HYDROGEN IN NORTHERN IRELAND: FUTURE COSTS, CHALLENGES AND IMPLICATIONS

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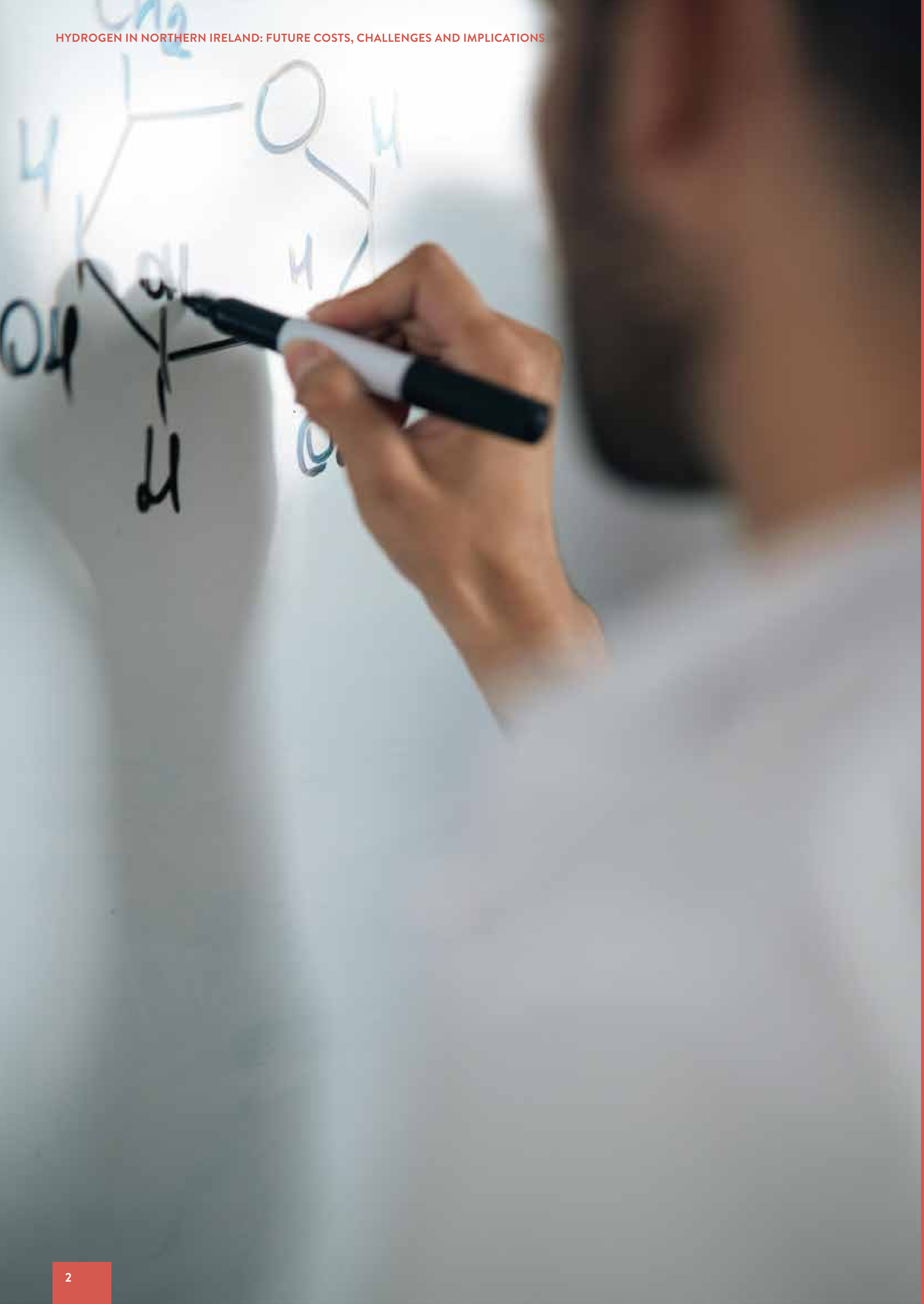

HYDROGEN IN NORTHERN IRELAND: FUTURE COSTS, CHALLENGES AND IMPLICATIONS

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the Department for the Economy of the Northern Ireland Executive

1. EXECUTIVE SUMMARY

As the world transitions towards a zero-carbon future, effective and economic alternatives to fossil fuels and CO_2 emitting industrial processes are essential. Green hydrogen has been proposed as a way to decarbonise many existing sectors of the global economy and for some industries such as chemicals and steel there are no realistic alternatives to the phasing out of carbon intensive, grey hydrogen and coking coal. New requirements are also emerging that require green hydrogen such as the production of liquid e-fuels for aviation and shipping as well as solutions for electricity grid challenges such as long-term energy storage or addressing constraints and curtailment.

Northern Ireland (NI) is unique in the UK with no significant use of grey hydrogen in industry and no steel industry dependent on coking coal. Therefore, NI is not obliged to go down the green hydrogen route but is able to choose the pathways that lead to decarbonisation and the best long-term economic benefit for the country. Green hydrogen does offer workable solutions for many applications from heating to transport and the first question this work sought to answer was:

> *In a competitive market, competing on both cost and non-cost factors with a wide and growing number of alternatives, is green hydrogen the best option for any* ***current*** *industries and economic activities in NI?*

The future world will see new opportunities develop as the supply and use of fossil carbon declines and concerns over energy and food security are addressed. This leads to a second question:

> *Are there new opportunities or requirements by 2050 that would require green hydrogen in NI?*

Here, the objective was to capture current developments and projections from academic literature, policy reports and industry perspectives and then to apply them to NI.

Finally, based on understanding what form green hydrogen's role will likely take in Northern Ireland and what factors drive this we sought to understand:

> *How these might be influenced, positively and negatively, by NI government policy?*

Answering these three questions is the purpose of this report. At the outset it was recognised that NI is still in the initial stages of transition to a low carbon future. For example, NI's electricity grid was built for large, centralised power generation constructed close to areas of high demand and not for a large number of smaller scale, intermittent, wind and solar farms often located away from major conurbations. Today's situation is therefore very different from that expected in 2035 and by 2050 the changes will be substantial. Published technology projections and plans for grid enhancements were assessed to get a picture of the environment in 2035 and 2050.

The cost of green hydrogen infrastructure (electrolysers and storage) and ultimately end-user prices are widely forecast to reduce but there are a large range of different views in academic, industry and government forecasts which creates uncertainty on predicting future pricing of green hydrogen. One certainty is that green hydrogen produced by electrolysis will always be dependent on the price of electricity and the more optimistic forecasts[1] require prices to drop by a factor of ten which is extremely unlikely in a UK or NI context.

Current issues with unused renewable electricity (dispatch down: curtailment and constraints) are forecast to drop dramatically as the grid develops, new uses such as short- and medium-term energy storage or electric vehicle fleet charging and better cross jurisdictional interconnection are built. Any remaining unutilised power will attract not just hydrogen producers. Other, new activities will compete such as vertical farming which becomes more economically viable the lower the cost of electricity or political choices will be made such as the potential to address fundamental social issues such as fuel poverty through heat-pump enabled district heating for social housing.

This analysis has been based on the fundamental economics of hydrogen and focuses on green hydrogen generated through electrolysis as the most likely route to production. Ultimately, the price of green hydrogen to the end-user will be affected by initial support mechanisms (capital grants, tax credits etc.) and at some future point potentially by taxes levied to offset falling fuel duty. However, NI must take care that such short-term incentives do not lock us onto a path which in time proves to be disadvantageous given the underlying economics compared to alternatives.

[1] For example: https://www.crugroup.com/en/communities/thought-leadership/sustainability/energy-from-green-hydrogen-will-be-expensive-even-in-2050/ or https://www.pwc.com/gx/en/industries/energy-utilities-resources/future-energy/green-hydrogen-cost.html

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At the time of writing a consultation has been launched in Great Britain around how subsidy to (limited initial) hydrogen generation may be structured under Gas Shipping Obligation (GSO). It is possible that this might be extended to Northern Ireland, and this might add a significant levy to consumer gas bills. The ambition is to reduce the cost of the generated hydrogen to that of fossil fuels. If this is ultimately enacted and extended across all production it would make hydrogen more affordable and hence attractive for some uses, transforming its projected usage. However, the costs of widening this support are likely to be very large and the scale of that subsidy may generate competition concerns unless the EU adopts a similar approach. The presumption in this paper is then that this action does not presage high general subsidy for hydrogen and that market forces, based on underlying costs, will play a determining role in the local energy market.

1.1 Key Findings

1.1.1 Decarbonisation of the current NI economy

Investigation of the requirements and paths for decarbonisation in NI clearly showed that given the current industry base in NI there were no cases where green hydrogen was the only option for decarbonisation, unlike in GB. The best options for **any current** NI industries and economic activities then depend on financial, environmental, security and social considerations. The picture for hydrogen has changed over the past few years and there is a growing consensus that it will have a more limited role across the economy in the UK. The recent Committee on Climate Change (CCC) seventh carbon budget[2] concludes:

> *"Hydrogen: by 2040, our Balanced Pathway sees hydrogen play a small but important role, particularly in industrial sectors such as ceramics and chemical production which may find it hard to electrify. Hydrogen also has an important role within the electricity supply sector as a source of long-term storable energy that can be dispatched when needed and as a feedstock for synthetic fuels. However,* ***we see no role for hydrogen in buildings heating and only a very niche, if any, role in surface transport."***

The CCC's view is a strong validation of the findings from the research carried out for this report. Green hydrogen will always be an expensive fuel as it relies on electricity to power an electrolyser and associated plant which together has significant efficiency losses. In the optimum situation for green hydrogen with use at the point of production, there would need to circa double the electrical power as an input in order to provide the same energy content at point of use after efficiency losses compared to an electrification option. A more realistic scenario with compression, distribution and storage included generates a ratio closer to a factor of three. For home heating a factor of six is reasonably expected i.e. electricity → hydrogen & storage → heat vs electricity → heat pump, as a heat pump can lever electricity inputs, moving three units of heat into the home for every unit of energy powering it. This implies that to go down the hydrogen route there would need to be a considerable increase in renewable generation capacity with consequences for visual amenity and land use as illustrated in Figure 1.

Northern Ireland will need to build additional renewable energy generation assets on land to achieve decarbonisation

Choosing green hydrogen for <u>transport</u> means at least THREE times more wind or solar generation is required than for electrification

Choosing green hydrogen for <u>heating</u> means at least SIX times more wind or solar generation is required that for electrification

Figure 1 Illustration of the impact on numbers of wind turbines if hydrogen was used for transport or heating in NI

[2] https://www.theccc.org.uk/publication/the-seventh-carbon-budget/

Taking a transport example and based on current lowest end-user price for green hydrogen including distribution and storage costs in GB the price equivalence to electrification is around £1.0/kWh (assuming fuel cell efficiency of 60%). For comparison, the lowest cost for eV charging in the same geographic area is £0.08/kWh (off-peak) and maximum £0.53/kWh for a fast charger. While cost of plant for green hydrogen will reduce with time and scale, fundamentally the price floor for green hydrogen is limited by the cost of electricity. As the above example is based on the use of a capital grant funded facility it is likely that the price of green hydrogen will not be reduced substantially when support schemes end.

There are a few companies in NI that have high heat requirements currently met by natural gas and a need for a transition using a drop-in replacement for natural gas. In both cases NI has the local resources to meet this need with biomethane at a much lower energy price and avoiding the high capital costs and additional handling challenges that adoption of hydrogen would incur. In the first hydrogen allocation round (HAR1) the strike price for hydrogen in the UK was set as £241/MWh[3], this compares to a production price for biomethane in NI of £90 - £140/MWh[4]. The strike price for hydrogen will drop but without some form of continued price support will always be the innately less competitive option due to the dependency on electrical power.

Many suggestions have been put forward for lowering the cost of green hydrogen to end users such as use of constrained electricity, construction of pipelines, reduced grid charges etc. While these might reduce costs, many could equally be applied to the broader electrification of the economy with a better economic outcome. Also, hydrogen production would face strong competition for off-peak/low-cost electricity from other forms of energy storage, heating for social housing, and emerging industries such as vertical farming. These are discussed in more detail later in the report.

Two other points are also relevant to the need for green hydrogen in NI. The first is the pace of technology development for eVs across all classes of vehicles. Hydrogen has lost the battle for cars and vans, is falling very far behind for buses and volume orders for electric HGVs is indicating this is also an area with a better market-ready solution. The recent doubling of battery energy density and other improvements are also eating away at any nominal advantage hydrogen has for longer-duration travel and colder climates.

The second point is potential environmental impact. Hydrogen is a secondary greenhouse gas with a global warming potential (GWP-100) of 11.6 ± 2.8[5] and with a comparatively high leakage rate from distribution and use this would need to be considered for NI's greenhouse gas inventory. Also, when combusted for heat or in an engine hydrogen can produce comparatively higher levels of NOx air pollution compared to fossil fuel alternatives[6]. Levels of NOx can be reduced either by hydrogen specific designs with higher air volumes or flue/exhaust gas treatment. The stark conclusion is that any existing use of hydrogen in Northern Ireland can be readily substituted by either electricity (most likely option) or biomethane, and that every one of these will find those alternatives to be cheaper than a hydrogen-based approach.

[3] https://www.gov.uk/government/publications/hydrogen-production-business-model-net-zero-hydrogen-fund-shortlisted-projects/hydrogen-production-business-model-net-zero-hydrogen-fund-har1-successful-projects

[4] https://www.economy-ni.gov.uk/consultations/developing-biomethane-production-northern-ireland-call-evidence

[5] https://www.nature.com/articles/s43247-023-00857-8

[6] https://uk-air.defra.gov.uk/assets/documents/reports/cat05/2411071337_H2_combustion_note_proof.pdf

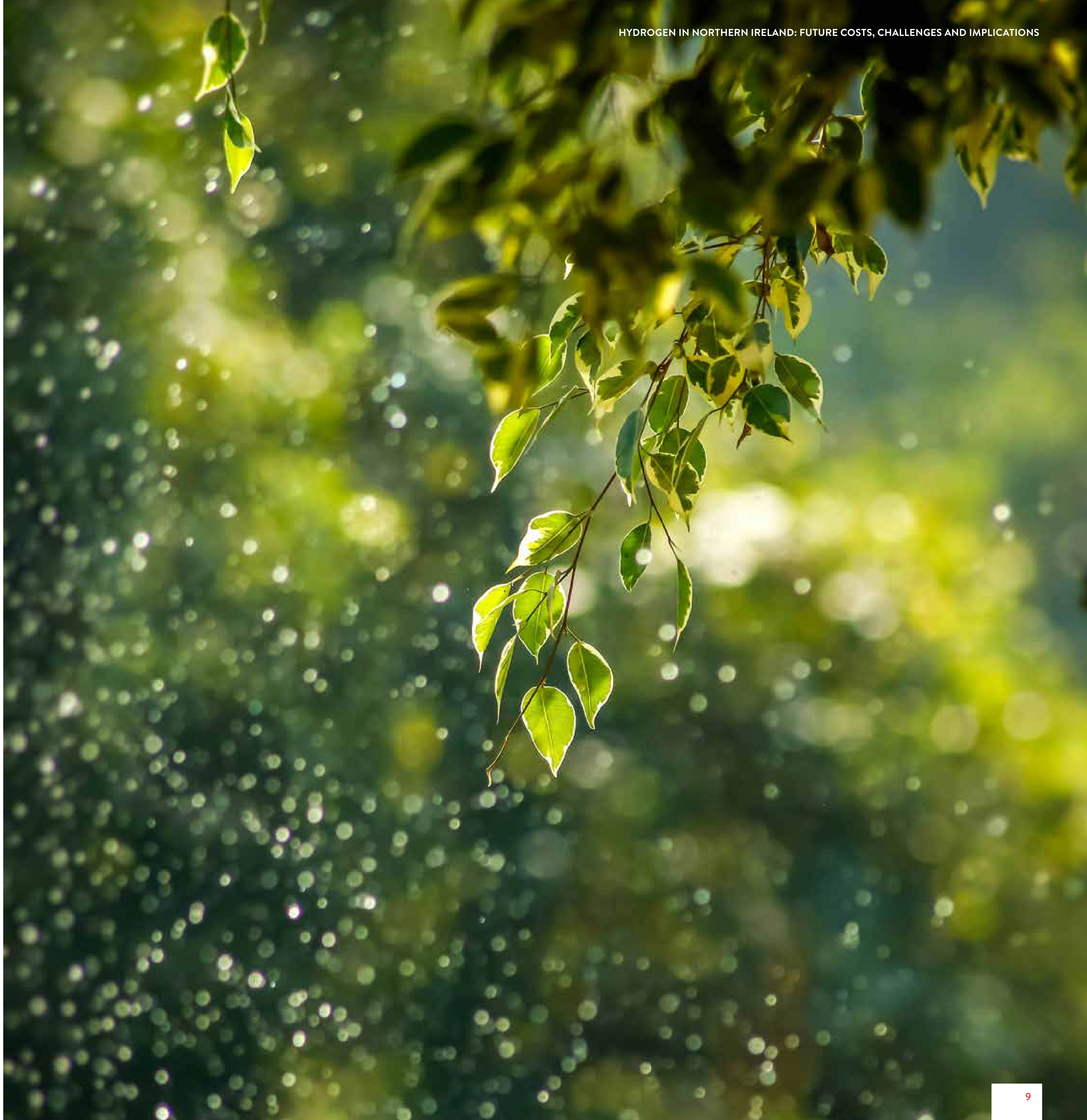
1.1.2 Future uses of green hydrogen in NI

While the finding of no economically justifiable requirements in NI at present is no surprise given the failure of much cheaper grey hydrogen to penetrate fuel and heat markets over the past century, the study did establish two potential future uses of green hydrogen in NI.

1) The first utilises green hydrogen as a chemical feedstock that is used with NI's biogenic carbon feedstocks to create e-fuels and chemicals. Here the economics would rely both on NI's relative advantages to provide green CO_2, biomethane or biomass as well as developing very low-cost renewable electricity. In practice this is likely to be a large scale (>500MW) electrolyser with a private wire connection (to avoid grid-related costs) to a fixed-bottom, offshore wind farm with a high-capacity factor. To be viable the electrolyser would need to be also directly linked with the e-fuels/e-chemical plant to minimise storage and transport costs and where the waste heat and the oxygen co-product from the electrolyser can be valorised to maximise economic gain and assure cost competitiveness within global markets.

2) A future energy system dependent on renewable forms of electricity generation will have to solve the problem of long-term and inter-seasonal energy storage, especially if energy security is a major driver. Low solar generation in winter coupled to week to month long periods of below normal wind speeds necessitate some form of alternative energy supply. Green hydrogen could be that vehicle but would need large capacity gas cavern storage to be feasible and would have to be more economic than the alternative for NI which would be biomethane.

Both options relate to the longer stem storage and densification of energy which is needed within the wider economy to provide resilience and support sectors such as shipping and aviation. This is not to discount that there may be unique scenarios where an organisation can effectively utilise green hydrogen or its co-products, oxygen and waste heat. This includes some areas of transport. However, such scenarios are in themselves likely to be relatively small scale and unlikely to be economical unless integrated as part of a wider system.



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1.1.3 The competitive analysis

Use Case	Primary Competitor(s)	Likely Future Scale of H_2 (NI)	Comment
Energy Storage	Short – battery, compressed air, gravity, flywheel Medium: pumped storage, Long: biofuel, interconnectors	Potentially high	Likely long duration storage is an option but need gas caverns or e-fuel production infrastructure. Might complement e-chemicals/biorefineries. Strong competition from biomethane. Needs in-depth study to determine best route, especially given political/public pressure against gas caverns.
Industrial Heat	Electrification Biomethane Thermal Batteries Biocoal	Low	Alternatives are less expensive in all applications including for energy intensive industries. Biomethane is a drop-in replacement for natural gas.
Domestic Heating	Heat Pump, Biogas	Low	Heat pump 6x more efficient than hydrogen and lower risk.
District/Public building / Commercial heating	Hot water, heat pump	Low	As for domestic heating efficiency advantage is 3-6x that of hydrogen.
Transport: Air	Biofuels	Potentially high	Aviation fuel will need to be replaced by a synthetic aviation fuel (SAF) as electrification and hydrogen lack the volumetric energy density and storage advantages of a liquid fuel.
Transport: Marine	Biofuels. Electrification of inshore vessels	Potentially high	Synthetic/e-fuels as hydrogen vector are most likely. Hydrogen on a boat possible but higher risk and more expensive.
Transport: Buses	Battery, biofuels	Low (except in niche areas)	Substantial improvement in battery technology has mitigated concerns over range and charging for latest generation of buses. Potentially niche roles where rapid turnaround required or for long distance journeys.
Transport: HGV	Battery Bio/Synthetic fuels	Low	Limited scope for long distance journeys in NI and UK owing to geography. Improvements in battery technology has extended range and reduced charging time. Hydrogen HGVs double the cost of eHGVs and three times higher running costs.

Use Case	Primary Competitor(s)	Likely Future Scale of H_2 (NI)	Comment
Transport: cars / vans	EV	Low	eVs have big efficiency and cost advantage. Market adoption of eVs is almost 100% of low-carbon vehicles.
Non-Road Mobile Machinery	Battery, biomethane, e-fuels, tethering to grid	Medium	There may be a requirement for hydrogen in remote from grid locations, but need can probably be met more cheaply with alternatives.
Synthetic fuels and chemicals	None	Potentially high	Specialist synfuels such as fuel for vintage cars not replaceable. Higher value-added chemicals and associated products.
Agriculture	Battery, biomethane, bio and e-fuels	Low	Better options that are cheaper.
Islands	Wind/solar/battery mix	Low	Limited requirement in NI.
Export	None	Low	Unlikely to be cost competitive compared to countries with low-cost renewable electricity, lower operational costs and cheaper land prices.
Byproduct: Oxygen	Existing suppliers	Medium	Potential for wastewater treatment, Oxyfuel combustion and in chemicals industry.
Research and Educational	None	Medium	Main requirement will be for businesses that develop products that use or enable hydrogen.

This review of potential use cases thus reaches a robust conclusion: in the same way that today hydrogen is not competitive against fossil fuels, so it will struggle against low carbon (mostly electrification based) solutions in the future. Many uses, such as domestic heating, that hydrogen could technically fulfil are found to be unlikely to be economic. In part this reflects the need to store and transport hydrogen, costs which have perhaps been under recognised in the past. A corollary of this is that where hydrogen is used, we might expect its generation to be close by, typically onsite. In turn this indicates that a pervasive distribution hydrogen network, spanning Northern Ireland, is not justified. The case for larger transmission pipes is dependent on assumptions around its role in energy storage, and this is developed in the first use case in the main report and discussed further below.

Note too, that while hydrogen's innate characteristics are, as an element, permanently fixed, limiting the potential for transformational change in its use, competing technologies are showing continuing progress. In many cases this improvement is transformational, with batteries for example reaching levels of energy density that appeared improbable in the recent past, while slashing costs. It follows that, other things remaining constant, the scope for hydrogen is more likely to narrow than widen. Thus, major infrastructural investments in hydrogen may only have a short life as has been found for hydrogen car refuelling.

Ultimately the case for hydrogen is intimately linked to the extent of future bifurcation of the cost of electricity. Off-peak electricity pricing has traditionally been based primarily around recovery of the related marginal cost, primarily the (fossil) fuel cost. This sets a floor for the input cost for generating hydrogen, one which is then necessarily above competing fuels.

For energy storage using hydrogen, the round-trip efficiency of electricity to hydrogen, storage and then electrical generation is c.36% with comparatively expensive storage as well as fuel-cell costs for electricity generation (see section 4.2). This compares to grid-scale battery storage round-trip efficiency of 80-90%. Clearly, but for the need for low carbon solution, using hydrogen for short-term energy storage would be strongly uneconomic. However, long-term and inter-seasonal storage has only a very limited array of options and therefore the high cost of hydrogen energy storage maybe justified or unavoidable. In general, where fossil fuels have dominated, generation electricity storage has been minimal as inefficiencies act to further raise the cost of the returned electricity. As a result of high costs, the use of electricity has traditionally been constrained to premium uses.

The impact of renewables, with a zero-fuel cost, upends this simple relationship. If there are frequent periods of very low (or even nil) cost electricity, new ways of using it will emerge. Heating water is an obvious mechanism, as water has a very high ability to store energy (requiring 0.07MWh to raise the temperature of a cubic metre by 60°C), has low capital costs, is safe and easily integrated into everyday usage. A single insulated tank can then replace individual boilers and heating appliances in an apartment block or service a district heating scheme. The appeal of free heat and hot water would of course be so compelling that quickly there would be sufficient demand to consume all 'free' electricity. The ultimate outcome will be a market equilibrium where at least some payment will be made.

