Research report

Application of life cycle assessment methodology to the understanding of the energy balance and efficiency of hydrogen value chain building blocks

energy institute

RESEARCH REPORT – APPLICATION OF LIFE CYCLE ASSESSMENT METHODOLOGY TO THE UNDERSTANDING OF THE ENERGY BALANCE AND EFFICIENCY OF HYDROGEN VALUE CHAIN BUILDING BLOCKS

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DEFINITION OF TERMS

The following terms underpin the Landscape Review study and provide definitions relevant to this study.

Blue hydrogen
There is no internationally accepted definition of 'blue hydrogen', therefore the term can easily be misinterpreted. For this study it is defined as hydrogen produced from the reformation of methane reforming with the waste carbon dioxide (CO_2) captured and stored. The blue hydrogen production analysis includes a range of CO_2 capture rates from 60–95 %; any analysis of blue hydrogen in value chains is based on 95 % capture of CO_2.

Carbon capture and storage (CCS)
The process of capturing and storing CO_2 from industrial activities that would otherwise have been released to the atmosphere. For this study, no distinction is drawn between CCS and carbon capture use and storage (CCUS), as the focus is on GHG emissions reduction.

Decarbonise
To reduce the greenhouse gas (GHG) emissions intensity associated with a particular activity or product from current levels.

Distribution
Distribution is defined as the means of hydrogen product transportation from the point of production to the point of use. This could be by pipeline, road transportation, rail, etc. Unless stated explicitly and in the case of hydrogen, this terminology does not refer to gas distribution pipelines only. Distribution includes pipeline, road transportation, rail, and domestic shipping.

Efficiency
The efficiency is a measure of useful energy provided by a value chain block as a percentage of total energy supplied to that block and allowing for any losses. This definition is expanded in 3.3.

Emissions intensity
Emissions intensity is the GHG emissions associated with a particular activity or product on a common per unit basis. For energy this is typically quoted as equivalent grams of carbon dioxide per kilowatt-hour, gCO_2e/kWh.

Feedstock
Feedstock is defined as the energy source used to produce hydrogen. For hydrogen produced from methane reforming, the feedstock is natural gas. For hydrogen produced by electrolysis of water, the feedstock is electrical power. For the purposes of this study, no energy efficiency is ascribed to the feedstock generation, but GHG emissions associated with its supply are accounted for.

Green hydrogen
There is no internationally accepted definition of 'green hydrogen', therefore the term can easily be misinterpreted. For this study, it means hydrogen produced by electrolysis of water using 100 % renewable energy.

Low carbon hydrogen
This is a generic term used to describe hydrogen that has been produced with lower emissions intensity than that associated with methane reforming compared to current day practice (i.e. without CCS).

Renewable energy

For this study, renewable energy is assumed to be 100 % generated by wind as this is the dominant source of renewable energy in the UK.

Steam-to-carbon ratio

The steam-to-carbon ratio is the ratio of moles of steam to moles of carbon in the reformer feed.

1 EXECUTIVE SUMMARY

1.1 INTRODUCTION

There is global recognition of the need to reduce GHG emissions significantly from current levels to mitigate climate change. Against this backdrop, the UK has legally binding targets to achieve 'net zero' by 2050 at the latest. However, energy policy is still under development to achieve this goal.

The potential role of hydrogen during and after the energy transition is keenly debated within society, academia, and the energy industry.

The goal of this study is to understand the efficiencies of the hydrogen energy system and quantify the energy intensity and associated GHG emissions, compared to other fuels, thus providing an independent view of all options.

Phase 1 is a desktop study to identify the energy balance and efficiency of a whole hydrogen energy system, from production to consumption. It is not intended as a holistic comparison of the advantages and disadvantages of hydrogen versus other energy vectors. The study covers three specific areas of the supply chain:

- Production (refer to section 4).
- Transmission, storage and distribution (refer to section 5).
- Usage/consumption (refer to section 6):
  - electricity;
  - heating;
  - power to a vehicle and drivetrain, and
  - ammonia, methanol, and similar chemical product.

By joining the outcomes of these three blocks together, an analysis of the energy balance and efficiencies of the whole system can be obtained. There's a particular focus on the two key emissions reduction opportunities:

- heat, and
- transport.

Note that the analysis has a UK setting and is carried out based on present day references provided in Annex A and metrics for technology performance and characteristics.

The study is based on publicly available information as much as possible and, where available, multiple sources have been reviewed. Typically, technology-based building blocks (e.g. fuel cells, green hydrogen production) have been assessed by consulting referenceable public material.

1.2 KEY FINDINGS

Figure 1.1 illustrates the efficiency ranges found throughout the hydrogen energy system value chain, indicating the maximum and minimum efficiencies for each of the value chain block options.

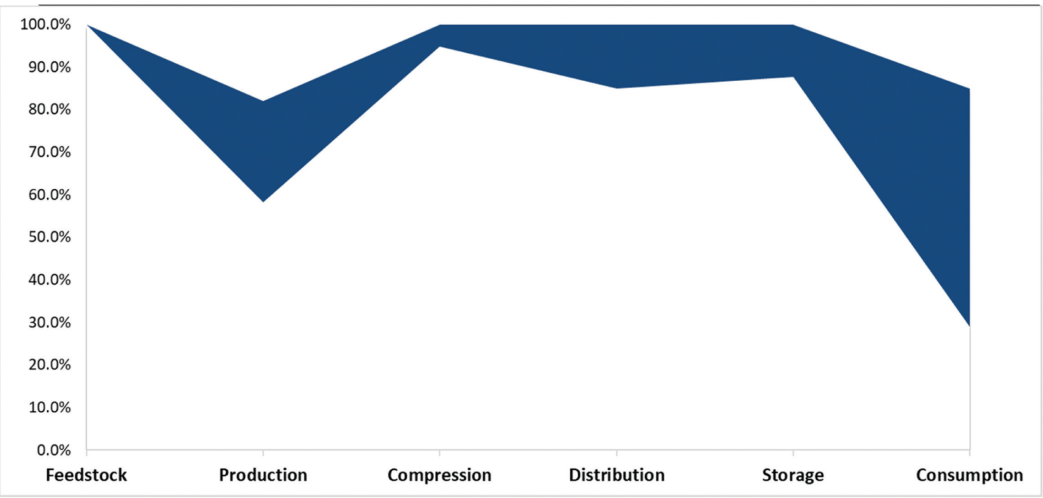


Figure 1.1: Efficiency range through the hydrogen system value chain

The value chain block options and details are provided in sections 4, 5 and 6 respectively. The key findings of the hydrogen efficiency ranges are:

- The major areas of inefficiency in the hydrogen value chain are production and consumption.
- Distribution and storage have only minor impact on overall efficiency losses and emissions for the distances associated with a regional network (<500 km) and are almost negligible for local distribution (<100 km).
- Technologies considering hydrogen liquefaction and trucking long distances represent the low end of the efficiency range for distribution and storage.

1.2.1 Feedstock comparison

Normalised feedstock requirements and emissions intensity for natural gas, blue hydrogen, green hydrogen, and current day UK electricity supply are presented in Figure 1.2. This chart shows energy efficiency and emissions intensity for alternative fuels for a normalised energy consumption.

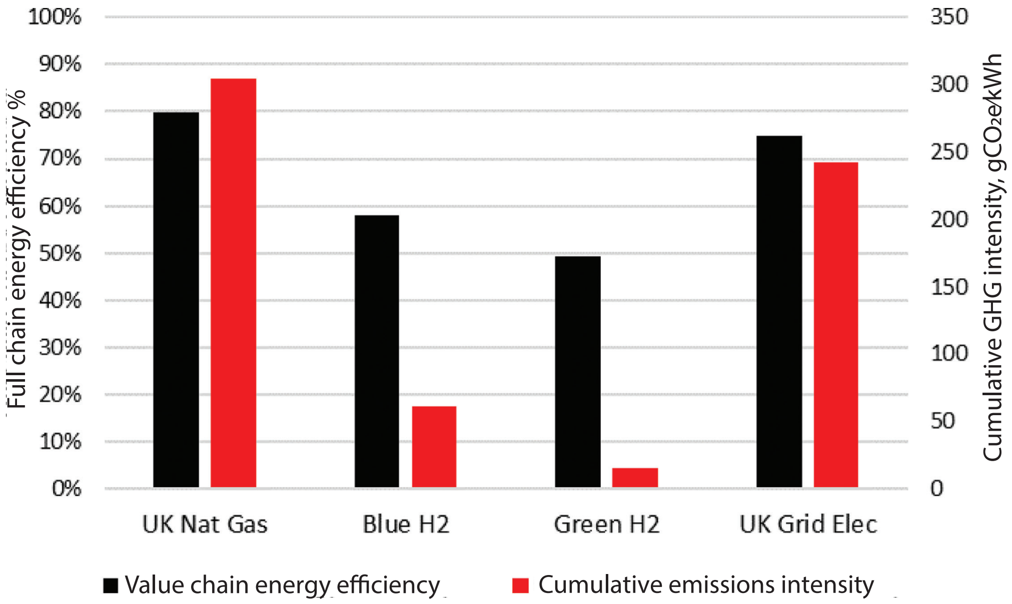


Figure 1.2: Feedstock demands and emissions intensities for alternative fuels

Footnotes to figure:

a) The chart considers feedstock required and emissions intensity for a given energy supply to consumer.

b) The 'UK Nat Gas' case is based on the United Kingdom Continental Shelf (UKCS) gas transmitted to domestic boiler via existing pipelines with geological storage for supply management.

c) The 'blue H_2' case considers natural gas coupled with autothermal referring (ATR) with syngas capture (blue hydrogen).

d) The 'green H_2' case considers alkaline electrolysis (green hydrogen).

e) The 'UK Grid Elec' considers 2020 average emissions intensity (see 4.1.1) for UK electricity, transmission, and domestic appliance usage. This is based on published data from the National Grid (Carbon Intensity API, National Grid).

The key finds are discussed as follows:

- Blue hydrogen can reduce emissions of natural gas users by around 80 % at the expense of a 38 % increase in natural gas feedstock.
- There is the potential to reduce the feedstock consumption with efficiency gains from process optimisations as the technology matures (as seen in the wind industry for example).
- If blue hydrogen is produced from liquified natural gas (LNG) the emissions intensity steps up significantly: a 40 % increase for typical UK imports, with the potential for this to be greater for specific cargoes. This highlights the importance of understanding the provenance and emissions intensity of feedstock for a blue hydrogen production facility.
- Green hydrogen can reduce emissions much further still (95 % lower than natural gas); however, it is significantly less efficient than direct use of the renewable electricity used to produce it. It is also currently more challenging to produce at scale than blue hydrogen.

Specific value chain comparisons are presented in the following sub-sections.

1.2.2 Blue hydrogen compared to natural gas

The emissions and feedstock impact of switching from natural gas to blue hydrogen is illustrated by Figure 1.3, with a 38 % increase in feedstock and an 80 % reduction in emissions. This is based on a 100 % hydrogen system but the impacts on emissions and feedstock can be considered to pro-rate for hydrogen/natural gas blends.

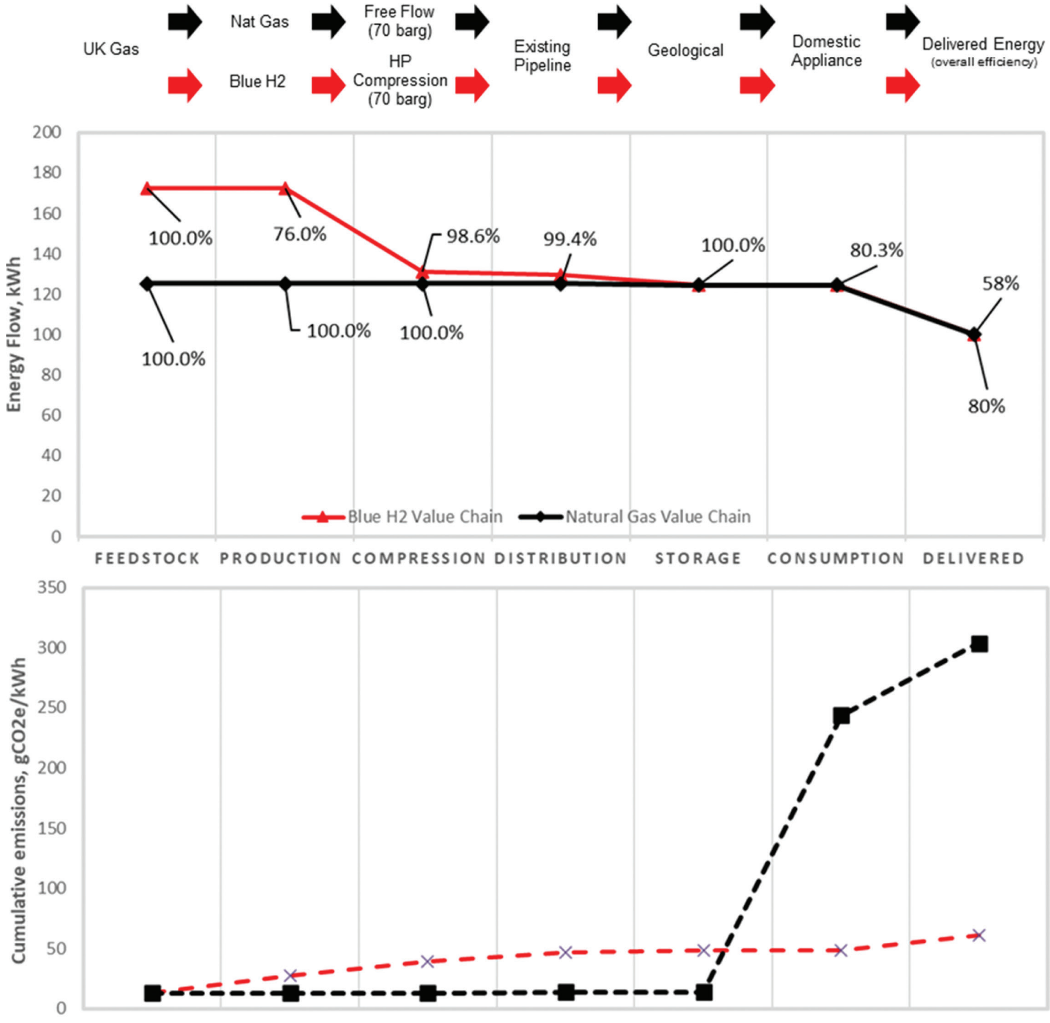


Figure 1.3: Energy flow and cumulative emissions for blue hydrogen vs natural gas

Footnotes to figure:

a) The energy efficiencies are presented for each value chain block; the efficiency shown for delivered energy is the overall value chain energy efficiency.

b) Emissions are cumulative GHG emissions intensity for the energy flow out of each value chain block. As such, GHG intensity will rise when more emissions occur and when energy losses occur because the cumulative emissions are then attributed to a lower amount of energy flowing out of the block.

c) Feedstock is 100 % efficiency as it is considered at the battery limit of the hydrogen production site.

These results demonstrate that switching from natural gas to blue hydrogen can offer significant emissions reduction; this opportunity should be viewed in the context of the required capital expenditure (CAPEX) and higher operating costs due to the increased consumption of natural gas and the cost of operating the hydrogen production facility.

1.2.3 Green hydrogen compared to electrification

Figure 1.4 presents the impact on feedstock demand and emissions for a green hydrogen to Fuel Cell Vehicle (FCV) compared to a Battery Electric Vehicle (BEV) powered by electricity from the UK grid with 2020 GHG emissions intensity.

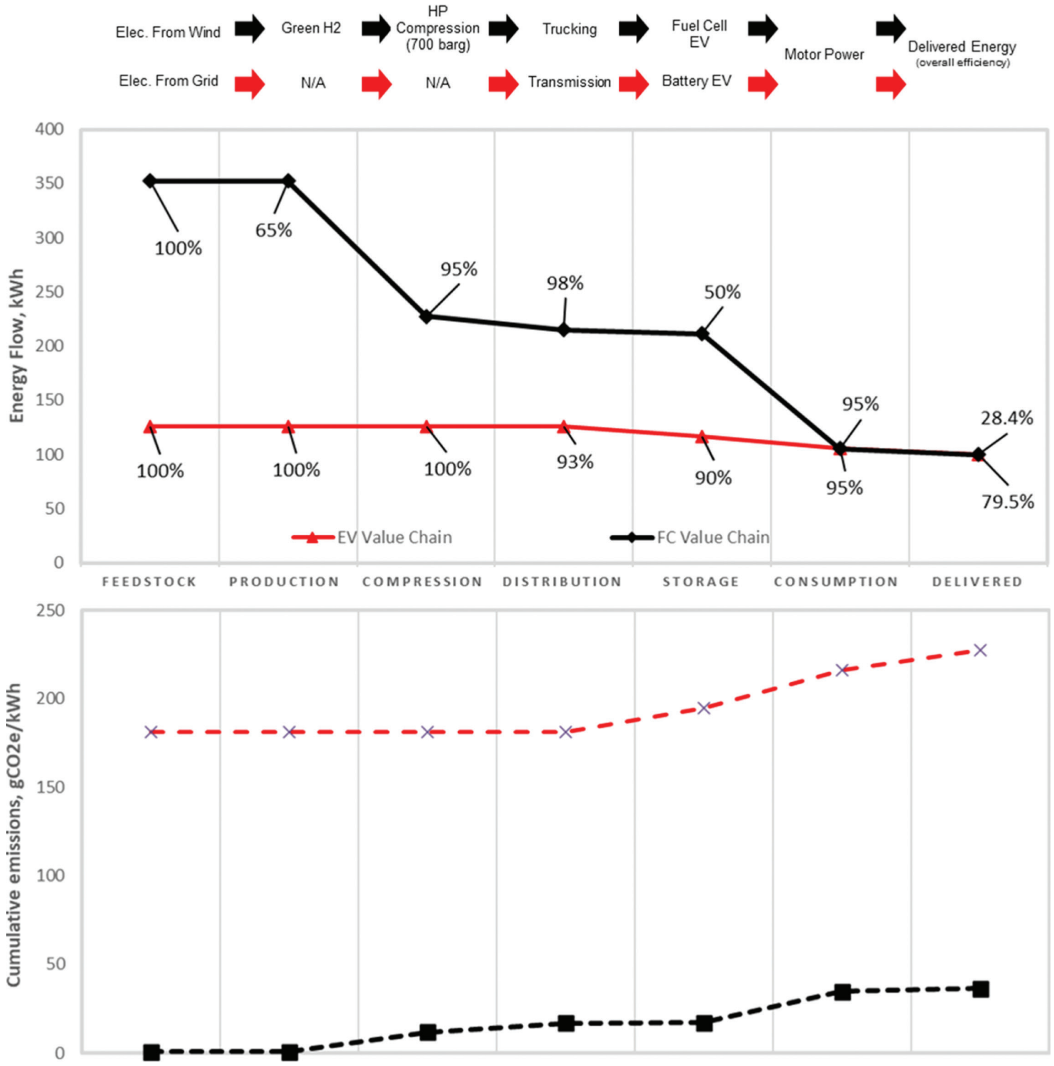


Figure 1.4: Battery electric vehicles vs Fuel cell electric vehicles

Footnotes to figure:

a) The energy efficiencies are presented for each value chain block; the efficiency shown for delivered energy is the overall value chain energy efficiency.
b) Emissions are cumulative GHG emissions intensity for the energy flow out of each value chain block. As such, GHG intensity will rise when more emissions occur and when energy losses occur because the cumulative emissions are then attributed to a lower amount of energy flowing out of the block.
c) Feedstock is 100 % efficiency as it is considered at the battery limit of the hydrogen production site.

As can be observed, fuel cells are less efficient than electrification via UK grid, requiring almost three times the energy input, but the associated emissions are reduced by over 80 %. This would likely be compounded when considering manufacturing emissions of BEVs compared to FCEVs due to the raw material extraction and processing of the battery.

It is accepted that the comparison in this section of renewable energy source versus mixed grid power sources is not a like-for-like comparison and thus the primary reason for the large differential in emissions. The green hydrogen is produced by 100 % renewable energy, whereas the battery EV is charged from the grid, therefore the energy is at the prevailing grid supply mix. If hydrogen was produced by electrolysis using power from the grid (rather than new build renewables) then the associated emissions would be higher than for a BEV due to the lower value chain energy efficiency. This is illustrated in 7.4.1.

Despite the low value chain efficiency, fuel cells are favourable for heavy vehicles which would require large batteries and long charge times with current technology.

The emissions and feedstock impacts of switching from direct use electricity (2020 UK grid mix) to combined heat and power (CHP) fuel cells (via green hydrogen) are illustrated by Figure 1.5.

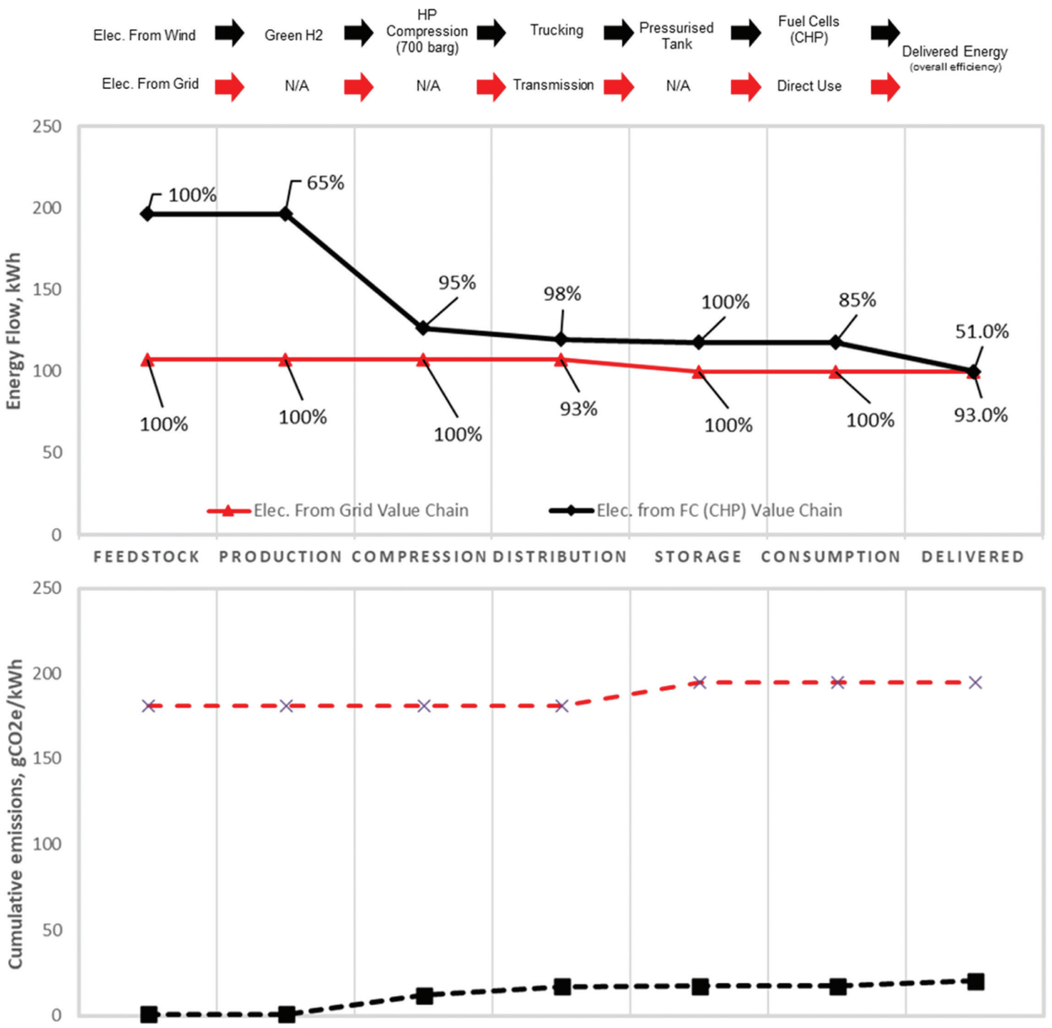


Figure 1.5: Fuel cells CHP vs Electricity

Footnotes to figure:

a) The energy efficiencies are presented for each value chain block; the efficiency shown for delivered energy is the overall value chain energy efficiency.

b) Emissions are cumulative GHG emissions intensity for the energy flow out of each value chain block. As such, GHG intensity will rise when more emissions occur and when energy losses occur because the cumulative emissions are then attributed to a lower amount of energy flowing out of the block.

c) Feedstock is 100 % efficiency as it is considered at the battery limit of the hydrogen production site.

As can be observed, CHP fuel cells are less efficient than electrification via UK grid (consuming ca. 80 % more electricity) but the associated emissions are significantly reduced by 90 %. The use of fuel cells with CHP is reliant on both electrical and heating demand at the end-user, so realising the achievable efficiency is application dependent.

When comparing hydrogen usage against electrification, it is important to note that the emissions intensity associated with grid power is not fixed: it is highly variable by region; it has been progressively decreasing and is expected to reduce further. However, the more grid emissions intensity reduces (due to renewables content), the greater the value of decoupling supply and demand as peaks in renewable power generation will often not coincide with peaks in consumer demand.

1.3 CONCLUSIONS

Both blue and green hydrogen require more feedstock to deliver the same energy value as natural gas or direct use electricity respectively, due to the efficiency losses of hydrogen production. However, the use of hydrogen can reduce emissions considerably compared to current energy vectors such as natural gas and electrical grid power.

To realise the emissions saving potential of hydrogen, the feedstock used is of paramount importance:

- Blue hydrogen produced by LNG cargoes could erode much of the emission benefit compared to a natural gas feedstock.
- Green hydrogen produced by UK grid electricity (i.e. not new build renewables) would generate considerably more emissions than the direct use of grid electricity; therefore, a green hydrogen development should always be considered with new build renewable generation.

Blue hydrogen appears suited to use in industrial clusters where there are few ready alternatives to the use of natural gas. The development of clusters allows for economies of scale to be realised for common infrastructure. The emissions savings may come at an economic cost, considering both the CAPEX on new facilities and the increased consumption of natural gas feedstock and plant operating costs.

Green hydrogen cannot currently be produced in high capacities; however, its high purity and relative flexibility in production location mean it could be suited to small integrated developments: for example, powering municipal vehicles (e.g. buses and refuse collection trucks) with fuel cells. Batteries are not currently practical for heavy vehicles due to large battery sizes and long charge times.

This study covers emissions and efficiency aspects of competing energy vectors; there are of course other factors to consider such as safety, societal acceptance, political policy impetus and commerciality which are outwith this scope. Ultimately, very low GHG emissions technologies like green hydrogen are going to be required to achieve mid-century net zero goals.

