Hydrogen applications and business models

Going blue and green?
Kearney Energy Transition Institute
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About the FactBook: hydrogen applications and business models
This FactBook seeks to provide an overview of hydrogen-related technologies, emerging applications, and new business models, covering the entire value chain and analyzing the environmental benefits and economics of this space.

About the Kearney Energy Transition Institute
The Kearney Energy Transition Institute is a nonprofit organization that provides leading insights on global trends in energy transition, technologies, and strategic implications for private-sector businesses and public-sector institutions. The Institute is dedicated to combining objective technological insights with economical perspectives to define the consequences and opportunities for decision-makers in a rapidly changing energy landscape. The independence of the Institute fosters unbiased primary insights and the ability to co-create new ideas with interested sponsors and relevant stakeholders.

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This FactBook is structured in four sections:

1. **H2 role in the energy transition**
   
   This section provides a brief description of the energy decarbonization challenge to mitigate climate change and gives an overview of hydrogen’s potential role and impact.

   *Hydrogen could help reduce GHG emissions in multiple sectors, representing about half of global GHG emissions*

2. **H2 value chain**

   This section provides an overview of production, storage, and transport technologies—looking at their performances, limitations, and environmental benefits and giving some perspective on their technology maturity and possible improvements.

   *The deployment of Blue Hydrogen could help develop large-scale infrastructures, providing time for Green Hydrogen to mature and scale up*

3. **Key H2 applications**

   This section looks at existing and emerging hydrogen applications and assesses their maturity. Hydrogen applications are categorized into four types: industrial applications, mobility, power generation, and gas energy.

   *Hydrogen is broadly used in industries but remains immature in the broader set of applications, for which cost reduction and innovative business models are required*

4. **H2 business Models**

   This section looks at the emerging business models, considering current market conditions and their possible long-term evolution assuming a potential technology cost reduction and performance improvement.

   *Most hydrogen business models require policy support, with heavy-duty transportation being the most promising one in the current context*
Some orders of magnitude in 2019

Executive summary

1. Hydrogen’s role in the energy transition

2. Hydrogen value chain: upstream and midstream
   2.1 Production technologies
   2.2 Conversion, storage, and transportation technologies
   2.3 Maturity and costs

3. Key hydrogen applications
   3.1 Overview
   3.2 Feedstock
   3.3 Energy

3. Business models
   4.1 Policies and competition landscape
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Appendix (Bibliography & Acronyms)
Some orders of magnitude regarding hydrogen in 2019

**Annual production of hydrogen**
- Global production: 118 Mt, of which 70 Mt is from dedicated sources
- From fossil fuels: 69 Mt
- From electrolysis: 4 Mt, of which 3 Mt is a by-product of the chlorine industry

**Current largest plants**
- Fossil fuel plant: 450 kt per year
- Alkaline electrolyzer: 165 MW
- PEM electrolyzer plant: 10 MW or 1.8 kt per year

**Annual use of global hydrogen production**
- Ammonia and methanol synthesis: 43 Mt per year (37%)
- Oil refining: 38 Mt year (33%)
- Steel manufacturing: 13 Mt per year (11%)
- Other: 21 Mt per year (18%)

**CO2 emissions from hydrogen production**
- 830 MtCO₂ per year
- About 2% of global CO₂ emissions

**Equivalence of 1 Mt of H₂ in terms of oil**
- About 21 Mboe
- About a quarter the world’s daily oil consumption

**What does 1 ton of H₂ represent?**
- Feedstock to refine about 285 barrels of crude oil
- 3,000 to 5,000 km of autonomy for a fuel cell train

**What does 1 kg of H₂ represent?**
- About 100 km of autonomy for a fuel cell car, equal to 6 to 10 liters of gasoline

**How to store 1 ton of H₂?**
- If uncompressed, about 56,000 bathtubs
- If compressed at 700 bars, about 120 bathtubs
- If liquefied, about 65 bathtubs

**How much hydrogen would be required if the hydrogen car fleet ... :**
- Reaches 100,000 vehicles: 15 kt per year
- Reaches 5 million vehicles in the BEV fleet: 750 kt per year
- Reaches 1.2 billion vehicles in the ICE car fleet: 180 Mt

**How will we possibly use hydrogen in 2050?**
- In industry: 245 Mt, of which 112 Mt will be for heating
- In transportation: 154 Mt, including synthetic fuels
- In power and gas: 140 Mt

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The need for decarbonization

Anthropogenic CO₂ emissions (excluding AFOLU1) have accelerated during the 20th century, rising to about 37 Gt per year in 2019, with global CO₂ atmospheric concentration reaching 415 ppm. At current emission levels, the remaining carbon budget to keep global warming below the +1.5 °C target could be exhausted in 10 years, which would have dramatic consequences on ecosystems and societies.

Hydrogen: a potential candidate

Most of the anthropogenic greenhouse gas (GHG) emissions (excluding AFOLU) comes from the production and transport of energy (about 40%, including electricity and heat production), industry (23%), buildings (21%), and transport (16%).

Hydrogen provides multiple pathways to reducing GHG emissions in these sectors and could address about half of their GHG emissions if produced, stored, and carried cleanly. Hydrogen can either be used as an energy carrier or as a feedstock for various industrial and chemical processes.

Hydrogen is a versatile energy carrier that can either be burnt to release heat or converted into electricity using fuel cells. Therefore, hydrogen offers a broad range of applications from energy production to mobility services. But H₂ is competing with other decarbonized solutions that tackle similar applications, such as renewable energy solutions and carbon capture and storage.

Hydrogen has high gravimetric energy density (MJ/kg) and can be stored under multiple forms (for example, gaseous, liquid, or converted to other molecules), which makes it a strong candidate for energy storage as an intermediary vector for the energy system (enabling coupling between electric grid, gas grid, transportation, and industries).

1. AFOLU is agriculture, forestry, and other land use.
Main brown/grey production sources are steam methane reforming (SMR), gasification, and autothermal reforming (ATR).

In a **Steam methane reforming** reactor, natural gas is mixed with high-temperature steam and nickel catalysts in an endothermic reaction to form H₂, CO and CO₂, called a syngas. It requires 3 to 4 kg of CH₄ per kg of H₂ (about 65% of lower heating value efficiency).

In a **coal gasification** reactor, O₂ is added to the high-temperature combustion chamber in substoichiometric conditions, releasing syngas, tar vapors, and solid residues. About 8 kg of coal are required to produce 1 kg of H₂ (70 to 80% LHV efficiency).

**Autothermal reforming** combines both production methods, with a combustion and a catalytic zone within the same chamber, also releasing a syngas. It requires 2.5 to 3 kg of CH₄/kgH₂ (80% LHV efficiency).

The syngas is a mixture of H₂, CO, CO₂, and other gases that can be used as is or purified. Syngas composition depends on reactor design and feedstock used. As H₂ and CO are main syngas components, syngas quality is measured with H₂/CO ratio in volumetric quantities. High ratio means high quantity of H₂ in the syngas.

Syngas can directly be consumed, such as for methanol synthesis or as a fuel. In other cases, purification is required. There are two main ways to purify syngas:

- **Pressure swing adsorption (PSA) purification**: syngas first undergoes a water–gas shift reaction, where water steam is added to convert CO into CO₂ and H₂. CO₂ is then removed and released through selective adsorption process.

- **Decarbonation and methanation purification**: after a water–gas shift reaction, syngas undergoes decarbonation where amines are added to remove the majority of the CO and CO₂. During methanation, the remaining CO and CO₂ reacts with H₂ to create CH₄.

**Blue hydrogen requires the combination of brown sources with CCS value chain (capture, transportation, storage, and/or usage of CO₂), for which multiple technologies are available.**

Within the energy value chain, CCS applied for hydrogen production is considered as pre-combustion capture: carbon is removed from fossil fuel to create hydrogen. Following on-site capture, carbon can be transported through pipelines or ships and is later stored in underground geological storage (for example, depleted oil and gas fields). Carbon can also be used for further processes, such as chemical feedstock (for example, for methanol or liquid fuels synthesis), enhanced oil recovery (EOR), or agriculture. CCS can be deployed at different stages of the end-to-end production and purification process. Several technologies are available, such as amine capture or membrane separation.
Green hydrogen mostly relies on electrolysis technologies, involving an electrochemical reaction where electrical energy allows a water split between hydrogen and dioxygen. An electrolysis cell is the assembly of two electrodes—a cathode and an anode—either immersed in an electrolyte (Alkaline) or separated by a polymer membrane (PEM). Direct current is applied from the anode to the cathode. For a potential difference above 1.23V, water is split into H₂ and O₂. An electrolyzer is an assembly of cell stacks in parallel, a stack being an assembly of cells in serial connection.

Three electrolysis technologies are available, all based on the same electrochemical reaction but with differences in the materials used and the operating point:

- **Alkaline electrolysis (AE)** is the oldest technology. Potassium hydroxide electrolyte is often used because it is a strong base (avoiding corrosivity caused by acid) with high mobility ions. Anode and cathode are separated by a thin porous foil enabling separation of H₂ and O₂ with a current density of 0.3 to 0.5 A.cm⁻². AE efficiency is usually 52 to 69%. It is currently the cheapest electrolysis option since it does not use rare materials, and large-scale production plants (up to 150 MW) have already been built.

- **Proton exchange membrane (PEM)** is a rapidly evolving technology and is being commercially deployed. The membrane used is a polymer membrane enabling higher current density (currently 1 to 3 A.cm⁻²). It is more expensive than AE technologies since rare materials are used (such as platinum for electrodes) but has higher flexibility and quicker response time, making it suitable for renewable energy integration. PEM efficiency is usually 60 to 77%.

- **Solid oxide electrolysis cell (SOEC)** is still in the R&D stage. The electrolyte used is high temperature steam water (650 to 1,000°C), which provides enough energy to decrease power consumption needs. However, it is economically viable only if fatal heat is available for free or at low cost. Because of high temperature operations, ceramic membranes usually have a shorter lifetime than other technologies. SOEC efficiency is usually 74 to 81%, excluding the energy needed to heat steam.

The balance includes all other components required for the process before electrolysis (AC/DC power converter, water deionizer, and storage tank) and after electrolysis (dehydration unit to purify H₂).

Other green hydrogen production sources include dark fermentation, microbial electrolysis, and photolytic conversion, which are still in laboratory stages.
Hydrogen is a versatile energy carrier that allows a broad range of conditioning options, which can be either a physical transformation or a chemical reaction, to increase volumetric energy density or improve handling.

There are two major categories of conditioning. Physical transformation includes compression and liquefaction. Chemical combination includes metal hydrides, liquefied organic hydrogen carrier, and other chemicals such as ammonia:

- **Compression** increases hydrogen pressure (up to 1,000 bars) to improve energy volumetric density and decrease storage and transportation costs. However, even at high pressure, energy density remains much lower than other solutions.
- **Liquefaction** is cooling gaseous hydrogen down to -253°C to increase volumetric energy density with potential losses as a result of boil-off.
- **Metal hydrides** is the binding of certain metals with hydrogen in a stable solid structure, which can be stored in cans. Metal hydride cans are particularly well-suited for transportation purposes, such as scooters and cars) as they can easily be replaced and do not require large recharging infrastructure deployment.
- **Liquefied organic hydrogen carrier** (LOHC) is the addition of hydrogen atoms to toluene to convert it into methylcyclohexane (MCH). MCH is liquid in ambient conditions, which avoids boil-off losses and limits explosion risks. However, toluene needs to be shipped back to a production plant, and MCH toxicity is high.
- Hydrogen can also be converted into **ammonia** and leverage current ammonia production and transportation infrastructure. Ammonia can be used directly as a chemical for the fertilizer industry. However, reconversion to hydrogen process has a low efficiency.

 Depending on conditioning, hydrogen can be stored and transported in different ways. Tanks are suited to store compressed gaseous hydrogen, liquefied hydrogen, LOHC, and ammonia and can easily be transported by **trucks, trains, or ships**. Hydrogen can also be stored in dedicated **pipelines** (in gaseous or as ammonia) or injected into gas pipelines (in gaseous form, if concentration does not exceed a certain limit, which depends on the infrastructure and consumption points). Finally, hydrogen can be stored in **salt caverns** for long-term reserves.
While brown technologies are the most mature, blue and green should close the gap by 2030; conditioning transportation remains costly (1/2)

Hydrogen value chain: upstream and midstream – Maturity and costs

(Section 2.3: pages 61–77)

Today, Hydrogen produced from Brown sources is two to ten times less expensive than from Green or Blue sources

The Levelized Cost Of Hydrogen is the average discounted cost of hydrogen generation over the lifetime of the considered plant. It is used to compare the production cost of hydrogen from the various sources.

For brown hydrogen production sources, LCOH depends on technology and feedstock price, and commonly range around 90¢ to $2.10 per kg. The SMR average estimated price is currently about $1.40 per kg, with LCOH mainly driven by the price of natural gas (about 75% of LCOH) and capex (about 22%).

For blue hydrogen production sources is ~50¢ per kg higher than brown sources, and is estimated to range between $1.50 and $2.50 per kg. It is still cheaper than electrolyzer but requires carbon storage caverns. The cost of CCS highly depends on the technology used, which will all have different efficiency (up to 90% capture rate).

For green hydrogen production sources, LCOH depends on technology, electricity price, and electrolyzer size as it benefits from economies of scale. Electrolyzers LCOH is estimated to range between $2.50 to $9.50 per kg depending on technologies.

- Alkaline electrolysis (AE) is currently the cheapest available technology with an average estimated LCOH of $4.00 per kg.
- The Proton exchange membrane (PEM) average estimated LCOH is $5.00 per kg, and SOEC $7.40 per kg. LCOH is mainly driven by electricity cost (71% for a PEM) and capex (21% for a PEM).

For green hydrogen, access to cheap renewable electricity could help reduce LCOH of electrolysis. However, renewable electricity from solar and wind power sources are not dispatchable and provide relatively low load factors. Thus, the capex part would dramatically increase. Reaching economical competitiveness with blue sources (LCOH of $2 to $3 per kg) requires low electricity prices and high load factor (commonly above 90%)

By 2030, LCOH of blue hydrogen is expected to go as low as $1.30 to $1.90 per kg, and between $1.60 to $3.80 per kg for green hydrogen, depending on the electrolysis technology used. R&D improvements will help reduce capex, increase lifetime and improve efficiency. The main focus will be on increasing density, lowering catalysts, and scaling up the balance of system components.
While brown technologies are the most mature, blue and green should close the gap by 2030; conditioning transportation remains costly (2/2)

Hydrogen LCOH is highly impacted by conditioning and transportation steps, which can double its LCOH cost.

LCOH from conditioning highly varies depending on technologies.

- **Compression and tank storage** is the cheapest option (20¢ to 40¢ kg) with no associated reconversion costs.
- **Liquefaction** LCOH is $1.80 to $2.20 per kg, which could be reduced with improvements on boil-off losses. As liquefied hydrogen naturally tends to become gaseous at ambient temperature, no associated reconversion process is required.
- **Ammonia conversion** LCOH is $1.00 to $1.20 per kg, and reconversion LCOH is 80¢ to $1.00 per kg. Finally, LCOH for LOHC is 40¢ per kg while reconversion can vary from $1.00 to $2.10 per kg.

LCOH from transportation depends on hydrogen conditioning, transportation mean used, and distance travelled:

- For long ranges (more than 1,000 km), **ships and pipelines** are possible options. Pipelines can carry compressed gaseous hydrogen or ammonia, while ships can be used for liquefied hydrogen, LOHC, or ammonia. For a 3,000 km journey, transporting gaseous hydrogen through a pipeline is about $2.00 per kg. For the same distance but with liquefied hydrogen transported by ship, LCOH is about $1.50 per kg. However, below 2,000 km of travelled distance, pipelines appear to be cheaper.
- For short ranges (less than 1,000 km), **trucks, rail, and pipeline** are possible options. Compressed gaseous, liquefied, LOHC, and ammonia can be transported by trucks, while pipelines can carry only compressed gaseous hydrogen and ammonia. For a 500 km journey, transporting compressed gaseous hydrogen by trucks costs about $2.00 per km versus about 40¢ to 80¢ for pipelines.

Decentralized production sources or on-site consumption allow skipping the midstream value chain.
Hydrogen versatility allows for multiple applications as a feedstock, as a gas, or for electricity generation (fuel cells). As of 2019, about 115 Mt of pure and mixed hydrogen are consumed annually, of which 94 Mt is for industrial processes. As a feedstock, hydrogen is mainly used in oil refining, ammonia synthesis, and steel manufacturing. Hydrogen can also be mixed with oxygen in a fuel cell to deliver a direct current and release water and heat, with an efficiency of about 60%. Hydrogen can be burnt in a dedicated turbine coupled with an alternator to produce electricity or be injected into gas network or a dedicated pipeline network to release heat at consumption point.

Industrial processes mainly use hydrogen as a feedstock with on-site production

In the chemicals industry, hydrogen can be combined with nitrogen to form ammonia (Haber–Bosh process). Ammonia can be later converted into fertilizers. Hydrogen can also be combined with CO and CO2 to form methanol in a catalytic reaction. Methanol can be further converted into polymers or olefins or be used as a fuel. About 44 to 45 Mt of hydrogen are consumed annually for chemicals synthesis. In oil refining, hydrogen is used in hydrodesulfurization to remove sulfur contents in crude and in hydrocracking processes to upgrade the oil quality of heavy residues. About 38 MT of hydrogen are consumed annually for chemicals synthesis.

In the steel industry, hydrogen is used in a basic oxygen furnace (BOF) and in direct reduction of iron (DRI) to convert iron ore into steel. Hydrogen can come as a by-product of BOF but needs to be produced on-site in DRI. Annual consumption is about 13 MT.

In mobility, hydrogen is converted to electricity through a fuel cell to power an electric engine.

Several types of fuel cells exist and are characterized by various combination of electrodes and electrolytes, with different requirements and performance. As of 2019, hydrogen deployment in mobility has been limited to bikes, scooters, cars, trucks, buses, and trains. Hydrogen use for marine roads and aviation is still in early-stage development.

In power generation, hydrogen will be mainly used as a energy storage vector. In peak times, hydrogen can be supplied to stationary fuel cells or gas turbines that will provide clean electricity to the grid.

By 2050, pure hydrogen consumption could grow eightfold to 540 MT per year, mainly driven by transportation and industrial processes.
Companies specialized in the hydrogen value chain are partnering with a broad range of other industrials to capture value. M&A activity has been growing over the past few years, with companies from different industries partnering to develop new business models based on hydrogen. The Hydrogen Council was created in 2017 by 30 private companies from industry, transportation, and energy to accelerate investments in hydrogen and encourage key stakeholders to back hydrogen as part of the energy mix.

Governments are putting in place regulations and mechanisms to promote hydrogen deployment. Multiple countries have launched support initiatives and incentives mechanisms to accelerate hydrogen deployment, mainly in the transportation sector. Countries have developed specific strategy cases based on their capabilities and economical situations:

– In Europe, Hydrogen Europe is partnering with the European Commission to identify legal barriers that could delay or deter investments in hydrogen. The objectives are to integrate more renewables and decarbonize mobility, heating, and industry.
– In the United States, multiple incentives have been given to fund hydrogen R&D in public laboratories and private R&D departments. Between 2004 and 2017, the Department of Energy was granted $2.5 billion to develop fuel cell electric vehicles (FCEV), build a mature hydrogen economy, decrease oil dependency, and create a sustainable energy economy.
– In Middle Eastern oil-rich countries, a blue hydrogen economy is being studied as a transition from oil exports to hydrogen exports and the use of CO₂ for enhanced oil recovery.
– Japan was the first country to adopt a "Basic Hydrogen Strategy" and plans to become a “hydrogen society”, targeting commercial scale capability to procure 300,000 tons of hydrogen annually.
– Australia adopted a National Hydrogen Strategy in late 2019 to open up opportunities in domestic use as well as export market.
New business models are developing for both blue and green solutions to take advantage of decarbonization. Centralized blue production sources are being considered for industrial areas, such as the Port of Rotterdam, where hydrogen could feed local industries and power plants. Electrolyzer coupled with renewable energy is being considered as it could both accelerate renewable energy integration on the grid and decarbonize end applications such as gas energy, power generation, industry, and mobility.

Hydrogen-based solutions provide decarbonization solutions that are not yet competitive with traditional solutions. The relevance of business cases has been assessed based on three criteria: economical viability, environmental impact (end-to-end CO2 emissions), and other benefits, such as reduced energy dependency, grid stabilization, job creation, and air-quality improvement in populated areas. All hydrogen solutions appear to be more expensive than conventional solutions. However, in certain cases, CO2 emissions can be significantly reduced. The carbon abatement cost has been calculated to assess the relevance of opportunities for hydrogen and is compared with the IPCC carbon price target of $220 per tCO2 by 2030 in a +2°C trajectory.

For a centralized blue production source feeding nearby industries, which would require adjustments to accept hydrogen rather than conventional fuels and feedstocks, mainly in gas power plants and refineries, the carbon abatement cost would be $110 to $215 per tCO2 for 27 to 130 mtpa of CO2 avoided.

Electrolyzer business models will be based on a power-to-x scheme. The surplus of electricity will be used to produce hydrogen, which will later be used as a fuel for gas heating, chemicals, power generation, or mobility. However, depending on the electricity source, the carbon impact and LCOH will differ. Electrolyzer can be connected to the grid and running at about 90% load factor, connected solely to a renewable source and be dependent on the source load factor (maximum 40% for wind power plants) or combine both sources:

- **Power-to-gas.** Hydrogen is injected into gas networks, either blended with natural gas with a certain volumetric limit, which depends on gas grid specifications and tolerance to hydrogen, or undergoing a methanation process to form methane. Injection is easier and cheaper, with a carbon abatement cost of $220 to $320 per tCO2. Adding a methanation step adds complexity and costs, leading to an abatement cost of $1,100 to $2,800 per tCO2.

- **Power-to-power.** Stored hydrogen is released in a fuel cell to deliver power at peak time rather than starting a coal or gas turbine. Compared with a coal turbine and depending on the electricity source that powered the electrolyzer, 40 to 790 gCO2 per MWhe could be saved at an abatement cost between $120 and $3,000 per tCO2.
Most hydrogen business models require policy support, with heavy-duty transportation being the most promising one in the current context (2/2)

– **Power-to-molecule.** Electrolyzer is built on a refinery or a chemicals production plant in addition to a SMR and provides hydrogen when electricity surplus is available. However, scalability is limited: electrolyzer (pilot plant) in the Wesseling refinery in Germany supplies only 1% of hydrogen needs to the refinery but could spare about 9 kgCO₂ per kgH₂ at a cost of about $120 to $150 per tCO₂.

– **Power-to-mobility.** Hydrogen is produced on site at the refueling station. If overall LCOH drops down to $4 to $5 per kg, making it competitive with gasoline, the vehicle acquisition cost is expected to remain higher, increasing total cost of ownership. The CO₂ abatement cost is $570 to $2,000 per tCO₂ for passenger cars, $120 per tCO₂ for buses, and $60 per tCO₂ for trains.

Lithium–ion batteries for electricity storage and mobility are the main competitor to hydrogen on its segments.

– **Lithium–ion batteries** are suited for intra-day storage and frequency stabilization, whereas hydrogen is more suited for long-term seasonal storage.

– **Battery electric vehicles** are the main competitor of hydrogen in the mobility segment, in particular for light-duty vehicles. (Heavy-duty BEV such as trucks and buses are limited by battery-size requirements.) However, BEV are limited in range (maximum of 650 km with an average of 100-200 km in real-life conditions) and long recharging time. A FCEV is expected to be more competitive than a BEV for a journey of more than ~300 km. For trains, hydrogen is the cheapest clean solution if the rail line is not electrified, which avoids high capex. However, on electrified lines, electric trains are already cheaper than diesel and hydrogen trains.

– The LCOE produced is expected to be comparable between the two technologies: $150 to $250 per MWhe.

Indirect value creation, such as local job creation and grid stabilization, should be considered for hydrogen valuation. Hydrogen business solutions generally provide additional indirect value that are not considered in its economic assessment. Developing a hydrogen economy would require gaining economies of scale and developing large production hubs that could supply multiple applications. To prioritize investments, carbon abatement cost and carbon avoided, as well as favorable impact on local economies, could be used as metrics to assess hydrogen’s relevance compared with other solutions.
Hydrogen’s role in the energy transition
Global warming can have a dramatic impact on ecosystems and societies

“Climate-related risks for natural and human systems are higher for global warming of 1.5°C than at present but lower than at 2°C (high confidence). These risks depend on the magnitude and rate of warming, geographic location, levels of development and vulnerability, and on the choices and implementation of adaptation and mitigation options (high confidence).”

– Intergovernmental Panel on Climate Change

### Key consequences of +1.5°C and +2°C global warming by 2100

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<th>+1.5°C</th>
<th>+2.0°C</th>
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<tbody>
<tr>
<td><strong>Global mean sea level rise</strong></td>
<td>0.26 to 0.77 m (medium confidence)</td>
<td>0.36 to 0.87 m (medium confidence)</td>
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<tr>
<td><strong>Biodiversity losses</strong> (among 105,000 species studied)</td>
<td>8% of plants</td>
<td>16% of plants</td>
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<td></td>
<td>6% of insects</td>
<td>18% of insects</td>
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<td></td>
<td>4% of vertebrates</td>
<td>8% of vertebrates</td>
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<td><strong>Decline of coral reefs</strong></td>
<td>70–90% (high confidence)</td>
<td>More than 99% (very high confidence)</td>
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<td><strong>Frequency of disappearance of the Arctic ice cap</strong></td>
<td>Once per century (high confidence)</td>
<td>Once per decade (high confidence)</td>
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<td><strong>Decrease in global annual catch for marine fisheries</strong></td>
<td>1.5 million tons (medium confidence)</td>
<td>3 million tons (medium confidence)</td>
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<tr>
<td><strong>Average increase of heat waves mean temperature</strong></td>
<td>+3°C (high confidence)</td>
<td>+4°C (high confidence)</td>
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Sources: “Special report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways (SR1.5).” Intergovernmental Panel on Climate Change, 2018; Kearney Energy Transition Institute analysis
At current emission levels, we only have about 10 years left in the estimated carbon budget for global warming of 1.5°C.

**GHG emissions (2018, GtCO₂eq per year)**

**Carbon GHG**
- Coal
- Oil
- Gas
- LUC(1)

**Other GHG**
- F-gases
- CH₄
- N₂O

**Remaining carbon budget (2018, GtCO₂eq)**

- 2.0°C target: +2080
- 1.5°C target: +1500
- 2.200

**Sources:**
- Global Carbon Budget 2018
- IPCC (2018) “SR5–Chapter 2”
- Kearney Energy Transition Institute analysis

1 LUC: deforestation and other land use change
Hydrogen could partially address GHG emissions as a fuel substitute in sectors responsible for more than 65% of global emissions.

### Current GHG emissions by segment (GT CO₂ eq/y)

- **Not substitutable by H₂**
  - Building: ~44 GT
  - Industry: 5 GT

- **Partially substitutable by H₂**
  - Agriculture, forestry & other land use: 27 GT
  - Transport: 17 GT
  - Electricity & heat, Oil & gas, others: 22 GT

- **Partially substitutable by H₂**
  - Building: 6 GT
  - Industry: 14 GT
  - Transport: 9 GT

### Hydrogen potential use cases for decarbonization

- **Use case**
  - Agriculture, forestry & other land use
  - Building
  - Industry
  - Transport
  - Electricity & heat, Oil & gas, others
  - Coal

- **Method of H₂ substitution**
  - Heating networks with H₂ (blended or full H₂)
  - Circular economy with CCU/CCS
  - Clean feedstock for oil refining & chemicals
  - Full cell electric vehicle (passenger cars, trucks, trains)
  - Synthetic fuels (airplanes, ships)
  - Integration of renewables:
    - Large scale storage for inter-seasonal storage
    - Geographic balance
    - Grid stabilization

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1. Includes land use, emissions from cattle, etc.; 2. Carbon Capture Utilisation/ Carbon Capture Storage

Sources: IEA; FAO; Kearney Energy Transition Institute analysis
Hydrogen provides multiple pathways enabled by various production technologies and applications across its value chain.

### Overview of H2 value chain and technologies

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<th>Upstream</th>
<th>Midstream and downstream</th>
<th>Consumption</th>
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<tr>
<td><strong>Production technology</strong></td>
<td><strong>Conversion, storage, transport, and distribution</strong></td>
<td><strong>End-use applications</strong></td>
</tr>
<tr>
<td>Steam methane reforming (SMR)</td>
<td>Hydrogen gas</td>
<td>Oil refining</td>
</tr>
<tr>
<td>Gasification</td>
<td>Liquid hydrogen</td>
<td>Chemicals production</td>
</tr>
<tr>
<td>Autothermal reforming (ATR)</td>
<td>NH₃</td>
<td>Iron and steel production</td>
</tr>
<tr>
<td>Pressurized combustion reforming</td>
<td>Liquefied organic hydrogen carrier (LOHC)</td>
<td>High-temperature heat</td>
</tr>
<tr>
<td>Chemical looping</td>
<td>Trucks</td>
<td>Food industry</td>
</tr>
<tr>
<td>Concentration solar fuels (CSF)</td>
<td>Trains</td>
<td>Light-duty vehicles</td>
</tr>
<tr>
<td>Heat exchange reforming (HER) and gas heated reforming (GHR)</td>
<td>Pipeline</td>
<td>Heavy-duty vehicles</td>
</tr>
<tr>
<td>Pyrolysis</td>
<td>Tankers</td>
<td>Maritime</td>
</tr>
<tr>
<td>Other technologies (such as microwave)</td>
<td>Geothermal storage</td>
<td>Rail</td>
</tr>
<tr>
<td>Alkaline electrolysis (AE)</td>
<td>Storage tanks</td>
<td>Aviation</td>
</tr>
<tr>
<td>Proton exchange membrane (PEM)</td>
<td>Chemical reconversion</td>
<td>Co-firing NH₃ in coal power plants</td>
</tr>
<tr>
<td>Solid oxide electrolyzer cell (SOEC)</td>
<td>Liquefaction and regasification</td>
<td>Flexible power generation</td>
</tr>
<tr>
<td>Other technologies (such as chlor-alkali)</td>
<td></td>
<td>Back-up and off-grid power supply</td>
</tr>
<tr>
<td>Dark fermentation</td>
<td></td>
<td>Long-term, large-scale storage</td>
</tr>
<tr>
<td>Microbial electrolysis</td>
<td></td>
<td>Blended H₂</td>
</tr>
<tr>
<td>Photoelectrochemical</td>
<td></td>
<td>Methanation</td>
</tr>
</tbody>
</table>

**End-use applications**
- Mobility
  - Gas
  - Energy
  - Power generation
  - Industrial applications
  - Gas mobility

Sources: Kearney Energy Transition Institute analysis
Hydrogen will potentially play a major role in the Energy Transition as a link between multiple energy sources and industrial applications.

Simplified value chain of hydrogen-based energy conversion solutions

1 Simplified value chain. End uses are non-exhaustive; 2 Several possible options (e.g. Steam methane reforming; autothermal reforming; chemical looping, etc.)

Sources: Kearney Energy Transition Institute
Hydrogen is competing with other low carbon solutions that tackle similar applications.

