The Institution of Mechanical Engineers' submission to the House of Commons Science and Technology Committee's call for evidence on the role of hydrogen in achieving Net Zero

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About the Institution of Mechanical Engineers

The Institution of Mechanical Engineers (IMechE) represents 120,000 engineering professionals and students in the UK and across the world.

The Engineering Policy Unit of the IMechE informs and responds to UK policy developments by drawing on the expertise of our members and partners.

This submission has been prepared with input from the following member volunteer committees:

- Process Industries Division
- Powertrain Systems and Fuels Group
- Energy, Environment and Sustainability Group
- Construction and Building Services Division

The submission does not necessarily represent the views of the wider membership.

Key messages:

- Hydrogen should be in the mix of clean fuels to meet the low carbon targets by 2030 and beyond, but direct employment of hydrogen as a fuel may end up being limited in scope due to various practical constraints.
- Hydrogen is presently considered likely to have most impact in those sectors that are most difficult to electrify, like heavy industry. A priority for the Government should be the rapid roll-out of the already announced low carbon hubs to scale-up processes, develop synergies between industries, and reduce costs through learning.
- In transportation, hydrogen could be particularly useful in decarbonising long distance and large-scale modes of travel, like road haulage, shipping, and aviation. This should mostly, however, be as a feedstock for synthetic fuels, rather than direct combustion or powering fuel cells.
- There are significant engineering and infrastructure challenges to overcome before low carbon hydrogen can be produced, distributed, and used in large enough quantities to have an impact on reducing overall greenhouse gas emissions.
- The sustainability of the production and use of hydrogen needs to be given a greater focus. Every proposed production method and application

of hydrogen should be assessed on the energy balance[1] against the alternatives.

1. The suitability of the Government's announced plans for "Driving the Growth of Low Carbon Hydrogen"

Focus, scale and timescales of the proposed measures

The 5GW 2030 target will require significant efforts to scale up current electrolyser technology alongside deployment of CCUS hubs. The target can be achieved if urgent prioritisation to the following is given:

- Designs for offshore floating wind farms.
- Production of standard designs of hydrogen production sites. The component technology exists but integrating them requires work.
- Parallel progress in both green and blue hydrogen for different applications and support new UK initiatives generating hydrogen from plastics.

There is research taking place into electrolyser membrane materials, selective catalysts, materials and protective coatings which will need to be brought together with proven design experience to realise the best design.

Generation of green hydrogen through renewables and proton exchange membrane (PEM) electrolysis is a proven method. However, electrolysis overall is not an energy efficient process. Currently, efficiencies of PEM electrolysers are 80% but they require significant energy input. Making productive use of waste heat can improve the economics of such systems.

Low carbon hydrogen production could be initially delivered on existing oil refineries where present hydrogen production results in significant GHG emissions from reformer process utilising hydrocarbon feed stock. Deployment on these existing COMAH regulated industrial sites that are familiar with hydrogen and operating high hazard plants will permit fast track deployment.

Co-ordination

Co-ordination of large multi-sector hydrogen infrastructure projects could be achieved by establishing a number of consortia similar to those for the Teesside Carbon Capture project and HyNet on Merseyside, focusing on different subprojects and run each of them as mega project. For example, enabling the power required from offshore wind and development of wind farms to connect with onshore electrolysis plants.

Co-ordination requires cooperation between many businesses and authorities, the targets set of 1GW by 2025 and 5GW by 2030 will require consortia with investment funding support by government.

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[1] The energy balance is the ratio of useable energy delivered compared to the energy expended to obtain that energy resource.

The capital investment, project management, delivery and operation of these complex and high hazard plants will require significant knowledge and experience, which fortunately exists in the UK oil & gas sector, the sector has many years of experience of delivering projects and reportedly has up to 30,000 skilled and experienced engineering and associated professionals and trades skilled personnel available for redeployment into the net zero technologies. Skills gained in oil & gas are fully transferable to the emerging net zero technologies and industries.

<u>The importance of CCUS</u>

CCUS is very important for ramping up the production of low carbon hydrogen. It is also needed to decarbonise existing hydrogen that is used for industrial processes, the vast majority of which is produced by steam methane reformation without any attempt to prevent release of the associated emissions. Electrolysis may be the more sustainable production method in the long term, but to scale up low carbon hydrogen we will also need CCUS.