2 INTRODUCTION

2.1 BACKGROUND

There is global recognition of the need to reduce GHG emissions significantly from current levels to mitigate climate change. The COP21 'Paris agreement' aims to limit the rise in global average temperature to no more than 2 °C above pre-industrial levels by achieving net zero GHG emissions in the second half of the 21st century.

Against this backdrop, the UK has legally binding targets to achieve 'net zero' by 2050 at the latest; however, energy policy is still under development to achieve this goal.

The potential role of hydrogen during and after the energy transition is keenly debated within society, academia, and the energy industry. Hydrogen has potential in that it is a transportable energy carrier that will not emit CO_2 at the point of use. However, the efficiency of a hydrogen energy system is often challenged compared to alternatives such as electrification.

The EI supports the energy industry's goal to achieve a low carbon energy system by supporting the energy transition. The EI is developing a range of projects to support this transition, and evaluating the energy balance and efficiency of a whole hydrogen energy system from production to consumption has been identified as a priority work area to be addressed.

2.2 STUDY OBJECTIVE

The goal is to understand the efficiencies or inefficiencies of the hydrogen energy system and quantify the energy intensity and associated equivalent CO_2 emissions compared to other fuels, providing an independent holistic view of all options from production through to utilisation.

The deliverable of Phase 1 will consist of a desktop study to identify the energy balance and efficiency of a whole hydrogen energy system, covering three specific areas of the supply chain:

a) production;
b) transmission, storage and distribution, and
c) usage/consumption.

By joining the outcomes of these three blocks together, an analysis of the energy balance and efficiencies of the whole system can be obtained.

2.3 SCOPE OF STUDY

The study scope relates to operating efficiencies and emissions and does not allow for pre- and post-operations phase, (e.g. construction and decommissioning) energy consumption and emissions.

Economics are excluded from the assessment as are system design considerations, although these will be considered subjectively in discussion of technology merits with respect to efficiency and emissions.

2.4 DOCUMENT STRUCTURE

The structure of this report is described in Table 2.1.

Table 2.1: List of sections in report 'understanding the energy balance and efficiency of the hydrogen energy system'

Section	Title	Intent
1	Executive Summary	Summarise study goals, methodology and key findings
2	Introduction	Study background, objectives, and scope
3	Methodology	Presents study methodology and key assumptions
4	Production	Technology overview, assessment basis and findings
5	Transmission, Storage and Distribution	Technology overview, assessment basis and findings
6	Consumption	Technology overview, assessment basis and findings
7	Important Value Chains	Discussion of key value chains based on results in sections 4–6
8	Conclusions	Conclusions within blocks and for important value chains
9	Further Work	Highlight areas of further study to complement this report
10	References	Summarise references used for this study

3 METHODOLOGY

3.1 GENERAL

This is a desktop study and has been performed by the methodology described in this section.

Three framing workshops were carried out at the start of the study between Genesis and the EI Working Group to align on the basis to apply to the following areas:

- production;
- transmission, storage and distribution, and
- usage/consumption.

For each of these areas a number of alternative technologies to be assessed were identified and agreed in the framing workshop. The technologies assessed are identified in 3.2.

Following agreement between the EI Working Group and Genesis on the basis of assessment, the study was executed as follows:

Assessment is based on publicly available information as much as possible and where available, multiple sources have been reviewed. Typically, technology-based building blocks, (e.g. fuel cells, green H_2 production) have been assessed by consulting referenceable public material.

Where system design has a major influence on the outcome, (e.g. transportation and storage), calculations have been performed to determine value chain block efficiencies and emissions intensities.

Power inputs have generally been assumed to be supplied from UK grid and emissions intensity associated with UK grid is as per 2020 annual average. Note that UK grid intensity has been progressively falling and it expected to reduce further, but this study does not project future scenarios for energy mix.

Efficiencies have been accounted for by assessing major power users and systems losses; the following are not included:

- minor power demands at sites dominated by single large users, (e.g. for compression stations there is no allowance for cooler fans or utilities), and
- maintenance operations and operator indirect emissions, (e.g. corporate activities).

The study considers currently available technology and does not speculate on potential advancements when assessing value chain block efficiency and emissions.

Value chain block efficiencies are expressed as a percentage as defined by 3.3.

Value chain block emissions intensities are expressed in terms of grams of CO_2 equivalent per kilowatt-hour (gCO_2e/kWh).

3.2 VALUE CHAIN BUILDING BLOCKS

The scope of this study has been compartmentalised by applying the concept of value chain building blocks. These are alternative means of producing, transporting, and storing and using hydrogen. Specific value chains can then be assessed by joining blocks from different columns horizontally; this is illustrated by section 7.

The building blocks assessed in this study are shown in Tables 3.1, 3.2 and 3.3.

Table 3.1: Hydrogen production and post-treatment value chain building blocks

Production and post-treatment				
Feedstock	**Production methods**	**CCS**	**Purification**	**Hydrogen purity**
Natural gas	SMR	None	Cryogenic separation	< 98 %
LNG	ATR	Chemical absorption	PSA	98 %
Wind	Alkaline	N/A	None	99,90 %
UK grid	PEM	N/A	N/A	99,99 %

Table 3.2: Hydrogen transport, storage, and distribution value chain building blocks

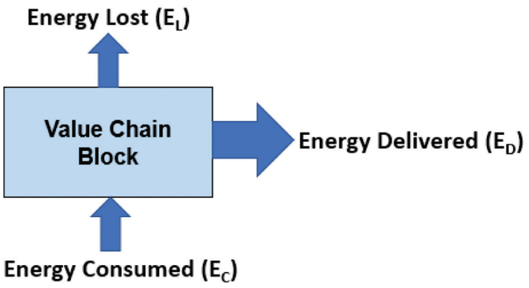
Hydrogen transmission, storage and distribution		
Hydrogen compression	**Storage**	**Transport and distribution**
Low pressure	Pressurised tank storage	Shipping
Medium pressure	Pipeline storage	Trucking/railways
High pressure	Cryogenic storage	Retrofitted/new pipelines networks
Very high pressure (350–700 barg)	Geological storage	N/A

Table 3.3: Hydrogen consumers value chain building blocks

Hydrogen usage			
Electricity generation	**Heating and cooling**	**Transportation**	**Refining and petrochemicals**
CCGT power generation	Domestic gas boilers and appliances	Railways (land transportation)	Ammonia production
Open cycle turbines	High heat for industry users > 800 °C	Mobility (i. cars, ii. trucks and buses)	Methanol production
Fuel cells	Low temperature cooling for industry users	Ocean shipping (marine transportation)	Refinery feedstock

3.3 ENERGY EFFICIENCY DEFINITION

The term 'efficiency' is widely used and misused, and as a result can be interpreted in many different ways. For the purposes of this study, it is defined by Figure 3.1 as a means of assessing how effectively energy is produced, moved, and utilised by each value chain block.



$$\mathbf{Energy\ Efficiency} = \frac{\mathbf{E_D}}{\mathbf{E_D + E_L + E_C}}$$

Figure 3.1: Definition of energy efficiency

3.4 ENERGY FLOW CONVERSIONS

This study assesses energy flow through the hydrogen value chain. To allow assessment of flows of natural gas, blended hydrogen, and pure hydrogen on a comparable basis, the higher heating value of these gases are used. Standard flows of the blends considered on an energy equivalent basis are presented in Table 3.4. Compositions are provided in Annex C of this guide; note that the natural gas composition selected is considered representative of UK gas and is not related to a specific asset. It should be noted that this would differ slightly depending on the source of gas (especially for LNG), but considering the broad nature of this study a single composition is applied.

Table 3.4: Equivalent flow of gas blends (natural gas, blended hydrogen, and pure hydrogen)

Parameter	Units	100 % NG	100 % H_2	20 % H_2 in NG [(a)]
HHV	MJ/Nm^3	41,53	12,77	35,74
Molar mass	g/mol	18,02	2,00	14,82
Flow	MMSCFD	1 500	4 877	1 743
Normal vol. Flow	m^3/d	40 264 168	130 917 069	46 783 320
Mass flow	t/h	1 349	487	1 289
Actual vol. Flow	m^3/h [(b)]	39 583	147 266	48 424
Energy flow	MJ/d	1 672 132 627	1 672 132 627	1 672 132 627
Energy flow	MW	19 353	19 353	19 353
Emissions [(c)]	gCO_2/Nm^3	2 129	0	1 703

Footnotes to table:

a) 20 % blend is on a molar basis, so will deviate from that ratio slightly when mixture is not at normal conditions.
b) Actual volumetric flow at 40 barg and 20 °C.
c) CO_2 emissions are based on complete combustion of the gas.

Important note: It can be observed that to deliver the same energy as natural gas, the volumetric flow of hydrogen is over three times as great, but almost three times less in terms of mass flow.

4 PRODUCTION

4.1 FEEDSTOCK

Several feedstocks are considered in this study:

- natural gas;
- LNG import;
- wind power, and
- UK grid.

Electricity is feedstock for green hydrogen and natural gas is feedstock for blue hydrogen.

4.1.1 Electricity supply

The emissions intensities used for this study are presented in Table 4.1; these intensities are based on current day UK supply and represent operating emissions only.

It is recognised that hydrogen energy systems as assessed in this study would operate in the future and that power supply is expected to progressively decrease in GHG emissions intensity over time. However, the study scope does not attempt to project future energy scenarios.

Table 4.1: Power supply emissions intensity

Power source	Emissions intensity
	gCO_2e/kWh
UK wind [(a)]	1
UK grid ave [(b)]	181

Notes:

a) Emissions intensity of UK wind is based on life cycle emissions intensity from the Great Britain Electricity Map (IPCC, 2014). This has been adjusted to allow for operating emissions only; ClimateXChange report, 2015 reports the operating emissions for wind power to be 6–20 % of the life cycle emissions.

b) Emissions intensity of UK grid is based on 2020 average from the Carbon Intensity API (National Grid).

UK wind emissions intensity is applied to green hydrogen production. Power demands for all other blocks are assumed to be supplied from the UK grid with 2020 emissions intensity.

4.1.2 Natural gas

4.1.2.1 UKCS gas

UKCS is a mature oil and gas production region; production rates have declined by over 50 % over the last 20 years and the UK is increasingly reliant on LNG import and continental gas via interconnectors. As many UK assets are operating in decline, their energy efficiency may be degraded from original design due to the fact many power loads and liquid fuel consumers do not reduce pro-rata with production.

GHG emissions associated with the upstream oil and gas sector predominantly stem from power and heat generation, gas compression, flaring, venting and fugitive emissions, all of which present GHG reduction opportunities.

Although the bulk of upstream GHG emissions (on an equivalent CO_2 basis) comprise CO_2, increasing attention is being directed towards methane emissions, which have a significantly higher Global Warming Potential (GWP) than CO_2 and are the second largest GHG emissions source from offshore UKCS operations. In 2019, the largest sources of methane emissions identified in the UK upstream chain were found to be from venting (48 %), flaring during production (31 %), cold flaring (11 %) and incomplete combustion of fuel for offshore power generation (7 %) (Methane Action Plan, 2021).

In an effort to reduce the emissions intensity of the upstream oil and gas sector, a number of technologies and approaches, ranging from minor operational changes to significant capital investment projects, are being deployed. Options considered by the sector include the electrification of platforms to enable them to be powered by onshore sources, the optimisation of operations to improve energy efficiency and minimise routine flaring, the installation of vapour recovery systems, and also the deployment of leak detection and repair (LDAR) systems and advanced satellite technology to detect fugitive methane leaks (International Energy Agency, 2021).

An example of the ambitious efforts being made to reduce upstream GHG emissions is the Johan Sverdrup field, the third largest oil field on the Norwegian Continental Shelf (NCS), which uses power supplied from shore (mainly hydroelectric power) rather than gas turbines. Doing so enables this field to achieve the lowest CO_2 emissions from production of any oil and gas field globally (Equinor, 2021). Johan Sverdrup claims an average GHG emissions intensity of 0,67 $kgCO_2e$/BoE compared to an NCS average of 9 $kgCO_2e$/BoE.

The emissions intensity figures used in this study (see 4.1.2.3) are based on the analysis recently undertaken by the Oil and Gas Authority (OGA) comparing the emissions intensity of UKCS gas production and imported LNG and pipelined gas (Oil and Gas Authority, 2021). In using recent emissions and production figures for domestic UKCS assets, the OGA's analysis provides an average emission intensity which is up-to-date and reflective of the current UK context.

4.1.2.2 *LNG import*

As UKCS gas production has declined, LNG imports have increased to meet gas demand; the bulk of UK imports are from Qatar, but the United States and Russia are also significant suppliers. LNG imports have a significant energy penalty due to their liquefaction process, but in mitigation their production and gathering systems benefit from economies of scale and the fact they operate at nameplate capacity, with several major assets undergoing expansion projects.

The emissions intensity data used in this study for imported LNG are based on analysis recently undertaken by the OGA (Oil and Gas Authority, 2021). As summarised in 4.1.2.1, this figure was selected on the basis that it was derived as part of the same work undertaken by the OGA to determine an emissions intensity for UKCS natural gas, and as such, has a consistent methodology in deriving emissions intensity values for UKCS and imported LNG. By doing so, this allows for a balanced comparison of the emission intensity values applied in this study.

It is important to note that while a single value for LNG emissions intensity is used for this study, the emissions intensity of individual cargoes is highly dependent on the source asset and is predominately influenced by:

- liquefaction technology;
- ambient conditions;
- upstream production operations, and
- power supply philosophy and extent of electrification.

4.1.2.3 Natural gas emission intensities

The emissions intensity applied for UK natural gas and imported LNG is presented in Table 4.2. As summarised in Oil and Gas Authority, 2021, the emissions intensity of imported LNG is around three times higher than that of UKCS natural gas. Factors which have a bearing on the emissions intensity of imported LNG include the inherent energy demand of the process, differing regional regulations on upstream production, distribution and storage at cryogenic conditions which naturally provides opportunities for boil-off emissions. This highlights the importance for any blue hydrogen development to carefully consider the source and associated emissions intensity of any natural gas feedstocks utilised.

Table 4.2: UK natural gas and imported LNG emission intensities

Emissions intensity	**$kgCO_{2e}$/boe (1) (2)**	**gCO_{2e}/kWh (3)**
UKCS natural gas (d)	22	12,9
Imported LNG (e)	59	34,7

Notes:

a) Sources: Wood Mackenzie Upstream Emissions Benchmarking Tool, OGA PPRS, EEMS Database, EU ETS, BEIS, NPD (Oil and Gas Authority, 2021).

b) Units – $kgCO_{2e}$/boe – kilograms of CO_2 equivalent (includes CO_2 and CH4) per barrel of oil equivalent produced.

c) Conversion from $kgCO_{2e}$/boe to gCO_{2e}/kWh based on (British Petroleum, 2021):
   a. 1 boe = 6 119 000 kJ
   b. 1 kWh = 3 600 kJ

d) The upstream emission intensities have not been compared with those detailed in recently published literature concerning the GHG emissions in regions where the upstream oil and gas production landscape is noticeably different to that of the UK.

e) It is noted that the diversity of supplies that the UK's LNG imports comprise will result in a higher degree of uncertainty in the emission intensity figure determined by the OGA; however, it is considered a suitable estimate for the purposes of this study.

4.2 NATURAL GAS REFORMING

Around 70 million tonnes of dedicated hydrogen are produced each year at present, 76 % from natural gas. Global hydrogen production today is responsible for 830 $MtCO_2$/ year; as a point of reference, this equates to the annual CO_2 emissions of Indonesia and the United Kingdom (UK) combined (IEA, 2019). This makes it clear that decarbonisation is required for current hydrogen production.

This section aims to provide an analysis of grey hydrogen (hydrogen produced using fossil fuels) and blue hydrogen (hydrogen produced using fossil fuels; however, a method of capturing the carbon dioxide is involved) in terms of plant efficiencies and CO_2 emissions.

4.2.1 Basis and methodology

4.2.1.1 Grey hydrogen assessment

The two most common technologies for hydrogen production from natural gas reforming have been assessed: steam methane reforming (SMR) and autothermal reforming (ATR).

Various open-source data were evaluated to gain an understanding of the efficiencies of the SMR and ATR processes (see Table 4.3). The evaluation criteria used to select a representative case for the rest of the study, was a reference source that included a complete data set, e.g. details of export steam rates, power loads within the plant and feed and fuel consumption for a given plant production rate. It was also considered to add value if a data source attempted to benchmark any theoretical results against operational data.

The amount of steam generated is an important consideration. The steam can be utilised within the plant, either as motive fluid for rotating equipment, or power generation through the use of back-pressure or condensing turbines. If the steam is not required by the process or there is a surplus, it can be exported to nearby users. However, it should be noted that the steam is being produced at the expense of natural gas as fuel which would inherently give rise to CO_2 emissions.

Table 4.3: Discussion of open-source data references used to evaluate grey hydrogen

Reference	Comments
PTQ Q3, 2013	The data provided in this paper are expansive, however, is based upon a simulation model. Although there is mention of the data of comparing the simulation model results with reference data available in literature, there is no mention of the validity of said data. Furthermore, the power requirements of production have not been discussed
Hydrogen Production Technologies, Current state, and future development, 2013	This reference states ranges for hydrogen production technologies based on other referenced data, however, fails to provide plant data
Economic assessments of hydrogen production processes based on natural gas reforming with carbon capture, 2018	The data provided in this paper includes all the relevant data, i.e. power loads and steam loads. They also provide the CO_2 emissions for the considered processes. Although the data are used to model a simulation they have been compared to industrial data for model validation (no significant differences being recorded)
SMR-X Zero steam hydrogen production, Air Liquide, 2021	The data in this reference refer to *SMR-X – Zero steam hydrogen production*. Though they provides the feed and fuel requirements for the process, they do not discuss the power load requirements, therefore do not give a whole picture analysis

Table 4.3: Discussion of open-source data references used to evaluate grey hydrogen (continued)

Reference	Comments
Steam methane reforming, Air Liquide, 2021	The data in this reference refer to steam methane reforming technology. Though they provide the feed, fuel, and steam requirements for the process, they do not discuss the power load requirements, therefore do not give a whole picture analysis
Autothermal reforming, Air Liquide, 2021	The data in this reference refer to autothermal reforming – syngas generation technology. Though they provide the feed, fuel, and oxygen requirements for the process, they do not discuss the power load requirements, or any mention of steam generation, therefore do not give a whole picture analysis. An estimation of steam generation has been used for the calculation based on a feed/steam generation ratio from an independent study. However, as the data are not directly from the reference, this cannot be confirmed as the true steam generation feed/steam generation ratio.
Clean hydrogen, 2019	This reference provides data on blue hydrogen as opposed to grey hydrogen; however, it is still considered to be a valid data point. It does provide a discussion on the feed requirements for the process, however fails to mention any discussion on steam or power loads. Inconsistencies have also been recognised concerning the stated natural gas energy
Techno-economics of deploying CCS in an SMR based hydrogen production using ng as feedstock/fuel, 2017	The data provided in this paper include all the relevant data, i.e. power loads and steam loads. They also provide the CO_2 emissions for the SMR process, however do not provide an analysis on the ATR process

The efficiency bounds based on the named references can be seen in Table 4.4:

Table 4.4: Efficiency values quoted from references (higher heating value (HHV) basis)

Parameter	SMR	ATR
Efficiency	83–92 %	74–88 %

Economic assessments of hydrogen production processes based on natural gas reforming with carbon capture (2018) was picked as the base case as it provided a complete data set of data and has been compared to industrial data for model validation. It also provides an analysis of both the SMR and ATR processes. The production rate for this reference is 100 000 Nm^3/h of hydrogen (355 MW) with a purity of 99,95 % with use of a pressure swing adsorber (PSA). This production rate is indicative of a mid-sized SMR plant. *Autothermal reforming* (Air Liquide, 2021) shows that an ATR plant can produce up to 600 000 Nm^3/h of hydrogen; however, increasing the production rate above 100 000 Nm^3/h has little effect on the overall efficiency of the process.

Table 4.5: Efficiency and CO_2 emissions from literature on autothermal reforming, (Air Liquide 2021) (HHV Basis)

Process	Units	SMR	ATR
Hydrogen production	kNm^3/h	100	100
Hydrogen production	MW	355	355
Natural gas required	MW	448	487
Power output	MW	14,97	21,73
Efficiency	%	83 %	77 %
CO_2 emissions	gCO_2/kWh	268	285

Note that the purity of the hydrogen produced is determined by the purification step and is largely an economic decision based on the cost of purification and end-user requirements; it has little influence on overall energy efficiency. Refer to 4.2.3 for further details.

4.2.1.2 *Blue hydrogen assessment*

Grey hydrogen flowsheets export power as steam in addition to hydrogen product; the blue hydrogen efficiency then subtracts heat and power consumption for the additional demands associated with CO_2 capture and processing:

- solvent regeneration duty for the amine CO_2 capture unit;
- CO_2 compression, and
- Triethylene Glycol (TEG) dehydration unit.

These data were then added to energy requirements for grey hydrogen to calculate an overall blue hydrogen efficiency.

Locations from the flue gas (post-combustion) and syngas (pre-combustion) were assessed for the SMR process and syngas capture for the ATR process. The location at which the CO_2 is captured is an important consideration as it determines how much CO_2 can be captured and the power load requirements required, primarily due to operating pressure at the capture location.

CO_2 present in the steam reformer flue gas has a very low partial pressure (about 0,2 bara) and the flue gas actual volumetric flow is 20 times or more the syngas volumetric flow (m^3/h). These two factors mean that CO_2 removal from this stream is generally more complicated and expensive compared to capture from syngas.

CO_2 can be separated from the high-pressure synthesis gas stream to reduce overall emissions by up to 60 %. The 60 % of CO_2 value is typical for an SMR, but can be up to 95 %, if syngas, or hydrogen, is used as fuel in the reformer and the SMR is operated in deep conversion mode, although this does reduce efficiency due to increased steam/carbon ratio in the feed and higher operating temperature. CO_2 capture from PSA tail gas is uneconomical and not standard practice and therefore has not been considered.

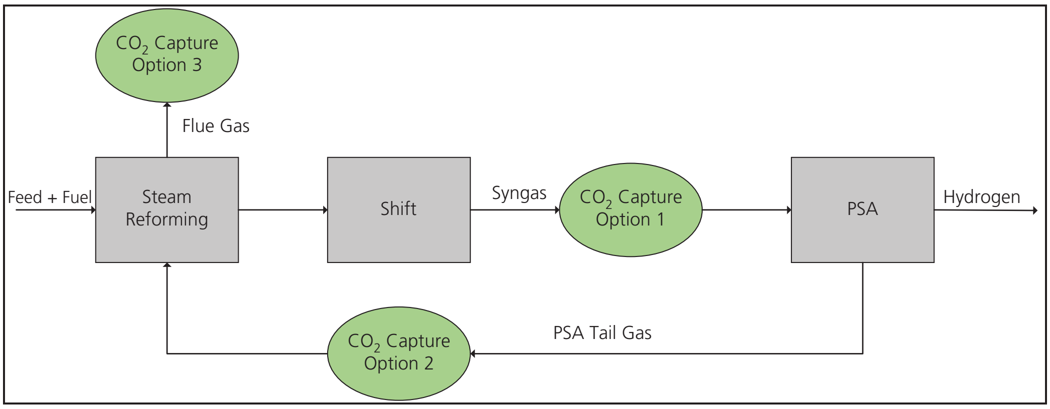


Figure 4.1: CO_2 capture locations for steam methane reforming processes

Footnotes to figure: PSA CO_2 capture has been shown on this diagram; however, this was not evaluated.

The following sections provide details on how the auxiliary equipment for CO_2 capture was accounted for.

CO_2 balance

Table 4.6 shows the CO_2 generated on a basis of 100 000 Nm^3/h of hydrogen produced (*Techno-economic evaluation of H_2 production with CO_2 capture for industry*, 2016).

Table 4.6: CO_2 balance generated on a basis of 100 000 Nm^3/h of hydrogen produced

Process configuration	CO_2 captured (t/h)	CO_2 capture %
SMR – flue gas capture	84,90	90
SMR – syngas capture	48,40	60–95 (note)
ATR – syngas capture	86,50	95

Note: using natural gas to pre-heat and heat the feed stream in an SMR process leads to the lowest overall CO_2 recovery from syngas. The fuel gas combustion products are vented as flue gas; it is not possible to recover these emissions with syngas capture for an SMR process.

It is understood, however, that licensors are developing configurations that utilise low carbon fuel streams generated within the reforming process to significantly reduce carbon emissions within the SMR flue gas. This has not been assessed in this study due to lack of publicly available data.

For ATR, there is no separate flue stream as the process self-generates the required heat and therefore higher capture rates are possible.

Solvent regeneration duty

Solvent regeneration duty has the biggest impact on blue hydrogen efficiency relative to grey hydrogen; more energy is required for flue gas capture compared to syngas capture. A range of regeneration duties for syngas capture and flue gas capture has been compiled and averaged. The average values are then used to provide an overall indicative value for typical energy requirement for pre-combustion and post-combustion.

Table 4.7: Average energy requirements for pre-combustion solvent regeneration energy for blue hydrogen production

Solvent type	Typical energy requirement (GJ/te CO_2)
ADVaMINE	1,75
aMDEA	0,91
UCARSOL	0,96
UOP Benfield process	1,85
Average	1,37

Table 4.8: Average energy requirements for post-combustion solvent regeneration energy for blue hydrogen production

Solvent type	Typical energy requirement (GJ/te CO_2)
MEA based chemical absorption	3,70
DMX process	2,90
CDRMAX solvent	3,25
Average	3,28

It can be seen that there is a 140 % increase over the solvent regeneration energy requirement when comparing flue gas capture to syngas capture; this is due to the higher circulation rate required for low pressure capture.

For this study it is assumed that the energy available in the hot syngas is used to provide the required duty to the amine CO_2 regeneration unit. For blue hydrogen efficiency therefore, it is the incremental duty of flue gas capture compared to syngas capture that is considered in modifying the system efficiency.

CO_2 compression

HYSYS was used to simulate a compression train from 1 barg to 150 barg (as per framing workshop). The duties have been extracted from HYSYS. To power the compressor, imported power will be required. The power of compression is added to the power and heating duties to calculate blue hydrogen efficiency.

Table 4.9: CO_2 compression duties and CO_2 emissions for calculating blue hydrogen efficiency

Process configuration	**CO_2 compressed (t/h)**	**Total duty (kW)**	**CO_2 emissions of imported power (tCO_2/h) (1)**
SMR – flue gas capture	84,92	8 028	1,45
SMR – syngas capture	48,40	4 575	0,82
ATR – syngas capture	86,50	8 177	1,48

Footnotes to table:

a) The power imported is based on UK 2020 average, see 4.1.1.

TEG dehydration

A triethylene glycol (TEG) dehydration unit will be required as the CO_2 will be saturated with water which would result in a highly corrosive stream. Multiple references were evaluated and then averaged to determine an indicative value for energy consumption. The regeneration duty is added to the power and heating duties to calculate blue hydrogen efficiency.

