFC, which are given for the whole facility (see below).

Table 5: Emission sources to be accounted for in gas facilities

Type/Source	Installation	Terminal
Consumption		
Gas Consumption – Plant Operations	Y	Y
Diesel Consumption – Plant Operations	Y	Y
Fuel Oil Consumption – Plant Operations	Y	Y
Gas Flaring	Y	Y
Direct Emission		
Gas Venting	Y	Y
Direct Process Emissions	Y	Y
Oil Loading	Y	Y
Storage Tanks	N	Y
Fugitive Emissions	Y	Y

Drilling		
Well Testing	Y	N
Diesel Consumption	Y	N

The consumption and drilling emission sources involve the combustion of fuel gas, flare gas, diesel and fuel oil. The direct emission sources, as the name suggests, involve the direct release of emission gases to the atmosphere. By aggregating the emission data across all emission sources and types the total mass for each emission gas can be calculated for each operated installation and terminal.

A further group of gases, the halogenated compounds, used in firefighting and refrigeration, must also be reported: Chlorofluorocarbons, Hydrochlorofluorocarbons, Halons, Hydrofluorocarbons, Perfluorocarbons, Sulphur hexafluoride. Quantities of halogenated compounds stored at each installation and terminal must be reported. Emissions data for species of the last three compounds, HFC, PFC and SF_6, must be reported as CO_2 equivalent emissions. Details of these calculations can be found in Section 9 and Annex F of Atmospheric Emissions Calculations document on this page: https://www.gov.uk/guidance/oil-and-gas-eems-database

3.2 Gas transport

If gas is transported via the UK gas network, producers are expected to use the average UK natural gas network value provided in the Data Annex section 3, which covers both gas transport and upstream extraction & processing emissions.

The natural gas may be moved in other forms of transport including road trailers or tankers, trains and ships. It may be moved in a compressed gaseous form or as a liquid. It may also be contained as a gas or a liquid in storage facilities. LNG and other storage facilities may be directly connected to a pipeline grid although this is not always the case.

All movements of natural gas on/off or into/out of the transport or infrastructure anywhere in the supply chain should be accounted for and evidenced to the reporting party's verifier. This applies anywhere in the world, whether as gas or liquid. In each case the gas quantities should be accounted for using the normal underlying rules of the transport or infrastructure operator.

Where gas is moved from/to pipeline infrastructure from/to any other type of infrastructure (such as storage or liquefaction/compression facilities) there must be a direct physical connection between the infrastructure concerned, otherwise information on the means of transport between them must also be provided.

3.3 Allocation method

Where facilities produce liquid hydrocarbons and gas, a LHV energy allocation method should be used to allocate GHG emissions between (co-)products.

4. Other fossil gases upstream emissions

Producers may choose to use other fossil feedstocks, such as refinery off-gases and other co-products from fossil fuel production processes. Where the co-product from another intermediate process (e.g. a refinery) is used as an input to the hydrogen production process, a LHV energy allocation method should be used to partition the intermediate processing emissions i.e. dividing the emissions between the hydrogen production feedstock and other co-products. The allocation should be based on the LHV energy content of the (co-)products, following Section 6.4.10 of the main guidance.

5. CO_2 capture and sequestration for fossil fuel reformation with CCS pathways

Only CO_2 capture with permanent geological storage underground is considered as CO_2 sequestration. CO_2 capture and utilisation (CCU) will not be given sequestration credits under the standard, meaning that CO_2 captured and utilised is to be considered as being emitted to the atmosphere.

Emissions associated with the compression, transport and entry of CO_2 into the network should be accounted for until the point of transfer to the CO_2 T&S (transport & storage) network operator. Any fugitive CO_2 emissions once the CO_2 liability has been transferred to the CO_2 network operator are outside of the scope of the standard.

In case of outages in the CO_2 transport and storage network, producers may need to vent the CO_2 they have captured. CO_2 vented by the producer will be considered as not having been sequestered for the purpose of calculating the hydrogen emissions intensity, but producers are still expected to report the emissions associated with operating the CO_2 capture equipment if this occurs.

Annex C: Hydrogen production pathway – Biogenic feedstock inputs (with CCS)

Biogenic feedstock inputs are derived from biomass. Biomass is defined as any material of biological origin (including biodegradable fraction of products, wastes and residues from biological origin).

1 Biogenic Feedstocks

Biogenic feedstocks could include:

- Conventional food and feed crops
- Food and agricultural waste (e.g. home food waste collection)
- Perennial energy crops (e.g. Miscanthus grass) and short rotation coppice (e.g. willow/poplar)
- Short rotation forestry (e.g. birch)
- Agricultural residues, forest residues & residues from processing
- Marine-based and novel feedstocks (e.g. algae)

Note that this list is not exhaustive – for any feedstocks used in the production process which are not listed above, the definition of biomass (provided above) should be taken as a guide to whether the feedstock in question, or a component of it, is biogenic.

Regardless of feedstock type and mix, it is likely that the feedstock will require some treatment, storage and transportation ahead of use in hydrogen production.

1.1 Biogenic feedstock requirements

Biogenic feedstocks used as an input to hydrogen production must meet certain sustainability criteria, the details of which are outlined in Annex D. These closely follow those set out in the Renewable Transport Fuel Obligation (RTFO).

To comply with the standard, biogenic feedstock use in hydrogen production must comply with the GHG threshold and the sustainability criteria. Failure to comply with either of these conditions means that the associated hydrogen production is not considered compliant with the standard.

In addition, where the biogenic feedstock concerned is converted to biomethane and then stored or moved prior to being utilised in hydrogen production, the guidance set out in Annex E should be adhered to. Meeting these requirements ensures that biomethane with certain sustainability characteristics can be claimed by the reporting party, when seeking to demonstrate compliance with the standard.

1.2 Minimum waste and residue requirement

For each facility producing hydrogen from a biogenic feedstock, at least 50% of the biogenic hydrogen produced (by LHV energy content) must be derived from biogenic feedstocks which can be classified as wastes or residues (see section 2 of the main guidance for definitions). This requirement also applies to electrolysis pathways that source their input energy from specific bioenergy generation plants, whereby these specific bioenergy generation plants have to show this 50% threshold is met for the feedstocks they use.

