Hydrogen Applications

1 Introduction

While small amounts of energy can temporarily be stored in batteries, flywheels or supercapacitors, chemical storage in the form of hydrogen or methane is particularly suitable for the long-term storage of large amounts of energy. For the emission-free production of hydrogen, the power-to-gas (PtG) concept is discussed, which involves the utilization of surplus renewable energy for the operation of water electrolysis (Buttler and Spliethoff 2018). In a consequent step this hydrogen can then be converted to methane (synthetic natural gas, SNG) by using an external CO or CO_2 source. The produced SNG is applicable for the injection into the gas grid or usable as motor fuel (Pan et al. 2019). Alternatively, the direct feeding of hydrogen into the gas grid is also conceivable.

Figure 1 shows a general overview of the PtG concept with possible mass and energy flows. In addition to the possible uses shown in the figure, it is also imaginable to use the hydrogen for fuelling vehicles, for the production of hydrocarbons via Fischer-Tropsch synthesis or other chemicals such as methanol or ammonia.

As mentioned before, water electrolysis represents the key technology for a successful realization of the PtG concept.

The global hydrogen demand in 2012 was approximately 600 billion Nm3 (≈ 54 million tonnes). It is especially needed in the chemical industry for ammonia production via Haber-Bosch process or petroleum refining, which each demand about 45% of the total production capacity. Today hydrogen is primarily produced by the reformation of natural gas or liquid hydrocarbons (Boretti 2021). Here, particularly three reforming methods are distinguished: Catalytic steam reforming (CSR), partial oxidation (POX) and autothermal reforming (ATR). Until now, steam reforming of natural gas represents the most economical and established industrial technology for hydrogen production. However, the main downside of this

P. Cavaliere, *Water Electrolysis for Hydrogen Production*,
https://doi.org/10.1007/978-3-031-37780-8_18

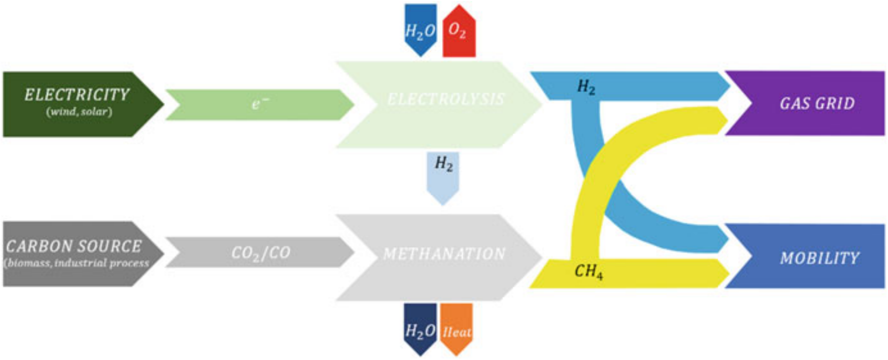


Fig. 1 Power-to-gas concept with possible mass and energy flows

production technology is that depending on the feedstock 9 t to 12 t of CO_2 are produced per tonne of H2.

Gasification of coal or biomass represents a further hydrogen production alternative (Midilli et al. 2021).

Using biomass can reduce CO_2 emissions into the atmosphere, since the CO_2 released during gasification has previously been absorbed from the atmosphere and converted by photosynthesis (Cao et al. 2020). Furthermore, hydrogen can be produced in a purely biological way by fermentation of biomass or by photobiological processes. However, biological processes are still at an early stage of development and therefore unlikely to become commercially available in the next years.

2 Current Uses of Hydrogen

The first industrial applications of hydrogen were in the early nineteenth century as a fuel gas for lighting and heating. The hydrogen was mainly produced from the anaerobic reaction of hot coal and water vapour. It was used for many years in commercial and residential applications until it was eventually replaced with natural gas.

Of the annual production of 8 EJ or ~ 190 Mtoe of hydrogen, most is in the form of ‘captive’ hydrogen (consumed at the producer’s place). Only an estimated 5% of the total hydrogen production is supplied as ‘merchant’ hydrogen (produced centrally und transported to the consumer), requiring the appropriate infrastructure for transportation and distribution. Other market types are by-product and stranded hydrogen produced in the chemical industries and either used internally as a raw material or fuel, or simply vented or flared if no marketing infrastructure is available. Only 1% of current hydrogen production is used for direct energy purposes. The hydrogen market in Europe is 64% captive hydrogen, 27% by-product hydrogen and 9% merchant hydrogen.

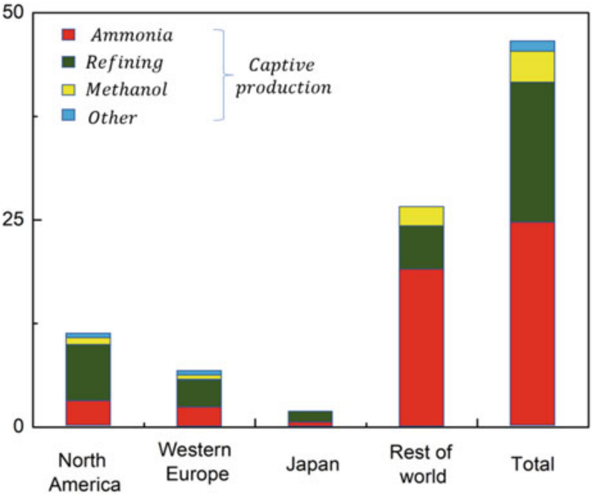


Fig. 2 Global hydrogen production and use (in million t)

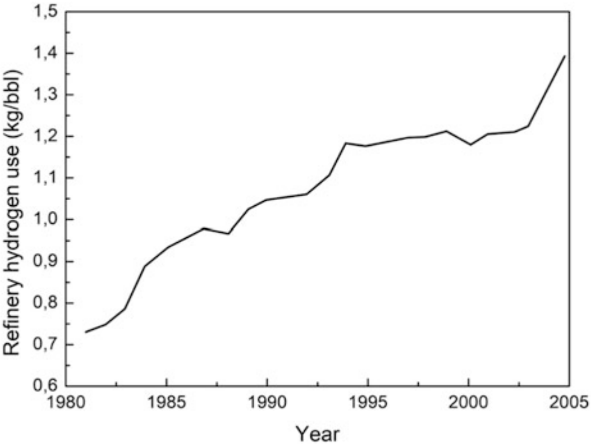


Fig. 3 Hydrogen consumption in the US refineries between 1985 and 2005

There is a wide variety of industrial customers for hydrogen which require, depending on the application area, different quantities and purities of hydrogen. The largest consumer of hydrogen is the chemical industry, with a demand for hydrogen growing at an annual rate of 7–10% (Ausfelder and Bazzanella 2016). As is shown in Fig. 2, about half the total hydrogen is used for producing ammonia (fertilizer), 35% is used in petroleum refining processes (tendency increasing due to heavier crude oils), 8% is used in methanol production, 1% is used as a fuel in space programmes, and the residual amount is used for other purposes (Dalena et al. 2018).

The most important processes for producing hydrogen in refineries are steam reforming of natural gas (59%) followed by off-gas purification (35%). The merchant suppliers may operate a hydrogen plant or a hydrogen supply pipeline. Figure 3 shows the specific demand for hydrogen in refineries in the USA over the past 25 years, revealing a strong increase in recent years due to the increased processing of lower quality, heavy crude oils and other unconventional fossil resources. For a present throughput of 20 Mbbl/d, this translates into a hydrogen demand of 28,000 t/d.

Indirect energetic use of hydrogen occurs in refineries where the H2 is used in catalytic cracking operations or hydro-treating to upgrade heavy and unsaturated compounds into lighter and more stable species (Speight 2016). It is also used in the production of synthetic fuels via Fischer–Tropsch synthesis, of methanol, or of SNG. Furthermore, it is used in the hydrogenation of coal and heavy crude oil. Hydrogen is also used to remove sulphur from crude oil and gasoline, and to purify gases, e.g. by capture of oxygen traces in argon. Other H2 consuming processes are welding and glass production. In the glass production process, the hydrogen is used as an oxygen scavenging atmosphere (~6% H2 and ~ 94% N2), and to prevent oxidation of the large tin bath in the float glass process. Polishing and melting of high quality optical glass is done by means of a soot free hydrogen flame. In the food industry, the properties of fats and oils are changed through hydrogenation of organic intermediate products like amines and fatty acids, making food less susceptible to oxidation and spoilage.

Specific applications for liquid hydrogen are in the metal industries, where LH2 is used in the metal production process directly (e.g. tungsten, tungsten carbide, molybdenum metal powder), and, if mixed with inert gases, in secondary processes to act as a reducing atmosphere in heat treating, sintering and copper brazing. In the electronics industry, highly pure hydrogen is mainly needed as a carrier gas for active elements such as arsine and phosphine in the manufacture of integrated circuits, polycrystalline silicon for semiconductors, optical fibres for communication, or fused quartz. The pure water vapour required is generated from mixing oxygen with vaporized LH2. The hydrogen is either used as atmosphere or as a clean burning fuel. In power plants, LH2 can be used for the cooling of large electric turbogenerators and to protect piping in nuclear reactors.

The following is a list of non-energy and indirect energy applications of hydrogen:

- Heavy oil hydrogenation for the production of preprocessed crude oil;
- Hydro-cracking of heavy distillates, which are difficult to reform, by using hydrogen and catalysts to convert into lighter fractions (kerosene, light and heavy gas oil, fuel oil (‘naphtha’); cracking by heating or catalytic reforming to obtain various fuel qualities;
- Hydro-treating, i.e. a process that reduces sulphur or nitrogen content of the feed;
- Hydro-processing, i.e. a process used for desulphurization and substantial removal of most other impurities (nitrogen, oxygen, heavy metals) from the products of distillation processes; for example, desulphurization of heating oil grade S by 80% requires approximately 146 Nm3 of H2 per toe;
- Fischer–Tropsch synthesis for the production of synthetic liquid fuels;
- Methanol synthesis, also for the production of base materials for plastics;
- Coal hydrogenation for the production of synthetic oil;

- Methanation for SNG production;
- Chemical processing to manufacture chlorine, caustic soda, and hydrogenated non-edible oils for soaps, insulation, plastics, ointments and other chemicals;
- Hydrogenation of organic interim products for the production of polyamides, cyclohexane, fat alcohols, fat hardening;
- Synthesis of ammonia (NH_3) for the production of fertilizer and synthetic materials (acrylic fibres);
- Oxo-synthesis for alcohol production;
- Pharmaceuticals to produce sorbitol, which is used in cosmetics, adhesives, surfactants and vitamins;
- Direct reduction of iron ore for sponge iron production, raw iron in the metal industries;
- Metallurgy to use pure hydrogen/oxygen flames in cutting, welding, brazing, annealing;
- Food processing to hydrogenate plant fats and oils, such as soybean, fish, cottonseed, and corn oil, for hardening;
- Electronics to create a special atmosphere for the production of semiconductor circuits;
- Reduction gas, protection gas in high temperature operations, such as glass manufacturing to use high-purity flames for cutting and welding, artificial gemstone/diamond production, to create high-purity atmospheres in furnaces or protective atmospheres for float glass production, sintering processes, silicon chemistry;
- Generator cooling in power industry.

Hydrogen was first used at a large scale in balloons and large airships (Zeppelin) toward the end of the nineteenth century, although here the hydrogen was not used directly as a fuel, but rather as a lighter-than-air gas to provide positive buoyancy. The idea of using liquefied hydrogen as aircraft and rocket fuel was considered as early as 1918, stressing that hydrogen had a larger heat content than any other fuel. A strong increase in the demand for hydrogen was given with the developing space aviation programme in the USA (Dincer and Acar 2016). The first systematic experimental investigations in the USA to investigate its use as a fuel for aircraft and to study the properties of LH2 and the low temperature impact on materials started in the 1940s. But it was not until the 1950s that the attractiveness of LH2gradually became evident, despite its low availability and handling hazards. This was due to incentives for the development of airplanes for use at very high altitudes, advances in LH2 technology, and experiments indicating that hydrogen could combust readily at low pressures. The first (of three) successful in-flight tests of an experimental hydrogen-propelled aircraft were made in the USA in 1957 with the ‘Project Bee’, a B-57B twin-engine aircraft. The one engine operated on hydrogen fuel for about 20 min at a speed of Mach 0.72 before the fuel tank ran empty.

In 1958–1959, it was decided in the USA to use LH2 and LOX in the rocket engines of the upper stages of Centaur and Saturn, successful programmes of unmanned space missions and manned moon voyages, respectively, marking the first time that this high energy propellant combination was used in practical applications. The subsequent NASA programmes Apollo and Space Shuttle then applied LH2 at a large scale. A total of 12,000 m3 of LH2 was necessary to fill up the tanks of the Saturn V carrier rockets. For a space shuttle launch, the required quantity of LH2 is 2380 m3, of which 1454 m3 is for loading the external tank, with the remainder mainly used for pre-chilling of fuel lines or lost as boiloff.

Some 40 years ago, almost all produced LH2 was consumed in the various space programmes. Although this share has decreased to about 25% today, the space industry still is one of the main customers for liquid hydrogen (Cecere et al. 2014).

3 Uses of Hydrogen as Raw Material

The refining of crude oil is a well established technology. The type of crude oil discovered and produced, however, is changing, with the average crude oil becoming gradually heavier connected with higher CO_2 emissions. From the processing, a tendency which is expected to continue. Industrial processes such as oil refining, shale oil production and tertiary oil recovery require massive quantities of hydrogen and high temperature heat/steam (Elsherif et al. 2015).

Temperatures required for petroleum refining processes are mainly in the range of 500–600 °C, but may sometimes reach 950 °C. From a typical refinery capacity of 180,000 bbl/d or 10.55 million t/a, approximately ten million t/a of refinery products are being generated. This corresponds to an energy consumption of about 5.5% of the energy content of the oil processed mainly in the form of high temperature heat for distillation columns and thermal crackers for distillation, desulphurization and many other processes. The corresponding CO_2 emissions amount to about 1.73 million t/a.

A refinery consists of a complex system of units with highly optimized energy and mass flow structures. The heat and power demand of a refinery depends on its size, but also on its distillation capacity and the type and amount of downstream processing, as well as on the product balance.

Petroleum refineries convert petroleum from its natural state to a range of commercial products. About 90% of petroleum products are fuels such as gasoline, aviation fuel, distillate and residual oil (diesel oil, heating oils, industrial oils), liquefied petroleum gas, coke and kerosene. The remaining 10% goes to non-fuel products such as ethylene, propylene and benzene.

Most industrial heat is consumed in the 400–600 °C temperature range. The energy is typically supplied by firing produced process gases. Additional natural gas firing is needed for high temperature processes. Standard practice is to use steam in equipment considered ‘critical units’ such as turbo-machines. Non-critical equipment usually relies on off-site electricity supply, with redundant equipment powered by steam in the case of maintenance or accidental shutdowns. To become totally independent of external energy providers, refineries are operating cogeneration plants which provide ‘secure’ electricity for their own needs, the surplus electricity being consumed in other facilities or sold to the grid.

More than 80% of the world's production of ammonia and ammonium compound derivatives is used as fertilizer (Chai et al. 2021). Of the remaining 20%, 5% is used in chemical manufacturing (explosives, fibres and plastics, pharmaceuticals), and the remainder is used for refrigerants and in the pulp and paper industry. The total demand of hydrogen is currently 250 × 109 Nm3 per year or about 50% of the world H2 production. Demand in the EU is 33 × 109 Nm3/a or ~ 55% of the European production. The synthesis reaction runs as an exothermic catalytic reaction according to the Haber–Bosch process which was developed between 1905 and 1913:

$$N_2 + 3\_H_2 \leftrightarrow 2NH_3$$

Operating conditions are low temperatures (~400–500 °C) and high pressures (up to ~50 MPa) to favor the equilibrium toward ammonia. The catalyst is a mixture of iron oxide and aluminum oxide. Still, not more than 15% of the feedstock is converted to ammonia, while the remaining unconverted gases are recycled. The most energy consuming part of an ammonia plant is the air liquefaction process and the compression steps. With high operation temperatures and atmospheric pressure, the above reaction is shifted toward ammonia decomposition. The separation step requires ~3.5 MJ of heat per Nm3 of H2.

The ammonia compound can also easily be utilized as a chemical energy carrier for long distance energy transportation (Klerke et al. 2008). The big advantage is the densification factor for the hydrogen of 1333. Ammonia is liquid at ambient temperature and easily transportable in pipes and storable in containers.

Among the largest consumers of hydrogen is the steel industry, where the hydrogen is used to upgrade raw iron to steel. The direct reduction iron (DRI) process is applied for the production of iron and steel from iron ore (Cavaliere 2019, 2022).

DRI is performed with either coal or synthesis gas in fixed or fluidized beds of iron ore to reduce the ore to sponge iron, which can be smelted directly to steel in an electric arc furnace. The major chemical reaction is:

$$Fe_2O_3 + 3CO \leftrightarrow 2Fe + 3CO_2$$

The chemical reduction process can also be conducted with hydrogen to replace the coal, thus reducing CO_2 emissions, assuming the H2 is from a nuclear or renewable source:

$$Fe_2O_3 + 3H_2 \leftrightarrow 2Fe + 3H_2O$$

While the latter process takes place at ~500 °C and 3–4 MPa, the former process operates at 800 °C and 0.3 MPa.

Steel production has risen sharply from 200 million t in the 1950s to about 1300 million t in 2007 and is responsible for the release of 2106 million t of CO_2 into the air. The traditional primary blast furnace is a countercurrent gas–solid reactor where the iron oxide is reduced with coke and limestone. With a typical input of 80% ore and 20% scrap metal plus fossil energy, the iron is melted and the liquid metal separated from the slag and converted into steel by oxidation of impurities and controlled addition of alloying elements.

According to the World Steel Association, the estimated energy consumption is in the order of ~30 GJ/t of steel for primary steel production methods and ~ 11 GJ/t for secondary steel production (recycling). Assuming a nuclear assisted process with cogeneration of hydrogen and electricity, and based on a 1000 t/d production rate, the feed required for the production of one million t of steel has been estimated to be about 1.43 million t of Fe2O3 plus ~65,800 t of hydrogen to obtain the iron at 900 ° C, plus ~8.4 MW(e) to heat the iron up to 1600 °C.

A large blast furnace plant at a power level of ~1600 MW(th) produces a tonne of iron every 10 seconds. The overall iron yield is very high at ~99.5%. Blast furnaces are used for about 65% of all steel making, but account for 90% of worldwide steel industry emissions. Purified iron is needed for the production of high quality steels with electric arc furnaces, which are more environmentally benign than the traditional blast furnaces. The heat needed to melt the metal is produced by electricity. This process requires inexpensive sources of hydrogen if the old production methods are to be replaced with electric arc furnaces.

Coal liquefaction processes were developed in the first half of the twentieth century. Coal has the potential to provide almost every product that can be produced from oil. Bergius or Pott/Broche used a direct method to convert coal by a hydrogenation process. The conversion to a liquid is done in a single step by dissolution in a solvent at elevated temperatures and pressures followed by hydro-cracking with hydrogen:

$$C + H_2 \leftrightarrow -CH_2^-$$

$$CH + 0.5H_2 \leftrightarrow -CH_2^-$$

Pulverized coal is mixed with oil and catalyst to produce an oily, medium sized interim slurry which is either reprocessed to a coal oil or, in a subsequent step, after mixing with hydrogen, passes through a series of hydrogenation reactors at 450–490 °C and 20 MPa, and in the presence of an iron oxide powder as catalyst to a coal oil. Here the coal having a molecular weight of over 5000 splits into smaller pieces with the concomitant accretion of hydrogen. Thermodynamic conditions determine the quantity and type of products, and they can be adjusted to the feedstock. Coal to liquids (CTL) processes require about 5–8 kg of H2 per bbl to produce transportation fuels. The coal demand for 1 t of 'coal oil' is 1.25 t to be hydrogenated plus 1.36 t for the hydrogen plus 1 t for the process heat.

Overall thermal efficiencies for the direct method are generally in the range of 60–70% in modern processes. Different kinds of pyrolysis (high temperature, mild, rapid) with different liquid yields have been developed and tested in pilot plants, however, no demonstration plant has been operated so far.

Direct coal liquefaction puts stringent requirements on the type and quality of the coal, and its products need further upgrading before being used as transportation fuel. On the other hand, it achieves favourable efficiencies.

Brought to large technical maturity by Pier, Germany operated 12 coal hydrogenation plants from 1940 to 1944 to produce four million t/a of coal gasoline. British Coal developed a two stage direct coal liquefaction process called ‘liquid solvent extraction’ where two reactors in series are applied. Coal dissolution with little or no catalyst is done in the first stage, while hydro-treatment of the heavy coal liquids takes place in the second stage. The thermal efficiency for a conceptual coal liquefaction plant based on this process was estimated to be >60%.

In contrast to the direct process, Fischer and Tropsch started from synthesis gas. In their indirect liquefaction process, developed between 1922 and 1926, coal is gasified in a first step to synthesis gas followed by a catalytic hydrogenation of the CO where synthesis gas is reacted at relatively low temperatures and pressures (220–340 °C, 2–2.5 MPa) to high quality clean fuels:

$$2nH_2 + nCO \leftrightarrow -CH_2^- + nH_2O$$

or, if the production of long carbon chain alkanes is favored:

$$\left(\frac{n}{2} + m\right)H_2 + mCO \leftrightarrow C_mH_n + mH_2O.$$

After the volatiles have been cleaned out of the gas stream, the water gas shift reaction is applied in order to adjust the H2:CO ratio and match requirements for the hydrocarbon synthesis and produce CO_2 as the main byproduct. In CTL processes, more than 40% of the synthesis gas is shifted to make the required hydrogen. Catalysts are selected depending on the product spectrum requirements. Special catalysts are used to rebuild the molecules into liquid hydrocarbons and remove by-products.

The product spectrum depends on the operating conditions applied with the higher temperatures/pressures to yield synthetic gasoline and chemicals, whereas the low temperature process leads to the production of synthetic naphtha, kerosene or high quality diesel fuel. Gasifier product gases with a H2:CO ratio of around 0.5 to 0.7 are recommended as a feed to the Fischer–Tropsch process when using an iron catalyst. A high H2, low CO_2, low CH4 content is required for chemical and fuel production. In general, liquid products are of lower quality compared with those from direct liquefaction processes.

The generation of 1 kg of Fischer–Tropsch product requires an input of 4.5 kg of coal and 7.2 kg of water, and it produces 9.3 kg of CO_2 plus 0.4 kg of solid waste. The tremendous CO_2 emissions of CTL fuels made from coal are a major disadvantage, being more than double of those for crude oil derived fuels.

The Fischer–Tropsch process is a preferred liquefaction process because it has a large experience basis and yields high quality fuel (diesel) containing only very little sulphur. The drawback is that coal liquefaction is comparatively expensive,

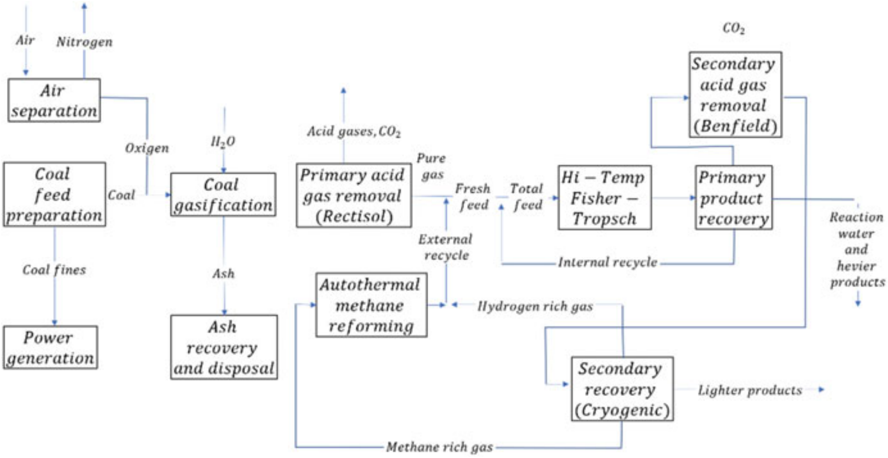


Fig. 4 Schematic of conventional CTL process

particularly at the front end where all contaminants have to be removed before processing to a gas or liquid. The indirect process is superior to the direct one because of the lower operational pressures necessary and thus a higher reliability of the plant, and a higher grade product spectrum. Efficiencies are around 40%, being lower than for the direct process, and in modern plants up to about 55%. Economics demand large scale plants with a massive demand for hydrogen and oxygen.

Figure 4 shows a schematic of the conventional CTL process.

