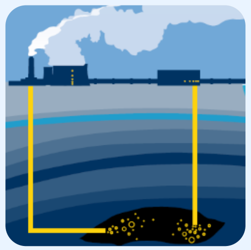


Low Carbon Hydrogen Well-to-Tank Pathways Study - Full Report

A report for Zemo Partnership
prepared by Element Energy

Zemo Partnership
Accelerating Transport to Zero Emissions

August 2021

elementenergy

About this work

Project Aims

- Hydrogen is a potentially vital fuel in the UK's plan for meeting its decarbonisation targets in the mobility sector for 2050. However, 99% of UK hydrogen today is 'grey hydrogen' and is not low carbon.
- In order to effectively appraise hydrogen's value in decarbonising transport and develop appropriate policy, UK decision makers need a clear and transparent evidence base of hydrogen's lifecycle emissions. This work has been instigated due to a lack of data specific to the UK on the carbon intensity (GHG emissions) of different low carbon hydrogen pathways.
- The study had the following aims:
  - To identify the range of hydrogen production, distribution and dispensing options that are emerging
  - To provide an exhaustive, transparent and up-to-date analysis of the emissions and energy use related to different low carbon hydrogen pathways (Well to Tank), considering feedstocks, production, distribution and dispensing
  - To identify the key sensitivities influencing the carbon intensity of the pathways considered
  - To create an Excel model to contain this data and allow users to easily explore the impact of a range of scenarios and sensitivities on full H_2 pathway emissions
  - This work will serve as the evidence base for decision and policy makers

This report provides a clear overview of the key findings and was delivered by Element Energy for Zemo. The study benefited from input from Zemo members and the wider UK supply chain.

Structure

This report provides an overview of the Well-to-Tank (WTT) emissions associated with the production, distribution, and dispensing of hydrogen.

The report is structured into:

- A section introducing the study's objectives and scope, and highlighting the process taken in this analysis
- A section detailing the key findings around the energy use and emissions associated with different pathways
- Conclusions on the pathways and discussion of key uncertainties
- Detailed appendices covering the hydrogen pathways and the data collected and used in this study, including:
  - Hydrogen production technologies and feedstocks
  - Distribution by pipeline and road transport
  - Dispensing options

About the authors

This report has been prepared by Element Energy for Zemo Partnership.

Element Energy is a strategic energy consultancy, specialising in the intelligent analysis of low carbon energy. The team of over 80 specialists provides consultancy services across a wide range of sectors, including low-carbon transport, hydrogen, carbon capture and storage, industrial decarbonisation, smart electricity and gas networks, energy storage, and renewable energy systems. Element Energy provides insights on both technical and strategic issues, believing that the technical and engineering understanding of the real-world challenges support the strategic work.

Project team:

Celine Cluzel	Director
Silvian Baltac	Principal Consultant
Oliver Robinson	Consultant
William Drake	Consultant

Subject Matter Experts:

Ben Madden	Director
Will Nock	Senior Consultant
Louis Day	Senior Consultant

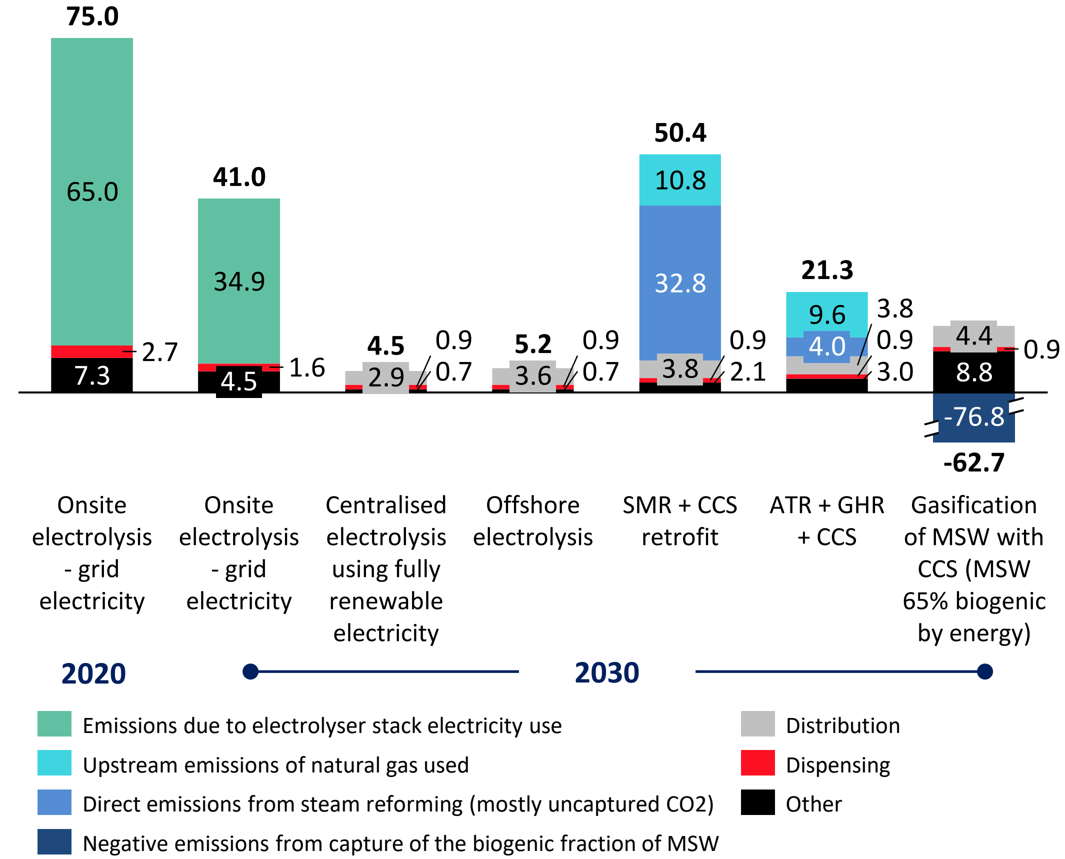
Acronym list

AGI	Above Ground Installation
ATR	Autothermal reforming
BECCS	Bio Energy with Carbon Capture and Storage
BEIS EEP	Department of Business, Energy and Industrial Strategy Energy and Emissions Projections
CCC	Climate Change Committee
CCS	Carbon Capture and Storage
CH_2	Compressed Hydrogen
COMAH	Control of Major Accidents and Hazards
CV	Calorific Value
DfT	Department for Transport
FC	Fuel Cell
FCH JU	Fuel Cells and Hydrogen Joint Undertaking
GHR	Gas Heated Reformer
GWP	Global Warming Potential
HGV	Heavy Goods Vehicle
HHV	Higher Heating Value
HRS	Hydrogen Refuelling Station
ICCT	International Council on Clean Transportation
LDS	Local Distribution System
LH_2	Liquefied Hydrogen
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LP	Low Pressure
LTS	Local Transmission System
MP	Medium Pressure
MSW	Municipal Solid Waste
NG	Natural Gas
NG FES	National Grid Future Energy Scenarios
NTS	National Transmission System
OUG	Own Use Gas
PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
PRI	Pressure Reduction Installation
PSA	Pressure Swing Adsorption
RDF	Refuse Derived Fuel
RED/RED II	Renewable Energy Directive
RTFC	Renewable Transport Fuel Certificate
RTFO	Renewable Transport Fuels Obligation
SMR	Steam Methane Reformation
TPD	Tonnes Per Day
TRL	Technology Readiness Level
VPSA	Vacuum Pressure Swing Adsorption
WTT	Well-to-tank (refers to whole H_2 pathway emissions from feedstock and production up to the point of dispensing to the vehicle's tank)

Executive summary

- As hydrogen is expected to play a key role in UK's legal target to reach net-zero by 2050, the carbon footprint of the hydrogen would be critical in deciding the production technologies and infrastructure that would require prioritisation.
- This study was undertaken by Element Energy for Zemo and established the well-to-tank emissions of different hydrogen production, distribution, and dispensing pathways used in mobility.
- The study benefited from significant industry engagement via a dedicated steering group and interviews with the supply chain.
- The study explored the emissions associated with electrolytic, fossil, and waste-based production of hydrogen, considering different technologies present today (small scale grid-powered electrolysis) and expected to be commercialised in the medium term, such as offshore electrolysis, gas reformation with CCS, and waste gasification with CCS.
- Both the energy use emissions and fugitive emissions were considered in this analysis. There is a wide variation in the pathway emissions depending on the carbon footprint of the feedstocks (electricity and natural gas). In general, emissions decline in time as the feedstock supply is decarbonised and efficiencies improve. For example:
  - Renewable-based electrolysis is expected to represent one of the lowest emissions pathways in the medium term.
  - Natural gas reformation using emerging ATR technology with CCS could greatly reduce the emissions of hydrogen, and could generate carbon-negative hydrogen when biomethane is used.
  - Gasification of waste with CCS could achieve the highest level of negative emissions.
- The study provided an overview of the quality of the data used, as well as identified areas for further work and monitoring, including:
  - Consolidation of the data used and collection of real-world data from demonstration projects
  - Monitoring of emerging technologies, such as CCS, grid blending, liquid hydrogen, and electrolysers
  - Further research around the fugitive emissions associated with the pathways.

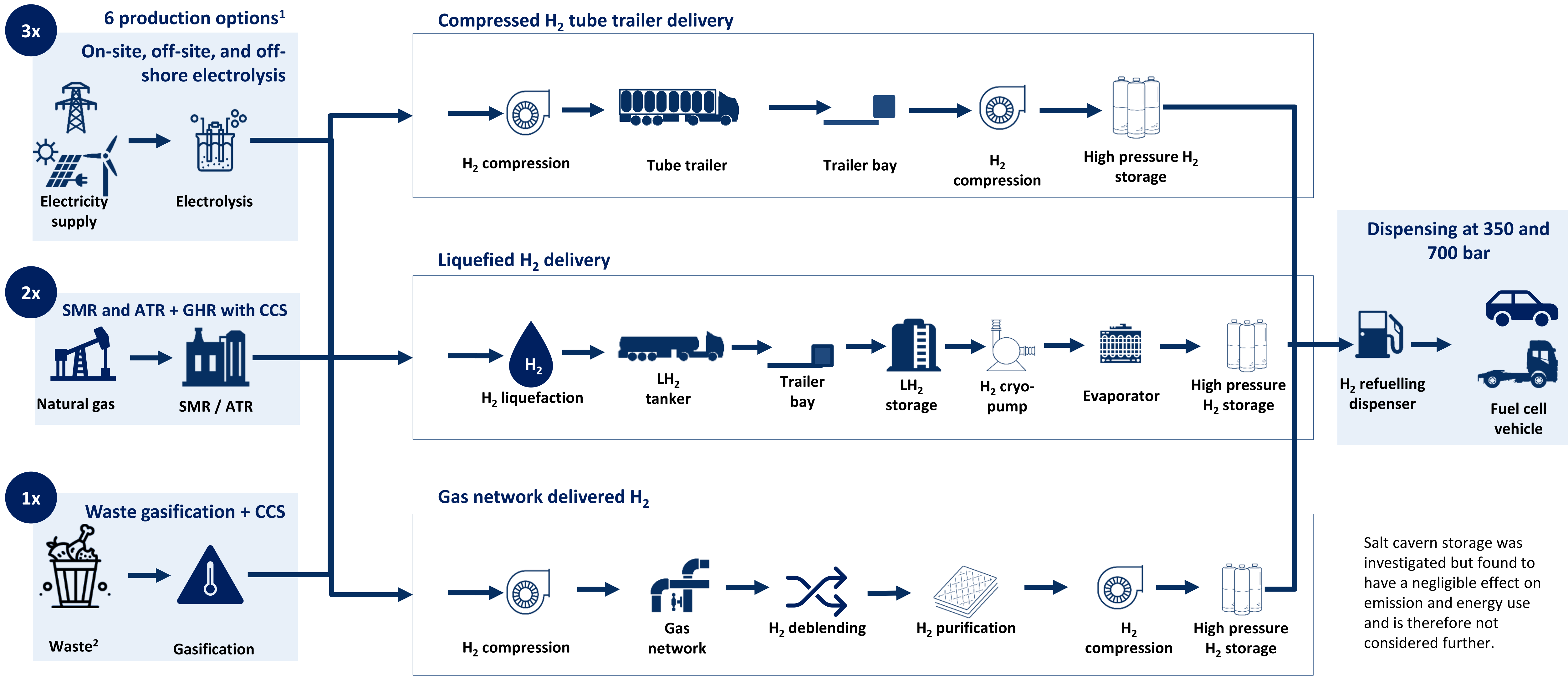
Emissions from 6 illustrative pathways for 2030 compared to 2020 onsite electrolysis, gCO2e/MJ H_2 LHV. The BEIS EEP 2019 baseline grid carbon intensity scenario is used and tube trailer delivery is shown where applicable



Note that the "Other" category in the table refers to factors which have a very small impact on overall supply chain emissions – electricity use of ATR, SMR and gasification plants, transport and processing of municipal solid waste (MSW) to form refuse derived fuel (RDF), CO2 transport and fugitive emissions of hydrogen. Please refer to the report content for the assumptions and sensitivity results.

ATR (Autothermal Reformer) carbon capture rate 95%, retrofit SMR (Steam Methane Reformer) carbon capture rate 60%, GHR: Gas Heated Reformer, MSW: Municipal Solid Waste

A combination of six production configurations, three distribution pathways, and two dispensing options were considered in this study (32 different combinations) – most are not yet in use



Fugitive emissions (hydrogen, methane, CO_2) are also included

1: Only on-site electrolysis modelled for 2020 – other production options modelled from 2030 onwards

2: Gasification uses municipal solid waste that is 65% biogenic by energy. For gas grid blending, a blending ratio of 20% is considered.

The model scope was carefully defined based on literature findings and input from the Steering Group throughout several workshops (1/2)

Literature review and data collection

Proposed model structure, pathways and model flexibility

Data review and validation workshops

Model building and quality assurance checks

Model and draft report handover

Final report

Data sources analysed – over 50 reports reviewed

- Public reports on technologies
- References submitted by the steering group
- Data provided by technology developers
- Element Energy datasets

Information and Parameters collected

- Understanding of technology timeframes, readiness, and potential
- Energy consumption
- Scenarios for future carbon intensity of energy

Data was collected in the literature tracker and graded by degree of uncertainty

1 - Fugitive emissions will be covered in each segment as relevant

The model scope was carefully defined based on literature findings and input from the Steering Group throughout several workshops (2/2)

Literature review and data collection

Proposed model structure, pathways and model flexibility

Data review and validation workshops

Model building and quality assurance checks

Model and draft report handover

Final report

Targeted interviews and engagement with technology providers, subject experts and hydrogen producers to collect data and refine assumptions:

Data and model review workshops

- A first session where the model objectives, scope and specification were discussed and validated – attended by 12 Steering Group members
- The data and scenarios review sessions focusing on the major value chain segments:
  - Feedstock, production and storage – attended by 10 Steering Group members
  - Transport and purification – attended by 11 Steering Group members
  - Dispensing – attended by 7 Steering Group members
- A session to validate findings of the report was also organised
- Steering Group attendees included:

Contents

About this section

The following section provides:

- An overview of the range of emissions from the hydrogen production, distribution, and dispensing pathways considered
- Deep-dives into each value chain element (in isolation of the whole pathway), taking into account plant performance and how this is likely to improve in future:
  - Electrolysis: energy consumption and production emissions
  - Natural gas reformation and gasification technologies with CCS considering:
    - The energy consumption and emissions for each production option
    - The impact of the gas feedstock on the carbon footprint of the hydrogen
  - Comparison of the energy use and emissions for each distribution pathway, including sensitivities
  - Comparison of the energy use and emissions for each dispensing pathways (350 & 700 bar)
- Results for whole-pathway emissions including
  - Emissions for the various hydrogen production, distribution and dispensing options
  - A range of emissions factor scenarios for natural gas and grid electricity use, exploring how these could change over the period studied
  - Upstream ‘well-to-terminal’ emissions for natural gas
  - Emissions resulting from losses/fugitive emissions during transmission and distribution for both grid electricity and natural gas
  - Total fugitive emissions across the whole pathway
  - Energy efficiency down the pathway
- Reflection on further work and areas to monitor

The following slides show (marked with icons):

Energy use across different value chain elements in MJ / kg H_2

CO_2 Emissions associated with each pathway in $gCO_2e/MJ\ H_2$ LHV currently and in the future (2020/2030/2035+)

- WTT hydrogen pathways from feedstock preparation to hydrogen dispensing; 6 hydrogen production cases considered: SMR with CCS, ATR + GHR with CCS, onsite electrolysis, large onshore centralized electrolysis, offshore electrolysis, waste gasification with CCS
- Lower Heating Value is used for hydrogen, natural gas and diesel, while Higher Heating Value is used for refuse derived fuel
- A 100-year Global Warming Potential of 5.8 is used for hydrogen – meaning that over 100 years 1 kg of hydrogen has the same warming effect as 5.8 kg of carbon dioxide. Note that hydrogen is an indirect greenhouse gas.
- A 100-year global warming potential of 28 is used for methane.
- Greenhouse gas emissions include emissions of CO_2, N_2O and CH_4

Results for 2035 and 2035+

- **Energy use:** Results beyond 2030 are shown as 2035+ because for all technologies no further energy efficiency improvements were modelled
- **Emissions:** Results continue to change for the years after 2035 according to the emissions factors selected for the energy used. In this report results are shown for 2035, but the model presents results up to 2050

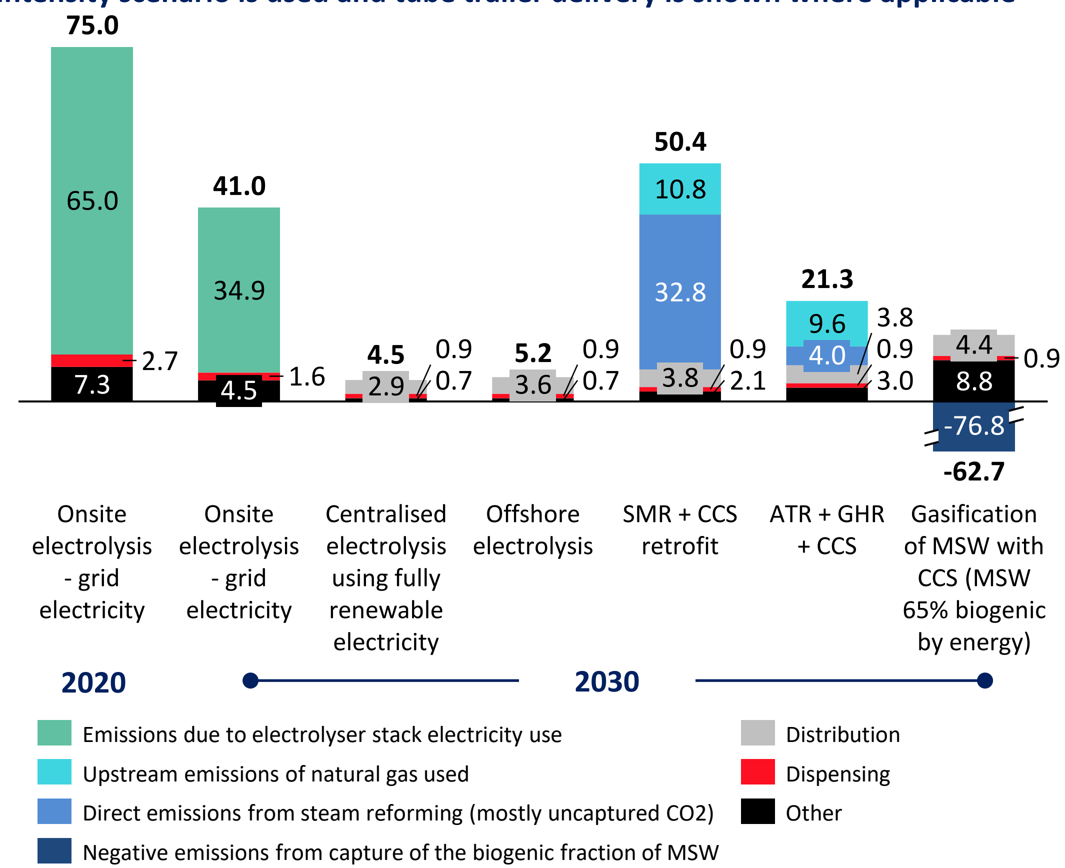
Contents

Overview of supply chain emissions for several possible 2030 hydrogen production pathways

Low carbon hydrogen for transport in the UK is currently produced by electrolysers on-site at hydrogen refuelling stations; the emissions of which are dominated by the use of grid electricity for the electrolyser. However, by 2030, other production pathways will emerge. In addition to onsite electrolysis, low carbon hydrogen will be produced from natural gas, using either newbuild autothermal reformers (ATRs) fitted with carbon capture and storage, or by retrofitting old steam methane reformers (SMRs) with carbon capture and storage. In addition, hydrogen will be produced by large centralised electrolysers and by gasification of municipal solid waste with CCS. Around 2030 or shortly after, offshore electrolysis may emerge, with electrolysers directly connected to offshore wind turbines, and hydrogen transported to the shore by pipeline. The figure on the right shows the supply chain emissions of 6 possible 2030 hydrogen production pathways, combined with tube trailer delivery (350 kg capacity) over 200 km, and dispensing at 350 bar.

- **The variation in emissions between production options dominates the variation in full supply chain emissions**.
- **Emissions from onsite electrolysis using grid average electricity fall sharply** between 2020 and 2030 even using the conservative BEIS EEP 2019 baseline grid carbon intensity adopted here. With net-zero BEIS grid intensity scenarios the fall is sharper, to around 20 gCO2e/MJ by 2030.
- **Natural gas upstream emissions are the largest source of emissions from hydrogen production by newbuild ATRs** owing to the very high carbon capture rates (95%) of these technologies. The use of pipeline natural gas rather than LNG - along with the elimination of methane emissions from the upstream natural gas supply chain – is crucial for this pathway to be low carbon.
- **Centralised electrolysis using renewable electricity** results in zero emissions from production. To be truly using renewable electricity, the electrolysers must not be diverting existing renewable electricity production from other sources of demand. Electrolysis performed using curtailed renewable generation is zero carbon.
- **Negative emissions can be achieved by gasification of municipal solid waste combined with CCS** owing to the biogenic fraction on the MSW – assumed to be 65% biogenic by energy.
- The following slides explore these paths in detail.

Emissions from 6 illustrative pathways for 2030 compared to 2020 onsite electrolysis, gCO2e/MJ H_2 LHV. The BEIS EEP 2019 baseline grid carbon intensity scenario is used and tube trailer delivery is shown where applicable



Note that the “Other” category in the table refers to factors which have a very small impact on overall supply chain emissions – electricity use of ATR, SMR and gasification plants, transport and processing of municipal solid waste (MSW) to form refuse derived fuel (RDF), CO_2 transport and fugitive emissions of hydrogen.

ATR carbon capture rate 95%, retrofit SMR carbon capture rate 60%

Key assumptions for modelling (1) – Energy use and emissions factors for H_2 production

Emissions across the H_2 pathway tend to be dominated by production. Apart from electrolysers, energy use is held constant throughout the period studied and it is the emissions factors of the energy used that determine changes in emissions over time

Energy use assumptions for H_2 production:

- **Energy use for non-electrolyser H_2 production:** For all H_2 production technologies except electrolysers, energy use is kept constant for all years and values are only included from 2030 onwards. This is because these technologies are at an earlier stage of development and have not yet been deployed for low carbon H_2 production (SMR plants are currently used at scale but without carbon capture). For these technologies, falling emissions over time are driven by the feedstock used (central case shown in table below but other options were explored) and the emissions factors applied to their energy use (these vary over time – see next slide)
- **Energy use for electrolysers:** On-site electrolysers are the only H_2 production technology considered in 2020 and significant improvements in terms of energy use are expected by 2030 and then some further improvements by 2035 – energy use figures then remain constant from 2035

Energy use assumptions	2020	2030	2035	Post-2035
On-site electrolyser	✓	↓	↓	→
Large centralised on-shore electrolyser	✗	✓	↓	→
Large off-shore electrolyser	✗	✗	✓	→
SMR + CCS	✗	✓	→	→
ATR + GHR + CCS	✗	✓	→	→
Gasification + CCS	✗	✓	→	→

✗ Not included in modelling ✓ First period included in modelling ↓ Reduction in energy use from previous period → Energy use constant from previous period

Emissions factors - Central case Other cases/sensitivities use other factors	Feedstock	Electricity use	Natural gas use
On-site electrolyser	Grid electricity	Grid electricity	✗
Large centralised on-shore electrolyser	Renewable electricity	Renewable electricity	✗
Large off-shore electrolyser	Renewable electricity	Renewable electricity	✗
SMR + CCS	Fossil natural gas	Grid electricity	Fossil natural gas
ATR + GHR + CCS	Fossil natural gas	Grid electricity	Fossil natural gas
Gasification + CCS	Municipal solid waste	Grid electricity	✗

Grid electricity Renewable electricity Fossil natural gas
Municipal solid waste

Key assumptions for modelling (2) – grid electricity and natural gas upstream emissions factors

For most production pathways energy use remains constant, so the emissions factors associated with their energy use are the main driver for changing emissions over time

Key assumptions around emissions factors for grid electricity:

- Unless otherwise stated, the results presented in this report use the 'central' case for electricity grid carbon emissions factors, which is the BEIS EEP 2019 baseline emissions factor projections shown in bold in the table[1].
- The model captures a range of possible future grid carbon intensity scenarios which have a strong impact on emissions results. The rate at which grid carbon intensity falls in future will depend on the pace of deployment for large scale renewable generation capacity
- Grid losses are included
- More information about the scenarios explored in the modelling and how they compare to other projections can be found on this slide.

Key assumptions around emissions factors for natural gas:

- Treatment of natural gas upstream emissions is discussed here
- Treatment of combustion emissions is discussed here
- FES 2020 Steady Progression (medium LNG) - combined with BEIS LNG and pipeline natural gas emissions factors - is used as the central scenario; other FES scenarios give very similar NG upstream WTT emissions, as discussed here
- The proportion of LNG is a key differentiator between scenarios for upstream NG emissions and the scenarios explored have varying proportions of LNG
- Biomethane is not included in the main NG upstream emissions scenarios but is explored separately as a sensitivity

Electricity grid emissions factors (gCO2e/MJ)	**2020**	**2030**	**2035**	**2040**	**2050**
FES 2020 - System Transformation	42	18	- 21	-24	- 23
BEIS EEP 2019 baseline (central scenario)	**41**	**25**	**22**	**19**	**17**
BEIS EEP 2019 net-zero low demand scenario	41	12	5	3	2
BEIS Marginal electricity emissions factors 2019	79	35	19	11	8

Natural gas upstream emissions factors (gCO2e/MJ)	**2020**	**2030**	**2035**	**2040**	**2050**
FES 2020 Steady Progression - High LNG	7.6	8.8	9.3	9.7	11.4
FES 2020 Steady Progression - Medium LNG	7.3	7.6	8.1	8.5	9.9
FES 2020 Steady Progression - Low LNG	7.1	6.4	6.9	7.2	8.3
Marginal LNG	19.6	19.6	19.6	19.6	19.6
No LNG - UKCS and Norway only	4.3	4.3	4.3	4.3	4.3

1. It should be noted that this scenario does not meet the government's own legally mandated target for 2050 and is therefore a relatively conservative baseline

Key assumptions for modelling (3) – Production

Key assumptions for electrolysers:

- Non-stack emissions – from water purification, AC-DC rectification and hydrogen drying and deoxygenation – are included
- On-site electrolysers use grid electricity in the central case - emissions could be reduced significantly by using 100% renewable electricity
- On-shore central case uses 100% renewable electricity as all green hydrogen developers Element Energy spoke to are using renewable procurement
- Desalination is included for the offshore electrolysis case but has a negligible effect on energy use and no effect on emissions as it is assumed to be performed using renewable electricity.

Key assumptions for SMR and ATR + GHR with CCS:

- 60% carbon capture rate for SMR with CCS central case - assumes the CCS equipment is retrofitted to an existing SMR plant
- 95% carbon capture rate for ATR + GHR with CCS central case
- Emissions include a very small contribution from methane in the flue gas[1]
- Energy use and emissions for CO_2 compression and transport are very small and are included within the plant electrical energy use figures. More details may be found here.

Key assumptions for Gasification + CCS:

- 97% carbon capture rate for gasification + CCS
- Municipal Solid Waste used to form the Refuse Derived Fuel feedstock for gasification is assumed to be 65% biogenic by energy. For gasification with CCS, emissions from the fossil fraction are ignored, and negative emissions are credited for the biogenic fraction only.

Key assumptions for CO_2 compression, transport and storage:

- Small energy uses for CO_2 compression and transport are included in plant electricity use for production plants in results; further details of this are discussed here
- Fugitive emissions of CO_2 during transport are negligible

(1) JRC,EUCAR,Concawe - JEC Well-To-Wheels report v5, accompanying data

Key assumptions for modelling (4) – Distribution

Key assumptions for gas network delivered H_2:

- **System level approach:** Whole-system own use gas and leakage figures for the transmission network and distribution network are used and these are adapted for hydrogen as discussed in the appendix. Hydrogen is assumed to be injected at the transmission level (80 bara), with the HRS connected to the IP/LP distribution network (2 bara). If hydrogen is instead injected at distribution level, then energy use from this pathway will be lower owing to the decreased initial compression requirement, as discussed here. Gas grid connected HRS energy use will also be lower if the HRS is connected to higher pressure tiers of the network owing to a reduction in HRS compression requirements – this is discussed here.
- **H_2 on the gas network:** The results for 2030 assume H_2 supplied via a gas network with a 20% hydrogen blend. From 2035 the results reflect a 100% hydrogen gas network. This does not imply full conversion of the UK gas network by these dates, but rather that some regional sections of the network could have converted by these dates and so they represent a pathway that would only be possible in those areas of the UK that convert first.
- **H_2 Purity:** Hydrogen delivered by a '100% hydrogen' gas network is assumed to be 98% pure. This is due to impurities picked up from the pipeline and odorants added to the gas for transport. All gas network delivered H_2 is assumed to require purification to fuel cell purity before dispensing.
- **Purification:** Assumed to use PSA. The energy use for this is in compression – overall this results in negligible additional energy use because compression from the gas network pressure to the dispensing pressure is required anyway and there is negligible pressure loss at the PSA plant. Unrecovered hydrogen in the PSA tail gas is assumed to be re-injected into the gas network and used elsewhere – for example, for heating.
- **Energy use for deblending:** This is only required in 2030 when the gas network supply is assumed to be from a 20% blended network. The recent Costain report[1] is used as the source for deblending energy use; further discussion of the uncertainty around this energy use may be found here and in the appendix.
- **Own use of gas by network:** this is a very small energy use and is discussed in more detail on this slide and this slide
- **Leakage:** Falls between 2030-2035 for distribution network due to iron mains replacement programme.

Key assumptions for LH_2 tanker truck delivery:

- Central case assumes 3,500kg LH_2 per delivery, 200km round trip delivery distance
- Emissions from liquefaction plants running on grid electricity drop sharply as the grid decarbonises

Key assumptions for CH_2 tube trailer truck delivery:

- Central case assumes 280 bar tube trailers delivering 350kg H_2, 200km round trip delivery distance

Gas network assumptions	2020	2030	2035	Post-2035
H_2 on gas network	✗	**20%**	**100%**	**100%**
De-blending required	✗	✓	✗	✗
Own use NG	✗	✓	✗	✗
Own use H_2	✗	✓	↑	→
H_2 transmission network leakage	✗	✓	→	→
H_2 distribution network leakage	✗	✓	↓	→

✗ Not included in modelling ✓ First period included in modelling ↓ Reduction from previous period ↑ Increase from previous period → Constant from previous period

(1) Costain, 2020, Hydrogen Deblending in the GB Gas Network

Key assumptions for modelling (5) – Dispensing

In general, the technologies required for H_2 dispensing are well known and the energy use of key equipment is not expected to change substantially over time. Low, Central and High values were not modelled, instead a variety of HRS archetypes were considered alongside the distribution options

Key HRS assumptions:

- The HRS archetypes included in the modelling are not differentiated by type of vehicle served, but by the steps required to process the H_2 to its dispensing state of 350 or 700 bar: **purification, compression, pumping and cooling.** These are determined by the distribution mode used to deliver H_2 to the HRS
- **Station size:** For a HRS supplied with CH_2, energy use is dominated by compression which does not vary significantly with station size per unit of H_2 dispensed and so this is not included as a variable. However, for LH_2 supplied stations H_2 boil-off is substantially higher for smaller stations and so a medium sized station is assumed for the central case (1,500kgH_2/day). More information about the impact of scale on boil-off available on this slide.
- **Station utilisation:** Apart from HRS with very low (<20%) utilisation where cooling demand per kgH_2 dispensed is very high, utilisation has little impact on energy use per kgH_2. All stations are assumed to have a high level of utilisation, as infrastructure without a clear demand source is unlikely to be built
- **CH_2 tube trailer deliveries:** The tube trailer is left at the HRS, providing medium pressure storage. Compression is modelled from the halfway point between the delivery pressure and 20 bar, at which point the trailer is depleted and is returned for refilling

Summary of HRS station archetypes and inclusion in modelling

H_2 supply	H_2 supply state – central scenario	2020	2030	2035+
On site electrolyser	30 bar	✓	✓	✓
Tube trailer	280 bar	✗*	✓	✓
Liquefied H_2 tanker	Liquefied	✗	✓	✓
H_2 pipeline	2 bar	✗	✓	✓

350 vs 700 bar refuelling

There is very little difference in energy use and emissions between 350 and 700 bar dispensing when the whole H2 pathway is considered. For clarity, only results for 350 bar refuelling are shown in the body of this report, but both 350 and 700 bar dispensing are included in the model and more detail on the difference in energy use between the two can be found on this slide

*Tube trailer delivery is available today, but there are no low carbon H_2 production facilities for these to supply a HRS from in the UK currently

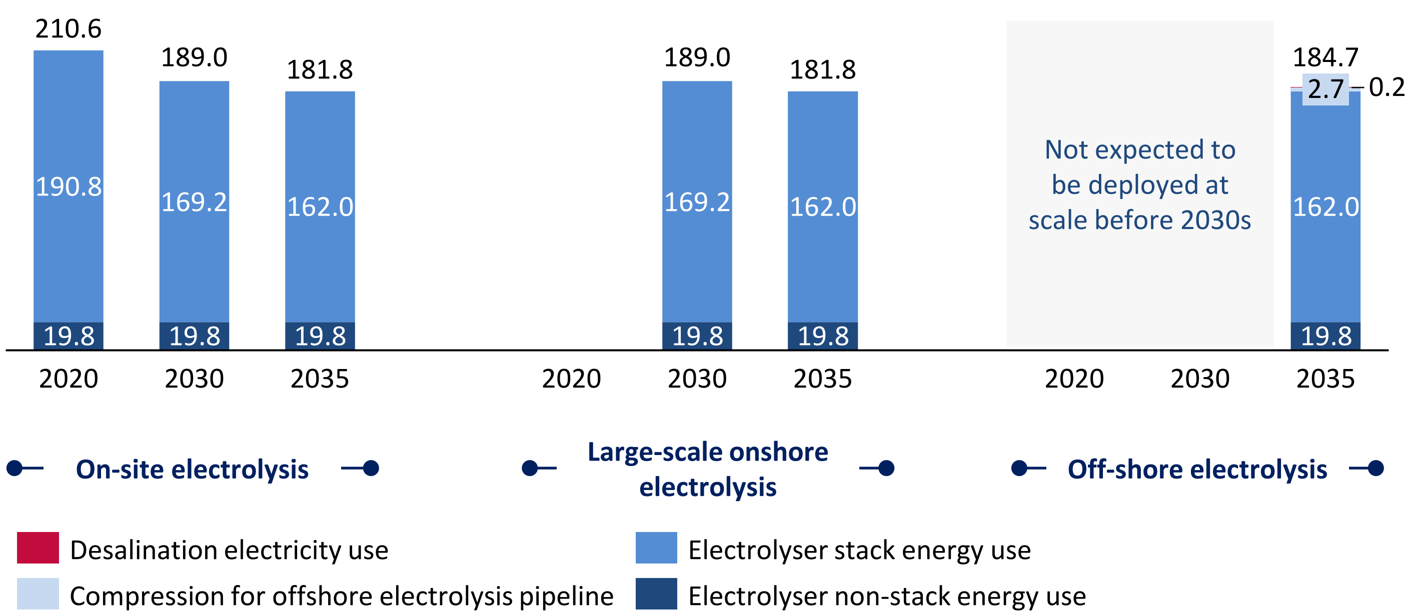
Contents

Energy consumption from electrolysis is expected to decline with technology advances

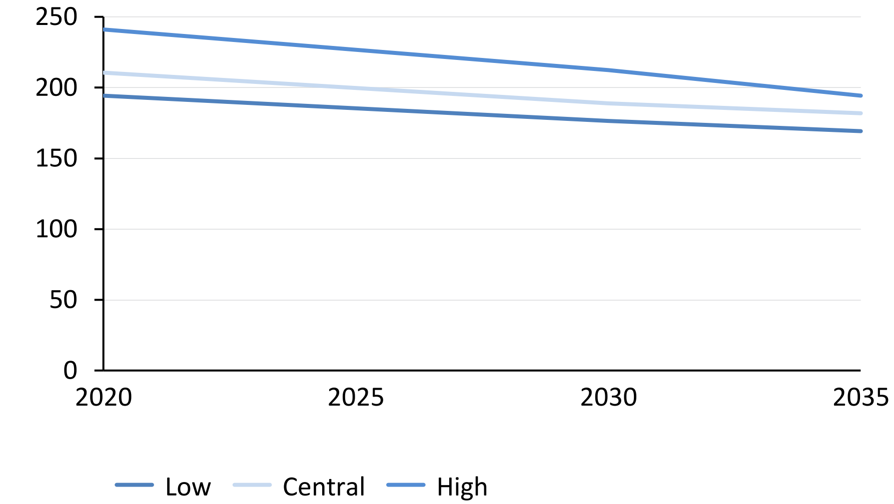
Electrolysers are expected to be deployed either on-site of the hydrogen refuelling station (as today), but also as large-scale electrolysers, on-shore and off-shore (in the 2030s). In terms of energy consumptions, the following factors are observed:

- Electrolyser **stack energy use dominates** the electrolysis contribution to the energy use. In general, electrolysis energy consumption is insensitive to the size of the electrolyser owing to the modular nature of the electrolysers
- Advances in electrolyser technology could reduce the energy use from electrolysis by around **14 %** from 2020 levels by 2035
- **Energy use for offshore electrolysis is very similar to onshore electrolysis** as energy requirements for compression for offshore pipeline and desalination are small. Note that energy use from desalination is included in the modelling but is a very small component.
- Electrolyser stack energy use is expected to fall over the 2020s and 2030s as the technology matures

Energy use for different electrolyser set-ups
Central case, excluding distribution and dispensing, MJ/kg H2



Energy use for on-site electrolysers considering different technology efficiencies, MJ/kg H2

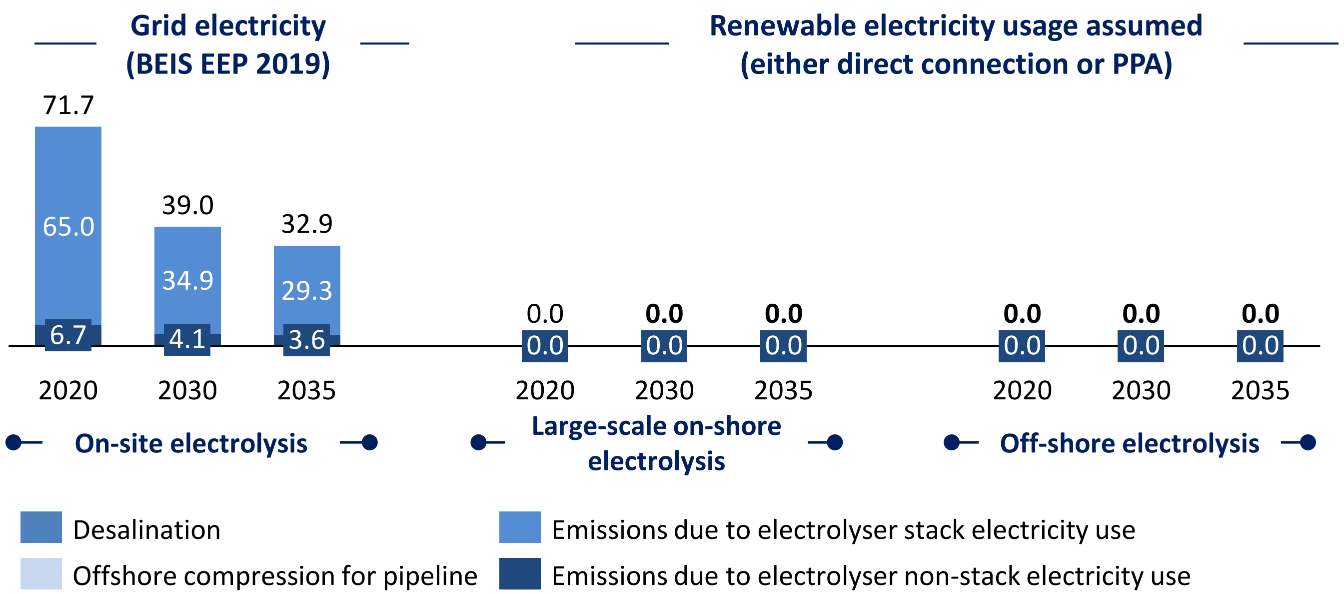


Improvement in electrolyser efficiency coupled with low-carbon or renewable electricity could produce hydrogen with a very low carbon footprint

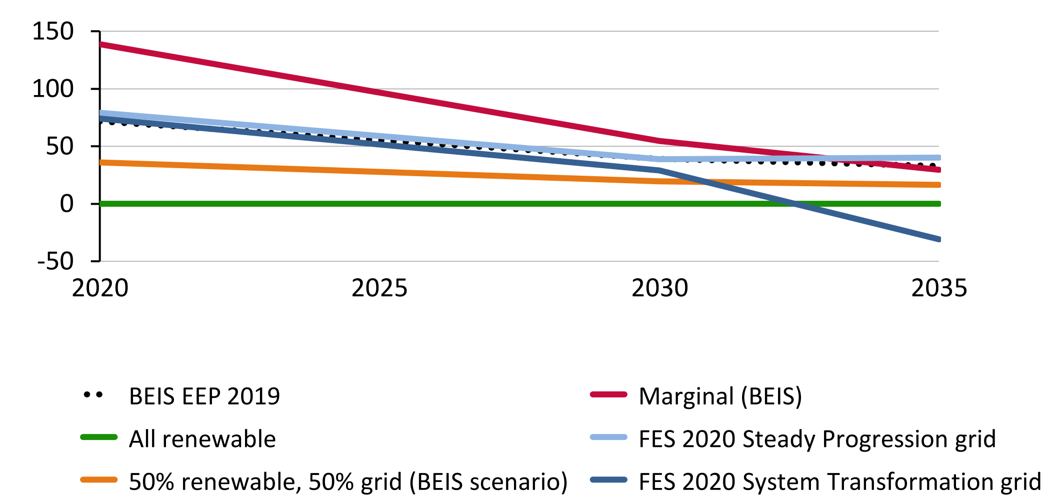
Emissions for hydrogen produced by electrolysis result from the carbon intensity of the electricity is used. For electrolysers using grid electricity, the rate at which the grid decarbonises is the driving force behind falling emissions during the 2020s and 2030s.

