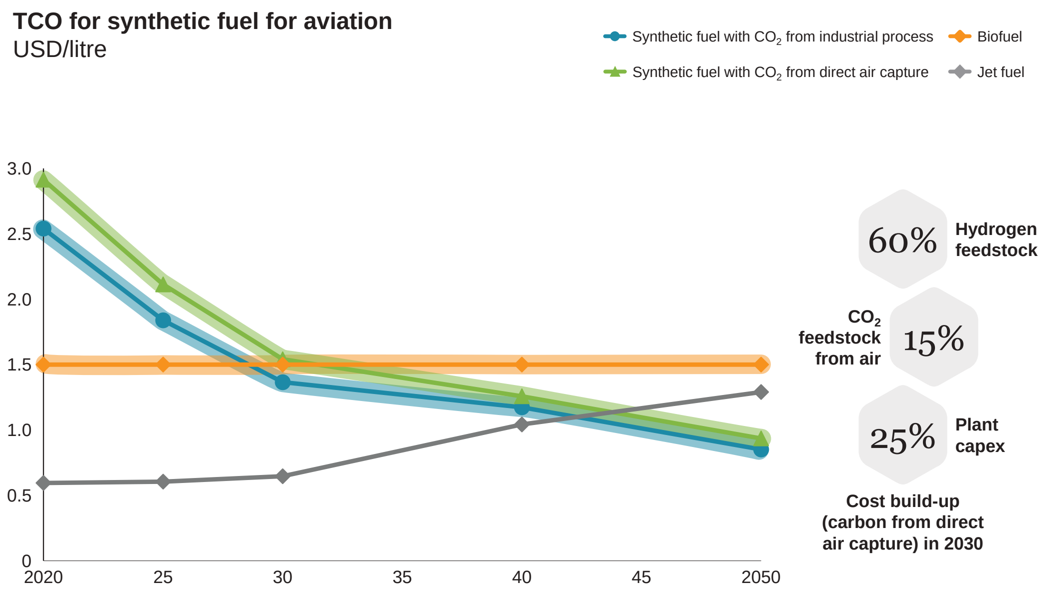
EXHIBIT 25 | Cost of synthetic fuel



Hydrogen ships

The maritime sector today emits approximately 2.5 per cent of global carbon emissions, equivalent to 940 Mt per year.[12] The International Maritime Organization (IMO) has committed to reducing emissions by 50 per cent or more by 2050,[13] and there are several pathways to decarbonisation. They include replacing current bunker fuels with LNG, and using liquid ammonia or hydrogen-based synfuels instead of burning marine fuel on larger ships and hydrogen fuel cells in smaller ones. LNG is likely not the preferred long-term option – while cleaner than marine diesel, it does not offer zero-emission performance. However, it can serve as a transition mechanism until technologies emerge that make hydrogen-based fuels more economically attractive.

Cost competitiveness. Exhibits 26 and 27 below show the competitiveness trajectories projected for regional ferries and RoPax (combined roll-on/roll-off vehicles and passenger ferries). For smaller ships with motor power requirements under 2 megawatts (MW), like passenger ferries or ferries with room for fewer than 100 cars, hydrogen fuel cells offer a potential alternative for the near term. In fact, hydrogen can serve as a competitive low-carbon alternative to electric ferries before 2030, as the latter requires expensive large batteries and associated charging and infrastructure. Competitiveness varies by region and exact location due to a number of factors such as existing infrastructure, cost of electricity and hydrogen fuel, and operational factors such as distance and sailing schedule. Hydrogen passenger ferries are particularly competitive in situations where there are short docking times that do not allow enough time for charging the battery. In such situations, the ferry operator may need to purchase additional battery electric ships to maintain the required service level, nearly doubling the TCO. Fuel cell ferries are also attractive alternatives where the grid connection is weak, requiring either significant upgrades to enable fast charging of the ship battery or an onshore battery to charge the ship, which are both expensive solutions.