The suggestion that current issues around the grid's inability to manage all renewable energy supply will mean that there will be ongoing surpluses of such 'free' energy is thus misguided. Hydrogen will have to compete in the market for its electricity input, and this competition will include storage solutions, potential export via interconnectors and new demand side innovations. The development of sophisticated trading, at the market level and tariffing / smart metering at the user level, makes this vision to 'use all electricity' a reality.

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1.2 Implications for Policy

This report does therefore offer a 'reality check' on the medium-term prospects for hydrogen in Northern Ireland. What the gas will likely do in the future is a very small subset of its broad capabilities, reflecting inevitable efficiency losses and costs around its production, storage, transport and ultimate use.

Widespread gas use in a low carbon future is then likely dependent on biomethane solutions where Northern Ireland benefits from a favourable environment. Consideration of the future of the existing gas network should focus on this while noting that in the longer-term, by 2050, that electrification of heat and the higher price that e-fuels and chemical industry will pay for biogenic carbon will probably mean that most, if not all, domestic use will be curtailed. This outcome will open additional opportunities for NI-based hydrogen production that may be necessary for the new industry plants that convert biomethane into fuels or chemicals.

This report sees a potentially viable, future use of green hydrogen in two, large-scale uses: energy storage and e-fuels/e-chemicals. The happy geological accident of the presence of major salt deposits around Islandmagee could provide for the large, safe and cost-effective storage of hydrogen (and other renewable gases) in gas caverns close to major potential users including ports, industry and, notably, power generation facilities.

This asset is of potentially very high economic value as it provides security of supply for energy, fosters the development of greater renewables, widens choice for business and industry, and directly drives investment, jobs and incomes in Northern Ireland. It can thus both strengthen and de-risk key future sectors of the local economy. Without some form of long-term energy storage or large increases in interconnector capacity then NI will be vulnerable to electricity shortages when renewable generation is low for days or weeks. Serious consideration needs to be given to development of this NI/UK/Ireland critical asset as NI moves towards 2050 and away from fossil fuel use.

Post 2050, the use of the caverns for energy storage could act as a gateway for other hydrogen uses to emerge and would also open the potential for expansion of this hub, with arms (pipelines) extending out across Northern Ireland and perhaps cross-border. An east coast hydrogen pipeline (Larne to Waterford) would act to add storage and allow cheaper transmission, bringing in more ports, airports, power stations, industry and population centres. This increased scale and diversity of user would reduce dependence on a single use and mitigate adverse impacts around timing, including seasonality, of use, which reduces average costs to users, improving sustainability. Linkage with Scotland could also bring benefit, though here a likely strong competitive position in renewables in Scotland may result in reducing local generation of hydrogen, though this is dependent on a wide raft of factors beyond the remit of this study.

Most importantly hydrogen storage keeps options open when changed circumstances are possible.

1.3 Policy Imperatives

The study highlights the need for further consideration around core issues:

- The extent to which hydrogen importation and/or generation occurs in Northern Ireland for the future uses identified, including the siting of necessary components and wider infrastructure for a hydrogen production/distribution hub
- The value of energy resilience, security and diversity of supply including understanding the most cost-effective solution for NI – green hydrogen, biomethane, another biofuel or e-fuel or greater interconnectivity to other countries
- The wider all-island perspective on hydrogen use, in particular the merits of a cross-border pipeline that could reduce costs and enhance supply if inter-seasonal energy storage or e-fuel production were to develop on the island
- The future of the existing gas distribution network in Northern Ireland and development of the local electricity grid, including large scale energy storage
- The tax treatment of low carbon uses, subsidies and the relationship with EU principles and policy, driving the hydrogen context in Ireland
- Avoidance of unnecessary levies on consumer bills in NI for supporting hydrogen production for use cases that are uncompetitive with other options and economically unsustainable in the longer term
- Creating a competitive market, for example requiring storage to be price regulated or be fully independent, to avoid market distortions.

Those reviews should inform supporting strategies, across the wider economic development front towards encouraging electrolyser production, maintenance and supply chains, supporting research and development, and enhancing green hydrogen skills in the workforce. This should be developed in tandem with industry and co-exist with an inclusive public engagement.

1.4 Conclusion

Green hydrogen is not an economically sensible route for the decarbonisation of any sector of the Northern Ireland economy today. Hydrogen will always be substantially more expensive than the electricity needed to produce it due to the many efficiency losses. Replacing current energy used with hydrogen will require at least twice as much generation capacity as electrification and realistically three times as much. Even with today's support schemes, green hydrogen is not really competitive compared to alternatives available in NI. Supporting hydrogen production through a levy on gas prices as under discussion in the UK could add £1m+ to major gas users[7] energy bills in NI and would be a significant burden on households.

However, green hydrogen offers considerable potential for benefit, including de-risking energy security, future industries and supply chains. In reality, this future can only be secured with action in the short to medium term, to enable major investment in globally significant capability, beyond which time opportunities will narrow as infrastructure develops elsewhere.

Storage is central to any future for hydrogen. It guarantees supply, allows its input electricity costs to be based on times where electricity demand, and hence price, is low, and ensures that economies of scale, vital for competitiveness, can be achieved. Considering how this storage might be achieved is then the primary challenge for policy. Scoping how this might be achieved is set out in the proposals for Phase 2 of this work.

Northern Ireland has a favourable endowment of renewable energy sources, but currently these are insufficient to meet the full requirements to decarbonise the power sector even before electrification of the rest of the economy. Dedicating future, large-scale offshore windfarms to power hydrogen production will be essential if NI is to play a significant part in the UK and European hydrogen-based economy.

The ultimate prize would go beyond simply aligning with net zero objectives. It would reshape and reinvigorate the Northern Ireland economy itself. However, this prize can only be achieved with parallel development of large-scale, renewable energy generation capacity, gas-cavern storage and e-fuel/e-chemical plant together with the necessary legislative and regulation frameworks as well as planning, safety and environmental approvals.

[7] This is an estimate based on a proposed hydrogen levy on gas shippers to cover the costs of the hydrogen allocation rounds (HAR1 + HAR2) see: https://assets.publishing.service.gov.uk/media/6787cbc3868b2b1923b6467b/proposed-design-gas-shipper-obligation-consultation-document.pdf

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1. INTRODUCTION AND CONTEXT

2.1 History

Hydrogen is the most fundamental, simplest and abundant element in the universe. Stars form from the collapse of clouds of hydrogen and shine due to the atomic fusion of hydrogen atoms. Here on earth, multi-decade efforts to create fusion reactors that produce abundant, continuous supplies of energy continue to progress steadily but are still at least a decade away from the first prototype fusion plants. In NI we are not anticipating that fusion-based power plants will shape our future, at least not by 2050. Instead, the use of hydrogen as a source of chemical energy in gaseous or liquid form is being explored as a route to displacing fossil fuels (oil, natural gas, coal) from the economy and achieve lower emissions of CO_2.

Today, research into hydrogen generation and applications is growing at a substantial rate with research publications increasing at an annual rate of 93.56%[8]. However, hydrogen research dates back 400 years with its initial discovery. While hydrogen was named by the French chemist Antoine Lavoisier in 1783 from the Greek hydros for water and genes meaning 'born of", it was Jan Baptist van Helmont who first observed hydrogen in 1625, and English chemist Henry Cavendish who in 1766 identified it as a unique element. Cavendish called it "inflammable air". Green hydrogen is a more recent development and was so named by NREL in 1995 as an alternative to renewable hydrogen. What we now call green hydrogen has been enthusiastically promoted as an energy solution for the global economy since as early as 1863. Large-scale electrolysers (100MW) have been used since the 1920s for hydrogen production to enable manufacture of fertilisers and heavy water[9]. Periodic peaks in interest have occurred since then, often linked to concerns over oil price or peak oil and the need to find alternatives to fossil fuels[10]. The latest cycle of interest started almost a decade ago with green hydrogen being pushed as the route to decarbonisation of much of the global economy. As interest developed, ambitious forecasts of green hydrogen providing as much as 30% of the global energy supply by 2050[11] were published and many large-scale projects announced at GW+ scale. However, the last 18 months have seen a considerable re-evaluation of many of the ambitions and several projects have been cancelled or postponed.

Today, over 99% of hydrogen used in the world is derived from fossil fuels with global production in 2023 of around 97 million tonnes[12]. Principally hydrogen is manufactured via steam reforming of methane (62%), gasification of coal (21%) or as a by-product of a chemical process (16%). Hydrogen from low-carbon sources accounts for less than 1 million tonnes of global supply. The IEA forecasts that low-emission hydrogen could rise to over 5 million tonnes per annum by 2030, but it is important to note that low-emissions hydrogen also included fossil fuel derived hydrogen where the carbon emissions are captured and stored.

Many areas of industry are dependent on hydrogen. Applications include oil refining for reducing the sulphur content of fuels, production of ammonia and fertilisers, metal treatment, methanol synthesis, food processing and as a rocket propellant. Emerging uses of hydrogen include production of synthetic fuels (e.g. SAF) and upgrading of biogenic carbon feedstocks to produce green chemicals, plastics and fuels. Current major users of hydrogen, such as oil refineries, produce hydrogen on site as required since transport and storage add substantially to costs.

Hydrogen has valuable characteristics which make it an attractive option for displacing fossil fuels. These include:

- Ability to deliver high temperature / process heat
- Long-term storage of energy
- Clean use, pollution free when used in fuel cells and not combusted
- Includes small scale uses (sufficiently small as to support mobility use)
- Building block for other e-fuels and chemical feedstock

[8]https://doi.org/10.1016/j.egyr.2024.12.037
[9]https://x.com/nworbmot/status/1317449761218285568
[10]https://www.carbonbrief.org/in-depth-qa-does-the-world-need-hydrogen-to-solve-climate-change/
[11]https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf
[12]https://www.iea.org/energy-system/low-emission-fuels/hydrogen

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The flexibility to address one or more of the above gives hydrogen many potential roles in the drive to decarbonisation agenda. For some industries, including chemicals and steel, there are no current realistic alternatives. However, hydrogen is not without challenges which can make it not the best option in many areas of the economy. These include:

- Low volumetric energy density (and hence requiring high pressure or liquification)
- Leakage rates during storage, transport and dispensing
- Safety
- Significant energy efficiency downsides in production and use
- Reactions in the atmosphere have a significant Global Warming Potential
- Potential air pollution (NOx) if combusted without additional pollution abatement.

Fuel	Gravimetric Energy Density MJ/kg	Volumetric Energy Density MJ/L
Kerosene	46.4	36.7
Diesel	45.4	34.6
Petrol	46.4	34.2
LPG	49.6	25.3
Natural Gas (Ambient)	53.6	0.0364
Natural Gas (250 bar)	53.6	9
LNG	53.6	22.2
Hydrogen (ambient)	143	0.0107
Hydrogen (700 bar)	143	5.6
Hydrogen (liquid)	143	10.1

Table 1 Gravimetric and Volumetric Energy Density of Fuels

Table 1 above shows the typical energy content for many fuels along with hydrogen. The high gravimetric energy density of hydrogen can be clearly seen, more than double any other fuel. However, by comparison hydrogen has the lowest volumetric energy density and where space is a premium, such as in air transport, then this can be a real barrier to adoption.

A molecule of Hydrogen, consisting of two hydrogen atoms, is the smallest and lightest molecule. As such, hydrogen more easily leaks compared to natural gas and as hydrogen is so light it tends to rise and accumulate in ceilings and high spaces in buildings. While hydrogen has the highest energy density by mass at 120 MJ/kgH_2 (lower heating value) of any fuel it has a low volumetric energy density and even when liquified it only has an energy density of around 8 MJ/Litre. This compares to liquid natural gas at around 22 MJ/Litre and petrol at around 34 MJ/litre. Hydrogen ideally needs to be highly compressed (400 bar or greater) or liquified for transport to maximise the energy transferred during shipping. However, compression to high pressures or achieving liquification at −253°C are both energy intensive (for liquification ~13.8 kWh/kg_{LH2}) and for liquid hydrogen the high temperature difference to ambient causes significant evaporation and requires re-liquification or venting during transport. This is a significant factor for long-distance shipment by road or sea with boil-off rates 1-5% by volume per day[13]. However, advances in large volume, cryogenic storage technology offer the future promise of reducing boil-off to as low as 0.05% per day[14].

Pipelines are preferred for transportation but are expensive to construct and not viable for long distances such as from equatorial regions to NI. Conversion of hydrogen to ammonia is an alternative method of transporting hydrogen. Although toxic, ammonia has a higher energy density than liquid hydrogen (12.7 MJ/Litre compared to 8MJ/Litre) and is easier to liquify (at -33°C). Recent work has shown that it may be cheaper to produce green hydrogen in Spain or further afield, convert it to ammonia, ship and then derive hydrogen cracked from the ammonia at the destination. The example given had hydrogen produced from ammonia imported to the Port of Rotterdam from China, Saudi Arabia, Egypt, the US and India at between $7.30/kg and $8.90/kg in 2028, this compares to green hydrogen produced in the Netherlands at an estimated price of $10.30/kg[15].

2.2 The colours of hydrogen

For easy identification of the hydrogen origins, then hydrogen from different production technologies is given 'colours'. These are:

1. Fossil fuel derived:
    a. Grey Hydrogen: Produced from natural gas through steam methane reforming without capturing carbon emissions.
    b. Blue Hydrogen: Similar to grey hydrogen but with carbon capture and storage (CCS) to reduce emissions.
    c. Brown Hydrogen: Produced from brown coal (lignite) through gasification, resulting in high carbon emissions.
    d. Black Hydrogen: Produced from black coal (bituminous) through gasification, with similarly high emissions.
2. Sustainable, low carbon generation:
    a. Green Hydrogen: Normally produced through the electrolysis of water using renewable energy sources.
    b. Turquoise Hydrogen: Produced by splitting methane into hydrogen and solid carbon using a non-oxidative process such as pyrolysis.
    c. Pink Hydrogen: Produced through electrolysis using electricity from nuclear power.
    d. Yellow Hydrogen: An emerging name for green hydrogen produced through electrolysis using solely solar energy.
    e. White Hydrogen (also called Gold Hydrogen): Naturally occurring hydrogen found in underground deposits.

[13]https://doi.org/10.1016/j.rser.2023.113204
[14]https://www.dnv.com/expert-story/maritime-impact/paving-the-way-for-large-scale-transportation-of-liquid-hydrogen/
[15]https://www.hydrogeninsight.com/production/hydrogen-cracked-from-imported-green-ammonia-could-be-cheaper-in-europe-than-eu-made-green-h2-bnef/2-1-1778240

HYDROGEN IN NORTHERN IRELAND: FUTURE COSTS, CHALLENGES AND IMPLICATIONS

Currently, as around 99% of hydrogen used globally is grey hydrogen with no abatement of carbon emissions[16] the quickest route to low-emission hydrogen in the coming decades will be blue hydrogen as carbon-capture and storage (CCS) can be retrofitted to existing grey-hydrogen plants. Given the cost advantages of relying on fossil fuels for hydrogen, the time required for green hydrogen production plants to be planned, financed and constructed as well as the need for further electrolyser technology development, blue hydrogen emerges as the only rational choice for existing industrial uses of hydrogen for the medium term to 2040.

This pragmatic choice offers the quickest route to reduce carbon emissions from hydrogen production but is not the panacea that some might claim, rather it is a stopgap while emissions free technologies are developed. A key issue is that while a few large-scale CCS units have been built, the technology still requires development to reduce costs including energy use as well as increasing carbon capture efficiency. The CCS industry claims target capture rates of over 90% but this has not been achieved in existing large-scale CCS plants used for supplying CO_2 for enhanced oil recovery or smaller plants for eventual storage of CO_2. Capture rates as low as 10% have been reported[17] but typically they are in the range up to 50%-80%[18] even for blue hydrogen production. Therefore, caution has to be applied to "low emission" blue hydrogen and verification of the carbon intensity is essential as it is unlikely that the carbon footprint is close to what CCS technology is sold as achieving.

Green hydrogen is considered the cleanest form of hydrogen although if not produced from fully renewable, low-carbon electricity then it can have a significant carbon footprint. Green hydrogen production primarily relies on electrolysis, a process that splits water into hydrogen and oxygen using electricity. To be green hydrogen the electricity source must be renewable such as from solar, wind, or hydro power. While electrolysis is the most widely adopted method of production of green hydrogen there are other technologies including gasification of biomass, steam reforming of biomethane, various catalytic based processes and biological processes such as dark fermentation. These technologies have all been put forward as potential future production methods technologies for green hydrogen but are not currently financially viable or need significant technology development.

Dark fermentation processes have advanced with improved yield through genetic engineering but still have barriers such as scale-up and production costs to overcome[19]. Photocatalysis has seen significant advancements in catalysts with efficiencies in the range of 10-20%[20]. However, stability of catalyst materials remains a challenge and even if this is overcome then photocatalysis will be far better suited to sunnier climates than NI.

Steam reforming of biomethane is probably the simplest and feasible of the alternative production methods[21] involving the substitution of fossil methane with biomethane in the most common method of grey hydrogen production. Alternatives, such as biomethane or e-methane pyrolysis have been proposed[22] as offering lower CO_2 emissions and more attractive economics. However, since most applications such as heat, power generation and transport can use biomethane directly without the additional costs of the engineering needed for hydrogen production and capital plant it is difficult to see the financial logic of this approach.

Gasification of biomass is also a proven technology, where biomass such as wood or waste agricultural products are heated in an oxygen-controlled atmosphere to produce a syngas. This syngas is then put through a water-shift process to produce relatively pure hydrogen. Gasification is energy intensive, is dependent on consistency of feedstock for reliability (difficult for low-cost biomass) and can require further purification of hydrogen, especially for fuel cell applications which can be highly sensitive to contamination. Where biogenic waste is already collected at central facilities then this is an option for NI that should be considered for future deployment once reliability and economics have been proven at scale for NI feedstocks.

[16]IEA. Global Methane Tracker, 2023. https://www.iea.org/reports/global-methane-tracker-2023
[17]https://zerocarbon-analytics.org/archives/energy/a-closer-look-at-ccs-problems-and-potential
[18]https://ieefa.org/ccs
[19]https://doi.org/10.21608/ijesr.2023.346724, https://doi.org/10.1088/1755-1315/1281/1/012034
[20]https://doi.org/10.1039/d3dt01676e
[21]https://doi.org/10.1016/j.ijhydene.2024.12.479
[22]https://doi.org/10.1016/j.ijhydene.2024.12.361

2.3 Electrolysers

There are three primary types of electrolysers commonly used for hydrogen production and other methods under development. The three main types of electrolysers are:

1. Alkaline Electrolysers

    Technology: These are the oldest and most mature type of electrolyser. They use an alkaline solution (typically potassium hydroxide) as the electrolyte. The process involves passing an electric current through the solution, separating water into hydrogen and oxygen.

    Advantages: Relatively low cost, robust, and can operate at high pressures.

    Disadvantages: Lower efficiency compared to other types, slower response time to load changes, and lower hydrogen purity.

2. Proton Exchange Membrane (PEM) Electrolysers

    Technology: Uses a polymer membrane to conduct protons, separating water into hydrogen and oxygen.

    Advantages: High efficiency, rapid response to load changes, high purity hydrogen output, and compact design.

    Disadvantages: More expensive due to the use of precious metals as catalysts and the need for purified water.

3. Solid Oxide Electrolyser (SOEC)

    Technology: Operates at high temperatures, using a solid ceramic electrolyte. This technology can be coupled with heat sources (like nuclear or industrial waste heat) to improve efficiency.

    Advantages: Very high efficiency, potential for cogeneration of heat and electricity, and can use lower purity water.

    Disadvantages: High operating temperatures, complex materials and manufacturing processes, and currently higher costs.

Electrolysers are a developing technology with improvements in efficiency, manufacturing and maintenance costs widely predicted in future projections to lower the levelised cost of hydrogen. However, a green hydrogen production plant is not just an electrolyser as a range of other equipment is needed, for example, to store, pump and purify water, electrical plant as well as local hydrogen handling and storage. Much of the balance of plant is mature technology and so is not expected to see the efficiency gains or cost reductions expected for electrolysers. In the Netherlands, TNO found that the average levelised cost of green hydrogen was €13.7/kg[23]. This cost was broken down into capital and electricity costs of which capital was around €5/kgH_2. Only 30% of the capital costs were down to the price of the electrolyser which means that even if electrolyser costs reduce by 50% then the total capital cost would only reduce to €4.2/kgH_2 making only a small difference to the levelised cost of green hydrogen. Therefore, caution needs to be applied to reports where total capital costs are predicted to fall substantially with the development of electrolyser technology.

[23]https://publications.tno.nl/publication/34642511/mzKCln/TNO-2024-R10766.pdf

There is a large volume of research published every year on improvements in electrolyser technology some of which may eventually make it from laboratory conditions to commercial products. Review and assessment of these technologies is not within the scope of this report, but it is worth noting that electrolysers with claimed efficiencies of 85% to 95% are being commercialised[24,25]. However, some claims need to be treated with caution such as over 50% gains in efficiency for current commercial electrolysers as these would break the laws of physics if true[26]. The typical performance of current electrolysers that are commercially available is between 55-80% efficiency at point of installation although this drops as components degrade during operation[27].

Globally, installed electrolyser capacity reached 1.4 GW at the end of 2023, almost double the installed capacity at the end of 2022. This capacity is set to grow further, with the IEA estimating that a global installed capacity could reach 5GW by the end of 2024 based on announced projects and those under construction[28]. Despite this prediction, as of September 2024, only 205MW of new capacity has started operations as many projects have been cancelled or postponed.

The installed capacity in 2023 represents only one-sixth of the expected capacity based on the IEA Global Hydrogen Review 2021. China accounted for 80% of the capacity that started operation in 2023, including the largest electrolyser project in the world (260 MW Kuqa plant by Sinopec). About 12% of the nearly 700 MW that came online in 2023 was in Europe. In the European Union, if all projects meet their planned timelines, total installed capacity could reach 0.7 GW at the end of 2024, falling very short of the interim target of 6 GW established in the EU Hydrogen Strategy back in 2020.

[24]https://www.pv-magazine.com/2024/01/09/the-hydrogen-stream-consortium-unveils-85-efficient-solid-oxide-electrolyzer/
[25]https://hysata.com/
[26]https://www.hydrogeninsight.com/innovation/pulsing-electricity-to-an-electrolyser-can-halve-the-power-needed-to-produce-each-kilo-of-hydrogen-study/2-1-1783923
[27]https://doi.org/10.1016/j.ijhydene.2025.01.033
[28]https://www.iea.org/reports/global-hydrogen-review-2024/hydrogen-production

2.4 The price of green hydrogen

The price that an end-user pays for green hydrogen is often not the cost that is routinely quoted in academic and industry reports. Instead, the Levelised Cost Of Hydrogen (LCOH) is more commonly quoted as a tool for comparison between technologies and installed facilities. However, headline figures for the LCOH only tell part of the story as these represent only the cost at point of production. Unless the green hydrogen is being directly fed into an industrial process or other end use then the LCOH is far from the price that an end-user would pay. The additional costs of extra compression or liquefication, storage, transport and dispensing are considerable. For example, in California which has a relatively high uptake of hydrogen vehicles when grey hydrogen was \$1-2/kgH_2 then the dispensing price at hydrogen fuelling stations was \$16/kgH_2[29].

The same paper[29] goes into some detail as to the costs of distribution and storage and this reinforces the message that the most cost-effective use of hydrogen is when production is co-located with the end-use as additional costs are minimised.

Industry analysts have started to reflect the economic reality of green hydrogen and revised cost estimates upwards[30]. This reflects a number of cancelled or postponed projects (e.g., Equinor, Shell, Origin Energy), green hydrogen prices rising 35% in 2 years[31], and the impact of a change in government in the USA.

