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POWER-TO-GAS

RENEWABLE HYDROGEN ECONOMY FOR THE ENERGY TRANSITION

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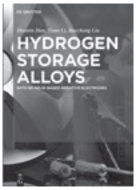

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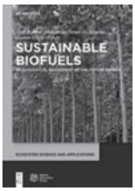

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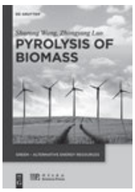

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Power-to-Gas

Renewable Hydrogen Economy

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To my mother
To my family

Foreword

Transport, industry, housing, services sector: the “drivers” of these activities are the energies necessary to move, produce, heat or light, distract, for example. Electricity (which is not an energy source but an energy vector) plays an increasing role.

This trend, on the one hand, is due to the increase in requests of standards for buildings (both residential and commercial buildings), leading to a reduction in heat requirements. On the other hand, development and extensive use of the Internet, computer and multimedia technologies, including office automation, have increased the number of equipment used and electricity consumption in some sectors.

Generation of electricity began in the nineteenth century and relied on hydropower, coal and natural gas. In the twentieth century this generation was extended to other technologies such as nuclear. Consequently, there have been increased atmospheric pollution (CO_2, particulates, etc.) and nuclear risks (not only at the plant level but also with regard to storage of radioactive waste).

The need to reduce CO_2 emissions has pushed towards creation of new “clean” electricity production paths, such as photovoltaic or wind power, with hydropower still in use. Although the number of facilities has exploded mostly because of subsidies, these facilities now allow for a significant production of renewable electricity, which can reach more than 50% of total electricity production, depending on the country and weather conditions.

Electricity production unfortunately has a major drawback: variability. Mainly depends on meteorological conditions such as wind and sunshine. Even if forecasts are fairly accurate, production maxima do not always coincide with consumption, resulting in higher than demand production; hence, there arises the need to be able to store this excess electricity for later use, regardless of its form.

Among the many technologies available, and depending on the country and the current or expected surplus volumes, which are sometimes large, the one that is going to emerge should allow the maximum of this surplus to be stored.

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Contents

Introduction

Faced with environmental challenges (pollution, reduced fossil fuel reserves, nuclear waste etc.) and a growing demand for energy, there is the necessity of a sustainable solution. Renewable energies such as wind and solar are unfortunately subject to weather conditions and therefore to a variability of production. As a result, there already exists a gap between production and consumption today and will increase in the future. It is therefore necessary to store unused electricity produced in order to be able to recover it during times of high demand or to use it in another form.

What technology should be used to store this excess electricity? The first solution that comes to mind is batteries. Although some have relatively large storage capacity, costs and limited lifetime do not allow for large-scale use. Other solutions exist, but all are limited in their storage capacity, compared to expected surpluses.

Apart from direct storage of electricity, the other approach is to convert it into another form to be able to store it. This is where electrolysis comes into play, i.e. conversion to hydrogen and oxygen, hence the name **power-to-gas.**

This hydrogen can be stored in different forms, converted into another gas (e.g. methane) or, if necessary, converted again into electricity in a fuel cell or a gas-fired power plant (or a cogeneration unit). Whatever the intended use, the excess electricity will be valued.

Although this approach seems to be the most elegant in terms of energy and technology, it still has some disadvantages. On the one hand, the cost of these installations are still high and, on the other hand, the hydrogen conversion capacity is still low compared to the current quantities of surplus electricity, and even more for those projected for the next decades.

Despite all, the power-to-gas technology combined with a decentralised approach (local use of hydrogen or methane) and optimised management at all levels, be it production, distribution or use (micro grid, smart grid, virtual power plant) would allow a better coverage of the needs as well as a facilitated stabilisation of the electricity networks.

The stakes of power-to-gas can only be seen in the context of the overall production and consumption of energy and their associated issues.

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1 Global energy consumption

In recent decades, there has been a significant increase in global energy consumption in virtually all sectors, led by the so-called emerging countries such as China and India. Non-renewable sources of energy, which are still predominant, lead to increasing pollution, nuisances and greenhouse gas levels. Faced with the consequences on the population, fauna, flora and climate, it is necessary to turn to renewable energies.

One of the factors to be addressed before defining the potential of power-to-gas technology is the overall energy consumption, its evolution and the associated technical challenges (production, distribution and storage).

1.1 Strong growth in energy demand

The overall increase in prosperity leads to an increase in energy requirements, whether for transport, industry, tertiary or residential sector. The evolution of the gross national product is an indicator of the energy consumption, although there remains a factor of uncertainty on the relation between these two parameters, whose projections for the next decades try to predict by studying several scenarios.

1.1.1 Evolution of total energy consumption

Data for recent decades show a steady increase in consumption (Figure 1.1), even if it is weighted by climatic variations or economic crises.

This energy comes from different sources: Non-renewable sources such as oil, coal, gas and uranium, and renewable sources such as wind, solar and hydropower. The contribution of each of these sources also varies from country to country (Figure 1.2).

A comparison of consumption trends shows that for many countries there is a tendency towards a decline or stabilisation of primary energy consumption (Figure 1.3) in recent decades. However, this does not mean that consumption by energy type or sector has also declined or remained stable, as shown in Chapter 2.

1.1.2 Energy storage

While solid or liquid fuels can be stored in large volumes, electricity can only be stored for small quantities in relation to production and consumption for technical (mainly relatively low capacity of available systems) and financial (high costs per kilowatt for some solutions such as batteries) reasons. Electricity storage therefore remains very limited in relation to consumption (Table 1.1) or production capacity.

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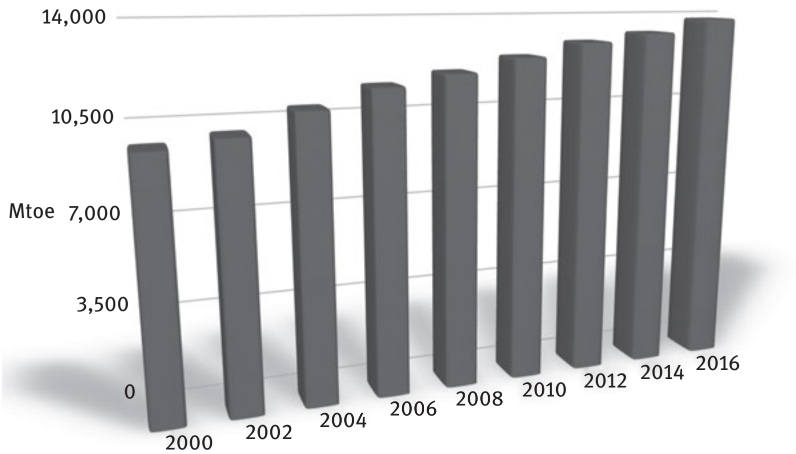

Figure 1.1: Global gross energy consumption in Mtoe (BP Statistical Review of World Energy 2016).

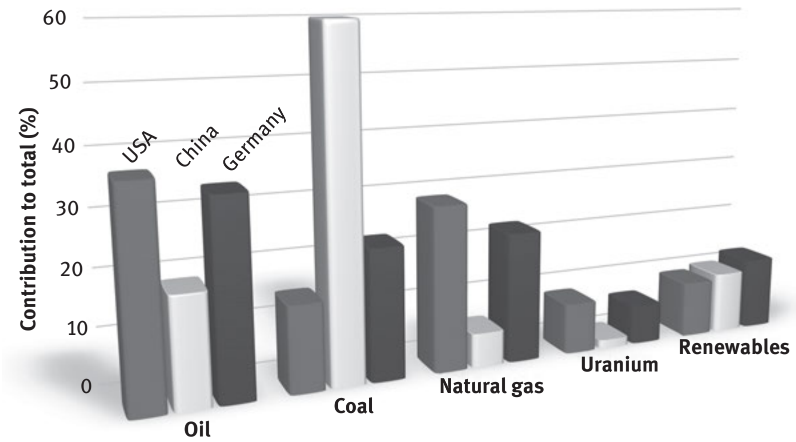

Figure 1.2: Contribution of different energy sources in Germany, China and the USA in 2016 (Data: US Energy Information Administration, AGEB (Germany), BP Statistical Review 2017).

The actual storage capacity of electricity is out of proportion in relation to production capacity or consumption when compared to that of natural gas or stored petroleum products. In the USA and China, the capacity of electricity storage accounts for about 2–3% of production capacity, with Japan being an exception, which is close to 9%. One could certainly include some of the hydropower plants as "latent" electricity, but they cannot be really considered as storage.

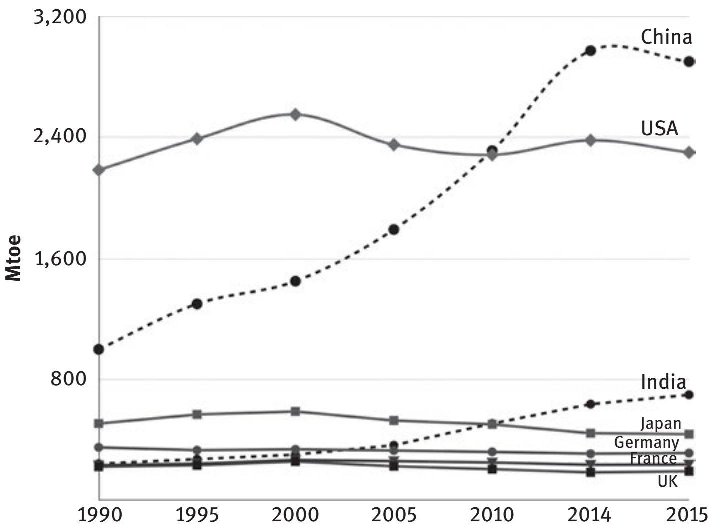

Figure 1.3: Comparative changes in primary energy consumption.

Table 1.1: Electricity storage capacities (Data: BP Statistical Review of World Energy 2016; BMWI, Germany; RTE, France).

	USA	China	Japan	Germany	France	UK
Electricity production						
Yearly production (TWh)	4,100	5,810	1,035	650	570	340
Production capacity (GW)	1,092	1,646	325	200	92	81
Electricity storage						
Storage power (GW)	31	32	28	9	5	3

Security stocks for oil, petroleum products and gas

Each country stores gas and crude oil or petroleum products to meet either significant demand or a shortage. The IEA (International Energy Agency) is requesting and the European Union imposes, for example, a minimum stock of 90 days of net imports of petroleum products.

In China for 91 million barrels of storage in 2014, the daily consumption was 10.7 million barrels per day, meaning nine days of consumption only. The goal of the Chinese government is to have a storage capacity of 500 million by 2020.

For natural gas, the USA in 2016 had a maximum storage capacity corresponding to 62 days of consumption and Germany theoretically has 100 days of reserves against 20 days maximum for the UK.

Unlike the storage of electricity, gas, liquefied natural gas (LNG) and oil or petroleum products stocks allow an autonomy of up to several months (Table 1.2 – storage capacities are the maximum volumes and not necessarily those stored). The actual volumes in reserve vary according to management strategies, market prices (e.g. purchases when prices are low) and level of consumption in relation to production or import.

Table 1.2: Maximum storage capacity in millions of tonnes (Data: BP Statistical Review of World Energy 2017).

	USA	China	Japan	Germany	France	UK
Petroleum products (million tonnes)						
Yearly consumption	863	578	184	113	76	73
Storage capacity	88	90	42	32	37	14
Gas (billion m^3)						
Yearly consumption	779	210	111	81	43	77
Storage capacity	132	17.7 + LNG	20	22	12	4.6

By the end of 2014, China had a storage capacity of 17.7 billion m^3 of natural gas (with 3 billion m^3 in stock) and 37 million tonnes of LNG (with 20 million tonnes in stock). The maximum capacities of these reserves as well as the quantities stored are also constantly changing, in view to ensure energy independence from potential risks (conflicts, high prices etc.).

1.1.2.1 Electricity peak load

The management of peak loads (Figure 1.4) is critical for electricity suppliers. It depends mainly on the use of this electricity. Electrical heating is still widespread in some countries and, at very cold temperatures, demand is rapidly increasing. Electricity providers must be able to respond to them without delay. They have to balance real-time production and consumption and instantly smooth out these peaks.

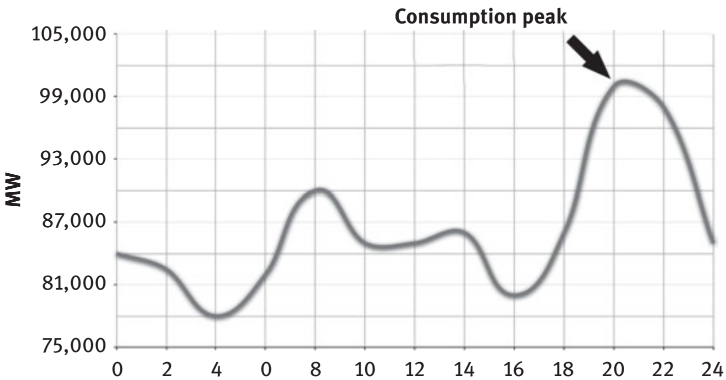

Figure 1.4: Example of peak consumption.

In case of demand greater than production, the low capacity of the electricity storage units requires either the use of imports if possible or run gas-fired power plants with a very rapid start-up time.

1.1.3 Consumption by sector of economy

Among the different sectors of the economy (housing, tertiary, industry, agriculture, transport), changes in energy consumption in recent years have experienced different trajectories. While in the long-standing industrialised countries (USA, Japan, UK, Germany etc.), the industry has been able to reduce its consumption, transport, residential and tertiary, have seen a steady increase in consumption in recent years, only modulated by climatic variations (e.g. a mild winter reduces heating consumption whereas a hot summer leads to an increase in the electricity consumption due to air conditioners). China does not yet show such a trend: It still has a very intensive energy industry (Figure 1.5).

Gross consumption and final consumption

The energy contained in raw sources such as oil, natural gas and uranium (primary energy) represents what could be used if the "extraction" yield was 100%. However, the different processes of transformation (coal, uranium or gas into electricity and/or heat) sometimes have significant losses (in a nuclear power plant only about one third of the initial energy is converted into electricity). The usable energy is called final energy.

1.1.4 Projection of the evolution of world energy consumption

In order to meet this growing demand, the strategies of each country are differentiated according to the resources available. Different models try to predict the evolution of consumption. Since the starting hypotheses are variable, at least two cases are often considered: the one with an evolution using the current mode of production and consumption more or less modulated (high hypothesis) and the other with an energy-oriented approach (low hypothesis).

The World Energy Council published a study in 2013 [1] with two scenarios: Jazz for widespread access to affordable energy and Symphony based on a priority on environmental issues (Figure 1.6).

Electricity generation and consumption will see a significant growth: from 17% of final energy consumption in 2010, it will rise to 27% (Jazz scenario) or 32% (Symphonie scenario). This study was completed in 2016 [2] and extended to 2060 with three scenarios: Modern Jazz, Unfinished Symphony and Hard Rock.

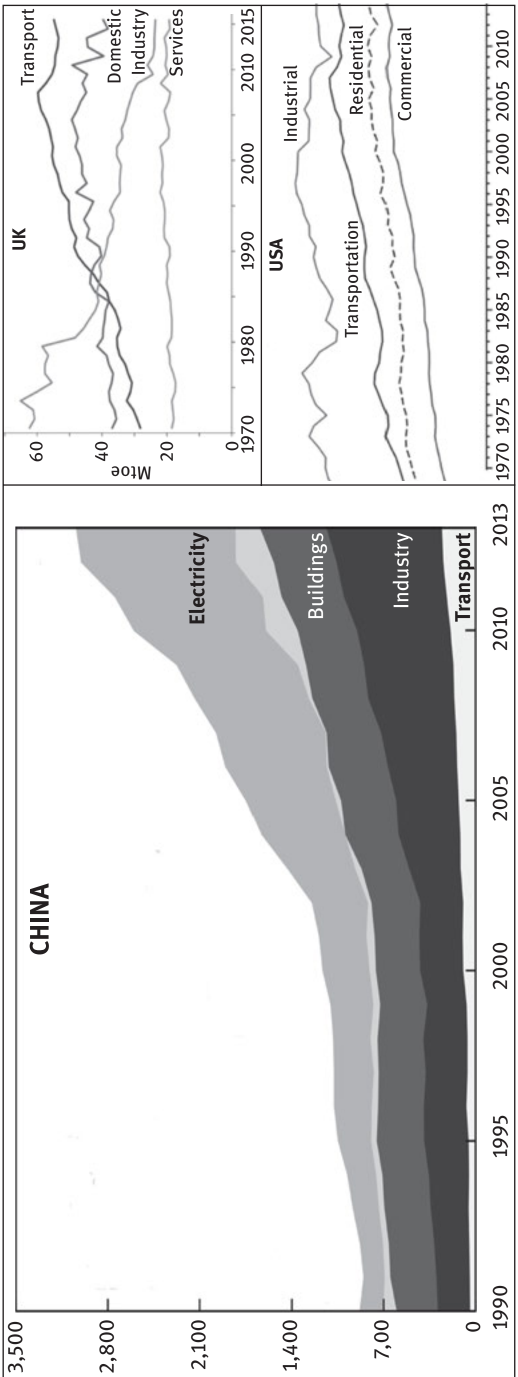

Figure 1.5: Evolution of energy consumption (Data: UK Department for Business, Energy & Industrial Strategy, US Energy Information Administration, IEA World Energy Outlook).

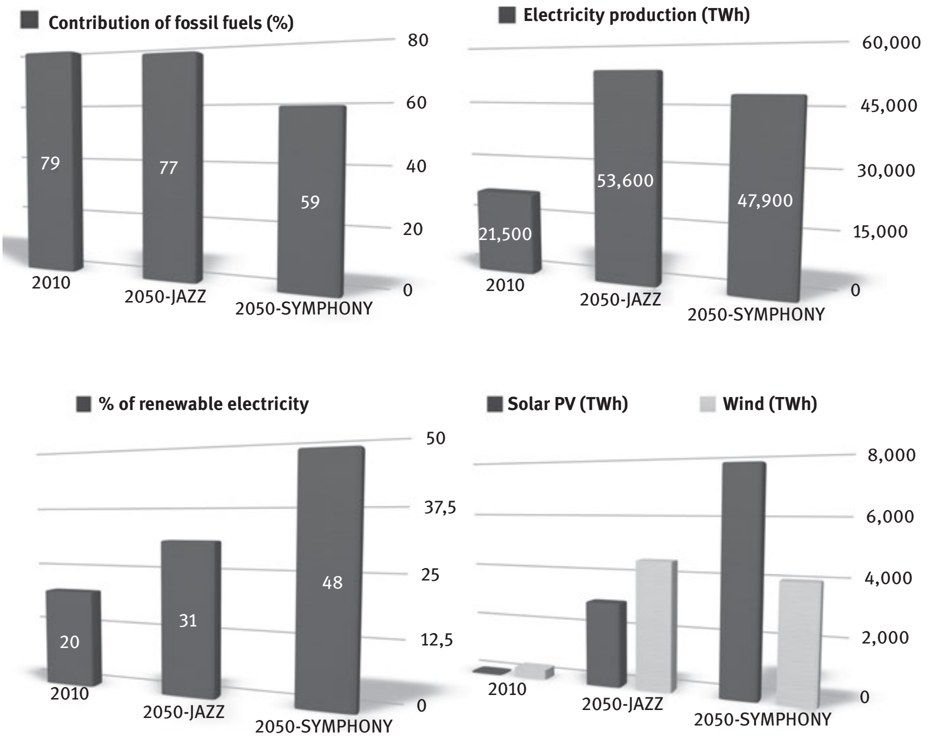

Figure 1.6: World Energy Council 2013 Scenarios.

Another study of 2015 (BP Energy Outlook 2035) is also in line with these forecasts with 18,000 Mtoe of primary energy consumed in 2035 (13,000 in 2010). Similarly, the report "Shell energy scenarios to 2050" expects 880 Exa Joules of primary energy produced (21,000 Mtoe) and an electricity consumption of 175 Exa Joules (48,000 TWh).

1.1.5 Potential for renewable energy sources

In 2009, Richard Perez, one of the IEA/SHC experts (Solar Resource Knowledge Management), compared the different sources of energy to global consumption [3]. It emerges that solar energy is, by far, the renewable source that not only could theoretically cover all human needs but also have no limit in time, at least as long as the sun is active. In this study, wind power can make an important contribution to energy production (Figure 1.7).

The annual solar energy reaching the surface of the earth is about 200 million TWh. Theoretically, it would be possible to produce 30,000,000 TWh of electricity annually from solar (photovoltaic or concentration with a 15% efficiency), 613,000

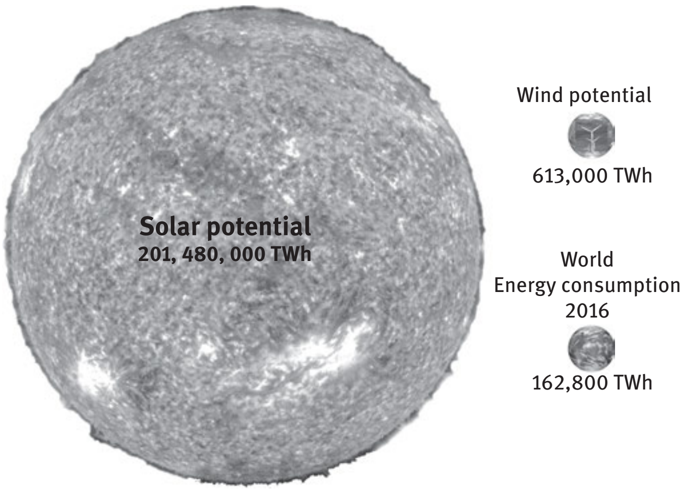

Figure 1.7: Potentially useful renewable energies (not to scale).

TWh from wind and 4,000 TWh from geothermal and hydroelectricity. World primary energy consumption in 2016 reached 14,000 Mtoe (about 162,800 TWh), or 1/1,200 of the total solar energy received!

Limitations

These energy sources produce only electricity (or heat) that can be used by all sectors of the economy and potentially largely replace non-renewable ones. These renewable energy sources may not necessarily directly replace all others, if only for the production of certain synthetic products, for example.

1.2 Electricity production and consumption

In the residential sector, the increase in the overall standard of living and the desired comfort as well as the development of technologies, such as multimedia or the Internet, lead to growth or stabilisation at a high level of electricity consumption. Despite the reductions in consumption of various equipments, their multiplication partially cancels efforts to reduce overall consumption.

1.2.1 Power generation

Electricity generation is still dependent on non-renewable energy sources, varying from country to country (Table 1.3).

Table 1.3: Electricity production by primary energy (%).

	China		USA		Japan		Germany		UK	
	2000	2016	2000	2016	2002	2015	2000	2016	2000	2015
Coal	68	64	52	30	21	34	51	40	37	27
Natural gas	1	3	16	34	24	40	8	12	28	27
Uranium	3	4	20	20	28	1	30	13	28	23
Oil	2	5	3	1	1	9	1	1	2	1
Hydro	26	19	7	6	9	9	4	3	1	1
Renewable	1	5	1	8	17	4	2	26	2	17
Others	–	–	1	1	–	3	4	4	2	3

Data: BDEW, Germany; IEA (values are rounded and totals do not necessarily correspond to 100% due to variations of data by source and rounding). For Japan, renewables in 2000 are mainly biofuels and biomass, while in 2015, wind and photovoltaic are the most important.

These comparisons show not only the importance of coal but also the great dependence of some countries on a single technology such as France with nuclear (78% in 2016), for example, while the other countries have at least a second source of electricity production (e.g. hydro for China and coal for Germany or the USA). Swedish production, is mainly divided between hydroelectricity (47% in 2015) and nuclear power (34%). In Japan, the total shutdown in March 2011 of nuclear power plants following the Fukushima accident led to an increase of the contribution of natural gas and coal (the first reactor was returned to service in September 2015).

1.2.1.1 New development or decline of nuclear energy?

By the end of 2015, 441 nuclear reactors were operational worldwide with a capacity of 383 GW. They produced about 11% of the world's electricity. Although many are under construction or planned, especially in China and Russia, by 2040 nearly 200 will have to be stopped (in 2016, 56% were over 30 years old and 15% were over 40 years old). The number of new reactors is still questionable due to delays in many construction sites (complex structures, increased safety measures and high costs) and, at best, the percentage of electricity produced is expected to remain stable. The plants under construction benefit from artificially high subsidised prices: for the British plants at Hinkley Point C (the study of which was launched in 2007 and the construction by the French EDF and the China General Nuclear Power Corporation decided in 2016), the government-guaranteed price of £92.50 is more than double the market price. Operators are also faced with the high cost of updating old nuclear plants to bring them into line with increasingly drastic safety requirements (in France, they are estimated at more than 100 billion euros). Some operators are shutting down some nuclear plants because they are not profitable, as the cost of kWh has become higher than that of the market (Exelon plans to shut down two nuclear plants in 2017 and 2018). Westinghouse, a subsidiary of Japan's

Toshiba and one of the pioneers, is experiencing financial difficulties. France has to restructure its sector (EDF and AREVA) and finance this operation. The number of countries engaging in nuclear exits is also increasing (Switzerland and South Korea in 2017).

Table 1.4: Nuclear primary energy and electricity consumption in France in 2016.

Overall primary energy	Nuclear primary energy	Final electricity production	Electricity efficiency
132.2 Mtoe	105.1 Mtoe	37.1 Mtoe	28%

The treatment of the hundreds of thousands of tonnes of nuclear waste created and to come will be even more crucial, even though no country has so far been able to dispose of them for a very long period of time. While the emphasis is placed by some operators and governments on nuclear power for the absence of direct CO_2 emissions, the resulting waste is not insignificant. Globally, 266,000 tonnes of heavy metals (tHM) from used nuclear fuel were stored in 2016 with an annual increase of 7,000 tonnes. In the European Community, 122,000 m^3 of radioactive waste was produced in 2016, including 3,200 tHM and about 200 m^3 of high-level radioactive waste.

Electricity production also shows the relatively low efficiency of nuclear power plants, compared with the corresponding primary energy, which generally does not exceed 30–35% (Table 1.4). Combined cycle gas turbine (CCGT) natural gas power plants have an efficiency reaching 60%.

Electricity generation is also only a part of the overall energy production, as shown in energy flow charts (Figure 1.8).

1.2.2 Increase of electricity consumption

Despite the gains in energy efficiency of consumer goods, electricity consumption is stagnant or increasing (Table 1.5), but at the global level it is still increasing.

Table 1.5: Increase in electricity consumption in TWh (Data: World Energy Council, IEA, ENERDATA).

	1990	2000	2010	2015	Change 1990–2015
World	10,400	13,250	18,700	27,050	2.6×
China	520	1,140	3,630	4,920	9.5×
India	270	380	730	1,030	3.8×
Brazil	210	330	460	515	2.4×
Japan	790	960	1,070	920	
USA	2,700	3,600	3,900	3,850	
Germany	455	500	550	520	
France	400	420	470	475	
UK	300	375	350	330	

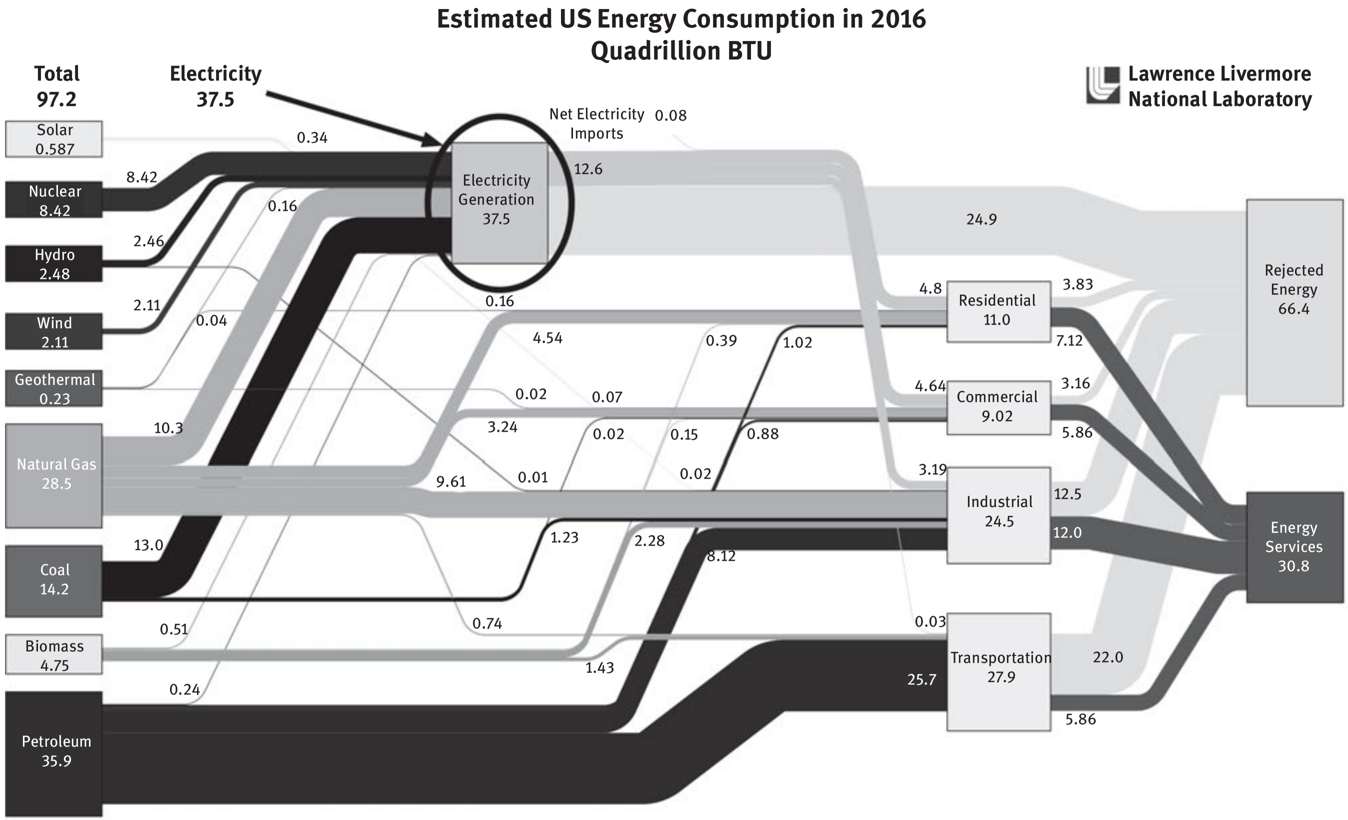

Figure 1.8: Global energy flows for the USA (Lawrence Livermore National Laboratory).

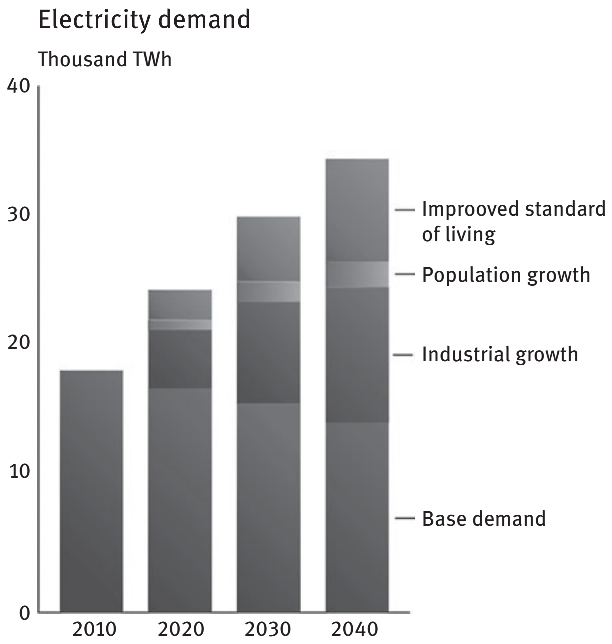

Figure 1.9: Factors affecting global electricity consumption (ExxonMobil).

A German study has shown that the factors responsible for this increase are population growth, but above all the increase in income (increasing expenditure on capital goods). This is confirmed by the ExxonMobil study (Figure 1.9) showing the increasing influence of the *improved standard of living* on electricity consumption [4].

1.2.2.1 Specific electricity

For some purposes, there is no alternative to electricity.

- For residential sector: lighting, auxiliaries such as ventilation or pumps, appliances, computers, multimedia etc.
- For the tertiary sector: lighting, office automation etc.
- For the industry: motors, machine tools, electronics, computers etc.

The trend for the residential sector is caused by an increase in this specific electricity consumption due mainly to the multiplication of equipment, especially computing, multimedia and Internet (e.g. development of streaming).

Logically, electricity should be reserved exclusively for these specific uses. Other applications such as heating of hot water or other fluids can be covered efficiently by energies such as natural gas, biogas, solar thermal or wood.

The electric vehicle

For electric vehicles or plugin hybrid vehicles (about 2 million in circulation worldwide by the end of 2015, i.e. 0.15% of the global fleet of vehicles), the forecasts for the coming decades on their number are extremely variable and often very optimistic (22 million for the IEA 4DS study or even 140 million for the IEA 2DS!). Their multiplication could also boost the power consumption for their charging and put pressure on the electricity networks and risk destabilising them as the charging can be carried out by the user at any time. The destabilisation would come rather from the rapid increase in load than from the overall consumption. Assuming 2 million electric vehicles consuming about 30 kWh per day over 300 days, the annual demand would be 18 TWh representing only 3% of German consumption in 2016. However, if 5% of vehicles use a 60 kW charger, the instantaneous demand would be 6 GW (60% of German nuclear capacity in 2016).

1.2.3 Significant growth in electricity generation from renewable sources

In recent years there has been an increase in the production of renewable electricity, mainly photovoltaic and wind (Figure 1.10). This same trend is to continue the next decades.

Not counting hydropower, the overall global production is still insufficient. If the growth rate of renewable electricity production (wind and photovoltaic) is large, it should not conceal the limited contribution (yet?) to the total electricity generation. This trend is unlikely to reverse in the coming decades faced to the strong growth in consumption. The expected results are even more disappointing if this production is compared to total energy consumption (Table 1.6) still relying on non-renewable energy sources.

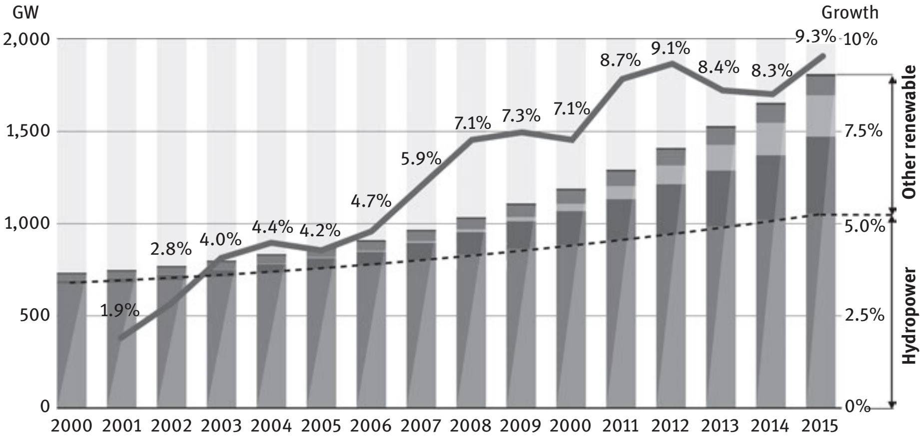

Figure 1.10: Global capacity of electricity generation from renewable sources in 2016 (IRENA).

Table 1.6: World growth forecasts of renewable electricity production (Data: ExxonMobil, IRENA, BP).

	2000	2010	2015	*2025*	*2040*	*2050*
Gross electricity generation	15,200	21,500	23,500	*27,400*	*34,000*	*47,900*
Renewable electricity	3,000	4,250	5,560	*7,200*	*10,000*	*23,000*
Included hydropower	2,650	3,510	3,950	*4,690*	*5,860*	*8,000*
Global energy production	116,300	145,400	160,500	*194,000*	*210,000*	*193,000*

1.2.3.1 Renewable electricity: a necessity

The electricity production from fossil fuels (coal, oil, natural gas or uranium) uses finite resources, which are also important for other sectors (transport, chemicals etc.). Electricity can be produced from renewable energies. The need to increase this production is not only economic but also ecological (making non-renewable raw materials last, no CO_2 emissions or other pollutants or waste to be stored or recycled as for nuclear).

1.3 Electricity market

Electricity networks are increasingly interconnected. The balance between electricity supply and demand is influenced by market exchanges where the price is fixed according to local or national criteria, such as surplus production or high demand. The exchanges are, depending on the legislation of the countries, either regulated by an organisation or left to the arbitrations between suppliers and buyers.

1.3.1 Electricity networks

All users require an uninterrupted supply of power and stable (voltage and frequency) variables. The different actors (production, Transmission and Distribution – T&D) must ensure that production and consumption coincide (Figure 1.11).

Power lines are typically high/very high (50–750 kV), medium (6–30 kV) or low voltage (≤400 V). Electricity is predominantly transported and distributed as alternating current, but land-based or underwater lines carrying DC (high-voltage direct current – HVDC) are beginning to be built. Progress in the transmission of DC allows transportation over thousands of kilometres of high power at reduced costs and with low losses (transportation of 6 GW under a voltage of 800 kV over 2,000 km with less than 3% losses).

To measure the quality of a network, the indicators used are SAIDI (System Average Interruption Duration Index), which indicates the average annual outage duration or SAIFI – System Average Interruption Frequency Index. However, SAIDI does not reliably take into account all interruptions, those that are less than 3 minutes, nor the microbreaks.

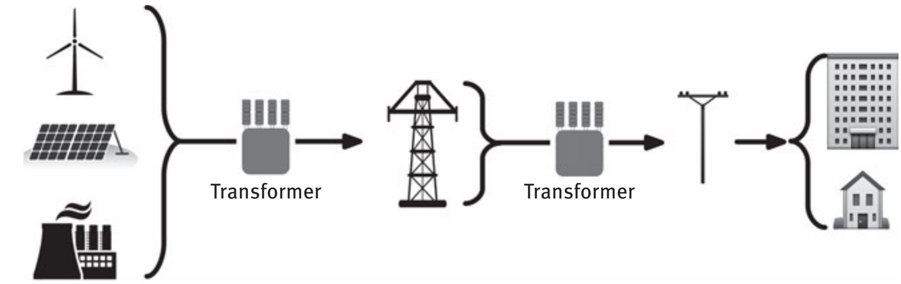

Figure 1.11: Power grid components.

1.3.2 Network stability

The criterion for the management of electrical networks, apart from the production/consumption ratio, is their stability. This is measured by the frequency variation with respect to the theoretical basic value (50 or 60 Hz).

Electricity producers (nuclear, gas, hydropower or wind farms, photovoltaic) and carriers must be able to regulate this frequency. If production and consumption balance, the frequency is stable. The inertia of the production system affects the frequency variation: if consumption is greater than production, the frequency decreases and vice versa.

If one of these two variables increases or decreases, the frequency will change. If the frequency is lower, it is necessary to increase the power supplied (production or import) or decrease the demand and, if higher, to reduce power to the grid (decrease production or increase export) or increase the load. This frequency is stabilised, but it can vary within a defined range.

In Europe, the Union for Coordination of Transmission of Electricity is responsible for defining the control of this frequency range, which must be maintained by the various operators.

Any variation must be corrected quickly. For this purpose, producers or suppliers define levels of control (primary, secondary and tertiary) that are represented by the required reserves, according to the time of use (Figure 1.12).

The stability of networks involves different power stations and strategies (Figure 1.13):

- The base load stations provide on a continuous basis the minimum level of demand, generally estimated for 24 hours (depending on the country, today it is mainly the nuclear or coal-fired plants that have this role)
- Medium-load plants correct the difference between the base load and peak loads and operate only part of the time (gas-fired plants or eventually wind farms or photovoltaic)

- The peak load units operate only for short periods of time, but have a very short start-up time and a wide range of power variation (gas or hydropower plants)
- For local solutions, batteries of high capacity (several MW) are also used

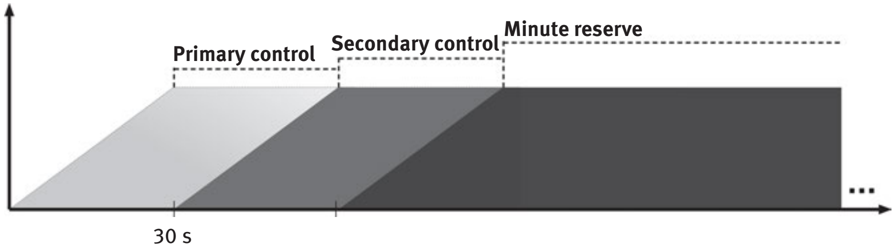

Figure 1.12: Correction of frequency changes-reserve activation.

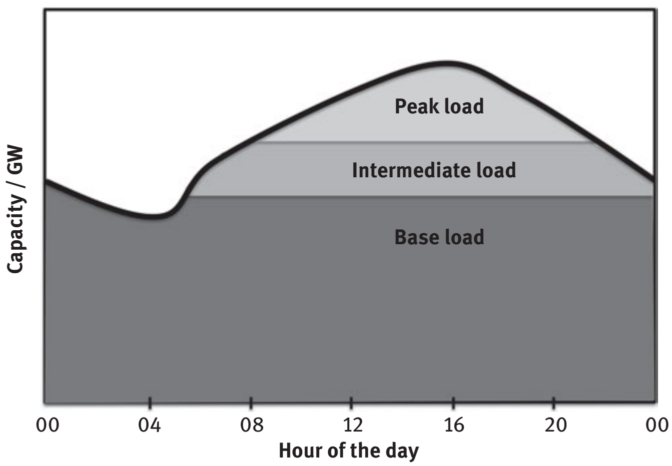

Figure 1.13: Load curve for a typical day.

1.3.2.1 Gas-fired power plants and security of supply

These power plants, which allow network regulation, especially for peak demand, have been undermined since the explosion of shale gas production in the USA. It has led to the fall in the price of coal and a massive export to Europe for use in coal-fired power plants, also favoured by the fall in CO_2 prices. Many operators put their gas-fired power station under cocoon or even plan to close it, which would entail a risk to the stabilisation of the power grids as those plants can be started very quickly.

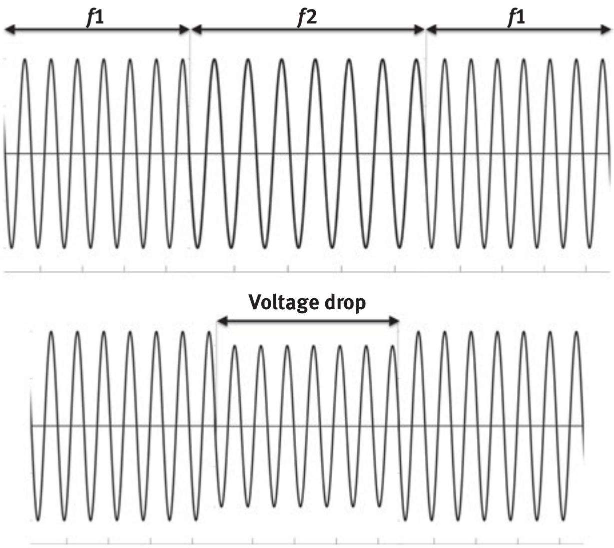

Figure 1.14: Example of variation of mains frequency or voltage.

The voltage supplied to the end user has a pure sinusoidal form of constant amplitude. Disturbances such as sudden change in load can vary the frequency (frequency excursion) or the voltage (drop) and possibly destabilise the network (Figure 1.14).

1.3.3 European electricity networks

The various European national networks are interconnected in order to facilitate trade (export of surplus or import). This network is the largest in the world (Figure 1.15). The exchange capacities vary from country to country.

Those interconnections must ensure security of supply and meet national deficits when demand exceeds production. These exchanges also allow regulation of the electricity market due to competition. Europe, through the ENTSO-E (European Network of Transmission System Operators for Electricity, grouping 20 countries in 2014), recommends an exchange capacity of at least 10% of production.

1.3.4 North American electricity network

The USA has extensive trade with Canada and Mexico. The US and Canadian networks are completely interconnected. Until 2016, the USA was divided into four zones: Eastern Interconnection, Western Interconnection, Texas Interconnection and Alaska

Interconnection (Figure 1.16). The Canadian provinces are grouped into three zones: Western Grid, Eastern Grid and Quebec Grid, including Atlantic Canada.

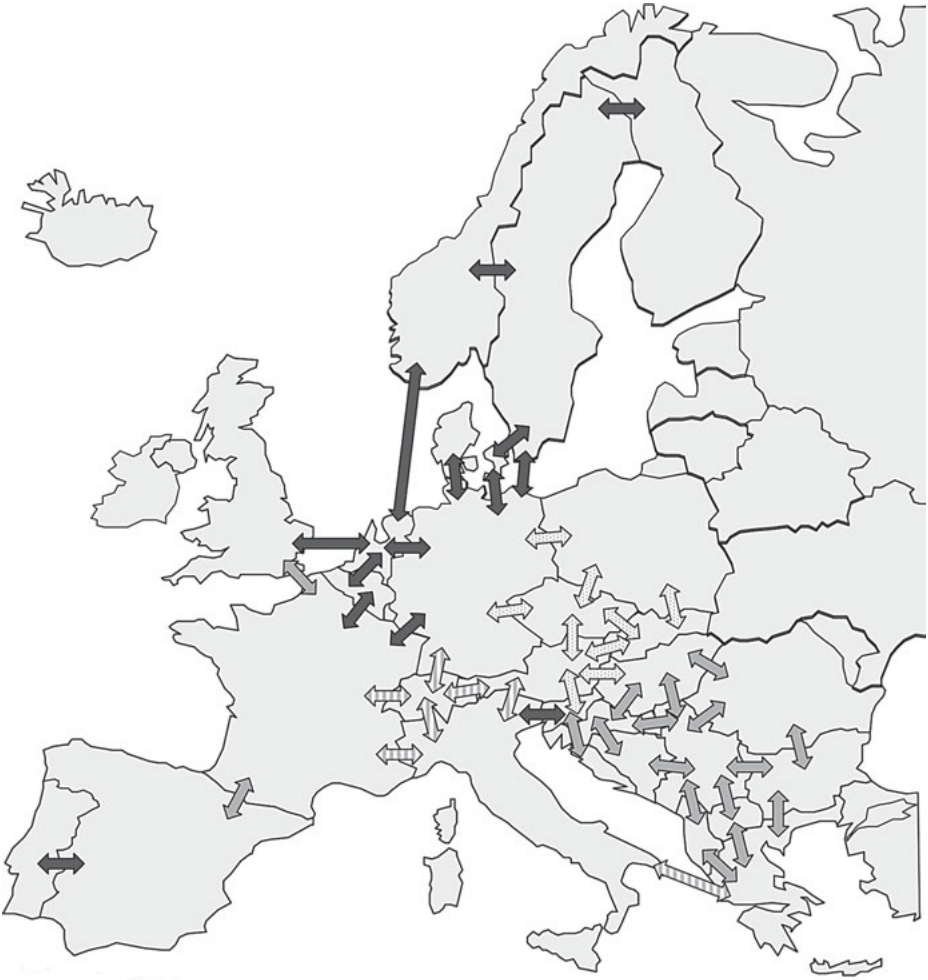

Figure 1.15: Interconnection of European electricity grids (ENTSO-E).

In 2016, the project called Tres Amigas is being implemented. It should connect the three major networks, i.e. 48 states with 8 Canadian provinces. The hub located in the state of New Mexico, point of convergence of the three networks, allows the transfer of a power of up to 20 GW. The node equipped with direct current (HVDC overlay) connecting AC networks must stabilise the network and make it more resistant to blackout. A 5 MW storage unit is used for frequency and voltage regulation.

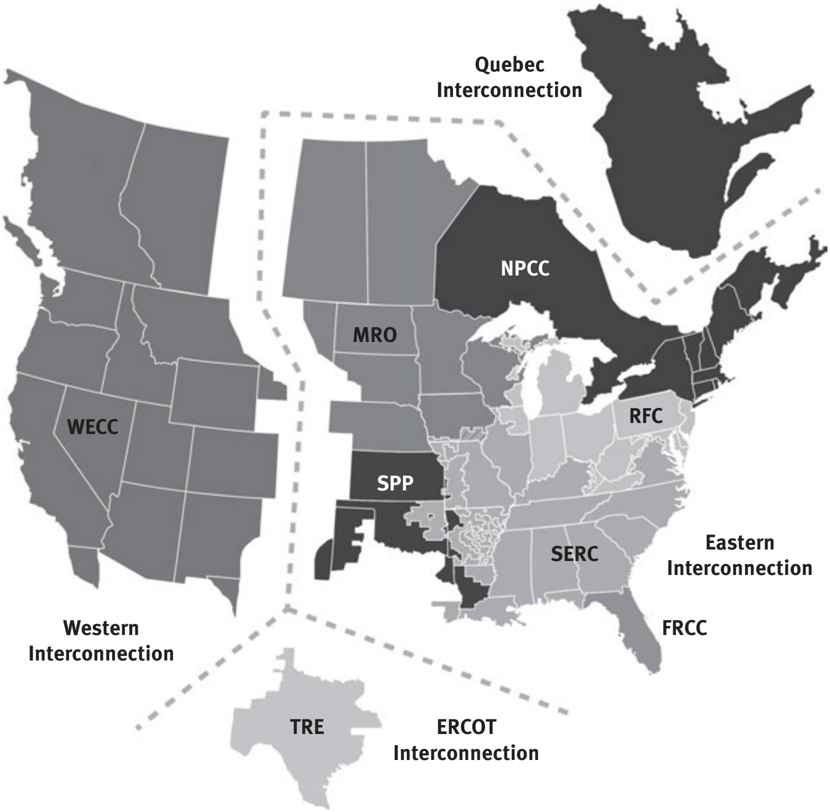

Figure 1.16: US electricity grid (EIA).

1.3.5 Other networks

In Central America, the SIEPAC initiative includes Panama, Costa Rica, Honduras, Nicaragua, El Salvador and Guatemala. It resulted in the creation of a regional electricity market (MER) and the construction of a transmission infrastructure to increase the exchange capacity. Guatemala opens up to Mexico.

Southeast Asia, through ASEAN (Association of Southeast Asian Nations), launched in 1997 actions to increase the security of supply by developing regional interconnections. The ASEAN Program of Action for Energy Cooperation 2016–2025 is expected to strengthen trade that is still often limited to bi-national agreements. An extension to the Greater Mekong Subregion zone started in 1992 covers five member countries of the ASEAN and two southern Chinese provinces (Yunnan and Guangxi).

1.3.5.1 Need for a stable network

The increase in electricity generation from renewable and intermittent sources (wind and photovoltaic) is a challenge for electricity producers and distributors. For network stability, which is solved in many countries where electricity production can sometimes reach or exceed 100% of consumption, the possibility of storing surplus electricity in large quantities can be a stabilising factor. The need for large-volume storage technologies, i.e. the **power-to-gas** technology can play a role in this security of supply.

1.4 Electricity market structure

The electricity market is divided into production, transportation and distribution. Depending on the country, these activities are carried out by one or many operators. These three sectors are not necessarily covered by all operators and depend on the old network structures and policies of liberalisation and deregulation.

In Germany, for example, very large producers (E.ON, EnBW, Vattenfall and RWE) as well as dozens of municipal authorities are active. In the USA, the market is covered at around 50% by regulated, vertically integrated structures (production, transmission and distribution – T&D), while the rest is divided among a large number of producers or distributors. A very small fraction belongs to the government or directly to the consumers. For the other extreme, in France a single operator covers more than 75% of production and controls indirectly T&D.

In Europe, the primary distribution network (HT) is usually provided by regional operators. Germany and the UK, for example, are divided into four zones (Figure 1.17). Geographical breakdown ensures competition that optimises transportation costs, which is not the case in all countries (in France T&D is still a state monopoly). Since the 1990s, the European Commission has set up an internal energy market with the creation of ENTSO-E [5]. The European electricity market has been fully open to competition since 1 July 2007. Countries such as France, Belgium, Germany and Holland (grouped as Central West Europe) have also formed a coupling of electricity prices leading to price convergence.

In the USA, the Federal Energy Regulatory Commission was created in the mid-1990s to introduce more competition into the electricity market. However, limited government regulation is necessary to control the conditions of competitiveness and possibly intervene. This gave rise to independent operators (Independent System Operators) or regional transmission organisations (TSOs). According to the Energy Information Administration, more than 60% of the electricity goes through these two groups. Public utilities, cooperatives or major cities cover about 15% of the market.

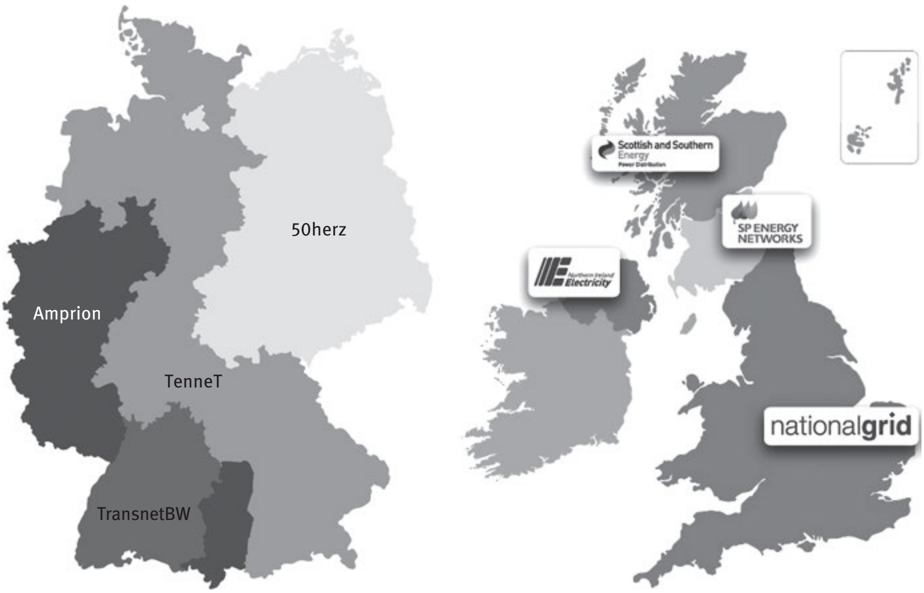

Figure 1.17: Distribution operators in Germany and the UK (BMWi, National Grid).

1.5 Structure of electricity prices

The wholesale electricity market is mainly divided into two options:
- Over-the-counter-agreements that represent the majority of transactions
- Electricity exchanges

At European level, prices are negotiated according to the time criteria (Figure 1.18), depending on the period of the transaction. Prices can be fixed in advance (several days, weeks or months). The spot price (short term) is either D-1 (day ahead) or the day of the transaction (intraday) and varies according to supply and demand.

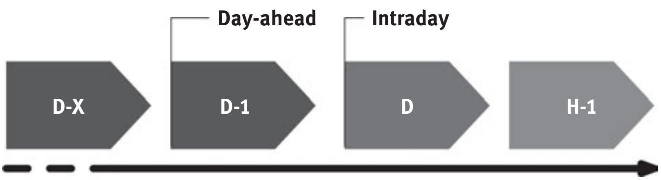

Figure 1.18: Electricity price adjustments.

These prices are traded on various stock exchanges, usually in several countries (the EPEX SPOT – European Power Exchange – for example, manages the electricity markets for France, Germany, Switzerland and Austria). In the very short term (H-1), there are still possible adjustments.

Transactions can also be traded days, months or even years ahead (Figure 1.19).

If supply is higher than demand (a situation that occurs especially when photovoltaic or wind generation is important), then prices may even be negative: the supplier pays the buyer. The example in Figure 1.20 is that of the German market on 11 May 2014 with a large renewable electricity production resulting in a purchase price of electricity of –65 €/MWh.

A record was reached in Germany on 8 May 2016 with an average of –12.89 €/MWh and a peak at –130.09 €/MWh. These phenomena are related to the very favourable weather conditions: strong wind and sun for photovoltaic.

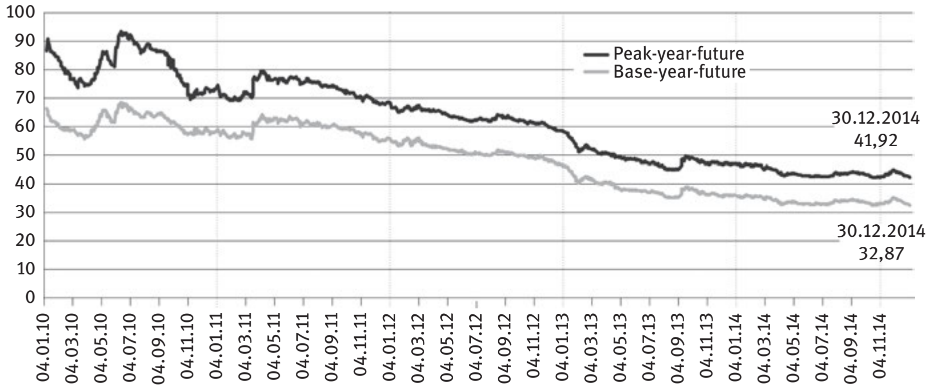

Figure 1.19: Example of fixed prices between 2010 and 2014 for delivery in 2016 (AGEB-EEX).

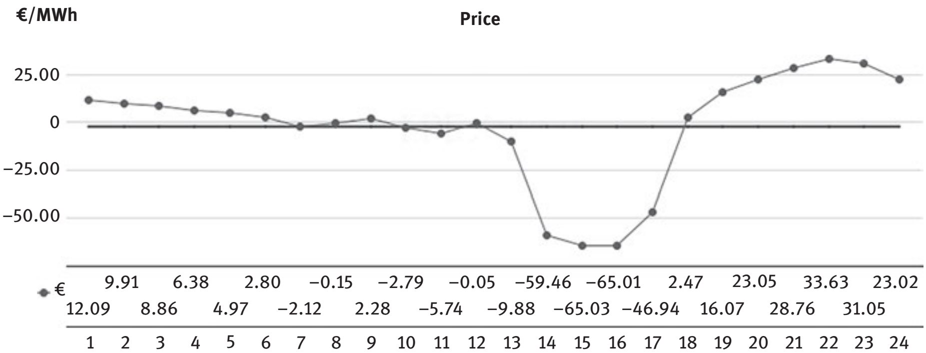

Figure 1.20: Negative electricity prices on the EPEX market on 11 May 2014 (EPEX).

