THE POTENTIAL OF POWER-TO-GAS

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Technology review and economic potential assessment

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Executive summary

Massive development of renewable electricity production from intermittent sources (i.e. wind and solar) is underway in some European countries (e.g. Denmark and Germany) and is expected in a larger extent in Europe in the future decades. Increased capacities of power production from intermittent sources lead to periods of low spot prices of electricity, offering an opportunity for the development of flexible electro-intensive processes, and power-to-gas (hydrogen and synthetic methane) processes in particular.

This perspective has recently been fostering the R&D activity and interest in power-to-gas in Europe and more specifically Germany. Around 50 pilot and demonstration projects have been launched worldwide since 2004, most of them being announced in the 3 past years, with a significant level of activity in grid injection applications.

This study assesses the economic potential of power-to-gas and other power-to-X applications with a technical-economic modelling of six case studies targeting energy markets (i.e. gas injection into the grid, green mobility, heat production). For each case study, we compared the levelized cost of the final product with the market prices of alternative products on the target markets. This comparison was performed for three time horizons (2015, 2030 and 2050) offering different set of assumptions regarding prices of electricity and cost of technologies, in order to identify conditions required for business cases to be viable.

Green mobility is the most promising market for power-to-gas (with hydrogen fuel) and should be the first target for large scale deployment of the technology. Already competitive with other green fuel options, competitiveness with fossil fuels will likely remain out of reach without financial incentives. Methanol could prove an interesting alternative as well with different deployment constraints[1].

With a levelized cost of 8 to 10 €/kg_{H2} of distributed hydrogen[2], hydrogen produced from power already competes with bioCNG on the "green fuel" market on a fuel cost per kilometer basis. This optimal cost is reached for high load factors (i.e. from 6,000 to 8,000 hours/year) and does not rely on very low electricity prices (average final purchase price between 40 to 70 €/MWh). To become competitive with fossil fuels (ex: gasoline) on a fuel cost per kilometer basis, power-to-hydrogen will have to be delivered at a levelized cost of 3 to 4 €/kg. This could be achieved for instance if CAPEX and cost of electricity were more than halved. However, halving CAPEX is an ambitious target, and having access to electricity at a final purchase price of 20 €/MWh during more than 6,000 hours appears unlikely. As a result, hydrogen from power will have a hard time competing with fossil fuels on a fuel cost per kilometer basis without financial incentives.

Conclusions on the competitiveness of methanol produced from power (power-to-liquids route) are very similar. The methanol option is however very different from a technical perspective, being a potential drop-in replacement of traditional fuels when used in blend. Nevertheless, many other options are already in competition for this market such as biofuels, other synthetic fuels from power-to-liquids, fuels from biomethane (CNG, LNG) or batteries.

Power-to-gas for grid injection will likely not meet viability without strong financial support, due to its high CAPEX and the low market value of the produced gas.

Based on current costs and advantageous electricity prices (average final purchase price of 40 €/MWh), the levelized cost of gas-from-power injected into the grid is 100 and 170 €/MW_{HHV} for hydrogen and synthetic methane respectively. Power-to-gas for grid injection is thus far from competitiveness with natural gas (about 20 €/MWh_{HHV}) and remains more costly than biomethane (60 to 100 €/MWh_{HHV}), in particular for synthetic natural gas.

At the 2030 or 2050 horizons, it is likely that hydrogen produced from power can reach costs comparable to current biomethane production costs; it however appears unlikely for synthetic natural gas.

[1] Many other aspects and mobility options out of the scope of the present study would need to be taken into account to draw a comprehensive green mobility perspective (cost of vehicles, CO_2 emissions and air pollution, autonomy, technology readiness, ease of implementation…)
[2] Power-to-methane for mobility is considered in this study as a downstream market of synthetic methane grid injection with CNG filling stations connected to the gas grid.

Power-to-heat with an electric boiler at an industrial site appears as a potentially competitive option, able to develop in contexts exhibiting short periods of low-cost electricity (typically 1,000 or 2,000 hours per year), but very sensitive to the spread between electricity and natural gas prices.

Such a spread in favour of electricity becomes likely with possible future increase of taxes on fossil fuels and CO_2 and increased shares of renewable electricity. The use of more efficient assets (i.e. heat pump) for power-to-heat would offer a higher resilience to the price of electricity but would require higher duration of operation.

Based on the case studies considered and the various scenarios analyzed, this study shows that power-to-gas technologies have most potential when applied to green mobility markets. As such, their fate will be strongly correlated to policies and incentives implemented in the much broader perspective of the transport sector decarbonisation.

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Context and objectives of the study

Massive development of renewable electricity production from intermittent sources (i.e. wind and solar) is underway in some European countries (e.g. Denmark and Germany) and is expected in a larger extent in Europe in the future decades. Increased capacities of power production from intermittent sources lead to periods of low spot prices of electricity, offering an opportunity for the development of flexible electro-intensive processes, and power-to-gas processes in particular.

This study initiated by the Tuck Foundation in the framework of the "The Future of Energy" program and co-funded by KIC InnoEnergy aims at assessing the potential of power-to-gas applications, as well as the potential of other power-to-X[3] processes able to seize the opportunity of periods of low cost electricity. A background review of power-to-gas technologies, markets and R&D activity is first provided. The economic potential of power-to-gas is then assessed based on the modelling of six business cases representative of the power-to-X landscape illustrated Figure 1.

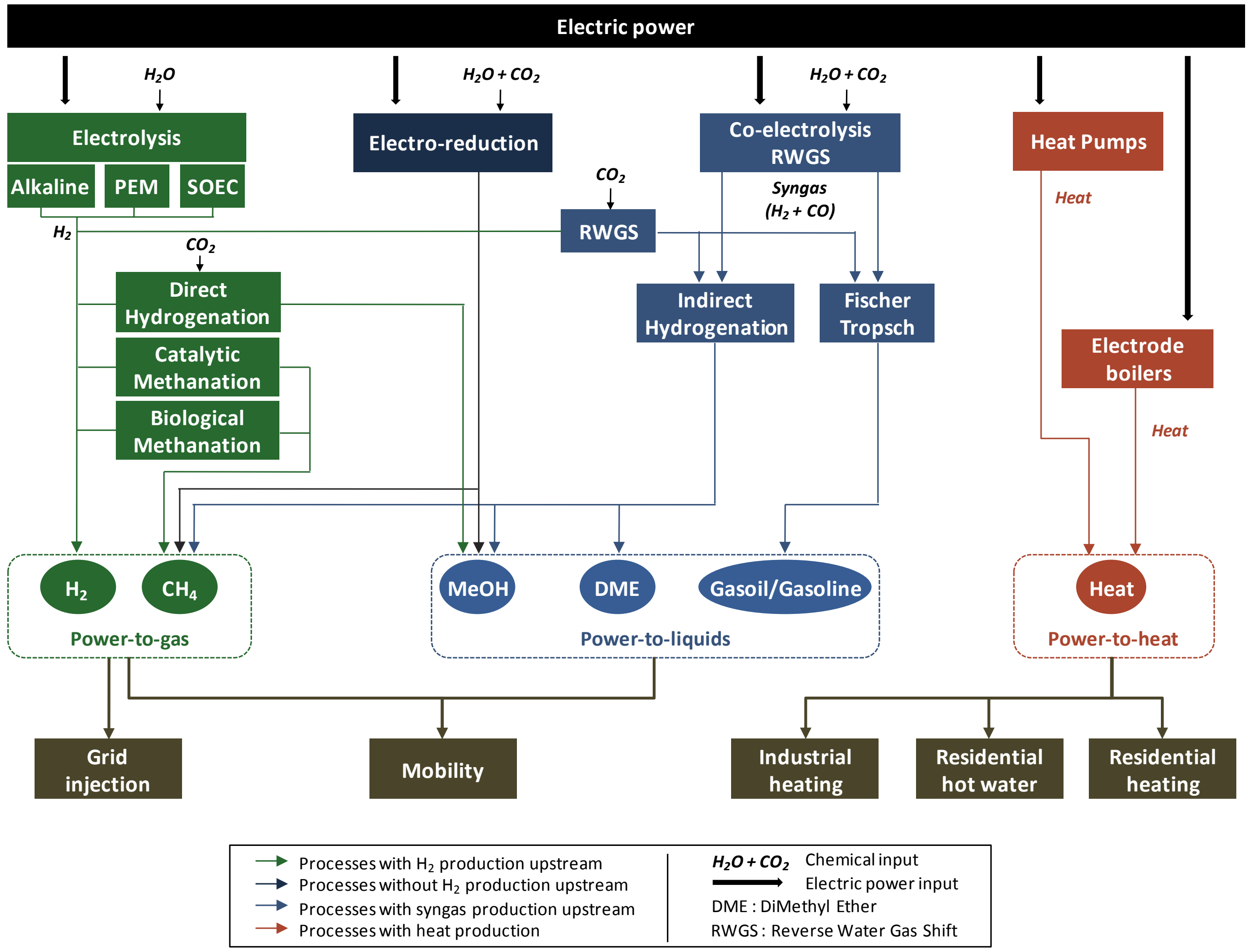

Figure 1 – Power-to-gas, power-to-liquids and power-to-heat routes and their energy markets

[3] Only power-to-X processes producing an energy vector (chemical or heat) have been considered in this study.

1 General background on power-to-gas

This section provides a general background on power-to-gas with a review of the technologies under development and markets considered in our analysis. A literature and project review describes the R&D activity in the field of power-to-gas since the emergence and the evolution of the concept in the 1990's to current demonstration projects.

1.1 Technologies

Hydrogen production by electrolysis of water and synthetic methane (SNG - Substitute Natural Gas) production by methanation are the two core process blocks of power-to-gas. For water electrolysis, alkaline technology is the only technology commercially available for hydrogen production. PEM electrolysis is still under demonstration but offers more long-term possibilities for cost reduction than alkaline technology. For methanation, catalytic isothermal methanation is the most likely technology to reach commercial stage. Biological methanation is an alternative process, with an interesting potential for cost reduction, but still faces technical barriers for scale-up. Detailed fact sheets are given in appendix (refer to §3.1) for the most mature technologies.

1.1.1 Water electrolysis

Water electrolysis is the first brick of the power-to-gas process, which consists in converting power to hydrogen and oxygen by dissociation of water. This hydrogen production process is well known and has been used for more than a century but it is still marginal[4] when considering the global production of hydrogen, mainly based on fossil fuels conversion (natural gas, naphta, coal). However, the possible production of green hydrogen from water electrolysis with renewable electricity is an opportunity for the process to address a new and large market.

Hydrogen production by dissociation of water occurs in electrolysis cells containing water, electrodes and an electrolyte material crossed by an electric current. Hydrogen and oxygen are produced separately in the two distinct sections of the electrolysis cell, respectively at the cathode and the anode. The electrolyte material ensures the transfer of ions from one section to the other, which are separated by a membrane or a diaphragm. The size of a cell is limited by the capacity of the membrane or the diaphragm to withstand the electric current. Electrolysis cells are therefore piled in stacks that compose the core of an electrolyzer. In addition, the electrolyzer comprises auxiliaries such as a current rectifier, a water demineralization unit, a water pump and a cooling system, a hydrogen purification unit, and instrumentation.

Three water electrolysis technologies can be considered for hydrogen production: Alkaline Electrolysis Cells (AEC), Proton Exchange Membrane Electrolysis Cells (PEM-EC) and Solid Oxide Electrolysis Cells (SOEC).

Alkaline electrolysis is the most mature technology available for the capacities considered in our case studies (1 to 10 MW_{el}, refer to §2.1.1) and has therefore been used in this study. PEM electrolysis is a little less mature, and SOEC electrolysis is still at an early stage of development. These three technologies are described in the following sections with a focus on alkaline and PEM.

1.1.1.1 Alkaline electrolysis

Alkaline electrolysis is the state of the art technology developed for water electrolysis, and currently the only commercially available power-to-gas application. It uses an alkaline solution (i.e. sodium hydroxide or potassium hydroxide) as electrolyte material to transfer electrons through hydroxide anions according to the following reactions:

Cathode reaction: $$2H_2O + 2e^- \rightarrow H_2 + 2OH^-$$

Anode reaction: $$2OH^- \rightarrow H_2O + \frac{1}{2}O_2 + 2e^-$$

[4] Only 4 % of hydrogen produced globally comes from water electrolysis, the majority of this share being produced as the by-product of chlorine in water electrolysis with sodium chloride (NaCl).

Depending on the capacity of the electrolyzer and the pressure of the hydrogen delivered, the energy efficiency of the devices vary between 66% and 74% (4.8 and 5.4 kWh_{el}/Nm^3H_2) and the installed[5] CAPEX varies from 1,000 to 2,000 €/kW_{el} (refer to the factsheet in §3.1 for more details).

Reducing CAPEX and energy consumption is of course an objective of alkaline electrolyzer manufacturers, but given the high maturity of the technology, technology improvement margins remain limited but do exist. For instance, an increase of the diaphragm surface would improve the output capacity of a stack, therefore optimizing the use of auxiliaries and reducing CAPEX and power consumption. Additional cost reduction can come from volume effects because of market growth (maximum reduction envisaged is 10 to 20 % of the final price) [1]. In this study, an ambitious cost reduction scenario was used, with a hypothesis of 50 % decrease of electrolyzers CAPEX at the 2050 horizon. For hydrogen production at 10 bar, energy efficiency (of about 66 % at current stage) – could reach 69 % with improvements of the technology. These two assumptions were used in our model depending on the time horizon.