Technical plants use solid bed (Arge process) or flue stream reactors (Synthol process). In the Arge process, apart from gasoline, preferably solid paraffins are produced, whereas gaseous hydrocarbons are produced in the Synthol process. The Fischer–Tropsch synthesis yields a gasoline with low octane number, but a higher value diesel fuel compared with coal hydrogenation (Aziz et al. 2017).

A major disadvantage is the significant quantity of CO_2 that is emitted during the synthesis gas production. If an independent source of H2 and O2 were available, e.g. from a water splitting process by nuclear or renewable energies, processes like air separation, steam generation and shift reaction would no longer be required and process related CO_2 release would be significantly reduced.

Starting as early as around 1840, both direct and indirect methods of coal liquefaction were developed in Germany to industrial maturity in the 1940s applying brown coal and stone coal. Coal liquefaction in Germany, however, eventually became uneconomic and was later abandoned. Significant R&D work was initiated during the oil crisis in the 1970s in the USA, the UK, Japan, and other countries. Activities in Germany resulted in the operation of a pilot plant with a production rate of 200 kg/d. Since then, only a few joint international projects, e.g. with South Africa, have remained, the only country to apply this technology still today at a large scale.

Recent trends have revived interest in coal liquefaction technologies as an alternative means of generating transportation fuels and other oil products used in a number of countries as insurance against crude oil supply problems. Primarily, high oil prices, increasing demand from China and India, US refining capacity limitations, and increasing reserve replacement costs as well as a growing desire for energy independence from foreign sources create the political will to explore more domestic energy resources. Lignite is considered an ideal feedstock for coal liquefaction because of its low relative cost and high hydrogen content. Newer processes convert the syngas to methanol before transforming it to other liquid fuels. An alternative option is use of outside (allothermal) production of hydrogen and oxygen, like from a (nuclear) water splitting process. Engineering studies are required to optimize the modified flowsheets for a nuclear assisted hydrogen coal liquefaction plant and to assess the economics (Lewis 2008).

The Mobil Oil process is principally based on a new catalyst which allows easy production of liquid fuels from methanol. Gas to liquid (GTL) capacity, however, is expected to grow slowly due to the huge and risky investment. By 2050, an estimated 5–10% of the transportation fuel demand may be covered by GTL fuels.

China, with its abundant coal reserves, is experiencing a strong growth in coal liquefaction. Fischer–Tropsch fuels are considered feasible and practical options to replace petroleum based fuels in China in both the short and medium terms, and thus reduce its dependence on oil imports. Commercial scale plants are already in the design and construction phase. A coal liquefaction plant has been constructed in Shenhua, China, with a throughput of 9.7 million t/a of coal to be converted into five million t of gasoline, kerosene, diesel and other fuels. For the next few years, China is planning the construction of 27 coal liquefaction plants. More liquefaction plants based on the direct process are planned, with a total capacity of 60 million t/a of oil. China will soon become the worldwide volume leader in CTL fuel production. In cooperation with SASOL, China is currently involved in two plants planned for Inner Mongolia to deliver an annual capacity of 60 Mt of oil. The first plant, with a one million t/a capacity, is expected to produce gasoline and diesel by 2007. Also a plant able to produce 50,000 bbl of ethanol per day is planned. Further coal to chemicals (CTC) plants are planned in regions with proven coal reserves for ammonia and methanol production.

In Japan, the liquefaction of bituminous coal was promoted under the Sunshine project which started in 1974. The so-called ‘NEDOL’ liquefaction technology (Fig. 5) has been developed where the three processes of direct hydrogenation, solvent extraction and solvolysis were merged to one.

The result is a light-distillate rich oil produced under mild reaction conditions. But also the liquefaction of low-rank coal is being investigated in Japan.

The so-called brown coal liquefaction (BCL) technology is currently being tested on pilot scale in a 50 t/d plant in Australia.

A 150 t/d pilot plant for bituminous coal was operated between 1996 and 1998 and provided engineering data for a commercial plant to follow. Japan is currently the only country active in large scale process development.

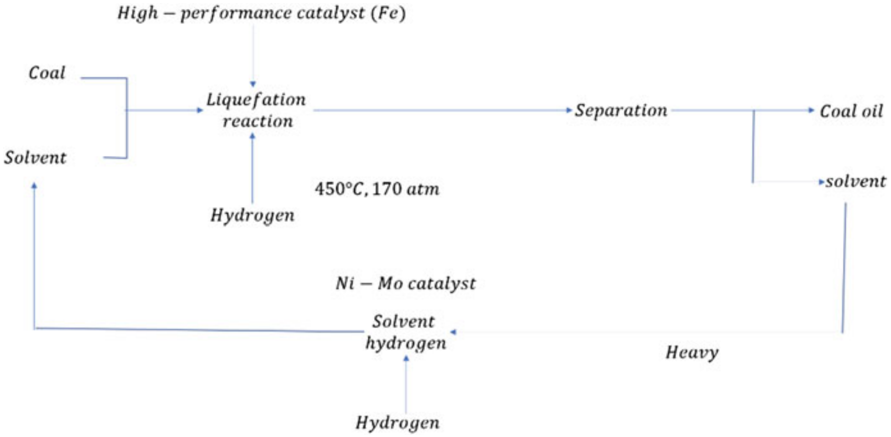


Fig. 5 Schematic of the Japanese NEDOL bituminous coal liquefaction process

The South African corporation SASOL Limited is a fuels and chemicals manufacturing company and the largest gasification centre in the world. Since 1955, SASOL has been producing higher value oil products from low grade coal, today at an output of 150,000 bbl/d of fuels and petrochemicals, supplying about 40% of the domestic demand for liquid fuels. The SASOL complex in South Africa consists of three facilities at two sites. Sasol Two and Sasol Three located in Sasolburg comprise the world's two largest gasification facilities. Within the USDOE's Clean Coal Technology Demonstration Program, a liquefaction plant with a capacity of 1000 t/d was commissioned based on the 'mild pyrolysis' process. North Dakota has received recent attention regarding coal liquefaction with the proposal of a 10,000 bbl/d facility with expansion opportunities to 50,000 bbl/d. If diesel is included in the fuel mix at the proposed coal liquefaction plant, coal based diesel could be blended with biodiesel. Also, the KIER in the Republic of Korea is currently testing CTL in a 15 bbl./d pilot plant.

The methanol industry is the third most important user of hydrogen. Methanol is a high octane alcohol, a colourless liquid with a boiling point of 65 °C that is easily ignitable, with a flammability range between 6.7 and 36.5 vol% in air. Commercial methanol synthesis involves reacting CO, H2 and steam over a copper–zinc oxide catalyst in the presence of a small amount of CO_2. Methanol is produced, e.g. through synthesis gas from coal by clean coal technologies with CO_2 from the reverse water shift reaction and the hydrogenation of carbon dioxide at 250–300 °C and 5–20 MPa by:

$$CO_2 + 3H_2 \leftrightarrow CH_3OH$$

$$CO_2 + 3H_2 \leftrightarrow CH_3OH + H_2O$$

Other feedstocks like natural gas or heavy oils are also possible. The product gas from coal gasification is not appropriate for methanol production owing to its high fraction of CO_2 and methane. The preceding POX step could reduce the methane fraction. To best use the raw product syngas in methanol synthesis and limit the extent of further syngas treatment and steam reforming, it is essential to maintain the following conditions:

- A H_2:CO ratio of at least 2;
- A CO_2:CO ratio of about 0.6 to prevent catalyst deactivation and keep the catalyst in an active reduced state;
- Low concentrations of N_2, CH_4, C_2+, etc., to prevent the buildup of inert gases within the methanol synthesis loop;
- Low concentrations of CH_4 and C_2+ to limit the need for further steam reforming.

Alternative methanol production occurs via direct hydrogenation of carbon monoxide:

$$CO + 2H_2 \leftrightarrow CH_3OH$$

This second reaction demands more energy, is slow and incomplete. Therefore the product gas should contain only small amounts of CO_2 and have an H_2:CO ratio of ~2.2. The methanol synthesis reaction is equilibrium controlled, and excess reactants (CO and H_2) must be recycled to obtain economic yields.

Methanol is a classic basic material for chemical production chains, e.g. the production of chemicals such as propylene, poly-propylene, phenol or acetone. The methanol to gasoline (MTG) process is an effective route for CTL processing where methanol is directly converted to gasoline:

$$nCH_3OH \leftrightarrow \left(-CH_2^-\right)_n + H_2O$$

The process is simple and robust in design and operation and promises high plant availabilities. It was demonstrated in New Zealand, but has not been conducted so far at a large scale. Still, MTG plants are currently foreseen in China and the USA. A new MTG plant with coal based methanol production in Jincheng, China, started operation in 2009. It has a 100,000 t/a of gasoline capacity which may be extended to one million t/a later.

Commercial application of methanol as a fuel, however, is limited due to its high toxicity and relatively low energy density (~65% of that of gasoline).

Methanol can be used in direct methanol fuel cells and also in higher temperature fuel cells for electricity production or even in PEFC after a reforming stage. Methanol is also used for the production of alternative automotive fuels such as DME. A route to transport fuels is hydro-treating/hydro-cracking to a naphtha-like product with upgrading to diesel. But the high pressure and high hydrogen requirement of hydrotreating routes makes this route much too expensive. A major issue is the catalyst stability and lifetime. The coproduction of chemicals and fuels undoubtedly offers the most interesting opportunities.

The world market for methanol was 40 million t/a in 2007 which is expected to increase to 80 million t/a by 2020. Most methanol is currently produced from coal and natural gas. It is used as feedstock for fuel addition and chemical materials such as formaldehyde and acetic acid. Emerging markets are seen in the transportation sector. At present, the largest plants with a capacity of ~5500 t/d are operational in the Islamic Republic of Iran and Trinidad.

The transportation sector and stationary power applications are widely viewed as the two critical sectors where there may be an opportunity to greatly expand the future use of hydrogen. Most of today's transportation fuels are being generated from refining crude petroleum oil. Petroleum fuels which are well qualified for widespread use and offer a number of benefits which make it likely that they will continue to dominate the overall fuel mix:

- High energy density;
- Strong demand from the current stock of vehicles and a widely established infrastructure for delivery to users;
- Relatively low cost;
- Easy, low-cost handling and transport at atmospheric temperature and pressure;
- Extensive experience and knowledge of fuel systems, coupled with considerable progress in optimization;
- Ease of long term storage.

But petroleum fuels also have at least two major drawbacks: potential supply limitations, including significant geopolitical dependencies for many countries, and high CO_2 emissions. For both of these reasons, there are strong incentives to develop and secure acceptable substitutes.

Figure 6 and Table 1 list various transportation fuels for both ICE and FCVs, and some of their characteristics.

Not only is hydrogen considered a transport fuel which may be applied in the future on a large scale, it is also a basic building block with increasing significance (and market potential) for the production of conventional liquid fuels, but also — partially — for other alternative fuels or synthetic fuels. Diversification of fuel supply is the driving force to move away from crude oil and gradually displace conventional petroleum products, meeting the challenges of air pollution, CO_2 emissions and supply security. If captured CO_2 is used for their production, they would even represent CO_2 neutral alternatives.

Production of synthetic liquid fuels requires the input of carbon, hydrogen and energy. All three can be taken from fossil fuels or biomass. An IEA analysis suggests that the least expensive alternative to oil based fuels is large CTL plants, which are cost effective at oil prices above US$60/bbl. GTL and hydrogen produced from natural gas are strongly influencing fuel production cost. Biomass to liquid (BTL) fuel is cost competitive only if low cost biomass is available.

SNG is the starting point for many industrial chemical processes. The exothermic methanation reactions are:

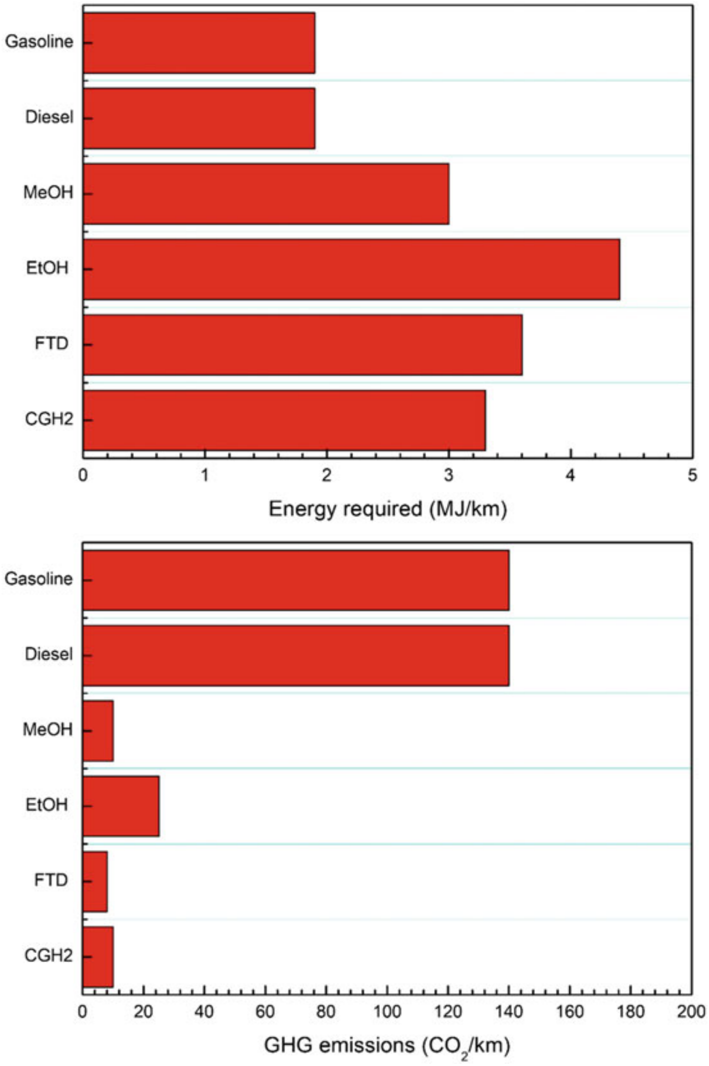


Fig. 6 Comparison of today's petroleum fuels with alternative non-fossil derived fuels

$$CO + 3H_2 \leftrightarrow CH_4 + H_2O$$

$$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O$$

The second reaction (Sabatier reaction) is slow and incomplete. Therefore, the product gas should contain only small amounts of CO_2 and have an H2 to CO ratio of ~3.2, conditions that are achievable in non-catalytic steam–coal gasification, but under stringent operating conditions not possible for the catalytic process. The

Table 1 Comparison of transport fuels

Fuel	Main source	Molecular weight	Density (kg/m3)	HHV (MJ/kg)	Energy per volume (GJ/m3)
Hydrogen	NG, oil, coal, methanol	2.02	0.08988	141.9	2.6 at 20 MPa 10.3 at 80 MPa
LH2	Hydrogen	2.02	70.8	141.9	9.9
NG (methane)	Fossil resource	16.04	0.7175	55.5	8.1 at 20 MPa 32.1 at 80 MPa
LNG	NG	16.04	422.6	55.5	20.5
LPG (propane)	Refining of petroleum, NG	44.1	581	50.4	25.2
Methanol	NG, cola, biomass	32.04	793	22.7	18
Ethanol	Biomass, grain, corn	46.07	794	29.9	23.5
Gasoline	Crude oil	100–105	745	47.4	30.4–34.8
Diesel	Crude oil	200	832	45.8	35.7–36.2
Biodiesel	Biological oil, animal fat	120–320	830–850	39.8	32.6–33.4
DME	NG, cola, organic material	46	670	31.7	21.1
MTBE	Isobutylene	88.15	741	7.8	28.1
Toluene	Crude oil, tolu tree	112	862	42.5	26.9
Ammonia	NG, heavy oil	17	771	22.5	17.4
Jet A	Crude oil	144–226	775–830	46.5	34.2

use of coal gasification raw gas is less economic for on-purpose methanol or hydrogen production compared with the gas from autothermal processes. The conversion of coal to SNG offers the option of transporting the energy content of coal via pipeline.

Besides storage, there is also the option of using CO_2 as a raw material, i.e. taking it directly as a C1 building block to be used as reaction partner in chemical and biotechnological processes and built into products. Storage time would correspond to the product's lifetime, ranging between decades for long lived polymers and practically zero for synthetic fuels.

As of 2005, the worldwide anthropogenic CO_2 emissions from using fossil fuels amounted to 28 Gt/a. The main (large, stationary) sources are the energy sector with 10.5 Gt or 46%, the transportation sector with 5.6 Gt or 24%, steel production with 1.5 Gt or 6%, refineries and the chemical industry with 1.2 Gt or 5%, and others. The CO_2 sources in the transportation sector are small and numerous and therefore not appropriate for sequestration and further use. The same holds for the firing of fossil fuels for heating purposes.

Different from the storage option where CO_2 is taken out of the CO_2 cycle, no CO_2 is usually saved in the case of using it as a carbon source. It would only be saved if the energy required for the reduction of CO_2 as the reverse process of combustion is from a CO_2 emission free energy source. CO_2 as a raw material is obviously available in large amounts, but only a small quantity can be utilized and only in a few industrial processes. The industry uses approximately 120 million t of CO_2 per year. Although most of it will be consumed again (urea synthesis), at least ten million t/a would be available for chemical conversions. Other applications are in the beverage industry, for enhanced oil recovery, and in its supercritical state as a technological fluid. As an inert and safe gas, it is also used as a protective gas and in its solid state for refrigeration.

For products of the chemical industries, the estimated substitution potential amounts to 178 million t of CO_2 per year, which is not more than 0.6% of the total annual anthropogenic CO_2 emissions worldwide. The use of carbon for synthetic fuel production would increase the potential by a factor of 10, but it would not change the atmospheric CO_2 concentrations, since subsequent combustion of the fuels will immediately recycle the CO_2 back to the atmosphere. The purity of CO_2 is an important prerequisite that eliminates the CO_2 emitted from fossil power plants as source candidates. Their use would require an extensive purification as a preceding step. Exceptions are the emissions from IGCC plants (Giuliano et al. 2018).

The most common method of recovering atmospheric CO_2 is by absorption using aqueous potassium carbonate. The external energy source to be used (mainly for hydrogen production) can be, for example, in the form of electricity. The use of nuclear primary energy would provide the option of unlimited liquid fuel production without any greenhouse impact.

The CO_2 or dry reforming process can be applied for the production of synthesis gas, which is then converted by means of Fischer–Tropsch synthesis to gasoline or diesel fuels. In GTL technologies, atmospheric CO_2 can be used as a carbon source for the conversion with hydrogen to synthetic liquid fuels, such as methanol or its derivates methyl T-butyl ether (MTBE), dimethylcarbonate, or dimethylether. Furthermore, it allows the direct production of DME from CO_2 and H2. Methanol and dimethyl-carbonate (DMC) are considered alternatives to the currently used gasoline; DME may replace diesel fuel. The above processes, however, are only reasonable if there is a source of (inexpensive and) ‘clean’ hydrogen feedstock. Technological challenges for the development of energetically efficient processes are seen in the areas of catalysis and reaction kinetics.

KIST developed and demonstrated a direct methanol production process using hydrogen and captured CO_2 (CAMERE-I process) with an integrated steam reformer for hydrogen production (CAMERE-II process). The concept of nuclear methanol is now to introduce nuclear energy into the steam reforming process using an advanced HTGR. A 450 MW(th) plant would be able to produce one million t/a of methanol and recycle at the same time 0.35 million t/a of CO_2.

Hythane is a blend of natural gas and hydrogen with a fraction of 8–30% of hydrogen. Since methane emits NOx and has a relatively narrow flammability range that limits the fuel efficiency, the addition of a small amount of hydrogen extends the lean flammability range significantly. Hythane is more buoyant and more diffusive than methane. Methane has a slow flame speed, especially in lean air–fuel mixtures, while hydrogen has a flame speed about eight times faster and is much more easily ignited (Mahant et al. 2021).

Hydrogen is a powerful combustion stimulant for accelerating the methane combustion within an engine, and it is also a powerful reducing agent for efficient catalysis at lower exhaust temperatures. In the case of explosive combustion, a hythane explosion is expected to be stronger than a methane explosion, but exhibits significantly lower pressures than do pure hydrogen explosions.

Hythane could represent an interim step on the way to a hydrogen based economy. A big advantage is the fact that hythane can benefit from the existing infrastructure for natural gas without major changes. The same holds for hythane combustion in a natural gas driven internal combustion engine. Test vehicles in public transportation running on hythane are being operated at various places in the world.

4 Prospective Uses of Hydrogen

For future large scale applications of hydrogen, it should be kept in mind that electricity and hydrogen can form a symbiosis, allowing an optimization of electricity generating systems with regard to the substitution of fossil energy carriers currently being used for load following and peak demands. This is due to the fact that electricity and hydrogen are principally interchangeable, i.e. the production of hydrogen (e.g. via electrolysis) and the re-conversion of hydrogen into electricity (and heat) (e.g. by fuel cells). This fundamental interconnection is being addressed as ‘hydricity’ (Hoffmann 2012).

With increasing production of electricity from renewable energies instead of fossil fuels, novel energy storage systems are needed to compensate for the strong variations of supply and demand. Hydrogen may here play an important role as a storage element for energy that can easily be retrieved upon demand. In addition to the industrial hydrogen demand as a chemical product, commercial growth of hydrogen production is expected, most probably starting in the coming decades in road transport and in the residential and service sector to expand the application as a fuel in fuel cell vehicles and stationary power generation (Tsujimura and Suzuki 2019).

Niche market applications such as hydrogen powered consumer electronics may play a role, specifically in the area of public acceptance, in the introduction of hydrogen in the energy system. All these potential applications may contribute in the medium term to an increased need for clean hydrogen production routes. The further future beyond 2030 may see a significant increase in hydrogen consumption due to cost reductions in the production technologies and a stronger demand from the transport sector.

Crude oil is a finite resource. Conventional oil production will peak at some point and then gradually decline, increasing the share for unconventional oil production. Therefore, there will be an increasing demand for more capacity to refine heavier grades of oil, including other non-conventional liquids such as condensates, natural gas liquids, tar sands, bitumen, extra heavy oil and oil shales, but also synthetic fuels from anything to liquid (XTL) processes to contribute to global petroleum supply. While the economics of heavy oil might be promising, the harnessing of non-conventional resources is handicapped by high development costs, consumption of large quantities of water and natural gas, and severe environmental impacts.

Heavy oil is a dense and viscous kind of oil with high contents of sulphur and metals. Extra-heavy oil resources are mainly located in Venezuela. Large reserves of oil exist in the form of highly viscous crude oils inaccessible by methods available at present.

Thermal methods are the most developed technology, where steam injection plays the overwhelming role. The type of steam required depends on, e.g. the depth of the resources, porosity of the rock matrix or oil viscosity. For improved recovery methods, high pressures of 12 MPa and more are necessary. Oil yield increases significantly with the steam temperature and pressure. Oil recovery steam generators currently on the markets are in the power range of 1.5–15 MW(th), providing steam at pressures up to 17 MPa and temperatures up to 350 °C, and at rates of up to 110 t/h (250 000 lb/h). Dry saturated steam of high temperature to be injected into deep oil wells could be produced by an HTGR.

But besides steam, large quantities of hydrogen will also be required for tertiary oil recovery (upgrading to synthetic crude), which requires a significant increase of the present power capacity to allow for efficient large scale hydrogen production in the future.

Most of the world’s oil shale resources (estimated at 75%) are located in the Green River Formation in the USA, with estimated resources of 1.5–1.8 trillion bbl of oil. The largest oil shale producer and consumer country, however, is Estonia, with peak production of 31 million t in 1980 (today ~15 million t/a). Shale is a fine-grained rock of sedimentary origin containing, but varying widely in content and composition (quality) of, high-molecular organic substances (kerogen) embedded in its inorganic matrix. Criteria of oil shale reserves are energy rating, location, depth and thickness of seams, mining technology, world price and transportation costs compared to alternatives, and protection of the environment.

Oil and gas can be extracted by destructive distillation. Only some of these organic compounds (the natural bitumen) are soluble. Depending on the site, the rock contains an average of 10–20% insoluble organic matter and bitumen — in some cases the organic content can be as high as 60%. At temperatures of 350–400 °C, the yield can be 20–200 L of oil per tonne of shale. The negative aspects are the immense toxic waste which is left by the oil shale chemical industry, the large CO_2 emissions from oil shale power stations and the deterioration of water quality.

The high temperature heat required to heat the oil shale could be provided by nuclear energy. The direct use of high temperature heat avoids the conversion of electricity to heat. Another advantage of the nuclear system is a significant reduction of CO_2 compared with other methods of synthetic crude oil production. The distances from reactor to well are sufficiently short that heat transport is practicable. About 12 GW(th) of high temperature heat would be required to produce a million barrels of oil per day. In practice, the required temperatures would be near 700 °C.