1.5.1 High electricity prices for consumers

Wholesale prices (Figure 1.21) are stable or declining, while for consumers, the price of electricity is increasing. How to explain this paradox?

On average, European household prices increased by more than 40% between 2006 and 2016. The main reason is the tax subsidies to develop electricity from renewable sources and guaranteed electricity prices higher than those on the market. The interconnection of European networks has also facilitated cross-border trade. The result is an average drop in wholesale prices from €52/MWh in 2012 to around €35/MWh in 2016 (EPEX).

For the consumers, some states directly report costs of subsidies on electricity prices (EEG Umlage in Germany, Environmental and Social Policy Costs in the UK and CSPE in France). This contribution, added to the various taxes, becomes proportionately more and more important. In Germany, this tax represented 8.6% in 2010, rising to 22% in 2016 (6.35 €ct/kWh for a total price of 28.80 €ct/kWh) and 4–20% for the British consumer. It is not expected to decline in the next few years. Many states have proposed or are still proposing subsidies for the installation of photovoltaic or wind-powered systems, for example, which may also have an impact on the price of electricity.

1.5.1.1 High subsidies for non-renewable energies

However, the industrialised countries continue to subsidise fossil fuels directly or indirectly. The Organisation for Economic Cooperation and Development in a 2015 study estimates support to 160–200 billion dollars a year. The IEA is advancing to 548 billion in 2013.

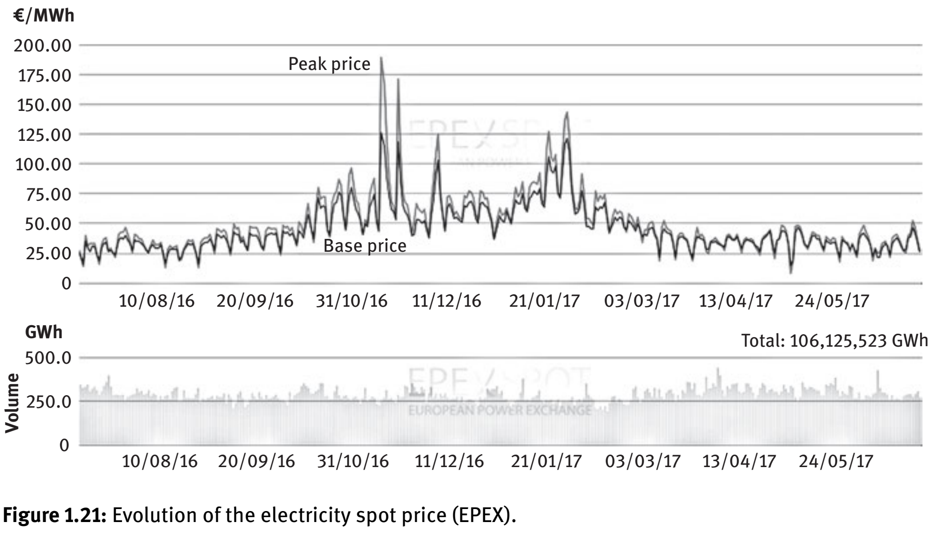

Figure 1.21: Evolution of the electricity spot price (EPEX).

These data only concern oil, coal or natural gas. The nuclear industry also benefits from substantial financial support. Two weights, two measures? Faced with electricity from renewable sources, subsidised directly by the user, these government subsidies can only favour non-renewable energies and polluting technologies.

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[2] World Energy Council, World Energy Scenarios – The Grand Transition, 2016.
[3] A Fundamental Look at Supply Side Energy Reserves for the Planet, Marc Perez and Richard Perez, 2009, Updated 2015.
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2 Electricity of renewable origin

Wind and photovoltaic have undergone significant development since the 1980s, due in part to the fact that these energies are (almost) free as far as "fuel" costs nothing and is available in abundance. Various government subsidies have also played an important role in this development. Today, the weak point of electricity from renewable sources (except mainly hydro and geothermal) is the production not related to consumption depending on meteorological conditions (wind and sun). Hence the today's need for optimised management, still combined with available non-renewable sources (coal, natural gas and uranium) in order to balance production to meet the demand.

2.1 Technologies

Renewable electricity generation is an alternative to non-renewable sources for many reasons:
- "Fuel" does not have to be imported like oil or natural gas
- Enables increased energy self-sufficiency
- Reduces balance of payments (less trade deficit)
- Promotes industrialisation (wind turbine or tower production plants, electronic control)

Specificity of electricity of hydraulic origin: The technologies that will be presented are mainly characterised by their intermittence and variability, which is not the case for hydropower or geothermal energy, for example. The hydropower stations can be controlled (started upon request) and their power is controlled by varying the flow of water. If they can contribute to the stability of the electricity grid, the question of storing the electricity produced does not really arise.

In terms of capacity, in many countries, unlike wind or photovoltaic, hydropower cannot be significantly expanded, as the potential of large resources has often been exhausted.

2.1.1 Wind energy

The wind energy production [1] is divided into land (onshore) and marine (offshore) installations (Figure 2.1), often grouped together in parks of several tens or hundreds of wind turbines.

"**Nuisance**" **of facilities:** wind turbine installations often encounter protests from residents or environmental associations (nature protection, fishing etc.). Criticisms of wind turbines include non-integration in the landscape, birds' hazards and

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Figure 2.1: Offshore wind farm (Siemens).

noise. Studies have shown, however, that these fears are often exaggerated and that localisation outside migration areas significantly reduces risk. Noise of onshore farms is covered by the wind noise.

It is also necessary to compare the few hundreds of wind turbines to the hundreds of thousands of electric pylons and associated power lines that disfigure the landscapes and also produce electromagnetic fields, sometimes installed even in inhabited areas.

2.1.1.1 Wind turbines

The power of the wind turbine generators is increasing. In 2016, Siemens presented a 7 MW model with a rotor diameter of 154 m, and in 2017, Vestas presented a 9.5 MW model with a 164 m blade diameter for a total height of 220 m. Each offshore wind turbine can produce up to 32 GWh per year, representing the consumption of 7,000 households (with an average of 4,500 kWh/household).

Repowering

This process involves replacing old turbines with new more powerful power. This amounts for the same number to increase the power supplied, or to reduce the area occupied for an equivalent power.

2.1.1.2 Wind power generation

The global capacity of wind power in 2016 (487 GW, an increase of 54 GW compared with 2015) represents the equivalent of about 450 nuclear power plants (Table 2.1). It should be noted, however, that this is a maximum theoretical capacity. World average production in 2016 represented about 28% of theoretical production and 33–43% for offshore wind turbines in Europe.

Table 2.1: Global capacity installed at the end of 2016 (in GW).

	Europe	Asia	America	Africa	Others	Total
Germany	50					
Spain	23					
UK	15					
France	12					
Others Europe	62					
China		168				
India		29				
Others Asia		8				
USA			82			
Canada			12			
Others America			19			
Total	**162**	**203**	**113**	**4**	**5**	**487**

2.1.1.3 Wind farms

At the end of 2016, more than 341,000 wind turbines were installed worldwide, including 105,000 in China, 52,000 in the USA and 28,000 in Germany. The USA, India and China dominate in terms of onshore facilities (Table 2.2).

Offshore wind is growing more and more in spite of technical difficulties [2]. Europe, with the majority of worldwide farms representing a generation capacity of 12.6 GW in 2016 (14.4 GW in the world), still has the largest number with a total of 3,600 wind turbines predominantly in the North Sea, the UK being the leader (Table 2.3).

Table 2.2: Main onshore wind farms in 2016.

Name	Power (MW)	Country
Gansu	6,000	China
Alta Wind Energy Centre	1,548	USA
Muppandal Wind Farm	1,064	India
Jaisalmer Wind Park	1,500	India
Shepherds Flat Wind Farm	845	USA
Roscoe Wind Farm	781	USA
Fowler Ridge Wind Farm	750	USA
Horse Hollow Wind Energy Centre	735	USA
Capricorn Ridge Wind Farm	662	USA
Fântânele-Cogealac Wind Farm	662	Romania

Table 2.3: Main European offshore wind farms in 2016.

Name	Power (MW)	Country	Wind turbines
London Array	630	UK	175 × 3.6 MW
Gemini	600	Netherlands	150 × 4.0 MW
Gwynt y Môr	576	UK	160 × 3.6 MW
Greater Gabbard	504	UK	140 × 3.6 MW
Anholt	400	Denmark	111 × 3.6 MW
BARD Offshore 1	400	Germany	80 × 5 MW
Global Tech I	400	Germany	80 × 5 MW
West of Duddon Sands	389	UK	108 × 3.6 MW
Walney 1 and 2	367	UK	102 × 3.6 MW
Thorntonbank	325	Belgium	6 × 5 MW + 48 × 6.15 MW

For offshore wind turbine, Siemens covered 96.4% of the European market in 2016, the remainder being supplied by Vestas.

In other countries, offshore wind starts or is slowly developing. China has an installed capacity of 1.6 GW in 2016 and the USA inaugurated the first park (Block Island Wind Park) only at the end of 2016.

2.1.1.4 Projections

In the Global Wind Energy Council forecasts, installed capacity will increase to 720 GW in 2020 (Figure 2.2).

If wind power has benefited from large subsidies such as a guaranteed price for electricity produced or a premium for kWh, this approach could change.

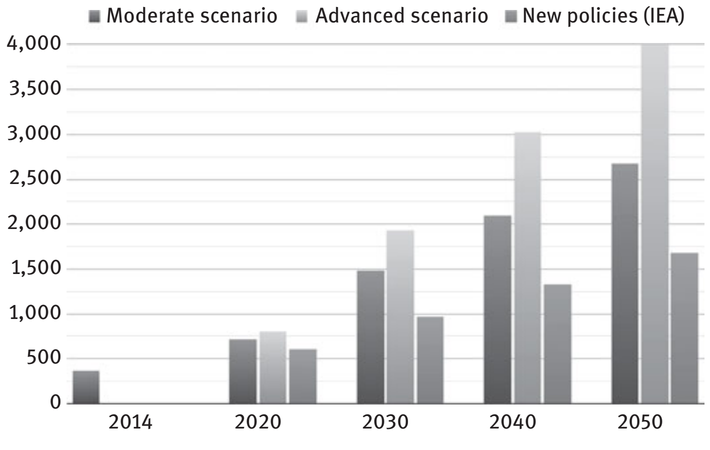


Figure 2.2: Wind development forecasts in GW (Global Wind Energy Council).

In early 2017, German energy supplier EnBW won a bid for a 900 MW farm without any subsidy or kWh premium. This can be attributed to technical developments (high-power wind turbines with higher efficiency), with the best financing conditions, this technology being now proven.

2.1.2 Photovoltaic

Photovoltaic solar energy can be divided into three segments: large-scale parks (Figure 2.3), installations on the roofs of industrial, agricultural or tertiary buildings and small installations on residential roofs. Photovoltaic is thus the only technology that can be easily implemented on a small scale (that of a residence).

The contribution and development of each of these sectors, especially for the residential sector, varies from country to country and year to year (buying price of kWh variable and decreasing). In Germany, the distribution of capacity by sector in 2015 was 36% for ground installations, 30% for commercial buildings, 19% for residential and 15% for public or agricultural buildings.

The world generation capacity installed in 2016 was 312 GW (75 GW more than in 2015, including 34 in China), of which 101 GW is located in Europe (41 GW in Germany, 19 GW in Italy and 11 GW in the UK), 77 GW in China and 42 GW in the USA.

The largest solar parks are located mainly in the USA, China and India (Table 2.4).

Figure 2.3: Photovoltaic park (Siemens).

Table 2.4: Large photovoltaic parks in 2016.

Name	Power (MW)	Country
Tenger Desert Solar Park	1,500	China
Datong Solar Power	1,000	China
Kurnool Ultra Mega	900	India
Longyangxia	850	China
Kamuthi	648	India
Solar Star	579	USA
Topaz Solar Farm	550	USA
...		
Cestas	300	France
...		
Solarpark Meuro	166	Germany

To reduce the occupancy on the ground, floating parks are installed on lakes or reservoirs of dams such as Huainan in China with a power of 40 MW. Others exist or are planned in Japan (13.7 MW), the UK (6.3 MW) or Singapore. In India, some irrigation canals are covered with photovoltaic panels that also reduce evaporation. The state of Gujarat in India has several achievements to its credit: the most important has a length of 3.6 km for a power of 10 MW. Other locations such as tunnel roofs can also be used: in Belgium, a rail tunnel is covered with panels with a capacity of 4 MW.

Photovoltaic in space: Space-based solar power consists of orbiting photovoltaic power stations transmitting electricity produced by laser or microwave to land stations [3]. The first projects dating back to the 1960s, were mainly evaluated in the USA and Japan, planning to launch a station in 2030.

2.1.2.1 Projections

The drop in the price of photovoltaic modules (US$ 0.37/W in 2016) has led to the development of large photovoltaic farms and has an influence on the prices of electricity produced. In 2017, Abu Dhabi launched a call for tenders and the proposals put the price at US$ 0.0242/kWh against 0.059 for the parks launched in 2015.

According to the International Energy Agency (IEA) or European Photovoltaic Industry Association, installed capacity is expected to grow extremely rapidly in the coming decades (Table 2.5).

Table 2.5: Evolution of photovoltaic capacity in GW according to IEA.

	2016	2030	2040
Operational	312		
New policy scenario		950	1,400
450 ppm scenario		1,280	2,100

If the drop in the price of panels has expanded the market, the production of photovoltaic electricity remains limited. It accounts for only 2% of total production in 17 countries: 10% in Honduras, 7% in Italy and Greece, and 6% in Germany. In China, despite an installed capacity of 77 GW and a production of 66 trillion kWh in 2016, photovoltaic electricity accounted for only 1% of total production.

2.1.3 Solar concentration

In the CSP (Concentrating Solar Power) technology, mirrors reflect solar radiation either to the top of a tower or to a receiver where this energy heats a fluid (water, oil etc.) that drives an alternator (Figure 2.4).

One of the advantages of this technology is that it can operate in the absence of sunlight (also at night) if during the day part of the heat produced is stored in molten salts, for example, and recovered at night to operate the turbine. If it was used as early as the nineteenth century, the first work on important industrial installations dates from the years 1960 to 1970. At the end of 2016, installed capacity was 5.02 GW (4.94 GW in 2015). Spain with 2.36 GW dominates this sector, followed by the USA with 1.8 GW, the other countries being India, South Africa and Israel. Most of the high-power installations are in Spain and the USA.

The USA had 17 operational plants in 2016. The Ivanpah plant in California, inaugurated in 2013, consists of three units comprising 300,000 piloted mirrors reflecting radiation to the top of a 150 m high tower. The maximum production is 377 MW.

In Spain, 52 power stations were operational at the end of 2016, many with a capacity of 50 MW and some with heat storage. The one located in Andasol with a generation power of 2 × 50 MW uses 28,500 tonnes of molten salt, allowing it to produce at night 50 MW for 7.5 h. The Gemasolar plant near Seville (Figure 2.5) uses 2,650 mobile mirrors to concentrate the beams towards a tower of 140 m. A salt (nitrate) is

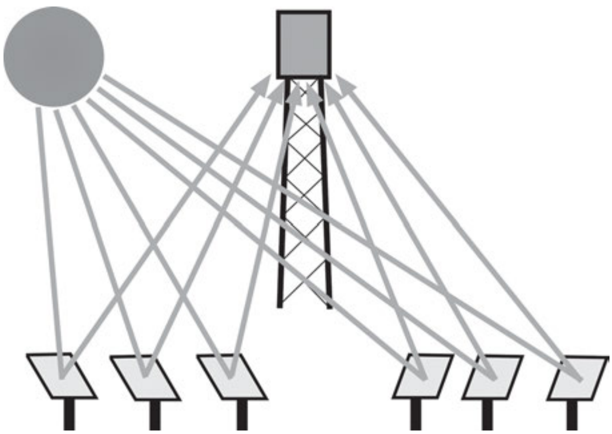


Figure 2.4: Diagram of a concentring solar installation.

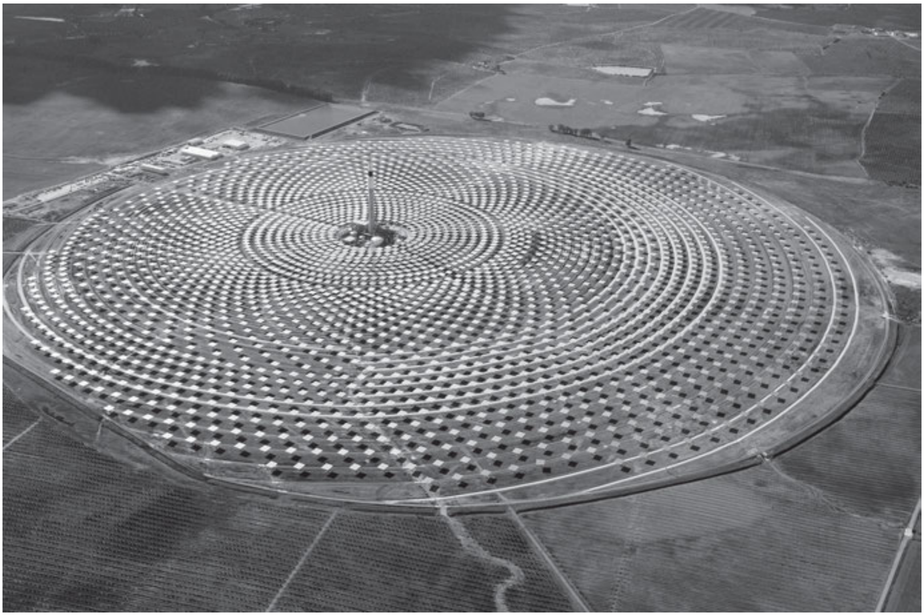


Figure 2.5: Solar power station Gemasolar (Andalusian Energy Agency).

heated to 565°C and produces steam operating a turbine with an electrical power of 19.9 MW. Thanks to the stored molten salt, the autonomy without sun reaches 15 h and the plant can operate continuously several weeks 24 h a day with an average annual production of 110 GWh.

Inaugurated in 2016 the first phase of the Noor power station in Morocco has a generation capacity of 10 MW. The second phase should bring the total power to 580 MW.

This technology is mainly used in areas of strong sunshine. Another important limitation is the high cost of such facilities also faced to the drop in photovoltaic module prices. The forecasts for 2030 estimate, depending on the scenarios, an installed capacity between 8 and 35 GW.

2.1.3.1 Solar chimneys

This technology, explored since the beginning of the twentieth century, uses also solar thermal energy but produces electricity by circulating air, heated in a greenhouse, from the base of the tower to the top, thus activating a turbine connected to a generator. This concept of the German engineer Jörg Schlaich was experimented between 1982 and 1989 with a prototype of 50 kW in Manzanares, Spain, with a tower of 195 m and a greenhouse of 46,000 m^2. In 2010, a 200 kW power plant with a 50 m chimney was commissioned in China.

While a few other projects were launched in the 2000s, no commercial projects have been implemented, since the cost of electricity produced is not competitive. In

Australia, a tower of nearly 1,000 m with a greenhouse of 5 km^2 and a generation power of 200 MW was due to be operational in 2010 but is still in draft state.

2.1.3.2 DESERTEC

This concept, developed in 2003, was meant to provide a renewable electricity network (wind, photovoltaic, CSP) located in northern Africa and the Middle East, and transmission lines (Super Grid) to Europe. The total planned production was more than 600,000 TWh/year, which could cover the needs of these countries and of Europe. This project was extended to southern Europe and then to other desert areas in the world. However, given the important investments and the political implications, no practical progress has been made since.

2.1.4 Marine energies

A variety of different projects involving several technologies are being evaluated around the world. The marine energy used can be that of waves, tides or currents. Another form is the thermal energy or the osmotic effect.

Marine current turbines are submarine wind turbines located where the sea currents are high or in the course of a river. The existing equipment are either attached to a tower anchored to the sea floor or to a frame placed on the sea floor (Figure 2.6, a model with a diameter of 10 m and a generation power of 500 kW with a current of 3 m/s).

Figure 2.6: Marine current turbine D10 from the French company Sabella.

The various constraints associated with this approach mean that potential marine areas (currents >2 m/s and geographical accessibility) are still limited. The experimental units (France, UK and Norway) are still of relatively low power, generally not exceeding 1 MW with a high cost per kW. If the production is sometimes intermittent, then it is very predictable, given the regularity of tides or currents.

The dream of the ocean currents: The Gulf Stream in the Atlantic or the Kuroshio off Japan and other ocean currents represent enormous energy potential. However, the distance to the coast and the depths to be reached are prohibitive obstacles. However, many projects, even being utopic, exist to use this gigantic potential.

Tidal energy is operational in only four countries: South Korea (Sihwa Lake, 254 MW, 2011), France (Rance, 240 MW, 1966), Canada (20 MW) and China (5 MW). It requires an appropriate site, heavy investments and may lead to risks to the ecosystem.

The exploitation of **wave energy** has attracted interest in dozens of projects. However, the experiments to date have not yielded convincing results to move to large-scale commercialisation. The most tested system (Pelamis Wave Power, 750 kW) has the structure of an articulated snake. Others use floating buoys anchored at the bottom of the sea and connected to a generator (Carnegie Wave Energy with its CETO 6 model 20 m in diameter capable of producing 1 MW; Figure 2.7) or oscillating panels.

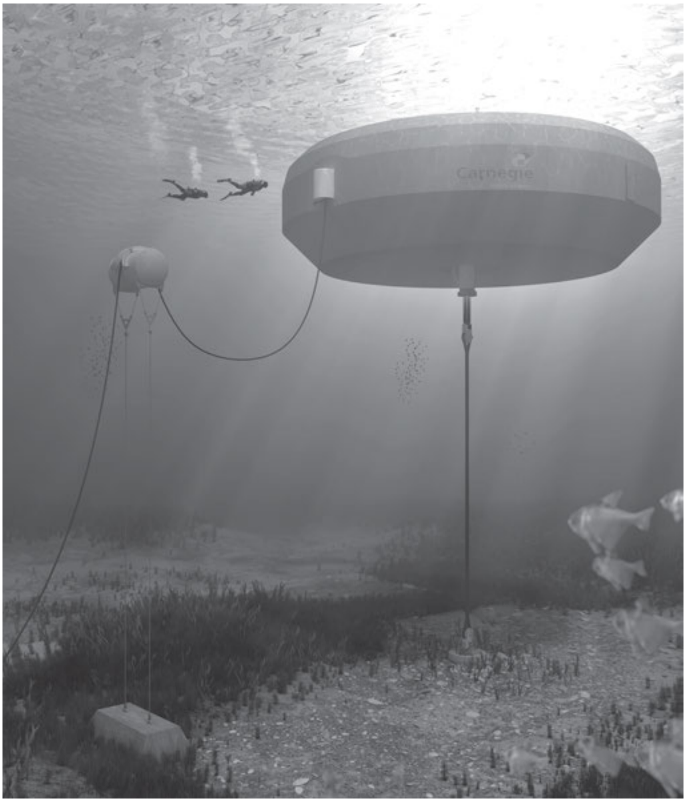


Figure 2.7: CETO 6 floating buoy (Carnegie Wave Energy).

These systems encounter technical difficulties related to sea conditions (corrosion, storms) or technology (mechanical problems).

The **ocean thermal energy** (OTEC) conversion can be exploited using the temperature difference between surface water (26–30°C in inter-tropical zones) and deep water (4°C to 1,000 m). These two sources at different temperatures can operate a thermal machine using an intermediate fluid (e.g. Rankine cycle). The yield is low (3–4%) but this technology can be a solution for islands with continuous production. The first power plant was built in Cuba in 1930, and a 1 MW Sagar Shakti mobile unit was commissioned in 2001 in India. In South Korea, a 20 kW unit is in operation with one project for another 1 MW. In Martinique, a floating unit of 10 MW is planned for 2018.

Osmotic energy uses the osmosis principle, which consists in bringing saltwater on one side of a membrane and freshwater into contact on the other. The water crosses the membrane and creates an overpressure that can turn a turbine. A 4 kW unit built in 2009 in Norway was stopped in 2014, and a 50 kW unit is under evaluation in the Netherlands since 2014. The main limitation is the "yield" of the membrane.

Limited potential of marine energy: All the solutions proposed are facing two main issues. The high costs, both for investment and maintenance, and also for the kWh produced as well as technical difficulties due to the maritime environment. While many countries have evaluation programmes underway and the overall theoretical potential for electricity generation is very large, the global contribution to electricity generation capacity is negligible, of the order of 0.5 GW in 2015 for operational units.

2.1.5 Biomass, geothermal energy

While being an indirect source of electricity production, the renewable origin of raw materials (biomass) or terrestrial energy (geothermal) makes it possible to classify electricity production as renewable. However, the possibility of managing the electricity generated (power, time of operation and running time) does not make it a variable and intermittent source such as solar or wind.

2.1.6 Renewable electricity production records

In Germany, on 12 December 2014 at 13:30, during the Hurricane Billie, production reached 29.7 GW. On the same day, 562 GWh was produced representing 30% of the German electricity generation. Between 2015 and 2017, several days saw a significant contribution from renewable electricity sources: 74% on 25 July 2015 (Figure 2.8), 90% for several hours on 8 May 2016 and 85% for part of 30 April 2017.

In **Portugal,** in 2015, the annual contribution was 48% and in May 2016, wind, photovoltaic and hydropower supplied 100% of electricity for 107 h. In **Spain**, in 2013, electricity production from renewable sources had an important contribution

(54% in April, mainly hydro and wind). A peak of 59.6% of the electricity generation was reached in 2014. In **Denmark**, in 28 October 2013 at 2 am, 122% of the consumption came from wind. For 2013, production exceeded consumption for 90 h (1,000 h are planned in 2020). In 2014, wind generated 39% of the electricity produced and 42% in 2015. Between June and August 2016, **Costa Rica** produced only renewable electricity for 76 days. Using all available renewable sources, the record set in 2015 was 299 days.

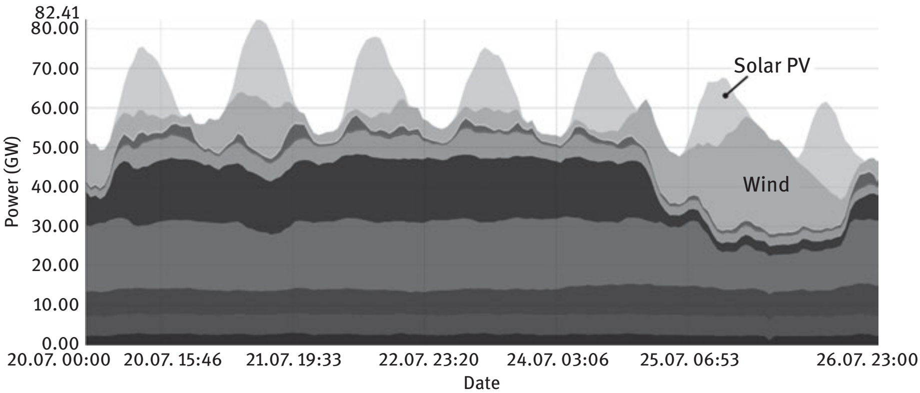


Figure 2.8: Electricity production in Germany week of 20 July 2015 (Energy-charts.de).

2.1.7 Comparison of electricity costs by origin

The price of electricity produced according to the primary energy used varies depending on the development of technologies and their extension. If the price of solar or wind electricity was initially higher than the average price from non-renewable sources, then it decreased as new facilities were developed.

Grid parity: It is the price of electricity generated by renewable sources compared to that of non-renewable sources. For some countries (Germany and Southern Italy), this parity has already been or is reached. For solar photovoltaic systems, for example, this means a lower kWh cost than the network, hence the advantage of using this electricity directly without injecting it into the grid.

Levelled cost of energy: This criterion for comparing the costs of different energies considers all those involved and, among others, variables such as initial capital, operating costs, fuel, maintenance. These costs are estimated for the lifetime of the facility. Many recent studies have compared the costs of different sources of electricity generation (Table 2.6). They present a cost range for each technology showing similar trends, but the overall trend is a drop of the price of renewable electricity.

Table 2.6: Electricity price comparison (2016 data).

Study	Gas	Coal	Nuclear	Wind onshore	Wind offshore	Solar PV
Lazard-US (US$/MWh)	48–78	60–143	97–136	32–62	118	46–61
EIA-US (US$/MWh)	56	140 (CCS)	99	64	158	85
Fraunhofer 2013 (€ct/kWh)	NA	3.8–9.8	NA	4.5–10.7	12.0–19.5	8.0–11.6
KfW-Germany (€ct/kWh)	7.5–9.8	3.8–8.0	NA	5.2–9.1	7.3–14.2	6.9–12.8

The costs of photovoltaic or wind power will continue to decrease as the number of installations increases (lower solar modules and wind turbine costs), while the one of other sources, especially nuclear power, will tend to increase (ageing of installations, maintenance costs, depollution etc.).

2.1.8 Energy transition and renewable energy

As part of an energy transition, many countries have set targets for reducing the use of non-renewable sources for energy production. According to the timetables, the deadlines are 2025, 2030 and 2050. Not all countries, however, put the needed financial or legislative means to achieve these objectives. For many countries, however, this energy transition is possible. Numerous studies show the feasibility of generating up to 100% renewable electricity from 2030 to 2050.

Europe has set a minimum of 27% renewable energy targets by 2030 with at least 30% improvement in energy efficiency and a 40% reduction of greenhouse gas emissions.

Among the pioneers, Germany has launched an ambitious energy transition (Energiewende) for 2050:
- Reduction of emissions of greenhouse gases by 80% compared to 1990 values
- Reduction of primary energy consumption by at least 50% compared to 2008
- Production of 80% renewable electricity (35% in 2020, 50% in 2030 and 65% in 2040)
- Increase in annual energy productivity by an average of 2.1% in the thermal, electrical and transportation sectors

The power-to-gas concept is seen as a key factor, which explains the number of experiments with this technology in Germany.

Concept „Energiewende“

Many countries are planning an energy transition but often without a clear global concept and/or a series of coherent long-term measures, often with little binding and sometimes unreliable targets.

Energiewende is the German concept launched by Chancellor Angel Merkel in 2011 after the explosion of the Fukushima nuclear power plants in Japan. The first measure announced was the phase-out of nuclear power by 2022. This has resulted in many reflections and accomplishments to accompany this waiver and chart new paths, such as improving energy efficiency and power-to-gas technology. This upheaval has allowed the German industry and research to be at the forefront in many energy sectors. Despite the difficulties, the questions and sometimes the doubts, Germany is staying the course.

In 2014, the German Institute Fraunhofer IWES (Institute for Wind Energy and Energie Systemtechnik) published a study showing the feasibility of this transition, both on the financial side (investment needed) and technological (new paths to develop) or social (job creation, new specialisations).

France has passed a law in 2015 on the energy transition, which envisages by 2030 an important contribution of renewable energies for electricity generation, final heat consumption, fuel consumption and gas consumption. However, this policy is hampered by the dominance of nuclear energy in the production of electricity (78% in 2016) and the refusal to abandon it, as well as administrative burdens for wind farms or biogas units, for example.

In 2015, a study published by the Royal Society of Chemistry showed the feasibility for the **USA** of 100% renewable energies in 2050 for electricity, transport, heating and industry. This would require using all available technologies (onshore and offshore wind, photovoltaic, CSP, hydropower, geothermal and marine energies). Electrical "storage" would be provided by CSP units, pumped hydro, batteries and hydrogen.

For **Japan**, this target for electricity could have been achieved by 2020 as a study in 2012 showed. This production would have been based on wind, photovoltaic, hydropower, geothermal and biomass. In the studies published by the Institute for Sustainable Energy Policies, one of the important points is the reduction of electricity consumption (there are more than 5 million distributors – vending machines, for example) associated with renewable energy sources.

For many other countries such as **Canada**, **Australia** and the **UK**, the transition to 100% renewable energy, at least for electricity, is possible between 2035 and 2050. Depending on the availabilities of renewable sources, the main contributors are often wind and photovoltaic, associated with pumped hydro for storage.

The rise of renewable electricity: A study by the IEA published at the end of 2014 foresees that photovoltaic will become the first source of renewable electricity in 2050, followed by wind. Other sources, despite technological developments, are expected to remain very limited due to high cost, complexity or (relatively) reduced power and will remain limited in their use as a response to specific needs. On the other hand, the renewable electricity would allow to eliminate the need to use non-renewable sources (oil, natural gas, uranium), since the initial energy (wind, sun) is free of charge. Moreover, the price of equipment (wind turbines, photovoltaic modules) should continue to fall. Maintenance costs are not to be compared with conventional power plants, not to mention nuclear ones with radioactive waste management and ageing. All this should lead to stable electricity prices of renewable origin.

2.2 Variability in production and electricity consumption

A significant volume generation of renewable electricity does not necessarily occur when demand is high, but rather depends on weather conditions (Figure 2.9). Total production/consumption management is therefore more critical because either the system must absorb quantities of electricity that can bring it to its maximum transmission capacity, or it is necessary to stop or reduce the power of certain power plants or even worse disconnect some wind or photovoltaic farms.

2.2.1 Production and consumption forecasts

Weather forecasts (sun, winds) are an important factor in the management of renewable electricity flows in the overall production framework. These forecasts, especially those of strong winds or storms, are also critical for the safety of wind power installations, for example.

2.2.2 Electricity flow management

The importance of production/consumption management will increase with the growth of electricity generation from renewable origin.

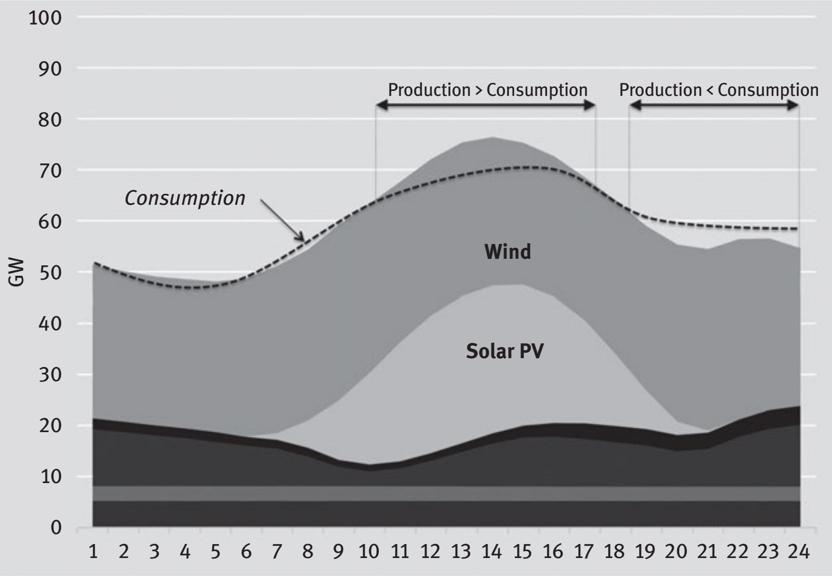


Figure 2.9: Example of a shift in renewable production/consumption (Data: Agora Energiewende).

All power grids are concerned because the production areas, especially for offshore wind, are often far from the consumption areas needing more transmission lines on long distances. Ideal management also contributes to the reduction of electricity cost through optimisation of storage (less required) or of the load of transmission lines. The storage capacity must reduce the need for local, regional and international interconnections to export or import electricity by reducing losses.

2.2.3 The need for storage

The storage of electricity makes it possible to transfer the availability of this energy over time (Figure 2.10): storage in case of low demand or high production and recovery in the opposite cases. Even if storage capacities are limited, they increase the flexibility of the energy system and reduce the building of new transmission lines, especially if the storage is local.

Direct electricity storage technologies are still expensive or limited in capacity and one of the objectives is to reduce these costs or develop an alternative solution(s).

Storage is related to the capacity (*Capacity Value*) of the generation of renewable electricity to correlate production and consumption. Photovoltaic solar energy has a significant capacity value when peaks in production and peaks in consumption coincide (e.g. in Spain). For Denmark, it will be wind power that will have a significant capacity value.

Renewable power: a challenge for production and transport. The intermittent generation of electricity from renewable sources increases the stresses on the electricity grid, which must be able to manage peaks of production that are not correlated with demand, even over short periods of time. Only storage allows optimisation of the energy efficiency of the various sources of electricity production. However, many countries (Spain, Portugal and Germany) have shown that high levels of electricity from renewable sources, sometimes as high as 100% (in Portugal) can be integrated without disturbing the network.

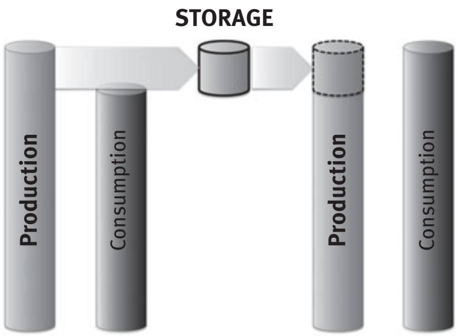


Figure 2.10: Advantages of storage for network regulation.

2.2.4 Estimation of surplus electricity

The amount of renewable electricity produced will increase. Their variability will lead to periods when production will be greater than consumption. One solution would be to export this electricity to neighbouring countries if they are not faced with surpluses and if the capacity of the exchange lines is sufficient. For large surpluses, the only solution not to lose them remains storage in any form whatsoever.

2.2.5 Simulations

This is a prospective forecasting exercise, which yields results with a wide range of uncertainty, depending on the sources (Table 2.7).

In **Germany**, which had an electricity surplus of 400 GWh in 2012, the KonSt-Gas project (2013–2016) evaluated this surplus, the necessary storage and the consequences on the electricity grid [4]. The results published in 2013 envisage two options:

– For 40% of renewable electricity in 2020, 25 TWh of surplus electricity is expected
– For 85% in 2050, this would increase to a surplus of 162 TWh (consumption was 520 TWh in 2015)

A report by the National Renewable Energy Laboratory (NREL) published in 2012 examined a scenario for 80% contribution of renewable electricity (50% wind or solar) for the **USA**. Losses of the order of 20–25% are estimated in the absence of surplus electricity storage for a production capacity of 1,450 GW.

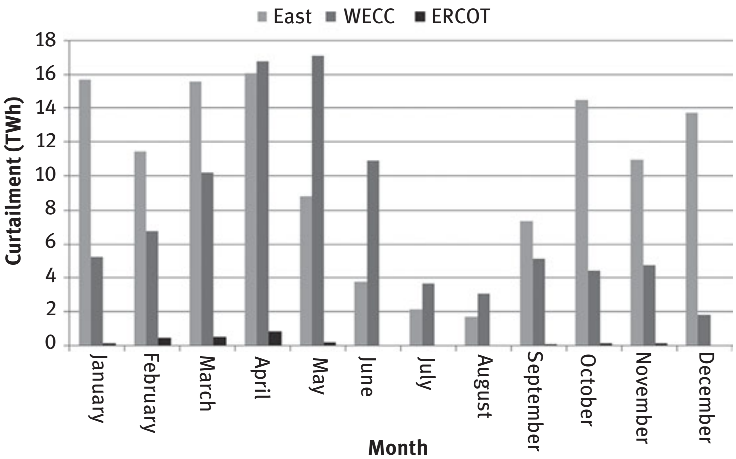
In **Denmark,** Energinet.dk estimates that by 2020 wind power generation will exceed demand 350–450 h per year.

In **France**, to reach 100% of electricity from renewable sources by 2050, a study by the ADEME done in 2014 gives an excess production capacity ranging between 20 and 120 GW. It must be covered either by storing electricity (excess production) or by using the stored electricity (excess demand). In both cases, the power-to-gas could fulfil the role of regulator.

Some studies try to estimate the detailed annual surplus (Figure 2.11). The difficulty is for a given period, to predict the maximum. These data are important because they determine the maximum storage capacity (e.g. hydrogen conversion) to be planned.

Table 2.7: Scenarios 2050 for 80–100% renewable electricity (high hypothesis).

	China	USA	Germany	France	Finland
Consumption (TWh)	15,000	5,100	600	420	90
Surplus (TWh)	NA	110	162	75	76
Production capacity (GW)	7,100	1,450	250	196	NA
Needed storage capacity (GW)	300	120	50	15	50



East : Eastern Interconnection
WECC: Western Electricity Coordinating Council
ERCOT: Electric Reliability Council of Texas

Figure 2.11: Estimated monthly surplus for the three US zones in 2050 (NREL 2012).

An increasing amount of surplus renewable electricity: The significant development of wind and photovoltaic power expected in the coming decades will lead, when the weather conditions are favourable (sun, wind), to volumes of electricity that the market will not be able to absorb due to a lower demand. These quantities may represent up to the equivalent of several days or even weeks of consumption and should be recovered for direct or indirect use.

2.3 Electricity storage

The need to make production and consumption of electricity to coincide with the increasing volume of renewable electricity requires an important storage in the event of overproduction. It can also stabilise or regulate the grid. Depending on the priority placed on storage, storage capacity or available power will be emphasised.

2.3.1 Why store electricity?

Electricity is produced and used in a continuous process where it is necessary to balance supply and demand. With renewable electricity generation increasing, networks could be sometimes at the limit of the power to be transmitted, shortages or blackouts due to technical problems or inclement weather can occur. The balance can be achieved only with a minimum of storage.

Storage allows:
- Grid frequency regulation (50 or 60 Hz) with rapid response and for a short time (usually up to a few minutes)
- Transition between production units requiring longer start time
- Electricity generation management to store the surplus

2.3.2 Characteristics of a storage system

What are the important criteria for choosing a storage solution? Among those to be examined are:
- storage capacity
- reaction time
- charging and discharging time
- frequency of call
- number of charging–discharging cycles
- performance
- lifetime
- price of stored kWh

2.3.3 Storage technologies

There are many available technologies for storing electricity. They are technically differentiated by the phenomena involved (Figure 2.12), which affect their storage

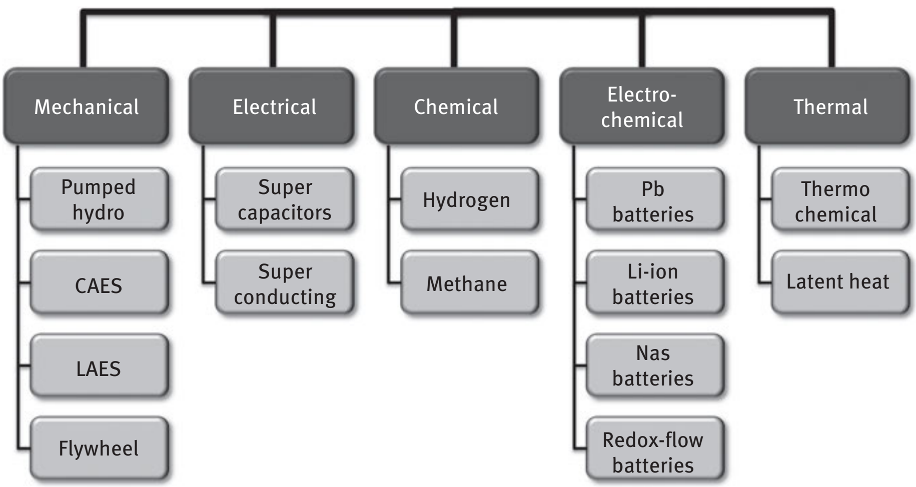


Figure 2.12: Electrical storage technologies.

capacity, their efficiency, their volume, their lifetime, the conversion method to electricity, their level of maturity and their cost.

2.3.3.1 Pumped hydrostorage

This technology stores electricity indirectly. A pumped hydrostorage station (PHS) consists of two large-capacity water reservoirs, at different altitudes, of pumps and turbines (Figure 2.13).

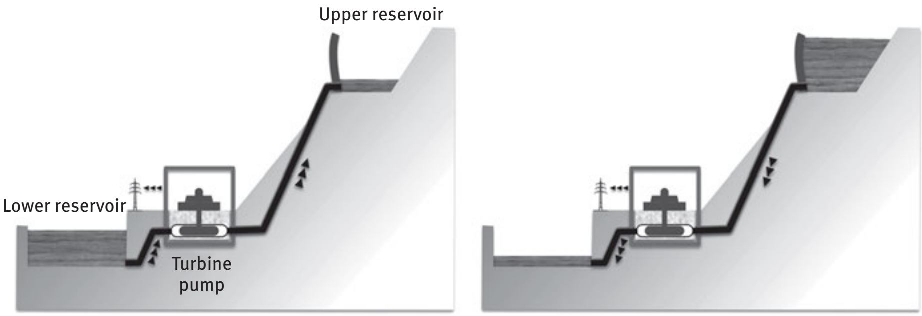


Figure 2.13: Principle of pumped hydrotechnology.

When the price of electricity is low, it is used to run the pumps bringing the water to the upper reservoir. When the demand exceeds the conventional production, the water in the upper reservoir is released and activates the turbine(s), thus producing the electricity that is injected into the network. For renewable electricity surpluses storage, the pumping power is critical as it has to cope with large volume of electricity in a relatively short time.

This technology has been used since 1920. In 2016, a power of 150 GW available for about 10 h was installed worldwide (21 GW in the USA and 38 in Europe) corresponding to an energy of approximately 500 GWh. It is divided into about 400 units with an average power of 0.4 GW. The largest station is located in the USA (Virginia), with a capacity of 3 GW and a storage capacity of 30 GWh.

In 1999, Japan had a unit in Okinawa using the sea as a lower reservoir (coastal PHS). This approach is interesting for the local control of electricity supply because 80% of the world's population lives near the coast in 2016. The Netherlands, however, is considering using the sea as upper reservoir.

An **hybrid system of wind turbine-pumped hydro** is being evaluated in Germany at Gaildorf with four wind turbines with a power of 13.6 MW. At the foot of each, a tank of 40,000 m^3 allows to store the water of a lower basin with 200 m level difference when the price of electricity is low or in case of surplus production. The generation power of the turbines is 16 MW.

Studies have also been made in Germany for the use of **abandoned coal mines** as a lower reservoir and a surface lake. The advantages are high dropping heights (up to 1,000 m), allowing turbines of several hundred megawatts to be used, as well as heat recovery, water reaching up to 40°C. In Australia, a project is considering a combination of a 150 MW photovoltaic park and the use of unused gold mines as a lower reservoir to produce up to 330 MW of electricity.

Although the theoretical potential is important for some countries, the achievements are limited to the optimal adequacy between the maximum possible power (depending on the height of the fall and the size of the reservoirs), the geological constraints and the high investments.

2.3.3.2 Compressed air energy storage

In the compressed air energy storage (CAES) approach, electricity is used, when surpluses are generated or prices are low, to compress air and store it in natural cavities. If needed, this air is released in a turbine producing electricity with a yield of 40–70% (Figure 2.14).

Diabatic-CAES: In 2016, there are two important operational installations working in diabatic mode: after compression, the air, at a temperature of the order of 600°C, is cooled and injected into a cavity. If electricity is required, the compressed air is released and mixed with natural gas to power a turbine. The first plant is located in Huntorf, Germany, in operation since 1978 with a cavity of 310,000 m^3 at 600 m depth. The turbine can provide 320 MW of power for 2 h. In the USA, the McIntosh plant, which has been in operation since 1991, can supply 226 MW (110 MW initially) for 26 h with 538,000 m^3 of storage at 450 m depth. Several other high-power projects in the USA (Iowa or Ohio with a capacity of 270 MW) were abandoned for economic reasons.

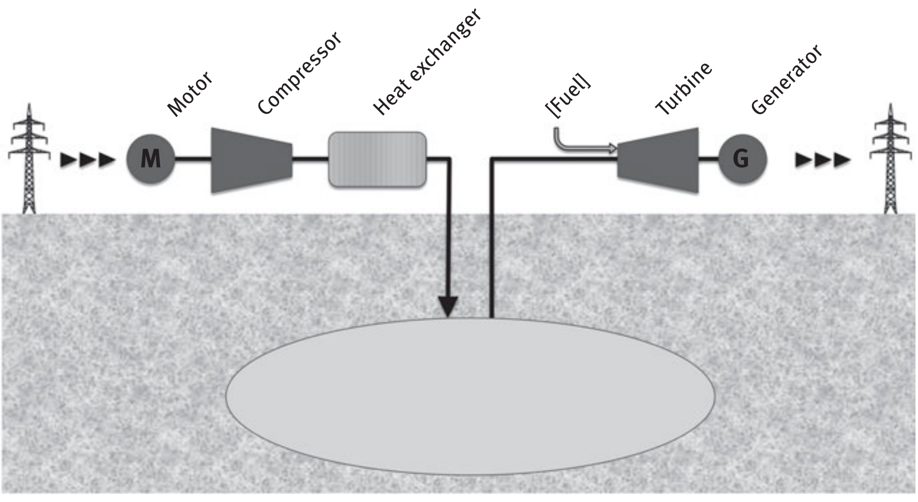


Figure 2.14: Compressed air storage scheme.

Northern Ireland launched a project in 2016 that could provide 330 MW for 6 h. Development units of less than 50 kW have been or are in service in China or Japan.

Adiabatic-CAES: With this technology, the heat of compression is recovered and stored in ceramics. When compressed air is released, it is passed through a heat exchanger to recover the stored heat and supplies the turbine without any use of fuel. A yield of above 70% is expected, if the projects under study (the most important being ADELE in Germany with a turbine of 260 MW) are realised, which does not seem to be the case.

Liquid air energy storage: Called sometimes cryogenic energy storage, it is still in the state of demonstrator. The air is compressed and then liquefied and stored at –169°C. The heat of compression is also recovered and used to vaporise the liquid air which actuates a turbine. Among the advantages, one can mention the high energetic capacity of liquefied air (214 Wh/kg, more than 10 times that of compressed air at 100 bar) and storage in tanks on the ground. The installation of the English company Highview Power Storage is a pilot unit near the Heathrow Airport with a power of 350 kW, connected to the electricity grid from 2011 to 2014. A unit of 5 MW of power is in the evaluation phase. Other projects (Mitsubishi/Linde) are being studied.

2.3.3.3 Battery storage

Storage in batteries offers, compared to previous solutions, as advantage modulated power and capacity that can vary from residential (a few kWh) to regulation of power plants (several hundred MWh). In addition, the storage capacity can be increased simply by adding additional batteries.

If battery technologies can take different approaches, the most spread are lead or lithium-ion batteries or derivatives (lithium/phosphate). Lead batteries are still used despite their low-energy density (30–50 Wh/kg), given their low cost. The largest facility in Europe is located in the Shetland Islands, where 3,168 batteries with a capacity of 3 MWh are used to regulate the power generation of the fuel-fired power plant.

Li-ion technology dominates mainly due to the constant fall of their price (from US$ 1,000 in 2010 to about 230 in 2016) following the increased global production capacity. Most of the production is located in Asia (China and South Korea) but the largest is Tesla's "Gigafactory 1" in the state of Nevada, which could produce 35 GWh of cells in 2020 for electric vehicles and electricity storage. In Germany, Mercedes has a first plant running since 2012 and a second one planned for 2018.

In 2016, STEAG Energy Services installed in Germany six units of 15 MW (total of 90 MW) to stabilise the production of a coal-fired power station. In the USA, San Diego Gas and Electricity has a 30 MW/120 MWh facility (Figure 2.15) in Southern California, with batteries supplied by AES and Southern California Edison a storage capacity of 80 MWh using Tesla batteries. Many other high-storage capacity projects, typically over 10 MW, have been installed or will be installed. Southern California Edison is to inaugurate a 100 MW/400 MWh unit in Long Beach, California, in 2021. In 2017, Tesla won a bid to build a 100 MW/129 MWh battery storage to stabilise the South Australian power grid.

Figure 2.15: Storage park with capacity of 30 MW (San Diego Gas and Electricity).

Li-ion batteries will play an increasingly important role in storage (Figure 2.16) following development of increased storage capacity and price drop.

Behind-the-meter batteries: This concept covers domestic photovoltaic coupling with household batteries (2–6 kWh of storage). This approach allows local use of the electricity produced to reduce the load on the networks and, depending on the price of electricity, reduces costs. In Germany, following a tax incentive campaign, more than 50,000 units were installed in 2016.

Sodium–sulphur batteries (NaS) commercialised by the Japanese company NGK Insulators are operating at high temperatures (at least 300°C) and offer a storage cost per kWh lower than the one of Li-ion batteries, for example. A 20-foot container represents a power of 800 kW and a capacity of 4,800 kWh. The total installed global power is of the order of a few hundred megawatts, especially in Japan. The Futamata Wind Development Co., Ltd. uses 17 units of 34 MW to stabilise electricity supplied by a 51 MW wind farm.

Other electrochemical systems also allow the storage of electricity. The circulating batteries or **redox-flow batteries** (Figure 2.17) use two reservoirs containing the electrolytes circulated in the core of the cell composed of two chambers separated by a membrane.

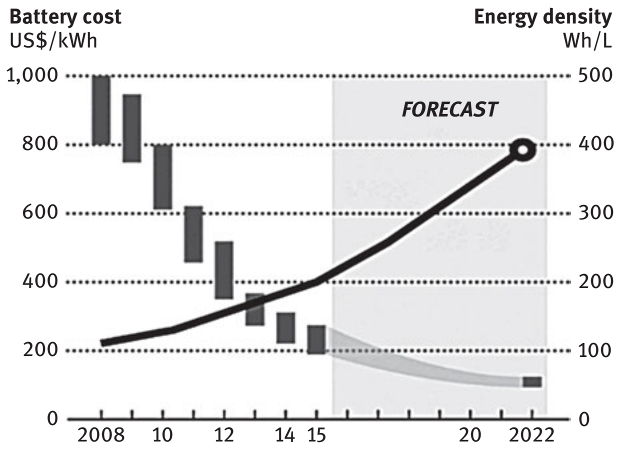


Figure 2.16: Evolution of prices and energy density of Li-ion batteries (US Department of Energy).

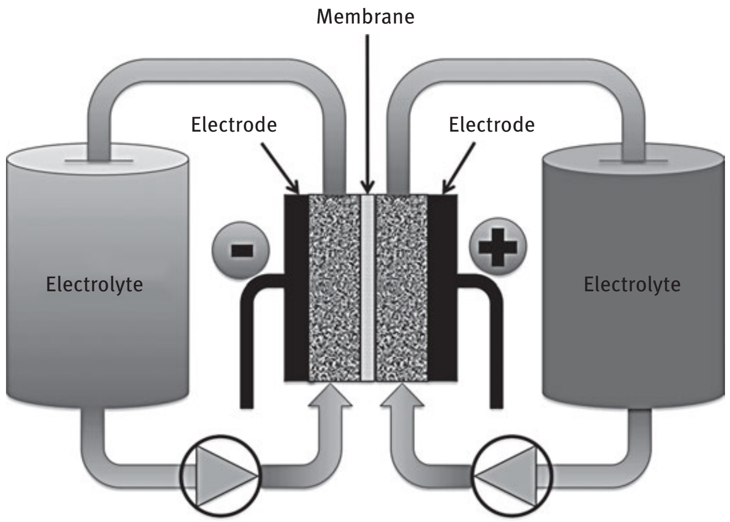


Figure 2.17: Principle of a circulating (Redox-flow) battery.

The electrolytes generally used are vanadium salts. This technology allows to store large quantities of electricity, compared to other types of batteries. Between 2005 and 2008, an experiment was carried out in Japan involving a 30 MW wind farm combined with circulating batteries with a storage capacity of 6 MW. Other wind farms in Australia, Scotland use these batteries to smooth out short fluctuations in production. In Germany, the energy supplier EWE is planning for 2023 a battery of 120 MW using two caverns to store both fluids. The CellCube module FB 200–400 from the German company Gildemeister offers a power of 200 kW with a weight of 20 tonnes empty and 60 tonnes with electrolyte. Vanadis Power is commercialising different models: The 2 MWh storage capacity/750 kW peak power module is integrated into a container, with the dimensions of the complete installation being 13.6 × 6.9 × 4.1 m (Figure 2.18). It has an AC–AC efficiency of about 65% and a lifetime of 20 years (>10,000 cycles). The smaller redox-flow batteries (90–120 kW) fit into a 20 ft container.

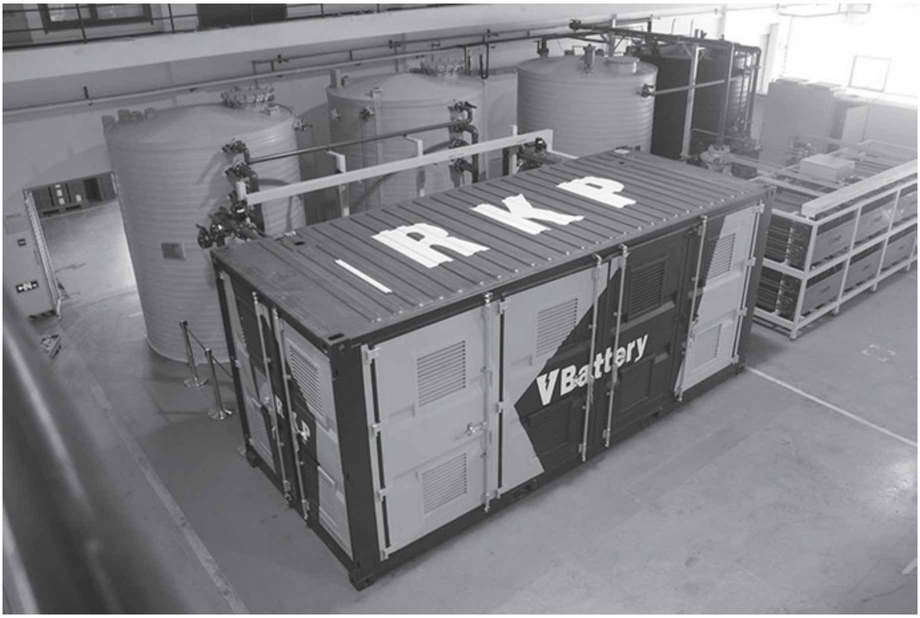


Figure 2.18: Redox-flow module (Dalian Rongke Power Co. Ltd.).

The redox-flow batteries offer an alternative to lithium batteries in terms of lifetime, number of cycles and cost per kWh. The downside is a lower efficiency but compensated by the fairly easy increase in capacity by adding more tank storage. Many suppliers worldwide are active on this market (Vionx Energy, USA; Dalian Bolong Holding Co., Ltd., China; one of the largest vanadium suppliers, redT, UK etc).