Table 4.10: Triethylene glycol (TEG) dehydration unit duties to remove water from CO_2 processed from blue hydrogen production

Process configuration	**Water to be removed (kg/h)**	**Total duty (kW)**
SMR – flue gas capture	93,52	120
SMR – syngas capture	53,30	68
ATR – syngas capture	95,27	122

4.2.1.3 Blue hydrogen results

The results for blue hydrogen efficiency and CO_2 emissions are presented in Table 4.11.

Table 4.11: Overall blue hydrogen efficiency and CO_2 emissions requirements

Parameter	**Units**	**SMR – flue gas capture**	**SMR – syngas capture**	**ATR – syngas capture**
Hydrogen production	Nm^3/h	100 000	100 000	100 000
Hydrogen production	MW	355	355	355
Natural gas required	MW	448	448	487
Net power output (grey) (6) (power output – power consumed)	MW	15,0	15,0	21,7
– Steam turbine output (power output)	MW	*16,0*	*16,0*	*31,5*
– Expander output (power output)	MW	*1,0*	*1,0*	*1,3*

Table 4.11: Overall blue hydrogen efficiency and CO_2 emissions requirements (continued)

Parameter	Units	SMR – flue gas capture	SMR – syngas capture	ATR – syngas capture
– air separation unit (power consumed)	MW	–	–	*8,6*
– Utilities (power consumed)	MW	*2,1*	*2,1*	*2,4*
Net power consumption for blue hydrogen (7)	MW	67,2	4,6	8,3
– Solvent regeneration duty (power consumed) (1)	MW	*77,5*	*18,4*	*32,8*
– Heat required after syngas integration (power consumed) (b)	MW	*59,1*	*0*	*0*
– CO_2 comp. (Power consumed) (c)	MW	*8,0*	*4,6*	*8,2*
– Teg regen. (Power consumed) (d)	MW	*0,10*	*0,07*	*0,12*
CO_2 capture rate	%	90 %	60 % (e)	95 %
Blue hydrogen efficiency	%	72 %	82 %	76 %
CO_2 emissions (i)	gCO_2/kWh	28,2	107,8	14,9
Hydrogen purity (h)	%	99,95	99,95	99,95

Footnotes to table:

a) This calculation is based on the average solvent regeneration duty for the service.

b) This calculation is based on the assumption that the energy in the hot syngas provides the necessary solvent regeneration duty required for the amine CO_2 regeneration unit. It is then the incremental duty of the flue gas capture compared to syngas capture that is considered in modifying the system efficiency.

c) This calculation is based on CO_2 compression power required from 1 barg to 150 barg.

d) This calculation is based on the duty required to dehydrate the CO_2 using a TEG dehydration unit.

e) It is possible to achieve 95 % CO_2 capture through this concept; however, this requires key modifications to the process: increase of steam to carbon ratio in feed; increased operating severity in reformer and the use of low carbon fuel in the reformer. These mods significantly reduce process efficiency but may still represent the most cost-effective way to capture a high percentage of CO_2 using an SMR process.

f) The net power output value reflects the power generated by the grey hydrogen process, (i.e. export steam) minus the power consumed to operate the process.

g) The power usage for hydrogen is calculated by summing the values for heat required after syngas integration, CO_2 compression and TEG regeneration.

h) Hydrogen purity is largely an economic decision based on the cost of purification step and end-user requirements; it has little influence on overall energy efficiency. Refer to 4.2.3 for further details.

i) CO_2 emissions include uncaptured process gas and CO_2 emissions associated with power import assuming UK grid on a 2020 basis, see 4.1.1.

4.2.2 Blue hydrogen efficiency and GHG emissions discussion

It is important to note that the grey ATR process is shown to be less efficient than the grey SMR, primarily due to the additional power requirement for the air separation unit (ASU). However, for blue hydrogen schemes ATRs are more efficient due to the ability to meet the amine regeneration heating duty with heat recovery. Figure 4.2 shows the efficiency penalty associated with capturing CO_2 is in the range of 1–10 %, which is largely dictated by the amount of heat integration available.

The production rate of 100 000 Nm^3/h used as a basis for this study is representative of a mid-sized SMR plant. *Autothermal reforming* (Air Liquide, 2021) shows that an ATR plant can produce up to 600 000 Nm^3/h of hydrogen; however, there are no known ATR plants that are used to produce solely hydrogen, due to their lower efficiencies compared to SMR plants.

Table 4.12: Hydrogen production capacity limits for steam methane reforming (SMR) and autothermal reforming (AR)

Parameter	Units	SMR	ATR
Capacity	Nm^3/h	300 000	600 000

Footnotes for table:

a) This value is based on a reported capacity (Air Liquide, 2021). It is stated that the ATR process can produce 1 000 000 Nm^3/h of syngas. Based on the stoichiometry of an ATR process this equates to approximately 700 kNm^3/h of hydrogen production; however, if the purpose of the ATR is to only produce hydrogen with all the carbon monoxide (CO) to be converted to CO_2 and hydrogen then the capacity is expected to drop due to the steam/carbon ratio. This is estimated to be approximately 600 kNm^3/h of hydrogen.

Although adopting a blue hydrogen scheme lowers the energy efficiency, it allows for significant reduction in CO_2 emissions. The location of the CO_2 capture point determines the potential CO_2 captured. The capture rates for each method are shown in Table 4.11. In particular for flue gas capture with SMR, up to 90 % of the CO_2 can be captured; however, due to the low partial pressure of CO_2 in the flue stream this system is more challenging to employ than syngas capture and comes with a significant energy penalty. It is understood that Licensors have identified options to move away from flue gas CO_2 capture for blue hydrogen schemes using SMR whilst retaining overall high (>90 %) carbon capture efficiencies. These modifications are in development and with limited published data.

The efficiencies for SMR syngas capture and ATR syngas capture remain high due to energy integration of the syngas. External heat input is only anticipated for flue gas capture, which then results in incremental efficiency losses. This analysis further shows that the solvent regeneration duty required for the amine CO_2 units plays a major role in determining the overall efficiency of a blue hydrogen process.

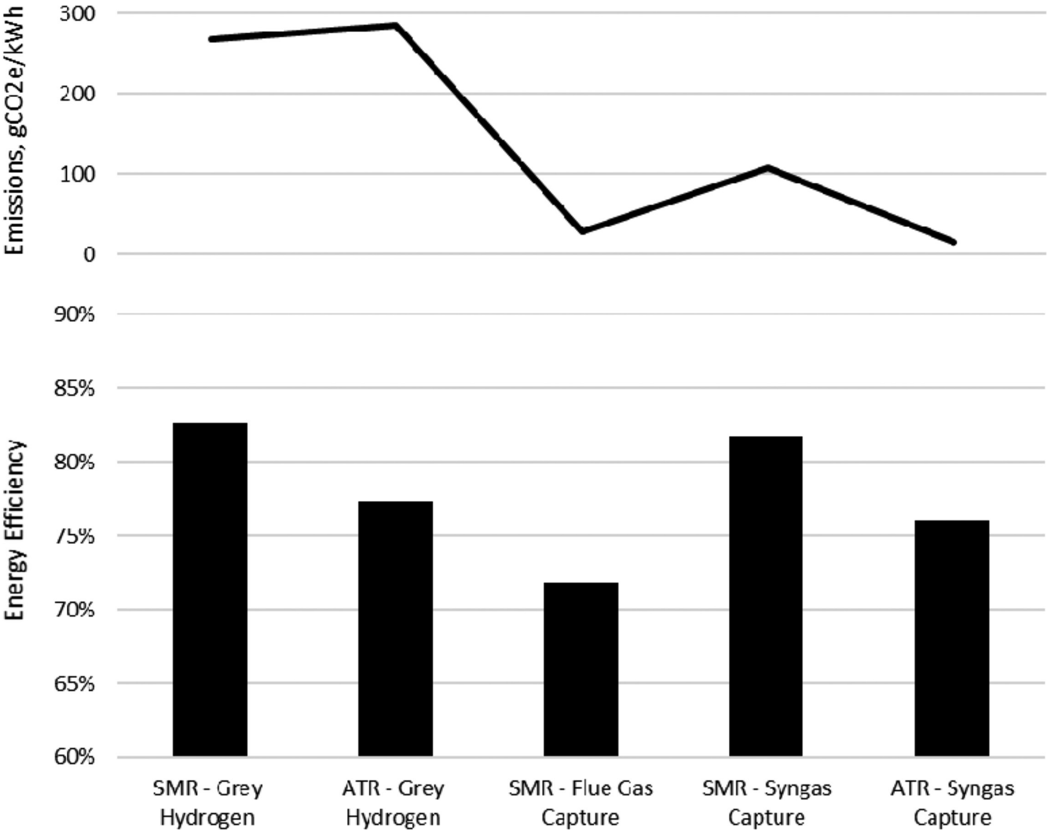


Figure 4.2: SMR and autothermal reforming (AR) efficiencies and CO_2 emissions summary for grey hydrogen, flue gas capture and syngas capture

It is important to note that this assessment is based on analysis of flow schemes developed for production of hydrogen for refinery operation where the hydrogen produced is a small part of the overall plant economics. As flow schemes are being developed for the specific purposes of blue hydrogen production a greater focus is given to overall energy balance; it is understood anecdotally that system efficiencies of 80+ % are generally targeted for new developments and this is expected to creep up incrementally as the technology matures.

4.2.3 Purity impact

The purity of hydrogen in syngas post-CO_2 removal is typically around 95–98 mol% for both ATRs and SMRs, depending on the specific design. This gas will contain a high proportion of CO which means it has little practical use without further purification.

The product purity of hydrogen has a relatively small impact on process efficiency. This is because technologies such as PSAs, can be tuned for a range of product purities and increasing product purity mostly results in increased tail gas flow. A higher purity product will result in a higher CAPEX. To achieve the same production rate at a higher purity the plant will need to be bigger as more product is lost to the PSA. This tail gas stream is generally used as fuel for the reformer furnace or, in the case of ATR processes, for the feed preheater. As long as the calorific value of the tail gas does not exceed the firing requirements of the reformer or fired heaters, then the energy content is recovered and is simply equivalent to natural gas fuel, albeit less by the overall efficiency of the hydrogen production process: i.e. as 1 kW of tail gas fuel takes ~1,25 kW of feed to make, this means that it is marginally less efficient to use tail gas as fuel compared to fresh feed.

For ATR processes, the fuel demands are low as most of the energy is generated within the ATR; this means that for high purity product scenarios, there may be an excess of tail gas. In this case, the tail can be compressed and recycled to the feed; however, this is energy/cost-intensive, and the degree to which this is possible is constrained by the accumulation of inert gases, e.g. argon and nitrogen.

For the purpose of this calculation, it is estimated that targeting high purity hydrogen has a 2,5–5 % efficiency penalty, but that this is already accounted for in the grey hydrogen calculations. There is therefore an efficiency gain of 5 % when producing 98 % or less purity product.

For high purity hydrogen (99,9 % or greater), 10–15 % of the hydrogen product is lost in the tail gas. This means roughly 25 % of 10–15 % of additional natural gas must be consumed for the same energy supply to the reformer. This is how the 2,5–5 % loss is estimated.

Note that in modern SMR processes where CO_2 is captured in the syngas, syngas may be used as fuel in the reformer to avoid additional CO_2 emissions in the reformer. In this case, hydrogen loss in the purification process has no impact as it simply reduces the quantity of syngas firing.

Table 4.13: Hydrogen purity effect on efficiency and emissions for SMR AR

Hydrogen purity (%)	SMR		ATR	
	Efficiency	CO_2 emissions (gCO_2/kWh)	Efficiency	CO_2 emissions (gCO_2/kWh)
95 % [(a)]	88 %	254	–	–
98 % [(b)]	–	–	82 %	270
99,95 %	83 %	268	77 %	285

Footnotes for table:

a) 90–95 % efficiency is achieved using an SMR process without a PSA.

b) 98 % efficiency is achieved using an ATR process without a PSA.

4.3 ELECTROLYSIS OF WATER

4.3.1 General

Electrolysis converts electrical energy and water into hydrogen and is under broad consideration for addressing the global desire to achieve net zero GHG emissions by 2050. Hydrogen is attractive as it is an energy carrier that can be created from renewable electricity and releases only water when it is used by the consumer. A green hydrogen production system can meet both consumers' instantaneous demand and is storable, providing the advantage that it can manage supply peaks. Electrolyser stacks are inherently flexible systems, allowing operation between 0 % and 10 % of nominal load (IEA, 2019) (IRENA, 2018); in this respect they are highly suited to variations in the availability of renewable electricity and instantaneous hydrogen demand.

An electrolyser system can produce very pure hydrogen (>99,95 %), thus having a very low level of impurities, typically oxygen and moisture. However, the impurity content in the hydrogen produced is less than 2ppmv for oxygen, and less than 2–5 ppmv for moisture, according to most major manufacturers. The installation of a simple dryer and filter can reduce these impurities if required, allowing purities higher than 99,999 % to be obtained. For most green hydrogen production projects, the by-product oxygen of the electrolysis process is vented.

The scope of this assessment will consider green hydrogen production starting at the generator terminals of the wind turbine: wind is selected as it is by far the most common form of renewable energy in the UK.

For electrolysers, water quality is an important factor for process efficiency, and the requirements for water treatment plant (including utility systems and water quality requirements) will depend on the electrolysis technology. There are three main technologies existing today for green hydrogen production:

- alkaline water electrolysis;
- polymer electrolyte membrane (PEM), and
- solid oxide electrolysis cells (SOECs).

These technologies differ significantly today in their levels of development and industrialisation, i.e. maturity.

SOEC electrolysers promise a high potential in terms of efficiency compared to alkaline and PEM technologies but requires a source of steam rather than water. SOEC is still in development stage and has been demonstrated small scale, although increased manufacturing capability for SOEC is expected into the 2020s.

However, the scope of this study will be limited to the most mature technologies, alkaline and PEM electrolysers. Table 4.14 provides an overview of the characteristics of both technologies with information drawn from multiple sources (IEA, 2019) (IRENA, 2018) (IRENA, 2020) (Meier. K, 2014) (EDF Energy, 2019).

Table 4.14: Overview of characteristics of alkaline and PEM technologies electrolysis

Parameter	Units	Alkaline	PEM
Feedstock	n/a	Fresh water with 25–30 % KOH/NaOH water solution (recycled)	Fresh water
Electrode material	n/a	Ni, Cu, Mn, W, Ru	Pt, Ir, Ru, Rh
Operating pressure	barg	1–30	30–40 (higher possible)
Operating temperature	degC	60–80	50–80
Stack lifetime	h (x1 000)	60–90(a)	30–90(a)
Load range(b)	%	20–100	0–100
Ramp time	n/a	~ 10 minutes	From 1 sec to 5 min
Plant footprint(c)	m^2/kW	0,095	0,048

Footnotes to table:

a) Average is estimated at 80 000 h for alkaline and 40 000 h for PEM electrolysers.

b) Relative to the nominal load. Alkaline units require heat to operate and below this certain value (~20 %) not enough heat is generated to allow the unit to actually operate.

c) Plant footprint refers only to the electrolyser. This is a representative value, and the size of both the electrolysers and entire system will depend largely on the manufacturer and the selected configuration.

Alkaline technology stands out for its longer stack life cycle (see 4.3.2 for more detail) and its relatively low capital costs, which make it the most widespread technology today.

PEM technology is characterised by its potential to operate over a wide load range, and even in overload situations, as well as its relatively small size, which makes it ideal for applications where space may be an issue. Nevertheless, it has higher costs and is currently less developed and deployed than alkaline technology.

4.3.2 Alkaline water electrolysis

Alkaline water electrolysis is the oldest and most mature technology for the production of green hydrogen; it has been used in industry for almost a century. This type of electrolyser is characterised by two electrodes operating in a 25–30 % liquid solution of potassium hydroxide (KOH) or sodium hydroxide (NaOH), and by a high durability mainly due to the interchangeable electrolyte.

While alkaline technology was not originally designed to be flexible and has traditionally operated at constant load to meet industrial needs, recent advances allow operation between 20 % and 100 % of the nominal load. If power falls below 20 % of the design, the electrolyser should be shut down for safety reasons, a limitation that does not apply to PEM. However, an alkaline electrolyser system can follow the fluctuations of green energy (both wind and solar) as it can be designed to operate multiple stacks allowing individual stacks to be turned on and off independently. It is generally recommended to have back-up supply (battery or grid) to allow the electrolyser to run at full capacity as much as possible to maximise economy and reduce the cost of hydrogen production.

For both alkaline and PEM, the core of the electrolysis system is mainly composed of the stacks, the balance of plant (BoP) and the purification and drying unit (PDU).

The electrolysis package also includes the auxiliary systems necessary to supply the core electrolyser with the required service fluids and to ensure its correct and safe operation. This includes systems such as a transformer/rectifier system, to supply direct current (d.c.) and the control system, to manage the operation of the entire package.

Other auxiliary production systems are typically:

- cooling water system;
- chilled water system;
- demineralised water system;
- nitrogen system;
- instrument air system, or
- electrolyte treatment system (KOH).

A simplified schematic of the electrolysis system package is shown in Figure 4.3.

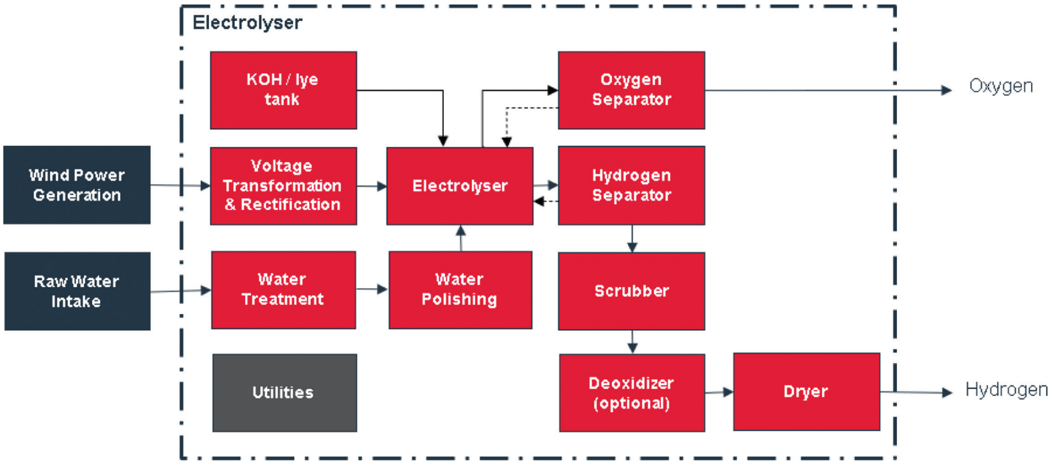


Figure 4.3: Alkaline water electrolyser block flow diagram (BFD) for green hydrogen production

Electrolyser

The electrolyser consists of the electrolysis cells ('stacks') and the BoP system, which includes all the equipment necessary for the treatment of the various fluids of the electrolysis process: fluids; electrolyte; hydrogen; oxygen; feed water; cooling water and nitrogen, including the following equipment:

- gas/liquid separators (one for hydrogen and one for oxygen), to separate the gases from the electrolyte;
- chillers and condensers to cool the hydrogen and oxygen and condense the water vapour with the cooling water;
- electrolyte circulation pumps;
- electrolyte exchangers to cool the electrolyte with cooling water;

- demineralised water injection pumps (directly connected to the demineralized water production system), and
- instrumentation, control, and safety systems.

Purification and drying units (PDU)

After the electrolysis process, the hydrogen produced is sent to the purification and drying processes, which take place in the following three phases:

1. Removal of the oxygen content from the produced hydrogen stream, in a reactor for catalytic combustion ('deoxidiser').
2. Cooling of the hydrogen produced, to condense and eliminate the water vapour produced in the catalytic reactor.
3. Drying of the hydrogen through molecular sieves to remove the residual water vapour.

Hydrogen losses in the PDU are minimal because, although part of the hydrogen produced is consumed in the catalytic oxygen removal reaction, the drying is carried out with a zero-loss technology.

Major losses of the system are generated in the form of heat, and a large part of the energy consumption will be used precisely for the cooling system in order to maintain the system at an adequate and safe operating temperature condition. However, the system also has losses due to stack degradation, which is estimated at 0,4 % per year for the PEM technology and 1 % per year for the alkaline technology (being zero the first year) (ANT Energy Solutions and DYNO Nobel Moranbah, 2020), by assuming about 8 500 hours of annual operation.

Assessment

The following basis is applied to the assessment of energy efficiency and emissions:

- Efficiency calculations assume the HHV as the energy content of hydrogen, so a value of 12,77 MJ/Nm^3 has been considered.
- The boundary limit for the production block has been set at 30 barg. This value has been applied for both alkaline and PEM (and blue hydrogen) as it is a range that can be achieved by both technologies; the actual value will depend on the development requirements and specific vendor.
- Stack efficiencies have been converted from kWh/Nm^3 to kWh/kg using a factor of 11.13.
- A typical value of 0,9 litres per Nm^3 has been taken for demineralised water consumption, according to information quoted by the main manufacturers. This is equivalent to around 10 litres of purified water per kg of hydrogen. Mains water requirement is assumed to be double the amount of purified water requirement (IHS, Markit, 2021) as per main manufacturers and literature, i.e. about 50 % of mains water is used to produce purified water, while the remaining half is mainly a liquid effluent with high ion concentration being rejected.
- Seawater has been considered as feedstock for the electrolysis process. Therefore, a desalination unit will be considered prior to the demineralisation treatment (see 4.3.4). The reason for studying this unit separately is because most of the literature and manufacturers consider mains water as feedstock. Therefore, this desalination unit would be necessary to provide the water feed for industrial scale units. The processes addressed for desalination include both membrane separation processes and thermal processes.

- BoP energy consumption is estimated at 15 % of the stack consumption based on prior experience indicating a range of 10–20 %. This includes all the auxiliary systems of the electrolyser package apart from the electrolyser itself: hydrogen treatment and dryer; oxygen separation; water treatment (demineralisation unit and utilities); cooling system; remote monitoring and control system.
- Power demands are assumed to be supplied from the UK Wind (see 4.1.1). No direct emissions are associated with green hydrogen production other than those related to electricity supply. In practice there may be a connection to the grid, in order to meet both consumers' instantaneous demand and manage supply peaks. However, the plants can operate without such a grid connection if there is a battery energy storage system (BESS). This study assumes use of BESS to ensure 'green' accreditation.
- Alkaline electrolysis requires the consumption of chemical components, mainly KOH or NaOH which are necessary for dilute solution in water. These components are not continuously consumed during normal operation but refilled for start-up and will only be replaced after every 30 000 hours of operation or in case of leakage. As this is a regenerative process the emissions associated with the supply of these components are considered to fall within the accuracy of the assessment.

A range of open sources has been evaluated in order to estimate the efficiencies of the alkaline electrolysis technology. Details on stack efficiency are shown in Table 4.15 and system efficiencies are provided in Table 4.16.

Table 4.15: Alkaline electrolysis stack efficiency references

Vendor/ reference	Stack consumption [kWh/Nm^3]	Efficiency HHV [%]	Capacity/remarks
Peric	4,5	78,8 %	5 to 15 Nm^3/h
	4,5	78,8 %	5 to 100 Nm^3/h
	4,3	82,5 %	15 to 100 Nm^3/h
Cummins	5,4	65,7 %	10 to 30 Nm^3/h
	5,4	65,7 %	60 to 70 Nm^3/h
	5,4	65,7 %	100 Nm^3/h
McPhy	4,6	77,1 %	20 Nm^3/h
	4,5	78,8 %	200 Nm^3/h
Hygear	5,2	68,2 %	50 Nm^3/h
	5,2	68,2 %	150 Nm^3/h
	5,2	68,2 %	250 Nm^3/h
H_2 Nitidor	4,6	77,1 %	200 Nm^3/h
Nel	4,4	80,6 %	500 Nm^3/h
John-Cockerill	4,7	76,1 %	1 000 Nm^3/h
Thyssenkrupp	4,3	82,5 %	2 000 to 4 000 Nm^3/h
Sunfire	4,7	75,5 %	2 150 Nm^3/h
IEA, 2019	4,1–4,5	78,8–86,5 %	
IRENA, 2020	4,7–6,6	53,8–75,6 %	As for 2020. Expected to be < 4,2 kWh/Nm^3 by 2050

Table 4.16: Alkaline electrolysis system efficiency references

Vendor/reference	System consumption [kWh/Nm^3] (a)	Efficiency [%]	Capacity/remarks
Development of water electrolysis in the European Union, 2014	4,4–6,9	51,4–80,6 %	Reference 17 is seven years old. Range between 4,3–5,9 expected in 2020
IRENA, 2020	5,0–7,8	45,5–71,0 %	As for 2020. Expected to be < 4,5 kWh/Nm^3 by 2050
Avalance	5,0–5,4	65,7–70,9 %	From 1 to 5 Nm^3/h
Teledyne	5,2–6,0	59,1–68,2 %	From 2,8 to 42,0 Nm^3/h
McPhy	5,5	64,5 %	100 Nm^3/h

Footnotes to table:

a) At system level. This includes hydrogen purification and drying, oxygen separation, water treatment, cooling system, control system, etc.

b) By multiplying the electrolyser capacity by the energy content of hydrogen (12,77 MJ/Nm^3 HHV), the energy flow rate can be calculated. As reference, a capacity of 200 Nm^3/h would be equivalent to 709,4 kW as thermal content of hydrogen product.

c) Note that manufacturing capacity is not assessed; it is known there is limited existing capacity to manufacture units at scale of several MW, but workshop space is being developed.

It is important to note that the information available from the suppliers is limited, especially with respect to BoP loads which are highly development-dependent.

4.3.3 Polymer electrolyte membrane (PEM)

A simplified schematic of the PEM electrolysis system package is shown in Figure 4.4.

Polymer Electrolyte Membrane electrolysis is a slightly less mature technology, but it is viewed as rapidly emerging and gaining market traction. It is the electrolysis of water in a cell equipped with a solid polymer electrolyte and is mainly characterised by a high operating capacity under partial load and overload conditions, allowing correct operation between 0 % and 160 % of nominal load. This characteristic is one of the reasons for the recent renewed interest in this technology.

PEM electrolysers are therefore ideal for pairing with wind plants for low-carbon hydrogen production or supplying fast response to the grid, thanks to its high flexibility. Commercial deployment has begun in various regions of the world, and several energy companies, as well as manufacturers and other interested parties, have positioned themselves and created advocacy groups, (e.g. the Hydrogen Council) to take advantage of this potentially large and fast-growing market.

