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Hydrogen Fuel Switch: Road, Sea and Pipe –
the Scottish Energy Transition

John McKenzie Low

Thesis submitted for the degree of Doctor of Philosophy
The University of Edinburgh
2023
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Declaration
I declare that this thesis was composed by myself, that the work contained herein is my own except where explicitly stated otherwise in the text, and that this work has not been submitted for any other degree or professional qualification except as specified.

Parts of this work have been published in:

Energy Policy
Clean Technologies and Environmental Policy
EnergyREV

John McKenzie Low
November 2023
Abstract / Lay Summary

The world is on fire! The problem of anthropogenic climate change is getting worse. There is scientific consensus that the net emissions of greenhouse gases must reduce to zero. Target dates have been agreed internationally up to 2060. Scotland has adopted 2045; the rest of the UK, 2050.

There is a common view that universal electrification is the net zero solution to our energy needs. It already exists and is familiar to consumers. Importantly, the electricity network already exists, making it easy to introduce solutions - at a small scale. This scaling matters: to replace all the energy currently provided by liquid vehicle fuels and natural gas would require a very large, and expensive, increase in the electrical network.

Electricity, however, is far from the only option. There are sectors where it is impractical or even impossible due to the size, weight and cost of batteries, the need for higher process temperatures than electricity can sustain, the time required for battery charging, or the off-grid location remoteness. Hydrogen, or its derivatives, appears to be the most viable alternative solution which addresses these issues. Advantages of hydrogen include relative ease of storage & transportation and much lower infrastructure costs. In transport, hydrogen offers faster refuelling, less system weight, and less raw material requirement in comparison to battery stored electricity. Disadvantages include the need for very large storage tanks due to the low density of hydrogen, and little existing infrastructure leading to higher barriers to entry than for electricity.

This thesis examines the hypothesis that in significant applications hydrogen will be more suitable than electricity; the most efficient future energy system will include both electricity and hydrogen.

This will be addressed by exploring some of the requirements by which hydrogen can be used as an source or vector for net-zero energy, in comparison with electricity or other fuels. Analysis is in the context of Scotland, with its abundant raw renewable natural energy resources and an ambitious interim target set by the government of a 75% reduction in net emissions by 2030. Adjusting for local factors, most of the methods used and principles of the findings can be applied to other parts of the UK, Europe and the rest of the world.

First, the need for infrastructure to support hydrogen road vehicles is investigated, through a model built in Excel. The base scenario explored is that the fuel demand from large vehicles – buses and HGVs - is most likely to be met by hydrogen in the long run, while it is less certain for smaller vehicles. A plan is developed for an initial investment programme of hydrogen refuelling stations at a cost of c.£140 million. At the pace required to meet government targets, if only large vehicles are replaced with hydrogen ones, that network will meet about 7-8 years’ demand. If all diesel vehicles are so replaced, it would be adequate for 5 years. This is substantially cheaper than widespread electric charging for a similar provision (over £1 billion). Hydrogen provision is given context with a case study considering the planning of a real application of hydrogen refuelling, along with hydrogen as a natural gas replacement.

The cost of the additional road wear due to the greater weight of zero emission vehicles is examined. With battery HGVs and buses, an additional 30%, some £160 million/yr, would be needed for road maintenance in Scotland, or ~£1.8bn more across the UK. The equivalent as hydrogen would lead to an additional 6%. The difference is ~£2,500/vehicle/yr. The impact of cars and vans is negligible in both cases.

The proposal that shipping fuels can be replaced with hydrogen rather than electricity is tested. It is found that battery electricity is prohibitive due to cost and system size except over very short distances. Costs and emissions of hydrogen compare favourably to alternative low or zero carbon fuels in the longer run, though ammonia, derived from hydrogen, appears to be more likely to have the optimum cost & emissions balance in the short term. The choice of drivetrain could be enough to make a material difference either way.

Lastly, there is an expectation that the gas network will be able to deliver hydrogen instead of natural gas. Does the existing network have enough capacity to deliver the energy required? Based on a purpose-built Python model, the network does function though with some localised intervention. An approach is proposed to identify the intervention needs.

Taking an overview, it is clear that electricity does not fit all situations. There are areas where hydrogen could be readily implemented as a fuel, bringing clear environmental, economic and customer choice advantages.
For detailed caption, see Figure 7-1
Acknowledgements

It’s been a long journey to get here. I’d like to express my thanks to the many people who have helped and supported me along the way. In particular –

Stuart Haszeldine and Gareth Harrison, my supervisors.
Mark Naylor, my advisor.
Wei Sun, for support, helpful suggestions, and collaboration in many areas.
Julien Mouli-Castillo for support and collaboration.
Everyone at the GeoEnergy and Hydrogen research groups for encouragement along the way.
The many people out there who have helped with one or more specific parts of this work – in particular Tom Biggart of Motor Fuels Group; Ray Blake and Phil Monger of the Petrol Retailers’ Association; Nick Stapely, formerly at Logan Energy and now at RWE; David Wylie, Barbara Kowalczyk and Christopher Gordon at SGN.

Chat GPT – generative AI

It’s a hot topic so it seems appropriate to mention the use I’ve made of Chat GPT, a useful tool if used carefully.

- Spelling and grammar checking large amounts of text at one go. Other than that, all the text is mine or attributed.
- Finding out how to do correlation analysis – though I carried out the analysis myself.
- Error checking python code.

For these things, it was very helpful.

On the other hand, for finding out useful information it was worse than useless. Data it came up with was usually wrong, and the academic references it provided were always literally made-up, fabricated, non-existent – the famous AI hallucinations. Use with care, it has no shame.
Hydrogen Fuel Switch: Road, Sea and Pipe – the Scottish Energy Transition

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## Glossary of abbreviations

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<th>Description</th>
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<tr>
<td>AASHO</td>
<td>American Association of Highway and Transportation Officials</td>
</tr>
<tr>
<td>AI</td>
<td>Artificial Intelligence</td>
</tr>
<tr>
<td>BEIS</td>
<td>Business, Energy &amp; Industrial Strategy (UK government department)</td>
</tr>
<tr>
<td>BEV</td>
<td>Battery Electric Vehicle</td>
</tr>
<tr>
<td>Blu</td>
<td>Blue</td>
</tr>
<tr>
<td>CCC</td>
<td>Committee on Climate Change</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon Capture and Storage</td>
</tr>
<tr>
<td>CCU</td>
<td>Carbon Capture and Utilisation</td>
</tr>
<tr>
<td>CH$_3$OH</td>
<td>Methanol</td>
</tr>
<tr>
<td>CH$_4$</td>
<td>Methane</td>
</tr>
<tr>
<td>CO</td>
<td>Carbon Monoxide</td>
</tr>
<tr>
<td>CO$_2$</td>
<td>Carbon Dioxide</td>
</tr>
<tr>
<td>CO$_2$ eq</td>
<td>Carbon Dioxide Equivalent</td>
</tr>
<tr>
<td>D</td>
<td>Diameter</td>
</tr>
<tr>
<td>DAC</td>
<td>Direct Air Capture</td>
</tr>
<tr>
<td>Drct</td>
<td>Direct</td>
</tr>
<tr>
<td>Dsl</td>
<td>Diesel</td>
</tr>
<tr>
<td>DUKES</td>
<td>Digest of UK Energy Statistics</td>
</tr>
<tr>
<td>ESI</td>
<td>Electronic Supplementary Information</td>
</tr>
<tr>
<td>EV</td>
<td>Electric Vehicle</td>
</tr>
<tr>
<td>fD</td>
<td>Darcy friction factor (also called the flow coefficient)</td>
</tr>
<tr>
<td>FER</td>
<td>Flow Exceedance Ratio</td>
</tr>
<tr>
<td>FERh</td>
<td>Flow Exceedance Ratio (hydrogen)</td>
</tr>
<tr>
<td>FERng</td>
<td>Flow Exceedance Ratio (Natural Gas)</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse Gas</td>
</tr>
<tr>
<td>GIS</td>
<td>Geographic Information System</td>
</tr>
<tr>
<td>Gov</td>
<td>Government</td>
</tr>
<tr>
<td>Grn</td>
<td>Green</td>
</tr>
<tr>
<td>Gry</td>
<td>Grey</td>
</tr>
<tr>
<td>HC</td>
<td>HydroCarbon</td>
</tr>
<tr>
<td>HCV</td>
<td>HydroCarbon Vehicle</td>
</tr>
<tr>
<td>HFCEV</td>
<td>Hydrogen Fuel Cell Electric Vehicle</td>
</tr>
<tr>
<td>HGV</td>
<td>Heavy Goods Vehicle</td>
</tr>
<tr>
<td>HHV</td>
<td>Higher Heating Value</td>
</tr>
<tr>
<td>HRS</td>
<td>Hydrogen Refuelling Station</td>
</tr>
<tr>
<td>ICE</td>
<td>Internal Combustion Engine</td>
</tr>
<tr>
<td>IEA</td>
<td>International Energy Agency</td>
</tr>
<tr>
<td>IMRP</td>
<td>Iron Mains Replacement Programme</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Full Form</td>
</tr>
<tr>
<td>--------------</td>
<td>-----------</td>
</tr>
<tr>
<td>IP</td>
<td>Intermediate Pressure</td>
</tr>
<tr>
<td>IPCC</td>
<td>Intergovernmental Panel on Climate Change</td>
</tr>
<tr>
<td>k</td>
<td>Logistic function gradient constant</td>
</tr>
<tr>
<td>ks</td>
<td>Pipe roughness coefficient</td>
</tr>
<tr>
<td>L</td>
<td>Pipe length</td>
</tr>
<tr>
<td>LGV</td>
<td>Light Goods Vehicle (Goods vehicle &lt;3500 kg maximum gross weight)</td>
</tr>
<tr>
<td>LHV</td>
<td>Lower Heating Value</td>
</tr>
<tr>
<td>Liq</td>
<td>Liquid</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
</tr>
<tr>
<td>LOHC</td>
<td>Liquid Organic Hydrogen Carrier</td>
</tr>
<tr>
<td>LPG</td>
<td>Liquid Petroleum Gas</td>
</tr>
<tr>
<td>LRH</td>
<td>Learning rate for hydrogen (% decrease in cost each time the number of installations doubles)</td>
</tr>
<tr>
<td>MeOH</td>
<td>Methanol (also CH$_3$OH)</td>
</tr>
<tr>
<td>MGO</td>
<td>Marine Gas Oil (marine diesel)</td>
</tr>
<tr>
<td>mu</td>
<td>Dynamic Viscosity</td>
</tr>
<tr>
<td>ng</td>
<td>Natural Gas</td>
</tr>
<tr>
<td>NH$_3$</td>
<td>Ammonia</td>
</tr>
<tr>
<td>NOx</td>
<td>Oxides of Nitrogen</td>
</tr>
<tr>
<td>NPV</td>
<td>Net Present Value</td>
</tr>
<tr>
<td>O$_2$</td>
<td>Oxygen</td>
</tr>
<tr>
<td>OECD</td>
<td>Organisation for Economic Co-operation and Development</td>
</tr>
<tr>
<td>Ofgem</td>
<td>Office of Gas and Electricity Markets (UK energy economic regulator)</td>
</tr>
<tr>
<td>P</td>
<td>Pressure</td>
</tr>
<tr>
<td>pcc</td>
<td>Pearson Correlation Coefficient</td>
</tr>
<tr>
<td>PE</td>
<td>Polyethylene</td>
</tr>
<tr>
<td>Pgas</td>
<td>Pressurised gas</td>
</tr>
<tr>
<td>Pliq</td>
<td>Pressurised liquid</td>
</tr>
<tr>
<td>PRA</td>
<td>Petrol Retailers' Association</td>
</tr>
<tr>
<td>Pup</td>
<td>Pressure upstream</td>
</tr>
<tr>
<td>Puph</td>
<td>Pressure upstream (hydrogen)</td>
</tr>
<tr>
<td>Q</td>
<td>Volume flow</td>
</tr>
<tr>
<td>Qe</td>
<td>Energy flow</td>
</tr>
<tr>
<td>Qm</td>
<td>Mass flow</td>
</tr>
<tr>
<td>Re</td>
<td>Reynold's number</td>
</tr>
<tr>
<td>Rho</td>
<td>Fluid Density</td>
</tr>
<tr>
<td>RWIF</td>
<td>Road Wear Impact Factor</td>
</tr>
<tr>
<td>RWP</td>
<td>Road Wear Potential</td>
</tr>
<tr>
<td>SBC</td>
<td>Scottish Borders Council</td>
</tr>
</tbody>
</table>
SE  Specific Energy
SGN  Scotland Gas Networks
SMR  Steam Methane Reformation
SOV  Service Operation Vessel
SpE  Specific Energy
SPEN  Scottish Power Energy Networks
$s_x$  standard deviation of parameter $x$
$s_y$  standard deviation of parameter $y$
TIMES  The Integrated MARKAL-EFOM System - a system for the generation of energy models.
ULEV  Ultra Low Emission Vehicle
V  Flow velocity
V  Velocity
Veh  Vehicle
Vel  Velocity
Vh  Velocity of hydrogen
VL  Vehicle life
Vmax  Maximum velocity
Vng  Velocity of natural gas
$x$  Mean value of parameter $x$
$x_i$  Individual value of parameter $x$
$xo$  Midpoint of logistic function
$y$  Mean value of parameter $y$
$y_i$  Individual value of parameter $y$
$yr$  Year
ZEV  Zero Emissions Vehicle
$\rho$  fluid density
$\mu$  Dynamic Viscosity
1 Introduction and context
Wild fires, driven by extreme dry and hot weather, have been spreading across large parts of Canada, Hawaii, Greece, Spain, and others during 2023, causing property destruction and death and ‘burning longer and more often … as the world warms’ [1]. Glaciers are retreating at their fastest rate, revealing new and unprotected ecosystems [2].

While these sorts of event have happened in the past, this is now happening with a far greater, and increasing, probability than previously experienced. This is attributed to global climate change by the UK Met Office [3]. It’s by now almost universally understood that global climate change is substantially caused by human activity, specifically processes leading to the emission of greenhouse gases such as carbon dioxide and methane [4]. Humanity needs to reduce its net emissions of such gases to zero in order to control the effect on the environment, and prevent the global mean temperature rising above an increase of 1.5-2.0 degrees C over the pre-industrial average [5]; it had already increased by 1.16°C in 2022 [6].

There is international consensus that this reduction to net zero greenhouse gas emissions is required, through the 2015 Paris Agreement; most countries have agreed target dates for reaching this at around 2050, with some notable exceptions (including China and India) out to 2060 [7].

The Scottish government has set itself some challenging targets to significantly reduce net greenhouse gas emissions by 2030, and then eliminate them by 2045 [8], while pursuing a socially inclusive Just Transition [9].

1.1 In the future
What will the future look like? We're in a time of unprecedented change. Global governments appear, slowly but perhaps unsteadily, to be beginning to engage properly on the need to transition away from fossil fuels as our key energy source. It shouldn't be controversial to state that we, the human species, need to eliminate net greenhouse gas emissions in order to prevent the world from overheating and suffering catastrophic consequences to our way of life and to the flora and fauna of the world. Despite the goals that are routinely announced at various international climate summits, progress appears to have been far too slow to say with confidence that we’re going to reach the position of net zero emissions by the loosely internationally agreed target of 2050.

In the 2015 Paris Agreement, most countries of the world agreed to adopt a target of a maximum rise in temperature of ‘well below’ 2.0°C and to ‘pursue efforts’ to limit the temperature increase to below 1.5°C[10]. At that time, this was thought to be adequate to prevent unacceptably severe consequences. However, the subsequent IPCC SR15 report shows that the consequences of any rise above 1.5°C would be extremely serious [11]. A reduction of greenhouse gas emissions from human activity to net zero by around 2050 (models actually showed 2040 – 2055) will be required to limit warming to 1.5°C . Anthropogenic warming is estimated to have already led to an 1.16°C Increase in temperature in 2022 [6]. We can see the effects of this in the seemingly routine reports of new temperature records, in heatwaves, wild fires, flooding, and glacier retreat becoming more common around the world [1, 2].
1.2 What can be done?

There are several key sources of greenhouse emissions – broadly, these can be considered as energy, industrial processes, agriculture, waste management, and land use change (which can also be a carbon sink) [12].

This research, explores energy use. Globally and in the UK, the three main ways in which energy is used, resulting in harmful emissions, are electricity, transport, and heat.

‘Heat’ covers a range of uses: it includes domestic and commercial cooking and building heating, industrial heating, and many industrial processes.

Transport has many aspects as well. Road transport, which is divided into various well known classes of vehicles. There’s also rail, air – domestic and international – and shipping, ranging from small leisure craft to the largest multinational container vessels and ships.

And then there is electricity, without which modern civilisation would not exist. Electricity is generated from a great many processes. Traditionally, most of the primary energy source for all these processes has been hydrocarbon fuels, whether it’s wood, coal, or crude oil derived products like petrol, diesel, kerosene, or natural gas. All of these fuels other than wood are finite in quantity, notwithstanding the climate change issue and the large quantities of greenhouse gases they produce, so civilisation cannot continue indefinitely relying on them.

Table 1-1 shows the current situation of energy use and associated emissions, globally and locally.

<table>
<thead>
<tr>
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<tbody>
<tr>
<td>Use (TWh/year)</td>
<td>Emissions (Mt CO₂ eq/yr)</td>
<td>Emissions intensity (kg CO₂ eq / kWh)</td>
<td>Use (TWh/year)</td>
</tr>
<tr>
<td>Heat</td>
<td>41,944*</td>
<td>12,120*</td>
<td>0.289</td>
</tr>
<tr>
<td>Transport</td>
<td>46,944</td>
<td>7,980</td>
<td>0.170</td>
</tr>
<tr>
<td>Electricity</td>
<td>25,500</td>
<td>14,650</td>
<td>0.575</td>
</tr>
<tr>
<td>Total</td>
<td>114,388</td>
<td>34,750</td>
<td>0.575</td>
</tr>
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Table 1-1 Global, UK and Scotland energy use and associated emissions from the key energy sectors of heat, transport and electricity.

* Heat taken as industrial + domestic; not exactly like for like but close. Includes cooling.
Heat and transport really do both end in 944.

1.3 Government related initiatives

The UK Committee on Climate Change (CCC), published a paper recommending the adoption of stricter emissions targets by the constituent nations of the UK[18], including reaching net zero emissions for all activities by 2045 for Scotland and 2050 for the rest of the UK. This recognises Scotland’s usable raw energy assets in the form of wind and marine resources, together with its lower population base. Moreover, as Scotland is a net exporter of electricity to the rest of the UK [17], early progress in reducing electricity related emissions in Scotland will lead to benefits for the rest of the UK.

In September 2019, following the CCC report, the Scottish Government and Scottish Parliament set what they described as the most ambitious emissions targets in the world [8]. The overall aim is to reach net zero carbon dioxide equivalent emissions by 2045, with an interim reduction of 75% by 2030 [8].
In 2021, the Scottish Government announced a target for the production of renewably produced hydrogen offshore of 5 GW by 2030, and 25 GW by 2045 (these energy values can be interpreted in different ways; if it’s the embodied energy at higher heating value, then this represents 1.1 and 5.5 million tonnes of hydrogen per year, respectively). For comparison, Scotland’s total power consumption across all sectors in 2021 averaged 16GW [19].

The Scottish Government has also committed to a “Just Transition” to a net zero-carbon economy, based on the International Labour Organisation Just Transition principles [9]. This sets out the steps and principles by which social values (social dialogue, social protection, working rights, employment, long term sustainable development) are incorporated, protected and enhanced through the energy transition [20].

1.4 Energy use change

All energy emissions have reduced somewhat in recent years. The electricity related emissions in Scotland have decreased enormously, they are now less than 10% of the level 10 to 15 years ago. This is shown in Figure 1-1 below.

Electricity was clearly previously a substantial emitter – at its peak in 2000, electricity generation emitted 19.7 Mt CO2 equivalent [21] – higher than the reference year of 1990 by around 30%, while by 2021 it had fallen to 1.6 Mt CO2 eq, a decrease of 92% from 2000. This large reduction is due to the successful policy of closing coal fired power stations and
encouraging renewable generation[22], primarily over the period 2007-2018. Electricity is now the lowest emitter in Scotland, among key energy sources, by a large margin. We can expect that the existing and future policy will continue this and enable electricity to reach net zero emissions as required; there is only a small amount to go.

However, there has clearly been less progress for heat (38% reduction) and transport (24% reduction), reflecting the lower emphasis placed on these sectors in government policy. The reduction in emissions to date can be attributed to increased efficiency in gas heating, e.g. condensing boilers[23] and vehicle technology, primarily improved fuel economy[24]. The small number of zero and ultra-low emissions vehicles (ULEV) on the road in Scotland – 65,000 registered plug-in hybrid and battery electric vehicles combined, out of 3,100,000 all vehicles in 2022, i.e. around 2%, [25] – will have made a small difference to this reduction. However, it’s more encouraging to note that by the end of 2022, new ZEV & ULEV registrations had a market share of 12.75% [25]. This is illustrated in Figure 1-2.

Natural gas, from the North Sea and imported, supplies the vast bulk of the fuel for heat shown above, although up to about 15% is from electricity.[27]. Natural gas also supplies most of the current CO₂-emitting electricity generation; electricity in Scotland can be summarised as Peterhead gas fired power station, Torness nuclear power station, lots of wind and hydro-electric generation, and a very small amount of oil [27, 28]. Only the Peterhead power station is a significant emitter of carbon dioxide. It’s also worth noting that the one remaining nuclear power station is due to be shut down by 2030 [29].

Other sources of emissions such as agriculture and land use, have shown a variable reduction. As stated elsewhere, these will not be addressed directly as part of this project, but the amounts of emissions involved are significant, and they will have to be addressed to enable net emissions to reach zero. The way in which land use negative emissions are

![Figure 1-2 New ZEV and hydrocarbon vehicle sales and total ZEV and hydrocarbon fleet, Scotland, since 2009.](image-url)

*Figure 1-2* New ZEV and hydrocarbon vehicle sales and total ZEV and hydrocarbon fleet, Scotland, since 2009. Market share and total numbers of new ULEV can be seen to increase noticeably. New sales have still not returned to the pre-pandemic levels; in fact total new sales have been steadily decreasing since 2016. That the fleet size keeps increasing suggests that vehicles are being kept on the road for longer before being scrapped [26].
calculated was changed in 2021; prior to that, it showed significant negative emissions for several years, but now it shows a large decrease (94%) but not negative except for minor amounts in some years. This means that the required emissions reduction from transport calculated in chapter 3 would be greater if repeated now. This is discussed in the preface to that chapter.

So let's give some thought to the present situation with heat and transport. They both currently depend on fossil fuels, with heat primarily being driven by natural gas, supplemented with a little domestic coal and heating oil and quite a lot of electricity - 15% or so [30]. Transport is of course almost exclusively still reliant on hydrocarbon-based fuels at present, although – as above – progress is being made. Petrol and diesel are the ubiquitous and long standing fuels there.

1.5 Initial zero emission fuel direction

1.5.1 Transport

As above, there has been considerable progress in rolling out zero emission vehicles, which so far overwhelmingly use electricity as their fuel source, over the ten or so years to 2023. There does, however, appear to be concerns about issues such as residual value, which has turned out to be much worse with battery electric vehicles than with petrol and diesel vehicles [31], and about the availability and cost of publicly accessible chargers. This might impact the growth in demand for BEVs. The fuelling cost of such vehicles is currently not significantly cheaper than petrol or diesel, although initially that was the case when they were a less mature solution and fuel costs were lower.

There are issues for people who don't have access to off-street parking at their homes. People who live in flats or many terraced houses don't have the practical ability to use their own domestic electricity supply to recharge a vehicle, so they have to use publicly available chargers. While there has been a Scottish Government initiative to heavily subsidise the cost of acquiring and using these chargers, that support will not be indefinite [32]. When publicly accessible charging is paid for at the time of use, the cost of electricity is significantly higher than in a domestic setting, and is also currently higher on a per-km basis than using petrol or diesel [33].

1.5.2 Heat

In terms of renewable heat sources, cooking with electricity is well known, so that is clearly a valid option. Heating for buildings can also be delivered at the moment with electricity, using storage heaters and similar methods. However, there is a modern trend towards the use of heat pumps for electric heating, with government support and subsidy [34]. These systems multiply the energy in electricity used to run them by extracting heat energy from the air or the ground. Even in cold weather, they can be effective. However, they are expensive upfront, and because the heat they generate is relatively low temperature, they are often said to be less efficient in older, less well-insulated properties which are common in the UK. Nevertheless, when installed along with suitable upgrades in insulation, they can improve the emissions relative to hydrocarbon fuels [35]. Clearly though, addressing the lack of insulation would be a beneficial way of reducing energy demand whatever source of energy is used. So, while they may be an option in many cases, there may be disadvantages and limitations to using them universally.
1.6 This brings us to hydrogen ...

1.6.1 Hydrogen for transport

Hydrogen can be used as a transport fuel. At the time of writing in 2023, hydrogen is sufficiently developed that vehicles are commercially available to use it in any form of road transport, shipping, and rail [36-38]. Propeller-driven air transport appears to be imminently available, and rockets have used hydrogen as a fuel for decades [39]. The one area that is not quite ready for using hydrogen is jet propulsion in commercial air travel; there, it is an experimental, though promising, solution [40].

Hydrogen in transport is most commonly used in fuel cells, which make electricity which is then used to power electric motors driving the vehicle, usually referred to as a Fuel Cell Electric Vehicle (HFCEV) [41]. It is also possible to burn hydrogen in an internal combustion engine. This is less efficient than a fuel cell, but slightly more efficient than petrol, and the higher temperatures can cause the formation of nitrogen oxides (NOx) [42], although this can be managed as discussed in chapter 6.

Compared to electricity, hydrogen has a number of advantages in use: it is quick to refuel, taking only a few minutes like petrol and diesel; the system weight is much lower (the weight of the hydrogen itself is negligible); it permits longer range simply through installing a bigger fuel tank; it is used and refuelled in a similar way to petrol and diesel, reducing the change in approach for people; it has lower impact in raw material in the vehicle manufacture; in the longer term, lower vehicle cost. The key disadvantage is the large volume of fuel tank required, and the higher barrier to entry for early adopters due to the lack of existing infrastructure. For those with at home or on site charging potential, that convenience can also favour electricity. It can be reasonably anticipated that there will be a demand for both, complementing each other in much the same way that petrol and diesel support differing, albeit overlapping, uses at present. Recent developments in hydrogen fuel tank technology also mean that the same basic vehicle could become available as either a BEV or an HFCEV [43], meaning that for manufacturers and fuel suppliers, the question of which fuel the vehicle uses is not likely to be significant – again much like petrol and diesel at present.

1.6.2 Hydrogen for heat

Hydrogen as a fuel could be used in a similar way that natural gas is used for heating properties and for cooking. It can also be used for industrial heat [44]. Unlike electric solutions, hydrogen, which can burn at over 2000°C, can be used readily to generate and sustain the very high temperatures which are essential in some industrial processes. This also allows for more effective, hot water based domestic heating systems as are commonly used with natural gas.

It is also likely to be an alternative to electricity in the future; the question of electric heat pumps compared to hydrogen boilers for domestic heat is a contentious issue at present [45]. However, just as in use as a transport fuel, we can anticipate that the pros and cons of each will lead to demand for both, and indeed other, solutions in the fullness of time. For comparison, at present domestic heating is at present supplied by both electricity and piped natural gas.

To use pure hydrogen instead of natural gas, existing gas-using appliances would have to be either converted or replaced to allow the use of hydrogen, due to the different combustion
characteristics. While this might appear to be a very large programme, a very similar programme was carried out in the 1960s and 1970s to convert the UK gas supply from coal gas (towns gas) to natural gas – so it’s possible [46].

1.6.3 Hydrogen for energy storage

There will be an increasing requirement for energy storage - in particular inter-seasonal storage of renewable electricity, so that energy produced in the summer months can be made available in the winter. This will apply whatever method of energy use is applied. It is prohibitively expensive to store electricity in batteries at the large size and timescale required. The most energy-efficient option is probably pumped hydro-electricity, but that is constrained in scale by geography, and is expected to be more expensive than underground hydrogen although substantially cheaper than batteries. It is likely that the most cost effective way of storing energy will be in the form of hydrogen, in underground geological formations, despite the losses in energy conversion [47, 48].

1.6.4 A word about tax.

A key aspect to bear in mind throughout this work will be tax – the retail cost of hydrocarbon vehicle fuel at the time of writing is approximately 50% tax, comprising both fuel tax and VAT [49]. Other fuels are presently only subject to VAT at 20% - or 5% for domestic fuel which, of course, includes electricity for charging cars at home [50].

The basic analyses here will be carried out assuming zero tax, and considered in the light of current levels of tax as appropriate, to understand the fundamental economics of the of the proposals compared with the visible headline cost. However, in practice, government policies on taxing fuels will be a key issue for decision makers, with a major cost implication.

1.7 More about hydrogen

As discussed above, hydrogen can have many uses as a fuel, including transport fuel, heating, and industrial processes. This section explores some of the background to hydrogen and its use, along with investigating previous research by others, in order to set this thesis in an appropriate context.

1.7.1 History of hydrogen

Let’s look at a potted history of hydrogen.

Hydrogen is nothing new. It was probably first isolated by the Swiss alchemist and military surgeon Paracelsus (real name Theophrastus von Hohenheim) in or around 1520, and again by Johann Baptista van Helmont in 1625[51], and it was described in 1671 by Robert Boyle through the reaction of acids on metal[52]. However, they did not identify it as a separate new or different gas.

It was first identified and named by Henry Cavendish in 1766 [53]

Electrolysis of water was first used to produce hydrogen in 1800 by Nicholson & Carlisle[54]

Hydrogen was liquefied for the first time by James Dewar (after whom James Dewar Road in King’s Buildings was named) in 1898, using cooling produced by the Joule-Thomson effect in conjunction with his own invention, the vacuum flask (still called Dewar flasks by some) [55]. Hydrogen has an almost unique Joule-Thomson effect, in that at ambient temperatures it warms on expansion. This is important; it is explored further in section 1.7.2 below.
The first internal combustion engine for road use, invented by the French-Swiss François de Rivaz in 1806, was fuelled by hydrogen [55]; hydrogen fuel cells, now becoming of great importance in the use of hydrogen for transport, were first developed in 1838 by the Welsh scientist and lawyer William Grove [56].

In the 1790s William Murdoch, of Cumnock in Ayrshire, introduced the use of coal gas (also known as towns gas) to power lighting and, later, heat across the UK. This stayed in use until the mid 1970s, when it was replaced by the cleaner burning natural gas from the North Sea. The extensive work needed to convert appliances across the UK to use the different gas should provide a useful analogue to the similar conversion process that will be required to switch the gas supply to 100% hydrogen[57]. Ironically, towns gas was 50-60% hydrogen.

More recently, the first modern hydrogen powered production cars were released by Toyota and Daimler in the 1990s, using fuel cells to produce electricity to drive an electric motor, which then propels the vehicle [58]; the UK's first commercial hydrogen filling station was opened in 2011 [59].

1.7.2 Characteristics of hydrogen

Some key difference in the properties of hydrogen compared to other fuels will have specific effects that need to be taken into consideration.

The Joule-Thomson inversion point is well below ambient temperature. At ambient temperatures, most gases cool on expansion – this is the Joule-Thomson effect[60]. However, as the temperature increases, the degree of cooling decreases. When temperatures rises above an inflexion point (different for each gas), the gas instead warms as it expands; this inflexion point is known as the Joule-Thomson inversion temperature. Hydrogen (along with only helium and neon) is unusual in that the Joule-Thomson inversion temperature is lower than ambient temperature, meaning that at ambient temperature it warms on expansion[60]. This means that on release of pressure, the stream of hydrogen from pressurised storage will increase in temperature. This might be perceived as a safety risk – self ignition might be considered to be a possibility in the case of a leak. However, in domestic heat situations replacing natural gas, this effect is considered to be insignificant[61]; in vehicle fuel cells the temperature change might be enough to adversely affect the operation of the fuel cell, but is unlikely to reach the auto-ignition temperature.

[62]

This is because, countering the high Joule-Thomson inversion temperature, hydrogen has a high ignition temperature, of 585°C, compared to methane at 540°C, petrol at 246-280°C and diesel at 210°C. This decreases the risk of self-ignition on expansion [63].

Low Energy density, i.e. energy per unit volume. It has been said that the energy transmission capacity of gas pipelines will decrease by about 20-30% because of this [61]. This will be investigated further in this research (see chapter 7).

High Specific Energy, i.e. energy per unit mass. This means that a hydrogen system will be considerably lighter than one using batteries; the hydrogen itself will be of negligible mass – typically around 6 kg in a passenger car [36, 64] For a typical family car with a range of approximately 500 km, the hydrogen vehicle would weigh approximately 400-500 kg less
than an equivalent battery fuelled vehicle, or about the same as a fully fuelled petrol or diesel powered vehicle [65, 66]

The latter two factors together mean that a hydrogen car's fuel tank would be about four times the volume of a petrol tank for a similar range; see Appendix 1A showing the calculation of relative fuel tank sizes.

### 1.7.3 Sources of hydrogen

On a large scale, hydrogen is primarily generated at present from Steam Methane Reformation (SMR), or by electrolysis of water[67]. Other sources include biomass, metal hydrides, biological sources[67], waste plastics[68], and others. SMR uses a finite resource (Natural gas), and it produces Carbon Dioxide which will have to be sequestered or used to prevent emissions. While these emissions can be mitigated to a large extent through the use of carbon capture and storage (CCS), it can also be produced in an inherently greenhouse gas free way by electrolysing water to separate the constituent hydrogen and oxygen. In order to be completely carbon neutral, this requires the use of a completely renewable electricity source such as solar or wind energy.

Until relatively recently, it was widely believed that hydrogen did not occur naturally in significant quantities, outside of other compounds. Recent research and exploratory activities have, however, challenged this [69], and an increased interest in naturally occurring hydrogen is evident [70]. If large quantities of naturally occurring hydrogen are found at economic prices, this could change the whole outlook for hydrogen and renewables. This would be driven, not least, by the oil and gas industry, which we can assume will be very happy to continue with their existing business processes. The large scale viability of this is not yet known.

Large scale production of hydrogen by electrolysis would require a considerable amount of new additional electricity generation[67], although this may be partially offset by reducing the often considerable amount of electricity used in the refining of fossil hydrocarbons into fuels[71] – depending on the source of that electricity. Refining of oil also currently uses fossil-fuel sourced hydrogen to convert long-chain hydrocarbons into short chain ones; this, and its associated emissions, could also be displaced by green hydrogen. [72].

New production methods are being researched and developed, including for example manufacturing hydrogen using waste plastics[68], and as a by-product of a number of industrial processes. However, here the assumption is that in the short to medium term hydrogen will be produced from either SMR with CCS, or by electrolysis of water with renewable electricity.

Sea water could be used for electrolysis, for example in conjunction with offshore wind turbines, making use of water desalination techniques. While water desalination is often thought of as an expensive option, this is only true in the context of water purification. The retail value of a cubic metre, or 1000 kilogrammes, of drinking water in Scotland is approximately £1 or less [73]. However, that same 1000 kilograms of water would yield approximately 111 kilogrammes of hydrogen when electrolysed (See Appendix 2A in chapter 2). At prices at the time of writing, that would have a value of between £500 and £1000. In this context the energy required for the desalination is insignificant, amounting to considerably less than 1% of the energy embedded in the hydrogen (See Appendix 2A in
chapter 2). If produced offshore, the hydrogen would need transported to shore, most likely by pipeline, or directly onto a ship for use or export.

It also appears that a number of industrial processes produce hydrogen as a by-product; this is at present frequently vented to the atmosphere. Recent research at the University of Edinburgh [74] shows that this vented hydrogen has a significant global warming impact.

1.7.4 Hydrogen in transport

As a vehicle fuel, hydrogen would displace liquid hydrocarbon fuels. Here it is most commonly used in fuel cells, which make electricity which is then used to power electric motors driving the vehicle, usually referred to as a Hydrogen Fuel Cell Electric Vehicle (HFCEV)[41].

It is also possible to burn hydrogen in an internal combustion engine. This is less efficient than a fuel cell (but slightly more efficient than petrol), and the higher temperatures cause the formation of Nitrogen Oxides (NOx)[42], although these can be managed as discussed in chapter 6.

It might also seem that hydrogen would compete against battery electric vehicles. However there are pros and cons to both, much like petrol and diesel, so it seems likely that there will be a need for both to complement one another in much the same way. Recent developments in hydrogen fuel tank technology also mean that the same basic vehicle could become available with either as either a BEV or an HFCEV [43].

Cars and light goods vehicles (LGV). There are currently 2.8 million of these on the roads in Scotland[75], emitting 7,400 kT of Carbon Dioxide per year. (See Chapter 3 – Fuel Infrastructure paper). Approximately 232,000 new cars and LGVs are sold in Scotland each year[75], compared to 81,500,000 worldwide[76]. Several hydrogen fuelled passenger cars are already commercially available from Honda (which left the market but is poised to re-enter it) [77], Toyota and Hyundai [78] [79, 80]. These are also forthcoming from for example Mercedes-Benz, BMW, and others [43]. LGVs are becoming available from Vauxhall and others [81].

The 52,000 buses and HGVs in Scotland [82] collectively emit 2,400 kT of Carbon Dioxide, that is 46 tonnes per large vehicle per year (see chapter 2). Approximately 700 new hydrocarbon fuelled buses and 4,300 HGVs are sold in Scotland each year[75]. Hydrogen buses are already in use throughout the world, including in service in Aberdeen following a successful pilot [83].

Diesel fuelled trains in Scotland emit a comparatively low 172 kT of CO2 equivalent per year in total [84]. Hydrogen fuelled electric trains have been developed and their deployment has begun in France and Germany[85]; trials are underway in Scotland and the rest of the UK [86]. The same trains as in France and Germany cannot be used in the UK as the standard height of bridges is lower – the trains would not fit under [87].

Maritime emissions account for about 5% of Scotland’s current emissions. All uses currently fuelled by marine fuel oil or diesel could be replaced by hydrogen, resulting in the most significant CO₂ emission reduction per vehicle/vessel of all, worldwide. A dual-fuel hydrogen-diesel car ferry is in development for service in Orkney [87]. The options for hydrogen as a maritime fuel are explored further in chapter 6.
It is also possible in principle to create a dual-fuelled combustion engine that can be run on either hydrogen or petrol/diesel, or a mixture; this might have application in the transition period [88] although it is not considered in any detail here.

1.7.5 Hydrogen in heat

Hydrogen can be used as a replacement for natural gas in domestic (or equivalent) heating and cooking, and in industrial heating applications[44]. In these applications it would be combusted in a similar way to the present use of natural gas. It also permits the sustained use of very high temperatures required by some industrial processes. It is likely to complement electricity in the future; the question of electric heat pumps compared to hydrogen boilers for domestic heat is a contentious issue at present [45]. However, just as in use as a transport fuel, we can anticipate that the pros and cons of each will lead to demand for both, and other, solutions in the fullness of time; they will be less like competing solutions and more like alternatives to be used in different circumstances.

Hydrogen is a viable substitute for methane/natural gas in most industrial and domestic (including cooking and food preparation) heating applications. However, if used as 100% hydrogen, existing appliances would need to be either adapted to use hydrogen instead of natural gas, leading to a reduction in performance, or replaced with new purpose-designed ones.[44, 89]. The same issue was addressed when the UK gas supply was converted from Towns Gas (i.e. coal gas, which was over 50% hydrogen) to natural gas over 10 years in the 1960s and 70s [61].

As a potentially easy start, hydrogen can be co-injected with methane into the gas networks up to about 20% by volume (or 6% by energy content), with no need to modify appliances [90]. The key issue is to stay within the standard range of Wobbe number (a function of energy density and mass density, describing the rate of energy supply) set by the local gas company, which reduces or eliminates the need to modify appliances[91]. A successful pilot at Keele University was conducted in 2019, with a blend of 20% hydrogen fuelling the university campus [92]. Scotland Gas Networks (SGN) is developing a pilot project (the H100 project) to supply around 300 homes with 100% hydrogen [93].

For industrial use, hydrogen combustion can produce very high temperatures, such as those required by blast furnaces, because a stoichometric mixture of hydrogen and oxygen burns at over 2000°C. Unlike electricity, hydrogen therefore has the potential to replace highly polluting coal derived fuels such as coke[94].

1.7.6 Safety of hydrogen

This project is not about hydrogen safety. Nevertheless, it is important to be confident that the technology under discussion can be used safely. Safety is governed by a range of international regulations and codes of practice.

For transport applications, vehicles have to comply with United Nations Global Technical Regulation GTR 13 (2013), which governs the fuel tank and valves, and the newer, more rigorous, ECE R134 (2019), also published as UN R 134, which covers the same but also governs the other hydrogen components and provides for heavy duty vehicles more explicitly. Hydrogen refuelling stations are constructed in accordance with ISO 19880-1 (2020).
For use as a heat heating fuel, there have been several practical experiments carried out examining the safety aspects of using hydrogen in buildings. One such experiment involved buying an existing farmhouse in a remote location in the Highlands, and simulating gas leaks, and monitoring the gas concentrations in various parts of the building to find out if enough hydrogen accumulated anywhere to reach an explosive limit. It proved impossible to create enough of an accumulation, due to the unusually high mobility of the hydrogen molecule, which led to it escaping from the building quickly and readily before it was able to build up to an unsafe concentration [95].

A trial including induced leakage and combustion of otherwise identical hydrogen and petrol fuelled vehicles showed that in that case the resulting burning, hydrogen could be more controlled and less dangerous [96], as shown in below.

![Figure 1-3 Comparison of combustion of leaking fuel in hydrogen fuelled car (left in both images) and petrol fuelled car (right in both images).](image)

Further research into hydrogen safety is also carried out through the HySAFER programme at Ulster University [97].
1.7.7 Emissions. Of hydrogen, of other fuels, of fugitive emissions.

Both electricity and hydrogen, when used through a fuel cell, emit no greenhouse emissions at the point of use[98]. Hydrogen can also be used in an internal combustion engine, which would give rise to a small amount of nitrogen oxides (NOx) due to the heat of combustion causing nitrogen from the air to react with oxygen [42]. However, these NOx emissions can be addressed through a combination of changing the fuel-air mixture (which reduces efficiency) and/or using a catalysis process, similar to that used for hydrocarbon engines at present [99]. This is discussed further in chapter 6.

Fugitive hydrogen is an important consideration. Hydrogen on its own does not have a global warming impact, but it has an effect of retarding the decomposition of atmospheric methane, ozone, and other high-impact gases, which increases the residence time and hence the impact of those gases; therefore leaked or vented hydrogen has a significant global warming contribution by secondary impact. This effect will decrease as the concentration of the affected gases in the atmosphere decreases, but in the meantime fugitive hydrogen could have a significant climate change impact, therefore it must be eliminated as much as possible [74]. The emissions due to the method of generating the electricity used to produce the hydrogen are also extremely important in assessing the overall cycle emissions.

So hydrogen can be used for most forms of transport and heat. It can be used in a very familiar way, and in terms of refuelling vehicles, they would be refuelled at filling stations in a similar manner and speed to petrol and diesel. Going back to the point in chapter 1 about reducing the amount of change that people have to make in our society to facilitate acceptance of the transition, hydrogen appears to have considerable benefits.

1.7.8 Transportation of hydrogen

In principle, hydrogen can be transported and distributed using the existing natural gas pipe network. However, modification might be required for high pressure steel transmission mains due to the effect of hydrogen embrittlement of steel at high pressure creating structural weakness in the pipe[100]. This appears to still not be yet well understood, though SGN are in the process of carrying out experiments on a real mothballed steel pipe [101]. There is also the Iron Mains Replacement Programme under way, due to complete in 2032, using polyethylene pipes to replace cast iron pipes within 30m of a property – these polyethylene pipes are thought to be suitable for the conveyance of hydrogen in principle [102].

It has been suggested that the gas network could be done away with altogether, and the entire energy system could be electrified[103]. However, there are considerable benefits in using hydrogen, as described above – particularly for those sectors of society that are particularly hard to decarbonise, such as heavy transport, marine transport, or high-temperature industrial heat [104]. Furthermore, a pipeline carrying hydrogen is considerably cheaper to construct, maintain and operate over longer transmission distances than an electricity cable, relative to the energy transported [105]. Given that the pipe network exists, and assuming that it can be repurposed appropriately, there appears to be a considerable advantage in using hydrogen.

A quick cost comparison of transport costs is to look at the turnover of transport and transmission companies, relative to their energy transported. Scottish Power Energy
Networks (SPEN) and Scotland Gas Networks (SGN) are the relevant energy transport companies in Scotland, or the South of Scotland. They are therefore subject to the same economic forces, and have their prices regulated by the same UK government regulator, OfGem. This analysis shows that the cost of electricity transport is approximately 2.6 pence per kWh, while the cost of natural gas transport is approximately 0.7 pence per kWh. Based on retail prices at the time of writing, the electricity transmission and distribution cost amounts to around 8% of the retail cost. The gas transport cost is around 6% of the retail fuel cost. As the vast majority of the cost is in the capital investment rather than marginal activity related costs, it seems likely that the cost for transporting hydrogen will be similar per kWh to the cost for transporting natural gas. On that basis, hydrogen should also be around 3 to 4 times cheaper to transport than electricity. The impact on the carrying capacity of the gas pipe network when converted to carry hydrogen is considered in chapter 7 of this thesis.

One of the benefits of using hydrogen is that as a physical molecule, it can be transported in tankers or similar vehicles or vessels when required. This can be done either as a pressurised gas, or as a liquid at -253 C, or as a compound in various forms of carrier liquid such as ammonia or Liquid Organic Hydrogen Carrier (LOHC) [106, 107]. It is also a practical alternative to manufacture hydrogen in situ where it is needed, using an electricity supply. However, if the electricity is drawn from the national grid, it is likely to be considerably more expensive; a resolution to this is to use a dedicated source of electricity, bypassing the national grid. Because the hydrogen is stored in a tank, the buffering effect of being supplied through the National Grid is unnecessary.

1.7.9 Pilots, trials and ramping up to the mainstream.

A number of pilot initiatives have been developed in Scotland and elsewhere to trial the use of hydrogen as a fuel, looking at transport, heating, a combination of the two, and also at storage. Within the UK, these included:

- The then-largest hydrogen bus fleet in Europe, in Aberdeen[108].
- Bright Green Hydrogen pilot to supply offices and some local authority vehicles in Methil, Fife[109].
- The H21 programme in Leeds[110].
- A co-use study at Keele University[111].
- The under-construction H100 project to trial 100% hydrogen supply to domestic customers in Fife – a world first [93].
- A dual-fuel hydrogen-diesel car ferry is still in development for service in Orkney[87].
- Underground geological storage study, Hystorpor [112].

In the 3-4 years up to 2023, within the UK, these have been added to -

- SGN trial hydrogen in a mothballed steel pipeline to examine the effect of embrittlement of steel pipelines when hydrogen is introduced under pressure [101].
- Hydrogen refuelling stations especially around London, Sheffield, Aberdeen, with others planned around the UK [113].
- More towns- London, Liverpool - are adopting hydrogen buses [113, 114].
- Hydrogen fuelled refuse collection has been started in St Helens council [115].
- Railway trials have been started in Scotland and NE England [86].
• The Scottish Government has announced a hydrogen policy to develop 5 GW hydrogen production by 2030, and 25 GW by 2045 [116]. It’s not clear how these 5 and 25 GW figures are actually calculated, but on the assumption that they represent the Higher Heating Value (HHV) of 39.4kWh/kg then that is 1.1 Mt/year and 5.5Mt/year respectively. For context, replacing all the diesel vehicles in Scotland with HFCEV would require about 0.45 Mt/year (see chapter 3); Scotland’s total energy consumption rate is around 16 GW (gas + electricity + vehicles) [19].

• The UK government has also announced a hydrogen policy to develop 10 GW of hydrogen production by 2030 [117].

• These have been supported by manufacturers in the UK, for example Logan Energy supplying integrated refuelling solutions, ADL and Wrightbus supplying hydrogen fuelled buses, JCB producing hydrogen ICE powered construction machinery, ITM manufactures electrolysers for the production of hydrogen.

However, UK hydrogen activity still appears to be not much more than at the level of pilot studies and trials. In several other countries hydrogen appears to be becoming mainstream.

In Japan, there was a major push to develop and install hydrogen systems for the Olympic Games in summer 2021. The Japanese government wanted to use the event to develop and showcase the use of hydrogen, and leave a legacy of a hydrogen society in Tokyo. It spent ¥40bn (£280m) to construct 80 refuelling stations[118, 119].

In a number of countries, hydrogen fuelled vehicles and refuelling stations are being rolled out in parallel as partnerships between vehicle manufacturers and fuelling infrastructure manufacturers:

In California, USA, Nikola Motor Co of the USA and NEL electrolysers of Norway are focussing on articulated lorries (semi-trucks), with a view to constructing 700 refuelling stations to provide coverage for the mainland USA by 2028. They have also formed a partnership with IVECO to develop an HGV tractor vehicle for the European market[120].

In Switzerland, Hyundai motors of South Korea and Swiss-French consortium Hydrosider have partnered to sell and support a target of 1600 hydrogen fuelled HGVs, initially focussing on an 18-tonne single rear axle vehicle [121].

In the USA, the Inflation Reduction Act identifies potentially $100bn in subsidies and supported investments for hydrogen and other renewable fuels programmes [122].

The EU has recently passed a requirement that all member states must provide hydrogen refuelling in all major cities and at minimum intervals along primary routes by 2030 [123].

It’s notable that much of the large deployments globally are arising from partnership arrangements – more so than in the UK. It appears that the UK would be well advised to make more use of such arrangements; this can reduce the risk of commercial uncertainty associated with the need for the provision of infrastructure to attract customers, and the need for customers to justify infrastructure.

In addition, hydrogen fuelled road vehicles are in development or are already in production from a number of different manufacturers around the world [124] – cars, buses and lorries are all available or becoming available. Toyota and Hyundai have hydrogen cars, lorries and buses in commercial production [36, 125]. BMW and Audi are developing hydrogen vehicles [126]. Lorry manufacturers, for example Hyundai, Mercedes Benz, Iveco, Volvo, Nikola, new
start HVS of Glasgow, and others, are developing hydrogen fuelled HGVs – the long list of such manufacturers underlines the common view that large vehicles are best suited to hydrogen (see chapters 3 and 4).

1.8 Other academic research

1.8.1 Transport

Joffe, Hart & Bauen modelled various types of hydrogen refuelling infrastructure for hydrogen buses in London as far back as 2004[127]. This was looking at on-site hydrogen generation from either SMR or electrolysis, for an expansion of a trial of three buses supplied with liquid hydrogen imported from the Netherlands; while they did not reach a specific conclusion about the optimum strategy, they identified that the fuelling process and on-site production operation would be better under different regimes depending on whether SMR or electrolysis was chosen.

Colbertaldo, Guandalini and Campanari modelled an integrated power and transport energy system for Italy, based on two scenarios – more and less disruptive – up to 2050[128]. Neither of these scenarios reached zero emissions by 2050, with the most optimistic leaving 36% of remaining cars powered by traditional internal combustion engines. They carry out a geographical node based model; a similar approach was taken by Searle et al [129] considering fuelling for large vehicles in the north of England.

Zhang, Chen and Huang used the TIMES model to investigate the impact of decarbonisation policy on the transport sector in the USA and China[130]. They consider BEV, HFCEV and also biofuels as option; they conclude that in the short term, biofuels are likely to be the most viable decarbonisation route, with only a small role for HFCEVs. However Raboni, Viotti & Capodaglio [131] point out that biofuels are very resource-intensive, and are unlikely to have enough capacity to supply a significant portion of energy demand without adverse social effects in parts of the world whose food production would necessarily be decreased. They also identify limitations in the potential for biogas except in a few specific localities in the world. This is contradicted in turn by a study by Imperial College[132], identifying more recently that biofuels could be used to a significant extent in Europe without impacting food crop requirements.

These seemingly contradictory studies suggest that some reconciliation or consideration of the differences will be required.

1.8.2 Heat

Sorgulu and Dincer [133] examined a renewable electricity plus hydrogen energy system. They estimate the quantity of renewable energy required to meet the domestic demand, and they use hydrogen production as a way of capturing and storing surplus renewable energy for use when needed. They use a community of 100 houses in Canada as a demand model.

Van der Roest et al [134] also look at a community based energy system, but from a more integrated perspective. They take a renewable energy source, and use it as the base supply for a system incorporating heat pumps, hydrogen production for vehicle fuelling, district heating and underground aquifer heat storage. This based on the needs of a community in the Netherlands, but also assumes the possibility of energy transfers to or from other localities. They analyse costs, practicality and emissions benefits from this integrated model.
1.9 About this thesis

This thesis, then, explores the ways in which hydrogen can be used, and more specifically the pathways, or specific steps, that need to be taken in order to most effectively deploy it as a fuel to meet climate goals.

1.9.1 Research questions & Hypothesis

- Does prioritising one route of zero-carbon vehicle fuel introduction over another produce any benefits? In either cost or speed of GHG reduction?
  
  \textit{Hypothesis: Prioritising large vehicles such as buses and HGVs ahead of smaller vehicles will have benefits over an equal, or unregulated, vehicle transition.}

- Can hydrogen road fuel be competitive with electric charging?
  
  \textit{Hypothesis: A seed network for hydrogen road fuelling can be defined which is cost-competitive with an equivalent electric charging system.}

- Will the extra weight of ZEVs affect road wear and hence maintenance costs?
  
  \textit{Hypothesis: There will be significant and quantifiable additional costs of road maintenance due to the increased weight of ZEVs over ICE vehicles. This will be markedly greater for BEVs than for HFCEVs.}

- Is hydrogen the best renewable fuel to use in a marine environment?
  
  \textit{Hypothesis: Hydrogen will perform better in cost and emissions than other alternative low carbon chemical fuels for shipping.}

- Does the existing natural gas network have enough capacity to be repurposed to distribute hydrogen?
  
  \textit{Hypotheses: The natural gas network can be converted to supply enough pure hydrogen to replace all natural gas in use, on the basis of energy transported, without enlargement or replacement of the pipes.}
  
  \textit{It will be possible to identify which parts of the network will need intervention when converted to supply hydrogen, on the basis of the natural gas characteristics alone.}

1.9.2 Extent of research

This thesis considers the situation in Scotland, given the government’s commitment to an early energy transition and its success to date in decarbonising the electricity system. However, with adjustment for local factors – e.g. relevant targets, nature of vehicle fleet, availability of renewable electricity, existing natural gas network – most of the learnings can be applied to other parts of the UK, Europe and the rest of the world.

1.9.3 Purpose and extent of thesis

The aim of this thesis is to assess the role which hydrogen could or should play in Scotland in eliminating greenhouse gas emissions from heat and transport. This will be considered in the context of electrification and other zero-emissions chemical fuels.

This will not look to any large extent at reducing emissions due to electricity generation, as that has been extensively addressed elsewhere.

This thesis is organized into this introduction, followed by five core chapters, then a discussion and conclusion.

Chapter 2, the first core chapter, examines the extent of infrastructure required to support the roll out of hydrogen fuel for transport, in a number of scenarios. The comparative cost
of electrification is considered briefly, based on work by others. This was published as a paper in Energy Policy journal, which is reproduced as this chapter.

Chapter 3 develops a case study to broadly examine the costs and practical issues around providing a suitable hydrogen refuelling solution to support Scottish Borders Council, primarily for their own vehicle fleet, but also with consideration to displacing natural gas use in the area. This work was carried out in conjunction with, and partly funded by, Scottish Borders Council as a part of a wider look at some decarbonisation options for them carried out by the University of Edinburgh. This chapter represents the work undertaken by the author as a contribution to that report.

Chapter 4 examines the impact on road wear and tear of hydrogen and electric vehicles. It is often mentioned that battery electric vehicles are substantially heavier than ICE vehicles, so will have a greater impact on road wear. HFCEVs tend to be only a little heavier than ICE vehicles, suggesting that additional road wear and tear will be minimal. However, while this has often been stated as an assumption, there appears to have been no attempt to actually quantify this. An analysis of the impact of both BEVs and HFCEVs on road wear and tear on a national average basis was carried out. This was published in Clean Technologies and Environmental Policy, and is reproduced here as chapter 4.

Chapter 5, considers the implications of using hydrogen as a marine fuel, compared with other potential zero or net zero emission fuels. The fuels considered are hydrogen (in the form of gas, liquid, or Liquid Organic Hydrogen Carrier (LOHC), ammonia, biodiesel, methanol, biomethane, along with marine gas oil (MGO, i.e. diesel) as a comparison. Aspects considered are a core comparison of cost and net emissions and how they are expected to change through the energy transition. This chapter is derived from work carried out by the author, with funding from BP, via the Offshore Renewable Energy Catapult, as part of their project to plan for zero emissions service vessels for their offshore wind farms.

Chapter 6 models capacity implications of converting the gas grid from natural gas to transport 100% hydrogen. For this chapter, a simple model was constructed using Python, based loosely on the network supplying the east of Scotland from St Fergus - the current primary natural gas injection point for Scotland and around 1/3 of the UK - down to the Borders. This model was used to investigate the impact of the different gas in terms of transport capacity, and to develop a means of predicting when intervention will be needed. A discussion in chapter 7 follows, which considers how these elements fit into the wider picture of hydrogen, renewable fuels, and the energy transition.

The thesis is complete with the conclusion in chapter 8, revisiting the hypotheses and setting out an energy transition pathway.

2 Refuelling infrastructure requirements for renewable hydrogen road fuel through the energy transition

This chapter concerns the size, cost, and speed of growth of hydrogen filling stations network which would be required to sustain a hydrogen road vehicle fleet in various scenarios.

This developed through various twists and turns looking at trying different appropriate scenarios, including complete hydrogen vehicle fleet and no hydrogen. These scenarios had two option components, (1) the pace of adoption and (2) the ultimate market penetration of hydrogen vehicles.

Hydrogen penetration options of 100% and zero were considered for a while, in order to be able to draw some comparisons with the cost of full electrification; a considerable amount of work on that was published by Scottish Power in 2000, in their publication Zero Carbon Communities [1]. However, it was difficult to make good comparison of like with like because it required considerable interpolation of the sparse data points provided by Scottish Power in their publication. Nevertheless, this is discussed to an extent in chapter 7.

For this chapter, a model was developed using Microsoft Excel to examine the pace at which hydrogen vehicles would be required to meet the government’s net zero targets, their fuelling requirements, the number of filling stations of various sizes which would be required, and the cost of providing that infrastructure.

The first ultimate market penetration option has only the largest vehicles – lorries and buses – replaced with hydrogen fuel vehicles, while smaller vehicles such as cars, vans and motorbikes are replaced with battery electric vehicles. This appears to be a commonly accepted view of where we will end up [2], although there are still many advocates for battery powered large vehicles – and indeed manufacturers, such as Nikola/Iveco HGV tractor units and ADL buses of Falkirk.

However, there are a number of issues looming with battery vehicles, which means that their universal deployment is far from inevitable, even among smaller vehicles. These include issues such as the availability of raw materials for manufacturing batteries in sufficient quantity [3], the ability of the electricity network to transmit enough electricity to supply all of these vehicles [1], and the convenience – or inconvenience – for people who cannot create access to charging facilities at home, such as people who live in flats or many terraced houses.

The second market penetration scenario carries that line of thinking a little further. In the current hydrocarbon dominated fuelling scenario, diesel is used by vehicles which typically are larger and cover longer distances. This is to do with the efficiency of the diesel engine compared to its higher cost; the reduced fuel consumption when used over longer distances outweighs the often higher cost of purchase and maintenance compared to petrol. Also the driving characteristics of a diesel engine favour particularly large and heavy vehicles.

Similarly, hydrogen also benefits or lends itself to larger longer distance vehicles. This is for different reasons however. With hydrogen, the fuel tank needs to be substantially larger than a hydrocarbon fuel tank (see Appendix 1A, chapter 1). This is also true for batteries, however batteries are more readily shaped to fit into the nooks and crannies in a vehicle, so the useful space taken up inside the vehicle tends to be greater for hydrogen. This will be
easier to hide, or will make less of an impact, in a larger vehicle. Also, the longer range and higher speed of refuelling which are possible with hydrogen are a benefit to a vehicle which covers long distances. Hydrogen can be refuelled in a very similar way to petrol and diesel, taking just a few minutes for a car or a little longer for a large vehicle [4]. Batteries, on the other hand, commonly require very much extended period of time for recharging, and the extra weight of the batteries would reduce the allowable payload on most large commercial vehicles. This is explored further in chapter 4.

Therefore, in the second market penetration scenario option, hydrogen will replace existing diesel vehicles; existing petrol powered vehicles will be replaced by battery vehicles in this scenario. This means all HGVs, buses, almost all vans, and about 40% of cars will be replaced with hydrogen. This does imply that motorbikes will be replaced with batteries, although there are in fact some initiatives to develop hydrogen fuelled motorbikes [5].

The first part of the paper, however is to forecast the total number of zero emission vehicles (ZEV) that will be required, and the pace at which they will be required, in order to meet government set emission reduction targets. Once that is established, the numbers of hydrogen and battery vehicles that that produces are apportioned in accordance with the two scenarios described above.

This forecast takes account of the achievement to date in reducing overall emissions, so that new ZEVs can play an appropriate part in closing the gap. At the time this work was carried out, the Scottish and UK governments attributed a substantial reduction in emission due to negative emissions arising from change inland use. However, in 2021 the method of assessment was changed so that there are minimal negative emissions taken into consideration. If the work in this chapter were re-run now, there would be an increase in the pace of new ZEV sales required in the order of 10%.

So this paper has a Monte Carlo analysis in two parts. The first considers the total emissions from road transport, and how quickly it needs to be decreased, and hence the replacement rate of existing hydrocarbon fuel vehicles with new ZEVs. This then allows the scenario options for the pace of change of ZEV deployment and displacement of hydrocarbon powered vehicles to be set.

One scenario considered for the pace of change was to allow it to not meet the 2030 target of a 75% reduction in national emissions from 1990 levels, but to only hit the 2045 target of net zero. This does allow a significantly slower transition, although it was only examined out of interest because it was significantly contrary to government policy [6]. However, in late 2023, the UK government cancelled its target to end new hydrocarbon vehicle sales by 2030 [7]. Given that, what I've chosen to call the laid back scenario might come become more relevant after all. Provided the long term targets can actually be met, it is arguably less important that we meet the 2030 targets – although there's no room for complacency.

The other two pace of change options provided for all vehicle classes to be replaced at the same pace, and for an accelerated replacement of large vehicles such as HGVs and buses permitting a slower deployment of ZEV cars.

These three pace of change options were then combined with the market penetration options to produce six combined scenarios. This then permitted the second Monte Carlo analysis, which considered the number of each type of filling station required to support the hydrogen vehicles.
The range of outputs arising from this then contributed to estimating the total capital cost of constructing these vehicle stations. This was followed by a short analysis looking at the likely wholesale or production cost of the fuel, to create an indication of the overall cost of providing and operating infrastructure to support the use of hydrogen vehicles.

The Electronic Supplementary Information, comprising the excel model developed for the works, is available in the GitHub repository, https://github.com/J-M-Low/H-road-fuel-infrastructure

This chapter was published as a paper of the same name in Energy Policy journal in 2022, available at https://doi.org/10.1016/j.enpol.2022.113300. Some modifications have been made for clearer and more consistent presentation within this thesis, without changing any of the substance. An unedited version of the paper as published is presented in the Supplementary Appendix
Refuelling infrastructure requirements for renewable hydrogen road fuel through the energy transition

September 2022
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Abstract

Current commercially available options for decarbonisation of road transport are battery electric vehicles or hydrogen fuel cell electric vehicles. BEVs are increasingly deployed, while hydrogen is in its infancy. We examine the infrastructure necessary to support hydrogen fuelling to various degrees of market penetration. Scotland makes a good exemplar of transport transition, with a world leading Net-Zero ambition and proven pathways for generating ample renewable energy.

We identified essential elements of the new transport systems and the associated capital expenditure. We developed nine scenarios based on the pace of change and the ultimate market share of hydrogen, and constructed a model to analyse their infrastructure requirements. This is a multi-period model, incorporating Monte Carlo and Markov Chain elements.

A “no-regrets” initial action is rapid deployment of enough hydrogen infrastructure to facilitate the early years of a scenario where diesel fuel becomes replaced with hydrogen. Even in a lower demand scenario of only large and heavy goods vehicles using hydrogen, the same infrastructure would be required within a further two years. Subsequent investment in infrastructure could be considered in the light of this initial development.

Keywords

Hydrogen, Fuel Cell, Electrolyser, Fuel, Infrastructure, Emissions
2.1 Introduction

Let’s look to the situation of road transport in just thirty years. We’ll be in a world that will be both very different and very similar to today. Different, in that so much of the technology we know and use today will have vanished, replaced by newer systems that emit practically no greenhouse gasses. Similar, in that we will still need and want to move ourselves, and things, around. It seems inconceivable that we won’t be using road transport in some form or another to do that.

At present, road transport is responsible for 11.9% of global greenhouse gas emissions [8]. In order to reach the global targets for net zero greenhouse gas emissions these must be eliminated.

Until relatively recently, the default assumption among many has been that all future road transport in the UK will be electrified using batteries [1]. Furthermore, at the time of writing in 2022 a wide range of road vehicles is available as battery electric vehicles (BEV) in cars, light goods vehicles, and buses, and these are taking an increasing market share[9]. However, an alternative in the form of hydrogen is available, and awareness is increasing of this option. There have been numerous trials and developments of hydrogen as a fuel, along with expressions of support from governments. These include - but are by no means limited to – California [10], Japan [11], South Korea [12], China [13], and also the EU [14]. Specifically relevant to our study area, the Scottish [15] and UK [16] governments have both recently released hydrogen strategic plans and policies.

The infrastructure requirement and associated cost has been examined by Robinius et al, identifying competitive relative costs for hydrogen infrastructure in Germany [17]. Greene et al [18] examine the challenges of deploying hydrogen refuelling infrastructure, concluding that hydrogen has the potential to supply a major share of the world’s transportation energy demand. Whiston et al [19] elicit the views of experts in the field to consider various aspects of future hydrogen vehicle use – among other conclusions, they anticipate up to 5,000,000 hydrogen fuel cell electric vehicles (HFCEV) in China by 2040.

Here we assess the infrastructure requirements of using hydrogen for some or all road vehicle fuel. We examine needs right through the transition period to the time where essentially all road transport produces zero carbon emissions.

Geographically we limit ourselves to a case study of Scotland. However, the approach should be generally transferable to the rest of Europe and other areas of the world, provided local factors are taken into consideration. Local factors such as vehicle life, annual distance travelled per vehicle, and emissions from the production of hydrogen and generation of electricity, will all be significant.

We chose Scotland for the case study because it has an excellent track record to date of implementing emissions reduction methods in electricity generation[20]. The high current planned and potential level of renewable electricity means that we can confidently expect that enough hydrogen from water electrolysis could be produced through carbon free means.
At present approximately 96% of Scotland’s electricity is produced by carbon free means, predominantly wind or nuclear, having reduced electricity generation related greenhouse gas emissions by 89% since 2000[20]. There is now only one significant fossil fuel power station in use, the natural gas fuelled power station at Peterhead [21]. This implies that hydrogen generated from new electricity sources will be responsible for essentially zero carbon emissions when used as a fuel. If necessary, this could be backed up by locally available natural gas sources, which could be used to produce ‘blue hydrogen’ as an interim measure - albeit at less than complete, but still substantial, elimination of emissions, and potentially with significant short-term cost savings and availability benefits [22].

Scotland has a defined and challenging set of emissions targets. The neighbouring jurisdiction in England has similar targets, although not identical[23]; the potential for contamination by cross-border sales is limited. The Scottish government has adopted a series of relevant emissions related objectives [24, 6, 25]:

- 2020 electricity generation to reach the equivalent of zero emissions for domestic use;
- 2030 reduction in greenhouse gas emissions across all sectors of 75% from 1990 levels;
- 2030 new hydrocarbon car and van sales are banned (UK government requirement);
- 2045 reduction in greenhouse gas emissions across all sectors to net zero.

We do not aim to make a comprehensive study of safety issues in this paper. Refuelling stations and similar activities are well regulated in Scotland and the UK by the Health and Safety Executive [26], and safe vehicle construction is regulated by the Driver and Vehicle Standards Agency [27]. We assume for the purposes of this study that these organisations will ensure safe construction of hydrogen vehicles and fuelling facilities.

We aim to address the following questions:

- For various scenarios of the extent of hydrogen fuel used within that transition, what quantity of hydrogen would be required over the energy transition period to 2050?
- What production, distribution, compression, storage, and dispensing infrastructure will be required to deliver the hydrogen to end users?
- What will be the capital cost?
- Which scenario, or scenarios, will be most likely?

As a precursor, we will also have to consider: How will Scottish and UK government overall emissions objectives translate into road transport? And how fast should the transition to zero emission vehicles be to meet those emissions objectives?

We developed a Multi-Period model, incorporating Monte Carlo and Markov chain methods, to answer these questions; a similar approach has been taken in the forecasting of renewable electricity generation requirement [28]. Here we present the results of the subsequent analysis. We also present details of the construction of the model and the underlying assumptions. We conclude with recommendations of the optimum pathway to use hydrogen in road transport to meet the objectives, and appropriate steps to deliver it. It is important to note that we are not trying to predict what will happen; we are developing a range of options for what must happen in order to meet the objectives.
We incorporate the beneficial reuse of the existing widespread natural gas network as the most likely scenario in Scotland [29, 30], allowing an understanding of a more integrated energy system than has traditionally been in place. We also consider the pace of change required to meet the Scottish government’s targets, based on several scenarios.

We aim to contribute to the literature by assessing the size and cost of the necessary hydrogen infrastructure at a large scale in the long-term for vehicle refueling purposes. We present a simple method for assessing the required infrastructure. This should inform policy makers not only for Scotland but also further afield, subject to incorporation of local factors.

This should also inform the debate around the question of battery electricity or hydrogen, although we hold the view that there are no winners and losers in that discussion. Just as petrol (gasoline) and diesel serve largely different needs at present, there will be a need for both future fuel types (and possibly others) as the demand grows exponentially.

2.2 Methods

2.2.1 Initial assumptions

We ignore the cost of construction and operation of wind turbines and other generation equipment – we use announced contracted costs of offshore wind electricity supply, or wholesale costs of network supplied electricity, as inputs to the model where required; this figure accounts for all such construction and operation costs [31].

We assume that hydrogen is initially produced locally from electrolysis of water. This can come from grid supplied, or local dedicated, renewable electricity. We model that centrally produced green hydrogen will gradually become available over a period from a variable start (2026-2030) to finish (2040-2045), supplied through the repurposed natural gas network. This repurposing of the network is expected over that timescale in any case, to replace the existing supply of natural gas with hydrogen [32]. We assume that, over time, hydrogen supplied in this way will displace locally produced hydrogen using grid electricity where practical, and that local re-purification cost to remove, e.g., odourants from the hydrogen will be low or insignificant [33]. Green hydrogen supplied in this way is assumed to be limited to the 85% of households currently connected to gas network [34], although this value is allowed to vary in the Monte Carlo cases in the model as low as zero; the rest will stay locally produced. For this locally produced element, we model variable proportions of grid supplied or local dedicated electricity. See worksheet 19 in the model, supplied as Electronic Supplementary Information (ESI).

Initial unit costs of hydrogen fuelling stations are derived from methods presented by Tlili et al [35], along with contract information published by a large manufacturer of electrolyser [36], and sense checked in discussion with a commercial manufacturer and installer of hydrogen refuellers. We apply learning rates to the costs of hydrogen refuelling equipment [37], varied among the Monte Carlo cases in the model.

We assume that sufficient supplies of hydrogen can be made available; indeed, one key purpose of this paper is to identify how much will be required so that appropriate provision can be made. However, in the event of competition for inadequate supply, this would be reflected in the supply price. For the purposes of this work, this operating cost is insignificant.
We assume, as a starting position, that the number of vehicles in each class and mileage will remain static from levels at the time of writing. This is modelled by keeping the sales of new and scrapped vehicles equal to the number of vehicles in the class divided by the average age at disposal of the vehicle (calculated in worksheet 6 of the model, supplied as ESI). This gives a modelled sales figure lower than the actual recent sales figure, due to the size of vehicle fleet increasing in recent years for most classes of vehicle[9], so this anticipates some active management of vehicle demand. However, the Scottish Government also has a target to reduce car use by 20% by 2030 [38]. We model this as a sensitivity analysis of no change, 10% reduction, and 20% reduction in average annual distance driven by cars by 2030, and unchanging after that. In reality such a reduction might manifest as a smaller number of vehicles covering the same annual distance, or the same number covering a smaller distance, or another equivalent variation; in terms of the fuelling requirement, the focus of this paper, that would make no difference.