2.3.3.4 Thermal storage

In this approach, excess electricity is converted to heat (power-to-heat) and stored in water or other fluid tanks. If this can be applied to small or very large scale, but this conversion is irreversible. Existing plants will be described in the chapter power-to-heat (Chapter 6.2).

2.3.3.5 Electric vehicle batteries (vehicle-to-grid, V2G)

In many publications, batteries of electric vehicles are considered as short-term storage of electricity and possibly be used as an auxiliary source if necessary (Figure 2.19).

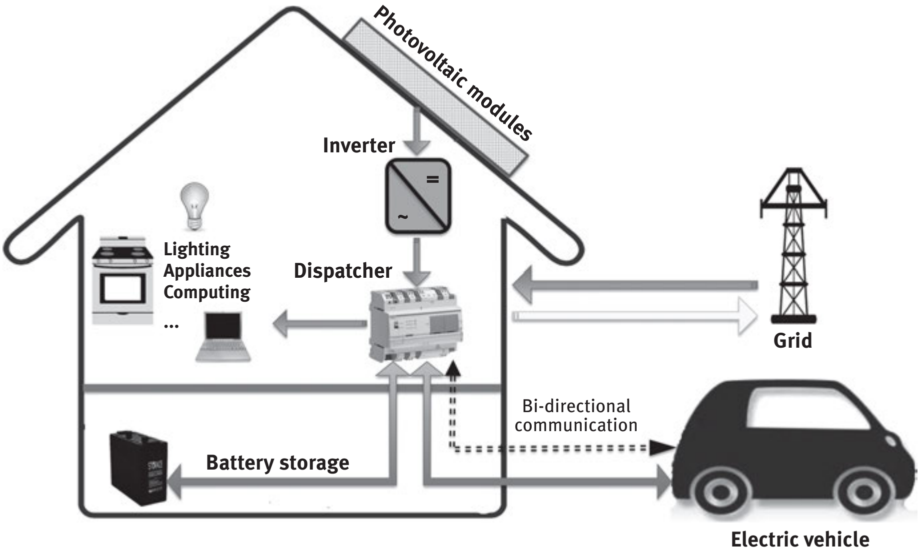


Figure 2.19: Storage and use of electric vehicle batteries.

While the approach seems elegant, it faces many limitations:
- The number of electric vehicles in circulation is still too low to have an impact on the management of electricity flows.
- The option for batteries to be a source for external uses is not always really provided by car manufacturers.
- Who would accept to see the autonomy of his electric vehicle, already limited, still reduced?
- Up to what level batteries are discharged without hindering users?

However, large fleet of several million electric vehicles would offer a significant storage and regulation capacity: 1 million vehicles with a 30 kWh battery each and a 50% capacity utilisation rate would allow to store (and to recover) 15 GWh.

Experiment in Germany in 2015: The city of Wolfhagen has received two prototype vehicles from the Japanese company Mitsubishi, an electric and a hybrid, specially designed for the use of their battery to power a house via a "Powerbox" or two-way station, according to the concept vehicle-to-grid.

2.3.3.6 Flywheel

A flywheel consists of a rotating mass (synthetic material, steel or other metal) mechanically connected to a motor/generator. The assembly is generally placed in a chamber with reduced pressure to minimise friction. When one wants to store electricity, the motor is started, driving the flywheel (electrical energy to kinetic energy). Once the motor is not powered, the steering wheel then continues its rotation. When it is necessary to recover electricity, the flywheel is coupled to the motor which then operates as a generator.

Flywheels are suitable for storage of relatively short duration (from a few minutes to a few tens of minutes) with an extremely short response time (a few ms). The charge–discharge cycles must be short because, depending on the model, the losses can be up to 5% per hour. For the units marketed in 2016, the power is generally of the order of a few tens of kW. In 2015, in Japan a flywheel of 300 kW/100 kWh of carbon fibre was developed with a superconducting magnetic suspension system.

Existing facilities use parks consisting of several flywheels. By 2016, nearly 80% of installations were in the USA and 10% in Europe. The American company Beacon Power has equipped numerous installations: In 2011, 20 MW in New York (200 units of 100 kW each) and in Pennsylvania in 2014 with the same power. In Munich, in 2015, SWM (Stadtwerk München) has installed 28 Stornetic units of 22 kW each capable of supplying 100 kWh. The 28 flywheels are installed in a 40-foot container. To stabilise the UK and Irish networks, a facility with a capacity of 500 kW peak power and 10 kWh storage capacity has been planned in 2017.

2.3.3.7 Supercapacitors

It is basically a capacitor with a modified structure enabling it to store a large amount of electricity with a very short charging time and to release it almost without loss and if necessary in a very short time. The supercapacitors are also characterised by an important number of charge–discharge cycles, of the order of several hundreds of thousands. The main limitation to their use is the high cost for high power. They are mainly used to stabilise grids for short periods of time (a few seconds). In comparison, the Tesla Li-ion module 2170 measures 21 mm in diameter and 70 mm in length for a weight of 66 g and can store 21.3 Wh. To store the same amount of electricity, it would take about five supercapacitors from Maxwell (Figure 2.20) of 3 V and 3,000 F (unit storage capacity of 3.75 Wh at 3 V DC) weighing 2.6 kg.

Figure 2.20: Supercapacitor modules and Li-ion battery to store 21 Wh.

The main limitation of supercapacitors is their high cost for high power (a 2.7 V/3,000 F module costs about US$ 50 in 2017, whereas a Li-ion battery with the same capacity costs about 10 times less). However, they have a very high number of cycles of charge/discharge (up to 1 million) and a very short charging/discharging times (ms).

2.3.3.8 Superconducting magnetic energy storage (SMES)

Electricity is stored as a magnetic field produced by electricity circulating in a coil maintained at very low temperatures, requiring complex cryogenic system using hydrogen or liquid helium. If the response time is very short and the efficiency is high (>95%), the cost is also due mainly to the equipment necessary to maintain the low temperatures.

2.3.3.9 Rail vehicles

The American company Advanced Rail Energy Storage proposes to use wag-on-weighted electric locomotives on a sloping track to store electricity when the locomotive rises up the slope. For release, the locomotive descends and electricity is recovered through braking energy, the engine acting as generator. After a demonstrator with a 5.7 tonne vehicle and a 268 m track, the final project in the state of Nevada provides for 8 km track and a total of 32 locomotives of 272 tonnes each a capacity of 1.5 MW with a yield of 80%, i.e. a total power of 50 MW/12.5 MWh. The cost would be US$ 55 million with an installation lifetime of 30–40 years.

2.3.3.10 Underwater spheres

The German Institute Fraunhofer is experimenting with a variant of pumped hydro using submerged concrete spheres as lower and upper reservoirs. Filling with seawater takes place under pressure and generates electricity. When the price of electricity is low or the electricity is in surplus, the sphere is emptied to start a new cycle. At 500 m depth, the energy produced reaches 1.4 kWh/m^3. This technology could be combined with offshore wind farms.

2.3.4 Comparison of available electricity storage solutions

Considering the different operational technologies around the world, pumped hydro dominated and accounted for more than 96% of global storage capacity in 2016. In comparison, batteries for network stabilisation accounted for only 1.7 GW (0.6 GW in the USA), electromechanical storage (CAES, flywheel etc.) for 1.6 GW and thermal storage (mainly molten salts of CSPs) for 3.1 GW.

The different technologies are at different levels of development, which explains either their cost (low or high) or their degree of implementation (Figure 2.21).

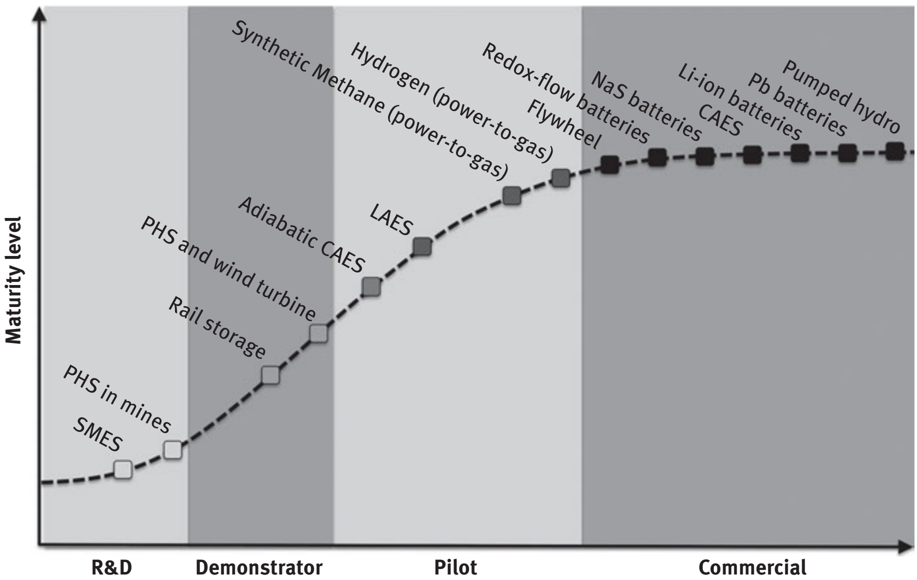


Figure 2.21: Maturity of different storage technologies.

2.3.5 Characteristics of electricity storage technologies

Each electricity storage technology has characteristics that condition the use: cost, reactivity, storage capacity etc. Figure 2.22 illustrates the different approaches (Table 2.8).

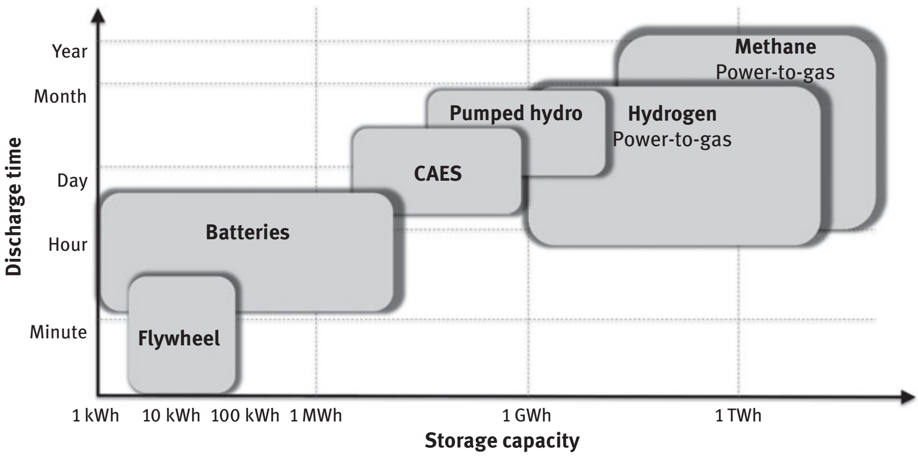


Figure 2.22: Electrical storage technologies.

Table 2.8: Comparison of the main characteristics of storage solutions – 2016 data.

Technology	World power 2016 (GW)	Lifetime	Efficiency
PHS	150	30–60 years	70–85%
Thermal	3.1	30 years	80–90%
Li-ion batteries	1.7	Up to 10,000 cycles	85–95%
Redox-flow batteries		Up to 14,000 cycles	60–85%
NaS batteries		Up to 4,500 cycles	70–90%
CAES	1.6	20–40 years	40–70%
Flywheels		Up to 100,000 cycles	70–95%

The main issue of the solutions presented is the global limited storage capacity over time due to their principle: when the batteries are charged or when the upper reservoir of the PHS or the compressed air storage caverns are filled, it is no longer possible to store the surplus provided by the wind or photovoltaic (Figure 2.23). An extension of capacity, if possible, requires new investments.

It is therefore necessary to find an approach to lift this limitation and use a technology that would offer virtually unlimited storage.

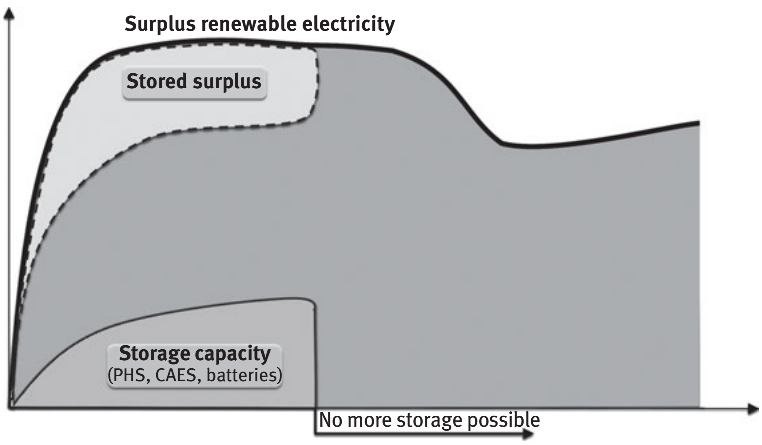


Figure 2.23: Intermittent storage.

2.3.6 Electricity storage requirements

Worldwide, the 156 GW of storage available in 2016 accounted for only about 2.6% of the electricity generation capacity. The installed global capacities, all technologies combined, are (still?) very small compared to the consumptions, which limit the capacity of regulation. The generation of large quantities of electricity of renewable origin in the coming decades as well as the expected surpluses will require volumes of storage that are not commensurate with current capacities.

The German institute Fraunhofer estimated that, for a 100% renewable electricity in Germany in 2050, a storage capacity of 24 GWh per battery, 60 GWh per PHS and 33 GWh (power-to-gas), i.e. a total of 117 GWh would be needed only for a single country compared to the 500 GWh of worldwide storage capacity installed in 2016.

The growth of electricity from renewable sources is related to storage

The development of the electricity market and the trend towards decentralisation go hand in hand with storage solutions at all levels: residential, tertiary and industrial. For each of these sectors there are appropriate technologies. However, at the level of the global network, solutions allowing storage of large volumes will prove necessary.

The actual overall available storage capacity (mainly PHS) related to consumption shows that it can at best smooth out peaks of local demand. The increase in renewable electricity production with inevitable fluctuations leading to production sometimes higher than demand will require storage capacities that are not comparable with what is currently available. The various limitations of "classical" solutions (cost, limited storage capacity, sometimes little or no extension possible) leave room for another technology that could potentially meet these challenges: the **power-to-gas** which is a technology breakthrough in storage.

Storage (almost) unlimited: In 2016, the European Commission defined the storage of electricity by including any technology to shift the electricity produced from its use either as electricity or in another form. This definition makes it possible to replace the concept of power-to-gas in the regulatory approach of energy storage.

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3 Principle of power-to-gas

When electricity production from renewable sources is greater than consumption, what can be done with this surplus electricity, which can be considered as "free"?

This is the challenge that power-to-gas (P2G) technology wants to address.

P2G is the use of surplus renewable electricity to produce a gas that can be stored or used directly.

What are the conditions and technologies involved?

– Have significant renewable electricity generation
– Have at certain times a production higher than consumption
– Directly produce gas using this electricity
– Store, use or process this gas

The "transformation" of electricity into gas is possible thanks to the **electrolysis** which allows the dissociation of water in hydrogen and oxygen.

An (relatively) old technology

In 1889, the Dane Poul la Cour (1846–1908) converted a traditional mill into a windmill (Figure 3.1) and associated it with a dynamo. The objective was then to be able to store this electricity to be independent of the meteorological conditions. After rejecting batteries due to their high cost, he turned to electrolysis (Figure 3.2), producing hydrogen and oxygen stored in separate tanks with a volume of 12 m^3. Production could reach 1,000 L of hydrogen per hour. Hydrogen was then used directly for lighting the mill and a nearby school. He then realised that the hydrogen/oxygen mixture could be used for autogenous welding. His attempt in 1902 to modify an engine to run it with hydrogen and thus have electricity continuously did not succeed.

A museum located in Vejen occupying the original mill (which has since undergone many modifications) presents the work of this pioneer.

All elements of the P2G concept were already gathered:

– Wind turbine for power generation
– Electrolyser for conversion to hydrogen
– Storage for future use

3.1 Basic layout

Excess renewable electricity is used by an **electrolyser**. This produces oxygen and hydrogen which can be used in many ways (Figure 3.3):

– Directly for the industry, for example (petrochemistry, chemistry, electronics etc.)
– Injection into the natural gas network
– Production of methane (CH_4) by methanation, eventually injected into the natural gas network

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Figure 3.1: Windmill transformed into a wind turbine by Poul la Cour (Poul la Cour Museum/Vejen).

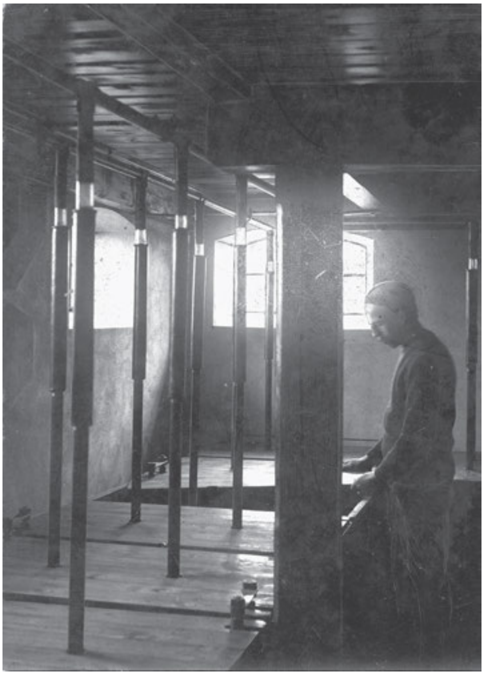

Figure 3.2: Electrolysers used by Poul la Cour (Poul la Cour Museum, Vejen).

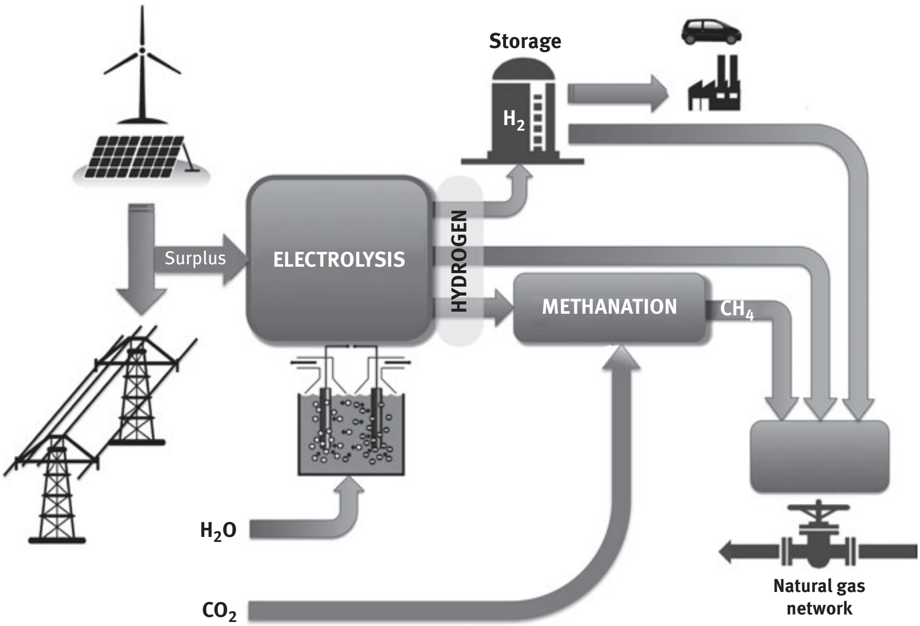

Figure 3.3: Power-to-gas concept diagram.

Hydrogen or methane produced by mixing with natural gas can then be stored in reservoirs for natural gas (tanks or natural caverns).

3.2 Hydrogen

Hydrogen was identified as an element by Henry Cavendish in 1766. It was Lavoisier who gave its name in 1788 (Hydrogenium) from the Greek roots “hydro” (water) and “genes” (from). In 1800, the English Nicholson and Carlisle used for the first time the electrolysis of water to produce it. It was liquefied by James Dewar in 1898.
Hydrogen is the simplest element: the atom consists of a nucleus formed by a single proton around which orbits an electron.

Hydrogen is not an energy source, but an **energy vector**. If it is the most widespread element in the universe, but there is practically no free form on earth.

3.2.1 Properties

Hydrogen is the lightest element (molecular weight = 2.016 g for 22.4 L under normal conditions of temperature and pressure), which is an advantage for balloons or dirigibles, but a disadvantage for its transportation and its storage. It is a colourless, odourless, non-toxic gas.

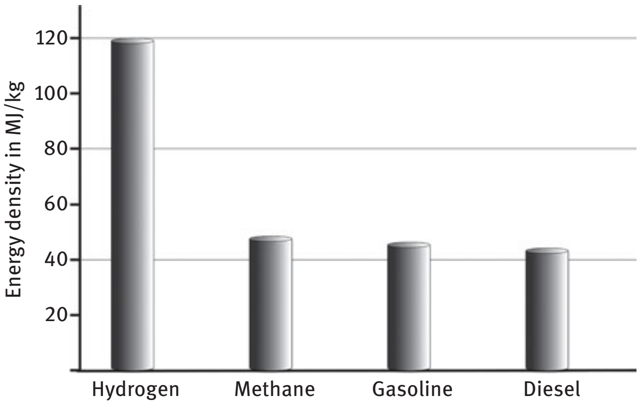

Figure 3.4: Comparison of energy densities.

3.2.1.1 A high energy density

When compared with other fuels, hydrogen contains for the same mass the largest amount of energy (Figure 3.4).

However, this high energy density of hydrogen corresponds to large volumes due to its low density.

3.2.1.2 Low density

In gaseous state, its density is 0.0899 with respect to air (1 Nm^3 of hydrogen weighs only 89.9 g, compared to 1,204 g/Nm^3 for air or 651 g/Nm^3 for gas natural). Liquefied at a temperature of 252.76°C (20.39 K), its density is only 70.79 g/L.
These two characteristics explain the large volumes required for storage or special isolation for liquid hydrogen tanks. In addition, liquefaction of hydrogen requires large quantities of energy (up to 40–50% of its energy content depending on the capacity of the production unit) (Table 3.1).

3.2.1.3 Large storage volumes needed

For the same amount of final energy (in this case 250 kWh), the volumes required to store gasoline, natural gas or hydrogen are shown in Table 3.2 and Figure 3.5.

Table 3.1: Energies required for hydrogen compression or liquefaction.

Initial energy content	Compression energy	Liquefaction energy/capacity	Final energy content
100% – 142 MJ/kg		80 MJ/kg @ 100 kg/day	62 MJ/kg
		50 MJ/kg @ 10,000 kg/day	92 MJ/kg
	14 MJ/kg @ 200 bar		128 MJ/kg
	22 MJ/kg @ 700 bar		120 MJ/kg

Table 3.2: Comparison of volumes required to store the same amount of energy.

	Gasoline	Natural gas	Compressed hydrogen (CGH_2)		Liquid hydrogen (LH_2)
		200 bar	200 bar	700 bar	
Fuel	20 kg	18 kg	7 kg	7 kg	7 kg
	16 L	128 L	500 L	194 L	98 L
Tank	6 kg	70 kg	80 kg	120 kg	140 kg

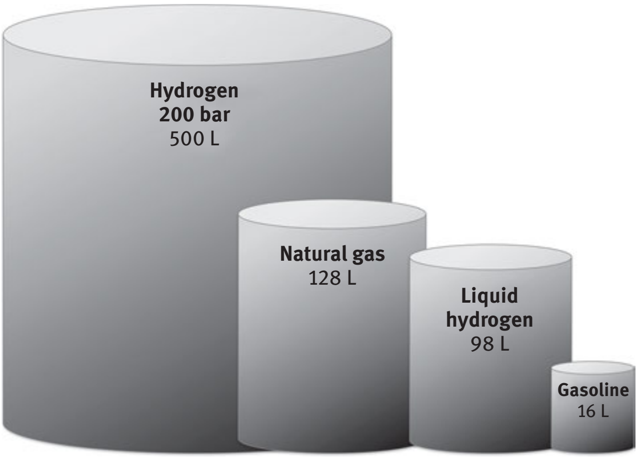

Figure 3.5: Comparison of volumes required to store the same amount of energy (not to scale).

Storage of hydrogen in reservoirs is certainly possible, but for very large volumes (thousands or millions of m^3), this solution is impractical.

Liquid hydrogen tanks for vehicles

Liquid hydrogen was tested to power fuel cell or thermal engine vehicles. The tank of the model BMW hydrogen 7 (IC engine) experienced late 2000s containing 8 kg of liquid hydrogen and weighed 168 kg, a ratio of 1:21. The volume of the tank was about 300 L.

3.2.2 Security

Since the fire of the Hindenburg airship in 1937, the collective unconscious classifies hydrogen as dangerous. The public's negative perception of safety should not be underestimated for its widespread use.

It is certainly not without risk, as do all the other fuels (gasoline, diesel, natural gas etc.). Each, however, has its own specificities. Hydrogen has the following characteristics:
– The low minimum ignition energy (20 μJ, compared to 290 μJ for natural gas)
– In the event of a leak, hydrogen ignites more frequently than other gases

- The small size of the molecule allows it to diffuse through materials and to weaken them
- The flammability range is between 4% and 75%
- The self-ignition temperature is high (585°C)

These characteristics do not make it an innocuous gas, but show that hydrogen can be used (largely in the industry) taking into account its specificities.

"City gas" and hydrogen

This gas (coal gas or town gas), obtained by pyrolysis of coal has been used in many countries for decades, in the 1950s in the USA and in 1970 in Britain, among others by households for heating and cooking.

This gas, which varied in composition from country to country, consisted mainly of hydrogen (up to 60%), methane (up to 55%) and CO (up to 10%).

3.2.3 Industrial production

World consumption was estimated as 85 million tonnes in 2016 (about 1,015 billion m^3), produced mainly (96%) from non-renewable sources: natural gas (50%), liquid hydrocarbons (30%) and coal (16%), or as a by-product of the chemical industry (e.g. chlorine production by electrolysis). Each tonne produced generates 11 tonnes of CO_2. Only 4% is produced by electrolysis, often from electricity produced by large dams (Canada, Egypt, Peru and Zimbabwe).

Hydrocarbons reforming

Reforming or steam reforming involves reacting hydrogenated compounds (hydrocarbons such as natural gas, gasoline, diesel or alcohols such as methanol and ethanol) or coal with steam or oxygen according to the reaction (for hydrocarbons):

$$C_nH_m + nH_2O \Rightarrow nCO + (n + m/2)\ H_2$$

About 95% of hydrogen is currently used in petroleum (desulphurisation) and chemical industry (ammonia production for fertiliser or methanol), and the rest is commercially available (*merchant hydrogen*). It is also the fuel for space launchers: *Saturn V* uses 65 tonnes (984 m^3) and *Ariane 5*, 26 tonnes (391 m^3).

3.2.3.1 Hydrogen and electricity from renewable sources

At present, the only method of storing large quantities of surplus renewable electricity is the production of hydrogen by electrolysis. This hydrogen opens the way, directly or indirectly, to many uses in industry, transportation and energy in all sectors of the economy.

4 Electrolysis

Discovered in 1800 by the English Nicholson and Carlisle, continuous electrolysis, which comes from Greek words (ἤλεκτρον [electron] "amber" and λύσις [lýsis] "dissolution"), allowed the production of hydrogen in large volumes. The reforming of natural gas and hydrocarbons or the gasification of coal then supplanted it, except in countries where electricity is abundant (e.g. Canada).

4.1 Basic principle

The key element of the power-to-gas chain is the **electrolyser** that allows the production of hydrogen from surplus renewable electricity. The electrolysers used can be grouped into two main families: alkaline and PEM (*proton exchange membrane*), whose characteristics will be described in detail. Other technologies are under evaluation or in development such as high-temperature electrolysis.

4.2 Chemical reactions

The decomposition of water by electricity makes it possible to separate hydrogen and oxygen according to the reaction

$$2\,H_2O\,(1) + \text{energy} \Rightarrow 2\,H_2\,(g) + O_2\,(g) \tag{4.1}$$

The energy to be supplied for the dissociation of water consists of electrical and thermal energies:

$$2\,H_2O + [237.2\ \text{kJ/mol of electricity} + 48.6\ \text{kJ/mol of heat}] \Rightarrow 2\,H_2 + O_2 \tag{4.2}$$

An electrolysis unit comprises an electrolyte and two electrodes separated by a membrane or diaphragm (Figure 4.1).

In an electrochemical cell (Figure 4.2), water is decomposed if a certain voltage (critical voltage) is applied between the two electrodes.

At equilibrium, there is always a partial dissociation of water into H^+ and OH^- ions. In alkaline medium, OH^- ions dominate.

At the anode (positive electrode), OH^- ions are decomposed according to the reaction whose standard potential E_0 is −0.4 V:

$$2\,OH^- \Leftrightarrow H_2O + \tfrac{1}{2}\,O_2 + 2\,\bar{e} \tag{4.3}$$

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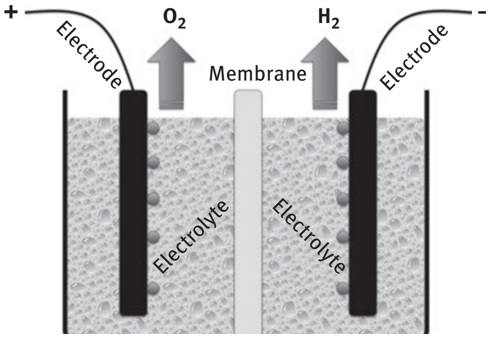

Figure 4.1: Principle of water electrolysis.

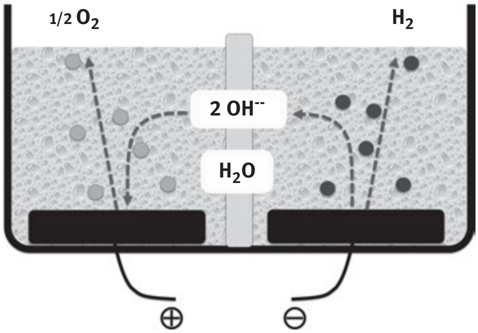

Figure 4.2: Principle of an electrochemical cell (alkaline electrolysis).

At the cathode (negative electrode), the reaction is carried out with a standard potential E_0 of −0.827 V:

$$2\,H_2O + 2\,\bar{e} \Leftrightarrow H_2 + 2\,OH^- \tag{4.4}$$

The minimum potential required for the water decomposition reaction is 1.227 V under normal temperature and pressure conditions. The standard potential E_0 of the oxidation–reducing reaction, expressed in volts, is measured with respect to a reference electrode.

Electrolysis in acid medium

In this medium, H^+ protons predominate.

Reaction at the anode:

$$H_2O \Leftrightarrow \tfrac{1}{2}\,O_2 + 2\,H^+ + 2\,\bar{e} \tag{4.5}$$

Reaction at the cathode:

$$2\,H^+ + 2\,\bar{e} \Leftrightarrow H_2 \tag{4.6}$$

4.2.1 Calculation from thermodynamic data

Thermodynamic laws allowing the description of electrochemical phenomena have been established, among others, by Nernst, Faraday and Gibbs.

Faraday's laws relating to electrolysis

1. The mass of a substance altered at an electrode during electrolysis is directly proportional to the quantity of electricity Q transferred ($Q = I \times t$).
2. For a given quantity of electric charge Q, the mass of an elemental material altered at an electrode is directly proportional to the element's equivalent weight. The equivalent weight of a substance is equal to its molar mass divided by the change in oxidation state it undergoes upon electrolysis.

Electrical and eventually thermal energies are converted to "stored" chemical energy in hydrogen and oxygen products. The energy required for decomposition of water is the enthalpy of water formation ΔH (285.84 kJ/mol under normal conditions). Only the free energy ΔG, known as Gibbs free energy, is to be supplied to the electrodes in electrical form, the remainder being represented by the thermal energy as a function of the temperature and the entropy variation ΔS. The enthalpy change is given by the relation $\Delta G^0 = \Delta H^0\ T\Delta S^0$ (Gibbs–Helmholtz equation).

The *enthalpy* of a system corresponds to the total energy of this system. *Entropy* characterises the degree of disorder of a system.

Different equations govern the equilibrium of the H_2–O_2/H_2O system and make it possible to calculate the minimum potential required for electrolysis from thermodynamic data at constant pressure and temperature:

$$E^0_{\text{cell}} = \frac{-\Delta G^0}{nF}$$

where ΔG^0 is the free energy change of Gibbs, n is the number of electrons involved and F is the Faraday constant.

The Gibbs–Helmholtz equation $\Delta G^0 = \Delta H^0 - T\Delta S^0$ allows to determine, from the data available for the elements involved in this reaction (the enthalpy of water formation is $\Delta H^0 = 285.84$ kJ/mol and the entropy $\Delta S^0_{\text{tot}} = 0.163$ kJ/mol), the minimum theoretical voltage to start the electrolysis (*reversible voltage*) which is 1.227 V under a pressure of 1 bar and a temperature of 298 K (25°C).

Without the addition or production of thermal energy (adiabatic conditions), the minimum isothermal decomposition voltage of water (thermoneutral voltage), which can also be calculated from the thermodynamic data, is 1.48 V under normal conditions (1 bar and 298 K) (Table 4.1).

The temperature and applied voltage affect the type of reaction and the hydrogen production (Figure 4.3).

The reversible voltage U_{rev} at a given temperature and pressure is defined by the Nernst equation:

$$U_{rev} = U_0 + \frac{RT}{2F} * \mathrm{Ln}\frac{P_{H_2}P_{O_2}^{1/2}}{P_{H_2O}}$$

where P_{H_2}, P_{O_2} and P_{H_2O} being the operating pressures of the electrolyser and U_0 the reversible voltage under normal conditions: Figure 4.4 shows the reversible voltage as a function of pressure at different temperatures.

Table 4.1: Minimum theoretical voltage for electrolysis.

Conditions	Reversible voltage	Thermoneutral voltage
P = 1 bar/T = 298 K	1.227 V	1.48 V

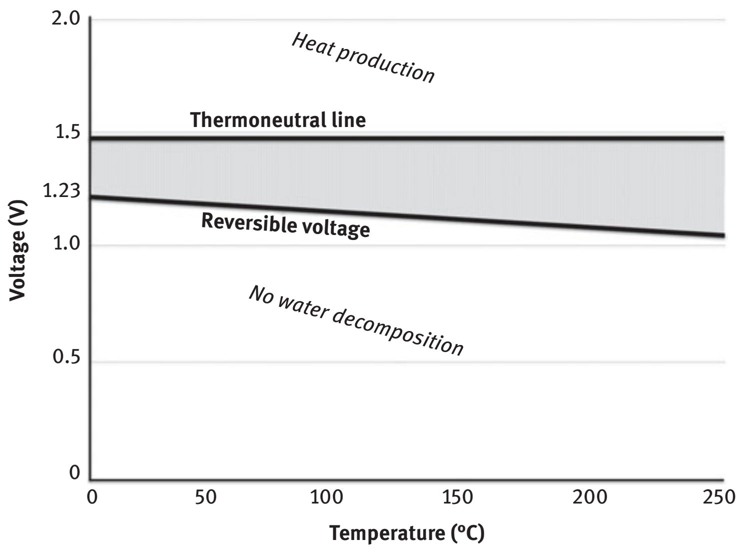

Figure 4.3: Influence of temperature and voltage on electrolysis parameters (ideal cell).

Depending on the temperature at which the electrolysis is carried out (Figure 4.5), three zones are distinguished: one where hydrogen cannot be produced, one where the reaction is endothermic (need to supply heat) and a third where the reaction is exothermic (production of heat to be evacuated). Along the thermoneutral line no heat input or cooling is required.

The actual operating voltages vary between about 1.7 and 2.0 V. This corresponds to a yield of the order of 75–85%.

4.2.2 Operating voltage – current density

If voltage is the important factor in producing hydrogen under optimum conditions, the current applied plays a role on the amount of hydrogen produced (Figure 4.6).

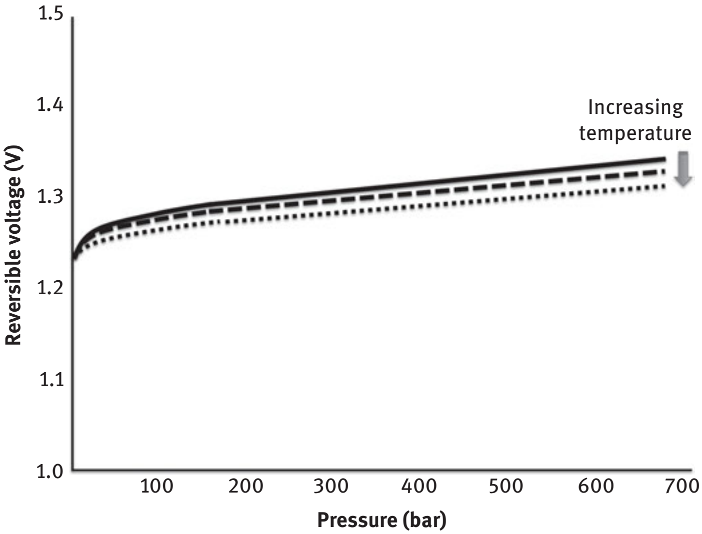

Figure 4.4: Influence of pressure on electrolysis parameters (ideal cell).

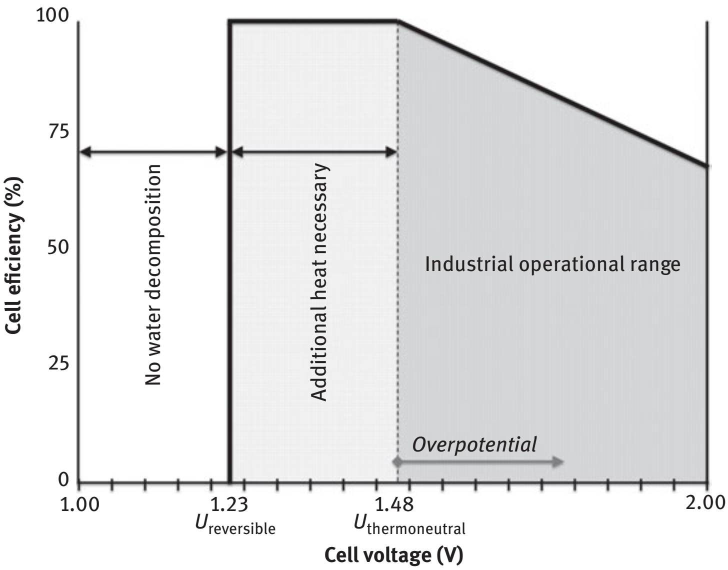

Figure 4.5: Efficiency of a cell as a function of voltage.

This current density (A/cm²) is a function of the voltage and internal resistance of the cell or stack. As a first approximation, this overall resistance is the sum of the resistances of the various elements (anode, electrolyte, gaseous layer, membrane, gaseous layer, electrolyte and cathode).

$$R_{\text{total}} = R_{\text{electrode}} + R_{\text{electrolyte}} + R_{\text{bubbles}} + R_{\text{membrane}}$$

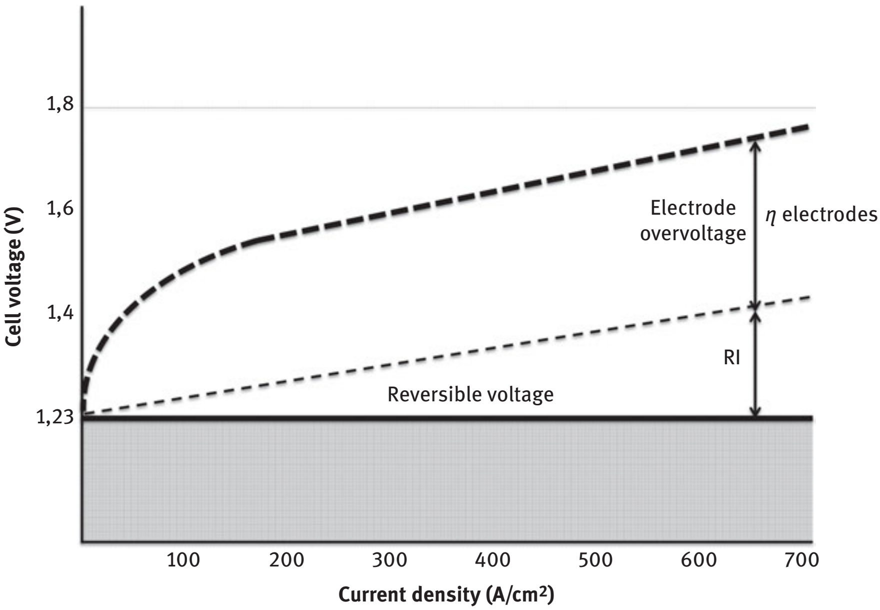

Figure 4.6: Actual operating voltage according to current density.

At the theoretical voltages (reversible or thermoneutral), the polarisation voltages η (overvoltages) due to the electrical resistances of the various components must be added:

$$E = E_0 + \eta_{\text{electrodes}} + \eta_{\text{electrolyte}} + \eta_{\text{bubbles}} + \eta_{\text{membrane}}$$

which can also be expressed in another form:

$$E = E_0 + \eta_{\text{electrodes}} + \text{RI}$$

where R is the sum of resistances in Ohm/cm^2 due to the electrolyte, the bubble formation and their migration as well as those due to the membrane and I the current density (A/cm^2).

The actual operating voltage is the result of the polarisation voltages and is a function of the current density. For low current densities, the theoretical efficiency increases because the activation energy and the ohmic overvoltages are low. However, low current densities result in lower hydrogen production.

4.2.3 Operating parameters

Many factors have an influence on the operation of the electrolyser and hence the production of hydrogen. Depending on the technology used they are:

– temperature
– pressure
– electrical resistance of the electrolyte (conductivity)
– electrolyte quality (impurities etc.)
– concentration of the electrolyte (viscosity)
– electrolyte flow
– material of the electrodes (electrical conductivity, chemical resistance etc.)
– distance between electrodes
– electrode size and alignment
– gas bubbles on the surface of electrodes
– membrane material
– type of current

During electrolysis, the water is consumed and an addition must be made in order to have the same concentration of electrolyte for electrolysis in an alkaline medium. Moreover, the circulation of the water/electrolyte solution or of the water must make it possible to evacuate the gas bubbles (H_2 and O_2) formed on the surface of the electrode and optionally to homogenise the concentration of the solution.

4.2.4 Cell yield

The electrical efficiency of a cell can be calculated according to the following formula:

$$\eta_{\text{electrical}}/\% = \frac{100 * (U_{\text{anode}} - U_{\text{cathode}})}{U_{\text{cell}}}$$

Which heating value to consider?

The higher heating value (HHV) includes all energy released by a reaction between initial and final state at the same temperature (usually 25°C). It should therefore be used for efficiency calculation.

Another expression is Faraday's performance:

$$\eta_{\text{Faraday}} = \frac{\Delta G}{\Delta G + \text{losses}}$$

It can also be expressed as a function of thermal efficiency:

$$\eta_{\text{thermal}} = \frac{\Delta H}{\Delta G + \text{losses}}$$

Use of lower Heating Value?

Depending on the final application, the higher heating value (HHV – 285 kJ/mol) or lower heating value (LHV – 241.8 kJ/mol) of hydrogen could be considered.

For electrolysis using water in liquid form, we consider the higher heating value to calculate the yield.

If the heat of condensation of water is not considered the lower heating value could be used. For a cell voltage of 1.8 V, for example, the respective yields are:
- 1.48/1.8 = 0.82 (82%) considering the higher calorific value
- 1.23/1.8 = 0.69 (69%) considering the lower calorific value

Since the system is not ideal, other losses and consumption of auxiliary equipment (pumps, control system etc.) must also be taken into account.

The actual efficiency is also a function of the type and size of the electrolyser: the higher the efficiency, the higher the yield which can reach 85% or more for the 2017 electrolyser.

4.2.5 Water dissociation energy

How much electricity is needed to dissociate water? If the thermodynamic data give the theoretical values, parasitic phenomena (e.g. resistance of the various components) as well as the auxiliary equipment require higher energy.

The theoretical yield of an electrolyser corresponds to HHV of hydrogen, which in normal conditions (298 K and 1 bar) requires **3.54 kWh/Nm^3** or 39.4 kWh/kg (assuming that all the heat of decomposition of the water is recovered and the final temperature of the water is equal to its initial temperature).

Physical parameters such as material structure, internal layout, ageing of certain components, auxiliary equipment (pumps, compressors etc.) mean that the actual energy required for dissociation is higher than the theoretical value.

For a 75% efficiency, the energy to supply will be theoretically 4.7 kWh/Nm^3 or 52 kWh/kg.

4.2.6 Water consumption

The theoretical quantity of water required for electrolysis is given by the reaction:

$$H_2O \Rightarrow H_2 + \tfrac{1}{2}\, O_2 \tag{4.7}$$

For 1 mol of hydrogen produced (22.4 L) the quantity of water required will be 18 g or 18 cm^3 (Table 4.2).

Table 4.2: Amount of water required as a function of the volume of hydrogen.

Hydrogen volume	Water volume
100 m^3	80,400 L
1,000 m^3	804 m^3
1,000,000 m^3	804,000 m^3

These figures show an often neglected parameter, which is the high water consumption, if we consider surplus electricity from renewable sources in the coming decades.

If an energy requirement of about 5 kWh/Nm^3 of hydrogen is assumed, an annual surplus of 1 TWh corresponding to the production of 200 million m^3 of hydrogen would require at least 160 million m^3 of water.

For comparison, this corresponds to a non-negligible percentage of the annual water consumption of large cities (Tokyo with 750, London with 440 or Berlin with 220 million m^3).

Depending on the country, the surplus of electricity will largely exceed this value, and the volumes of water will be even greater.

4.2.6.1 Two main families of electrolysers

Although it was originally an acid solution that made it possible to demonstrate the phenomenon, it was then alkaline electrolysis that was industrially used, allowing chemicals that are easier to use and relatively less aggressive for the materials.

Another technology was later developed, based on the use of specific membranes where protons (H^+) were circulating (PEM).

Following the development of the high-temperature fuel cell, a new technology based on it emerges.

4.3 Alkaline electrolyser

This type, the oldest used industrially, is based on an alkaline electrolyte. It benefits from a long experience resulting in a reliable and competitive technology.

4.3.1 History and industrial development

In April 1800, English scientists Nicholson and Carlisle observed the decomposition of water by electricity into two gases. They used a Volta battery discovered the previous year. The German Johann Wilhelm Ritter quantifies in the same year the production of hydrogen and oxygen by electrolysis.

Early in the twentieth century, more than 400 industrial electrolysers were in operation. They were using electricity of hydraulic origin. The hydrogen produced was used for the synthesis of ammonia (NH_3) and the manufacturing of fertilisers. As early as 1927, high-power electrolysers (1 MW and higher) were available from the Norwegian company Norsk Hydro, now NEL Hydrogen. From 1927, production sites used up to 150 units, i.e. 150 MW (Figure 4.7 shows electrolysers installed in Rjukan, Norway).

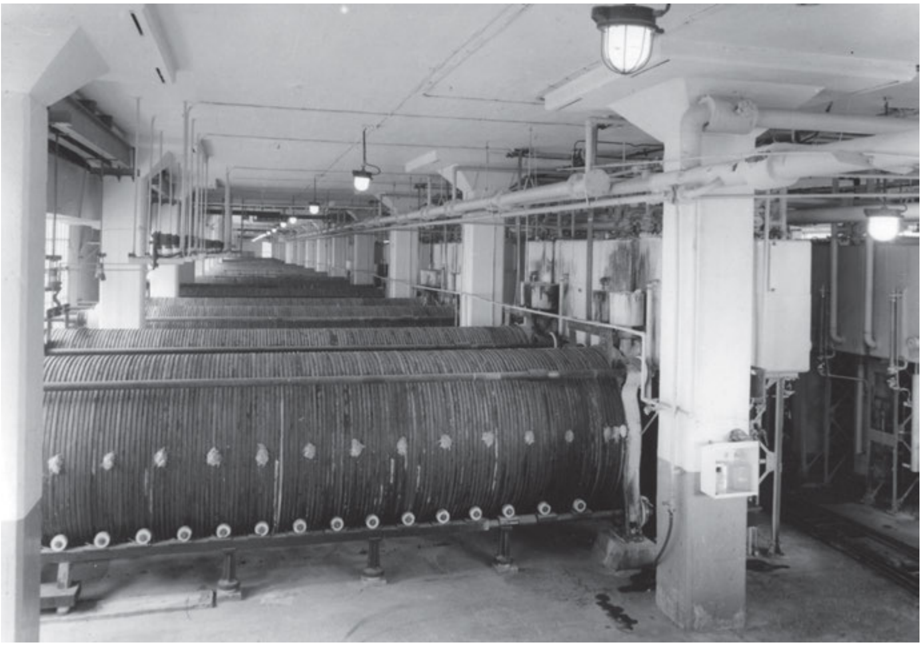

Figure 4.7: Alkaline electrolysers in 1927 (NEL Hydrogen).

4.3.2 Operating parameters

4.3.2.1 Components

An electrolysis cell (Figure 4.8) comprises an alkaline solution, two electrodes and a membrane (or diaphragm) allowing the passage of OH^- ions.

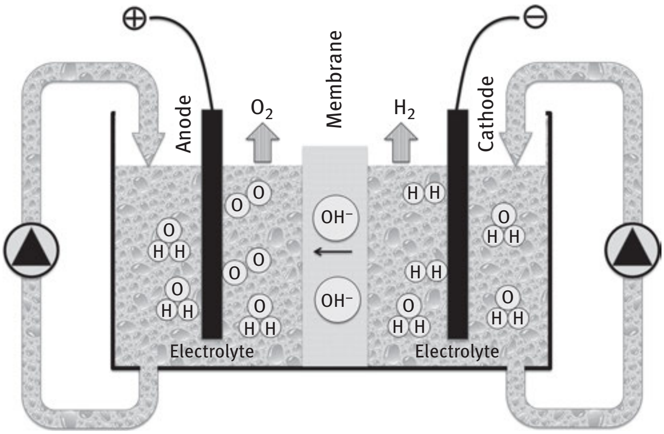

Figure 4.8: Basic cell of an alkaline electrolyser.

The most commonly used electrolyte is potassium hydroxide (KOH), which is more conductive and less aggressive than sodium hydroxide, at a concentration between

25% and 30%. Additives are used in order to increase the ionic activity or reduce the aggressiveness of the electrolyte.

The diaphragm is made of a porous material, which has the role of letting the OH^- ions circulate, separating the hydrogen from the oxygen formed. The materials used are either asbestos, micro-perforated fabric or nickel in sintered form. In the latter case, the diaphragm must not be in contact with the electrodes.

The electrodes (anode or cathode) are generally made of nickel or its alloys (Ni/Fe, Ni/Co/Zn, Ni/Mo etc.) with sometimes electrolytic or vapour deposition of other metals (Zn, Co, Fe, Pt etc.) to increase the reaction rate.

4.3.2.2 Effects of temperature and pressure

The Gibbs–Helmholtz equation involves temperature in the calculation of the operating voltage. It is a factor that influences performance. Generally, operating temperatures for alkaline electrolysers vary between 40 and 90°C.

Table 4.3: Comparison of atmospheric/high-pressure configurations.

Electrolyser type	Atmospheric pressure	High pressure
Advantages	Simple configuration	Compact design at identical power
	Long industrial experience	Possibility to increase the number of cells
	Reduced costs	
	Easier control	
Disadvantages	Large size	Higher costs
	More complex gas drying	Safety
	More limited number of stacks	Reduced operating range at high pressure

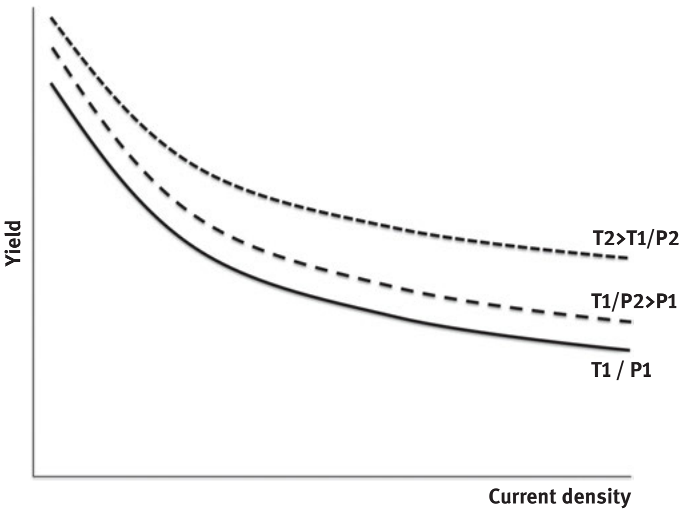

Figure 4.9: Schematic influence of temperature and pressure on performance.

Depending on the design of the stacks, electrolysers can supply hydrogen (and oxygen) at atmospheric pressure or under pressure up to 60 bar (Table 4.3).

The combined influence of these two parameters (*P* and *T*) on the output is illustrated in Figure 4.9. At equal current density, the pressure plays a negligible role, while the efficiency is improved if the temperature increases.

4.3.2.3 Current type

The direct current (DC) used is generally constant. However, a current of variable amplitude about a mean value or a pulsed current may be used (Figure 4.10).

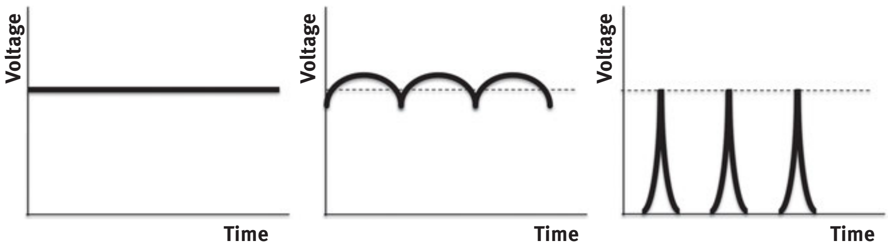

Figure 4.10: Current types (DC voltage–steady DC voltage waveform–short pulse DC voltage).

4.3.2.4 Loss of voltage

Electrolysis is a complex phenomenon due to the numerous interfaces involved and the reactions at these interfaces.

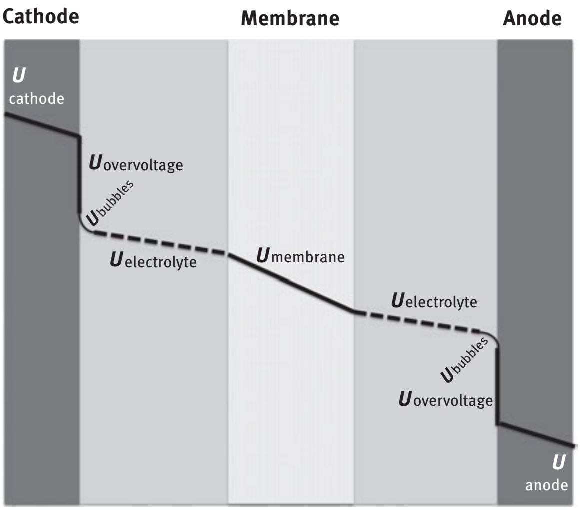

Figure 4.11: Voltage losses along the chain.

For the electrochemical part, the voltage losses at each interface and in the various components accumulate. Figure 4.11 gives an idea of these losses:
- Losses at anode and cathode
- Overvoltages at the surface of electrodes
- Losses due to gas bubbles
- Losses due to electrolyte
- Loss due to membrane

4.3.2.5 Gas contamination

The membrane is not completely gas-tight, which results in oxygen diffusion into the compartment where hydrogen is produced and vice versa. The gases produced also carry potassium hydroxide and water to be separated. The purity of the hydrogen obtained is generally greater than 99.5%.

4.3.3 Structure of an alkaline electrolyser

The electrodes and membrane (or diaphragm) can be arranged (Figure 4.12) with or without spacing (zero gap).

The layout of the cell groups can have two configurations: monopolar and bipolar.

In the monopolar stack (Figure 4.13), all anodes and cathodes are fed directly by the current source which supplies a voltage equal to that of a cell.

For the bipolar configuration (Figure 4.14), only the terminal electrodes are directly supplied with current with a voltage corresponding to the sum of the voltages of each cell.

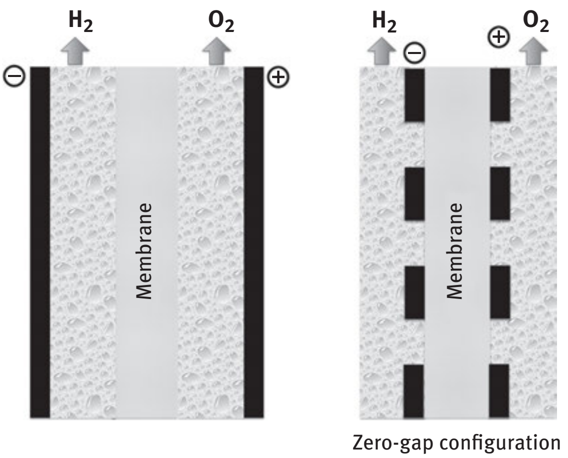

Figure 4.12: Layout of electrodes and membrane.

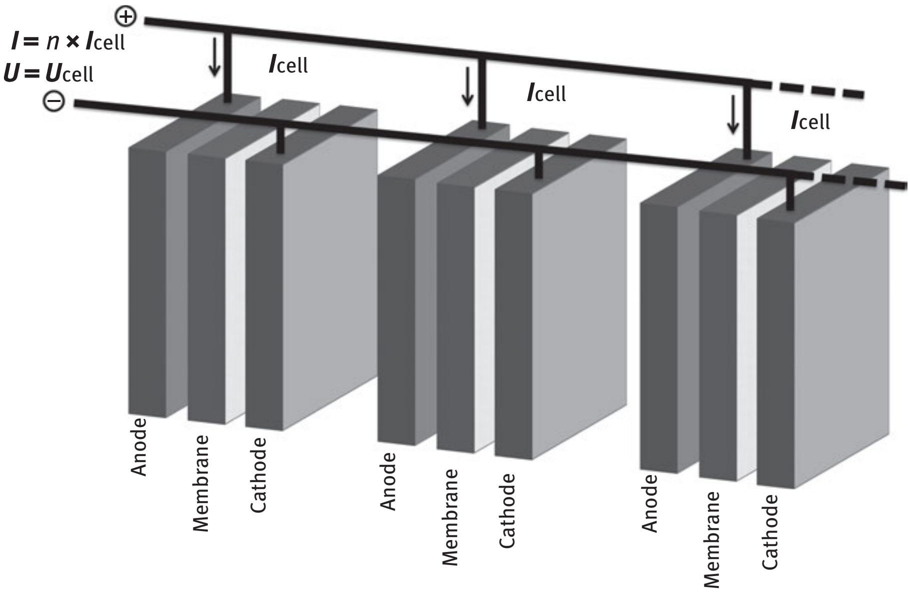

Figure 4.13: Monopolar design.

