Fugitive Hydrogen Emissions in a Future Hydrogen Economy

Frazer-Nash Consultancy

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Hydrogen Production	Transport and Storage	Consumers
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Any enquiries regarding this publication should be sent to us at:
enquiries@beis.gov.uk

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Summary

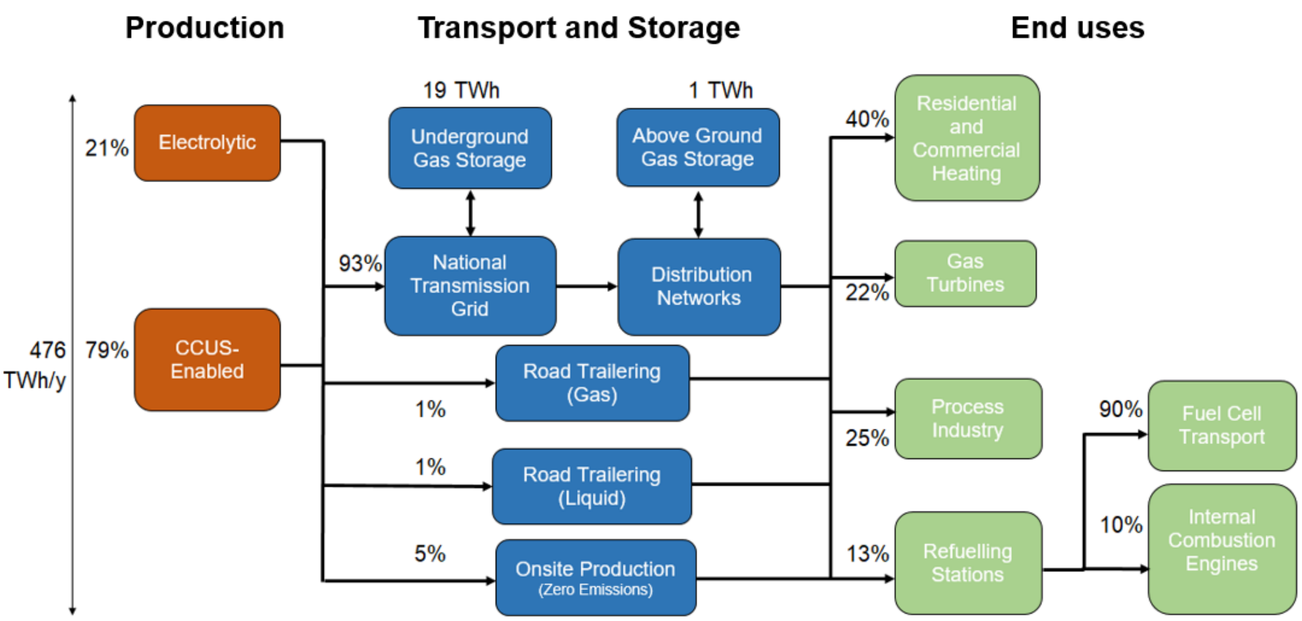
Hydrogen is likely to play a significant role in the decarbonisation of the UK's future energy system. However, there is an increasing body of evidence that hydrogen is itself an indirect greenhouse gas and recent research suggests that it has a Global Warming Potential 11 times that of carbon dioxide (over a 100-year time horizon). Hydrogen, by its nature, is hard to contain and understanding how much hydrogen could be emitted to the atmosphere in a future hydrogen energy system is important for policy development.

Approach

This research study has identified and quantified the different mechanisms for fugitive hydrogen emissions in a future 2050 hydrogen economy. These include all mechanisms where hydrogen may be released to the atmosphere including unintended leaks (e.g. from joints, pipework and storage) as well as deliberate purging or venting.

A Central Scenario has been used to provide an illustrative framework for assessing hydrogen emissions in a future energy system. This scenario is based on National Grid's Future Energy Scenario: System Transformation. It has an ambitious deployment of hydrogen across industry, transport power and heating, and a broad set of hydrogen production technologies; methane, bio-energy and electrolysis. This large-scale deployment of hydrogen will require a significant transport and storage infrastructure. The central scenario has therefore allowed for fully repurposing the National Transmission System (NTS) and distribution networks to transport 100% hydrogen, as well as storage of hydrogen in salt caverns.

Central Scenario



Initially, the different elements of the central scenario have been considered separately to quantify the emissions of each element in isolation. These have then combined into a central scenario, allowing for their size contribution (given the percentages in the diagram above) to predict the overall hydrogen emissions. In both cases a probabilistic model has been used to predict emissions at different confidence levels allowing for uncertainty in the inputs.

Results

Emissions from Individual Elements

The hydrogen emissions from the individual elements are summarised as follows. These are given as a percentage of the hydrogen produced, transported or used within that element.

<table>
<tr><th rowspan="2">Sector</th><th rowspan="2" colspan="2">Specific Area</th><th colspan="2">Predicted Emission Confidence level</th></tr>
<tr><th>50 %</th><th>99 %</th></tr>
<tr><td rowspan="3">Production</td><td rowspan="2">Electrolytic</td><td>With venting and purging</td><td>3.32 %</td><td>9.20 %</td></tr>
<tr><td>With full recombination of hydrogen from purging and crossover venting</td><td>0.24 %</td><td>0.52 %</td></tr>
<tr><td colspan="2">CCUS-enabled</td><td>0.25 %</td><td>0.50 %</td></tr>
<tr><td rowspan="6">Transport and Storage</td><td colspan="2">National Transmission System</td><td>0.04 %</td><td>0.48 %</td></tr>
<tr><td colspan="2">Distribution Network</td><td>0.26 %</td><td>0.53 %</td></tr>
<tr><td colspan="2">Underground Storage</td><td>0.02 %</td><td>0.06 %</td></tr>
<tr><td colspan="2">Above Ground Storage (gas)</td><td>2.77 %</td><td>6.52 %</td></tr>
<tr><td colspan="2">Road Trailering (gas)</td><td>0.30 %</td><td>0.66 %</td></tr>
<tr><td colspan="2">Road Trailering (liquid)</td><td>3.76 %</td><td>13.20 %</td></tr>
<tr><td rowspan="7">End-uses</td><td colspan="2">Residential</td><td>0.30 %</td><td>0.69 %</td></tr>
<tr><td colspan="2">Gas Turbines</td><td>0.01 %</td><td>0.01 %</td></tr>
<tr><td colspan="2">Refuelling Stations</td><td>0.25 %</td><td>0.89 %</td></tr>
<tr><td rowspan="2">Fuel Cells</td><td>With venting and purging</td><td>1.36 %</td><td>2.64 %</td></tr>
<tr><td>With full recombination of hydrogen from purging and crossover venting</td><td>0.56 %</td><td>1.02 %</td></tr>
<tr><td colspan="2">Combustion Engines</td><td>0.30 %</td><td>0.66 %</td></tr>
<tr><td colspan="2">Process Industry</td><td>0.25 %</td><td>0.50 %</td></tr>
</table>

Hydrogen Production

Electrolytic Hydrogen: Three main hydrogen emission mechanisms have been identified: venting at start-up and shutdown, venting due to hydrogen cross-over, and operational purging as part of the purification process. Leakage through the electrolyser casing is likely to be negligible. Operational purging is the most significant mechanism and industry experts suggest this could be as high as 10%. However, it would be relatively easy to incorporate technology to recombine the hydrogen purged and vented due to cross-over back into water. As electrolytic hydrogen production is scaled up, it will become more feasible to incorporate this technology. The central scenario is therefore based on the widespread adoption of hydrogen recombining.

CCUS-enabled Hydrogen: Hydrogen may be released from pipework leakage and purging (similar to electrolysis). Any hydrogen produced from methane will be at significant scale and any purged hydrogen is likely to be recombined to water or used for process heat. Engagement with industry highlighted that any waste hydrogen will be sent to flare rather than vented to atmosphere. In practice, there will be residual hydrogen emissions, but it has not been possible to quantify these. For the purposes of the central scenario an emission of between 0 and 0.5% of the hydrogen produced has been assumed.

Transport and Storage

Pipelines: Hydrogen emissions from a repurposed NTS and Distribution Networks have been predicted by converting current estimates for natural gas leakage to hydrogen using gas leakage relationships. Leakage from the pipelines may be laminar or turbulent and there is almost a factor of three difference between these two regimes. It has not been possible to characterise the leakage for either the NTS or Distribution Networks and predictions are bounded by the laminar and turbulent limits. The existing natural gas leakage from the NTS is very uncertain and this in turn gives a high uncertainty to the NTS hydrogen emission predictions. At the top end of the potential leakage, the NTS has a comparable emission to the distribution networks, although expectations from industry are that it is significantly less.

Road Trailering: Emissions from compressed gas and liquid transport are very significant as a proportion of the amount of hydrogen stored, but they will transport only a small fraction of a repurposed NTS and distribution networks and their contribution to the overall emissions is likely to be small. Similarly, hydrogen emissions from underground storage of hydrogen in salt caverns are predicted to be very small.

End Users

Fuel Cells: Hydrogen fuel cells may be used for surface and potentially aviation transport applications. Fuel cells emit a similar amount of hydrogen to electrolysers and when incorporated into transport applications will also emit hydrogen from the compressed storage. Similar technologies to those proposed for electrolysers could be readily implemented to reduce these.

Hydrogen Refuelling Stations: The main emissions from Hydrogen Refuelling Stations are from the compression of hydrogen and the short-term storage of compressed hydrogen prior to injection into vehicles. The emissions from refuelling stations should be relatively low (at 50% confidence) but there are some uncertainties that push up the upper limit (99% confidence).

Heating: Hydrogen may also be used in homes and businesses for heating and hot water. Existing boilers, ovens, hobs and fires could be repurposed to run on 100% hydrogen. The two main emission mechanisms are unburnt hydrogen that is vented from boilers during start-up and shutdown, and leakage from pipework. The pipework leakage is very uncertain and for the purposes of this study, a conservative estimate has been made based on the Maximum Permissible Leak Rate (MPLR) for domestic and commercial properties. This is likely to be a significant overestimate.

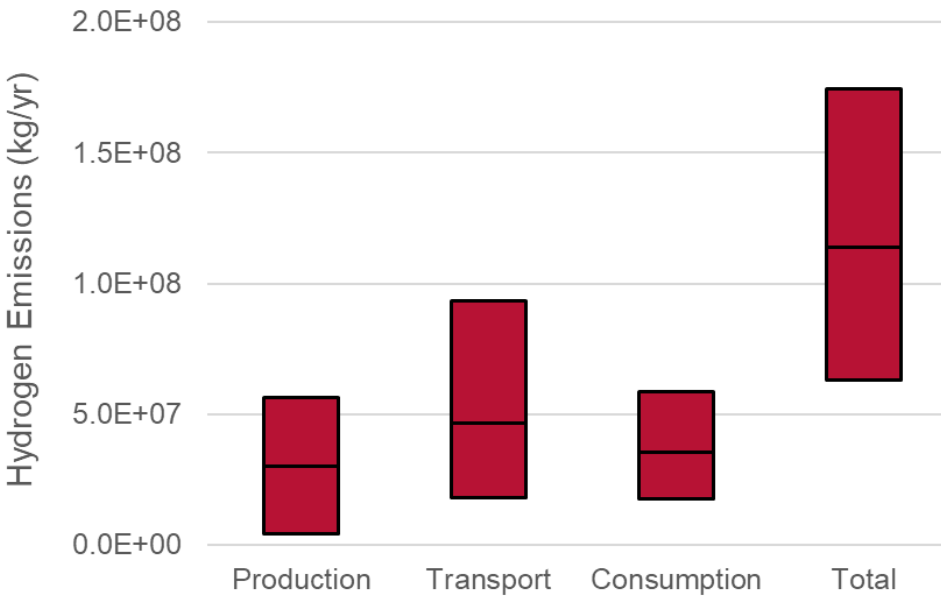
Gas Turbines: Gas Turbines running on 100 % hydrogen may emit unburnt hydrogen at start-up and shutdown similar to boilers. Gas Turbines are likely to run more continuously than boilers and overall this emission is very low.

Industry: Hydrogen is also likely to be used to decarbonise industrial processes such as steel and chemicals. It has not been possible to predict the emissions from industry at this stage and this will require further consideration. For the purposes of the central scenario an emission of between 0 and 0.5% of the hydrogen used has been assumed.

Overall Hydrogen Emissions

The emissions from the individual elements have been combined to predict the overall emissions from the central scenario. For each element, the emission is scaled based on the percentage contribution to the three sectors: production, transport and storage, and end-uses.

The total hydrogen emission is predicted to be 114 kt/year (at 50 % confidence) and 174 kt/year at 99 % confidence. The overall size of the central scenario is 476 TWh (12,000 kt/year) so this represents a loss of 0.96 % (50% confidence) or 1.50 % (99 % confidence). Of the three sectors, transport is predicted to have the highest emission and this is dominated by the losses from the distribution network.



The bars represent the 1st, 50th and 99th percentiles (confidence levels)

In summary, there are likely to be hydrogen emissions across the hydrogen landscape from production, transport, and storage through to end-use applications. Technologies can be implemented to reduce the key emissions from production (electrolysis) and end-users (fuel cells). If these are widely adopted the dominant emission source is likely to be a gas distribution network repurposed to transport 100 % hydrogen. Although as a percentage emission it is comparable, and even lower than some of the other elements, the magnitude of the throughput of hydrogen in a repurposed distribution network means it is likely to have the single largest emission.

The findings of this study can be used as follows:

- Technology improvements: Where technologies have been identified that can reduce the emissions (electrolysis and fuel cells), these can be explored further to understand how they will affect the economics of hydrogen production (Levelised Cost of Hydrogen, LCOH), any minimum viable scale required to make them feasible, and how they could be included in the UK government's low carbon hydrogen standard.
- Overall emissions: The overall (central scenario) emissions can be combined with the estimated GWP of hydrogen to consider the implications for the UK's decarbonisation policy. The central scenario was chosen to provide a credible but bounding size of a future hydrogen economy. The findings on the individual emissions can also be readily applied to explore alternative scenarios.