- Before a facility is in operation, evidence should be provided of commercial arrangements (with suppliers of wastes and/or residues) which ensure that this minimum threshold can be met.
- For the purpose of ongoing compliance, the producer will need to meet the minimum threshold on the basis of a weighted average across all consignments of biogenic hydrogen produced in a calendar month (independent of which consignments are chosen to be included in the GHG emissions weighted average for that month).

2 Process Description

Hydrogen production from biogenic feedstocks can refer to a number of different conversion processes. These can be categorised as:

- Thermochemical (e.g. gasification, pyrolysis, steam biomethane reforming)
- Biological (e.g. dark fermentation, photo-fermentation)
- Electrochemical (e.g. microbial electrolysis)

Thermochemical production routes are the most technologically mature, and therefore are the focus of this annex. In general, these can be categorised as one of:

- Biomethane reforming, which may involve: (a) feedstock pre-treatment, (b) bio-digestion (e.g. anaerobic digestion) and biogas pre-treatment (e.g. upgrading to biomethane) (c) reforming, (d) high-temperature shift reaction and (e) pressure swing adsorption.
- Gasification, which may involve: (a) feedstock pre-treatment, (b) gasification (and combustion) (c) reforming (if combustion is also part of the process), (d) high-temperature shift reaction and (e) pressure swing adsorption.

However, hydrogen production from biogenic feedstocks is at a nascent stage, especially with CCS. Due to this and the range of potential available feedstocks, it is difficult to define standardised production pathways.

In biomass routes, biogenic CO_2 emissions are produced during gas processing (in the pre-treatment phase), reforming and high-temperature reactions, and the combustion in the pressure swing adsorption phase. Non-biogenic CO_2 emissions may be associated with feedstock transportation, electricity inputs, and other energy inputs for the production system.

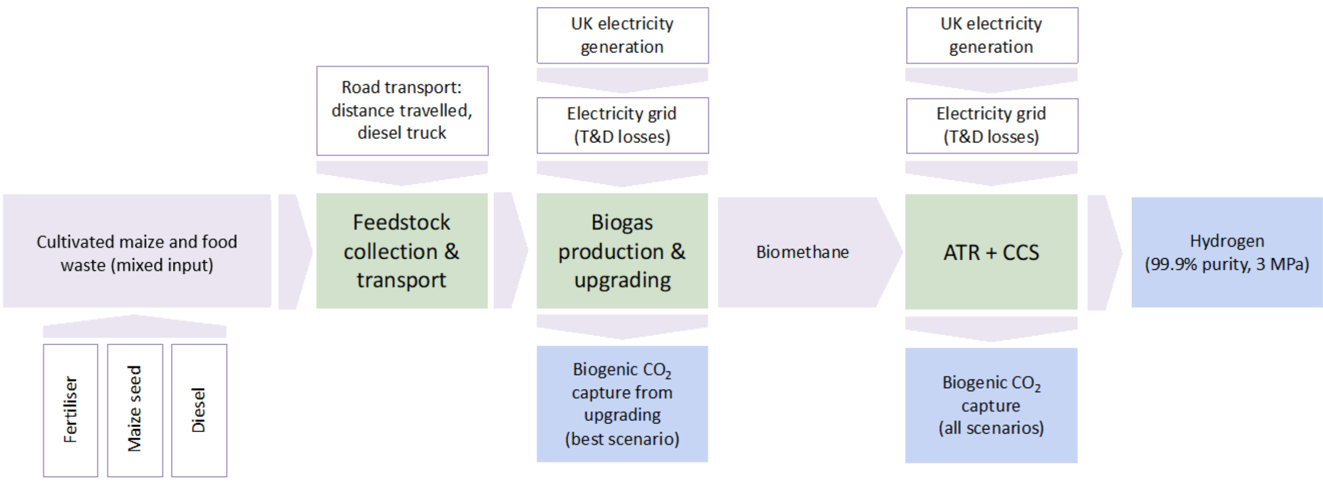
Due to similarities to coal gasification and SMR processes, similar CO2 capture technologies and processes are likely to be used for the biomass pathway. Depending on the facility and the biomass conversion process, CO_2 may be captured by different means such as chemical solvents, physical solvents and pressure swing adsorption.

3 Process Overview

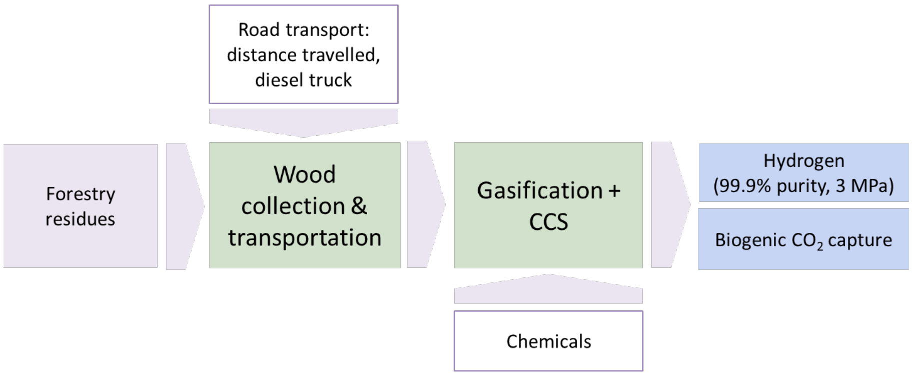
The process of hydrogen production from biogenic feedstocks chiefly vary according to the type of feedstock(s) and the conversion technology (technologies) used. Other factors, such as the inclusion of CCS, are also significant points of variation between production processes.

For indicative purposes, simplified flow diagrams are shown in the figures below for three different hydrogen production processes using biogenic, or partly biogenic, feedstocks. Note that where the feedstock is a mix of biogenic and non-biogenic components, as in example C, the biogenic and non-biogenic components are treated as distinct inputs, leading to discrete hydrogen consignment outputs.