- Electrolysis using renewable electricity results in zero emissions, while electrolysers using grid average electricity give rise to higher emissions – around 72 gCO2e/MJ H_2 LHV produced in 2020 but expected to decrease in time, as the grid is decarbonised.
- The type of electricity used by the electrolyser is the largest single factor effecting the supply chain emissions – this is illustrated in the diagram on the right. Under most scenarios, electrolysers could achieve below 42 gCO2e/MJ H_2 LHV by 2030.
- Large centralised electrolysers are expected to either be connected to a wind farm (either directly or through a PPA) or to operate predominantly during periods of curtailed renewable generation and therefore give rise to zero emissions by default.
- Discussions with green hydrogen project developers confirm that all projects being scoped will have a strategy for near 100% renewable electricity procurement (albeit with different load factors according to their RE procurement strategy) - this is likely to be further supported by Government subsidies linked to a requirement for green hydrogen.

Emissions for different electrolyser set-ups,
Central case, excluding distribution and dispensing, $gCO_2e/MJ\ H_2$ LHV



Emissions for electrolysers under different electricity grid carbon intensities, Central electrolyser energy efficiency scenario ($gCO_2e/MJ\ H_2$ LHV)



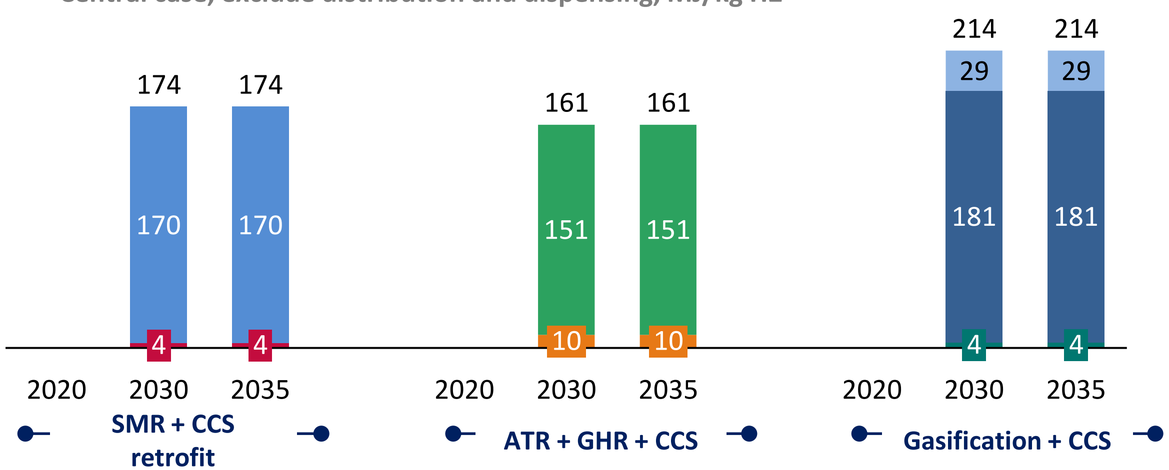
PPA: Power Purchase Agreement; data shown for PEM electrolysers

Blue hydrogen production pathways are expected to emerge in the late 2020s, with the deployment of Carbon Capture and Storage clusters

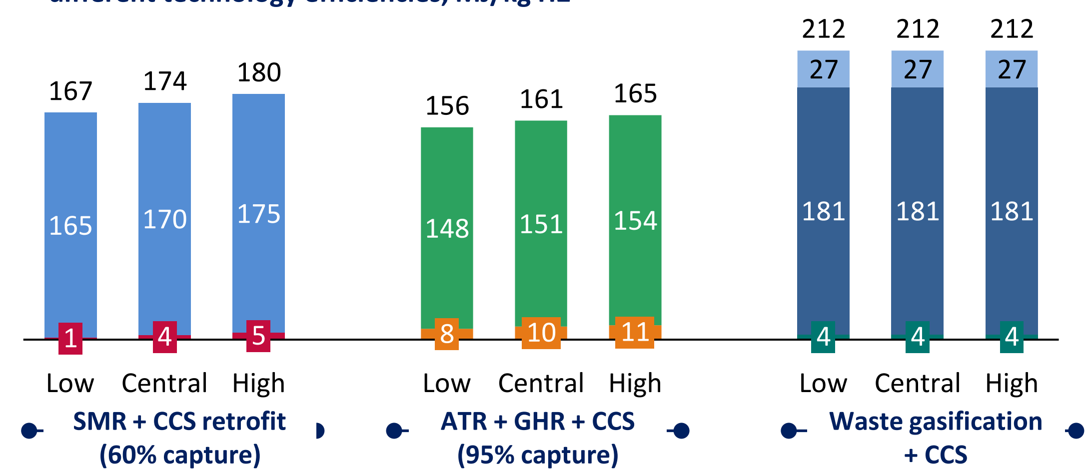
Hydrogen could also be produced from natural gas and waste feedstocks, via reformation (SMR or ATR + GHR) and gasification. To deliver low-carbon "blue" hydrogen, such processes would need to be fitted with Carbon Capture and Storage (CCS). Key drivers for energy consumption and differences between technologies are:

- **ATR + GHR plants have not yet been deployed at scale, but they are expected to be significantly more efficient than SMR plants**, with around 11% lower natural gas consumption for the same hydrogen output
- Electricity use by the plant, including for CO_2 transport and compression for offshore pipeline, makes up a small proportion – less than 7% – of the energy use for SMRs and ATR + GHRs with CCS. **Natural gas consumption dominates the energy use of SMR and ATR + GHR plants.**

Energy use for different reformation and gasification technologies
Central case, exclude distribution and dispensing, MJ/kg H2



Energy use for different reformation and gasification technologies considering different technology efficiencies, MJ/kg H2



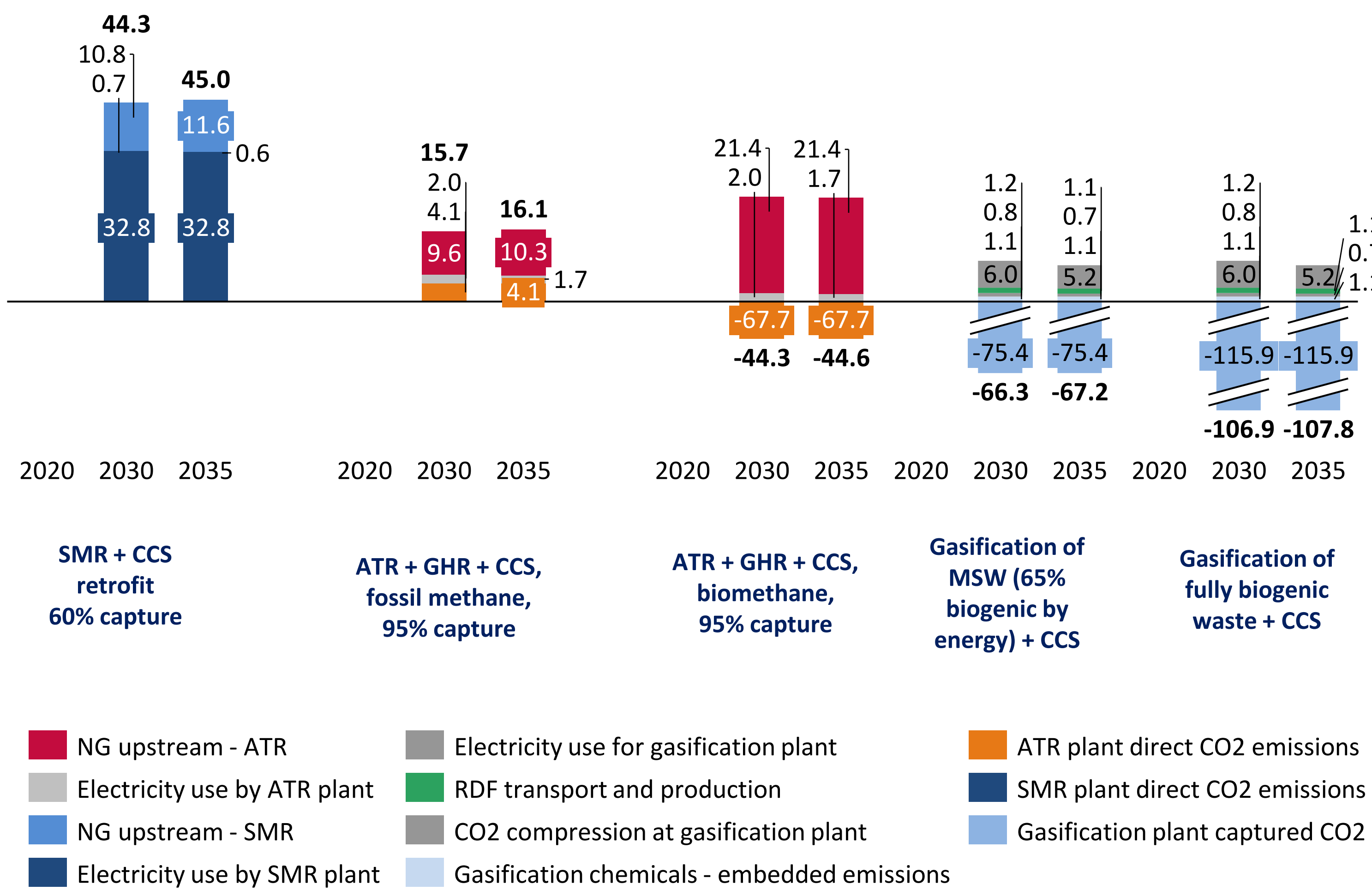
Waste Gasification data is based on one single technology – the energy efficiency is thus kept flat due to data availability

Depending on the feedstock and carbon capture rate for the CCS plant, carbon-negative hydrogen could be produced

- Not all of the carbon dioxide produced by hydrogen production from natural gas is captured, leading to emissions.
- Emissions also arise from the natural gas supply chain – these are referred to in this report as NG upstream emissions.
  - Newbuild reformers are expected to be primarily ATR + GHR, which will operate with very high capture rates (95% or more), so that the **emissions from hydrogen production by ATR + GHR are dominated by the NG upstream emissions.**
  - ATR + GHR + CCS achieves negative emissions when using biomethane as a feedstock
  - Retrofitted SMRs only achieve capture rates around 60% as dilute combustion CO_2 streams are not captured, leading to large combustion direct CO_2 emissions.
  - Small contributions to emissions arise from the use of small amounts of grid average electricity in SMR and ATR + GHR plants, as well as for CO_2 transport and compression for the offshore pipeline. This has a relatively small impact on the emissions.
  - Emissions from gasification with CCS are dominated by the large negative contribution due to storage of CO_2 originating from the biogenic fraction in the waste – this is assumed to be 65% by energy as a UK average figure. Emissions are more negative for the case of gasification of fully biogenic waste, as shown in the diagram. There are also small contributions to emissions from gasification resulting from the use of grid average electricity by the gasification plant.
  - Note that ATR + GHR + CCS and SMR + CCS plant direct CO2 emissions contain a very small contribution from methane emissions in the flue gas of 0.5gCO2e/MJ H_2 LHV[1]

Emissions for different reformation and gasification technologies

Central case, excluding distribution and dispensing, $gCO_2e/MJ\ H_2$ LHV



(1) JRC,EUCAR,Concawe - JEC Well-To-Wheels report v5, accompanying data

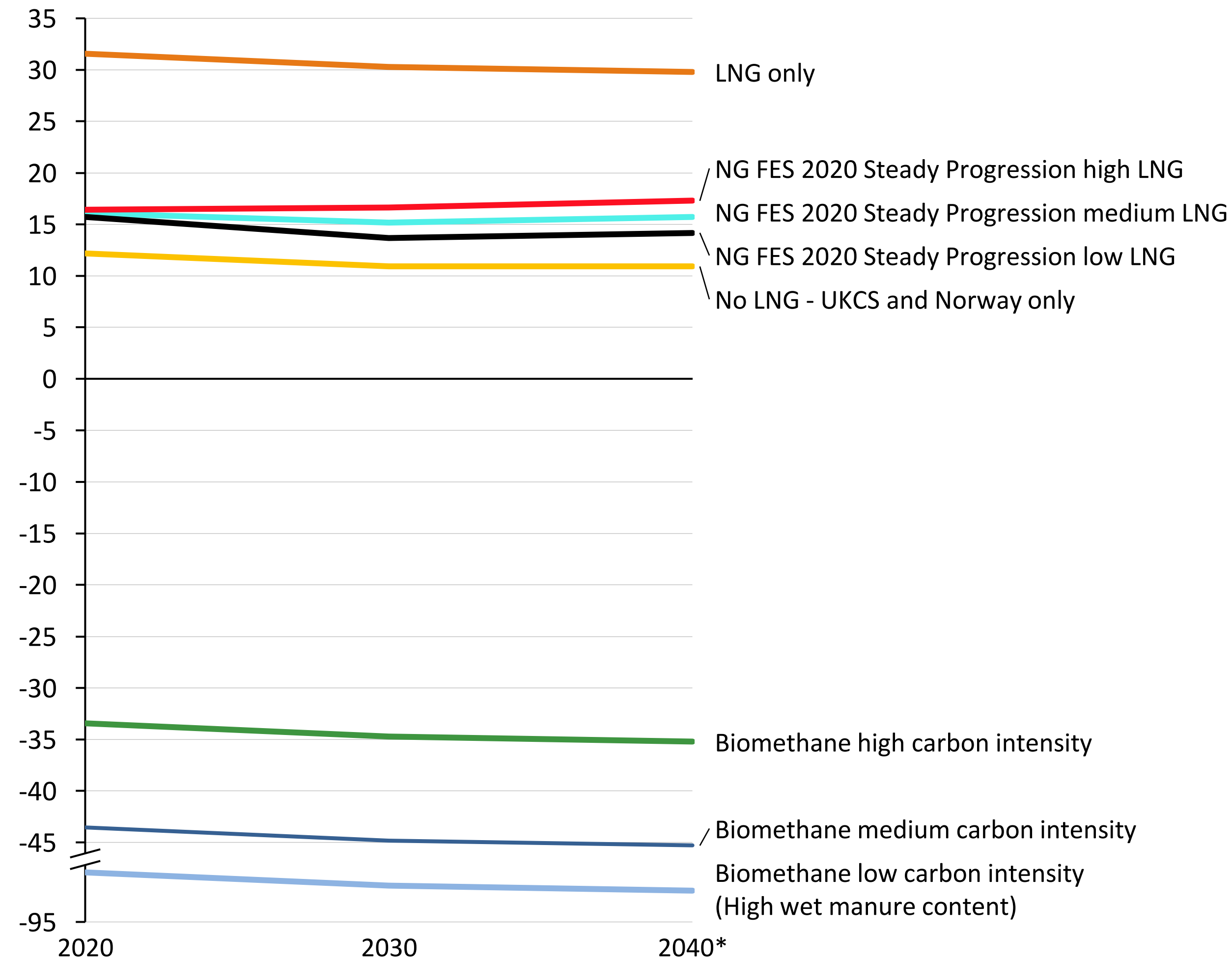
Natural gas upstream emissions vary according to the proportion of LNG in the natural gas used, while biomethane source has a large impact on emissions

- The upstream emissions associated with the natural gas used for hydrogen production have a significant impact on the WTT pathway emissions for production via SMR and ATR + GHR.
- The chart on the right compares the emissions for hydrogen production via ATR + GHR with CCS for several natural gas NG upstream emissions scenarios.
  - Total emissions vary between around 13 gCO2e/MJ H2 LHV and 18 gCO2e/MJ H2 LHV depending on the proportion of LNG in the natural gas within the uncertainty of the FES 2020 Steady Progression Scenario
  - Emissions fall slightly between 2020 and 2030 as the carbon intensity of the electricity used drops sharply, before rising between 2030 and 2040 as an increasing share of the natural gas used comes from LNG
  - **Biomethane:** Because biomethane is accounted for separately via certificates such as RTFCs, it is considered separately as a sensitivity in this modelling. Using 100% biomethane under the scenarios set out in **this slide**, achieves negative emissions in the range of -92 to -33 gCO2e/MJ H_2 LHV
  - Hydrogen produced by ATR + CCS using LNG only creates emissions very close to the RTFO limit of 33.5 gCO2e/MJ H_2 LHV

Key drivers for emissions:

- Higher LNG scenarios produce higher overall emissions: for instance, in the FES 2020 Steady Progression scenario, **emissions are 22% higher if all of the "generic imports" are LNG than if they arrive from pipeline sources**.
- The NG upstream emission factor cancels out a significant fraction of the BECCS negative emissions, and there is very large variation in emissions even when biomethane feedstock is used. **However, supply of biomethane for H_2 production may be limited in the short to medium term as demand is growing for its direct use in heating and heavy trucks. In the longer term as these sectors transition to zero emission electrical or hydrogen systems, biomethane supply may be freed up for use as a feedstock for H_2.**
- **The natural gas upstream emissions are discussed on the next slide**

Total emissions from hydrogen production by ATR + GHR + CCS for different feedstocks, $gCO_2e/MJ\ H_2$ LHV (Steady Progression medium LNG is the central scenario)



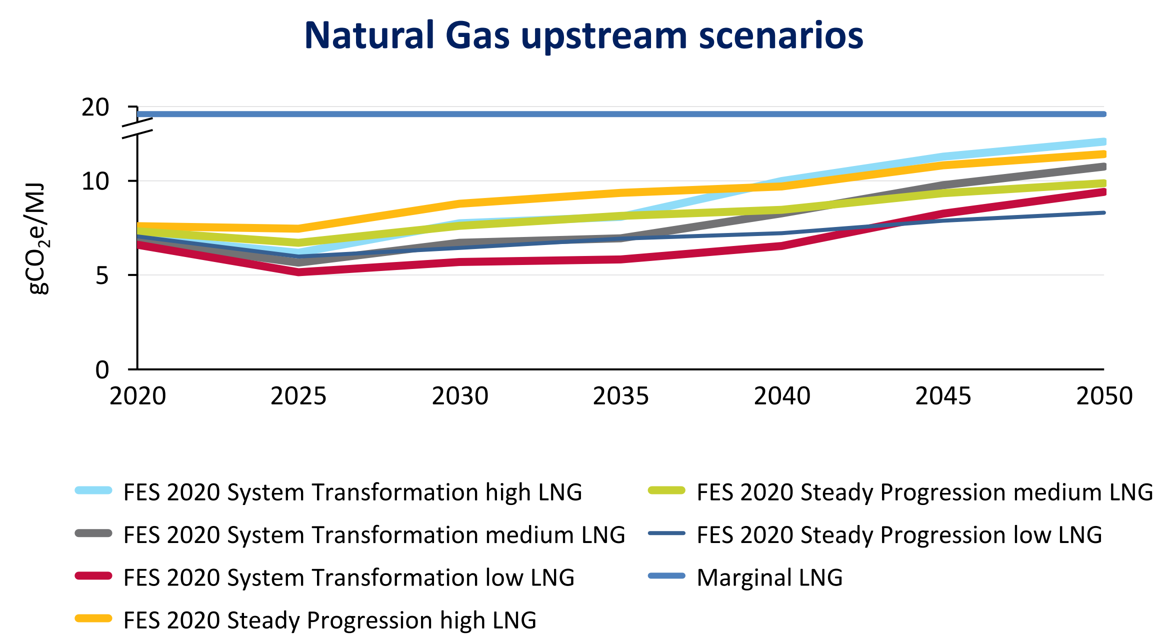
Assumes 95% capture rate for ATR + GHR + CCS natural gas

*Energy use for production held constant from 2030 – emissions factors are the driving force of changing emissions post-2030

Natural Gas upstream emissions factors: key assumptions and methodology

- The average emissions factors for LNG and non-LNG natural gas are obtained from BEIS[1] figures, while the relative proportion of LNG in future is obtained from the National Grid FES[2].
- The BEIS 2019 upstream emission factors for Natural Gas are 7.38 kg CO_2e/GJ Net CV for UK average Natural Gas mix and 19.6 kg CO_2e/GJ Net CV for LNG[1]
- The Natural Gas emissions factor includes the percentage share of LNG which is the main driver of the emissions. The pipeline, (non-LNG), components (such as UKCS and Norway pipeline) have similar, low emissions. 20% of the UK gas supply in 2019 was LNG, allowing back-calculation of the non-LNG emission factor from the BEIS figures: 4.3 kg CO_2e/GJ Net CV.
- The future NG upstream emissions of the UK average gas mix are obtained using a weighted average of the BEIS LNG and non-LNG emission factors. The weighting factors are given in the FES scenarios, which all include some LNG as well as a "generic imports" category that can be between 0% and 100% LNG[3] . In the model therefore, we consider scenarios where the "generic imports" fraction in the FES scenarios is 0%, 50% and 100% LNG, reflecting future uncertainties in the volumes of LNG supplied to the UK. These form low, medium and high LNG scenarios. The options of 100% and 0% LNG are also considered.
- The projections do not take into account the future changes in GWP of methane, but the impact of this is small compared to the uncertainty in the future fraction of LNG in the UK gas mix.

- We use the System Transformation and Steady Progression FES scenarios. We do not include the FES Consumer Transformation and Leading the Way scenarios as these give very similar upstream emissions to the other scenarios and the variation is dominated by the uncertainty in the future fraction of LNG within each scenario.
  - FES 2020 steady progression medium LNG is the central scenario
  - LNG upstream emissions may decrease significantly in future, for example from use of partial carbon offsets, leakage reductions and use of renewable electricity in liquefaction plants – this is not captured in the model.
  - LNG should be avoided as much as possible to minimise the emissions from blue hydrogen production.



Contents

Distribution pathways use a mix of energy inputs, with the most energy intensive being liquid hydrogen distribution

Hydrogen can be distributed in different ways:

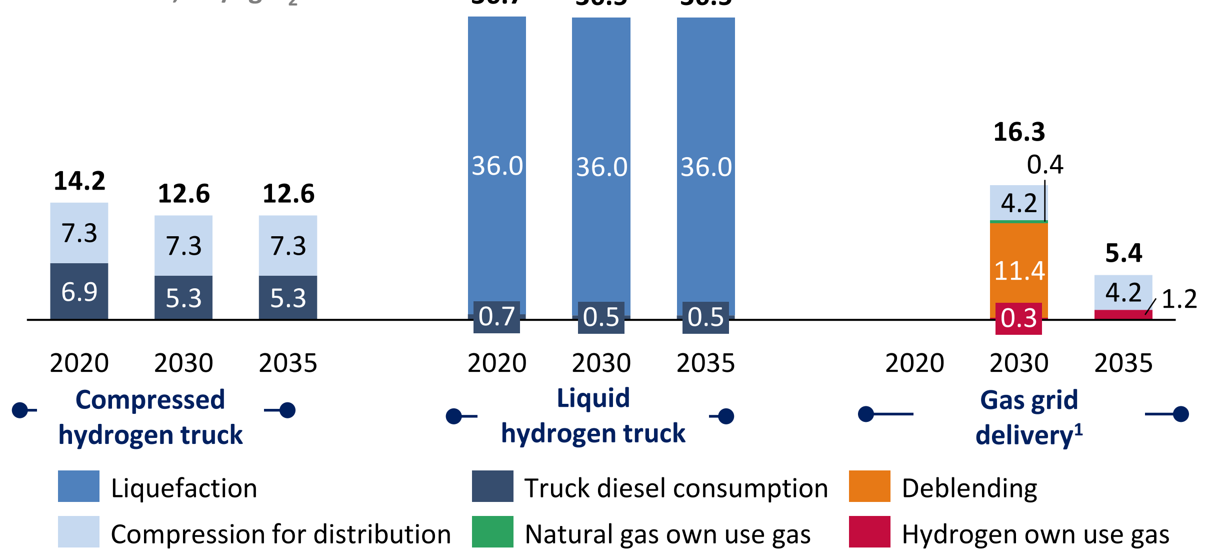
- **By road:** transport in tube trailers (compressed gas) or as liquified hydrogen.
- **By pipeline:** expected to take place in the medium to long term, with conversion of the natural gas grid taking place in regional phases. Gas network delivered H_2 is likely to be available in some regions earlier, such as those with industrial clusters, initially as a blend in the natural gas grid (20% from 2030) and eventually through conversion of the grid to supply 100% hydrogen (from 2035). Full conversion of the national gas network to H_2 would likely be completed in the 2040s

Key trends:

- Because more H_2 can be transported per LH_2 tanker (up to 3500 kg H_2) compared to CH_2 deliveries (around 350 kg H_2), diesel makes up a significant amount of the energy used for distributing CH_2, while LH_2 distribution is dominated by liquefaction energy use
- Energy use (and therefore emissions) from diesel consumption are inversely proportional to the mass of hydrogen carried. When higher delivery pressures are used, the increase in initial compression is largely offset by the decrease in compression requirement at the HRS. 500 bar, 1000 kg tube trailers would therefore give lower supply chain energy use and emissions than the current 350 kg, 280 bar tube trailers presented in this report.
- Liquid hydrogen transport is by far the most energy intensive method of delivery for typical UK distances owing to the energy intensive nature of the liquefaction process, which requires around one quarter of the higher heating value of hydrogen
- Initially (2030), deblending from a 20% hydrogen blend on the gas network dominates the energy use associated with gas grid transport:
  - Gas grids become a highly efficient distribution method once deblending is no longer required. However, compression duties for HRS connected to low pressure gas pipes are large, as discussed elsewhere
  - For a fully hydrogen gas grid, compression is the main source of energy use. Further discussion on the use of natural gas and hydrogen in gas grid compressors may be found in the appendix

Energy use for different distribution methods

Central case, MJ/kg H_2



Large reductions in liquefaction energy use are possible in future. The IdealHY project suggest that the energy requirement of liquefaction could be reduced to as low as 24 MJ/kg[2] in future, over 30% lower than typical plants today. However, since this has not yet been demonstrated, it is not included the model. Whether or not these low energy uses are achieved in future will have a significant impact on emissions from liquefaction.

Compression requirements for gas grid distribution will be lower if the gas is injected at distribution level rather than transmission level, and **zero if the gas is injected at a distribution network at or below the production output pressure** – for example if a 20 bar electrolyser output is injected into the 7 bar IP distribution network. The chart above assumes 11 bar production output pressure – from gasification. **Compression requirements for distribution will be lower for higher production output pressures – for example if production output pressure is 50 bar from an ATR, only 0.9 MJ/kg H_2 is required for compression to 80 bar for gas grid distribution.**

Note: 2020 values for compressed and liquid truck delivery are shown, but these are not used in the model since only on-site electrolyser HRS exist in 2020.

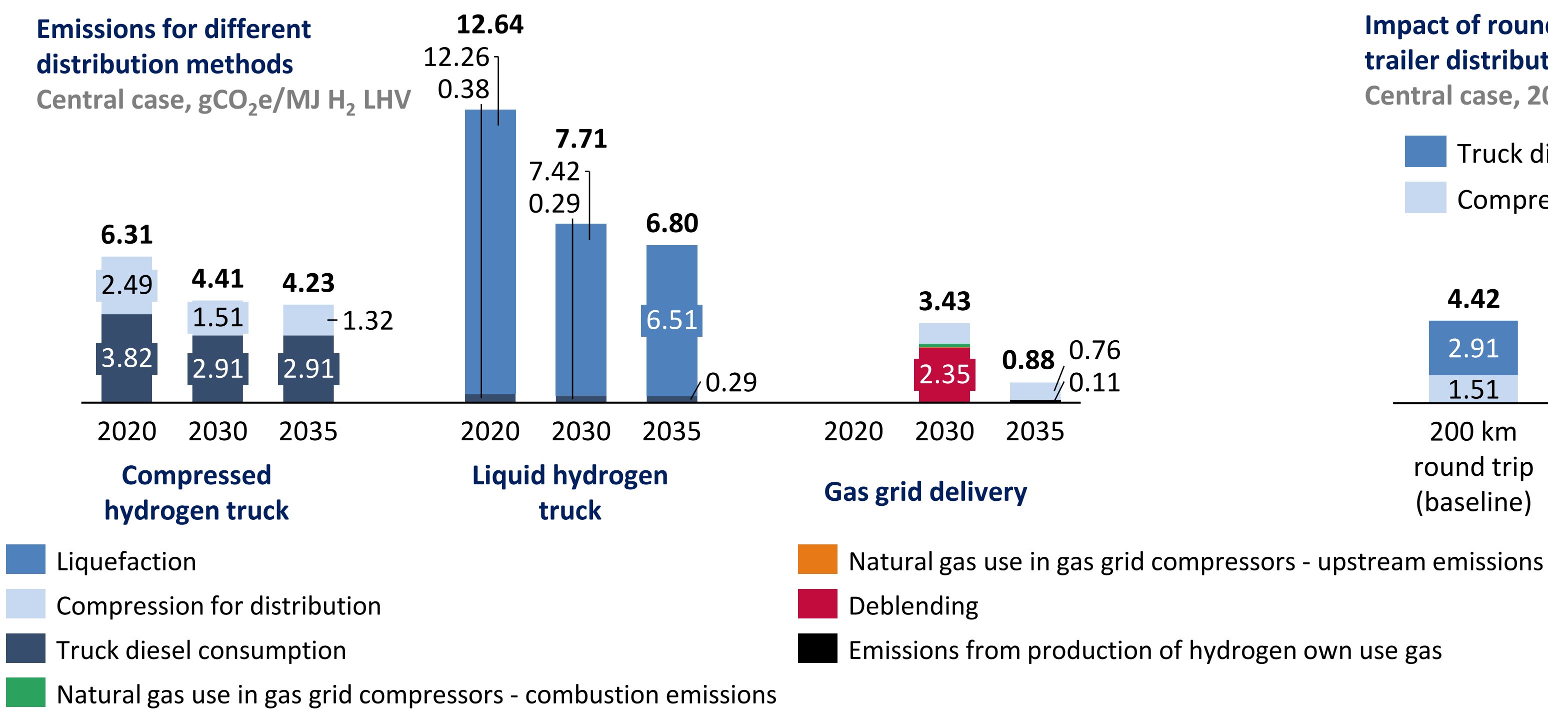
1: Purification is modelled at the HRS site and counted under dispensing 2: FCH JU - Integrated Design for Demonstration of Efficient Liquefaction of Hydrogen – 2013

Emissions from hydrogen distribution are expected to significantly reduce in the medium term

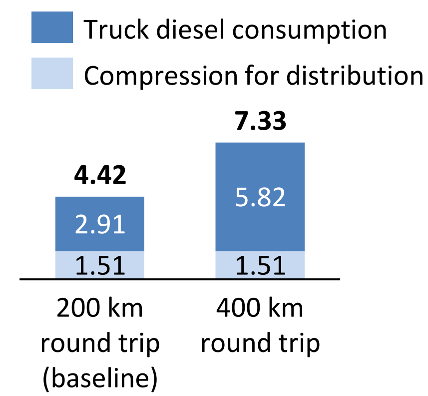
Distribution emissions arise from the use of grid average electricity for compression or liquefaction of hydrogen prior to distribution, use of diesel in trucks, use of grid average electricity for deblending, and the emissions associated with producing the hydrogen used to power compressors on the gas grid. The charts below assume 11 bar production output pressure (for gasification). Emissions from compression for distribution are lower for higher production output pressures. For example, **for NTS gas grid delivery (which requires compression to 80 bar), emissions from compression for distribution drop from 0.76 gCO_2e/MJ H_2 LHV to 0.16 gCO_2e/MJ H_2 LHV if production output pressure is 50 bar rather than 11 bar.**

- **All-hydrogen gas grids represent the lowest emission method for distributing hydrogen,** although the emissions resulting from compressional energy use at the HRS affect this conclusion for the supply chain as a whole
- Emissions from liquid hydrogen transport almost halve as the grid carbon intensity falls between 2020 and 2035. The emissions associated with liquefaction are highly sensitive to the grid carbon intensity scenario used, as shown below on the right – in an optimistic scenario emissions from liquid truck transport could drop below those from compressed hydrogen truck. **On-site liquefaction or compression plants for large onshore electrolysers will likely use the same renewable energy as the electrolyser and therefore have zero emissions**.
- Emissions from gas grid delivery are much higher in 2030 than 2035 owing to the use of grid average electricity for deblending in 2030. In 2035, deblending is no longer required, thus reducing the emissions from hydrogen transport by gas grid four-fold. Detailed discussion of deblending energy use may be found here.

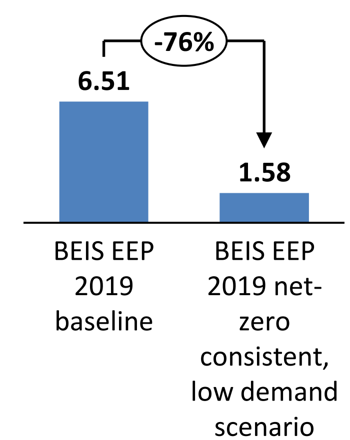
Emissions for different distribution methods
Central case, gCO_2e/MJ H_2 LHV



Impact of round-trip distance on tube trailer distribution emissions
Central case, 2030, gCO_2e/MJ H_2 LHV



Impact of the grid carbon intensity on the liquefaction emissions
Central case, 2035, gCO_2e/MJ H_2 LHV



This analysis assumes that the truck is a Diesel EURO 6 truck. If a hydrogen or battery electric truck was used, then fuel use emissions would be close to zero.