Opportunities for Improving the Predictions

This study has highlighted various gaps in emissions data that would benefit from further work. The key areas are as follows:

- Quantifying hydrogen emissions from CCUS-enabled hydrogen production processes.
- Quantifying hydrogen emissions from the process industry.

- Improving estimates for natural gas emissions from the NTS.
- Undertaking experimental work to better understand how hydrogen may leak from domestic pipework.

1 Introduction

1.1 Background

Hydrogen is an increasingly certain part of the future UK energy system. Its ability to decarbonise hard-to-abate sectors such as high-temperature industrial processes, heavy road transport and shipping, as well as provide broader energy system balancing means that it is likely to play a significant role as the energy system continues to be decarbonised.

Against this backdrop there is an increasing body of evidence that hydrogen, though emitting no carbon dioxide at the point of use, is itself an indirect greenhouse gas. Hydrogen is not a strong absorber of infrared radiation so does not act as a direct greenhouse gas. However, it reacts with, and depletes naturally occurring hydroxyl radicals in the earth's atmosphere which are a key mechanism for methane removal. Methane is a potent greenhouse gas and leakage of hydrogen will increase its atmospheric lifetime and its impact on the climate. The latest estimate for the Global Warming Potential (GWP) for hydrogen is 11 ± 5 [1] over a 100-year time horizon. Leakage of hydrogen into the atmosphere will therefore offset some of the benefits of a hydrogen-based economy.

Hydrogen presents significant containment challenges compared to existing energy carriers like natural gas. It has a low volumetric energy density so is often stored at high pressure and this provides the potential for leakage. It can also be stored as a liquid, but it has a boiling point of 20 K [2] so will suffer from boil-off losses. Hydrogen also presents safety challenges with combustion. It has a high flame speed and is more prone to detonation than other gases and this means it is sometimes vented to atmosphere for safety. As the role of hydrogen in the energy system increases, it is therefore important to understand how much hydrogen could leak to atmosphere, assess whether this is acceptable, and if necessary develop technologies and procedures to reduce this leakage.

1.2 Purpose of Research Study

This research study has sought to identify and quantify the different mechanisms for hydrogen emissions in a future 2050 hydrogen economy. This includes all mechanisms where hydrogen could be emitted to the atmosphere:

- Unintended leaks from joints, pipework and storage;
- Deliberate purging or venting either as part of a process (e.g. control valves in pipework) or for safety reasons.

A central scenario has been used to provide a basis for the deployment of hydrogen in the energy system in 2050. This scenario is used to highlight the individual aspects of the hydrogen landscape that need to be considered, and also, the size of their contribution to a future hydrogen energy system. National Grid's System Transformation Future Energy

Scenario [3] has been used, as it allows for an ambitious and widespread deployment of hydrogen:

- Production from both electrolytic hydrogen and hydrogen derived from methane (via Steam Methane Reformation or from bio-energy);
- Hydrogen will be used in industry and transport, stationary power applications and as a fuel for residential heating;
- The UK gas network will need to be repurposed from natural gas to 100 % hydrogen;
- Long term storage using salt caverns will also be required for energy balancing.

The System Transformation scenario therefore provides the basis for predicting a credible worst-case amount of hydrogen that could be emitted per year to the atmosphere.

Although the objective of this study is to predict the hydrogen emissions in 2050, it has conservatively been based on currently available technology scaled-up to meet the magnitude of the central scenario. For some hydrogen emission mechanisms, there may be existing technologies that could be deployed now to reduce the emission, but which are not economically viable to deploy at low scale. Increasing the size of hydrogen technologies to the scale of the central scenario may mean that techniques to reduce emissions are more viable. The impact of these technologies has important implications for future hydrogen policy and are therefore considered in this study.

1.3 Layout of Report

Section 2 provides more detail on the central scenario, the underlying elements and the size of their contribution to the overall scenario.

In Sections 3 - 5, the hydrogen emissions from production, transport and storage, and end-use applications are considered individually. For each sector, the aim has been to:

- Identify the sources of hydrogen leakage;
- Quantify these emissions including areas of uncertainty with bounding ranges.

In Section 5, the information collected on the individual sources of emissions has then been combined into a probabilistic model. This provides predictions at different confidence levels allowing for uncertainty in the inputs. 50 % confidence (central estimate) and 99 % confidence (credible maximum) are used throughout to highlight the most likely and upper limit of the emissions respectively. This model has the benefit that it highlights the key drivers of variability and hence the focus areas for improving the predictions. As well as assessing the individual emissions, the elements are combined to predict the overall emissions for the central scenario, highlighting the key uncertainties in the overall picture.

In Section 6, the key gaps in information are discussed and used to provide recommendations for future studies.

2 Development of Central Scenario

To provide a credible, but bounding scenario for hydrogen emissions, a central scenario based on National Grid's System Transformation [3] has been adopted. This scenario allows for a widespread use of hydrogen in a variety of sectors.

Components of System Transformation Future Energy Scenario

Hydrogen Production: Steam Methane Reformation (SMR) reformed with Carbon Capture and Storage (CCS), networked electrolysis, nuclear electrolysis, BECCS and imports.

End-uses of Hydrogen: Road transport and rail, residential, industrial and commercial, power generation, shipping and aviation.

The magnitude of the hydrogen production and end-use sectors are presented in Table 1.

Hydrogen produced by methane reforming with CCS (so called blue hydrogen) and Bio-Energy Carbon Capture and Storage (BECCS) are assumed to have similar types of hydrogen emissions and for this study have been combined into a single sector called CCUS-Enabled Hydrogen. Equally, networked electrolysis and nuclear electrolysis have been combined into a single sector called Electrolytic Hydrogen. In practice, different types of electrolysis may be used depending on the energy supply. These have been investigated (Section 3.1) and the most conservative hydrogen emissions across the different electrolysis technologies are assumed to apply across this whole category. It is recognised that some hydrogen may be imported in 2050, but this is assumed to be either CCUS-enabled hydrogen, electrolytic hydrogen or a combination of the two. No allowance has been made for any UK hydrogen liquification facilities and any liquified hydrogen will be brought in from abroad.

For the end-use applications, road and rail transport are assumed to use a mixture of fuel cells and internal combustion engines, both of which will be supplied by hydrogen refuelling stations. Hydrogen gas turbines will be used for both stationary power and aviation applications.

Whilst the System Transformation scenario provides predictions for the supply and demand of hydrogen in 2050, it does not provide any predictions for how the hydrogen will be transported from the production facilities to the end-users, or for any system-level storage of hydrogen. As the central scenario has full adoption of 100% hydrogen in the residential sector, the UK gas network comprising the National Transmission System (NTS) and gas distribution networks will need to be repurposed to transport 100% hydrogen (rather than blending with natural gas). The NTS is assumed to operate at the same pressure as the existing natural gas system and an allowance has been made for a small uplift in the distribution network pressure. The remaining hydrogen will be produced at the point of use or transported by road trailering, either as a gas or liquid. For the purposes of this study, the gas network is assumed to transport 93% of the hydrogen from production to end-users, road trailering by gas and liquid will transport

1% each and 5% will be produced onsite. For onsite production, no allowance for hydrogen emissions has been made.

Hydrogen may be stored in large quantities in salt caverns to balance supply and demand. In the UK, caverns vary in size but even just considering those with a storage capacity of 140 - 160 GWh, there is potential for around 40 TWh [4]. For the purposes of this study, an allowance of 19 TWh storage has been made [5]. In practice, the amount of hydrogen stored in salt caverns will vary over the course of a year but in this study it has been assumed to be constant. A small amount (1 TWh) of additional above ground compressed gas storage has also been included for shorter duration gas system balancing.

Table 1: Size of individual hydrogen sectors in the Central Scenario

Hydrogen Production		**Hydrogen Uses**	
Type	**Size**	**Type**	**Size**
CCUS-enabled	376 TWh (79 %)	Surface Transport (road, rail, marine)	62 TWh (13 %)
Electrolytic	100 TWh (21 %)	Residential	190 TWh (40 %)
		Process Industry	121 TWh (25 %)
		Gas Turbines (power generation and aviation)	103 TWh (22 %)
Total	**476 TWh**	**Total**	**476 TWh**

The central scenario comprises the individual elements to be assessed and the overall proposed 2050 hydrogen economy is shown in Figure 1.

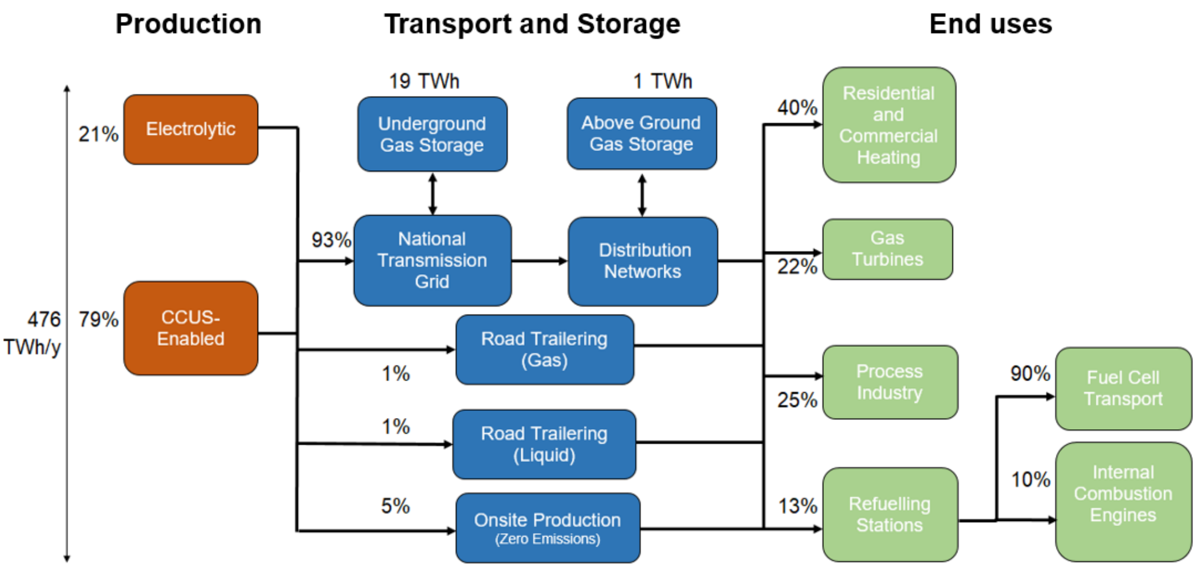


Figure 1: Schematic of the Central Scenario. The total energy throughput is 476 TWh and the contribution of each element is given as a percentage.

The following sections explore the hydrogen emissions in the individual sectors and consider the factors that make these emissions uncertain. Whilst the form of the hydrogen energy system in 2050 is itself highly uncertain, the central scenario is assumed to be fixed.

2.1 Limitations of Scenario

The central scenario is intended to provide a credible, but bounding basis for understanding hydrogen emissions in a future 2050 hydrogen economy. There are various existing industrial processes, such as chlorine manufacture, that emit hydrogen to the atmosphere as a waste product, which have not been included. As hydrogen is progressively used more broadly it will become a commodity of value and methods will be developed to recover and sell this hydrogen. There is still potential for fugitive emission of hydrogen from these plants, but these leaks should be small in comparison to the widespread use of hydrogen. Nevertheless, this presents a limitation of this work.

There are also other technologies that have not been included in this central scenario. This includes the widespread use of hydrogen vectors such as ammonia and Liquid Organic Hydrogen Carriers (LOHC) that could emit hydrogen during their production and end-use applications.

Finally, this study has not considered the carbon emissions associated with methane from CCUS-enabled hydrogen production. Total carbon dioxide emissions for CCUS-enabled hydrogen would need to take into account methane emissions from both the hydrogen production process and upstream of the production facility. However, this study only considers hydrogen emissions to the atmosphere and so methane emissions are not included.

3 Hydrogen Production

3.1 Electrolytic Hydrogen

Hydrogen electrolysers use Direct Current (DC) electricity to split water into ions that are separated by an electrolyte before recombining to produce hydrogen and oxygen (Figure 2). The different electrolyser technologies (alkaline, PEM, AEM and solid oxide) are constructed from different materials and operate at different temperatures and pressures, which will impact hydrogen emissions. Currently, only PEM and alkaline electrolysers are commercially available and hydrogen emissions from these technologies will be similar to, or greater than those of the newer technologies. The emissions from PEM and alkaline electrolysers are therefore bounding and have formed the basis of this study.

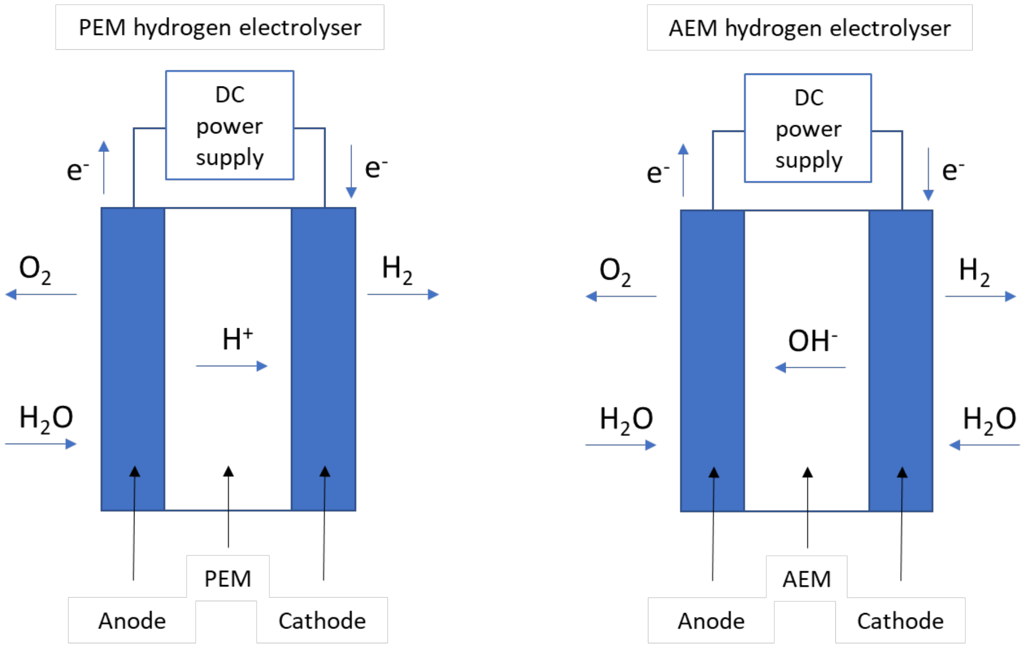


Figure 2: Schematic of a PEM and AEM (or Alkaline) electrolyser cells showing the hydrogen ions (PEM) and hydroxide anions (AEM) moving between the electrodes. In both cases, electrons are then transported from the anode to the cathode via the electrical circuit.