For larger ferries with motor power up to 4 MW, hydrogen can be an attractive low-carbon alternative. Batteries are unlikely to be suitable due to the high cost, weight, and volume of the battery required for ships of this size and fuel consumption. Therefore, the low-carbon alternative is biodiesel, which is expected to be more competitive until 2030. However, the hydrogen fuel cell ship could become competitive by 2035, as the cost of fuel cells and hydrogen fuel declines following scale-up of other mobility segments such as trucks and passenger vehicles. The cost of fuel plays a larger role for larger ships such as the RoPax than for the smaller passenger ferries, so competitiveness is highly sensitive to the cost and availability of biodiesel. This means that cost competitiveness with conventional marine diesel is more challenging. The RoPax requires a cost of carbon of USD 80 to 150 per ton of CO_2e to outcompete diesel in 2030, while the passenger ferry requires only USD 50 to 100 per ton of CO_2e.

Cost development. The cost drivers for fuel cell ships are similar to those of other mobility segments such as cars, trucks, and trains. Due to the high importance of fuel for the ship operator TCO, the majority of the cost reductions are driven by lower-cost hydrogen fuel, accounting for more than 90 per cent of the reduction in cost until 2030.

[12] European Commission (2019).
[13] International Maritime Organization (2019).

For longer-distance shipping involving, e.g. large container ships, ammonia fuel may offer the most viable low-carbon option. This solution usually involves a modified engine similar to today's technology but requires less modification overall than with the use of a fuel cell. While using liquid hydrogen is also possible in theory, its relatively low energy density of 2.4 kilowatt-hours per litre (kWh/l) compared with ammonia's 3.5 kWh/l likely makes it less attractive. Liquid hydrogen also requires extremely low temperatures to remain liquid (–252.87°C versus –33.6°C for ammonia) and boil-off can be a problem on longer routes, especially in the presence of 'sloshing'. For these reasons, ammonia likely offers a more attractive alternative for ship bunker fuel. Furthermore, the conversion of hydrogen to ammonia is a well-established and low-cost process, and ammonia would be a low-cost option if used directly. As discussed in Chapter 2, the reconversion of ammonia is expensive and energy intense, but ammonia as shipping fuel is feasible as the ammonia can be used directly as fuel.