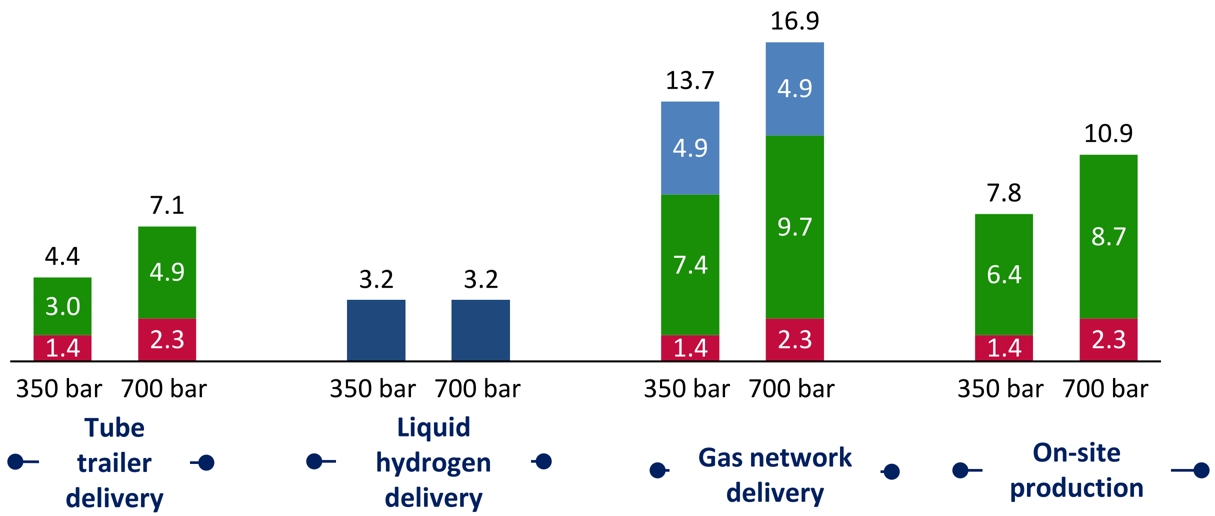
Contents

Energy is mainly used at the HRS for compressing hydrogen to the output pressure

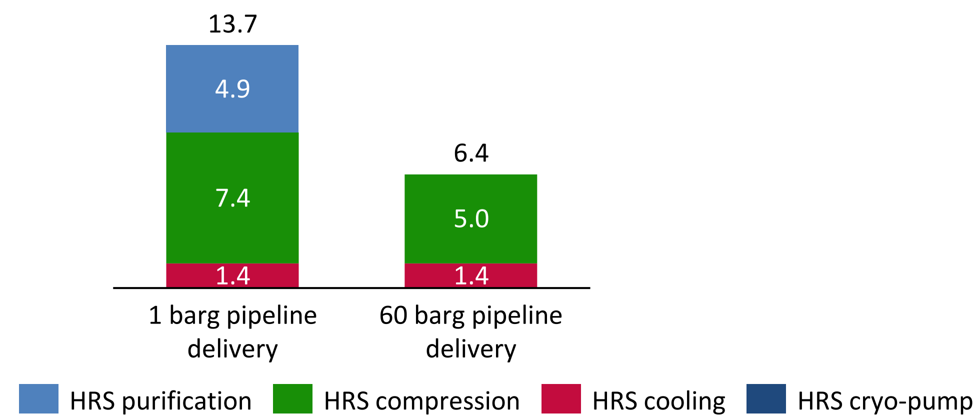
The energy consumption associated with dispensing depends on 1) the condition and pressure of the hydrogen arriving at the station, and 2) the pressure at which hydrogen is being dispensed (an increase in energy use of around 3 MJ/kg hydrogen dispensed is observed for dispensing at 700 bar as opposed to 350 bar).

- In general, the biggest driver for energy consumption is the compression at the station.
  - Stations receiving hydrogen delivered by tube trailer have a lower energy requirement for compression as opposed to on-site production, since the hydrogen in the tube trailer would have been compressed elsewhere.
  - Stations receiving liquid hydrogen have low energy uses, as the cryo-pump and thermo management system use the liquid boil off to pressurise the hydrogen for dispensing, requiring limited compressional energy use.
- Grid–connected HRS connected to LP/MP pipelines (1 barg) have the highest HRS energy use owing to the large compression energy.
  - The energy use associated with purification is entirely compressional. Since this compression is also needed without purification, purification does not increase the HRS energy use. The graphs below demonstrate the compression requirements to the pressure required for purification (“HRS purification”) and the energy requirements for subsequent compressions (“HRS compression”).
  - If the hydrogen arrives by pipeline at 60 barg – for example if the HRS is connected to the NTS – then compression is not required prior to the PSA, and the compressional energy requirements are reduced significantly.

Dispensing energy use for different distribution pathways, Central Case, MJ/kg H2



Energy use for dispensing depending on pipeline delivery pressure, MJ/kg H_2, for 350 bar dispensing pressure (2030)



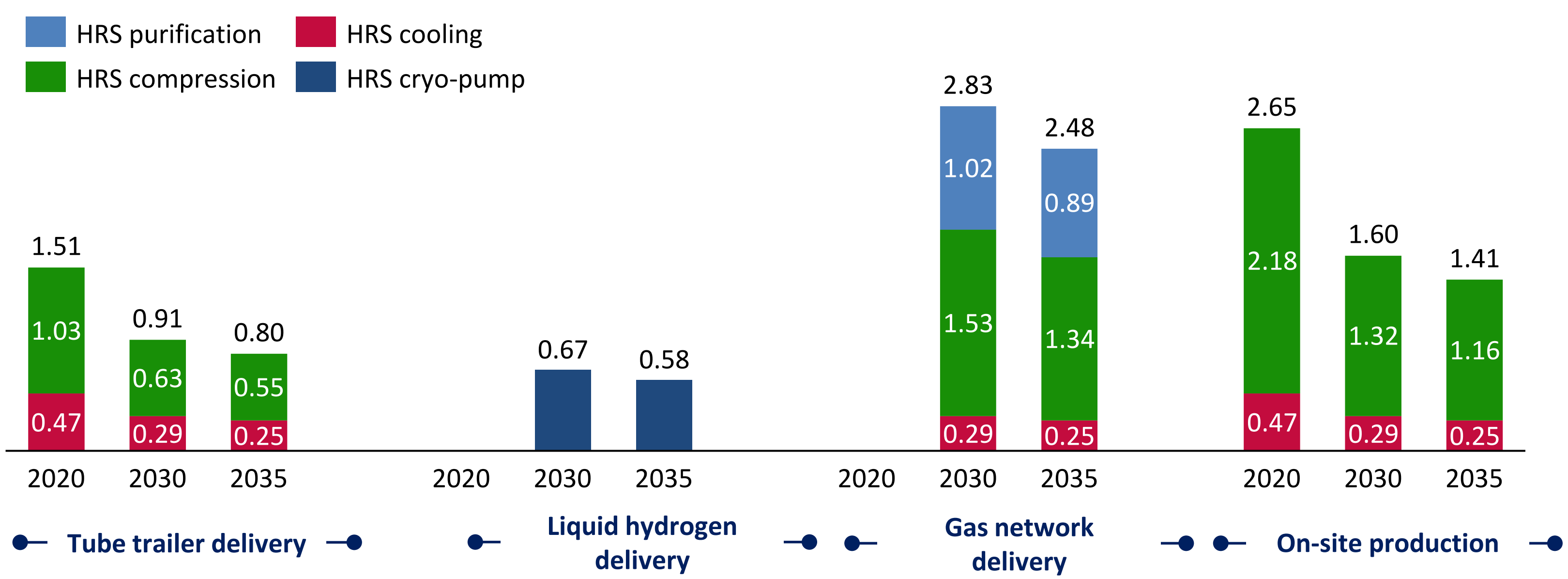
LP: Low Pressure, MP: Medium Pressure, HRS: Hydrogen Refuelling Station, NTS: National Transmission System, PSA: Pressure Swing Adsorption

Emissions from energy use at the HRS are expected to decline in time due to reductions in the electricity grid carbon footprint

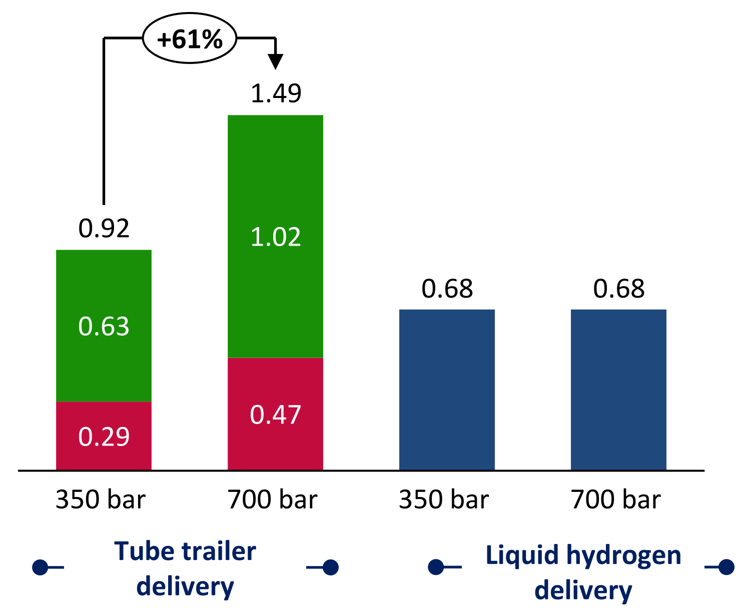
Emissions from the HRS arise from the use of grid average electricity for compression and cooling of hydrogen, and where applicable, running cryo-pumps. The impact of fugitive emissions is discussed elsewhere.

- As with HRS energy use, it should be noted that the emissions associated with purification result from a compression step that would have been needed even if the pipeline had been delivering high purity hydrogen.
- The biggest driver for emissions from the HRS is the grid carbon intensity, which falls sharply as the electricity grid decarbonises between 2020 and 2035, causing HRS emissions to decrease.

Dispensing emissions, 350 bar dispensing pressure, BEIS EEP 2019 grid carbon intensity scenario, $gCO_2e/MJ\ H_2$ LHV



Sensitivity of emissions to dispensing pressure, 2030, $gCO_2e/MJ\ H_2$ LHV



In future, liquid hydrogen dispensing may emerge – the energy use for this will be very small

Current HRS supplied with liquid hydrogen (in mainland Europe) convert the hydrogen to a compressed gas before delivery. However, in future hydrogen may be dispensed into the vehicle as a liquid. Whilst no real-world data was available for this technology, the energy use will be close to zero as little or no compression will be required. A first principles approach has been adopted to the modelling, considering the following contributors to the emissions:

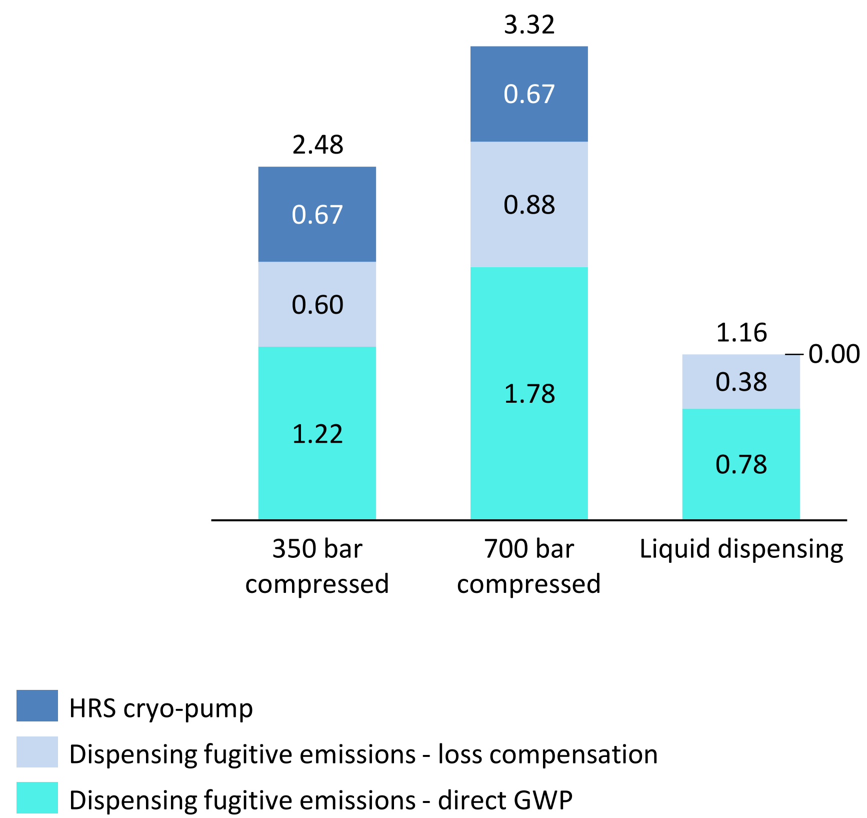
1. **Transfer losses – boil-off during delivery of liquid hydrogen to the HRS**. These have been assumed as the same as for the case of an HRS supplied with liquid hydrogen but dispensing compressed hydrogen. These fugitive losses are included as part of distribution.
2. **Storage boil-off**: storage requirements on site are expected to be similar to an HRS supplied with liquid hydrogen but dispensing compressed hydrogen, so storage boil-off is assumed to be the same for the two cases.
3. **Boil-off during dispensing**: dispensing liquid hydrogen into a truck is similar to delivering liquid hydrogen into the storage vessel at the HRS. Boil-off during dispensing is therefore assumed to be the same as during delivery to the HRS.
4. **Energy use** will be close to zero as little or no compression is required, and is therefore set to zero in the central case. In any case the energy use will be lower than for an HRS dispensing compressed hydrogen. Very small amounts of energy will be used for the liquid hydrogen pump and vapour compression, but these will have a negligible effect on supply chain emissions. Emissions from the HRS dispensing liquid hydrogen therefore result entirely from the GWP of the fugitive emissions and the increase in production emissions to compensate for fugitive losses.

The difference between compressed hydrogen and liquid hydrogen dispensing has a negligible effect on supply chain emissions, unless boil-off is highly mismanaged. A comparison of the expected emissions is show on the right. Note that the difference between the two cases will become even smaller as the grid decarbonises further.

The emissions from this pathway will need to be monitored once real world data is available.

Emissions for different HRS supplied with liquid hydrogen and dispensing 1500 kg H_2/day, 2030, using BEIS EEP 2019 baseline grid carbon intensity scenario, $gCO_2e/MJ\ H_2$ LHV

Emissions from loss compensation are calculated assuming ATR production



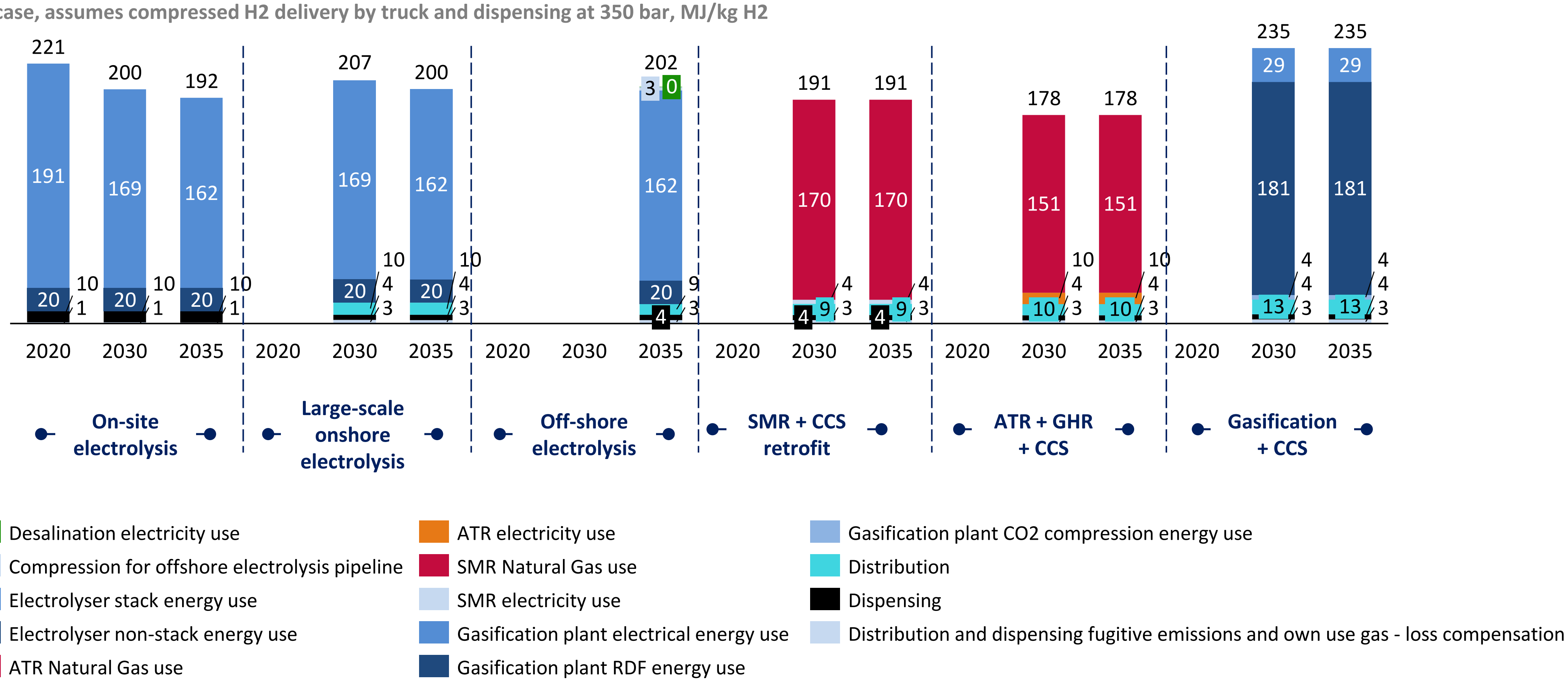
Contents

Summary of energy consumption: tube trailer delivery

- Full supply chain energy use is dominated by production. If distribution by tube trailer is used, this accounts for around 5% of total supply chain energy use.

Energy use for different production pathway set-ups

Central case, assumes compressed H2 delivery by truck and dispensing at 350 bar, MJ/kg H2



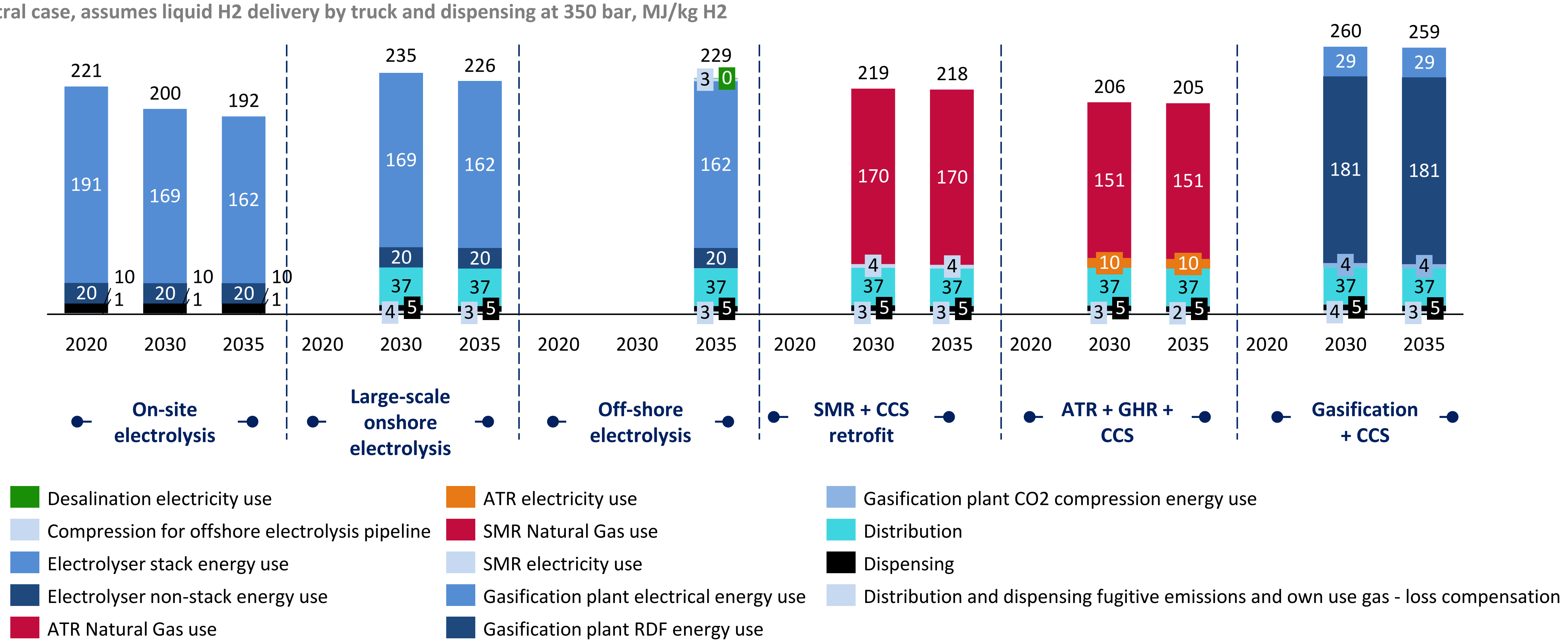
Note: SMR and ATR energy use includes compression of CO2 to 110 bar. Plant electrical use for SMR, ATR and gasification includes a small contribution from CO2 transport and compression for offshore pipeline.

Summary of energy consumption: liquid hydrogen delivery

- With liquefaction, the proportion of supply chain energy use attributable to distribution rises, to up to 18% in the case of the ATR + GHR pathway.

Energy use for different production pathway set-ups

Central case, assumes liquid H2 delivery by truck and dispensing at 350 bar, MJ/kg H2

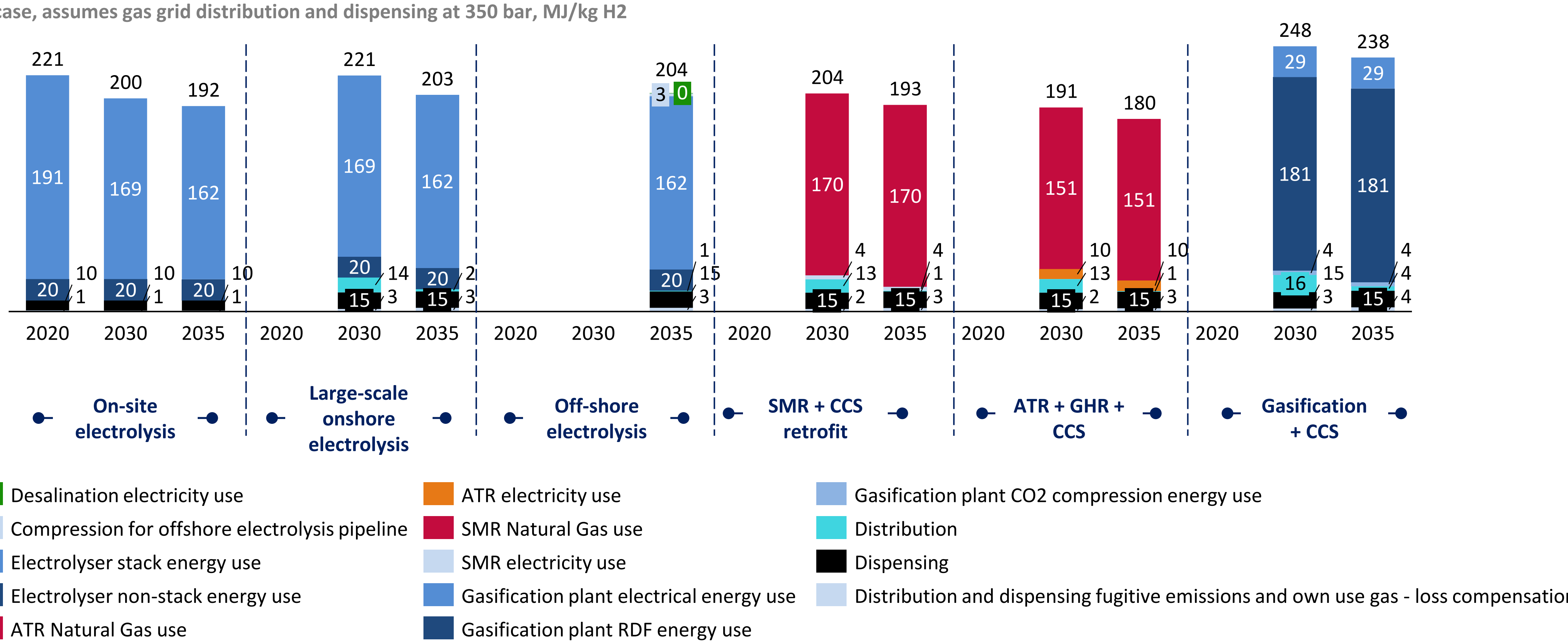


Summary of energy consumption: pipeline delivery

- For a fully hydrogen gas grid, HRS energy use dominates the non-production energy use.

Energy use for different production pathway set-ups

Central case, assumes gas grid distribution and dispensing at 350 bar, MJ/kg H2



Note: SMR and ATR energy use includes compression of CO2 to 110 bar. Plant electrical use for SMR, ATR and gasification includes a small contribution from CO2 transport and compression for offshore pipeline.

Contents

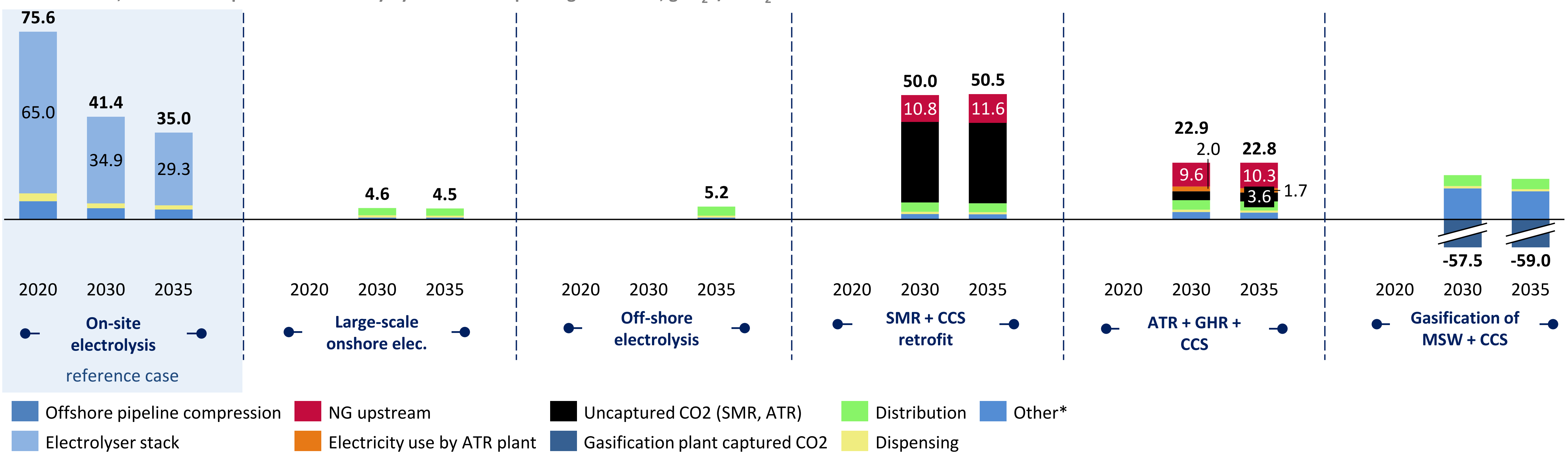
Overview of the whole pathway emissions for tube trailer delivery

Tube trailers are currently used for moving compressed hydrogen from the production point to the HRS. Tube trailers are expected to continue to be used in the future.

- Production emissions dominate the supply chain emissions, unless a zero-carbon production method is used, namely electrolysis supplied exclusively by renewable electricity.
- For an on-site electrolyser using grid average electricity, the grid carbon intensity scenario is by far the largest emissions driver.
- For gasification, the emissions are negative, since the refuse derived fuel used originates from municipal solid waste that would otherwise have been incinerated.
- The emissions associated with diesel use for hydrogen distribution by trailer are around 4 $gCO_2e/MJ\ H_2$ LHV for transport of 350 kg H2 compressed at 280 bar for shipment round trip distance of 200 km.

Emissions for different production pathways set-ups

Central case, assumes compressed H2 delivery by truck and dispensing at 350 bar, $gCO_2e/MJ\ H_2$ LHV

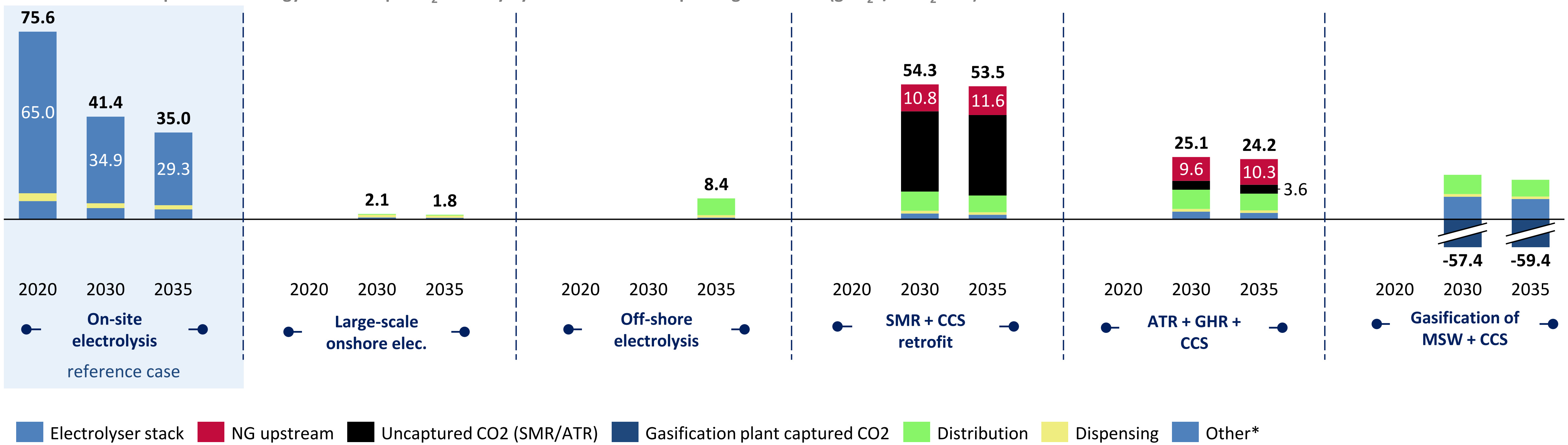


Overview of the whole pathway emissions for liquid hydrogen delivery

- Liquid hydrogen delivery is by far the most energy intensive distribution option owing to the large energy use associated with the liquefaction plant:
  - Emissions from liquefaction using grid average electricity dominate the distribution emissions in these pathways. Large scale onshore electrolysers are by default assumed to use renewable energy for both the electrolyser and the liquefaction plant, leading to zero emissions from liquefaction in this case. If instead the onsite liquefaction plant uses grid average electricity, emissions from liquefaction in this pathway would be the same as in the other pathways.
  - If the liquefaction plant is using grid average electricity, the liquefaction results in emissions in 2030 of 6.7 $gCO_2e/MJ\ H_2$ LHV – this is nearly one third of supply chain emissions from the ATR + GHR + CCS production pathway.
- The emissions associated with the use of diesel for transport and boil-off of hydrogen are 0.25 $gCO_2e/MJ\ H_2$ LHV and 1.1 $gCO_2e/MJ\ H_2$ LHV respectively

Emissions for different production pathways set-ups

Central case for liquefaction energy use and liquid H_2 delivery by truck. Assumes dispensing at 350 bar ($gCO_2e/MJ\ H_2$ LHV)



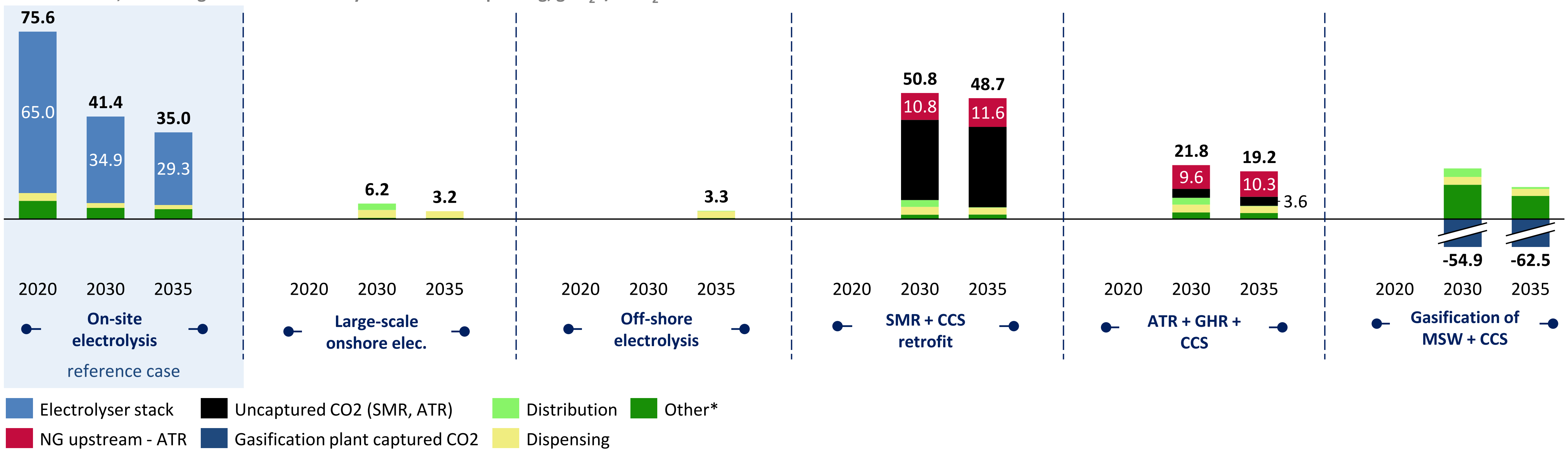
Overview of the whole pathway emissions for gas network delivery

Blending of hydrogen in the gas grid could represent a pathways for rapid scale-up of hydrogen availability around the UK.

- As with tube trailer delivery, production emissions dominate the supply chain emissions, unless a zero-carbon production method is used.
- Emissions from gas grid distribution are dominated by those associated with electricity use for deblending until the gas grid is fully converted to hydrogen, leading to a drop in emissions from gas grid distribution between 2030 (20% hydrogen blend in gas grid) and 2035 (100% hydrogen blend in gas grid).
- Retrofitted SMRs are expected to have low capture rates – around 60% - leading to high direct CO_2 emissions which dominate the supply chain emissions for this pathway. By contrast, newbuild ATR + GHR + CCSs are expected to achieve capture rates of around 95%, and emissions from this pathway are dominated by the NG upstream emissions.

Emissions for different production pathways set-ups

Central case, assumes gas network delivery and 350 bar dispensing, $gCO_2e/MJ\ H_2$ LHV

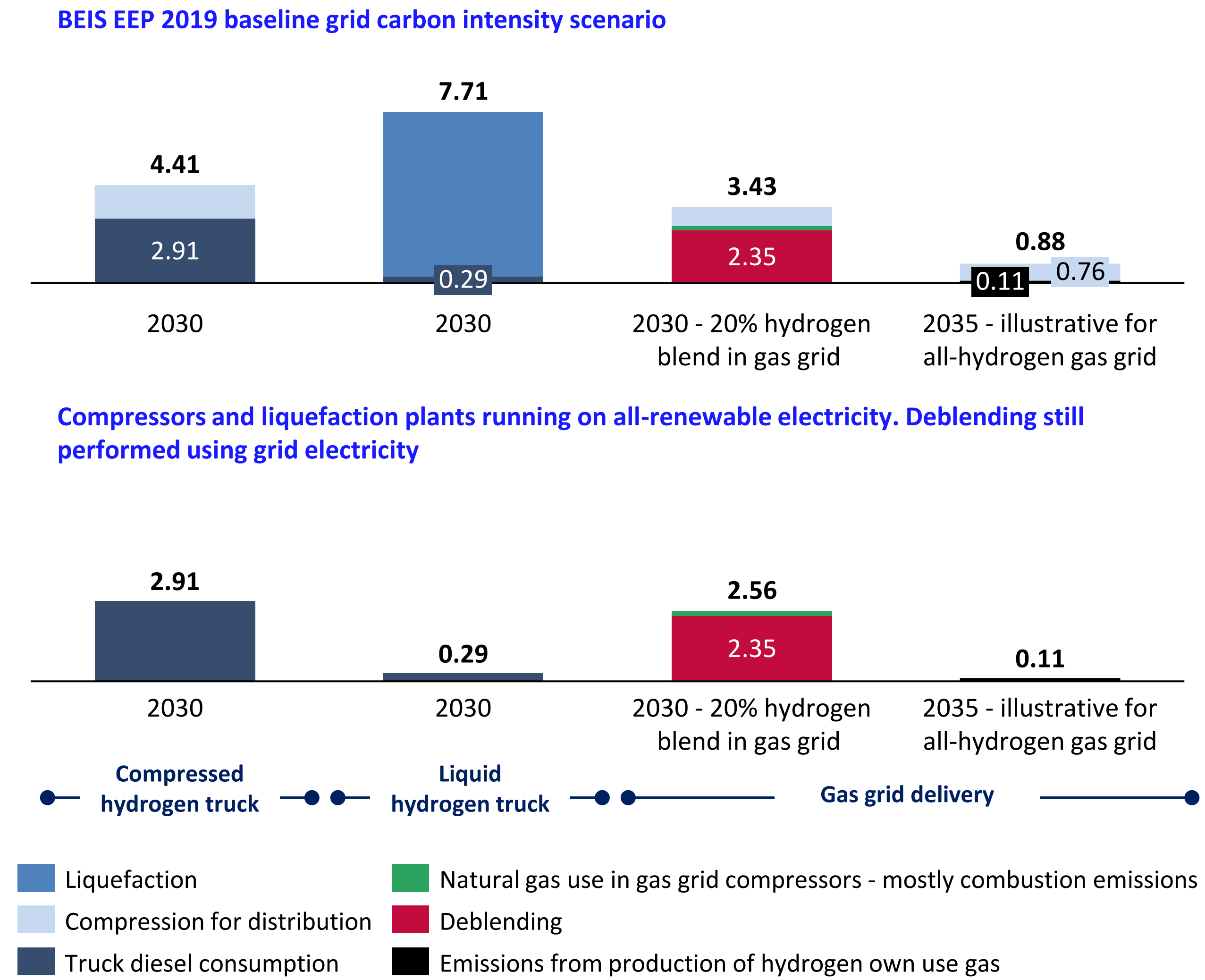


*Includes fugitive emissions

Emissions from distribution become significant once production is fully decarbonized, but could be further reduced by using renewable electricity

- Distribution emissions become relevant when large amounts of hydrogen are produced by very low or zero carbon sources – for example renewable electrolysis.
- If liquefaction plants run on grid average electricity they constitute the largest source of distribution emissions in the short term.
- On-site compressors or liquefaction plants for large centralized electrolysers are likely to primarily use the same (mostly or entirely renewable) source of electricity as the electrolyser, leading to zero emissions from compression for distribution and liquefaction.
- Emissions from electrical energy use for deblending dominate emissions from gas grid distribution for 20% hydrogen/natural gas blend.
- If the gas grid converts fully to hydrogen, emissions from gas grid distribution will be close to zero.
- HRS emissions originate from grid electricity use for compressors, cryo pumps and cooling. The emissions are very small and fall sharply as the grid decarbonises. For example, emissions from an HRS with tube trailer delivery are around 0.9 $gCO_2e/MJ\ H_2$ LHV in 2030 using the BEIS EEP 2019 baseline grid carbon intensity scenario.