Hydrogenics and NEL hydrogen are the two largest alkaline electrolyzer manufacturers. Hydrogenics is particularly active in power-to-gas applications with numerous pilot or demonstration plants. McPhy energy (formerly Enertrag HyTec and PIEL) also positions itself as a technology provider for the power-to-gas market.

1.1.1.2 PEM electrolysis

PEM electrolysis is a more recent technology that is currently used for small applications in niche industrial markets, and is under demonstration for larger scales (up to 2 MW_{el} per electrolyzer). This technology uses proton transfer polymer membranes that play the simultaneous role of electrolyte and separation material between the different sections of the electrolysis cell, in which the following reactions occur:

Cathode reaction: $2\boldsymbol{H}^+ + 2e^- \rightarrow H_2$

Anode reaction: $H_2O \rightarrow 2\boldsymbol{H}^+ + \frac{1}{2}O_2 + 2e^-$

PEM electrolyzers have currently higher CAPEX than alkaline electrolysers. Further development of the technology could however reduce investment costs below the alkaline technology thanks to higher compactness and suitability for stack pressurization. According to technology developers, for a 10 MW_{el} unit the installed cost of a PEM electrolyzer could reach 1,000 €/kW_{el} in the coming years, 700 €/kW_{el} in 2030 and even decrease down to 400 €/kW_{el} in 2050[6] (refer to the factsheet in §3.1 for more details) [2] [3] [4]. Some CAPEX reductions have already been achieved by reducing the scarce material content on membranes [5]. R&D activities now focus on the increase of membrane surface, cell stack throughput and auxiliaries mutualisation [3] [5].

PEM electrolyzer manufacturers are very active in the development of the technology for power-to-gas applications. The two most visible are SIEMENS and ITM Power.

1.1.1.3 SOEC electrolysis

Solid Oxide Electrolyzer Cells operates at high temperature (700-800 °C) to reduce electrical input required for the electrolysis reaction. Ceramic materials that can withstand high temperatures are used as electrolyte and electrode materials. Electron transfer between the two sections of the cell is ensured by oxide anions (O_2^-) through the ceramic material according to the following reactions:

Cathode reaction: $H_2O + 2e^- \rightarrow H_2 + O^{2-}$

Anode reaction: $O^{2-} \rightarrow \frac{1}{2}O_2 + 2e^-$

The main interest of the SOEC technology is its higher efficiency of the electrolysis process (typically 80 to 90%) and possible use as a fuel cell in a "reverse" mode. CAPEX target published in the literature can vary significantly and reach very low levels down to few hundreds of euros per kW_{el} [6]. However, the costs of solid oxide electrolysers have not been confirmed yet given the early stage of development of the technology. The company Sunfire is developing a

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[5] Installed CAPEX is the investment cost of an equipment including its transport, installation and commissioning costs (refer to § 2.1.2 for more details on cost modelling).

[6] Note that this figure is in close the cost scenario we used for alkaline electrolysers at the 2050 horizon (i.e. 500€/kW_{el}).

200 kW stack pressurized at 30 bar for integration with a methanation reactor or for power-to-liquids applications. The coupling of a SOEC electrolyser with an exothermic reactor (ex: methanation) allows for heat recovery on the reactor to produce steam for the electrolysis stack.

1.1.2 Methanation

Methanation refers to the synthesis of methane by hydrogenation of carbon monoxide or carbon dioxide. Carbon monoxide methanation through catalytic processes has been used for decades for ammonia synthesis, in coal-to-gas/liquids processes or for natural gas treatment in the oil & gas sector. In the case of power-to-gas applications, methanation refers to the hydrogenation of carbon dioxide according to the following reaction:

$$4H_2 + CO_2 \rightarrow CH_4 + 2H_2O(g) \quad \Delta H = -165 \text{ kJ/mol}$$

This reaction can happen through two different techniques: catalytic methanation or biological methanation. The catalytic option is the focus of current R&D activity due to its historical importance in the industry and has thus been selected in the context of our power-to-methane case study. Biological methanation is an emerging alternative to the catalytic option, with interesting perspectives for cost reduction, but it still faces scale-up challenges. Both routes are described below.

1.1.2.1 Catalytic methanation

Catalytic methanation is a thermochemical process operated on a catalyst at high temperature (between 200 and 700 °C) and pressures between 1 and 100 bar. The reaction is highly exothermic and temperature must be controlled in order to avoid thermodynamic limitation of the reaction and catalyst degradation [7]. In large-scale industrial applications and for continuous operations, this is achieved with a series of adiabatic fixed-bed reactors and inter-cooling of the stream between each reactor. However, power-to-gas processes are implemented at smaller scales, with intermittent operations, for which adiabatic reactors are not suitable. In this context, isothermal reactors where a cooling fluid directly cools the reactor are usually preferred (refer to the factsheet in §3.1 for more details) [2]. Other types of reactors such as fluidized bed reactors, three-phase reactors or structured reactors are also researched but are not mature today [7].

Estimations of CAPEX for a methanation unit used in a power-to-gas plant can vary significantly, from 400 to 1,500 €/$kW_{HHV\text{-}SNG}$, due to the lack of units under commercial operation so far [7]. Isothermal reactors still face challenges in terms of temperature control and operational flexibility with regards to power-to-gas requirements. Current R&D efforts focus on reactor design to improve the performance of the reactor cooling system (e.g. KIC InnoEnergy CO_2 SNG and DemoSNG projects).

The energy efficiency of the chemical reaction is close to 80 % and the overall energy efficiency of the plant can be improved through the recovery of the reactor heat and its internal reuse or external valorisation.

1.1.2.2 Biological methanation

Biological methanation produces methane from hydrogen and carbon dioxide using methanogenic microorganisms operating as bio-catalysts. The reaction occurs under anaerobic conditions in an aqueous solution, at atmospheric pressure or under pressure, between 20 and 70 °C. Biological methanation has the potential to dramatically reduce costs thanks to a simpler reactor design and convenient pressure and temperature conditions [2]. However, several barriers will have to be overcome. In particular, the gas/liquid interface of the reaction medium is a strong barrier for mass transfer within the reactor and limits dramatically the effective kinetics of the reaction [7]. Moreover, the reaction must occur in specific pH conditions, which restrict the control of its kinetics by increasing hydrogen or carbon dioxide concentration in the reactor [2][7]. The Biocat Project (Denmark) aims at testing the technology in actual conditions (raw biogas stream and pure CO_2 from biomethane plant), with a 1 MW_{el} electrolyzer to be provided by Hydrogenics and a biological methanation reactor to be provided by Electrochaea. The project completed the permitting process in August 2015, and has now entered the engineering phase.

1.2 Markets

Two power-to-gas markets are considered in this study: hydrogen or methane (SNG) injection into the natural gas grid and hydrogen mobility. Methane injection in the grid, given it can be done economically, could represent considerable volumes, since SNG complies with grid specifications. Hydrogen injection represents a smaller and hard-to-quantify market due to technical limits on the maximum allowable content of hydrogen in the grid. The hydrogen mobility market is still at an early stage, and its development will depend on national strategies and policies for clean mobility.

1.2.1 Gas injection into the natural gas grid

Gas injection into the natural gas grid represents a huge market given the final consumption of natural gas in Europe (4,722 TWh in 2013 in the EU-28 [8]). Moreover, natural gas grids offer substantial storage capacities with possible pressure variation in the pipelines and their connection to natural storage caverns (e.g. more than 100 TWh in France [2]) that allow a decoupling of gas production and consumption.

National gas grids are generally composed of a transmission grid connected to supply points, storage facilities, distribution grids and some large gas consumers. A power-to-gas plant can inject gas into the transmission or the distribution grid by connecting the plant to the grid with a pipeline and an injection station similar to those used for biomethane injection[7]. The gas must be compressed to sufficient pressure to be injected into the grid, typically 40 to 60 bar in the transmission grid and 5 to 10 bar in the distribution grid.

Power-to-methane plants aim at producing a synthetic natural gas with composition similar to natural gas. Therefore, no particular constraint shall be expected on SNG injection into the grid in contrary to hydrogen. Pipelines used in the natural gas grid have not been designed to withstand the specific properties of hydrogen such as higher permeation and corrosion than natural gas. For safety reasons, hydrogen concentration in the gas grids must be controlled. In Europe the maximum hydrogen content allowed by national standards for biomethane injection into the grids generally varies from 0.1 to 10 % in volume depending on the country [9]. According to ongoing work on European standardization of power-to-hydrogen applications, most of the European natural gas infrastructure can withstand a volume concentration 10 % of hydrogen [10]. More investigation is still required to assess the tolerance to hydrogen of several gas grid components, including storage caverns, surface facilities, storage tanks, gas flow monitors and gas analysis instruments [10]. Downstream uses of gas also impose constraints on hydrogen mixture in the gas. For instance, Compressed Natural Gas (CNG) vehicles and gas turbines are currently designed for a fuel gas containing less than 2 or 3 % of hydrogen in volume [6].

As a result, the development of a large market of power-to-hydrogen for grid injection requires further work to define and standardize the maximum amount of hydrogen acceptable in the gas grids. Proper siting of plants accounting for the grid structure (flowrates, types of consumers, other power-to-hydrogen plants) and precise monitoring of injected volumes will also be necessary to comply with these specifications.

Natural gas and biomethane are the two products that are currently injected into European grids. Natural gas price fluctuates on the markets, while biomethane injection currently benefits from feed-in tariffs or premiums. If no support mechanism is implemented for power-to-gas, wholesale natural gas prices will set the price (on a MWh basis) of H_2 or SNG produced by power-to-gas plants.

1.2.2 Mobility

Hydrogen and SNGcan be used as a mobility fuel in hydrogen or CNG vehicles respectively. CNG refuelling stations are expected to be connected to the natural gas grid, the CNG mobility market therefore being a downstream market of grid injection for power-to-methane plants.

Hydrogen mobility cannot rely on existing pipeline infrastructures. Refuelling stations integrating hydrogen production through water electrolysis, hydrogen compression and storage, and finally vehicles refuelling infrastructure will most likely be developed. This model of hydrogen refuelling station thus represents a market for power-to-hydrogen.

[7] For hydrogen injection, the injection station must be suited for pure hydrogen and the pipeline has to have enough capacity for hydrogen injection without exceeding the maximum hydrogen fraction according to the national standards.

The hydrogen mobility market is currently at an early stage of development. Even though hydrogen fuel cell vehicles and hydrogen refuelling stations are technically proven, their commercial implementation will need joint investment of public and private entities. Several initiatives and projects are planned or ongoing in Europe with the most ambitious being the Clean Energy Partnership in Germany targeting a network of 100 stations by 2019 and of 200 to 400 stations by 2023 [11]. National policies, regulations and support mechanisms on hydrogen mobility are expected to play a predominant role in the development of this market which relies on national strategic plans for mobility.

Direct competitors of hydrogen as mobility fuels are fossil fuels (gasoline, diesel, CNG), biofuels (bioethanol, bioCNG) and electricity for electric vehicles. To be fully comparable, the cost of mobility solutions should be assessed over the complete value chain (from well to wheel) and for the final functionality provided (distance of transport). In the frame of our analysis we will assess the market price of hydrogen considering the market price of competing fuels excluding the cost of vehicles.

1.3 Historical R&D activity

The growing maturity of solar and wind power technologies in the 1990's motivated academic investigations on hydrogen-based electricity storage for stand-alone power supply [12] [13] [14]. Such systems involve hydrogen production with water electrolysis in power production periods (sun or wind), hydrogen storage and conversion back to electricity with a fuel cell in power shortage periods. The emergence of the PEM technology allowing faster response time of the electrolyzer compared to alkaline technology probably contributed to the growing interest in power-to-gas-to-power systems for direct coupling with solar panels or wind turbines [15]. At this time, using renewable hydrogen produced through water electrolysis was also envisaged for mobility applications [16] [17]. The use of methanation also emerged in this period as a solution for CO_2 reuse. Massive production of methane in the Middle-East in power-to-gas plants supplied with solar power produced in the neighbouring desert and CO_2 shipped from Asia was then envisaged as a world scale mitigation solution for CO_2 emissions [18].

The use of power-to-gas as a mean to store massive amount of electricity in high wind penetration contexts emerged in the early 2000's. Hydrogen for mobility was then assessed as economically more attractive than stationary power generation but still not viable due to high CAPEX of electrolyzers and the need for very low prices of electricity [19]. In the meantime, hydrogen injection into the natural gas grid was identified as a storage mean for hydrogen and was investigated at laboratory scale [20] [21] [22]. Figure 2 illustrates the R&D development of power-to-gas concepts from laboratory to industrial demonstration.