2.4.1 Levelised cost of hydrogen (LCOH)

The LCOH is dependent on many factors such as:

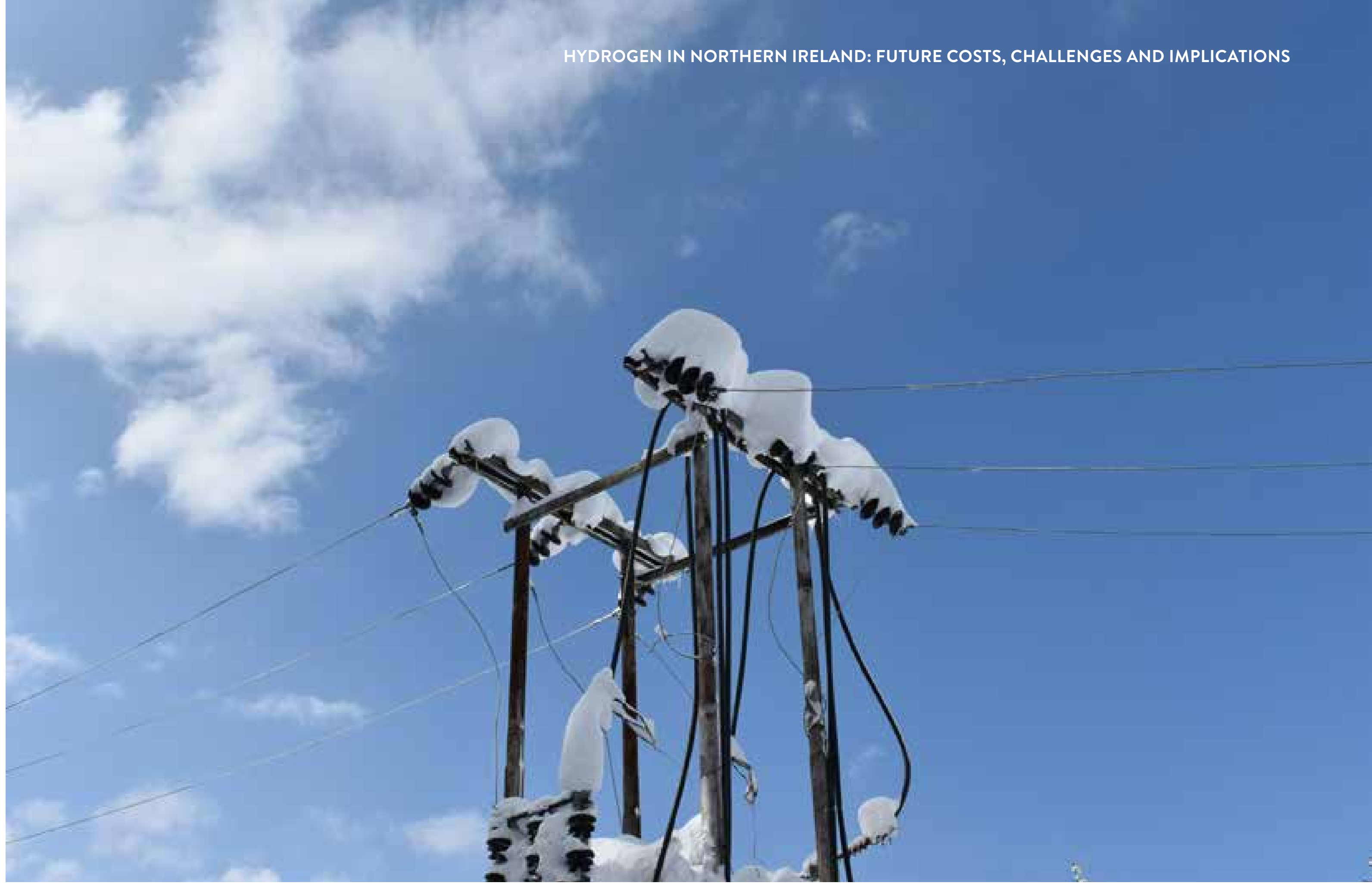
1. Electricity price
2. Capital cost of electrolysers and plant
3. Financing costs
4. Operational and maintenance costs including water
5. Sale of co-products (Oxygen and waste heat)
6. Any grant or other income (e.g., grid balancing)

Typically, a rule of thumb is that around 30% of the eventual cost of production is down to the price of capital with electricity costs dominating the final LCOH. The scientific literature, industry papers and government reports have limited consensus, forecasting a wide range of prices from \$1/kgH_2 upwards that are heavily dependent on location and assumptions used. Many of these forward predictions are based on expert opinion or derived from experience curves that predict how fast and by how much the technology declines in price with the volume of sales. A recent review gives a good overview of the current literature[32].

Fundamentally, the price of green hydrogen is critically dependent on the cost of electricity used to split water into its component molecules using an electrolyser. While scaling up of electrolyser production and improvements in technology will improve efficiency and lower capital costs this will have a limited impact on the LCOH given the balance of plant and electricity cost dependency. Low-cost green hydrogen requires very cheap renewable electricity which means NI is uncompetitive compared to equatorial regions with high-capacity factor solar energy, low land and operational costs. Utilisation of current unused, dispatch down, electricity in NI will, at best, have a small impact on price in the longer-term as discussed in the next section.

For GB, a recent industry report[33] outlines mechanisms by which the strike price for hydrogen could be reduced from £241/MWh to £100/MWh. There are a number of proposals which include reducing costs such as by changing hydrogen business models, incentivising electrolyser use to reduce constraints and development of a hydrogen transmission network. Some of these options could apply to NI but overall, while prices will reduce, it is unlikely that £100/MWh would be achieved in NI unless electricity prices could be reduced considerably or commitments to ongoing incentives were made.

[29]https://doi.org/10.1016/j.joule.2024.09.003
[30]https://www.bloomberg.com/news/articles/2024-12-23/green-hydrogen-prices-will-remain-stubbornly-high-for-decades
[31]https://about.bnef.com/blog/five-energy-transition-lessons-for-2025/
[32]https://doi.org/10.1016/j.ijhydene.2024.12.078
[33]https://www.renewableuk.com/media/gjkhpx2n/splitting-the-difference-hydrogen-co-report.pdf



Connecting a renewable energy source directly to an electrolyser without going via the grid (with its imposed costs) is seen as the optimal model for the most economically efficient way of producing green hydrogen. On this basis, investors and governments across the world are building large-scale (GW+) renewable energy generation with banks of electrolysers to produce green hydrogen.

Ideally, the wind or solar farm needs to operate with a high-capacity factor – i.e. it is delivering the maximum amount of electricity for the capital invested in the facility because the wind or solar energy average at a location is reliably at a high level. Solar is currently the cheapest form of renewable electricity generation and so vast solar farms are being built in guaranteed sunny countries such as Australia, Namibia and Saudi Arabia. These solar farms have high-capacity factors and capital costs are minimised due to scale and low land prices. These locations offer the lowest levelised cost of hydrogen with claimed prices around \$1/kg of hydrogen. Northern Ireland is currently unlikely to approach parity in production costs with these locations. However, these countries are remote from where hydrogen is used and so transport becomes a constraining factor in the economics around use, particularly due to hydrogen loss from leakage or boil off (for liquified hydrogen).

Despite transport challenges, the importation of green hydrogen from equatorial countries (which are effectively monetising cheap solar energy and shipping it round the world as hydrogen) is probably the major competition to future production in Northern Ireland. Closer to home, wind farms off the north-west coast of Ireland or north of Scotland may also be operating in the future (2040+) with the high-capacity factors and scale economics that could enable cheap green hydrogen to be produced.

2.4.2 Electricity price: the input cost driver for green hydrogen

European countries such as the UK and Ireland are at the upper end of the production cost spectrum for green hydrogen mainly because of the high forecast cost of electricity. The latest allocation round (AR6) in the UK awarded contracts at strike prices of £50.9/MWh (onshore wind) and £58.87/MWh (offshore bottom fixed) – prices are indexed to 2012 and inflated to 2024 equivalents are £70.83/MWh and £81.92/MWh respectively. Production prices are increasing and not dropping towards the £38/MWh which was the DESNZ prediction for 2025[34]. A similar situation exists in some of northern Europe, and it is difficult to see how electricity prices can drop to the levels needed to achieve $1/kgH$_2$ which may be reached elsewhere by 2050 but only if electricity prices of less than €7/MWh are achieved[32]. For comparison the average day ahead price for the Single Electricity Market (SEM) across Ireland in January 2025 was €167/MWh.

Electricity prices set a floor for the production cost of green hydrogen without additional support. The cost of electricity is a limiting factor for many industries and energy storage operators, not just for hydrogen production. In the last couple of years, dispatch down electricity has become substantial in NI for several reasons but mainly due to low-cost electricity flowing into the SEM from Europe due to the European grid not yet having the flexibility to cope with peaks of generation that come from renewables. SONI published a draft plan[35] in December 2024 which will see much of the dispatch down issue addressed in the coming years with grid improvements and installation of up to 1GW of battery storage. It is expected that current levels of dispatch down will reduce by 75% by 2030 and will remain below 10% after that[36].

Modelling of dispatch down electricity and use for hydrogen production is superficially simple when looking at just the overall unutilised electricity and factoring in dispatch down payments to electrolyser owners to avoid paying compensation to renewable generators for curtailing production. However, the real-world situation is far more complex with a number of factors:

1) Spatial: Dispatch down electricity is partly grid dependent in that where constraints and curtailment occur determine where electrolysers will need to be located. This may require several electrolysers which need to be located at key nodes on the grid across NI and incur significant transport costs for hydrogen. A second order spatial effect to be modelled will be the variation in wind and solar across the geography on NI.

2) Temporal: Short-term (minutes-hours) and Longer-term (days- months) variation is very significant (see Figure 2 and Figure 3 below for real-world examples of monthly dispatch-down). This adds complexity to electrolyser operation as near continuous operation is ideal for maximum efficiency and minimising operational costs. Ramp-up/down reduces efficiency, increases maintenance and increases capital costs in terms of additional storage and other plant. Extended periods of low renewables generation will also need to be built into business models.

3) As electrolysers and associated plant for green hydrogen production are capital-intensive assets, they need consistently high utilisation rates to be financially viable. Unfortunately, as shown in Figure 3 below, dispatch down electricity from wind and solar is unpredictable and intermittent. Relying on unused, surplus dispatch down electricity does not allow electrolysers to operate at optimum utilisation rates and increase costs of hydrogen. Relying on intermittent power also increases the need for expensive storage as sufficient capacity needs to be maintained to bridge periods when dispatch down electricity is unavailable or alternatively, more expensive grid power will have to be utilised. Either option significantly increases hydrogen production costs and supports the conclusion that coupling to dedicated and consistent electricity supplies is the best option for lowest cost hydrogen production.

[34]https://assets.publishing.service.gov.uk/media/6556027d046ed400148b99fe/electricity-generation-costs-2023.pdf
[35]https://lnkd.in/ev-XuH_m
[36]Communication from SONI on their expectations as a result of grid development and execution of their draft dispatch down action plan – see https://cms.soni.ltd.uk/sites/default/files/publications/Draft%20Dispatch%20Down%20Action%20Plan%20-%20System%20Operator%20for%20Northern%20Ireland%20-%20December%202024.pdf

4) Grid development: Planned development of the grid in NI will mitigate many of causes of dispatch down[35]. Changes in industry/societal demand will also alter the congestion points on the grid especially as many parts of the economy are being electrified. A full predictive model will have to take in these factors and look at different scenarios.

5) Cross-jurisdictional issues: The NI grid is part of the all-island Single Electricity Market which in turn is connected to GB and European grids by an ever-growing number of interconnectors. These interconnections allow low-cost electricity to flow into the SEM and equally could allow renewable energy generators to export power.

6) Grid stabilisation: The move away from a few large power stations to a large number of renewable energy assets requires additional services such as short-term energy storage, inertia/frequency/reactive services. Energy storage providers in particular will look to store electricity when it is lowest cost so would be in competition for dispatch down power. These options also reduce intermittency as well as increasing grid stability while being more economically competitive than hydrogen production.

7) Markets/Arbitrage: Today weather can be forecast with some accuracy several days ahead and so predict energy generation from all renewable sources. SMART grids are also evolving and so electricity markets and brokers for day/week/month ahead will be able to offer dispatch-down electricity to end-users who can increase or shift their load profile to take advantage of the lowest cost electricity. There are many options available such as:

    i. Charging of BEV of all types including HGVs, buses, PSV and cars
    ii. Medium term energy storage such as pumped hydro, compressed air or gravity systems
    iii. Heat batteries for Heat as a Service and district heating applications
    iv. Data Centres and Bitcoin mining
    v. Social schemes to reduce fuel poverty such as water heating overnight[37]

A full analysis of the opportunity for hydrogen would need to involve many of the key stakeholders across the energy sector in NI and beyond to consider the many options available as well as chosen pathways to net zero and technology development. This complex exercise is beyond the scope of this report, but it is worth noting that any payment for dispatch down would have to be met as a levy on consumer bills which may be politically unacceptable when alternative lower or no-cost options exist.

[37]https://renews.biz/98829/irish-scheme-tackles-energy-poverty/

However, it is within the aim of this report to definitively cancel the false belief that dispatch down electricity is in some sense 'free' or worse, that payment for curtailed or constrained production could be instead deployed to subsidise taking that electricity to make hydrogen. This assumption could be applied to many industries to make business models work or products more competitive against alternatives but ultimately somebody (usually the electricity consumer) pays the cost.

The electricity that the grid is unable to take only exists because of previous investment in the renewables; wind turbines, solar array, biogas generator or wave, tidal or another generating device. That investment decision was based on an understanding of potential output and the price or value thereof. It includes expectations around being paid even where the grid is unable to take the power. If this is removed, it makes the investment decision less certain and likely pushes up the price of the power that is sold. Thus, while at the point of dispatch down it is true that the potential electricity is wasted and any payment seems to be for no benefit, this is not true when considering the life cycle of the investment. Asking generators to forgo payment and still actually produce is economically unsustainable as is expecting consumers to evermore pay a levy to enable green hydrogen to compete in use cases where there are better and cheaper alternatives.

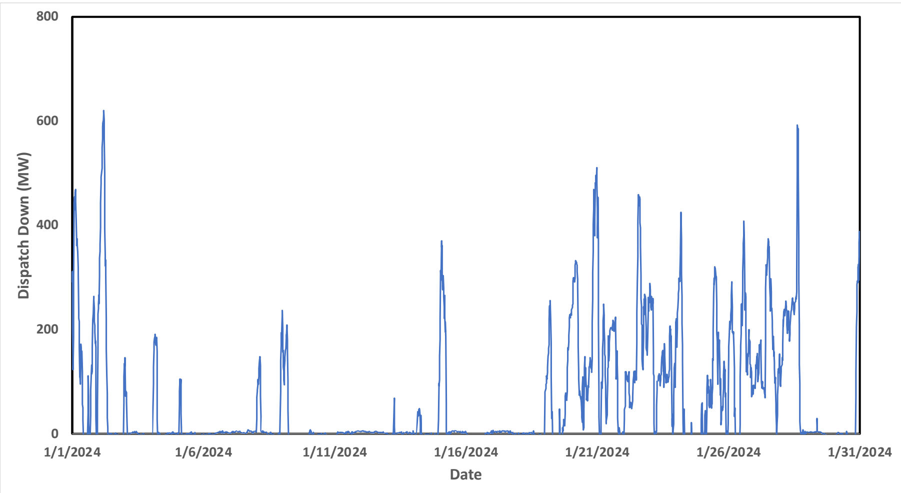


Figure 3 Example of impact of low wind/solar on dispatch down electricity for NI from January 2024

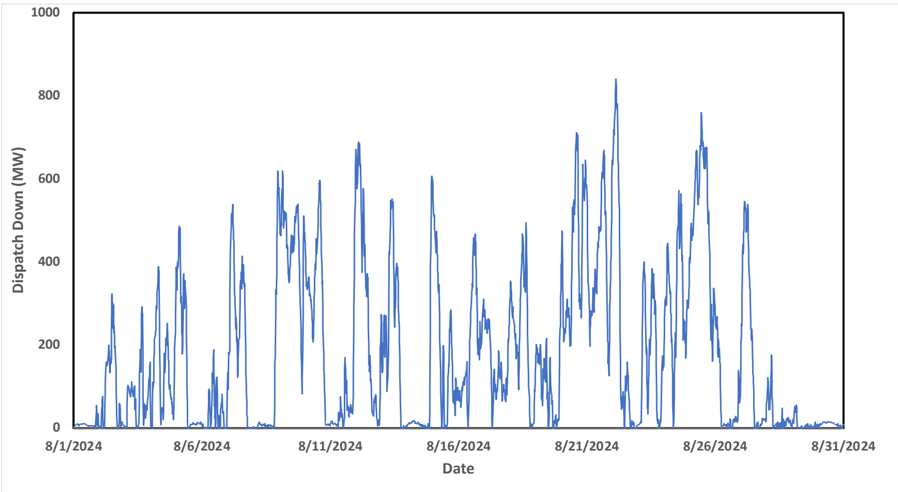


Figure 2 Example of temporal variation in dispatch down electricity for Northern Ireland August 2024

2.4.3 Water

The substantial volumes of pure water needed for hydrogen production are often overlooked. However, with 1 kg of hydrogen requiring approximately 10 to 20 litres of water[38] (including process cooling) then this can have a very significant demand on water infrastructure and may well require additional investment to deliver. For example, a 500MW electrolyser would consume around 100 m^3 per hour of ultra-pure water[39] and a similar amount of water (not ultra-pure) for processes including cooling.

Assuming 200 m^3/h, or 4800 m^3/day then this equates to 1.7 million m^3 of water per year which in NI would cost around £1.7m just for the supply of water[40] and not including any other wastewater or other charges. While not insignificant this adds an extra cost to the overall utility demand. Research work is underway to allow direct use of seawater[41] and if this succeeds then this would remove pressure on local water infrastructure assuming the hydrogen plant was situated close to the sea which is the most likely situation for NI.

2.4.4 Storage, transportation and distribution

As hydrogen has a very low volumetric energy density at normal atmospheric pressure it needs to be either highly compressed to >350bar and preferentially higher pressures or liquified for storage and transport. Compression and storage losses are typically 10-20% and for liquification 30-40%[42] in terms of the overall energy input into the production system. Storage costs will always be higher than liquid fuels since expensive pressure vessels (steel or composite) are required rather than simple tanks. However, costs are higher even for compressed methane or natural gas. For the same energy content hydrogen will require three to four times as much space – hence larger storage vessels are required. The cost of cylinders depends on type, pressure and capacity and a wide variety are available from China and other countries. In terms of future costs, it is worth noting that the US Department of Energy has a 2030 target of \$9/kWh (or \$300/kg H_2) with it expected that \$8/kWh (\$266/kg H_2) can be achieved[43]. It is reported that currently a tank for 1000kgH_2 costs around \$600,000 and for liquid hydrogen \$30-50/kgH_2[44].

Hydrogen's low boiling point of 20 K can lead to some evaporation in storage of liquid hydrogen, known as "boil-off"[44]. According to the National Renewable Energy Laboratory (NREL), typical liquid hydrogen storage will boil off an average of 1% per day with the supply transfer process, resulting in an estimated 15% loss of stored hydrogen. Gaseous hydrogen transportation, storage and delivery show little product loss, but gaseous hydrogen transfers can be time-consuming as the transfer is completed through differential pressure.

Inter-seasonal storage will require substantial quantities of hydrogen to be stored. This can only be achieved using underground storage such as depleted gas fields, under aquifers or in salt caverns. In NI, salt cavern storage under Larne lough in Islandmagee has been shown to be viable. Typical capital costs in the literature for salt cavern storage are upwards of €7/kgH_2[45] and operating costs £0.26/kgH_2[46]. However, a full feasibility study would need to be completed to understand the hydrogen storage necessary to address NI's inter-seasonal and long-duration storage requirements and the full cost of salt cavern development and operation.

High cost of transportation is another factor. In the UK there are both steel cylinder-based tube trailers (type I) and composite based cylinder tube trailers (type III and IV). Type 1 can typically transport 300 kg of hydrogen at 228 bar and type III/IV trailers up to 1300kg[46]. Transporting the same energy content of green hydrogen as would be contained in one diesel fuel tanker would require 9 trips from a 1300kg capacity hydrogen trailer and 23 trips if a 500kg capacity trailer was used. In HGV terms, one diesel tanker (40,000 litres) can refuel approx. 160 HGVs (250 litres per HGV). One 500kg hydrogen trailer can refuel about seven hydrogen HGVs (70kgH_2 per HGV) and the 1300kg trailer around 19 hydrogen HGVs.

[38]https://rmi.org/hydrogen-reality-check-distilling-green-hydrogens-water-consumption/
[39]https://hydrogentechworld.com/water-treatment-for-green-hydrogen-what-you-need-to-know
[40]NI Water 2024-25 water charges: https://www.niwater.com/large-user-tariff/
[41]https://www.science.org/content/article/splitting-seawater-provide-endless-source-green-hydrogen
[42]https://doi.org/10.1016/j.ijhydene.2023.04.014
[43]https://www.energy.gov/sites/prod/files/2020/02/f71/fcto-compressed-gas-storage-workshop-2020-adams.pdf
[44]https://escholarship.org/content/qt83p5k54m/qt83p5k54m_noSplash_8bb1326c13cfb9aa3d0d376ec26d3e06.pdf?t=s9oa2u
[45]https://doi.org/10.1016/j.ijhydene.2023.06.269
[46]https://assets.publishing.service.gov.uk/media/659e600b915e0b00135838a6/hydrogen-transport-and-storage-cost-report.pdf

Table 2 shows the estimated range of transport costs for hydrogen in the UK as published by DESNZ[46]. These costs compare to an equivalent of one diesel tanker load costing c.£800 to deliver[47].

Transport mechanism	Levelised cost (£/kg) for 100km travel		Levelised cost (£) for one trailer over 100km		Number of trailers equivalent to diesel tanker energy content	Cost of equivalent transport to diesel tanker (£)	
	Minimum	Maximum	Minimum	Maximum		Minimum	Maximum
Pipeline	0.26	0.31	NA	NA	NA	2,912	3,472
500kgH_2 Trailer	2.49	4.09	1,245	2,045	22.4	27,588	45,808
1300kgH_2 Trailer	2.10	3.56	2,730	4,628	8.6	23,250	39,872

Table 2 Hydrogen transport costs based on data from DESNZ report on UK hydrogen transport and storage costs[46]

The costs for transport shown in Table 2 clearly show the very substantial increase in transport costs for hydrogen compared to diesel. Given the very significant expense for high-pressure tanks, costs for compression and the limited quantity that can be shifted in one trailer load then it is to be expected that transport costs are much higher than those for diesel, biodiesel or a liquid fuel or, in the majority of cases, electrical infrastructure costs for BEV charging. In terms of energy content then hydrogen delivery costs are equivalent to diesel distribution costs of between £0.68p/litre and £1.32p/litre. While costs are forecast to fall, hydrogen transport will remain very much more expensive than petrol and diesel distribution costs.

A final factor is the cost of the hydrogen refuelling station. These are much more expensive than a charging station for BEVs given that high-cost local storage and dispensing systems are required along with the costs of compliance with stringent safety standards as well as high maintenance costs. The actual cost depends on the capacity but a project in Middlesborough was awarded £7m in 2023 by UK Government for a hydrogen filling station capable of dispensing 1500 kgH_2 a day[48]. This project includes financing of £2.1million for more than 20 FCEVs ranging from 4.2 to 27 tonnes. Aegis has also announced a £100million investment to build 30 new multi-energy hubs for commercial vehicles which include Charging, Bio-CNG and HVO at the outset with the potential to add hydrogen if demand arises[49,50]. These costs compare to £15,000 - £25,000 for a single 50kW charge point plus installation and network connection costs £10,000 - £75,000 in GB[51]. Higher capacity chargers and multiple charge points will cost more as will grid reinforcement if this is required. For example, in GB, a 350kW charger could cost up to £1 million if the grid needs to be reinforced[52].

The financial figures above explain to some extent real-world data for cost of dispensed hydrogen. Figures published for California show that for a LCOH for grey hydrogen of \$1-2/kgH_2 results in a dispensing price of \$14-16/kgH_2 due to the significant cost of hydrogen storage and distribution infrastructure[53]. This compares to prices in the UK of £10 - £15 per kgH_2 for grey hydrogen[54] at fuelling stations and £20 - £30 per kgH_2 for capital grant aided green hydrogen[55].