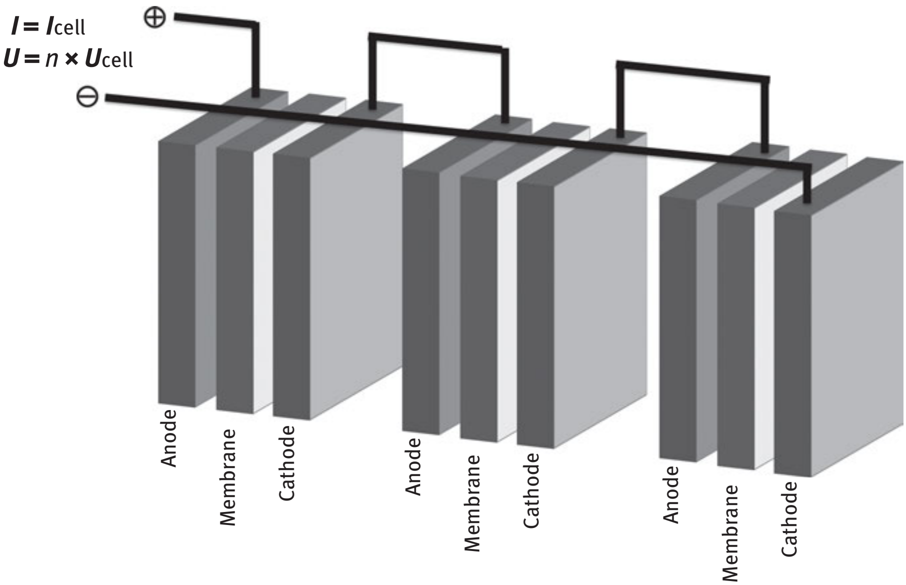

Figure 4.14: Bipolar design.

The industrial electrolysers (Figure 4.15) have practically all adopted the bipolar structure, which allows a higher current density. Table 4.4 compares these two configurations of electrodes positioning.

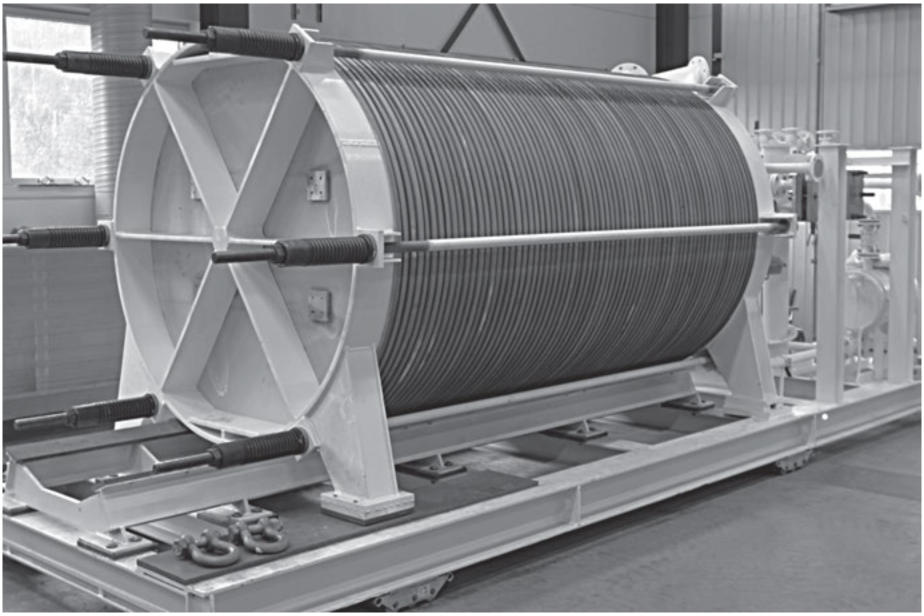

Figure 4.15: Alkaline electrolyser stack (NEL Hydrogen).

Table 4.4: Comparison of monopolar and bipolar configurations.

	Monopolar design	Bipolar design
Characteristics	Low operation voltage (of one cell)	Voltage equal to the sum of the voltage of each cell
	High current density	
Advantages	Lower investments	Compacity
	Defective cells may be short-circuited	Higher yield
Disadvantages	Large size	Higher cost
	Low potential for yield improvement	If a cell is not working, dismantling the rack is needed

4.3.4 Auxiliary equipment

The electrolyser is associated with different equipment (balance of plant, Figure 4.16) necessary for optimal operation:

– A water demineralisation and feeding unit (pumps)
– A unit for separating oxygen from hydrogen
– Optionally a unit for separating hydrogen from oxygen
– Drying units for both gases
– A temperature control unit
– DC power (voltage and current)
– A control and management unit for the various parameters

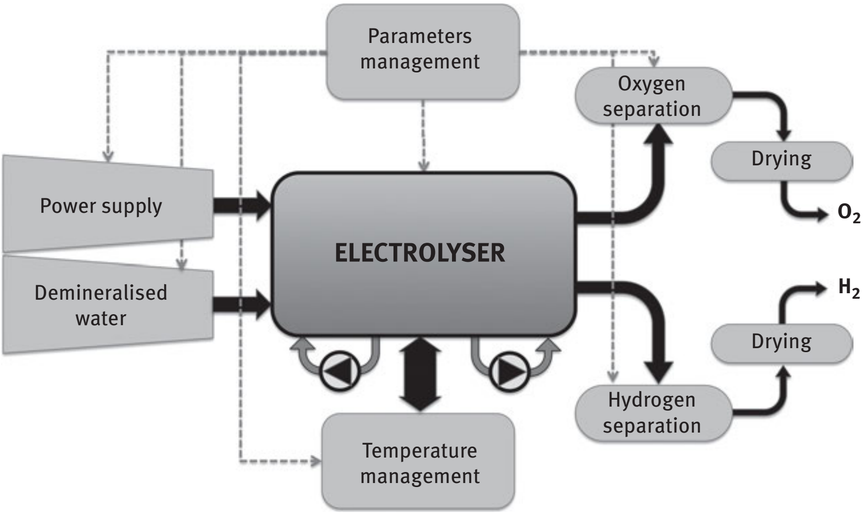

Figure 4.16: Auxiliary equipment (BOP – balance of plant).

4.3.5 Industrial equipment

4.3.5.1 Power of electrolysers

This power is calculated taking into account the current density, the supply voltage and the number of cells. It allows to optimise the design according to the volume of hydrogen to be produced.

The most important existing industrial plants operate continuously, often using hydropower and can produce up to 30,000 Nm^3/h of hydrogen, used for the production of ammonia and fertilisers. In 2017, the alkaline electrolysers used for power-to-gas evaluations have a power of up to 6 MW.

4.3.5.2 Start-up time

In the case of cold start, alkaline electrolysers require up to 20 min to be operational. For power-to-gas, the start-up should ideally be instantaneous in order not to lose electricity when there is surplus production. To bypass this limitation, isolating the electrolyser to maintain the temperature above 30°C may allow a start in a few seconds.

4.3.5.3 Lifetime

For an alkaline electrolyser, the elements that wear are the membranes and the electrodes that must be regularly revised. Depending on the size of the installation, the type of operation (continuous or not) or other parameters, the lifetime of a unit varies between 50,000 and 90,000 h.

4.3.5.4 Suppliers

Only some high-power electrolyser suppliers that are compatible with the power-to-gas concept are listed.

The Norwegian company NEL Hydrogen (formerly Norsk Hydro) has been designing electrolysers since the 1920s. Model A 485 (Figure 4.17) with a power of 2.2 MW can produce up to 500 Nm^3/h of hydrogen under 1 bar at a purity of 99.9%.

The P•60 electrolyser (Figure 4.18) can produce up to 60 Nm^3/h of hydrogen at a pressure of 15 bar. The response time is less than 3 s and it can vary its power between

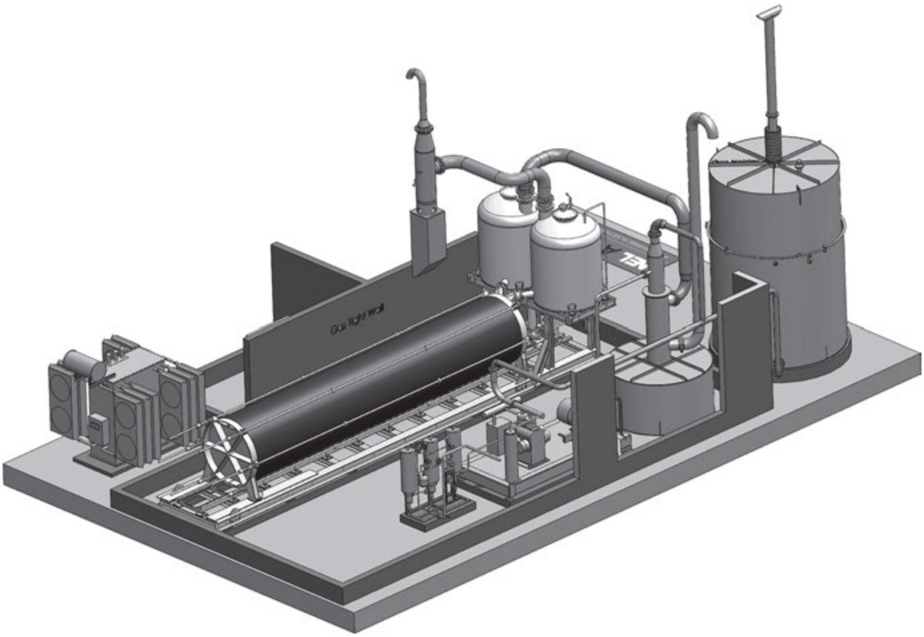

Figure 4.17: High-power A 485 alkaline electrolyser with auxiliary equipment (NEL Hydrogen).

10% and 100%. The electrolyser and ancillary equipment are installed in a 20-ft container (6.1 m).

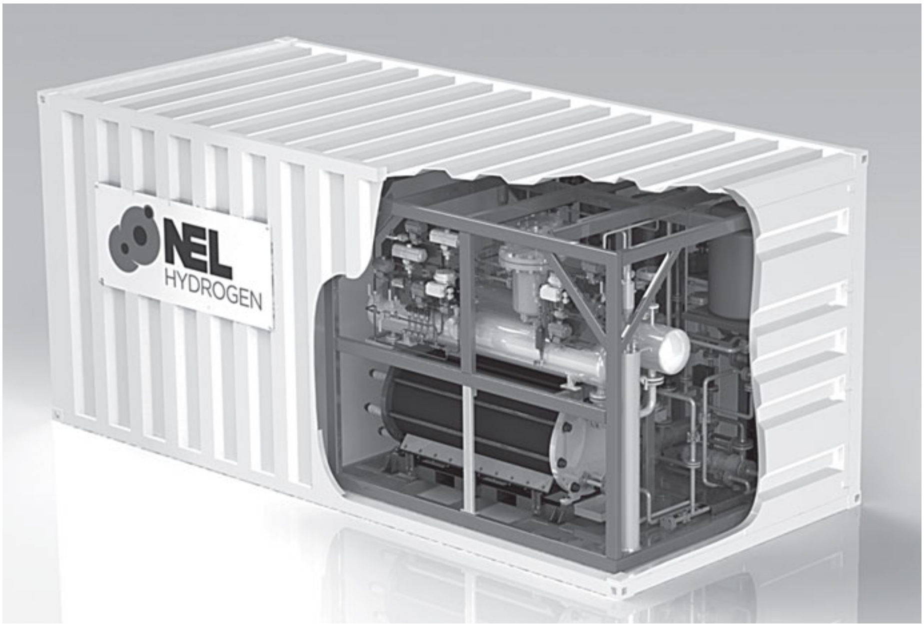

Figure 4.18: Alkaline electrolyser P • 60 (NEL Hydrogen).

The same applies to HySTAT 60 from Hydrogenics (Figure 4.19).

Other companies also offer alkaline electrolysers with a capacity greater than 1 MW, capable of producing several hundred cubic metres of hydrogen per hour, such as Hydrogenics in Canada, McPhy in France, IHT in Switzerland, Jingli or Tianjin Mainland Hydrogen Equipment in China.

4.3.5.5 The alkaline electrolyser, a proven technology

Alkaline electrolysers have a long experience in optimising performance (materials used, efficiency, lifetime and cost). The power range available (up to several megawatts) allows it to be used for the exploration phase of power-to-gas technology.

4.4 PEM electrolyser

Following the development of PEM fuel cells for the US space programme, General Electric used the same technology to produce an electrolyser in 1966 (SPE or Solid Polymer Electrolyser). The first high-power commercial models (100 kW, 20 Nm^3 of hydrogen per hour) were produced by the company ABB from 1987.

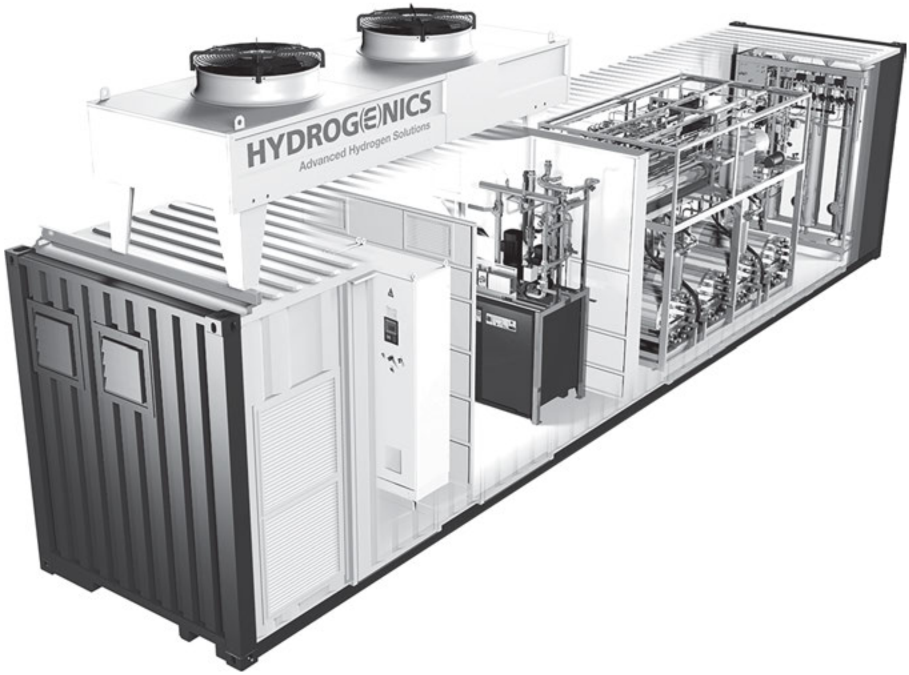

Figure 4.19: HySTAT 60 Alkaline electrolyser (Hydrogenics Corp.).

4.4.1 Principle

A membrane coated with a **catalyst** separates the anode from the cathode (Figure 4.20). The decomposition reactions of the water occur at the anode.

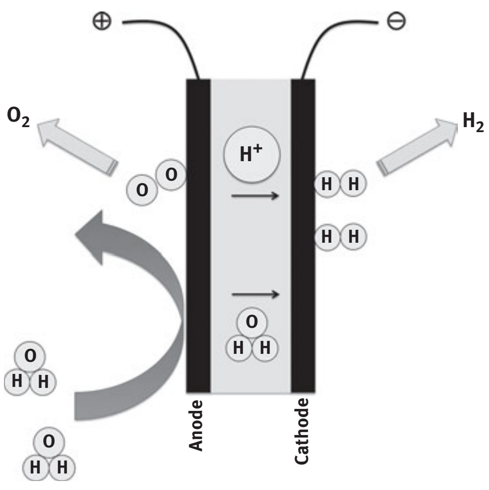

Figure 4.20: Principle of the PEM electrolyser.

The water is decomposed at the anode:

$$2\,H_2O \Rightarrow O_2 + 4\,H^+ + 4\,\bar{e} \tag{4.8}$$

After passing through the membrane, the protons H^+ react with the cathode to form a hydrogen atom:

$$4\,H^+ + 4\,\bar{e} \Rightarrow 2\,H_2 \tag{4.9}$$

The core of the PEM electrolyser is the PEM membrane. This reaction is very slow and only the use of catalysts accelerates its speed.

4.4.2 PEM electrolyser structure

The central component is the MEA (membrane–electrode assembly) (Figure 4.21). It comprises a membrane with a thickness of the order of 100–300 µm, coated on each side with catalyst generally based on precious metal (Precious Metal Group, often platinum, iridium and ruthenium) as well as the electrodes (or current collectors).

The membrane should have the following characteristics:
- High ionic conductivity in S/cm to allow proton circulation
- Low permeability to gases, especially hydrogen and oxygen in order to avoid their diffusion in the other compartment
- Very good resistance to chemicals
- Very good thermal and mechanical stability
- High permeability to water

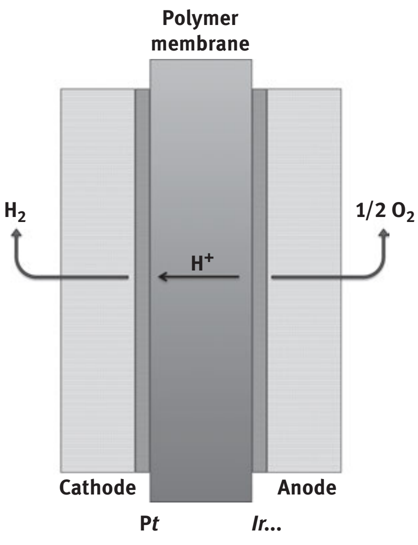

Figure 4.21: Structure of a membrane–electrode assembly.

The **membrane** is a material allowing the passage of protons H^+. The oldest is the Nafion® developed in the 1960s by the American company Du Pont de Nemours and available in the form of powder or sheets of different thicknesses.

Nafion® (Figure 4.22) is a perfluorosulphonic acid/polytetrafluoroethylene stabilised composite copolymer in the acid form (H^+). Sulphonic groups SO_3^- favour the conductivity of protons.

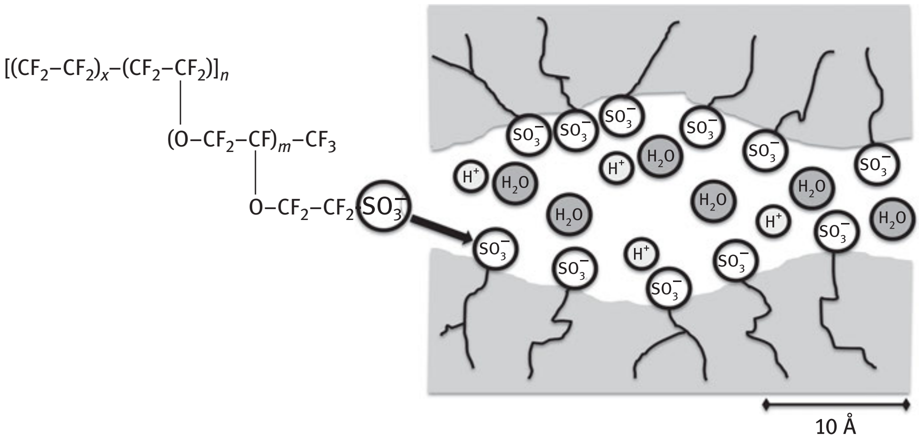

Figure 4.22: Chemical structure of Nafion®.

Other membranes have been developed, either around this family of copolymers or to be able to work at higher temperatures (above 100°C). Those are based on the family of polybenzimidazole doped with an acid (phosphoric or sulphuric acid) or pyridines. The cost of these membranes is generally high. In 2017, the Nafion costs more than 1,000 euros/m^2 for 117 µm thickness (N117).

This membrane is coated with catalyst (e.g. platinum for the cathode, and iridium or ruthenium for the anode) in the form of very fine particles in order to have a large contact surface.

A **current collector** in contact with the catalyst allows the flow of current and the evacuation of the gases produced (GDL or gas diffusion layer). It must be porous, good electrical conductor, resistant to corrosion, allow the anode to pass water to the catalytic sites and evacuate the oxygen produced. The materials used are titanium in the form of sintered powder or in the form of carbon tissues at the cathode.

The **bipolar plates** serve as electrodes and circulators for water and for the product gas (hydrogen at the cathode and oxygen at the anode). They have channels where these elements circulate. They also separate the cells from each other (Figure 4.23).

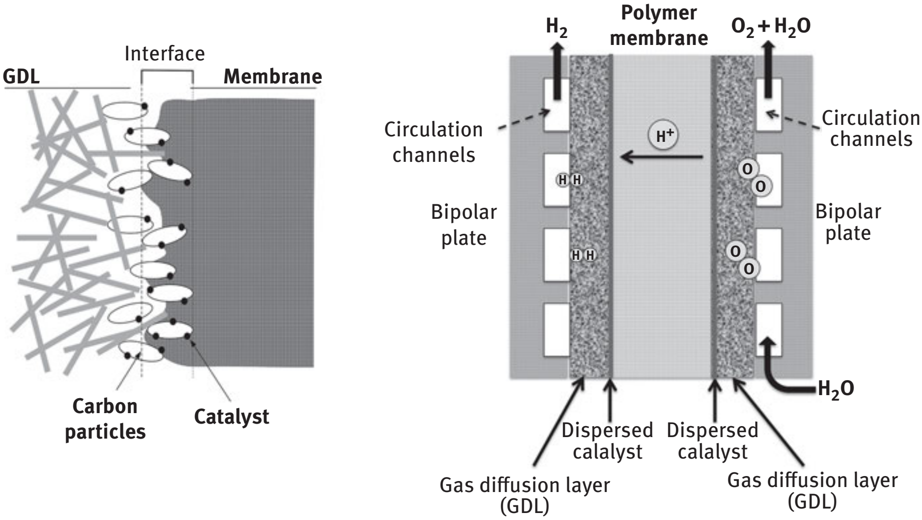

Figure 4.23: Diagram of the components of a PEM electrolytic cell.

An elementary cells assembly (MEA, current distributors, bipolar plate) forms a stack (Figure 4.24). Commercial electrolysers are composed of several tens of stacks (Figure 4.25).

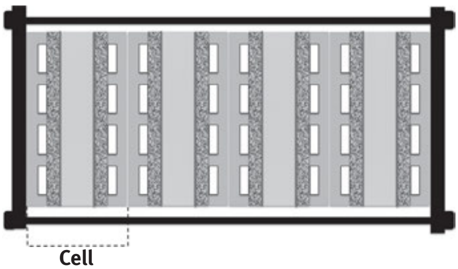

Figure 4.24: Assembling of elementary cells (stack).

4.4.3 Balance of plant

As for alkaline electrolysers, they are all auxiliaries around a cell or a stack (see Figure 4.16).

4.4.4 Influence of the catalyst

4.4.4.1 Catalyst loading

The catalyst acts as an accelerator for the decomposition of water. It is therefore necessary to optimise the concentration (expressed in mg/cm^2 or g/m^2 of membrane), its structure (the finest particle size possible) and its distribution on the membrane (homogeneous dispersion).

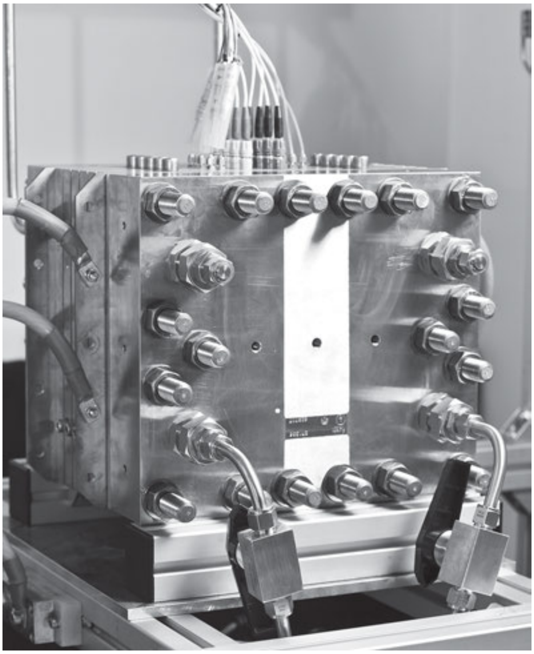

Figure 4.25: Stack for PEM electrolyser (Siemens).

The high cost of the catalysts results in a shift towards increasingly low loads from a few mg/cm^2 to less than 1 mg/cm^2, the compromise being excellent catalytic activity and catalyst stability over time (little deterioration in performance). Even if these charges appear to be small, extended to several m^2, they represent a significant cost.

4.4.4.2 Precious metals group

The metal used as catalyst at the cathode is platinum, optionally combined with other metals. This metal is produced mainly in South Africa, Russia and Canada. Its price is very variable (Figure 4.26 in US$ per troy ounce, 31.1 g) and strongly influences the price of the MEA. By way of comparison, over the past 10 years, the price of gold has risen to a maximum of US$ 1,900 per ounce with an average of US$ 1,200.

For the anode, it is the ruthenium and especially the iridium which is more stable or their oxides which serve as catalyst.

Replacing platinum?

By its high and variable price, platinum contributes to the higher cost of PEM electrolysers. For many years, numerous studies have been conducted in order to find an alternative, however, without success. While some metals have shown positive laboratory results, their catalytic properties decline rapidly over time (a few hundred hours at best). The work in the industry is oriented rather towards a reduction of the charge of precious metals while maintaining the catalytic activity over a long period.

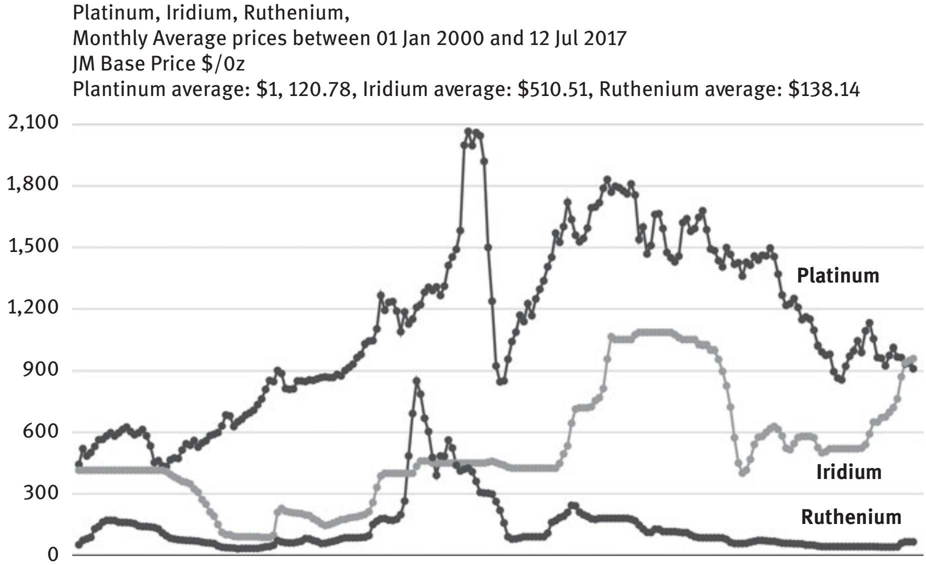

Figure 4.26: Trends in the price of platinum, iridium and ruthenium between 2000 and 2017 (Johnson Matthey).

4.4.5 Operating parameters

As with the alkaline electrolyser, factors such as temperature and pressure affect the performance of the PEM electrolyser.

4.4.5.1 Temperature

For a given voltage, hydrogen production increases with temperature. It is important, however, not to exceed a certain threshold which depends on the nature of the membrane so as not to degrade it. Generally, the temperature remains between 70 and 90°C.

4.4.5.2 Pressure

PEM-type electrolysers can directly supply hydrogen under high pressures (over 100 bar). In 2016, pressures of up to 350 bar were reached with prototypes.

4.4.5.3 Current density

PEM-type electrolysers can be used at higher current densities than alkaline electrolysers, thus permitting higher hydrogen production. The densities can reach several A/cm^2 depending on the parameters, including the thickness of the membrane.

4.4.5.4 Membrane area

This parameter determines the volume of hydrogen production by influencing the applied current density per unit area of the membrane (in A/cm^2 or A/m^2). This current density must be optimised to achieve both high hydrogen production and also to have a maximum lifetime of the membrane and catalysts.

4.4.5.5 Efficiency of the electrolyser

As for alkaline electrolysis where the thermodynamic parameters of water decomposition are identical, the theoretical minimum energy of decomposition along the thermoneutral curve is 3.54 kWh/Nm^3 of hydrogen if one considers the HHV.

The required energy depends also on the maximum production capacity of the electrolyser. Generally, it varies between 5 and 8 kWh/Nm^3 depending on the capacity of the units. At atmospheric pressure, hydrogen is produced with a purity of more than 99.995% (class 5).

4.4.5.6 Lifetime

Degrading elements are the membrane and the catalysts (the particles combine reducing the catalytic efficiency). In 2017, the service life exceeds 40,000 h in continuous operation.

4.4.6 Industrial equipment

Only some suppliers of high-power PEM electrolysers, compatible with the power-to-gas concept, are presented.

The Siemens Silyzer 200 (Figure 4.27 and Table 4.5) with a power of 1.25 MW can produce hydrogen under a pressure of 35 bar.

The Silyzer 300 electrolyser with a power of 6 MW was evaluated in Austria as part of the European project H2Future before commercialisation in 2018. The hydrogen produced is used by the Voestalpine steel plant.

Proton OnSite (USA) has developed a modular electrolyser of 1 or 2 MW. The 1 MW model with its ancillary equipment occupies a container of 40 ft (12.2 m) and can produce up to 200 m^3 of hydrogen per hour.

The high-power PEM electrolyser stack of Hydrogenics (Figure 4.28) can produce up to 285 Nm^3/h of hydrogen under 40 bar. It measures 1.00 × 0.80 × 0.55 m.

Hydrogenics in Canada, ITM Power in Great Britain, AREVA H2 Gen in France and Ginner, Inc. in the USA offer also PEM electrolysers with a power of more than 1 MW.

Figure 4.27: 1.25 MW electrolyser (Siemens).

Table 4.5: Characteristics of the Silyzer 200.

Silyzer 200	Specifications
Power	1.25 MW
Size with auxiliary equipment (in m)	6.3 × 3.1 × 3.0
Weight of complete unit	17 tonnes
Starting time	<10 s
Hydrogen pressure	35 bar
Hydrogen purity	99.5–99.9%
Nominal production	225 Nm^3/h
Water consumption	1.5 $L/Nm^3\ H_2$
Lifetime	>80,000 h

4.4.7 Water treatment and consumption

The starting element for electrolysis is water. The cells of the PEM electrolyser are susceptible to numerous contaminations. For this reason, water must meet certain criteria, such as conductivity and impurity concentration.

The power-to-gas installation in Mainz, Germany, uses a PEM-type electrolyser and treats the water in several stages (Figure 4.29) to provide demineralised water.

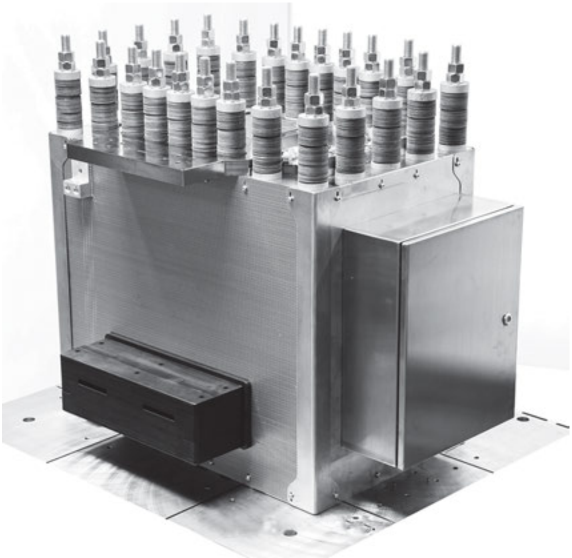

Figure 4.28: 1.5 MW Electrolyser stack (Hydrogenics Corp.).

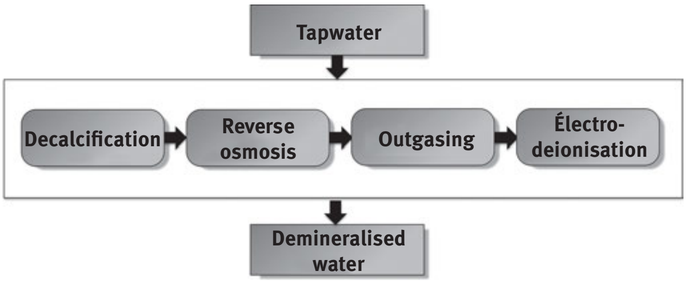

Figure 4.29: Preliminary water treatment.

4.4.7.1 PEM electrolysis, strong potential for improvement

The more complex structure than the alkaline electrolysis and some specific components (membrane and catalysts) make the PEM electrolyser still expensive. This technology is relatively recent compared to alkaline electrolysis, but has a high potential to improving performance in terms of overall efficiency and reducing cost.

4.5 High-temperature electrolyser

This technology (SOEC – solid oxide electrolyser cell) shown in Figure 4.30 aims to achieve high efficiency with lower electricity consumption than other families of electrolysers. The decomposition reaction of water takes place at high temperatures

(500–900°C) and requires an external heat source which can be obtained from an industrial process. High temperatures require specific materials, such as ceramics for electrodes and electrolyte.

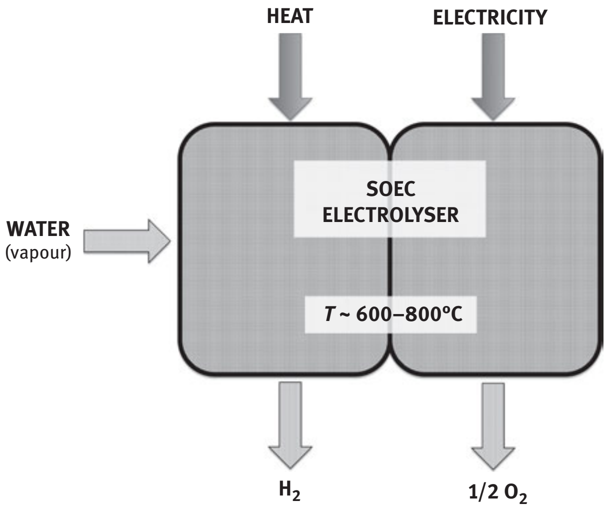

Figure 4.30: Principle of high-temperature electrolysis.

At high temperature, the water is vaporised and decomposed at the cathode according to the reaction:

$$2\,H_2O + 4\,\bar{e} \Rightarrow 2\,H_2 + 2\,O^{2-} \tag{4.10}$$

The anions O^{2-} pass through the membrane and form oxygen at the anode:

$$2\,O^{2-} \Rightarrow O_2 + 4\,\bar{e} \tag{4.11}$$

The thermodynamic conditions for this reaction are energetically more favourable than low-temperature electrolysis. The Gibbs ΔG energy of the reaction goes from 237 kJ/mol at room temperature to 183 kJ/mol at 900°C while the molar enthalpy ΔH (total energy required) varies little (Figure 4.31). Some of the energy can be supplied by an external heat source ($T\Delta S$).

The structure (Figure 4.32) is composed of a solid electrolyte (YSZ-stabilized mixed oxide of zirconium and yttrium) and electrodes, a mixed oxide of lanthanum, strontium and manganese (LSM) for the anode and a YSZ/nickel mixture for the cathode. The electrodes have a porous structure and water decomposition reactions take place on their surface. The O^{2-} ions circulate in the electrolyte using the crystalline defects.

High-temperature electrolysis allows a lower voltage than alkaline or PEM and a high current density (up to 12 A/cm^2 in laboratory). The developments are oriented towards a reversible solid oxide cell system where the electrolyser (solid oxide electrolytic cell) can also be used as a fuel cell (solid oxide fuel cell) using hydrogen, natural gas or methane.

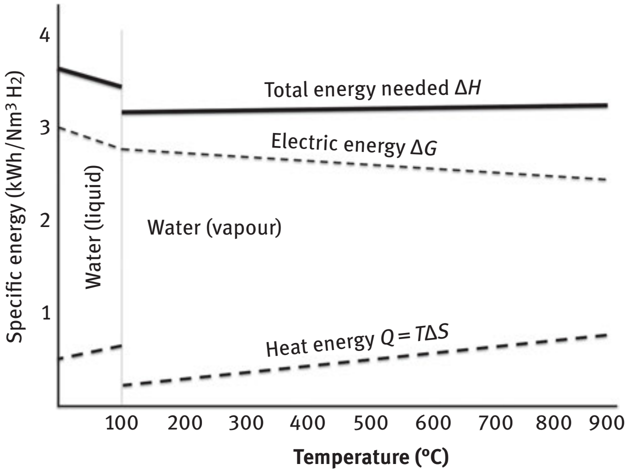

Figure 4.31: Energy balance as a function of temperature.

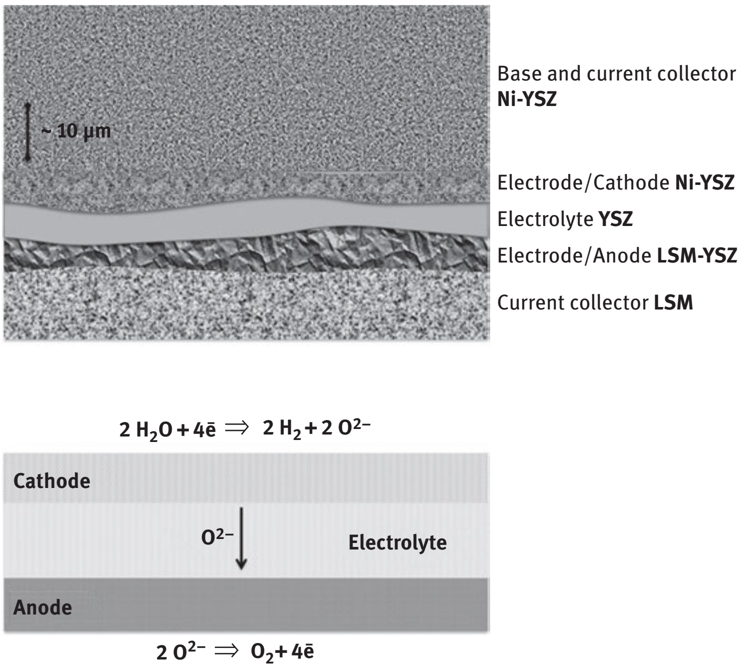

Figure 4.32: Structure of a cell and reactions.

The European project GrInHy (Green Industrial Hydrogen, 2016–2019) with eight partners in five countries, including Sunfire for Germany, aims to validate the use of high-temperature reversible electrolysis in a steel plant to produce hydrogen with the required quality and in industrial economic conditions.

Sunfire developed in 2016 a prototype of 200 kW operating at a temperature of 850°C and supplying hydrogen under a pressure of 30 bar. The external heat input from another industrial process reduces the electrical requirements by about 16% (electrical efficiency >90%). In 2016, a 160 kW reversible module (fuel cell/electrolysis) with a capacity of 42 Nm^3/h of hydrogen with an 85% yield was delivered to Boeing (Figure 4.33), followed in 2017 by a unit of 150 kW for Salzgitter Flachstahl GmbH for its smelting plant. The steam supplied by the plant allows the electrolyser to produce up to 40 Nm^3/h of hydrogen.

Nuclear power plant and SOEC

Heat from a nuclear reactor could be used to supply superheated steam at 500°C which would feed a high-temperature electrolyser. The French EDF and AREVA NP evaluated Hydrogen production from a nuclear reactor of 600 MW_{th}. The electricity consumption of the electrolyser would be of the order of 3.2 kWh/Nm^3 but would require an additional infrastructure. None of the studies had an industrial follow–up, the French nuclear energy entering into a restructuring phase.

SOEC technology offers a better overall efficiency of electrolysis than other technologies, and reversibility makes it possible to convert it quickly into a fuel cell with an electrical efficiency of 55%. With the German company Sunfire, Japan's Toshiba and USA's Fuel Cell Energy are also active in this sector. Research is mainly focused on improving the degradation of cell performance.

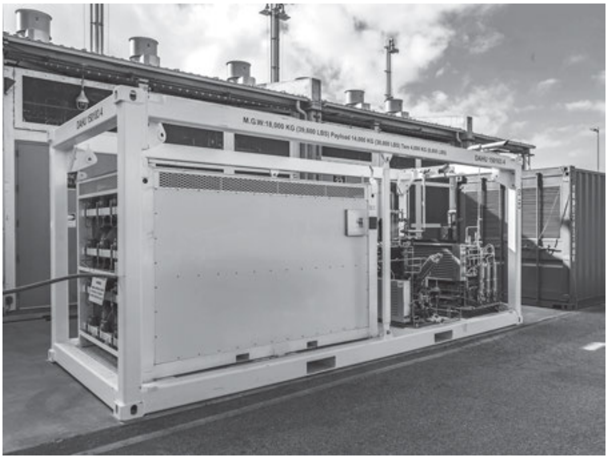

Figure 4.33: A 160 kW reversible solid oxide system unit (Sunfire, Boeing).

4.6 Other technologies

4.6.1 High-frequency electrolysis

This technology uses the dissociation of water at very high temperatures (>3,000 K). These temperatures are reached by a thermal plasma using a torch initially fuelled by air which is gradually replaced by water (liquid or vapour) [1].

The German company Graforce Hydro GmbH has developed an electrolyser using a plasma which would achieve a very high efficiency and a low cost of the hydrogen produced (an estimation in 2017 gives about €3/kg). The water used would not require any special preparation.

This technology must above all demonstrate its capabilities in an industrial context: technological development, cost of equipment, lifetime and real output.

4.6.2 Photoelectrolysis (photolysis)

In nature, the production of hydrogen by biophotolysis takes place in two stages: photosynthesis by light irradiation of green algae or cyanobacteria and production of hydrogen catalysed by enzymes.

Industrial photocatalysis is based on the direct decomposition of water into hydrogen and oxygen under the effect of light. This approach promises a lower cost of production than electrolysis.

The phenomena involved can be:
- At the surface of an electrode (titanium oxide is often used)
- On the surface of a photocatalyst (e.g. rare earths) or a semiconductor
- Specialised microorganisms (algae or cyanobacteria)

Many problems remain to be solved. For biological photocatalysis, for example, the production of oxygen reduces the activity of the enzymes or the absorption of the greater part of the photons by the chlorophyll of the microalgae.

All these approaches, started in 1972 in Japan, are still being studied in laboratories, far from any evaluation in real conditions.

4.6.3 Solar hydrogen

This technology (photoelectrochemical) combines a photovoltaic panel and an electrolyser (PEM membrane) into a sandwich unit [2]. The semiconductor element is in direct contact with the electrolyte, the oxidation–reduction reactions occurring at the surface. Laboratory studies have achieved a maximum yield of about 20%. The problems to be solved are, among others, corrosion, transportation of ions and gases in the cells.

4.6.4 Other non-electrolysis ways to produce hydrogen

Thermochemical water splitting is a thermal-driven reaction to split water into hydrogen and oxygen.

Other reactions like metal-oxide redox pairs and sulphur–iodine processes have also been evaluated.

4.7 Hydrogen purification

The hydrogen produced by the electrolyser must undergo a series of operations in order to bring it in line with subsequent uses, in particular its purification to meet the criteria for the intended destination.

According to the applications envisaged, hydrogen must meet certain purity standards. The membranes or electrodes used are not completely impermeable to oxygen, of which small quantities (0.1–0.2%) are then mixed with hydrogen. The hydrogen produced also contains traces of water or potassium hydroxide for alkaline electrolysis. The concentrations of contaminants depend on the operating parameters (temperature, pressure etc.).

4.7.1 Elimination of potassium hydroxide

For alkaline electrolysis, the use of a scrubber eliminates the traces of electrolyte, cools the hydrogen and collects the water for reuse after treatment.

4.7.2 Oxygen removal

The technology to be adopted for removing entrained oxygen will depend on the degree of purity required and the volumes to be treated.

4.7.2.1 Palladium/silver membrane

These membranes (Figure 4.34) make it possible to extract the hydrogen molecules by dissociating into monoatomic hydrogen at the surface of the membrane Pd/Ag and then diffusing where ionisation takes place followed by recombination into diatomic hydrogen after passing through this membrane. This process provides high-purity hydrogen (>99.999%), but the cost of membranes is high.

The main parameters are the pressure, the temperature (300–400°C) and the thickness of the membrane. Regular purging of the surface of the membrane makes it possible to eliminate the molecules remaining on the surface.

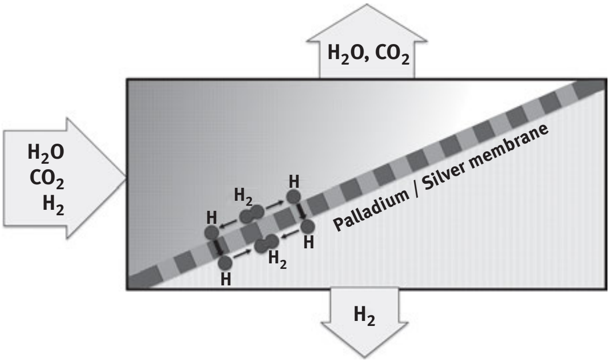

Figure 4.34: Membrane purification.

Other membranes (ceramic, polymer) are studied, but their separating power is lower than that of palladium/silver.

4.7.2.2 Cryogenic process

The gas mixture to be purified is firstly treated to remove any compound that can solidify during the cryogenic treatment (water etc.), then it is compressed and passes through a series of exchangers (where it is cooled by an external source and/or a series of detents by Joule–Thompson valve) and separators where the hydrocarbons condense, leaving an increasingly pure hydrogen.

4.7.2.3 Adsorption by pressure variations (pressure swing adsorption)

This process is based on the selective adsorption of all the components except hydrogen (due to its low molecular weight) by a substrate (activated carbon, molecular sieves etc.) and supplies high-purity hydrogen (up to 99.9999%). In general, the system (Figure 4.35) consists of a battery of several units, one part in operation (adsorption under pressure from 10 to 40 bar) and the other in regeneration (the collected adsorbed gases can be used to reheat the reformer). This process also makes it possible to process large volumes (units of more than 100,000 m³/h).

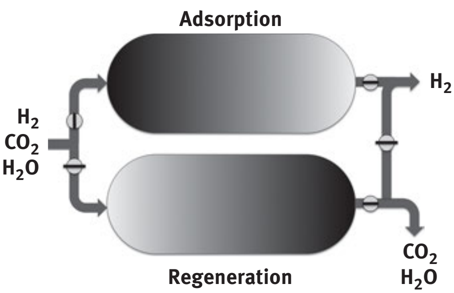

Figure 4.35: Adsorption units (pressure swing adsorption).

4.7.3 Dehydration

The drying of hydrogen is generally carried out by units equipped with molecular sieves at a temperature of −60°C. (Dew point). The regeneration of the absorbent is done thermally.

4.7.3.1 Purification

The approach used to purify hydrogen must be oriented towards the end-use criteria in order to optimise investments, costs and the overall energy balance.

4.8 Technology comparison

The operational technologies over a wide range of power are alkaline and PEM. High-temperature electrolysis (SOEC) is still in a development phase.

4.8.1 Characteristics of electrolysers

Each technology offers characteristics that condition its use in a given field or for a specific application (Table 4.6).

PEM-type electrolysis has the advantage of avoiding the chemically aggressive potash solution and of having a wider operating range. It accepts a higher current density. However, it requires a specific membrane of high cost.

Alkaline electrolysis, on the other hand, benefits from decades of experience and optimisation of performance and costs.

SOEC electrolysers promise higher efficiency but have to show their durability in the long term due to the thermal stresses to which they are subjected (Figure 4.36).

Table 4.6: Comparison of alkaline, PEM and SOEC electrolysers.

Property	Alkaline	PEM	SOEC
Electrolyte	KOH	Membrane	Solid state
Charge carrier	OH^-	H^+	O^{2-}
Operating temperature	40–90°C	Up to 100°C	600–800°C
Hydrogen pressure	Up to 30 bar	Up to 200 bar	Up to 30 bar
Electrodes	Ni/Fe	Pt, Ir, Ru	Mixed oxides
Power variation range	20–100%	0–100%	0–100%
Electrical efficiency (kWh/Nm^3)	4.5–5.0	4.5–9.0	About 4.0
Current density	<1 A/cm^2	5–8 A/cm^2	Many A/cm^2
Rated life	8–15 years	4–7 years	>10 years

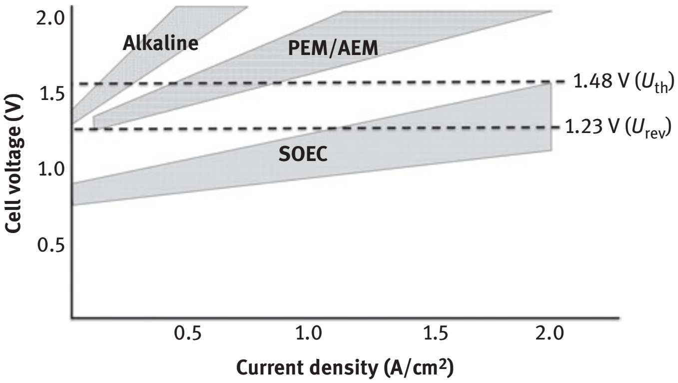

Figure 4.36: Comparison of the electrical parameters of the different electrolyser technologies.

4.8.2 Alkaline membrane electrolyser: the best compromise?

Alkaline electrolysers use potassium hydroxide which is corrosive and can form carbonate deposits by reacting with CO_2 from the air. The PEM type uses a proton exchange membrane and precious metals as catalysts that increase the cost.

Research is striving to develop an alkaline membrane (anion exchange membrane) based on polysulphones, thus eliminating the need of a liquid electrolyte, the OH^- ions, passing through the membrane.

The evaluated catalysts, based on nickel or cobalt, do not use precious metals. The electrode reactions are those of alkaline electrolysis and operating temperatures between 50 and 70°C. The materials for the membrane may be benzyltriethylamine, for example, used as the functional group.

This approach would combine the benefits of both technologies. However, progress has yet to be made in reducing performance degradation over time, increasing efficiency (with a higher current density than alkaline electrolysis) and stabilising the catalysts.

4.8.2.1 Electrolysers for power-to-gas

For use in the power-to-gas concept, electrolysers must meet a number of basic criteria:

- High capacity (several hundred to several thousand Nm^3/h)
- A wide operating range (at least 0–100%)
- Fast response time

Electrolysers must be able to rapidly absorb production peaks of excess renewable electricity. As in the case of gas-fired power plants, this results in the need for high peak power with the possibility of a relatively short operating time at maximum power. But this is one of the conditions to recover all the excess electricity.

References

[1] Boudesocque, N. and al. Hydrogen production by thermal water splitting using a thermal plasma. WHEC 16 / June 13–16, 2006, Lyon, France.

[2] Rongé, J. and al. Solar Hydrogen Reaching Maturity. Oil & Gas Science and Technology, Rev. IFP Energies nouvelles, 2015.

5 Power-to-gas strategies

5.1 Hydrogen transportation

Once excess renewable electricity is used to produce hydrogen, it must be used directly or indirectly. Each of these options meets the needs of different sectors of the economy. After purification and according to the planned application, the hydrogen produced must be transported in gaseous or eventually liquid form.

5.1.1 Compression of hydrogen

Whether used locally or transported, the volume of hydrogen must be reduced by either compression or liquefaction. Depending on the technology used, the hydrogen produced can already be compressed at the outlet of the electrolyser at pressures of up to several tens of bars.
For higher compression rates, four technologies are used:
– Piston compressor
– Diaphragm compressor
– Ionic liquids
– Thermal compressor

What pressure to specify? It will depend on the intended use of hydrogen (Figure 5.1).

5.1.1.1 Piston compressor

One or more pistons compress the gas (Figure 5.2). Several stages can be connected to achieve high pressures. The choice of suitable materials avoids any lubricant that can contaminate the gas.

The pressures can reach 1,000 bar (some models of the German company Andreas Hofer can compress gas up to 4,500 bar).

5.1.1.2 Membrane compressor

In this type of compressor (Figures. 5.3 and 5.4), a piston moves a membrane that compresses the gas. High-performance models have metallic membranes. Several stages can be used to achieve high pressures (up to 1,000 bar in 2017).

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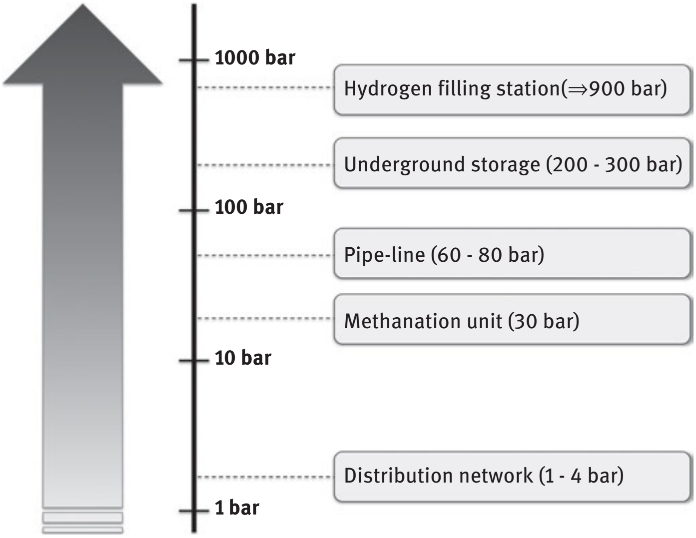

Figure 5.1: Pressure versus hydrogen use.

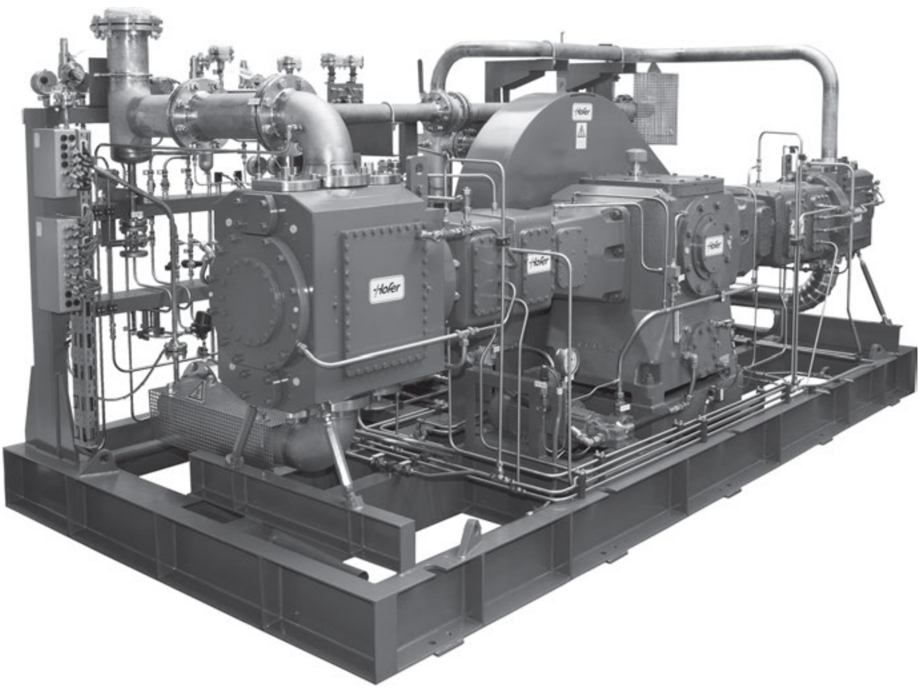

Figure 5.2: Piston compressor (Andreas Hofer Hochdrucktechnik GmbH).

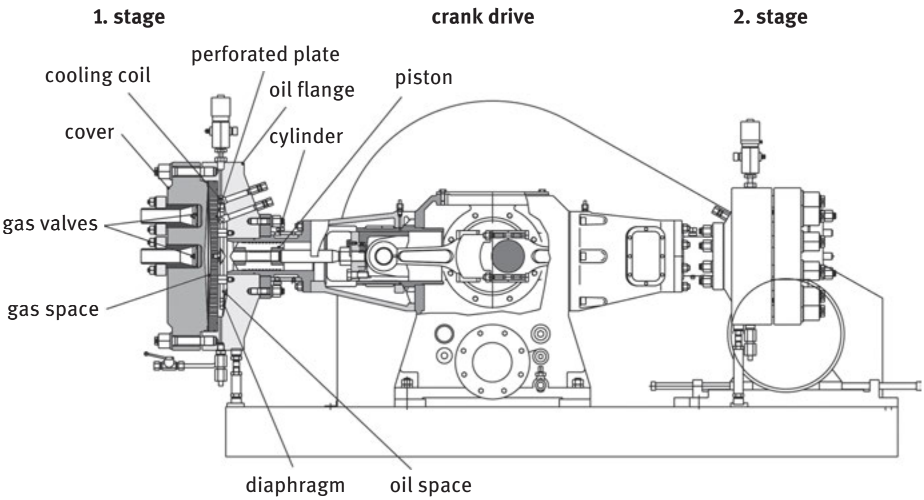

Figure 5.3: Membrane compressor principle (Andreas Hofer Hochdrucktechnik GmbH).

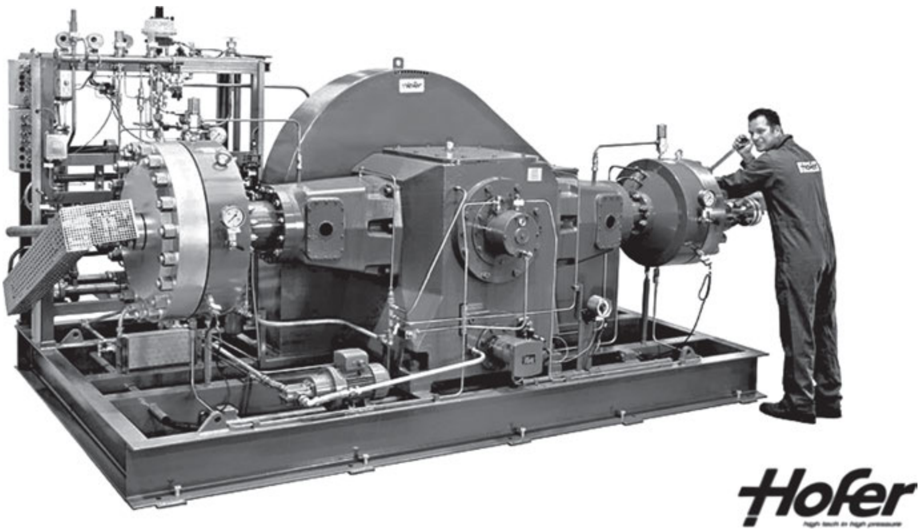

Figure 5.4: Single-stage membrane compressor (Andreas Hofer Hochdrucktechnik GmbH).