One possible flaw in this projection is the potential for people to keep existing hydrocarbon vehicles running for longer. This would have the effect of reducing the number of new Zero Emissions Vehicles (ZEV) sold while maintaining the number of vehicles on the road, and hence extending the time before the emissions targets are met. However, estimating the effect of this, or remedial measures, is outwith the scope of this analysis.

We use the standard vehicle classes used by the UK and Scottish governments, shown in Table 2-1 along with their numbers and selected characteristics:
### Vehicle Classes, Number in Service, Fuel Types, Fuel Consumption, and Carbon Dioxide Emissions

<table>
<thead>
<tr>
<th>Class</th>
<th>Number in Service</th>
<th>Fuel Type/s</th>
<th>Gross Annual Fuel Consumption for Fleet</th>
<th>Typical per Vehicle Emissions</th>
<th>Typical Fleet Annual Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>[t1.1]</td>
<td>[t1.1]</td>
<td>[t1.2] (Ml/yr, 2018)</td>
<td>[t1.3] (kT/yr, 2018)</td>
<td></td>
</tr>
<tr>
<td>Buses &amp; Coaches</td>
<td>14,700 (2018)</td>
<td>Typically diesel</td>
<td>147</td>
<td>818</td>
<td>27.8</td>
</tr>
<tr>
<td></td>
<td>13,100 (2021)</td>
<td></td>
<td>2,215</td>
<td>157</td>
<td>2.3</td>
</tr>
<tr>
<td>Cars</td>
<td>2,483,000 (2018)</td>
<td>Diesel 41%, Petrol 59%</td>
<td>632</td>
<td>675</td>
<td>47.5</td>
</tr>
<tr>
<td></td>
<td>2,520,000 (2021)</td>
<td>Diesel 37%, Petrol 62%, ZEV 1.2%</td>
<td>617</td>
<td>213</td>
<td>5.8</td>
</tr>
<tr>
<td>Motorcycles</td>
<td>79,500 (2018)</td>
<td>Petrol 99%, ZEV 0.9%</td>
<td>13</td>
<td>109</td>
<td>0.4</td>
</tr>
<tr>
<td></td>
<td>76,200 (2021)</td>
<td></td>
<td>2,215</td>
<td>157</td>
<td>2.3</td>
</tr>
<tr>
<td>Heavy Goods Vehicles</td>
<td>36,900 (2018)</td>
<td>Typically diesel.</td>
<td>632</td>
<td>675</td>
<td>47.5</td>
</tr>
<tr>
<td>(HGV)(^1)</td>
<td>36,300 (2021)</td>
<td></td>
<td>617</td>
<td>213</td>
<td>5.8</td>
</tr>
<tr>
<td>Light Goods Vehicles</td>
<td>294,700 (2018)</td>
<td>Diesel 96%, Petrol 3%</td>
<td>632</td>
<td>675</td>
<td>47.5</td>
</tr>
<tr>
<td>(LGV)(^2)</td>
<td>331,200 (2021)</td>
<td>Diesel 96%, Petrol 3%, ZEV 0.6%</td>
<td>617</td>
<td>213</td>
<td>5.8</td>
</tr>
</tbody>
</table>

Table 2.1 Vehicle classes, number of vehicles in service in Scotland, fuel types, fuel consumption, and Carbon Dioxide emissions for fleet and single vehicles. Where more than one fuel type is in use, the split is based on the proportions for the whole UK. Petrol includes hybrid and plug-in hybrid.

\(^1\) The vehicle classes in the UK Government statistics are termed “Goods” and “Light Goods” for commercial vehicles over and under 3,500kg respectively (other than buses and coaches). In this paper we use the less ambiguous common terms Heavy Goods Vehicle (HGV) and Light Goods Vehicle (LGV) respectively.

A list of other model input assumptions, with sources and background, is presented in Appendix 2A.

#### 2.2.2 Preliminary assessment of sector emissions targets

As a preliminary step, we examine what emissions reduction will be required in the road transport sector in Scotland. As at 2019, road transport is responsible for 20% of Scotland’s greenhouse gas emissions [40].

The key Scottish Government all-sectors targets are (i) reduction from 1990 totals by 75% by 2030, and (ii) zero net emissions by 2045 [24, 6]. There is also a recent UK Government requirement to eliminate solely hydrocarbon fuelled vehicle sales by 2030, with hybrids eliminated by 2035 [25]. We assume that all sectors’ emissions decrease at an equal proportionate rate from the present day levels to reach these overall targets, with three differences:

---

1 The vehicle classes in the UK Government statistics are termed “Goods” and “Light Goods” for commercial vehicles over and under 3,500kg respectively (other than buses and coaches). In this paper we use the less ambiguous common terms Heavy Goods Vehicle (HGV) and Light Goods Vehicle (LGV) respectively.
1. Negative emissions allocated to land use change stay at current levels; they have not changed significantly for several years [41].

2. Emissions from electricity production will reach zero before 2030. The target for this (affected by the Covid-19 pandemic) was 2020, but the exact date (before 2030) it is achieved does not affect this calculation[24].

3. Emissions due to air travel reduce by only 10% in each of these two stages. This figure is somewhat arbitrary - there are no currently available zero emissions commercial aircraft [42], but the calculation is not sensitive to variations in this value as air travel is only a small contributor to the total [41] as can be seen in worksheet 2 of the model (provided as Electronic Supplementary Information).

2.2.3 Scenarios

We based our analysis on a series of transition scenarios. These combine three pace of transition options and three fuel choice options, as follows:

Pace options.

We project the annual change in zero emissions vehicles (ZEV) in each vehicle class using standard logistics functions creating typical ‘S’ curves. The logistic function takes the form

\[ f(x) = \frac{L}{1+\exp(-k(x-x_0))} \]  

Equation 1 [43]

Where L is the target value (discussed below)

k is the gradient function, typically in the range 0.5-1.0.

x is the year (or other period) under consideration

xo is the mid-point year of the time series under consideration.

The first logistic function used represents new ZEV sales rising to meet the existing level of sales of all vehicles. The constant L here represents the number of sales of all vehicles. Where a class of vehicle has a mandatory date in legislation for ending hydrocarbon vehicle sales, the number of sales is forced to the full value of new vehicle sales (L) by the end of that year rather than allowing the function to produce a natural taper.

The second logistics function represents the future scrapping of ZEVs based on the typical average lifespan of vehicles in each class. Again it rises to meet the existing level of sales (required to keep total numbers constant). In this case, L represents the total number of vehicles scrapped in an average year. Clearly, for the case where the total number of vehicles remains constant, the two values of L will be equal.

As total numbers of vehicles and total annual sales are held constant, the annual change in number of ZEVs and hydrocarbon vehicle (HCV) sales is then in a matter of simple arithmetic.

In an iterative process, the constants k and xo, which control the two logistic functions, are varied manually (the same constants are used for both functions, within each scenario) until the emissions in use meet the objectives (see section 2.2.5).
The pace options used are -

- **Equal Pace** – all vehicle classes transition at an equal pace. That is, the logistic functions for all classes have the same initial midpoint and gradient.
- **Accelerate Bus & Truck** – Larger vehicles (Buses & Coaches and HGVs) transition faster than Equal Pace. Cars, LGVs and motorcycles are allowed to transition slightly more slowly, provided the targets are met.
- **Laid Back** – all vehicles transition at an equal pace, but the 2030 intermediate targets are not met, only the ultimate 2045 net-zero one. This would still be a viable transition route if there became more scope to decarbonise other sectors faster.

**Fuel choice options.**

These represent the share of zero carbon fuels between hydrogen and other fuels in the future.

- **Large Vehicles Only** – all vehicles in the classes Buses & Coaches and HGVs are HFCEV. Other vehicles use other means of decarbonisation.
- **Like for Like** – There is a view that hydrogen is more suitable for longer range and larger vehicles, especially with restricted maximum weight, due to the high volume, light weight, and fast refuelling times [44]. Similarly, large and long distance vehicles favour diesel at present, albeit for other reasons. So this scenario has current diesel fuel vehicles replaced with HFCEVs, and current petrol vehicles replaced by BEVs. This means that all Buses & Coaches and HGVs, and 41% of cars and 97% of LGVs, will be hydrogen fuelled [9].
- **100% hydrogen.** This replaces all hydrocarbon fuelled vehicles with hydrogen fuel cell vehicles.

These Pace and Fuel Choice options combine to give nine Transition Scenarios for evaluation, within which we examine the vehicle classes shown in table 2-1.

**2.2.4 General approach for analysis**

For each Transition Scenario, we took the following steps, analysed over the period 2021 to 2050. The overall investigation is based on a Multi-Period model which we constructed using Microsoft Excel. The model incorporates a Monte Carlo analysis of 1000 randomly generated cases to test the effects of varying unknown and forecast quantities, and a Markov Chain projection of future hydrocarbon vehicle emissions.

We use the model to:

1. Identify annual change in numbers, and total numbers, of ZEVs required to meet the emissions targets. This means that in all scenarios, the targets relevant to that transition scenario will be met or bettered, with a +5% allowed variance.
2. Identify demand for hydrogen as a fuel to supply these ZEVs to the relevant proportion.
3. Identify the fuelling and related infrastructure required to deliver that quantity of hydrogen. Infrastructure here refers to equipment specifically needed for storing and dispensing fuel, upgraded or new distribution systems, and local or central production.
4. Identify capital costs of providing the infrastructure.

These steps are also shown in Figure 2-1 (section 2.2.8).
2.2.5 Approach for Emissions calculations

First we examined the constraints on future HC vehicle emissions, based on current EU and UK legislation, and existing vehicle fleet emissions as set out in Table 2-1. We used a Markov chain assessment (meaning that each value generated in a series is affected by the previous value generated) to create future emissions. Over several time steps, we generated a random level of emissions for new vehicles. This random level was constrained to (i) not exceed the anticipated legislative constraints and (ii) not to exceed the previous time step value. The effect is to produce randomised, but downwards trending, average new vehicle emissions. This method was carried out for each vehicle class independently, and different random values were generated for each of the Monte Carlo cases described in section 2.2.4.

Next, we took the number of new hydrocarbon vehicles in each class for each year of the model and multiplied by the new vehicle emissions.

Then we removed the number of scrapped HC vehicles in each class, multiplied by the previous year’s average emissions in class.

This allowed us to arrive at a total figure for each year’s class emissions from HC vehicles, and the new class average per vehicle emissions.

In an iterative process, the constants in the logistic functions generating the numbers of new ZEVs were manipulated until the total emissions for the scenario reached the targets. This was done such that no random Monte Carlo case produced emissions exceeding the target by more than 5%. This process allows us to generate the required number of ZEVs of each class in use each year.

Due to the large amount of renewable electricity available now or imminently, emissions from ZEVs in use are taken as zero. Emissions in vehicle manufacturing are outwith the scope of this study.

We also limit this study to greenhouse gas emissions from fuel use. Particulate emissions from fuel use and non-fuel sources are also outwith the scope of the study.

2.2.6 Computation of Hydrogen Refuelling Station numbers

We split the Monte Carlo cases into three sections of 330 for each of the three fuel choice options. These defined the proportions of ZEV in each vehicle class using hydrogen for each year, which then produces the actual numbers of vehicles when combined with the total number of ZEVs found in section 2.2.5.

The number of hydrogen fuelled vehicles is then used to calculate the total demand for hydrogen fuel each year.
Three Hydrogen Refuelling Station (HRS) sizes were defined, based on the sizes of typical existing hydrocarbon stations in use today. The proportion of fuel supplied by each size of HRS was taken as fixed at the proportion supplied at present by the corresponding sizes of petrol / diesel station (see worksheet 18 in the model, supplied as ESI).

The proportion of each station’s capacity that would be actually used on an annual average was given a central value of 71%, after Robinius et al [17]. This was allowed to vary randomly in each case, constrained between 61% and 81%.

By combining these with the gross hydrogen demand for each year, the required gross capacity of each HRS size could be readily calculated. Dividing this by the capacity of the HRS, and rounding up to the next integer, gives the aggregate numbers of HRS of each size required in each year. Finding the numbers of new HRS required each year is then a matter of simple arithmetic.

### 2.2.7 Calculation of costs

For the calculation of costs, we identify two types of HRS: Those which produce hydrogen in-situ with renewable electricity, and those which use hydrogen taken from the re-purposed natural gas network. The in-situ producing HRS are subdivided into those which use electricity from the electricity grid, and those which have a direct, dedicated connection to a local source of renewable electricity.

The Monte Carlo cases have random allocations of the following variables (introduced in section 2.2.1) related to the type of HRS:

- The start and finish dates of the conversion of the natural gas network to hydrogen.
- The maximum proportion of network supplied HRS, reached at the end date of the network conversion through typical logistic function (‘S’ curve).
- The proportions of in-situ producing HRS which use a dedicated connection to a renewable electricity source or a connection to the electricity grid.

For each case, the numbers of HRS of each type are computed. The capital cost associated with each type is found by combining the initial cost and the learning rate, described in section 2.2.1. The capital cost of the electrolyser capacity required to produce the hydrogen distributed through the network is assessed separately, in a similar way.
2.2.8 Modelling tool

The model is outlined as follows:

Figure 2-1 Schematic of model created to analyse required fuel infrastructure and emissions to meet emissions targets.

N.B. Worksheet numbers refer to the worksheets within the model. Worksheets 1-10 set out input information and carry out preliminary calculations; 13 is an input data summary page; un-numbered pages beyond 25 hold combined outputs from running multi-scenario macros.

The model input values, assumptions and sources are presented in Appendix 2A.

The calculations used are detailed in Appendix 2B.

A reviewable version of the model as used, including all worksheets referred to in Figure 2-1 and elsewhere in this paper, is presented as Electronic Supplementary Information.
2.3 Results

2.3.1 Preliminary assessment of emissions targets

The key Scottish Government all-sectors targets are a reduction in emissions from 1990 totals to 75% by 2030, and net zero by 2045 [24, 6]. There is also a UK government requirement to eliminate solely hydrocarbon fuelled vehicle sales by 2030.

Projecting the emissions data gives target residual road transport emissions of 5,586 and 1,185 kt yr CO$_2$ equivalent by 2030 and 2045 respectively, or a required reduction from 2018 levels of approximately 45% by 2030 and 88% by 2045. These are the emissions targets that we work to in this project (model worksheet 2).

Figure 2-2 shows these targets in the context of the recent emissions records and the primary energy related emissions sources.

Figure 2-2: Scottish emissions targets, showing overall government targets, road transport estimated target for 2030, and energy related emissions history and required trajectories to achieve ultimate net zero target. Non-energy emissions not shown but accounted for in the net-zero calculated end points. Historic data from Scottish Government Climate Statistics [41].

2.3.2 Pace of transition

The Pace of Transition question depends on how quickly end-of-life hydrocarbon vehicles can be replaced with ZEVs rather than new HCVs. This is independent of whether the ZEVs are HFCEVs or something else (e.g. BEV). Figure 2-3 and illustrate the rate of increase of new ZEV sales required to meet the targets, and their effect on greenhouse gas emissions.
We see that the *Accelerate Bus & Truck* options require a smaller number of total ZEVs than *Equal Pace* in the early years, while meeting the same targets. This means that the *Accelerate Bus & Truck* scenarios might be easier to implement, due to reduced demand on manufacturers. Also, given that large vehicles are typically owned in fleets, fewer decision makers will need to be influenced. However, smaller vehicle transition will still be required at a good pace and cannot be ignored. The *Laid Back* scenario allows a significantly slower transition in all vehicles. This is illustrated in Figure 2-3.

Figure 2-4 shows the range of emission profiles arising from these pace options. This shows that meeting the demanding 2030 objectives should lead to a considerable overshoot of the 2045 objective – this could create some headroom in other harder to decarbonise
sectors. Conversely, the Laid Back scenario emissions shows that even if it proves impossible to meet the interim targets for road transport, meeting the ultimate 2045 target should be much more achievable. This would still not prevent the overall objectives for 2030 from being met, if sufficient early gains could be made in other sectors.

For each scenario, it can be seen that the variation in emissions between Monte Carlo cases is small – this means that variation in the forecast future level of per-vehicle emissions is much less significant than the pace of removing hydrocarbon fuelled vehicles altogether.

2.3.3 Quantity of hydrogen required

By forecasting the energy demand for the numbers of HFCEVs identified, we modelled the quantity of hydrogen fuel required for each of the transition scenarios. This is found from the energy provided by liquid fuels to the hydrocarbon vehicles removed from the road, adjusted to account for the different levels of efficiency. The results of this assessment are presented in figure 2-5.

Figure 2-5 illustrates the quantity of hydrogen fuel required, expressed in terms of the energy value of the hydrogen. The ultimate requirement is also shown in terms of mass. This allows comparison with the decreasing energy value of hydrocarbon fuel used, also illustrated. The hydrocarbon Like for Like line is equivalent to the hydrogen Like for Like line – the hydrogen one is lower due to the improved efficiency of a hydrogen fuel cell vehicle compared to an internal combustion engine, reducing the total quantity of input energy required. For simplicity, figure 2-5 only shows the hydrogen demand for the Equal Pace and Accelerate Bus and Truck pace options (indistinguishable in this graph) for the 100% Hydrogen and Like for Like demand options. The Large Vehicles Only demand option also shows the Laid Back option. As can be seen, the Laid Back pace results in meeting the same
ultimate demand, but not until around 2050; the same holds for all other fuel choice options (not illustrated).

Figure 2-5 also shows the quantity of hydrogen required in terms of weight as kilotonnes per year; this is only illustrated for Like for Like / Equal Pace options.

2.3.4 Infrastructure requirement for refuelling

Existing fuelling stations hydrocarbon were categorised as “company owned”, “dealer owned”, and “hypermarket” in a 2012 study carried out for the UK Government [45]. These titles refer to the ownership of the fuelling stations; they are in effect Medium, Small and Large respectively. By extrapolating the numbers from the 2012 survey in proportion to the overall UK numbers today (based on correspondence with the UK Petrol Retailers’ Association, unpublished but available on request from the authors), along with UK government statistics on fuel sales [39], we arrived at the numbers of stations and average fuel volumes shown in Table 2-2.

<table>
<thead>
<tr>
<th>Number of stations</th>
<th>Average hydrocarbon volume dispensed</th>
<th>Efficiency adjusted Hydrogen equivalent</th>
<th>Rounded size used</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nr.</td>
<td>%</td>
<td>Ml / yr</td>
<td>kg/day</td>
</tr>
<tr>
<td>Company Owned</td>
<td>171</td>
<td>20%</td>
<td>5.5</td>
</tr>
<tr>
<td>Dealer Owned</td>
<td>546</td>
<td>63%</td>
<td>2.0</td>
</tr>
<tr>
<td>Hypermarket</td>
<td>861</td>
<td>17%</td>
<td>11.0</td>
</tr>
</tbody>
</table>

We then calculate equivalent quantity of hydrogen to provide the same useful energy as these three filling station sizes. This takes account of the improved efficiency of the fuel cell over internal combustion engines, and uses the lower heating value of hydrogen [46]. These values are then rounded to provide useful sizes for small, medium and large hydrogen fuelling stations. These results are also shown in Table 2-2. See worksheet 18 in the model for calculation.

We assume that the numbers of each size of fuelling station will be in the same proportion as the numbers of each size of hydrocarbon filling station at present.
Carrying out the process described in section 2.2.6 yields 330 possible out-turns for each of our transition scenarios. Figure 2-6 shows the maximum, minimum and mean total HRS numbers for the pace options Equal Pace and Accelerate Bus & Truck, with the fuel options of Like For Like and Large Vehicles Only. Other scenario options are presented in worksheet 25 of the model.

Figure 2-6 Numbers of hydrogen refuelling stations for selected scenarios.
Unlike for Like and Large Vehicles Only fuel options, with Equal Pace and Accelerate Bus & Truck pace options. Maximum and minimum cost cases are presented, along with the case derived from the core estimated model inputs.

We can see from Figure 2-6 that there is only a little variation between Accelerate Bus & Truck and Equal Pace in the Like For Like option, with a more pronounced variation in the early stages of the Large Vehicles Only option. This is perhaps unsurprising.

It’s also clear from Figure 2-6 that numbers of HRS required in the Like For Like options doesn’t exceed the ultimate likely minimum of the Large Vehicles Only options until around 2030. This has implications about the confidence of investing in, or supporting, the early stage development of HRS. We explore this further in section 2.5.

2.3.5 Annual investment

Following on from that, we can estimate the annual investment required, as described in section 2.2.7. This is illustrated for the Equal Pace option only in Figure 2-7, for the three fuel choice options. The Accelerate Bus & Truck pace option is essentially identical to this.
Figure 2-7 Capital expenditure required for hydrogen, showing all scenarios with the Equal Pace option. Solid lines represent the outputs from the core values used in the Monte Carlo input cases. Vertical bubbled lines represent the range of outputs from the Monte Carlo analysis. Approximate range of annual expenditure on capital upgrades to hydrocarbon infrastructure renewals is also shown as the grey lines.

The Laid Back cases, not displayed, require a similar total expenditure, but skewed significantly to the later years as might be expected.

Figure 2-7 also shows the estimated annual value of capital refurbishment and upgrade for hydrocarbon filling stations. Clearly this is approximated in a very wide range, but we can see that it is comparable in magnitude to the costs of establishing new HRS, which would all be required by 2045. The main curves in figure 2-7 relate only to the costs of establishing new HRS, not to the ongoing expenditure associated with maintaining or renewing them as they age – that would of course continue indefinitely beyond 2045/50.

The potential range of investment required suggested by the Monte Carlo analysis in the model is also shown here. A significant source of variability, especially in the later years, is the question of what proportion of fuelling stations are supplied from the gas grid, compared to using local generation – grid connected stations being considerably cheaper since they don’t require their own electrolyser. The other main source of variability is the usage rate of the fuelling stations; as would be expected, if fuelling stations are used more intensively, fewer are required.
2.4 Sensitivity analysis

We carried out this analysis on the basis that vehicle use would stay the same. However, the Scottish Government has a further target to reduce car use by 20% by 2030. We carried out a sensitivity analysis, considering the effect of a 10% or 20% reduction in car use by 2030 with use remaining constant beyond that date. We modelled this by keeping the vehicle numbers constant, but reducing the average annual distance covered.

This meant that for each of the Pace options, the constants in the logistic were revised so that the same emissions targets were met.

In the Equal Pace options, this also reduces the pace of conversion to ZEV of other vehicle classes; with all vehicles converting at the same pace, all see the benefit of the reduced car emissions. Thus, even for the Large Vehicles Only fuel choice options, there is a short term reduction in the numbers of fuelling stations required. However, the Accelerate Bus and Truck pace options have buses and HGVs on a different path from smaller vehicles. Here, motorcycles and LGVs share a reduced pace of decarbonisation, but buses and HGVs are unchanged. This way the Large Vehicles Only fuel choice options show no change in infrastructure requirement from the base case. The Laid Back option was not considered in this sensitivity analysis.

The outputs from this analysis are combined in Figure 2-8.

![Combined sensitivities chart](image)

**Figure 2-8** Hydrogen fuelling stations required by year.

This combined chart shows the extremes found from the base case and 20% car use reduction, Equal Pace and Accelerate Bus and Truck pace options, for the Like for Like and Large Vehicles Only fuel choice options. It also shows the mean numbers for both base case and 20% car use reduction, in the Equal Pace options.

The maximum numbers of hydrogen refuelling stations are found from the unreduced car use, in the Accelerate Bus & Truck pace option in both Like for Like and Large Vehicles Only fuel choice options. The minimum numbers are found from the reduced car use and Equal Pace option for both fuel choice options. This is as expected. For comparison, Figure 2-8 also shows the mean number of HRS required for both unreduced and 20% reduced car use.
The effect of a 10% reduction lies between the 20% reduction and no change, as expected. However, as the 20% reduction has only a limited impact on our conclusions and recommendations, we have not considered further the effect of a 10% reduction.

2.5 Discussion

2.5.1 In the Future

We can envisage the future zero emissions road transport system. In this future transport world, all vehicles will be zero greenhouse emissions at the point-of-use. The technology required to do this has existed from the early transition, and all new vehicle sales will have been zero emissions from 2030 for smaller vehicles and approximately 2035 for larger vehicles [25]. The technology exists today to deliver a zero carbon road transport system for Scotland, at an achievable financial cost, and hydrogen should play a substantial role in that.

There will always be a need for a choice of fuel types; different fuels serve different purposes. Much as the pre-transition road fuel system uses both petrol and diesel for different, but overlapping, purposes, so we can expect that both battery electricity and hydrogen will be used for different purposes. Quite possibly other fuels that are not available in the early stages of the transition will become viable as well.

As a fuel, the important characteristics of hydrogen for users are: lower weight (similar to existing hydrocarbon systems), fast refuelling time (a few minutes), long range readily achievable, and fuel cost competitive with electricity when made at scale (worksheet 4 in the model, supplied as ESI). Conversely, internal space is more compromised by the large volume the fuel tank requires, and for some users overnight recharging could be convenient [47, 48]. All of this means that, just like diesel in the present day, hydrogen will lend itself predominantly to larger and longer distance vehicles. No one type of fuel is likely to become universal.

So what proportion of vehicles will be fuelled by hydrogen? It seems likely that essentially all buses and coaches and HGVs will be hydrogen fuelled (this paper’s Large Vehicles Only option). It also seems likely that some car and van owners will choose hydrogen fuelled vehicles – it is quite conceivable that all pre-transition diesel vehicles will be replaced with hydrogen (this paper’s Like For Like option).

This future fleet of hydrogen vehicles will be supported by a network of around 300 (Large Vehicles Only) to 820 (Like For Like) hydrogen refuelling stations of various sizes (see Figure 2-6). The majority of these HRS will be supplied with hydrogen generated from offshore wind electricity. This forms part of the Scottish government’s programme of developing renewable hydrogen production, for use domestically and for export, from North Sea wind, announced in 2020 [15]. This hydrogen will be supplied through the national gas network, which will be converted over a period from the late 2020s to the early 2040s, from its original purpose of distributing natural gas [32]. At the upper end of this scale, the number of HRS would be similar to the number of petrol & diesel fuelling stations currently in service (861 - model worksheet 18); this suggests that the ultimate spacing between them could be similar to that at present, with provision available in more remote areas. Of
course, the HRS fuelling industry might develop into a smaller number of larger stations, or vice versa – which could have an impact on the service provision in rural areas.

Those hydrogen refuelling stations which couldn’t be sited with a connection to the hydrogen gas network will probably use their own dedicated renewable electricity supply - most likely wind turbines - to produce their own hydrogen in-situ. This approach will be widespread in the early days of the transition before the gas grid is fully converted to hydrogen. The production cost of the fuel is likely to be broadly similar (model worksheet 4), so there won’t be a significant commercial disadvantage in one supply method or the other – other than the risk of the local electricity source not producing for some time. So, just like the early hydrogen refuelling stations, these future non-grid hydrogen filling stations will require a backup supply in the event that their own electricity supply is inactive for too long. This is likely to be in one of three forms: a connection to the electricity grid, but this tends to be very expensive in actual use, adding around 80% to the wholesale fuel cost; a larger on-site storage facility than would normally be required; or a supply delivered by road using a tube trailer (a specialised tanker).

An alternative scenario could be around the use of several hydrogen hubs as production and distribution centres. This is considered in the Scottish Government’s recent consultation on hydrogen [49], but analysis of this option is outwith the scope of this paper.

2.5.2 Present day

Let's now consider what has to be done in the short term in order to permit that future to unfold. Primarily, enough hydrogen refuelling stations of sufficient capacity need to be constructed to allow the use of hydrogen fuel vehicles up and down the country. The problem being that we don’t know how many to build, or where. Key questions about the future are presently unanswerable with accuracy: Will all vehicle classes transition at the same rate (this papers Equal Pace option)? Or might it be possible to encourage larger vehicles to transition to hydrogen faster, giving more carbon dioxide reduction per vehicle replaced (this paper’s Accelerate Bus and Truck option)? Or even, might a more relaxed transition take place, missing out the Scottish government 2030 75% emissions reduction target (Laid Back option)? For planning purposes we should assume that the 2030 target will be met. This also means that the 2045 transport target compatible with overall net zero will almost certainly be comfortably exceeded.

For the early stage activities, it would be ideal if we could identify a way which minimises the risk of over-construction, while offering the maximum appropriate support for hydrogen fuelled vehicles. Fortunately there is enough overlap in the requirements to facilitate this - the ultimate number of hydrogen refuelling stations required for the smallest out-turn of the Large Vehicles Only option will still provide enough capacity for the first 8-10 years of the Like For Like option, as in Figure 2-6. Conversely, following the highest predicted demand for the Like For Like scenario up to 2025 would provide enough capacity for any likely out-turn in that time, and would not be wasted if the Large Vehicles Only option transpired.
In section 2.4, we considered the implication of a reduction in car use of 20% by 2030, a policy goal of the Scottish Government. If this came about, the above balance of requirements would only change to the extent that the minimum ultimate requirement for \textit{Large Vehicles Only} would provide enough for the \textit{Like for Like} fuel option for 8-12 years; planning for such provision then would still not be wasted.

Putting actual numbers to this, then, shows that a sensible initial program to 2025 should consist of 9 large fuelling stations, 11 medium, and 36 small ones to service a total demand of 71,500 kg/day (26 kT/year) by 2025. These will most likely use hydrogen produced locally. The best option for local production would be to bypass the national electricity grid and use dedicated wind turbines, or a specific offtake agreement with nearby wind farms. This would influence the location of the filling stations.

If our Accelerate Bus And Truck - Like For Like scenario holds good, then this capacity could be required by 2025. If the reduced demand, and initially slower, scenario Equal Pace - Large Vehicles Only is the out-turn, then this capacity would be required by 2028. A reduction in car use of 20% by 2030 would extend this later date by less than one year. This initial construction programme can be expected to cost in the region of £140M. This compares very favourably to Scottish Power’s forecast costs for electrification of road transport, even excluding the substantial electricity grid reinforcement costs [1]. Alongside this, though, the existing program of EV charger rollout should continue for some time - for the future envisaged here, there will be a need for a large capacity to charge battery electric vehicles as well.

There is always a risk associated with setting up this type of new infrastructure. Without extensive existing users, an operator may not be confident of being able to sell enough hydrogen to cover their costs. But without enough infrastructure, people and companies are not likely to buy new hydrogen vehicles to create the demand. To resolve this chicken-and-egg situation fast enough to meet the emissions targets will likely require some market stimulation or support to enable initial progress.

However, the annual costs involved are comparable in magnitude to the current expenditure on hydrocarbon refuelling refurbishments. Hydrogen is very important to the fuelling industry due to the substantially different requirement of electric charging, and the way hydrogen refuelling is carried out in a similar manner to liquid hydrocarbons at present – taking just a few minutes at a pump – which means that the future business model will be similar to the present day. This means that the a substantial part of the costs might be reasonably borne by the industry; some underwriting of risk may be all that is necessary in terms of government support. This view was shared by a director of a large UK refuelling company in an informal discussion.

Availability, as in manufacturing capacity, of vehicles and infrastructure will be critical. ZEV HGVs have only recently been introduced as BEVs [50]. HFCEV HGVs are expected by 2023 and are already available in some markets, e.g. Switzerland, where a partnership between a vehicle manufacturer and a refuelling operator has helped to pave the way [51]. HFCEV cars are slowly becoming available [52-55] and can reasonably be expected to become more popular once the fuelling infrastructure is in place to make their use practical.
2.5.3 The Transition Phase

We can turn our thoughts to what will happen between this initial phase of investment and the longer-term. We can expect the number of hydrogen vehicles to increase enormously over that period 2025 to 2045 in the case of our Like For Like scenarios; so the number of hydrogen refuelling stations required would increase as well.

The ultimate number of hydrogen refuelling stations of the sizes we have considered could be around 820, somewhat fewer than the 860 petrol and diesel refuelling stations in service today, reflecting the fact that a substantial part of the vehicle refuelling load would be taken by charging of battery vehicles. The potential reduction in car use by 20% would reduce this ultimate number to around 760. The effects of this, though, would be seen more clearly after some years, by which time market forces and other effects should be better understood.

If the out-turn were Large Vehicles Only - and the position between these two scenarios would be subject to market forces driven both by fuel costs and user preference - there would be a need for around 300 hydrogen refuelling stations (possibly fewer but larger, since almost all of the relevant demand would come from larger vehicles). Over this period we can also expect the existing natural gas network to become fully converted to supply hydrogen produced at a centralised location. We therefore anticipate that new hydrogen refuelling stations would use this as a source of hydrogen, where a network connection can practically be made.

In the earlier part of this period, we can anticipate that the cost of installing and operating the infrastructure, along with vehicles, should reduce enough to permit any market stimulation to be withdrawn. We also expect that the extent of renewable electricity available offshore will increase dramatically in line with, or exceeding, the Scottish government announced targets [15]. However, the total renewable electricity requirement for hydrogen generation (at around 73% of road transport energy requirement) could ultimately be provided by a windfarm/s supplying around 18 TWh per year (calculated in model, worksheet 19).

For context, Scotland’s 2020 renewable energy generation was around 39 TWh (of which onshore wind electricity 19.5 TWh, and offshore wind 3.5 TWh with the balance being solar, hydro-electricity, heat and biofuels), compared with an all sector energy demand of 155 TWh [19]. Consented further offshore wind generation represents around 22 TWh per year [56]. A contribution might also be drawn from curtailed wind generation; in 2019, 1.9 TWh of potential wind powered electricity generation was curtailed in Scotland [57]. In addition, the January 2022 Scottish offshore wind electricity leasing round indicates a further 25 GW capacity is expected to be delivered indue course [58], which should provide over 100 TWh per year of additional renewable electricity.

In December 2020 the Scottish Government announced its hydrogen strategy [15], which includes the production of 5 GW equivalent of hydrogen by 2030 and 25 GW by 2045 for a range of uses including export. These are well in excess of the requirements we forecast for road transport, which are equivalent to approximately 1 GW in 2030 and around 2.5 GW in 2045 (based on a Like for Like fuel demand option).
At current fuel and energy prices and tax rates, hydrogen at a large scale should be cheaper to the consumer than petrol or diesel however it is produced; if grid electricity is avoided, it should be also be cheaper than electricity for batteries (Model worksheet 4; although note that because of the volatility in energy and fuel prices at the time of writing, this indicates relative position better than actual values). The question of how to equitably charge customers supplied by different routes – that is, network and non-network gas, and local dedicated or grid supplied electricity – will have to be addressed as a policy decision. This may be tied into taxation – in the long run, governments will undoubtedly seek to replace some of the lost fuel duty currently paid though hydrocarbon fuel sales.

Overall, the key constraints are more likely to be the availability of vehicles, fuelling equipment and hydrogen generation. We see the practical delivery of these in the in the required timescale as a bigger hurdle than the cost or the development of new technology.

We think the emissions targets are achievable, but they are also extremely challenging. This a very big undertaking, and time is of the essence.

2.6 Conclusion and Policy Implications

Our aim in this analysis was to estimate what extent of fuelling infrastructure, and associated costs, would be required to support the use of hydrogen as a fuel for road. We did this primarily using a Multi-Period model, incorporating Monte Carlo and Markov Chain components, which we constructed for the purpose using Microsoft Excel.

Our key findings were that (i) the most probable scenario meeting the targets is Equal Pace – Like for Like, and (ii) that providing an initial seed network for this scenario would still be well within the needs of the likely minimum out-turn, the Large Vehicles Only option.

This most likely scenario means anticipating that (i) all vehicles will transition to zero emissions vehicles at a similar pace, and (ii) existing diesel vehicles will be replaced with HFCEVs, and petrol vehicles will be replaced with BEVs or other technology. Because larger vehicles use proportionately more energy, this would mean ultimately around 73% of fuel energy being transported as hydrogen.

The infrastructure to supply this in the first 5 years would be around 9 large scale (5,700 kg/day) hydrogen fuelling stations, 11 medium sized (2,850 kg/day) ones, and around 36 smaller ones (1,000 kg/day). However, if the Large Vehicles Only option transpired, as an effective minimum likely out-turn, the same infrastructure would still be required within 7-8 years. This infrastructure would cost around £140 million, which compares very favourably to the cost of electrification for battery electric vehicles.

Ultimate numbers for the Like For Like option could reach around 820 hydrogen fuelling points of various sizes; significantly fewer would be required under Large Vehicles Only at about 300. These would cost around £740M and £320M respectively, expressed as NPV to 2050 at 6%, or £2.1bn & £670M as a simple aggregate. Annual expenditure would peak at around £100M/year between 2028 -2038 for Like for Like, or around £40M for Large Vehicles Only. The cost of providing for alternative zero emissions fuels to fill the gap between these scenarios would be likely to be substantially higher than the apparent saving in hydrogen infrastructure, based on the costs set out by Scottish Power [1].

It may become possible to accelerate the deployment of larger vehicles, that is buses and HGVs, as in our Accelerated Bus & Truck pace option. This would have advantages in
reducing the number of zero emissions vehicles required in the short term; the early years’ expenditure on refuelling infrastructure would be slightly higher (up to 5% extra). However, this may not be achievable over the next few years due to the different development stages of the vehicle types.

We propose that this initial programme of hydrogen refuelling locations and charging points should be pushed forward as a seed and development network, as a matter of some urgency. This should, however, add to rather than replace the ongoing programme of expanding the network of battery electric vehicle chargers. It also seems likely that the vehicle fuelling industry should be able to fund a large part of the hydrogen infrastructure within the existing pace of commercial investment.

Shorter term market stimulation for hydrogen fuelling systems, vehicle sales and/or fuel costs might be required, until commercial risks and costs reduce to a level similar to current fuel systems. Vehicle and fuel costs are anticipated to reach this level by around 2025 [59, 60]. A policy of ongoing support might be needed in areas obliged to use more expensive technology.

We also recommend developing a partnering strategy, involving government, academia, vehicle manufacturers, energy and fuelling companies, and others, as soon as possible to push this forward as efficiently and as quickly as possible, if these challenging targets are to be met. This could be developed into a permanent centre of excellence, supporting the development of Scotland’s related industry to take advantage of the currently underdeveloped global supply chain.

2.7 Acknowledgements

We acknowledge with thanks help from the following:

Ray Blake and Phil Monger of the Petrol Retailers’ Association, in obtaining a range of information from their members that would not otherwise have been readily available.

Tom Biggart of Motor Fuels Group, for an open discussion and specific information about the vehicle fuelling industry and expectations about hydrogen as a fuel.

Dr Wei Sun of the School of Engineering at the University of Edinburgh, for suggestions about the general direction of the paper.

2.8 Conflicts of Interest

There are no conflicts to declare

2.9 Funding

JML is partly funded by the University of Edinburgh.

RSH is funded by EPSRC UKCCSRC 2017 EP/P026214/1 and HyStorPor P/S027815/1, and Scottish Gas Networks Academic Alliance H100 project from Ofgem.

JM-C was part-funded by SGN under the Ofgem Gas Network Innovation Allowance fund. For more information: https://www.smarternetworks.org/project/nia_sgn0105.
3 Case Study: Scottish Borders Council

This case study considers the location and demand of a refuelling hydrogen refuelling station, or stations, in the Scottish Borders Council (SBC) area. This is primarily for the council’s own vehicle fleet, but also considers the additional use of hydrogen to feed into the natural gas network. This work was carried out in conjunction with Scottish Borders Council and a wider look at renewable energy.

Scottish Borders Council is in the process of deciding on their plan for decarbonisation, both of their own energy use and the areas which they can support the broader energy transition.

For the transport aspect of this, the initial consideration was what would be needed to support the replacement of appropriate vehicles from Scottish Borders Council’s vehicle fleet with hydrogen fuelled vehicles. The council has already replaced some of its cars with BEVs, but they acknowledge that as the vehicle size increases the difficulty of using batteries will also increase. This ties in with the “like for like” market penetration option described in chapter 2, that larger and longer distance vehicles – typically diesel fuelled at present - are more appropriately replaced with a hydrogen fuel cell vehicle. This also ties in with views expressed by some manufacturers, for example Toyota (see ).

This is a high level assessment based on the gross quantity of diesel fuel actually used, because detailed data of vehicle type and use was not readily available. Within the council, this includes specialised vehicles such as those for construction and road maintenance, vans, minibuses, cars, refuse collection vehicles, and others. From the quantity of diesel used the capacity of refilling station that would be required could be identified, on an energy replacement basis, adjusted for efficiency.

The council covers a large rural area and it might ultimately prove appropriate to have more than one refuelling point, although this was not explored as it would require more details of, and possibly modification to, fleet operating practice. The expectation was also that this would use land already belonging to the local authority, so land costs were ignored for the purpose of this assessment.

The geography of the area was assessed, and one possible approximate location for the refuelling point was identified. The council area can be somewhat challenging because the topography and the location of key destinations means that major roads run approximately northwest to southeast. The connecting roads from approximately southwest to northeast are generally fewer and lower quality. This can be seen in . There are no cities in the council area; the two largest towns, Hawick and Galashiels, have populations of approximately 14,000 and 13,000 respectively. All other towns have below 10,000 population.

The second part of this study was to consider the potential use of hydrogen as a natural gas substitute. In this case the analysis considered the quantity that would be required to displace the natural gas currently used in the local authority area, first just in public sector activities, and second including for domestic, commercial and industrial use. This was based on two scenarios: the displacement of 20% by volume of natural gas, which represents about 6% of the energy content, and ultimately the replacement of all natural gas with hydrogen. In both of these cases the displacement is on the basis of energy available, so the energy currently supplied by natural gas is replaced by the same energy supplied by hydrogen.
The following part of this chapter formed part of the report submitted to Scottish Borders Council in July 2022. The full report was published as: Zhou, Y., Low, J., Lyden, A., Essayeh, C., Sun, W., Friedrich, D. and Morstyn, T. 2023. Assessment of options for a smart, resilient and low-carbon multi-vector energy system in the Scottish Borders. The role of energy networks in smart local energy systems. EnergyREV, University of Strathclyde Publishing.; the other parts other aspects of this report, carried out by others, considered various aspects of electrification of microgrids.
Hydrogen options - Scottish Borders Council

3.1 Description
Hydrogen has been talked about as the “Fuel of the Future” since at least the 1970s; most of the basic principles of the technology have been well established. In the 21\textsuperscript{st} century requirement to remove carbon dioxide emissions, hydrogen has the potential to be used in a number of ways – any one of which could be useful to Scottish Borders Council:

- As a vehicle (or railway engine, etc) fuel though a fuel cell. The fuel cell uses the reaction between hydrogen and oxygen to produce electricity, with the waste product being water\[1\].
- As a vehicle fuel in a combustion engine. This replaces diesel or petrol in a similar type of engine\[2\]; it is possible in principle to convert an existing petrol engine to run on hydrogen\[3\].
- As co-combustion in a diesel engine. Here hydrogen replaces up to 70\% of the diesel fuel used – although less is currently standard – but does not replace it completely. This does allow the use of 100\% diesel as a backup service provision\[4\].
- In combustion for heating or industrial purposes, to replace natural gas \[5\].
- As an energy storage medium, where it can be produced using electricity and readily stored, then can be used to generate electricity\[6\].

3.2 Case study 1 – Scottish Borders Council Vehicle Fleet

3.2.1 Hydrogen fuelled vehicles
SBC operates – either owned, leased or rented – a fleet of around 500 vehicles of various types. These are mostly fuelled with diesel, although some battery electric vans and cars are in service.

Broadly, hydrogen lends itself to larger and longer range vehicles due to its low weight, fast refuelling, and bulky fuel tank – as does diesel, albeit for different reasons. So we have a general expectation that ultimately hydrogen will replace diesel vehicles, and we assess this situation on that basis – this is illustrated in Figure 3-1 below. However, the actual future out-turn is likely to be more complicated than we can readily foresee or assess at this time.

![Figure 3-1 Overlapping future uses of renewable fuel types- Toyota](image-url)
We assume here that fuel cell vehicles will be the system of choice to replace existing diesel vehicles, due to the significantly better fuel consumption and complete elimination of emission in use. However, vehicles with heavy duty onboard equipment may require a hydrogen internal combustion engine to operate hydraulics and respond to sudden changes in power demand, as developed by JCB[7]. Fuel cell powered refuse collection vehicles are available [8]

To consider the purchase cost of hydrogen vehicles, we consider the costs of hydrogen vehicles based on a selection of vehicle types, shown in Table 3-1 below. This data has been difficult to come by, with only single data points available if any. As such, the results are only approximate, and only reflective of the situation in 2022; over time, the uplift can be reasonably expected to reduce.

<table>
<thead>
<tr>
<th>Vehicle type</th>
<th>Make and model</th>
<th>Cost</th>
<th>Diesel equivalent considered</th>
<th>Diesel equivalent cost</th>
<th>Cost uplift</th>
</tr>
</thead>
<tbody>
<tr>
<td>Family car</td>
<td>Toyota Mirai [9]</td>
<td>£50,000</td>
<td>Peugeot 508 1.5 diesel</td>
<td>£32,000</td>
<td>56%</td>
</tr>
<tr>
<td>Refuse lorry</td>
<td>Unbranded [10]</td>
<td>£368,000</td>
<td>TBC</td>
<td>TBC</td>
<td></td>
</tr>
<tr>
<td>Double decker bus</td>
<td>ADL [11]</td>
<td>£350,000</td>
<td>ADL</td>
<td>£230,000</td>
<td>52%</td>
</tr>
</tbody>
</table>

Table 3-1 Comparative Purchase costs of hydrogen and diesel fuelled vehicles.

The average extra cost for a hydrogen fuel cell vehicle is therefore approximately 54%, though over time and at large scale, that can be expected to decrease to zero, or even negative, due to the simpler construction of a fuel cell than an internal combustion engine[12].

3.2.2 Hydrogen – quantity needed

The SBC report “Proposed Fleet Replacement Strategy 2022-2027” identifies a total of 1.9 million litres (ML) of diesel fuel used per year (including around 500,000 litres of low duty red diesel, which is now unavailable).

On the assumption that future hydrogen road vehicles will use more efficient fuel cells rather than combustion, it is relatively straightforward to convert this amount into an equivalent quantity of hydrogen:

Energy content of diesel used = 1.9 ML x 10.57kWh/litre [13] = 19.7 GWh

Useful energy at wheels = 19.7 GWh x 40% diesel drivetrain efficiency [14] = 7.9 GWh

Energy content required from hydrogen = 7.9 GWh / 60% HFCEV drivetrain efficiency [15] = 13.1 GWh

Quantity of hydrogen required = 13.1 GWh / 33.3 kWh/kg (at LHV$^2$) = 395,000 kg/year

= 1,520 kg/day (at 5 days/week).

= 1,083 kg/day (at 7 days/week).

$^2$ The energy content of fuels can be measured in two ways: Lower Heating Value (LHV) and Higher Heating Value (HHV). For most hydrocarbon derived fuels the difference is insignificant, but for hydrogen the difference is about 20%. HHV assumes that the heat of vaporisation embedded in the water vapour produced can be recovered, such as in a condensing boiler. LHV excludes this, which would be more applicable in a road vehicle[17].
This assumes that all current diesel powered vehicles will be replaced with hydrogen vehicles, as discussed above. However, if other factors will change this for SBC, then the hydrogen forecast can be reassessed – this will also require a more detailed breakdown of current fuel use by vehicle or vehicle type.

If the council wishes to facilitate use of hydrogen fuelling by the public or businesses, then clearly the total demand would increase.

3.2.3 Fuel source – the Hydrogen Hub

A hydrogen hub, or centralised production facility, could be constructed in the Scottish Borders area. Depending on the fleet operating strategy, a single refuelling site might be enough to support the fleet demand, or an additional number of distributed refuelling points might be required.

A production facility would be most likely to use electrolysis of water to produce the hydrogen. This requires a supply of electricity and water, and an electrolyser. It produces no harmful emissions – only oxygen, which has a commercial value itself or can safely be vented to the atmosphere. There are a number of potential international suppliers of electrolysers, and, closer to home, Aqualution in Duns aspires to commercialise a high efficiency electrolyser of their own design. The other currently viable source of hydrogen is through steam reformation of methane. That, however, requires natural gas as a feedstock and produces carbon dioxide as a waste product. While capturing the carbon dioxide and sequestering it is feasible, it is unlikely to be viable a relatively small scale. Also at present it is an incomplete capture process meaning that some carbon dioxide would escape to the atmosphere. A number of other possible production methods are at the research and development stage.

Production of hydrogen via electrolysis would require approximate quantities of water and electricity as shown, with cost profiles, in Table 3-2:

<table>
<thead>
<tr>
<th>Hydrogen requirement (kg/day)</th>
<th>Water (kg/day)</th>
<th>Electricity input incl compression. (Assuming 90% electrolyser efficiency and 24 hour operation).</th>
<th>Capital cost estimate incl electrolyser, compression, storage and dispensing equipment but excluding electricity source.</th>
<th>Cost as NPV per kg of hydrogen, assuming electricity at £0.04/kWh, operating at 80% capacity.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,080</td>
<td>9,750</td>
<td>2.1 MW</td>
<td>£2.2M</td>
<td>£1.85</td>
</tr>
<tr>
<td>1,520</td>
<td>13,680</td>
<td>3.0 MW</td>
<td>£2.9M</td>
<td>£1.82</td>
</tr>
</tbody>
</table>

Table 3-2 Inputs and costs to electrolysers – supply for SBC operated vehicles. Calculations in Appendix 4A. 1080 kg/day supply would be adequate if used over 7 days per week. 1520 kg/day would be required if used over 5 days per week.

A contribution to the energy requirement could come from curtailed energy from local wind farms. As the energy requirement increases, however, it is most likely that dedicated source of renewable electricity will also be required. A dedicated supply arrangement with an electricity source, or a wholly owned source, should be considerably cheaper than purchasing electricity through the national grid. The balancing effect of the grid would be less necessary due to the ability to store hydrogen in tanks.

If SBC wishes to facilitate the wider uptake of hydrogen vehicles outwith the council, then a larger capacity hydrogen hub would be required. Additional capacity could be added on at a later date; this would be easier if the possibility is taken into consideration during the initial planning.
Ideally, the Hydrogen Hub would be located in an area close to good road transport links and to the main centres of operation. The map in Figure 3-2 below illustrates the key infrastructure and towns in the Scottish Borders area.

SBC has previously indicated that suitable land might be available in Lauder, which as can be seen in Figure 3-2 is reasonably central with good access by road. It is also the location of a pressure reduction station in the natural gas network, which might be a useful injection site in the case that hydrogen is supplied into the gas network (see Case Study 2 below). It is also close to a number of established windfarms to the north. However, it is still a distance of around 20km from the key central area around Galashiels, Selkirk and St Boswells, and depending on the number of vehicle movements needed for refuelling, this might become significant— it would be appropriate to conduct a fuller feasibility study into site options.

It would also be appropriate to take account of the operating strategy of SBC vehicles, in terms of whether or not they all return to the same base, or are there often enough to facilitate a central refuelling solution. If they don’t, then consideration should be given to establishing one or more remote refuelling points. These could either produce their own hydrogen via on-site electrolysis, or they could be supplied from the hydrogen hub by pipeline or tanker or a combination.
### 3.2.4 Costs of hydrogen

On the basis of the capital cost figures above, and assuming a 25 year lifespan of the equipment, the unit cost will be approximately as set out in table 3-3 below. This is based on a 1520 kg/day capacity installation.

<table>
<thead>
<tr>
<th>Item</th>
<th>Unit cost</th>
<th>Hydrogen produced per unit at 80% capacity</th>
<th>Cost per kg Hydrogen</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital installation as above.</td>
<td>£2,900,000</td>
<td>11,100,000 kg</td>
<td>£0.26</td>
</tr>
<tr>
<td>Electricity for electrolysis and compression, if dedicated source constructed.</td>
<td>£0.04 per kWh (most recent strike price for offshore wind)</td>
<td>1/47 kg</td>
<td>£1.88</td>
</tr>
<tr>
<td>Water</td>
<td>£1 per m³ (base cost from Scottish Water)</td>
<td>111 kg</td>
<td>£0.01</td>
</tr>
<tr>
<td>Percentage uplift to allow for ancillary works, maintenance and other ongoing costs.</td>
<td>50%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total unit cost estimate by weight</td>
<td></td>
<td></td>
<td>£3.24 / kg</td>
</tr>
<tr>
<td>By energy content at LHV (applicable to road transport)</td>
<td></td>
<td></td>
<td>£0.09 / kWh</td>
</tr>
<tr>
<td>Project NPV, assuming 6% discount rate, ignoring land and tax.</td>
<td></td>
<td></td>
<td>£20.2M</td>
</tr>
<tr>
<td>NPV per unit produced</td>
<td></td>
<td></td>
<td>£1.82 / kg</td>
</tr>
<tr>
<td>NPV per unit energy content at LHV</td>
<td></td>
<td></td>
<td>£0.05/kWh</td>
</tr>
</tbody>
</table>

*Table 3-3 Breakdown of capital and operating costs. Calculation in Appendix 4A.*

Clearly, among the quantifiable elements, the cost of electricity is dominant and water is insignificant; also the uplift for additional costs is somewhat arbitrary and open for discussion.

The cheapest source of electricity at a larger scale is likely to be a wholly owned wind turbine, though a contribution from curtailed energy might be possible depending on availability and contract issues. However, if a large proportion of curtailed energy is to be used, that might lead to the need for a larger electrolyser and storage facilities to be able to deal with the increased intermittency of electricity supply.

At the scale of installation above, it is likely that a single turbine could provide sufficient electricity, although in that case consideration should be given to specifying a larger storage tank and electrolyser to improve resilience against periods of low wind. A backup connection to the national grid would also be an important provision, although as the energy cost crisis of 2022 is showing, excessive reliance on that could lead to high and fluctuating costs.

For context, a Toyota Mirai - a hydrogen powered large family car - has an official fuel consumption of 0.8 kg/100km, or 78 miles per kg[9], making an approximate fuel cost of 2.6p per km or 4.1p per mile (not taking account of taxation or NPV discounting). For comparison, a petrol car consuming 7.0 l/100 km (41 mpg) at £1.40 per litre would cost about 9.8p per km, or 15.8p per mile, in fuel costs. This cost of hydrogen is therefore considerably cheaper than any other fuel source at present, including mains supplied electricity for batteries, and could create the opportunity for SBC to create an income stream by selling hydrogen at a profit.

### 3.2.5 Greenhouse Gas Emissions

SBC vehicles typically use around 1.9 million litres per year of diesel. It is then simple to calculate the associated emissions, as burning 1 litre of diesel releases 2.68kg carbon dioxide[13]. So the total fleet annual emissions are slightly over 5,000 tonnes CO₂. The
renewable hydrogen production system described here would result in zero emissions associated with hydrogen production (other than during construction of the facilities), so those 5,000 tonnes CO$_2$ would be eliminated.

### 3.3 Case Study 2 – Natural gas replacement

Other potential demand for hydrogen could be from replacing existing use of natural gas in domestic and commercial / industrial / public sector use in the Scottish Borders Council area. We can estimate the maximum extent of this as follows:

Domestic average annual demand for natural gas in SBC = 803 GWh (although note that winter demand is typically 4x summer demand) [16]

Industrial and commercial demand = 365 GWh (From private correspondence with SGN, available on request).

Total natural gas demand = 1168 GWh.

Energy content of hydrogen at mean of LHV and HHV = 36.35 kWh/kg[17]. The mean value is used slightly arbitrarily, because some processes will be able to recover the heat of vaporisation of the resultant water vapour (such as condensing boilers) making the HHV applicable; some, such as cookers, will not.

Required quantity of hydrogen = 1168 GWh / 36.35 kWh/kg = 32,000 tonnes per year

= 83,000 kg per day.

This figure would only be reachable following full conversion of the gas network to run on hydrogen. At present, this is envisaged to take place from the late 2020s to early 2040s [5].

In the meantime, however, it is technically feasible to blend 20% by volume of hydrogen with no modification of appliances or network[18]. This requires a UK legislative change, but that is expected within one or two years. 20% by volume, however, represents around 6% by energy use (and a corresponding 6% reduction in emissions) due to the low density of hydrogen. Therefore the potential shorter term requirement for hydrogen in the gas network could be 32,000 x 6% = 1,930 tonnes per year or 5,280 kg/day. The input requirements of this are shown in Table 3-4 below:

<table>
<thead>
<tr>
<th>Hydrogen requirement (kg/day)</th>
<th>Water (kg/day)</th>
<th>Electricity input incl compression. (Assuming 90% electrolyser efficiency and 24 hour operation).</th>
<th>Capital cost estimate incl electrolyser, compression, storage and dispensing equipment but excluding electricity source.</th>
<th>Cost as NPV per kg of hydrogen, assuming electricity at £0.04/kWh, operating at 80% capacity.</th>
</tr>
</thead>
<tbody>
<tr>
<td>5,280</td>
<td>47,520</td>
<td>10.4 MW</td>
<td>£7.9M</td>
<td>£1.75</td>
</tr>
</tbody>
</table>

*We have not considered the requirements for 83,000 kg/day; this is a very large quantity and it seems more likely that it would be served by large offshore plant, distributing the hydrogen through a converted or new transmission grid.*

**Table 3-4 Inputs and costs to electrolyseras – supply for replacement of grid supplied natural gas.**

### 3.4 Conclusion

Replacing all of SBC’s current diesel powered vehicles with hydrogen fuel cell equivalents would displace around 5,000 tonnes per year of carbon dioxide emissions.

To achieve this, a renewable (‘green’) hydrogen fuelling facility, or Hydrogen Hub, supplying around 1,500 kg hydrogen per day would be enough to supply all the diesel road vehicles currently operated by Scottish Borders Council, if they were replaced with hydrogen fuel cell vehicles. This would require an average power supply of around 3MW and a water supply of
around 14 m³/day, and the capital investment, excluding the power supply and land, would be in the region of £2.9M.

The most cost effective source of the power supply would be a wholly owned, or directly connected and contracted, wind turbine/s. Assuming that this is the case, the cost of the hydrogen produced should be in the region of £3.24 / kg, which would lead to, for example, running costs of a family sized car of around 2.6p/km. This compares very favourably with diesel at around 10.1p/km (at 55mpg and £1.95/litre), or grid electricity supplied through a public charger at around 8p/km. This also assumes that hydrogen produced by the council for its own use would not be subject to tax.

An optimum location for the hydrogen hub has yet to be determined. However, a council owned site at Lauder has been put forward as a possibility, being centrally located and well served with roads, gas network connection, and it is not far from existing wind farms. This is, however, some 20 km / 12 miles from the council offices at Newton St Boswells, which might lead to a cumulative significant additional travel cost and fuel requirement. This needs to be considered in more detail.

For the council’s recent fuel consumption level of diesel at 1.9 million litres/year, the cost at current diesel prices of £1.95 per litre would be around £3.7 million per year (although SBC may be able to purchase bulk fuel more cheaply). Using hydrogen produced in the way described, the discounted annual equivalent cost of the 395,000 kg hydrogen required would be around £719,000 – a substantial saving of around £3,000,000 per year which would very quickly offset the initial capital costs.

Given this differential, it may also be possible to create an income stream for the council while also encouraging the take up of hydrogen vehicles, by selling excess hydrogen to the public. However, this may create a taxation complexity which would need to be investigated.

Depending on the operational strategy of the council vehicles - whether or not they all return to the same base at the end of each day – it may be necessary to have one or two outlying refuelling points. These could either produce their own hydrogen in-situ, or could be supplied by tanker or pipeline from the hydrogen hub.

Vehicle cost appears at the moment to be around 54% more than a comparable diesel fuelled vehicle; however, this is a very approximate figure due to the lack of publicly available information.

To produce enough hydrogen to displace 20% by volume of natural gas used in the area (6% by energy and emissions) would require a further 5,300kg hydrogen production, at a capital cost of approximately £7.9M, an average power demand of 10MW and a water supply of 48 m³/day. This would have an annualised production cost of around 4.8p / kWh.
4 The hidden cost of road maintenance due to the increased weight of battery and hydrogen trucks and buses

Chapter 4 examines the impact on road wear of the choice of fuel type for zero emission vehicles. This examines the two currently, or imminently, commercially available vehicle fuelling systems, battery electric vehicles and hydrogen fuel cell electric vehicles.

This came about because there has been considerable informal talk that the extra weight of electric vehicles will increase road wear and tear; this has been mentioned frequently as a disadvantage of electric vehicles. However, on investigation it did not appear that anyone has quantified the extent to which they really do increase road wear - it could easily have been an insignificant amount, a game changing amount, or anything in between.

The key issue was to establish the relationship between vehicle weight and road wear. Fortunately, a considerable amount of research was carried out in this area, between the 1950s and 1980s, and indeed more recently in more specialised aspects. The seminal work was carried out in the 1950s in the USA, where several identical roads were constructed and tested to destruction by driving different vehicle types repeatedly around them. The ensuing data was analysed in the UK (among others), in a nice bit of nominative determinism, by A. H. Rhodes (Rhodes, 1983) This gave rise to the 4th power law - or rule of thumb – which has been used ever since by highways engineers around the world. This says that the wear on a road is proportional to the load on the axle passing over it, to the power of four. This has quite a dramatic impact; it tells us that, for example, if a vehicle has its weight increased by 30% - which is approximately right for a BEV car (Lombardi et al 2020) - the road wear due to it will increase by 1.3^4, or a factor of almost three.

That basic relationship was applied across the whole of the road network and vehicle fleet. Similar to the previous chapters, and in line with this thesis in general, the work was focussed on Scotland. This gives a convenient closed data set, but the findings are likely to be very similar in any industrialised country which uses a comparable type of road construction and no studded winter tyres (Nilsson et al 2020). The analysis takes total number of vehicles in each of the main vehicle classes used by the Scottish and UK governments - buses and coaches, cars, motorcycles, light goods vehicles, and heavy goods vehicles. These are also available more finely broken down by fuel type, and HGVs are broken down by tax class, number of axles (which determines the maximum allowable vehicle weight), and between rigid body and articulated (semi-truck) construction. Previous research in Italy (Lombardi et al 2020) shows the typical increase in weight for battery electric vehicles and hydrogen fuel cell electric vehicles. Using that research plus comparable manufacturers’ details, a function to predict the approximate weight change from internal combustion engine (ICE) vehicles for different vehicle classes was created.

Increasing the vehicle weight according to the formula allowed the calculation of the likely increase in wear due to that vehicle’s use – the term Road Wear Potential for a vehicle is introduced here, which depends on vehicle weight and number of axles; multiplying that by the average annual distance travelled by vehicles in each class leads to an assessment of the impact of each vehicle class, termed here the class or fleet Road Wear Impact Factor.

This appears to have been the first quantified correlation between vehicle weight due to renewable fuel choice and road wear. This work was published in Clean Technology and Environmental Policy in December 2022, available at https://doi.org/10.1007/s10098-022-02433-8.

This research was also reported on by the Daily Telegraph (Electric cars pothole damage is double that of petrol, Telegraph data show https://www.telegraph.co.uk/news/2023/06/26/pothole-electric-cars-damage-roads-double-petrol-telegraph/) newspaper; unfortunately they chose to focus on the impact of cars alone, which due to that 4th power law is - at least on an overall countrywide basis - not significant compared to the impact of large vehicles like buses and lorries. The Telegraph article was in turn picked up
by Finnish (Swedish-language) public television station Yle, which challenged the Telegraph’s focus on the narrow look at cars alone, and reported on the broad point here, that the main issue is around large vehicles (Expert om påståenden att elbilar orsakar stort vägslitage: ”Totalt nonsens” – Inrikes – svenska.yle.fi https://svenska.yle.fi/a/7-10038815 ). This article is published in Swedish, but can be auto-translated with sufficient clarity. The title translates as ‘Experts on claims that electric cars cause great road wear: ”Total nonsense’.

This chapter was published as a paper of the same name in Energy Policy journal in 2022, available at https://doi.org/10.1016/j.enpol.2022.113300. Some modifications have been made for clearer and more consistent presentation within this thesis, without changing any of the substance. An unedited version of the paper as published is presented in the Supplementary Appendix. NB. the reference formatting used in this chapter is that requested by the publishing journal.
The hidden cost of road maintenance due to the increased weight of battery and hydrogen trucks and buses – a perspective

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Keywords: hydrogen; battery; BEV; HFCEV; road maintenance; hidden cost

4.1 Abstract

Decarbonisation of transport emissions is essential to meet climate targets. For road transport, currently available technologies are battery electric vehicles and hydrogen fuel cell electric vehicles. Battery vehicles are more established than hydrogen; both could deliver the emissions reduction required. However, battery vehicles are considerably heavier than equivalent hydrogen vehicles, which are in turn slightly heavier than internal combustion engine (ICE) vehicles; a heavier vehicle will have a bigger impact on road wear and associated costs. Here we carry out a desk based analysis, developed in 2021-2022, examining the impact and cost of the increased weight of zero emissions vehicles on road wear in an entire national vehicle fleet. The novelty is in the first quantified application of the long-understood relationship between axle load and road wear to the problem of the additional weight of zero emissions vehicles. This leads to an approximate quantification of additional costs of road maintenance as the vehicle fleet transitions to zero emissions vehicles. We examine these in four scenarios: all battery vehicles; all hydrogen vehicles; a combination; current ICE vehicles for comparison. We find 20-40% additional road wear associated with battery vehicles compared to ICE vehicles; hydrogen leads to a 6% increase. This is overwhelmingly caused by large vehicles – buses, heavy goods vehicles. Smaller vehicles make a negligible contribution. Governmental bodies liable for road maintenance may wish to set weight limits on roads, require additional axles on heavier vehicles, or construct new roads to a higher standard, to decrease road wear.

Graphical Abstract
4.2 Introduction

Decarbonisation of energy used in road transport will be essential for the world to meet the necessary reductions in emissions. The two currently commercially available technological solutions for road vehicles are Battery Electric Vehicles (BEV) and Hydrogen Fuel Cell Electric Vehicles (HFCEV) (Robinius et al. 2018). At present, HFCEV vehicles are in their infancy, while BEVs are more established. However, in the UK, Zero Emission Vehicles (ZEV) of any type have not yet made significant inroads into the hydrocarbon fuelled internal combustion engine (ICE) fleet with less than 1% of the vehicle fleet and about 4.3% of new vehicle sales in 2020 (UK Government 2021a, Scottish Government 2020b).

HFCEV are typically slightly (1-2%) heavier than ICE vehicles; BEVs are usually significantly heavier (10-30%) due to the high weight of batteries (Lombardi et al. 2020). In this paper we apply existing knowledge of the relationship between vehicle weight and road wear to consider the impact of the heavier ZEVs. We do this by assessing the road wear due to the main vehicle classes at present and in future scenarios of (1) all battery vehicles; (2) all hydrogen vehicles; (3) a combination, and comparing the overall results. A significant increase in wear would lead to a combination of increased maintenance costs, increased particulate emissions, and potentially the need to construct new roads to a higher standard.

We select Scotland as an area of analysis. This allows analysis of a fairly homogenous road construction and vehicle standard (Low et al. 2020). This is also connected with the Scottish Government’s commitment to unusually demanding targets for early decarbonisation, with a ban on new hydrocarbon car & LGV sales, and an all-sector emissions reduction of 75% from 1990 levels, to be achieved by 2030, followed by net zero emissions by 2045 (Scottish Government 2019), and also with the Scottish Government’s recent announcement of substantial investment in the hydrogen economy (Scottish Government 2020a).

This approach can be applied to other locations, subject to local factors such as (i) existing road quality and construction standards, (ii) typical vehicle weight, numbers and construction & use regulations, and (iii) an assessment of the local applicability of the method of road wear assessment used (Rhodes 1983).

4.3 Context & Literature

There have been several relevant studies investigating the connection between vehicle weight and road wear, starting with seminal work by the American Association of Highway and Transportation Officials (AASHO) in the 1950s (AASHO 1962). This was further developed in the UK by Rhodes (Rhodes 1983) and the Transport Research laboratory (Addis and Whitmarsh 1981), and re-examined by Martin in 2002 with a focus on Australian roads of similar construction (Martin 2002), confirming the relationship first developed.

Nilsson, Svensson and Haraldson (Nilsson et al. 2020) assess the economic impact and life between major restoration of road surfaces subject to different types of loading. However, their results also find additional surface wear due to smaller vehicles. They attribute this to the use of studded snow tyres in their study area, Sweden, which are not used in Scotland.

Gustafsson (Gustafsson 2018), Denby, Kupiainen and Gustafson (Denby et al. 2018) and Stafofagia and Faustini (Stafofagia and Faustini 2018) review the impact and measurement of road wear emissions on public health, within Non-Exhaust Emissions: an Urban Air Quality Problem for Public Health; Impact and Mitigation Measures (Fulvio 2018).

This all contributes to the established and widely used principle that relates vehicle axle load to road wear in the 4th power. This is described in more detail in the Method section below.

Lombardi, Triboi, Guandalini and Iora (Lombardi et al. 2020) examine the impact of different drivetrain types, including HFCEV and BEV on the weights of a range of vehicles, as part of their analysis into efficiency.
As the world moves into a transition to zero emissions, new vehicles will require different zero emission drivetrains. At present, available options are either BEV or HFCEV (Robinius et al. 2018). Both of these are heavier overall, with current technology, than existing hydrocarbon ICE drivetrains (Lombardi et al. 2020). Additional road wear is considered in a number of works in the context of particulate emissions (Matthias et al. 2020, Beddows and Harrison 2021), or in BEV specific road design (Börjesson et al. 2021).

Here, then, we take the established relationship between axle load and road wear and apply it to the increased weight of vehicles arising from replacing an existing national vehicle fleet with ZEVs, to arrive at the scale of the increased wear on existing roads, and hence future maintenance cost.

The novelty in this paper is that this appears to be the first quantified application of the long-understood relationship between vehicle axle load and road wear to the problem of the additional weight of zero emissions vehicles. This leads to an approximate quantification of the additional cost of road maintenance as the vehicle fleet transitions to zero emissions vehicles, filling that gap in published knowledge. We introduce the new terms Road Wear Potential (RWP) of an individual vehicle, and the Road Wear Impact Factor (RWIF) which reflects the total annual wear caused by a vehicle fleet.

4.4 Hypothesis

There will be significant and quantifiable additional costs of road maintenance due to the increased weight of ZEVs over ICE vehicles. This will be markedly greater for BEVs than for HFCEVs.

4.5 Method

Rhodes (Rhodes 1983) (and many others) describes the 4th power relationship between road wear and axle load, developed from the experimental work on the subject by the AASHO in the 1950s (AASHO 1962). Rhodes introduces the concept of using a Standard Axle as a way of comparing the impact of various vehicle types. The Standard Axle is taken as a single axle imposing a total load of 80kN (equivalent to 8 tonnes); the wear relative to such an axle can be readily calculated using the 4th power to give a number of effective standard axles per actual axle. We express this mathematically in Equation 4-1 below.

\[ \text{Effective Standard Axles per axle} = \left( \frac{\text{Axle load in kN}}{80} \right)^4 \]  \hspace{1cm} \text{Equation 4-1}

This approach allows an assessment of cumulative impact of vehicles of different classes, and is used in other studies into road wear (Nilsson et al. 2020). As road wear is very tightly controlled by axle load, it becomes apparent that larger vehicles such as HGVs and buses will have a much greater impact than cars, relative to the vehicle weight.

Other researchers have developed different relationships - for example the UK Transport and Roads Research Laboratory produced a range of exponential powers between 2.4 to 6.6 depending on a number of factors including existing road condition and construction standard (Addis and Whitmarsh 1981). Johnsson derives a range of powers for Swedish roads between 1.2 and 8.5 (Johnsson 2004). However, for the purpose of this preliminary assessment of the road wear impact by future vehicles, we consider the single 4th power of axle weight to be adequate; this is currently used in UK and many other countries’ highways design and maintenance (UK Government 2021b).

Based on this established relationship, we introduce the terms Road Wear Potential (RWP) of an individual vehicle, and the Road Wear Impact Factor (RWIF), reflecting the total annual wear caused, which could apply to each vehicle class, sub-class, or national fleet.

The RWP reflects the potential of a vehicle to wear out the road, without considering the extent to which it is used. It depends on the weight of the vehicle and the number of axles it uses, and uses the above 4th power relationship to determine the number of effective standard axles per vehicle. We assume for these
purposes that each axle in a vehicle carries an equal load. In practice this will not be the case; we examine the effect of this in the Sensitivities section.

\[ \text{RWP} = (\text{Nr. of axles}) \times (\text{Vehicle Weight}/(\text{Nr. of axles} \times 80)) \]

Equation 4-2

The RWIF for each class (or sub-class) is based on the Road Wear Potential of a typical vehicle of a given class, multiplied by the average distance such a vehicle drives and by the number of vehicles in each class. This gives an overall value for comparison of the road wear associated with an entire vehicle class over the course of a year.

\[ \text{Annual Class RWIF} = \text{RWP(typical in class)} \times (\text{nr. vehicles in class}) \times (\text{average annual distance driven}) \]

Equation 4-3

The Class Road Wear Impact Factors are then summed to create an overall RWIF for each scenario.