[47]Based on 2023 distribution cost of £0.02/litre from https://www.lookers.co.uk/blog/how-is-the-cost-of-fuel-broken-down
[48]https://www.fleetnews.co.uk/news/funding-for-publicly-accessible-hydrogen-refuelling-station
[49]https://drivinghydrogen.com/2025/01/21/aegis-lands-100-million-to-build-30-new-uk-hydrogen-refuelling-stations/
[50]https://www.aegisenergy.uk/energy-hubs
[51]https://bett.cenex.co.uk/guidance/costs
[52]https://www.versinetic.com/news-blog/ac-vs-dc-charging-public-ev-infrastructure/
[53]https://doi.org/10.1016/j.joule.2024.09.003
[54]https://www.soguard.uk/where-can-i-fill-my-hydrogen-car-in-the-uk
[55]Figures from Logan Energy

2.4.5 The hydrogen use cycle – efficiency losses

The major argument against green hydrogen is that it is not a very efficient method of using renewable energy to power any application that could be directly electrified. Production, storage and distribution of green hydrogen has energy losses at each stage which ultimately means that it is an inefficient and expensive use of renewable electricity. Extensive studies have shown that it is at least six times less efficient than using heat pumps for home heating[56] and around two to three times more inefficient than BEVs for transport.

For this report we modelled the efficiency of using hydrogen for transport. A range of scenarios were examined and the most likely route to market for hydrogen was identified as a best and most realistic scenario. This can be seen in Figure 4, below. Here we have assumed that a short private wire connection is used to connect renewable energy generation to an electrolyser with onsite compression and storage. This site acts as a central distribution hub to refuelling stations much as present day petrol and diesel is distributed. Alternatives where pipelines were used for distribution were thought to be unlikely in the NI context as were a large number of individual sites each with renewable generation, electrolysers and storage.

A model of a typical BEV system was used as a comparison. Please note that this model looked at efficiency of BEV and green hydrogen only and where ranges of efficiency values were given in the literature the typical value (usually close to the median value) was used for calculations. Cost of infrastructure or transmission of electricity or distribution and transportation of hydrogen was not considered. A summary of results is shown in Figure 4 below.

For the green hydrogen model, an electrolyser efficiency of 70% was chosen. This was based on published ranges of 55-85%[27] where the upper end is associated with newly installed systems. As noted in the previous section, compression and storage losses are typically 10-20% depending on pressure. Here we assume 15% loss which is 85% efficiency[42]. It is worth noting that for liquefication the energy loss is 30-40%. Distribution losses could be highly variable, here we have used a value of 96% i.e. 4% loss[57]. Dispensing losses will be dependent on losses during offload from the tanker to the refuelling station and dispensing losses. As our model assumes compressed rather than liquid hydrogen the offload losses of 13% for liquid hydrogen and dispensing losses of 3%[58] are unlikely to occur so a reasonable estimate of a 4% loss has been assumed. Hydrogen fuel cells used in cars are claimed to have a 40-60% efficiency[59] in conversion of hydrogen to electricity. For this model we have taken the upper value to reflect the claims for the latest generation of FCEV vehicles[60].

For the counterpoint, BEV efficiency model we have taken the transmission losses for renewable electricity on the grid to be around 1.7% with the distribution network accounting for another 5-8% in the UK[61]. The actual transmission efficiency will depend on how far the renewable generation asset is from the point of use, especially the distance the electricity is transferred over the distribution network and not the high voltage (275kV and 400kV) transmission grid. Other factors such as the age of the grid and distribution infrastructure will also play a role. For modelling purposes, we have assumed an 8% loss or 92% transmission efficiency.

Electrical charging losses for an EV will depend on a number of factors:

Causes of Energy Loss:

- Charging Cable Losses: Longer cables increase resistance, leading to more power loss. Shorter cables result in lower resistance and less power loss.
- On-Board Charger Efficiency: The efficiency of the car's on-board charger impacts how much energy is actually stored in the battery.
- Chemical Reaction: When an electric vehicle charges, the electrical energy from the charge point causes a chemical reaction in the lithium-ion battery, which causes heat as a result of power loss

For modelling purposes, we have assumed that 10% of energy is lost during charging (90% efficiency) and 13% loss (87% efficiency) in the electric drive system in the EV[62]. In total, for an EV then the total efficiency of generation-transmission-charging-to energy for motion is 72%. More modern vehicles will be more efficient, and other factors will come into play for real world use such as use of air conditioning or heating and higher charging currents will generally result in larger energy losses.

[56]https://doi.org/10.1016/j.crsus.2023.100010
[57]https://www.linkedin.com/in/michael-sura-9a47511bb/recent-activity/all/
[58]https://genh2hydrogen.com/blog/unlocking_the_secret_to_zero-loss_transfer/
[59]https://www.californiahydrogen.org/wp-content/uploads/files/doe_fuelcell_factsheet.pdf
[60]https://doi.org/10.3390/en17051085
[61]https://www.neso.energy/document/144711/download#:~:text=On%20the%20Transmission%20network%2C%20the,lost%20over%20the%20distribution%20networks2.
[62]https://electroverse.com/community/ev-blogs-and-guides/how-efficient-are-electric-vehicles

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Both electric and hydrogen fuel cell vehicles use regenerative braking as both have batteries that can be re-charged to enable re-use of the energy and for modelling purposes, we have assumed equivalence and not factored this into the comparison. Hydrogen combustion vehicles could have a regenerative braking system that is used to generate electricity to power onboard systems, but this doesn't contribute to powering vehicle motion although it does reduce overall energy consumption. Typically, hydrogen combustion engines are much less efficient that FCEVs at around half (20-30% efficiency) compared to a FCEV at 40-60%.

The results of the efficiency comparison are shown in Figure 4 below. This shows that 1 MWh of generated energy will result in 0.283 MWh to power motion. This compares to a BEV where efficiency losses are much lower giving 0.72MWh showing that a fully electrified system gives over 2.5 times the range as compared to going down the green hydrogen route. Modelling gave a range of values from 2 times the range to over 3 times the range depending on how optimistic assumptions on improvement in efficiency for each step in the hydrogen chain would be with innovation compared to more pessimistic figures quoted for current systems in use. Unfortunately, it is difficult to get real-world figures which are independently verified as opposed to manufacturers sales figures or those obtained from technology models in the literature. However, it can be concluded, with some confidence, that green hydrogen is at best half as efficient as direct electrification. The added cost of hydrogen generation, compression, storage, distribution and dispensing compared to electrification will tip the economics even further in the direction of electrification.

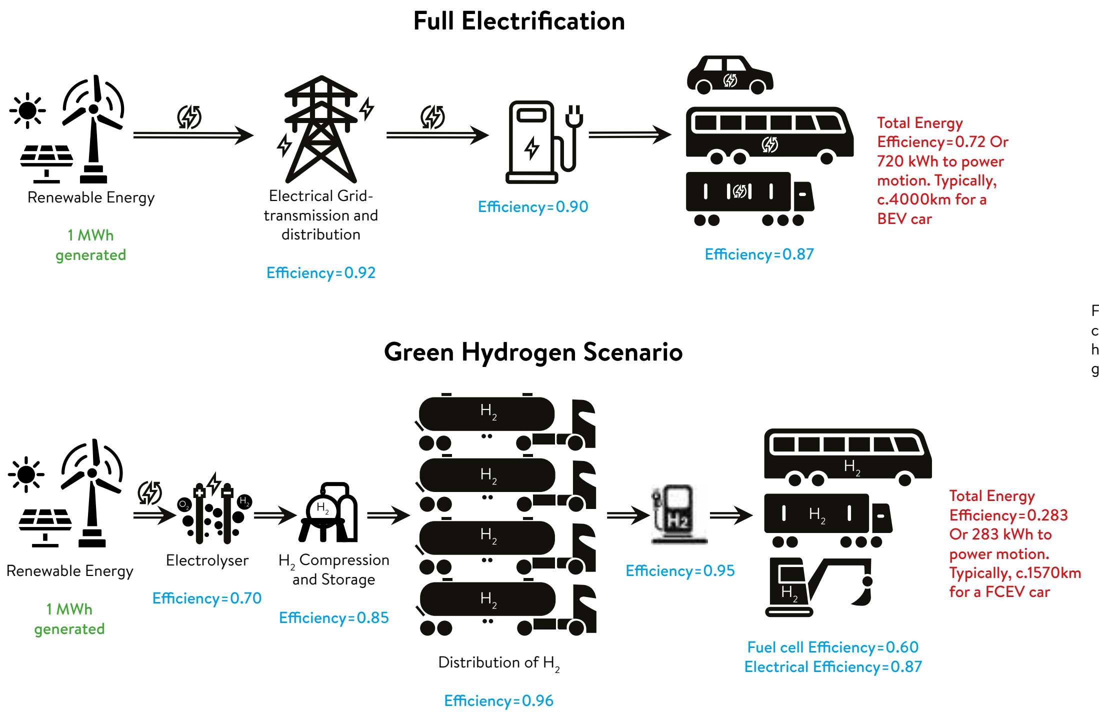

Figure 4 Example efficiency comparison between a BEV and hydrogen FCEV from power generation to delivering motion

In the best-case scenario when renewable energy is converted to green hydrogen to electricity via a fuel cell, with no storage and distribution, this would require over twice the amount of renewable energy generation (wind and solar) as would be needed just going the electrification route. Adding storage and distribution adds considerable cost and additional efficiency losses. An example for hydrogen vehicles in GB saw end-user prices for green hydrogen after distribution from a capital grant funded production facility given as £20-£30 per kgH_2 which is equivalent to 60p/kWh to 99p/kWh. Using a fuel cell at 60% typical efficiency further adjusts the price comparison to electricity and implies a minimum equivalent cost of £1/kWh for electricity compared to market values for EV charging of between 8p/kWh (home charging, 5% VAT) and 53p/kWh (public fast charging, 20% VAT)[63], in GB – overnight prices are currently more expensive in NI, typically 14-18p/kWh[64]. Business users can claim back the VAT on public fast charging use which gives a price point of 42.4p/kWh. Removal of grant funding or other support mechanism for green hydrogen just makes this fuel even less competitive.

It is worth noting that a council or business with private wire access to renewable electricity could be effectively paying less than 10p/kWh depending on capacity factors, size, type and capital cost of the renewable energy system. Most PSV, bus, van and HGV fleets are tethered in that they return to a depot overnight so could benefit from low-cost, off-peak electricity (including dispatch-down electricity when available) for charging even if a dedicated private wire connection is not feasible.

[63]https://www.theguardian.com/environment/2025/jan/26/a-tax-on-living-greener-how-can-britain-make-charging-evs-cheaper
[64]https://www.consumercouncil.org.uk/consumers/help-consumers/electricity-oil-and-gas/switching-electricity-or-gas-supplier/economy-7

2.4.6 Exploitation of co-products to maximise economic efficiency

Electrolysis is not a perfectly efficient process as discussed in the previous section. Input electrical energy used to split the water molecule results in waste heat and oxygen as well as producing hydrogen. In the majority of cases both the waste heat and oxygen are vented to atmosphere. However, it is possible to monetarise both as they have a market value.

Heat is produced during electrolysis and during the further compression or liquification of hydrogen. Typically, this is removed from the process equipment via water or air cooling in the form of low-grade heat (typically 30°C to 55°C) which can be utilised for district or industry heat applications[65,66]. Utilisation of waste heat will increase the overall efficiency of hydrogen production but the additional capital and operational costs, availability of a suitable off-taker and contractual requirements regarding heat supply need to be factored in. Each heat recovery installation is bespoke to the hydrogen production plant and location but to give a sense of scale of opportunity a system in Finland was estimated to provide a levelised cost of heat of €44/MWh[66]. Another example of a modelled system integrating a hydrogen plant into a district heating network in the United Kingdom was capable of recovering 312 kW of thermal energy per MW of electricity supplied to the electrolyser[67]. Overall, the addition of heat recovery can improve overall hydrogen plant efficiency, potentially increasing it from 75-80% to 86-95%[65] or as high as 98%[68] but this will depend on the system design and equipment chosen.

For each hydrogen molecule (H_2) one oxygen atom is released from a water molecule (H_2O). In mass terms for 1kg of hydrogen, 8kg of oxygen is produced. Capture and sale of this oxygen has often been suggested as a route to maximise the economic return from a hydrogen plant. Reversing the hydrogen business case, oxygen production has also been seen as the principal driving factor in some cases for electrolysis with hydrogen sales an opportunity to offset the cost of the oxygen. A prime example of this is the use of oxygen to enhance wastewater treatment such as being developed by NI Water[69]. Sale of hydrogen is key in such cases as using electrolysis to just produce oxygen has been shown to be not cost competitive to traditional production methods[70].

There are currently several uses for oxygen in industry and healthcare such as welding, food sector, metal production and processing, paper production, chemicals and pharmaceuticals manufacturing as well as in medical applications to assist breathing. These are met by current suppliers who typically use large-scale, cryogenic distillation or pressure swing adsorption to produce oxygen and other gases such as nitrogen. Capturing oxygen from electrolysis will require additional equipment to capture, purify and compress or liquify the gas as well as development of a distribution network. How competitive oxygen from electrolysis will be depends on the scale of production and local market opportunities. Provision of oxygen for medical purposes is the most attractive given this market commands the highest prices. The high purity of oxygen from electrolysis is competitive to the levels achieved by cryogenic distillation but in reality, medical grade oxygen is a small market and could not absorb the volumes of oxygen from projected green hydrogen production levels. The traditional markets for oxygen are relatively small, $35 million in 2022 with growth rate of 12.2%[71]. Consumption is likely to increase steadily so new supplies from electrolysis would have an opportunity, especially if lower priced than existing suppliers to create market share. Creation of new markets such as for oxyfuel combustion or wastewater treatment is possible, but these new applications require very low-cost oxygen to be feasible. There is a risk that as more electrolysis plants come online, oxygen supplies could exceed market demand and so lower prices. As for hydrogen production the optimum route would be to utilise the oxygen close to the point of generation such as for wastewater treatment or oxyfuel combustion.

There is comparatively little published academic work on the co-production and valorisation of oxygen[72] and a range of oxygen prices are quoted from $0.06 to $3.76 per kg which does significantly affect the financial returns[73]. A fairly detailed model[72] developed for a UK based hydrogen production system showed that above a price for oxygen of £0.16/kg the extra costs of capturing and processing oxygen were mitigated. As oxygen prices increased then the LCOH decreased reaching a reduction of c.£1.9/kgH_2. This work indicates that in a UK setting, any large-scale electrolyser facility should consider oxygen production as a route to improve the economics of green hydrogen production.

[65]See for example: https://doi.org/10.1016/j.ijhydene.2023.03.374, https://lup.lub.lu.se/luur/download?func=downloadFile&recordOId=9123887&fileOId=9123897
[66]https://doi.org/10.1016/j.energy.2024.132181
[67]https://doi.org/10.1016/j.enconman.2021.114686
[68]https://doi.org/10.1016/j.apenergy.2023.121333
[69]https://www.niwater.com/news-detail/12338/NI-Water-commences-liquid-oxygen-trials-as-part-of-ground-breaking-hydrogen-project/
[70]Rao, P.; Muller, M. Industrial Oxygen: Its Generation and Use. In ACEEE Summer Study on Energy Efficiency in Industry; American Council for an Energy-Efficient Economy: Washington, DC, USA, 2007.
[71]https://doi.org/10.3390/en16124829
[72]http://dx.doi.org/10.1016/j.ijhydene.2020.04.259
[73]https://doi.org/10.3390/en17020281

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2.4.7 Safety

Compliance with safety regulations is mandatory for all activities in the UK. For hydrogen these add significant cost which is not surprising given the high pressures (> 400 bar) commonly used and explosive nature of the gas. Hydrogen has a very low flashpoint of -231°C which is a benefit for ignition of hydrogen powered engines in sub-zero environments but does also mean that it vaporises and ignites much more easily than liquid fuels or natural gas. Hydrogen also has a wide flammability range of 4-75% compared to methane of 5.3-15% which means that hydrogen ignites and burns at a greater range of concentrations in air[27].

The properties of hydrogen mean that special precautions need to be taken:

1) Hydrogen/air mixtures need to be avoided due to flammability. Precautions such as avoiding or adding venting to areas which could contain leaking gas are important as is regular planned maintenance of hydrogen equipment. Note that as hydrogen is a buoyant gas it can collect in ceilings or roof voids forming explosive mixtures.
2) Hydrogen has no smell, and a hydrogen flame can be hard to detect as it is difficult to see in daylight and does not emit a large amount of heat. UV or IR flame detectors or other gas detection sensors are essential. Where hydrogen is not going to be used in a fuel cell then odorant and colorant could be added to the gas.
3) Hydrogen embrittles and corrodes certain materials such as steel which means both careful choice of materials and regular, planned maintenance with scheduled replacement of critical parts.

Hydrogen has had some misleading press[74] around safety for home heating as a result of reporting of quantified risk assessment by Arup as part of the Hy4Heat programme[75]. If a hydrogen supply is fitted with excess flow valves, then the actual prediction is that the same number of injuries would occur as for natural gas, but the number of explosions would be three times greater[76] as a hydrogen explosion with an excess flow valve is less likely to cause injuries.

The main requirements are compliance with the following regulations:

- **Planning (Hazardous Substances) Regulations 2015:** Consent is mandatory for sites intending to store two or more tonnes of hydrogen. This regulation aims to control the risks associated with storing significant quantities of hazardous substances.
- **Control of Major Accident Hazards (COMAH) Regulations 2015:** Facilities storing hydrogen above specified thresholds must comply with COMAH, which requires operators to take all necessary measures to prevent major accidents and limit their consequences for human health and the environment.
- **Dangerous Substances and Explosive Atmosphere Regulations (DSEAR) 2002:** These regulations mandate that employers assess risks associated with dangerous substances, including hydrogen, and implement appropriate measures to eliminate or control potential hazards.
- **Pressure Equipment (Safety) Regulations 2016:** These regulations apply to the design, manufacture, and conformity assessment of pressurised equipment used for storing hydrogen, ensuring that such equipment meets essential safety standards.

"Properly designed and engineered hydrogen projects can be safe and reliable...."

[74]https://fullfact.org/environment/hydrogen-boiler-explosion/
[75]https://static1.squarespace.com/static/5b8eae345cfd799896a803f4/t/60e399b094b0d322fb0dadc4/1625528759977/conclusions+inc+QRA.pdf
[76]https://www.thechemicalengineer.com/features/home-hydrogen-is-it-safe/

2.4.8 Environmental considerations

While hydrogen combustion or its use in a fuel cell produce no direct carbon emissions, hydrogen is considered to be a greenhouse gas with a global warming potential (GWP) through indirect effects on atmospheric chemistry which result from leakage of hydrogen during its production, distribution, storage, and utilisation. Combustion of hydrogen can also produce NOx emissions which is an air pollutant with significant respiratory health impacts.

Hydrogen's indirect greenhouse effect occurs primarily due to its influence on atmospheric methane (CH_4), ozone (O_3), water vapour (H_2O) and aerosols[77]. Recent research underscores that hydrogen emissions lead to increased atmospheric methane lifetimes and ozone concentrations, both potent greenhouse gases, thus amplifying hydrogen's indirect GWP[78]. Furthermore, hydrogen leakage, which is inevitable across production, distribution, and utilisation chains, significantly affects its net climate benefit[79].

Hydrogen exhibits a GWP100 (Global Warming Potential over 100 years) of 11.6 ± 2.8, meaning each kilogram of hydrogen emitted into the atmosphere has 11.6 times the warming effect of CO_2 over a century. This estimate is substantially higher when considering shorter timescales (GWP20), reflecting hydrogen's strong but relatively short-lived indirect effects, including its contribution to increased tropospheric ozone and reduced hydroxyl radicals, which extend methane's atmospheric lifetime.

A 2022 review commissioned by the UK's Department for Business, Energy and Industrial Strategy (BEIS, now Department for Energy Security and Net Zero) highlights the necessity for stringent control of hydrogen leakage to minimise its indirect warming impacts[79]. The UK Hydrogen Strategy acknowledges these indirect effects and recommends strict protocols and advanced monitoring techniques throughout the hydrogen value chain to ensure emissions remain minimal.

In conclusion, aiming to achieve reductions in NI's greenhouse gas emissions with the introduction of a hydrogen economy needs to consider the likely impact of hydrogen leakage and how this could be minimised through emission controls and deployment strategies. Arguably, for NI, this problem is made worse by hydrogen interfering with methane emissions which are protected under the NI climate act. A further study would need to be performed to understand if there is a low or more significant risk to NI's target of achieving net-zero by 2050 from the more extensive use of hydrogen.

[77]https://doi.org/10.1038/s43247-023-00857-8
[78]http://dx.doi.org/10.1016/j.ijhydene.2022.11.219
[79]https://www.gov.uk/government/publications/atmospheric-implications-of-increased-hydrogen-use

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3. CHALLENGES FOR ESTABLISHING A HYDROGEN ECONOMY

A hydrogen economy has been pursued for many years as an alternative to an oil based global economy. Initially, this was driven by the oil crisis in 1973-74 with the establishment of the International Energy Agency (IEA) and the International Association for Hydrogen Energy (IAHE) in 1974 to pursue alternative energy vectors. In the last couple of decades hydrogen has re-emerged as proposed solution to the need to drastically reduce emissions of CO_2 to avoid the worst-case scenarios of global warming. While advances in low-carbon hydrogen technologies have improved the economics for generation, storage and use, collectively these developments have been outpaced by alternative energy technologies for most applications. Principally, these changes focus on renewable electricity generation and storage. A key example is the 73% drop in lithium battery cell prices over the past 10 years[80] which has enabled the battery electric vehicle evolution. The pace of change is considerable, in the past few months' announcements have been made of:

- Semi-solid lithium batteries coming to market, doubling the energy density and allowing battery packs to halve in weight for the same range[81]
- Solid state batteries with up to twice the energy density giving increased range, stability and temperature performance being tested in real world vehicles for launch in the next few years[82,83]
- BYD announcing 5-minute, ultra-rapid charging for their latest cars[84]

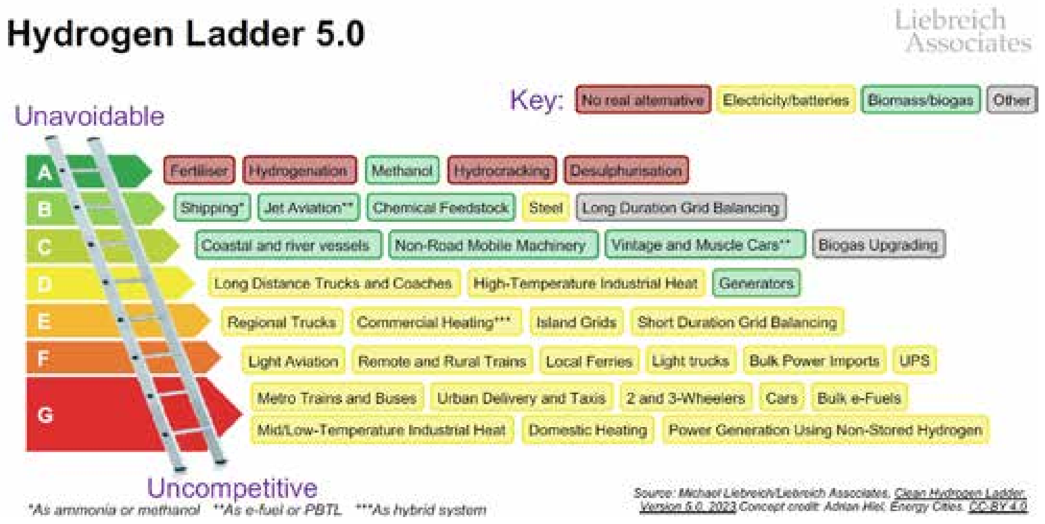

Figure 5 Hydrogen ladder v5.0
(c) Michael Liebreich/Liebreich Associates

[80]https://source.benchmarkminerals.com/article/how-lithium-ion-batteries-keep-getting-cheaper
[81]https://spectrum.ieee.org/semi-solid-state-battery
[82]https://electrek.co/2025/02/27/toyotas-all-solid-state-ev-batteries-just-got-a-lift/
[83]https://group.mercedes-benz.com/innovations/drive-systems/electric/solid-state-battery-test-car.html
[84]https://insideevs.com/news/753913/byd-ev-one-megawatt-charging/

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The shift away from hydrogen as the best solution is probably best captured by the hydrogen ladder that was originally developed by Michael Liebreich and associates. This is now on version 5.0[85] and is shown in Figure 5 on the previous page. The hydrogen ladder is basically a representation of where green hydrogen is competitive against alternative technologies or where there is no other choice. This has evolved over time as a better understanding has developed of the technical role hydrogen and other technologies can play alongside changes to the cost of green hydrogen or alternatives. A fair summary is that most applications are now assessed as having better or cheaper alternatives. The applications that remain are focused on the chemical properties of hydrogen and basically are dominated by current processes that use grey hydrogen.

