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.

Authors
Thibault L’Huby, Prashant Gahlot, and Romain Debarre

Hydrogen – *H2* FactBook Overview

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 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 MtCO_2 per year
– About 2% of global CO_2 emissions

Equivalence of 1 Mt of H_2 in terms of oil
– About 21 Mboe
– About a quarter the world's daily oil consumption

What does 1 ton of H_2 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 H_2 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 H_2?
– 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

Hydrogen (H_2) could play a major role in various energy applications, contributing to global decarbonization

Hydrogen's role in the energy transition

(Section 1: pages 16–24)

Executive summary (1/10)

The need for decarbonization

Anthropogenic CO_2 emissions (excluding AFOLU[1]) have accelerated during the 20th century, rising to about 37 Gt per year in 2019, with global CO_2 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 H_2 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.

Blue and green hydrogen sources offer potential decarbonization solutions, requiring either CCS deployment or use of renewables (1/2)

Hydrogen value chain: upstream and midstream - Production technologies

(<u>Section 2.1</u>: pages 27–48)

Executive summary (2/10)

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 a endothermic reaction to form H_2, CO and CO_2, called a syngas. It requires 3 to 4 kg of CH_4 per kg of H_2 (about 65% of lower heating value efficiency).

In a **coal gasification** reactor, O_2 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 H_2 (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 CH_4/kgH_2 (80% LHV efficiency).

The syngas is a mixture of H_2, CO, CO_2, and other gases that can be used as is or purified.

Syngas composition depends on reactor design and feedstock used. As H_2 and CO are main syngas components, syngas quality is measured with H_2/CO ratio in volumetric quantities. High ratio means high quantity of H_2 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 CO_2 and H_2. CO_2 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 CO_2. During methanation, the remaining CO and CO_2 reacts with H_2 to create CH_4.

Blue hydrogen requires the combination of brown sources with CCS value chain (capture, transportation, storage, and/or usage of CO_2), 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.

Blue and green hydrogen sources offer potential decarbonization solutions, requiring either CCS deployment or use of renewables (2/2)

Hydrogen value chain: upstream and midstream - Production technologies

(Section 2.1: pages 27–48)

Executive summary (3/10)

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 immerged 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 H_2 and O_2. 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 H_2 and O_2 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 H_2).

Other green hydrogen production sources include dark fermentation, microbial electrolysis, and photolytic conversion, which are still in laboratory stages.

Note: LCOH calculation: (present value of investments + present value of costs)/(present value of yearly hydrogen production), in $/kg

Hydrogen can be converted into multiple energy carriers, offering a broad range of storage and transportation options

Hydrogen value chain: upstream and midstream - Conversion, storage, and transportation technologies

(Section 2.2: pages 49–60)

Executive summary (4/10)

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)

Executive summary (5/10)

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 value chain: upstream and midstream – Maturity and costs

(Section 2.3: pages 61–77)

Executive summary (6/10)

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 is being tested or implemented in a broad range of industrial processes, mobility solutions, power generation, and gas energy

Key hydrogen applications

(Section 3: pages 78–113)

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 CO_2 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.

Private companies and governments are investing more in the clean hydrogen economy

Business models - Policies and competition landscape

(Section 4.1: pages 116–124)

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 CO_2 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.

Executive summary (8/10)

Most hydrogen business models require policy support, with heavy-duty transportation being the most promising one in the current context (1/2)

Business models - Business cases

(Section 4.2: pages 125–186)

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 CO_2 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, CO_2 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 tCO_2 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 tCO_2** for 27 to 130 mtpa of CO_2 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 tCO_2**. Adding a methanation step adds complexity and costs, leading to an abatement cost of **\$1,100 to \$2,800 per tCO_2**.
- **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 gCO_2 per MWhe could be saved at an abatement cost **between \$120 and \$3,000 per tCO_2**.

Most hydrogen business models require policy support, with heavy-duty transportation being the most promising one in the current context (2/2)

Business models - Business cases

(Section 4.2: pages 125–186)

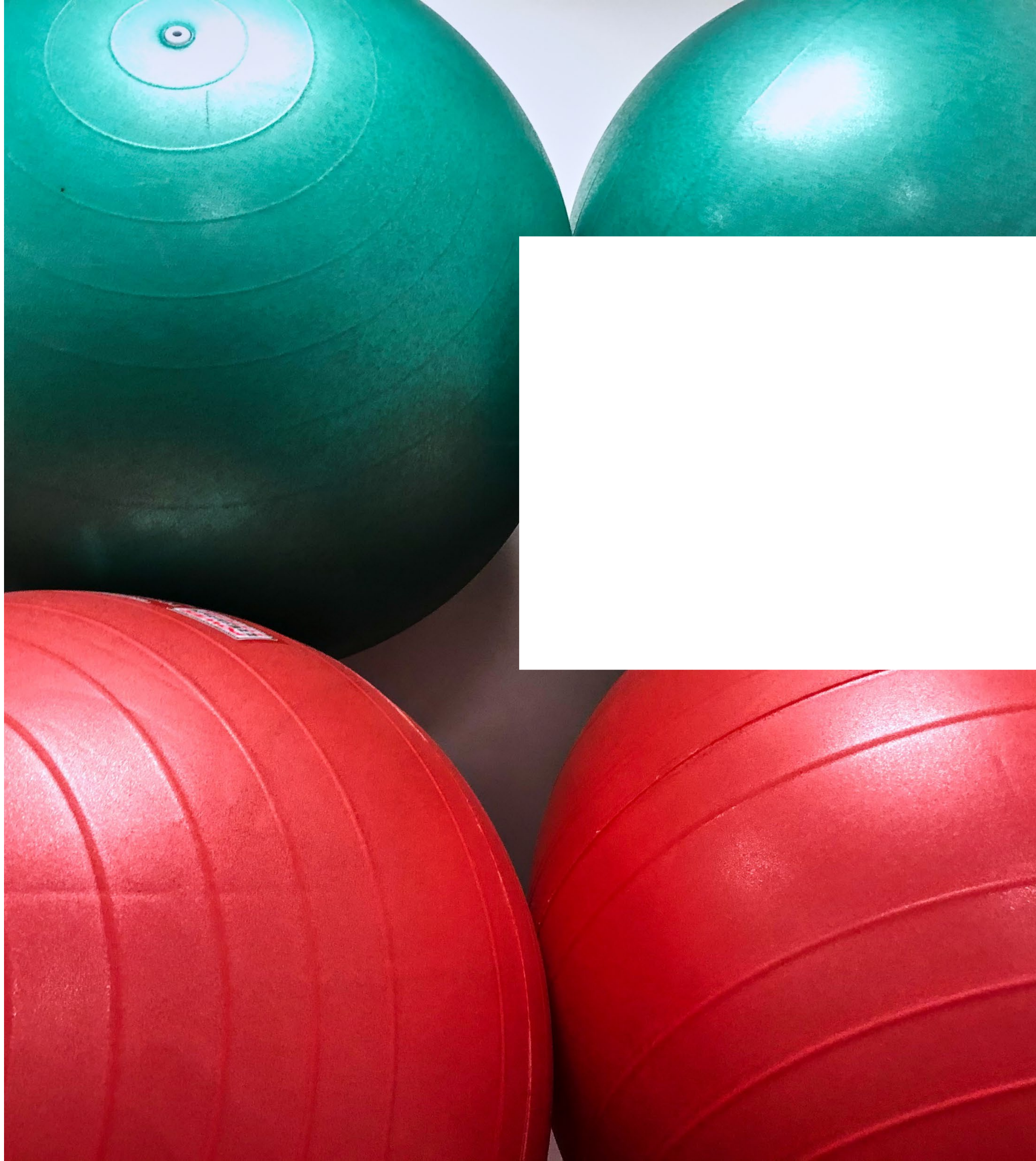
- **Power-to-molecule.** Electrolyzer is built on a refinery or a chemicals production plant in addition to a SMR and provides hydrogen when electricity surplus is available. However, scalability is limited: electrolyzer (pilot plant) in the Wesseling refinery in Germany supplies only 1% of hydrogen needs to the refinery but could spare about 9 $kgCO_2$ per kgH_2 at a cost of about **\$120 to \$150 per tCO_2**.
- **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 CO_2 abatement cost is **\$570 to \$2,000 per tCO_2** for passenger cars, **\$120 per tCO_2** for buses, and **\$60 per tCO_2** 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

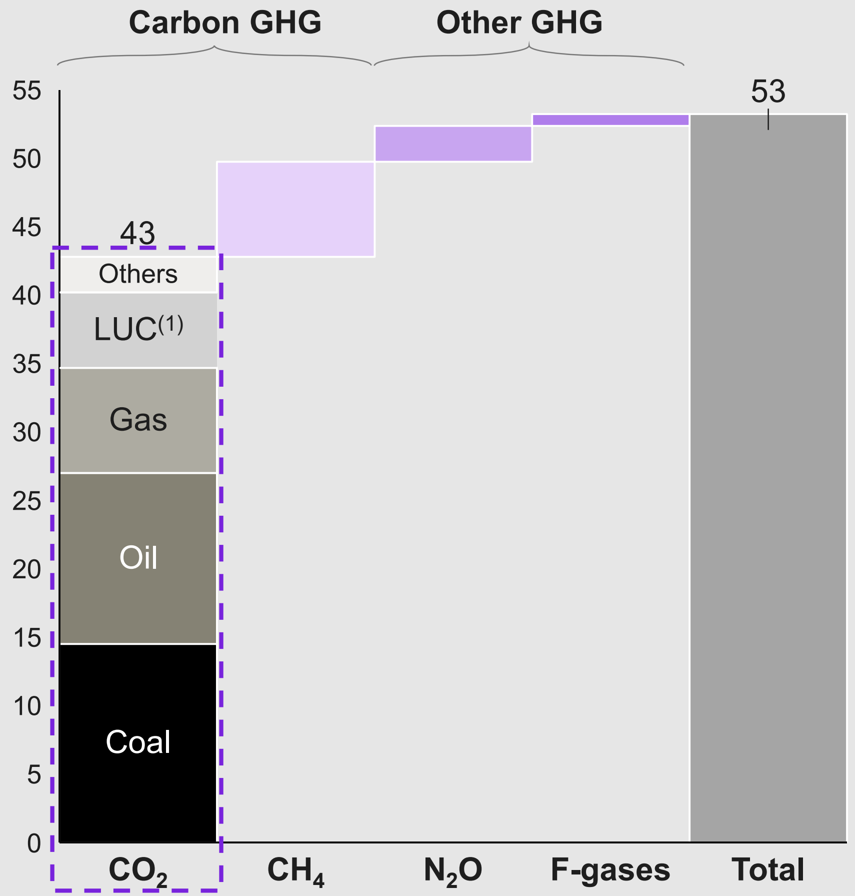
Key consequences of +1.5°C and +2°C global warming by 2100

	+1.5°C	+2.0°C
Global mean **sea level** rise	0.26 to 0.77 m (medium confidence)	0.36 to 0.87 m (medium confidence)
Biodiversity losses (among 105,000 species studied)	8% of plants 6% of insects 4% of vertebrates (medium confidence)	16% of plants 18% of insects 8% of vertebrates (medium confidence)
Decline of **coral reefs**	70–90% (high confidence)	More than 99% (very high confidence)
Frequency of disappearance of the **Arctic ice cap**	Once per century (high confidence)	Once per decade (high confidence)
Decrease in global annual catch for **marine fisheries**	1.5 million tons (medium confidence)	3 million tons (medium confidence)
Average increase of **heat waves** mean temperature	+3°C (high confidence)	+4°C (high confidence)

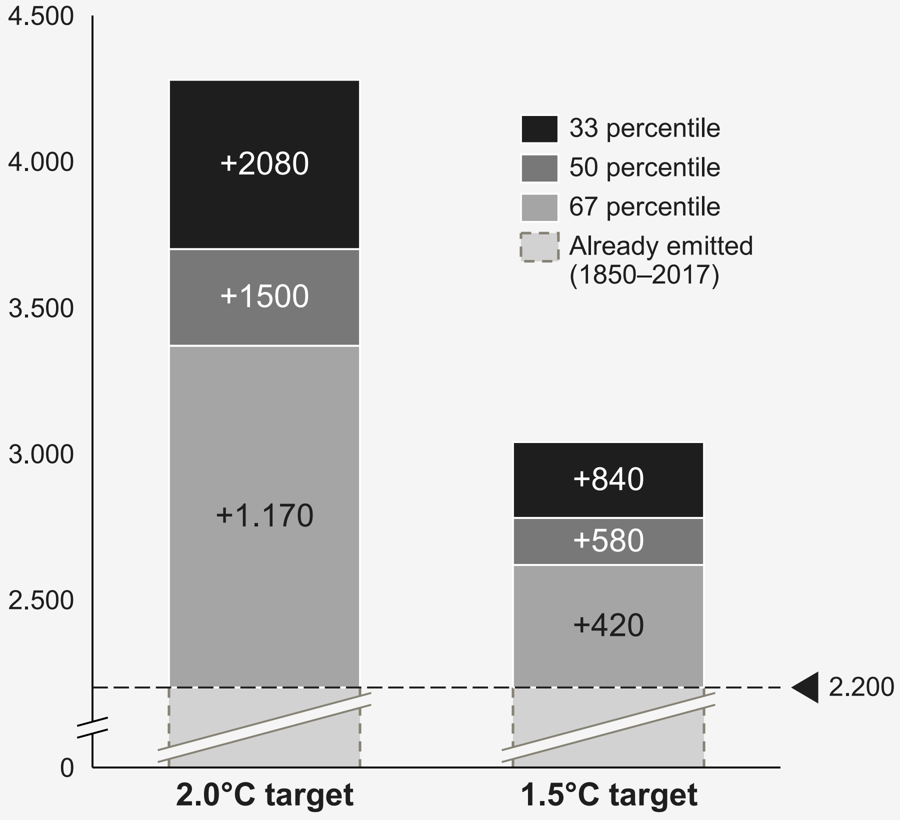
Sources: "Special report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways (SR1.5)," Intergovernmental Panel on Climate Change, 2018; Kearney Energy Transition Institute analysis

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, $GtCO_2eq$ per year)



Remaining carbon budget
(2018, $GtCO_2eq$)



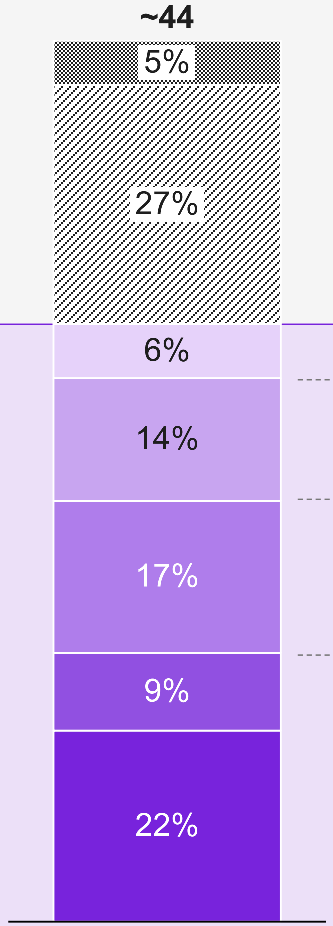
1 Hydrogen's role in energy transition

1 LUC : deforestation and other land use change
Sources: Global Carbon Budget 2018; IPCC (2018) "SR5–Chapter 2"; BP (2015) "Statistical review"; Kearney Energy Transition Institute analysis

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 CO_2 eq/y)

Hydrogen potential use cases for decarbonization



Not substitutable by H_2

Partially substitutable by H_2

(Either as fuel for heat and power or as feedstock for industry)

Use case	Method of H_2 substitution
Others	
Agriculture, forestry & other land use[1]	
Building	– Heating networks with H_2 (blended or full H_2)
Industry	– Circular economy with CCU/CCS[2] – Clean feedstock for oil refining & chemicals
Transport	– Full cell electric vehicle (passenger cars, trucks, trains) – Synthetic fuels (airplanes, ships)

Electricity & heat
Oil & gas, others
Coal
	– Integration of renewables:
	  – Large scale storage for inter-seasonal storage
	  – Geographic balance
	  – Grid stabilization

1 Hydrogen's role in energy transition

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

Upstream — Production technology

Thermochemical
- Steam methane reforming (SMR)
- Gasification
- Autothermal reforming (ATR)
- Pressurized combustion reforming
- Chemical looping
- Concentration solar fuels (CSF)
- Heat exchange reforming (HER) and gas heated reforming (GHR)
- Pyrolysis
- Other technologies (such as microwave)

Electro-lysis
- Alkaline electrolysis (AE)
- Proton exchange membrane (PEM)
- Solid oxide electrolyzer cell (SOEC)
- Other technologies (such as chlor-alkali)

Other
- Dark fermentation
- Microbial electrolysis
- Photoelectrochemical

Midstream and downstream — Conversion, storage, transport, and distribution

Conversion
- Hydrogen gas
- Liquid hydrogen
- NH_3
- Liquefied organic hydrogen carrier (LOHC)

Transport
- Trucks
- Trains
- Pipeline
- Tankers

Storage
- Geological storage
- Storage tanks
- Chemical reconversion
- Liquefaction and regasification

Consumption — End-use applications

Industrial applications
- Oil refining
- Chemicals production
- Iron and steel production
- High-temperature heat
- Food industry

Mobility
- Light-duty vehicles
- Heavy-duty vehicles
- Maritime
- Rail
- Aviation

Power generation
- Co-firing NH_3 in coal power plants
- Flexible power generation
- Back-up and off-grid power supply

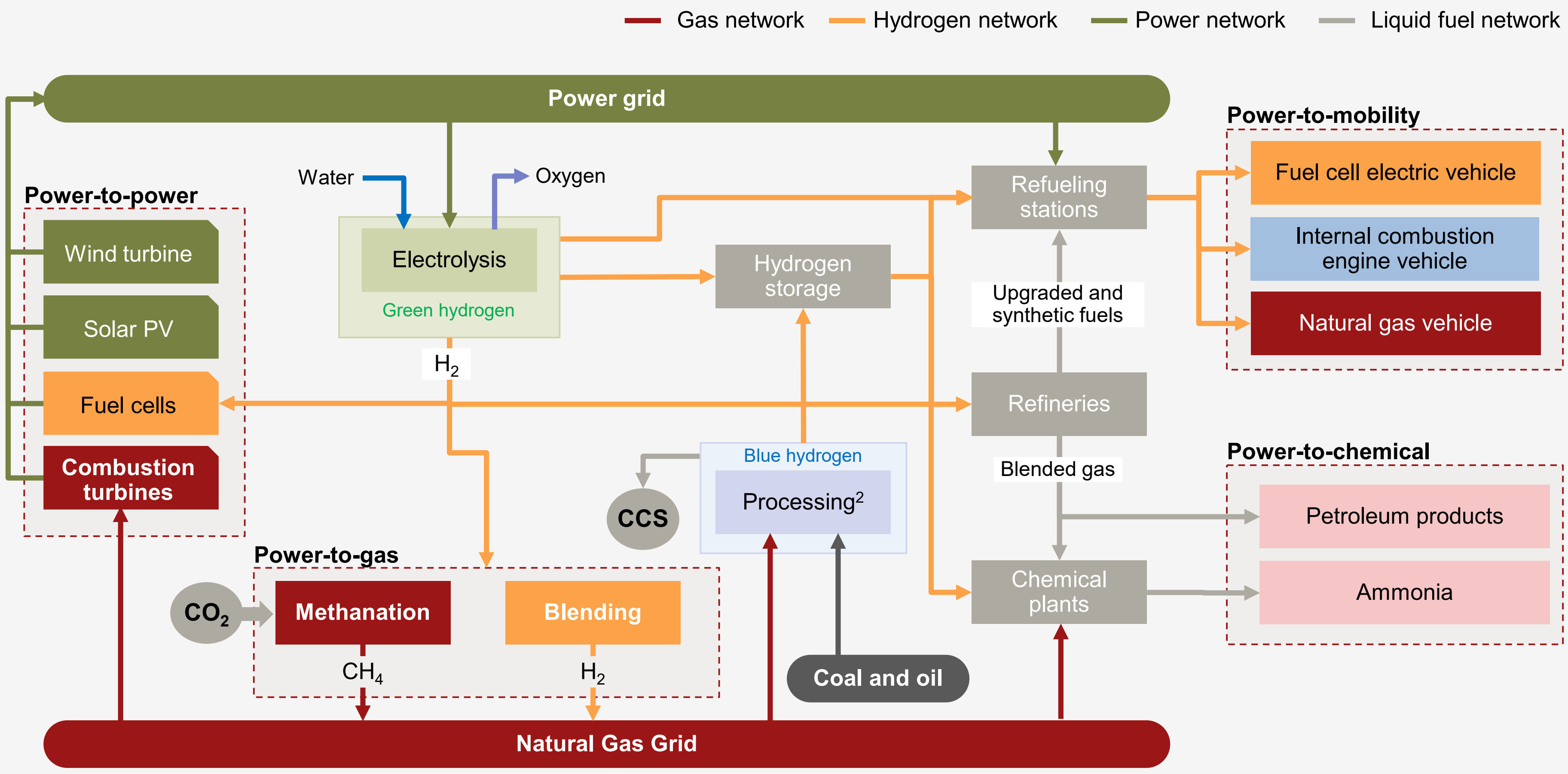
Gas Energy
- Long-term, large-scale storage
- Blended H_2
- Methanation
- Pure H_2

Brown H_2 | Blue H_2 | Green H_2

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

1 Hydrogen's role in energy transition

Hydrogen is competing with other low carbon solutions that tackle similar applications

Hydrogen substitution matrix

Sector (consuming fossil fuels)	Total oil consumption usage (Mtoe[3], 2018)	Potential application of other decarbonisation technologies (2030+ time horizon)				Potential role of hydrogen	
		Biomass (Bio-fuels and biogas)	Electrification (renewables + storage)	Carbon Capture Storage[1]	Overall score for decarbonisation solutions (other than hydrogen)	Hydrogen Applicability	Opportunity for Hydrogen
Aviation & Shipping	600	◑	◔	○	++	◔	▼
Rail[2]	29	◑	◔	○	++	◕	▲
Trucks	2,110	●	◑	○	+++	◕	▲
Road		●	●	○	+++	◕	▶
Industry & petrochem	915	○	○	◑	++	◑	▶
Heat & power	615	●	◕	◑	+++	◑	▼

- Hydrogen not mature for commercial aviation application, more progressing for shipping (small boats)
- H_2 application for rail is relevant to replace diesel engine in non-electrified rails
- H_2 relevant for heavy duties vehicle (trucks and buses, for which battery weight is a major issue)
- H_2 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

Maturity of technologies: ● Commercial stage ◑ Pilot stage ◔ Research stage ○ Not an option

Maturity of decarbonisation options: +++ At least one commercial option ++ At least one pilot project + Ongoing R&D investment

Use of CO_2 from CCS is not considered in the range of possible solutions 2. Based on 2017 figures 3. Million tonnes oil equivalent
Sources: IEA WEO 2019; Kearney Energy Transition Institute

1 Hydrogen's role in energy transition

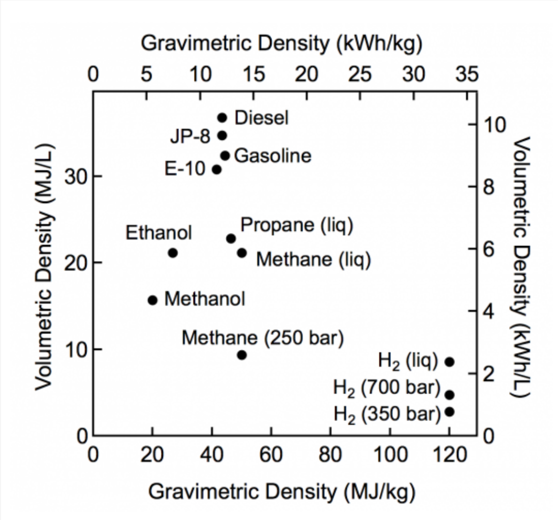
Hydrogen is the lightest molecule with the highest gravimetric energy density

Hydrogen fact card

Description

- **Name:** Hydrogen ("water former" in ancient Greek)
- **State in ambient conditions:** gaseous, diatomic (H_2)
- **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:**

$$2H_2 + 2O_2 \rightarrow 2\,H_2O + 572\ \text{kJ} \qquad \Delta H = -286\ \text{kJ/mol}$$



Comparison of specific energy (energy per mass or gravimetric density) and energy density (energy per volume or volumetric density) for several fuels based on lower heating values

Advantages

- High energy density
- No CO_2 emissions during combustion
- Abundant on earth (water and hydrocarbons)
- Multiple applications in industrial and energy sectors

Disadvantages

- Rare in natural H_2 form
- High CO_2 emissions for industrial production
- Large ignition range
- Corrosive

Physical properties

Density (kg/m^3)	**0.089 (gas) 71 (liquid)[1]**
Boiling point (°C)	**-253 °C**
Lower heating value (MJ/kg)	**120**
Specific energy, liquefied (MJ/kg)	**8.5**
Ignition range (% of gas in air volume)	**4–77%**

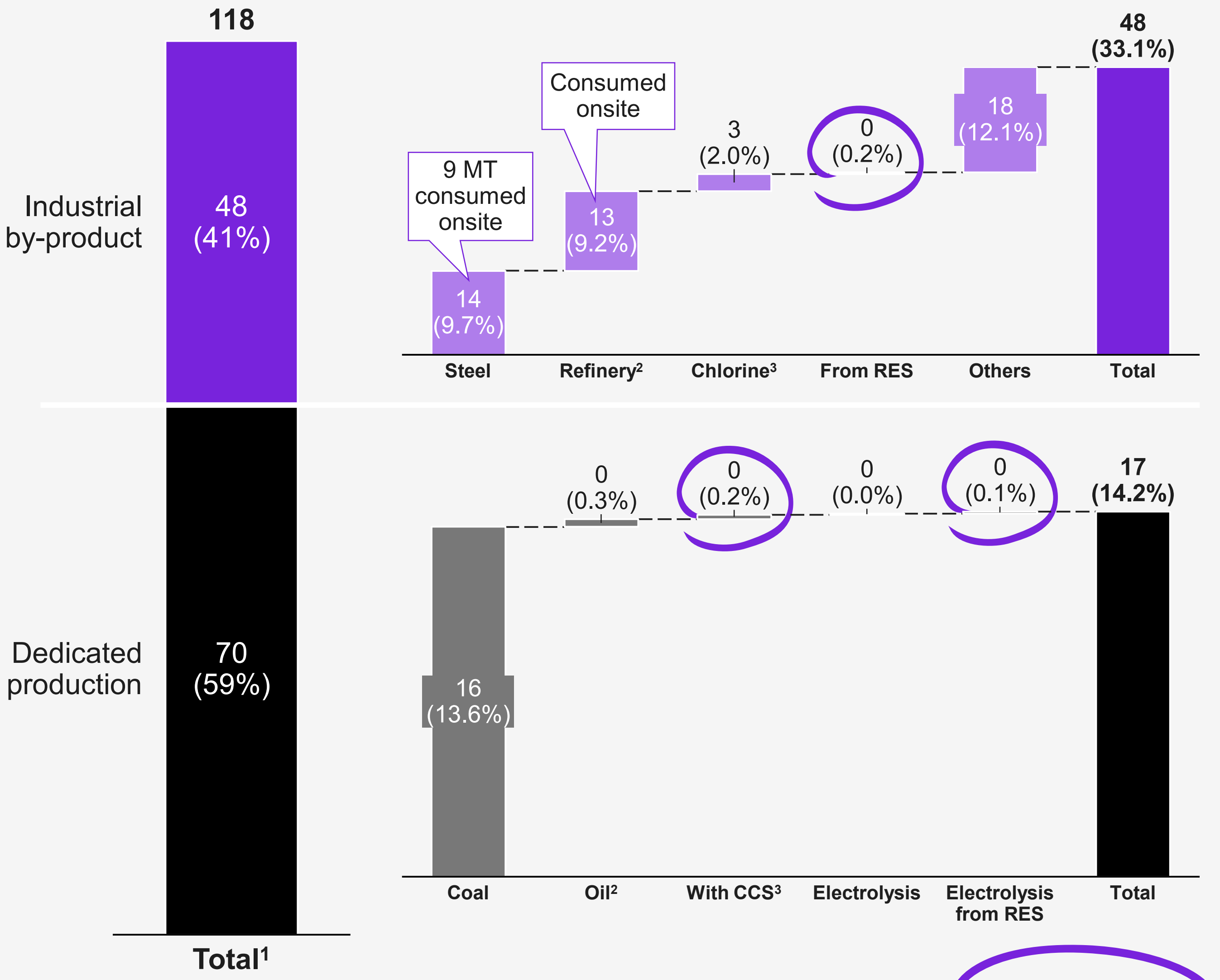
1 Hydrogen's role in energy transition

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

About 118 Mt of H_2 are produced each year and release about 830 Mt of CO_2, mainly from fossil fuels

Global hydrogen production
(2018, Mt H_2, % of total production)



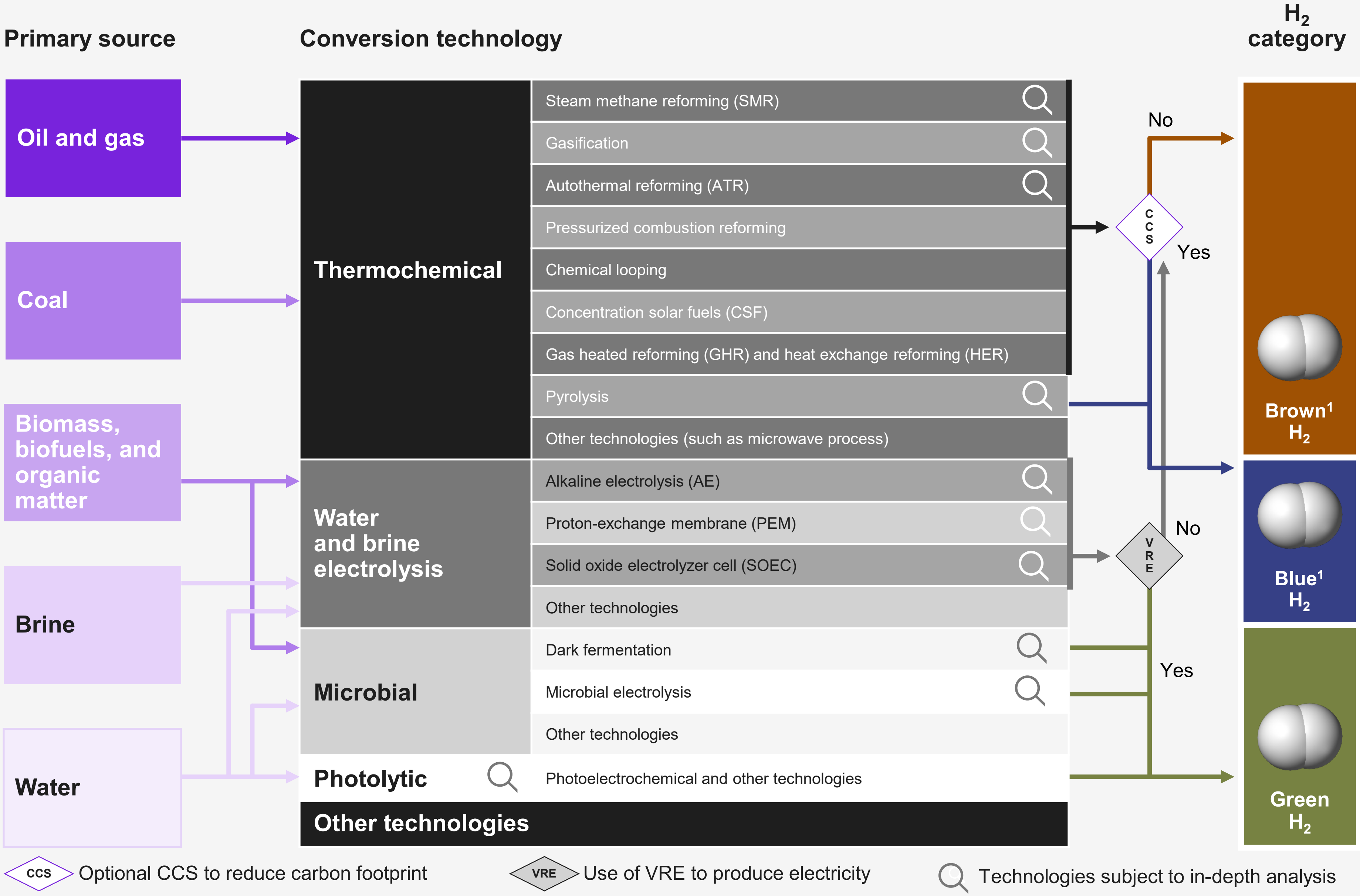
1 1 Mtoe = 0.35 Mt H2
2 35% of refinery H2 needs come as a by-product.
3 World chlorine production: about 100 MT per year – ratio of 1/35 tH2/tCl2
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute

Key considerations

- H_2 production has reached 118 Mt per year, 59% of which comes from dedicated sources.
  - Use of fossil fuels for H_2 production represented about 6% of global demand for natural gas and about 2% of global demand for coal.
  - Global CO_2 emissions from H_2 represented 830 Mt CO_2 equivalent.
  - Overall, 0.6% of H_2 is from renewable or fossil fuels plants equipped with CCS.
- **About 3 Mt of H_2 are lost or not recovered** (for example, during purification).

H_2 conversion technologies can be split into thermochemical, electrolysis, microbial, and photolytic

H_2 production technologies overview



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

2.1 Hydrogen value chain - Production technologies

Natural production sources of H_2 have been found at different places but are not exploited

Fact card: Natural H_2 production sources

Description

- In the 1970s, scientific research highlighted a natural H_2 presence mainly in the following:
  - Mid-ocean ridges and hydrothermal vents, where hydrothermal fluids contain up to 36% of H_2
  - Volcano gases, such as at Etna, Augustin, and Kliuchevskoi, with H_2 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 H_2 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, H_2 is formed differently:
  - In ocean rifts or mountains (which were formerly an ocean), ferrous minerals are oxidized by water to form Fe_3O_4—water is reduced and releases H_2.
  - The origin of H_2 is still unclear for volcanoes.

Pros

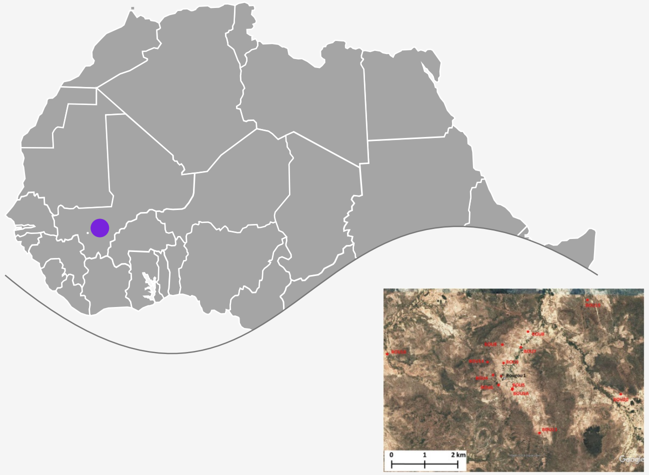
- Non-polluting, free[1] source

Cons

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

Overview

The only exploited natural source: Mali



Bourakebougou field

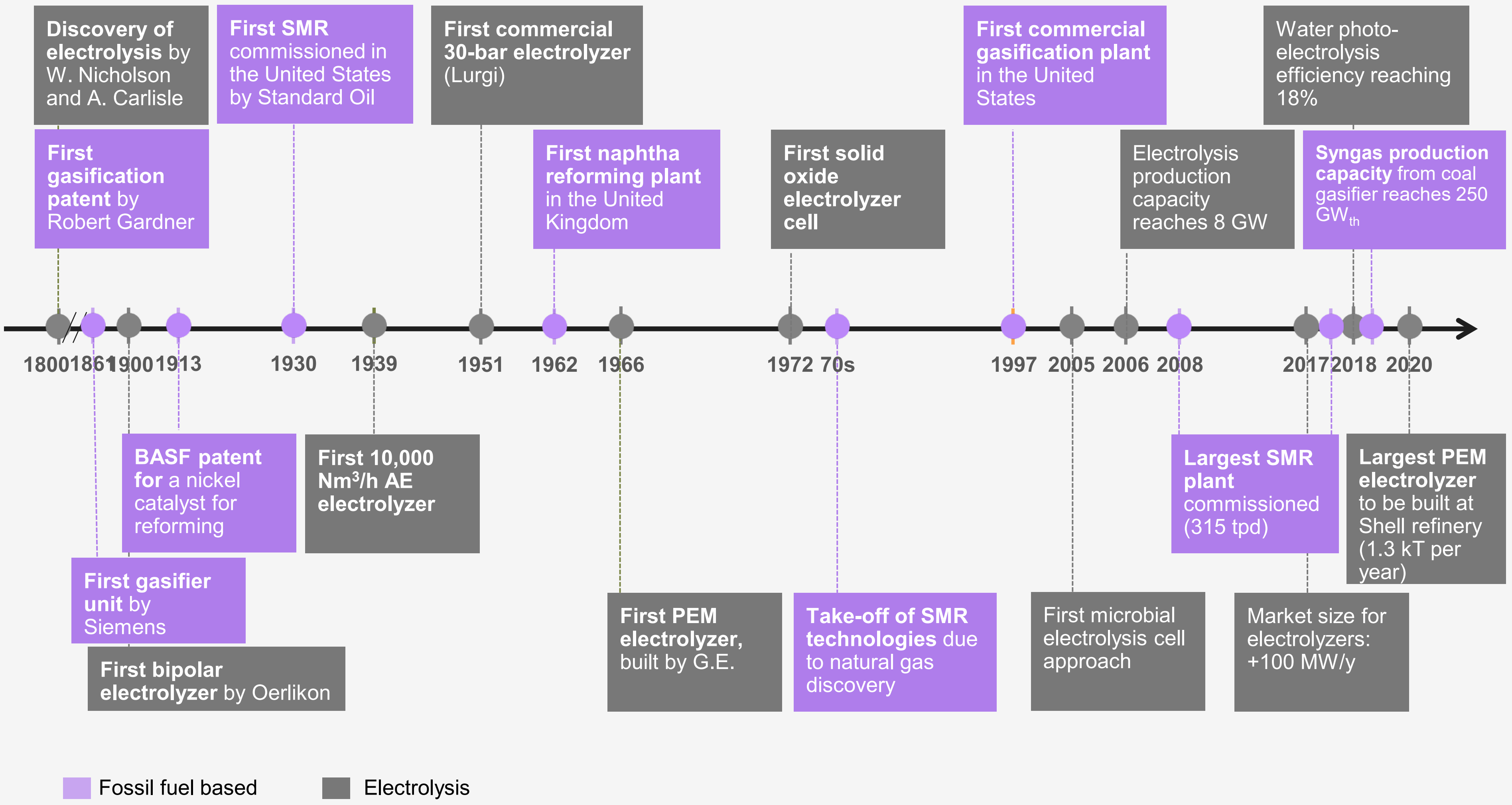
City	**Bourakebougou**	Exploitation	**Hydroma (Petroma)**
Discovery	**1980**	Operation start	**2011**
Number of reservoirs	**5**	Number of wells	**18**
Deep (m)	**100–1.700**	Usage	**Electricity and light for about 100 families**
H_2 content	**~98%**		
Key features estimates			
Current cost estimate (\$ per kgH_2)			**Below manufactured H_2**
H_2 emission rate (kgH_2 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

2.1 Hydrogen value chain - Production technologies

Electrolysis was the first H_2 production technology deployed but was overtaken by fossil fuel-based technologies in the early 1970s

History of H_2 production technologies



Sources: Johnson Matthey; Norsk H Hydroydro; 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 H_2 production technologies

		LCOH 2019, $ per kg	Efficiency kWh per kg	Efficiency % LHV	Advantages and risks: Feedstock	Emissions	Scalability	Footprint	Other
Thermochemical sources	Steam methane reforming (SMR)	0.9–1.8	52	64%	Fossil fuel Biomass	11 $kgCO_2/kgH_2$	200 to 500 tpd	n.a.	n.a.
Thermochemical sources	Gasification	1.6–2.2	41–47	70–80%	Fossil fuel Biomass	20 $kgCO_2/kgH_2$	500 to 800 tpd	n.a.	n.a.
Thermochemical sources	Autothermal reforming	n.a.	40–42	78–82%	Fossil fuel Biomass	9 $kgCO_2/kgH_2$	500 to 1000 tpd	n.a.	n.a.
Thermochemical sources	Pyrolysis	2.2–3.4	47–66	50–70%	Fossil fuel Biomass	n.a. (lower[3])	50 tpd	n.a.	n.a.
Electrolysis	Alkaline electrolysis (AE)	2.6–6.9	48–64	52–69%	Water Electricity	Depends on electricity source World avg. 19-21 $kgCO_2/kgH_2$	<70 tpd	200m^2/tpd	Waste water mgt.
Electrolysis	Proton-exchange membrane (PEM) electrolysis	3.5–7.5	43–60	60–77% up to 86%	Water Electricity		<300 tpd[2]	50m^2/tpd	Rare materials
Electrolysis	Solid oxide electrolyzer cell (SOEC) electrolysis	5.0–8.5	40–44[1]	74–81%[1]	Steam Electricity		n.a.	n.a.	High T° heat
Microbial	Microbial electrolysis	n.a.	n.a.	n.a.	Water Electricity		n.a.	n.a.	Research stage
Microbial	Biomass dark fermentation	n.a.	47	70%	Water Biomass	-	n.a.	n.a.	
P.S.	Photoelectrical synthesis	n.a.	n.a.	n.a.	Water Sunlight	-	n.a.	n.a.	

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.
Sources: IEA, "The Future of Hydrogen," June 2019; Commonwealth Scientific and Industrial Research Organisation; Institute of Energy Economics Japan; D.B. Pal et al (2018); S. Reza et al (2014); IEA Greenhouse Gas R&D Programme; Foster Wheeler; Nel; Kearney Energy Transition Institute

H_2 is separated from CH_4 at a high temperature in a steam methane reformer while producing CO and CO_2

Fact card: Steam methane reforming

50% of the H2 produced comes from water

Description

- **Step 1: Desulfurization treatment**
  - Natural gas is naturally mixed with sulfur, which is removed thanks to H_2.
- **Step 2: Reforming**
  - CH_4 and high-temperature steam under 3–35 bar pressure are mixed with nickel catalyst to produce H_2, CO, and a small amount of carbon CO_2. Heat for the highly endothermic reaction is provided by burning fuel gas.

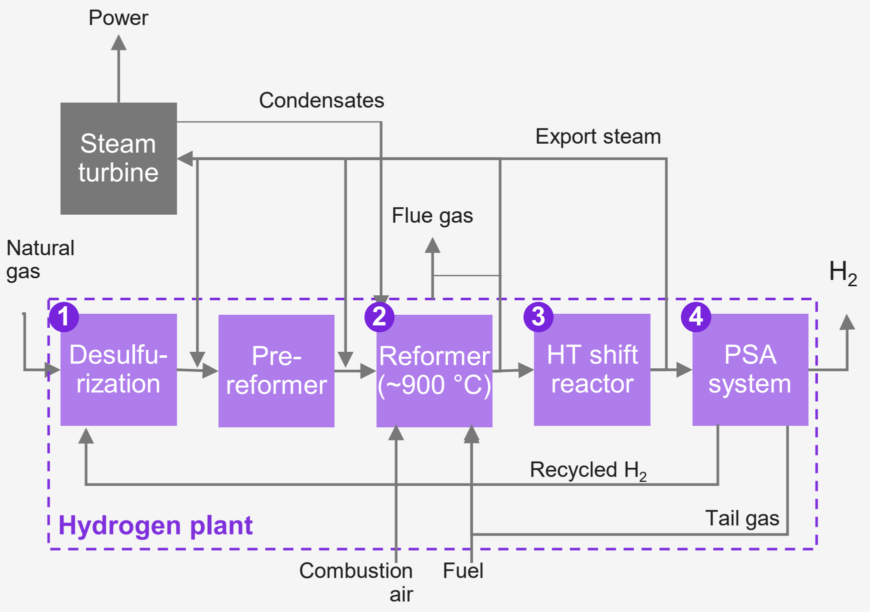
(1) $CH_4 + H_2O \rightleftharpoons CO + 3\,H_2 \qquad \Delta H = +206\ MJ/kmolCH_4$

- **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) $CO + H_2O \rightleftharpoons CO_2 + H_2 \qquad \Delta H = -41\ MJ/kmolCH_4$

- **Step 4: Pressure swing adsorption**
  - In the final step, H_2 is separated from the tail gas through a selective adsorption.

(1)+(2) $\mathbf{CH_4} + \mathbf{2H_2}O \rightleftharpoons CO_2 + 4H_2 \ \ \Delta H = 165\ MJ/kmolCH_4$



Pros

- Established technology
- Integration potential with refineries

Cons

- High temperature required
- Requires purification by PSA
- CO_2 emissions
- Dependence on natural gas

Key feature estimates

Current cost estimate ($ per kgH_2)	**0.9–1.9**
Typical plant size (kgH_2 per day)	**200,000**
Feedstock use ($kgCH_4$ per kgH_2)	**3.43**
Water use (L per kgH_2)	**4.5**
Operating CO2 emissions ($kgCO_2$ per kgH_2)	**9–12**
Efficiency (%, LHV)	**64**
Temperature (°C)	**750–1,100**
Purity of H_2	**99.9%**
Primary energy source	**Natural gas**

Sources: Commonwealth Scientific and Industrial Research Organisation; Institute of Energy Economics Japan; D. B. Pal et al (2018); S. Reza et al (2014); International Energy Agency Greenhouse Gas R&D Programme; Foster Wheeler; Kearney Energy Transition Institute

Gasification is a substoichiometric reaction occurring at a high temperature where fossil fuel is converted to syngas containing mainly H_2 and CO

Fact card: Gasification — partial oxidation

Description

- **Step 1:** Coal (or other feedstock[1]) is heated in a pyrolysis process at 400°C, vaporising volatile component of feedstock in H_2, CO, CO_2, and CH_4.
  - 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).
    $C_nH_m + n/2\ O_2 \rightleftharpoons n\ CO + m/2\ H_2\ \Delta H_{n=1} = -36$ MJ/kmol
- **Step 3:** Water–gas shift reaction to convert CO in CO_2
  $nCO + n\ H_2O \rightleftharpoons n\ CO_2 + n\ H_2\ \Delta H_{n=1} = -41$ MJ/kmol
- **Step 4:** Purification through methanation or PSA
  - Operating conditions depend on coal type, properties of resulting ash, gasification technology: high temperature favors H_2/CO, high pressure favors H_2/CO_2.

Pros

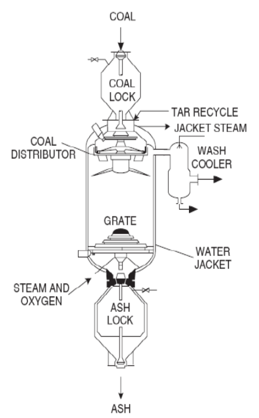
- Abundant fuel, adaptable to all hydrocarbons, biomass, and waste
- Easy capture of CO_2 from the syngas, especially in integrated gasification combined cycle

Cons

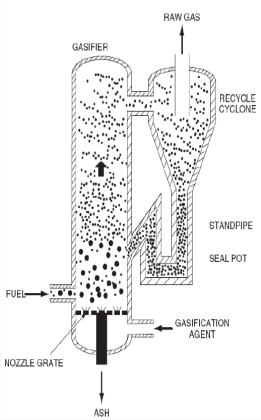
- Purification required

Overview of technologies

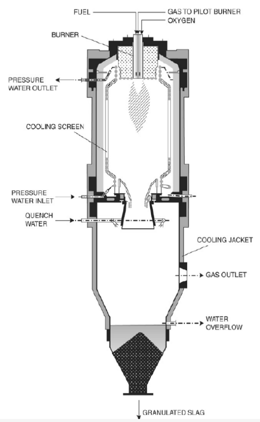
Moving-bed gasifier



Fluidized-bed gasifier



Entrained-flow gasifiers



Key feature estimates

Current cost estimate (\$ per kgH_2)	**1.6–2.2**
Typical plant size (kgH_2 per day)	**500.000**
Feedstock use (kg coal per kgH_2)	**8.0**
Water use (L per kgH_2)	**9.0**
Operating CO_2 emissions (kgCO_2/kgH_2)	**20**
Efficiency (%, LHV)	**70 – 80%**
Temperature (°C)	**800 – 1,800 °C**
Purity of H_2	**More than 99.5%**
Primary energy source	**Coal, biomass, oil, and gas**

1 Feedstock may include coal, biomass, solid waste, heavy oil, oil sands, oil shale, and petroleum coke.
Sources: "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; "Syngas Production from Coal," International Energy Agency Energy Technology Network, 2010; Black & Veatch; Afhypac; Kearney Energy Transition Institute

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

Fact card: Autothermal reforming (ATR)

2.1 **Hydrogen value chain - Production technologies**

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: $4\,CH_4 + O_2 + 2\,H_2O \rightarrow 4\,CO + 10\,H_2$
  – Using CO_2: $2\,CH_4 + O_2 + CO_2 \rightarrow 3\,CO + 3\,H_2 + H_2O + \text{Heat}$
– Water–gas shift reaction happens after ATR reaction

$$CO + H_2O \rightleftharpoons CO_2 + H_2$$

  – CO_2 at exit is less than in SMR because of a higher operating temperature that restricts exothermic water gas shift reaction.

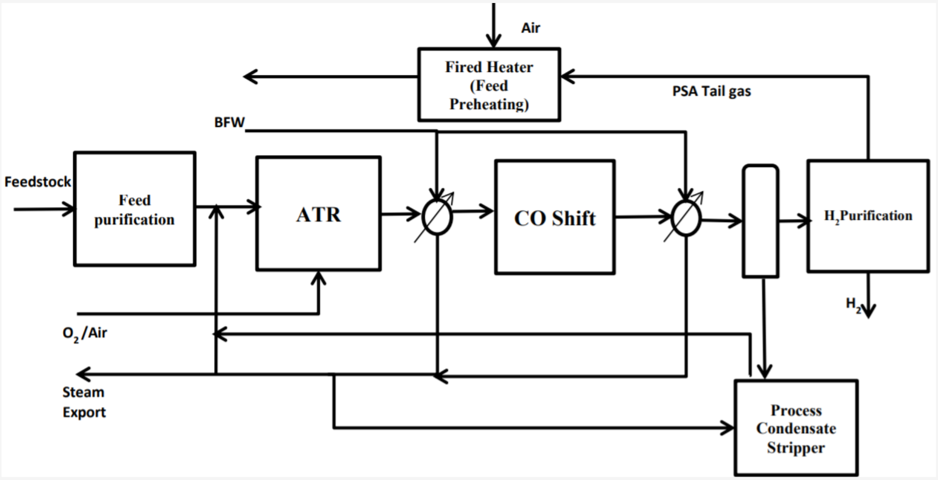
Pros

– Compact design and low investment
– Variable H_2/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



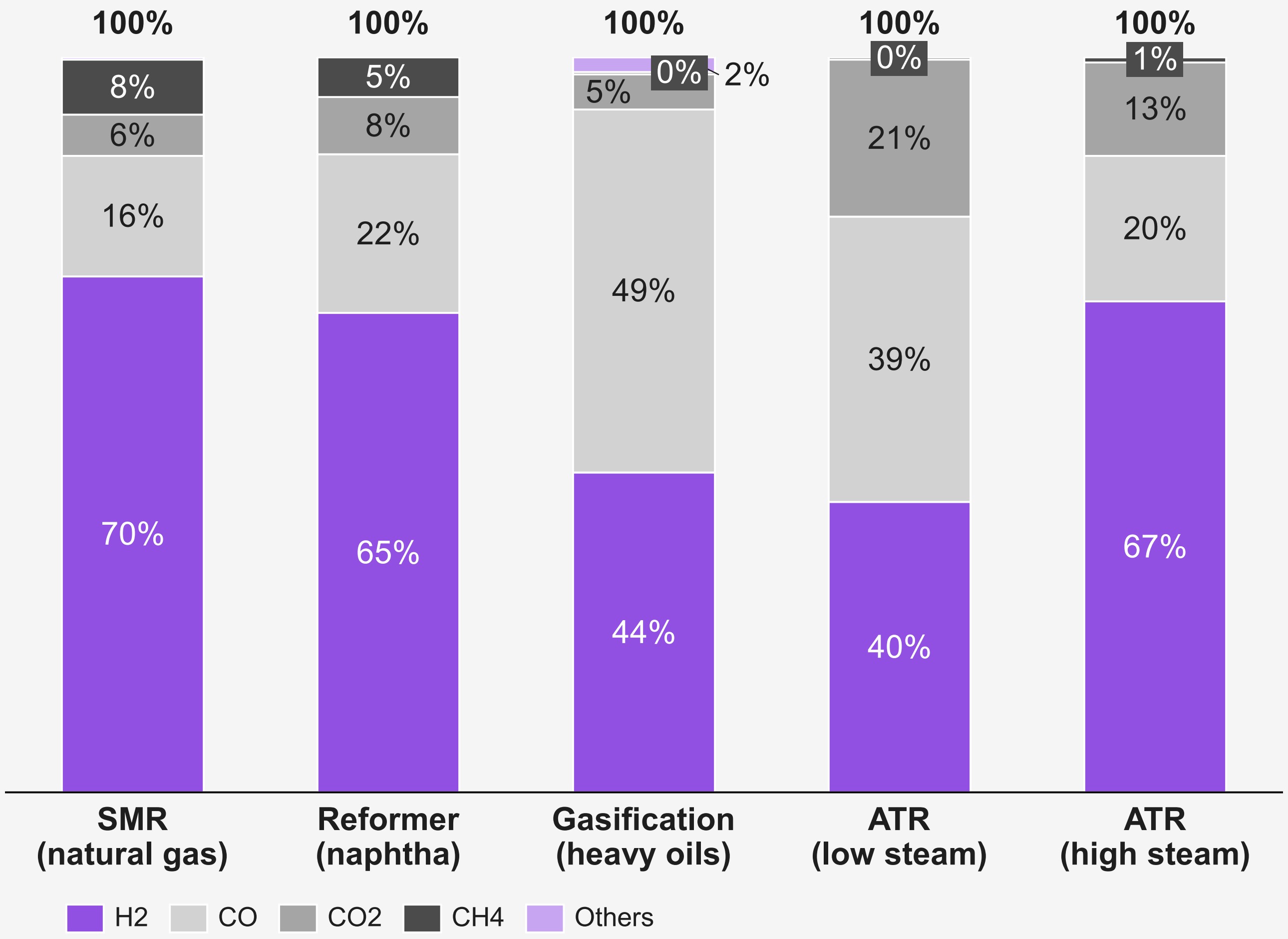
Key feature estimates

Current cost estimate (\$ per kgH_2) w. CCS	n.a.
Typical plant size (kgH2 per day)	**Up to 1,500,000**
Feedstock use ($kgCH_4/kgH_2$)	**2.8**
Water use (L/kgH_2)	n.a.
Operating CO_2 emissions ($kgCO_2/kgH_2$)	**9**
Efficiency (%, LHV)	**78–82**
Temperature (°C)	**980–1200**
Purity of H_2	**95.5%**
Primary energy source	**Hydrocarbons**

Sources: “National Hydrogen Roadmap,” Commonwealth Scientific and Industrial Research Organisation, 2018; Air Liquide; Haldor Topsoe, International Energy Agency Greenhouse Gas R&D Programme; “Blue hydrogen as accelerator and pioneer for energy transition in the industry,” H-vision, July 2019; Afhypac; Kearney Energy Transition Institute analysis

Syngas is a mixture of H_2, CO, and other gases that comes out of SMR, ATR, and gasification reactors

Syngas usual composition per production method
(% of volume)



Note: Others include N_2, Ar, H_2S, and COS
Sources: IFP–Afhypac; Kearney Energy Transition Institute

Key takeaways

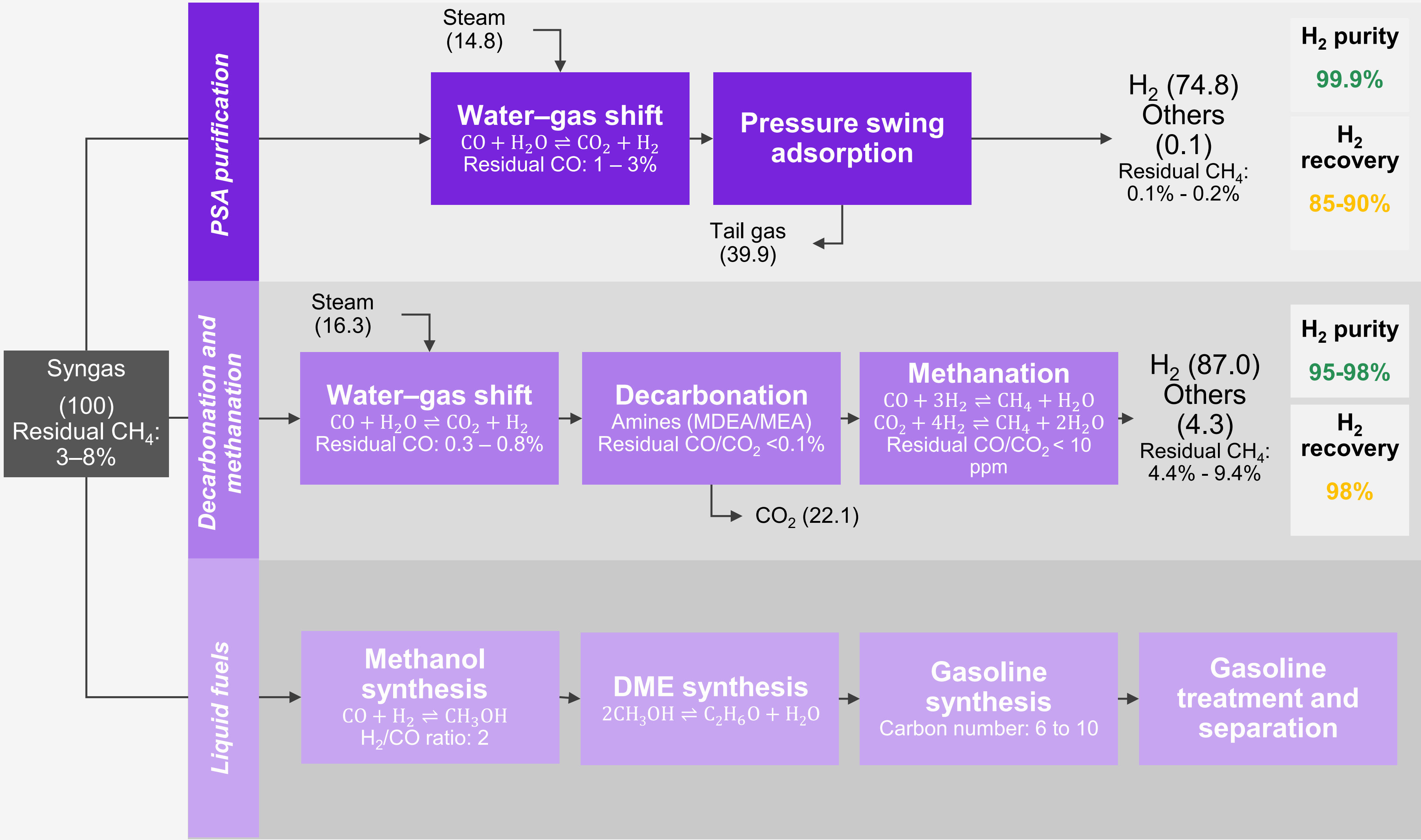
- Syngas has been used for many years for lighting, cooking, and to some extent heating before electric lightning and natural gas infrastructure were deployed.
- During World War II, syngas was used to power cars in Europe as a replacement for gasoline.
- Syngas composition depends on feedstock and the 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.