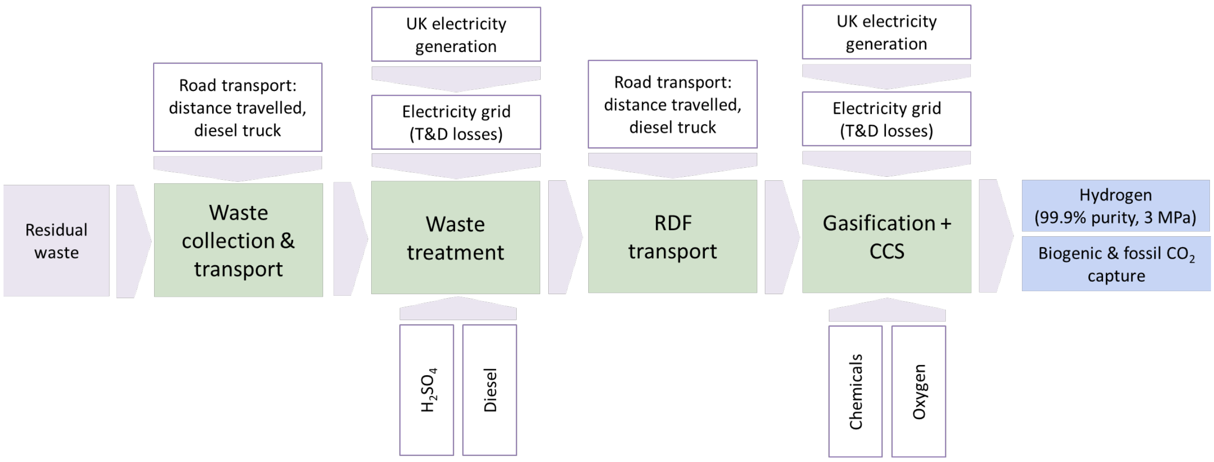
A) Biomethane ATR with CCS using food waste and maize feedstocks



B) Forestry residue gasification with CCS



C) Residual waste gasification with CCS



4 Emission Sources

Note that where CO_2 emissions arise directly from treatment of the biogenic feedstock, or its derivatives (e.g. biogas), they are biogenic. It is assumed that these biogenic CO_2 emissions have a neutral effect on atmospheric CO_2 concentration, and therefore are counted as zero-emission (a nil GWP)[9].

If these biogenic CO_2 emissions are captured and permanently stored, the resulting hydrogen could have a negative emissions intensity, if the CO_2 sequestration term in the calculations is large enough, and subject to the conditions around sequestered CO_2 (outlined in the main body of this document) being satisfied.

The emission sources listed below may not apply to every hydrogen production process which uses biogenic feedstocks, or there may be additional emission sources not listed here – those listed in Table 6 are only illustrative.

[9] However, biogenic GHG emissions with a non-neutral impact on atmospheric GHG concentrations are accounted for as equal to fossil GHG emissions, including CO_2 emissions from land use change, and all CH_4 and N_2O emissions.

Table 6: GHG emissions summary for biomass and waste

Process unit/stage	**Key emissions sources**	**Other emissions sources**
Feedstock cultivation (for non-wastes, non-residues)	Annualised emissions from direct land use change associated with feedstock cultivation (applies to agricultural residues too) Crop cultivation, harvesting, storage and movement	
Feedstock processing & transport	Electricity and/or liquid fuel combustion for feedstock treatment and movement Fugitive methane and/or (biogenic) CO_2 from biogas upgrading	Water and oxygen consumption for feedstock treatment
Heat recovery and electricity generation	No significant emissions other than those covered under common emissions sources	
Hydrogen enrichment	Water gas shift reactions occurring as part of hydrogen enrichment	
Syngas purification	Electricity and/or heat for operation of the relevant purification units	Exhaust CO_2 due to sulphur removal of exhaust gases (where applicable)
CO_2 capture and separation	Chemicals, electricity and/or heat for relevant separation units Residual CO_2 which is not captured for permanent storage	Changes in actual capture rate because of T&S network outages Fugitive carbon dioxide emissions prior to entry into T&S network
Compression and transportation of CO_2	Electricity for compression of CO_2 Electricity and/or gaseous fuel combustion for pipeline transport	Fugitive carbon dioxide from CO_2 compression and transportation prior to entering T&S network

	Liquid and/or gaseous fuel combustion for motive transport	
Storage of CO_2	Electricity or liquid/gaseous fuels consumed for injection or transformation	
Hydrogen purification, compression and storage	Electricity for purification, compression and storage operations	

5 Land-use change

5.1 Direct land-use change

Land-use change can occur due to the cultivation of feedstock for hydrogen production. Direct land-use change describes the land-use change which occurs within the land used to create the feedstock. Most commonly, it refers to previously uncultivated land (e.g. forest, peatland, grassland) being converted for agricultural use.

Annualised emissions from carbon stock changes caused by direct land-use change[10] shall be calculated by dividing total emissions equally over 20 years. These emissions should be calculated as follows[11]:

$e_l = (CS_R - CS_A) \times 3.664 \times (1/20) \times (1/P)$

Where:

- e_l = the annualised GHG emissions from carbon stock change due to land-use change (in gCO_2e/MJ). 'Cropland'[12] and 'perennial cropland'[13] shall be regarded as one land use;
- CS_R = the carbon stock associated with the reference land use (i.e. the land use in January 2008 or 20 years before the feedstock was obtained, whichever was later) (in gC/ha);

[10] Emissions related to indirect land-use change are covered in the next section. The impact of land-use change is not applicable to hydrogen derived from wastes and non-agricultural residues.
[11] The quotient obtained by dividing the molecular weight of CO_2 (44,010 g/mol) by the molecular weight of carbon (12,011 g/mol) is equal to 3,664.
[12] Cropland as defined by IPCC.
[13] Perennial crops are defined as multi-annual crops, the stem of which is usually not annually harvested such as short rotation coppice and oil palm.