The ladder for current Northern Ireland uses only reaches as high as the penultimate rung: 'B'. That eliminates all the 'no real alternative to hydrogen' use cases. Levels B and C for the generic or typical location are characterised by a potential reliance on biomass/biogas, but this is an area in which Northern Ireland has a competitive advantage. It therefore follows that these uses would be pushed further down the ladder (i.e. hydrogen uncompetitive) if the diagram was specific to Northern Ireland.

[85]https://www.liebreich.com/hydrogen-ladder-version-5-0/

3.1 Scoping

The consideration of the likely future use of hydrogen in Northern Ireland gives rise to issues of considerable complexity. There are several questions that lie at a nexus of policy, competition, technology and taxation / incentives:

- Wires or pipes? Will energy be moved from dispersed renewables to users primarily over the grid (electricity) or through a gas network? Or both? Would electrolysers act as congestion amplifiers or alleviators to a grid?
- How would fuel duty and other taxes be levied in the future, including on hydrogen?
- Cross-border – cooperate or compete? What will Ireland do?
- How will the EU rules on RFNBO (renewable fuels of non-biological origin) develop and apply? Could the Carbon Border Adjustment Mechanism (CBAM) become important in trade with Great Britain, and if so, with what implications for the NI economy? What will the future carbon pricing in NI be?
- What balance is appropriate between central planning and market choices?
- How would the appropriate location for electrolysers and hydrogen networks be determined?
- Should renewables be scaled to facilitate hydrogen or hydrogen sized to reflect projected renewables surplus? A possible answer is both – creating a desirable synergy – but this needs to be made explicit and transmitted in policy and/or market terms and raises the question of cross-subsidies and implications for wider competition including biogas.
- How does non-renewable hydrogen (fossil derived with carbon capture) fit in? Would it be supported during a transition to build demand?
- More generally how does the temporal aspect manifest itself; what policies would apply when? Should there be a kick-start or pump priming? Might that be through initial low charges on any hydrogen network? If so, who pays for this?
- Is the focus on the impact on the current NI economy – or what that economy could be if able to access cheap hydrogen?
- What should hydrogen be used for? As an energy carrier, energy store or feedstock, including to energy (synfuels)? Would priority be given to the hard to abate such as marine or other longer distance transport? Or let the market decide?
- Who owns what? Can third parties access any network?
- What technologies are in scope? (Requiring assumptions about future innovation in hydrogen use but also competing fuels).
- What value is placed on security of supply, including reducing volatility in fuel prices?
- What impact might new import tariffs have on electrolyser prices, as China is currently significantly cheaper? It is also worth noting that such tariffs might push up solar costs in a way that is unhelpful or helpful to hydrogen?
- How would access to clean water resources, important for electrolysis, be managed?
- Would support be given towards infrastructure, e.g. charging stations for trucks?
- How capable is the current gas infrastructure for handling hydrogen? As deployment was later than that in Great Britain are the pipes in Northern Ireland better able to minimise leakage (hydrogen being a much smaller molecule)?

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3.2 European Comparisons

It is helpful to put assumptions within the context of wider activity in Europe. Commitments to provide large amounts of hydrogen could depress its price, making it uneconomic to produce in Northern Ireland, while conversely efforts to increase demand could have, at least in the short term, the opposite effect.

Supply / Demand

The EU has a strategic goal of 20 Mt of renewable hydrogen consumption by 2030; current consumption is 7.2 Mt, of which almost all (99.7%) of it comes from fossil fuels. The amount produced with electrolysis (around 22 kt) is negligible. EU renewable energy and decarbonisation targets imply 2-4 Mt of low carbon hydrogen by 2030. However, progress is slow.

The total installed capacity of electrolysers in Europe is currently just over 200 MW. Projects accounting for another 1.8 GW of capacity, mostly captive to a single off-taker or industry, are though under construction and expected to become operational by the end of 2026. Projects accounting for around 60 GW of capacity announced as being operational by 2030 are waiting for final investment decision. Although funding instruments are becoming increasingly available, the actual deployment of these projects remains at risk due to sector uncertainties, in particular the evolution of demand and renewable hydrogen cost prospects.

The conclusion is though stark: the EU is betting big on hydrogen but seeing difficultly in delivering on this to date. The key limiter is the current cost of green hydrogen which is around 3 times (depending on natural gas prices) that of hydrogen that is fossil fuel derived. This implies a 70% or more reduction in cost.

The cost gap further increases by the EU production rules for renewable fuels of non-biological origin (RFNBOs), which aim to ensure the net decarbonisation impact of renewable hydrogen deployment is zero, making renewable hydrogen overall three to four times more expensive than fossil-based hydrogen.

Surprisingly perhaps, the first European Hydrogen Bank auction resulted in very low premiums, revealing promising instances of significantly lower production costs (some lower than 3 EUR/kg). There was also a willingness among some off-takers to pay prices within the renewable hydrogen cost range.

This suggests that green hydrogen can potentially achieve commerciality. However some caution must be applied as the results were obtained under the unique situation of a first auction, and some participants may have been bidding to help the auction process or position themselves at the heart of further process.

The European Commission's analysis of the auction indicates that the average levelised cost of hydrogen (LCOH) of all the submitted projects per country ranged between 5.3 and 13.5 EUR/kg, yet individual bidders' LCOHs as low as 2.8 EUR/kg were reported. In terms of technology, all but one bidder planned to use either alkaline or proton-exchange membrane (PEM) electrolysers. The average LCOH of the two competing technologies is around 7 EUR/kg for alkaline and around 10 EUR/kg for PEM electrolysers.

Most notably however, the average price that off-takers seem to be willing to pay for renewable hydrogen, according to the information provided by bidders, is estimated at 5.7 EUR/kg for the industrial sector and 8.3 EUR/kg for the transport sector. This indicates that, under current EU and national policies, some buyers are willing to pay prices that are very close to (and even higher for some very competitive projects) the expected cost of renewable hydrogen production in some European locations.

It also demonstrates that industry will only be interested where costs are low, a transport authority can take a different view as fuel represents a small part of overall costs and local trips are not subject to competition.

The successful sellers were primarily either Nordic or Iberian Peninsula based, reflecting renewables based, respectively, on hydro or sun/wind.

Northern Ireland Comparison

If NI was developing its hydrogen economy pro-rata (based on population) to the EU it would therefore be consuming 32 tonnes now, and would have an electrolyser presence of 900kW now, with 9MW by 2026 and a target of 267MW by 2030. Currently, in NI there are a number of mostly potential projects shown in Figure 6 below. In summary, these are:

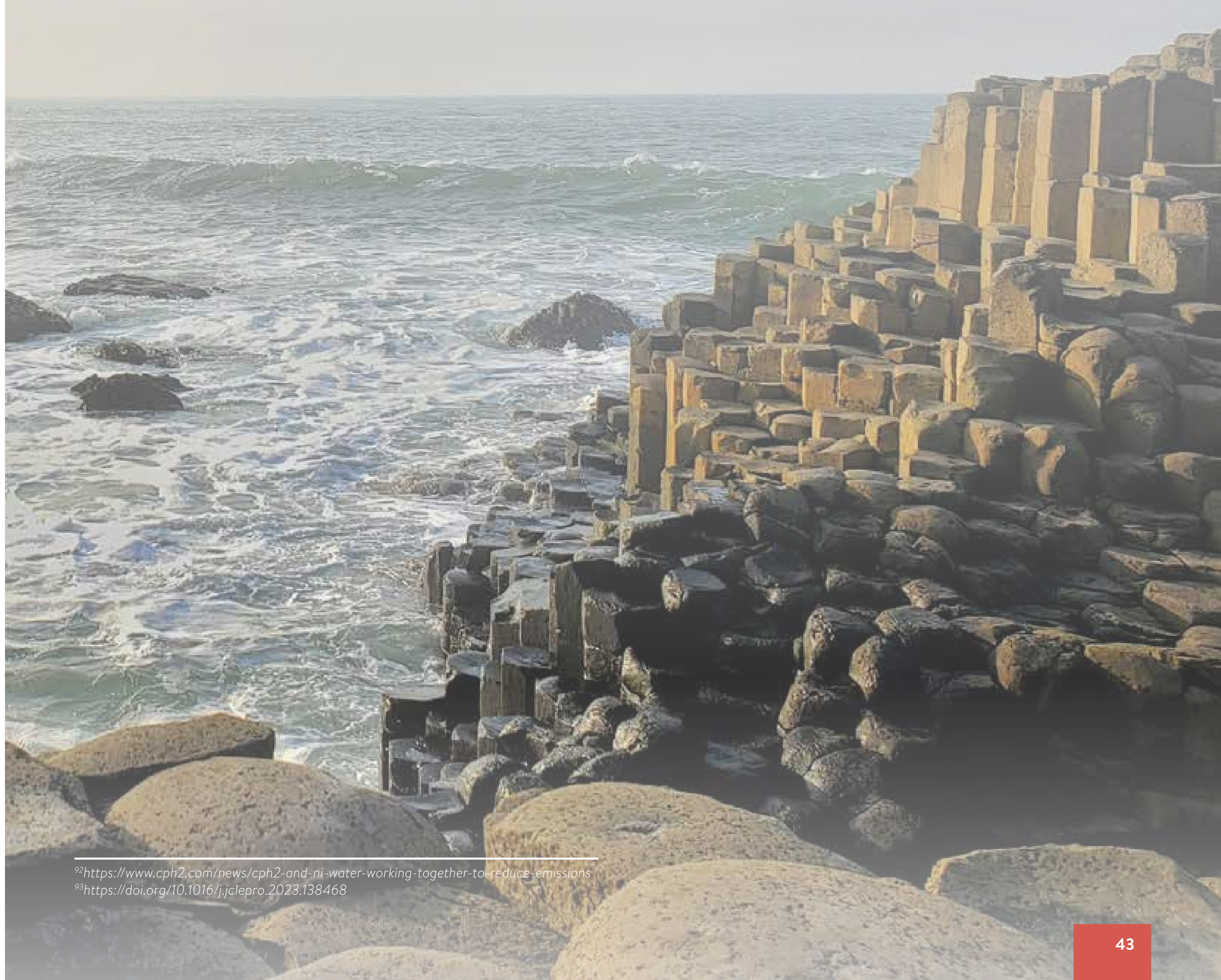
- A 1MW electrolyser situated at Energia's Long Mountain Wind farm[86]
- A 20 MW electrolyser at Ballylumford Power Station as part of the Power-2-X project[87]
- A CPH2 MFE110 electrolyser being installed at NI Water's Duncrue Street wastewater treatment works[88]
- A prospective 10 MW electrolyser at Mannok's site in Fermanagh (pending outcome of HAR2 competition)
- A proposed facility planned by Hygen in Ballymena[89]
- An outline concept for a Belfast Hydrogen Hub[90]

Figure 6 Map of current or planned electrolysers in NI (Data from Olsights[91]

[86]https://www.energiagroup.com/renewables/green-hydrogen/
[87]https://www.mutual-energy.com/wp-content/uploads/2023/06/3105-Mutual-Energy-Ballylumford-Power2X-Summary-Brochure-2023-Artwork-Final-Reduced-Size-1.pdf
[88]https://www.cph2.com/news/cph2-completes-level-2-site-acceptance-test/
[89]https://www.hygenenergy.com/project/hygen-ballymena-green-hydrogen-facility/
[90]https://www.mutual-energy.com/wp-content/uploads/2024/09/Belfast-Hydrogen-Hub-online-version-v1.pdf
[91]https://olsights.com/

HYDROGEN IN NORTHERN IRELAND: FUTURE COSTS, CHALLENGES AND IMPLICATIONS

The NI Water electrolyser is of particular interest as the co-product oxygen is to be used to increase capacity at the wastewater treatment works. While performance figures for the smaller scale CPH2 MFE110 electrolyser are yet to be known, an idea of the output can be gained by looking at the larger scale CPH2 MFE220 1MW Membrane-Free Electrolyser which has been shown to produce up to 451kg of hydrogen and up to 3609kg of medical-grade oxygen per day[92], but this can change depending on the water and the treatment site, as highlighted in a techno-economic analysis of a co-located wastewater treatment and hydrogen facility. The study also highlighted that the subsidy value of using by-product oxygen could range between 2.4p/kg.H_2 and 35.2p/kg.H_2 under their scenarios[93]. This idea of system integration with an existing process can bring the cost of hydrogen down through this new subsidised cost from the sale or use of oxygen.



[92]https://www.cph2.com/news/cph2-and-ni-water-working-together-to-reduce-emissions
[93]https://doi.org/10.1016/j.jclepro.2023.138468

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"Green hydrogen is not an economically sensible route for the decarbonisation of any sector of the Northern Ireland economy today.... However, green hydrogen offers considerable potential for benefit, including de-risking energy security, future industries and supply chains"

4. USE CASES

4.1 Identification

The hydrogen ladder shown in Figure 5 is a presentational device to demonstrate where uses lie on a continuum, or 'ladder' depending on how relevant hydrogen is. The most recent version, (v 5.0, 2023), depicts four uses where hydrogen is required as there is 'no real alternative'.

These use cases are:

- Fertiliser production
- Hydrogenation – used in the food, pharmaceutical and chemical industries
- Hydrocracking – refinery process to convert products with a heavy fraction to lighter, more valuable products
- Desulphurisation – removing sulphur from natural gas, flue gases and others.

All these use cases are well established. It is noteworthy that no new use case has joined this group in recent years.

These uses, tied to major chemical activities, are not present at scale in Northern Ireland. It is possible that, if the Northern Ireland price of hydrogen was very much lower than that applying elsewhere, such activities might be attracted.

However, the chemical industry is characterised by economies of scale that result in very large, and capital intensive, plant which represents an investment that will not be easily given up. Further, refinery activity is in any case now reducing in Great Britain. It is then considered unrealistic to assume that Northern Ireland may attract any of these use cases. They are therefore not considered further in this work.

4.2 Use Case: Energy Storage

This use case is based on releasing hydrogen through electrolysis, storing it, and then using it to generate electricity, through either a fuel cell or engine. This shifts the availability of electricity to a time when it is more needed, similar to a battery.

A key factor is the inherent inefficiency, at least currently, in the process. In section 2.4.5 the efficiency of various steps in the hydrogen cycle have been listed. For longer-term storage and use for inter-seasonal energy transfer then we are looking at a generation and storage efficiency of c.60%, and similarly when converted back to electricity an optimum efficiency of 60% from a fuel cell generator is at the higher end of what can be currently achieved. Combusting hydrogen in the latest CCGT instead of natural gas could give efficiencies of 50-60% but lower when operated at partial capacity.

Assuming a fuel cell generation system is used then a round-trip efficiency of c.36%, that is for each 1MWh of renewable electricity used to generate green hydrogen then c.0.36MWh could be produced on demand. A simple cost model[94] indicates that this could mean that the cost of electricity from stored hydrogen could be >£700/MWh. However, a much more detailed study would need to be done to look at costs of large-scale offshore renewables connected by private wire to an electrolyser which is sited close to proposed gas caverns under Larne Lough and the cost of grid scale fuel cell systems (or re-purposed CCGT station (Kilroot and/or Ballylumford).

Despite the efficiency losses hydrogen storage could be economically valuable in both short- and longer-term storage cases but this would need comparison to alternative options such as biomethane or greater interconnectivity to other electricity grids.

[94] *Assumptions for simple cost model: Private wire PPA offshore wind electricity at £120/MWh, Electrolyser efficiency 70%, compression 90%, Hydrogen plant capital costs 30% of power costs, Gas caverns cost £78/MWh (from DESNZ), decompression/transmission from gas cavern 95% efficiency, fuel cell efficiency 60%.*

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Short duration storage

As the demand for electricity fluctuates there is an arbitrage value in consuming power when it is valued lowly and returning it at a time of high demand, perhaps only a few hours later. While the obvious example is night-time to daytime, the complexity of power generation means that there may be times through the day, including around the morning 'ramp', where a highly agile response is valued.

In addition to simple arbitrage, dispatchable power from hydrogen storage can provide a number of services to the grid, such as voltage and frequency control, and 'black start', the ability to restart power stations following outages or maintenance.

Basing electrolysis activities at or near power stations offers ready and low-cost access to the grid and allows peaking plant capacity to be replaced with hydrogen fired units. The outcome is then one that permits very high level of renewables on the system, aiding the growth of renewable energy in Northern Ireland, as the hydrogen provides a peak lopping / trough filling role, helping maintain a stable and, potentially, low-cost system.

The weakness in this model is the poor round-trip efficiency of hydrogen, which compares to around 90% for batteries, and 80%+ for pump storage. Effectively the latter will be able to return 50% more of the earlier electricity take than the hydrogen-based cycle, batteries will return around twice as much.

The competitor here is therefore batteries. Batteries have been chosen for this role in the UK and Ireland, as well as globally. They offer cost advantages and are also superior in grid services with much faster responsiveness. They are well understood by the market and thus easy to finance, and also offer speed in installation, with flexibility in potentially relocating, even abroad, where market conditions change.

The major negative around (current) batteries is the potential for a fire, which is challenging to put out. Hydrogen has the potential for similar safety concerns.

Thus, when considering very short-term energy storage only, hydrogen will be non-competitive owing to its poor overall round-trip efficiency and its additional operational complexity.

Long / Very Long duration storage

However, while batteries are attractive for short durations this advantage collapses as longer-term storage is considered. Battery costs rise linearly with duration[95], so that availability to provide power for 4 hours costs twice that of a 2-hour capability. Providing power for a week or more, or significant help through a winter season is then prohibitively expensive.

Yet sufficient energy needs to be stored to help the country through a dunkelflaute (a German word for cold weather with a dark sky and lull in wind). These climatic conditions are not unusual and may persist for days, during which renewable energy will not be generated and energy demand will rise. Unless there is adequate storage to bridge this period other dispatchable means must be made available, probably natural gas or biomethane-powered plant.

This longer duration requirement is where support for hydrogen for energy storage is gaining traction. A paper[96] published by the Royal Society last year proposed an extensive network of underground caverns that would be used to store billions of cubic metres of hydrogen. The report states:

> *Storing hydrogen in solution-mined salt caverns will be the best way to meet the long-term storage need as it has the lowest cost per unit of energy storage capacity. Great Britain has ample geological salt deposits that could accommodate the large number of salt caverns that will be needed.*

The Department for Energy Security and Net Zero published a report[97] in later 2023 outlining its support for hydrogen storage and indicated the form of business case it was 'minded to' pursue. The conclusion was:

> *The minded to positions in this chapter provide a direction of travel for the hydrogen storage business model design. We propose a revenue 'floor' to mitigate demand risk for storage providers; an incentive to maximise sales to users and a mechanism to give the subsidy provider a potential share of the 'upside'. We anticipate the initial focus for support to be geological storage, though we are minded to retain optionality to support above-ground storage where it faces similar market barriers. We consider the model best delivered through a private law contract lasting at least 15 years*

[95] *Hydrogen costs also scale with duration, but larger volumes of hydrogen are easier and cheaper to store in gas caverns.*
[96] *Large-scale electricity storage: September 2023: https://royalsociety.org/news-resources/projects/low-carbon-energy-programme/large-scale-electricity-storage/*
[97] *https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1175804/hydrogen-transport-storage-minded-to-positions.pdf*

The opportunity has attracted the private sector with UK Oil and Gas being an example. Its subsidiary, UK Energy Storage (UKEn), has been working for the past four years on a £1 billion underground hydrogen storage project in South Dorset. This project boasts an impressive maximum annual capacity of ~30 TWh (approximately 1.0 billion m^3 static storage).

Northern Ireland is fortunate, as are additional parts of Great Britain (East Yorkshire, Cheshire, Wessex), in having the potential for salt caverns near the grid. The proposed caverns in Northern Ireland lie under Larne Lough at Islandmagee and have been the subject of a recent major study[98] funded by BEIS under its Longer Duration Energy Storage Demonstration programme.

This study showed that it was possible to store 500 million cubic meters of green hydrogen within seven large underground caverns at a depth 1,350m below sea level, estimated to cost around £168 million to integrate hydrogen compression, dehydration and cooling.

While the study was positive a Judicial Review halted development, as environmental campaigners are concerned about the effect on the coastal waters of creating the caverns, which is achieved by pumping water in and the resulting highly saline solution out. Critical to this is the rate at which the caverns are created as the sea scales the outflow. Of course, the sea dilutes this outflow, so the area of high salinity is limited.

It is though important to assess this opportunity from the standpoint of identifying if there is a use with a sufficient need for such storage, rather than seeking to identify a use to justify development of the asset.

A study in 2011[99] looked at the loss of natural gas supply to Ireland which would mean gas fired power stations couldn't operate. Just the economic cost was estimated to be up to €1 billion per day in 2011 (€1.36 billion/day in 2025). The challenge with renewable energy is that at some points in the year, both wind and solar could be generating virtually zero amounts of power. If this lasted beyond 6-8 hours, then lights would start to go out as short-term electricity storage ran out. Without some form of dispatchable power attached to substantial hydrogen/other fuel storage or much greater interconnector capacity then NI would be in difficulty, particularly when the economy becomes fully electric.

The question of long-term energy storage is critical to NI's future and should be a priority to address. NI needs to have some form of insurance policy and potentially public ownership or a regulated asset model of a strategic national energy store such as gas caverns under Larne lough.

Rural

There may be an opportunity for further investment in rural areas, based around a standalone wind turbine, without grid connection and perhaps unlikely to justify connection cost if/when its turn comes for grid connection. A simple but comprehensive installation of the turbine, battery, appropriately scaled electrolyser and some storage allows for energy independence. A possible development is a peripatetic collection, akin to a tanker on a milk round, that could collect surplus hydrogen and take it to the nearest user or network point.

> "The importance of long-term energy storage should not be underestimated."

[98]https://www.gov.uk/government/publications/longer-duration-energy-storage-demonstration-programme-successful-projects/longer-duration-energy-storage-demonstration-programme-stream-1-phase-1-details-of-successful-projects
[99]https://www.esri.ie/publications/the-cost-of-natural-gas-shortages-in-ireland

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4.3 Use Case: Large Industrial User (high heat / other)

Hydrogen lends itself to use in common high heat processes in manufacturing, able to support both varying and constant heat requirements.

The challenge for locally produced hydrogen lies then not with establishing the potential for use, which is already present, but in being price competitive. This applies at a number of levels: firstly, is locally produced hydrogen cheaper than imported hydrogen delivered to Northern Ireland? Secondly, is it cheaper than biomethane, local or delivered? Is the process competitive with an electrical alternative? And, finally, however energy is sourced, is the process competitive with industrial activity elsewhere?

These combine to quite a high bar: hydrogen must not only be appropriate in the setting, but it must also be cheaper than imports if it is to be produced locally, cheaper than biomethane to displace it, cheaper than any alternate electricity based option and ultimately permit the local firm to compete with industry elsewhere, including locations which might benefit from economies of scale and possibly lower energy costs.

The key competitors locally will be biomethane and thermal batteries. Thermal batteries are similar in principle to storage heaters but at much larger scale, higher temperatures and efficiencies. They offer high heat and can be energised / charged at off peak times, eradicating any advantage hydrogen might have had in being able to separate the timing of electricity use from the end heat use. Process heat for industry is claimed to give up to 1300°C using off-peak electricity and could save energy costs compared to direct electrification or hydrogen heating using thermal energy storage (TES). An emerging trend is for Heat as a Service (HaaS) as a new utilities option[100].

There may be some residual benefit to using hydrogen, where instantaneous control is required, but the general case will be best served by the thermal batteries, unless there is an abundance of biomethane nearby.

For the highest heat applications, electrification is not yet a commercial possibility, so the competition is between hydrogen and biomethane in NI. Biomethane at a predicted production price point of £0.09-£0.14/kWh[4] will be the lower cost option compared to green hydrogen.

Manufacturing opportunity

Northern Ireland has been successful in manufacturing power solutions, notably generators. It is possible that manufacture of fuel cells could be an industry that could be fostered locally. This would of course require hydrogen for testing and development, but only to a limited scale.

It is worth noting that much of the supply chain behind fuel cells and electrolysers is similar to aviation, which is strong in NI. Hence, there is an opportunity for NI industry to use existing strengths to develop business streams supporting hydrogen equipment production and the role out of green hydrogen in those sectors that require it in the UK and beyond.

However, it is undoubtable that, in general, manufacturing industry would probably see more benefit in low electricity costs than in the development of a hydrogen network.