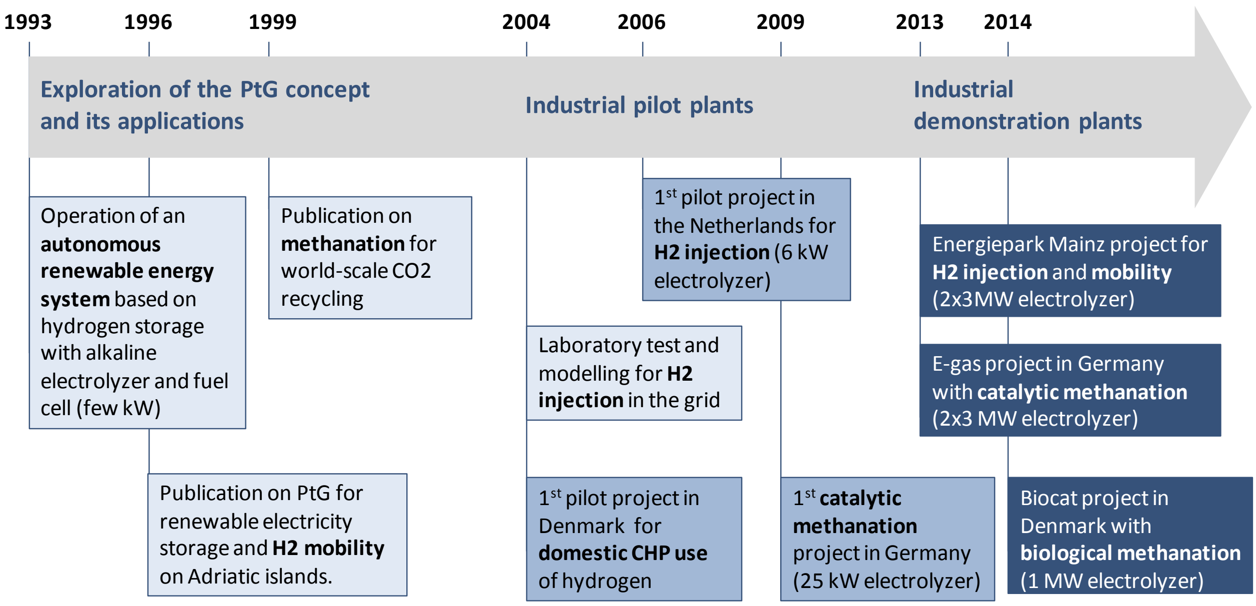

Figure 2 – Historical development of power-to-gas from concept to industrial demonstration

First pilot projects of power-to-gas were launched between 2004 and 2009 with operational testing of technologies between 2007 and 2012. The pilot project in Lolland (Denmark) was one of the first tests of hydrogen production and use, at domestic scale with micro electrolyzers and CHP (Combined Heat and Power) fuel cells. Most of later industrial

R&D activity on power-to-gas was oriented on grid injection or mobility applications rather than on autonomous energy systems. In 2005 and 2006, pilot projects of power-to-hydrogen for mobility and grid injection were launched in the UK and in the Netherlands respectively. The first pilot project of power-to-methane with catalytic methanation was been launched later in 2009 in Germany.

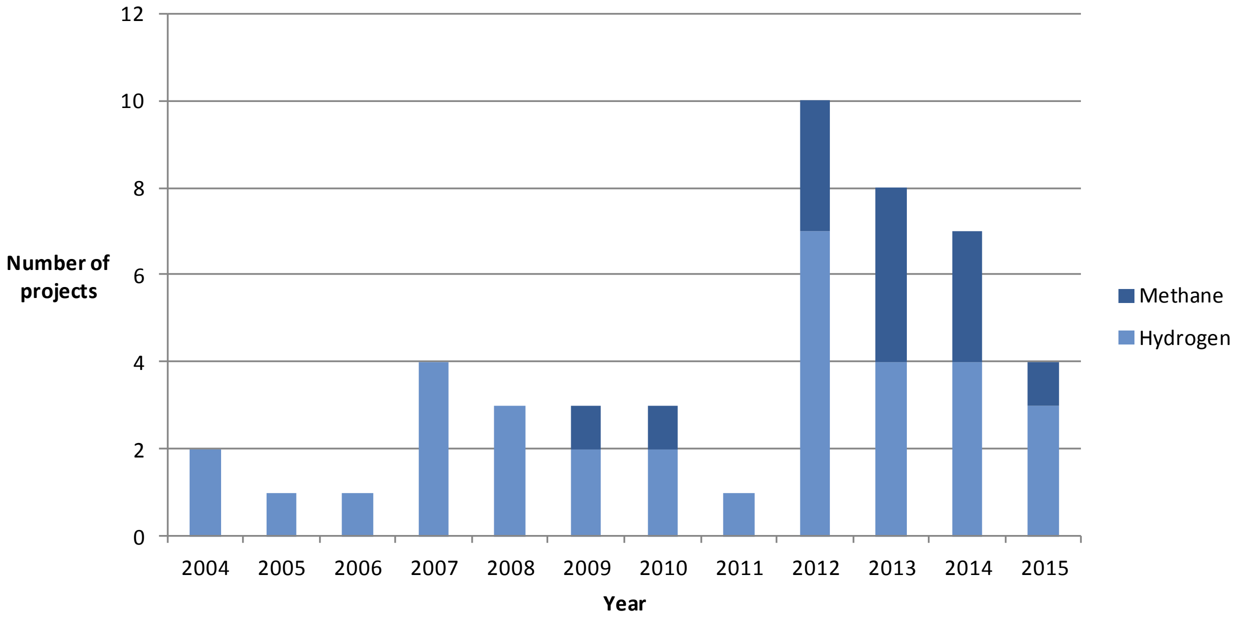

Figure 3 – Number of pilot and demonstration projects of power-to-gas launched worldwide in the past decade

The technical validation of power-to-gas at pilot scale, thanks to the first series of projects, combined with increasing targets for renewable electricity integration in Europe are two likely causes for the boom observed in the number of R&D projects launched since 2012 (see Figure 3). Power-to-gas for grid injection and mobility was then seen as a way to bring flexibility to the electricity grid, given the perspective of increasing amounts of wind and solar productions. Among these projects, two emblematic demonstrators are currently in operation in Germany for hydrogen injection into the grid (Energiepark Mainz) and SNG production for mobility (E-gas project).

R&D activity for power-to-gas has been extremely concentrated in Europe with 44 projects over the 49 launched worldwide since 2004. Even though Japan is particularly active in hydrogen technologies development, it focuses on consumption-side technologies, such as fuel cell technologies for vehicles or stationary power production more than on electrolyzers. The USA are just entering the sector with the first power-to-gas project announced in 2015 for testing hydrogen injection in a simulated natural gas pipeline.

Even though Denmark and the Netherlands were pioneers in power-to-gas and are still active, Germany is now leading the European R&D activity with 17 pilot and demonstration projects launched since 2004 (see Figure 4). Germany's interest for power-to-gas is directly linked with its *Energiewende* and high targets[8] of renewable electricity production. R&D activity in France and in the UK is much less important than in Germany and started recently in France with most of projects launched after 2012.

Regarding power-to-gas routes, projects on power-to-methane mainly focus on the developments of improved methanation technologies [23]. On the opposite, projects on power-to-hydrogen tend to focus on the demonstration of integrated plants at commercial scale from hydrogen production to grid injection, the later part being a challenge with regards to the control of hydrogen content in the grid [24] [25].

[8] 40 to 45 % of electricity should be produced from renewable sources by 2025 and 55 to 62 % by 2035.

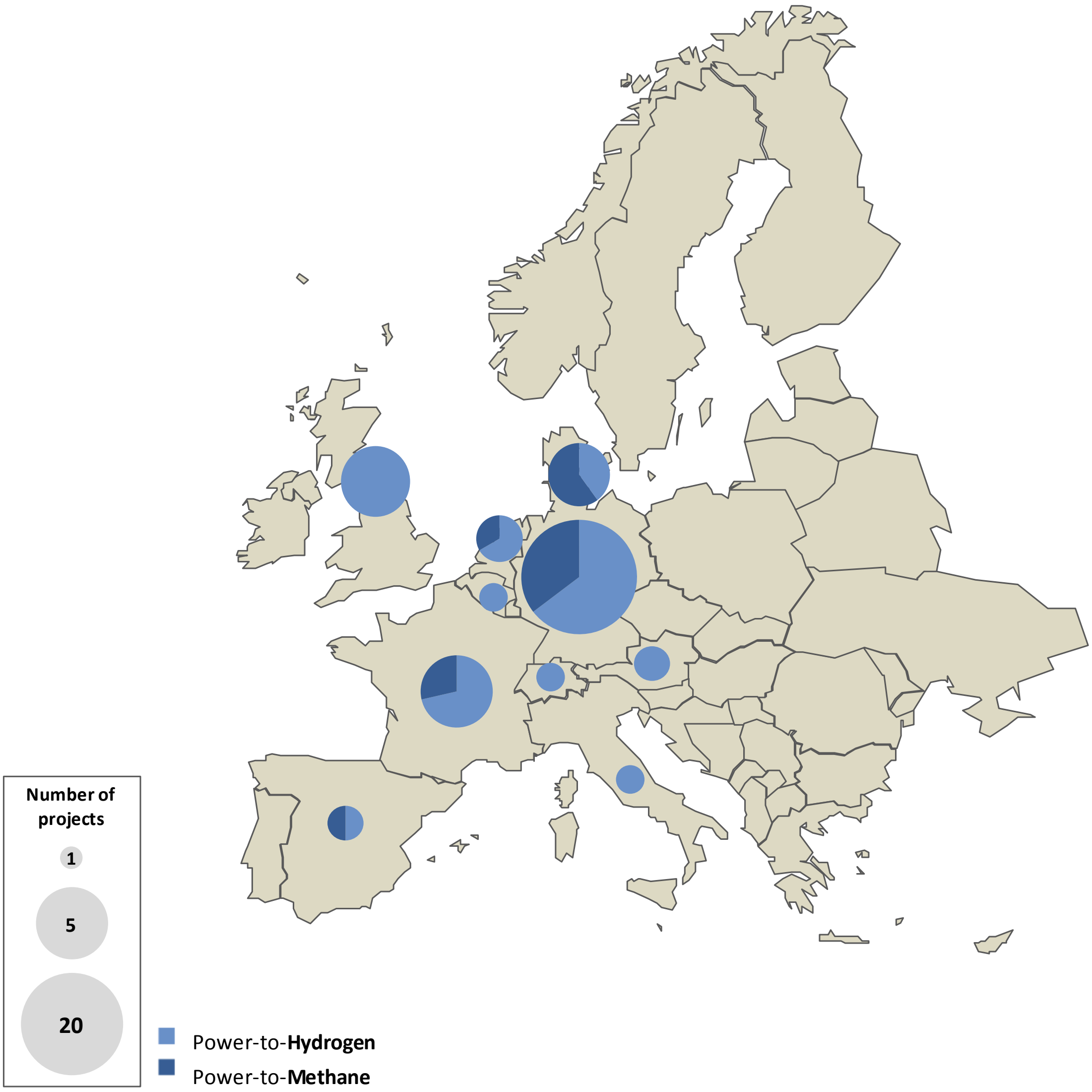

Figure 4 – Mapping of pilot and demonstration projects of power-to-gas in Europe

2 Power-to-X business cases

The objective of this section is to assess the potential of a particular power-to-gas or power-to-X process. For this purpose, we compared the levelized cost of the final product (refer to §2.1.2) with the market price of alternative products on the target market (refer to §2.1.4).

This comparison was performed for three time horizons (2015, 2030 and 2050) and for six case studies. These case studies focus on potential mass market applications (gas injection into the grid, green mobility, heat), and involve technologies with proven technical feasibility, which costs can be estimated with a satisfactory level of accuracy (refer to §2.1).

2.1 Methodology

2.1.1 Case studies

Three case studies focus on grid injection (see Figure 5). The first one is a small scale (1 MW_{el} input) power-to-hydrogen plant injecting hydrogen into the distribution grid. It is composed of a power grid connection to an HV line, an alkaline electrolyzer producing hydrogen at 10 bar, a gas pipeline and an injection station connected to the gas distribution grid. Additional compression of hydrogen is not required due to the low pressure of distribution grids (5 to 10 bar).

The second case targets a larger scale power-to-hydrogen plant (10 MW_{el} input) injecting into the transmission grid. The technical feasibility of this case study still needs to be validated (refer to § 1.2.1). The plant comprises the same blocks as the previous case with higher capacities and an additional compressor, to compress hydrogen to 60 bar in order to comply with the transmission grid pressure (40-60 bar).

The third case is a power-to-methane (or SNG) plant with a capacity of 10 MW_{el} input connected to the transmission grid. In the case of SNG production no constraints are expected regarding injection (refer to § 1.2.1). Downstream the alkaline electrolyzer, hydrogen reacts at 10 bar with CO_2 into a catalytic methanation reactor to produce SNG. As for hydrogen injection, the gas is compressed, transported in a pipeline and injected into the grid at an injection station.

Two case studies focus on green mobility applications. The first one is representative of a hydrogen refuelling station with onsite hydrogen production (1 MW_{el}). It is composed of a power grid connection to an HV line, an alkaline electrolyzer producing hydrogen at 10 bar and a refuelling station. The refuelling station includes a compression train up to 700 bar, hydrogen storage and all the infrastructure required to refuel vehicles. This refuelling station can produce up to 370 kg_{H2}/day, allowing the supply of a fleet of 1,000 light duty vehicles. Refuelling stations currently operational in Europe or California and to be installed in the next 5 years are smaller (typically 100 to 200 kg_{H2}/day). This case study is thus representative of refuelling stations that would be installed later on, typically between 2020 and 2030 in Europe.