Emissions for different distribution methods, Central case, $gCO_2e/MJ\ H_2$ LHV



Fugitive emissions represent a very small portion of the total emissions

Fugitive emissions occur from two main sources along the pathway and are considered in the modelling:

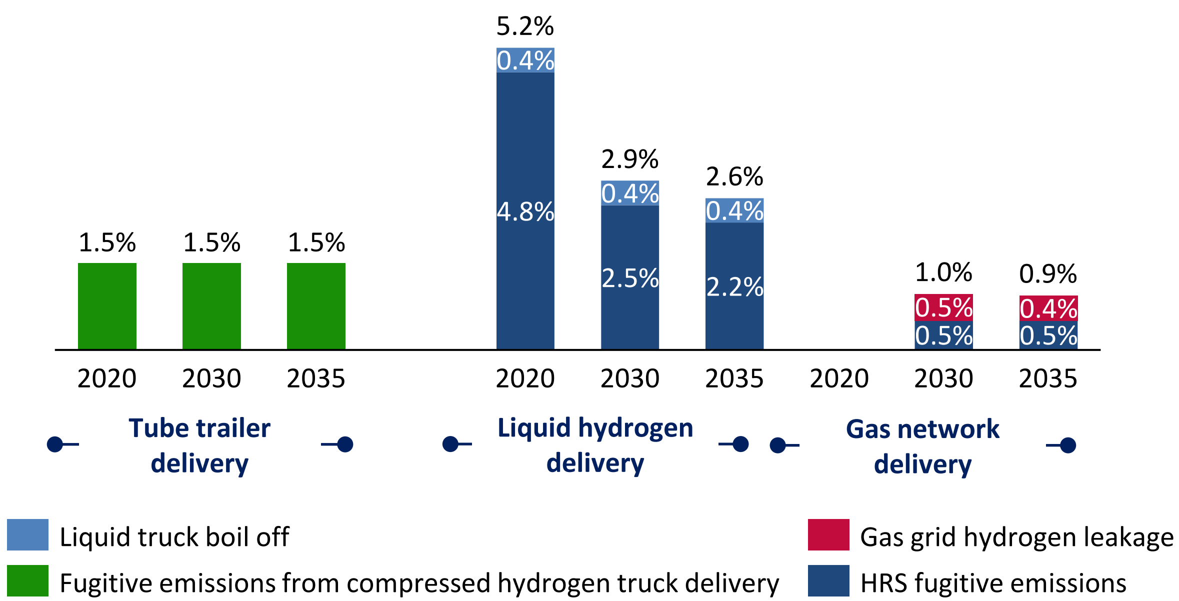
- The largest potential source of fugitive emissions is the relatively large boil-off losses in small HRS – this is reduced for larger HRS
- Fugitive emissions also occur along pipeline infrastructure and as gas is transferred from one system to another (e.g. to/from tube trailers)

Fugitive emissions contribute to supply chain emissions in two distinct ways, both of which are included in the model:

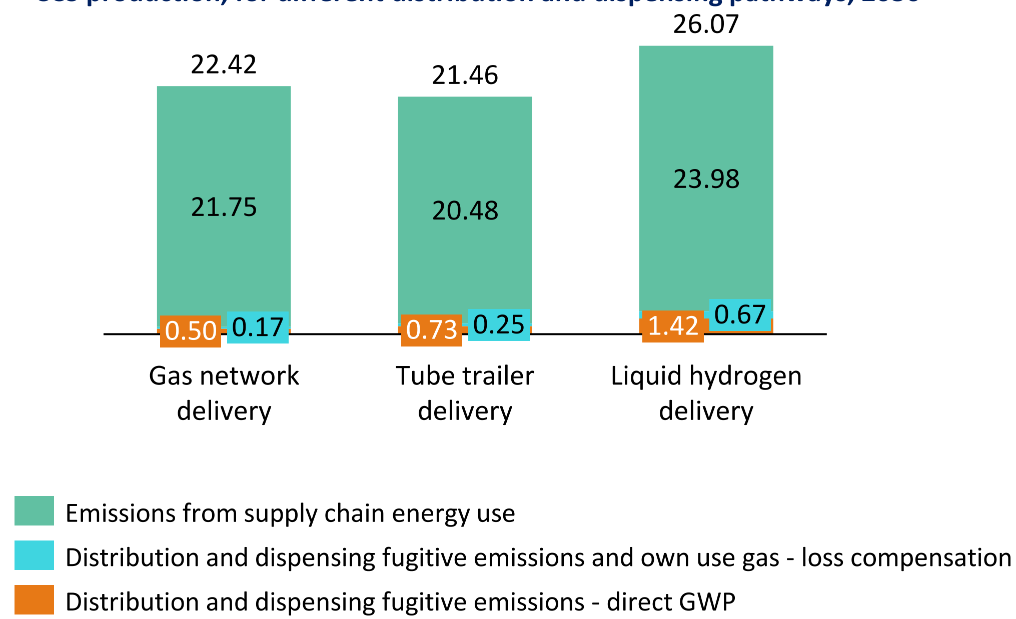
- Through the direct global warming potential of the emitted hydrogen;
- Through the increase in upstream emissions associated with production of the hydrogen that is lost.

There is some uncertainty around the exact magnitude of the fugitive emissions but their impact on supply chain emissions is small, typically around 0.8 gCO2e/MJ H_2 LHV . Fugitive emissions from hydrogen systems should continue to be monitored as more infrastructure is deployed and real-world data collected.

Fugitive emissions, % of hydrogen lost for different distribution and dispensing pathways, assuming 350 bar dispensing



Emissions resulting from fugitive emissions (gCO2e/MJ H2 LHV dispensed) compared to emissions from the rest of the supply chain, for ATR + GHR + CCS production, for different distribution and dispensing pathways, 2030

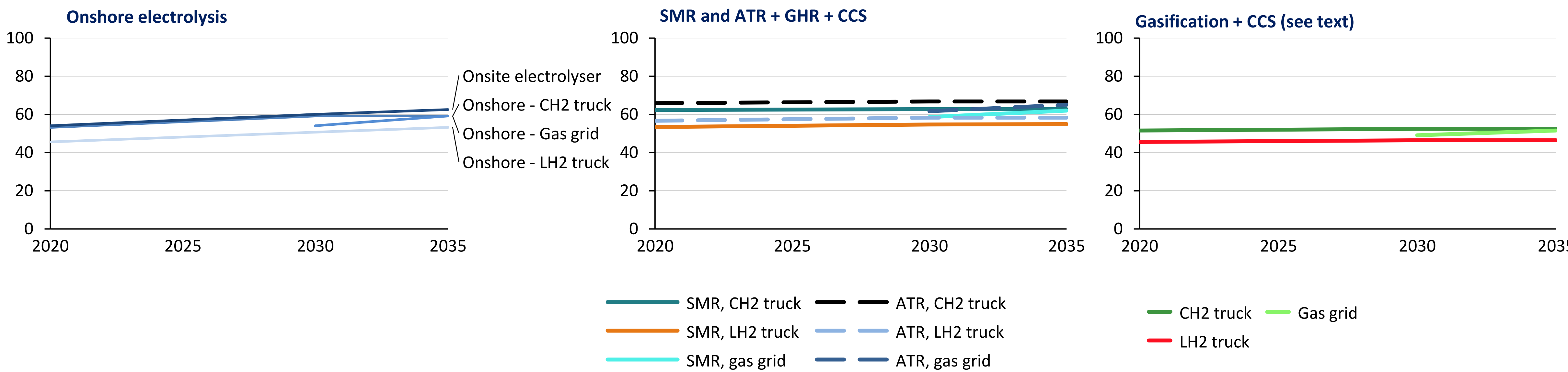


Pathway energy efficiencies should be interpreted with caution

Energy efficiency is determined as the hydrogen lower heating value (per kg) divided by the total energy content of the feedstock used for the pathway to produce 1 kg of hydrogen. This involves adding electrical energy use to natural gas energy use and therefore has limited physical meaning. The energy efficiency figures start with electricity and/or natural gas arriving at the production facility and do not include energy use during distribution of the feedstocks to the hydrogen production plant. LHV is also used for Natural Gas and diesel, for consistency. Owing to data availability, HHV is used for RDF, which causes the energy efficiencies of the gasification pathways to appear artificially lower.

When interpreting energy efficiencies of electrolysis, it is crucial bear in mind that energy use by electrolysis when using curtailed generation is energy that would otherwise have been wasted. Under these circumstances energy efficiency is less relevant as capturing any renewable energy that can be used is beneficial regardless of the efficiency of the process. Electrolysers can increase efficiency of the system as a whole by preventing wastage of curtailed renewable generation.

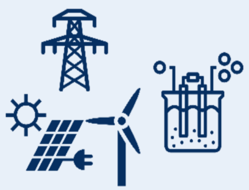
Pathway energy efficiencies with different distribution options, %



Contents

Summary of key conclusions (1/2)

The variation in emissions between production options dominates the variation in supply chain emissions between pathways, and policy aimed at supporting the lowest emission hydrogen supply chains should focus on enabling the lowest emission production options to be deployed at scale.

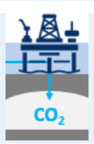


- The electricity grid carbon intensity has a very significant impact on the whole-pathway emissions, particularly for electrolysers running on grid average electricity.
- The carbon intensity of the electricity used by the electrolyser has the dominant impact on the carbon footprint of hydrogen (39 $gCO2e/MJ$ H_2 LHV for average grid electricity[1] in 2030 to 0 $gCO2e/MJ$ H_2 LHV when renewable electricity is used). All green hydrogen project developers Element Energy interviewed confirmed their intent to procure essentially 100% renewable energy by 2030 (using a variety of procurement approaches), which will lead to very low emissions from this pathway.
- Improvements in electrolyser technologies are also expected to deliver significant energy and emissions reductions in the near term.

The carbon footprint of blue hydrogen production from natural gas is heavily dependent on:

- The carbon capture rate of the SMR or ATR + GHR with CCS. This is particularly reflected in the case of SMR retrofits (which could achieve only 60% capture). Clean hydrogen would have to be produced by technologies with higher capture rates, such as ATR + GHR + CCS (with a capture rate of 95% among announced projects).
- The NG upstream emissions of the fossil natural gas or biomethane feedstock used have a significant impact on the emissions pathway.
  - Emissions for natural gas are expected to increase in time, as the UK focus shifts towards LNG imports. However, the increase in LNG share only account for a 2% change in emissions from hydrogen production by ATR + GHR + CCS between 2030 and 2035.
  - Because only upstream emissions from biomethane are counted, its use in ATR + GHR or SMR with CCS could deliver carbon-negative hydrogen, however due to feedstock availability, the amount of hydrogen that could be produced via this pathway is limited.

- Gasification of waste with CCS could also produce negative emissions. However, the technology is at a lower TRL than natural gas reformation and heavily depends on the availability of biogenic waste.



- Both reformation and gasification technologies rely on carbon capture and storage. Whilst the UK has clear ambitions in developing two CCS clusters by 2025 and two additional clusters by 2030, further uncertainties exist around the feasibility and actual energy consumption associated with these production pathways.

(1) Using BEIS EEP 2019 reference scenario

Summary of key conclusions (2/2)

Emissions from distribution become relevant when hydrogen is produced by zero or near-zero carbon sources – in all other cases they are very small compared to production emissions.

Transporting compressed hydrogen by road is a well understood distribution pathway. Further efficiencies could be achieved by increasing the amount of hydrogen delivered per shipment, which could reduce emissions by 40% compared to 2020 levels. However, this pathway becomes logistically challenging in the long term as the daily demand for hydrogen is expected to increase above the delivery capacity of a single trailer, implying multiple deliveries per station per day.

Hydrogen liquefaction using current grid average electricity is the most energy and emissions intensive step in the distribution value chain. **However, for production by centralised onshore electrolysis, the liquefaction plant is likely to use the same renewable source of electricity are the electrolyser, in which case emissions from this pathway will be close to zero**. This is because emissions from the liquefaction would be eliminated to leave only a very small contribution (around 0.3 gCO2e/MJ H_2 LHV) from truck delivery**.** With the 200 km round trip distance taken as the central case, the reduction in energy use from trucking caused by the increased capacity of a liquid hydrogen truck (3500 kg) compared to a gaseous hydrogen truck (350 kg) is insufficient to compensate for the high energy use of liquefaction compared to compression. However, liquid hydrogen is currently not produced at scale in the UK – action in this area would be required by the supply chain and decision makers. Large scale deployment of liquefaction may lead to significant reductions in energy use – discussed here.

The lowest-emissions and most energy efficient distribution pathway is transport of hydrogen by pipeline. This is partially offset by the larger HRS compression requirements if the hydrogen arrives at low pressure (see this slide and the one after), which make pipeline delivery and dispensing similar to tube trailer delivery and dispensing if deblending is required. However, if either the gas grid is fully hydrogen (so no deblending is required) or hydrogen is taken off at a higher pressure (reducing HRS compression duties), gas grid delivery remains the lowest emission and most energy efficient option from a whole pathway perspective. Pipeline transport provides a feasible way to scale up hydrogen distribution to align with the expected demand in the medium and long term:

- The gas grid is already in the process of becoming hydrogen-ready, for example through replacement of iron mains with polythene pipes.
- Blending of hydrogen at 20% is seen as a stepping-stone in enabling full grid conversion but **involves significant energy use for deblending**.
- Purification of hydrogen following offtake from the grid would still be required even for a 100% hydrogen grid. However, the energy used for purification by PSA is in compression and this compression would need to take place anyway at the HRS ahead of dispensing to vehicles: purification therefore does not make a significant contribution to supply chain emissions and energy use, provided that the off-gas is deployed usefully. A detailed discussion may be found here.

Dispensing emissions are mainly associated with the compression electricity use by the HRS, which is assumed to use grid electricity. Decarbonisation of the electricity grid could bring significant emissions reductions of carbon intensity of over 40% between 2020 and 2035 for dispensing even when using the very conservative BEIS EEP 2019 baseline scenario for grid carbon intensity. Dispensing at 700 bar requires around 40% more electricity. However, HRS capable of dispensing up to 20t/day are likely to be required to service fleets of H_2 HGVs. Stations on this scale have yet to be built, with more real-world data required. **Dispensing emissions are very small and fall sharply as the grid decarbonises**. For example, emissions from an HRS with tube trailer delivery are around 0.9 gCO_2e/MJ H_2 LHV in 2030 using the BEIS EEP 2019 baseline grid carbon intensity scenario.

Areas for further work and future monitoring (1/2)

The areas where increased data quality is desirable are two-fold:

- **Real world performance data for H_2 production technologies:** several of the production technologies considered in this work are at a relatively early stage of development. Large-scale electrolysers are still in development and gasification, ATR + GHR with CCS and SMR with CCS have yet to be deployed at commercial scale. The values used in this study should be cross-referenced against real world data obtained as these technologies are deployed at scale.
- **Fugitive emissions:** There is considerable uncertainty around fugitive emissions, from natural gas, H_2 and CO_2 systems. This will need to be better understood and developments in this area should be monitored to ensure the results of this can be updated as more information becomes available.

Areas to monitor and areas for further research:

- **Use of renewable electricity for grid-connected electrolysers** – the exact carbon intensity of electricity used by electrolysers will be linked to future policy direction with clear direction from the market that project developers expect to use all-renewable sources
- **Grid carbon intensity** – the BEIS reference and net-zero scenarios vary significantly in their predictions of grid carbon intensity, with the key differentiator being the large amounts of storage required to meet net-zero scenarios. The rate of grid-connected storage build-out, and the resulting decreased reliance on natural gas peaking plants, will have a decisive impact on the future grid carbon intensity. This will affect the emissions associated with energy-intensive technologies, such as liquefaction plants that could be running on grid electricity.
- **Conversion of gas grid to hydrogen** – while there is some uncertainty over the timescale over which the gas grid will fully convert to hydrogen, much of the transition pathway has already been developed through projects such as HyNet and H21 North of England. The energy use achieved by deblending plants and variation between manufacturers will need to be monitored as the technology is rolled out – **stakeholder engagement with Linde (a world leader in this technology) revealed that energy use for deblending could be reduced significantly below the figures presented in this report with design optimisation**. This would significantly lower emissions and energy use from the gas grid blend scenario, increasing its viability. There is also some uncertainty over the pressure tier and full details of the way in which HRS will be connected to the gas grid – this will need to be monitored as trail projects are rolled out.
- **Carbon Capture and Storage** – CCS has not been deployed at scale in the UK yet (projects expected to commence in late 2020s). In addition, the capture rates of ATR + GHR + CCS plants may change once the technology is deployed in the field. Understanding capture rates will be critical to the emissions for all hydrogen production from carbon-based feedstocks.
- **Natural gas sources** – have a significant impact on the emissions of blue hydrogen, especially as there is growing uncertainty around the future volumes of LNG imports in the UK. In addition, further improvements in the carbon intensity of LNG shipments are expected, as a result of leakage reductions, electrification of liquefaction plants and decarbonisation of shipping.

Areas for further work and future monitoring (2/2)

Areas to monitor and areas for further research (continued):

- **CO_2 leakage from storage sites –** it is currently assumed that the CO_2 captured and stored via CCS will remain captured indefinitely. This should be monitored as projects are deployed and real-world data becomes available.
- **Liquefaction** – the energy use of liquefaction plants may decrease significantly in future with increased scale driving increased investment in efficiency reductions which may reduce liquefaction energy intensity 30% or more below current levels (see this slide)
- **Alkaline electrolysis** was not considered in this study, since announced UK projects currently focus on PEM technologies, however the technology should be taken into account in further research pieces, as an alternative technology that may reduce the energy use of electrolysers.
- **Biogenic fraction for waste gasification pathway** – municipal solid waste has been assumed to be 65% biogenic by energy. This will vary considerably between regions and may change in future. The RED approach has been used in the modelling, whereby for a gasification plant with CCS, the emissions from the fossil carbon are ignored, negative emissions are credited for the biogenic carbon. An alternative approach would be explicit comparison to an energy from waste plant counterfactual. In this approach, negative emissions are credited to all of the carbon (both fossil and biogenic), since the carbon from the fossil fraction is released in the gasification plant. However, in addition, the negative emissions from the fossil carbon are offset by noting that if fossil carbon is diverted away from energy from waste plants marginal sources of electricity must be switched on to replace the electricity that would have been generated from this fuel. The size of this offset will decrease dramatically in future as the grid decarbonises. The suitability of the approach used in this report compared to the latter, more complex approach described in this paragraph should be reviewed in future, particularly in the light of any developments in emissions accounting methods for the RED and RTFO.
- **Carbon intensity of biomethane** – biomethane upstream emissions vary widely between sources and the exact form of biomethane used for hydrogen production will have a large impact on emissions as shown on this slide. In addition, there is uncertainty around the availability of bioenergy in the future and its role in the energy system (e.g. biomethane production vs other uses)
- **Purification** – purification is assumed to be performed by PSA. It is assumed that unrecovered hydrogen in the PSA tail gas is used usefully, for example it is injected into the gas grid. This assumption should be monitored as purification plants are deployed increasingly in the real world. If the purification results in wastage of hydrogen, then upstream emissions will be increased to compensate for the loss. Additionally, in future electrochemical purification may emerge, which would change the picture significantly. Further discussion of PSA modelling assumptions and electrochemical purification may be found in the appendix.
- **Fugitive emissions** are in general poorly understood throughout the supply chain. The size and utilisation of HRS using liquid hydrogen will have a particularly significant impact on supply chain fugitive emissions in future. Future measurements will also be needed to better understand hydrogen leakage from purification plants and above ground installations in hydrogen gas grid infrastructure. Monitoring of leakages across the whole pipeline network will also be important to understand the full impact of fugitive emissions on H_2 pathways.

Contents

Energy use and emissions for six H_2 production pathways are included in the model including multiple feedstock options

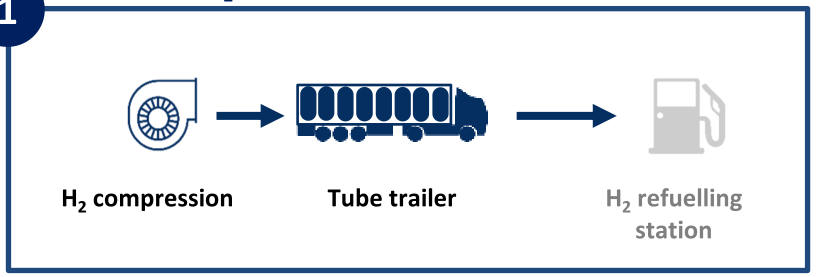
Production emissions are determined from feedstock use and carbon intensity - fugitive emissions are also included in the modelling

Pathway	Carbon footprint of the feedstock	x	Energy and feedstock consumption	Direct CO_2 emissions
Electricity supply → Electrolysis	• Grid electricity (several options) • Renewable electricity • Marginal electricity use		• Energy use from water splitting the stack • Small additional contributions from: – Electrical transformer and rectifier – Hydrogen drying and deoxygenation	• None
Natural gas → SMR / ATR	• Grid electricity (several options) • Average natural gas carbon intensity • Marginal natural gas use		• Natural gas used as both feedstock and fuel • Small amounts of electricity used in plant	• Uncaptured CO_2 – depends on capture rate
Biomass → Gasification	• Grid electricity (several options) • Refuse derived feedstock from municipal solid waste		• Electricity use for: – Oxygen production – Compression – Process heating (e.g. electric arc for gasification)	• When CCS is used, emissions are net-negative

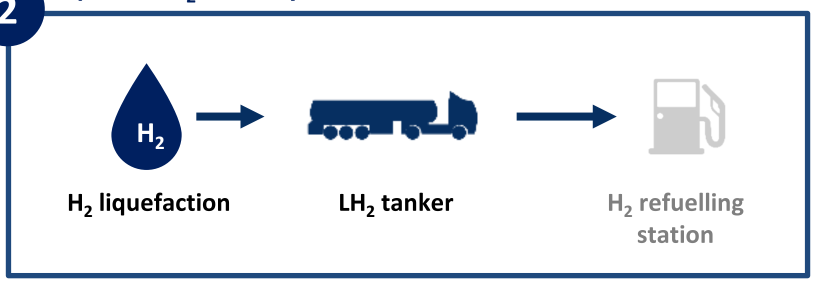
- Fugitive emissions are included at each stage, and contribute both from the direct global warming potential of hydrogen emitted, and the increase in emissions upstream of the fugitive emission point from production of hydrogen that is leaked

Three distribution pathways were investigated, including energy use and fugitive emissions

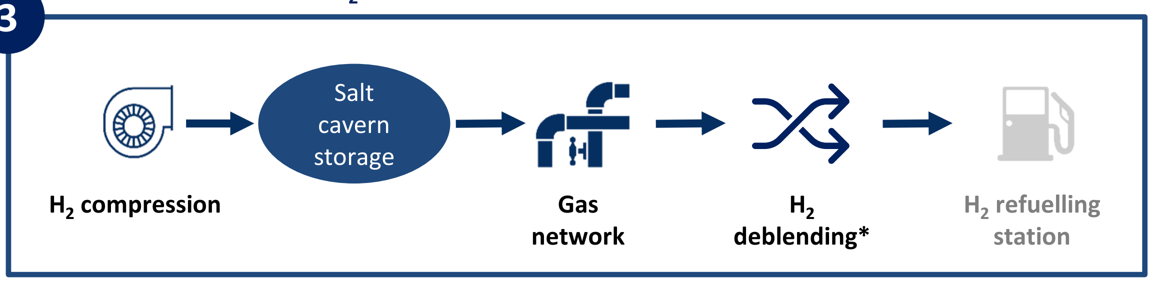
1 **Compressed H_2 tube trailer delivery**



2 **Liquefied H_2 delivery**



3 **Gas network delivered H_2**



* Deblending may not be required in the longer term if the gas network is converted to 100% hydrogen

Emissions drivers considered in the modelling (discussed in more details in the Distribution & Storage section of this report):

On-site production and dispensing:

- No distribution is required, but there are energy requirements for compression and cooling for dispensing in addition to production.

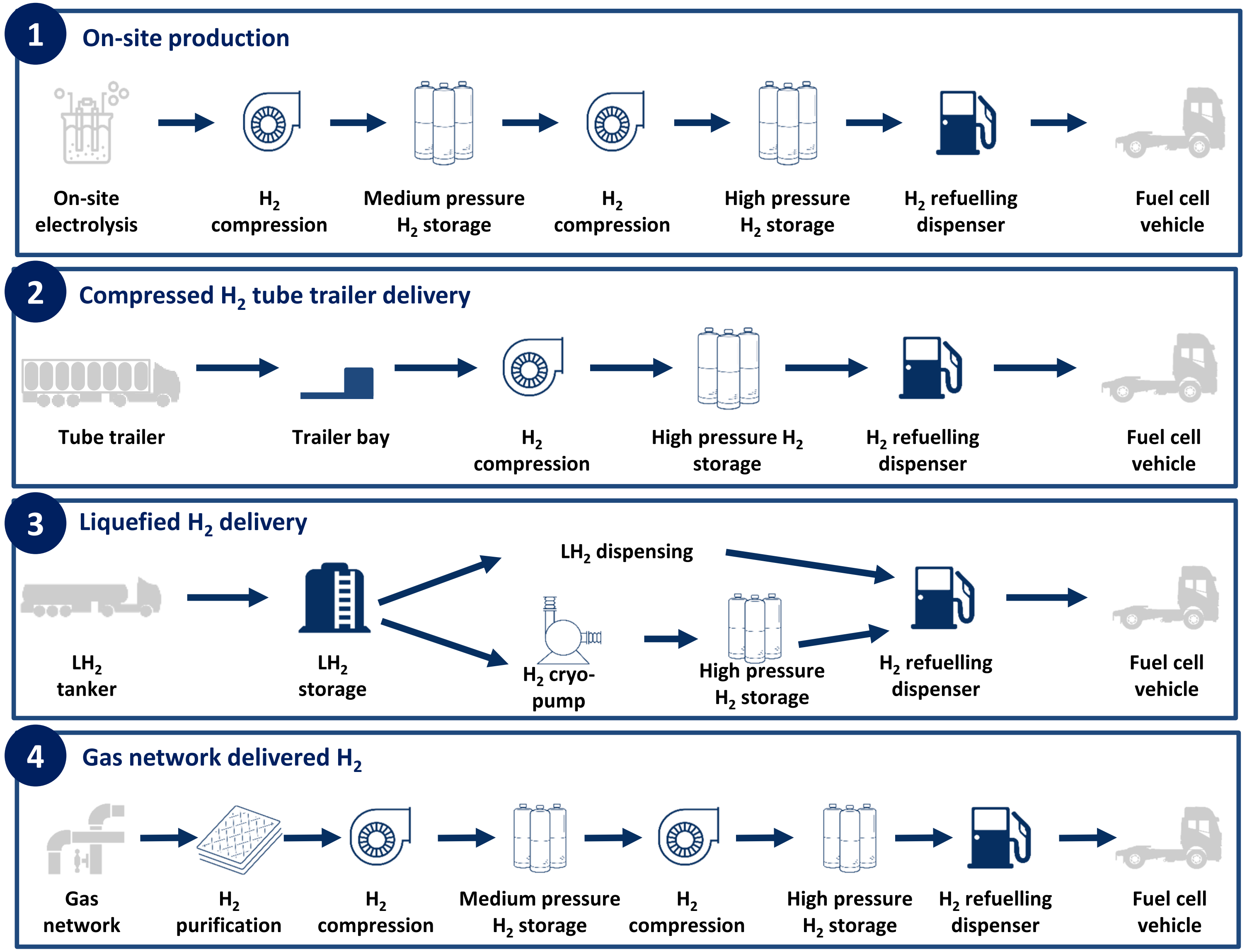
1 & 2: H_2 delivery via truck

- **Emissions associated with fuel use from transporting hydrogen,** depending on travel distance, mass of hydrogen transported, and truck fuel consumption (Euro 6).
- **Compression** from H_2 production to pressure requirements for distribution, storage and dispensing.
- **Liquefaction** for transport in liquid hydrogen truck – very large electrical energy use

3: Gas network delivered H_2

- **Deblending and purification**: depending on the pathway, the hydrogen will need to be deblended and/or purified up to five-9 standard. This process requires energy use through the compression steps involved, using electricity/hydrogen/NG-hydrogen blend
- **Fugitive emissions** from pipeline leakage, boil-off during LH_2 storage and transport, losses during dispensing and delivery. Fugitive emissions increase emissions both indirectly by increasing the energy requirement per kg of hydrogen dispensed and directly through the global warming potential of the emitted gas. This is small for hydrogen emission, and much larger for a 20% hydrogen-natural gas blend.
- Salt caverns storage was not explicitly included in the model, as the energy use associated with it was found to be negligible - more details may be found here.

Four dispensing options were investigated, each depending on the distribution pathway used



Emissions drivers considered in the modelling (discussed in more details in the Dispensing section of this report):

Compression: The main source of energy use at the HRS is for compression. The amount of compression required depends on the arrival state of the hydrogen and the desired dispensing pressure. Sites supplied with LH_2 use a cryo-pump and thermo-management system which negates the need for compression

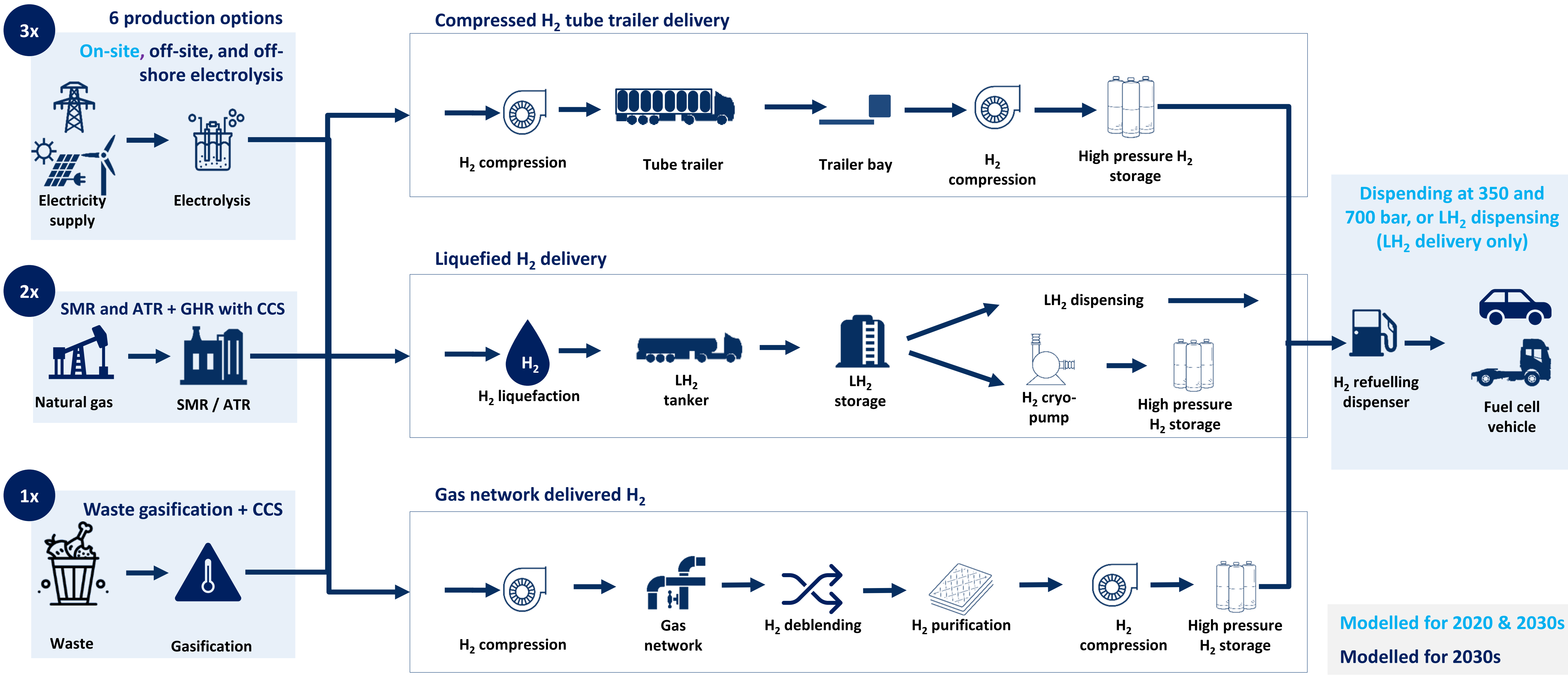
On-site storage: Each HRS type requires capacity to store H2 before it can be dispensed to vehicles

- **Medium pressure storage:** Sites supplied with H2 at low pressure require medium pressure storage as an intermediate stage before compression up to dispensing pressure
- **Tube trailer storage:** Tube trailers delivered to site can be used as on-site storage, removing the need for medium pressure storage before compression to dispensing pressures
- **LH_2 storage:** H_2 is stored in its liquid state until required for dispensing
- **High pressure storage:** H_2 is compressed into high pressure storage vessels for cascade dispensing so that the pressure differential rather than direct compression is used to dispense to vehicles

Purification: When hydrogen arrives at the HRS site via a pipe it will require purification up to the fuel cell standard (99.93% purity). This is the case regardless of whether the H_2 arrives following deblending from a blended gas grid, via a 100% hydrogen gas network or via a direct piped connection to a production site.

Fugitive emissions: At the HRS these primarily occur during transfer from delivery vessels or during boil-off from cryogenic storage

A combination of six production configurations, three distribution pathways, and three dispensing options were considered in this study – most are not yet in use



Modelled for 2020 & 2030s

Modelled for 2030s

Fugitive emissions (hydrogen, methane, CO_2) are also included

Contents

The value chain elements considered in this study depend on the year selected

- **Electrolysis**: currently only small on-site electrolysers are used for hydrogen production. In 2030 and 2035, large scale centralised electrolysers will be deployed, increasing the range of options for electricity use type and distribution. Offshore electrolysers are also expected to be deployed in the long term. Energy use is dominated by the electrolysis process itself, occurring in the stack, with small contributions from feedstock and product processing.
- **SMR and ATR + GHR with CCS:** energy use is dominated by natural gas use. The dominant factor affecting the emissions is the carbon capture rate, which will be higher for ATR + GHR than SMR. No SMR/ATR plants with CCS were operational in 2020.
- **Gasification with CCS**: this will be taken by default to be attached to a CO_2 transport pipeline as part of an industrial cluster. Emissions from plant electrical use will become very small by 2030 as the grid carbon intensity decreases. Emissions will be dominated by the carbon dioxide production occurring as a direct result of the gasification process. The carbon dioxide streams produced will be highly concentrated, leading to capture rates close to 100%, as confirmed through stakeholder engagement.
- **Compressed and liquid H_2 by truck**: the emissions associated with a diesel truck transporting hydrogen will decrease between 2020 and 2030, driven by lower truck fuel consumption.
- **Pipeline transport** emissions will decrease dramatically once deblending is no longer required.
- **Dispensing emissions** are from the grid carbon emissions associated with electricity use at the HRS, primarily for compression, and depend on the dispensing pressure used.

		2020/1	2030	2035+
Production	On-site small-scale electrolysis	✓	✓	✓
	Off-site on-shore centralised electrolysis	✗	✓	✓
	Off-site off-shore centralised electrolysis	✗	✓	✓
	SMR + CCS	✗	✓	✓
	ATR + GHR + CCS	✗	✓	✓
	Gasification + CCS	✗	✓	✓
Distribution	Compressed H_2 by truck	✓	✓ Included*	✓ Included*
	Liquid H_2 by truck	✓	✓	✓ Included*
	Pipeline transport	✗	✓ As a blend	✓ Dedicated H2 network
Dispensing	Dispensing @350 bar	✓	✓	✓
	Dispensing @ 700 bar	✓	✓	✓
	Liquid hydrogen dispensing	✗	✓	✓ Included*

* The role of compressed and liquid hydrogen is expected to decline beyond 2030 as the size of hydrogen refuelling stations will increase, prompting for the need of pipeline transport

The type of electricity used in the value chain depend on the location of the hydrogen production

At a high level, the electricity use for different elements of the value chain is shown on the side.

- Grid electricity is assumed as default for more steps in the value chain with the following exceptions:
  - Electrolysis at large-scale on-shore and off-shore with renewables
  - Compression and liquefaction of hydrogen at the site of production from renewables
  - Hydrogen transport by pipeline from off-shore (i.e. compressors powered by renewable electricity)
- However, there is uncertainty around the availability of renewable electricity for hydrogen production. A series of sensitivities were conducted as shown on this slide.
- The data on the grid intensity for the electricity use, including any scenarios as sensitivities, are shown on this slide in the Feedstocks and Production section.

		Grid electricity (different carbon footprint scenarios)	Renewable electricity
Production	On-site small scale electrolysis	✓	×
Production	Off-site on-shore centralised electrolysis	✓ Could to use grid electricity at time of low RES renewable output (sensitivity)	✓ Main source
Production	Off-site off-shore centralised electrolysis	×	✓
Production	SMR + CCS	✓ (not main energy demand)	×
Production	ATR +GHR + CCS	✓ (not main energy demand)	×
Production	Biomass + CCUS	✓ (not main energy demand)	×
Distribution	Compression at the production site	✓ if at small scale electrolyser, SMR/ATR, biomass	✓ if produced by centralised electrolysis
Distribution	Liquefaction at the production site	✓ if at small scale electrolyser, SMR/ATR, biomass	✓ if produced by centralised electrolysis
Distribution	Energy for pipeline transport (e.g. network compressors)	✓ for gas grid transport	✓ for H_2 transported via off-shore pipeline to land
Dispensing	Deblending	✓	×
Dispensing	Conversion of LH_2 to gas	✓	×
Dispensing	Coolers, storage and dispensers not collocated with production	✓	×

The data used in the modelling was extracted from literature, has different levels of accuracy and was discussed and validated with the Steering Group and external experts

Overview of the data quality for the feedstocks and production value chain elements		Electricity use	Natural gas use	Carbon capture rate (if applicable)	Overall emissions	Comment
Feedstocks	Water use for desalination and reverse osmosis	✗✗ (grey)	n/a	n/a	✗✗ (grey)	Process used in other application – off-shore electrolysis not demonstrated yet
	Gas and electricity grid carbon emissions	n/a	n/a	n/a	✗ (orange)	Good understanding of the emissions – multiple scenarios considered to minimise uncertainty
	Gasification feedstock production	✗ (orange)	n/a	n/a	✗ (orange)	Limited number of sources considered
Production	On-site small-scale electrolysis	✗✗✗ (green)	n/a	n/a	✗✗✗ (green)	Good data availability – demonstrated at scale
	Off-site on-shore centralised electrolysis	✗✗✗ (green)	n/a	n/a	✗✗✗ (green)	on-shore electrolysers still to be demonstrated at scale
	Off-site off-shore centralised electrolysis	✗✗✗ (green) ✗* (grey)	n/a	n/a	✗✗✗ (green)	Data adapted from on-shore electrolysers - off-shore electrolysis not demonstrated yet
	SMR + CCS	✗✗ (orange)	✗ (orange)	✗✗ (orange)	✗✗ (orange)	Retrofit capture rate 60%, higher for new built
	ATR + GHR + CCS	✗✗ (orange)	✗ (orange)	✗✗ (orange)	✗✗✗ (orange)	Capture rates typically around 95% for emerging projects, CCS expected to be available in late 2020s
	Waste gasification + CCS	✗ (orange)	n/a	✗ (orange)	✗ (orange)	Based on report about the ABSL/APP gasification plant using RDF, and stakeholder engagement with ABSL
	CO_2 Transport	✗ (orange)	✗ (orange)	✗ (orange)	✗ (orange)	

Data quality

✗ excellent quality ✗ good quality ✗ large uncertainty ✗ large uncertainty but minor contributor to overall WTT emissions

Data availability

✗ one source ✗ ✗ few sources ✗ ✗ ✗ several sources

*Uncertainty around factors such as auxiliary power sources needed to prevent freezing, but very small impact on overall results.