5.1.1.3 Ionic compressor

The German company Linde started in 2002 to develop an ionic compressor which was commercialised in 2009 for hydrogen.

In this type of equipment (Figure 5.5), the gas is compressed by a practically incompressible ionic liquid replacing the pistons. A hydraulic pump moves the ionic liquid between two cylinders.

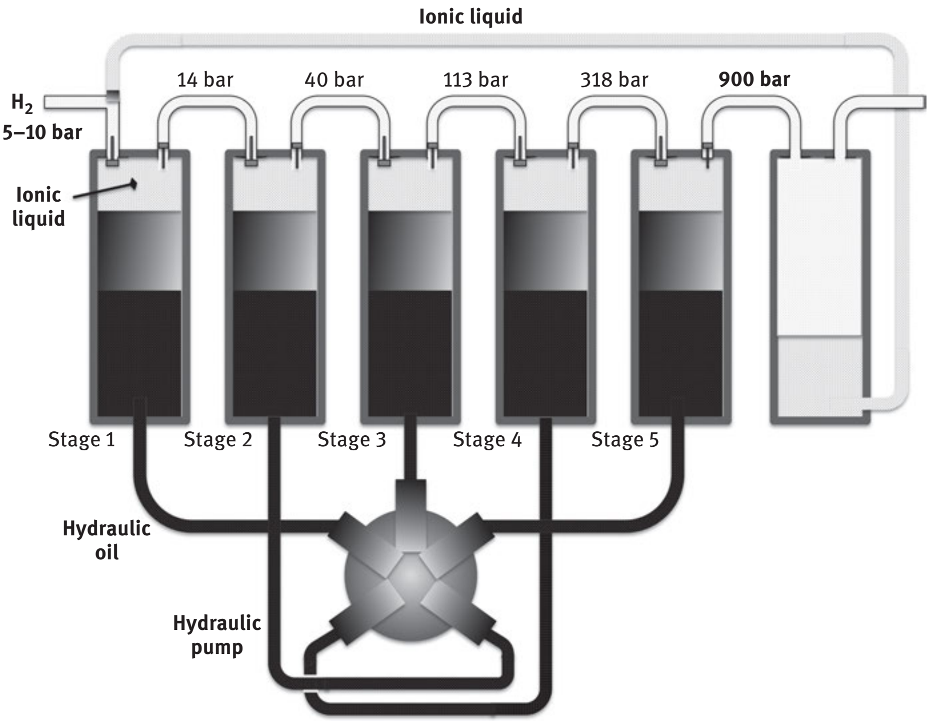

Figure 5.5: Principle of the multi-stage ionic compressor (according to Linde Gas documents).

Ionic liquids

Ionic liquids are organic salts with melting points below 10°C. Unlike ordinary molecular liquids, they consist entirely of particles with negative and positive electric charges. They are not volatile or combustible and they have no measurable vapour pressure. They also do not mix with hydrogen.

Figure 5.6 shows a five-stage IC90 compressor with a maximum capacity of 370 Nm^3/h for a final pressure of 900 bar.

When compared with piston or diaphragm compressors, the ionic compressor is characterised by its small dimensions (1.1 m high for IC90; Figure 5.7).

One unit is installed at the only hydrogen station in Switzerland existing in 2017 for fuel cell vehicles with 350 or 700 bar tanks.

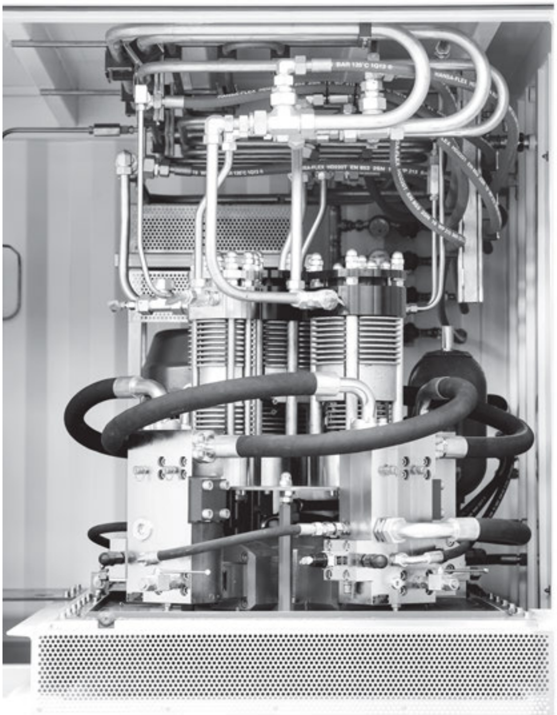

Figure 5.6: Ionic compressor (Linde Gas).

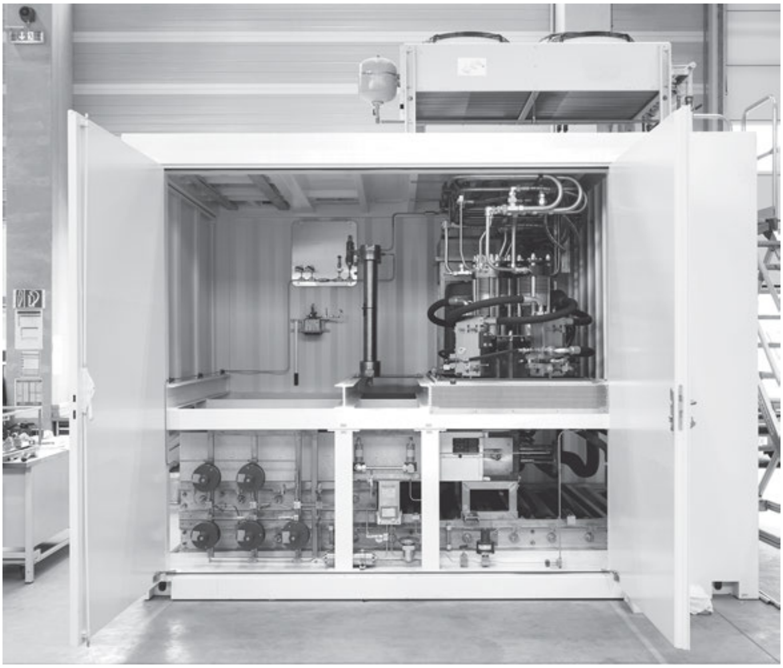

Figure 5.7: Complete station with ionic compressor (Linde Gas).

5.1.1.4 Thermal compressor

Numerous studies have been done on the storage of hydrogen in hydrides. The next step was the possibility to reach high pressures at the hydride tank outlet [1].

The first compression is carried out during the filling under low pressure of the hydride tank at low or normal temperature. The desorption activated by heating increases the pressure of hydrogen at the outlet. Cyclic operation (low-temperature adsorption–desorption by heating) allows practically a continuous compression.

Developed by the Norwegian company Hystorsys with a first commercial model introduced in 2013, the hydride used absorbs hydrogen in monoatomic form in its crystalline structure and offers an important storage capacity.

The HYMEHC-10 (Figure 5.8) is a two-stage compressor system, which could supply continuously up to 10 Nm^3/h hydrogen.

In the first stage, hydrogen is compressed from 10 to about 50 bar. In the second stage, the pressure is increased further to at least 200 bar. The alternating temperature cycle applies to both stages (low temperature of 20°C and high temperature of 140°C). The compressor is based on six metal hydride pressure vessels (three in each stage) and a controller running a time-based scheme for heating and cooling the vessels according to a defined sequence. Thus, by periodic heating/cooling (Figure 5.9) of the six vessels, continuous hydrogen compression is obtained.

This technology reduces considerably the number of mobile components outside the valves and is characterised by a silent operation. The systems are becoming more and more compact and the choice of hydrides makes it possible to adapt the equipment to the final use.

5.1.1.5 Balance of plant

The compressors described in this section require all the connections (gas, liquid, electrical) which make it possible to connect all the components to each other, to the electrolyser and to the following stations either for injection into the natural gas network or for an hydrogen service station (Figure 5.10).

Other auxiliary equipments are, for example, sensors or control and regulation electronics. Their operation also contributes to the optimisation of the electrolysis.

5.1.1.6 Auxiliary equipment and performance

The auxiliary equipment for the optimal operation of an electrolyser can contribute to the efficiency of electrolysis if they are designed with maximum efficiency and reliability in order to allow an intensive use, especially during the peaks of excess electricity from renewable sources.

Figure 5.8: Two-stage thermal compressor (Hystorsys AS).

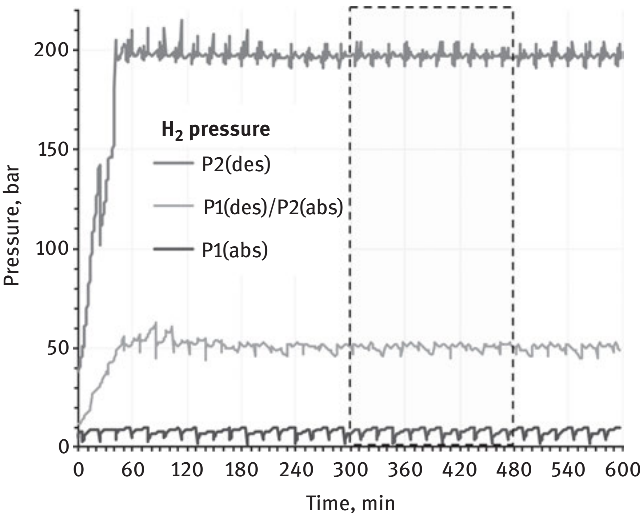

Figure 5.9: Compression cycles (Hystorsys AS).

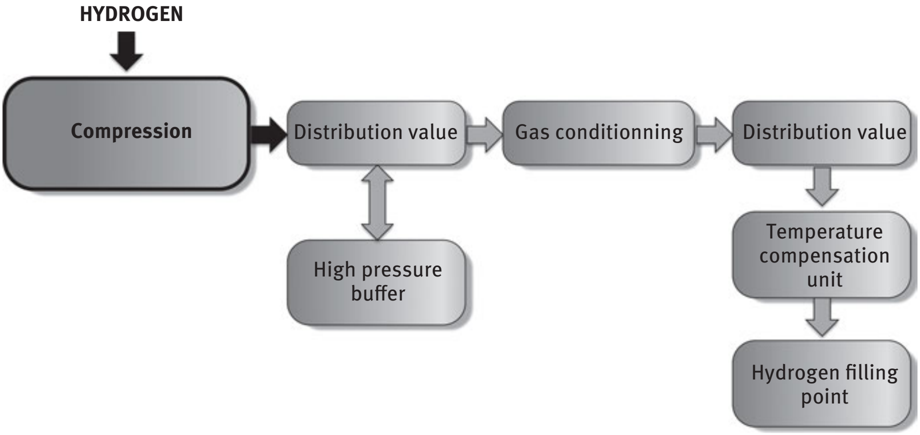

Figure 5.10: Example of ancillary equipment for a hydrogen service station.

5.1.2 Hydrogen liquefaction

Industrial hydrogen liquefaction uses a variety of processes with helium, hydrogen or gas mixtures as coolant. The simplest method of liquefying hydrogen is that of Joule–Thompson (Linde cycle). For very large volumes, the cycles of Claude (pre-cooling with liquid nitrogen) and Brayton (helium or neon) are used nowadays.

The basic liquefaction method is based on the following steps: hydrogen is first compressed. It is then further cooled through multi-stage liquid nitrogen exchangers at 196°C (78 K). Throttling through an expansion valve causes partial liquefaction (Joule–Thompson isenthalpic expansion). The remaining gaseous hydrogen is then returned to the compressor after passing through a heat exchanger where the cycle is repeated. The liquid hydrogen is stored in an insulated tank for further distribution.

***Ortho*- and *para*-hydrogen**

Hydrogen exists in two forms (*ortho* and *para*) according to the orientation of the spin of the nucleus (Figure 5.11). At room temperature, the *ortho*/*para* ratio is 75/25. In the liquid state, *ortho*-hydrogen slowly converts into *para* with a high energy release (527 kJ/kg), thus accelerating evaporation. To avoid this phenomenon, during liquefaction, *ortho*-hydrogen is converted into *para* by using a catalyst (iron oxide, activated carbon etc.).

Cryogenic hydrogen, referred to as liquid hydrogen (LH2), has a density of 70.8 kg/m^3 at normal boiling point (–253°C), critical pressure being 13 bar and critical temperature –240 °C. LH2 has a much better energy density than compressed. The disadvantages are the evaporation losses (boil-off) and the need for super-insulated cryogenic containers.

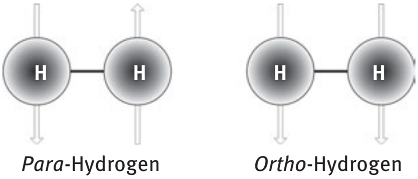

Figure 5.11: *Ortho* and *para*-hydrogen.

Compression and liquefaction energies

Hydrogen compression at pressures between 200 and 700 bar requires an energy which depends on the final pressure and the chosen compression method (isotherm, adiabatic, multi-stage). This energy depends also on the initial pressure. For adiabatic compression (without heat exchange with the external environment), the compression energy is in the order of 10–16 MJ/kg of hydrogen for pressures of 200–700 bar, which represents between 8% and 12% of the energy content of hydrogen (higher calorific value). If the associated losses (consumption of auxiliary equipment etc.) are taken into account the compression energy is 15–20 MJ/kg, i.e. 10–15% of the energy content.

The energy required for **liquefaction** of hydrogen represents a larger share of its energy content (LHV of 119.9 MJ/kg). If theoretically about 11.8 MJ/kg are sufficient to liquefy hydrogen (in the case of an ideal liquefaction process), in reality, and depending on the size of the liquefaction unit, minimum values of the order of 40 MJ/kg are needed (for large capacity from 1,000 kg/h), or practically a minimum of 30% of the energy content.

5.2 Hydrogen transportation

5.2.1 Transportation dedicated to hydrogen

If the local use of hydrogen or its injection into the natural gas network is the most optimal solution, it can be transported in relatively large quantities in different ways:
- By pipeline
- Compressed in tanks or bottles
- In liquid form

The main networks of pure hydrogen pipelines are located in Europe (1,600 km) and in the USA (2,600 km) and are managed by the main producers (Air Liquide, France; Linde, Germany; and Air Products, USA). They represent a total of approximately 4,500 km in 2016. They link certain production sites directly to their users.

A network dedicated to hydrogen?

A study of the German research centre Forschungszentrum Jülich of 2016 [2] quantified the construction of a hydrogen pipeline network for Germany. The proposed 40,000 km would be divided into a transportation network (12,000 km) and a distribution network (29,700 km). The cost of the project would be €18.7 billion with a transportation capacity of 2.93 million tonnes of hydrogen (about

33 billion Nm^3) per year to supply mainly a network of about 10,000 service stations the cost of which is not included in the project. A study by the National Renewable Energy Laboratory in 2012 estimated the cost between US$ 2.8 and US$ 5 million per service station.

The transportation of compressed hydrogen is hampered by its low density even at high pressures. Road delivery per cylinder transports about 300 kg of hydrogen, i.e. 3400 Nm^3 under 200 bar (Figure 5.12).

The German company Wystrach has developed a range of containers for transporting hydrogen based on bottles. The largest module capacity is 45.5 Nm^3 at 250 bar.

Liquefied (which absorbs at least 30% of its energy) hydrogen requires thermally insulated tanks to reduce losses by evaporation. The only advantage is the reduction in the cost of road transportation of hydrogen due to the higher density than that of compressed hydrogen. A 45 m^3 tank can deliver about 3.2 tonnes of LH2 (Figure 5.13).

The Kawasaki Heavy Industries Shipyard is in the process of developing an LH2 transportation ship with several tanks of 1,000 m^3 of unit capacity. The goal is to have a demonstrator for the 2020 Olympic Games.

Figure 5.12: Transportation of gaseous hydrogen under 200 bar (Linde Gas).

5.2.2 Direct injection of hydrogen into the natural gas network

This is the most logical and technically simple option: Purified hydrogen is injected into the existing natural gas network. This approach should ensure transparency for the end-user who should not alter the settings of natural gas equipment.

Figure 5.13: Transportation of liquid hydrogen (Linde Gas).

Hydrogen added to natural gas may affect the infrastructure through:

- hydrogen-induced stress or corrosion
- increased safety risks during the transmission, distribution and use
- degradation of performance of end-user equipment
- degradation of performance or quality of industrial processes

5.2.2.1 Natural gas network

As with the power grid, natural gas is transported to the end-user through a series of pipelines (Table 5.1). The diameters and pressures vary from 1.4 m up to 100 bar for the transportation network to 100 mbar for the residential, for example.

Table 5.1: Natural gas network.

Country	Transmission (km)	Distribution (km)
USA	490,000	2,000,000
Japan	5,000	250,000
China	90,000	
Germany	511,000	
France	32,000	200,000
UK	7,600	275,000

These networks allow the transportation and distribution of large quantities of natural gas, both annually (90 billion Nm^3 for Germany or 130 for Japan) and in terms of flow (millions of Nm^3/h). In addition, they represent a non-negligible storage capacity. As an example, an 80 km section with a diameter of 105 cm under 70 bar contains 5.7 million Nm^3 of natural gas.

The European *Naturalhy* project (2005–2009) involving 39 industrial and academic partners studied the injection of hydrogen into natural gas networks. It covered safety aspects, influence on pipelines and equipment using the mixture.

Hydrogen diffusion and embrittlement in steel alloys

Given the small size of the hydrogen molecule, any mechanical or crystalline defects in natural gas pipeline, gas engines or gas turbine can result in the diffusion of hydrogen into the structure where it is in atomic (H^+) form. Hydrogen can also be present in the manufacturing process (casting of steel, welding operations etc.). This imprisoned hydrogen can lead to brittleness of steels. However, their surface undergoes a passivation which reduces the risks of diffusion. It can occur if defects are formed (extreme variation in temperature, high mechanical stress etc.). This risk increases with the concentration of hydrogen in natural gas.

5.2.2.2 Percentage of hydrogen injectable

The maximum level of hydrogen injection into the natural gas network is not specified for all countries. It is very variable without a valid scientific or technical reason being always advanced (Table 5.2).

Table 5.2: Limit of injection of hydrogen into the natural gas network in mol%.

Country	Belgium	UK	Sweden	Austria	Switzerland	Germany	France	Netherlands
	0	0.1	0.5	4	5	5	8	12

A necessary harmonisation, based on technical and scientific criteria, would allow injections and exchanges at European level, for example, as it is only possible on the basis of the country that has specified the lowest concentration of hydrogen.

5.2.2.2.1 A standard for vehicles using natural gas In Europe, the hydrogen concentration for natural gas used as fuel (CNG – compressed natural gas) is limited to 2% in 2017 (German standard DIN 51624 or UN ECE R 110 specification for steel tanks).

5.2.2.3 Criteria for reliable injection

Numerous parameters have to be verified, from the injection station to the final user (households, industry, energy etc.):

– Transportation network (pipes made of metal or plastic): possible embrittlement in materials
– Distribution network: compatibility of compressors and measuring or control devices
– Transmission and distribution network: hydrogen loss assessment
– Households: compatibility of domestic equipment (e.g. boilers)
– Energy: compatibility of gas turbines or cogeneration units
– Transport: compatibility with natural gas vehicles above 2%

Separately, each parameter can allow the injection of high levels of hydrogen (current gas stoves tested with up to 30% hydrogen), natural gas networks allowing up to 10%. However, a total compatibility for all users whatever the injected level must be guaranteed.

All necessary adaptations (sensors, ranges or boilers, transportation and distribution pipe equipment etc.) may also lead to significant costs of the order of several hundred million euros for Europe.

Between 2014 and 2015, an experiment has been carried out in Germany by the distributor *Schleswig–Holstein Netz AG* in two localities, increasing gradually the hydrogen concentration of up to 10%. Users (households and restaurants) representing 176 equipment (cookers, boilers or micro-CHP units, combined heat and power) found no anomaly or difference.

Separation of injected hydrogen from natural gas

Another option is, depending on the intended use, the extraction of injected hydrogen from natural gas. This option requires an additional step. The available technologies include:
– pressure swing adsorption (PSA)
– separation by membrane
– cryogenic process
– electrochemical separation
– In addition to the costs of equipment and treatment, it will be necessary to reinject or use the separated natural gas

The Austrian program *HylyPure* [3] studied the separation of hydrogen injected into the natural gas network. Austria allows a hydrogen concentration of up to 4%. The process consists of three steps: pre-separation by selective polymer membrane, enrichment by PSA and then purification. The recovered hydrogen has a purity of 99.97%, compatible with fuel cells for hydrogen vehicles.

5.3 Hydrogen storage

Once purified hydrogen produced can be used directly or passed into the natural gas network, it can also be stored separately in large volumes before use or injection. Different approaches are possible.

5.3.1 Compressed in tanks

This solution is the simplest, but given the low density of hydrogen, it would require high storage volumes even under high pressures. It would be incompatible for quantities produced with excess electricity with the power-to-gas.

5.3.2 In liquid form

The energy required to liquefy hydrogen is too important compared to the energy content, resulting in a low overall efficiency. In addition, transportation and storage require specially designed and expensive tanks. Liquid hydrogen applications are also limited (space launchers, some filling stations for fuel cell vehicles, industry and research).

5.3.3 In metal hydrides

Some alloys can combine with hydrogen to form metal hydrides: MgH_2, Mg_2NiH_4, $LaNi_5H_4$, $NaAlH_4$ etc. The absorption of hydrogen takes place at the surface of the metal or alloy (physical and/or chemical adsorption) and then it diffuses into the structure of the crystal lattice (Figure 5.14). These hydrides can thus store hydrogen in their structure and release it if heated.

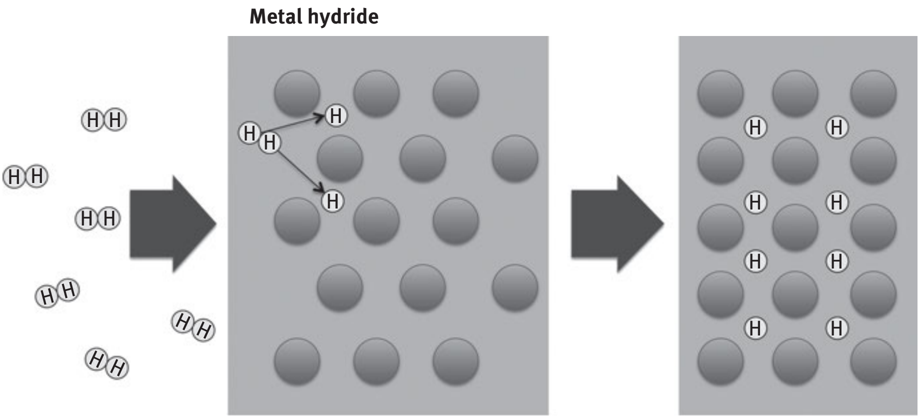

Figure 5.14: Principle of storage of hydrogen in hydrides.

The storage of hydrogen in hydrides does not require high pressures and delivers the stored hydrogen at constant adjustable pressure. The counterpart is the weight of the system: the stored hydrogen represents a few per cent of the mass depending on the hydride used; the theoretical values (Table 5.3) are rarely reached. The desorption temperatures of the compounds with useful storage ratios (>5%) are also relatively high.

This results in an important weight of storage units using hydrides, such as those installed, in German submarines *Type U 212* for supplying fuel cells. Eighteen tanks weigh each 4.4 tonnes and contain 55 kg of hydrogen (620 Nm^3) representing 1.25% of the total weight.

Table 5.3: Properties of some hydrides.

Hydride	Hydrogen storage % mass	Desorption temperature at 1 bar in °C
$La\ Ni_5H_6$	1.4	25
TiV_2H_4	2.6	40
$ZrMn_2H_3$	1.8	167
$NaAlH_4$	5.0	220
MgH_2	7.6	>300

When filling under pressure (generally 20–30 bar), the reaction being exothermal, it is necessary to cool the system. The stored hydrogen is released by increasing the temperature of the system as a function of the hydride (Figure 5.15). Thermal flux management is therefore the most critical parameter to manage.

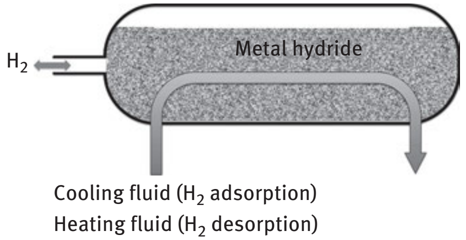

Figure 5.15: Hydrogen storage and recovery.

The compromise to be found lies between the storage capacity (weight of H_2/weight of hydride), the release conditions (temperature and pressure) and the stability over time of the hydride.

Among the hydrides used, the sodium alanate ($NaAlH_4$) makes it possible to illustrate the release mechanism under the effect of heat:

$$3\ NaAlH_4 \rightarrow Na_3AlH_6 + 2\ Al + 3\ H_2 \tag{5.1}$$

$$Na_3AlH_6 \rightarrow 3\ NaH + Al + \frac{3}{2}\ H_2 \tag{5.2}$$

The storage of hydrogen in hydrides, nevertheless, offers a safety with respect to gas or liquid storage.

One of the leaders in this field is the French company McPhy, which has developed modules for storing large quantities of hydrogen in magnesium hydride (MgH_2) to up to 1,000 kg by 2017. These modules can be combined with a heat storage in a phase change material: the heat released during storage is used subsequently to desorb hydrogen. The basic elements are 1 kg hydride pellets (storage capacity of 500 L of hydrogen or 43 g) stacked in cylinders, which are then mounted in containers with external control and thermal management components, regulation electronic etc. (Figure 5.16).

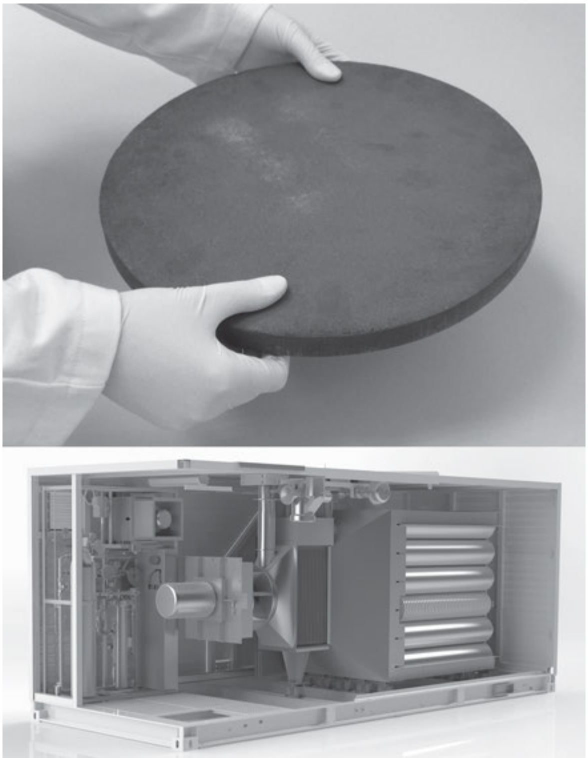

Figure 5.16: Hydride pellet and storage unit of 100 kg of hydrogen (McPhy Energy).

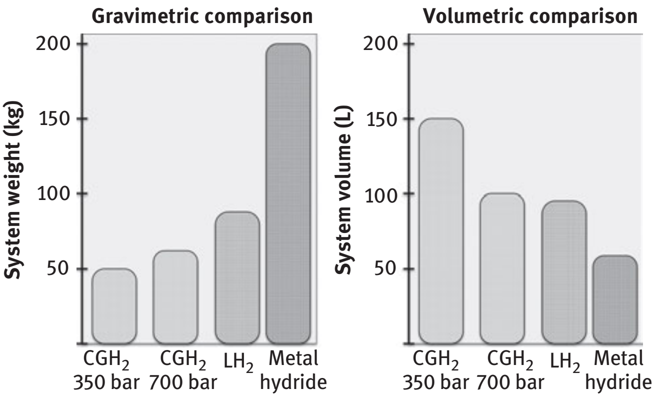

Figure 5.17: Comparison of storage capacities for 3 kg H_2.

McPhy hydride storage modules are used in many power-to-gas technology evaluation programmes.

If hydrides offer advantages in terms of storage safety (e.g. no high pressures) or occupied volume compared to reservoirs (hydrogen gas or liquid), the main disadvantage is the weight of the system (reservoir and hydrides) hydrogen representing at best 4–5% of hydrides (Figure 5.17).

5.3.4 Storage in caverns

This solution allows to store large quantities of hydrogen in the underground. In addition to existing facilities, studies and simulations have also been based on saline caves with volumes up to 500,000 m^3 (Figure 5.18). Hydrogen can be stored at pressures up to 200 bar.

According to the German company *KBB Underground Technologies GmbH*, such a cavern in a saline layer about 1,000 m deep would store 4,000 tonnes of hydrogen under a pressure of 10 bar. The corresponding energy stored would be 133 GWh. Storage efficiency would be about 98%. The costs of geological research, creation of the cavern and associated facilities would be in the order of 90 million euros in 2016.

An installation exists in England at Teeside with three caverns located at 370 m depth, each capable of storing 70,000 Nm^3 of hydrogen under a pressure of 45 bar. At the end of 2016, Austria launched an "Underground Sun Storage" hydrogen storage

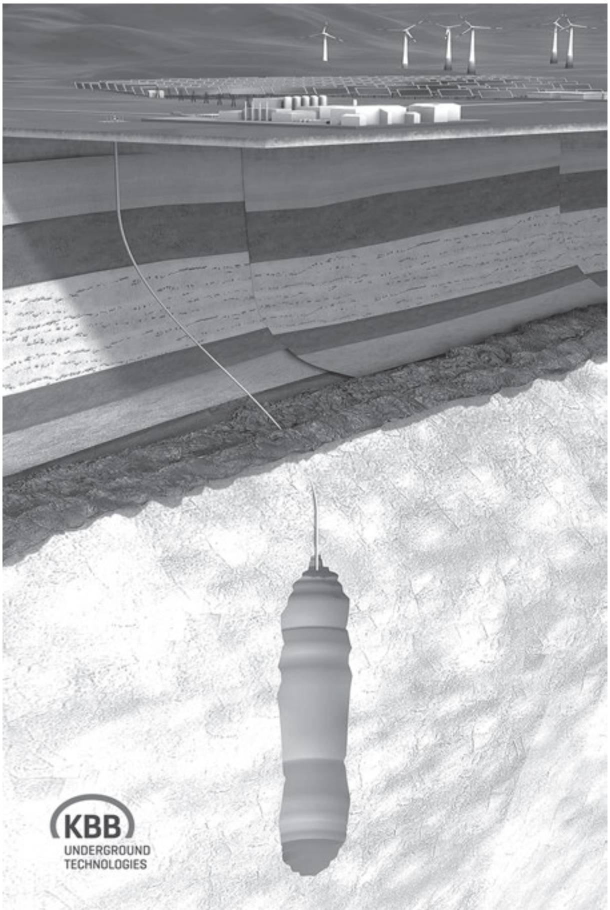

Figure 5.18: Storage of hydrogen in a cave (KBB Underground Technologies GmbH).

programme in a cavern used to store natural gas. Hydrogen is supplied by four alkaline electrolysers (1.2 MW) with a production of up to 250 Nm^3/h which is then mixed with natural gas and injected. In Texas, Air Liquide and Praxair store hydrogen in caverns. Other facilities of relatively small capacity exist in Germany, Russia and Czechoslovakia.

This approach, if it allows to store large quantities of hydrogen for a posteriori recovery, could only be conceived in an area close to electrolysers in order to avoid building pipelines dedicated exclusively to hydrogen over long distances. Moreover, the geology of the underground must have a structure allowing the creation of such caverns.

5.3.5 In natural gas reserves

5.3.5.1 Storage of natural gas

In order to benefit from a strategic reserve in the event of a breakdown in delivery or high demand, each country has large volumes of natural gas storage sites, generally and mostly in natural caverns. The addition of hydrogen to natural gas would allow it to be stored without additional investments.

The available storage capacities for large volumes of hydrogen will depend on the percentage accepted (Table 5.4).

By assuming the hydrogen production energy at 5 kWh/Nm^3, each million Nm^3 produced would store the equivalent of 5 GWh of surplus electricity. For an injection rate of 5%, Germany could store 5.5 TWh of electricity and 33 for the USA. Furthermore, this storage could be carried out continuously, the hydrogen–natural gas mixture being then injected into the network for use.

Table 5.4: Potential storage capacity of hydrogen mixed with natural gas (million m^3).

	Natural gas storage capacity (million Nm^3)	**Hydrogen injected**		
		2%	**5%**	**10%**
USA	132,000	2,640	6,600	13,200
Germany	22,000	440	1,100	2,200
Japan	20,000	400	1,000	2,000
France	14,000	280	700	1,400

5.3.6 Other storage methods

5.3.6.1 (Liquid organic hydrogen carrier)

In this technology, the energy carrier is a liquid where hydrogen is indirectly stored through chemical binding with a liquid compound like dibenzyltoluene (Figure 5.19) with a "storage" capacity of 624 Nm^3 (57 kg) H_2/m^3 liquid organic hydrogen carrier (LOHC).

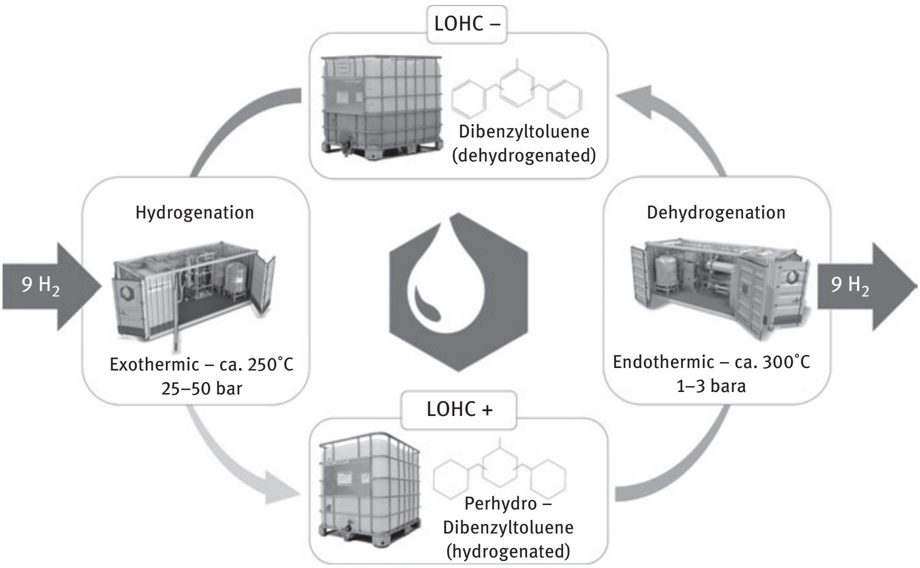

Figure 5.19: LOHC storage (Hydrogenious Technology).

When compared to storage under pressure, the advantages are reduced weight and volume and easier handling: to store 3 kg of hydrogen under pressure (300 bar), bottles with a volume of 150 L and weighing 250 kg would be required, whereas the technology LOHC would store the same quantity in a volume of 50 L weighing 50 kg.

The German company *Hydrogenious Technology* has developed several storage (StorageBOX) or recovery (ReleaseBOX, Figure 5.20) units with different capacities (10–100 Nm^3/h storage).

This approach should allow hydrogen to be transported more easily and in larger volumes than in gaseous form and also with greater safety (e.g. supply of hydrogen service stations).

5.3.6.2 "Hydrozine ™"

The University of Eindhoven in the Netherlands (*TeamFAST project*) has developed an alternative based on the use of surplus electricity for the conversion of water and CO_2, mainly into formic acid (HCOOH) through a new catalyst, supplemented by additives forming Hydrozine™ with an energy density of 2 kWh/L:

$$2\bar{e} + CO_2 + H_2O \Rightarrow HCOOH + ½\, O_2 \tag{5.3}$$

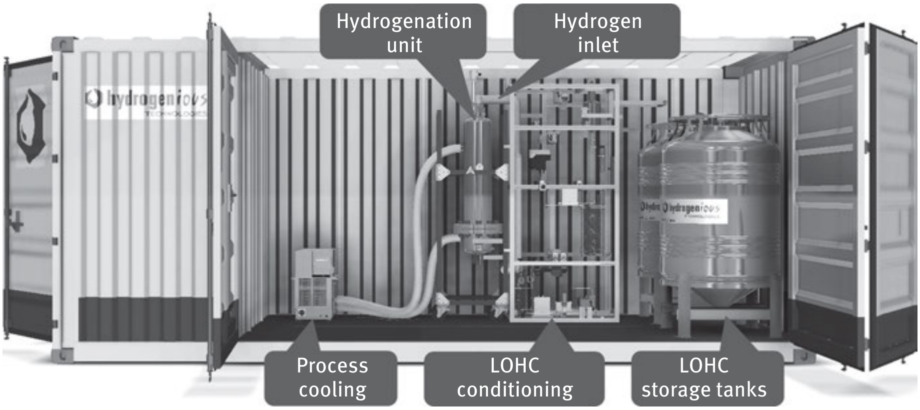

Figure 5.20: StorageBOX (Hydrogenious Technology).

The liquid can be stored and handled at room temperature for industrial or transportation applications. In the latter case, the formic acid makes it possible, after reforming, to recover hydrogen to supply a fuel cell. With the Dutch transportation company VDL, a demonstrator for a bus equipped with range extender (25 kW fuel cell) in a trailer was presented in 2017 (Figure 5.21).

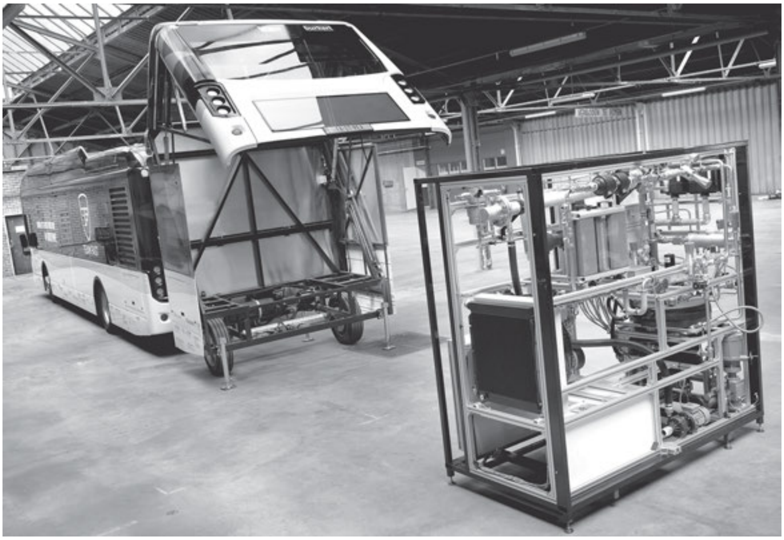

Figure 5.21: Range extender using Hydrozine (TeamFAST).

5.3.6.3 PowerPaste

This compound is based on magnesium hydride which reacts with water (exothermic reaction) by releasing 1,700 L of hydrogen per kg of hydride. The challenge is to find an equilibrium for the hydrolysis reaction to provide a hydrogen flow rate function of demand. The use of additives makes it possible to form a paste that is easy to handle. The German institute *Fraunhofer IFAM* [4] has developed two demonstrators around this technology to supply a fuel cell (50 or 300 W). In spite of all this system is linked to a distribution network of PowerPaste which is a consumable and remains the management of the residues, mainly of the magnesium hydroxide.

5.3.6.4 Other methods

Ammonia (NH_3) or hydrazine (N_2H_4) in the late 1960s were also considered as an energy carrier for indirect "storage" of hydrogen to be used as fuel for internal combustion engine or for fuel cells. But their toxicity prevented their commercial use.

Studies have been or are being carried out by research institutes on the possibility of industrial storage of hydrogen in clathrates, metal organic framework, nanomaterials or graphene. None of these technologies has reached the stage of demonstrator.

5.4 Methanation

5.4.1 Thermochemical methanation

Methanation (Figure 5.22) is the process of converting hydrogen into methane according to the reactions:

$$H_2 + CO_2 \Leftrightarrow CO + H_2O \tag{5.4}$$

$$CO + 3\,H_2 \Leftrightarrow CH_4 + H_2O \tag{5.5}$$

The overall reaction is

$$CO_2 + 4\,H_2 \Leftrightarrow CH_4 + 2\,H_2O \tag{5.6}$$

The reaction is exothermic (heat release: ΔH = –164.9 kJ/mol under normal conditions) and takes place in the presence of a catalyst generally in the form of pellets through which the gases pass.

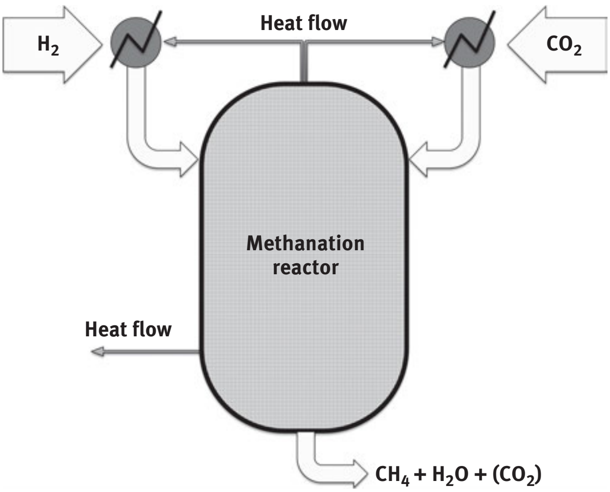

Figure 5.22: Thermochemical methanation.

Type of thermochemical methanation reactor

- In fixed bed methanation, the reactor is packed with the catalyst with a particle size in the range of millimetres
- In fluidised bed methanation, fine catalyst particles are fluidised by the gaseous reactants
- In three-phase methanation, a solid catalyst (powder <100 µm) is suspended in a stable temperature inert liquid as dibenzyltoluene

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The yield is of the order of 80% with a methane content greater than 90%. This conversion rate depends on temperature and pressure. This reaction has been known since 1905: the chemist Paul Sabatier experimented it with the use of nickel catalyst.

Methanation can be carried out without direct temperature control (which can rise to 700°C) using a series of reactors with gas cooling between each. The other option is to regulate the temperature of the reaction by using a cooling system and recovering the heat released (Figure 5.23).

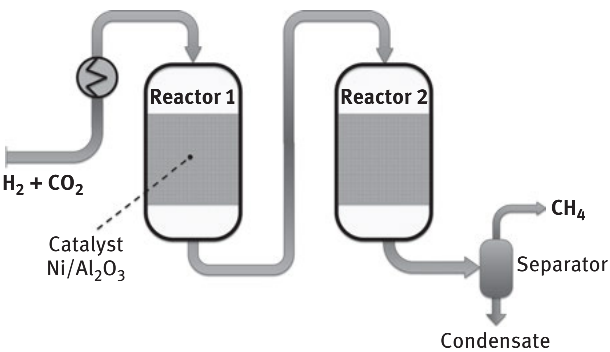

Figure 5.23: Lurgi methanation steps (simplified).

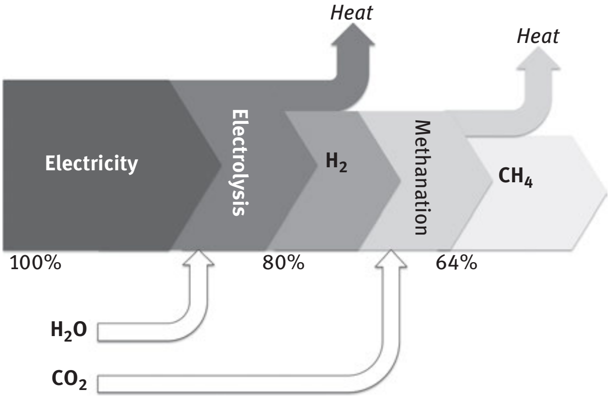

Figure 5.24: Performance of the power-to-gas chain with methanation.

At the reactor outlet, a mixture of methane and hydrogen is obtained. The methane obtained (synthetic natural gas) can be injected into the natural gas network after treatment in order to have a hydrogen level corresponding to that allowed.

5.4.1.1 Overall yield of thermochemical methanation

Like any transformation, the yield of this step (Figure 5.24) affects the final one of the power-to-gas technology.

The best conversion rates for methanation alone reach 80%. A recovery of the released heat makes it possible to improve the total efficiency.

5.4.2 Co-electrolysis

It is the combination of high-temperature electrolysis (SOEC) with CO_2 injection, followed by methanation using the CO/H_2 mixture supplied (Figure 5.25).

Two reactions occur in the high-temperature electrolyser (Figure 5.26):
Decomposition of water

$$2\,H_2O \Leftrightarrow 2\,H_2 + O_2 \tag{5.7}$$

Reverse shift reaction:

$$CO_2 + H_2 \Leftrightarrow CO + H_2O \tag{5.8}$$

Methanation is carried out in a reactor, in the presence of nickel:

$$CO + 3\,H_2 \Leftrightarrow CH_4 + H_2O \tag{5.9}$$

The overall reaction is

$$CO_2 + 2\,H_2O \Leftrightarrow CH_4 + 2\,O_2 \tag{5.10}$$

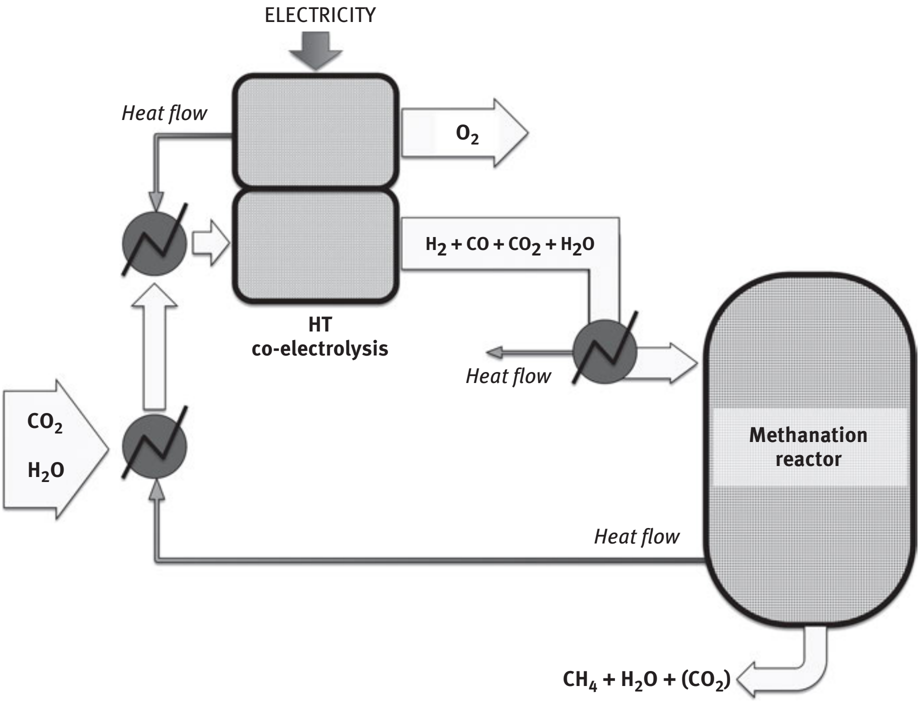

Figure 5.25: Principle of co-electrolysis.

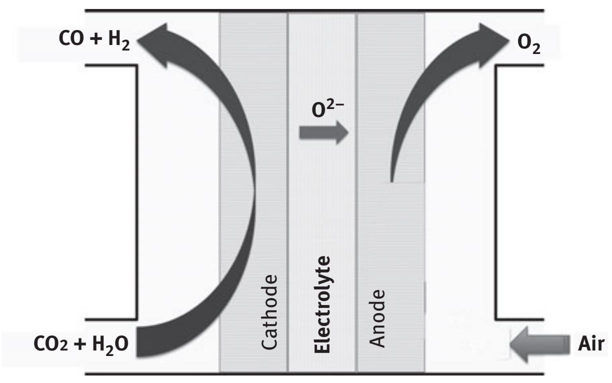

Figure 5.26: Co-electrolysis cell.

The development of co-electrolysis is based on chemical equilibrium models to evaluate the composition of the mixture produced as a function of the proportions of CO_2 and water injected as well as the parameters of the electrolysis (operating temperature, current density, voltage etc.).

High-temperature electrolysis and methanation coupling offer a better yield but some limitations (cost, degradation, development of new materials, etc.) remain to be overcome.

5.4.3 Biological methanation

In this approach, selected microorganisms use hydrogen and carbon dioxide to produce methane and water (Figure 5.27). This reaction takes place under atmospheric pressure and low temperature (40–70°C) compared to the conditions of the thermochemical methanation.

The *Electrochaea* company, based on developments at the University of Chicago, was founded in 2010. In Denmark, it has set up a biological methanation unit within the framework of the BioCat project (Figure 5.28).

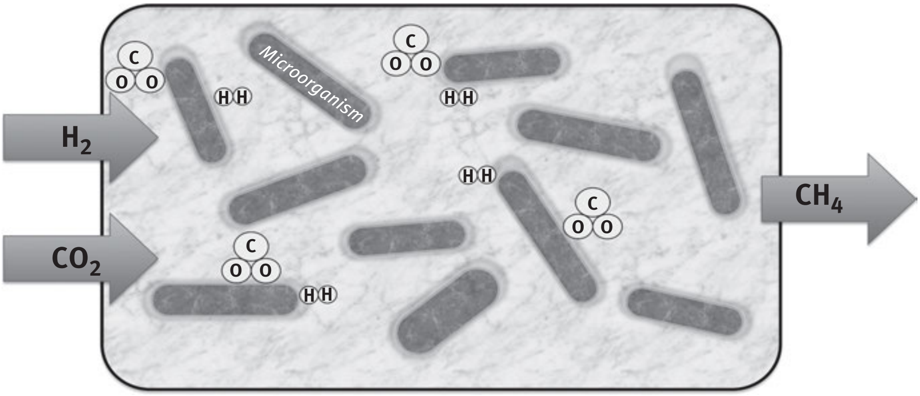

Figure 5.27: Principle of biological methanation.

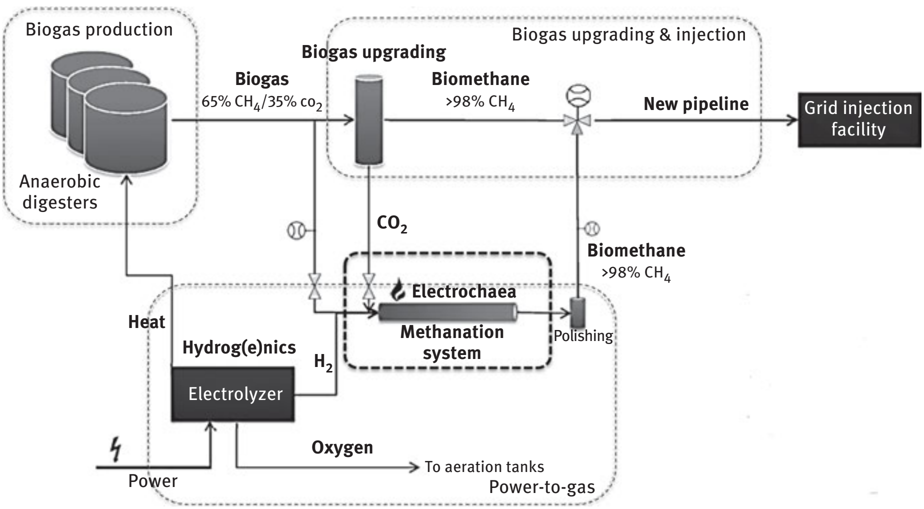

Figure 5.28: Biological methanation – BioCat project (BioCat).

The microorganism used (Archaea, Figure 5.29) is monocellular without genetic modification. The reactor temperature is 60–65°C. In this project, conversion yield to methane is greater than 98%. The first phase in 2012 on the location of a biogas unit at Folum saw the implementation of a 4,800 L bioreactor which operated for 3,600 h with methane production ranging from 0.5 to 18 Nm^3/h.

An industrial unit in Avedøre, with a production capacity of 50 Nm^3/h, integrated into a biogas unit, with a 1 MW electrolyser benefiting from an optimised reactor was tested in 2015. The first methane production took place in April 2016, 4 h after introduction of the microorganisms. The final mixture contained 97% methane. Future steps foresee an increase in the power of the electrolyser to 10 and then 50 MW.

The German company Viessmann, through its subsidiary **MicrobEnergy** founded in 2012, has evaluated, after several preliminary stages (electrolyser of 12.5 then 300 kW), since March 2015 an installation in Allendorf in Germany. The proton exchange membrane (PEM) electrolyser installed (300 KW with 2 stacks of 150 kW) allows the production of 20 Nm^3/h of methane with a purity of 98%, the remainder being mainly hydrogen. The demonstration unit (see Chapter 7 for a detailed description of this installation) near a sewage treatment plant supplying CO_2 was validated

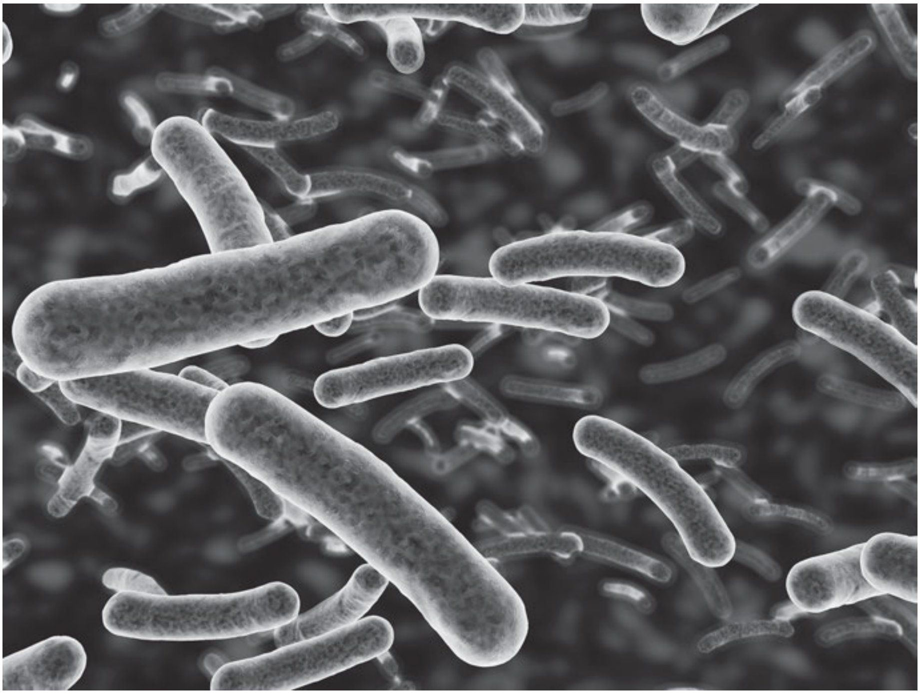

Figure 5.29: Archaea microorganisms (Electrochaea).

until the end of 2014. Extension of the system with an electrolyser of more than 2 MW for a methane production of up to 400 Nm^3/h of hydrogen is planned.

Compared to thermochemical methanation, biological methanation allows, among others:
– integration into biogas plants (several thousands in Germany) to use CO_2
– better catalyst management (biological self-reproducing)
– excellent yield (75–80%)
– operation at lower temperature

Origin of CO_2

The CO_2 needed for any methanation or co-electrolysis reaction can come from different sources:
– Recovery after purification of biogas
– CO_2 capture of industrial or power generation emissions
– Air sampling, despite a low concentration (about 400 ppm)

The Swiss company *Climeworks* has developed an industrial process for recovering CO_2 from air.

Through a cyclic adsorption/desorption process, the atmospheric CO_2 is absorbed into a material while all other air molecules pass through (CO_2 free air is released). Once the filter is saturated, CO_2 is released at 95°C. After CO_2 recovery, the absorbing material can be reused for other cycles. Commercial units are scalable modules with a daily capacity of 135 kg CO_2/day each. In 2017, an installation using 18 modules produces about 900 tonnes/year CO_2 for a greenhouse.

5.4.4 Methanisation and synergy with power-to-gas

Methanisation consists in using organic waste, sewage sludge, for example, to produce, by *anaerobic fermentation* of microorganisms, a gas mixture whose most important constituents are methane (50–85%) and carbon dioxide (15–50%). After purification, methane is injected into the natural gas system or is used directly to supply a natural gas vehicle service station or used locally for a cogeneration or CHP unit with recovery of the heat produced.
In the power-to-gas approach, CO_2 produced by the methanisation unit can be used in methanation units (Figure 5.30).

5.4.5 Methanation, the key to electricity from renewable sources?

This technology allows the conversion of hydrogen produced by electrolysis using excess electricity into methane. It can then integrate the natural gas distribution network or storage units, without any changes in the network or for the users. Even if the efficiency of power-to-gas is reduced through this approach, the integration of methane in the energy circuit does not require any modification of the existing procedures and installations.