- CS_A = the carbon stock associated with the actual land use (in gC/ha). In cases where the carbon stock accumulates over more than one year, the value attributed to CSA shall be the estimated stock per unit area after 20 years or when the crop reaches maturity, whichever was earlier;
- P = the productivity of the crop (in MJ/ha/y).

Calculation of carbon stock for land-use change emissions (CS_R and CS_A)

The equation provided above should be used for reporting emissions relating to direct land-use change. The key part of the land-use change calculation is an estimation of the change in carbon stocks. This is based on the difference between the carbon stock now and the carbon stock in January 2008 (or 20 years before the feedstock was obtained, whichever is the later date).

Carbon stock can be calculated using the following equation:

$CS_i = SOC + C_{VEG}$

Where:

- CS_i is the carbon stock of the land
- SOC is the soil organic carbon (in gC/ha)
- C_{VEG} is the above and below-ground vegetation carbon stock (in gC/ha)

Carbon stock estimates are based on a number of key parameters which should be determined by reporting parties:

- previous land use
- climate and in some cases ecological zone
- soil type
- soil management (for both previous and new land use)
- soil input (for both previous and new land use)

Definitions of the different land use categories for determining previous land use are provided below:

- Cropland – non-protected: this category includes cropped land, (including rice fields and set-aside), and agroforestry systems where the vegetation structure falls below the thresholds used for the forest categories[14]. The cropland is not in a nature-protected area.

[14] Note that perennial crop plantations are classed as cropland under this standard

- Cropland – protected – no interference with nature protection purpose: same as above, but the cropland is in a nature protection area and the production of the raw material did not interfere with the nature protection purpose.
- Cropland - protected/protection status unknown: this category of cropland should be used where:

    a) the cropland had protected status but evidence could not be provided that there was no interference with the nature protection purpose; or

    b) the protection status could not be determined.

- Grassland (and other wooded land not classified as forest): this category includes rangelands and pasture land that are not considered cropland, but which have an agricultural use. It also includes grasslands without an agricultural use, but excludes highly biodiverse grassland and cropland lying temporarily fallow for less than 5 years. It additionally includes systems with woody vegetation and other non-grass vegetation such as herbs and brushes that fall below the threshold values used in the forest land categories including both those with and without an agricultural use. It includes extensively managed rangelands as well as intensively managed (e.g. with fertilisation, irrigation, species changes) continuous pasture and hay land.
- Highly biodiverse grassland: this is defined as any grassland spanning more than one hectare which is included as a priority grassland habitat under the UK Biodiversity Action Plan[15]. For grasslands located outside of the UK, definitions of highly biodiverse grassland according to the relevant competent authority in that country may be used. This category cannot be reported for natural grassland that is highly biodiverse. It should only be reported for non-natural highly biodiverse grasslands that would cease to be grassland in the absence of human intervention, where evidence is provided that harvesting of the raw material is necessary to preserve its grassland status.
- Highly biodiverse forest: highly biodiverse forest and other wooded land which is species-rich and not degraded[16].
- Forest greater than 30% canopy cover: continuously forested areas, namely land spanning more than one hectare with trees higher than five metres and a canopy cover of more than 30%, or trees able to reach those thresholds in situ.
- Forest 10 to 30% canopy cover: land spanning more than one hectare with trees higher than five metres and a canopy cover of between 10% and 30%, or trees able to reach those thresholds in situ.
- Wetland: land that is covered with or saturated by water permanently or for a significant part of the year.

[15] Further guidance on what constitutes a priority grassland habitat is also available in Annex 2 of the JNCC Guidelines for the Selection of Biological Sites of Special Scientific Interest (SSSIs).

[16] More specific guidance on how to determine if land is highly biodiverse forest will be provided as soon as it is available.

- Undrained peatland: this is peatland that was not completely drained in January 2008 (or 20 years before the feedstock was obtained, whichever is the later date). This includes peatland that was not drained at all and peatland that was partially drained.
- Settlement: includes all developed land, including transportation infrastructure and human settlements of any size, unless they are already included under other categories. Examples of settlements include land along streets, in residential (rural and urban) and commercial lawns, in public and private gardens, in golf courses and athletic fields, and in parks, provided such land is functionally or administratively associated with particular cities, villages or other settlement types and is not accounted for in another land use category[17].

Climate, ecological zone and soil type can be taken from maps and data provided by the Joint Research Centre (JRC) and the Food and Agriculture Organisation of the United Nations (FAO) - it will be necessary therefore for reporting parties to determine the exact location of the land-use change. Soil management (whether full-till, reduced-till or no-till) and soil inputs (low, medium, high-with manure, and high-without manure) are factors that also need to be determined and included in the calculations.

In most cases, it is possible to use the information above to find the values for the different parameters in the look-up tables in the RTFO standard values. However, under certain conditions, actual carbon stock measurements or other calculation methodologies will need to be undertaken e.g. if the soil is a histosol or if no value exists in the look-up tables. In the absence of specified carbon stock, it is required that the carbon stock is measured for any settlement or degraded land converted for hydrogen production.

Soil organic carbon - mineral soils

Reporting parties may use several methods to determine soil organic carbon, including measurements[18]. When measurements are not used, the method used shall take into account climate, soil type, land cover, land management and inputs.

As a default method, the following equation can also be used:

$SOC = SOC_{ST} \times F_{LU} \times F_{MG} \times F_I$

Where:

- SOC_{ST} is the standard soil organic carbon in the 0 - 30 cm topsoil layer (in gC/ha)
- F_{LU} is the land use factor reflecting the difference in soil organic carbon associated with the type of land use compared to the standard soil organic carbon (no unit)

[17] This definition is taken from the 2006 IPCC Guidelines for National GHG inventories (Vol 4).
[18] Soil organic carbon levels can traditionally be measured using mass loss on ignition or wet oxidation. However, newer techniques are being developed, which can either be carried out in the field or remotely (near-infrared reflectance spectrometry, remote hyperspectral sensing).