Tar sands are a mixture of sand, clay, water and bitumen (viscous heavy oil), from which the bitumen is extracted. They represent a major energy resource that increases in importance as world supplies of crude oil become limited; on the other hand, they are the dirtiest fuel on Earth. The hydrogen to carbon ratio of tar sand is ~1, which must be raised to 1.5–2 for conversion to gasoline. Oil sands are mainly located in Canada in the state of Alberta, the regions of Athabasca, Cold Lake River and Peace River, with proven reserves of 174 billion bbl of oil, representing about 80% of the world's technically recoverable resources and 95% of Canadian oil reserves.

Oil sands feature an intermediate density and viscosity. The methods involve the in situ steam assisted gravity drainage (SAGD) technology, since ~80% of the deposits in Canada are not accessible for surface mining. The product recovered from the sands is a heavy, sour bitumen. Upgrading with hydrogen is required to transform it into a lighter product (with lower density and viscosity) that can be transported to refineries via pipelines. The products are synthetic crude (refinable by current technology) and petroleum coke. The Athabasca oil sands are estimated to require 3–4 kg of H2 per barrel as well as steam (14 MPa, 340 °C) and electric power for the recovery and upgrading processes. Current production from oil sands amounts to 1300 bbl/d, which is expected to increase to six million bbl/d by 2030.

Producing fuels from oil sands requires large amounts of natural gas and water, and produces large quantities of waste material and carbon dioxide. The shale can be distilled autothermically after open pit mining. This method requires hot water of ~70 °C and process steam at around 1–2 MPa and has a yield of less than 50% of the organic matter. A second in situ method for high-permeability shales is SAGD, in which two horizontal wells of 0.5–1 km length and at least 50 m below surface are drilled with one about 5 m below the other one. Steam at high pressure and temperature (10 MPa and 540 °C) is continuously injected into the upper well, where the bitumen heats up and flows downwards. The formed emulsion of bitumen, steam and water is drained through the lower well and recovered. A pair of wells is able to recover in the range of 2000 bbl/d of synthetic crude oil.

Other methods are cyclic steam stimulation (CSS) or pressure cyclic steam drive (PCSD) requiring steam of more 300 °C and pressures of 8–16 MPa. Novel technologies replace the steam with either solvents, e.g. a liquid salt, or in situ combustion. The possible yield also represents 50% of the in-place reserve. Oil shale contribution is marginal so far, as no industrial scale recovery has yet been envisaged due to the high production costs.

Furthermore, the processing is presumed to produce five times more CO_2 emissions than conventional refining. But oil shale would roughly add another 300 billion bbl of oil to the global reserves.

Various fuel cell types have been developed, usually classified according to the electrolyte used. In Table 2, fuel cell types (Fig. 7) are listed along with their operating temperatures and anode/cathode reactions (Staffell et al. 2019).

Certain constraints to the fuel cell do apply depending on the type of fuel cell. In low temperature fuel cells, noble metal (Pt) electrodes are necessary to increase the reactivity. Poisoning of electrodes can be minimized by purification of the feed

Table 2 Different types of fuel cells

	Electrolyte	Temperature (°C)	Fuel	Oxidant	Efficiency (% LHV)
Low temperature					
AFC	Alkaline	80–200	H2	O2	50–60
PEFC	Polymer	80–100	H2	O2, air	40–45
HT-PEFC	Polymer	120–180	H2, CO	O2, air	40–50
DMFC	Polymer	80–100	MeOH	O2, air	25–30
PAFC	Phosphoric acid	200	H2	O2, air	40–45
High temperature					
MCFC	Molten carbonate	650	H2, CO, CO2, CH4	O2, air	50–55
SOFC	Ceramic	750–1000	H2, CO, CH4	O2, air	50–55
LT-SOFC	Ceramic	550–650	H2, CO, CH4	O2, air	50–55

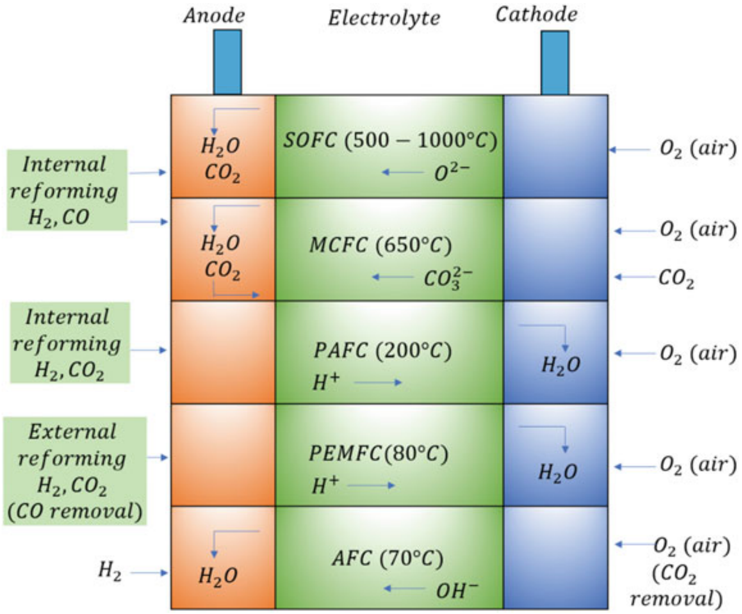


Fig. 7 Fuel cells schematic

stream. Various methods have been developed to remove sulphur, which is a poison to many oxygen electrode catalysts. High temperature fuel cell designs avoid expensive noble metal catalysts. Thermal activation is insensible to pollutants. Drawbacks are performance degradation limiting lifetime and expensive plant components. To avoid dilution of the electrolyte by the product water, it must be removed by evaporation or vaporization. In high temperature fuel cell systems, the water is steamed off anyway.

If carbon containing fuel gases are used instead of pure hydrogen, oxidation must be realized first in a reforming reaction. Internal reforming has the advantage that there is no requirement for hydrogen storage (Sengodan et al. 2018).

Incomplete reaction at lower temperatures results in the presence of carbon monoxide, which is a catalyst poison and must be removed, at the expense of efficiency. CO causes no trouble at high operating temperatures since reforming can take place internally. Attempts at a direct conversion of coal or oil in an integrated gasification fuel cell system are currently at an early R&D stage, but they are considered potential primary fuels in the long run.

The alkaline fuel cell (AFC) is a highly efficient low temperature fuel cell (<100 ° C) with a very high power density, and therefore ideally appropriate for mobile applications. The AFC, however, requires a demanding process control that is complicated because of the corrosive liquid electrolyte, a 30% potash lye, and the need for extremely pure fuel (no CO_2), leading to high cost. Efficiencies of 60% and more have been achieved with clean hydrogen and oxygen and noble electrode materials (Haseli 2018). The AFC was demonstrated to also work with a hydrogen–air system. What remains unsatisfactory is its observed power decrease with operating time.

The polymer electrolyte fuel cell (PEFC), or proton exchange membrane fuel cell (PEM-FC), is an efficient, compact, robust and quiet method of generating electricity. It has a 0.1 mm thick proton conducting foil as a solid electrolyte which is coated on either side with the electrodes representing the so-called membrane electrolyte assembly (MEA). It has the highest power density of all cell types, a relatively low operating temperature and thus long cell lifetime, good load change behaviour and good efficiency at partial load, and good standby performance, thus being appropriate for mobile applications. A problem in PEFCs is the need to keep the polymer electrolyte membrane in a wet state and at higher operating temperatures to prevent a dry-out by means of external wetting. Applicable fuels are hydrogen, reformed methanol or methane with purity requirements of less than 10 ppm of CO, less than 1 ppm of NH3 and less than 0.1 ppm of H2S. The development is concentrating on improvement of catalysts and reduction of CO poisoning effects. The electricity output from the fuel cell depends on the availability of oxygen. It is maximal when pure O2 is used, but can be reduced by a factor of 2–4 in the case of air.

The first complete PEM fuel cell system was developed in 1963 and utilized during the Gemini space flights.

The 1 kW cell stack employed sulfonated polystyrene membranes as an electrolyte, which was later replaced by the polymer Nafion. Today, PEFCs constitute the main pillar of fuel cell technology in both transport and stationary applications, with an emphasis being placed on system integration and demonstration programmes. The market is generally seen in smaller scale applications, whereas those on a larger scale have mainly disappeared.

Another low temperature fuel cell, the direct methanol fuel cell (DMFC), runs on either liquid or, with better performance but higher system complexity, on gaseous methanol and is normally based on a solid polymer electrolyte. The operating temperature for DMFCs is in the range of 60–130 °C, typically around 120 °C, producing an efficiency of about 40%. Due to the low temperature conversion of methanol to hydrogen and carbon dioxide, the DMFC system requires a noble metal catalyst. Pt–Ru catalysts were found to produce the best oxidation results at the oxygen electrode. Because of the still ten times higher loading with catalysts compared with PEFCs and the relatively low efficiency and power density due to internal fuel leakage through the membrane, the DMFC is not suitable for large units. Typical areas for DMFCs are in small units from a few Watts up to approximately 2 kW for portable applications. An advantage in mobile applications is the use of the methanol in liquid form at low pressures. But detailed development is still necessary, with major improvements to be seen in a further reduction of degradation rates, simplification and compaction of the system, and further increase of system efficiencies.

Most practical experience has been gained in the operation of phosphoric acid fuel cells (PAFCs). Because of the higher operating temperature, PAFCs have a minor CO poisoning problem, plus they offer operation in the CHP mode providing good quality steam of approximately 200 °C. The fuel is hydrogen or reformed methane plus CO converter. The principal poison for the Pt catalyst is sulphur carried in the reformate stream as H2S. The PAFC has successfully played a pioneering role in the introduction of fuel cell systems. Several hundred ONSI-delivered PAFC stations were tested and have proven technical maturity with 8000 operating hours per year and an availability of more than 90%. Most demonstration tests, however, were terminated after sufficient data were collected. Investment costs are still too high to be competitive.

A molten carbonate fuel cell (MCFC) is being operated in the 500–700 °C temperature range with porous Ni catalysts and a molten binary carbonate made of Li_2CO_3/K_2CO_3 or Li_2CO_3/Na_2CO_3 immobilized in a porous matrix of $LiAlO_2$ as an electrolyte. Carbon dioxide yielded at the anode needs to be fed back to the cathode, where it is consumed by conversion to carbonate ions which provide the means of ion transfer. Due to the high operating temperature, there is no need to employ noble metals as a catalyst. A key advantage over low temperature fuel cells is the fuel flexibility. Besides hydrogen, the MCFC can be operated with methanol or methane or coal gas, with external or with partial or full internal reformation; the possibility of internal naphtha reforming is also being examined. In the future, synthesis gas from (internal) coal gasification systems may be linked to MCFC electricity generation, inducing a further increase of coal conversion efficiencies. Recently, the applicability of biomass derived gases has also been investigated.

A number of MCFC installations with the ‘HotModule’ manufactured by the German company MTU are being operated successfully in Germany, Italy and Spain, and have achieved an a accumulated operating time (by 2007) of more than 170,000 h, and the industrial development is expanding. The drawbacks of this fuel cell type are its low current and power densities. A problem often observed in

MCFCs is the strong corrosivity of the electrolyte and its leakage through gaskets. Long term experimental operation is still required to demonstrate that ageing of the stack is acceptable. Also, the high serial resistance of the hot carbonate electrolyte limits the efficiency to 40%.

The solid oxide fuel cell (SOFC) has a solid ceramic as the electrolyte, e.g. zirconium oxide stabilized with yttrium oxide, in which oxygen ions migrate from the cathode to the anode. Heat and CO_2 are also generated at the anode. The SOFC is attractive because of its very high operating temperature range of 800–1000 °C, which allows fast chemical reactions. The high temperatures, on the other hand, imply stringent requirements for materials and construction. Two different stack designs are currently pursued using tubular or flat cell geometry. Typical dimensions of the tubular design are: support (cathode) with an inner diameter of 12–22 mm, 2.2 mm wall thickness, and a length up to 1500 mm, an electrolyte layer of 20–40 μm, and outside the anode with 100 μm thickness. For a flat cell, the typical data are: a gas-tight electrolyte of 150–200 μm thickness, electrodes with 50 μm thickness and 30–50% porosity. Most research efforts are currently conducted on planar SOFCs. With only slight modifications, the SOFC can be operated either in the electrolysis or in the fuel cell mode.

Due to the high operation temperatures, SOFCs convert gaseous hydrocarbons either directly or after internal reforming with a very low emission level. Utilization of the high temperature waste heat raises the overall efficiency to a maximum. Furthermore, the waste gas at the anode, consisting of CO_2, H_2O, CO and residual H_2, could be utilized in other chemical processes. The time needed to heat up or cool down the system limits the use of SOFCs in applications with rapid temperature changes. Heat release during internal reforming, creating sharp temperature gradients, is difficult to control. Also, high temperature corrosion can sometimes be a problem and requires the use of expensive materials and protective layers within the cell. Problems related to sealing have also been observed.

SOFC systems are generally thought to be best suited to the generation of electricity and heat in industrial applications, especially in combination with gas turbines. Recent SOFC development shows potential for high electricity efficiencies of ~60%. The main SOFC applications are seen in larger scale stationary power generation and in smaller scale residential power generation (<10 kW) and auxiliary power units (APUs) for mobile applications. Most of the SOFC power units currently being tested have a power capacity of 1 and 5 kW, respectively. A 100 kW SOFC power plant is being operated in Italy. A 10 kW(e) SOFC stack with 60 planar cells has been constructed at the Research Centre Jülich and operated for 1500 h. Both hydrogen and methane fuels were tested. The next step will be a 20 kW (e) SOFC system demonstration. Goals of the future development are the reduction of the operating temperature and the extension to larger power units.

5 Hydrogen Vehicles

Hydrogen is being considered as a potential energy vector in the transport sector both for internal combustion engine (ICE) and FCV applications, basically with on-board storage of the hydrogen. In recent years, car producers have manufactured a range of prototype ICE and PEM fuel cell passenger cars using hydrogen as the fuel (Jones et al. 2020).

Numerous demonstration programmes for hydrogen powered vehicles with PEM fuel cell drive trains and — to a lesser extent — with ICE have been initiated, mainly in Europe, Japan and the USA, comprising a broad spectrum of vehicle classes for small and medium range requirements. The development of hydrogen fueled vehicles is mainly driven by the market, i.e. they have to compete against other technologies such as gasoline–electric hybrid vehicles, which have already achieved a high level of efficiency.

For a broad application of hydrogen as a vehicle fuel, however, further R&D work needs to be done, e.g. to develop a hydrogen storage medium allowing hydrogen fueled PEM fuel cell cars to have range capabilities comparable with those of current baseline gasoline and diesel vehicles. Also, the infrastructure and logistics for distribution and supply must be established, which in turn will be strongly dependent on the demand for hydrogen in the transportation sector. Therefore, before hydrogen is broadly introduced as a fuel in the traffic sector, it may appear in niche applications characterized by special boundary conditions such as a locally high environmental benefit. The main niche markets for the commercial use of hydrogen as transportation fuel are seen in city buses, passenger car fleets and light duty vehicles. Public transportation buses may represent an ideal entry point. Heavy duty trucks may switch to other alternatives such as biofuels (Onarheim et al. 2020).

Hydrogen can be directly used as a fuel in ICEs where the hydrogen burning engine mechanically drives the vehicle. The positive features for such a hydrogen application are the low spark energy requirement, wide flammability range, high auto-ignition temperature and high flame speed. A disadvantage is the low volumetric density which limits the power output of the engine. BMW and Mazda have been the only two mainstream manufacturers to seriously pursue internal combustion hydrogen technology, with most others preferring to use it to supply a fuel cell and produce electricity. Further advancements to internal combustion hydrogen units appear to be limited in the future.

Electricity is expected to play an increasingly important role in the transport sector. PEM fuel cells can be used for on-board supply with electricity (APUs), for uninterrupted electricity supply in decentralized applications, and in light transport systems. The use of pure hydrogen with fuel cells in vehicle propulsion systems offers the benefit that it produces electricity at high efficiency without combustion and, except for water vapor, with zero emissions. It shows reliable startup and can be sized in small and large power packages.

Fuel cell technology has arrived at an advanced technological state. But a gap is apparent between the impressive success of technologies and the development of market opportunities, especially with vehicles. A major market introduction is hampered by the high costs and limited demonstration of reliability and longevity. According to today's fuel cell technology, about 60 g of platinum is necessary for a PEFC for automotive application, whose worth is more than 30% of the current engine costs. Progress is expected from a further development of the membrane electrolyte assembly with higher operation temperatures (>120 °C), more freezing tolerance, more impurity tolerance and reduced catalyst need (~0.2 mg/cm2 of Pt). Resulting from a USDOE field evaluation of fuel cell vehicle from several automobile manufacturers, an average fuel efficiency for future fuel cell car production of 60 miles (~100 km) per kg was deemed a reasonable goal. About 120 fuel cell buses under various demonstration support programmes have been or are currently being tested worldwide, along with more than 1000 prototype, concept and demonstration cars, refueled at approximately 100 refueling stations. But costs for FCVs are still far too high. The current cost of a fuel cell bus averages US$1.5 million, and passenger cars cost more than US$100000. Extrapolating the current development status of a fuel cell stack to the production of 500,000 cars per year, the USDOE reports a value of US$61 per kW and compares this value with the target of US$30 per kW for 2015.

Research is a basis for solving many of the outstanding problems, including lifetime extension to practical levels, cost reduction to acceptable levels in specialized markets, battery replacement, fuel supply and distribution, and advanced fuel conversion technologies (biomass and waste). However, with increasing pressure for higher efficiency and lower emissions, fuel cells can expect a bright future.

Fuel cell technology has also been considered in connection with a chemical processing unit for the use of widely available liquid hydrocarbons as feedstock to extract the hydrogen by on-board autothermal reforming (ATR) and operate the electric propulsion system of a vehicle (Rau et al. 2017). It appears, however, that potential users have moved away from on-board fuel processing and are concentrating instead on on-board storage of hydrogen. This tendency became obvious with the decision of the USDOE in 2004 to discontinue funding of R&D activities. The "no go" decision was based on the expectation that decisive technical criteria such as startup time (less than 1 min at 20 °C) and startup energy (less than 2 MJ for a 50 kW fuel processor) would not be met within a reasonable time frame and thus there was no economic advantage over the rapidly emerging gasoline/battery hybrid vehicles.

On-board reforming has since been concentrating on small scale fuel processors in combination with a fuel cell for 'power on demand' applications. With the increasing demand for on-board electricity from about 0.8 kW(e) in today's cars to several kW(e) in future vehicles, it is considered to provide this electricity (plus heat) by means of a fuel cell-based APU. Combined with a small fuel cell stack in the order of 5 kW(e), APUs may generate all non-propulsion power in future cars to substitute for the conventional battery. They are advantageous because of their high efficiency and low noise, vibrations, and emissions. In addition, they extend the lifetime of the main engine. If sufficiently dynamic and stable to follow all potential states of the system and if reaction by-products and other contaminants can be kept at tolerable levels, APUs may represent the first step for fuel cells to penetrate the transportation market at a larger scale, with the prime candidates being energy consuming trucks or recreational vehicles (Doucet et al. 2009).

Today there are numerous vehicles being tested with electricity supply from PEFC based APUs to gradually substitute for conventional batteries. In cooperation with Delphi Automotive Systems, BMW is considering an SOFC based APU for their future vehicles. Its feasibility was demonstrated in 2001 with a proof-of-concept unit. BMW has already achieved some experience with low-temperature fuel cell based APUs, where among the 15 hydrogen fueled vehicles of the fifth generation, a few cars were equipped with a PEM fuel cell.

Marine transport worldwide currently contributes 14% of the global nitrogen oxide emissions and 7% of sulphur emissions. Therefore, fuel cells are also envisaged for use in marine applications if the specific maritime requirements can be fulfilled. Small demonstration projects are testing fuel cells in passenger boats and submarines. An example is the European Fuel Cell Systems for Zero Emission Ships (ZEMSHIPS) project demonstrating a 48 kW(e) fuel cell propulsion system for a ship in Hamburg. Hydrogen fueled fuel cells may be used in ships that do not need long ranges and can be filled up frequently, whereas ships that need longer ranges would need to use fuel cells based on fuels with higher energy densities, such as liquid natural gas, methanol or ethanol. In particular, the molten carbonate fuel cell (MCFC) with LNG as the fuel currently offers the largest potential as a power system for maritime applications (de-Troya et al. 2016). In the EU's MethAPU project (Validation of a Renewable Methanol Based Auxiliary Power System for Commercial Vessels), methanol fueled SOFCs in the power range of 250 kW have been investigated, including on-board testing of a 20 kW SOFC. For larger sea-going ships, fuel cell application currently would be limited to auxiliary supply of power in the 500 kW range.

A major driver for using fuel cells in ships is the possibility of reducing emissions drastically. Although, as a rule, gas applications on ships are not permitted, discussions have started on the on-board use of natural gas. The European project FCSHIP (Fuel Cell Technologies for Ships — Environmental Impacts and Costs of Hydrogen, Natural Gas and Conventional Fuels for Fuel Cell Ships) indicates possible future concepts and prepares regulations for the design and operation of fuel cell technology in the marine market.

Aviation is another energy consuming sector growing at a rate of ~5%/a that is required to reduce emissions in the future. Currently contributing a relatively low 2.6% of global CO_2 emissions, this is expected to increase to 3.2% by 2020, since synthetic hydrocarbons or hydrogen may play a significant role in the future.

Aviation fuels are characterized by special technical requirements in terms of energy density, flow characteristics (freeze, viscosity) and thermal stability at higher temperatures (carbon deposition). Alternative products to kerosene, at present the standard aviation fuel, have started either to be blended with or to even substitute for the kerosene. The mixture of traditional Jet A-1 fuel with GTL fuel is in the testing phase. The first commercial flight with a 1:1 mixture was in 2008. A first flight test with a 1:1 mixture of Jet-1 and BTL fuel took place in 2009. In this regard, hydrogen may play a role in the long term. Another role that H2 may play in aviation is as a fuel in PEFCs or SOFCs for ground or on-board power supply. The water at a high quality resulting from fuel cell operation could be further used on-board. The preferred storage options are liquid hydrogen for short range missions and JET A-1/ BTL reforming for long range missions. Further development here needs to concentrate on extreme reliability and availability.

The direct use of liquid hydrogen as a substitute for kerosene in an airplane propulsion system was investigated in the CRYOPLANE project. This project was launched in 1990 by a joint German–Russian consortium (DASA as the lead, with the main partners being MBB, MTU, Tupulev and Kuznetsov), and later continued as an EU activity with 35 partners from 11 countries and coordinated by EADS Airbus GmbH. Its objective was to study the feasibility of an aircraft propelled by cryogenic fuels. The aim was to find out whether the use of liquefied natural gas (mainly on the Russian side) or liquid hydrogen (on both sides) as an aircraft fuel was technically possible and reasonable in terms of ecology and economy. Topics covered by the project were scenarios for the transition to an alternative aviation fuel, infrastructure, aircraft design, fuel system layout, engine modifications and ecological issues (e.g. water vapor and NOx emissions). The transition of short/medium range aircraft serving routes between leading industrial nations was seen as an introduction phase, followed by the development of the appropriate infrastructure and the operation of a demonstrator airplane (Hoelzen et al. 2022).

An Airbus A310–300 was selected as the baseline aircraft to be converted to LH2 propulsion. For the new fuel tank concept, the most favorable design was seen in the top-mounted tank configuration with four tanks, two active ones with 40 m3 each for either engine, and two passive ones with 80 m3 each to refill the active tanks. Total fuel weight for the Airbus cryoplane was estimated to be 15.6 t of LH2 (compared with 27 t of kerosene for the same flight range). Due to the environmental impact on the stratosphere from the formation of long-lived ice cloud condensation trails, the typical cruising height of ~12 km would be lowered to ~10 km. The cruising range of the cryoplane was estimated to be 2700 nautical miles (5000 km). At a later stage in the project, a smaller airplane was chosen to precede the Airbus as the LH2 demonstrator — a 30 passenger Fairchild-Dornier 328 regional airplane with one of the two engines to be converted to hydrogen fuel. The fuel capacity is 420 kg (6 m3) of LH2 stored in two cylindrical tanks underneath the wings (plus 1150 kg of kerosene for the second engine). The advantages of this intermediate step are the availability of the hydrogen engine, the lower investment in infrastructure and the earlier introduction of a series aircraft.

A technological development programme for the fuel system components began in 1993, including the selection of materials for tanks and piping, control system and sensors for hydrogen leak detection, fuel pumps, LH2 gasifier and combustion chamber. The first generation of LH2 aviation was foreseen to require a fleet of 400–500 airplanes and the modification of ~70 European airports. The fuel consumption was assessed to be about two million t/a of LH2 or ~170 t/d for an average size airport.