Exhibit 26 | TCO development of regional ferry

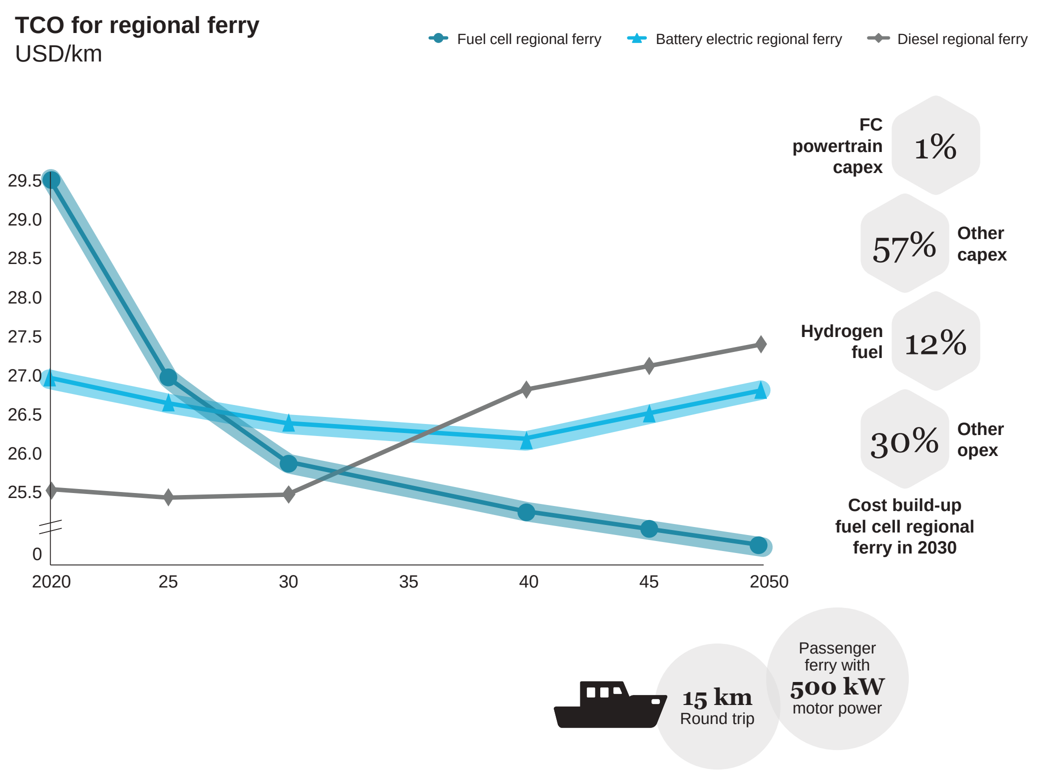
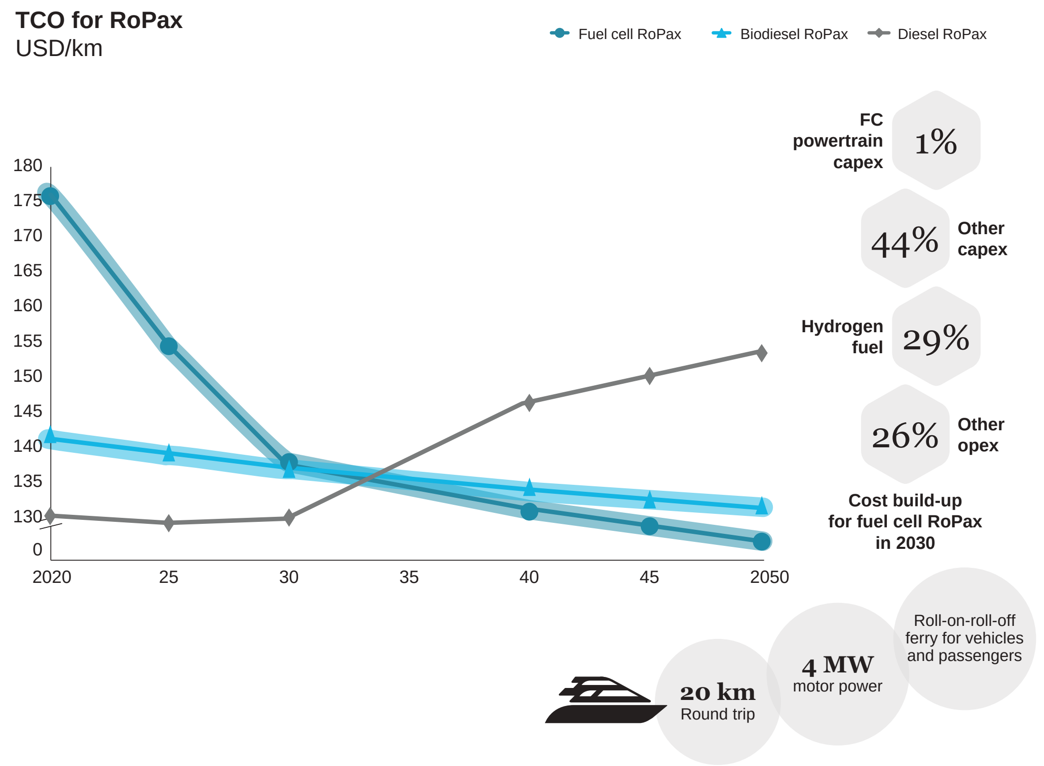


Exhibit 27 | TCO development of RoPax



Heat and power for buildings

Heat and power for buildings represents over a third of global energy demand (118 EJ) and a quarter of global carbon emissions (8.67 Gt of CO_2).[14] The sector has proven difficult to decarbonise, particularly for heating where only a few low-carbon alternatives exist to compete with natural gas (the most common heating fuel). Of these limited options, hydrogen solutions are among the most cost-effective and flexible ways to facilitate the sector's energy transition. The following section explores the potential competitiveness of hydrogen boilers for home heating and fuel cell CHPs.