The inputs and data sources are as follows:

- The number of vehicles in each standard vehicle class (buses & coaches, cars, motorcycles, HGV and LGV)\(^1\) (Scottish Government 2020b)
- The typical weight, or range of weights, or fuel based sub-classes, of ICE vehicles in each class (Scottish Government 2020b).
- The likely change in weight due to a similar vehicle having HFCEV or BEV type fuelling and drive systems (see below for derivation).
- The average annual distance travelled per vehicle by class, in km (UK Government Department of Transport 2019).
- We assume that the wear and tear is directly related to the use made of the roads, i.e. the number, class and weight of vehicles using the roads, and not significantly connected to seasonal, weather and simple aging related impacts alone (Nilsson et al. 2020).
- We use the standard UK government vehicle classes of cars, motorcycles, Light Goods Vehicles (LGV), Heavy Goods Vehicles (HGV)\(^3\), and Buses & Coaches. HGVs are further divided into ten weight-based sub-classes, while cars and LGVs are divided into fuel based, that is petrol (gasoline) and diesel (the number of BEVs is still small enough to be insignificant) sub-classes.

To estimate the applicable vehicle weight, or reference weight, for ZEVs, we make an initial assessment of the increase in vehicle weight due to the two new fuel types, and derive simple formulas that fit data previously identified by Lombardi et al (Lombardi et al. 2020) and vehicle manufacturers (Mercedes Benz UK 2019).

We calculate the RWP and RWIF for all classes and sub-classes, and hence the nationwide RWIF, for four scenarios:

1. Current situation, vehicle fleet overwhelmingly dominated by ICE vehicles.
2. All BEV – all vehicles replaced in the same numbers and load carrying capacity with BEVs.
3. All HFCEV – all vehicles replaced in the same numbers and load carrying capacity with HFCEVs.
4. Like for Like – all current diesel vehicles replaced by HFCEVs, and all current petrol vehicles replaced by BEVs.

\(^1\) The Scottish and UK Governments use the terms “Goods” and “Light Goods” for goods vehicles above and below 3,500 kg maximum gross weight respectively. Here, to reduce ambiguity, we use the older common terms Heavy Goods Vehicle (HGV) and Light Goods Vehicle (LGV).
4.6 Results

4.6.1 Initial assessment of vehicle weight and other inputs

Based on Lombardi et al (Lombardi et al. 2020) for larger vehicles (3500kg and over), and manufacturers’ published data for cars (Mercedes Benz UK 2019), we identify the following equivalent vehicle weights for vehicles of the same carrying capacity:

<table>
<thead>
<tr>
<th>Typical ICE vehicle weight (kg)</th>
<th>Equivalent BEV weight (kg)</th>
<th>Equivalent HFCEV weight (kg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1950</td>
<td>2455</td>
<td>1970</td>
</tr>
<tr>
<td>3500</td>
<td>4224</td>
<td>3566</td>
</tr>
<tr>
<td>5200</td>
<td>6028</td>
<td>5255</td>
</tr>
<tr>
<td>18000</td>
<td>19816</td>
<td>18236</td>
</tr>
<tr>
<td>44000</td>
<td>47686*</td>
<td>44760*</td>
</tr>
</tbody>
</table>

Table 4-1  Gross vehicle weights for equal payload, three fuel types.

Note that the weights marked * exceed the maximum allowable vehicle weight of 44,000 kg.

To get a suitable equivalence from manufacturers’ data, it is necessary to identify almost identical vehicles made with different fuel types. The only car commercially available both as an HFCEV and as an ICE vehicle is the Mercedes-Benz GLC (now ceased production), which is a medium-large SUV. The HFCEV version has a larger battery than is usual for an HFCEV (13.5kWh instead of around 1.6kWh (Hyundai UK 2020)), and can be used as a plug in hybrid. It is also available as a BEV (called the EQ-C, with some styling differences) (Mercedes Benz UK 2022). Other vehicles exist as both BEV and ICE, but not HFCEV. For the purposes of consistency in this table, we use the Mercedes-Benz GLC / EQ-C for both ZEV types. We adjust the weight of the GLC Fuel Cell down by 95kg to reflect the typical extra weight of the larger Li-Ion battery (Jung et al. 2018), to create a more relevant entry for this table.

From this Table, we derive a simple relationship between the weight of a BEV and an ICE vehicle of the same carrying capacity based on the trendline function in Microsoft Excel, as follows:

\[
\text{BEV Weight (kg)} = (1.0744 \times \text{ICE Weight}) + 430
\]

And between an HFCEV and an ICE vehicle:

\[
\text{HFCEV Weight (kg)} = (1.014 \times \text{ICE Weight})
\]

Both of these formulas match the Table 4-1 data well, with a very close \( R^2 \) value of at least 0.9999.

Given that the lowest data point in the original table still represents a large car, it will be necessary to extrapolate the formula slightly to get a vehicle weight more representative of a smaller one; it may be unrepresentative of motorcycles. However, as it turns out, the RWIF of cars and motorcycles is so low that this immaterial (see below).

For each class or sub-class, we have to estimate a reference vehicle weight. The key factor affecting this for large vehicles is the proportion of time the vehicles run empty or lightly loaded. This will obviously happen some of the time, with a significant change in weight. Vehicle operators will clearly try to maximise the load in their vehicles, so the actual average weight can be expected to be higher than, for example, a mid-point between empty and full. We expect that buses will run for a higher proportion of the time empty or lightly loaded, as they will be sized for peak demand. However, due to the 4\(^{th}\) power relationship described above, the heavier loading will have a proportionately greater impact on road wear.

As a working assumption, we take the reference vehicle weight as the midpoint of the applicable weight range. We examine the implications of inaccuracies in the Sensitivities section below.

The annual distance travelled by each vehicle is taken as the average for the class or sub-class from UK government statistics. There are cases where this data is only available for a group of sub-classes (e.g., all
2- or 3- axle rigid chassis HGVs) – in this case we take the average for all relevant sub-classes. This is also examined in Sensitivities, below.

For some sub-classes of HGV, the regulated maximum weight was exceeded when the modelled ZEV vehicle weight was calculated, as seen in Table 4-1. In these circumstances, we assume that the maximum weight will not be exceeded, but that instead the affected vehicles will be used for additional trips to reach the same aggregate carrying capacity. We explore the effect of this further in Sensitivities, below.

### 4.6.2 Road Wear Potential per vehicle

We examined the wear potential associated with individual vehicles. Figure 4-1 below shows the relationship between vehicle weight and Road Wear Potential, taken as the number of standard axles per vehicle. This shows the RWP of a vehicle in each sub-class based on its weight and number of axles, for the three fuel types under consideration.

![Road Wear Potential by vehicle class and fuel type](image)

*Figure 4-1 Road Wear Potential (RWP) per vehicle, sorted by vehicle sub-class, comparing ICE, BEV and HFCEV. RWP is the number of standard axles per axle, multiplied by the number of axles on the vehicle. Vehicles under 7.5t have negligible RWP in this context.*

We can see from Figure 4-1 that the wear potential of a larger vehicle is overwhelmingly greater than that of a smaller one, due to the 4th power law exponentially increasing the effect of greater axle load. We also see a significant increase in wear potential for a relatively small increase in vehicle weight in large vehicles, for the same reason. The mitigating effect of additional axles is also clear – the reduced number of effective standard axles per actual axle more than offsets the increased number of axles, hence the total RWP decreases for vehicles where the axle count increases. This happens at the 16-20t category, where the axle count increases to 3, at 28-32t where it increases to 4, at 38-40t which requires 5 axles, and 40-44t requiring 6 axles.

### 4.6.3 Road Wear Impact Factor

Next, we develop this into the assessment of the Road Wear Impact Factor by Class and overall, for the four scenarios under consideration. Multiplying each vehicle’s Road Wear Potential by the number of vehicles in the class and the average distance driven each year(UK Government Department of Transport 2019) produces the total Road Wear Impact Factor for each class. This produces Road Wear Impact Factors as shown in Figure 4-2 below.
Clearly the overall RWIF is overwhelmingly due to the largest vehicles in use, even though they don’t have the highest RWP. This reflects the greater use made of the largest vehicles – there are more 40-44t HGVs than any other category of HGV other than the smallest 3.5-7.5t vehicles, which has about 20% more; also a typical 44t vehicle covers well over twice the annual distance of a 7.5t one. Due to the much smaller RWP, vehicles below 12t have a negligible impact on national RWIF with any fuel type.

The impact of ZEV technology in larger vehicles can be clearly seen, with BEV having a substantially greater impact than HFCEV. A table with a detailed breakdown of the calculations and results is presented in the Appendix 4A.

### 4.7 Sensitivities

We considered the sensitivity of the results to different ways of estimating the input simplifications:

- Reference weight estimate
- Varied load distribution, other than equal on each axle;
- Using HGV subcategories based on axle number rather than tax bracket.

#### Reference weight estimate

We initially assumed a reference weight at the midpoint between the top and bottom of each tax class. However, the reference weight, or typical effective weight, could be significantly different for HGVs, due to the potential for different loading and use patterns. We varied the originally estimated reference weight by scaling factors ranging from 0.5 to 1.07. Beyond 1.07, the ICE reference weight began to exceed the allowable weight in each category, particularly the heaviest, therefore a higher factor than this was clearly unrealistic.

We then used the same method to assess the overall RWIF for a range of scaling factors. We continued to use the principle that if the allowable weight for a particular axle configuration were exceeded, the weight would be held at the maximum allowable, and the distance travelled for vehicles in that sub-class would increase to provide the same gross annual carrying capacity. The result from this assessment is shown in Figure 4-3:

---

**Figure 4-2** Class / Sub-class Road Wear Impact Factor, comparing the present and future scenarios.

Road Wear Impact Factor is the Road Wear Potential multiplied by the number of vehicles in each class or sub-class and by the average annual distance travelled. Vehicle classes with a typical vehicle weight below 12t have negligible RWIF on a national scale.
Figure 4-3 Change in overall fleet RWIF as a consequence of change in modelled ICE reference weight.

Where allowable vehicle weight is exceeded, modelled distance travelled per vehicle is increased.

The final output, the change in RWIF with different fuels, is assessed as the ratio between the old and the new rather than as a meaningful absolute value, so a change to both produces a similar result for most of the range. The change in RWIF decreases at higher scaling factors because increasing the distance travelled has a smaller impact than increasing vehicle weight due to the 4\textsuperscript{th} power relationship, so this becomes significant at higher load scaling factors. On this basis, we describe the change in overall RWIF due to a fully BEV fleet as 20-40%, and for a fully HFCEV and Like for Like fleet as 6%.

**Unequal loading**

To assess the effect of unequal load distribution, we considered the effect of one axle carrying a percentage more than all the other axles, which were set as equal. An unevenly distributed load would result in a higher RWP than an evenly distributed one. The maximum permitted load on a single driving axle is 103kN (10.5 tonnes), or 83kN each if there are two driving axles (UK Government 2010). However, when the same proportion of unevenness is applied to current and future cases, the relative increase in RWP and RWIF is unchanged. Ensuring that loads are more evenly distributed in ZEVs than at present would be a way of mitigating the increased RWP, but that analysis is beyond the scope of this paper.

**Different HGV subclasses**

Data is available for HGV numbers and usage based on weight related tax bracket or on number of axles, which is also related to maximum weight. Using tax brackets gives a finer division of data; using the axle number gives a better match to the effects between sub-classes and permitted vehicle weights. Our main approach has been to use the former. Here, we re-run the analysis on the basis of axle numbers, for comparison.

However, again because the treatment is the same for ICE and ZEV, the effect on the overall result is minimal. Results are presented in Table 4-2:

<table>
<thead>
<tr>
<th>% increase in overall RWIF (tax bracket based sub-classes)</th>
<th>BEV</th>
<th>HFCEV</th>
<th>Like for Like</th>
</tr>
</thead>
<tbody>
<tr>
<td>% increase in overall RWIF (axle number based sub-classes)</td>
<td>31.0%</td>
<td>5.7%</td>
<td>5.9%</td>
</tr>
</tbody>
</table>

Table 4-2 Comparison of overall RWIF for different types of HGV sub-class categorisation

We consider this effect to be insignificant.
4.8 Conclusion and Discussion

We introduced the hypothesis “There will be significant and quantifiable additional costs of road maintenance due to the increased weight of ZEVs over ICE vehicles. This will be markedly greater for BEVs than for HFCEVs.”

We find that this partially correct – in the case of the largest vehicles, that is buses and heavy good vehicles, the hypothesis is shown to be true. However, in the case of smaller vehicles such as cars, light goods vehicles and motorcycles, it is unlikely that there will be a significant difference.

A complete conversion of the existing vehicle fleet to BEV would be likely to increase annual road wear in Scotland by around 20-40%, with a modelled base case value of 31.0%. Conversely, the same conversion to HFCEV would increase road wear by around 6% (Figure 4-4). The combined, or “Like for Like” future fleet, where existing diesel vehicles are replaced by HFCEV and existing petrol vehicles are replaced by BEV, would also lead to increased road wear of around 6%.

We can see from Figure 4-2 above that in each scenario, the Road Wear Impact Factor is dominated by the relatively small number of HGVs, 37,000 vehicles out of a total vehicle fleet of approximately 3 million, which contribute around 87% of the Road Wear Impact Factor. The 14,000 buses and coaches are also significant, contributing around 12%. The Road Wear Impact Factors due to cars, light goods vehicles and motorcycles are insignificant, contributing in total less than 1% of the Road Wear Impact Factor in all scenarios. This will not be news to highways engineers, but needs to be understood in the energy sector. HGVs and Buses & Coaches would be HFCEVs in both the all-HFCEV and the Like for Like scenarios; as those are the vehicles overwhelmingly responsible for road wear, this leads to the Road Wear Impact Factors being effectively identical for both of these scenarios.

This effect could possibly be mitigated in the future by the introduction of lighter-weight battery technology. This is, however, speculative – while such batteries are being researched, they are not yet commercially available (Ye and Li 2021). It might also be possible to re-engineer the basic vehicle to be lighter by using lighter materials or construction methods, although these would be equally applicable to other fuel types. Also, if “e-roads” - which charge vehicles as they drive - became ubiquitous, the need for large and heavy batteries might be reduced (Coban et al. 2022).
A further mitigating effect, requiring no new technology, would be to increase the required number of axles on large vehicles – due to the 4th power effect, the reduction in wear per axle would outweigh the extra wear due to the additional axles. This would, however, increase the vehicle manufacturing costs and fuel consumption (Johnsson 2004).

The all-BEV scenario represents an increase in road wear of about 31% from the present situation; all HFCEV and Like For Like both represent an increase of about 6% - that they are almost identical reflects the dominance of diesel in large vehicles at present.

It would also be important to design vehicles such that the additional weight of batteries is evenly distributed across all axles – this would prevent an imbalanced load creating significant extra wear. This could, however, force a change in operating practice for articulated HGVs, as some of the batteries might have to be installed in the trailer unit.

It should be noted that this study considers the impact on the road network as a whole, and takes account of the relative position of present and future requirements. It is likely that specific areas, especially where the existing road has deteriorated or is of lower initial quality, that the impact will be different and smaller vehicles might become significant. Future study, including more localised analysis, might be necessary to better understand local effects. Future study would also be useful to better understand the benefit of the mitigating factors outlined above.

In Scotland, responsibility for road maintenance is shared between the Scottish Government for trunk (primary) roads, and local authorities for the much greater network of all other roads from large A-class roads through to urban access; these bodies would bear the costs related to this additional road wear. The most recent Audit Scotland report into road maintenance expenditure refers to 2015 (Audit Scotland 2016), showing the required road maintenance expenditure to maintain the existing condition. This is set out in Table 4-3, converted to 2021 values (Bank of England 2022), along with the additional expenditure required to provide for ZEVs in the future. This assumes that the calculated wear factor reflects the time until maintenance is required (further assuming the annual amount of goods etc transported is unchanged), which would lead to the cost of maintenance being directly proportional to the extent of road wear.

<table>
<thead>
<tr>
<th></th>
<th>Transition to BEV</th>
<th>Transition to HFCEV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Required to</td>
<td>Additional</td>
<td>Overall</td>
</tr>
<tr>
<td>maintain</td>
<td>required</td>
<td>total</td>
</tr>
<tr>
<td>condition</td>
<td>expenditure</td>
<td>expenditure</td>
</tr>
<tr>
<td>(BEV)</td>
<td>(BEV)</td>
<td>(BEV)</td>
</tr>
<tr>
<td>Local Authorities</td>
<td>£324M</td>
<td>£100M</td>
</tr>
<tr>
<td>Scottish</td>
<td>£206M</td>
<td>£64M</td>
</tr>
<tr>
<td>Government</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>£530M</td>
<td>£164M</td>
</tr>
</tbody>
</table>

Table 4-3 Required annual expenditure on road maintenance in Scotland, with expected additional costs due to the conversion to ZEVs. Amounts converted from 2016 to 2021 values, inflation factor 1.108.

This shows the additional road maintenance expenditure in Scotland required to maintain existing condition would need to increase by around £164M per year if all large vehicles transitioned to battery electricity. Conversely, if all large vehicles transition to hydrogen fuel cells, then an additional £31M would be required.
It has been reported that current levels of road maintenance are inadequate at present to sustain existing road quality (Williams 2019, Audit Scotland 2016). If this is still the case, the greater demands made of the roads in the future that we outline here can be expected to lead to an even faster deterioration (Addis and Whitmarsh 1981). However, we do not assess that impact in this paper.

This cost increase assumes that the additional wear and related costs are spread evenly across all roads. However, in practice it is likely that larger HGVs would tend to travel on more major roads; this difference may be less pronounced with buses. The effect would be that the additional wear percentage should be applied to the maintenance costs of larger loads, and a smaller uplift applied to minor roads. However, the counterpoint to this is that roads with a less robust construction are more susceptible to wear than major roads – the 4th power can increase as high as 6.6 (Addis and Whitmarsh 1981). Analysing this effect is outwith the scope of this paper; for the purpose of this initial examination of the issue, we assume a uniform 4th power.

These additional costs, and the consequence of the additional emissions, should be included when planning the support of different fuel types on a national fleet. The fuel choice of cars, light goods vehicles and motorcycles will make little difference to road wear. However, with more HFCEV buses & coaches and heavy goods vehicles, the overall road maintenance cost will be substantially lower than with those vehicles as BEVs; it will require only a relatively small increase over the current ICE vehicle situation.

Figure 4-5 Summary conclusion
4.9 Statements & Declarations

4.9.1 Funding

JML is partly funded by the University of Edinburgh.

RSH is funded by EPSRC UKCCSRC 2017 EP/P026214/1 and HyStorPor P/S027815/1, and Scottish Gas Networks Academic Alliance H100 project from Ofgem.

GPH is the Bert Whittington Chair of electrical power engineering with the University of Edinburgh, Edinburgh, U.K.

4.9.2 Competing Interests

The authors have no relevant financial or non-financial interests to disclose.

4.9.3 Author Contributions


RSH: Paper structure and content review, Validation, Writing – review, Supervision.

GPH: Paper content review, Validation, Writing – review, Supervision.

4.9.4 Data Availability

The datasets generated during and/or analysed during the current study are available in the GitHub repository, https://github.com/J-M-Low/Battery-Battering.git
5 Hydrogen as a marine fuel

This chapter is based on work carried out as part of a project, funded by BP and managed by the Offshore Renewable Energy Catapult, to examine renewable fuels for use in offshore service operation vessels (SOV). These vessels would be used to service offshore wind farms.

The overall project was divided into a number of different areas; these included the adapted ship design, procurement of appropriate technology, legislation, an emissions calculation tool, and a review of fuel options. The work on which this chapter is based was the review of fuel options; this included emissions, costs, supply chain, and safety aspects, which resulted in a report for the project management organisation employed by BP. This chapter is condensed from the relevant sections of that report.

There appears to have been no similar wide-ranging study carried out; Mukherjee et al [1] carried out a meta-analysis of the cost of certain fuels, some of which are included in this study. This was a very useful background information for this work.

The fuels considered in this chapter are hydrogen - in the form of gaseous hydrogen, liquid hydrogen, or liquid organic hydrogen carrier - along with ammonia, methanol, biodiesel, and electricity. These are considered in comparison with marine gas oil (diesel) which is currently used for such vessels, as a baseline. The original report also considered Liquefied Natural Gas (LNG) at the funders’ request – this is not included here as it is not a net-zero fuel.

The core part of the work, presented here, considered the costs and emissions for each component of production, transport, storage, and use. This is assessed this both at present and anticipated for 2040 to 2050.

Based on this, the optimum fuel to use in the shorter and longer terms is considered. Perhaps inevitably, the answer is not clear cut; it depends upon the priorities attached to the different aspects considered.

This work was carried out as a desk study, alongside other aspects such as safety risk associated with each fuel, and the existence of the supply chain an appropriate supply chain. These latter aspects are not addressed in depth in this thesis chapter, although they are referred to where appropriate.

The rest of this chapter is extracted from the report issued to the Offshore Renewable Energy Catapult for BP.
5.1 Marine Renewable Fuels

Based on work carried out as part of the project
“SOV Zero emission Fuels and Technology – Feasibility Study”,
managed by Offshore Renewable Energy Catapult and funded by BP.

5.2 Introduction

BP wish to develop net-zero emissions Service Operation Vessels (SOV) to service their new Scotwind wind farms. The vessels are scheduled to be ordered in 2026, with a view to commissioning in 2029.

This chapter is extracted from a work package forming part of the feasibility study examining the fuel and technology options that might be used to decarbonise the vessels. Specifically, this extract will examine the potential energy sources, the ‘well to tank’ greenhouse emissions associated with each fuel and the associated costs. It considers the present-day situation and the forecast position in 2040-2050.

The fuels considered here are: Biodiesel, Methanol, Ammonia, Electricity, and Hydrogen in various forms (Compressed gas, Cryo-Liquid, or Liquid Organic Hydrogen Carrier (LOHC)), along with marine gas oil (MGO, or diesel) for a baseline comparison.

For each fuel type, the following information will be identified:

- Greenhouse emissions from production, transport, storage and use of the fuel.
- Costs associated with production, transport, storage and use of each fuel type.
- These costs and emissions are identified at their levels in 2023, and are forecast to approximately 2045.

A consideration of the safety and other environmental implications of each fuel type is made.

The work is carried out using a specific example vessel and a 2-week mission profile. The vessel design, basic fuel quantity required, and the mission requirements were developed by other parts of the overall project. The key information for this part of the work is that it would require 85 tonnes of MGO to complete a voyage, including an appropriate emergency reserve.
5.3 Introduction to the fuel options

5.3.1 A note about electricity

Electricity is used in the production of the fuels under consideration. It can come from various sources with different levels of emissions. When examining the emissions relevant to each fuel, three scenarios are considered:

All electricity comes from renewable sources. Given the Scottish Government’s commitment to reducing electricity emissions to zero [2], and the success in achieving that to date [3], it seems reasonable to anticipate this by 2029 and beyond. However, some fuels might be made elsewhere, and it is possible that this goal might not be achieved, so two further scenarios are considered as examples.

Electricity is produced at an emission level equivalent to the Scottish average in 2020, 0.034 kg CO2 eq/kWh [4].

Electricity is produced at an emission level equivalent to the UK average in 2020, 0.233 kg CO2 eq/kWh [4].

These are example levels used for comparison only; by the time the vessels are launched in 2029, the situation will undoubtedly be different. The fuels will not necessarily be made in Scotland or the rest of the UK; this is intended to allow comparison of the effect of an example level of emissions, wherever the fuel is produced.
5.3.2 Ammonia

Ammonia is produced using the Haber-Bosch process, developed around 100 years ago [5]. This involves reacting a stream of nitrogen and hydrogen at a pressure of around 100 bar and a temperature between 400 and 500°C, over a catalyst. The nitrogen is obtained from the atmosphere, while the hydrogen can come from a number of sources. The hydrogen supply options considered here are: 1) produced from the electrolysis of water using renewable electricity (creating “green hydrogen”) and 2) produced using the steam reforming of methane, with (“blue hydrogen”) or without (“grey hydrogen”) capture and storage of the resulting carbon dioxide.

At a pressure in excess of around 10 bar, or temperatures below minus 33°C, ammonia forms a liquid. These are easily achieved, making it considerably easier to transport and store in bulk. In this way, Ammonia can be readily transported in pressurised tankers [5]. At very large volumes it is usually more cost effective to refrigerate it rather than pressurise it. However, at the relevant scales, the most appropriate form of ammonia transport and storage on-shore and on-board is as liquid under a light pressure [6].

In use, ammonia can be burned in an internal combustion engine (ICE) or used in a fuel cell to generate electricity. The electricity can then be used to drive an electric motor. The combustion engine produces NOx when no abatement technologies are employed. However, using a selective catalytic reduction (SCR) system along with specific engine tuning can reduce the NOx levels in exhaust gases from 1000 ppm to below 10 ppm [7]. These are established technologies in common use in road transport. The emissions then are water vapour and nitrogen gas [6]. The calculations here assume that oxides of nitrogen will be reduced to negligible levels in a similar way.

Alternatively, the ammonia can be cracked into its constituent nitrogen and hydrogen, and the hydrogen on its own can be used in a combustion engine or a fuel cell. This requires the ammonia to be heated to approximately 500 degC in the presence of a catalyst, or 650 degC with no catalyst [8]. In that situation, the nitrogen would be vented back to the atmosphere harmlessly, and the waste product from the engine or the fuel cell would be water. This cracking process uses at least 7% of the available energy [9].

In this way, the Ammonia is in effect a carrier for hydrogen; liquid Ammonia carries approximately 50% more hydrogen than liquid hydrogen by volume, as well as being easier to store and handle [9]. illustrates the potential fuel journeys for Ammonia.

![Ammonia fuel journey options from production to use.](image_url)
5.3.3 Biodiesel

Biodiesel is produced from biomass, or waste oil such as cooking oil and fats. As a liquid at ambient conditions, it can be transported and used in the same way as MGO or mineral diesel. Biodiesel typically has a lower specific energy than MGO [10].

Biodiesel is used in an internal combustion engine in the same way as mineral diesel. It also produces carbon dioxide emissions in a similar manner. However, it can be considered to have net-zero emissions across its lifecycle provided it is produced from renewable materials that remove an equal amount of greenhouse gases from the atmosphere as are emitted in combustion.

The sustainability of biodiesel production, however, also depends on other factors, such as the feedstock used, the production methods employed, and the potential impacts on land use, food security, and biodiversity. For instance, if the production of biomass for biodiesel involves clearing of natural habitats or deforestation, it can have negative environmental impacts overall.

Biodiesel or synthetic diesel can be used in conventional internal combustion engines with little modification [11].

illustrates the potential fuel journeys for biodiesel along with marine gas oil (MGO).

![Figure 5-2 Fuel journeys for biodiesel and marine gas oil.](image)
Electricity can be produced from a number of methods. Appropriate zero emissions technologies for the production of electricity in Scotland are mainly onshore and offshore wind generation and hydroelectricity. Marine sources such as wave or tidal are in development, and solar is becoming more efficient making it increasingly viable in the cooler climate. Nuclear is available at the time of writing but is expected to be fully phased out before 2030 [2]. On board a ship, electricity would have to be stored in a large battery, which could then be used to power an electric motor to propel the ship.

Recharging a large battery is not straightforward. A heavy duty connection to an electricity supply could be installed to directly charge the battery during the refuelling time. However, this would require a very large supply power; it may be the case that the investment would only be beneficial if there are a large number of vessels using the connection regularly. Other options include an onshore storage battery, which could be charged more slowly while the vessel was on duty, then used to charge the vessel on its return. Alternatively a swap arrangement might be possible, where full battery is exchanged for a depleted one, depending on the size of the battery required.

A further possibility, perhaps more practical, is the use of a charging facility offshore, on site at the wind turbines. This would permit a significantly smaller battery to be used.

below shows the battery electricity charging journey.

Figure 5-3 Battery stored electricity journey options from production to use.
5.3.5 Hydrogen

As mentioned above under ammonia, hydrogen can be made primarily in three ways. The first is using electricity to power an electrolyser, which separates water into its constituent hydrogen and oxygen. The oxygen can be safely vented, or captured and sold as a product with a number of uses, and the hydrogen is transported to where it’s needed by pipeline or tanker. If renewable electricity is used to power the electrolyser and produce the hydrogen, then the resulting hydrogen is considered to have zero or very low carbon emissions. This type of hydrogen is commonly referred to as ‘green hydrogen’. Hydrogen can also be produced through the steam reforming of methane or other hydrocarbons, with (termed ‘blue hydrogen’) or without (‘grey hydrogen’) capturing and sequestering the ensuing carbon dioxide [12]. There are other methods of producing hydrogen but these are not currently used to a significant extent. There is an increasing awareness of naturally occurring hydrogen [13], however this is not yet available at commercial levels.

For transportation and storage, hydrogen can be compressed as a gas at pressures of up to 700 bar, or it can be liquefied by cooling to -253 degC and stored in cryo-insulated vacuum tanks. In such circumstances, there is a small amount of boil-off, that is, liquid hydrogen vaporising. This must be released via a pressure valve; however, in the circumstances on board the ship, this should be captured into the fuel stream so it is not lost nor makes a contribution to global warming [14]. It could also be transferred through pipelines as a compressed gas at lower pressures of up to 100 bar. Pipeline transmission of liquid hydrogen is unlikely to be practical except over very short distances, due to the insulation required.

A further storage option is liquid organic hydrogen carrier (LOHC); here, a carrier liquid reacts with hydrogen to form a stable liquid compound which can be readily pumped into storage tanks. In use, the hydrogen is separated from the LOHC by heating it, returning the carrier liquid to its original state. The depleted carrier liquid must be stored and returned to port where it can be exchanged for charged LOHC [15].

Hydrogen can also be stored in the form of ammonia, as described above in section 5.3.2 [16].

In use, hydrogen can be used in either an internal combustion engine, or fuel cell to generate electricity which then drives an electric motor. In both of these cases, the waste product is water vapour. In the case of a combustion engine, the high combustion temperatures can lead to the formation of oxides of nitrogen (NOx), with undesirable impacts on global warming and local air quality; this can be controlled by using catalytic combustion which keeps temperatures lower, leading to low or no NOx formation. Any NOx production can be reduced this way to between 0.09 and 9.49 ppmv, which is equivalent to an average of 0.08 mg/kWh. This compares very favourably to the EU regulation level of 56 mg/kWh. By further comparison, the open flame combustion of hydrogen produces NOx values of approximately 335 ppmv [17].

The primary calculations here assume that oxides of nitrogen will be reduced to negligible levels in this way. Below illustrates the hydrogen journey options.
Figure 5-4 Hydrogen journey options from production to use.

5.3.6 Methanol

The vast majority of methanol currently made in the world is derived from natural gas, resulting in significant CO2 emissions in both manufacture and use. However, it is also possible to synthesise it using carbon dioxide or biomass, and hydrogen, as feedstock. Methanol made in this way can be considered net zero emissions provided that the carbon dioxide is ultimately derived from atmospheric sources. In this respect, the production issues are similar to those for biodiesel [18]. The source of carbon is gaseous carbon dioxide. Where it is either captured from a waste process or direct air capture, the result is known as E-methanol; where it is biomass, the product is known as BioMethanol. These are all however chemically identical.

The use of methanol is very similar to the use of ammonia, although it can be transported and stored as a liquid at atmospheric pressure, making handling easier. It can then be used either directly in a combustion engine or, in principle, in a fuel cell, although it appears that such fuel cells are not currently commercially available.

below illustrates the Methanol fuel journey from production to use.

Figure 5-5 Methanol fuel journey from production to use.

5.3.7 Marine gas oil

Marine gas oil (MGO) is a type of mineral diesel obtained from the oil industry and, as is well known, produces significant amounts of carbon dioxide as a by-product of its use. The fuel journey for MGO, similar to that for biodiesel, is illustrated in above.
5.4 Methods

This is a desk study, using publicly available data combined with appropriate calculations. This involves looking at the performance of the various fuels in terms of greenhouse gas emissions and cost, in the present day and forecast in 2045. The analyses described below are carried out for each fuel type applicable.

5.4.1 Greenhouse Gas Emissions:

An assessment is made of the greenhouse gases emitted by each fuel, expressed as kg of carbon dioxide-equivalent per kWh (kg CO2eq/kWh) of energy stored in the fuel as delivered to the ship. This method allows for a direct comparison between fuel types. This is based on the production, transport, and storage options described above, using academic and publicly available published information to provide the input data.

Where the emissions are likely to change over the transition period, the short term (i.e. 2023) and longer term (2045) emissions are considered separately. This has effects, first, in transport, where road transport in the short term by diesel fuelled road tanker is assumed, while in the longer term it is by hydrogen, or other zero-emission fuel, road tanker. Second, in the short term fossil fuel derived versions of fuels as an interim step is considered, but in the longer term these are excluded.

Transport is assumed from the nearest available potential supplier to the expected home port of Aberdeen. Given the planned vessel launch date in 2029, and the time of writing in 2023, this includes facilities which are one of –

1. In operation;
2. In construction;
3. Have received planning consent from their local authority for construction.

Facilities which are described as planned, but have not yet received planning consent, are excluded.

As described in Section 5.2 above, assessments are made on the basis of three different emissions scenarios based on for the emissions relevant to the input electricity at each stage:

- Zero scenario. All new electricity is renewable. In this case, all the electrical input required is considered to have zero greenhouse emissions per kWh of input electricity.
- 34g scenario. Emissions due to input electricity are equivalent to the average for grid-supplied electricity in Scotland. This was 0.034 kg CO2 eq/kWh of electricity supplied in 2020.
- 233g scenario. Emissions due to input electricity are equivalent to UK-wide average emissions for grid electricity is used. This was 0.233 kg CO2 eq/kWh of electricity supplied in 2020.

An assessment of the emissions released during use of the fuel is included. This accounts for the complete combustion of the fuel, but it does not provide for differing efficiencies as a consequence of different drivetrain systems.

To allow for a like-for-like comparison, the emissions are calculated relative to the energy content of the fuel, in other words as kg CO2 eq / kWh.
5.4.2 Cost of fuel

The likely fuel supply unit cost is estimated. This section is necessarily imprecise as the cost of fuel supply is most likely to be commercially confidential. However, an estimate is made based on publicly available data and costs. The cost is expressed relative to energy content, that is as £/kWh, to allow ready comparison between fuels.

Similar to the approach to emissions in section 5.4.1 above, the costs are considered in the three emissions scenarios, in 2023 and in 2045, and from supply facilities that have at least received planning consent. Costs are assessed separately for production, transport, storage, and transfer to the vessel.

Current and forecast unit costs for the supply of the various fuels from various production methods are compiled from a number of sources identified.

Transport related costs are based on the same fuel sources as used for emissions calculations. This also assumes the use of diesel fuelled road tankers. Further, operating costs of future zero emissions road tankers are assumed to be similar to current costs of diesel tankers.

Storage related costs are based on two aspects. First, the capital cost of the provision of storage, based on the storage vessel type, which is determined by the nature and state of the fuel with few options. The key assumption made is the lifespan of the storage facility, taken as 20 years. A nominal maintenance allowance of 1% of capital cost per year is also included. Second, the cost of using the storage, in terms of energy used in putting the fuel into and out of storage (or a state suitable for storage), and any energy lost during storage.
5.5 Results

5.5.1 Emissions

to 5-8 below summarise the emissions for each fuel, production method, storage type and transport method combination. The abbreviations used are set out in table 5-1 below.

A comprehensive set of tables, from which these charts are derived, setting out the emissions for each stage (production, transport, storage) along with the sources of data and calculation method is shown in Appendix 5D.

Figure 5-6 Unit emissions for all fuel combinations, based on the Zero scenario, electricity supply coming entirely from renewable sources.
Figure 5-7  Unit emissions for all fuel combinations, based on the 34g scenario, electricity supply coming from a substantially decarbonised grid supply.

Figure 5-8  Unit emissions for all fuel combinations, based on the 233g scenario - electricity supply comes from a partially decarbonised grid.
In Figures 5-6 to 5-8 above, the emissions for fuels using direct air capture, biomass or intercepted waste stream as a source of carbon show negative production emissions, coupled with positive emissions in use. This reflects the carbon dioxide extracted, or blocked, from the atmosphere, and then returned to it when the fuel is used. Where the carbon source is intercepted waste carbon dioxide, 50% of the ultimate waste CO2 is taken as blocked from the atmosphere; this way, the ultimate emissions are shared equally between the original producer and the fuel use. The net overall emissions profile for each fuel type is shown on each chart. Transport emissions are very low for all scenarios. They are shown in the charts, but may be so small as to be barely visible.

The effect of increasing the electricity source emissions is clear in the increasing overall emissions from figures 5-6 to 5-8. However, by the time the vessels are launched in 2029, it seems likely that the electricity generation emissions will be significantly lower than they are now. We can also reasonably anticipate that this will continue through the energy transition.

If electricity emissions are essentially zero, several fuel combinations result in a net-zero, or virtually net-zero, emissions profile:

- All battery electricity options (This does not take into account the often substantial emissions from manufacturing a large battery).
- All green hydrogen options.
- Green ammonia.
- E-methanol and biomethanol.
- Biodiesel (not completely zero unless CCS is deployed during production – not accounted for here).
- Blue hydrogen options are also very low.

However, even if the electricity emissions are substantially reduced but not eliminated, as in the 34g scenario, or are only partially reduced, as in the 233g scenario, there are some options which permit a net-zero, or virtually net-zero, emissions profile:

- Battery electricity where the supply is taken direct from the renewable generation, bypassing the grid electricity mixing.
- Green hydrogen where the supply is taken direct from the renewable generation, bypassing the grid electricity mixing.
- Biomethanol.
- Biodiesel with CCS.

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>Production</th>
<th>Storage</th>
<th>Transport</th>
</tr>
</thead>
<tbody>
<tr>
<td>Elec – Electricity</td>
<td>Ren – Renewable</td>
<td>Bat – Battery</td>
<td>Road – road tanker</td>
</tr>
<tr>
<td>H2 – Hydrogen</td>
<td>Grn – Made with electrolysis produced hydrogen</td>
<td>LOHC – Liquid Organic Hydrogen Carrier</td>
<td>Pipe – Pipeline</td>
</tr>
<tr>
<td>MeOH – Methanol</td>
<td>Blu – Steam reformation of methane with carbon capture and storage</td>
<td>NH3 – Ammonia</td>
<td>Grid – through national electricity grid</td>
</tr>
<tr>
<td>NH3 – Ammonia</td>
<td>Gry – Steam reformation of methane</td>
<td>Pgas – Gas under pressure</td>
<td>Drc – direct electricity supply, bypassing grid</td>
</tr>
<tr>
<td>CH4 – Biomethane, natural gas</td>
<td>Bio – Biofuel</td>
<td>Liq – Liquid at ambient conditions</td>
<td></td>
</tr>
<tr>
<td>Dsl – Diesel, Marine Gas Oil</td>
<td>Foss – fossil fuel</td>
<td>Pliq – Liquid under pressure</td>
<td></td>
</tr>
<tr>
<td>IntC – intercepted waste carbon dioxide</td>
<td>Cliq – Cryo liquid (cryo is defined as below -153 °C)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>MGO – Fossil derived Marine Gas Oil</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 5-1  Abbreviations used in figures 5-6 to 5-9
At this stage, if electrolytic hydrogen is produced using a grid mix of electricity, the emissions associated with its production become significant. It can only be called “green” hydrogen if the electricity source is renewable - for example, it could be supplied directly from a dedicated renewable source, bypassing the electricity grid and any associated emissions.

5.5.2 Costs

summarises the costs of each fuel, based on similar combinations of production, transport, storage, and – in this case – refuelling, to those used for emissions. The same abbreviations are used, as set out in above.

A comprehensive set of tables for each stage (production, transport, storage, refuelling) along with the sources of data and calculation method is shown in Appendix 5E.

The 2023 total cost of MGO is shown, although long term forecasts of its costs have not been made. This is clearly the least expensive fuel at present. This is perhaps unsurprising, as it is by far the most established in supply chain and production. In the long term, zero emission fuels are still likely to be a little more expensive than MGO is now.

Of the zero or net zero emission fuels, in the short and longer term all varieties of ammonia, along with biomethanol, are cheaper than the other fuels; in the longer term, varieties of hydrogen, biomethanol and biodiesel all come close to the cost of ammonia, though ammonia is still expected to be the most economical in this application due to its much lower cost of storage. It is noticeable

![Figure 5-9: Forecast total costs for 2045, for all zero emission fuel combinations. Cost components are shown in detail. 2023 overall total is shown for comparison. 2023 total cost of MGO is also shown for comparison.](image)
that, for all fuels, the production and storage cost overwhelmingly dominate over transport and use, and for chemical fuels the production is the bigger of those two.

5.6 Discussion

It seems clear that hydrogen, ammonia, and methanol, along with battery stored electricity, will all be capable of producing a true net-zero solution in the quantities required provided an appropriate production method is used. Biodiesel will be able to come close, but the emitted carbon dioxide from the production will prevent it from reaching net zero unless Carbon Capture and Storage (CCS) is used during production.

From the perspective of market size and supply chain, current local and global production of ammonia, methanol and biodiesel are expected to be large enough that there should be no short-term difficulty in obtaining supplies. However, for ammonia and methanol this might initially include a proportion of fossil derived fuel. Both of these fuels have local renewable sources in development, which are currently expected to be available in advance of the vessels being launched. Present production of hydrogen is probably not sufficient, given the anticipated increase in demand, and low or zero carbon hydrogen is currently only available in very small quantities. However, there are a number of initiatives underway to increase production, and setting up a dedicated production facility is also a viable option.

Methanol will require extraction of carbon dioxide from the atmosphere, either via biomass used to produce the fuel or via direct capture of carbon dioxide from the atmosphere, to manufacture a true net-zero fuel. Direct air capture of carbon dioxide is currently in its infancy and hence expensive, although it is under development. Biodiesel will clearly also require a substantial amount of biomass. Biomass sources may have difficulties in securing enough land for the volumes required, however a report from Imperial College [19] suggests that there can be sufficient biomass available in Europe to make a significant contribution to renewable fuels, without adversely affecting food supply. On the expectation that this can be managed effectively in the longer run, methanol and biodiesel continue to be taken here as viable net zero fuels.

To effectively use electricity to power the example vessel, the battery would require to be enormous (586 MWh, 1400 tonnes) to provide for the whole mission to be refuelled or recharged fully from the start. By comparison, the largest battery system installed in Europe to date is 196 MWh, cost around £75 million, and covers approximate 1.6 hectares [20]. This is therefore prohibitive for the vessel and will not be considered further.

There is a potentially viable option of recharging from the wind turbines at sea, although the battery would still require to be large enough for the journey; a battery capacity of 50MWh has been proposed by the vessel technology workstream in the overall project. This would still represent an exceptionally large and expensive battery, by comparison with the above [20], and it would also require a very high charging rate of around 14 MW to recharge in a 4-hour window.

This leaves four potential net-zero fuels: hydrogen, ammonia, methanol, and biodiesel. All of these can be produced and used in a zero, or net-zero, emissions manner, provided CCS is used in the biodiesel production; the first three of these are currently produced predominantly in a manner that leads to greenhouse emissions, although they are obtainable in sufficient quantities for the requirements of the two vessels. However, there are projects in development which will lead to a net zero, or low carbon, version of these fuels being available by the time the vessels launch.
Whichever of these is selected, it would be necessary to ensure that, as quickly as possible, the fuel supply moves to a zero or net-zero emissions source.

In the case of hydrogen, there are two conveniently located projects to produce hydrogen on a zero or low emissions basis, which could probably be used to supply the vessels. However, the question of hydrogen storage is a further consideration. If it is stored as a compressed gas, readily available compressors could be used to refuel the vessel at a suitable pressure. If the hydrogen is stored as a liquid, then an additional liquefaction process would be required to be constructed at the refuelling or production areas, and the storage tanks and vessels on board the ship and at the fuelling sites are likely to be more expensive. The liquefaction process consumes approximately 22% of the energy stored in the hydrogen, compared to about 11% for compression of gas to 700 bar [21]. Liquefaction does, however, reduce the volume of storage required by around 50%, which leads to a net benefit in capital cost.

Hydrogen stored in the form of LOHC is an interesting option and a relatively recent development; in the short term it is likely to be the most expensive way of storing hydrogen, due to the need for large amounts of energy to release it from storage [15]. However, it may be possible to substantially reduce that demand by using waste heat from the ships’ drive systems [15], in which case the cost and efficiency of using LOHC will be greatly improved. However, in the longer run, as the basic fuel becomes cheaper, there is a further beneficial feedback in cost reduction so that LOHC appears to become the cheapest way to use hydrogen. Added to that, the LOHC compounds – charged or discharged – are non-toxic and easy to handle, bringing further benefits.

Table 5-1 below summarizes the key factors as they relate to these four fuels. These include overall emissions from production to use, safety factors, storage requirements, refilling or resupply rates, and anticipated annual and capital costs. This table is based on the most efficient use and storage method considered. This summary table also assumes that electricity used in production of the chemical fuels is from substantially decarbonised sources in the short term – that is, the 34g scenario – and is fully decarbonised in the long term.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Potential 2023 Net Emissions kgCO2e/kWh</th>
<th>Potential 2045 Net Emissions kgCO2e/kWh</th>
<th>2023 Unit cost, p/kWh</th>
<th>2045 Unit cost, p/kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>0.063</td>
<td>0.000</td>
<td>6.3-9.3</td>
<td>5.7-7.1</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>0.031</td>
<td>0.000</td>
<td>14.3-19.4</td>
<td>9.2-15.2</td>
</tr>
<tr>
<td>Methanol</td>
<td>0.008</td>
<td>0.000</td>
<td>9.3-25.1</td>
<td>8.4-16.8</td>
</tr>
<tr>
<td>Biodiesel</td>
<td>0.006</td>
<td>0.004</td>
<td>~ 11.1</td>
<td>~ 9.6</td>
</tr>
</tbody>
</table>

Table 5-1 Summary of positions of key fuel types.

Emissions shown are the best available options, assuming transport by diesel road tanker in the short term. Short term electricity production emissions are assumed to be 0.034 kg CO2 eq/kWh, and longer term are zero. By the end of the transition period, or well before, zero emissions road transport can be expected, leading to essentially zero emissions. The small amount of net emissions from biodiesel are in the production stage so could be captured and stored using CCS technology.

As discussed above, in the early stages, it should be possible to acquire enough zero or low emission versions of all these fuels. The fossil derived versions may prove to be cheaper in the short term, and might be considered as a backup, though obviously with an emissions penalty. 

below shows how the cost and emissions profile of the practical zero or net zero fuel types is expected to move through the transition.
Figure 5-10: Expected change in cost and emissions, various fuels, from 2023 to 2045.

5.7 Conclusion

In conclusion, then, it seems likely that a suitably large battery – even if only for a hybrid fuel solution – would be prohibitively complex and expensive for the mission profile envisaged. In fact, this is likely to be the case for other marine applications except for the shortest duration requirements, unless there is an order of magnitude improvement in battery technology in terms of weight, size and cost.

Therefore a chemical fuel will be required. Of the four potential net zero chemical fuels, that is ammonia, methanol, biodiesel and hydrogen, they all are capable of being deployed in a net zero manner. It appears that ammonia would be the cheapest in both the long term and short term, although in the longer term the forecast advantage over the other fuels is small and probably within a margin of error. It does have a higher risk profile due to its toxicity [22], but there are well-established procedures for handling ammonia, which has been shipped around the world in large quantities for over 100 years [22]. This global experience significantly mitigates the risk. Hydrogen starts off more expensive than the others, but in the longer run it is likely to be comparable to methanol and biodiesel. However, methanol and hydrogen are more likely to be readily available in the shorter term at a convenient location. Methanol, like ammonia, is somewhat toxic, but also has plenty of global experience in handling it safely [22]. Hydrogen does not have such toxicity issues, but accidental releases can have a meaningful secondary global warming effect due to its effect on other greenhouse gases such as methane and ozone. In the longer term, as the atmospheric concentrations of the affected gases decreases, the global warming consequences of leaked hydrogen will also decrease [23].

It seems that overall, Ammonia provides the best combination of short term availability, emissions reduction, cost profile, and risk. Methanol is not dissimilar, but is likely to be more expensive in the long run and appears to have a greater level of toxicity; balanced against that is the storage benefit of being liquid at ambient conditions. However, if the risk factor is considered more important, then hydrogen stored in the form of Liquid Organic Hydrogen Carrier is likely to be the optimum solution, and its costs will become competitive over time.

The costs will also be affected, however, by the efficiency of the drivetrain used. A fuel cell / electric drivetrain is around 50% more efficient than a combustion engine one. If the anticipated ammonia
fuel cells do not become commercially available, meaning that internal combustion engines are required to use ammonia, then hydrogen used in a fuel cell will become more cost competitive.

This approach can be taken for other shipping uses, though the result will not always be the same – the most important differentiating factor will be the intended duration of the voyage, which will affect the cost of on-board storage and the rate at which fuel has to be delivered to the dockside. A very short duration mission profile could allow batteries to become more competitive.

5.8 Acknowledgements

I would like to recognise the input of Dr Wei Sun, University of Edinburgh School of Engineering, for help and support in planning the work, reviewing the outputs, and in liaising with the project management / funding agency.

Also, the wider team carrying out the SOV Zero Emission Fuels and Technology Feasibility Study; their work provided the necessary context for this chapter.

5.9 Funding

This project was funded by BP, and managed on their behalf by the Offshore Renewable Energy Catapult.

5.10 Conflict of Interest

There are no conflicts of interest to declare.
6 Conversion of natural gas network to hydrogen

This final core chapter considers the implications of converting the existing natural gas distribution network to carry hydrogen. If the existing network can be fairly readily converted, then this will be a cheap and robust method of delivering hydrogen nationwide. The main aim here is to consider the capacity issue; can the existing gas network deliver enough hydrogen to provide a suitable service to consumers? If not, what can be done to enhance the network capacity?

Through the Iron Mains Replacement Programme, also known as the 30 in 30 programme, every iron or steel gas main within 30 metres of a property is to be replaced with Polyethylene pipes. This programme started in 2002, and is expected to finish after 30 years, in other words 2032 [1].

These polyethylene pipes are expected to be impervious to hydrogen as well as natural gas [2]. This means that the almost £28 billion investment in replacing these pipes can continue to be used for the lifetime of the new polyethylene pipes, facilitating the replacement of natural gas use in domestic and commercial properties. Natural gas distributed this way is most commonly used for heat, either in a domestic context of space heating and cooking, or for various industrial processes; it can be reasonably expected that hydrogen transported in the same network will be used for the same purposes. However, it is also possible that the network could have enough capacity to transport hydrogen for vehicle fuelling as well, as described earlier in chapter 2.

A computer model was constructed using Python of an example network inspired by the real life natural gas network for Scotland. This uses the scale of both the local transmission network and the intermediate pressure distribution network. The real network is considerably more complicated than the modelled one network, which is very much a simplified one for the purpose of evaluating the options.

This modelled network was created to reflect the performance of a natural gas network with adequate capacity but limited excess. It was then tested for hydrogen by changing the key characteristics – viscosity, density, and specific energy.

As constraints, the pressure and flow velocity parameters specified by the pipe manufacturers and the UK gas network operation regulations were used [3]. Exceeding the flow velocity has the potential to entrain dust in the flow, resulting in scour damage to the inside of the pipe [4].

The hypotheses tested here are:

1. The natural gas network can be converted to supply enough pure hydrogen to replace all natural gas in use, on the basis of energy transported, without enlargement or replacement of the pipes.
2. It will be possible to identify which parts of the network will need intervention when converted to supply hydrogen, on the basis of the natural gas characteristics alone.
6.1 Abstract

It has been described frequently that the existing natural gas network could be converted to carry hydrogen. This is because the polyethylene pipes, which the majority of the natural gas network is comprised of, are thought to be safe for the transportation of hydrogen. These polyethylene pipes have been installed as part of the UK’s ongoing Iron Mains Replacement Programme.

Hydrogen has often been described as being a potential replacement for natural gas as well as for vehicle fuel. While it may be possible to convey hydrogen in principle through the existing and imminently installed polyethylene pipes, the question remains as to whether the network will have sufficient capacity to deliver enough hydrogen to consumers. The key concern is that the while the specific energy of hydrogen is significantly higher than natural gas, the energy density is considerably lower. This means that in order to deliver the same amount of energy to consumers as is currently delivered using natural gas, the volume flow rate must be considerably greater. As a corollary to this, the flow velocity will be considerably higher.

Manufacturers set a maximum permissible flow velocity to limit the amount of scour that might occur on the inside of pipes due to the entrainment of dust in the gas flow. The gas network regulators has a range of operating pressure at which the gas mains are operated.

A model was built using Python, based loosely on the existing pipe network for natural gas serving the east of Scotland from the main injection point at St Fergus, just north of Aberdeen, down to the Scottish Borders region. This model was then tested with hydrogen gas instead of natural gas.

In most cases the hydrogen could be transmitted through the pipeline within the pressure and velocity constraints. The lower density and viscosity of hydrogen compared to natural gas mean that the pressure loss is less than might have been expected, although there is still invariably a bigger pressure loss than for natural gas. Nevertheless, there are localised areas where the maximum flow velocity is exceeded, or pressure falls below that required to sustain the required service level at peak times. In these cases, additional short term downstream storage needs and/or boosting the upstream pressure are required to restore service levels.

The storage requirements in this respect would in all cases have to be less than 24 hours supply; there is always enough capacity to deliver 24 hours’ demand in the space of 24 hours.

A means of predicting which pipes will be able to deliver enough energy in the form of hydrogen, and which will require the upstream pressure boost and/or downstream short term storage, is also tentatively proposed.
6.2 Introduction

It has been described, or accepted [5], that the natural gas network could be converted to carry hydrogen. This is because the polyethylene pipes which comprise the majority of the natural gas network are thought to be safe for the transportation of hydrogen [6, 7]. These polyethylene pipes have been installed as part of the UK mandated Iron Mains Replacement Programme, which is a replacement of all the UK’s iron gas mains within 30 metres of a property for safety reasons, over a 30 year period scheduled to finish in 2032 [1].

Hydrogen has been described as being a potential replacement for natural gas as well as for vehicle fuel, as described in the preceding chapters. While it may be possible in principle to convey hydrogen through the existing and anticipated polyethylene pipes, the question remains as to whether the network will have sufficient capacity to deliver enough hydrogen to consumers. While the specific energy of hydrogen is about 2.6x higher than natural gas, the energy density of natural gas is about 9 – 11x greater than hydrogen (pressure dependent). This means that in order to deliver the same amount of energy to consumers as is currently delivered using natural gas, the volume flow rate of hydrogen must be considerably greater.

Manufacturers establish a maximum permissible flow velocity to limit the amount of scour that might occur on the inside of pipes due to the entrainment of dust in the gas flow. It is possible that a higher velocity might be acceptable if it can be shown that the dust transported by hydrogen is lower than that transported by natural gas at higher flow velocities. That is outwith the scope of this initial analysis, however, although the extent to which the high velocity problem exists will be identified.

The UK gas operating companies have a range of operating pressures at which it operates the gas means. There are four different classes of pressure ratings for gas pipes [3]:

- High Pressure / Transmission mains 700 – 8500 kPa
- Intermediate pressure 200 – 700 kPa
- Medium pressure 7.5 – 200 kPa
- Low pressure / distribution mains – below 7.5 kPa.

To investigate these questions, A simple model using Python was constructed and interrogated. This was based loosely on the existing network for natural gas serving the east of Scotland from the main injection point at St. Fergus, north of Aberdeen, down to the Scottish Borders region. For the purposes of this analysis, only high and intermediate pressure pipes were considered. The model network, described in more detail below, takes the core transmission section as equivalent to high pressure. The pipes, leading to the local authority based demand nodes, are taken as equivalent to intermediate pressure pipes. These two classes of pipe are termed ‘network pipes’ and ‘demand pipes’ in the model respectively. The implication is that the medium and low pressure mains comprise the distribution network downstream of the modelled demand points. In reality, the interface between the different pressure regimes is not so clear cut.
6.3 Previous relevant work

In An Investigation into the Volumetric Flow Rate Requirement of Hydrogen Transportation in Existing Natural Gas Pipelines and Its Safety Implications, Abbas et al [8] limit their analysis to a single large diameter pipe. They mention a 3x increase in volume flow requirement, though this refers to the volume difference at ambient conditions rather than at pressure.

In Conversion of the UK gas system to transport hydrogen (2013), Dodds & Demoulin [7] carry out a series of expert interviews and a literature review to consider broadly the opportunity to convert the UK gas network to supply hydrogen. In terms of energy transportation capacity, they find that the energy transmissibility with hydrogen is ‘approximately 20% lower’ than for natural gas, in the same pipe and upstream pressure.

Dodds & Demoulin also anticipate an increase of 25% (which could be mitigated) in demand for gas-transported energy, with the expectation that households would adopt fuel cell powered micro-CHP (Combined Heat & Power generation) instead of the conventional heating boilers. This is in contrast to the current trend towards electric powered heat pumps for domestic heating [9]. A number of studies have considered a combined approach between these two technologies, for example Yang et al [10] and Cooper et al [11].

In this study, the related aim is to consider a wider range of pipe diameters and pressure regimes to understand if the 3x factor is broadly applicable, to confirm the ‘approximately 20%’ reduction in energy transmissibility, and to understand the relevance of those figures in a more detailed scenario.

6.4 Methods

6.4.1 Network arrangement

The starting point was the network of gas pipes supplying the whole of Scotland. This information was obtained from Scotland Gas Network's GIS database. This network is considerably too complicated to permit the creation of a detailed representative model of this type. Instead, a simple hypothetical network was created, loosely based on – or ‘inspired by’ might be a better expression – the real network. This allows a much more simple model to be created, with some confidence that it is at a realistic scale and variability. It is not, however, intended to be a representative simulation of the real network; just an experimental model at a life-like scale.

Initially it was based on the entire Scottish network, but including both the east (Kirriemuir – Dunfermline – Lauder) and west (Kirriemuir – Stirling – Glasgow – Dumfries) sections added considerable additional and unnecessary complexity – see Figure 6-1 N below.

So, the model was pared back created to reflect the network and the associated demands down the eastern side of Scotland. This is laid out such that it can be simplified to a ‘tree’ type network, that is a central core and with branches, but no loops. Demand nodes were taken as local authorities. This was because enough information is collected at the level of local authorities to allow these to be created as realistic demand nodes. A single injection node was created at St Fergus, north of Aberdeen. This is the injection point for all of the natural gas currently used in Scotland and about one-third of the whole UK. A related assumption is that the hydrogen would be produced offshore at the forthcoming extensive North Sea wind farms [12], or immediately onshore with electricity direct from those windfarms, and similarly injected at St Fergus.

The network derived this way is shown in Figure 6-1N, superimposed on an image of the actual network for comparison.
The demand nodes were identified as the main town or city within each local authority, in which the local authority head office is based. The only exception to this was Aberdeenshire because Aberdeenshire's council office is actually within the city of Aberdeen, a different local authority. The town of Banchory was chosen as an appropriate location for the representation of the node point. Network nodes, defined as junctions without a demand, were created at appropriate points reflecting the real-life network as much as possible. All of these node points were defined by their National Grid coordinates, and were allocated a four letter name derived from the local authority name (for demand nodes) or the nearest town (network nodes) and a number. The pipes themselves were created simply as a straight line between the relevant National Grid coordinates.

6.4.2 Model calculation basis

The model is designed so that unlimited flow is available at the upstream end at a constant pressure, held at 8500kPa – the maximum operating pressure of transmission pipes, as in section 6.2. The flow through the model is then driven by the demand, which is accumulated up the network from the downstream end.

The pressure loss in each transmission pipe is then found from equations of flow (see section 6.4.4), based on the volume flow in the pipe and the upstream pressure, along with the pipe and fluid characteristics, starting at the top of the network with its fixed pressure. This then allows the downstream pressure in each pipe to be calculated, which is the same as the upstream pressure in
the next pipe. This approach is possible because it is a simple ‘tree’ model, i.e. a central transmission ‘trunk’ with ‘branches’ off it, and no loops.

The upstream pressure in the demand pipes (based on Intermediate Pressure pipes) is in reality governed by a pressure regulator to a maximum of 700kPa. This is modelled by setting the upstream node pressure to the lesser of the transmission pipe pressure at the same node, or 700kPa.

The flow velocity is found from the volume flow rate, which comes from the demand or cumulative demand, and the pipe cross sectional area.

### 6.4.3 Pipe diameters

The modelled pipe diameters were set up using a manually iterative process, by running the model and identifying the minimum standard size commercially available pipe that would allow the pressure targets to be met with natural gas. This provides for a model which can deliver the current peak demand, but has little spare capacity. It does, by implication, have excess capacity at lower demand periods. The flow velocity was checked, and for each of the pipes in the network, it was found that the maximum flow velocity was well within the tolerance set by the manufacturers (a maximum flow velocity of 40 m/s is permitted [4]).

### 6.4.4 Equations of flow

The equations of flow used are the Buzzelli solution to the Darcy Weisbach[13] flow equations.

The Buzzelli and Darcy Weisbach procedure calculates the pressure drop in a pipe, based on inputs including the pipe characteristics, the gas flow rate (determined by demand), and the gas viscosity and density. Because the density varies greatly with pressure, and the viscosity varies somewhat with pressure, this is an iterative process; the calculation must be repeated based on a changing assumed pressure drop until the calculated pressure drop equals the assumed pressure drop.

The Buzzelli solution takes the form:

\[
B1 = \left( \frac{0.774 \ln(Re) - 1.41}{1 + 1.32 \left( \frac{Re}{D} \right)^{0.5}} \right)
\]

\[\text{Equation 6-1}\]

\[
B2 = \frac{ks \cdot Re}{3.7 \cdot D} + 2.51
\]

\[\text{Equation 6-2}\]

\[
\frac{1}{f_D^{1/2}} = B1 - \left( \frac{B1 + 2 \log_{10}(\frac{B2}{Re})}{1 + \left( \frac{2 \ln(B1)}{B2} \right)} \right)
\]

\[\text{Equation 6-3}\]

The Darcy Weisbach flow equation is

\[
\Delta P = \left( \frac{L \cdot f_D \cdot p \cdot V^2}{2 \cdot D} \right)
\]

\[\text{Equation 6-4}\]

Where

- \(L\) = length of pipe. Set in the model structure.
- \(ks\) = Pipe roughness coefficient. Looked up from standard tables and set in the model structure.
- \(D\) = pipe diameter. Set in the model structure, manually varied.
- \(\Delta P\) = change in pressure along pipe length. Iterated through the computation.
- \(f_0\) = Darcy friction factor (also called the flow coefficient). Recalculated each iteration step.
- \(P\) = pressure – taken as linear mean pressure. Recalculated each iteration step.
ρ = ﬂuid density. Recalculated each itera on step, from look-up tables based on P.
μ = dynamic viscosity of the ﬂuid. Recalculated each itera on step, from look-up tables based on P.
V = ﬂow velocity. Recalculated each itera on step.
Re = Reynolds Number. Re = ρ.D.V/ μ, recalculated each itera on step.

The commonly accepted solu on to the Darcy Weisbach theory is the Colebrook – White equa on
[13]. However, that is itself an itera ve calcula on, so the analysis would require a double itera on,
which would be computa onally complex. Within this project, a separate comparison was made
between the Buzzelli calcula on and the Colebrook-White method; the results were found to agree
to an accuracy of be er than 0.1%, which should be is more than adequate for these purposes.
Demands
Demand data was set up at each of the node points by combining a number of sources. The
popula on of each local authority was obtained from the Sco sh Government, along with the gross
annual gas usage for Scotland. These were combined to produce an annual average consump on
for each local authority in propor on to its popula on, which was converted into an average daily
consump on. This average daily consump on ﬁgure was converted into an hourly demand proﬁle
based on standard varia on curves provided by Scotland Gas Networks. This gave a 24 hour
demand proﬁle as shown in Table 6-1.
Calculated hourly energy demand at each demand node, over 24 hours. Values in MWh/hour (i.e. MW)
Hr. ND26_ ND27_ ND28_ ND29_ ND31_ ND32_ ND33_ ND34_ ND35_ ND36_
Wlot
Edin
Mlot
Elot
Fife
Dund
Angs
Absh
Abdn
Mory
1
92.7
265.8
46.8
54.2
189.2
75.6
58.8
132.3
115.8
48.5
2
61.8
177.2
31.2
36.2
126.1
50.4
39.2
88.2
77.2
32.4
3
61.8
177.2
31.2
36.2
126.1
50.4
39.2
88.2
77.2
32.4
4
61.8
177.2
31.2
36.2
126.1
50.4
39.2
88.2
77.2
32.4
5
71.1
203.8
35.9
41.6
145.0
58.0
45.1
101.4
88.8
37.2
6
120.5
345.6
60.9
70.5
245.9
98.3
76.5
172.0
150.5
63.1
7
268.9
770.9
135.8
157.3
548.6
219.3
170.7
383.6
335.8
140.7
8
309.1
886.1
156.1
180.8
630.6
252.1
196.2
440.9
386.0
161.7
9
247.3
708.9
124.9
144.6
504.4
201.6
156.9
352.7
308.8
129.4
10
216.4
620.3
109.3
126.5
441.4
176.4
137.3
308.7
270.2
113.2
11
200.9
576.0
101.5
117.5
409.9
163.8
127.5
286.6
250.9
105.1
12
200.9
576.0
101.5
117.5
409.9
163.8
127.5
286.6
250.9
105.1
13
200.9
576.0
101.5
117.5
409.9
163.8
127.5
286.6
250.9
105.1
14
200.9
576.0
101.5
117.5
409.9
163.8
127.5
286.6
250.9
105.1
15
200.9
576.0
101.5
117.5
409.9
163.8
127.5
286.6
250.9
105.1
16
253.4
726.6
128.0
148.2
517.1
206.7
160.8
361.6
316.5
132.6
17
278.2
797.5
140.5
162.7
567.5
226.9
176.5
396.8
347.4
145.6
18
293.6
841.8
148.3
171.7
599.0
239.5
186.3
418.9
366.7
153.7
19
247.3
708.9
124.9
144.6
504.4
201.6
156.9
352.7
308.8
129.4
20
231.8
664.6
117.1
135.6
472.9
189.0
147.1
330.7
289.5
121.3
21
216.4
620.3
109.3
126.5
441.4
176.4
137.3
308.7
270.2
113.2
22
154.5
443.0
78.0
90.4
315.3
126.0
98.1
220.5
193.0
80.9
23
123.6
354.4
62.4
72.3
252.2
100.8
78.5
176.4
154.4
64.7
24
92.7
265.8
46.8
54.2
189.2
75.6
58.8
132.3
115.8
48.5

ND37_
High
119.4
79.6
79.6
79.6
91.6
155.3
346.3
398.1
318.5
278.7
258.8
258.8
258.8
258.8
258.8
326.4
358.3
378.2
318.5
298.6
278.7
199.0
159.2
119.4

ND39_
Pkin
77.0
51.3
51.3
51.3
59.0
100.0
223.2
256.5
205.2
179.5
166.7
166.7
166.7
166.7
166.7
210.3
230.8
243.7
205.2
192.4
179.5
128.3
102.6
77.0

ND46_
Sbor
58.5
39.0
39.0
39.0
44.9
76.0
169.6
195.0
156.0
136.5
126.7
126.7
126.7
126.7
126.7
159.9
175.5
185.2
156.0
146.2
136.5
97.5
78.0
58.5

Table 6-1 Calculated hourly gas energy demand at demand nodes, in MWh/hour, or simply MW.

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6.4.6 Model code and functionality

The model code is presented in Appendix 6A. The flowchart in Figure 6-2 Mo below outlines the function of the code.

Figure 6-2 Model code schematic.
Core functions only are shown, not presentation of outputs or summing of aggregate pipe values.
6.4.7 Test with hydrogen

The model was then re-calculated with hydrogen as a gas in the same pipes; this was simulated by using the density, viscosity and specific energy appropriate to hydrogen instead of to natural gas.

6.5 Results

6.5.1 Initial setup

The process of setting up the pipes gave the following dimensions and peak flow pressure situations for natural gas.

<table>
<thead>
<tr>
<th>Pipe name</th>
<th>Diameter (m)</th>
<th>Length (m)</th>
<th>Upstream Pressure (kPa)</th>
<th>Downstream Pressure (kPa)</th>
<th>Pressure drop (kPa)</th>
<th>Velocity (m/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network pipes</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PN00_Sfeg_Petc</td>
<td>0.5</td>
<td>57,558</td>
<td>8500</td>
<td>7241</td>
<td>1259</td>
<td>6.07</td>
</tr>
<tr>
<td>PN01_Petc_Foch</td>
<td>0.25</td>
<td>76,121</td>
<td>7241</td>
<td>6012</td>
<td>1228</td>
<td>3.72</td>
</tr>
<tr>
<td>PN02_Petc_Kiri</td>
<td>0.45</td>
<td>65,160</td>
<td>7241</td>
<td>5778</td>
<td>1463</td>
<td>6.42</td>
</tr>
<tr>
<td>PN03_Kiri_Glen</td>
<td>0.45</td>
<td>39,357</td>
<td>5778</td>
<td>4795</td>
<td>982</td>
<td>7.60</td>
</tr>
<tr>
<td>PN04_Glen_Dunf</td>
<td>0.45</td>
<td>35,503</td>
<td>4795</td>
<td>4050</td>
<td>746</td>
<td>7.64</td>
</tr>
<tr>
<td>PN05_Dunf_Balo</td>
<td>0.4</td>
<td>22,717</td>
<td>4050</td>
<td>3487</td>
<td>563</td>
<td>8.43</td>
</tr>
<tr>
<td>PN06_Balo_Laud</td>
<td>0.25</td>
<td>41,028</td>
<td>3487</td>
<td>2774</td>
<td>713</td>
<td>5.74</td>
</tr>
<tr>
<td>Demand pipes</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PD19_Petc_Abdn</td>
<td>0.35</td>
<td>11,950</td>
<td>700</td>
<td>460</td>
<td>240</td>
<td>17.21</td>
</tr>
<tr>
<td>PD20_Petc_Absh</td>
<td>0.4</td>
<td>15,328</td>
<td>700</td>
<td>501</td>
<td>199</td>
<td>14.55</td>
</tr>
<tr>
<td>PD21_Foch_Mory</td>
<td>0.25</td>
<td>13,801</td>
<td>700</td>
<td>400</td>
<td>300</td>
<td>14.91</td>
</tr>
<tr>
<td>PD22_Foch_High</td>
<td>0.5</td>
<td>69,400</td>
<td>700</td>
<td>435</td>
<td>265</td>
<td>8.85</td>
</tr>
<tr>
<td>PD23_Kiri_Angs</td>
<td>0.25</td>
<td>7,811</td>
<td>700</td>
<td>474</td>
<td>226</td>
<td>16.85</td>
</tr>
<tr>
<td>PD24_Glen_Dund</td>
<td>0.35</td>
<td>26,549</td>
<td>700</td>
<td>458</td>
<td>242</td>
<td>11.24</td>
</tr>
<tr>
<td>PD25_Glen_Pkin</td>
<td>0.25</td>
<td>3,500</td>
<td>700</td>
<td>541</td>
<td>159</td>
<td>20.96</td>
</tr>
<tr>
<td>PD26_Dunf_Fife</td>
<td>0.45</td>
<td>22,883</td>
<td>700</td>
<td>318</td>
<td>382</td>
<td>19.37</td>
</tr>
<tr>
<td>PD27_Balo_Wlot</td>
<td>0.3</td>
<td>11,032</td>
<td>700</td>
<td>360</td>
<td>340</td>
<td>20.55</td>
</tr>
<tr>
<td>PD28_Balo_Edin</td>
<td>0.45</td>
<td>12,485</td>
<td>700</td>
<td>300</td>
<td>400</td>
<td>27.77</td>
</tr>
<tr>
<td>PD29_Balo_Mlot</td>
<td>0.25</td>
<td>16,890</td>
<td>700</td>
<td>336</td>
<td>364</td>
<td>15.23</td>
</tr>
<tr>
<td>PD30_Laud_Elot</td>
<td>0.3</td>
<td>26,331</td>
<td>700</td>
<td>415</td>
<td>285</td>
<td>11.37</td>
</tr>
<tr>
<td>PD31_Laud_Sbor</td>
<td>0.3</td>
<td>16,600</td>
<td>700</td>
<td>510</td>
<td>190</td>
<td>11.25</td>
</tr>
</tbody>
</table>

Table 6-2 Initial model setup of pipe diameter, length, and corresponding pressures, with natural gas.

Note that where more than 700 kPa is available upstream of a demand pipe, it is regulated down to 700 kPa in accordance with gas operating companies operating practice [3]. It can also be seen that the flow velocities are well within the 40m/s limit.