Multiple power-to-liquid processes can synthesize competing “green” liquid fuels as described in Figure 1. Synthesis of methanol by direct hydrogenation has been chosen for the second mobility case study, due to its simpler process and higher maturity[9] than other routes [26]. This process consists in the production of hydrogen and the catalytic conversion of hydrogen and carbon dioxide in a reactor to produce methanol. The most likely market for methanol as a mobility fuel is the blending with gasoline to be used in conventional internal combustion engines[10].

Finally, a power-to-heat case targets heat production for industrial plants with a base load heating demand. A 10 MW_{el} electrode boiler is used for steam production alternatively to a gas boiler when low prices of electricity allow for a reduced steam production cost.

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[9] The technology is at industrial demonstration stage: Carbon Recycling International (CRI) is operating a demonstrator in Iceland for several years and recently launched a second demonstration project with Mitsubishi Hitachi Power Systems Europe.

[10] The use of pure methanol in fuel cells can also be envisaged even though it faces challenges due the high toxicity of pure methanol.

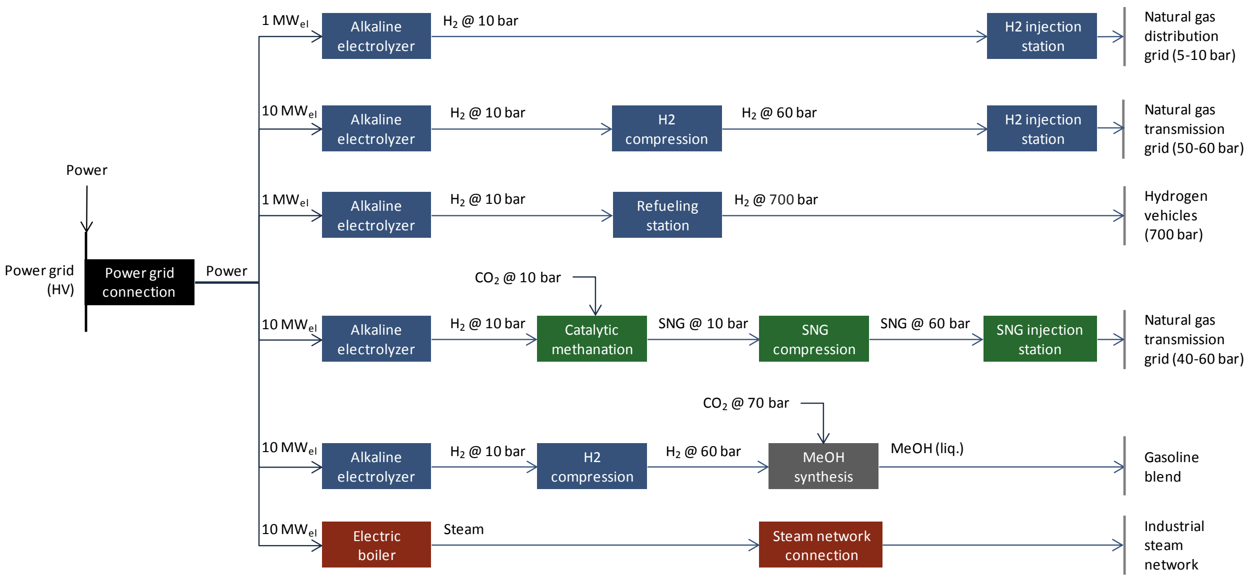

Figure 5 – Block flow diagram of the case studies modelled

2.1.2 Cost modelling

For a given power-to- X case study, the levelized cost of X (LCOX) represents the breakeven selling price of the product. For a particular plant[11] of lifetime n, the LCOX, expressed in €/unit of X (€/u) is defined by:

$$LCOX = \frac{\sum_{i=0}^{n} \frac{Costs\ in\ year\ i}{(1+WACC)^i}}{\sum_{i=0}^{n} \frac{Number\ of\ X\ units\ produced\ in\ year\ i}{(1+WACC)^i}}$$

In this study, a weighted average cost of capital (WACC) of 8% was assumed. Costs were separated into CAPEX and operational costs, and both operational costs and yearly production were assumed constant over time.

CAPEX was calculated as the total project capital expenditures as described below:

$$Total\ CAPEX = Installed\ CAPEX + Project\ CAPEX$$

With,

$$Installed\ CAPEX = Factory\ gate\ cost + Additional\ costs$$

And,

$$Project\ CAPEX = 0{,}3\ \times\ Installed\ CAPEX$$

Installed CAPEX includes the factory gate cost of equipments and additional costs comprising transport, civil work, installation, balance of plant and commissioning costs.

[11] To take into account differentiated equipment lifetimes, the LCOX is actually computed based on the levelized cost of intermediary products established for each block and on intermediary consumptions.

For most of the process blocks, installed CAPEX were directly estimated from the feedback of technology providers and project developers. Factory gate costs and additional costs were estimated separately for methanation, methanol synthesis and compression. Estimates were derived from feedback of technology developers and ENEA's experience of economics on these technologies. Additional costs were estimated at:

- 50 % of the factory gate cost for methanation and methanol synthesis;
- 15 % of the factory gate cost for compressors.

Project CAPEX comprises design, engineering, overhead and permitting costs. Depending on technologies involved, plant scale and project environment, project costs of a plant can vary from 10 to 100 % of the installed CAPEX. Based on ENEA's experience on industrial projects in the energy sector, project costs were assumed to represent 30 % of the installed CAPEX.

CAPEX decrease was considered for the 2030 and 2050 horizons for the electrolyzer, hydrogen compressor, methanation reactor injection station, hydrogen refuelling station, and methanol synthesis reactor. Ambitious targets of CAPEX reduction were chosen for the 2050 scenario in order to assess business cases in optimistic conditions. Intermediate values between 2015 and 2050 were set for the 2030 scenario (refer to § 3.2). Except for the power-to-heat case with a constant CAPEX for the three time horizons, the total CAPEX of business cases are reduced from 18 % to 36 % in 2030 and from 37 % to 48 % in 2050 compared to 2015 (refer to § 3.3 for details).

Operational costs are composed of operation and maintenance (O&M) costs and input costs (e.g. electricity, CO_2, water). Annual O&M costs were assumed to be a fraction of the CAPEX (independently of the annual production).

Input costs were calculated based on the price (or levelized cost) of inputs. The input consumption was calculated from energy and mass balances of the plant accounting for chemical and energy efficiencies. Assumptions made regarding the price of electricity are described in § 2.1.3. A conservative assumption on CO_2 price was made, and the CO_2 price was set at 50 €/ton for methanation assuming CO_2 purchase from a biogas plant including CO_2 pressurization at 10 bar and transport[12]. The price of CO_2 consumed for methanol production was set at a higher price of 100 €/ton assuming CO_2 purchase from industrial or fossil power plants[13] including CO_2 pressurization at 70 bar and transport. Based on previous ENEA studies, the water consumption was neglected given its low impact on the overall LCOX.

Numerical assumptions are summarized in § 3.2.

2.1.3 Load factor and electricity price

Figure 6 illustrates that the price of electricity significantly fluctuates on a daily time scale, even reaching zero during some off-peak hours. As a result, power-to-X plants should be operated preferably when the price of electricity is at its lowest value to minimize the LCOX. However, operating the plant only during these periods would not allow for CAPEX amortization. Consequently, a compromise must be found between CAPEX amortization and running the plant only during the cheapest hours.

In practice, finding this compromise consists of determining the load factor H (in hours/year) that minimizes the LCOX. Indeed, for a given load factor of H hours per year, the best strategy to minimize the LCOX is to operate the plant only during the H cheapest hours of the year[14]. In practice, these hours can be identified on a "price duration curve",

[12] A 10 MW_{el} power-to-SNG plant consumes 44 Nm3/h of CO_2, compatible with CO_2 flowrates of typical biogas plants (114 Nm^3/h or 205 kg/h [2]). CO_2 for methanation could then be recovered at reduced cost from biogas plants capturing CO_2 for biomethane production. The price of CO_2 would then comprise conditioning and transport costs only.

[13] The power-to-methanol case is modeled based on a 10 MW_{el} input but commercial target capacities range from 70 to 140 MW_{el} (equivalent to 50 to 100 ktpa) [34]. This corresponds to a CO_2 consumption of 8.6 to 17.3 t_{CO2}/h (1.38 kg_{CO2}/kg_{MeOH}). Methanol plants are thus likely to be supplied with CO_2 coming from large scale industrial plants or fossil power plants.

[14] In this study, power-to-X plants are assumed to be ideally flexible, with no start up or shut down constraints and costs.

where hourly electricity prices are sorted from the cheapest to the most expensive. Price duration curves of some European countries including France, Denmark, Sweden and Norway in 2014 are shown in Figure 7[15].

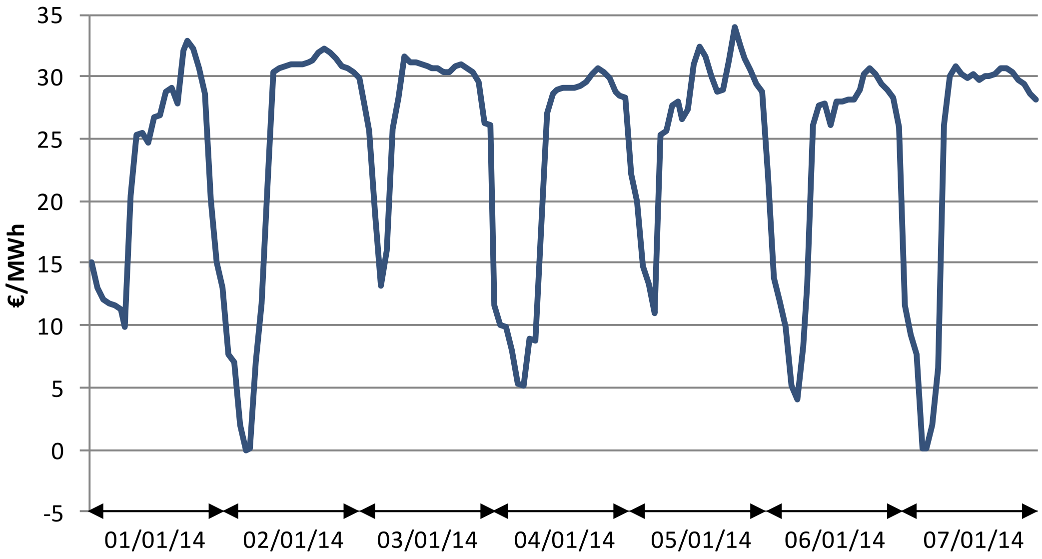

Figure 6 – Spot NordPool prices of electricity in Denmark (DK1 zone) during the first week of January 2014

The average price of electricity over the H cheapest hours of the year thus represents the lowest average electricity price a power-to-X plant can pay. Figure 8 shows that this average electricity price varies with the load factor at different locations. For example, a plant running 2,000 hours in West Denmark (zone DK1) would buy electricity at a minimum average cost of 18.7 €/MWh in 2014 (see Figure 8).

Renewable energy sources represent an important fraction of the mix in Denmark (e.g. wind represents almost 40 % of the electricity consumed). Even if strong interconnections with Norway and Germany dampen electricity price variations, the DK1 curve exhibits the lowest prices under 1,000 hours of operation (see Figure 8). In this study, the DK1 profile was chosen for the 2015 horizon to assess the competitiveness of power-to-X plants having access to electricity at a particularly low price for a limited number of hours per year.