Boilers for heating

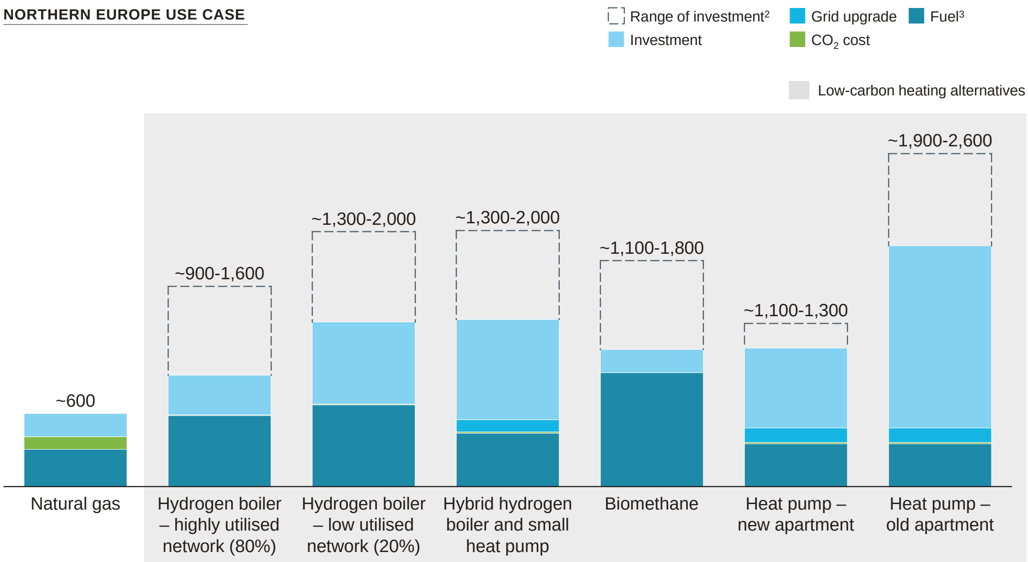
Hydrogen in gaseous form can provide a low-carbon alternative to natural gas heating as it can largely utilise the same infrastructure network – from pipelines to the boilers themselves.

Cost competitiveness. Hydrogen boilers can be the most attractive solution to providing low-carbon heating to residential building in regions with existing natural gas infrastructure. Competitiveness is driven in large part by the falling cost of hydrogen production and boiler capex, and by hydrogen's ability to utilise the natural gas pipeline. The cost of hydrogen boilers could fall to about USD 900 to 1,600 per household per year by 2030, similar to natural gas boilers. This would put hydrogen-based heating on par with biomethane solutions and heat pumps for new buildings. Notably, hydrogen-based heating would also become more competitive than heat pumps for older buildings, which incur significant refurbishment costs in implementation (Exhibit 28). Notice that the ranges on these estimates are large, as TCO can fluctuate due to several factors, such as local climatic conditions, exact infrastructure upgrades required and ranging costs of accompanying home retrofits.

14 Figures from 2017, IEA (2019b).

Exhibit 28 | Cost components of residential heating solutions in 2030

Household heating
USD/year per household in 2030[1] (consumption 10 MWh/year)



1. One household is assumed to consume 10 MWh of heat per year
2. Range due to different state of insulation in building (new vs. old)/grid infrastructure requirements from high heat pump penetration/cost and utilisation of hydrogen network
3. Fuel cost varies by resources available; can be lower or higher than shown here

Hydrogen heating cost depends heavily on the utilisation of existing natural gas pipelines, at a rate of 90%.

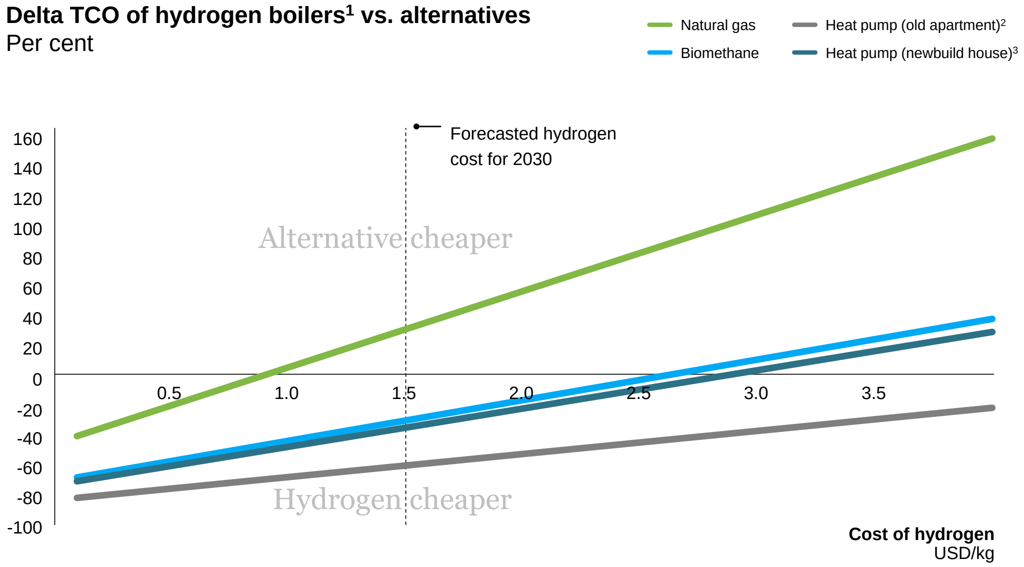
In contrast, the cost of heat pumps is strongly impacted by the refurbishment cost: low- to no-cost for new builds but substantial for old apartments.