6.5.2 Hydrogen pressure drops

We can see from Table 6-3 below that when the network is converted to hydrogen, the pressure drop in each pipe is greater than when it is used for natural gas. This effect is cumulative down the network pipes, meaning that in the southern (downstream) end of the network the available pressure at the upstream end of the demand pipes is lower than the 700 kPa requirement for serviceability. The higher flow velocity is the main contributor to the additional pressure loss. This is a function of the low density of hydrogen.
Clearly some method of boosting the pressure will be required. Trials of (1) a single pressure boost at the upstream end of the low pressure zone, and (2) multiple small pressure boosts distributed along the length of the pipe were carried out. The outcome of this is set out in Table 6-3 below.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Upstream (kPa)</td>
<td>Downstream (kPa)</td>
<td>Pressure drop (kPa)</td>
</tr>
<tr>
<td>PN00_Sfeg_Petc</td>
<td>8500</td>
<td>6143</td>
<td>2357</td>
</tr>
<tr>
<td>PN01_Petc_Foch</td>
<td>6143</td>
<td>3194</td>
<td>2949</td>
</tr>
<tr>
<td>PN02_Petc_Kiri</td>
<td>6143</td>
<td>2450</td>
<td>3693</td>
</tr>
<tr>
<td>PN03_Kiri_Glen</td>
<td>2450</td>
<td>0</td>
<td>2450</td>
</tr>
<tr>
<td>PN04_Glen_Dunf</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>PN05_Dunf_Balo</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>PN06_Balo_Laud</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 6-3  Comparison of pressure drops with hydrogen, network pipes only, with initial conditions and pressure boosted on the network pipes. Boosted pressures shown in shaded bold.

We can see from this that both of these approaches are viable. The best one to take in reality would depend on a more detailed analysis of the real life circumstances, which is beyond the scope of this study. We can also see that the maximum flow velocity only slightly exceeds the maximum specified by manufacturers; the acceptability of this will require further investigation, but the lower density and viscosity of hydrogen may mean that it entrains less scour-causing dust, making a higher velocity acceptable.

Once the upstream pressure in the demand pipes is high enough (i.e. 700 bar) then there is adequate pressure to provide enough hydrogen at most of the demand points. However in some cases this is not possible. Two solutions were trialled: an increase in pipe capacity by the simple expedient of increasing the upstream pressure; and the provision of downstream storage. This is shown in Table 6-4.
Table 6-4 Demand pipes pressure drop with hydrogen at peak flow.

Entries in bold show where the minimum allowable downstream pressure is reached, meaning that insufficient hydrogen can be delivered to meet demand within the pressure requirement. Note the peak flow velocities generally become very high in these pipes due to the lower pressure than network pipes, although the mean flow velocity in the event of storage is within manufacturer’s specifications.

Increasing the upstream pressure helps in two ways. The first is more obvious: more pressure available means that given the losses due to flow, more pressure is available downstream. The second is more subtle: by operating the pipe at a higher pressure, the gas density increases. Therefore the same mass of gas – and hence energy – can be transferred at a lower volume flow rate. This means the flow velocity is lower, leading to lower pressure loss due to flow. This is why flow velocities are lower at higher pressure. Nevertheless, even at higher pressures there are several pipes which exceed 40 m/s flow velocity.

A relatively small increase in upstream pressure from 700 kPa to 850 kPa was enough to overcome the additional losses through the demand pipes. This is still within the European standard pressure rating of such pipes of 10bar / 1,000 kPa [14], and in usual practice could be achieved from the pressure available in the transmission pipe rather than requiring an active booster pump. However, there may be other operating factors preventing the widespread adoption of this higher pressure rating – including lack of certainty of the pressure rating of pipes installed many years ago.

The downstream storage is not explicitly modelled; instead, a separate analysis was made of the maximum capacity of each pipe, given the specified upstream pressure. The maximum daily delivery of the pipe was then calculated as that maximum capacity multiplied by 24 hours. In every case, the maximum capacity so calculated exceeds the total 24-hour demand by a factor of at least...
1.46. Also, the mean velocity required to deliver the required quantity is always within the 40 m/s operating practice limit. This indicates that the lack of capacity to meet the highest hourly demand can be addressed by the provision of a downstream local storage facility of less than 24 hours’ capacity. Due to the issue of flow velocities, the downstream storage is likely to be a more robust solution than operating at increased pressure.

6.5.3 Correlation and prediction

Figure 6-3 and Figure 6-4 show the relative velocities of natural gas and hydrogen in each pipe.

![Figure 6-3](image1)

**Figure 6-3** Flow velocity of hydrogen against flow velocity of natural gas, network pipes. Each data point represents a one-hour time increment in a single pipe. Each coloured line represents the 24 hour flow pattern of a single pipe, although identifying the individual pipes is not important at this stage.

![Figure 6-4](image2)

**Figure 6-4** Flow velocity of hydrogen against flow velocity of natural gas, demand pipes. Each data point represents a one-hour time increment in a single pipe. Each coloured line represents the 24 hour flow pattern of a single pipe, although identifying the individual pipes is not important at this stage.

It can be seen clearly that there is a minimum gradient to these. This represents the multiple by which hydrogen flow velocity is greater than natural gas flow velocity - around 3.6 for demand pipes.
and 4.4 for network pipes. This is due to the difference in specific energy (natural gas: 13.9 kWh/kg, hydrogen 36.35 kWh/kg, a factor of 2.6) and density. At higher pressure ranges, the density difference is a factor of up to 11.5 (natural gas / hydrogen); at the lower ranges it is around 9.1. The minimum gradients then are found from:

\[ V_h = \frac{V_{ng}SpE_{ng}SpE_h}{\rho_h SpE_{ng}} \]

*Equation 6-5*

Where

- \( V \) = velocity (m/s)
- \( \rho \) = density (kg/m³)
- \( SpE \) = Specific Energy (kWh/kg)
- (h) denotes Hydrogen
- (ng) denotes Natural Gas

This suggests that there is some correlation between the existing natural gas regime flow and pressure and the likelihood of a pipe being unable to deliver the required energy via hydrogen. Understanding this could enable forecasting of which pipes to prioritise for intervention, such as pressure boost or additional downstream storage.

Pearson correlation coefficients [15] were calculated for each potential natural gas parameter which might cause the hydrogen delivery capacity to be exceeded.

The Pearson correlation coefficient is found from the equation

\[ pcc = \frac{\sum(x_i - \bar{x})(y_i - \bar{y})}{(n - 1)s_x s_y} \]

*Equation 6-6*

Where

- \( pcc \) = Pearson Correlation Coefficient
- \( x_i \) is the individual value of the parameter being considered
- \( \bar{x} \) is the mean value of the parameter being considered
- \( y_i \) is the individual value of the parameter to be forecast
- \( \bar{y} \) is a mean value of the parameter to be forecast
- \( n \) is the number of samples in the data set
- \( s_x \) is the standard deviation of parameter \( x \)
- \( s_y \) is the standard deviation of parameter \( y \).

The result of this calculation is a single value between -1 and 1, for each parameter. A strong correlation between the two parameters gives a result close to either -1 or 1; the closer the result to zero, the weaker the correlation.

The parameter to be forecast was created as the flow exceedance ratio (FER), defined as

\[ FER = \frac{Q_m(\text{demand})}{Q_m(\text{max})} \]

*Equation 6-7*

Where \( Q_m(\text{demand}) \) is the mass flow demand, derived from the energy demand profile, and \( Q_m(\text{max}) \) is the maximum mass flow given the pipe and fluid characteristics, and the upstream pressure.
The Pearson correlation coefficient for a number of parameters potentially relating to the FER(h), as shown in Table 6-5:

<table>
<thead>
<tr>
<th>Parameter (NB. ng = natural gas)</th>
<th>pcc</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area/Length</td>
<td>-0.051</td>
</tr>
<tr>
<td>$Q_{m\text{(demand)}}\ (\text{ng})$</td>
<td>0.112</td>
</tr>
<tr>
<td>$Q_{m\text{(max)}}\ (\text{ng})$</td>
<td>-0.262</td>
</tr>
<tr>
<td>$Q_{m\text{(demand)}}\ /\ Q_{m\text{(max)}}\ (\text{ng})$</td>
<td>0.836 ($= \text{FER(ng)}$)</td>
</tr>
<tr>
<td>$V(\text{ng})$</td>
<td>0.666</td>
</tr>
<tr>
<td>$R_{e\text{(ng)}}$</td>
<td>0.189</td>
</tr>
<tr>
<td>$V(\text{max})(\text{ng})$</td>
<td>-0.101</td>
</tr>
<tr>
<td>$R_{e\text{(max)}}(\text{ng})$</td>
<td>-0.279</td>
</tr>
</tbody>
</table>

Table 6-5  Pearson correlation coefficients, various potential forecasting parameters.

$Q_m =$ mass flow rate  
$V =$ flow velocity  
$R_e =$ Reynold’s number  
$V(\text{max}) =$ maximum flow velocity  
$R_{e\text{(max)}} =$ maximum Reynold’s number.

Clearly, there is a fairly strong correlation between the FER(ng) and FER(h). There is also a moderately strong correlation with $V(\text{ng})$.

Charting FER(h) against FER(ng) produces Figure 6-5:

![Figure 6-5 Chart showing FER(h) against FER(ng). Each data point represents a one-hour time increment in a single pipe. Each coloured line represents the 24 hour flow pattern of a single pipe, although identifying the individual pipes is not important at this stage.](image-url)
The solid base line of minimum gradient includes all the demand pipes. This passes through the point FER(ng) = 0.8, FER(h) = 1.0. Where the FER exceeds 1.0, the demand is greater than the maximum possible supply, and the pipe fails. This corresponds to the 20% lower energy delivery for hydrogen identified by Dodds & Demoulin [7], discussed in the introduction above. The upward ‘tails’ are where the network pipes begin to fail to deliver the required quantity of hydrogen. A key observation here is that the demand pipes are modelled at a fixed upstream pressure, while the network pipes have a gradually reducing pressure upstream pressure further downstream. This appears to be connected to the fact that the demand pipes show a consistent ratio in Figure 6-5, while the network pipes do not.

This was normalised for pressure by plotting FER(h).Pup(h) against FER(ng).Pup(ng), where Pup is pressure upstream. With some experimentation, this became FER(h).Pup(h)\(^{1.1}\) against FER(ng).Pup(ng)\(^{1.1}\) to achieve a closer correlation. This is shown below in Figure 6-6.

![Figure 6-6 FER(h).Pup(h)\(^{1.1}\) against FER(ng).Pup(ng)\(^{1.1}\).](image)

This shows a very strong correlation, which can be expressed as:

\[
\text{FER}_h \cdot \text{Pup}_h^{1.1} = 1.27 \cdot \text{FER}_{ng} \cdot \text{Pup}_{ng}^{1.1}
\]

*Equation 6-8*

However, Equation 6-8 is not fully predictive of FER\(_h\), as it requires knowledge of Pup, the upstream pressure. We need to know when FER\(_h\) will exceed 100%, without knowledge of other factors relating to hydrogen.

Charting Pup\(_h\) against Pup\(_{ng}\), restricted to network pipes, produces Figure 6-7:
It appears that there is a close relationship. After some experimenting, a close correlation between \( P_{uph}^{1.85} \) and \( P_{upg}^{1.85} \) was found – as shown in Figure 6-8:

\[
P_{uph}^{1.85} / P_{upg}^{1.85} = 1.768.
\]

Equation 6-9

By calculating the \( P_{uph} \) from that formula for network pipes then substituting it for the relationship shown in Figure 6-6, the following relationship is found:
We can simply rearrange Equation 6-8 here to:

$$FER_h = 1.27 \cdot FER_{ng} \cdot \left(\frac{Pup_{ng}}{Pup_h}\right)^{1.1}$$

*Equation 6-10*

Where $Pup_h$ is found from the rearranged Equation 6-9:

$$Pup_h = \left(1.768 \cdot Pup_{ng}^{1.85} - 14.3 \times 10^6\right)^{0.541}$$

*Equation 6-11*

And clearly, from Figure 6-9, when $FER_{ng} \cdot \left(\frac{Pup_{ng}}{Pup_h}\right)^{1.1}$ exceeds approximately 0.79, then the $FER_h$ will exceed 100%, and the pipe will be unable to deliver the quantity of hydrogen required.

### 6.6 Discussion and conclusion

#### 6.6.1 Model construction.

In terms of the model construction, this worked well. While obviously it cannot replicate the real world situation, it provides a big enough range of scenarios to provide some insight into the expected behaviour of the real network. On reflection, it might have been more representative to use the peak winter demand rather than the annual average. However, the model pipe sizes chosen are relative to the calculated peak demand, and the consequences of conversion to hydrogen are considered relative to the initial conditions, so the results would not be materially different.

A key assumption in the model construction has been to use a specific energy value for hydrogen of 36.35 kWh/kg. This is the average of the Lower Heat Value (LHV) of 33.3 kWh/kg [16] and Higher Heat Value (HHV), 39.4 kWh/kg [17]. This approach was adopted because of the likely mixed use of the hydrogen: a modern condensing boiler would be able to recover the heat of condensation, so the higher heat value would apply. However, an open flame such as a gas cooker, or a fuel cell application such as vehicle fuel or backup electricity generation, would not, so the LHV would apply.
As the hydrogen supplied through the network would be for mixed use, with hard to forecast proportions, a mid value between the two has been used. If a different value of specific energy were found to be more appropriate, this would affect some of the values and factors found in this analysis, but would not change the fundamental findings.

6.6.2 Energy delivery with hydrogen

Some pipes turned out to be unable to deliver enough hydrogen within the maximum allowable upstream pressure and the minimum acceptable downstream pressure. Where there is a shortfall in capacity this might be addressed by either (1) increasing pipe capacity through additional or replacement pipes, (2) by increasing the upstream pressure, or (3) providing short term (< 24 hours) downstream storage. The issue appears at peak demand but not throughout the day, so filling short term storage at the lower demand periods would be a viable way of ensuring that enough hydrogen can be delivered.

In demand pipes, for every pipe analysed there was a comfortable excess in 24 hour capacity to deliver hydrogen compared to the 24-hour demand for hydrogen. This indicates that this would be a viable strategy. This should be at the downstream end of the pipes, to keep the flow velocity lower (see Table 6-4). Boosting the upstream pressure in the demand pipes to 850 kPa would also resolve the problem. However, this runs the risk of exceeding the pressure rating of older pipes (although they may need to be replaced anyway if the material is unsuitable for hydrogen), and the peak flow velocity would exceed the maximum allowable (see also Table 6-4). Given that one or both of these solutions should be viable, it should not be necessary to enlarge the actual pipe capacity.

In network pipes, the inadequate delivery appears to be more appropriately addressed by boosting the pressure at the upstream end of the affected section. In these pipes, the higher operating pressure increases the hydrogen density enough to keep the flow velocity within tolerance. This could be appropriately done through a series of smaller pressure boosting stations, or a single larger one, depending on a detailed assessment of the real life situation.

The flow velocity of hydrogen is at least 3.6x that for natural gas in the demand pipes; it is at least over 4.4x higher in network pipes (see Figure 6-3 and Figure 6-4), because natural gas is more compressible than hydrogen. At peak times this leads to very high flow velocities approaching 80 m/s, or more in cases where full delivery is not possible (Table 6-4). Further study will be required to identify whether or not this is acceptable for the characteristics of hydrogen; if not, then downstream storage or operation at higher pressure will be required to ensure that enough hydrogen can be delivered at acceptable flow velocities.

6.6.3 Predicting the need for intervention

It is possible to predict the natural gas pipes that will require intervention – in the form of pressure boost or downstream storage – when used to supply hydrogen.

The first step is to calculate a forecast hydrogen upstream pressure (Pup) for the network pipes from the natural gas pressure, using Equation 6-11:

\[
P_{up_h} = \left( 1.768 \cdot P_{up_{ng}}^{1.85} - 14.3 \times 10^6 \right)^{0.541}
\]

For demand pipes, this does not apply because the upstream pressure is constrained by being actively reduced from that delivered by the network pipes to 700 kPa (in current standard practice).
The calculated or constrained Pup(h) is then used to find the maximum flow capacity of the pipe using the Buzzelli and Darcy-Weisbach procedure, which requires an iterative process using equations 6-1 to 6-4:

\[
B1 = \frac{(0.774 \ln(Re) - 1.41)}{1 + 1.32 \left(\frac{k_s}{D}\right) 0.5}
\]

Equation 6-1: \[B1 = \frac{(0.774 \ln(Re) - 1.41)}{1 + 1.32 \left(\frac{k_s}{D}\right) 0.5}\]

Equation 6-2: \[B2 = \frac{k_s \cdot Re}{3.7 \cdot D} + 2.51\]

Equation 6-3: \[\frac{1}{f_D^{6.5}} = B1 - \left(\frac{B1 + 2 \cdot \log_{10} \left(\frac{B2}{Re}\right)}{1 + \left(\frac{2.18}{B2}\right)}\right)\]

Equation 6-4: \[\Delta P = \frac{(L \cdot f_D \cdot p \cdot V^2)}{(2 \cdot D)} \Delta P = \frac{(L \cdot f_D \cdot p \cdot V^2)}{2 \cdot D}\]

The calculated Pup(h) is also used in the flow exceedance ratio calculation, Equation 6-10:

\[FER_h = 1.27 \cdot FER_{ng} \left(\frac{P_{up, ng}}{P_{up, h}}\right)^{1.1}\]

The result is the Flow Exceedance Ratio for hydrogen, that is the mass flow demand relative to the maximum capacity of the pipe. If this exceeds 100%, the pipe will be unable to deliver the quantity of hydrogen required without intervention such as boosting the upstream pressure or providing downstream storage of less than 24 hours’ demand.

### 6.6.4 Testing the hypotheses.

The starting hypotheses were:

1. The natural gas network can be converted to supply enough pure hydrogen to replace all natural gas in use, on the basis of energy transported, without enlargement or replacement of the pipes.
2. It will be possible to identify which parts of the network will need intervention when converted to supply hydrogen, on the basis of the natural gas characteristics alone.

These appear to be confirmed, albeit with caveats - some other modification will be required. This model has been set up on the basis of having little excess capacity. In these circumstances, it seems unlikely that the network can be changed over with no modification. If in a real situation there is more excess capacity, the change should be considerably easier.

However, even in the limited excess capacity scenario tested it should be possible to use the existing pipe network as stated in the hypothesis. However, this will require a combination of other modifications, including the addition of targeted local storage, pressure boosts within the network, and/or operating at slightly higher pressures than current standard practice.
6.7 Further study

Further modelling work should also be carried out to understand the impact on the lower pressure flow regimes at the point of connection to customers. If there is a substantial need for storage at that level, then the cost and complexity might increase significantly. However, it is encouraging that in this study, the velocity increase factor reduces as pressure reduces.

The acceptability of higher flow velocities should be assessed. It is possible that the hydrogen will have less capacity to transport dust, which leads to scour damage to the inside of pipes. If so, higher flow velocities may be acceptable. This may involve experimentation and discussion with pipe manufacturers.

Further modelling should examine the effect of linepack storage, that is storing additional mass of gas inside the pipes by varying the operating pressure and hence the density – a simple comparison of compressibility suggests that the linepack storage capacity of hydrogen will be about 25% that of natural gas [7]. However, it is important to understand how much is actually needed compared to how much surplus capacity there is available at present.

A similar analysis examining the effect of a mixed 20% hydrogen, 80% natural gas would also inform the transitional position.
7 Discussion

In the future, the energy system will be considerably more complicated than it is today, with more cross-over between fuel types and uses than there are with hydrocarbon based fuelling. Hydrogen will be an integral part of this, as there are many applications where electricity will be impractical or impossible to use but hydrogen could be used. In some other applications there are benefits to using hydrogen instead of electricity, which will make it more desirable for some customers.

These include (but are not limited to):

- Medium and long distance shipping, due to the size, weight and cost of batteries needed (Explored in chapter 5). Other fuels such as ammonia might also be better than hydrogen here.
- Large road vehicles such as buses and heavy goods vehicles, due to the weight and consequent reduced payload and increased road wear (Explored in chapter 4).
- Long distance transportation of energy, again due to the size, weight and cost of batteries (Explored somewhat in chapter 5; while that focusses on fuels for powering the vessel, most of the issues are similar for movement of energy).
- On a global basis, it will be difficult to replace all cars and other road transport using current battery technology, due to the shortage of critical minerals for batteries [1, 2]. This shortage appears to be already pushing up battery prices [3]. Hydrogen, whether in a fuel cell or a combustion engine, has a much lower whole-life requirement for minerals and metals [4].
- Aviation, due to the weight of batteries using current and imminently forthcoming technology, is unlikely to be practical with battery electricity except for very short range aircraft. There is no current solution for jet-speed electric air transport [5, 6]. Hydrogen is a strong contender for both jet and propeller aircraft, under development now [7, 8], although Sustainable Aviation Fuel, that is, bio- or E-kerosene, is also a viable alternative which can be used in existing engines [9].
- With cars and light goods vehicles, where range or refuelling speed are important, hydrogen has an advantage over batteries. Also where recharging facilities are not readily available, for example for people living in flats or many terraced houses (This is explored in chapter 2).
- The significant disturbance needed to retrofit older houses to make them suitable for installation heat pumps [10] may make a cheaper hydrogen fuelled conventional boiler more attractive [11-13].
- The real world energy gains from heat pumps are often lower than expected – Coefficients of Performance between 1.4 and 3.2 have been found in the UK, with a mid value of 2.2 [14], tipping the balance more in favour of hydrogen boilers. See also further discussion in section 7.2.6 below.
- For inter-seasonal energy storage, underground storage of hydrogen will be a small fraction of the cost of batteries or even pumped storage, and will be more scaleable than pumped storage due to fewer geographical constraints [15, 16].
An energy system supplied by hydrogen is schematically illustrated in Figure 7-1 below, highlighting the areas examined in detail in this thesis, along with the associated hypotheses. This would interface with the electricity distribution network, not illustrated, as well as other fuels that might become appropriate.

This thesis has investigated a number of aspects of this hydrogen energy system and its impacts, alongside consideration, where appropriate, of alternatives such as electricity, biofuels and hydrogen derived fuels like ammonia and methanol.

This discussion chapter will proceed with a brief recap of each part of the research, followed by an examination of some other relevant aspects of fuel choices and the decision making processes. It will then conclude with a description of a potential energy transition pathway involving hydrogen, showing how the work presented in the preceding chapters fits in.

7.1 Recap

7.1.1 Refuelling Infrastructure (chapter 2)

Hypotheses:

*Prioritising large vehicles such as buses and HGVs ahead of smaller vehicles will have benefits over an equal, or unregulated, vehicle transition.*

*A seed network for hydrogen road fuelling can be defined which is cost-competitive with an equivalent electric charging system.*

Here a model was constructed to examine the extent of hydrogen fuelling infrastructure that would be required to support hydrogen road transport in a number of different scenarios. Two fuel demand scenarios are examined: a base case of only large lorries and buses being replaced with hydrogen ones (‘Large Vehicles Only’ scenario), and a more advanced case where every diesel vehicle (that includes about 40% of cars and almost all vans) is replaced with a hydrogen vehicle (‘Like for Like’ scenario). The pace of change that would be required to support the Scottish government’s emissions targets was examined, in three pace scenarios: one where all vehicles are replaced by zero emission vehicles at an equal pace (‘Equal Pace’ scenario); the second where the deployment of larger vehicles is accelerated – most likely by incentivisation – allowing that of smaller vehicles to progress slightly more slowly (‘Accelerate Bus and Truck’ scenario); and the third, where the 2030 target is allowed to slide, provided the 2045 target is met (‘Laid Back’ scenario).

The Accelerate Bus and Truck scenario was found to reduce the total number of vehicles required to meet the Scottish Government’s targets, but increase the number of refuelling stations required in the early stages of the transition.

A seed infrastructure provision of around 90 refuelling stations, costing around £140 million was identified, which should provide enough hydrogen to support 5-6 years development at the Like for Like scenario, or 7-8 years at the Large Vehicles Only scenario.

In the longer run, up to 300 (Large Vehicles Only) or 800 (Like for Like) hydrogen refuelling stations might be required, at a Net Present Value of £320 million or £740 million respectively. This compares to about 860 petrol/diesel stations in service now.

These are illustrated in Figure 2-6, reproduced below as Figure 7-2.
Figure 7-1 Hydrogen energy system schematic

Elements shown with hypotheses are developed in chapters 2-6. At the top of the image, hydrogen is produced by various means – electrolysis of water, and steam reformation of natural gas plus carbon capture and storage, are the most likely zero and low carbon methods respectively, but other sources are in development. The hydrogen is (1) injected into the distribution network, converted from the existing natural gas network, without enlargement or replacement of the pipes. Chapter 6.

To electricity

Hydrogen will perform better in cost and emissions than other alternative chemical fuels for shipping. Chapter 5.

Prioritising large vehicles such as buses and HGVs ahead of smaller vehicles will have benefits over an equal, or unregulated, vehicle transition. Chapter 2.

There will be significant and quantifiable additional costs of road maintenance due to the increased weight of ZEVs over ICE vehicles. This will be markedly greater for BEVs than for HFCEVs due to the weight difference. Chapter 4.

A seed network for hydrogen road fuelling can be defined which is competitive with an equivalent electric charging system. Chapters 2 & 3.

Downstream injection of Hydrogen

The natural gas network can be converted to supply enough hydrogen to replace all natural gas in use, on the basis of energy transported, without enlargement or replacement of the pipes. Chapter 6.

The network may require additional intervention such as local storage (beyond linepack) and/or operating at higher pressure. Possible uses of network-distributed hydrogen include shipping fuel (early adoption stage), domestic and industrial heat (pilot trials), road vehicle fuelling (in service now), air transport (experimental), rail (in service now), and cross-border exports.
We can make a further comparison if we rerun the model that we used in this paper (Chapter 2), but create a scenario with 100% of vehicles hydrogen-fuelled. This produces a net present value of approximately £800 million. We can then compare this with the costs found by Scottish Power Energy Networks (SPEN) in their document "Zero Carbon Communities," [17] which looks at the costs of deploying sufficient recharging infrastructure and electricity network upgrades. The SPEN report becomes slightly unclear because the cost of cabling network upgrades includes an allowance for providing additional electricity for converting domestic heating to electric heat pumps, abandoning the natural gas network and infrastructure and other boilers and appliances. However, allocating the cost of network upgrades between the heat pumps and electric vehicle chargers based on actual energy use, a net present value for the electric charger network and associated network upgrades can be estimated at approximately £4 billion, about five times as much as for hydrogen.

![Hydrogen fuelling station numbers by year, selected scenarios](image)

**Figure 7-2** Numbers of hydrogen refuelling stations for selected scenarios: Like for Like and Large Vehicles Only fuel options, with Equal Pace and Accelerate Bus & Truck pace options. Maximum and minimum cost cases are presented, along with the case derived from the core estimated model inputs.

This analysis was carried out on the basis that hydrogen refilling stations would have a similar range of capacities to existing hydrocarbon refuelling stations, which leads to a total number of filling stations comparable to the present. However, more recently, the question of ‘hydrogen hubs’ has come more to the fore. These represent locally centralised production facilities, in effect, ideally with dedicated local renewable electricity supplies. Hydrogen would be produced at these facilities – perhaps there might be 15 to 20 such hubs around Scotland - and then transported to where it's required in the surrounding area, most likely at refuelling stations or for heat applications. This transport could be in the form of pipelines or road tankers for compressed gas or for liquid hydrogen. It's credible that there are significant potential cost savings to be had from adopting this regional ‘hub and spoke’ approach to hydrogen production and distribution, rather than replicating the piecemeal development of the national hydrocarbon refuelling infrastructure, which has evolved over
the last 100-plus years. On the other hand, widespread distribution of hydrogen through the repurposed gas network might negate the need for such hydrogen hubs. Further study comparing these approaches might well be beneficial, provided that it is not taken as a reason to sit still and not take urgently required action.

This chapter was published as a paper in Energy Policy, doi.org/10.1016/j.enpol.2022.113300.

7.1.2 Refuelling Case Study (chapter 3)

Following the examination of the nationwide infrastructure requirements, a case study was developed, exploring the provision of hydrogen fuelling for Scottish Borders Council. This local authority is considering replacing its own fleet of large vehicles with hydrogen fuelled ones. This identified some of the practical issues with developing a fuelling facility, whether it is thought of in terms of either a dedicated fuelling station for the local authority’s own vehicles or as the beginnings of a potential regional hydrogen hub development. This helped to provide a more focussed context for the development of individual refuelling facilities, within the nationwide study.

The assessment was carried out on the basis that all diesel vehicles would be replaced with hydrogen fuelled vehicles. As the council had already replaced many of its cars with battery electric vehicles, the remaining diesel vehicles were generally the larger ones. This meant that the council’s total diesel consumption data could be used as the key input, without knowing the consumption of individual vehicles. This was about 1.9 million litres per year, equivalent in energy requirement to around 400,000 kg hydrogen per year. This represents capacity of about 1500 kg/day (5 days per week), similar in scale to a single medium sized fuelling station as identified in chapter 2.

Important considerations are simple practical matters, such as having land available to construct such a site. That’s a bigger issue, obviously, if the hydrogen station is developed as a regional hub, than if it were an addition to an existing commercial vehicle fuelling station. In the latter case, we might imagine some of the facilities could be replaced or added in a slow and gradual manner, retaining and making use of the existing land.

Another issue that came into sharper relief is supplying electricity for manufacturing hydrogen. The hydrogen is ideally made from the electrolysis of water using renewable energy. This so-called green hydrogen is then fully renewable and has zero emissions from production right through to use. If it’s produced on-site, it will require a substantial electricity supply of around 3.0MW, running 24 hours/day, 5 days/week. Electricity supplied through the national electricity grid tends to be expensive due to the grid charges. The grid is necessary to balance the supply and demand around the UK. However, for hydrogen production, because the produced gas could be stored on-site, such a balancing requirement is largely not needed. It therefore becomes more economical to make use of dedicated renewable energy sources, owned or leased, most likely wind turbines but other options like solar might be viable. The capital cost of the wind turbines then becomes more relevant than the purchase price of electricity. These would then require cabling to be installed to transfer the electricity to the hydrogen production site, if they aren’t co-located.

A related aspect to this is the use of curtailed energy. This has been talked about frequently. A preliminary look at available data suggests that this represents about 9% of potentially generated electricity, which is less than might have been expected. However, this might be
more significant at a local level. One thing to consider, however, is that the electricity generators are subsidised by the National Grid for not producing electricity in a curtailed wind scenario. Therefore, any curtailed electricity that should be used can be expected to cost at least as much as the subsidy the producers get for not producing it. Also, the use of curtailed energy alone would mean that the expensive electrolyser equipment is sitting unused for substantial periods of time, and a large storage facility would be required; based on that 9% figure, one could extrapolate that the equipment is unused 91% of the time. This is not likely to be a very cost-effective solution.

It might be appropriate to have a both dedicated wind turbine/s attached to a wind farm, and an arrangement that curtailed electricity produced at that same wind farm could also be diverted to the production of hydrogen. This would ensure a base supply of electricity for electrolyser, creating a more commercially viable route to making use of curtailed energy. We might conceive how this could be expanded to using hydrogen stores as backup electricity supply, although the scale of storage available and required that way would have to be investigated. There might also be cases where, if the hydrogen stores are full, the dedicated wind turbines could be used to generate grid-supplied electricity instead, making maximum use of the assets.

It appears that making use of the demand in a local authority fleet would be a good way to initiate the development of a hydrogen refuelling station or stations. This could apply to other captive fleets as well, e.g., buses, ambulances, police, construction, taxis - any scenario where there is a large but locally operating fleet would be ideal.

This chapter formed chapter 5 a report prepared for Scottish Borders Council by the University of Edinburgh, titled ‘Assessment of options for a smart, resilient and low-carbon multi-vector energy system in the Scottish Borders. The role of energy networks in smart local energy systems.’

7.1.3 Hidden Cost – Road Wear (chapter 4)

_Hypothesis:_

There will be significant and quantifiable additional costs of road maintenance due to the increased weight of ZEVs over ICE vehicles. This will be markedly greater for BEVs than for HFCEVs due to the weight difference.

The next area investigated was the impact on road wear and tear of new zero emission vehicles. This was unusual in that it appeared to have never been quantified in a research context. It is a subject that is raised frequently informally, with battery operated vehicles being significantly heavier than hydrogen fuelled vehicles, which in turn are slightly heavier than their diesel and petrol counterparts.

1. Three future scenarios were considered for this analysis:
   All vehicles become hydrogen powered (HFCEV in Figure 7-3).
2. All vehicles become battery electric powered (BEV in Figure 7-3).
3. All existing diesel vehicles become hydrogen powered, all existing petrol vehicles become battery electric. This corresponds to the ‘Like for Like’ scenario in chapter 2 (L4L in Figure 7-3).
These are compared with the existing hydrocarbon internal combustion engine situation (ICE in Figure 7-3).

As described in the paper, a long-established and widely used road construction and management principle was used: road wear is proportional to the axle load to the power of 4 [18]. This 4th power effect means that larger vehicles such as lorries, buses, and coaches overwhelmingly dominate road wear on a national average basis – to the extent that no matter what fuel type used, smaller vehicles such as cars, vans and motorcycles are responsible for less than 1% of the road wear. This can be seen from Figure 7-3.

![Aggregated Road Wear Impact Factor by vehicle class, four scenarios](image)

*Figure 7-3  Overall Road Wear Impact Factors, grouped by class. Subclass values have been combined to produce the overall class values.*

The upshot of this is that in Scotland, the additional road maintenance cost from replacing larger battery-operated vehicles is substantial: in the order of £164 million per year extra, or about 30%. For hydrogen vehicles, with a much smaller increase in weight, the figure is around 6% or £31 million (all at 2021 values). This can be seen in figure 4-4, reproduced here as Figure 7-3; the RWIF is proportional to the annual maintenance cost.

Road maintenance is the responsibility of the Scottish Government for trunk roads and local authorities for other roads. This factor should be taken into consideration when planning the types of fuel to be used.

This chapter was published as a paper in Clean Technology and Environmental Policy. doi.org/10.1007/s10098-022-02433-8

This analysis was also the subject of an article in the Daily Telegraph on 26 July 2023 (https://www.telegraph.co.uk/news/2023/06/26/pothole-electric-cars-damage-roads-double-petrol-telegraph/), and on the Finnish (Swedish language) news website Yle on 9 August 2023 (Experter om påståenden att elbilar orsakar stort vägslitage: ”Totalt nonsens” – Inrikes – svenska.yle.fi) https://svenska.yle.fi/a/7-10038815
7.1.4 Renewable Marine Fuels (chapter 5)

Hypothesis:

Hydrogen will perform better in cost and emissions than other alternative chemical fuels for shipping.

The next section looks at the expected progress in cost and emissions in the production, transport, storage, and use of hydrogen in various forms, compared with methanol, ammonia, biofuels and electricity in the context of its use as a marine fuel for vessels used to service offshore wind farms. A analysis is made of how costs and emissions are likely to change between the present and the late/end transition period.

The context of the analysis was a ship to service offshore wind farms, based on the Service Operation Vessels used to support oil platforms. The reference vessel would be based out of Aberdeen, and would carry out a 2-week voyage between visits to port for refuelling and resupplying. It was also interesting to find that all of the fuel options have planned or advanced stage production facilities within Scotland or the North of England. This is an encouraging indication that fairly soon we may be able to get to a point where renewable fuels become sufficiently widely available to make their use practical.

Battery electricity was ruled out early: the battery capacity required would have been 586 MWh for a full two-week voyage, or 50 MWh for a one-way single day journey to the site assuming recharging of the battery from the electricity produced on-site (with an emergency backup for return to port). For comparison, the largest battery system currently in use in Europe is near Hull, in Yorkshire. It has a capacity of 196 MWh, cost £75m, and covers almost 2 hectares [19]. There was a further constraint in that recharging would be required within a 4-hour window at port, which would require an extraordinarily high charging rate of 164MW or 14MW for the two options. Based on this comparison, the battery option appears to be unviable based on current technology.

The key disadvantage with hydrogen is the bulk it takes up on board the ship in the large quantities required – it was to replace 85 tonnes, or 101 m$^3$, of marine gas oil (diesel). Gaseous hydrogen at 700bar would take up 652 m$^3$; this is improved somewhat using liquid hydrogen, which would require 352 m$^3$, although it requires more energy to liquefy the liquid hydrogen. Liquid organic hydrogen carriers (LOHC) are a very interesting area of further investigation; the cost profile is higher at present than gas or liquid, although is expected to reduce significantly with time and upscaling. The comparable storage volume would be 447 m$^3$. The advantage of LOHCs is that they are liquid at ambient conditions, making for easy handling, and are specifically selected to be non-toxic and environmentally benign.
Figure 5-10, reproduced here as Figure 7-4, illustrates the relationship between cost and emissions for the fuels under consideration; the progression from the present to 2045 is also shown.

Hydrogen-derived fuels such as ammonia or methanol could be a better solution. Methanol is liquid at ambient conditions, making it easier to handle and store. Ammonia is very easily liquefied, much more easily and cheaply than hydrogen. This makes it also much easier to store. However, both of these have some toxicity issues, although in mitigation there is considerable global experience in handling these substances in a safe way. The advantage to ammonia is that it contains no carbon at all, and can also be made in a zero emission way. Methanol is only net zero, rather than actually zero, emissions so there is a risk of some mismatch or leakage leading to emissions.

This chapter is extracted from a report prepared by this author for the Offshore Renewable Energy Catapult, acting on behalf of BP, titled *Renewable fuels for Offshore Service Operation Vessels*.

### 7.1.5 Network Conversion modelling (chapter 6)

**Hypothesis:**

The natural gas network can be converted to supply enough pure hydrogen to replace all natural gas in use, on the basis of energy transported, without enlargement or replacement of the pipes. It will be possible to identify which parts of the network will need intervention when converted to supply hydrogen, on the basis of the natural gas characteristics alone.

A hypothetical gas network model was built in Python to examine the effect on network capacity of switching from natural gas to hydrogen. This was based loosely on the existing gas network serving the east of Scotland.

On investigating the conversion, the network as modelled has the capacity to deliver the same amount of energy as it currently does, with some modification. There will be some constrained areas where an existing pipeline is already close to capacity, and in such cases some reinforcement in terms of pressure boosting and/or downstream storage may be required.
Since 2002, the UK gas industry has carried out the majority of the 30 year Iron Mains Replacement Programme; this involved the replacement of iron natural gas pipes, other than large high pressure transmission pipes, with new polyethylene pipes. These pipes are also expected to be suitable for transporting hydrogen. This work is being carried out at a cost of around £28bn across the UK, so the fact that the vast majority of this replacement pipework can be reused is an enormous benefit. That this work has been carried out already also indicates that, at a national scale, the UK has the capacity to manage this type of very large energy transition project. This has been carried out more or less out of the public eye; this doesn’t reduce the fact that it will have been an enormously complex project or series of projects to manage and deliver.

Through this modelling, an empirical process was also developed by which the risk of a section of pipeline requiring reinforcement could be identified from the information known from its use for natural gas. However, this would require some further investigation before it can be applied with confidence to more complex real world situation.

Figure 6-8, reproduced here as Figure 7-5, shows the correlation achieved with this empirical process.

The first step is to use Equation 6-11, reproduced as \( P_{up_h} = (1.768. P_{up_{ng}^{1.85}} - 14.3 \times 10^6)^{0.541} \)

Equation 7-1:

\[ P_{up_h} = (1.768. P_{up_{ng}^{1.85}} - 14.3 \times 10^6)^{0.541} \]

Figure 7-5 (reproduced from Figure 6-9) then illustrates the relationship between the Flow Exceedance Ratio (FER) for hydrogen and the FER for natural gas, adjusted by the upstream pressures for hydrogen and natural gas.

![Figure 7-5](image-url)  
**Figure 7-5**  
FER\(_{h}\) against FER\(_{ng}\)\((P_{up_{ng}}/P_{up_h})^{1.1}\), where \(P_{up_h}\) is found from Equation 7-1 above. There is some scatter in the higher reaches of this chart; this is past the FER\(_{h} = 100\%\) level, so will not affect the result.
7.2 Some other considerations about the use of hydrogen

7.2.1 Blended hydrogen and natural gas

Several studies have shown that it will be possible to blend up to 20% hydrogen by volume (approximately 6% by energy) into the natural gas stream and still use existing, unmodified, appliances [20-22].

Beyond that, recent advances in gas separation technology mean that the two gases could be fairly readily separated [23, 24]. This means that the use of hydrogen could be greatly accelerated and simplified, by introducing a higher proportion of hydrogen into the gas stream and separating it out where needed.

This could work by a larger energy equivalent than the current use of natural gas being distributed through the network. The gas transported would be a mix of hydrogen and natural gas. The amount of natural gas transported would be equivalent to 94% by volume of the total natural gas demand. The quantity of hydrogen would be (1) the energy equivalent of the remaining 6% by volume of natural gas (which would occupy approximately 25% of the volume of natural gas), plus (2) any additional hydrogen required by pure hydrogen consumers, such as refuelling stations, industrial users, residential zones converted to hydrogen, and others. The additional hydrogen at (2) would be removed by the separation methods discussed above, ahead of the remaining natural gas consumers, and used by the pure hydrogen consumers. The residual then would be around 20% hydrogen and 80% natural gas by volume, or 94% and 6% by energy content. This would then be used in un-modified natural gas appliances. Over time, as the energy transition progresses, the natural gas transported would decrease and the hydrogen would increase, until the network was transporting only hydrogen.

This would greatly facilitate the conversion process, and should reduce or eliminate the need to construct dedicated hydrogen transmission pipelines.

7.2.2 Energy Storage

Energy storage is a key argument for hydrogen. Renewable electricity is, or will be, produced in Scotland by wind turbines or solar panels, alongside existing hydro-electricity power stations. Demand for heat is around six times as big in winter as it is in summer across Great Britain; the summer heat demand in terms of energy content is similar to the summer electricity demand. Electricity demand increases by around 50% from summer to winter [16]. These are illustrated in Figure 7-6. Combining these two factors means that the winter demand is approaching four times as big as the summer demand, for non-transport energy.

Figure 7-6 Heat & electricity typical annual demand, Great Britain. Figures modified from Samsatli & Samsatli (2019) [16].
Clearly, then, this leads to an issue of either massively excess production capacity in summer, or inadequate production capacity in the winter. This is only partly mitigated by increased wind availability in winter, shown in figure 7-7. The solution is large scale intra-seasonal storage.

![Figure 7-7](Image of offshore and onshore wind speeds, UK offshore and zone 7. Figure from Samsatli & Samsatli (2019) [16])

Battery storage of electricity is not suitable for this on cost grounds - as discussed in section 7 and chapter 5 - current global Lithium-ion battery prices are approximately US$152 /kWh capacity [3], or $152 bn/TWh. The UK would have an interseasonal energy storage requirement to decarbonise gas of around 150TWh [25]. Looking again at Figure 7-6, the electricity interseasonal power demand variation is about 15MW; the gas variation is around 260MW. As an approximation, we take the gas demand to represent heat, and assume the electricity and heat storage energy requirements are in proportion to the variation in power demand.

This gives a total interseasonal storage requirement of ((260+15)/260) x 150 = 159TWh.

Taking a simple pro-rata by total heat + electricity demand (Table 7-1) gives an interseasonal storage requirement for Scotland of 159 x (74.2+32.3)/(539+274) = 22 TWh, or about 20% of the annual non-transport energy demand. The cost of lithium-ion batteries at this scale is an impossible $3.3 trillion. A different solution is clearly required.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Use (TWh / year)</td>
<td>Emissions (MT CO₂ eq/yr)</td>
<td>Emissions intensity (kg CO₂ eq / kWh)</td>
</tr>
<tr>
<td>Heat</td>
<td>41,944*</td>
<td>12,120*</td>
<td>0.289</td>
</tr>
<tr>
<td>Transport</td>
<td>46,944</td>
<td>7,980</td>
<td>0.170</td>
</tr>
<tr>
<td>Electricity</td>
<td>25,500</td>
<td>14,650</td>
<td>0.575</td>
</tr>
<tr>
<td>Total</td>
<td>114,388</td>
<td>34,750</td>
<td>1,405</td>
</tr>
</tbody>
</table>

*Global heat taken as industrial + domestic; not exactly like for like but close. Includes cooling.

Table 7-1 Global, UK and Scotland energy use and associated emissions from the key energy sectors of heat, transport and electricity. Reproduced from Table 1-1 above. Heat and transport really do both end in 944.

Pumped storage is the most energy efficient electricity storage method other than batteries, although its capital cost is around €20-€40/kWh [15], or €420 - €840bn for Scotland’s storage requirement. This is still extraordinarily expensive. Pumped storage is also limited by specific topographical requirements, and due to its high cost and high speed of response, it is more appropriately used in shorter timescales as at present [15].

The most cost effective way of storing energy at large scale, over timescales of months, is likely to be in the form of hydrogen, stored in underground strata or salt caverns [15, 31].
These have an estimated capital cost of around €0.30 - €0.60/kWh capacity [15], or about €6.3 - €12.6bn; across the UK, €45 - €90bn. Still a lot of money, but an achievable amount.

This has a key consequences in terms of efficiency. If electricity is converted to hydrogen in this way for the purpose of storage, and back to electricity when needed, the round-trip efficiency of the process is about 56% (modified from [15] with updated electrolyser efficiency from [32]). If, as above, about 20% of energy is stored in this way, the average efficiency loss to electricity would be around 9% (0.2(1 – 0.56)). This will have a significant impact on the overall efficiency of using electricity, which will be explored in section 7.2.3 below.

Conversely, hydrogen can be stored underground as just mentioned. It would be produced from electricity through the electrolysis of water (or from natural gas with CCS), then stored and used in the form of hydrogen. The strategic energy storage could then be shared between electricity stored in the form of hydrogen, and hydrogen ready to use as hydrogen. This type of holistic integrated electricity and hydrogen system should negate the need for direct storage of electricity. This also lends itself to the flexibility that varying customer choice might require.

### 7.2.3 Efficiency

This leads onto a discussion about efficiency. It is frequently said that an electric vehicle or using electricity in a battery-powered vehicle is more efficient than using hydrogen [33]. This may be true at a simplistic level, although the most recent developments in hydrogen electrolysis are massively more efficient than was the case as little as two years ago [34], so the basic situation might now be different anyway. However, by the time the energy losses in long-term storage are taken into consideration, whatever storage method is used, the ‘turbine to wheel’ efficiency of electricity in road vehicles is likely to be closer to that of hydrogen than previously suggested.

Taking this into account, a turbine to wheel efficiency summary of BEVs and HFCEVs would look like this:

<table>
<thead>
<tr>
<th>Stage</th>
<th>BEV</th>
<th>Residual</th>
<th>HFCEV</th>
<th>Residual</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial energy production from wind.</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Conversion to hydrogen (electrolysis)</td>
<td>-</td>
<td>100%</td>
<td>80% [at LHV] [34]</td>
<td>80%</td>
</tr>
<tr>
<td>Transmission by cable or pipeline</td>
<td>94% [33]</td>
<td>94%</td>
<td>99.5% [35-37]</td>
<td>79%</td>
</tr>
<tr>
<td>Storage round trip, 20% of annual energy supply averaged across year.</td>
<td>91% [sec 7.2.2]</td>
<td>86%</td>
<td>99% [15]</td>
<td>78%</td>
</tr>
<tr>
<td>Compression</td>
<td>-</td>
<td>-</td>
<td>89% [38]</td>
<td>69%</td>
</tr>
<tr>
<td>Charging / fuelling</td>
<td>95% [33]</td>
<td>81%</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Battery discharging / fuel cell</td>
<td>95% [33]</td>
<td>77%</td>
<td>72% [39]</td>
<td>50%</td>
</tr>
<tr>
<td>Electric motor</td>
<td>90% [33]</td>
<td>69% [finl]</td>
<td>90% [33]</td>
<td>45% [finl]</td>
</tr>
</tbody>
</table>

*Table 7-2 Comparative efficiencies of BEV and HFCEV, taking account of electricity storage losses.*

This table is based on Tsakiris (2019) [33], modified to take account of the improved efficiency of electrolysers and compression, losses due to interseasonal energy storage, and transport of hydrogen by pipeline instead of tanker. References shown in table.
A similar analysis comparing hydrogen boilers to electric heat pumps looks like this:

<table>
<thead>
<tr>
<th>Stage</th>
<th>Heat pump</th>
<th>Hydrogen boiler</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Efficiency</td>
<td>Efficiency</td>
</tr>
<tr>
<td>Initial energy production from wind.</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Conversion to hydrogen</td>
<td>-</td>
<td>100%</td>
</tr>
<tr>
<td>Transmission by cable / pipeline</td>
<td>94% [33]</td>
<td>94%</td>
</tr>
<tr>
<td>Storage round trip, 20% of annual energy supply averaged across year.</td>
<td>91% [sec 7.2.2]</td>
<td>86%</td>
</tr>
<tr>
<td>Heat pump / boiler efficiency</td>
<td>220% [14]</td>
<td>188% (final)</td>
</tr>
</tbody>
</table>

Table 7-3 Comparative efficiencies of heat pump and hydrogen condensing boiler, taking account of the losses due to interseasonal storage.

Both BEVs and HFCEVs represent better efficiency than hydrocarbon ICEs, where even the most efficient diesels are no more efficient in the vehicle than HFCEVs even without accounting for the supply chain [41]. BEVs appear to be more efficient than HFCEVs, but that does not necessarily translate into lower cost, nor does it compensate for other user-friendly factors. This difference in overall efficiency is less than is often stated. Tsakiris [33] cites a distribution loss of 23% for hydrogen, but that is based on transport by tanker and takes account of the fuel used by the tanker.

The difference between heat pumps and hydrogen boilers appears more significant, with heat pumps around 2x as efficient overall as hydrogen boilers. However, this does not necessarily translate into a better cost position – this is explored further in section 7.2.6.

However, the discussion of efficiency as a factor for decision making is really a red herring. What matters are deliverability, usability, and cost. And while it's true that efficiency would affect all of these considerations, it is only one factor among many. We can draw a comparison with the existing hydrocarbon road fuel situation. Solely based on efficiency, there would only be diesel vehicles as that is a significantly more efficient process than petrol. However, as with the choice between hydrogen and electricity, there are other factors affecting the decision.

7.2.4 The Hydrogen Ladder

The hydrogen ladder, developed by Michael Liebreich, is a widely known attempt to classify the potential uses of hydrogen on the basis of competitiveness. Liebreich is a fairly high profile person who created the business now known as Bloomberg New Energy Finance. He was involved in convincing the public in Whitby not to agree to a trial of hydrogen heating in their village [42].

Liebreich seeks to identify which uses of hydrogen are more likely to be viable or competitive in the future compared to primarily electricity and which are uncompetitive. He uses the familiar ranking of the EU energy efficiency label to position these uses on a ranking ladder. It can be found at https://www.liebreich.com/the-clean-hydrogen-ladder-now-updated-to-v4-1/ (version 4.1) or https://www.linkedin.com/pulse/hydrogen-ladder-version-50-michael-liebreich/ (version 5.0).

As a general observation, it seems unwise to attempt to close off potential uses of hydrogen for the next 25 to 30 years at this stage, based on such scant information, given that it is still in the early stages of development. It's also notable that this hydrogen ladder is updated or changed reasonably frequently, suggesting that such seemingly fixed assessments are still
subject to change – and consequent potential future regret. As of November 2023, it is presented at version 4.1 and version 5. These changes typically involve moving one or more particular uses from one level of competitiveness to another – for example, v3 to v4 made aviation less competitive and off-road machinery (e.g. construction) more competitive; v5 apparently moves three uses up and six down. The fact that these revisions are made at all illustrates the inappropriateness of making such long-range forecasts based on a short term snapshot, and the unwisdom in using them to effectively condemn entire sectors.

Liebreich proceeds to make a series of statements about various energy aspects, sometimes without providing any justification at all. For example, “You can forget use cases like urban delivery, two and three wheelers, metro trains and buses.” Nothing more is offered about these. Sometimes he offers at least some elaboration on his personal opinion on hydrogen’s potential in specific sectors.

Numerous factors remain unconsidered. For example, the higher cost of transferring energy via electricity cables compared to hydrogen pipelines (chapter 1 of this thesis), limited access to domestic charging facilities for many individuals (chapter 2), the likely necessity for substantial investment in the electric network to meet future demands (chapter 2), and the potential scarcity of raw materials and minerals essential for battery production [2] are not mentioned.

This hydrogen ladder and its development approach are, at best, naïve and, at worst, dangerous. It represents one person’s attempt to use his moderately high personal profile to push his own opinions on to an unquestioning audience.

However, this quote from the hydrogen ladder website as it stands illustrates the value of the opinions presented in an academic context: “Some people have asked whether the ladder is based on peer-reviewed research. The answer is yes, lots of it …” But he doesn’t cite any sources at all.

This approach creates an engaging visual, using a recognised format which gives it a veneer of respectability. However, the use of it to condemn whole sectors based on little information of substance is inappropriate. A more useful approach might be to assess the current technology readiness levels of hydrogen in each potential use area. That could be done in a more objective manner, and it would focus on the known current position rather than second-guessing the future.

### 7.2.5 Electricity vs. Hydrogen: The grudge match

It’s very easy to see electricity and hydrogen competing with one another. One only has to look at the discourse in social media forums to see that a great many people have very polarised views on this subject. The hydrogen ladder discussed above is another example. This is extremely frustrating; it seems absolutely clear that while there is a very important role for the electrification of many of our present-day energy uses that we use today, there’s also a very important role for hydrogen. There’s plenty of room and plenty of growth for advocates of both fuels. We can see that, by making a comparison with the hydrocarbon energy environment: in terms of road fuels, we can use petrol or diesel, or indeed LPG or compressed natural gas, and each users choice depends on a number of different factors depending on what’s appropriate. There is enormous potential growth, a huge market for both, and the fuels should be seen as complementing and not competing with each other -
not least because the same companies produce both, or indeed all fuels, and vehicles that use both.

The same applies to domestic and commercial heat - we have electricity and natural gas as the two main sources of energy for heat, and then there is also, more commonly in remote areas, coal, heating fuel oil, and LPG. With the comparison between electric heat pumps and hydrogen boilers also becoming very polarised, again there should be benefits to each depending on the individual circumstances. While the headline efficiency gains of heat pumps appear seductive, the reality is often not as good as expected [14] and the overall costs appear to favour hydrogen boilers, as discussed in section 7.2.6.

7.2.6 Socio-economic effects and the nature of market choice

This brings us to an important consideration that is often it seems, overlooked when considering this type of question. Fundamentally, users have a choice for what they think will suit them. We do not live in a centralised command economy, dictating that.

There exist advantages to hydrogen vehicles- lighter weight (leads to less tyre and brake wear, hence lower running costs), faster refuelling, longer range. There also exist advantages to battery vehicles - they can recharge at home or at base, where that's an option. There is existing infrastructure creating a lower barrier to initial entry.

And in heating, there exist benefits to hydrogen - better controllability, instant response to controls, minimal conversion alterations required to a currently gas fuelled property. For electricity, especially in the form of heat pumps, it is convenient where there is no gas network. Heat pumps are a new technology with better emissions than natural gas, where a decision must be made in the short term and hydrogen is not available. Running costs are likely to be competitive between the two, although the upfront cost of a heat pump is considerably higher than a hydrogen boiler [11-13].

Heat pumps are cheaper to run than traditional electric heaters because of the energy recovery operation providing a multiplication factor of, in reality, on average, 2.2 (range 1.4 – 3.2) [14]. This therefore reduces the effective cost of energy from the typical current price of 27p/kWh [43], to around 12p/kWh. This is higher than the current retail price of natural gas, which is around 7p/kWh [43]. For hydrogen at a retail price of £3.12 - £3.70/kg when produced at a large scale (chapter 2, model tab 4), an efficiency of 95% for a modern condensing boiler [40], and using the higher heat value of 39.4 kWh/kg, the unit cost of heat is approximately 8-10p per kWh – more than natural gas but still cheaper than heat pumps at current prices. However, this is a long range forecast so might lack accuracy. To consider it the other way around, at a cost of heat price of 12p/kWh from an electric powered heat pump, hydrogen would be competitive at 11.4 p/kWh - given the efficiency of 95% - which is equivalent to £4.49 /kg. This is considerably in excess of most long range estimates for renewable hydrogen [44, 45]. So it appears that on operating cost grounds, hydrogen should be competitive with electric heat pumps for heating. On capital costs, the difference is even more stark: heat pumps currently cost over £8,000 [11], while gas boilers – hydrogen boilers are expected to cost almost the same, due to their very similar nature [13] – cost from £1,000 [12], although the heat pump attracts a government subsidy of £7,500 [11].

So, there are advantages and disadvantages all round. Some people will prefer one option and others another. Because we live in a free market economy, if some people prefer an option then others will provide that option. It seems inappropriate and unwise to sit back as
government or as researchers and determine that choice will be removed for everyone for the next 2-3 decades.

7.2.7 We've done it before.

There is another indication of another previous gas network public transition; from approximately 1966 to 1977, the previously existing town gas network was entirely converted and expanded to supply natural gas instead [46]. Each town, or area, had its own gas works, rather than there being a nationwide transmission network – for example, Grumbly Gasworks, by Grumbly Town in North West Wales [47]. This conversion required the replacement or renovation of every domestic and industrial gas-using appliance in the UK [46], and the construction of a national gas transmission network. As such, it was an enormous project - possibly one of the most complicated national projects involving the public ever delivered. Again, this illustrates that this type of work can be done, and it has been done before.

Something striking about that is the timeline; the issue was first discussed in early 1966. A decision was taken to carry out a trial later in 1966. The trial was started almost immediately, in Canvey Island in London, an island in the River Thames with then about 5,000 population. This island was converted to run on natural gas for a period of about eight months to a year, which means that by the middle of 1967, the decision was made to go ahead. The detailed planning started immediately, along with recruitment and training of technicians to carry out all the necessary work, and the actual work began at the beginning of the next year. Over the following ten years, every household and business connected to the gas network in the UK had its appliances converted to run on natural gas, and a national transmission network was constructed [46].

The speed at which decisions were taken then seems scarcely believable compared to the extended process that appears to be necessary nowadays - one long drawn-out decision after another long drawn-out decision, followed by a small multi-year trial, followed by potentially a larger-scale multi-year trial, before an actual decision to do the work can be made. Clearly, there's a whole raft of social, political, and economic factors that are different now from the way they were 55 years ago, but it seems bizarre that we are unable to make decisions anything like as quickly as our forebears could - even though we are faced with a far more pressing, worldwide, problem to deal with, in the shape of global warming.

A further irony is that the ‘towns gas’, or coal gas, used before natural gas was usually 50-60% hydrogen [46].

The other very relevant bit of work is not yet complete. The Iron Mains Replacement Programme is a 30 year programme which has been running since 2002. Under the terms of this, every old cast-iron gas main gas supply pipe within 30 metres of a property has to be replaced with modern polyethylene pipes which are at much lower risk of damage and leakage [48].

This has been a bigger, more expensive programme than the towns gas to natural gas conversion was. In 2020 values, the IMRP will have cost about £28 billion by the time it’s complete [49], compared to about £3bn for the 1960s-70s natural gas conversion, also in 2020 values [46]. We can reason that this probably reflects the much greater amount of street works required, excavation to replace pipes and other equipment, and large-scale replacement of materials. The natural gas conversion programme will have been much
more of a logistical exercise, co-ordinating many small projects along with the construction and connection of a trunk gas distribution system.

Both of these would give an indication that it is quite achievable to carry out the type of gas mains or gas network conversion as will be required for hydrogen.

### 7.3 A pathway to the energy transition

Everything comes together in the future energy network. It's quite easy to look at each component and see advantages and disadvantages. What's really beneficial, though, is when all the different aspects of the new energy system can come together and support each other in a wide ranging manner. The ideal solution for connecting everything interlink and transporting the hydrogen is the conversion of the gas network (chapter 6). So much can rely on that. But there are other ways of obtaining hydrogen. It can be produced in-situ from electricity (chapter 2), or it can be delivered by tanker in the liquid or compressed gas form (chapter 5).

Nevertheless, we can imagine that the network converted to hydrogen permits the widespread use of hydrogen at a lower cost than would be the case if it were produced in situ using dedicated electrolysers and an electricity supply. That extensive hydrogen refuelling availability then leads to making it more practical to use large hydrogen vehicles. This, in turn, reduces the future costs borne by central and local government in road maintenance or road construction to a higher standard. The transport and widespread production of hydrogen will also allow both hydrogen and its derivatives to be used as marine fuel or railway fuel - hydrogen rail is currently being trialled in Scotland and in the north of England, and already rolled out in Germany, among other places [2]. And it's this large-scale deployment which will enable the costs and the practicalities of using hydrogen to become significantly improved through economies of scale. We can say that in many ways, the whole of the system will be worth more or will be better or more useful than the sum of its individual parts might suggest.

So, how do we describe a pathway to actually make it happen? We set out at the beginning to examine pathways – to examine not just ways in which hydrogen could be used, but the steps to actually make it happen. It's a little more complicated with hydrogen than with electricity because there's no pre-existing network. So small trials here, or an initial release there, cannot be accommodated as readily as in the pre-existing electricity infrastructure. This makes the initial hurdle more of a challenge to get over. Blending and de-blending gases (sec. 7.2.1) could help to resolve this.

Figure 7-8 shows the effective starting point, the current position of the energy network, with electricity beginning to make inroads into the hydrocarbon dominated system.
Figure 7-8  Existing hydrocarbon dominated energy network. Fairly discrete connections between sources and uses.

From here, a very useful initial step in the use of hydrogen would be - as quickly as can be organised – to use it to displace some of the existing network-supplied natural gas. Existing appliances can use up to 20% by volume of hydrogen mixed in with natural gas. This is equivalent to approximately 6% of the energy content, therefore it displaces 6% of the emissions associated with the combustion of natural gas. This is an intermediate step to the full conversion of the network to transport hydrogen, as examined in chapter 6. Further analysis might be required to confirm the capacity of the network to transport the blend, but it seems likely that any modification to the network would be substantially less than that required for 100% hydrogen.

The benefit of doing this, beyond the obvious removal very quickly and easily of 6% of emissions associated with natural gas combustion, will be that it will allow the transport of large quantities of hydrogen around the country. Hydrogen refuelling stations and other consumers could tap into the combined gas in the network and separate out the two gases – as in section 7.2.1, recent technology developments mean that separation of this type is now practical [3, 4] – and return the surplus natural gas to the gas network. This would then allow hydrogen refuelling stations to have a cheap and readily available source of hydrogen; it would also facilitate people becoming more familiar with hydrogen as a fuel.

This would also greatly simplify the conversion of the gas network by allowing hydrogen to be co-transported with natural gas, and pure hydrogen could be extracted as required as the appliance conversion programme proceeds.

The next step in the path would be to provide sufficient refuelling facilities for hydrogen to enable the replacement of all diesel vehicles over the next five years, at a pace required to meet the renewable energy the emissions reduction targets (chapter 2). These refuelling stations would ideally extract the hydrogen in the network as mentioned above, using filtration systems to separate and return the natural gas to the network. Those refuelling
stations in areas where the network cannot supply enough hydrogen, or doesn’t exist at all, could produce their own hydrogen using electrolysis and a dedicated electricity supply, or receive tanker delivered supplies. Even if the demand from replacing diesel cars does not materialise, the demand from replacing heavy goods vehicles and buses should be more than enough to make use of the same extent of refuelling stations after perhaps only two more years, assuming that ultimately the vast majority of heavy goods vehicles and buses are replaced with hydrogen vehicles. Battery fuelled buses and heavy goods vehicles should be considered an interim step at best, due to the extra road wear they would cause when rolled out as a large proportion of the vehicle fleet (chapter 4). Other factors will also apply, such as a significantly reduced payload in HGVs due to the weight of batteries, meaning that more vehicles would be required to move the same quantity of goods. This is also discussed in chapter 4.

This initial network should be enough to facilitate the use of hydrogen vehicles and the roll-out of hydrogen as a natural gas replacement for heat across the whole of Scotland (and indeed the UK; the principles discussed will be widely applicable across the UK and beyond). Then, as the demand grows, the next stage rollout of hydrogen refuelling facilities should be able to be more readily based on real-life commercial trends rather than initial modelling, as we are of necessity doing at the moment.

Strategic siting of the hydrogen fuelling and production - if required - facilities should allow, at the same time, the use of hydrogen (or its derivatives such as ammonia and methanol – see chapter 5) as a fuel for shipping and rail and even air transport, although the technology for using hydrogen in air transport is less advanced than in other areas [5, 6]. The benefit of this is that initial investment in hydrogen refuelling and transportation facilities can be used by many different consumers, reducing the risk of unnecessary investment.

Having said that, it’s worth taking a moment to consider this point. A great deal of what we're doing is driven by the need to make operations and projects commercially viable. Investment decisions are being held back because of the need to have a very high level of confidence in the demand. This obviously creates a chicken and egg scenario; there will also be no new users if there’s no fuelling available. This consideration is important because it has a bearing on the comments above about the 1960s conversion from towns gas to natural gas. Back then, the gas supply was in the hands of the national gas boards, and it was run not on a purely commercial basis, in that it wasn’t a private company required to satisfy its shareholders. And that might well be a key reason why it was easier to make decisions then than it is now. Today's investment, as things stand, needs to come from commercial companies which have to satisfy their shareholders. Perhaps this is not the place to extend the discourse into redesigning how markets should work in the 21st century; however, given the urgency of the climate issues we are dealing with, this suggests that investment is required in a way that can reduce – or does not rely on – the corporate or commercial risk. Either this is carried out on a not for profit basis – in other words, in effect, government-funded - or the risk element of the private sector investment can be reduced in the short term, which would probably require a form of government subsidy or at least, underwriting the demand risk.

So at this point in our pathway, around 2030, where have we got to? We have 20% by volume hydrogen being delivered by the natural gas network to our homes. This will be higher in the transmission side of the network, and indeed through the intermediate and medium pressure networks. That then can be tapped into by vehicle fuelling stations and
other larger users, which will reduce the amount of hydrogen in the network before it is distributed to users, reducing the percentage of hydrogen to 20% or below. This makes it unnecessary to have appliance conversions in the shorter term. We also have enough hydrogen refuelling stations in place to supply heavy goods vehicles, with some capacity for light goods vehicles and cars as well. This is likely to then be enough to support five to seven years of hydrogen vehicle fuel demand (chapter 2). It seems likely that there will be other situations where having hydrogen distributed within the gas network, and separable through filtration or other technology, could permit other commercial processes to use hydrogen as required. This way of conveying proportion of hydrogen in the existing gas network could make the transition phase massively simpler, as not everything would have to be converted all at the same time.

Figure 7-9 Intermediate stage of combined energy network. Complex due to including both hydrocarbon fuels and renewable fuels.

Figure 7-9 illustrates the combined energy system at the intermediate stage, 2030. It is particularly complex due to the need to provide for both hydrocarbon and renewable fuels.

The next stage in our pathway then would be to continue to roll out hydrogen refuelling stations either at regional hubs or at existing fuelling station sites, but this would be in response to market-driven demand by that stage. Beyond that, hopefully, there will be a conclusion to the interminable trials of 100% hydrogen in domestic consumption, allowing the start of nationwide appliance conversion program. And we can also foresee that the other demands for hydrogen, for shipping or for rail, will also begin to be able to respond to network market forces rather than the at-risk early adopter stages.’

In this phase, the fuller conversion of the natural gas network will get under way. A steadily increasing proportion of the energy transmitted in the network will be hydrogen, as natural gas users are converted and more and more other users will use hydrogen for commercial and transport needs. This is described more fully in section 7.2.1 above.
In parallel with all of this, the integrated energy storage system using underground geological storage of hydrogen should be developed. This would allow the production of excess energy in the summer to be stored in the form of hydrogen to be used in the winter. This would also provide a strategic reserve of energy, to be used as a backup supply for those occasions when the very large amount of electricity generation required for all of this is incapable of producing the electricity base load. This would be on those days in Scotland and all around its coastal waters when there is no wind. This is discussed in more detail in section 7.2.2 above.

The final stage envisages a complete conversion of the energy system to use hydrogen and renewable electricity, with some provision for other fuels such as bio- or E-fuels in specialised applications, such as classic road vehicles and as sustainable aviation fuel. This is illustrated in Figure 7-10.

![Figure 7-10 Ultimate renewable energy system incorporating extensive use of hydrogen alongside electricity.](image-url)
8 Conclusion

8.1 Revisiting the hypotheses

For significant applications, hydrogen will be more suitable than electricity; The most efficient energy system will include both hydrogen and electricity.

That was the overarching hypothesis set out in chapter 1 of this thesis.

There were separate hypotheses expressed relating to each of the detailed study areas:

- Prioritising large vehicles such as buses and HGVs ahead of smaller vehicles will have benefits over an equal, or unregulated, vehicle transition.
- A seed network for hydrogen road fuelling can be defined which is cost-competitive with an equivalent electric charging system.
- There will be significant and quantifiable additional costs of road maintenance due to the increased weight of ZEVs over ICE vehicles. This will be markedly greater for BEVs than for HFCEVs due to the weight difference.
- Hydrogen will perform better in cost and emissions than other alternative low carbon chemical fuels for shipping.
- The natural gas network can be converted to supply enough hydrogen to replace all natural gas in use, on the basis of energy transported, without enlargement or replacement of the pipes.
- It will be possible to identify which parts of the network will need intervention when converted to supply hydrogen, on the basis of the natural gas characteristics alone.

8.1.1 Chapter 2 hypotheses

Prioritising large vehicles first will have benefits over an equal, or unregulated, transition.

A seed network for hydrogen road fuelling can be defined which is cost-competitive with an equivalent electric charging system.

These were explored in chapter 2, through the use of a model to assess the pace at which zero emissions vehicles should be introduced in order to meet the government targets, and to assess the scale of the hydrogen infrastructure required to support them.

Figure 2-3, reproduced here as Figure 8-1, illustrates the findings of required zero emissions vehicle sales numbers to meet the government’s targets. ‘Equal pace’ shows the situation where all vehicle types progress equally, and ‘Accelerate bus and truck’ is where larger vehicles are prioritised. As can be seen, the total numbers of vehicles required is lower with ‘Accelerate bus and truck’, which should bring advantages in the total number of ZEV power systems required, albeit that some are significantly larger. However, the difference is not large. The very recent UK government announcement of withdrawing the target to ban new hydrocarbon fuelled car sales by 2030 will have a small effect; the same two lines in Figure 8-1 would have the sharp top smoothed out, to naturally taper in at around 2035. The new UK government goal is a reduced target of 80% of new cars and 70% of new vans to be ZEV by 2030, with all of them to be ZEV by 2035 [1]. This will therefore have a minimal effect on the pace of transition needed.
Figure 8-1  New sales of zero emission vehicles, projected for pace of transition scenarios.  The step at 2030/31 reflects the ban on hydrocarbon car & LGV sales by that date, forcing the curve to the maximum value. Without this, the curves would naturally meet the maximum around 2035. This chart applies to all fuel choice options.

Figure 2-6, reproduced here as Figure 8-2, shows the growth in numbers of hydrogen refuelling stations required to support the necessary growth in hydrogen vehicles in two scenarios. A seed network of around 90 hydrogen refuelling stations of various sizes would support 5-6 years’ growth in the ‘Like for Like’ scenario, in which all existing diesel vehicles become replaced by hydrogen vehicles. It would support 7-8 years’ growth if ‘Large Vehicles Only’ was the out-turn.

Figure 8-2 Numbers of hydrogen refuelling stations for selected scenarios: Like for Like and Large Vehicles Only fuel options, with Equal Pace and Accelerate Bus & Truck pace options. Maximum and minimum cost cases are presented, along with the case derived from the core estimated model inputs.
This programme would have a capital cost of around £140M. Deriving costs from the Scottish Power publication ‘Zero Carbon Communities’ [2] leads to an equivalent cost of electric charging infrastructure of around £1bn, or more. Much of the extra is in the expansion in capacity of the electricity network, which has not yet been needed at a large scale but will be as the transition progresses.

It can also be seen from Figure 8-2 that for the ‘Accelerate Bus and Truck’ options, the number of refuelling stations would have to increase more quickly, although the ultimate provision would be the same.

Taking these two elements together suggests that the first hypothesis is unproven: in the short term, fewer vehicles but more refuelling provision would be required.

The second hypothesis is confirmed. The hydrogen refuelling seed network would cost substantially less than the equivalent electric charging provision at large scale.


8.1.2 Chapter 4 hypothesis

There will be significant and quantifiable additional costs of road maintenance due to the increased weight of ZEVs over ICE vehicles. This will be markedly greater for BEVs than for HFCEVs.

This was investigated in chapter 4. The key fact is that the wear on roads is proportional to the axle load to the power of 4 [3]. This means that larger vehicles are responsible for over 99% of road wear, on a national average basis; any additional weight of cars, vans and motorcycles due to fuel choice will be insignificant. However, the fuel choice from larger vehicles will make a difference: Battery large vehicles are around 10% heavier than their diesel equivalents, while hydrogen vehicles are around 1% heavier [4]. If buses and HGVs become hydrogen fuelled, an increase in road maintenance costs of around 6% can be expected in real terms, compared to the present situation with very few ZEV large vehicles. If they are replaced with battery electric power, the equivalent increase will be around 30%. In Scotland, this will be equivalent to an additional annual road maintenance cost of around £30,000,000, or £500 per vehicle, if hydrogen powered; £162,000,000, or £3,000 per vehicle, if battery electric powered.