2.1 Hydrogen value chain - Production technologies

Depending on purity, syngas can either undergo multiple processes to extract H_2 or be converted into liquid fuels

Non-Exhaustive

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

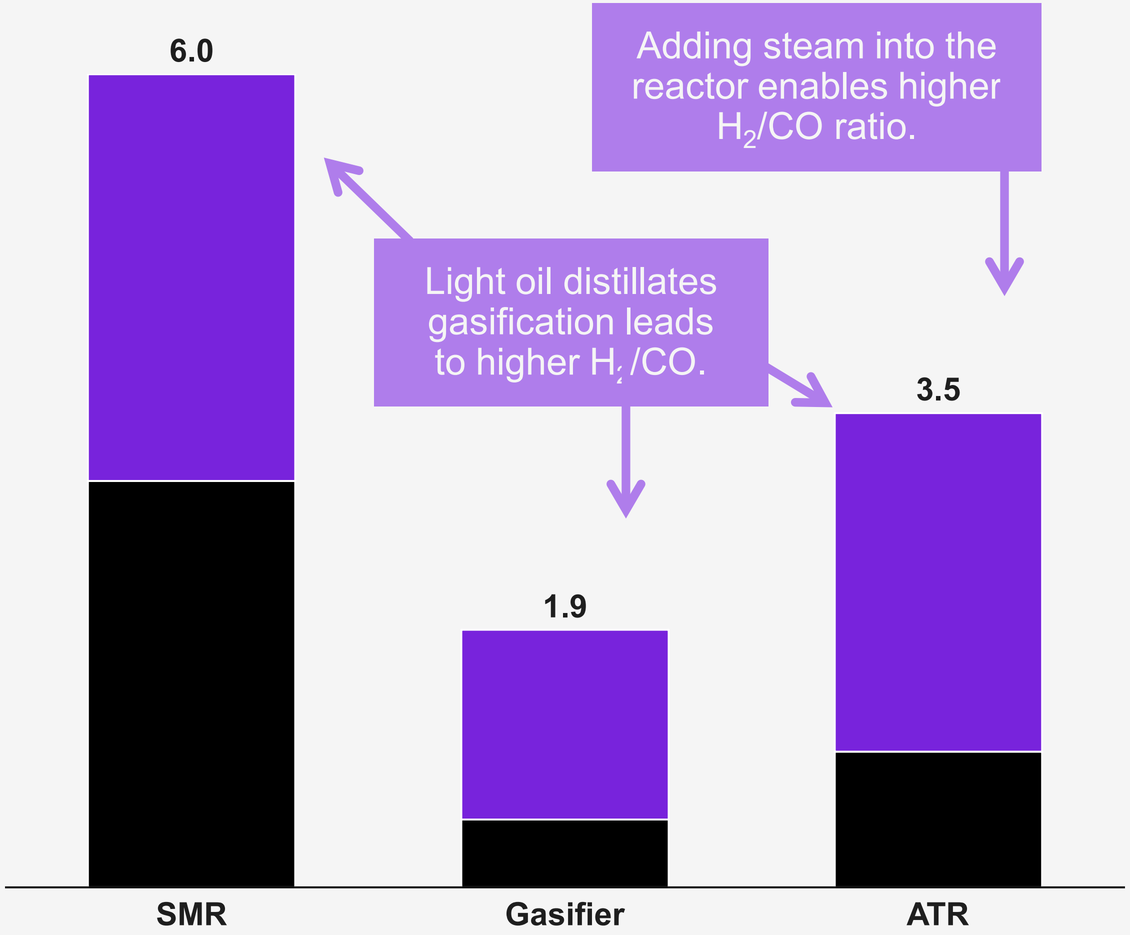


Note: DME is dimethyl ether.
Sources: IFP; Afhypac; Kearney Energy Transition Institute

2.1 Hydrogen value chain - Production technologies

The H_2/CO ratio has a high impact on end-application performance and potential uses, and controlling it allows greater flexibility

H_2/CO ratio range per production mean
(% of volume/% of volume, before water–gas shift)



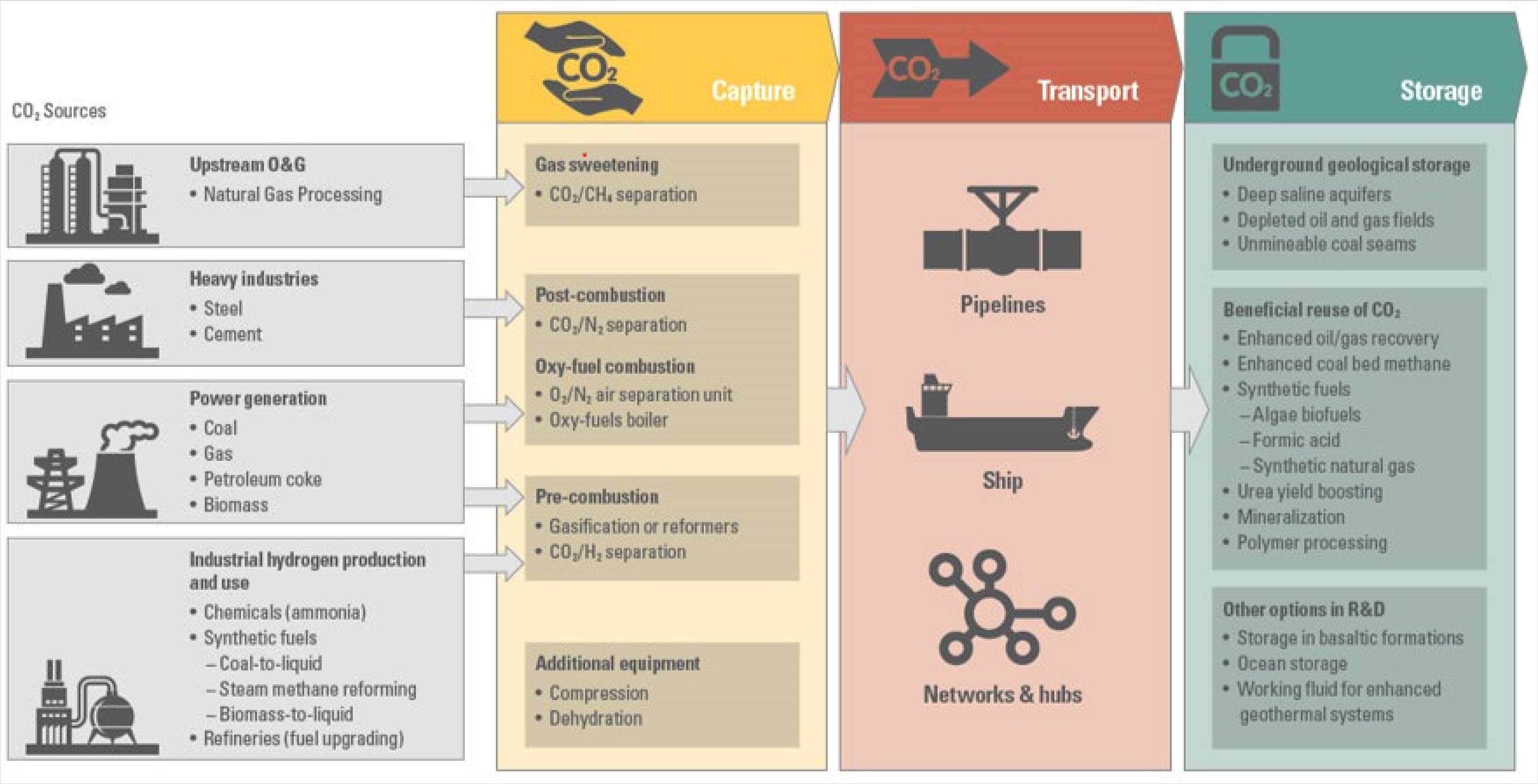
Sources: IFP–Afhypac; B. Sahoo, N. Sahoo, and U. Saha, Applied Thermal Engineering, 2011; Kearney Energy Transition Institute analysis

Key comments

- The H_2/CO ratio depends on the feedstock used, operating temperature, and technology.
- Some applications require specific H_2/CO ratio
  - In the gas-to-liquid pathway, H_2 and CO react in stoichiometric proportions to produce synthetic fuels. The optimal H_2/CO ratio is 2.
- For pure H_2 applications, syngas requires purification. The higher the H_2/CO ratio, the easier the purification.

Carbon capture and storage (CCS) refers to a set of CO_2 technologies that are put together to abate emissions from stationary CO_2 sources

Carbon Capture and Storage – CCS - value chain

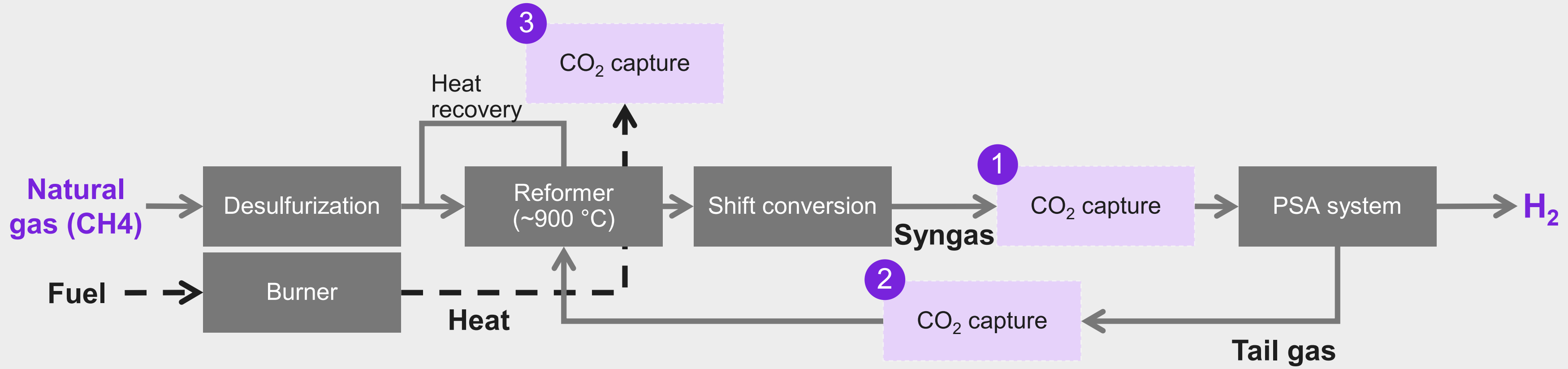


Source: Kearney Energy Transition Institute, CCS FactBook

2.1 Hydrogen value chain - Production technologies

Combining CCS with thermochemical production sources could reduce CO_2 emissions

Overview of SMR and CCS options



Non-Exhaustive

	Option	Description	Maturity	Capture rate
1 a	Capture of CO_2 from shifted syngas with MDEA	$MDEA + CO_2 + H_2O \Leftrightarrow MDEAH^+ + HCO_3^-$	State-of-the art technology, with twice the carrying capacity of MEA	54%
1 b	Capture of CO_2 from shifted syngas with MDEA with H_2-rich burners	$MDEA + CO_2 + H_2O \Leftrightarrow MDEAH^+ + HCO_3^-$	State-of-the art technology, with twice the carrying capacity of MEA	64%
2 a	Capture of CO_2 from PSA tailgas with MDEA	$MDEA + CO_2 + H_2O \Leftrightarrow MDEAH^+ + HCO_3^-$	State-of-the art technology, with twice the carrying capacity of MEA	52%
2 b	Capture of CO_2 from PSA tailgas using low temperature and membrane separation	CO_2 liquefied and purified to food-grade quality	Pilot scale, under deployment	53%
3	Capture of CO_2 from SMR fuel gas using MEA	$MEA + CO_2 \Leftrightarrow H_2O + C_3H_5NO_2 - N_2 + H_2O$	Standard technology	89%

1 USD = 0,89 €
Sources: International Energy Agency Greenhouse Gas R&D Programme, Global CCS Institute, Air Liquide; Kearney Energy Transition Institute analysis

Pyrolysis requires a lower temperature than other technologies and happens in a vacuum chamber

Fact card: Pyrolysis

Description

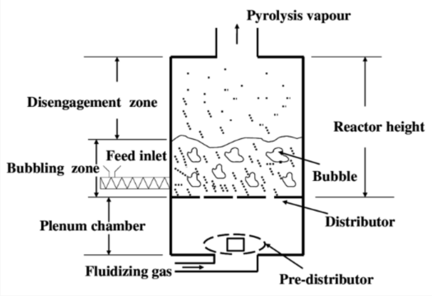
- Hydrocarbons waste undergoes heating without air combustion to break chemical bonds.[1]

$$CH_4 + Heat \rightarrow C + 2\,H_2$$

- 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.

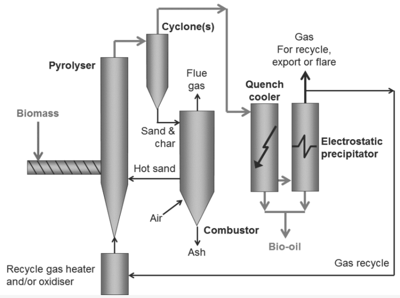
Overview of technologies

Bubbling fluidize bed pyrolizer



Residence time of vapors controlled by fluidizing gas flow rate

Circulating fluid bed pyrolizer



Fast residence time due to high gas velocities

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 H_2 by applying a direct current to an electrolyte solution, which allows high purity of hydrogen

Fact card: Electrolysis

2.1 **Hydrogen value chain - Production technologies**

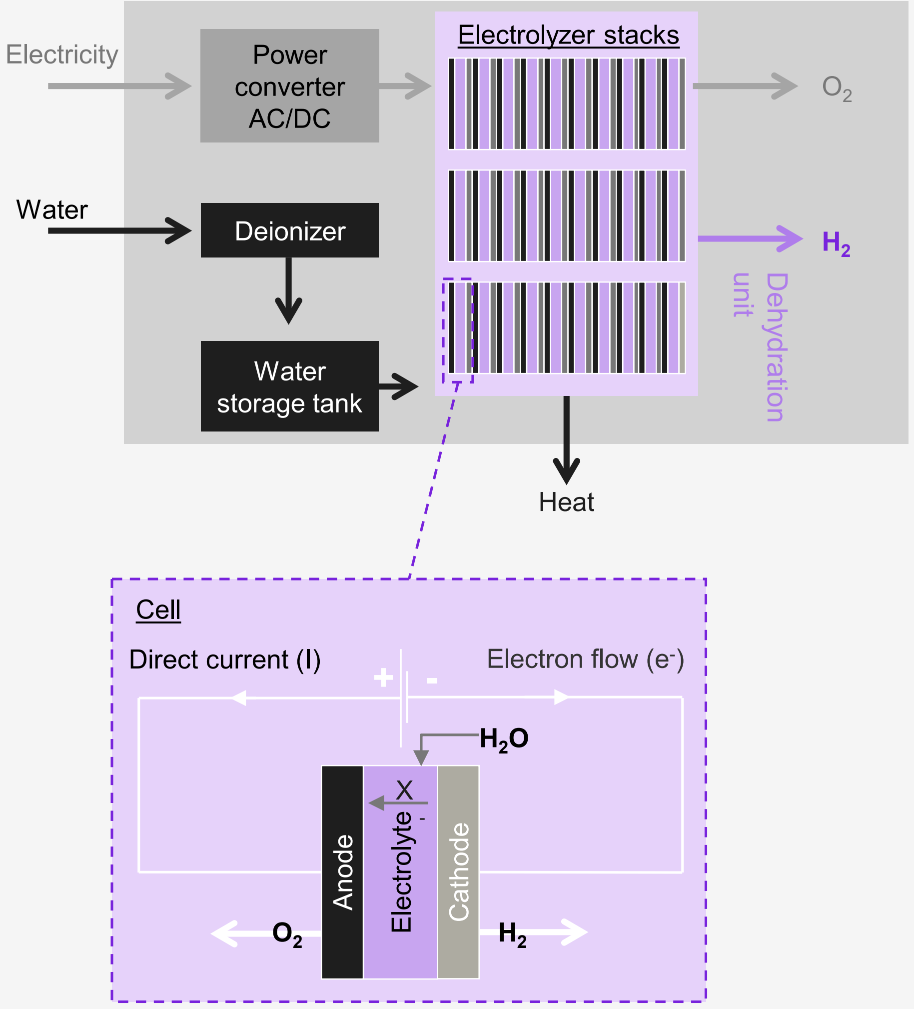
Description

- A direct current passes through an ionic substance, producing chemical reactions at the electrodes (cathode and anode) and decomposing materials.
  - Electrodes are immerged in electrolyte and separated by a membrane where ions can move.
- Hydrogen ions move toward the cathode to form H_2.
- Receivers collect hydrogen and oxygen in gaseous forms.
- Reactions that happen at anode and cathode in a water electrolysis are:
  - Anode: $H_2O \rightarrow 2H^+ + \frac{1}{2}O_2 + 2\,e^-$ (E0 = 1.23V vs. SHE[1])
  - Cathode: $2H^+ + 2\,e^- \rightarrow H_2$(E0 = 0.00V vs SHE[1])
- Overall reaction of water electrolysis is

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2 \text{ (E0 = -1.23V vs SHE}^1\text{)}$$

- For water electrolysis, approximately 9–15 L of water and 50–60 kWh of electricity are required to produce 1 kg of H_2 and 8 kg of O_2 (depends on technology).

Electrolyzer and cell overview
(PEM example)



H_2 production rate
= proportional to I
= Input power * η_{cell}

Pros

- High purity hydrogen
- Oxygen as a by-product, often not used
- No dependency on fossil fuels

Cons

- More expensive than most of thermochemical solutions
- High emitter of CO_2 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

Fact card: Alkaline electrolysis (AE)

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: $2\,OH^- \rightarrow H_2O + \frac{1}{2}O_2 + 2\,e^-$ (E_0 = 0.40V vs SHE[1])
  - Cathode: $2\,H_2O + 2\,e^- \rightarrow H_2 + OH^-$ (E_0 = -0.83V vs SHE[1])
- Overall reaction remains similar to the general one.
- It differs from chlor-alkali/chlorate electrolyzers used in the chlorine industry (using brine water instead of fresh water)
  - 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:

$$2Cl^- + 2H_2O \rightarrow 2\,OH^- + H_2 + Cl_2$$
$$NaCl + 3H_2\,O \rightarrow 3H_2 + NaClO_3$$

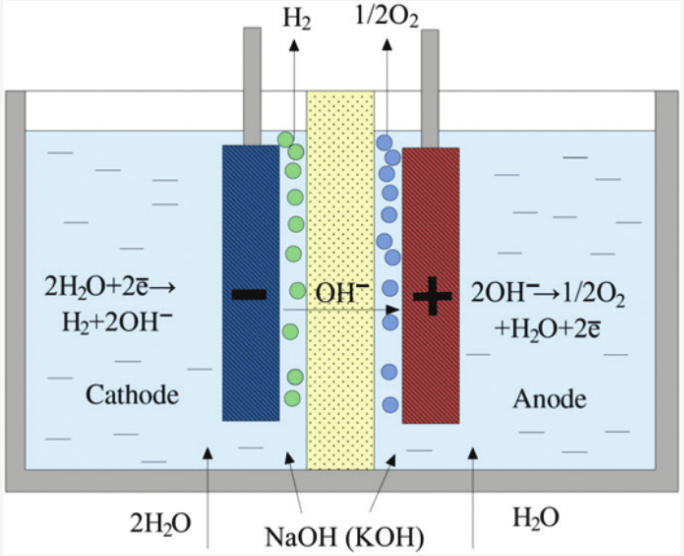
Pros

- 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

Overview of technology



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

1 Standard hydrogen electrode

Sources: "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; "The Future of Hydrogen," International Energy Agency, June 2019; KTH Royal Institute of Technology; Kearney Energy Transition Institute

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

Fact card: Proton exchange membrane (PEM)

2.1 **Hydrogen value chain - Production technologies**

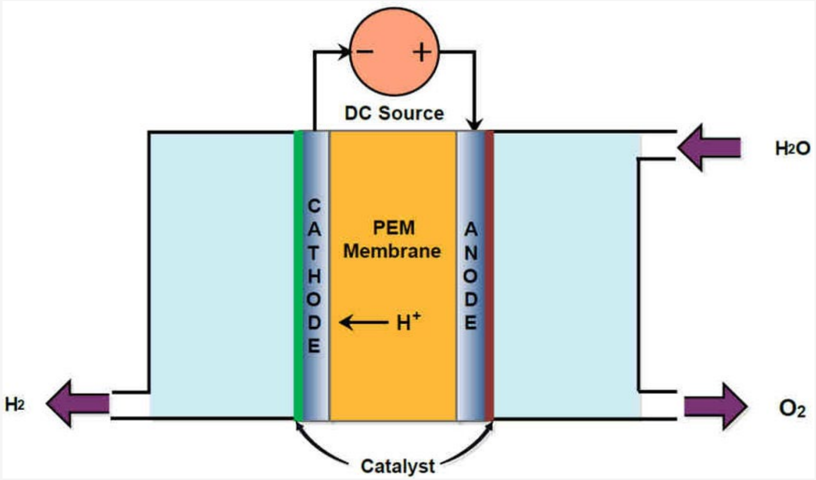
Description

- The PEM electrolyzer uses a ionically conductive solid polymer.
- H+ ions travel through polymer membrane toward the cathode when a potential is applied to form H then H_2.
- Reactions that happen at anode and cathode are:
  - Anode: $H_2O \rightarrow 2H^+ + \frac{1}{2}O_2 + 2\,e^-$ (E_0 = 1.23V vs. SHE[1])
  - Cathode: 2H_++2 e−→H2 (E0 = 0.00V vs SHE1)
- Overall reaction of water electrolysis is:

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2 \; (E_0 = \text{-}1.23\text{V vs SHE}^1)$$

- The PEM electrolyzer has a short response time: below 2 seconds and a cold start time below 5 minutes.
- Most commercial PEM water electrolyzers use self-pressurized PEM cells

Overview of technology



Pros

- Low plant footprint, compacity
- Self-pressurized H_2 well-suited for storage facilities
- Short response time (less than 2 seconds)

Cons

- High capex and OPEX
- Presence of platinum for electrodes

Key feature estimates

Current cost estimate (\$ per kgH_2)	3.5–7.5
Typical plant size (kgH_2 per day)	50–500, up to 50,000
Efficiency (%, LHV)	60–77%
Temperature (°C)	50–80
Operating pressure (bars)	20–50
Current density (A/cm^2)	1–3
Purity of H_2	99.9–99.9999%
Primary energy source	Electricity
Current cost estimate (\$ per kgH_2)	3.5–7.5

1 Standard hydrogen electrode

Sources: “National Hydrogen Roadmap,” Commonwealth Scientific and Industrial Research Organisation, 2018; “The Future of Hydrogen,” International Energy Agency, June 2019; Hydrogenics; Kearney Energy Transition Institute analysis

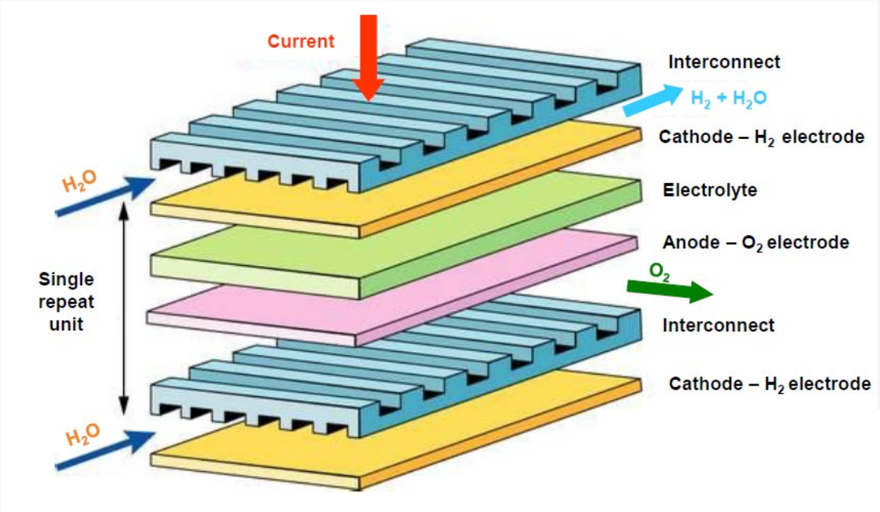
SOEC, the electrolysis of steam, is still in the R&D stage but is more efficient than other electrolysis technologies

Fact card: Solid oxide electrolysis cell (SOEC)

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.

Overview of technology



Pros

- High efficiency and low electricity consumption

Cons

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

Key feature estimates

Current cost estimate (\$ per kgH_2)	5.8–7.0
Typical plant size (kgH_2 per day)	Pilot scale
Efficiency (%, LHV)	74–81%
Temperature (°C)	650–1.000
Operating pressure (bars)	1
Current density (A/cm^2)	0.5–1
Primary energy source	Electricity
Current cost estimate (\$ per kgH_2)	5.8–7.0
Typical plant size (kgH_2 per day)[2]	Pilot scale

1 Standard hydrogen electrode

Sources: “National Hydrogen Roadmap,” Commonwealth Scientific and Industrial Research Organisation, 2018; “The Future of Hydrogen,” International Energy Agency, June 2019; Hydrogenics; Kearney Energy Transition Institute analysis

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

Electrolysis production technologies

	AE (Alkaline)	PEM	SOEC
Operating pressure (bar)	1–30	20–50	1
Operating temperature (°C)	60–80°C	50–80°C	650–1,000°C
Current density	0.3–0.5 A/cm²	1–3 A/cm²	0.5–1 A/m²
Load range (% of nominal load[1])	10–110%	20–100%, up to 160%	20–100%
System efficiency (% LHV)	52–69%	60–77%	74–81%
Response time	Start: 1–10 minutes; shut: 1–10 minutes	Start: 1 second–5 minutes; shut: few seconds	High
Reverse mode (fuel cell mode)	No	No	Depends on design
Stack lifetime (hours)	60,000–90,000; 100,000–150,000 expected	30,000–70,000 (80, 000 achieved by ITM); 100,000–120,000 expected	10,000–30,000, 75,000–100,000 expected
Expected R&D improvements	– Scaling benefits and lower cost of BoP – Improved lifetime of components through R&D – Improved heat exchangers	– Scaling benefits, smaller footprint of stack, and lower cost of BoP – Improvement in materials and components lifetime (such as lower resistance membrane, catalyst coating, and current density) through R&D	– Improvement in component lifetime (especially ceramic membrane) by improving resistance to high temperatures – Improve response to fluctuating energy inputs
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.
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; National Renewable Energy Laboratory; Kearney Energy Transition institute analysis

Dark fermentation is the conversion of organic matter to hydrogen through biochemical reactions

Fact card: Dark fermentation

Description

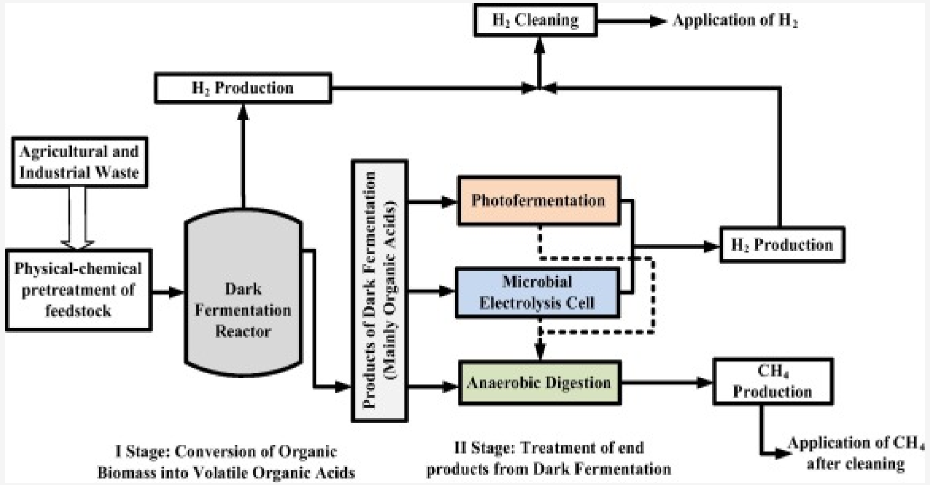
- Dark fermentation happens in a tank with no light. Bacteria will trigger a series of biochemical reactions.
  - Anaerobic bacterial and microalgae reacts with carbohydrate (refined sugars, raw biomass) and water (even with waste water) to produce H_2 and CO_2.

$$C_6H_{12}O_6 + H_2O \rightarrow 2\ CH_3CO_2H + 4\ H_2 + CO_2$$

$$C_6H_{12}O_6 + H_2O \rightarrow CH_3CH_2CH_2CO_2H + 2\ H_2 + 2\ CO_2$$

- 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.

Overview of technology



Pros

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

Cons

- Low yield of production
- Production of CO_2 and CO requiring a purification step
- Early-stage technology

Key feature estimates

Current cost estimate ($ per kgH_2)	No industrial use yet
Hydrogen production yield (kgH_2 per kg)	0.03–0.04
Efficiency (%, LHV)	30–40%
Operating temperature (°C)	25–40
Primary energy source	Biomass

2.1 Hydrogen value chain - Production technologies

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 H_2 with low energy inputs

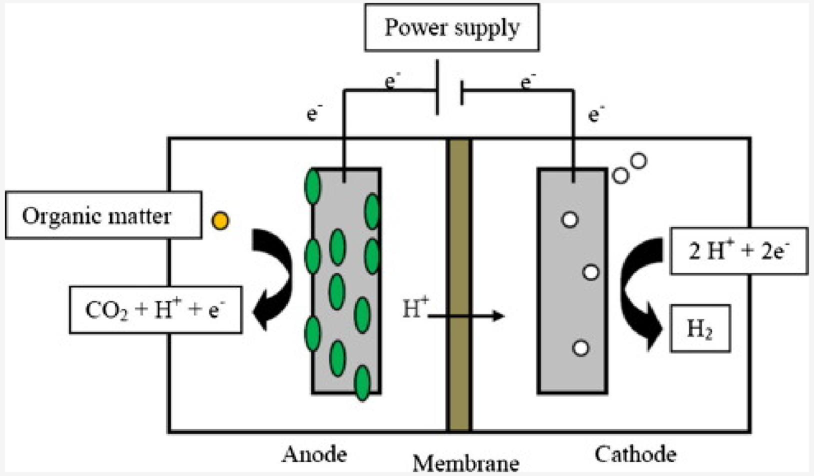
Fact card: Microbial electrolysis

Description

- Microorganisms are attached to the anode and bacteria consume acetic acid to release e- and protons combining into H^+ and CO_2.
- 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: $C_2H_4O_2 + 2\,H_2O \rightarrow 2\,C02 + 8\,H^+ + 8\,e^-$
  - Cathode: $8\,H^+ + 8\,e^- \rightarrow 4\,H_2$
- Overall, reaction can be summarized as follows:

$$C_2H_4O_2 + 2\,H_2O \rightarrow 2\,CO_2 + 4\,H_2$$

Overview of technology



Pros

- Carbon neutral technology[1]
- Abundant resource
- Ongoing development of membrane-free reactors with high production rates

Cons

- No comprehensive review on reactor configurations
- Early stage technology

Key feature estimates

Current cost estimate ($ per kgH_2)	1.7–2.6 in laboratory conditions
Typical plant size (kgH_2 per day)	No industrial use yet
Efficiency (%, LHV)	About 70% (up to 300% if only considering electrical input)
Current density (A/cm^2)	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

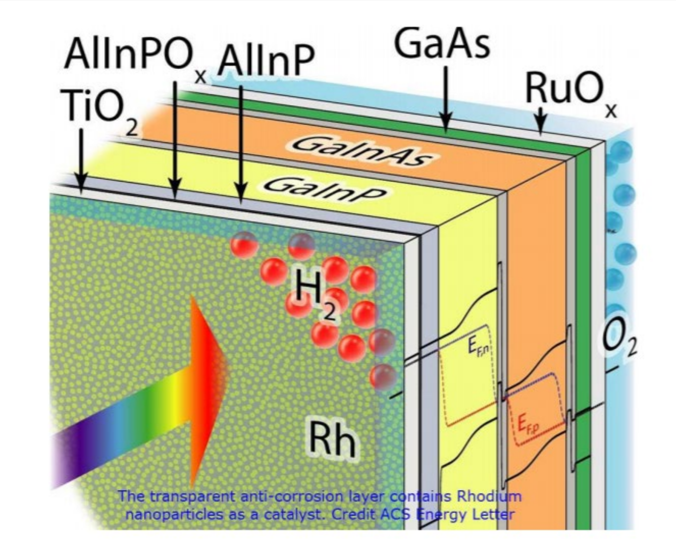
Fact card: Photolytic conversion technologies

Description

- Microorganisms are attached to the anode and bacteria consume acetic acid to release e- and protons combining into H^+ and CO_2.
- 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: $C_2H_4O_2 + 2\,H_2\,O \rightarrow 2\,C02 + 8\,H^+ + 8\,e^-$
  - Cathode: $8\,H^+ + 8\,e^- \rightarrow 4\,H_2$
- Overall, reaction can be summarized as follows:

$$C_2H_4O_2 + 2\,H_2\,O \rightarrow 2\,CO_2 + 4\,H_2$$

Overview of technology



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

Key feature estimates

Current cost estimate (\$ per kgH_2)	n.a. (laboratory stage)
Typical plant size (kgH_2 per day)	n.a. (laboratory stage)
Efficiency (%, LHV)	~15% (max. 23%)
Current density (A/cm^2)	~10^{-2}
Primary energy source	Sunlight

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

Storing and transporting hydrogen adds complexity to the value chain

Hydrogen midstream value chain

Purification and conversion

- Hydrogen needs to purified, either to remove other components from syngas (including CO and CO_2) 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.

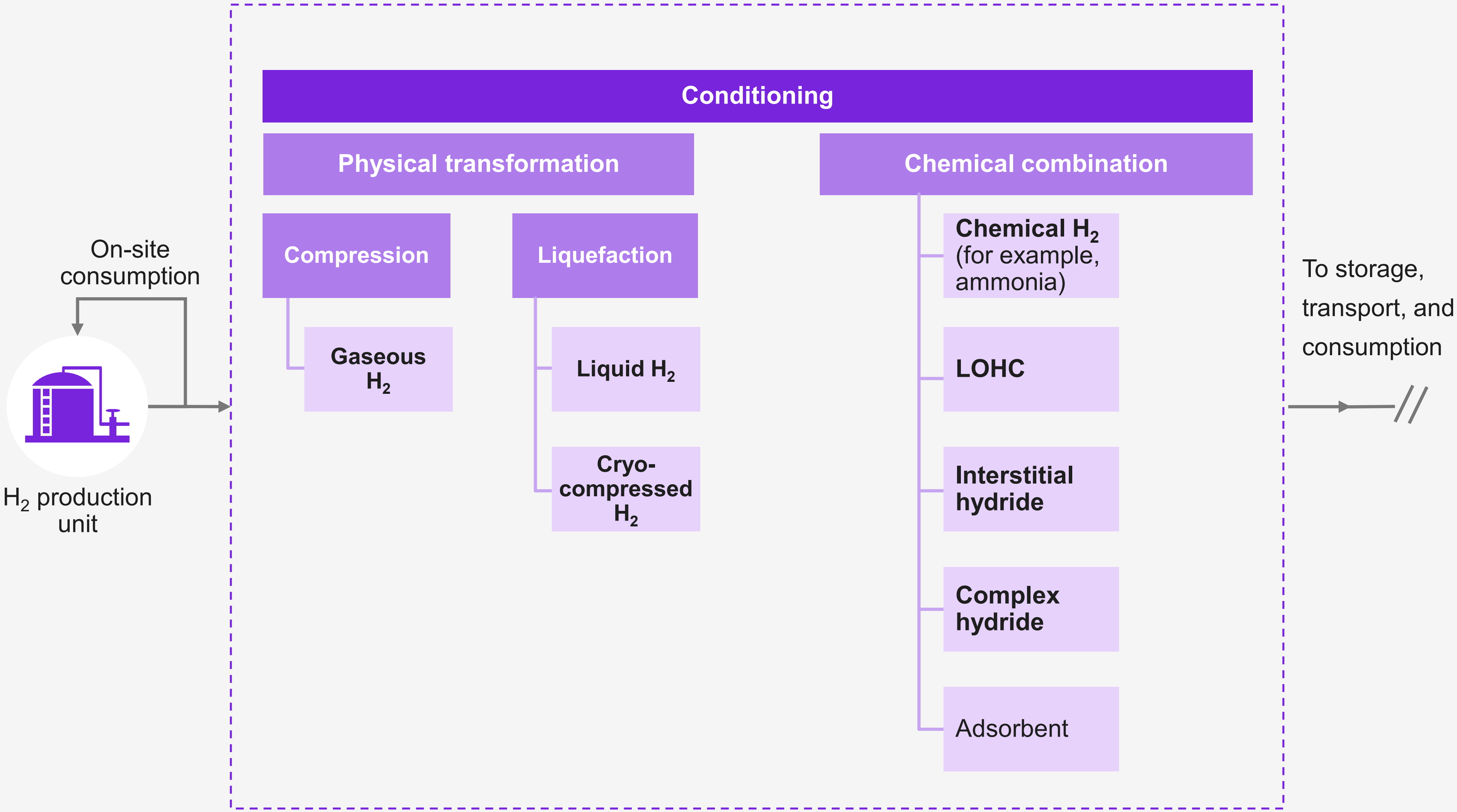
Storage and reconversion

- 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.

Note: LOHC is liquefied organic hydrogen carrier. 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

H_2 Conditioning



Note: LOHC is liquefied organic hydrogen carrier.
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; US Department of Energy; Kearney Energy Transition Institute analysis

Depending on the conversion process, H_2 can be stored and transported in multiple ways

H_2 storage and transport

Transformation method		Long-distance transportation		Short-distance distribution			Storage			
		Pipeline	Tankers	Pipeline	Trucks	Trains	Tank	Pipeline	Can	Cavern
Physical transformation	Compression	✓	✓	✓	✓	✓	✓	✓		✓
	Liquefaction		✓		✓	✓	✓			
Chemical combination	Ammonia	✓	✓	✓	✓	✓	✓	✓		
	LOHC		✓		✓	✓	✓			
	Hydrides		✓		✓	✓			✓	
Scale		~2,000 km	>3,000 km	<500 km	<500 km	<1,000 km	Small to mid scale	Small to mid scale	Small scale	Large scale

1. Note: LOHC is liquefied organic hydrogen carrier.
2. Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

There are multiple opportunities to carry hydrogen: either in gaseous, liquid or in another molecule form

2.2 **Hydrogen value chain - Conversion, storage, and transportation technologies**

H_2 conversion and reconversion key facts

Technology advantage: Low | Medium | High

Material-based		Technology description	Density (kg/m^3)	Energy input (kWh/kg H_2)	Energy input (% LHV)	Process maturity	Advantages	Disadvantages
Gas	35	Compression of H_2 at desired pressure to increase energy density	3	-1	-	High	– PEM produces H_2 at 35 bars pressure	– Flammable
	150		11	~1	>90%	High	– Compression at 25 °C	
	350		23	~4	>85%	High		
	700		38	~6	80%	High		
Liquefied hydrogen		Cooling of H_2 at -253°C through cryo-compression	71	~9	65-75%	High for small scale Low for large scale	– Economically viable where space is limited and high H_2 demand	– High energy losses, esp. compared to LNG conversion – Boil off losses (up to 1% per day)
Ammonia		Reaction with nitrogen	121	3 kWh/kg at conversion, up to 8 at reconversion	82%-93% at conversion, ~80% at reconversion	High for conversion, medium for reconversion	– Mature industry, potential to leverage current infrastructure	– Toxicity and air polluter – High energy req. for reconversion
LOHC to MCH[2]		Mixing with MCH and converted back to hydrogen	110	Exothermic conversion, ~12 kWh/kg at reconversion	Exothermic conversion, ~65% at reconversion	Medium	– No need for cooling	– Toxicity and flammability of toluene – Price of toluene – Back-shipping of toluene
Metal hydrides		Chemical bonding with metals, reheat back to hydrogen	86 (MgH_2)	4	88%	Medium	– Lower costs and losses – Higher safety – Higher energy density than compression	– Heavy storage unit – Long charging/discharging times – Low lifetime

1. 1 PEM produces H2 at this pressure with no additional need for compressor.
2. 2 Methylcyclohexane (C7H14)
3. Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; Kearney Energy Transition Institute analysis

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

Technology advantage: Low | Medium | High

	Storage type	Range (kms)	Key data: Sub-type	Key data: Metrics	Process maturity	Advantages	Disadvantages
Pipeline	Compression	1,000–4,000	Low pressure (shorter distances)	– Capex/km (MUSD): 0.3 – Gas density (kg/m3): 0.55 – Gas velocity (m/s): 15	High	– Lowest-cost option for continuous delivery – Low operation costs	– Higher capital costs because of infrastructure requirements
			High pressure (longer distances)	– Capex/km (MUSD): 0.5 – Gas density (kg/m3): 6.4 – Gas velocity (m/s): 15			
Trucks	Compression, liquefaction, ammonia	Less than 1,000	n.a.	– Capex ($ thousand): 185 (truck), 650–1,000 (trailer) – Loading/unloading time (trailer, hours): – 3 (LH_2), 1.5 (GH_2) – Net capacity (trailer, kgH_2): 4300 (LH_2), 670 (GH_2)	High	– 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
Trains	Compression, liquefaction, ammonia	800–1,100	n.a.	n.a.	Medium	– Lower operational costs, larger quantities, and distances compared with trucks	– Limited route flexibility
Tankers	Liquefaction, ammonia	More than 4,000	n.a.	– Capacity/ship (tH_2): 11,000 – capex/ship (MUSD): 412 – Fuel use (MJ/km): 1487	Low	– Likely option for exporting huge volumes	– Unlikely to use compression storage because of the cost of operation, distance, and lower hydrogen density

Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; Kearney Energy Transition Institute analysis

Pressurized tanks are the most mature and common hydrogen storage technology

Fact card: Pressurized tanks

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

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

Current cost estimate	\$6,000–\$10,000 per MWh (storage tank)
Typical size	100 kWh–10 MWh per tank
Volumetric density (kWh/m^3)	670–1,300
Efficiency (%)	89–91% (350 bar); 85–88% (700 bar)

Sources: “The Future of Hydrogen,” International Energy Agency, June 2019; “National Hydrogen Roadmap,” Commonwealth Scientific and Industrial Research Organisation, 2018; Kearney Energy Transition Institute analysis

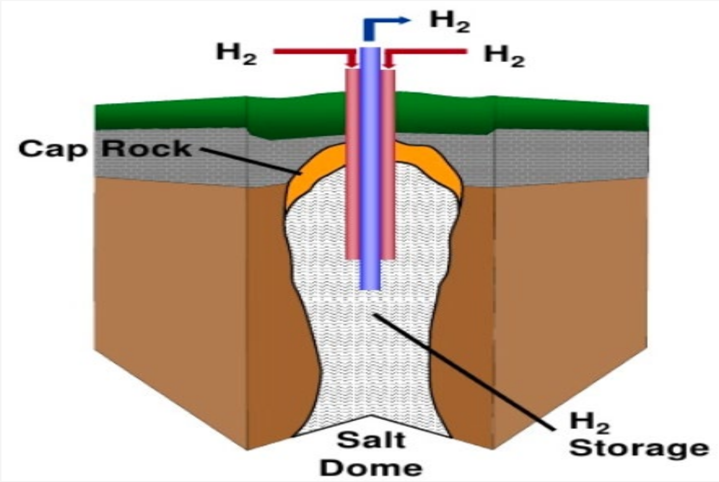
Salt caverns, depleted natural gas, or oil reservoirs and aquifers are potential options for large-scale and long-term hydrogen storage

Fact card: Geological 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.

Overview of technology



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

Current cost estimate ($ per kgH_2)	Less than 0.6
Typical size	1–1,000 GWh
Volumetric density (kWh/m^3)	65 (at 100 bar)
Efficiency (%)	90–95%

Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; Praxair (2009); Kearney Energy Transition Institute analysis

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

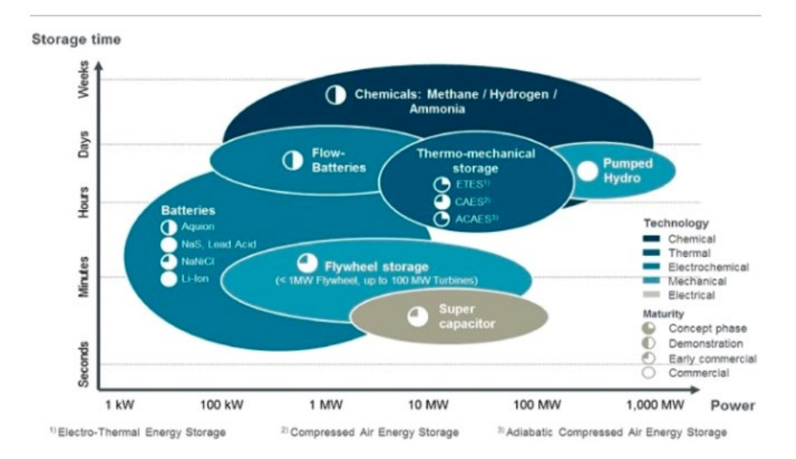
Preliminary

Fact card: Long-term energy storage

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

Overview of technologies



H_2 Market trends

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

Source: Kearney Energy Transition Institute analysis

Para-meter	Units	PHES	CAES	Li-ion	Comp-ressed H_2
Capex (power)	$ per kWe	1130	870	95	1820
Capex (storage)	$ per kWh	80	39	110	0.25
Opex (power)	$ per kWe	8	4	10	73
Opex (storage)	$ per kWh	1	4	3	0
Round-trip efficiency	%	78	44	86	37
Lifetime	Years	55	30	13	20

2.2 Hydrogen value chain - Conversion, storage, and transportation technologies

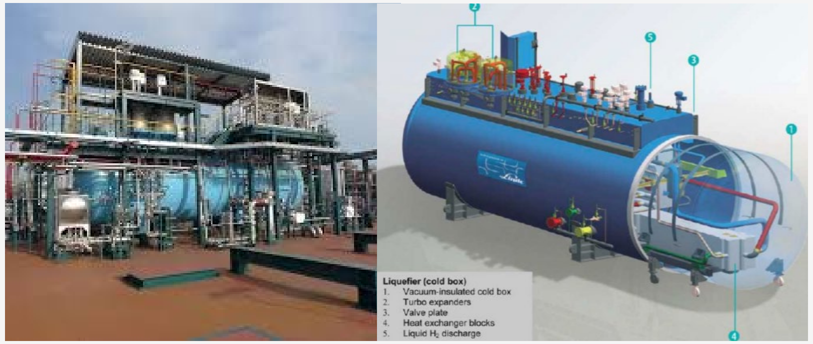
Liquefying H_2 must be cooled down to -253°C, with potential losses from boil-off

Fact card: Liquefaction of H_2

Description

- George Claude's cycle to liquefy H_2 is a three-step process:
  - H_2 is first cooled with a liquid nitrogen heat exchanger.
  - Then, H_2 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 H_2.
- As natural H_2 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.

Overview of technology



Linde's liquefaction plant

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

Key feature estimates

Current cost estimate ($ per kgH_2)	~1.0
Typical plant size (kgH_2 per day)	5,000–25,000
Energy required (kWh/kgH_2)	10–13
Energy consumption (% of LHV of Hydrogen)	20–25%, potential to 18%

Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; Afhypac; Linde; Kearney Energy Transition Institute analysis

Ammonia is synthetized through the Haber–Bosch process and can be reconverted to H_2 or used as a feedstock for fertilizers

Fact card: Ammonia conversion

Description

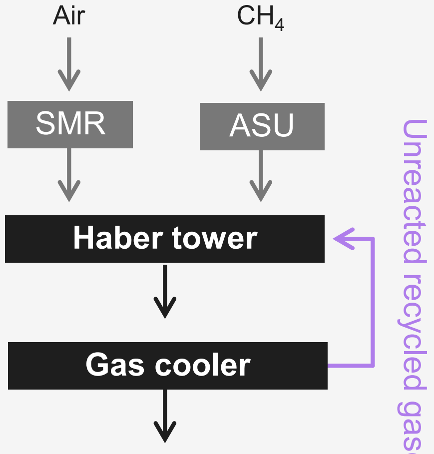
- Synthetized through the Haber–Bosch process:

$$N_2 + 3H_2 \rightarrow 2NH_3 \quad \Delta H = -92 \text{ kJ/mol}$$

- 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 N_2 and H_2 are converted to ammonia. Therefore. gases are recycled to increase conversion rate to 98%.

Overview of technology

Haber tower



Liquid ammonia

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

Key feature estimates

Current cost estimate ($ per kgH_2)	Conversion: 0.98–1.2 Reconversion: 0.80–1.0
Typical plant size (kgH_2per day)	About 200,000
Energy required (kWh/kgH_2)	Conversion: 2–3 Reconversion: 8
Energy consumption (% of LHV of hydrogen)	Conversion: 7–18% Reconversion: Less than 20%

Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; Afhypac; Linde; Kearney Energy Transition Institute analysis

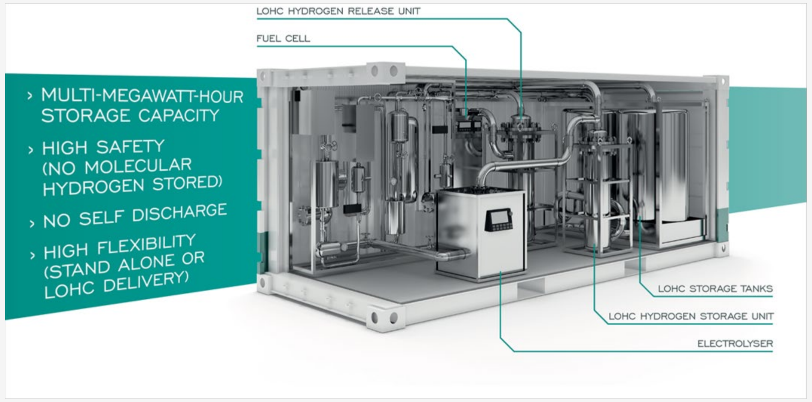
LOHC is a liquid hydrogenated carrier, which enables easier and safer handling and do not require cooling

Fact card: Liquefied Organic Hydrogen Carrier (LOHC)

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.

Overview of technology



Hydrogenious LOHC reconversion unit

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

Key feature estimates

Current cost estimate ($ per kgH_2)[3]	Conversion: 1.0 Reconversion: 2.1
Typical plant size (kgH_2 per day)[2]	About 10,000
Energy required (kWh/kgH_2)	Reconversion: about 10
Energy consumption (% of LHV of hydrogen)	35–40%, potential to 25%

2.2 Hydrogen value chain - Conversion, storage, and transportation technologies

Sources: “The Future of Hydrogen,” International Energy Agency, June 2019; “National Hydrogen Roadmap,” VTT; Hydrogenious; Kearney Energy Transition Institute analysis

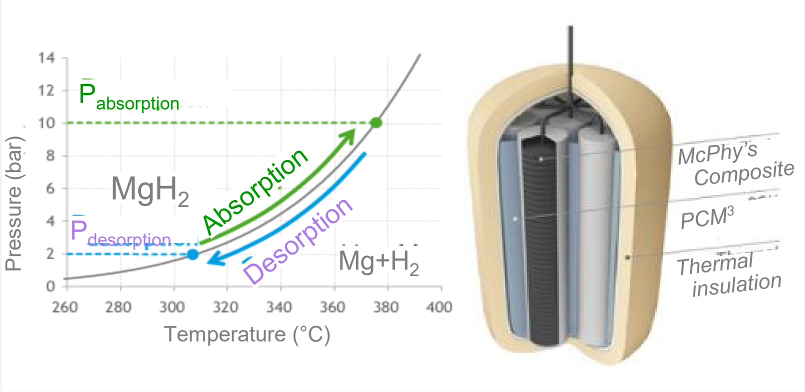
Metal hydrides operate at low pressure and improve hydrogen-handling safety but must still demonstrate their economic feasibility

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.