The data used in the modelling was extracted from literature, has different levels of accuracy and was discussed and validated with the Steering Group and external experts

	Overview of the data quality for the distribution and end-use value chain elements	Electricity use	Natural gas use	Fugitive emissions	Overall emissions	Comment
Distribution	Compression (electrical)	✗✗✗	n/a	n/a	✗✗✗	Well understood process and technology. Use of hydrogen in gas grid compressors is discussed here.
Distribution	Liquefaction	✗✗✗	n/a	n/a	✗✗✗	Some uncertainty over potential future decrease – for example IdealHy set standards for liquefaction plants to achieve 6.8 kWh/kg H2 in future – more details may be found here
Distribution	Energy for pipeline transport (e.g. network compressors)	✗✗	✗✗	✗	✗	Some uncertainty over how fugitive emissions will change for hydrogen in high pressure pipelines 2030, however there is a need for further RD&D
Distribution	Transport by truck	n/a	n/a	✗	✗	Diesel consumption, diesel WTW, mass of H_2 carried all known; some uncertainty around future truck capacities
Distribution	Deblending	✗	n/a	✗	✗	Not demonstrated at scale yet – limited data
Dispensing	HRS (compression, purification, storage, and cooling, and dispensers)	✗✗	n/a	✗	✗✗	Includes data based on extensive research from NREL (HDSAM model) and data provided by BOC / Linde group
Dispensing	LH_2 dispensing	✗	n/a	✗	✗	No LH2 stations have been built yet, so no data available. Station was modelled from first principles using these assumptions

Data quality around fugitive emissions from pathways other than LH_2 is generally poor and needs further work

Data quality

✗ excellent quality ✗ good quality ✗ large uncertainty ✗ large uncertainty but minor contributor to overall WTT emissions

Data availability

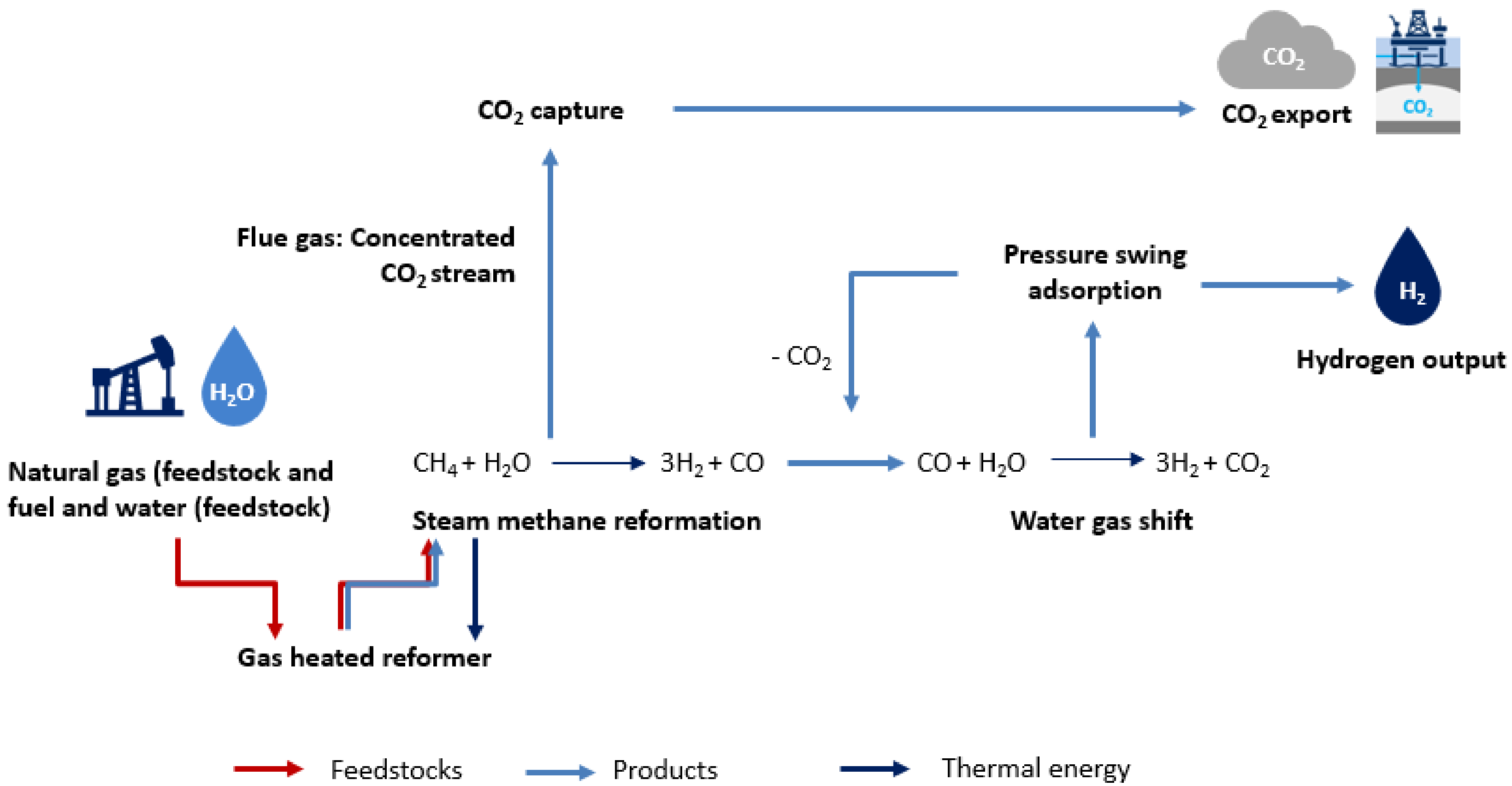
✗ one source ✗ ✗ few sources ✗ ✗ ✗ several sources

RD&D: Research Development and Demonstration,

Contents

Autothermal reforming will allow large scale hydrogen production with efficient carbon capture

Autothermal reforming (ATR) contrasts with steam methane reforming in that the thermal energy required for reformation is provided by combustion of methane in the reformer (using small amounts of oxygen introduced), rather than in a separate vessel. As a result, there is only one, concentrated carbon dioxide stream, allowing high capture rates. A basic schematic of an autothermal plant fitted with a **gas heated reformer (GHR)** is shown in the diagram below. Modern ATR designs almost always use a GHR to increase efficiency by using some waste heat from the main reforming chamber to pre-reform some of the mixture before it enters the main reforming chamber.



ATR + GHR hydrogen output pressures vary between 80 bar (H21[2]) down to 19 bar (HyNet[5]).

	ATR + GHR output pressure/bar
Low	19
Central	50
High	80

(1)Progressive Energy, Johnson Matthey, SNC Lavalin - HyNet Low Carbon Hydrogen Plant Phase 1 report for BEIS, (2) Northern Gas Networks – H21 North of England – national launch -2018, (3) Pale Blue Dot – Acorn Hydrogen Feasibility Study – 2019 , (4) Vince White, Air Products – World Scale Hydrogen Production – 2019 (5) Cadent – HyNet Northwest – from vision to reality

Autothermal reforming has only one concentrated CO_2 stream, allowing high capture rates

- ATR + GHR plant emissions are **dominated** by the emissions at the chimney (determined by the **carbon capture rate**) and the **NG upstream emissions**
  - The **HyNet** ATR + GHR[1] has a target capture rate of **97.2%** and an energy use of **42 kWh/kg** hydrogen and an electricity use of **2.55 kWh/kg** hydrogen
  - The **H21** ATR + GHR[2] concept has a capture rate of **94.1%,** a natural gas use of **42.8 kWh/kg** hydrogen and an electricity use of **1.91 kWh/kg** hydrogen
  - The **Acorn** ATR + GHR[3] concept has a capture rate of **98.7%,** a natural gas use of **42 kWh/kg** and an electricity use of **2.67 kWh/kg** hydrogen
  - **Air Products**[4] quote a **95%** capture rates and a natural gas use of **41.44 kWh/kg** hydrogen for ATR + GHR
- Most modern designs feature as **gas heated reformer** which uses some of the hot product gases from the main reforming chamber pre reform some of the feedstock in a separate chamber before passing into the main chamber, **increasing the efficiency** of the system.
- A very small contribution to the energy use comes from transport of the captured carbon dioxide and is discussed later.
- We note that **higher capture rates** require **marginally higher electricity uses**; however the effect on emissions of varying electricity use is very small compared to the effect of varying capture rates.
- **Negligible methane is emitted at the SMR plant**[5]; however methane emissions are part of natural gas upstream CO_2e emissions.
- For scope 1 emissions the work uses a conversion factor of **0.205 kg CO_2e/kWh Natural Gas LHV** as used the Acorn project evaluation[3], combined with the capture rates, to determine the direct uncaptured CO_2 emissions from SMR and ATR + GHR plants.

Capture rates and electrical energy use

	Capture rate %	Electrical energy use, kWh/kg
Low	94.1	1.91
Central	95	2.37
High	98.7	2.67

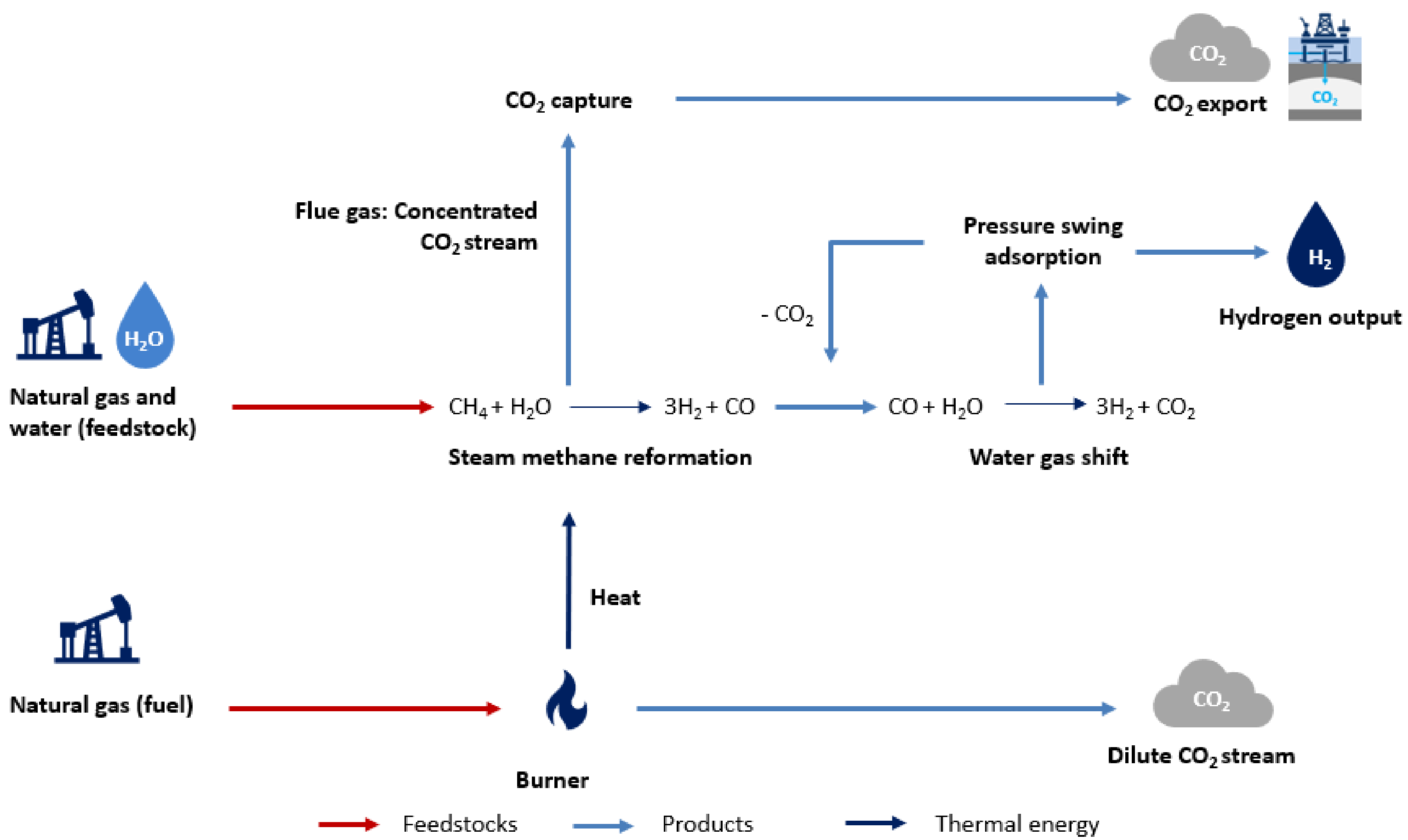
Natural gas use, kWh/kg H_2 produced

	2030/2035, with GHR
Low	41.4
Central	42
High	42.8

(1)Progressive Energy, Johnson Matthey, SNC Lavalin - HyNet Low Carbon Hydrogen Plant Phase 1 report for BEIS, (2) Northern Gas Networks – H21 North of England – national launch -2018, (3) Pale Blue Dot – Acorn Hydrogen Feasibility Study – 2019 , (4) Vince White, Air Products – World Scale Hydrogen Production – 2019 (5) E4Tech – H2 Emission Potential Literature Review – 2019, pg 17-18

Hydrogen will also be produced by retrofitting CCS to old steam methane reformers, however the dilute CO_2 stream from the burner is not captured in retrofits

Steam methane reformation (SMR) involves production of hydrogen and carbon dioxide via reaction of methane and steam at temperatures of 700–1,000 Celsius and pressures of 3-25 bar[1]. When coupled with **carbon capture and storage (CCS)** the process constitutes a form of low carbon hydrogen production. Whilst newbuild reforming projects in the UK mostly focus on ATR + GHR because of the higher efficiency, existing SMRs can be retrofitted with CCS. Newbuild SMRs capture some of the dilute CO_2 stream from the burner, while retrofit SMRs do not.



SMR hydrogen output pressures range from 25 bar[2,3] to 80 bar[1]

	SMR output pressure/bar
Low	25
Central	53
High	80

(1) Northern Gas Networks – H21 North of England – national launch -2018, (2) IEAGHG – Techno-Economic Evaluation of SMR based standalone (merchant) hydrogen plant with CCS – 2017 , (3) Linde-Hydrogen manual

Steam methane reformation is currently the most widely used method for hydrogen production

- As shown earlier, SMR plant emissions are **dominated** by the emissions at the chimney (determined by the **carbon capture rate**) and the **NG upstream emissions**
- The main existing SMR currently retrofitted with CCS is run by Air Products at Port Arthur and has a capture rate of **60%**. We suggest using this figure for the SMR archetype
- **We use SMR retrofitted with CCS as our SMR scenario, with a 60% capture rate**

Capture rates differ greatly between new build and retrofitted SMR + CCS plants:

- The **newbuild H21** SMR[2] concept has a capture rate of **91.2%** and a natural gas use of **48.6 kWh/kg** hydrogen. It requires **0.94 kWhe/kg** of electrical power.
- The **newbuild IEAGHG** baseline[3] capture rate is **90%,** and a natural gas use of **48.2 kWh/kg** corresponding to emission of 1.0 kg CO_2/kg H_2 produced and export of 8.9 kg CO_2/kg H_2. Electrical energy use is **1.25 kWhe/kg.**
- For comparison, the Linde[4] SMR design **(without CCS)** requires **0.19 kWhe/kg of electrical energy and 45.9 kWh/kg of natural gas**
- An industry stakeholder reported that they see a **continuing role for SMR in the future**, even with the development of ATR + GHR
- Plant energy use includes small amounts of energy required for captured CO_2 compression

Energy inputs and operational parameters for a retrofitted SMR with CCS

	Natural gas use, kWh/kg H2 produced	Electricity use, kWh/kg	Capture rate %
Low	45.9	0.19	60
Central	47.3	0.79	60
High	48.6	1.25	60

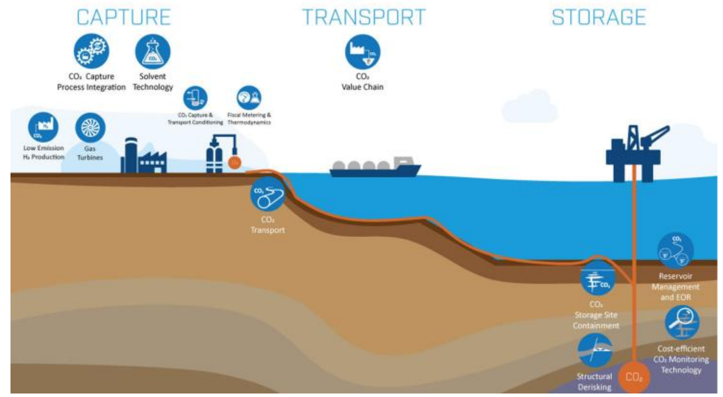
Source: (1) US DOE – Hydrogen production natural gas reforming (2) Northern Gas Networks – H21 North of England – national launch -2018, (3) IEAGHG – Techno-Economic Evaluation of SMR based standalone (merchant) hydrogen plant with CCS – 2017 (4) Linde – Hydrogen manual, https://www.linde-engineering.com/en/images/H2_1_1_e_12_150dpi_NB_tcm19-4258.pdf

Carbon dioxide is compressed and transported as a supercritical fluid for sequestration

Following capture, the CO_2 is dried and compressed. The energy requirement for this is approximately 0.9 kWh/kg hydrogen produced[1] and is included within the plant electricity consumption figures.

The carbon dioxide is transported in the supercritical phase (as phase formed by breakdown of the difference between liquid and gas at high pressure), which gives a high density for efficient transport:

- Carbon dioxide leaves the SMR/ATR + GHR plant at **110-120 bar following compression** and enters a pipeline, and the energy required for compression of the carbon dioxide to this pressure is included as part of the plant energy use discussed earlier.
- The pipeline transports the carbon dioxide to the point where it is sequestered. For example, for the HyNet project, sequestration takes place in disused gas fields off Liverpool.
- The pressure in the pipeline must be maintained above **100 bar** in order keep the carbon dioxide in the supercritical phase, which gives a high density for efficient transport.
- For realistic pipeline lengths for the UK, the pressure drop in the pipeline is approximately **10 bar[2]**, which corresponds to an energy use of **0.009 kWh/kg[2]** carbon dioxide transported. This energy use is electrical energy used by compressors to limit the pressure drop to 10 bar, thus keeping the carbon dioxide in the supercritical phase.
- The CO_2 is compressed from 100 bar to 250 bar for an offshore pipeline, which has a small energy requirement of 0.025 kWh/kg CO_2 (calculated using Element Energy in house compression energy model and using the compressor efficiency from the 2018 Element Energy BEIS shipping model).
- This is therefore multiplied by the exported CO_2 to obtain the energy use per kg of hydrogen produced. This energy use is very small, around 0.3 kWh/kg hydrogen.
- In addition, the fugitive emissions from the pipelines are negligible



(1) IEAGHG – Techno-Economic Evaluation of SMR based standalone (merchant) hydrogen plant with CCS – 2017 (2) Element Energy – Shipping CO_2- UK cost estimation study – 2018

Contents

Natural gas upstream well-to-terminal emissions result from transmission and processing

Sources of natural gas upstream emissions

Exploration: Field activities prior to production that have fugitive emissions. This includes prospecting, exploratory well drilling, testing, completion, field and well development

Production: Emissions during production activities such as flaring and fugitive emissions through leaks

Processing: Gas treatment and processing such as acid gas and natural gas liquid removal, liquefaction for transportation

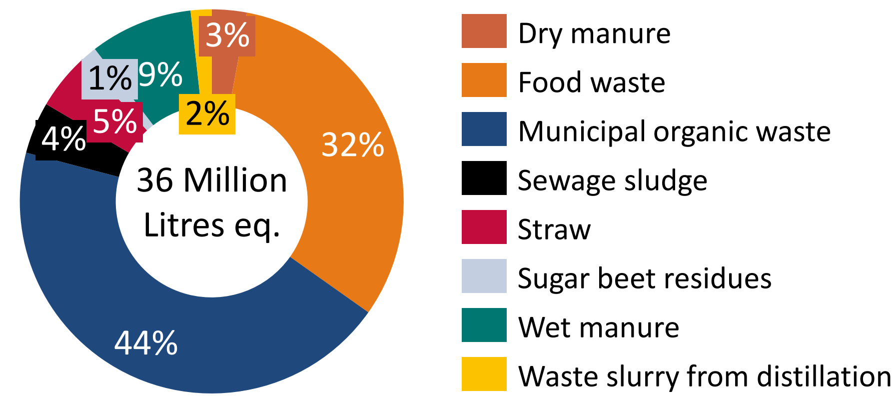
Transmission: Emissions during bulk transport through LNG tankers or long distance pipelines e.g. from boil-off and fugitive emissions and processing such as regassification

Storage: Fugitive emissions during large scale storage e.g. underground storage or stationary LNG storage at terminals

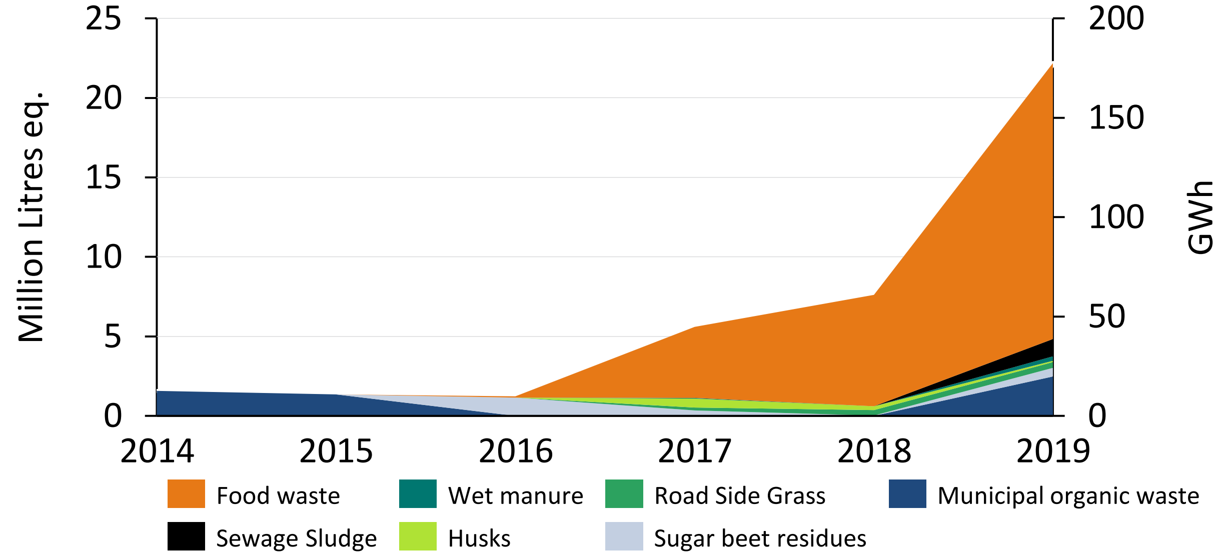
Biomethane used in transport is accounted for under the RTFO and has been treated separately from natural gas on the network in this report to avoid double counting

- Under the RTFO, fuel suppliers are obligated to sell a proportion of renewable fuels each year. Producers of renewable transport fuels such as biomethane are awarded RTFCs which can be sold to fuel suppliers along with the renewable fuel to demonstrate they have met their obligation
- Biomethane can be 'mass-balanced', meaning that it can be injected into the gas network where it is produced (including outside the UK), and the same mass can be extracted elsewhere on the network and supplied to UK customers. The emissions savings from biomethane used in transport are accounted for separately from the fossil natural gas supplied via the network using the RTFCs
- To avoid double counting, the emissions benefits of biomethane are also treated separately in this work. Biomethane as a feedstock for H_2 is included in the model as a sensitivity exploring the impact on emissions if a facility purchased 100% biomethane for H_2 production, rather than as part of the mix of sources of natural gas supplied via the network.
- In the modelling, any uncaptured CO_2 from H_2 production using biomethane is disregarded, while captured CO_2 produces negative emissions. Upstream emissions from the production and transport of biomethane are included as positive emissions.
- The feedstock used to produce biomethane determines its upstream emissions. Food waste is currently the dominant feedstock for biomethane used in transport, though the provisional RTFO report for 2020 suggests that this mix is changing with increased share of municipal organic waste
- The role of wet manure is also growing and this is expected to continue, due to the potential to provide negative upstream emissions (see next slide)

Qualifying biomethane by feedstock under the RTFO in 2020[1]



Qualifying biomethane by feedstock under the RTFO in 2014-2019[2]



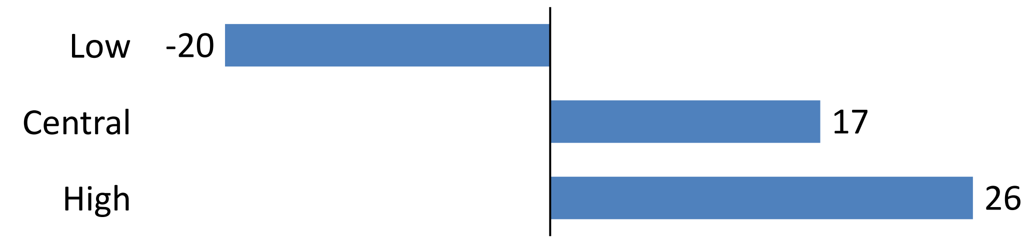
1: Renewable fuel statistics 2020: Third provisional report RF_01, https://www.gov.uk/government/statistics/renewable-fuel-statistics-2020-third-provisional-report.
2: Renewable fuel statistics 2019: Final report data tables RF_01 https://www.gov.uk/government/statistics/renewable-fuel-statistics-2019-final-report

The model takes a range of upstream emissions factors for biomethane that reflect the range of possible future feedstock mixes

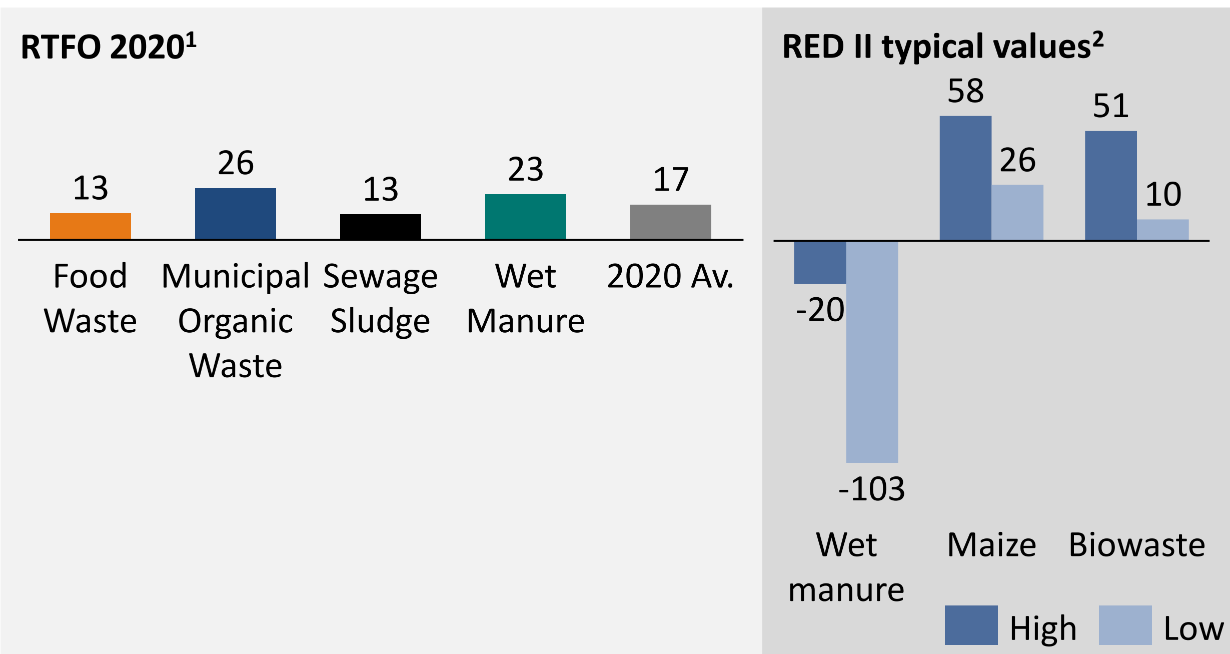
It is currently unclear how the mix of feedstocks used to produce biomethane for use in transport in the UK will change in future. To the test the sensitivity of this uncertainty, the three scenarios were included in the modelling:

- **High:** The highest emitting feedstock qualifying for RTFO in 2020
- **Central:** Reflects the average emissions for biomethane qualifying under the RTFO in 2020
- **Low:** Reflects a high proportion of wet manure in the mix qualifying for the lowest emissions factor under the REDII (see doughnut chart bottom right)

Proposed range of emissions factors for biomethane (gCO_2e/MJ)

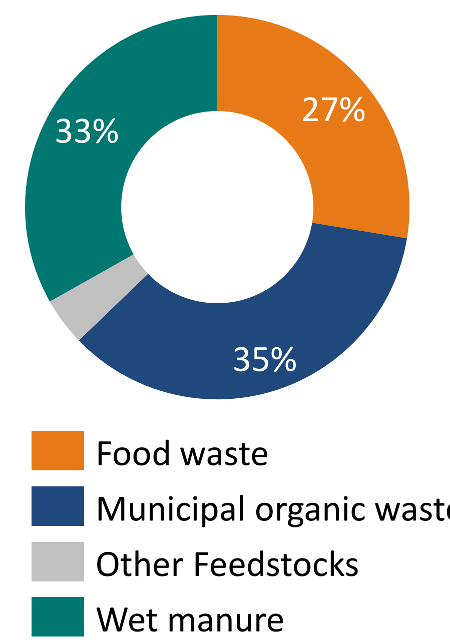


Biomethane production emissions factors (gCO_2e/MJ)



Representative feedstock mix required to achieve -20 gCO_2e/MJ

- To achieve -20 gCO_2e/MJ overall for UK biomethane, wet manure achieving the -103 gCO_2e/MJ value listed under REDII would need to make up 33% of feedstocks
- Wet manure represents 35% of the UK's 2030 biomethane production potential[3]
- The -103 gCO_2e/MJ value for biomethane from wet manure under REDII applies to a covered system using off-gas combustion
- Under the government's Clean Air Strategy[4], all slurry and digestate stores will need to be covered by 2027



1: Renewable fuel statistics 2020: Third provisional report RF_01, https://www.gov.uk/government/statistics/renewable-fuel-statistics-2020-third-provisional-report , 2: EU, RED II Full Text, 2018, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=fr 3: ADBA 2030 Report, 2020, http://staging.adbioresources.org/docs/Biomethane_-_Pathway_to_2030_-_Full_report.pdf, 4: Defra Clean Air Strategy 2019, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/770715/clean-air-strategy-2019.pdf

Contents

Large scale electrolysis projects on the 100 MW scale are due to start operation in the early 2020s

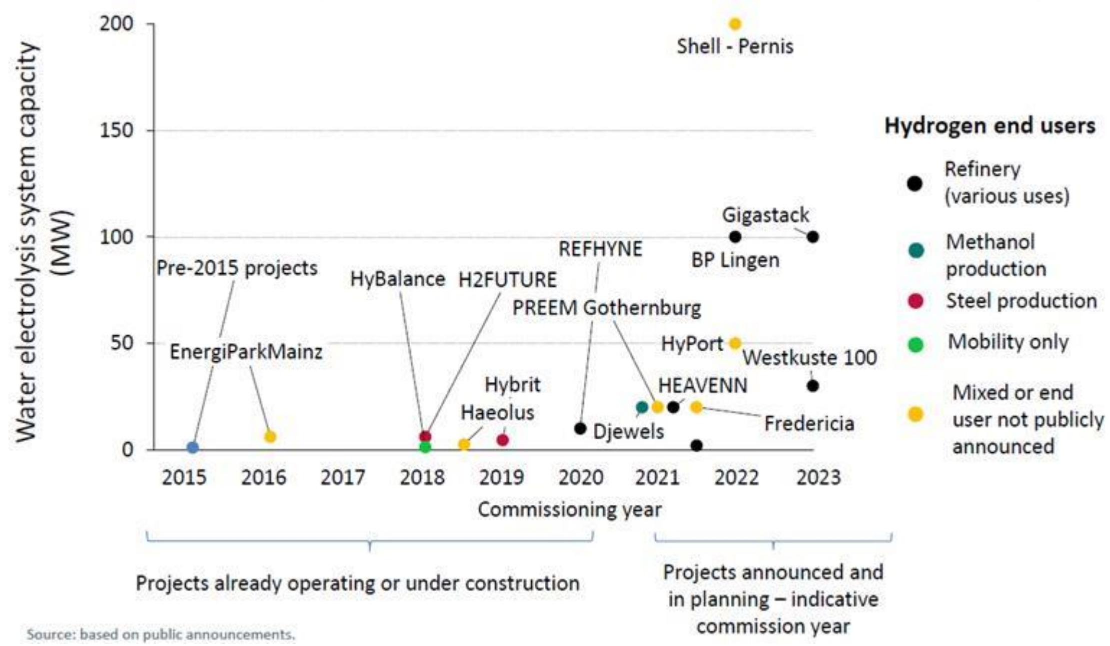
Electrolysis could account for around **21%** of hydrogen supply by **2035** and **44%** by **2050**[1] and owing to its high purity will be preferentially used for automotive applications over other forms of hydrogen production.

Electrolysis could be deployed:

- At small-scale, often co-located with a hydrogen refuelling station. This has been the case for many of the early hydrogen mobility projects
- Large scale enabling centralised production
  - On-shore: in an area with access to renewable electricity, such as the Gigastack project in the UK
  - Off-shore: emerging concept aiming to minimise the costs of high-voltage underwater connection cables. This requires desalination of seawater as well as the construction of a pipeline to shore. The Dolphyn project in Scotland represents such an example (more information on this project and the energy requirement for desalination is on this slide)

- The role of large scale electrolysis is expected to grow in the 2020s, with innovations in electrolyser modular design and decrease in costs, as well as driven by a higher demand for hydrogen.
- Multiple electrolyser technologies exist, however this study is examining Polymer Electrolyte Membrane (PEM) electrolysis technology only.
- Electrolyser **system** energy use is normally specified and represents that energy requirement for pure, dry hydrogen production from an AC electrical supply. It is composed predominantly of the **stack** energy use – which is the DC electrical energy use for electrolysis itself – and small additional contributions, such as hydrogen drying, discussed in the following slides.

Evolution of publicly announced electrolysis projects in Europe (non-exhaustive)

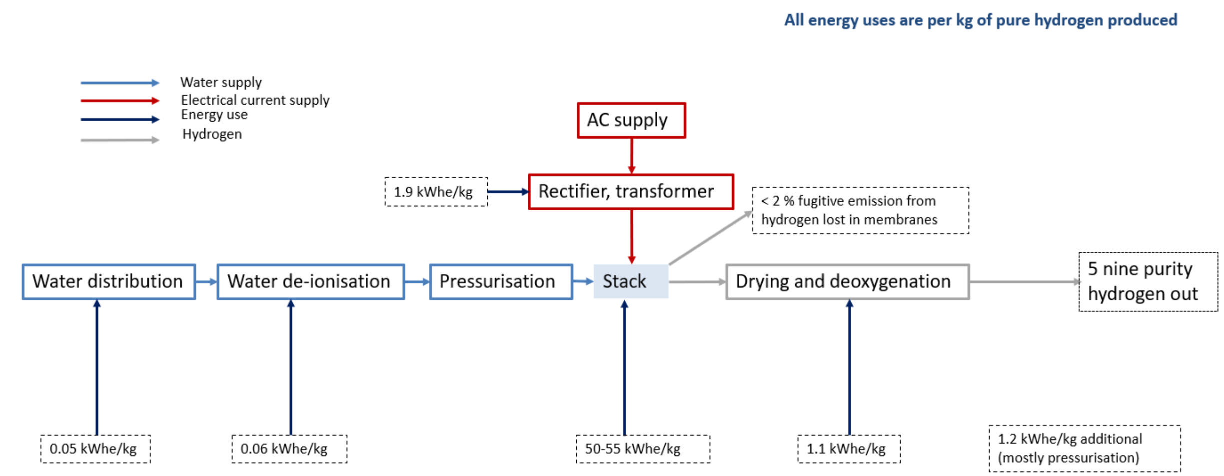


Source: based on public announcements.

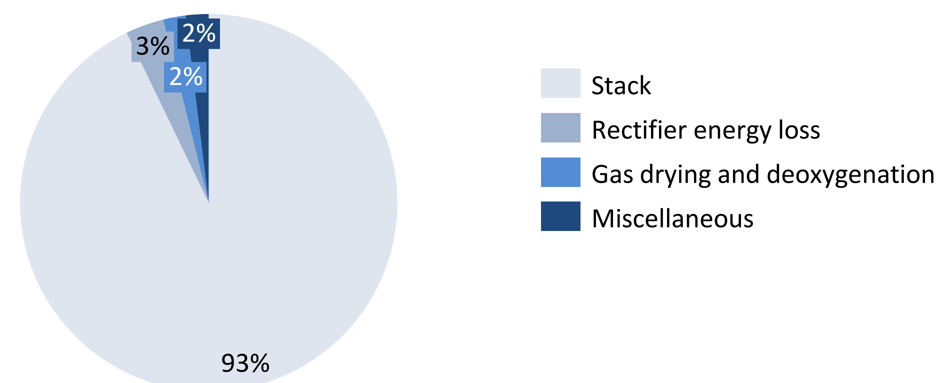
PEM Electrolyser plants require pre-processing and post processing, accounting for around 10% of the total energy use

- The electrolyser itself, which splits water into hydrogen and oxygen using a **DC electrical supply**, is known as the **stack**. A full electrolyser plant consists of the stack along with post-processing and pre-processing components, as shown in the diagram.
- As shown in the bottom right, **electrolyser energy use is dominated by the stack**
- An electrolyser is supplied with **AC electrical supply** from the grid and **drinking quality water**. This necessitates the following:
  - **De-ionisation** of the water before entering the stack
  - **Rectification** of the electrical supply from AC to DC. A transformer is also used to alter the supply voltage to match the requirements of the stack.
- The hydrogen produced by the stack must be **dried** and **deoxygenated** to produce hydrogen of automotive grade purity
- For current PEM electrolysers, total **plant** energy consumption **at full load** is typically around **55-60 kWh/kg H_2** produced. As shown in the diagram, this energy consumption is dominated by the stack. The total energy consumption of the non-stack components is around **5-6 kWh/kg H_2** . The energy consumption of electrolysers is expected to decrease significantly in future, as discussed later.
- Energy requirements associated with **water** supply and purification are negligible, at around 0.1 kWh/kg hydrogen produced.