As detailed in earlier chapters, the falling cost of hydrogen supplied will be a key driver of competitiveness across applications. This is evident in the cost trajectory for hydrogen boilers: it outcompetes heat pumps for refurbished residences when hydrogen's cost falls to USD 5.4 per kg, and it can beat biomethane and heat pumps for newly built houses as hydrogen costs drop to approximately USD 3 per kg. This presents a clear production cost target for future heating networks.

However, none of the low-carbon options are likely to outcompete natural gas on cost alone. As shown in Exhibit 29, hydrogen boilers can only break even with natural gas heating if the cost of hydrogen falls to under USD 1 per kg. A regulatory push to support low-carbon technologies will be critical. There are already several similar initiatives underway in the US, Canada, the UK and the Netherlands, among others.

Exhibit 29 | Break-even cost of hydrogen at which H_2 boilers outcompete alternatives

Delta TCO of hydrogen boilers[1] vs. alternatives
Per cent



1. Assumes partial use of an existing natural gas network
2. Refurbishment included in cost of heat pump for old apartment
3. No refurbishment required

SOURCE: H21; DoE; Element Energy

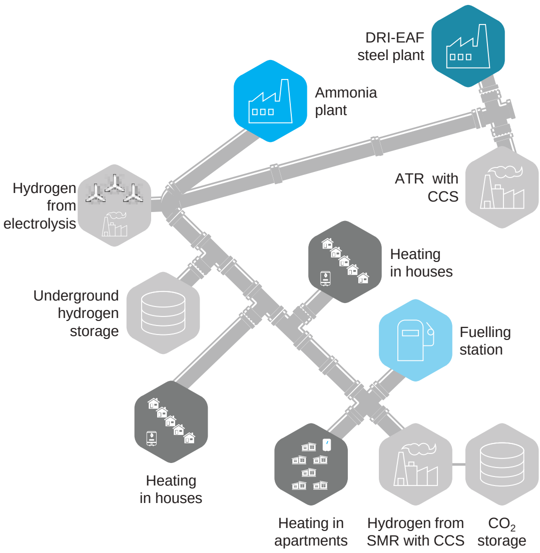
Cost development. In addition to the costs avoided by not building new infrastructure, developing a hydrogen-based heating network using the existing natural gas network provides other cost-reduction benefits that biomethane and heat pump solutions cannot necessarily offer.

First, hydrogen's ability to leverage the existing natural gas network ensures the value of the existing pipeline assets is not lost. Second, for hydrogen-based heating networks, higher utilisation drives down costs. The tipping point occurs once network utilisation reaches 80 per cent, and achieving this level is facilitated if an existing natural gas network can be accessed to which those users are already connected. Costs could fall even further if other industrial users and refuelling stations connect to the same network as shown in Exhibit 30. For example, adding two steel plants producing 500,000 tons of steel p.a. (56,000 tons of hydrogen per year each), the network cost per household is reduced by about USD 78, from USD 380 per year to around 300. In contrast, for heat pumps, increasing utilisation to 80 per cent would likely increase peak demand loads and put additional strain on the electricity grid. This would require additional grid upgrades which would increase the cost of heating for each household further.

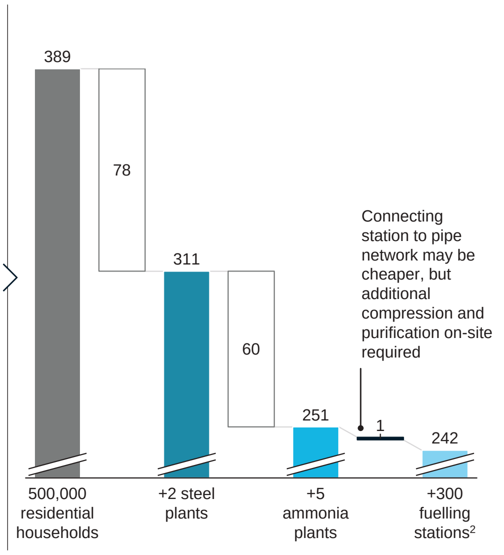
Lastly, though not directly related to cost drivers, a hydrogen pipe network can provide line pack hydrogen storage, allowing peaks and troughs in demand to be more effectively managed. Used in conjunction with power-to-hydrogen, this can support the transition towards lower-carbon hydrogen production, as it compensates for part of the variability of renewable energy sources. Due to the lower density of hydrogen, this is primarily viable in the transmission network.