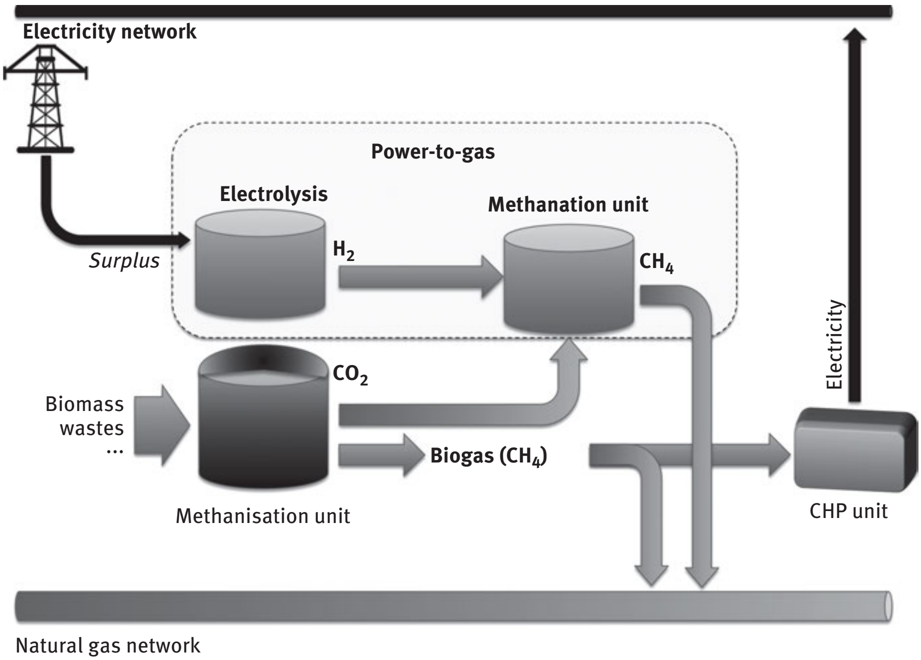

Figure 5.30: A methanation unit coupled to a methanisation unit.

5.5 Use of hydrogen or methane produced

Hydrogen and methane are commodities already used by different sectors of the economy. The additional production due to power-to-gas may open up other prospects or have an influence on the markets (price of these gases, for example, or development of new uses).

The production of hydrogen from surplus renewable electricity must make it possible to replace some of the hydrogen produced by hydrocarbons reforming and/or eventually open up other utilisations. For each TWh of surplus electricity, it is possible to produce 200 million Nm^3 of hydrogen (hypothesis of 5 kWh/Nm^3).

5.5.1 Industry

The first customer of hydrogen is the petrochemical industry mainly for desulphurisation. Another important use is the production of ammonia for fertilisers.

Hydrogen, excluding petrochemicals and ammonia production, serves as the basis for many sectors, from steel production to fine chemicals and electronics. Even if the quantities are relatively small, the purity of hydrogen produced by electrolysis and the possibility of producing it locally or even on site would be an advantage.

5.5.2 Energy – conversion into electricity

This approach, which could be called **P2G2P** (power-to-gas-to-power), involves generating electricity from hydrogen or methane produced through electrolysis or methanation. For this conversion, the existing technologies cover a whole range of power: CHP units, fuel cell or gas-fired power plants.

5.5.2.1 Fuel cells

This technology works on the same principle as PEM electrolysis with the same structure, but hydrogen and oxygen (or air) injected react to produce electricity (Figure 5.31). The principle was discovered in 1838 by the Swiss Schönbein and by the English Grove in 1839 [5]. It was only in the mid-1960s that this technology has been developed by NASA for the first space flights and towards the 1990s that high-power fuel cells reaching the power of megawatts have become available.

5.5.2.2 Types of fuel cells

Fuel cells are distinguished mainly by the type of electrolyte and the operating temperature (Table 5.5).

Their denomination reflects the electrolyte used:

- PEMFC (proton exchange membrane fuel cell)
- DMFC (direct methanol fuel cell)
- PAFC (phosphoric acid fuel cell)
- AFC (alkaline fuel cell)
- MCFC (molten carbonate fuel cell)
- SOFC (solid oxide fuel cell)

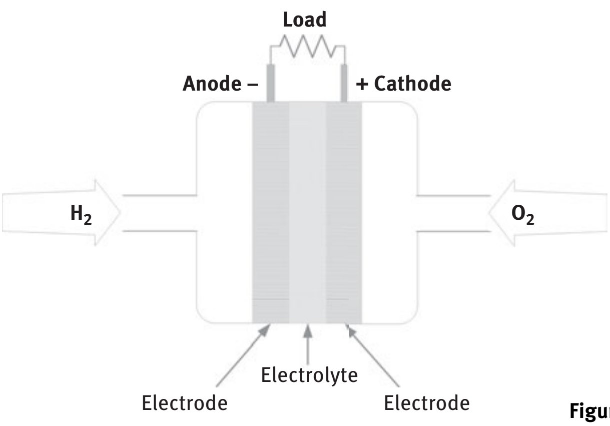

Figure 5.31: Principle of the fuel cell.

Table 5.5: Specifications of fuel cell types

Type	Average temperature (°C)	Fuel anode	Ions	Fuel cathode
PEMFC	80–120	H_2	$H^+ \Rightarrow$	O_2 or air
DMFC	110	Methanol	$H^+ \Rightarrow$	O_2 or air
PAFC	200	H_2	$H^+ \Rightarrow$	O_2 or air
AFC	80	H_2	$\Rightarrow OH^-$	O_2 or air
MCFC	650	H_2	$\Rightarrow (CO_3)^{2-}$	O_2 or air
SOFC	800–900	CH_4	$\Rightarrow O^{2-}$	O_2 or air

Fuel cells operating at low temperatures (<200°C) use precious metals (platinum) as catalysts at both electrodes. The same problem as for the PEM-type electrolysers arises concerning the cost of these catalysts and the actual impossibility of replacing them. High-temperature fuel cells (MCFC or SOFC) do not require them, but use special alloys.

Some types cannot use hydrogen (e.g. SOFC), but only natural gas or methane. Others such as PEMFC and AFC can use methane, but by feeding it first in a reformer for conversion into hydrogen that can then be used by the cell.

High-power fuel cells (more than 100 kW) include PEMFC (Ballard, Canada; Hydrogenics, Canada; or Nedstack, Netherlands), PACF (Doosan Fuel Cell America, USA), MCFC (FuelCell Energy, USA; Posco Energy, South Korea), AFC (AFC Energy, UK) and SOFC (Bloom Energy, USA).

The Ballard fuel cell (PEMFC, 1 MW) can be installed on a truck trailer (13.7 × 2.9 × 2.4 m) and weighs 30 tonnes. A Bloom Energy module (SOFC, 100 kW) measures 5.7 × 2.1 × 2.0 m and weighs 10 tonnes (Figure 5.32).

Figure 5.32: A 100 kW SOFC fuel cell module (Bloom Energy).

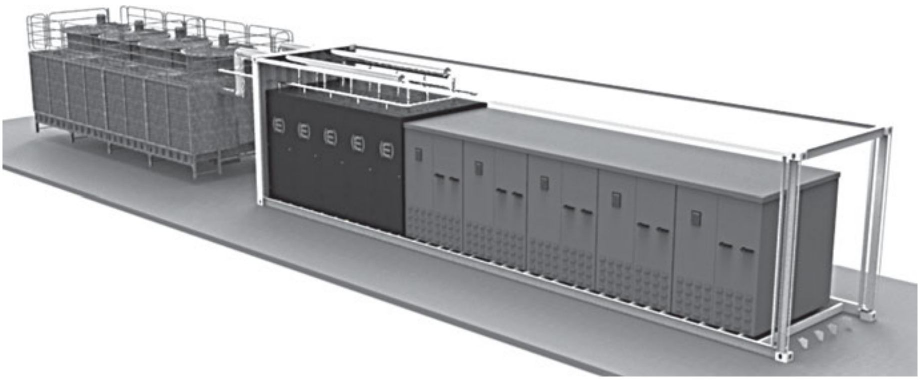

Figure 5.33: A 1 MW PEMFC at Kolong, South Korea (Hydrogenics Corp).

The PEMFC installed by Hydrogenics in Kolong, South Korea (Figure 5.33), has a power of 1 MW and an electrical efficiency of 49%. Its total dimensions are 2.4 × 3.0 × 15 m for a weight of 32 tonnes. It uses hydrogen with a purity of 99.99% and consumes 780 Nm^3/h at maximum power.

5.5.2.3 Fuel cell efficiency

Depending on the type and the power, the electrical efficiency can reach 50–60% and more than 90% if the heat is recovered, the reactions in the fuel cell being exothermic.

5.5.2.4 Advantage of fuel cells

Compared to a CHP unit or a gas-fired power plant, a fuel cell has virtually no moving parts (apart from auxiliary equipment such as pumps, fans etc.). Units operating at low temperatures (<100°C) have a very short start-up time.

In 2008, South Korean government launched a major programme of high-power fuel cell equipment to stabilise the electricity grid while recovering heat. Several parks contain dozens of fuel cells (Hwaseong city had 21 fuel cells of MCFC type with 2.8 MW or a total of 59 MW and Busan had 70 PAFCs with 400 kW each).

5.5.2.5 Power plants or CHP units

Natural gas power plants or high-power CHP units can take advantage of this additional production of fuel and use methane to operate. This is already the case for some methanisation units and some power-to-gas projects (e.g. Enertrag in Berlin).

For these two electricity generation technologies, the use of methane from methanation is more appropriate because it does not require modification of certain components or new settings for combustion (PEMFCs use hydrogen directly, saving one step). Due to the low overall yields (at best 35–40% from renewable to final electricity), however, this approach should be used when excess electricity exceeds storage capacity or when electricity needs cannot be covered otherwise.

In many countries, gas-fired power plants are an important element in stabilising electricity grids during peak demand periods. However, they are used less and less because of the decline in the price of coal (important shell gas production in the USA), which favours those using it. The possibility of having large quantities of methane could revive their use as they have a very short start-up time.

5.5.2.6 Conversion efficiency

The electrical efficiency of the P2G2P approach varies according to the chosen pathway (Figure 5.34). Whether it is the use of a fuel cell, a CHP unit or a gas-fired power plant, conversion efficiencies are at best 40% for stationary applications. Overall only one third of the initial electricity is recovered. However, depending on the production or supply strategy decided, this approach may have an economic and/or strategic justification (e.g. security of supply), be it at the level of energy producer or industrial users.

The overall efficiency can be significantly improved by recovering the heat produced. This recovery will be all the easier if the gas-to-power unit is installed near the users (local district heating).

5.5.2.6.1 Conversion to electricity: low overall efficiency The relatively low yields of this conversion to electricity must keep this approach to applications where the electricity needs justify it.

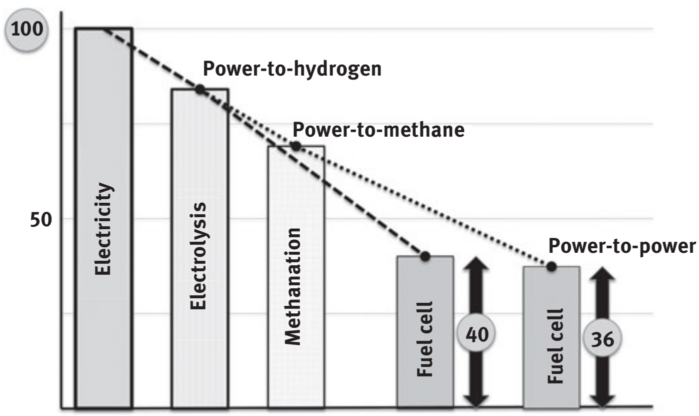

Figure 5.34: Comparative electrical efficiency.

Existing technologies, especially fuel cells, however offer a proven technology, especially at high power levels.

5.5.3 Mobility

5.5.3.1 The hydrogen vehicle: still a utopia?

Hydrogen can be used for fuel cell vehicles (Figure 5.35). The current number is, however, so limited that the amount of hydrogen used remains and should remain small despite the development forecasts (which have always been very optimistic).

Although many manufacturers have embarked on this development in recent years, most of them have only shown demonstrators, the production being at the most a few dozen units but without large-scale commercialisation. By the end of 2016, 2,500 fuel cell vehicles were in operation worldwide. The fleet of electric vehicles with batteries, even relatively small, was 2 million vehicles. If the average real autonomy is about 400 km, the weak point is the low number of hydrogen service stations. Nearly 300 were operational in 2016 worldwide (not all of them accessible to the public), compared to the 6,000 superchargers for electric vehicles only from Tesla. In California, for 23 hydrogen service stations, Tesla offered nearly 1,000 superchargers.

The other concern for fuel cell vehicles is the low overall efficiency of the hydrogen fuel cell pathway (Figure 5.36).

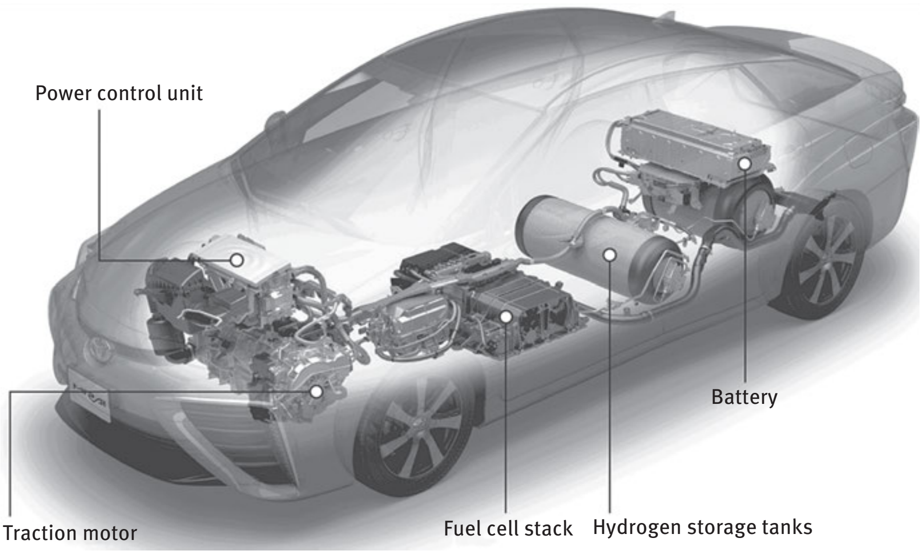

Figure 5.35: Mirai hydrogen vehicle and fuel cell (Toyota Motors).

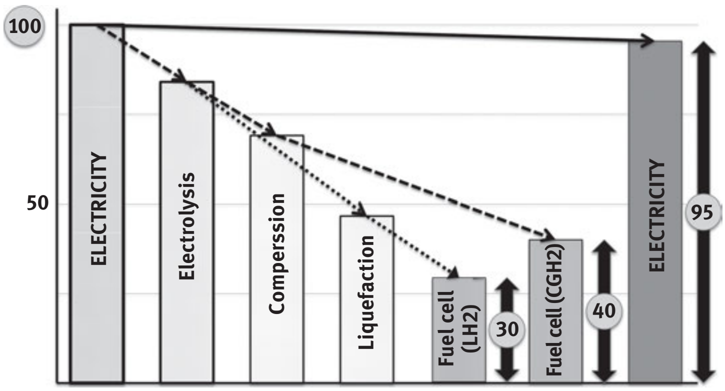

Figure 5.36: Yield of hydrogen/fuel cell vehicle (from well to wheel).

Range extender

Some companies offer an extension of autonomy for electric vehicle. These are compact fuel cells using hydrogen and providing extra electricity to increase driving range. If this solution seems, a priori, elegant, it does not solve the dilemma battery/hydrogen: high-speed charging is still too long and very few hydrogen service stations.

Many hydrogen and fuel cell bus evaluation campaigns have been launched since the year 2000 (Clean Urban Transportation for Europe, Ecological City Transparency System, Clean Hydrogen in European Cities) but in 2017 less than hundred hydrogen buses using fuel cells were in operation in Europe. Their use is sometimes limited to demonstrators at specific events (Vancouver 2010 for Winter Olympic Games and London 2012 Olympics).

Experiments have been conducted with conventional vehicles (internal combustion engines) fuelled by a mixture of hydrogen–methane (Hythane). Hydrogen generally represents 20% by volume. Compared to methane alone, the mixture reduces emissions (THC, CO and NO_x) as well as providing a better yield (10–15%). The French programme ALT-HY-TUDE (2005–2008) allowed experimenting this mixture on buses. In India, a first filling station was opened in 2009 and in 2011 another at the San Francisco airport with a fleet of 30 vehicles.

5.5.3.2 Other experiments in transportation

Hydrogen associated with a fuel cell has been or is being experimented in other sectors.

In the railway sector, if a hydrogen train prototype was used in a mine in the USA in 2002, it was not until 2017 that a train was certified on a regular line in Germany (suppliers were Alstom, France, for the structure, Hydrogenics, Canada, for the fuel cell and Wystrach, Germany, for the gaseous hydrogen storage).

In 2011, electric-powered trucks used at the Port of Los Angeles were modified to use a fuel cell. In 2017, prototypes developed by Toyota Motor in Japan and Nikola Motor Company in the USA were shown. Tesla also presented a concept.

In the maritime sector, no commercial vessel uses fuel cells for propulsion and none of the many programmes launched [6] have been successful (e4ships or HyFerry in Germany, SF BREEZE in the USA etc.). Only a few submarines built by the German shipyards ThyssenKrupp Marine systems in the 2000s were equipped with fuel cells fuelled by hydrogen and oxygen stored on board. Between 2008 and 2013, a tourist boat was running in Hamburg under the Zemship programme. A dedicated hydrogen station allowed it to refill and store 50 kg for two PEMFCs of 48 kW each (100 kW propulsion engine). Some other projects or prototypes have been developed to show the possibility of usage of hydrogen/fuel cell for propulsion. Some research vessels use on-site hydrogen production to power the electrical propulsion motors. The "Race for Water" (e.g. "PlanetSolar") catamaran is equipped with 500 m^2 of solar modules, whose electricity is also used to produce hydrogen from seawater (5 kW electrolyser). It is stored in 25 cylinders at 350 bar (200 kg of hydrogen), which will be converted into electricity through two fuel cells of 30 kW each. The "Energy Observer", also a catamaran launched in 2017, uses electricity mainly from photovoltaic panels (130 m^2) to produce hydrogen (62 kg stored under 350 bar) and power the electric motors with a fuel cell.

If two light aircrafts used a fuel cell for propulsion (Boeing in 2008 and DLR in 2009), studies for application to large aircraft to supply reactors (European programme *Cryoplane*) did not have a follow-up. The same was true for use as an auxiliary power unit on the ground. Some drones equipped with a fuel cell and a hydrogen tank (compressed or in hydrides) are evaluated, the first experiments dating from 2009. A study has been carried out by Boeing in the mid-1970s on the conversion of a 747 for use of hydrogen instead of kerosene for reactors, while keeping the same characteristics (autonomy and number of passengers). If the quantity of fuel is reduced to 41 tonnes of hydrogen instead of 121 tonnes, the volume required (578 m^3) exceeds any internal storage capacity. The project was then oriented towards two external reservoirs 4 m in diameter and 46 m long in the form of a nacelle under the wings.

One of the few sectors where the use of fuel cells/hydrogen begins to be largely used and which tends to develop is that of logistics. Since the first experiments in 1960, several thousand hydrogen **forklifts** are in operation. The economic sectors using them are as well large retailers (Walmart, USA, with 6,600 units in 2017; Kroger, USA, more than 1,000; or Carrefour, France) or factories (BMW, USA, with more than 400 units) or deliveries (FedEx). The players in this field are hydrogen suppliers like Linde Gas or fuel cells like Plug Power, HyGear or Nuvera in association with forklift manufacturers (Yale, Still). The use of hydrogen, sometimes produced on site, avoids the long charging times of the batteries and makes the forklifts operational continuously (Figure 5.37).

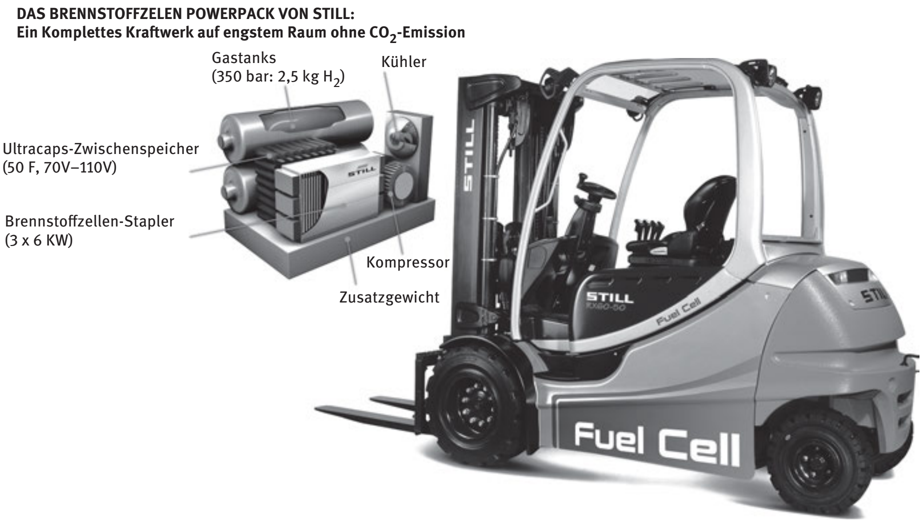

Figure 5.37: Hydrogen/fuel cell forklift (Still GmbH).

In the transportation sector, the combination hydrogen/fuel cell remains very marginal and is likely to remain as a result of fuel cell prices and the lack of filling stations for vehicles (cars and buses).

5.5.3.3 Methane for transportation: a transitional stage

More interesting than the combination hydrogen/fuel cell is the use of methane from hydrogen (methanation) or from methanisation (biomass) for natural gas (CNG) or hybrid/natural gas vehicles (Figures 5.38 and 5.39). This approach can be a transitional alternative not only to the battery electric vehicle whose large-scale commercialisation does not seem to really start but also to gasoline and diesel vehicles for pollution reduction.

The benefits of using methane for vehicles include:

– lower and reduced overall emissions (Figure 5.40) if the CO_2 used for methanation comes from a biogas unit
– the absence of particulate emissions as is the case for diesel
– operation silence (3 dB less)

Economically, this results also in a reduction in the oil bill. For 1 TWh of excess electricity, about 640 GWh can be "recovered" in the form of methane, i.e. 128 million Nm^3. This quantity of about 100,000 tonnes could allow 200,000 vehicles to travel 10,000 km.

The global number of registered cars is still relatively small (about 24 million vehicles worldwide in 2016 with 5 million in China, 4 in Iran, 3 in Pakistan and 900,000 in Italy), but a recovery is expected, notably by increasing the number of service stations. Many countries are starting to launch programmes in this direction and the International Gas Union projects 65 million vehicles by 2020.

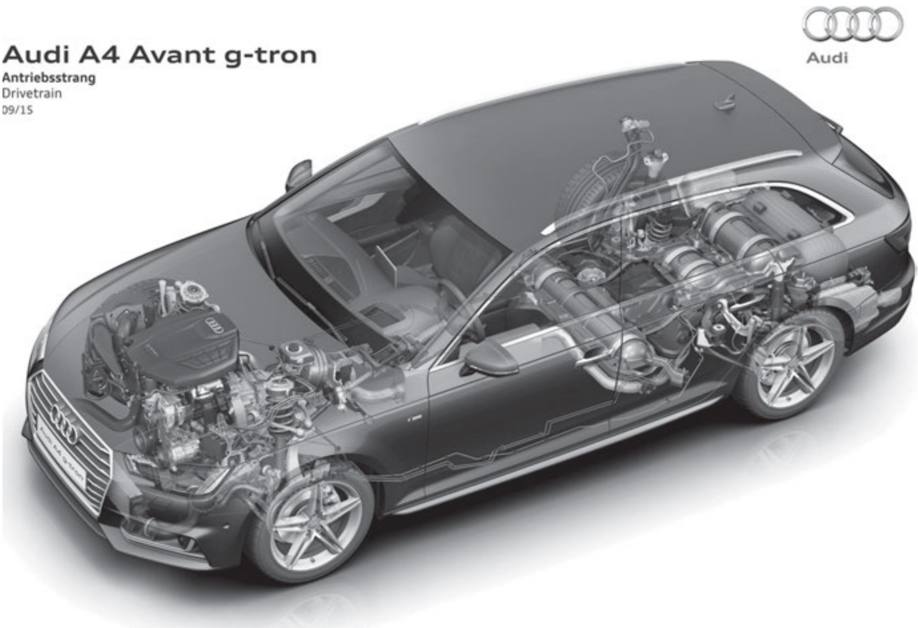

Figure 5.38: Hybrid natural gas vehicle–gasoline vehicle (Audi).

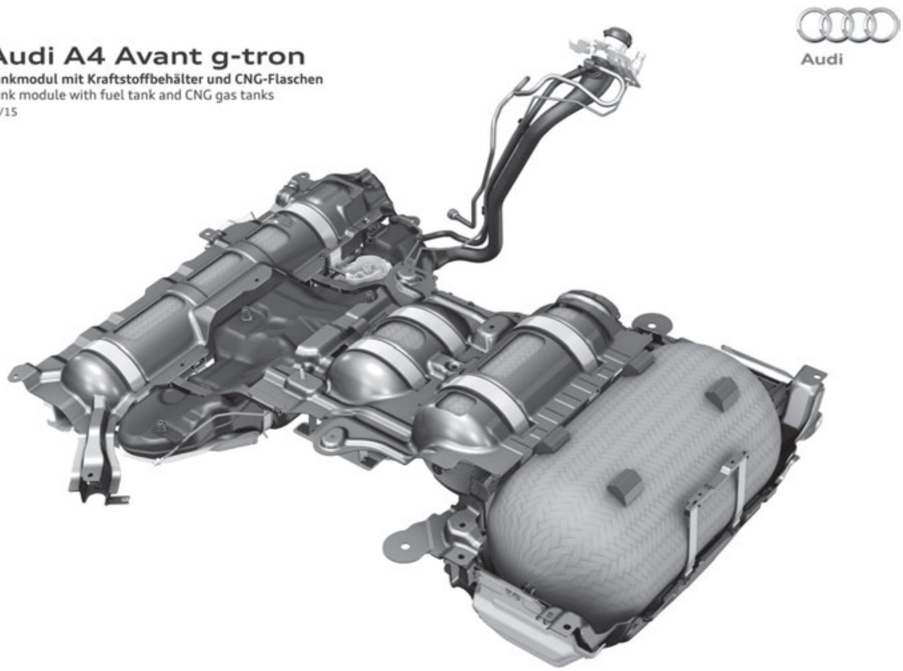

Figure 5.39: Hybrid vehicle fuel and natural gas vehicle tanks (Audi).

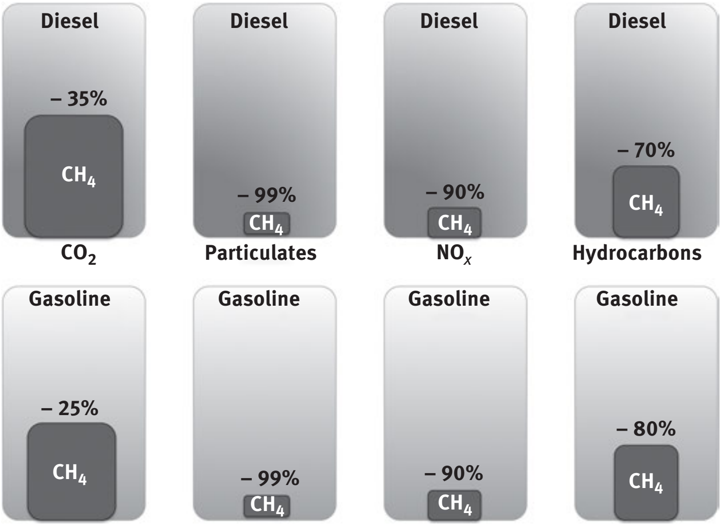

Figure 5.40: Comparative emissions.

5.5.4 Domestic use

The domestic use of pure hydrogen is nowadays limited to a few experiments in areas such as micro-CHP. In Denmark, an experiment carried out in 2008 on the island of Lolland validated the direct use of hydrogen to supply low-power domestic fuel cells by a distribution network of hydrogen produced by electrolysis (electricity from wind turbines). However, methane from methanation and injected into the natural gas network offers the optimal solution that does not require changes in domestic equipment that runs on natural gas.

5.5.4.1 Hydrogen, methane or electron? Direct use of electricity: a priority

If the electrolysis has made possible to recover the surplus of electricity of renewable origin, the relatively low overall energy efficiency and the infrastructure to be installed must lead first to the direct use of this electricity. The different fields of application (industry, energy and transport) must be further optimised in terms of energy efficiency and equipment.

However, power-to-gas technology is the only way to store the large expected surpluses. The hydrogen produced and methane from methanation contribute to overall energy efficiency, the first step in an energy transition.

There are still many technological barriers but the projects and achievements make it possible to bring this technology to large-scale commercialisation.

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6 Beyond power-to-gas

6.1 Power-to-liquid

6.1.1 Synthetic fuels

In the 1920s, German chemists Franz Fischer and Hans Tropsch were able to synthesise the first hydrocarbons according to the exothermic reaction called Fischer–Tropsch (FT) eg. for alcanes:

$$(2n + 1)\ H_2 + nCO \Rightarrow C_nH_{(2n+2)} + nH_2O \tag{6.1}$$

Starting materials were hydrogen and carbon monoxide (syngas) from coke gas. A catalyst (iron, cobalt or ruthenium) was required and the reaction was carried out under high pressure and temperature. The choice of conditions (composition of the mixture, catalyst, temperature, pressure etc.) makes it possible to obtain different hydrocarbons:

$$2CO + 4H_2 \rightarrow C_2H_4 + 2H_2O \text{ (methane)} \tag{6.2}$$

$$2CO + 4H_2 \rightarrow C_2H_5OH + H_2O \text{ (methanol)} \tag{6.3}$$

$$8CO + 17H_2 \rightarrow C_8H_{18} + 8H_2O \text{ (octane)} \tag{6.4}$$

As a result of the ever-increasing discoveries of oil and natural gas deposits and the corresponding decline in prices, this approach has not been as successful as expected. It was, however, used by countries without oil or gas resources (Germany from the mid-1930s and the Second World War to produce synthetic fuels) or without access to the fuel market (South Africa during the boycott following apartheid).

However, surplus electricity from renewable sources in the coming decades will increase the availability of hydrogen in significant quantities and may allow a renewal of this technology to produce synthetic fuels or chemicals.

The term "synthetic" can be misleading: It does not mean that the fuels are produced from basic atoms (H, C and O) but from chemical conversion.

6.1.2 Power-to-liquid

To produce the initial mixture (syngas) used by the FT reaction, the power-to-gas supplies hydrogen, whereas carbon dioxide (CO_2) can be derived from a biogas unit or captured from the air. CO_2 is reduced to carbon monoxide (CO) using oxygen from the air. High-temperature electrolysis provides the optimum conditions for the use of excess

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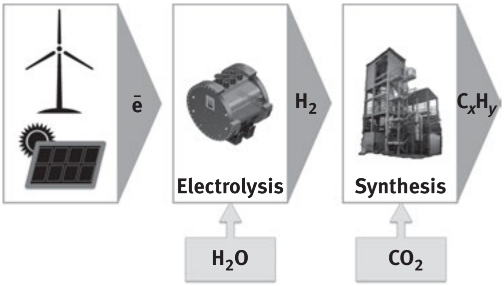

Figure 6.1: Power-to-liquid principle.

electricity to the production of hydrocarbons (Figure 6.1): steam electrolysis makes it possible to increase the efficiency of electrolysis and of the conversion to hydrocarbon.

6.1.3 Gas-to-liquid

In this approach, **natural gas** is used as the starting point to produce synthetic compounds. The first step is the production of syngas according to the reactions

$$CH_4 + H_2O \Rightarrow CO + 3H_2 \text{ with } \Delta H^0 = 206 \text{ kJ/mol} \tag{6.5}$$

$$CH_4 + CO_2 \Rightarrow 2\,CO + 2H_2 \text{ with } \Delta H^0 = 247 \text{ kJ/mol} \tag{6.6}$$

Two important reactions are the exothermic water gas shift reaction, which converts CO into hydrogen and reverse water gas shift. The two coexist in an equilibrium varying with the temperature:

$$CO + H_2O \Leftrightarrow CO_2 + H_2 \text{ with } \Delta H^0 = -41 \text{ kJ/mol} \tag{6.7}$$

The synthesis of methanol, for example, occurs according to the reaction:

$$CO_2 + 3H_2 \Rightarrow CH_3OH + H_2O \text{ with } \Delta H^0 = -62 \text{ kJ/mol} \tag{6.8}$$

Experiments are mainly directed towards the production of synthetic fuels [1].

6.1.4 PtL experimentations

6.1.4.1 Production of synthetic diesel

The pilot plant initiated by Audi and carried out by Sunfire (Figure 6.2) was built in Werlte and has been operational since the end of 2014. The unit produces synthetic diesel (Figure 6.3).

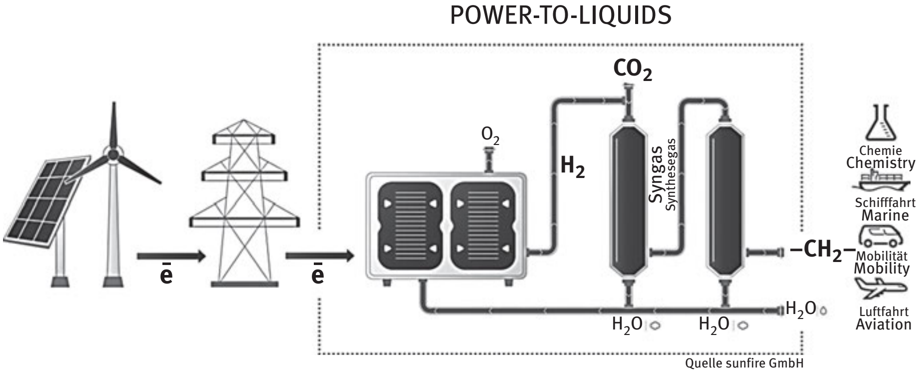

Figure 6.2: Power-to-liquid with high-temperature electrolysis (Sunfire).

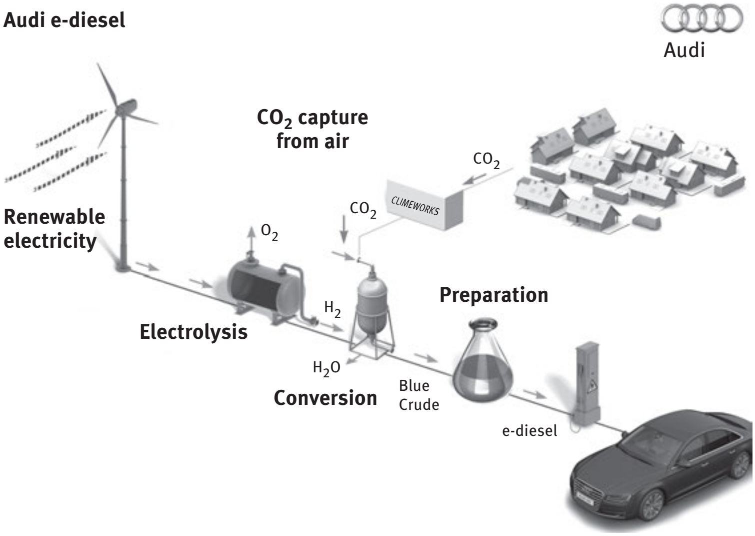

Figure 6.3: Diagram of the power-to-liquid unit in Werlte (Audi).

A SOEC high-temperature electrolyser (10 bar and 800°C) supplied by Sunfire dissociates the water into hydrogen and oxygen with 90% yield.

Hydrogen reacts with CO_2 from a biogas unit in a reactor under pressure and temperature to produce a liquid hydrocarbon (*Blue Crude*). The efficiency of the operation is of the order of 70%. By distillation, this hydrocarbon can be converted into synthetic diesel (160 L/day with 80% yield) without sulphur or aromatics and with a high cetane number (Figure 6.4).

Depending on the type of distillation, other fuels such as gasoline, kerosene etc. can be produced.

Figure 6.4: Power-to-liquid unit in Werlte (Audi).

A similar plant is to be installed in Norway (Heroya Industrial Park) with production start-up in 2020. Nordic Blue Crude, Sunfire (high-temperature electrolysis), Climeworks (capture of air CO_2) and EDL Anlagenbau (infrastructure) companies are involved in this project with an initial capacity of 10 million L/year.

6.1.4.2 MefCO2 project – production of methanol

An installation near Dortmund in Germany produces methanol from hydrogen obtained by electrolysis (1 MW Hydrogenics electrolyser producing 200 Nm^3/h of hydrogen). CO_2 comes from the Steag coal-fired power plant. The methanol production unit was developed by Carbon Recycling International. Production began in 2017 with a capacity of 250,000 L/year.

In Iceland, an installation with a capacity of 5 million L/year is already in operation.

6.1.4.3 Soletair project

This research project was carried out by the Finnish Research Centre (capture of CO_2 from air), the Finnish University of Lappeenranta (electrolyser) and the German Institute of Technology KIT – Karlsruhe Institute of Technology (Compact synthesis reactor developed by the spin-of INERATEC – Figure 6.5).

Figure 6.5: Synthetic reactor (INERATEC).

Figure 6.6: Power-to-gas research unit in Finland (VTT Technical Research Centre of Finland Ltd).

The initial equipment allowed to validate the operation of the unit installed in Finland (Figure 6.6) which uses the electricity of a photovoltaic plant. Its capacity is 80 L of gasoline per day and in July 2017 nearly 200 L were produced after the first start.

The German Fraunhofer Institute has been carrying out its project "Strom als Rohstoff" (electricity as raw material) since 2015. Various demonstrators aim at the production of hydrogen peroxide (H_2O_2), ethylene (C_2H_4) or alcohols (C_1–C_{20}). The project objectives are to demonstrate the feasibility of these PtL options.

6.1.4.4 Conclusion

Power-to-gas technology with the availability of hydrogen (or methane) from electricity of renewable origin opens up a new perspective to the production of synthetic fuels or chemical compounds of high purity and is an alternative to fossil fuels (petroleum, natural gas and coal) [2]. The reached yield makes it possible to envisage commercial production.

Another advantage is the low greenhouse gas emissions for PtL using renewable electricity, CO_2 and water compared with conventional oil or other chemicals obtained from natural gas, oil or coal. Fuel production can be speeded up by the European Commission's Renewable Energy Directive for the post-2020 period (RED II), from December 2016, which will introduce a gradual phase-out of conventional biofuels.

CO_2 from industrial processes or power plants should reduce the necessity to move to carbon capture and storage. On the economic side, the unit planned in Norway has a price objective of 2 euros/L of Blue Crude.

6.2 Power-to-heat

6.2.1 Principle

Another option for storing excess electricity is the conversion into heat stored in tanks or other materials, at the domestic, urban or industrial level. This option could be an alternative to supplement battery storage where no power-to-gas unit is available to absorb the excess electricity when the battery is fully loaded (Figure 6.7).

However, the conversion of electricity to heat should only be activated when electricity generation is in excess and cannot be used otherwise.

6.2.2 Heat storage

Apart from water, other materials can be used to store heat from the conversion of excess electricity: phase change materials, stone, concrete etc.

The Dutch company Ecovat BV has built in Uden a prototype of underground storage of heat for an office building. The reservoir (20 m in diameter and 26 m in height) has a capacity of 1,500 m^3 of water (88,000 kWh). The insulation keeps hot water (>90°C) for several months with less than 10% losses in 6 months.

"Thermal batteries" use a phase-change salt instead of water. The German company HM Heizkörper has developed a hybrid (Figure 6.8) water/sodium acetate trihydrate module (40 cm diameter for 1.8 m high) capable of storing a latent heat of 2 kWh over a long period (several weeks or months).

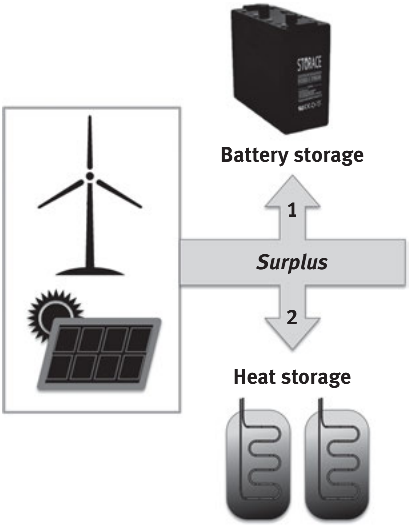

Figure 6.7: Principle of the power-to-heat concept.

This type of excess electricity storage offers considerable autonomy over storage in water.

Hybrid heat–electricity project

A heat storage project is being carried out in Hamburg by Siemens-Gamesa, the Hamburg-Harburg Technical University and the local energy supplier Hamburg Energie. In case of excess electricity a fan circulates the air through resistances which heat this air up to 600°C to warm up 200 m^3 of insulated rocks. In case of electricity needs, a fan sends cold air that heats up through the rocks. Hot air vaporises water and this steam operates a 1.5 MW turbine. The overall yield, however, does not exceed 25%.

The Norwegian start-up Energy Nest uses the same approach for storage but with special concrete. Heat is transmitted to the concrete through an integrated pipe network.

6.2.3 Urban experiments

In **Germany**, since 2015, a large-scale experimentation took place in a district of Berlin (Adlershof). A central combination of cogeneration using natural gas (96 $MW_{th.}$ and 13 $MW_{él.}$) and storage of heat makes it possible to regulate the supply of electricity (Figure 6.9).

In case of electricity deficit, the power of the CHP units is increased and in case of excess electricity it is converted into heat and stored in five tanks totalling 2,000 m^3 of water (6 MW) for distribution in the local district heating network.

Also in Berlin, the energy supplier Vattenfall is investing from 2017 in a unit capable of storing 120 $MW_{th.}$ which will also supply local district heating network.

Figure 6.8: Thermal battery module for individual housing (picture of the author – ISH 2015 Frankfurt)

In **Switzerland**, since 2016, Alpiq has been managing two units of 11 MW each in Lausanne to produce steam from surplus electricity at the Gösgen power station. This steam is used by a paper mill.

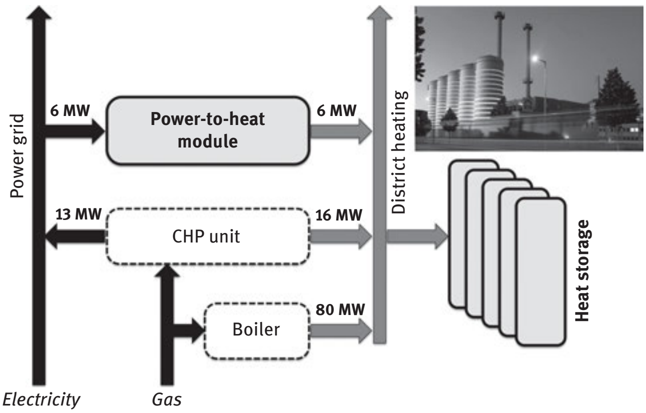

Figure 6.9: Principle of operation of the power-to-heat Adlershof concept (Data: BTB GmbH, Berlin).

6.2.4 Experiments in industry

Manufacturers requiring hot water or steam production can also use power-to-heat (PtH) technology to reduce production costs. This approach can be done internally or through contracting. The German company Enerstorage has been offering this option since 2014, optimising the unit to meet industrial needs (pressure, temperature, volumes etc.).

In this context, the German sugar producer Südzucker has installed a 10 MW PtH unit in 2016, both for internal needs and to supply a local steam network, thus increasing the flexibility of the installation.

6.2.5 Domestic experiments

The direct use of excess electricity uses the resistances of existing **hot water tanks**, which can be controlled by the electricity supplier and activated only in the event of a surplus (Figure 6.10).

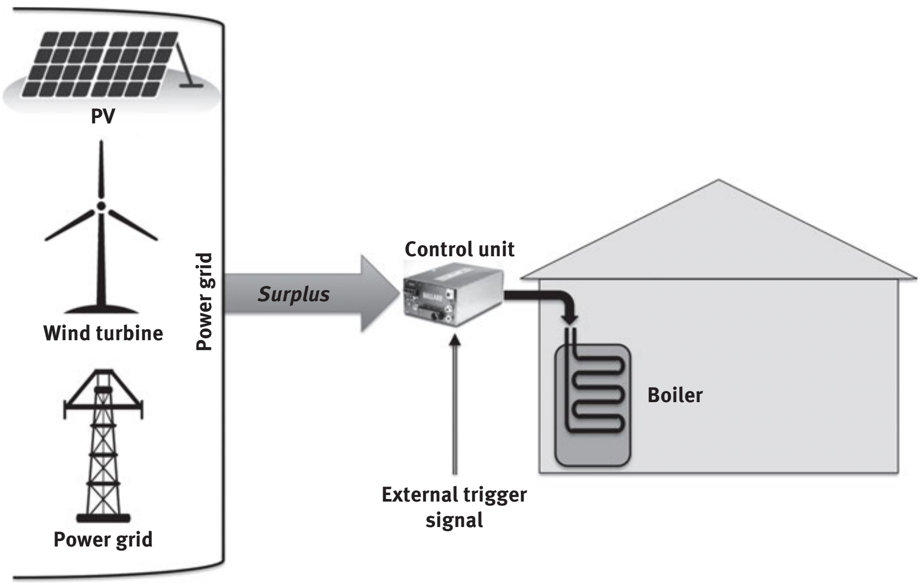

Figure 6.10: Domestic power-to-heat concept.

The other option (Figure 6.11) uses electricity produced by a **domestic photovoltaic system**. Many companies offer management modules that can optionally integrate battery storage: they detect overproduction phases and send electricity to the heating resistance of the hot water tank.

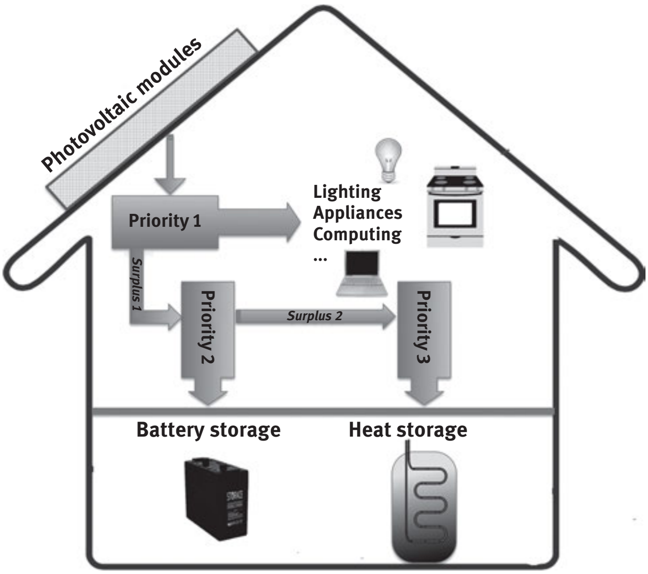

Figure 6.11: Power-to-heat from photovoltaic installation.

Heat pumps can also use surplus electricity from renewable sources. In this regard, the real efficiency (coefficient of performance [COP] taking into account primary energy) is improved and the capacity of the electricity grid is used optimally.

An energetically limited approach

The transformation of electricity into a lower form of energy (heat) leads to an energy "deadlock" because low-temperature heat can hardly be converted into another form of energy or with a very low yield. However, the PtH approach can be a complement to maintain the stability of the electricity grid or use the excess electricity produced locally that can no longer be stored or converted into another form.

6.3 Combination of PtH and PtL

For the industry, PtH technology has a very short reaction time and can almost immediately use excess electricity. The PtL process requires a start-up time to have water or steam at a given temperature. The combination of the two approaches is based on the use of excess electricity to first power the PtH unit to immediately use this surplus and then allow the PtL unit to take over with steam at the required temperature.

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7 Power-to-gas experiments

While one of the earliest experiments took place at the end of the nineteenth century by the Dane Poul la Cour (see Chapter 3), more recent research projects were launched in the mid-1980s, followed by projects with higher power pilot units.

7.1 Early developments

7.1.1 HySolar programme (1986–1995)

In the mid-1980s, a 10-year research contract was signed between Saudi Arabia and Germany for the HySolar (*Hydrogen from Solar Energy*) programme. This programme saw the design and installation, between 1985 and 1989, of a building in Stuttgart (Figure 7.1) housing a pilot unit of 10 kW. It used electricity supplied by photovoltaic panels (14.7 kW) to produce hydrogen (2 kW electrolyser with an efficiency of 80%) which was compressed at 200 bar and stored in tanks. The hydrogen produced has been used for research on catalytic combustion, for fuel cells (alkaline fuel cell [AFC] or phosphoric acid fuel cell [PAFC] type) or for modified internal combustion engines.

A 2 kW teaching and research unit (photovoltaic panels and electrolyser) was installed on the rooftops of the University of Ryad. A demonstrator using electricity from photovoltaic panels (3,800 m^2) was built north of Ryad and commissioned in 1993. It consisted of a 350 kW electrolyser supplying compressed hydrogen at 150 bar stored in tanks.

HySolar, a precursor programme

The approach of this programme has laid the foundation for a power-to-gas (P2G) installation. The numerous visitors (up to 3,000 per year) were able to judge the validity of this concept despite the relatively low yields linked to the technological development of that time. The objectives and concerns corresponded to those of the current facilities.

Other experiments were carried out in the 1990s. One of them, led by the Spanish institute Instituto Nacional de Técnica Aeroespacial, included the entire energy chain:
- Photovoltaic panels (144 modules) producing 7.5 kW
- An alkaline electrolyser of 5.2 kW (1 Nm^3/h of hydrogen)
- A purification system followed by storage of hydrogen combining metal hydrides and reservoir under a pressure of 6 or 200 bar
- A 10 kW PAFC mixed fuel cell capable of using either hydrogen or methanol with a reformer

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Figure 7.1: HySolar building in Stuttgart (DLR – Deutsches Zentrum für Luft- und Raumfahrt).

7.1.2 Projects at the level of a building

In the programme run between 1992 and 1995 by the German institute Fraunhofer in Freiburg, a low-energy building was specially designed for this concept. Electricity consumption has been minimised by the use of energy-saving equipment. It included:
- photovoltaic panels (34 m^2 producing 4,500 kWh/year)
- lead-acid batteries for electricity storage with a capacity of 19.2 kWh
- a proton exchange membrane (PEM)-type electrolyser of 2 kW producing hydrogen under a pressure of 30 bar
- external storage of hydrogen (15 m^3) and oxygen (7.5 m^3)
- A fuel cell of the PEM type

Hydrogen was used for heating by catalytic combustion without flame. It was also used for cooking. When the production of photovoltaic electricity was insufficient or when the batteries were discharged, a fuel cell took over for the production of electricity. It operated at a temperature of 70°C with an electrical efficiency of 60%. The heat produced was recovered to heat water.
Solar energy was also used for the thermal part with 12 m^2 of collectors. After experimentation and dismantling of the equipment, the building still houses offices.

On an even smaller scale, the Swiss Markus Friedli equipped his home in the 1990s with a system combining solar and hydrogen. Photovoltaic panels with a peak power of 7.4 kW powered an alkaline electrolyser of 10 kW. The hydrogen produced (0.3–0.95 Nm^3/h) is purified (removal of the carried potash, oxygen and water), compressed and stored in a buffer tank and then in hydrides (91 L tank weighing 235 kg and containing up to 19 Nm^3 of hydrogen). Hydrogen supplies a stove and a modified minibus which also stores hydrogen in hydrides.

Other experiments to use hydrogen produced from wind or photovoltaic energy at a housing level have been conducted since the 1980s.

7.1.3 Exploratory projects

Exploratory projects were carried out in many countries in the early 2000s. These include:
- in Great Britain between 2000 and 2004 (PURE project on the island of Unst)
- in the USA in 2001 in Reno and in 2004 in Chicago
- in Canada in 2003
- in Italy in 1997 and 2000
- in Germany in 2003 (project PHOEBUS)

Most of these projects used a proton exchange membrane fuel cell (PEMFC) with a few kilowatts of power (typically less than 10 kW) to generate electricity from stored hydrogen.

7.1.4 First field experiments

7.1.4.1 Solar Park/hydrogen from Neunburg vorm Wald (Germany)

This project, launched in 1987, was based on a photovoltaic plant of 350 kW associated with three electrolysers of about 100 kW each. The hydrogen produced was stored in gaseous (tanks of 6,000 m^3 under 30 bar) or liquid form (tanks of 3,000 L).

Hydrogen gas, mixed with natural gas, was supplied to several boilers or was converted into electricity by three fuel cells (one mounted on a forklift and the other two stationaries, respectively, of the AFC type of 7 and 79 kW). A liquid hydrogen service station, produced on another site, was used to test the filling of tanks of modified ICEs (internal combustion engines) supplied by BMW and running on hydrogen.

7.1.4.2 Utsira (Norway)

One of the first complete installations was that of the Norwegian island of Utsira and experimented between 2004 and 2008. On this island of 220 inhabitants, two wind turbines of 600 kW each were put into service in 2003. In order to be able to store electricity in excess, an installation comprising an electrolyser, a hydrogen compressor and a reservoir for its storage has been used. This hydrogen supplied a fuel cell and an ICE generator that provided electricity uninterruptedly (up to 48 h without wind) to ten houses on the island. A flywheel regulated electricity supplied directly to the grid by wind turbines (Figure 7.2).

Figure 7.2: Power-to-gas installation on the island of Utsira (Norsk Hydro ASA).

Table 7.1: Utsira power-to-gas components.

Equipment			
Wind turbines	2 × 600 kW	Blades diameter 40 m	Enercon
Electrolyser	10 Nm^3		Norsk Hydro
H_2 storage	2,400 L – 200 bar		Norsk Hydro
Fuel cell	10 kW	PEMFC	IRD
Generator	55 kW		Continental
Flywheel	5 kW		Enercon

The technical characteristics of the installation are summarised in Table 7.1.
The final electrical yield was of the order of 25% but allowed to continually feed the houses, an important point on an island. At the end of the experimentation, only the wind turbines were kept.

Early promising approaches

All these initial experiments validated the P2G technology despite the technological limitations mainly related to equipment that was not always optimised or that had low yield. Projects over a long period have also shown economic and social viability (e.g. experimentation on islands), allowing an uninterrupted supply of electricity.

7.2 Research projects

Following the exploratory programmes of this technology from the 1980s to the 2000s, other institutes, companies and organisations have launched higher power units, bringing together the technological advances of the last few years (e.g. methanation).

7.2.1 The ZSW Institute in Stuttgart

In collaboration with the Fraunhofer Institute IWES, the German research centre for solar and hydrogen ZSW (Zentrum für Sonnenenergie– und Wasserstoff-Forschung) near Stuttgart and the ETOGAS company (formerly Solarfuel GmBH, bought in 2017 by the Swiss company Hitachi Zosen Inova) evaluated a high-power demonstrator of 250 $kW_{el.}$ (Figure 7.3).

The installation, which follows a low-power unit launched 3 years before, consists of:

– an alkaline electrolyser (Figure 7.4) with a power of 295 kW providing up to 65 Nm^3 of hydrogen per hour (or 300 m^3 per day) under a pressure of 6–11 bar
– a methanation plant with a methane capacity of up to 15 Nm^3/h

The results and experiences of this project have been used for other pilot installations (e.g. Audi "e-gas").

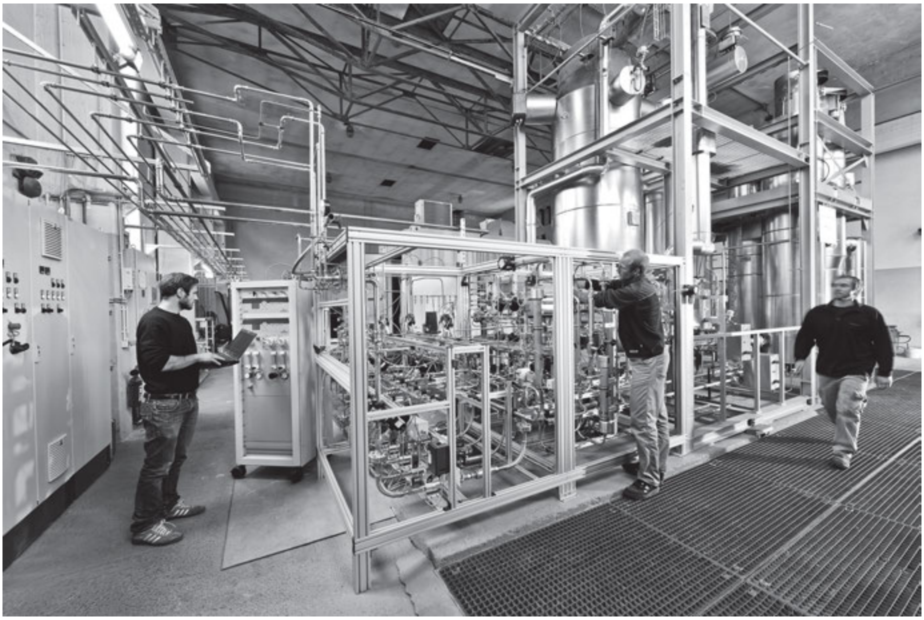

Figure 7.3: ZSW driver installation (ZSW-BW/Solar Consulting GmbH).

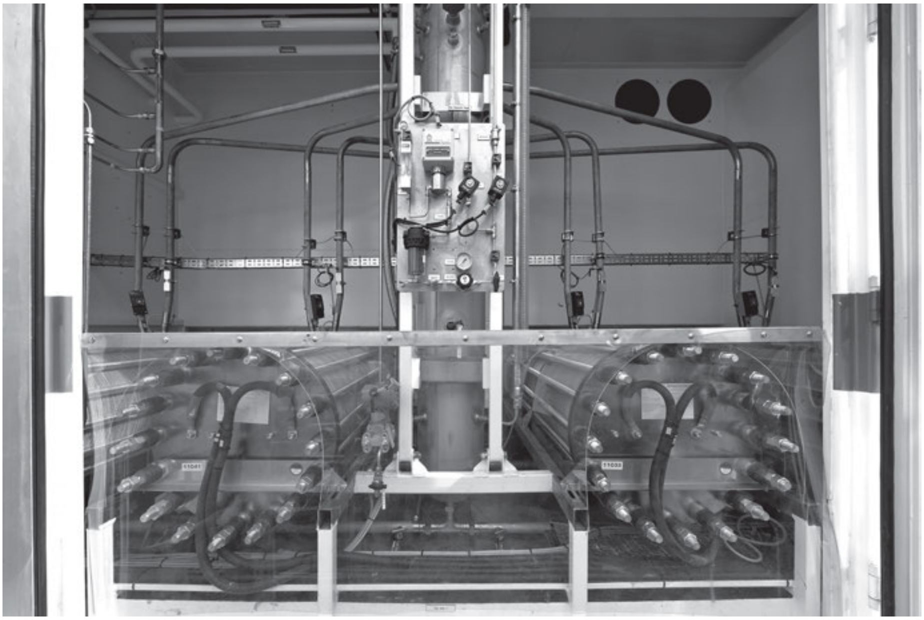

Figure 7.4: Alkaline electrolyser (ZSW-BW/Solar Consulting GmbH).