6 Stationary Applications

Stationary applications refer to decentralized power generation by fuel cells, combustion engines or gas turbines, including residential (1–10 kW) and community (5–50 kW) applications, public and commercial buildings, and industrial (50–500 kW) and large scale (1 MW and above) applications (Felseghi et al. 2019). Moreover:

- Large cogeneration (combined heat and power) systems are being manufactured for large commercial buildings or industrial sites that require significant amounts of electricity, water heating, space heating and/or process heat. Fuel cells combined with a heat recovery system can meet some or all of these needs, as well as providing a source of purified water.
- Uninterruptible power supply systems, in which fuel cells are used as backup power supplies if the primary power system fails, are one of the fastest growth areas for stationary fuel cell technologies.
- Niche and power premium applications such as uninterruptible power supply and other backup systems which require short or even instantaneous response, load flexibility, high degree of safety, reliability and availability.

For applications in power and in CHP production, fuel cells have to compete with technologies that have already been established, such as gas and steam turbine plants. Fuel cells promise higher efficiencies at comparable unit sizes. They offer the chance to reduce the pollution level in urban areas with high population density. Fuel cells also allow for small CHP units for residential use. Many fuel cell power units may be combined to large virtual power plants. In connection with energy storage, the hydrogen and fuel cell system may compensate for the mismatch between renewable energy sources and energy demand.

The general design of a fuel cell power system forms an assembly of integrated systems including:

- Fuel cell module — assembly of one or more fuel cell stacks and electrical connections;
- Fuel cell stack — assembly of cells, separators, cooling plates, manifolds and supporting structure;
- Fuel and oxidant processing system — to prepare the fuel for utilization by means of catalytic or chemical processing equipment;
- Thermal management system — to provide cooling and heat rejection, and recovery of excess heat, and to assist in heating the power train during startup;
- Water treatment system — to treat and purify recovered or added water;
- Power conditioning system — to adapt the produced electrical energy to the manufacturer's requirements;
- Automatic control system — to maintain the system parameters within the specified limits by means of an assembly of sensors, actuators, valves, switches and logic components;
- Ventilation system — to provide air.

Unlike the use of hydrogen in mobile applications, stationary power applications with hydrogen or natural gas or coal derived gas as a fuel have advanced and have reached market penetration status already. A near term area of demand for H2 fuel cells includes backup power units, power for remote locations, and distributed generation for hospitals, industrial buildings and small towns (Oldenbroek et al. 2017).

Stationary fuel cell power systems are currently being tested in field experiments in several countries (e.g. Germany and Norway) to show the feasibility of a combined electrical power and heat supply for households utilizing, for example, PEM fuel cells or SOFCs. They are already commercially viable in remote areas, where they can be installed independent of the grid and where fossil fuel transportation costs are prohibitive. By 2008, the cumulative power capacity had reached 180 MW (e), with an average of 50 units per year installed and an average size of 1 MW. The potential flexibility of SOFCs is what is especially is important for a future strategy of decentralized electrical power supply, as this will help stabilize the demand of electrical power.

The energy used for small scale combustion installations is mainly used for the heating of buildings (residential and corporate), hot water and boilers for small industrial applications, including agriculture. A significant amount of this heat could be replaced with hydrogen or electricity. Both could be provided by nuclear power.

Different types of fuel cell systems are currently being demonstrated and introduced commercially in sizes ranging from a few kW up to MW sizes, often as small, standalone cogeneration systems combining local production of electricity with the use of waste heat for producing hot water and residential heating. For example, 1.2 kW PEM fuel cells are currently being introduced in Japan in limited volume by Ballard Power Systems, and the company Vaillant is currently installing a number of PEM fuel cells in Europe. SOFCs can also be made available for small scale CHP in the future.

For large generators today’s fuel cell systems do not offer higher electrical efficiencies than other technologies that are already on the market such as gas turbines. At the utility scale, hybrid systems integrating fuel cell systems and gas turbines could bring about systems using natural gas with electric efficiencies greater than 65%, and such systems are expected to become cost competitive with competing generating technologies within the next decades. By comparison, current state of the art power plants using combined-cycle technology combining gas turbines and steam turbines have electrical efficiencies of around 55–60% and are currently less expensive (400–500 €/kW) than fuel cell systems (2500–8000 €/kW).

Technologies available for distributed power generation, with electrical capacities of less than 60 MW, include gas turbines, reciprocating engines, microturbines, wind turbines, biomass based generators, solar photovoltaic systems and fuel cells. Some studies foresee that fuel cells might initially emerge as distributed generators in applications where users are willing to pay an extra margin for reliable energy generators. In the USA, 10.7 million distributed generators are in place, of which 99% are small emergency/standby reciprocating engines that are not connected to the grid. The market for distributed generation is typically in the commercial sector in applications where reliable energy is needed or in remote locations where grid power is not available.

The oxy-hydrogen steam cycle represents the direct production of high pressure, high temperature (~1500 °C) steam and is applicable for peak electricity production. It is a system with low capital cost promising a high efficiency of ~70%.

In a cooperative effort between the DLR (today the Deutsches Zentrum für Luft- und Raumfahrt) and other German companies from 1989 to 1993, the concept of a hydrogen and oxygen fueled steam generator was developed. This component is actually the re-configuration of an H2/O2 rocket engine which allows the instantaneous provision of steam of any desired quality. H2 and O2 are compressed and injected into a combustion chamber.

A stoichiometric mixture is necessary to generate superheated steam of high quality without any side products. The combustion gas with a temperature of 3000 °C can be cooled by adding water to achieve exactly the desired steam condition for injection into the power plant process. The startup time of such a steam generator is in the order of 1–2 s with a combustion efficiency of greater than 99%. The steam generator can act as a backup system for fast power-up of steam generation plants to serve as a cold standby spinning reserve in decentralized power production.

In a first experimental series, a total of 285 combustion tests were conducted in 1991–1992 with a prototype operated in the power output range of between 25 and 70 MW. The second step was the construction of the demonstration facility for H2/O2 instant reserve, HYDROSS, consisting of a modified H2/O2 steam generator of 2 m length and 0.4 m outer diameter plus a storage and supply system. Full power was obtained after 1 s, and after 3–5 s, there was stable steam production. The experimental version produced steam of 560–950 °C at 4–9 MPa. This compact, soot free and low-cost component is largely ready for the market.

7 Potential Industrial Uses of Hydrogen

Hydrogen use today is dominated by industrial applications. The top four single uses of hydrogen today (in both pure and mixed forms) are: oil refining (33%), ammonia production (27%), methanol production (11%) and steel production via the direct reduction of iron ore (3%).

Virtually all of this hydrogen is supplied using fossil fuels. These existing uses of hydrogen underpin many aspects of the global economy and our daily lives. Their future growth depends on the evolution of demand for downstream products, notably refined fuels for transport, fertilizers for food production, and construction materials for buildings.

More than 60% of hydrogen used in refineries today is produced using natural gas. Tougher air pollutant standards could increase the use of hydrogen in refining by 7% to 41 MtH2/yr by 2030, although further policy changes to curb increases in oil demand could dampen the pace of growth. Current global refining capacity is generally thought sufficient to meet rising oil demand, which implies that the majority of future hydrogen demand is likely to arise from existing facilities already equipped with hydrogen production units. This suggests an opportunity for retrofitting CCUS as a suitable option to reduce related emissions.

Demand for ammonia and methanol is expected to increase over the short to medium term, with new capacity additions offering an important opportunity to scale up low-emissions hydrogen pathways. Greater efficiency can reduce overall levels of demand, but this will only partially offset demand growth. Whether via natural gas with CCUS or electrolysis, the technology is available to provide the additional hydrogen demand growth projected for ammonia and methanol (up 14 MtH2/yr by 2030) in a low-carbon manner. As a priority, substituting low-emissions pathways for any further coal-based production without CCUS would significantly help cut emissions.

In the longer term, steel and high-temperature heat production offer vast potential for low-emissions hydrogen demand growth. If the technological challenges that currently inhibit the widespread adoption of hydrogen in these areas can be overcome, the key challenges will be reducing costs and scaling up. In the long term it should be technically possible to produce all primary steel with hydrogen, but this would require vast amounts of low-carbon electricity (around 2500 TWh/yr, or around 10% of global electricity generation today) and would only be economic without policy support at very low electricity prices.

7.1 Hydrogen in Oil Refining

Oil refining – turning crude oil into various end-user products such as transport fuels and petrochemical feedstock – is one of the largest users of hydrogen today. Some 38 MtH2/yr, or 33% of the total global demand for hydrogen (in both pure and mixed forms), is consumed by refineries as feedstock, reagent, and energy source. Around two-thirds of this hydrogen is produced in dedicated facilities at refineries or acquired from merchant suppliers (together called “on-purpose” supply). Hydrogen use is responsible for around 20% of total refinery emissions, and produces around 230 MtCO2/yr. Refineries’ existing large-scale demand for hydrogen is set to grow as regulations for sulphur content of oil products tighten. This provides a potential early market for hydrogen from cleaner pathways, which could lower the emissions intensity of transport fuels (Abdin et al. 2020).

Hydrotreatment and hydrocracking are the main hydrogen-consuming processes in the refinery. Hydrotreatment is used to remove impurities, especially sulphur (it is often simply referred to as desulphurisation) and accounts for a large share of refinery hydrogen use globally. Today refineries remove around 70% of naturally incurring sulphur from crude oils.

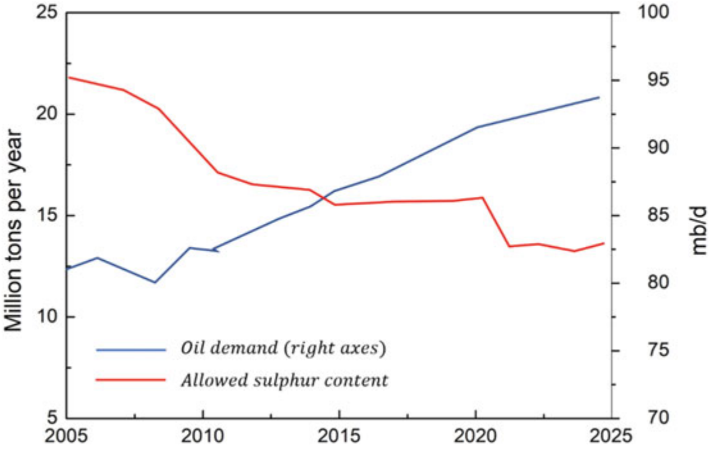


Fig. 8 Allowed sulphur content in oil products

With concerns about air quality increasing, there is growing regulatory pressure to further lower the sulphur content in final products. By 2020 40% less sulphur will be allowed in refined products than in 2005 despite the continued growth in demand (Fig. 8).

Hydrocracking is a process that uses hydrogen to upgrade heavy residual oils into higher-value oil products. Demand for light and middle distillate products is growing and demand for heavy residual oil is declining, leading to an increase in the use of hydrocracking. In addition to hydrotreatment and hydrocracking, some hydrogen that is used or produced by refineries cannot be economically recovered and is burned as fuel as part of a mixture of waste gases (Felix et al. 2017).

The United States, the People's Republic of China ("China") and Europe are the largest consumers of hydrogen in refineries. The three regions represent around half of total refinery hydrogen consumption, reflecting the volume of crude oil they process and the stringency of their product quality standards.

Hydrogen is also used for upgrading oil sands and hydrotreating biofuels. For oil sands, the amount of hydrogen needed to remove sulphur from the raw bitumen varies considerably depending on the upgrading technology and the quality of the synthetic crude oil produced.

Overall around 10 kg of hydrogen is used per tonne of bitumen processed.24 The resulting synthetic crude oil still needs to be refined at a refinery, using hydrogen. For biofuels, hydrotreatment removes oxygen and improves the fuel quality of vegetable oils and animal fats processed into diesel substitutes. This process requires around 38 kg of hydrogen per tonne of biodiesel produced, but no further hydrogen is needed in subsequent refining steps.

Globally, refinery hydrogen demand is met through the use of on-site by-products, dedicated on-site production, or merchant supply.

On-site by-product hydrogen comes largely from catalytic naphtha reforming, a process that produces high-octane gasoline blending components and generates hydrogen at the same time. Refineries with integrated petrochemical operations also derive by-product hydrogen from steam cracking. However, on-site by-product hydrogen is unable to fully cover refinery hydrogen demand, except in small refineries running on very low sulphur crude oils and with relatively low yields of road transport fuels. On average, on-site by-product hydrogen meets one-third of refinery hydrogen demand. The gap needs to be met, either by dedicated on-site production (about 40% globally) or procurement from merchant suppliers (around a quarter).

Most dedicated on-site production uses natural gas feedstock, but light fractions of oil distillation and heavier feedstocks – petroleum coke, vacuum residues and coal – are also used in some regions. Use of heavier feedstocks is mostly restricted to India and China, where gas needs to be imported. Coal gasification is routinely included in new refinery setups in China as a main or auxiliary hydrogen production unit.

Merchant supply of hydrogen is an option in densely industrialised areas where developed hydrogen pipeline infrastructure exists, such as the US Gulf Coast and Europe's Amsterdam-Rotterdam-Antwerp hub. As with dedicated on-site production, merchant hydrogen is mostlyproduced from natural gas, although a certain amount also comes from chemical processes, where it is a by-product of operations such as steam cracking and chlorine production. In regions such as the US Gulf Coast, merchant hydrogen can meet over a third of total hydrogen demand.

Hydrogen production costs vary widely, largely reflecting differences in natural gas prices. US production costs are among the world's lowest, while costs are substantially higher in Europe and Asia. In the United States, hydrogen costs amount to around USD 1.1/kgH2 or USD 0.7 per barrel of oil refined. This may seem a relatively small cost component for refineries overall, for example in comparison with crude costs, but even a small cost advantage in hydrogen costs can have a notable impact on refining margins, which are generally thin in what is a very competitive market.

In recent decades, refinery hydrogen demand has grown substantially as a result of growing refining activity and rising requirements for hydrotreating and hydrocracking. This trend is set to continue as fuel specifications globally further reduce acceptable levels of sulphur content.

Many countries, including China, have already reduced sulphur content requirements in road transport fuels such as gasoline or diesel to under 0.0015%, and others may introduce similar standards. The International Maritime Organization has also introduced new bunker fuel regulations that limit the sulphur content of marine fuels to no more than 0.5% from 2020, and this is likely to lead to a significant increase in hydrogen requirements for marine fuel production. However, hydrogen demand is also a function of inherent sulphur content in crude oils. The average quality of crude oil supply has been getting lighter and sweeter in recent years, due primarily to surging US tight oil output, and this is likely to moderate the need for hydrogen to some degree. Under current trends, overall hydrogen demand in refineries is set to grow by 7% to 41 MtH2/yr in 2030.

Beyond 2030 current trends and policies suggest the pace of hydrogen demand growth to slow down, as the scope to tighten product quality standards decreases and as oil demand for transport fuels is affected by a combination of efficiency improvements and electrification (Gjorgievski et al. 2021).

Refiners are also likely to increase the efficiency of hydrogen recovery from waste refinery gases, lowering requirements for additional hydrogen production. Refinery hydrogen demand would decline in a scenario compatible with the objectives of the Paris Agreement, with the impact of declining oil demand more than offsetting that of higher hydrogen intensity.

Irrespective of the future trajectory of global energy demand, one common aspect is the dominant share of existing refineries in projected hydrogen demand. There is already sufficient refining capacity globally to fulfil the expected need for oil products. Together with the long lifetime of refineries, this limits the scope for substantial addition of new refining capacity. As a result, some 80–90% of cumulative on-purpose hydrogen supply (including both dedicated on-site production and merchant procurement) between today and 2030 would come from existing refineries in both scenarios (Fig. 9).

Hydrogen production – unless supplied as a by-product of refining operations – currently results in considerable CO_2 emissions. Globally the production of hydrogen for use in refineries contributes some 230 MtCO2/yr emissions, which is around 20% of total refinery emissions.

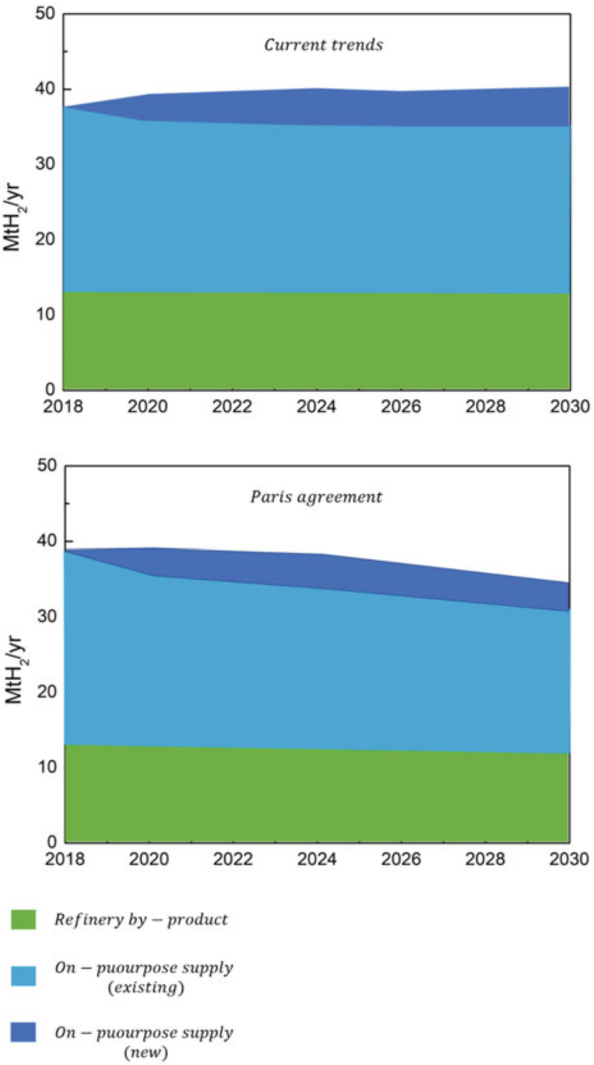
Demand and emissions are all set to rise in future. If future demand growth is met using coal, which is widely used without CCUS to produce hydrogen in countries such as China, the level of CO_2 emissions would further increase.

Producing hydrogen in a cleaner way is therefore vital to achieving a significant reduction in emissions from refining operations. Other key measures – such as energy efficiency and fuel switching away from emission-intensive fuels – have already been widely adopted in many refineries, limiting opportunities for further emissions reduction. Against this background, together with sizeable demand already existing today, the refining industry offers a potential early market for low-carbon hydrogen.

There are two main cleaner pathways to hydrogen production for refineries: equipping coal- or natural gas-based hydrogen production facilities with CCUS; and using electrolytic hydrogen from low-carbon electricity. Given that the bulk of future hydrogen demand comes from existing refineries and that most refineries are already equipped with SMR units, natural gas with CCUS offers a more obvious route to low-carbon hydrogen than does renewables-based electrolysis. The incremental costs for the production of low-carbon hydrogen are limited to CCUS facilities, which makes natural gas with CCUS more competitive than electricity-based options, and capturing CO_2 emissions from an SMR unit represents one of the lowest-cost opportunities to apply CCUS in a refinery because much of this CO_2 is emitted in a highly concentrated stream.

However, despite the continued decline of technology costs for CCUS, the large-scale adoption of CCUS at hydrogen production units in refineries needs a helping hand from policy makers, especially given the tight margins and highly competitive

Fig. 9 Future hydrogen demand in oil refining under two different pathways

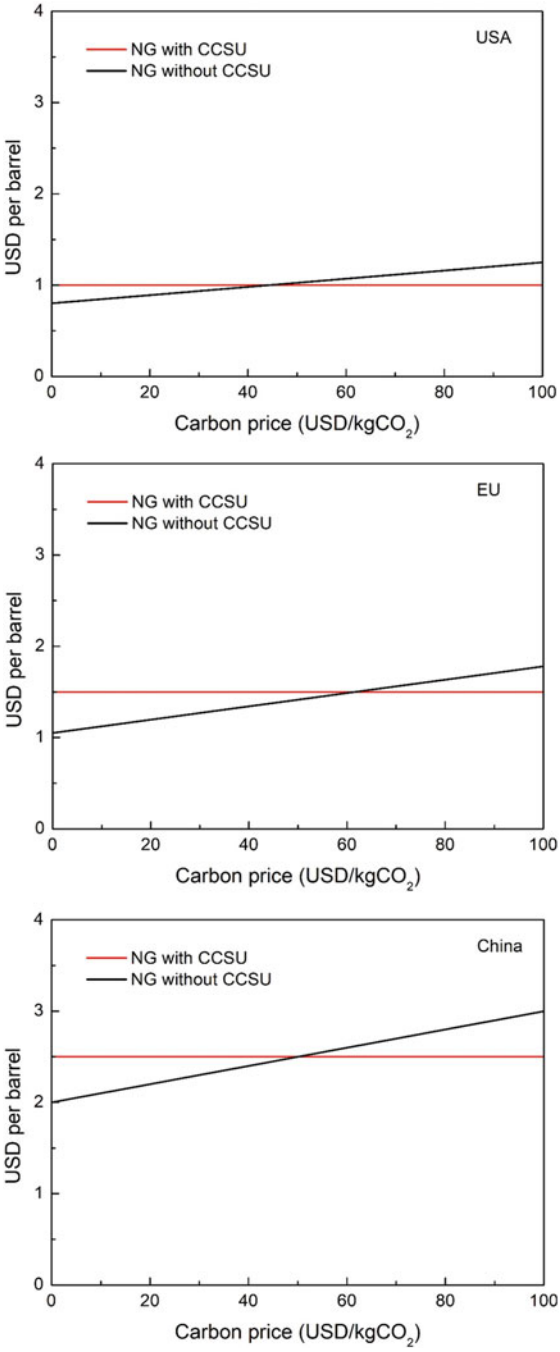


nature of the refining industry. Introducing CCUS would add an incremental cost of some USD 0.25–0.5/barrel, which is higher than today's carbon price levels (zero to USD 0.1/barrel).25 This implies that refiners are likely to be inclined to pay CO_2 prices rather than to direct effort to capturing and storing CO_2. Higher carbon prices, or equivalent policy incentives, would change the picture.

A carbon price higher than USD 50/tCO_2, for example, would make natural gas with CCUS economically attractive in most regions and could trigger a wider deployment of CCUS at SMR facilities (Fig. 10).

In the United States a tax incentive known as "45Q" is worth up to USD 50/tCO_2 for CCUS operations online by 2026. The case for investment would be further

Fig. 10 Hydrogen production costs from natural gas with and without CCUS by region under different carbon prices, 2030



strengthened if captured CO_2 could be sold to industrial users or upstream oil companies for enhanced oil recovery (EOR). Low-carbon fuel standards could also help spur CCUS: standards of this kind have already been introduced in Canada, Europe and some US states, including California.

The costs of introducing CCUS also depend on the costs of CO_2 storage, which means that the successful introduction of CCUS is contingent on CO_2 storage being available and accessible with known and manageable costs and risks. Cost reduction efforts therefore need to be complemented by policy measures to bring about the building of CO_2 storage infrastructure and the development of operating businesses in the appropriate locations. This would also have the benefit of laying the ground for the adoption of CCUS in other industries (Goel et al. 2018).

Several refineries have already installed CCUS facilities for hydrogen production. Some of the emissions from the 400 thousand barrels per day (kb/d) Pernis refinery in Rotterdam are captured, transported and used in nearby greenhouses. In 2017 Air Product's Port Arthur project in Texas completed its demonstration phase; it captures CO_2 for EOR operations at the West.

Hastings oil field. In France, Air Liquide's Port Jerome project captures and sells CO_2, and Hokkaido Refinery in Japan has put in place pilot CCUS facilities. There is also one bitumen upgrader equipped with CCUS in operation today – the Quest project in Canada – which captures around 20% of the emissions from the 255 kb/d upgrader. In total, the four CCUS plants which are now in operation in refineries have the capacity to produce over 150 ktH2/yr of low-carbon hydrogen.

Potential also exists at refineries for electrolytic hydrogen to replace dedicated hydrogen production from natural gas or coal. For the moment no refineries are using electrolytic hydrogen, but Shell's 200 kb/d Rheinland refinery in Germany has announced a 10 MW electrolyzer project for 2020 that will supply around 1 ktH2, or 1% of the refinery's hydrogen needs. Heide, a small refinery near Hamburg, Germany, has announced a 30 MW electrolyzer paired with offshore wind power to replace purchases of up to 3 ktH2/yr. BP, Nouryon and the Port of Rotterdam Authority are also jointly assessing the feasibility of a 250 MW electrolysis plant for the production of 45 ktH2/yr for the BP refinery in Rotterdam. Despite this progress, policy support is going to be needed if electrolysis is to take off at scale.