Overview of technology



Hydrogenious LOHC reconversion unit

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

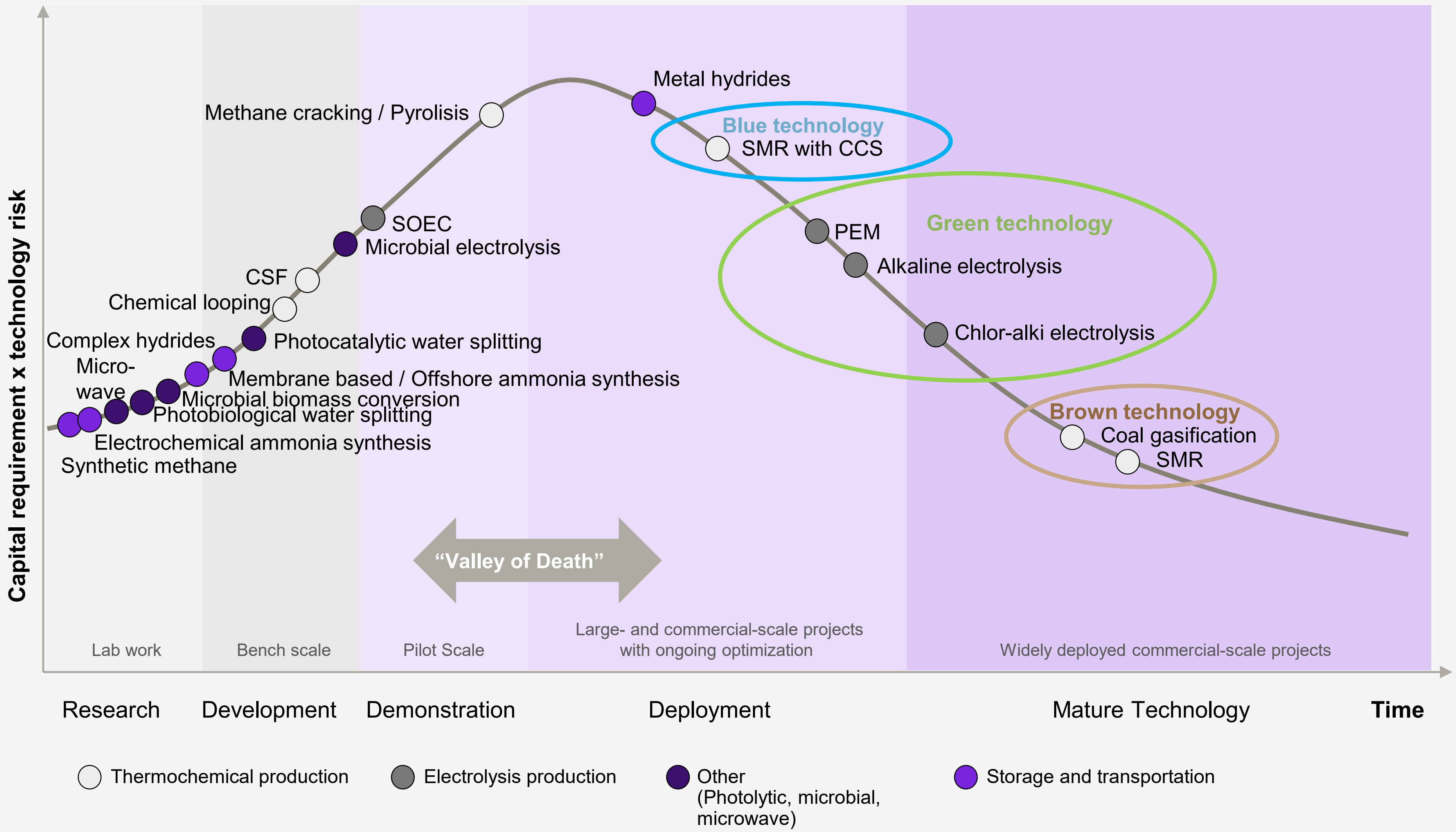
Key feature estimates

Current cost estimate ($ per kgH_2)	NA
Typical size	10–20 (United States), 1 (United Kingdom)
Volumetric density (kWh/m3)	4,200
Efficiency (%)	~80-90%

Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; Kearney Energy Transition Institute analysis

Multiple new H_2 production technologies are being developed, brown technologies being the most mature

Hydrogen technology maturity curve



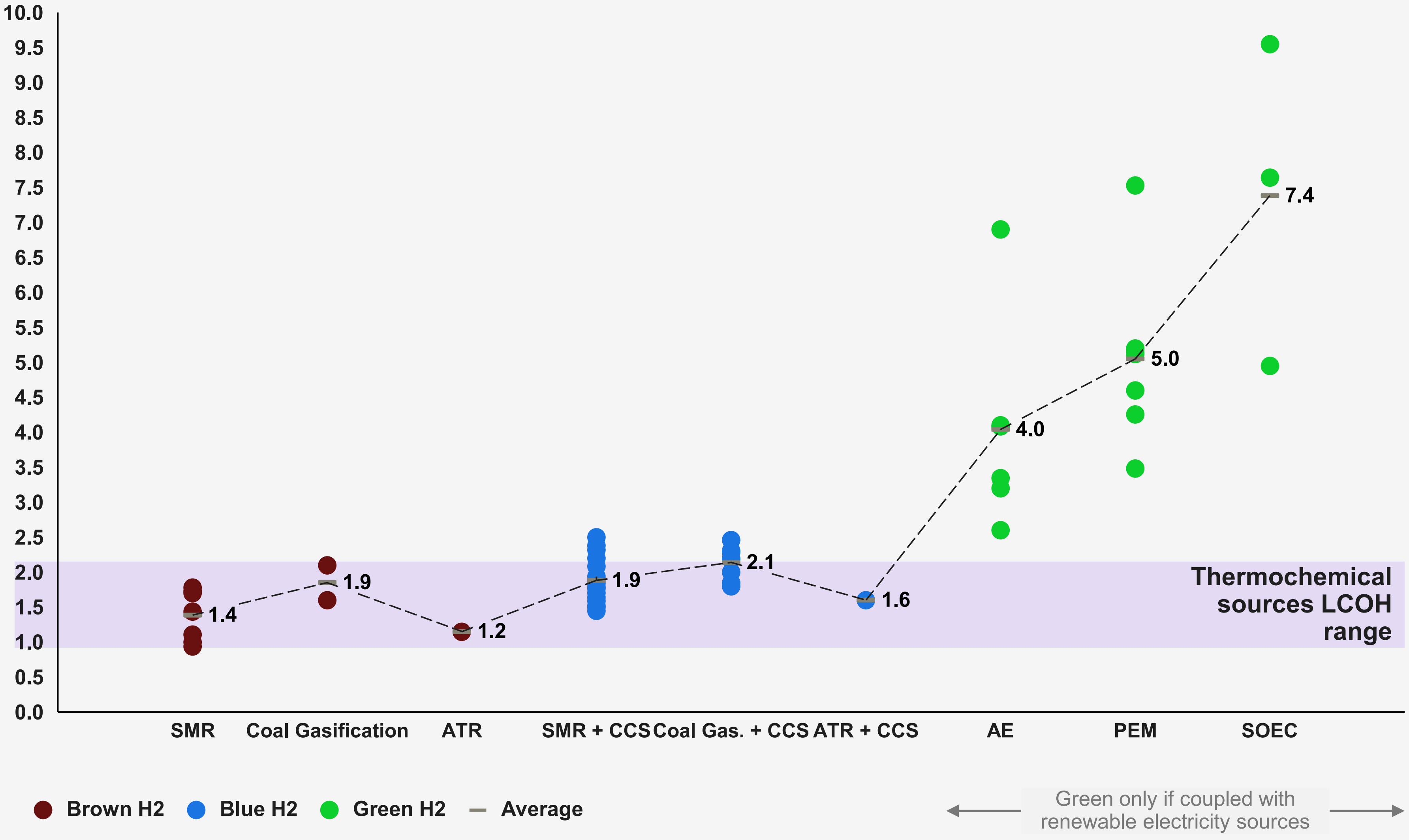
Sources: IEA – The Future of Hydrogen (2019), Csiro – National Hydrogen Roadmap (2018), IRENA – Hydrogen from Renewable Power (2015); Kearney Energy Transition Institute "Hydrogen Applications and Business Models" (2020)

2.3 **Hydrogen value chain - Maturity and costs**

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

Not Exhaustive; Indicative

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

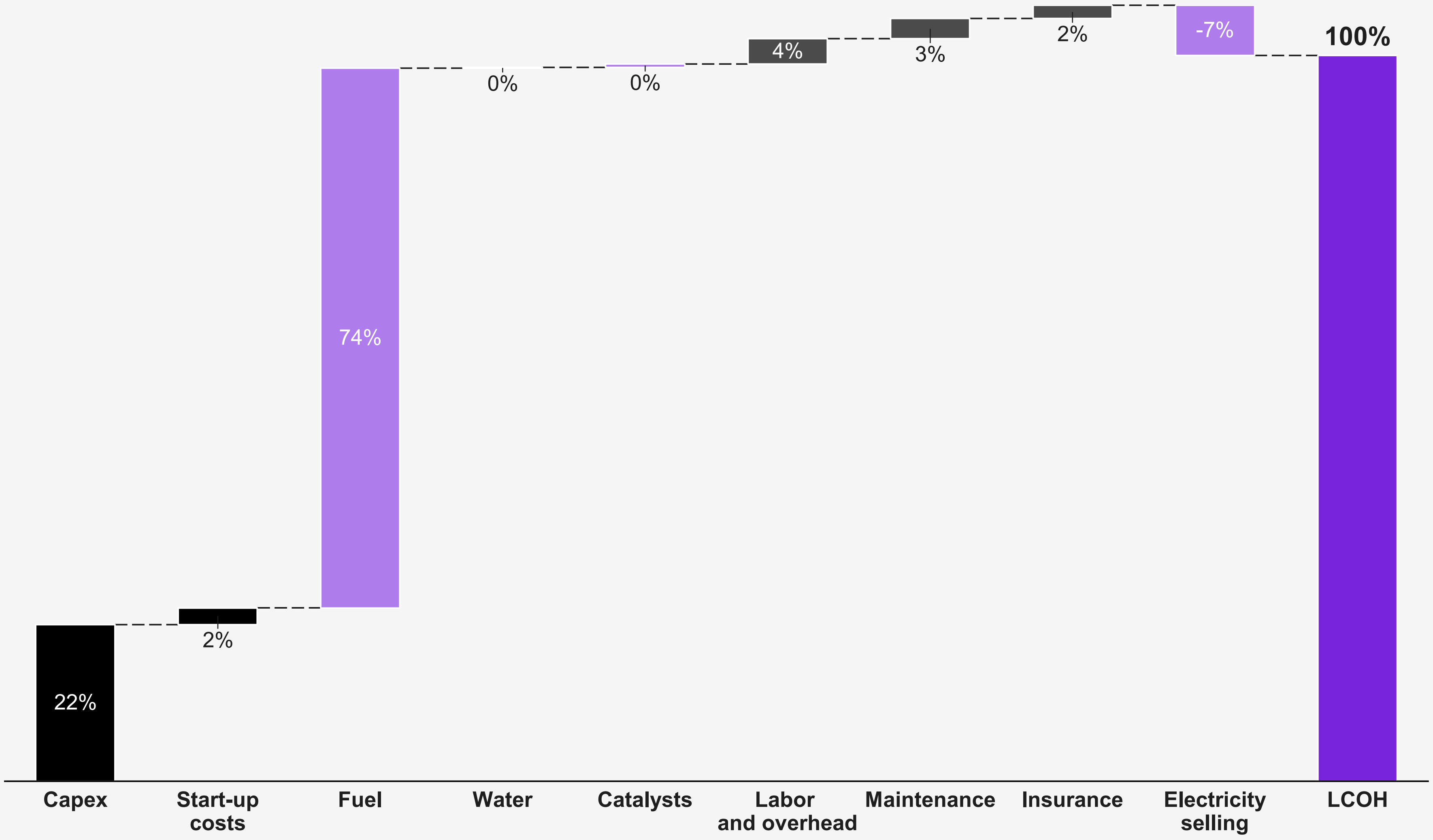


Note: All hypotheses are detailed in the appendix.
Sources: International Energy Agency Greenhouse Gas R&D Programme, Commonwealth Scientific and Industrial Research Organisation, International Renewable Energy Agency, Foster Wheeler, McPhy, Areva H2Gen, Rabobank, TOTAL, Department of Energy, Air Liquide; Kearney Energy Transition Institute analysis

LCOH for thermochemical production sources is driven by fuel costs and capex, accounting for about 96% of total LCOH

Illustrative

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



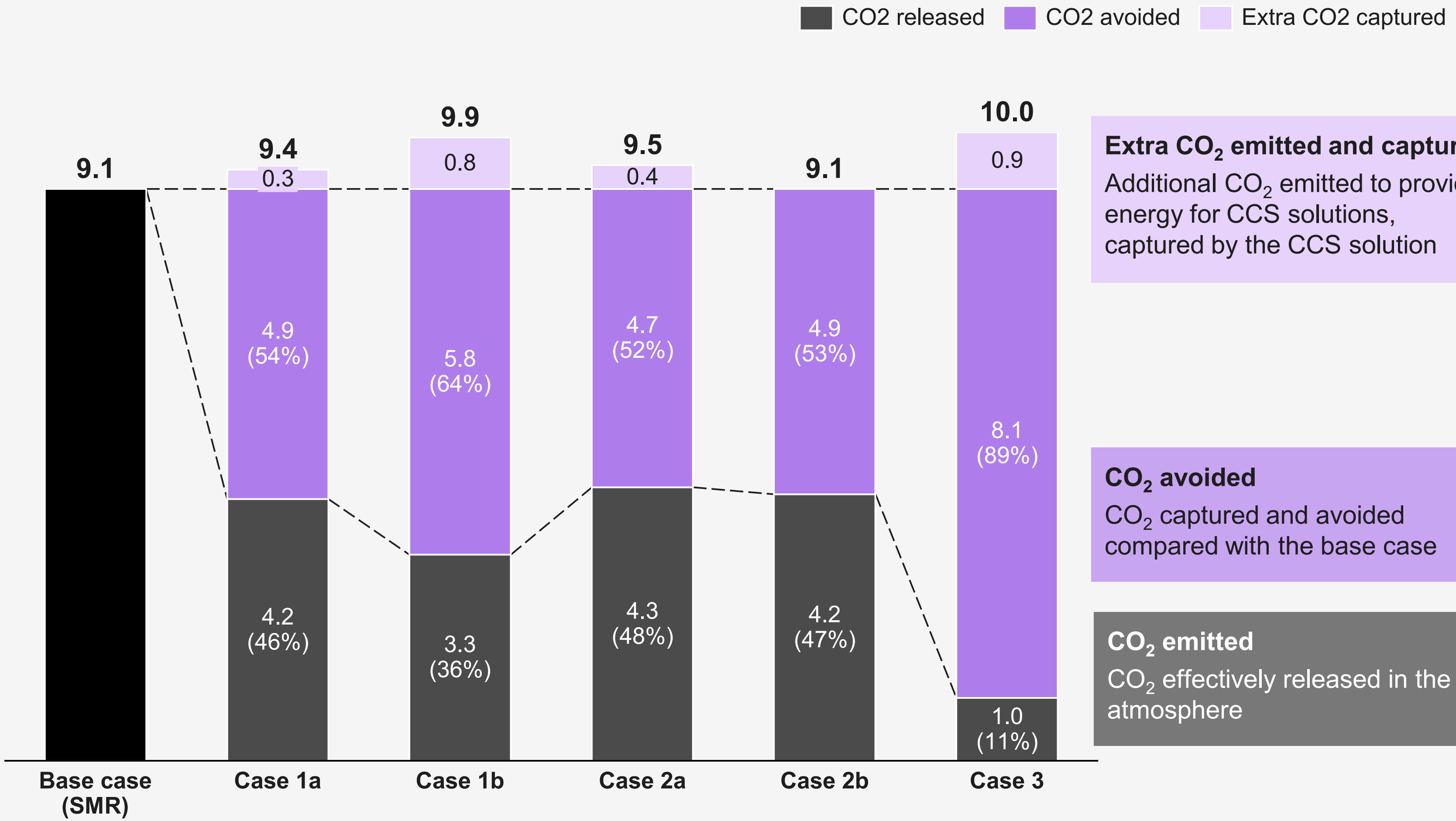
Note: Obtaining higher purity requires further investments that are not detailed in this study. All hypotheses are detailed in the appendix.
Sources: International Energy Agency Greenhouse Gas R&D Programme, Foster Wheeler; Kearney Energy Transition Institute analysis

Brown H_2 sources can be coupled with CCS to reduce emissions, but LCOH could jump by 64¢ per kg

Illustrative

CO_2 capture rate per case

(SMR, kg CO_2/kg H_2, % of base case, $ per kg)



	Base case (SMR)	Case 1a	Case 1b	Case 2a	Case 2b	Case 3
LCOH ($ per kg)	1.44	1.70	1.84	1.79	1.76	2.08
Delta ($ per kg)	-	0.26	0.40	0.35	0.32	0.64

Extra CO_2 emitted and captured
Additional CO_2 emitted to provide energy for CCS solutions, captured by the CCS solution

CO_2 avoided
CO_2 captured and avoided compared with the base case

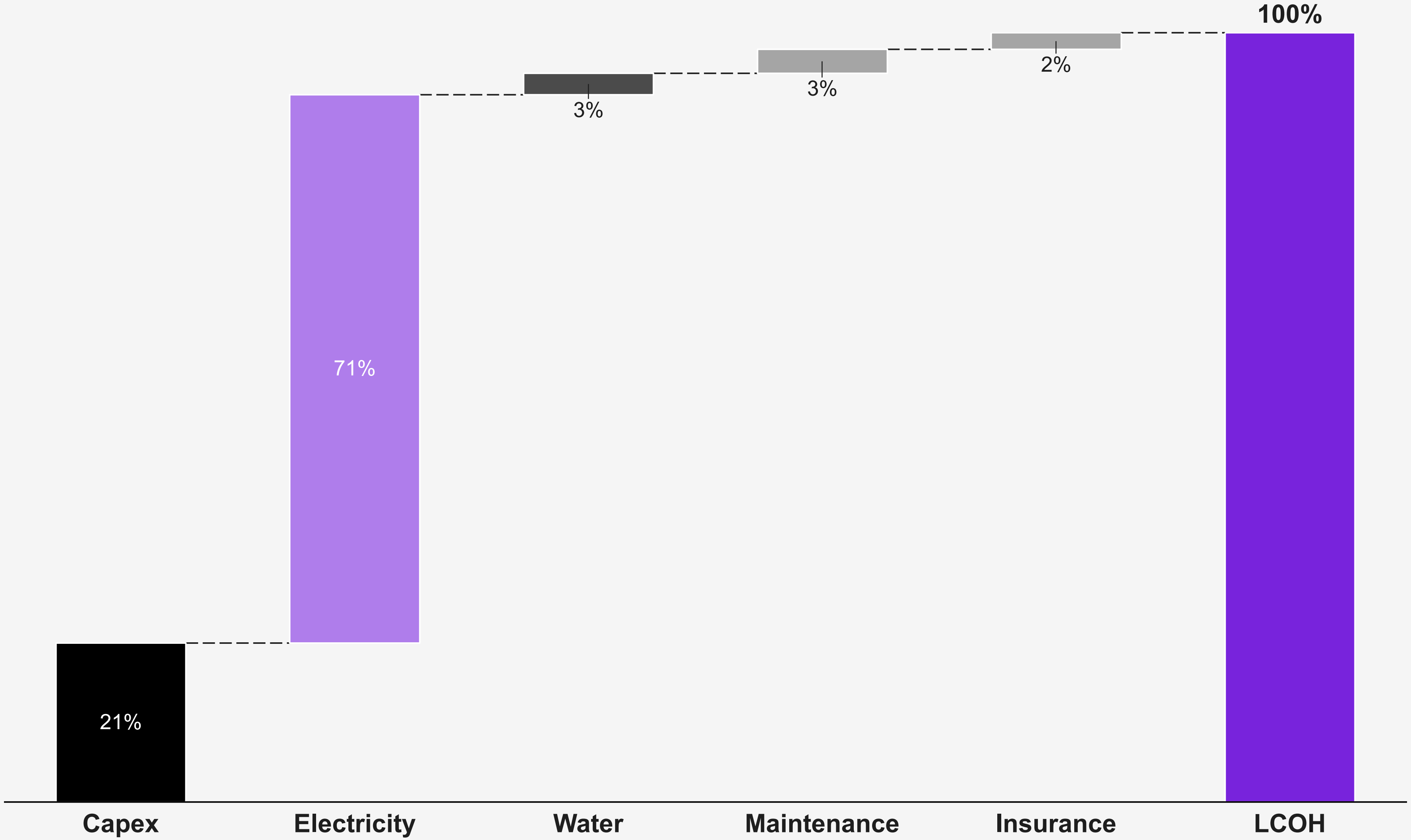
CO_2 emitted
CO_2 effectively released in the atmosphere

Note: CO² emissions could go up to 11 kg/kgH_2. $1 = €0.89
Sources: International Energy Agency Greenhouse Gas R&D Programme; Kearney Energy Transition Institute analysis

2.3 **Hydrogen value chain - Maturity and costs**

Electrolyzer cost is mainly driven by electricity costs and capex

LCOH breakdown - PEM example
($ per kg)



Illustrative

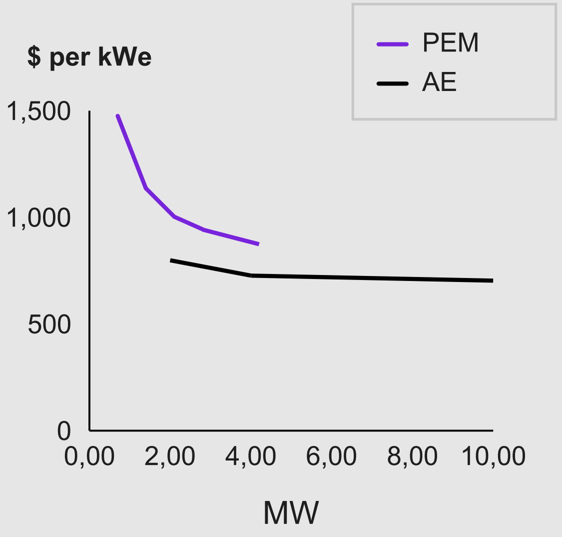
Note: All hypotheses are detailed in the appendix.
Sources: AREVA H2Gen; Kearney Energy Transition Institute analysis

Two factors can improve electrolysis LCOH: reducing capex and optimizing electricity price and load factor

Factors to improve electrolysis LCOH

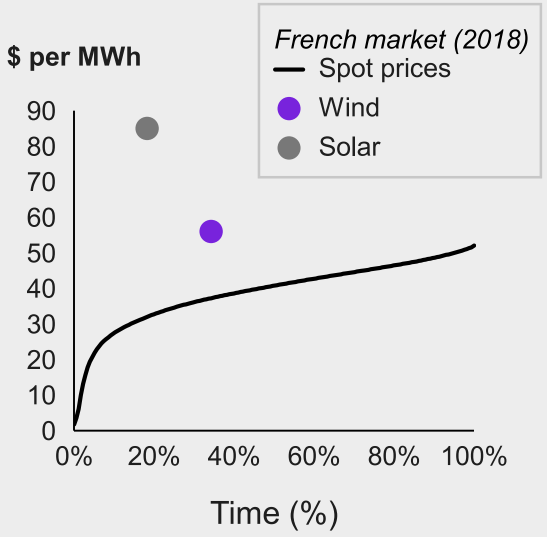
Capex (size and technology)

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



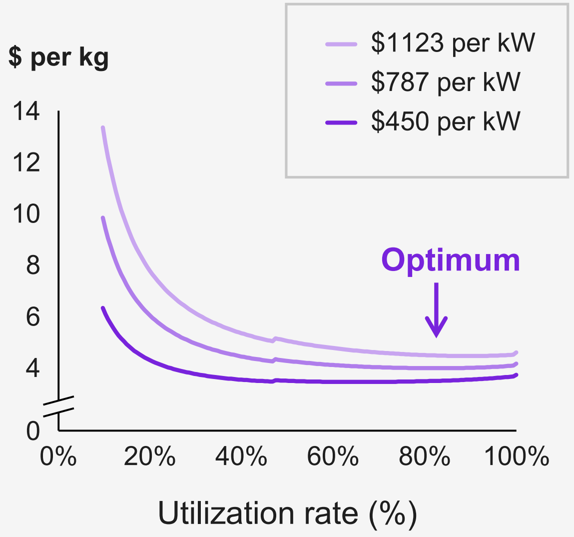
Electricity price (local market)

– 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

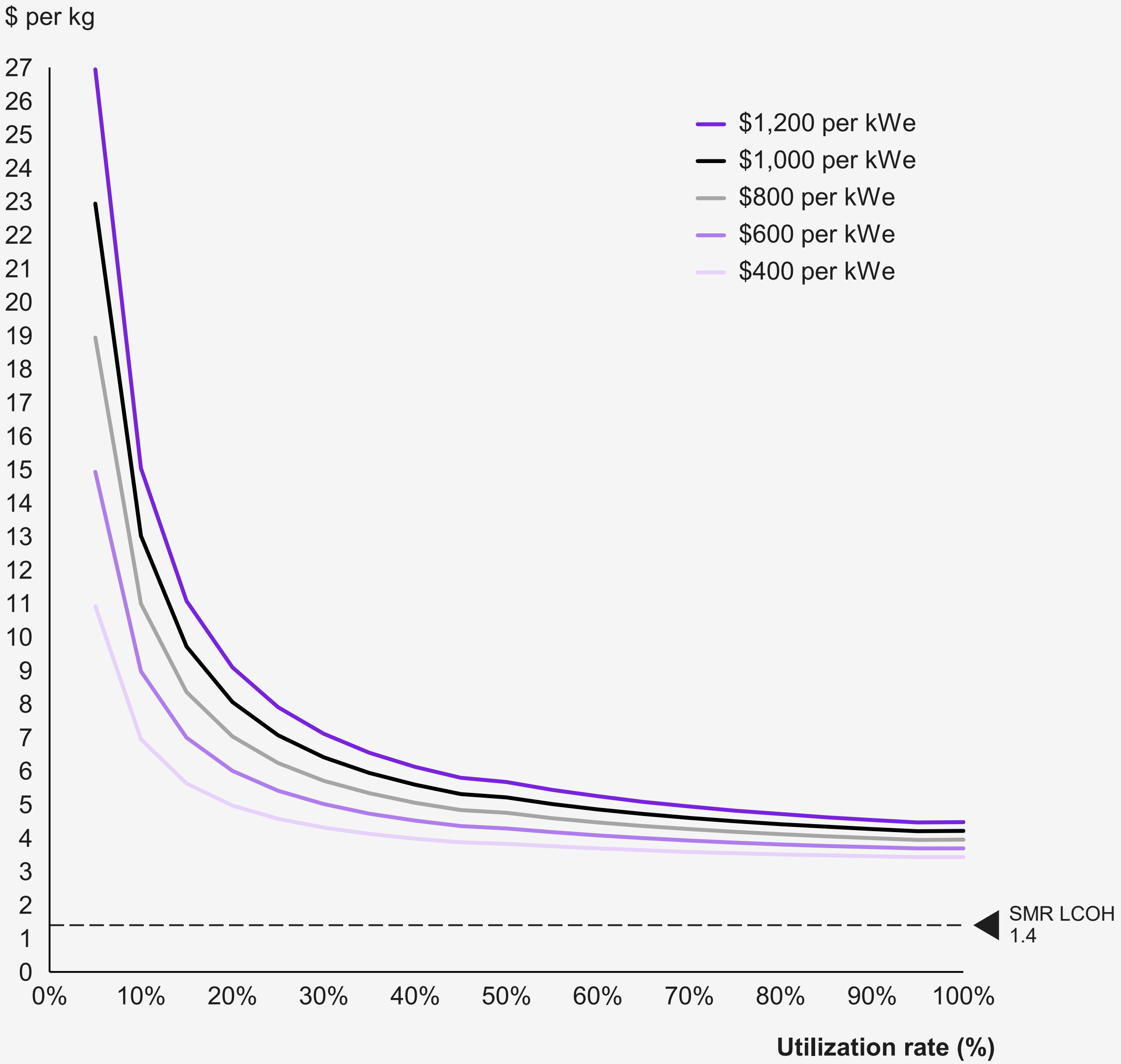


Note: Other factors include efficiency, operations and maintenance, and stack replacement and are expected to be improved as technology becomes more mature and the system size grows.
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; European Network of Transmission System Operators; International Renewable Energy Agency; Kearney Energy Transition Institute analysis

2.3 Hydrogen value chain - Maturity and costs

Capex relative weight is offset at a high load factor, but LCOH can dramatically increase when utilization is low

LCOH for various capex



$1 = €0.89
Hypotheses: Electricity price: $52/MWh, WACC: 8%, lifetime: 20 years
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

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 kgH_2.
  - 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.

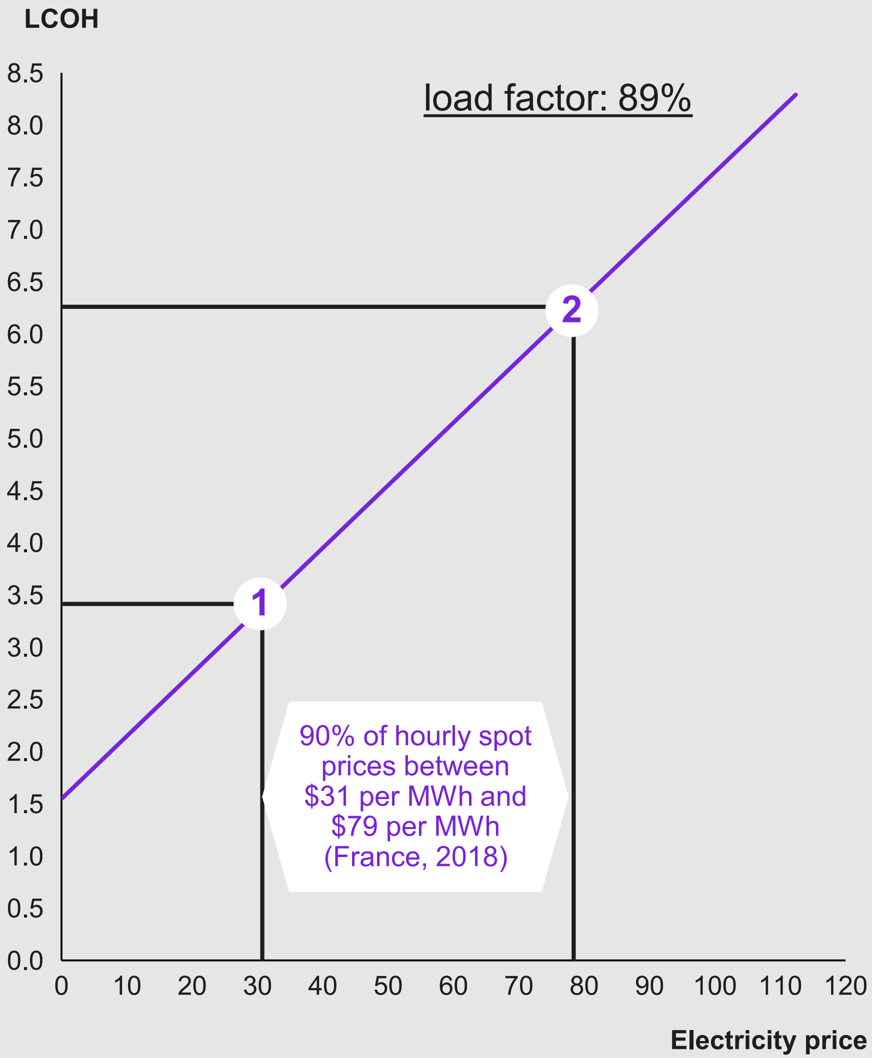
2.3 Hydrogen value chain - Maturity and costs

Power price has a high impact on LCOH; securing favorable PPA would improve LCOH

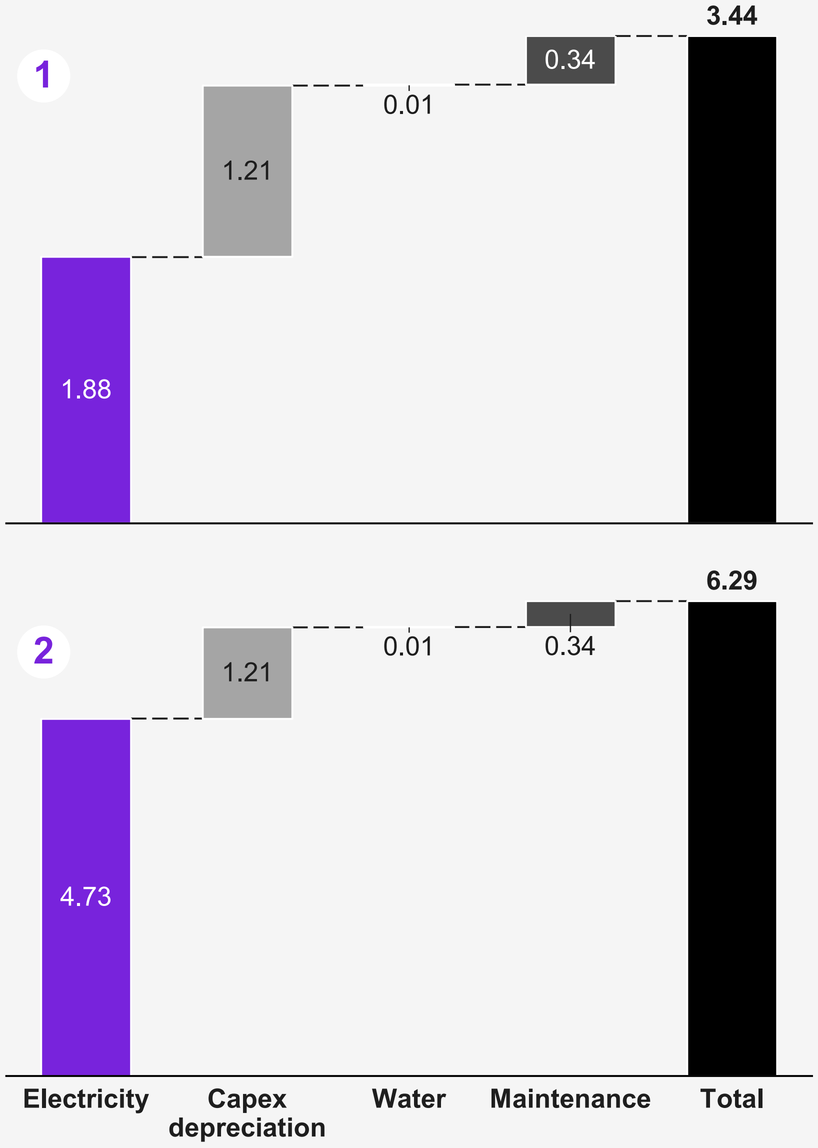
Reaching a competitive cost of $2 to $3 per kg requires low-cost electricity with high load factors.

LCOH function of electricity price

($ per kg; electricity price: $ per MWh)



LCOH breakdown



Note: PPA is power purchase agreement. Hypothesis: 1MW, capex: €1,000 per kW.
Sources: Areva H2Gen; "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

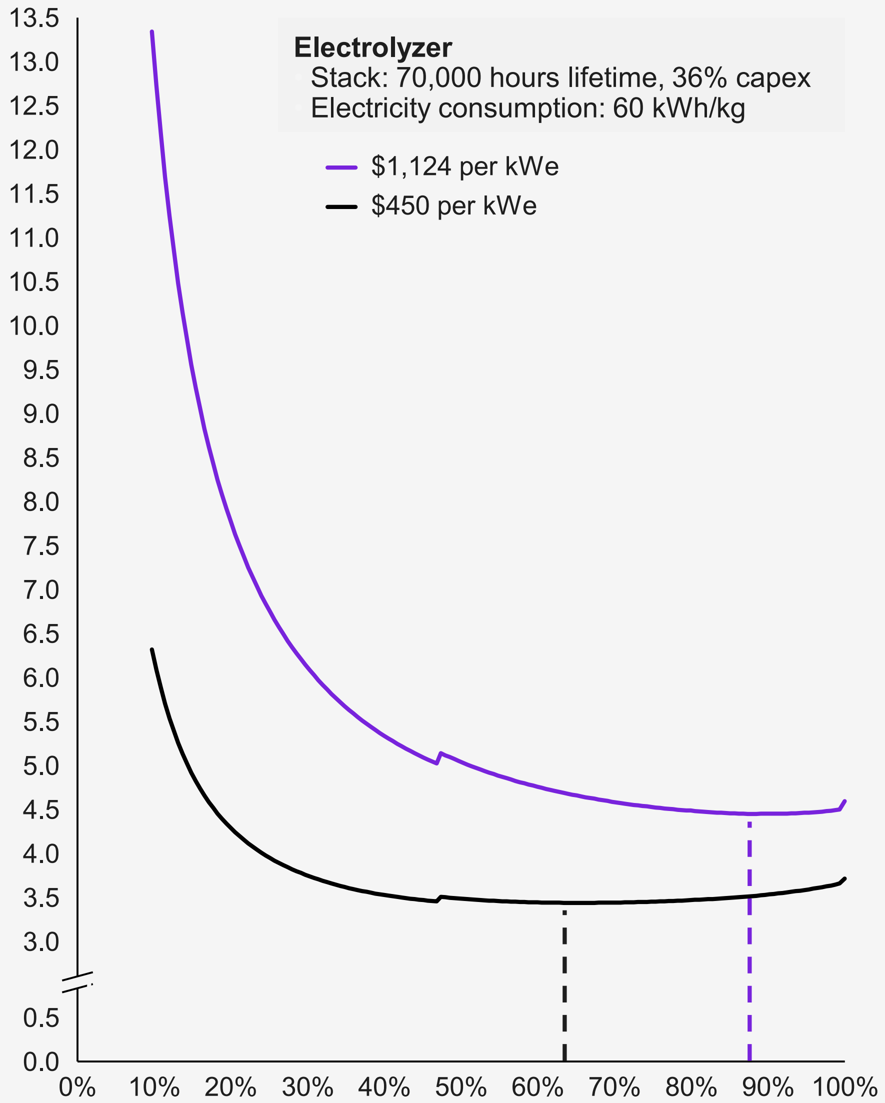
Minimal LCOH occurs at load factors between 70 and 90%, but the spot price range is too narrow to impact LCOH at a high utilization rate

Illustrative

Electricity spot price
(January–December 2018, $ per MWh, France)

Sources: European Network of Transmission System Operators; Kearney Energy Transition Institute

LCOH per load factor
($ per kg)



2.3 **Hydrogen value chain - Maturity and costs**

Upcoming R&D initiatives will help improve the efficiency of applications while reducing LCOH of blue hydrogen

Key cost drivers and improvement per technology

	Steam methane reforming + CCS	Black coal gasification + CCS
Capacity factor	– No change expected	– No change expected
Scale and capacity	– Secure export offtake agreements	– Successful demonstration at scale – Export offtake agreements
Capex	– Scaling benefits, – Process intensification	– R&D process intensification – Scaling benefits
Opex	– Scaling benefits	– Scaling benefits – Improvements in build-up of slag and ash
Efficiency	– R&D process improvements, reused heat, membrane separation	– R&D improvements of purification, ASU, and CO2 removal
Risk	– Reduced risk of CO_2 capture	– First of kind demonstration
Cost of capital	– Support for CCS	– Support for CCS

Sources: "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; Kearney Energy Transition Institute analysis

RD&D efforts required to lower LCOH for electrolyzers 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)

	Reduced capital cost	Longer lifetime	Higher efficiency
Cell	– **Increase current density** – **Lower loading of platinum group metal catalysts**, new and improved catalysts – Improved coating of electrodes – Thinner membranes, advanced chemistry	– Improved catalyst durability – Structural improvements in electrodes – **Higher physical stability of membrane** – **Higher impurity tolerance of membrane**	– Thinner membranes
Stack	– Electrochemical pressurization, increased stack size – Reduction of titanium use – Optimized diffusor set-up	– Slower H_2 embrittlement through more suitable coating	– Higher operating temperatures leading to stack and cooling efficiencies
System	– **Scale up of system components** – Efficient water purification – Improved component integration – **Optimized operation set points** – Alkaline polymer systems – New low-cost stack designs – Design for high-pressure operation	– Improved water purification – Avoidance of impurity penetration	– More efficient rectification through more expensive diodes – More efficient hydrogen purification

Note: Bold terms refers to the higher priority with in the impact area. Efficiency improvements are not prioritized. Non-continuous operations mean that operating costs are small, so reduction of capital costs is a higher priority. Efficiencies are maximized at low current density, but to reduce capital costs, research is focused on increasing current density instead.
Sources: "Future Cost and Performance of Water Electrolysis: An Expert Elicitation Study," International Journal of Hydrogen Energy, 28 December 2017; Kearney Energy Transition Institute

Capital cost reduction will become more important as low-cost electricity from renewables becomes possible

Non-Exhaustive

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

Key levers	Description
Increasing current density	**Impact area: Cell** – 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/cm^2 (by 2020) and further (>3A/cm^2) through better electrode design, catalyst coatings, and thinner membranes
Catalysts	**Impact area: Cell** – 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	**Impact area: Stack** – 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	**Impact area: System** – 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

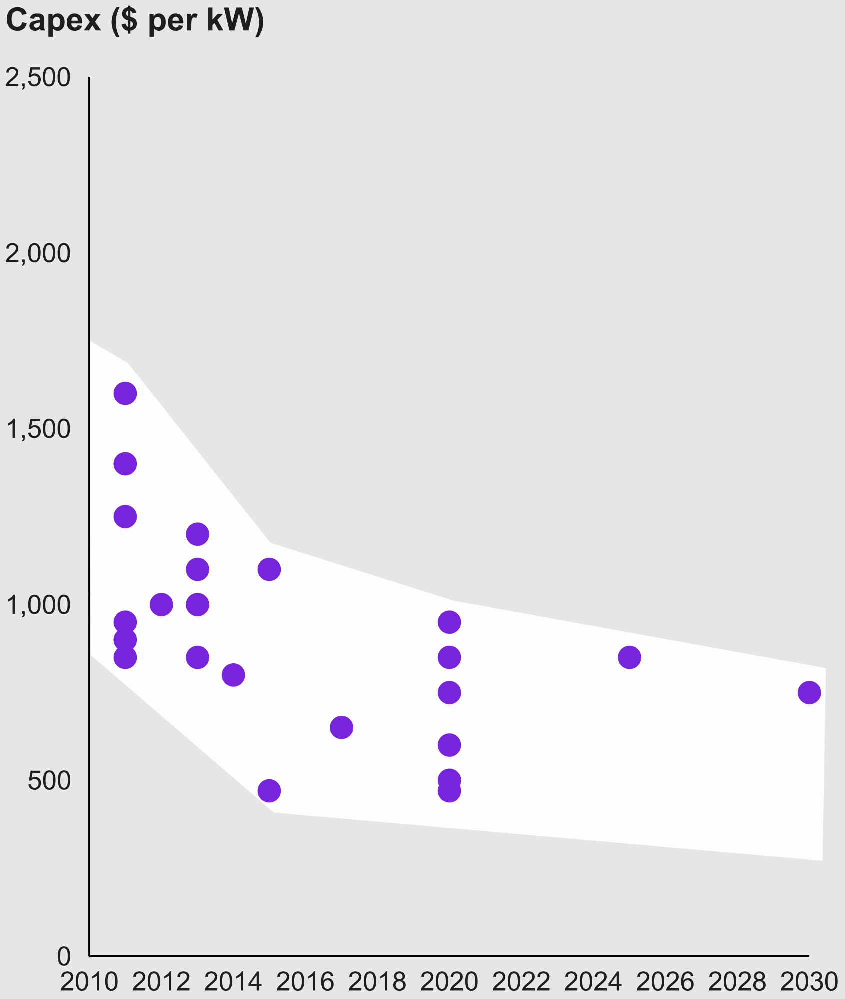
Sources: "Future Cost and Performance of Water Electrolysis: An Expert Elicitation Study," International Journal of Hydrogen Energy, 28 December 2017, "Membraneless Electrolyzers for Low-Cost Hydrogen Production in a Renewable Energy Future," Joule, 20 December 2017; Kearney Energy Transition Institute

Capex for electrolyzer is expected to dramatically decrease by 2030

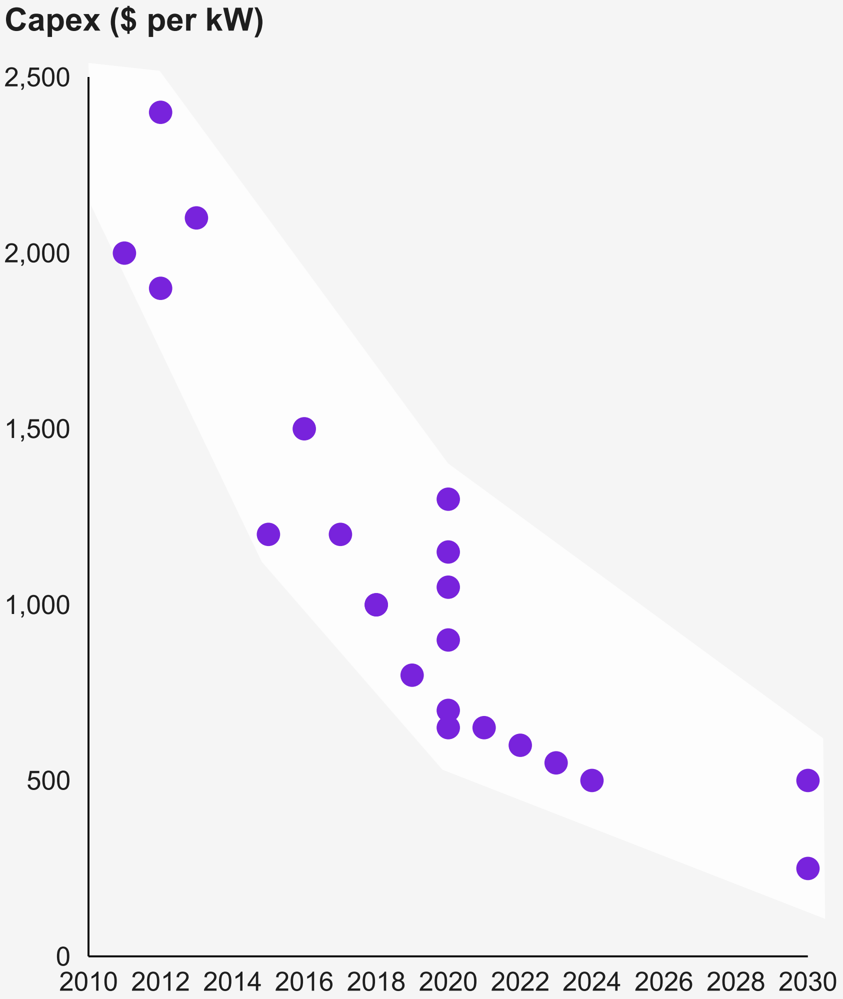
R&D initiatives on AE and PEM could drive capex down to about €400 per kW for both technologies by 2030.

2.3 **Hydrogen value chain - Maturity and costs**

AE capex evolution
(2010–2030, $ per kW)



PEM CAPEX Evolution
(2010–2030, $ per kW)

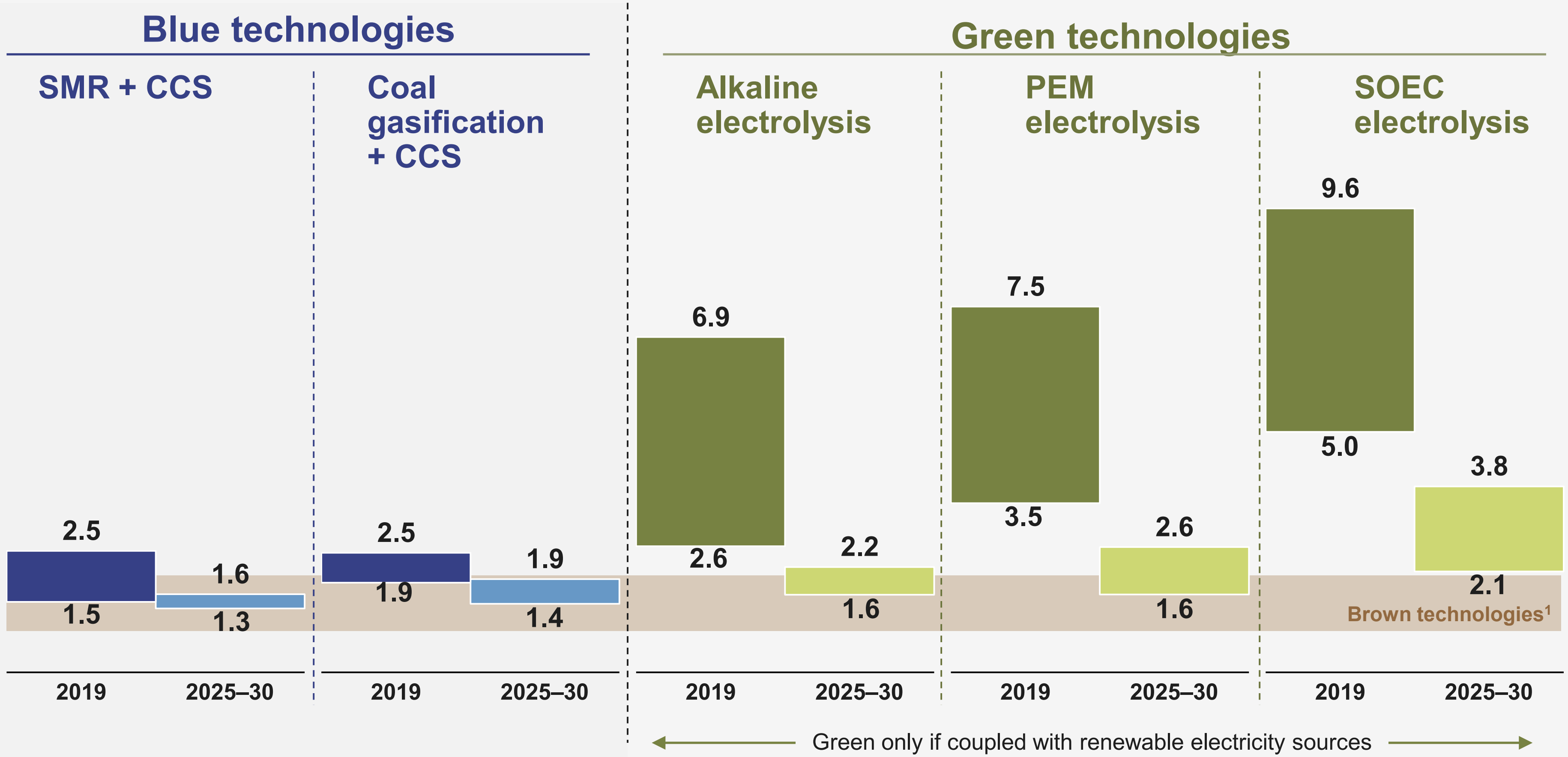


Sources: E4Tech, ITM Power; Kearney Energy Transition Institute

Blue hydrogen and green hydrogen costs are expected to decline and close the gap with brown sources by 2030

Illustrative

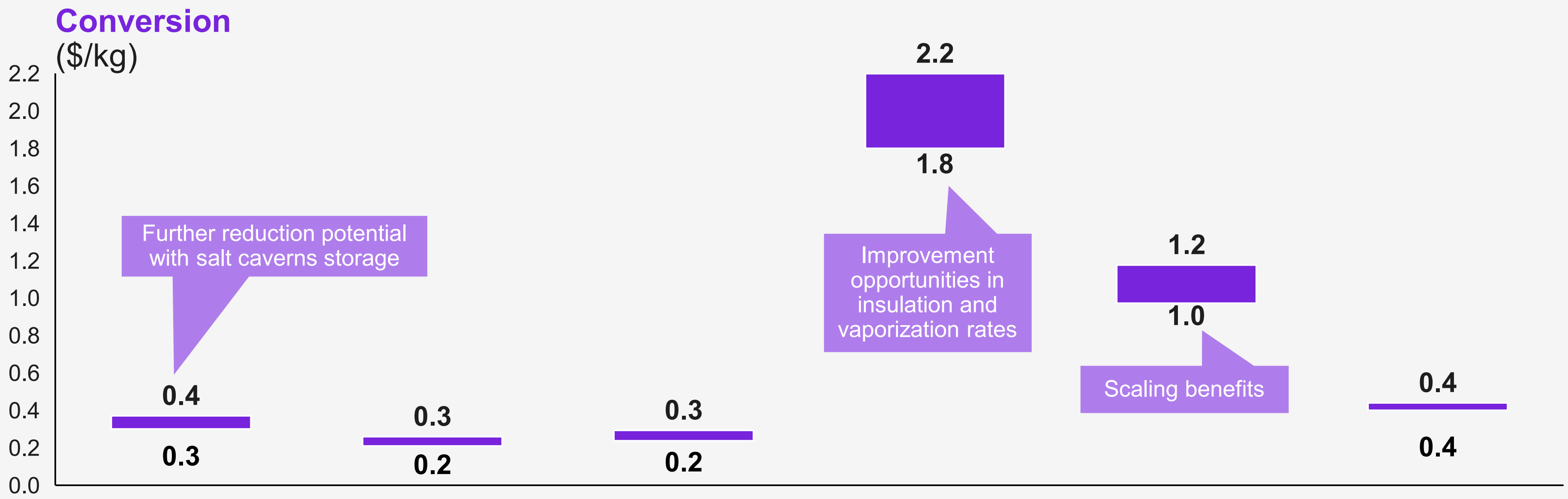
LCOH evolution
($ per kg, min–max. average)

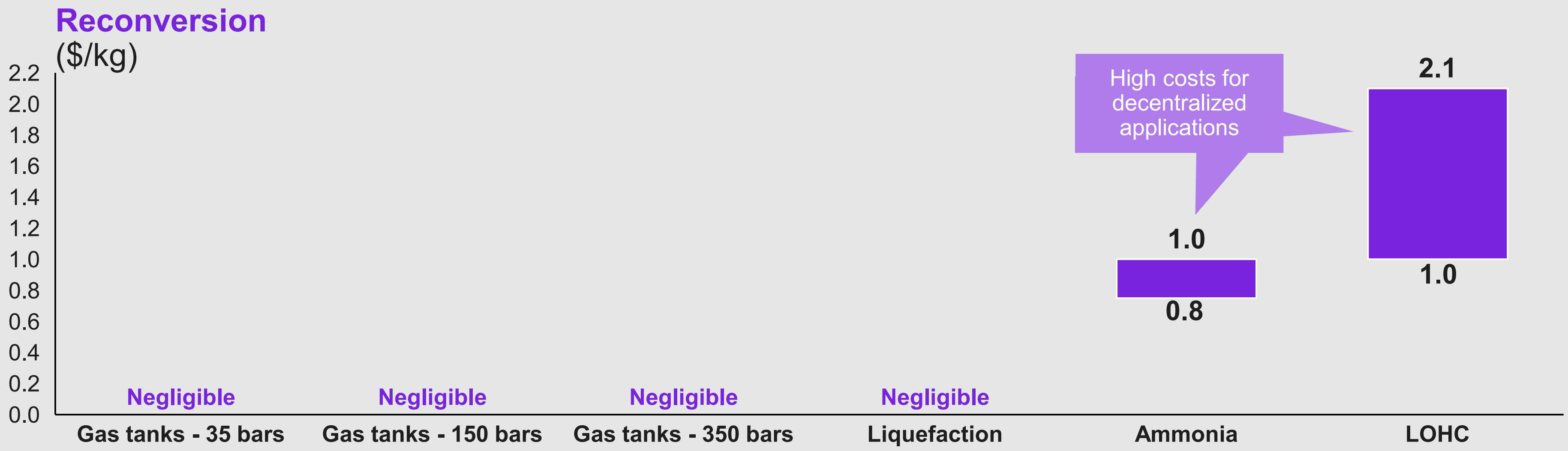


1 AUD = 70¢
1 Thermochemical sources LCOH range
Note: All hypotheses are detailed in the appendix. Ranges are indicative ranges. LCOH highly depends on fossil fuel prices, electricity prices, and asset utilization.
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; International Energy Agency Greenhouse Gas R&D Programme; Commonwealth Scientific and Industrial Research Organisation; McPhy; Areva; Foster Wheeler; Department of Energy; International Renewable Energy Agency; Rabobank; TOTAL; CEA; Kearney Energy Transition Institute analysis

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

H_2 conversion and reconversion LCOH, including on-site storage

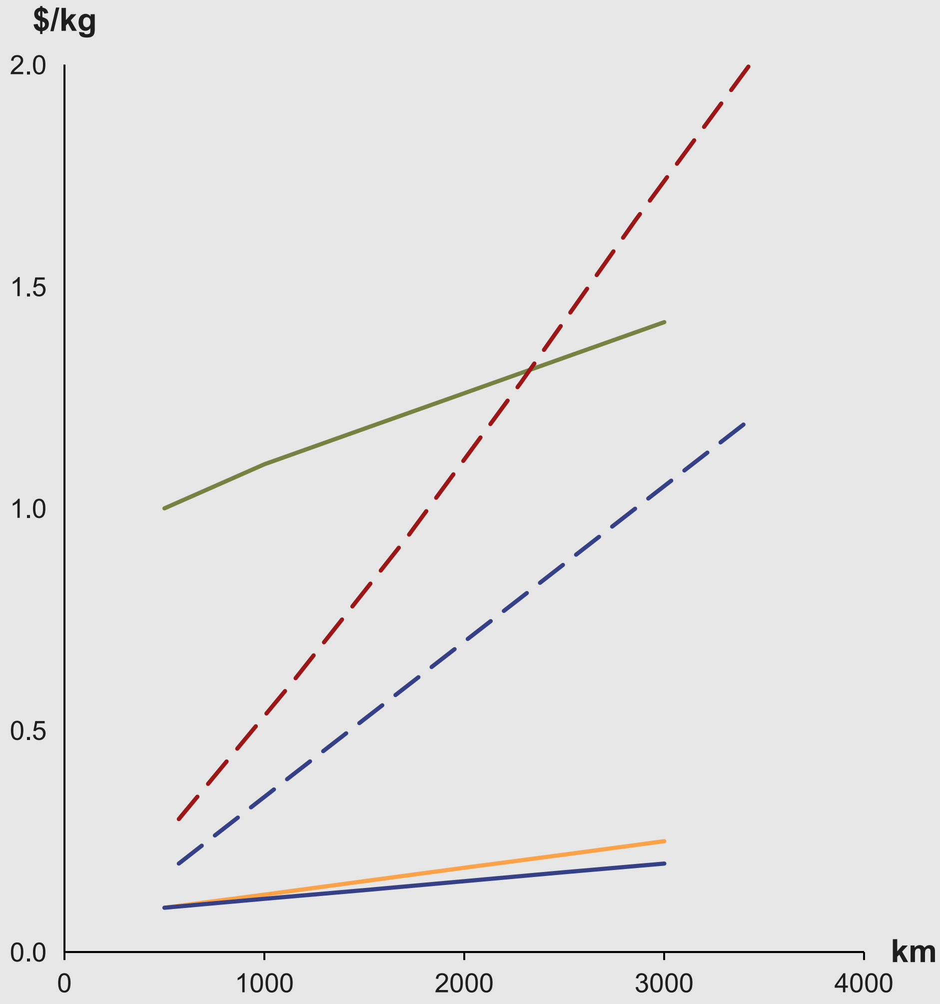




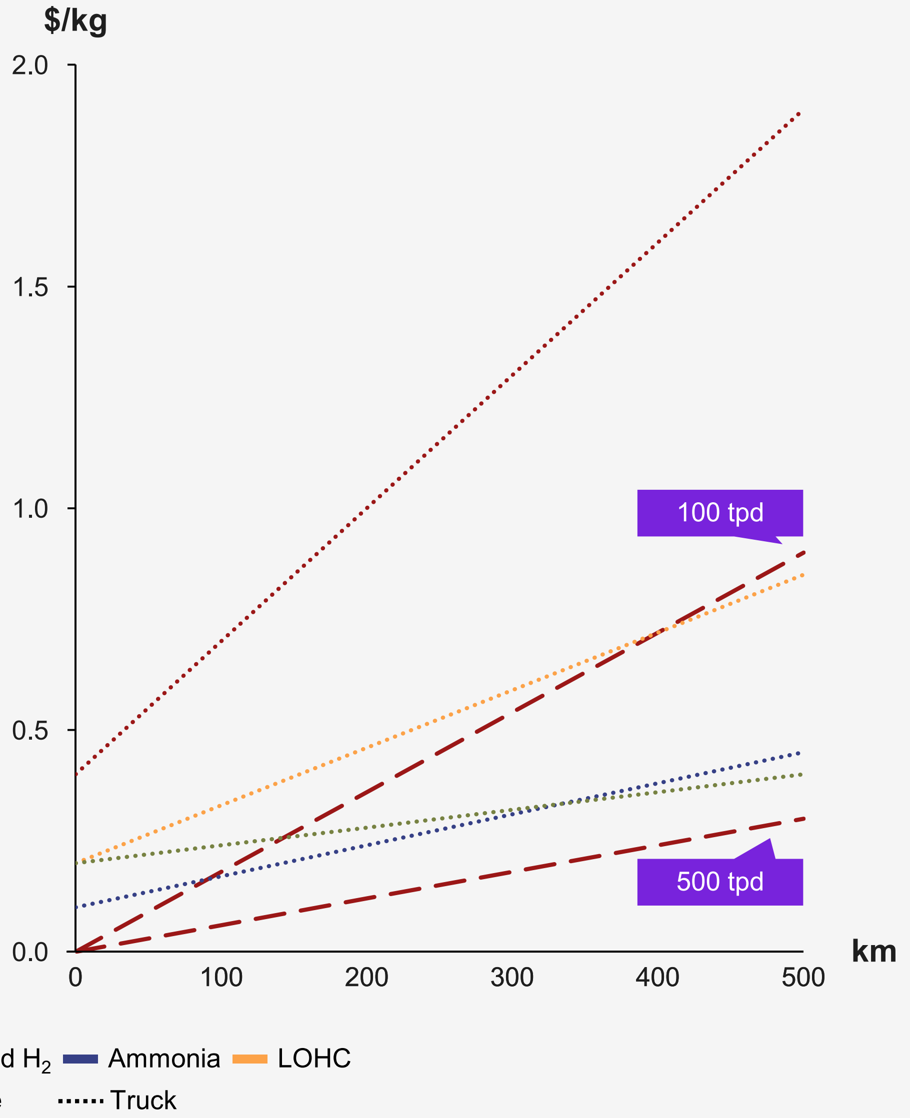
Note: 1 AUD = 0.7 USD
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; Kearney Energy Transition Institute

Transportation costs depends on the hydrogen form, carrier, and distance traveled

H2 transmission LCOH
($ per kg, km)



H2 distribution LCOH
($ per kg, km)



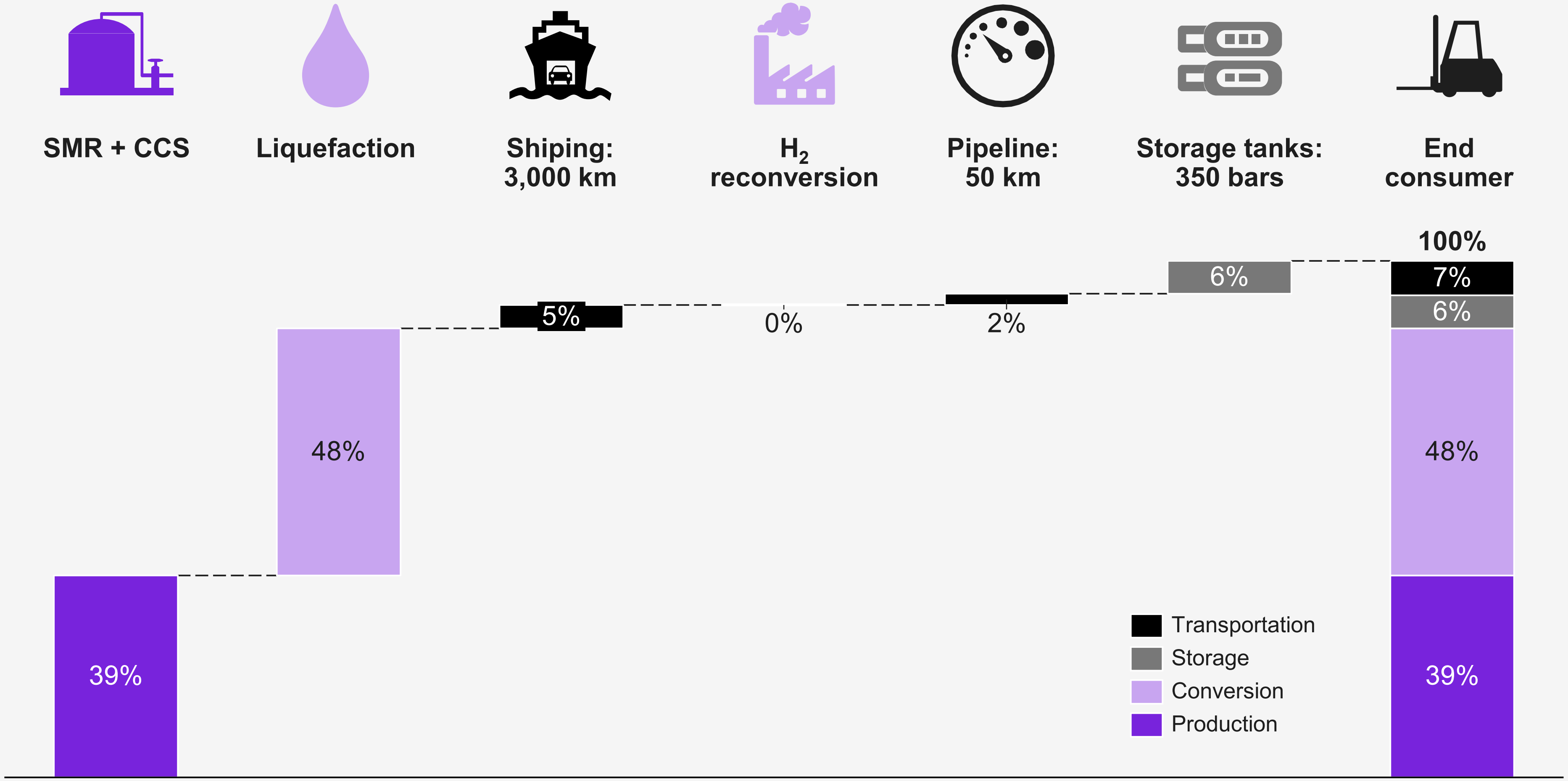
Note: 1 AUD = 70¢
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

2.3 **Hydrogen value chain - Maturity and costs**

Conversion and transportation of H_2 can double LCOH, which could be avoided with decentralized production sources