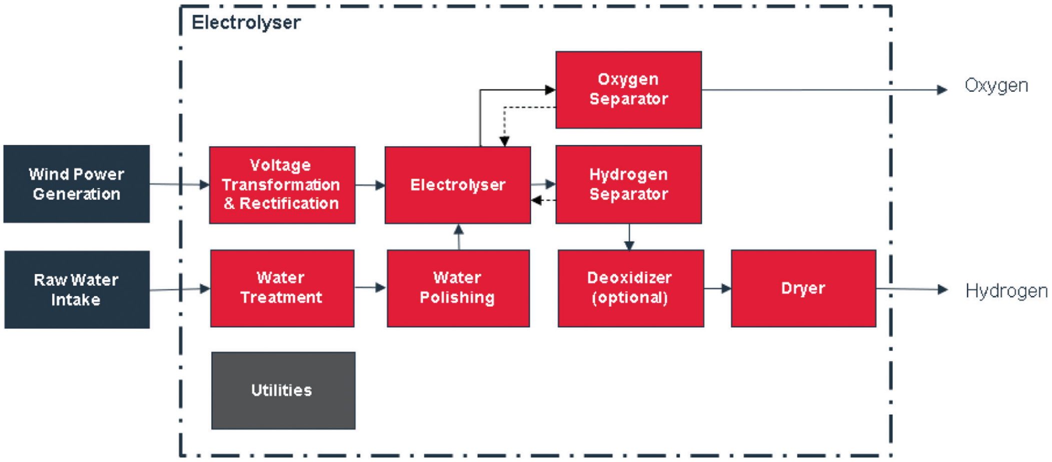


Figure 4.4: A simplified schematic of the PEM electrolysis system package block flow diagram (BFD)

The core of the electrolysis system is mainly composed of the stacks, the BoP and the PDU, plus various auxiliary systems to ensure a smooth and safe operation.

Note that PEM electrolysis does not require an electrolyte treatment system (KOH or lye) as is needed for alkaline technology, nor a downstream unit (scrubber) to remove any remaining impurities, since PEM technology uses a solid polymer electrolyte. However, PEM electrolysers are more sensitive to contaminants than alkaline and therefore require higher purity and quality requirements for water feedstock. Therefore, this type of electrolyser requires a deionisation unit, i.e. a reverse osmosis plus ion exchange process to remove additional remaining ions (IHS Markit). PEM electrodes are also more expensive than those for alkaline systems due to the precious metals content.

Assessment

The following basis is applied to PEM efficiency assessment:

- Efficiency calculations assume the HHV as the energy content of hydrogen, so a value of 12,77 MJ/Nm^3 has been considered.
- The boundary limit for the production block has been set at 30 barg.
- Stack efficiencies have been converted from kWh/Nm^3 to kWh/kg using a factor of 11.13.
- A typical value of 0,9 litres per Nm^3 has been considered for deionised water consumption, according to information quoted by the main manufacturers. Mains water requirement is assumed to be double the amount of purified water requirement (IHS Markit), as per main manufacturers and literature, i.e. about 50 % of mains water is used to produce purified water while the remaining half is mainly a liquid effluent with high ion concentration being rejected to the sewer.
- Seawater has been considered as feedstock for the electrolysis process. Therefore, a desalination unit will be considered prior to the demineralisation treatment (see 4.3.4) – water consumption depends strongly on whether a membrane separation or thermal process is selected.
- BoP energy consumption is estimated at 15 % of the stack consumption based on prior experience indicating a range of 10–20 %. This includes all the auxiliary systems

of the electrolyser package apart from the electrolyser itself: hydrogen treatment and dryer; oxygen separation; water treatment; cooling system; remote monitoring and control system.

– Power demands are assumed to be supplied from the UK Wind (see 4.1.1). No direct emissions are associated with green hydrogen production other than those related to electricity supply.

A range of open sources and catalogues of major manufacturers has been consulted to estimate the efficiencies of the PEM electrolysis process, which are listed in Table 4.17; system efficiencies are provided in Table 4.18 but it should be noted these are dependent on individual development requirements.

Table 4.17: PEM electrolysis process stack efficiency references

Vendor/ reference	Stack consumption [kWh/Nm^3]	Efficiency [%]	Capacity/remarks
Nel	6,1	58,2 %	0,3 to 1 Nm^3/h
	6,0	59,1 %	10 to 30 Nm^3/h
	4,5	78,3 %	100 to 400 Nm^3/h
Peric	5,4	65,7 %	1 to 100 Nm^3/h
GTT	4,4	80,6 %	10 to 200 Nm^3/h
	4,9	72,4 %	20 Nm^3/h
Diamond Lite	6,2	57,2 %	10 Nm^3/h
	5,8	61,2 %	30 Nm^3/h
iGas Energy	5,3	66,9 %	10 to 320 Nm^3/h
H-Tecs	4,9	72,4 %	13 to 210 Nm^3/h
Proton Onsite	5,7	62,2 %	30 Nm^3/h
ITM	5,7	62,0 %	125 Nm^3/h
	5,7	62,5 %	250 Nm^3/h
	5,9	60,5 %	400 Nm^3/h
Plug Power	4,5	79,0 %	200 Nm^3/h
Cummins	4,9	71,8 %	200 to 250 Nm^3/h
	4,9	73,1 %	400 to 500 Nm^3/h
	4,6	77,4 %	1 000 Nm^3/h
Siemens	5,4	65,8 %	225 Nm^3/h
IEA, 2019	4,8–5,1	69,6–73,9 %	
IRENA, 2020	4,7–6,6	53,8–75,6 %	As for 2020. Expected to be < 4,2 kWh/Nm^3 by 2050

Table 4.18: PEM electrolysis system efficiency references

Vendor/reference	System consumption [kWh/Nm^3] [(a)]	Efficiency [%]	Capacity/remarks
Development of water electrolysis in the European Union, 2014	4,4–7,3	48,6–80,6 %	Reference is 7 years old. Range between 3,9–5,4 expected in 2020
IRENA, 2020	5,0–8,3	42,8–71,0 %	As for 2020. Expected to be < 4,5 kWh/Nm^3 by 2050
Proton Onsite	5,5–6,2	57,2–64,5 %	From 1 to 10 Nm^3/h
Plug Power	4,8–5,4	65,7–73,9 %	200 Nm^3/h. Variation is due to plant characteristics

Footnotes to table:

a) At system level. This includes hydrogen purification and drying, oxygen separation, water treatment, cooling system, control system, etc.

b) By multiplying the electrolyser capacity by the energy content of hydrogen (12,77 MJ/Nm^3 HHV), the energy flow rate can be calculated. As reference, a capacity of 200 Nm^3/h would be equivalent to 709,4 kW.

It is important to note that the information available from the suppliers is limited, especially with respect to BoP loads which are highly development-dependent.

4.3.4 Desalinated water supply

Most references for electrolysis consider mains/tap water as a feed. For larger scale applications with higher water demand, seawater seems the mostly likely water source, therefore a desalination unit is needed. This unit is considered separately since most of the data extracted from literature and manufacturers consider mains water as feedstock. For this purpose, three different water desalination processes have been reviewed:

- membrane separation processes, considering reverse osmosis (RO) and forward osmosis (FO), and
- thermal processes, considering multistage flash (MSF).

RO overtook thermal desalination processes as the preferred method more than 20 years ago and will therefore be the process of choice for the assessment. FO was not chosen because of its technological immaturity.

Table 4.19 shows the estimated desalination unit efficiencies for the three processes mentioned.

Table 4.19: Estimated water desalination unit efficiencies for RO, FO and multistage flash (MSF)

Parameter	Units	RO	FO	MSF
Energy consumption per m^3 water	kWh/m^3	3,0	1,0	12,0
Energy consumption per Nm^3 of H_2	kWh/Nm^3	0,002	0,001	0,007
Desalination unit efficiency	%	99,95 %	99,98 %	99,80 %
System emissions	gCO_2/kWh	0	0	0
Seawater consumption	l/Nm^3	4		7

Footnotes to table:

a) Energy consumption is based on average numbers. Newest RO plants are reaching 1 8 kWh/m^3.

b) Consumption of seawater is assumed to be about twice the mains water requirement if a membrane separation process is applied, and about four times higher in the case of a thermal process (IHS Markit). Average values have been selected for the study.

c) Power consumption is compared to energy of resulting hydrogen produced.

d) Power demand is assumed to be supplied from the UK Wind (see 4.1.1).

It can be observed that desalination is an efficient step; as the efficiencies are so low, for this study it is assumed to be included in the allowance for BoP.

4.3.5 Electrolysis results

Based on the strongest references in 4.3.2 and 4.3.3, results representing these technologies are presented here.

Table 4.20 and Figure 4.5 show the results for the calculated alkaline and PEM efficiencies and CO_2 emissions. No direct emissions are associated with green hydrogen production as green electricity is considered as feedstock, see 4.1.1.

Table 4.20: Electrolysis results for the calculated alkaline and PEM efficiencies and CO_2 emissions

Parameter	Units	Alkaline	PEM
Stack energy consumption	kWh/Nm^3	4,8	5,3
System energy consumption	kWh/Nm^3	5,5	6,1
Hydrogen energy content	MJ/Nm^3	12,77	12,77
Stack efficiency	%	73,8	66,9
System efficiency	%	64,2	58,2
System emissions (d)	gCO_2e/kWh	0	0
Purified water consumption	l/Nm^3	0,9	
Mains water consumption	l/Nm^3	1,8	

Footnotes to table:

a) Nominal stack and systems efficiencies are considered at start of life. For Alkaline, a stack degradation is estimated at zero the first year and at 1 % per year in the following years (ANT Energy Solutions and DYNO Nobel Moranbah, 2020), although this is expected to improve as the technology matures. For PEM technology, a stack degradation of 0,4 % per year is estimated for the remaining life; all this assuming a utilisation of 8 500 hours per year. After 80 000 hours, stacks can be easily refurbished to as-new efficiency.

b) The efficiency calculated for both alkaline and PEM electrolysers assumes the use of a BESS as a back-up and considers hydrogen delivery at 30 barg (see 4.3.2 – Assessment).

c) Consumption of mains water is assumed to be double the amount of purified water requirement (IHS Market, 2021).

d) Emissions associated with manufacture and supply of consumables and other indirect emissions are not included in the scope of this assessment.

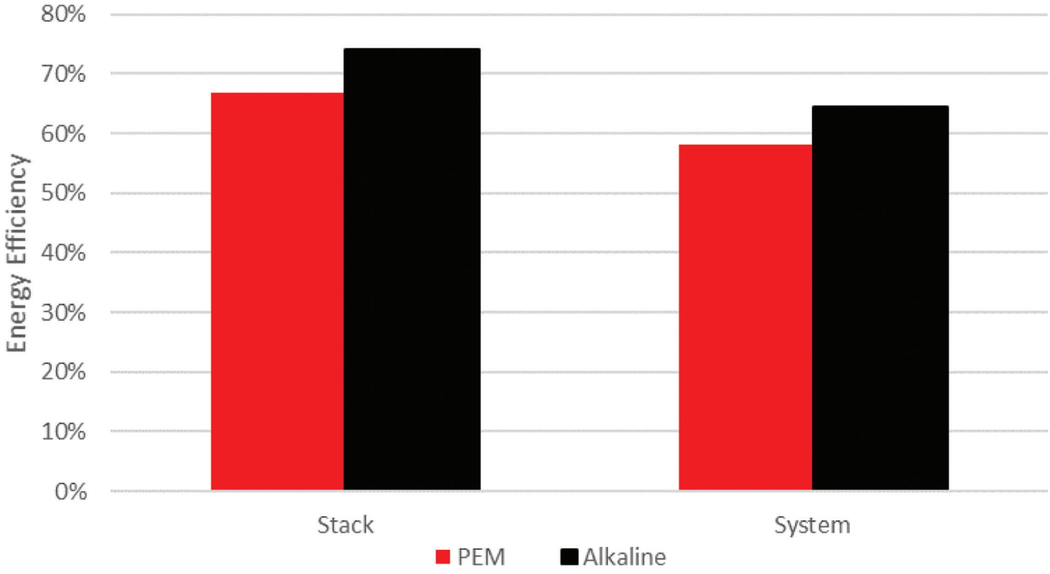


Figure 4.5: Electrolysis results for the calculated alkaline and PEM electrolysis results

As expected, the results show that alkaline technology has a higher efficiency than PEM electrolysers, although it should be noted that both the plant capacity and the diversity of manufacturers and electrolyser models of both technologies could alter these values to a greater or lesser extent. The results are nevertheless consistent with the literature, and the higher efficiency found for alkaline electrolysers could justify the fact that it is currently the most widespread and mature technology. It is also the process with the lowest capital costs in the market, mainly due to the avoidance of precious materials in the manufacturing process.

However, PEM technology has seen an increase in the number of facilities in the last decade, making its way into the international market, notably with a growing presence in Europe. Similarly, the increase in the average size of these electrolysers over the last few years indicates that this technology has rapidly evolved from small projects (0,1 MW in the 2000s) to commercial scale (1,0 MW in 2015–2019). This scale up is expected to continue over time and will help to reduce the costs of this technology and the widespread deployment of this technology in coming years.

The appeal of PEM lies mainly in the potential of the electrolysers to operate over a wide load range, and even function properly in overload situations (up to 160 % of nominal load). They use pure water as the electrolyte solution, thus avoiding the recovery and recycling of chemical electrolyte solutions that is necessary in alkaline electrolysers. In addition, they are capable of producing hydrogen at a higher pressure than alkaline technology without additional compression. This, coupled with their relatively small size, makes them a very attractive technology in areas where space may be an issue, such as dense urban areas or for mobility applications.

5 TRANSMISSION, STORAGE AND DISTRIBUTION

5.1 GENERAL

The vast majority of hydrogen produced today is produced at sites adjacent to the intended consumers due to the cost and challenges associated with its transportation, due to low density of hydrogen. As such, there is no real commodity market for hydrogen as exists for hydrocarbons and therefore the transportation and logistics associated with a large hydrogen market are undeveloped. Small users are commonly supplied by truck transport of hydrogen in compressed gas bottles.

A notable exception to this is the US gulf coast hydrogen network which supplies a network of regional hydrogen users (refineries and ammonia producers) via a network of ~600 miles of pipeline. This also includes geological storage at the Spindletop facility in Texas which has been in operation since 2017. In addition, a hydrogen pipeline has been in operation in Teeside (UK) for many decades having originally been operated by ICI.

This section assesses the energy balance and emissions associated with transporting produced hydrogen (pure or as part of a gas blend) to end-users via a number of methodologies.

5.2 COMPRESSION

Gas compression is a mature technology that is commonly used for movement and storage of natural gas and other industrial gases. Compression of hydrogen is also well established, some refineries employing large hydrogen compressors to feed hydrocracking units. However, capacities for large gas transmission systems are still to be developed. It is impractical to compress low molecular weight gases using centrifugal compression as this would result in a large number of stages and very high speeds; for this reason reciprocating compressors are generally used.

Assessment

The boundary limit for the production block has been set at 30 barg, therefore the compression block only considers pressures above this; LP distribution can be achieved by pressure gradient. The following pressure levels have been assessed:

- HP Compression (70 barg), which is typical for regional transmission through pipelines. This block is assessed for natural gas, 20 % hydrogen blend and 100 % hydrogen blend.
- VHP Compression (350 barg), which is required for some hydrogen users, e.g. fuel cells for heavy vehicles. This is only assessed for 100 % hydrogen stream.
- VHP Compression (700 barg), which is required for some hydrogen users, e.g. fuel cells for light vehicles due to space limitations. This is only assessed for 100 % hydrogen stream.

The following basis is applied:

- Reference case is 1 500 MMscfd of natural gas (equivalent to 40 300 000 Nm^3/d); hydrogen blends consider flows on an energy equivalent basis.
- Compression suction pressure is 30 barg.

- Adiabatic efficiency of 75 % is assumed for natural gas and 20 vol% hydrogen. This is on the low side for large industrial units but allows for other losses through the compression system, (e.g. cooler fans and utilities).
- Adiabatic efficiency of 65 % is assumed for hydrogen compression. Again, this is considered conservative for pressure range considered based on recent project experience but allows for other system losses, (e.g. cooler fans and utilities).
- The power consumption associated with utilities and minor process users is allowed for by an addition of 10 % on top of the compression duties.
- Power is assumed to be supplied from UK grid, see 4.1.1.

The calculation results are shown in Table 5.1 and depicted in Figure 5.1.

Table 5.1: Higher power compression results for natural gas, 20 % hydrogen blend and 100 % hydrogen blend

Fluid	Pressure	Power	Gas flow	Energy flow	Emissions	Block efficiency
	Barg	MW	MMscfd	MW	gCO_2e/kWh	
100 % NG (a)	70	0	1 500	19 353	0,0	100,0 %
20 % H_2 (b)	70	19	349		0,2	99,9 %
100 % H_2	70	275	4 877		2,6	98,6 %
	350	824			7,7	95,9 %
	700	1 108			10,4	94,6 %

Footnotes to table:

a) 100 % natural gas case assumes no compression is needed to transmission pressure as this is within scope of UK natural gas production block (see 4.1).

b) 20 % hydrogen blend assumes this hydrogen portion of the blend is compressed to transmission pressure; the power associated with this operation is then compared to the overall energy flow of the blend to calculate the block efficiency.

c) Compression of hydrogen to 350 barg and 700 barg considers multistage machines.

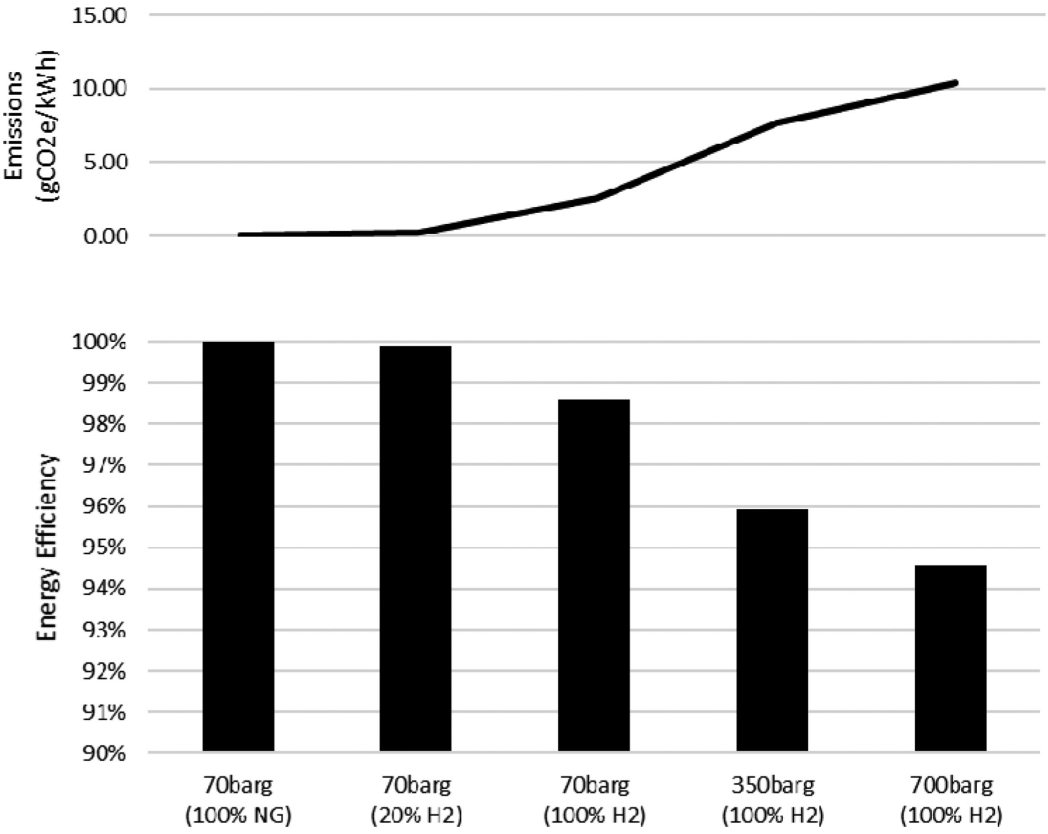


Figure 5.1: 70 barg, 350 barg and 700 barg compression results for natural gas, 20 % hydrogen blend and 100 % hydrogen blend

The results demonstrate that compressing hydrogen involves very large power demands, several times greater than needed to compress the equivalent energy flow of natural gas. However, despite the large compression loads, the power demand is still a small proportion of the fluid's energy content and therefore compression is a relatively efficient value chain block, especially at pipeline transmission pressures.

The greatest challenges for large compression systems are likely to be technical and economic. Feedback from a compressor manufacture indicated that a hydrogen compression system could be up to an order of magnitude greater in plot space than would be needed for a comparable natural gas system, as suggested by the compression powers in Table 5.1. This has significant implications for the feasibility of developing a regional hydrogen network that could meet similar end-user demand to existing natural gas infrastructure.

5.3 STORAGE

Gas storage has been used in the UK since the 1980s to manage supply disturbances and seasonal variations in demand. Typically, this has been by geological storage (depleted gas reservoir and salt caverns), but currently LNG bunkering also serves a similar purpose.

In the UK, hydrogen is primarily stored in two forms: as a liquid and as compressed gas in bottles; domestic demand has not justified storage on the scale currently provided for natural gas. There is precedent for storing hydrogen geologically as there are operating facilities in Texas and this is a growing area of study with a number of potential projects globally.

Assessment

The following methods of storage are assessed:

– pressurised tank, mechanical containment, considered at 350 barg;
– pipeline storage, pipeline packing, considered at 20 barg above normal operation;
– geological storage, considered at 150 barg, typical geological storage pressure, and
– cryogenic storage, at low pressure and very cold temperature (-252 °C at 1 bara).

The following basis is applied:

– Reference case is 1 500 MMscfd of natural gas (equivalent to 40 300 000 Nm^3/d); hydrogen blends consider flows on an energy equivalent basis.
– Storage facility supply pressure is 50 barg for geological storage and pressurised tanks, (i.e. to avoid taking credit for high normal operating pressure).
– Pipeline packing considers 20 barg above normal high operating pressure, (i.e. 90 barg rather than 70 barg); in reality this value would depend on system volume and storage hold-up requirement.
– Adiabatic efficiency of 75 % is assumed for natural gas and 20 vol% hydrogen. This is on the low side for large industrial units but allows for other losses through the compression system, (e.g. cooler fans and utilities).
– Adiabatic efficiency of 65 % is assumed for hydrogen compression. Again, this is considered conservative for pressure range considered based on recent project experience but allows for other system losses, (e.g. cooler fans and utilities).
– Storage for grid management assumes 5 % of demand must go in and out of storage, per (OGUK 2020).
– Storage for intermittency of renewables supply assumes 40 % of demand must go in and out of storage. This number is highly dependent on system design (installed capacity compared to average demand); Graham Sinden of the Environmental Change Institute (2005) states that UK wind turbines typically produce some electricity for 80 % of the year; it is also widely reported that the average UK wind load factor is over 40 % and expected to exceed 50 %. An allowance of 40 % production going into storage allows for some downtime with installed overcapacity. The results can easily be scaled for different storage requirements.
– For pipeline packing for intermittency, as storage requirement is eight times greater, the packing differential pressure is considered to be eight times larger. This is not considered practical from system design perspective, but the results are shown to illustrate the energy efficiency and emissions implications.
– Hydrogen liquefaction process is assumed to consume 35 % of the energy content of the hydrogen stream (Engie and Stevens) (Bossel. U and Eliasson. B). Natural gas liquefaction is assumed to consume 10 % of the fluid's energy content based on industry rule of thumb.
– Power is assumed to be supplied from UK grid with 2020 emissions intensity, see 4.1.1.

- Power associated with filling and emptying storage is estimated by process simulation, assuming the facility is filled and emptied in one day. This is a simplification; for the purposes of this study, it is academic whether the storage fills rapidly with a large power demand for short duration or fills slowly with a lower power demand for longer duration.
- The power consumption associated with utilities and minor process users is allowed for by an addition of 10 % on top of the main process duties.
- Storage capacity is also academic for this study, whether a large facility with low cycle rate or smaller facility with more frequent cycles the annualised power is determined by the amount of annual gas supply that transits in and out of storage.

The calculation results are shown in:

1. Table 5.2 for natural gas.
2. Table 5.3 for 20 % hydrogen blend in natural gas.
3. Table 5.4 for 100 % hydrogen blend.

Table 5.2: Storage capacity results for natural gas

Parameter	Units	Pipeline storage	Pressurised tank	Geological	Cryogenic
Supply pressure	barg	70	50	50	50
Storage pressure	barg	90	350	150	0
Gas flow	MMscfd	1 500	1 500	1 500	1 500
Network energy	MW	19 353	19 353	19 353	19 353
Annual supply	GWd(c)	7 064	7 064	7 064	7 064
Power for 1 day fill	MW	14 (a)	149	81	1 935
Power for 1 day empty (b)	MW	0	0	5	10
Grid management					
Annualised storage supply	%	5 %	5 %	5 %	5 %
Annualised power	GWd(c)	5,0	2,7	1,6	35,3
Block efficiency	%	99,93 %	99,96 %	99,98 %	99,50 %
Emissions intensity	gCO_2e/kWh	0,13	0,07	0,04	0,91

Footnotes to table:

a) For pipeline packing all flow must be compressed to elevated pressure during period when storage is not being drawn down.

b) Withdrawing from geological storage allows for operation of TEG Dehydration system; withdrawing from cryogenic storage allows for regasification.

c) GWd is one gigawatt of power output/consumption for 24 hours and is equivalent to 24 000 MWh.

Table 5.3: Storage capacity results for 20 % hydrogen blend

Parameter	Units	Pipeline storage	Pressurised tank	Geological
Supply pressure	barg	70	50	50
Storage pressure	barg	90	350	150
Gas flow	MMscfd	1 743	1 743	1 743
Network energy	MW	19 353	19 353	19 353
Annual supply	GWd(c)	7 064	7 064	7 064
Power for 1 day fill	MW	18 (a)	187	101
Power for 1 day empty (b)	MW	0	0	6
Grid management				
Annualised storage supply	%	5 %	5 %	5 %
Annualised power	GWd(c)	6,3	3,4	1,9
Block efficiency	%	99,91 %	99,95 %	99,97 %
Emissions intensity	gCO_2e/kWh	0,16	0,09	0,05

Footnotes to table:

a) For pipeline packing all flow must be compressed to elevated pressure during period when storage is not being drawn down.

b) Withdrawing from geological storage allows for operation of TEG Dehydration system.

c) GWd is one gigawatt of power output/consumption for 24 hours and is equivalent to 24 000 MWh.