There are four categories for potential hydrogen leakage from electrolysis:

- Leakage through casing and pipework;
- Venting during start-up and shutdown;
- Contamination of the vented oxygen (hydrogen crossover);
- Purging or bleeding processes during operation to remove impurities.

3.1.1 Leakage Through Casing

The leakage of hydrogen through the casing of electrolysers is considered in BS ISO 22734 [6]. This highlights that "*Hydrogen generators shall be manufactured such that unintentional hydrogen releases during normal operation are precluded*". It defines a method to test the hydrogen leakage and requires that "*when the test pressure is reached, the flow of test fluid shall be stopped and the pressure in the hydrogen generator shall be monitored for at least 2 min. There shall be no measurable pressure drop.*" Fugitive leakage of hydrogen through the casing of the electrolyser is assumed to be negligible and mitigated through laminated gaskets and welded joints.

3.1.2 Venting During Start-Up and Shutdown

Electrolyser systems are designed to prevent the build-up of an explosive mixture of hydrogen and oxygen. The Lower Explosive Limit (LEL) of hydrogen in an oxygen containing atmosphere is 4 % [2], and to provide a factor of safety the hydrogen concentration is driven down to less than 25 % of this limit, so <1 %. At start-up, any air within the cathode side of the system is vented as shown in Figure 3. Similarly, at shutdown it is vented again to remove moisture and any explosive gas mixture from the system.

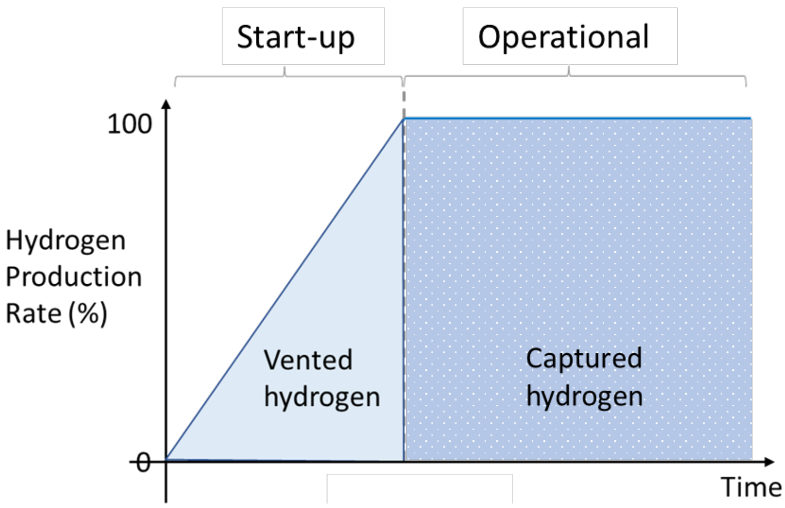


Figure 3: During the start-up (and shutdown) phases, hydrogen is vented. It is assumed that these follow a linear increase (or decrease) in hydrogen output.

Consultation with OEMs indicated that hydrogen venting during start-up and shutdown is around ~0.1 % of total hydrogen produced. For the purposes of this study, it is assumed that start-up and shutdown sequences are a linear ramp-up or down in hydrogen production. Following guidance from OEMs, these sequences last for between 5 and 10 minutes, and they occur at a frequency of at least weekly, but less than daily (50 - 300 times a year). This gives a hydrogen release of 0.05 - 0.6 % of the total produced.

3.1.3 Hydrogen Crossover

During operation, hydrogen is produced on the cathode side and is collected, whilst oxygen is produced on the anode side and is currently generally vented to atmosphere. However, a small proportion of the gas can cross the membrane or separator between the electrodes, known as "crossover". The majority of gas crossover is the hydrogen moving from the cathode to the anode, due to the combined effect of gas molecule size (hydrogen being smaller than oxygen) and pressure differential (the cathode pressure is generally higher than that of the anode). Any hydrogen that crosses over to the anode is vented to the atmosphere with the oxygen (Figure 4). Factors that increase the rate of hydrogen crossover are an increase in pressure differential, current density (rate of hydrogen production) and temperature [7].

No guidance from OEMs was given to the specific hydrogen release with the vented oxygen arising from hydrogen crossover. Conservative estimates have therefore been made based on the safety requirement to remain below 1% hydrogen in the anode oxygen environment (<25% LEL). The hydrogen crossover is almost constant regardless of the hydrogen production (output rating). However, as hydrogen production increases so too does the amount of oxygen. Since the concentration of hydrogen must always be <1 % (25 % of LEL), the rate of hydrogen crossover can be calculated at the lowest hydrogen production rate.

As the volume of hydrogen produced is twice as much as the oxygen produced (according to the stoichiometry of the electrolysis reaction below), a maximum 0.5 % of the hydrogen produced can crossover into the anode (assuming it does not recombine with the oxygen at the anode) to ensure the environment remains below the 25 % LEL.

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2$$

As the maximum concentration of hydrogen at the anode will occur at low rates of hydrogen production [7], an upper bound is based on the conservative assumption that the lowest production rate is at 30 % of maximum. This gives an upper bound level of hydrogen released with the oxygen vented gas at 0.15 % of the total hydrogen produced.

The catalytic activity of iridium dioxide catalyst in the anode of standard PEM electrolysers means that the hydrogen is unlikely to recombine with oxygen. This is not the case for reversible PEM electrolyser / fuel cell systems (or other electrolyser technologies), where a significant proportion (if not all) of the hydrogen will recombine with the oxygen at the anode to produce water. However, a lower bound of 0.05 % is used to represent incomplete recombination noted in some reversible electrolyser / fuel cell system studies [8].

3.1.4 Purging during Purification

The hydrogen produced from electrolyser systems undergoes a purification step in order to meet the hydrogen fuel quality standard ISO 14687:2019 [9]. The main contaminants that require removal are moisture and oxygen to levels below 5 ppm (nitrogen content is required to be below 300 ppm but is controlled by the purification of input water and the start-up and shutdown venting procedures discussed above). Whilst one of the absorption units is in use, the other undergoes a regeneration step to release the absorbed water, during which time it is purged from the system by a flow of hydrogen (Figure 3) that is then vented, with the moisture.

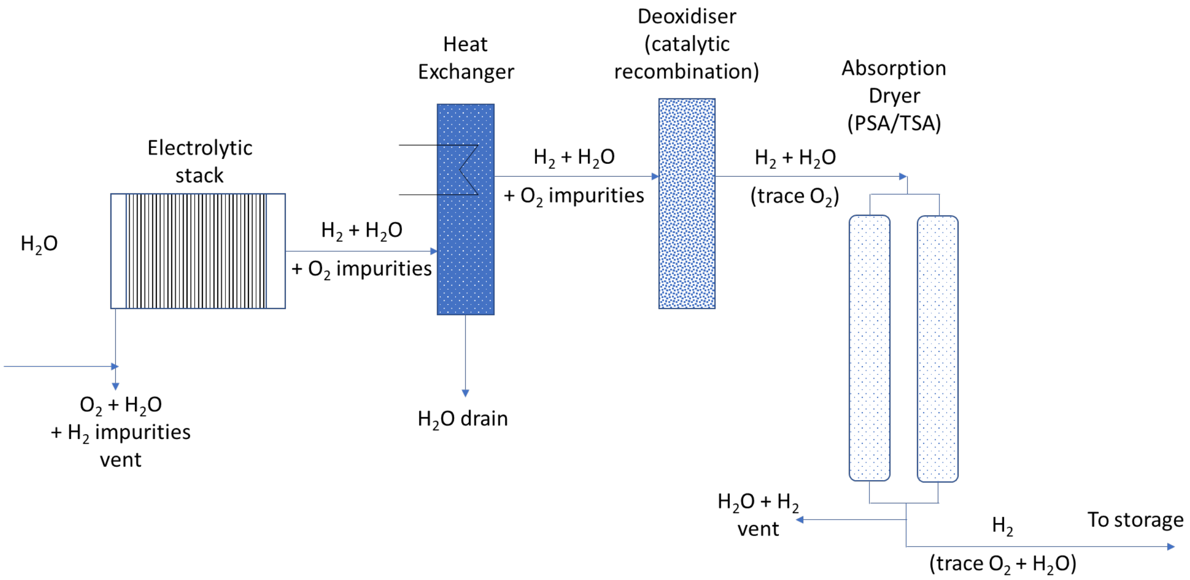


Figure 4: Schematic of a hydrogen electrolyser system (adapted from [10], [11]**). The hydrogen exiting the electrolysis stack contains water and oxygen impurities. This is passed through a heat exchanger, deoxidiser (catalytic recombiner) and an adsorption dryer (typically Pressure Swing Adsorption (PSA) or Temperature Swing Adsorption (TSA)) to purify the hydrogen.**

In terms of hydrogen emissions, it is the pressure or temperature swing absorption processes which have the largest impact. The bounding value for purging is around 10 % [10] based on operating experience of steam methane reforming (see for example [12]). The applicability of this to water electrolysis is questionable, and the experts engaged with as part of this work indicated this bounding value would be lower in electrolyser systems due to the much lower range and concentration of impurities in the hydrogen produced. Specific values found in the literature as part of this study were in the range of 3 – 4 % [13], however an upper bound range of 10 % was maintained for the purposes of this study without further data to support an alternative.

It is worth noting that the purged and vented hydrogen (hydrogen cross-over) could be readily oxidised to water by re-routing the vented and purged gases and passing them over recombining catalysts. There is likely to be a minimum scale of hydrogen production to make this economical, but as the central scenario allows for a considerable ramp-up in electrolytic hydrogen, allowance is made for this as discussed in Section 6.

3.1.5 Summary of Hydrogen Leakage

The predicted hydrogen leakage as a function of percentage produced by the electrolysis process is summarised in Table 2.

Table 2: Summary of hydrogen emissions for electrolysis as a percentage of the hydrogen produced.

Emission Category	Hydrogen Release to Atmosphere as a Proportion of Hydrogen Produced	Factors that affect emissions predictions with ranges for model
Leakage through Casing and Pipework	n/a	n/a
Venting during start-up & shutdown	0.05 - 0.6 %	Duration of start-up/shutdown sequence [5 – 10 mins] Number of start-ups/ shutdowns [50 - 300 per year]
Venting of oxygen (hydrogen crossover)	0.05 - 0.15 %	Minimum production capacity: [10 – 30 %] Amount of hydrogen recombined to produce water [0 – 100 %]
Purging processes to remove impurities	0 – 10 %	Vented hydrogen during operation [3 – 10 %] Amount of hydrogen recombined to produce water [0 – 100 %]

3.2 CCUS-Enabled Hydrogen

The following categories of leakage from CCUS-enabled hydrogen production have been identified:

- Leakage from pipework and equipment;
- Operational procedures:
- Start-up and shutdown;
- Purging for maintenance or during fault conditions;
- Monitoring of process gases;

- Post processing;
- Residual hydrogen in carbon dioxide stream;
- Purging or bleeding processes to remove impurities.

3.2.1 Leakage from Pipework and Equipment

Engagement with industry involved with developing new CCUS-enabled hydrogen production facilities highlighted that these facilities will be designed to work with hydrogen from the outset and will be well sealed. Welded joints will be used as much as possible with flanged joints only where necessary. Similar to the leakage from electrolysis, this is likely to be negligible for new, purpose-built plant.

3.2.2 Operational Procedures

During start-up, the hydrogen produced cannot be stored or exported until it has reached appropriate purity. Equally, at shutdown the system will need to be purged to remove production gases. Industry developers highlighted that in all new plants start-up and shutdown process gases will be sent through to flare rather than venting them to atmosphere.

During maintenance or fault conditions, some aspects of the plant may need to be isolated and this will require re-routing process gases. Where previously these gases may have been vented to atmosphere, developers of new hydrogen production facilities from methane highlighted that any hydrogen that cannot be exported will be sent to flare. This will be a temporary measure and if after a short period (a few days) the plant cannot be restarted, it will be shutdown.

Sample Operating Philosophy for SMR with CCS [14]

Before introducing any natural gas to the process, the flare and vent systems must be operational.

Should the hydrogen export routes be unavailable (i.e. blockage at hydrogen export compressor outlet or hydrogen export compressor trip), the plant will initially flare hydrogen product downstream of the PSA unit…If hydrogen export cannot be recommenced within a reasonable timeframe, plant shutdown is required.

A very small amount of unburnt hydrogen may be left from flaring but given hydrogen's high flame speed and large flammability range this is likely to be very small. All stakeholders agreed that hydrogen emissions from flaring (unburnt hydrogen in exhaust) will be negligible.

Other operational leakage mechanisms include monitoring of process gases. Trace amounts of hydrogen will be lost as part of process gas stream analysis. However, these are only likely to be in the region of a few grammes per sample so can be ignored.