Chapter 4 was published as: Low, J.M., Haszeldine, R.S. and Harrison, G.P., 2023. The hidden cost of road maintenance due to the increased weight of battery and hydrogen trucks and buses—a perspective. Clean Technologies and Environmental Policy, 25(3), pp.757-770. https://doi.org/10.1007/s10098-022-02433-8
8.1.3 Chapter 5 hypothesis

"Hydrogen will perform better in cost and emissions in marine use than other alternative fuels or energy sources."

This was investigated in Chapter 5 as a desk study. Several fuels are capable of being produced, transported and used on a net zero greenhouse emissions basis in the long term. The cheapest of these is expected to be ammonia at 7-9p/kWh in the short term and 6-7p/kWh in 2045. Green hydrogen is expected to come closest to that in the longer term at 8-11p/kWh, though in the shorter term it is expected to be more at 17-19p/kWh.

Both are capable of being produced and used in a zero-emission manner, though at present they are made from fossil fuels. In the short term, biodiesel and green or blue hydrogen appear to be the lowest emission options, provided that they can be produced in large enough quantities for a potentially large demand. Other fuels considered were biodiesel and methanol, both of which could be viable options especially in the shorter term when zero emission sources are not well developed.

The drivetrain efficiency will become significant, affecting the quantity of fuel burned and hence both costs and emissions; in a combustion engine, efficiency can be expected to be around 44% [5], while in a fuel cell it could reach as high as 70% [6].

Other factors may become decisive: ammonia and methanol are somewhat toxic, although there is considerable global experience in handling them safely. Hydrogen, especially as a gas, has a very high storage volume with a density of 34 kg/m$^3$, which might be a problem in a space constrained use.

In terms of confirming the original hypothesis, it is not confirmed, as the result depends on more factors than simply the energy content of the fuels; the method of use could become decisive.

Chapter 5 was extracted from a report prepared for BP and the Offshore Renewable Energy Catapult, titled *Renewable fuels for Offshore Service Operation Vessels*, forming part of the project “SOV Zero emission Fuels and Technology – Feasibility Study”.

8.1.4 Chapter 6 hypotheses

"The natural gas network can be converted to supply enough hydrogen to replace all natural gas in use, on the basis of energy transported, without enlargement or replacement of the pipes."

"It will be possible to identify which parts of the network will need intervention when converted to supply hydrogen, on the basis of the natural gas performance."

This was explored in chapter 6 by using a hypothetical model constructed in Python for the purpose. This allowed the examination of pressures and flows in a network inspired by the existing natural gas network on the east of Scotland.

It was found that at the highest flow rates, in some locations the pipes were unable to transfer enough hydrogen to meet demand. However, this could resolved by either supplying additional downstream storage, by operating at slightly higher pressure regime, or by incrementally boosting the transmission main operating pressure – or a combination. Thus the first hypothesis is confirmed: it should not be necessary to replace or augment pipe capacity.
A set of empirical formulas were developed allowing the excess capacity of a pipe transporting hydrogen to be predicted from the excess capacity of that pipe transporting natural gas, and its natural gas operating pressure.

The first step is to calculate a forecast hydrogen upstream pressure (Pup) for the pipe. In demand pipes, that is pipes connecting the core transmission main to the demand centres, the pressure is taken as constant at 700kPa provided there is more than that pressure in the associated transmission pipe.

The hydrogen pressure in the transmission pipes is found from the natural gas pressure, using Equation 6-11, reproduced here as Equation 8-1.

$$P_{up} = (1.768 . P_{up}^{1.85} - 14.3 \times 10^6)^{0.541}$$

Equation 8-1

Where Pup is pressure upstream, h denotes hydrogen, and ng denotes natural gas.

The calculated Pup,h is then used in the flow exceedance ratio calculation, Equation 6-10, reproduced here as Equation 8-2:

$$FER_h = 1.27 . FER_ng . \left( \frac{P_{up\_ng}}{P_{up\_h}} \right)^{1.1}$$

Equation 8-2

Where FER is Flow Exceedance Ratio, the ratio of demand to maximum capacity of the pipe at the upstream pressure. When the FER exceeds 100%, the excess capacity falls below zero and the pipe will be unable to transport enough hydrogen to meet demand.

This appears to confirm the second hypothesis: it is possible to predict when intervention will be required. However, further investigation will be required to confirm the wider applicability of this approach beyond this initial model.

8.2 Overarching hypothesis

The overarching hypothesis was expressed as: "for significant applications, hydrogen will be more suitable than electricity; the most efficient energy system will include both hydrogen and electricity.”

This is demonstrated to a great extent in many areas through this thesis:

Chapters 2 & 3: Hydrogen infrastructure at large scale is significantly cheaper for vehicle refuelling than electricity charging – an initial seed network should cost about £140 million, compared to about £1bn for electric charging at an equivalent stage. Much if this is due to the electric network improvements, which are likely to be proportionately greater early in in the transition. By the end of the transition, on a net present value basis, large scale hydrogen infrastructure is likely to cost around 20% of the cost of equivalent electric charging.

Chapter 4: Hydrogen fuelled large vehicles (buses and heavy good vehicles) will have substantially less impact on road wear and tear than electric battery vehicles. In fact this excess due to battery vehicles works out at approximately £2,500 per year per vehicle. There is no significant extra impact from smaller vehicles like cars, vans or motorbikes.

Chapter 5: For anything but the shortest of sea voyages – less than one day – electricity is inappropriate on both cost and practicality. Hydrogen is a possible solution, but here it might be better served by ammonia or another derivative.
Chapter 6: The pipeline modelling does not directly make comparisons with electricity, but it does show that, in the aspect of carrying capacity, it should be possible to make full use of the existing natural gas network to transport hydrogen, which will in turn enable the delivery of many of the other aspects discussed.

8.3 Summary
This research has examined a number of aspects of the use of hydrogen as a zero carbon energy vector. While the focus has been geographically on Scotland, most of the work presented here could be readily adapted to apply to other industrialised economies. The areas of work addressed are:

- Modelling of road transport refuelling infrastructure requirements.
- Case study of road refuelling station planning.
- Additional road maintenance requirements due to weight of hydrogen or battery vehicles.
- Hydrogen as a marine fuel, in comparison with alternatives.
- Modelling of natural gas network conversion to hydrogen to examine capacity issues.

This was completed with a discussion examining how these aspects of use fit into the wider energy transition, and the likely shape of such a transition making the best use of hydrogen. It was shown that, as initially hypothesised, there are many areas where hydrogen would be a better solution than electricity; the future energy network should include both.

In final conclusion, Figure 8-3 illustrates the likely future renewable energy network, including a substantial usage of hydrogen.

Figure 8-3 Ultimate renewable energy system incorporating extensive use of hydrogen alongside electricity.
References

Chapter 1 References


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Chapter 2 References


3. Reuter, Benjamin, Johannes Riedl, Thomas Hamacher, Markus Lienkamp, and Alex M Bradshaw. 2014. "Future resource availability for the production of Lithium-ion vehicle batteries." CoFAT.


Chapter 3 References


Chapter 4 References

NB the references for chapter 4 are presented in the format requested by the publishing journal


Chapter 5 References


Chapter 6 References


Chapter 7 References


**Chapter 8 References**


Appendices

Chapter 1 Appendix

Appendix 1A - Relative fuel tank size calculation.

<table>
<thead>
<tr>
<th></th>
<th>Petrol</th>
<th>Diesel</th>
<th>700 bar Hydrogen</th>
<th>Battery electric*</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Basic parameters</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Density (ρₘ)</td>
<td>kg/l</td>
<td>0.75 [1]</td>
<td>0.83 [1]</td>
<td>0.039 [2]</td>
</tr>
<tr>
<td>Energy Density (ρₑ)</td>
<td>kWh/l</td>
<td>9.6</td>
<td>10.5</td>
<td>1.30</td>
</tr>
</tbody>
</table>

**Efficiencies (η)**

- Engine efficiency (η(engine))
- Fuel cell/battery
  - η(fuel cell), η(battery)
- Electric motor (η(motor))
- η(hydrogen) = η(fuel cell) X η(motor)
- η(electric) = η(battery) X η(motor)
- Efficiency adjusted energy density (ρₑ(a)) kWh/l
  - 3.2 4.6 0.85 0.71

<table>
<thead>
<tr>
<th></th>
<th>Petrol/ Hydrogen</th>
<th>Diesel/ Hydrogen</th>
<th>Petrol/ Electricity</th>
<th>Diesel/ Electricity</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Tank size ratio (hydrogen)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Φₑ(hydrocarbon) /</td>
<td>Φₑ(zero-carbon)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.7</td>
<td>5.4</td>
<td>4.4</td>
<td>6.4</td>
</tr>
<tr>
<td><strong>Efficiency ratio</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>η(hydrocarbon) /</td>
<td>η(zero-carbon)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>50%</td>
<td>67%</td>
<td>35%</td>
<td>47%</td>
</tr>
</tbody>
</table>

* Data based on Li-ion battery.
** Typical value. Variable depending on charge & use profile.
## Chapter 2 Appendices

### Appendix 2A - Model input values, assumptions and sources

<table>
<thead>
<tr>
<th>Item / Assumption</th>
<th>Value (Where applicable)</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>The total number of vehicles in each class will be constant. In fact in recent years there has been a gradual upwards trend in vehicle numbers. For this assumption to hold, there will therefore require to be some management of demand for new vehicles. This also implies that annual new vehicle sales will be constant at current levels, and gradually all will become zero emissions vehicles. Vehicles of each class continue to be scrapped at the same average age as at present.</td>
<td></td>
<td>UK Department of Transport [1] This is also tested in the sensitivity analysis.</td>
</tr>
<tr>
<td>Enough offshore or other green electricity will be available to produce enough green hydrogen for vehicle fuelling purposes. This implies that hydrogen fuel will be responsible for zero emissions in use.</td>
<td></td>
<td>Scottish Government policy [2], also described in the introduction to this paper.</td>
</tr>
<tr>
<td>Offshore wind electricity generation, including transmission to shore.</td>
<td>£40/MWh</td>
<td>Strike price for 2019 round of UK offshore wind power bids [3].</td>
</tr>
</tbody>
</table>
| Hydrogen fuelling station, incl. in-situ electrolysis generation, compression, local storage, dispensing. Initial capital costs. | Initial values:  
1000 kg/day £2.1M  
2850 kg/day £4.8M  
5700 kg/day £8.4M | Base costs derived from Tiili et al 2020 [5] Incorporating electrolyser capital cost (above), and sense-checked in consultation with Logan Energy, Edinburgh - Hydrogen fuelling solution manufacturers and installers. Further breakdown of this is in the model. |
<p>| Energy requirement for compression of hydrogen. | 3.7 kWh / kg | Hua et al, 2011 [6] |
| Learning rates | 12% per doubling for hydrogen refuellers. | Approximated from Ruffini &amp; Wei [7]. Varied in analysis. |</p>
<table>
<thead>
<tr>
<th>Description</th>
<th>Cost Data</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas network operating cost</td>
<td>£336,000,000</td>
<td>SGN plc 2018 annual sales [8] / annual energy delivered [9]</td>
</tr>
<tr>
<td></td>
<td>47,578 GWh</td>
<td>We assume the cost will be similar for hydrogen, as most of this is a fixed asset related cost.</td>
</tr>
<tr>
<td></td>
<td>£0.007 (0.7p)/kWh</td>
<td></td>
</tr>
<tr>
<td>Electricity network operating costs</td>
<td>£450,000,000</td>
<td>SPEN plc 2018 annual sales / annual energy delivered [10]</td>
</tr>
<tr>
<td></td>
<td>17,003 GWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td>£0.0265 (2.65p)/kWh</td>
<td></td>
</tr>
<tr>
<td>Discount rate</td>
<td>6% used in all transition scenarios.</td>
<td>Assumed; can be varied in the model.</td>
</tr>
<tr>
<td>Efficiency of electrolysis Excluding compression and transmission costs.</td>
<td>71%</td>
<td>Buttler &amp; Spliethoff [11]. The high end of current technology is used, as we expect average efficiencies to improve over the transition.</td>
</tr>
<tr>
<td>Wholesale cost of grid supplied electricity</td>
<td>£0.188 / kWh</td>
<td>UK Government [12]. Assumed to include values for network operations, losses, routine capital expenditure. This is held constant through the modelled period.</td>
</tr>
<tr>
<td>Timescale for conversion of natural gas network</td>
<td>2028-2042 +/- 2 years at each end</td>
<td>We assume that the proportion of hydrogen fuelling stations supplied through the gas network rises in a logistic function to a maximum of 85% by the end date – representing the proportion of the population connected to the gas grid at present. [13]</td>
</tr>
</tbody>
</table>

As this conversion progresses and more network hydrogen becomes available, the forecast number of stations producing hydrogen locally decreases a little after 12-15 years. We assume the redundant ones will be converted to dispense grid supplied hydrogen, although we have not identified a cost saving as the number affected is small.

Data on hydrocarbon fuelling equipment costs and lifespan (shown in model worksheet 20) are obtained from information canvassed by the Petroleum Retailers’ Association (PRA) from its members on our behalf, supplemented by a discussion with the investment
director of a large fuel retailing company. The correspondence with the PRA is available from the authors on request.

Cost of water is negligible. Scottish Water website shows metered charge at 88p/cubic metre for domestic metered customers [14] – in reality for our purposes this would be lower due to larger demand. 1 m3 water weighs 1000kg, which would yield 111kg of hydrogen. 88p for 111kg hydrogen is 0.8p/kg, about 0.5% of our total cost estimate.

The number of hybrid smaller vehicles sold between 2030 and 2035 will be insignificant. Early experimenting with the model showed that allowing the hydrocarbon sales to taper naturally to zero at around 2035, rather than forcing them to zero at 2030 as in current legislation, makes little difference to either gross emissions or to the zero emission refuelling infrastructure required. If these are hybrid rather than fully hydrocarbon, the impact will be even lower.

Sizes of hydrogen refuelling stations

- Small: 1000 kg/day.
- Medium 2850 kg/day
- Large 5700 kg/day.

Derived from DECC/Deloitte [15]
Appendix 2B  Model details

Step 1
This creates a randomised data set for the modelled cases for the Monte Carlo simulation. The variables for which the data are generated are as follows (shown with the variable name for use in subsequent calculations):

- **UnitEmNewHCclass** = Per-Vehicle emissions from new hydrocarbon fuelled vehicles, by vehicle class, at intervals through the transition. The range of values of this is constrained by current and expected EU and UK legislation, and is further constrained not to exceed the value generated in the previous timestep. This creates a Markov Chain value generation. We generate values for the key dates of 2020, 2025, 2030, and 2040.
- **%Hclass** = Future zero carbon fuel market share of hydrogen, using the three input constraints from the fuel choice options of **Large Vehicles Only**, **Like for Like**, and **100% Hydrogen**.
- **%EllUse** = Electrolyser usage rates as a % of capacity. This is allowed to vary randomly between constraints, set at 81% and 61%, based on a central value of 71% [16].
- **LocalElec** = The proportion of in-situ produced hydrogen using local dedicated electricity generation, rather than grid supplied electricity. This is allowed to vary randomly between 0-100%.

For each modelled case, calculation steps 2-8 below were applied.

Step 2
This generates the future vehicle numbers, which control all the subsequent steps.

The numbers of ZEVs in each class for each year is generated, using a pair of standard logistics functions, where one represents new sales and the second represents vehicles scrapped at end of life. The two are offset by the average age on scrapping of the class.

The values of the constants creating this distribution were adjusted manually for each vehicle class, until the emissions in use (calculated in step 3) met the relevant 2030 and 2045 targets within 5% for all modelled cases. The constants were varied for the different classes of vehicle as appropriate. The values of the constants developed are presented in the model in worksheet 12.

From there, the total numbers of ZEVs, and new sales, number scrapped, and total registered hydrocarbon vehicles for each year are then calculated using simple arithmetic. The sales figures are forced to 100% of cars and vans at the end of 2030, reflecting the UK Government’s ban on hydrocarbon sales from that date.

Inputs:

**NewVehclass** is the total annual sales of new vehicles of any fuel type for each class, taken as constant through the transition.
k is an arbitrary constant affecting the gradient of the curve
x is the year in question
xo is the mid-point of the time distribution, that is the point at which NZEclass = NewVehclass/2
VL is approximately average vehicle life, found from total fleet size / annual sales (this assumes a constant fleet size).
EndHCdate = year after which hydrocarbon vehicle sales are to be stopped.
TotVehclass = Total numbers of vehicles in class, assumed to be constant at current levels.

Outputs:
NewZEC = New ZEVs in class
= NewVehclass/\[1+\exp(-k(x-xo))] \quad \text{(standard logistic function).}

ScrZEC = Scrapped ZEVs in class
= NewVehclass/\[1+\exp(-k(x-(xo+VL)))]

TotZEC = total numbers of ZEVs
= TotZEC(yr-1) + NewZEC - ScrZEC

TotHC = Total registered HCVs at end of year
= TotVehclass-TotZEC

NewHC = new sales of hydrocarbon vehicles (HCV) in year
= NewVehclass - NewZEC

DHC = change in number of HC vehicles
= TotHC(yr)-TotHC

Step 3
Calculates the emissions in use for each class each year based on the numbers of hydrocarbon vehicles remaining in step 2 and the Markov chain generated future emissions created in step 1.

AvAnKm = Average Annual distance driven per vehicle in class (km)

UnitEmAvPrevHC = UnitEmAvAllHC (defined below) for previous year

TotEm = Total emissions from class in year (kT/yr CO2 eq)
= UnitEmAvPrevHC * (TotHC-ScrHC) * AvAnKm + UnitEmNewHC * NewHCclass * AvAnKmclass

UnitEmAvAllHC = Unit emissions, average for all HC vehicles in service in class
= TotEmclass / [TotHCclass + NewHCclass - ScrHCclass]
Equation B. 10

TotEmclass is calculated for each vehicle class, and summed across all classes for each year.

Step 4

Calculates the required quantity of hydrogen (produced locally and centrally), based on the numbers of ZEVs of each class (Step 2) and the proportion of them using hydrogen (Step 1).

The average demand for hydrogen is found from the average current demand for hydrocarbon fuels for each vehicle class, adjusted by an efficiency factor relating the energy required from petrol or diesel to that from hydrogen.

The annual total and proportionate demand for hydrogen is calculated:

Inputs:

- TotZEclass = total numbers of ZEVs in class
- %Hclass = Proportion of ZEVs in class using hydrogen fuel
- UnitDemHclass = Annual Fuel demand per HFCEV in class

Outputs

- DemHclass = Annual demand for hydrogen from class
  = TotZEclass x %Hclass x UnitDemHclass

Equation B. 11

SumDemHclass = Total demand for hydrogen, summed across all classes

The aggregate of SumDemHclass (SumDemHclass) over the transition period is used to estimate the fuel proportion used in many of the output graphs, expressed as the percentage of zero carbon fuel used as Hydrogen, based on fuel energy supplied. We assume for this calculation that the non-hydrogen energy is supplied as electricity to BEVs.

The proportionate share between locally produced hydrogen and network distributed hydrogen is calculated using a standard logistic function. We assume that the transition to network supplied hydrogen (i.e. the conversion of the existing gas network to hydrogen) takes place from 2028 – 2040, and that at maximum 85% of the hydrogen demand will be met through the network.

Step 5

This step calculates the infrastructure required to deliver the hydrogen and electricity:

For hydrogen, three station capacities (CapStn) are considered: Large (5700 kg/day), Medium (2850 kg/day) and Small (1000 kg/day). These are derived from current hydrocarbon station sizes, calculated independently in Step 8. These are allocated in the same proportion (%Stn) as existing small, medium and large hydrocarbon fuelling stations.

Other inputs, found in steps above:

SumDemHclass

%EllUse

Outputs:

GrossCapStn = Gross capacity required from stations of this size
  = SumDemHclass * %Stn / %EllUse
NrStnCap = number of fuelling stations of this capacity and type required.

\[ NrStnCap = \text{GrossDemStn}/\text{CapStn} \] (rounded up to next integer)

\( \text{Equation B. 12} \)

**Step 6**

Calculates the capital and fuel costs of the infrastructure in **step 5**.

**Capital costs.**

Unit cost for hydrogen equipment is decreased based on the learning rate. This is the percentage decrease in cost each time the number of installations doubles. Costs including and excluding electrolysers are used for local and centralised production respectively.

Multiplying the annual unit cost by the number of new installations required (**step 5**) gives the annual cost of new hydrogen infrastructure by station size and type.

Aggregate, Annual and NPV costs are then calculated using simple arithmetic and standard methods of NPV calculation. These are summed as appropriate to give the hydrogen capital cost.

**Definitions**

\( \text{LRH} = \text{learning rate for hydrogen (\% decrease in cost each time the number of installations doubles).} \)

\( \text{NrStnCap}_{\text{source}} = \text{NrStnCap} \) divided according to the split between locally produced and network supplied hydrogen.

\( \text{InitUnitCostCap}_{\text{source}} = \text{initial unit cost, with suffices as above.} \)

**Outputs**

\( \text{UnitCostsize}_{\text{source}} = \text{unit cost in each year.} \)

\[ \text{UnitCostsize}_{\text{source}} = (1-\text{LRH})^{\log_{2}(\text{NrStnCap}/\text{NrStnCap(yr-1)})} \times \text{InitUnitCostCap}_{\text{source}} \]  

\( \text{Equation B. 14} \)

This is repeated for other station sizes and hydrogen sources.

Aggregate, Annual and NPV costs are then calculated using simple arithmetic and standard methods of NPV calculation. These are summed as appropriate to give the hydrogen capital cost.

**Fuel Costs**

The fuel costs are taken as the cost of production and distribution of the fuels, but excludes retail margins and tax. This is because retail margins are subject to local market forces, and taxes are at the government’s discretion. The demand for both fuels is brought forward from **step 4**.

The energy requirement of locally produced hydrogen is found from the energy content of the hydrogen divided by the efficiency of electrolysers. The wholesale cost of grid electricity required to supply this energy demand represents the production cost of the hydrogen. The proportion supplied using local dedicated electricity has the electricity cost reduced by the cost of grid transmission.
The production cost of network supplied hydrogen is found from the input electricity cost from new offshore wind electricity generation, the efficiency of electrolysis, and the capital cost of electrolysers divided by their expected life. To this is added the cost of transferring the hydrogen to shore via pipeline, and the cost of network transmission onshore.

Both hydrogen production methods are summed, and the cost of compression to 700 bar is added. This is found from the energy cost of compression per kg and the wholesale cost of electricity.

The hydrogen and electricity operating costs are then added to get the operating costs for the case.

Inputs:
EffEll = Efficiency of Electrolysis, %
EnH = Energy density of hydrogen, kWh/kg
EnComp = Energy required for compression of hydrogen to 700bar, kWh/kg
UnitCostGrdE = unit cost of electricity supplied through grid (wholesale), £/kWh
UnitCostSuppH = unit cost of offshore produced hydrogen supplied into repurposed network (wholesale, calculated), £/kg
UnitCostDistH = unit cost of operating the repurposed gas network, £/kg
UnitCostTransE = Transmission cost of grid electricity (included in UnitCostGrdE)
DemH = Annual total demand for Hydrogen
%Hn = Proportion of hydrogen supplied through network.
%Hc = Proportion of hydrogen produced locally
%Ec = Proportion of electricity produced from local dedicated generation

Demand Calculations:
DemHn = gross demand for hydrogen supplied through network, kT/yr
   = DemH x %Hn
   \( Equation \ B. \ 15 \)

DemHc = gross demand for hydrogen produced locally, kT/yr
   = DemH x %Hc
   \( Equation \ B. \ 16 \)

\( EnHc = \text{Energy (as electricity) requirement for hydrogen produced locally, GWh/yr} \)
   \( = \text{DemHc*EnH/EffElect} \)
   \( Equation \ B. \ 17 \)

Fuel Cost calculations:
UnitCostComp = unit cost of compression of hydrogen to 700 bar, £/kg = EnComp*UnitCostGrdE
   \( Equation \ B. \ 18 \)

AnnCostComp = Annual total cost of compression of hydrogen to 700 bar, £
   \( = (\text{DemHc+DemHn})*\text{UnitCostComp*kg_in_kT_kWh_in_GWh} \)
   \( Equation \ B. \ 19 \)

AnnCostSuppHn = Annual total cost of hydrogen supplied into repurposed network, £
   \( = \text{DemHn*kg_in_kT_kWh_in_GWh*UnitCostSuppH} \)
Equation B. 20

\[ \text{AnnCostDistH} = \text{cost of operating the repurposed gas network, £} \]
\[ = \text{DemHn} \times \text{kg}\_\text{in} \_\text{kT} \_\text{kWh}\_\text{in} \_\text{GWh} \times \text{UnitCostDistH} \]

Equation B. 21

\[ \text{AnnCostHc} = \text{Annual total cost for hydrogen produced locally, £} \]
\[ = \text{EnHc} \times (1 - \%Ec) \times \text{UnitCostGrdE} + \text{EnHc} \times \%Ec \times (\text{UnitCostGrdE} - \text{UnitCostTransE}) \]

Equation B. 22

Fuel Cost Totals

\[ \text{AnnTotH} = \text{total operating cost of hydrogen, £} \]
\[ = \text{AnnCostComp} + \text{AnnCostSuppHn} + \text{AnnCostDistHn} + \text{AnnCostHc} \]

Equation B. 23

Step 7

This is a separate assessment of the typical sizes of hydrogen refuelling station that would ultimately be needed and current annual average capital expenditure on the existing hydrocarbon refuelling infrastructure.

The sizes of refuelling station are based on three typical sizes of hydrocarbon station. The energy content of the fuel dispensed annually from these is modified for the difference in efficiency between internal combustion engines and hydrogen fuel cells. This is then used to calculate the corresponding quantity of hydrogen, based on the specific energy of hydrogen (Lower Heating Value, 33.3 kWh/kg). The resulting values are then rounded for convenience to the three sizes used of 1000, 2850 and 5700 kg/day.

The annual expenditure is found from the cost and typical service life of the following elements:

- Fuel pump
- Hoses and pipes associated with each pump
- Storage tanks
- Fuelling station general refurbishment.

Combining these with the number of pumps at a typical fuelling station and the estimated number of fuelling stations in Scotland allows an estimate of the annual cost. There are a number of approximations used in this approach, so the result is treated as an indicative range for comparison rather than an accurate calculation.

Fuelling Station Size Inputs

- \( \text{SpEnH} \) = Hydrogen specific energy
- \( \text{EnDP} \) = Energy Density, Petrol (also ~D, Diesel)
- \( \text{AvAnnConsP} \) = Average Annual Consumption of Petrol, Scotland (also ~D, Diesel)
- \( \text{EffPH} \) = Efficiency ratio Petrol / Hydrogen
- \( \text{EffPE} \) = Efficiency ratio Petrol / Electricity
- \( \text{VolHCsize} \) = Annual volume of hydrocarbon supplied from Small, Medium or Large hydrocarbon fuelling station.

Fuelling Station Size Calculations
EquivHP = Equivalent kg of hydrogen to one litre Petrol (also ~D, Diesel)
   = EnDP*EffPH/SpEnH

EqvSupPsize = Annual volume of Petrol supplied from hydrocarbon fuelling station
   (also ~D~, Diesel)
   = VolHCsize*AvAnnConsP/(AvAnnConsP + AvAnnConsD)

EquivDlySupPHsize = Daily hydrogen supply equivalent to Petrol (Also ~D~, Diesel)
   = VolSupPsize*EquivHP

EquivDlySupHCHSm = Daily hydrogen supply equivalent to all fuel from fuelling station
   = EqvAnnSupDHSm+EqvAnnSupPHSm

Capital refurbishment costs for hydrocarbon fuel dispensing related apparatus

Inputs
NrStnSco = No. fuelling stations in Scotland
CostPump = Cost of pump
CostPipes = Cost of associated pipelines
LifePuPi = Service life of pump and pipelines
CostTank = Cost of storage tank (ranges from cost of a new tank to cost of refurbishing one in-situ)
LifeTank = Service life of storage tank
NrTankStn = No. storage tanks per station site
NrPumpStn = No. pumps per station site

Calculations
UnitCostAnnPuPi = Cost per year per pump & associated pipelines
   = (CostPump + CostPipes)/LifePuPi

UnitCostAnnTank = Cost per year per storage tank
   = CostTank/LifeTank

UnitCostAnnApp = Cost per year per site, apparatus only
   = UnitCostAnnPuPi*NrPumpStn+UnitCostAnnTank*NrTankStn
ScoCostAnnApp = Total cost per year, apparatus only (Scotland)
    = UnitCostAnnApp*NrStnSco

*Step 8* combines the outputs into various graphs as presented through this paper.

The associated macro “RunMultipleScenarios” runs the model sequentially for all three Pace options, giving the results for all nine scenarios, and records the results.

A reviewable online version of the model is presented as the Electronic Supplementary Information.
Chapter 3 Appendices – not used.

Chapter 4 Appendix

Appendix 4A Calculation Tables for modelled base case
## Internal Combustion Engine Vehicles

<table>
<thead>
<tr>
<th>Veh. class</th>
<th>Subclass</th>
<th>Number registered in Scotland</th>
<th>Chassis type (ICE)</th>
<th>Weight range</th>
<th>Ref. weight (ICE)</th>
<th>Nr. of axles per vehicle</th>
<th>Average annual km, per vehicle</th>
<th>Standard 80kN axles per axle (ICE)</th>
<th>RWP</th>
<th>RWIF</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>II</td>
<td>III</td>
<td>IV</td>
<td>V</td>
<td>VI</td>
<td>VII</td>
<td>VIII</td>
<td>IX</td>
<td>XI</td>
<td>XII</td>
</tr>
<tr>
<td>Buses &amp; Coaches</td>
<td></td>
<td>14,154</td>
<td>Two axle rigid</td>
<td>14,000</td>
<td>24,800</td>
<td>17000</td>
<td>2</td>
<td>83</td>
<td>45,471</td>
<td>1.180</td>
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<tr>
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<td>Two axle rigid</td>
<td>1,000</td>
<td>2,600</td>
<td>1,800</td>
<td>2</td>
<td>9</td>
<td>14,571</td>
<td>0.0001</td>
</tr>
<tr>
<td>Cars Diesel</td>
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<td>973,215</td>
<td>Two axle rigid</td>
<td>1,000</td>
<td>2,600</td>
<td>1,800</td>
<td>2</td>
<td>9</td>
<td>14,571</td>
<td>0.0001</td>
</tr>
<tr>
<td>Motorcycles</td>
<td></td>
<td>71,666</td>
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<td></td>
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<td>200</td>
<td>2</td>
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<tr>
<td>HGV 3.5t - 7.5t</td>
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<td>7,986</td>
<td>Two axle rigid</td>
<td>3,500</td>
<td>7,500</td>
<td>5,500</td>
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<td>27</td>
<td>49,967</td>
<td>0.013</td>
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<tr>
<td>HGV 7.5t - 12t</td>
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<td>Two axle rigid</td>
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<td>12,000</td>
<td>9,750</td>
<td>2</td>
<td>48</td>
<td>49,967</td>
<td>0.128</td>
</tr>
<tr>
<td>HGV 12t - 16t</td>
<td></td>
<td>1,238</td>
<td>Two axle rigid</td>
<td>12,000</td>
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<td>14,000</td>
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<td>69</td>
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<tr>
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<tr>
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<td>678</td>
<td>Three axle rigid</td>
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<td>5,367</td>
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<td>637</td>
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<td>38,000</td>
<td>35,000</td>
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<td>173,886</td>
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<td>40,000</td>
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<td>125,999</td>
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</tr>
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<td>3,500</td>
<td>3000</td>
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<td>15</td>
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<td>0.001</td>
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<td>2,500</td>
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<td></td>
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<td></td>
<td></td>
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<tr>
<td>Total LGVs</td>
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<td></td>
<td></td>
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<td></td>
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</table>

Table 4-A1 Calculation of the Road Wear Impact Factor for the current scenario of an Internal Combustion Engine based national vehicle fleet. Where 'Calculated' is shown at Data Source or Method, Roman numerals in the formula refer to the preceding columns as numbered in the heading row. Max weight set at 19,000kg and 27,000 kg, the maximum allowable for ZEV HGVs with 2 axles and 3 axles respectively.
## Battery Electric and Fuel Cell Electric Vehicles

| I       | II     | Sub-class | III  | IV     | V     | VI    | VII   | VIII  | IX    | X     | XI    | XII | XV    | XVI   | XVII  | XVIII | XIX   | XX    | XXI   | XXII  | XXIII | XXIV  | XXV   | XXVI  | XXVII | XXVIII | XXIX  | XXX   | XXXI  | XXXII | XXXIII | XXXIV  | XXXV  | XXXVI | XXXVII | XXXVIII | XXXIX | XXXX  | XXXXI | XXXXII | XXXXIII | XXXXIV | XXXXV | XXXXVI | XXXXVII | XXXXVIII | XXXIX | XXXX  |
|---------|--------|-----------|------|--------|-------|-------|-------|-------|-------|-------|-------|------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
|         | BEV    | weight    | =   | 1.0744 | x ICE | weight | + 430.17 |
|         | HFCEV  | weight    | =   | 1.014  | x ICE | weight |

### Data source/method

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
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<td>92</td>
<td>45,471</td>
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<td>2,222</td>
<td>17238</td>
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<td>85</td>
<td>45,471</td>
<td>1.248</td>
<td>2.496</td>
<td>1,606</td>
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<td>2</td>
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<td>14,571</td>
<td>0.0004</td>
<td>0.0009</td>
<td>20</td>
<td>1825</td>
<td>2</td>
<td>9</td>
<td>14,571</td>
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<td>0.0004</td>
<td>0.0009</td>
<td>13</td>
<td>1825</td>
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<td>9</td>
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<td>neg.</td>
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<td>2</td>
<td>1</td>
<td>4,490</td>
<td>neg.</td>
<td>neg.</td>
<td>&lt;0.1</td>
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<td>0.046</td>
<td>18</td>
<td>5577</td>
<td>2</td>
<td>27</td>
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<td>0.027</td>
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<tr>
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<td>2</td>
<td>53</td>
<td>49,967</td>
<td>0.200</td>
<td>0.400</td>
<td>25</td>
<td>9887</td>
<td>2</td>
<td>48</td>
<td>49,967</td>
<td>0.135</td>
<td>0.270</td>
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<td>HGV 12t - 16t</td>
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<td>2</td>
<td>76</td>
<td>49,967</td>
<td>0.810</td>
<td>1.620</td>
<td>100</td>
<td>14196</td>
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<td>0.574</td>
<td>1.148</td>
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<td>HGV 16t - 20t</td>
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<td>2</td>
<td>94</td>
<td>49,967</td>
<td>1.933</td>
<td>3.867</td>
<td>900</td>
<td>17745</td>
<td>2</td>
<td>87</td>
<td>49,967</td>
<td>1.401</td>
<td>2.802</td>
<td>652</td>
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<td>HGV 20t - 24t</td>
<td>23530</td>
<td>3</td>
<td>77</td>
<td>30,420</td>
<td>0.856</td>
<td>2.567</td>
<td>53</td>
<td>21801</td>
<td>3</td>
<td>71</td>
<td>30,420</td>
<td>0.631</td>
<td>1.892</td>
<td>39</td>
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<tr>
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<td>27000</td>
<td>3</td>
<td>88</td>
<td>31,352</td>
<td>1.483</td>
<td>4.450</td>
<td>749</td>
<td>25857</td>
<td>3</td>
<td>85</td>
<td>30,420</td>
<td>1.248</td>
<td>3.743</td>
<td>613</td>
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<td>HGV 28t - 32t</td>
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<td>3.705</td>
<td>756</td>
<td>29913</td>
<td>4</td>
<td>73</td>
<td>45,693</td>
<td>0.707</td>
<td>2.829</td>
<td>575</td>
</tr>
<tr>
<td>HGV 32t - 38t</td>
<td>38000</td>
<td>4</td>
<td>93</td>
<td>174,042</td>
<td>1.842</td>
<td>7.367</td>
<td>817</td>
<td>38490</td>
<td>4</td>
<td>87</td>
<td>173,886</td>
<td>1.401</td>
<td>5.605</td>
<td>621</td>
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<tr>
<td>HGV 38t - 44t</td>
<td>40000</td>
<td>5</td>
<td>78</td>
<td>133,344</td>
<td>0.926</td>
<td>4.631</td>
<td>2,444</td>
<td>39546</td>
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<td>78</td>
<td>125,999</td>
<td>0.885</td>
<td>4.424</td>
<td>2,206</td>
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<td>HGV 40t - 44t</td>
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<td>6</td>
<td>72</td>
<td>130,452</td>
<td>0.654</td>
<td>3.923</td>
<td>3,376</td>
<td>42588</td>
<td>6</td>
<td>70</td>
<td>125,999</td>
<td>0.574</td>
<td>3.444</td>
<td>2,862</td>
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<td>17</td>
<td>27,413</td>
<td>0.002</td>
<td>0.004</td>
<td>1</td>
<td>3042</td>
<td>2</td>
<td>15</td>
<td>26,262</td>
<td>0.001</td>
<td>0.002</td>
<td>1</td>
</tr>
<tr>
<td>LGV Diesel</td>
<td>3500</td>
<td>2</td>
<td>17</td>
<td>27,413</td>
<td>0.002</td>
<td>0.004</td>
<td>34</td>
<td>3042</td>
<td>2</td>
<td>15</td>
<td>26,262</td>
<td>0.001</td>
<td>0.002</td>
<td>19</td>
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</tbody>
</table>

| Total million Standard axle km per year, as Road Wear Impact Factor | 11,528 | Total million Standard axle km per year, as Road Wear Impact Factor | 9,302 |

| All HGVs | 9,238 | 7665 |
| All Cars  | 32 | 12 |
| All LGVs  | 36 | 19 |

### Table 4-A2 Calculation of the Road Wear Impact Factor for the all BEV and all HFCEV scenarios.

Where 'Calculated' (or 'calc') is shown at Data Source or Method, the formula is given, with Roman numerals in the formula refer to the preceding columns as numbered in the heading row.
### Appendix 5A Basic properties and parameters

#### Specific Energy, Density and Energy density.

<table>
<thead>
<tr>
<th>Source</th>
<th>Specific Energy</th>
<th>Lower Heat Value</th>
<th>Higher Heat Value</th>
<th>Density (at storage conditions)</th>
<th>Energy density (at storage conditions)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MJ/kg kWh/kg</td>
<td>MJ/kg kWh/kg</td>
<td></td>
<td>kg/m3 source</td>
<td>kWh/m3 source</td>
</tr>
<tr>
<td>Electricity*</td>
<td>0.385</td>
<td>0.385</td>
<td></td>
<td>2083 calc</td>
<td>802 [3]</td>
</tr>
<tr>
<td>Hydrogen (700 bar gas)</td>
<td>120.00 33.33 141.70 39.36</td>
<td>[1]</td>
<td>39 [4]</td>
<td>1300 calc</td>
<td></td>
</tr>
<tr>
<td>Hydrogen (liquid)</td>
<td>120.00 33.33 141.70 39.36</td>
<td>[1]</td>
<td>71 [5]</td>
<td>2367 calc</td>
<td></td>
</tr>
<tr>
<td>Biodiesel</td>
<td>39.77 11.05</td>
<td></td>
<td></td>
<td>887 [7]</td>
<td>9799 calc</td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>50.05 13.90 55.50 15.42</td>
<td>[1]</td>
<td>456 [8]</td>
<td>6340 calc</td>
<td></td>
</tr>
<tr>
<td>Biomethane</td>
<td>50.05 13.90</td>
<td>55.50 15.42</td>
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<td>456 [8]</td>
<td>6340 calc</td>
</tr>
<tr>
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<td>20.27 5.63</td>
<td>24.00 6.67</td>
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<tr>
<td>Marine gas oil</td>
<td>47.50 13.19</td>
<td>45.60 12.67</td>
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<td>846 [1]</td>
<td>11163 calc</td>
</tr>
</tbody>
</table>

Other key input values:

- Capture efficiency of CO2 from SMR process, for CCS: 90% (85%-95%) [11]
- Efficiency of electrolyser: 82% (98% at HHV) [12]
- Energy requirement for compression of hydrogen to 700 bar: 3.7 kWh/kg [13]
## Appendix 5B  Atomic and molecular masses of key chemicals

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<th>Atom:</th>
<th>Carbon</th>
<th>Oxygen</th>
<th>Hydrogen</th>
<th>Nitrogen</th>
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</thead>
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<td>Mass of atom:</td>
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<td>1</td>
<td>14</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Molecule</th>
<th>Formula</th>
<th>Number of atoms</th>
<th>Molecular mass</th>
</tr>
</thead>
<tbody>
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<td>O₂</td>
<td>2</td>
<td>32</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>H₂</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>N₂</td>
<td>2</td>
<td>28</td>
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<td>Methanol</td>
<td>CH₃OH</td>
<td>1 1 4</td>
<td>32</td>
</tr>
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<td>NH₃</td>
<td>3 1</td>
<td>17</td>
</tr>
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<td>Carbon Dioxide</td>
<td>CO₂</td>
<td>1 2</td>
<td>44</td>
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<td>Methane</td>
<td>CH₄</td>
<td>1 4</td>
<td>16</td>
</tr>
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</table>
Appendix 5C  CO2 / CO2 equivalent production and energy demand

Calculable CO2 production ratios from stoichiometric combustion or use

Methanol

\[ 2 \text{CH}_3\text{OH} + 3 \text{O}_2 \rightarrow 2 \text{CO}_2 + 4 \text{H}_2\text{O}. \]  Production ratio = \( 2 \text{CO}_2 / 2 \text{CH}_3\text{OH} = 88/64 = 1.375 \text{mass/mass} \)

Methane

\[ \text{CH}_4 + 2\text{O}_2 \rightarrow \text{CO}_2 + 2\text{H}_2\text{O}. \]  Production ratio = \( 1 \text{CO}_2 / 1 \text{CH}_4 = 44/16 = 2.75 \text{mass/mass} \)

Methane greenhouse gas impact = 17 CO2 equivalent (ref), so combustion of methane to produce CO2 means a reduction in GHG of (17-2.75)/17 = 84%.

<table>
<thead>
<tr>
<th>Energy requirement for production of methanol using CCU CO2 and electrolyser hydrogen</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrogen requirement in CH3OH</td>
</tr>
<tr>
<td>CO2 requirement in CH3OH</td>
</tr>
<tr>
<td>Hydrogen energy requirement</td>
</tr>
<tr>
<td></td>
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<tr>
<td>Energy for CH3OH production</td>
</tr>
<tr>
<td>Electricity for H2 compression</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Electricity required for CO2 capture</td>
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<td></td>
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<tr>
<td>Electricity for H2 compression</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Total electricity requirement - CH3OH production</td>
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</table>

Derived and empirical CO2 emissions

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<td>2.639</td>
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<tr>
<td>846</td>
</tr>
<tr>
<td>0.85</td>
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<tr>
<td>3.12</td>
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</table>
### Biodiesel emissions, assuming complete combustion

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<th>% reduction in emissions from 100% mineral diesel at point of use.</th>
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</thead>
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<td>% biodiesel in mineral / bio diesel blend</td>
<td>Soybean biodiesel</td>
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<tr>
<td>5</td>
<td>0.36%</td>
</tr>
<tr>
<td>10</td>
<td>0.56%</td>
</tr>
<tr>
<td>15</td>
<td>0.83%</td>
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<tr>
<td>20</td>
<td>1.10%</td>
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<tr>
<td>50</td>
<td>1.23%</td>
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<tr>
<td>100</td>
<td>1.50%*</td>
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</tbody>
</table>

[7, 15]

* extrapolated.
Tables 5-3 to 5-5 show emissions in production for each fuel and production method considered.

Production emissions. Electricity emissions = zero.

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<tr>
<th>I</th>
<th>II</th>
<th>III</th>
<th>IV</th>
<th>V</th>
<th>VI</th>
<th>VII</th>
<th>VIII</th>
<th>IX</th>
<th>X</th>
<th>XI</th>
<th>XII</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Fuel</td>
<td>Method</td>
<td>Energy source</td>
<td>Electricity input required</td>
<td>Ref / basis</td>
<td>Electricity specific emissions from primary energy input</td>
<td>All Emissions associated with production</td>
<td>Ref / basis</td>
<td>Emissions captured in fuel</td>
<td>Net production emissions</td>
<td>Energy content of fuel at LHV</td>
</tr>
<tr>
<td></td>
<td>Ammonia</td>
<td>Hydrogen from renewable source</td>
<td>Electricity</td>
<td>33 MJ/kg NH3</td>
<td>[16]</td>
<td>0.00</td>
<td>0.00</td>
<td>[16]</td>
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<td>5.53</td>
<td>0.00</td>
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<td>Hydrogen from SMR + CCS</td>
<td>Combustion of methane</td>
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<td>[16]</td>
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<td>5.53</td>
<td>0.072</td>
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<tr>
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<td>Ammonia</td>
<td>Hydrogen from SMR</td>
<td>Combustion of methane</td>
<td>n/a</td>
<td>1.60</td>
<td>[16]</td>
<td>1.6</td>
<td>5.53</td>
<td>0.289</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Electricity</td>
<td>Assume as grid</td>
<td>Electricity</td>
<td>1 kWh/kWh</td>
<td>0.000 kg CO2 eq/kWh</td>
<td>0.000 kg CO2 eq/kWh</td>
<td>0</td>
<td>0.39 (batteries)</td>
<td>0.000</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Electricity</td>
<td>Direct renewable (ren)</td>
<td>Electricity</td>
<td>1 kWh/kWh</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.39 (batteries)</td>
<td>0.000</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hydrogen</td>
<td>Electrolys is</td>
<td>Electricity</td>
<td>40.7</td>
<td>LHV H2 / LHV efficiency of electrolyser.</td>
<td>0.00</td>
<td>0.00</td>
<td>calc.</td>
<td>0</td>
<td>33.33</td>
<td>0.000</td>
</tr>
<tr>
<td></td>
<td>Hydrogen</td>
<td>SMR + CCS</td>
<td>Methane combustion.</td>
<td>29.2</td>
<td>3.75 (3.5-4.0) MJ/kg CO2 for CCS. [17]</td>
<td>0.92</td>
<td>Assume 0.9 CO2 capture rate.</td>
<td>[4]</td>
<td>0.917</td>
<td>33.33</td>
<td>0.028</td>
</tr>
<tr>
<td></td>
<td>Hydrogen</td>
<td>SMR</td>
<td>Methane combustion</td>
<td>20.6</td>
<td>Calculate d</td>
<td>9.17</td>
<td>Calculate d [18]</td>
<td>9.167</td>
<td>33.33</td>
<td>0.275</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Biodiesel</td>
<td>Crop biodiesel</td>
<td>External heat</td>
<td>0.35</td>
<td>[19]</td>
<td>0.00</td>
<td>0.00</td>
<td>20g CO2 eq/MJ, (taken as mean of rapeseed oil and palm oil)[20]</td>
<td>3.09</td>
<td>-3.03</td>
<td>11.05</td>
</tr>
<tr>
<td></td>
<td>Bio- methane</td>
<td>Biomethane</td>
<td>Electricity, biogas</td>
<td>0.285</td>
<td>0.22 - 0.35 for high purity</td>
<td>0.00</td>
<td>0.0000</td>
<td>0</td>
<td>0</td>
<td>13.90</td>
<td>0.0000</td>
</tr>
<tr>
<td></td>
<td>Process</td>
<td>Energy for capture of CO₂ + production of hydrogen at 0.14 kg/kg [22]</td>
<td>Energy</td>
<td>CO₂ Electricity</td>
<td>Energy</td>
<td>CO₂ Electricity</td>
<td>CO₂ Electricity</td>
<td>CO₂ Electricity</td>
<td>CO₂ Electricity</td>
<td>CO₂ Electricity</td>
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<td>----------------</td>
<td>----------------</td>
<td>----------------</td>
<td>----------------</td>
</tr>
<tr>
<td>Methanol</td>
<td>Direct air capture CO₂</td>
<td>Electricity</td>
<td>12.3</td>
<td>0.00</td>
<td>Assume Air Capture CO₂ = amount released in use</td>
<td>1.29</td>
<td>-1.29</td>
<td>5.53</td>
<td>-0.233</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methanol</td>
<td>Intercepted CO₂</td>
<td>Electricity</td>
<td>10.163</td>
<td>0.000</td>
<td>Assume Intercepted CO₂ is zero production emissions when captured.</td>
<td>0.65</td>
<td>-0.645</td>
<td>5.53</td>
<td>-0.117</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methanol</td>
<td>Biomass</td>
<td>2% of energy content</td>
<td>0.111</td>
<td>0.000</td>
<td>0.0184</td>
<td>0.07 kg CO₂ eq/GJ [24]</td>
<td>1.29</td>
<td>-1.27</td>
<td>5.53</td>
<td>-0.230</td>
<td></td>
</tr>
<tr>
<td>Marine Gas Oil</td>
<td>Refining process</td>
<td>Oil refining</td>
<td>0.660</td>
<td>0.05 MJ/MJ [25]</td>
<td>0.0810</td>
<td>[25, 26]</td>
<td>3.09</td>
<td>-3.03</td>
<td>11.05</td>
<td>-0.274</td>
<td></td>
</tr>
</tbody>
</table>

Table 5-2: Development of emissions due to production of fuels, where emissions due to input electricity equals zero.
Production emissions. Electricity production emissions = 0.0336 kg CO2eq/kWh

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Method</th>
<th>Energy source</th>
<th>Electricity input required</th>
<th>Ref / basis</th>
<th>Electricity specific emissions from primary energy input</th>
<th>Emissions associated with production</th>
<th>Ref / basis</th>
<th>Emissions captured in fuel</th>
<th>Net production emissions</th>
<th>Energy content of fuel at LHV</th>
<th>Emissions per kWh energy content at LHV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia Hydrogen from renewable source</td>
<td>Electricity</td>
<td>33 MJ/kg NH3</td>
<td>[16]</td>
<td>0.31</td>
<td>0.31</td>
<td>[16]</td>
<td>0.31</td>
<td>5.53</td>
<td>0.056</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ammonia Hydrogen from SMR + CCS</td>
<td>Combustion of methane</td>
<td>n/a</td>
<td></td>
<td></td>
<td>0.4</td>
<td>[16]</td>
<td>0.4</td>
<td>5.53</td>
<td>0.072</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ammonia Hydrogen from SMR</td>
<td>Combustion of methane</td>
<td>n/a</td>
<td></td>
<td></td>
<td>1.60</td>
<td>[16]</td>
<td>1.6</td>
<td>5.53</td>
<td>0.289</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity</td>
<td>Assume as grid</td>
<td>Electricity</td>
<td>1 kWh/kWh</td>
<td></td>
<td>0.034 kg CO2 eq/kWh</td>
<td>0.034 kg CO2 eq/kWh</td>
<td>0.0336</td>
<td>0.39 (batteries)</td>
<td>0.034</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity</td>
<td>Direct renewable (ren)</td>
<td>Electricity</td>
<td>1 kWh/kWh</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.39 (batteries)</td>
<td>0.000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrogen Electrolysis</td>
<td>Electricity</td>
<td>40.7</td>
<td>LHV H2 / LHV efficiency of electrolyser</td>
<td>1.37</td>
<td>1.37</td>
<td>calc.</td>
<td>1.37</td>
<td>33.33</td>
<td>0.041</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrogen SMR + CCS</td>
<td>Methane combustion</td>
<td>29.2</td>
<td>3.75 (3.5-4.0) MJ/kg CO2 for CCS</td>
<td>0.92</td>
<td></td>
<td></td>
<td>0.917</td>
<td>33.33</td>
<td>0.028</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrogen SMR</td>
<td>Methane combustion</td>
<td>20.6</td>
<td>Calculated</td>
<td>9.17</td>
<td></td>
<td>Calculated</td>
<td>9.167</td>
<td>33.33</td>
<td>0.275</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Biodiesel Crop biodiesel</td>
<td>External heat</td>
<td>0.35</td>
<td>[19]</td>
<td>0.01</td>
<td>0.0614</td>
<td>3.09</td>
<td>-3.02</td>
<td>11.05</td>
<td>-0.273</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bio-methane Bio-methane</td>
<td>Electricity, biogas</td>
<td>0.285</td>
<td>0.22 - 0.35 for high purity</td>
<td>0.01</td>
<td>0.0096</td>
<td>0</td>
<td>0.009576</td>
<td>13.90</td>
<td>0.0007</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel Type</td>
<td>Process</td>
<td>Energy for Capture of CO₂ + Production of Hydrogen at 0.14 kg/kg [22]</td>
<td>0.41</td>
<td>0.41</td>
<td>Assume Air Capture CO₂ = Amount Released in Use</td>
<td>1.29</td>
<td>-0.87672</td>
<td>5.53</td>
<td>-0.158</td>
<td></td>
<td></td>
</tr>
<tr>
<td>----------------</td>
<td>--------------------------------</td>
<td>---------------------------------------------------------------------</td>
<td>------</td>
<td>------</td>
<td>-------------------------------------------------</td>
<td>------</td>
<td>----------</td>
<td>------</td>
<td>--------</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methanol</td>
<td>Direct air capture CO₂</td>
<td>Electricity</td>
<td>12.3</td>
<td>0.34</td>
<td>Assume Intercepted CO₂ is zero production emissions when captured.</td>
<td>0.65</td>
<td>-0.304</td>
<td>5.53</td>
<td>-0.055</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Intercepted CO₂</td>
<td></td>
<td>Electricity</td>
<td>10.163</td>
<td>0.341</td>
<td>0.341</td>
<td>1.29</td>
<td>-1.2641</td>
<td>5.53</td>
<td>-0.228</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methanol</td>
<td>Biomass</td>
<td></td>
<td>0.110666667 67</td>
<td>0.004</td>
<td>0.0222 0.07 kg CO₂ eq/GJ [24]</td>
<td>1.29</td>
<td>-0.1031592</td>
<td>13.19</td>
<td>0.008</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Marine Gas Oil | Oil refining Refining process  |                                                                     | 0.6595 | 0.02 | 0.1032 [25, 26] | 1.29 | 0.0336 kg/kWh.

Table 5-3 Development of emissions due to production of fuels, where emissions due to input electricity = 0.0336 kg/kWh.
Production emissions. Electricity emissions = 0.233 kg CO2eq/kWh

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Method</th>
<th>Energy source</th>
<th>Electricity input required</th>
<th>Ref / basis</th>
<th>Electricity specific emissions from primary energy input</th>
<th>Emissions associated with production</th>
<th>Ref / basis</th>
<th>Emissions captured in fuel</th>
<th>Net production emissions</th>
<th>Energy content of fuel at LHV</th>
<th>Emissions per kWh energy content at LHV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia Hydrogen from renewable source</td>
<td>Electricity</td>
<td>33 MJ/kg NH3</td>
<td>kWh/kg unless stated</td>
<td>[16]</td>
<td>2.14</td>
<td>2.14</td>
<td>kWh/kg unless stated</td>
<td>kg CO2eq/kg fuel if not stated</td>
<td>0.233</td>
<td>0.39</td>
<td>(tab: properties)</td>
</tr>
<tr>
<td>Ammonia Hydrogen from SMR + CCS Combustion of methane</td>
<td>n/a</td>
<td></td>
<td>kWh/kg unless stated</td>
<td>[16]</td>
<td>0.4</td>
<td>0.4</td>
<td>kWh/kg unless stated</td>
<td>kg CO2eq/kg fuel if not stated</td>
<td>0.233</td>
<td>0.39</td>
<td>(batteries)</td>
</tr>
<tr>
<td>Ammonia Hydrogen from SMR Combustion of methane</td>
<td>n/a</td>
<td></td>
<td>kWh/kg unless stated</td>
<td>[16]</td>
<td>1.6</td>
<td>1.6</td>
<td>kWh/kg unless stated</td>
<td>kg CO2eq/kg fuel if not stated</td>
<td>0.233</td>
<td>0.39</td>
<td>(batteries)</td>
</tr>
<tr>
<td>Electricity Direct renewable Direct renewable</td>
<td>1 kWh/kg</td>
<td>kWh/kg</td>
<td>kWh/kg unless stated</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>kWh/kg unless stated</td>
<td>kg CO2eq/kg fuel if not stated</td>
<td>0.233</td>
<td>0.39</td>
<td>(batteries)</td>
</tr>
<tr>
<td>Hydrogen Electrolysis Electricity</td>
<td>40.7</td>
<td>kWh/kg</td>
<td>kWh/kg unless stated</td>
<td>9.47</td>
<td>9.47</td>
<td>9.47</td>
<td>kWh/kg unless stated</td>
<td>kg CO2eq/kg fuel if not stated</td>
<td>0.233</td>
<td>0.39</td>
<td>(batteries)</td>
</tr>
<tr>
<td>Hydrogen SMR + CCS Methane combustion</td>
<td>29.2</td>
<td>kWh/kg</td>
<td>kWh/kg unless stated</td>
<td>0.92</td>
<td>0.92</td>
<td>0.92</td>
<td>kWh/kg unless stated</td>
<td>kg CO2eq/kg fuel if not stated</td>
<td>0.233</td>
<td>0.39</td>
<td>(batteries)</td>
</tr>
<tr>
<td>Hydrogen SMR Methane combustion</td>
<td>20.6</td>
<td>kWh/kg</td>
<td>kWh/kg unless stated</td>
<td>9.17</td>
<td>9.17</td>
<td>9.17</td>
<td>kWh/kg unless stated</td>
<td>kg CO2eq/kg fuel if not stated</td>
<td>0.233</td>
<td>0.39</td>
<td>(batteries)</td>
</tr>
<tr>
<td>Biodiesel Crop biodiesel External heat</td>
<td>0.35</td>
<td>kWh/kg</td>
<td>kWh/kg unless stated</td>
<td>0.08</td>
<td>0.08</td>
<td>0.08</td>
<td>kWh/kg unless stated</td>
<td>kg CO2eq/kg fuel if not stated</td>
<td>0.233</td>
<td>0.39</td>
<td>(batteries)</td>
</tr>
<tr>
<td>Bio-methane Biomethane Electricity, biogas</td>
<td>0.285</td>
<td>kWh/kg</td>
<td>kWh/kg unless stated</td>
<td>0.07</td>
<td>0.07</td>
<td>0.07</td>
<td>kWh/kg unless stated</td>
<td>kg CO2eq/kg fuel if not stated</td>
<td>0.233</td>
<td>0.39</td>
<td>(batteries)</td>
</tr>
<tr>
<td>Internal Combustion Engine Fuel</td>
<td>Use</td>
<td>Energy</td>
<td>Emissions</td>
<td>CO2</td>
<td>Oil refining</td>
<td>CO2</td>
<td>Oil refining</td>
<td>CO2</td>
<td></td>
<td></td>
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<td>-----</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methanol Direct air capture CO2</td>
<td>Electricity</td>
<td>12.3</td>
<td>Energy for capture of CO2 + production of hydrogen at 0.14 kg/kg [22]</td>
<td>2.87</td>
<td>0.00</td>
<td>Assume Air Capture CO2 = amount released in use</td>
<td>1.29</td>
<td>1.759</td>
<td>5.53</td>
<td>0.285</td>
<td></td>
</tr>
<tr>
<td>Methanol Intercepted CO2 Electricity</td>
<td>10.163</td>
<td>2.368</td>
<td>0.00</td>
<td>Assume intercepted CO2 is zero production emissions when captured.</td>
<td>0.65</td>
<td>1.723</td>
<td>5.53</td>
<td>0.311</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methanol Biomass</td>
<td>0.1106666</td>
<td>2% of energy content [24]</td>
<td>0.026</td>
<td>0.0184</td>
<td>0.07 kg CO2 eq/GJ [24]</td>
<td>1.29</td>
<td>-1.220</td>
<td>5.53</td>
<td>-0.220</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Marine Gas Oil Oil refining Refining process</td>
<td>0.6595</td>
<td>0.05 MJ/MJ [25]</td>
<td>0.15</td>
<td>0.0810</td>
<td>[25, 26]</td>
<td>0.235</td>
<td>13.19</td>
<td>0.018</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Table 5-4 Development of emissions due to production of fuels, where emissions due to input electricity = 0.233 kg/kWh.*
Transport emissions

Table 5-6 below sets out the transport related emissions, based on diesel fuel road transport within the UK. As road haulage emissions are reduced to zero through the energy transition, these emissions will also fall to zero.

Transport emissions, assuming diesel road transport.

<table>
<thead>
<tr>
<th>Diesel fuelled HGV tanker:</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fuel consumption</strong></td>
</tr>
<tr>
<td><strong>Specific energy</strong></td>
</tr>
<tr>
<td><strong>Emissions</strong></td>
</tr>
<tr>
<td><strong>Density</strong></td>
</tr>
<tr>
<td><strong>Energy consumption</strong></td>
</tr>
<tr>
<td><strong>Emissions /km</strong></td>
</tr>
<tr>
<td><strong>Emissions as g/km</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>I</th>
<th>II</th>
<th>III</th>
<th>IV</th>
<th>V</th>
<th>VI</th>
<th>VII</th>
<th>VIII</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel</td>
<td>Location</td>
<td>Distance (km)</td>
<td>Capacity per tanker load</td>
<td>energy density (kWh/m³) / Specific energy (kWh/kg, H₂ only)</td>
<td>Energy transported per load</td>
<td>Emissions per 2-way journey (kg CO₂ eq)</td>
<td>Emissions per kWh fuel transported (kg CO₂ eq / kWh fuel)</td>
</tr>
<tr>
<td>Ammonia</td>
<td>Orkney</td>
<td>410</td>
<td>36 m³</td>
<td>3774</td>
<td>135,854</td>
<td>930</td>
<td>0.007</td>
</tr>
<tr>
<td>Electricity</td>
<td>Grid</td>
<td>0</td>
<td>0.00</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Aberdeen</td>
<td>3</td>
<td>1.3</td>
<td>33.33</td>
<td>43,333</td>
<td>7</td>
<td>0.00016</td>
</tr>
<tr>
<td>Hydrogen (pipe)</td>
<td>Aberdeen</td>
<td>3</td>
<td>pipeline</td>
<td>33.33</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Hydrogen (Liquid)</td>
<td>Aberdeen</td>
<td>3</td>
<td>3.5 t</td>
<td>33.33</td>
<td>116,667</td>
<td>7</td>
<td>0.00006</td>
</tr>
<tr>
<td>Hydrogen (LOHC)</td>
<td>Aberdeen</td>
<td>3</td>
<td>36 m³</td>
<td>1867</td>
<td>67,200</td>
<td>7</td>
<td>0.0001</td>
</tr>
<tr>
<td>Biodiesel</td>
<td>Motherwell</td>
<td>240</td>
<td>36 m³</td>
<td>9799</td>
<td>352,760</td>
<td>544</td>
<td>0.002</td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>Milford Haven</td>
<td>880</td>
<td>36 m³</td>
<td>6340</td>
<td>228,228</td>
<td>1996</td>
<td>0.009</td>
</tr>
<tr>
<td>Biomethane</td>
<td>Northampton</td>
<td>525</td>
<td>36 m³</td>
<td>6340</td>
<td>228,228</td>
<td>1191</td>
<td>0.005</td>
</tr>
<tr>
<td>Methanol</td>
<td>Nigg</td>
<td>220</td>
<td>36 m³</td>
<td>4482</td>
<td>161,349</td>
<td>499</td>
<td>0.003</td>
</tr>
<tr>
<td>Marine Gas Oil</td>
<td>Grangemouth</td>
<td>200</td>
<td>36 m³</td>
<td>11163</td>
<td>401,850</td>
<td>454</td>
<td>0.001</td>
</tr>
</tbody>
</table>

*Table 5-6* transport related emissions, based on diesel fuelled road tanker from nearest appropriate UK production facility or import terminal.
### Storage emissions

Tables 5-7 to 5-9 below set out the emissions associated with placing the fuel into storage, keeping it there, and recovering it afterwards.

**Storage emissions. Electricity production emissions = 0**

<table>
<thead>
<tr>
<th>I</th>
<th>II</th>
<th>III</th>
<th>IV</th>
<th>V</th>
<th>VI</th>
<th>VII</th>
<th>VIII</th>
<th>IX</th>
<th>X</th>
<th>XI</th>
<th>XII</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Source in</td>
<td>Source in</td>
<td>Energy required to store</td>
<td>Energy loss in storage</td>
<td>Energy required to remove from storage</td>
<td>Specific energy</td>
<td>Emissions associated with energy to store</td>
<td>Energy loss due to maintaining storage and removing from storage</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>V</td>
<td>V</td>
<td>Ref / basis</td>
<td>Ref / basis</td>
<td>Ref or basis</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>kWh/kg</td>
<td>%/day</td>
<td>units as shown</td>
<td>kWh/kg</td>
<td>kgCO2/kWh</td>
<td>%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Method</th>
<th>Energy source to store</th>
<th>Energy required to store</th>
<th>Ref / basis</th>
<th>Energy loss in storage</th>
<th>Ref or basis</th>
<th>Specific energy</th>
<th>Emissions associated with energy to store</th>
<th>Energy loss due to maintaining storage and removing from storage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia **</td>
<td>Pressurised liquid</td>
<td>From production process</td>
<td>0</td>
<td>(Guerra, 2020 #297)</td>
<td>0</td>
<td>0</td>
<td>5.5</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>Electricity</td>
<td>Battery</td>
<td>Electricity</td>
<td>0</td>
<td>0.20%</td>
<td>0</td>
<td>0.4</td>
<td>0</td>
<td>2.8%</td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Pressurised gas</td>
<td>Electricity</td>
<td>3.7</td>
<td>[13]</td>
<td>0</td>
<td>0</td>
<td>33.3</td>
<td>0.000</td>
<td>0.0%</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Cryo-liquid (H)</td>
<td>Electricity</td>
<td>7</td>
<td>[30]</td>
<td>0.10%</td>
<td>[30]</td>
<td>0</td>
<td>33.3</td>
<td>0.000</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>LOHC</td>
<td>Assume Self-sustaining reaction at heat and pressure.</td>
<td>0</td>
<td>[6]</td>
<td>0</td>
<td>33.03%</td>
<td>[6]</td>
<td>33.3</td>
<td>0</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Ammonia</td>
<td>From production process</td>
<td>0</td>
<td>(Guerra, 2020 #297)</td>
<td>0.00%</td>
<td>1.41 kWh/kg NH₃</td>
<td>[31]</td>
<td>33.3</td>
<td>0</td>
</tr>
<tr>
<td>Biodiesel</td>
<td>Liquid</td>
<td>External heat</td>
<td>0</td>
<td>*</td>
<td>0</td>
<td>0</td>
<td>11.0</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>Cryo-liquid (M)</td>
<td>Electricity</td>
<td>0.75</td>
<td>[21]</td>
<td>0.00%</td>
<td>0</td>
<td>13.9</td>
<td>0.000</td>
<td>0.0%</td>
</tr>
<tr>
<td>Bio-methane</td>
<td>Cryo-liquid (M)</td>
<td>Electricity</td>
<td>0.75</td>
<td>[21]</td>
<td>0</td>
<td>0</td>
<td>13.9</td>
<td>0.000</td>
<td>0.0%</td>
</tr>
<tr>
<td>Methanol</td>
<td>Liquid</td>
<td>Electricity</td>
<td>0</td>
<td>*</td>
<td>0.00%</td>
<td>0</td>
<td>5.5</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>Marine Gas Oil</td>
<td>Liquid</td>
<td>Refining process</td>
<td>0</td>
<td>*</td>
<td>0</td>
<td>0</td>
<td>13.2</td>
<td>0</td>
<td>0.0%</td>
</tr>
</tbody>
</table>

**Table 5-6  Development of emissions due to storage of fuels, where electricity generation emissions = 0**

---

* Ammonia ** Pressurised liquid from production process.*

---

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Storage emissions. Electricity production emissions = 0.034 kg CO2 eq/kWh

<table>
<thead>
<tr>
<th>Fuel Method</th>
<th>Energy source to store</th>
<th>Energy required to store</th>
<th>Energy loss in storage</th>
<th>Energy required to remove from storage</th>
<th>Specific energy</th>
<th>Emissions associated with energy to store</th>
<th>Energy loss due to maintaining storage and removing from storage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Ammonia</strong></td>
<td>Pressurised liquid</td>
<td>From production process</td>
<td>0</td>
<td>0</td>
<td>5.5</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>Electricity Battery</td>
<td>Electricity</td>
<td>0</td>
<td>0.20%</td>
<td>0</td>
<td>0.4</td>
<td>2.8%</td>
<td>additional fuel demand rather than explicit emissions</td>
</tr>
<tr>
<td>Hydrogen Pressurised gas</td>
<td>Electricity</td>
<td>3.7</td>
<td>[13]</td>
<td>0</td>
<td>33.3</td>
<td>0.004</td>
<td>0.0%</td>
</tr>
<tr>
<td>Hydrogen Cryo-liquid (H)</td>
<td>Electricity</td>
<td>7</td>
<td>[30]</td>
<td>0.10%</td>
<td>33.3</td>
<td>0.007</td>
<td>0.0%</td>
</tr>
<tr>
<td>Hydrogen LOHC</td>
<td>Assume self-sustaining reaction at heat and pressure</td>
<td>0</td>
<td>33.03%</td>
<td>[6]</td>
<td>33.3</td>
<td>33.0%</td>
<td></td>
</tr>
<tr>
<td>Hydrogen Ammonia</td>
<td>From production process</td>
<td>0</td>
<td>0.00%</td>
<td>1.41 kWh/kg NH3 [31]</td>
<td>33.3</td>
<td>#N/A</td>
<td>25.6%</td>
</tr>
<tr>
<td>Biodiesel Liquid</td>
<td>External heat</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>11.0</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>Liquid Natural Gas Cryo-liquid (M)</td>
<td>Electricity</td>
<td>0.75</td>
<td>[21]</td>
<td>0.00%</td>
<td>0.002</td>
<td>0.0%</td>
<td></td>
</tr>
<tr>
<td>Bio-methane Cryo-liquid (M)</td>
<td>Electricity</td>
<td>0.75</td>
<td>[21]</td>
<td>0</td>
<td>13.9</td>
<td>0.002</td>
<td>0.0%</td>
</tr>
<tr>
<td>Methanol Liquid</td>
<td>Electricity</td>
<td>0</td>
<td>0.00%</td>
<td>0</td>
<td>5.5</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>Marine Gas Oil Liquid</td>
<td>Refining process</td>
<td>0</td>
<td>*</td>
<td>0</td>
<td>13.2</td>
<td>0</td>
<td>0.0%</td>
</tr>
</tbody>
</table>

Table 5-7 Development of emissions due to storage of fuels, where electricity generation emissions = 0.034 kg CO2 eq/kWh
Storage emissions. Electricity production emissions = 0.233 kgCO2 eq/kWh

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Method</th>
<th>Energy source to store</th>
<th>Energy required to store</th>
<th>Ref / basis</th>
<th>Energy loss in storage</th>
<th>Ref / basis</th>
<th>Energy required to remove from storage</th>
<th>Ref or basis</th>
<th>Specific energy</th>
<th>Emissions associated with energy to store</th>
<th>Energy loss due to maintaining storage and removing from storage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia **</td>
<td>Pressurised liquid</td>
<td>From production process</td>
<td></td>
<td>[Guerra, 2020 #297]</td>
<td>0</td>
<td>0</td>
<td>5.5</td>
<td>0</td>
<td>0.00%</td>
<td></td>
<td>Additional fuel demand rather than explicit emissions</td>
</tr>
<tr>
<td>Electricity</td>
<td>Battery</td>
<td>Electricity</td>
<td></td>
<td>0</td>
<td>0.20%</td>
<td>0</td>
<td>0.4</td>
<td>0</td>
<td>2.8%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Pressurised gas</td>
<td>Electricity</td>
<td></td>
<td>3.7 [13]</td>
<td>0</td>
<td>0</td>
<td>33.3</td>
<td>0.026</td>
<td>0.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Cryo-liquid (H)</td>
<td>Electricity</td>
<td></td>
<td>7 [30]</td>
<td>0.10%</td>
<td>0</td>
<td>33.3</td>
<td>0.049</td>
<td>0.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>LOHC</td>
<td>Assume self-sustaining reaction at heat and pressure.</td>
<td></td>
<td>0 [6]</td>
<td>0</td>
<td>33.03%</td>
<td>33.3</td>
<td>0</td>
<td>33.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Ammonia</td>
<td>From production process</td>
<td></td>
<td>0 [Guerra, 2020 #297]</td>
<td>0.00%</td>
<td>1.41 kWh/kg NH3</td>
<td>33.3</td>
<td>0</td>
<td>25.6%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Biodiesel</td>
<td>Liquid</td>
<td>External heat</td>
<td></td>
<td>0 *</td>
<td>0</td>
<td>0</td>
<td>11.0</td>
<td>0</td>
<td>0.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>Cryo-liquid (M)</td>
<td>Electricity</td>
<td></td>
<td>0.75 [21]</td>
<td>0.00%</td>
<td>0</td>
<td>13.9</td>
<td>0</td>
<td>0.013</td>
<td>0.0%</td>
<td></td>
</tr>
<tr>
<td>Bio-methane</td>
<td>Cryo-liquid (M)</td>
<td>Electricity</td>
<td></td>
<td>0.75 [21]</td>
<td>0</td>
<td>0</td>
<td>13.9</td>
<td>0</td>
<td>0.013</td>
<td>0.0%</td>
<td></td>
</tr>
<tr>
<td>Methanol</td>
<td>Liquid</td>
<td>Electricity</td>
<td></td>
<td>0 *</td>
<td>0.00%</td>
<td>0</td>
<td>5.5</td>
<td>0</td>
<td>0.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Marine Gas Oil</td>
<td>Liquid</td>
<td>Refining process</td>
<td></td>
<td>0 *</td>
<td>0</td>
<td>0</td>
<td>13.2</td>
<td>0</td>
<td>0.0%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 5- 8 Development of emissions due to storage of fuels, where electricity generation emissions = 0.233 kgCO2 eq/kWh
Emissions in use

Table 5-10 sets out the emissions associated with the use of each fuel type. This is independent of the drivetrain type but assumes complete consumption of the fuel. The efficiency of any selected drivetrain must be applied to the whole system emissions.