Table 5.4: Storage capacity results for 100 % hydrogen blend

Parameter	Units	Pipeline storage	Pressurised tank	Geological	Cryogenic
Supply pressure	barg	70	50	50	50
Storage pressure	barg	90	350	150	0
Network energy	MW	19 353	19 353	19 353	19 353
Gas flow	MMscfd	4 877	4 877	4 877	4 877
Annual supply	GWd(c)	7 064	7 064	7 064	7 064
Power for 1 day fill	MW	68	667	357	6 774
Power for 1 day empty	MW	0	0	15	10
Grid management					
Annualised storage supply	%	5 %	5 %	5 %	5 %
Annualised power	GWd(c)	23,5	12,2	6,8	123,6
Block efficiency	%	99,7 %	99,8 %	99,9 %	98,3 %
Emissions intensity	gCO_2e/kWh	0,60	0,31	0,17	3,17

Table 5.4: Storage capacity results for 100 % hydrogen blend (continued)

Parameter	**Units**	**Pipeline storage**	**Pressurised tank**	**Geological**	**Cryogenic**
Wind intermittency					
Annualised storage supply	%	40 %	40 %	40 %	40 %
Annualised power	GWd[(c)]	93,8	97,4	54,3	990,4
Block efficiency	%	98,7 %	98,6 %	99,2 %	87,7 %
Emissions intensity	gCO_2e/kWh	2,4	2,5	1,4	25,4

Footnotes to the table:

a) For pipeline packing all flow must be compressed to elevated pressure during period when storage is not being drawn down.

b) Withdrawing from geological storage allows for operation of TEG Dehydration system; withdrawing from cryogenic storage allows for regasification.

c) GWd is one gigawatt of power output/consumption for 24 hours and is equivalent to 24 000 MWh.

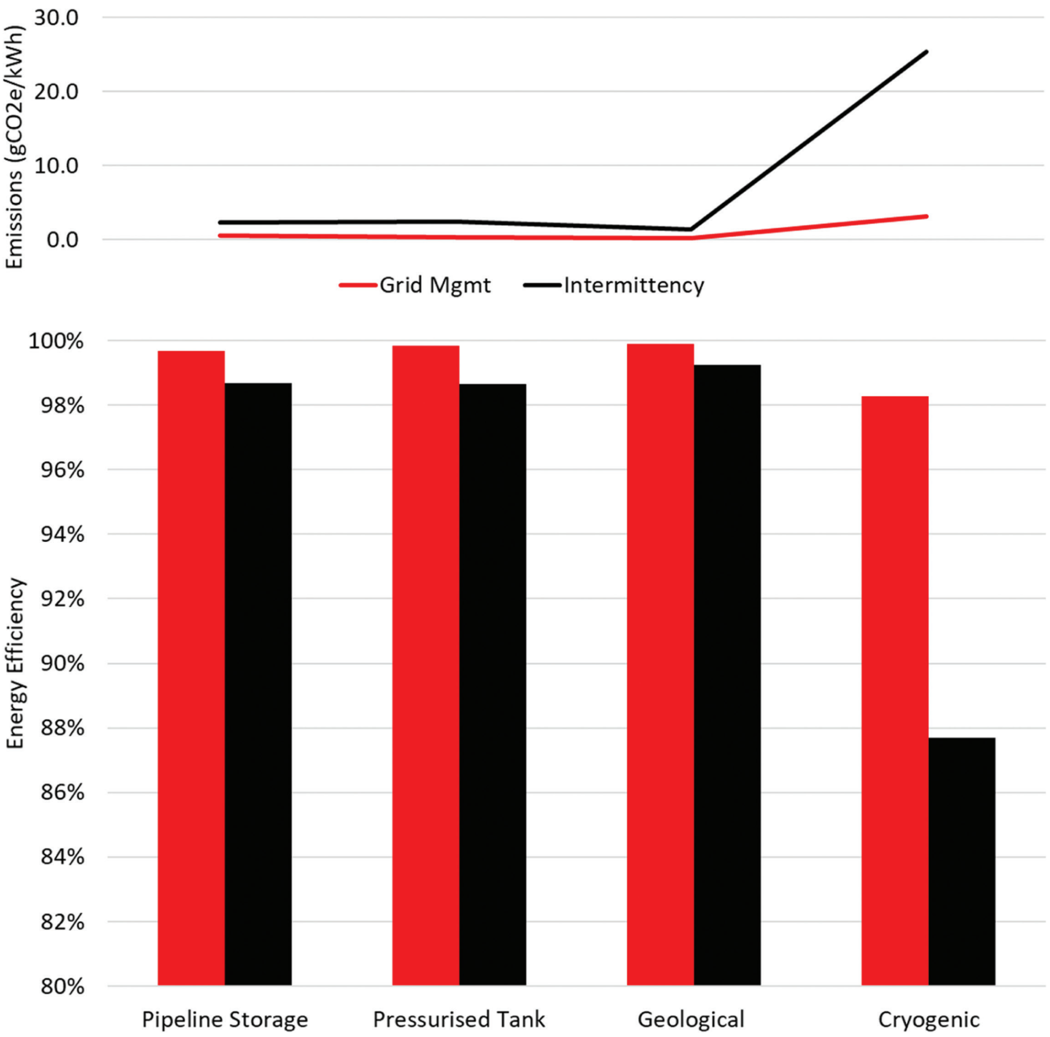


Figure 5.2: Emission and energy efficiency results for storage of 100 % hydrogen blend

Whilst compression is an energy intensive activity, it can be observed that storage of gases is an efficient value chain block when the energy system is viewed as a whole. Only a portion of overall gas supply needs storing to ensure stable flow to consumers.

The power consumption associated with compressed storage is small relative to the energy delivered by the gas system; even for a large storage capacity associated with 40 % of energy delivered storage by compression can be highly efficient.

Geological storage has the lowest energy demands for bulk storage, with corresponding low emissions intensity. This is due to the lower storage pressure compared to pressurised tanks. Geological storage also offers the largest capacity and could be the obvious choice for large scale storage associated with a regional gas network.

Cryogenic storage is noticeably less efficient than compressed gas storage, especially for hydrogen. It may not be considered a good choice for bulk storage associated with managing supply and demand of a network.

Increasing hydrogen content in a blend with natural gas will degrade storage efficiencies due to the increased power of compression (and liquefaction); however, efficiencies remain high relative to the overall value chain losses.

5.4 TRANSPORTATION

5.4.1 Pipeline

Gas is commonly transported by pipelines when used in large volumes due to the efficiency and practicality compared to alternatives. System design typically involves periodic booster stations to maintain the operating pressure within a design range. Assessing the energy efficiency and emissions intensity for pipeline transport means estimating the overall booster compression requirements of the network.

It is important to note that there are technical challenges associated with repurposing natural gas pipelines for transport of hydrogen. The two main challenges are:

- hydrogen embrittlement of steel, and/or
- higher propensity of hydrogen to leak compared to natural gas.

Both of these issues may result in the pipeline operating pressure being reduced, which may then increase pressure boosting requirements or reduce allowable flowrates.

No allowance has been made for mitigation of these issues in this assessment, as they are likely to be highly dependent on the specific pipeline under consideration and are ultimately bigger issues from a technical feasibility (go/no-go) perspective than from an energy efficiency perspective.

Assessment

The following basis is applied:

- Reference case is 1 500 MMscfd of natural gas (equivalent to 40 300 000 Nm^3/d); hydrogen blends consider flows on an energy equivalent basis (see 3.4).
- Booster stations compress gas from 40 to 70 barg. Note the pipeline operating pressures and booster compression philosophy would need to be revised for 100 % hydrogen (and possibly 20 % blend), but for the purposes of this assessment a single set of suction and discharge pressures are considered, and higher-pressure drop will result in more frequent booster stations and therefore higher energy cost associated with the pipeline.
- A nominal network length of 500 km is considered, which is estimated to require three booster stations for natural gas, and a 3 200-mile network is estimated to require 25 booster stations (Natural Transmission System, 2021). This is a simplified analysis to allow compression requirements to be developed given that system design is out of scope.
- Adiabatic efficiency of 75 % is assumed for natural gas and 20 vol% hydrogen. This is on the low side for large industrial units but allows for other losses through the compression system, (e.g. cooler fans).
- Adiabatic efficiency of 65 % is assumed for hydrogen compression, although these compressors are likely to be multistage reciprocating machines which typically apply volumetric efficiency; this is considered conservative for the pressure range considered.

- The power consumption associated with utilities and minor process users is allowed for by an addition of 10 % on top of the compression duties.
- Power is assumed to be supplied from UK grid, see 4.1.1.

Pressure drops associated with the blends considered were assessed calculating the pressure drop per km for equivalent of 1 500 MMscfd natural gas (equivalent to 40 300 000 Nm^3/d) through a 36″ID pipeline at the proposed operating conditions. Results are shown in Table 5.5.

Table 5.5: Pressure drop per km for 100 % natural gas, 20 % hydrogen blend and 100 % hydrogen blend

Parameter	100 % NG		20 % H_2		100 % H_2	
OP, barg	70	40	70	40	70	40
Flow, MMscfd	1 500		1 743		4 877	
DeltaP/km	0,30	0,56	0,36	0,65	0,46	0,78
Factor	–	–	1,20	1,16	1,53	1,39
Factor to use	100 %		118 %		146 %	

Note that the operating pressures considered for all pipelines cases in this section are effectively between 40 barg and 70 barg depending on proximity to booster station. Velocity restrictions have not been considered; further restrictions would increase the de-rating factor for hydrogen but in practice, if this were significant, it is likely this would result in the requirement for the installation of new piping.

The calculation results are shown in Table 5.6 for existing pipelines.

Table 5.6: Transmission pipeline operating pressures for existing pipelines for 100 % natural gas, 20 % hydrogen blend and 100 % hydrogen blend

Fluid	Booster power	Energy flow	No. of booster stations	Total power, MW	Emissions	Block efficiency
	MW	MW			gCO_2e/kWh	
100 % NG	39	19 353	3,0	117	1,1	99,4 %
20 % H_2	48	19 353	3,5	169	1,6	99,1 %
100 % H_2	170	19 353	4,4	745	7,0	96,3 %

For new pipelines the calculation results are shown in Table 5.7. The difference with this assessment is that it is assumed the network will have a similar number of booster stations to the existing gas network as it would have been designed for the new service.

Table 5.7: Transmission pipeline operating pressures for new pipelines (not repurposed) for 100 % natural gas, 20 % hydrogen blend and 100 % hydrogen blend

Fluid	Booster power	Energy flow	No. of booster station	Total power, MW	Emissions	Block efficiency
	MW	MW			gCO$_2$e/kWh	
100 % NG	39	19 353	3,0	117	1,1	99,4 %
20 % H$_2$	48	19 353	3,0	143	1,3	99,3 %
100 % H$_2$	170	19 353	3,0	509	4,8	97,4 %

Results are shown in Table 5.8 for local distribution in existing pipelines; it is assumed that for 100 % hydrogen a booster station would be required to allow for the increased pressure drop. For a 20 % blend the incremental pressure drop is relatively modest and would be mitigated by lower gas demand due to increase in electrification. Any new local distribution would be designed for the service and would not be expected to require booster compression.

Table 5:8: Local distribution pipeline operating pressures for existing pipelines for 100 % natural gas, 20 % hydrogen blend and 100 % hydrogen blend

Fluid	Booster power	Energy flow	No. of booster stations	Total power, MW	Emissions	Block efficiency
	MW	MW			gCO$_2$e/kWh	
100 % NG	0	19 353	0,0	0	0,0	100,0 %
20 % H$_2$	0	19 353	0,0	0	0,0	100,0 %
100 % H$_2$	116	19 353	1,0	116	1,1	99,4 %

As expected, pipelines can be observed to be a highly efficient means of transporting gas. The losses associated with transporting hydrogen by pipeline are an order of magnitude greater than for natural gas; however, they are still low compared to the rest of the value chain. This would not be the case for international pipeline transportation covering large distances.

5.4.2 Trucks, rail and ships

Compressed hydrogen in 'tube trailers' is commonly transported by truck; the gas is usually compressed to 200–250 barg. This method of transportation is convenient for small, dispersed demands where a pipelines system would not be justified or practical to install.

Transport by rail and domestic shipping is less common but references are available for their relative efficiency compared to trucking per tonne of cargo.

Assessment

The following basis is applied:

- Two network lengths are considered: 500 km (comparable with transmission pipeline) and 50 km for local distribution.

- Three pressure levels are considered: 250 barg, 350 barg and 700 barg. It should be noted that technology is currently limited to 250 barg, but higher pressures are anticipated based on new material technology allowing higher pressure containment at manageable vessel weight.
- The literature suggests a payload ranging from 400–720 kg for a 40te truck and tube trailer; 550 kg is considered typical for current technology and is used for this assessment (Bossel, U. and Eliasson, B.) (HyLAW, 2019) (*Advanced hydrogen fuelling stations supply*, 2016).
- A range of 30–40 l/100 km was found for diesel trucks fuel consumption; for this study a value of 35l/100 km is applied for round trip journey.
- A value of 11 kWh/l is applied for diesel energy content.
- Hydrogen densities were found from the National Institute of Standards and Technologies (2018) at 30 °C; these are based on experimental data:
  - 17,3 kg/m^3 at 250 barg.
  - 23,0 kg/m^3 at 350 barg.
  - 38,8 kg/m^3 at 700 barg.
- Rail is considered to use 75 % less energy to transport a given payload compared to trucks (Nippon Express, 2021) (Freighter Blog, 2019). However, rail transportation is limited in terms of volume by a restricted loading gauge.
- Domestic shipping is considered to use 50 % less energy to transport given payload compared to trucks (Nippon Express 2021). For this study 'domestic shipping' is taken to mean near shore transport by ship.

Results are shown in Table 5.9 and Figure 5.3.

Table 5.9: Truck, rail, and domestic shipping transportation results

Parameter	Units	Road truck					
Pressure level	barg	250	350	700	250	350	700
Delivery distance	km	500	500	500	50	50	50
Gas per 40te truck	kg	550	730	1 230	550	730	1 230
H_2 HHV	MJ/kg	142	142	142	142	142	142
Energy delivered	MWh	22	29	49	22	29	49
Truck diesel consumption	l/100km	35	35	35	35	35	35
Diesel consumed	litres	350	350	350	35	35	35
Diesel energy content	kWh/l	11	11	11	11	11	11
Total energy of delivery	MWh	3,85	3,85	3,85	0,385	0,385	0,385
Truck emissions	kgCO_2e/l	2,7	2,7	2,7	2,7	2,7	2,7
Truck emissions total	kgCO_2e	945	945	945	94,5	94,5	94,5
Block efficiency	%	84,9 %	88,2 %	92,7 %	98,3 %	98,7 %	99,2 %
Emissions intensity	gCO_2e/kWh	43,6	32,8	19,5	4,4	3,3	1,9

Table 5.9: Truck, rail, and domestic shipping transportation results (continued)

Parameter	**Units**	**Rail**					
Total energy of delivery	MWh	0,96	0,96	0,96	0,10	0,10	0,10
Block efficiency	%	95,8 %	96,8 %	98,1 %	99,6 %	99,7 %	99,8 %
Emissions intensity	gCO_2e/kWh	10,9	8,2	4,9	1,1	0,8	0,5
Parameter	**Units**	**Shipping**					
Total energy of delivery	MWh	1,93	1,93	1,93	0,19	0,19	0,19
Block efficiency	%	91,8 %	93,7 %	96,2 %	99,1 %	99,3 %	99,6 %
Emissions intensity	gCO_2e/kWh	21,8	16,4	9,7	2,2	1,6	1,0

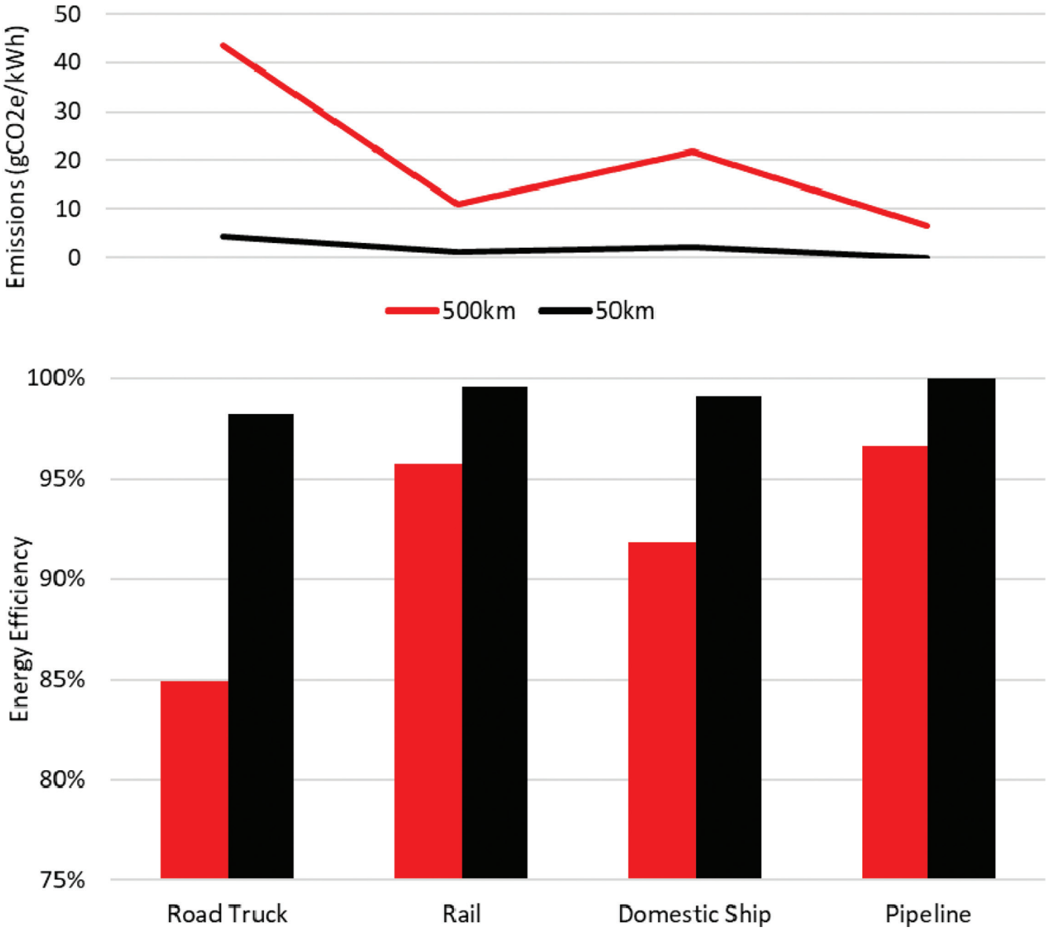


Figure 5.3: Transport of 100 % H_2 by truck, rail, domestic ship, and pipeline

Footnotes to figures:

a. Results shown for road, rail and domestic shipping are for 250 barg compressed gas; pipeline results are for 70 barg transmission in existing pipelines. Efficiency of compression prior to transport is assessed separately in 5.2.

It can be observed that over comparable distances (500 km) trucks, rail and shipping are appreciably less efficient than pipeline transportation, especially so for trucks and much more carbon-intensive (nearly seven times more CO_2 equivalent for trucking 500 km compared to pipelines).

Over shorter distances (50 km), while these modes of transport are less efficient than pipelines, the energy losses are relatively small (<2 %); considering the low capital cost and ease of deployment it would be difficult to justify a pipeline installation for short range distribution unless it were an economic decision due to high flowrate.

It should be noted that while trucks are standard sizes, rail and ships are not and the energy efficiency is highly dependent on the payload in a single cargo, (i.e. larger trains and ships are more efficient). However, their efficiency would always be expected to be better than trucks and worse than pipelines when assessed on an equivalent basis.

5.5 ALTERNATIVE TECHNOLOGIES

Ammonia has the potential to be used as an energy carrier as it can be synthesised from hydrogen and nitrogen which is abundant in the atmosphere and is carbon-free. There are two primary advantages relative to transportation of hydrogen:

- It is more energy dense therefore can be transported more efficiently.
- It can be stored at much more benign conditions than hydrogen which is either very high-pressure gas or extremely cold liquid.

However, the conversion and reconversion will have an efficiency penalty so this must be compensated for by the efficiency savings of transport. This may favour transportation of supplies over interregional distances by road transport and international transport, e.g, from Middle East export developments into consumer markets.

There is ongoing research into using ammonia directly as a fuel (often cited for shipping) or direct electrical generation; however, it is challenging to combust. This is a promising area that would mitigate many of the practical challenges associated with hydrogen usage, although there are noted disadvantages to uses of ammonia: it is a toxic gas at atmospheric conditions so presents an HSE challenge that must be managed. Combustion of ammonia will also result in nitrous oxide emissions which is a GHG and NOx which are considered to contribute to global warming although not GHG themselves. This must be mitigated by the emerging technology or accepted as a drawback of using ammonia as a fuel.

Methanol is often cited as an energy carrier; however, it contains carbon and would release CO_2 at point of use similar to natural gas. Even if the CO_2 were sourced from direct air capture this would essentially introduce a carbon recycle to the atmosphere and air capture is challenging and expensive.

6 CONSUMPTION

6.1 ELECTRICITY GENERATION

6.1.1 Combustion

Combustion is currently the most widely used means of electricity generation from fuel. Hydrogen can be used by combustion technologies that currently use natural gas as a fuel. The most common combustion technologies for generating electricity, which are assessed in this section are:

- open cycle gas turbines (OCGT);
- combined cycle gas turbines (CCGT), and
- combined heat and power (CHP).

Electricity is generated in an OCGT by mixing compressed air with fuel and igniting the mixture; the resulting combustion gases are hot and at high pressure. These gases are expanded through the gas turbine, reducing the gases' pressure and temperature, and driving the turbine. The turbine drives an alternator which generates electricity. This is the simplest and cheapest (in terms of capital) technology, but it is also the least efficient.

The gas out of the OCGT although cooler than at the inlet of the turbine is still hot. Further energy can be extracted from this gas in CCGT. This low-pressure hot gas is used to generate high pressure steam, further cooling the combustion gases. The steam is expanded through a steam turbine driving an alternator and therefore generating more electricity. The gas turbine and steam turbine comprise the CCGT. This process is more complicated and therefore more expensive, but is much more efficient as it utilises more energy from the combustion gases. This is the most common technology for modern UK gas power stations.

CHP comprises a power generation system and a heat recovery system to utilise typically low-grade waste heat from the power generation. This system can be configured in multiple ways, using different power generation technologies and the heat recovered can be used directly or used to heat a heating medium which is then sent to users. The heat recovered can be used by local industries or used in district heating for local residential and businesses for space heating and/or hot water heating. The heat users are typically located close to the power generation as it is inefficient to transport the heat over long distances due to heat losses. CHP offers the highest efficiency as it recovers the most energy from the fuel.

The CHP system assessed here is CCGT with district heating. The gas out of the CCGT, after generating steam, still has heat but is too low-grade to generate more work. Instead, the hot stream is used to heat a district heating system which is used to heat local households. CHP is common in parts of northern Europe but is challenging to retrofit due to the extent of the distributed network to multiple users. It is important to note that the system can be designed to maximise power production or provide power and heat; in the case of CHP the heat output will come at the expense of some reduction in electrical power output.

All three of these are considered mature technologies. OGCT were the first gas turbines to be used for generating electricity and CCGT gas been the preferred technology for producing electricity from gas for several years. CHP is common for industrial uses where a site requires electricity and heat and is an established technology. CHP for district heating has been utilised in a number of countries. The Diemen CHP plant, which consists of a CCGT with district heating in the Netherlands is used as a reference.

Most of the major turbine manufactures have committed to developing models which can run on 20 % hydrogen and many already have flexible machines capable of handling a 20 % hydrogen blend with natural gas. Similarly, most major manufactures have committed to developing models that can burn 100 % H_2, albeit by a later date. There are models which will burn 100 % H_2 although the range is more limited.

Assessment

The fuel heating values used are shown in Table 6.1, as per Section 3.4.

Table 6.1: Fuel heating values

Parameter	Units	100 % NG	100 % H_2	80/20 NG-H_2
HHV	MJ/Nm^3	41,5	12,8	35,7
LHV	MJ/Nm^3	37,5	10,2	32,1

The composition and CO_2 emissions of the natural gas and hydrogen-natural gas blend are shown in Annex C – Gas Compositions. Pure hydrogen has CO_2 emissions of zero.

The efficiencies for the different technologies and different fuels with respect to the LHV and HHV are shown in Table 6.2 and Table 6.3 respectively. Note that these are based on ISO ratings, therefore actual performance will vary depending on site conditions.

Table 6.2: Combustion power generation efficiencies (LHV)

Open cycle GT	Efficiency	Reference/remarks
100 % NG	38 % LHV	(General Electric, 2021)
100 % H_2	36 % LHV	As advised by major supplier (Baker Hughes)
80/20 NG-H_2	38 % LHV	Ansaldo Energia considered same as natural gas
Combined Cycle GT	**Efficiency**	**Reference/remarks**
100 % NG	60 % LHV	(Power Magazine 2018)
100 % H_2	58 % LHV	(Bates, C. and Read, A., 2018) 2 % less than NG
80/20 NG-H_2	60 % LHV	Considered same as natural gas, as with OCGT
CHP	**Efficiency**	**Reference/remarks**
100 % NG CHP eff	85 % LHV	(Vattenfall, 2021)
100 % H_2 CHP eff	92 % LHV	Calculated from HHV
80/20 NG-H_2 CHP eff	85 % LHV	Calculated from HHV

Table 6.3: Combustion power generation efficiencies (HHV)

Open cycle GT	**Efficiency**	**Reference/remarks**
100 % NG	34,3 % HHV	Calculated from LHV
100 % H_2	28,9 % HHV	Calculated from LHV
80/20 NG-H_2	34,1 % HHV	Calculated from LHV
Combined cycle GT	**Efficiency**	**Reference/remarks**
100 % NG	54,2 % HHV	Calculated from LHV
100 % H_2	46,5 % HHV	Calculated from LHV
80/20 NG-H_2	53,9 % HHV	Calculated from LHV
CHP	**Efficiency**	**Reference/remarks**
100 % NG	76,7 % HHV	Calculated from LHV
100 % H_2	73,9 % HHV	Calculated from 100 % NG HHV efficiency. Assumes that CCGT portion of CHP uses the above efficiency. Sensible heat factored on water content with respect to natural gas flue
80/20 NG-H_2	76,7 % HHV	Calculated from 100 % NG HHV efficiency. Assumes that CCGT portion of CHP uses the above efficiency. Sensible heat factored on water content with respect to natural gas flue

These heating values, efficiencies and emissions are used to calculate the carbon intensity of each technology and fuel, shown in Tables 6.4, 6.5 and 6.6. It is noted that pure hydrogen fuel will have a tendency to produce more NOx than natural gas due to higher flame temperatures; however, it is anticipated the technology will develop to mitigate this and CO_2 by far dominates GHG emissions when comparing natural gas with hydrogen.