3.2.3 Post Processes

From conversations with industry experts, a small fraction of the produced hydrogen (approx. 0.03%) could leave the carbon dioxide capture process within the carbon dioxide stream. This could be removed using an oxidation process but is likely to be maintained in the carbon dioxide and sequestered underground. It is unlikely that any of this hydrogen would be emitted to the atmosphere, although this may depend on the specific sequestering process.

The hydrogen produced will need to be purified and this is typically achieved by Pressure Swing Adsorption (PSA). As highlighted for electrolytic hydrogen production (Section 3.1.4), the hydrogen losses from this process can be as much as 10 % [12]. This is due to the relatively low hydrogen recovery rate of around 90 %. PSA is an active area of research and new methods of improving hydrogen recovery are likely to be developed by increasing the binding between the adsorbent material and the impurity molecules. The remaining process gas containing residual amounts of hydrogen could be sent to flare or used to produce process heat. Certainly, the very large scale of SMR and bio-energy plants is likely to make this economically viable. For the purposes of the central scenario, it is assumed that all purged hydrogen will be recombined.

3.2.4 Summary of Hydrogen Leakage

As new plants specifically designed for producing hydrogen, the hydrogen emissions from this process are likely to be very small. However, given the huge throughput of hydrogen, some will undoubtedly be lost to the atmosphere. Overall, it has not currently been possible to assign a hydrogen emission for CCUS-enabled hydrogen production but the purpose of predicting an overall emission for the central scenario, a hydrogen emission of 0 – 0.5 % has been assumed.

4 Hydrogen Transportation and Storage

4.1 National Transmission System

The National Transmission System (NTS) is assumed to be converted to transport 100% hydrogen. Hydrogen emissions have been predicted using existing predictions for natural gas leakage, and then converting these to hydrogen by comparing the gas leakage characteristics of the two gases.

There are three leakage mechanisms for natural gas and therefore hydrogen:

- Pipework leakage (pipes, valves, traps, assets etc.)
- Compressor leakage (leakage through seals, planned process venting, start-up purging)
- Other emissions

4.1.1 Current Natural Gas Leakage Through Pipework

There is significantly uncertainty in the leakage of natural gas in the NTS. National Grid formally reports methane emissions to the EU as part of Annual European Union Greenhouse Gas Inventory and in 2020 these were 3.4 kt/year [15]. Industry experts recognise that this figure is likely to be an under-estimate as it is based on only limited monitoring, it assumes all assets are new, and it omits some known emissions sources.

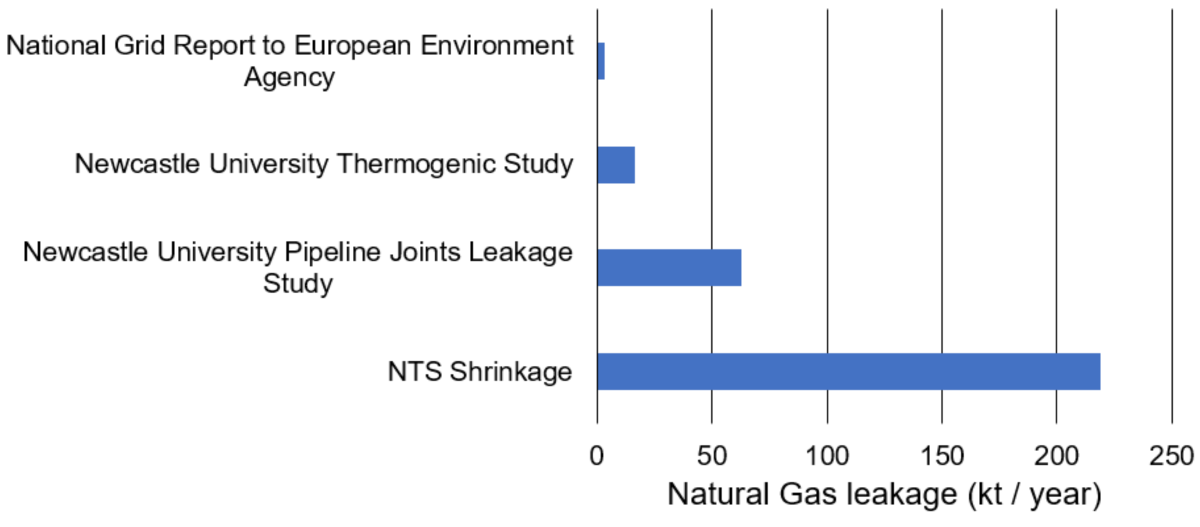


Figure 5: Comparison of NTS natural gas leakage predictions. Methane emissions of 3.4 kt/year are reported to the EU, although studies by Newcastle University predict emissions of between 17 (thermogenic emissions only) and 63 kt/year. Shrinkage data obtained from meter readings is much higher at over 200 kt/year but this is considered to be an overestimate.

The NTS also publish shrinkage data from inflowing and outflowing meter readings. This is significantly higher at 220 kt/year [16] and is considered by industry to be a significant overestimate as a leakage of this magnitude should be detectable by satellite imaging.

Shrinkage includes leakage but also other losses from the network such as own-use and stolen gas that are less likely to result in emissions to the atmosphere. Newcastle University undertook a measurement study of a small section of the transmission system (270 km of a total 7600 km so <4 % of total). When extrapolated across the whole network this predicted 63 kt/year [17]. Newcastle University also undertook a thermogenic study (that distinguishes between biogenic methane produces by biological processes) that predicted a leakage of 17 kt/year [17]. Industry experts engaged with during this suggested that natural gas leakage is likely to be around 15 kt/year although it has not been possible to corroborate this.

4.1.2 Natural Gas Leakage from Compressors

Compressor stations located on the NTS are responsible for around 4.5 kt/year of natural gas [18]. This mostly comprises leakage from seals but also process venting and start-up purging. The CH4RGE programme aims to reduce these emissions to under 0.5 kt/year by the early 2030s.

4.1.3 Other Emissions

There are other smaller natural gas leakage mechanisms including venting of pipelines for maintenance, incomplete natural gas combustion from gas turbines driving compressors and chromograph measurements. However, these are all considered to be negligible compared to pipeline leakage.

4.1.4 NTS Total Natural Gas Emissions

The NTS currently transports around 700 TWh of natural gas per year [19] (equivalent to 45,000 kt of natural gas). Based on a leakage of 19.5 kt/year (15 kt from the pipeline and 4.5 kt from compressor stations) this equates to a loss of 0.04 %. At the extreme natural gas leakage of 220 kt/ year this is almost 0.5 %.

4.1.5 Converting Natural Gas leakage to Hydrogen Leakage

Leaks of gas from pressurised pipes can occur in several different flow regimes. When the leakage velocity is low, and/or the hole size is small then the flow will be laminar. At higher velocities or larger hole sizes, the flow will be turbulent. This is important as converting natural gas leakage rates to hydrogen are different for these two flow regimes. In laminar flow, for the same pipe pressure, hole size and shape the leakage volume flow rate of hydrogen relative to natural gas is given by the ratio of the dynamic viscosities of the two gases and is approximately 1.2. Since the density of hydrogen is so much less than natural gas, the ratio of the mass flow rate of hydrogen to natural gas (allowing for the densities) is approximately 0.15 [20].

Equations 1 & 2: Laminar flow:

$$\frac{\dot{V}_{(hydrogen)}}{\dot{V}_{(natural\ gas)}} = \frac{\mu_{(natural\ gas)}}{\mu_{(hydrogen)}} = 1.2$$

$$\frac{\dot{m}_{(hydrogen)}}{\dot{m}_{(natural\ gas)}} = \frac{\rho_{(hydrogen)}}{\rho_{(natural\ gas)}} \frac{\mu_{(natural\ gas)}}{\mu_{(hydrogen)}} = 0.15$$

Where $\dot{V}$ is the volume flow rate, $\dot{m}$ is the mass flow rate, ρ is the density and μ is the viscosity.

Whilst volumetrically hydrogen leaks more than natural gas, the mass leakage rate of hydrogen is significantly lower. The ratio of hydrogen to methane release rates can also be expressed in terms energy (or heat) fluxes of the two gases and is 0.4.

Under turbulent flow, for the same pressure and hole size and shape, the ratio of hydrogen to methane volumetric flow rates is equal to the inverse of the square-root of the gas densities and is approximately 2.8. The mass flow rate of hydrogen compared to natural gas is approximately 0.35. The conversion from natural gas leakage rates (either volume or mass flow rate) is almost a factor of three different for the two regimes. The ratio of hydrogen to methane release in terms of energy is 0.91 [20].

Equation 3 & 4: Turbulent flow:

$$\frac{\dot{V}_{(hydrogen)}}{\dot{V}_{(natural\ gas)}} = \sqrt{\frac{\rho_{(natural\ gas)}}{\rho_{(hydrogen)}}} = 2.8$$

$$\frac{\dot{m}_{(hydrogen)}}{\dot{m}_{(natural\ gas)}} = \sqrt{\frac{\rho_{(hydrogen)}}{\rho_{(natural\ gas)}}} = 0.35$$

4.1.6 Summary of Hydrogen Emissions

Based on these scaling factors, if the current natural gas NTS is converted to transport hydrogen, a leakage of 19.5 kt/year with natural gas would change to either 3 kt/year of hydrogen (laminar) or 7 kt/year (turbulent). The flow regime is dependent on the pipeline pressure, but also the leakage path (size and shape of the holes). It has not been possible to find any details on typical leakage paths in the NTS, so the leakage rate has been assumed to be between these two bounds. Engagement with industry suggested a future NTS would either operate at the same pressure as the current natural gas NTS or at a slightly reduced pressure. As a conservative assessment, no allowance has been made for pressure reduction.

The calorific value of hydrogen by volume is only a third of that for natural gas so to transport the same amount of energy the volume flow rate will need to be three times higher for hydrogen. However, because the density of hydrogen is so much lower than natural gas, for the same operating pressure, a similar amount of energy can be transported by hydrogen as natural gas [21].

A loss of 3 - 7 kt/year of hydrogen would equate to 0.02 - 0.04 % of the total hydrogen transported at the same overall throughput of energy (700 TWh). This percentage loss can then be applied to a future hydrogen NTS in the central scenario to predict the overall annual leakage in terms of mass.

In the probabilistic model, the following factors have been included:

- Current total natural gas leakage; known to be between 8 and 225 kt/year but suggested by industry to be around 19.5 kt/year. This has been modelled as a bi-uniform distribution between 8 and 225 kt/year but with a central estimate of 19.5 kt/year;
- Leakage conversion factor (in terms of mass) from natural gas to hydrogen; 0.15 – 0.35 (allowing for laminar or turbulent leakage);
- Energy throughput of existing NTS; 600 - 1,000 TWh.

4.2 Gas Distribution Networks

Similar to the National transmission System, the gas distribution networks are assumed to be converted to 100% hydrogen. Hydrogen leakage is predicted by using the current natural gas leakage predictions and converting these to hydrogen.

4.2.1 Current Natural Gas Leakage

The distribution networks publish gas shrinkage predictions that comprise leakage, own use gas and theft for natural gas. Leakage is by far the largest of the three and for the purposes of this study, shrinkage is assumed to be the same as leakage (and hereafter referred to as leakage). The distribution network predictions include allowance for the Mains Replacement Programme that is gradually replacing old metal piping with Poly-Ethylene (PE) and hence reducing leakage year-on-year. Leakage predictions are made by the individual gas network operators using a model developed by Advantica (now DNV), that is approved by OFGEM.

The combined gas network model predictions for natural gas leakage are shown in Figure 6 [22]. At present, the Low Pressure (LP) gas network is responsible for the majority of the leakage, followed by Above Ground Installations (AGI) and the Medium Pressure (MP) network. The distribution networks also include an Intermediate Pressure (IP) network but this is assumed not to leak and is therefore not included in the model. The DNV model used by the network operators predicts that the mains replacement programme will reduce overall leakage significantly over the next decade. This programme is due to be completed by 2032 when over 90% of the gas distribution network will be PE (although funding for this programme is only secure until 2026) [23]. After completion of this programme LP leakage should be comparable to AGI emissions.