- F_{MG} is the land use factor reflecting the difference in soil organic carbon associated with the principle management practice compared to the standard soil organic carbon (no unit)
- F_I is the land use factor reflecting the difference in soil organic carbon associated with different levels of carbon input to soil compared to the standard soil organic carbon (no unit)

SOC_{ST} can be looked up in the RTFO standard values available online depending on climate region and soil type. The climate region can be determined from the climate region data layers produced by the JRC and available online. The soil type can be determined by following the flow diagram in Figure 2 or following the soil type data layers produced by the JRC and available online.

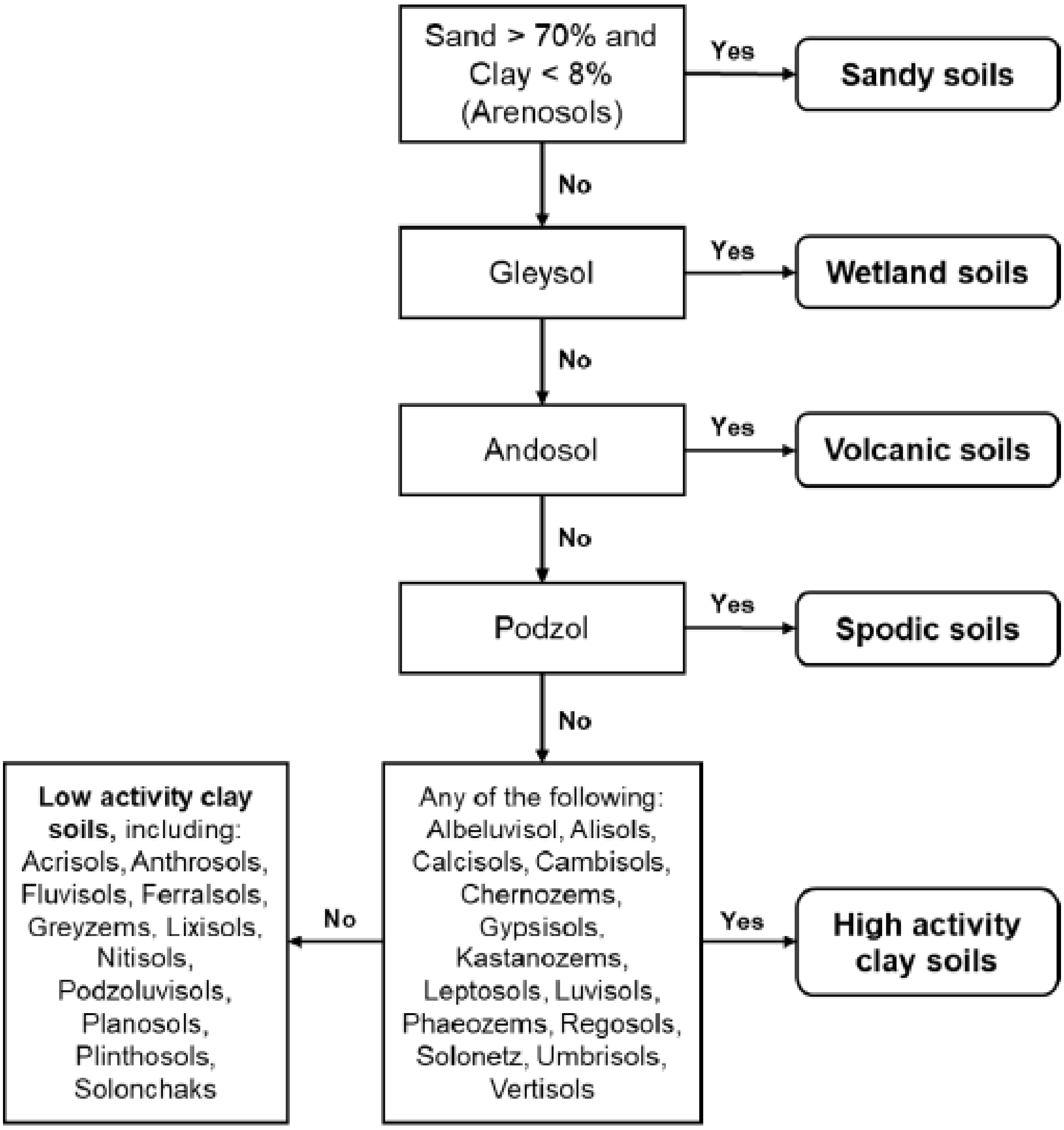


Figure 2: Flow diagram for classifying soil type

F_{LU}, F_{MG} and F_I can be looked up in the RTFO standard values available online depending on climate region, land use, land management and input.

Soil organic carbon - organic soils (histosols)

No default method is available for determining the SOC value of organic soils. The method used by reporting parties should however take into account the entire depth of the organic soil layer as well as climate, land cover, land management and input. Such methods may include measurements.

Where carbon stock is affected by soil drainage, losses of carbon following drainage shall be taken into account by appropriate methods, potentially based on annual losses of carbon following drainage.

Above and below-ground vegetation carbon stock

For some vegetation types, C_{VEG} can be directly read from RTFO standard values available online. Relevant ecological zones can be determined from maps produced by the FAO.

If a look-up value is not available, vegetation carbon stock shall take into account both above and below-ground carbon stock in living stock (C_{BM} in gC/ha) and above and below-ground carbon stock in dead organic matter (C_{DOM} in gC/ha). For C_{DOM} the value of 0 may be used, except forest land (excluding forest plantations) with more than 30% canopy cover.