Table 6.4: Open cycle gas turbines carbon emissions intensity

Parameter	**Units**	**100 % NG**	**80/20 NG-H_2**	**100 % H_2**
LHV	MJ/Nm^3	37	32	10
Efficiency	% LHV	38	38	36
Power	MJ/Nm^3	14,24	12,20	3,68
Fuel CO_2	g/Nm^3	2 129	1 703	0
Emissions intensity	gCO_2/kWh	538,2	502,5	0,00

Table 6.5: Combined cycle gas turbines carbon emissions intensity

Parameter	Units	100 % NG	80/20 NG-H_2	100 % H_2
LHV	MJ/Nm^3	37	32	10
Efficiency	% LHV	60	60	58
Power	MJ/Nm^3	22,49	19,27	5,94
Fuel CO_2	g/Nm^3	2 129	1 703	0
Emissions intensity	gCO_2/kWh	340,8	318,2	0,00

Table 6.6: Combined heat and power carbon emissions intensity

Parameter	Units	100 % NG	80/20 NG-H_2	100 % H_2
LHV	MJ/Nm^3	37	32	10
Efficiency	% LHV	85	85	92
Power	MJ/Nm^3	31,86	27,37	9,43
Fuel CO_2	g/Nm^3	2 129	1 703	0
Emissions intensity	gCO_2/kWh	240,6	224,0	0

The combustion technologies' efficiencies and emissions are shown in Figure 6.1. As expected, the OCGT has the worst efficiency, and the CHP has the best. For all fuels CHP has over double the efficiency of OGCT, meaning that for a given production and distribution system the same fuel provides twice as much energy and therefore deeper decarbonisation for hydrogen blends.

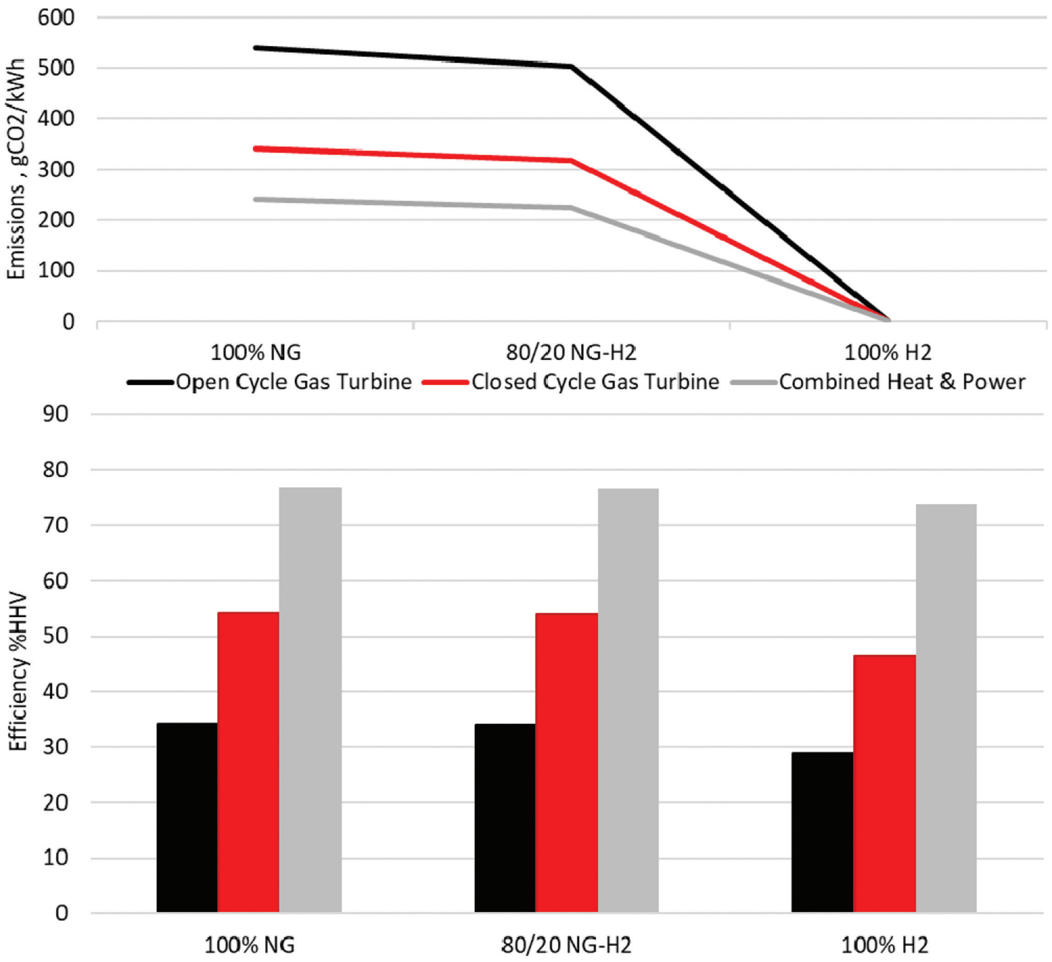


Figure 6.1: Combustion technologies efficiencies and emissions

6.1.2 Fuel cells

Fuel cells produce electricity by releasing the chemical energy of a fuel through a redox reaction. They are highly flexible in size and can provide power for virtually any application, from cars and buses to commercial buildings to laptops. Hydrogen fuel cells emit only water and heat at the point of use, so the emissions associated with their use depends on the nature of their supply chain.

The basic premise of a fuel cell comprises two electrodes, an anode and cathode, and an electrolyte between them. There is a range of electrolytes and electrodes on the market and their electrochemical processes occur at different temperature levels. As such, each type of fuel cell has its own strengths and weaknesses that dictate their suitability for different markets and application. Table 6.7 provides an overview of the main fuel cell technologies.

Table 6.7: Overview of main fuel cell technologies

Parameter	Polymer Electrolyte Membrane (PEM)	Alkaline (AFC)	Phosphoric Acid (PAFC)	Molten Carbonate (MCFC)	Solid Oxide (SOFC)
Typical Stack Size	<1 kW–100 kW	1–100 kW	5–400 kW	300 kW–3 MW, 300 kW module	1 kW – 2 MW
Applications	– Back-up power – Portable power – Distributed generation – Transportation – Speciality vehicles	– Military – Space – Back-up power – Transportation	– Distributed generation	– Electric utility – Distributed generation	– Auxiliary power – Electric utility – Distributed generation
Advantages	– Solid electrolyte reduces corrosion and electrolyte management problems – Low temperature – Quick start-up and load following	– Wider range of stable materials allows lower cost components – Low temperature – Quick start-up	– Increased tolerance to fuel impurities	– Fuel flexibility – Suitable for CHP – Hybrid/gas turbine cycle	– Fuel flexibility – Solid electrolyte – Hybrid/gas turbine cycle
Challenges	– Expensive catalysts – Sensitive to fuel impurities	– Wider range of materials allows lower cost components – Low temperature – Quick start-up – Sensitive to CO_2 in fuel and air – Electrolyte management (aqueous) – Electrolyte conductivity (polymer)	– Expensive catalysts – Long start-up time – Sulfur sensitivity	– High temperature corrosion and breakdown of cell components – Long start-up time – Low power density	– High temperature corrosion and breakdown of cell components – Long start-up time – Limited number of shutdowns

Footnotes for table:

a) It should be recognised that fuel cells are a rapidly evolving technology, so capacities, efficiencies and technical limitations are expected to change as the technology matures.

Please refer to 6.3 for further information regarding hydrogen fuel cell vehicles.

Assessment

Tables 6.8 and 6.9 show the efficiencies obtained for fuel cells and CHP fuel cells based on open-source references.

Direct CO_2 emissions are not associated with the usage of fuel cells.

Table 6.8: Fuel cell electrical efficiency based on open-source references

Fuel cell electrical efficiency	Reference	Ref. date	Remarks
53–59 %	Development of Water Electrolysis in the European Union	2014	Range covers PEM and AFC
54 %	Transport and Environment	2020	Quoted for PEM. Expected to be 56 % in 2030
50 %	Railway Technical Research Institute	unknown	Possibly old reference (both references it quotes are 2007)
30–60 %	DLR Institute of Networked Energy Systems	2019	Wide range quoted for PEM (best fit for vehicles). 50 % was assumed for the study [see also Ref. 0]
53–55 %	The National Academies Press	2013	Expected to be 55–57 % in 2030
50–60 %	Hydrogen Fuel Cells	2006	Range quoted for PEM

Table 6.9: CHP fuel cell overall efficiency based on open-source references

Fuel Cell (CHP) Overall Efficiency	Reference	Ref. Date	Remarks
80–85 %	Hydrogen Fuel Cells	2006	Efficiency quoted for PAFC
85 %	Hydrogen Fuel Cells	2006	Efficiency quoted for MCFC
85 %	Hydrogen Fuel Cells	2006	Efficiency quoted for SOFC
92 %	Viessmann	2019	
90 %	Fuel Cells Bulletin	Dec 2019	

The fuel cell combined with a CHP system results in significantly higher efficiencies. This is because the heat that would been wasted is being used to provide useful thermal energy, increasing the overall efficiency. To achieve this overall efficiency the electrical power and heating requirements need to be balanced with the fuel cell output, i.e. if the heat generated is not needed then the effective overall efficiency approaches the electrical efficiency of the fuel cell as shown in Table 6.8.

Efficiencies applied in this study are provided by Table 6.10.

Table 6.10: Electric and CHP fuel cell efficiencies applied in research report – application of life cycle assessment methodology to the understanding of the energy balance and efficiency of hydrogen value chain building blocks (2022)

Fuel cell technology	Efficiency	Remarks
Fuel cell (electric)	54 %	Mid-high-range considering technology development
Fuel cell (CHP)	85 %	Mid-range considering variable heat balance

6.2 HEATING AND COOLING

6.2.1 Domestic heating

Space heating makes up 85 % of the UK domestic gas usage (Table U2 in 'ECUK: End uses data tables' 2019 gas usage, Energy and Industrial, 2021). The remaining usage is for cooking. Efficiency data for ovens and hobs are difficult to find for hydrogen; additionally, efficiency is not required to be reported for gas hobs which means data for natural gas are almost non-existent. Domestic cookers are easily electrified with the market split between gas and electric; for these reasons cookers are not included in this assessment.

Condensing domestic boilers are the norm in the UK for new boilers and have been for a number of years so are considered a mature technology; additionally, a large number of these are capable of burning 20 % hydrogen. Many brands are developing 100 % hydrogen boilers but as of yet domestic hydrogen boilers are not available.

Assessment

The fuel heating values use are shown in Table 6.1, as per 3.4.

The composition and CO_2 emissions of the natural gas and hydrogen-natural gas blend are provided in Annex C – Gas Compositions. Pure hydrogen has CO_2 emissions of zero.

The efficiencies for different technologies and different fuels with respect to the LHV and HHV are shown in Tables 6.11 and 6.12. The efficiencies for these appliances are commonly reported as LHV efficiency so have been converted to HHV in keeping with the rest of this study. Note that these are rated performance points, therefore actual performance will vary based on site conditions, maintenance, and operating point, (i.e. if system is oversized for demand).

Table 6.11: Domestic heating technology efficiencies for 100 % natural gas (NG), 100 % hydrogen (H_2) and 80:20 % natural gas hydrogen blends (NG-H_2) for lower heating values

Domestic appliances	Efficiency	Reference/remarks
100 % NG eff	89 % LHV	Baxi, 2021
100 % H_2 eff	100 % LHV	Calculated from HHV
80/20 NG-H_2 eff	89 % LHV	Calculated from HHV

Table 6.12: Domestic heating technology efficiencies for 100 % natural gas (NG), 100 % hydrogen (H_2) and 80:20 % natural gas hydrogen blends (NG-H_2) for higher heating values

Domestic appliances	Efficiency	Reference/remarks
100 % NG eff	80,3 % HHV	Calculated from LHV
100 % H_2 eff	80,3 % HHV	Considered the same as natural gas
80/20 NG-H_2 eff	80,3 % HHV	Considered the same as natural gas

It is considered that the HHV efficiency will be the same for all fuels allowing the same proportion of heat to be recovered from condensing flue vapours. If some sensible heat were also recovered this would favour higher efficiency of hydrogen blends due to the higher water content in the flue.

The heating values, efficiencies and emissions quoted are used to calculate the carbon intensity of each technology and fuel, shown in Table 6.13. It is noted that pure hydrogen fuel will have a tendency to produce more NOx than natural gas due to higher flame temperatures; however, it is anticipated the technology will develop to mitigate this and CO_2 by far dominates GHG emissions when comparing natural gas with hydrogen.

Table 6.13: Domestic heating carbon emissions intensity for 100 % natural gas (NG), 100 % hydrogen (H_2) and 80:20 % natural gas hydrogen blends (NG-H_2)

Parameter	Units	100 % NG	100 % H_2	80/20 NG-H_2
Lower heating value (LHV)	MJ/Nm^3	37	10	32
Efficiency	% LHV	89	100	89
Power	MJ/Nm^3	33,36	10,26	28,71
Fuel CO_2	g/Nm^3	2 129	0	1 703
Emissions intensity	gCO_2/kWh	230	0,00	214

It is recognised that this is an immature technology with limited available references. There are also practical issues to be managed particularly for high hydrogen blends, such as:

- safety considerations associated with much higher flammable range compared to natural gas;
- larger effluent plumes due to great volumetric flow and higher water content of flue gas;
- greater propensity of hydrogen to leak compared to natural gas. Domestic pipework may need replacing or recertification, and/or
- suitability of existing pipework due to risk of embrittlement; operation at lower pressure may mitigate this but raises new challenges.

These are issues that can be addressed and will be more manageable for early blends of hydrogen, up to 20 vol%, but nevertheless pose economic and social obstacles for the technology to overcome.

6.2.2 Industrial high heat

A number of industries currently use fossil fuels to provide necessary high temperatures required for production; these include steel, cement and glass. For the purposes of this study switching steel production from natural gas fuel to hydrogen is reviewed.

The global GHG emissions from iron and steel production are about 2,8 Gt per annum making up about 8 % of global energy system emissions. If no attempt is made to reduce emissions from the iron and steel sector, this figure could rise to 3,1 Gt per annum by 2050 (Energy Transitions Commission, 2018).

As steel is a commodity it is hard to ascribe an energy efficiency to the process. To assess this value chain block the total emissions are compared for three feeds:

- natural gas;
- 20 % hydrogen blend, and
- 100 % hydrogen.

In steelmaking, there are several CO_2 emissions sources in the process, and each route has a different emission footprint. The NG-DRI/EA (Natural Gas – Direct Reduced Iron/Electric Arc Furnace) emits 1,4 teCO_2/tSteel as described in European Parliamentary Research Service (2021).

Taking into account the energy content of hydrogen, if a 20 % blend is used in conjunction with natural gas this equates to 7 % of the energy requirement. Therefore 93 % of the natural gas will still be needed to provide the rest of the energy resulting in 1,3 teCO_2/teSteel.

Using 100 % hydrogen as the reductant gas will fully decarbonise the steel furnace operation, i.e. 0 teCO_2/teSteel.

Table 6.14: Emissions for 100 % natural gas (NG), 100 % hydrogen (H_2) and 80:20 % natural gas hydrogen blends (NG-H_2) associated with steel production

Process	Energy requirements (GJ/teSteel)	Emissions (tCO_2/tSteel)
Natural gas	16–18	1,4
H_2 – 20 % blend	16–18	1,3
H_2 – 100 % (a)	17–19	0

Footnotes to table:

a) A gas heater is required to heat the gas to the required temperature thereby accounting for the additional energy requirement.

6.3 TRANSPORTATION

The global transport sector was responsible for emitting almost 8,5 Gt of CO_2 in 2019 and more than 7 Gt in 2020, still influenced by the Covid pandemic (IEA, 2021). Electrification accompanied by low-carbon fuels such as hydrogen are expected to play a crucial role in the decarbonisation of this sector.

Hydrogen has long been viewed as a fuel with great decarbonisation potential for the transportation industry, offering a low-carbon alternative to petroleum products for mobility. Direct use in fuel cell vehicles is currently the most widespread alternative, although another option is the combination with nitrogen or carbon (preferably sustainably sourced, e.g. from CO_2 capture units) to produce ammonia and other synthetic fuels for shipping and aviation (see 6.4).

FCEVs differ from battery electric vehicles (BEVs) in the use of a fuel cell for energy storage (and the efficiency of energy release) compared to the use of a battery in a BEV. The power system and electric motor/drive train of FCEVs are very similar to BEVs and therefore have similar efficiency. Currently hydrogen vehicles have a number of advantages over BEVs, some of which are as follows:

- Faster recharging and longer ranges (especially for large vehicles). FCEVs currently have a similar autonomy and refuelling time to conventional vehicles.
- More practical for extended range, especially for large vehicles with capacity for fuel containment.
- BEVs charged from grid so are only as 'green' as the UK electricity at time of charge.
- FCEVs allow energy usage to be decoupled from energy supply; this is potentially very advantageous for capturing as much useful energy as possible from an intermittent supply. Batteries may function similarly – this would rely on smart charging infrastructure, yet to be developed.
- FCEVs could take advantage of excess wind to produce truly 'green' energy, while it's difficult to envisage how BEVs could take advantage of these supply peaks without sophisticated network integration.

The hydrogen supply to the fuel cell is typically pressurised to 350 barg or 700 barg for light vehicles to allow for smaller fuel tanks. The efficiency losses associated with a fuel cell vehicle can be summarised as those caused by the conversion of the fuel cell to electricity, and the losses associated with the electric motor and drivetrain.

Hydrogen can be used for most modes of powered transportation. This assessment will provide an overview of the road, rail, and ship transportation sectors. Hydrogen-powered aircraft will be excluded as it is still at a very early stage of development, with only feasibility studies and demonstration projects having been carried out. The preferred fuel cell for automotive applications is by far the Polymer Electrolyte Membrane Fuel Cell (PEMFC), characterised by a smaller size and lower start-up time than the other fuel cells available on the market, which makes it ideal for this type of application, see Section 6.1.2 for further information.

For the following applications, emissions are zero at the point of use.

6.3.1 Road transportation

Within road transportation,two main categories of vehicles can be identified: light/passenger vehicles and heavy vehicles (buses, trucks etc). Due to shorter refuelling time and higher potential range compared to BEVs, FCEVs present a great potential for the heavy-duty vehicle market in the short term as these vehicles would require very large batteries.

To date, the fuel cell bus market has been developed and validated in real-world environments, while the market for fuel cell trucks is still in the development phase; a significant obstacle for trucks is the requirement for dispersed refuelling infrastructure.

For hydrogen to gain a good share of the passenger vehicle market, improvements in the refuelling supply chain and infrastructure are needed. There are examples of commercial passenger vehicles, with almost 25 000 vehicles in operation worldwide in 2019 (IEA, 2019), mainly manufactured by Toyota, Honda, and Hyundai. However, it should be recognised that FCEVs are lagging significantly behind BEVs for low-carbon vehicle market share and may remain a niche product.

For heavy vehicles or long-distance transport, electrification will be a very slow process, as batteries with a higher density than those currently available on the market will be needed. It is thus in this sector that hydrogen-powered vehicles will have the greatest potential.

6.3.2 Railways

Similar to road transportation, the two major solutions for decarbonising the rail industry lie in electrification and hydrogen-powered trains. Of all the modes of transport discussed, rail is by far the most electrified mode of transportation.

There are currently many countries that have a high percentage of their rail network electrified, with the Netherlands (76 %), Italy (71 %) and Spain (61 %) at the top of the ranking. The United Kingdom has only 42 % of its network electrified, although electric trains account for 72 % of the British passenger fleet (Institution of Mechanical Engineers, 2019).

Currently, hydrogen is being deployed for commercial service and is considered a good alternative for trains running outside the electrified rail network, which would otherwise be diesel-driven. Hydrogen could therefore take an important role in the railway industry where 100 % electrification is not economically viable. For context, several electrification projects have been cancelled in the UK due to the high CAPEX involved in building new overhead wires (The Guardian, 2018).

The cancellation of these plans has relaunched the concept of hydrogen-powered trains. Teeside and Cumbria have been identified as key regions with an active interest in developing the first UK hydrogen trains.

Hydrogen will find a greater potential mainly in rural areas where the cost of electrification is excessively high, or in localised transport systems, for example for trains operating close to the production area, thus avoiding losses and costs derived from storage, transportation, and distribution of the fuel.

Nevertheless, hydrogen-powered trains have some technical disadvantages in comparison to electrification, suggesting its long-term potential may be to fill a niche where electrification in impractical. Indeed, if the goal is to use green hydrogen produced by electrolysis as fuel, the overall efficiency of the hydrogen train will be about one third that of the electric train, primarily due to the energy losses associated with hydrogen production and the fuel cell itself.

6.3.3 Shipping

Shipping is considered to be one of the most challenging sectors to decarbonise by 2050, mainly due to the lack of low-carbon fuel options on the market and the long service life of existing vessels. The main fuels targeted for decarbonisation in this industry are currently hydrogen and ammonia. The world's major ports could become industrial centres for the production of these fuels, in order to supply energy needs while facilitating the refuelling of vessels.

Hydrogen is a fuel with the potential to address these challenges in shipping, primarily through its use in the form of hydrogen-based fuels for internal combustion engines and in fuel cells for shorter routes. While there are a large number of projects underway, the market for hydrogen-powered ships is still very limited, with fuel cell ships still in the demonstration phase.

The electrification of the maritime sector plays a very minor role, due to the lack of such powerful batteries currently on the market. It would only be possible to supply maritime routes of up to 200 km (IEA, 2021).

Lastly, ammonia appears to have the best potential for long-range transoceanic travel in the medium- and long-term as it is characterised by its high energy density, see Table 6.16. Therefore, hydrogen-powered ships will find potential to take a share of the market only for short- and medium-distance applications.

6.3.4 Results

To estimate the efficiency losses associated with a fuel cell vehicle, the energy losses associated with the conversion of the fuel cell into electricity, and those associated with the powertrain have been taken into consideration. The efficiencies for the different sectors of the transportation industry are shown in Table 6.15.

Table 6.15: Efficiencies for different sectors of the transportation industry

Vehicle	Fuel cell efficiency	Motor efficiency	Overall efficiency
Light vehicle	54 %[(a)]	92,2 %[(b)]	49,8 %
Heavy vehicle		95,8 %[(c)]	51,7 %
Rail		95,0 %[(d)]	51,3 %
Ship		95,0 %[(d)]	51,3 %

Footnotes to table:

a) Based on latest references. The effective efficiency may be lower depending on specific usage requirements (see 6.1.2). Nevertheless, efficiency is expected to increase in the coming years as the technology advances.
b) Assuming 100-hp for a medium size car (US Department of Energy, 2012).
c) Assuming 500-hp for a medium truck/bus (US Department of Energy, 2012).
d) Assumed based on a typical range of 90–95 % for most engines and annotation 5.

e) Larger motors have higher efficiencies, heavy vehicles tend to have more constant loads so will have better 'real-world' efficiency. Smaller motors tend to be at the lower end of efficiency scale. Light vehicles also will have more variable load therefore operate away from peak efficiency more often. For reference, the efficiency for a standard 5-hp motor would drop to 83,3 % (US Department of Energy, 2012).

f) Emissions are zero at the point of use.

As expected, if clean hydrogen is to be used for mobility, energy losses associated with production of hydrogen and the fuel cell operation will need to be accepted. Hydrogen-powered vehicles require approximately three times more energy than electric vehicles. Nevertheless, green hydrogen can play a crucial role in supporting decarbonisation in those sectors where direct renewable electrification is not technically or economically feasible or would take too long.

6.4 REFINING AND PETROCHEMICALS

6.4.1 Ammonia production and use

Ammonia is the second most produced industrial chemical after sulfuric acid. The production of ammonia from hydrogen comes in at a close second, after refining, as the biggest consumer of hydrogen globally. Figure 6.2 from the IEA shows the production of hydrogen over the last 50 years.

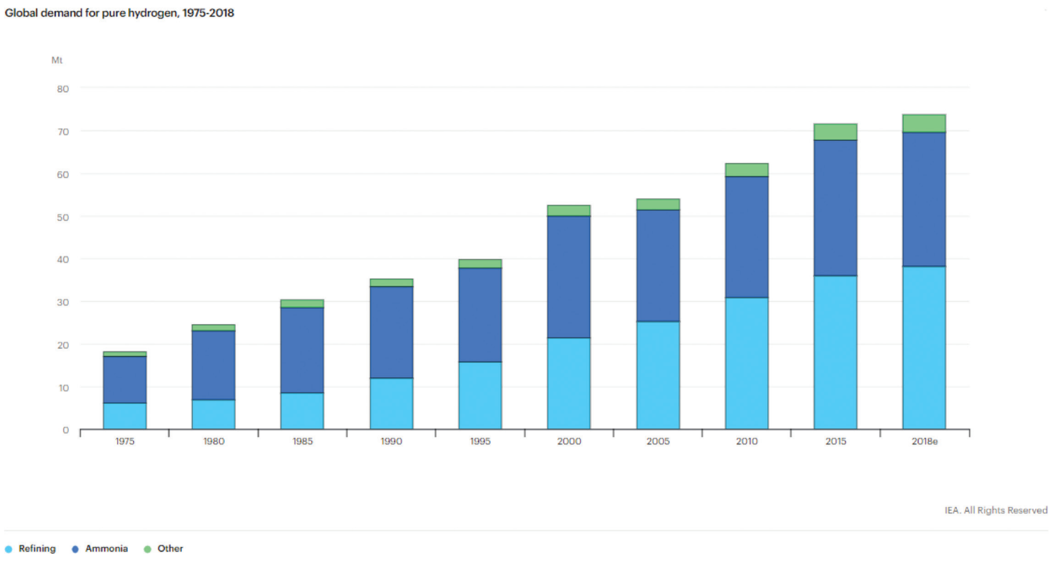


Figure 6.2: Global demand for pure hydrogen production (1975–2018)

6.4.1.1 *Ammonia uses*

The majority of ammonia is produced for use as fertiliser, either in its pure form, or as a pre-cursor to solids fertilisers such as a urea and ammonium nitrate. Ammonia also has other applications as a refrigerant, cleaning agent and sterilisation agent.

In the context of this study however, it is the potential of ammonia to be a low carbon fuel that is of interest. This is not a new idea, and several experiments have been performed. These include:

- Ammonia-fuelled automobiles, operating on a modified internal combustion engine.
- The X-15 aircraft, a precursor to the Mercury missions to space, was propelled by an ammonia-fuelled rocket engine.
- Ammonia can also be catalytically converted back into nitrogen and hydrogen, allowing the hydrogen to be used in fuel cells. This has been demonstrated at laboratory level.