Hydrogen substitution matrix

<table>
<thead>
<tr>
<th>Sector (consuming fossil fuels)</th>
<th>Total oil consumption usage (Mtoe³, 2018)</th>
<th>Potential application of other decarbonisation technologies (2030+ time horizon)</th>
<th>Potential role of hydrogen</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Biomass (Bio-fuels and biogas)</td>
<td>Electrification (renewables + storage)</td>
<td>Carbon Capture Storage¹</td>
</tr>
<tr>
<td>Commercial stage</td>
<td>Pilot stage</td>
<td>Research stage</td>
<td>Not an option</td>
</tr>
<tr>
<td>Aviation &amp; Shipping</td>
<td>600</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rail²</td>
<td>29</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Trucks</td>
<td>2,110</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Road</td>
<td>615</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Industry &amp; petrochem</td>
<td>915</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heat &amp; power</td>
<td>615</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- Hydrogen not mature for commercial aviation application, more progressing for shipping (small boats)
- H₂ application for rail is relevant to replace diesel engine in non-electrified rails
- H₂ relevant for heavy duties vehicle (trucks and buses, for which battery weight is a major issue)
- H₂ is required for petrochemicals, and is generally produced by reforming of methane (Brown)
- Relevant for heat and power but expensive and already addressed by Renewables

Use of CO₂ from CCS is not considered in the range of possible solutions. Based on 2017 figures. Million tonnes oil equivalent.
Sources: IEA WEO 2019; Kearney Energy Transition Institute.
Hydrogen is the lightest molecule with the highest gravimetric energy density

Description
- **Name**: Hydrogen ("water former" in ancient Greek)
- **State in ambient conditions**: gaseous, diatomic (H₂)
- **Properties**:
  - Smallest, lightest, oldest, and most abundant element in the universe
  - Mainly found in combination with carbon (hydrocarbons), oxygen (water), or nitrogen (ammonia)
  - Colourless, odourless, tasteless, non-toxic, and non-metallic
  - Highly diffusive and oxidizing
- **Reactants**: Reacts spontaneously with oxygen, chlorine, and fluorine
- **Combustion**:
  \[2H_2 + 2O_2 \rightarrow 2H_2O + 572 \text{ kJ}\]
  \[\Delta H = -286 \text{ kJ/mol}\]

Hydrogen fact card

Advantages
- High energy density
- No CO₂ emissions during combustion
- Abundant on earth (water and hydrocarbons)
- Multiple applications in industrial and energy sectors

Disadvantages
- Rare in natural H₂ form
- High CO₂ emissions for industrial production
- Large ignition range
- Corrosive

Physical properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density (kg/m³)</td>
<td>0.089 (gas) 71 (liquid)¹</td>
</tr>
<tr>
<td>Boiling point (°C)</td>
<td>-253 °C</td>
</tr>
<tr>
<td>Lower heating value (MJ/kg)</td>
<td>120</td>
</tr>
<tr>
<td>Specific energy, liquefied (MJ/kg)</td>
<td>8.5</td>
</tr>
<tr>
<td>Ignition range (% of gas in air volume)</td>
<td>4–77%</td>
</tr>
</tbody>
</table>

¹ Gas: 0°C, 1 bar; liquid: -253°C, 1 bar

Sources: "Hydrogen Storage," US Department of Energy; Kearney Energy Transition Institute
Hydrogen value chain: upstream and midstream
<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Some orders of magnitude in 2019</td>
<td>5</td>
</tr>
<tr>
<td>Executive summary</td>
<td>6</td>
</tr>
<tr>
<td>1. Hydrogen’s role in the energy transition</td>
<td>16</td>
</tr>
<tr>
<td>2. Hydrogen value chain: upstream and midstream</td>
<td>25</td>
</tr>
<tr>
<td>2.1 Production technologies</td>
<td>27</td>
</tr>
<tr>
<td>2.2 Conversion, storage, and transportation technologies</td>
<td>49</td>
</tr>
<tr>
<td>2.3 Maturity and costs</td>
<td>61</td>
</tr>
<tr>
<td>3. Key hydrogen applications</td>
<td>78</td>
</tr>
<tr>
<td>3.1 Overview</td>
<td>80</td>
</tr>
<tr>
<td>3.2 Feedstock</td>
<td>84</td>
</tr>
<tr>
<td>3.3 Energy</td>
<td>90</td>
</tr>
<tr>
<td>3. Business models</td>
<td>114</td>
</tr>
<tr>
<td>4.1 Policies and competition landscape</td>
<td>116</td>
</tr>
<tr>
<td>4.2 Business cases</td>
<td>125</td>
</tr>
<tr>
<td>Appendix (Bibliography &amp; Acronyms)</td>
<td>187</td>
</tr>
</tbody>
</table>
About 118 Mt of H₂ are produced each year and release about 830 Mt of CO₂, mainly from fossil fuels.

Key considerations

- H₂ production has reached 118 Mt per year, 59% of which comes from dedicated sources.
- Use of fossil fuels for H₂ production represented about 6% of global demand for natural gas and about 2% of global demand for coal.
- Global CO₂ emissions from H₂ represented 830 Mt CO₂ equivalent.
- Overall, 0.6% of H₂ is from renewable or fossil fuels plants equipped with CCS.
- About 3 Mt of H₂ are lost or not recovered (for example, during purification).

### Global hydrogen production (2018, Mt H₂, % of total production)

<table>
<thead>
<tr>
<th>Source</th>
<th>Mt H₂</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial by-product</td>
<td>48</td>
<td>(41%)</td>
</tr>
<tr>
<td>Dedicated production</td>
<td>70</td>
<td>(59%)</td>
</tr>
<tr>
<td>Total</td>
<td>118</td>
<td>(100%)</td>
</tr>
</tbody>
</table>

- Steel (9.2%)
- Refinery (2.0%)
- Chlorine (9.2%)
- From RES (0.2%)
- Others (12.1%)
- Total (33.1%)

### Hydrogen value chain - Production technologies

1 Mtce = 0.35 Mt H₂
2 35% of refinery H₂ needs come as a by-product.
3 World chlorine production: about 100 MT per year – ratio of 1/35 tH₂/tCl₂

H₂ conversion technologies can be split into thermochemical, electrolysis, microbial, and photolytic.

### H₂ production technologies overview

<table>
<thead>
<tr>
<th>Primary source</th>
<th>Conversion technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and gas</td>
<td>Steam methane reforming (SMR)</td>
</tr>
<tr>
<td>Water and brine electrolysis</td>
<td>Alkaline electrolysis (AE)</td>
</tr>
<tr>
<td>Microbial</td>
<td>Dark fermentation</td>
</tr>
<tr>
<td>Photolytic</td>
<td>Photoelectrochemical and other technologies</td>
</tr>
<tr>
<td>Biomass, biofuels, and organic matter</td>
<td></td>
</tr>
<tr>
<td>Water</td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>Gasification</td>
</tr>
<tr>
<td>Brine</td>
<td>Proton-exchange membrane (PEM)</td>
</tr>
<tr>
<td>Brine</td>
<td>Solid oxide electrolyzer cell (SOEC)</td>
</tr>
</tbody>
</table>

#### Technologies subject to in-depth analysis

- VRE: Use of VRE to produce electricity
- CCS: Optional CCS to reduce carbon footprint

*1 Only for fossil fuels: renewable biomass-based thermochemical production can be considered as green H₂.
Sources: Shell; International Energy Agency; Kearney Energy Transition Institute*
Natural production sources of H₂ have been found at different places but are not exploited

**Description**

- In the 1970s, scientific research highlighted a natural H₂ presence mainly in the following:
  - Mid-ocean ridges and hydrothermal vents, where hydrothermal fluids contain up to 36% of H₂
  - Volcano gases, such as at Etna, Augustin, and Kliuchevskoi, with H₂ concentration varying from 50 to 80%
  - Peridotite mountain waters (Oman, Philippines, and Turkey)
  - Some mines and in very deep wells
  - Hundreds of geological structures emitting H₂ have recently been found in deep oceans, in mountains where oceans used to be million years ago, and in continental crust.
  - Depending on the production site, H₂ is formed differently:
    - In ocean rifts or mountains (which were formerly an ocean), ferrous minerals are oxidized by water to form Fe₃O₄—water is reduced and releases H₂.
    - The origin of H₂ is still unclear for volcanoes.

**Pros**

- Non-polluting, free¹ source

**Cons**

- Unclear view on global resources
- Non-mature exploitation technologies

**Overview**

The only exploited natural source: Mali

**Fact card: Natural H₂ production sources**

**Bourakebougou field**

<table>
<thead>
<tr>
<th>City</th>
<th>Bourakebougou</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discovery</td>
<td>1980</td>
</tr>
<tr>
<td>Operation start</td>
<td>2011</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Exploitation</th>
<th>Hydroma (Petroma)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of reservoirs</td>
<td>5</td>
</tr>
<tr>
<td>Number of wells</td>
<td>18</td>
</tr>
<tr>
<td>Deep (m)</td>
<td>100–1,700</td>
</tr>
<tr>
<td>H₂ content</td>
<td>~98%</td>
</tr>
<tr>
<td>Usage</td>
<td>Electricity and light for about 100 families</td>
</tr>
</tbody>
</table>

**Key features estimates**

- Current cost estimate ($ per kg H₂): Below manufactured H₂
- H₂ emission rate (kg H₂ per day): Up to 2,400 per structure

¹ Depending on factors such as location and available resources, estimates of the exploitation price at the Bourakebougou field are below manufactured hydrogen, either from fossil fuels or electrolysis.

Sources: Afhypac; International Journal of Hydrogen Energy (2018); Kearney Energy Transition Institute
Electrolysis was the first H₂ production technology deployed but was overtaken by fossil fuel-based technologies in the early 1970s.

Sources: Johnson Matthey; Norsk H Hydro/Endo; SRI (2007); FuelCellToday (2013); Afhypac; Royal Society of Chemistry; Kearney Energy Transition Institute
Among production technologies, thermochemical sources benefit from lower cost and high efficiency but are GHG emitters.

### Comparison of H₂ production technologies

<table>
<thead>
<tr>
<th>LCOH 2019, $ per kg</th>
<th>Efficiency kWh per kg</th>
<th>% LHV</th>
<th>Advantages and risks</th>
<th>Feedstock</th>
<th>Emissions</th>
<th>Scalability</th>
<th>Footprint</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Thermochemical sources</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Steam methane reforming (SMR)</td>
<td>0.9–1.8</td>
<td>52</td>
<td>64%</td>
<td>Fossil fuel</td>
<td>Biomass</td>
<td>11 kgCO₂/kgH₂</td>
<td>200 to 500 tpd</td>
<td>n.a.</td>
</tr>
<tr>
<td>Gasification</td>
<td>1.6–2.2</td>
<td>41–47</td>
<td>70–80%</td>
<td>Fossil fuel</td>
<td>Biomass</td>
<td>20 kgCO₂/kgH₂</td>
<td>500 to 800 tpd</td>
<td>n.a.</td>
</tr>
<tr>
<td>Autothermal reforming</td>
<td>n.a.</td>
<td>40–42</td>
<td>78–82%</td>
<td>Fossil fuel</td>
<td>Biomass</td>
<td>9 kgCO₂/kgH₂</td>
<td>500 to 1000 tpd</td>
<td>n.a.</td>
</tr>
<tr>
<td>Pyrolysis</td>
<td>2.2–3.4</td>
<td>47–66</td>
<td>50–70%</td>
<td>Fossil fuel</td>
<td>Biomass</td>
<td>n.a. (lower³)</td>
<td>50 tpd</td>
<td>n.a.</td>
</tr>
<tr>
<td><strong>Electrolysis</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Alkaline electrolysis (AE)</td>
<td>2.6–6.9</td>
<td>48–64</td>
<td>52–69%</td>
<td>Water</td>
<td>Electricity</td>
<td></td>
<td>&lt;70 tpd</td>
<td>200 m²/tpd</td>
</tr>
<tr>
<td>Proton-exchange membrane (PEM) electrolysis</td>
<td>3.5–7.5</td>
<td>43–60</td>
<td>60–77% up to 86%</td>
<td>Water</td>
<td>Electricity</td>
<td></td>
<td>&lt;300 tpd²</td>
<td>50 m²/tpd</td>
</tr>
<tr>
<td>Solid oxide electrolyzer cell (SOEC) electrolysis</td>
<td>5.0–8.5</td>
<td>40–44¹</td>
<td>74–81%¹</td>
<td>Steam</td>
<td>Electricity</td>
<td></td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td><strong>Microbial</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Microbial electrolysis</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
<td>Water</td>
<td>Electricity</td>
<td></td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td>Biomass dark fermentation</td>
<td>n.a.</td>
<td>47</td>
<td>70%</td>
<td>Water</td>
<td>Biomass</td>
<td>-</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td><strong>P.S.</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Photoelectrical synthesis</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
<td>Water</td>
<td>Sunlight</td>
<td>-</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
</tbody>
</table>

¹ Excluding the energy required for heat to vaporize water
² Expected maximum size of PEM electrolyzers
³ Carbon products are mainly solid carbon residues.

**Pros**
- Established technology
- Integration potential with refineries

**Cons**
- High temperature required
- Requires purification by PSA
- CO₂ emissions
- Dependence on natural gas

---

H₂ is separated from CH₄ at a high temperature in a steam methane reformer while producing CO and CO₂

**Description**

- **Step 1: Desulfurization treatment**
  - Natural gas is naturally mixed with sulfur, which is removed thanks to H₂.

- **Step 2: Reforming**
  - CH₄ and high-temperature steam under 3–35 bar pressure are mixed with nickel catalyst to produce H₂, CO, and a small amount of carbon CO₂. Heat for the highly endothermic reaction is provided by burning fuel gas.

\[
(1) \text{CH}_4 + \text{H}_2\text{O} \rightleftharpoons \text{CO} + 3 \text{H}_2 \quad \Delta H = +206 \text{ MJ/kmolCH}_4
\]

- **Step 3: Water–gas shift reaction**
  - The carbon monoxide and steam are then reacted to produce carbon dioxide and more hydrogen in what is known as water–gas shift reaction. Iron-chromium and copper-zinc are used as catalysts.

\[
(2) \text{CO} + \text{H}_2\text{O} \rightleftharpoons \text{CO}_2 + \text{H}_2 \quad \Delta H = -41 \text{ MJ/kmolCH}_4
\]

- **Step 4: Pressure swing adsorption**
  - In the final step, H₂ is separated from the tail gas through a selective adsorption.

\[
(1)+(2) \text{CH}_4 + 2\text{H}_2\text{O} \rightleftharpoons \text{CO}_2 + 4\text{H}_2 \quad \Delta H = 165 \text{ MJ/kmolCH}_4
\]

**Fact card: Steam methane reforming**

- 50% of the H₂ produced comes from water

---

**Key feature estimates**

- **Current cost estimate ($ per kgH₂)**: 0.9–1.9
- **Typical plant size (kgH₂ per day)**: 200,000
- **Feedstock use (kgCH₄ per kgH₂)**: 3.43
- **Water use (L per kgH₂)**: 4.5
- **Operating CO₂ emissions (kgCO₂ per kgH₂)**: 9–12
- **Efficiency (% LHV)**: 64
- **Temperature (°C)**: 750–1,100
- **Purity of H₂**: 99.9%
- **Primary energy source**: Natural gas

---

Gasification is a substoichiometric reaction occurring at a high temperature where fossil fuel is converted to syngas containing mainly H₂ and CO

**Pros**
- Abundant fuel, adaptable to all hydrocarbons, biomass, and waste
- Easy capture of CO₂ from the syngas, especially in integrated gasification combined cycle

**Cons**
- Purification required

---

**Description**

- **Step 1:** Coal (or other feedstock) is heated in a pyrolysis process at 400°C, vaporising volatile component of feedstock in H₂, CO, CO₂, and CH₄.
  - Biomass tends to have more volatile component than coal.
- **Step 2:** Oxygen is added in the combustion chamber, and char undergoes gasification releasing gases, tar vapors, and solid residues.
  - Dominant reaction is a **partial oxidation**: oxygen is at sub-stoichiometric level—at a high temperature (800°–1,800 °C).
    \[ C_nH_m + n/2 O_2 \rightarrow n CO + m/2 H_2 \Delta H = -36 \text{ MJ/kmol} \]
- **Step 3:** Water–gas shift reaction to convert CO in CO₂
  \[ nCO + n H_2O \rightarrow n CO_2 + n H_2 \Delta H = -41 \text{ MJ/kmol} \]
- **Step 4:** Purification through methanation or PSA
  - Operating conditions depend on coal type, properties of resulting ash, gasification technology: high temperature favors H₂/CO, high pressure favors H₂/CO₂.

---

**Fact card: Gasification — partial oxidation**

**Overview of technologies**

<table>
<thead>
<tr>
<th>Gasifier Type</th>
<th>Current cost estimate ($ per kgH₂)</th>
<th>Typical plant size (kgH₂ per day)</th>
<th>Feedstock use (kg coal per kgH₂)</th>
<th>Water use (L per kgH₂)</th>
<th>Operating CO₂ emissions (kgCO₂/kgH₂)</th>
<th>Efficiency (%) LHV</th>
<th>Temperature (°C)</th>
<th>Purity of H₂</th>
<th>Primary energy source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Moving-bed gasifier</td>
<td>1.6–2.2</td>
<td>500.000</td>
<td>8.0</td>
<td>9.0</td>
<td>20</td>
<td>70 – 80%</td>
<td>800 – 1,800 °C</td>
<td>More than 99.5%</td>
<td>Coal, biomass, oil, and gas</td>
</tr>
<tr>
<td>Fluidized-bed gasifier</td>
<td></td>
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<td></td>
<td></td>
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<tr>
<td>Entrained-flow gasifiers</td>
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</tr>
</tbody>
</table>

---

1 Feedstock may include coal, biomass, solid waste, heavy oil, oil sands, oil shale, and petroleum coke.

Autothermal reforming is a combination of an exothermic POX reaction and an endothermic steam reforming.

Fact card: Autothermal reforming (ATR)

Description

- ATR is mainly used with natural gas and combines endothermic reaction of steam reforming and exothermic reaction of oxidation.
- Feedstock, steam, or sometimes carbon dioxide and dioxygen are directly mixed before pre-heating.
- ATR is described with two reaction zones:
  - Combustion zone, where partial oxidation occurs producing a mixture of carbon monoxide and hydrogen (syngas)
  - Catalytic zone where the gas leaving combustion zones reach thermodynamic equilibrium
- Reaction can be described in the following equations:
  - Using steam: \(4 \text{CH}_4 + \text{O}_2 + 2 \text{H}_2\text{O} \rightarrow 4 \text{CO} + 10 \text{H}_2\)
  - Using CO\(_2\): \(2 \text{CH}_4 + \text{O}_2 + \text{CO}_2 \rightarrow 3 \text{CO} + 3 \text{H}_2 + \text{H}_2\text{O} + \text{Heat}\)
- Water–gas shift reaction happens after ATR reaction: \(\text{CO} + \text{H}_2\text{O} \rightleftharpoons \text{CO}_2 + \text{H}_2\)
- \(\text{CO}_2\) at exit is less than in SMR because of a higher operating temperature that restricts exothermic water gas shift reaction.

Pros

- Compact design and low investment
- Variable \(\text{H}_2/\text{CO}\) ratio, fitting gas-to-liquid requiring a 2:1 ratio

Cons

- Non-uniform axial temperature distribution with "hot-spots"
- Fuel evaporation
- Coke formation

Overview of technologies

Key feature estimates

<table>
<thead>
<tr>
<th>Current cost estimate ($ per kg\text{H}_2) w. CCS</th>
<th>n.a.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Typical plant size (kg\text{H}_2 per day)</td>
<td>Up to 1,500,000</td>
</tr>
<tr>
<td>Feedstock use (kg\text{CH}_4/kg\text{H}_2)</td>
<td>2.8</td>
</tr>
<tr>
<td>Water use (L/kg\text{H}_2)</td>
<td>n.a.</td>
</tr>
<tr>
<td>Operating (\text{CO}_2) emissions (kg\text{CO}_2/kg\text{H}_2)</td>
<td>9</td>
</tr>
<tr>
<td>Efficiency (% LHV)</td>
<td>78–82</td>
</tr>
<tr>
<td>Temperature (°C)</td>
<td>980–1200</td>
</tr>
<tr>
<td>Purity of (\text{H}_2)</td>
<td>95.5%</td>
</tr>
<tr>
<td>Primary energy source</td>
<td>Hydrocarbons</td>
</tr>
</tbody>
</table>

Key takeaways

- Syngas has been used for many years for lighting, cooking, and to some extent heating before electric lightning and natural gas infrastructure were deployed.
- During World War II, syngas was used to power cars in Europe as a replacement for gasoline.
- Syngas composition depends on feedstock and the production methods used. Its energy density is half natural gas one.
- Syngas is often used as an intermediate for hydrogen, ammonia, methanol, and liquid fuels production.

Syngas is a mixture of H₂, CO, and other gases that comes out of SMR, ATR, and gasification reactors.

Syngas usual composition per production method (% of volume)

<table>
<thead>
<tr>
<th>Production Method</th>
<th>H₂ %</th>
<th>CO %</th>
<th>CO₂ %</th>
<th>CH₄ %</th>
<th>Others %</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMR (natural gas)</td>
<td>70%</td>
<td></td>
<td>22%</td>
<td>8%</td>
<td>16%</td>
</tr>
<tr>
<td>Reformer (naphtha)</td>
<td>65%</td>
<td>22%</td>
<td>5%</td>
<td>8%</td>
<td>20%</td>
</tr>
<tr>
<td>Gasification (heavy oils)</td>
<td>49%</td>
<td>44%</td>
<td>5%</td>
<td>2%</td>
<td>2%</td>
</tr>
<tr>
<td>ATR (low steam)</td>
<td>40%</td>
<td></td>
<td>39%</td>
<td>21%</td>
<td>1%</td>
</tr>
<tr>
<td>ATR (high steam)</td>
<td>67%</td>
<td></td>
<td>39%</td>
<td>21%</td>
<td>1%</td>
</tr>
</tbody>
</table>

Note: Others include N₂, Ar, H₂S, and COS
Sources: IFP–Afhypac; Kearney Energy Transition Institute
Depending on purity, syngas can either undergo multiple processes to extract H₂ or be converted into liquid fuels.

**Syngas applications**
(Volume for 100 m³ of syngas, % of volume)

### Water–gas shift
\[ CO + H₂O \rightarrow CO₂ + H₂ \]
Residual CO: 1 – 3%

### Pressure swing adsorption
Tail gas (39.9)

### Steam (14.8)

### Syngas (100)
Residual CH₄: 3–8%

### Decarbonation and methanation

#### Water–gas shift
\[ CO + H₂O \rightarrow CO₂ + H₂ \]
Residual CO: 0.3 – 0.8%

#### Decarbonation
Amines (MDEA/MEA)
Residual CO/CO₂ <0.1%

#### Methanation
\[ CO + 3H₂ \rightarrow CH₄ + H₂O \]
\[ CO₂ + 4H₂ \rightarrow CH₄ + 2H₂O \]
Residual CO/CO₂ < 10 ppm
Residual CH₄: 4.4% - 9.4%

### Methanol synthesis
\[ CO + H₂ \rightarrow CH₃OH \]
H₂/CO ratio: 2

### DME synthesis
\[ 2CH₃OH \rightarrow C₂H₆O + H₂O \]

### Gasoline synthesis
Carbon number: 6 to 10

### Gasoline treatment and separation

**Note:** DME is dimethyl ether.
Sources: IFP; Afhypac; Kearney Energy Transition Institute

---

2.1 **Hydrogen value chain - Production technologies**

---

Non-Exhaustive
The H₂/CO ratio has a high impact on end-application performance and potential uses, and controlling it allows greater flexibility.

H₂/CO ratio range per production mean
(% of volume/% of volume, before water–gas shift)

Key comments

- The H₂/CO ratio depends on the feedstock used, operating temperature, and technology.
- Some applications require specific H₂/CO ratio
- In the gas-to-liquid pathway, H₂ and CO react in stoichiometric proportions to produce synthetic fuels. The optimal H₂/CO ratio is 2.
- For pure H₂ applications, syngas requires purification. The higher the H₂/CO ratio, the easier the purification.

Adding steam into the reactor enables higher H₂/CO ratio.

Light oil distillates gasification leads to higher H₂/CO.

SMR

Gasifier

ATR

Sources: IFP–Afhyac; B. Sahoo, N. Sahoo, and U. Saha, Applied Thermal Engineering, 2011; Kearney Energy Transition Institute analysis
Carbon capture and storage (CCS) refers to a set of CO₂ technologies that are put together to abate emissions from stationary CO₂ sources.
**Combining CCS with thermochemical production sources could reduce CO₂ emissions**

### Overview of SMR and CCS options

<table>
<thead>
<tr>
<th>Option</th>
<th>Description</th>
<th>Maturity</th>
<th>Capture rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 a</td>
<td>Capture of CO₂ from shifted syngas with MDEA</td>
<td>MDEA + CO₂ + H₂O ⇌ MDEAH⁺ + HCO₃⁻</td>
<td>State-of-the-art technology, with twice the carrying capacity of MEA</td>
</tr>
<tr>
<td>1 b</td>
<td>Capture of CO₂ from shifted syngas with MDEA with H₂-rich burners</td>
<td>MDEA + CO₂ + H₂O ⇌ MDEAH⁺ + HCO₃⁻</td>
<td>State-of-the-art technology, with twice the carrying capacity of MEA</td>
</tr>
<tr>
<td>2 a</td>
<td>Capture of CO₂ from PSA tailgas with MDEA</td>
<td>MDEA + CO₂ + H₂O ⇌ MDEAH⁺ + HCO₃⁻</td>
<td>State-of-the-art technology, with twice the carrying capacity of MEA</td>
</tr>
<tr>
<td>2 b</td>
<td>Capture of CO₂ from PSA tailgas using low temperature and membrane separation</td>
<td>CO₂ liquefied and purified to food-grade quality</td>
<td>Pilot scale, under deployment</td>
</tr>
<tr>
<td>3</td>
<td>Capture of CO₂ from SMR fuel gas using MEA</td>
<td>MEA + CO₂ ⇌ H₂O + C₅H₇NO₂ - N₂ + H₂O</td>
<td>Standard technology</td>
</tr>
</tbody>
</table>

1 USD = 0.89 €

Sources: International Energy Agency Greenhouse Gas R&D Programme, Global CCS Institute, Air Liquide; Kearney Energy Transition Institute analysis

---

**2.1 Hydrogen value chain - Production technologies**

[Diagram showing the hydrogen value chain with steps for desulfurization, reformer (~900 °C), shift conversion, and CO₂ capture.]

**Hydrogen value chain - Production technologies**

- **Natural gas (CH₄)**
  - Desulfurization
  - Burner (~900 °C)
  - Shift conversion
  - CO₂ capture
  - PSA system
  - Fuel
  - Heat recovery
  - Tail gas
  - Syngas

---

Non-Exhaustive
Pyrolysis requires a lower temperature than other technologies and happens in a vacuum chamber.

**Description**
- Hydrocarbons waste undergoes heating without air combustion to break chemical bonds.\(^1\)
  \[ CH_4 + \text{Heat} \rightarrow C + 2 H_2 \]
- There are four types of pyrolysis:
  - **Slow pyrolysis:** low temperature increase (0.1 to 2°C per second) to reach about 500°C. Residence time of gas over 5 sec per biomass minutes to days. Tar and char are released.
  - **Flash pyrolysis:** rapid heating rate, from 400°C to 600°C. Vapor residence time less than 2 seconds, less gas and tar produced.
  - **Fast pyrolysis:** mainly for bio-oil and gas. Rapid heating from 650 to 1,000°C. Large quantities of char must be removed.
  - **Microwave pyrolysis:** lower time and temperatures required.
- However, hydrogen production yield of 25% makes it difficult to establish a business case for H\(_2\) production.
- Research is focusing on using microwaves to heat crude oil and produce H\(_2\).

**Pros**
- Simple technology
- Low capex
- Graphitic carbon as by-product
- Low to no CO\(_2\) emissions

**Cons**
- Low H\(_2\) content
- Low scalability

---

**Key feature estimates**

| Current cost estimate ($ per kgH\(_2\)) | 2.2–3.4 |
| Typical plant size (kgH\(_2\) per day) | 10,000–50,000 |
| Water use (L/kgH\(_2\)) | – |
| Operating CO\(_2\) emissions (kgCO\(_2\)/kgH\(_2\)) | – |
| Efficiency (% LHV) | 50–70% |
| Temperature (°C) | 200–760 °C |
| Primary energy source | Hydrocarbons |
| Current cost estimate ($ per kgH\(_2\)) | 2.2–3.4 |
| Typical plant size (kgH\(_2\) per day) | 10,000–50,000 |

---

1 Methane pyrolysis is also called methane cracking.
Sources: "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; Afhypac; Kearney Energy Transition Institute analysis
Electrolysis produces H₂ by applying a direct current to an electrolyte solution, which allows high purity of hydrogen

**Description**
- A direct current passes through an ionic substance, producing chemical reactions at the electrodes (cathode and anode) and decomposing materials.
- Electrodes are immersed in electrolyte and separated by a membrane where ions can move.
- Hydrogen ions move toward the cathode to form H₂.
- Receivers collect hydrogen and oxygen in gaseous forms.
- Reactions that happen at anode and cathode in a water electrolysis are:
  - Anode: \( \text{H}_2\text{O} \rightarrow 2\text{H}^+ + \frac{1}{2}\text{O}_2 + 2\text{e}^- \) (E₀ = 1.23V vs. SHE¹)
  - Cathode: \( 2\text{H}^+ + 2\text{e}^- \rightarrow \text{H}_2 \) (E₀ = 0.00V vs SHE¹)
- Overall reaction of water electrolysis is \( \text{H}_2\text{O} \rightarrow \text{H}_2 + \frac{1}{2}\text{O}_2 \) (E₀ = -1.23V vs SHE¹)
- For water electrolysis, approximately 9–15 L of water and 50–60 kWh of electricity are required to produce 1 kg of H₂ and 8 kg of O₂ (depends on technology).

**Pros**
- High purity hydrogen
- Oxygen as a byproduct, often not used
- No dependency on fossil fuels

**Cons**
- More expensive than most of thermochemical solutions
- High emitter of CO₂ if electricity is not clean

---

1 Standard hydrogen electrode
Sources: "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; Kearney Energy Transition Institute analysis
Water alkaline electrolysis is one of the oldest electrolysis technology, used in large-scale projects.

**Description**

- Alkaline technology is a very mature technology thanks to the chlorine industry.
- A strong base with high-mobility ions solution is used as electrolyte: KOH (potassium hydroxide) is normally used to avoid corrosion problems caused by acid electrolytes and because of high conductivity.
- Electrochemical reactions that happen are:
  - Anode: \(2 \text{OH}^- \rightarrow \text{H}_2\text{O} + \frac{1}{2} \text{O}_2 + 2 \text{e}^- (E_0 = 0.40 \text{V vs SHE})\)
  - Cathode: \(2 \text{H}_2\text{O} + 2 \text{e}^- \rightarrow \text{H}_2 + \text{OH}^- (E_0 = -0.83 \text{V vs SHE})\)
- Overall reaction remains similar to the general one.
- Yearly production is about 80-100 MT of Cl\(_2\) and 4 MT of NaClO\(_3\) leading to ~2 MT of H\(_2\) as by-product:
  \[2\text{Cl}^- + 2\text{H}_2\text{O} \rightarrow 2\text{OH}^- + \text{H}_2 + \text{Cl}_2\]
  \[\text{NaCl} + 3\text{H}_2\text{O} \rightarrow 3\text{H}_2 + \text{NaClO}_3\]

**Pros**

- Cheapest option for electrolyzers, with large-scale proven (up to 150 MW)
- Higher durability
- Efficient but only at high temperature

**Cons**

- Low flexibility
- Recovery/recycling of KOH
- Corrosive electrolyte
- Inefficient at high current density
- Maintenance complex

**Key feature estimates**

| Current cost estimate ($ per kgH\(_2\)) | 2.6 – 6.9 |
| Typical plant size (kgH\(_2\) per day) | Up to 70,000 |
| Efficiency (% LHV) | 52 – 69% |
| Temperature (°C) | 60-80 |
| Operating pressure (bars) | 1-30 |
| Current density (A/cm\(^2\)) | 0.3 – 0.5 |
| Purity of H\(_2\) | 99.7% - 99.9% |
| Primary energy source | Electricity |
| Current cost estimate ($ per kgH\(_2\)) | 2.6 – 6.9 |

 PEM is rapidly developing thanks to its compacity, its improved current density and flexibility but requires precious materials

Fact card: Proton exchange membrane (PEM)

Overview of technology

Key feature estimates

Pros

- Low plant footprint, compacity
- Self-pressurized H₂ well-suited for storage facilities
- Short response time (less than 2 seconds)

Cons

- High capex and OPEX
- Presence of platinum for electrodes

---

1 Standard hydrogen electrode

SOEC, the electrolysis of steam, is still in the R&D stage but is more efficient than other electrolysis technologies.