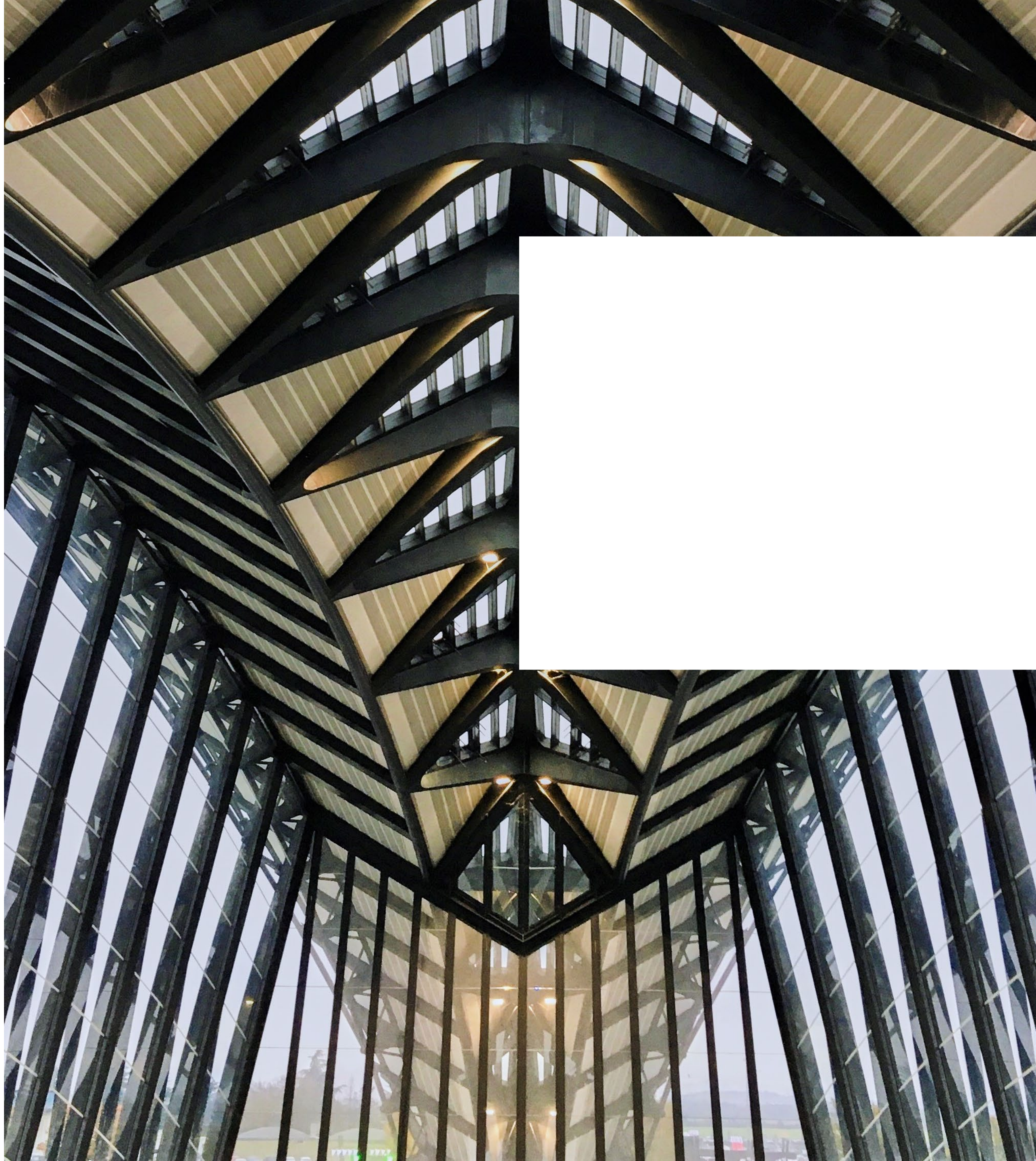
Illustrative

Case study: shipping H_2 from A to B
(2019, $ per kg, base case)



Notes: The main hypotheses are detailed in the appendix. 1 AUD = 70¢
Sources: "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

Key hydrogen applications



Key applications include chemicals and steel manufacturing, gas energy, power generation, and mobility

3.1 **Key hydrogen applications - Overview**

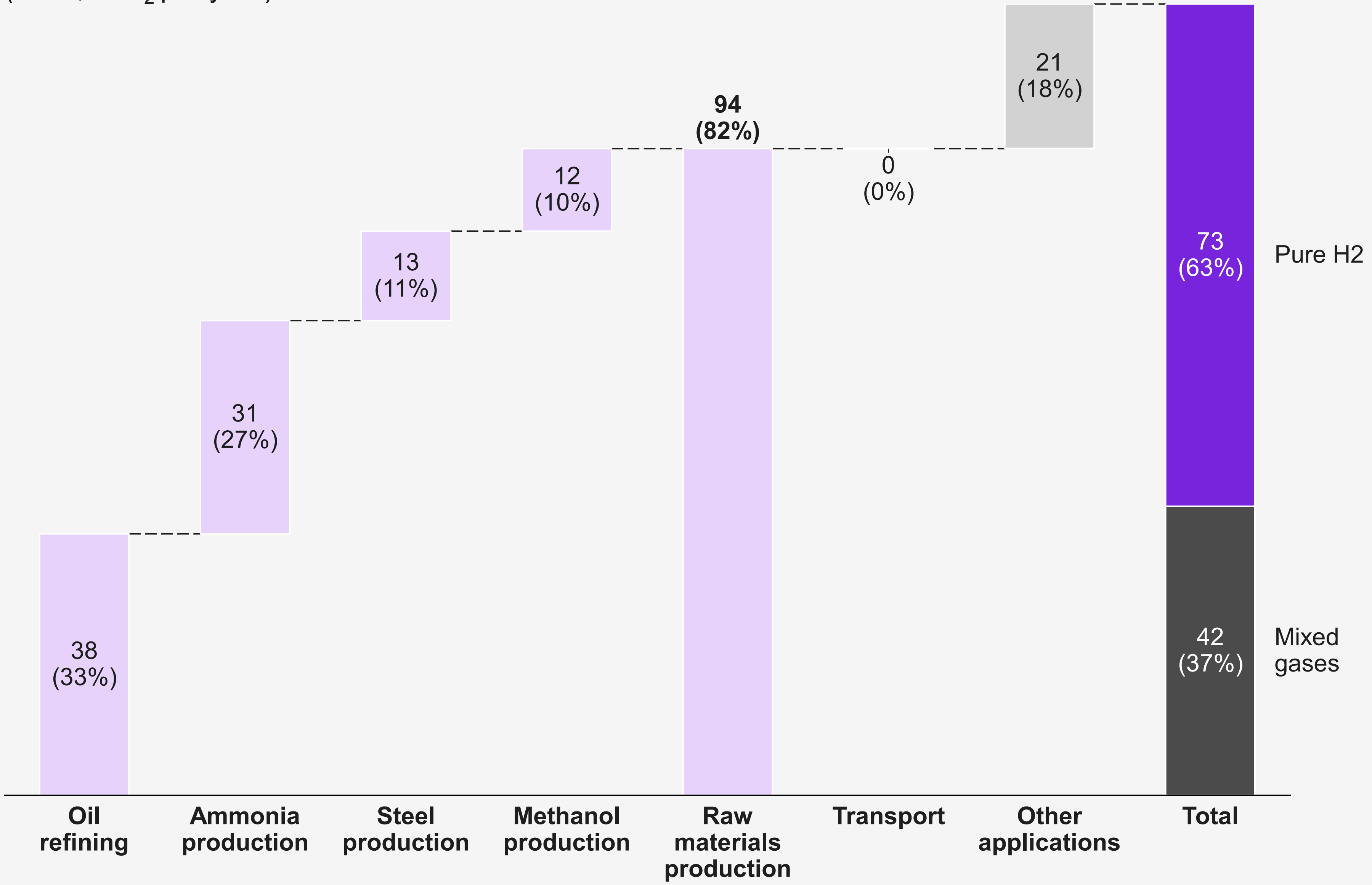
Main H2 applications

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

Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

Most H_2 today is consumed by the chemicals, oil refining, and steel industries

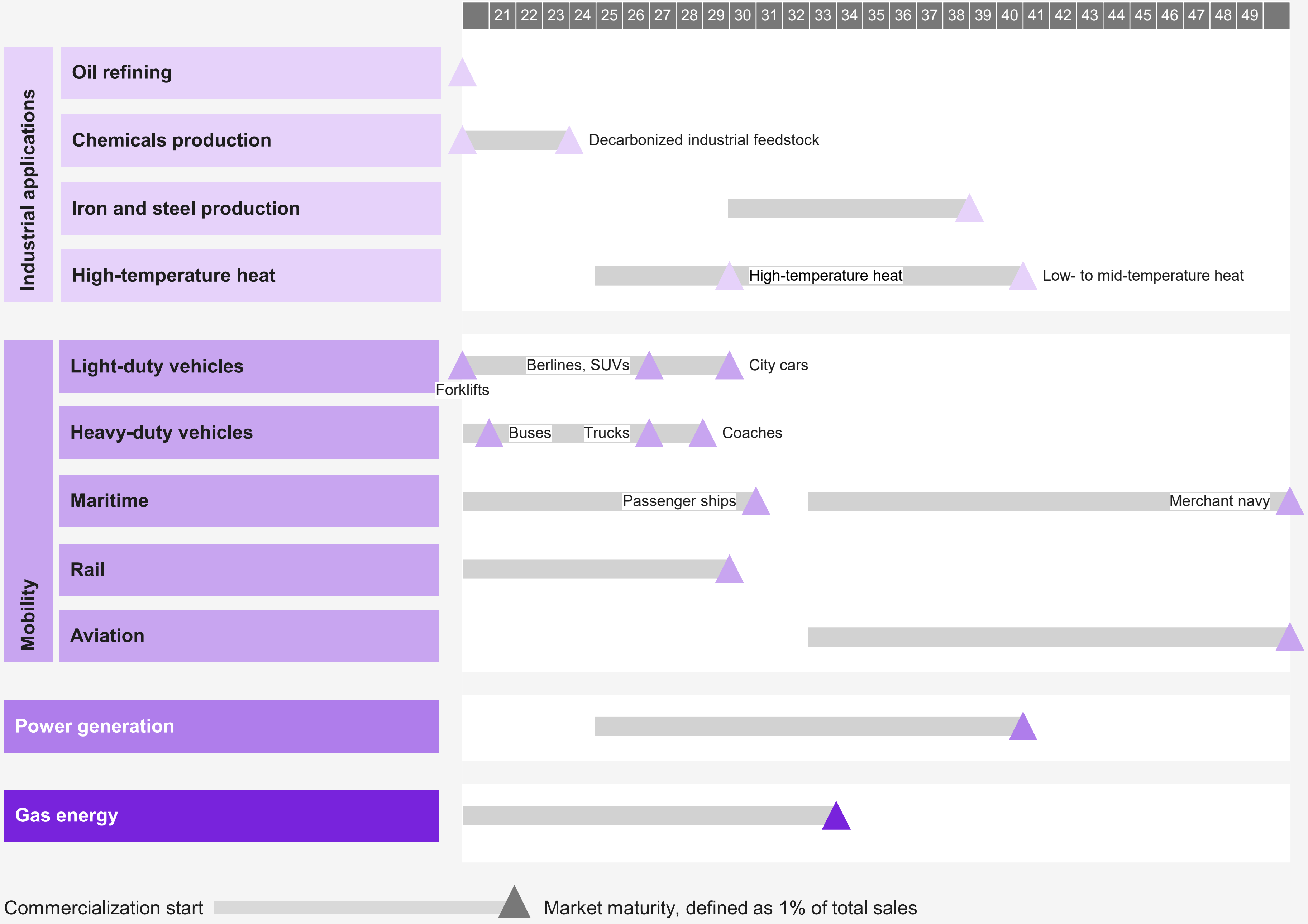
Hydrogen consumption by category
(2018, MtH_2 per year)



Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy transition Institute

Applications will mature at different rates; some of them already have

Expected commercial maturity per application (2020–2050)

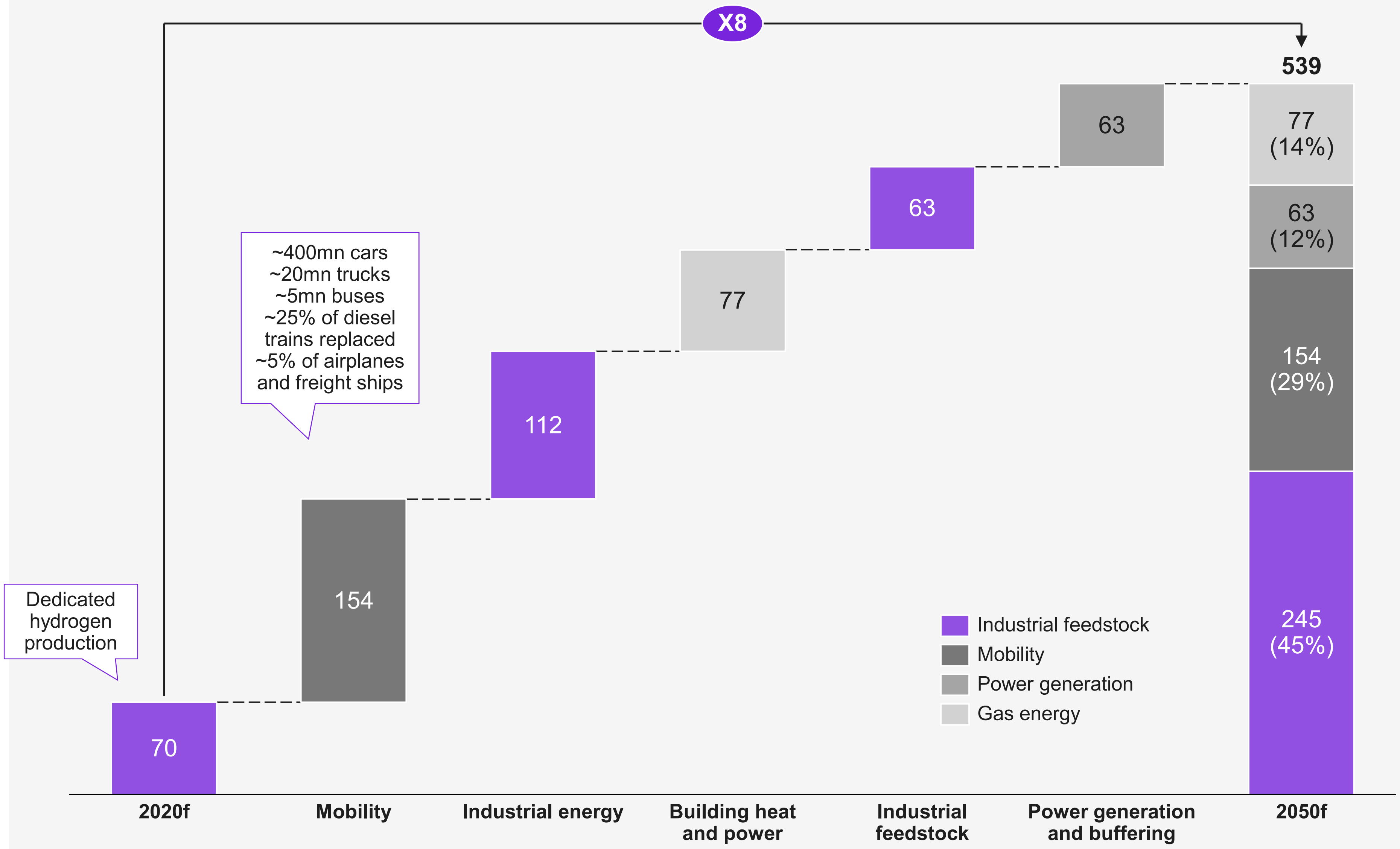


Sources: Afhypac; Kearney Energy Transition Institute analysis

3.1 **Key hydrogen applications - Overview**

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)



Sources: Hydrogen Council, Kearney Energy Transition Institute analysis

3.1 **Key hydrogen applications - Overview**

Oil refining is the second main H_2 consumption source, with 38 Mt or about 33% of global production used for hydrotreatment and hydrocracking

Preliminary

Fact card: Oil refining

3.2 **Key hydrogen applications - Feedstock**

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_2S 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.

Overview of technologies

HDS unit

Capacity: 32,000 BPD

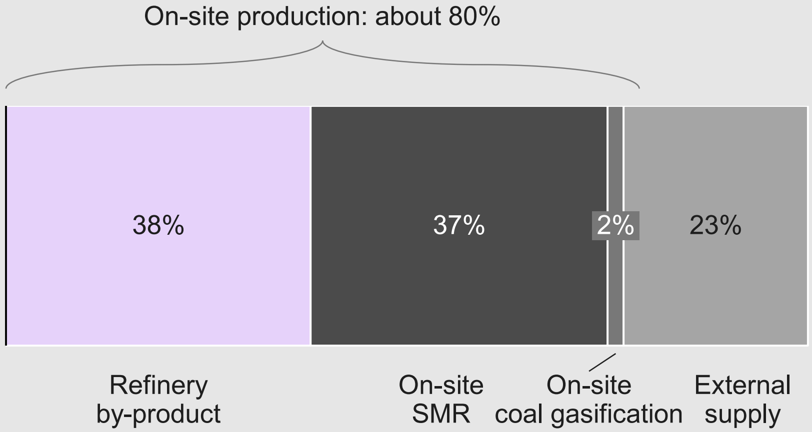
Hydrocracking plant

Hydrocracking plant from Yaroslavl Petroleum refinery

H_2 Market trends

Market maturity	Mature
Market size (MtH_2/year)	38
Expected growth (CAGR 19-30)	Less than +1%
Competing technologies	-

H_2 source in oil refining



Sources: “The Future of Hydrogen,” International Energy Agency, June 2019; Phoenix Equipment Corporation; Tokyo Engineering; Kearney Energy Transition Institute analysis

The chemicals industry consumes about 45 Mt of H_2 a year for ammonia and methanol synthesis

Preliminary

Fact card: Chemicals industry

3.2 **Key hydrogen applications - Feedstock**

Description

Ammonia synthesis:

- H_2 is combined with N_2 extracted from a air separation unit through the Haber–Bosch process.

$$N_2 + 3H_2 \rightarrow 2NH_3$$

- About 80% of global NH_3 production is used in fertilizer production ($(NH_2)_2CO$, NH_4NO_3).

Methanol production:

- H_2 is combined with CO and CO_2 to form methanol in a catalytic reaction.

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$$
$$CO + 2H_2 \rightarrow CH_3OH$$
$$CO_2 + H_2 \rightarrow CO + H_2O$$

- Methanol can be converted into polymers and hydrocarbon olefins and used as fuel for ICE, even if this technology is in an early stage.

Overview of technologies

Ammonia production

Ammonia production plant in Slovakia for Duslo

Methanol production

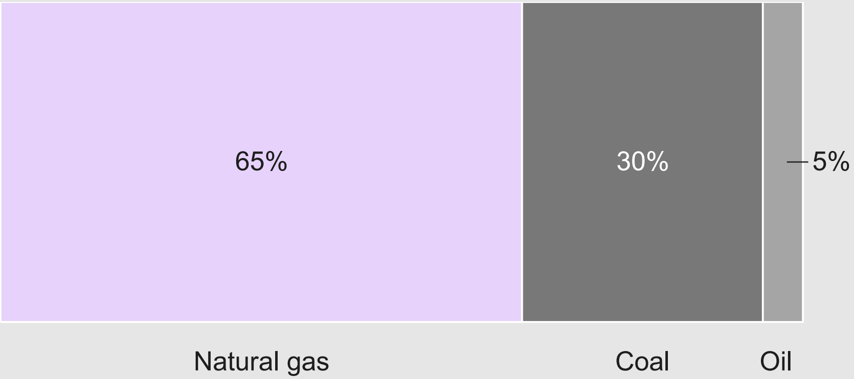
Methanol production plant

H_2 Market trends

Market maturity	Mature
Market size (MTH_2 per year)	44–46
Expected growth (CAGR 19–30)	+2%
Competing technologies	Traditional fuels vs. methanol

Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Norway Exports; Kearney Energy Transition Institute analysis

H_2 source in chemical industry



The steel industry consumes about 13 Mt H_2 per year, 4 of which is dedicated for direct reduction of iron

Preliminary

Fact card: Steel industry

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 MTH_2 per year.
- About 65% of this gas is used on-site for various applications (9 MTH_2 year), and the remaining (5 MTH_2 year) is used in other sectors, such as power production and methanol production).

Basic oxygen furnace from Nippon Steel

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 H_2 and CO as reducing agent. H_2 is produced in dedicated facilities (SMR/gasification plants) and not as a by-product.

$$3\,Fe_2O_3 + H_2 \rightarrow 2Fe_3O_4 + H_2O$$
$$Fe_3O_4 + 2H_2 \rightarrow 3\,FeO + H_2O$$
$$FeO + H_2 \rightarrow Fe + H_2O$$

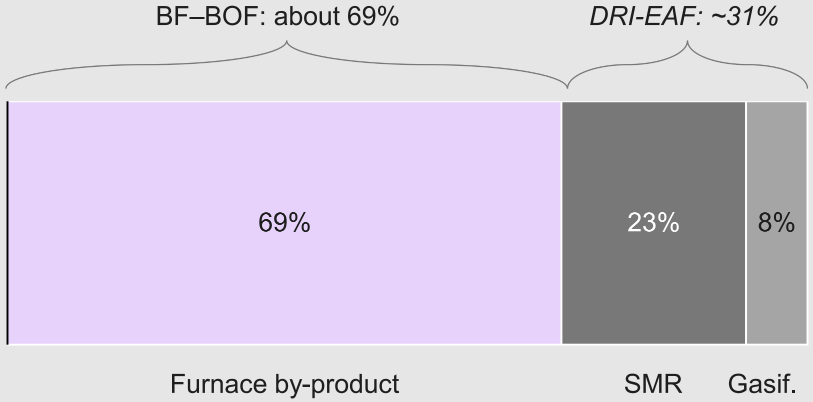
Electric arc furnace from Acciaieria Arvedi SpA

H_2 Market trends

Market maturity	Mature
Market size (MtH_2/year)	13
Expected growth (CAGR 19-30)	+6%
Competing technologies	Recycling of scrap steel (25% of total prod.)

Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Nippon Steel Engineering; Acciaieria Arvedi SpA; Kearney Energy Transition Institute analysis

H_2 source in oil refining



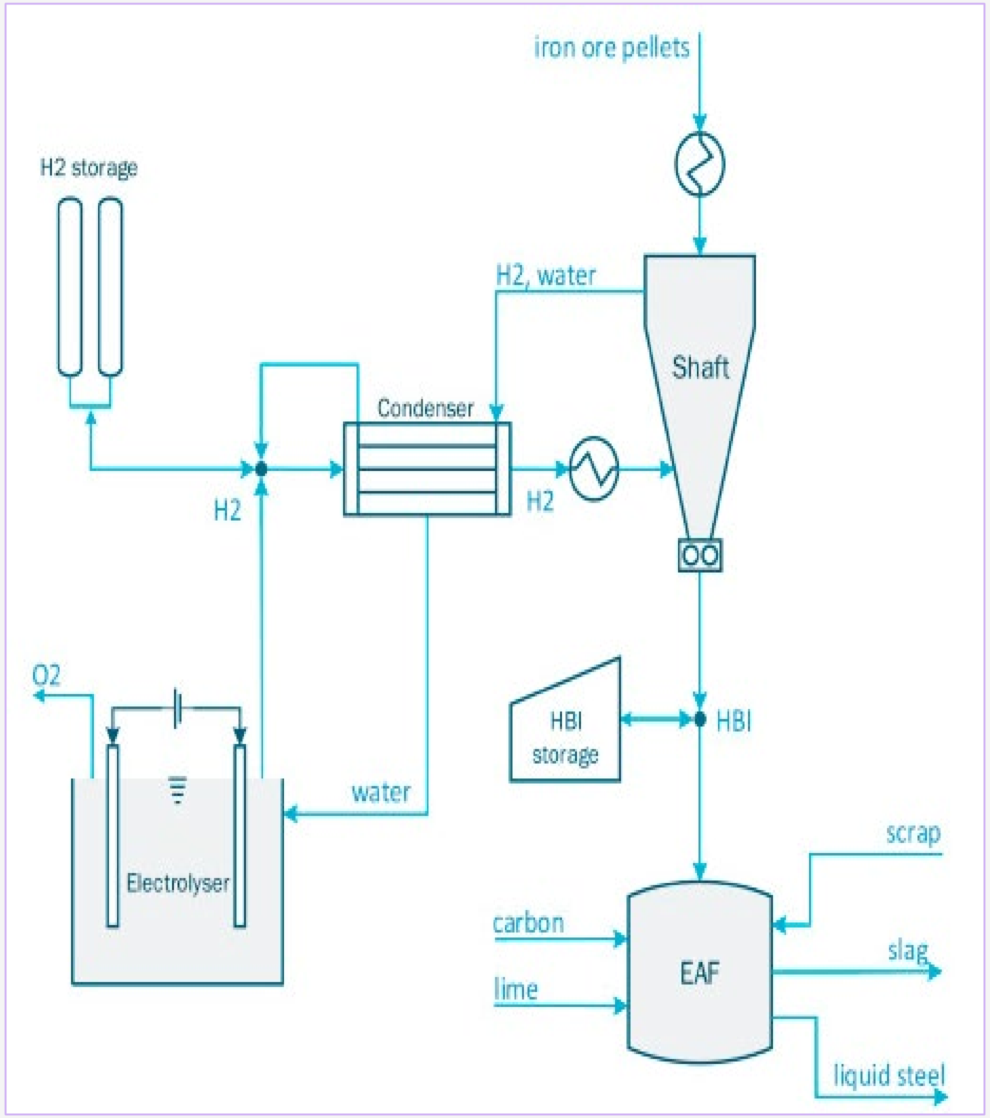
3.2 **Key hydrogen applications - Feedstock**

Adopting low carbon energy sources and reducing agents, such as Hydrogen, can help decarbonize steel production

Fact card: Steel industry

3.2 **Key hydrogen applications - Feedstock**

Hydrogen based Direct Reduction proposed process design[1]



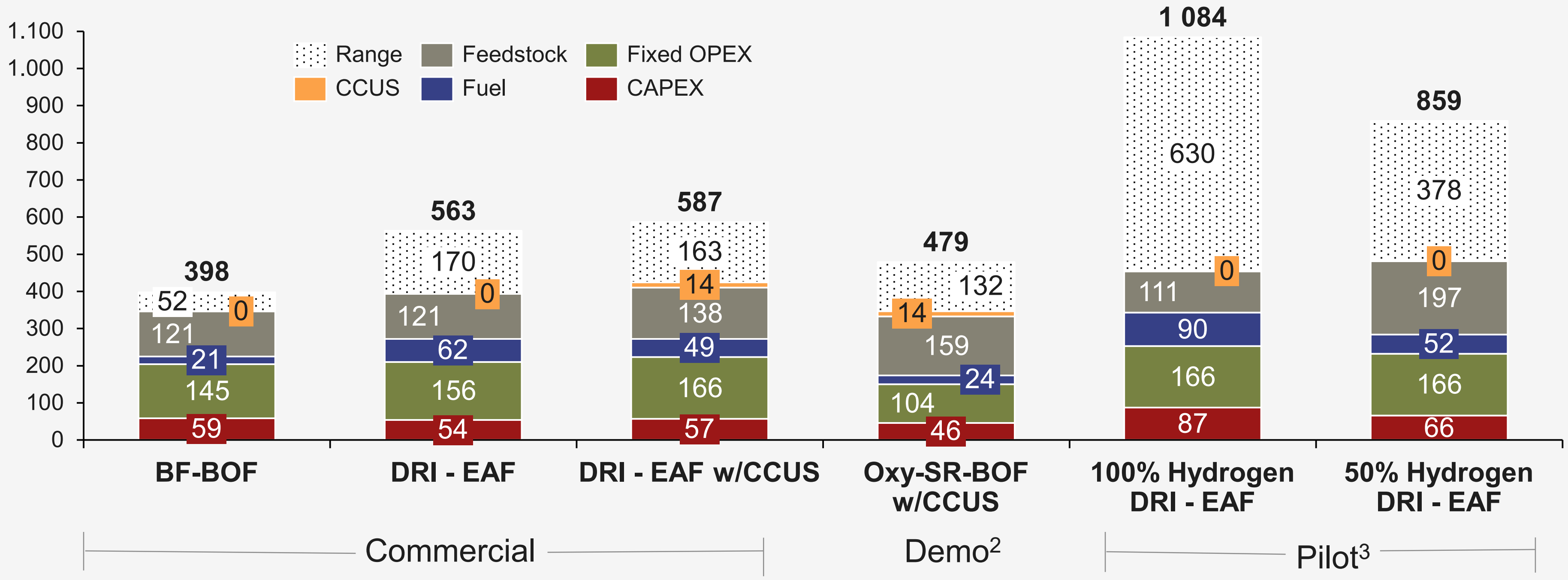
Use of Hydrogen to lower emissions

- 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

1. HBI – Hot-briquetted iron, EAF - Electric arc furnace
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

Estimated costs of steel for selected greenfield production routes[1]
Levelized costs (USD/t), 2018 estimates



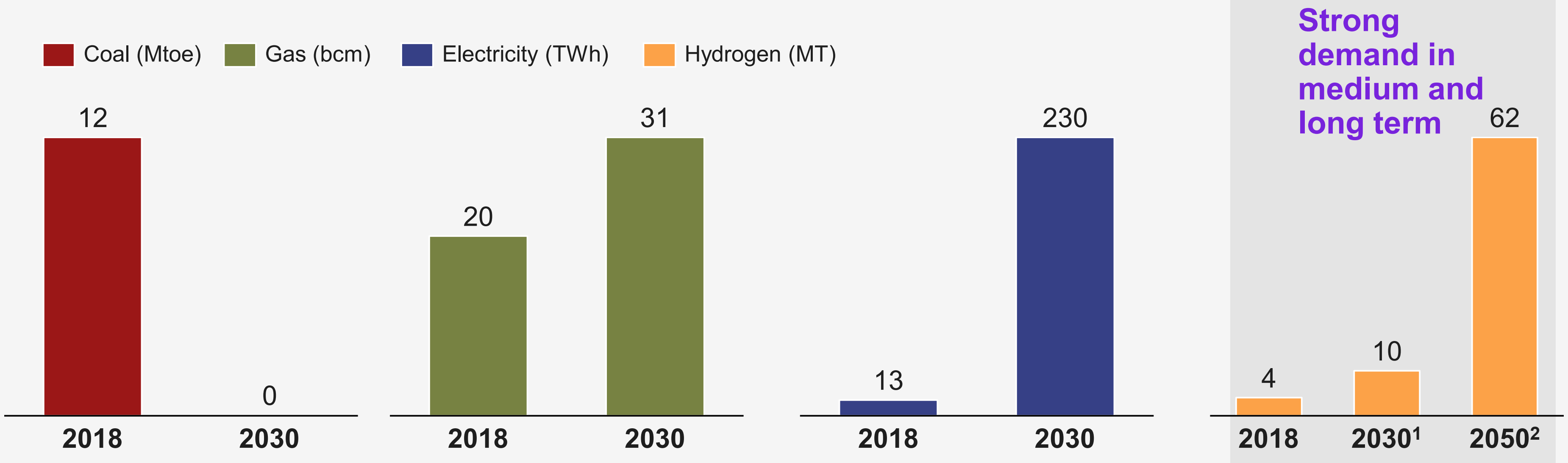
The economic viability of the hydrogen-based steel production pathways is highly dependent on the low cost clean electricity or higher carbon prices

3.2 **Key hydrogen applications - Feedstock**

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
Sources: IEA – The Future of Hydrogen (2019)

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

Energy and hydrogen requirements for DRI-EAF production route



- 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
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
Sources: IEA – The Future of Hydrogen (2019)

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

	Temperature	Slack size	Electrical performance (LHV)	Current applications: Backup power	Portable power	Distributed generation	Transport	Specialty vehicles	Military	Space	Electric utility	Auxiliary power	Advantages	Challenges	Improvement potential
Polymer electrolyte membrane (PEM)	<120°C	<1–100kW	**60%**	✓	✓	✓	✓	✓	✗	✗	✗	✗	– Low corrosion and electrolyte management – Low temperature – Quick start-up and load following	– Expensive catalysts – Sensitive to fuel impurities	↑
Alkaline (AFC)	<100°C	1-100kW	**60%**	✓	✗	✗	✓	✗	✓	✓	✗	✗	– Lower cost components – Low temperature – Quick start-up	– Sensitive to CO_2 in fuel and air – Electrolyte management (aqueous) – Electrolyte conductivity (polymer)	→
Phosphoric acid (PAFC)	<150 – 200°C	5-400kW	**40%**	✗	✗	✓	✗	✗	✗	✗	✗	✗	– Suitable for CHP – Increased tolerance to fuel impurities	– Expensive catalysts – Long start-up time – Sulfur sensitivity	→
Molten carbonate (MCFC)	600-700°C	300kW – 3MW	**50%**	✗	✗	✓	✗	✗	✗	✗	✓	✗	– High efficiency – Fuel flexibility – Suitable for CHP – Hybrid–gas turbine cycle	– High temperature – Long start-up time – Low power density	→
Solid oxide (SOFC)	500-1000°C	1kW-2MW	**60%**	✗	✗	✓	✗	✗	✗	✗	✓	✓	– High efficiency – Fuel flexibility – Solid electrolyte – Suitable for CHP – Hybrid/ gas turbine cycle	– High temperature – Long start-up time – Limited number of shutdowns	↑

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

Fact card: Fuel cell

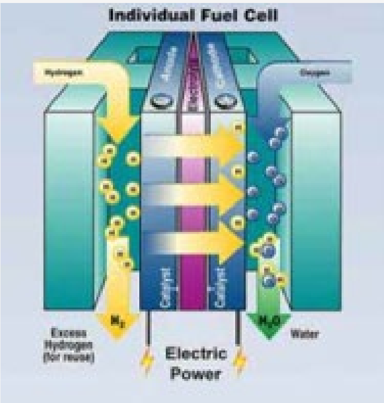
Description

- 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 Δ 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.

Overview of Technology



Fuel cell principle

Main technologies

Type	Anode and cathode	Ions
AFC	PT/Pt–Ag	OH^-
PEMFC	Pt/Pt	H^+
PAFC	PT/Pt	H^+
MCFC	Ni/Ni–LiO	CO_3^{2-}
SOFC	Ni-YSZ/ $La_xSr_{1-x}MnO_3$	O^{2-}
PCFC	Perovskite/ $Pr_2NiO_4^+$	H^+

Expanded in following slides

H_2 Market trends

Market maturity	Depend on technology
Market size (MW per year)	+1,000 (about 75% for mobility)
Historical growth (CAGR 10–17)	+33% in MWe
Competing technologies	– Electricity production sources – Internal combustion engines

Sources: Afhypac, Areva; Kearney Energy Transition Institute analysis

Key features

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

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

Alkaline fuel cells were one of the first fuel cell technologies

Fact card: Alkaline fuel cell

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

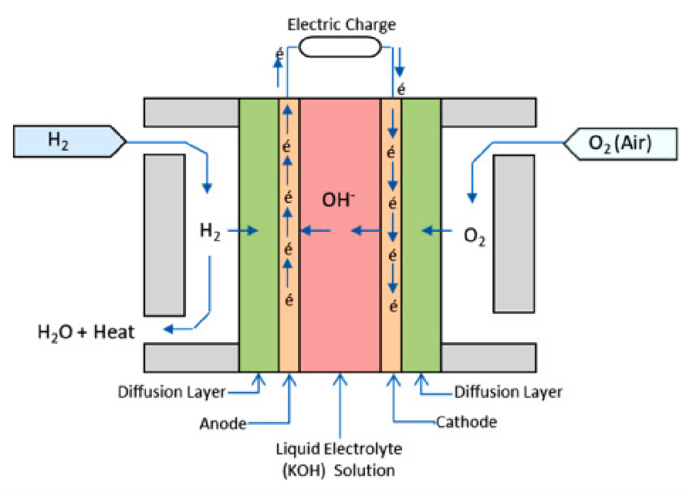
Description

- 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:

$$2H_2 + O_2 \rightarrow 2H_2O$$

- 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 CO_2, which can be addressed through alkaline membrane fuel cells (AMFC)
  - However, CO_2 still affects performance, and performance and durability of the AMFCs still lag that of PEMFC.
- Key application areas: military, space, backup power, and transportation

Overview of Technology



Alkaline fuel cell principle

Advantages

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

Disadvantages

- Sensitive to CO_2 in fuel and air
- Electrolyte management (aqueous)
- Electrolyte conductivity (polymer)

Key features

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

Sources: US Department of Energy; "Introduction to Hydrogen Technology," Introduction to Transfer Phenomena in PEM Fuel Cell, Bilal Abderezzak, 2018; Kearney Energy Transition Institute analysis

Polymer electrolyte membrane fuel cells deliver high power density and lower weight and volume

Fact card: Polymer electrolyte membrane fuel cell

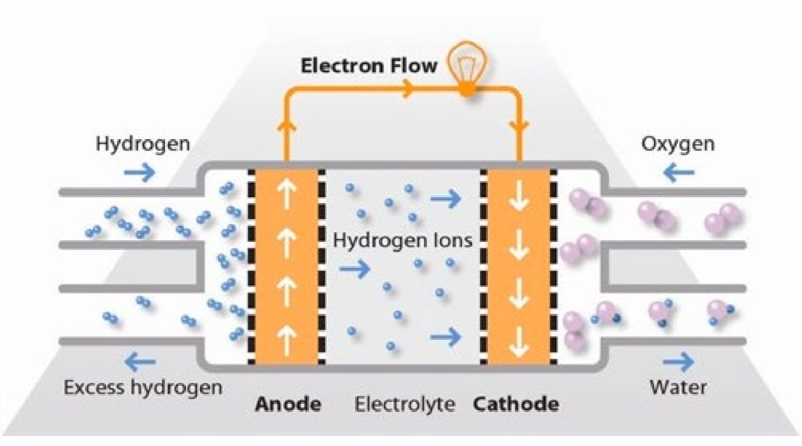
Description

- 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:

$$H_2 \rightarrow 2H^+ + 2e^-$$

- 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.

Overview of Technology



Polymer electrolyte membrane fuel cell principle

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

Efficiency (%)	60% direct H_2; 40% reformed fuel
Operating temperature (°C)	Less than 120
Typical stack size	Less than 1–100 kW
Common electrolyte	Perfluoro sulfonic acid
Anode/Cathode	Pt / Pt

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

Fact card: Phosphoric acid fuel cell

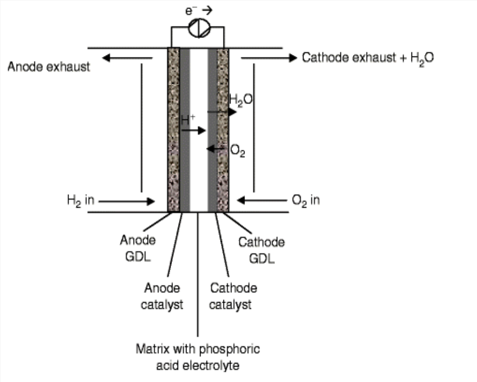
Description

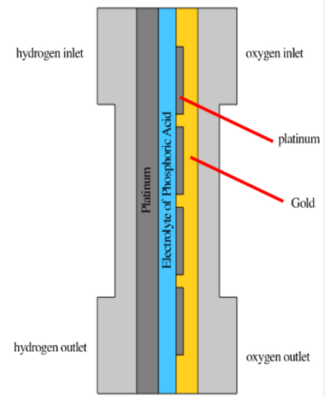
- Phosphoric acid fuel cells (PAFC) use liquid phosphoric acid as an electrolyte—the acid is contained in a Teflon-bonded silicon carbide matrix—and porous carbon electrodes containing a platinum catalyst.
- Fuel cell reaction can be described as:

$$H_2 + \frac{1}{2}O_2 \rightarrow H_2O$$

- 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

Overview of Technology





2D model of PAFC

Phosphoric Acid Fuel cell principle

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

Molten carbonate fuel cells are being developed for natural gas and coal-based power plants for electrical utility applications

Fact card: Molten carbonate fuel cell

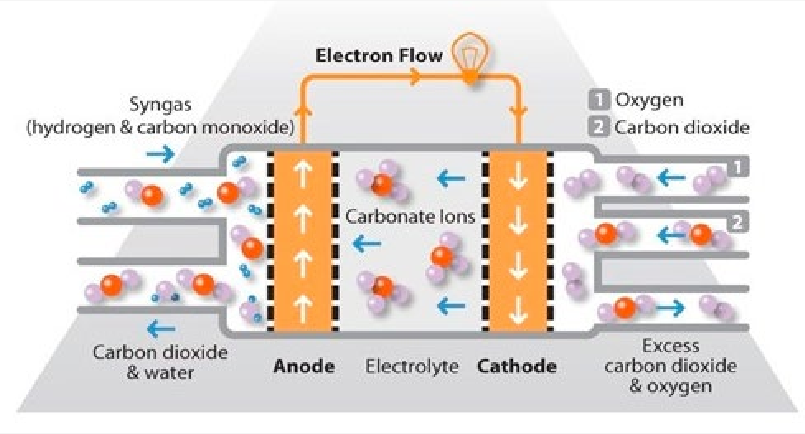
Description

- 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

Overview of Technology



Molten carbonate fuel cell principle

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

Efficiency (%)	50%
Operating temperature (°C)	600–700
Typical stack size	300 kW–3 MW
Common electrolyte	Molten lithium, sodium, and/or potassium carbonates, soaked in a porous matrix
Anode/Cathode	Ni / Ni – LiO

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

Solid oxide fuel cells are the most sulfur-resistant type of fuel cell

Fact card: Solid oxide fuel cell

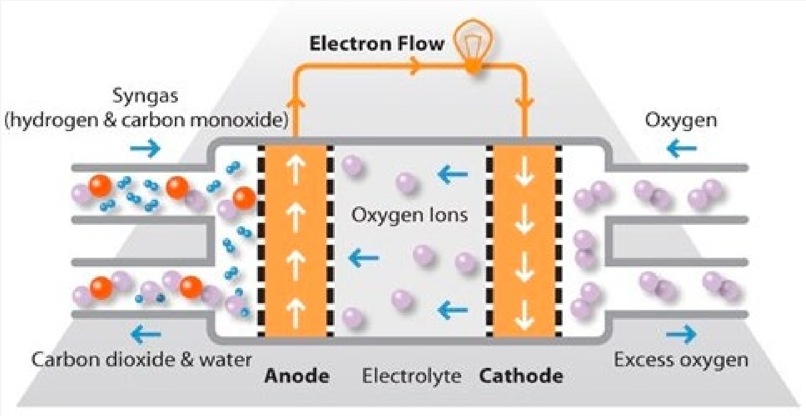
Description

- Solid oxide fuel cells (SOFC) use a hard, non-porous ceramic compound as the electrolyte.
- Fuel cell reaction can be described as:

$$CO + O_2 + H_2 \rightarrow H_2O + CO_2 + \Delta E$$

- 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

Overview of Technology



Solid Oxide Fuel cell principle

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

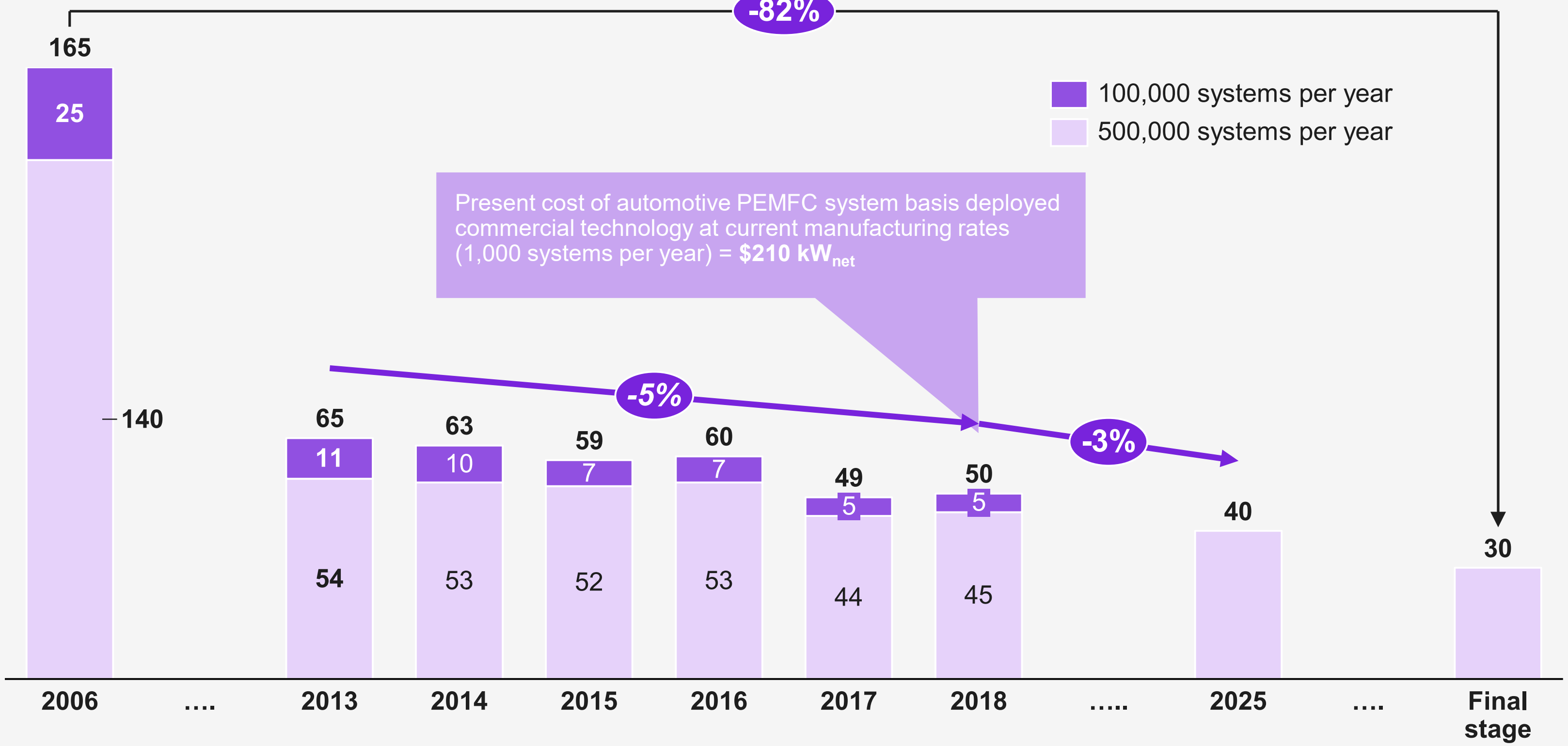
Key features

Efficiency (%)	60%
Operating temperature (°C)	500–1,000
Typical stack size	1 kW–2 MW
Common electrolyte	Yttria stabilized zirconia
Anode/Cathode	Ni-YSZ / $La_xSr_{1-x}MnO_3$

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]



	2015	2020	Final stage
Peak energy efficiency (%)	60	65	70
Power density (W/L)	640	650	850
Specific power (W/kg)	659	650	650
Durability (hours)	3,900	5,000	8,000[2]

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

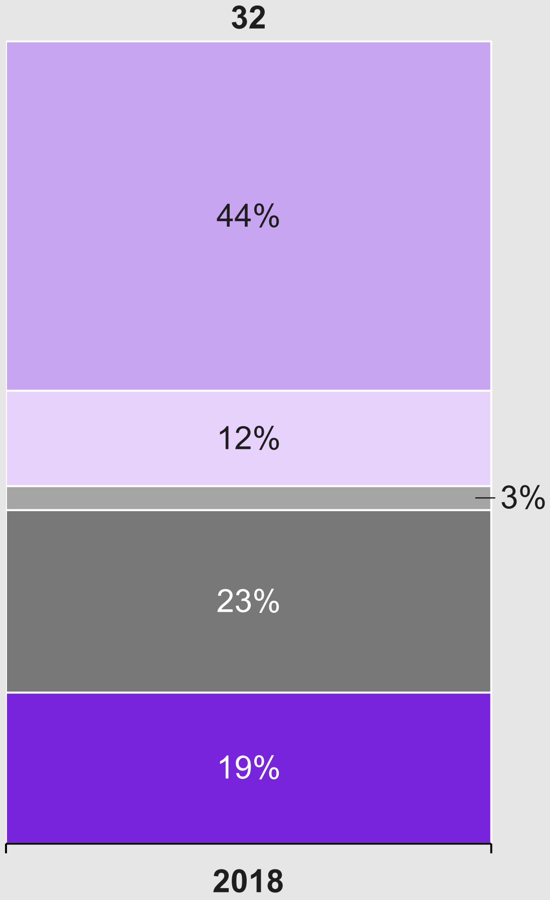
Reducing costs and improving durability while maintaining performance continues to be a key challenge

Non-Exhaustive

Catalyst developments are crucial to future fuel cell technology

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

Fuel cell R&D funding[1]
(Total $ million, % breakup)



- Catalyst and electrodes
- Performance and durability
- Testing and technical assessment
- Membrane and electrolytes
- Membrane electrode assembly, cells, and stack components

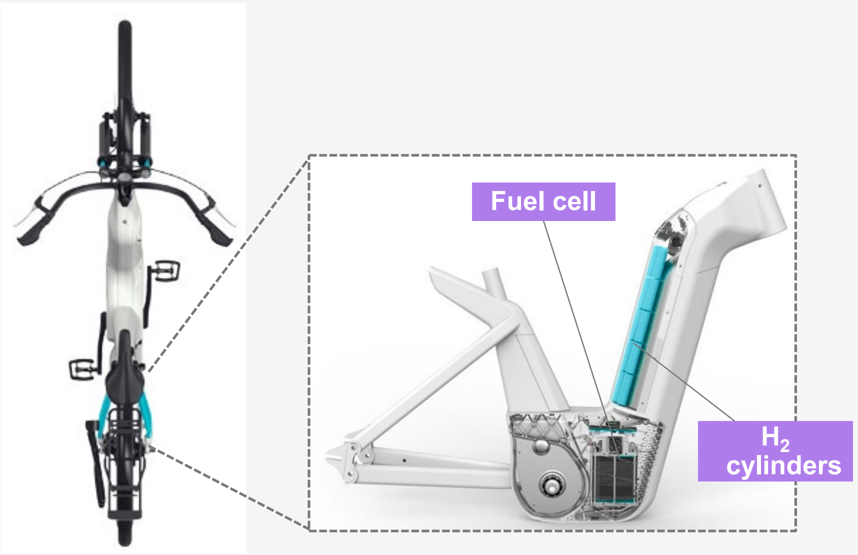
Key improvement levers	Areas improved	Benefits and challenges
Catalyst	For platinum group metal (PGM) based catalysts, both a reduction in PGM loading and an increase in membrane electrode assembly (MEA) areal power density are required to reduce material costs.	Current state-of-the-art MEAs with very low cathode PGM loadings experience a higher-than-expected reduction in performance when operating at high power.
	Improving high-current density performance at low PGM loadings (≤0.125 mgPGM/cm2)	State-of-the-art electrode structures are hindered by severe mass-transport limitations during high-power operation, in part because of transport resistance induced by the ionomer, particularly as the PGM loading decreases.
	Development of low PGM catalysts such as accessible porous carbon-supported PtCo catalysts, ultrathin-film catalysts (to stabilize Pt)	Initial results show PtCo/HSC-f catalyst matches or surpasses the performance of a catalyst used in commercial FCEVs despite having less than one-fifth the platinum loading.
Intermediate-Temperature Membranes	Potential benefits of favorable kinetics and decreased sensitivity to fuel impurities, such as CO, also reduce PGM catalyst usage.	Higher efficiency as a result of the production of useful waste heat and/or the elimination of balance-of-plant components
Reversible fuel cells (RFC)	RFC provides easily dispatchable power and is sufficiently flexible to address grid and microgrid reliability and resiliency.	Viability and cost competitiveness of RFC technology require continued improvements to target round-trip efficiency and capital cost targets.

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

H_2 Market trends

Market maturity	Advanced prototype/ demonstration
Market size (number of units)	More than 200 in France
Future growth	Multiple orders of hundreds of bikes expected in European cities
Competing technologies	Electric bikes

Key features

Power output (kw)	0.1–0.25
Fuel consumption (Kg H_2/100 km)	.035
Range (km)	100–150
Capex/acquisition cost ($)	5,000–7,500
Lifetime (years)	5

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

Fact card: Hydrogen scooter

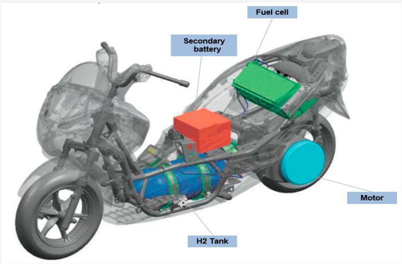
3.2 Key hydrogen applications – Energy (mobility)

Description

- H_2 is stored in compressed tanks and then converted into electricity through a PEMFC, powering an electrical motor.
- Refueling of a compressed H_2 tank is performed in dedicated stations.
- The latest research focuses on metal hydrides, where H_2 is stored as a powder in 2 cans, which facilitate refueling as no H_2-dedicated infrastructure is needed.
  - H_2 can could be bought in petrol stations and supermarkets.
  - Metal hydrides are easy to refuel and can operate at low temperature but are more expensive.
- H_2 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.

Overview of technologies

Compressed H_2 tank



Hydrogen can

Hydrogen is stored in powder in a 2.5 L can

H_2 Market trends

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

Key features

Fuel consumption (gH_2/km)	0.3–0.8/2 cans for 200 km
Range (km/tank)	120–200, up to 350
Lifetime (years)	5
Capex/acquisition cost ($)	3,400–13,000
Output (kW)	3–4 kW

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

Fork lifts powered by fuel cells are already in use since they don't need capex-intensive infrastructure for recharging

Fact card: Hydrogen forklift

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

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.

Overview of technologies

H_2 Market trends

Market maturity	Commercialization
Market size (number of vehicles)	25,000
Expected growth (CAGR 19–XX)	n.a.
Competing technologies	Petrol and diesel, battery EV, compressed natural gas (CNG)

Key features

Fuel consumption (kgH_2 per hour)	0.15
Range (km per tank)	8
Capex/acquisition cost ($)	$14,000–$30,000 (fuel cell system)
Output (kW)	2.5–4.5
Fuel consumption (kgH2 per hour)	0.15

Sources: Toyota; BallardThe Fuel Cells and Hydrogen Joint Undertaking (FCH JU); "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute

Fuel-cell hydrogen cars are commercially available as an alternative to diesel-based internal combustion engine cars

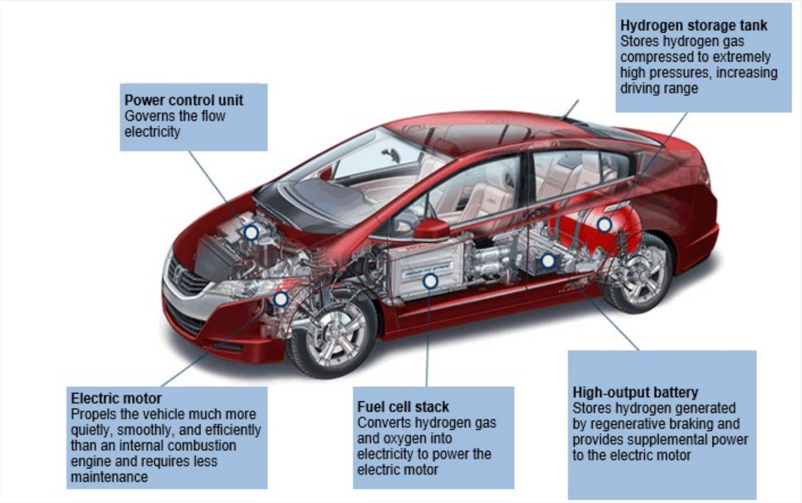
Preliminary

Fact card: Hydrogen car

Description

- As with scooters, H_2 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).
- H_2 stored in metal hydride cans is also under development (a car requiring about nine cans), which could offset a low number of refueling stations.
- H_2 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.

Overview of technologies



H_2 Market trends

Market maturity	Commercialization
Market size (number of vehicles)	11,200
Expected growth (CAGR 2025f)	18% (+56% 17–18)
Competing technologies	Petrol and diesel, petrol and diesel–electric hybrid, battery powered cars

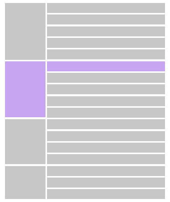
Key features

Fuel consumption (kgH_2/100km)	0.8–1.0
Range (km per tank)	500–700
Lifetime (years)	5
Capex/acquisition cost ($)	56,000–86,000
Output (kW)	70–130 kW

Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute

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

Fact card: Hydrogen van



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

Description

- Vans can also be equipped with a H_2 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 H_2 is powering non-vital applications, such as for garbage trucks or a power box for a loader and compactor.

Overview of technologies

H_2 Market trends

Market maturity	Deployment
Market size (number of vehicles)	About 100 vans
Expected growth (CAGR 2019f)	n.a.
Competing technologies	Petrol and diesel, petrol and diesel-electric hybrid, battery powered vans

Key features

Fuel consumption (kgH_2/100km)	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.

Sources: “The Future of Hydrogen,” International Energy Agency, June 2019; Kearney Energy Transition Institute

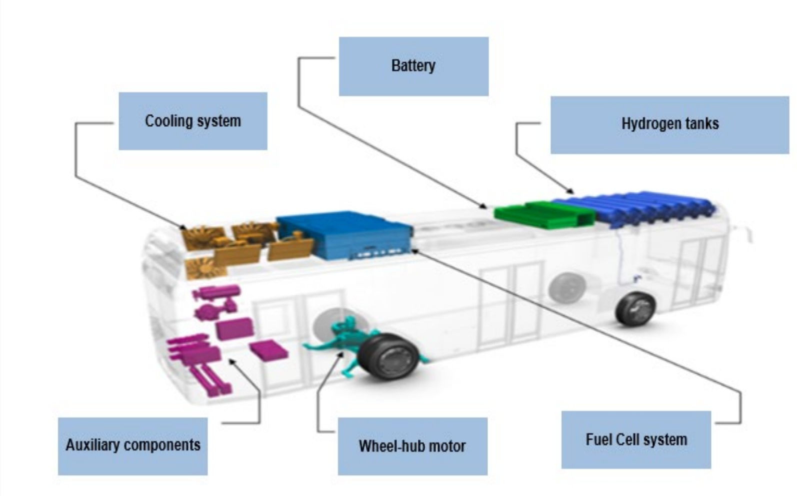
Hydrogen buses powered by fuel cells are a zero-emission alternative to diesel buses

Fact card: Hydrogen 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



H_2 Market trends

Market maturity	Deployment
Market size (number of vehicles)	More than 500
Future growth	Several thousand buses expected in China, Japan, and South Korea
Competing technologies	Electric, diesel, diesel-electric hybrid, biofuels, CNG

Key features

Fuel consumption (Kg H_2/100km)	8–14
Range (km per tank)	250–450
Power output (kW)	100
CAPEX/Acquisition cost ($)	680,000
Total cost of ownership ($ per km)	4

Source: Kearney Energy Transition Institute analysis

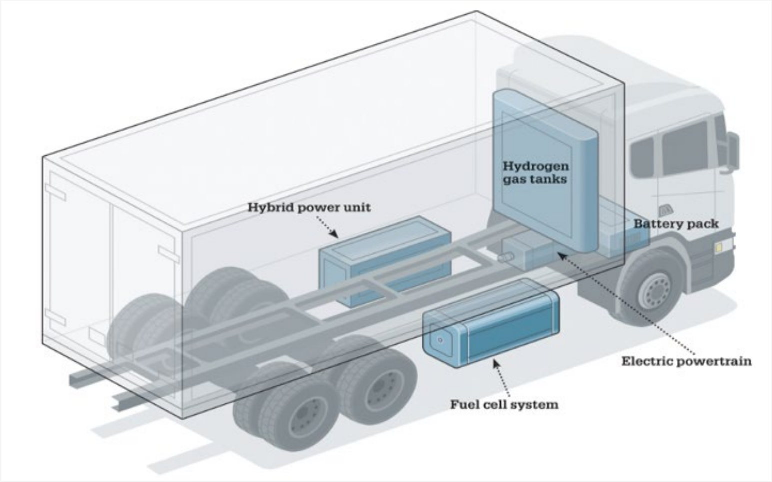
Hydrogen trucks and buses powered by fuel cells are expected to gain market share, mainly in China

Fact card: Hydrogen truck

Description

- Buses and trucks can be equipped with a H_2 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 kgH_2, making it lighter than the battery part from a BEV truck.