Above and below-ground carbon stock in living stock can be calculated using one of the following equations:

$$C_{BM} = B_{AGB} \times CF_B + B_{BGB} \times CF_B$$

Or

$$C_{BM} = (B_{AGB} \times CF_B) \times (1+R)$$

Where:

- B_{AGB} is the weight of above-ground living biomass (in kg dry matter/ha) which shall be taken to be the average weight of the above-ground living biomass during the production cycle for cropland, perennial crops and forest plantations
- B_{BGB} is the weight of below-ground living biomass (in kg dry matter/ha) which shall be taken to be the average weight of the below-ground living biomass during the production cycle for cropland, perennial crops and forest plantations
- CF_B is the carbon fraction of dry matter in living biomass (in kgC/kg dry matter) which can be taken to be 0.47
- R is the ratio of below-ground carbon stock in living biomass to above-ground carbon stock in living biomass which can be read in the RTFO standard values available online

Above and below-ground carbon stock in dead organic matter shall be calculated as follows:

$$C_{DOM} = DOM_{DW} \times CF_{DW} + DOM_{LI} \times CF_{LI}$$

Where:

- DOM_{DW} is the weight of the deadwood pool (in kg dry matter/ha)
- CF_{DW} is the carbon fraction of dry matter in the deadwood pool (in kgC/kg dry matter) which can be taken to be 0.5
- DOM_{LI} is the weight of litter (in kg dry matter/ha)

- CF_{LI} is the carbon fraction of dry matter in the litter (in kgC/kg dry matter) which can be taken to be 0.4

5.2 Indirect land-use change

Indirect land-use change (ILUC) is land-use change where the cause is at least one step removed from the effects. In this case, it is the global knock-on effect of expansion of agricultural land use resulting from the cultivation of biogenic feedstocks for hydrogen production.

GHG emissions associated with ILUC vary depending on the situation, but can be significant to a point which greatly reduces (or even nullifies) the GHG emission benefits generally associated with low carbon hydrogen production and use.

The biomass feedstock requirements outlined above help to mitigate the risk of high emissions associated with ILUC. In particular, the land criteria (see below for more detail) and minimum waste and residue requirement help to limit the role in hydrogen production that high-risk ILUC feedstocks can play.

Although not included in the GHG calculation methodology of the standard, evidence will be requested on estimated ILUC emissions, where available and appropriate (i.e. where the biogenic feedstock in question may be associated with ILUC). In the absence of evidence from the reporting party, information provided on feedstock characteristics will be used alongside default ILUC emission values, to estimate the ILUC GHG emission impact.

In either case, the information provided is used for reporting purposes only and is not taken into account in the GHG calculation methodology of the standard, nor used in any other way to determine compliance.

There is ongoing work to improve our understanding of ILUC emissions, the outcomes of which will inform any future changes to this approach.

Default reporting values in Table 7 follow those used under the RTFO, and apply to cereals and other starch-rich crops, sugars and oil crops.

Table 7: ILUC values of feedstock groups

Feedstock group	ILUC values (gCO_2e/MJ)
Cereals and other starch-rich crops	12
Sugars	13

Oil crops	55

ILUC emissions will be estimated as zero for all other types of feedstock.

Annex D: Biomass feedstock sustainability criteria

1 Biomass sustainability criteria overview

1.1 Hydrogen production pathways which use biogenic feedstocks must comply with the GHG threshold set out under this standard, using the methodology outlined above. It may be required that certain biogenic feedstocks also comply with additional sustainability criteria to be compliant with the standard, to mitigate against other negative environmental and social outcomes.

1.2 These additional sustainability criteria are categorised as follows:

- Land criteria
- Forest criteria
- Soil carbon criteria

In each case, the criteria (which are laid out below in Table 8) follow the precedent set out in the sustainability criteria of the RTFO.

1.3 The exact criteria which a given consignment of hydrogen must meet depend on the feedstock from which it is made.

Table 8: Relevant sustainability criteria that types of biogenic feedstock must meet

Feedstock	GHG emissions threshold	Land criteria	Forest criteria	Soil carbon criteria
Forest biomass, including residues from forestry or wastes from forestry	✓		✓	
Residues, including processing residues, which are not residues from agriculture, aquaculture, fisheries or forestry	✓			
Wastes, which are not wastes from agriculture, aquaculture, fisheries or forestry	✓			

Residues or wastes from agriculture	✓	✓		✓
Any feedstock not falling within entries listed above	✓	✓		

1.4 It is strongly recommended that hydrogen producers using biogenic feedstocks[19] meet the land, forest and soil carbon criteria by reporting through a voluntary scheme that has been recognised as demonstrating compliance with the relevant criteria, as this means that no further evidence is required. Demonstrating compliance is covered in more detail below.

Land criteria

1.5 The land criteria ensure that relevant biogenic feedstocks are sourced in a way that preserves biodiversity and carbon stocks. To achieve this, it is prohibited to source biogenic feedstocks for hydrogen production from land that has or previously had a certain status (high biodiversity or carbon stock). In some cases, it is permitted to source material from land of a certain status if specific criteria are met.

1.6 The land criteria are made up of two sub-criteria, one which covers biodiversity and the other carbon stocks and peatlands.

Biodiversity criteria

1.7 To satisfy the biodiversity criteria, hydrogen may not be made from raw material obtained from land with high biodiversity value in or after January 2008. The prohibited land categories are:

a. Primary forest or other wooded land of native species where there is no clearly visible indication of human activity and ecological processes are not significantly disturbed.

b. Highly biodiverse forest or other wooded land which is species-rich and not degraded except in cases where the land is designated for nature protection purposes and the production of relevant feedstock is a necessary management action that did not interfere with the purposes for which the land concerned was designated for nature protection purposes.

c. Land designated for nature protection purposes, including those designated for the protection of rare, including for the protection of rare, threatened or

[19] A hydrogen producer may handle the original biogenic feedstock, or a product derived from it (e.g. biogas, biomethane). Either way, it is the original biogenic feedstock, prior to any engineered conversion, that is subject to the sustainability criteria laid out in this standard.

endangered ecosystems or species, unless production of the relevant feedstock can be shown not to have interfered with those nature protection purposes.

d. Natural highly biodiverse grassland[20] spanning more than one hectare.

e. Non-natural highly biodiverse grassland spanning more than one hectare, unless harvesting of the raw material is necessary to preserve its status as highly biodiverse grassland.

1.8 For the exemptions permitted above (for land categories b, c and e), evidence must be provided that the exemption is valid.