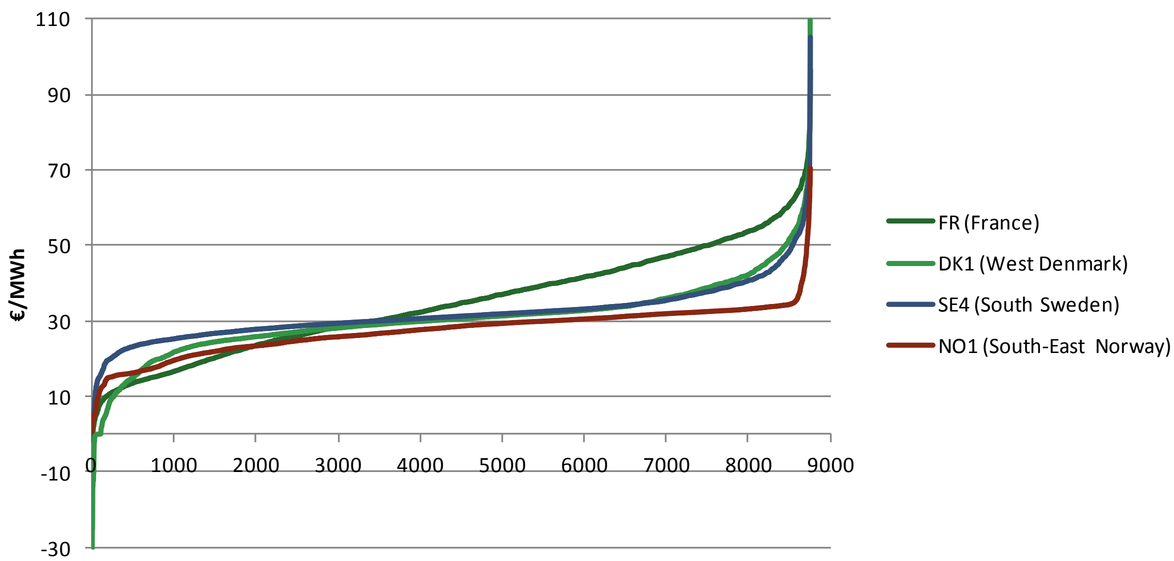

Figure 7 – Electricity spot price duration curve for selected European zones in 2014

[15] Negative prices are a consequence of renewable injection priority on the electricity grid

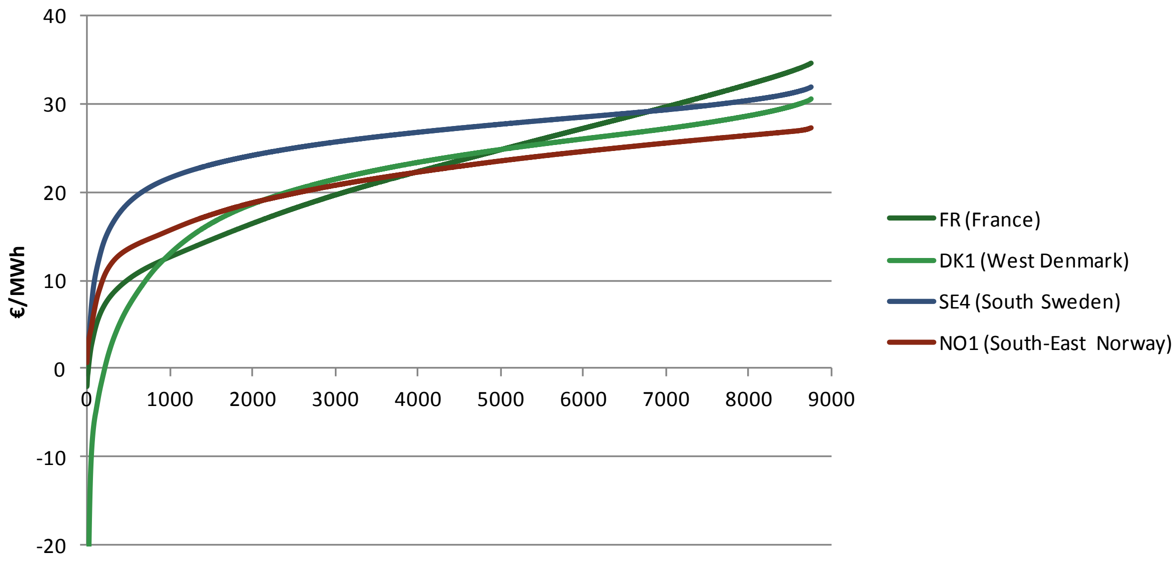

Figure 8 – Minimum average electricity spot price for selected European zones in 2014

For the 2030 and 2050 horizons, prospective scenarios of electricity price were used. Figure 9 shows several price duration curves found in the literature and derived from models of electricity markets with increased shares of intermittent renewable capacities for Germany (DE) or Great Britain (GB). These curves have been extracted from three publicly available documents:

- A thesis published in 2011 by Marco Nicolisi (EWI – University of Köln) [27],
- A presentation performed in 2013 by Alfred Voss (IER – University of Stuttgart) [28],
- A report published in 2014 by DNV GL in cooperation with the Imperial College and NERA Economic Consulting [29].

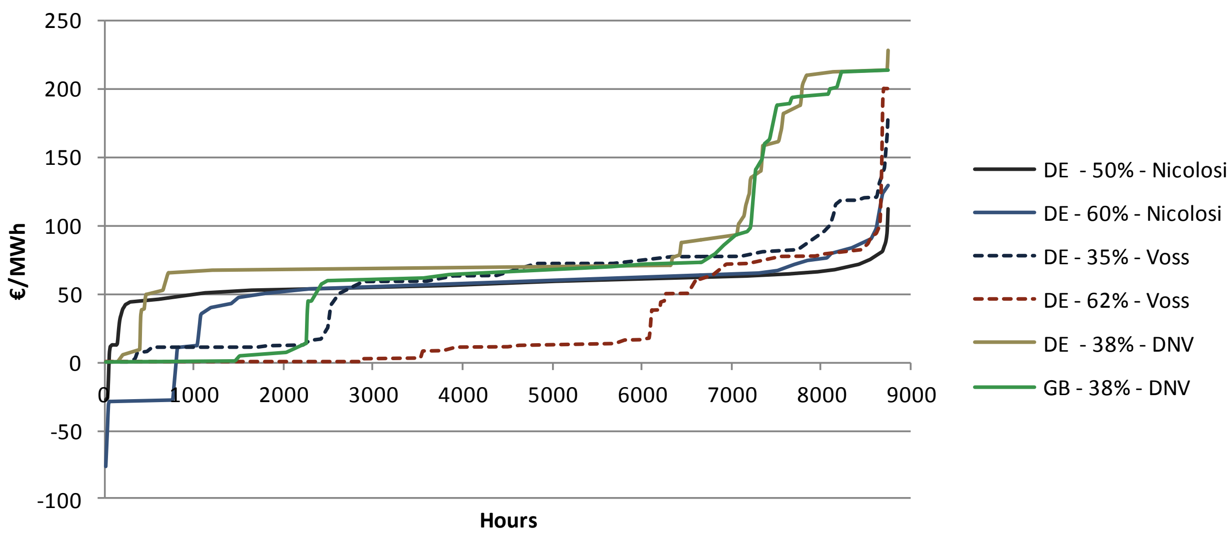

Figure 9 – Prospective price duration curves derived from models and published in the literature. Curve names mention the country, the share of intermittent renewable capacity (wind and solar) and the source.

These price duration curves are the result of complex models developed by the authors of the documents, based on numerous hypotheses related to offer and demand, regulations and incentives, storage capacities and technologies[16],

[16] The use of power-to-gas might be included in these prospective scenarios but is not mentioned in the previously quoted documents.

interconnection with neighbouring countries. Analyzing and discussing those hypotheses is out of the scope of this study.

The curves produced by Voss for Germany were selected for the 2030 and 2050 horizons. They exhibit long periods of cheap electricity, therefore allowing us to test the potential of power-to-X in such favourable conditions.

Figure 10 presents the minimum average electricity price curves calculated from three curves in Figure 8 and Figure 9 and used in our model for each time horizon. The minimum average electricity price of a number of hours X is the average price of the cheapest X hours of the year. For up to 3,500 hours of operation, it is cheaper to procure electricity in the 2030 scenario than in the 2015 scenario but more expensive for higher load factors. The 2050 scenario exhibits the cheapest prices with a price close to zero for up to 4,000 hours a year, but no negative price[17].

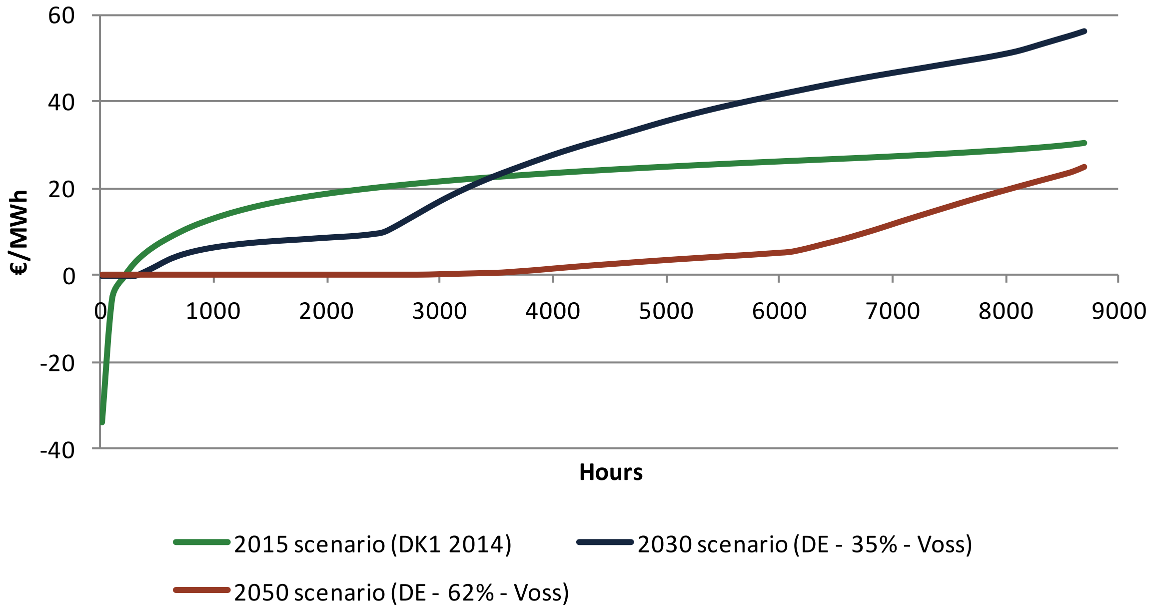

Figure 10 – Minimum average electricity spot prices selected

In addition to the generation costs (embodied in the spot price), the cost of electricity for the consumer includes transmission and distribution grid fees and taxes.

The calculation of grid fees generally includes a fixed factor (subscribed capacity), a variable factor (proportional to the amount of energy consumed), but differs between countries and can depend on the period of consumption. In this study, a purely variable grid fee of 10 €/MWh has been assumed (the average value of transmission grid fees is comprised between 5 and 15 €/MWh in most European countries [30]).

In Europe, a growing share of electricity taxes is dedicated to the support of the development of renewable energy. This renewable tax is mostly calculated on a variable basis (i.e. proportional to the consumption). However, different mechanisms of tax exemption or cap for industrial consumers or electricity storage facilities are currently in place depending on the country and its energy regulation framework. In Germany for instance, the tax is mainly applied to domestic consumers while industrial consumers and electricity storage facilities are exempted. In France the "CSPE" is capped, lowering its impact for electricity-intensive consumers. Both the tax level (today, typically between 20 and 60 €/MWh – e.g. in Germany) and tax application (fixed/variable tax, domestic/industrial consumers) might change in the future. As a result, we chose to calculate the LCOX excluding the cost of any taxes for the nominal case. The impact of different levels of variable electricity tax is then assessed and discussed (20, 40 and 60 €/MWh).

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[17] Representative of a market where renewable injection has no more priority.

2.1.4 Products market prices

The competing products selected for comparison with power-to-X products are listed in Table 1. For each product a range of market prices is defined with a low and a high value that aim at representing possible prices for the different time horizons considered.

For fossil fuels (natural gas and gasoline), the low value is the current market price and the high value is the forecast market price for 2030. The latter value is based on oil and gas spot prices in 2030 in the New Policies scenario of the IEA World Energy Outlook published in 2012 with an additional CO_2 tax of 100 €/t_{CO2}.

For biomethane, ethanol and BioCNG, forecast prices for 2030 are hardly predictable. The low and high market prices are thus set as current low and high production costs of the products.

Market prices for grid injection are calculated in €/MWh_{HHV}. For biomethane, the injection costs are included in the production costs. Market prices for mobility fuels are calculated at refuelling station and in €/100km assuming fuel consumption of light duty vehicles. The market price of heat from natural gas is calculated in €/MWh_{th} and assumed to be the fuel cost of natural gas consumed in a 90 % efficiency gas boiler (costs of the boiler are not relevant since no downscaling of the gas boiler is considered in our power-to-heat case study).

Table 1 sums up the low and high prices calculated (refer to § 3.4 for assumptions used in calculations).

Product	Price unit	Low price	High price
Natural gas	€/MWh_{HHV}	22.0	47.8
Biomethane	€/MWh_{HHV}	62.1	103.4
Gasoline without taxes	€/100km	2.7	4.2
Gasoline with taxes	€/100km	6.6	9.1
Ethanol	€/100km	3.8	4.6
BioCNG	€/100km	5.6	12.6
Heat from natural gas	€/MWh_{th}	32.7	62.3

Table 1 – Product market prices for power-to-X business cases

2.2 Power-to-gas for grid injection

2.2.1 Main results

Three case studies focus on grid injection: the first one is a small scale (1 MW_{el}) power-to-hydrogen plant injecting into the distribution grid; the second case is a larger scale power-to-hydrogen plant (10 MW_{el}) injecting into the transmission grid; the third case is a power-to-methane plant with a capacity of 10 MW_{el} injecting into the transmission grid.

For the three case studies, the lowest LCOX are reached in the 2050 scenario, benefiting from the lowest CAPEX and the lowest electricity prices[18]. Whatever the scenario, no power-to-gas case reaches competitiveness with natural gas under our hypotheses [19]. The cost of the injected gas is however of the same order of magnitude as the current cost of biomethane, from now on for the 10 MW_{el} power-to-hydrogen case, and in the 2050 scenario for all three case studies.