**Description**

- SOEC technology is still at an early stage of development but could benefit from high efficiency.
- SOEC is based on steam water electrolysis at high temperature, reducing needs for electrical power.
- Molar Gibbs energy of the reaction drops from about 1.23 eV (237 kJ/mol) at ambient temperatures to about 0.95 eV at 900 °C (183 kJ/mol).
- High temperature for heat can be obtained from nuclear power or waste heat from industrial process—part of it being already supplied by Joule effect in the cells.
- Heat is only needed to vapor water. Operating point can be chosen slightly exothermic to recycle exhaust gas and heat input gases from 150°C to 700°C without additional electricity.

**Fact card: Solid oxide electrolysis cell (SOEC)**

**Overview of technology**

**Key feature estimates**

<table>
<thead>
<tr>
<th>Feature</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current cost estimate ($) per kgH₂</td>
<td>5.8–7.0</td>
</tr>
<tr>
<td>Typical plant size (kgH₂ per day)</td>
<td>Pilot scale</td>
</tr>
<tr>
<td>Efficiency (% LHV)</td>
<td>74–81%</td>
</tr>
<tr>
<td>Temperature (°C)</td>
<td>650–1,000</td>
</tr>
<tr>
<td>Operating pressure (bars)</td>
<td>1</td>
</tr>
<tr>
<td>Current density (A/cm²)</td>
<td>0.5–1</td>
</tr>
<tr>
<td>Primary energy source</td>
<td>Electricity</td>
</tr>
<tr>
<td>Current cost estimate ($) per kgH₂</td>
<td>5.8–7.0</td>
</tr>
<tr>
<td>Typical plant size (kgH₂ per day)²</td>
<td>Pilot scale</td>
</tr>
</tbody>
</table>

**Pros**

- High efficiency and low electricity consumption

**Cons**

- High temperature required
- Limited flexibility
- Low ceramic membrane lifetime due to extreme operating conditions

---

1 Standard hydrogen electrode

These electrolysis technologies exist with different characteristics which make them suitable for different applications.

# Electrolysis production technologies

<table>
<thead>
<tr>
<th></th>
<th>AE (Alkaline)</th>
<th>PEM</th>
<th>SOEC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating pressure (bar)</td>
<td>1–30</td>
<td>20–60</td>
<td>1</td>
</tr>
<tr>
<td>Operating temperature (°C)</td>
<td>60–80°C</td>
<td>50–80°C</td>
<td>650–1,000°C</td>
</tr>
<tr>
<td>Current density</td>
<td>0.3–0.5 A/cm²</td>
<td>1–3 A/cm²</td>
<td>0.5–1 A/m²</td>
</tr>
<tr>
<td>Load range (% of nominal load)</td>
<td>10–110%</td>
<td>20–100%, up to 160%</td>
<td>20–100%</td>
</tr>
<tr>
<td>System efficiency (% LHV)</td>
<td>52–69%</td>
<td>60–77%</td>
<td>74–81%</td>
</tr>
<tr>
<td>Response time</td>
<td>Start: 1–10 minutes; shut: 1–10 minutes</td>
<td>Start: 1 second–5 minutes; shut: few seconds</td>
<td>High</td>
</tr>
<tr>
<td>Reverse mode (fuel cell mode)</td>
<td>No</td>
<td>No</td>
<td>Depends on design</td>
</tr>
<tr>
<td>Stack lifetime (hours)</td>
<td>60,000–90,000; 100,000–150,000 expected</td>
<td>30,000–70,000 (80,000 achieved by ITM); 100,000–120,000 expected</td>
<td>10,000–30,000, 75,000–100,000 expected</td>
</tr>
<tr>
<td>Expected R&amp;D improvements</td>
<td>Scaling benefits and lower cost of BoP</td>
<td>Scaling benefits, smaller footprint of stack, and lower cost of BoP</td>
<td>Improvement in component lifetime (especially ceramic membrane) by improving resistance to high temperatures</td>
</tr>
<tr>
<td></td>
<td>Improved lifetime of components through R&amp;D</td>
<td>Improvement in materials and components lifetime (such as lower resistance membrane, catalyst coating, and current density) through R&amp;D</td>
<td>Improve response to fluctuating energy inputs</td>
</tr>
</tbody>
</table>

## Pros and cons

|                          | Mature technology with track records of large scale projects but from old alkaline technologies | Highly reactive technology with small land footprint thanks to high current density | High potential of economical benefits if coupled with heat source, geothermal, or CSP |

1 | Depends on design and size  
Note: BoP is balance of plant.  
Dark fermentation is the conversion of organic matter to hydrogen through biochemical reactions.

Description

- Dark fermentation happens in a tank with no light. Bacteria will trigger a series of biochemical reactions.
- Anaerobic bacterial and microalgae react with carbohydrate (refined sugars, raw biomass) and water (even with waste water) to produce H₂ and CO₂.
  \[
  \text{C}_6\text{H}_{12}\text{O}_6 + \text{H}_2\text{O} \rightarrow 2 \text{CH}_3\text{CO}_2\text{H} + 4 \text{H}_2 + \text{CO}_2
  \]
  \[
  \text{C}_6\text{H}_{12}\text{O}_6 + \text{H}_2\text{O} \rightarrow \text{CH}_3\text{CH}_2\text{CH}_2\text{CO}_2\text{H} + 2 \text{H}_2 + 2 \text{CO}_2
  \]
- Operating temperature is mainly between 25 and 40°C even if operations can be conducted at temperature above 80°C.
- Temperature has a significant impact on hydrogen production rate as it affects growth rate of microorganisms. If the temperature exceeds optimum value, it can lead to thermal inactivation of enzymes.
- Dark fermentation is followed by photo fermentation.

Fact card: Dark fermentation

Pros

- Simple reactor design
- Abundant resource
- Scaling issues already addressed by biofuel industry (for fermentation)

Cons

- Low yield of production
- Production of CO₂ and CO requiring a purification step
- Early-stage technology

Key feature estimates

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current cost estimate ($ per kgH₂)</td>
<td>No industrial use yet</td>
</tr>
<tr>
<td>Hydrogen production yield (kgH₂ per kg)</td>
<td>0.03–0.04</td>
</tr>
<tr>
<td>Efficiency (% LHV)</td>
<td>30–40%</td>
</tr>
<tr>
<td>Operating temperature (°C)</td>
<td>25–40</td>
</tr>
<tr>
<td>Primary energy source</td>
<td>Biomass</td>
</tr>
</tbody>
</table>

Sources: Renewable Hydrogen Technologies, Luis M. Gandía, Gurutze Arzamendi, and Pedro M. Diéguez, 2013; Afhypac, Department of Energy; Kearney Energy Transition institute analysis
Microbial electrolysis combines electrical energy with microorganisms activation to produce H₂ with low energy inputs.

**Description**
- Microorganisms are attached to the anode and bacteria consume acetic acid to release e- and protons combining into H⁺ and CO₂.
- A power source provides additional energy (~0.2 V to 0.8 V), below typical water electrolysis technologies (1.23 V – 1.8 V).
- Electrode reactions are as follows:
  - Anode: \( \text{C}_2\text{H}_4\text{O}_2 + 2 \text{H}_2\text{O} \rightarrow 2 \text{CO}_2 + 8 \text{H}^+ + 8 \text{e}^- \)
  - Cathode: \( 8 \text{H}^+ + 8 \text{e}^- \rightarrow 4 \text{H}_2 \)
- Overall, reaction can be summarized as follows: \( \text{C}_2\text{H}_4\text{O}_2 + 2 \text{H}_2\text{O} \rightarrow 2 \text{CO}_2 + 4 \text{H}_2 \)

**Fact card: Microbial electrolysis**

**Overview of technology**

**Key feature estimates**

<table>
<thead>
<tr>
<th>Pros</th>
<th>Cons</th>
</tr>
</thead>
<tbody>
<tr>
<td>– Carbon neutral technology¹</td>
<td>– No comprehensive review on reactor configurations</td>
</tr>
<tr>
<td>– Abundant resource</td>
<td>– Early stage technology</td>
</tr>
<tr>
<td>– Ongoing development of membrane-free reactors with high production rates</td>
<td></td>
</tr>
</tbody>
</table>

| Current cost estimate ($ per kgH₂) | 1.7–2.6 in laboratory conditions |
| Typical plant size (kgH₂ per day) | No industrial use yet |
| Efficiency (% LHV) | About 70% (up to 300% if only considering electrical input) |
| Current density (A/cm²) | \( 8.10^{-4} – 11.10^{-4} \) |
| Primary energy source | Biomass |

¹ Not including emissions from electricity generation
Sources: Alexandria Engineering Journal, 2016; Afhypac; Department of Energy; Kearney Energy Transition institute analysis
Photolytic technologies directly converts sun energy into hydrogen

Fact card: Photolytic conversion technologies

<table>
<thead>
<tr>
<th>Description</th>
<th>Overview of technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>– Microorganisms are attached to the anode and bacteria consume acetic acid to release e- and protons combining into H+ and CO₂.</td>
<td>![Diagram of photolytic technology]</td>
</tr>
<tr>
<td>– A power source provides additional energy (~0.2 V to 0.8 V), below typical water electrolysis technologies (1.23 V – 1.8 V).</td>
<td></td>
</tr>
<tr>
<td>– Electrode reactions are as follows:</td>
<td></td>
</tr>
<tr>
<td>– Anode: ( \text{C}_2\text{H}_4\text{O}_2 + 2 \text{H}_2\text{O} \rightarrow 2 \text{CO}_2 + 8 \text{H}^+ + 8 \text{e}^- )</td>
<td></td>
</tr>
<tr>
<td>– Cathode: ( 8 \text{H}^+ + 8 \text{e}^- \rightarrow 4 \text{H}_2 )</td>
<td></td>
</tr>
<tr>
<td>– Overall, reaction can be summarized as follows:</td>
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</tr>
<tr>
<td>( \text{C}_2\text{H}_4\text{O}_2 + 2 \text{H}_2\text{O} \rightarrow 2 \text{CO}_2 + 4 \text{H}_2 )</td>
<td></td>
</tr>
</tbody>
</table>

Pros

– Can be developed in thin films
– Able to operate at low temperatures
– One-step process, offering cost-reduction potential
– Efficiency rapidly increasing (3% in 2000 vs. 19% in 2018 reached in laboratory)

Cons

– Low lifetime of materials
– Need to protect the semiconductor from water

Sources: Afhypac, ACS Energy; Kearney Energy Transition institute analysis

Key feature estimates

| Current cost estimate ($ per kgH₂) | n.a. (laboratory stage) |
| Typical plant size (kgH₂ per day) | n.a. (laboratory stage) |
| Efficiency (% LHV) | ~15% (max. 23%) |
| Current density (A/cm²) | ~10⁻² |
| Primary energy source | Sunlight |
## Hydrogen midstream value chain

### Purification and conversion
- Hydrogen needs to be purified, either to remove other components from syngas (including CO and CO₂) out of gasifier and reformers or remaining water out of electrolyzer.
- These steps are conducted at the production stage.
- To increase energy density and/or improve stability and safety, hydrogen can be transformed before being stored.
- Compression in gaseous form to increase energy density
- Liquefaction at -252°C to increase energy density
- Material-based transformation, either in liquid form (ammonia and LOHC) or solid form (hydrides) to improve stability and energy density

### Transportation
- Depending on transformation method, hydrogen can be transported by different means.
- Long-distance transportation means include pipelines and vessels, but infrastructure has not yet been deployed.
- Last-mile hydrogen delivery includes road, rail, and pipeline.
- Generally, hydrogen is consumed on-site, requiring short pipeline networks, and when needed is transported by trucks (about 200 kg per truck).
- Hydrogen pipeline network length is around 5,000 km globally, compared with 1.3 million km for natural gas.

### Storage and reconversion
- Depending on the transportation method, hydrogen can be stored in tanks, salt caverns, cans (hydrides only), or a pipeline network (even in natural gas pipelines, up to a limit)¹
- Reconversion might be needed if the new product is not suited for further application.
- Ammonia can be used as feedstock for multiple applications, especially fertilizers.
- LOHC does not have proper application.

---

¹ The limit depends on gas infrastructure and consuming applications connected. Source: Kearney Energy Transition Institute analysis
To increase energy density, hydrogen conditioning is a prerequisite before storage and transport.
Depending on the conversion process, H₂ can be stored and transported in multiple ways.

### H₂ storage and transport

<table>
<thead>
<tr>
<th>Transformation method</th>
<th>Long-distance transportation</th>
<th>Short-distance distribution</th>
<th>Storage</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Pipeline</td>
<td>Tankers</td>
<td>Pipeline</td>
</tr>
<tr>
<td>Physical transformation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compression</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Liquefaction</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chemical combination</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ammonia</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>LOHC</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Hydrides</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Scale</th>
<th>~2,000 km</th>
<th>&gt;3,000 km</th>
<th>&lt;500 km</th>
<th>&lt;1,000 km</th>
<th>Small to mid scale</th>
<th>Small to mid scale</th>
<th>Small scale</th>
<th>Large scale</th>
</tr>
</thead>
</table>

1. Note: LOHC is liquefied organic hydrogen carrier.
There are multiple opportunities to carry hydrogen: either in gaseous, liquid or in another molecule form.

### H₂ conversion and reconversion key facts

<table>
<thead>
<tr>
<th>Material-based</th>
<th>Technology description</th>
<th>Density (kg/m³)</th>
<th>Energy input (kWh/kg H₂)</th>
<th>(% LHV)</th>
<th>Process maturity</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Gas</strong></td>
<td>Compression of H₂ at desired pressure to increase energy density</td>
<td>35</td>
<td>3</td>
<td>-1</td>
<td>-</td>
<td>High</td>
<td>PEM produces H₂ at 35 bars pressure</td>
</tr>
<tr>
<td></td>
<td>150</td>
<td>11</td>
<td>11</td>
<td>&gt;90%</td>
<td>High</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>350</td>
<td>23</td>
<td>-4</td>
<td>&gt;85%</td>
<td>High</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>700</td>
<td>38</td>
<td>-6</td>
<td>80%</td>
<td>High</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Liquefied hydrogen</strong></td>
<td>Cooling of H₂ at -253°C through cryo-compression</td>
<td>71</td>
<td>-9</td>
<td>65-75%</td>
<td>High for small scale, Low for large scale</td>
<td>Economically viable where space is limited and high H₂ demand</td>
<td>High energy losses, esp. compared to LNG conversion, Boil off losses (up to 1% per day)</td>
</tr>
<tr>
<td><strong>Ammonia</strong></td>
<td>Reaction with nitrogen</td>
<td>121</td>
<td>3 kWh/kg at conversion, up to 8 at reconversion</td>
<td>82%-93% at conversion, ~80% at reconversion</td>
<td>High for conversion, medium for reconversion</td>
<td>Mature industry, potential to leverage current infrastructure</td>
<td>Toxicity and air polluter, High energy req. for reconversion</td>
</tr>
<tr>
<td><strong>LOHC to MCH²</strong></td>
<td>Mixing with MCH and converted back to hydrogen</td>
<td>110</td>
<td>Exothermic conversion, ~12 kWh/kg at reconversion</td>
<td>Exothermic conversion, ~65% at reconversion</td>
<td>Medium</td>
<td>No need for cooling</td>
<td>Toxicity and flammability of toluene, Price of toluene, Back-shipping of toluene</td>
</tr>
<tr>
<td><strong>Metal hydrides</strong></td>
<td>Chemical bonding with metals, reheat back to hydrogen</td>
<td>86 (MgH₂)</td>
<td>4</td>
<td>88%</td>
<td>Medium</td>
<td>Lower costs and losses, Higher safety, Higher energy density than compression</td>
<td>Heavy storage unit, Long charging/discharging times, Low lifetime</td>
</tr>
</tbody>
</table>

---

1. PEM produces H₂ at this pressure with no additional need for compressor.
2. 2 Methylcyclohexane (C/TH₁/4)
Trucks are most suited for short distances and small throughputs; pipelines are preferred for point-to-point transport of large quantities.

### Key hydrogen transport methods

<table>
<thead>
<tr>
<th>Storage type</th>
<th>Range (kms)</th>
<th>Key data</th>
<th>Process maturity</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pipe</strong></td>
<td>Compression</td>
<td>1,000–4,000</td>
<td>Low pressure (shorter distances)</td>
<td>High</td>
<td>Lowest-cost option for continuous delivery, Low operation costs - Higher capital costs because of infrastructure requirements</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>High pressure (longer distances)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Trucks</strong></td>
<td>Compression, liquefaction, ammonia</td>
<td>Less than 1,000</td>
<td>n.a.</td>
<td>High</td>
<td>Delivery to multiple locations before they are connected to a pipeline - Lower capacity compared with other options, Boil-off rate requiring rapid delivery of liquid hydrogen</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>n.a.</td>
<td>Medium</td>
<td>Lower operational costs, larger quantities, and distances compared with trucks - Limited route flexibility</td>
</tr>
<tr>
<td><strong>Trains</strong></td>
<td>Compression, liquefaction, ammonia</td>
<td>800–1,100</td>
<td>n.a.</td>
<td>Low</td>
<td>Likely option for exporting huge volumes - Unlikely to use compression storage because of the cost of operation, distance, and lower hydrogen density</td>
</tr>
<tr>
<td><strong>Tankers</strong></td>
<td>Liquefaction, ammonia</td>
<td>More than 4,000</td>
<td>n.a.</td>
<td>High</td>
<td></td>
</tr>
</tbody>
</table>
Pressurized tanks are the most mature and common hydrogen storage technology

Description

– To increase its energy density, hydrogen can be compressed and stored in pressurized vessels, mainly tanks, but also bottles. In general, pressurized tanks operate at pressures ranging from 200 to 700 bar.
– Tanks storage compressed or liquefied hydrogen have high discharge rates and efficiencies, making them appropriate for smaller-scale applications where a local stock of fuel or feedstock needs to be readily available.
– Pressurized tanks need a high operational cycling rate to be economically feasible. If the storage time, relative to the power rating, increases beyond a few days, the capital costs of vessels and compressors become a drawback for this technology.
– Research is continuing with the aim of finding ways to reduce the size of tanks for densely populated areas.

Overview of technology

Outdoor storage infrastructure consisting of bulk storage tank, compression pumps, and gaseous storage tubes

Fact card: Pressurized tanks

Pros

– Mature technology
– Fast charge and recharge time
– Easy to transport

Cons

– Low volumetric and gravimetric density, resulting in large and heavy tanks
– Low storage capacity per vessel

Key feature estimates

<table>
<thead>
<tr>
<th>Current cost estimate</th>
<th>$6,000–$10,000 per MWh (storage tank)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Typical size</td>
<td>100 kWh–10 MWh per tank</td>
</tr>
<tr>
<td>Volumetric density (kWh/m³)</td>
<td>670–1,300</td>
</tr>
<tr>
<td>Efficiency (%)</td>
<td>89–91% (350 bar); 85–88% (700 bar)</td>
</tr>
</tbody>
</table>

Salt caverns, depleted natural gas, or oil reservoirs and aquifers are potential options for large-scale and long-term hydrogen storage.

**Description**

- Hydrogen gas is injected and compressed in underground salt caverns, which are excavated and shaped by injecting water into existing rock salt formations.
- Withdrawal and compressor units extract the gas when required.
- Salt caverns have been used for hydrogen storage by the chemical sector in the United Kingdom since the 1970s and the United States since the 1980s.
- Depleted oil and gas reservoirs are typically larger than salt caverns, but they are also more permeable and contain contaminants.
- Water aquifers are the least mature of the three geological storage options. There is mixed evidence for their suitability, although they were used for years to store town gas with 50–60% hydrogen.

**Pros**

- Allows for high-volume storage at lower pressure and cost
- Seasonal storage
- Low risk of contaminating the stored hydrogen

**Cons**

- Geographical specificity, large size, and minimum pressure requirements
- Less suitable for short-term and smaller-scale storage

**Key feature estimates**

<table>
<thead>
<tr>
<th>Feature</th>
<th>Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current cost estimate ($ per kgH₂)</td>
<td>Less than 0.6</td>
</tr>
<tr>
<td>Typical size</td>
<td>1–1,000 GWh</td>
</tr>
<tr>
<td>Volumetric density (kWh/m³)</td>
<td>65 (at 100 bar)</td>
</tr>
<tr>
<td>Efficiency (%)</td>
<td>90–95%</td>
</tr>
</tbody>
</table>

Compressed hydrogen storage in salt caverns offers the most economic option at discharge durations longer than 20 to 45 hours.

Description

– In the form of compressed gas stored in salt caverns, hydrogen could also become a long-term storage option to balance seasonal variations in electricity demand or generation from renewables.
– However, compressed hydrogen suffers from a low round trip efficiency (60% of the original electricity is lost).
– Other hydrogen-based storage alternatives include:
  – Underground hydrogen storage options, such as pore storage and storage in depleted oil and gas fields
  – Storing hydrogen-based fuels, such as methane, liquid organic hydrogen carriers (LOHCs), and ammonia produced from electricity via electrolysis, in respective storage mediums, including methane (gas grid) and ammonia (steel tanks)
– Prospective customers: utilities

Fact card: Long-term energy storage

Market maturity Early prototype and demonstration
Market size (number of units) 3 salt caverns (United States and United Kingdom)
Future growth Few alternatives for long-duration, large-scale storage
Competing technologies Pumped hydro, batteries, thermo-mechanical storage technologies

H₂ Market trends

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Units</th>
<th>PHES</th>
<th>CAES</th>
<th>Li-ion</th>
<th>Compressed H₂</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capex (power)</td>
<td>$ per kWe</td>
<td>1130</td>
<td>870</td>
<td>95</td>
<td>1820</td>
</tr>
<tr>
<td>Capex (storage)</td>
<td>$ per kWh</td>
<td>80</td>
<td>39</td>
<td>110</td>
<td>0.25</td>
</tr>
<tr>
<td>Opex (power)</td>
<td>$ per kWe</td>
<td>8</td>
<td>4</td>
<td>10</td>
<td>73</td>
</tr>
<tr>
<td>Opex (storage)</td>
<td>$ per kWh</td>
<td>1</td>
<td>4</td>
<td>3</td>
<td>0</td>
</tr>
<tr>
<td>Round-trip efficiency</td>
<td>%</td>
<td>78</td>
<td>44</td>
<td>86</td>
<td>37</td>
</tr>
<tr>
<td>Lifetime</td>
<td>Years</td>
<td>55</td>
<td>30</td>
<td>13</td>
<td>20</td>
</tr>
</tbody>
</table>

Source: Kearney Energy Transition Institute analysis
Liquefying H₂ must be cooled down to -253°C, with potential losses from boil-off

Description
- George Claude’s cycle to liquefy H₂ is a three-step process:
  - H₂ is first cooled with a liquid nitrogen heat exchanger.
  - Then, H₂ is compressed and expanded in adiabatic conditions, which cools down the gas and the system itself.
  - To avoid liquid presence in the system and mechanical troubles, isenthalpic Joule-Thomson expansion allows to recover liquid H₂.
  - As natural H₂ is a mixture of ortho-hydrogen (75%) and para-hydrogen (25%), liquefying transforms all ortho into para-hydrogen, which is an exothermic reaction.
  - In addition to thermal losses as a result of the non-perfect insulation of the system, boil-off also happens because of the reaction heat emissions.

Fact card: Liquefaction of H₂

Pros
- Easy reconversion
- High energy density
- Already used in aerospace industry

Cons
- Flammable
- Not mature for large-scale systems
- Boiling off, with 0.3% to 1% losses per day

Overview of technology

Key feature estimates

<table>
<thead>
<tr>
<th>Feature</th>
<th>Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current cost estimate ($ per kgH₂)</td>
<td>~1.0</td>
</tr>
<tr>
<td>Typical plant size (kgH₂ per day)</td>
<td>5,000–25,000</td>
</tr>
<tr>
<td>Energy required (kWh/kgH₂)</td>
<td>10–13</td>
</tr>
<tr>
<td>Energy consumption (% of LHV of Hydrogen)</td>
<td>20–25%, potential to 18%</td>
</tr>
</tbody>
</table>

Ammonia is synthetized through the Haber–Bosch process and can be reconverted to H₂ or used as a feedstock for fertilizers.

**Description**
- Synthetized through the Haber–Bosch process:
  \[ \text{N}_2 + 3\text{H}_2 \rightarrow 2\text{NH}_3 \quad \Delta H = -92 \text{ kJ/mol} \]
- Reaction temperature is set at about 500°C at 20 MPa to accelerate the reaction.
- The catalyst used is iron and potassium hydroxide.
- At each pass of gases through the reactor, only 15% of N₂ and H₂ are converted to ammonia. Therefore, gases are recycled to increase conversion rate to 98%.

**Pros**
- High hydrogen density
- Low energy requirements
- Mature industry thanks to fertilizers, with existing infrastructures

**Cons**
- Flammable
- Acute toxicity
- Air pollutant
- Corrosive
- Inefficient and non-mature reconversion process

**Fact card: Ammonia conversion**

**Overview of technology**

- **Conversion:** 0.98–1.2
- **Reconversion:** 0.80–1.0

<table>
<thead>
<tr>
<th>Current cost estimate ($ per kgH₂)</th>
<th>Conversion: 0.98–1.2</th>
<th>Reconversion: 0.80–1.0</th>
</tr>
</thead>
<tbody>
<tr>
<td>Typical plant size (kgH₂ per day)</td>
<td>About 200,000</td>
<td></td>
</tr>
<tr>
<td>Energy required (kWh/kgH₂)</td>
<td>Conversion: 2–3</td>
<td>Reconversion: 8</td>
</tr>
<tr>
<td>Energy consumption (% of LHV of hydrogen)</td>
<td>Conversion: 7–18%</td>
<td>Reconversion: Less than 20%</td>
</tr>
</tbody>
</table>

Description

– Hydrogen is loaded on organic liquid through hydrogenation and dehydrogenated at the use point.
– The hydrogenation process releases heat, which can be used for alternative applications or for dehydrogenation if the plant can support both.
– Toluene is a potential carrier for hydrogen by converting it to methylcyclohexane (MCH)
– Dibenzyltoluene (DBT) is an alternative to MCH and is reported to be safer, easier to handle, and cheaper.

Pros

– Liquid in ambient conditions, opportunity to leverage current oil infrastructures
– Fluid carrier reusable
– No boil-off losses

Cons

– MCH is a toxic substance
– Energy intensive for dehydrogenation to reach 250–350°C
– Need to ship back once the carrier has been dehydrogenated

Fact card: Liquefied Organic Hydrogen Carrier (LOHC)

Key feature estimates

<table>
<thead>
<tr>
<th>Feature</th>
<th>Conversion: 1.0</th>
<th>Reconversion: 2.1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current cost estimate ($ per kgH₂)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Typical plant size (kgH₂ per day)</td>
<td></td>
<td>About 10,000</td>
</tr>
<tr>
<td>Energy required (kWh/kgH₂)</td>
<td></td>
<td>Reconversion: about 10</td>
</tr>
<tr>
<td>Energy consumption (% of LHV of hydrogen)</td>
<td>35–40%, potential to 25%</td>
<td></td>
</tr>
</tbody>
</table>

Metal hydrides operate at low pressure and improve hydrogen-handling safety but must still demonstrate their economic feasibility

Fact card: Metal hydrides

**Description**

- Certain metals bind very strongly with hydrogen, forming a metal hydride compound. Under low temperature or at high pressure, hydrogen gas molecules adhere to the surface of the metal and break down into hydrogen atoms, which penetrate the metal crystal to form a solid metal hydride. When the metal hydride is heated, the metal–hydrogen bonds break, and hydrogen atoms migrate to the surface where they recombine into hydrogen molecules.

- To minimize the energy penalty, heat released during absorption can be captured and stored for use during desorption. The combined use of metal hydrides and thermal storage, known as adiabatic metal hydrides, is already on the market.

- Currently, they are being re-examined for niche applications where stability is a key requirement, such as the military.

**Pros**

- Low pressure operation mode implies lower costs and losses.
- Safety than compressed gas / liquified hydrogen
- Larger energy capacity than compressed tanks

**Cons**

- Attaching hydrogen to metal results in a heavy storage unit
- Long charging and discharging times
- Low lifetime

**Overview of technology**

Hydrogenious LOHC reconversion unit

**Key feature estimates**

<table>
<thead>
<tr>
<th>Feature</th>
<th>Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current cost estimate ($ per kgH₂)</td>
<td>NA</td>
</tr>
<tr>
<td>Typical size</td>
<td>10–20 (United States), 1 (UK)</td>
</tr>
<tr>
<td>Volumetric density (kWh/m³)</td>
<td>4,200</td>
</tr>
<tr>
<td>Efficiency (%)</td>
<td>~80-90%</td>
</tr>
</tbody>
</table>

Multiple new H₂ production technologies are being developed, brown technologies being the most mature.

Hydrogen technology maturity curve

- Methane cracking / Pyrolysis
- SOEC
- Microbial electrolysis
- Chemical looping
- Photocatalytic water splitting
- Membrane based / Offshore ammonia synthesis
- Microbial biomass conversion
- Photobiological water splitting
- Electrochemical ammonia synthesis
- Synthetic methane
- CSF
- Metal hydrides
- Blue technology
- SMR with CCS
- PEM
- Green technology
- Alkaline electrolysis
- Chlor-alki electrolysis
- Brown technology
- Coal gasification
- SMR

The levelized cost of hydrogen is an average of two to four times higher for green sources than for hydrocarbon-based solutions.

Estimated LCOH per production technology (2019, $ per kg, average from multiple sources)

Not Exhaustive; Indicative

Note: All hypotheses are detailed in the appendix.
LCOH for thermochemical production sources is driven by fuel costs and capex, accounting for about 96% of total LCOH.

LCOH breakdown: SMR example
($ per kg, purity: 99.5%)

Note: Obtaining higher purity requires further investments that are not detailed in this study. All hypotheses are detailed in the appendix.
Brown H₂ sources can be coupled with CCS to reduce emissions, but LCOH could jump by 64¢ per kg.
Electrolyzer cost is mainly driven by electricity costs and capex

LCOH breakdown - PEM example
($ per kg)

Illustrative

2.3 Hydrogen value chain - Maturity and costs

Note: All hypotheses are detailed in the appendix.
Sources: AREVA H2Gen; Kearney Energy Transition Institute analysis
Two factors can improve electrolysis LCOH: reducing capex and optimizing electricity price and load factor.

- Capex varies with technology and plant size.
- Electrolyzer size is expected to increase driving marginal capex down.

- Spot prices are market dependent, and average prices vary with time.
- REN have a specific functioning point and range.

- Capex highly impacts LCOH when the utilization rate is low.
- Average electricity prices increase with load factor.
- Optimum not at 100% utilization.

**Factors to improve electrolysis LCOH**

**Capex**
- (size and technology)
- Capex varies with technology and plant size.
- Electrolyzer size is expected to increase driving marginal capex down.

**Electricity price**
- (local market)
- Spot prices are market dependent, and average prices vary with time.
- REN have a specific functioning point and range.

**LCOH**
- (load factor and size)
- Capex highly impacts LCOH when the utilization rate is low.
- Average electricity prices increase with load factor.
- Optimum not at 100% utilization.

Note: Other factors include efficiency, operations and maintenance, and stack replacement and are expected to be improved as technology becomes more mature and the system size grows.
Capex relative weight is offset at a high load factor, but LCOH can dramatically increase when utilization is low.

Key comments

- Increasing full load hours decreases the impact of capex on LCOH.
- At 90% utilization rate, increasing capex from $400 per kWe to $1,200 per kWe increases LCOH by $1.10 per kgH₂.
- However, at 10% utilization rate and similar power prices, LCOH jumps by $8.10 per kg for the same capex increase.
- Moreover, marginal capex decreases with the size of the electrolyzer. Economies of scale are achievable in the future.


Hypotheses: Electricity price: $52/MWh, WACC: 8%, lifetime: 20 years

$1 = €0.89
Power price has a high impact on LCOH; securing favorable PPA would improve LCOH.