[100]https://www.kraftblock.com/blog/cost-savings-of-flexible-electrification

4.4 Use Case: Domestic Heating / Hot Water

Hydrogen is a small molecule, one eighth the size of natural gas, and has less energy per unit volume so needs to be pressurised at a higher level to provide the same heating. As a result, pure hydrogen leaks in a pipe network that is otherwise fit for purpose. The cost of enhancing a natural gas network through relining pipes etc is high, close to that of new provision.

Direct insertion of hydrogen is possible into the existing gas network provided it is added as a minor proportion (circa 5 – 10%) to the existing gas blend (methane/propane/butane). Greater concentration requires recalibration of appliances (primarily boilers) although more recent appliances may well be 'hydrogen ready'. Thus, hydrogen does not offer a simple substitute for natural gas, rather in anything other than small quantities it presents considerable costs around new or renewed infrastructure and consumer adaptations. A competitor is Biomethane, in which NI has a comparative advantage given that CASE has shown we have the potential to generate enough biomethane from agricultural wastes to almost entirely displace natural gas from the gas network[101].

The UK government is championing heat pumps, common in Nordic countries. A unit of electricity used in a heat pump can deliver 3 (or more) units of heat to the house. The same unit of electricity can provide for around half a unit of heat via a hydrogen channel (electrolysis followed by fuel cell or boiler). The heat pump is thus 6 times more energy efficient than hydrogen in turning electricity into useful domestic heat[56].

Given that the hydrogen also requires greater infrastructure spend (as an electricity network will typically be present) hydrogen can only compete if it is taking electricity at a cost that is less than a sixth of the cost faced by the heat pump. This focuses attention on the precise timing of heat-pump use. Where a home is heated only at peak times, when electricity is expensive, it is possible that the heat pump is financially less attractive than hydrogen. However, if the heat-pump can be deployed in an insulated dwelling, ideally one with underfloor hearing and high thermal mass, its deployment can be significantly shifted in time to benefit from off-peak electricity.

Alternative technologies such as hybrid heat pumps (a heat pump combined with a fuel cell) or micro combined heat and power (CHP) systems could improve the case for hydrogen. However, electrification via heat pump still typically gives at least three times the energy output per unit of electricity compared to these options.
While there remain concerns around heat pumps, including their siting and noise, and acceptance that they will not be relevant to a few households, such as those in apartments, there are some signs of growing acceptance, aided by the substantial grant support on offer. It is worth noting that proposed pilots of hydrogen boilers have encountered considerable consumer resistance on perceived safety and cost grounds.

While the relative competitive offerings are not yet fully settled it is clear that there is little case for hydrogen as a provider of domestic heating.

4.5 Use Case: Collective / Commercial Heating

Hydrogen based district heating or centralised for very large apartment blocks avoids or at least minimises concerns around use of hydrogen in the home as only hot water is circulated.

However, use of hydrogen for heating faces twin challenges: more remote or separated buildings require a (leakproof) network, with concomitant costs, while densely grouped housing is likely better served by a district heating system based on direct use of electricity (or source of waste heat – such as from an electrolyser or other industry) and a simple hot water network.

It is concluded that this use is uneconomic.

"...there is little case for hydrogen as a provider of domestic heating"

[101] https://doi.org/10.1016/j.renene.2022.06.115

4.6 Use Case: Transport

The government published the UK's first-ever Hydrogen Strategy in August 2021[102]. This highlighted the role that blue and green hydrogen could play in the UK's transition to net zero. The original ambition was for 5GW of low carbon hydrogen production capacity by 2030 and includes consideration of the potential for hydrogen for cars, vans, HGVs, trains and buses. The emphasis in the hydrogen strategy is for a mix of blue and green hydrogen with the replacement of unabated grey hydrogen a key focus. When the strategy was launched in 2021 there were about 300 hydrogen vehicles in the UK and at the end of 2024 this had fallen to 265[103] with a total of 16 hydrogen fuelling stations[104] by the same date following the closure of several small-scale, 1st generation hubs.

Hydrogen vehicles sales reached a peak in 2022 and since then have declined by 20.7% in 2023[105] and then a further 21.6% in 2024[106]. Issues such as the cost of hydrogen, lack of fuelling infrastructure, durability of fuel cells, and hydrogen contamination problems are thought to reasons for sales slumps[107]. In 2024, sales of all hydrogen FCEVs were reported as 12,866 globally[106]. This compares to 17 million battery electric and hybrid vehicles which globally saw 25% growth in volume in 2024[108]. In the UK, at the end of June 2024[109], there were 41.7 million licensed vehicles, of these 1,183,000 were zero emission vehicles (this includes hybrids).

Table 3 below shows the number of different FCEV and BEV vehicles by type that were licensed as at the end of June 2024 in the UK[110], vehicles that were unlicensed and off-road are not included. The very small number of vehicles that were labelled as fuel type "other" were not included and it is possible that some of these could be hydrogen combustion vehicles.

Vehicle Type	Power Source	Q2 2024	Q2 2023	Q2 2022	Q2 2021	Q2 2020
Buses	BEV	4086	2609	1616	889	625
Buses	FCEV	83	84	90	43	1
HGV	BEV	784	487	302	179	130
HGV	FCEV	0	0	0	0	0
LGV	BEV	72115	52607	35108	19458	10800
LGV	FCEV	2	3	3	2	3
Cars	BEV	1088728	779212	491987	265495	119777
Cars	FCEV	119	137	187	212	190

Table 3 Licensed BEV and FCEV vehicle by type for the UK 2020 - 2024

[102] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1175494/UK-Hydrogen-Strategy_web.pdf
[103] https://assets.publishing.service.gov.uk/media/6761915126a2d1ff18253493/hydrogen-strategy-update-to-the-market-december-2024.pdf
[104] https://www.igem.org.uk/resource/hydrogen-fuel-filling-stations-when-can-we-see-them-in-the-uk.html
[105] https://fuelcellsworks.com/news/global-hydrogen-car-market-to-decline-34-1-year-on-year-in-the-first-half-of-2024
[106] https://www.hydrogeninsight.com/transport/global-hydrogen-vehicle-sales-fell-by-more-than-20-for-second-year-in-a-row-in-2024/2-1-1778041
[107] https://www.sneresearch.com/en/insight/release_view/270/page/0?s_cat=|&s_keyword=#ac_id
[108] https://www.reuters.com/business/autos-transportation/global-electric-vehicle-sales-up-25-record-2024-2025-01-14/
[109] https://www.gov.uk/government/statistics/vehicle-licensing-statistics-april-to-june-2024
[110] Data from table VEH0133a accessed on 18th February 2025, https://www.gov.uk/government/statistics/vehicle-licensing-statistics-april-to-june-2024

Examination of the vehicle figures in Table 3 show the strong growth in BEV vehicles of all types and the low static or declining numbers of FCEV vehicle in the UK. This reflects the issues of cost, lack of infrastructure and reliability identified earlier for hydrogen vehicles across the UK. In February 2024, UK Government estimated that up to £2 billion[111] would need to be spent on transport and storage to enable a hydrogen economy. Most of this is focused on GB on projects such as salt cavern storage and transport pipelines.

Globally it is a more mixed picture with technology development, but FCEV sales are very limited compared to BEVs and there have been some major financial issues for hydrogen HGV and bus manufacturers due to high prices and low market penetration.

4.6.1 Use Case: Transport - Marine

Hydrogen has low volumetric energy density and consequently needs to be stored in pressure vessels which are cylindrical or spherical in nature. Applications where fuel storage volumes or spaces available are a limiting factor are generally not best suited for hydrogen. These applications include many marine activities as well as aviation. However, the move away from fossil fuels requires low-carbon alternatives. These could be biofuels, such as biodiesel for fishing boats or, more likely, they will be e-fuels derived from hydrogen and/or biogenic carbon or, in the future when costs drop, atmospheric carbon from direct air capture technologies.

For marine applications, there are a range of options depending on the use case. For shipping and ferries which currently use bunker fuel then methanol and ammonia are the leading options, perhaps supplemented by modern sailing technologies. It is forecast that there will be 350 methanol powered ships in operation by 2030[112] and as of March 2025 there were 130 ammonia fuelled vessels, and 225 ammonia-ready vessels ordered with the first due to be in operation in 2026/27[113].

For smaller vessels, such as for fishing or leisure activities then there will be a transition period where a drop-in replacement fuel, such as biodiesel, is required to replace fossil-oil derived marine diesel. Further into the future, this smaller class of vessels could shift to methanol or another e-fuel with inshore vessels with shorter duration requirements becoming electrified. A good example of the potential of electrification is the Artemis foiling boats that are being developed in NI[114].

Green Methanol

Methanol, the simplest alcohol, is a highly versatile chemical widely used in various industries with nearly 70% consumed in the petrochemicals sector for producing olefins (e.g., ethylene, propylene, and butadiene) and formaldehyde (used in plywood, textiles, and coatings for automotive and construction). In 2023, global methanol production capacity reached 183 million tonnes, with actual output at 110 million tonnes, according to the Methanol Institute. Most methanol is produced from natural gas or coal using grey hydrogen, and the sector consumes around 14 million tonnes of grey hydrogen annually. According to the International Energy Agency, conventional methanol production relies heavily on fossil fuels, generating 261 million tonnes of CO_2 in 2022—about 28% of primary chemical production emissions. The European contract price for April-June 2025 was reported to be €625/tonne ($676/tonne) for methanol from fossil fuels[115]. Green methanol is not yet produced at the scale of green ammonia, but an indicative contract price is around $1000/tonne[116].

Methanol is a liquid at room temperature and pressure so can be shipped in simple tanks and although a poison if ingested is much less hazardous than ammonia. The energy density of methanol is 15.6MJ/L (Lower Heating Value or combustion value) which is just under half that of petrol at c.33MJ/L and around 40% of that in diesel at c.38.6 MJ/L. As a fuel, this means that a greater volume or bigger fuel tank is required for the same energy content of diesel. This is an important consideration for marine applications where space is limited.

[111]https://assets.publishing.service.gov.uk/media/65ddc51dcf7eb10015f57f9b/hydrogen-net-zero-investment-roadmap.pdf
[112]https://www.methanex.com/about-methanol/marine-fuel/
[113]https://ammoniaenergy.org/lead/vessels/
[114]https://www.artemistechnologies.co.uk/ef-24-passenger-ferry/
[115]https://www.methanex.com/about-methanol/pricing/ (accessed 25th March 2025)
[116]https://luxresearchinc.com/blog/future-of-methanol-the-cost-of-moving-away-from-natural-gas/

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Green, low-carbon production methods can produce bio-methanol and e-methanol:

- Bio-methanol is produced from biomass feedstocks such as forestry and agricultural waste, municipal solid waste, and biogas from anaerobic biomass decomposition.
- e-methanol is made through CO_2 hydrogenation, where the CO_2 has been captured, and H_2 has been produced through low-carbon means (e.g. green hydrogen)

Northern Ireland has a leading position in developing methanol-based shipping. Currently, the Maritime Power-to-X project[117], which is led by B9 Energy Storage is exploring how fully scalable green methanol can be used as a zero-emission fuel for the global maritime industry. This project is funded from the Clean Maritime Demonstration Competition Round 4 (CMDC4), which is part of the overall UK Department for Transport's UK Shipping Office for Reducing Emissions (UK SHORE) programme, a £206m initiative focused on developing the technology necessary to decarbonise the UK domestic maritime sector.

A key driver for the impact on Northern Ireland is the cost of local hydrogen generation and subsequent methanol cost compared to prices on ports on sea lanes in other jurisdictions. Some reports have suggested that it would be cheaper to ship methanol from regions better suited to low-cost renewable energy generation[118] although they would also need a source of biogenic carbon or utilise the energy intensive option of direct air capture (DAC).

A future study will need to look to see if the economics are better for the collection and shipping of biogenic carbon from NI to where the least cost hydrogen is available. Manufacturing green methanol or other green fuels/chemical products at that overseas location may be the lowest cost option rather than either producing hydrogen in NI or shipping hydrogen (or ammonia) to NI to produce the same fuels or other products.

Green Ammonia

Ammonia, like methanol is extensively used across the globe to make fertilisers and in the chemicals industry. Around 176 million tonnes per year is produced, predominately using grey hydrogen from steam reforming of methane for ammonia synthesis using the Haber-Bosch process and accounting for 1.8% of global CO_2 emissions[119]. Green ammonia would use green hydrogen from electrolysis instead of grey hydrogen to synthesize ammonia or more likely, in the short-to-medium term, blue hydrogen where the greenhouse gas footprint of grey hydrogen is reduced by capturing and storing underground most of the CO_2 emitted during the steam-reforming process.

The advantage of ammonia, over hydrogen as a fuel is its volumetric energy density as ammonia is about 12.7 MJ/L compared to liquid hydrogen at around 8MJ/L. Ammonia also readily compresses to liquid at around 8bar at normal atmospheric temperatures or liquifies at -33°C compared to hydrogen which requires -253°C. Ammonia is also much less flammable than hydrogen although ammonia's toxicity makes it hazardous to handle.

As ammonia has been in use and shipped in large volumes for many decades, there is greater experience in its handling and much existing infrastructure exists which makes it attractive. Ammonia can be used directly in a fuel cell, combusted or cracked at point of use to give hydrogen. Contract prices for Northwest Europe for grey ammonia are $584/tonne, blue ammonia $646.60/tonne and for green ammonia $1051.81/tonne[120].

The attraction of ammonia as a fuel and energy transfer vector for renewable energy generators is that it is comparatively straightforward to make with the mature technology of the Haber-Bosch process and there are no requirements for biogenic carbon as part of the process as it requires just atmospheric nitrogen. For these reasons ammonia, as an energy vector, is under active consideration for large-scale solar and wind farms which are best placed in remote locations to obtain the highest capacity factors. Locations such as equatorial regions for solar or the north Atlantic for wind are under consideration and the electrical energy generated would be converted to hydrogen and then ammonia for onward shipment by tanker. Hydrogen arriving in the form of ammonia which is then cracked at point of use maybe cheaper than hydrogen produced locally for Northern Europe according to some reports[121].

[117]https://b9energy.co.uk/cmdc-4/
[118]https://doi.org/10.1016/j.renene.2024.122336
[119]https://royalsociety.org/-/media/policy/projects/green-ammonia/green-ammonia-policy-briefing.pdf
[120]https://cilive.com/commodities/energy-transition/news-and-insight/051023-interactive-ammonia-price-chart-natural-gas-feedstock-europe-usgc-black-sea (prices for February 2025, accessed 25th March 2025)
[121]https://doi.org/10.1016/j.jclepro.2023.139212

4.6.2 Use Case: Transport – Buses

A local manufacturer, Wrightbus, was one of the early movers on hydrogen and produced hydrogen FCEV buses for Translink, Go-ahead (UK) and German operators amongst others (as well as those powered by other fuels). Recently, Wrightbus received their largest order of up to 1200 zero-emission buses for Go-Ahead group with 43 being hydrogen FCEV buses. This announcement for new hydrogen buses is interesting as the general trend is towards BEV buses given their operational cost advantages. In the UK this can be clearly seen by comparing the numbers and growth in BEV buses compared to hydrogen FCEV buses as shown earlier in Table 3.

Once the most public face of hydrogen vehicles on the road, hydrogen buses are no longer seen as competitive in Europe as bus fleets switch to BEV and countries like the Netherlands are phasing them out due to the expense of operation[122] and reliability issues compared to BEV buses[123]. Ultimately, BEV buses are simply much cheaper to purchase, operate and maintain than their hydrogen counterparts. Montpellier, France, discovered that the cost per kilometre for hydrogen was €0.95, compared to just €0.15 for a BEV bus[122] and cities in Italy similarly found the hydrogen bus costs were at least double those for BEV buses. Real-world data from Bolzano showed that hydrogen fuel cell buses consumed between 310 and 336 kWh of energy per 100 km, whereas battery-electric buses used only 137 to 154 kWh per 100 km[123].

This downturn in fortunes for hydrogen buses has seen declining orders and hydrogen bus manufacturer Safra being placed into receivership[124]. It is notable that TfL plans to make all of its buses electric by 2030 following closure of its hydrogen bus maintenance facility[125]. TfL currently has 20 FCEV buses in its fleet compared to 1397 electric buses[126].

As part of undertaking this study, discussions were held with Translink about their experience of hydrogen buses. Translink were an early adopter and enthusiastic supporter of hydrogen buses and battery electric buses as part of their mission to move to sustainable, reliable, and decarbonised public transport. Translink received their first three hydrogen buses in December 2020. Since then, they have added another 20 hydrogen buses to their fleet. Translink emphasised that they had a positive experience with the buses, finding them reliable and with a range of about 220 miles on one tank fill. An advantage of hydrogen was the similar operational model as diesel buses in as much as after refuelling, buses were free to operate within range.

Quick refuelling at a depot (typically 7-9 minutes for one fill) was the key advantage over BEV buses given the charging time for batteries. An important point for BEV buses was that although fast charge options were available this shortened the service life and warranty on the vehicles due to higher battery degradation rates.

While Translink were happy with the buses they had experienced more technical challenges with the filling station. A point that was noted that a significant electrical load is required for compression at the filling station. A significant challenge faced by Translink was the current cost of hydrogen and the establishment of a robust supply chain and they were keen for a reliable, green hydrogen supply chain and supporting policies to be developed in Northern Ireland to meet their future needs for hydrogen.

Translink indicated that the next bus procurement would be for BEV buses given the current cost of the hydrogen gas supply although they would reconsider if operational costs of hydrogen buses were to reduce.

To get the whole bus fleet electrified will require that space and electrical supply challenges at depots are addressed. It was encouraging to hear that Translink were thinking of how re-development of bus depots could also encompass a community role to provide a hub for charging of BEV HGVs, vans etc. given that the charging infrastructure would be mainly used for buses overnight and have free capacity during the day. The proposed approach aligns well with leading thinking on SMART grid infrastructure, extending charging networks for BEVs and proposed energy islands in NI. There is clearly potential here and an opportunity for a pilot demonstrator which should be considered by NI Government.

[122]https://www.hydrogeninsight.com/transport/-not-interesting-financially-state-owned-operator-ends-the-use-of-hydrogen-buses/2-1-1789314
[123]https://cleantechnica.com/2025/03/08/the-end-of-diesel-europes-buses-are-going-fully-electric-fast/
[124]https://www.hydrogeninsight.com/transport/hydrogen-bus-manufacturer-safra-placed-in-receivership-after-70-years-in-business/2-1-1776243
[125]https://www.here.com/learn/blog/tfl-zero-emission-bus-fleet-journey-london-cleaner-air
[126]https://content.tfl.gov.uk/fleet-annual-audit-report-31-march-2024.pdf

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In further evidence of changing opinions on hydrogen buses, a recent survey[127] of decision makers from UK, Germany and Italy working in public transport by IMI, a supplier of electrolysers and hydrogen refuelling stations, reported that 89% in the UK thought it was feasible to decarbonise public transport without use of hydrogen. Overall, the survey showed that cost of vehicles, cost of fuel, re-fuelling/charge time, range and maintenance cost were amongst key concerns. 72% said that storage safety was a significant barrier to deployment in the UK.

Safety and added complexity for maintenance facilities are specific challenges that have to be addressed and as hydrogen needs much tighter safety systems compared to conventional diesel or battery. HSE have recently advised against hazardous substances consent on safety grounds for a bus maintenance and refuelling hub in Crawley[128]. However, note that hydrogen was chosen in preference to BEV due to the 24/7 nature of operation for the Gatwick bus fleet, and as extra space and time would be required for recharging infrastructure.

[127]https://go.imi-critical.com/IMI_VIVO_Insights_report
[128]https://busandtrainuser.com/2024/04/11/theres-currently-just-one-small-problem-with-hydrogen-buses/

4.6.3 Use Case: Transport – Heavy Goods Vehicles

Hydrogen powered; heavy duty HGVs have long been argued as the one road vehicle application where BEV HGVs were uncompetitive. Range as well as the weight penalty and charging time for batteries as opposed to re-fuelling time for hydrogen are all often quoted as reasons long-haul, 44 tonne HGVs were required to adopt green hydrogen if they were to decarbonise. Indeed, there is still a lot of activity underway to develop hydrogen FCEV and combustion HGVs with many manufacturers (e.g., Daimler, Volvo, Nikola Motors, Hyzon, Man) continuing to develop new products.

However, as seen from figures for UK vehicle registrations, the UK is yet to see any significant numbers of hydrogen HGVs on the roads although the UK Government has funded a number of projects which aim to address both infrastructure and roll-out of hydrogen HGVs. Notable projects include:

- Hyhaul[129]: Covering the M4 Corridor with £30m funding, planning for 30 hydrogen HGVs by 2030
- Tees Valley Hydrogen Transport hub[130]: A £13m project covering the Tees Valley region to deploy up to 60 hydrogen HGVs and provide up to 7 refuelling stations
- ZEN Freight[131]: Demonstrating both BEV and hydrogen HGVs in a £54.6m project with seven sites being developed for both charging and hydrogen refuelling in the north of England.

There is also significant development activity by manufacturers on hydrogen HGVs including Toyota announcing two advances in hydrogen FCEV HGVs:

1) A new generation of hydrogen refuelling systems which have a twin mid-flow system that delivers 2x90g/s for HGV refuelling and compares to the normal 60g/s of current hydrogen refuelling systems. The new twin mid flow system can refuel a HGV FCEV with 80kg of hydrogen in 12 minutes, giving a range of 900km[132].
2) An improved fuel cell which is both more efficient and tackles the degradation issues with existing fuel cells. The new design gives 20% greater range and is twice as durable as current fuel cells. Commercial production is anticipated to start after 2026 at the earliest for heavy duty commercial vehicles[133].

In other news from FCEV manufacturers:

- Honda have recently announced a next-generation fuel cell design which halves costs and trebles power density but has indicated it is moving away from hydrogen vehicles to power from hydrogen generation[134].
- Accelera by Cummins set a new Guinness World Record for the longest distance travelled by a hydrogen FCEV truck without refuelling. The Kenworth 5370, powered by Accelera's fuel cells, travelled 1,806 miles in California on a single fill.
- In Europe, Daimler Truck launched a fleet of its GenH2 liquid hydrogen-fuelled trucks for a 12-month trial with INEOS, Amazon, Air Products, Holcim and Wiedmann & Winz.
- MAN Truck & Bus is to supply about 200 heavy duty hydrogen trucks with 700bar tank, 56kgH_2 capacity and 363-mile range. These will be delivered to customers in Germany, the Netherlands, Norway, Iceland and selected non-European countries from 2025. However, MAN Truck & Bus made clear that "We anticipate that we will be able to best serve the vast majority of our customers' transport applications with battery-powered trucks."[135]
- Volvo Trucks is beginning on-road tests with trucks using hydrogen in combustion engines in 2026, with the commercial launch planned towards the end of this decade.

"...the technology and charging infrastructure behind BEVs has developed at a much faster pace with all the key advantages of hydrogen being addressed."

However, early hydrogen HGV pioneer Nikola, one of the principal companies developing hydrogen HGVs filed for bankruptcy in February 2025, this follows difficulties[136] at other hydrogen HGV specialists such as Hyzon and HVS. Nikola's problems centred around not meeting the challenge of lowering production costs and having to sell hydrogen HGVs at around $350k while they cost c.$680k to produce[137]. For comparison, while not yet fully commercially available, hydrogen FCEV HGVs are being quoted at prices between £500,000 and £700,000[138].

While hydrogen HGV developers and transport analysts were probably correct in their assessment of hydrogen vs battery HGVs five years ago, the technology and charging infrastructure behind BEVs has developed at a much faster pace with all the key advantages of hydrogen being addressed. This has seen battery prices fall dramatically and further predictions from Goldman Sachs that by 2026, battery prices should reach $80/kWh, which is roughly 50% the 2023 price[139]. At the same time battery energy densities are increasing and will double in the coming five years with the introduction of solid-state batteries.

Electric HGVs are available for all applications currently served by diesel vehicles. This includes short and long-haul logistics, public service vehicles and quarrying/construction. Battery capacity depends on use and load. Currently, long-haul versions can travel up to 750km on a single charge but generally battery capacity is designed for 4-5 hours duration which fits in with UK and EU mandated driver rest period frequency. Newly launched batteries offer a practical doubling of energy density so as these are adopted then range will improve, or weight of batteries could be reduced where range is not a key requirement, but maximum load capacity is important.