In terms of meeting the UK's Net Zero target, hydrogen is likely to have most impact in those sectors that are difficult to electrify, like heavy industry.

Much analysis on decarbonisation pathways, notably by the Intergovernmental Panel on Climate Change[2], suggests that negative emissions technologies, particularly bio-energy with carbon capture and storage (BECCS), will be necessary in the long term to meet Net Zero. It is therefore crucial that the transport and storage infrastructure, and legal and commercial frameworks for storage, are developed. Decarbonising hydrogen production by steam methane reformation through the employment of carbon capture technology is one of the ways we can quickly reduce emissions from existing industries, and will have the positive spin-over of putting in place the infrastructure that may allow other CCUS technologies to be deployed quickly in the future.

The recent increased focus by the Government on developing low carbon hubs around existing industrial areas is welcome. A priority should be the rapid roll-out of these hubs to scale-up processes, develop synergies between industries, and reduce costs through learning.

<u>Business models</u>

Electrolysis is a high electrical power consumer which leads to high production costs. The process however does have the advantage that it releases high purity oxygen which could be sold in the merchant gas market to help offset these costs. Analysis of the future market for oxygen would be required to determine its value as a by-product.

With their experience in designing and operating both hydrogen and oxygen plants, industrial gas companies might be interested in taking the lead role in

[2] https://www.ipcc.ch/sr15/

building and running electrolysers in consortium with other companies. Benefits of this model include:

- The IG companies have pools of personnel skilled in the management and operation of oxygen and hydrogen plants.
- The quality of the oxygen is very high and comparable with that produced by cryogenic plants. This would allow old and inefficient cryogenic plants to be retired.
- The IG companies have the infrastructure to sell oxygen in the merchant market.

Alternatively, the oil companies might be interested in building and operating these plants. Shell currently operate what is currently the largest electrolyser in the world at their refinery at Wesseling in Germany. The benefits of this approach include:

- Oil companies are established at the 7 terminals where natural gas is imported.
- Oil companies are experienced in managing large projects and managing design contractors.

For direct injection into the high-pressure gas grid the injection percentage must be within approved limits at each injection point. To create a viable business model for investment it may well be necessary for alterations to be made to the wholesale gas market to ensure minimum viable flows are maintained at injection points where hydrogen generation is feasible. Existing market economics result in a number of injection points such as LNG import terminals operating at minimum send out (negligible flow) for significant periods during low demand months, during these periods they could be unable to inject hydrogen because the composition would exceed specification. As such the viability of hydrogen production at these terminals will require further study.

The engineering and commercial challenges associated with using hydrogen as a fuel, including production, storage, distribution and metrology, and how the Government could best address these.

<u>Potable water for electrolysers</u>

Generating hydrogen from electrolysis requires 'potable water' with very low particle concentration. PEM plant water consumption for 5GW of hydrogen production will require over 20 million litres of clean water per day, present UK surplus water supply is 950 million litres per day however this is not evenly distributed and projected to be in deficit by mid-century with a 2°C temperature rise.

For any plants to be economically viable, they will need to be located close to where the energy and water will be supplied. Most electrolyser experience to date has been with fresh water, but to deliver the volumes required in the long term extensive desalination of sea water is likely to be required.

Sea water is highly corrosive to anode elements. Research into this issue has resulted in the development of relatively successful coatings being demonstrated in research labs, but the practicality for large scale plants would need to be demonstrated.

The flammability of hydrogen

Hydrogen is flammable in air over a far wider range of concentrations than methane (from 4 to 75% versus 4.4 to 17% for methane). It is far easier to ignite hydrogen that methane.[3] This may be particularly relevant if hydrogen were to be considered for gas hobs or heating boilers in homes and the safety of such appliances would need rigorous scrutiny before any roll-out. The Energy Networks Association has begun co-ordinating research on this and wider use of hydrogen in the gas grid through its Gas Goes Green initiative.[4]

Keele University has just begun a heat trial with a 20% hydrogen blend in their standalone natural gas network, which is the working assumption of the highest level of hydrogen mix with existing infrastructure. Future trials should look to determine the feasibility of 100% hydrogen in small-scale private networks.