Reaching a competitive cost of $2 to $3 per kg requires low-cost electricity with high load factors.

LCOH function of electricity price
($ per kg; electricity price: $ per MWh)

Load factor: 89%

90% of hourly spot prices between $31 per MWh and $79 per MWh (France, 2018)

Note: PPA is power purchase agreement. Hypothesis: 1MW, capex: €1,000 per kW.
Minimal LCOH occurs at load factors between 70 and 90%, but the spot price range is too narrow to impact LCOH at a high utilization rate.

Illustrative

2.3 Hydrogen value chain - Maturity and costs

Sources: European Network of Transmission System Operators; Kearney Energy Transition Institute
Upcoming R&D initiatives will help improve the efficiency of applications while reducing LCOH of blue hydrogen.

### Key cost drivers and improvement per technology

<table>
<thead>
<tr>
<th></th>
<th>Steam methane reforming + CCS</th>
<th>Black coal gasification + CCS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Capacity factor</strong></td>
<td>– No change expected</td>
<td>– No change expected</td>
</tr>
<tr>
<td><strong>Scale and capacity</strong></td>
<td>– Secure export offtake agreements</td>
<td>– Successful demonstration at scale</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– Export offtake agreements</td>
</tr>
<tr>
<td><strong>Capex</strong></td>
<td>– Scaling benefits, Process intensification</td>
<td>– R&amp;D process intensification</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– Scaling benefits</td>
</tr>
<tr>
<td><strong>Opex</strong></td>
<td>– Scaling benefits</td>
<td>– Scaling benefits</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– Improvements in build-up of slag and ash</td>
</tr>
<tr>
<td><strong>Efficiency</strong></td>
<td>– R&amp;D process improvements, reused heat, membrane separation</td>
<td>– R&amp;D improvements of purification, ASU, and CO2 removal</td>
</tr>
<tr>
<td><strong>Risk</strong></td>
<td>– Reduced risk of CO₂ capture</td>
<td>– First of kind demonstration</td>
</tr>
<tr>
<td><strong>Cost of capital</strong></td>
<td>– Support for CCS</td>
<td>– Support for CCS</td>
</tr>
</tbody>
</table>

RD&D efforts required to lower LCOH for electrolysers are primarily focused on lowering capital costs and increasing the lifetime of the system.

### Key innovation themes in research and development

**Proton exchange membrane (PEM)**

<table>
<thead>
<tr>
<th>Reduced capital cost</th>
<th>Longer lifetime</th>
<th>Higher efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Increase current density</td>
<td>- Improved catalyst durability</td>
<td>- Thinner membranes</td>
</tr>
<tr>
<td>- Lower loading of platinum group metal catalysts, new and improved catalysts</td>
<td>- Structural improvements in electrodes</td>
<td></td>
</tr>
<tr>
<td>- Improved coating of electrodes</td>
<td>- Higher physical stability of membrane</td>
<td></td>
</tr>
<tr>
<td>- Thinner membranes, advanced chemistry</td>
<td>- Higher impurity tolerance of membrane</td>
<td></td>
</tr>
<tr>
<td><strong>Cell</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Electrochemical pressurization, increased stack size</td>
<td>- Slower H₂ embrittlement through more suitable coating</td>
<td></td>
</tr>
<tr>
<td>- Reduction of titanium use</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Optimized diffusor set-up</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Stack</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Scale up of system components</td>
<td>- Improved water purification</td>
<td>- Higher operating temperatures leading to stack and cooling efficiencies</td>
</tr>
<tr>
<td>- Efficient water purification</td>
<td>- Avoidance of impurity penetration</td>
<td></td>
</tr>
<tr>
<td>- Improved component integration</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Optimized operation set points</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Alkaline polymer systems</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- New low-cost stack designs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Design for high-pressure operation</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>System</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Scale up of system components</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Efficient water purification</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Improved component integration</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Optimized operation set points</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Alkaline polymer systems</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- New low-cost stack designs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Design for high-pressure operation</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Capital cost reduction will become more important as low-cost electricity from renewables becomes possible.

### Mechanism of capital cost reductions - Proton exchange membrane (PEM)

#### Key levers

**Increasing current density**
- High current density allows the stack size to be smaller with increased efficiency. Hydrogen production rate is approximately proportional to the current density.
- Increase up to 3 A/cm² (by 2020) and further (>3A/cm²) through better electrode design, catalyst coatings, and thinner membranes.

**Catalysts**
- Better catalysts can lead to increased current density and reaction rate.
- Reduction in usage of expensive precious metals-based catalysts through the introduction of new and improved catalysts (telluride, nano-catalysts, and mixed metal oxides such as RuOx and IrOx).

**Reduction in titanium use**
- Titanium in bipolar plates (up to 51% of the stack cost) is costly, using a high-conductivity coating on low-cost substrate instead (such as stainless steel).

**Scale-up of system components**
- Enhance combination and scale-up (for example, safe operation with more than 200 cells) of system components due to system design de-risking and increased operational confidence; leads to better system integration and operation at optimized set points.

#### Description

**Impact area: Cell**
- Enhance combination and scale-up (for example, safe operation with more than 200 cells) of system components due to system design de-risking and increased operational confidence; leads to better system integration and operation at optimized set points.

Capex for electrolyzer is expected to dramatically decrease by 2030.

R&D initiatives on AE and PEM could drive capex down to about €400 per kW for both technologies by 2030.

Sources: E4Tech, ITM Power; Kearney Energy Transition Institute
Blue hydrogen and green hydrogen costs are expected to decline and close the gap with brown sources by 2030.

**LCOH evolution**
($ per kg, min–max. average)

<table>
<thead>
<tr>
<th>Blue technologies</th>
<th>Green technologies</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SMR + CCS</strong></td>
<td><strong>Alkaline electrolysis</strong></td>
</tr>
<tr>
<td><strong>Coal gasification + CCS</strong></td>
<td><strong>PEM electrolysis</strong></td>
</tr>
<tr>
<td><strong>SOEC electrolysis</strong></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>2019</th>
<th>2025–30</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Blue</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>SMR + CCS</strong></td>
<td>2.5</td>
<td>1.6</td>
</tr>
<tr>
<td><strong>Coal gasification + CCS</strong></td>
<td>2.5</td>
<td>1.9</td>
</tr>
<tr>
<td><strong>SOEC</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Alkaline electrolysis</strong></td>
<td>6.9</td>
<td>2.6</td>
</tr>
<tr>
<td><strong>PEM electrolysis</strong></td>
<td>7.5</td>
<td>2.2</td>
</tr>
<tr>
<td><strong>SOEC electrolysis</strong></td>
<td>9.6</td>
<td>5.0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>2019</th>
<th>2025–30</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Green</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Alkaline electrolysis</strong></td>
<td>2.6</td>
<td>1.6</td>
</tr>
<tr>
<td><strong>PEM electrolysis</strong></td>
<td>3.5</td>
<td>1.6</td>
</tr>
<tr>
<td><strong>SOEC electrolysis</strong></td>
<td>5.0</td>
<td>2.1</td>
</tr>
</tbody>
</table>

**Brown technologies\(^1\)**

<table>
<thead>
<tr>
<th>Year</th>
<th>2019</th>
<th>2025–30</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SMR + CCS</strong></td>
<td>1.5</td>
<td>1.3</td>
</tr>
<tr>
<td><strong>Coal gasification + CCS</strong></td>
<td>1.9</td>
<td>1.4</td>
</tr>
<tr>
<td><strong>SOEC</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Alkaline electrolysis</strong></td>
<td>2.1</td>
<td></td>
</tr>
<tr>
<td><strong>PEM electrolysis</strong></td>
<td>3.5</td>
<td></td>
</tr>
<tr>
<td><strong>SOEC electrolysis</strong></td>
<td>5.0</td>
<td></td>
</tr>
</tbody>
</table>

Green only if coupled with renewable electricity sources

---

1 AUD = 70¢
1 Thermochmical sources LCOH range

Note: All hypotheses are detailed in the appendix. Ranges are indicative ranges. LCOH highly depends on fossil fuel prices, electricity prices, and asset utilization.

Conversion and reconversion increase LCOH, with compression being the cheapest option but with the lowest energy density once stored.

H₂ conversion and reconversion LCOH, including on-site storage.

Further reduction potential with salt caverns storage.

Improvement opportunities in insulation and vaporization rates.

Scaling benefits.

Note: 1 AUD = 0.7 USD
Transportation costs depend on the hydrogen form, carrier, and distance traveled.

Note: 1 AUD = 70¢

Conversion and transportation of H₂ can double LCOH, which could be avoided with decentralized production sources.

Case study: shipping H₂ from A to B
(2019, $ per kg, base case)

Notes: The main hypotheses are detailed in the appendix. 1 AUD = 70¢
Key hydrogen applications
Some orders of magnitude in 2019

Executive summary

1. Hydrogen’s role in the energy transition

2. Hydrogen value chain: upstream and midstream
   2.1 Production technologies
   2.2 Conversion, storage, and transportation technologies
   2.3 Maturity and costs

3. Key hydrogen applications
   3.1 Overview
   3.2 Feedstock
   3.3 Energy

3. Business models
   4.1 Policies and competition landscape
   4.2 Business cases

Appendix (Bibliography & Acronyms)
### Key hydrogen applications - Overview

<table>
<thead>
<tr>
<th>H2 use</th>
<th>Application areas</th>
<th>End-use application</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Feedstock</strong></td>
<td><strong>Industrial applications</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Oil refining</td>
<td>Sulphur removal, heavy crude upgrade</td>
</tr>
<tr>
<td></td>
<td>Chemicals production</td>
<td>Feedstock for ammonia and methanol</td>
</tr>
<tr>
<td></td>
<td>Iron &amp; steel production</td>
<td>Direct reduction of iron (DRI)</td>
</tr>
<tr>
<td></td>
<td>Food industry</td>
<td>Hydrogenation</td>
</tr>
<tr>
<td></td>
<td>High temperature heat</td>
<td>Fuel gas</td>
</tr>
<tr>
<td><strong>Mobility</strong></td>
<td>Light-duty vehicles</td>
<td>Fuel cells</td>
</tr>
<tr>
<td></td>
<td>Heavy duty vehicles</td>
<td>Fuel cells</td>
</tr>
<tr>
<td></td>
<td>Maritime</td>
<td>Synthetic fuels / Fuel cells</td>
</tr>
<tr>
<td></td>
<td>Rail</td>
<td>Fuel cells</td>
</tr>
<tr>
<td></td>
<td>Aviation</td>
<td>Synthetic fuels / Fuel cells</td>
</tr>
<tr>
<td><strong>Energy</strong></td>
<td>Co firing NH3 in coal power plants</td>
<td>Additional fuel for coal power plant</td>
</tr>
<tr>
<td></td>
<td>Flexible power generation</td>
<td>Combustion turbines / Fuel cells</td>
</tr>
<tr>
<td></td>
<td>Back-up / off-grid power supply</td>
<td>Fuel for fuel cells</td>
</tr>
<tr>
<td></td>
<td>Long-term / large scale energy storage</td>
<td>Energy storage in caverns, tanks,…</td>
</tr>
<tr>
<td><strong>Gas energy</strong></td>
<td>Blended H2</td>
<td>5-20% H2 mixed with CH4</td>
</tr>
<tr>
<td></td>
<td>Methanation</td>
<td>Transformation into CH4</td>
</tr>
<tr>
<td></td>
<td>Pure H2</td>
<td>100% H2 injected on network</td>
</tr>
</tbody>
</table>

Most H₂ today is consumed by the chemicals, oil refining, and steel industries.
Applications will mature at different rates; some of them already have expected commercial maturity per application (2020–2050).

<table>
<thead>
<tr>
<th>Industrial applications</th>
<th>Applications</th>
<th>2020–2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil refining</td>
<td></td>
<td>2022–2024</td>
</tr>
<tr>
<td>Chemicals production</td>
<td></td>
<td>2025–2026</td>
</tr>
<tr>
<td>Iron and steel production</td>
<td></td>
<td>2027–2028</td>
</tr>
<tr>
<td>High-temperature heat</td>
<td></td>
<td>2029–2030</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Mobility</th>
<th>Applications</th>
<th>2020–2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Light-duty vehicles</td>
<td>Forklifts, Berlins, SUVs, City cars</td>
<td>2023–2025</td>
</tr>
<tr>
<td>Heavy-duty vehicles</td>
<td>Buses, Trucks, Coaches</td>
<td>2026–2028</td>
</tr>
<tr>
<td>Maritime</td>
<td>Passenger ships, Merchant navy</td>
<td>2029–2031</td>
</tr>
<tr>
<td>Rail</td>
<td></td>
<td>2032–2034</td>
</tr>
<tr>
<td>Aviation</td>
<td></td>
<td>2035–2037</td>
</tr>
</tbody>
</table>

| Power generation | 2038–2040 |
| Gas energy      | 2041–2044 |

Commercialization start: Market maturity, defined as 1% of total sales.

Sources: Afhypac; Kearney Energy Transition Institute analysis.
Hydrogen consumption could reach 540 Mt per year by 2050, driven by industrial processes and transportation.

Possible hydrogen consumption by 2050 (pure hydrogen, MTH$_2$)

<table>
<thead>
<tr>
<th>Source</th>
<th>Category</th>
<th>2020f</th>
<th>Mobility</th>
<th>Industrial energy</th>
<th>Building heat and power</th>
<th>Industrial feedstock</th>
<th>Power generation and buffering</th>
<th>2050f</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>70</td>
<td>154</td>
<td>112</td>
<td>63</td>
<td>63</td>
<td>154</td>
<td>245</td>
</tr>
<tr>
<td></td>
<td>Mobility</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Industrial energy</td>
<td></td>
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<tr>
<td></td>
<td>Building heat and power</td>
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<td></td>
<td>Industrial feedstock</td>
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<tr>
<td></td>
<td>Power generation and buffering</td>
<td></td>
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<td></td>
</tr>
<tr>
<td></td>
<td>2050f</td>
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</tr>
</tbody>
</table>

- ~400mn cars
- ~20mn trucks
- ~5mn buses
- ~25% of diesel trains replaced
- ~5% of airplanes and freight ships

Key hydrogen applications - Overview

Sources: Hydrogen Council, Kearney Energy Transition Institute analysis
Oil refining is the second main H$_2$ consumption source, with 38 Mt or about 33% of global production used for hydrotreatment and hydrocracking.

### Description

**Hydrotreatment and hydrodesulfurization:**
- 70% of sulfur content in crude oil is removed through this process to reduce SO$_2$ emissions when oil is burned.
- H$_2$S generated is captured and burned in an SRU to form SO$_2$ and elemental sulfur.
- By 2020, new regulations will impose to reduce sulfur content by 40% from 2005 levels.

**Hydrocracking:**
- Hydrocracking is the process to upgrade heavy residual oils into higher-value products — light and distillate with less bonds.
- The majority of H$_2$ is supplied by on-site production sources.

### H$_2$ Market trends

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Mature</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (MtH$_2$/year)</td>
<td>38</td>
</tr>
<tr>
<td>Expected growth (CAGR 19-30)</td>
<td>Less than +1%</td>
</tr>
<tr>
<td>Competing technologies</td>
<td>-</td>
</tr>
</tbody>
</table>

### Overview of technologies

**HDS unit**
- Capacity: 32,000 BPD

**Hydrocracking plant**
- Hydrocracking plant from Yaroslavl Petroleum refinery

### H$_2$ source in oil refining

- On-site production: about 80%
  - Refinery by-product: 38%
  - On-site SMR: 37%
  - On-site coal gasification: 2%
  - External supply: 23%

The chemicals industry consumes about 45 Mt of H₂ a year for ammonia and methanol synthesis.

**Description**

Ammonia synthesis:
- H₂ is combined with N₂ extracted from an air separation unit through the Haber–Bosch process.
  \[ N_2 + 3H_2 \rightarrow 2NH_3 \]
- About 80% of global NH₃ production is used in fertilizer production ((NH₂)₂CO, NH₄NO₃).

Methanol production:
- H₂ is combined with CO and CO₂ to form methanol in a catalytic reaction.
  \[ \text{CO}_2 + 3H_2 \rightarrow \text{CH}_3\text{OH} + H_2O \]
  \[ \text{CO} + 2H_2 \rightarrow \text{CH}_3\text{OH} \]
  \[ \text{CO}_2 + H_2 \rightarrow \text{CO} + H_2O \]
- Methanol can be converted into polymers and hydrocarbon olefins and used as fuel for ICE, even if this technology is in an early stage.

**Fact card: Chemicals industry**


**Overview of technologies**

**Ammonia production**
Ammonia production plant in Slovakia for Duslo

**Methanol production**
Methanol production plant

**H₂ source in chemical industry**

<table>
<thead>
<tr>
<th>Natural gas</th>
<th>Coal</th>
<th>Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>65%</td>
<td>30%</td>
<td>-5%</td>
</tr>
</tbody>
</table>

**H₂ Market trends**

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Mature</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (MTH₂ per year)</td>
<td>44–46</td>
</tr>
<tr>
<td>Expected growth (CAGR 19–30)</td>
<td>+2%</td>
</tr>
</tbody>
</table>

**3.2 Key hydrogen applications - Feedstock**

The steel industry consumes about 13 Mt H₂ per year, 4 of which is dedicated for direct reduction of iron.

**Description: Basic oxygen furnace**
- About 75% of production comes from primary sources where iron ore is converted to steel.
- 90% is made through a blast furnace–basic oxygen furnace (BF–BOF) producing hydrogen as a by-product of coal mixed with other gases, such as CO.
- Global annual production reaches about 14 MTH₂ per year.
- About 65% of this gas is used on-site for various applications (9 MTH₂ year), and the remaining (5 MTH₂ year) is used in other sectors, such as power production and methanol production.

**H₂ Market trends**

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Mature</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (MtH₂/year)</td>
<td>13</td>
</tr>
<tr>
<td>Expected growth (CAGR 19-30)</td>
<td>+6%</td>
</tr>
<tr>
<td>Competing technologies</td>
<td>Recycling of scrap steel (25% of total prod.)</td>
</tr>
</tbody>
</table>

**H₂ source in oil refining**

<table>
<thead>
<tr>
<th>BF–BOF: about 69%</th>
<th>DRI-EAF: ~31%</th>
</tr>
</thead>
<tbody>
<tr>
<td>69%</td>
<td>23%</td>
</tr>
<tr>
<td>8%</td>
<td>SMR Gasif.</td>
</tr>
</tbody>
</table>

**Fact card: Steel industry**


---

**Description: Direct reduction of iron**
- About 75% of production comes from primary sources where iron ore is converted to steel.
- 7% is made through direct reduction of iron-electric arc furnace (DRI–EAF), using H₂ and CO as reducing agent. H₂ is produced in dedicated facilities (SMR/gasification plants) and not as a by-product.

\[ 3 \text{Fe}_2\text{O}_3 + \text{H}_2 \rightarrow 2\text{Fe}_3\text{O}_4 + \text{H}_2\text{O} \]
\[ \text{Fe}_3\text{O}_4 + 2\text{H}_2 \rightarrow 3 \text{FeO} + \text{H}_2\text{O} \]
\[ \text{FeO} + \text{H}_2 \rightarrow \text{Fe} + \text{H}_2\text{O} \]

3.2 Key hydrogen applications - Feedstock
Adopting low carbon energy sources and reducing agents, such as Hydrogen, can help decarbonize steel production.

Fact card: Steel industry

Hydrogen based Direct Reduction proposed process design

Use of Hydrogen to lower emissions

- To reduce carbon emissions in steel making, two fundamental options include
  - continued use of fossil fuels but with carbon capture and storage (CCS)
  - the use of renewable electricity for producing hydrogen as reduction agent or directly in (yet undeveloped) electrolytic processes
- Blast furnace – basic oxygen furnace (BF/BOF) production route, which is the dominant production pathway currently, relies on the use of coking coal making it difficult to switch to other reduction agents in the blast furnace
- Key concept is to use a hydrogen direct reduction process to produce direct reduced iron (DRI) which is then converted to steel in an electric arc furnace (EAF)
- Ideally Hydrogen should be produced from renewable sources. However, as an intermediate solution, fossil fuels (mainly natural gas) are used to produce Hydrogen until sufficient carbon free electricity will be available at competitive prices

Sources: Assessment of hydrogen direct reduction for fossil-free steelmaking (Vogi, Ahman, Nilsson 2018), Steel Institute VDEh
Currently 100% Hydrogen based steel production is not cost competitive compared to the more established alternatives.

The economic viability of the hydrogen-based steel production pathways is highly dependent on the low cost clean electricity or higher carbon prices.

1. BF = Blast furnace, DRI = Direct reduced Iron, EAF = Electrical arc furnace, Oxy. SR-BOF = oxygen-rich smelt reduction, CCUS = Carbon capture and storage
2. Hisarna project
3. HYBRIT project for 100% Hydrogen DRI - EAF

Demand for dedicated Hydrogen production in steel is expected to grow at a rapid pace over the next decade.

Without any policy intervention and projecting on the current trends, the demand for dedicated hydrogen production (derived chiefly from natural gas) in steel-making is expected to track growth of gas based DRI-EAF production route.

- DRI-EAF tends to be deployed in geographies with low natural gas prices (i.e. Middle East) or low coal price (i.e. India) and could supply 14% of primary steel demand by 2030.

- For an accelerated rate of emission reduction in steel making process, the following technological breakthroughs are required which would further increase the demand for hydrogen:
  - 30% of the natural gas consumed in DRI-EAF to be replaced by hydrogen produced from electrolysis (renewable sources)
  - Commercial-scale 100% Hydrogen based DRI-EAF plant by 2030

Based on trends in total crude steel production, the split between primary & secondary steel production and the share of the DRI-EAF route in primary steel production:

1. Assumption - share of secondary production in total steel production in 2030 = 25%, gas based DRI maintains current growth in primary production
2. Assumption - share of secondary production in total steel production in 2050 = 29%, gas based DRI accounts for 100% primary production

Among Fuel Cells, PEM seems to be the most promising fuel cell technology, with the widest range of application and demonstrated high-power efficiency.

### Fuel cell technologies comparison

<table>
<thead>
<tr>
<th>Technology</th>
<th>Temperature</th>
<th>Slack size</th>
<th>Electrical performance (LHV)</th>
<th>Current applications</th>
<th>Advantages</th>
<th>Challenges</th>
<th>Improvement potential</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer electrolyte membrane (PEM)</td>
<td>&lt;120°C</td>
<td>1-100kW</td>
<td>60%</td>
<td>☑ ☑ ☑ ☑</td>
<td>Low corrosion and electrolyte management, Low temperature, Quick start-up and load following</td>
<td>Expensive catalysts, Sensitive to fuel impurities</td>
<td>↑</td>
</tr>
<tr>
<td>Alkaline (AFC)</td>
<td>&lt;100°C</td>
<td>1-100kW</td>
<td>60%</td>
<td>☑ ☑ ☑ ☑</td>
<td>Lower cost components, Low temperature, Quick start-up</td>
<td>Sensitive to CO₂ in fuel and air, Electrolyte management (aqueous), Electrolyte conductivity (polymer)</td>
<td>→</td>
</tr>
<tr>
<td>Phosphoric acid (PAFC)</td>
<td>&lt;150 – 200°C</td>
<td>5-400kW</td>
<td>40%</td>
<td>☑ ☑ ☑</td>
<td>Suitable for CHP, Increased tolerance to fuel impurities</td>
<td>Expensive catalysts, Long start-up time, Sulfur sensitivity</td>
<td>→</td>
</tr>
<tr>
<td>Molten carbonate (MCFC)</td>
<td>600-700°C</td>
<td>300kW – 3MW</td>
<td>50%</td>
<td>☑ ☑</td>
<td>High efficiency, Fuel flexibility, Suitable for CHP, Hybrid–gas turbine cycle</td>
<td>High temperature, Long start-up time, Low power density</td>
<td>→</td>
</tr>
<tr>
<td>Solid oxide (SOFC)</td>
<td>500-1000°C</td>
<td>1kW-2MW</td>
<td>60%</td>
<td>☑ ☑</td>
<td>High efficiency, Fuel flexibility, Solid electrolyte, Suitable for CHP, Hybrid/ gas turbine cycle</td>
<td>High temperature, Long start-up time, Limited number of shutdowns</td>
<td>→</td>
</tr>
</tbody>
</table>

3.3 Key hydrogen applications – Energy (fuel cells)

Sources: US Department of Energy, 2015; Kearney Energy Transition Institute analysis
Fuel cell is a reverse electrolysis in which $H_2$ is combined with $O_2$ to produce electricity, heat, and water.

**Description**

- Fuel cells are made of an anode and a cathode in an electrolyte solution.
- Fuel-cell reaction can be described as:
  $$H_2 + \frac{1}{2}O_2 \rightarrow H_2O + We + \Delta Q$$
  where $We$ is electrical power and $\Delta Q$ heat generated.
- Fuel cells generate DC current. An AC/DC converter might be needed depending on the end application.
- As for electrolyzer, there are multiple categories of fuel cells based on the electrolyte and electrodes used:
  - AFC is the oldest available technology, but efforts are now focusing on PEMFC used in electric vehicles.
  - Microbial fuel cells are being developed, based on bacteria metabolism.
- Application types for fuel cells can be portable (consumer electronics), mobile (vehicles), or stationary.

**H$_2$ Market trends**

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Depend on technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (MW per year)</td>
<td>+1,000 (about 75% for mobility)</td>
</tr>
<tr>
<td>Historical growth (CAGR 10–17)</td>
<td>+33% in MWe</td>
</tr>
</tbody>
</table>

**Key hydrogen applications – Energy (fuel cells)**

- Electricity production sources
- Internal combustion engines

**Overview of Technology**

<table>
<thead>
<tr>
<th>Type</th>
<th>Anode and cathode</th>
<th>Ions</th>
</tr>
</thead>
<tbody>
<tr>
<td>AFC</td>
<td>Pt/Pl–Ag</td>
<td>OH$^-$</td>
</tr>
<tr>
<td>PEMFC</td>
<td>Pt/Pt</td>
<td>H$^+$</td>
</tr>
<tr>
<td>PAFC</td>
<td>Pt/Pl</td>
<td>H$^+$</td>
</tr>
<tr>
<td>MCFC</td>
<td>Ni/Ni–LiO</td>
<td>CO$_3^{2-}$</td>
</tr>
<tr>
<td>SOFC</td>
<td>Ni-YSZ/ La$<em>x$Sr$</em>{1-x}$MnO$_3$</td>
<td>O$_2^-$</td>
</tr>
<tr>
<td>PCFC</td>
<td>Perovskite/ Pr$_2$NiO$_4$</td>
<td>H$^+$</td>
</tr>
</tbody>
</table>

**Fact card: Fuel cell**

- Sources: Afhyoaс, Areva; Kearney Energy Transition Institute analysis

---

3.3 Key hydrogen applications – Energy (fuel cells)

- Efficiency (%) 55–60%
- Power (W/cm$^2$) 0.3–0.4
- Lifecycle (hours) Up to 100,000
- Compacity (kW/kg) About 3
- Capex (€ per kWe) 500–1,000
Alkaline fuel cells were one of the first fuel cell technologies.

**Description**

- Alkaline fuel cell (AFC) uses a solution of potassium hydroxide in water as the electrolyte and can use a variety of non-precious metals as a catalyst at the anode and cathode.
- Fuel cell reaction can be described as:
  \[ 2\text{H}_2 + \text{O}_2 \rightarrow 2\text{H}_2\text{O} \]
- The high performance of AFC is due to the rate at which electro-chemical reactions take place in the cell.
- Closely related to polymer electrolyte membrane (PEM) fuel cells, except they use an alkaline membrane instead of an acid membrane.
- Suffers from the poisoning by CO₂, which can be addressed through alkaline membrane fuel cells (AMFC).
- However, CO₂ still affects performance, and performance and durability of the AMFCs still lag that of PEMFC.
- Key application areas: military, space, backup power, and transportation.

**Fact card: Alkaline fuel cell**

**Sources:**

### Key features

<table>
<thead>
<tr>
<th>Efficiency (%)</th>
<th>60%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating temperature (°C)</td>
<td>Less than 100</td>
</tr>
<tr>
<td>Typical stack size</td>
<td>1–100 kW</td>
</tr>
<tr>
<td>Common electrolyte</td>
<td>Aqueous potassium hydroxide soaked in a porous matrix or alkaline polymer membrane</td>
</tr>
<tr>
<td>Anode/Cathode</td>
<td>PT / Pt-Ag</td>
</tr>
</tbody>
</table>

### Advantages

- Wider range of stable materials allows lower cost components
- Low temperature
- Quick start-up

### Disadvantages

- Sensitive to CO₂ in fuel and air
- Electrolyte management (aqueous)
- Electrolyte conductivity (polymer)
Polymer electrolyte membrane fuel cells deliver high power density and lower weight and volume

**Description**

- Polymer electrolyte membrane (PEM) fuel cell uses solid polymer as an electrolyte and porous carbon electrodes containing a platinum or platinum alloy catalyst.
- Fuel cell reaction can be described as:
  \[ \text{H}_2 \rightarrow 2\text{H}^+ + 2\text{e}^- \]
- PEM fuel cells exhibit high efficiency and power density in vehicle engine size class.
- Among different fuel cells, PEM fuel cell has been found to be most suitable for automobiles end use.
- Hybrid vehicle can be run by pairing PEMFC with rechargeable batteries.
- A variant that operates at elevated temperatures is known as the high-temperature PEMFC (HT PEMFC) as electrolyte shifts to a mineral acid-based system from water-based.
- Key application areas: backup power, portable power, distributed generation, transportation, and specialty vehicles.

**Advantages**

- Solid electrolyte reduces corrosion and electrolyte management issues
- Low temperature
- Lower weight and volume
- Quick start-up and load following

**Disadvantages**

- Expensive platinum catalyst that is sensitive to CO poisoning
- Requires cooling

**Key features**

| Key hydrogen applications – Energy (fuel cells) | 3.3 |

**Sources:** US Department of Energy; Kearney Energy Transition Institute analysis
Phosphoric acid fuel cell is one of the most mature cell types and the first to be used commercially.

**Description**

- Phosphoric acid fuel cells (PAFC) use liquid phosphoric acid as an electrolyte—the acid is contained in a Teflon-bonded silicon carbide matrix—and porous carbon electrodes containing a platinum catalyst.
- Fuel cell reaction can be described as:
  \[ H_2 + \frac{1}{2} O_2 \rightarrow H_2O \]
- Typically used for stationary power generation, but some PAFCs have been used to power large vehicles:
  - More than 85% efficient when used for the co-generation of electricity and heat but they are less efficient at generating electricity alone (37–42%)
  - PAFCs are also less powerful than other fuel cells, given the same weight and volume.
- Key application areas: Distributed generation and heavy vehicle transport, such as public buses.

**Fact card: Phosphoric acid fuel cell**

**Advantages**

- Suitable for CHP
- Increased tolerance to fuel impurities

**Disadvantages**

- Expensive catalysts
- Long start-up time
- Sulfur sensitivity

**Key features**

| Efficiency (%) | 40% |
| Operating temperature (°C) | 150–200 |
| Typical stack size | 5–400 kW |
| Common electrolyte | Phosphoric acid soaked in a porous matrix or imbibed in a polymer membrane |
| Anode/Cathode | Pt / Pt |

Sources: US Department of Energy; Kearney Energy Transition Institute analysis

---

**Overview of Technology**

**Phosphoric Acid Fuel cell principle**

**2D model of PAFC**

**3.3 Key hydrogen applications – Energy (fuel cells)**
Molten carbonate fuel cells are being developed for natural gas and coal-based power plants for electrical utility applications.