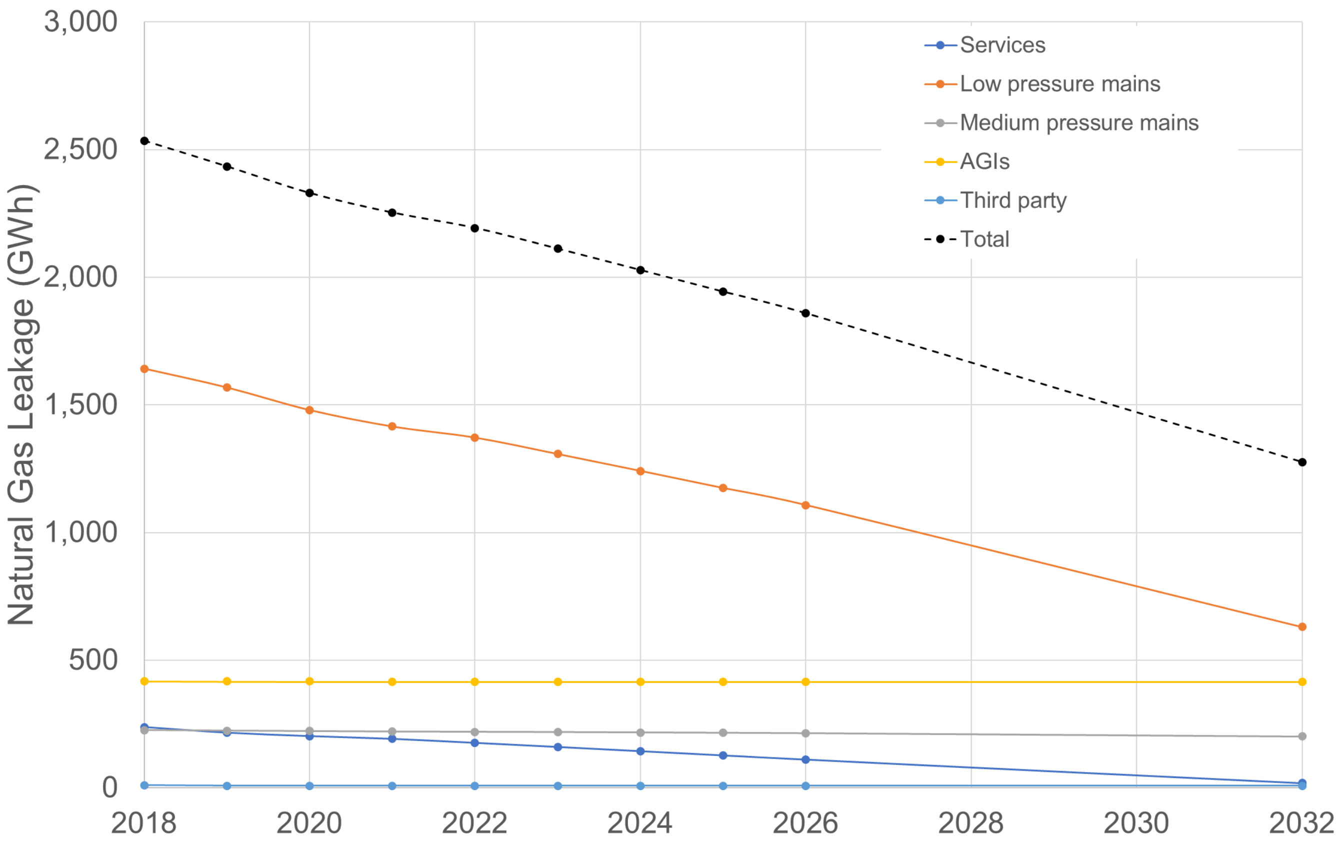


Figure 6: Gas distribution network leakage predictions up to 2032 provided by OFGEM [22]**. By the end of the mains replacement programme in 2032 natural gas leakage is predicted to be 1,277 GWh per year, a 50% reduction since 2018. By 2032, leakage from the low pressure mains will be only slightly higher than from Above Ground Installations (AGI).**

The total annual predicted natural gas leakage from distribution networks is currently 2,500GWh (Figure 6), equivalent to around 160 kt/year of natural gas. The distribution system has an annual throughput of around 500 TWh [19] and so around 0.5 % of the natural gas is lost to shrinkage. If the mains replacement programme is completed, the rate of leakage should be reduced to around 83 kt/year or 0.25 % (percentage of mass of natural gas lost to total mass of throughput of natural gas).

4.2.2 Converting Natural Gas leakage to Hydrogen Leakage

The H21 National Innovation Competition Project has investigated how hydrogen will leak differently to natural gas in the LP, MP and IP networks. The primary interest of this project has been the ratio of the hydrogen leak rate to the methane leak rate not the absolute leak rate. Tests were undertaken on a range of assets and pipe configurations representative of the UK gas distribution network. The assets were removed from the network and transported to the HSE Science and Research Centre at Buxton where they underwent controlled testing with methane and 100 % hydrogen. The tests highlight that Leakage in the LP network tended to be laminar (volume flow rate increase from natural gas to hydrogen of 1.1), whilst the MP tended to be turbulent (volume flow rate increase of 2.8). This suggests that leakage on the NTS is likely to be turbulent, although there is no testing to corroborate this.

Whilst the H21 testing has highlighted trends in leakage between the LP and MP networks, it only considered a small selection of the assets on the network and as such it is not possible to assert that all LP leakage will be laminar and all MP leakage will be turbulent.

The objective of the H21 tests was to predict hydrogen leakage that could pose a safety risk. There may be additional smaller leakages that could, if consistent along the network, make an additional contribution to leakage:

- The experiments undertaken ran for relatively short periods of time (120 seconds of recording the leakage rate). They therefore did not take into consideration long term, slow permeation of gas through the asset materials [24].
- The minimum flow rate measured was 100 cc/min, which was sufficient to identify leaks of interest from a safety perspective. However, there remains some uncertainty over the behaviour of smaller leaks [25].

The limitations of these tests and the implications for further work is discussed in Section 7.

If the distribution networks are converted to transport 100% hydrogen, the leakage would be between 12 and 30 kt/year of hydrogen (depending on if the leakage is laminar of turbulent). Based on the same throughput of energy (500TWh) this is a loss of 0.1 to 0.23% (in mass terms). There are, however, other factors that may affect the hydrogen leakage predictions and these are included in the probabilistic model as follows:

- Completion of mains replacement programme. The programme is predicted to half current natural gas emissions. A leakage rate of 0.1 - 0.23 % is based on the completion of this programme. However, in principle it could be stopped any time before 2032 and so a factor of 1 – 2 is applied (1 if fully completed and 2 if aborted in 2022)
- Energy throughput of existing distribution system; 400 - 600 TWh.
- Mass flow conversion from natural gas to hydrogen leaks; 0.15 – 0.35 (allowing for laminar or turbulent leakage)
- Leakage from IP network; 1 – 1.2 (allowing for up to 20 % additional leakage from the IP network).
- Additional leakage if pressure of hydrogen distribution network is higher than existing natural gas network; 1 - 1.2 (allowing for up to 20 % additional leakage).

4.3 Salt Cavern Storage

Two leakage mechanisms for hydrogen storage in salt caverns have been identified:

- Natural leakage from cavern due to permeability of substrate;
- Leakage associated with process plant on surface - venting and purging due to maintenance and fault conditions.

Leakage due to salt permeability or pipe/well head leakage is predicted to be negligible and estimated at 1.76×10-11 kg/s per cavern [26]. The main leakage will be from the surface processing plant and includes deliberate releases from scheduled annual whole plant shutdown, annual component maintenance releases and emergency shutdown. Based on conversations with industry experts, the leakage of hydrogen from a typical surface plant servicing 15 - 20 caverns would be around 25 tonnes per year. A surface plant servicing 17 caverns will have a total storage of around 2.6 TWh or 65 kt/year. The loss of hydrogen is therefore predicted to be around 0.04%.

The hydrogen leakage will depend on the amount of release from each of the maintenance and emergency activities and the number of surface plants required to service a set of caverns. In the future, these hydrogen emissions could be sent to flare or recombined to form water but in this study, they are assumed to be released to atmosphere. The following parameters are included in the probabilistic model:

- Scheduled shutdown release; 0 – 20 tonnes/yr (allowing for technology improvements);
- Component maintenance release; 1 – 3 tonnes/yr;
- Emergency shutdown release; 5 – 15 tonnes per year;
- Emergencies per year; 0.1 - 0.3;
- Size of each cavern; 100 – 200 GWh;
- Number of caverns required per plant; 10 – 30.

4.4 Above Ground Storage

Hydrogen may be stored in compressed tanks for gas system balancing. Leakage rates from compressed gas cylinders range from 0.005 [27] to 0.01 % per hour [28] (0.12 – 0.24 % per day). Over short durations this is therefore very small, but when stored for extended periods this can be very significant. The leakage rate is very dependent on the storage pressure, cylinder and valve material, and the size of the cylinder. Larger cylinders will lose less as a percentage of their storage capacity. It is likely that any hydrogen stored for gas system balancing will be relatively short term, but an upper limit of 30 days has been applied as the duration is uncertain. The following parameters have been included:

- Leakage rate; 0.12 – 0.24 % per day;
- Assumed average duration of compressed hydrogen delivery; 2 – 30 days.

4.5 Transport of Hydrogen by Gas or Liquid

Although this study has included a repurposed NTS and gas distribution system to transport hydrogen, some hydrogen will need to be transported from production facilities to end-users. This may be transported as either a compressed gas in trailers or a cryogenic liquid. The UK does not currently have any hydrogen liquification facilities so it assumed that any liquid hydrogen will be imported.

4.5.1 Transporting Compressed Hydrogen Gas

The leakage rates from above ground stationary storage have been applied to the transportation of compressed gas in trailers. In this case, the duration of an average journey is likely to be at most a few days and the following parameters have been included:

- Leakage rate; 0.12 – 0.24 % per day;
- Assumed average duration of compressed hydrogen delivery; 0.5 – 3 days.

4.5.2 Transporting Liquid Hydrogen

For liquid hydrogen the main leakage mechanism is boil-off. The boiling point of hydrogen is 20K and some amount of vaporisation of the liquid hydrogen is inevitable. This boil-off is currently often vented to the atmosphere, particularly in smaller transport quantities like road trailers.

The amount of boil-off depends on the size and type of storage but is anything between 0.1 and 5 %, with typical values around 1 %. There are technologies that could be used to reduce this emission including reliquification and compression of the hydrogen for process heat but these are only likely to be feasible for larger applications.

The key uncertainties in predicting leakage from liquid hydrogen are as follows:

- Boil-off rate; 0.1 – 5 % per day;
- Assumed average duration of compressed hydrogen delivery; 0.5 – 3 days.

5 End-uses of Hydrogen

End-uses of hydrogen include transport applications, residential heating, gas turbines (for aviation and stationary power) and process industries. Hydrogen for transport applications is used either in fuel cells or internal combustion engines and these are both assumed to be provided by hydrogen refuelling stations.

5.1 Hydrogen Refuelling Stations

The key mechanisms for leakage in gaseous hydrogen refuelling are as follows:

- Purging during normal operation and emergency venting;
- Fugitive leakage from high pressure compressed hydrogen tanks;
- Leakage of hydrogen during compression process (permeation through seals).

At the end of each vehicle refuelling operation, the flexible hose is purged to remove hydrogen. However, even repeated for each refill operation, this is negligible. There are other small mechanisms for hydrogen emissions such as venting of the buffer storage tank and fugitive leakage through pipework but discussions with industry suggested these should also be negligible. The two main mechanisms are therefore fugitive leakage from the high pressure compressed hydrogen tank and the fugitive leakage during the compression process.

Based on conversations with industry experts, the leakage from compression of hydrogen is estimated to be between 0.05 – 0.25 %. All hydrogen being processed and distributed by the refuelling station is assumed to undergo one round of compression.

Leakage from the high-pressure storage is 0.12 – 0.24 % per day [27], [28] (the same as compressed storage in Section 4.4.1). The parameters used to assess the hydrogen emissions from refuelling stations are as following:

- Daily output of a single hydrogen refuelling station: 80 – 1,300 kg. The output of a single station determines the number of stations required for a given overall hydrogen demand.
- Amount of hydrogen stored at high pressure at any given time at a refuelling station: 100 – 500 kg.
- Leakage from high pressure storage: 0.12 – 0.24 % per day.
- Compressor leakage: 0.05 – 0.25 % (hydrogen lost during compression process).

5.2 Fuel Cells

Hydrogen fuel cells are a very similar technology to hydrogen electrolysers, but operating in reverse; they use (rather than produce) hydrogen and oxygen and produce (rather than use)

DC electricity and water. The differences are shown in Figure 7 for a PEM cell, although the same principles could also be applied to convert from an alkaline electrolyser technology (shown in Figure 2) to an alkaline fuel cell technology.

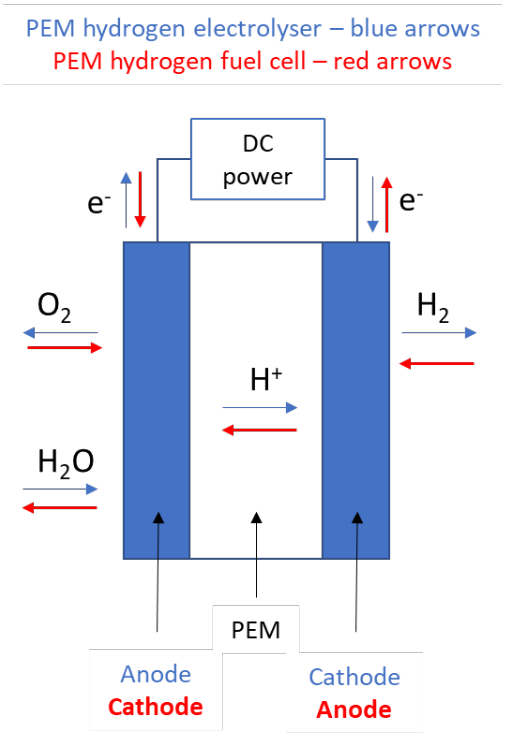


Figure 7: Difference in operation between a PEM fuel cell and PEM electrolyser. Fuel cells essentially operate as electrolysers in reverse; the blue lines indicate electrolysis and red lines operating as a fuel cell.

The similarity of the basic principles and components of the electrolyser and fuel cell means that the routes for hydrogen release are broadly similar, falling into the following four categories:

- Leakage through casing and pipework.
- Venting during start-up and shutdown.
- Hydrogen crossover causing contamination of the vented oxygen (air).
- Purging or bleeding hydrogen during operation.

The details described in Section 3.1 should be taken as applicable to fuel cells, unless otherwise stated.

5.2.1 Leakage Through Casing

Different standards apply to fuel cell systems (in comparison to electrolyser systems). The series of BS EN IEC 62282 standards [29] are directly applicable to hydrogen fuel cell systems and include allowable leakage through casing and pipework.

As with the electrolysers, the leakage through casing and pipework was taken to be negligible, on the assumption that the electrolysers are produced in accordance to BS EN IEC 62282 and that risk of leakage can be mitigated by laminated gaskets, welded joints and adequate servicing.