Health and Safety Executive Research Report RR1047 – Injecting Hydrogen into the Gas Network - literature search, 2015 is a comprehensive report detailing limits and implications of hydrogen injection.[5]

Leakage

Hydrogen is particularly difficult to contain in piping systems due to its small molecular size, fugitive emissions of hydrogen from process plans are significant and require robust engineering standards, sealing systems and hence increased capital build costs as well maintenance costs.

The engineering challenges associated with plant integrity (High Temperature Hydrogen Attack (HTHA) of steel) and flammability of hydrogen are managed by Health and Safety and COMAH (Control of Major Accident Hazards) regulations. Most Hydrogen facilities with more than 5Tonne of hydrogen will fall under COMAH controls.

The infrastructure that hydrogen as a Net Zero fuel will require in the short- and longer-term, and any associated risks and opportunities.

Location of production facilities

Locating hydrogen producers close to the hydrogen/natural gas blending stations could initially be advantageous as they will probably be located at the gas receiving terminals on the coast. However, thought therefore needs to be given to locating the hydrogen producers and the blending stations clear of any

[3] https://www.sciencedirect.com/science/article/abs/pii/S0957582019309802
[4] https://www.energynetworks.org/creating-tomorrows-networks/gas-goes-green
[5] https://www.hse.gov.uk/research/rrhtm/rr1047.htm

possible coastal flooding owing to ever rising sea levels. The IMechE detailed the risk to industrial facilities from rising seas levels in a report published in 2019.[6]

Transport

The construction of hydrogen vehicle refuelling stations in the UK has been slow and a number of the early trial stations have been decommissioned upon completion of the research trials. The H2 Stations website provides location data of operating and planned stations.[7]

The high cost of construction, delivery, and operation of the refuelling stations will tend to drive their deployment to:

- Large scale refuelling as required by bus and coach operators, especially in urban settings where strict particulate and pollution controls are enforced.
- Road haulage depots, especially those servicing urban setting with similar pollution controls.
- Rail refuelling depots in non-electrified network locations.
- Ferry and ship bunkering operations especially urban river crossings and coastal operations.

Significant reductions in the deployment costs of hydrogen as a transport fuel may be obtained when hydrogen generation plants are located close to significant vehicle, rail or ship refuelling operations as direct piping of liquid hydrogen from the producer to the refuelling stations will reduce distribution costs significantly.

The infrastructure required to deploy hydrogen as a transport fuel is substantial primarily due to the risk mitigations required to ensure a safe fuel network. The Health and Safety Executive Research Report RR769 – Hazards of Liquid Hydrogen Position Paper provides a summary of the hazards and controls.[8]

Pipe networks

If 100% hydrogen is to be delivered nationally via the existing gas grid in the future, much of the existing network of mostly steel pipes will need replacing as hydrogen embrittlement and permeability make steel an unsuitable material.[9] [10] Also, because the calorific value for a given volume is approximately 1/3 that of natural gas, volumes or pressures will have to be much higher, so to deliver the same heating value or pipes much larger. Although this has already begun in some places, it will be a challenge to replace the entire system.

External distribution systems must be co-ordinated with all other external utilities. Digging and installing new pipes should be carried out at same time as other utility upgrades to reduce cost and disruption.

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[6] https://www.imeche.org/policy-and-press/reports/detail/rising-seas-the-engineering-challenge
[7] www.h2stations.org
[8] https://www.hse.gov.uk/research/rrhtm/rr769.htm
[9] https://www.sciencedirect.com/science/article/pii/S2452321618302683
[10] https://www.energy.gov/sites/prod/files/2014/03/f12/hpwgw_permeability_integrity_feng.pdf

3D Building Information Management (BIM) data sets must be developed for all areas so that buried services locations are actually known. The data must include services plus other features such as foundations, landscape features, trees, etc. Access for future changes and maintenance must also be easy and avoid disruption.

One solution which is particularly relevant in coastal areas where flooding is predicted (rising sea Levels could be 3m by 2100) is to install at first floor level using service zones between buildings which are above ground – such as bridge links, etc. This is relatively easy and low cost compared to burying infrastructure.