**Description**
- Molten carbonate fuel cells (MCFC) use a molten carbonate salt suspended in a porous ceramic matrix as the electrolyte.
- Fuel cell reaction can be described as:
  \[ H_2 + \frac{1}{2}O_2 \rightarrow H_2O \]
- When coupled with a turbine, MCFC can reach efficiencies approaching 65%.
  - Overall efficiencies can be more than 85% in CHP or CCP applications where the process heat is also utilized.
- Unlike alkaline, phosphoric acid, and PEM fuel cells, MCFC do not require an external reformer to convert fuels such as natural gas and biogas to hydrogen.
- As they operate at high temperatures, non-precious metals can be used as catalysts reducing costs.
- Key application areas: electric utility and distributed generation

**Advantages**
- High efficiency
- Fuel flexibility
- Suitable for CHP, hybrid–gas turbine cycle

**Disadvantages**
- High temperature corrosion and breakdown of cell components
- Long start-up time
- Low power density

**Key features**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Efficiency (%)</td>
<td>50%</td>
</tr>
<tr>
<td>Operating temperature (°C)</td>
<td>600–700</td>
</tr>
<tr>
<td>Typical stack size</td>
<td>300 kW–3 MW</td>
</tr>
<tr>
<td>Common electrolyte</td>
<td>Molten lithium, sodium, and/or potassium carbonates, soaked in a porous matrix</td>
</tr>
<tr>
<td>Anode/Cathode</td>
<td>Ni / Ni – LiO</td>
</tr>
</tbody>
</table>

**Fact card: Molten carbonate fuel cell**

Sources: US Department of Energy; Kearney Energy Transition Institute analysis

---

**Overview of Technology**

Molten carbonate fuel cell principle
**Description**

- Solid oxide fuel cells (SOFC) use a hard, non-porous ceramic compound as the electrolyte.
- Fuel cell reaction can be described as:
  \[
  \text{CO} + \text{O}_2 + \text{H}_2 \rightarrow \text{H}_2\text{O} + \text{CO}_2 + \Delta E
  \]
- SOFCs are around 60% efficient at converting fuel to electricity.
- In applications designed to capture and utilize the system's waste heat (co-generation), overall efficiencies could be more than 85%.
- High-temperature operation removes the need for precious-metal catalyst reducing costs, but development of low-cost materials with high durability remains a challenge.
- SOFC are not poisoned by carbon monoxide, and this allows them to use natural gas, biogas, and gases made from coal.
- Key application areas: auxiliary power, electric utility, and distributed generation.

**Advantages**

- High efficiency
- Fuel flexibility
- Sulfur resistant
- Suitable for CHP, Hybrid/gas turbine cycle

**Disadvantages**

- High temperature corrosion and breakdown of cell components
- Long start-up time

**Key features**

- Efficiency (%): 60%
- Operating temperature (°C): 500–1,000
- Typical stack size: 1 kW–2 MW
- Common electrolyte: Yttria stabilized zirconia
- Anode/Cathode: Ni-YSZ / La$_{0.5}$Sr$_{0.5}$MnO$_3$

**Fact card: Solid oxide fuel cell**

- Key hydrogen applications – Energy (fuel cells)

Sources: US Department of Energy; Kearney Energy Transition Institute analysis
Fuel cell research is focused on achieving higher efficiency, increased durability, and reduced costs.

Technical targets and system cost reduction projections for 80 kWe (net) integrated transportation fuel cell power systems operating on direct hydrogen:\(^1,2\)

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak energy efficiency (%)</td>
<td>140</td>
<td>110</td>
<td>65</td>
<td>59</td>
<td>60</td>
<td>49</td>
<td>50</td>
<td>40</td>
</tr>
<tr>
<td>Power density (W/L)</td>
<td>640</td>
<td>650</td>
<td>850</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Specific power (W/kg)</td>
<td>659</td>
<td>650</td>
<td>650</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Durability (hours)</td>
<td>3,900</td>
<td>5,000</td>
<td>8,000(^2)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1 Polymer electrolyte membrane (PEM) fuel cell-based systems
2 8,000 hours (equivalent to 150,000 miles of driving) with less than 10% loss of performance

Sources: US Department of Energy Fuel Cell Technologies Office; Kearney Energy Transition Institute analysis
Reducing costs and improving durability while maintaining performance continues to be a key challenge

Catalyst developments are crucial to future fuel cell technology

3.3 Key hydrogen applications – Energy (fuel cells)

### Fuel cell R&D funding

<table>
<thead>
<tr>
<th>Year</th>
<th>Catalyst and electrodes</th>
<th>Performance and durability</th>
<th>Testing and technical assessment</th>
<th>Membrane and electrolytes</th>
<th>Membrane electrode assembly, cells, and stack components</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018</td>
<td>44%</td>
<td>12%</td>
<td>3%</td>
<td>23%</td>
<td>19%</td>
</tr>
</tbody>
</table>

1 US Department of Energy Fuel Cell R&D subprogram budget

Sources: US Department of Energy Fuel Cell Technologies Office; Kearney Energy Transition Institute analysis
Bikes powered by fuel cells offer an easy mobility option for intra-city travel

Description

– Fuel-cell electric bikes use stored compressed hydrogen gas cylinders as a fuel source to generate electricity via an energy converter (fuel cell) to power an electric motor but still needs human muscular energy to be in motion. Hydrogen cylinders can be purchased from refueling stations and other retail outlets.

– Benefits:
  – Lower battery size, superior operability at low temperatures, longer range, and shorter refueling time compared with battery-powered bikes
  – No emissions of pollutants and greenhouse gases
  – Prospective customers: private consumers, bike-sharing operators and rental providers, tourism players, last-mile delivery specialists, corporate staff mobility, and municipalities

Fact card: Hydrogen bike

H₂ Market trends

<table>
<thead>
<tr>
<th></th>
<th>Advanced prototype/demonstration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market maturity</td>
<td>Advanced prototype/demonstration</td>
</tr>
<tr>
<td>Market size (number of units)</td>
<td>More than 200 in France</td>
</tr>
<tr>
<td>Future growth</td>
<td>Multiple orders of hundreds of bikes expected in European cities</td>
</tr>
<tr>
<td>Competing technologies</td>
<td>Electric bikes</td>
</tr>
</tbody>
</table>

Key features

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Power output (kw)</td>
<td>0.1–0.25</td>
</tr>
<tr>
<td>Fuel consumption (Kg H₂/100 km)</td>
<td>.035</td>
</tr>
<tr>
<td>Range (km)</td>
<td>100–150</td>
</tr>
<tr>
<td>Capex/acquisition cost ($)</td>
<td>5,000–7,500</td>
</tr>
<tr>
<td>Lifetime (years)</td>
<td>5</td>
</tr>
</tbody>
</table>

Source: Kearney Energy Transition Institute analysis
Scooters and bikes powered by fuel cells offer emission-free and low-noise mobility options for intra-city travel

Description

- H₂ is stored in compressed tanks and then converted into electricity through a PEMFC, powering an electrical motor.
- Refueling of a compressed H₂ tank is performed in dedicated stations.
- The latest research focuses on metal hydrides, where H₂ is stored as a powder in 2 cans, which facilitate refueling as no H₂-dedicated infrastructure is needed.
- H₂ can be bought in petrol stations and supermarkets.
- Metal hydrides are easy to refuel and can operate at low temperature but are more expensive.
- H₂ scooters offer multiple benefits, such as no pollutant emissions, lower noise, and operability at low temperatures.
- Potential users include private consumers, company and public entity fleets, or vehicle sharing companies.
- Large-scale deployment will require refueling infrastructure and compliance with local regulations.

Fact card: Hydrogen scooter

Sources: The Fuel Cells and Hydrogen Joint Undertaking (FCH JU); Kearney Energy Transition Institute analysis

<table>
<thead>
<tr>
<th>H₂ Market trends</th>
<th>Deployment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market maturity</td>
<td>More than 100, demonstration projects in Europe (such as the ZERE project in the United Kingdom)</td>
</tr>
<tr>
<td>Market size (number of vehicles)</td>
<td>Public services to lead the demand due to high price premiums</td>
</tr>
<tr>
<td>Expected growth (CAGR 19–XX)</td>
<td></td>
</tr>
<tr>
<td>Competing technologies</td>
<td>Petrol and diesel, battery EV, compressed natural gas (CNG)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Key features</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel consumption (gH₂/km)</td>
</tr>
<tr>
<td>Range (km/tank)</td>
</tr>
<tr>
<td>Lifetime (years)</td>
</tr>
<tr>
<td>Capex/acquisition cost ($)</td>
</tr>
<tr>
<td>Output (kW)</td>
</tr>
</tbody>
</table>

3.2 Key hydrogen applications – Energy (mobility)
Fork lifts powered by fuel cells are already in use since they don’t need capex-intensive infrastructure for recharging.

Fact card: Hydrogen forklift

Description

- Forklifts use gaseous hydrogen compressed in a 350 bars tank.
- Hydrogen is then converted into electricity through a fuel cell—electric engine system.
- Potential users include logistics companies, warehouses, and other industrial plants.
- A hydrogen forklift does not release toxic gases during operations, which makes it a candidate for indoor operations.
- Tanks are recharged every eight hours. Quick refueling time (less than three minutes) allows operation continuity for industrial users.
- Performances are maintained even when the tank is half depleted.
- The operating perimeter is relatively limited. Single refueling stations with multiple plants can be enough to supply hydrogen.

H₂ Market trends

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Commercialization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (number of vehicles)</td>
<td>25,000</td>
</tr>
<tr>
<td>Expected growth (CAGR 19–XX)</td>
<td>n.a.</td>
</tr>
</tbody>
</table>

| Competing technologies | Petrol and diesel, battery EV, compressed natural gas (CNG) |

<table>
<thead>
<tr>
<th>Key features</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel consumption (kgH₂ per hour)</td>
</tr>
<tr>
<td>Range (km per tank)</td>
</tr>
<tr>
<td>Capex/acquisition cost ($)</td>
</tr>
<tr>
<td>Output (kW)</td>
</tr>
<tr>
<td>Fuel consumption (kgH₂ per hour)</td>
</tr>
</tbody>
</table>


3.2 Key hydrogen applications – Energy (mobility)
Fuel-cell hydrogen cars are commercially available as an alternative to diesel-based internal combustion engine cars.

**Description**

- As with scooters, H₂ is stored in compressed tanks (700 bars) and then converted into electricity through a PEM fuel cell, powering an electrical motor and refueled in dedicated stations.
- A rechargeable (Li–ion or lead–acid) battery is added to provide additional power for the engine—mainly for regenerative braking and acceleration (1.6–9 kWh capacity).
- H₂ stored in metal hydride cans is also under development (a car requiring about nine cans), which could offset a low number of refueling stations.
- H₂ cars offer multiple benefits, such as no pollutant emissions, lower noise, and operability at low temperatures.
- Potential users include private consumers, company and public entity fleets, or vehicle-sharing companies.
- Large-scale deployment will require refueling infrastructure and compliance with local regulations, especially on tank safety.

**Fact card: Hydrogen car**

- **Market maturity**: Commercialization
- **Market size (number of vehicles)**: 11,200
- **Expected growth (CAGR 2025f)**: 18% (+56% 17–18)
- **Capex/acquisition cost ($)**: 56,000–86,000
- **Output (kW)**: 70–130 kW

**H₂ Market trends**

<table>
<thead>
<tr>
<th>Key features</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel consumption (kgH₂/100km)</td>
<td>0.8–1.0</td>
</tr>
<tr>
<td>Range (km per tank)</td>
<td>500–700</td>
</tr>
<tr>
<td>Lifetime (years)</td>
<td>5</td>
</tr>
<tr>
<td>Capex/acquisition cost ($)</td>
<td>56,000–86,000</td>
</tr>
<tr>
<td>Output (kW)</td>
<td>70–130 kW</td>
</tr>
</tbody>
</table>

**Key hydrogen applications – Energy (mobility)**

Vans and utility trucks powered by fuel cells can be used for short-distance, cyclical trips.

### Key features
- Vans can also be equipped with a H₂ tank–PEM fuel cell–Li-ion battery–electric motor combination.
- Battery packs have a 22 to 80 kWh capacity (vans).
- Potential users include company fleets (such as parcel delivery companies) and public fleets (such as garbage trucks and sweepers).
- Large-scale deployment will require refueling infrastructure and compliance with local regulations, especially on tank safety.
- However, because of the cyclical nature of trips, a refueling station for public applications could be centralized and shared between all city vehicles.
- Hydrogen–diesel hybrid trucks are also commercialized, where H₂ is powering non-vital applications, such as for garbage trucks or a power box for a loader and compactor.

### Overview of technologies

#### Description
- Vans can also be equipped with a H₂ tank–PEM fuel cell–Li-ion battery–electric motor combination.
- Battery packs have a 22 to 80 kWh capacity (vans).
- Potential users include company fleets (such as parcel delivery companies) and public fleets (such as garbage trucks and sweepers).
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- However, because of the cyclical nature of trips, a refueling station for public applications could be centralized and shared between all city vehicles.
- Hydrogen–diesel hybrid trucks are also commercialized, where H₂ is powering non-vital applications, such as for garbage trucks or a power box for a loader and compactor.

### Fact card: Hydrogen van


<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Deployment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (number of vehicles)</td>
<td>About 100 vans</td>
</tr>
<tr>
<td>Expected growth (CAGR 2019f)</td>
<td>n.a.</td>
</tr>
<tr>
<td>Competing technologies</td>
<td>Petrol and diesel, petrol and diesel-electric hybrid, battery powered vans</td>
</tr>
</tbody>
</table>

| Fuel consumption (kgH₂/100km) | 3–9 |
| Range (km per tank) | 300–400 |
| Capex/acquisition cost ($) | n.a. |
| Output (kW) | 45–150 kW |
| Total cost of ownership ($ per km) | n.a. |

### Key hydrogen applications – Energy (mobility)
Hydrogen buses powered by fuel cells are a zero-emission alternative to diesel buses

**Description**

- Fuel-cell electric buses, including hybrids with range extenders, use compressed hydrogen gas as a fuel to generate electricity via the fuel cell.
- Benefits:
  - No emissions of pollutants and greenhouse gases
  - Lower noise pollution
  - Potential to be more cost effective than electric biofuels or diesel based variants
- Prospective customers: public transport authorities, bus service operators, airports (minibuses), hotels, and resorts

**Overview of technologies**

**Fact card: Hydrogen buses**

**H₂ Market trends**

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Deployment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (number of vehicles)</td>
<td>More than 500</td>
</tr>
<tr>
<td>Future growth</td>
<td>Several thousand buses expected in China, Japan, and South Korea</td>
</tr>
<tr>
<td>Competing technologies</td>
<td>Electric, diesel, diesel-electric hybrid, biofuels, CNG</td>
</tr>
</tbody>
</table>

**Key features**

<table>
<thead>
<tr>
<th>Fuel consumption (Kg H₂/100km)</th>
<th>8–14</th>
</tr>
</thead>
<tbody>
<tr>
<td>Range (km per tank)</td>
<td>250–450</td>
</tr>
<tr>
<td>Power output (kW)</td>
<td>100</td>
</tr>
<tr>
<td>CAPEX/Acquisition cost ($)</td>
<td>680,000</td>
</tr>
<tr>
<td>Total cost of ownership ($ per km)</td>
<td>4</td>
</tr>
</tbody>
</table>

Source: Kearney Energy Transition Institute analysis
Hydrogen trucks and buses powered by fuel cells are expected to gain market share, mainly in China.

### Key features

- Buses and trucks can be equipped with a H₂ tank–PEM fuel cell–Li-ion battery–electric motor combination.
- The Li-ion battery can be used to regenerate energy from braking or can be recharged with plug-in solutions to deliver power during acceleration phases or to extend range.
- Hydrogen tank has a capacity of about 150 kgH₂, making it lighter than the battery part from a BEV truck.

### Overview of technologies

![Diagram of a hydrogen truck](image)

### Fact card: Hydrogen truck


### H₂ Market trends

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Deployment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (number of vehicles)</td>
<td>About 400 trucks</td>
</tr>
<tr>
<td>Expected growth (CAGR 2019f)</td>
<td>Several thousand trucks expected in China</td>
</tr>
<tr>
<td>Competing technologies</td>
<td>Diesel, diesel-electric hybrid, battery-powered trucks</td>
</tr>
</tbody>
</table>

### Key features

<table>
<thead>
<tr>
<th>Feature</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel consumption (kgH₂/100km)</td>
<td>7.5–16</td>
</tr>
<tr>
<td>Range (km per tank)</td>
<td>1,200</td>
</tr>
<tr>
<td>Fuel cell efficiency</td>
<td>55%</td>
</tr>
<tr>
<td>Output (kW)</td>
<td>250–750 kW (trucks)</td>
</tr>
<tr>
<td>Capex/acquisition cost ($)</td>
<td>350,000</td>
</tr>
<tr>
<td>Total cost of ownership ($ per km)</td>
<td>0.95–1.75</td>
</tr>
</tbody>
</table>

Hydrogen can be the main power source for small boats or supply electricity to on-board applications

**Description**
- Fuel-cell ships, boats, and ferries use stored compressed hydrogen gas as a fuel source to generate electricity via an energy converter (fuel cell) to power an electric motor.
- This is a viable low-carbon fuel for smaller marine vessels. For larger vessel, fuel cells can supplement the main power.
- Hydrogen can also be converted in synthetic fuels through methanol.
- Existing infrastructure in industrial ports (such as SMR providing hydrogen to nearby factories) can be leveraged.
- Benefits:
  - Depending on the crude prices and clean fuel regulations, potentially lower total cost of ownership in the future
  - No emissions of pollutants and greenhouse gases
  - Lower noise pollution and beneficial to marine wildlife

**Fact card: Marine applications**

| Source: Kearney Energy Transition Institute analysis |

### H₂ Market trends

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Concept or early prototype</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (number of units)</td>
<td>Demonstration projects under way in the European Union</td>
</tr>
<tr>
<td>Future growth</td>
<td>Medium-term commercialization unlikely</td>
</tr>
<tr>
<td>Competing technologies</td>
<td>Hydrocarbon fuels, diesel-electric hybrid, battery electric</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Power output (kw)</th>
<th>12–2,500 (ferries)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel consumption (Kg H₂/nm)</td>
<td>3.4 (ferries)</td>
</tr>
<tr>
<td>Range (km, hours)</td>
<td>50–90, 8–12 (smaller boats)</td>
</tr>
<tr>
<td>Capex/acquisition cost ($)</td>
<td>12–16.5 million (ferries)</td>
</tr>
<tr>
<td>Lifetime (years)</td>
<td>25</td>
</tr>
</tbody>
</table>

3.2 Key hydrogen applications – Energy (mobility)
Hydrogen trains powered by fuel cells can offer a low-carbon alternative to diesel locomotives

**Description**
- Hydrogen trains use multiple H₂ storage tanks combined with PEMFC and electric engines.
- Hydrogen trains also have Li-ion batteries to regenerate brake energy.
- Large autonomy makes it suitable for regional routes, with cyclical trips (100–200 km) and a refueling station.
- No electric lines are required, which makes it suitable for different topographic profiles, such as tunnels and mountains.
- Potential uses include non-electrified lines for diesel trains replacement, city trams, and trains for industrial applications, such as mining.

**Overview of technologies**

**Alstom’s hydrogen train**

**H₂ Market trends**

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Deployment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (number of vehicles)</td>
<td>Multiple projects worldwide Two trains in Germany</td>
</tr>
<tr>
<td>Expected growth (CAGR 2019f)</td>
<td>n.a.</td>
</tr>
</tbody>
</table>

**Key features**

| Fuel consumption (kgH₂/100km) | About 33 |
| Range (km per tank) | 600–800 |
| Output (kW) | 400 |
| Capex/acquisition cost ($) | 13 million for a regional 150-coach train |
| Total cost of ownership ($ per km) | – |

Key hydrogen applications – Energy (mobility)

Hydrogen aircrafts powered by fuel cells could offer a solution to reduce aviation-based emissions

**Description**

- Small aircraft powered by fuel cells can use stored compressed hydrogen gas to generate electricity via an energy converter (fuel cell) to power an electric motor. The focus is on using it as a propeller powertrain for smaller aircraft or as an auxiliary power unit (APU) on large conventional aircraft.
- Pure hydrogen or hydrogen-based liquid fuels also offer alternative pathways, subject to further R&D.
- Benefits:
  - Reduced costs as a result of lower OPEX (engine) and increased efficiency
  - No emissions of pollutants and greenhouse gases
  - Prospective customers: airlines, national and local governments, airport operators, and private fleets

**Overview of technologies**

**Fact card: Aviation**

**H₂ Market trends**

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Concept or early prototype</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (number of units)</td>
<td>Limited to demonstration projects for small aircrafts, such as HY4</td>
</tr>
<tr>
<td>Future growth</td>
<td>Short-range non-essential uses, unmanned missions, and drones</td>
</tr>
<tr>
<td>Competing technologies</td>
<td>Petroleum-based aviation fuel, battery powered</td>
</tr>
</tbody>
</table>

| Power output (kw)       | 80 (based on HY4 project) |
| Fuel consumption (Kg H₂) | 170 (based on HY4 project) |
| Range (km)              | 750–1,500 (based on HY4 project) |
| Capex/acquisition cost ($) | n.a. |
| Lifetime (years)        | n.a. |

Source: Kearney Energy Transition Institute analysis.
Co-firing ammonia in coal-power plants could reduce carbon emissions at low cost; special attention needs to be given to NOx emissions.

Fact card: Ammonia co-firing in coal power plants

Description

- Hydrogen-based fuel ammonia can be co-fired in coal-fired power plants to reduce coal usage and plant carbon emissions.
- IHI Corporation successfully co-fired a ammonia–coal mix with 20% ammonia in a 10 MW furnace (% of energy content).
- The previous test conducted by Chugoku Electric in a 150 MW furnace reached a 0.8% (% of energy content).
- Boiler’s energy conversion efficiency is maintained.
- Ammonia feeding pipe design allows to control NOx emissions, which are similar to regular coal plant.
- In small furnaces (less than 10 MWth), reaching 20% of ammonia in the combustion zone does not pose any particular problems, and no slippage of ammonia into exhaust gas was detected.
- Technology can be retrofitted into existing coal-fired boilers.
- The economics of projects will depend on availability of low-cost ammonia.

H₂ Market trends

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Early stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size</td>
<td>2,100</td>
</tr>
<tr>
<td>(2019, GW, coal-fired)</td>
<td></td>
</tr>
<tr>
<td>Expected market size</td>
<td>1,650 (including combined heat and power)</td>
</tr>
<tr>
<td>(2030, GW, coal-fired)</td>
<td></td>
</tr>
<tr>
<td>Competing technologies</td>
<td>CCS, decarbonized sources</td>
</tr>
</tbody>
</table>

Key features

<table>
<thead>
<tr>
<th>Ammonia marginal consumption (kgNH₃/%ammonia/MW per y)</th>
<th>26,800</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrogen marginal consumption (kgH₂/%ammonia/MW per year)</td>
<td>4,800</td>
</tr>
</tbody>
</table>

Flexible power generation is the use of hydrogen to produce electricity on demand and operating at low load factors

**Description**

- Hydrogen can be used as a fuel in existing gas turbines and CCGTs, which can handle a 3 to 5% share of hydrogen, up to 30% for some turbines.
- Ammonia can also be used as a fuel in gas turbine. However, NOx emissions and flame stability needs to be controlled.
- Fuel cells have efficiencies close to CCGTs but suffer from a shorter lifetime than turbines and have smaller output (less than 50 MW).
- It offers low-carbon flexibility on power system, can be coupled with intermittent renewable sources, and can generate power during peak hours.
- Competitiveness is to be assessed against other low-carbon technologies, such as gas turbines with CCS and biomass gas turbines.

**Key features**

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- Competitiveness is to be assessed against other low-carbon technologies, such as gas turbines with CCS and biomass gas turbines.

**Overview of technologies**

- BHGE NovaLT gas turbine reconfigured for 100% hydrogen

**H₂ Market trends**

<table>
<thead>
<tr>
<th>Market maturity</th>
<th>Early stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market size (GW of VRE)</td>
<td>n.a.</td>
</tr>
<tr>
<td>Expected market size (2050, GW of VRE)</td>
<td>n.a.</td>
</tr>
<tr>
<td>Competing technologies</td>
<td>Batteries, biomass turbines, gas + CCUS turbines</td>
</tr>
</tbody>
</table>

**Competitive price for H₂ vs. gas turbine ($ per kgH₂)**

| 15% load factor: 1.5 |

**Competitive price for H₂ vs. gas turbine + CCUS**

| 15% load factor: 2.5 |

**Competitive price for H₂ vs. biomass turbine ($ kgH₂)**

| 15% load factor: 4 |

---

1 Hypothesis: CO₂ price of $100 per ton; natural gas price of $7 per mmbtu; biomass gas price of $14 per mmbtu.

111

**Key features**

| H₂ tolerance in gas networks (min/max, % vol) | Compressors: about 10% Distribution: 50–100% |
| Expected market size (2030, MTH₂ per year) | 2 – 4 |
| H₂ tolerance for end-applications (min/max, % vol) | Gas turbines: 5% Boilers: 30% |

**Overview of technologies**

GRHYD project in Dunkirk

**Fact card: Hydrogen blending**

**Market maturity**

- Natural gas demand (bcm per year): 3,900
- Expected market size (2030, MTH₂ per year): 2 – 4

**Competing technologies**

- Natural, gas, Methanation, H₂, fuel cells and cogeneration, Biogas

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3.3 Key hydrogen applications – Energy (gas energy)

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**Description**

- Blending low shares of H₂ in most gas networks would have little impact for the end-use applications, such as boilers and cookstoves.
- Blending H₂ into the current gas network allows clean energy to be distributed while saving capex for a new H₂ network.
- Multiple challenges still need to be addressed:
  - Lower energy density in a gaseous form, leading to a reduction in transported energy through the pipeline
  - Increasing risk of flames spreading as a result of high flame velocity
  - Variability in hydrogen volumes, negatively impacting end equipment designed to operate in certain conditions
  - Many industrial gas applications have a low upper limit of H₂ blend in natural gas, which will set the upper limit for the whole network.
- Current regulations allow a H₂ blend limit up to 6% (for example, in France).
### Key hydrogen applications – Energy (gas energy)

- **Overview of technologies**
  - Methanation is an exothermic catalytic process operating at 320–430°C to produce synthetic CH₄ through Sabatier reaction:
    \[
    \text{CO}_2 + 4\text{H}_2 \rightarrow 2\text{H}_2\text{O} + \text{CH}_4 \quad \Delta H = -165 \text{ MJ/kmol}
    \]
  - Reaction can be split in two steps:
    - \(\text{CO} + 3\text{H}_2 \rightarrow \text{H}_2\text{O} + \text{CH}_4\) \(\Delta H = -206 \text{ MJ/kmol}\)
    - \(\text{CO}_2 + \text{H}_2 \rightarrow \text{H}_2\text{O} + \text{CO}\) \(\Delta H = 41 \text{ MJ/kmol}\)
  - Higher saturated hydrocarbons and solid carbon deposits can be found in the products.
  - The main advantage of methanation is its use of fatal CO and CO₂:
    - If coupled with low carbon H₂ and CO₂ inputs, there is a potential for full decarbonisation of gas.
    - Synthetic CH₄ may be injected on the gas network for residential and industrial applications (gas heating, electricity generation), stored or as a fuel for NGV.

### Fact card: Hydrogen methanation

- Considering H₂ through electrolysis coupled with PV plant and CO₂ sources from exhaust gas of cement factory
- Sources: Afhypac, Frontiers, GRTgaz; Kearney Energy Transition Institute analysis

### H₂ Market trends

<table>
<thead>
<tr>
<th></th>
<th>Development</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Market maturity</strong></td>
<td>n.a.</td>
</tr>
<tr>
<td><strong>Market size</strong></td>
<td>(Germany: ~2.5 kTCH₄ per year)</td>
</tr>
<tr>
<td><strong>Expected market size</strong></td>
<td>n.a.</td>
</tr>
<tr>
<td><strong>Competing technologies</strong></td>
<td>Natural, gas, blending, H₂, fuel cells and cogeneration, biogas</td>
</tr>
</tbody>
</table>

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>H₂ consumption (kgH₂/kgCH₄)</strong></td>
<td>0.5</td>
</tr>
<tr>
<td><strong>CAPEX/Acquisition cost ($ per kW)</strong></td>
<td>210–445 for methanation plant only</td>
</tr>
<tr>
<td><strong>Energy efficiency (%)</strong></td>
<td>83%</td>
</tr>
<tr>
<td><strong>Marginal cost ($ per kWh)</strong></td>
<td>0.10–0.45¹</td>
</tr>
</tbody>
</table>

¹ Considering H₂ through electrolysis coupled with PV plant and CO₂ sources from exhaust gas of cement factory

Sources: Afhypac, Frontiers, GRTgaz; Kearney Energy Transition Institute analysis
A 100% H₂ network can also be considered for providing energy to end users through fuel cells, co-generation, or other hybrid systems.

**Description**

- A 100% hydrogen network could be coupled with fuel cells and other systems at the end user’s consumption site to meet demand for heating, cooling, and electricity.
- Worldwide, there are 4,500 km of pipelines, mostly operated by hydrogen producers.
- Investment costs are high but may pay off only with large shipping volume of hydrogen.
- H₂ transported through pipeline could also find other applications, such as refueling stations and industrial use.
- Developing micro-networks with decentralized production sources could reduce infrastructure costs.
- By 2030, final energy prices for hydrogen would need to be in the range of $1.50 to $3.00 per kg to compete with natural gas and electricity.

**H₂ Market trends**

<table>
<thead>
<tr>
<th>Key features</th>
<th>Fuel cell m-CHP</th>
<th>Gas boiler (+ grid)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technical specification</td>
<td>1 kW_e / 1.5 kW_m m-CHP and 20 kW_m auxiliary boiler, heat storage</td>
<td>20 kW_m boiler connected to the grid</td>
</tr>
<tr>
<td>Capex (€)</td>
<td>16,600</td>
<td>4,000</td>
</tr>
<tr>
<td>Opex (€)</td>
<td>140 per year</td>
<td>110 per year</td>
</tr>
<tr>
<td>Lifetime (years)</td>
<td>10 years with 2 FC replacement</td>
<td>15</td>
</tr>
<tr>
<td>Net efficiency</td>
<td>37% electrical, 52% thermal</td>
<td>90% thermal</td>
</tr>
</tbody>
</table>

Fact card: Pure hydrogen consumption

Hydrogen’s role in the energy transition
Some orders of magnitude in 2019

Executive summary

1. Hydrogen's role in the energy transition

2. Hydrogen value chain: upstream and midstream
   2.1 Production technologies
   2.2 Conversion, storage, and transportation technologies
   2.3 Maturity and costs

3. Key hydrogen applications
   3.1 Overview
   3.2 Feedstock
   3.3 Energy

3. Business models
   4.1 Policies and competition landscape
   4.2 Business cases

Appendix (Bibliography & Acronyms)
M&A, joint ventures, and partnerships have increased, highlighting large corporations’ interest in hydrogen.