Overview of technologies



H_2 Market trends

Market maturity	Deployment
Market size (number of vehicles)	About 400 trucks
Expected growth (CAGR 2019f)	Several thousand trucks expected in China
Competing technologies	Diesel, diesel-electric hybrid, battery-powered trucks

Key features

Fuel consumption (kgH_2/100km)	7.5–16
Range (km per tank)	1,200
Fuel cell efficiency	55%
Output (kW)	250–750 kW (trucks)
Capex/acquisition cost ($)	350,000
Total cost of ownership ($ per km)	0.95–1.75

Sources: The Fuel Cells and Hydrogen Joint Undertaking (FCH JU); "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute

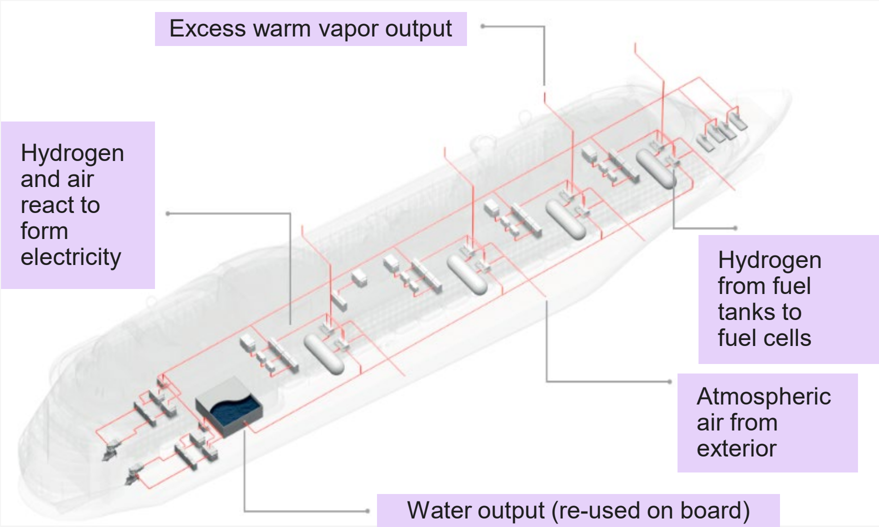
Hydrogen can be the main power source for small boats or supply electricity to on-board applications

Fact card: Marine 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

Overview of technologies



H_2 Market trends

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

Source: Kearney Energy Transition Institute analysis

Key features

Power output (kw)	12–2,500 (ferries)
Fuel consumption (Kg H_2/nm)	3.4 (ferries)
Range (km, hours)	50–90, 8–12 (smaller boats)
Capex/acquisition cost ($)	12–16.5 million (ferries)
Lifetime (years)	25

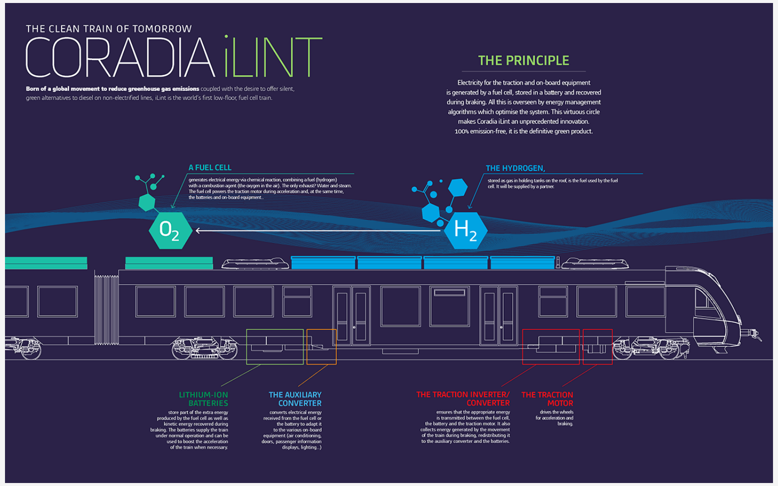
Hydrogen trains powered by fuel cells can offer a low-carbon alternative to diesel locomotives

Fact card: Hydrogen train

Description

- Hydrogen trains use multiple H_2 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

H_2 Market trends

Market maturity	Deployment
Market size (number of vehicles)	Multiple projects worldwide Two trains in Germany
Expected growth (CAGR 2019f)	n.a.
Competing technologies	Diesel, electric, battery-powered

Key features

Fuel consumption (kgH_2/100km)	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)	–

Sources: The Fuel Cells and Hydrogen Joint Undertaking (FCH JU); "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute

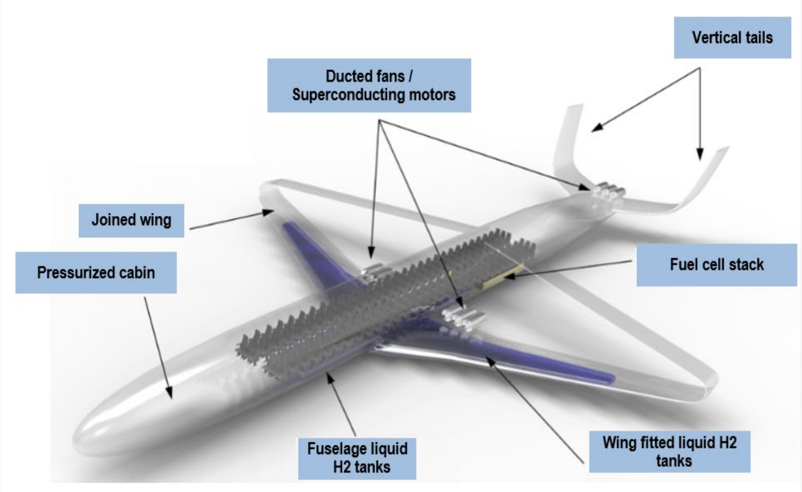
Hydrogen aircrafts powered by fuel cells could offer a solution to reduce aviation-based emissions

Fact card: Aviation

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



H_2 Market trends

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

Key features

Power output (kw)	80 (based on HY4 project)
Fuel consumption (Kg H_2)	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.

Overview of technologies

Mizushima coal plant, operated by Chugoku Electric

H_2 Market trends

Market maturity	Early stage
Market size (2019, GW, coal-fired)	2,100
Expected market size (2030, GW, coal-fired)	1,650 (including combined heat and power)
Competing technologies	CCS, decarbonized sources

Key features

Ammonia marginal consumption (kgNH3/%ammonia/MW per y)	26,800
Hydrogen marginal consumption (kgH2/%ammonia/MW per year)	4,800

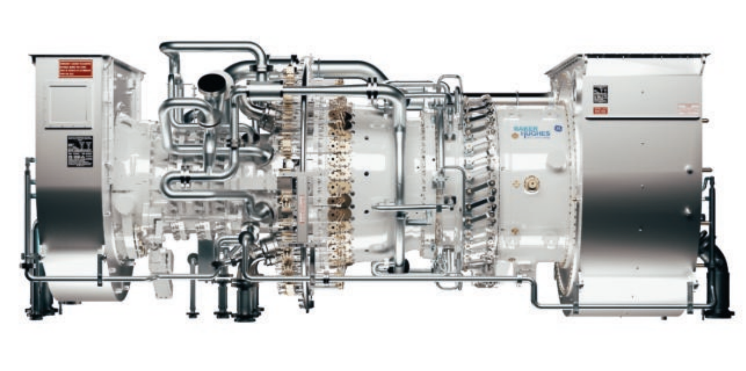
Sources: “The Future of Hydrogen,” International Energy Agency, June 2019; IHI Corporation; Chugoku Electric; Kearney Energy Transition Institute analysis

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

Description

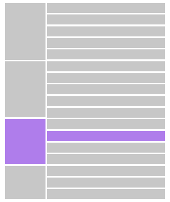
- Hydrogen can be used as a fuel in existing gas turbines and CCGTs, which can handle a 3 to 5% share of hydrogen, up to 30% for some turbines.
- Ammonia can also be used as a fuel in gas turbine. However, NOx emissions and flam stability needs to be controlled.
- Fuel cells have efficiencies close to CCGTs but suffer from a shorter lifetime than turbines and have smaller output (less than 50MW).
- 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.

Overview of technologies



BHGE NovaLT gas turbine reconfigured for 100% hydrogen

Fact card: Flexible power



H_2 Market trends

Market maturity	Early stage
Market size (GW of VRE)	n.a.
Expected market size (2050, GW of VRE)	n.a.
Competing technologies	Batteries, biomass turbines, gas + CCUS turbines

Key features

Competitive price for H_2 vs. gas turbine (\$ per kgH_2)	15% load factor: 1.5
Competitive price for H_2 vs. gas turbine + CCUS[1] (\$ per kgH_2)	15% load factor: 2.5
Competitive price for H_2 vs. biomass turbine (\$ kgH_2)	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.
Sources: BloombergNEF; “The Future of Hydrogen,” International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

H_2 can be blended with CH_4 before being injected on the gas grid

Description

- Blending low shares of H_2 in most gas networks would have little impact for the end-use applications, such as boilers and cookstoves.
- Blending H_2 into the current gas network allows clean energy to be distributed while saving capex for a new H_2 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 H_2 blend in natural gas, which will set the upper limit for the whole network.
- Current regulations allow a H_2 blend limit up to 6% (for example, in France).

Overview of technologies

GRHYD project in Dunkirk

Fact card: Hydrogen blending

H_2 Market trends

Market maturity	Development
Natural gas demand (bcm per year)	3.900
Expected market size (2030, MtH_2 per year)	2 – 4
Competing technologies	Natural, gas, Methanation, H_2, fuel cells and cogeneration, Biogas

Key features

H_2 tolerance in gas networks (min/max, % vol)	Compressors: about 10% Distribution: 50–100%
H_2 tolerance for end-applications (min/max, % vol)	Gas turbines: 5% Boilers: 30%

3.3 **Key hydrogen applications – Energy (gas energy)**

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

H_2 can be converted into natural gas to be injected or directly combusted onsite for power generation

Fact card: Hydrogen methanation

3.3 **Key hydrogen applications – Energy (gas energy)**

Description

- Methanation is a exothermic catalytic process operating at 320–430°C to produce synthetic CH_4 through Sabatier reaction:
  $$CO_2 + 4H_2 \rightarrow 2\,H_2O + CH_4 \quad \Delta H = -165\ \mathrm{MJ/kmol}$$
- Reaction can be split in two steps:
  $$CO + 3H_2 \rightarrow H_2O + CH_4 \quad \Delta H = -206\ \mathrm{MJ/kmol}$$
  $$CO_2 + H_2 \rightarrow H_2O + CO \quad \Delta H = 41\ \mathrm{MJ/kmol}$$
- 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 CO_2:
  - If coupled with low carbon H_2 and CO_2 inputs, there is a potential for full decarbonisation of gas.
- Synthetic CH_4 may be injected on the gas network for residential and industrial applications (gas heating, electricity generation), stored or as a fuel for NGV.

Overview of technologies

Methanation plant in Falkenhagen

H_2 Market trends

Market maturity	Development
Market size	n.a. (Germany: ~2.5 $kTCH_4$ per year)
Expected market size (2030)	n.a.
Competing technologies	Natural, gas, blending, H_2, fuel cells and cogeneration, biogas

Key features

H2 consumption ($kgH_2/kgCH_4$)	0.5
CAPEX/Acquisition cost ($ per kW)	210–445 for methanation plant only
Energy efficiency (%)	83%
Marginal cost ($ per kWh)	0.10–0.45[1]

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

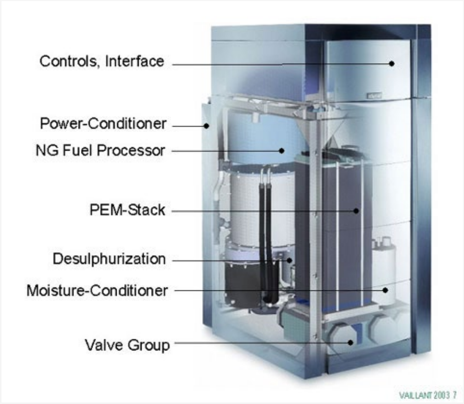
A 100% H_2 network can also be considered for providing energy to end users through fuel cells, co-generation, or other hybrid systems

Fact card: Pure hydrogen consumption

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.
  - H_2 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.

Overview of technologies



Domestic fuel cell

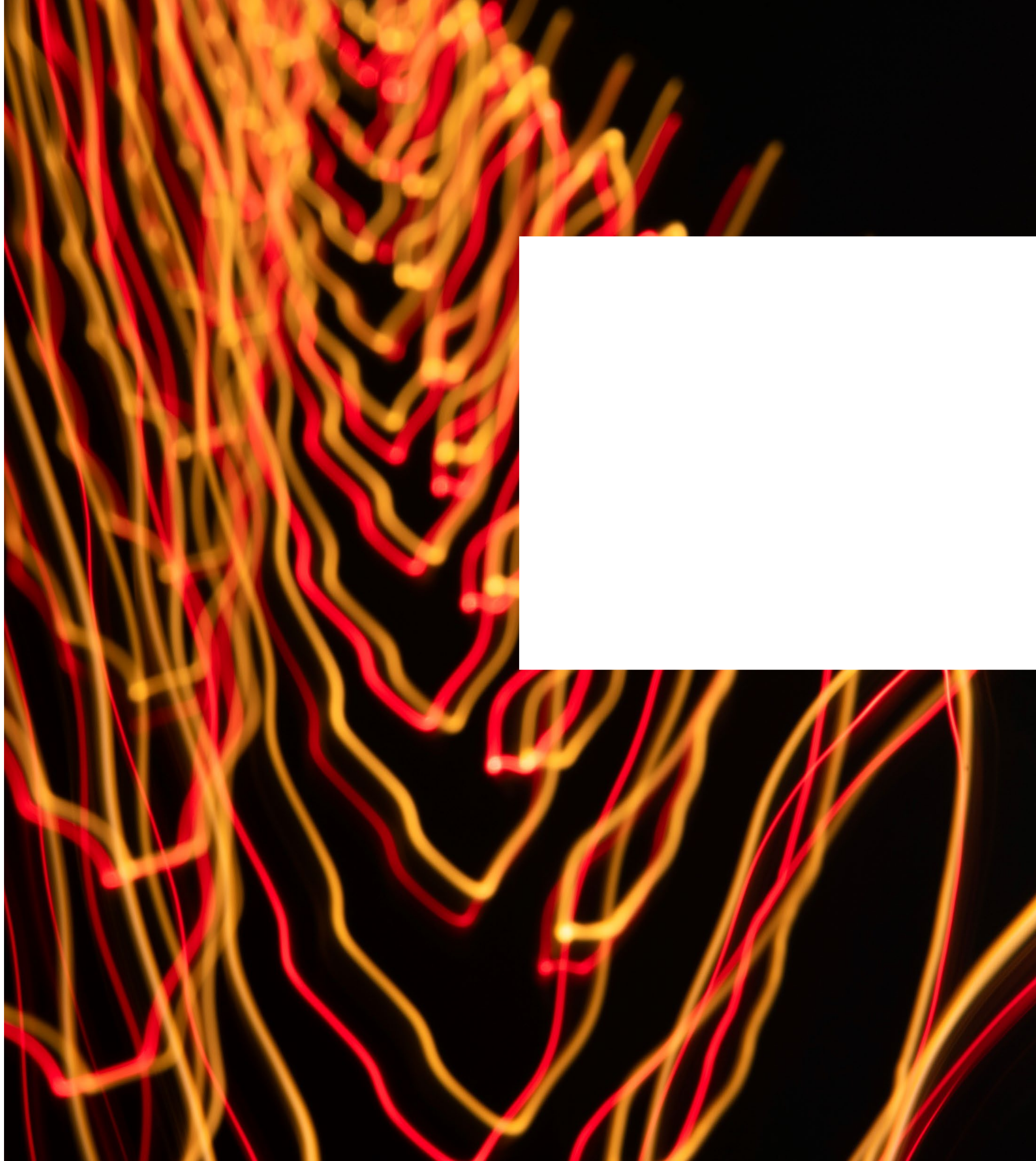
H_2 Market trends

Market maturity	Commercial
Market size (number of units)	1,046 units in a trial project in the European Union
Future growth	0.3 million units (2020) and 5.3 million units (2050) as per ENE–FARM Japan
Competing technologies	Heating systems, power grid

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

Sources: “The Future of Hydrogen,” International Energy Agency, June 2019; Hydrogen Europe; Kearney Energy Transition Institute analysis

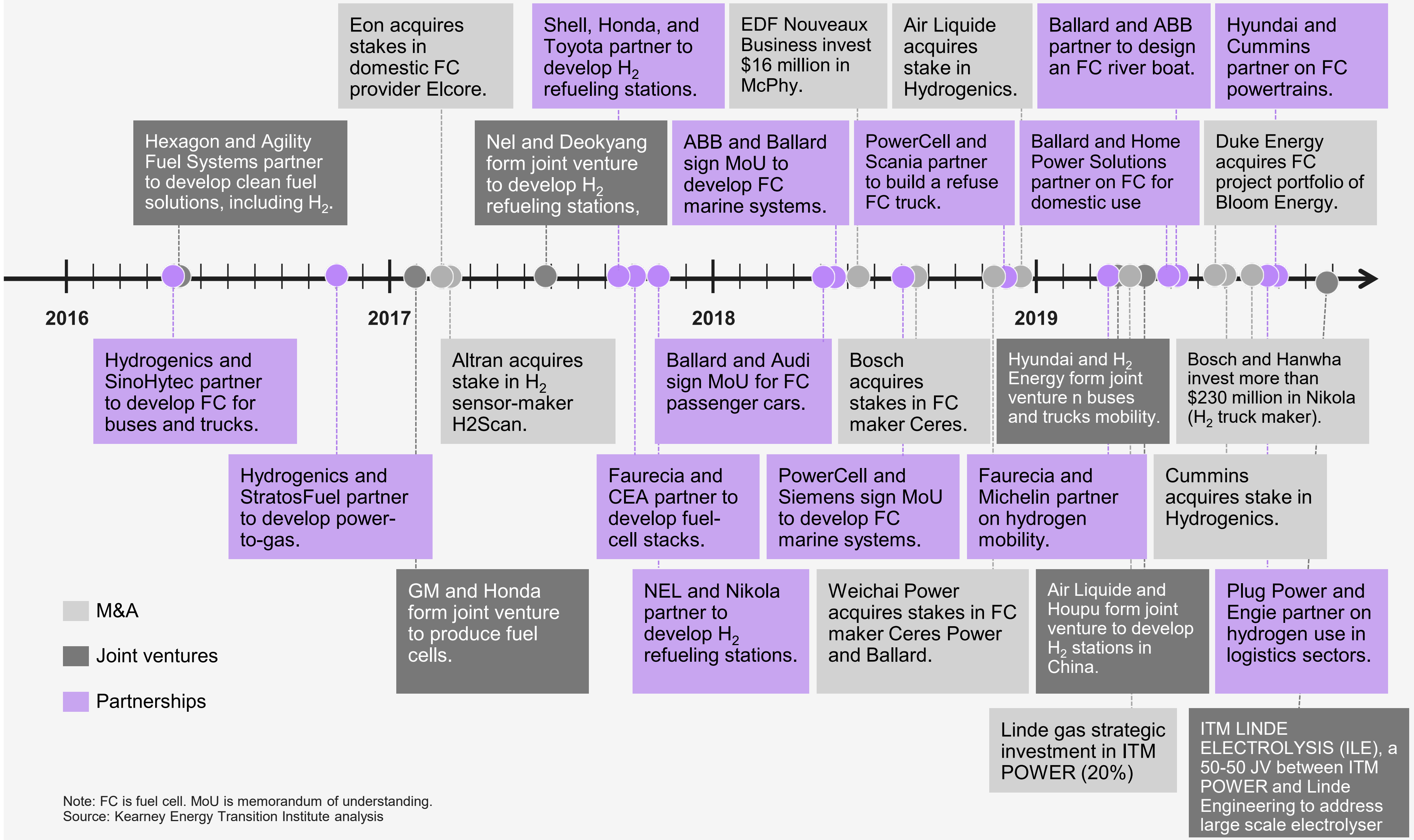
Hydrogen's role in the energy transition



M&A, joint ventures, and partnerships have increased, highlighting large corporations' interest in hydrogen

Non-Exhaustive

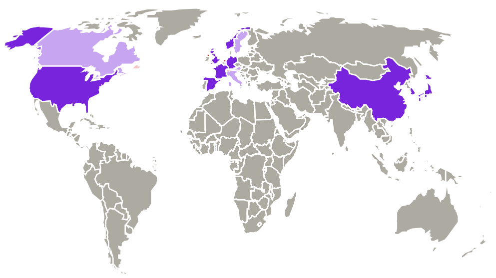
Main M&A, JV, and partnership agreements on H_2 (2016–19)



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

4.1 Business models - Policies and competition landscape

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



4.1 **Business models - Policies and competition landscape**

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

Hydrogen Council vision: The hydrogen economy in 2050

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 CO_2 and decarbonized existing feedstock
- 8% of global energy demand

Power generation
- 500 TWh of excess power converted to about 10 MTH$_2$ of hydrogen
- About 126 MTH$_2$ stored in strategic reserves

Expected outcome

- **18%** of final energy demand
- **6 GT year** of CO_2 abatement (20% of the required CO_2 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

Sources: Hydrogen Council; Kearney Energy Transition Institute analysis

Steering members

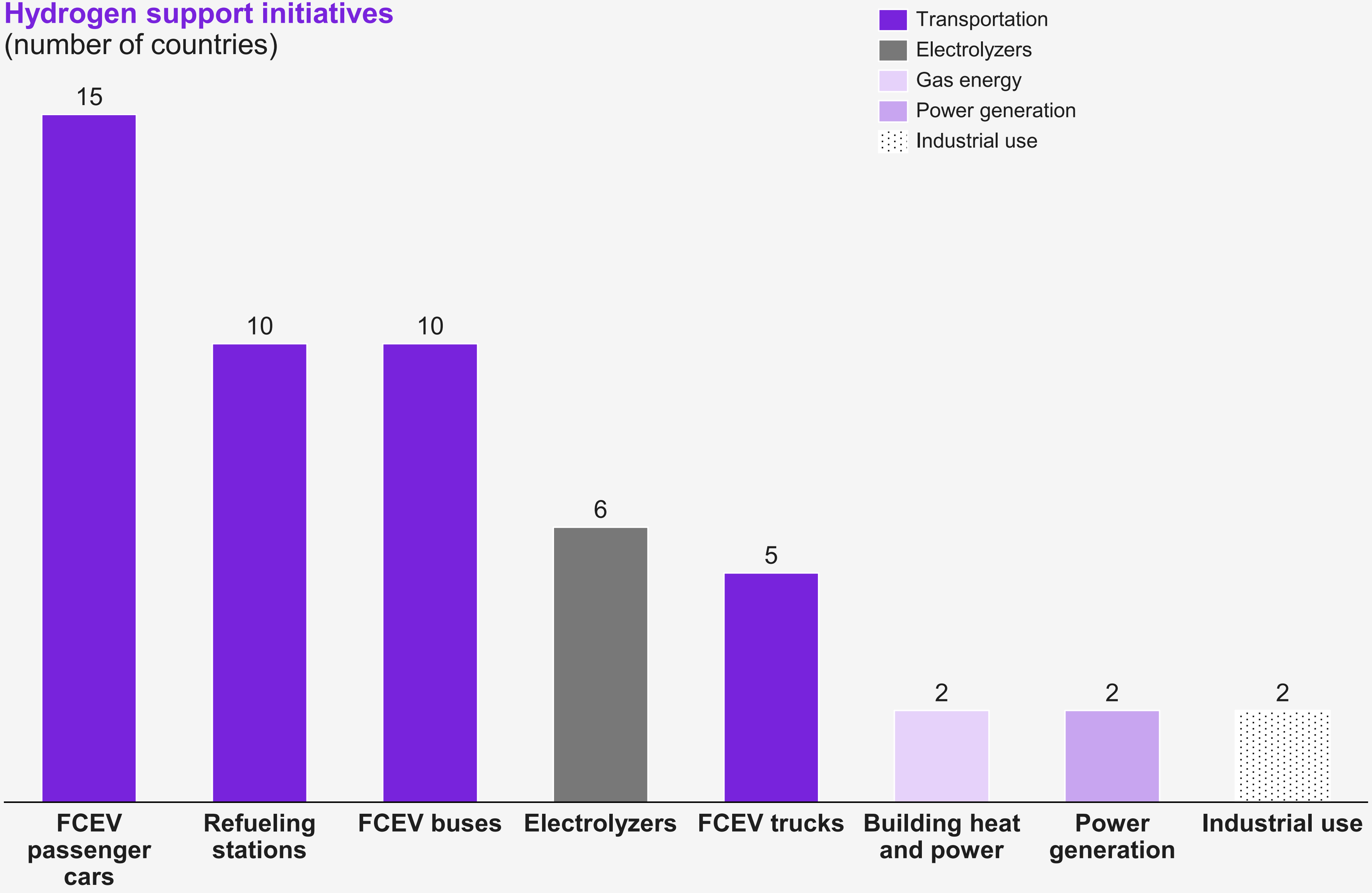
- Airbus
- Air Liquide
- Air Products
- Alstom
- AngloAmerican
- Audi
- BMW Group
- Bosch
- BP
- CHN Energy
- Cummins
- Daimler
- EDF
- Engie
- Equinor
- Faurecia
- GM
- Great Wall Motors
- Honda
- Hyundai
- Iwatani Corporation
- Johnson Matthey
- JXTG Nippon Oil and Energy Corp.
- Kawasaki
- Kogas
- Linde
- Plastic Omnium
- Shell
- Sinopec
- Thyssenkrupp
- Total
- Toyota
- Weichai Power
- 3M

Supporting members

- AFC Energy
- AVL
- Ballard
- Faber cylinders
- W. L. Gore
- Hexagon
- Hydrogenics
- Itochu Corp
- Liebherr
- Marubeni
- McPhy
- Mitsubishi Heavy industries
- Nel ASA
- NGK NTK
- Plug Power
- Power Assets Holdings
- Re-fire Technology
- SinoHytec
- SoCalGas
- Sumitomo
- Toyota Tsusho
- True Zero
- Vopak

Multiple countries have launched supportive initiatives to accelerate hydrogen deployment, mainly in transportation …

Hydrogen support initiatives
(number of countries)



4.1 **Business models - Policies and competition landscape**

Note: FCEV is fuel cell electric vehicle.
Sources: International Energy Agency; Kearney Energy Transition Institute analysis

… and developing specific strategy use case

Non-Exhaustive

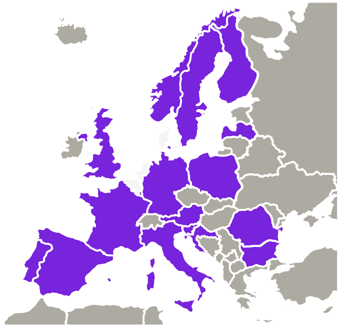
Business cases

									
Industrial feedstock		✓	✓✓		✓✓				✓
FCEV manufacturing								✓✓	✓✓
Use of H_2 for FCEV passenger cars	✓✓	✓	✓		✓	✓✓	✓✓	✓✓	✓✓
Use of H_2 for heavy vehicles	✓✓	✓✓	✓✓		✓	✓✓	✓✓	✓✓	✓✓
Electricity generation	✓✓	✓			✓			✓	
Combined heat and power generation				✓✓				✓✓	✓✓
Long-term energy storage	✓	✓✓			✓			✓	
Blending and methanation in gas networks		✓✓		✓✓	✓✓			✓	✓✓
Household heating		✓✓		✓✓	✓✓		✓	✓	
Industrial heating		✓✓			✓				✓
Hydrogen production for export						✓✓	✓✓	✓✓	

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

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

Focus on European Union



4.1 **Business models - Policies and competition landscape**

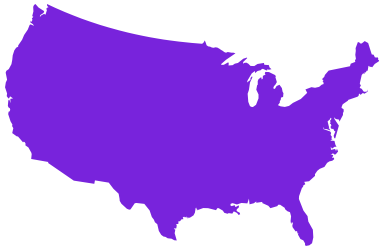
Objectives		Policy change proposition

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 CO_2, 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.
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.

The United States has launched incentive programs to accelerate hydrogen deployment

Focus on the United States



4.1 **Business models - Policies and competition landscape**

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.

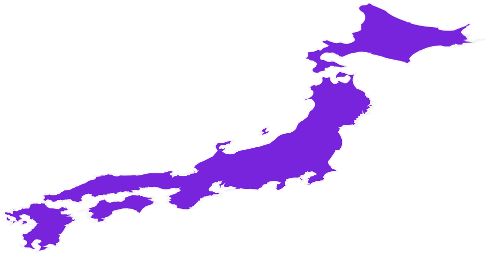
The Fuel Cell Technical Task Force is responsible for planning a safe, economical, and ecological hydrogen infrastructure and establishing uniform hydrogen codes, standards, and safety protocols.

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

Note: OEM is original equipment manufacturers; FCEV is fuel cell electric vehicle.
Sources: Department of Energy; Kearney Energy Transition Institute

Japan was the first country to adopt a basic hydrogen strategy and plans to become a “hydrogen society”

Focus on Japan



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 800,00 units (2030) – Hydrogen stations targets: 160 (2020) to 320 (2025) – Specific focus in developing fuel cell-based buses, forklifts, trucks, and small ships

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

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.

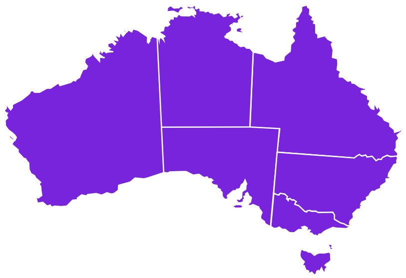
Japan intends to lead international standardization through international frameworks in cooperation with relevant organizations.

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.

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



4.1 **Business models: policies and competition landscape**

Focus areas		Policy initiatives
Develop a strong hydrogen industry and capabilities that will support the country's low emission energy transition and local job creation	Australia would take an adaptive approach to capitalize on the growth in domestic and global hydrogen demand: **Foundation and demonstration** – 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. – Demonstration scale hydrogen hubs will help prove technologies, test business models, and build capabilities. **Large-scale market activation** – 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.	Since 2015, the Australian government has committed more than $146 million to hydrogen projects along the supply chain. – R&D: $67.83 million – Feasibility:$4.88 million – Demonstration: $5.04 million – Pilot: $68.57 million 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.
Transform Australia into a clean hydrogen exporter	Australia has significant competitive advantages for developing a substantial hydrogen export industry. The country has abundant natural resources needed to make clean hydrogen and has a track record in building large-scale energy industries. It has an established reputation as a trusted energy supplier to Asia.	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

Sources: Australia's National Hydrogen Strategy (2019); Kearney Energy Transition Institute

Oil-rich countries are looking into H_2 to export as a clean fuel alternative to oil and gas

Focus on Gulf Cooperation Council countries

4.1 **Business models - Policies and competition landscape**

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.
  - CO_2 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.

Sources: Kuwait Foundation for the Advancement of Sciences; Kearney Energy Transition Institute analysis

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 H_2 production by KPC

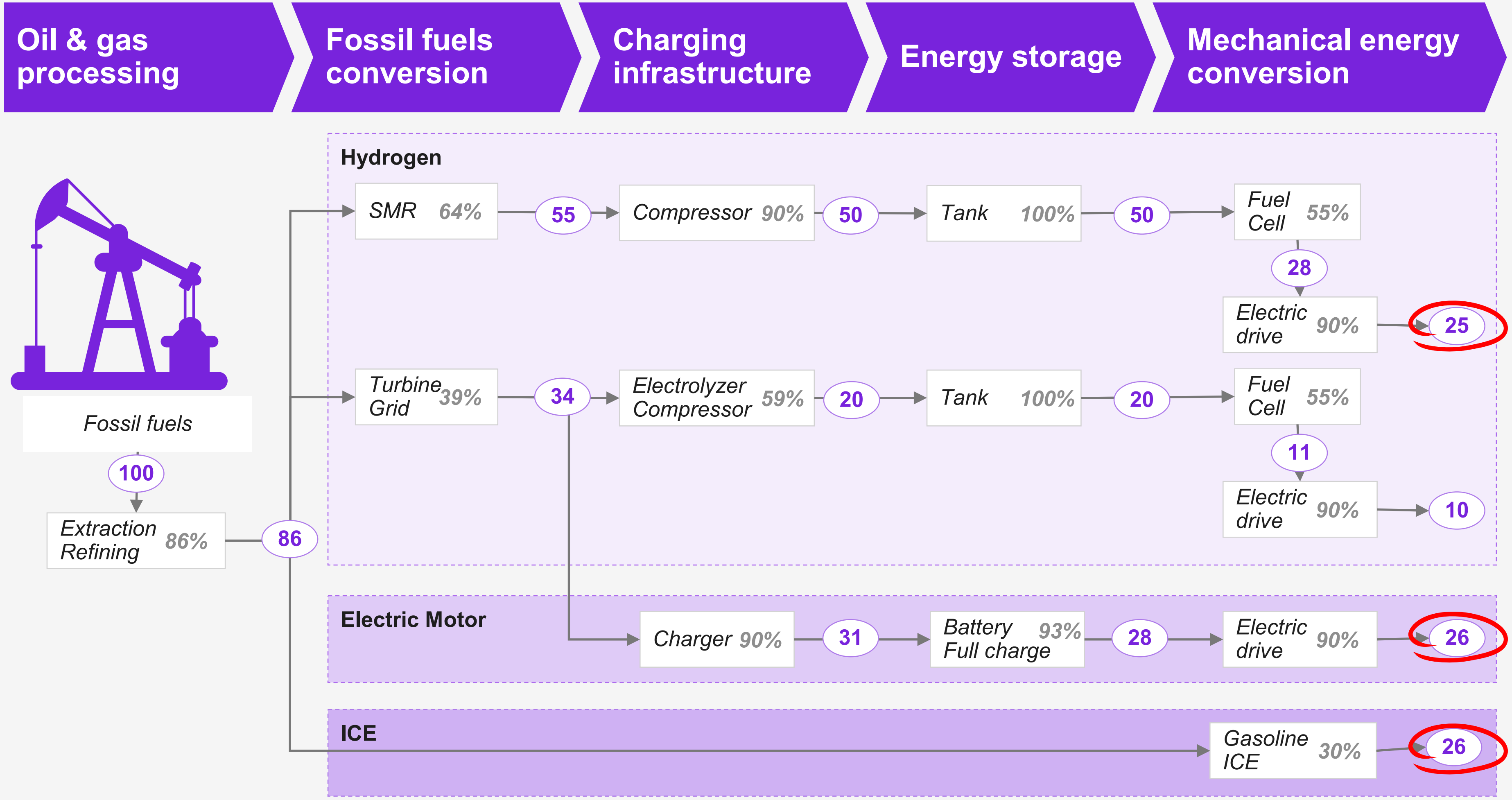
Converting fossil fuels into hydrogen through SMR is almost as efficient as a ICE and BEV, leading to no extra fossil fuel consumption

Illustrative

X% Conversion efficiency
X% Energy content

4.2 **Business models – Business cases**

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



Source: Kearney Energy Transition Institute analysis

The battery pathway also appears more efficient than hydrogen when the primary source comes from renewable sources

Illustrative

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

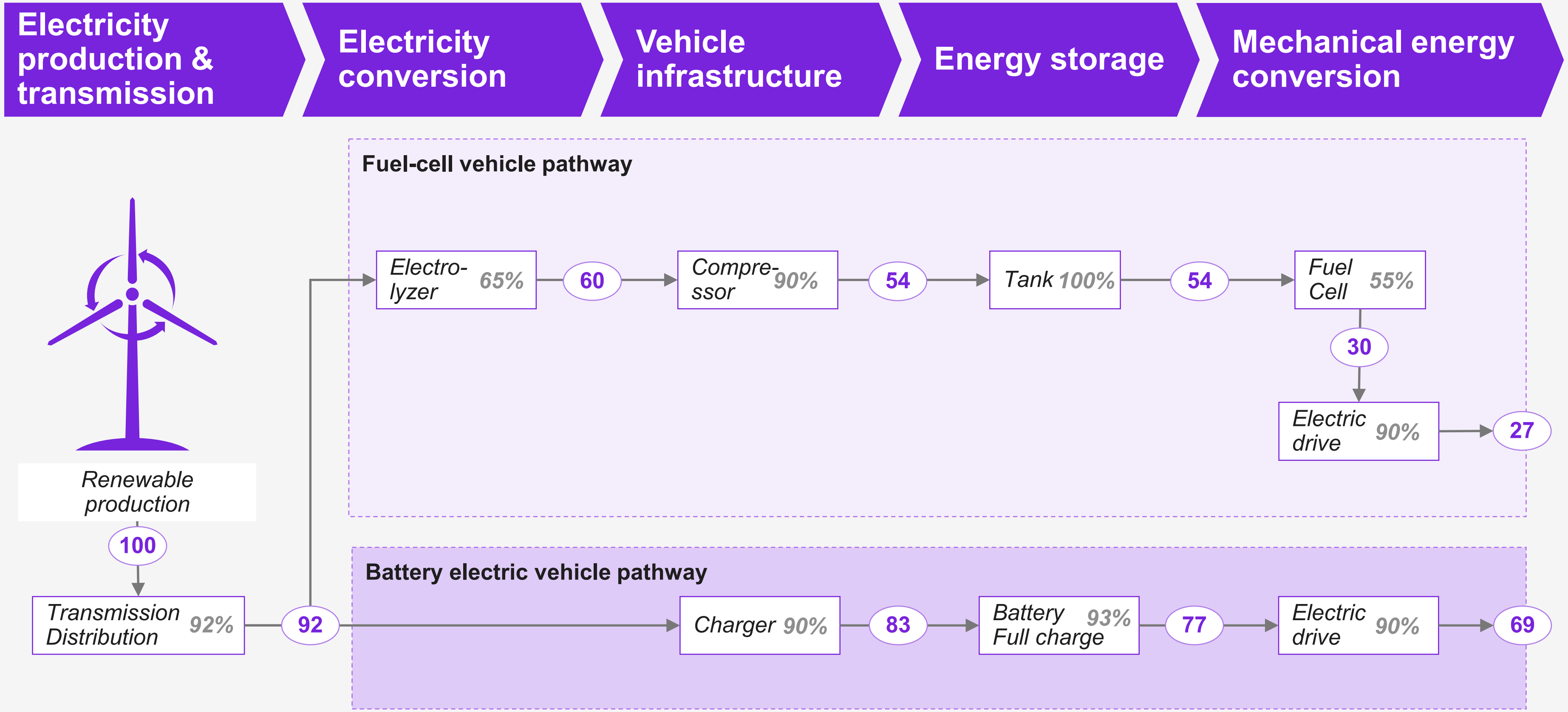
X% **Conversion efficiency**

X% **Energy content**

4.2 **Business models – Business cases**

Well-to-wheel energy efficiency example

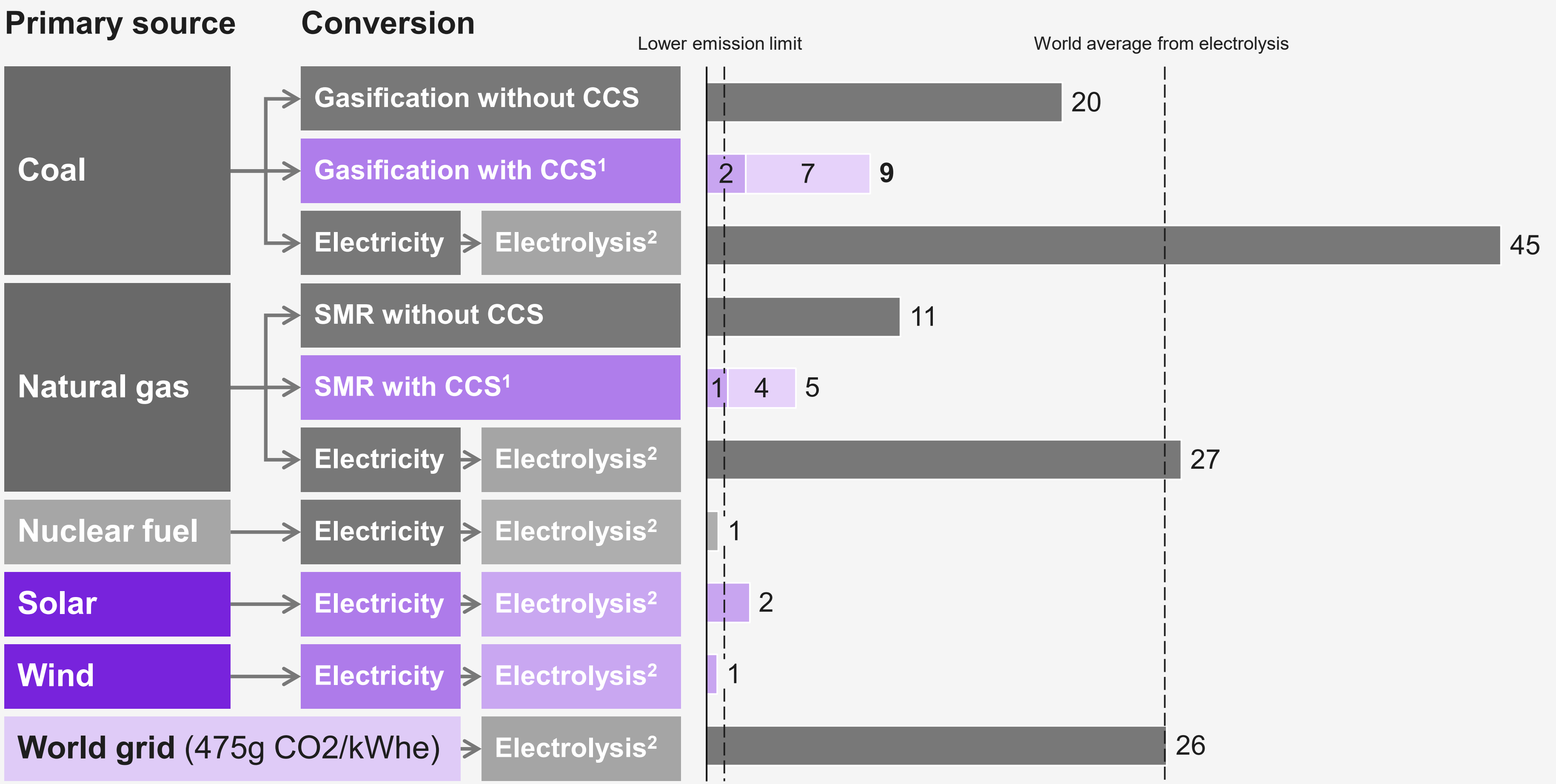
(Energy in kWhe)



Source: Kearney Energy Transition Institute analysis

CO_2 emissions related to hydrogen production vary depending on the production pathway

CO_2 intensity of hydrogen production
($kgCO_2/kgH_2$, includes full life cycle of power plant)



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 kWhe/kgH2 for an electrolyzer
Sources: "Hydrogen Roadmap Europe," International Energy Agency, 2019; RTE; Kearney Energy Transition Institute analysis

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

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

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 CO_2 can be avoided thanks to the hydrogen solution, and what is the avoidance cost?
- How many tons of CO_2 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?

Business cases

A. Thermochemical production

A – Centralized production from ATR to serve local industries with heat and H_2

B. Electrolysis

B – Power-to-X

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

B2 – Power-to-power: how to store electricity and discharge it when needed

B3 – Power-to-molecule: how to optimize refinery power consumption and reducing footprint

B – Green mobility

B4 – Hydrogen cars: economic assessment of main H_2 cars

B5 – Hydrogen buses: additional cost vs. impact for local economy

B6 – Hydrogen trains: how to value local H_2 fatal production and avoid large investment for rail electrification

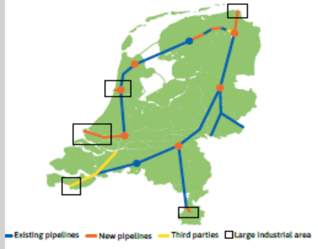
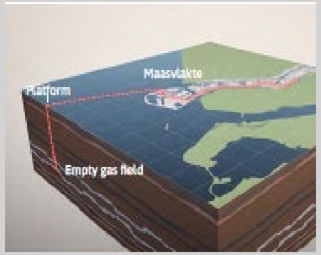
Carbon abatement costs vary widely depending on the business case

	Business cases (2030)		Extra Cost	Carbon abatement costs (MIN)	Carbon abatement costs (MAX)
A	**Centralized production from ATR**	Convert fossil fuels into hydrogen, and capture carbon at production point.	+12–30% vs. av. electricity price	100	215
B1	**Power-to-gas**	Convert electricity into hydrogen for heat generation.	+60–100% injection	220	320
			+250–400% methanation vs. gas	1100	2800
B2	**Power-to-power**	Convert electricity into hydrogen for electricity peak management.	+35–35% vs. coal turbine	110	3000
B3	**Power-to-molecule**	Convert electricity into hydrogen for further industrial applications.	+35–110% vs. SMR	130	150
B4	**Hydrogen cars**	Create clean fuel to power cars.	+150–215% vs ICE car	570	2000
B5	**Hydrogen buses (Pau example)**	Create clean fuel to power buses.	+10–15% vs. diesel bus	120	
B6	**Hydrogen trains (Cuxhaven example)**	Create clean fuel to power trains.	+1–15% vs. diesel train	0	60

Note: The carbon abatement cost is equal to (LCOX(H_2) – LCOX(Ref))/(Avoided CO2), with the LCOX(H2) 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

A The Rotterdam port is investigating the benefits of H_2 in its H-vision plan, which would combine fossil fuel-based production and CCS

Hydrogen hub produce from SMR

	Production of H_2 and CO_2 capture	Distribution of H_2	End use	CO_2 storage
Technology	– High pressure ATR unit – Centralized production of H_2 from CH_4 with CO_2 capture with Rectisol physical absorption	– Pipeline – No storage	– Power plants: new gas turbines to enable H_2 firing, power generation from ATR steam – Furnace heat in refineries	– Storage in North Sea depleted oil and gas fields
Illustrative				
Main characteristics	– Up to 1,500 kt H_2 per day – H_2 purity of 96% – CCS: 88% capture rate (8 kg CO_2 captured per kg H_2)	– Diameter: 12–28 inches – Operating pressure: about 70 bars	– Power plants: 2x147 MWe H_2 turbines + 2x100 MWe gas/H_2 turbines: 1.9 GW of H_2 – Refinery: H_2-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

A H-vision projects have multiple partners from various industries

H-vision business model overview

4.2 **Business models – Business cases**

Objective
- Reaching a carbon-neutral industry in Rotterdam by 2050

Context
- Industries in Rotterdam port areas consumption of about 400 ktH_2 per year, half of the Netherlands production
- H_2 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 H_2, including power, heat generation, chemicals
  - Development of new production sources for H_2, 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
1. Production	– Production of H_2	– Uniper – Shell – BP – Air Liquide – Gasunie
2. Distribution	– Transportation and storage of blue H_2	– Vopak – Gasunie
3. End use	– Power plant – Refineries – Chemical sites	– Uniper – Shell – BP – ExxonMobile – Air Liquide
4. Evacuation	– Transportation and storage of CO_2	– Vopak – Port of Rotterdam – Gasunie

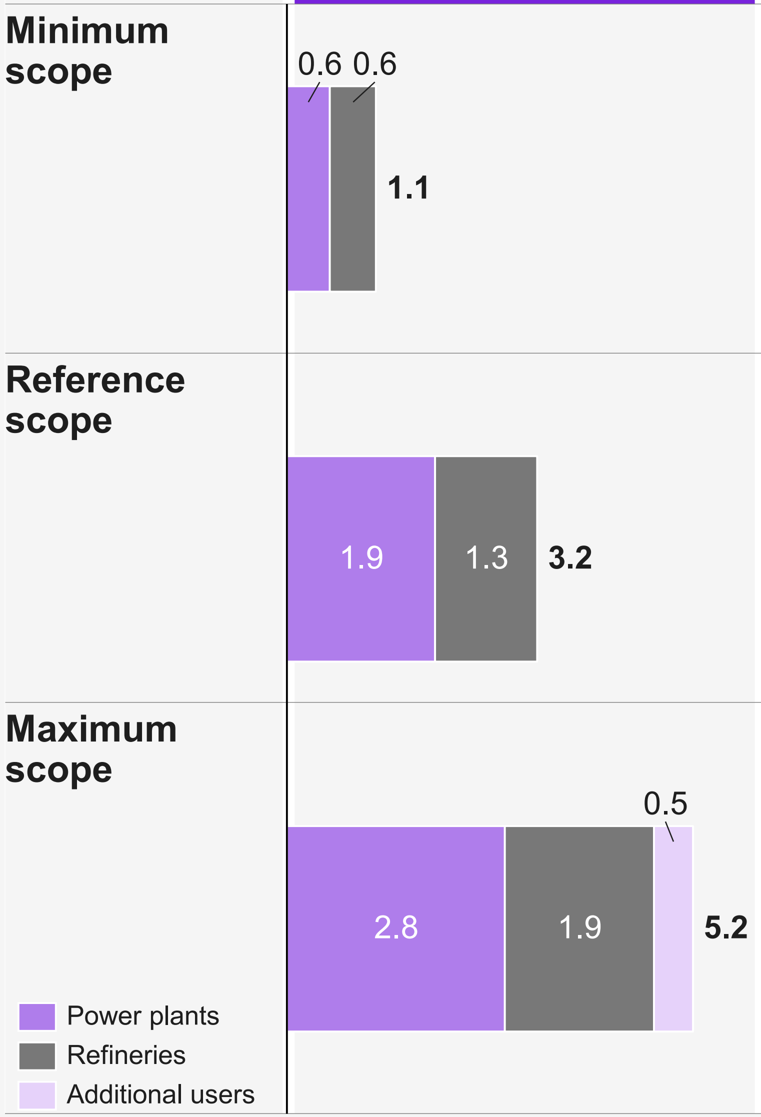
Sources: "Blue Hydrogen as Accelerator and Pioneer for Energy Transition in the Industry," H-vision, July 2019; Kearney Energy Transition Institute analysis

A

Multiple scenarios have been developed with various carbon impacts

H-vision scenarios overview

Hydrogen demand (GW)



	Details
Minimum scope	– 10% hydrogen co-firing in coal power plants – 25% co-firing in natural gas turbines – Adjustments to replace RFG with hydrogen fuel – Replacement of natural gas imported to balance the fuel gas grid (excluding gas turbines)
Reference scope	– 4x147 MWe hydrogen turbines (36.5% efficiency) added – 50% co-firing of hydrogen in natural gas turbines – Maximum adjustments to replace RFG with hydrogen-rich fuel – Replacement of natural gas imported to balance the fuel gas grid, excluding gas turbines
Maximum scope	– 4x147 MWe hydrogen turbines (36.5% efficiency) added – 15% co-firing of hydrogen in power plants or direct firing in boilers – Maximum adjustments to replace RFG in all refineries with hydrogen-rich fuel – Replacement of natural gas imported to balance the fuel gas grid, excluding gas turbines – Additional potential to replace natural gas of other end users

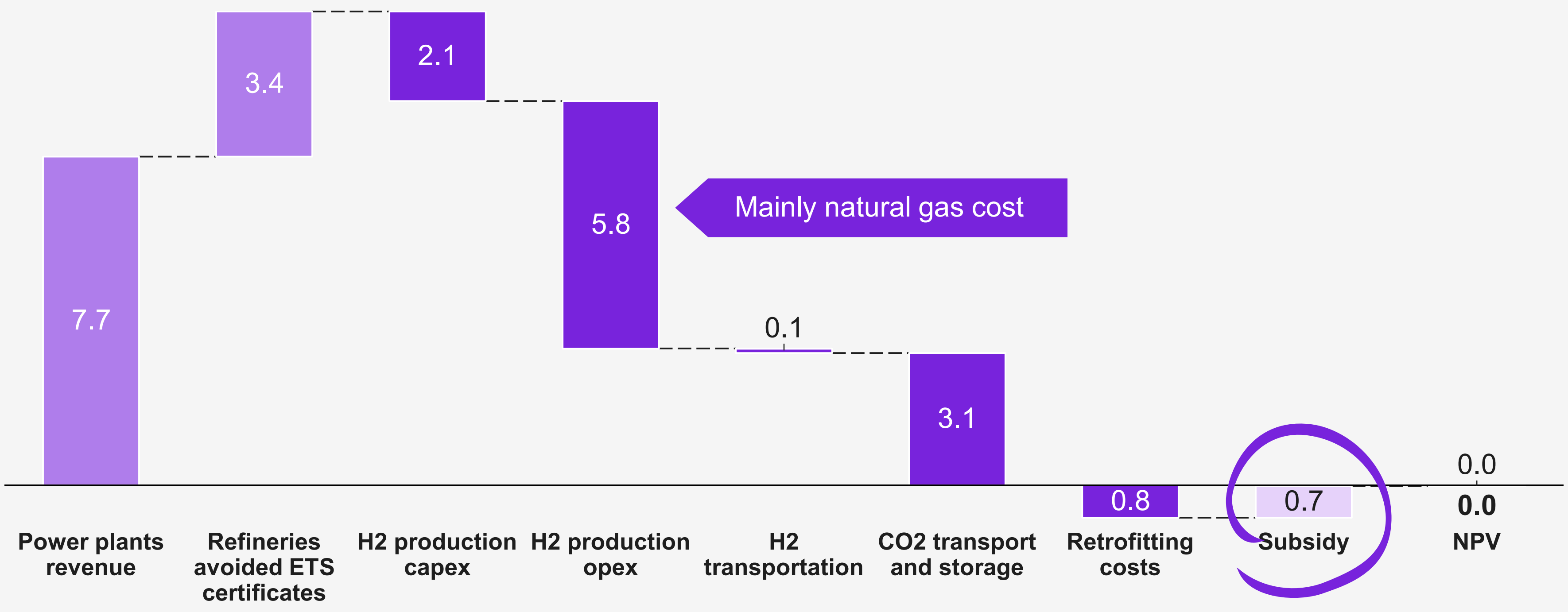
4.2 **Business models – Business cases**

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

A

H-vision project NPV build-up
(€ billion, reference scope, economical world)



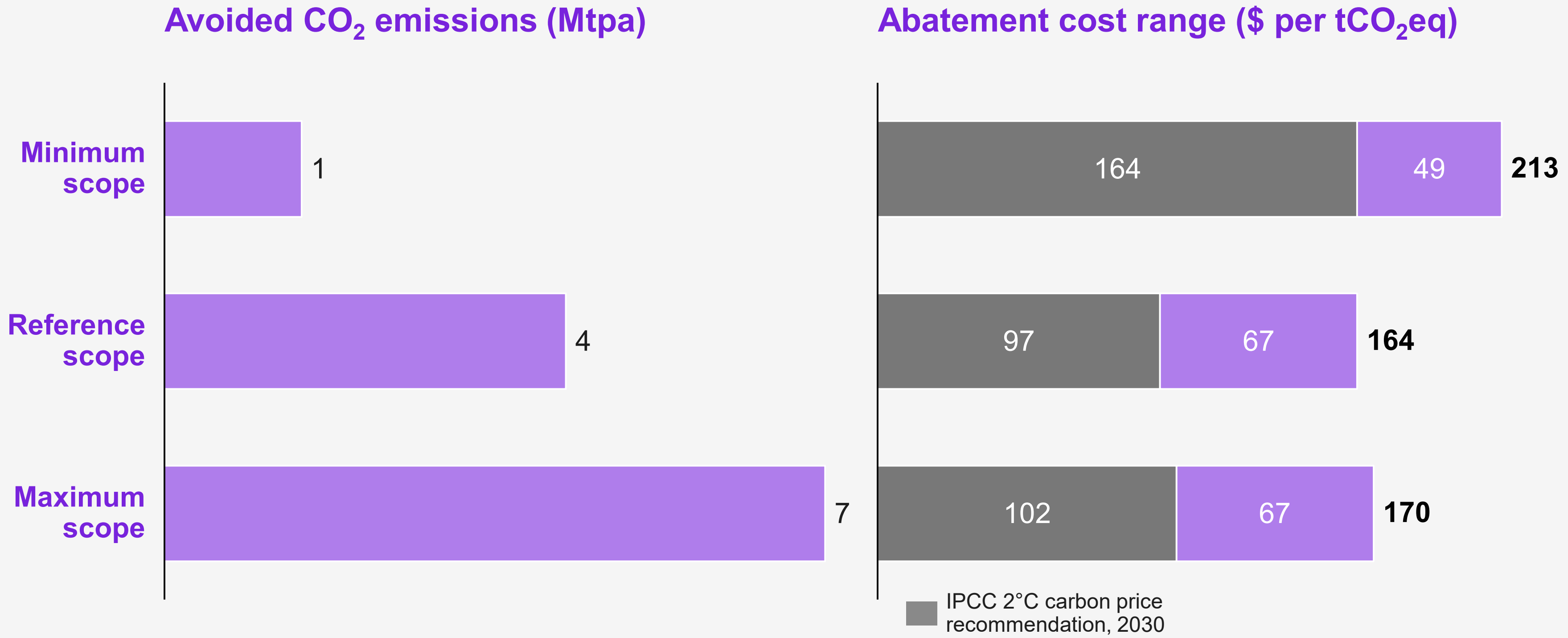
Main hypotheses	
CO_2 emissions price	From €22 per ton in July 2019 to €149 per ton in 2045
Gas price	€34 per MWh
CO_2 captured and stored	About 6 MT per year
Total H_2 demand	3 207 MW, only for power plants and refineries
H_2 storage	No storage
WACC	3%

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 CO_2 over 20 years with an abatement cost of CO_2 \$97 to \$213 per tCO2

CO_2 impact of H-vision
(Avoided CO_2 in Mtpa, abatement cost in \$ per tCO_2)



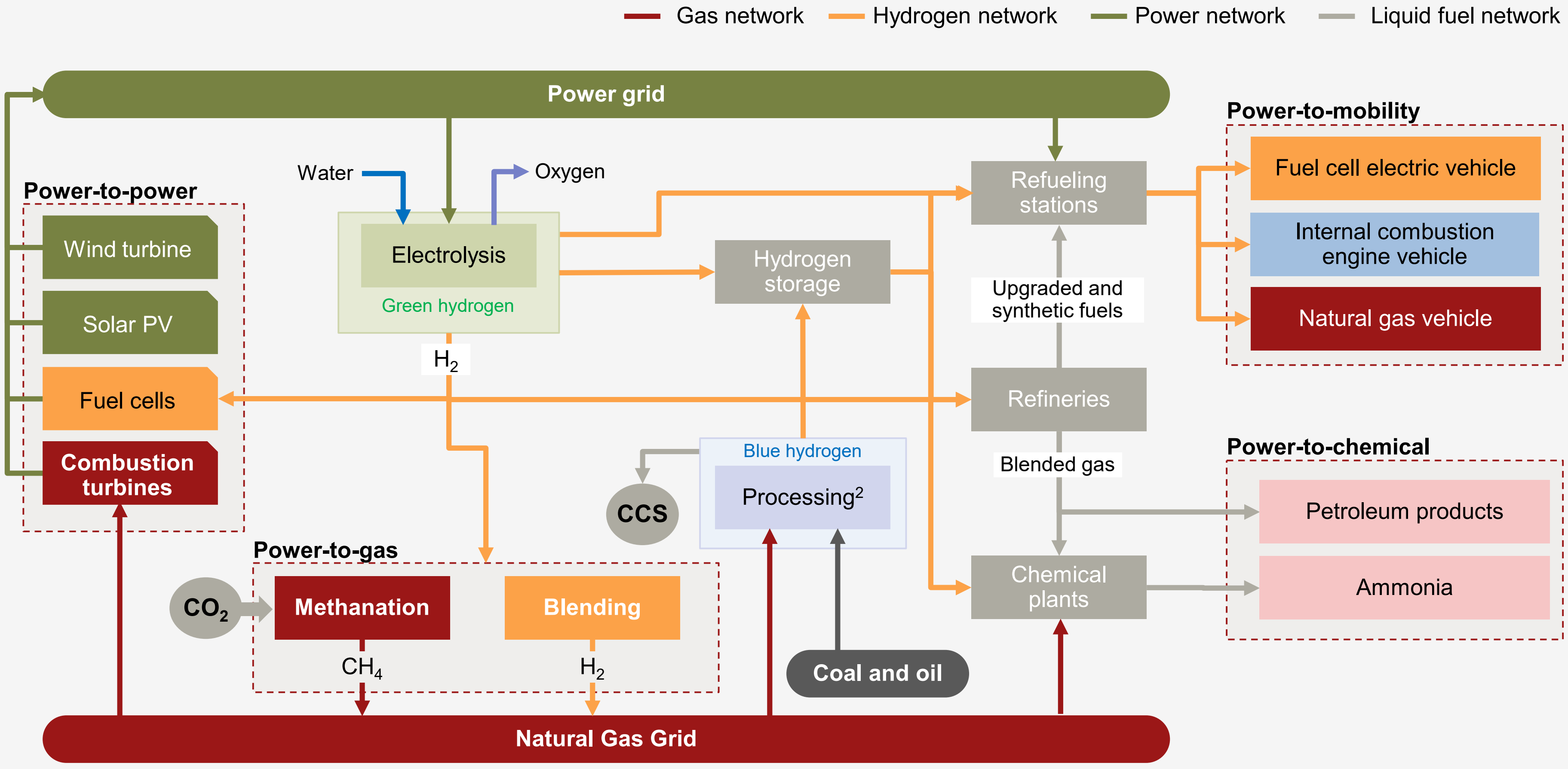
- A CCS unit on the ATR has a capture rate of 88%. Therefore, CO_2 emissions from hydrogen production for refinery use would be cut by 88%.
- For power generation, efficiency losses imply an overall emission reduction rate of about 80%. Natural gas turbines are slightly more efficient, and converting to hydrogen adds an intermediary step with additional losses.