Power-to-hydrogen at small scale (1 MW_{el}) could compete with biomethane in the 2050 scenario with an LCOX of 80 €/MWh_{HHV}. With taxes applied on electricity purchase, this case study rapidly goes beyond areas of competitiveness with LCOX from 110 to 170 €/MWh_{HHV} in the 2050 scenario.

The 10 MW_{el} power-to-hydrogen case offers lower LCOX thanks to scale effects. Without taxes on electricity the 2015 and 2030 scenarios have an optimal LCOX of 95 and 110 €/MWh_{HHV} respectively which is in the upper bound of the biomethane production costs. The 2050 scenario offers an LCOX of 50 €/MWh_{HHV} which could compete with future prices of natural gas depending on the natural gas spot price and CO_2 taxes. If taxes are applied on electricity purchase, the 2015 and 2030 scenarios cannot compete anymore with biomethane (LCOX between 130 and 205 €/MWh). The 2050 scenario could still compete with biomethane if electricity taxes are lower than 40 €/MWh.

The 10 MW_{el} power-to-methane case study has the highest LCOX due to increased CAPEX and reduced energy efficiency due to the additional methanation step. Even with tax-free electricity the LCOX of the 2015 and 2030 scenarios are by far out of the competitiveness area with LCOX of respectively 170 and 185 €/MWh_{HHV}. In the 2050 scenario, the LCOX could go down to 95 €/MWh without electricity taxes which is close to the upper bound of the current biomethane cost.

More generally, our modelling shows that economic viability of power-to-gas for grid injection requires to reduce CAPEX by a factor 2 and to benefit from very low electricity prices. Gains on CAPEX are possible with R&D efforts on electrolysis and methanation and with project costs optimisation (e.g. mutualisation of infrastructures, standardization of procedures and equipments). Nevertheless, a reduction by 2 of the total CAPEX of power-to-gas projects seems a very ambitious target. The purchase of electricity at a price sufficiently low (i.e. 15 €/MWh during 6,000 hours/year) requires an electric mix with very high shares of wind and solar power (typically 60 % in capacity) and exemption of the power-to-gas plant from paying for the fixed cost of such renewable mix. This could be achieved whether through tax exemption or in specific project configurations (power-to-gas plant located at an industrial site already exempted from the tax for instance, or at a baseload production plant depending on the regulation framework).

[18] The LCOX in the 2030 scenario are higher than in the 2015 scenario because of higher prices of electricity at optimal load factors.
[19] Except for the 10 MW_{el} power-to-hydrogen case in 2050, that reaches a cost of 50 €/MWh_{HHV}, comparable to the upper bound of natural gas price range

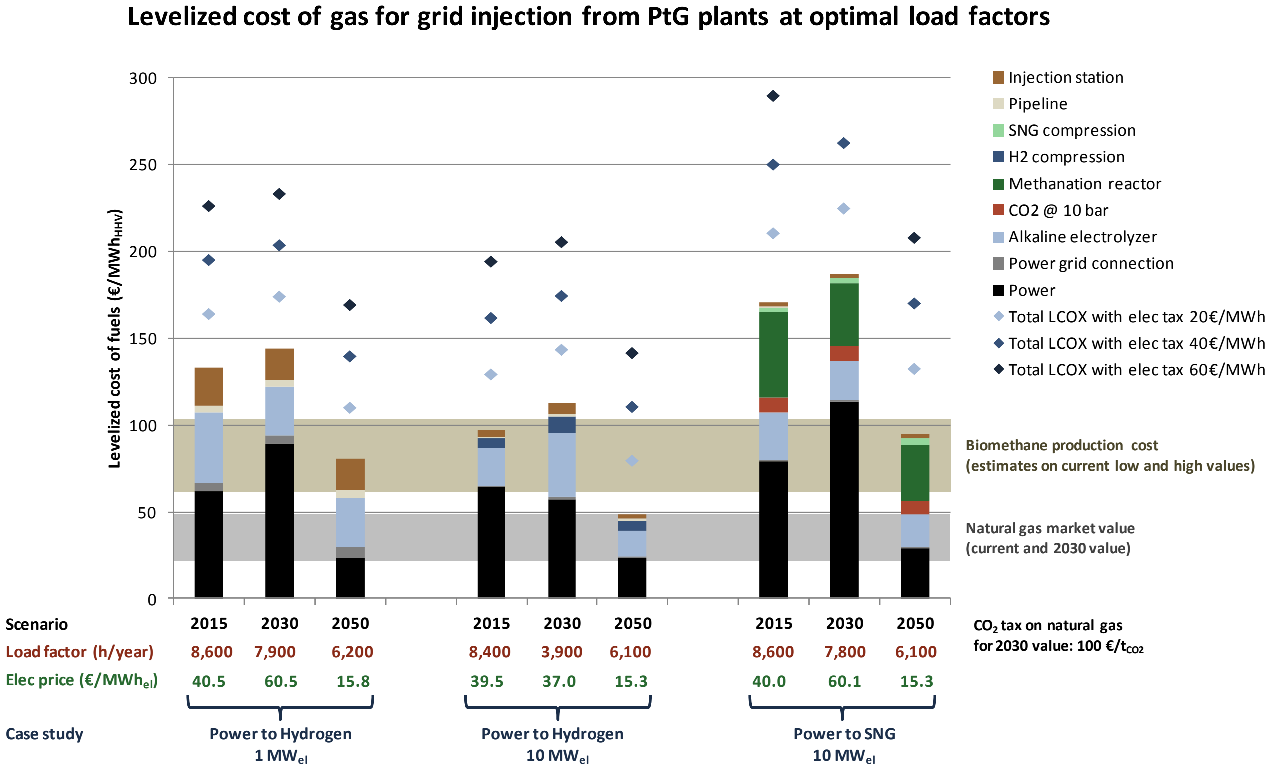

Figure 11 – Levelized costs of hydrogen and SNG produced from power-to-gas plants for grid injection for the three relevant case studies, three time horizons (2015, 2030, 2050) and for the load factor minimizing the LCOX (refer to 2.2.2 for details on load factor impact on LCOX); grid fees are taken into account while electricity tax is not in the nominal case. The effect of electricity taxes is shown separately for three different levels of taxes (20, 40 and 60 €/MWh) and is materialized by blue markers on the graph. Finally, ranges of cost of biomethane and price of natural gas are displayed for comparison (refer to §2.1.4 for details).

2.2.2 Sensitivity analysis

Figure 12, Figure 13 and Figure 14 below display the levelized cost of gas as a function of load factor for the three grid injection case studies.

Whatever the business case and time horizon, the plant must run a relatively high number of hours in the year to amortize the CAPEX. Operation of a power-to-gas asset for only 1,000 or 2,000 hours per year is economically inefficient given the high CAPEX of the facility. The minimum load factor required to reach the low LCOX area varies from 2,500 and 8,000 hours depending on assumptions on CAPEX and electricity prices.

Sensitivity analysis on other parameters of business cases highlights that long distances between the plant and the power grid or gas grid can rapidly increase costs. The electrolyzer efficiency also plays a significant role in the economics of business cases but margins of improvements are reduced. Variations on assumptions on the CO_2 purchase price has a reduced impact on the LCOX of methane (refer to § 3.5 for detailed results).

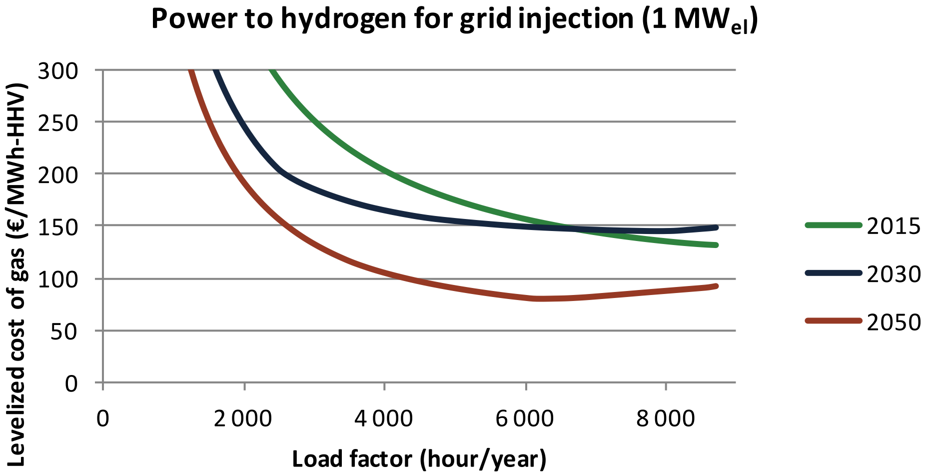

Figure 12 – Sensitivity of the levelized cost of hydrogen for grid injection (1 MW_{el}) to electricity price and load factor; LCOX is calculated with a price of electricity including the spot price and the grid fee but excluding taxes

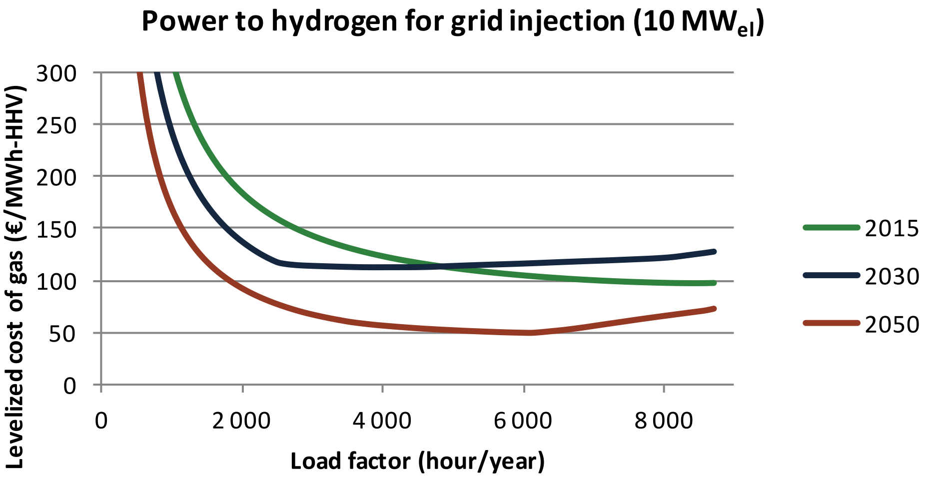

Figure 13 – Sensitivity of the levelized cost of hydrogen for grid injection (10 MW_{el}) to electricity price and load factor; LCOX is calculated with a price of electricity including the spot price and the grid fee but excluding taxes

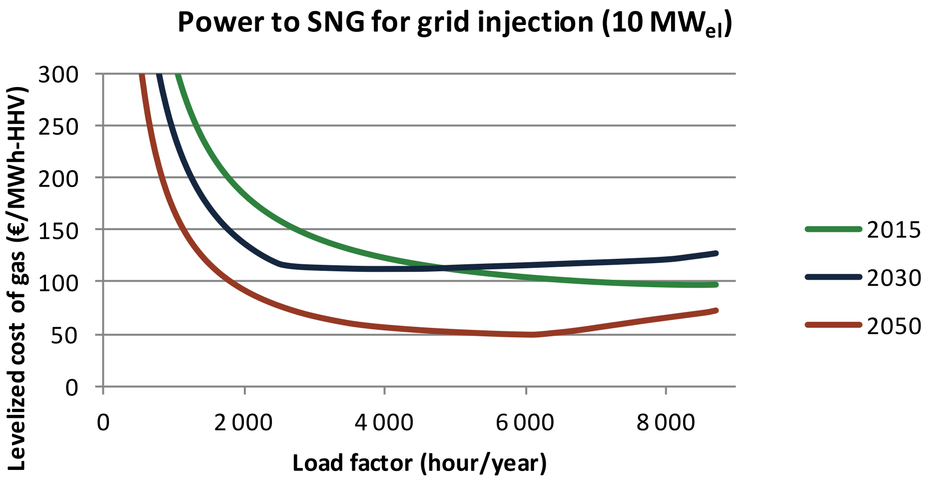

Figure 14 – **Sensitivity of the levelized cost of SNG for grid injection (10 MW_{el}) to electricity price and load factor; LCOX is calculated with a price of electricity including the spot price and the grid fee but excluding taxes**

2.3 Power-to-gas and power-to-liquids for mobility

2.3.1 Main results

Two case studies focus on mobility: the first is a 1 MW_{el} power-to-hydrogen refuelling station, the second is a 10 MW_{el} power-to-methanol plant.

For the two case studies, the lowest LCOX are reached in the 2050 scenario, benefiting from the lowest CAPEX and the lowest electricity prices[20]. Depending on scenarios and assumptions on electricity tax, hydrogen and methanol cost vary from 5 to 16 €/100km which is comparable to the range of production cost of bioCNG (6 to 12 €/100km) but it is systematically higher than the price of gasoline before taxes[21] (2.5 to 4 €/100km).

In the 2015 and 2030 scenarios, hydrogen and methanol must be produced from tax-free electricity to have an LCOX ranging in prices of taxed-gasoline. In the 2050 scenario, they reach competitiveness with taxed-gasoline even if produced with a purchase price of electricity between 40 to 80 €/MWh (i.e. including electricity tax). This is the result of low spot prices of electricity and CAPEX reduction assumed in the 2050 scenario.