Power supply

The ITM ”Gigastack” project referenced as a case study in the 10 Point Plan makes clear that the government’s objective is to promote the production of zero carbon hydrogen by integrating scaled up electrolysers with offshore wind facilities. It may be that greater flexibility of operation and location could be gained by managing both the wind turbines and electrolysers through the electrical grid.

The relative advantages and disadvantages of hydrogen compared to other low-carbon options (such as electrification or heat networks), the applications for which hydrogen should be prioritised and why, and how any uncertainty in the optimal technology should be managed.

Heating

In reducing emissions from heating, it must always first be emphasized that demand reduction through efficiency measures and insulation should be the first priority.

In the short term, to begin decarbonising the heating of buildings, other low carbon technologies and systems will be cheaper and/or easier to implement. Biomethane, heat pumps, and potentially heat networks could all be deployed initially as low risk options while strategies for 100% decarbonisation are assessed. The IMechE covered these topics in our submission to the BEIS Committee’s inquiry into decarbonising heat in home. Our submission can be provided if requested (email at the end of this document).

Heat networks, ideally making use of waste heat, are a good solution where the infrastructure allows. The UK has installed district heating energy systems in a few locations such as Southampton, Media City UK and more recently Birmingham City Centre. However none of these ‘tap’ into the enormous heat wasted from UK thermal power stations and other large sources of waste heat.

More widely, hydrogen could initially deployed at energy centres to generate power and heating. Energy centres could supply hot water heating, chilled water cooling as well as electricity all using hydrogen as the primary energy source.

Transport

As with heating, the first step in decarbonising transport should be to reduce the energy demand. For example, the IMechE is a part of the Smart Green Shipping Alliance who are trialling the retrofit of metal 'sails' on ships to reduce fuel requirements.[11]

In transport, the direct use of hydrogen as a fuel is likely to be only for niche applications. For light duty transportation, battery electric vehicles are already widely sold and are becoming cost competitive with conventional internal combustion engine vehicles. Many (trolley) buses, trams and trains have long used direct electricity for traction, usually via overhead wires. Battery electric medium and heavy trucks and buses are also being developed and sold widely by many makers.

Where hydrogen fuel cells are used to power light vehicles it may be due to environmental concerns associated with the mining of materials for batteries. If hydrogen can be produced in large volumes via low carbon means, the environmental impact has the potential to be lower than for battery electric vehicles.[12]

For most heavy-duty road vehicles, the larger energy density of renewable synthetic fuels (RSFs) and biomethane (particularly liquid biomethane) will put them at an advantage. (All renewable synthetic fuels require hydrogen as a feedstock so large volumes of hydrogen will still need to be produced for use in the transport sector.)

This leaves mostly niche applications for hydrogen fuel cell vehicles in road, rail and marine transport.

The large storage requirement of hydrogen may limit direct use in fuel cells to trucks and trains, and short-range ships, such as ferries, and aircraft, such as inland flights. High energy density is even more important for ships and aircraft operating long, trans-oceanic stage lengths.

Validating hydrogen for aircraft would take at least a decade and require all aircraft to be replaced at huge expense. Conversely – as with bio-based fuels - RSFs could be introduced progressively as blends with existing fossil-based fuels.

Hydrogen is used to fuel very few trucks, trains and ships, with fuel cells powering electric motors. Most are in 'captive fleets' which avoids the need for an extensive hydrogen infrastructure. However, almost all hydrogen is made from natural gas and is carbon intensive, with very little made using renewable sources, such as electricity and biomass.

Renewable synthetic fuels for transport can be introduced via the current infrastructure into existing and new non-electric trains, ships and aircraft. Some are 'drop-in' fuels, which can directly replace fossil-based fuels, such as gasoline, jet fuel (kerosene) and diesel. This means no loss of vehicle range, payload or

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[11] https://smartgreenshipping.com/projects-1

[12] https://www.imeche.org/policy-and-press/reports/detail/accelerating-road-transport-decarbonisation

other functionality and a flexible and seamless transition to near-zero carbon. Ships may use such diesel or possibly synthetic methane or ammonia, where their lower energy densities are less important, and they may be cheaper.