4.2 Business models – Business cases

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

B Power-to-X is the process of converting electricity into hydrogen for additional applications

Simplified value chain of hydrogen-based energy conversion solutions[1]



1 End uses are non-exhaustive.
2 There are several possible options.
Source: Kearney Energy Transition Institute analysis

B **Analyses have been conducted for multiple scenarios, with optimistic assumptions on renewable production sources evolution**

Assumptions used for business cases

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

Configurations			2019	2025f	2030f
Electrolyzer		Size	1 MW	10 MW	100 MW
		Capex	€1,000 per kW	€800 per kW	€450 per kW
		Stack	70,000 hours, 36% capex	80,000 hours, 28% capex	90,000 hours, 28% capex
		Elec. Cons	60 kWh/kg	55 kWh/kg	50 kWh/kg
Grid utilization		Load Factor	90%		
		Elec. Price	$48.60 per MWhe		
		CO_2	475g per kWhe		
VRE average	Wind	Load Factor	34%	35%	36%
		Elec. Price	$56 per MWhe	$45 per MWhe	$31 per MWhe
		CO_2	11g per kWhe		
	Solar	Load Factor	21%	23%	25%
		Elec. Price	$85 per MWhe	$60 per MWhe	$22 per MWhe
		CO_2	42g per kWhe		
VRE and grid	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
		CO_2	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
		CO_2	373g per kWhe	365g per kWhe	354g per kWhe

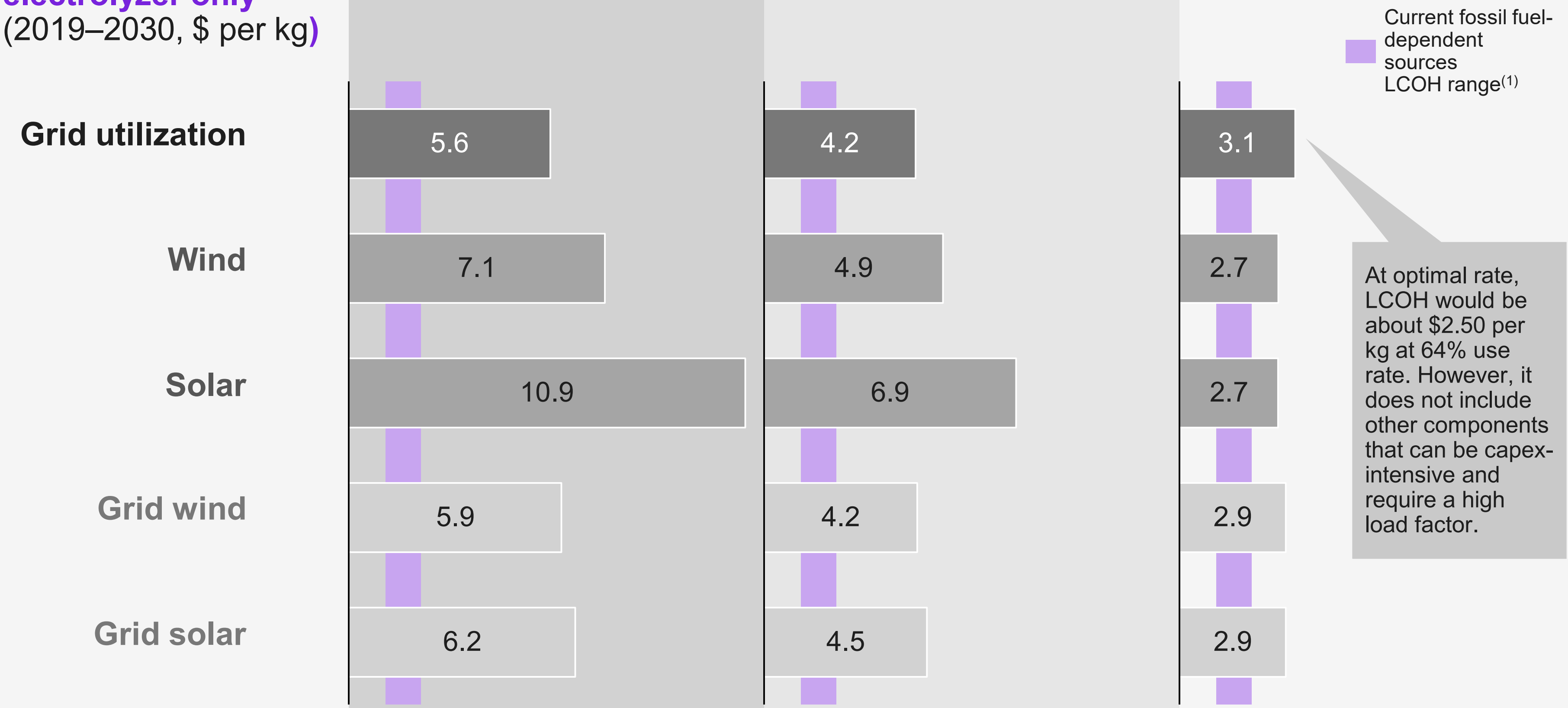
Sources: “The Future of Hydrogen,” International Energy Agency, June 2019; International Renewable Energy Agency; Oxford Institute for Energy Studies; French Environment and Energy Management Agency (ADEME); RTE; expert interviews; Kearney Energy transition Institute analysis

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

H2 electrolysis cost from various power sources

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

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



As of today, the cheapest option is to produce H_2 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 H_2 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 H_2 competitive out of the electrolyzer.

4.2 **Business models – Business cases**

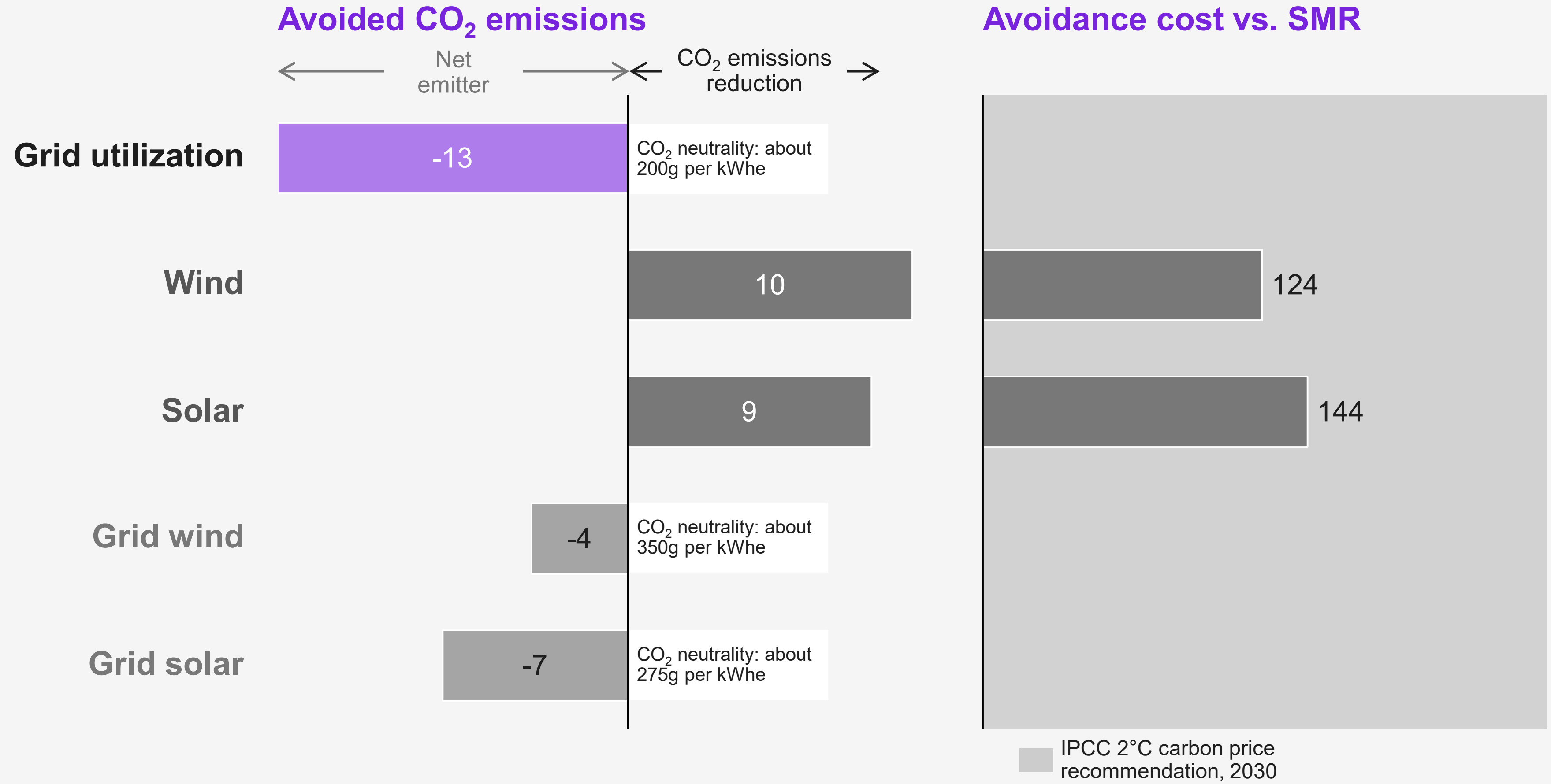
1. Current LCOH of brown hydrogen commonly ranges between 1$/kg to 2$/kg (more details slide 62)
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; GRHYD; International Renewable Energy Agency; Oxford Institute for Energy Studies; French Environment and Energy Management Agency (ADEME); RTE; Kearney Energy transition Institute analysis

B

The carbon footprint from electrolysis would be reduced only if powered by renewable sources, at an abatement cost of \$125 to \$145 per tCO_2

Avoided CO2 and abatement cost vs. SMR

(2030, $kgCO_2/kgH_2$, \$ per tCO_2)



Considering only hydrogen production (excluding additional infrastructure, storage, and consumption end points that might be needed), only electrolyzers powered by renewable would have a positive impact on CO_2 emissions compared with SMR.

As LCOH from electrolysis is expected to decline sharply, green hydrogen could become competitive with SMR if CO_2 prices reach \$124 to \$144 per tCO_2.

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

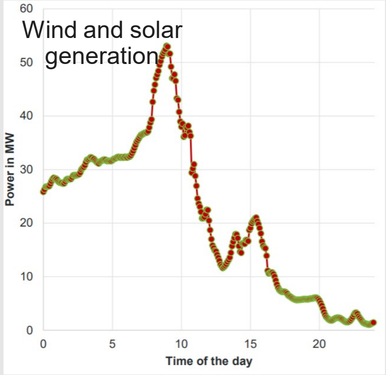
B Electrolyzer could also provide services to the grid to support renewable integration while offsetting variability and improve LCOH

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)



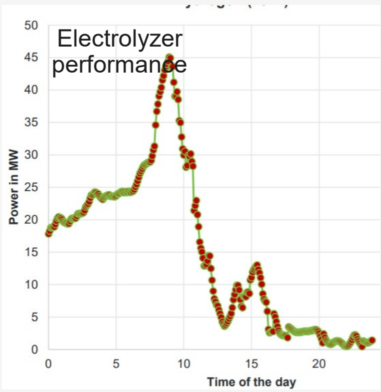
Quick response time and flexibility of PEM

45 MW of electrolyzers with advanced control is considered in the

National Renewable Energy Laboratory 2022 business case

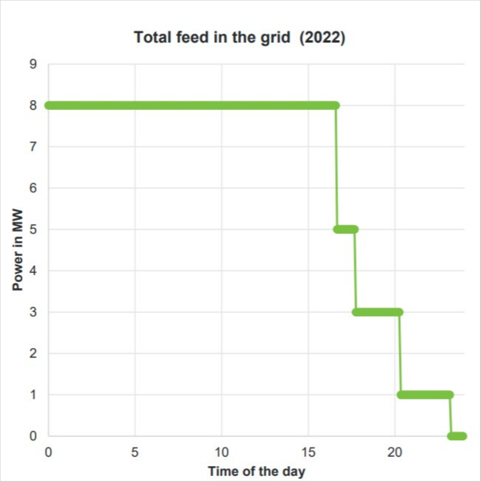
PEM can operate at higher rates than nominal load for a certain period of time without impacting its lifetime, which can provide negative power control to the grid.

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.



Sources: National Renewable Energy Laboratory, adapted from Siemens (2013) and Mansilla et al. (2012); Kearney Energy Transition Institute analysis

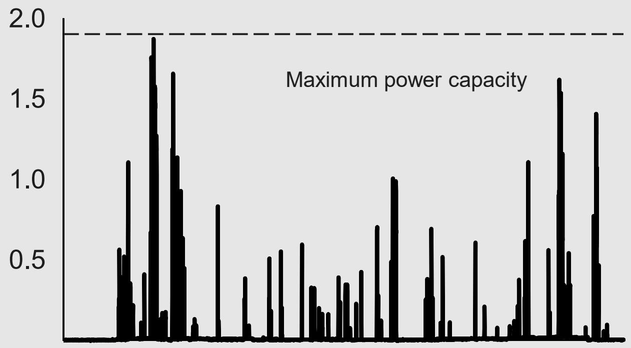
B There is potential for a H_2 producer to monetize this service, which could further reduce LCOH

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.

TAC power output (GW)



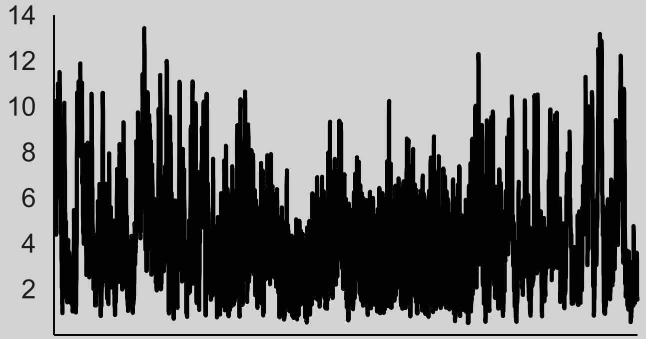
Remuneration system, based on Austria tender prices:
– €10 per MW available per hour
– €120 per MWh delivered

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.

Solar and wind power output (GW)



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

4.2 Business models – Business cases

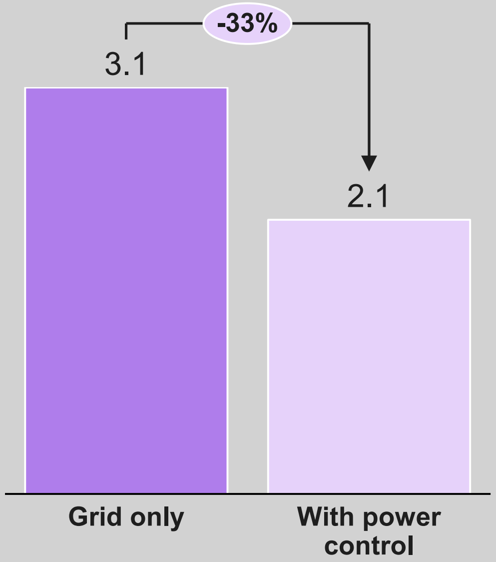
Note: Grid stabilization with electrolysis (2018 example, France)
Sources: National Renewable Energy Laboratory, RTE, Smarten.eu; Kearney Energy Transition Institute analysis

B 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)

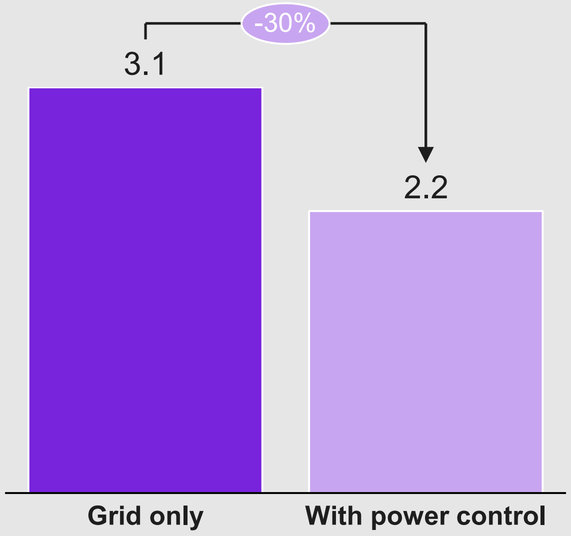
Positive power control

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



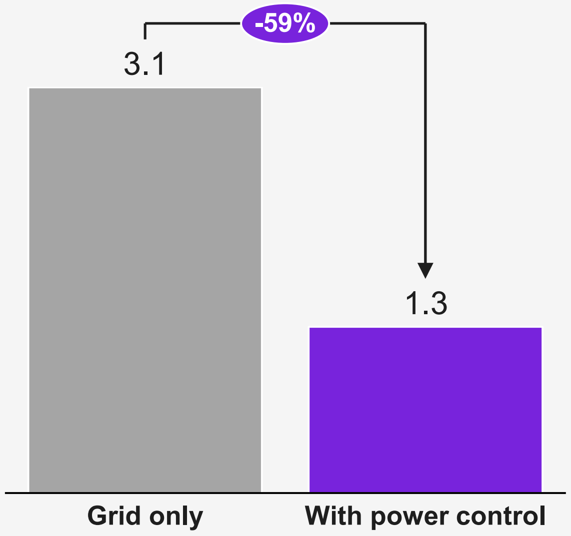
Negative power control

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.

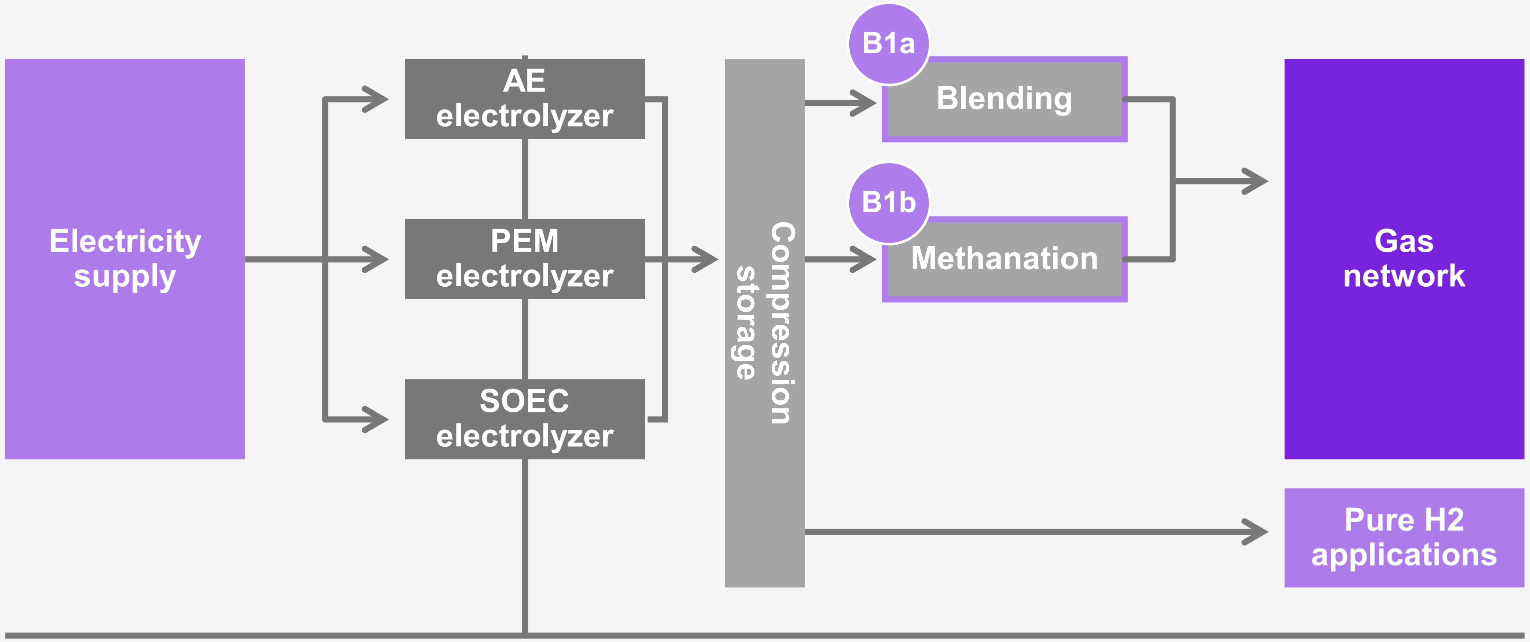
Sources: National Renewable Energy Laboratory, RTE, Smarten.eu; Kearney Energy Transition Institute analysis

B1 Power-to-gas is the process of converting surplus electricity into H_2 through electrolysis for further applications, such as heating and mobility

Power-to-gas: overview

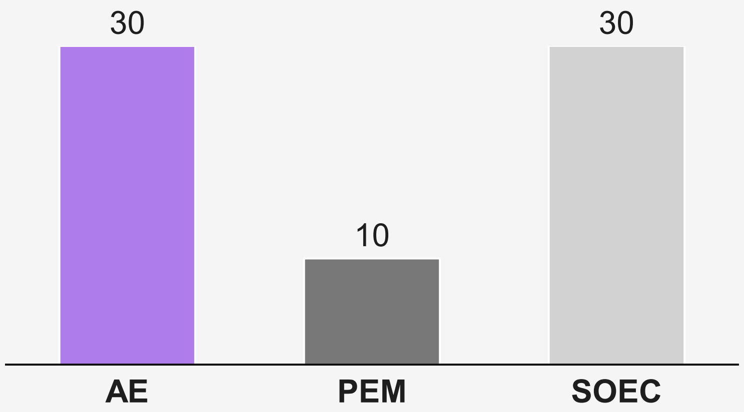
4.2 **Business models – Business cases**

Power-to-gas overview



- 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.

Start-up time per technology (10 MW per minute)



Sources: International Renewable Energy Agency; Kearney Energy transition Institute

B1

P2G has been identified as a tool to enable high penetration of renewable on the electricity grid

Power-to-gas: overview

4.2 **Business models – Business cases**

Key advantages of P2G

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.

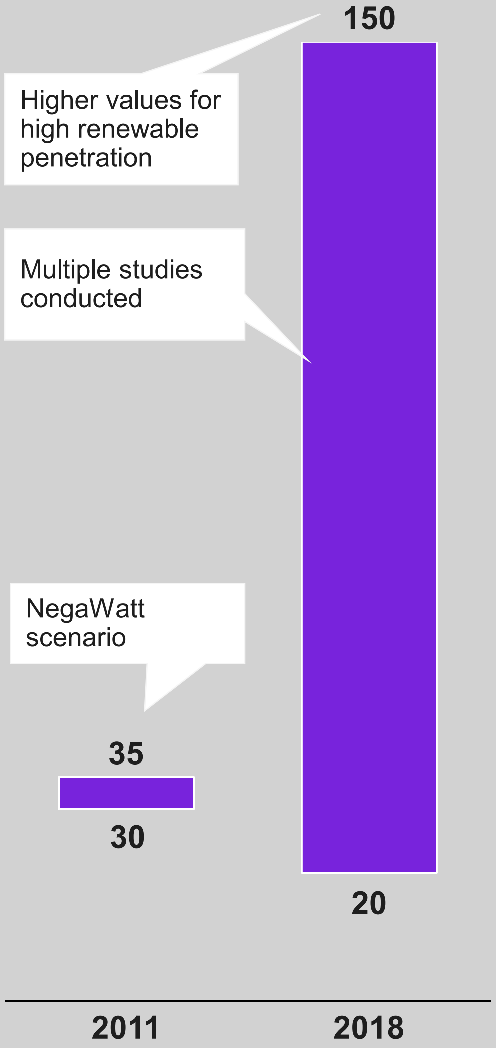
Store at different time scale and transport energy through gas grid

- Existing gas networks are able to store energy, either as H_2 or CH_4 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.

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



Sources: GRDF; Kearney Energy Transition Institute analysis

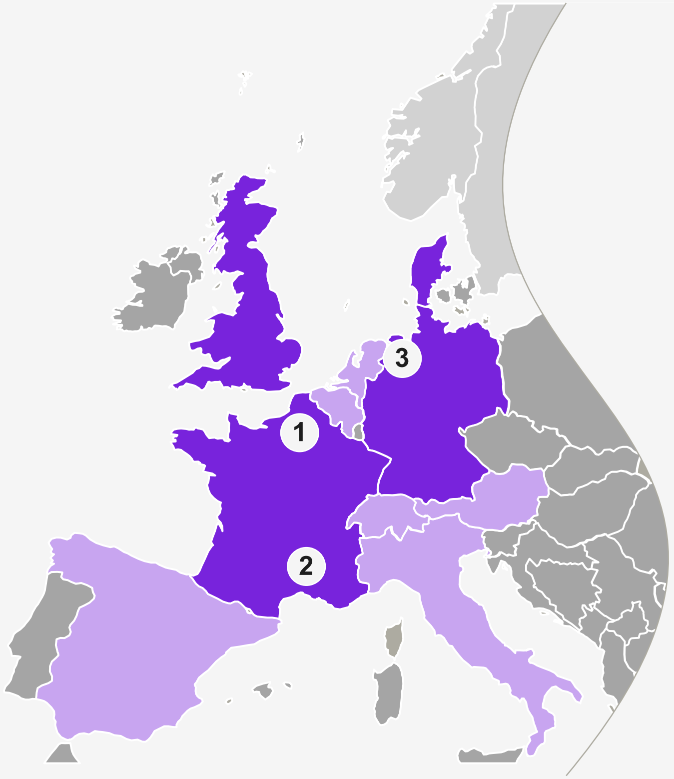
B1 **Multiple projects are being launched to test the viability of the system**

Power-to-gas: overview

4.2 **Business models – Business cases**

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

Non-Exhaustive



1 to 5 P2G projects
More than 5 P2G projects

Project name	Production	Storage and injection	End-use applications	Budget
1 GRHYD	– 50 kW PEM electrolyzer	– Stored in metal hydrides (50 m^3) – Blended with CH_4 before injection (up to 20% H_2)	– Residential district heating – Hythane (H_2 and CH_4 mixed) fuel for city buses	€15 million
2 Jupiter 1000	– 500 kW AE electrolyzer – 500 kW PEM electrolyzer	– Blended with CH_4 before injection (up to 6% H_2) – Methanation, with CO2 injection from CCS plant	– Industrial and residential applications in Fos-sur-Mer district	€30 million
3 Audi e-gas	– 3x 2 MW AE electrolyzers	– Methanation, with CO2 injection from CCS plant	– Synthetic gas used for vehicles fuel	n.a.

As of 2017, 49 P2G projects were launched, 44 of which were in Europe.
Sources: GRHYD, Jupiter 1000, L'Usine Nouvelle, Oxford Institute for Energy Studies, ENEA Consulting; Kearney Energy Transition Institute analysis

B1 The GRHYD project was launched in Dunkirk to inject up to 20% of green H_2 on residential gas network for heating and mobility

Power-to-gas: overview

4.2 **Business models – Business cases**

GRHYD project example

Objective

– Value fatal electricity production from renewable sources through green H_2.

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

Electricity	– Fatal electricity production from VRE	– CEA – Engie – McPhy – AREVA H2GEN – Dunkerque Grand Littoral – INERIS
Electrolysis	– PEM electrolyzer producing H_2 and O_2 (released)	
Storage	– Storage in metal hydrides	
Injection	– Blending up to 20% – Injection of mixed gas (hythane[1]) on gas network	– GRDF – CETIAT
End use	– Heating for new residential buildings – Fuel for Hydrogen buses	– Engie – DK Bus

1 Hydrogen and methane
Sources: GRHYD; Kearney Energy Transition Institute analysis

B1a

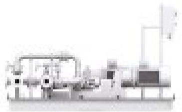
Production of H_2 and injection on gas network systems (blending) include electricity generation, electrolyzer, and injection station

Power-to-gas: blending business case

4.2 Business models – Business cases

P2G: injection value chain

Illustrative



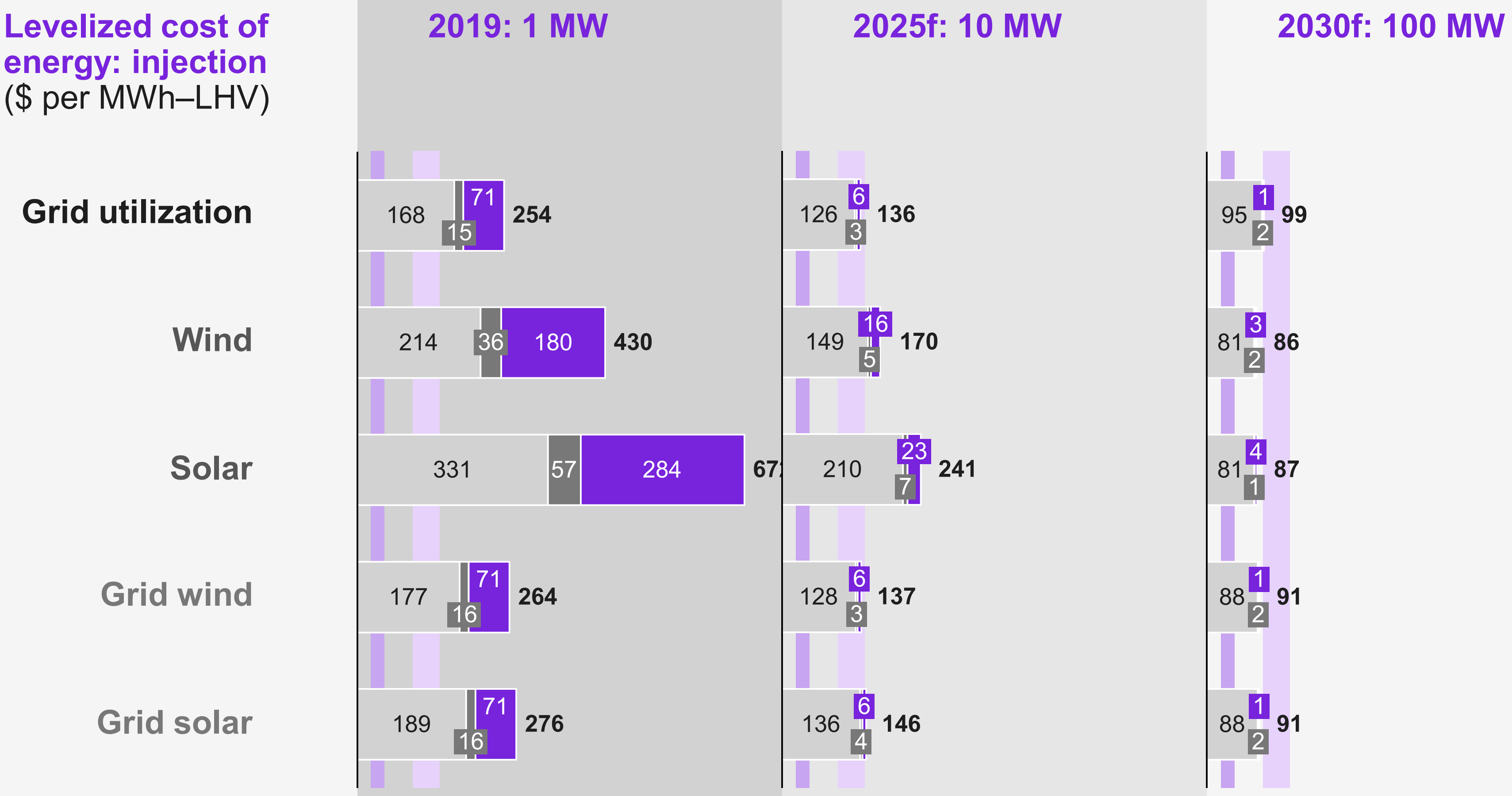
	Grid connection and infrastructure		Electrolyzer	Injection station	
Year	2019: 1 MW	2030f: 100 MW		2019: 1 MW	2030f: 100 MW
Capex ($ million)	Transformer: $0.013 Line: $0.112 Pipeline: $0.3		All hypotheses are described in slide 134 (more details slides 65 to 69)	1.46	3.10
OPEX (% capex)	Electrification: 0% Pipeline: 2%			8%	8%
Electricity required (% losses)	3% (losses)	3% (losses)		–	–

Sources: expert interviews; Kearney Energy Transition Institute

B1a The levelized cost of energy (blending) could go down to \$86 to \$99 per MWh by 2030, making it competitive with biomass gas

Power-to-gas: blending business case

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



Injection plant
Infrastructure
Electrolysis

Current natural gas price range[1]
Current biogas price range[2]

2019: 1 MW
- 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.

2025f: 10 MW
- As production grows, capex for infrastructure and injection plant is amortized faster.
- Production from grid electricity is now competitive with biomass but may have CO_2 impact.

2030f: 100 MW
- By 2030, gas injection on the grid would be competitive with biogas.

1. Current natural gas price range: 25-50 \$/MWh; 2. Current biogas price range 100-150\$/MWh
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; International Renewable Energy Agency; Kearney Energy Transition Institute analysis

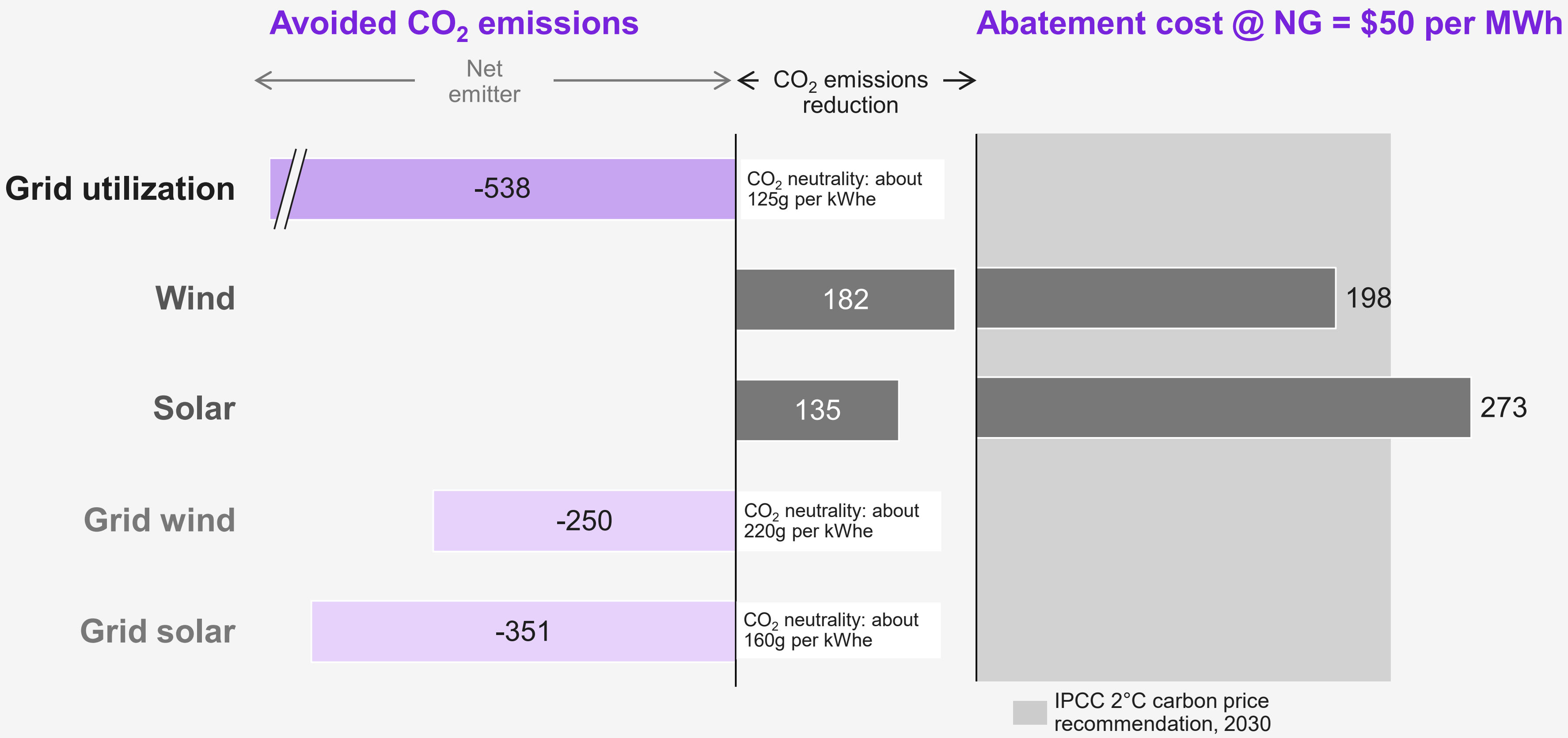
B1a

Only injection plants connected to REN without grid back-up would help reduce CO_2 emissions at a cost of \$200 to \$270 per tCO_2

Power-to-gas: blending business case

4.2 **Business models – Business cases**

Avoided CO_2 and abatement cost (2030, $kgCO_2/kgH_2$, \$ per tCO_2)



- Natural gas emissions in combustion are around 200 kg per MWh.
- On average, if electrolyzer is connected to the grid to ensure a 90% service rate, P2G Injection systems will be net emitters of CO_2.
- However, when purely coupled with renewables, 130 to 180 kg of CO_2 per MWh LHV could be avoided.

- The carbon abatement cost from wind powered electrolysis and H_2 injection through P2G system would be in line with the IPCC recommendations on carbon price upper limit (\$220 per tCO_2).
- 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.

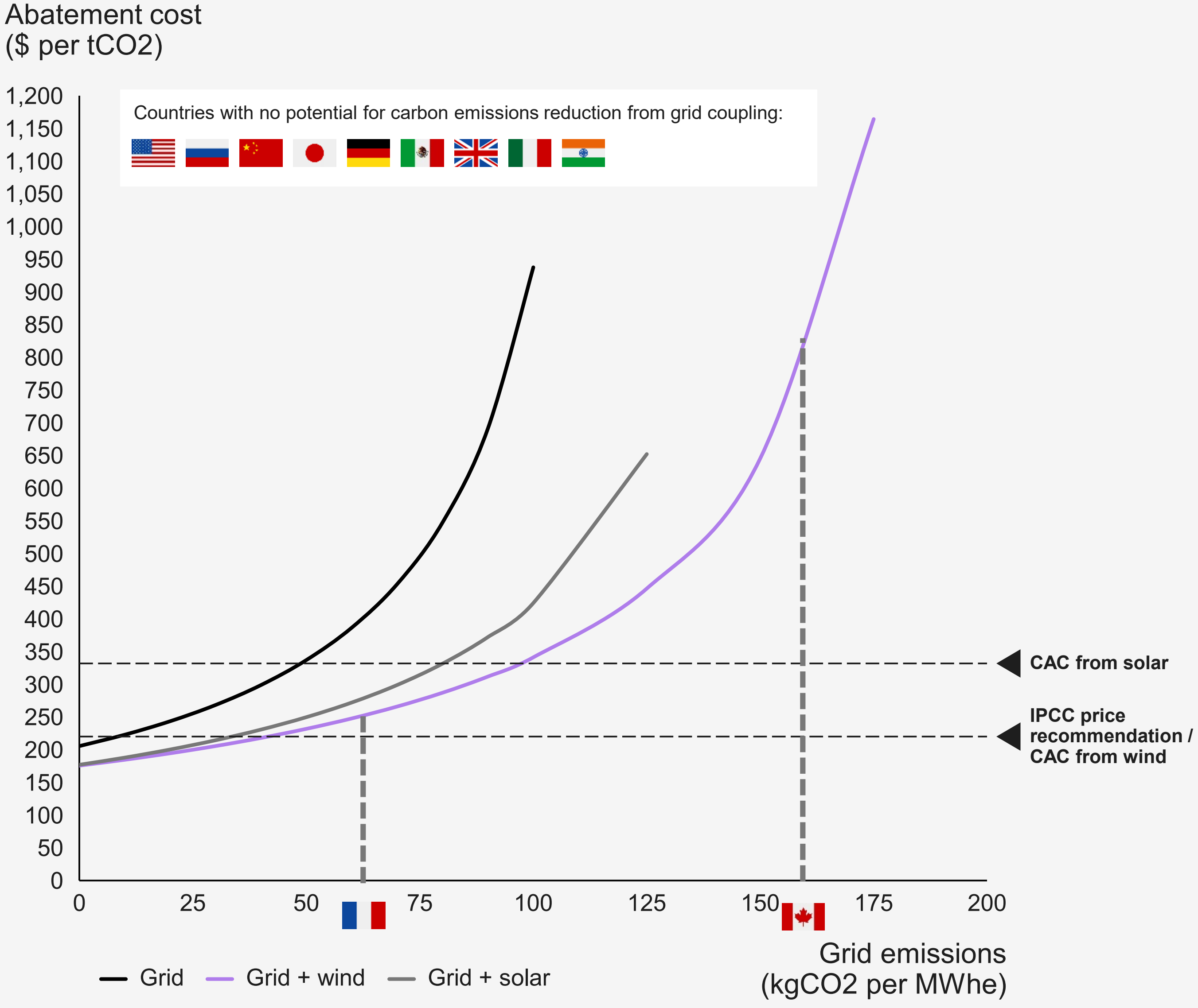
Notes: The hypothesis is detailed in the appendix. CO2 neutrality is defined as the maximum CO2 footprint from the power sector to reach carbon neutrality between natural gas and injection.
Sources: Intergovernmental Panel on Climate Change; Kearney Energy Transition Institute analysis

B1a

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

Power-to-gas: blending business case

CAC vs. CO_2 emissions from electricity generation (2030)



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

Heading

- For most countries, as the CO_2 intensity of the power sector is above 200g per kWhe (LHV of natural gas), the injection of H_2 from the grid would generate more CO_2 emissions.
- Among the top 10 OECD natural gas consumers, only Canada could reduce its CO_2 emissions with injection and grid + wind coupling, but at a higher cost than wind or solar only.
- In countries with a low carbon intensity in the power sector, such as France, Switzerland, or Norway, which are not top natural gas consumers, could reduce their CO_2 emissions from natural gas at a cost of between \$180 and \$400 per ton of CO_2.

B1a

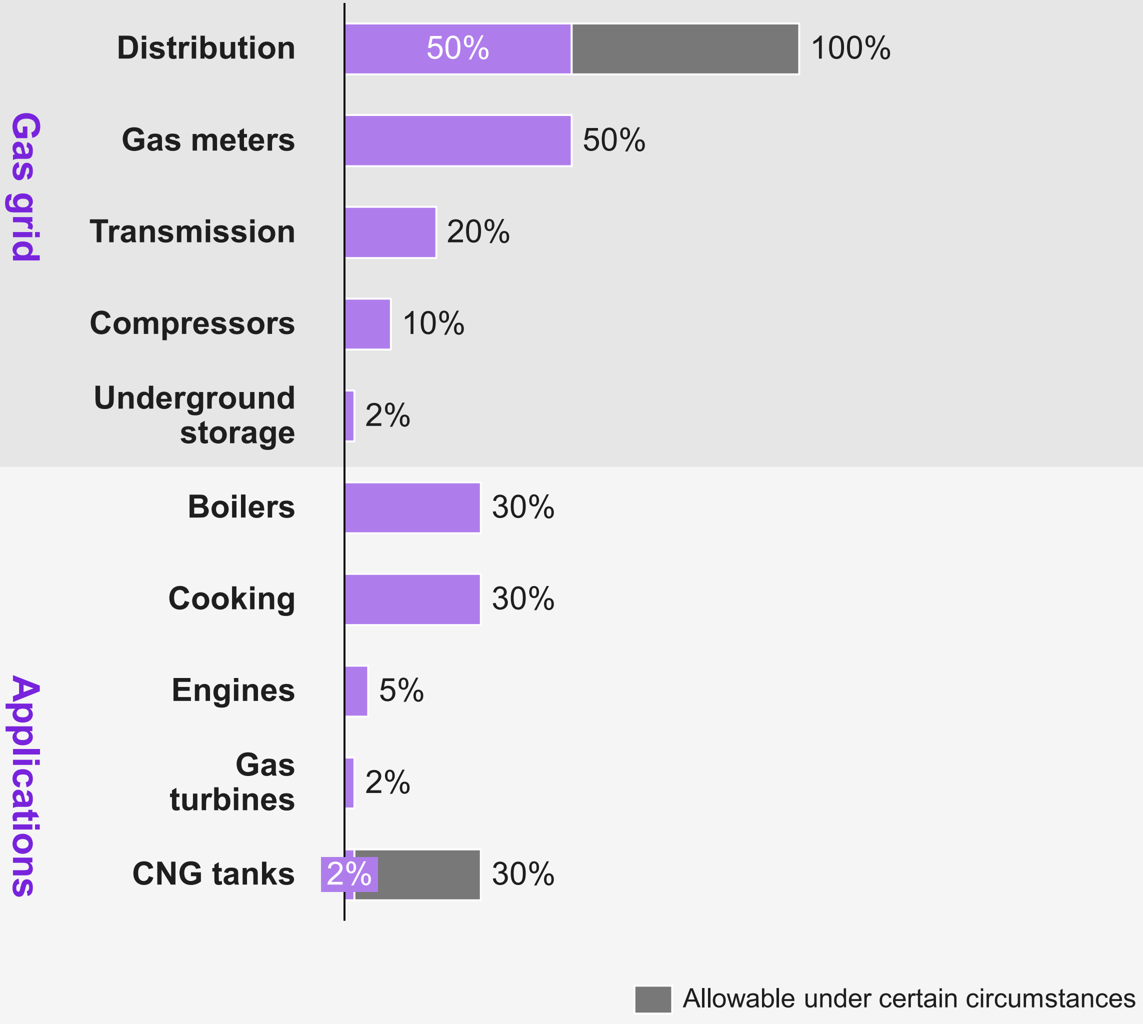
The hydrogen injection potential is limited in volume by end applications for safety and performance reasons

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

4.2 **Business models – Business cases**

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

Tolerance of selected elements



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

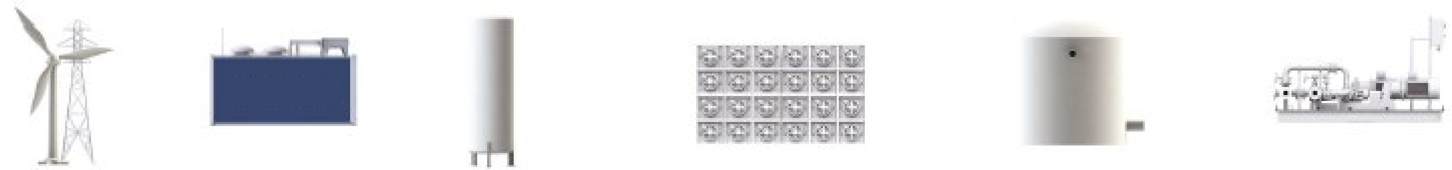
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

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

Power-to-gas: methanation business case

P2G: methanation value chain

Illustrative



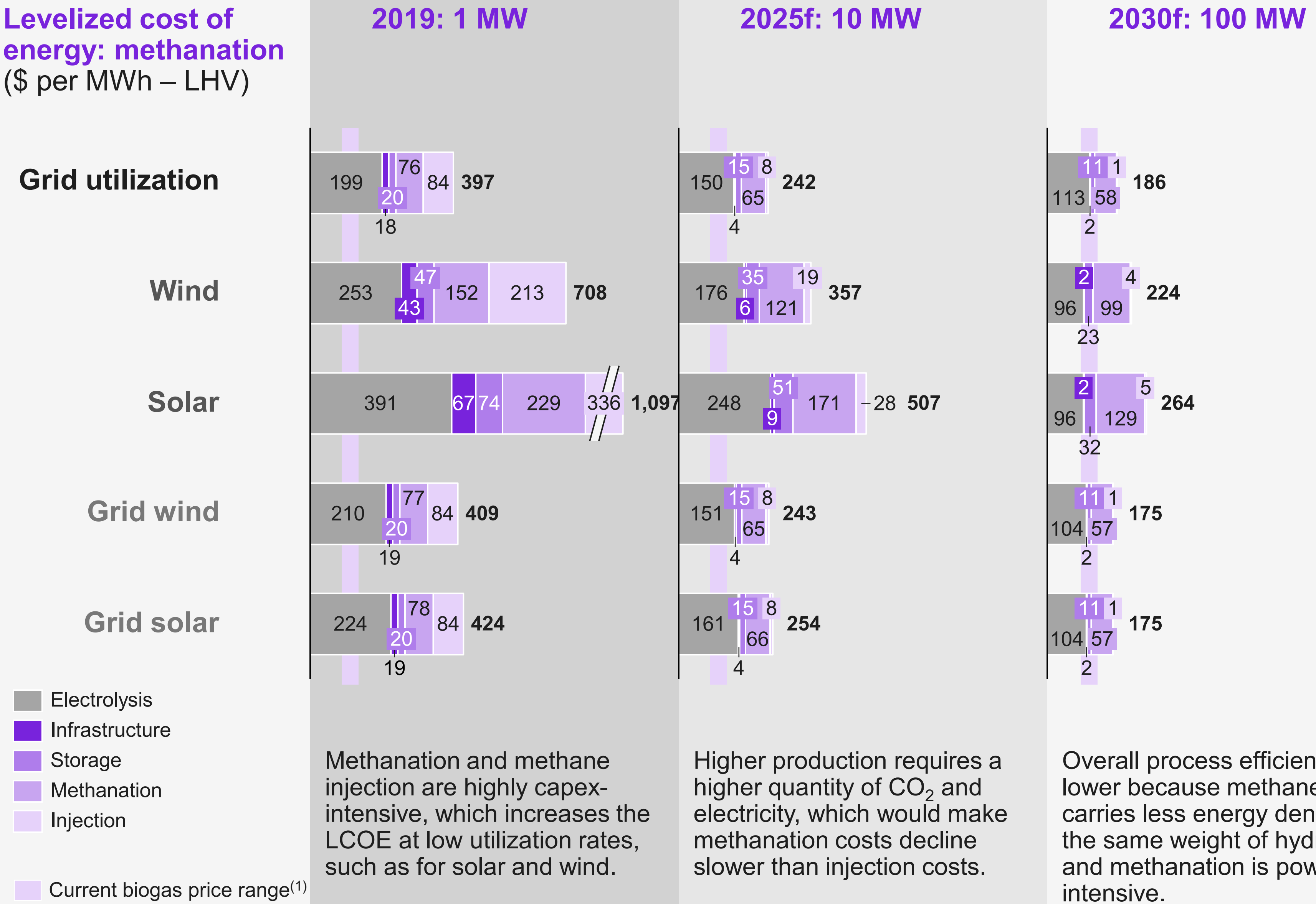
	Grid connection and infrastructure		Electro-lyzer	LP storage (60 bars)		CO_2 capture and storage		Methanation reactor		Injection station	
Year	1 MW	100 MW	All hypotheses are described in slide 107.	1 MW	100 MW	1 MW	100 MW	1 MW	100 MW	1 MW	100 MW
Capacity (tH2/m³ per year)	-	-		0.78 t H_2 2 days	94 t H_2 2 days	-	-	400,000 m³ per year	54 million m³ per year	-	-
Capex ($ million)	Transfer: $0.013 Line: $0.112 Pipeline: $0.3			$0.53	$31.8	-	-	$0.9	$76.7	1.46	3.10
OPEX (% capex/$ million per year)	Electrification: 0% Pipeline: 2%			$0.01	$1.2	-	-	8%	8%	8%	8%
Electricity required (% losses per kWh)	3% (losses)			-	-	0.88 kWh/kWh$_{CH4}$	0.88 kWh/kWh$_{CH4}$	0.21 kWh/kWh$_{CH4}$	0.21 kWh/kWh$_{CH4}$	-	-
CO2 cost[1] ($ per ton)	-	-		-	-	$76	$71			-	-

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

B1b 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

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



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 CO_2 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.

4.2 Business models – Business cases

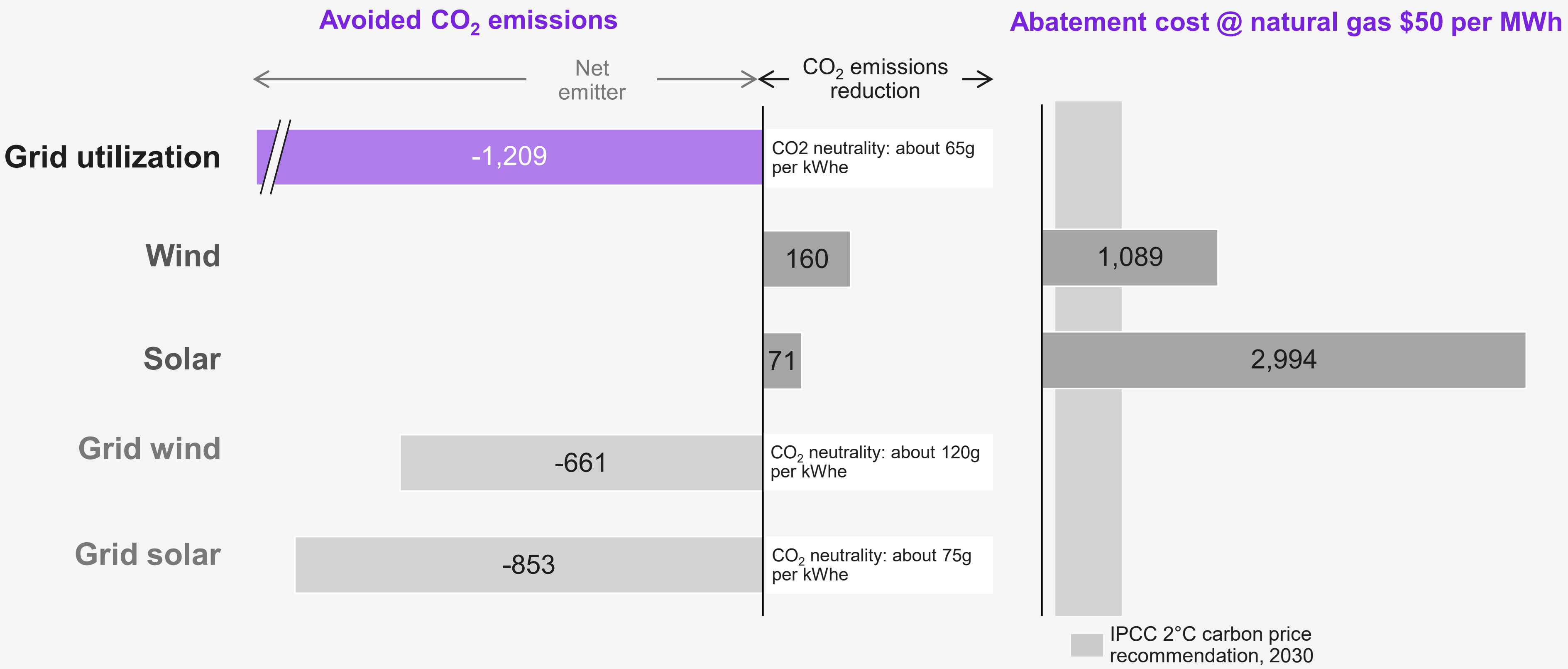
1. Current biogas price range: 100-150$/MWh

Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; International Renewable Energy Agency; ENEA Consulting; Kearney Energy Transition Institute analysis

B1b The carbon cost would need to be priced at \$1,100 to \$3,000 per tCO_2 to make a methanation solution competitive with natural gas prices

Power-to-gas: methanation business case

Avoided CO_2 and abatement cost (2030, $kgCO_2$ per MWh, \$ per tCO_2)



- Natural gas emissions in combustion are around 200 kg per MWh.
- With a low-carbon electrical mix, CO_2 emissions are always below when hydrogen is produced, even if connected to the electrical grid.
  - If CO_2 emissions for electricity production are above 65 g per kWh, hydrogen from grid would be a net emitter.

- Wind-powered electrolysis and methanation could be competitive with methane if CO_2 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.

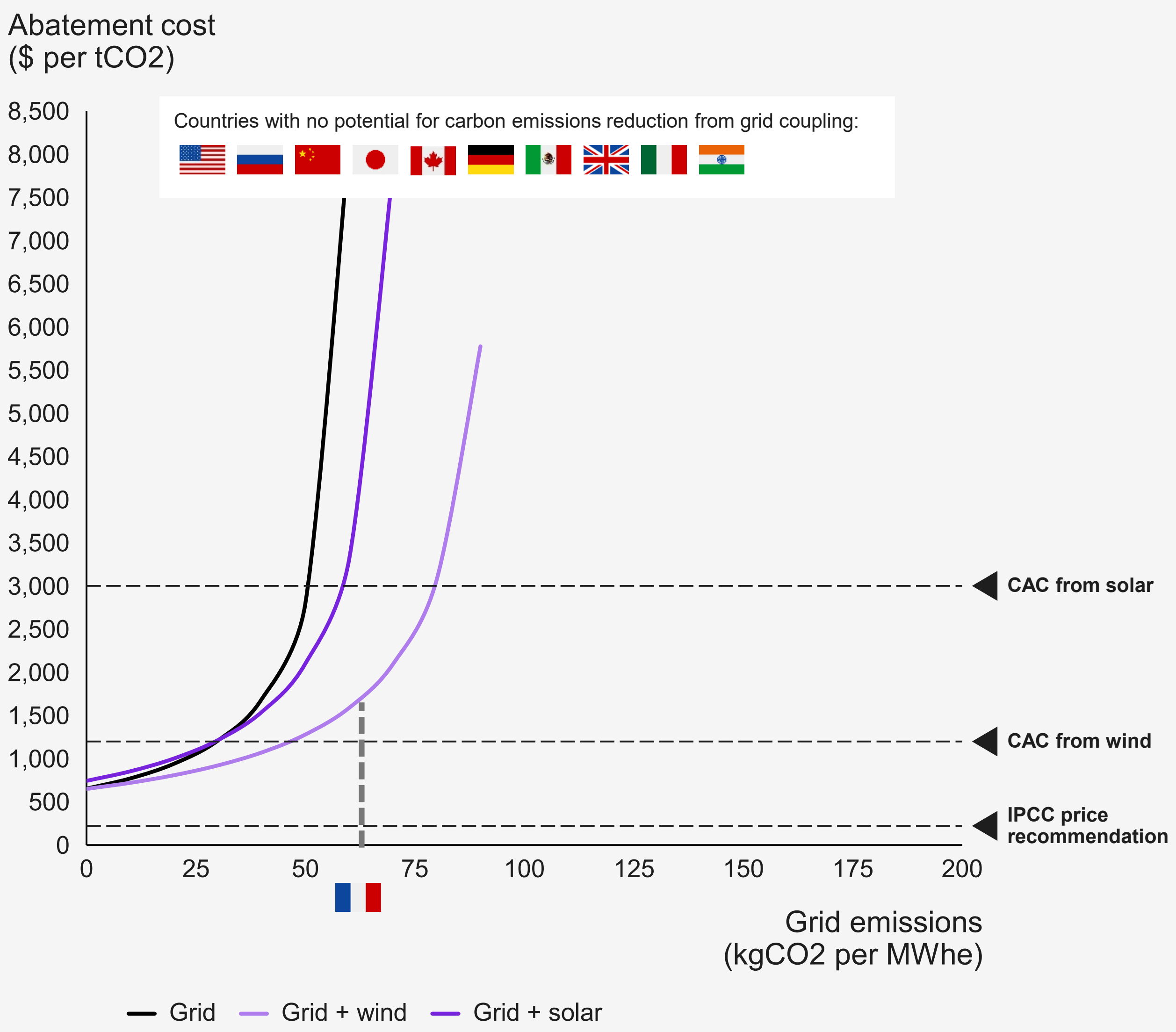
Note: Hypothesis detailed in the appendix. CO2 neutrality is defined as the maximum CO2 footprint from the power sector to reach carbon neutrality between SMR and electrolysis.
Sources: Intergovernmental Panel on Climate Change; Kearney Energy Transition Institute analysis

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

Power-to-gas: methanation business case

4.2 **Business models – Business cases**

CAC vs. CO_2 emissions from electricity generation (2030)



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

Heading

- For most countries, because the CO_2 intensity of the power sector is above 200g per kWhe (LHV of natural gas), methanation of H2 from the grid would generate more CO_2 emissions.
- Because methanation is power intensive, a carbon intensity below 120 g per kWh is required to reduce CO_2 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 kWhe would benefit from connecting the electrolyzer to the grid.