5.2.2 Hydrogen Crossover

Crossover occurs within a fuel cell in the same way as an electrolyser insofar as the hydrogen side is typically at a higher pressure than the oxygen (air) side, and hydrogen crossover to the oxygen side occurs. However, within a fuel cell system the operation and implications for hydrogen release are slightly different (Figure 8). Fuel cells operate with air as the oxygen containing gas for practicality and cost reasons. As air is ~80% nitrogen, nitrogen also crosses the electrolyte from the cathode to the anode. To maintain high current densities and prevent starvation of the anode catalysts, an excess of hydrogen is supplied to the anode side, which is then recirculated back to the hydrogen inlet for recycling. To prevent excessive dilution of the hydrogen fuel by nitrogen (and other impurities) within the fuel cell, the gas exiting the anode is either periodically purged, or a small percentage is continually bled [30], either process giving rise to hydrogen emissions.

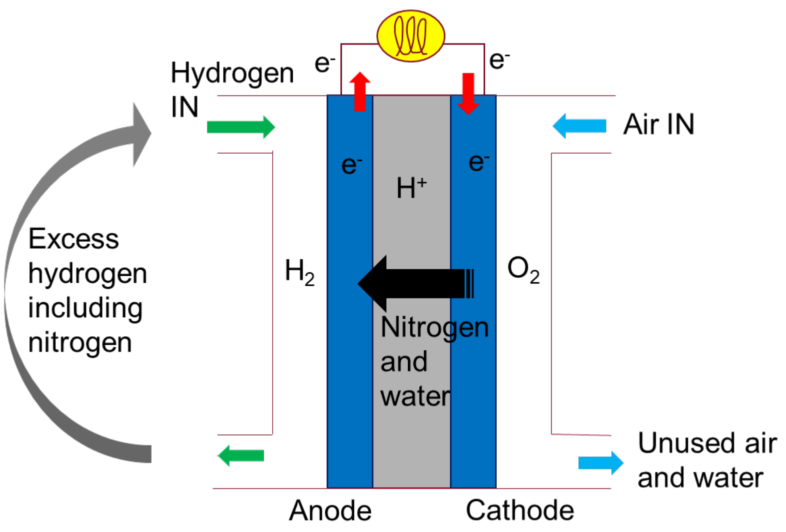


Figure 8: Schematic of crossover in a fuel cell operation. An excess of hydrogen is supplied to the anode side, which is then recirculated back to the hydrogen inlet.

The catalyst at the oxygen electrode (cathode) of standard PEM fuel cells will mean that any hydrogen crossover is likely to recombine with the oxygen. This is in contrast to the catalyst used for electrolyser systems. For the purposes of the uncertainty modelling however, the higher range was pessimistically kept at 0.15% (no recombination), but the lower range (and typical value) reduced to 0% to reflect the different catalysts used within the fuel cells.

5.2.3 Purging During Operation

The largest quantity of hydrogen released is during the purging processes to remove the nitrogen and impurities which build up in the hydrogen fuel cell system. One study noted that typical hydrogen emissions were 0.8 % for steady state operation and 1.2 % for transient load changes [30] for a system which automatically vents at a given nitrogen content. It is anticipated this is likely to be typical values, as the cost of hydrogen will drive losses of this nature to be minimised; however, the same study indicated emissions could be as high as 2 %

for a simplified continual bleed of the fuel on exit. The lower bound of 0 % represents the condition if the system were to be fitted with a catalytic convertor to burn the purged hydrogen prior to emission to the atmosphere.

5.2.4 Leakage from Tank

In surface transport applications the hydrogen is likely to be stored as a compressed gas. The leakage from a compressed gas cylinder discussed in Section 4.5.1 is therefore also relevant here. This leakage is dependent on the rate of leakage from a pressurised cylinder (0.12 – 0.24 % per day [27], [28]) and the average duration that the hydrogen is stored in the tank, assumed to be 0.5 to 3 days.

5.2.5 Summary of Hydrogen Leakage

The range of hydrogen leakage predictions as a function of hydrogen input into the fuel cell is summarised in Table 3. This also includes the parameters that influence these predictions with the range of values used in the probabilistic model. It is worth noting that, if required, an adaption of a hydrogen fuel system design would be relatively simple to achieve, re-routing the vented and purged gases to ensure the hydrogen was oxidised to water before release to the atmosphere.

Table 3: Summary of the Hydrogen Emissions for Fuel Cells

Emission Category	Hydrogen Emission (% of Hydrogen Produced)	Factors that affect emissions predictions [model parameters]
Leakage through Casing and Pipework	n/a	n/a
Venting during start-up & shutdown	0.04 - 0.7 %	Duration of start-up/shutdown sequence [2 – 5 mins]* No. start-ups, shutdowns [100 – 750 /yr]*
Venting of oxygen (hydrogen crossover)	0 - 0.15 %	Minimum output: [10 – 30 %] Amount of hydrogen recombined to produce water [0 – 100 %]
Purging processes to remove impurities	0 – 2 %	Venting during operation [0.8 – 2 %] Amount of hydrogen recombined to produce water [0 – 100 %]
Leakage from compressed gas tank	0.06 – 0.72 %	Rate of leakage [0.12 – 0.24 %/day] Duration of hydrogen in tank [0.5 – 3 days]

*Note: The range of hydrogen emissions arising from start-up and shutdown processes for fuel cell systems is slightly broader than that of an electrolyser system. This is to incorporate an assumed faster response time for fuel cell systems with particular relevance to the transport sector, and a corresponding higher number of start-up and shutdown events per year.

5.3 Internal Combustion

Hydrogen can be burned in an internal combustion engine either as a pure gas (mono-fuel) or combined with diesel (dual-fuel). In dual-fuel mode, some hydrogen may be left unburned in the exhaust stream but this should be converted to water via an oxidation catalyst. In mono-fuel mode, hydrogen in the exhaust is likely to be 10-15ppm and a catalyst will generally not be employed as the hydrogen concentration is too low. Fuel lines will need to be vented at shutdown but this release is negligible. Overall, the hydrogen emissions from combustion of hydrogen in internal are likely to be negligible and have not been included in this model. However, hydrogen-fuelled internal combustion vehicles will have hydrogen storage and this is assumed to be the same as for fuel cell vehicles summarised in Table 3.

5.4 Residential and Commercial

If boilers and other gas equipment such as fires, hobs and ovens are run on hydrogen, there are a number of mechanisms where hydrogen could be emitted to the atmosphere similar to natural gas appliances today.

- Installation and maintenance - purging the gas line;
- In-service operation;
- Leakage from appliance casing;
- Leakage from pipework.

5.4.1 Installation and Maintenance

During installation and maintenance, a small volume of hydrogen will be purged. This will just be the volume contained in a short section of pipework and is considered to be negligible.

5.4.2 In Service Operation

In current natural gas boilers, gas and air are pumped into the boiler where they are forced through a gauze and ignited. The hot combustion gases are then drawn through a heat exchanger, to heat water for heating and hot water, before being vented to atmosphere. Boilers start-up and shutdown numerous times per day based on demand. As they start up, some natural gas located away from the point of ignition will ejected to the atmosphere without being combusted. Similarly at burner shutdown, a small amount of gas is likely to be vented to clear the system. These are transient effects and during normal operation, the unburned gas in the exhaust is likely to be negligible.

It is likely that hydrogen boilers will operate on similar principles to natural gas boilers and will therefore observe the same leakage. Hydrogen has a much faster flame speed than natural gas and also has a much larger flammability range, so the amount of unburnt hydrogen is likely to be less than natural gas. Initial findings from industry suggest that for a typical domestic boiler operating cycle with an annual heat load of 12,000 kWh (equivalent to 300 kg of hydrogen) the combined annual release from start-up and shutdown will be around 0.4 kg per year. This represents a loss of 0.13 %.

Similar emissions mechanisms apply to hobs, ovens and fires that run on hydrogen, although these are likely to be significantly smaller due to the much lower energy output.

5.4.3 Leakage from Boiler Casing

Initial findings from industry suggest that leakage through the casing of a typical hydrogen domestic boiler will be <0.01 kg per year and therefore negligible compared to in service emissions.

5.4.4 Leakage from Pipework

A significant amount of work has been carried out under the BEIS Hy4Heat programme to understand how hydrogen may leak differently to natural gas in domestic pipework and the safety implications for this. The work has shown that [31]:

- A non-leaking fitting in methane will be non-leaking in hydrogen;
- A leak in methane will result in a leak in hydrogen.

However, the annual leakage of natural gas from domestic properties is not well quantified and this makes predicting hydrogen leakage difficult. The maximum leakage rate of natural gas in domestic properties is limited by the Maximum Permissible Leakage Rate (MPLR) [32] and this can be used as a conservative starting point for predicting how hydrogen may leak. There is currently no defined MPLR for hydrogen, with work ongoing to determine an appropriate value. Based on the similarity between the lower flammable limits of hydrogen and natural gas, the current volumetric MPLR for natural gas could also be applied to hydrogen. The MPLR for new installations is 0.0014 m3/hr, equivalent to 12 m3 per year per property (just less than 1 kg of hydrogen). For a typical home of annual heat load 12,000 kWh (300 kg) this equates to around 0.32 % leakage. It is worth noting that this is likely to be a considerable overestimate. The majority of leakage is likely to be from a small proportion of the housing stock that has old pipework. If 100% hydrogen is used in homes, as a minimum the older pipework systems would be replaced.

5.4.5 Summary of Hydrogen Leakage

Combining the hydrogen emission from boilers (0.13 %) and pipework leakage (0.33 %), this is just under 0.5 % in total.

The UK has around 21 million domestic boilers [33] and in total this would result in a hydrogen emission of up to 24.6 kt. There is significant uncertainty in this leakage and this has been captured in the probabilistic model as follows:

- Appliance leakage; 0.3 – 0.5 kg per year for a typical 12,000 kWh annual heat demand.
- Annual heat demand for a typical property; 7,000 – 17,000 kWh.
- Variability on domestic pipework leakage; 0 – 100 %. The pipework leakage is likely to be bounded by the MPLR but could be significantly lower.

5.5 Gas Turbines

There are two main mechanisms for hydrogen emission when used a fuel in gas turbines:

- System venting at start-up and shutdown;
- Hydrogen in exhaust at idle (part load).

5.5.1 System Venting

The Inlet fuel pipe is vented at start up. This has a small interior volume and even at 20 - 30 bar this emission is negligible. Equally, the whole internal fuel system is vented at shut down. The volume of fuel system is likely to be <10 m3 (less than 1 kg) and even at an elevated pressure, this emission is negligible for high utilisation equipment like gas turbines.

5.5.2 Hydrogen in Exhaust

Combustion efficiency at full load is anticipated to be very close to 100%. During start-up, the gas turbine is run at idle for a few minutes and this could result in the exhaust gas containing a small proportion of unburned hydrogen. Conservatively, this is estimated to be 5 – 10 % of the hydrogen input during the duration of the start-up and shutdown sequences. The overall hydrogen emission from gas turbines is dependent on the following parameters:

- Unburned hydrogen input; 5 – 10 %;
- Duration of idle operating mode; 2 – 5 mins;
- Number of start-ups per year; 50 – 200.

5.6 Process Industry

Hydrogen is likely to be used to decarbonise a range of industrial processes including iron and steel making, glass and other chemicals. Very limited information has been found on the hydrogen emissions from these processes as they have a low technical maturity.

For iron production, hydrogen is likely to be used for process heat and as a reductant in Direct Reduced Iron (DRI). For steel making, hydrogen's main role is in process heat.

The mechanisms for hydrogen emissions are likely to be as follows:

- Unburned gas exiting the reheat furnaces;
- Leakage and exhaust losses from the blast furnace.

All systems in iron and steel production are run with an excess air, which should facilitate complete combustion or oxidation of the natural gas.

At this stage, it has not been possible to quantify the hydrogen emissions from these processes. However, for the purpose of predicting an overall emission for the central scenario a hydrogen emission of 0 – 0.5 % has been assumed, the same as for CCUS-enabled hydrogen production.

Hydrogen is likely to be widely deployed to decarbonise the process industry and improving this information is a key recommendation from this study. This is discussed further in Section 7.

6 Probabilistic Analysis of Emissions

The information in Sections 3 – 5 has been incorporated into an uncertainty model to provide probabilistic predictions for hydrogen emissions. The model provides predictions (at a given confidence level) for the emissions of the individual sectors and also combines these to provide the overall emissions from the central scenario.

The model is a Bayesian Network, designed and tested for scenarios where there is a high degree of uncertainty. A Bayesian Network is a graphical representation of a calculation, made up of nodes (factors) and directional links (relationships), where everything is treated as uncertain. Through application of Bayes' rule, it examines the causal relationships between drivers and resultant emissions much faster than through standard Monte Carlo analysis. A key benefit for assessing fugitive emissions is that it calculates Sobol indices that are a measure of how the variability of input parameters affects a particular emission prediction. The model provides a probabilistic output and for the purpose of this study predictions are provided at 50% (median or central estimate) and 99 % confidence.

6.1 Individual Sector Emissions Predictions

The hydrogen emissions for the individual sectors at 50% and 99% confidence levels are presented in Table 4. For each specific area, the dominant parameters causing uncertainty has been extracted from the Sobol indices and is highlighted.

Table 4: Summary of hydrogen emissions predictions for the separate areas.