In certain instances, there is also scope to avoid some current hydrogen-related emissions through "outside-gate collaboration". Petrochemical steam crackers tend to generate a surplus of hydrogen that could be used in refineries; conversely, the low-value fuel gases produced by refineries can be used in steam crackers. Incentivizing the development of the necessary infrastructure to exchange these products within industrial clusters would help to reduce overall emissions.

7.2 Chemical Sector

The chemical sector accounts for the second- and third-largest sources of demand for hydrogen today: ammonia at 31 MtH2/yr and methanol at 12 MtH2/yr. Other comparatively minor applications take its overall demand to 46 MtH2/yr, or 40% of total hydrogen demand in both pure and mixed forms. It is also a large producer of by-product hydrogen, which is both consumed within the sector itself and distributed for use elsewhere. Most of the hydrogen that the chemical sector consumes is produced using fossil fuels, and this generates considerable quantities of greenhouse gas emissions. Reducing the level of emissions represents an important challenge for the sustainability of the sector's energy use, and a significant opportunity to make use of low-carbon hydrogen (Rambhujun et al. 2020).

The chemical sector produces a complex array of outputs, from plastics and fertilizers to solvents and explosives. This section focuses primarily on ammonia and methanol, and to a lesser extent on ethylene, propylene, benzene, toluene and mixed xylenes. These seven "primary chemicals" account for around two-thirds of the chemical sector's energy consumption, and much of its demand for energy products as raw material inputs (so-called "feedstocks").

Hydrogen is part of the molecular structure of almost all industrial chemicals, but only some primary chemicals require large quantities of dedicated hydrogen production for use as feedstock, notably ammonia and methanol.

More than 31 MtH2/yr of hydrogen are used as feedstock to produce ammonia, and more than 12 MtH2/yr to produce methanol. A further 2 MtH2/yr are consumed in comparatively small-volume processes (for example in hydrogen peroxide and cyclohexane production), but most of this is supplied from by-product hydrogen generated within the sector.

Fossil fuels have long been a convenient and cost-effective source of both the hydrogen and carbon for ammonia and methanol production. In 2018 around 270 Mtoe/yr of fossil fuels were used to produce the hydrogen for these two products, 27 roughly equivalent to the combined oil demand of Brazil and the Russian Federation. Because production via natural gas (reforming) is more efficient than via coal (gasification), the former accounts for 65% of hydrogen production, but less than 55% of the energy inputs required to produce it. The differing regional prices of gas and coal are also a key determining factor in the choice of process route. Almost all hydrogen from coal for use in the chemical sector is produced and used in China.

Ammonia is mostly used in the manufacture of fertilizers such as urea and ammonium nitrate (around 80%). The remainder is used for industrial applications such as explosives, synthetic fibers and other specialty materials, which are an increasingly important source of demand.

Methanol is used for a diverse range of industrial applications, including the manufacture of formaldehyde, methyl methacrylate and various solvents. Methanol is also used in the production of several other industrial chemicals, and for the methanol-to-gasoline process that produces gasoline from both natural gas and coal, which has proven attractive in regions with abundant coal or gas reserves but with little or no domestic oil production. This is one of the fuel applications of methanol, whether blended in pure form or used after further conversion (e.g. to methyl-tert butlyl ether), that account for around a third of the chemical's use globally.

The development of methanol-to-olefins and methanol-to-aromatics technology has opened up an indirect route from methanol to high-value chemicals (HVCs), and thus to plastics. Methanol-to-olefins technology is currently deployed at commercial scale in China, accounting for nine million tons per year (Mt/yr) or 18% of domestic HVC production in 2018. Methanol-to-aromatics, which is used to produce more complex HVC molecules, is currently still in the demonstration phase.

Unlike ammonia and methanol, HVCs – the precursors of most plastics – are produced mostly from oil products such as ethane, liquefied petroleum gas and naphtha. HVCs produced directly from oil products do not require hydrogen feedstock, but their production generates by-product hydrogen that can be used in oil refining and other chemical sector operations, such as the upgrading of other cracker by-products. Steam cracking and propane dehydrogenation processes for HVC manufacture produce around 18 MtH2/yr as a by-product globally. HVC demand is growing at a faster rate than refined oil product demand, which means that an increasing quantity of this by-product hydrogen could be available for use in other industries.

Chlor-alkali processes are another source of by-product hydrogen in the chemical sector, supplying around 2 MtH2/yr. While by-product hydrogen generated in the steam cracking process stems from oil products (mainly ethane and naphtha), the chlor-alkali process is a form of electrolysis (of brine) and is powered by electricity. Smaller volumes of by-product hydrogen are also produced from other processes such as styrene production.

Demand for hydrogen for primary chemical production is set to increase from 44 Mt/yr today to 57 Mt/yr by 2030 as demand for ammonia and methanol grows.

Demand for ammonia for existing applications is set to increase by 1.7% per year between 2018 and 2030 and to continue to rise thereafter. The share represented by demand for industrial applications grows more quickly during this period; that for nitrogen-based fertilizers is likely to start to plateau or even decline in many regions after 2030.

Demand for methanol for existing applications is set to grow at 3.6% per year between 2018 and 2030. The methanol-to-olefins/methanol-to-aromatics demand segment grows more quickly than the total, at 4.1% per year over the same period, with nearly all this growth coming from China. This rate of growth would require 19 MtH2/yr for methanol production for these existing applications by 2030, compared with 12 MtH2/yr today.

Together with energy efficiency measures, materials efficiency strategies are an important way of reducing emissions in IEA decarbonization scenarios and could reduce these increases in demand. Recycling and reusing plastics and other materials could reduce the amount of future primary chemical production required, although this would be likely to have a less pronounced impact on ammonia and methanol demand than on demand for other primary chemicals such as ethylene. Improving the efficiency with which fertilizer is used could also reduce future demand for chemicals. Specific policies have been announced in some countries to limit fertilizer use, such as the target for zero growth from current levels in China.

Conversely, demand for ammonia and methanol could rise further if these chemicals were to become established as energy carriers for the transmission, distribution and storage of hydrogen, facilitating its use in new applications, or if they were to be used as fuels in their own right. If these new applications were to become widespread, the chemical sector could evolve to share the role that refineries play today in providing energy to downstream users.

Without any change in the current economics or regulation of production, current growth trajectories for chemical products are likely to lead to a growth in hydrogen production from natural gas and coal without the application of CCUS. Projecting forward current trends, this growth would cause total direct CO_2 emissions from ammonia and methanol production to rise by around 20% between 2018 and 2030.

The global production of ammonia and methanol currently generates CO_2 emissions of around 630 $MtCO_2$/yr. The global average direct emissions intensity of ammonia production is 2.4 tons of CO_2 per ton (tCO_2/t), with average intensities for major regions in the range of 1.6–2.7 tCO_2/t. New gas-based plants in the Asia Pacific region tend to be at the lower end of this range, whereas pure coal-based production (around 4 tCO_2/t), widespread in China, constitutes the most CO_2-intensive production route. For methanol the global average figure is 2.3 tCO_2/t, with average intensities for major regions in the range of 0.8–3.1 tCO_2/t. As for ammonia, production based purely on coal is the most emissions-intensive pathway.

The production of HVCs is responsible for a further 250 $MtCO_2$/yr of CO_2 emissions. However, the key mitigation options currently under development (including the direct application of CCUS to existing process units, dry methane reforming and steam cracker electrification) do not involve additional dedicated hydrogen production. HVCs could also be produced from methanol, but this would similarly not involve additional hydrogen production beyond that required for the methanol. The focus in this section is therefore on ammonia and methanol.

Alternative process technologies and feedstocks could meet growing demand for large quantities of dedicated hydrogen feedstock in the chemical sector for ammonia and methanol while reducing CO_2 emissions. The three main cleaner process technology options are: using CCUS to reduce fossil fuel-related emissions (assuming sufficient CO_2 transport and storage infrastructure is in place); using electrolysis-derived hydrogen (assuming a renewable electricity supply); and using biomass feedstocks (assuming a sustainable supply of bioenergy). Today all these options are more costly than using fossil fuels without CCUS.

Using biomass for ammonia and methanol production looks significantly less cost-competitive than the other options.

Meeting future ammonia and methanol demand entirely from these cleaner pathways would considerably increase demand for energy inputs to the chemical sector (Fig. 11).

If future demand in a Paris-compatible pathway were to be met entirely with hydrogen produced from natural gas with CCUS, around 320 bcm of natural gas would be required by 2030, nearly half of which would be used as feedstock. This is around 10% of global natural gas demand today.

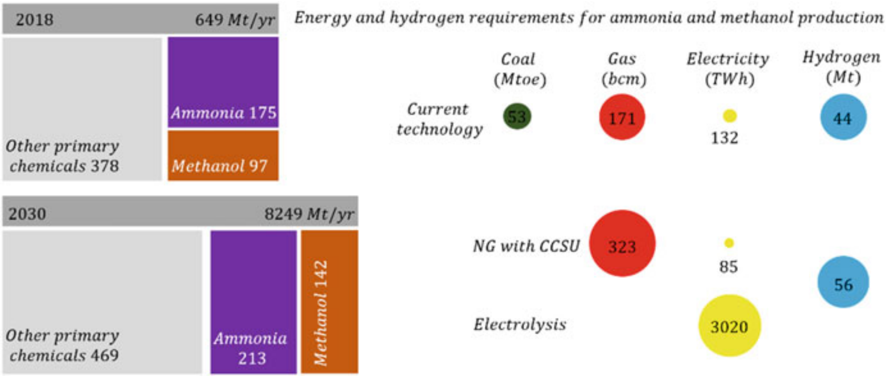


Fig. 11 The implications of cleaner process routes for methanol and ammonia production

Around 450 $MtCO_2$/yr would need to be captured, although around one-third of this could be used to produce urea. The largest carbon capture installations today are in the region of 1 $MtCO_2$/yr. Capturing 450 $MtCO_2$/yr by 2030 would require around 450 new projects of this size to be operational by this date, with a build rate of around 4 new projects per month between now and 2030.

If future demand were to be met entirely from low-carbon electrolytic hydrogen, this would require around 3020 terawatt hours per year (TWh/yr) of additional electricity by 2030, equivalent to around 11% of today's global electricity generation. It would also require 350–450 GW of electrolyzer capacity, depending on efficiency levels and capacity factors. The largest individual electrolyzers currently under development are at the 100+ MW scale, meaning that 3500–4000 such installations would need to be constructed by 2030, or 6–7 per week between 2018 and 2030. Around 0.6 billion cubic meters per year (bcm/yr) of water would also be needed as feedstock for the electrolyzers, which is around 1% of total water consumption in the energy sector today. Some 0.5 gigatons per year (Gt/yr) of oxygen would be produced as a by-product, which could be used in other industrial processes.

The electrolysis pathway would use some CO_2 for the manufacture of urea (CH4N2O) and methanol (CH3OH).30 To avoid fossil fuel use in methanol synthesis altogether in 2030, 200 MtCO2/yr (or the equivalent amount of carbon monoxide, if available) would need to be sourced and captured from biogenic (e.g. biomass gasification) or atmospheric (e.g. direct air capture) sources. A further 170 MtCO2/yr or equivalent would be required for urea.

In the absence of an economic source of biogenic or atmospheric CO_2, it would still be beneficial to capture and utilize CO_2 streams from unabated stationary point sources of CO_2 (e.g. steel and cement production). These are likely to remain much cheaper in the short to medium term. However, the total emissions avoided would be much lower unless that CO_2 would otherwise unavoidably have been emitted. Geographically matching locations of low-cost renewable electricity, water availability and persistent CO_2 sources that are not prohibitively expensive presents a significant challenge.

Cleaner ways of producing ammonia and methanol have higher costs than those that are commercially available today. Production costs vary widely, however, between regions, depending on the costs of in each region of natural gas, coal, biomass and electricity.

In locations with the lowest cost renewable electricity (for example in Chile, Morocco and China), electrolytic hydrogen would be close to being competitive in cost terms with natural gas and coal for ammonia and methanol production, even if they did not use CCUS.

Transporting renewable electricity to the main demand centers is another option, but would also involve additional costs.

Much of the technology and equipment required for the cleaner pathways in the chemical sector is already in widespread use across the industry, including the pumps, compressors and separation units required for CO_2 capture. Electrolyzers have been constructed at scales above 100 MW in the past, and significant efforts are being made to bring down their costs further. The key variables affecting the economics of production via electrolysis and natural gas with CCUS are natural gas and electricity prices.

Electrolysis becomes competitive with natural gas with CCUS at electricity prices in the range of USD 15–50/MWh for ammonia and in the range of USD 10–65/MWh for methanol, on the assumption of gas prices of USD 3–10/MBtu.31 In order to compete with natural gas without CCUS at these gas prices, however, electricity prices would need to drop to USD 10–40/MWh for ammonia and USD 5–50/MWh for methanol.

While the upper end of these cost-competitive electricity price ranges show promise for alternative pathways, the economics in most regions are such that policy support is likely to be required in the short to medium term if low-carbon forms of production are to take off. Policy measures could stimulate demand for low-carbon hydrogen in the chemical sector and thus stimulate investment in a cleaner supply of hydrogen. These measures could include the use of certificates, public procurement, or portfolio standards to create market value for chemicals produced via low-carbon process routes. In the case of methanol produced as a fuel or fuel additive, this could include the use of fuel specifications or fuel standards. Governments could also use standards to support ammonia produced with lower CO_2 intensity. In the near term, initial projects that take on value chain and market risks to invest in CCUS or electrolysis hydrogen for chemical production are likely to need some direct government support. The support should be aimed at managing these risks and extending the benefits of cost sharing to other facilities in industrial clusters.

7.3 Iron and Steel Sector

DRI is a method for producing steel from iron ore. This process constitutes the fourth-largest single source of hydrogen demand today (4 MtH2/yr, or around 3% of total hydrogen used in both pure and mixed forms), after oil refining, ammonia and

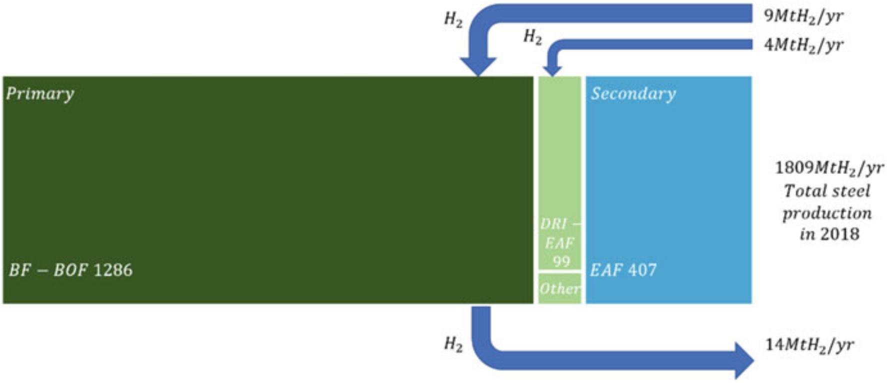


Fig. 12 Hydrogen consumption and production in the iron and steel sector today

methanol. Based on current trends, global steel demand is set to increase by around 6% by 2030, with demand for infrastructure and a growing population in developing regions compensating for declines elsewhere.

Like the chemical sector, the iron and steel sector produce a large quantity of hydrogen mixed with other gases as a by-product (e.g. coke oven gas), some of which is consumed within the sector and some of which is distributed for use elsewhere. Virtually all this hydrogen is generated from coal and other fossil fuels. To reduce emissions, efforts are underway to test steel production using hydrogen as the key reduction agent (as opposed to carbon monoxide derived from fossil fuels), with the first commercial-scale designs expected in the 2030s. In the meantime, low-carbon hydrogen could be blended into existing processes that are currently based on natural gas and coal to lower their overall CO_2 intensity.

More than three-quarters of global steel demand today is met using primary production methods that convert iron ore to steel, as opposed to the secondary production route, which utilizes limited supplies of recycled scrap steel (Fig. 12).

The two main primary production routes already involve some production and consumption of hydrogen (Cavaliere 2019).

The blast furnace-basic oxygen furnace (BF-BOF) route accounts for about 90% of primary steel production globally. It produces hydrogen as a by-product of coal use. This hydrogen, contained in so-called “works-arising gases” (WAG), is produced in a mixture with other gases such as carbon monoxide.33 WAG is used for various purposes on site, but also transferred for use in other sectors including power generation and, in China, methanol production. The portion utilized within the iron and steel sector is estimated at 9 MtH2/yr today, or around 20% of the global use of hydrogen in mixed forms (i.e. not as pure hydrogen).

The direct reduction of iron-electric arc furnace (DRI-EAF) route accounts for 7% of primary steel production globally. It uses a mixture of hydrogen and carbon monoxide as a reducing agent. The hydrogen is produced in dedicated facilities, not as a by-product. Around three-quarters of it is produced using natural gas (reforming) and the rest using coal (gasification). It accounts for around 4 MtH2/yr in 2018, or 10% of the use of hydrogen consumed in mixed forms globally.

Without policy intervention, demand for dedicated hydrogen production in steelmaking is expected to grow from the current level of 4 MtH2/yr roughly in line with the gas-based DRI-EAF route.

While the gas-based DRI-EAF can be more energy-intensive than the BF-BOF route, it uses simpler and slightly less capital-intensive equipment. It tends to bedeployed in regions with low natural gas prices (e.g. the Middle East) or low coal prices (e.g. India).

The two main factors to influence future dedicated hydrogen demand for steel production are: the share of the DRI-EAF route in primary steel making, and the split between primary and secondary steel production in overall output. Considering the dynamics of steel stocks in the built environment, on current trends the share of scrap-based production in total steel production is projected to grow from around 23% today to 25% in 2030. In this case, the commercial gas-based DRI-EAF route could supply 14% of primary steel demand. This would require 8 MtH2/yr as a reducing agent, doubling the use of hydrogen for DRI-EAF production from today's levels. In the same case, if the share of secondary steel production continued to rise (to 29% by 2050) and the gas-based DRI-EAF route was used to satisfy 100% of primary steel demand, hydrogen demand in the sector could theoretically reach 62 MtH2/yr.

If, instead of following current trends, an alternative pathway was to be followed that aligns the future development of the energy sector with the goals of the Paris Agreement, the outlook for hydrogen demand and production in the sector could be very different. In such a pathway, the share of scrap recycling in total steel production is projected to grow more rapidly, from 23% today to 29% in 2030 and 47% in 2050, limited only by the availability of steel scrap. Our analysis suggests a slightly larger share of the gas-based DRI-EAF in primary steel production by 2030 (16%) in this case, and that progress on materials efficiency strategies would also be accelerated, leading to a reduction in the overall level of output.

Two parallel technological developments relating to DRI-EAF are also assumed to take place in this case. First, 30% of the natural gas consumed in DRI-EAF production would be replaced by 2030 by externally sourced pure hydrogen from electrolysis, which could be done without major equipment changes. Second, progress on developing the HYBRIT concept would be sufficient to demonstrate the first commercial-scale 100% hydrogen-based DRI-EAF plant by 2030, supplying 1.5 Mt/yr of crude steel, or 0.1% of total steel demand.

If these ambitious developments were to take place, hydrogen demand for iron and steel production would be 9–11 MtH2/yr by 2030, like the level of 8 MtH2/yr expected on the basis of current trends. However, only around 4.5 MtH2/yr would be sourced from renewable electricity, with the remainder coming from natural gas. By comparison, under current trends all of the additional hydrogen demand would be met by natural gas without CCUS. This would require 230 TWh/yr of electricity, approximately equivalent to the total electricity consumption of Turkey today (Fig. 13).

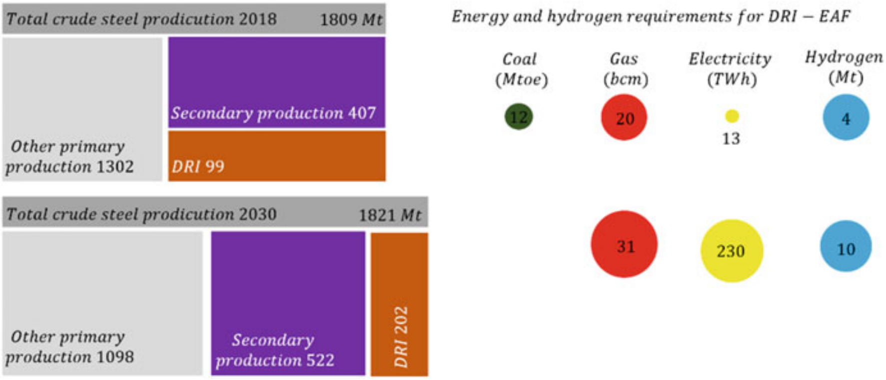


Fig. 13 Energy implications of fulfilling hydrogen demand via the DRI-EAF route

Natural gas would nonetheless still play an important role in supplying the remaining hydrogen in 2030, resulting in 31 bcm/yr of natural gas demand, which is approximately equal to the natural gas consumption of Spain today. Coal-based DRI-EAF production would disappear by 2030 in this scenario, eliminating 12 Mtoe/yr, roughly the annual coal consumption of Mexico today.

In the long term a Paris-compatible pathway would seek to drastically reduce CO_2 emissions from primary steel production.38 Using the 100% hydrogen DRI-EAF route for all primary steel production would largely eliminate CO_2 emissions, provided the electricity was sourced from renewables. This would require 47–67 MtH2/yr.

More than 2500 TWh/yr of electricity would be needed to produce this much hydrogen, or roughly the combined electricity consumption of India, Japan and Korea today. A substantial but manageable amount of water would also be required as feedstock for electrolyzers: around 0.6 bcm/yr, which is about 1% of total water consumption in the energy sector today. Some 500 Mt/yr of oxygen would be produced as a by-product; this could be put to use elsewhere in industry.

7.4 High Temperature Heating

Industrial high-temperature heat is a potential source of hydrogen demand growth in the future, but virtually no dedicated hydrogen is produced for this application today. Industry uses heat for a variety of different purposes, including melting, gasifying, drying, and mobilizing a wide array of chemical reactions. Heat can be used both directly, for example in a furnace, or indirectly, for example by first raising steam and then transferring it for heating needs. There are three main temperature ranges for industrial heat: low temperature (<100 °C), medium temperature (100–400 °C) and high temperature (>400 °C).

Global demand for high-temperature heat in industry was around 1280 Mtoe/yr in 2018, of which just 370 Mtoe/yr was outside the chemical and iron and steel sectors covered in the previous sections. More than half of this remainder was consumed in cement manufacture. This level of demand is set to rise gradually on current trends to just over 400 Mtoe/yr in 2030. This demand trajectory would not change significantly even if strong climate change mitigation measures were pursued, although some small differences would arise from increases in energy and materials efficiency.

Fossil fuels are the primary source of high-temperature heat today (around 65% from coal, 20% natural gas and 10% from oil), although small amounts of biomass and waste are used in certain sectors. Electricity is also used extensively to generate high-temperature heat in specific applications, either directly (e.g. electric arc and induction furnaces in the steel industry) or indirectly (e.g. to drive electro-chemical reactions in aluminum smelting). Resistance heaters are used in the production of carbon fiber, reaching temperatures of 1800 °C, and there are ways to utilize electromagnetic heating technologies (e.g. microwave and infrared) to achieve similar temperatures for other specific heating applications.

However, several large-scale processes, such as steam crackers and cement kilns, remain challenging to electrify although demonstration and feasibility studies are being conducted in both of these areas.

Excluding the chemical and iron and steel sectors, industrial high-temperature heat is responsible for approximately 1.1 $GtCO_2$/yr of direct emissions today, or around 3% of global energy-sector CO_2 emissions. Combustion of sustainable bioenergy or hydrogen (or direct use of hydrogen-based fuels such as ammonia) offer ways of reducing emissions that are proven at scale. However, negligible quantities of hydrogen are currently used for this purpose today.

Despite having the potential to eliminate emissions from high-temperature heat for industry, hydrogen remains an expensive alternative to fossil fuels in the context of a low-carbon pathway for the energy system, even when CO_2 prices reach USD 100/tCO_2.

Bioenergy tends to be more cost-competitive in this context, assuming a bioenergy price range of USD 8–12/GJ in 2030.

Bioenergy is set to become cost-competitive with natural gas as a source of high-temperature heat in 2030 in India, China and Japan, even at the higher end of the bioenergy price range explored (USD 12/GJ). This is due to relatively high natural gas prices in these regions in the context of a Paris-compatible pathway for the energy system (USD 3.8–10.6/MBtu). A CO_2 price of around USD 200/tCO_2 would be needed before the cheapest hydrogen-based fuels (at a delivered cost of USD 2.3–2.7/kgH_2) become competitive with coal and natural gas.