<table>
<thead>
<tr>
<th>I</th>
<th>II</th>
<th>III</th>
<th>IV</th>
<th>V</th>
</tr>
</thead>
<tbody>
<tr>
<td>source: III</td>
<td>emissions in use</td>
<td>ref</td>
<td>energy content of fuel at LHV</td>
<td>emissions in use per kWh</td>
</tr>
<tr>
<td>kWh/kg</td>
<td>kg CO₂ eq/kg fuel used</td>
<td>(tab: properties)</td>
<td>calculated here</td>
<td></td>
</tr>
<tr>
<td>Ammonia</td>
<td>0</td>
<td>either lean mix or post combustion elimination of NOx [32]</td>
<td>5.53</td>
<td>0</td>
</tr>
<tr>
<td>Ammonia</td>
<td>0</td>
<td></td>
<td>5.53</td>
<td>0</td>
</tr>
<tr>
<td>Electricity</td>
<td>0</td>
<td>catalytic combustion [33]</td>
<td>0.39</td>
<td>0</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>0</td>
<td></td>
<td>33.33</td>
<td>0</td>
</tr>
<tr>
<td>Biodiesel</td>
<td>3.094</td>
<td>appendix c</td>
<td>11.05</td>
<td>0.2801</td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>2.75</td>
<td>appendix c</td>
<td>13.90</td>
<td>0.1978</td>
</tr>
<tr>
<td>Biomethane</td>
<td>2.75</td>
<td>appendix c</td>
<td>13.90</td>
<td>0.1978</td>
</tr>
<tr>
<td>Methanol</td>
<td>1.29</td>
<td>appendix c</td>
<td>5.53</td>
<td>0.2331</td>
</tr>
<tr>
<td>Marine Gas Oil</td>
<td>3.142</td>
<td>appendix c</td>
<td>13.19</td>
<td>0.2381</td>
</tr>
</tbody>
</table>

Table 5-9 Development of emissions due to use of the fuel
Combined emissions

to 5- 13 below sum the different sources of emissions for each combination considered.

Combined emissions – electricity emissions= 0.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Production</th>
<th>Storage</th>
<th>Transport</th>
<th>Emissions in production</th>
<th>Emissions into storage</th>
<th>Emissions in use (kg CO2 eq / kWh at LHV)</th>
<th>Additional fuel use due to storage method (%)</th>
<th>Transport emissions (kg CO2 eq/kWh at LHV)</th>
<th>Total emissions per kWh consumed (kg CO2 eq / kWh at LHV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>Hydrogen from renewable source</td>
<td>Pressurised liquid</td>
<td>Road tanker</td>
<td>0.000</td>
<td>0</td>
<td>0.0%</td>
<td>0.0068</td>
<td>0.0068</td>
<td></td>
</tr>
<tr>
<td>Ammonia</td>
<td>Hydrogen from SMR + CCS</td>
<td>Pressurised liquid</td>
<td>Road tanker</td>
<td>0.072</td>
<td>0</td>
<td>0.0%</td>
<td>0.0068</td>
<td>0.0791</td>
<td></td>
</tr>
<tr>
<td>Ammonia</td>
<td>Hydrogen from SMR</td>
<td>Pressurised liquid</td>
<td>Road tanker</td>
<td>0.289</td>
<td>0</td>
<td>0.0%</td>
<td>0.0068</td>
<td>0.2960</td>
<td></td>
</tr>
<tr>
<td>Electricity</td>
<td>Assume as grid</td>
<td>Battery</td>
<td>Grid</td>
<td>0.000</td>
<td>0</td>
<td>2.8%</td>
<td>0.0000</td>
<td>0.0000</td>
<td></td>
</tr>
<tr>
<td>Electricity</td>
<td>Direct renewable</td>
<td>Battery</td>
<td>Direct cable</td>
<td>0.000</td>
<td>0</td>
<td>2.8%</td>
<td>0.0000</td>
<td>0.0000</td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Electrolysis</td>
<td>Pressurised gas</td>
<td>Road tanker</td>
<td>0.000</td>
<td>0</td>
<td>0.0%</td>
<td>0.0002</td>
<td>0.0002</td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>SMR + CCS</td>
<td>Pressurised gas</td>
<td>Road tanker</td>
<td>0.028</td>
<td>0</td>
<td>0.0%</td>
<td>0.0002</td>
<td>0.0277</td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Electrolysis</td>
<td>Pressurised gas</td>
<td>Pipeline</td>
<td>0.028</td>
<td>0</td>
<td>0.0%</td>
<td>0.0000</td>
<td>0.0000</td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>SMR + CCS</td>
<td>Pressurised gas</td>
<td>Pipeline</td>
<td>0.028</td>
<td>0</td>
<td>0.0%</td>
<td>0.0000</td>
<td>0.0275</td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Electrolysis</td>
<td>Cryo-liquid (H)</td>
<td>Road tanker</td>
<td>0.000</td>
<td>0</td>
<td>0.0%</td>
<td>0.0001</td>
<td>0.0001</td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>SMR + CCS</td>
<td>Cryo-liquid (H)</td>
<td>Road tanker</td>
<td>0.028</td>
<td>0</td>
<td>0.0%</td>
<td>0.0001</td>
<td>0.0276</td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Electrolysis</td>
<td>LOHC*</td>
<td>Road tanker</td>
<td>0.000</td>
<td>0</td>
<td>33.0%</td>
<td>0.00010</td>
<td>0.00010</td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>SMR + CCS</td>
<td>LOHC*</td>
<td>Road tanker</td>
<td>0.028</td>
<td>0</td>
<td>33.0%</td>
<td>0.00010</td>
<td>0.0367</td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Electrolysis</td>
<td>Ammonia</td>
<td>Road tanker</td>
<td>0.000</td>
<td>0</td>
<td>25.6%</td>
<td>0.0068</td>
<td>0.0068</td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>SMR + CCS</td>
<td>Ammonia</td>
<td>Road tanker</td>
<td>0.072</td>
<td>0</td>
<td>25.6%</td>
<td>0.0068</td>
<td>0.0977</td>
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</tr>
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<td>Liquid Natural Gas</td>
<td>Natural gas</td>
<td>Cryo-liquid (M)</td>
<td>Road tanker</td>
<td>0.0001</td>
<td>0</td>
<td>0.198</td>
<td>0.0%</td>
<td>0.0087</td>
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</tr>
<tr>
<td>Biomethane</td>
<td>Biomethane</td>
<td>Cryo-liquid (M)</td>
<td>Road tanker</td>
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<td>0</td>
<td>0.198</td>
<td>0.0%</td>
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</tr>
<tr>
<td>Methanol</td>
<td>Direct air capture CO2</td>
<td>Liquid</td>
<td>Road tanker</td>
<td>-0.229</td>
<td>0</td>
<td>0.229</td>
<td>0.0%</td>
<td>0.0031</td>
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<tr>
<td>Methanol</td>
<td>Intercepted CO2</td>
<td>Liquid</td>
<td>Road tanker</td>
<td>-0.115</td>
<td>0</td>
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<td>0.0%</td>
<td>0.0031</td>
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<tr>
<td>Methanol</td>
<td>Biomass</td>
<td>Liquid</td>
<td>Road tanker</td>
<td>-0.226</td>
<td>0</td>
<td>0.229</td>
<td>0.0%</td>
<td>0.0031</td>
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<tr>
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<td>Crop biodiesel</td>
<td>Liquid</td>
<td>Road tanker</td>
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<td>0</td>
<td>0.278</td>
<td>0.0%</td>
<td>0.0015</td>
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<tr>
<td>Marine Gas Oil</td>
<td>Oil refining</td>
<td>Liquid</td>
<td>Road tanker</td>
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<td>0</td>
<td>0.236</td>
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<td>0.0011</td>
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Table 5- 10 Combined emission values for all combinations of fuel type, production, transport and storage considered, where electricity generation emissions = 0.
Combined emissions table – electricity emissions = 0.0336 kg CO2 eq/kWh

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Production</th>
<th>Storage</th>
<th>Transport</th>
<th>Emissions in production</th>
<th>Emissions into storage</th>
<th>Emissions in use</th>
<th>Additional fuel use due to storage method</th>
<th>Transport emissions</th>
<th>Total emissions per kWh consumed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>Hydrogen from renewable source</td>
<td>Pressurised liquid</td>
<td>Road tanker</td>
<td>0.056</td>
<td>0</td>
<td>0</td>
<td>0.0%</td>
<td>0.0068</td>
<td>0.0625</td>
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<td>Hydrogen from SMR + CCS</td>
<td>Pressurised liquid</td>
<td>Road tanker</td>
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<td>0</td>
<td>0.0%</td>
<td>0.0068</td>
<td>0.0791</td>
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<tr>
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<td>Hydrogen from SMR</td>
<td>Pressurised liquid</td>
<td>Road tanker</td>
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<td>0</td>
<td>0</td>
<td>0.0%</td>
<td>0.0068</td>
<td>0.2960</td>
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<tr>
<td>Electricity</td>
<td>Assume as grid</td>
<td>Battery</td>
<td>Grid</td>
<td>0.034</td>
<td>0</td>
<td>0</td>
<td>2.8%</td>
<td>0</td>
<td>0.0345</td>
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<td>Direct renewable</td>
<td>Battery</td>
<td>Direct cable</td>
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<td>0</td>
<td>0</td>
<td>2.8%</td>
<td>0</td>
<td>0.0000</td>
</tr>
<tr>
<td>Hydrogen Electrolys</td>
<td>Pressurised gas</td>
<td>Road tanker</td>
<td>0.041</td>
<td>0.004</td>
<td>0</td>
<td>0.0%</td>
<td>0.0002</td>
<td>0.0449</td>
<td></td>
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<tr>
<td>Hydrogen SMR + CCS</td>
<td>Pressurised gas</td>
<td>Road tanker</td>
<td>0.028</td>
<td>0.004</td>
<td>0</td>
<td>0.0%</td>
<td>0.0002</td>
<td>0.0314</td>
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</tr>
<tr>
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<td>Pressurised gas</td>
<td>Pipeline</td>
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<td>0.004</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0447</td>
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<tr>
<td>Hydrogen SMR + CCS</td>
<td>Pressurised gas</td>
<td>Pipeline</td>
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<td>0.004</td>
<td>0</td>
<td>0.0%</td>
<td>0</td>
<td>0.0312</td>
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<td>Hydrogen Electrolys</td>
<td>Cryo-liquid (H)</td>
<td>Road tanker</td>
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<td>0.007</td>
<td>0</td>
<td>0.0%</td>
<td>0.0001</td>
<td>0.0481</td>
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<tr>
<td>Hydrogen SMR + CCS</td>
<td>Cryo-liquid (H)</td>
<td>Road tanker</td>
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<td>0.007</td>
<td>0</td>
<td>0.0%</td>
<td>0.0001</td>
<td>0.0346</td>
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<td>Road tanker</td>
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<td>0</td>
<td>33.0%</td>
<td>0.00010</td>
<td>0.05461</td>
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<tr>
<td>Hydrogen SMR + CCS</td>
<td>LOHC*</td>
<td>Road tanker</td>
<td>0.028</td>
<td>0</td>
<td>0</td>
<td>33.0%</td>
<td>0.00010</td>
<td>0.0367</td>
<td></td>
</tr>
<tr>
<td>Hydrogen Electrolys</td>
<td>Ammonia</td>
<td>Road tanker</td>
<td>0.056</td>
<td>0</td>
<td>0</td>
<td>25.6%</td>
<td>0.0068</td>
<td>0.0768</td>
<td></td>
</tr>
<tr>
<td>Hydrogen SMR + CCS</td>
<td>Ammonia</td>
<td>Road tanker</td>
<td>0.072</td>
<td>0</td>
<td>0</td>
<td>25.6%</td>
<td>0.0068</td>
<td>0.0977</td>
<td></td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>Natural gas</td>
<td>Cryo-liquid (M)</td>
<td>Road tanker</td>
<td>0.0001</td>
<td>0.002</td>
<td>0.198</td>
<td>0.0%</td>
<td>0.0087</td>
<td>0.2085</td>
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<td>Biomethane</td>
<td>Cryo-liquid (M)</td>
<td>Road tanker</td>
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<td>0.002</td>
<td>0.198</td>
<td>0.0%</td>
<td>0.0052</td>
<td>0.2055</td>
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<tr>
<td>Methanol</td>
<td>Direct air capture CO2</td>
<td>Liquid</td>
<td>Road tanker</td>
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<td>0</td>
<td>0.229</td>
<td>0.0%</td>
<td>0.0031</td>
<td>0.0765</td>
</tr>
<tr>
<td>Methanol</td>
<td>Intercepted CO2</td>
<td>Liquid</td>
<td>Road tanker</td>
<td>-0.054</td>
<td>0</td>
<td>0.229</td>
<td>0.0%</td>
<td>0.0031</td>
<td>0.1783</td>
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<td>Biomass</td>
<td>Liquid</td>
<td>Road tanker</td>
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<td>0.0078</td>
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<td>Biodiesel</td>
<td>Crop biodiesel</td>
<td>Liquid</td>
<td>Road tanker</td>
<td>-0.273</td>
<td>0</td>
<td>0.278</td>
<td>0.0%</td>
<td>0.0015</td>
<td>0.0063</td>
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<td>Marine Gas Oil</td>
<td>Oil refining</td>
<td>Liquid</td>
<td>Road tanker</td>
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<td>0.0011</td>
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Table 5-11 Combined emission values for all combinations of fuel type, production, transport and storage considered, where electricity generation emissions = 0.0336 kg/kWh
<table>
<thead>
<tr>
<th>Fuel</th>
<th>Production</th>
<th>Storage</th>
<th>Transport</th>
<th>Emissions in production</th>
<th>Emissions into storage</th>
<th>Emissions in use</th>
<th>Additional fuel use due to storage method</th>
<th>Transport emissions</th>
<th>Total emissions per kWh consumed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>Hydrogen from renewable</td>
<td>Pressurised liquid</td>
<td>Road tanker</td>
<td>0.386</td>
<td>0</td>
<td>0</td>
<td>0.0%</td>
<td>0.0068</td>
<td>0.3928</td>
</tr>
<tr>
<td></td>
<td>source</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ammonia</td>
<td>Hydrogen from SMR + CCS</td>
<td>Pressurised liquid</td>
<td>Road tanker</td>
<td>0.072</td>
<td>0</td>
<td>0</td>
<td>0.0%</td>
<td>0.0068</td>
<td>0.0791</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ammonia</td>
<td>Hydrogen from SMR</td>
<td>Pressurised liquid</td>
<td>Road tanker</td>
<td>0.289</td>
<td>0</td>
<td>0</td>
<td>0.0%</td>
<td>0.0068</td>
<td>0.2960</td>
</tr>
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<td>Assume as grid</td>
<td>Battery</td>
<td>Grid</td>
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<td>Direct cable</td>
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<td>0</td>
<td>0</td>
<td>2.8%</td>
<td>0.0000</td>
<td>0.0000</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Electrolysis</td>
<td>Pressurised gas</td>
<td>Road tanker</td>
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<td>0.026</td>
<td>0</td>
<td>0.0%</td>
<td>0.0002</td>
<td>0.3102</td>
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<td>SMR + CCS</td>
<td>Pressurised gas</td>
<td>Road tanker</td>
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<td>0.0535</td>
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<td>Pressurised gas</td>
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<td>0.0%</td>
<td>0</td>
<td>0.3100</td>
</tr>
<tr>
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<td>Pressurised gas</td>
<td>Pipeline</td>
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<td>0.0%</td>
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<td>0.0534</td>
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<tr>
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<td>Cryo-liquid (H)</td>
<td>Road tanker</td>
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<td>0.049</td>
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<td>0.0%</td>
<td>0.0001</td>
<td>0.3331</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>SMR + CCS</td>
<td>Cryo-liquid (H)</td>
<td>Road tanker</td>
<td>0.028</td>
<td>0.049</td>
<td>0</td>
<td>0.0%</td>
<td>0.0001</td>
<td>0.0765</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Electrolysis</td>
<td>LOHC*</td>
<td>Road tanker</td>
<td>0.284</td>
<td>0</td>
<td>0</td>
<td>33.0%</td>
<td>0.00010</td>
<td>0.37811</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>SMR + CCS</td>
<td>LOHC*</td>
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<td>0</td>
<td>0</td>
<td>33.0%</td>
<td>0.00010</td>
<td>0.0367</td>
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<td>Electrolysis</td>
<td>Ammonia</td>
<td>Road tanker</td>
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<td>0.4918</td>
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<td>SMR + CCS</td>
<td>Ammonia</td>
<td>Road tanker</td>
<td>0.072</td>
<td>0.000</td>
<td>0</td>
<td>25.6%</td>
<td>0.0068</td>
<td>0.0977</td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>Natural gas</td>
<td>Cryo-liquid (M)</td>
<td>Road tanker</td>
<td>0.0001</td>
<td>0.013</td>
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<td>Methanol</td>
<td>Direct air capture CO2</td>
<td>Liquid</td>
<td>Road tanker</td>
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<td>0</td>
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<td>0.0%</td>
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<td>0.5121</td>
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<td>Methanol</td>
<td>Intercepted CO2</td>
<td>Liquid</td>
<td>Road tanker</td>
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<td>Biomass</td>
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<td>Road tanker</td>
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<td>0.229</td>
<td>0.0%</td>
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<td>Crop biodiesel</td>
<td>Liquid</td>
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<td>Oil refining</td>
<td>Liquid</td>
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<td>0</td>
<td>0.236</td>
<td>0.0%</td>
<td>0.0011</td>
<td>0.2553</td>
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</tbody>
</table>

* The production of hydrogen-charged LOHC (assuming Benzyl Toluene is the carrier) is a self-sustaining exothermic reaction. The surplus heat produced may be recoverable and reusable, but no additional allowance is made for this here.
## Fuel supply costs

Current and forecast unit costs for the supply of the various fuels from various production methods are compiled below, from a number of sources [34-39].

<table>
<thead>
<tr>
<th>Fuel &amp; production method</th>
<th>2023</th>
<th>2030</th>
<th>2045</th>
</tr>
</thead>
<tbody>
<tr>
<td>Green Ammonia</td>
<td>£0.053-£0.110</td>
<td>£0.046-£0.082</td>
<td>£0.027-£0.065</td>
</tr>
<tr>
<td>Blue Ammonia</td>
<td>£0.033-£0.088</td>
<td>£0.044-£0.076</td>
<td>£0.060-£0.060</td>
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<tr>
<td>Grey ammonia</td>
<td>£0.026-£0.078</td>
<td>£0.026-£0.078</td>
<td>£0.026-£0.078</td>
</tr>
<tr>
<td>Direct Electricity</td>
<td>£0.044-£0.057</td>
<td>£0.039-£0.047</td>
<td>£0.033-£0.044</td>
</tr>
<tr>
<td>Grid electricity</td>
<td>c.£0.178</td>
<td>c.£0.180</td>
<td>c.£0.174</td>
</tr>
<tr>
<td>Green hydrogen</td>
<td>£0.056-£0.203</td>
<td>£0.049-£0.107</td>
<td>£0.042-£0.080</td>
</tr>
<tr>
<td>Blue hydrogen</td>
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<td>£0.090-£0.142</td>
<td>£0.078-£0.142</td>
</tr>
<tr>
<td>Grey Hydrogen</td>
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<td>£0.073-£0.125</td>
<td>£0.073-£0.128</td>
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<tr>
<td>Fossil LNG</td>
<td>£0.013-£0.025</td>
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</tr>
<tr>
<td>Biomethane</td>
<td>£0.102-£0.185</td>
<td>£0.094-£0.177</td>
<td>£0.076-£0.159</td>
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<tr>
<td>DAC E-LNG</td>
<td>£0.217-£0.503</td>
<td>£0.173-£0.467</td>
<td>£0.079-£0.391</td>
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<td>Point E-LNG</td>
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<tr>
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<td>£0.058-£0.112</td>
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<tr>
<td>DAC E-Methanol</td>
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<td>Biodiesel</td>
<td>£0.080-£0.137</td>
<td>£0.077-£0.13</td>
<td>£0.072-£0.116</td>
</tr>
<tr>
<td>MGO</td>
<td>£0.032-£0.051</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Table 5-13 Estimated ranges of costs of various fuel types and production methods through the transition period. These costs represent the likely range of sales costs excluding transport and storage. Values shown in italics are interpolated. Future values for fossil fuels have not been estimated.*
**Transport costs**

Transport related costs are based on the same sources as used for emissions calculations, as above. This also assumes the use of diesel fuelled road tankers.

Below shows the resulting costs, expressed as £ per kWh.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Location</th>
<th>Dist (km)</th>
<th>Specific energy (kWh/kg)</th>
<th>Energy carried per load (MWh)</th>
<th>Max single mission demand (MWh)</th>
<th>Max nr. tanker movements required per 2-weeks for 2 vessels</th>
<th>Cost per 2-way tanker trip (£)</th>
<th>Transport cost (£/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>Orkney</td>
<td>410</td>
<td>5.53</td>
<td>136</td>
<td>834</td>
<td>7</td>
<td>£1,409</td>
<td>£0.0104</td>
</tr>
<tr>
<td>Electricity</td>
<td>Grid</td>
<td>Not applicable</td>
<td></td>
<td></td>
<td>571</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Aberdeen</td>
<td>3</td>
<td>33.33</td>
<td>43</td>
<td>834</td>
<td>20</td>
<td>£10</td>
<td>£0.0002</td>
</tr>
<tr>
<td>Hydrogen (LOHC)</td>
<td>Aberdeen</td>
<td>3</td>
<td>33.33</td>
<td>117</td>
<td>834</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Biodiesel</td>
<td>Motherwell</td>
<td>3</td>
<td>2.33</td>
<td>67</td>
<td>834</td>
<td>13</td>
<td>£10</td>
<td>£0.0002</td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>Milford Haven</td>
<td>240</td>
<td>11.05</td>
<td>353</td>
<td>1030</td>
<td>3</td>
<td>£825</td>
<td>£0.0023</td>
</tr>
<tr>
<td>Biomethane</td>
<td>Northampton</td>
<td>880</td>
<td>13.90</td>
<td>228</td>
<td>1030</td>
<td>5</td>
<td>£3,025</td>
<td>£0.0133</td>
</tr>
<tr>
<td>Methanol</td>
<td>Nigg</td>
<td>525</td>
<td>13.90</td>
<td>228</td>
<td>1030</td>
<td>5</td>
<td>£1,805</td>
<td>£0.0079</td>
</tr>
<tr>
<td>Marine Gas Oil</td>
<td>Aberdeen</td>
<td>220</td>
<td>5.63</td>
<td>161</td>
<td>1030</td>
<td>7</td>
<td>£756</td>
<td>£0.0047</td>
</tr>
</tbody>
</table>

Table 5- 14 Costs and transport requirements for different fuel types by road transport from nearest practical known supplier.

*Based on tanker operating cost of £1.72 / km [40]*
Storage related costs

Storage related costs are based on:

Capital cost of the provision of storage, based on the storage vessel type, which is determined by the nature and state of the fuel with few options. The key assumption made is the lifespan of the storage facility, which is taken here as 20 years. A nominal maintenance allowance of 1% of capital cost per year is also included.

Cost of using the storage, primarily in terms of energy used in putting the fuel into and out of storage (or a state suitable for storage) and any energy lost during storage.

below shows the resulting costs of the capital provision, expressed as both £ per kWh capacity (capital cost) and an amortised unit cost of fuel stored over the lifespan of the facility.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Storage Method</th>
<th>Data source</th>
<th>Unit cost of storage from source</th>
<th>Unit cost of capacity</th>
<th>Size of storage required, two ships</th>
<th>Capital cost of storage</th>
<th>Gross cost of storage provision for lifespan incl maintenance</th>
<th>Unit cost of storage £/kWh stored</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>Pressurised liquid</td>
<td>[41]</td>
<td>3 $/kg</td>
<td>£0.43</td>
<td>1668</td>
<td>£717,765</td>
<td>£861,318</td>
<td>0.0006</td>
</tr>
<tr>
<td>Electricity</td>
<td>Battery</td>
<td>[42]</td>
<td>150 $/kWh</td>
<td>£119.05</td>
<td>1141</td>
<td>£135,871,653</td>
<td>£163,045,983</td>
<td>0.1587</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Pressurised gas, surface pressure tank</td>
<td>[43]</td>
<td>400 $/kg</td>
<td>£9.52</td>
<td>1668</td>
<td>£15,886,532</td>
<td>£19,063,838</td>
<td>0.0127</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Cryo-liquid (H)</td>
<td>[44]</td>
<td>7.86 $/litre</td>
<td>£2.64</td>
<td>1668</td>
<td>£4,396,765</td>
<td>£5,276,119</td>
<td>0.0035</td>
</tr>
<tr>
<td>Hydrogen (LOHC)</td>
<td>LOHC</td>
<td>[45]</td>
<td>0.757 £/litre</td>
<td>£0.41</td>
<td>1668</td>
<td>£676,468</td>
<td>£811,762</td>
<td>0.0005</td>
</tr>
<tr>
<td>Biodiesel</td>
<td>Liquid</td>
<td>[45]</td>
<td>0.757 £/litre</td>
<td>£0.08</td>
<td>2060</td>
<td>£358,568</td>
<td>£430,282</td>
<td>0.0004</td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>Cryo-liquid (M)</td>
<td>[46]</td>
<td>2.32 $/litre</td>
<td>£0.29</td>
<td>2060</td>
<td>£598,324</td>
<td>£717,989</td>
<td>0.0004</td>
</tr>
<tr>
<td>Biomethane</td>
<td>Cryo-liquid (M)</td>
<td>[46]</td>
<td>2.32 $/litre</td>
<td>£0.29</td>
<td>2060</td>
<td>£598,324</td>
<td>£717,989</td>
<td>0.0004</td>
</tr>
<tr>
<td>Methanol</td>
<td>Liquid</td>
<td>[45]</td>
<td>0.757 £/litre</td>
<td>£0.17</td>
<td>2060</td>
<td>£358,568</td>
<td>£430,282</td>
<td>0.0002</td>
</tr>
<tr>
<td>Marine Gas Oil</td>
<td>Liquid</td>
<td>[45]</td>
<td>0.757 £/litre</td>
<td>£0.07</td>
<td>2060</td>
<td>£139,708</td>
<td>£167,649</td>
<td>0.0001</td>
</tr>
</tbody>
</table>

Table 5-15 Storage costs for various fuel types and storage methods.
below shows the cost of the energy required to put the fuel into storage, keep it there, and remove it from storage. Energy requirement is taken from tables 5-7 above.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Method</th>
<th>Energy required to put into storage kWh/kg</th>
<th>Energy required to remove from storage kWh/kg</th>
<th>Fuel energy lost in storage %/day</th>
<th>Unit cost of energy lost: 2023 (grid electricity or final fuel cost) £/kWh</th>
<th>Unit cost of energy lost: 2045 (grid electricity or final fuel cost) £/kWh</th>
<th>Unit cost of storage energy: 2023* £/kWh</th>
<th>Unit cost of storage energy: 2045* £/kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>Pressurised liquid</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>n/a</td>
<td>n/a</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Electricity</td>
<td>Battery</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>0.178</td>
<td>0.174</td>
<td>0.0004</td>
<td>0.0003</td>
</tr>
<tr>
<td>Hydrogen (700 bar gas)</td>
<td>Pressurised gas</td>
<td>3.7</td>
<td>0</td>
<td>0%</td>
<td>0.178</td>
<td>0.174</td>
<td>0.0198</td>
<td>0.0193</td>
</tr>
<tr>
<td>Hydrogen (700 bar gas)</td>
<td>Pressurised gas</td>
<td>3.7</td>
<td>0</td>
<td>0%</td>
<td>0.178</td>
<td>0.174</td>
<td>0.0198</td>
<td>0.0193</td>
</tr>
<tr>
<td>Hydrogen (liquid)</td>
<td>Cryo-liquid (H)</td>
<td>7</td>
<td>0</td>
<td>0%</td>
<td>0.178</td>
<td>0.174</td>
<td>0.0374</td>
<td>0.0365</td>
</tr>
<tr>
<td>Hydrogen (LOHC)</td>
<td>LOHC</td>
<td>0</td>
<td>11.01 ***</td>
<td>0%</td>
<td>0.1944</td>
<td>0.0921</td>
<td>0.0642</td>
<td>0.0304</td>
</tr>
<tr>
<td>Biodiesel</td>
<td>Liquid</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>n/a</td>
<td>n/a</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>Cryo-liquid (M)</td>
<td>0.75</td>
<td>0</td>
<td>0%</td>
<td>0.178</td>
<td>0.174</td>
<td>0.0096</td>
<td>0.0094</td>
</tr>
<tr>
<td>Biomethane</td>
<td>Cryo-liquid (M)</td>
<td>0.75</td>
<td>0</td>
<td>0%</td>
<td>0.178</td>
<td>0.174</td>
<td>0.0096</td>
<td>0.0094</td>
</tr>
<tr>
<td>Methanol</td>
<td>Liquid</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>n/a</td>
<td>n/a</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Marine Gas Oil</td>
<td>Liquid</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>n/a</td>
<td>n/a</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* Assume based on half-full storage for 2 weeks
** Assume zero cost because this would be recovered and diverted into fuel stream
*** Based on mass of hydrogen removed, not of carrier liquid.

Table 5-16 Storage operational cost based on energy requirements
below sets out the combined storage related costs.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Method</th>
<th>Total storage cost, 2023</th>
<th>Total storage cost, 2045</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>Pressurised liquid</td>
<td>0.0006</td>
<td>0.0006</td>
</tr>
<tr>
<td>Electricity</td>
<td>Battery</td>
<td>0.1591</td>
<td>0.1591</td>
</tr>
<tr>
<td>Hydrogen (700 bar gas)</td>
<td>Pressurised gas</td>
<td>0.0325</td>
<td>0.0320</td>
</tr>
<tr>
<td>Hydrogen (700 bar gas)</td>
<td>Pressurised gas</td>
<td>0.0204</td>
<td>0.0199</td>
</tr>
<tr>
<td>Hydrogen (liquid)</td>
<td>Cryo-liquid (H)</td>
<td>0.0409</td>
<td>0.0401</td>
</tr>
<tr>
<td>Hydrogen (LOHC)</td>
<td>LOHC</td>
<td>0.0648</td>
<td>0.0310</td>
</tr>
<tr>
<td>Biodiesel</td>
<td>Liquid</td>
<td>0.0001</td>
<td>0.0001</td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>Cryo-liquid (M)</td>
<td>0.0100</td>
<td>0.0098</td>
</tr>
<tr>
<td>Biomethane</td>
<td>Cryo-liquid (M)</td>
<td>0.0100</td>
<td>0.0098</td>
</tr>
<tr>
<td>Methanol</td>
<td>Liquid</td>
<td>0.0002</td>
<td>0.0002</td>
</tr>
<tr>
<td>Marine Gas Oil</td>
<td>Liquid</td>
<td>0.0001</td>
<td>0.0001</td>
</tr>
</tbody>
</table>

*Table 5-17 Combined storage costs for 2023 and 2045.*
Combined costs

below presents a summary of the total cost situation for all fuels, in 2023. A mid value of the supply costs is used.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Production</th>
<th>Storage</th>
<th>Transport</th>
<th>Supply cost Min</th>
<th>Supply cost Max</th>
<th>Transportation cost</th>
<th>Storage cost</th>
<th>Fuelling cost</th>
<th>Total cost Min</th>
<th>Total cost Max</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>£/kWh</td>
<td>£/kWh</td>
<td>£/kWh</td>
<td>£/kWh</td>
<td>£/kWh</td>
<td>£/kWh</td>
<td>£/kWh</td>
</tr>
<tr>
<td>Ammonia</td>
<td>Hydrogen from</td>
<td>Pressurised</td>
<td>Road tanker</td>
<td>0.053</td>
<td>0.110</td>
<td>0.0104</td>
<td>0.0006</td>
<td>0.000005</td>
<td>0.0925</td>
<td>0.0715</td>
</tr>
<tr>
<td></td>
<td>renewable source</td>
<td>liquid</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ammonia</td>
<td>Hydrogen from</td>
<td>Pressurised</td>
<td>Road tanker</td>
<td>0.033</td>
<td>0.088</td>
<td>0.0104</td>
<td>0.0006</td>
<td>0.000005</td>
<td>0.0715</td>
<td>0.0630</td>
</tr>
<tr>
<td></td>
<td>SMR + CCS</td>
<td>liquid</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ammonia</td>
<td>Hydrogen from</td>
<td>Pressurised</td>
<td>Road tanker</td>
<td>0.026</td>
<td>0.078</td>
<td>0.0104</td>
<td>0.0006</td>
<td>0.000005</td>
<td>0.0630</td>
<td>0.0630</td>
</tr>
<tr>
<td></td>
<td>SMR</td>
<td>liquid</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity</td>
<td>Assume as grid</td>
<td>Battery</td>
<td>Grid</td>
<td>0.178</td>
<td>0.178</td>
<td>0.0000</td>
<td>0.1591</td>
<td>0.0183</td>
<td>0.3554</td>
<td>0.2279</td>
</tr>
<tr>
<td>Electricity</td>
<td>Direct renewable</td>
<td>Battery</td>
<td>Direct cable</td>
<td>0.044</td>
<td>0.057</td>
<td>0.0000</td>
<td>0.1591</td>
<td>0.0183</td>
<td>0.2279</td>
<td>0.2279</td>
</tr>
<tr>
<td>Hydrogen (700 bar gas)</td>
<td>Electrolysis</td>
<td>Pressurised</td>
<td>Road tanker</td>
<td>0.056</td>
<td>0.203</td>
<td>0.0002</td>
<td>0.0325</td>
<td>0.0101</td>
<td>0.1723</td>
<td>0.1723</td>
</tr>
<tr>
<td></td>
<td>Pressurised gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrogen (700 bar gas)</td>
<td>SMR + CCS</td>
<td>Pressurised</td>
<td>Road tanker</td>
<td>0.059</td>
<td>0.142</td>
<td>0.0002</td>
<td>0.0325</td>
<td>0.0101</td>
<td>0.1433</td>
<td>0.1433</td>
</tr>
<tr>
<td></td>
<td>Pressurised gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Hydrogen (700 bar gas)</td>
<td>Electrolysis</td>
<td>Pressurised</td>
<td>Pipeline</td>
<td>0.056</td>
<td>0.203</td>
<td>0.0002</td>
<td>0.0325</td>
<td>0.0101</td>
<td>0.1723</td>
<td>0.1723</td>
</tr>
<tr>
<td>Hydrogen (700 bar gas)</td>
<td>SMR + CCS</td>
<td>Pressurised</td>
<td>Pipeline</td>
<td>0.059</td>
<td>0.142</td>
<td>0.0002</td>
<td>0.0325</td>
<td>0.0101</td>
<td>0.1433</td>
<td>0.1433</td>
</tr>
<tr>
<td>Hydrogen (liquid)</td>
<td>Electrolysis</td>
<td>Cryo-liquid (H)</td>
<td>Road tanker</td>
<td>0.056</td>
<td>0.203</td>
<td>0.0000</td>
<td>0.0409</td>
<td>0.0053</td>
<td>0.1757</td>
<td>0.1757</td>
</tr>
<tr>
<td>Hydrogen (liquid)</td>
<td>SMR + CCS</td>
<td>Cryo-liquid (H)</td>
<td>Road tanker</td>
<td>0.059</td>
<td>0.142</td>
<td>0.0000</td>
<td>0.0409</td>
<td>0.0053</td>
<td>0.1467</td>
<td>0.1467</td>
</tr>
<tr>
<td>Hydrogen (LOHC)</td>
<td>Electrolysis</td>
<td>LOHC</td>
<td>Road tanker</td>
<td>0.056</td>
<td>0.203</td>
<td>0.0002</td>
<td>0.0648</td>
<td>0.0000</td>
<td>0.1944</td>
<td>0.1944</td>
</tr>
<tr>
<td>Hydrogen (LOHC)</td>
<td>SMR + CCS</td>
<td>LOHC</td>
<td>Road tanker</td>
<td>0.059</td>
<td>0.142</td>
<td>0.0002</td>
<td>0.0648</td>
<td>0.0000</td>
<td>0.1654</td>
<td>0.1654</td>
</tr>
<tr>
<td>Liquid Natural Gas</td>
<td>Natural gas</td>
<td>Cryo-liquid (M)</td>
<td>Road tanker</td>
<td>0.013</td>
<td>0.025</td>
<td>0.0133</td>
<td>0.0100</td>
<td>0.0000</td>
<td>0.0423</td>
<td>0.0423</td>
</tr>
<tr>
<td>Biomethane</td>
<td>Biomethane</td>
<td>Cryo-liquid (M)</td>
<td>Road tanker</td>
<td>0.102</td>
<td>0.185</td>
<td>0.0079</td>
<td>0.0100</td>
<td>0.0000</td>
<td>0.1614</td>
<td>0.1614</td>
</tr>
<tr>
<td>Methanol</td>
<td>Direct air capture CO2</td>
<td>Liquid</td>
<td>Road tanker</td>
<td>0.159</td>
<td>0.334</td>
<td>0.0047</td>
<td>0.0002</td>
<td>0.0000</td>
<td>0.2514</td>
<td>0.2514</td>
</tr>
<tr>
<td>Methanol</td>
<td>Intercepted CO2</td>
<td>Liquid</td>
<td>Road tanker</td>
<td>0.032</td>
<td>0.159</td>
<td>0.0047</td>
<td>0.0002</td>
<td>0.0000</td>
<td>0.1004</td>
<td>0.1004</td>
</tr>
</tbody>
</table>

Page 217 of 318
<table>
<thead>
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<th>Fuel</th>
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|                      | Min /kWh Max /kWh | £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kWh £/kH...
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*Table 5-19 Summary of forecast key costs of all fuel types under consideration, in 2045.*

*Table 5-20 Summary of forecast key costs of all fuel types under consideration, in 2023 and 2045.*
# Basic abridged network model for methane or hydrogen, version 3
# Western branch of the network has been removed, that is Kirriemuir - Stirling - Glasgow area - Gretna.
# This includes pipes nos. PN07 - PN17 and PD32 - PD47. These numbers are therefore not used here.
# PN17 was created to provide for export at the south end of the network at Coldstream, so is also not used here, although it is not out.
# This version of the model only contains the East coast segments, chosen for simplicity because it has fewer nodes and no loop, essentially it's a straight line with several branches.
# Updates over v2: Varying demand profile through the day. Introduce mixed gas as placeholder.

from datetime import datetime

# Getting the current date and time
dt = datetime.now().strftime("%Y-%m-%d %H:%M:%S")
print()
print()
print("started at ", dt)

### Define which gas is to be used (Methane, Hydrogen, 80/20 mix by volume of Methane and hydrogen respectively) ###
gas = "hydrogen"
#gas = "natural gas"
#gas = "80/20 mix"

# Create output file. NB this will over-write previous versions, so go and save them under a different name first if you want to keep them.
if gas == "hydrogen":
    outputfile = "East network model output base with linepack v3 (hydrogen).txt"
elif gas == "natural gas":
    outputfile = "East network model output base with linepack v3 (natural gas).txt"
elif gas == "80/20 mix":
    outputfile = "East network model output base with linepack v3 (80-20 mix).txt"
else:
    print("please check gas selection")

print("writing to ",outputfile)

with open(outputfile, "w") as fileout:
    print("Output file for abridged network model, loosely based on the eastern part of the transmission and distribution network in Scotland", file=fileout)
    print("", file=fileout)
    print("", file=fileout)
    print("Started: ", dt, file=fileout)
    print("Gas type: ",gas, file=fileout)
    print("", file=fileout)

import math
#Import numpy

print("----- Section 1. Basic data. ------", file=fileout)

# Define input and output node locations (national grid, metres)
# [Reference, Easting, Northing, elevation mOD] # elevation taken as constant initially as gravity effect on gas is small.

# Network node points
NS00_Sfeg = ["St Fergus", 409589, 852173, 50]
NN01_Petc = ["Peterculter", 384019, 800606, 50]
NN02_Foch = ["Fochabers", 334763, 858643, 50]
NN03_Kiri = ["Kirriemuir", 338549, 753933, 50]
NN04_Glen = ["Glendoick", 314935, 722447, 50]
NN05_Dunf = ["Dunfermline", 314035, 722447, 50]
NN06_Balo = ["Balerno", 316345, 665962, 50]
NN07_Laud = ["Lauder", 353041, 647613, 50]
#NN16_Cold = ["Coldstream", 384180, 639767, 50]
# Demand node locations

ND26_Wlot = ['West Lothian', 305331, 666598], 50
ND27_Edin = ['Edinburgh', 325893, 674006], 50
ND28_Mlot = ['Midlothian', 333180, 667318], 50
ND29_Elot = ['East Lothian', 351436, 673895], 50
ND31_Fife = ['Fife', 327397, 78016], 50
ND32_Dund = ['Dundee', 340311, 738250], 50
ND33_Angs = ['Angus', 345627, 758629], 50
ND34_Absh = ['Aberdeenshire', 369496, 795764], 50
ND35_Abdn = ['Aberdeen', 394483, 806377], 50
ND36_Mory = ['Moray', 321621, 862858], 50
ND37_High = ['Highland', 266642, 845382], 50
ND39_Pkin = ['Perth and Kinross', 311608, 723534], 50
ND46_Sbor = ['Scottish Borders', 357711, 631683], 50

# Pipe names = [PN00_Sfeg_Petc, PN01_Petc_Foch, PN02_Petc_Kiri, PN03_Kiri_Glen, PN04_Glen_Dunf,
# PN05_Dunf_Balo, PN06_Balo_Laud, PD27_Balo_Wlot, 
# PD28_Balo_Edin, PD29_Balo_Mlot, PD30_Laud_Elot, PD26_Dunf_Fife, PD24_Glen_Dund,
# PD23_Kiri_Angs, PD20_Petc_Absh, PD19_Petc_Abdn, 
# PD21_Foch_Mory, PD22_Foch_High, PD25_Glen_Pkin, PD31_Laud_Sbor]

# Calculate pipe lengths (metres), assuming straight between nodes

# Network pipes

Len_PN00_Sfeg_Petc = ((NN00_Sfeg[1] - NN01_Petc[1])**2 + (NN00_Sfeg[2] - NN01_Petc[2])**2)**0.5
Len_PN01_Petc_Foch = ((NN01_Petc[1] - NN02_Foch[1])**2 + (NN01_Petc[2] - NN02_Foch[2])**2)**0.5
Len_PN02_Petc_Kiri = ((NN02_Petc[1] - NN03_Kiri[1])**2 + (NN02_Petc[2] - NN03_Kiri[2])**2)**0.5
Len_PN05_Dunf_Balo = ((NN05_Dunf[1] - NN06_Balo[1])**2 + (NN05_Dunf[2] - NN06_Balo[2])**2)**0.5

# Demand pipes

Len_PD20_Petc_Absh = ((NN03_Petc[1] - ND35_Absh[1])**2 + (NN03_Petc[2] - ND35_Absh[2])**2)**0.5

print('"", file=fileout)

print("Pipe lengths (m):", file=fileout)
print("Network Pipes", file=fileout)
print("Len_PN00_Sfeg_Petc: ", round(Len_PN00_Sfeg_Petc), file=fileout)
print("Len_PN01_Petc_Foch: ", round(Len_PN01_Petc_Foch), file=fileout)
print("Len_PN02_Petc_Kiri: ", round(Len_PN02_Petc_Kiri), file=fileout)
print("Len_PN03_Kiri_Glen: ", round(Len_PN03_Kiri_Glen), file=fileout)
print("Len_PN04_Glen_Dunf: ", round(Len_PN04_Glen_Dunf), file=fileout)
print("Len_PN05_Dunf_Balo: ", round(Len_PN05_Dunf_Balo), file=fileout)
print("Len_PN06_Balo_Laud: ", round(Len_PN06_Balo_Laud), file=fileout)
print("Len_PN07_Laud_Cold: ", round(Len_PN07_Laud_Cold), file=fileout)
print('"", file=fileout)

print("Demand pipes", file=fileout)
print("Len_PD19_Petc_Abdn: ", round(Len_PD19_Petc_Abdn), file=fileout)
print("Len_PD20_Petc_Absh: ", round(Len_PD20_Petc_Absh), file=fileout)
print("Len_PD21_Foch_Mory: ", round(Len_PD21_Foch_Mory), file=fileout)
print("Len_PD22_Foch_High: ", round(Len_PD22_Foch_High), file=fileout)
print("Len_PD23_Kiri_Angs: ", round(Len_PD23_Kiri_Angs), file=fileout)
print("Len_PD24_Glen_Dund: ", round(Len_PD24_Glen_Dund), file=fileout)
print("Len_PD25_Glen_Pkin: ", round(Len_PD25_Glen_Pkin), file=fileout)
print("Len_PD26_Dunf_Fife: ", round(Len_PD26_Dunf_Fife), file=fileout)
print("Len_PD27_Balo_Wlot: ", round(Len_PD27_Balo_Wlot), file=fileout)
print("Len_PD28_Balo_Eedin: ", round(Len_PD28_Balo_Eedin), file=fileout)
print("Len_PD29_Balo_Mlot: ", round(Len_PD29_Balo_Mlot), file=fileout)
print("Len_PD30_Laud_Elot: ", round(Len_PD30_Laud_Elot), file=fileout)
# Define pipe parameters - diameters (m), roughness coefficients (mm), and minimum acceptable downstream pressure (kPa).

# Network pipes
# These are set to the minimum standard size which allows service to be met with natural gas / methane

# OG
Param_PN00_Sfeg_Petc = [0.500, 0.0015, 0]  # fixed 500
Param_PN01_Petc_Foch = [0.250, 0.0015, 0]  # fixed 250
Param_PN02_Petc_Kiri = [0.450, 0.0015, 0]  # fixed 450
Param_PN03_Kiri_Glen = [0.450, 0.0015, 0]  # fixed 450
Param_PN04_Glen_Dunf = [0.450, 0.0015, 0]  # fixed 450
Param_PN05_Dunf_Balo = [0.400, 0.0015, 0]  # fixed 400
Param_PN06_Balo_Laud = [0.250, 0.0015, 0]  # fixed 250
#Param_PN07_Laud_Cold = [0.050, 0.0015, 0]  #

# Demand pipes
# These are set to the minimum standard size which allows service to be met with natural gas / methane

Param_PD19_Petc_Abdn = [0.350, 0.0015, 0]  # fixed 350
Param_PD20_Petc_Absh = [0.400, 0.0015, 0]  # fixed 400
Param_PD21_Foch_Mory = [0.250, 0.0015, 0]  # fixed 250
Param_PD22_Foch_High = [0.500, 0.0015, 0]  # fixed 500
Param_PD23_Kiri_Angs = [0.250, 0.0015, 0]  # fixed 250
Param_PD24_Glen_Dund = [0.350, 0.0015, 0]  # fixed 350
Param_PD25_Glen_Pkin = [0.250, 0.0015, 0]  # fixed 250
Param_PD26_Dunf_Fife = [0.450, 0.0015, 0]  # fixed 450
Param_PD27_Balo_Mlot = [0.300, 0.0015, 0]  # fixed 300
Param_PD28_Balo_Edin = [0.450, 0.0015, 0]  # fixed 450
Param_PD29_Balo_Mlot = [0.250, 0.0015, 0]  # fixed 250
Param_PD30_Laud_Elot = [0.300, 0.0015, 0]  # fixed 300
Param_PD31_Laud_Sbor = [0.300, 0.0015, 0]  # fixed 300

# Define density and viscosity for natural gas, given pressure
#                        Pressure   Density        Viscosity
#                           (kPa)    (kg/m3)        (uPa-s)
Natural_gas_properties = {  10 : [ 0.079, 11.073],
20 : [ 0.158, 11.075],
30 : [ 0.247, 11.078],
40 : [ 0.348, 11.081],
50 : [ 0.467, 11.085],
60 : [ 0.609, 11.090],
70 : [ 0.787, 11.095],
80 : [ 1.024, 11.103],
90 : [ 1.379, 11.114],
100 : [ 0.790, 11.095],
110 : [ 0.870, 11.098],
120 : [ 0.950, 11.100],
130 : [ 1.030, 11.103],
140 : [ 1.110, 11.105],
150 : [ 1.190, 11.108],
160 : [ 1.270, 11.110],
170 : [ 1.350, 11.113],
180 : [ 1.430, 11.115],
190 : [ 1.510, 11.118],
200 : [ 1.590, 11.120],
210 : [ 1.670, 11.122],
220 : [ 1.750, 11.124],
230 : [ 1.830, 11.126],
240 : [ 1.910, 11.127],
250 : [ 1.990, 11.129],
260 : [ 2.070, 11.131],
270 : [ 2.150, 11.133],
280 : [ 2.230, 11.134],
290 : [ 2.310, 11.136],
300 : [ 2.390, 11.138],
310 : [ 2.471, 11.139],
320 : [ 2.552, 11.141],
330 : [ 2.633, 11.142],
340 : [ 2.714, 11.144],
350 : [ 2.795, 11.145],
360 : [ 2.876, 11.146],
370 : [ 2.957, 11.148],

NB this table continues to page 231. The corresponding hydrogen table that follows it, continues to page 243.
<p>| 380 | 3.038 , 11.149 |
| 390 | 3.119 , 11.151 |
| 400 | 3.200 , 11.152 |
| 410 | 3.281 , 11.153 |
| 420 | 3.362 , 11.155 |
| 430 | 3.443 , 11.156 |
| 440 | 3.524 , 11.157 |
| 450 | 3.605 , 11.159 |
| 460 | 3.686 , 11.160 |
| 470 | 3.767 , 11.162 |
| 480 | 3.848 , 11.163 |
| 490 | 3.929 , 11.164 |
| 500 | 4.010 , 11.166 |
| 510 | 4.091 , 11.167 |
| 520 | 4.172 , 11.168 |
| 530 | 4.253 , 11.169 |
| 540 | 4.334 , 11.170 |
| 550 | 4.415 , 11.171 |
| 560 | 4.496 , 11.172 |
| 570 | 4.577 , 11.173 |
| 580 | 4.658 , 11.175 |
| 590 | 4.739 , 11.176 |
| 600 | 4.820 , 11.177 |
| 610 | 4.901 , 11.178 |
| 620 | 4.982 , 11.179 |
| 630 | 5.063 , 11.180 |
| 640 | 5.144 , 11.182 |
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| 660 | 5.306 , 11.184 |
| 670 | 5.387 , 11.185 |
| 680 | 5.468 , 11.187 |
| 690 | 5.549 , 11.188 |
| 700 | 5.630 , 11.189 |
| 710 | 5.712 , 11.191 |
| 720 | 5.794 , 11.192 |
| 730 | 5.876 , 11.194 |
| 740 | 5.958 , 11.196 |
| 750 | 6.040 , 11.197 |
| 760 | 6.122 , 11.199 |
| 770 | 6.204 , 11.200 |
| 780 | 6.286 , 11.202 |
| 790 | 6.368 , 11.204 |
| 800 | 6.450 , 11.205 |
| 810 | 6.532 , 11.207 |
| 820 | 6.614 , 11.208 |
| 830 | 6.696 , 11.210 |
| 840 | 6.778 , 11.212 |
| 850 | 6.860 , 11.213 |
| 860 | 6.942 , 11.215 |
| 870 | 7.024 , 11.217 |
| 880 | 7.106 , 11.218 |
| 890 | 7.188 , 11.220 |
| 900 | 7.270 , 11.221 |
| 910 | 7.353 , 11.223 |
| 920 | 7.436 , 11.225 |
| 930 | 7.519 , 11.226 |
| 940 | 7.602 , 11.228 |
| 950 | 7.685 , 11.230 |
| 960 | 7.768 , 11.231 |
| 970 | 7.851 , 11.233 |
| 980 | 7.934 , 11.235 |
| 990 | 8.017 , 11.236 |
| 1000 | 8.100 , 11.238 |
| 1010 | 8.185 , 11.240 |
| 1020 | 8.270 , 11.241 |
| 1030 | 8.355 , 11.243 |
| 1040 | 8.440 , 11.245 |
| 1050 | 8.525 , 11.247 |
| 1060 | 8.610 , 11.249 |
| 1070 | 8.695 , 11.251 |
| 1080 | 8.780 , 11.252 |
| 1090 | 8.865 , 11.254 |
| 1100 | 8.950 , 11.256 |
| 1110 | 9.035 , 11.258 |</p>
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if gas == "hydrogen":
    SpecEn = (33.3+39.4)/2  # specific energy (kWh/kg). Using average if LHV and HHV due to blended use
    properties = Hydrogen_properties
elif gas == "natural gas":  # specific energy (kWh/kg)
    SpecEn = 13.9
    properties = Natural_gas_properties
elif gas == "80/20 mix":
    print("sorry, the 80/20 mix is not yet available, please choose methane or hydrogen for the time being")
    print("sorry, the 80/20 mix is not yet available, please choose methane or hydrogen for the time being", file=fileout)
else:
    print("Please identify the gas. Check capitals.")
    print("Please identify the gas. Check capitals.", file=fileout)

# Define universal constants
g = 9.81 # gravity (N/kg)
p = 1.01 # pi (Mmm, pie)

print("------ Section 2. Initial Pressures. ------", file=fileout)
# Define initial Pressure at inlet node (kPa)
InPres_NS00_Sfeg = 8500.0 # ie 85 bar, max in transmission mains as discussed with SGN

print("Initial Pressure at Sfeg inlet", file = fileout)
print("InPres_NS00_Sfeg: ", InPres_NS00_Sfeg, file=fileout)

# Define demand profiles (MWh/h, hourly for 1 average day)
# Demand nodes only, obviously.
Profile_ND26_Wlot = [92.72, 61.81, 61.81, 61.81, 71.09, 120.54, 268.89, 309.07, 247.26, 216.35, 200.90, 200.90, 200.90, 200.90, 253.44, 278.17, 293.62, 247.26, 231.81, 216.35, 154.54, 123.63, 92.72, ]
Profile_ND27_Edin = [46.82, 31.21, 31.21, 31.21, 35.90, 60.87, 135.78, 156.07, 124.86, 109.25, 101.45, 98.07, 78.46, 62.43, 46.82, ]
Profile_ND28_Mlot = [41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, 41.58, ]
Profile_ND31_Fife = [189.17, 126.11, 126.11, 126.11, 145.03, 189.17, 126.11, 126.11, 126.11, 126.11, 126.11, 126.11, 126.11, 126.11, 126.11, 126.11, 126.11, ]
Profile_ND32_Dund = [75.62, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, 50.41, ]
Profile_ND34_Absh = [132.28, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, 88.18, ]
Profile_ND35_Abdn = [115.80, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, 77.20, ]
Profile_ND36_Mory = [48.52, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, 32.35, ]
Profile_ND46_Sbor = [58.49, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, 39.00, ]

print(" ------Section 3. Calculate flows ---------", file=fileout)
print("Energy flux rates", file = fileout)
# Define arrays for energy flux rates
# Network pipes
Flux_PN00_Sfeg_Petc = []
Flux_PN01_Petc_Foch = []
Flux_PN02_Petc_Kiri = []
Flux_PN03_Kiri_Glen = []
Flux_PN04_Glen_Dunf = []
Flux_PN05_Dunf_Balo = []
Flux_PN06_Balo_Laud = []
#Flux_PN07_Laud_Cold = []

# Demand pipes
Flux_PD19_Petc_Abdn = []
Flux_PD20_Petc_Absh = []
Flux_PD21_Foch_Mory = []
Flux_PD22_Foch_High = []
Flux_PD23_Kiri_Angs = []
Flux_PD24_Glen_Dund = []
Flux_PD25_Glen_Pkin = []
Flux_PD26_Dunf_Fife = []
Flux_PD27_Balo_Wlot = []
Flux_PD28_Balo_Edin = []
Flux_PD29_Balo_Mlot = []
Flux_PD30_Laud_Elot = []
Flux_PD31_Laud_Sbor = []

# Calculate Energy Flux rate in pipes (kWh/sec) due to demand
# 1000 factor converts MWh to kWh
# 3600 factor converts Flux per hour to Flux per second
# Demand pipes entered first as network pipes use those as inputs - so this basically counts back up the network.
# Also Network pipes are entered in reverse order, for the same reason.
# Define counter for hours
Hours = list(range(0,24))

for h in Hours:
    # Demand pipes
    Flux_PD19_Petc_Abdn_h = (Profile_ND35_Abdn[h] * 1000 / 3600)
    Flux_PD20_Petc_Absh_h = (Profile_ND34_Absh[h] * 1000 / 3600)
    Flux_PD21_Foch_Mory_h = (Profile_ND36_Mory[h] * 1000 / 3600)
    Flux_PD22_Foch_High_h = (Profile_ND37_High[h] * 1000 / 3600)
    Flux_PD23_Kiri_Angs_h = (Profile_ND33_Angs[h] * 1000 / 3600)
    Flux_PD24_Glen_Dund_h = (Profile_ND32_Dund[h] * 1000 / 3600)
    Flux_PD25_Glen_Pkin_h = (Profile_ND39_Pkin[h] * 1000 / 3600)
    Flux_PD26_Dunf_Fife_h = (Profile_ND31_Fife[h] * 1000 / 3600)
    Flux_PD27_Balo_Wlot_h = (Profile_ND26_Wlot[h] * 1000 / 3600)
    Flux_PD28_Balo_Edin_h = (Profile_ND27_Edin[h] * 1000 / 3600)
    Flux_PD29_Balo_Mlot_h = (Profile_ND28_Mlot[h] * 1000 / 3600)
    Flux_PD30_Laud_Elot_h = (Profile_ND29_Elot[h] * 1000 / 3600)
    Flux_PD31_Laud_Sbor_h = (Profile_ND46_Sbor[h] * 1000 / 3600)

    # Network pipes (reverse order)
    Flux_PN07_Laud_Cold_h = 0
    Flux_PN06_Balo_Laud_h = (Flux_PN07_Laud_Cold_h + Flux_PD30_Laud_Elot_h + Flux_PD31_Laud_Sbor_h)
    Flux_PN05_Dunf_Balo_h = (Flux_PN06_Balo_Laud_h + Flux_PD27_Balo_Wlot_h + Flux_PD28_Balo_Edin_h + Flux_PD29_Balo_Mlot_h)
    Flux_PN04_Glen_Dunf_h = (Flux_PN05_Dunf_Balo_h + Flux_PD26_Dunf_Fife_h)
    Flux_PN03_Kiri_Glen_h = (Flux_PN04_Glen_Dunf_h + Flux_PD25_Glen_Pkin_h + Flux_PD24_Glen_Dund_h)
    Flux_PN02_Petc_Kiri_h = (Flux_PN03_Kiri_Glen_h + Flux_PD23_Kiri_Angs_h)
    Flux_PN01_Petc_Foch_h = (Flux_PD21_Foch_Mory_h + Flux_PD22_Foch_High_h)
    Flux_PN00_Sfeg_Petc_h = (Flux_PN01_Petc_Foch_h + Flux_PN02_Petc_Kiri_h + Flux_PD19_Petc_Abdn_h + Flux_PD20_Petc_Absh_h)

    # Append Flux array
    # Network pipes
    Flux_PN00_Sfeg_Petc.append(Flux_PN00_Sfeg_Petc_h)
    Flux_PN01_Petc_Foch.append(Flux_PN01_Petc_Foch_h + Flux_PN02_Petc_Kiri_h)
    Flux_PN02_Petc_Kiri.append(Flux_PN02_Petc_Kiri_h)
    Flux_PN03_Kiri_Glen.append(Flux_PN03_Kiri_Glen_h)
    Flux_PN04_Glen_Dunf.append(Flux_PN04_Glen_Dunf_h)
    Flux_PN05_Dunf_Balo.append(Flux_PN05_Dunf_Balo_h)
    Flux_PN06_Balo_Laud.append(Flux_PN06_Balo_Laud_h)
    #Flux_PN07_Laud_Cold.append(Flux_PN07_Laud_Cold_h)

    # Demand pipes
    Flux_PD19_Petc_Abdn.append(Flux_PD19_Petc_Abdn_h)
    Flux_PD20_Petc_Absh.append(Flux_PD20_Petc_Absh_h)
    Flux_PD21_Foch_Mory.append(Flux_PD21_Foch_Mory_h)
    Flux_PD22_Foch_High.append(Flux_PD22_Foch_High_h)
Flux_PD23_Kiri_Angs.append(Flux_PD23_Kiri_Angs_h)
Flux_PD24_Glen_Dund.append(Flux_PD24_Glen_Dund_h)
Flux_PD25_Glen_Pkin.append(Flux_PD25_Glen_Pkin_h)
Flux_PD26_Dunf_Fife.append(Flux_PD26_Dunf_Fife_h)
Flux_PD27_Balo_Wlot.append(Flux_PD27_Balo_Wlot_h)
Flux_PD28_Balo_Edin.append(Flux_PD28_Balo_Edin_h)
Flux_PD29_Balo_Mlot.append(Flux_PD29_Balo_Mlot_h)
Flux_PD30_Laud_Elot.append(Flux_PD30_Laud_Elot_h)
Flux_PD31_Laud_Sbor.append(Flux_PD31_Laud_Sbor_h)

# print flux rates
# print header for output
print("Calculated energy Flux rates for each pipe. kWh/s. Network Pipes", file = fileout)
print("{:<5} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} ",
format("Time", "PN00_Sfeg_Petc", "PN01_Petc_Foch", "PN02_Petc_Kiri", "PN03_Kiri_Glen", "PN04_Glen_Dund", "PN05_Dunf_Balo", "PN06_Balo_Laud"), file=fileout)
for h in Hours:
    print("{:5} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} ",
    format(h, Flux_PN00_Sfeg_Petc[h], Flux_PN01_Petc_Foch[h], Flux_PN02_Petc_Kiri[h], Flux_PN03_Kiri_Glen[h], Flux_PN04_Glen_Dund[h], Flux_PN05_Dunf_Balo[h], Flux_PN06_Balo_Laud[h]), file=fileout)
print('', file=fileout)

print("Calculated energy Flux rates for each pipe. kWh/s. Demand Pipes", file = fileout)
print("{:<5} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} ",
# print('', file=fileout)
for h in Hours:
    print("{:5} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} ",
    format(h, Flux_PD19_Petc_Abdn[h], Flux_PD20_Petc_Absh[h], Flux_PD21_Foch_Mory[h], Flux_PD22_Foch_Balo[h], Flux_PD23_Kiri_Angs[h], Flux_PD24_Glen_Dund[h], Flux_PD25_Glen_Pkin[h], Flux_PD26_Dunf_Fife[h], Flux_PD27_Balo_Wlot[h], Flux_PD28_Balo_Edin[h], Flux_PD29_Balo_Mlot[h], Flux_PD30_Laud_Elot[h], Flux_PD31_Laud_Sbor[h]), file=fileout)
print('', file=fileout)

#Calculate mass flow rates
print("Mass flow rates", file = fileout)

# Define arrays for mass flow rates
# Network pipes
Mflo_PN00_Sfeg_Petc = []
Mflo_PN01_Petc_Foch = []
Mflo_PN02_Petc_Kiri = []
Mflo_PN03_Kiri_Glen = []
Mflo_PN04_Glen_Dund = []
Mflo_PN05_Dunf_Balo = []
Mflo_PN06_Balo_Laud = []
Mflo_PN07_Laud_Cold = []
# Demand pipes
Mflo_PD19_Petc_Abdn = []
Mflo_PD20_Petc_Absh = []
Mflo_PD21_Foch_Mory = []
Mflo_PD22_Foch_Balo = []
Mflo_PD23_Kiri_Angs = []
Mflo_PD24_Glen_Dund = []
Mflo_PD25_Glen_Pkin = []
Mflo_PD26_Dunf_Fife = []
Mflo_PD27_Balo_Wlot = []
Mflo_PD28_Balo_Eedin = []
Mflo_PD29_Balo_Mlot = []
Mflo_PD30_Laud_Elot = []
Mflo_PD31_Laud_Sbor = []

# Calculate Mass flow rate in pipes (kg/hour) due to demand
# 1000 factor converts MWh to kWh
# SpecEn factor converts energy flux per hour to mass flow per hour
# Demand pipes entered first as network pipes use those as inputs - so this basically counts back up the network.
# Also Network pipes are entered in reverse order, for the same reason.

for h in Hours:
    # Demand pipes
    MFlo_PD19_Petc_Abdn_h = (Profile_ND35_Abdn[h] * 1000 / SpecEn)
    MFlo_PD20_Petc_Absh_h = (Profile_ND34_Absh[h] * 1000 / SpecEn)
    MFlo_PD21_Foch_Mory_h = (Profile_ND33_Mory[h] * 1000 / SpecEn)
    MFlo_PD22_Kiri_Angs_h = (Profile_ND32_Angs[h] * 1000 / SpecEn)
    MFlo_PD24_Glen_Dund_h = (Profile_ND31_Dund[h] * 1000 / SpecEn)
    MFlo_PD25_Glen_Pkin_h = (Profile_ND30_Pkin[h] * 1000 / SpecEn)
    MFlo_PD26_Dunf_Fife_h = (Profile_ND29_Fife[h] * 1000 / SpecEn)
    MFlo_PD27_Balo_Wlot_h = (Profile_ND28_Wlot[h] * 1000 / SpecEn)
    MFlo_PD28_Balo_Edin_h = (Profile_ND27_Edin[h] * 1000 / SpecEn)
    MFlo_PD29_Balo_Mlot_h = (Profile_ND26_Mlot[h] * 1000 / SpecEn)
    MFlo_PD30_Laud_Elot_h = (Profile_ND25_Elot[h] * 1000 / SpecEn)
    MFlo_PD31_Laud_Sbor_h = (Profile_ND24_Sbor[h] * 1000 / SpecEn)

    # Network pipes (reverse order)
    MFlo_PN07_Laud_Cold_h = 0
    MFlo_PN06_Balo_Laud_h = (MFlo_PN07_Laud_Cold_h + MFlo_PD30_Laud_Elot_h + MFlo_PD31_Laud_Sbor_h)
    MFlo_PN05_Dunf_Balo_h = (MFlo_PN06_Balo_Laud_h + MFlo_PD27_Balo_Wlot_h + MFlo_PD28_Balo_Edin_h + MFlo_PD29_Balo_Mlot_h)
    MFlo_PN04_Glen_Dunf_h = (MFlo_PN05_Dunf_Balo_h + MFlo_PD26_Dunf_Fife_h + MFlo_PD24_Glen_Dund_h)
    MFlo_PN03_Kiri_Glen_h = (MFlo_PN04_Glen_Dunf_h + MFlo_PD25_Glen_Pkin_h + MFlo_PD23_Kiri_Angs_h)
    MFlo_PN02_Petc_Kiri_h = (MFlo_PN03_Kiri_Glen_h + MFlo_PD22_Foch_High_h + MFlo_PD21_Foch_Mory_h)
    MFlo_PN01_Petc_Foch_h = (MFlo_PD20_Petc_Absh_h + MFlo_PD19_Petc_Abdn_h + MFlo_PN00_Sfeg_Petc_h)
    MFlo_PN00_Sfeg_Petc.append(MFlo_PD19_Petc_Abdn_h + MFlo_PD20_Petc_Absh_h + MFlo_PD21_Foch_Mory_h + MFlo_PD22_Foch_High_h + MFlo_PD23_Kiri_Angs_h + MFlo_PD24_Glen_Dund_h + MFlo_PD25_Glen_Pkin_h + MFlo_PD26_Dunf_Fife_h + MFlo_PD27_Balo_Wlot_h + MFlo_PD28_Balo_Edin_h + MFlo_PD29_Balo_Mlot_h + MFlo_PD30_Laud_Elot_h + MFlo_PD31_Laud_Sbor_h)

    # Append Mass flow array
    # Network pipes
    MFlo_PN00_Sfeg_Petc.append(MFlo_PN00_Sfeg_Petc_h)
    MFlo_PN01_Petc_Foch.append(MFlo_PN01_Petc_Foch_h)
    MFlo_PN02_Petc_Kiri.append(MFlo_PN02_Petc_Kiri_h)
    MFlo_PN03_Kiri_Glen.append(MFlo_PN03_Kiri_Glen_h)
    MFlo_PN04_Glen_Dunf.append(MFlo_PN04_Glen_Dunf_h)
    MFlo_PN05_Dunf_Balo.append(MFlo_PN05_Dunf_Balo_h)
    MFlo_PN06_Balo_Laud.append(MFlo_PN06_Balo_Laud_h)
    MFlo_PN07_Laud_Cold.append(MFlo_PN07_Laud_Cold_h)

    # Demand pipes
    MFlo_PD19_Petc_Abdn.append(MFlo_PD19_Petc_Abdn_h)
    MFlo_PD20_Petc_Absh.append(MFlo_PD20_Petc_Absh_h)
    MFlo_PD21_Foch_Mory.append(MFlo_PD21_Foch_Mory_h)
    MFlo_PD22_Foch_High.append(MFlo_PD22_Foch_High_h)
    MFlo_PD23_Kiri_Angs.append(MFlo_PD23_Kiri_Angs_h)
    MFlo_PD24_Glen_Dund.append(MFlo_PD24_Glen_Dund_h)
    MFlo_PD25_Glen_Pkin.append(MFlo_PD25_Glen_Pkin_h)
    MFlo_PD26_Dunf_Fife.append(MFlo_PD26_Dunf_Fife_h)
    MFlo_PD27_Balo_Wlot.append(MFlo_PD27_Balo_Wlot_h)
    MFlo_PD28_Balo_Edin.append(MFlo_PD28_Balo_Eedin_h)
    MFlo_PD29_Balo_Mlot.append(MFlo_PD29_Balo_Mlot_h)
    MFlo_PD30_Laud_Elot.append(MFlo_PD30_Laud_Elot_h)
    MFlo_PD31_Laud_Sbor.append(MFlo_PD31_Laud_Sbor_h)

    # print mass flow rates
    # print header for output
    print("Calculated mass flow rates for each pipe. kg/hr.  Network Pipes", file = fileout)
    print("{:<5} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} ",
        format("Time", "PN00_Sfrg_Petc", "PN01_Petc_Foch", "PN02_Petc_Kiri", "PN03_Kiri_Glen", "PN04_Glen_Dunf", "PN05_Dunf_Balo", "PN06_Balo_Laud"), file=fileout)
    # print(\n    #   "", file=fileout)
    for h in Hours:
        print("{:<5} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} ",
            format(h, round(MFlo_PN00_Sfeg_Petc[h]), round(MFlo_PN01_Petc_Foch[h]), round(MFlo_PN02_Petc_Kiri[h]), round(MFlo_PN03_Kiri_Glen[h]), round(MFlo_PN04_Glen_Dunf[h]), round(MFlo_PN05_Dunf_Balo[h]), round(MFlo_PN06_Balo_Laud[h])), file=fileout)
        print("", file=fileout)
print("Calculated mass flow rates for each pipe. kg/hr. Demand Pipes", file = fileout)
print(" Time           PD19_Petc_Abdn            PD20_Petc_Absh            PD21_Foch_Mory            PD22_Foch_High            PD23_Kiri_Angs            PD24_Glen_Dund            PD25_Glen_Pkin            PD26_Dunf_Fife            PD27_Balo_Wlot            PD28_Balo_Edin            PD29_Balo_Mlot            PD30_Laud_Elot            PD31_Laud_Sbor")
for h in Hours:
  print(" Time           PD19_Petc_Abdn            PD20_Petc_Absh            PD21_Foch_Mory            PD22_Foch_High            PD23_Kiri_Angs            PD24_Glen_Dund            PD25_Glen_Pkin            PD26_Dunf_Fife            PD27_Balo_Wlot            PD28_Balo_Edin            PD29_Balo_Mlot            PD30_Laud_Elot            PD31_Laud_Sbor")
print(" ------Section 4. Calculate Pressures ---------", file=fileout)