Carbon stocks and peatlands criteria

1.9 Hydrogen must not be made from raw material if the sourcing of such biomass would cause adverse effects on land carbon stocks or to peatlands. To satisfy the carbon stocks and peatlands criteria the following criteria outlined below need to be satisfied:

1.10 Hydrogen may not be made from raw material obtained from land which had the following land status at any time in January 2008 and no longer has that status:

a. Wetlands, defined as land that is covered with or saturated by water permanently or for a significant part of the year.

b. Continuously forested areas spanning more than one hectare with trees higher than five metres and a canopy cover of more than 30%, or trees able to reach those thresholds in situ.

1.11 Where raw material is sourced from land which at any time in January 2008 was a forested area spanning more than one hectare with trees higher than five metres and a canopy cover of between 10% and 30%, or trees able to reach those thresholds in situ, and the land no longer has that status, suppliers must be able to demonstrate that any hydrogen made from that raw material meets the GHG emission threshold, with emissions due to (direct) land-use change taken into account.

1.12 Hydrogen may not be made from raw material obtained from land which was peatland at any time in January 2008, unless it can be demonstrated that the cultivation and harvesting of that raw material did not involve drainage of previously undrained soil.

Soil carbon criteria

1.13 The soil carbon criteria apply specifically to hydrogen made from wastes and residues derived from agriculture and is in addition to the land criteria.

[20] Natural grassland is grassland that would remain as grassland and that maintains its natural species composition and ecological characteristics and processes in the absence of human intervention.

1.14 To meet the soil carbon criteria, it must be demonstrated that monitoring or management plans are in place to address the impacts on soil quality and soil carbon of the harvesting of the relevant feedstock concerned.

1.15 To comply with the soil carbon criteria, it should be demonstrated that appropriate monitoring or management practices are either:

- required by law in the country of origin of the feedstock, and that their implementation is monitored and enforced
- in place at the farms from which the material was sourced

Forest criteria

1.16 The forest criteria apply to hydrogen derived from forest biomass including wastes and residues. Such feedstocks do not have to meet the land criteria.

1.17 Where hydrogen is derived from such feedstocks, it must be demonstrated that the feedstocks meet the following criteria:

- the material has not been harvested from wetlands, peatlands or protected land areas unless the land is designated for nature protection purposes and the production of the relevant feedstock did not interfere with the purposes for which the land concerned was designated for nature protection purposes
- the material has been legally harvested
- the material has been harvested in such a way that negative impacts on soil quality and forest biodiversity are minimised and which maintains or improves the long-term production capacity of the forest from which it was harvested
- that areas that have been harvested are subject to forest regeneration[21]
- that changes in carbon stock associated with forest biomass harvest are accounted for in submissions related to the country's commitment to reduce or limit greenhouse gas emissions through the ‘Paris Agreement’, or the material has been harvested in such a way that carbon stocks and sinks levels in the forest are maintained or increased over the long term

1.18 To comply with the forest criteria, it should be demonstrated that appropriate monitoring or management practices which ensure the criteria described in paragraph 2.17 are satisfied are either:

- required by law in the country of origin of the feedstock, and that their implementation is monitored and enforced

[21] “Forest regeneration” means the re-establishment of a forest stand by natural or artificial means following the removal of the previous stand by felling or as a result of natural causes, including fire or storm.

- in place at forest sourcing area[22] from which the material is sourced

2 Demonstrating compliance with biomass sustainability criteria

2.1 It is strongly recommended that a reporting party provides evidence of compliance with one or all of the sustainability criteria by using one or more existing voluntary schemes. Voluntary schemes that can be used to provide evidence of compliance include[23]:

- Biomass biofuels voluntary scheme (2BSvs)
- Bonsucro EU (formerly Better Sugar Cane Initiative (BSI)
- International sustainability and carbon certification (ISCC)
- KZR INiG System
- Better biomass (formerly NTA 8080)
- Red tractor farm assurance combinable crops and sugar beet scheme (Red tractor)
- REDcert
- Roundtable on sustainable biomaterials EU RED (RSB EU RED)
- Scottish quality farm assured combinable crops (SQC)
- Trade assurance scheme for combinable crops (TASCC)
- Universal Feed Assurance Scheme (UFAS)

2.2 Voluntary schemes are recognised for a specific scope. For example, they might be recognised as providing evidence for one or more of the land criteria, forest criteria, or soil carbon criteria. Where a voluntary scheme does not provide evidence for all of the land, forest and/or soil carbon criteria, then suppliers will need to demonstrate compliance with those criteria through another voluntary scheme or by following one of the compliance routes outlined in the following sections.

2.3 The chain of custody rules of a voluntary scheme must be complied with for a reporting party to claim that the feedstock in question complies. A reporting party should either be certified under the voluntary scheme or, where it is not certified, check with the voluntary scheme before a claim is made.

[22] "Sourcing area" means the geographically defined area from which the forest biomass is sourced from which reliable and independent information is available and where conditions are sufficiently homogeneous to evaluate the risk of the sustainability and legality characteristics of the forest biomass.
[23] These are the voluntary schemes that are recognised under the RTFO. Further information on the schemes can be found here: https://www.gov.uk/government/publications/renewable-transport-fuel-obligation-rtfo-voluntary-schemes/rtfo-list-of-recognised-voluntary-schemes

2.4 Reporting parties must have evidence that the biogenic feedstock in question complies with a voluntary scheme. For example, it is not sufficient to purchase from an economic operator that has been certified against a voluntary scheme unless the biogenic feedstock supplied by that entity is accompanied by evidence of meeting the scheme, e.g. a proof of sustainability. This is because being certified under a voluntary scheme does not require that entity to only supply sustainable biogenic feedstock.

Alternative options for demonstrating compliance with the biomass sustainability criteria

2.5 Reporting a 'voluntary scheme' that has been recognised as demonstrating compliance for the land criteria is the recommended option.