High level diagram of a small-scale electrolyser plant. All energy uses are per kg of pure hydrogen produced (pressurisation includes compression, and figures are shown for 100% load point – energy use is lower down to 40% load point)



Proportion of total plant energy consumption consumed by the stack, rectifier and hydrogen purifier

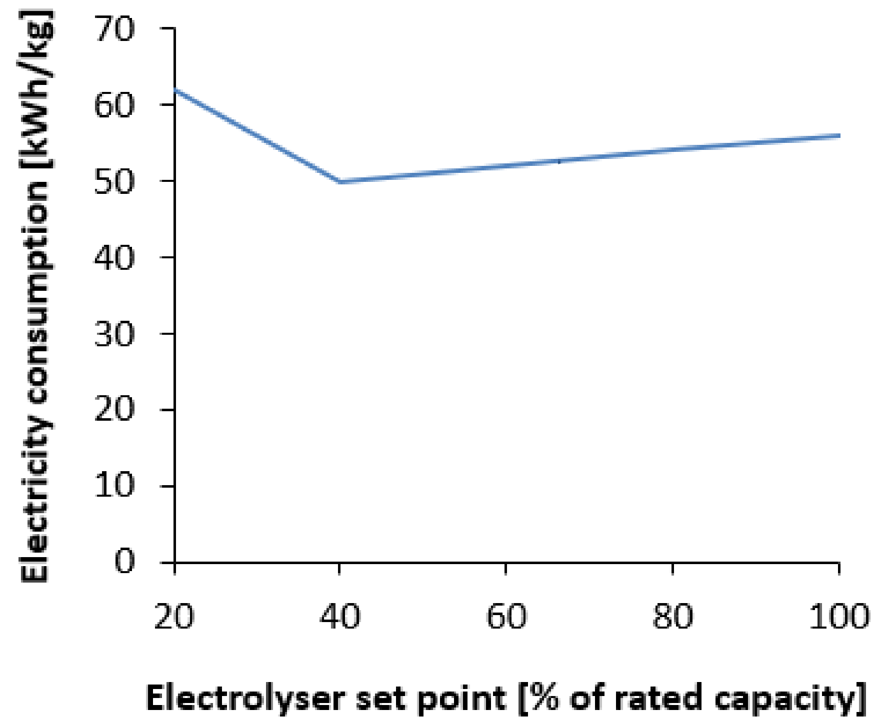


Sources: SA - Techno-economic Analysis of PEM electrolysis – 2014, ITM Power, Element Energy - Hydrogen Supply Chain Evidence Base – 2018, (1) CCC – 6th Carbon Budget – 2020, (2) National Grid – Future Energy Scenarios – 2020

PEM Electrolyser energy use varies significantly depending on load point, but in energy use terms is largely immune to economies of scale

- **Electrolyser energy use is significantly affected by load point**: as shown in the diagram, electrolyser energy use is approximately 6 kWh/kg higher when operating at 100% load point than when operating at 40% load point as a result of increased resistive power losses when operating at higher load points. Load point is the fraction of peak capacity at which the plant is operating at **one instant in time**.
- A load **factor** of 50% can be achieved by running at 100% load **point** for 50% of the time or at 50% load **point** for 100% of the time.
- The modular nature of ITM Power electrolysers means energy use per kg of hydrogen is independent of scale for 670 kWe and higher electrolysers: ITM technical data reveals a plant energy use **at 100% load point** of **59.6-59.7 kWh/kg** hydrogen produced for **670 kWe, 2 MWe and 10 MWe** electrolysers (see appendix slide).
- Previous work by the FCH JU, MAWP and Element Energy[2] suggests electrolyser energy use will fall by around 10% by 2030, based on targets from electrolyser suppliers.
- The low, medium and high values for electrolyser energy use in the model encapsulate the variation in energy use with load point, as well as the variation in energy use between suppliers and models of PEM electrolysers.

Load point dependence of electrolyser system (stack plus balance of plant) energy use[1]



Electrolyser system energy use will decrease significantly over the next 10 years

- **System** energy use is the sum of the **stack** energy use and a small contribution – **5-6 kWh/kg**[1,2] – from **non-stack** energy use.
- Element Energy Gigastack public report[1] gives state of the art values for **system** electricity consumption of PEM electrolysers at **full load** as **55 kWh/kg** in **2020** and **50 kWh/kg** in **2030**
- The Gigastack project[1] uses ITM Power 4th generation 5MW modules with a targeted system efficiency of **54 kWh/kg**
- The National Grid FES report[3] gives electrolyser system efficiency as **56 kWh/kg** in 2020 and predicts a decrease in energy use to **49 kWh/kg** in **2050**.
- IRENA[4] gives electrolyser energy system use as 50-83 kWh/kg in 2020 and predicts this will fall to **45 kWh/kg** or lower in **2050**.
- PEM Electrolysers have a stack lifetime of approximately 10 years, and their efficiencies degrade over time. At any instant in time, some of the electrolysers operating will be several years old and will therefore have lower efficiencies – both because they were built with lower efficiencies and because efficiencies degrade by around 1% per year.
- A trend towards larger electrolysers is expected as HRS size increases. As discussed previously, evidence shows that there is no significant size dependence of the energy use - this is not included in the modelling undertaken.
- Electrolyser energy use independent of scale owing to modular nature of electrolysers – see here.
- **Electrolyser output pressures vary between 20 bar and 60 bar**.
  - For example, ITM catalogue electrolysers show an output pressure of 20 bar (see appendix).
  - For the Gigastack project, the next generation of ITM electrolysers are expected to have an output pressure of 30 bar[1].
  - Siemens electrolysers have output pressures of 35 bar[6] while Tractebel electrolysers have output pressures of 30-60 bar[6].

Electrolyser stack energy use scenarios used in the model, kWh/kg hydrogen produced. The figures account for variation between manufacturers as well as inefficiencies under intermittent operation. Electrolyser efficiencies (LHV) are given in brackets.

Electricity input [a)]			2020	2030	2035
kWh_{el}/kgH_2 for stack	Alkaline[2]	Central	52	50	48
		Range	49-67	48-63	46-61
	PEM[2]	Central	53 (63%)	47 (71%)	45 (74%)
		Range	49-61	44-53	42-48

System energy use from non-stack energy requirements, kWh/kg, (additive to the above)	5.5

Electrolyser output pressures/bar

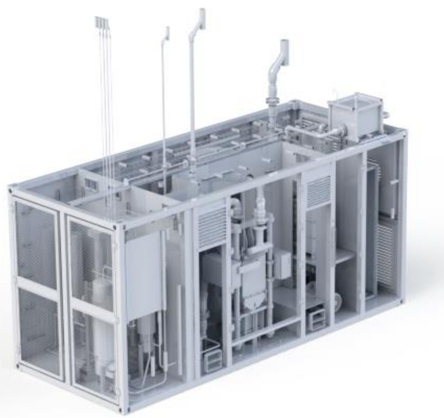
	2020	2030	2035
Low	20	20	20
Central	30	30	30
High	60	60	60

Sources: (1) Element Energy – Gigastack: Bulk supply of renewable hydrogen – 2020; (2) SA - Techno-economic Analysis of PEM electrolysis – 2014(3) National Grid – Future Energy Scenarios – 2020; (4) IRENA – Green Hydrogen Cost Reduction – 2020; (5) Element Energy – Hydrogen Supply Chain Evidence Base – 2018 , L. Bertucciolo, A. Chan, D. Hart, F. Lehner, B. Madden, and E. Standen, "Development of Water Electrolysis in the European Union," *FCH JU*, no. February, 2014 (6) North Sea Energy - Technical assessment of Hydrogen transport, compression, processing offshore – 2020, Element Energy – Hydrogen supply chain evidence base - 2018

Modular nature of ITM electrolysers makes them immune to economies of scale in energy terms

670 kWe

HGAS1SP



Demonstrated benefits include:

- ITM Power's PEM technology provides leading performance, longevity and self-pressurisation
- Rapid response enables participation in primary and secondary grid balancing markets
- Modular structure allows flexibility of sizing using well proven technology and design
- Hydrogen purity suitable for use in fuel cell vehicles

HGas1SP I is fully integrated, autonomous and carries a CE mark.

HGas1SP	Specs
Electrolyser technology	PEM
Number of stacks	1
System packaging and size	20ft & 30ft ISO container and external cooling equipment
Power supply	400V AC, 3 Phase, 50Hz
Control	PLC
Hydrogen generation pressure (bar)	20
Hydrogen purity	Up to 99.999% (ISO standard)
Maximum hydrogen production apprx (kg/24h)	270
Input power at maximum apprx (kW)	670

2 MWe

HGAS3SP

Demonstrated benefits include:

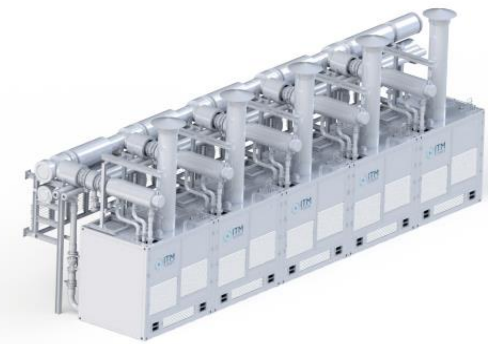
- ITM Power's PEM technology provides leading performance, longevity and self-pressurisation
- Rapid response enables participation in primary and secondary grid balancing markets
- Modular structure allows flexibility of sizing using well proven technology and design
- Hydrogen purity suitable for use in fuel cell vehicles

HGas3SP is fully integrated, autonomous and carries a CE mark.

HGas3SP	Specs
Electrolyser technology	PEM
Number of stacks	3
System packaging and size	2 x 40ft ISO containers and external cooling equipment
Power supply	11kV AC, 3 Phase, 50Hz
Control	PLC
Hydrogen generation pressure (bar)	20
Hydrogen purity	Up to 99.999% (ISO standard)
Maximum hydrogen production apprx (kg/24h)	810
Input power at maximum apprx (kW)	2,015

10 MWe

HGASXMW



Demonstrated benefits include:

- ITM Power's PEM technology provides leading performance, longevity and self-pressurisation
- Rapid response enables participation in primary and secondary grid balancing markets
- Modular structure allows flexibility of sizing using well proven technology and design
- Hydrogen purity suitable for use in fuel cell vehicles

HGasXMW is fully integrated, autonomous and carries a CE mark.

HGasXMW	Specs
Electrolyser technology	PEM
Number of stacks	15
Electrolyser packaging	Installation indoors
Power supply	11kV AC, 3 Phase, 50Hz
Control	PLC or DCS
Hydrogen generation pressure (bar)	20
Hydrogen purity	Up to 99.999% (ISO standard)
Maximum hydrogen production appx (kg/24h)	4,050
Input power at maximum appx (kW)	10,070

All 59.6 – 59.7 kWhe/kg H_2 produced

Sources: https://www.itm-power.com/images/Products/HGas1SP.pdf; https://www.itm-power.com/images/Products/HGas3SP.pdf ; https://www.itm-power.com/images/Products/HGasXMW.pdf

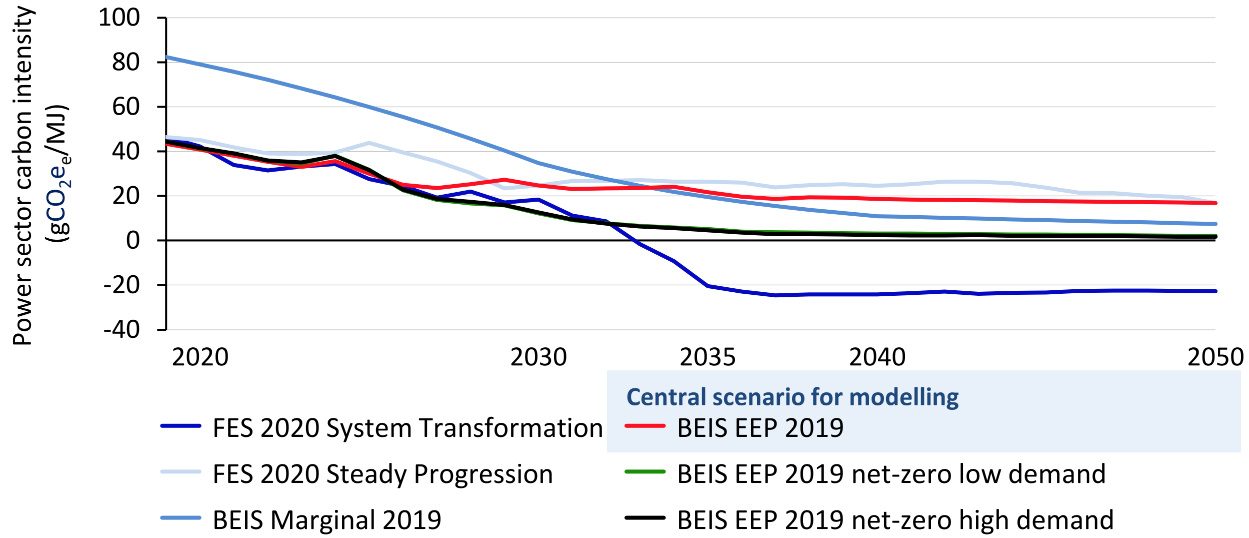
The Dolphyn offshore electrolysis project is planned to become commercial in 2032

- First off-shore hydrogen production project, the Dolphyn project located in the North Sea off Scotland, will be operational by **2032** (i.e. offshore electrolysis outputs are only shown for 2035)
- The project plans to use electrical compressors to compress the hydrogen up to **100 bar**[2] to move the hydrogen to the shore over a 300 km pipeline length, aiming to connect with the SGN gas network in Scotland.
  - A 30 bar electrolyser output pressure will require around 0.75 kWh/kg hydrogen
  - This is a modest contribution to the energy use for moving the hydrogen over to the onshore gas grid but will be included.
- Pressure drops in offshore pipelines are typically 10-20 bar per 100 km[3] , therefore for a 300 km pipeline a pressure drop of 30-60 bar would be expected.
- The hydrogen would therefore arrive at the shore at 40-70 bar (assuming 100 bar initial pressure[2]) and there would be a small compressional energy requirement prior to distribution which is included in this modelling.
- As the project is looking to use sea water, a desalination step will be required. The energy consumption for this is estimated to be minimal (below 0.1 kWh/kg H_2), calculated by multiplication of the energy requirement for desalination per litre of water (0.003 – 0.008 kWh/litre)[4,5] by the volume of de-ionised water required per kilogram of hydrogen produced (9 litres/kg H_2)[6].
- There is a small uncertainty around auxiliary power unit energy use – a low carbon source is planned (as highlighted in reference 2)
- **The additional energy requirements for offshore electrolysis are very small.**

The Dolphyn project[1]

(1)National Development Programme: ERM Dolphyn Project, (2)BEIS and ERM - Dolphyn Hydrogen Phase 1 - Final Report - 2019 (3) North Sea Energy – Technical assessment of Hydrogen transport, compression and processing offshore – 2020 (4) IEA – The Future of hydrogen – 2019 (5) Environment Agency – GHG emissions of water supply and demand management options (6) Element Energy – Hydrogen supply chain evidence base – 2019

The future electricity production mix



The following scenarios were included in the modelling:

- **BEIS EEP 2019 baseline scenario** – central scenario
- **FES 2020 – system transformation**: this has the highest hydrogen demand in all sectors, including the **most extensive use of hydrogen in transport**
- BEIS EEP 2019 net-zero consistent scenarios and FES 2020 – steady progression

The modelling also allows for the calculation of two additional important cases:

- **Renewable electricity:** (0 gCO_2e/MJ)
- A mixture of grid average and renewable electricity
- **Marginal electricity use** (based on BEIS marginal electricity)

FES includes average transmission (2%) and distribution (6%)[5] losses.

Discussions with green hydrogen project developers confirm that essentially all projects being scoped will have a strategy for near 100% renewable electricity procurement (albeit with different load factors according to their RE procurement strategy).

Marginal electricity use

When producing hydrogen from electrolysis with a grid connected electrolyser at a time when VRES is not curtailed, then the default counterfactual (for example, for comparison with petrol) would not be to use that electricity at all. Switching on an electrolyser could therefore in the worst case be viewed as sourcing electricity exclusively from the marginal source at the time.

In the past few years, the **marginal generation** has been **predominantly CCGT**[1], with a carbon intensity of **109 gCO_2e/MJ**[3], with some contribution from coal[2] , which has a carbon intensity of approximately 260 gCO_2e/MJ[3], but will be phased out in 2024/2025[4]. For an electrolyser operating at 100% load factor, the carbon intensity of electricity used is therefore generally that of CCGT, except at times of renewable curtailment, when renewables become the marginal generation, and the carbon intensity used is zero.

Marginal generation will therefore be predominantly CCGT and wind, with the proportion of wind increasing dramatically in the 2020-2030 timeframe. Combined with this, decreasing electrolyser capex will result in electrolysers operating at lower load factors, and avoiding operation at times when prices are higher and CCGT is the marginal generation.

Note: BEIS EEP only extends to 2040, so has been linearly interpolated to equal the FES 2020 steady progression at 2050

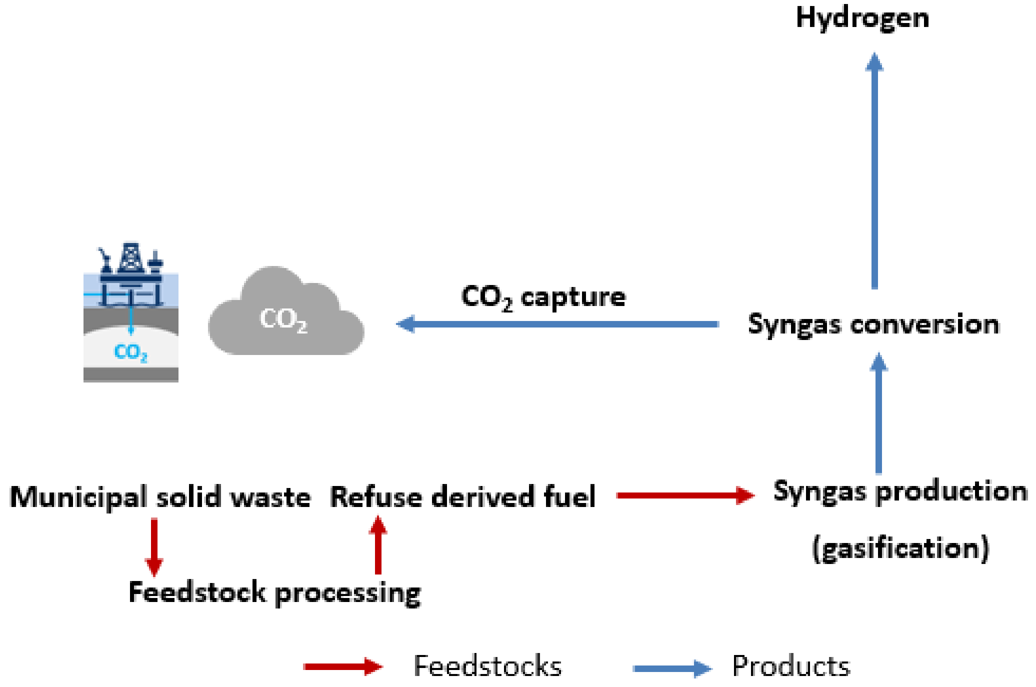
Source graph: BEIS, 2020, Updated Energy and Emissions Projections. National Grid, 2020, Future Energy Scenarios. PPA: Power Purchase Agreement, (1) BEIS – Valuation of energy use and greenhouse gas – 2019 , (2), Thomson, Harrison and Chick - Marginal Greenhouse Gas Emissions Displacement of Wind Power in Great Britain – 2017 (3) Electricityinfo.org - real-time-fuel-mix-and-carbon-intensity-methodology, Houses of Parliament - Carbon footprint of electricity generation – 2011, (4) BEIS - Consultation On The Early Phase Out Of Unabated Coal Generation In Great Britain – 2021, (5) NG ESO – FES modelling methods 2020

Contents

Gasification produces hydrogen from municipal solid waste

- Hydrogen can be produced from municipal solid waste by gasification, as shown on the right. The municipal solid waste (MSW) is processed to form refuse derived fuel (RDF). The RDF is then gasified in a fluid bed to form syngas, composed primarily of carbon monoxide and hydrogen. In a subsequent step, syngas conversion, the CO is reacted with steam (water-gas shift) to form hydrogen and carbon dioxide.
- A feasibility study by Progressive Energy, **Advanced Plasma Power/ABSL** and Cadent provided a design for a plant[1] with a production capacity of **1.9 tonnes per day** of fuel cell grade hydrogen, alongside **37.2 tonnes per day** of grid quality hydrogen for heating applications, using **322 tonnes per day** of refuse derived feedstock. The plants will make use of CO_2 sequestration pipeline networks in industrial clusters.
- **Kew technologies** are developing a gasification technology that will initially be commercialised[2] at the Clyndach Nickel refinery, producing around **3 tonnes per day of hydrogen from 38 tonnes per day of RDF**. More details on the Kew technology may be found in the appendix.
  - The ABSL design produces highly concentrated CO_2 streams that can be captured with almost **100% capture rate** using carbonate-based solution and Benfield stripper. The Kew technology, by contrast, achieves **lower capture rates** and uses amine based capture technology.
  - The ABSL design uses electrical arcing to produce free radicals to catalyse the syngas conversion, allowing it to be achieved at lower temperatures than the Kew design.
- An overview of the hydrogen production via waste gasification has not yet been used commercially at scale, so data availability is low.
- This study focuses on the ABSL technology, as it is at a larger scale than the Kew technology.

Highly simplified diagram of hydrogen production by gasification of municipal solid waste



Source: (1) Progessive Energy Ltd, Advanced Plasma Power Ltd, Cadent - Biohydrogen production - 2017, (2) Kew Projects - KEW H2: ZERO-CARBON BULK SUPPLY – 2019, (3) Linde

Small amounts of electricity are used by the ABSL gasification plant, with most of the energy being provided by the waste feedstock

- **Hydrogen production from refuse derived fuel (RDF)** is considered in the model and report. Based on industry stakeholder engagement, this is expected to be the dominant feedstock, since using it creates a revenue stream of £80/tonne used, as opposed to a cost of £30/tonne if biomass was to be used instead.
- **We focus on gasification with CCS as a baseline.** The current consensus across stakeholders is that it only makes sense to produce hydrogen by gasification in combination with CCS, since without CCS the hydrogen production is inferior to methane production by gasification from both an environmental and economic point of view.
- Small contributions to plant energy use arise from **on-site oxygen production**, **refuse derived fuel production**, **embedded emissions of chemicals**, **feedstock transport**, **syngas compression**, **arcing and carbon dioxide compression**.
- High, medium and low scenarios are constructed by varying the capture rate, as this dominates the emissions. Capture rates of 100%, 97% and 90% are used as low, central and high **emission** scenarios, as confirmed by stakeholder engagement.
- Negative emissions are credited to the biogenic fraction of MSW only as the baseline case, while emissions from the fossil fraction are ignored. MSW is assumed to be 65% biogenic by energy.

Plant electrical energy uses, kWhe/kg hydrogen produced[2]	2030/2035
Energy for electrical discharge (arcing)	1.6
Syngas compression	1.6
Miscellaneous electricity use	1.6
Oxygen production by vacuum pressure swing adsorption	2.7

	2030/2035
Gasification output pressure/bar	11

Emissions from production and transport of feedstocks	2030/2035
MSW-RDF conversion facility, electrical energy use kWhe/kg RDF produced[1]	0.16
Mass of RDF/mass of hydrogen produced[2]	8.2
Feedstock transport, kg CO_2e/kg RDF transported	0.0035
Embedded emissions of chemicals used, gCO_2e/MJ H_2 LHV produced[2]	1.1

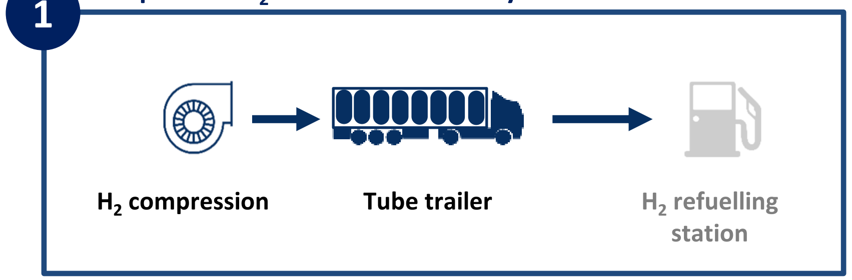
Carbon capture, 2030/2035	Low	Central	High
Carbon capture, gCO_2e/MJ H_2 LHV produced[2]	-79	-77	-71
CO_2 compression, kWhe/kg hydrogen produced		1.1	

Source: (1) E4Tech - Solid and Gaseous Biomass Carbon Calculator (2) Progressive Energy Ltd, Advanced Plasma Power Ltd, Cadent - Biohydrogen production – 2017, (3) Kew Projects - KEW H2: ZERO-CARBON BULK SUPPLY – 2019 (4) ABSL stakeholder engagement.

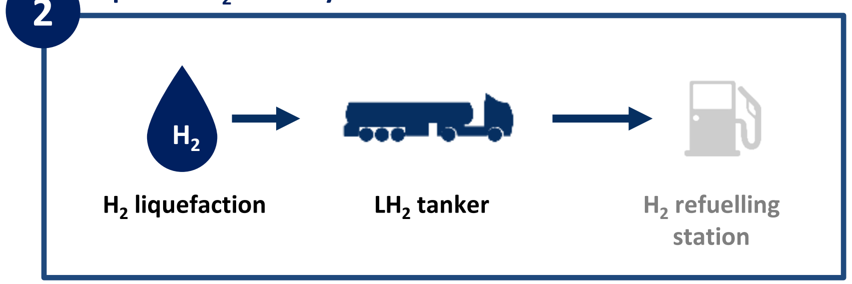
Contents

Three distribution pathways were investigated, including energy use and fugitive emissions

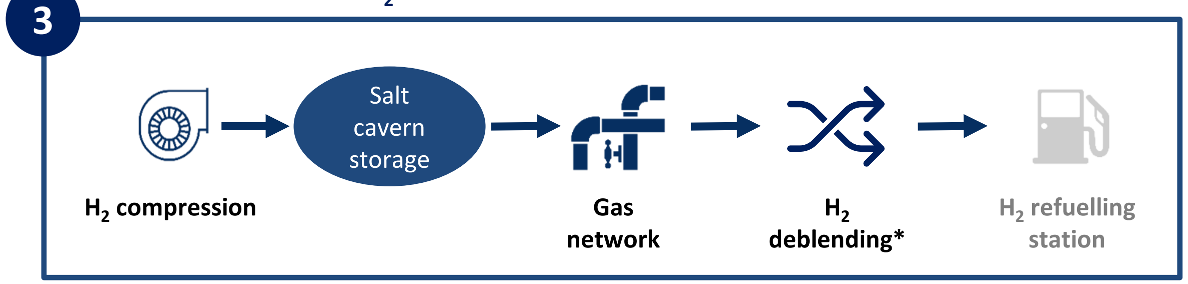
Compressed H_2 tube trailer delivery



Liquefied H_2 delivery



Gas network delivered H_2



* Deblending may not be required in the longer term if the gas network is converted to 100% hydrogen

Emissions drivers considered in the modelling:

On-site production and dispensing:

- No distribution is required, but there are energy requirements for compression and cooling for dispensing in addition to production.

1 & 2: H_2 delivery via truck

- **Emissions associated with fuel use from transporting hydrogen,** depending on travel distance, mass of hydrogen transported, and truck fuel consumption (Euro 6).
- **Compression** from H_2 production to pressure requirements for distribution, storage and dispensing.
- **Liquefaction** for transport in liquid hydrogen truck – very large electrical energy use

3: Gas network delivered H_2

- **Deblending and purification**: depending on the pathway, the hydrogen will need to be deblended and/or purified up to five-9 standard. This process requires energy use through the compression steps involved, using electricity/hydrogen/NG-hydrogen blend
- **Fugitive emissions** from pipeline leakage, boil-off during LH_2 storage and transport, losses during dispensing and delivery. Fugitive emissions increase emissions both indirectly by increasing the energy requirement per kg of hydrogen dispensed and directly through the global warming potential of the emitted gas. This is small for hydrogen emission, and much larger for a 20% hydrogen-natural gas blend.
- Salt caverns storage was not explicitly included in the model, as the energy use associated with it was found to be negligible - more details may be found here.

Contents

Overview of road transport options for hydrogen

Hydrogen can be transported in **compressed gas** form in a **tube trailer**, or in **liquid** form in a truck

- Liquefaction of hydrogen is highly energy intensive but increases the mass of hydrogen that can be transported in a truck, reducing the number of trucks required. Liquid hydrogen transport is therefore suited economically to large transport distances. Industry agrees that, owing to the short distances involved, **compressed hydrogen trucks are expected to continue to dominate the UK market**.
- **BOC tube trailers** (shown on the right) transport **350 kg** of compressed hydrogen at **280 bar**, which optimises the economics of the transport. Engagement with BOC suggested that in future, pressures of **500 bar** and capacities of **900-1,000 kg** may become more common.
- **Liquid hydrogen trucks** typically transport around **3,000 – 4,000 kg.**

Fugitive emissions

- A representative from BOC reported that product loss during hydrogen delivery for compressed gas and liquid hydrogen is typically around 1%.
- Boil off is typically 0.3-0.6% per day for liquid hydrogen trucks. Liquid hydrogen supply chain fugitive emissions are dominated by losses once the hydrogen is at the HRS, as discussed on this slide.

Hydrogen tube trailer, 350 kg capacity

Liquid hydrogen transport

Low, medium and high values for tube trailer (left) and liquid hydrogen (right) delivered by truck, kg hydrogen/trip[1,2]

	All years
Low	300
Central	350
High	1000

	All years
Low	3000
Central	3500
High	4000

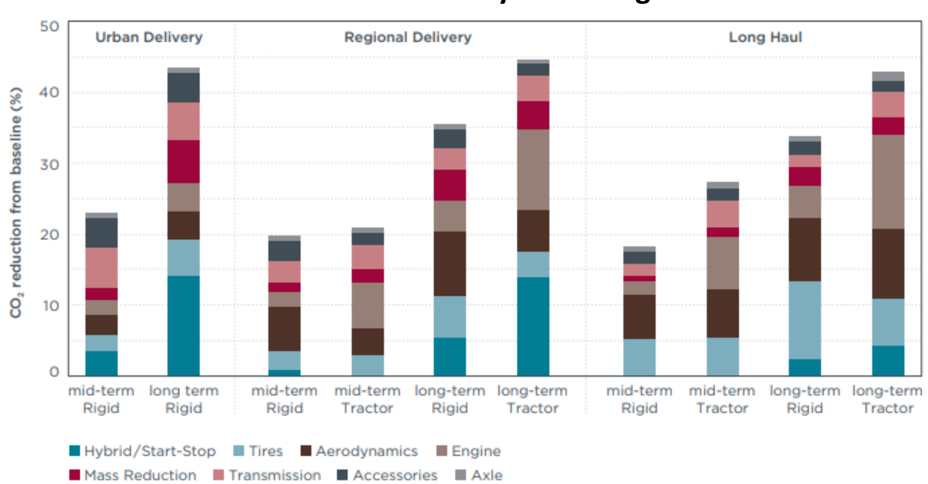
Fugitive emissions associated with hydrogen delivery	Low	Medium	High
LH_2 Time for which liquid hydrogen is in truck/days	0.5	0.5	0.5
LH_2 Diesel truck, boil-off per day[1]	0.3%	0.45%	0.6%
LH_2 Product loss during delivery to HRS[6]	0.2%	0.2%	0.2%
LH_2 Product loss during filling truck[6]	0	0	0
CH_2 Product loss during delivery to HRS	0.5%[3]	0.75%	1%[2]
CH_2 Product loss during filling truck[5]	0.5%[4]	0.75%[4]	1%[4]
CH_2 total losses	1%	1.5%	2%
LH_2 total losses	0.3%	0.4%	0.5%

Sources: (1) IChemE – Hydrogen The Future Fuel – 2020; (2) BOC (3) Balcombe, Speirs - CH4 Greenhouse gas emissions associated with purification; (4) Assumed that product loss during filling of truck and product loss during delivery are the same , (5) Values given are for gas and are assumed to be the same for liquid (large uncertainty), (6) Petitpas - Boil-off losses along the LH2 pathway - 2018

Diesel truck fuel consumption assumptions

- The fuel consumption figures used are based on detailed work by the ICCT which identified that fuel consumption could be reduced in HGVs by 20-40% by 2030[1]
- The ambitious improvements in diesel fuel consumption set out in the Low, Central and High cases considered for this project are the same values that have been used by Element Energy for extensive modelling work carried out for DfT and the CCC
- While ambitious, in terms of lowering the contribution to H_2 WTT emissions in this case, these are the preferred values for both DfT and the CCC because they represent a conservative counterfactual for diesel vehicles compared to low and zero-emission options from a total cost of ownership perspective
- We therefore apply these values for fuel consumption in this project for consistency with current government modelling

Potential fuel consumption reduction from selected rigid truck and tractor-trailer efficiency technologies 2020–2030[1]



Diesel truck fuel consumption, L/100km[2]

	2020/1	2030	2035+
Low	30.4	23.7	23.7
Central	33.5	26.0	26.0
High	39.6	30.8	30.8

Round trip distances have been updated (all years, km)

	All years
Low	100
Central	200
High	350

Sources: (1) ICCT, 2017, Fuel Efficiency Technology in European Heavy-Duty Vehicles: Baseline and Potential for the 2020–2030 Time Frame (2) Element Energy for CCC - Analysis to provide costs, efficiencies and roll-out trajectories for zero emission HGVs, buses and coaches -2020;

Assumptions: conversion factors are used for diesel and biodiesel WTW emissions

- BEIS greenhouse gas conversion factors for company reporting were used for the diesel and biodiesel WTW emissions, and confirmed that 2020 forecourt diesel was 6% biodiesel by volume.

Variable	Unit	Year			Literature
		2020/1	2030	2035	
Biodiesel Well to Wheel Emissions	$kgCO_2e/L$	0.166	0.166	0.166	UK Government 2020 GHG conversion factors for company reporting
Diesel Well to Wheel Emissions	$kgCO_2e/L$	2.688	2.688	2.688	UK Government 2020 GHG conversion factors for company reporting
Share of Biodiesel	%	6%	8%	8%	RTFO Renewable Fuel Statistics 2019
Resulting Diesel Well to Wheel Emissions for above inputs	$kgCO_2e/L$	2.54	2.49	2.49	*Calculated based on UK Gov factor and assumed mix of biodiesel*

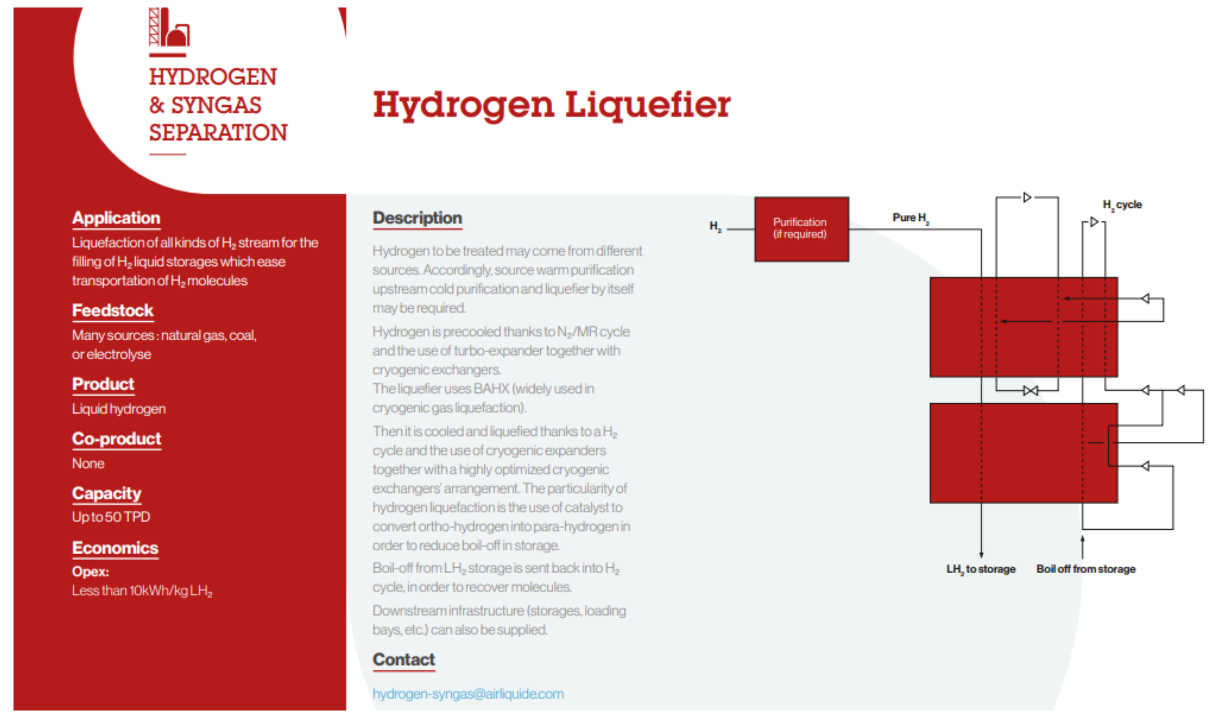
UK Gov, Greenhouse gas reporting: conversion factors 2020, https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2020

Contents

Hydrogen is liquefied to increase its energy density for storage and transport

- Liquefaction of hydrogen is necessary in order to increase its energy density for storage and transportation by truck. This is important for larger HRS than would otherwise require many tube trailer deliveries per day.
- Data from both Linde[1] and Air Liquide[2] show liquefaction energy use as 10 kWh/kg for **modern** plants. This figure has also been confirmed in discussion with BOC.
- Since hydrogen is not currently liquefied in the UK, future plants will be newbuilds using modern technology.
- Current plants have capacities of 50 tonnes per day but future plants are likely to have capacities of around 100 tonnes per day.