### Main M&A, JV, and partnership agreements on H₂ (2016–19)

**Eon acquires stakes in domestic FC provider Elcore.**

**Shell, Honda, and Toyota partner to develop H₂ refueling stations.**

**EDF Nouveaux Business invest $16 million in McPhy.**

**Air Liquide acquires stake in Hydrogenics.**

**Ballard and ABB partner to design an FC river boat.**

**Hyundai and Cummins partner on FC powertrains.**

**Hexagon and Agility Fuel Systems partner to develop clean fuel solutions, including H₂.**

**Nel and Deokyang form joint venture to develop H₂ refueling stations.**

**ABB and Ballard sign MoU to develop FC marine systems.**

**PowerCell and Scania partner to build a refuse FC truck.**

**Ballard and Home Power Solutions partner on FC for domestic use.**

**Duke Energy acquires FC project portfolio of Bloom Energy.**

**Altran acquires stake in H₂ sensor-maker H₂Scan.**

**Ballard and Audi sign MoU for FC passenger cars.**

**Bosch acquires stakes in FC maker Ceres.**

**Hyundai and H₂ Energy form joint venture n buses and trucks mobility.**

**Bosch and Hanwha invest more than $230 million in Nikola (H₂ truck maker).**

**Hydrogenics and SinoHytec partner to develop FC for buses and trucks.**

**Hydrogenics and StratosFuel partner to develop power-to-gas.**

**Faurecia and CEA partner to develop fuel-cell stacks.**

**PowerCell and Siemens sign MoU to develop FC marine systems.**

**Faurecia and Michelin partner on hydrogen mobility.**

**Cummins acquires stake in Hydrogenics.**

**GM and Honda form joint venture to produce fuel cells.**

**NEL and Nikola partner to develop H₂ refueling stations.**

**Weichai Power acquires stakes in FC maker Ceres Power and Ballard.**

**Air Liquide and Houpu form joint venture to develop H₂ stations in China.**

**Plug Power and Engie partner on hydrogen use in logistics sectors.**

**Linde gas strategic investment in ITM POWER (20%)**

**ITM LINDE ELECTROLYSIS (ILE), a 50-50 JV between ITM POWER and Linde Engineering to address large scale electrolyser.**

---

Non-Exhaustive

4.1 Business models - Policies and competition landscape

Note: FC is fuel cell. MoU is memorandum of understanding. Source: Kearney Energy Transition Institute analysis
Hydrogen Council overview

- Established at the World Economic Forum 2017 in Davos
- Global initiative of leading energy, transport, and industry companies to:
  - Accelerate investments in the development and commercialization of hydrogen and fuel cell-related topics
  - Encourage key stakeholders to back hydrogen as part of the future energy mix with appropriate policies and support schemes
  - Investment plan of $1.9 billion over five years, mainly for market introduction, deployment, and R&D

Launched in 2017, the Hydrogen Council regroups companies from various industries in North America, Asia, and Europe

<table>
<thead>
<tr>
<th>Steering members</th>
</tr>
</thead>
<tbody>
<tr>
<td>Airbus</td>
</tr>
<tr>
<td>Air Liquide</td>
</tr>
<tr>
<td>Air Products</td>
</tr>
<tr>
<td>Alstom</td>
</tr>
<tr>
<td>AngloAmerican</td>
</tr>
<tr>
<td>Audi</td>
</tr>
<tr>
<td>BMW Group</td>
</tr>
<tr>
<td>Bosch</td>
</tr>
<tr>
<td>BP</td>
</tr>
<tr>
<td>CHN Energy</td>
</tr>
<tr>
<td>Cummins</td>
</tr>
<tr>
<td>Daimler</td>
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<td>EDF</td>
</tr>
<tr>
<td>Engie</td>
</tr>
<tr>
<td>Equinor</td>
</tr>
<tr>
<td>Faurecia</td>
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<tr>
<td>GM</td>
</tr>
<tr>
<td>Great Wall Motors</td>
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<tr>
<td>– Airbus</td>
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<tr>
<td>– Air Liquide</td>
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<td>– Air Products</td>
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<td>– Alstom</td>
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<td>– AngloAmerican</td>
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<td>– Audi</td>
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<tr>
<td>– BMW Group</td>
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<tr>
<td>– Bosch</td>
</tr>
<tr>
<td>– BP</td>
</tr>
<tr>
<td>– CHN Energy</td>
</tr>
<tr>
<td>– Cummins</td>
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<tr>
<td>– Daimler</td>
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<tr>
<td>– EDF</td>
</tr>
<tr>
<td>– Engie</td>
</tr>
<tr>
<td>– Equinor</td>
</tr>
<tr>
<td>– Faurecia</td>
</tr>
<tr>
<td>– GM</td>
</tr>
<tr>
<td>– Great Wall Motors</td>
</tr>
</tbody>
</table>

Sources: Hydrogen Council; Kearney Energy Transition Institute analysis

Hydrogen demand targets

**Transportation**
- 400 million passengers vehicle, 5 million trucks, and 15 million buses
- 20% of diesel trains replaced by hydrogen trains

**Industry and building heat**
- 12% of global energy demand, mainly in steel, chemicals, and cement
- 10% of crude steel production, 20% of methanol and ethanol derivatives recycling CO₂ and decarbonized existing feedstock
- 8% of global energy demand

**Power generation**
- 500 TWh of excess power converted to about 10 MTH₂ of hydrogen
- About 126 MTH₂ stored in strategic reserves

**Expected outcome**
- 18% of final energy demand
- 6 GT year of CO₂ abatement (20% of the required CO₂ abatement), mainly from transportation thanks to 20 million barrels of oil replaced
- Market size of $2,500 billion, including hydrogen and fuel-cell equipment
- 30 million jobs created

Hydrogen Council vision: The hydrogen economy in 2050

### Hydrogen demand targets

<table>
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<tr>
<th>Transportation</th>
<th>Industry and building heat</th>
<th>Power generation</th>
</tr>
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<tr>
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- 6 GT year of CO₂ abatement (20% of the required CO₂ abatement), mainly from transportation thanks to 20 million barrels of oil replaced
- Market size of $2,500 billion, including hydrogen and fuel-cell equipment
- 30 million jobs created

4.1 Business models - Policies and competition landscape

Kearney Energy Transition Institute
Multiple countries have launched supportive initiatives to accelerate hydrogen deployment, mainly in transportation ...

**Hydrogen support initiatives (number of countries)**

- **FCEV passenger cars**: 15
- **Refueling stations**: 10
- **FCEV buses**: 10
- **Electrolyzers**: 6
- **FCEV trucks**: 5
- **Building heat and power**: 2
- **Power generation**: 2
- **Industrial use**: 2

**Note:** FCEV is fuel cell electric vehicle.

Sources: International Energy Agency, Kearney Energy Transition Institute analysis
... and developing specific strategy use case

### Business cases

<table>
<thead>
<tr>
<th></th>
<th>US</th>
<th>UK</th>
<th>FR</th>
<th>DE</th>
<th>NO</th>
<th>CH</th>
<th>JP</th>
<th>KR</th>
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<tbody>
<tr>
<td>Industrial feedstock</td>
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<td>✔️</td>
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<td>✔️</td>
<td>✔️</td>
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</tr>
<tr>
<td>FCEV manufacturing</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
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<tr>
<td>Use of H₂ for FCEV passenger cars</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
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<tr>
<td>Use of H₂ for heavy vehicles</td>
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<td>✔️</td>
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<tr>
<td>Electricity generation</td>
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<td>✔️</td>
<td>✔️</td>
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</tr>
<tr>
<td>Combined heat and power generation</td>
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<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
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<td>Long-term energy storage</td>
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<td>✔️</td>
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</tr>
<tr>
<td>Blending and methanation in gas networks</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
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<tr>
<td>Household heating</td>
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</tr>
<tr>
<td>Industrial heating</td>
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</tr>
<tr>
<td>Hydrogen production for export</td>
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<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
</tr>
</tbody>
</table>

Note: FCEV is fuel cell electric vehicle.
Sources: “Advancing Hydrogen: Learning from 19 Plans to Advance Hydrogen from Across the Globe,” Australia Department of Industry, Innovation, and Science, July 2019; Kearney Energy Transition Institute analysis

Non-Exhaustive
In partnership with the European Commission, Hydrogen Europe launched HyLaw to identify the legal barriers to hydrogen deployment.

Focus on European Union

<table>
<thead>
<tr>
<th>Objectives</th>
<th>Policy change proposition</th>
</tr>
</thead>
</table>
| **Integrate more renewables, and enable sectoral integration** | - Integration of the power sector within transport, industry, heating, and cooling via energy carriers (electricity and hydrogen)  
  - Commission’s proposal to integrate more renewable energy in other economic sectors, such as in transport via the use of, renewable gaseous, and liquid fuels of non-biological origin (hydrogen) and carbon-based streams  
  - Recognize different pathways of electricity rather than using the average EU greenhouse gas emissions from power or from new plants:  
    - Through the use of guarantee of origins and renewable PPAs  
    - Considering period when energy surplus is available as "zero-emissions" period for hydrogen |
| **Decarbonize mobility** | - Air-quality issues in multiple cities because of particle emissions — not only CO₂, but also NOₓ and SOₓ  
  - Electrification of transportation means (BEV and FCEV) to reduce emissions at the consumption point  
  - Developing a hydrogen infrastructure on the model of current gas stations to preserve jobs and capital assets  
  - Opportunity to store electricity surplus or renewable electricity as zero-emission fuel |
| **Decarbonize industry** | - Replace current brown hydrogen production sources with green hydrogen production sources in steel, chemical, and oil refining industries.  
  - Through the new Industrial Policy Strategy, support green hydrogen pilots and projects while keeping the industry competitive.  
  - Support hydrogen blending and methanation to keep using gas grid assets as renewable energy transportation and storage mean.  
  - Support projects that value by-product hydrogen in industrial areas that could be used as a low-grade heating solution. |
| **Decarbonize heating** | - Replace current carbon-intensive heating sources (mainly from fossil fuels) to electrification or via the introduction of renewable gases such as biogas and hydrogen.  
  - Support hydrogen blending and methanation to keep using gas grid assets as renewable energy transportation and storage mean.  
  - Support projects that value by-product hydrogen in industrial areas that could be used as a low-grade heating solution. |

Note: BEV is battery electric vehicle; FCEV is fuel cell electric vehicle; PPA is power purchase agreement.

Sources: Hydrogen Europe; Kearney Energy Transition Institute analysis
The United States has launched incentive programs to accelerate hydrogen deployment

Focus on the United States

4.1 Business models - Policies and competition landscape

The United States has launched incentive programs to accelerate hydrogen deployment

**Funding and incentives**

**R&D Funding**
- Between 2004 and 2017, about $2.5 billion was granted to the Department of Energy for hydrogen R&D activities across its energy efficiency and renewable energy, coal, nuclear energy, and science departments.
- In 2005, OEMs and oil majors partnered to create FreedomCAR within the Department of Energy to "examine and advance the pre-competitive, high-risk research needed to develop the component and infrastructure technologies necessary to enable a full range of affordable cars and light trucks, and the fueling infrastructure for them that will reduce the dependence of the nation's personal transportation system on imported oil and minimize harmful vehicle emissions, without sacrificing freedom of mobility and freedom of vehicle choice," identifying FCEV as potential venue for R&D.

**Incentives**
- At the federal and state level, 280 incentive programs support hydrogen, which includes grants, tax incentives, loans, leases, exemptions, and rebates, and apply for private businesses (fuel producers, OEM, fuel infrastructure operators and others), government entities and personal vehicle owners.
- Clean cities, clean ports, clean agriculture, and clean construction initiatives have developed private-public partnerships to promote alternative fuels and provide information on financial opportunities.

**Policy acts**

**Title VIII act objectives:**
- Promote development, demonstration, and commercialization of hydrogen and fuel-cell technologies in partnership with industries.
- Make investments in building links between private industries, institutions of higher education, national laboratories, and research institutions to expand innovation and industrial growth.
- Build a mature hydrogen economy creating fuel diversity in the transportation sector.
- Decrease US dependency on imported oil, eliminate emissions from transportation sector, and enhance energy security.
- Create, strengthen, and protect a sustainable national energy economy.

The Energy Policy Act of 2005 calls for a wide R&D program at each step of the hydrogen value chain to demonstrate the use of hydrogen in multiple applications.
- By 2020, OEMs must offer at least one FCEV to the mass consumer market.

The Fuel Cell Technical Task Force is responsible for planning a safe, economical, and ecological hydrogen infrastructure and establishing uniform hydrogen codes, standards, and safety protocols.

Cash prizes are awarded competitively to individuals, universities, and small and large businesses that advanced the research, development, demonstration, and commercialization of hydrogen technologies.

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Sources: Department of Energy; Kearney Energy Transition Institute

Note: OEM is original equipment manufacturers; FCEV is fuel cell electric vehicle.
Japan was the first country to adopt a basic hydrogen strategy and plans to become a “hydrogen society”

### Objectives

| Realize low-cost hydrogen use | Developing commercial scale capability to procure 300,000 tons of hydrogen annually  
Cost at 30 yen/Nm3 (2030) and 20 yen/Nm3 (beyond) |
| Develop international hydrogen supply chains | Developing energy carrier technologies  
Demonstrating liquefied hydrogen supply chain by mid-2020  
Better handling of ammonia and methanation process |
| Decarbonize industry and power generation | Carbon-free hydrogen to be used in energy areas where electricity use is difficult and replace fossil fuel-based hydrogen in industrial applications  
Commercialize hydrogen power generation and cut hydrogen power generation cost to 17 yen/kWh by 2030 |
| Decarbonize mobility | FCV targets: 40,000 units (2020), 200,000 units (2025), and 800,000 units (2030)  
Hydrogen stations targets: 160 (2020) to 320 (2025)  
Specific focus in developing fuel cell-based buses, forklifts, trucks, and small ships |

### Policy initiatives

| Financial support | The Japanese government has dedicated $1.5 billion over the past six years to promote research development, demonstration, and commercialization of hydrogen technologies and subsidies.  
In 2018, the Japanese government allocated $272 million to hydrogen research and subsidies that is 3.5% of its energy budget  
The R&D efforts are channeled through the government research institution the New Energy and Industrial Technology Development Organization (NEDO), which oversees the national program on new technologies.  
Japan H2 Mobility (JHyM), a joint venture of more than 20 participating companies, was established in 2017 to accelerate the deployment of hydrogen filling stations throughout Japan with the help of government subsidies. In cooperation with the Japanese government, JHyM plans to build 80 new hydrogen filling stations by early 2022.  
Japan intends to lead international standardization through international frameworks in cooperation with relevant organizations. Proactively promoting hydrogen to citizens and local governments to share information and facilitate adoption. Japanese companies are already involved in international hydrogen projects such as in Brunei, Norway and Saudi Arabia. Kawasaki Heavy Industries has also announced the construction of a liquefaction plant, storage facility, and loading terminal for hydrogen export to Japan in the Australian state of Victoria as a pilot project for 2020–2021. |

Sources: Hydrogen Europe; Kearney Energy Transition Institute analysis  
Note: FCV is fuel cell vehicle.  
Sources: Ministry of Economy, Trade and Industry (Japan); Kearney Energy Transition Institute analysis
Australia adopted a national hydrogen strategy in late 2019 to open up opportunities in domestic use as well as the export market.

**Focus on Australia**

<table>
<thead>
<tr>
<th>Focus areas</th>
<th>Policy initiatives</th>
</tr>
</thead>
<tbody>
<tr>
<td>Develop a strong hydrogen industry and capabilities that will support the country’s low emission energy transition and local job creation</td>
<td>Australia would take an adaptive approach to capitalize on the growth in domestic and global hydrogen demand: <strong>Foundation and demonstration</strong>&lt;br&gt;– Early actions will focus on developing clean hydrogen supply chains to service new and existing uses of hydrogen, such as ammonia production, and developing capabilities for rapid industry scale-up.&lt;br&gt;– Demonstration scale hydrogen hubs will help prove technologies, test business models, and build capabilities. <strong>Large-scale market activation</strong>&lt;br&gt;– Scale up the end use of the clean hydrogen in the domestic market, such as industrial feedstock, heating, blending of hydrogen in the gas network, and use of hydrogen in heavy-duty transport along with refueling infrastructure.</td>
</tr>
<tr>
<td>Transform Australia into a clean hydrogen exporter</td>
<td>Since 2015, the Australian government has committed more than $146 million to hydrogen projects along the supply chain.&lt;br&gt;– R&amp;D: $67.83 million&lt;br&gt;– Feasibility: $4.88 million&lt;br&gt;– Demonstration: $5.04 million&lt;br&gt;– Pilot: $68.57 million&lt;br&gt;The support is provided though the Australian Research Council, CSIRO, the Australian Renewable Energy Agency (ARENA), the Clean Energy Finance Corporation, and the Northern Australia Infrastructure Fund. National Energy Resources Australia (NERA) will support SMEs to take advantage of opportunities in the hydrogen industry by forming an industry-led hydrogen cluster. The hydrogen industry cluster will help build capabilities and drive industry collaboration across the hydrogen value chain. The Australian government has supported nine projects in the past two years alone. The state and territory governments have also made early moves through supporting specific projects and, in some cases, releasing their own hydrogen strategies. The Australian government will establish agreements with key international markets to underpin investment. It has already signed a cooperation agreement with Japan and a letter of intent with Korea. The four year (2018–2021) HESC Pilot Project comprises multiple stages to produce and export hydrogen (from brown coal) to Japan from the Latrobe Valley, using established and scientifically proven technologies. The Pilot Project is the world’s largest hydrogen demonstration project and includes the transportation of liquified hydrogen in a world-first, purpose-built liquified hydrogen carrier.</td>
</tr>
</tbody>
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Oil-rich countries are looking into H₂ to export as a clean fuel alternative to oil and gas

Business case overview

– Several options can be used to convert hydrocarbons into clean H₂ (see Part 2):
  – Either from natural gas (e.g. SMR) or from any hydrocarbon sources (e.g. gasification; ATR, Pyrolysis), and combining with CCS
  – Using non-emitting technologies (e.g. microwave)
– Blue hydrogen provides a clean opportunity for Arab countries to extend the useful life of their reserves:
  – Gulf Cooperation Council countries have a proven track record of brown hydrogen production thanks to their refineries.
  – CO₂ from CCS can be stored more easily in depleted oil and gas fields or be used for enhanced oil recovery and nearby industries.
  – Value from heavy oil resources can be enhanced.
  – Carbon emissions targets from Paris agreement can be met.
– Blue hydrogen production costs are half of green hydrogen, but the gap is expected to close by 2030.
  – However, renewable electricity infrastructure in Gulf Cooperation Council countries is not big enough to scale up hydrogen production.

Actions taken

Saudi Arabia

– Agreement between Air Products and Aramco to build the country’s first compressed hydrogen refueling station for fuel cell electric vehicles
– Development of a blue hydrogen production strategy with planned pilots

United Arab Emirates

– Test of Toyota Mirai FCEV on roads to evaluate the potential of hydrogen as road fuel
– Al Reyadah CCUS plant at Emirates Steel plant in Abu Dhabi, used for EOR in ADNOC oilfields

Kuwait

– Discussions on CCUS and H₂ production by KPC

Focus on Gulf Cooperation Council countries

Sources: Kuwait Foundation for the Advancement of Sciences; Kearney Energy Transition Institute analysis
Converting fossil fuels into hydrogen through SMR is almost as efficient as a ICE and BEV, leading to no extra fossil fuel consumption.

**Well-to-wheel energy efficiency example**  
(Energy in kWhe)

- **Oil & gas processing**: Extraction 86%, Refining 86%
- **Fossil fuels conversion**: SMR 64%, Compressor 90%, Tank 100%
- **Charging infrastructure**: Electrolyzer 59%, Charger 90%, Battery Full charge 93%
- **Energy storage**: Fuel Cell 55%
- **Mechanical energy conversion**: Electric drive 90%, Gasoline ICE 30%
The battery pathway also appears more efficient than hydrogen when the primary source comes from renewable sources.

However, efficiency considerations could be put aside if renewable sources are considered as not limited.

Illustrative

Well-to-wheel energy efficiency example
(Energy in kWhe)

<table>
<thead>
<tr>
<th>Component</th>
<th>Conversion Efficiency</th>
<th>Energy Content</th>
</tr>
</thead>
<tbody>
<tr>
<td>Renewable production</td>
<td>X%</td>
<td>X%</td>
</tr>
<tr>
<td>Electric production &amp; transmission</td>
<td>X%</td>
<td>X%</td>
</tr>
<tr>
<td>Fuel cell</td>
<td>55%</td>
<td>54</td>
</tr>
<tr>
<td>Electric drive</td>
<td>90%</td>
<td>27</td>
</tr>
<tr>
<td>Battery</td>
<td>93%</td>
<td>77</td>
</tr>
<tr>
<td>Full charge</td>
<td>90%</td>
<td>69</td>
</tr>
<tr>
<td>Battery infrastructure</td>
<td>X%</td>
<td>X%</td>
</tr>
<tr>
<td>Energy storage</td>
<td>X%</td>
<td>X%</td>
</tr>
<tr>
<td>Mechanical energy conversion</td>
<td>X%</td>
<td>X%</td>
</tr>
</tbody>
</table>

Source: Kearney Energy Transition Institute analysis
CO₂ emissions related to hydrogen production vary depending on the production pathway.

**CO₂ intensity of hydrogen production**

(kgCO₂/kgH₂, includes full life cycle of power plant)

<table>
<thead>
<tr>
<th>Primary source</th>
<th>Conversion</th>
<th>Lower emission limit</th>
<th>World average from electrolysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>Gasification without CCS</td>
<td>2</td>
<td>45</td>
</tr>
<tr>
<td></td>
<td>Gasification with CCS¹</td>
<td>7</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Electricity &gt; Electrolysis²</td>
<td>9</td>
<td></td>
</tr>
<tr>
<td>Natural gas</td>
<td>SMR without CCS</td>
<td>11</td>
<td></td>
</tr>
<tr>
<td></td>
<td>SMR with CCS¹</td>
<td>45</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Electricity &gt; Electrolysis²</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>Nuclear fuel</td>
<td>Electricity &gt; Electrolysis²</td>
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<tr>
<td>Solar</td>
<td>Electricity &gt; Electrolysis²</td>
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<td></td>
</tr>
<tr>
<td>Wind</td>
<td>Electricity &gt; Electrolysis²</td>
<td>26</td>
<td></td>
</tr>
<tr>
<td>World grid (475g CO₂/kWhe)</td>
<td>&gt; Electrolysis²</td>
<td>20</td>
<td></td>
</tr>
</tbody>
</table>

Other hydrocarbons, such as oil, can be used to produce hydrogen, the resulting CO₂ intensity is generally comprise between those of coal and natural gas.

¹ Considering 54 to 89% of capture rate. More details on CCS are in production technologies section.

² Considering energy consumption of 55 kWh/kgH₂ for an electrolyzer.

Seven business cases, based on real-life situations, have been studied to assess their competitiveness with other available solutions.

**Economical competitiveness**
- What is the net present value and the LCOX of the investment?1
- What is the net present value of other alternatives, including carbon-intensive and low-carbon solutions?
- LCOH converted either in $ per kg, $ per MWh, $ per km, or $ per passenger depending on the business case

**Environmental impact**
- How many tons of CO₂ can be avoided thanks to the hydrogen solution, and what is the avoidance cost?
- How many tons of CO₂ would have been avoided with other solutions, and what is the avoidance cost?

**Other benefits**
- Will the solution contribute to an economic development at local or global level?
- Will the solution reduce dependency on fossil fuels imports and improve energy supply security?
- Will the solution help REN integration on the electric grid?

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1 Levelized cost of X: levelized cost of hydrogen, energy, or Mobility depending on the end-use application. Calculation methodology does not differ, and the denominator is adapted (for example, energy produced or number of passengers). Source: Kearney Energy Transition Institute analysis

**Evaluation criteria**

**Centralized production from ATR to serve local industries with heat and H₂**

**A. Thermochemical production**

**B. Electrolysis**

- Power-to-gas: how to value fatal electricity production into gas or heat energy
  - B1: overview; B1a - blending; B1b: methanation

- Power-to-power: how to store electricity and discharge it when needed

- Power-to-molecule: how to optimize refinery power consumption and reducing footprint

**B.1 Business cases**

- B1: Hydrogen buses: additional cost vs. impact for local economy
- B2: Hydrogen trains: how to value local H₂ fatal production and avoid large investment for rail electrification
- B3: Hydrogen cars: economic assessment of main H₂ cars
- B4: Power-to-X
- B5: Green mobility
Carbon abatement costs vary widely depending on the business case

### Business cases (2030)

<table>
<thead>
<tr>
<th>Business Case</th>
<th>Description</th>
<th>Extra Cost</th>
<th>Carbon Abatement Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Centralized production from ATR</td>
<td>+12–30% vs. avg. electricity price</td>
<td>MIN: 100, MAX: 215</td>
</tr>
<tr>
<td>B1</td>
<td>Power-to-gas</td>
<td>+60–100% injection</td>
<td>220–320</td>
</tr>
<tr>
<td></td>
<td></td>
<td>+250–400% methanation vs. gas</td>
<td>1100–2800</td>
</tr>
<tr>
<td>B2</td>
<td>Power-to-power</td>
<td>+35–35% vs. coal turbine</td>
<td>110–3000</td>
</tr>
<tr>
<td>B3</td>
<td>Power-to-molecule</td>
<td>+35–110% vs. SMR</td>
<td>130–150</td>
</tr>
<tr>
<td>B4</td>
<td>Hydrogen cars</td>
<td>+150–215% vs ICE car</td>
<td>570–2000</td>
</tr>
<tr>
<td>B5</td>
<td>Hydrogen buses (Pau example)</td>
<td>+10–15% vs. diesel bus</td>
<td>120</td>
</tr>
<tr>
<td>B6</td>
<td>Hydrogen trains (Cuxhaven example)</td>
<td>+1–15% vs. diesel train</td>
<td>0–60</td>
</tr>
</tbody>
</table>

Note: The carbon abatement cost is equal to \((LCOX(H_2) - LCOX(Ref)) / (Avoided CO_2)\), with the \(LCOX(H_2)\) being the \(LCOX\) of the \(H_2\) solution, \(LCOX(Ref)\) being the \(LCOX\) of the reference solution, both in $ per unit, and the (avoided CO\(_2\)) being the CO\(_2\) avoided between the \(H_2\) solution and \(Ref\) solution, in ton per unit.

Source: Kearney Energy Transition Institute analysis

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**4.2 Business models – Business cases**
A. The Rotterdam port is investigating the benefits of H₂ in its H-vision plan, which would combine fossil fuel-based production and CCS.

### Production of H₂ and CO₂ capture

<table>
<thead>
<tr>
<th>Technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>- High pressure ATR unit</td>
</tr>
<tr>
<td>- Centralized production of H₂ from CH₄ with CO₂ capture with Rectisol physical absorption</td>
</tr>
</tbody>
</table>

### Distribution of H₂

<table>
<thead>
<tr>
<th>End use</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Power plants: new gas turbines to enable H₂ firing, power generation from ATR steam</td>
</tr>
<tr>
<td>- Furnace heat in refineries</td>
</tr>
</tbody>
</table>

### CO₂ storage

| - Storage in North Sea depleted oil and gas fields |

### Illustrative

- **Main characteristics**
  - Up to 1,500 kt H₂ per day
  - H₂ purity of 96%
  - CCS: 88% capture rate (8 kg CO₂ captured per kg H₂)
  - Diameter: 12–28 inches
  - Operating pressure: about 70 bars
  - Power plants: 2x147 MWₑ H₂ turbines + 2x100 MWₑ gas/H₂ turbines: 1.9 GW of H₂
  - Refinery: H₂-rich refinery fuel gas
  - Multiple sites identified, with total capacity of 470 Mt
  - Stored quantity over 20 years: 120–288 MT

- **Cost components**
  - Capex: up to €910 million
  - Opex: 2.5% of capex
  - Cost: €0.5 million to €1.5 million per km
  - Total capex: €0.8 billion to €2.8 billion
  - Transport and storage: €17–€30 per ton

Sources: "Blue Hydrogen as Accelerator and Pioneer for Energy Transition in the Industry," H-vision, July 2019; Kearney Energy Transition Institute analysis

---

**Business cases**

Hydrogen hub produce from SMR
## Objective

- Reaching a carbon-neutral industry in Rotterdam by 2050

## Context

- Industries in Rotterdam port areas consumption of about 400 ktH₂ per year, half of the Netherlands production
- H₂ mainly produced from SMR without CCS
- Almost all production used for oil refineries

## H-vision scope

- Developing a blue hydrogen economy
- Development of new applications for H₂, including power, heat generation, chemicals
- Development of new production sources for H₂, preferably ATR combined with CCS
- FID by 2021 and project start-up by 2025

## Value chain and possible partners

### Supply

- Supply of natural gas, refinery fuel gas, and oxygen
  - Equinor
  - Shell
  - BP
  - Air Liquide

### Production

- Production of H₂
  - Uniper
  - Shell
  - BP
  - Air Liquide
  - Gasunie

### Distribution

- Transportation and storage of blue H₂
  - Vopak
  - Gasunie

### End use

- Power plant
  - Chemical sites
  - Vopak
  - Uniper
  - Shell
  - BP
  - ExxonMobile
  - Air Liquide

### Evacuation

- Transportation and storage of CO₂
  - Vopak
  - Port of Rotterdam
  - Gasunie

---

Sources: "Blue Hydrogen as Accelerator and Pioneer for Energy Transition in the Industry," H-vision, July 2019; Kearney Energy Transition Institute analysis
A. Multiple scenarios have been developed with various carbon impacts

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Hydrogen demand (GW)</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum scope</td>
<td>0.6 0.6 1.1</td>
<td>– 10% hydrogen co-firing in coal power plants</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– 25% co-firing in natural gas turbines</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– Adjustments to replace RFG with hydrogen fuel</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– Replacement of natural gas imported to balance the fuel gas grid (excluding gas turbines)</td>
</tr>
<tr>
<td>Reference scope</td>
<td>1.9 1.3 3.2</td>
<td>– 4x147 MWe hydrogen turbines (36.5% efficiency) added</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– 50% co-firing of hydrogen in natural gas turbines</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– Maximum adjustments to replace RFG with hydrogen-rich fuel</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– Replacement of natural gas imported to balance the fuel gas grid, excluding gas turbines</td>
</tr>
<tr>
<td>Maximum scope</td>
<td>2.8 1.9 5.2</td>
<td>– 4x147 MWe hydrogen turbines (36.5% efficiency) added</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– 15% co-firing of hydrogen in power plants or direct firing in boilers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– Maximum adjustments to replace RFG in all refineries with hydrogen-rich fuel</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– Replacement of natural gas imported to balance the fuel gas grid, excluding gas turbines</td>
</tr>
<tr>
<td></td>
<td></td>
<td>– Additional potential to replace natural gas of other end users</td>
</tr>
</tbody>
</table>

Sources: "Blue Hydrogen as Accelerator and Pioneer for Energy Transition in the Industry," H-vision, July 2019; Kearney Energy Transition Institute analysis
In the reference scenario, a total subsidy of €0.7 billion is required to make the H-vision project profitable given avoided ETS certificates of €3.4 billion.

Main hypotheses
- CO₂ emissions price: From €22 per ton in July 2019 to €149 per ton in 2045
- Gas price: €34 per MWh
- CO₂ captured and stored: About 6 MT per year
- Total H₂ demand: 3 207 MW, only for power plants and refineries
- H₂ storage: No storage
- WACC: 3%

Sources: "Blue Hydrogen as Accelerator and Pioneer for Energy Transition in the Industry," H-vision, July 2019; Kearney Energy Transition Institute analysis
A. The H-vision project could help avoid 27 to 130 Mtpa of CO₂ over 20 years with an abatement cost of CO₂ $97 to $213 per tCO₂.

### CO₂ impact of H-vision
(Avoided CO₂ in Mtpa, abatement cost in $ per tCO₂)

<table>
<thead>
<tr>
<th>Avoided CO₂ emissions (Mtpa)</th>
<th>Abatement cost range ($ per tCO₂eq)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum scope</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td></td>
</tr>
<tr>
<td>164</td>
<td>49</td>
</tr>
<tr>
<td>213</td>
<td></td>
</tr>
<tr>
<td>Reference scope</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td></td>
</tr>
<tr>
<td>97</td>
<td>67</td>
</tr>
<tr>
<td>164</td>
<td></td>
</tr>
<tr>
<td>Maximum scope</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td></td>
</tr>
<tr>
<td>102</td>
<td>67</td>
</tr>
<tr>
<td>170</td>
<td></td>
</tr>
</tbody>
</table>

Sources:  "Blue Hydrogen as Accelerator and Pioneer for Energy Transition in the Industry," H-vision, July 2019; Kearney Energy Transition Institute analysis

- A CCS unit on the ATR has a capture rate of 88%. Therefore, CO₂ emissions from hydrogen production for refinery use would be cut by 88%.
- For power generation, efficiency losses imply an overall emission reduction rate of about 80%. Natural gas turbines are slightly more efficient, and converting to hydrogen adds an intermediary step with additional losses.

4.2 Business models – Business cases
B. Power-to-X is the process of converting electricity into hydrogen for additional applications.