Sector	**Specific Area**		**Predicted Emission Confidence level**		**Largest parameter affecting uncertainty**
			50%	**99%**	
Production	Electrolytic	With venting and purging	3.32 %	9.20 %	Emission from purging during purification
		With full recombination of hydrogen from purging and crossover venting	0.24 %	0.52 %	Number of start-up and shutdowns per year
	CCUS-enabled		0.25 %	0.50 %	Quantification of leakage (this is an assumed leakage rate)

Transport and Storage	NTS		0.04 %	0.48 %	Current natural gas leakage of NTS
	Distribution Network		0.26 %	0.53 %	Flow regime of leakage (laminar or turbulent)
	Underground Storage		0.02 %	0.06 %	No. caverns
	Above Ground Storage (gas)		2.80 %	6.80 %	Average duration of storage
	Road Trailering (gas)		0.30 %	0.66 %	Average duration of hydrogen delivery
	Road Trailering (liquid)		3.76 %	13.20 %	Boil-off rate of liquid hydrogen (%/day)
End-uses	Residential		0.30 %	0.69 %	Leakage from pipework
	Gas Turbines		0.01 %	0.01 %	Number of start-ups per year
	Refuelling Stations		0.25 %	0.89 %	Daily output of a hydrogen refuelling station
	Fuel cells	With venting and purging	1.36 %	2.64 %	The emission from purging during purification
		With full recombination of hydrogen from purging and crossover venting	0.56 %	1.02 %	Duration of time hydrogen remains in storage tank
	Combustion Engines		0.30 %	0.66 %	
	Process Industry		0.25 %	0.50 %	Quantification of leakage (this is an assumed leakage rate)

The emissions predictions for electrolysis at 50 % and 99 % confidence are 3.32 % and 9.20 %. Purging during operation has been identified as the single largest contributor to the overall emission from electrolytic hydrogen. It is also the most uncertain and is the main cause of the variance in the predictions. In Section 3.1.4, technology solutions were highlighted that could be used to avoid emissions from purging during purification and venting due to hydrogen crossover. If these technologies are implemented and purging losses are completely mitigated, then the 50 % and 90 % hydrogen emissions reduce to 0.24 % and 0.52 % respectively. A similar argument can be made for the purging and venting of fuel cells and for the overall predictions in the central scenario, it is assumed that technologies to recombine the purged and vented hydrogen are implemented in electrolysers and fuel cells.

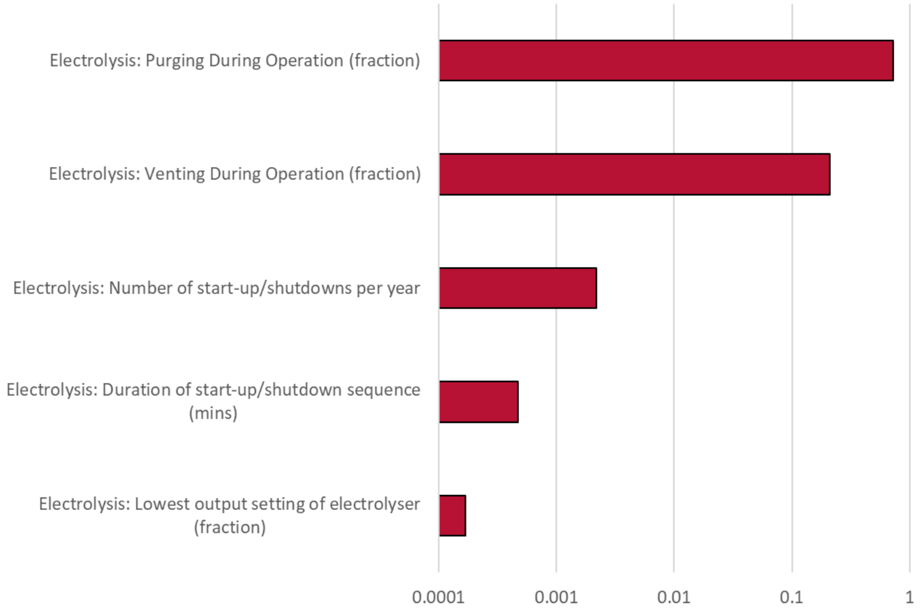


Figure 9: Variance decomposition of electrolytic hydrogen production. Purging during operation is the single largest contributor to the uncertainty in electrolytic hydrogen emissions, followed by venting during operation.

Another area with a high emission is road trailering of liquid hydrogen. The predictions at 50 % and 99 % confidence are 3.76 % and 13.20 % and the boil-off rate is the main contributing factor to the significant variation. Technologies could in principle be implemented to recombine or use the hydrogen boil-off but the contribution of trailered liquid hydrogen to the overall emissions is likely to be small.

6.2 Central Scenario Emissions Predictions

The uncertainty model has also been used to predict the overall hydrogen emissions for the central scenario. The individual emissions areas have been scaled up based on their relative contribution (in TWh) to the scenario, according to Figure 1.

The total hydrogen emission is predicted to be 114 kt/year (at 50 % confidence) and 174 kt/year at 99 % confidence. The overall size of the central scenario is 476 TWh (12,000 kt/year) so this represents a loss of 0.96 % (50 % confidence) and 1.50 % (99% confidence). Of the three sectors, transport is predicted to have the highest emission and is responsible for approximately half of the total (Figure 10).

Breakdown of the individual emissions is shown in Figure 11. In hydrogen production, the majority of the emissions come from CCUS-enabled hydrogen but this is due to its larger contribution to the central scenario; 79 % of hydrogen production is from this method. In transport and storage, the distribution network is the largest emitter. The NTS has a low emission at 50 % confidence and this is relatively small compared to the distribution network. However, the significant uncertainty in the current NTS natural gas emissions that are used as the basis for predicting hydrogen does increase the 99 % confidence emission from transport. Of all the end-use applications, emissions from hydrogen in the residential and commercial sector is the most significant. This is due to the emissions from pipework that is very uncertain.

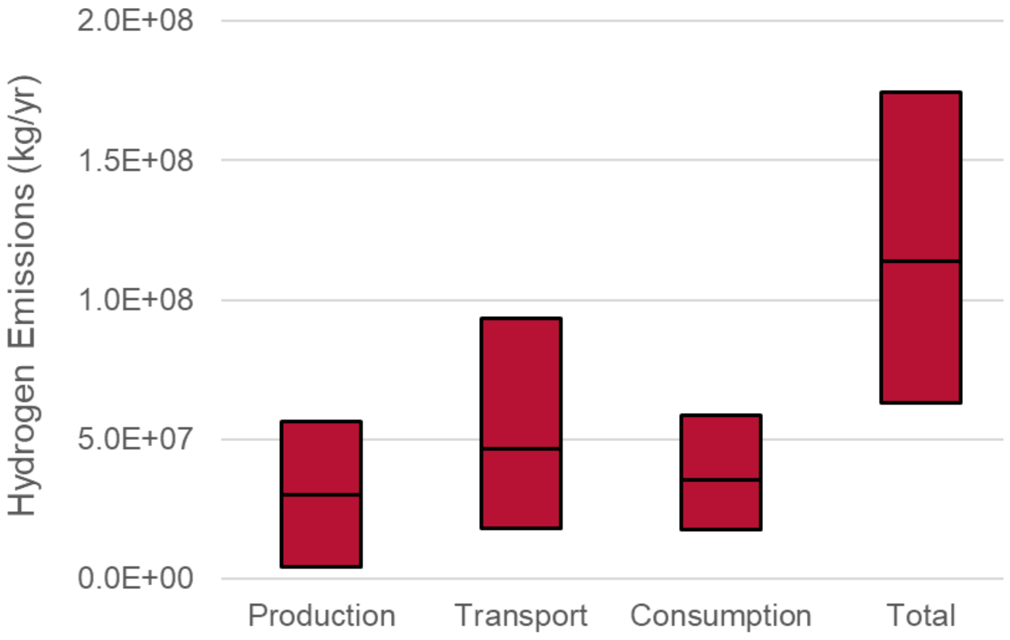


Figure 10: Central scenario emissions breakdown for production, transport and storage, and consumption. The bars represent the 1st, 50th and 99th percentiles (confidence levels). Transport and storage is predicted to have the largest hydrogen emissions out of the three sectors (production, transport and storage, consumption)

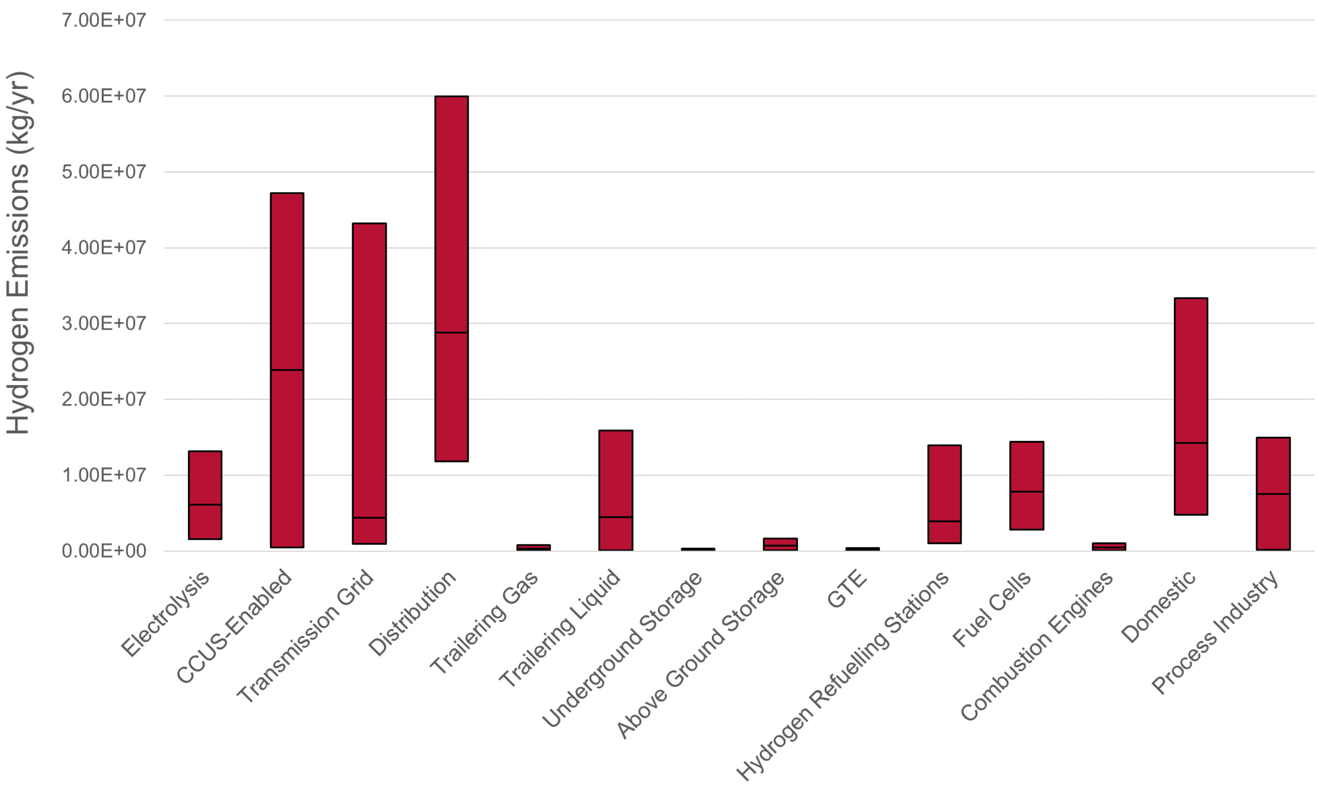


Figure 11: Central scenario emissions breakdown into individual areas. The bars represent the 1st, 50th and 99th percentiles. The distribution network is predicted to be the element with the single highest hydrogen emissions.

The key parameters affecting the variability in the hydrogen emissions predictions for the central scenario are shown in Figure 12. The emission from CCUS-enabled hydrogen is the largest cause of variability followed by the prediction of the current NTS leakage and then scaling leakage from natural gas to hydrogen in the distribution network.

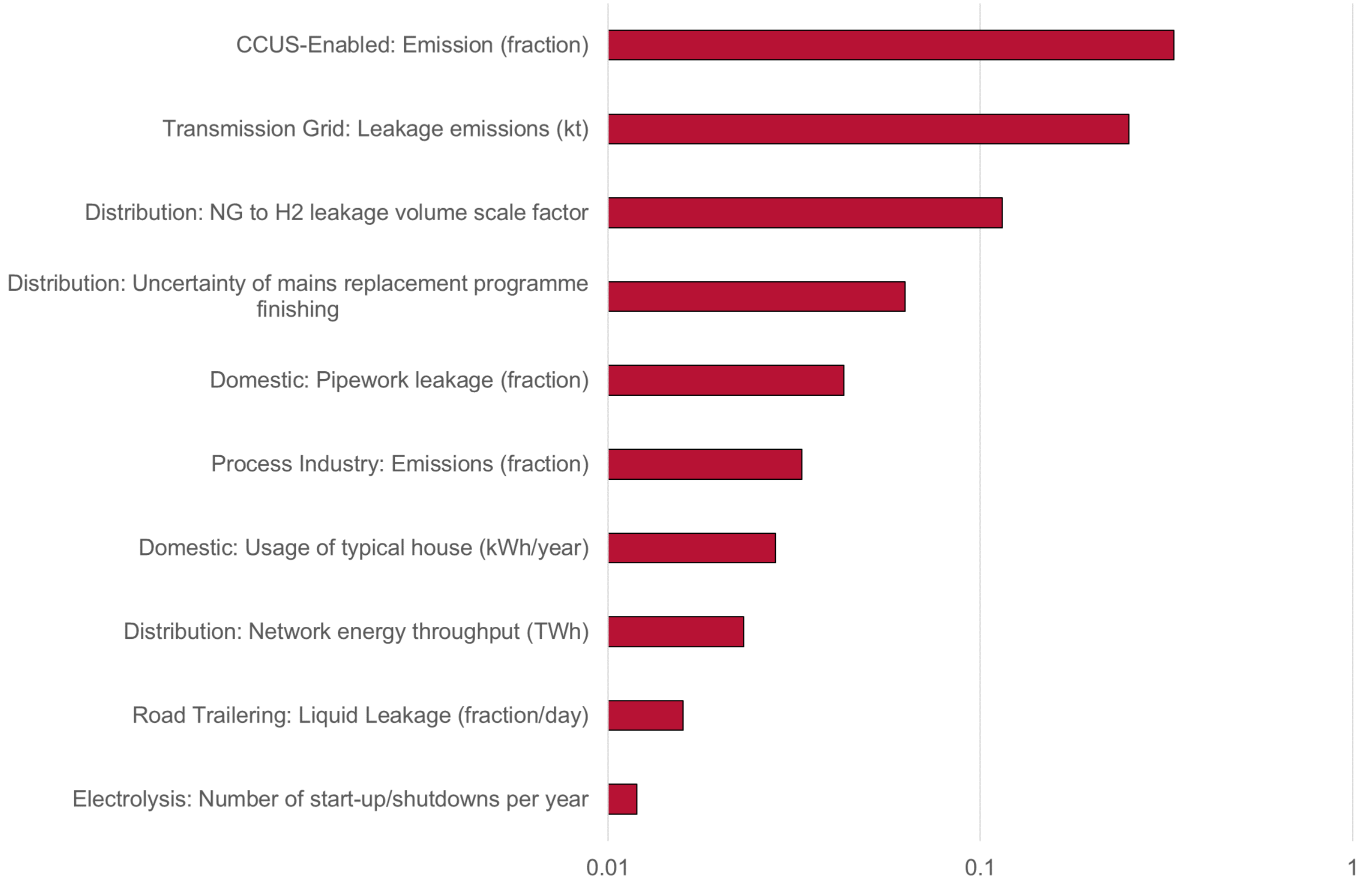


Figure 12: Variance decomposition for the central scenario. The emissions from CCUS-enabled hydrogen production and the NTS leakage are the largest contributors to the uncertainty in the overall leakage predictions for the central scenario.