6.4.1.2 Ammonia as a fuel

The principal reason for considering ammonia as a fuel is its substantially higher energy storage potential. To highlight this comparison, the calorific values have been compared in Table 6.16:

Table 6.16: Property comparison of ammonia as a fuel compared to hydrogen

Parameter	Units	Hydrogen		Ammonia
Molar HHV	MJ/kmol	283,4		382,5
Mas LHV	MJ/kg	141,7		22,5
Representative storage conditions	n/a	20 °C @ 700 bara	–253 °C @ 1 bara	20 °C @ 9 bara
Mass density @ storage conditions	kg/m^3	39,5	70,9	610
Volume hhv @ storage conditions	GJ/m^3	5,6	10	13,7

Table 6.16 shows that liquid ammonia at relatively mild conditions achieves a factor of 2,5 improved energy storage compared to high pressure hydrogen at 700 bara, and nearly 1,4 improvement over liquid hydrogen. When both the substantial energy cost of bringing hydrogen either to very high-pressure storage or liquefaction as well as the impracticalities of containing hydrogen at either condition are factored in, it is clear why ammonia has an appeal.

However, in order to perform a fair comparison, the energy cost of producing ammonia needs to be considered. The reaction is a mildly exothermic gas phase reaction between nitrogen and hydrogen. Due to the comparatively inert properties of nitrogen, the reaction conditions required are very severe, and involve pressures in excess of 150 barg, and temperatures in excess of 200 °C, making the process expensive and energy-intensive:

$$N_2 + 3H_2 \rightarrow 2NH_3 \qquad \Delta H = -92{,}4\ kJ/kmol$$

Considering just the stoichiometry of the reaction and the calorific value of the feeds and products, it can be seen that this reaction results in a 10 % loss of energy. Added to this is the issue that ammonia synthesis loops are susceptible to the accumulation of inertia, and require a continuous purge, and the process efficiency drops further. This means that if the production of blue hydrogen is approximately 80 % efficient, then blue ammonia can at best be in the order of 70 % efficient.

While hydrogen compression costs are significant when compared to the relative ease with which ammonia can be stored, it seems likely that ammonia as a fuel will only appeal where storage weight and volume are at a significant premium, for example in vehicles and aircraft.

6.4.1.3 *Safety considerations*

There are also a number of serious safety consideration with ammonia. It is highly corrosive, and in its anhydrous gaseous form, will seek to dissolve in any water it comes in contact with, including that of eyes and lungs. As a result, exposure to anhydrous ammonia is at best an exceedingly unpleasant experience, and at worst fatal. In the early years of refrigeration, ammonia was a popular refrigerant in home fridges, and containment failures were not uncommon, and frequently lead to hospitalisation for any individuals exposed.

This hazard is currently managed by the chemicals sector, but it should be kept in mind that the scale of the fuels sector is much greater and would represent a significant step-change in risk to the public as a result.

6.4.2 Methanol production

Methanol is an important petrochemical intermediate, with the majority converted into formaldehyde, which has extensive uses in the production of polymers, solvents, and petrochemical synthesis. Methanol is also a precursor for acetic acid.

The industrial process for methanol production comprises the gas phase reaction between carbon monoxide and hydrogen, where the stoichiometry requires a 2:1 ratio of hydrogen to carbon monoxide:

$$CO + 2H_2 \Leftrightarrow CH_3\,OH \qquad \Delta H = -91\ kJ/kmol$$

When syngas is produced via the conventional SMR process, the hydrogen:carbon monoxide ratio is 3:1 which would result in excess hydrogen. To address this, it is not uncommon to capture some of the CO_2 produced from the hydrogen production and add this to the methanol synthesis process where CO_2 will also react with hydrogen to form methanol. This second reaction is less efficient as it consumes 50 % more hydrogen per molecule of methanol, due to production of water as a by-product:

$$CO_2 + 3H_2 \rightarrow CH_3\,OH + H_2O$$

It is this second reaction that is of interest to those working to combat climate change, because it represents a method for converting CO_2 into a useful energy source. If the source of the CO_2 is from the atmosphere, then the resulting methanol could be argued as being carbon neutral when it is subsequently burned as a fuel.

The reuse of CO_2 from industrial processes where it would otherwise be vented to atmosphere represents a grey zone for this concept. Arguably better than burning fossil fuels, but it still results in new CO_2 emissions to the atmosphere and therefore does not represent a sustainable route to eliminating CO_2 emissions.

The concept for green methanol comprises three processes:

– production of green hydrogen from renewable power and water by means of electrolysis;

- capture of CO_2 from the atmosphere, in a process known as direct air capture (DAC), an emerging technology with a number of demonstrator scale plants in operation around the world, or
- synthesis of methanol from hydrogen and CO_2.

A block flow diagram from the North-C-Methanol Project is presented in Figure 6.3.

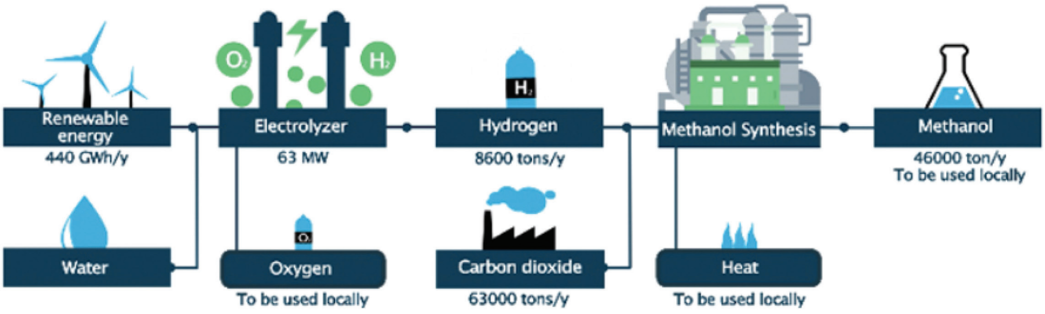


Figure 6.3: Block flow diagram from green methanol production (North-C-Methanol Project)

This process requires DAC to provide CO_2 if it is to represent true green methanol; Figure 6.4 from the IEA provides indicative energy requirements for this based on current technology.

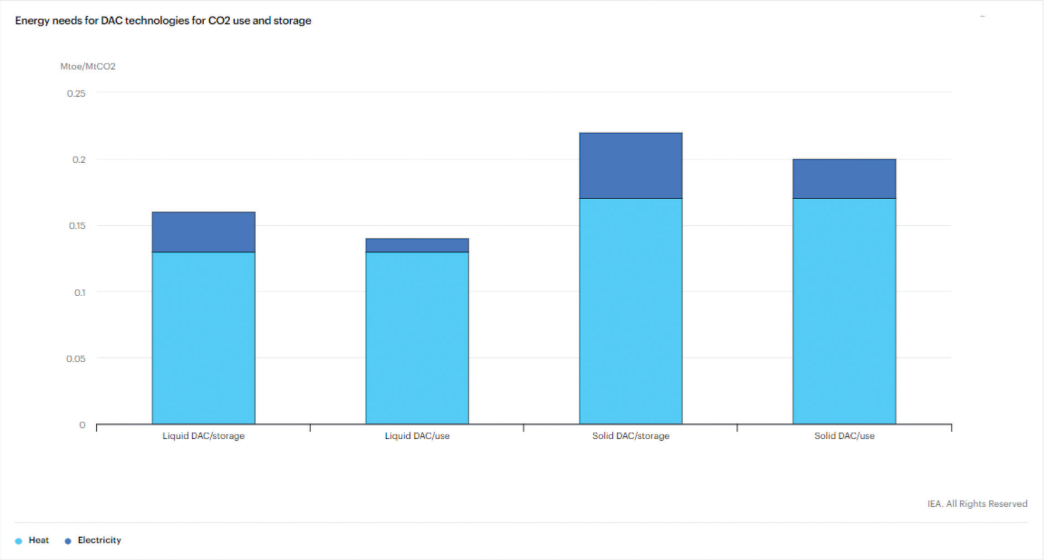


Figure 6.4: Direct air capture energy requirements for DAC technologies for CO_2 use and storage

Based on a concept of direct capture and using a value of 0,14 $Mtoe/MtCO_2$ provided in the IEA *Direct Air Capture analysis*, which is equivalent to 5,9 GJ/tonne of CO_2.

Using the values presented in the flow diagram and the table on DAC, an indication of the energy flows and efficiencies from green methanol can be determined.

Table 6.17: Methanol as a fuel property comparison

Parameter	Units	Hydrogen from electrolysis	CO_2 from direct air capture	Methanol synthesis	Total energy balance
Energy content	kWh	338 505 556	102 900 000	293 888 889	190 988 889
	Tonnes	8 600	63 000	46 000	–
Energy efficiency	%			87 %[(a)]	56 %[(b)]

Notes:

a) Energy value of methanol relative to hydrogen energy content, not accounting for energy cost of CO_2.

b) Energy value of methanol with CO_2 capture included.

This demonstrates that conversion of hydrogen to methanol results in an energy loss of around 13 % if CO_2 is readily available as a waste stream; if CO_2 is captured from the atmosphere almost 50 % of the energy content of the hydrogen is lost in the conversion process.

6.4.3 Refinery feedstock

The bulk of hydrogen consumed in the UK (and globally) is as a feedstock in refineries where it is used primarily to reduce the sulfur content of liquid fuels. The production of this hydrogen emits CO_2 at source and therefore replacing it with a cleaner (blue or green) source of hydrogen would provide immediate emissions savings.

In the case of blue hydrogen, this would reduce emissions by ca. 90 %. The existing onsite production unit would effectively be replaced by a more modern offsite plant; the production efficiency may be similar considering modern technology gains approximately balanced against the energy loss for carbon capture. The distribution losses through a pipeline would be expected to be minimal, if any.

For green hydrogen, the emissions would be eliminated almost completely. The energy efficiency would be appreciably lower, but it should be considered that the feedstock would be electricity rather than natural gas.

Notwithstanding economic considerations, there are two main challenges associated with supplying clean hydrogen to existing refineries:

- The existing hydrogen plants are likely to be heat integrated with other units, therefore mothballing them creates additional challenges for the refinery operator. This may also result in incremental emissions if hot utility is needed to replace heat integration.
- The third-party supplier (hydrogen as a utility) must be able to match the refinery's required up-time and perhaps turnaround schedule for maintenance. This could be difficult to manage contractually, especially if a single clean hydrogen producer supplies more than one user.

It may also be true that some potential users may have other drivers that make a new hydrogen supply attractive, for example if their existing unit has operational issues or is a capacity constraint.

Providing hydrogen as a refinery feedstock is a good way of decarbonising by providing a clean product in place of an emission's intensive product. The practical implementation of this is likely to need reviewing on a case-by-case basis due to the specific challenges and opportunities for individual sites. However, combing multiple users in hubs may be enabling as it allows economies of scale to support new infrastructure associated with the development.

7 IMPORTANT VALUE CHAINS

Based on the findings of this study a number of full value chains have been assessed; these are:

1. Blue H_2 – Regional Transmission – Domestic Appliance vs Green H_2.
2. Blue H_2 – Regional Transmission – Domestic Appliance vs Natural Gas.
   - Sensitivity on LNG to produce blue hydrogen.
3. Green H_2 – Local Distribution – Fuel Cells (CHP) vs Electricity.
4. Green H_2 – Local Distribution – Transportation vs EVs.
   - Sensitivity on green hydrogen generated from grid electricity
5. Blue H_2 – Regional Transmission – CCGT vs CHP.

The results for these value chains are presented and discussed in this section.

7.1 BLUE H_2 VS GREEN H_2

The purpose of this assessment is to determine the difference in system efficiency and emissions when considering blue versus green hydrogen production. The results are presented in Figure 7.1.

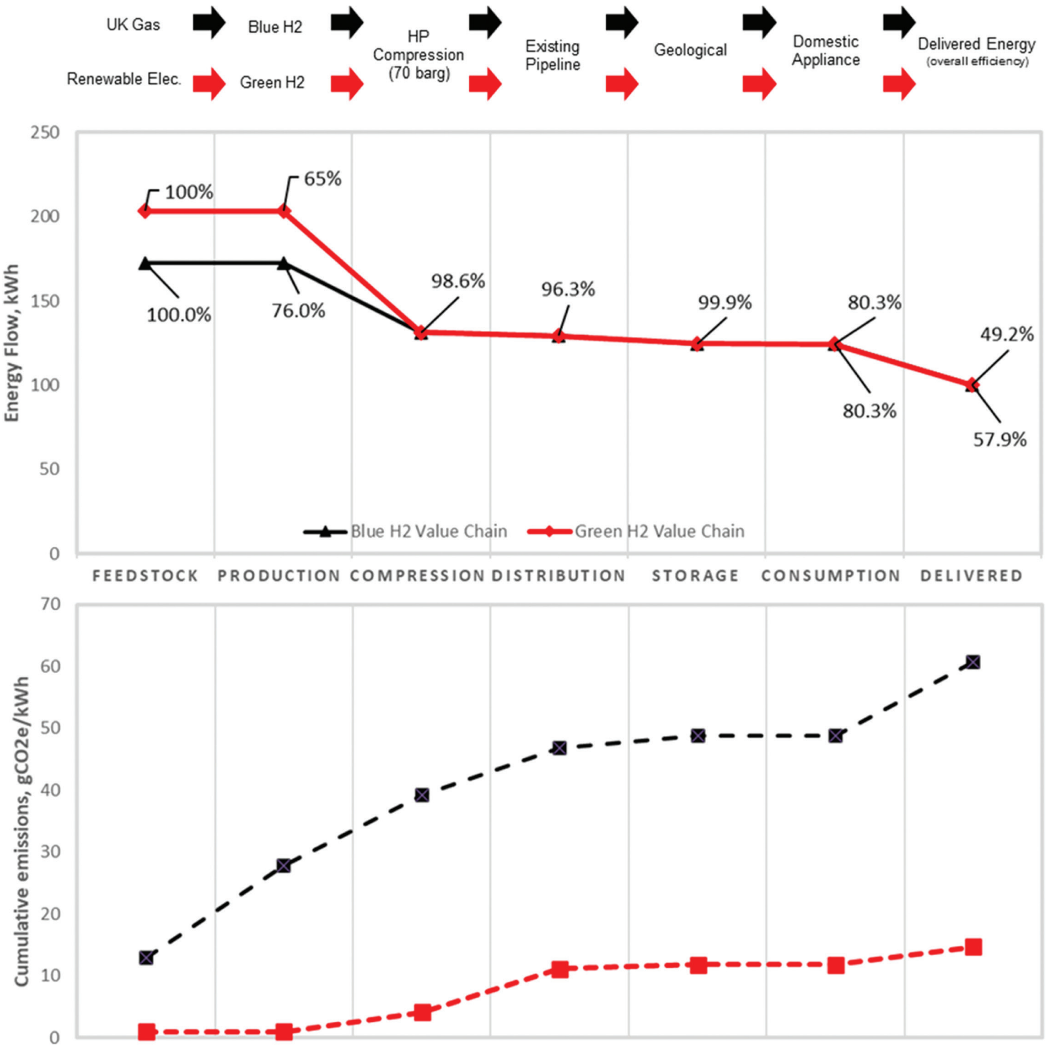


Figure 7.1: System efficiency and emissions for blue versus green hydrogen production – domestic appliance

Footnotes to figure:

a) The energy efficiencies are presented for each value chain block; the efficiency shown for delivered energy is the overall value chain energy efficiency.

b) Emissions are cumulative GHG emissions intensity for the energy flow out of each value chain block. As such, GHG intensity will rise when more emissions occur and when energy losses occur because the cumulative emissions are then attributed to a lower amount of energy flowing out of the block.

c) Feedstock is 100 % efficiency as it is considered at the battery limit of the hydrogen production site.

As can be observed, blue hydrogen is more efficient than green hydrogen but it also has a higher emissions impact, with around four times greater GHG emissions intensity. This differential would be even larger if LNG were used to produce blue hydrogen.

Green hydrogen offers a significant emissions reduction for a relatively modest efficiency penalty. However, the technologies use different feedstock and green hydrogen cannot currently be produced at the same scale as blue hydrogen.

7.2 BLUE H_2 VS NATURAL GAS

The purpose of this assessment is to determine the difference in system efficiencies and emissions when considering blue hydrogen compared to natural gas. The results are presented in Figure 7.2.

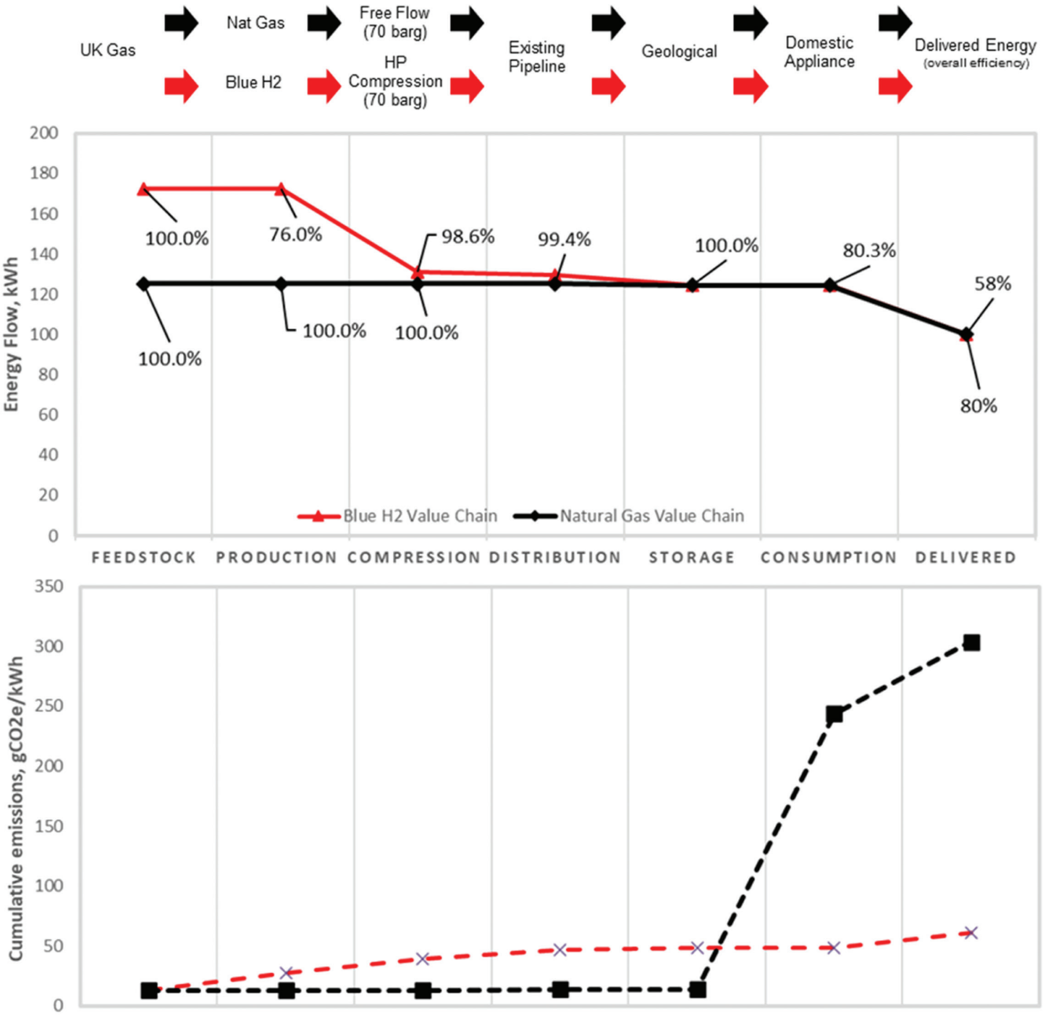


Figure 7.2: System efficiency and emissions for blue hydrogen vs natural gas – domestic appliance

Footnotes to figure:

a) The energy efficiencies are presented for each value chain block; the efficiency shown for delivered energy is the overall value chain energy efficiency.

b) Emissions are cumulative GHG emissions intensity for the energy flow out of each value chain block. As such, GHG intensity will rise when more emissions occur and when energy losses occur because the cumulative emissions are then attributed to a lower amount of energy flowing out of the block.

c) Feedstock is 100 % efficiency as it is considered at the battery limit of the hydrogen production site.

As can be observed, blue hydrogen is more feedstock-intensive (consuming almost 40 % more natural gas) but reduces emissions significantly, by 80 %. This is based on a 100 % hydrogen system but the impacts on emissions and feedstock (and cost) can be considered as incremental changes for hydrogen/natural gas blends.

7.2.1 Sensitivity on LNG to produce Blue H_2

The purpose of this assessment is to assess the impact of using LNG as a feedstock for blue hydrogen production in place of locally produced natural gas. For this assessment the GHG emissions intensity for LNG is for a typical cargo to the UK (see 4.1.2.2).

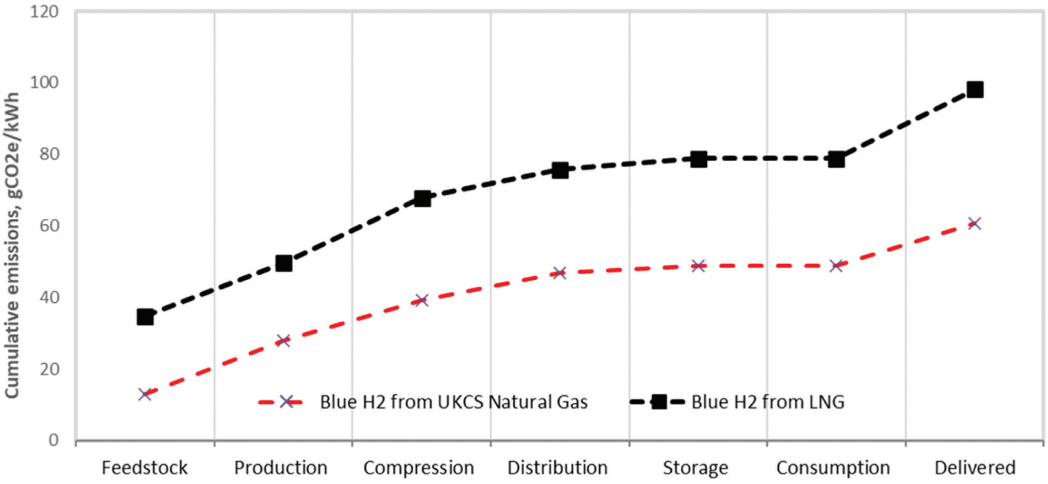


Figure 7.3: Cumulative emissions from producing blue hydrogen from liquified natural gas (LNG) compared to locally produced natural gas

Using LNG as a feedstock can appreciably increase the emissions intensity through the value chain by around 50 % for a typical cargo. This is unavoidable as the technology requires much more energy to liquify the gas and maintain it at cryogenic conditions; this process naturally gives rise to opportunities for boil-off emissions. While a 'typical' value has been used for emissions intensity it is important to note that this is highly variable depending on the source of the LNG and the journey of the specific cargo.

7.3 GREEN H_2 FUEL CELLS (CHP) VS ELECTRICITY

The purpose of this assessment is to determine the difference in system efficiencies and emissions when considering use of fuel cells compared to electrification. The results are presented in Figure 7.4.

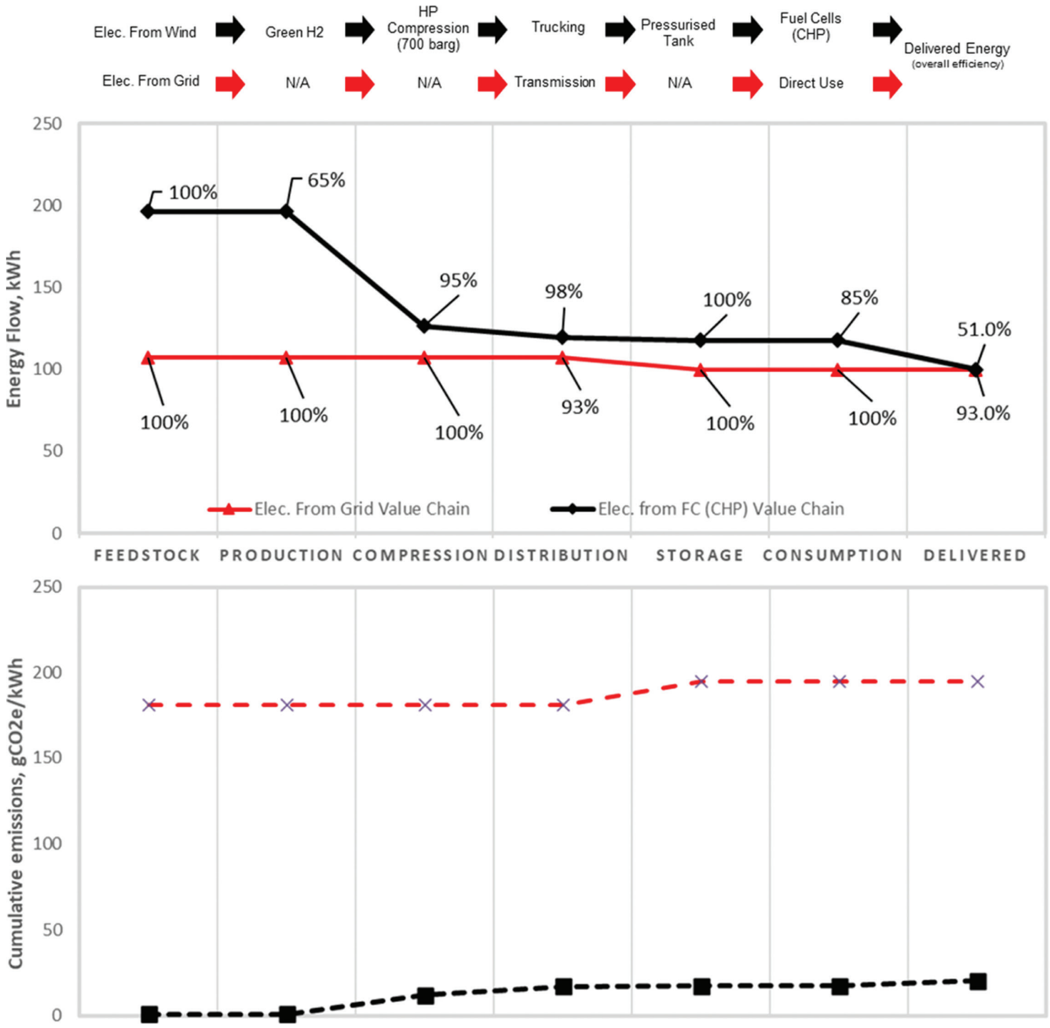


Figure 7.4: Differences in system efficiencies and emissions of combined heat and power (CHP) vs electricity fuel cells

Footnotes to figure:

a) The energy efficiencies are presented for each value chain block; the efficiency shown for delivered energy is the overall value chain energy efficiency.

b) Emissions are cumulative GHG emissions intensity for the energy flow out of each value chain block. As such, GHG intensity will rise when more emissions occur and when energy losses occur because the cumulative emissions are then attributed to a lower amount of energy flowing out of the block.

c) Feedstock is 100 % efficiency as it is considered at the battery limit of the hydrogen production site.