### 4.2 Business models – Business cases

#### 1 End uses are non-exhaustive.
#### 2 There are several possible options.

Source: Kearney Energy Transition Institute analysis
**Analyses have been conducted for multiple scenarios, with optimistic assumptions on renewable production sources evolution.**

Assumptions used for business cases

### 4.2 Business models – Business cases

**Configuration description for P2G project (based on France electrical mix)**

<table>
<thead>
<tr>
<th>Configurations</th>
<th>2019</th>
<th>2025f</th>
<th>2030f</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Electrolyzer</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Size</td>
<td>1 MW</td>
<td>10 MW</td>
<td>100 MW</td>
</tr>
<tr>
<td>Capex</td>
<td>€1,000 per kW</td>
<td>€800 per kW</td>
<td>€450 per kW</td>
</tr>
<tr>
<td>Stack</td>
<td>70,000 hours, 36% capex</td>
<td>80,000 hours, 28% capex</td>
<td>90,000 hours, 28% capex</td>
</tr>
<tr>
<td>Elec. Cons</td>
<td>60 kWh/kg</td>
<td>55 kWh/kg</td>
<td>50 kWh/kg</td>
</tr>
</tbody>
</table>

| **Grid utilization**            |                 |                 |                 |
| Load Factor                     | 90%             |                 |                 |
| Elec. Price                     | $48.60 per MWhe |                 |                 |
| CO₂                             | 475g per kWhe   |                 |                 |

| **Wind**                        |                 |                 |                 |
| Load Factor                     | 34%             | 35%             | 36%             |
| Elec. Price                     | $56 per MWhe    | $45 per MWhe    | $31 per MWhe    |
| CO₂                             | 11g per kWhe    |                 |                 |

| **Solar**                       |                 |                 |                 |
| Load Factor                     | 21%             | 23%             | 25%             |
| Elec. Price                     | $85 per MWhe    | $60 per MWhe    | $22 per MWhe    |
| CO₂                             | 42g per kWhe    |                 |                 |

| **Grid + wind**                 |                 |                 |                 |
| Load Factor                     | 90% (Wind 34–36% of time and grid 54–56% of time) |                 |                 |
| Elec. Price                     | $53.6 per MWhe  | $49.30 per MWhe | $43.60 per MWhe |
| CO₂                             | 300g per kWhe   | 294g per kWhe   | 289g per kWhe   |

| **Grid + solar**                |                 |                 |                 |
| Load Factor                     | 90% (Solar 25–30% of time and grid 60–65% of time) |                 |                 |
| Elec. Price                     | $59.70 per MWhe | $54.10 per MWhe | $43.70 per MWhe |
| CO₂                             | 373g per kWhe   | 365g per kWhe   | 354g per kWhe   |

In the long-term, as capex goes down, electrolyzer powered from renewables could be competitive with grid-connected.

### LCOH for P2X project: electrolyzer only (2019–2030, $ per kg)

<table>
<thead>
<tr>
<th>Year</th>
<th>2019: 1 MW</th>
<th>2025f: 10 MW</th>
<th>2030f: 100 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid utilization</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind</td>
<td>5.6</td>
<td>4.2</td>
<td>3.1</td>
</tr>
<tr>
<td>Solar</td>
<td>10.9</td>
<td>6.9</td>
<td>2.7</td>
</tr>
<tr>
<td>Grid wind</td>
<td>5.9</td>
<td>4.2</td>
<td>2.9</td>
</tr>
<tr>
<td>Grid solar</td>
<td>6.2</td>
<td>4.5</td>
<td>2.9</td>
</tr>
</tbody>
</table>

As of today, the cheapest option is to produce H₂ with a grid-connected electrolyzer. However, coupling grid with wind to reduce the carbon footprint is close to becoming competitive.

LCOE reduction from renewable and improvement of electrolyzer capex and opex is not expected to make green H₂ competitive compared with grid-connected electrolysis by 2025.

Reduction in LCOE for renewable sources, which is expected to become lower than average grid prices, will make green H₂ competitive out of the electrolyzer.

---

1. Current LCOH of brown hydrogen commonly ranges between 1$/kg to 2$/kg (more details slide 62).


---

H₂ electrolysis cost from various power sources

<table>
<thead>
<tr>
<th>Power Source</th>
<th>Grid utilization</th>
<th>Wind</th>
<th>Solar</th>
<th>Grid wind</th>
<th>Grid solar</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

At optimal rate, LCOH would be about 2.50 per kg at 64% use rate. However, it does not include other components that can be capex-intensive and require a high load factor.
The carbon footprint from electrolysis would be reduced only if powered by renewable sources, at an abatement cost of $125 to $145 per tCO₂.

Avoided CO₂ and abatement cost vs. SMR (2030, kgCO₂/kgH₂, $ per tCO₂)

<table>
<thead>
<tr>
<th>Grid utilization</th>
<th>Avoided CO₂ emissions</th>
<th>Net emitter</th>
<th>CO₂ emissions reduction</th>
<th>Avoidance cost vs. SMR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid wind</td>
<td>-4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grid solar</td>
<td>-7</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind</td>
<td>10</td>
<td></td>
<td></td>
<td>124</td>
</tr>
<tr>
<td>Solar</td>
<td>9</td>
<td></td>
<td></td>
<td>144</td>
</tr>
</tbody>
</table>

CO₂ neutrality: about 200g per kWh
CO₂ neutrality: about 350g per kWh
CO₂ neutrality: about 275g per kWh

As LCOH from electrolysis is expected to decline sharply, green hydrogen could become competitive with SMR if CO₂ prices reach $124 to $144 per tCO₂.

Considering only hydrogen production (excluding additional infrastructure, storage, and consumption end points that might be needed), only electrolysers powered by renewable would have a positive impact on CO₂ emissions compared with SMR.

Note: Hypothesis detailed in the appendix. CO₂ neutrality is defined as the maximum CO₂ footprint from the power sector to reach carbon neutrality between SMR and electrolysis.

Sources: Intergovernmental Panel on Climate Change; Kearney Energy Transition Institute analysis

4.2 Business models – Business cases
Overview of grid services from electrolysis (2022, wind and solar generation)

High variability of renewable production
Wind and solar production in NREL 2022 business case
Variable energy production from solar and wind sources directly injected on the grid can impact operations (for example, demand lower than production, frequency variations)

Quick response time and flexibility of PEM
45 MW of electrolyzers with advanced control is considered in the National Renewable Energy Laboratory 2022 business case
PEM can operate at higher rates than nominal load for a certain period of time without impacting its lifetime, which can provide negative power control to the grid.
It can also operate below its nominal rate (to 20%) to provide positive power control to the grid.

Business case opportunity
With coordinated operations between electrolyzers, a fixed power is injected to the grid from solar and wind power plant.
There is potential for a H₂ producer to monetize this service, which could further reduce LCOH.

**Positive power control opportunity**

In France, TAC ("turbines à combustible") provide electricity during peak times to maintain grid frequency.

In 2018, TAC delivered power above 60MW for about 467 hours.

**Negative power control opportunity**

Variability in renewable production can lead to excess supply on the electric grid, which may require switching off other sources or incentivizing consumers to use the surplus if switch-off time is too long, too risky, or too expensive.

In 2018, renewable production growth occurring at the same time as a decrease of other production sources happened for 2,451 hours.

**Remuneration system, based on Austria tender prices:**
- €10 per MW available per hour
- €120 per MWh delivered

**Note:** Grid stabilization with electrolysis (2018 example, France)

Sources: National Renewable Energy Laboratory, RTE, Smarten.eu; Kearney Energy Transition Institute analysis
LCOH could be reduced by up to 60% if grid servicing provided by electrolyzers are considered and managed.

LCOH reduction from grid servicing (2030, $ per kg, 100 MW electrolyzer)

**Positive power control**
Electrolyzer running at 100 MW, with the possibility to run at 20 MW when power on the grid is required, which would have happened for 440 hours per year.

**Negative power control**
Electrolyzer running at 80 MW, with the possibility to run at 100 MW when electricity needs to be absorbed on the grid, which would have happened for 2,451 hours.

**Combined power control**
Electrolyzer running at 80 MW, with the possibility to run at 100 MW when electricity needs to be absorbed on the grid or at 20 MW when power is required on the grid.

Because these mechanisms are still in preliminary stages for electrolyzers, the following analyses will not include power control remuneration.

Sources: National Renewable Energy Laboratory, RTE, Smarten.eu; Kearney Energy Transition Institute analysis.
Power-to-gas is the process of converting surplus electricity into H₂ through electrolysis for further applications, such as heating and mobility.

- Electrolyzer is a key component in a P2G business case and needs to be flexible enough to adapt to sudden power changes and multiple switch-on and switch-off.
- PEM, even if more expensive than AE electrolyzers, is currently the preferred solution thanks to its quick reaction time and its capability to operate at 160% of nominal power for a short period of time.

Sources: International Renewable Energy Agency; Kearney Energy transition Institute
P2G has been identified as a tool to enable high penetration of renewable on the electricity grid.

Value electricity production surplus from RES

- Wind and photovoltaic have high potential to penetrate electricity grids with fast declining LCOE.
- These generation sources are dependent on weather changes and a high level of integration will require more flexibility.

Store at different time scale and transport energy through gas grid

- Existing gas networks are able to store energy, either as H₂ or CH₄ if there is a methanation step.
- In France, gas network storage capacity is about 140 TWh, compared with 0.4 TWh on the electricity network.

Use renewable electricity for multiple applications

- Hydrogen—or methane—produced can be used as a fuel for mobility, feedstock for chemicals, or heat for industry or be converted back to electricity if needed.

Key advantages of P2G

2050 P2G potential, year of study (TWh, France)

Higher values for high renewable penetration

Multiple studies conducted

NegaWatt scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>35</td>
</tr>
<tr>
<td>2018</td>
<td>150</td>
</tr>
</tbody>
</table>

Sources: GRDF; Kearney Energy Transition Institute analysis
Multiple projects are being launched to test the viability of the system.

**Power-to-gas project examples (2015, Europe)**

<table>
<thead>
<tr>
<th>Project name</th>
<th>Production</th>
<th>Storage and injection</th>
<th>End-use applications</th>
<th>Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 GRHYD</td>
<td>50 kW PEM electrolyzer</td>
<td>Stored in metal hydrides (50 m³)</td>
<td>Residential district heating</td>
<td>€15 million</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Blended with CH₄ before injection (up to 20% H₂)</td>
<td>Hythane (H₂ and CH₄ mixed) fuel for city buses</td>
<td></td>
</tr>
<tr>
<td>2 Jupiter 1000</td>
<td>500 kW AE electrolyzer</td>
<td>Blended with CH₄ before injection (up to 6% H₂)</td>
<td>Methanation, with CO₂ injection from CCS plant</td>
<td>€30 million</td>
</tr>
<tr>
<td></td>
<td>500 kW PEM electrolyzer</td>
<td></td>
<td>Industrial and residential applications in Fos-sur-Mer district</td>
<td></td>
</tr>
<tr>
<td>3 Audi e-gas</td>
<td>3x 2 MW AE electrolyzers</td>
<td>Methanation, with CO₂ injection from CCS plant</td>
<td>Synthetic gas used for vehicles fuel</td>
<td>n.a.</td>
</tr>
</tbody>
</table>
## GRHYD project example

**Objective**
- Value fatal electricity production from renewable sources through green H₂.

**Context**
- France’s objective is to have renewable energy representing 23% of final energy consumption by 2020.
- According to ADEME, up to 30 TWh of hydrogen could be produced by power-to-gas by 2035, and a full conversion to a 100% renewable gas-based scenario by 2050 is feasible.

## GRHYD scope
- Experiment with power-to-gas at project scale:
  - Test reactivity of PEM electrolyzer.
  - Test gas network adaptability to hydrogen injection.
  - Determine upper limit of injection (currently at 20% on new networks).
  - Test metal hydrides storage option.

## Value chain and possible partners

<table>
<thead>
<tr>
<th>Value chain and possible partners</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Electricity</strong></td>
</tr>
<tr>
<td>Fatal electricity production from VRE</td>
</tr>
<tr>
<td><strong>Electrolysis</strong></td>
</tr>
<tr>
<td>PEM electrolyzer producing H₂ and O₂ (released)</td>
</tr>
<tr>
<td><strong>Storage</strong></td>
</tr>
<tr>
<td>Storage in metal hydrides</td>
</tr>
<tr>
<td><strong>Injection</strong></td>
</tr>
<tr>
<td>Blending up to 20%</td>
</tr>
<tr>
<td>Injection of mixed gas (hythane¹) on gas network</td>
</tr>
<tr>
<td><strong>End use</strong></td>
</tr>
<tr>
<td>Heating for new residential buildings</td>
</tr>
<tr>
<td>Fuel for Hydrogen buses</td>
</tr>
</tbody>
</table>

Sources: GRHYD; Kearney Energy Transition Institute analysis

1 Hydrogen and methane

---

B1 The GRHYD project was launched in Dunkirk to inject up to 20% of green H₂ on residential gas network for heating and mobility.
### Power-to-gas: blending business case

#### Production of H₂ and injection on gas network systems (blending) include electricity generation, electrolyzer, and injection station

#### Year 2019: 1 MW 2030f: 100 MW

<table>
<thead>
<tr>
<th>Capex ($ million)</th>
<th>Transformer: $0.013</th>
<th>Line: $0.112</th>
<th>Pipeline: $0.3</th>
<th>2019: 1 MW</th>
<th>2030f: 100 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPEX (% capex)</td>
<td>Electrification: 0%</td>
<td>Pipeline: 2%</td>
<td></td>
<td>1.46</td>
<td>3.10</td>
</tr>
<tr>
<td>Electricity required (% losses)</td>
<td>3% (losses)</td>
<td>3% (losses)</td>
<td></td>
<td>–</td>
<td>–</td>
</tr>
</tbody>
</table>

All hypotheses are described in slide 134 (more details slides 65 to 69).
The levelized cost of energy (blending) could go down to $86 to $99 per MWh by 2030, making it competitive with biomass gas.

Levelized cost of energy: injection ($ per MWh–LHV)

<table>
<thead>
<tr>
<th>Year</th>
<th>Capacity</th>
<th>Grid utilization</th>
<th>Wind</th>
<th>Solar</th>
<th>Grid wind</th>
<th>Grid solar</th>
</tr>
</thead>
<tbody>
<tr>
<td>2019</td>
<td>1 MW</td>
<td>168</td>
<td>214</td>
<td>331</td>
<td>177</td>
<td>189</td>
</tr>
<tr>
<td>2025f</td>
<td>10 MW</td>
<td>126</td>
<td>149</td>
<td>210</td>
<td>128</td>
<td>136</td>
</tr>
<tr>
<td>2030f</td>
<td>100 MW</td>
<td>95</td>
<td>81</td>
<td>81</td>
<td>88</td>
<td>86</td>
</tr>
</tbody>
</table>

- As of today, injection on the gas grid is not competitive compared with natural gas or biomass.
- The capex required for an injection plant is not amortized because of low production levels.
- As production grows, capex for infrastructure and injection plant is amortized faster.
- Production from grid electricity is now competitive with biomass but may have CO₂ impact.
- By 2030, gas injection on the grid would be competitive with biogas.

Only injection plants connected to REN without grid back-up would help reduce CO₂ emissions at a cost of $200 to $270 per tCO₂.

Avoided CO₂ and abatement cost (2030, kgCO₂/kgH₂, $ per tCO₂)

- **Avoided CO₂ emissions**
  - Grid utilization: -538
    - CO₂ neutrality: about 125g per kWhe
  - Wind: 182
    - CO₂ neutrality: about 220g per kWhe
  - Solar: 135
    - CO₂ neutrality: about 160g per kWhe
  - Grid wind: -250
    - CO₂ neutrality: about 220g per kWhe
  - Grid solar: -351
    - CO₂ neutrality: about 160g per kWhe

- **Abatement cost @ NG = $50 per MWh**
  - IPCC 2°C carbon price recommendation, 2030

- The carbon abatement cost from wind powered electrolysis and H₂ injection through P2G system would be in line with the IPCC recommendations on carbon price upper limit ($220 per tCO₂).
- Other benefits, such as frequency balancing, jobs creation, and lower dependency to fossil fuels, are not included in the calculation and could further reduce the avoidance cost.

Notes: The hypothesis is detailed in the appendix. CO₂ neutrality is defined as the maximum CO₂ footprint from the power sector to reach carbon neutrality between natural gas and injection.

Sources: Intergovernmental Panel on Climate Change; Kearney Energy Transition Institute analysis

Power-to-gas: blending business case

4.2 Business models – Business cases

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B1a Top natural gas consumers would not be able to reduce carbon emissions if electrolyzer is coupled with the grid

4.2 Business models – Business cases

Power-to-gas: blending business case

Note: CAC is carbon abatement cost. The hypothesis is detailed in the appendix. Sources: Intergovernmental Panel on Climate Change, Organisation for Economic Co-operation and Development; Kearney Energy Transition Institute analysis
The hydrogen injection potential is limited in volume by end applications for safety and performance reasons.

Injection on highly connected grids will be limited by end use applications. However, injection on local networks has greater potential.

### Safety issues
- High flame velocity increasing risk of spreading and requiring new flame detectors for high blend ratios
- Corrosivity on old gas networks

### Performance issues
- Lower energy density (in volume) than methane, requiring end users to burn higher volume of gas
- Industrial sectors that rely on carbon content in natural gas (e.g. steel) needing to use higher volumes

#### Limits of hydrogen injection on gas networks (% of volume)

<table>
<thead>
<tr>
<th>Applications</th>
<th>Distribution</th>
<th>Gas meters</th>
<th>Transmission</th>
<th>Compressors</th>
<th>Underground storage</th>
<th>Boilers</th>
<th>Cooking</th>
<th>Engines</th>
<th>CNG tanks</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>50%</td>
<td>50%</td>
<td>20%</td>
<td>10%</td>
<td>2%</td>
<td>30%</td>
<td>30%</td>
<td>5%</td>
<td>30%</td>
</tr>
<tr>
<td></td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**B1b Methanation**

Methanation is the process of converting hydrogen into synthetic methane before injection on the gas grid.

---

**Power-to-gas: methanation business case**

---

**4.2 Business models – Business cases**

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**151 KEARNEY | Energy Transition Institute**

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**P2G: methanation value chain**

<table>
<thead>
<tr>
<th>Year</th>
<th>1 MW</th>
<th>100 MW</th>
<th>Capacity (tH₂/m³ per year)</th>
<th>Capex ($ million)</th>
<th>OPEX (% capex/$ million per year)</th>
<th>Electricity required (% losses per kWh)</th>
<th>CO₂ cost¹ ($ per ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Transfer: $0.013</td>
<td>Electrification: 0%</td>
<td>3% (losses)</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Line: $0.112 Pipeline: $0.3</td>
<td>Pipeline: 2%</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$0.01</td>
<td>0.01</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$1.2</td>
<td>0.88 kWh/kW hCH₄ 0.88 kWs/kW hCH₄</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$0.9</td>
<td>0.21 kWh/kW hCH₄ 0.21 kWs/kW hCH₄</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$76</td>
<td>0.17</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$71</td>
<td>0.17</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.17</td>
<td></td>
</tr>
</tbody>
</table>

1 Includes capture and storage. Supposed on-site capture, not requiring transportation and operated independently from the rest of the plant delivering CO₂ at constant cost. Sources: TM Power, expert interviews; Kearney Energy Transition Institute analysis.
The levelized cost of energy (for methanation) could go down to $175 to $264 per MWh by 2030, which would make it uncompetitive with biogas (or injection).

**Power-to-gas: methanation business case**

<table>
<thead>
<tr>
<th>Storage</th>
<th>Infrastructure</th>
<th>Methanation</th>
<th>Injection</th>
<th>Electrolysis</th>
<th>Current biogas price range</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>100-150$/MWh</td>
</tr>
</tbody>
</table>

**Levelized cost of energy: methanation ($ per MWh – LHV)**

<table>
<thead>
<tr>
<th>Grid utilization</th>
<th>2019: 1 MW</th>
<th>2025f: 10 MW</th>
<th>2030f: 100 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grid wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grid solar</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Methanation and methane injection are highly capex-intensive, which increases the LCOE at low utilization rates, such as for solar and wind.

Higher production requires a higher quantity of CO2 and electricity, which would make methanation costs decline slower than injection costs.

Overall process efficiency is lower because methane carries less energy density for the same weight of hydrogen, and methanation is power intensive.

1. Current biogas price range: 100-150$/MWh

**Avoided CO₂ and abatement cost** (2030, kgCO₂ per MWh, $ per tCO₂)

### Avoided CO₂ emissions

<table>
<thead>
<tr>
<th>Grid utilization</th>
<th>Net emitter</th>
<th>CO₂ emissions reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>-1,209</td>
<td></td>
</tr>
<tr>
<td>Solar</td>
<td>-661</td>
<td></td>
</tr>
<tr>
<td>Grid wind</td>
<td>-661</td>
<td></td>
</tr>
<tr>
<td>Grid solar</td>
<td>-853</td>
<td></td>
</tr>
</tbody>
</table>

**CO₂ neutrality:** about 65 g per kWeh

**IPCC 2°C carbon price recommendation, 2030**

- Wind-powered electrolysis and methanation could be competitive with methane if CO₂ were priced around $1,300 per ton, which is unlikely to happen as the IPCC CO₂ price scenario varies from $15 to $220 per ton in the 2°C scenario to more than $6,000 per t in the 1.5°C scenario.

**Business cases**

- Natural gas emissions in combustion are around 200 kg per MWh.
- With a low-carbon electrical mix, CO₂ emissions are always below when hydrogen is produced, even if connected to the electrical grid.
- If CO₂ emissions for electricity production are above 65 g per kWh, hydrogen from grid would be a net emitter.

**Note:** Hypothesis detailed in the appendix. CO₂ neutrality is defined as the maximum CO₂ footprint from the power sector to reach carbon neutrality between SMR and electrolysis.

Sources: Intergovernmental Panel on Climate Change; Kearney Energy Transition Institute analysis
The carbon abatement cost appears to always be higher than the IPCC recommendation, even if electrical mix is fully decarbonized.

For most countries, because the CO2 intensity of the power sector is above 200g per kWh (LHV of natural gas), methanation of H2 from the grid would generate more CO2 emissions. Because methanation is power intensive, a carbon intensity below 120 g per kWh is required to reduce CO2 emissions if connected with the grid.

For France, carbon avoidance cost is cheaper with a fully wind-powered electrolyzer with no grid connection but still higher than the IPCC’s recommendation. Countries with a carbon intensity below 25 g per kWh would benefit from connecting the electrolyzer to the grid.

Notes: CAC is carbon abatement cost. The hypothesis is detailed in the appendix.
Sources: Intergovernmental Panel on Climate Change, Organisation for Economic Co-operation and Development; Kearney Energy Transition Institute analysis

Power-to-gas: methanation business case

4.2 Business models – Business cases

B1b The carbon abatement cost appears to always be higher than the IPCC recommendation, even if electrical mix is fully decarbonized

CAC vs. CO2 emissions from electricity generation (2030)

Abatement cost ($ per tCO2)

Countries with no potential for carbon emissions reduction from grid coupling:

CAC from solar

CAC from wind

IPCC price recommendation

Grid Grid + solar Grid + wind

Grid emissions (kgCO2 per MWhe)

0 50 100 150 200

Notes: CAC is carbon abatement cost. The hypothesis is detailed in the appendix. Sources: Intergovernmental Panel on Climate Change, Organisation for Economic Co-operation and Development; Kearney Energy Transition Institute analysis
Power-to-power requires high-pressure storage to feed the fuel cell for electricity generation.

### P2P value chain

<table>
<thead>
<tr>
<th>Year</th>
<th>1 MW</th>
<th>100 MW</th>
<th>1 MW</th>
<th>100 MW</th>
<th>1 MW</th>
<th>100 MW</th>
<th>1 MW</th>
<th>100 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity (tH₂ per MW)</td>
<td>-</td>
<td>-</td>
<td>0.78 t H₂ 2 days</td>
<td>94 t H₂ 2 days</td>
<td>-</td>
<td>-</td>
<td>16 kg H₂ 1 hour</td>
<td>2 t H₂ 1 hour</td>
</tr>
<tr>
<td>Capex ($ million)</td>
<td>Transfer: $0.013</td>
<td>Line: $0.112</td>
<td>Pipeline: $0.3</td>
<td>$0.53</td>
<td>$31.8</td>
<td>0.3</td>
<td>17.6</td>
<td>$0.045</td>
</tr>
<tr>
<td>Opex (% capex/$ million per year)</td>
<td>Electrification: 0%</td>
<td>Pipeline: 2%</td>
<td>$0.01 million</td>
<td>$1.2 million</td>
<td>6%</td>
<td>6%</td>
<td>$0.01 million</td>
<td>$0.9 million</td>
</tr>
<tr>
<td>Electricity required (% losses per kWh)</td>
<td>3% (losses)</td>
<td>-</td>
<td>-</td>
<td>8.3 kWh/kg</td>
<td>3.0 kWh/kg</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Efficiency (%)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>65%</td>
</tr>
</tbody>
</table>

### Illustrative Grid connection and infrastructure
- Electrolyzer
- LP storage (60 bars)
- Compression
- HP storage (900 bars)
- Stationary fuel cell


**4.2 Business models – Business cases**
The levelized cost of electricity from power-to-power could vary from $180 to $270 per MWhe by 2030.

P2P: Energy Storage System business case

1. Current ESS battery price range: 100-200 $/MWh


4.2 Business models – Business cases

Fuel Cell
Storage (LP & HP)
Compression
Infrastructure
Electrolysis
Current ESS battery price range

Levelized cost of energy: Power
($ per MWhe)

2019: 1 MW
2025f: 10 MW
2030f: 100 MW

Grid utilization

Wind
Solar
Grid wind
Grid solar

– P2P systems are capital-intensive as they require electrolyzer, fuel cell, storage tanks, and compressor.

– Low-pressure tanks could store up to two days of production to ensure business continuity even during renewable disruptions. If needed, trailers could supply additional H₂ to the plant (not included in calculations).

– High-pressure tanks and fuel cells delivers electricity to the grid, with a capacity of 70 MWhe and a maximum power output of 100 MW.

– Additional capacity and power output would increase HP storage and fuel cell capex and overall LCOE.
Selling P2P electricity on the spot market appears to be very opportunistic as prices are over LCOE less than 1% of the time.

P2P: Energy Storage System business case

---

4.2 Business models – Business cases

- Spot prices are below $100 per MWh 99% of the time.
- Producing hydrogen during low spot prices and providing electricity to the grid when prices are higher than production costs appears to have low potential as LCOE from P2P may always be higher than spot prices, except for a few hours per year.
- P2P systems can also provide grid flexibility and help load management.

### Avoided CO₂ and abatement cost vs. coal turbines (2030, kgCO₂/MWh, $ per tCO₂)

**Coal turbines** are among the highest polluting electricity sources, with about 820 gCO₂ per kWhe emitted.

- **While many countries use coal turbines as a baseload for electricity generation, some use coal turbines as reserve capacity to meet demand at peak times.**
- **Coupling electrolyzer with renewables and store H₂ to ensure operations during peak times.**
- **In 2019, coal power plants generated more than 10,000 TWh of electricity (about 38% of global electricity production).**
- **Shifting all coal power plants to P2P H₂ sources would require electricity generation from wind turbines of about 16,500 TWh (at least 5,000 GW of installed capacity only dedicated to H₂ production).** As of 2018, worldwide wind production capacity was about 600 GW, growing 55 GW per year over the past three years.

**Sources:** Bilan Electrique 2018; RTE; Lazard; International Energy Agency; Kearney Energy Transition Institute analysis

---

**Carbon Neutrality** is defined as the maximum CO₂ footprint from the power sector to reach carbon neutrality between coal turbine and P2P solution.

**Note:** CO₂ neutrality is defined as the maximum CO₂ footprint from the power sector to reach carbon neutrality between coal turbine and P2P solution.

- **Coal turbines** are among the highest polluting electricity sources, with about 820 gCO₂ per kWhe emitted.
- **While many countries use coal turbines as a baseload for electricity generation, some use coal turbines as reserve capacity to meet demand at peak times.**
- **Coupling electrolyzer with renewables and store H₂ to ensure operations during peak times.**
- **In 2019, coal power plants generated more than 10,000 TWh of electricity (about 38% of global electricity production).**
- **Shifting all coal power plants to P2P H₂ sources would require electricity generation from wind turbines of about 16,500 TWh (at least 5,000 GW of installed capacity only dedicated to H₂ production).** As of 2018, worldwide wind production capacity was about 600 GW, growing 55 GW per year over the past three years.

**Sources:** Bilan Electrique 2018; RTE; Lazard; International Energy Agency; Kearney Energy Transition Institute analysis

---

**P2P: Energy Storage System business case**

#### 4.2 Business models – Business cases

**Note:** CO₂ neutrality is defined as the maximum CO₂ footprint from the power sector to reach carbon neutrality between coal turbine and P2P solution.

**Sources:** Bilan Electrique 2018; RTE; Lazard; International Energy Agency; Kearney Energy Transition Institute analysis
The top coal consumers would not reduce CO₂ emissions by coupling electrolyzer with grid, except the United States and Russia, but at a higher cost than RES.

P2P: Energy Storage System business case

**4.2 Business models – Business cases**

Note: CAC is carbon abatement cost. The hypothesis is detailed in the appendix. Sources: Intergovernmental Panel on Climate Change, Organisation for Economic Co-operation and Development; Kearney Energy Transition Institute analysis.
Green H₂ can be produced in chemical plants or refineries to provide a decarbonized feedstock

**REFHYNE project overview**
(Pilot project)

**Shell refinery in Wesseling**

**Current situation**
- The refinery supplies 10 to 15% of Germany’s fuel needs.
- Hydrogen produced by steam methane reforming, with about 180 kTH₂ every year
- CO₂ emissions from SMR at Wesseling amounts to about 1.6 to 2.0 mtCO₂ per year.

**Integration of a 10 MW PEM electrolyzer**
- Test economical, technical, and environmental impact of the solution

**Business case review**
- Electrolyzer will be connected to the grid with the following revenue streams:
  - Supply of hydrogen to refinery (1% of refinery demand)
  - Load management for refinery site
  - Grid balancing
- If produced from RES, electrolyzer could save up to 16 ktCO₂ per year at the refinery.
- In the future, hydrogen will also be supplied to other local users, such as bus networks.
- Total investment is about €20 million, with financing from the European Union.
- To achieve 100% green hydrogen production, the electrolyzer size needs to reach 1 GW.
### Green hydrogen as a feedstock

includes a low number of steps and could become competitive in certain situations.

---

#### Levelized cost of energy: feedstock ($ per kg)

<table>
<thead>
<tr>
<th></th>
<th>2019: 1 MW</th>
<th>2025f: 10 MW</th>
<th>2030f: 100 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid utilization</td>
<td>5.6 0.5 6.1</td>
<td>4.2 0.1 4.3</td>
<td>3.1 0.1 3.2</td>
</tr>
<tr>
<td>Wind</td>
<td>7.1 1.2 8.3</td>
<td>4.9 0.2 5.1</td>
<td>2.7 0.1 2.7</td>
</tr>
<tr>
<td>Solar</td>
<td>10.9 1.9 12.8</td>
<td>6.9 0.2 7.2</td>
<td>2.7 0.1 2.7</td>
</tr>
<tr>
<td>Grid wind</td>
<td>5.9 0.5 6.4</td>
<td>4.2 0.1 4.3</td>
<td>2.9 0.1 3.0</td>
</tr>
<tr>
<td>Grid solar</td>
<td>6.2 0.5 6.8</td>
<td>4.5 0.1 4.6</td>
<td>2.9 0.1 3.0</td>
</tr>
</tbody>
</table>

- Hydrogen for industrial use is currently much more expensive than brown sources.
- Hydrogen from REFHYNE electrolyzer (10 MW PEM) is probably more expensive than onsite SMR, but services provided to refinery power grid could help reduce LCOH.
- A 100 MW electrolyzer running at about 90% would supply only 10% of Wesseling refinery needs.

---

#### Power-to-chemical: business case refining

- Hydrogen from brown sources will become competitive with green hydrogen.

---

### Business models – Business cases

- **Power-to-chemical:**
  - Business case refining

---

#### Notes:

1. Current SMR LCOH range: $1-$2/kg

Reducing carbon emissions is only possible with renewable sources coupling, with an abatement cost of $129 to $150 per ton.