B2

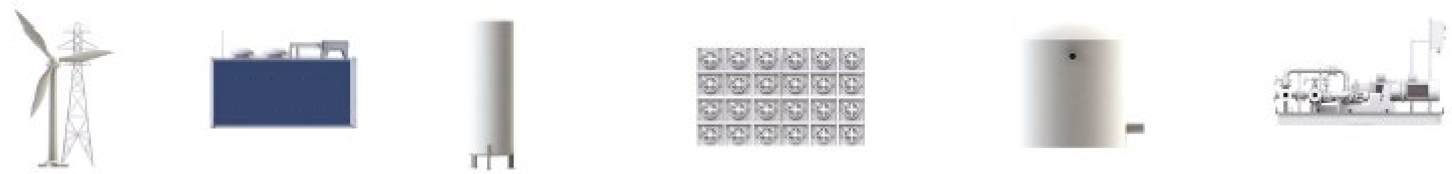
Power-to-power requires high-pressure storage to feed the fuel cell for electricity generation

P2P: Energy Storage System business case

P2P value chain

Illustrative

	Grid connection and infrastructure		Electro-lyzer	LP storage (60 bars)		Compression		HP storage (900 bars)		Stationary fuel cell	
Year	1 MW	100 MW	All hypotheses are described in slide 107.	1 MW	100 MW	1 MW	100 MW	1 MW	100 MW	1 MW	100 MW
Capacity (tH2 per MW)	-	-		0.78 t H_2 2 days	94 t H_2 2 days	-	-	16 kg H_2 1 hour	2 t H_2 1 hour	1 MW	100 MW
Capex ($ million)	Transfer: $0.013 Line: $0.112 Pipeline: $0.3			$0.53	$31.8	0.3	17.6	$0.045	$3.4	$1.1	$50.6
Opex (% capex/$ million per year)	Electrification: 0% Pipeline: 2%			$0.01 million	$1.2 million	6%	6%	$0.01 million	$0.9 million	4%	2%
Electricity required (% losses per kWh)	3% (*losses*)			-	-	8.3 kWh/kg	3.0 kWh/kg	-	-		
Efficiency (%)	-	-								65%	70%



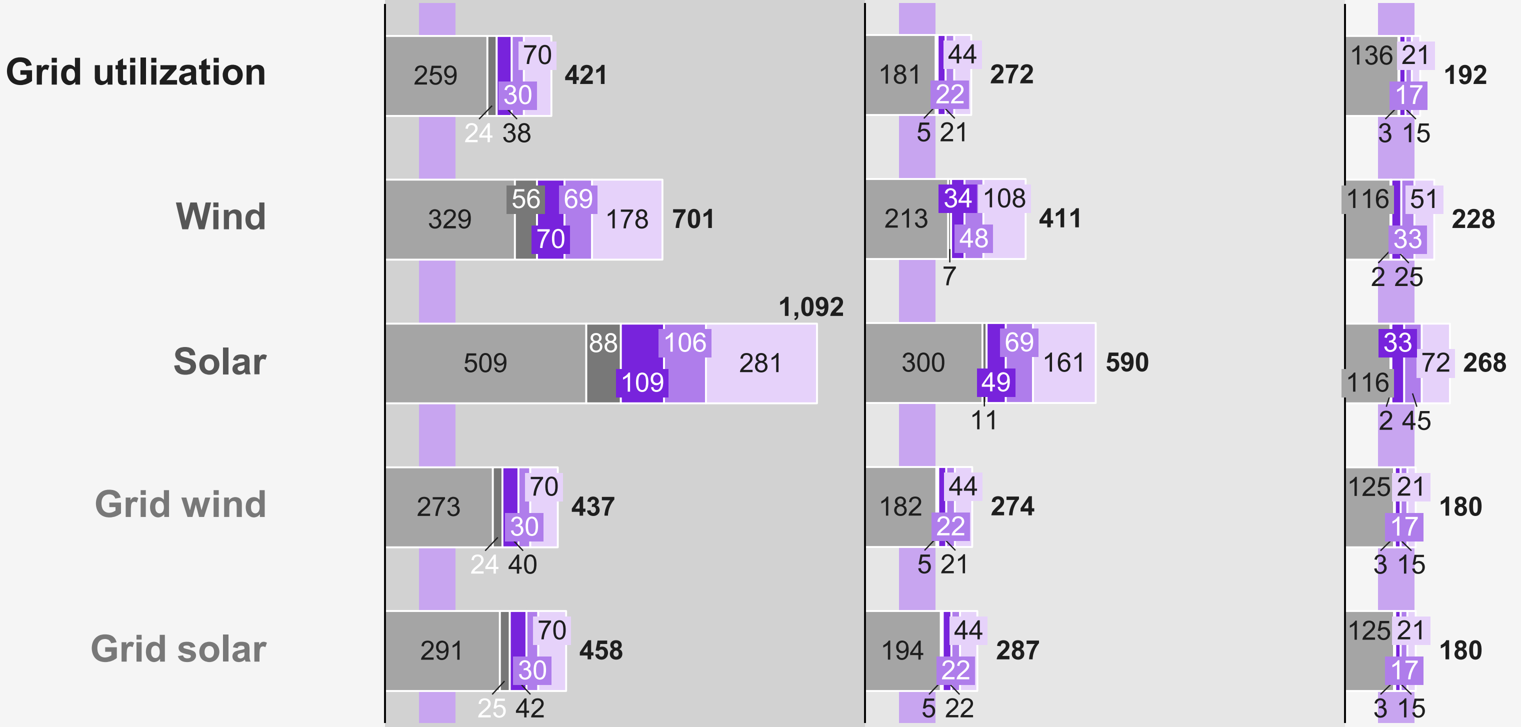
Sources: ENEA Consulting; ITM Power; "The Future of Hydrogen," International Energy Agency, June 2019; expert interviews; Kearney Energy Transition Institute analysis

B2 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

Levelized cost of energy: Power
($ per MWhe)

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



- Fuel Cell
- Storage (LP & HP)
- Compression
- Infrastructure
- Electrolysis

Current ESS battery price range

– 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 H_2 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.

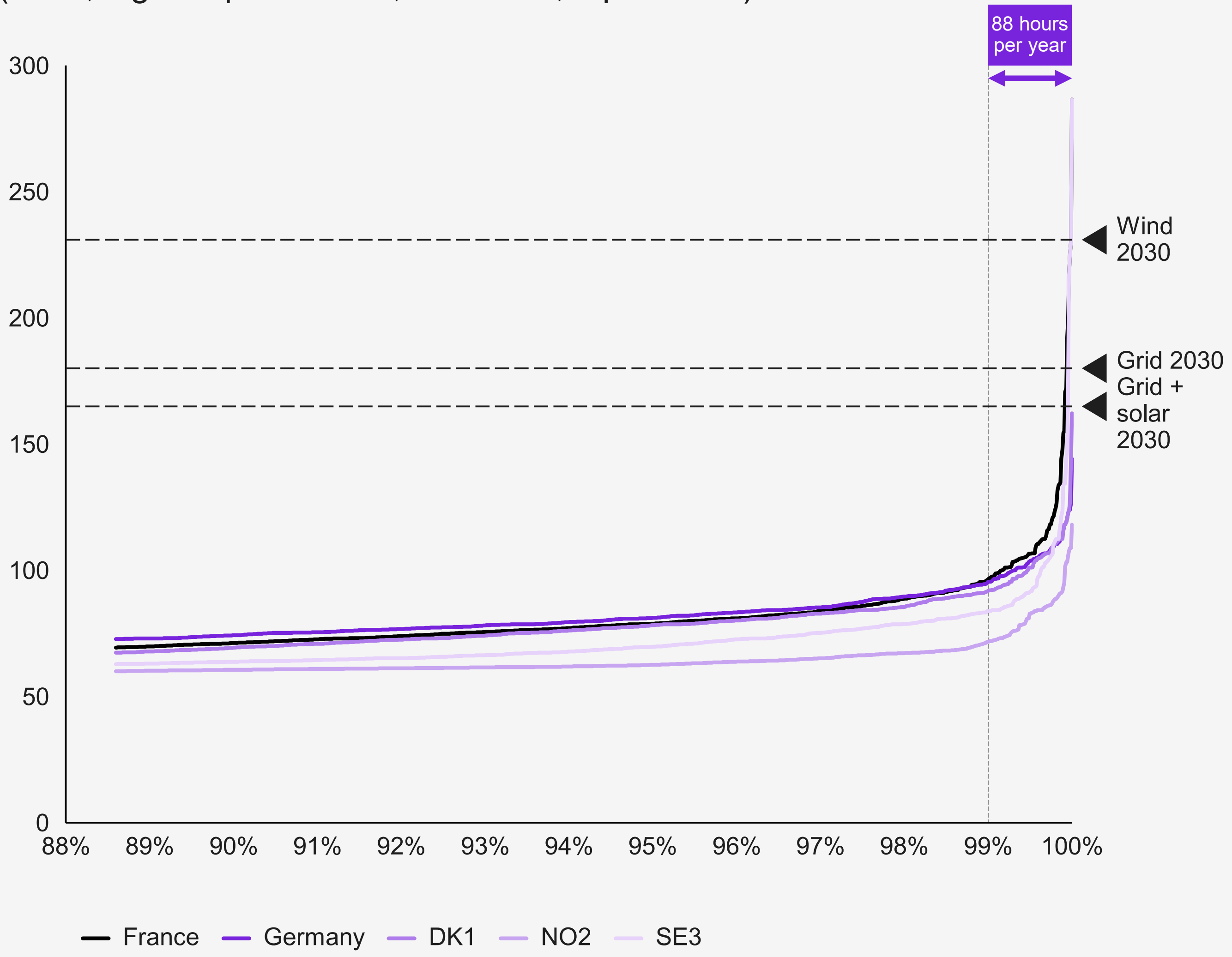
1. Current ESS battery price range: 100-200 $/MWh
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; International Renewable Energy Agency; Lazard; Kearney Energy Transition Institute analysis

B2 **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

EPEX spot prices: selected countries

(2018, highest prices on 1,000 hours, $ per MWh)



Sources: Energi Data Service; European Network of Transmission System Operators; "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; International Renewable Energy Agency; Kearney Energy Transition Institute analysis

Heading

- 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.

B2

Converting coal turbines to P2P systems coupled with renewable could save 800 gCO_2 per kWh at a cost of $100 to 1,200 per tCO_2

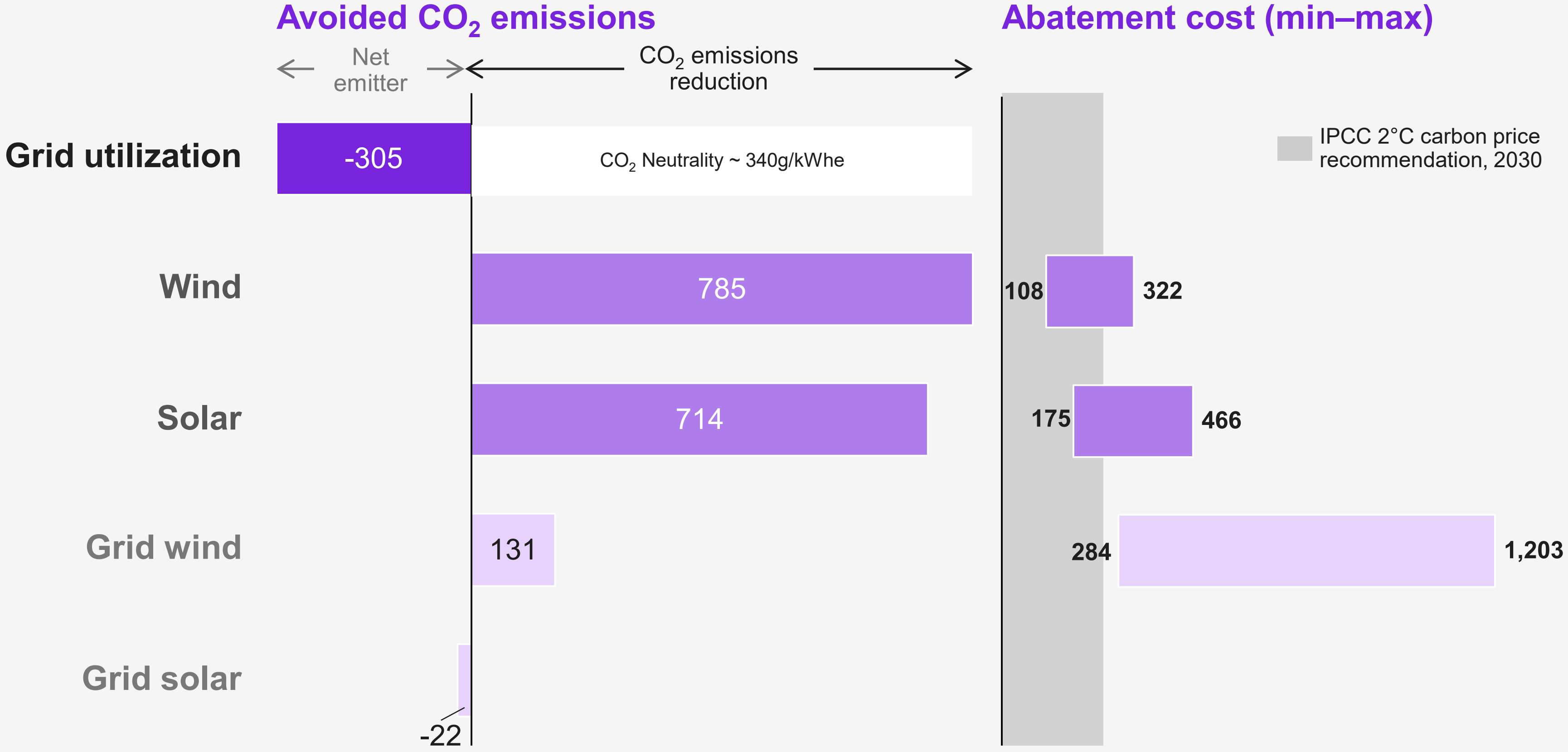
P2P: Energy Storage System business case

4.2 **Business models – Business cases**

Avoided CO_2 and abatement cost vs. coal turbines

(2030, kgCO2/MWh, $ per tCO_2)

Illustrative



- Coal turbines are among the highest polluting electricity sources, with about 820gCO_2 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 H_2 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 plant to P2P H_2 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.

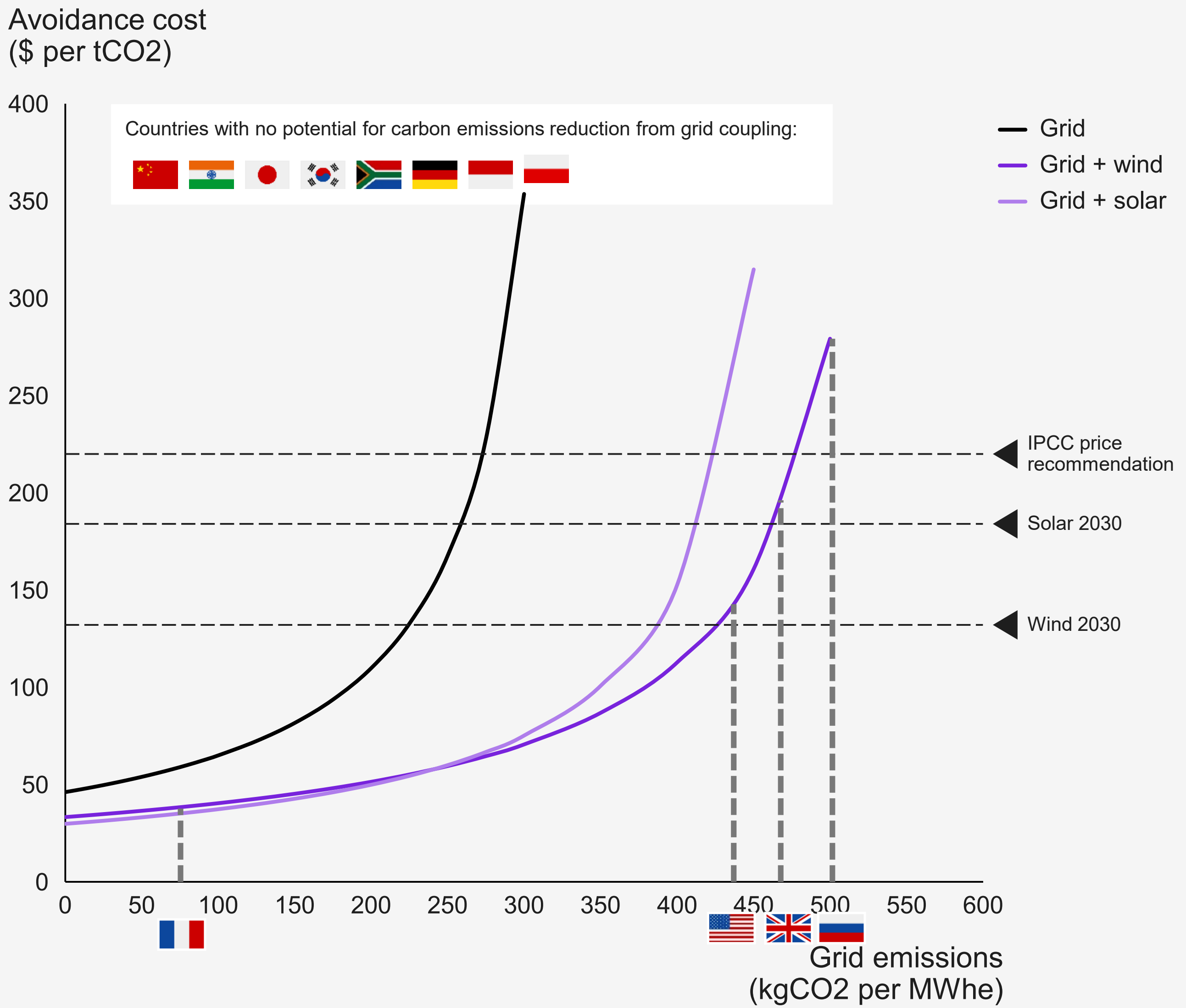
Note: CO_2 neutrality is defined as the maximum CO_2 footprint from the power sector to reach carbon neutrality between coal turbine and P2P solution.
Sources: Bilan Electrique 2018; RTE; Lazard; International Energy Agency; Kearney Energy Transition Institute analysis

B2 The top coal consumers would not reduce CO_2 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**

CAC vs. CO_2 emissions from electricity gen. (2030)



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

Heading

- P2P systems connected to the grid and REN could save CO_2 emissions from coal turbines if CO_2 intensity from power sector does not exceed 500g (grid + wind case).
- For top coal consumer countries, coupling electrolyzer with the grid would not allow for reducing CO_2 emissions, except for Russia and the United States.
  - However, the carbon avoided cost is higher than a wind-powered electrolyzer.
- Countries with an average low carbon footprint from electricity generation (below 200g per kWh) could reduce CO2 emissions from coal turbines at an abatement cost of \$45 to \$100 per tCO_2.

B3

Green H_2 can be produced in chemical plants or refineries to provide a decarbonized feedstock

Power-to-chemical: business case refining

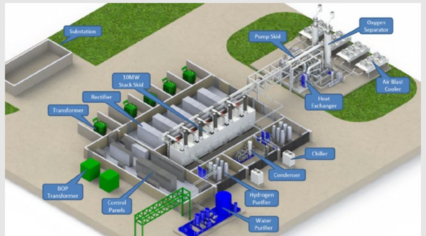
REFHYNE project overview
(Pilot project)

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 kTH_2 every year
- CO_2 emissions from SMR at Wesseling amounts to about 1.6 to 2.0 mtCO_2 per year.

Integration of a 10 MW PEM electrolyzer

- Test economical, technical, and environmental impact of the solution

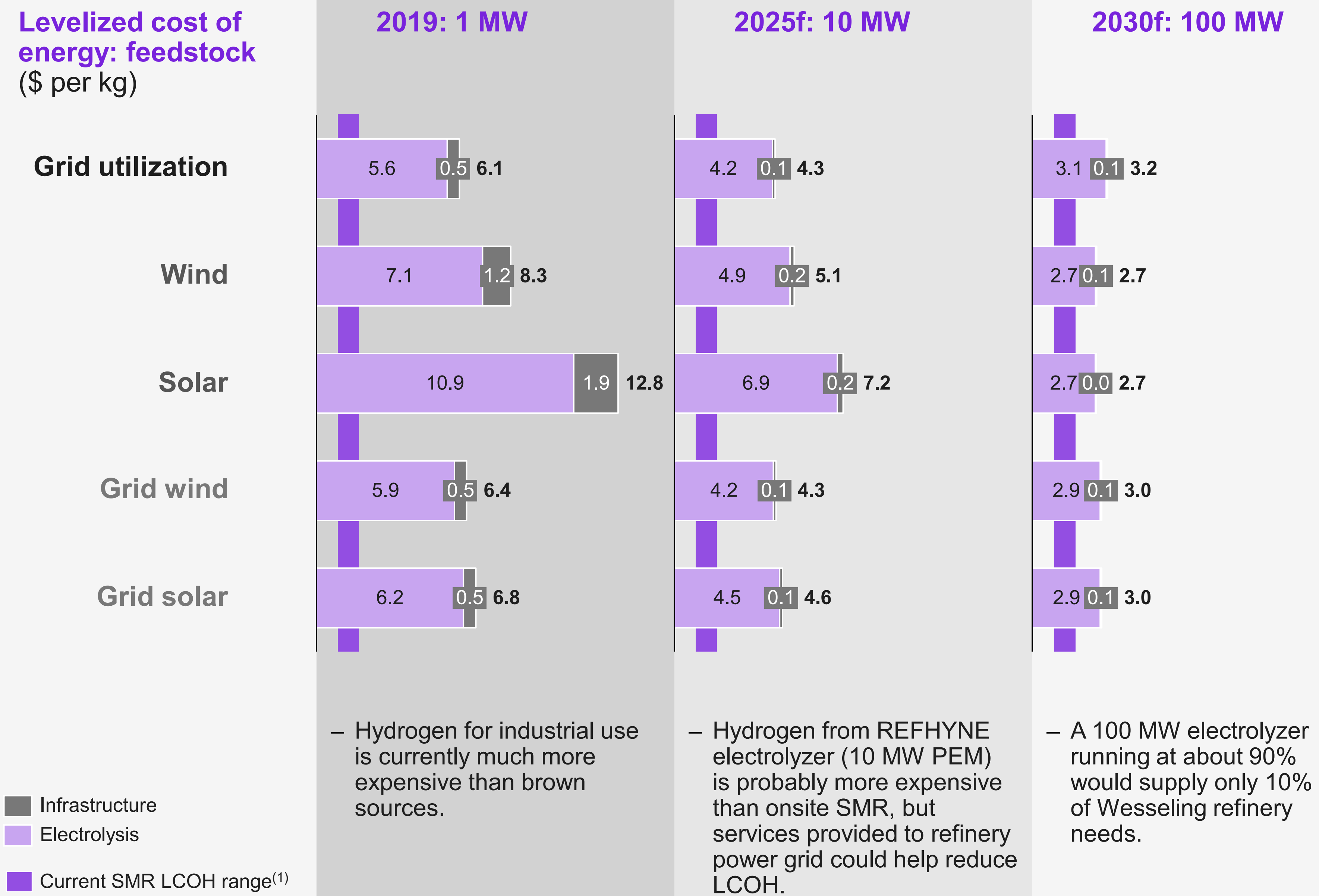


Business case review

- 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 ktCO_2 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.

B3 Green hydrogen as a feedstock includes a low number of steps and could become competitive in certain situations

Power-to-chemical: business case refining



– 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.

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

Sources: "The Future of Hydrogen," International Energy Agency, June 2019; "National Hydrogen Roadmap," Commonwealth Scientific and Industrial Research Organisation, 2018; International Renewable Energy Agency; Lazard; Kearney Energy Transition Institute analysis

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

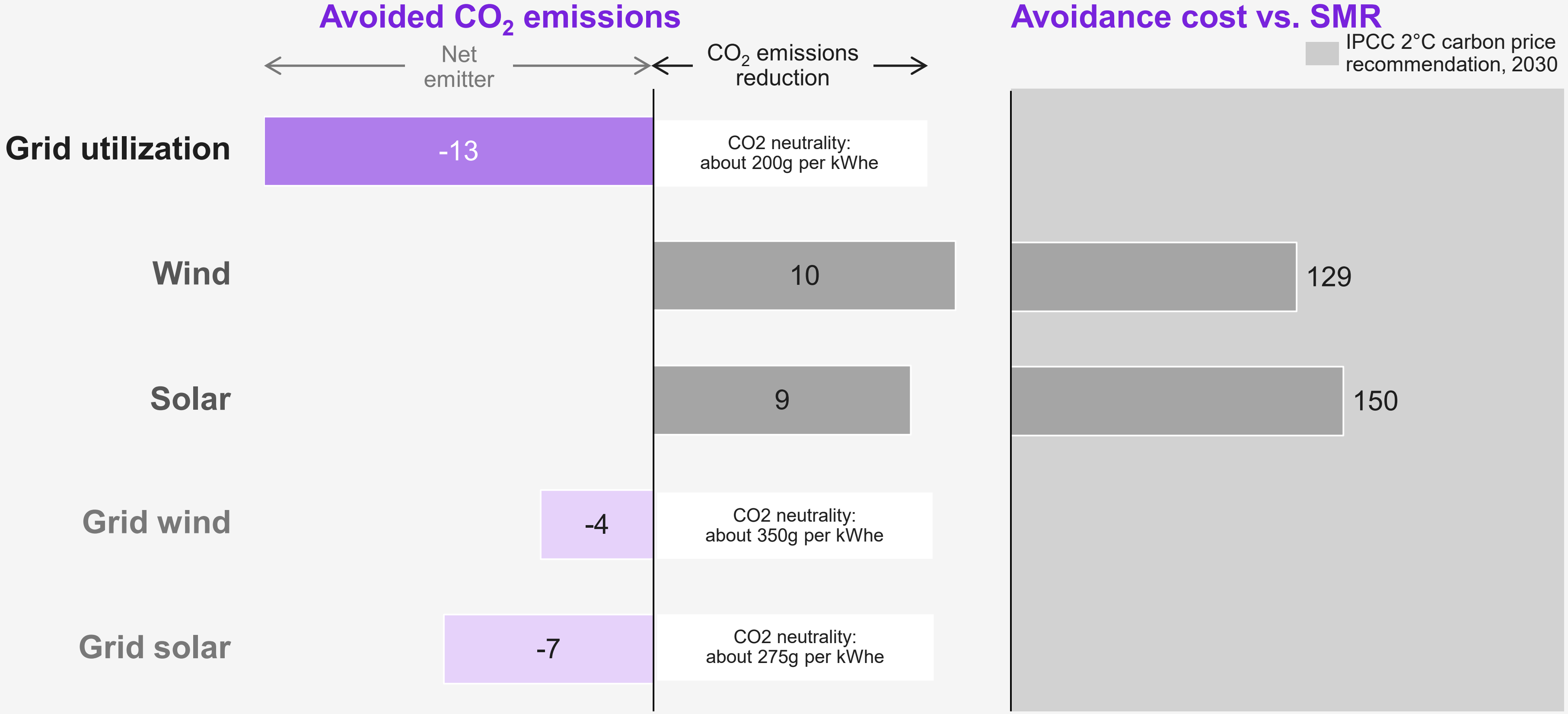
B3

Power-to-chemical: business case refining

4.2 **Business models – Business cases**

Avoided CO_2 and avoidance cost vs. SMR

(2030, $kgCO_2/kgH_2$, $ per tCO_2, based on world electrical mix)



- Only electrolyzers powered by renewable sources would have a positive impact on CO_2 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 tCO_2). 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.

Notes: The hypothesis is detailed in the appendix. CO_2 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

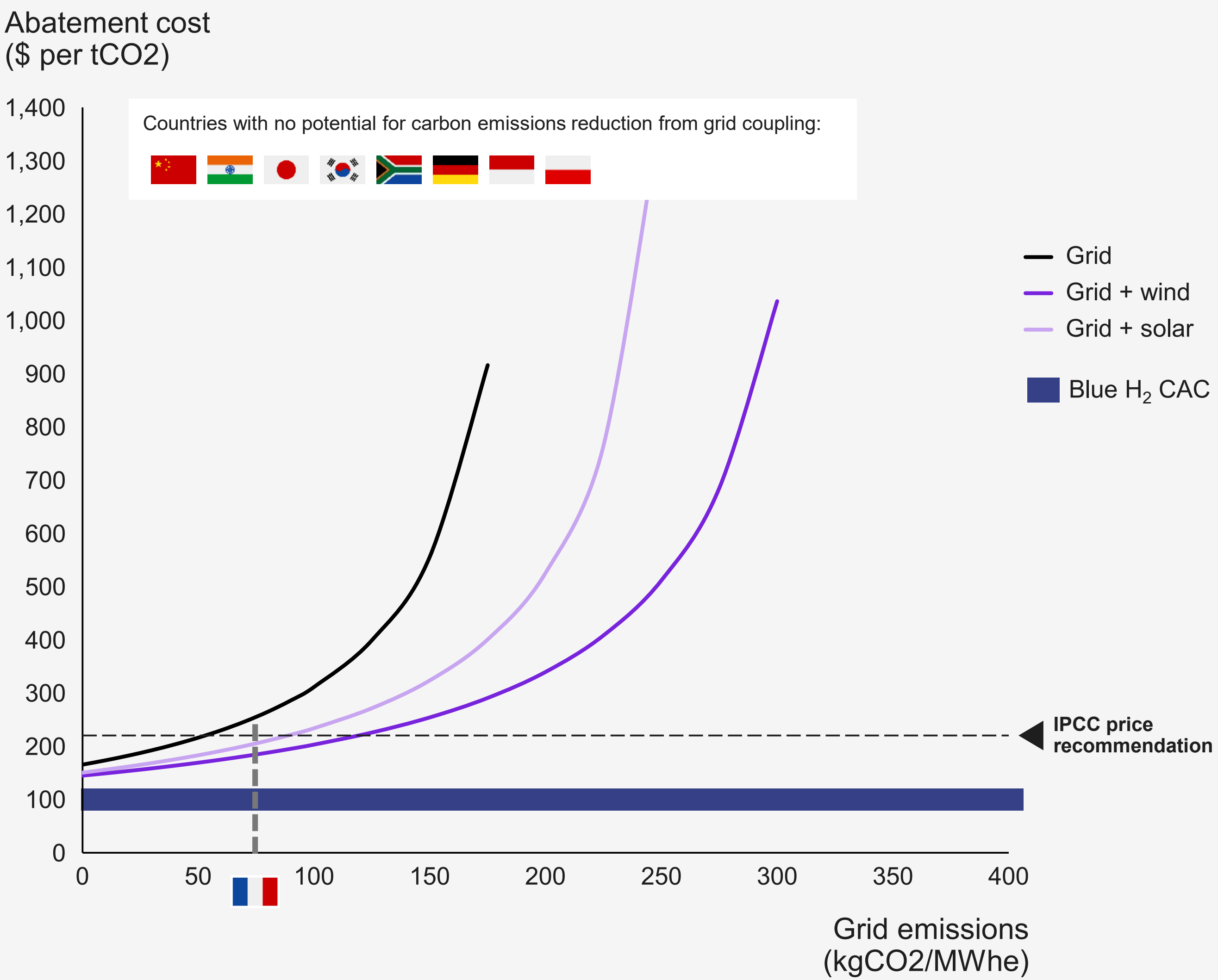
B3

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

Power-to-chemical: business case refining

4.2 **Business models – Business cases**

CAC vs. CO_2 emissions from electricity gen. (2030)



Heading

- 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.

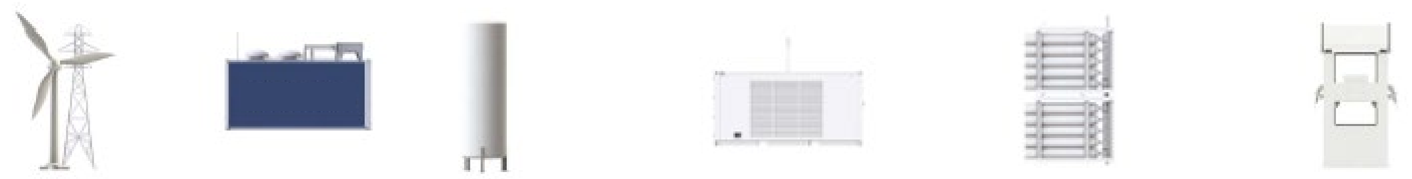
Note: CAC is carbon abatement cost. The additional cost of blue H2 has been studied in the production section of this factbook. The hypothesis detailed in the appendix.
Sources: Intergovernmental Panel on Climate Change, Organisation for Economic Co-operation and Development; Kearney Energy Transition Institute analysis

B4 B5 B6

Hydrogen could also be the vector to couple power and mobility with local electrolyzer and refueling stations

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

Power to Mobility value chain



	Electricity		Electro-lyzer	LP storage (60 bars)		Compression		HP storage (900 bars)		Dispenser	
Year	1 MW	100 MW	All hypotheses are described in slide 107.	1 MW	100 MW	1 MW	100 MW	1 MW	100 MW	1 MW	100 MW
Capacity (tH_2)	-	-		0.78 t H_2 2 days	94 t H_2 2 days	-	-	48 kg H_2 3 hours	6 t H_2 3 hours	-	-
Capex[1] ($ million)	Transfer: $0.013 Line: $0.112	Transfer: $0.30 Line: $0.112		$0.53	$31.8	$0.3	$17.6	$0.15	$10.2	$0.078	$2.4
Opex (% capex/$ million per year)	0%	0%		$0.01 million	$1.2 million	6%	6%	$0.02 million	$2.7 million	8%	8%
Electricity required (% losses per kWh)	3%	3%		-	-	8.3 kWh/kg	3.0 kWh/kg	-	-	-	-
Capacity (tH_2)	-	-		0.78 t H_2 2 days	94 t H_2 2 days	-	-	48 kg H_2 3 hours	6 t H_2 3 hours	-	-

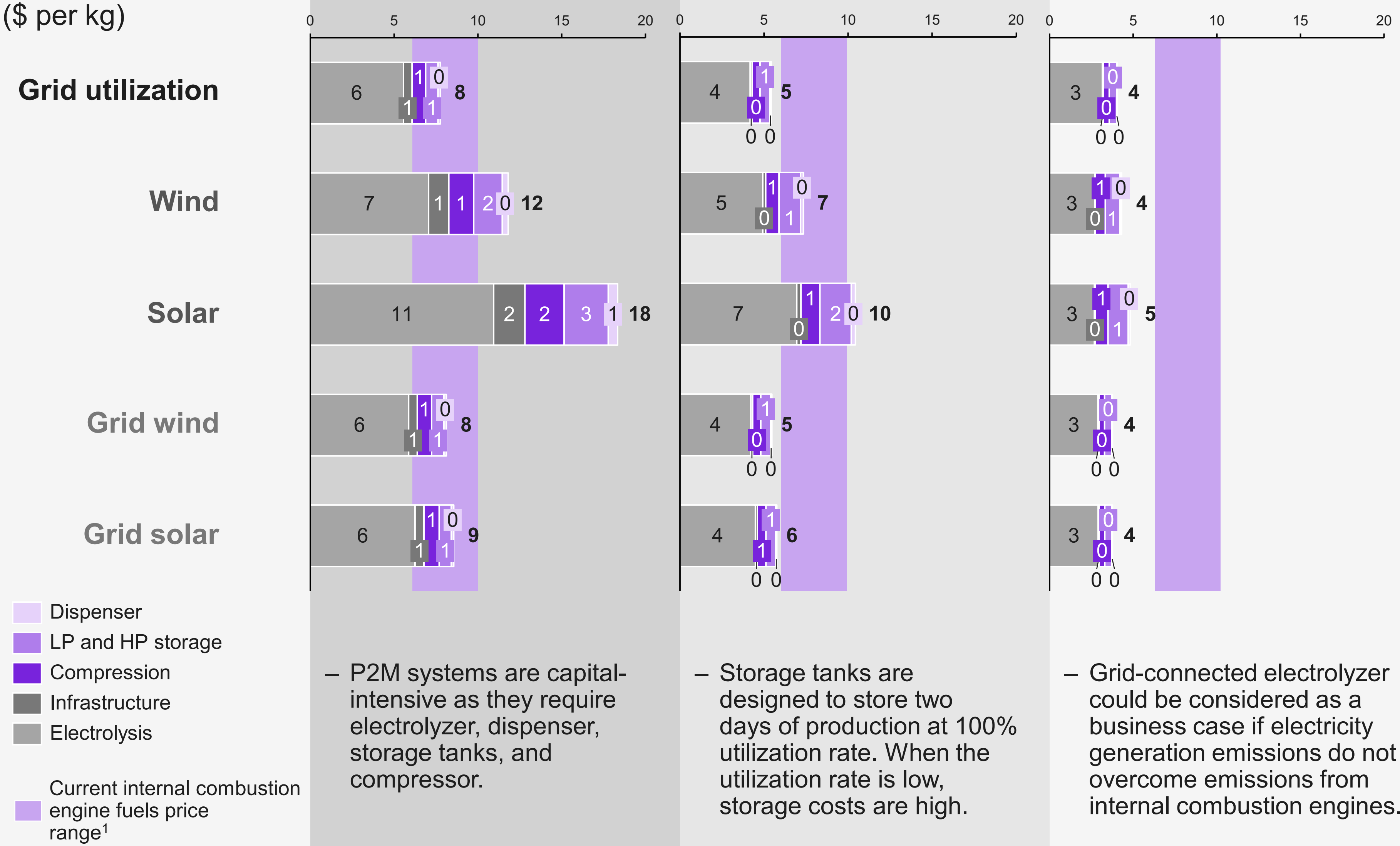
1 Includes capture, storage, and transportation costs
Sources: ENEA Consulting; ITM Power; "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

B4 B5 B6

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)



– 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.

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.
Sources: “The Future of Hydrogen,” International Energy Agency, June 2019; “National Hydrogen Roadmap,” Commonwealth Scientific and Industrial Research Organisation, 2018; International Renewable Energy Agency; ENEA Consulting; Kearney Energy Transition Institute analysis

B4 B5 B6

Faster refueling time for hydrogen-based vehicles also leads to less space requirements and lower investment costs

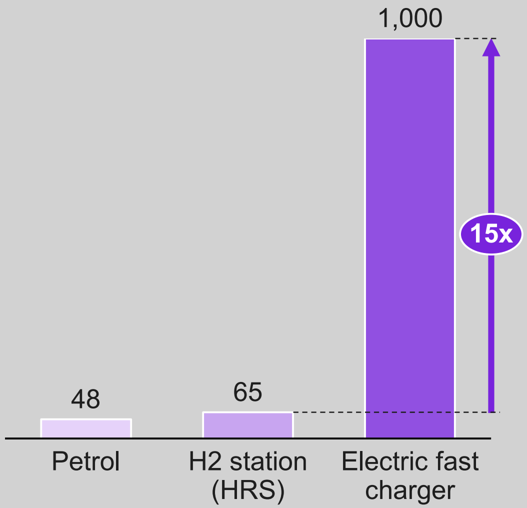
Power-to-mobility: business cases car, bus and train

Space requirements and investment costs for HRS

Average Estimates

Refueling speed

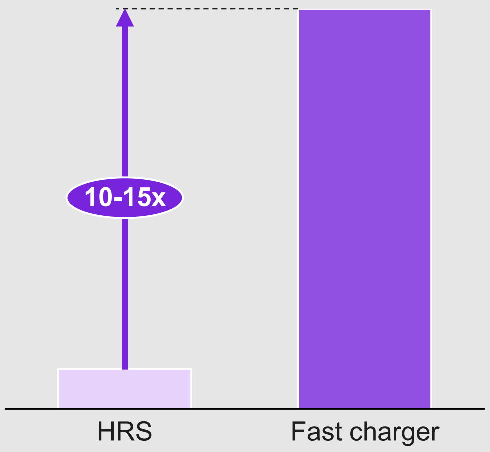
Refueling speed (s per 100km of refueling)



- 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

Space requirements

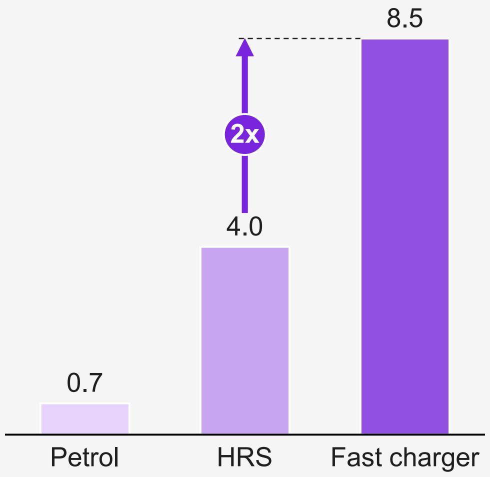
Space required to service (same number of vehicles, comparative basis)



- 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

Investment costs

Investment costs per refueling ($/refueling)



- 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.

Note: HRS is hydrogen refueling station.
Source: Kearney Energy Transition Institute analysis

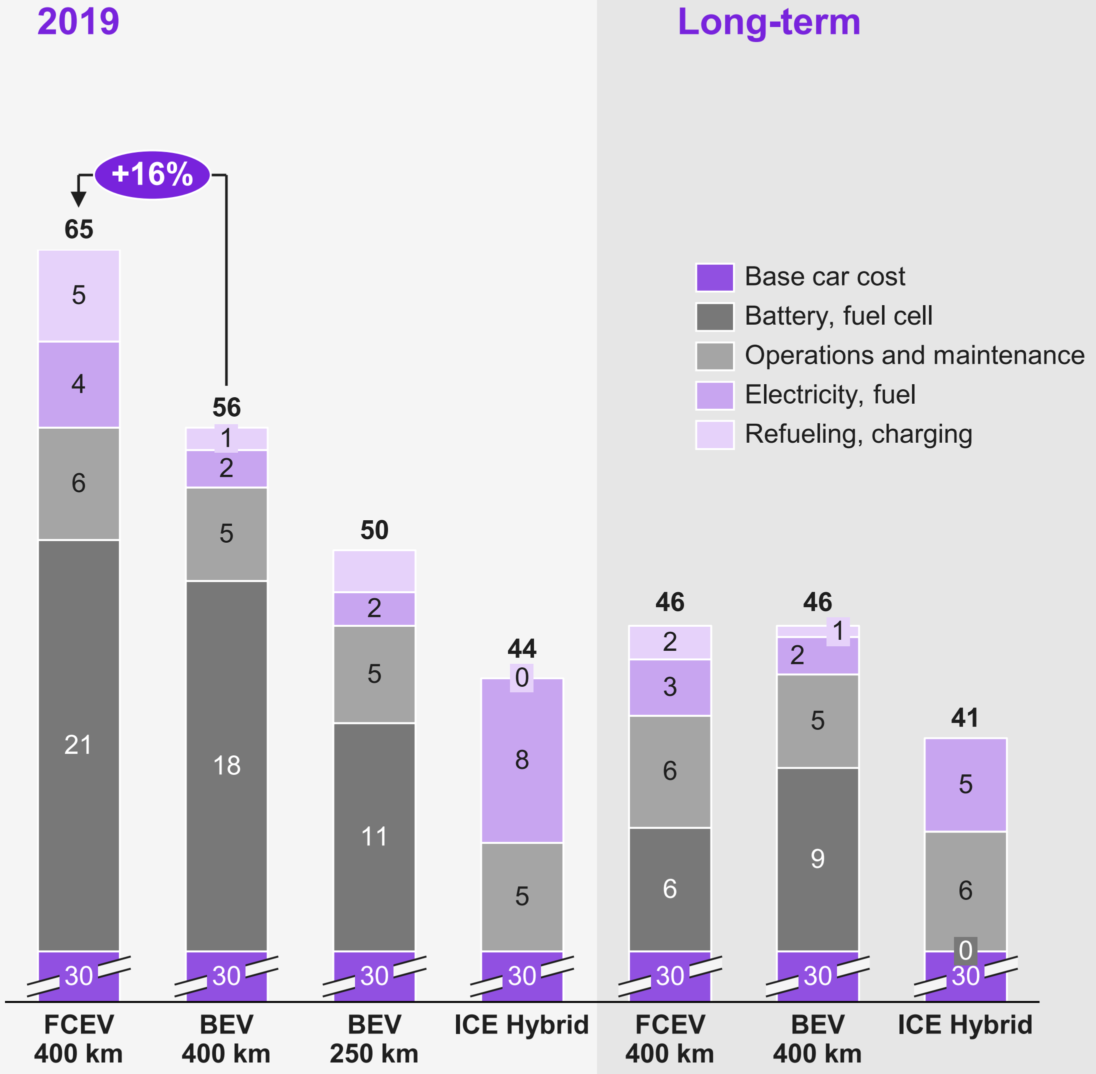
B4

TCO for a H_2 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)



Note: The hypotheses are detailed in the appendix.
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

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 H_2 station at 10% adds a marginal LCOH of $13 per 100km 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.

B4

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

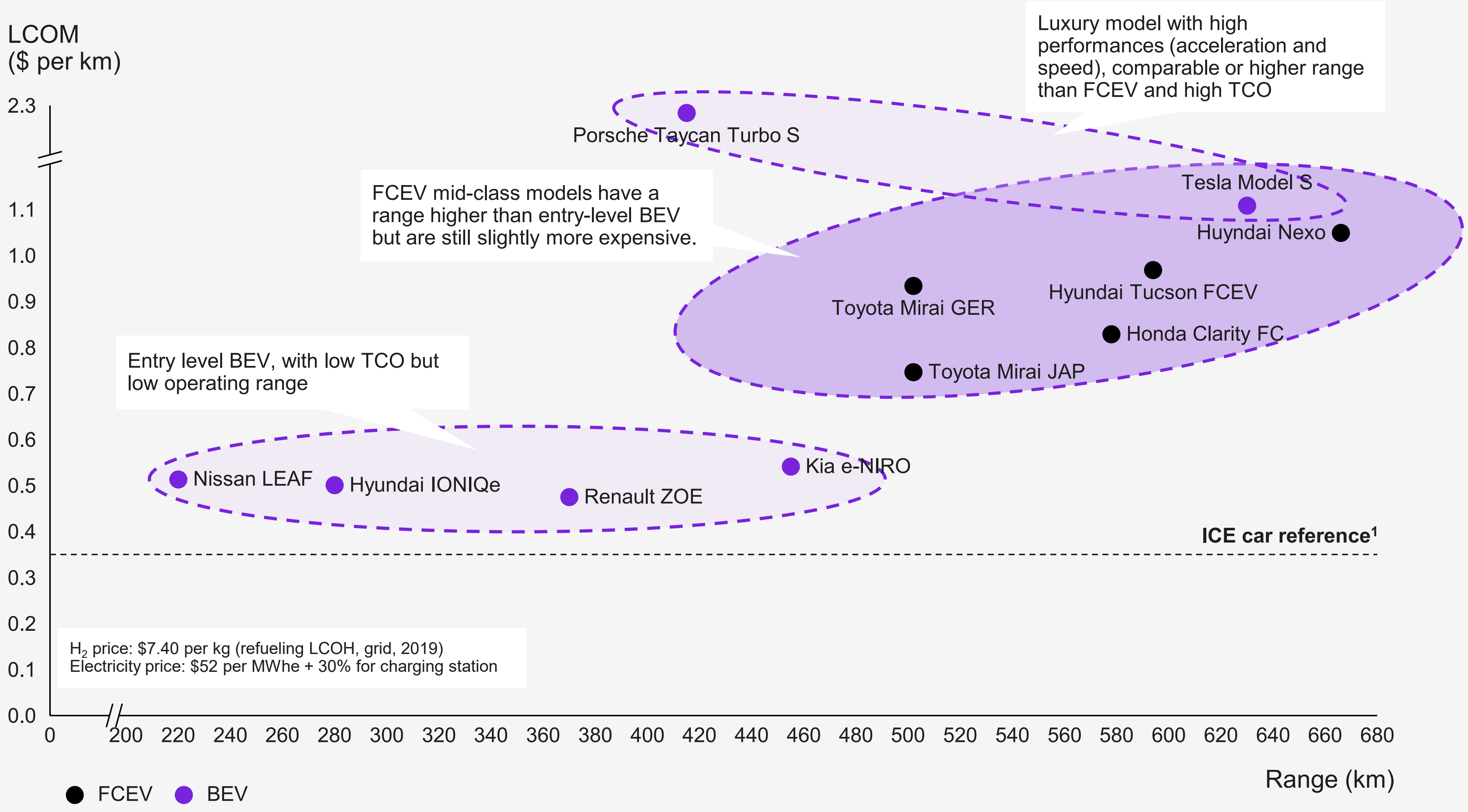
Power-to-mobility: business case car

4.2 **Business models – Business cases**

LCOM and range for selected models

(2019; X axis: range in km; Y axis: LCOM in $ per km)

Non-Exhaustive



1 Car price: $20,000; fuel consumption: 6.0L/100km

Sources: BNEF; "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

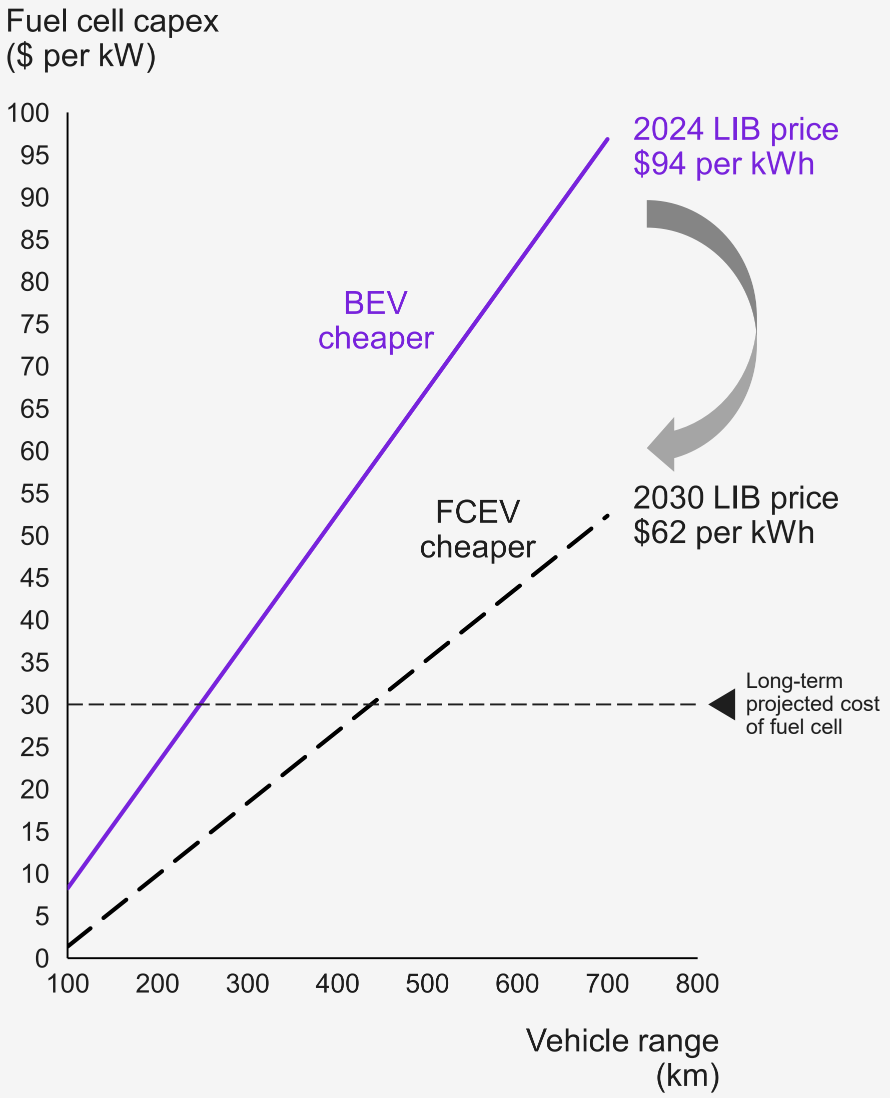
B4

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

Competitiveness FCEV vs. BEV

(X axis: range in km; Y axis: FC cost in $ per kW)



Note: Hypotheses from the International Energy Agency are detailed in the appendix.
Sources: BNEF; "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute Analysis

How to read

- In 2024, lithium–ion batteries for vehicles are expected to cost $94 per kWh.
- To be competitive, fuel cells in FCEV will have to be below the red-line boundary.
  - For a 400-km range vehicle, fuel cell costs have to be lower than $50 per kW.
- In 2030, LIB cost is expected to go as low as $62 per kWh.
  - For a 400-km range vehicle, fuel cell costs have to be lower than $25 per kW.
- By 2030, the Department of Energy expects that the cost of fuel cells will go down to $30 per kW.

Further considerations

- **Charging time:** See slide 130.
- **CO2 emissions:** End-to-end CO_2 emissions have to be evaluated, including battery and fuel cell production and recycling as well as fuel production (either H_2 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.

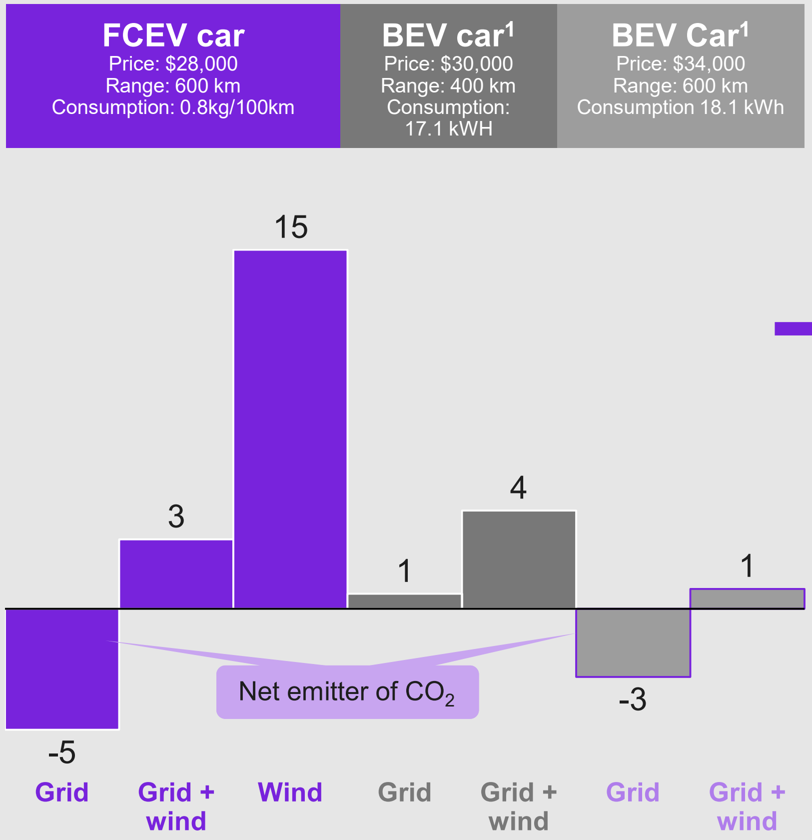
B4

Carbon abatement cost is lower for short-range BEVs if charging stations are coupled with wind and grid, but FCEVs would save more CO_2 at a lower cost for long ranges

Power-to-mobility: business case car

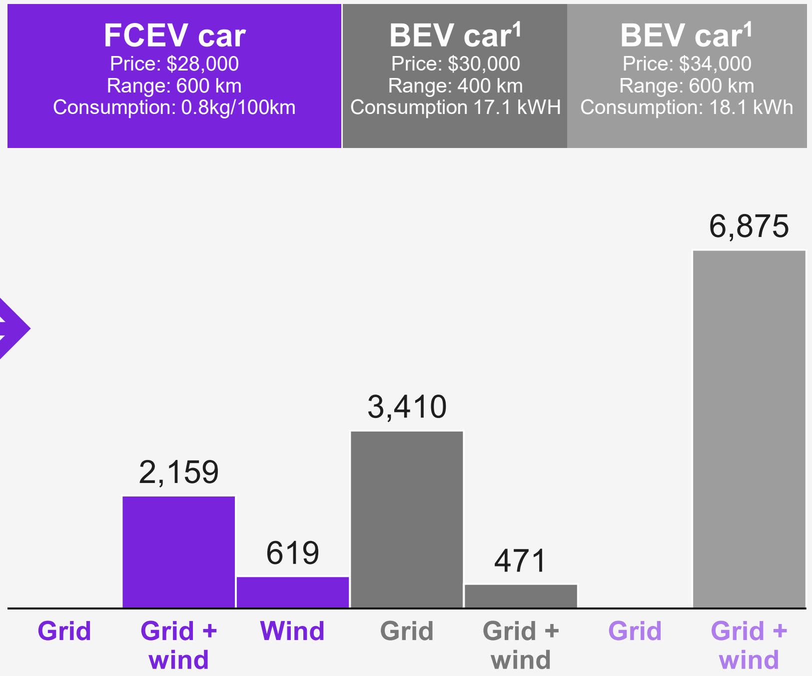
CO_2 avoided[1]

(2030, kgCO2/100km)



CO_2 avoidance cost

(2030, $ per ton)



1. Including battery manufacturing footprint

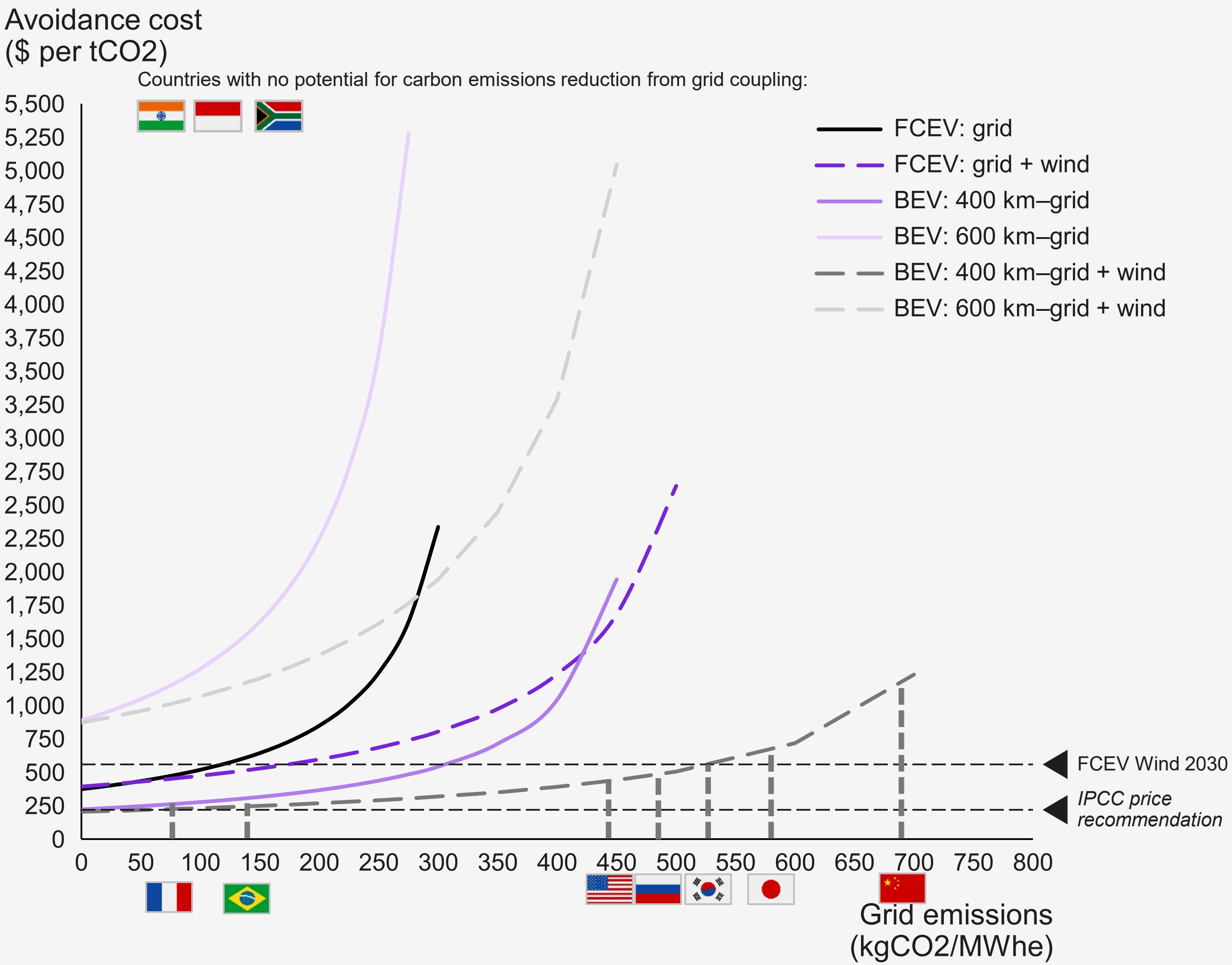
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Commonwealth Scientific and Industrial Research Organisation; Pau; ITM Power; RTE; CRMT; Kearney Energy Transition Institute analysis

B4

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

Power-to-mobility: business case car

CAC vs. CO_2 emissions from electricity generation
(2030, selected countries)



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

Key comments

- Wind-powered electrolyzer has a lower CAC than grid-connected hydrogen stations unless grid emissions are below 200g 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.