Exhibit 30 | Example hydrogen pipeline network

Hydrogen pipeline network schematic



Cost of network as additional users connect
USD/year per apartment[1]



1. Considers apartments in North of England consuming 10 MWh/year, with total H_2 flow of 176,000 ton/year covering 500,000 apartments
2. 480 kg/day stations utilised at 60%, each stations required 0.5 km distribution pipeline at USD 280,000/km

SOURCE: H21; DoE

Finally, it should be noted that blending hydrogen into the natural gas grid is a potential transition alternative. For example, blending hydrogen at levels of up to 20 per cent into the natural gas network can be achieved without the need for major modification to pipes or household appliances, thereby incurring relatively minimal investment costs. Moreover, the safety risk remains essentially the same as for natural gas, and although not a fully low-carbon solution, blending can potentially save significant amounts of CO_2 emissions. For a blending level of 5 per cent, 32 to 58 kg of CO_2 could be saved annually per household consuming 10 to 18 MWh per year; assuming 3.3 million households with natural gas heating, about 200,000 tons of CO_2 can be saved annually.

Fuel cells for combined heat and power

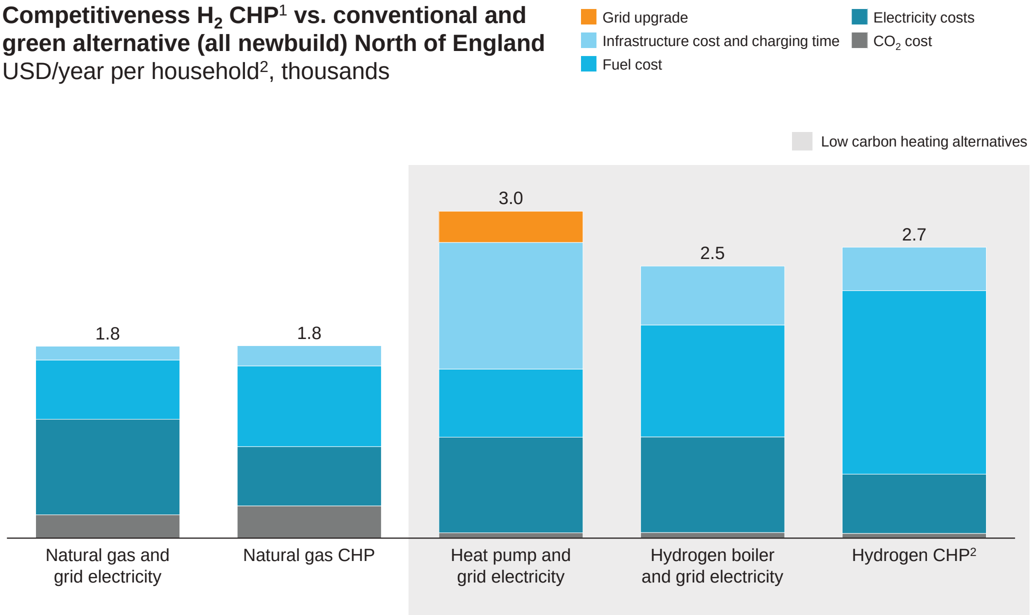
Hydrogen fuel cells for combined heat and power technology (FC CHP) is another low-carbon alternative that generates electricity from fuel cells and then recovers and uses the by-product heat for hot water, space heating, and/or cooling in residential and commercial buildings.

Cost competitiveness. FC CHP was compared to both low-carbon (hydrogen boilers and heat pumps with grid electricity) and natural gas (boiler plus grid electricity and natural gas CHP) alternatives for the case of a new-build home in the north of England, having a total area of 120 m2 and consuming 7.5 MWh of electricity and 18 MWh of heat per year. The findings suggest FC CHP can be a viable alternative to hydrogen boilers and heat pumps by 2030 when the cost of hydrogen is approximately USD 1.9 per kg. As shown in Exhibit 31, the FC CHP total cost per household per year would be USD 2,700, falling between the slightly lower-cost hydrogen boiler and slightly higher-cost heat pump option when factoring in necessary grid upgrades.