Air Liquide hydrogen liquefier[2]


HYDROGEN & SYNGAS SEPARATION

Hydrogen Liquefier

Application
Liquefaction of all kinds of H_2 stream for the filling of H_2 liquid storages which ease transportation of H_2 molecules

Feedstock
Many sources : natural gas, coal, or electrolyse

Product
Liquid hydrogen

Co-product
None

Capacity
Up to 50 TPD

Economics
Opex:
Less than 10kWh/kg LH_2

Description

Hydrogen to be treated may come from different sources. Accordingly, source warm purification upstream cold purification and liquefier by itself may be required.

Hydrogen is precooled thanks to N_2/MR cycle and the use of turbo-expander together with cryogenic exchangers.
The liquefier uses BAHX (widely used in cryogenic gas liquefaction).

Then it is cooled and liquefied thanks to a H_2 cycle and the use of cryogenic expanders together with a highly optimized cryogenic exchangers' arrangement. The particularity of hydrogen liquefaction is the use of catalyst to convert ortho-hydrogen into para-hydrogen in order to reduce boil-off in storage.

Boil-off from LH_2 storage is sent back into H_2 cycle, in order to recover molecules.

Downstream infrastructure (storages, loading bays, etc.) can also be supplied.

Contact
hydrogen-syngas@airliquide.com

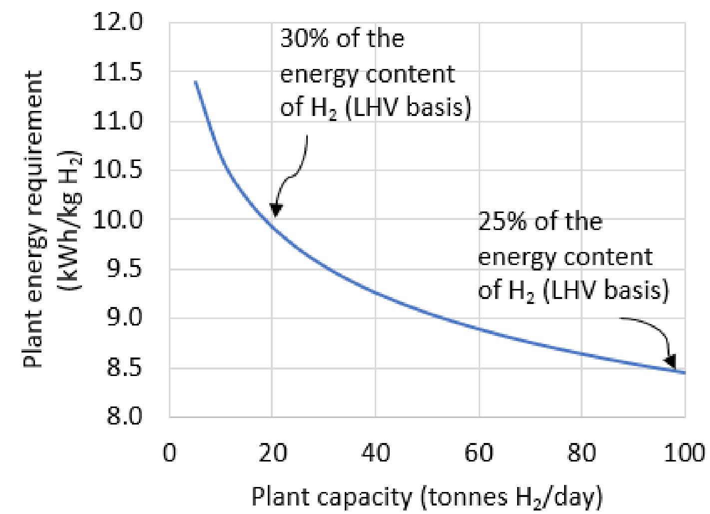
Liquefaction energy consumption (kWhe/kg H_2), assuming 50 tonnes per day – 100 tones per day (equivalent to around 15-30 LH_2 delivery truck fillings per day) and 100% load point

	Low	Central	High
All years	8.5	10	13

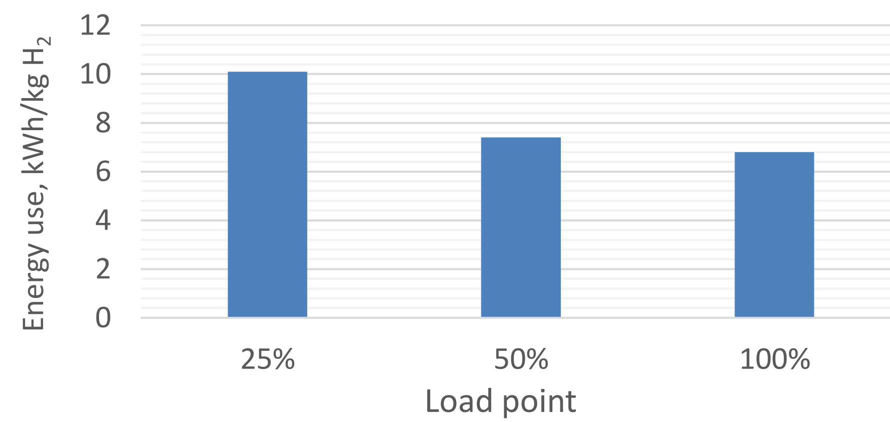
Liquefaction is susceptible to economies of scale, which impact the energy use

- Liquefaction is susceptible to two economies of scale which impact the energy use:
  - **Large plants are more efficient**: a 50 tonnes per day plant might consume 9 kWh/kg, while the corresponding figure for a 5 tpd plant is around 11.5 kWh/kg (top diagram)
  - Energy use in the IdealHY project was **strongly influenced by load point** (lower diagram)
- Plants with capacities greater than 50 tonnes per day are more complex to build and must be serving very large sources of hydrogen demand
- Optimisation of plants to achieve higher efficiencies results in increased capex, creating a trade off .
- We assume in the Central scenario that the liquefaction plants are run at close to 100% load, as this would be the most favourable economically
- We assume a 50-100 tonne per day plant, noting that larger plant sizes are favoured economically.
- Other liquefaction technologies – particularly magnetic regenerative cooling – do exist but are disregarded on account of their low TRL. For this reason, they are not considered in this study.

Plant size dependence of liquefaction energy use[1]



Dependence of energy use on load point

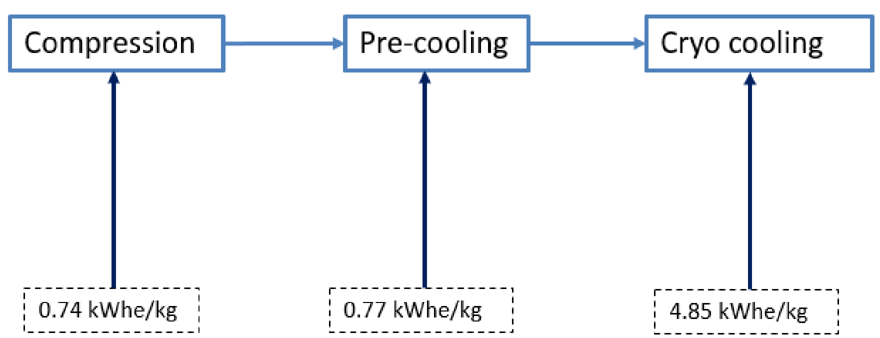


Further improvements in liquefaction are expected, reducing the energy use to around 7 kWh/kg hydrogen

Potential for optimisation

- The IdealHY project commissioned by the Hydrogen and Fuel Cells Joint Undertaking was aimed at identifying innovations to reduce the energy use of hydrogen liquefaction plants and quantify the effect of these innovations on the plant energy use.
- The project produced a design for a 50 tpd liquefaction plant with – in principle - lower energy use, based an optimisation study of each stage of the liquefaction process. This suggested that the energy use for a 50 tpd plant could be reduced to **6.8 kWhe/kg** hydrogen. The main sources of energy use are compression, pre-cooling and cryo-cooling, which together make up **6.36 kWhe/kg** as shown in the diagram on the right. There are small additional contributions from balance of plant energy uses, bring the total energy use to **6.8 kWhe/kg**. This is equivalent to around 12% of the energy currently required to produce hydrogen by electrolysis[1]. **However, this was not demonstrated in the real world and is not included in the modelling in this project.**
- Liquefaction can be broadly broken down into four steps:
  - **compression** of hydrogen gas to approximately **80 bar**,
  - **pre-cooling** to **130 K** using mixed (liquid nitrogen and liquid methane/ethane/propane/butane) refrigerant heat exchangers
  - **cryo cooling** down to **27 K**.
  - a final **80 bar – 2 bar expansion step**, requiring very small amounts of energy (approximately 0.05 kWh/kg hydrogen) is used to **liquefy** the gas.
- The most energy intensive step by far is **cryo cooling**. This step uses large amounts of mechanical compressional work to drive heat flow out of the hydrogen to the surroundings. In the IdealHY demonstration project this accounted for around three quarters of the energy use at full load, as shown in the diagram.

Main energy uses in the FCH JU IdealHY energy use breakdown for liquefaction, excluding small auxiliary balance of plant energy uses



Sources: FCH JU - Integrated Design for Demonstration of Efficient Liquefaction of Hydrogen – 2013, Element Energy - Gigastack Bulk Supply of Renewable Hydrogen Public Report - 2020

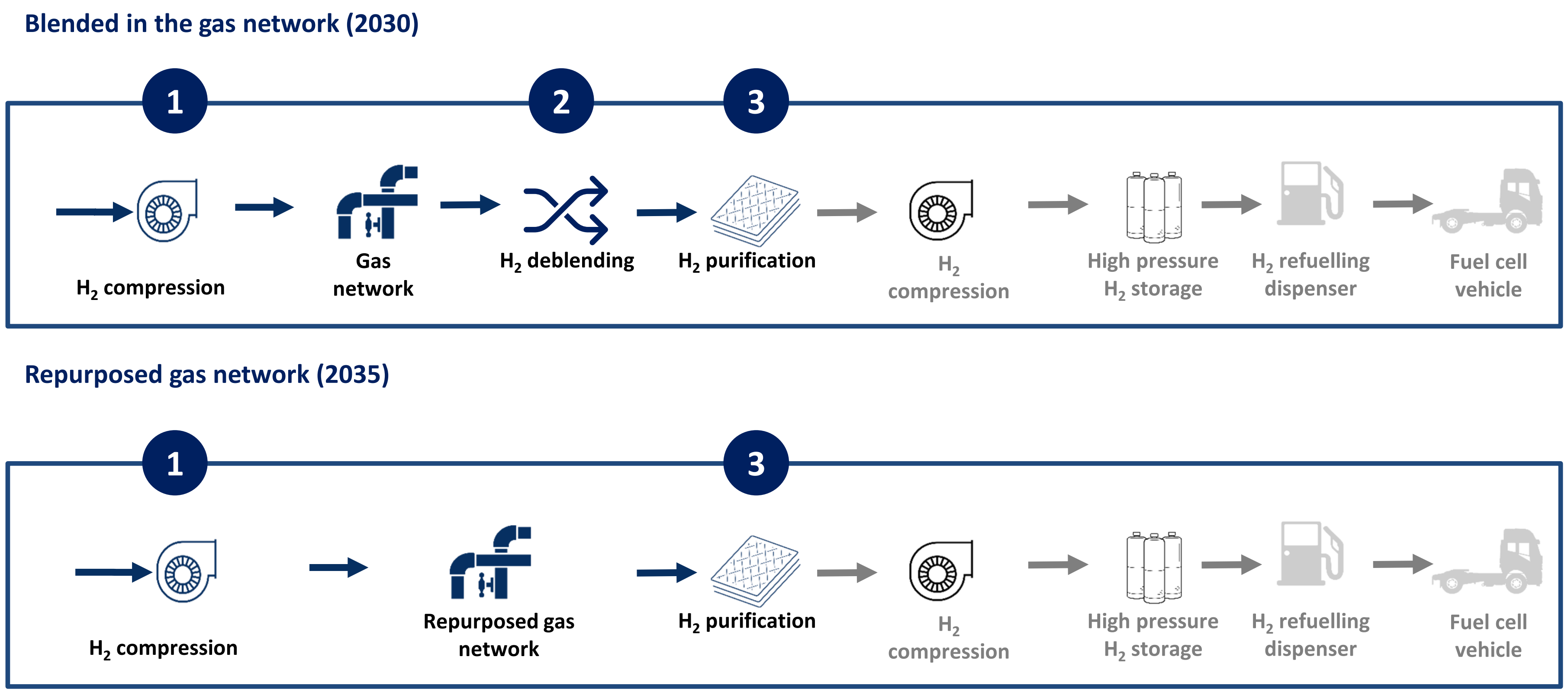
Contents

Overview of the main emission sources associated with hydrogen distribution via pipelines

There are three main energy usage steps associated with the distribution of hydrogen by pipeline:

1. Energy required for the compression and distribution of hydrogen through pipelines
2. Energy for deblending hydrogen
3. Energy for purification to automotive purity levels

Each step is also associated with fugitive emissions and are presented on the following slides



Hydrogen use in heating would require a phased repurposing of current gas infrastructure

The potential of hydrogen in the gas grid can be seen as two-fold:

In the short term, injection of low-carbon hydrogen into the NTS is being considered as a means of reducing the carbon intensity of natural gas supplies.

- For example, National Grid is already conducting work on the "Hy-NTS" project, aiming to understand the feasibility of injection of hydrogen, see roadmap:

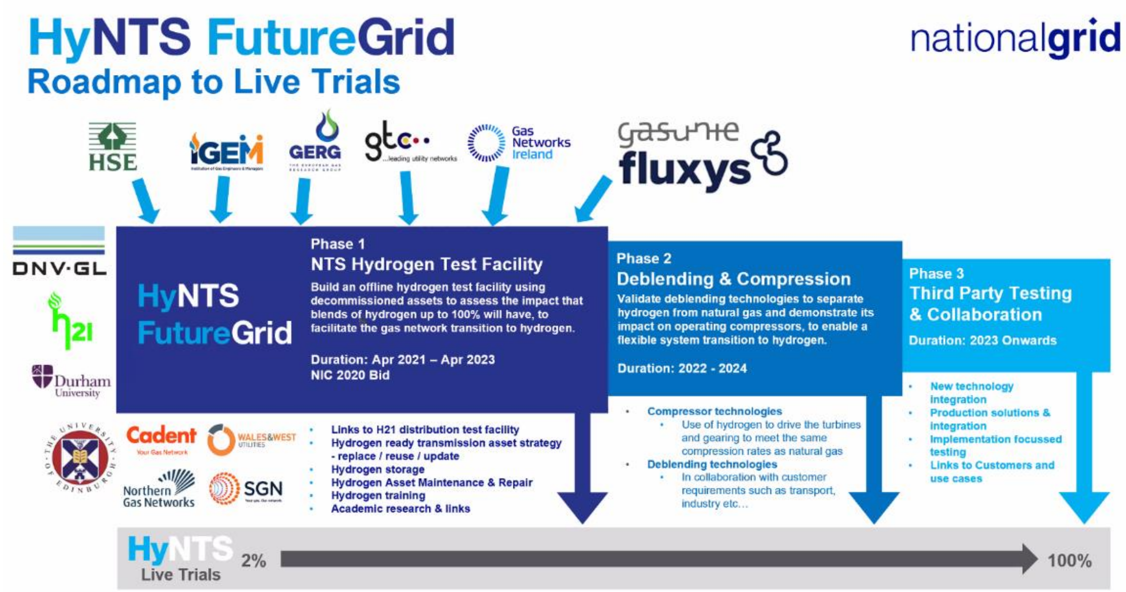
In the long term, hydrogen could be used at wide scale by domestic and commercial users once the gas grid has been converted to hydrogen, such as in the case of the **H21 North of England** project.

The Acorn Hydrogen project is looking at developing hydrogen production with CCS at St Fergus, with the aim to blend hydrogen into the NTS at 2% from 2025. Higher increase is expected in the long term, subject to additional technical and regulatory barriers being lifted.

Aberdeen Vision is a project being developed by SGN in collaboration with National Grid and Acorn Hydrogen / Pale Blue Dot Energy.

- The project will provide a case for building a hydrogen pipeline from St Fergus to Aberdeen City.
- The transition to hydrogen for Aberdeen City is expected to be phased, starting first at a 20% blend and, once operation has been proven, increasing to 100% following a conversion of the network.
- The project is aiming for a blending of 20% by 2025, with a full conversion being possible by 2030. The injection would take place at intermediate tier.

HyNTS project plan (National Grid, 2020)



Gas grid operation contributes to supply chain energy use and fugitive emissions

1

The contribution of the gas grid to energy use and fugitive emissions comprises:

- **Compression energy use prior to injection** – depending on the output pressure of the production facility, the hydrogen may need to be compressed prior to injection into the gas grid. For example, an electrolyser with a 20 bar output pressure, around 1 kWhe of energy would be used in compressing the hydrogen up to 80 bar for NTS injection. This energy is assumed to be electrical.
- **Own use of gas** - additional compressors are needed to pump gas around the grid and these currently mostly use gas from the grid. These compressors are assumed to be **hydrogen** powered, contrasting with the initial compressor which is assumed to be **electrical**. The energy requirement of the hydrogen own use gas is the energy required to produce that hydrogen and therefore depends on the production method – this effect is included in the model. A detailed discussion of own use gas in an all-hydrogen gas grid may be found on this slide, and a discussion of own use gas in blends on this slide.
- **Leakage** – National Grid data reports transmission level leakage is 0.1-0.2%; while distribution level leakages are currently 0.4-0.5%, as confirmed by Cadent. The approach taken to modelling gas grid leakage is discussed in detail on this slide.

Methane emissions are not attributed to the hydrogen transport as this is double counting.

An own use of hydrogen of 1% would be accounted for by multiplying all upstream emissions and energy uses (primarily production) by 1/0.99, in the same way as for leakage. For leakage, an additional small contribution arises due to global warming potential of hydrogen.

Own use of gas and leakage from gas grids makes only a very small contribution to supply chain energy use and emissions in all of the scenarios considered.

In addition to being delivered by the gas grid, hydrogen may be delivered by a short purpose-built pipeline from a production facility (similar to the trunk and spur pipelines in the HyNet project[2]), for which own use gas and leakage will be lower owing to the shorter pipeline distances involved. These pipelines may also operate below NTS pressures, leading to a slightly lower initial compression energy requirement.

Assumptions for hydrogen gas grid energy use

	Low	Medium	High
Own use of gas, %	0.5	0.75	1

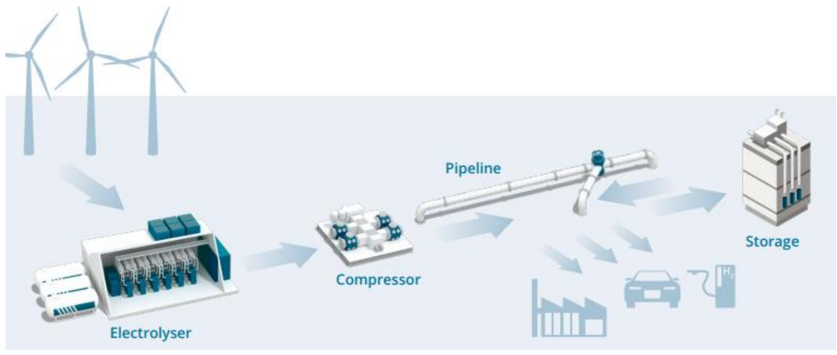
Source: (1) NG - Forecast NTS Shrinkage Factor 201819 – 2018 (2) Cadent – HyNet North West: from vision to reality – 2018

In an all-hydrogen gas grid, Own use of gas will be 4-5 times higher than in the natural gas based grid

1

- National Grid **OUG** is currently 0.1-0.2%
- Energy use in the all-hydrogen gas grid will differ from that in the natural gas grid for the following reasons:
  - The **volumetric energy density** is around three times lower for hydrogen, so a **flow rate three times larger** is required to achieve the same energy flow;
  - The **viscosity and density of hydrogen** are lower than for methane – for turbulent flow, both are relevant
  - Transmission pipes may be sized differently (larger diameters), reducing flow resistance
- Calculations by Siemens[2] have shown that **83%** of the **energy flow** can be achieved with the same **pressure drop** when comparing hydrogen to methane for a 100 km, 1m diameter pipeline. This suggests that pressures and pipeline sizes for hydrogen will be similar to the current natural gas based grid.
  - However, the flow rate is just over three times larger, so three times as much gas must be compressed. The energy required for the pipeline transport will be approximately 1/(0.31x0.83) = 3.9 times higher than for methane.
  - Additionally, three times as much hydrogen will be needed by compressors for the same energy use because of the lower calorific value; however the hydrogen flow rate is three times higher, so no additional correction factor is needed to determine OUG.
  - This therefore suggests that **OUG will be 3.9 times higher for hydrogen than for methane.** Bossel and Eliasson[3] suggest that OUG will be 4.6 times higher for hydrogen than for methane. This brings OUG up to **0.5-0.9%.**
  - **This has been confirmed in discussion with an expert at DNV**
- As confirmed by discussion with Cadent, we assume there will be no major pressure differences between the current gas network and the fully hydrogen gas grid:
  - Polythene pipes at the distribution level have negligible leakage for both hydrogen and methane, as confirmed by Cadent.
  - For iron mains at the LTS/NTS level, leakages may be higher than the current 0.2%

Gas grid infrastructure[2]



(1) Element Energy – Hydrogen Supply Chain Evidence Base – 2018, (2) Siemens Energy - Hydrogen infrastructure – the pillar of energy transition The practical conversion of long-distance gas networks to hydrogen operation – 2020 (3) Bossel and Eliasson – Energy and the Hydrogen Economy, NG - Forecast NTS Shrinkage Factor 201819 – 2018, NG- Shrinkage Incentive Methodology Statement Review – 2016 (4) Mejia et al - Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure - 2020

With a 20% hydrogen blend, some methane OUG is attributable to hydrogen transport in addition to hydrogen OUG – the hydrogen transport therefore requires both methane and hydrogen combustion

1

- **The gas grid (compressors, pipes, pressures) will be virtually unchanged with a 20% hydrogen blend (the situation of course changes moving to a 100% hydrogen gas grid)**
- **Hydrogen** has a viscosity of around 80% of that of methane. This is a minor difference for a 20% blend. For the purposes of estimating the OUG we therefore assume that the blend viscosity is the same as the methane viscosity.
- **Hydrogen has a molar calorific value of one-third that of methane**. The energy density (molar or volumetric) of a 20% hydrogen in methane blend will therefore be 80x1 + 20x(1/3) = 87% of that of the 100% methane scenario. Flow rates therefore need to be correspondingly higher, but this is partly compensated for by the slightly lower viscosity. There will be a small, unimportant increase in the energy requirement per kg of hydrogen transported as a result of this effect.
- National Grid data[1] suggests that **OUG** is 0.1-0.2% for the current gas grid. Because of the lower calorific value of hydrogen, this will be 1/0.87 times higher with the blend, so if originally 0.2%, OUG will become 0.2/0.87 = 0.23% for the blend.
- Therefore, for every mole of blend transported (0.2 mol H2 and 0.8 mol methane), 0.23% of this, i.e. 0.00184 mol methane and 0.00046 mole hydrogen are used for transporting the blend. However, for transporting 0.8 mol methane in an all methane has grid, 0.2% of 0.8 or 0.0016 mole of methane would have been used. Transporting 0.2 mole of hydrogen has therefore used 0.00184-0.0016 = 0.00024 mol methane as well as 0.00046 mole hydrogen. **Therefore transporting 1 mole of hydrogen requires 0.0012 mol methane and 0.0023 mol hydrogen OUG, i.e. 0.23% of the hydrogen + roughly half that amount of methane to compensate for the lower molar calorific value of hydrogen. Very small emissions corresponding to the combustion and upstream emissions of this methane are included in the model.**

HyDeploy hydrogen gas grid injection into a low pressure network[5]

Source: (1) NG - Forecast NTS Shrinkage Factor 201819 – 2018, NG- Shrinkage Incentive Methodology Statement Review – 2016, (2) Element Energy – Hydrogen supply chain evidence base – 2018, (3) Wales & West Utilities Ltd LDZ Shrinkage and Leakage Report – 2020, (4) Wales and West Utilities – Our business plan for 2021-2026 -2019 (5) https://www.itm-power.com/news/hydeploy-uk-gas-grid-injection-of-hydrogen-in-full-operation

Hydrogen leakage from pipelines is an active research area

1

- A recent experimental paper by Mejia et al[1] concluded that in low pressure gas networks operating just above atmospheric pressure, hydrogen leakage is similar to methane leakage. For example, transmission level leakage figures are assumed to remain at their current 0.1-0.2%.
  - Discussion with Cadent revealed that the gas-tight polythene pipes that are replacing steel pipes in the distribution network do not leak either hydrogen or methane. It was also noted that gas leakage from transmission pipelines currently only occurs during maintenance.
  - Discussions with Imperial College revealed that gas leakage is currently very poorly covered in the literature and that it will be necessary to make a fairly sweeping assumption.
  - The overall qualitative consensus is that leakage can be higher for pipelines with hydrogen, but that this is being offset by the replacement of steel pipes with polythene pipes.
  - As a result, this study assumed that leakage values are similar to natural gas and making the uncertainty around this clear in the report.
  - Whilst there is significant uncertainty, hydrogen leaks are very small, likely < 1 % based on data from the current gas grid presented earlier.
- Stakeholder engagement with Cadent revealed that:
  - distribution level leakage is between 0.37% and 0.51% today;
  - approximately 80% of this is from mains pipelines;
  - leakage from mains pipelines is reduced almost to zero (by 99%) when iron pipes are replaced with polythene pipes.
- We model the distribution level leakage by taking 0.37% and 0.51% as low and high values for today, and then assuming that the 80% of this due to mains leakage is eliminated by 2050 to make the 2050 figures 20% of the 2020 figures.

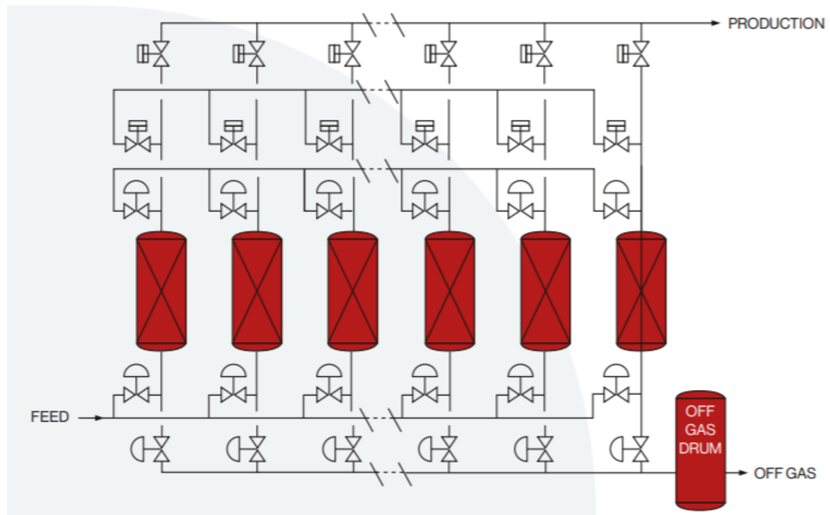
(1) Mejia et al - Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure – 2020 (2) Siemens Energy - Hydrogen infrastructure – the pillar of energy transition The practical conversion of long-distance gas networks to hydrogen operation – 2020

Hydrogen distribution by gas grid will initially require deblending

2

- Blending is a method of gradually transferring the gas grid over from natural gas to hydrogen, by initially mixing small proportions of hydrogen into the natural gas. The proportion of hydrogen mixed in is referred to as the blending ratio. A blending ratio of a 20% vol blend in 2030 and a 100% blend in 2035 is assumed in this work.
- To use the hydrogen, it must be separated from natural gas, a process known as deblending, which requires energy. Deblending involves separating the hydrogen and natural gas at a transmission system offtake, allowing the hydrogen and natural gas to be distributed separately in separate local distribution pipes.
  - As confirmed by engagement with Cadent, deblending is expected to be performed at offtakes from the high pressure national or local transmission systems. Selected local gas distribution systems will then be fully hydrogen (approximately 98% purity), fed by hydrogen deblended from the transmission system. Gas grid connected hydrogen refuelling stations are modelled as being connected to a medium pressure (2 barg) local distribution pipeline, containing 98% pure hydrogen. In 2030 this is supplied by a deblending plant located at a transmission system offtake, while in 2035 the whole gas grid is assumed to operate on hydrogen.
  - Deblending plants could also produce hydrogen at high purity for transport by tube trailer a short distance from the deblending plant to the hydrogen refuelling station. This option is not included in the model, but would result in relatively high emissions, since it would combine the emissions from deblending and tube trailer transport.
  - Deblending can be done using a combination of a hydrogen-selective membrane and a pressure swing adsorption (PSA) purification process.
  - During deblending, only around 60% of the hydrogen is recovered from the blend. The hydrogen that is not recovered is re-injected into the gas grid along with the natural gas. This hydrogen is then used (for example) to partially decarbonise heating. The unrecovered hydrogen is assumed to be used elsewhere and therefore the recovery rate has no impact on the modelled supply chain emissions.
  - A detailed description of deblending and the energy consumptions involved may be found on the following slide.

Diagram of a pressure swing adsorption plant, showing feed gas, purified hydrogen (production) and residue (off gas).
Source: Air Liquide



Source: Costain - HYDROGEN DEBLENDING IN THE GB NETWORK FEASIBILITY STUDY – 2020; Air Liquide – Technology Handbook - 2020

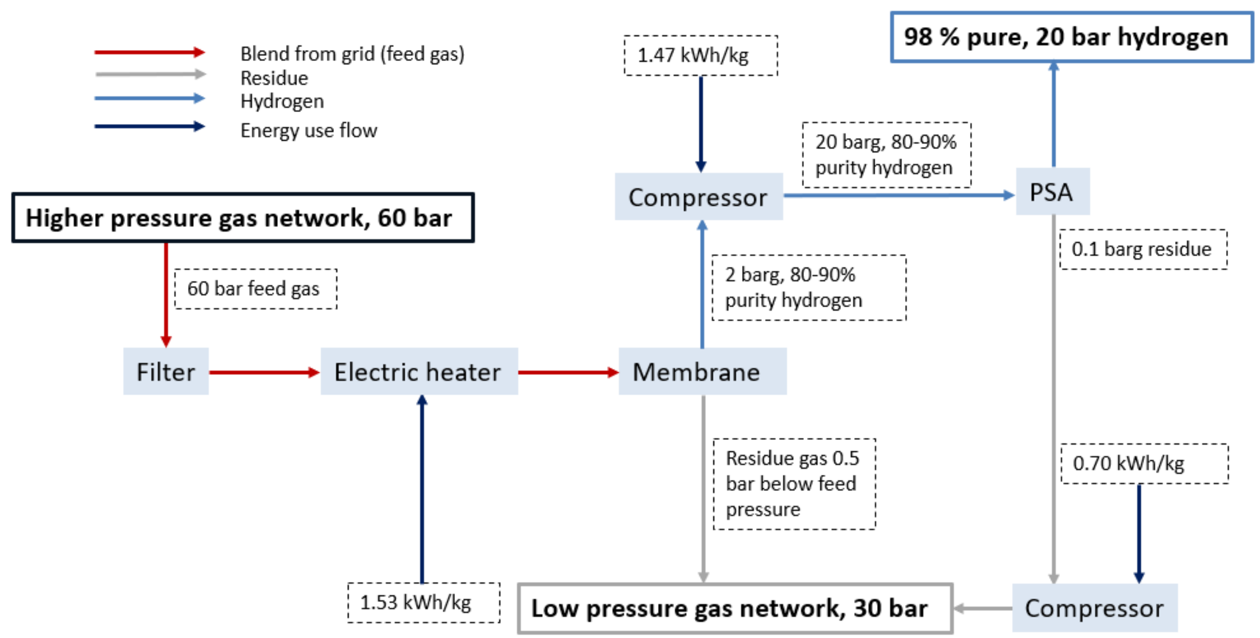
Deblending requires energy for compression and heating

2

The deblending process is shown in the diagram and requires a membrane which separates the bulk of the hydrogen from the Natural Gas. The process is as follows:

- A mix of natural gas and hydrogen at high pressure is heated (to improve membrane performance) before being fed into the membrane. Hydrogen is separated and released at 2 bar on the other side of the membrane. Some **energy is therefore used from the pressure drop** at the NTS offtake/LTS PRI to drive the deblending, and an industry stakeholder has confirmed that this **would otherwise have been wasted.**
- The natural gas mostly does not pass through the membrane and remains close to the feed pressure, allowing direct injection into the natural gas-fed section of the local distribution network.
- The hydrogen is then be compressed to 20 bar for further purification by pressure swing adsorption, before passing into the hydrogen-fed section of the local distribution network.
- Stakeholder engagement with Linde (a world leader in deblending technology) revealed that it will probably be possible to reduce deblending energy use to below the figures from the Costain report used here. The energy use and configuration of deblending plants should therefore be reviewed once these are deployed in the real world.

Deblending and purification to 98 %



All energy uses are per kg of pure hydrogen produced and refer to NTS offtake with 60 bar inlet/30 bar outlet

Table 1: detailed assumptions for deblending/purification energy use and hydrogen recovery; all per kg of hydrogen produced [1,2]	**Energy use for feed gas heating for membrane, kWh/kg [1]**	**Energy use for compression for PSA, kWh/kg [1]**	**Energy use for residue gas compression, kWh/kg [1]**	**Hydrogen recovery for separation followed by purification to 98% [1]**	**Hydrogen recovery for 98-99.999% purification[2]**
Low: **30 bar to 2 bar LTS PRI**	1.4	1.6	0	66%	90%
Medium: **60 bar NTS outlet, 7 bar LTS inlet**	1.5	1.5	0	66%	90%
High: **60 bar NTS outlet, 30 bar LTS inlet**	1.5	1.5	0.7	66%	90%

Source: (1) Costain - HYDROGEN DEBLENDING IN THE GB NETWORK FEASIBILITY STUDY – 2020; NTS: National Transmission System; LTS: Local Transmission System; PRI: Pressure Reduction Installation

Gas grid connected HRS will require on-site purification

3

- The dominant purification technology today capable of reaching 99.999% purity is pressure swing adsorption (PSA).
- PSA separation broadly consists of two key steps:
  – **Adsorption:** high pressure feed gas passes over the adsorption beds, moving upwards through the column. Impurities are adsorbed, reaching equilibrium with the gas as it passes up the column. Purified hydrogen emerges at the top of the column. Feed gas pressures of 10-40 bar are used to give sufficiently high partial pressure of impurities to drive their adsorption.
  – **Regeneration:** the pressure is released to just over 1 bar (absolute) to allow desorption of impurities, which form the tail gas/residue gas/off gas. Pressure is lowered at the bottom of the column first so that the tail gas is dumped in the opposite direction to the pure hydrogen.
- Energy is used in a PSA for compression (where needed) of the feed gas, and compression of the tail gas where needed. However, the volumes of tail gas are very small compared to the volumes of feed gas, so the compressional energy requirement for tail gas compression is negligible compared to that for feed gas compression.
- **Purification steps (excluding deblending) have negligible impact on the well-to-tank emissions, owing to the following assumptions:**
  – The purification plant is positioned at a point in the supply chain where compression would be needed anyway. Since almost all of the energy use for a PSA is associated with compression of the feed gas, this energy requirement is already included within the compression step. For instance, for an HRS supplied with a 2 barg local distribution system pipeline, compression to 20 bar is required for the PSA. However, compression to 200 bar is needed for storage in any case. The compressional energy requirement for compressing from 2 - 20 bar for the PSA followed by 20 – 200 bar for storage is almost identical to the compressional energy requirement for compressing from 2–200 bar directly. The onsite purification therefore makes a negligible contribution to HRS energy use.
  – Approximately 10% of the hydrogen is not recovered by the PSA and emerges with the impurities in the tail gas. This hydrogen is assumed to be used elsewhere – for example, the hydrogen not recovered during onsite HRS purification is re-injected into the gas grid, where it is used for domestic heating. The 10% of unrecovered hydrogen is not wasted and is treated as hydrogen originally produced for heating. The 90% recovery rate therefore does not factor into the well-to-tank emissions.
- PSA purification energy use is insensitive to the exact purity of hydrogen that is needed. SMR and ATR + GHR plants feature PSA units and the energy consumption for these is included within the plant energy consumption figures – for example, the Johnson Matthey Low Carbon Hydrogen technology used in the HyNet project produces hydrogen of 99.999% purity[1]. For gasification, hydrogen not recovered during purification to automotive grade purity is assumed to be used elsewhere, for example injected into the gas grid for heating. Electrolysers produce hydrogen at automotive grade purity. For these reasons, a post-production purification step does not need to be considered separately in the model and it not included.
- These assumptions should be reviewed once the real-world configurations of purification plants are known. If hydrogen is lost as a result of purification, emissions upstream of the purification plant will be increased to compensate for the lost hydrogen, in the same way as for fugitive emission loss compensation.

(1) Linde – Hydrogen Recovery By Pressure Swing Adsorption – 2010 (2) Progressive Energy – HyNet Low Carbon Hydrogen Plant – phase 1 report for BEIS

Electrochemical purification may reduce energy uses associated with deblending and HRS compression in future

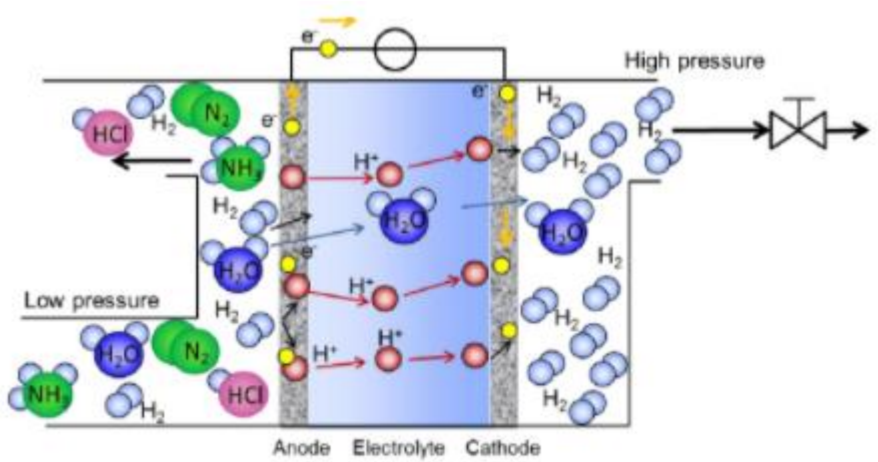
2 3

- The report and modelling focus on what is possible with existing membrane and PSA technologies.
- Electrochemical purification could allow deblending, compression to 875 bar and purification to automotive grade purity to be performed in a single step.
- This could decrease supply chain energy use. In addition, electrochemical purification could change the picture by:
  - improving the practicality of onsite purification at HRS by requiring a **much smaller footprint than a PSA plant;**
  - potentially making **deblending at an HRS feasible.**
- The technology works by selective oxidation of hydrogen – it selects the hydrogen atoms from a blend.
- However, **TRL is low**, leading to some uncertainty around future predictions – as a result, the technology is not considered in the modelling undertaken in this study

Overview of electrochemical purification

Technology	Electrochemical
Description	Hygrid[1]/MEMPHYS/HyEt projects aimed at developing electrochemical purification. Designed to purify to **99.97%** and compress to **875 bar** in a single step. Simulated **90-95%** recovery rate even with a **1-5%** blend. Design is small scale, **25 kg/day**.
Maturity	**TRL 5**, goal for 7 in next 2 years
Energy use	**3-5 kWh/kg hydrogen produced**

Electrochemical purification operation[2]



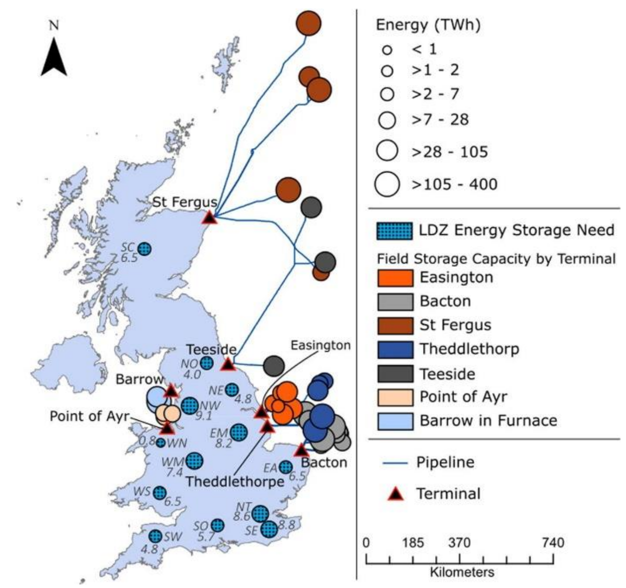
(1) HyGrid - 3rd-Public_presentation_March – 2020, (2) MEMPHYS, “A brief presentation about MEMPHYS,” no. 735533, 2018.