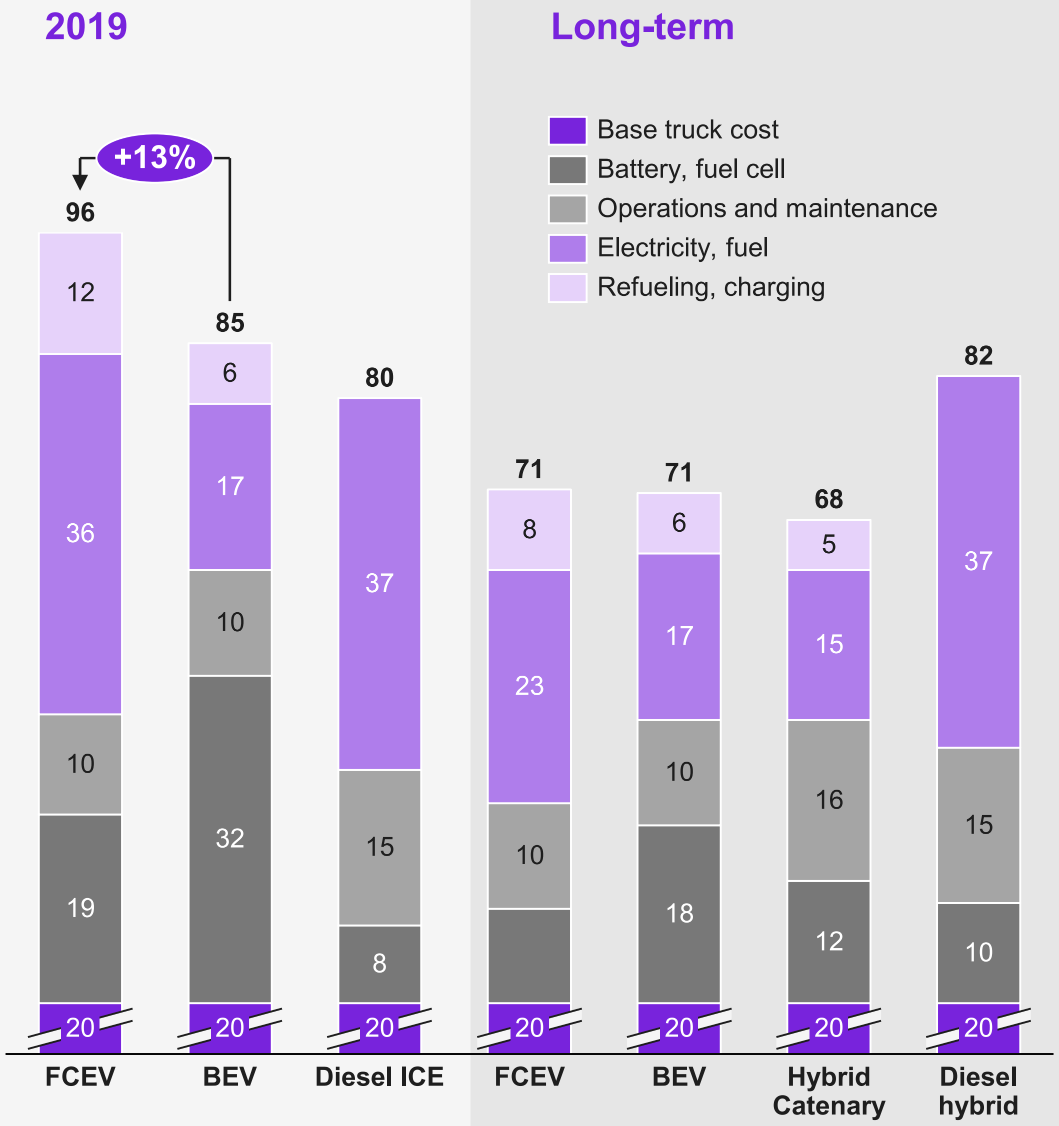
4.2 **Business models – Business cases**

B5

Fuel-cell trucks are expected to compete with other low-carbon solutions, such as BEV trucks and hybrid catenary

Power-to-mobility: business case bus

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



Note: The hypothesis is detailed in the appendix.
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Kearney Energy Transition Institute analysis

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 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 H_2 price below $7 per kg and a fuel-cell cost of about $95 per kW is required to make FCEV trucks competitive with ICE.

4.2 **Business models – Business cases**

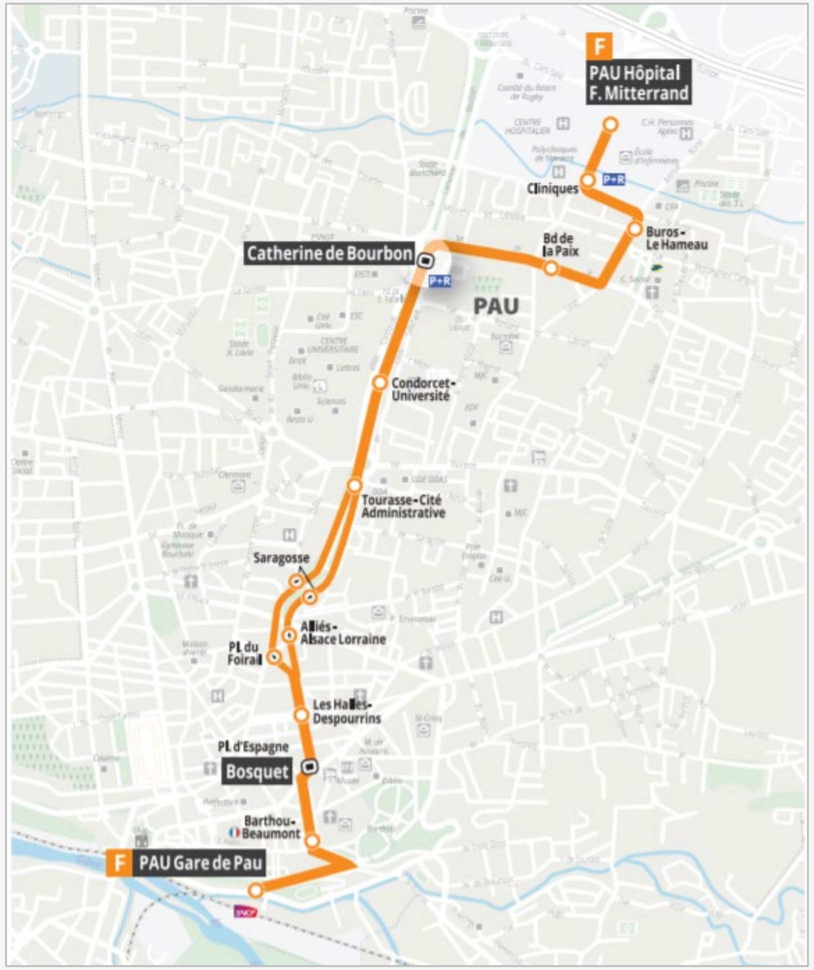
B5

A city in France is experimenting with H_2 buses for its city fleet and has promised no cost increase for passengers

Illustrative

Power-to-mobility: business case bus

Pau, France zero-emission public transportation project, FEBUS



Key characteristics	
Project investment	€74.5 million (of which €14.5 million is for bus and recharging station)
Commissioning date	Autumn 2019
Fuel cell power	100 kW
Consumption	10–12 kgH_2 per 100 km
Autonomy	More than 240 km
Electrolyzer	PEM: up to 268 kgH_2 per day
Number of passengers per bus	125

Key project partners

- ITM Power
- Pau Porte des Pyrénées
- Ville de Pau
- Idelis
- Engie Gnvert
- VanHool

Note: The hypothesis is detailed in the appendix.
Sources: Pau, ITM Power; Kearney Energy Transition Institute analysis

4.2 Business models – Business cases

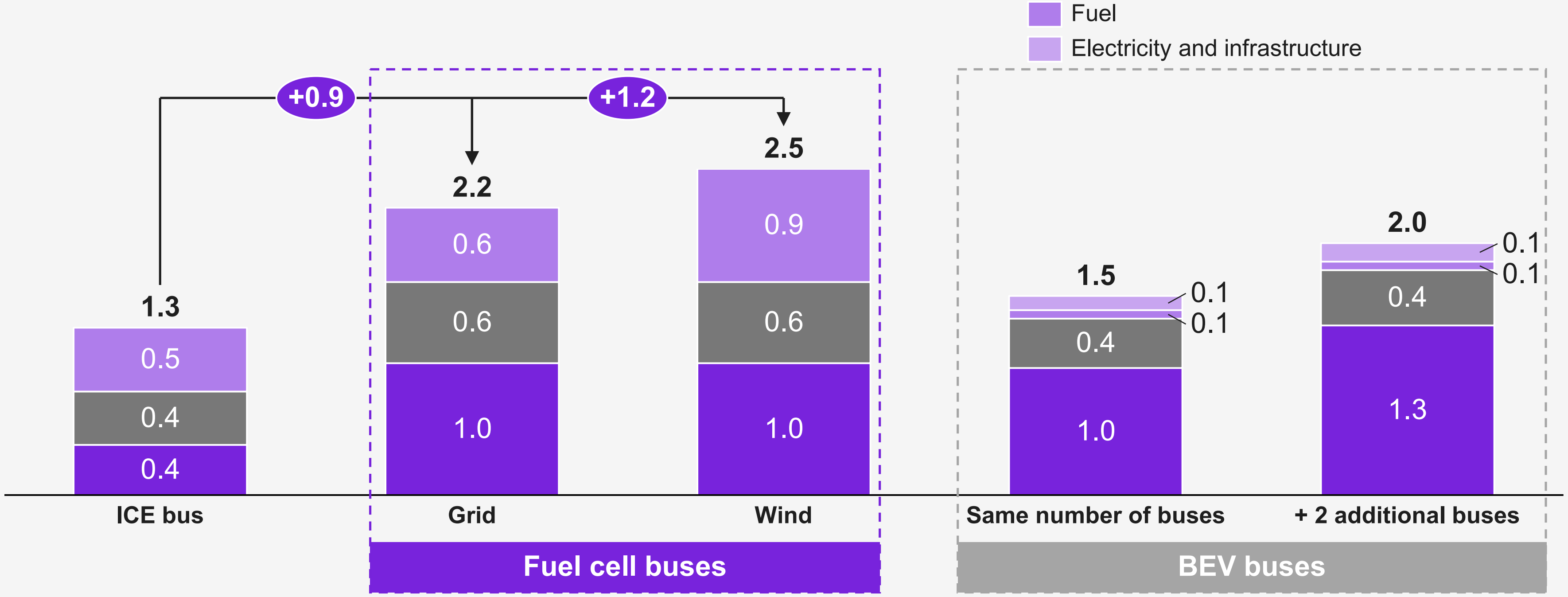
B5

An H_2 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[3] per passenger
(2019, $ per passenger)



Fuel price	$1.30 per L	$7.80 per kg[2]	$11.80 per kg[2]	$52 per MWh	
Capex bus	$294,000 x 6 buses	$730,000 per bus x 6 buses		$675,000 per bus x 6 buses	$675,000 per bus x 8 buses
Operations & maintenance: drivetrain	30¢ per km	60¢ per km		30¢ per km	
Operations & maintenance: warehouse	$112,000 per year per bus				
Passengers	489,000 per year				

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
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Commonwealth Scientific and Industrial Research Organisation; Kearney Energy Transition Institute analysis

4.2 Business models – Business cases

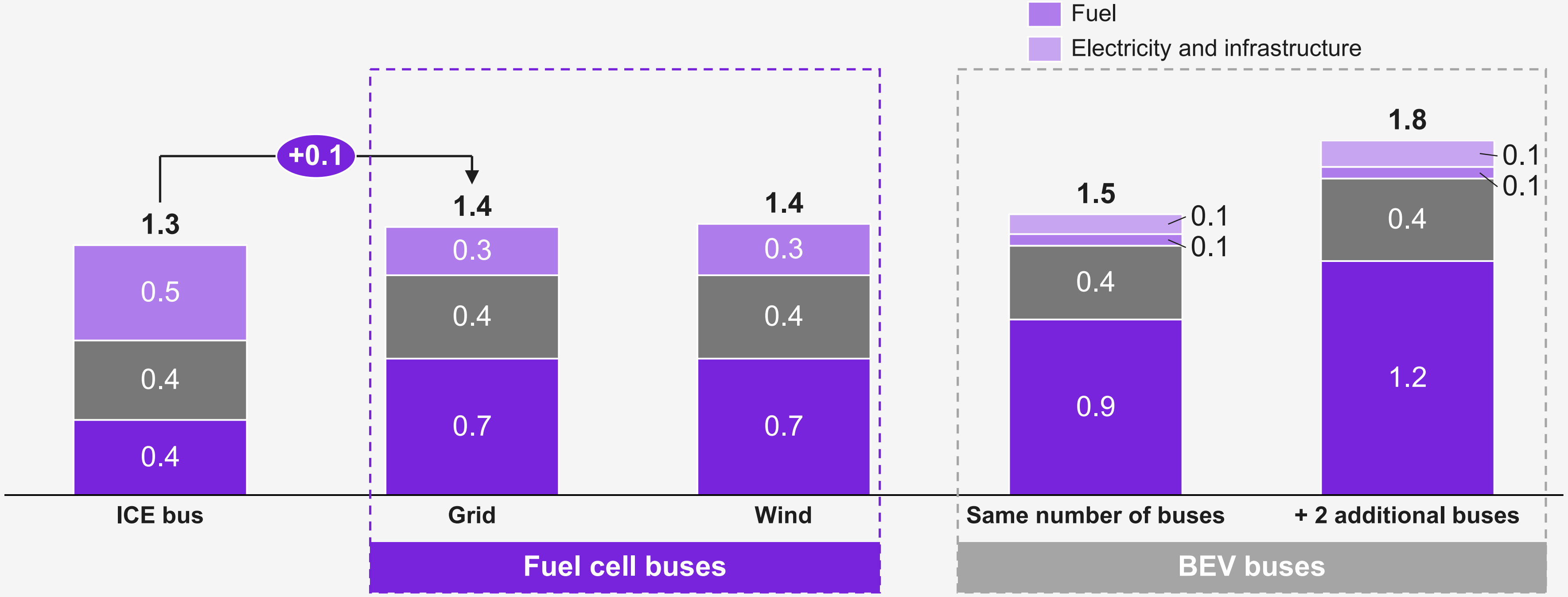
B5

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

Illustrative

Power-to-mobility: business case bus

Levelized cost of mobility[3] per passenger
(2030f, $ per passenger)



	ICE bus	Fuel cell buses: Grid	Fuel cell buses: Wind	BEV buses: Same number of buses	BEV buses: + 2 additional buses
Fuel price	$1.30 per L	$3.80 per kg[2]	$4.40 per kg[2]	$52 per MWh	
Capex bus	$294,000 x 6 buses	$450,000 per x 6 buses		$617,000 per bus x 6 buses	$617,000 per bus x 8 buses
Operations & maintenance: drivetrain	30¢ per km	60¢ per km		30¢ per km	
Operations & maintenance: warehouse	$112,000 per year per bus				
Passengers	489,000 per year				

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
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Commonwealth Scientific and Industrial Research Organisation; Kearney Energy Transition Institute analysis

4.2 **Business models – Business cases**

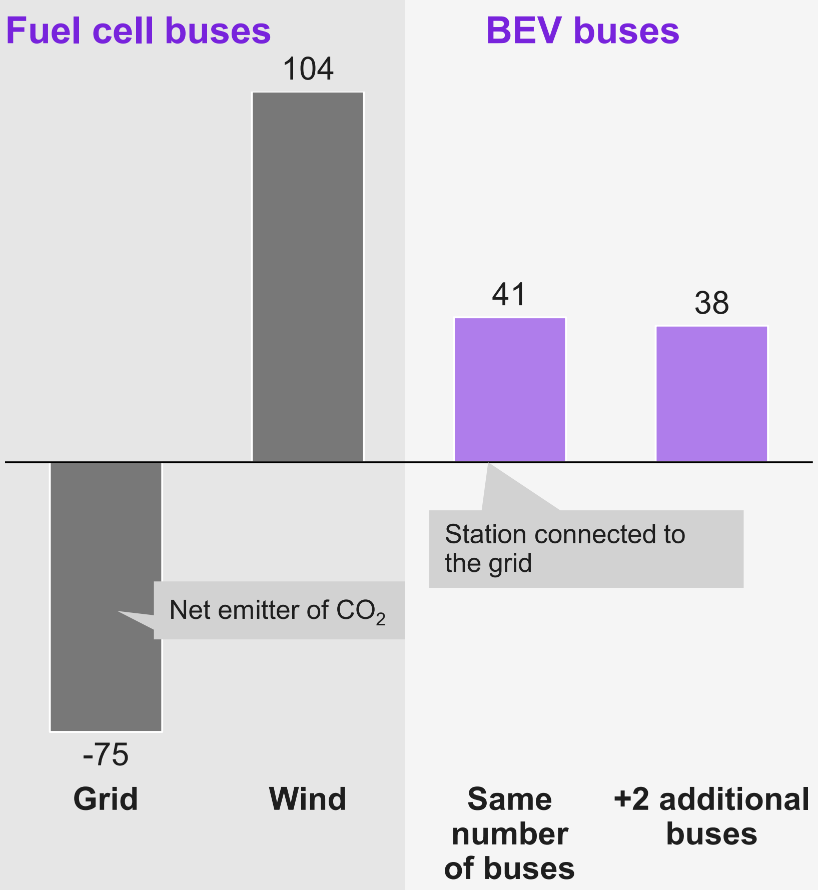
B5

Under the current electrical mix, only refueling stations powered by renewables would reduce CO_2 emissions at a cost below $220 per ton

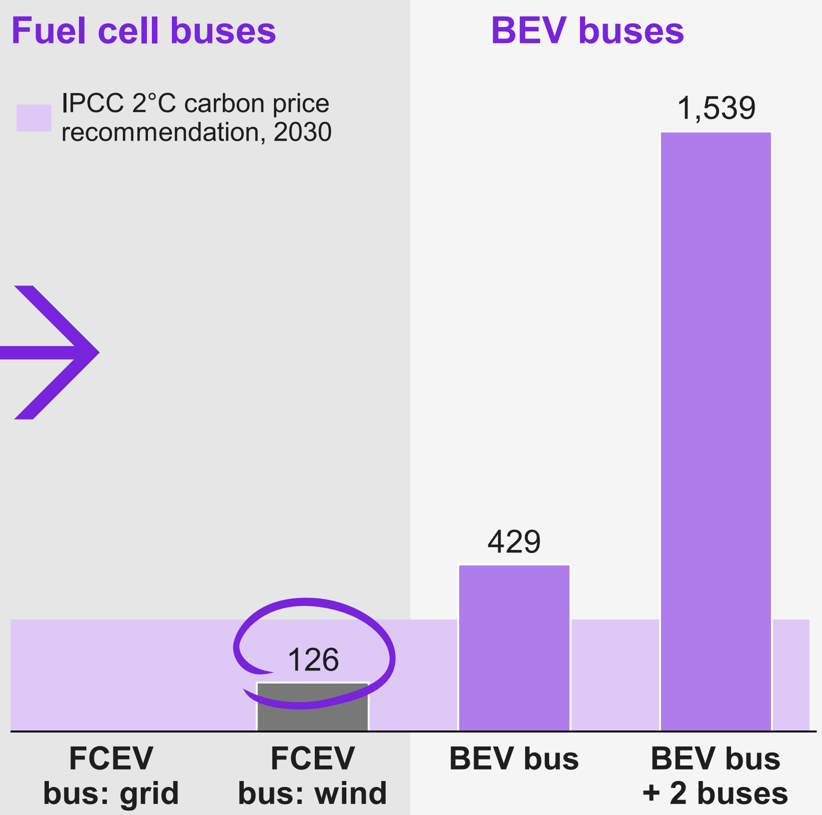
Illustrative

Power-to-mobility: business case bus

CO2 avoided[1]
(2030, kgCO2/100km)



CO2 avoidance cost
(2030, $ 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.

1 Including battery manufacturing footprint
Sources: "The Future of Hydrogen," International Energy Agency, June 2019; Commonwealth Scientific and Industrial Research Organisation;; Pau; ITM Power; RTE; CRMT; Kearney Energy Transition Institute analysis

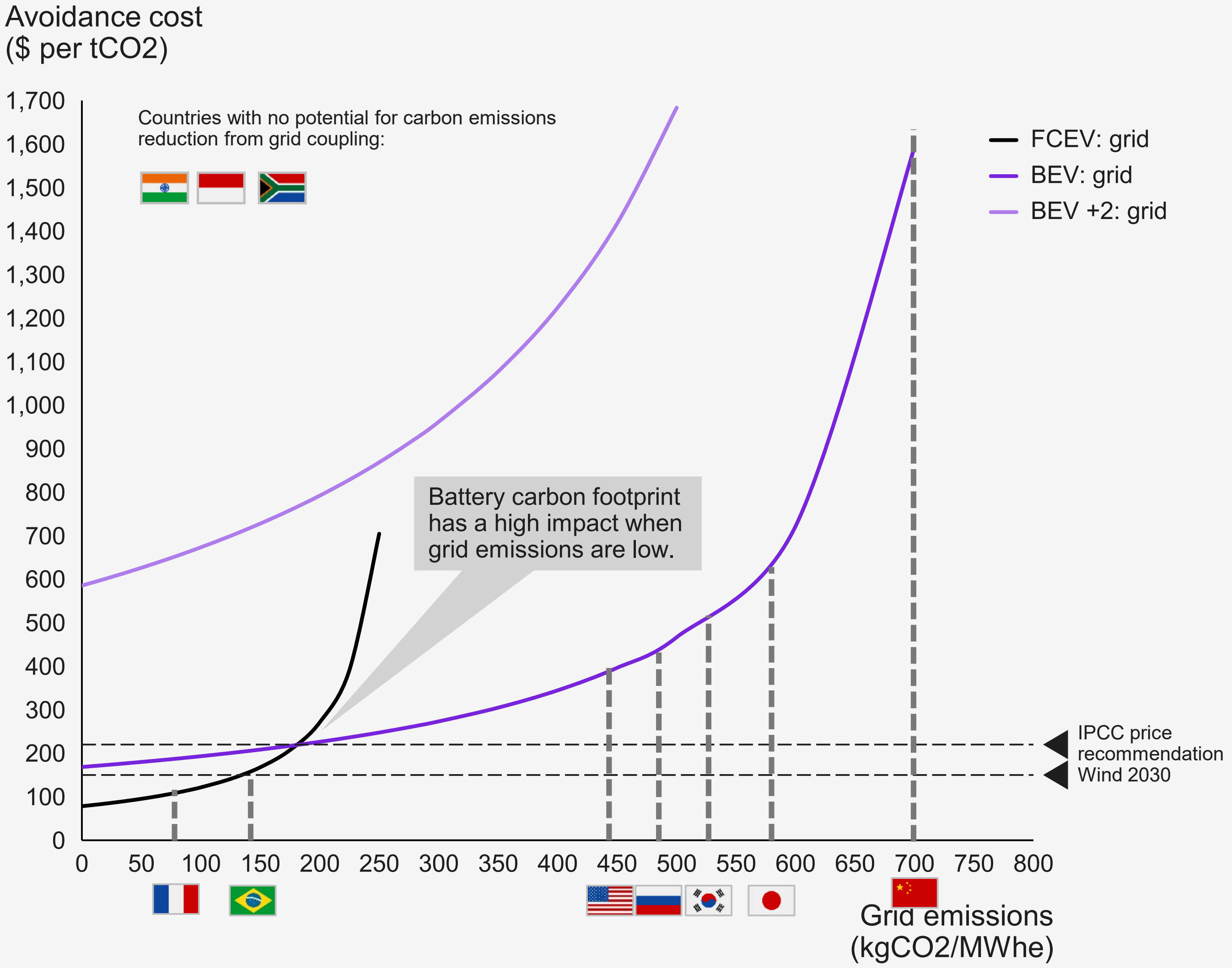
B5

While FCEV buses powered by wind H_2 appear to have the lowest CAC, grid-powered BEV buses are the second best alternative

Power-to-mobility: business case bus

4.2 Business models – Business cases

CAC vs. CO_2 emissions from electricity generation
(2030, selected countries)



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

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 an 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 CO_2 emissions by switching to BEV buses.

B5

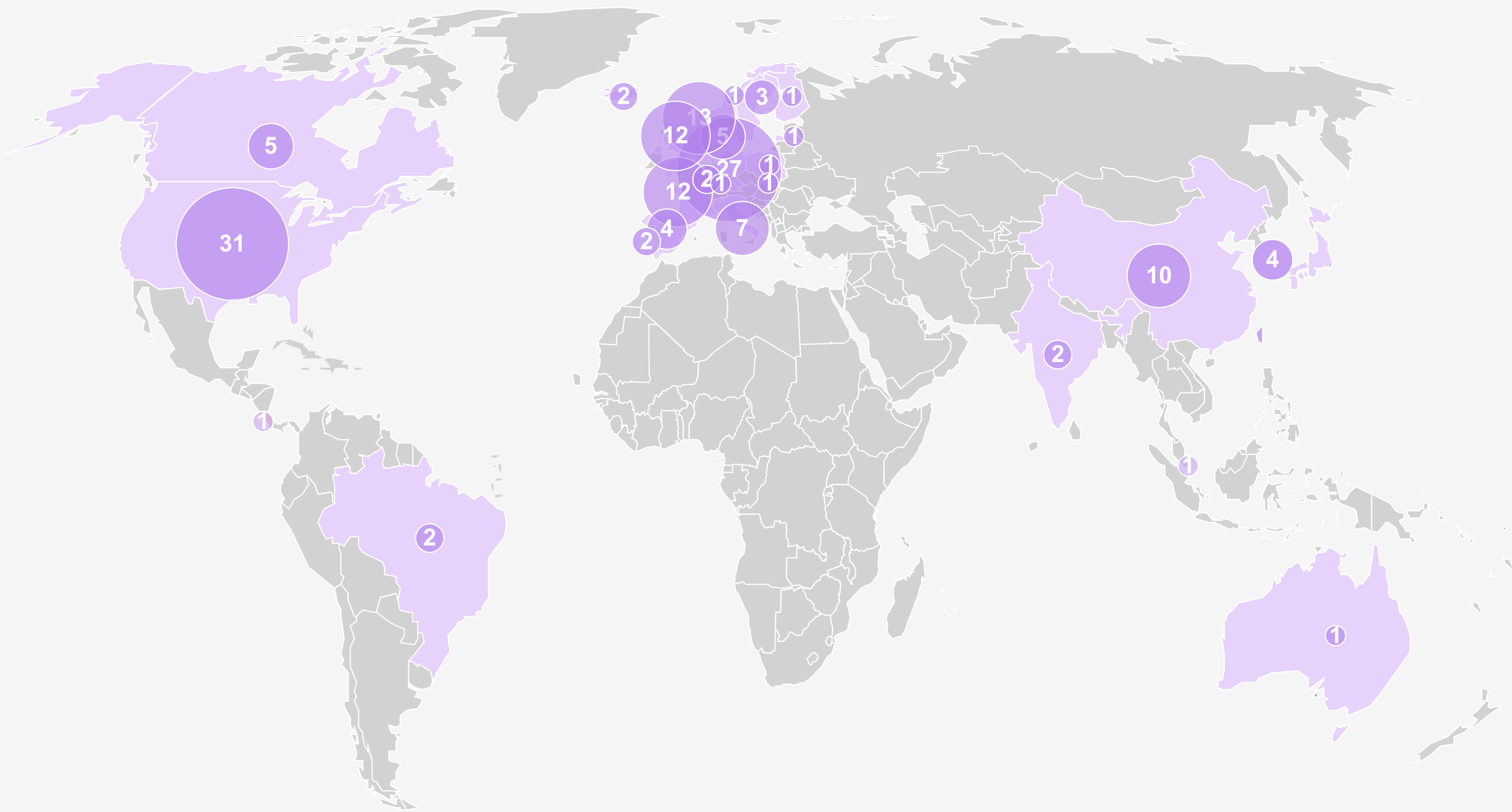
Cities around the world are launching H_2 buses projects to evaluate the potential

Power-to-mobility: business case bus

4.2 **Business models – Business cases**

Overview of H_2 buses project
(Number of projects per country)

Non-Exhaustive



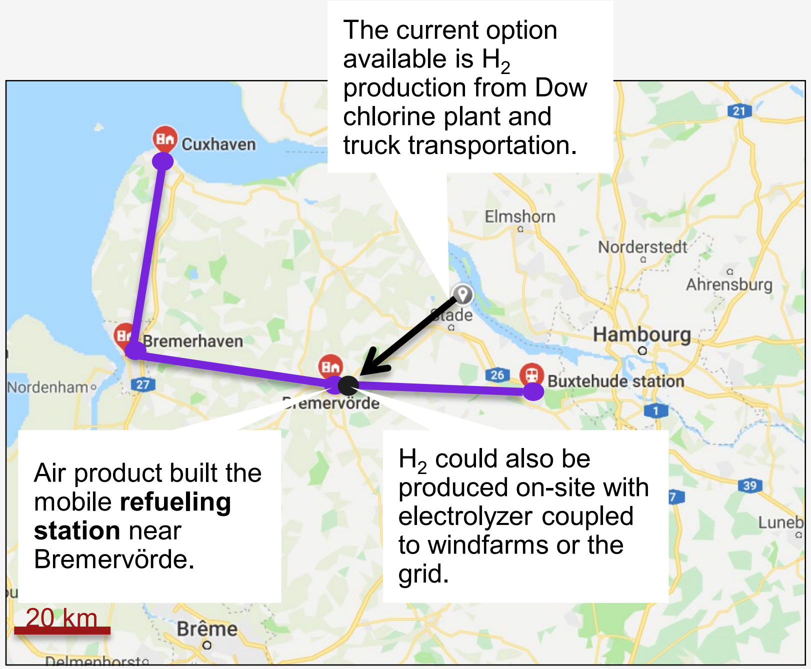
Source: Kearney Energy transition Institute analysis

B6

Hydrogen-powered trains are a robust alternative to electrification for replacing diesel trains

Power-to-mobility: business case train

H_2 train example: Germany



"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

- 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

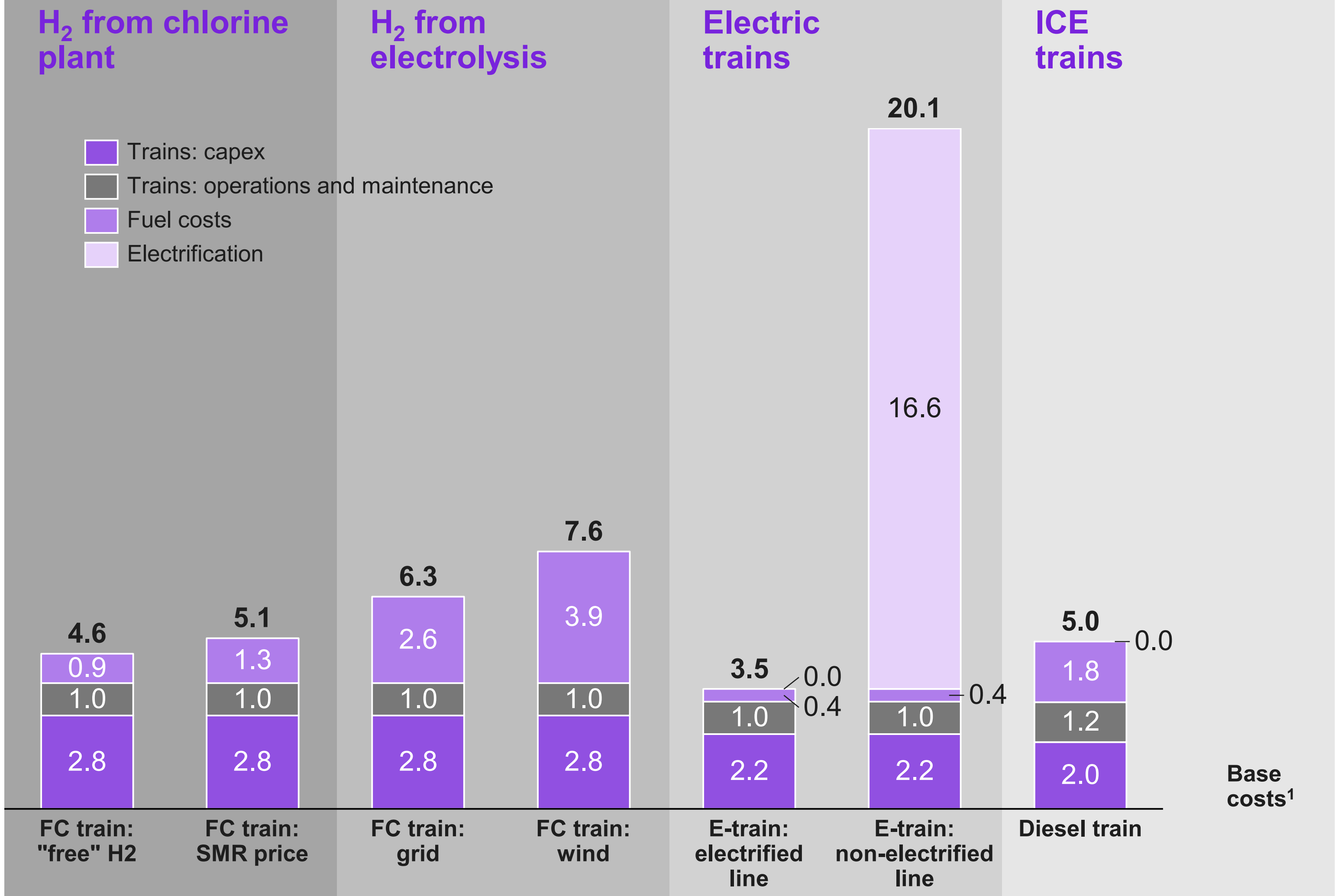
Source: Kearney Energy transition Institute analysis

B6

H_2 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 mobility[1]
(2019, $ per passenger)



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.

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

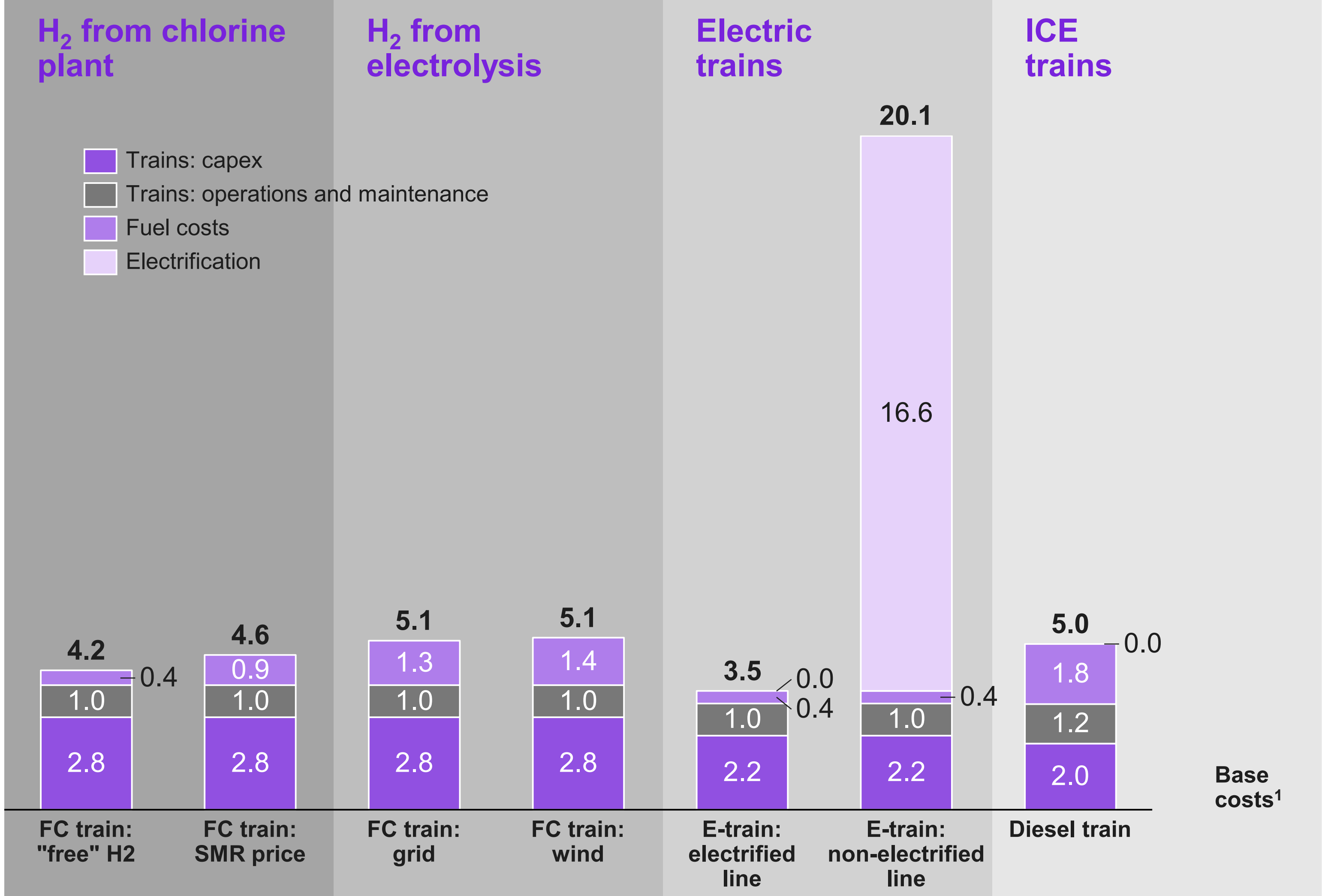
4.2 **Business models – Business cases**

B6

H_2 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 mobility[1]
(2030f, $ per passenger)



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

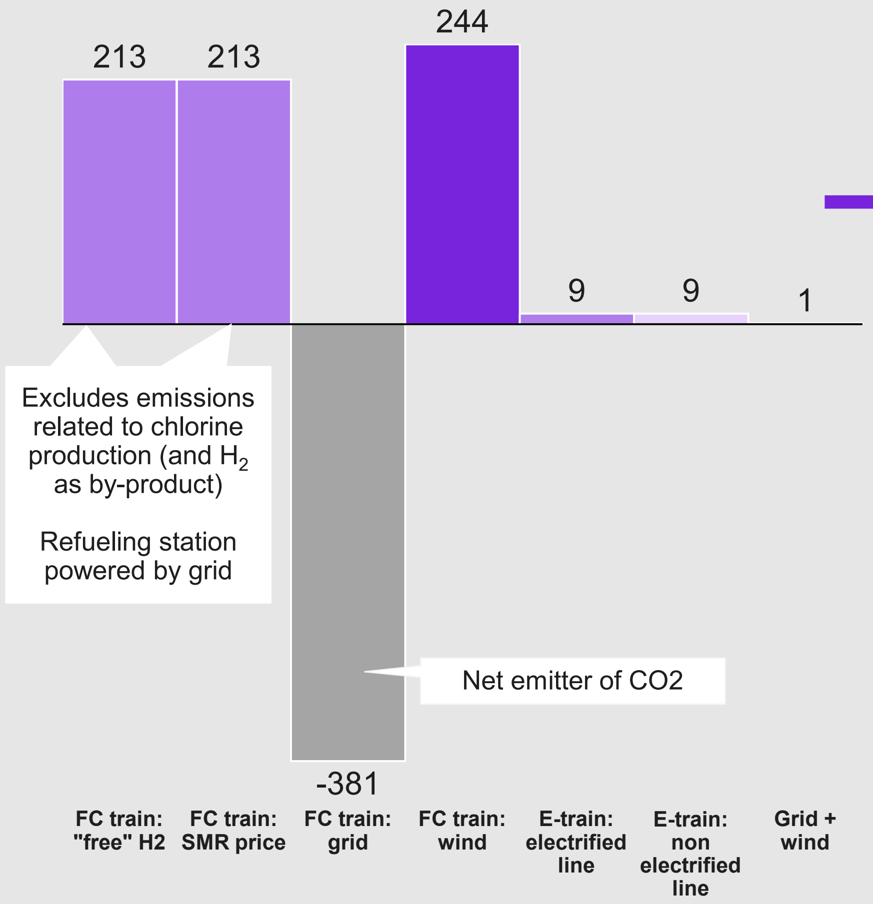
4.2 **Business models – Business cases**

B6

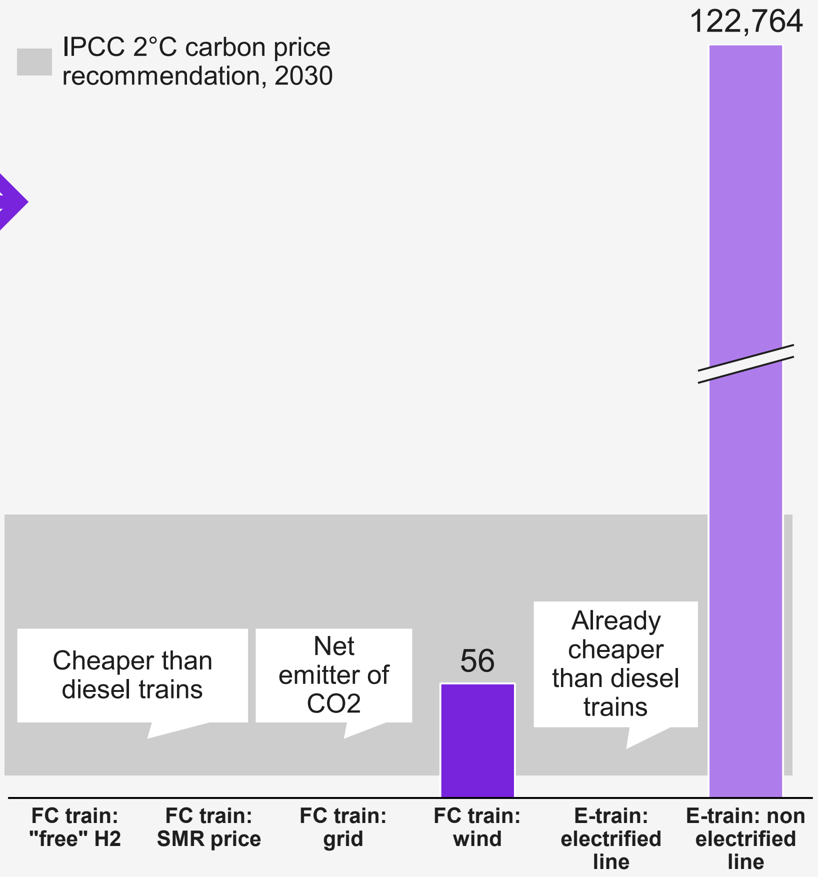
Using by-product H_2 from the chlorine industry appears to have the cheapest avoidance cost

Power-to-mobility: business case train

CO_2 avoided[1]
(2030, kgCO2/100km)



CO_2 avoidance cost
(2030, $ per t)



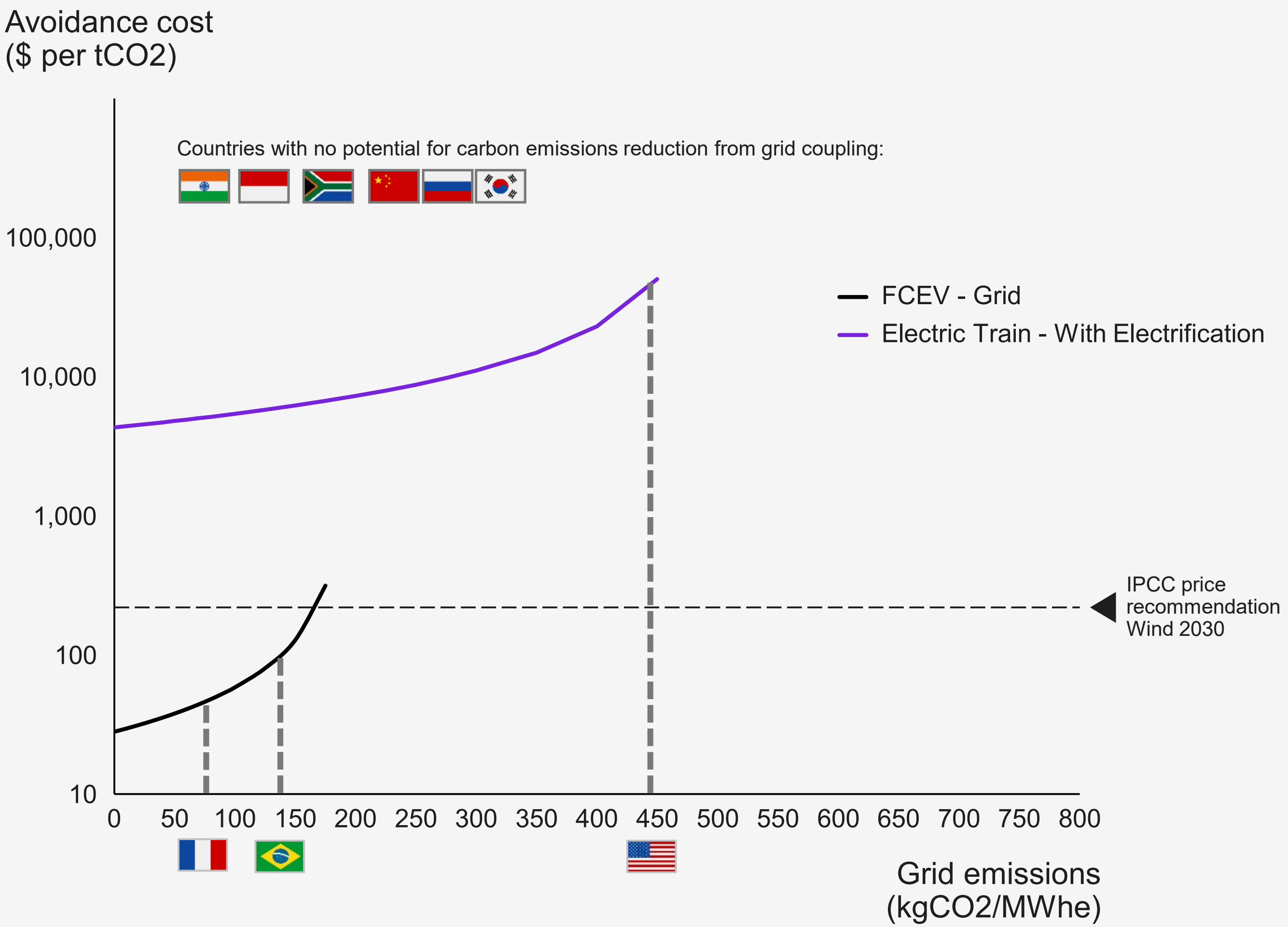
1 Not including base costs, such as driver, rail, and station-related costs
Sources: Deutsche Bahn; Usine Nouvelle; Bloomberg; EESI; "The Future of Hydrogen," International Energy Agency, June 2019; RTE; Kearney Energy Transition Institute analysis

B6

An FCEV train with H_2 by grid could save CO_2 if grid emissions are below 300g/kWhe at a lower avoidance cost than electrification

Power-to-mobility: business case train

CAC[1] vs. CO_2 emissions from electricity generation
(2030, selected countries)



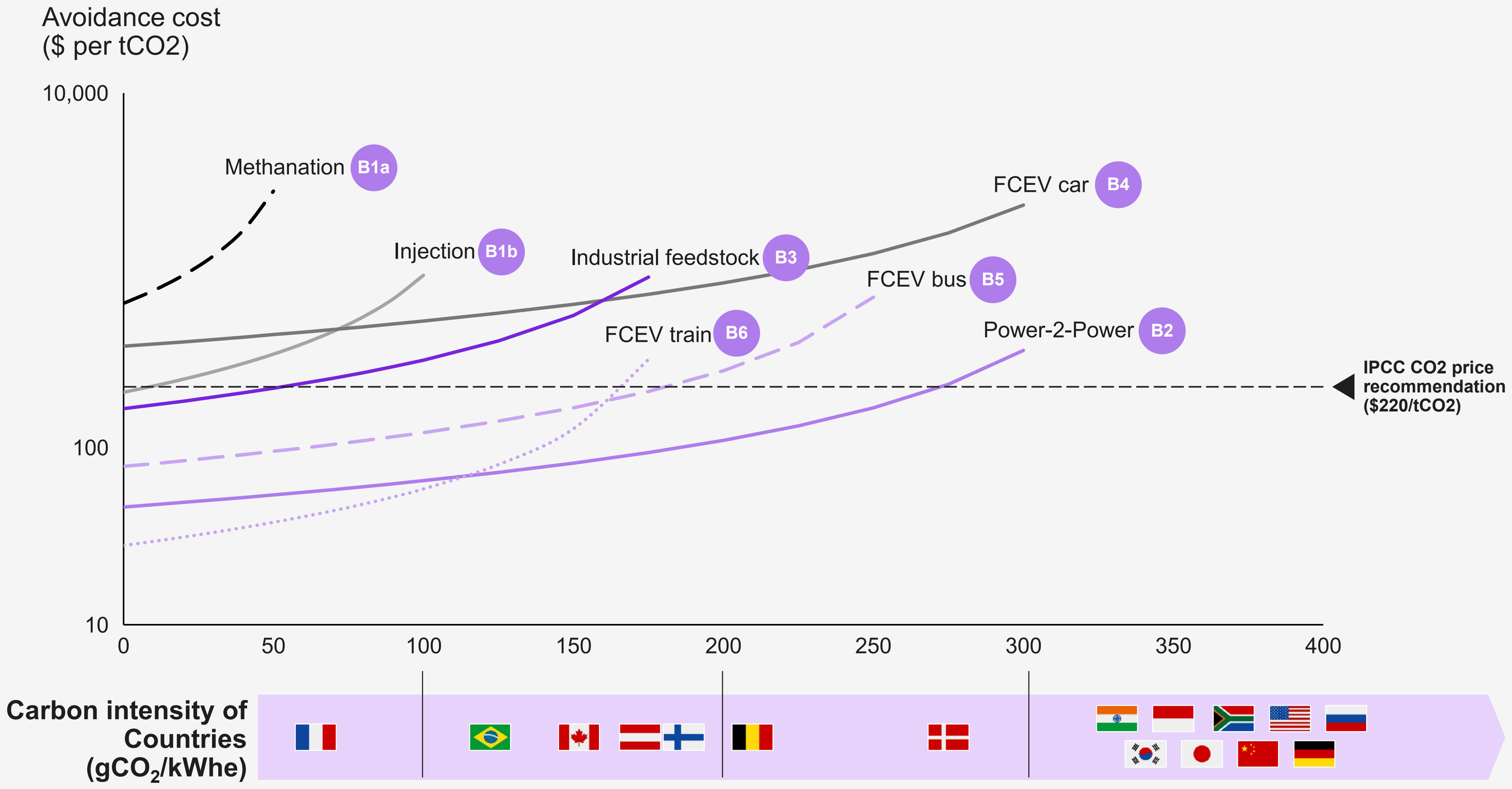
Note: CAC is carbon abatement cost. The hypothesis is detailed in the appendix.
Sources: Intergovernmental Panel on Climate Change, Organisation for Economic Co-operation and Development; Kearney Energy Transition Institute analysis

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 H_2 produced from grid are sustainable only if grid intensity is below 200gCO_2/kWhe.
  - A wind-powered production plant is the cheapest alternative when grid emissions are above about 100gCO_2/kWhe.

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 tCO_2 log scale; X axis: CO_2 emissions in kg/MWhe)

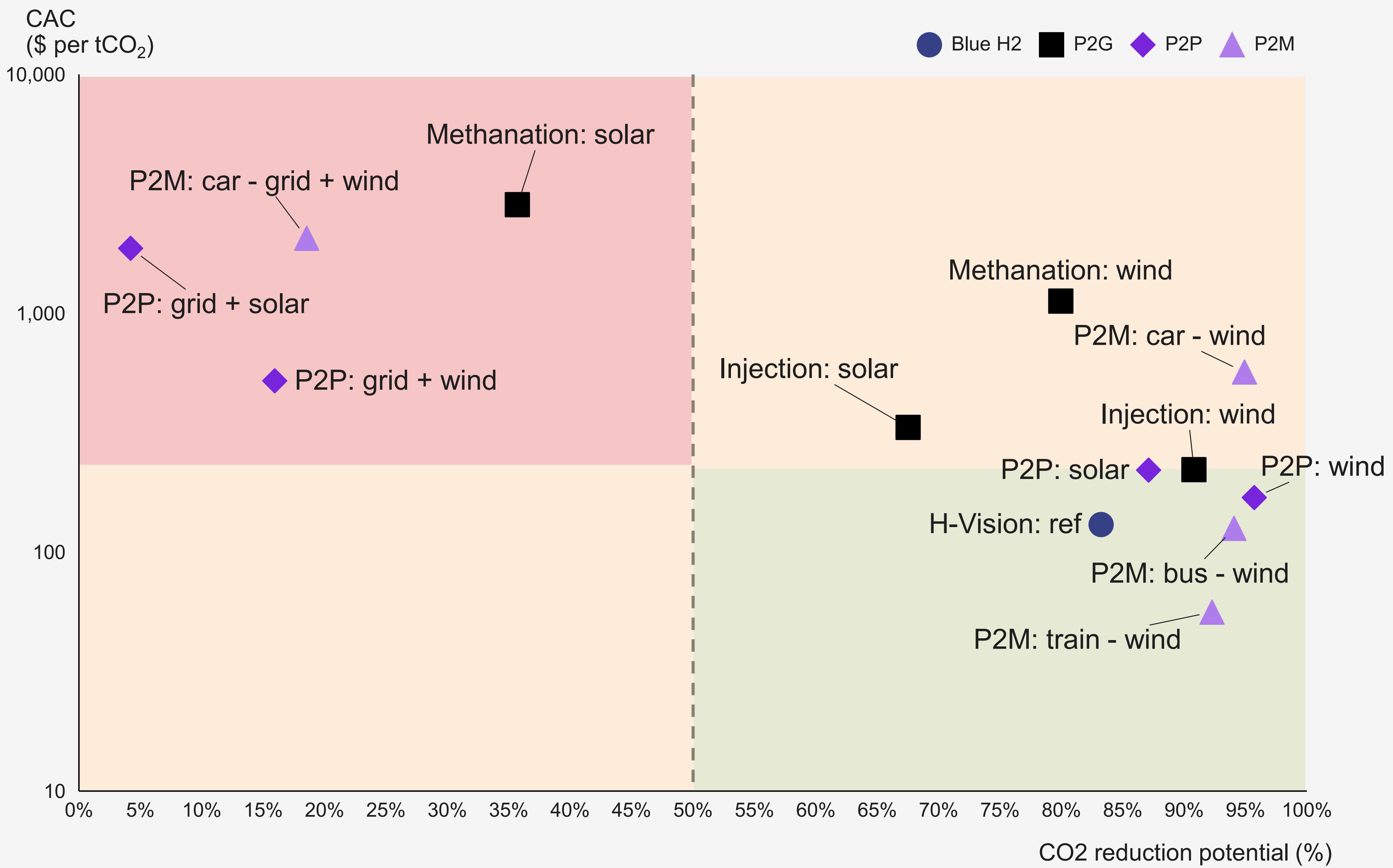


Note: IPCC is Intergovernmental Panel on Climate Change.
Source: Kearney Energy Transition Institute analysis

4.2 **Business models – Business cases**

Power-to-mobility, power-to-power, and Injection coupled with renewable production have high potential to decarbonize their sector at low cost

Carbon reduction potential vs. Carbon abatement cost (CAC)



Note: P2M: Power to Mobility; P2P: Power to Power
Source: Kearney Energy Transition Institute

4.2 Business models – Business cases

Large-scale H_2 production that can serve multiple users to maximize load factor is vital to competitiveness

Illustrative H_2-electrolysis hub

Source: Kearney Energy Transition Institute

4.2 Business models – Business cases

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Appendix
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Appendix
Bibliography & Acronyms

Acronyms – (1/2)

AC/DC	Alternating/Direct current
AFC	Alkaline fuel cell
AFOLU	Agriculture, Forestry and Other Land Use
API	American Petroleum Institute
BoP	Balance of plant
BTU	British thermal unit (Btu)
BEV	Battery electric vehicle
CAES	Compressed air energy storage
CAGR	Compound annual growth rate
CAPEX	Capital expenditure
CCS	Carbon capture & storage
CHP	Combined heat and power
CNG	Compressed natural gas
CO_2	Carbon dioxide
DH	District heating
DME	Dimethyl ether
DSO	Distribution system operator
E	Electricity
EPEX	European Power Exchange
FC	Fuel cell
FCEV	Fuel cell electric vehicle
FCHJU	Fuel Cell and Hydrogen Joint Undertaking
FIT	Feed-in tariff
GHG	Greenhouse gas
GtCO2eq	Giga tonnes of CO2 equivalent
H2	Hydrogen
H2ICE	Hydrogen internal-combustion-engine vehicle
HDS	Hydrodesulfurization
HENG	Hydrogen enriched natural gas
H-Gas	High calorific gas
HHV	Higher heating value
HT	High temperature
ICE	Internal combustion engine
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRR	Internal rate of return
K	Kelvin (unit of measurement for temperature)
kWh	Kilowatt hour
LCA	Life cycle analysis
LCOE	Levelized cost of electricity
LCOH	Levelized cost of hydrogen
LDV	Light duty vehicle
L-Gas	Low calorific gas
LHV	Lower heating value
LOHC	Liquid organic hydrogen carrier
LPG	Liquefied petroleum gas
MCFC	Molten carbonate fuel cell
MEA	Membrane electrode assembly
MtG	Methanol-to-gas
NG	Natural gas
NH3	Ammonia
NPV	Net present value
NREL	National Renewable Energy Laboratory
O&G	Oil and gas
O&M	Operation and maintenance
OPEX	Operating expenditure

Acronyms – (2/2)

Pa	Pascal (Unit of measurement for pressure)
P2G	Power-to-gas
P2P	Peer-to-peer
P2S	Power-to-synfuel
PAFC	Phosphoric acid fuel cell
PCM	Phase change material
PEM	Proton exchange membrane
PES	Primary energy source
PGM	Platinum group metal
PHS	Pumped-hydro Storage
PV	Solar photovoltaic
R,D&D	Research, Development & Demonstration
RE	Renewables
REC	Renewable energy certificate
RES	Renewable electricity source
SMES	Super-conducting magnetic energy storage
SMR	Steam methane reforming
SNG	Synthetic natural gas
SOEC	Solid oxide electrolyzer cell
SOFC	Solid oxide fuel cell
STES	Seasonal thermal energy storage
T&P	Temperature and pressure
T&D	Transmission and distribution
TCM	Thermo-chemical material
TCNG	Turbocharged natural gas
TEPS	Total primary energy supply
TSO	Transmission system operator
URFC	Unitized regenerative fuel cell
USDOE	US Department of Energy
VRB	Vanadium Redox Batteries
W	Watt
Zn/Br	Zinc-bromine

Appendix
Bibliography & Acronyms

Kearney Energy Transition Institute

The Kearney Energy Transition Institute is a nonprofit organization. It 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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