Following this project, the German Ministry of Finance and Industry decided to launch another programme for the development of a 1 MW unit in 2017.

7.2.2 Project WIND2H2

The US WIND2H2 project led by the National Renewable Energy Laboratory (NREL) and the XcelEnergy energy provider between 2007 and 2010 explored various options (Figure 7.5).

Electricity was supplied by a 10 kW photovoltaic plant and two wind turbines (10 and 100 kW). The hydrogen produced either by two PEM electrolysers of 6 kW (2.25 kg H_2/day) or by an alkaline electrolyser of 33 kW (12 kg H_2/day) was compressed under 240 bar and stored (115 kg capacity). This hydrogen made it possible to feed:
- a 5 kW fuel cell
- a modified 60 kW ICE engine and a generator (P2G2P)
- a service station, after compression to 400 bar and storage (capacity of 18 kg)

This programme allowed to confirm the better efficiency of the PEM electrolyser (57% versus 41% for alkaline) and to extrapolate the cost of hydrogen to US$ 5.83 for a larger 2.33 MW electrolyser.

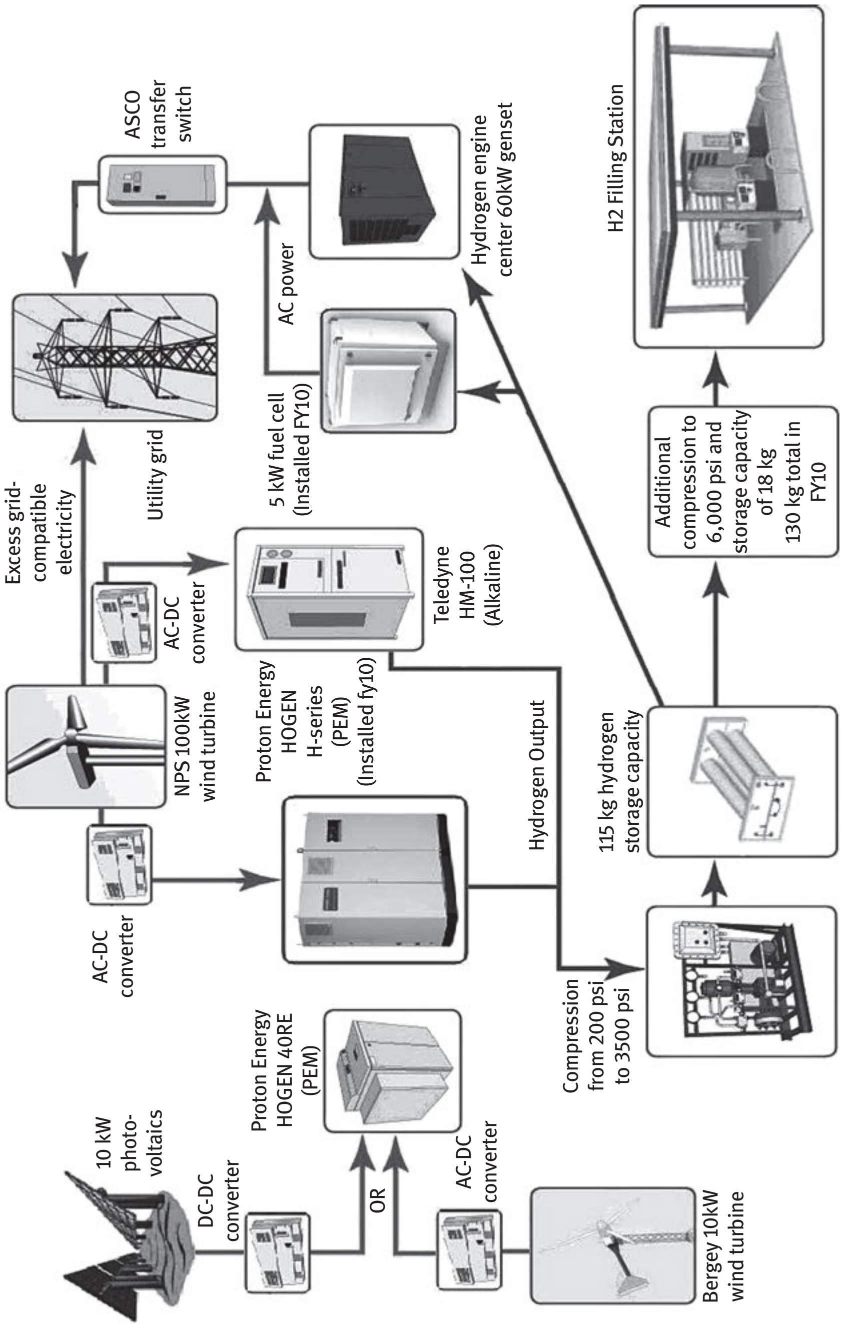

Figure 7.5: Project WIND2H2 (NREL).

7.2.3 National programmes or international cooperations

Many national or European programmes have been or are being carried out in various fields related to the P2G concept. They mainly concern hydrogen.

7.2.3.1 Example of projects

- NaturalHy (2004–2009) with a cost of € 17 million for the study of hydrogen injection in the natural gas network
- HyMAT for the study of the influence of hydrogen on the properties of steels
- HySAFE (2004–2009) covering safety issues related to the use of hydrogen
- IdealHy to develop a concept to reduce the energy requirements for hydrogen liquefaction
- HELMET (2014–2017) for the study of high-temperature electrolysis (800°C)

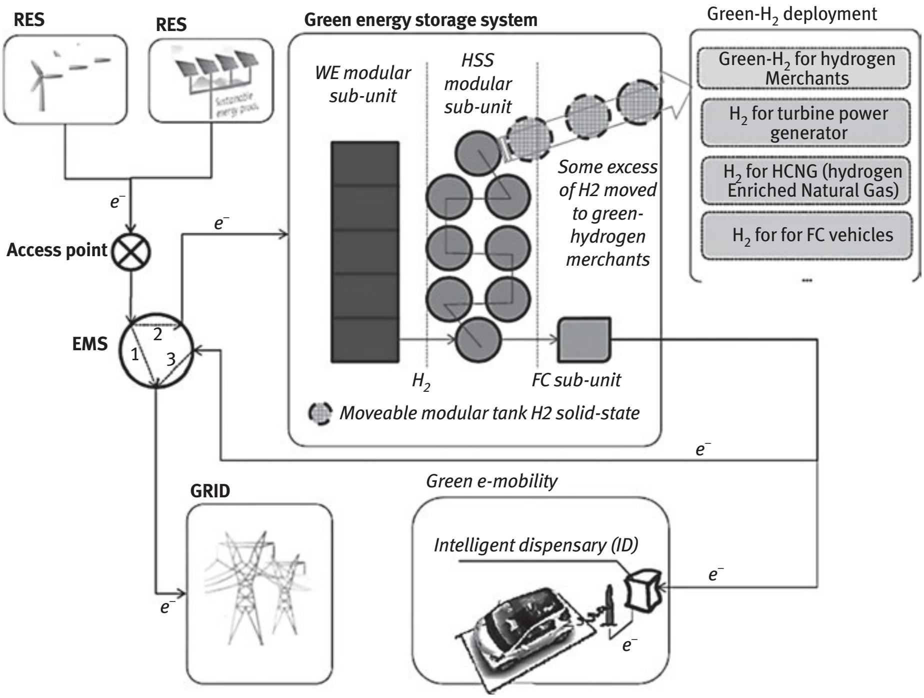

Figure 7.6: INGRID project diagram (ingridproject.eu).

7.2.3.2 INGRID project

This European project (high-capacity hydrogen-based green energy storage solutions for grid balancing) launched in 2012 and planned until 2016 with a cost of 24 million euros evaluated the electricity produced by a wind farm in Troia, Italy. It included an electrolyser from Hydrogenics (1.2 MW – 240 Nm^3/h), 750 kg storage in hydrides

(McPhy Energy), i.e. 39 MWh and a 60 kW fuel cell. In addition to experimenting with various parameters, simulation studies of the various elements were carried out in order to optimise the operation of the installation (Figure 7.6).

The hydrogen produced was used for transportation (service station), injection into the natural gas network or industry.

What were the real benefits of these programmes?

The cumulative costs of European and national programmes amount to hundreds of millions of euros or US$. While some have provided results that can be exploited for experiments with operational P2G installations, others, often due to lack of information or clear conclusions, do not reveal whether they have really contributed to a better understanding of different phenomena or helped in the development of operational projects.

7.3 Pilot projects

Many installations, mostly in Germany, are demonstrators of this technology, their power being not yet related to the future needs of storage of surplus renewable electricity. However, the operating conditions reflect those needed on a larger scale.

Among the many initiatives, either those offering a unique specificity or a few showing the different possible approaches of this technology will be presented.

7.3.1 Germany, the leader

Germany can be considered as a pioneer in exploring different approaches to P2G. By mid-2017, more than 30 facilities were under evaluation or under construction (Figure 7.7).

7.3.1.1 Enertrag – Prenzlau

One of the first installations, built in 2009 and operational in 2011, combining many technological approaches, is that of the German company Enertrag in Prenzlau, near Berlin (Figures 7.8 and 7.9).

The installation (Table 7.2) offers a great deal of flexibility, allowing the choice of operating modes and covering different needs.

Operating modes available:

- Maximum production of hydrogen
- Guaranteed electrical production with operation of cogeneration modules, if necessary, to stabilise electricity production
- Predictive mode based on 8-h weather forecasts to guarantee a given electricity production
- Regulation of the network with needs communicated 24 h in advance

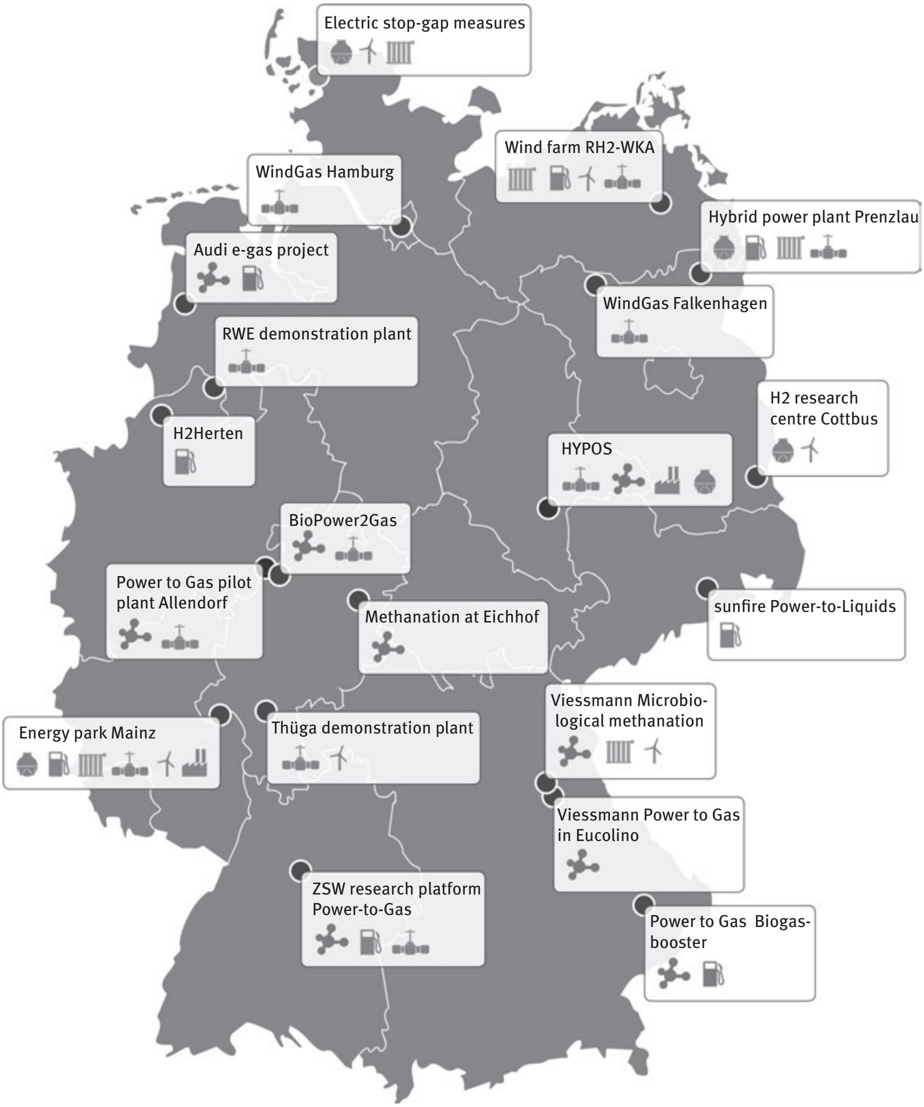

Figure 7.7: Power-to-gas projects in Germany during mid-2017 (DENA – Strategisplatform Power to Gas).

Table 7.2: Enertrag installation components.

Equipment		
Wind turbine	3 × 2 MW	Enertrag
Alkaline electrolyser	500 kW – 129 Nm^3/h	
H_2 compressor	31 bar	
H_2 storage	1,350 kg – 31 bar	
Combined heat and power unit	2 × 350 kW	

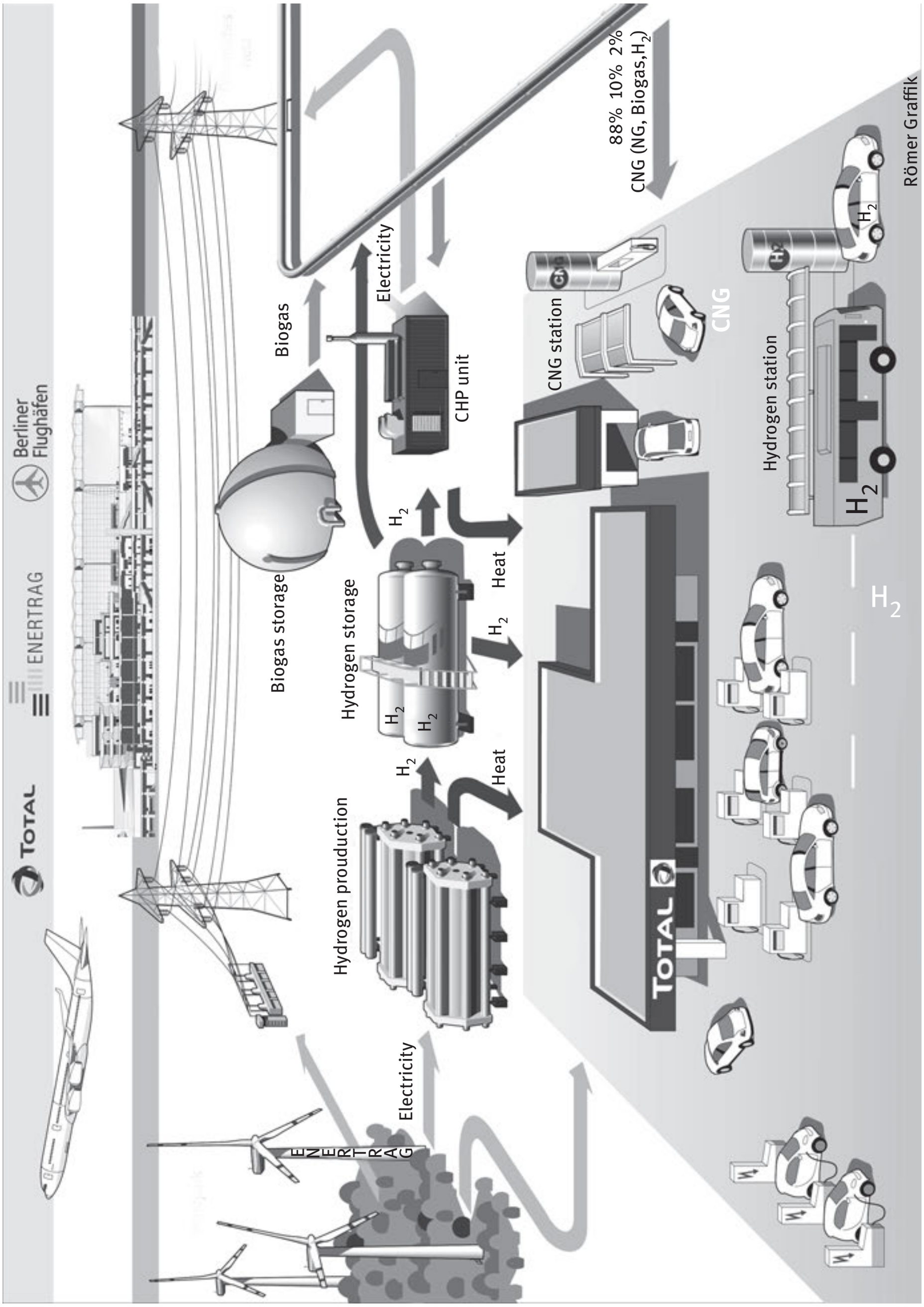

Figure 7.8: Power-to-gas Enertrag installation (Enertrag).

The injection of hydrogen into the natural gas network started at the end of 2014.

H2BER project

The objectives are the optimisation of a hydrogen service station for the future international Berlin airport (supposed to open in 2011 but still not operational in 2017). Hydrogen is produced on-site with an electrolyser and stored in tanks or in hydrides at different pressures. Delivery pressures of 350 and 700 bar are available depending on the vehicles.

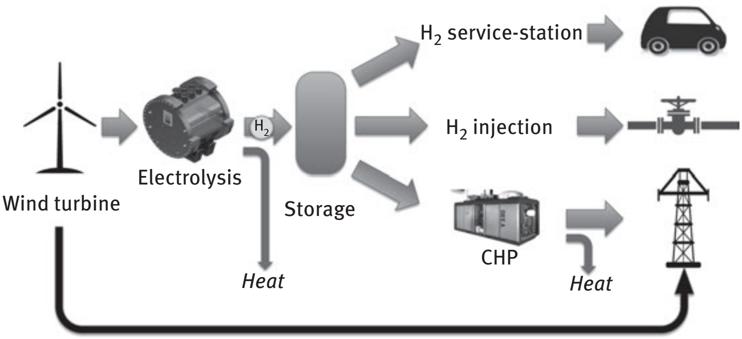

Figure 7.9: Schematic of the Enertrag installation.

7.3.1.2 Thüga/Mainova – Frankfurt

In 2012, the Thüga group of energy suppliers launched a P2G installation project. In 2013, the various modules were installed in Frankfurt-am-Main on a site of Mainova, the local energy supplier (Figure 7.10).

The installation includes:

– a 320 kW PEM-type electrolyser with a capacity of up to 60 Nm^3/h of hydrogen
– a hydrogen injection unit in the natural gas network (between 2% and 5%) under a pressure of 3.5 bar

Each module was installed in a 20 ft container, the electrolyser being supplied by the ITM Power (Figure 7.11).

As of November 2013, hydrogen produced (130 kg/day) was first injected into the natural gas network under a pressure that did not require a compressor (Figure 7.12). The official inauguration took place in March 2014 and the project continued until 2016 with the possible extension of a methanation unit in 2017.

By 2015, the overall hydrogen conversion efficiency was 77%. Monitoring and control were carried out from the Mainova control centre.

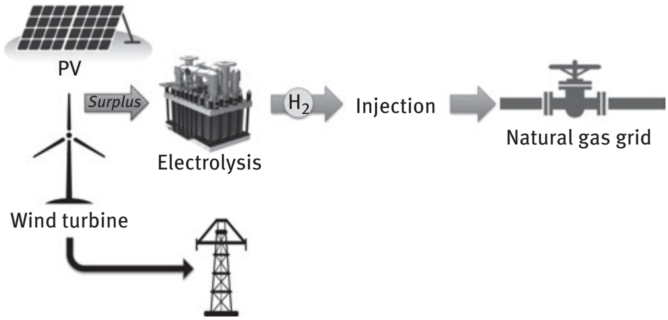

Figure 7.10: Schematic of the Thüga plant in Frankfurt.

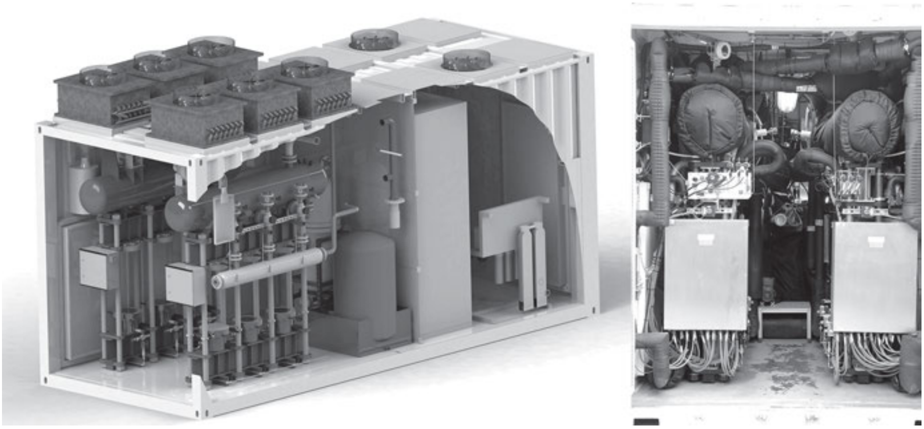

Figure 7.11: A 320 kW electrolyser (Thüga/Mainova).

Figure 7.12: Hydrogen injection station in the natural gas network (Thüga / Mainova).

7.3.1.3 Viessmann – biological methanation (bioPower2Gas)

A biological methanation demonstration unit of MicrobEnergy, a subsidiary of Viessmann, was tested until the end of 2014 with a constant gas production (up to 5 Nm^3/h) containing more than 98% methane (Figure 7.13).

At the beginning of 2015, a unit installed at Allendorf at Viessmann's head office (Figures 7.14 and 7.15) uses hydrogen produced locally by a 400 kW (1) PEM-type electrolyser supplied by Schmack Carbotech (also a Viessmann subsidiary).

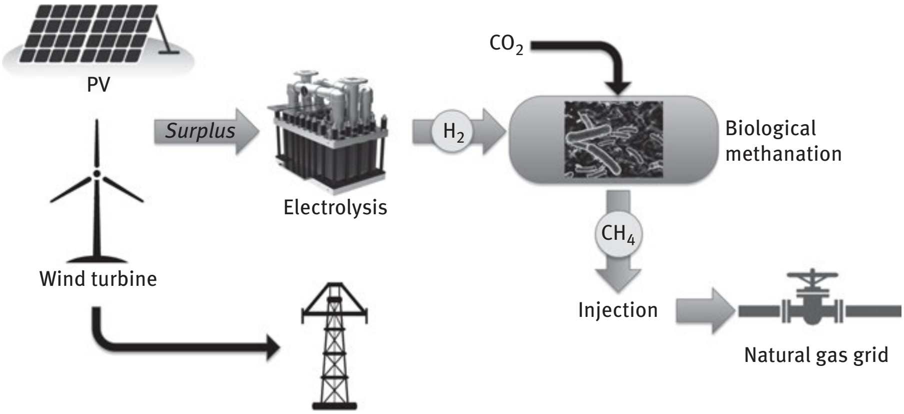

Figure 7.13: Concept of the Viessmann biological methanation plant.

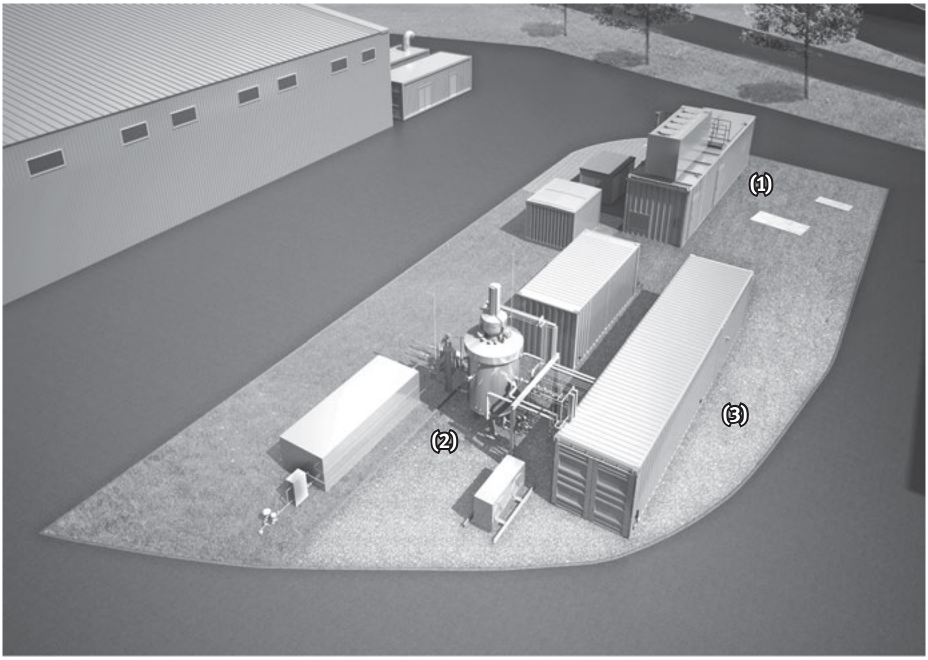

Figure 7.14: Viessmann power-to-gas unit (Viessmann).

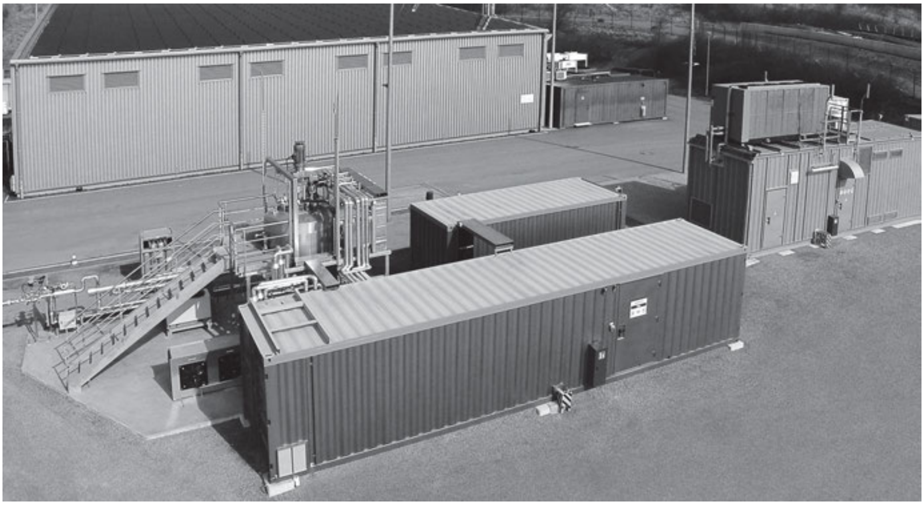

Figure 7.15: Biological methanation unit (Viessmann).

Hydrogen production capacity up to 220 Nm^3/h was used by the biological methanation units (2) and (3) with a capacity of 55 Nm^3/h. The required CO_2 comes from a biogas unit.

The next step allowing the methanation of 400 Nm^3 of hydrogen per hour was approved.

7.3.1.4 RH2-WKA

The RH2-WKA project (RH2-Werder/Kessin/Altentreptow), inaugurated in 2013, was designed to provide electricity primarily for the wind farm (Figure 7.16).

This project uses the surplus electricity from 28 wind turbines (including 15 of 7.5 MW) with a total power of 140 MW supplied by Enercon. Three 1 MW alkaline electrolysers (Hydrogenics HySTAT®) can produce up to 210 Nm^3/h of hydrogen. After drying and separating the oxygen, hydrogen is compressed to 300 bar (Hofer compressor) and stored in 120 steel bottles (810 kg, i.e. 9,500 Nm^3 representing an energy of 27 MWh). Two cogeneration units (Senergie GmbH) of 160 and 90 kW (250 $kW_{th.}$ and 400 $kW_{th.}$ respectively) were modified to operate with hydrogen. The heat produced is used by a nearby farm (Figure 7.17).

The hydrogen storage capacity allows the cogeneration units to operate at 28 h at maximum speed.

A second phase (RH2-PtG) involves the installation of a hydrogen injection unit into the natural gas network at a pressure of 25 bar. The maximum permitted concentration is 2%.

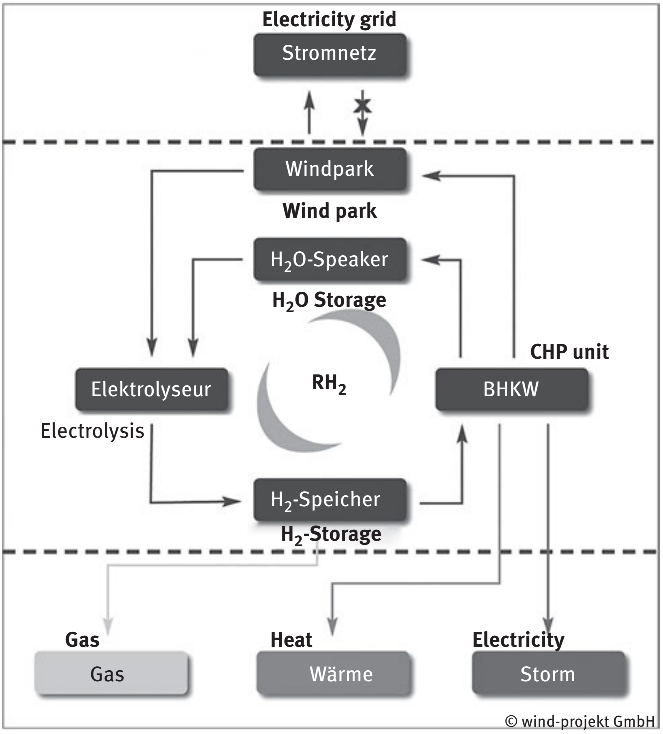

Figure 7.16: Schematic of the RH2-WKA installation (WIND projekt GmbH).

Figure 7.17: RH2–WKA installation (WIND projekt GmbH).

7.3.1.5 Herten

Inaugurated in 2013 as part of the H2Herten project, this facility (Figure 7.18) uses the hydrogen produced to supply electricity to a local Mini Grid.

As the wind farm is too far from the electrolyser, the electricity used is “virtual”: when the wind farm generates excess electricity, the same quantity is taken from the grid to supply the electrolyser.

Electricity is partly stored in Li-ion batteries and partly used by the 280 kW (30 Nm^3/h) electrolyser for an annual production of about 6,500 kg of hydrogen. This hydrogen is stored and used by a 50 kW fuel cell supplying electricity to a research centre and an industrial and commercial park (Mini Grid). This unit is designed to be able to operate autonomously, using the 250 MWh of electricity produced per year.

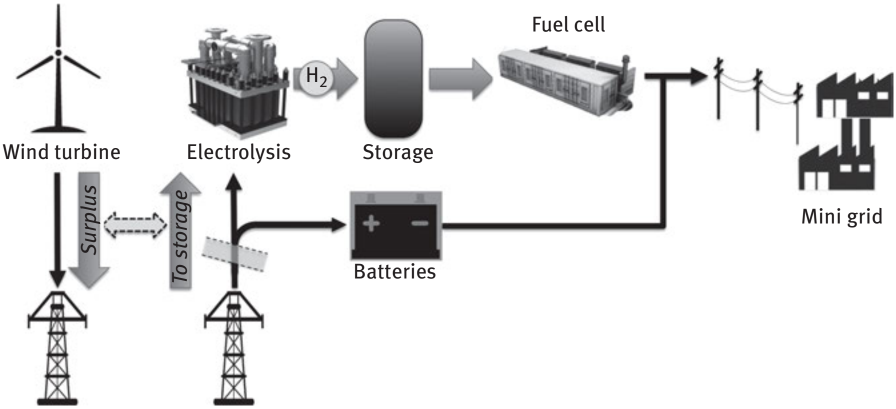

Figure 7.18: Schematic diagram of the concept installed in Herten.

7.3.1.6 Mainz

The Energiepark Mainz (Figures 7.19 and 7.20), inaugurated in March 2015, is a research unit for the production of hydrogen from wind-generated electricity. It is located on the premises of the municipal energy provider (Stadtwerke) of Mainz (Figure 7.21).

It consists of a wind farm comprising four wind turbines with a total power of 10 MW, three electrolysers with 2 MW power each (Figure 7.22) supplied by Siemens (1,000 Nm^3/h under a pressure of 35 bar), an ionic compressor from Linde and storage in two 82 m^3 tanks.

The hydrogen produced is either delivered by trailers or used by an on-site service station (Figure 7.23) or injected into the natural gas network.

Hydrogen (500 MWh in 2017) is also supplied to Greenpeace Energy, which delivers the “proWindgas” blend with up to 1% hydrogen mixed with natural gas.

Figure 7.19: Energiepark of Mainz (Energiepark Mainz).

Figure 7.20: Power-to-gas installation of the Energiepark in Mainz (Energiepark Mainz).

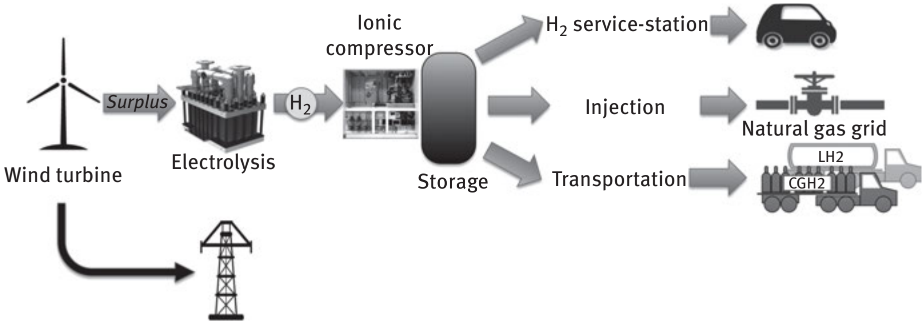

Figure 7.21: Concept of the Energiepark in Mainz.

Figure 7.22: Electrolysers (Energiepark Mainz).

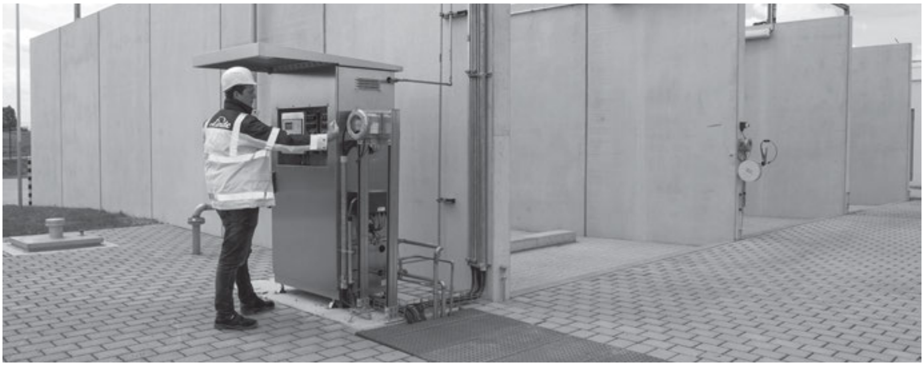

Figure 7.23: Hydrogen service station (Energiepark Mainz).

7.3.1.7 Audi "e-gas" project

The "e-gas" concept developed by the car manufacturer Audi, based on the work of the ZSW Institute in Stuttgart, was commissioned in 2014. It consists of a methanation unit built by ETOGAS (bought in 2017 by the Swiss company Hitachi Zosen Inova), already involved in the experimental project ZSW. It is located on the site of the biogas unit of EWE Energie AG in Werlte, Lower Saxony, which provides CO_2 for methanation (Figure 7.24).

Electricity is produced by four wind turbines of 3.6 MW each. The three alkaline electrolysers with a total power of 6 MW operate intermittently in case of excess electricity and can produce up to 1,300 Nm^3/h of hydrogen for a water consumption of 1.3 m^3. The heat from the electrolysers is recovered for the biogas unit (Figure 7.25).

After purification, compression and intermediate storage, hydrogen is used by the methanation unit (Figure 7.26), with a production capacity of 300 Nm^3/h and a methane concentration of more than 99%. The heat produced converts the cooling water into steam (250–300°C under 70 bar). The methanation unit is operational in less than 5 min.

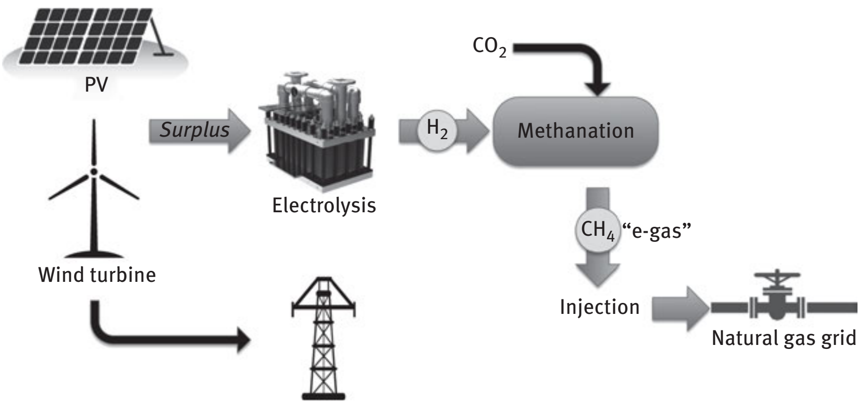

Figure 7.24: Audi e-gas concept.

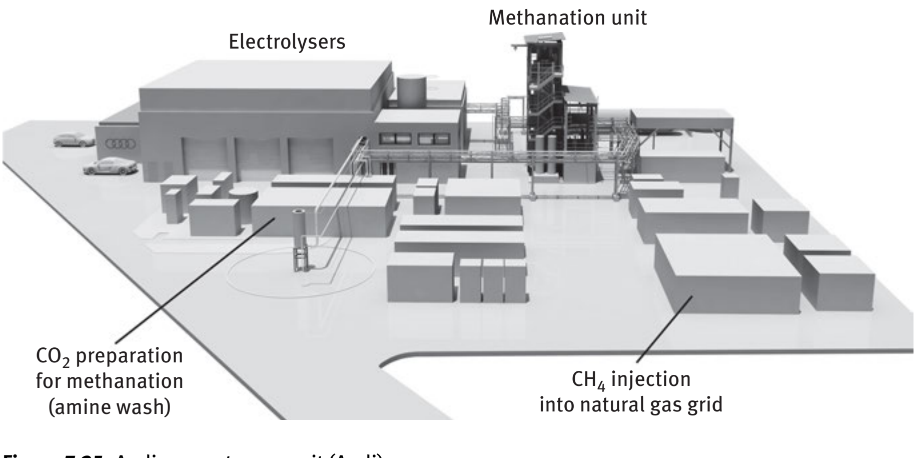

Figure 7.25: Audi power-to-gas unit (Audi).

Figure 7.26: Methanation unit (Audi).

Originally, a service station has been planned to deliver the methane produced directly on-site. However, Audi has focused on the use of hybrid vehicles Audi A3 or A4 g-tron bi-fuel running on gasoline or natural gas available at the 600 NGV service stations in Germany. A specific card system allowed payment and counting the volume of gas used. CO_2 emissions from these vehicles are then calculated on the basis of natural gas consumption by the vehicle and production by the P2G unit. The result is an average corrected emission of 20 g/km (well to wheel analysis) per vehicle, the annual methane production corresponding to the consumption of 1,500 vehicles travelling each 15,000 km (Figure 7.27).

7.3.1.8 CO2RRECT

This programme (CO_2 reaction using Renewable Energies and Catalytic Technologies), carried out by 15 industry, energy and research partners with a cost of 11 million euros, has been operational since 2013. It is conducted on the site of the electricity producer RWE in Niederaußem near Cologne.

A 300 kW electrolyser from Siemens produces hydrogen (50 Nm^3/h) used by a methanation unit. The required CO_2 is recovered from the fumes of a coal-fired power plant. Different catalysts for methanation are evaluated. A methanol production unit is also tested.

In the longer term (2020?), the production of polycarbonate or isocyanate (basis for polyurethane) could be considered without starting from petroleum products.

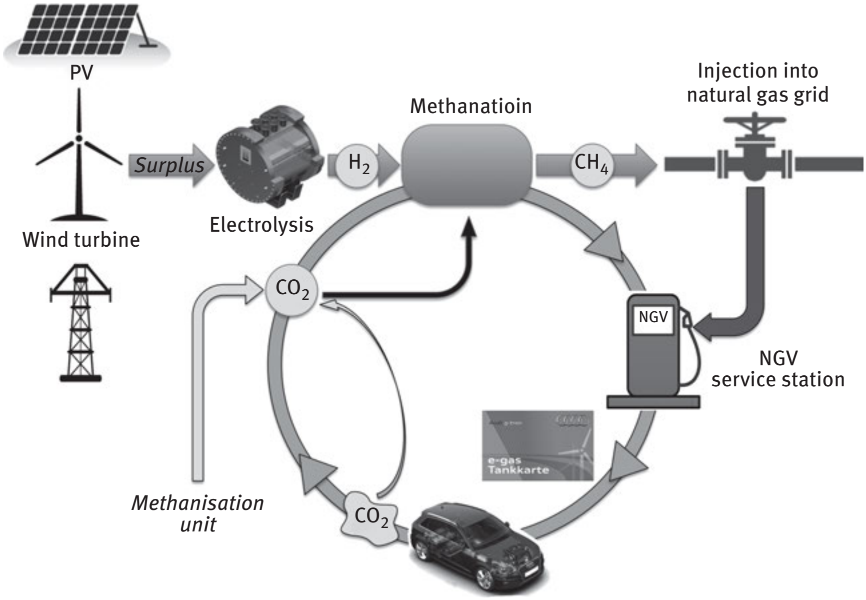

Figure 7.27: Compensation of CO_2 emissions by Audi NGV vehicles.

7.3.1.9 E.ON – Falkenhagen

E.ON, through its subsidiary E.ON Gas Storage in partnership with Swissgas, inaugurated in 2013 an installation in Falkenhagen ("WindGas" project) near Hamburg (Figures 7.28, 7.29 and 7.30).

It uses the excess electricity from a 400 MW wind farm and consists of:

– a series of six electrolysers from Hydrogenics with a power of 2 $MW_{el.}$ producing up to 360 Nm^3/h of hydrogen under 10 bar by consuming 288 L/h of water
– a hydrogen compressor (55 bar)
– a 1.6 km pipeline between the power-to-gas unit and the natural gas injection
– An injection unit into the natural gas network (up to 2% hydrogen under 55 bar)

The yield (electricity used/injection in the natural gas network) was 58% in 2015 and should be improved by exploiting the oxygen that is released into the atmosphere and the heat produced (e.g. adding one unit of methanation) and an increase in the concentration of hydrogen in natural gas.

Figure 7.28: Falkenhagen power-to-gas unit (E.ON).

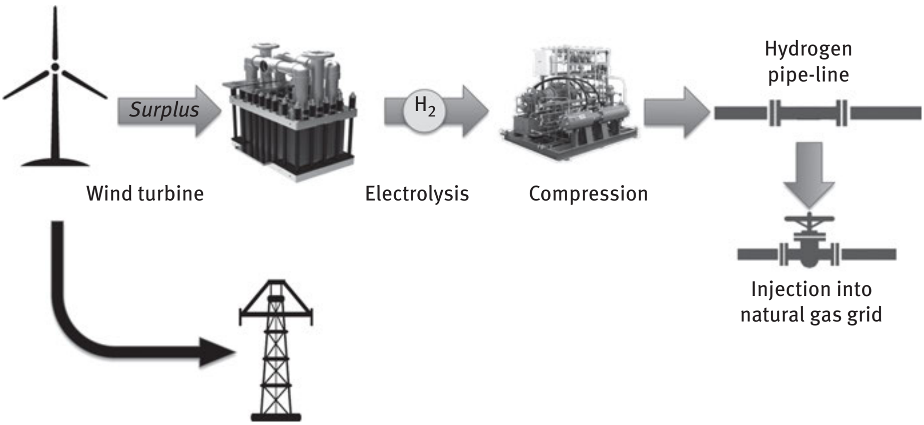

Figure 7.29: Concept of the Falkenhagen power-to-gas unit.

Another E.ON project, launched in 2014, still under the “WindGas” model, is located in Hamburg/Reitbrook and consists of a 1 $MW_{el.}$ PEM-type electrolyser supplied by Hydrogenics and producing 265 Nm^3/h of hydrogen which is injected into the natural gas network.

Figure 7.30: Electrolysers of the Falkenhagen power-to-gas unit (Hydrogenics Corp.).

7.3.1.10 Compact P2G unit

The German company Exytron has developed a compact P2G unit. A demonstrator (21 kW to 4 Nm^3/h electrolyser) was commissioned in Rostock in 2015. Field testing began in the late 2016 in the town of Alzey near Mannheim for a 37-housing residential unit (Figure 7.31).

The complete system (Figure 7.32) contains the alkaline electrolyser (62 kW–10 Nm^3/h) using a photovoltaic park of 125 kW, a methanation unit (2.5 Nm^3/h), condensing boilers, combined heat and power (CHP) unit, hot water storage and control unit.

Figure 7.31: Compact P2G unit (Exytron).

The houses will also be supplied with heat from district heating. When needed "green" electricity is provided by the grid.

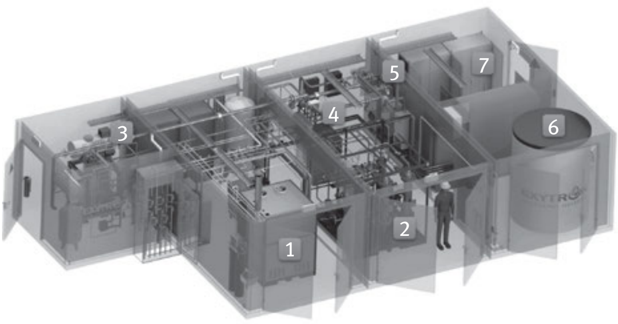

Figure 7.32: Complete system for the dwelling unit.

7.3.1.11 Other installations in Germany

Many research projects, sometimes with relatively high–power electrolysers, have been operational since 2012:

- BioCONNECT uses biological methanation (MicrobEnergy) with, in a second phase, recovery of CO_2 from a brewery
- Fraunhofer IWES in Bad Hersfeld (25 kW electrolyser) with thermochemical methanation and CO_2 from a biogas unit
- The BTU Cottbus hydrogen research institute with a 145 kW electrolyser
- Since 2015, RWE has been testing an experimental unit in Ibbenbüren. A 150 kW electrolyser can produce up to 30 Nm^3/h of hydrogen injected into the natural gas network

7.3.2 France

Paradoxically, while France still relies on nuclear power (which accounts for about 78% of electricity production in 2017), some innovative P2G projects have been carried out, are under way or planned.

7.3.2.1 MYRTE project

It is a research and feasibility project located in Corsica, in Vignola near Ajaccio (MYRTE – Mission hYdrogène Renouvelable pour l'inTégration au réseau Electrique

– *Renewable Hydrogen Mission for Integration into the Electrical Network*) with the objective to study the stabilisation of the electrical network (Figures 7.33 and 7.34).

At a cost of 21 million euros, the programme was launched in 2006 and led by the University of Corsica, the HELION company and the Commissariat à l'énergie atomique – Commission of nuclear energy. It was inaugurated in early 2012 (Figure 7.35). It consists of the following elements:

- A photovoltaic park of 550 kW
- A 200 kW electrolyser supplying hydrogen (40 Nm^3/h) at a pressure of 35 bar
- Storage units for hydrogen (four tanks) and oxygen (two tanks) under 35 bar, each tank having a capacity of 28 m^3
- Heat storage
- A PEMFC fuel cell of 200 kW

The aim of the project is to define strategies for the management and stabilisation of the electricity network (using the ORIENTE software – Optimization of Renewable Intermittent Energies with Hydrogen for Autonomous Electrification). The option studied is to smooth wind power production; another is to use the fuel cell to generate extra electricity in case of peak demand. The University of Corsica operates the facility and coordinates R&D activities.

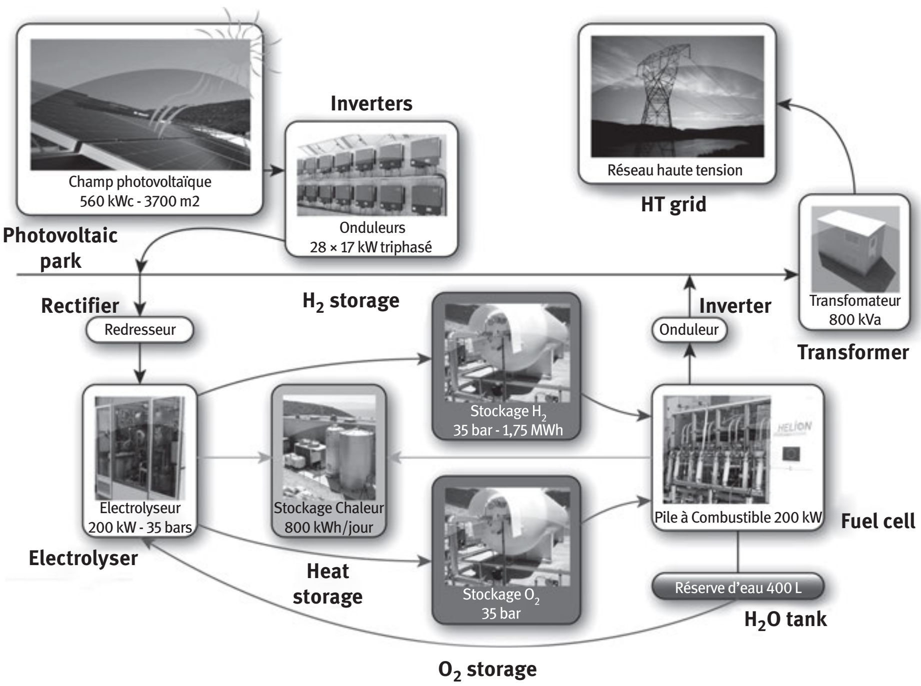

Figure 7.33: Project concept MYRTE (University of Corsica).

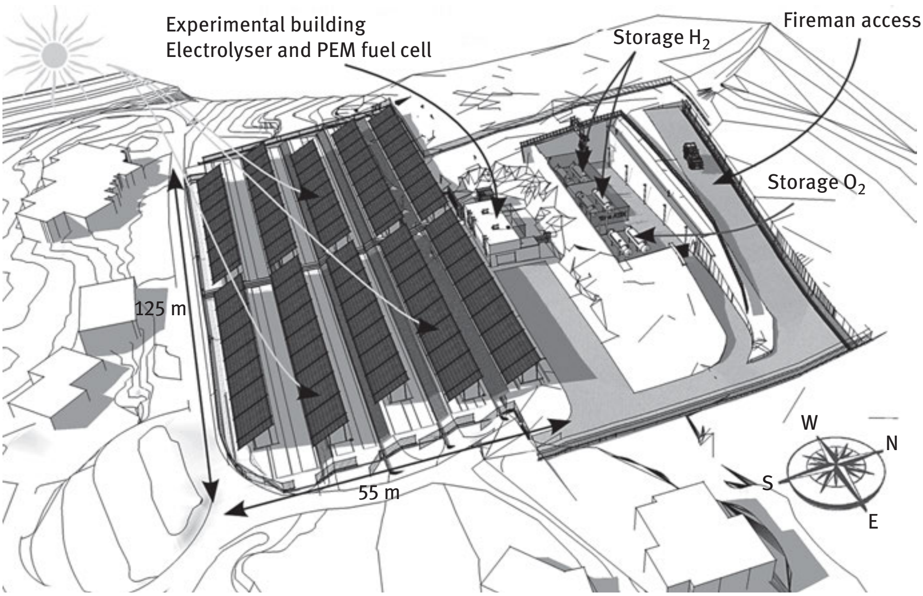

Figure 7.34: Schematic of the MYRTE project installation (University of Corsica).

Figure 7.35: MYRTE installation (University of Corsica).

7.3.2.2 GRHYD project

The GRHYD Demonstrator (Gestion des Réseaux par l'injection d'HYdrogène pour Décarboner les énergies – *Network management through hydrogen injection for decarbonising energy*) coordinated by energy provider Engie was launched at the end of 2013 and has two objectives:

– Injection of hydrogen produced by electrolysis into the local natural gas network
– Evaluation of hythane fuel, a mixture of hydrogen (6–20%) and natural gas for transport

It is implemented in the Dunkerque community, north of France. The required hydrogen is produced by electrolysis (PEM type electrolyser supplied by AREVA/CETH2), compressed and stored in metal hydrides (McPhy Energy).

The first part concerns a district of 200 low-energy dwellings delivered at the end of 2015 and which will be fuelled in 2018 by a mixture of natural gas and hydrogen (less than 20%) to cover heating, hot water and cooking needs.

The second part will involve a fleet of buses (initially at least 50 planned) originally using only natural gas. The service station will be installed at the depot of these buses. Hythane is delivered under a pressure of 200 bar to fill the tanks of the buses. It reduces emissions (CO, HC, NO_x) by up to 50% compared to the use of natural gas alone. This programme has been operational since early 2017.

7.3.2.3 Jupiter 1000 project

French gas grid operator GRTgaz coordinates the demonstration project (Figure 7.36) for methane production from surplus electricity, generated by four wind turbines (10 MW) and located on the industrial zone of Fos-sur-Mer (INNOVEX platform). The two evaluated electrolysers supplied by McPhy Energy (PEM and alkaline of 500 kW each) will produce up to 200 Nm^3/day of hydrogen which will be used partly for direct injection in the natural gas grid, and partly for methanation (25 Nm^3/day) whose equipment is supplied by the Atmostat company. CO_2 is captured from a close metallurgical plant. The methane produced will be also injected into the gas network. This project is expected to be operational by 2018.

7.3.2.4 Industrial hydrogen production units

The manufacturer of electrolysers NeL ASA has signed an agreement with the French company H2V PRODUCT for the supply of 40 alkaline units (100 MW) to be installed in Normandy. This project (2018–2020) will allow the hydrogen produced (100,000 tonnes/year when the facility will be fully operational) to be injected into the natural gas network, supplied for industry or used for methanation.

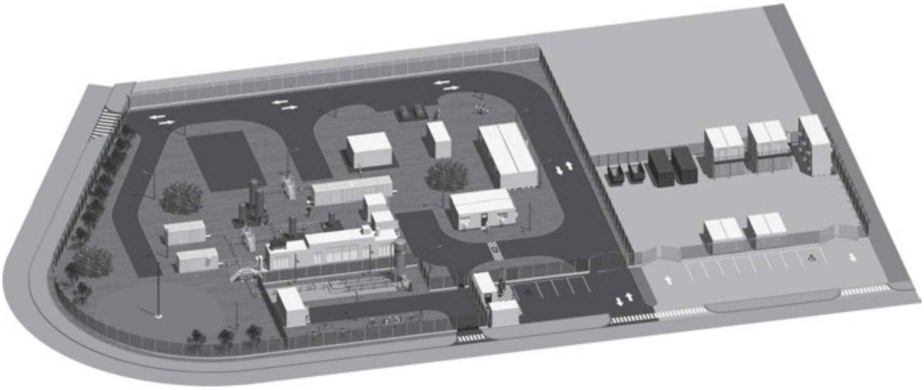

Figure 7.36: Layout of Jupiter 1000 power-to-gas installation.

In France, projects are still limited

MYRTE in Corsica, GRHYD, Jupiter 1000 and possibly the H2V PRODUCT in preparation are the only projects with an electrical power to exploit the results for larger P2G units. However, it is also not clear whether the projects will really use excess electricity. No other experimentation is envisaged, whereas ADEME and the association NEGAWATT, for example, have published studies on the possibility of increasing the proportion of renewable electricity by up to 100% in 2050 with large surplus production to manage.

7.3.3 Other countries

7.3.3.1 Denmark

As early as 2006, Denmark began studying the production of hydrogen from renewable electricity. The first operational system in 2007 consisted of two 4 kW PEM and two PEMFCs with 2 and 7.5 kW power. The oxygen and hydrogen produced were stored separately in two tanks (25 and 12.5 m^3) under low pressure. Hydrogen was used by fuel cells and oxygen by the wastewater treatment plant.

Experimentation at the level of a district began in 2007 in the locality of Vestenskov on the island of Lolland. An electrolyser used the electricity of a wind turbine and the hydrogen produced, after storage, was distributed through a specific network initially feeding five houses and then extended to 30 others. Low-power fuel cells installed in housings (PEMFC from the Danish company IRD) used directly pure hydrogen to produce electricity (0.9–2.0 kW) and heat (0.8–2.0 kW).

The “**BioCat**” project (P2G via Biological Catalysis), based on the transformation of hydrogen into methane using microorganisms in the presence of CO_2 has been launched in February 2013, and since April 2016 the installation in Avedøre is operational.

As part of the ForskEL project, two further pilot projects with 1,2 MW (PEM) to Hobro and 1 MW alkaline electrolysers are planned starting in 2017.

7.3.3.2 The Netherlands

A demonstrator has been tested in Rozenburg (part of the Rotterdam agglomeration) until 2015. It included an electrolyser and a methanation unit housed in two containers and a CO_2 storage unit for methanation.

The electricity was supplied by photovoltaic panels and by the grid if necessary. The installation included:

– A PEM-type electrolyser with a production capacity of 1.0 Nm^3/h of hydrogen (2.27 kg/day) under a pressure of 13.8 bar, with a yield of about 47%
– A drying unit (pressure swing adsorption)
– A methanation unit with four reactors with an overall efficiency of 73% (Figure 7.37)
– A chromatograph to measure the composition of the gas from the methanation unit and verify that it meets the standards for injection into the natural gas network

Figure 7.37: Demonstrator of Rozenburg (DNV GL).

Taking into account the initial checks, the electrolyser is operational after 4 min (hydrogen production). The methanation unit takes approximately 37 min before methane is supplied (Figures 7.38 and 7.39).