As can be observed, CHP fuel cells are less efficient than electrification via UK grid (consuming ca. 80 % more electricity) but the associated emissions are significantly reduced, by 90 %. Again, this is within the context of falling UK grid emissions intensity and assumes the hydrogen is produced using new-build renewable energy. However, as emissions intensity falls (due to renewables content) there is ever greater value in decoupling supply and demand.

The use of fuel cells with CHP is reliant on both electrical and heating demand at the end-user, so realising the achievable efficiency is application-dependent.

When comparing hydrogen usage against electrification, it is important to note that the emissions intensity associated with grid power is not fixed: it is highly variable by region, it has been progressively decreasing and is expected to reduce further. However, the more grid emissions intensity reduces (due to renewables content) the greater the value of decoupling supply and demand.

7.4 GREEN H_2 FCEVs VS EVs

The purpose of this assessment is to determine the difference in system efficiencies and emissions when considering use of fuel cells vehicles compared to electric vehicles. The results are presented in Figure 7.5.

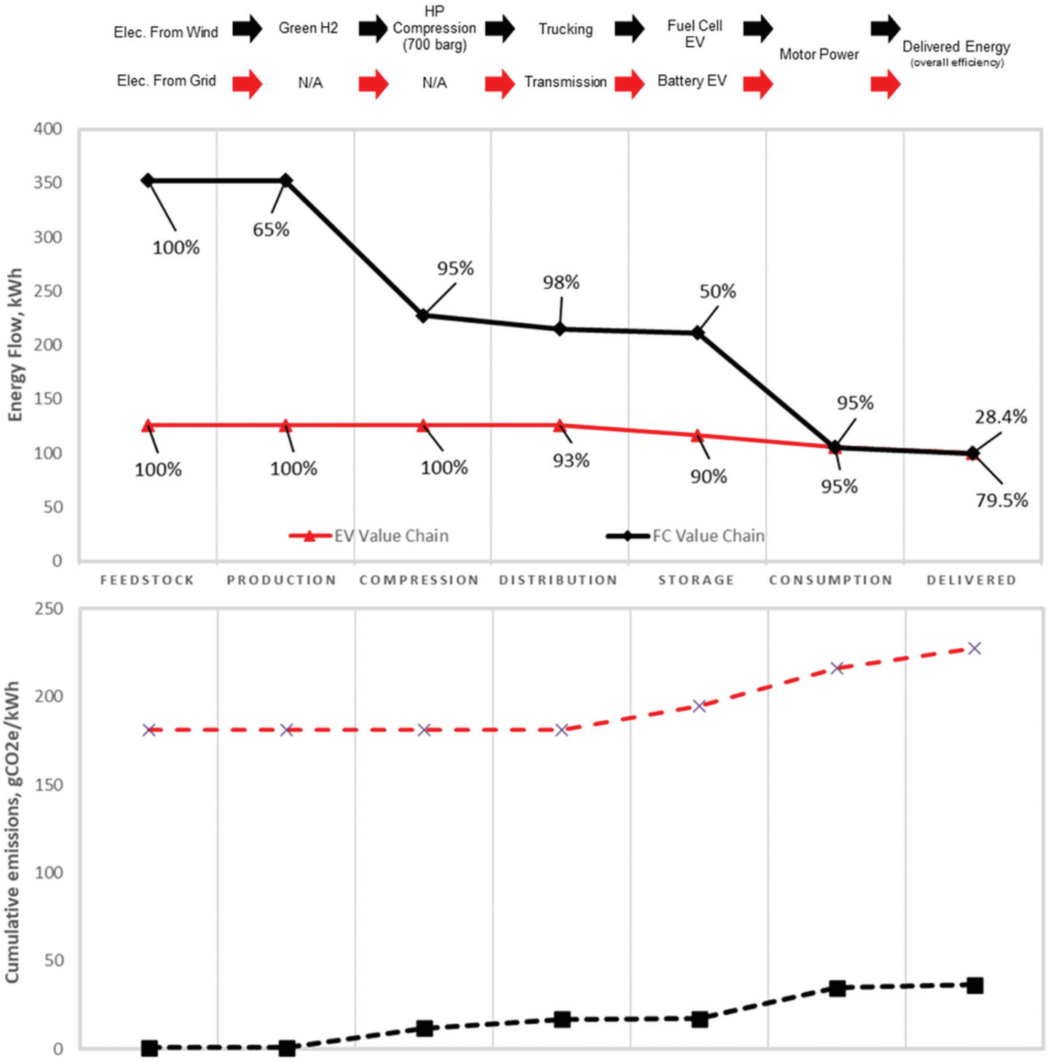


Figure 7.5: Differences in system efficiencies and emissions when considering use of fuel cells vehicles compared to electric vehicles (EVs)

Footnotes to figure:

a) The energy efficiencies are presented for each value chain block; the efficiency shown for delivered energy is the overall value chain energy efficiency.

b) Emissions are cumulative GHG emissions intensity for the energy flow out of each value chain block. As such, GHG intensity will rise when more emissions occur and when energy losses occur because the cumulative emissions are then attributed to a lower amount of energy flowing out of the block.

c) Feedstock is 100 % efficiency as it is considered at the battery limit of the hydrogen production site.

As can be observed, fuel cells are much less energy efficient than electrification via UK grid, requiring almost three times the energy input, but the associated emissions are reduced by over 80 %. The emissions saving would likely be compounded when considering manufacturing emissions of BEVs compared to FCEVs, although it should be noted that UK grid emissions intensity is expected to fall from 2020 levels and is also highly variable by region.

Despite the low value chain efficiency, FCEVs are favourable for heavy vehicles which would require large batteries and long charge times with current technology; development of heavy FCEVs in parallel to EVs for light vehicles may support faster decarbonisation of the transportation market due to lower competition for resources and supply chain access.

7.4.1 Sensitivity on green H_2 produced from grid electricity

The purpose of this assessment is to assess the impact of producing green hydrogen from UK grid electricity rather than standalone new build renewable supply. The results can be compared to those shown in Figure 7.6.

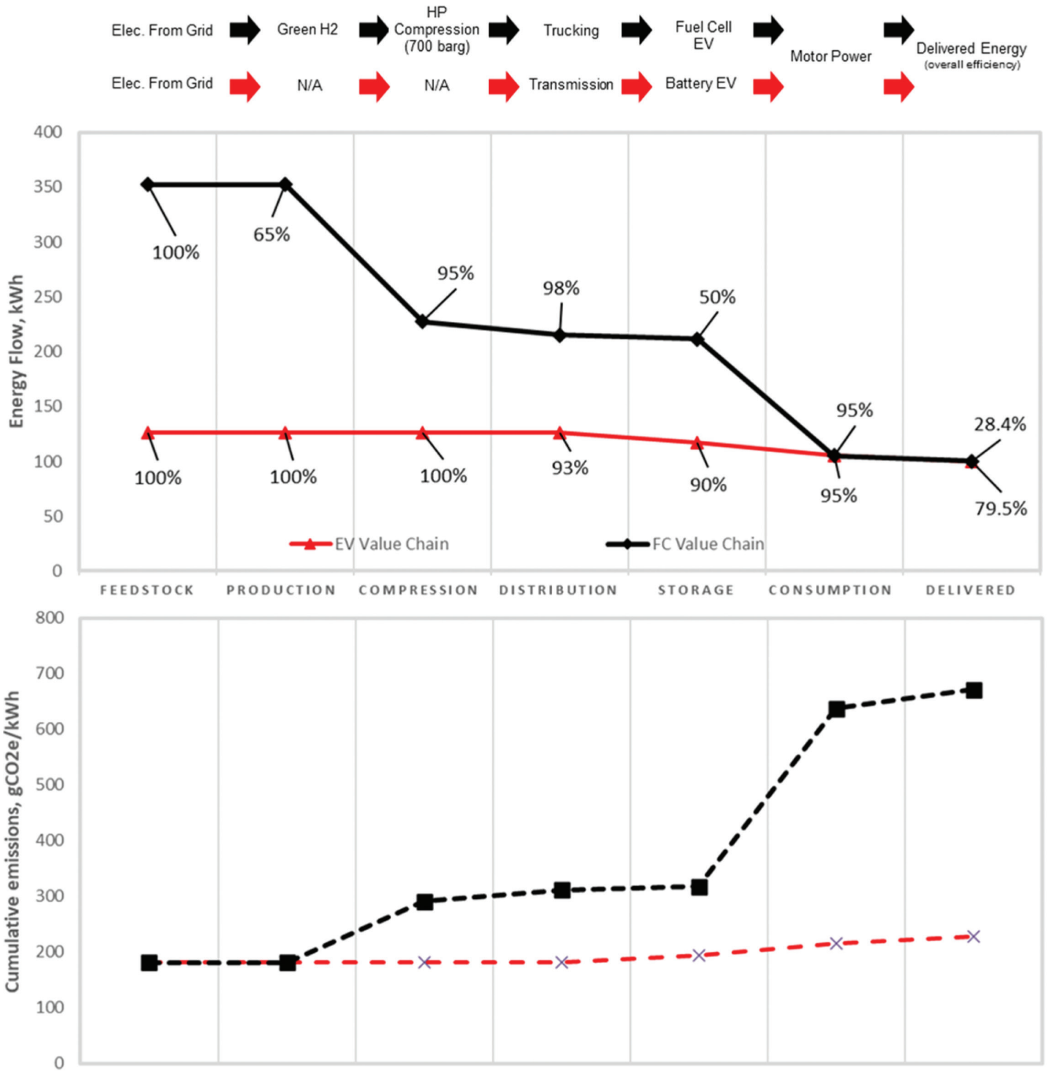


Figure 7.6: Assessment of impact of producing green hydrogen from UK grid electricity vs new build renewable supply

Producing green hydrogen from UK grid electricity and using it to operate fuel cells will consume around three times as much electricity as direct electrification using a battery. There is a corresponding increase in operating emissions.

This assessment illustrates the importance of producing green hydrogen from new build renewable power generation rather than considering a production facility in isolation.

7.5 BLUE H_2 CCGT VS CHP

The purpose of this assessment is to determine the difference in system efficiencies and emissions when considering an upgrade in end-user efficiency for similar markets. The results are presented in Figure 7.7.

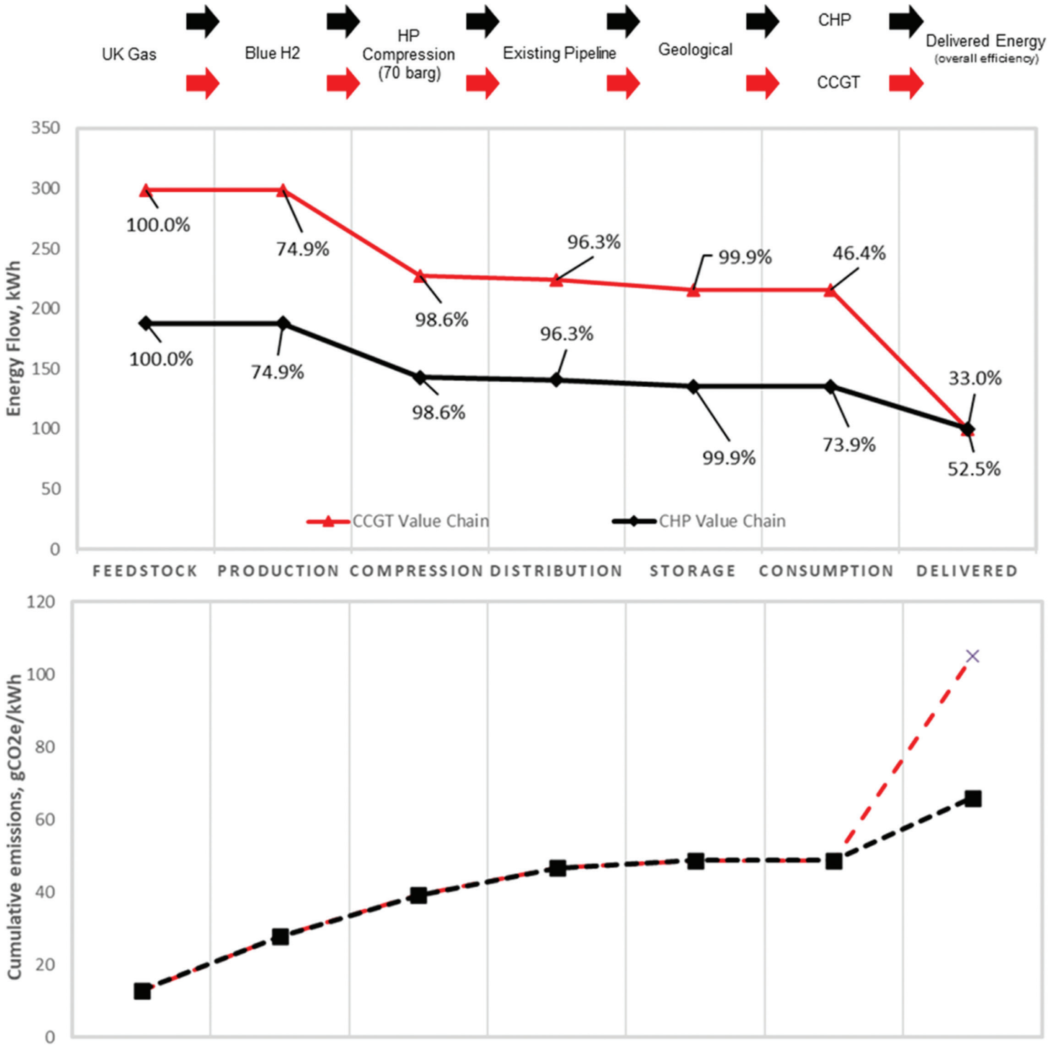


Figure 7.7: Differences in system efficiencies and emissions for combined cycle gas turbines (CCGT) vs combined heat and power (CHP) for blue hydrogen production

Footnotes to figure:

a) The energy efficiencies are presented for each value chain block; the efficiency shown for delivered energy is the overall value chain energy efficiency.

b) Emissions are cumulative GHG emissions intensity for the energy flow out of each value chain block. As such, GHG intensity will rise when more emissions occur and when energy losses occur because the cumulative emissions are then attributed to a lower amount of energy flowing out of the block.

c) Feedstock is 100 % efficiency as it is considered at the battery limit of the hydrogen production site.

As can be observed, the step change of +27 % in consumer efficiency results in a saving of 37 % in feedstock. Viewed another way, a given hydrogen production rate is able to decarbonise more consumers. This could be extremely valuable when low carbon resources are scarce.

8 CONCLUSIONS

8.1 PRODUCTION

Blue hydrogen appears a more efficient production method than green hydrogen and can produce hydrogen at significantly higher rates.

The most common criticism of blue hydrogen is that it would prolong the reliance on hydrocarbons and involves upstream emissions, amplified by the fact more gas needs to be produced to deliver the same energy to the consumer.

This study suggests that switching from natural gas to blue hydrogen could reduce emissions by around 80 %. This would represent a significant step forward from current day emissions for gas consumers but at an economic cost: firstly, the CAPEX for new facilities, and secondly for the increased natural gas consumption by just under 40 %.

If blue hydrogen is produced from LNG the emissions intensity steps up significantly, by 40 % for typical UK imports, with the potential for this to be greater for specific cargoes. This highlights the importance of understanding the provenance and emissions intensity of feedstock to a blue hydrogen production facility.

Natural gas use with CCS is likely to be best developed for industrial cluster sites and may be incorporated with a blue hydrogen development to achieve economies of scale on the CO_2 transport and sequestration infrastructure.

The biggest strength of blue hydrogen is that it can be deployed in relatively large capacities and unlike other low carbon technologies (electric vehicles, fuel cells, heat pumps) it is not reliant on consumer choices for initial market penetration, i.e. low hydrogen percentage blends.

While green hydrogen is less energy efficient than blue hydrogen and currently more limited in production capacity, it does not necessarily compete for the same market and has the following advantages:

- Much lower emissions: the main sources of emissions through a green hydrogen value chain are in the distribution from producer to consumer.
- Geographical location is much less restricted compared to blue hydrogen which requires access to both gas supply and a suitable sequestration site.
- Higher purity product naturally suited to some users, e.g. fuel cells.
- Very easy to ramp up/down with fluctuations in electrical supply.
- Offers opportunity to capture peak wind generation that may be restricted by electrical transmission limits. In this respect it is truly green as the electricity would not otherwise have been generated.
- It is a means of decoupling electricity generation from consumption, similar to other energy storage methods. This will have growing importance as the UK energy mix becomes increasingly reliant on renewables.
- Offers potential in areas where electrification is challenging, (e.g. heavy haulage).

As such, green hydrogen can be considered to compete more with electrification solutions using renewable energy and energy storage.

In order to realise the emissions reduction, it is advised that green hydrogen production systems are developed alongside new build renewables; if they draw on existing power generation facilities there would be a net increase in emissions due to the low value chain efficiency of green hydrogen compared to the direct use of electricity.

8.2 TRANSMISSION, STORAGE AND DISTRIBUTION

Transportation and storage of hydrogen are relatively efficient steps in the value chain. Pipeline transmission and distribution coupled with pressurised storage (mechanical or geological) considering a 500 km network of existing pipelines gives the following efficiencies:

- ca. 95 % for 100 % hydrogen.
- ca. 99 % for 20 % hydrogen in natural gas blend.

For new pipelines (with lower pressure drops and therefore lower booster requirements) these efficiencies will increase, and the associated emissions are reduced. While compression powers become significantly greater for hydrogen compared to natural gas, the energy demand is relatively small compared to the energy delivered. For an equivalent energy flow pure hydrogen has a volumetric rate over three times that of natural gas due to lower density; however, the lower mass rate and viscosity mean the pressure drop is approximately 50 % greater.

The most significant issue to overcome for long distances pipelines networks is that the compression facilities may be an order of magnitude larger and more expensive than equivalent natural gas facilities. For this reason, there are significant drivers for locating hydrogen production facilities close to major consumers, i.e. without the need for booster stations.

Transporting hydrogen by truck in pressurised containment is quite inefficient over long distances but over short distances the losses are modest at <5 % for a 100 km round trip including compression to 250 barg. Technology is under development to transport hydrogen at higher pressure (up to 700 barg) in lighter weight containment; this would increase overall efficiency, even allowing for compression, for all but very short distances (<100 km round trip). Transport by rail or domestic ship appears more efficient than by road truck, which is less efficient than pipeline but also much less CAPEX-intensive if existing infrastructure can be used.

If the end-user requires very high-pressure hydrogen (250+ barg), it makes sense to compress to this level at the production site prior to transportation to minimise energy losses and emissions, providing this is acceptable from an HSE perspective.

Storage of pure hydrogen by pressure containment seems less efficient than natural gas due to requiring higher compression power, but still represents losses of <1 % as only a portion of the overall gas flow needs compressing to elevated pressure. Storage by pipeline packing is inherently less efficient than storing in discrete containment; this is because all the gas flow must be over-compressed to allow for draw-down that may not be needed. It is also likely to be impractical for anything but intra-daily fluctuations.

Cryogenic storage can be inefficient due to large heat losses of liquefaction. At face value when only 5 % of total gas flow needs storing, this appears marginal. However, for bulk storage associated with managing supply and demand fluctuations it is likely to be more expensive, less efficient, and more technically challenging than pressurised containment.

In summary, transportation by pipelines is generally preferred if there is sufficient scale for the upfront investment to be economic. Gas network sized hydrogen compressors are not currently available; there would be significant technical and economic challenges associated with developing integrated national infrastructure, similar to that currently in use for natural gas.

For smaller local demands, trucking is attractive due to relatively low energy losses, low CAPEX barrier and operational flexibility. It should be kept in mind that trucking over long distances, (e.g. a single production hub serving multiple regions) could become very energy inefficient and emissions intensive if truck transportation were used. This may be a risk for early hydrogen developments. In this instance, where practical, rail or domestic shipping should be investigated as an alternative.

For large demands, storage in geological structures, as is done for natural gas, is preferred from an energy efficiency perspective; it is also likely to be the most economic and practical means of bulk storage.

8.3 CONSUMERS

Industrial users (e.g. steel production) are challenging to abate by electrification and therefore hydrogen is seen as the most practical low GHG alterative to consuming natural gas. Due to the required scale, especially considering formation of industrial hubs, it is likely this would need to be blue hydrogen, which would reduce emissions by around 80 % compared to natural gas usage.

For bulk electricity generation and domestic heat (via boilers) hydrogen has very similar energy efficiency at the point of use to natural gas which is currently the primary means of supplying these users. Again, there is the potential to reduce emissions by around 80 % compared to current natural gas usage; this should be balanced by the upfront capital cost of the hydrogen production facilities and the ongoing cost of greater natural gas consumption (almost 40 % greater).

In the case of green hydrogen, fuel cells are valuable in that they are a means of decoupling electrical supply from energy users which is a growing challenge facing the renewables industry. Available supply peaks in renewable power generation will not always coincide with peaks in consumer demand.

A fuel cell used only for electrical power is significantly less efficient than a battery; when coupled with the energy losses associated with hydrogen production it makes little sense to deploy a fuel cell if battery technology is available. However, fuel cells can be deployed for users where batteries would be prohibitively large and have excessive charge times, for example for heavy haulage and power to large buildings/sites. When CHP is deployed, as can be done for large buildings/campus facilities, the fuel cell efficiency is not far below that of a battery.

9 FURTHER WORK

Suggestions for further study work to build on the findings of this study may include additional scope, alternative technologies or areas that need more attention:

1. Study the scale of hydrogen markets for technologies where hydrogen has an apparent advantage over alternative low carbon solutions.
2. Study the potential decarbonisation rate of the main low carbon solutions being considered today, i.e. how quickly can they scale-up and therefore what is the potential carbon reduction impact.
3. Study potential for abatement of carbon with excess wind converted to green hydrogen.
4. How low is it possible to go with blue hydrogen? It represents a significant step change below natural gas emissions but is it low enough for net zero 2050?

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ANNEX B
ABBREVIATIONS, ACRONYMS AND GLOSSARY

B.1 GLOSSARY

B.2 ABBREVIATIONS AND ACRONYMS

AFC	alkaline fuel cell
ASU	air separation unit
ATR	autothermal reforming
Ave	average
Bbls	barrels
BESS	battery energy storage system
BEV	battery electric vehicle
BFD	block flow diagram
BoE	barrel of oil equivalent
BoP	balance of plant
Ca.	circa
CAPEX	capital expenditure
CCGT	combined cycle gas turbines
CCS	carbon capture and storage
CCUS	carbon capture use and storage
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
COP21	21st Conference of the Parties
Cu	copper
DAC	direct air capture
d.c.	direct current
DegC	degree celsius
DP	drop pressure
ECUK	Engineering Council United Kingdom
e.g.	for example
EAF	electric arc furnace
EI	Energy Institute
EEMS	environmental and emissions monitoring system

FCEV	fuel cell electric vehicle
FCV	fuel cell vehicle
FO	forward osmosis
GHG	greenhouse gas
GHR	gas heated reformer
GSMR	Gas Safety Management Regulations
GWP	global warming potential
H_2	hydrogen
H_2S	hydrogen sulfide
HHV	higher heating value
HP	high pressure
hp	horsepower
HSE	health, safety and environmental
ID	internal diameter
i.e.	that is
IEA	International Energy Agency
Ir	iridium
km	kilometre
KOH	potassium hydroxide
LCH	low carbon hydrogen
LDAR	leak detection and repair
LHV	lower heating value
LNG	liquified natural gas
LP	low pressure
MCFC	molten carbonate fuel cell
MEA	mono ethanol amine
MMscfd	million standard cubic feet per day
Mn	manganese
MSF	multistage flash
NaOH	sodium hydroxide
NCS	Norwegian Continental Shelf
NG	natural gas
NG-DRI/EA	natural gas – direct reduced iron/electric arc furnace
Ni	nickel
Nm^3	cubic metres at 'normal' conditions.

NOx	nitrogen oxides
OCGT	open cycle gas turbines
OGA	Oil and Gas Authority
OGUK	Oil and Gas United Kingdom
OP	operating pressure/outlet pressure
PAFC	phosphoric acid fuel cell
PDU	purification and drying unit
PEM	polymer electrolyte membrane
PEMFC	polymer electrolyte membrane fuel cell
ppmv	parts per million volume
PSA	pressure swing adsorption
Pt	platinum
Rh	rhodium
RO	reverse osmosis
Ru	ruthenium
SMR	steam methane reformer
SOEC	solid oxide electrolysis cell
SOFC	solid oxide fuel cell
TEG	triethylene glycol
TSA	temperature swing adsorption
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
US	United States
VHP	very high pressure
vol	volume
VPSA	vacuum pressure swing adsorption
W	wolfram

ANNEX C
GAS COMPOSITIONS

Table C.1: Natural gas composition

Parameter	Mol Fraction	Carbon stoichiometry	Component carbon (mol/mol)
H_2O	0	0	0
H_2	0	0	0
N_2	0,0089	0	0
H_2S	0	0	0
CO_2	0,02	1	0,02
CO	0	1	0
METHANE	0,89	1	0,89
ETHANE	0,07	2	0,14
PROPANE	0,01	3	0,03
IBUTANE	0	4	0
BUTANE	0,001	4	0,004
IPENTANE	0	5	0
PENTANE	0,0001	5	0,0005
HEXANE	0	6	0
HEPTANE	0	7	0
OCTANE	0	8	0
NONANE	0	9	0
DECANE	0	10	0
METHANOL	0	1	0
BENZENE	0	6	0
XYLENE	0	8	0
ETHYL BENZENE	0	8	0
TOLUENE	0	7	0
	Fuel carbon content (mol/mol)		1,085
	Fuel carbon content (mol/Nm^3)		48,4
	Emissions (gCO_2/Nm^3)		2 129

Table C.2: Natural gas-hydrogen blend composition

Parameter	Mol Fraction	Carbon stoichiometry	Component carbon (mol/mol)
H_2O	0	0	0
H_2	0,2	0	0
N_2	0,0073	0	0
H_2S	0	0	0
CO_2	0,016	1	0,016
CO	0	1	0
METHANE	0,7118	1	0,7118
ETHANE	0,056	2	0,112
PROPANE	0,008	3	0,024
IBUTANE	0	4	0
BUTANE	0,0008	4	0,0032
IPENTANE	0	5	0
PENTANE	0,0001	5	0,0005
HEXANE	0	6	0
HEPTANE	0	7	0
OCTANE	0	8	0
NONANE	0	9	0
DECANE	0	10	0
METHANOL	0	1	0
BENZENE	0	6	0
XYLENE	0	8	0
ETHYL BENZENE	0	8	0
TOLUENE	0	7	0
	Fuel carbon content (mol/mol)		0,868
	Fuel Carbon content (mol/Nm^3)		38,7
	Emissions (gCO_2/Nm^3)		1 703

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