As a result, it is likely that in the medium to long term, gains on CAPEX achieved with R&D efforts on electrolysis, standardization of hydrogen refuelling stations and scale effect on the methanol plant will be sufficient for power-to-hydrogen and power-to-methanol to become economically viable if the fuels produced are not taxed (i.e. competing with prices of taxed-gasoline). Moreover, both options are already competitive, and power-to-hydrogen in particular, with certains "green" fuels such as BioCNG for instance. Competitiveness with untaxed fossil fuels or ethanol is however likely to stay out of reach.

[20] The LCOX in the 2030 scenario are higher than in the 2015 scenario because of higher prices of electricity at optimal load factors.

[21] The price before taxes still includes a CO_2 tax of 100 €/t_{CO2} for the upper bound of the range (2030 value).

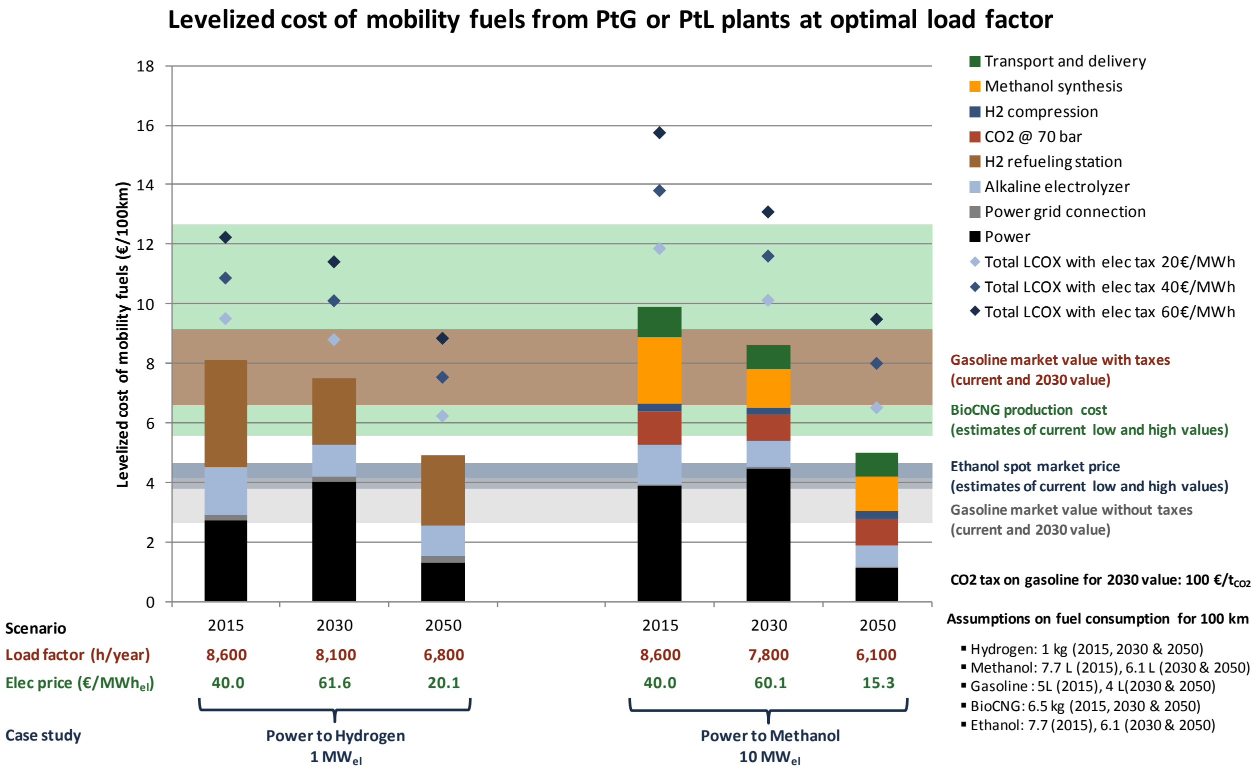

Figure 15 – Levelized costs of hydrogen and methanol produced from power-to-X plants for mobility for three time horizons (2015, 2030, 2050) and for the load factor minimizing the LCOX (refer to §2.2.2 for details on load factor impact on LCOX); the LCOX does not account for possible tax on the fuel product; grid fees are taken into account while electricity tax is not in the nominal case. The effect of electricity taxes is shown separately for three different levels of taxes (20, 40 and 60 €/MWh) and is materialized by blue markers on the graph. Finally, ranges of price of gasoline (with and without taxes), and cost of BioCNG and ethanol are displayed for comparison (refer to §2.1.4 for details).

2.3.2 Sensitivity analysis

Figure 16 and Figure 17 below display the levelized cost mobility fuel as a function of load factor for the two power-to-mobility case studies. Whatever the business case and time horizon, the plant must run at least 6,000 hours in the year to amortize the CAPEX.

Sensitivity analysis on other parameters of business cases highlights that the LCOX is mostly sensitive to CAPEX, and electricity price. The electrolyzer efficiency also plays a significant role in the economics of business cases but margins of improvements are reduced. Variations on assumptions on the CO_2 purchase price has a reduced impact on the LCOX of methanol (refer to § 3.5 for detailed results).

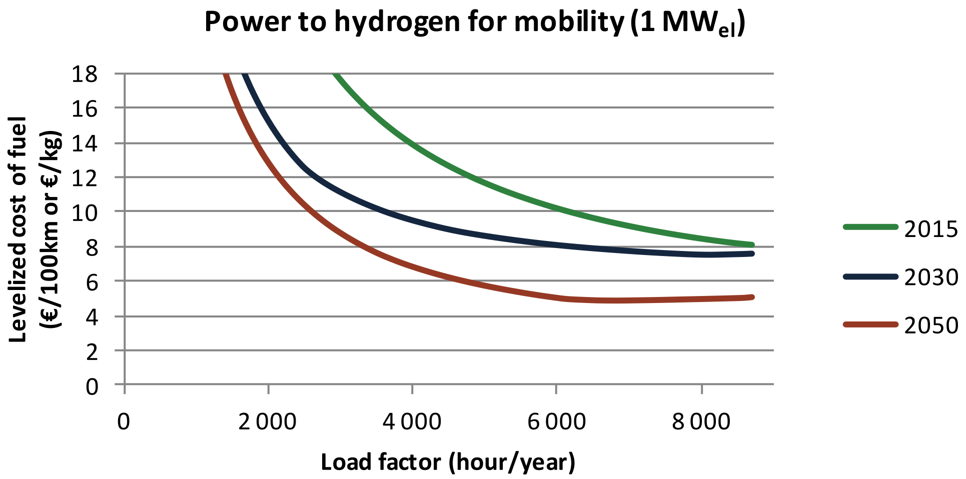

Figure 16 – Sensitivity of the levelized cost of hydrogen for mobility (1 MW_{el}) to electricity price and load factor; LCOX is calculated with a price of electricity including the spot price and the grid fee but excluding taxes

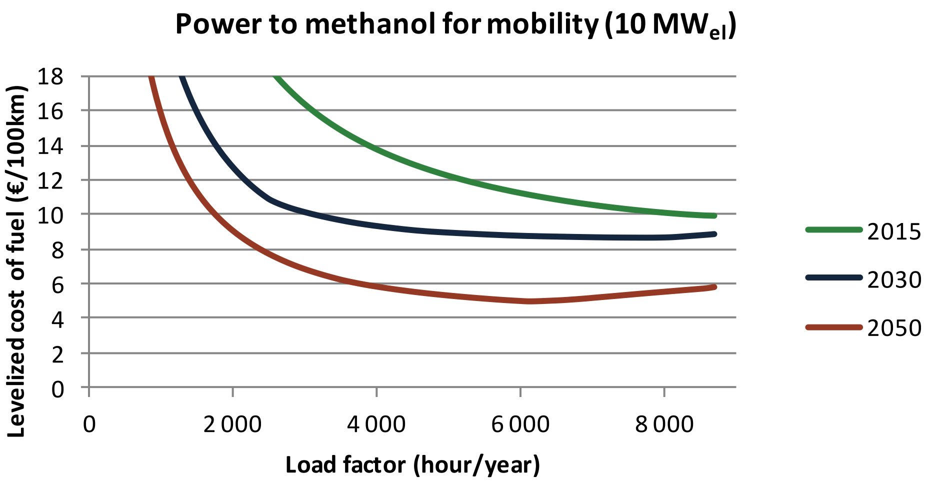

Figure 17 – Sensitivity of the levelized cost of methanol for mobility (10 MW_{el}) to electricity price and load factor; LCOX is calculated with a price of electricity including the spot price and the grid fee but excluding taxes

2.4 Power-to-heat for industry

2.4.1 Main results

One case study focuses on power-to-heat with a 10 MW_{el} electrode boiler producing steam at an industrial site. Nominal LCOX breakdown shown in Figure 18 indicate that independently from the scenario, the purchase price of electricity is the main contributor to the levelized cost of heat. The low CAPEX contribution to the LCOX allows power-to-heat plants to operate on a reduced number of hours (typically 1,000 or 2,000 hours per year). Depending on the cost of heat from natural gas (current and forecast), the threshold electricity purchase price required for competitiveness ranges between 20 and 50 €/MWh. More generally, the economical viability of the case relies on the spread of electricity and natural gas prices. Such a spread in favour of electricity becomes likely with possible future increase of taxes on fossil fuels and CO_2 and increased shares of renewable electricity.

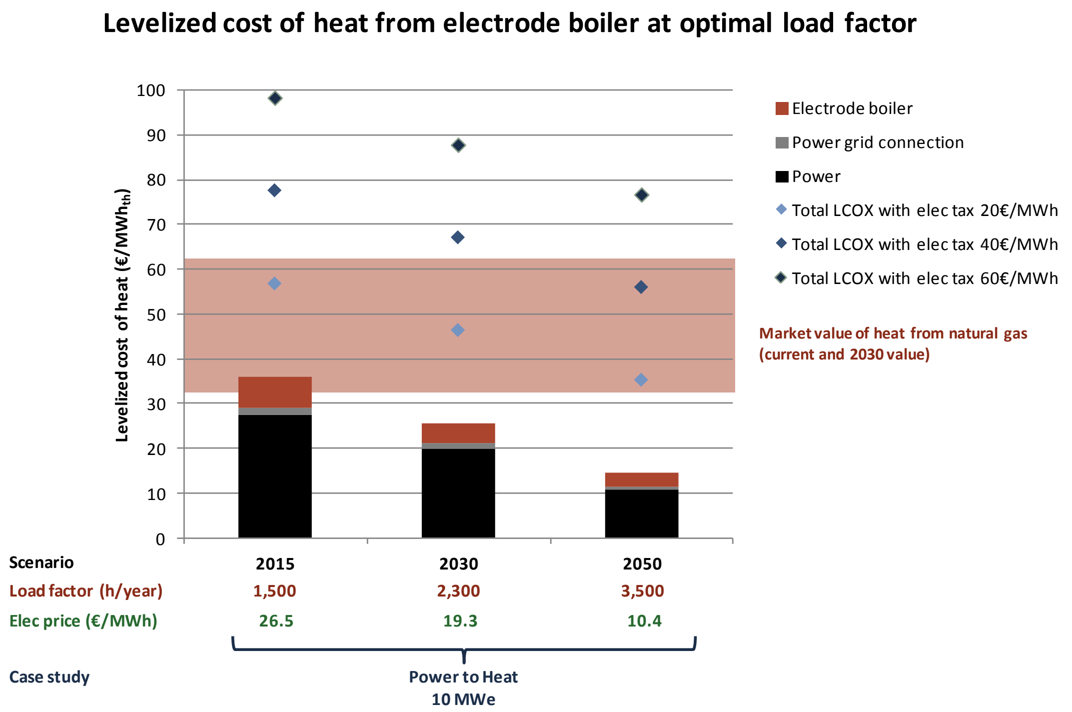

Figure 18 – Levelized costs of heat produced from a power-to-heat plant for three time horizons (2015, 2030, 2050) and for the load factor minimizing the LCOX (refer to §2.2.2 for details on load factor impact on LCOX); grid fees are taken into account while electricity tax is not in the nominal case. The effect of electricity taxes is shown separately for three different levels of taxes (20, 40 and 60 €/MWh) and is materialized by blue markers on the graph. Finally, the range of price of heat produced from a natural gas boiler is displayed for comparison (refer to §2.1.4 for details).Sensitivity analysis

2.4.2 Sensitivity analysis

Figure 19 displays the levelized cost of heat as a function of load factor for the power-to-heat case study. Given the low CAPEX, the plant is suited for operation at reduced load factor: after 1,000 hours of operation, the cost of heat is driven up by the purchase price of electricity in the three scenarios.