# Pressure drops - Network
PresDrop_PN00_Sfeg_Petc = []
PresDrop_PN01_Petc_Foch = []
PresDrop_PN02_Petc_Kiri = []
PresDrop_PN03_Kiri_Glen = []
PresDrop_PN04_Glen_Dunf = []
PresDrop_PN05_Dunf_Balo = []
PresDrop_PN06_Balo_Laud = []
PresDrop_PN07_Laud_Cold = []

# Pressure drops - Demand
PresDrop_PD19_Petc_Abdn = []
PresDrop_PD20_Petc_Absh = []
PresDrop_PD21_Foch_Mory = []
PresDrop_PD22_Foch_High = []
PresDrop_PD23_Kiri_Angs = []
PresDrop_PD24_Glen_Dund = []
PresDrop_PD25_Glen_Pkin = []
PresDrop_PD26_Dunf_Fife = []
PresDrop_PD27_Balo_Wlot = []
PresDrop_PD28_Balo_Edin = []
PresDrop_PD29_Balo_Mlot = []
PresDrop_PD30_Laud_Elot = []
PresDrop_PD31_Laud_Sbor = []

# ----------------- Buzzelli (2008) & Darcy-Weisbach Calculations - define PressureDrop function ---------------- #

def PressureDrop(D, Qe, ks, L, Pup, props, name, h, minpress):
  # Carries out calculation from upstream pressure down to zero downstream pressure, until input pressure drop (Pdrop) = calculated Pdrop (PdropC)
  # tests for upstream pressure. If zero or negative, returns error. Otherwise continues calculation.
  NoPup = 0  # Sets up error counter for zero or negative upstream pressure
  noconverge = 0  # Sets up error counter for non-converging iterations
  zerodrop = 0  # Sets up error counter for zero pressure drop, ie zero flow
  lowpressure = 0  # Sets up error counter for inadequate upstream pressure for flow demanded.
  Max available flow is returned

  if Pup <= 0:
print("Timestep",h, name, "Upstream pressure zero or negative. No calculations. Pdrop, Vel, rho, mu, linepack all set to zero.", file = fileout)
Pdrop = 0
Pdown = Pup
Vel = 0
Rho = 0
Mu = 0
Linepack = 0
NoPup = 1
QMcalc = 0
else:
Pdrop1 = 1  # kPa  # initial guess of Pressure drop for iterative calculation
count = 1
maxcount = 200  # Limits number of iterations
while count <= maxcount:
    # iteration counter
    Pdown = Pup - Pdrop1  #kPa
    Pav = round((Pup + Pdown)/20)*10  #kPa
    if Pav<=9000 and Pav >= 10:
        rho = props[Pav][0]  # kg/m3
        mu = props[Pav][1]/1000000  #Pa-s
    elif Pav > 9000:
        rho = props[9000][0]  #kg/m3
        mu = props[9000][1]/1000000  #Pa-s
    else:  # ie Pav>0 and <10 - use values for 10.
        rho = props[10][0]  #kg/m3
        mu = props[10][1]/1000000  #Pa-s
    # Calculates flow velocity, V
    V = Qe/(SpecEn*rho*(pi*D**2)/4)   # V (m/s) = Energy flux (kWh/s) / [Specific energy (kWh/kg) x Density (kg/m3) x Pipe Area (m2)]
    # Calculates Reynolds Number, Re.  Re = D*V*rho/mu  # m * m/s * kg/m3 / (kg/m/s) = dimless
    # Calculates Buzzelli component B1.  B1 = (0.774*ln(Re)-1.41) / (1+1.32.sqrt(ks/D))
    B1 = (0.774*cmath.log(Re) - 1.41) / (1 + 1.32 * ((ks/1000)/D)**0.5)
    B2 = (ks/1000)*Re/((3.7*D) + 2.51*B1)
    # Calculates pressure drop according to Darcy-Weisbach formula.  Pdrop = L*fD*rho*V**2/(2*D)
    Pdrop = (L*fD*rho*V**2/(2*D))/1000  # Factor of 1/1000 converts result in Pa to kPa
    QMcalc = rho * V * (pi*(D**2)/4) * 3600
    print("Timestep ",h, "Iteration ",count, ",name, ":
D",D,"m.  V",round(V,3),"m/s.  ks",round(ks,7),"mm.  Rho ",round(rho,4),"kg/m3.  mu ",
round(mu,7),"Pa-t.  Pup ",round(Pup,2)," kPa.  Pdrop1(input) ","round(Pdrop1,2), ",
kJPa.  Pdrop2 (output) ","round(Pdrop2,2),"kPa. ", file=fileout)
print("Timestep ",h, "Iteration ",count, ",name, ": Re: ",round(Re), ", B1: ",round(B1,2),", B2: ",round(B2,2),", Fd: ",round(Fd,5),"Qe",round(Qe,2),
"SpecEn",round(SpecEn,2),"kWh/kg.  L",round(L),"m.  rho",rho,"kg/m3.
Qm",QMcalc,"kg/hour", file=fileout)
print("",file = fileout)
else:
    Pdrop2 = (Pup-minpress):
negative pressure after ", count, "iterations. Downstream pressure set to minimum allowable for pipe type (network or demand). Restricted downstream flow calculated.",
file=fileout)  # Inadequate pressure error. Impossible to push all the gas demanded down the pipe with the pressure available. Computes the flow available.
# Calculate available flow for Pdrop = Pup-minpress and Pdown = minpress.
# Break.
cnt = 1
maxcnt = 200
Pdrop = Pup    # kPa
Pdown = minpress    # kPa
Pav = round(((Pup+Pdown)/20)*10 # kPa. Function rounds result to nearest 10kPa
rho = props[Pav][0]    # kg/m3
mu = props[Pav][1]/1000000    # Pa.s or kg/m.s
Vcalc1 = 1    # m/s
while cnt < maxcnt:  # NB Inadequate pressure output calculator
    Re = (D)*Vcalc1*rho/mu  # dimless
    B1 = (0.774*math.log(Re) - 1.41) / (1 + 1.32*((ks/1000)/D)**0.5)  # dimless
    B2 = (ks/1000)*Re/(3.7*D) + 2.51*B1  # dimless
    fD = ( B1 - ( (B1 + 2*math.log10(B2/Re)) / (1 + 2.18/B2) ) )**-2  # IDPK
    Vcalc2 = ((2*D*(Pdrop*1000)) / (L*fD*rho))**0.5  # m/s
    if Vcalc2 <= Vcalc1 * 1.001 and Vcalc2 >= 0.999 * Vcalc1:
        # Accept calculated Vcalc2 if within 0.1% of Vcalc1.
Pdrop = Pup - minpress  # kPa
Pdown = minpress  # kPa
Vel = Vcalc2  # m/s
Rho = rho  # kg/m3
Mu = mu  # Pa.s
lowpressure = 1  # NB Inadequate pressure counter
QMcac = rho * Vel * (pi*(D**2)/4) * 3600  # Calculates actual mass flow
Linepack = rho * (pi*(D**2)/4) * L  # Calculates mass of gas contained in pipe length. Density * Area * Length
print("B1: ",round(B1,2),"  B2: ",round(B2,2),"  fD: ",round(fD,4),"]
print("Velocity: ",round(Vel,3)," m/s. Mass flow: ",QMcac,"kg/hour. Linepack: ",round(Linepack),"kg. Not resolved, restricted flow = ",round(Vel * D**2*pi*0.25 * Rho * 3600)," kg/hr", file=fileout)
break
if cnt == maxcnt:  # NB Inadequate pressure output calculator
    print("restricted flow did not converge after ", cnt, ", iterations. Downstream pressure and flow set to zero.",file=fileout)
break
if V == 0:
    # Zero flow error.
    # No calculations.
    # Break.
print("Zero pressure drop", file = fileout)
print("", file=fileout)
Pdrop = 0
Pdown = Pup
Vel = 0
Rho = rho
Mu = mu
QMcalc = 0
Linepack = 0
zerodrop = 1
break

if count == maxcount:
  # Did Not Converge error.
  # No calculations.
  # Break.
  print("did not converge after ", count, "iterations. Pressure drop and flow set to zero",file=fileout)
  print("",file=fileout)
Pdrop = Pup
Pdown = 0
Vel = 0
Rho = rho
Mu = mu
QMcalc = 0
Linepack = 0
noconverge = 1
break

# If output and input Pdrops are close enough, accept result and stop iterating.
if Pdrop2 <= Pdrop1 * 1.001 and Pdrop2 >= 0.999 * Pdrop1:
  Pdrop = Pdrop2
  Pdown = Pup - Pdrop
  Vel = V
  Rho = rho
  Mu = mu
  QMcalc = rho * Vel * (pi*(D**2)/4) * 3600
  Linepack = rho * (pi*(D**2)/4) * L  # Calculates mass of gas contained in pipe length. Density * Area * Length
  print("Final: Pipe: ",name,  h,"| Pup: ",round(Pup,2)," Pdrop: ",
        file=fileout)

  print("Final: Pipe: ",name,  h,"| B1: ",round(B1,2)," B2: ",round(B2,2)," fD: ",
        round(fd,4),"| Velocity: ",round(Vel,3)," m/s. Linepack: ",\n        round(Linepack,2)," kg. Resolved at ",count," iterations.", file=fileout)

  print("",file=fileout)
  print("",file=fileout)
  break

# Iterate calculation.
# Find new Pdrop to evaluate. Next iteration to try is 1/10 of average of Pdrop1 and Pdrop2 past Pdrop1.
  # This resulted in a quicker computation time than the simple average.
Pdrop1 = Pdrop1 + (Pdrop2 - Pdrop1)/10  # kPa

# Return outputs from calculation
return(Pdrop, Pdown, Vel, Rho, Mu, noconverge, zerodrop, lowpressure, NoPup, Linepack, QMcalc)

#-------- Calculate Pressure drop in pipes using Buzzelli & Darcy-Weisbach equations [using PressureDrop function above] -------##
# Set up input parameters:
(D,Qe,ks,l,props,name,h)
# Call function "PressureDrop" to calculate Pressure Drop for each set of inputs

NoCon = 0  # error check - counts total pipes with no convergence. For valid results, must equal zero.
ZeroD = 0  # error check - counts total pipes with no pressure drop. For valid results, must equal zero.
LowPress = 0  # error check - counts pipes with inadequate upstream pressure. For valid results must = 0.
ZeroPup = 0  # error check - counts pipes with zero or negative pressure upstream.
Lpacknet = []  # Sum of linepack in network pipes (kg)
Lpackdem = []  # Sum of linepack in demand pipes (kg)
Lpacktot = []  # Total linepack (kg)

for h in Hours:
    print("", file=fileout)
    print("timestep start: ", h, file=fileout)
    # Network
    PresDrop_PN00_Sfeg_Petc_h = PressureDrop(Param_PN00_Sfeg_Petc[0], Flux_PN00_Sfeg_Petc[h], Param_PN00_Sfeg_Petc[1], Len_PN00_Sfeg_Petc, InPres_NS00_Sfeg, properties, "PN00_Sfeg_Petc",h,)
    PresDrop_PN00_Sfeg_Petc.append(PresDrop_PN00_Sfeg_Petc_h)  
    NoCon = NoCon + PresDrop_PN00_Sfeg_Petc_h[5]
    ZeroD = ZeroD + PresDrop_PN00_Sfeg_Petc_h[6]
    LowPress = LowPress + PresDrop_PN00_Sfeg_Petc_h[7]
    ZeroPup = ZeroPup + PresDrop_PN00_Sfeg_Petc_h[8]
    Lpacknet[h] = Lpacknet[h] + PresDrop_PN00_Sfeg_Petc_h[9]  
    # print("Lpacknet[",h,"]: ",Lpacknet[h])  
    PresDrop_PN01_Petc_Foch_h = PressureDrop(Param_PN01_Petc_Foch[0], Flux_PN01_Petc_Foch[h], Param_PN01_Petc_Foch[1], Len_PN01_Petc_Foch, PresDrop_PN00_Sfeg_Petc[h][1], properties, "PN01_Petc_Foch",h,)
    PresDrop_PN01_Petc_Foch.append(PresDrop_PN01_Petc_Foch_h)  
    NoCon = NoCon + PresDrop_PN01_Petc_Foch_h[5]
    ZeroD = ZeroD + PresDrop_PN01_Petc_Foch_h[6]
    LowPress = LowPress + PresDrop_PN01_Petc_Foch_h[7]
    ZeroPup = ZeroPup + PresDrop_PN01_Petc_Foch_h[8]
    Lpacknet[h] = Lpacknet[h] + PresDrop_PN01_Petc_Foch_h[9]  
    # print("Lpacknet[",h,"]: ",Lpacknet[h])  
    PresDrop_PN02_Petc_Kiri_h = PressureDrop(Param_PN02_Petc_Kiri[0], Flux_PN02_Petc_Kiri[h], Param_PN02_Petc_Kiri[1], Len_PN02_Petc_Kiri, PresDrop_PN01_Petc_Foch[h][1], properties, "PN02_Petc_Kiri",h,)
    PresDrop_PN02_Petc_Kiri.append(PresDrop_PN02_Petc_Kiri_h)  
    NoCon = NoCon + PresDrop_PN02_Petc_Kiri_h[5]
    ZeroD = ZeroD + PresDrop_PN02_Petc_Kiri_h[6]
    LowPress = LowPress + PresDrop_PN02_Petc_Kiri_h[7]
    ZeroPup = ZeroPup + PresDrop_PN02_Petc_Kiri_h[8]
    Lpacknet[h] = Lpacknet[h] + PresDrop_PN02_Petc_Kiri_h[9]  
    # print("Lpacknet[",h,"]: ",Lpacknet[h])  
    PresDrop_PN03_Kiri_Glen_h = PressureDrop(Param_PN03_Kiri_Glen[0], Flux_PN03_Kiri_Glen[h], Param_PN03_Kiri_Glen[1], Len_PN03_Kiri_Glen, PresDrop_PN02_Petc_Kiri[h][1], properties, "PN03_Kiri_Glen",h,)
    PresDrop_PN03_Kiri_Glen.append(PresDrop_PN03_Kiri_Glen_h)  
    NoCon = NoCon + PresDrop_PN03_Kiri_Glen_h[5]
    ZeroD = ZeroD + PresDrop_PN03_Kiri_Glen_h[6]
    LowPress = LowPress + PresDrop_PN03_Kiri_Glen_h[7]
    ZeroPup = ZeroPup + PresDrop_PN03_Kiri_Glen_h[8]
    Lpacknet[h] = Lpacknet[h] + PresDrop_PN03_Kiri_Glen_h[9]  
    # print("Lpacknet[",h,"]: ",Lpacknet[h])  
    PresDrop_PN04_Glen_Dunf_h = PressureDrop(Param_PN04_Glen_Dunf[0], Flux_PN04_Glen_Dunf[h], Param_PN04_Glen_Dunf[1], Len_PN04_Glen_Dunf, PresDrop_PN03_Kiri_Glen[h][1], properties, "PN04_Glen_Dunf",h,)
    PresDrop_PN04_Glen_Dunf.append(PresDrop_PN04_Glen_Dunf_h)
NoCon = NoCon + PresDrop_PN04_Glen_Dunf_h[5]
LowPress = LowPress + PresDrop_PN04_Glen_Dunf_h[7]
ZeroPup = ZeroPup + PresDrop_PN04_Glen_Dunf_h[8]
Lpacknet[h] = Lpacknet[h] + PresDrop_PN04_Glen_Dunf_h[9]
# print("Lpacknet","h": ",Lpacknet[h])

PresDrop_PN05_Dunf_Balo_h = PressureDrop(Param_PN05_Dunf_Balo[0], Flux_PN05_Dunf_Balo[h],
Param_PN05_Dunf_Balo[1], Len_PN05_Dunf_Balo, \ PresDrop_PN04_Glen_Dunf[h][1], properties,
"PN05_Dunf_Balo",h, Param_PN05_Dunf_Balo[2])
PresDrop_PN05_Dunf_Balo.append(PresDrop_PN05_Dunf_Balo_h)
NoCon = NoCon + PresDrop_PN05_Dunf_Balo_h[5]
ZeroD = ZeroD + PresDrop_PN05_Dunf_Balo_h[6]
LowPress = LowPress + PresDrop_PN05_Dunf_Balo_h[7]
ZeroPup = ZeroPup + PresDrop_PN05_Dunf_Balo_h[8]
Lpacknet[h] = Lpacknet[h] + PresDrop_PN05_Dunf_Balo_h[9]
# print("Lpacknet","h": ",Lpacknet[h])

PresDrop_PN06_Balo_Laud_h = PressureDrop(Param_PN06_Balo_Laud[0], Flux_PN06_Balo_Laud[h],
Param_PN06_Balo_Laud[1], Len_PN06_Balo_Laud, \ PresDrop_PN05_Dunf_Balo[h][1], properties,
"PN06_Balo_Laud",h, Param_PN06_Balo_Laud[2])
PresDrop_PN06_Balo_Laud.append(PresDrop_PN06_Balo_Laud_h)
NoCon = NoCon + PresDrop_PN06_Balo_Laud_h[5]
ZeroD = ZeroD + PresDrop_PN06_Balo_Laud_h[6]
LowPress = LowPress + PresDrop_PN06_Balo_Laud_h[7]
ZeroPup = ZeroPup + PresDrop_PN06_Balo_Laud_h[8]
Lpackdem.append(PresDrop_PN06_Balo_Laud_h[9])
# print("Lpackdem","h": ",Lpackdem[h])

##--- Demand pipes ---##  NB upstream pressure set to a maximum of 700 kPa

PresDrop_PD19_Petc_Abdn_h = PressureDrop(Param_PD19_Petc_Abdn[0], Flux_PD19_Petc_Abdn[h],
Param_PD19_Petc_Abdn[1], Len_PD19_Petc_Abdn, \ min(PresDrop_PN00_Sfeg_Petc[h][1],700), properties,
"PD19_Petc_Abdn",h, Param_PD19_Petc_Abdn[2])
PresDrop_PD19_Petc_Abdn.append(PresDrop_PD19_Petc_Abdn_h)
NoCon = NoCon + PresDrop_PD19_Petc_Abdn_h[5]
ZeroD = ZeroD + PresDrop_PD19_Petc_Abdn_h[6]
LowPress = LowPress + PresDrop_PD19_Petc_Abdn_h[7]
ZeroPup = ZeroPup + PresDrop_PD19_Petc_Abdn_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD19_Petc_Abdn_h[9]
# print("Lpackdem","h": ",Lpackdem[h])

PresDrop_PD20_Petc_Absh_h = PressureDrop(Param_PD20_Petc_Absh[0], Flux_PD20_Petc_Absh[h],
Param_PD20_Petc_Absh[1], Len_PD20_Petc_Absh, \ min(PresDrop_PN00_Sfeg_Petc[h][1],700), properties,
"PD20_Petc_Absh",h, Param_PD20_Petc_Absh[2])
PresDrop_PD20_Petc_Absh.append(PresDrop_PD20_Petc_Absh_h)
NoCon = NoCon + PresDrop_PD20_Petc_Absh_h[5]
ZeroD = ZeroD + PresDrop_PD20_Petc_Absh_h[6]
LowPress = LowPress + PresDrop_PD20_Petc_Absh_h[7]
ZeroPup = ZeroPup + PresDrop_PD20_Petc_Absh_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD20_Petc_Absh_h[9]
# print("Lpackdem","h": ",Lpackdem[h])

PresDrop_PD21_Foch_Mory_h = PressureDrop(Param_PD21_Foch_Mory[0], Flux_PD21_Foch_Mory[h],
Param_PD21_Foch_Mory[1], Len_PD21_Foch_Mory, \ min(PresDrop_PN01_Petc_Foch[h][1],700), properties,
"PD21_Foch_Mory",h, Param_PD21_Foch_Mory[2])
PresDrop_PD21_Foch_Mory.append(PresDrop_PD21_Foch_Mory_h)
NoCon = NoCon + PresDrop_PD21_Foch_Mory_h[5]
ZeroPup = ZeroPup + PresDrop_PD21_Foch_Mory_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD21_Foch_Mory_h[9]
# print("Lpackdem","h": ",Lpackdem[h])

PresDrop_PD22_Foch_High_h = PressureDrop(Param_PD22_Foch_High[0], Flux_PD22_Foch_High[h],
Param_PD22_Foch_High[1], Len_PD22_Foch_High, \ min(PresDrop_PN01_Petc_Foch[h][1],700), properties,
"PD22_Foch_High",h, Param_PD22_Foch_High[2])
PresDrop_PD22_Foch_High.append(PresDrop_PD22_Foch_High_h)
NoCon = NoCon + PresDrop_PD22_Foch_High_h[5]
ZeroD = ZeroD + PresDrop_PD22_Foch_High_h[6]
LowPress = LowPress + PresDrop_PD22_Foch_High_h[7]
ZeroPup = ZeroPup + PresDrop_PD22_Foch_High_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD22_Foch_High_h[9]

# print("Lpackdem[",h,"]": Lpackdem[h])

PresDrop_PD23_Kiri_Angs_h = PressureDrop(Param_PD23_Kiri_Angs[0], Flux_PD23_Kiri_Angs[h], Param_PD23_Kiri_Angs[1], Len_PD23_Kiri_Angs, \nmin(PresDrop_PN02_Petc_Kiri[h][1], 700), properties, "PD23_Kiri_Angs", h, Param_PD23_Kiri_Angs[2])
PresDrop_PD23_Kiri_Angs.append(PresDrop_PD23_Kiri_Angs_h)
NoCon = NoCon + PresDrop_PD23_Kiri_Angs_h[5]
ZeroD = ZeroD + PresDrop_PD23_Kiri_Angs_h[6]
LowPress = LowPress + PresDrop_PD23_Kiri_Angs_h[7]
ZeroPup = ZeroPup + PresDrop_PD23_Kiri_Angs_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD23_Kiri_Angs_h[9]
# print("Lpackdem[",h,"]": Lpackdem[h])

PresDrop_PD24_Glen_Dund_h = PressureDrop(Param_PD24_Glen_Dund[0], Flux_PD24_Glen_Dund[h], Param_PD24_Glen_Dund[1], Len_PD24_Glen_Dund, \nmin(PresDrop_PN03_Kiri_Glen[h][1], 700), properties, "PD24_Glen_Dund", h, Param_PD24_Glen_Dund[2])
PresDrop_PD24_Glen_Dund.append(PresDrop_PD24_Glen_Dund_h)
NoCon = NoCon + PresDrop_PD24_Glen_Dund_h[5]
ZeroPup = ZeroPup + PresDrop_PD24_Glen_Dund_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD24_Glen_Dund_h[9]
# print("Lpackdem[",h,"]": Lpackdem[h])

PresDrop_PD25_Glen_Pkin_h = PressureDrop(Param_PD25_Glen_Pkin[0], Flux_PD25_Glen_Pkin[h], Param_PD25_Glen_Pkin[1], Len_PD25_Glen_Pkin, \nmin(PresDrop_PN04_Glen_Dunf[h][1], 700), properties, "PD25_Glen_Pkin", h, Param_PD25_Glen_Pkin[2])
PresDrop_PD25_Glen_Pkin.append(PresDrop_PD25_Glen_Pkin_h)
NoCon = NoCon + PresDrop_PD25_Glen_Pkin_h[5]
ZeroPup = ZeroPup + PresDrop_PD25_Glen_Pkin_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD25_Glen_Pkin_h[9]
# print("Lpackdem[",h,"]": Lpackdem[h])

PresDrop_PD26_Dunf_Fife_h = PressureDrop(Param_PD26_Dunf_Fife[0], Flux_PD26_Dunf_Fife[h], Param_PD26_Dunf_Fife[1], Len_PD26_Dunf_Fife, \nmin(PresDrop_PN05_Dunf_Balo[h][1], 700), properties, "PD26_Dunf_Fife", h, Param_PD26_Dunf_Fife[2])
PresDrop_PD26_Dunf_Fife.append(PresDrop_PD26_Dunf_Fife_h)
NoCon = NoCon + PresDrop_PD26_Dunf_Fife_h[5]
LowPress = LowPress + PresDrop_PD26_Dunf_Fife_h[7]
ZeroPup = ZeroPup + PresDrop_PD26_Dunf_Fife_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD26_Dunf_Fife_h[9]
# print("Lpackdem[",h,"]": Lpackdem[h])

PresDrop_PD27_Balo_Wlot_h = PressureDrop(Param_PD27_Balo_Wlot[0], Flux_PD27_Balo_Wlot[h], Param_PD27_Balo_Wlot[1], Len_PD27_Balo_Wlot, \nmin(PresDrop_PN05_Dunf_Balo[h][1], 700), properties, "PD27_Balo_Wlot", h, Param_PD27_Balo_Wlot[2])
PresDrop_PD27_Balo_Wlot.append(PresDrop_PD27_Balo_Wlot_h)
NoCon = NoCon + PresDrop_PD27_Balo_Wlot_h[5]
ZeroD = ZeroD + PresDrop_PD27_Balo_Wlot_h[6]
LowPress = LowPress + PresDrop_PD27_Balo_Wlot_h[7]
ZeroPup = ZeroPup + PresDrop_PD27_Balo_Wlot_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD27_Balo_Wlot_h[9]
# print("Lpackdem[",h,"]": Lpackdem[h])

PresDrop_PD28_Balo_Edin_h = PressureDrop(Param_PD28_Balo_Edin[0], Flux_PD28_Balo_Edin[h], Param_PD28_Balo_Edin[1], Len_PD28_Balo_Edin, \nmin(PresDrop_PN05_Dunf_Balo[h][1], 700), properties, "PD28_Balo_Edin", h, Param_PD28_Balo_Edin[2])
PresDrop_PD28_Balo_Edin.append(PresDrop_PD28_Balo_Edin_h)
NoCon = NoCon + PresDrop_PD28_Balo_Edin_h[5]

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LowPress = LowPress + PresDrop_PD28_Balo_Edin_h[7]
ZeroPup = ZeroPup + PresDrop_PD28_Balo_Edin_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD28_Balo_Edin_h[9]

# print("Lpackdem[",h, "]: ",Lpackdem[h])

PresDrop_PD29_Balo_Mlot_h = PressureDrop(Param_PD29_Balo_Mlot[0], Flux_PD29_Balo_Mlot[h],
Param_PD29_Balo_Mlot[1], Len_PD29_Balo_Mlot, \min(PresDrop_PN05_Dunf_Balo[h][1],700), properties,
"PD29_Balo_Mlot",h, Param_PD29_Balo_Mlot[2])
PresDrop_PD29_Balo_Mlot.append(PresDrop_PD29_Balo_Mlot_h)
NoCon = NoCon + PresDrop_PD29_Balo_Mlot_h[5]
ZeroD = ZeroD + PresDrop_PD29_Balo_Mlot_h[6]
LowPress = LowPress + PresDrop_PD29_Balo_Mlot_h[7]
ZeroPup = ZeroPup + PresDrop_PD29_Balo_Mlot_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD29_Balo_Mlot_h[9]
# print("Lpackdem[",h, "]: ",Lpackdem[h])

PresDrop_PD30_Laud_Elot_h = PressureDrop(Param_PD30_Laud_Elot[0], Flux_PD30_Laud_Elot[h],
Param_PD30_Laud_Elot[1], Len_PD30_Laud_Elot, \min(PresDrop_PN06_Balo_Laud[h][1],700), properties,
"PD30_Laud_Elot",h, Param_PD30_Laud_Elot[2])
PresDrop_PD30_Laud_Elot.append(PresDrop_PD30_Laud_Elot_h)
NoCon = NoCon + PresDrop_PD30_Laud_Elot_h[5]
ZeroD = ZeroD + PresDrop_PD30_Laud_Elot_h[6]
LowPress = LowPress + PresDrop_PD30_Laud_Elot_h[7]
ZeroPup = ZeroPup + PresDrop_PD30_Laud_Elot_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD30_Laud_Elot_h[9]
# print("Lpackdem[",h, "]: ",Lpackdem[h])

PresDrop_PD31_Laud_Sbor_h = PressureDrop(Param_PD31_Laud_Sbor[0], Flux_PD31_Laud_Sbor[h],
Param_PD31_Laud_Sbor[1], Len_PD31_Laud_Sbor, \min(PresDrop_PN06_Balo_Laud[h][1],700), properties,
"PD31_Laud_Sbor",h, Param_PD31_Laud_Sbor[2])
PresDrop_PD31_Laud_Sbor.append(PresDrop_PD31_Laud_Sbor_h)
NoCon = NoCon + PresDrop_PD31_Laud_Sbor_h[5]
ZeroD = ZeroD + PresDrop_PD31_Laud_Sbor_h[6]
LowPress = LowPress + PresDrop_PD31_Laud_Sbor_h[7]
ZeroPup = ZeroPup + PresDrop_PD31_Laud_Sbor_h[8]
Lpackdem[h] = Lpackdem[h] + PresDrop_PD31_Laud_Sbor_h[9]
# print("Lpackdem[",h, "]: ",Lpackdem[h])

Lpacktot.append(Lpacknet[h] + Lpackdem[h])

# Print noconverge and zerodrop error checks
print("".file=fileout)
print("Non-converging pipe count: ",NoCon,file=fileout)
print("Zero drop pipe count: ",ZeroD,file=fileout)
print("Low pressure pipe count: ",LowPress,file = fileout)
print("zero pressure upstream: ", ZeroPup, file = fileout)

# Print Pressure drop output table, network pipes
print("".file=fileout)
print("Pressure drop table - network pipes (kPa)", file = fileout)
print("Time", "PN00_Sfeg_Petc", "PN01_Petc_Foch", "PN02_Petc_Kiri", "PN03_Kiri_Glen",
"PN04_Glen_Dunf", "PN05_Dunf_Balo", "PN06_Balo_Laud", ).file=fileout)

# print("",file=fileout)

for h in Hours:
    print("".file=fileout)
    print("Time", "PN00_Sfeg_Petc", "PN01_Petc_Foch", "PN02_Petc_Kiri", "PN03_Kiri_Glen",
"PN04_Glen_Dunf", "PN05_Dunf_Balo", "PN06_Balo_Laud", ).file=fileout)

# Print Pressure drop output table, demand pipes
print("".file=fileout)
print("Pressure drop table - demand pipes (Pa)", file = fileout)
print("".file=fileout)

# Print Pressure drop output table, network pipes
print("".file=fileout)
print("Pressure drop table - network pipes (kPa)", file = fileout)
print("".file=fileout)

for h in Hours:
    print("".file=fileout)
    print("Time", "PD19_Petc_Abdn", "PD20_Petc_Absh", "PD21_Foch_Mory", "PD22_Foch_High",
"PD27_Balo_Wlot", "PD28_Balo_Edin", "PD29_Balo_Mlot", "PD30_Laud_Elot",
"PD31_Laud_Sbor").file=fileout)
    print("",file=fileout)
for h in Hours:
    print("{:5} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} {:<14} "
    format(h, round(PresDrop_PN01_Petc_Abdn[h][0]), round(PresDrop_PN02_Petc_Absh[h][0]),
    round(PresDrop_PN03_Foch_Mory[h][0]), round(PresDrop_PN04_Foch_High[h][0]),
    round(PresDrop_PN05_Kiri_Angs[h][0]), round(PresDrop_PN06_Kiri_Angs[h][0]),
    round(PresDrop_PN07_Balo_Wlot[h][0]), round(PresDrop_PN08_Balo_Edin[h][0]),
    round(PresDrop_PN09_Dunf_Balo[h][0]), round(PresDrop_PN10_Elot[h][0]),
    round(PresDrop_PN11_Laud_Elot[h][0]), round(PresDrop_PN12_Laud_Sbor[h][0])),file=fileout)

print("",file=fileout)

# Print downstream pressure at nodes
# Define output arrays
# Network nodes
Press_NS00_Sfeg=[]
Press_NN01_Petc=[]
Press_NN02_Foch=[]
Press_NN03_Kiri=[]
Press_NN04_Glen=[]
Press_NN05_Dunf=[]
Press_NN06_Balo=[]
Press_NN07_Laud=[]
#Press_NN16_Cold=[]

# Demand nodes
Press_ND26_Wlot=[]
Press_ND27_Edin=[]
Press_ND28_Mlot=[]
Press_ND29_Elot=[]
Press_ND31_Fife=[]
Press_ND32_Dund=[]
Press_ND33_Angs=[]
Press_ND34_Absh=[]
Press_ND35_Abdn=[]
Press_ND36_Mory=[]
Press_ND37_High=[]
Press_ND39_Pkin=[]
Press_ND46_Sbor=[]
for h in Hours:
    # Append to arrays
    # Network nodes
    Press_NS00_Sfeg.append(InPres_NS00_Sfeg)
    Press_NN01_Petc.append(PresDrop_PN00_Sfeg_Petc[h][1])
    Press_NN02_Foch.append(PresDrop_PN01_Petc_Foch[h][1])
    Press_NN03_Kiri.append(PresDrop_PN02_Petc_Kiri[h][1])
    Press_NN04_Glen.append(PresDrop_PN03_Kiri_Glen[h][1])
    Press_NN05_Dunf.append(PresDrop_PN04_Glen_Dunf[h][1])
    Press_NN06_Balo.append(PresDrop_PN05_Dunf_Balo[h][1])
    Press_NN07_Laud.append(PresDrop_PN06_Balo_Laud[h][1])
    #Press_NN16_Cold.append(PresDrop_PN07_Laud_Cold[h][1])

    # Demand nodes
    Press_ND26_Wlot.append(PresDrop_PD27_Balo_Wlot[h][1])
    Press_ND27_Edin.append(PresDrop_PD28_Balo_Edin[h][1])
    Press_ND28_Mlot.append(PresDrop_PD29_Balo_Mlot[h][1])
    Press_ND29_Elot.append(PresDrop_PD30_Laud_Elot[h][1])
    Press_ND31_Fife.append(PresDrop_PD26_Dunf_Fife[h][1])
    Press_ND32_Dund.append(PresDrop_PD24_Glen_Dund[h][1])
    Press_ND33_Angs.append(PresDrop_PD23_Kiri_Angs[h][1])
    Press_ND34_Absh.append(PresDrop_PD28_Petc_Absh[h][1])
    Press_ND35_Abdn.append(PresDrop_PD19_Petc_Abdn[h][1])
    Press_ND36_Mory.append(PresDrop_PD21_Foch_Mory[h][1])
    Press_ND37_High.append(PresDrop_PD22_Foch_High[h][1])
    Press_ND39_Pkin.append(PresDrop_PD25_Glen_Pkin[h][1])
    Press_ND46_Sbor.append(PresDrop_PD31_Laud_Sbor[h][1])

print("",file=fileout)
print("Table of Pressure at each node (kPa)", file=fileout)
# Print node Pressure table, network nodes
print("Node Pressure table - network nodes (kPa)", file = fileout)
For natural gas, local transmission network carries pressures from 19bar to 85bar, ie 1900 - 8500 kPa, with a minimum of 7bar."

# Print node Pressure table, demand nodes
print("Node Pressure table - demand nodes (kPa)", file = fileout)
print("Consider the demand pipes and nodes here as equivalent to IP mains.", file = fileout)
print("Consider the demand pipes and nodes here as equivalent to IP mains, so a minimum of 200kPa is required at the demand node.", file = fileout)
print("Source: SGN Pipeline Engineering Manager, 18/10/22.", file = fileout)
print("Source: SGN Pipeline Engineering Manager, 18/10/22.", file = fileout)
print("For natural gas, intermediate pressure pipes carry pressures from 2-7 bar, ie 200-700 kPa.", file = fileout)
print("For natural gas, intermediate pressure pipes carry pressures from 2-7 bar, ie 200-700 kPa.", file = fileout)
print("For natural gas, local transmission network carries pressures from 19bar to 85bar, ie 1900 - 8500 kPa, with a minimum of 7bar.", file = fileout)
Pipe velocity table - network pipes

For natural gas, allowable flow velocity = 40 m/s, though preferably below 20 m/s.

Pipe velocity table, network pipes (m/s)

Source: SGN Pipeline Engineering Manager, 18/10/22

For natural gas, allowable flow velocity = 40 m/s, though preferably below 20 m/s.
network pipes

PD19_Petc_Abdn

PN06_Balo_Laud

PN05_Dunf_Balo

PN04_Glen_Dunf

PN03_Kiri_Glen

PN02_Petc_Kiri

PN01_Petc_Foch

PN00_Sfeg_Petc

Demand pipes

PD19_Petc_Abdn

PN06_Balo_Laud

PN05_Dunf_Balo

PN04_Glen_Dunf

PN03_Kiri_Glen

PN02_Petc_Kiri

PN01_Petc_Foch

PN00_Sfeg_Petc

Network pipes

PD19_Petc_Abdn

PN06_Balo_Laud

PN05_Dunf_Balo

PN04_Glen_Dunf

PN03_Kiri_Glen

PN02_Petc_Kiri

PN01_Petc_Foch

PN00_Sfeg_Petc

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```python
print("{:5} {:15} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} ",
  format(h, "PD20_Petc_Absh", Param_PD20_Petc_Absh[g], round(Len_PD20_Petc_Absh[h],2),
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  round(min(Press_NN02_Foch[h],700)), round(Press_NN01_Balo[h]),
  round(min(Press_NN00_Dunf[h],700)), round(min(Press_NN02_Dunf[h],700)),
  round(min(Press_NN03_Dunf[h],700)), round(min(Press_NN04_Dunf[h],700)),
  PresDrop_PD20_Petc_Absh[h][5], PresDrop_PD20_Petc_Absh[h][6], PresDrop_PD20_Petc_Absh[h][7],
  PresDrop_PD20_Petc_Absh[h][8], file=fileout)

print("{:5} {:15} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} ",
  format(h, "PD21_Foch_Mory", Param_PD21_Foch_Mory[g], round(Len_PD21_Foch_Mory[h],2),
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  round(min(Press_NN02_Foch[h],700)), round(Press_NN01_Balo[h]),
  round(min(Press_NN00_Dunf[h],700)), round(min(Press_NN02_Dunf[h],700)),
  round(min(Press_NN03_Dunf[h],700)), round(min(Press_NN04_Dunf[h],700)),
  PresDrop_PD21_Foch_Mory[h][5], PresDrop_PD21_Foch_Mory[h][6], PresDrop_PD21_Foch_Mory[h][7],
  PresDrop_PD21_Foch_Mory[h][8], file=fileout)

print("{:5} {:15} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} ",
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  round(min(Press_NN02_Foch[h],700)), round(Press_NN01_Balo[h]),
  round(min(Press_NN00_Dunf[h],700)), round(min(Press_NN02_Dunf[h],700)),
  round(min(Press_NN03_Dunf[h],700)), round(min(Press_NN04_Dunf[h],700)),
  PresDrop_PD22_Foch_High[h][5], PresDrop_PD22_Foch_High[h][6], PresDrop_PD22_Foch_High[h][7],
  PresDrop_PD22_Foch_High[h][8], file=fileout)

print("{:5} {:15} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} ",
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  round(min(Press_NN02_Foch[h],700)), round(Press_NN01_Balo[h]),
  round(min(Press_NN00_Dunf[h],700)), round(min(Press_NN02_Dunf[h],700)),
  round(min(Press_NN03_Dunf[h],700)), round(min(Press_NN04_Dunf[h],700)),
  PresDrop_PD23_Kiri_Angs[h][5], PresDrop_PD23_Kiri_Angs[h][6], PresDrop_PD23_Kiri_Angs[h][7],
  PresDrop_PD23_Kiri_Angs[h][8], file=fileout)

print("{:5} {:15} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} ",
  format(h, "PD24_Glen_Dund", Param_PD24_Glen_Dund[g], round(Len_PD24_Glen_Dund[h],2),
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  round(min(Press_NN02_Foch[h],700)), round(Press_NN01_Balo[h]),
  round(min(Press_NN00_Dunf[h],700)), round(min(Press_NN02_Dunf[h],700)),
  round(min(Press_NN03_Dunf[h],700)), round(min(Press_NN04_Dunf[h],700)),
  PresDrop_PD24_Glen_Dund[h][5], PresDrop_PD24_Glen_Dund[h][6], PresDrop_PD24_Glen_Dund[h][7],
  PresDrop_PD24_Glen_Dund[h][8], file=fileout)

print("{:5} {:15} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} ",
  format(h, "PD25_Glen_Pkin", Param_PD25_Glen_Pkin[g], round(Len_PD25_Glen_Pkin[h],2),
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  round(min(Press_NN02_Foch[h],700)), round(Press_NN01_Balo[h]),
  round(min(Press_NN00_Dunf[h],700)), round(min(Press_NN02_Dunf[h],700)),
  round(min(Press_NN03_Dunf[h],700)), round(min(Press_NN04_Dunf[h],700)),
  PresDrop_PD25_Glen_Pkin[h][5], PresDrop_PD25_Glen_Pkin[h][6], PresDrop_PD25_Glen_Pkin[h][7],
  PresDrop_PD25_Glen_Pkin[h][8], file=fileout)

print("{:5} {:15} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} ",
  format(h, "PD26_Dunf_Fife", Param_PD26_Dunf_Fife[g], round(Len_PD26_Dunf_Fife[h],2),
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  round(min(Press_NN03_Dunf[h],700)), round(Press_NN02_Dunf[h]),
  round(min(Press_NN01_Dunf[h],700)), round(Press_NN00_Dunf[h]),
  PresDrop_PD26_Dunf_Fife[h][5], PresDrop_PD26_Dunf_Fife[h][6], PresDrop_PD26_Dunf_Fife[h][7],
  PresDrop_PD26_Dunf_Fife[h][8], file=fileout)