7 Discussion & Recommendations

This study has investigated the individual hydrogen emissions from production, transportation, storage and end-users that form the hydrogen landscape. It has then combined these in a bounding central scenario to predict the overall predictions.

Production

As a percentage of the hydrogen produced, evidence suggests that current electrolysis technologies have significant hydrogen emissions. However, technologies could be readily implemented to recombine both the hydrogen purged during the purification phase and hydrogen vented during operation into water using an oxidation catalyst. Electrolytic hydrogen production at present is at a relatively small scale and the additional equipment required to recombine the hydrogen with no apparent economic incentive to do so may be hard to justify. However, at the much larger scale assumed in the central scenario, the marginal cost of this process should be much less and there may be alternative technologies that could use the collected hydrogen for process heat.

It has not been possible to gather quantitative data on emissions for CCUS-enabled hydrogen production. Similar to electrolytic production there could be emissions from purging during purification, but at the large scale of these facilities, this hydrogen could be readily used for process heat. A notional emission of 0 - 0.5 % (uniformly distribution) has been used for the purpose of the central scenario, but this represents a gap in understanding. Given the importance of CCUS-enabled hydrogen in the central scenario, and other scenarios of a future hydrogen economy, this gap needs to be addressed.

Transport and Storage

Hydrogen emissions from repurposed NTS and distribution networks has been predicted using existing estimated emissions for natural gas and then scaling these to hydrogen based on gas leakage relationships in different flow regimes. Leakage from the pipelines may be laminar or turbulent and there is almost a factor of three difference between these two regimes. An improved understanding of the leakage pathways (e.g. hole sizes and shapes) in NTS and distribution network pipes would help reduce this uncertainty.

The distribution network has a baseline model for natural gas emissions, which has been developed to monitor how leakage is being reduced as part of asset improvement such as the mains replacement programme. The leakage of natural gas from the NTS is however, significantly less well understood. At the top end of the potential leakage, the NTS has a comparable emission to the distribution networks, although expectations from industry are that it is significantly less. There is therefore a need to improve the understanding of natural gas emissions from the NTS.

Emissions from compressed gas and liquid transport are very significant as a proportion of the amount of hydrogen stored, but they will transport only a small fraction of a repurposed NTS and distribution networks and their contribution to the overall emissions is small.

Hydrogen emissions from underground storage of hydrogen in salt caverns are predicted to be very low. The main mechanism for leakage will be from the surface plant during maintenance or emergency venting and technologies could in principle be developed to reduce, or even eliminate these.

End Uses of Hydrogen

Fuel cells emit a similar amount of hydrogen to electrolysers and when incorporated into transport applications will also suffer from leakage from the stored compressed hydrogen. Without incorporating technologies to recombine purged and vented hydrogen into water the emissions could be significant. However, technologies could be readily implemented to reduce these. The main emissions from Hydrogen Refuelling Stations are from the compression of hydrogen and the short-term storage of compressed hydrogen prior to be injected into vehicles. It would be beneficial to provide improved predictions of hydrogen leakage from compressed gas storage.

The use of hydrogen in boilers for home heating is the dominant emission mechanism for end-uses applications. This comprises unburnt hydrogen vented from boilers during start-up and shutdown and also leakage from the pipework. The pipework leakage is very uncertain and for the purposes of this study, a conservative estimate has been made based on the Maximum Permissible Leak Rate (MPLR) for domestic and commercial properties. This is likely to be a significant overestimate and should be considered further prior to the demonstration of hydrogen use in homes.

The hydrogen emission from Gas Turbines is expected to be very low. The main mechanism for emission is through unburnt hydrogen in the exhaust at start-up and shutdown (similar to domestic boilers) but they are likely to be run less intermittently than boilers.

It has not been possible to predict hydrogen emissions from process industries and manufacturing. A notional emission of 0 - 0.5 % (uniformly distribution) has been used for the purpose of the central scenario, but this represents a gap in knowledge.

Central Scenario

Overall, there are likely to be hydrogen emissions across the hydrogen landscape from production, transport, and storage through to end-use applications. Electrolytic hydrogen production and fuel cells, if scaled up from today’s technology could provide very significant emissions. However, relatively simple procedures can be implemented to reduce these that should become more economically viable at larger scale. Assuming these technologies are implemented, a repurposed gas distribution network is likely to be the single largest source of hydrogen emission. Although as a percentage emission it is comparable, and even lower than some of the other elements, the magnitude of the throughput of hydrogen in a repurposed distribution network means it is likely to have the single largest emission.

The findings of this study can be used as follows:

- Technology improvements: Where technologies have been identified that can reduce the emissions (electrolysis and fuel cells), these can be explored further to understand how they will affect the economics of hydrogen production (Levelised Cost of Hydrogen, LCOH), any minimum viable scale required to make them feasible, and how they could be included in the UK government's low carbon hydrogen standard.
- Overall emissions: The overall (central scenario) emissions can be combined with the estimated GWP of hydrogen to consider the implications for the UK's decarbonisation policy. The central scenario was chosen to provide a credible but bounding size of a future hydrogen economy. The findings on the individual emissions can also be readily applied to explore alternative scenarios.

Recommendations for Future Work

Based on the findings of this study, the following recommendations for follow-on work are proposed:

- Explore the leakage mechanisms for CCUS-enabled hydrogen and the process industry. This could involve investigating if there are any credible scenarios where hydrogen may be vented rather than flared, the residual amount of unburnt hydrogen in the exhaust after flaring, and the leakage of hydrogen across from pipework, storage and compressors.
- Identify technologies that could be incorporated into electrolysers and fuel cells to recombine the hydrogen that is currently purged and vented into water. Assess the effectiveness of these technologies and how they affect the levelised cost, allowing for greater capital and maintenance cost.
- Undertake monitoring studies to improve the prediction of natural gas leakage from the NTS.
- Undertake experimental studies to better understand the leakage flow regime (laminar or turbulent) within both the NTS and distribution networks. These could involve materials characterisation of the leakage paths (hole sizes and shapes) in representative pipework. Investigate if there are any, as yet unidentified, slow leakage mechanisms within the pipework that haven't been considered in work to date.
- Undertake experimental studies to quantify the current leakage of natural gas from domestic and commercial pipework.

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Appendix

Variance of Individual Emissions

Transmission System

For the transmission system the key uncertainty is the existing natural gas emissions, which is used as the basis for predicting the hydrogen leaks (Figure 13). The uncertainty over the energy throughput also has an effect as this is used to scale current natural gas leaks with a future hydrogen network. The emissions from the compressors only provide a small uncertainty.

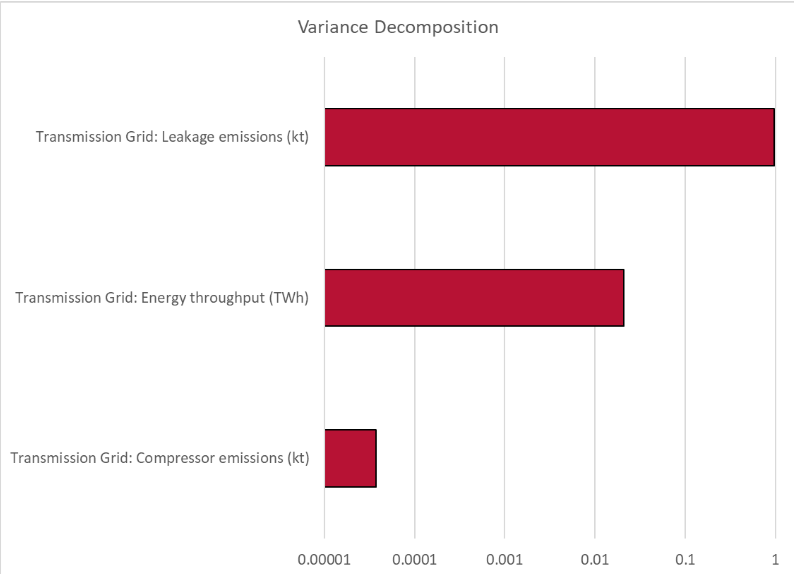

Figure 13: Variance decomposition of hydrogen transportation in the NTS. The single largest contributor to uncertainty in leakage predictions of a future 100% hydrogen NTS is the extent to which the existing NTS would leak if it was converted to transport 100% hydrogen.

Distribution Networks

Unlike the transmission network, the distribution network has an existing model of the current natural gas emissions and this reduces the uncertainty of the existing natural gas emissions. For the distribution network, the main factors affecting the uncertainty are the scaling of natural gas leaks to hydrogen (given the type of leakage mechanisms) and uncertainty over the completion of the mains replacement programme. The energy throughput of the distribution networks also causes some uncertainty as this is used to scale the current natural gas leakage.

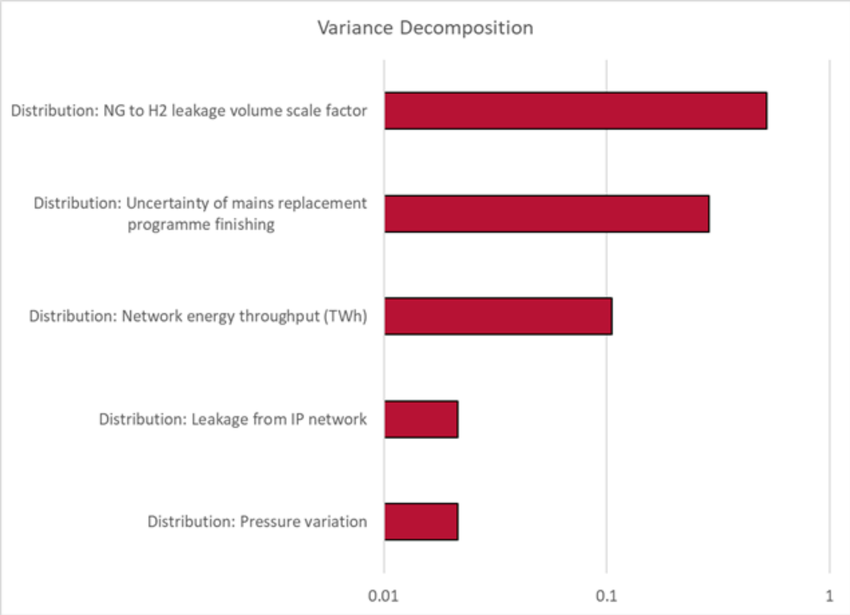

Figure 14: Variance decomposition of hydrogen transportation in distribution network. The conversation factor from natural gas to hydrogen leakage (based on the gas characteristics and leakage paths in the pipework) is the largest single contributor to uncertainty in the distribution network leakage predictions.

Domestic Heating

The main uncertainty on the hydrogen emissions for boilers, cooking and fires in residential and commercial buildings is the leakage from domestic pipework. The pipework leakage was based on very conservative worst-case Maximum Permissible Leak Rate (MPLR), with a 0 – 100% factor applied. The annual heat demand of a typical house also provides significant variability as this is used to scale the individual emissions from a single property.

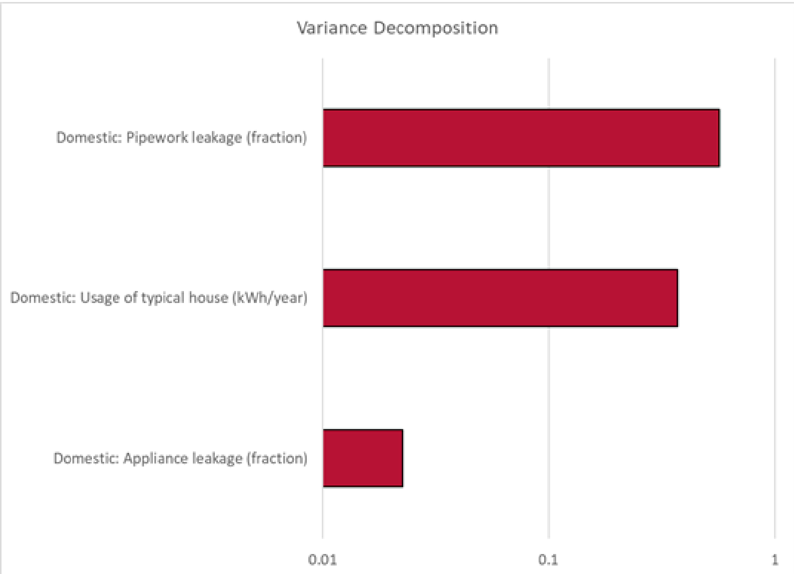

Figure 15: Variance decomposition of hydrogen transportation in domestic heating. The leakage from domestic pipework is the largest single contributor to the leakage predictions for domestic and commercial heating with 100% hydrogen.

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