Hydrogen does, however, offer some advantages for decarbonizing elements of this diverse segment of energy demand, despite its relatively high costs and the need for it to overcome certain practical difficulties. For example, low-carbon hydrogen has the potential to help decarbonize the more geographically fragmented portions of industrial high-temperature heat demand where direct application of CCUS may prove impractical. Hydrogen, either via pipeline or using small-scale on-site electrolysis, could form a low-carbon energy supply to these “hard-to-reach” segments of industry. Its potential role may also grow if the supply of sustainable bioenergy is limited in the future; bioenergy is also likely to be in demand in other end-use sectors such as aviation.

8 Potential Uses of Hydrogen in Transport

Hydrogen holds long-term promise in many sectors beyond existing industrial applications.

The transport, buildings and power sectors all have potential to use hydrogen if the costs of reduction and utilization develop favorably relative to other options. The complex processes involved in developing and deploying hydrogen, however, mean that carefully crafted policy support will be critical.

The competitiveness of hydrogen FCEVs in transport depends on fuel cell costs and on the building and utilization of refueling stations. For cars the priority is to bring down the cost of fuel cells and on-board hydrogen storage. This could make them competitive with battery electric vehicles at driving ranges of 400–500 km and make them potentially attractive for consumers that prioritize range. For trucks the priority is to reduce the delivered price of hydrogen. In early stages of deployment, building hydrogen stations that serve captive fleets on hub-and-spoke missions could help to secure high refueling station utilization and thus could be a way to get infrastructure construction off the ground (Hienuki et al. 2021).

Shipping and aviation have limited low-carbon fuel options available and represent an opportunity for hydrogen-based fuels. Ammonia and hydrogen have the potential to address environmental targets in shipping, but their cost of production is high relative to oil-based fuels. Hydrogen-based liquid fuels provide a potentially attractive option for aviation at the expense of higher energy consumption and potentially higher costs. Policy support in the form of low-carbon targets or other approaches is critical to their prospects.

The largest near-term opportunity in buildings is blending hydrogen into existing natural gas networks. In 2030 up to 4 Mt of potential hydrogen use for heating buildings could come from low-concentration blending which, if low-carbon, could help to reduce emissions. The potential is highest in multifamily and commercial buildings, particularly in dense cities, where conversion to heat pumps is more challenging than elsewhere. Longer-term prospects in heating could include the direct use of hydrogen in hydrogen boilers or fuel cells, but both of these would depend on infrastructure upgrades and on measures to address safety concerns and provide public reassurance.

Power generation offers many opportunities for hydrogen and hydrogen-based fuels. In the near-term ammonia could be co-fired in coal-fired power plants to reduce CO_2 emissions.

Hydrogen and ammonia can be flexible generation options when used in gas turbines or fuel cells. At the low-capacity factors typical of flexible power plants, hydrogen costing under USD 2.5/kg has good potential to compete. Key low-carbon competitors for such services include natural gas with CCUS and biogas. In the longer term, hydrogen can play a role in largescale and long-term storage to balance seasonal variation.

Maximizing the potential long-term promise of hydrogen depends on moving beyond the existing industrial uses of hydrogen described in chapter "Hydrogen in the Chemical Industry", and on the development of a strong case for its use as a versatile fuel in various new sectors. This case rests largely on its ability to help diversify the fuel mix and, if produced from low-carbon sources, support the transition to a cleaner energy system. Numerous opportunities exist to use hydrogen outside industrial applications: practically all modes of transport could potentially be run on hydrogen or hydrogen-based fuels; building heating, cooling and electricity needs could be supplied through hydrogen; and the power sector could use hydrogen or hydrogen-rich fuels such as ammonia for the production of electricity.

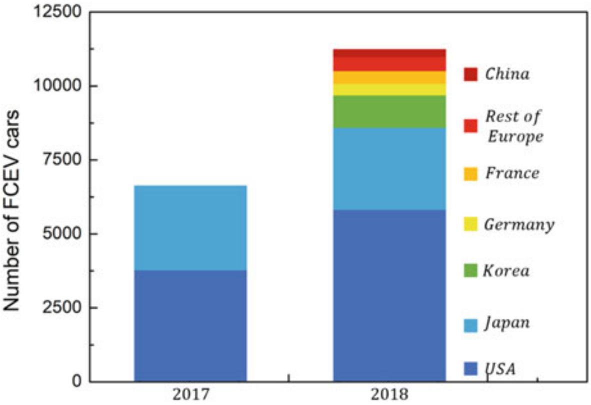
Given this versatility, it may be tempting to envisage an all-encompassing low-carbon hydrogen economy in the future. However, other clean energy technology opportunities have greatly improved recently, most importantly solutions that directly use electricity, which means that the future for hydrogen may be much more one of integration into diverse and complementary energy networks. This is especially so since the use of hydrogen in certain end-use sectors faces technical and economic challenges compared with other (low-carbon) competitors. There is also an element of path dependency; for example, rail transport is already widely electrified in many countries.

8.1 Hydrogen as a Clean Transport Fuel

Hydrogen gas has long been heralded as a potential transport fuel. It is seen as offering a low-carbon alternative to refined oil products and natural gas, and complementing other alternatives like electricity and advanced biofuels. Hydrogen fuel cell electric vehicles (FCEVs) would reduce local air pollution because – like battery electric vehicles (BEVs) – they have zero tailpipe emissions. Hydrogen can be converted to hydrogen-based fuels, including synthetic methane, methanol and ammonia, and synthetic liquid fuels, which have a range of potential transport uses. Synthetic liquid fuels produced from electrolytic hydrogen are often referred to as "power-to-liquid" (Blanco et al. 2018).

Hydrogen-based fuels could take advantage of existing infrastructure with limited changes in the value chain, but at the expense of efficiency losses. Hydrogen-based fuels offer particular advantages for aviation (in the form of synthetic jet fuel) and for shipping (as ammonia), sectors where it is more difficult to use either hydrogen or electricity.

Fig. 14 Fuel cell electric cars in circulation



Light-duty FCEVs receive most public attention when it comes to the direct use of hydrogen in mobility applications today. FCEVs have, however, also been deployed for material handling applications (mainly forklifts), buses, trains and trucks.

Cars account for the vast majority of fuel cell power deployed in road transport. About 4000 fuel cell electric cars were sold in 2018 to reach a total stock of 11,200 units (Fig. 14), an increase of 56% over the previous year.

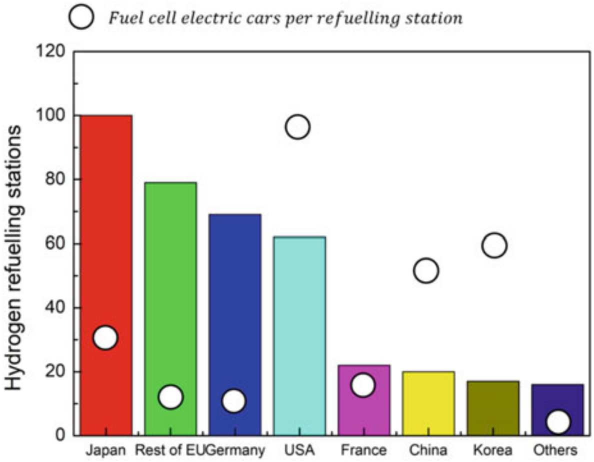
This is still a small number compared with the 2018 BEV stock of 5.1 million or the global car stock of more than one billion. The United States accounts for about half of registered FCEVs, followed by Japan (about a quarter), the European Union (11%, primarily in Germany and France) and Korea (8%).

Almost all passenger car FCEVs are made by Toyota, Honda and Hyundai, although Mercedes-Benz has recently begun leasing and selling limited volumes of a plug-in hybrid electric vehicle with a fuel cell.

Hydrogen fuel cell electric forklifts are already commercially viable as replacements for existing battery electric forklifts, and it is estimated that 25,000 forklifts have fuel cells globally. In the case of buses, the People's Republic of China ("China") has reported the largest deployment, with more than 400 registered by the end of 2018 for demonstration projects. An estimated 50 fuel cell electric buses were also in operation in Europe in 2017, 25 in California and about 30 in other US states. Other demonstration projects have rolled out fuel cell electric buses in Korea and Japan. Volumes are scaling up rapidly and thousands are expected to be in operation by the end of 2020 (mostly in China).

Globally at least 11 companies currently manufacture fuel cell electric buses. Because their long range means that there is generally no need to recharge during the day, they are in general well suited to: higher daily mileage (above 200 km per day); larger bus fleets, where refueling can be simpler than recharging battery electric buses; and flexible routing and operations, for example extending a given route at certain periods of the year.

Fig. 15 Hydrogen refuelling stations and utilisation, 2018



New models of battery electric trucks and buses have recently been produced, purchased and put into operation. The market growth has been fastest in fleets that have access to daily charging opportunities and limited daily ranges (up to 350 km per day), notably urban buses and delivery fleets. Certain operations in these fleets are intensively used and require long ranges, and some fleet owners and operators have found it cost-effective in regions where hydrogen stations exist to install fuel cell range extenders on light- and medium-duty trucks and buses.

Intercity buses in particular are likely to be a promising and competitive application for fuel cell electric powertrains.

As regards trucks, China leads the global deployment of fuel cell electric trucks and accounts for the majority of demonstration projects. Country-level statistics in 2018 refer to 412 units registered in China, supplemented by 100 vans. Separately 500 hydrogen fuel cell delivery vehicles are reported as operating in the city of Rugao alone and well over 100 are in full daily operation in and around Shanghai. Outside China, FedEx and UPS, two delivery companies, are trialing fuel cell range-extender Class 6 delivery vehicles in the United States, and the h2Share project is planning to test a 27-tonne heavy-duty truck in Europe. The French postal service and other logistics companies in France have also installed small fuel cells as range extenders onto 300 battery electric vehicles in their fleet, and other companies have brought to market fuel cell range extenders for electric vans in France.

The installation of hydrogen refueling infrastructure, while relatively limited to date, has picked up momentum in the past few years. Hydrogen refueling stations for road transport vehicles, including both publicly accessible and private refueling points, reached a worldwide total of 381 in 2018 (Fig. 15).

Japan (100), Germany (69) and the United States (63) are the three countries with the highest numbers of publicly available hydrogen refueling stations. These are, however, still small numbers compared with those for BEVs: there are almost 144,000 public fast chargers in the world for light-duty vehicles, 395,000 public slow chargers and 4.7 million private chargers.

These numbers mean that there are around 10 BEVs for every public charger and one for every private charger; the average number of FCEVs for every hydrogen refueling station in most regions where they have been deployed is currently much higher. For a fully developed infrastructure, 2500–3500 FCEVs per station are expected.

Delivered hydrogen prices are highly sensitive to hydrogen refueling station utilization. For example, a ratio close to 10 cars per station (as is the case in Europe) implies that pumps operate less than 10% of the time if the refueling stations were as small as 50 kgH2 per day.

This translates to a high price of around USD 15–25/kgH2 if the costs of building and operating refueling stations are repaid by fuel sales over the lifetime of a station.44 A higher ratio of cars to refueling stations implies better co-ordination between vehicle and infrastructure deployment and should lead to lower hydrogen prices. However, some countries with high ratios today have FCEVs that are mostly used as fleet vehicles, with fixed routes and refueling patterns that are not representative of the needs of more widespread deployment. This is the case in China and France, for example.

The variability of this ratio among countries indicates different approaches to the risks associated with refueling infrastructure development. Refueling stations can take as little as six months to bring into operation in China, but generally take up to two years.

Approaches that try to mitigate the co-ordination problem and time lag related to infrastructure development include using refueling stations at or near hydrogen production sites (for instance at industrial sites, intermodal interchange hubs or ports) to serve dedicated fleets (such as industrial operations or, potentially, public buses or taxis).

Together with BEVs, FCEVs are the only vehicles with no exhaust emissions and thus offer the potential to drastically reduce local air pollution, especially in cities. They can also dramatically reduce CO_2 emissions when low-carbon hydrogen is used. The driving range and pattern of refueling for FCEVs is similar to internal combustion engine vehicles. Furthermore, hydrogen has some attractive attributes compared to biofuels as it does not generally face resource constraints or competition for land use. FCEVs have nevertheless been slow to take off.

Technical challenges and high prices have delayed their market introduction. While the Hyundai Tucson-ix 35 was introduced in 2013 and the Toyota Mirai in 2014, there is a need to further reduce costs and build up refuelling station networks concurrently with vehicle uptake if more automakers are to be attracted to the market.

The theoretical potential for future use of hydrogen in road transport is very large. Any road transport mode can technically be powered using hydrogen, either directly using fuel cells or via hydrogen-based fuels in internal combustion engines. As an indication of the size of this market, if all the one billion cars, 190 million trucks and 25 million buses currently on the road globally were replaced by FCEVs, hydrogen demand would be as high as 300 MtH2/yr, more than four times current global demand for pure hydrogen.

The theoretical potential future demand is even larger. Over the next 10 years to 2030, oil demand from road transport is set to grow by 10% without strong action to meet the goals of the Paris Agreement. In particular, this would be driven by demand for trucks in emerging economies, but also rising car ownership. Car ownership in countries like India and even China is well below that of industrialized countries such as the European Union and the United States. US per-capita car ownership is 25 times higher than India's.

While the theoretical potential is very large, actual deployment will depend very strongly on the interactions between vehicle costs, fuel costs and policies, as well as the cost of alternatives and evolving driving habits in different countries.

The fuel cell has seen considerable cost reductions over the past decade, but costs remain high and production volumes are still low. The current commercial cost of a typical fuel cell is estimated to be USD 230/kW, although the use of state-of-the-art technologies is soon likely to bring this cost down to USD 180/kW.

Costs could be further reduced in the future through research-driven advances in technology. It may be possible to increase catalyst activity and thus reduce the platinum content, which is one of the expensive components of the fuel cell. It may also be possible to develop a platinum-free catalyst. Research is also needed to optimize the design and integration of fuel cell components in the membrane electrode assembly and to decrease the costs of the bipolar plates (which are expected to account for an increasing share of the future costs) and balance of plant components (e.g. compressors and humidifiers).

Costs could also be reduced in the future through economies of scale: increasing the number of units fabricated in a single manufacturing plant reduces the specific cost of each component.

About half of the system cost is in the bipolar plates, membranes, catalyst and gas diffusion layers. The combined cost of these components could be reduced by 65% by increasing plant scale from 1000 to 100,000 units per year, bringing system costs down to USD 50/kW.

Increasing the scale further to 500,000 units per year would be likely to decrease the cost by only an additional 10%, taking it down to USD 45/kW. These cost reduction estimates must, however, be balanced against the challenge of simultaneously improving fuel cell performance and durability. Higher durability requirements could translate into higher fuel cell cost and limit the cost reductions achieved through economies of scale. Recent US Department of Energy (DOE) data take into account these trade-offs and provide a preliminary durability-adjusted cost target of USD 75/kW. However, automakers are working to increase durability, such as via constructing fuel cell operation maps to mitigate performance degradation.

Economies of scale in manufacturing could be achieved quickly. Global truck sales stood at around 1.6 million medium-duty and 1.8 million heavy-duty vehicles in 2017. A medium-duty truck requires about twice as much power as a car, and a heavy-duty truck needs about four times as much. These requirements could, however, be met by installing fuel cell stacks next to each other; the most cost-effective way of proceeding might be to equip a medium-duty fuel cell electric truck with two fuel cell stacks, and a heavy-duty truck with four. To reach a 5% global market share in trucks would require five fuel cell system plants producing 100,000 units (stacks) a year. China would need 10 plants producing 100,000 units annually to satisfy just a quarter of its current annual sales for domestic medium- and heavy-duty trucks. The passenger vehicle sector has a market size much larger than trucks, with annual new car sales of around 85 million and light commercial truck sales of ten million in 2017. These light-duty vehicles

require a system consisting of a single fuel cell stack, with a peak power of 80–100 kW per vehicle. Achieving a market share of 5% of the global car market would require 40 fuel cell manufacturing plants, each with an average output of 100,000 units a year.

On-board storage tank costs are determined by expensive composite materials and are expected to fall at a slower pace than fuel cells. On-board storage of hydrogen requires it to be compressed at 350–700 bar for cars and trucks, and this uses the equivalent of 6–15% of the hydrogen energy content.45 The costs of current on-board storage systems (including fittings, valves and regulators) are estimated at USD 23/kWh of useable hydrogen storage at a scale of 10,000 units per year, decreasing to USD 14–18/kWh at a scale of 500,000 units per year. The US DOE has an ultimate target of USD 8/kWh. For a car with a range of 600 km, this implies costs of around USD 3400 today and USD 1800 in the long term for a tank of 225 kWh. For a heavy-duty truck with a range of 700 km, it implies costs of USD 27700 today and a potential reduction to USD 16700 for a tank of 1800 kWh, compared with USD 100000–150,000 for the full cost of a conventional diesel truck tractor.

The roll-out of hydrogen refueling infrastructure is a key requirement for FCEVs. Hydrogen refueling takes almost as little time as refueling conventional liquid transport fuels.

Supplying refueling stations with hydrogen, however, may require more time and labor than is the case for conventional transport fuels. Validation of cost estimates is difficult because there are fewer than 400 hydrogen refueling stations around the world and because their data are usually not disclosed. However, investment costs for hydrogen refueling stations are estimated to be in the range of USD 0.6–2 million for hydrogen at a pressure of 700 bar, and USD 0.15–1.6 million at 350 bar. The lower end of these ranges is for stations with a capacity of 50 kgH_2/day while the upper is for 1300 kgH_2/day.

The two largest cost components are the compressor (which can be up to 60% of the total cost when the delivery pressure is 700 bar) to achieve the delivery pressure, and the storage tanks (which are relatively large due to lower hydrogen density). The actual cost of building a station varies considerably across countries, mainly as a result of different safety and permitting requirements. There are strong economies of scale. Increasing the capacity from 50 to 500 kgH2/day would be likely to reduce the specific cost (i.e. the capital cost per kg of hydrogen dispensed) by 75%. Larger capacity stations of up to a few 1000 kgH2/day are being planned, especially for heavy-duty applications, and these offer potential for further economies of scale. There is also potential for costs to be reduced through a shift to more advanced supply options (such as very high pressure or liquid hydrogen) and through scale-up in the manufacturing of refueling station products (via mass production of components, such as the compressors).

Risks related to the tension between refueling station size, the cost of hydrogen and hydrogen demand are among the barriers to rapid hydrogen uptake for transport. Small stations make more economic sense in the initial deployment phase as they are more likely to secure higher capacity utilization rates when demand for hydrogen from transport vehicles is limited, but they come at higher cost per unit of hydrogen delivered. Once sufficient demand volumes have been established, larger stations become more economic and can help reduce the cost of hydrogen for the end users. The cost of delivered hydrogen will also depend on whether the hydrogen is produced locally or delivered from centralized production facilities. The cost advantages of centralized production may be outweighed by the cost of distribution to the refueling station by truck or pipeline. The cheapest option will be determined case by case.

Despite higher initial costs than BEV charging infrastructure, hydrogen refueling stations can offer significant advantages when deployed at scale, such as faster refueling and space requirements around 15 times lower, as well as potentially lower final investment costs. In the longer term over 400 refueling stations would be needed to service a fleet of one million hydrogen FCEVs if the ratio of refueling stations to cars were similar to that for today's oil-powered car fleet. This compares to almost one million private charging stations and at least 10,000 fast-charging public stations that would be needed for a fleet of one million BEVs.

To meet the needs of a growing FCEV fleet, policy makers will need to ensure investment flows at the right times. Most fueling stations serving non-captive fleets in the early stages of FCEV deployment will be small (< 200 kgH2/day), and the total investment needed to build these 400 stations is likely to be on the order of USD 0.5–0.6 billion. This would rapidly increase, however, and for a mature market with larger stations (>1000 kg/d) an investment of USD 35–45 billion would be required to serve just 5% of the global car fleet (around 60 million vehicles).

As well as collaborating with industrial stakeholders on roadmaps for building refueling stations in the initial phases, before their revenue can sustain investment in expansion, policy makers could incentivize owners of captive fleet stations to open them for public use, thus allowing general users to access more stations.

Energy consumption per kilometer tends to be greatest on large vehicles used over long distances. This means that fuel costs generally make up a greater share of total costs for heavier vehicles, and for vehicles with high utilization (such as long-haul trucks, intercity buses and commercial car fleets). As the capital cost of a car ranges from 70% to 95% of the total cost of ownership, depending on the vehicle, it will be imperative to bring down the cost of fuel cell systems and hydrogen storage tanks to achieve cost competitiveness with other options. The case is somewhat different for trucks, for which the capital cost ranges from 40% to 70% of the total ownership cost, meaning that cost reductions for delivered hydrogen are just as important.

Car buyers typically consider the total cost of ownership as one among several decision criteria.

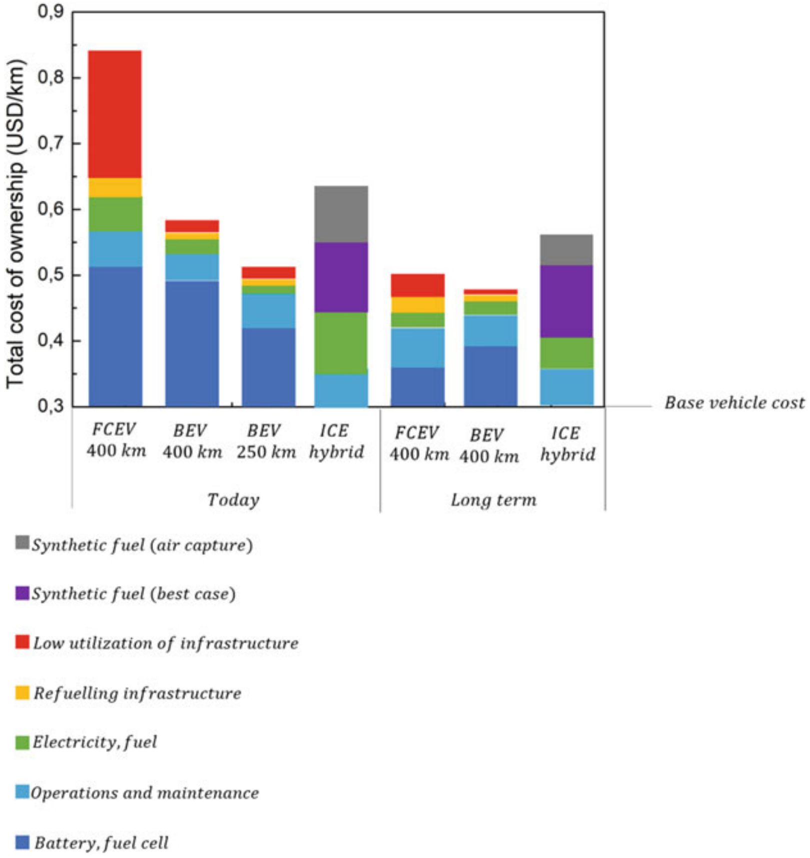
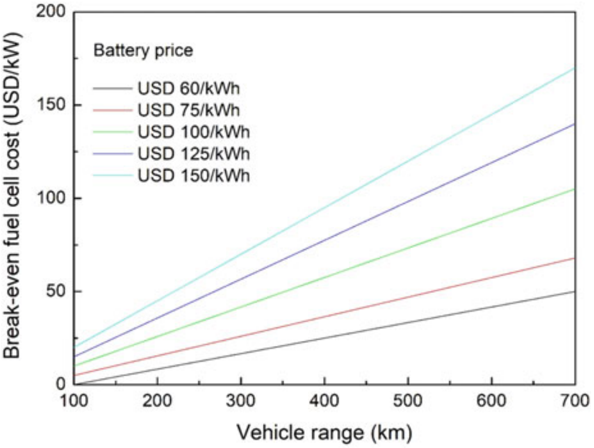


Fig. 16 Total cost of car ownership by powertrain, range and fuel

For example, the range of a car can be important to some buyers. The global average BEV sold today has a range of around 250 km; this is sufficient for most daily trips. FCEVs sold today offer a longer range: the Toyota Mirai offers some 400 km and the Hyundai Nexo even more. This makes them attractive for consumers who prioritize range. To illustrate the relevance, assuming hydrogen refueling facilities are located along desired routes, FCEVs could drive from Paris to Marseille (about 750 km) with a single short refueling stop. The same trip in a BEV with a range of 250 km would require stopping to charge at least twice, with fast charging depending on the availability of stations. This extra range offered by FCEVs, however, comes at a price in terms of the cost of the vehicle. Different consumers will weigh the considerations differently, according to their individual priorities and preferences.

Currently hydrogen fuel cell cars are generally more expensive than battery electric cars, owing to the high cost of the fuel cell and fuel tanks and to the fact that they are generally designed to have a longer range (Fig. 16).