print("{:5} {:15} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} {:13} ",
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  round(min(Press_NN04_Balo[h],700)), round(Press_NN03_Balo[h]),
  round(min(Press_NN02_Balo[h],700)), round(Press_NN01_Balo[h]),
  PresDrop_PD27_Balo_Wlot[h][5], PresDrop_PD27_Balo_Wlot[h][6], PresDrop_PD27_Balo_Wlot[h][7],
  PresDrop_PD27_Balo_Wlot[h][8], file=fileout)
```

Chapter 7 Appendices – not used
Chapter 8 Appendices – not used

Supplementary Appendix  Unedited papers as published
Abstract

Current commercially available options for decarbonisation of road transport are battery electric vehicles or hydrogen fuel cell electric vehicles. BEVs are increasingly deployed, while hydrogen is in its infancy. We examine the infrastructure necessary to support hydrogen fuelling to various degrees of market penetration. Scotland makes a good exemplar of transport transition, with a world leading Net-Zero ambition and proven pathways for generating ample renewable energy.

We identified essential elements of the new transport systems and the associated capital expenditure. We developed nine scenarios based on the pace of change and the ultimate market share of hydrogen, and constructed a model to analyse their infrastructure requirements. This is a multi-period model, incorporating Monte Carlo and Markov Chain elements.

A “no-regrets” initial action is rapid deployment of enough hydrogen infrastructure to facilitate the early years of a scenario where diesel fuel becomes replaced with hydrogen. Even in a lower demand scenario of only large and heavy goods vehicles using hydrogen, the same infrastructure would be required within a further two years. Subsequent investment in infrastructure could be considered in the light of this initial development.

Keywords

Hydrogen, Fuel Cell, Electrolyser, Fuel, Infrastructure, Emissions
1 Introduction

Let’s look to the situation of road transport in just thirty years. We’ll be in a world that will be both very different and very similar to today. Different, in that so much of the technology we know and use today will have vanished, replaced by newer systems that emit practically no greenhouse gasses. Similar, in that we will still need and want to move ourselves, and things, around. It seems inconceivable that we won’t be using road transport in some form or another to do that.

At present, road transport is responsible for 11.9% of global greenhouse gas emissions [1]. In order to reach the global targets for net zero greenhouse gas emissions these must be eliminated.

Until relatively recently, the default assumption among many has been that all future road transport in the UK will be electrified using batteries [2]. Furthermore, at the time of writing in 2022 a wide range of road vehicles is available as battery electric vehicles (BEV) in cars, light goods vehicles, and buses, and these are taking an increasing market share[3]. However an alternative in the form of hydrogen is available, and awareness is increasing of this option. There have been numerous trials and developments of hydrogen as a fuel, along with expressions of support from governments. These include - but are by no means limited to – California [4], Japan [5], South Korea [6], China [7], and also the EU[8]. Specifically relevant to our study area, the Scottish [9] and UK [10] governments have both recently released hydrogen strategic plans and policies.

The infrastructure requirement and associated cost has been examined by Robinius et al, identifying competitive relative costs for hydrogen infrastructure in Germany [11]. Greene et al [12] examine the challenges of deploying hydrogen refuelling infrastructure, concluding that hydrogen has the potential to supply a major share of the world’s transportation energy demand. Whiston et al [13] elicit the views of experts in the field to consider various aspects of future hydrogen vehicle use – among other conclusions, they anticipate up to 5,000,000 hydrogen fuel cell electric vehicles (HFCEV) in China by 2040.

Here we assess the infrastructure requirements of using hydrogen for some or all road vehicle fuel. We examine needs right through the transition period to the time where essentially all road transport produces zero carbon emissions.

Geographically we limit ourselves to a case study of Scotland. However, the approach should be generally transferable to the rest of Europe and other areas of the world, provided local factors are taken into consideration. Local factors such as vehicle life, annual distance travelled per vehicle, and emissions from the production of hydrogen and generation of electricity, will all be significant.

We chose Scotland for the case study because It has an excellent track record to date of implementing emissions reduction methods in electricity generation [14]. The high current planned and potential level of renewable electricity means that we can confidently expect that enough hydrogen from water electrolysis could be produced through carbon free means.

At present approximately 96% of Scotland’s electricity is produced by carbon free means, predominantly wind or nuclear, having reduced electricity generation related greenhouse gas emissions by 89% since 2000 [14]. There is now only one significant fossil fuel power station in use, the natural gas fuelled power station at Peterhead[15]. This implies that hydrogen generated from new electricity sources will be responsible for essentially zero carbon emissions when used as a fuel. If necessary, this could be backed up by locally available natural gas sources, which could be used to produce ‘blue hydrogen’ as an interim
measure - albeit at less than complete, but still substantial, elimination of emissions, and potentially with significant short-term cost savings and availability benefits [16].

Scotland has a defined and challenging set of emissions targets. The neighbouring jurisdiction in England has similar targets, although not identical[17]; the potential for contamination by cross-border sales is limited. The Scottish government has adopted a series of relevant emissions related objectives [18-20]:

- 2020 electricity generation to reach the equivalent of zero emissions for domestic use;
- 2030 reduction in greenhouse gas emissions across all sectors of 75% from 1990 levels;
- 2030 new hydrocarbon car and van sales are banned (UK government requirement);
- 2045 reduction in greenhouse gas emissions across all sectors to net zero.

We do not aim to make a comprehensive study of safety issues in this paper. Refuelling stations and similar activities are well regulated in Scotland and the UK by the Health and Safety Executive [21], and safe vehicle construction is regulated by the Driver and Vehicle Standards Agency [22]. We assume for the purposes of this study that these organisations will ensure safe construction of hydrogen vehicles and fuelling facilities.

We aim to address the following questions:

- For various scenarios of the extent of hydrogen fuel used within that transition, what quantity of hydrogen would be required over the energy transition period to 2050?
- What production, distribution, compression, storage, and dispensing infrastructure will be required to deliver the hydrogen to end users?
- What will be the capital cost?
- Which scenario, or scenarios, will be most likely?

As a precursor, we will also have to consider: How will Scottish and UK government overall emissions objectives translate into road transport? And how fast should the transition to zero emission vehicles be to meet those emissions objectives?

We developed a Multi-Period model, incorporating Monte Carlo and Markov chain methods, to answer these questions; a similar approach has been taken in the forecasting of renewable electricity generation requirement [22B]. Here we present the results of the subsequent analysis. We also present details of the construction of the model and the underlying assumptions. We conclude with recommendations of the optimum pathway to use hydrogen in road transport to meet the objectives, and appropriate steps to deliver it. It is important to note that we are not trying to predict what will happen; we are developing a range of options for what must happen in order to meet the objectives.

We incorporate the beneficial reuse of the existing widespread natural gas network as the most likely scenario in Scotland [23, 24], allowing an understanding of a more integrated energy system than has traditionally been in place. We also consider the pace of change required to meet the Scottish government's targets, based on several scenarios.

We aim to contribute to the literature by assessing the size and cost of the necessary hydrogen infrastructure at a large scale in the long-term for vehicle refueling purposes. We present a simple method for assessing the required infrastructure. This should inform policy makers not only for Scotland but also further afield, subject to incorporation of local factors.

This should also inform the debate around the question of battery electricity or hydrogen, although we hold the view that there are no winners and losers in that discussion. Just as petrol (gasoline) and diesel...
serve largely different needs at present, there will be a need for both future fuel types (and possibly others) as the demand grows exponentially.

## 2 Methods

### 2.1 Initial assumptions

We ignore the cost of construction and operation of wind turbines and other generation equipment – we use announced contracted costs of offshore wind electricity supply, or wholesale costs of network supplied electricity, as inputs to the model where required; this figure accounts for all such construction and operation costs[25].

We assume that hydrogen is initially produced locally from electrolysis of water. This can come from grid supplied, or local dedicated, renewable electricity. We model that centrally produced green hydrogen will gradually become available over a period from a variable start (2026-2030) to finish (2040-2045), supplied through the repurposed natural gas network. This repurposing of the network is expected over that timescale in any case, to replace the existing supply of natural gas with hydrogen[26]. We assume that, over time, hydrogen supplied in this way will displace locally produced hydrogen using grid electricity where practical, and that local re-purification cost to remove, e.g., odourants from the hydrogen will be low or insignificant[27]. Green hydrogen supplied in this way is assumed to be limited to the 85% of households currently connected to gas network [28], although this value is allowed to vary in the Monte Carlo cases in the model as low as zero; the rest will stay locally produced. For this locally produced element, we model variable proportions of grid supplied or local dedicated electricity. See worksheet 19 in the model, supplied as Electronic Supplementary Information (ESI).

Initial unit costs of hydrogen fuelling stations are derived from methods presented by Tlili et al [29], along with contract information published by a large manufacturer of electrolysers [30], and sense checked in discussion with a commercial manufacturer and installer of hydrogen refuellers. We apply learning rates to the costs of hydrogen refuelling equipment[31], varied among the Monte Carlo cases in the model.

We assume that sufficient supplies of hydrogen can be made available; indeed, one key purpose of this paper is to identify how much will be required so that appropriate provision can be made. However, in the event of competition for inadequate supply, this would be reflected in the supply price. For the purposes of this work, this operating cost is insignificant.

We assume, as a starting position, that the number of vehicles in each class and mileage will remain static from levels at the time of writing. This is modelled by keeping the sales of new and scrapped vehicles equal to the number of vehicles in the class divided by the average age at disposal of the vehicle (calculated in worksheet 6 of the model, supplied as ESI). This gives a modelled sales figure lower than the actual recent sales figure, due to the size of vehicle fleet increasing in recent years for most classes of vehicle [3], so this anticipates some active management of vehicle demand. However, the Scottish Government also has a target to reduce car use by 20% by 2030 [32]. We model this as a sensitivity analysis of no change, 10% reduction, and 20% reduction in average annual distance driven by cars by 2030, and unchanging after that. In reality such a reduction might manifest as a smaller number of vehicles covering the same annual distance, or the same number covering a smaller distance, or another equivalent variation; in terms of the fuelling requirement, the focus of this paper, that would make no difference.

One possible flaw in this projection is the potential for people to keep existing hydrocarbon vehicles running for longer. This would have the effect of reducing the number of new Zero Emissions Vehicles (ZEV)
sold while maintaining the number of vehicles on the road, and hence extending the time before the emissions targets are met. However, estimating the effect of this, or remedial measures, is outwith the scope of this analysis.

We use the standard vehicle classes used by the UK and Scottish governments, shown in Table 1 along with their numbers and selected characteristics:

<table>
<thead>
<tr>
<th>Class [t1.1]</th>
<th>Number in service [t1.1]</th>
<th>Fuel type/s [t1.1]</th>
<th>Gross annual fuel consumption for fleet [t1.2] (ML/yr, 2018)</th>
<th>Typical per vehicle emissions [model worksheet 8] g CO2/km</th>
<th>Typical fleet annual emissions [t1.3] (kT/yr, 2018) tonnes/year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buses &amp; Coaches</td>
<td>14,700 (2018) 13,100 (2021)</td>
<td>Typically diesel</td>
<td>147</td>
<td>818</td>
<td>27.8</td>
</tr>
<tr>
<td>Cars</td>
<td>2,483,000 (2018) 2,520,000 (2021)</td>
<td>Diesel 41%, Petrol 59%</td>
<td>2,215</td>
<td>157</td>
<td>2.3</td>
</tr>
<tr>
<td>Motorcycles</td>
<td>79,500 (2018) 76,200 (2021)</td>
<td>Petrol 99% ZEV 0.9%</td>
<td>13</td>
<td>109</td>
<td>0.4</td>
</tr>
<tr>
<td>Heavy Goods Vehicles (HGV)</td>
<td>36,900 (2018) 36,300 (2021)</td>
<td>Typically diesel</td>
<td>632</td>
<td>675</td>
<td>47.5</td>
</tr>
<tr>
<td>Light Goods Vehicles (LGV)</td>
<td>294,700 (2018) 331,200 (2021)</td>
<td>Diesel 96% Petrol 3% Diesel 96% Petrol 3% ZEV 0.6%</td>
<td>617</td>
<td>213</td>
<td>5.8</td>
</tr>
</tbody>
</table>

Table 1  Vehicle classes, number of vehicles in service in Scotland, fuel types, fuel consumption, Carbon Dioxide emissions for fleet and single vehicles. Where more than one fuel type is in use, the split is based on the proportions for the whole UK. Petrol includes hybrid and plug-in hybrid.

4 The vehicle classes in the UK Government statistics are termed “Goods” and “Light Goods” for commercial vehicles over and under 3,500kg respectively (other than buses and coaches). In this paper we use the less ambiguous common terms Heavy Goods Vehicle (HGV) and Light Goods Vehicle (LGV) respectively.

A list of other model input assumptions, with sources and background, is presented in Appendix A.
2.2 Preliminary assessment of sector emissions targets

As a preliminary step, we examine what emissions reduction will be required in the road transport sector in Scotland. As at 2019, road transport is responsible for 20% of Scotland’s greenhouse gas emissions [34].

The key Scottish Government all-sectors targets are (i) reduction from 1990 totals by 75% by 2030, and (ii) zero net emissions by 2045 [18, 19]. There is also a recent UK Government requirement to eliminate solely hydrocarbon fuelled vehicle sales by 2030, with hybrids eliminated by 2035 [20]. We assume that all sectors’ emissions decrease at an equal proportionate rate from the present day levels to reach these overall targets, with three differences:

1. Negative emissions allocated to land use change stay at current levels; they have not changed significantly for several years [35].
2. Emissions from electricity production will reach zero before 2030. The target for this (affected by the Covid-19 pandemic) was 2020, but the exact date (before 2030) it is achieved does not affect this calculation[18].
3. Emissions due to air travel reduce by only 10% in each of these two stages. This figure is somewhat arbitrary - there are no currently available zero emissions commercial aircraft [36], but the calculation is not sensitive to variations in this value as air travel is only a small contributor to the total [35] as can be seen in worksheet 2 of the model (provided as Electronic Supplementary Information).

2.3 Scenarios

We based our analysis on a series of transition scenarios. These combine three pace of transition options and three fuel choice options, as follows:

2.3.1 Pace options.

We project the annual change in zero emissions vehicles (ZEV) in each vehicle class using standard logistics functions creating typical ‘S’ curves. The logistic function takes the form

\[ f(x) = \frac{L}{1 + \exp(-k(x-xo))} \]

Equation 1 [37]

Where L is the target value (discussed below)

k is the gradient function, typically in the range 0.5-1.0.

x is the year (or other period) under consideration

xo is the mid-point year of the time series under consideration.

The first logistic function used represents new ZEV sales rising to meet the existing level of sales of all vehicles. The constant L here represents the number of sales of all vehicles. Where a class of vehicle has a mandatory date in legislation for ending hydrocarbon vehicle sales, the number of sales is forced to the full value of new vehicle sales (L) by the end of that year rather than allowing the function to produce a natural taper.

The second logistics function represents the future scrapping of ZEVs based on the typical average lifespan of vehicles in each class. Again it rises to meet the existing level of sales (required to keep total numbers constant). In this case, L represents the total number of vehicles scrapped in an average year. Clearly, for the case where the total number of vehicles remains constant, the two values of L will be equal.

As total numbers of vehicles and total annual sales are held constant, the annual change in number of ZEVs and hydrocarbon vehicle (HCV) sales is then in a matter of simple arithmetic.
In an iterative process, the constants \(k\) and \(x_0\), which control the two logistic functions, are varied (the same constants are used for both functions, within each scenario) until the emissions in use meet the objectives (see section 2.5).

The pace options used are:

- Equal Pace – all vehicle classes transition at an equal pace. That is, the logistic functions for all classes have the same initial midpoint and gradient.
- Accelerate Bus & Truck – Larger vehicles (Buses & Coaches and HGVs) transition faster than Equal Pace. Cars, LGVs and motorcycles are allowed to transition slightly more slowly, provided the targets are met.
- Laid Back – all vehicles transition at an equal pace, but the 2030 intermediate targets are not met, only the ultimate 2045 net-zero one. This would still be a viable transition route if there became more scope to decarbonise other sectors faster.

2.3.2 Fuel choice options.

These represent the share of zero carbon fuels between hydrogen and other fuels in the future.

- Large Vehicles Only – all vehicles in the classes Buses & Coaches and HGVs are HFCEV. Other vehicles use other means of decarbonisation.
- Like for Like – There is a view that hydrogen is more suitable for longer range and larger vehicles, especially with restricted maximum weight, due to the high volume, light weight, and fast refuelling times [38]. Similarly, large and long distance vehicles favour diesel at present, albeit for other reasons. So this scenario has current diesel fuel vehicles replaced with HFCEVs, and current petrol vehicles replaced by BEVs. This means that all Buses & Coaches and HGVs, and 41% of cars and 97% of LGVs, will be hydrogen fuelled [3].
- 100% hydrogen. This replaces all hydrocarbon fuelled vehicles with hydrogen fuel cell vehicles.

These Pace and Fuel Choice options combine to give nine Transition Scenarios for evaluation, within which we examine the vehicle classes shown in table 1.

2.4 General approach for analysis

For each Transition Scenario, we took the following steps, analysed over the period 2021 to 2050. The overall investigation is based on a Multi-Period model which we constructed using Microsoft Excel. The model incorporates a Monte Carlo analysis of 1000 randomly generated cases to test the effects of varying unknown and forecast quantities, and a Markov Chain projection of future hydrocarbon vehicle emissions.

We use the model to:

1. Identify annual change in numbers, and total numbers, of ZEVs required to meet the emissions targets. This means that in all scenarios, the targets relevant to that transition scenario will be met or bettered, with a +5% allowed variance.
2. Identify demand for hydrogen as a fuel to supply these ZEVs to the relevant proportion.
3. Identify the fuelling and related infrastructure required to deliver that quantity of hydrogen. Infrastructure here refers to equipment specifically needed for storing and dispensing fuel, upgraded or new distribution systems, and local or central production.
4. Identify capital costs of providing the infrastructure.

These steps are also shown in Figure 1 (section 2.8).
2.5 Approach for Emissions calculations

First we examined the constraints on future HC vehicle emissions, based on current EU and UK legislation, and existing vehicle fleet emissions as set out in Table 1. We used a Markov chain assessment (meaning that each value generated in a series is affected by the previous value generated) to create future emissions. Over several time steps, we generated a random level of emissions for new vehicles. This random level was constrained to (i) not exceed the anticipated legislative constraints and (ii) not to exceed the previous time step value. This method was carried out for each vehicle class independently, and different random values were generated for each of the Monte Carlo cases described in section 2.4.

Next, we took the number of new hydrocarbon vehicles in each class for each year of the model and multiplied by the new vehicle emissions. Then we removed the number of scrapped HC vehicles in each class, multiplied by the previous year’s average emissions in class.

This allowed us to arrive at a total figure for each year’s class emissions from HC vehicles, and the new class average per vehicle emissions.

In an iterative process, the constants in the logistic functions generating the numbers of new ZEVs were manipulated until the total emissions for the scenario reached the targets. This was done such that no random Monte Carlo case produced emissions exceeding the target by more than 5%. This process allows us to generate the required number of ZEVs of each class in use each year.

Due to the large amount of renewable electricity available now or imminently, emissions from ZEVs in use are taken as zero. Emissions in vehicle manufacturing are outwith the scope of this study.

We also limit this study to greenhouse gas emissions from fuel use. Particulate emissions from fuel use and non-fuel sources are also outwith the scope of the study.

2.6 Computation of Hydrogen Refuelling Station numbers

We split the Monte Carlo cases into three sections of 330 for each of the three fuel choice options. These defined the proportions of ZEV in each vehicle class using hydrogen for each year, which then produces the actual numbers of vehicles when combined with the total number of ZEVs found in section 2.5.

The number of hydrogen fuelled vehicles is then used to calculate the total demand for hydrogen fuel each year.

Three Hydrogen Refuelling Station (HRS) sizes were defined, based on the sizes of typical existing hydrocarbon stations in use today. The proportion of fuel supplied by each size of HRS was taken as fixed at the proportion supplied at present by the corresponding sizes of petrol / diesel station (see worksheet 18 in the model, supplied as ESI).
The proportion of each station’s capacity that would be actually used on an annual average was given a central value of 71%, after Robinius et al [11]. This was allowed to vary randomly in each case, constrained between 61% and 81%.

By combining these with the gross hydrogen demand for each year, the required gross capacity of each HRS size could be readily calculated. Dividing this by the capacity of the HRS, and rounding up to the next integer, gives the aggregate numbers of HRS of each size required in each year. Finding the numbers of new HRS required each year is then a matter of simple arithmetic.

2.7 Calculation of costs

For the calculation of costs, we identify two types of HRS: Those which produce hydrogen in-situ with renewable electricity, and those which use hydrogen taken from the re-purposed natural gas network. The in-situ producing HRS are subdivided into those which use electricity from the electricity grid, and those which have a direct, dedicated connection to a local source of renewable electricity.

The Monte Carlo cases have random allocations of the following variables (introduced in section 2.1) related to the type of HRS:

- The start and finish dates of the conversion of the natural gas network to hydrogen.
- The maximum proportion of network supplied HRS, reached at the end date of the network conversion through typical logistic function (‘S’ curve).
- The proportions of in-situ producing HRS which use a dedicated connection to a renewable electricity source or a connection to the electricity grid.

For each case, the numbers of HRS of each type are computed. The capital cost associated with each type is found by combining the initial cost and the learning rate, described in section 2.1. The capital cost of the electrolyser capacity required to produce the hydrogen distributed through the network is assessed separately, in a similar way.
2.8 Modelling tool

The model is outlined as follows:

Figure 1 Schematic of model created to analyse required fuel infrastructure and emissions to meet emissions targets.

N.B. Worksheet numbers refer to the worksheets within the model. Worksheets 1-10 set out input information and carry out preliminary calculations; 13 is an input data summary page; un-numbered pages beyond 25 hold combined outputs from running multi-scenario macros.

The model input values, assumptions and sources are presented in Appendix A.

The calculations used are detailed in Appendix B.

A reviewable version of the model as used, including all worksheets referred to in Figure 1 and elsewhere in this paper, is presented as Electronic Supplementary Information.
3 Results

3.1 Preliminary assessment of emissions targets

The key Scottish Government all-sectors targets are a reduction in emissions from 1990 totals to 75% by 2030, and net zero by 2045 [18, 19]. There is also a UK government requirement to eliminate solely hydrocarbon fuelled vehicle sales by 2030.

Projecting the emissions data gives target residual road transport emissions of 5,586 and 1,185 kt/yr CO2 equivalent by 2030 and 2045 respectively, or a required reduction from 2018 levels of approximately 45% by 2030 and 88% by 2045. These are the emissions targets that we work to in this project (model worksheet 2).

Figure 2 shows these targets in the context of the recent emissions records and the primary energy related emissions sources.

![Figure 2 Scottish emissions targets, showing overall government targets, road transport estimated target for 2030, and energy related emissions history and required trajectories to achieve ultimate net zero target. Non-energy emissions not shown but accounted for in the net-zero calculated end points. Historic data from Scottish Government Climate Statistics[35].]

3.2 Pace of transition

The Pace of Transition question depends on how quickly end-of-life hydrocarbon vehicles can be replaced with ZEVs rather than new HCVs. This is independent of whether the ZEVs are HFCEVs or something else (e.g. BEV). Figures 3 and 4 illustrate the rate of increase of new ZEV sales required to meet the targets, and their effect on greenhouse gas emissions.
We see that the Accelerate Bus & Truck options require a smaller number of total ZEVs than Equal Pace in the early years, while meeting the same targets. This means that the Accelerate Bus & Truck scenarios might be easier to implement, due to reduced demand on manufacturers. Also, given that large vehicles are typically owned in fleets, fewer decision makers will need to be influenced. However, smaller vehicle transition will still be required at a good pace and cannot be ignored. The Laid Back scenario allows a significantly slower transition in all vehicles. This is illustrated in Figure 3.

Figure 4 shows the range of emission profiles arising from these pace options. This shows that meeting the demanding 2030 objectives should to lead to a considerable overshoot of the 2045 objective – this could create some headroom in other harder to decarbonise sectors. Conversely, the Laid Back scenario emissions shows that even if it proves impossible to meet the interim targets for road transport, meeting the ultimate 2045 target should be much more achievable. This would still not prevent the overall objectives for 2030 from being met, if sufficient early gains could be made in other sectors.
For each scenario, it can be seen that the variation in emissions between Monte Carlo cases is small – this means that variation in the forecast future level of per-vehicle emissions is much less significant than the pace of removing hydrocarbon fuelled vehicles altogether.

### 3.3 Quantity of hydrogen required

By forecasting the energy demand for the numbers of HFCEVs identified, we modelled the quantity of hydrogen fuel required for each of the transition scenarios. This is found from the energy provided by liquid fuels to the hydrocarbon vehicles removed from the road, adjusted to account for the different levels of efficiency. The results of this assessment are presented in figure 5.

Figure 5 illustrates the quantity of hydrogen fuel required, expressed in terms of the energy value of the hydrogen. This allows comparison with the decreasing energy value of hydrogen fuel used, also illustrated. For simplicity, figure 5 only shows the hydrogen demand for the equal pace and accelerate bus and truck pace options (indistinguishable in this graph), other than for the Large Vehicles Only fuel choice which also shows the Laid Back option. As can be seen, the Laid Back pace results in meeting the same ultimate demand, but not until around 2050; the same holds for all other fuel choice options (not illustrated).

Figure 5 also shows the quantity of hydrogen required in terms of weight as kilotonnes per year; this is only illustrated for Like for Like / Equal Pace options.

### 3.4 Infrastructure requirement for refuelling

Existing fuelling stations hydrocarbon were categorised as “company owned”, “dealer owned”, and “hypermarket” in a 2012 study carried out for the UK Government [39]. By extrapolating the numbers from the 2012 survey in proportion to the overall UK numbers today (based on correspondence with the UK Petroleum Retailers’ Association, unpublished but available on request from the authors), along with UK government statistics on fuel sales [33], we arrived at the numbers of stations and average fuel volumes shown in Table 2.
We then calculate equivalent quantity of hydrogen to provide the same useful energy as these three filling station sizes. This takes account of the improved efficiency of the fuel cell over internal combustion engines, and uses the lower heating value of hydrogen [40]. These values are then rounded to provide useful sizes for small, medium and large hydrogen fuelling stations. These results are also shown in Table 2. See worksheet 18 in the model for calculation.

We assume that the numbers of each size of fuelling station will be in the same proportion as the numbers of each size of hydrocarbon filling station at present.

Carrying out the process described in section 2.6 yields 330 possible out-turns for each of our transition scenarios. Figure 6 shows the maximum, minimum and mean total HRS numbers for the pace options Equal Pace and Accelerate Bus & Truck, with the fuel options of Like For Like and Large Vehicles Only. Other scenario options are presented in worksheet 25 of the model.

We can see from Figure 6 that there is only a little variation between Accelerate Bus & Truck and Equal Pace in the Like For Like option, with a more pronounced variation in the early stages of the Large Vehicles Only option. This is perhaps unsurprising.

<table>
<thead>
<tr>
<th>Company Owned</th>
<th>Dealer Owned</th>
<th>Hypermarket</th>
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</thead>
<tbody>
<tr>
<td>Nr.</td>
<td>%</td>
<td>Ml / yr</td>
</tr>
<tr>
<td>Average hydrocarbon volume dispensed</td>
<td>kg/day</td>
<td>kT/ yr</td>
</tr>
<tr>
<td>171</td>
<td>20%</td>
<td>5.5</td>
</tr>
<tr>
<td>546</td>
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<td>2.0</td>
</tr>
<tr>
<td>861</td>
<td>17%</td>
<td>11.0</td>
</tr>
</tbody>
</table>

Table 2  Estimated current (2020) numbers of various types of refuelling station in use, with current fuel sales (shaded boxes), along with equivalent capacities of hydrogen refuelling stations (white boxes). The hydrogen station sizes take account of the different efficiency of the fuel and engine types, to supply the same useful energy.
It’s also clear from Figure 6 that numbers of HRS required in the Like For Like options doesn’t exceed the ultimate likely minimum of the Large Vehicles Only options until around 2030. This has implications about the confidence of investing in, or supporting, the early stage development of HRS. We explore this further in section 5.

3.5 Annual investment

Following on from that, we can estimate the annual investment required, as described in section 2.7. This is illustrated for the Equal Pace option only in Figure 7, for the three fuel choice options. The Accelerate Bus & Truck pace option is essentially identical to this.

The Laid Back cases, not displayed, require a similar total expenditure, but skewed significantly to the later years as might be expected.

Figure 7 also shows the estimated annual value of capital refurbishment and upgrade for hydrocarbon filling stations. Clearly this is approximated in a very wide range, but we can see that it is comparable in magnitude to the costs of establishing new HRS, which would all be required by 2045. The main curves in figure 7 relate only to the costs of establishing new HRS, not to the ongoing expenditure associated with maintaining or renewing them as they age – that would of course continue indefinitely beyond 2045/50.

The potential range of investment required suggested by the Monte Carlo analysis in the model is also shown here. A significant source of variability, especially in the later years, is the question of what proportion of fuelling stations are supplied from the gas grid, compared to using local generation – grid connected stations being considerably cheaper since they don’t require their own electrolyser. The other main source of variability is the usage rate of the fuelling stations; as would be expected, if fuelling stations are used more intensively, fewer are required.

4 Sensitivity analysis

We carried out this analysis on the basis that vehicle use would stay the same. However, the Scottish Government has a further target to reduce car use by 20% by 2030. We carried out a sensitivity analysis, considering the effect of a 10% or 20% reduction in car use by 2030 with use remaining constant beyond
that date. We modelled this by keeping the vehicle numbers constant, but reducing the average annual distance covered.

This meant that for each of the Pace options, the constants in the logistic were revised so that the same emissions targets were met.

In the Equal Pace options, this also reduces the pace of conversion to ZEV of other vehicle classes; with all vehicles converting at the same pace, all see the benefit of the reduced car emissions. Thus, even for the Large Vehicles Only fuel choice options, there is a short term reduction in the numbers of fuelling stations required. However, the Accelerate Bus and Truck pace options have buses and HGVs on a different path from smaller vehicles. Here, motorcycles and LGVs share a reduced pace of decarbonisation, but buses and HGVs are unchanged. This way the Large Vehicles Only fuel choice options show no change in infrastructure requirement from the base case. The Laid Back option was not considered in this sensitivity analysis.

![Combined sensitivities chart](image)

**Figure 8** Hydrogen fuelling stations required by year. This combined chart shows the extremes found from the base case and 20% car use reduction, Equal Pace and Accelerate Bus and Truck pace options, for the Like for Like and Large Vehicles Only fuel choice options. It also shows the mean numbers for both base case and 20% car use reduction, in the Equal Pace options.

The maximum numbers of hydrogen refuelling stations are found from the unreduced car use, in the Accelerate Bus & Truck pace option in both Like for Like and Large Vehicles Only fuel choice options. The minimum numbers are found from the reduced car use and Equal Pace option for both fuel choice options. This is as expected. For comparison, Figure 8 also shows the mean number of HRS required for both unreduced and 20% reduced car use.

The effect of a 10% reduction lies between the 20% reduction and no change, as expected. However, as the 20% reduction has only a limited impact on our conclusions and recommendations, we have not considered further the effect of a 10% reduction.

5 Discussion

5.1 In the Future

We can envisage the future zero emissions road transport system. In this future transport world, all vehicles will be zero greenhouse emissions at the point-of-use. The technology required to do this has existed from the early transition, and all new vehicle sales will have been zero emissions from 2030 for
smaller vehicles and approximately 2035 for larger vehicles [20]. The technology exists today to deliver a zero carbon road transport system for Scotland, at an achievable financial cost, and hydrogen should play a substantial role in that.

There will always be a need for a choice of fuel types; different fuels serve different purposes. Much as the pre-transition road fuel system uses both petrol and diesel for different, but overlapping, purposes, so we can expect that both battery electricity and hydrogen will be used for different purposes. Quite possibly other fuels that are not available in the early stages of the transition will become viable as well.

As a fuel, the important characteristics of hydrogen for users are: lower weight (similar to existing hydrocarbon systems), fast refuelling time (a few minutes), long range readily achievable, and fuel cost competitive with electricity when made at scale (worksheet 4 in the model, supplied as ESI). Conversely, internal space is more compromised by the large volume the fuel tank requires, and for some users overnight recharging could be convenient [41, 42]. All of this means that, just like diesel in the present day, hydrogen will lend itself predominantly to larger and longer distance vehicles. No one type of fuel is likely to become universal.

So what proportion of vehicles will be fuelled by hydrogen? It seems likely that essentially all buses and coaches and HGVs will be hydrogen fuelled (this paper’s Large Vehicles Only option). It also seems likely that some car and van owners will choose hydrogen fuelled vehicles – it is quite conceivable that all pre-transition diesel vehicles will be replaced with hydrogen (this paper’s Like For Like option).

This future fleet of hydrogen vehicles will be supported by a network of around 300 (Large Vehicles Only) to 820 (Like For Like) hydrogen refuelling stations of various sizes (see Figure 6). The majority of these HRS will be supplied with hydrogen generated from offshore wind electricity. This forms part of the Scottish government’s programme of developing renewable hydrogen production, for use domestically and for export, from North Sea wind, announced in 2020 [9]. This hydrogen will be supplied through the national gas network, which will be converted over a period from the late 2020s to the early 2040s, from its original purpose of distributing natural gas [26]. At the upper end of this scale, the number of HRS would be similar to the number of petrol & diesel fuelling stations currently in service (861 - model worksheet 18); this suggests that the ultimate spacing between them could be similar to that at present, with provision available in more remote areas. Of course, the HRS fuelling industry might develop into a smaller number of larger stations, or vice versa – which could have an impact on the service provision in rural areas.

Those hydrogen refuelling stations which couldn’t be sited with a connection to the hydrogen gas network will probably use their own dedicated renewable electricity supply - most likely wind turbines - to produce their own hydrogen in-situ. This approach will be widespread in the early days of the transition before the gas grid is fully converted to hydrogen. The production cost of the fuel is likely to be broadly similar (model worksheet 4), so there won’t be a significant commercial disadvantage in one supply method or the other – other than the risk of the local electricity source not producing for some time. So, just like the early hydrogen refuelling stations, these future non-grid hydrogen filling stations will require a backup supply in the event that their own electricity supply is inactive for too long. This is likely to be in one of three forms: a connection to the electricity grid, but this tends to be very expensive in actual use, adding around 80% to the wholesale fuel cost; a larger on-site storage facility than would normally be required; or a supply delivered by road using a tube trailer (a specialised tanker).

An alternative scenario could be around the use of several hydrogen hubs as production and distribution centres. This is considered in the Scottish Government’s recent consultation on hydrogen [43], but analysis of this option is outwith the scope of this paper.

5.2 Present day
Let's now consider what has to be done in the short term in order to permit that future to unfold. Primarily, enough hydrogen refuelling stations of sufficient capacity need to be constructed to allow the use of hydrogen fuel vehicles up and down the country. The problem being that we don't know how many to build, or where. Key questions about the future are presently unanswered with accuracy: Will all vehicle classes transition at the same rate (this paper’s Equal Pace option)? Or might it be possible to encourage larger vehicles to transition to hydrogen faster, giving more carbon dioxide reduction per vehicle replaced (this paper’s Accelerate Bus and Truck option)? Or even, might a more relaxed transition take place, missing out the Scottish government 2030 75% emissions reduction target (Laid Back option)? For planning purposes we should assume that the 2030 target will be met. This also means that the 2045 transport target compatible with overall net zero will almost certainly be comfortably exceeded.

For the early stage activities, it would be ideal if we could identify a way which minimises the risk of over-construction, while offering the maximum appropriate support for hydrogen fuelled vehicles. Fortunately there is enough overlap in the requirements to facilitate this - the ultimate number of hydrogen refuelling stations required for the smallest out-turn of the Large Vehicles Only option will still provide enough capacity for the first 8-10 years of the Like For Like option, as in Figure 6. Conversely, following the highest predicted demand for the Like For Like scenario up to 2025 would provide enough capacity for any likely out-turn in that time, and would not be wasted if the Large Vehicles Only option transpired.

In section 4, we considered the implication of a reduction in car use of 20% by 2030, a policy goal of the Scottish Government. If this came about, the above balance of requirements would only change to the extent that the minimum ultimate requirement for Large Vehicles Only would provide enough for the Like for Like fuel option for 8-12 years; planning for such provision then would still not be wasted.

Putting actual numbers to this, then, shows that a sensible initial program to 2025 should consist of 9 large fuelling stations, 11 medium, and 36 small ones to service a total demand of 71,500 kg/day (26 kT/year) by 2025. These will most likely use hydrogen produced locally. The best option for local production would be to bypass the national electricity grid and use dedicated wind turbines, or a specific offtake agreement with nearby wind farms. This would influence the location of the filling stations.

If our Accelerate Bus And Truck - Like For Like scenario holds good, then this capacity could be required by 2025. If the reduced demand, and initially slower, scenario Equal Pace - Large Vehicles Only is the out-turn, then this capacity would be required by 2028. A reduction in car use of 20% by 2030 would extend this later date by less than one year. This initial construction programme can be expected to cost in the region of £140M. This compares very favourably to Scottish Power’s forecast costs for electrification of road transport, even excluding the substantial electricity grid reinforcement costs [2]. Alongside this, though, the existing program of EV charger rollout should continue for some time - for the future envisaged here, there will be a need for a large capacity to charge battery electric vehicles as well.

There is always a risk associated with setting up this type of new infrastructure. Without extensive existing users, an operator may not be confident of being able to sell enough hydrogen to cover their costs. But without enough infrastructure, people and companies are not likely to buy new hydrogen vehicles to create the demand. To resolve this chicken-and-egg situation fast enough to meet the emissions targets will likely require some market stimulation or support to enable initial progress.

However, the annual costs involved are comparable in magnitude to the current expenditure on hydrocarbon refuelling renewables. Hydrogen is very important to the fuelling industry due to the substantially different requirement of electric charging, and the way hydrogen refuelling is carried out in a similar manner to liquid hydrocarbons at present – taking just a few minutes at a pump – which means that the future business model will be similar to the present day. This means that the a substantial part of the costs might be reasonably borne by the industry; some underwriting of risk may be all that is necessary in
terms of government support. This view was shared by a director of a large UK refuelling company in an informal discussion.

Availability, as in manufacturing capacity, of vehicles and infrastructure will be critical. ZEV HGVs have only recently been introduced as BEVs[44]. HFCEV HGVs are expected by 2023[45] and are already available in some markets, e.g. Switzerland, where a partnership between a vehicle manufacturer and a refuelling operator has helped to pave the way [46]. HFCEV cars are slowly becoming available [47-50] and can reasonably be expected to become more popular once the fuelling infrastructure is in place to make their use practical.

5.3 The Transition Phase

We can turn our thoughts to what will happen between this initial phase of investment and the longer-term. We can expect the number of hydrogen vehicles to increase enormously over that period 2025 to 2045 in the case of our Like For Like scenarios; so the number of hydrogen refuelling stations required would increase as well.

The ultimate number of hydrogen refuelling stations of the sizes we have considered could be around 820, somewhat fewer than the 860 petrol and diesel refuelling stations in service today, reflecting the fact that a substantial part of the vehicle refuelling load would be taken by charging of battery vehicles. The potential reduction in car use by 20% would reduce this ultimate number to around 760. The effects of this, though, would be seen more clearly after some years, by which time market forces and other effects should be better understood.

If the out-turn were Large Vehicles Only - and the position between these two scenarios would be subject to market forces driven both by fuel costs and user preference - there would be a need for around 300 hydrogen refuelling stations (possibly fewer but larger, since almost all of the relevant demand would come from larger vehicles). Over this period we can also expect the existing natural gas network to become fully converted to supply hydrogen produced at a centralised location. We therefore anticipate that new hydrogen refuelling stations would use this as a source of hydrogen, where a network connection can practically be made.

In the earlier part of this period, we can anticipate that the cost of installing and operating the infrastructure, along with vehicles, should reduce enough to permit any market stimulation to be withdrawn. We also expect that the extent of renewable electricity available offshore will increase dramatically in line with, or exceeding, the Scottish government announced targets [9]. However, the total renewable electricity requirement for hydrogen generation (at around 73% of road transport energy requirement) could ultimately be provided by a windfarm/s supplying around 18 TWh per year (calculated in model, worksheet 19).

For context, Scotland’s 2020 renewable energy generation was around 39 TWh (of which onshore wind electricity 19.5 TWh, and offshore wind 3.5 TWh with the balance being solar, hydro-electricity, heat and biofuels), compared with an all sector energy demand of 155 TWh [14]. Consented further offshore wind generation represents around 22 TWh per year[51]. A contribution might also be drawn from curtailed wind generation; in 2019, 1.9 TWh of potential wind powered electricity generation was curtailed in Scotland[52]. In addition, the January 2022 Scottish offshore wind electricity leasing round indicates a further 25 GW capacity is expected to be delivered in due course[53], which should provide over 100 TWh per year of additional renewable electricity.

In December 2020 the Scottish Government announced its hydrogen strategy[9], which includes the production of 5 GW equivalent of hydrogen by 2030 and 25 GW by 2045 for a range of uses including export. These are well in excess of the requirements we forecast for road transport, which are equivalent to approximately 1 GW in 2030 and around 2.5 GW in 2045 (based on a Like for Like fuel demand option).
At current fuel and energy prices and tax rates, hydrogen at a large scale should be cheaper to the consumer than petrol or diesel however it is produced; if grid electricity is avoided, it should be also be cheaper than electricity for batteries (Model worksheet 4; although note that because of the volatility in energy and fuel prices at the time of writing, this indicates relative position better than actual values). The question of how to equitably charge customers supplied by different routes – that is, network and non-network gas, and local dedicated or grid supplied electricity – will have to be addressed as a policy decision. This may be tied into taxation – in the long run, governments will undoubtedly seek to replace some of the lost fuel duty currently paid though hydrocarbon fuel sales.

Overall, the key constraints are more likely to be the availability of vehicles, fuelling equipment and hydrogen generation. We see the practical delivery of these in the in the required timescale as a bigger hurdle than the cost or the development of new technology.

We think the emissions targets are achievable, but they are also extremely challenging. This a very big undertaking, and time is of the essence.

6 Conclusion and Policy Implications

Our aim in this analysis was to estimate what extent of fuelling infrastructure, and associated costs, would be required to support the use of hydrogen as a fuel for road. We did this primarily using a Multi-Period model, incorporating Monte Carlo and Markov Chain components, which we constructed for the purpose using Microsoft Excel.

Our key findings were that (i) the most probable scenario meeting the targets is Equal Pace – Like for Like, and (ii) that providing an initial seed network for this scenario would still be well within the needs of the likely minimum out-turn, the Large Vehicles Only option.

This most likely scenario means anticipating that (i) all vehicles will transition to zero emissions vehicles at a similar pace, and (ii) existing diesel vehicles will be replaced with HFCEVs, and petrol vehicles will be replaced with BEVs or other technology. Because larger vehicles use proportionately more energy, this would mean ultimately around 73% of fuel energy being transported as hydrogen.

The infrastructure to supply this in the first 5 years would be around 9 large scale (5,700 kg/day) hydrogen fuelling stations, 11 medium sized (2,850 kg/day) ones, and around 36 smaller ones (1,000 kg/day). However, if the Large Vehicles Only option transpired, as an effective minimum likely out-turn, the same infrastructure would still be required within 7-8 years. This infrastructure would cost around £140 million, which compares very favourably to the cost of electrification for battery electric vehicles.

Ultimate numbers for the Like For Like option could reach around 820 hydrogen fuelling points of various sizes; significantly fewer would be required under Large Vehicles Only at about 300. These would cost around £740M and £320M respectively, expressed as NPV to 2050 at 6%, or £2.1bn & £670M as a simple aggregate. Annual expenditure would peak at around £100M/year between 2028 -2038 for Like for Like, or around £40M for Large Vehicles Only. The cost of providing for alternative zero emissions fuels to fill the gap between these scenarios would be likely to be substantially higher than the apparent saving in hydrogen infrastructure, based on the costs set out by Scottish Power [2].

It may become possible to accelerate the deployment of larger vehicles, that is buses and HGVs, as in our Accelerated Bus & Truck pace option. This would have advantages in reducing the number of zero emissions vehicles required in the short term; the early years’ expenditure on refuelling infrastructure would be slightly higher (up to 5% extra). However, this may not be achievable over the next few years due to the different development stages of the vehicle types.

We propose that this initial programme of hydrogen refuelling locations and charging points should be pushed forward as a seed and development network, as a matter of some urgency. This should, however,
add to rather than replace the ongoing programme of expanding the network of battery electric vehicle chargers. It also seems likely that the vehicle fuelling industry should be able to fund a large part of the hydrogen infrastructure within the existing pace of commercial investment.

Shorter term market stimulation for hydrogen fuelling systems, vehicle sales and/or fuel costs might be required, until commercial risks and costs reduce to a level similar to current fuel systems. Vehicle and fuel costs are anticipated to reach this level by around 2025 [54, 55]. A policy of ongoing support might be needed in areas obliged to use more expensive technology.

We also recommend developing a partnering strategy, involving government, academia, vehicle manufacturers, energy and fuelling companies, and others, as soon as possible to push this forward as efficiently and as quickly as possible, if these challenging targets are to be met. This could be developed into a permanent centre of excellence, supporting the development of Scotland’s related industry to take advantage of the currently under-developed global supply chain.

7 Acknowledgements

We acknowledge with thanks help from the following:

Ray Blake and Phil Monger of the Petrol Retailers’ Association, in obtaining a range of information from their members that would not otherwise have been readily available.

Tom Biggart of Motor Fuels Group, for an open discussion and specific information about the vehicle fuelling industry and expectations about hydrogen as a fuel.

Dr Wei Sun of the School of Engineering at the University of Edinburgh, for suggestions about the general direction of the paper.

8 Conflicts of Interest

There are no conflicts to declare

9 Funding

JML is partly funded by the University of Edinburgh.

RSH is funded by EPSRC UKCCSRC 2017 EP/P026214/1 and HyStorPor P/S027815/1, and Scottish Gas Networks Academic Alliance H100 project from Ofgem.

JM-C was part-funded by SGN under the Ofgem Gas Network Innovation Allowance fund. For more information: https://www.smarternetworks.org/project/nia_sgn0105.

10 References


Appendix A
Model input values, assumptions and sources
## Model input assumptions.

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<th>Item / Assumption</th>
<th>Value (Where applicable)</th>
<th>Source</th>
</tr>
</thead>
<tbody>
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<td></td>
<td>UK Department of Transport [3]</td>
</tr>
<tr>
<td>years there has been a gradual upwards trend in vehicle numbers. For this assumption</td>
<td></td>
<td>This is also tested in the sensitivity analysis.</td>
</tr>
<tr>
<td>to hold, there will therefore require to be some management of demand for new</td>
<td></td>
<td></td>
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<tr>
<td>vehicles. This also implies that annual new vehicle sales will be constant at</td>
<td></td>
<td></td>
</tr>
<tr>
<td>current levels, and gradually all will become zero emissions vehicles. Vehicles</td>
<td></td>
<td></td>
</tr>
<tr>
<td>of each class continue to be scrapped at the same average age as at present.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Enough offshore or other green electricity will be available to produce enough</td>
<td></td>
<td>Scottish Government policy [18], also described in the introduction to</td>
</tr>
<tr>
<td>green hydrogen for vehicle fuelling purposes. This implies that hydrogen fuel will</td>
<td></td>
<td>this paper.</td>
</tr>
<tr>
<td>be responsible for zero emissions in use.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Offshore wind electricity generation, including transmission to shore.</td>
<td>£40/MWh</td>
<td>Strike price for 2019 round of UK offshore wind power bids[25].</td>
</tr>
<tr>
<td>Electrolyser capital cost.</td>
<td>US$300 / kW input capacity. Used as £222.</td>
<td>NEL/Nikola contract announcement, June 2020[30]</td>
</tr>
<tr>
<td>Hydrogen fuelling station, incl. in-situ electrolysis generation, compression,</td>
<td>Initial values: 1000 kg/day £2.1M, 2850 kg/day £4.8M, 5700 kg/day £8.4M</td>
<td>Base costs derived from Tlili et al 2020 [29]</td>
</tr>
<tr>
<td>local storage, dispensing.</td>
<td></td>
<td>Incorporating electrolyser capital cost (above), and sense-checked in</td>
</tr>
<tr>
<td>Initial capital costs.</td>
<td></td>
<td>consultation with Logan Energy, Edinburgh - Hydrogen fuelling solution</td>
</tr>
<tr>
<td></td>
<td></td>
<td>manufacturers and installers. Further breakdown of this is in the model.</td>
</tr>
<tr>
<td>Energy requirement for compression of hydrogen.</td>
<td>3.7 kWh / kg</td>
<td>Hua et al, 2011[56]</td>
</tr>
<tr>
<td>Learning rates</td>
<td>12% per doubling for hydrogen refuellers.</td>
<td>Approximated from Ruffini &amp; Wei[31]. Varied in analysis.</td>
</tr>
<tr>
<td>Gas network operating cost</td>
<td>£336,000,000,000, 47,578 GWh, £0.007 (0.7p)/kWh</td>
<td>SGN plc 2018 annual sales[57] / annual energy delivered [14]</td>
</tr>
</tbody>
</table>
We assume the cost will be similar for hydrogen, as most of this is a fixed asset related cost.

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
<th>Source/Note</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity network operating costs</td>
<td>£450,000,000 17,003 GWh</td>
<td>SPEN plc 2018 annual sales / annual energy delivered [58]</td>
</tr>
<tr>
<td></td>
<td>= £0.0265 (2.65p)/kWh</td>
<td></td>
</tr>
<tr>
<td>Discount rate</td>
<td>6% used in all transition scenarios.</td>
<td>Assumed; can be varied in the model.</td>
</tr>
<tr>
<td>Efficiency of electrolysis</td>
<td>71%</td>
<td>Buttler &amp; Spliethoff[59]. The high end of current technology is used, as we expect average efficiencies to improve over the transition.</td>
</tr>
<tr>
<td>Wholesale cost of grid supplied electricity</td>
<td>£0.188 / kWh</td>
<td>UK Government [60]. Assumed to include values for network operations, losses, routine capital expenditure. This is held constant through the modelled period.</td>
</tr>
<tr>
<td>Timescale for conversion of natural gas network</td>
<td>2028-2042 +/- 2 years at each end</td>
<td>We assume that the proportion of hydrogen fuelling stations supplied through the gas network rises in a logistic function to a maximum of 85% by the end date – representing the proportion of the population connected to the gas grid at present.[28]</td>
</tr>
</tbody>
</table>

As this conversion progresses and more network hydrogen becomes available, the forecast number of stations producing hydrogen locally decreases a little after 12-15 years. We assume the redundant ones will be converted to dispense grid supplied hydrogen, although we have not identified a cost saving as the number affected is small.

Data on hydrocarbon fuelling equipment costs and lifespan (shown in model worksheet 20) are obtained from information canvassed by the Petroleum Retailers’ Association (PRA) from its members on our behalf, supplemented by a discussion with the investment director of a large fuel retailing company. The correspondence with the PRA is available from the authors on request.

Cost of water is negligible. Scottish Water website shows metered charge at 88p/cubic metre for domestic metered customers[61] – in reality for our purposes this would be
lower due to larger demand. 1 m³ water weighs 1000 kg, which would yield 111 kg of hydrogen. 88p for 111 kg hydrogen is 0.8p/kg, about 0.5% of our total cost estimate.

The number of hybrid smaller vehicles sold between 2030 and 2035 will be insignificant. Early experimenting with the model showed that allowing the hydrocarbon sales to taper naturally to zero at around 2035, rather than forcing them to zero at 2030 as in current legislation, makes little difference to either gross emissions or to the zero emission refuelling infrastructure required. If these are hybrid rather than fully hydrocarbon, the impact will be even lower.

| Sizes of hydrogen refuelling stations | Small: 1000 kg/day. | Medium 2850 kg/day | Large 5700 kg/day. | Derived from DECC/Deloitte [39] |
Appendix B
Model details

Step 1
This creates a randomised data set for the modelled cases for the Monte Carlo simulation. The variables for which the data are generated are as follows (shown with the variable name for use in subsequent calculations):

- UnitEmNewHCclass = Per-Vehicle emissions from new hydrocarbon fuelled vehicles, by vehicle class, at intervals through the transition. The range of values of this is constrained by current and expected EU and UK legislation, and is further constrained not to exceed the value generated in the previous timestep. This creates a Markov Chain value generation. We generate values for the key dates of 2020, 2025, 2030, and 2040.
- %Hclass = Future zero carbon fuel market share of hydrogen, using the three input constraints from the fuel choice options of Large Vehicles Only, Like for Like, and 100% Hydrogen.
- %EllUse = Electrolyser usage rates as a % of capacity. This is allowed to vary randomly between constraints, set at 81% and 61%, based on a central value of 71% [11].
- LocalElec = The proportion of in-situ produced hydrogen using local dedicated electricity generation, rather than grid supplied electricity. This is allowed to vary randomly between 0-100%.

For each modelled case, calculation steps 2-8 below were applied.

Step 2
This generates the future vehicle numbers, which control all the subsequent steps.

The numbers of ZEVs in each class for each year is generated, using a pair of standard logistics functions, where one represents new sales and the second represents vehicles scrapped at end of life. The two are offset by the average age on scrapping of the class.

The values of the constants creating this distribution were adjusted manually for each vehicle class, until the emissions in use (calculated in step 3) met the relevant 2030 and 2045 targets within 5% for all modelled cases. The constants were varied for the different classes of vehicle as appropriate. The values of the constants developed are presented in the model in worksheet 12.

From there, the total numbers of ZEVs, and new sales, number scrapped, and total registered hydrocarbon vehicles for each year are then calculated using simple arithmetic. The sales figures are forced to 100% of cars and vans at the end of 2030, reflecting the UK Government’s ban on hydrocarbon sales from that date.

Inputs
NewVehclass is the total annual sales of new vehicles of any fuel type for each class, taken as constant through the transition.

k is an arbitrary constant affecting the gradient of the curve

x is the year in question

xo is the mid-point of the time distribution, that is the point at which NZEclass = NewVehclass/2

VL is approximately average vehicle life, found from total fleet size / annual sales (this assumes a constant fleet size).

EndHCdate = year after which hydrocarbon vehicle sales are to be stopped.

TotVehclass = Total numbers of vehicles in class, assumed to be constant at current levels.

**Outputs**

NewZEclass = New ZEVs in class

\[\text{NewZEclass} = \text{NewVehclass}/\left[1 + \exp\left(-k(x-xo)\right)\right] \text{ (standard logistic function).}\]  

\[\text{Equation B. 2}\]

ScrZEclass = Scrapped ZEVs in class

\[\text{ScrZEclass} = \text{NewVehclass}/\left[1 + \exp\left(-k\left(x-(xo+VL)\right)\right)\right]\]

\[\text{Equation B. 3}\]

TotZEclass = total numbers of ZEVs

\[\text{TotZEclass} = \text{TotZEclass(yr-1)} + \text{NewZEclass} - \text{ScrZEclass}\]

\[\text{Equation B. 4}\]

TotHCclass = Total registered HCVs at end of year

\[\text{TotHCclass} = \text{TotVehclass} - \text{TotZEclass}\]

\[\text{Equation B. 5}\]

NewHCclass = new sales of hydrocarbon vehicles (HCV) in year

\[\text{NewHCclass} = \text{NewVehclass} - \text{NewZEclass}\]

\[\text{Equation B. 6}\]

DHclass = change in number of HC vehicles

\[\text{DHclass} = \text{TotHCclass} - \text{TotHCclass(yr-1)}\]

\[\text{Equation B. 7}\]

**Step 3**

Calculates the emissions in use for each class each year based on the numbers of hydrocarbon vehicles remaining in step 2 and the Markov chain generated future emissions created in step 1.

AvAnKmclass = Average Annual distance driven per vehicle in class (km)

UnitEmAvPrevHCclass = UnitEmAvAllHCclass (defined below) for previous year

\[\text{Equation B. 8}\]

TotEmclass = Total emissions from class in year (kT/yr CO2 eq)

\[\text{TotEmclass} = \text{UnitEmAvPrevclass} \times \left(\text{TotHCclass} - \text{ScrHCclass}\right) \times \text{AvAnKmclass} + \text{UnitEmNewHCclass} \times \text{NewHCclass} \times \text{AvAnKmclass}\]

\[\text{Equation B. 9}\]

UnitEmAvAllHCclass = Unit emissions, average for all HC vehicles in service in class

\[\text{UnitEmAvAllHCclass} = \text{TotEmclass} / \left[\text{TotHCclass} + \text{NewHCclass} - \text{ScrHCclass}\right]\]

\[\text{Equation B. 10}\]

TotEmclass is calculated for each vehicle class, and summed across all classes for each year.

**Step 4**

Calculates the required quantity of hydrogen (produced locally and centrally), based on the numbers of ZEVs of each class (Step 2) and the proportion of them using hydrogen (Step 1).
The average demand for hydrogen is found from the average current demand for hydrocarbon fuels for each vehicle class, adjusted by an efficiency factor relating the energy required from petrol or diesel to that from hydrogen.

The annual total and proportionate demand for hydrogen is calculated:

**Inputs**
- TotZEclass = total numbers of ZEVs in class
- %Hclass = Proportion of ZEVs in class using hydrogen fuel
- UnitDemHclass = Annual Fuel demand per HFCEV in class

**Outputs**
- DemHclass = Annual demand for hydrogen from class
  - \( \text{DemHclass} = \text{TotZEclass} \times \%Hclass \times \text{UnitDemHclass} \)  

\( \text{SumDemHclass} = \text{Total demand for hydrogen, summed across all classes} \)
The aggregate of \( \text{SumDemHclass} \) over the transition period is used to estimate the fuel proportion used in many of the output graphs, expressed as the percentage of zero carbon fuel used as Hydrogen, based on fuel energy supplied. We assume for this calculation that the non-hydrogen energy is supplied as electricity to BEVs.

The proportionate share between locally produced hydrogen and network distributed hydrogen is calculated using a standard logistic function. We assume that the transition to network supplied hydrogen (i.e. the conversion of the existing gas network to hydrogen) takes place from 2028 – 2040, and that at maximum 85% of the hydrogen demand will be met through the network.

**Step 5**
This step calculates the infrastructure required to deliver the hydrogen and electricity:

For hydrogen, three station capacities (CapStn) are considered: Large (5700 kg/day), Medium (2850 kg/day) and Small (1000 kg/day). These are derived from current hydrocarbon station sizes, calculated independently in Step 8. These are allocated in the same proportion (%Stn) as existing small, medium and large hydrocarbon fuelling stations.

**Other inputs**, found in steps above:
- SumDemHclass
- %EllUse

**Outputs**
- GrossCapStn = Gross capacity required from stations of this size
  - \( \text{GrossCapStn} = \text{SumDemHclass} \times \%\text{Stn} / \%\text{EllUse} \)  

\( \text{NrStncap} = \text{number of fuelling stations of this capacity and type required.} \)
= \( \text{GrossDemStn/CapStn} \) (rounded up to next integer)
Step 7
Calculates the capital and fuel costs of the infrastructure in step 5.

Capital costs.
Unit cost for hydrogen equipment is decreased based on the learning rate. This is the percentage decrease in cost each time the number of installations doubles. Costs including and excluding electrolysers are used for local and centralised production respectively. Multiplying the annual unit cost by the number of new installations required (step 5) gives the annual cost of new hydrogen infrastructure by station size and type.

Aggregate, Annual and NPV costs are then calculated using simple arithmetic and standard methods of NPV calculation. These are summed as appropriate to give the hydrogen capital cost.

Definitions
LRH = learning rate for hydrogen (% decrease in cost each time the number of installations doubles).
NrStnCap,source = NrStnCap divided according to the split between locally produced and network supplied hydrogen.
InitUnitCostCap,source = initial unit cost, with suffices as above.

Outputs
UnitCostsize,source = unit cost in each year.
= [(1-LRH)^Log2(NrStnCap/NrStnCap(yr-1))] *InitUnitCostCap,source

Equation B. 14
This is repeated for other station sizes and hydrogen sources.

Aggregate, Annual and NPV costs are then calculated using simple arithmetic and standard methods of NPV calculation. These are summed as appropriate to give the hydrogen capital cost.

Fuel Costs
The fuel costs are taken as the cost of production and distribution of the fuels, but excludes retail margins and tax. This is because retail margins are subject to local market forces, and taxes are at the government’s discretion. The demand for both fuels is brought forward from step 4.
The energy requirement of locally produced hydrogen is found from the energy content of the hydrogen divided by the efficiency of electrolysers. The wholesale cost of grid electricity required to supply this energy demand represents the production cost of the hydrogen. The proportion supplied using local dedicated electricity has the electricity cost reduced by the cost of grid transmission.
The production cost of network supplied hydrogen is found from the input electricity cost from new offshore wind electricity generation, the efficiency of electrolysis, and the capital cost of electrolysers divided by their expected life. To this is added the cost of transferring the hydrogen to shore via pipeline, and the cost of network transmission onshore.
Both hydrogen production methods are summed, and the cost of compression to 700 bar is added. This is found from the energy cost of compression per kg and the wholesale cost of electricity.
The hydrogen and electricity operating costs are then added to get the operating costs for the case.

Inputs
EffEll = Efficiency of Electrolysis, %
EnH = Energy density of hydrogen, kWh/kg
EnComp = Energy required for compression of hydrogen to 700bar, kWh/kg
UnitCostGrdE = unit cost of electricity supplied through grid (wholesale), £/kWh
UnitCostSuppH = unit cost of offshore produced hydrogen supplied into repurposed network (wholesale, calculated), £/kg
UnitCostDistH = unit cost of operating the repurposed gas network, £/kg
UnitCostTransE = Transmission cost of grid electricity (included in UnitCostGrdE)
DemH = Annual total demand for Hydrogen
%Hn = Proportion of hydrogen supplied through network.
%Hc = Proportion of hydrogen produced locally
%Ec = Proportion of electricity produced from local dedicated generation

**Demand Calculations:**
DemHn = gross demand for hydrogen supplied through network, kT/yr
   = DemH x %Hn

DemHc = gross demand for hydrogen produced locally, kT/yr
   = DemH x %Hc

EnHc = Energy (as electricity) requirement for hydrogen produced locally, GWh/yr
   = DemHc*EnH/EffElect

**Fuel Cost calculations:**
UnitCostComp = unit cost of compression of hydrogen to 700 bar, £/kg = EnComp*UnitCostGrdE

AnnCostComp = Annual total cost of compression of hydrogen to 700 bar, £
   ={(DemHc+DemHn)*UnitCostComp*kg_in_kT_kWh_in_GWh

AnnCostSuppHn = Annual total cost of hydrogen supplied into repurposed network, £
   =DemHn*kg_in_kT_kWh_in_GWh*UnitCostSuppH

AnnCostDistH = cost of operating the repurposed gas network, £
   =DemHn*kg_in_kT_kWh_in_GWh*UnitCostDistH

AnnCostHc = Annual total cost for hydrogen produced locally, £
   = EnHc*(1-%Ec)*UnitCostGrdE + EnHc*%Ec*(UnitCostGrdE – UnitCostTransE)

**Fuel Cost Totals**
AnnTotH = total operating cost of hydrogen, £
   =AnnCostComp+AnnCostSuppHn+AnnCostDistHn+AnnCostHc

**Step 8**
This is a separate assessment of the typical sizes of hydrogen refuelling station that would ultimately be needed and current annual average capital expenditure on the existing hydrocarbon refuelling infrastructure.

The sizes of refuelling station are based on three typical sizes of hydrocarbon station. The energy content of the fuel dispensed annually from these is modified for the difference in efficiency between internal combustion engines and hydrogen fuel cells. This is then used to calculate the corresponding quantity of
hydrogen, based on the specific energy of hydrogen (Lower Heating Value, 33.3 kWh/kg). The resulting values are then rounded for convenience to the three sizes used of 1000, 2850 and 5700 kg/day.

The annual expenditure is found from the cost and typical service life of the following elements:

Fuel pump
Hoses and pipes associated with each pump
Storage tanks
Fuelling station general refurbishment.

Combining these with the number of pumps at a typical fuelling station and the estimated number of fuelling stations in Scotland allows an estimate of the annual cost. There are a number of approximations used in this approach, so the result is treated as an indicative range for comparison rather than an accurate calculation.

**Fuelling Station Size Inputs**
SpEnH = Hydrogen specific energy
EnDP = Energy Density, Petrol (also ~D, Diesel)
AvAnnConsP = Average Annual Consumption of Petrol, Scotland (also ~D, Diesel)
EffPH = Efficiency ratio Petrol / Hydrogen
EffPE = Efficiency ratio Petrol / Electricity
VolHCsize = Annual volume of hydrocarbon supplied from Small, Medium or Large hydrocarbon fuelling station.

**Fuelling Station Size Calculations**
EquivHP = Equivalent kg of hydrogen to one litre Petrol (also ~D, Diesel)
\[ \text{EquivHP} = \frac{\text{EnDP} \times \text{EffPH}}{\text{SpEnH}} \]  
\[ \text{Equation B. 24} \]
VolSupPsize = Annual volume of Petrol supplied from hydrocarbon fuelling station (also ~D~, Diesel)
\[ \text{VolSupPsize} = \frac{\text{VolHCsize} \times \text{AvAnnConsP}}{\text{AvAnnConsP} + \text{AvAnnConsD}} \]  
\[ \text{Equation B. 25} \]
EquivDlySupPHsize = Daily hydrogen supply equivalent to Petrol (Also ~D~, Diesel)
\[ \text{EquivDlySupPHsize} = \text{VolSupPsize} \times \text{EquivHP} \]  
\[ \text{Equation B. 26} \]
EquivDlySupHCHSm = Daily hydrogen supply equivalent to all fuel from fuelling station
\[ \text{EquivDlySupHCHSm} = \text{EquivAnnSupDHSm} + \text{EquivAnnSupPHSm} \]  
\[ \text{Equation B. 27} \]

**Capital refurbishment costs for hydrocarbon fuel dispensing related apparatus**

**Inputs**
NrStnSco = No. fuelling stations in Scotland
CostPump = Cost of pump
CostPipes = Cost of associated pipelines
LifePuPi = Service life of pump and pipelines
CostTank = Cost of storage tank (ranges from cost of a new tank to cost of refurbishing one in-situ)
LifeTank = Service life of storage tank
NrTankStn = No. storage tanks per station site
NrPumpStn = No. pumps per station site
Calculations
UnitCostAnnPuPi = Cost per year per pump & associated pipelines
   = (CostPump + CostPipes)/LifePuPi  

UnitCostAnnTank = Cost per year per storage tank
   = CostTank/LifeTank  

UnitCostAnnApp = Cost per year per site, apparatus only
   = UnitCostAnnPuPi*NrPumpStne+UnitCostAnnTank*NrTankStn  

ScoCostAnnApp = Total cost per year, apparatus only (Scotland)
   = UnitCostAnnApp*NrStnSco  

Step 9 combines the outputs into various graphs as presented through this paper.

The associated macro “RunMultipleScenarios” runs the model sequentially for all three Pace options, giving the results for all nine scenarios, and records the results.

A reviewable online version of the model is presented as the Electronic Supplementary Information.
The hidden cost of road maintenance due to the increased weight of battery and hydrogen trucks and buses – a perspective

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**Keywords:** hydrogen; battery; BEV; HFCEV; road maintenance; hidden cost

**Abstract**

Decarbonisation of transport emissions is essential to meet climate targets. For road transport, currently available technologies are battery electric vehicles and hydrogen fuel cell electric vehicles. Battery vehicles are more established than hydrogen; both could deliver the emissions reduction required. However, battery vehicles are considerably heavier than equivalent hydrogen vehicles, which are in turn slightly heavier than internal combustion engine (ICE) vehicles; a heavier vehicle will have a bigger impact on road wear and associated costs. Here we carry out a desk based analysis, developed in 2021-2022, examining the impact and cost of the increased weight of zero emissions vehicles on road wear in an entire national vehicle fleet. The novelty is in the first quantified application of the long-understood relationship between axle load and road wear to the problem of the additional weight of zero emissions vehicles. This leads to an approximate quantification of additional costs of road maintenance as the vehicle fleet transitions to zero emissions vehicles. We examine these in four scenarios: all battery vehicles; all hydrogen vehicles; a combination; current ICE vehicles for comparison. We find 20-40% additional road wear associated with battery vehicles compared to ICE vehicles; hydrogen leads to a 6% increase. This is overwhelmingly caused by large vehicles – buses, heavy goods vehicles. Smaller vehicles make a negligible contribution. Governmental bodies liable for road maintenance may wish to set weight limits on roads, require additional axles on heavier vehicles, or construct new roads to a higher standard, to decrease road wear.
Introduction

Decarbonisation of energy used in road transport will be essential for the world to meet the necessary reductions in emissions. The two currently commercially available technological solutions for road vehicles are Battery Electric Vehicles (BEV) and Hydrogen Fuel Cell Electric Vehicles (HFCEV) (Robinus et al. 2018). At present, HFCEV vehicles are in their infancy, while BEVs are more established. However, in the UK, Zero Emission Vehicles (ZEV) of any type have not yet made significant inroads into the hydrocarbon fuelled internal combustion engine (ICE) fleet with less than 1% of the vehicle fleet and about 4.3% of new vehicle sales in 2020 (UK Government 2021a, Scottish Government 2020b).

HFCEV are typically slightly (1-2%) heavier than ICE vehicles; BEVs are usually significantly heavier (10-30%) due to the high weight of batteries (Lombardi et al. 2020). In this paper we apply existing knowledge of the relationship between vehicle weight and road wear to consider the impact of the heavier ZEVs. We do this by assessing the road wear due to the main vehicle classes at present and in future scenarios of (1) all battery vehicles; (2) all hydrogen vehicles; (3) a combination, and comparing the overall results. A significant increase in wear would lead to a combination of increased maintenance costs, increased particulate emissions, and potentially the need to construct new roads to a higher standard.

We select Scotland as an area of analysis. This allows analysis of a fairly homogenous road construction and vehicle standard (Low et al. 2020). This is also connected with the Scottish Government’s commitment to unusually demanding targets for early decarbonisation, with a ban on new hydrocarbon car & LGV sales, and an all-sector emissions reduction of 75% from 1990 levels, to be achieved by 2030, followed by net zero emissions by 2045 (Scottish Government 2019), and also with the Scottish Government’s recent announcement of substantial investment in the hydrogen economy (Scottish Government 2020a).

This approach can be applied to other locations, subject to local factors such as (i) existing road quality and construction standards, (ii) typical vehicle weight, numbers and construction & use regulations, and (iii) an assessment of the local applicability of the method of road wear assessment used (Rhodes 1983).

Context & Literature

There have been several relevant studies investigating the connection between vehicle weight and road wear, starting with seminal work by the American Association of Highway and Transportation Officials (AASHO) in the 1950s (AASHO 1962). This was further developed in the UK by Rhodes (Rhodes 1983) and the Transport Research laboratory (Addis and Whitmarsh 1981), and re-examined by Martin in 2002 with a focus on Australian roads of similar construction (Martin 2002), confirming the relationship first developed.

Nilsson, Svensson and Haraldson (Nilsson et al. 2020) assess the economic impact and life between major restoration of road surfaces subject to different types of loading. However, their results also find additional surface wear due to smaller vehicles. They attribute this to the use of studded snow tyres in their study area, Sweden, which are not used in Scotland.

Gustafsson (Gustafsson 2018), Denby, Kupiainen and Gustafson (Denby et al. 2018) and Stafoggia and Faustini (Stafoggia and Faustini 2018) review the impact and measurement of road wear emissions on public health, within Non-Exhaust Emissions: an Urban Air Quality Problem for Public Health; Impact and Mitigation Measures (Fulvio 2018).

This all contributes to the established and widely used principle that relates vehicle axle load to road wear in the 4th power. This is described in more detail in the Method section below.

Lombardi, Tribioli, Guandalini and Iora (Lombardi et al. 2020) examine the impact of different drivetrain types, including HFCEV and BEV on the weights of a range of vehicles, as part of their analysis into efficiency.
As the world moves into a transition to zero emissions, new vehicles will require different zero emission drivetrains. At present, available options are either BEV or HFCEV (Robinius et al. 2018). Both of these are heavier overall, with current technology, than existing hydrocarbon ICE drivetrains (Lombardi et al. 2020). Additional road wear is considered in a number of works in the context of particulate emissions (Matthias et al. 2020, Beddows and Harrison 2021), or in BEV specific road design (Börjesson et al. 2021).

Here, then, we take the established relationship between axle load and road wear and apply it to the increased weight of vehicles arising from replacing an existing national vehicle fleet with ZEVs, to arrive at the scale of the increased wear on existing roads, and hence future maintenance cost.

The novelty in this paper is that this appears to be the first quantified application of the long-understood relationship between vehicle axle load and road wear to the problem of the additional weight of zero emissions vehicles. This leads to an approximate quantification of the additional cost of road maintenance as the vehicle fleet transitions to zero emissions vehicles, filling that gap in published knowledge. We introduce the new terms Road Wear Potential (RWP) of an individual vehicle, and the Road Wear Impact Factor (RWIF) which reflects the total annual wear caused by a vehicle fleet.

**Hypothesis**

There will be significant and quantifiable additional costs of road maintenance due to the increased weight of ZEVs over ICE vehicles. This will be markedly greater for BEVs than for HFCEVs.

**Method**

Rhodes (Rhodes 1983) (and many others) describes the 4th power relationship between road wear and axle load, developed from the experimental work on the subject by the AASHO in the 1950s (AASHO 1962). Rhodes introduces the concept of using a Standard Axle as a way of comparing the impact of various vehicle types. The Standard Axle is taken as a single axle imposing a total load of 80kN (equivalent to 8 tonnes); the wear relative to such an axle can be readily calculated using the 4th power to give a number of effective standard axles per actual axle. We express this mathematically in Equation 1 below.

\[
\text{Effective Standard Axles per axle} = \left(\frac{\text{Axle load in kN}}{80}\right)^4
\]

Equation 1

This approach allows an assessment of cumulative impact of vehicles of different classes, and is used in other studies into road wear (Nilsson et al. 2020). As road wear is very tightly controlled by axle load, it becomes apparent that larger vehicles such as HGVs and buses will have a much greater impact than cars, relative to the vehicle weight.

Other researchers have developed different relationships - for example the UK Transport and Roads Research Laboratory produced a range of exponential powers between 2.4 to 6.6 depending on a number of factors including existing road condition and construction standard (Addis and Whitmarsh 1981). Johnsson derives a range of powers for Swedish roads between 1.2 and 8.5 (Johnsson 2004). However, for the purpose of this preliminary assessment of the road wear impact by future vehicles, we consider the single 4th power of axle weight to be adequate; this is currently used in UK and many other countries' highways design and maintenance (UK Government 2021b).

Based on this established relationship, we introduce the terms Road Wear Potential (RWP) of an individual vehicle, and the Road Wear Impact Factor (RWIF), reflecting the total annual wear caused, which could apply to each vehicle class, sub-class, or national fleet.

The RWP reflects the potential of a vehicle to wear out the road, without considering the extent to which it is used. It depends on the weight of the vehicle and the number of axles it uses, and uses the above 4th power relationship to determine the number of effective standard axles per vehicle. We assume for these
purposes that each axle in a vehicle carries an equal load. In practice this will not be the case; we examine the effect of this in the Sensitivities section.

\[
RWP = (\text{Nr. of axles}) \times (\text{Vehicle Weight}/(\text{Nr. of axles} \times 80))^4
\]  
\text{Equation 2}

The RWIF for each class (or sub-class) is based on the Road Wear Potential of a typical vehicle of a given class, multiplied by the average distance such a vehicle drives and by the number of vehicles in each class. This gives an overall value for comparison of the road wear associated with an entire vehicle class over the course of a year.

\[
\text{Annual Class RWIF} = RWP(\text{typical in class}) \times (\text{nr. vehicles in class}) \times (\text{average annual distance driven})
\]  
\text{Equation 3}

The Class Road Wear Impact Factors are then summed to create an overall RWIF for each scenario.

The inputs and data sources are as follows:

- The number of vehicles in each standard vehicle class (buses & coaches, cars, motorcycles, HGV and LGV\(^1\)) (Scottish Government 2020b)
- The typical weight, or range of weights, or fuel based sub-classes, of ICE vehicles in each class (Scottish Government 2020b).
- The likely change in weight due to a similar vehicle having HFCEV or BEV type fuelling and drive systems (see below for derivation).
- The average annual distance travelled per vehicle by class, in km (UK Government Department of Transport 2019).
- We assume that the wear and tear is directly related to the use made of the roads, i.e. the number, class and weight of vehicles using the roads, and not significantly connected to seasonal, weather and simple aging related impacts alone (Nilsson et al. 2020).
- We use the standard UK government vehicle classes of cars, motorcycles, Light Goods Vehicles (LGV), Heavy Goods Vehicles (HGV)\(^5\), and Buses & Coaches. HGVs are further divided into ten weight-based sub-classes, while cars and LGVs are divided into fuel based, that is petrol (gasoline) and diesel (the number of BEVs is still small enough to be insignificant) sub-classes.

To estimate the applicable vehicle weight, or reference weight, for ZEVs, we make an initial assessment of the increase in vehicle weight due to the two new fuel types, and derive simple formulas that fit data previously identified by Lombardi et al (Lombardi et al. 2020) and vehicle manufacturers (Mercedes Benz UK 2019).

We calculate the RWP and RWIF for all classes and sub-classes, and hence the nationwide RWIF, for four scenarios:

5. Current situation, vehicle fleet overwhelmingly dominated by ICE vehicles.
6. All BEV – all vehicles replaced in the same numbers and load carrying capacity with BEVs.
7. All HFCEV – all vehicles replaced in the same numbers and load carrying capacity with HFCEVs.
8. Like for Like – all current diesel vehicles replaced by HFCEVs, and all current petrol vehicles replaced by BEVs.

\(^5\) The Scottish and UK Governments use the terms “Goods” and “Light Goods” for goods vehicles above and below 3,500 kg maximum gross weight respectively. Here, to reduce ambiguity, we use the older common terms Heavy Goods Vehicle (HGV) and Light Goods Vehicle (LGV).
Results

Initial assessment of vehicle weight and other inputs

Based on Lombardi et al (Lombardi et al. 2020) for larger vehicles (3500kg and over), and manufacturers’ published data for cars (Mercedes Benz UK 2019), we identify the following equivalent vehicle weights for vehicles of the same carrying capacity:

<table>
<thead>
<tr>
<th>ICE weight (kg)</th>
<th>BEV weight (kg)</th>
<th>HFCEV weight (kg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1950</td>
<td>2455</td>
<td>1970</td>
</tr>
<tr>
<td>3500</td>
<td>4224</td>
<td>3566</td>
</tr>
<tr>
<td>5200</td>
<td>6028</td>
<td>5255</td>
</tr>
<tr>
<td>18000</td>
<td>19816</td>
<td>18236</td>
</tr>
<tr>
<td>44000</td>
<td>47686*</td>
<td>44760*</td>
</tr>
</tbody>
</table>

Table 1 Gross vehicle weights for equal payload, three fuel types.
Note that the weights marked * exceed the maximum allowable vehicle weight of 44,000 kg.

To get a suitable equivalence from manufacturers’ data, it is necessary to identify almost identical vehicles made with different fuel types. The only car commercially available both as an HFCEV and as an ICE vehicle is the Mercedes-Benz GLC (now ceased production), which is a medium-large SUV. The HFCEV version has a larger battery than is usual for an HFCEV (13.5kWh instead of around 1.6kWh (Hyundai UK 2020)), and can be used as a plug in hybrid. It is also available as a BEV (called the EQ-C, with some styling differences)(Mercedes Benz, Mercedes Benz UK 2022). Other vehicles exist as both BEV and ICE, but not HFCEV. For the purposes of consistency in this table, we use the Mercedes-Benz GLC / EQ-C for both ZEV types. We adjust the weight of the GLC Fuel Cell down by 95kg to reflect the typical extra weight of the larger Li-Ion battery (Jung et al. 2018), to create a more relevant entry for this table.

From this table, we derive a simple relationship between the weight of a BEV and an ICE vehicle of the same carrying capacity based on the trendline function in Microsoft Excel, as follows:

BEV Weight (kg) = (1.0744 × ICE Weight) + 430

And between an HFCEV and an ICE vehicle:

HFCEV Weight (kg) = (1.014 × ICE Weight)

Both of these formulas match the table 1 data well, with a very close $R^2$ value of at least 0.9999.

Given that the lowest data point in the original table still represents a large car, it will be necessary to extrapolate the formula slightly to get a vehicle weight more representative of a smaller one; it may be unrepresentative of motorcycles. However, as it turns out, the RWIF of cars and motorcycles is so low that this immaterial (see below).

For each class or sub-class, we have to estimate a reference vehicle weight. The key factor affecting this for large vehicles is the proportion of time the vehicles run empty or lightly loaded. This will obviously happen some of the time, with a significant change in weight. Vehicle operators will clearly try to maximise the load in their vehicles, so the actual average weight can be expected to be higher than, for example, a mid-point between empty and full. We expect that buses will run for a higher proportion of the time empty or lightly loaded, as they will be sized for peak demand. However, due to the 4th power relationship described above, the heavier loading will have a proportionately greater impact on road wear.
As a working assumption, we take the reference vehicle weight as the midpoint of the applicable weight range. We examine the implications of inaccuracies in the Sensitivities section below.

The annual distance travelled by each vehicle is taken as the average for the class or sub-class from UK government statistics. There are cases where this data is only available for a group of sub-classes (e.g., all 2- or 3- axle rigid chassis HGVs) – in this case we take the average for all relevant sub-classes. This is also examined in Sensitivities, below.

For some sub-classes of HGV, the regulated maximum weight was exceeded when the modelled ZEV vehicle weight was calculated, as seen in Table 1. In these circumstances, we assume that the maximum weight will not be exceeded, but that instead the affected vehicles will be used for additional trips to reach the same aggregate carrying capacity. We explore the effect of this further in Sensitivities, below.

**Road Wear Potential per vehicle**

We examined the wear potential associated with individual vehicles. Figure 1 below shows the relationship between vehicle weight and Road Wear Impact Factor, taken as the number of standard axles per vehicle. This shows the RWP of a vehicle in each sub-class based on its weight and number of axles, for the three fuel types under consideration.

![Road Wear Potential by vehicle class and fuel type](image)

**Fig. 1** Road Wear Potential (RWP) per vehicle, sorted by vehicle sub-class, comparing ICE, BEV and HFCEV. RWP is the number of standard axles per axle, multiplied by the number of axles on the vehicle. Vehicles under 7.5t have negligible RWP in this context.

We can see from Figure 1 that the wear potential of a larger vehicle is overwhelmingly greater than that of a smaller one, due to the 4th power law exponentially increasing the effect of greater axle load. We also see a significant increase in wear potential for a relatively small increase in vehicle weight in large vehicles, for the same reason. The mitigating effect of additional axles is also clear – the reduced number of effective standard axles per actual axle more than offsets the increased number of axles, hence the total RWP decreases for vehicles where the axle count increases. This happens at the 16-20t category, where the axle count increases to 3, at 28-32t where it increases to 4, at 38-40t which requires 5 axles, and 40-44t requiring 6 axles.

**Road Wear Impact Factor**

Next, we develop this into the assessment of the Road Wear Impact Factor by Class and overall, for the four scenarios under consideration. Multiplying each vehicle’s Road Wear Potential by the number of vehicles in the class and the average distance driven each year(UK Government Department of Transport 2019)
produces the total Road Wear Impact Factor for each class. This produces Road Wear Impact Factors as shown in Figure 2 below.

![Fig. 2 Class / Sub-class Road Wear Impact Factor, comparing the present and future scenarios. Road Wear Impact Factor is the Road Wear Potential multiplied by the number of vehicles in each class or sub-class and by the average annual distance travelled. Vehicle classes with a typical vehicle weight below 12t have negligible RWIF on a national scale.](image)

Clearly the overall RWIF is overwhelmingly due to the largest vehicles in use, even though they don’t have the highest RWP. This reflects the greater use made of the largest vehicles – there are more 40-44t HGVs than any other category of HGV other than the smallest 3.5-7.5t vehicles, which has about 20% more; also a typical 44t vehicle covers well over twice the annual distance of a 7.5t one. Due to the much smaller RWP, vehicles below 12t have a negligible impact on national RWIF with any fuel type.

The impact of ZEV technology in larger vehicles can be clearly seen, with BEV having a substantially greater impact than HFCEV. A table with a detailed breakdown of the calculations and results is presented in the Appendix.

**Sensitivities**

We considered the sensitivity of the results to different ways of estimating the input simplifications:

- Reference weight estimate
- Varied load distribution, other than equal on each axle;
- Using HGV subcategories based on axle number rather than tax bracket.

**Reference weight estimate**

We initially assumed a reference weight at the midpoint between the top and bottom of each tax class. However, the reference weight, or typical effective weight, could be significantly different for HGVs, due to the potential for different loading and use patterns. We varied the originally estimated reference weight by scaling factors ranging from 0.5 to 1.07. Beyond 1.07, the ICE reference weight began to exceed the allowable weight in each category, particularly the heaviest, therefore a higher factor than this was clearly unrealistic.

We then used the same method to assess the overall RWIF for a range of scaling factors. We continued to use the principle that if the allowable weight for a particular axle configuration were exceeded, the weight would be held at the maximum allowable, and the distance travelled for vehicles in that sub-class would...
increase to provide the same gross annual carrying capacity. The result from this assessment is shown in Figure 3:

Fig. 3  Change in overall fleet RWIF as a consequence of change in modelled ICE reference weight. Where allowable vehicle weight is exceeded, modelled distance travelled per vehicle is increased

The final output, the change in RWIF with different fuels, is assessed as the ratio between the old and the new rather than a meaningful absolute value, so a change to both produces a similar result for most of the range. The change in RWIF decreases at higher scaling factors because increasing the distance travelled has a smaller impact than increasing vehicle weight due to the $4^{th}$ power relationship, so this becomes significant at higher load scaling factors. On this basis, we describe the change in overall RWIF due to a fully BEV fleet as 20-40%, and for a fully HFCEV and Like for Like fleet as 6%.

Unequal loading

To assess the effect of unequal load distribution, we considered the effect of one axle carrying a percentage more than all the other axles, which were set as equal. An unevenly distributed load would result in a higher RWP than an evenly distributed one. However, when the same proportion of uneven-ness is applied to current and future cases, the relative increase in RWP and RWIF is unchanged. Ensuring that loads are more evenly distributed in ZEVs than at present would be a way of mitigating the increased RWP, but that analysis is beyond the scope of this paper.

Different HGV subclasses

Data is available for HGV numbers and usage based on weight related tax bracket or on number of axles, which is also related to maximum weight. Using tax brackets gives a finer division of data; using the axle number gives a better match to the effects between sub-classes and permitted vehicle weights. Our main approach has been to use the former. Here, we re-run the analysis on the basis of axle numbers, for comparison.

However, again because the treatment is the same for ICE and ZEV, the effect on the overall result is minimal. Results are presented in Table 2:
Table 2  Comparison of overall RWIF for different types of HGV sub-class categorisation

We consider this effect to be insignificant.

## Conclusion and Discussion

We introduced the hypothesis “There will be significant and quantifiable additional costs of road maintenance due to the increased weight of ZEVs over ICE vehicles. This will be markedly greater for BEVs than for HFCEVs.”

We find that this partially correct – in the case of the largest vehicles, that is buses and heavy good vehicles, the hypothesis is shown to be true. However, in the case of smaller vehicles such as cars, light goods vehicles and motorcycles, it is unlikely that there will be a significant difference.

A complete conversion of the existing vehicle fleet to BEV would be likely to increase annual road wear in Scotland by around 20-40%, with a modelled base case value of 31.0%. Conversely, the same conversion to HFCEV would increase road wear by around 6% (Figure 4). The combined, or “Like for Like” future fleet, where existing diesel vehicles are replaced by HFCEV and existing petrol vehicles are replaced by BEV, would also lead to increased road wear of around 6%.

We can see from figure 2 above that in each scenario, the Road Wear Impact Factor is dominated by the relatively small number of HGVs, 37,000 vehicles out of a total vehicle fleet of approximately 3 million, which contribute around 87% of the Road Wear Impact Factor. The 14,000 buses and coaches are also significant, contributing around 12%. The Road Wear Impact Factors due to cars, light goods vehicles and motorcycles are insignificant, contributing in total less than 1% of the Road Wear Impact Factor in all scenarios. This will not be news to highways engineers, but needs to be understood in the energy sector. HGVs and Buses & Coaches would be HFCEVs in both the all-HFCEV and the Like for Like scenarios; as those are the vehicles overwhelmingly responsible for road wear, this leads to the Road Wear Impact Factors being effectively identical for both of these scenarios.
This effect could possibly be mitigated in the future by the introduction of lighter-weight battery technology. This is, however, speculative – while such batteries are being researched, they are not yet commercially available (Ye and Li 2021). It might also be possible to re-engineer the basic vehicle to be lighter by using lighter materials or construction methods, although these would be equally applicable to other fuel types. Also, if “e-roads” - which charge vehicles as they drive - became ubiquitous, the need for large and heavy batteries might be reduced (Coban et al. 2022).

A further mitigating effect, requiring no new technology, would be to increase the required number of axles on large vehicles – due to the 4th power effect, the reduction in wear per axle would outweigh the extra wear due to the additional axles. This would, however, increase the vehicle manufacturing costs and fuel consumption (Johnsson 2004).

The all-BEV scenario represents an increase in road wear of about 31% from the present situation; all HFCEV and Like For Like both represent an increase of about 6% - that they are almost identical reflects the dominance of diesel in large vehicles at present.

It would also be important to design vehicles such that the additional weight of batteries is evenly distributed across all axles – this would prevent an imbalanced load creating significant extra wear. This could, however, force a change in operating practice for articulated HGVs, as some of the batteries might have to be installed in the trailer unit.

It should be noted that this study considers the impact on the road network as a whole, and takes account of the relative position of present and future requirements. It is likely that specific areas, especially where the existing road has deteriorated or is of lower initial quality, that the impact will be different and smaller vehicles might become significant. Future study, including more localised analysis, might be necessary to better understand local effects. Future study would also be useful to better understand the benefit of the mitigating factors outlined above.

In Scotland, responsibility for road maintenance is shared between the Scottish Government for trunk (primary) roads, and local authorities for the much greater network of all other roads from large A-class roads through to urban access; these bodies would bear the costs related to this additional road wear. The most recent Audit Scotland report into road maintenance expenditure refers to 2015 (Audit Scotland 2016), showing the required road maintenance expenditure to maintain the existing condition. This is set out in

---

**Fig. 4** Overall Road Wear Impact Factors, grouped by class. Subclass values have been combined to produce the overall class values.
Table 3, converted to 2021 values (Bank of England 2022), along with the additional expenditure required to provide for ZEVs in the future:

<table>
<thead>
<tr>
<th></th>
<th>Transition to BEV</th>
<th>Transition to HFCEV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Required to maintain condition</td>
<td>Additional required expenditure (BEV)</td>
<td>Overall total required expenditure (BEV)</td>
</tr>
<tr>
<td>Local Authorities</td>
<td>£324,000,000</td>
<td>£100,000,000</td>
</tr>
<tr>
<td>Scottish Government</td>
<td>£206,000,000</td>
<td>£64,000,000</td>
</tr>
<tr>
<td>Total</td>
<td>£530,000,000</td>
<td>£164,000,000</td>
</tr>
</tbody>
</table>

*Table 3  Required annual expenditure on road maintenance in Scotland, with expected additional costs due to the conversion to ZEVs. Amounts converted from 2016 to 2021 values, inflation factor 1.108.*

This shows the additional road maintenance expenditure in Scotland required to maintain existing condition would need to increase by around £164M per year if all large vehicles transitioned to battery electricity. Conversely, if all large vehicles transition to hydrogen fuel cells, then an additional £31M would be required.

It has been reported that current levels of road maintenance are inadequate at present to sustain existing road quality (Williams 2019, Audit Scotland 2016). If this is still the case, the greater demands made of the roads in the future that we outline here can be expected to lead to an even faster deterioration (Addis and Whitmarsh 1981). However, we do not assess that impact in this paper.

These additional costs, and the consequence of the additional emissions, should be included when planning the support of different fuel types on a national fleet. The fuel choice of cars, light goods vehicles and motorcycles will make little difference to road wear. However, with more HFCEV buses & coaches and heavy goods vehicles, the overall road maintenance cost will be substantially lower than with those vehicles as BEVs; it will require only a relatively small increase over the current ICE vehicle situation.

![Figure 5 Summary conclusion](image-url)
References


**Statements & Declarations**

**Funding**

JML is partly funded by the University of Edinburgh.

RSH is funded by EPSRC UKCCSRC 2017 EP/P026214/1 and HyStorPor P/S027815/1, and Scottish Gas Networks Academic Alliance H100 project from Ofgem.

GPH is the Bert Whittington Chair of electrical power engineering with the University of Edinburgh, Edinburgh, U.K.

**Competing Interests**

*The authors have no relevant financial or non-financial interests to disclose.*

**Author Contributions**


RSH: Paper structure and content review, Validation, Writing – review, Supervision.

GPH: Paper content review, Validation, Writing – review, Supervision.

**Data Availability**

*The datasets generated during and/or analysed during the current study are available in the GitHub repository, https://github.com/J-M-Low/Battery-Battering.git*
Appendix

Calculation tables for modelled base case.
### Internal Combustion Engine vehicles

<table>
<thead>
<tr>
<th>I</th>
<th>II</th>
<th>III</th>
<th>IV</th>
<th>V</th>
<th>VI</th>
<th>VII</th>
<th>VIII</th>
<th>IX</th>
<th>X</th>
<th>XI</th>
<th>XII</th>
<th>XIII</th>
</tr>
</thead>
<tbody>
<tr>
<td>Veh. class</td>
<td>Subclass</td>
<td>Number registered in Scotland</td>
<td>Chassis type (ICE)</td>
<td>Weight range</td>
<td>Ref. weight (ICE)</td>
<td>Nr. of axles per vehicle</td>
<td>Ref. weight / axle</td>
<td>Average annual km, per vehicle</td>
<td>Standard 80kN axles per axle (ICE)</td>
<td>RWP</td>
<td>RWIF</td>
<td></td>
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<tr>
<td>Buses &amp; Coaches</td>
<td>Petrol</td>
<td>1,544,505</td>
<td>Two axle rigid</td>
<td>14,000</td>
<td>24,800</td>
<td>17000</td>
<td>2</td>
<td>83</td>
<td>45,471</td>
<td>1.180</td>
<td>2.361</td>
<td>1,519</td>
</tr>
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<td>Diesel</td>
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<td>Two axle rigid</td>
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<td>2,600</td>
<td>1,800</td>
<td>2</td>
<td>9</td>
<td>14,571</td>
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<td>0.0003</td>
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<tr>
<td>Motorcycles</td>
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<td>71,666</td>
<td>Two axle rigid</td>
<td>200</td>
<td>2</td>
<td>1</td>
<td>4,490</td>
<td>neg.</td>
<td>neg.</td>
<td>&lt;0.1</td>
<td></td>
<td></td>
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<tr>
<td>HGV 3.5t - 7.5t</td>
<td>Petrol</td>
<td>7,986</td>
<td>Two axle rigid</td>
<td>3,500</td>
<td>7,500</td>
<td>5,500</td>
<td>2</td>
<td>27</td>
<td>49,967</td>
<td>0.013</td>
<td>0.026</td>
<td>10</td>
</tr>
<tr>
<td>HGV 7.5t - 12t</td>
<td>Petrol</td>
<td>1,275</td>
<td>Two axle rigid</td>
<td>7,500</td>
<td>12,000</td>
<td>9,750</td>
<td>2</td>
<td>48</td>
<td>49,967</td>
<td>0.128</td>
<td>0.255</td>
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<tr>
<td>HGV 12t - 16t</td>
<td>Petrol</td>
<td>1,238</td>
<td>Two axle rigid</td>
<td>12,000</td>
<td>16,000</td>
<td>14,000</td>
<td>2</td>
<td>69</td>
<td>49,967</td>
<td>0.543</td>
<td>1.086</td>
<td>67</td>
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<tr>
<td>HGV 16t - 20t</td>
<td>Petrol</td>
<td>4,656</td>
<td>Two axle rigid</td>
<td>16,000</td>
<td>19,000</td>
<td>17,500</td>
<td>2</td>
<td>86</td>
<td>49,967</td>
<td>1.325</td>
<td>2.651</td>
<td>617</td>
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<tr>
<td>HGV 20t - 24t</td>
<td>Petrol</td>
<td>678</td>
<td>Three axle rigid</td>
<td>19,000</td>
<td>24,000</td>
<td>21,500</td>
<td>3</td>
<td>70</td>
<td>30,420</td>
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<td>1.789</td>
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<td>HGV 24t - 28t</td>
<td>Petrol</td>
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<td>Three axle rigid</td>
<td>24,000</td>
<td>27,000</td>
<td>25,500</td>
<td>3</td>
<td>83</td>
<td>30,420</td>
<td>1.180</td>
<td>3.541</td>
<td>578</td>
</tr>
<tr>
<td>HGV 28t - 32t</td>
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<td>4,446</td>
<td>Four axle rigid</td>
<td>27,000</td>
<td>32,000</td>
<td>29,500</td>
<td>4</td>
<td>72</td>
<td>45,693</td>
<td>0.669</td>
<td>2.676</td>
<td>544</td>
</tr>
<tr>
<td>HGV 32t - 38t</td>
<td>Petrol</td>
<td>637</td>
<td>Four axle articulated</td>
<td>32,000</td>
<td>38,000</td>
<td>35,000</td>
<td>4</td>
<td>86</td>
<td>173,88</td>
<td>1.325</td>
<td>5.302</td>
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<tr>
<td>HGV 38t - 40t</td>
<td>Petrol</td>
<td>3,958</td>
<td>Five axle articulated</td>
<td>38,000</td>
<td>40,000</td>
<td>39,000</td>
<td>5</td>
<td>77</td>
<td>125,99</td>
<td>0.837</td>
<td>4.185</td>
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<td>HGV 40t - 44t</td>
<td>Petrol</td>
<td>6,596</td>
<td>Six axle articulated</td>
<td>40,000</td>
<td>44,000</td>
<td>42,000</td>
<td>6</td>
<td>69</td>
<td>125,99</td>
<td>0.543</td>
<td>3.257</td>
<td>2,707</td>
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<tr>
<td>LGV Petrol</td>
<td>9,842</td>
<td>2,500</td>
<td>3,500</td>
<td>3000</td>
<td>2</td>
<td>15</td>
<td>26,262</td>
<td>0.001</td>
<td>0.002</td>
<td>1</td>
<td></td>
<td></td>
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<tr>
<td>LGV Diesel</td>
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<td>2,500</td>
<td>3,500</td>
<td>3000</td>
<td>2</td>
<td>15</td>
<td>26,262</td>
<td>0.001</td>
<td>0.002</td>
<td>18</td>
<td></td>
<td></td>
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</table>

| Total million Standard axle –km per year, as Road Wear Impact Factor | 8,799 |

Table A1: Calculation of the Road Wear Impact Factor for the current scenario of an Internal Combustion Engine based national vehicle fleet. Where 'Calculated' is shown at Data Source or Method, Roman numerals in the formula refer to the preceding columns as numbered in the heading row. * Max weight set at 19,000kg and 27,000 kg, the maximum allowable for ZEV HGVs with 2 axles and 3 axles respectively.
### Table A2 Calculation of the Road Wear Impact Factor for the all BEV and all HFCEV scenarios.

Where ‘Calculated’ (or ‘calc’) is shown at Data source / method, the formula is given, with Roman numerals in the formula refer to the preceding columns as numbered in the heading row.

<table>
<thead>
<tr>
<th>Vehicle class</th>
<th>BEV weight formula</th>
<th>HFCEV weight formula</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1.0744 x ICE weight + 430.17</td>
<td>1.014 x ICE weight</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Sub-class</th>
<th>Reference weight</th>
<th>Ref. / axle</th>
<th>Average annual km / vehicle</th>
<th>Standard 80kN axles per axle</th>
<th>RWP</th>
<th>RWIF</th>
</tr>
</thead>
<tbody>
<tr>
<td>All LGVs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>All Cars</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>All HGVs</td>
<td></td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Vehicle class</th>
<th>Sub-class</th>
<th>Reference weight</th>
<th>Ref. / axle</th>
<th>Average annual km / vehicle</th>
<th>Standard 80kN axles per axle</th>
<th>RWP</th>
<th>RWIF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buses &amp; Coaches</td>
<td>18695</td>
<td>2</td>
<td>92</td>
<td>45,471</td>
<td>1.726</td>
<td>3.45</td>
<td>2,222</td>
</tr>
<tr>
<td>Cars Diesel</td>
<td>2364</td>
<td>2</td>
<td>12</td>
<td>14,571</td>
<td>0.0004</td>
<td>0.0009</td>
<td>20</td>
</tr>
<tr>
<td>Cars Petrol</td>
<td>2364</td>
<td>2</td>
<td>12</td>
<td>14,571</td>
<td>0.0004</td>
<td>0.0009</td>
<td>13</td>
</tr>
<tr>
<td>Motorcycles</td>
<td>645</td>
<td>2</td>
<td>3</td>
<td>4,490</td>
<td>neg.</td>
<td>neg.</td>
<td>&lt;0.1</td>
</tr>
<tr>
<td>HGV 3.5t-7.5t</td>
<td>6339</td>
<td>2</td>
<td>31</td>
<td>49,967</td>
<td>0.023</td>
<td>0.046</td>
<td>18</td>
</tr>
<tr>
<td>HGV 7.5t-12t</td>
<td>10905</td>
<td>2</td>
<td>53</td>
<td>49,967</td>
<td>0.200</td>
<td>0.400</td>
<td>25</td>
</tr>
<tr>
<td>HGV 12t-16t</td>
<td>15472</td>
<td>2</td>
<td>76</td>
<td>49,967</td>
<td>0.810</td>
<td>1.620</td>
<td>100</td>
</tr>
<tr>
<td>HGV 16t-20t</td>
<td>19232</td>
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<td>94</td>
<td>49,967</td>
<td>1.933</td>
<td>3.867</td>
<td>900</td>
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<tr>
<td>HGV 20t-24t</td>
<td>23530</td>
<td>3</td>
<td>77</td>
<td>30,420</td>
<td>0.856</td>
<td>2.567</td>
<td>53</td>
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<tr>
<td>HGV 24t-28t*</td>
<td>27000</td>
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<td>88</td>
<td>31,352</td>
<td>1.483</td>
<td>4.450</td>
<td>749</td>
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<tr>
<td>HGV 28t-32t</td>
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<td>78</td>
<td>45,871</td>
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<td>3.705</td>
<td>756</td>
</tr>
<tr>
<td>HGV 32t-38t</td>
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<tr>
<td>HGV 38t-40t</td>
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<td>3.923</td>
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<tr>
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<td>17</td>
<td>27,413</td>
<td>0.002</td>
<td>0.004</td>
<td>1</td>
</tr>
<tr>
<td>LGV Diesel</td>
<td>3500</td>
<td>2</td>
<td>17</td>
<td>27,413</td>
<td>0.002</td>
<td>0.004</td>
<td>34</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Sub-class</th>
<th>Reference weight</th>
<th>Ref. / axle</th>
<th>Average annual km / vehicle</th>
<th>Standard 80kN axles per axle</th>
<th>Calc: (XXIII/80)^4</th>
</tr>
</thead>
<tbody>
<tr>
<td>All LGVs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Calc: (XX/80)^4</td>
</tr>
<tr>
<td>All Cars</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Calc: (XXI/80)^4</td>
</tr>
<tr>
<td>All HGVs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Calc: (XXV/80)^4</td>
</tr>
</tbody>
</table>

**Total million Standard axle -km per year, as Road Wear Impact Factor:**

- BEV: 11,528
- HFCEV: 9,302

**Table A2** Calculation of the Road Wear Impact Factor for the all BEV and all HFCEV scenarios. Where ‘Calculated’ (or ‘calc’) is shown at Data Source or Method, the formula is given, with Roman numerals in the formula refer to the preceding columns as numbered in the heading row.