Typically, HGVs can be charged on off-peak electricity either overnight (e.g. central depot) or on a fast charger. For high duty cycle HGVs used close to 24 hours a day or long-distance transport charging times have been an issue since this could take over 2 hours depending on the specification of the fast charger. However, 1 MW chargers are now being deployed which typically reduce charging times for a long-distance HGV down to around 35-45 minutes which is comparable to the hydrogen filling time of 15-20 minutes for a hydrogen FCEV HGV. 1 MW chargers are being installed at port locations and Moto are intending to install 300 new HGV charging bays at 23 locations[140] providing capacity for 5000 BEV HGVs. It is worth noting that higher capacity chargers are under development and 1.2MW rated chargers[141] should be available in the coming months.

Hydrogen supply is also an issue and recently[142] Abdul Chowdhury, head of vehicle policy at the Office for Zero Emission Vehicles, admitted that priority would most likely go to the larger industrial transport sectors of maritime and aviation, rather than road transport due to limitations on the supply of hydrogen.

Academic experts, consultants and the CCC[2] have also looked at the use of hydrogen for transport and HGVs and have all concluded that BEV HGVs are the optimum choice to meet all the UK's goods transport requirements. Indeed, Professor David Cebon, the director of the Centre for Sustainable Road Freight at Cambridge University, summed up the situation in a single quote[143]:

> *"Three times more on running costs, two times more on capital costs, you'd have to be insane to buy a hydrogen-powered truck"*

[129] *https://iuk-business-connect.org.uk/projects/zehid/hydrogen-aggregated-uk-logistics-hyhaul/*
[130] *https://www.gov.uk/government/publications/tees-valley-hydrogen-transport-hub-successful-bidders/tees-valley-hydrogen-transport-hub-successful-bidders*
[131] *https://dynamon.co.uk/zenfreight/*
[132] *https://www.highmotor.com/irizar-presenta-camion-electrico-urbano-pila-combustible-hidrogeno.html*
[133] *https://www.h2-view.com/story/toyota-unveils-new-hydrogen-fuel-cell-with-20-more-range/2121590.article/*
[134] *https://www.h2-view.com/story/honda-claims-next-gen-hydrogen-fuel-cell-halves-costs-while-trebling-power-density/2121838.article/*
[135] *https://www.smmt.co.uk/2024/09/clean-power-the-development-of-hydrogen-powered-hgvs/*

[136] *https://www.h2-view.com/story/trios-woes-shine-spotlight-on-stalling-hydrogen-fuel-cell-trucking-sector/2121874.article/*
[137] *https://www.hydrogeninsight.com/transport/loss-making-nikola-motors-is-selling-hydrogen-trucks-for-about-half-the-amount-it-costs-to-make-them/2-1-1615574*
[138] *https://www.hydrogeninsight.com/transport/opinion-battery-electric-trucks-will-be-three-times-cheaper-to-run-than-hydrogen-models-and-be-able-to-perform-all-the-same-tasks/2-1-1365662*
[139] *https://www.goldmansachs.com/insights/articles/electric-vehicle-battery-prices-are-expected-to-fall-almost-50-percent-by-2025*
[140] *https://www.edie.net/moto-plans-for-up-to-300-new-electric-hgv-charging-bays/*
[141] *https://kempower.com/industries/truck-charging/*
[142] *https://www.fleetnews.co.uk/features/hydrogen-what-part-will-it-play-in-zero-emission-road-transport*
[143] *https://www.einride.tech/insights/prof-david-cebon-on-electric-vs-hydrogen-the-gap-will-widen*

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Element Energy developed two reports[144] in 2023 on BEV HGVs using UK department of Transport data on HGV journey profiles. The reports show that:

- 65-75% of the UK's rigid HGVs and 30-35% of articulated HGVs will be able to operate with battery electric trucks without significant reliance on future charging infrastructure anywhere other than their home base
- 93% of truck charging points will be at home depots as most HGVs return to base overnight
- Heavy duty 40-44t articulated HGVs will be able to perform their operations using battery electric vehicles and appropriate static charging infrastructure
- Battery electric trucks will be cheaper to run than diesels in city, urban and regional applications by the early 2030s and in some cases before 2030
- Downtime due to charging for the most demanding back-to-back operations will still have a lower cost of ownership due to a reduction in fuel costs
- The reduction in maximum loads due to BEV battery weight which may require additional journey is more than compensated for by the reduction in running costs
- Trucks in the UK usually take shorter journeys due to geography and density of development.

To evaluate the actual economics a financial model to provide a comparative cost analysis was constructed for a 44-tonne gross (6x2 + tri-axle c/s) combination HGV looking at diesel, electric and hydrogen. The results are shown in Table 4 below.

	Diesel	Electric (BEV)	Hydrogen (fuel cell) [146]
Capital Cost (tractor unit) £	125,000	200,000	350,000
Capital cost per year £	17,000	27,200	47,600
Maintenance Costs (per year) £	7,500	5,000	5,000
Fuel consumption	22,740 litres	100,000 kWh	7,140 Kg
Fuel Cost £	30,926	24,000	71,400
TOTAL ANNUAL COST	**55,426**	**56,200**	**124,000**

Table 4 Comparison of Diesel, Battery and Hydrogen HGV running costs[145]

[144]https://www.transportenvironment.org/te-united-kingdom/articles/e-trucks-its-time-for-the-uk-to-make-the-switch
[145]Assumptions: 50,000 miles (80,500km) a year, vehicle lifespan 10 years, maintenance costs for diesel £0.15 per mile. Fuel average consumption 8 miles per gallon, 3.54 km per litre. Average diesel cost 136p/l. Average hydrogen cost £10/kg, 7 miles per kg. Average electricity cost (weighted) £0.24, 2kwh/mile. Maintenance costs for BEV and fuel cell based on expected future costs. Capital cost per year assumes finance costs of 6% (giving annual cost 13.6%).
[146]Source: Hydrogen Operating Cost data: https://haush.co.uk/costs-and-options-available-for-the-uk-transport-industry-to-transition-to-green-hydrogen/

To match BEV costs, at the stated mileage, the price of hydrogen would have to be £0.50 per kg, reflecting the greater capital costs of a hydrogen truck. In reality, hydrogen costs are likely to be much higher for green hydrogen and the capital cost of the hydrogen HGV is lower than given in [138] so this is a future case scenario.

Note that a litre of diesel at 136p[147] includes fuel duty of 52.95p and VAT of 22.7p, a total of 75.65p, or £17,200 for the above truck per year. If a hydrogen truck was subsidised to bring its fuel costs in line with current diesel (£40,474) the total cost to the public purse would be £57,674. Avoiding the release of 61 tonnes of CO_2 (based on 2.68kg per litre of diesel) would then cost (to the public purse) around £950 per tonne. This is a very high figure that compares poorly with alternative carbon reducing approaches, such as supporting domestic insulation.

[147]Source: Fuel: https://www.consumercouncil.org.uk/fuel-price-checker (25 March 2025)

4.6.4 Use Case: Transport – Cars / Vans

Hydrogen can provide for clean running of a vehicle provided this is by fuel cell, as combustion in an engine will produce some NOx, a dangerous pollutant in the quantity associated with congested traffic.

A hydrogen vehicle would be lighter than its EV equivalent as it avoids the heavy battery and associated reinforcement of the wider vehicle. This lower weight results in the hydrogen car having less tyre degradation, which creates a fine dust that is problematic for health.

However, no hydrogen car will be sold in Northern Ireland to the general public until there is somewhere to fill up, including when travelling further from home. This requires an extensive infrastructure which is simply not present. Even 'early adopters', who lead on technology adoption, will not purchase a hydrogen car until the infrastructure is in place. Given that there is currently no demand it is unlikely that the necessary infrastructure investment will be forthcoming, for at least the foreseeable future, unless support is given towards the cost. The effect of limited refuelling infrastructure (and cost of hydrogen) can be seen in the decline in the very limited number of hydrogen FCEV cars registered in GB as shown in Table 3.

It is possible to imagine that hydrogen cars could become more popular if charging infrastructure does not develop and if a consumer price point close to or equivalent to diesel/petrol could be achieved (c. £6/kgH_2) as 60% of Belfast households do not have access to a driveway in which they could charge an EV. This group could be interested in a hydrogen offering, more so once ICE (petrol and diesel) vehicles are phased out.

A hydrogen vehicle's comparative purchase cost is expected to be competitive to electrically powered alternatives, though this will likely narrow as battery improvements are likely to outpace those seen in fuel cells. However, as the cost of filling up on green hydrogen will effectively be at least three times that of charging in order to travel the same distance, the incentive to go down the hydrogen route will be almost non-existent.

In conclusion the demand for hydrogen to fuel cars and vans in Northern Ireland is expected to be nil in the short to medium term, and to stay at that level until a source of very inexpensive green hydrogen is developed.

4.7 Use Case: Feedstock – Synthetic Fuels

The simplest synthetic fuels are e-methanol and e-ammonia as covered in the use case for marine transport. Here the opportunity mainly centres around large-scale investment in coastal locations with strong grid connections and access to both offshore wind farms and port infrastructure for easy shipment of these bulk fuels. For these product lines there is likely to be strong competition from locations better suited to production of low-cost hydrogen (green and blue), this includes current large-scale industrial plants that are currently using natural gas as a feedstock for hydrogen. It is expected that across the world these plants will shift to using blue hydrogen with the addition of CCS technology. However, in the longer term, a shift to 100% use of green hydrogen is expected but this is likely to be beyond 2050 given the scale of investment needed and the lifetime of current industrial plants.

CASE has previously shown that NI has a significant commercial advantage in the ready availability of biogenic carbon from waste and agricultural resources. Utilisation of these resources could be leveraged to create a bio and e-fuels/chemicals industry with all the added benefits for going up the value chain rather than simply exporting BioCO_2 and other carbon feedstocks to be valorised elsewhere. Some of these options have been explored for NI in previous CASE reports[148,149,150,151,152].

[148]https://case-research.net/opportunities-for-provision-of-synthetic-fuels-in-northern-ireland-from-waste-and-re-use-of-carbon/
[149]https://case-research.net/wp-content/uploads/2023/10/Capturing-prosperity-from-CO2-and-waste-final.pdf
[150]https://case-research.net/ni-report-into-biochar-based-atmospheric-co2-removal/
[151]https://www.brydencentre.com/ccus
[152]https://doi.org/10.1016/j.renene.2022.06.115

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One of the simpler cases was for CO_2 upgrading to biomethane where a co-located electrolyser to an AD plant could be used to provide the necessary hydrogen. Here it was shown that this could be viable if the co-product of oxygen could be sold to offset costs, the electricity to drive the electrolyser was provided by private wire from an onshore wind turbine (or potentially solar) and there was a pipeline connection to the gas grid to minimise transport costs. It is worth noting that this is an example of a distributed model of production where, because of feedstock collection costs, it may be more financially sensible to have regional hubs which collect and utilise local biogenic resources.

This concept has been developed in terms of a green industry park[153] where a central biorefinery is used to process biogenic carbon into energy and other products with a cascade of industries using those outputs and local waste streams to create economic value in a circular economy approach. The concepts are illustrated in Figure 7 and Figure 8 below. When developed at scale such a collection of energy generation and carbon utilisation businesses could decarbonise the local area, onshore energy and food supplies and create both high-value jobs and exports.

"Utilisation of these [biogenic] resources could be leveraged to create a bio and e-fuels/chemicals industry with all the added benefits..."

[153]https://static1.squarespace.com/static/63e375cf5e54d90afd00712b/t/6489dcf82ae90f74f096eea1/1686756630089/CASE_APathwayToOurRenewableFuture_Spreads_LR.pdf

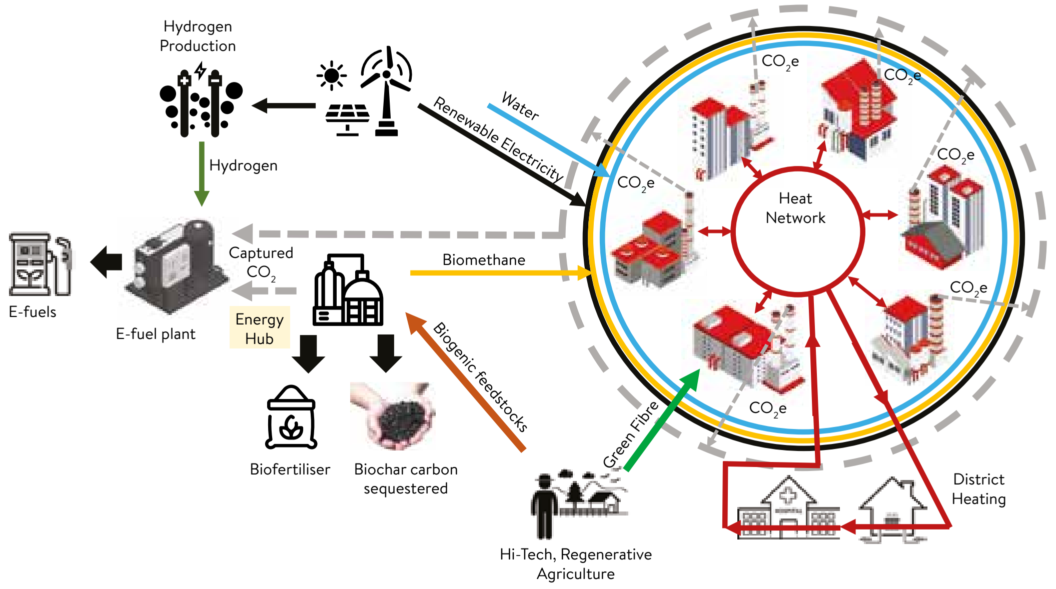

Figure 7 A conceptual green industry park in NI

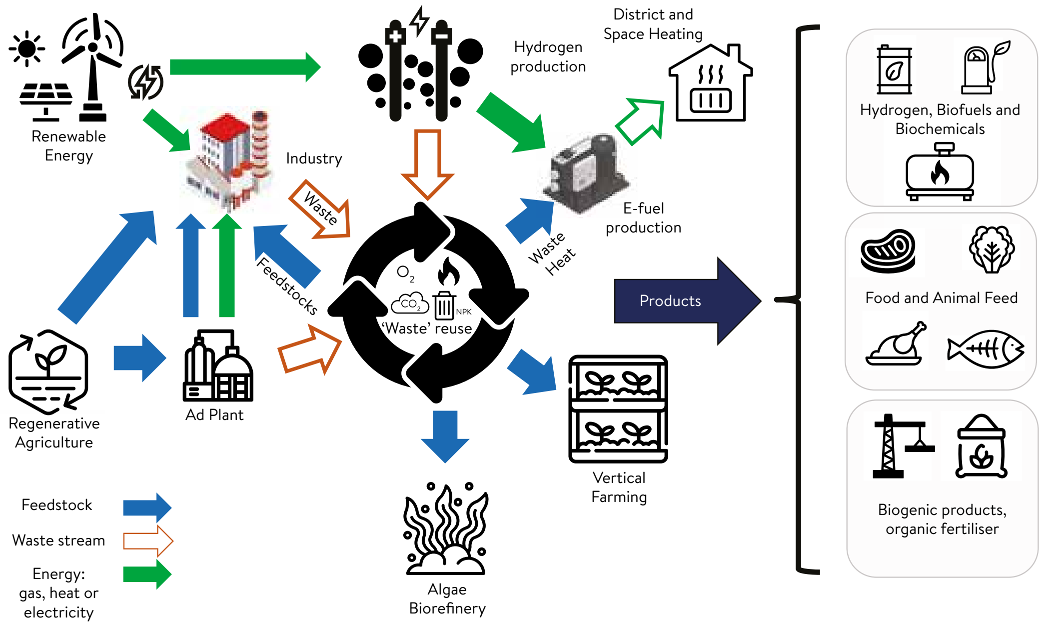

Figure 8 A illustrative picture of a circular economy approach in a green industry park with example product streams

Cautionary notes:

1. While NI has a relatively high abundance of biogenic carbon resources this will not translate to a globally significant bulk e-fuels or e-chemicals business without the importation of huge quantities of biomass or the expensive capture of atmospheric CO_2 using DAC. The reason is simple, NI is geographically small on a European and global scale. The total amount of biogenic resources NI can annually collect is insufficient to meet demand for any of the major green fuels and chemicals. For example, even for the most financially attractive fuel market (SAF) then NI couldn't meet a significant fraction of the global aviation fuel consumption in 2023 which was 348.75 billion litres[154].

2. Biogenic carbon including BioCO_2 is increasing in value with the shift away from fossil fuels. Most of the literature and industry activities are focused on the bulk fuels and chemicals of today such as methanol and ammonia. However, these are high volume but are both comparatively low value-added and low margin. Given NI needs to maximise GVA and high value jobs then a focus on bulk e-fuels and e-chemicals would not be the optimum use of resources, especially as NI would be competing against well-established incumbents.

Establishment of new industries and supply chains can be difficult, even when there is a domestic advantage with raw materials. NI would probably benefit most from going down the higher-value route for bio and e-chemicals, leveraging NI's strengths in Agri-food. If this route is followed, then it would be sensible to focus on those areas where we already have a significant industry base and look to supply green alternatives to these domestic businesses before looking to grow export markets. On this basis, two industry sectors stand out as prime candidates for establishment of domestic supply chains that utilise NI's biogenic feedstocks for high value products. These are:

1. Pharmaceuticals – provision of chemical pre-cursors and other compounds

2. Advanced manufacturing – supply of biogenic derived fibres, bio resins and epoxy glues

A suitably designed supply chain, based around a green industry park as shown could provide the necessary processing capacity as well as decarbonising the energy supply. Relevant to the e-fuels/e-chemicals question for NI is that there is an in-depth study underway to examine the potential for Ireland to be a large-scale producer of green hydrogen and products synthesised from it for export to Germany[155]. This project, "HYreland" is led by Fraunhofer ISE and started in 2024 with the final report scheduled for release towards the end of 2025. The work will assess the technological, economic, and environmental potential. Ireland has one of the biggest potentials in Europe for offshore wind generation with plans for 37GW+ by 2050 and the possibility of >400GW. However, this electricity generation capacity, if fully utilised, is beyond local needs for Ireland and so would need to be exported by interconnectors or converted to hydrogen and/or other energy vector (e.g. ammonia, synthetic kerosene). By comparison, NI has comparatively limited territorial waters so the scale of opportunity for offshore generation is around two orders of magnitude lower. However, the potential plans for Irish waters would give access to low cost green hydrogen and other products if realised and potentially thus address questions of energy security and provide a source of hydrogen for inter-seasonal storage in salt caverns.

[154]*https://atag.org/facts-figures*
[155]*https://www.ise.fraunhofer.de/en/research-projects/hyreland.html*

4.8 Use Case: Agriculture

Vertical farming

Vertical farming uses energy to grow food, particularly that which would otherwise not be grown in Northern Ireland, avocado being a prime example. Growing it in NI, for consumption in these islands, reduces the significant energy and carbon footprint involved in transporting it in a refrigerated state from its usual source, typically Spain. In a sense food is then a battery, taking in energy at a growth stage and reducing energy outflows at a later time.

The question is then – does hydrogen offer any advantage over electrification-based solutions (heat lamps and so on)? As a fully automated process the required energy can be taken at off-peak times, effectively the plants' 'day' will be during the night.

Hydrogen's efficiency loss in production precludes it competing with simply using the electricity directly. More widely agriculture has limited relevance of hydrogen other than as an energy carrier, and thus there is no predicted demand in this sector.

It is though possible that in an area without grid access that some co-location of renewables, hydrogen production and use in vertical farming could make sense. For example, a quarry in a wind turbine area, generating hydrogen to ensure there is always sufficient heat available for the plants. However, this is a one-off opportunistic possibility and therefore not a mainstream policy issue.

In a previous report[149] for DfE, CASE did conclude that co-location of a vertical farm with an electrolyser could be beneficial as the use of co-product oxygen from an electrolyser to super oxygenate the water in a hydroponic system would boost plant growth and hence yield.

4.9 Use Case: Islands

This use case is around creating self-contained energy systems, where the grid is not available.

Rathlin Island has an existing electricity link and therefore the benefit of a hydrogen based integrated energy system combining renewables, hydrogen generation and storage, would be reduced. The Copeland Islands are too small for consideration.

The concept of hydrogen islands[156] (as advocated by an electrolyser manufacturer, ITM Power) is therefore found as unlikely to be relevant to Northern Ireland but may be important to Scotland and Ireland.

[156] https://itm-power.com/markets/hydrogen-islands

4.10 Use Case: Generation for Export

Make it or buy it? That is one question for hydrogen in Northern Ireland as the potential import price, probably from solar rich countries, may be highly competitive.

Make it and sell it? This also needs to be considered. Indeed, a hybrid where Northern Ireland both imports and exports, just not at the same time, depending on local demand, is quite possible.

Northern Ireland's position on the spectrum of possibility from hydrogen importer to producer for own demand and right through to producing for export too, might vary over time, depending in part on geopolitics.

Scotland has developed a highly competitive position in renewables, this raises the question of whether the existing natural gas transmission pipeline from Scotland to Northern Ireland might be repurposed for the importation of hydrogen? Would this be a Trojan Horse for local hydrogen production, or a beneficial energy supply?

A related issue is that of synthetic fuels. It makes more sense to ship these, as they are generally easier to handle and denser, than hydrogen. But this may create a need for storage, notably bunkering fuel for shipping. Could Larne, Belfast or Derry/Londonderry perhaps establish itself as a marketplace for these fuels? There is an existing analogous use in that the Kilroot oil bunkers now hold Ireland's strategic oil reserve.

A Northern Ireland key use might then have little to do with domestic demand for hydrogen or its derived synthetic fuels, being based instead on serving external and international needs.

This opportunity has not previously been identified. If there was substantial hydrogen and synfuels storage capacity at or around Larne/Belfast, readily accessible to shipping / tankers / networks, this could provide a pricing benchmark for west European hydrogen.

Similar salt caverns to those proposed for Larne Lough do exist in Cheshire, which is a superior location in terms of access to a hydrogen network and major chemical production facilities, but these are much less accessible to shipping.

Clearly the key challenge if electrolysis is to be viable in Northern Ireland is the need for a buyer of the hydrogen and ideally the oxygen as well. (Note self-use of hydrogen for generation is considered within the power-to-power use case / energy storage above). This would suggest that a location must be near a hydrogen network, or substantial user. However, such locations are also likely to be well served by the electricity grid, which can directly take the initial renewable energy. Somewhat counterintuitively then it may be that somewhat remote renewables, perhaps windy hilltops, flat plateaus (solar) or tidal flows at a challenging coast, which are unable to access a grid connection, might benefit from this approach. This would require some hydrogen (and probably oxygen) storage on site, with a regular ('milk round') collection of the gas(es).

Location will then be slightly remote (away from networks) but sufficiently clustered so as to minimise the 'collection round', to make collection and delivery to a network or end user commercially viable.

"....the key challenge if electrolysis is to be viable in Northern Ireland is the need for a buyer of the hydrogen and ideally the oxygen as well."

4.11 Use Case: Oxygen coproduct

Earlier, in section 2.4.6 the prospect for valorisation of the oxygen coproduct from electrolysis was explored to improve the financial return from a green hydrogen plant. For a model UK hydrogen system, above a price for oxygen of £0.16/kg the extra costs of capturing and processing oxygen were mitigated by the sale of oxygen. Higher oxygen prices then reduced the LCOH (or increased profitability).

In Northern Ireland, could oxygen valorisation work to reduce the cost of hydrogen to end-users? To assess the opportunity the price of oxygen (in bulk) needs to be determined as oxygen prices as distributed by BOC/Air products/Air Liquide reflect the costs of separation into smaller quantities and costs of gas cylinders or cryogenic containers as well as shipping costs. An estimate of bulk prices was obtained from import and export prices extracted from Eurostat and shown in Table 5 below. Examination of the data shows that the latest import price for oxygen was £0.19/kg (€0.223/kg in table) which is significantly above the £0.16/kg price point that was modelled as the breakeven point.

Year	Import (euro/kg) to NI	Export (euro/kg) from NI
2021	-	0.271
2022	0.206	0.270
2023	0.223	0.263

Table 5 Import and export prices for Oxygen for Northern Ireland[157]

What is the opportunity given current market size? In the UK, total oxygen production capacity is reported to be approximately 1,650 metric tonnes per day[158] with, in the UK, an estimated 10 large-scale cryogenic separation units operated by BOC, Air Products, and Air Liquide, with two in Ireland operated by BOC and the Irish Oxygen Company Ltd. There are no large-scale facilities in Northern Ireland apart from two BOC cryogenic storage tanks (argon and liquid oxygen) located in the BOC facility in Belfast. There are no exact numbers of smaller-scaled oxygen production systems for smaller volumes across the UK and Ireland.