Fig. 17 Break-even fuel cell cost to be competitive with BEV in the long term



The competitiveness improves if one assumes the same range for FCEVs and BEVs, although such range would be only possible today for a limited number of BEV models. If cost reductions through economies of scale were to bring down fuel cell costs to USD 50/kW and those of batteries fall to USD 100/kWh, then FCEVs become competitive with BEVs at a range of 400 km. If fuel cell costs were only to fall to USD 75/kW, for example because of the need for durability requirements as discussed earlier in this chapter, then FCEVs would become competitive with BEVs at a range of 500 km (Fig. 17). This underscores the fact that FCEVs can be economically attractive for consumers who prioritize driving range.

Utilization of refueling infrastructure is another determinant of the future competitiveness of FCEVs. In the initial roll-out phase, the cost of hydrogen fuel can be expected to range from 12% (at USD 9/kgH2) to 22% (at USD 18/kgH2) of the total cost of ownership. As discussed above, the additional cost accounted for by the hydrogen refueling station depends on size and utilization: stations with a capacity of 200 kgH2 per day that dispense fuel at 10–33% of capacity add a margin of USD 4–13/kgH2, and that margin declines with station size and higher capacity utilization. The risk of underutilized hydrogen refueling stations highlights the importance of securing high utilization to bring down costs in the initial stages of FCEV deployment, even in cars, the mode where fuel costs are least determinant.

It is worth noting that in California it took around two years to increase the average utilization of the network from 5% to 40%; the average station size is now around 200 kgH_2/d and some stations are still operating at below 10% utilization. The high cost of synthetic fuel, however, suggests that transitioning to alternative powertrains – whether battery or fuel cell electric – is likely to be a lower-cost strategy for reducing CO_2 and local pollutant emissions from cars and trucks, also considering the significant energy consumption and need for biogenic CO_2 this route would require.

The above analysis suggests that BEVs and FCEVs could complement each other as alternative options satisfying different consumers, with FCEVs offering the best opportunities for vehicles driven at long ranges, with fast refueling requirements and in regions with access to cheap hydrogen. Furthermore, it suggests that once a hydrogen refueling infrastructure has been built out, light-duty FCEVs with different configurations (e.g. fuel cell range extenders) could take advantage of cost and performance improvements in both fuel cells and batteries.

The heavy-duty long-haul segment, including trucks and intercity buses (or "coaches"), offers strong prospects for hydrogen FCEVs because it calls for long range and high-power requirements. As a result, heavy-duty FCEVs tend to be more immediately competitive against BEVs than in the case of cars. The direct electrification of regional bus operations and heavy-duty trucking for long-distance freight both face major challenges with larger battery capacity, long charging times and high-power requirements that translate into payload loss and additional recharging infrastructure costs. Fuel cell electric trucks overcome some of these challenges.

In the case of heavy-duty long-haul trucks, fuel cell costs are higher than light-duty vehicle applications, mainly as a result of high durability requirements. This currently necessitates increased catalyst loading, translating into higher costs. Future fuel cell system costs for heavy-duty trucks are estimated at USD 95/kW (for a production volume of 100,000 units per year). Even with current fuel cell costs, FCEVs could in general be competitive against BEVs in heavy-duty applications at ranges of more than 600 km if hydrogen could be delivered at less than USD 7/kgH2, although the exact hydrogen price at which they become competitive depends on overall annual mileage and other operational characteristics.

Powertrain and fuel options for decarbonizing heavy-duty long-haul trucking include FCEVs, battery electric trucks, dynamic charging (catenaries are the most commercially advanced and lowest-cost option on existing roads) and conventional diesel hybrids using synthetic fuels (or advanced biofuels).

A range of low-carbon powertrain options could conceivably co-exist: plug-in hybrid electric vehicles, BEVs with or without fuel cell range extenders and FCEVs of different configurations could be designed and ordered to cater to different mission profiles.

Bringing down fuel cell costs to USD 95/kW could make hydrogen fuel cell trucks in the heavy-duty segment competitive with diesel hybrid trucks at a hydrogen price of around USD 7/kgH_2, compared with the price of USD 5/kg currently needed to make them competitive with an ICE truck running on diesel. For fuel cell electric trucks to be competitive with electric road systems or battery electric trucks at a range of less than 500 km, however, the hydrogen price would need to be less than USD 5/kg H2. Because of the limited size of the truck market, reaching this fuel cell cost target may not be feasible by deployment of fuel cells in trucks alone and will most likely rely on substantial deployment of fuel cells in cars.

Fuel cell production for small mobile equipment, such as forklifts, may also help to bring down costs, but since the power requirements of this equipment is typically less than one-third that of a car, high production volumes of roughly 3000 units per year would be needed to achieve cost reductions below USD 80/kW.

In the case of trucks (and also buses), the cost contribution from the infrastructure could be reduced by the operation of a "hub-and-spoke" model: a dedicated fleet operating on fixed routes could refuel at a single centralized hydrogen refueling station. Since refineries and industrial clusters are often co-located at ports, port operations (and handling equipment) offer further attractive initial markets. The efficiency of these strategies has been demonstrated by the rapid adoption of hydrogen fuel cell electric buses and trucks in China, where the business case for intensive medium- and heavy-duty operations has been strengthened considerably by success in accessing low-cost hydrogen and achieving high utilization rates of refueling stations.

8.2 Hydrogen in Maritime Sector

The maritime sector is an important consumer of oil products, accounting for around 5% of global oil demand. This section of the report focuses on international shipping, which is the cheapest way to move long-distance freight. By volume around 90% of global physical trade in goods is by sea, of which one-third is energy products, in particular oil products.

About 80% of fuel use in the maritime sector is in international shipping, of which 90% is used for maritime freight. As a result, international shipping is an important contributor to climate change: it is responsible for around 2.5% of global energy-related CO_2 emissions. As it uses heavy fuel oil, it also has large detrimental effects on air quality, notably around ports. Hydrogen, mostly in the form of hydrogen-based fuels, is a leading option for tackling these challenges in international shipping. One advantage of these applications is that they offer the opportunity to address not only emissions during sea transport, but also those arising from port operations, making use of synergies with forklifts, trucks and goods movement in and around ports. Opportunities also exist to use hydrogen and fuel cells for shorter routes within national jurisdictions, especially those operated by ferries (Temiz and Dincer 2021).

Oil products currently dominate the shipping sector, and the use of hydrogen-based fuels in shipping is accordingly very limited. There is, however, one project in Belgium for co-firing hydrogen with diesel in maritime internal combustion engines, and more than 20 projects for fuel cells of up to 300 kW, mostly for auxiliary power units. Projects using fuel cells, often in combination with batteries, are planned in California, Ireland, Norway and for some Europe-wide operations.

Ships do not use ammonia as fuel today, but ammonia containing the equivalent of around 3.5 MtH_2/yr is traded in ships. Several research and demonstration projects are looking at the firing of ammonia as fuel for ships. Satisfactory combustion of ammonia in existing engines would generally require ignition promotors (to overcome its lower ignition energy) and engine modifications.

The volume of international shipping is expected to more than triple by 2050 under current trends. In the absence of climate change mitigation policies, this could lead to a 50% increase in demand for oil products in the sector, to around 6 mb/d. Action to reduce the emissions associated with this oil use could open a pathway to the use of hydrogen-based fuels. The International Maritime Organization (IMO) has put in place strategies for reducing both sulphur and greenhouse gas emissions.

Possible measures to address the challenge of reducing sulphur emissions are the installation of scrubbers, fuel switching to LNG and the use of very low sulphur fuel oil (VLSFO), although these measures will only make a partial contribution to the 50% greenhouse gas reduction target by 2050 compared to 1990. As described in chapter "Hydrogen in the Chemical Industry", limitations on sulphur emissions are likely to stimulate demand for hydrogen at refineries rather than as shipping fuel. To achieve the greenhouse gas emissions target, advanced biofuels, hydrogen and ammonia are all options, as well as hydrogen-based synthetic liquid fuels. The choice of fuel switching relies on infrastructure deployment outside the direct control of ship owners. LNG, hydrogen and ammonia would require the development of bunkering facilities, while both LNG and ammonia could build upon the existing distribution network. Availability and costs of advanced biofuels are uncertain as there is demand competition from other sectors for a limited supply of sustainable biomass.

Targets are also in place in some countries for low-carbon alternatives in domestic shipping. Sweden and Norway are two examples of this, while the European Commission is developing a strategy to set CO_2 reduction targets for maritime transport based on monitoring, reporting and verification of CO_2 emissions from large ships. Shipping may be incorporated into the European Emission Trading System from 2023.

Among businesses, Maersk, the world's largest maritime company, announced in 2018 that it aims to become carbon neutral by 2050. To achieve this, it recognizes that low-carbon vessels will need to be commercially viable by 2030. Industry leaders have also drafted an action plan to decarbonize the shipping sector, which includes demonstration projects, technology adoption, transparency and knowledge sharing.

Ships have high per-kilometer energy intensity and large power needs (up to 130 MW for the largest container ships), and therefore pose demanding fuel requirements. The main cost components for ships are the same as for road transport: infrastructure (bunkering facilities), on-board equipment (fuel cell/engine and storage) and fuel.

Information on the costs of using liquid hydrogen for international shipping is uncertain. One estimate for the additional cost of bunkering facilities suggests that liquid hydrogen infrastructure could be 30% more expensive than LNG. However, this estimate is likely to omit the upfront costs associated with developing a new infrastructure for hydrogen that does not currently exist. The main cost components are the storage and bunker vessels, which would need to be scaled in parallel with the number of ships serviced.

On-site or nearby hydrogen would be needed for small ports given the smaller flows and the high cost of dedicated hydrogen pipelines. Conversely, ship and infrastructure costs are a relatively small component of total shipping costs over a 15-year lifetime, with fuel costs being a much larger factor.

Among hydrogen-based fuels, ammonia is already globally traded and some of the infrastructure that would be needed to use it as a fuel already exists (distribution to ports and storage tanks). However, new bunkering facilities would need to be built; massive scale-up of ammonia production, port and distribution facilities and storage tanks would also be needed.

As an indication, satisfying shipping demand in the long term would require 500 Mt of ammonia, almost three times the level of current global production and around thirty times the volume of ammonia currently traded.

A switch to low-carbon fuels seems unlikely to occur in the absence of policy, whether mandates, direct carbon pricing, and/or more flexible and potentially more palatable measures such as low-carbon fuel standards (LCFS). Charterers, who currently oversee more than half of container fleet operations and who hire vessels from ship owners on a lump-sum or per-ton basis, are likely to operate much shorter payback periods.

Ships serving long-distance maritime trade routes may offer the best potential scope for hydrogen, ammonia and other hydrogen-based fuels. This is because fuel cell system and hydrogen storage costs have a comparatively lower impact when compared to fuel costs.

In addition, the space requirements of fuel cells could be an issue, especially for smaller ships (< 2 MW), as they need almost double the space of an ICE.

Storage of liquid hydrogen requires at least five times more volume than conventional oil-based fuels, and ammonia requires three times more volume. In the longer term this could require the redesign of ships, shorter distance trips and more frequent refueling, reduced cargo volumes, or a mix of these operational factors, depending on ship and cargo types and routes.

Low-carbon fuels are expensive today compared with fuel oil and LNG. Fuel prices are the key to cost competitiveness; the share of total cost that comes from infrastructure is much lower for ships than for other transport modes, currently accounting for about 3% of the total cost of using hydrogen in shipping on the basis of a hydrogen price of USD 10/kgH2.

This would rise to 17% if hydrogen prices were to decrease to USD 2/kgH2, and could be significantly higher (up to 40%) if bunkering facilities were oversized or underutilized. As for road transport, risks of underutilization of bunkering facilities can be hedged by: rolling out smaller vessels; using smaller storage tanks (which can be expanded as the capacity grows); using tank trucks to fuel ships; and using a smaller refueling station. However, to lower fuel costs, larger facilities would be needed for more widespread deployment.

In a 15-year first-owner lifetime calculation, a CO_2 price of USD 40–230/tCO_2 would be required to make ammonia cost-competitive with fossil-based fuels, depending on the delivered cost of ammonia, which will vary by region (Fig. 18).

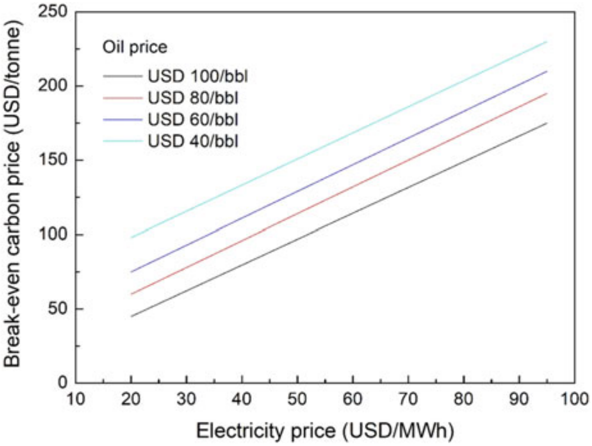


Fig. 18 Break-even carbon price for ammonia to be competitive with fossil fuels

The break-even carbon prices for hydrogen are USD 35–45/tCO_2 higher than ammonia, mainly due to the higher storage cost resulting from its lower energy density. It would represent a substantial cost increase for the ship owner and the switch would require policies that have an effect equivalent to these CO_2 prices across competing fleets, for example mandates or low-carbon fuel standards. However, the impact of passing these costs on to the final consumer would be limited because transport costs represent a small share (often less than 1%) of the total price of shipped goods.

8.3 *Hydrogen in Rail*

Rail is already the most electrified mode of transport. Although the percentage share of electrified tracks is still expanding in most countries, further electrification of rail networks is likely to come up against diminishing returns on investment, since highly utilized lines are the first to be electrified.

In France and Germany, for example, electrified lines now carry over 80% of traffic, even though less than half of the railway network has been electrified. Beyond bi-mode diesel-electric options, several technologies offer zero tailpipe emissions on non-electrified tracks and the industry seems set to move towards these in the coming decades. The most innovative of such technologies are battery electric trains and hydrogen fuel cell trains. Battery electric trains with smaller batteries can also be used on partially electrified lines, enabling electrification costs to be sharply reduced by missing out those portions of track that are most difficult to electrify (such as bridges or tunnels).

Plans involving hydrogen trains already exist in a number of countries, with at least three companies working to supply them (Böhm et al. 2022). Germany intends to expand the fleet of hydrogen trains to 14 by 2021 and 5 federal states have signed a letter of intent to purchase 60 trains from Alstom, with 27 ordered as of May 2019.

Two hydrogen trains that can travel almost 800 km a day on a single refueling already operate in Lower Saxony in Germany. Austria's Zillertalbahn plans to deploy five hydrogen trains by 2022 for a total investment of almost USD 175 million. The UK government is supporting development of the first hydrogen trains by 2022. The French government is similarly considering 2022 as the target for the first hydrogen train to be on the rails. Japan Rail East also has a project underway, in partnership with Toyota.

Under optimistic assumptions about fuel cell cost reductions, hydrogen trains could become competitive against other passenger services options with low frequency of utilization. Hydrogen fuel cell technology is most competitive for services requiring long-distance movement of large trains with low-frequency network utilisation, a common set of conditions in rail freight. The use of hydrogen in rail could be combined with its use for forklifts, trucks and other railyard and logistics hub machinery to decrease costs and improve flexibility.

8.4 Hydrogen in Aviation

Aviation accounted for almost 2.8% of global energy-related CO_2 emissions in 2017, and air passenger traffic is expected to more than double to almost 16,000 billion km/yr by mid-century under current trends. Efficiency improvements should reduce energy consumption and slow the increase in energy demand, but alternative fuels will eventually be needed to avoid increases in emissions from the sector. Advanced biofuels and hydrogen-based fuels are leading options.

While there have been feasibility studies and demonstration projects testing the scope for using hydrogen in small planes, the use of pure hydrogen as an aviation fuel requires significant further R&D. Hydrogen's low energy density and the need for cryogenic storage would require changes in aircraft design, as well as new refueling and storage infrastructure at airports. More projects – 130 in total in 2018 – are in development for the direct use of electricity than for pure hydrogen, mostly for urban air taxis (Ahluwalia et al. 2021).

However, direct electrification also faces challenges, specifically relating to battery weight and costs.

In contrast, hydrogen-based liquid fuels would require no changes to design or refueling infrastructure at airports. Synthetic fuels based on electrolytic hydrogen (so-called power-to-liquid) are estimated to be four to six times more expensive than conventional jet fuel currently.

Fuel represents a large share of the total costs of operating aircraft so this would significantly increase the operating costs and, presumably, ticket prices. This would be the case regardless of the cost of conventional jet fuel, which could itself become more expensive due to carbon pricing or other policies to reduce emissions. Estimates of the CO_2 price that would be needed to encourage a shift to power-to-liquids in aviation in the long term vary widely, from USD 115/tCO_2 to USD 660/tCO_2, with the lower value accounting for the possible value provided to the wider energy system via the electricity grid. Given the lack of other alternatives, most estimates place these costs among the higher abatement costs to complete the transition to a low-carbon energy system.

As with biofuels, the use of hydrogen-based fuels in aviation could be promoted through a target for blend shares. Even a modest target could help to demonstrate feasibility and support the scaling up of production. The standards development organization, ASTM, currently sets blending limits for alternative fuels that vary by fuel from as low as 10% to up to 90%. These might provide a helpful reference point for public and private decision makers to set upper bounds and could be updated as new engine technology emerges.

Besides on-board use of hydrogen in aviation, hydrogen is already used today in a few auxiliary power units that generate electricity when the jet engine is not running. Such units, which usually run on natural gas, can account for up to 20% of ground aircraft emissions.

9 Hydrogen for Power Generation and Electricity Storage

Hydrogen plays a negligible role in the power sector today: it accounts for less than 0.2% of electricity generation. This is linked mostly to the use of gases from the steel industry, petrochemical plants, and refineries. But there is potential for this to change in the future. Co-firing of ammonia could reduce the carbon intensity of existing conventional coal power plants, and hydrogen-fired gas turbines and combined-cycle gas turbines could be a source of flexibility in electricity systems with increasing shares of variable renewables. In the form of compressed gas, ammonia or synthetic methane, hydrogen could also become a long-term storage option to balance seasonal variations in electricity demand or generation from renewables (Elberry et al. 2021).

Although pure hydrogen does not generally feature as a fuel in power generation today, there are small-scale exceptions. For example, a 12 MW hydrogen-fired combined-cycle gas turbine in Italy uses hydrogen from a nearby petrochemical complex, while in Kobe, Japan, a hydrogen-fired gas turbine is providing heat (2.8 watts thermal) and electricity (1.1 MWe) to a local community. Somewhat more common is the use of hydrogen-rich gases from steel mills, petrochemical plants and refineries. Reciprocating gas engines today can handle gases with a hydrogen content of up to 70% (on a volumetric basis), 53 while in the future gas engines should be able to operate on even 100% hydrogen. Gas turbines also have the capability to run on hydrogen-rich gases. In Korea a 40 MW gas turbine at a refinery has run on gases with a hydrogen content of up to 95% for 20 years.

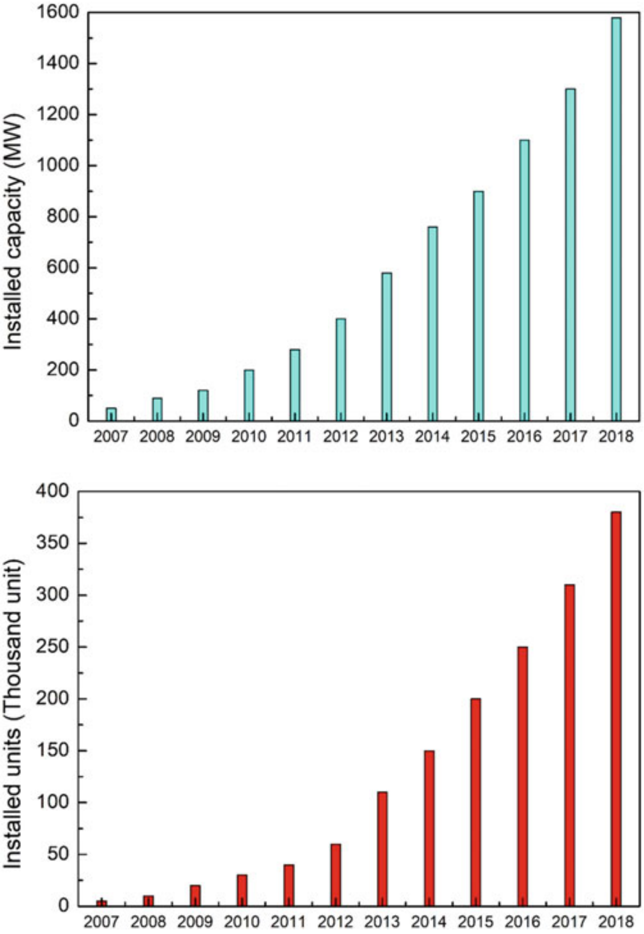


Fig. 19 Development of global stationary fuel cell capacity, 2007–18

Fuel cells are a further option to convert hydrogen into electricity and heat, producing water and no direct emissions. They can achieve high electric efficiencies of over 60% and reveal a higher efficiency in part load than full load, which makes them particularly attractive for flexible operations such as load balancing.

Global installed stationary fuel cell capacity has been rapidly growing over the last ten years, reaching almost 1.6 GW in 2018 (Fig. 19), although only around 70 MW uses hydrogen as fuel; most of the existing fuel cells today run on natural gas.

The number of globally installed fuel cell units is around 363,000, largely dominated by micro co-generation systems. The Japanese ENE-FARM initiative accounts for the majority, with around 276,000 micro co-generation systems, but represents only 12% of the installed capacity at 193 MW. Outside Japan, the residential fuel cell market is also growing in Germany, driven by the KfW433 support program with around 1900 funding approvals by November 2018. Larger fuel cell systems above 100 kW to 2.4 MW are still almost exclusively deployed in Korea and the United States, with installed capacities of 300 MW and 150 MW, respectively. A further growing market for fuel cells is the provision of back-up power and off-grid electricity.

Very few countries have stated explicit targets for the use of hydrogen or hydrogen-based fuels in the power sector. Japan is one of the few exceptions: it aims to reach 1 GW of power capacity based on hydrogen by 2030, corresponding to an annual hydrogen consumption of 0.3 MtH2, rising to 15–30 GW in the longer term, corresponding to annual hydrogen use of 15–30 MtH2. Korea is another exception: its hydrogen roadmap sets a target of 1.5 GW installed fuel cell capacity in the power sector by 2022, and 15 GW by 2040. A number of countries have, however, recognized the potential of hydrogen as a low-carbon option for power and heat generation.

Research and pilot projects to introduce hydrogen and ammonia as fuel for gas turbines and coal power plants are being pursued in Japan. An existing 440 MW combined-cycle gas turbine (CCGT) plant is being converted from natural gas to hydrogen in the Netherlands, and ammonia is being considered for long-term storage there; it would be reconverted into hydrogen and nitrogen before combustion of the hydrogen in the gas turbine. The Port Lincoln Green Hydrogen Project under construction in Australia includes a 30 MW electrolyzer plant and an ammonia production facility, as well as a 10 MW hydrogen-fired gas turbine and a 5 MW hydrogen fuel cell, which will supply balancing services to the grid and the ammonia plant. The facility will also support to two new solar farms, as well as a nearby micro-grid which will be utilized by local aqua agriculturists who have been affected by ageing back-up power generation.

Hydrogen and hydrogen-based fuels such as ammonia and synthetic natural gas can be fuels for power generation. Ammonia can be co-fired in coal-fired power plants to reduce coal usage and reduce the carbon footprint of these plants; if low carbon, it would also reduce overall emissions. Hydrogen and ammonia can also be used as fuels in gas turbines, CCGTs or fuel cells, thus providing a flexible and potentially low-carbon generation option. Hydrogen-based fuels are also options for large-scale and long-term energy storage to balance seasonal variations in electricity demand or variable renewable power generation.

In 2017 the Japanese Chugoku Electric Power Corporation successfully demonstrated the co-firing of ammonia and coal, with a 1% share of ammonia (in terms of total energy content) at one of their commercial coal power stations (120 MW). Using ammonia as fuel raises concerns about an increase in NOx emissions, but the demonstration managed to keep them within the usual limits and to avoid any ammonia slip into exhaust gas. Higher blending shares of up to 20% ammonia in energy terms might be feasible with only minor adjustments to a coal power plant. In smaller furnaces with a capacity of 10 MW thermal, blending shares of 20% ammonia have been achieved without problems, and in particular without any slippage of ammonia into exhaust gas.