The specific low-carbon heating solution that is most cost effective will depend on the heat and electricity demand profile, locational energy costs and actual prices of equipment. However, all low-carbon options will struggle to compete with natural gas solutions for home heating, for which the annual costs are only USD 1,800 per household.

Exhibit 31 | Cost competitiveness of fuel cell CHP vs alternatives

Competitiveness H_2 CHP[1] vs. conventional and green alternative (all newbuild) North of England
USD/year per household[2], thousands



1. We system (30% electrical efficiency; 80% overall efficiency)
2. Assumes new build house with 18 MWh heat and 7.5 MWh electricity consumption – Note that fuel and electricity costs will vary due to specific local conditions

SOURCE: H21; DoE; Element Energy; SGC Rapport 2014; Eurostat; IEA; Battelle Memorial Institute

Cost development. Cost-reduction potential for hydrogen FC CHP is driven mainly by lower hydrogen production costs, with some contribution from cheaper CHP systems and reduced electricity cost over time. A flatter annual heat load curve and/or a closer match between heat and electricity load over the course of the year will also tend to improve the utilisation factor and therefore, the economics of CHP, but analysis of time series data shows that the peak-median load ratio does not vary greatly across property types, so the effect is unlikely to be significant.

Heat and power for industry and the grid

Hydrogen can provide industry heat as well as power for grid and off-grid demand. Several specific use cases are covered in the cost assessment, including medium- and high-grade heat, flexible simple cycle hydrogen turbines for peaking capacity, combined cycle hydrogen turbines for baseload as well as fuel cell generators for backup and remote power.

In thermal applications, hydrogen competes with conventional fossil fuel heat sources on a heat-value basis. This leads to a low hydrogen production break-even cost of about USD 1.10 per kg versus average natural gas prices (roughly USD 7 per million British thermal units, or MMBtus) at USD 50 per ton of CO_2. Such low hydrogen production costs will likely occur only in the most optimal locations. However, when compared with other low-carbon options, several use cases are possible where hydrogen would become the lowest-cost decarbonised solution available at scale. These include high-grade heat for industrial processes that do not allow for electrification, peaking capacity for the power grid, and remote power generation in regions with high diesel prices and/or non-optimal renewables conditions. In the long term, full competitiveness with conventional alternatives will be achievable if CO_2 costs exceed USD 100 per ton.

Power and heat applications offer an easily expandable demand segment for hydrogen that could support the scale-up of the production industry, which will drive down costs for all other segments. Applying hydrogen in heat and power can also help regions increase their energy autonomy and reduce industry-related emissions of fine particulate matter and other pollutants.

Industrial heating

Industry heat is classified into three temperature ranges: low-grade heat up to 100°C, medium-grade heat of 100 to 400°C and high-grade heat that exceeds 400°C. Today, fossil fuels (coal, natural gas) and electric power (resistor heating or heat pumps) primarily cover demand for industrial heat. Decarbonisation options include direct electrification, biomass or fossil fuels plus CCS.

Cost competitiveness. For low-grade heat, electrification is the lowest-cost decarbonisation option; therefore, hydrogen will likely not play a significant role. For mid- and high-grade heat, biomass is an option, but faces supply constraints in several regions. CCS, for example, only works in regions with access to CO_2 storage; but where biomass or CCS are not options, hydrogen and electric heating are the only two low-carbon solutions for mid- and high-grade heat.

Since the heat demand patterns differ from application to application, no one-size-fits-all solution exists. Hydrogen-based heating offers high flexibility and is thus well-suited for applications with intermittent heat demand.

The competitiveness of hydrogen with conventional and other low-carbon solutions is mainly determined by fuel costs, as shown in Exhibit 32. Hydrogen cost will correspond to 80 to 90 per cent of the total cost for providing heat via hydrogen burning by 2030. Comparing hydrogen to other energy carriers on a pure heat-value basis shows that its cost needs to decline below about USD 1.10 per kg to be competitive with natural gas or coal in 2030, assuming USD 50 per ton of CO_2. This figure increases to USD 1.50 per kg if the resulting CO_2 cost reaches USD 100 per ton, while hydrogen should reach a break-even point with biomass at USD 2 to 3 per kg (depending greatly on local resources and supply of biomass).