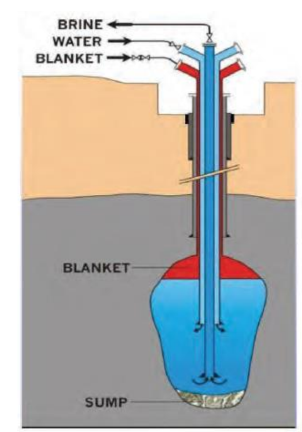
Contents

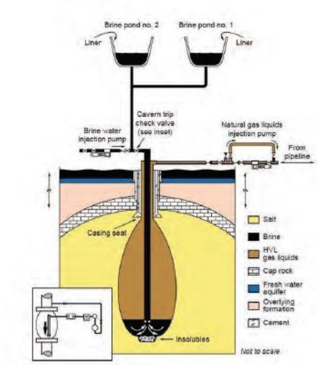
Salt caverns would be key for storing hydrogen in a scenario of a fully decarbonised gas grid, but their energy use is negligible

- Salt caverns provide seasonal grid scale storage of hydrogen and are the preferred solution for bulk hydrogen storage[1]. Current salt caverns in the UK vary in storage capacity between approximately **7,000** and **28,000 tonnes** of hydrogen. However, practical storage is limited by the finite pumping rates and the requirement for cushion gas.
- An industry stakeholder reported that the storage potential from linepack (i.e. variations in gas grid pressure varying the amount of gas stored in the pipes themselves) is much lower for hydrogen. This increases the need for other forms of storage.
- Analysis of supply and demand data from the H21 project[1] suggests that **5-10%** of the hydrogen supplied by the SMRs used will pass through salt caverns for seasonal storage. Salt cavern storage requires compression from around 40-200 bar. This suggests that the total energy use of salt caverns per kg of hydrogen supplied, averaged over the year, is **very small** – **0.05-0.1 kWhe/kg** hydrogen with an electrical compressor.
- Fuel cell grade hydrogen stored in a salt cavern would require purification after extraction if it is to be used for fuel cells (as confirmed by an industry stakeholder); however gas grid hydrogen would require purification prior to fuel cell use in any case.
- Industry engagement reported that fugitive emissions from salt cavern leakage are 'very minimal indeed'. The salt is impermeable to hydrogen[1].

Overview of the hydrogen storage potential in the UK







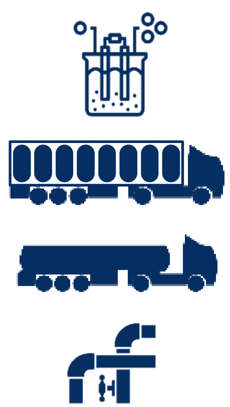
Contents

Four HRS archetypes capture the range of H_2 supply options that will be available during 2020-2035. The supply route and dispensing pressure are the key determinants of HRS energy use

The four H_2 supply modes considered are: On-site electrolysis, compressed tube trailer, LH_2 tanker and H_2 pipeline delivery

Overview of modelling approach for energy use at the HRS:

- The state of the hydrogen supplied to the HRS is determined by the production and distribution options selected upstream of the HRS
- The energy use at the HRS is then determined by the steps required to process the hydrogen from its arrival state to the selected dispensing state: **purification, compression, storage and cooling for dispensing**
- The dispensing pressure included in the model are either 350 or 700 bar and can be defined depending on the vehicle type to be refuelled
- Analysis suggests that HRS utilisation has a very small impact on energy use at the HRS and it is thus excluded as a variable
- HRS type is not defined e.g. public LDV forecourt/private bus depot as this does not affect energy use or emissions
- The steps involved in the HRS are well understood and so Low, Central and High values are not used. Instead, variations in energy use from the HRS are determined by upstream factors determining the H_2 supply state as well as user inputs such as the required dispensing pressure and trailer delivery pressure



H_2 supply	H_2 supply state	2020	2030	2035
On site electrolyser	20-80 bar	✓	✓	✓
Tube trailer	230/280/500 bar	✗*	✓	✓
Liquefied H_2 tanker	Liquefied	✗	✓	✓
H_2 pipeline	2 bar	✗	✓	✓

*Tube trailer delivery is available today, but there are no low carbon H_2 production facilities in the UK currently for these to supply a HRS from

There are multiple H_2 supply options for HRS with <4tH_2/day capacity (referred to in this work as 'small'), which are unlikely to be viable for 'large' stations (defined as >4t/day)

Practical limitations for smaller scale HRS

Existing HRS in the UK:

- Existing HRS in the UK have capacities of 80-360kgH_2/day
- These are very small stations with the largest capable of serving ~20 H_2 buses. They are supplied by:
  - Trucked deliveries of compressed H_2 in tube trailers - each typically capable of carrying 350 kgH_2 at 280 bar today
  - On-site electrolysers

Limitations for on-site production:

- **On-site electrolysers:** The footprint of electrolyser equipment does not scale well and takes up more than 50% of the footprint of a station, meaning that for larger sites appropriate locations are harder to identify
- **On-site SMR:** This technology is available from companies such as HyGear[1], however no UK companies are developing this technology for hydrogen refuelling and no existing HRS in the UK use this technology. It is also challenging to capture carbon from small sites and so this would likely continue to be a carbon intensive route. Therefore this option is not included in the analysis

Modelling note: Due to these likely practical limitations as stations scale up, on-site electrolysers should only be considered for stations up to ~2,000 kgH_2/day

Limitations for trucked delivery:

- **COMAH regulations:** A key limiting factor for HRS size is the Control of Major Accidents and Hazards regulations which apply to sites storing more than 5tH_2. This is likely to place a practical limit of **4,000 kgH_2/day** capacity for sites in built up areas, to ensure there is sufficient on-site storage to manage gaps between deliveries
- **Trucked delivery of H_2:** More than 3-4 CH_2 deliveries or 1 LH_2 delivery per day are also likely to place practical constraints on a HRS

Modelling note: Due to these likely practical limitations as stations scale up, trucked delivery should only be considered for stations up to ~4,000kgH_2/day

Hydrogen supply options considered for a smaller HRS:

On-site production: Only on-site electrolysers will be considered

Tube trailer delivery: Could be over 1000 kg per delivery with higher pressures of 500 bar

LH_2 trailer delivery: 3,000 - 3,500 kg per trailer

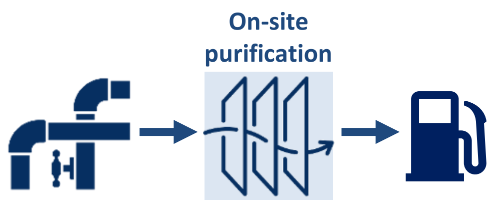
Not considered: A piped connection to a small HRS is unlikely to be economically viable for most locations due to the additional cost of connecting to the network

1: On-site hydrogen generation through steam methane reforming, HyGear, https://hygear.com/technologies/hy-gen/

As demand grows from FCEVs, HRS will likely require a piped supply of H_2 in order to achieve large-scale capacity

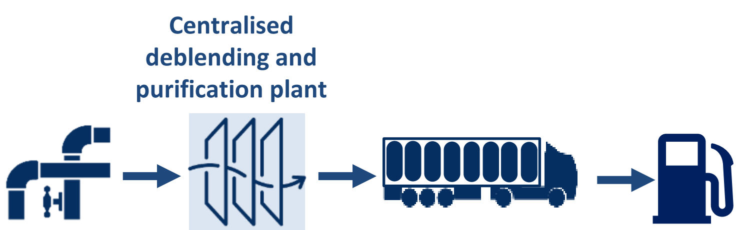
The supply pressure and purity of H_2 supplied are the main determinants of energy use at a pipe-connected HRS

There are three main options for supplying large HRS with sufficient volumes of H_2:



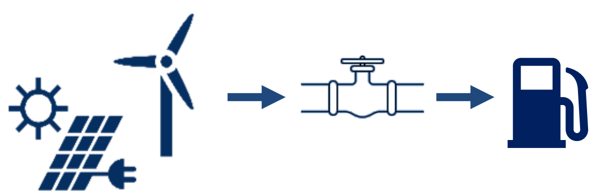
1. **Direct piped connection to pure hydrogen gas network with on-site purification**

Within the 2020-2035 timeframe, hydrogen will begin to be blended in significant quantities on the gas network. A recent report by Costain[1] suggests that in this case, it may be economical to de-blend the mix of gases and allow certain parts of the distribution network convert to supply pure (>98% mol) H_2. This would require on-site purification at the HRS to achieve fuel cell (FC) grade H_2 – included in this work.



2. **Tube trailer delivery from a centralised deblending and purification plant**

An alternative to option 1 would be a centralised deblending purification facility, turning network-delivered H_2 into FC grade purity for a range of local users. This would then be delivered by tube trailer a short distance to a HRS. Once the gas grid is fully hydrogen, this facility would perform purification only – this is not included in the modelling in this study.



3. **Short dedicated pipeline from H_2 production facility**

Where a large HRS is close to H_2 production, a short (<5km) dedicate pipeline could be deployed to serve the HRS directly from the production site – this is not included in the modelling in this study.

1: Costain, 2020, Hydrogen Deblending in the GB Gas Network

Overview of the major process steps across all hydrogen dispensing options

	Large HRS (>4tH_2/day)		Small HRS (<4tH_2/day)		
H_2 supply	Network delivery	Dedicated pipe	On site production	Compressed tube trailer	Liquefied tanker
Arrival state	2 bar Not FC grade	2 bar Not FC grade	30 bar FC grade	280/500/700 bar FC grade	Liquefied FC grade
Processing for storage	Purification + 200 bar compression		Compression to 200 bar storage pressure	No compression required	Transfer to cryogenic storage
	Storage 200 bar			Trailer storage	Cryo-storage
Processing for dispensing	Compression to 500/900 bar cascade storage				Cryo-pump & thermo management system
Dispensing	Cooling Dispensing (350 bar)		Cooling Dispensing (700 bar)		350 bar dispensing / 700 bar dispensing

Red text – significant energy use step

HRS are supplied with compressed H_2 at different pressures, depending on the different supply sources, with the main energy demand being from compression

For HRS that are supplied with gaseous H_2, there are three main parts to the HRS from an energy use perspective:

1. **Purification**

Sites that are supplied via a pipe will require on-site purification to remove impurities and odorants. Only PSA purification is modelled and the main energy use for this step is in compression. Since compression to 200 bar for storage is needed in any case, the additional energy use from purification is minimal, as discussed elsewhere.

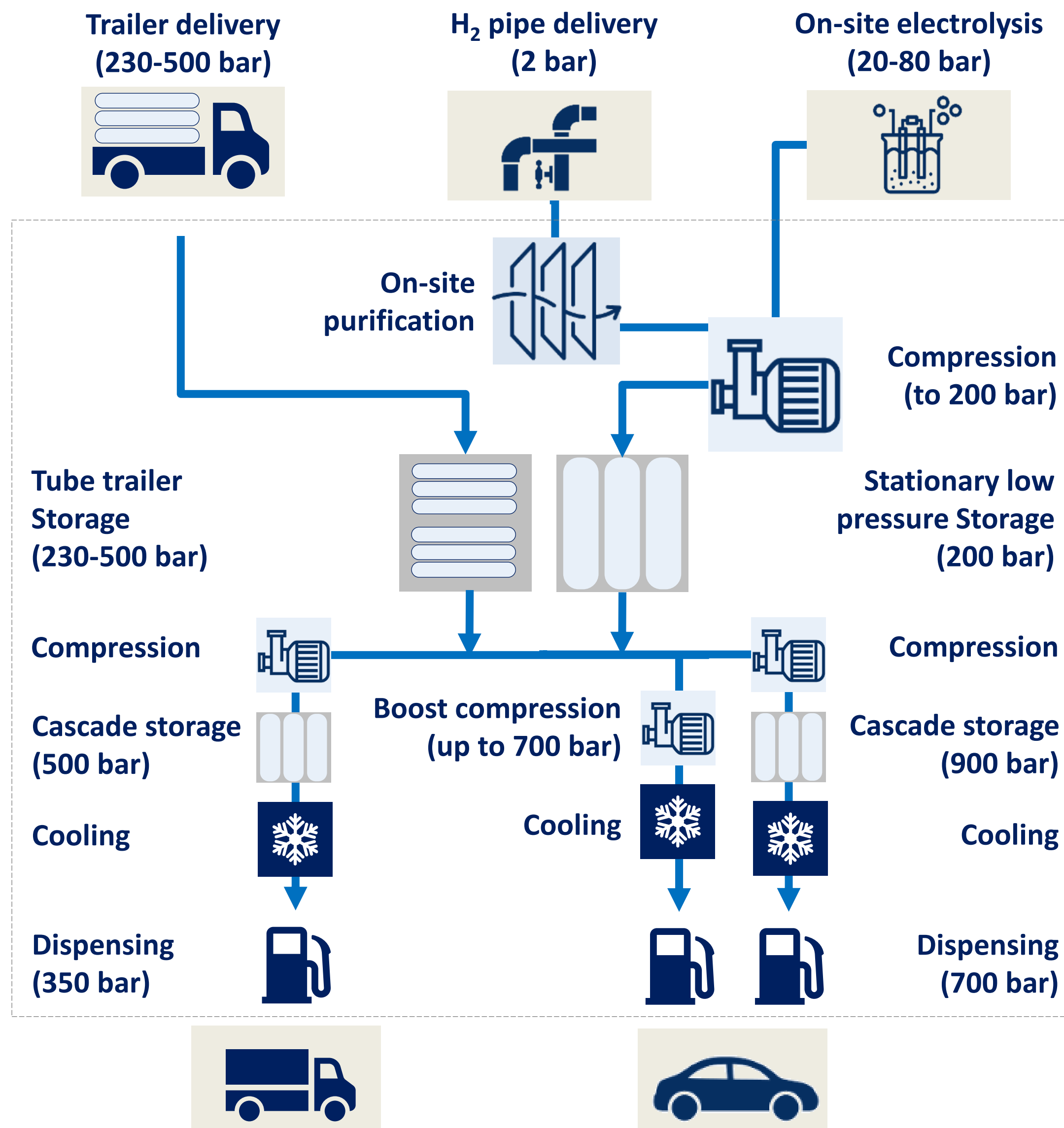
2. **H_2 compression**

The H_2 can arrive at the HRS from 2-500 bar depending on the delivery method. For tube trailer deliveries the trailer is left on-site, providing storage that depletes to 20 bar before being replaced with a full trailer (see table below). For stationary storage, the delivered H_2 is typically compressed to 200 bar.

3. **Cooling**

For supply to the vehicle's tank, the hydrogen is either compressed directly from stationary storage up to 700 bar using a boost compressor, or compressed to 500/900 bar high pressure cascade storage for 350/700 bar dispensing. Cooling to -40C is required for 700 bar to ensure the vehicle's tank does not exceed 85C. At high utilisation cooling is also required for 350 bar dispensing.

Tube trailer delivery pressure	Modelled tube trailer pressure for compression
230 bar	125 bar
280 bar	150 bar
500 bar	260 bar



HRS dispensing compressed H_2 that is delivered to site via LH_2 tanker can function in a similar way to a HRS with a compressed H_2 supply, or utilise a more efficient cryo-pump system

There are two main configurations for a HRS supplied with liquefied hydrogen that impact on the energy consumption of LH_2 sites:

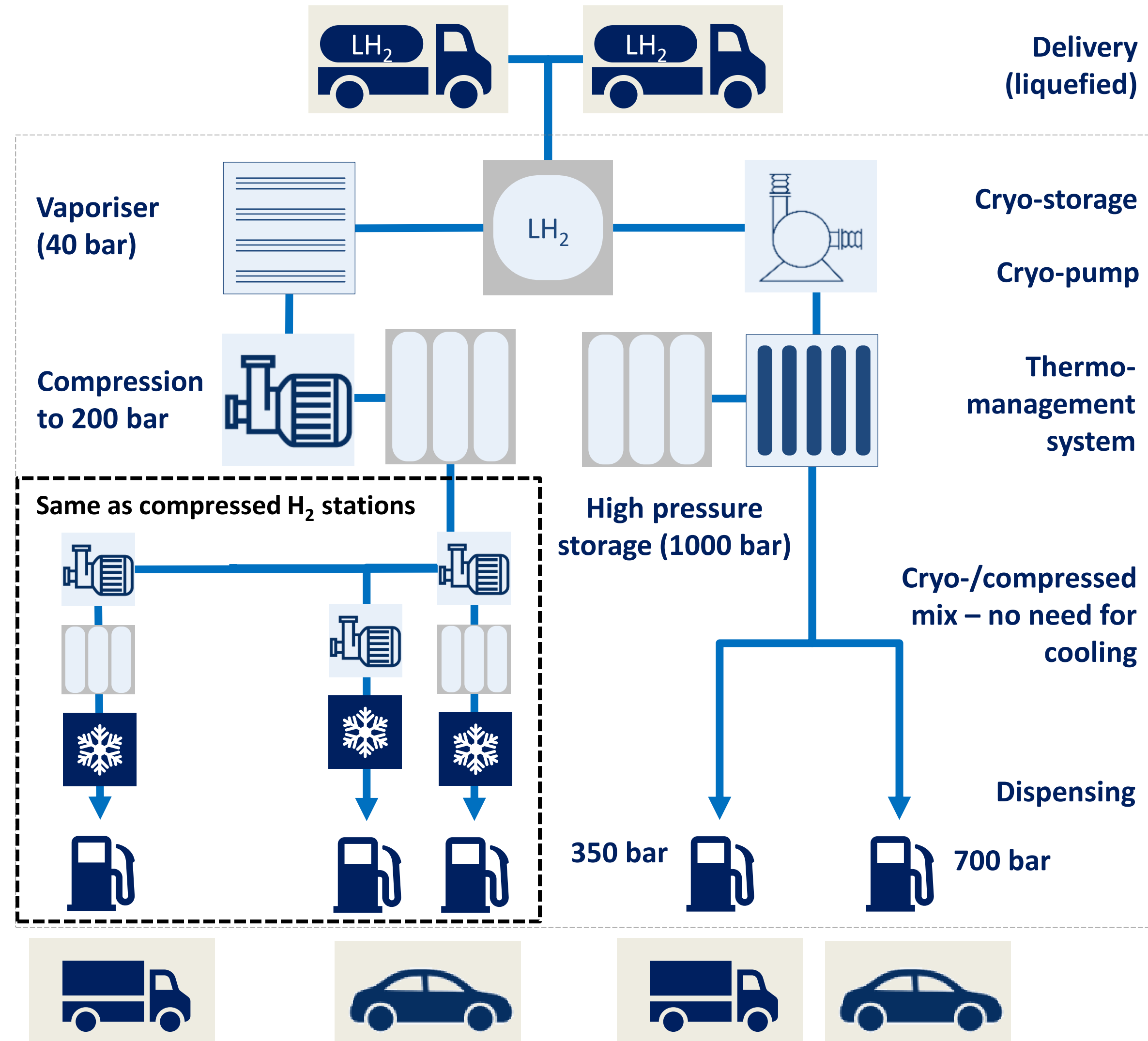
1. **Liquefied storage with vaporiser and compressed H_2 dispensing**

A station in this configuration stores liquefied H_2 on-site after delivery. As the hydrogen is processed for dispensing, it is first re-gasified in a vaporiser and compressed for storage. From this point on, the dispensing process is the same as for a site supplied with compressed H_2 where further compression and refrigeration is required (see previous slide) – Not considered in this report

2. **Cryo-pump system**

In this configuration, a cryo-pump and thermo-management system take LH_2 from storage and supply ambient compressed H_2 to the high pressure storage. The thermo-management system then supplies a mixture of very low temperature (-200C) hydrogen from the cryo-pump and ambient H_2 from the high pressure storage to supply H_2 to the dispenser. In this way, the temperature and pressure for dispensing at 350/700 bar are achieved without additional compression or refrigeration.

Due to its higher efficiency, the cryo-pump system is the main type of LH_2-supplied HRS deployed in practice and is the only LH_2-supplied HRS configuration modelled in this work

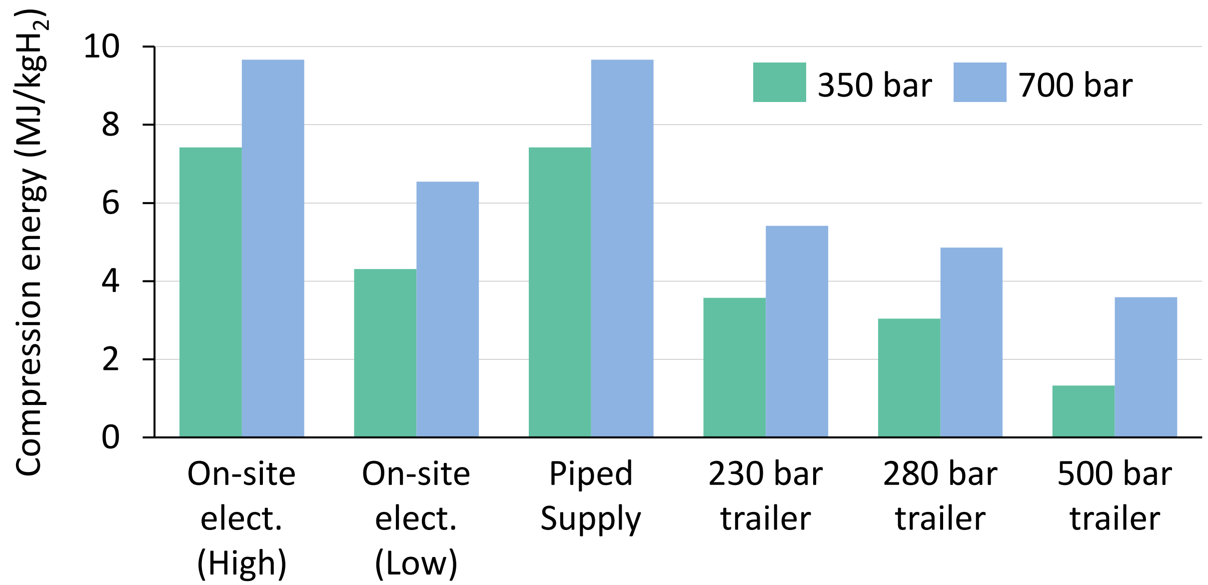


Contents

HRS energy use is dominated by compression and dependent on the delivery pressure, the dispensing pressure and whether compression for stationary storage is also required

- **Delivery via high pressure tube trailer:** Requires significantly lower compression energy at the HRS compared to low pressure delivery options
- **Compression from tube trailer delivery:** Modelled from the mid-point between the pressure of a fresh trailer (230, 280 or 500 bar) trailer and 20 bar at which point the tube is depleted and replaced
- **Cascade dispensing:** The model only considers cascade dispensing, where multiple high pressure cylinders are used in succession for refuelling. This requires compression up to 500/900 bar for 350/700 bar dispensing
- **Booster dispensing:** This is used for 700 bar refuelling to compress directly to the pressure required by the vehicle. While this can be less energy intensive than cascade dispensing it is more challenging at high utilisation because one compressor is required per refuelling bay. **This option is not considered in the model**

HRS energy for storage compression plus dispensing compression by H_2 delivery route



H_2 via piped supply or on-site production arrives at lower pressure and has an additional compression step for on site storage Total compression for each option in blue box		Compression from tube trailer			Piped supply[1]	On-site elect. (High)	On-site elect. (Low)
	Unit	230 bar	280 bar	500 bar	20 bar	20 bar	80 bar
Modelled delivery pressure	bar	125	150	260	20	20	80
Compression - to 200 bar storage	MJ/kgH_2	N/A	N/A	N/A	5.17	5.17	2.06
Total compression for 350 bar dispensing	MJ/kgH_2	3.58	3.04	1.33	7.42	7.42	4.31
Total compression for 700 bar dispensing	MJ/kgH_2	5.41	4.86	3.59	9.67	9.67	6.55

1: Modelling includes 2 bar piped hydrogen delivery to HRS plus purification via PSA which increases pressure to 20 bar before processing at the HRS for dispensing

2: Elgowainy, A., et al, Hydrogen Delivery Scenario Analysis Model (HDSAM) V3.1

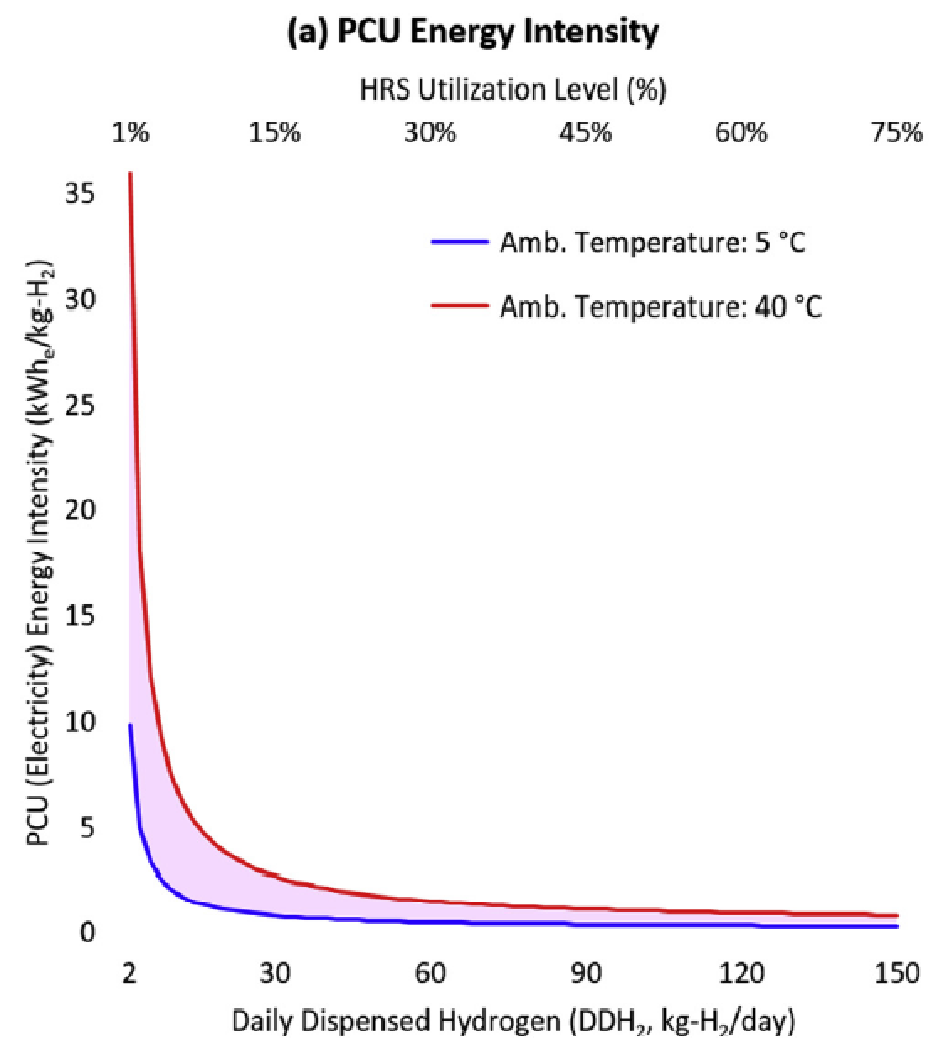
Pre-cooling of hydrogen is required to ensure that tank temperatures remain within safe limits during refuelling – this is a relatively small component of HRS energy use

- The chart to the right shows the results of a thermodynamic analysis of energy use for a HRS pre-cooling unit[1]
- While station utilisation is very low, cooling energy per kgH_2 dispensed is very high, but this rapidly falls as utilisation reaches 20% - it then remains relatively flat as utilisation continues to increase

Pre-cooling energy use modelling approach:

- The table below shows figures for cooling electricity use from detailed HRS techno-economic modelling by NREL[2]. **These are the values used in this work**
- Since cooling energy quickly becomes a small component of energy use at relatively low levels of utilisation, these values are kept constant across all scenarios
- In a review of the modelling approach for this work, BOC noted that while pre-cooling is always necessary for 700 bar refuelling, it is also necessary for 350 bar refuelling for sites with high utilisation
- As a result values for 350 bar cooling are also included in the model and kept constant across all scenarios

Dispensing pressure	Cooling energy use (kWh/kgH_2)
350 bar	0.39
700 bar	0.64

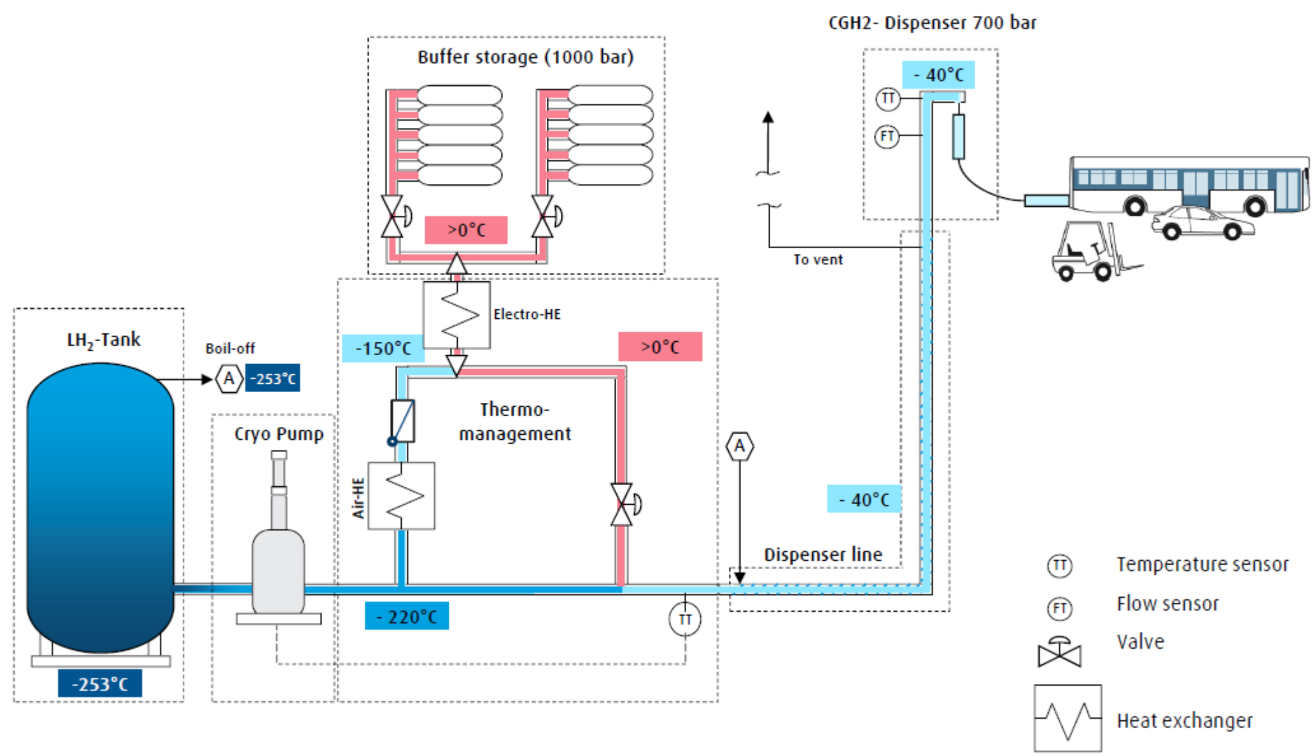


1: Elgowainy, A., et al, 2017, Techno-economic and thermodynamic analysis of pre-cooling systems at gaseous hydrogen refuelling stations
2: Elgowainy, A., et al, Hydrogen Delivery Scenario Analysis Model (HDSAM) V3.1

A HRS supplied with LH_2 and using a cryo-pump and thermo-management system can be a low energy use option for a HRS

- The HRS option modelled in this work that is supplied with LH_2 utilises a cryo-pump and thermo-management system to transfer hydrogen from the liquid storage to the dispenser at the required pressure and temperature
- As shown in the schematic, the thermo-management system supplies a mix of high pressure ambient H_2 from storage and low temperature hydrogen from the liquid storage to the dispensing equipment
- This means that the additional compression and cooling steps for dispensing are not required. As a result there is little difference in energy used to dispense at 350 or 700 bar
- This work assumes 0.6 kWh/kgH_2, 0.9 kWh/kgH_2, and 1.2 kWh/kgH_2 as low, central and high values for both dispensing options, based on data from Linde[1] and the IEA[2].

Linde cryo-pump and thermo-management system schematic[1]



Contents

Fugitive emissions for HRS delivered with LH_2 include boil-off from on-site storage and processing

- Fugitive emissions from HRS receiving deliveries of LH_2 are higher than the corresponding figures for CH_2 delivery, which are modelled as only occurring during delivery to the HRS.
- Measurements and modelling at the Lawrence Livermore National Laboratory have revealed that in addition to boil-off during storage, four sources dominate the fugitive emissions from an HRS supplied with liquid hydrogen:[2,3]
  - **Cryo-pump idling -** boil off that occurs as a result of the cryo pump warming up overnight when not in use. This is the largest source of fugitive emissions
  - **Cryo-pump pre-cooling** – LH_2 boils when it is used to pre-cool the cryo-pump
  - **Cryo-pump utilization** – boil off during use of the cryo-pump
  - **Transfer losses** - very small losses occur during transfer of the LH_2 to the station from the delivery truck – these are accounted for as part of distribution rather than at the HRS and are around 0.2%.
- In addition, there are some losses from boil off during storage at the HRS.
- The figures used in the model may be found on the following slide .

Linde HRS liquid hydrogen storage tank[3], optimised for low boil-off

(1) IEA – The Future of Hydrogen – 2019, (2) Petitpas - Boil-off losses along the LH2 pathway – 2018 (3) Linde - Liquid Hydrogen Distribution Technology HYPER Closing Seminar - 2019

Size has a significant impact on the fugitive emissions from HRS using LH_2

HRS fugitive emissions arise from storage boil-off, as well as cryo-pump idling, pre-cooling, utilisation and transfer losses

- Linde[2] data shows that **boil off during storage** varies between **0.5%/day** and **0.95%/day. 2 days of storage are assumed.**
- Data from Petitpas et al[1] shows that the combined losses from cryo-pump idling, pre-cooling, utilisation and transfer losses decrease sharply with station size for station sizes below 1000 kg H_2/day
- The Low, Central and High values used in the model are shown in the diagram below. The sizes of LH_2-supplied HRS deployed today are within the Central-High range, but emissions from operation of the dispensing equipment could continue to fall as larger stations are deployed

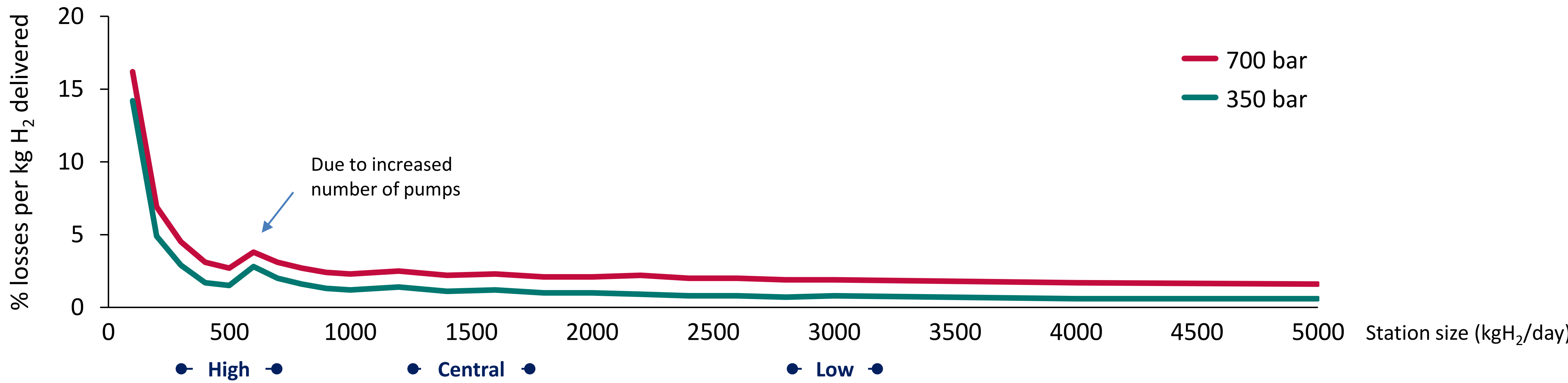
HRS fugitive emissions due to storage boil-off, assuming 2 days of storage

	Low	Central	High
Storage boil-off[2], % *	1.0	1.4	1.9

HRS fugitive emissions due to cryo-pump idling, pre-cooling, utilisation and transfer losses, %

	Low	Central	High
350 bar	0.8	1.1	1.5
700 bar	1.9	2.3	2.7

HRS fugitive emissions due to cryo-pump idling, pre-cooling, utilisation and transfer losses



1: Pepitas, 2018, Boil-off losses along LH2 pathway, https://www.osti.gov/servlets/purl/1466121 2: Linde - Liquid Hydrogen Distribution Technology HYPER Closing Seminar - 2019

Contents

This project benefitted from the input of 15 expert steering group members from a wide range of organisations within the hydrogen industry, as well as several stakeholder interviews

Steering group

Organisation	Steering group member
Zemo Partnership	Gloria Esposito
ABSL	Andy Cornell
Air Liquide	David Hurren
Advanced Propulsion Centre	Bhavik Shah
Cadent Gas	Luke Bates David Jones
Consultant	David Lemon
NGN	David Gill
SGN	Joseph Mitchell
Shell	Michael Copson
University of Bath (SupergenHFC)	Sam Cooper
University of Brighton	Penny Atkins
University of Cambridge	Molly Haugen
WWU	Neil Stovold

Interviewed stakeholders

Organisation	Stakeholder interviewed
BOC	Geraint Thomas
Cadent Gas	Lorna Millington Matt Marshall
DNV	Martin Brown
Imperial College London	Jamie Speirs
Linde	Martin Bauer Oliver Purrucker Alexander Siemens
National Physical Laboratory	Thomas Bacquart