The economics of substituting coal with ammonia depend on the availability of low-cost ammonia, but ammonia could help to reduce emissions if produced from low-carbon hydrogen. By 2030 around 1250 GW of coal power plants worldwide that are currently in operation or under construction could not only still be in service but could also still have a remaining lifetime of at least 20 years. Co-firing with a 20% share of ammonia could reduce the 6 $GtCO_2$/yr annual emissions of these coal plants by 1.2 $GtCO_2$, provided that the ammonia was produced from low-carbon hydrogen. Reaching a 20% blending share would result in an annual ammonia demand of 670 Mt, more than three times today's global ammonia production, which in turn would require 120 MtH_2.

Hydrogen can be used as a fuel in gas turbines and CCGTs. Most existing gas turbine designs can already handle a hydrogen share of 3–5% and some can handle shares of 30% or higher.

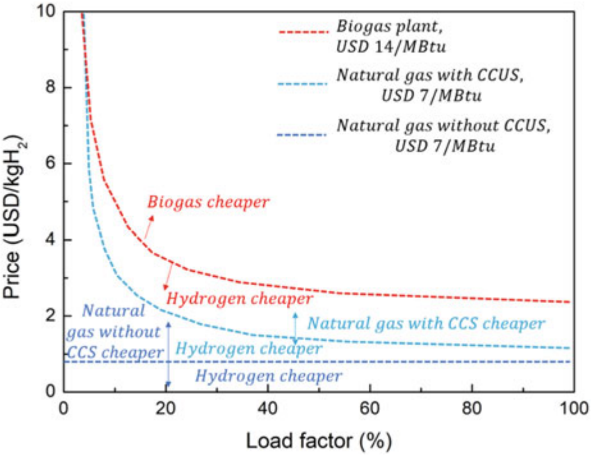
The industry is confident that it will be able to provide standard turbines that are able to run entirely on hydrogen by 2030.

Ammonia is another potential fuel for gas turbines. The direct use of ammonia has been successfully demonstrated in micro gas turbines with a power capacity of up to 300 kW. In larger gas turbines above 2 MW, the slow reaction kinetics of ammonia with air, the flame stability and the NOx emissions are issues still being investigated by researchers. Instead of directly burning ammonia, an alternative approach is to reconvert the ammonia first into hydrogen and nitrogen, to burn hydrogen in the combustor of the gas turbine. The heat required for decomposing (or cracking) the ammonia at temperature levels of 600–1000 °C (the temperature depends on the catalyst) can be supplied by the gas turbine, though this slightly reduces the electricity generation efficiency of the overall process.

Fuel cells can also be used as a flexible power generation technology. With electric efficiencies of 50–60% (lower range today, upper future potential) being in a similar range to those of CCGTs, the choice between fuel cells and CCGTs in economic terms largely depends on their capital costs. It is, however, worth noting that fuel cell stacks today still suffer from a shorter technical lifetime than gas turbines (10,000 to 40,000 hours of operation), and that stationary fuel cells today typically have a smaller power output (up to 50 MW for the largest fuel cell power plants), which makes them most suitable for distributed generation. For comparison, CCGT units can reach capacities of 400 MW. The heat produced by the fuel cell while generating power can be used to provide an additional revenue stream. Future cost reductions for fuel cells will depend on future deployment levels and the learning effects and economies of scale that follow from this. On optimistic assumptions, CAPEX for hydrogen fuel cells may fall to USD 425/kW by 2030 compared to USD 1600/kW for a 1 MW PEMFC unit today or USD 1000/kW for a CCGT today.

Hydrogen and ammonia could offer low-carbon flexibility for electricity systems with increasing shares of VRE. Alternative low-carbon flexible generation options are natural gas-fired power plants equipped with CCUS and biogas power plants. Both alternatives are characterized by higher capital costs per unit of power than needed for a hydrogen-fired CCGT power plant, due to the additional capture equipment needed for CCUS and the typically smaller scale of biogas power plants.

Fig. 20 Break even for hydrogen CCGT against other flexible power generation options



The capital cost advantage of the hydrogen option is more pronounced when the load factor is low (Fig. 20), and it often is low in systems with high shares of VRE. At a capacity factor of 15%, low-carbon hydrogen would become competitive with electricity generation from natural gas with CCS at hydrogen prices of USD 2.5/ kgH_2, if the gas price is USD 7/MBtu.

The competitiveness of hydrogen-fired power plants with natural gas-fired power generation for load balancing and peak load generation depends on the gas price and the potential level of carbon prices. Looking, for example, at a load factor of 15% and a natural gas price of USD 7/MBtu, the CO_2 price would have to be USD 100/tCO_2 to make hydrogen-fired power generation at a hydrogen price of USD 1.5/ kgH_2 competitive with natural gas. If the hydrogen price was USD 2/kg H2, the CO_2 price would have to be USD 175/tCO_2 to make electricity from hydrogen competitive against natural gas.

For illustrative purposes, if 1% of the globally installed gas-fired power capacity (or 25 GW) was fired by hydrogen (or ammonia) in 2030, this would result in annual electricity generation of around 90 TWh (40% load factor) and hydrogen demand of 4.5 MtH_2 (or 30 Mt. of ammonia). This would help to scale up demand and the supply infrastructure for hydrogen, since the annual hydrogen demand of 25 GW of hydrogen power plants would correspond to the annual consumption of around 23 million fuel cell vehicles. Even a single 500 MW power plant would create a hydrogen demand equivalent to 455,000 fuel cell vehicles or the heat demand of 221,000 homes in the United Kingdom and might therefore provide an opportunity to create a hub for other potential hydrogen users, such as transport or buildings.

The integration of increasing shares of VRE sources in the electricity system requires a more flexible electricity system. High shares of renewables can create a need for long-term and seasonal storage, for example to provide electricity during periods of several days with very little wind and or sunshine.

Hydrogen and hydrogen-based fuels (such as methane, liquid organic hydrogen carriers [LOHCs] and ammonia produced from electricity via electrolysis) are potential options for long-term and large-scale storage of energy. Salt caverns are the best choice for the underground storage of pure hydrogen because of their tightness and low risk of contamination. Alternative underground hydrogen storage options such as pore storage and storage in depleted oil and gas fields are also being investigated. Converting electricity into methane via power-to-gas is a further long-term storage option, and one which could take advantage of the existing transport and storage infrastructure for natural gas. Around 70 power-to-gas projects to produce methane are in operation today, most of them in Europe. Storing electricity in the form of ammonia is another long-term and large-scale storage option. Large steel tanks are already commonly used in the fertilizer industry for storing ammonia.

Hydrogen-based storage options suffer from low round-trip efficiency: in the process of converting electricity through electrolysis into hydrogen and then hydrogen back into electricity, around 60% of the original electricity is lost, whereas for a lithium-ion battery the losses of a storage cycle are around 15% (Fig. 21).

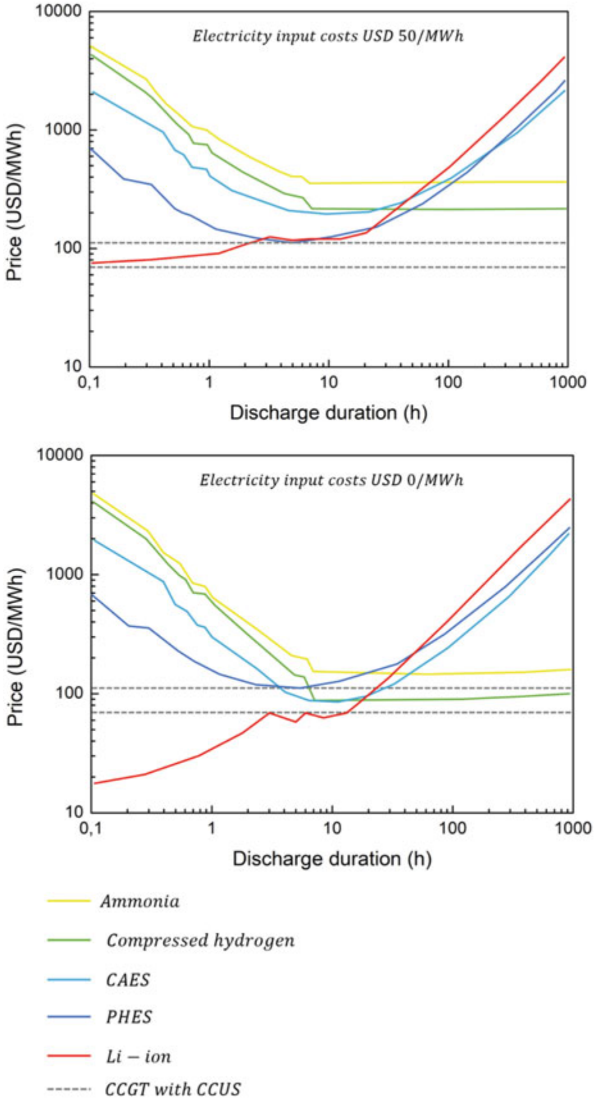
Pumped-hydro storage facilities offer one alternative: they have been used for more than a century to store electricity for relatively long periods. Batteries offer another alternative, although they are unlikely to be used for long-term and large-scale storage because they suffer from self-discharge and because of the immense number of batteries that would be needed for large-scale storage. A single large, refrigerated liquid ammonia tank with a diameter of 50 meters and a height of 30 meters, as typically used in the fertilizer industry, can store energy amounting to 150 GWh, comparable to the annual electricity consumption of a city with a population of 100,000. To store the same amount of electricity with batteries would require around 1150 times the installation of the Australian

Hornsdale Battery Reserve, the largest lithium-ion battery storage today in the world with a capacity of 129 MWh.

All the alternatives have advantages and disadvantages. For shorter discharge durations below a few hours, hydrogen and ammonia are much more expensive than pumped-hydro storage or battery storage. With longer discharge durations, compressed hydrogen and ammonia become more attractive, benefitting from their relative low capital costs for energy storage volumes (the investment costs to develop underground salt caverns or storage tanks). Among the different storage technologies considered here, compressed hydrogen becomes the most economic option for discharge durations beyond 20–45 hours.

Hydrogen as an electricity storage option could also be combined with other uses of hydrogen in the interests of competitiveness. In the United States, for example, the Three-State Generation and Transmission utility is considering producing ammonia from electricity for the domestic fertilizer market. Situated in an area with low-cost electricity from wind, solar and hydropower, the project would use a reversible solid oxide electrolyzer cell (rSOEC) to produce hydrogen when the cost of electricity is less than USD 25/MWh (which is 85% of the time), turning it into ammonia for sale on the market, while storing some of it for electricity generation in the rSOEC during peak hours, thus improving its overall utilization rate. This approach may be an

Fig. 21 Levelised costs of storage as a function of discharge duration



alternative to installing new electric generation resources that are expected only to be needed during peak load times.

It may not be necessary to use large-scale storage of hydrogen-based fuels to cover the full storage cycle, i.e. taking electricity as input and converting it in the end back into electricity.

Instead of filling long-term storage with hydrogen from domestic electricity, hydrogen-based fuels can also be imported from other parts of the world with seasonal surpluses of renewable electricity generation at that time, taking advantage of complementary seasonal patterns of renewable electricity supply and electricity demand. Depending on the frequency and scale of the imports, this could reduce the storage volumes needed in the importing region. The conversion back to electricity may also not always be needed. Stored methane, ammonia or hydrogen could be directly used as fuel to cover seasonal demands, such as for space heating.

10 Conclusions

The increased focus on reducing emissions to near zero by mid-century has brought into sharp relief the challenge of tackling hard-to-abate emissions sources. These emissions are in sectors and applications for which electricity is not currently the form of energy at the point of end use, and for which direct electricity-based solutions come with high costs or technical drawbacks.

Four-fifths of total final energy demand by end users today is for carbon-containing fuels, not electricity. In addition, much of the raw material for chemicals and other products contains carbon today and generate CO_2 emissions during their processing.

Hard-to-abate emissions sources include aviation, shipping, iron and steel production, chemicals manufacture, high-temperature industrial heat, long-distance and long-haul road transport and, especially in dense urban environments or off-grid, heat for buildings. Rapid technological transformations in these sectors have made limited progress in the face of the costs of low-carbon options, their infrastructure needs, the challenges they pose to established supply chains, and ingrained habits. While significant financial and political commitments will be necessary to realise deep emissions cuts, there is an increasing sense of urgency on the part of governments and companies about the need to start developing appropriate solutions. As a low-carbon chemical energy carrier, hydrogen is a leading option for reducing these hard-to-abate emissions because it can be stored, combusted and combined in chemical reactions in ways that are similar to natural gas, oil and coal. Hydrogen can also technically be converted to “drop-in” low-carbon replacements for today’s fuels, which is particularly attractive for sectors with hard-to abate emissions, especially if there are limits to the direct use of biomass and CCUS.

While interest in hydrogen continues to be strongly linked with climate change ambition, there has been a noticeable broadening of the policy objectives to which hydrogen can contribute.

The benefits of hydrogen for energy security, local air pollution, economic development and energy access are now routinely cited.

Hydrogen can support energy security in several ways. When hydrogen is deployed alongside electricity infrastructure, electricity can be converted to hydrogen and back, or further converted to other fuels, making end users less dependent on specific energy resources and increasing the resilience of energy supplies. Hydrogen produced from fossil fuels with CCUS or from biomass can also increase the diversity of energy sources, especially in a low-carbon economy. If the right infrastructure is developed, it could be attractive in the future for countries to diversify their economies by exporting low-carbon energy in the form of hydrogen and hydrogen-based fuels, or importing hydrogen to benefit from competition that restrains prices. Countries with high-quality resources for hydrogen production are widely dispersed around the globe, and many current energy exporting countries are also endowed with renewable resources that could produce hydrogen. In an ambitious low-carbon context, such hydrogen trade would effectively enable trade and storage of wind and sunshine between different regions to overcome seasonal differences. Lastly, hydrogen could provide an additional way for countries to store reserves of energy strategically in a highly electrified low-carbon world.

Using hydrogen instead of carbon-containing fuels in energy end uses could also reduce local air pollution, improving environmental and health outcomes. Urban air pollution concerns and its related health impacts are now major drivers of energy policy decisions, and governments are keenly interested in ways of reducing air pollution and improving air quality. When used in vehicles and heating appliances, hydrogen does not produce particulates or sulphur oxides or raise ground-level ozone. When used in a fuel cell, hydrogen does not produce nitrogen oxides.

Because hydrogen can be stored or used in a variety of sectors, converting electricity to hydrogen can help with the matching of variable energy supply and demand, both temporally and geographically, alongside alternatives such as pumped-storage hydropower, batteries and grid upgrades. If renewable power generation becomes sufficiently cheap and widespread, it can be used not only to provide low-carbon electricity, but also to create low-carbon hydrogen that can displace fossil fuels in transport, heating and industrial raw materials, and indeed almost any application not susceptible to electrification. All this makes hydrogen one of a suite of technologies that work well together to support the growth of low-carbon energy at the level of the overall energy system.

The question of cost is of course very important in this context. The cost of electricity is the single most significant factor in the cost of electrolytic hydrogen production, and recent sharp declines in solar and wind power costs have therefore reduced the real and expected prices of renewable hydrogen. For example, utility-scale solar photovoltaic (PV) capital costs are 75% lower than in 2010, and electricity from onshore wind is around one quarter cheaper today than it was ten years ago. This has led more potential end users to look closely at whether renewable hydrogen is becoming a competitive way to meet their needs and reduce their environmental impact. Recent investments include a project to use electrolysers for the generation of low-carbon hydrogen to displace a share of fossil fuel-based hydrogen in oil refining and fertiliser production.

References

Abdin Z, Zafaranloo A, Rafiee A et al (2020) Hydrogen as an energy vector. Renew Sustain Energy Rev 120:109620. https://doi.org/10.1016/j.rser.2019.109620

Ahluwalia RK, Peng JK, Wang X et al (2021) Performance and cost of fuel cells for urban air mobility. Int J Hydrog Energy 46(74):36917–36929. https://doi.org/10.1016/j.ijhydene.2021.08.211

Ausfelder F, Bazzanella A (2016) Hydrogen in the chemical industry. https://doi.org/10.1002/9783527674268.ch02

Aziz M, Zaini IN, Oda T et al (2017) Energy conservative brown coal conversion to hydrogen and power based on enhanced process integration: Integrated drying, coal direct chemical looping, combined cycle and hydrogenation. Int J Hydrog Energy 42(5):2904–2913. https://doi.org/10.1016/j.ijhydene.2016.10.060

Blanco H, Nijs W, Ruf J et al (2018) Potential for hydrogen and Power-to-Liquid in a low-carbon EU energy system using cost optimization. Appl Energy 232:617–639. https://doi.org/10.1016/j.apenergy.2018.09.216

Böhm M, Del Rey AF, Pagenkopf J et al (2022) Review and comparison of worldwide hydrogen activities in the rail sector with special focus on on-board storage and refueling technologies. Int J Hydrog Energy 47(89):38003–38017. https://doi.org/10.1016/j.ijhydene.2022.08.279

Boretti A (2021) There are hydrogen production pathways with better than green hydrogen economic and environmental costs. Int J Hydrog Energy 46(46):23988–23995. https://doi.org/10.1016/j.ijhydene.2021.04.182

Buttler A, Spliethoff H (2018) Current status of water electrolysis for energy storage, grid balancing and sector coupling via power-to-gas and power-to-liquids: a review. Renew Sustain Energy Rev 82(3):2440–2454. https://doi.org/10.1016/j.rser.2017.09.003

Cao L, Iris KM, Xiong X (2020) Biorenewable hydrogen production through biomass gasification: a review and future prospects. Environ Res 186:109547. https://doi.org/10.1016/j.envres.2020.109547

Cavaliere P (2019) Clean ironmaking and steelmaking processes. https://doi.org/10.1007/978-3-030-21209-4

Cavaliere P (2022) Hydrogen assisted direct reduction of iron oxides. Springer, Cham. https://doi.org/10.1007/978-3-030-98056-6

Cecere D, Giacomazzi E, Ingenito A (2014) A review on hydrogen industrial aerospace applications. Int J Hydrog Energy 39(20):10731–10747. https://doi.org/10.1016/j.ijhydene.2014.04.126

Chai WS, Bao Y, Jin P et al (2021) A review on ammonia, ammonia-hydrogen and ammonia-methane fuels. Renew Sustain Energy Rev 147:111254. https://doi.org/10.1016/j.rser.2021.111254

Dalena F, Senatore A, Marino A et al (2018) Methanol production and applications: an overview. https://doi.org/10.1016/B978-0-444-63903-5.00001-7

de-Troya JJ, Alvarez C, Fernández-Garrido C et al (2016) Analysing the possibilities of using fuel cells in ships. Int J Hydrog Energy 41(4):2853–2866. https://doi.org/10.1016/j.ijhydene.2015.11.145

Dincer I, Acar C (2016) A review on potential use of hydrogen in aviation applications. Int J Sustain Aviat 2(1):74–100. https://doi.org/10.1504/IJSA.2016.076077

Doucet G, Etievant C, Puyenchet C et al (2009) Hydrogen-based PEM auxiliary power unit. Int J Hydrog Energy 34(11):4983–4989. https://doi.org/10.1016/j.ijhydene.2008.12.029

Elberry AM, Thakur J, Santasalo-Aarnio A et al (2021) Large-scale compressed hydrogen storage as part of renewable electricity storage systems. Int J Hydrog Energy 46(29):15671–15690. https://doi.org/10.1016/j.ijhydene.2021.02.080

Elsherif M, Manan ZA, Kamsah MZ (2015) State-of-the-art of hydrogen management in refinery and industrial process plants. J Nat Gas Sci Eng 24:346–356. https://doi.org/10.1016/j.jngse.2015.03.046

Félix G, Quitian A, Rodríguez E et al (2017) Methods to calculate hydrogen consumption during hydrocracking experiments in batch reactors. Energy Fuels 11:11690–11697. https://doi.org/10.1021/acs.energyfuels.7b01878

Felseghi RA, Carcadea E, Raboaca MS et al (2019) Hydrogen fuel cell technology for the sustainable future of stationary applications. Energies 12(23):4593. https://doi.org/10.3390/en12234593

Giuliano A, Poletto M, Barletta D (2018) Pure hydrogen co-production by membrane technology in an IGCC power plant with carbon capture. Int J Hydrog Energy 43(41):19279–19292. https://doi.org/10.1016/j.ijhydene.2018.08.112

Gjorgievski VZ, Markovska N, Pukšec T et al (2021) Supporting the 2030 agenda for sustainable development: special issue dedicated to the conference on sustainable development of energy, water and environment systems 2019. Renew Sustain Energy Rev 143:110920. https://doi.org/10.1016/j.rser.2021.110920

Goel M, Sudhakar M, Shahi RV (2018) Carbon capture, storage and utilization-A possible climate change solution for energy industry. ISBN 9780367179083

Haseli Y (2018) Maximum conversion efficiency of hydrogen fuel cells. Int J Hydrog Energy 43(18):9015–9021. https://doi.org/10.1016/j.ijhydene.2018.03.076

Hienuki S, Hirayama M, Hirayama Y et al (2021) Public acceptance for the implementation of hydrogen self-refueling stations. Int J Hydrog Energy 46(72):35739–35749. https://doi.org/10.1016/j.ijhydene.2021.08.115

Hoelzen J, Silberhorn D, Zill T et al (2022) Hydrogen-powered aviation and its reliance on green hydrogen infrastructure–review and research gaps. Int J Hydrog Energy 47(5):3108–3130. https://doi.org/10.1016/j.ijhydene.2021.10.239

Hoffmann P (2012) Tomorrow's energy: hydrogen, fuel cells, and the prospects for a cleaner planet. https://www.jstor.org/stable/j.ctt5vjpvs

Jones J, Genovese A, Tob-Ogu A (2020) Hydrogen vehicles in urban logistics: a total cost of ownership analysis and some policy implications. Renew Sustain Energy Rev 119:109595. https://doi.org/10.1016/j.rser.2019.109595

Klerke A, Christensen CH, Nørskov JK et al (2008) Ammonia for hydrogen storage: challenges and opportunities. J Mater Chem 18:2304–2310. https://doi.org/10.1039/B720020J

Lewis D (2008) Hydrogen and its relationship with nuclear energy. Prog Nucl Energy 50(2–6): 394–401. https://doi.org/10.1016/j.pnucene.2007.11.072

Mahant B, Linga P, Kumar R (2021) Hydrogen economy and role of Hythane as a bridging solution: a perspective review. Energy Fuels 19:15424–15454. https://doi.org/10.1021/acs.energyfuels.1c02404

Midilli A, Kucuk H, Topal ME (2021) A comprehensive review on hydrogen production from coal gasification: challenges and opportunities. Int J Hydrog Energy 46(5):25385–25412. https://doi.org/10.1016/j.ijhydene.2021.05.088

Oldenbroek V, Verhoef LA, Van Wijk AJM (2017) Fuel cell electric vehicle as a power plant: Fully renewable integrated transport and energy system design and analysis for smart city areas. Int J Hydrog Energy 42(12):8166–8196. https://doi.org/10.1016/j.ijhydene.2017.01.155

Onarheim K, Hannula I, Solantausta Y (2020) Hydrogen enhanced biofuels for transport via fast pyrolysis of biomass: a conceptual assessment. Energy 199:117337. https://doi.org/10.1016/j.energy.2020.117337

Pan Z, Chan WP, Veksha A et al (2019) Thermodynamic analyses of synthetic natural gas production via municipal solid waste gasification, high-temperature water electrolysis and methanation. Energy Conv Manag 202:112160. https://doi.org/10.1016/j.enconman.2019.112160

Rambhujun N, Salman MS, Wang T et al (2020) Renewable hydrogen for the chemical industry. MRS Energy Sustain 7:E33. https://doi.org/10.1557/mre.2020.33

Rau F, Herrmann A, Krause H et al (2017) Production of hydrogen by autothermal reforming of biogas. Energy Proc 120:294–301. https://doi.org/10.1016/j.egypro.2017.07.218

Sengodan S, Lan R, Humphreys J et al (2018) Advances in reforming and partial oxidation of hydrocarbons for hydrogen production and fuel cell applications. Renew Sustain Energy Rev 82(1):761–780. https://doi.org/10.1016/j.rser.2017.09.071

Speight JG (2016) Hydrogen in refineries. https://doi.org/10.1002/9783527674268.ch01

Staffell I, Scamman D, Abad AV et al (2019) The role of hydrogen and fuel cells in the global energy system. Energy Environ Sci 12:463–491. https://doi.org/10.1039/C8EE01157E

Temiz M, Dincer I (2021) Techno-economic analysis of green hydrogen ferries with a floating photovoltaic based marine fueling station. Energy Convers Manag 247:114760. https://doi.org/10.1016/j.enconman.2021.114760

Tsujimura T, Suzuki Y (2019) Development of a large-sized direct injection hydrogen engine for a stationary power generator. Int J Hydrog Energy 44(22):11355–11369. https://doi.org/10.1016/j.ijhydene.2018.09.178