Avoided CO₂ and avoidance cost vs. SMR
(2030, kgCO₂/kgH₂, $ per tCO₂, based on world electrical mix)

- Grid utilization
  - Wind: -13
  - Solar: -13
  - Grid wind: -4
  - Grid solar: -7

- CO₂ neutrality: about 200g per kWhe

Notes: The hypothesis is detailed in the appendix. CO₂ neutrality is defined as a maximum CO₂ footprint from the power sector to reach carbon neutrality between SMR and electrolysis.

Sources: Intergovernmental Panel on Climate Change; Kearney Energy Transition Institute analysis.

- Only electrolyzers powered by renewable sources would have a positive impact on CO₂ emissions compared with SMR.

- The abatement cost is similar to the one from centralized ATR blue production in business case n°1 (100 to 150 $ per tCO₂). However, it might be more competitive for existing chemical plants and refineries to add CCS to existing SMR.

- Further services provided by electrolyzer, such as power consumption optimization, might help reduce the abatement cost.
Power-to-chemical: business case refining

B3 Hydrogen from grid-powered electrolyzer could reduce emissions at low cost if the carbon footprint is below 50g per kWhe

4.2 Business models – Business cases

CAC vs. CO₂ emissions from electricity gen. (2030)

Abatement cost
($ per tCO₂)

Countries with no potential for carbon emissions reduction from grid coupling:

- Grid
- Grid + wind
- Grid + solar
- Blue H₂ CAC

IPCC price recommendation

Grid emissions (kgCO₂/MWhe)

- Industrial processes such as oil refining require large volumes of hydrogen.
- Converting all current hydrogen production for industrial applications (about 70 Mt) to electrolyzers would require about 500 GW of electrolysis capacity running at 90%.
- Blue production sources could also be considered to reduce carbon emissions at lower cost but has associated risks, such as carbon leakage, and is still dependent on fossil fuels.
- The carbon avoidance cost from electrolysis is higher than blue sources, but large-scale electrolyzers could provide additional services to the plant grid, such as power consumption management.

Note: CAC is carbon abatement cost. The additional cost of blue H₂ has been studied in the production section of this factbook. The hypothesis detailed in the appendix.

Sources: Intergovernmental Panel on Climate Change, Organisation for Economic Co-operation and Development; Kearney Energy Transition Institute analysis.
Hydrogen could also be the vector to couple power and mobility with local electrolyzer and refueling stations.

Power to Mobility value chain

<table>
<thead>
<tr>
<th>Year</th>
<th>1 MW</th>
<th>100 MW</th>
<th>1 MW</th>
<th>100 MW</th>
<th>1 MW</th>
<th>100 MW</th>
<th>1 MW</th>
<th>100 MW</th>
<th>1 MW</th>
<th>100 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Capacity (tH₂)</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Capex ($ million)</strong></td>
<td>Transfer: $0.013</td>
<td>Line: $0.112</td>
<td>Transfer: $0.30</td>
<td>Line: $0.112</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>$0.53</td>
<td>$31.8</td>
<td>$0.3</td>
<td>$17.6</td>
<td>$0.15</td>
<td>$10.2</td>
<td>$0.078</td>
<td>$2.4</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Opex (% capex/$ million per year)</strong></td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>8%</td>
<td>8%</td>
</tr>
<tr>
<td></td>
<td>$0.01 million</td>
<td>$1.2 million</td>
<td>6%</td>
<td>6%</td>
<td>6%</td>
<td>6%</td>
<td>8%</td>
<td>8%</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Electricity required (% losses per kWh)</strong></td>
<td>3%</td>
<td>3%</td>
<td>-</td>
<td>-</td>
<td>8.3 kWh/kg</td>
<td>3.0 kWh/kg</td>
<td>-</td>
<td>-</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Capacity (tH₂)</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>0.78 t H₂ 2 days</td>
<td>94 t H₂ 2 days</td>
<td>-</td>
<td>-</td>
<td>48 kg H₂ 3 hours</td>
<td>6 t H₂ 3 hours</td>
<td>-</td>
<td>-</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

All hypotheses are described in slide 107.


4.2 Business models – Business cases
Overall LCOH could go as low as $4 to $5 per kg by 2030 and become more competitive than ICE fuels (however total cost of ownership should also be considered).

Power-to-mobility: business cases car, bus and train

### Levelized cost of hydrogen: mobility ($ per kg)

#### Grid utilization
- **2019: 1 MW**
  - Wind: 11
  - Solar: 4
  - Grid wind: 6
  - Grid solar: 6

#### 2025f: 10 MW
- Wind: 4
- Solar: 1
- Grid wind: 4
- Grid solar: 4

#### 2030f: 100 MW
- Wind: 0
- Solar: 0
- Grid wind: 0
- Grid solar: 0

---

\(^1\) Considering 6 to 10L/100km of fuel consumption at $1 per L, equivalent to 6-10 $/kg of hydrogen. Full comparison between ICE and FCEV also presented in the following slides.


---

4.2 Business models – Business cases

- **P2M systems are capital-intensive as they require electrolyzer, dispenser, storage tanks, and compressor.**
- **Storage tanks are designed to store two days of production at 100% utilization rate. When the utilization rate is low, storage costs are high.**
- **Grid-connected electrolyzer could be considered as a business case if electricity generation emissions do not overcome emissions from internal combustion engines.**
Faster refueling time for hydrogen-based vehicles also leads to less space requirements and lower investment costs.

- Hydrogen refueling takes one tenth to one fifteenth of the time fast charging demands.
- **Charging times (HRS vs EV)**
  - Bus: 7–15 mins vs. several hours
  - Car: 3–4 mins vs. 4 hours
  - Forklift: 1–3 mins vs. 25 mins
  - Scooter: less than 1 minute vs 4–8 hours
  - Train: 15 minutes vs. 45 minutes

- Fast-charging stations handling the same number of vehicles need 10 to 15 times the space of a comparable HRS.
- One HRS with four dispensers could potentially replace 60 fast-charger stations.
- Beneficial to the customer and for municipalities with space constraints.

When fully utilized, HRS are estimated to cost only half of the capex per refueling compared with fast chargers.

- Lower costs present an attractive business case for operators.

### Space requirements and investment costs for HRS

#### Refueling speed

Refueling speed (s per 100km of refueling)

- Petrol: 48
- H2 station (HRS): 65
- Electric fast charger: 1,000

#### Space requirements

Space required to service (same number of vehicles, comparative basis)

- HRS: 10–15x
- Fast charger: 2x

#### Investment costs

Investment costs per refueling ($/refueling)

- Petrol: 0.7
- HRS: 4.0
- Fast charger: 8.5

Note: HRS is hydrogen refueling station.
Source: Kearney Energy Transition Institute analysis
TCO for a H₂ car could compete with a traditional ICE engine if refueling stations are not under-used.

Power-to-mobility: business case car

4.2 Business models – Business cases

---

**Total cost of ownership: cars** (2019–long term, $ per 100 km)

<table>
<thead>
<tr>
<th></th>
<th>2019</th>
<th>Long-term</th>
</tr>
</thead>
<tbody>
<tr>
<td>FCEV 400 km</td>
<td>65</td>
<td>46</td>
</tr>
<tr>
<td>BEV 400 km</td>
<td>56</td>
<td>46</td>
</tr>
<tr>
<td>BEV 250 km</td>
<td>50</td>
<td>44</td>
</tr>
<tr>
<td>ICE Hybrid 400 km</td>
<td>21</td>
<td>46</td>
</tr>
<tr>
<td>BEV 400 km</td>
<td>18</td>
<td>2</td>
</tr>
<tr>
<td>BEV 250 km</td>
<td>11</td>
<td>2</td>
</tr>
<tr>
<td>ICE Hybrid 400 km</td>
<td>8</td>
<td>0</td>
</tr>
</tbody>
</table>

- **Base car cost**
- **Battery, fuel cell**
- **Operations and maintenance**
- **Electricity, fuel**
- **Refueling, charging**

---

**Investment costs**

- About 24 to 32% of costs are driven by fuel cells. Cost reduction will help improve FCEV cars’ competitiveness.
- Today’s FCEVs have a broader range per tank than most BEV (400–600 km vs. 250–400 km). However, TCO is higher.
- Acquisition and infrastructure cost are higher.
- Utilization of infrastructure is key for competitiveness of FCEV. For example, a 200 kg H₂ station at 10% adds a marginal LCOH of $13 per 100 km vs. $4 per 100 km if utilized at 33%.
- In the long term, the TCO for FCEV will be comparable with BEV, which would have by then an extended range as well.
- Consumers could also value qualitative benefits in addition to TCO, such as charging time and infrastructure deployment.

---

Hydrogen cars have ranges close to high-end BEVs and at a lower cost, but TCO remains higher than mid-end BEVs.

Power-to-mobility: business case car

4.2 Business models – Business cases

1 Car price: $20,000; fuel consumption: 6.0L/100km
In the long term, FCEV is expected to be more competitive than BEV if the vehicle range is 200 to 400 km

Power-to-mobility: business case car

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

Further considerations

- **Charging time**: See slide 130.
- **CO2 emissions**: End-to-end CO₂ emissions have to be evaluated, including battery and fuel cell production and recycling as well as fuel production (either H₂ or electricity).
- For a 500 km range, the FCEV car price could reach about $30,000 by 2030 compared with $35,000 for a BEV.
Carbon abatement cost is lower for short-range BEVs if charging stations are coupled with wind and grid, but FCEVs would save more CO₂ at a lower cost for long ranges.

Power-to-mobility: business case car

---

1. Including battery manufacturing footprint

As emissions from the grid grow, FCEV would save more CO2 than 600-km range BEV, but for 400 km, BEV would still be better.

Key comments:
- Wind-powered electrolyzer has a lower CAC than grid-connected hydrogen stations unless grid emissions are below 200 g per kWhe.
- However, a 400-km range BEV has a lower carbon avoidance cost until grid emissions reach 300 to 550 g per kWhe.
- A 600-km range BEV has high avoidance cost due to higher battery carbon footprint and higher electricity consumption per km.

Note: CAC is carbon abatement cost. The hypothesis is detailed in the appendix. Sources: Intergovernmental Panel on Climate Change, Organisation for Economic Co-operation and Development; Kearney Energy Transition Institute analysis.
Fuel-cell trucks are expected to compete with other low-carbon solutions, such as BEV trucks and hybrid catenary.

Key comments

– Long-haul trucks have high range and power requirements.
– FCEV long-haul trucks tend to be more immediately competitive than BEV compared with cars (13% TCO delta vs. 18% for cars).
– BEV trucks face many challenges, such as battery weight (limiting payload transportation), long recharging time, and additional recharging infrastructure.
– FCEV could be competitive with BEV in heavy-duty applications in a range of more than 600 km.
– A H2 price below $7 per kg and a fuel-cell cost of about $95 per kW is required to make FCEV trucks competitive with ICE.

Total cost of ownership: trucks
(2019–long-term, $ per 100km)

Operations and maintenance
Refueling, charging
Electricity, fuel
Operations and maintenance
Battery, fuel cell
Base truck cost

Power-to-mobility: business case bus

Note: The hypothesis is detailed in the appendix.
A city in France is experimenting with H₂ buses for its city fleet and has promised no cost increase for passengers.

Key project partners
- ITM Power
- Pau Porte des Pyrénées
- Ville de Pau
- Idelis
- Engie Gvert
- VanHool

Illustrative

Power-to-mobility: business case bus

4.2 Business models – Business cases

Key characteristics

<table>
<thead>
<tr>
<th>Key characteristics</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project investment</td>
<td>€74.5 million (of which €14.5 million is for bus and recharging station)</td>
</tr>
<tr>
<td>Commissioning date</td>
<td>Autumn 2019</td>
</tr>
<tr>
<td>Fuel cell power</td>
<td>100 kW</td>
</tr>
<tr>
<td>Consumption</td>
<td>10–12 kgH₂ per 100 km</td>
</tr>
<tr>
<td>Autonomy</td>
<td>More than 240 km</td>
</tr>
<tr>
<td>Electrolyzer</td>
<td>PEM: up to 268 kgH₂ per day</td>
</tr>
<tr>
<td>Number of passengers per bus</td>
<td>125</td>
</tr>
</tbody>
</table>

Note: The hypothesis is detailed in the appendix. Sources: Pau, ITM Power; Kearney Energy Transition Institute analysis
An H₂ bus network comes at an extra cost of 90¢ to $1.20 per passenger and is more expensive than battery electric buses.

Illustrative

Power-to-mobility: business case bus

**Levelized cost of mobility**

(2019, $ per passenger)

<table>
<thead>
<tr>
<th>Fuel price</th>
<th>ICE bus</th>
<th>Grid</th>
<th>Wind</th>
<th>Fuel cell buses</th>
<th>Same number of buses</th>
<th>+ 2 additional buses</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capex bus</td>
<td>$294,000 x 6 buses</td>
<td>$730,000 per bus x 6 buses</td>
<td>$675,000 per bus x 6 buses</td>
<td>$675,000 per bus x 8 buses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operations &amp; maintenance:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>drivetrain</td>
<td>$1.30 per L</td>
<td>$7.80 per kg²</td>
<td>$11.80 per kg²</td>
<td>$52 per MWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operations &amp; maintenance:</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>warehouse</td>
<td>$0.5</td>
<td>$1.1</td>
<td>$1.5</td>
<td>$0.4</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Passengers</td>
<td>$489,000 per year</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1. Including driver wages and bus-stop infrastructure
2. The price calculation is detailed on slide 136.
3. Defined as present value of costs divided by present value of number of passengers

Declining LCOH and acquisition cost reduction triggered by mass production could make FCEV buses competitive with BEV and ICE.

Levelized cost of mobility\(^3\) per passenger
(2030f, $ per passenger)

<table>
<thead>
<tr>
<th>Fuel price</th>
<th>$1.30 per L</th>
<th>$3.80 per kg(^2)</th>
<th>$4.40 per kg(^2)</th>
<th>$52 per MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capex bus</td>
<td>$294,000 x 6 buses</td>
<td>$450,000 per x 6 buses</td>
<td>$617,000 per bus x 6 buses</td>
<td>$617,000 per bus x 8 buses</td>
</tr>
<tr>
<td>Operations &amp; maintenance: drivetrain</td>
<td>30¢ per km</td>
<td>60¢ per km</td>
<td>30¢ per km</td>
<td></td>
</tr>
<tr>
<td>Operations &amp; maintenance: warehouse</td>
<td>$112,000 per year per bus</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Passengers</td>
<td>489,000 per year</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1 Including driver wages and bus-stop infrastructure
2 The price calculation is detailed on slide 136.
3 Defined as present value of costs divided by present value of number of passengers
Under the current electrical mix, only refueling stations powered by renewables would reduce CO₂ emissions at a cost below $220 per ton.

However, because of the intermittency of production, an emergency supply of hydrogen might be needed (for example, by trailer), which would increase the overall cost.

---

**4.2 Business models – Business cases**

---

While FCEV buses powered by wind H₂ appear to have the lowest CAC, grid-powered BEV buses are the second best alternative.

### Key comments

- Wind-powered electrolyzer has the lowest carbon avoidance cost for city buses, except for countries with electricity carbon intensity below 140g/kWhe.
- However, because of the limiting load factor, this solution might not be always feasible as it requires a minimum service rate.
- Grid-connected electrolyzer can be a sustainable solution over grid-charged BEV buses in countries with low electricity carbon intensity below 175g/kWhe, as battery manufacturing footprint weight is higher.
- Countries with carbon intensity below 700g/kWhe when no extra BEV bus is needed and 580 g/kWhe when 33% extra buses are needed would reduce their CO₂ emissions by switching to BEV buses.

### Notes:

CAC is carbon abatement cost. IPCC is Intergovernmental Panel on Climate Change. The hypothesis is detailed in the appendix. CO₂ neutrality is defined as the maximum CO₂ footprint from power sector to reach carbon neutrality between natural gas and injection.

Sources: Intergovernmental Panel on Climate Change, Organisation for Economic Co-operation and Development; Kearney Energy Transition Institute analyses.
Cities around the world are launching H₂ buses projects to evaluate the potential

Overview of H₂ buses project
(Number of projects per country)

Source: Kearney Energy transition Institute analysis
The Local Transport Authority of Lower Saxony has already ordered an additional **14 hydrogen trains** from Alstom, which are scheduled to start driving this route by 2021.

RMVs issued a tender for **27 fuel cell trains**, and Alstom will deliver the vehicles by the timetable change in 2022. Alstom also manages the supply of hydrogen in cooperation with Infraserv GmbH & Co. Höchst KG, with the filling station located on the premises of the Höchst industrial park., maintenance and the provision of reserve capacities for the next 25 years for €500M.

The Coradia iLint trains can run for about 600 miles (1,000 km) on a single tank of hydrogen, similar to the range of diesel trains that represent 40% of the lines in Germany.

Lower Saxony is Germany’s leading wind-power state producing 20% of Germany’s wind-generated electricity and has plans to increase this to 20,000MW by 2050.

At a later stage, green hydrogen will be produced by on-site electrolysis powered by a wind turbine.

---

**“Switching to hydrogen-powered trains is a quickly feasible alternative to expensive electrification”**

Tarek Al-Wazir, Minister of Economics, Energy, Transport, and Regional Development for Hesse

Source: Kearney Energy transition Institute analysis
H₂ trains on non-electrified lines are more competitive than electrification but more expensive than diesel trains

Power-to-mobility: business case train

<table>
<thead>
<tr>
<th>H₂ from chlorine plant</th>
<th>H₂ from electrolysis</th>
<th>Electric trains</th>
<th>ICE trains</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trains: capex</td>
<td>4.6</td>
<td>6.3</td>
<td>20.1</td>
</tr>
<tr>
<td>Trains: operations and maintenance</td>
<td>5.1</td>
<td>7.6</td>
<td>16.6</td>
</tr>
<tr>
<td>Fuel costs</td>
<td>0.9</td>
<td>2.6</td>
<td>3.5</td>
</tr>
<tr>
<td>Electrification</td>
<td>1.0</td>
<td>1.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

<p>| Fuel costs | 2.8 | 3.9 | 0.0 |</p>
<table>
<thead>
<tr>
<th>FC train: &quot;free&quot; H₂</th>
<th>FC train: SMR price</th>
<th>FC train: grid</th>
<th>FC train: wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.8</td>
<td>2.6</td>
<td>2.8</td>
<td>2.8</td>
</tr>
<tr>
<td>2.8</td>
<td>1.0</td>
<td>1.0</td>
<td>0.4</td>
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<tr>
<td>1.3</td>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
<td>0.4</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>E-train: electrified line</th>
<th>E-train: non-electrified line</th>
<th>Diesel train</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.5</td>
<td>0.0</td>
<td>5.0</td>
</tr>
<tr>
<td>0.4</td>
<td>1.0</td>
<td>-0.0</td>
</tr>
<tr>
<td>2.2</td>
<td>1.2</td>
<td>2.0</td>
</tr>
</tbody>
</table>

Key comments

- Fuel costs for hydrogen trains include production to refueling costs, including storage, compression, and refueling stations.
- Hydrogen is currently more competitive if it comes as a by-product from the chlorine production plant, even if it is priced at SMR cost or $1.40 per kg.
- However, diesel trains remain more competitive.

Sources: Deutsche Bahn; Usine Nouvelle; Bloomberg; EESI; "The Future of Hydrogen," International Energy Agency, June 2019; RTE; Kearney Energy Transition Institute analysis

1 Not including base costs, such as driver, rail, and station-related costs

Business models – Business cases

FC train: "free" H₂ | FC train: SMR price | FC train: grid | FC train: wind | E-train: electrified line | E-train: non-electrified line | Diesel train |
<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>4.6</td>
<td>5.1</td>
<td>6.3</td>
<td>7.6</td>
<td>3.5</td>
<td>0.0</td>
<td>5.0</td>
</tr>
<tr>
<td>0.9</td>
<td>1.3</td>
<td>2.6</td>
<td>3.9</td>
<td>0.0</td>
<td>1.0</td>
<td>-0.0</td>
</tr>
<tr>
<td>1.0</td>
<td>1.0</td>
<td>2.8</td>
<td>2.8</td>
<td>1.0</td>
<td>0.4</td>
<td>2.0</td>
</tr>
<tr>
<td>2.8</td>
<td>2.8</td>
<td>2.8</td>
<td>2.8</td>
<td>1.0</td>
<td>1.0</td>
<td>1.2</td>
</tr>
</tbody>
</table>

Base costs

1.0 1.0 1.0 1.0 1.0 2.2 2.0
**H₂ trains on non-electrified lines are more competitive than electrification but more expensive than diesel trains**

Power-to-mobility: business case train

---

### Levelized cost of mobility¹
(2030f, $ per passenger)

<table>
<thead>
<tr>
<th></th>
<th>H₂ from chlorine plant</th>
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<th>Electric trains</th>
<th>ICE trains</th>
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<td>Trains: operations and maintenance</td>
<td>Fuel costs</td>
<td>Electrification</td>
</tr>
<tr>
<td>FC train: &quot;free&quot; H₂</td>
<td>4.2</td>
<td>0.4</td>
<td>5.1</td>
<td>20.1</td>
</tr>
<tr>
<td>FC train: SMR price</td>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
<td>16.6</td>
</tr>
<tr>
<td></td>
<td>2.8</td>
<td>2.8</td>
<td>1.4</td>
<td>0.0</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2.8</td>
<td>0.4</td>
</tr>
</tbody>
</table>

### Key comments

No capex reduction for FCEV trains has been considered.
- As hydrogen production costs will become cheaper, including related infrastructure, fuel-cell trains could become more competitive than diesel trains if H₂ is purchased at free cost or SMR price and transported to refueling station.

---

¹ Not including base costs, such as driver, rail, and station-related costs

Sources: Deutsche Bahn; Usine Nouvelle; Bloomberg; EESI; “The Future of Hydrogen,” International Energy Agency, June 2019; RTE; Kearney Energy Transition Institute analysis
Using by-product H₂ from the chlorine industry appears to have the cheapest avoidance cost.


1 Net including base costs, such as driver, rail, and station-related costs.
An FCEV train with H₂ by grid could save CO₂ if grid emissions are below 300g/kWhe at a lower avoidance cost than electrification.

Key comments:
- Electrifying lines is very expensive – CAC is therefore always higher than $4,500 per ton.
- FCEV trains appear as a strong alternative to railway electrification at a lower carbon avoidance cost.
- However, FCEV trains with H₂ produced from grid are sustainable only if grid intensity is below 200gCO₂/kWhe.
- A wind-powered production plant is the cheapest alternative when grid emissions are above about 100gCO₂/kWhe.

Power-to-mobility: business case train

4.2 Business models – Business cases

Note: CAC is carbon abatement cost. The hypothesis is detailed in the appendix.
Sources: Intergovernmental Panel on Climate Change, Organisation for Economic Co-operation and Development; Kearney Energy Transition Institute analysis
Benefits of electrolysis vary by application and depend on the country’s energy mix.

Carbon abatement cost vs. grid emissions for business cases
(2030; Y axis: CAC in $ per tCO₂ log scale; X axis: CO₂ emissions in kg/MWhe)

Avoidance cost
($ per tCO₂)

- Methanation (B1a)
- Injection (B1b)
- Industrial feedstock (B3)
- FCEV car (B4)
- FCEV bus (B5)
- Power-2-Power (B2)

IPCC CO₂ price recommendation ($220/tCO₂)

Carbon intensity of Countries (gCO₂/kWhe)

Note: IPCC is Intergovernmental Panel on Climate Change.
Source: Kearney Energy Transition Institute analysis
Power-to-mobility, power-to-power, and Injection coupled with renewable production have high potential to decarbonize their sector at low cost.

Note: P2M: Power to Mobility; P2P: Power to Power

Source: Kearney Energy Transition Institute
Large-scale H₂ production that can serve multiple users to maximize load factor is vital to competitiveness.

Illustrative H₂-electrolysis hub

**Source:** Kearney Energy Transition Institute

**4.2 Business models – Business cases**

Source: Kearney Energy Transition Institute
Some orders of magnitude in 2019

Executive summary

1. Hydrogen’s role in the energy transition

2. Hydrogen value chain: upstream and midstream
   2.1 Production technologies
   2.2 Conversion, storage, and transportation technologies
   2.3 Maturity and costs

3. Key hydrogen applications
   3.1 Overview
   3.2 Feedstock
   3.3 Energy

3. Business models
   4.1 Policies and competition landscape
   4.2 Business cases

Appendix (Bibliography & Acronyms)
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- The Fuel Cells and Hydrogen Joint Undertaking (FCH JU) (link)
- US Department of Energy Fuel Cell Technologies Office (FCTO) (link)
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC/DC</td>
<td>Alternating/Direct current</td>
</tr>
<tr>
<td>AFC</td>
<td>Alkaline fuel cell</td>
</tr>
<tr>
<td>AFOLU</td>
<td>Agriculture, Forestry and Other Land Use</td>
</tr>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>BoP</td>
<td>Balance of plant</td>
</tr>
<tr>
<td>BTU</td>
<td>British thermal unit (Btu)</td>
</tr>
<tr>
<td>BEV</td>
<td>Battery electric vehicle</td>
</tr>
<tr>
<td>CAES</td>
<td>Compressed air energy storage</td>
</tr>
<tr>
<td>CAGR</td>
<td>Compound annual growth rate</td>
</tr>
<tr>
<td>CAPEX</td>
<td>Capital expenditure</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon capture &amp; storage</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined heat and power</td>
</tr>
<tr>
<td>CNG</td>
<td>Compressed natural gas</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>DH</td>
<td>District heating</td>
</tr>
<tr>
<td>DME</td>
<td>Dimethyl ether</td>
</tr>
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<td>DSO</td>
<td>Distribution system operator</td>
</tr>
<tr>
<td>E</td>
<td>Electricity</td>
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<td>EPEX</td>
<td>European Power Exchange</td>
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<tr>
<td>FC</td>
<td>Fuel cell</td>
</tr>
<tr>
<td>FCEV</td>
<td>Fuel cell electric vehicle</td>
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<tr>
<td>FCHJU</td>
<td>Fuel Cell and Hydrogen Joint Undertaking</td>
</tr>
<tr>
<td>FIT</td>
<td>Feed-in tariff</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse gas</td>
</tr>
<tr>
<td>GtCO₂eq</td>
<td>Giga tonnes of CO₂ equivalent</td>
</tr>
<tr>
<td>H₂</td>
<td>Hydrogen</td>
</tr>
<tr>
<td>H₂ICE</td>
<td>Hydrogen internal-combustion-engine vehicle</td>
</tr>
<tr>
<td>HDS</td>
<td>Hydrodesulfurization</td>
</tr>
<tr>
<td>HENG</td>
<td>Hydrogen enriched natural gas</td>
</tr>
<tr>
<td>H-Gas</td>
<td>High calorific gas</td>
</tr>
<tr>
<td>HHV</td>
<td>Higher heating value</td>
</tr>
<tr>
<td>HT</td>
<td>High temperature</td>
</tr>
<tr>
<td>ICE</td>
<td>Internal combustion engine</td>
</tr>
<tr>
<td>IEA</td>
<td>International Energy Agency</td>
</tr>
<tr>
<td>IPCC</td>
<td>Intergovernmental Panel on Climate Change</td>
</tr>
<tr>
<td>IRR</td>
<td>Internal rate of return</td>
</tr>
<tr>
<td>K</td>
<td>Kelvin (unit of measurement for temperature)</td>
</tr>
<tr>
<td>kWh</td>
<td>Kilowatt hour</td>
</tr>
<tr>
<td>LCA</td>
<td>Life cycle analysis</td>
</tr>
<tr>
<td>LCOE</td>
<td>Levelized cost of electricity</td>
</tr>
<tr>
<td>LCOH</td>
<td>Levelized cost of hydrogen</td>
</tr>
<tr>
<td>LDV</td>
<td>Light duty vehicle</td>
</tr>
<tr>
<td>L-Gas</td>
<td>Low calorific gas</td>
</tr>
<tr>
<td>LHV</td>
<td>Lower heating value</td>
</tr>
<tr>
<td>LOHC</td>
<td>Liquid organic hydrogen carrier</td>
</tr>
<tr>
<td>LPG</td>
<td>Liquefied petroleum gas</td>
</tr>
<tr>
<td>MCFC</td>
<td>Molten carbonate fuel cell</td>
</tr>
<tr>
<td>MEA</td>
<td>Membrane electrode assembly</td>
</tr>
<tr>
<td>MtG</td>
<td>Methanol-to-gas</td>
</tr>
<tr>
<td>NG</td>
<td>Natural gas</td>
</tr>
<tr>
<td>NH₃</td>
<td>Ammonia</td>
</tr>
<tr>
<td>NPV</td>
<td>Net present value</td>
</tr>
<tr>
<td>NREL</td>
<td>National Renewable Energy Laboratory</td>
</tr>
<tr>
<td>O&amp;G</td>
<td>Oil and gas</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>Operation and maintenance</td>
</tr>
<tr>
<td>OPEX</td>
<td>Operating expenditure</td>
</tr>
<tr>
<td>Acronym</td>
<td>Description</td>
</tr>
<tr>
<td>---------</td>
<td>-------------</td>
</tr>
<tr>
<td>Pa</td>
<td>Pascal (Unit of measurement for pressure)</td>
</tr>
<tr>
<td>P2G</td>
<td>Power-to-gas</td>
</tr>
<tr>
<td>P2P</td>
<td>Peer-to-peer</td>
</tr>
<tr>
<td>P2S</td>
<td>Power-to-synfuel</td>
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<tr>
<td>PAFC</td>
<td>Phosphoric acid fuel cell</td>
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<tr>
<td>PCM</td>
<td>Phase change material</td>
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<tr>
<td>PEM</td>
<td>Proton exchange membrane</td>
</tr>
<tr>
<td>PES</td>
<td>Primary energy source</td>
</tr>
<tr>
<td>PGM</td>
<td>Platinum group metal</td>
</tr>
<tr>
<td>PHS</td>
<td>Pumped-hydro Storage</td>
</tr>
<tr>
<td>PV</td>
<td>Solar photovoltaic</td>
</tr>
<tr>
<td>R,D&amp;D</td>
<td>Research, Development &amp; Demonstration</td>
</tr>
<tr>
<td>RE</td>
<td>Renewables</td>
</tr>
<tr>
<td>REC</td>
<td>Renewable energy certificate</td>
</tr>
<tr>
<td>RES</td>
<td>Renewable electricity source</td>
</tr>
<tr>
<td>SMES</td>
<td>Super-conducting magnetic energy storage</td>
</tr>
<tr>
<td>SMR</td>
<td>Steam methane reforming</td>
</tr>
<tr>
<td>SNG</td>
<td>Synthetic natural gas</td>
</tr>
<tr>
<td>SOEC</td>
<td>Solid oxide electrolyzer cell</td>
</tr>
<tr>
<td>SOFC</td>
<td>Solid oxide fuel cell</td>
</tr>
<tr>
<td>STES</td>
<td>Seasonal thermal energy storage</td>
</tr>
<tr>
<td>T&amp;P</td>
<td>Temperature and pressure</td>
</tr>
<tr>
<td>T&amp;D</td>
<td>Transmission and distribution</td>
</tr>
<tr>
<td>TCM</td>
<td>Thermo-chemical material</td>
</tr>
<tr>
<td>TCNG</td>
<td>Turbocharged natural gas</td>
</tr>
<tr>
<td>TEPS</td>
<td>Total primary energy supply</td>
</tr>
<tr>
<td>TSO</td>
<td>Transmission system operator</td>
</tr>
<tr>
<td>URFC</td>
<td>Unitized regenerative fuel cell</td>
</tr>
<tr>
<td>USDOE</td>
<td>US Department of Energy</td>
</tr>
<tr>
<td>VRB</td>
<td>Vanadium Redox Batteries</td>
</tr>
<tr>
<td>W</td>
<td>Watt</td>
</tr>
<tr>
<td>Zn/Br</td>
<td>Zinc-bromine</td>
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</tbody>
</table>
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