During this experiment, methane had to meet the following criteria:

– Wobbe index between 44.10 and 44.41 MJ/m^3
– Less than 0.5 mol% oxygen
– Less than 10.3 mol% CO
– Less than 0.1 mol% hydrogen

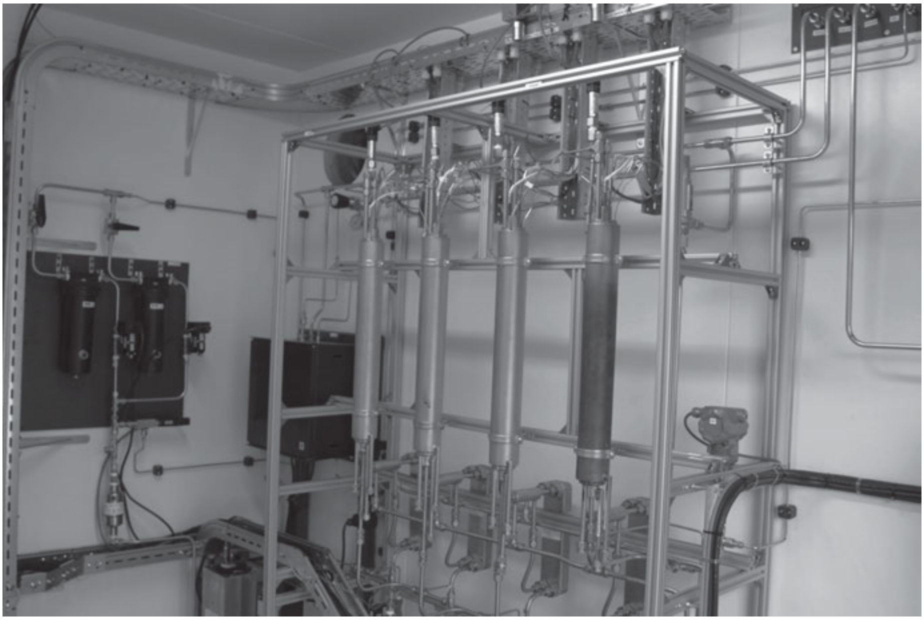

Figure 7.38: Methanation units (DNV GL).

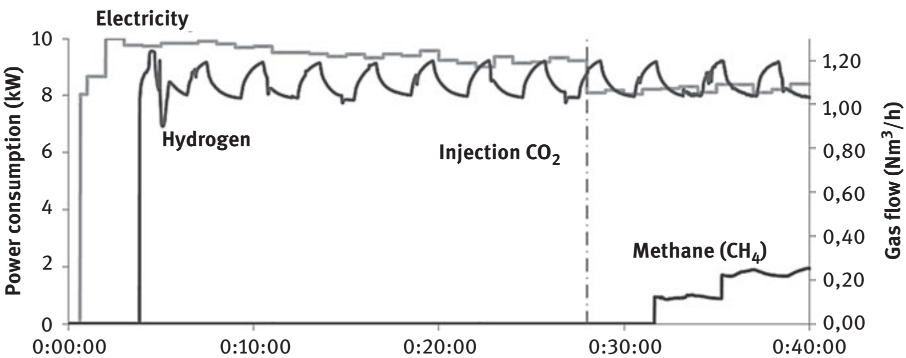

Figure 7.39: Starting time of the various processes (DNV GL).

A series of sensors checked the parameters and the injection could be stopped as soon as one of them did not meet the specified values. This experiment demonstrated the viability of the concept. Due to the small size of the plant, the yields (especially of the electrolyser) could be improved.

The other **Hystock** project was initiated in 2017 by Gasunie New Energy and Gasunie EnergyStock with a pilot unit consisting of a 1 MW electrolyser. The facility uses electricity from a photovoltaic plant with 5,000 modules and is located near the underground natural gas storage site in Zuidwending (Groningen province). The hydrogen produced will be compressed and stored in cylinders for use in transportation or industry.

7.3.3.3 The UK

In 2016, a project was started in Levenmouth (wind turbine of 750 kW, alkaline electrolyser of 30 kW, storage of 11 kg of hydrogen) with hydrogen used by a service station (vehicles with range extender) and for production of electricity and heat (10 kW fuel cell and hydrogen-fired boiler).

Another project in Aberdeen, Scotland (Aberdeen Hydrogen Bus Project) supplies a fleet of 10 hydrogen buses. The installation includes an alkaline electrolyser of 1 MW (20 kg/h of hydrogen), two compressors, storage under 500 bar and a filling station under 350 bar.

As part of the **HyDeploy** project launched in 2017 and funded by Ofgem (Office of Gas and Electricity Markets) and coordinated by National Grid, ITM Power will provide a 500 kW electrolyser to produce hydrogen that will be injected into the gas grid of the Keele University campus with nearly 340 residential, research or industrial buildings. Over a period of 3 years, the objective will be to achieve an injection rate of 20% by volume without change in equipment using natural gas and also to assess the perception of users with a view to generalisation of hydrogen injection.

7.3.3.4 The USA

The WIN2H2 project (2007–2010), managed by the NREL and Xcel Energy, was a first step towards the production of electricity and the use of hydrogen for transportation .

A P2G project (SoCalGas – Southern California Gas Company, NREL and Electrochaea) located in Golden, Colorado, has been scheduled from September 2014 to March 2016 in the NREL laboratories with a 150 kW electrolyser to produce hydrogen. CO_2 was transformed into methane through biological methanation. The gas produced was used in a fuel cell.

The University of California at Irvine, in association with Proton Onsite as supplier of an electrolyser, started a hydrogen production project in mid-2016. Since mid-2017, it is injected after compression into the university's natural gas grid and supplies the gas turbine producing electricity and heat.

In California, Hydrogenics and StratosFuel started the Zero Impact Production (ZIP) project in Palm Springs, California, in 2017. A 2.5 MW PEM electrolyser is expected to deliver hydrogen with a production capacity of 1,000 kg/day. Hydrogen will be used by StratosFuel for its service stations.

SoCalGas launched a demonstrator in early 2017, supported by the Department of Energy. It will be installed at the NREL Energy facility (Energy Systems Integration Facility) and will include a biological methanation facility.

7.3.3.5 Canada

In 2015, Glencore inaugurated a Mini Grid project for the Raglan nickel mine supplying the 25 kV local power grid. An alkaline electrolyser of 315 kW uses the electricity of a 3 MW wind turbine (the fluctuations are filtered by a flywheel) and supplies hydrogen stored under pressure in three tanks with a PEM fuel cell of 200 kW which supplement the battery storage (250 kW/250 kWh) or the diesel generator.

Enbridge Gas Distribution in partnership with Hydrogenics Corp. has conducted a project with a 2 MW electrolyser in Markham, Ontario, which was operational till mid-2017.

The Canadian Gas Association has initiated a joint P2G Task Force with the USA to examine guidelines for the blending of hydrogen into the natural gas distribution network of both countries.

7.3.3.6 Japan

The first P2G project of the New Energy & Industrial Technology Development Organization (NEDO), which began in 2015, is located in Kofu City, Yamanashi Prefecture, west of Tokyo. The electricity is produced by a 1 MW photovoltaic park, solar modules on the roof of the visitor centre and a hydropower generator. The excess electricity is used by an electrolyser from Kobelco Eco-Solutions Co. to produce hydrogen stored under pressure which powers a Panasonic Fuel Cell that compensates for the lack of electricity in the event of low solar production.

7.3.3.7 Switzerland

The Aarmat hybrid plant (Regio Energie Solothurn) operational since 2015 combines conventional units (natural gas-fired boiler and CHP, heat storage) with a P2G installation. A PEM electrolyser (350 kW) supplied by Proton Onsite produces up to 60 Nm^3/h hydrogen stored under 30 bar in tanks (180 m^3) and then injected into the natural gas grid. In the frame of the European projects “Horizon 2020” and “Store & Go”, a biological methanation unit is planned for 2018.

Other evaluations

Many other countries (Austria, Sweden, Greece, Spain, Thailand etc.) have evaluated, are running or planning P2G installations. Generally, these are often programmes involving universities or research centres that emphasise the demonstrating aspect.

7.4 Comparison of current projects

7.4.1 Technologies

The main sources of renewable electricity are either predominant wind, solar or a combination of both.

The alkaline electrolysers remain used although their efficiency is lower than the one of the PEM type. The advantage is lower cost and proven technology.

The hydrogen produced is generally stored, in a first step under a pressure not exceeding 250 bar. Most facilities use tanks, storage in hydrides being more expensive.

7.4.2 Applications

Considering the projects and demonstrators in Germany which are more representative, the applications can be divided into four categories (Table 7.3):
- Injection of hydrogen into the natural gas network
- Direct use for service stations
- Methanation (thermochemical or biological) and injection of methane into the natural gas network
- Conversion of hydrogen (or methane) into chemical compound or fuel (power-to-liquid).

Table 7.3: Data of some German projects.

Project	Electricity	Electrolyser	MW methanation	Use
Enertrag-Prenzlau	Wind	Alkaline	0.5	Injection, service station, CHP
RH2-WKA	Wind	Alkaline	1	Injection, CHP
Grapzow	Wind, PV	Alkaline	1	Injection, CHP
E.ON Falkenhagen	Wind	Alkaline	2	Injection
Audi e-gas	Wind, PV	Alkaline	6 biological	CH_4 injection
RWE Ibbenbüren	Wind, PV	PEM	0.1	Injection
Herten	Wind	PEM	0.15	Fuel cell
GPJOULE	Wind, PV	PEM	0.2	Injection, CHP
Thüga/Mainova	Wind, PV	PEM	0.4	Injection
E.ON Reitbrook	Wind	PEM	1.5	Injection
Energiepark Mainz	Wind	PEM	6	Injection, service station
CO2RRECT	Wind, PV	PEM	0.1 chemical	CH_4 injection
Viessmann-bioPower2Gas	Wind, PV	PEM	0.4 biological	Injection

7.5 Experimental results

The ongoing experiments that serve primarily to demonstrate the feasibility of this technology can only be considered currently as prototypes in terms of costs.

The key points of the installations for their exploitation are the commercialisation of hydrogen or methane produced or the (re)conversion of these gases into electricity.

The first experiments and results associated with P2G show the following average yields for each equipment:
- Alkaline electrolysis: 70–75%
- PEM electrolysis: ≥80%
- Methanation: ≥80%
- Methanation and heat recovery: ≥90%
- Electricity production (CHP or fuel cell): 35–50%
- Electricity production (CHP or fuel cell) and heat recovery: 80–85%

These results show the technical feasibility from the point of view of efficiency, especially if the heat produced during the different stages is valued (district heating, biogas plants, farms, greenhouses or industry).

A diversity of units in evaluation

High-power projects (>1 MW) under evaluation or planned represent the different approaches of the P2G concept. These solutions make it possible to evaluate the economic profitability and the technical feasibility of the possible alternatives.

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8 Financial approach to power-to-gas

8.1 Hydrogen conversion capacity

Given the electricity surplus expected in the coming decades, their storage and eventually their conversion to electricity will require equipment (especially electrolysers) of high power. It is in these areas that progress is expected in order to store the maximum of the surplus.

8.1.1 Capacity of electrolysers

In 2017, the maximum power of an electrolyser reaches 6 MW. For the electricity surpluses expected over the next few decades (Table 8.1), the power of the installed electrolysers should theoretically be able to cover the surplus peaks.

A 6 MW electrolyser only converts surplus electricity from a single 6 MW wind turbine operating at maximum power. If one considers a surplus of 1 TWh distributed over 5% of the year, i.e. 438 h, this corresponds to a surplus of average electricity production capacity of approximately 2,300 MW which should theoretically be converted in hydrogen by 380 electrolysers of 6 MW each. This figure is a minimum because the surpluses are not located in one place.

It is possible to consider units of higher power or a combination of less powerful units. In any case, to maximise the conversion of all the surplus electricity, the maximum power will have to be able to absorb the peaks of surpluses which can last only a few tens (or hundreds) of hours per year. The compromise to be found will be between the maximum power of the electrolysers and these peaks of surplus: recovering all surpluses will probably lead to a relatively low utilisation of the maximum capacity.

The capacity of the electrolyser must be capable to operate very quickly (within seconds) and should vary its power over a wide range (ideally between 0 and 100%), depending on fluctuations of excess electricity.

Table 8.1: Potential surplus of electricity from renewable sources.

Pays		Yearly surplus	
Germany	Excess en 2012	400 GWh	
	2020 scenario	25 TWh	
	2050 scenario	162 TWh	85% renewable
Denmark	2020 scenario	3 GWh	Over 350–450 h
USA	2050 scenario	110 TWh	Production capacity 1,450 GW

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8.1.2 Power-to-gas-to-power

This concept (or power-to-power) covers the production of electricity from hydrogen or methane produced by electrolysis. This production can be achieved by a fuel cell, a combined heat and power (CHP) unit or a gas-fired power plant.

8.1.2.1 Fuel cell power

In the context of power generation from hydrogen or methane from power-to-gas, it is possible to use fuel cells or modified CHP units to use these gases.

There are few manufacturers of high-power fuel cells greater than 100 kW (Table 8.2). In addition, molten carbonate fuel cell (Figure 8.1) or solid oxide fuel cells use generally hydrocarbons (natural gas or biogas).

Table 8.2: High-power fuel cells in 2017.

Supplier	Type	Power
FuelCell Energy, USA	MCFC	1.4 or 2.8 or 3.7 MW
UTC Power, USA	PAFC	400 kW
Bloom Energy, USA	SOFC	200 kW
Ballard, Canada	PEMFC	1 MW
Ned stack, Netherland	PEMFC	1 MW
Hydrogenics, Canada	PEMFC	1 MW

MCFC, molten carbonate fuel cell; PAFC phosphoric acid fuel cell, SOFC, solid oxide fuel cell; PEMFC, proton exchange membrane fuel cell.

Using methane from methanation decreases the overall yield. Only proton exchange membrane fuel cells with high power and high efficiency can use pure hydrogen.

8.1.2.2 CHP and conventional power stations

For CHP units, the maximum power is of the order of a few MW but the electrical efficiency is lower than for the fuel cells.

Gas–fired power plants are the only one with high power of up to several hundred MW and a high efficiency (60% for combined cycle gas turbine [CCGT] units).

The total yield, calculated from excess electricity generation, even if the one of fuel cells or gas-fired power stations may exceed 50%, is still low compared to the direct use of hydrogen or methane produced. Whatever the technology, heat recovery and its use increases the overall efficiency.

Electrolysers and fuel cells: a necessary compromise

If theoretically it would be desirable to recover all the surplus electricity, the ratio between the total power of the electrolysers and the peaks of surpluses will have to take into account the financial factors like the optimisation of the investments in relation to the valued electricity.

For the use of high-power fuel cells, a compromise must be found between the real need to produce electricity and the overall efficiency of this chain.

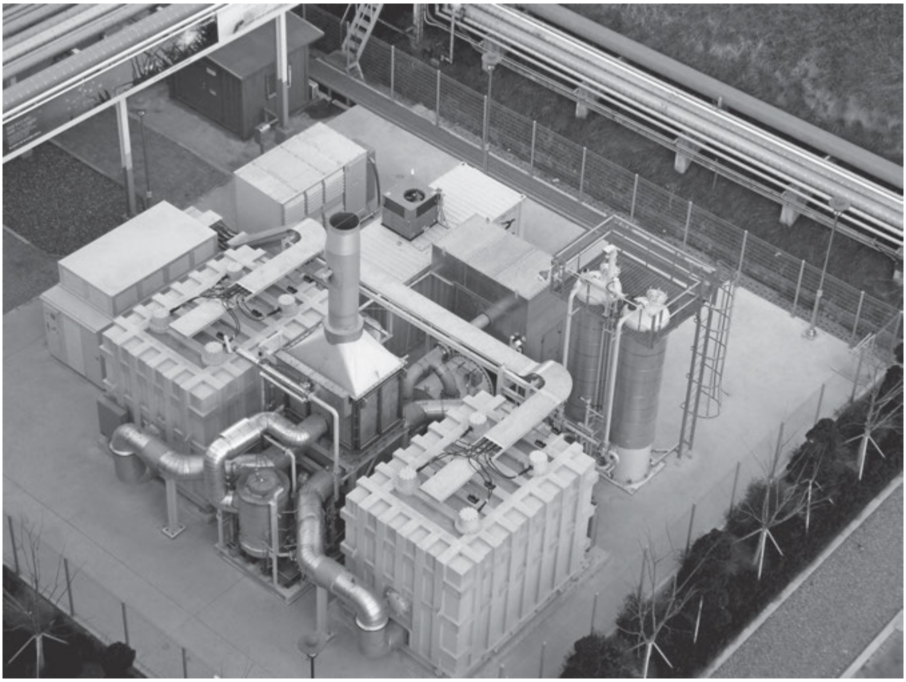

Figure 8.1: A 2.8 MW fuel cell with 2 1.4 MW modules (FuelCell Energy, Inc.).

8.2 Power-to-gas economic evaluations

Given the exploratory nature of existing facilities, it is difficult to give a cost that would be representative of mass production, such as wind turbines or photovoltaic panels currently. However, the cost of existing equipment gives an estimate of the financing needs of existing or planned projects in the short or medium term.

8.2.1 Cost of operational facilities

Some basic components such as compressors or fuel cells are already produced industrially, sometimes in small batches. On the other hand, high-power electrolysers or methanation units remain as prototypes or pre-series, the cost of which, often part of an evaluation programme, cannot yet be really estimated for future products.

8.2.1.1 Cost of an installation

An estimate made in 2013 for a unit of 5 MW (corresponding to the power of a single wind turbine) producing 1,000 Nm^3/h of hydrogen was carried out by the German organisation DBI GUT and gave values indicated in Table 8.3.

Table 8.3: Costs of a power-to-gas station (in million euros).

Electrolyser	5.0	
Compressor	0.3	
Buildings	1.4	
Storage	0.8	
Injection	0.2	Hydrogen injection into the natural gas network
Others	2.3	
TOTAL	10.0	

The electrolyser, the main element in the power-to-gas concept, accounted for about 50% of the cost of the station in this simulation. This trend is reflected in 2017.

8.2.1.2 Cost of pilot projects

Although the costs of projects carried out or in progress include investments that are unlikely to be necessary for an industrial installation, they nevertheless allow to give a range of investment (Table 8.4).

In the costs of these programmes (data from the different actors), all installed elements are taken into account, sometimes even wind turbines, fuel cells, CHP units etc.

Table 8.4: Overall costs of ongoing experiments.

Experimentation	Power	End product	Capacity	Global cost/euros
Enertrag	500 kW	Hydrogen production	120 Nm^3/h	21 million
Audi e–gas	6 MW	Methane production	1,300 Nm^3/h	20 million
Mainz	6 MW	Hydrogen production	735 Nm^3/h	17 million
E.ON Hamburg	1 MW	Hydrogen production	265 Nm^3/h	13.5 million
E.ON Falkenhagen	2 MW	Hydrogen production	360 Nm^3/h	5 million
Thüga–Frankfurt	320 kW	Hydrogen production	60 Nm^3/h	1.5 millions

Cost of series production

Facilities in service in 2017 can still be considered as pilot units to explore the different options and technologies available. As for solar photovoltaic or wind power, the development of high-power units and possibly the emergence of leaders in this sector (especially electrolysis and methanation) should allow a reduction in equipment costs.

8.3 Business model for power-to-gas

The profitability of a power-to-gas installation depends on many variables, both economic (electricity and equipment prices), technical (technologies used), strategic (which option to implement), legislation and subsidies. All these factors will influence the overall costs of this technology.

8.3.1 Analysed system

The economic analysis of a power-to-gas unit can be based on a three-part division (input, process and output) whose different components vary according to the technology and the objective: hydrogen, methane or electricity production (Figure 8.2).

The cost of a specific system should consider:

- Price of electrolyser, depending on the technology (alkaline, PEM or solid oxide electrolyte cell [SOEC])
- Price of compressor(s) if needed
- Price if hydrogen storage unit if needed
- Price of methanation unit production of methane is considered
- Price of injection unit (hydrogen or methane) if needed
- Price of transportation (trailers) if needed
- Price of infrastructure (buildings, piping, cabling, electronics etc.).

The return on investment should be also related to the consumable (electricity, water, CO_2, complementary heat) and operational costs (OPEX) and to the market price of hydrogen or methane for the users.

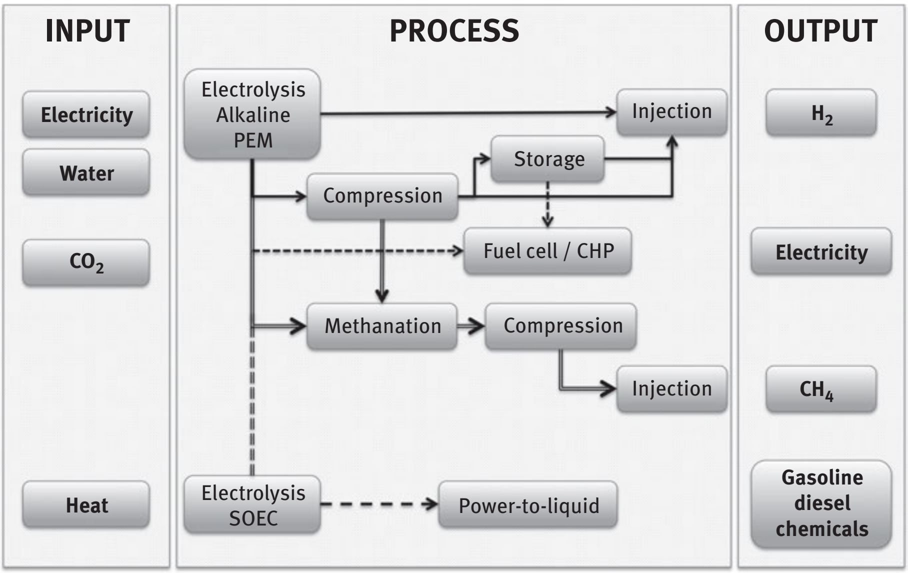

Figure 8.2: Potential systems for the power-to-gas approach.

8.3.2 Technical and economical analysis

The economic viability of a power-to-gas unit should be analysed considering the capital (CAPEX – CAPital EXpenditure) and operational (OPEX – OPerational EXpenditure) expenditures. As of 2017, the cost calculations for existing or future installations or projects vary from one unit or from one source to another depending on the assumptions for the costs of input, process and output considered.

8.3.2.1 Levelised cost of electricity

Levelised cost of electricity (LCOE) represents the cost of generating electricity according to the technology used, allowing a cost comparison. The essential elements are the costs of the equipment, operation and maintenance as well as the annual operating time. Fuel costs (for conventional power plants: natural gas, fuel oil or coal) are zero for solar and wind.

In the electricity markets, the price of MWh fluctuates according to production and demand. On average, around 35–40 €/MWh in Europe in 2016 (EPEX SPOT), variations are important (see Figure 1.19) both between countries [**1**] and weather conditions (high wind and solar production) like low (use of electric heating) or high (use of air-conditioning) temperatures.

While overall average electricity prices show a gradual downward trend, renewable sources are approaching conventional ones. A projection by the US Energy Information Administration [**2**] for 2022 gives an advantage to photovoltaic (US$ 85 MWh) and onshore wind power (US$ 63.7 MWh) compared to other conventional electricity sources. Only CCGT natural gas-fired plants would offer a better cost (about US$ 57 MWh).

For power-to-gas the price of electricity will fluctuate significantly and may even be negative (e.g. see Figure 1.20, and the occurrences in May 2015 with 15 consecutive hours and in March 2016 for Germany not counting other countries such as Austria) which will influence the profitability of the installations.

8.3.2.2 Grid parity

The comparison of the grid electricity price (depending on the country, mainly nuclear, coal or hydraulic) with that from renewable sources, without subsidies gives an indication of the cost evolution.

For some countries, this parity (renewable price ≤ grid price) is reached or close for photovoltaic or even wind power. Evolution has been fast as since a 2013 study by the Fraunhofer Institute for Solar Energy Systems gave for Germany an LCOE for coal and natural gas lower than photovoltaic and wind power [**3**].

In 2016, the Spanish government awarded 300 MW of onshore wind to the company Forestalia which proposed the grid price as basis, and an invitation to tender from Germany in 2017 for an offshore wind farm (“He Dreiht”) of 900 MW in the North Sea was won by the energy supplier EnBW without any subsidy.

8.3.2.3 Electricity price for power-to-gas technology

As the electricity used by the power-to-gas units is the one in excess, the cost per kWh vary in a very wide window and could be even negative in some cases. Power-to-gas units can also negotiate guaranteed low prices insofar as they offer an alternative to the disconnection of photovoltaic or wind farms in the event of overproduction.

Cost of other inputs

The cost of consumables includes the water and carbon dioxide. The cost of water can be considered as negligible compared with that of electricity, and the same may be applied to today's carbon dioxide price (however depending on the carbon market price evolution) and the heat needed by the SOEC electrolysers.

8.3.3 CAPEX

Depending on the followed path, the investment of power-to-gas plant consists mainly of electrolysis, methanation, hydrogen storage, compression, injection into natural gas network. In addition, the costs of real estate and investments and other auxiliary devices such as pipelines and gas conditioners contribute to the total CAPEX. For hydrogen injection in the natural gas network, the CAPEX is determined by the costs of the different components needed:

$$\text{CAPEX} = \Sigma \text{ costs (electrolyser + injection unit + infrastructure + [storage/compression])}$$

Here infrastructure covers costs of building, piping, electronics etc. and storage or compression, depending on the characteristics of the electrolyser (output pressure) and the production capacity versus injection rate for an eventual storage.

The main cost contributor is the **electrolyser** with a range of 800–3,000 €/kW in 2017, depending on the power and the technology, PEM being still more expensive than alkaline. However, with the extension of the power-to-gas technology, a decrease in prices is to be expected from about 1.5 million euros in 2017 to 0.55 in 2030 for a 1 MW PEM electrolyser.

For hydrogen **injection** into the natural gas network, the costs (compression and injection unit) are estimated to about 0.5 million euros in 2017.

The electrolyser operating continuously as long as excess renewable electricity is available, a buffer **storage** is sometimes necessary. Storage pressure depends on the output pressure from the electrolyser and/or on the next step (injection into the natural gas network requires a lower final pressure than storage in a trailer or for transportation) and has an influence on compressor cost.

Very few data are available for costs of **methanation** unit as the existing are demonstrators. However, it seems that biological methanation should be less expensive than thermochemical. Study [**4**] reports costs between 130 and 400 €/kw depending on the size of the unit.

The **delivery** of compressed hydrogen if not used on-site will require a trailer.

8.3.4 OPEX

The main cost of producing hydrogen is the one of electricity. Two different ways of electricity purchase can be considered: on the spot market and through a long-term contract from a renewable energy producer (wind or solar).

The other influencing factors are:
- electricity consumption
- consumables (water, carbon dioxide etc.)
- labour cost
- depreciation and replacement
- other OPEX related to auxiliary equipment (storage etc.)

All of them depend on the capacity of the power-to-gas unit, the annual running time, the amortisation scheme and duration.

Usually the OPEX is estimated for a specified power of electrolyser and amortisation time. The Fuel Cell and Hydrogen Joint Undertaking has calculated it as about 10% for a 10 MW system (alkaline electrolyser) and 20 years lifetime [**5**].

8.3.5 Revenues

The operation of a power-to-gas unit derives its revenues from the sale of hydrogen or methane produced and eventually electricity (power-to-gas-to-power [P2G2P]). The oxygen and the heat produced can also be used for other processes.

The injection of hydrogen or methane gives advantages to the electricity grid (less "losses" of renewable electricity, stabilisation of networks etc.). For this reason, at least for a first phase, methane injection should benefit from a special tariff as the production costs (US$ 0.1–0.5 kWh depending on the assumptions) are expected to remain higher than natural gas costs (US$ 0.02–0.03 kWh).

For industry, the price of methane or hydrogen produced does not have any real added value other than their purity which may be an important factor in some fields. In this case, hydrogen or methane produced should not be injected into the grid but follow a separate marketing circuit.

8.3.6 Levelised cost of hydrogen

For hydrogen, the current price for the industry is that of the market (*merchant hydrogen*) produced by reforming and not used by large consumer (petrochemical industry, ammonia production etc.). Other applications envisaged for hydrogen such as industries needing high purity or eventually transportation (fuel cell electric vehicle), although these represent a small market, may require a different pricing.

In 2008, Europe (HyWays programme) estimated the price evolution (Table 8.5) of hydrogen for the end-user.

This is in agreement with the ITM Power company giving the cost of hydrogen in 2015 between £ 3.88 and £ 10.71 depending on the price of electricity (4–8 p/kWh) and the amortisation time (20 or 5 years).

The price of hydrogen will also depend on the operating time of the power-to-gas unit (Figure 8.3) and the capacity used. At low capacity, depreciation will be low and at high capacity, the cost of electricity that will not necessarily be in excess will be higher.

Table 8.5: Evolution of hydrogen price (Data: Hyways).

	2010	2015	2025
€/kg H_2	16.60	9.90	5.50

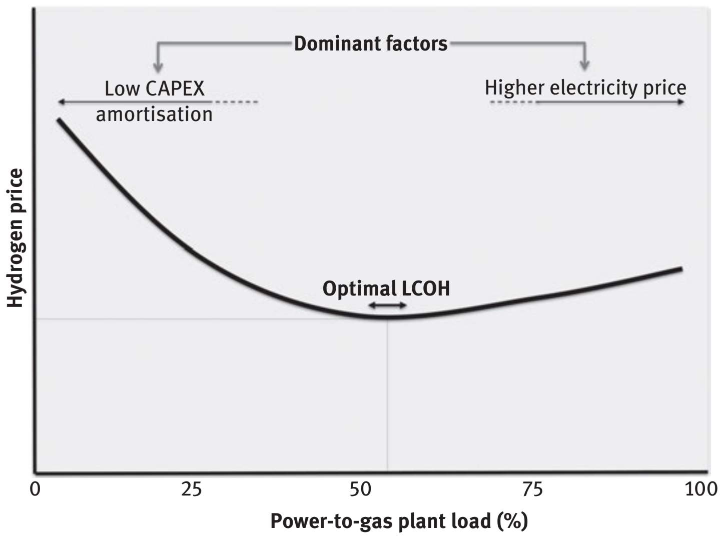

Figure 8.3: Hydrogen prices as a function of the duration of the electrolyser operation.

8.3.7 Comparative studies

Numerous studies have tried to estimate the cost of the power-to-gas technology depending on the selected option. The starting assumptions vary from a source to another as the equipments are not produced in large series.

The ENEA Consulting company published in a 2016 study [**6**] estimations for 2015, 2030 and 2050 of the CAPEX and OPEX for different options (injection, methanation etc.) and for 1 and 10 MW including all process steps. Table 8.6 gives a summary (rounded values) of the two options.

HyWays, The European Hydrogen Roadmap Project co-funded by the European Commission within the Seventh Framework Programme [**7**] estimated the CAPEX and OPEX for PEM and alkaline electrolysers but also for chemical and biological methanation (2 MW units) for different capacities (Table 8.7).

The Dutch ECN and DNV GL Institutes have developed a calculation model (OPERA – Option Portfolio for Emissions Reduction Assessment) for the TKI gas project [**8**]. It is a technology model that determines which configuration and operation of the energy system combined with other sources of emissions meets all requirements at minimal costs, helping to draw a power-to-gas roadmap.

All these studies, even if they sometimes diverge on cost calculated, are in line with various trends: strong influence of unit power, lower costs of PEM electrolysers and competitiveness of the P2G2P option at high electricity demand.

Table 8.6: Total CAPEX in euros/kW (Data: ENEA Consulting).

Process/Power	2015	2030	2050
H_2 injection/1 MW	3,300	2,500	2,100
H_2 injection/10 MW	1,700	1,400	970
Methanation/10 MW	3,100	2,300	1,600

Table 8.7: Costs estimations for 2050 (Data: HyWays).

Process	Alkaline electrolyser	PEM electrolyser	Chemical methanation	Biological methanation
Costs	800–1,500 €/kW	2,000–6,000 €/kW	1,200 €/kW CH_4	900 €/kW CH_4

8.3.8 Comparison with other technologies

Different technologies are available for electricity storage. Their application will depend on the defined use which could be grid stability, surplus storage, time shifting, resiliency (backup or reserve) etc. Pumped hydrostorage, compressed air energy storage, batteries (conventional where lithium technology is dominating, redox-flow, NaS) or flywheels are the current options.

To compare the costs of storage, the common metrics used are the investment costs and the LCOS (Levelised Cost Of Storage) covering the operations and maintenance during the lifetime of the installation.

From the numerous studies [**9**–**11**], most of the technologies like batteries or power-to-gas will see a decrease in the LCOS following the increase in manufacturing capacity. Power-to-gas "storage" (hydrogen injection) is estimated to be equivalent to lithium batteries by 2030, the LCOS being influenced by the storage capacity, the lifetime of the equipment, the cycling (operating days or hours/year) and the type of use (Table 8.8).

The increasing and sustained growth of renewable electricity will accelerate the adoption of storage technologies. The available ones are not necessarily competing but complementary. Power-to-gas keeps, however, an advantage over the other technologies for the (almost) unlimited capacity storage and the numerous possibilities for the use of hydrogen produced.

Table 8.8: LCOS in US$/MWh.

Technology	2015	2030
Pumped hydrostorage	150–300	100–300
Lithium batteries	300–800	150–200
P2G with alkaline electrolyser	400	200

8.3.9 Energy mix and the cost for society

Power-to-gas technology is only a brick in the energy system. It cannot be considered as independent factor but its development will allow policy makers to integrate it and include it in the energy transition strategy.

The Siemens Company extended the LCOE-only approach [**12**] to the new opportunities offered by the development of the wind onshore or offshore power generation to the "SCOE – Society's costs of electricity" concept which is based on a decentralised grid and on gas power plants as backup. The small size and the expected extension of the large-scale manufacturing makes local production easier.

This approach could be extended to photovoltaic power generation and power-to-gas with methanation which can at the same time "store" the excess electricity and allow the later use of methane by gas power plants.

Power-to-gas financial approach and sustainability

The necessary investments to increase the renewable electricity ratio (up to 50%, 80% or even 100%) will include the storage of surplus electricity. The power-to-gas technology could absorb the expected large surpluses. The profitability is not reached yet but the costs (CAPEX and OPEX) will decrease due to the production of equipment in series and the increase of the overall yields. Before reaching this critical stage, an intermediate step through government support and a specific policy will be needed to put this technology on a path of profitability.

Currently, the main economic value of power-to-gas technology is the production of hydrogen or methane. However, the real benefits to the energy system are the development of local solutions (decentralised grids), avoiding costs of extension of electricity infrastructure (transmission over long distances), often promoted by governments or energy companies, and extending the use of the existing gas network.

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9 Role of power-to-gas in energy transition

Global world energy consumption is rising. Fossil fuels, in addition to their depletion, result in greenhouse gas emissions and direct or indirect pollution, as well as, for some countries, a significant dependency on imports.

The strong development expected of renewable electricity (mainly solar photovoltaic and wind) will lead to surplus production during favourable weather conditions. The management of these surpluses of the order of several TWh the incoming decades will require new approaches, of which power-to-gas will be the most important element to valorise such quantities of potentially "lost" electricity.

9.1 Impact of power-to-gas on energy systems

The power-to-gas concept goes beyond the national framework. For a multi–state solution, harmonisation of the various national regulations is necessary in order to facilitate the approval of installations as well as the production, storage or use of hydrogen and injection into the gas network natural.

9.1.1 Legislation and regulations

9.1.1.1 Energy policy targets

The implementation of power-to-hydrogen can help address a variety of climate and energy-related objectives:
- Reduction of greenhouse gas emissions
- Increase of the share of renewable energies
- Reduce energy consumption by moving to more energy-efficient vehicles

The different strategies defined by many countries for an energy transition are often part of a series of regulations concerning energy, transportation, housing, industry or agriculture.

The development of the power-to-gas technology will influence many sectors of the economy and should be integrated in the regulatory and legislative framework. Its specific contribution (decarbonisation, energy efficiency, energy storage etc.) and added value needs specific incentives like:
- Subsidies for electricity used for hydrogen or methane production (reduction of electricity losses when over-production)
- Feed-in tariff for hydrogen or methane produced and injected in the natural gas grid

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– Subsidies for storage of electricity as hydrogen or methane
– Subsidies for local production and direct use by consumers (scheme existing for photovoltaic in some countries)

Legislations should follow the same pattern by removing barriers hindering the use or extension of power-to-gas like increasing gas storage capacity or recognising indirect electricity storage as gas, specifying a percentage of hydrogen in the natural gas network based on ongoing experimentations etc. The implementation of results of projects like CertifHy (Definition of Green Hydrogen), HyReady (Preparing Natural Gas Networks for Hydrogen Injection) or the standardisation of systems and devices for the production, storage, transport, measurement and use of hydrogen through ISO, CENELEC should also facilitate the penetration of power-to-gas technology.

9.1.2 A new architecture for energy networks

9.1.2.1 A separation between production, transmission and distribution of electricity

A decentralised approach should encourage local experiments carried out by other entities (municipalities, communities, alternative energy providers etc.). A separation of production, transmission and distribution can only be favourable to a competitive market with all producers considered as equal for access to the electricity or gas grid.

In many countries, several electricity or gas producers and operators of transmission/distribution networks or local actors are active, while in others like in France, for example, a situation of a de facto monopoly exists (the energy producer EDF manages the transmission and distribution through its subsidiaries RTE and ENEDIS) causing a distortion of the market.

9.1.3 Need for decentralisation

The centralised approach that still characterises the strategies of many producers and suppliers of energy (electricity or gas) runs against the evolution of electricity generation, which is increasingly decentralised: wind farms or photovoltaic installations scattered throughout the territory, combined heat and power (CHP) units of all sizes etc.

Distributed generation can be characterised by:
– local production or storage of electricity
– locating near or at load centres
– grid connected or isolated
– automated grid management

The power-to-gas technology can be integrated in such a scheme through local production of hydrogen or methane as well as a local use or if necessary injection of the surplus not used into the natural gas network.

9.1.3.1 Microgrid

Local electricity management should allow a better optimisation of production/consumption flows. The gains expected from this approach include short–distance transmission (less losses), reduced transmission or distribution line loads, local network stability easier to manage than large networks and economic value by avoiding the construction of new transmission lines.

Depending on the size of these local networks, as microgrid covering a street or as mini grid for larger areas or small agglomeration, local production and consumption must allow for appropriation by users. A local power-to-gas unit, possibly coupled with a biogas unit, would first feed the nearby users (hydrogen, methane, electricity and heat) and the surplus could either be stored or injected into the electricity or natural gas grid. The power-to-heat approach could complement the microgrid. A microgrid also requires a control and communication infrastructure in order to dispatch and store locally the energies produced and only after injecting them into the respective networks.

Experimentation of a microgrid with storage in Germany

The "Strombank" (power bank) project in Mannheim, Germany, conducted between 2014 and 2016 tested a microgrid based on photovoltaic electricity generation or micro-CHP and involved 18 participants (14 dwellings and 4 tertiary activities). Storage was provided by batteries (100 kW/100 kWh) and each user had an "account" where he/she could store his/her surplus electricity and use it later. If the account was empty, it was possible to "purchase" virtually electricity from other participants. With this approach, self-consumption increased from 30% to 60–80%.

The use of a small power-to-gas unit would have made it possible to switch to an electricity and gas microgrid.

Many evaluations of urban microgrids [**1**] are under way, particularly in the USA and Japan, to ensure, among others, security of supply and stability of the local network.

9.1.3.2 Virtual power plant

This concept, based on the convergence of micro- or minigrids, covers the management of a set of power and heat generation units forming a network and spreading over a territory (district, agglomeration) in order to optimise production and local consumption, the whole being managed as a single central (virtual) unit (Figure 9.1).

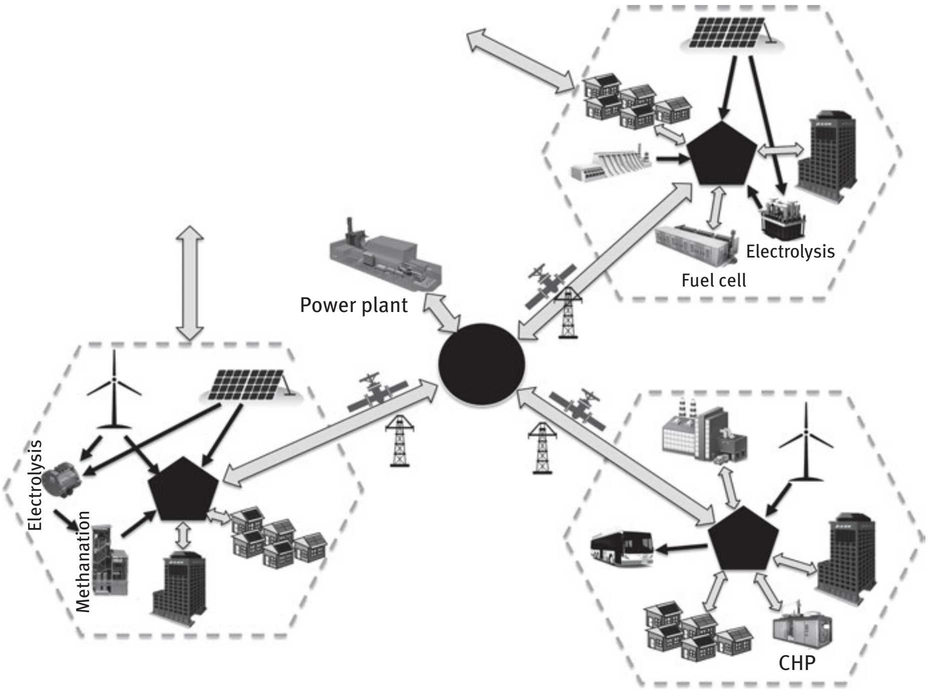

Figure 9.1: Local virtual power plant.

The management of the different units (start-up, power to be delivered etc.) allows an optimal use of available resources, whatever the type of energy available: renewable (wind, photovoltaic, small hydro) or non-renewable (natural gas). Local management can also be extended over time with local storage controlled by production and consumption forecasts.

The overall optimised domestic approach to energy should be based on the smallest unit, a **Smart Home**, where some appliances can communicate bi-directionally with the **Smart Meter** and others are optimised for low power consumption (e.g. lighting with the presence of detector, shutters or blinds controlled by brightness and outside temperature). This management can only be done if the price of electricity to the consumer is updated at a frequency sufficient to reflect the price on the electricity exchange market. In this way, a low price of kWh would lead to the start of domestic appliances (**Smart Appliances**) having a high consumption (washing machine, dishwasher etc.), which can be controlled by the Smart Meter. Consumer awareness would be possible if the consumer can check easily this information on display screen or smartphone, for example.

9.1.3.3 Smart Grid

It refers to the integration of information technology (IT) (sensors, communication, monitoring, control) into the power grid. It is supposed to deliver efficiently sustainable, economic and secure electricity. All users and equipment connected to this grid and the bidirectional flow of electricity and information could be managed in real–time.

The Smart Grid is only “intelligent” through the software structure for meeting user demand, managing energy from any source including solar and wind, avoiding system overload and working autonomously when needed.

From the last years’ experiments, it appears that many challenges remain to be overcome:
- Definition of a common standard for all involved equipment
- Management of a very large data flow collected
- Real-time electricity prices (dynamic pricing)
- Availability of appliances with standard communication protocol
- Vulnerability of the infrastructure (hacking, manipulation)
- Heavy IT infrastructure requiring high-level expertise
- Electricity consumption of the Smart Grid infrastructure itself
- Overall cost of deployment of Smart Grid structure

Although Smart Grid evaluations have been conducted in some countries (France, Germany, UK, Spain, Japan, USA etc.) and are the subject of many laboratory studies [**2**], it is not clear whether the benefits will cover the installation and running costs of the current projects.

In 2006, the European investments in Smart Grids were 505 million euros in France (37 million euros for GreenLys, 28 million euros for Smart Grid Vendée), 490 in the UK, 360 in Germany and 355 in Spain.

However, the principle of the Smart Grid is to provide a decentralised, autonomous, and intelligent energy management system but it is still often planned or conducted by the large energy suppliers in a top-down and still locally centralised approach.

Data protection and network security

The technologies described allow operators to collect very detailed consumer data (high-frequency data transmission) which would allow to know the habits of each user. Data mining could, for example, allow this data to be used for targeted marketing strategies.

A regulation of the rights of users to manage the use of generated data must be part of the data protection approach. The European Commission has launched a regulatory approach.

The connectivity envisaged also opens the door to hacker’s attacks of these networks. The numerous examples of pirated equipment, companies or organisations show that absolute protection is non-existent.

9.1.3.4 Blockchain technology and power-to-gas

The blockchain, often associated with the bitcoin, a virtual cryptocurrency invented in 2008, is an approach that can be applied in many sectors including energy.

The basis of blockchain technology is a direct digital transaction ("Smart Contracts") between two actors where the data, gathered in a block, are secured (validation, transmission and storage) using a peer-to-peer network involving all users of the network. This transaction is finally integrated with the others in a chain (blockchain) and retained by all users. Compared to traditional transactions, the blockchain makes it possible to avoid any intermediary, especially if a cryptocurrency (bitcoin, ether) is used (Figure 9.2).

Applied to electricity, for example, salesperson (producer) and user each having an account on the same platform could agree on a volume of exchange and on price. This transaction, which can be immediate or linked to certain criteria, then passes into the blockchain process to be validated.

Current experiments in the field of energy cover only certain aspects of the blockchain as there is always still one or more intermediaries involved:

In New York, TransActive Grid connects two electricity producers (solar photovoltaic) and 13 buyers in the same street. Each producer distributes the amount of electricity available. The transaction is then done by exchanging tokens.

In South Africa, the Bankymoon project, based on a prepaid Smart Meter, uses the bitcoin. Each counter is linked to a digital account credited to each payment of the user who pays according to his means. The suppliers are thus assured of payment, weak point in South Africa. Bankymoon also targets schools that require reliable electricity supply through a system allowing any person or company in the world to effect a donation in bitcoin.

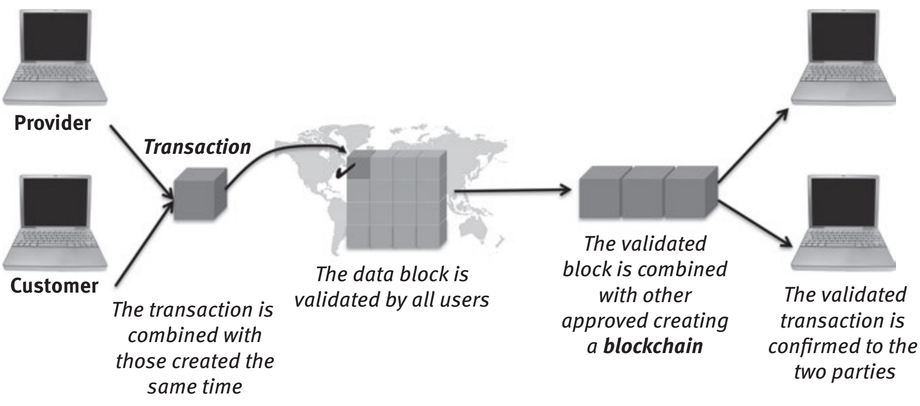

Figure 9.2: Blockchain principle.

In Germany, the BlockCharge project from the RWE Innovation Hub aims at simplifying the payment of electric vehicle loads by developing a direct Smart Contract between the electricity supplier and the user via a special Smartplug for all terminals.

Peer-to-peer digital transactions can lead to drift in terms of Smart Contracts (consumer rights, litigation management etc.) or in their implementation, hence the need for a regulatory authority. While all aspects of the transaction are carried out via the Internet, it remains that electricity, for example, needs a physical transportation and distribution network where other external actors intervene. Moreover, the financial part, if it is not done in a cryptocurrency (the Bitcoin has a very variable exchange rate vs. euro or US$) must also involve a banking institution. We are therefore still far from a real peer-to-peer direct transaction that was the heart of the blockchain and that would be applicable to a microgrid. The main advantage that the major players in the world of energy currently see in the blockchain is simplified and, in principle, secures transactions and accounting (Smart Contracts) (Figure 9.3).

Blockchain technology can be used to control electrical networks via Smart Contracts. Depending on the conditions of the transactions, they automatically manage production, sale or storage ensuring a balance between supply and demand. In case of surplus production, the surplus is automatically stored by other entities (this storage can also be the subject of a Smart Contract) and if the demand exceeds production the stored electricity is used which can also be part of another Smart Contract.

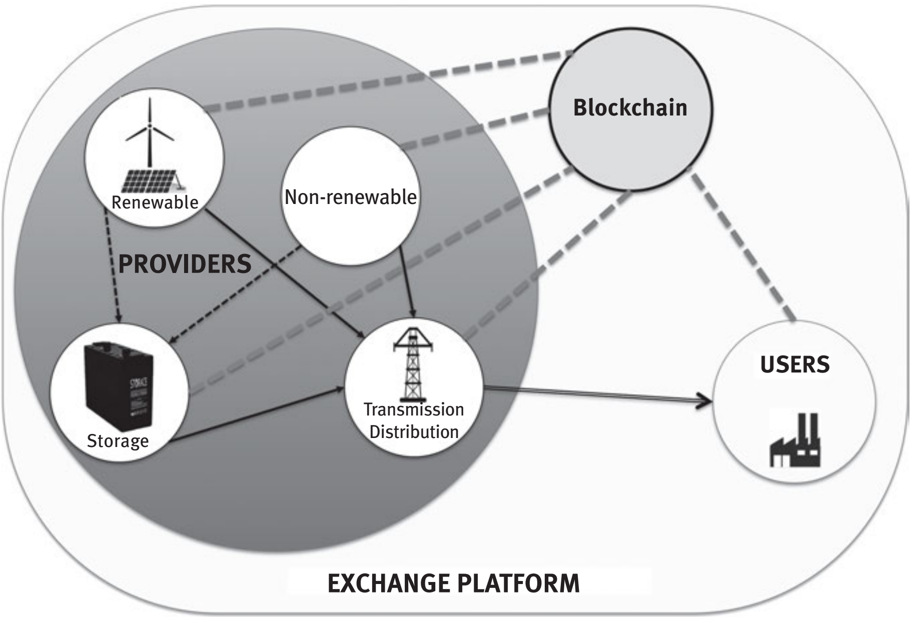

Figure 9.3: Blockchain principle applied to the electric grid.

Other than executing energy transactions, the blockchain can provide documentation of ownership, asset management, guarantees of origin of electricity or green certificates.

9.1.4 Convergence of electricity and gas grids – sector coupling

If the power-to-gas main value is to "recover" surplus electricity, the resulting output (hydrogen or methane production) can be integrated into the natural gas network. So far the two grids were using two different sources and were separated. The coupling of these two networks (electricity and natural gas) is a key technology for an energy network characterised by a high volume of intermittent energy sources (Figure 9.4).

This synergy will lead to a better optimised management of these two networks in order to maximise the gains of each: production of hydrogen or methane from the electricity grid and use and/or storage of these gases mixed with natural gas. This would allow the later use of these gases for households, services, transport, industry or electricity production (CHP, fuel cell and gas power plant).

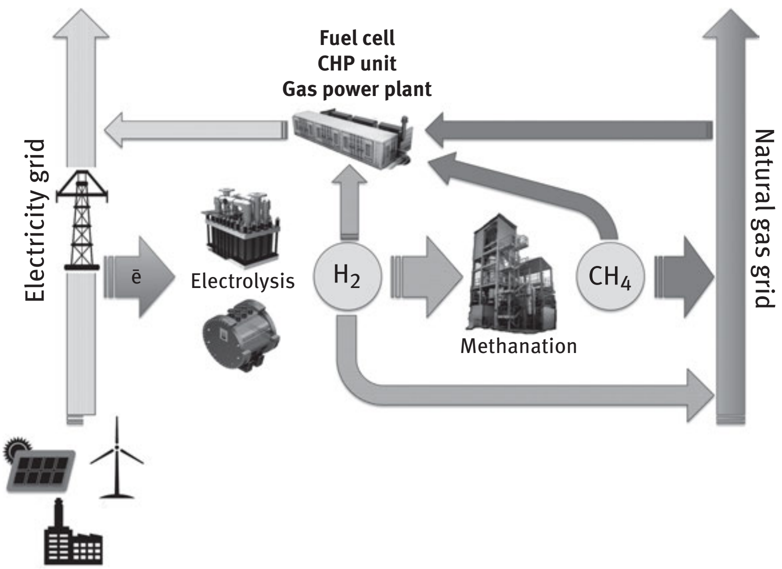

Figure 9.4: Convergence of electricity and gas networks.

9.2 Power-to-gas technology: a contribution to the protection of the environment

The impact of climate change, resulting in meteorological disruptions, which makes it difficult to assess the extent of change, increases the vulnerability of energy systems.

Hydropower with more drought periods and the electricity network with more frequent hurricanes or storms will be strained. **Energy decentralisation**, whether for production, management or use, should make it possible to secure supplies by managing resources locally.

The local exploitation of the surplus electricity and its possible conversion to methane should make it possible to avoid the construction of new high voltage lines: this methane could be carried by the existing natural gas network for residential, tertiary, industry or agricultural sectors. It will also be possible to use it for gas-fired power plants, CHP units or fuel cells to produce electricity locally.

9.3 "Hydrogen civilisation" or electron civilisation?

The production of hydrogen in large quantities from excess electricity has led to the concept of "hydrogen civilisation". The main thesis of this approach is the creation of a hydrogen infrastructure that would penetrate many sectors of the economy including transportation . The fascination of hydrogen, a simple element, periodically leads to a "renewal" of this idea.

Hydrogen and transportation

Considering the costs of fuel cell electric vehicle and of the necessary infrastructure (delivery, service station), hydrogen is not well suited for transportation. All components of this approach are still expensive and energetically (well-to-wheel) not efficient. But for some captive applications like forklifts, for example, the economic advantages are more obvious than conventional solutions (batteries or natural gas-powered internal combustion engine).

In the "hydrogen civilisation" approach, the European Commission published a study in 2003 [**3**] with scenarios projecting the production of up to 123 million tonnes of hydrogen in 2030 (including 100 million from fossil fuels), a European network of hydrogen pipelines and a fleet of 66 million vehicles (!) running on hydrogen. The cost of this programme exceeded 500 billion euros. Apart from transportation, no further use of this hydrogen was foreseen.

The power-to-gas technology is a way to move out from non-renewable sources of energy. It does not mean going towards a "hydrogen society" but to open a new economic field based on hydrogen. The objective is not to build an energetic approach based upon and around one source of energy (in this case hydrogen), as the past has shown what relying only on one (coal first then oil) can hinder development of other alternatives.

The hydrogen illusion

The production of hydrogen is sustainable only if it is produced from (excess) renewable energies. Renewable electricity is already needed to reduce emissions from other sources (coal or natural gas). Directly using this electricity for transportation, for example, is the most efficient method in terms of efficiency even if the electric vehicle suffers from limitations such as relative low effective range and long charging times: it can use up to 90% of the electricity produced, while the one using hydrogen for an on-board fuel cell will use only about 30% of the initial energy.

According to Ulf Bossel, an expert in this field, the "rush" towards an economy based solely on hydrogen [**4**] is not supported by reasons of energy efficiency nor by economic or ecological considerations. Hydrogen will be limited to niches where it will be impossible to circumvent (e.g. the power-to-gas), because in a sustainable economy, its production can be more efficient than the energy used to produce it. Renewable electricity is better used in the form of electrons than hydrogen. The current energy structure linked to power-to-gas technology does not permit the direct use of hydrogen, which is still linked to too many uncertainties (concentrations to be used, equipment to be modified or replaced etc.). Methanation, on the other hand, opens up prospects for the exploitation of excess electricity without changes for users.

9.4 Conclusion

The power-to-gas approach can be easily integrated into the existing energy infrastructure. However, focus should not be based only on technology but on the role it can play in the energetic transition. Power-to-gas can be considered as a unique disruptive "storage" technology compared to other options (batteries, PHS [pumped hydrostorage], compressed air energy storage or flywheel) as it shows specific features:

- It is the only storage technology being able to "absorb" large volume of excess electricity versus batteries or PHS
- It is the one whose "product" (hydrogen) can be easily stored over long time without losses and used in many economic areas

Added to those advantages, power-to-gas can also contribute to reduce energetic dependency with mature basic technology (validated electrolysers with up to 6 MW in 2017 and injection into the natural gas network). The next step for its large-scale integration remains series production to reduce costs.

The power-to-gas concept, whether by hydrogen or methane produced, is an element of the energy transition and decentralisation of the energy system. Faced with energy and environmental challenges, the solution cannot be provided by a single technology, but power-to-gas can contribute to it.

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Acronyms

AC	Alternating current
CAES	Compressed air energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CEN	European Committee for Standardization
CENELEC	European Committee for Electrotechnical Standardization
CGH2	Compressed hydrogen
CHP	Combined heat and power
COP	Coefficient of performance (of heat pumps)
CSP	Concentrating solar power
CSPE	Contribution au Service Public de l'Electricité (France)
DC	Direct current
EEG	Erneuerbare-Energien-Gesetz (Germany)
EPEX	European Power Exchange
EPIA	European Photovoltaic Industry Association
ENTSO–E	European Network of Transmission System Operators for Electricity
ESO	European Standardization Organization
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
GDL	Gas diffusion layer
GWEC	Global Wind Energy Council
GHG	Greenhouse gases
GNP	Gross national product
HVDC	High-voltage direct current
HHV	Higher heating value
ICE	Internal combustion engine
IEA	International Energy Agency
ISO	International Organization for Standardization
LCOE	Levelled cost of energy
LCOH	Levelled cost of hydrogen
LCOS	Levelled cost of storage
LH2	Liquid hydrogen
LHV	Lower heating value
LAES	Liquid air energy storage
LNG	Liquefied natural gas
MCFC	Molten carbonate fuel cell
MEA	Membrane electrode assembly
MH	Metal hydride
NGV	Natural gas for vehicle
O&M	Operations and maintenance
OECD	Organisation for Economic Cooperation and Development
P2G	Power-to-gas
P2G2P	Power-to-gas-to-power
P2H	Power-to-heat
P2L	Power-to-liquid
PEM	Proton exchange membrane
PEMFC	Proton exchange membrane fuel cell

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PMG	Precious metal group
PHEV	Plug-in hybrid electric vehicle
PHS	Pumped hydrostorage
PSA	Pressure swing adsorption
PtG	Power-to-gas
PtH	Power-to-heat
PtL	Power-to-liquid
PV	Photovoltaic
RES	Renewable energy sources
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SMES	Superconducting magnetic energy storage
SMR	Steam methane reforming
SNG	Synthetic or substitute natural gas
SOEC	Solid oxide electrolyte cell
SOFC	Solid oxide fuel cell
T&D	Transmission and distribution
UCTE	Union for Coordination of Transmission of Electricity
YSZ	Yttrium-stabilized zirconia

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