2.6 Where a voluntary scheme is not available (e.g. for a particular feedstock or region), reporting parties can conduct independent third-party audits to evidence compliance with the biomass sustainability criteria.

2.7 To evidence compliance, a third party audit should seek to capture the same evidence as a listed voluntary scheme. A list of potential evidence sources that could be used as part of a third party audit report (e.g. on historic land use) can be found in the guidance for the RTFO[24], which shares the same land, forest and soil carbon criteria.

[24] https://www.gov.uk/government/publications/renewable-transport-fuel-obligation-rtfo-compliance-reporting-and-verification

Annex E: Additional guidance for biomethane input to hydrogen production

The standard allows for national and international sourcing of biomethane; and its storage, movement by dedicated pipeline or movement by any other means of dedicated transport as part of a supply chain, prior to being utilised in a hydrogen production facility.

However, the standard does not currently allow for biomethane to be claimed as an input to the hydrogen production facility if mixed with fossil methane (natural gas) at any point in the supply chain. DESNZ will continue to work across government to consider this issue and relevant methodologies for tracking the chain of custody of biomethane where mixed with natural gas and will return to this question in future iterations of the standard.

For the use of biomethane as an input to hydrogen production to be claimed, information is required which demonstrates to the delivery partner(s) that the biomethane will be / has been physically supplied to the hydrogen production facility. This is required for the environmental characteristics of a biomethane input to be used in evidencing compliance with the requirements of the standard. Should the information provided be deemed insufficient by the relevant delivery partner(s), or if any stage of the supply chain involves mixing with fossil methane (natural gas), the methane input used shall be treated as natural gas, with CO_2 emissions considered as fossil CO_2, rather than biogenic CO_2.

Where a hydrogen production facility is not yet operational, reporting parties will need to provide information on:

a) the commercial arrangements of the supply of biomethane;

b) the location of biomethane production;

c) the planned route and mode(s) of delivery to the hydrogen production process from the point of biomethane production.

In relation to point c), the information provided should cover every stage of the movement (and storage) of biomethane from its point of production, through to input to hydrogen production.

For a hydrogen production facility with on-site biomethane production, which is directly supplied to and fully meets the demand of the hydrogen production process, information on the whole site configuration is likely to be sufficient to fulfil these reporting requirements.

For ongoing monitoring, reporting and verification when a hydrogen production facility is operational, it is likely that operators will be required to provide further evidence of the chain of custody for biomethane inputs. We will continue to consider the requirements for ongoing monitoring, reporting and verification, working across government to ensure a consistent approach.

Renewable guarantees of origin, commercial green gas certificates and other book and claim systems[25] are not sufficient in and of themselves to evidence biomethane use under the standard since they do not prove that the biomethane has been physically supplied to the hydrogen production plant.

Natural gas transmission and distribution grids in the UK and overseas are not currently permitted under the standard for the transport of biomethane inputs, as it involves the mixing of biomethane with natural gas. As above, this would result in the methane input being treated as natural gas. The information requirements set out in this annex shall be provided in addition to evidence of compliance with other requirements set out in this guidance document, including those that specifically relate to the use of biomass (e.g. the biomass sustainability criteria and the minimum waste and residue requirement).

[25] Book and claim systems are systems where certificates of sustainability are sold/traded separately from the physical commodity.

Annex F: Production pathways modelled to support the design of the standard

Our analysis suggests that each of the production pathways included within the main guidance and default data modelling has the potential to produce hydrogen with GHG emissions complying with the standard. Inclusion on this list of modelled pathways below does not, however, guarantee the hydrogen will comply with the standard – producers will need to design and operate their hydrogen production facilities to ensure the standard is met in practice, and on an ongoing basis, including non-GHG criteria.

- Electrolysis
    - Electrolysis using wind/solar electricity
    - Electrolysis using nuclear electricity
    - Electrolysis using the above inputs with some grid average electricity
- Natural Gas Reforming (with CO_2 capture and storage)
    - Steam methane reforming (with CO_2 capture and storage)
    - Auto-thermal reforming (with CO_2 capture and storage)
- Biomass/waste conversion to hydrogen (with/without CO_2 capture and storage)
    - Forestry residue Gasification (with/without CO capture and storage)
    - Food waste biomethane auto-thermal reforming (with/without CO_2 capture and storage)
    - Mixed Refuse Derived Fuel gasification (with/without CO_2 capture and storage)

Annex G: Conversion Factors

1. How to convert units for hydrogen

LHV to HHV

To convert an LHV energy content of hydrogen into an HHV energy content of hydrogen, multiply the LHV amount of energy by 1.182 to obtain the HHV amount of energy.

/MJ to /kWh

To convert from a per MJ H_2 measure to a per kWh H_2 measure, multiply the per MJ H_2 measure by 3.6.

/MJ to /kg

To convert from a per MJ_{LHV} H_2 measure to a per kg H_2 measure, multiply the MJ_{LHV} H_2 measure by 120 MJ_{LHV}/kg H_2. To convert from a per MJ_{HHV} H_2 measure to a per kg H_2 measure, multiply the MJ_{LHV} H_2 measure by 141.8 MJ_{HHV}/kg H_2.

2. Example conversion factors

Table 9: Example conversion factors

Measure	1 gCO_2e/MJ_{LHV} H_2 is equal to:	LCHS threshold of 20 gCO_2e/MJ_{LHV} H_2 is equal to:
gCO_2e/MJ_{HHV} H_2	0.846 gCO_2e/MJ_{HHV} H_2	16.93 gCO_2e/MJ_{HHV} H_2
gCO_2e/kWh_{LHV}	3.6 gCO_2e/kWh_{LHV}	72 gCO_2e/kWh_{LHV}
gCO_2e/MWh_{HHV}	3046.5 gCO_2e/MWh_{HHV}	60,930.9 gCO_2e/MWh_{HHV}
$kgCO_2e$/kg H_2	0.12 $kgCO_2e$/kg H_2	2.4 $kgCO_2e$/kg H_2
tCO_2e/tH_2	0.12 tCO_2e/tH_2	2.4 tCO_2e/tH_2