For each tonne of hydrogen that is produced by electrolysis, eight tonnes of oxygen are also produced. Each 1MW of electrolyser capacity produces c.450kgH_2 and 3.6 tonnes O_2. This is 1248 tonnes per year of O_2 (assuming 95% uptime). Smaller scale electrolysers systems are therefore unlikely to be a sensible choice for generation of oxygen for current markets. However, larger capacity electrolyser systems could be competitive and capture a significant part of existing markets. For example, a 100MW hydrogen production plant for e-fuels production would also produce over 120k tonnes of oxygen annually which is c.21% of the current UK consumption and a comparable size to existing cryogenic separation plants.

The economics will improve if an electrolyser is co-located with a point of oxygen use. NI Water's colocation of a CPH2 electrolyser with a wastewater treatment works is an example of this. Ideally, for the best economics an electrolyser would be sited where hydrogen, oxygen and waste heat could be utilised. The prime example of where this is likely to occur is for an e-fuels or e-chemicals plant located near an offtaker for the waste heat.

In conclusion, utilisation of the oxygen co-product could make sense (a) In a large-scale electrolyser system or (b) where an application uses hydrogen, oxygen and waste heat. As each location and situation is unique then the economics would need to be carefully evaluated before the additional investment needed for oxygen valorisation was included in any project.

[157] *https://ec.europa.eu/eurostat/comext/newxtweb/submitresultsextraction.do*
[158] *Available at: https://questions-statements.parliament.uk/written-questions/detail/2021-11-15/HL4021/# (Accessed: 28 February 2025).*

4.12 Use Case: Research and Educational

There will always be some demand for hydrogen within the research community and wider educational sector. This is very limited in scale and is unlikely to grow significantly. However, at some point, supplied hydrogen will switch from grey hydrogen to green or blue. This may be as a consequence of research and educational users requiring a low-carbon product or because of changing the source of bulk supply. At the point of switching there may be an opportunity to develop a local supply source in partnership with one of the large specialist gas supply companies, but this is unlikely to be materially significant quantities for this market use case and would be of the order of single figure tonnes for the local market at best.

5. KEY FINDINGS

5.1 Assessment Challenge

Data – general issues, plus ‘blue sky’ nature

Analysis is complicated by the range of relevant factors discussed in the scoping assessment in section 3.1 above. It is further complicated by an understandable paucity of data, reflective mostly of the low current need for and use of hydrogen in Northern Ireland.

There are concerns over cost transparency as much of the existing system relies on bilateral arrangements with no market, though the development of the EU Auction is a step towards greater clarity on actual costs.

Analysis is complicated by the lack of availability of extensive real-world data that is fit-for-purpose in a NI context. This is unsurprising given the commercial sensitivity in an emerging market area. Costs and prices from the literature vary hugely depending on assumptions made and the optimism bias of hydrogen industry advocates on one hand or outright pessimism of supporters for alternatives on the other side. In this report we have tried to be pragmatic and base our assessment on basic physical and engineering principles.

Technological innovation

Along the development journey for this report, an extensive number of academic papers, analyst predictions, industry and government reports have been analysed. New announcements on hydrogen and competitor technologies have been difficult to keep pace with even in the short period that this work was undertaken. However, the rate of development for market ready or near market ready technologies has favoured alternatives to hydrogen. That said, improvements in electrolyser efficiencies and manufacturing cost reductions are in the pipeline but while these will improve the economics of hydrogen, they do not change the fundamental issue that the price for hydrogen from electrolysis will always be inextricably linked to the price of electricity. Even with the improvements forecast in electrolyser efficiency, fundamentally green hydrogen will remain more expensive than direct electrification. We do not see the price of hydrogen (without subsidy or incentives) being less than double the price of electricity used to generate it. The cost of compression, transport and storage will also remain high, simply because of the demands that hydrogen and high pressure (or liquification) place on materials and equipment and the engineering required to cope with these conditions.

‘Cultural’ issues

Public attitudes to hydrogen will be important. The experience of fracking evidence this as do the campaigns in GB against hydrogen gas-grid test beds and the false claims about hydrogen being four times more likely to cause explosions than natural gas.

Also, important, are attitudes against new infrastructure essential for the low-carbon energy transition. NI has seen opposition in Stormont to a motion on green energy while those in opposition to it then support a motion on green hydrogen. NI can’t have green hydrogen without renewable energy. Equally, there has been vociferous opposition to gas caverns under Larne Lough from local communities and environmental groups. However, without long-term, high-capacity storage, then NI would struggle in a de-carbonised economy to keep the lights on and industry working in an extended period of low-wind and solar. Somehow, a better balance needs to be struck between accepting short-term and temporary environmental pressures and achieving the much bigger prize of a long-term sustainable ecosystem.

> “In this report we have tried to be pragmatic and base our assessment on basic physical and engineering principles.”

Wider Policy

Even seemingly well-defined policy is evolving with growing pragmatism around Net Zero. Great Britain, for example, is moving from a vaunted ‘100%’ net zero target for electricity generation to a more realistic 95% target across the year, recognising that renewable generation, even with some storage, will have an inescapable need for some dispatchable generation when the sun doesn’t shine and the wind doesn’t blow, ‘dunkleflaute’.

Policy has also to develop, focusing on market failures such as the undervaluing of security of supply, and of wider economic and social benefits, such as lower pollution.

Policy should be technology neutral – requiring clarity around aims – as opposed to methods. This would then emphasise, say, low emissions, rather than supporting a particular fuel. There is a need for a ‘hydrogen policy’ but this should be aimed at helping it compete economically (not necessarily ‘win’) by eliminating or mitigating barriers. These include regulation to assuage concerns around safety, or pump-prime a network, or make strategic interventions beyond the capacity of the market, e.g. in storage.

Challenges in one sector – such as the growing constraint and curtailment in the electricity grid – might provide considerable opportunity for hydrogen but reliance on persistence of this feature is a major policy risk as other measures are likely (batteries, EVs, pump storage and so on).

One key finding, driven in part by the existence of uncertainty, is that it can be robustly asserted that the optimal outcome in the energy sector will be a mix of fuels, rather than a single winner. It must also be recognised that the sector will continue to be dynamic, so assessment must have a temporal dimension, some uses might be valid for a while and then perish in the face of technological change elsewhere.

Infrastructure will be important, but it must be noted that any that is publicly financed will impact on emergence and competitiveness.

The importance of the development of the grid in driving wider decisions, and vice versa, must be recognised. Proximity to renewable electricity production sites, and the use of pipelines to transport hydrogen, might reduce the need for more extensive electricity networks. Conversely, co-location of production and demand for hydrogen can reduce the need for hydrogen infrastructure and may be preferrable considering the uncertainties in the development of hydrogen demand.

Bioenergy, in which Northern Ireland has a competitive advantage and had a record of innovation, may be more important to Northern Ireland than to neighbouring countries.

Innovation will be present – and ongoing – and consequently the optimal solution, or energy mix, will continue to change.

There is a need for an all-island consideration, though this should be developed in a way that helps all.

Overall, the assessment of hydrogen must confront its essential paradox: low electricity costs both aid and hinder the development of hydrogen, helping by making hydrogen affordable, but then reducing demand for it through a substitution effect. In extremis free electricity will make hydrogen an apparently compelling proposition pricewise but also act to eliminate a large proportion of the market that hydrogen would seek to serve.

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5.2 Nature and scale of future hydrogen use

The individual use cases considered in Section 4 are aggregated in Table 6 below.

Use Case	Primary Competitor(s)	Likely Future Scale of H2 (NI)	Comment
Energy Storage	Short – battery, compressed air, gravity, flywheel Medium: pumped storage, Long: biofuel, interconnectors	Potentially high	Likely long duration storage is an option but need gas caverns or e-fuel production infrastructure. Might complement e-chemicals/biorefineries. Strong competition from biomethane. Needs in-depth study to determine best route, especially given political/public pressure against gas caverns.
Industrial Heat	Electrification Biomethane Thermal Batteries Biocoal	Low	Alternatives are less expensive in all applications including for energy intensive industries. Biomethane is a drop-in replacement for natural gas.
Domestic Heating	Heat Pump, Biogas	Low	Heat pump 6x more efficient than hydrogen and lower risk.
District/Public building / Commercial heating	Hot water, heat pump	Low	As for domestic heating efficiency advantage is 3-6x that of hydrogen.
Transport: Air	Biofuels	Potentially high	Aviation fuel will need to be replaced by a synthetic aviation fuel (SAF) as electrification and hydrogen lack the volumetric energy density and storage advantages of a liquid fuel.
Transport: Marine	Biofuels. Electrification of inshore vessels	Potentially high	Synthetic/e-fuels as hydrogen vector are most likely. Hydrogen on a boat possible but higher risk and more expensive.
Transport: Buses	Battery, biofuels	Low (except in niche areas)	Substantial improvement in battery technology has mitigated concerns over range and charging for latest generation of buses. Potentially niche roles where rapid turnaround required or for long distance journeys.
Transport: HGV	Battery Bio/Synthetic fuels	Low	Limited scope for long distance journeys in NI and UK owing to geography. Improvements in battery technology has extended range and reduced charging time. Hydrogen HGVs double the cost of eHGVs and three times higher running costs.
Transport: cars / vans	EV	Low	eVs have big efficiency and cost advantage. Market adoption of eVs is almost 100% of low-carbon vehicles.
Non-Road Mobile Machinery	Battery, biomethane, e-fuels, tethering to grid	Medium	There may be a requirement for hydrogen in remote from grid locations, but need can probably be met more cheaply with alternatives.
Synthetic fuels and chemicals	None	Potentially high	Specialist synfuels such as fuel for vintage cars not replaceable. Higher value-added chemicals and associated products.
Agriculture	Battery, biomethane, bio and e-fuels	Low	Better options that are cheaper.
Islands	Wind/solar/battery mix	Low	Limited requirement in NI.
Export	None	Low	Unlikely to be cost competitive compared to countries with low-cost renewable electricity, lower operational costs and cheaper land prices.
Byproduct: Oxygen	Existing suppliers	Medium	Potential for wastewater treatment, Oxyfuel combustion and in chemicals industry.
Research and Educational	None	Medium	Main requirement will be for businesses that develop products that use or enable hydrogen.

Table 6 Projected future scale of hydrogen use in Northern Ireland by use case

5.3 Policy

The overarching policy aim is a trilemma – to provide energy that is affordable, green and secure. Hydrogen related policy must therefore demonstrate how it improves on at least one of those aims, without degrading others.

There is something of an inherent paradox for hydrogen: when it is most wanted it is hard to provide, and when it is not necessary it is cheap to provide. This reflects green hydrogen's dependence on electricity, with which its costs move in lockstep. High electricity prices that would seem to offer an opening for hydrogen act to increase its costs, rendering it uncommercial, while cheap electricity lessens interest in seeking an alternative.

This is the challenge green hydrogen must meet: to steer a path between uncompetitive and unneeded.

Within the context of the trilemma, it is possible to see how it can reduce, even resolve, the usual tension amongst the aims. For example, hydrogen storage clearly aids achieving both more green and more secure, but possibly also affordability, depending on the cost.

This illustrates how strongly the effect of hydrogen on the energy framework in Northern Ireland is dependent on the underlying assumptions: if powered by surplus renewables then fully green, but only if there is no opportunity cost, such as pump storage, batteries or water heating.

Energy policy does not operate in a vacuum, particularly important is the relationship between energy and economic development: competitiveness. There is also a direct impact on energy poverty and wider disadvantage, ultimately affecting also health and wellbeing.

Planning policy is potentially affected by the development of a hydrogen economy as direct – non grid – use of renewables has implications for major infrastructure such as interconnectors. A hydrogen network will also shift some activities, changing the spatial nature of the economy.

All of the above argues for policy in this area to be cognisant of a wider picture and particularly the incidence of future benefits and costs.

5.4 Locational Aspects of future use

This study has considered a wide range of hydrogen use cases for Northern Ireland. The only economically sensible options to pursue are long-duration energy storage and large-scale production of marine or other e-fuels and e-chemicals. For the storage option, the only current candidate for large-scale storage of hydrogen are gas caverns under Larne Lough and so a large-scale electrolyser would be best placed somewhere between Belfast and Larne to effectively co-locate with an injection point for the caverns (or worst case having a short pipeline). An electrolyser in this location could benefit from a strong grid connection and the potential ease of being powered by private wire to a future offshore windfarm.

Locating hydrogen production elsewhere and shipping hydrogen by road would add considerably to the cost even if the existing gas transmission network could be re-purposed in the future for the sole purpose of shipping hydrogen.

Assuming the need for long-term energy storage is fulfilled using hydrogen then it would be sensible to co-locate any large-scale e-fuel business close to the gas caverns to exploit both the electrolyser capacity and the buffering of hydrogen production which the gas caverns allow. This Larne-to-Belfast axis also has the best transport links for shipping e-fuels or potentially shipping in ammonia or hydrogen from overseas if that is the cheapest option. The strong grid connectivity has the advantage of greater continuity of electricity supply in a low wind situation when the supply from the connected offshore wind farm is insufficient. The benefits of the highest density of skilled workers and academic institutions as well as potential industry supply chains should also factor in the location decision.

[159]https://cms.soni.ltd.uk/sites/default/files/media/documents/SONI-Transmission-Map.pdf

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Other locations are possible but are probably best planned to benefit from co-location to the present or future grid in order to secure sufficient electricity supply. SONI's latest plan for the grid[159] is shown in Figure 9. Examination of the plan shows that Derry/Londonderry could also be a suitable location for an e-fuels/e-chemicals business as it has a harbour for shipment, a good grid connection and the potential to connect into a wind farm that is probably located in Scottish waters.

Beyond Larne-Belfast and Derry/Londonderry then generally locations are less attractive for a large-scale operation, mainly because of the shipping costs and inability for a private wire connection to an offshore windfarm. However, an alternative business model could see multiple smaller scale e-fuel business that take advantage of cheaper local supply logistics for biogenic carbon collection and can then justifying co-locating an electrolyser with the e-fuels plant. Such a model has been explored before by CASE[149] and works best if waste heat is used for district heating or an industrial use and the co-product oxygen is also utilised.

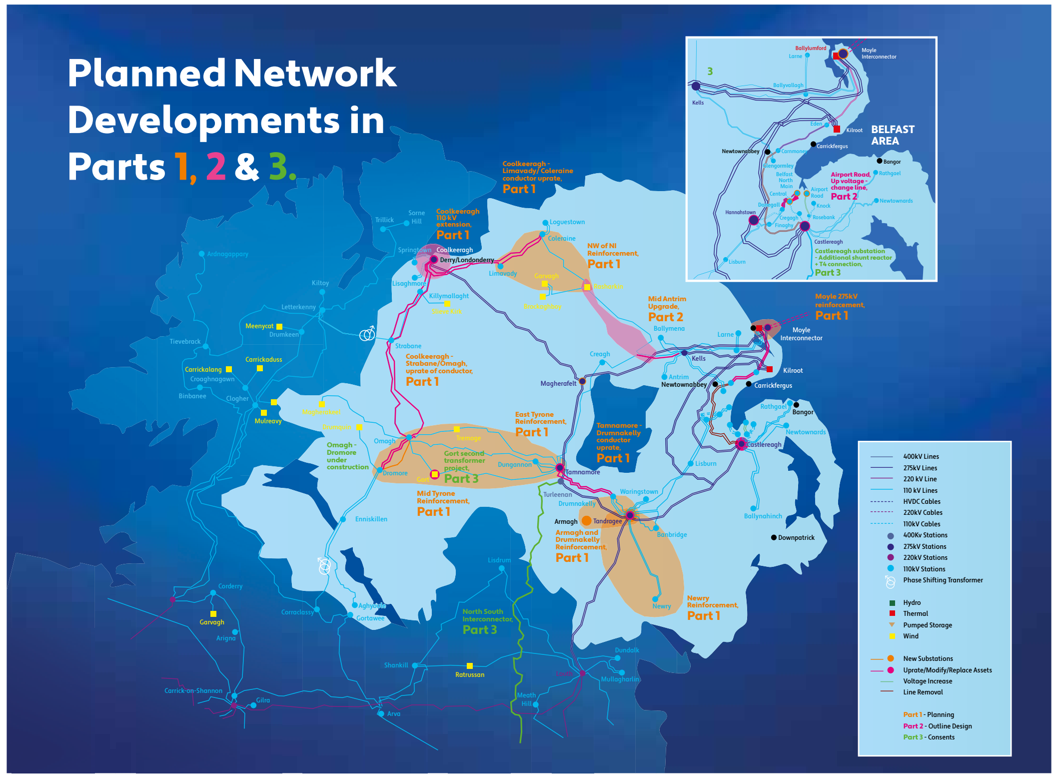

Figure 9 Map of Future Electrical Transmission Grid across Northern Ireland as proposed by SONI (System Operator Northern Ireland)

5.5 Timing and evolution of future use

This report has identified the role that hydrogen could play in the development of long-term energy storage. This is a critical need for NI if no alternative can be found through interconnector linkages. As NI moves to 100% renewable energy on the grid after 2030 then development of a solution will be of increasing importance. Therefore, in terms of priorities an in-depth study of the long-term energy storage challenges should be undertaken as soon as possible since given the timescales for significant infrastructure development a decision to proceed would be needed before 2030.

Gas cavern storage of hydrogen would open up the other opportunities identified in this report and if this could be completed by 2035-40 then this would coincide with the possible completion of proposed offshore windfarms. These windfarms would be another essential component of hydrogen's future in NI as the electricity they provide are essential to power the size of electrolysers required for NI's long-term energy storage and/or any future e-fuels/e-chemicals industry.

Alternative options, such as using a windfarm in Scottish Waters to power an electrolyser/e-fuels business in Derry/Londonderry or specific hydrogen projects co-located with a biorefinery are probably best developer led to reflect the need for commercial funding of a realistic business case.

There is no case to justify development of a hydrogen-base transport system so beyond the sustaining of current Translink hydrogen buses investment in refuelling hubs is not required for the foreseeable future.

6. CONCLUSIONS

6.1 Likely Hydrogen Future

When focusing on indigenously generated hydrogen via electrolysis the review of the generic use cases finds three that offer the prospect of sustainability in Northern Ireland:

- Energy storage
- Marine fuels
- Other synthetic fuels/chemicals including SAF.

The latter two are dependent on Northern Ireland being price competitive, as these products are easily tradeable. As their cost is likely to benefit from economies of scale it will be challenging for Northern Ireland, even with its favourable endowment of renewables to compete with other countries, such as Scotland (predominantly wind) and Morocco (solar).

Green hydrogen produced via biomass including carbon capture is not considered to be economically feasible unless heavily subsidised, however analysis suggests that biomass upgrading using electrolytic hydrogen could generate value streams alongside energy densification and fuels production.

The most competitively robust use is therefore energy storage, which by its very nature must be delivered in Northern Ireland (or be securely linked to it). In addition to this there is likely to be some 'opportunistic' use, for example a factory that has a wind turbine using night-time power to run an electrolyser for high heat uses.

The paper notes that the lower the cost of hydrogen the more likely it is that it can be attractive for other uses, but that low hydrogen costs are necessarily linked to low electricity costs, at least for off-peak generation. It follows that even with low costs hydrogen will struggle to expand its market, not least as its wider characteristics, such as being difficult to handle and potentially explosive, are not advantageous to its case.

The prime advantage hydrogen has over electrification solutions is that it can avail of low cost long duration storage. Use must play to this strength.

The paper also notes that the wider hydrogen supply chain, as is the case with existing fossil fuels, can impact on uptake. Clearly if cheap hydrogen is made available to NI via pipelines etc. then additional use cases will develop. However, at present this is considered unlikely and hence regional production and use has been the focus.

This projection must be understood as indicative rather than determinative, as key policy questions remain to be decided, in some cases yet to be aired. These include views around energy security, market and subsidy issues, financial including taxes and technology innovation, societal habits and customs, from housing to transport use.

These policy choices are discussed below.

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6.2 Policy

The key conclusions for this report are around the use cases where there are better alternatives. This should help guide policy such as NI public investment in hydrogen infrastructure, policies on transport, home heating options and support and guidance for industry making the energy transition to green energy.

However, many questions remain. Beyond the imperative for determining the long-term energy storage needs for NI which is the primary use case, and which would enable e-fuels/e-chemicals as highlighted in this report, the study highlights the need for further consideration around core issues:

- The need for understanding as to how or if NI is going to produce fuels for those use case where a liquid fuel is the only or best option – marine and aviation in particular. In particular the case for 'Green Ports' with all NI ports offering synthetic fuels to all users. Ultimately, it may or may not be best to import these fuels.
- Understanding how NI is to green the supply chains for NI industries dependent on chemicals, plastics, fibres, pharmaceutical pre-cursors, epoxy resins and other fossil fuel derived chemical products. NI has a competitive advantage in the supply of biogenic carbon so could capture a significant market share for a higher-value green chemicals industry.
- The value of energy security, and the business model that might encourage private sector investment in related infrastructure, critical to the establishment of major hydrogen storage, and the related impetus to creating a wider hydrogen hub.
- The value of energy diversity, which aids security but also allows greater flexibility to energy users, potentially opening new commercial opportunities and bringing savings to industry, business and consumers.
- The potential for maximising co-products and linking across sectors e.g., water industry, heat networks for social housing, biorefineries and vertical farming.
- The wider all-island perspective on hydrogen use, in particular, in the longer term (2040+), the merits of a cross-border pipeline that could reduce costs and enhance supply, aiding the emergence of a developed market that would underpin commitments to use and investment, and also consideration of broader co-operation and the appropriate competition framework.
- The future of the existing gas distribution network in Northern Ireland, noting that hydrogen addition is not a recommendation of this report or the growing consensus in the UK. NI's comparative advantage in biomethane is likely to lead to a different solution compared with GB.
- The speed of development of the local electricity grid and its consequential ability to minimise constraint, noting the valuable endowment of renewables across Northern Ireland and around its coast, requiring a reshaping of the traditional grid model of locating power stations near demand.
- The development of grid level storage (including battery and potentially pumped storage), interconnection and flexible demand uses for electricity that minimise curtailment.
- The combined impact on constraint and curtailment and the resulting implications for 'surplus' electricity generation, sometimes erroneously portrayed as 'free', that could be used for hydrogen generation. SONI's predictions indicate that this will lessen considerably in the coming years to less than 10% of electricity generation so it is likely this is an "opportunity" that will disappear.
- The tax treatment of low carbon uses, from Fuel Duty (currently levied solely on petrol and diesel for road use) on vehicles to Vehicle Excise Duty to VAT rates on EV charging, heating and other uses. This is primarily a UK matter, but the border raises the possibility of significantly differential tax treatment for hydrogen, synthetic fuels, biogas or EV charging, with challenging consequences. The future path of the Carbon-Border-Adjustment Mechanism (CBAM) (which places tariffs on imports to the EU from countries with high carbon emissions) is particularly important to manufacturing in Northern Ireland.

6.3 Further Work

This further work is needed to resolve the exceptionally strong 'Chicken and Egg' nature of hydrogen, with Equinor in Germany stating that there is no demand without supply but no supply until proven demand.

The strategic options thus fall into two distinct groups depending on the proposed use:

1. Intervene to create a necessary critical mass for a hydrogen sector in Northern Ireland aligned to the limited use cases for hydrogen identified in this report.
2. Leave it to the market for the majority of use cases, noting that this is likely to mean no hydrogen sector emerges due to the economic and other disadvantages of hydrogen compared to alternatives.

In practical terms this means that further work is required to understand how to deliver option 1 where there is a potential requirement for green hydrogen:

A. Commission in-depth study on long-term energy storage options for NI to include detailed analysis of requirements, options, costs and benefits. This should include an analysis of the hydrogen generation capacity needed for this to be successful or if hydrogen importation is the better option considering security of supply issues.

B. Commission a study to look at the best options for NI regarding provision of synthetic fuels for marine, aviation or other niche use cases. The key question being: produce in NI or import?

C. Undertake a cross-sectoral study of the market opportunity for NI in developing a high-value/small volume green chemicals industry based on initially developing supply chains to displace fossil-fuel derived chemicals in use by NI industries.

D. Investigate the potential for public transport to act as a local hub for BEV charging as part of a wider energy island concept. Outside the hydrogen scope of this report but something that has substantial attractions that emerged during engagement with stakeholders.