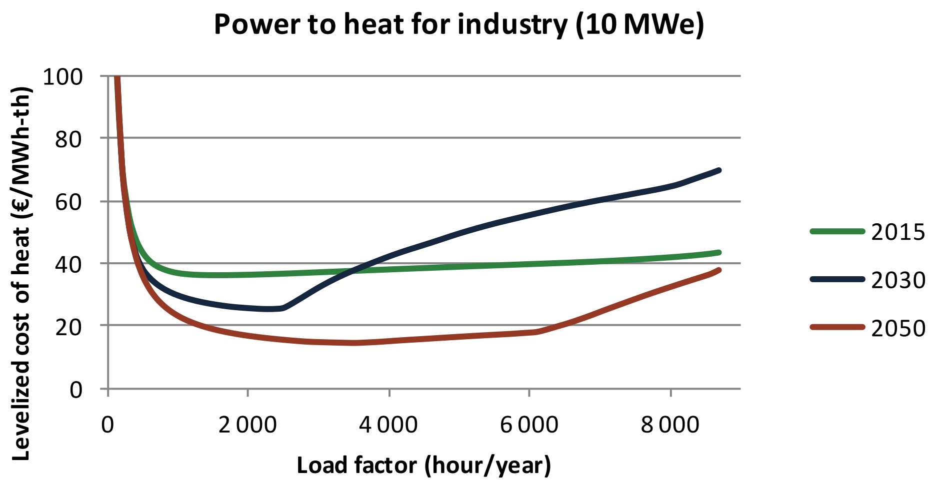

Figure 19 – Sensitivity of the levelized cost of heat to electricity price and load factor; LCOX is calculated with a price of electricity including the spot price and the grid fee but excluding taxes

Sources

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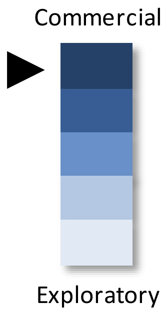
3 Appendix

3.1 Technology fact sheets

Alkaline electrolyzer	
Technical-economic specifications	
Pressure of hydrogen delivered:	Alkaline electrolyzers for the industry are typically operated at atmospheric pressure. Pressurized hydrogen at 10-15 bar can be delivered with small pressurized cell stacks. Research and development is ongoing for higher pressure stacks.
Operating temperature:	60 – 80 °C
Hydrogen purity:	▪ **99.5 %** before purification (H_2 contains water and oxygen) ▪ **>99.999 %** after the purification unit (deoxidiser and dryer)
Energy efficiency (HHV):	▪ **74 % to 78 %** with H_2 at atmospheric pressure (4.6 to 4.8 $kWh_{el}/Nm3_{H2}$). ▪ **66 %** with H_2 delivered at 10 bar (5.4 $kWh_{el}/Nm3_{H2}$) Figures include energy consumption of auxiliaries and purification unit.
Cell stack capacity:	▪ **400 to 500 Nm^3/h** for the largest atmospheric pressure stacks ▪ **60 Nm^3/h** for the currently mature pressurized stacks
Start-up time:	▪ **10 to 40 minutes** for cold start-up (depends on the initial temperature) ▪ **few seconds** for standby start-up (auxiliaries ready to run)
Lifetime	▪ **60,000 hours** for the cell stack ▪ **20 – 30 years** for the rest of the full installation
CAPEX:	**Current costs:** Total installed CAPEX for turnkey delivery of a 10 bar electrolyzer including balance of plant, transport, installation and commissioning, excluding civil work and connection to other section of the plant: ▪ 500 kW: 2000 €/kW ▪ 1 MW: 1500 €/kW ▪ 10 MW: 1000 €/kW The purification unit generally represents 5 to 10% of the factory gate cost of the electrolyzer. Transport, integration, installation and commissioning generally represent 10 to 20% of the factory gate of the electrolyzer. **Possible levers for cost reduction thanks to technology improvement (not quantified):** ▪ The increase of the membrane surface of cell stacks will increase the throughput of each cell stack and then reduce the number of auxiliaries per stack. **Possible cost reduction thanks to scale effect on the market volume manufacturing (maximum 10 to 20% of cost reduction):** ▪ Reduction of cost of equipments purchased to suppliers due to the increase of the market and competing effect. ▪ Reduction of margins thanks to higher volumes produced and less R&D efforts.

OPEX:	**Cost of operation and maintenance (excluding cell stack replacement):** ▪ 1-2 % of CAPEX/year (for a 10 MW electrolyzer) ▪ 4-5 % of CAPEX/year (for a 1 MW electrolyzer) **Replacement cost of cell stack:** Approximately 30 % of the total CAPEX every 60,000 hours of operation.

Advantages	Drawbacks
▪ The only current mature technology ▪ Current cheapest technology ▪ Long lifetime	▪ Low margin of improvement on CAPEX ▪ Hazardous corrosive electrolyte

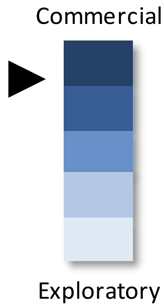
Maturity		Technology suppliers/developers
TRL 9: Commercial The technology is used for decades in the industry at scales compatible with power-to-gas applications (1-10 MW_{el}).		▪ Hydrogenics, ▪ NEL Hydrogen ▪ McPhy Energy ▪ IHT ▪ WEJT ▪ ELB Elektrolyse Technik ▪ H2 Nitidior ▪ Erredue ▪ Accagen

Sources used in the factsheet: [3] [1] [5] [2]

PEM electrolyzer

Technical-economic specifications	
Pressure of hydrogen delivered:	Current commercial products generally deliver hydrogen up to 30 bar. Technology developers intend to pressurize the stack up to 80 bar.
Operating temperature:	60 – 80°C
Product purity:	▪ **99.95 %** before purification (H_2 contains water and oxygen) ▪ **>99.9998 %** after the purification unit (deoxidiser and dryer)
Energy efficiency (HHV):	Expected to be slightly higher than for alkaline electrolysis. Commercial performance at large scale (10 MW_{el}) to be confirmed.
Cell stack capacity:	Up to 200 Nm^3/h under current demonstration.
Start-up time:	▪ **10 to 40 minutes** for cold start-up (depends on the initial temperature) ▪ **few seconds** for standby start-up (auxiliaries ready to run)
Lifetime	▪ **40,000 hours** for the cell stack ▪ **20 – 30 years** for the rest of the full installation
CAPEX:	PEM technology is more compact than the alkaline with a higher throughput per cell stack, reducing the number of auxiliaries required. CAPEX targets for technology developers are: ▪ In the coming years: - 10 MWe: 1000 €/kW_{el} ▪ 2030 - 1 MWe: 1000 €/kW_{el} - 10 MWe: 700€/kW_{el} ▪ 2050 - 1 MWe: 500-550 €/kW_{el} - 10 MWe: 350-400 €/kW_{el} The CAPEX includes turnkey supply with balance of plant, transportation and commissioning:
OPEX:	**Cost of operation and maintenance (excluding cell stack replacement):** ▪ 1-2 % of CAPEX/year (for a 10 MW electrolyzer) ▪ 4-5 % of CAPEX/year (for a 1 MW electrolyzer) **Replacement cost of cell stack:** Approximately 50 % of the total CAPEX every 40,000 hours of operation.

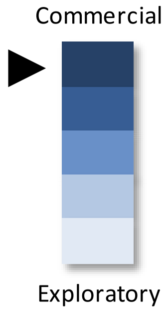
Advantages	Drawbacks
▪ Offers CAPEX reduction margins ▪ Easier to operate than alkaline technology (e.g. no hazardous circulating electrolyte)	▪ Reduced lifetime of the cell stack ▪ Not commercial at large scale yet

Maturity	**Technology suppliers/developers**
TRL 7-8: Commercial demonstration The technology is used commercially at small scale and under commercial demonstration at large scale for power-to-gas applications (1-10 MW_{el}). 	▪ Proton Onsite ▪ ITM Power ▪ SIEMENS ▪ AREVA H2 Gen ▪ Cerm Hyd ▪ Acta Spa ▪ H-Tec Systems

Sources used in the fact sheet: [3] [5] [2] [4]

Methanation isothermal reactor	
Technical-economic specifications	
CO_2 sulphur content:	Few ppm (sulphur deactivates Nickel catalysts)
Operating pressure:	Up to 10 bar
Operating temperature:	Around 450 °C on the catalyst
Heat recovery:	Steam production up to 80 bars and 300 °C.
Energy efficiency of the reaction (HHV):	79.4 %
Methane yield:	Reactors can reach a one-way yield of 96 %. Water produced by the reaction is removed by cooler and condenser unit and possibly by a dehydration unit depending on the specifications of downstream application.
Power consumption:	Power consumptions of auxiliaries used for the methanation reactor (pumps, instrumentation, etc.) are negligible compared to the electrolyzer power consumption.
Start-up time:	The main challenge for a quick start-up of a catalytic reactor is the progressive ramp up of temperature required to prevent the damaging of the catalyst. Two solutions can be envisaged: ▪ Continuous operation of the reactor thanks to hydrogen buffer storage upstream. ▪ Maintain the reactor at a sufficient temperature thanks to external heating or a thermal insulation of the reactor (e.g. if maintained at 250 °C the reactor can be started up in few minutes).
Lifetime	▪ **20,000 to 25,000 hours** for the catalysts when the reactor is cycling (not yet validated in commercial conditions) ▪ **20 years** for the reactor vessel
CAPEX:	**Estimated factory gate cost of a 5 $MW_{HHV\text{-}SNG}$ methanation reactor (no feedback available from commercial units):** ▪ For the coming years: 1,500 €/$kW_{HHV\text{-}SNGout}$ ▪ In 2030: 1,000 €/$kW_{HHV\text{-}SNGout}$ ▪ In 2050: 700 €/$kW_{HHV\text{-}SNGout}$ Additional costs for balance of plant, transport, installation and commissioning: 50 % of the factory gate cost.
OPEX:	**Cost of operation and maintenance (including catalyst replacement):** ▪ 5-10 % of CAPEX/year (for a reactor corresponding to a 10 MW_{el} electrolyzer input)

Advantages	Drawbacks
▪ Thermochemical catalytic processes are well known from the industry. ▪ Isothermal reactors are suited to capacities in the order of magnitude of 1-10 MW. ▪ Nickel is efficient and relatively cheap.	▪ Catalysts are not suited to intermittent operation. ▪ Temperature control inside the reactor is challenging.

Maturity	**Technology suppliers/Developers**
TRL 5-7: Technology development and demonstration The first generation of methanation reactors for power-to-gas application is under demonstration (e.g. Audi Werlte plant). New generation of technologies are under development (e.g. KIC InnoEnergy CO2SNG, DemoSNG projects). 	▪ Etogas ▪ CEA ▪ KIT ▪ MAN ▪ Haldor Topsoe

Sources used in the fact sheet: [2] [31] [7] [23]

3.2 Input data used in the model for LCOX calculation

All input data used in the model for the calculation of the levelized cost are given in the following tables. Most of input data are fixed (i.e. they do not vary with the scenario). Input data varying with scenario are the electrolyzer energy efficiency[22] and CAPEX of most of equipments. Data in grey rows are calculated from input data in white rows.

General assumptions	Unit	Fixed	2015	2030	2050
Project costs	*% of Total CAPEX of proces blocs*	30,0%			
WACC	*-*	8,0%			
Load factor	*h/year*	8 600			
Electricity cost	*€/MWhe*	60			
CO2 cost @ 10 bar	*€/ton*	50			
CO2 cost @ 100 bar	*€/ton*	100			
CO2 density	*ton/Nm3-CO2*	0,0018			
HHV volumic H2	*MWh/Nm3-H2*	0,0035			
HHV massic H2	*MWh/kg-H2*	0,0394			
HHV volumic SNG	*MWh/Nm3-SNG*	0,0113			
HHV massic SNG	*kWh/kg-SNG*	0,0145			
HHV massic MeOH	*kWh/kg-MeOH*	0,0056			
Power grid connection	**Unit**	**Fixed**	**2015**	**2030**	**2050**
Lifetime power grid connection	*years*	40			
Transformer capacity out - 1MW	*MWe*	1,0			
Transformer capacity out - 10MW	*MWe*	10,0			
Transformer losses	*%*	2,5%			
Length HV line	*km*	1,0			
Equipment CAPEX HV circuit breaker	*€*	125 000			
Specific equipment CAPEX HV line	*€/km*	100 000			
Equipment CAPEX transformer	*€*	30 000			
Fixed OPEX power grid connection	*%CAPEX/year*	0,00			
Alkaline electrolyzis 10 bar	**Unit**	**Fixed**	**2015**	**2030**	**2050**
Lifetime electrolyzer	*years*	25			
Electrolyzer capacity in - 1MW	*MWe*	1,0			
Electrolyzer capacity in - 10MW	*MWe*	10,0			
Electrolyzer efficiency	*kWhHHV-H2/kWhe*		66%	69%	69%
Electrolyzer capacity out - 1MW	*MWHHV-H2*	0,7			
Electrolyzer capacity out - 10MW	*MWHHV-H2*	6,9			
Specific equipment CAPEX electrolyzer - 1MW	*€/MWe in*	1 500 000	1 500 000	1 000 000	800 000
Specific equipment CAPEX electrolyzer - 10MW	*€/MWe in*	1 000 000	1 000 000	800 000	500 000
Fixed O&M electrolyzer - 1MW	*% CAPEX/year*	4,5%			
Fixed O&M electrolyzer - 10MW	*% CAPEX/year*	1,5%			
Methanation	**Unit**	**Fixed**	**2015**	**2030**	**2050**
Lifetime methanation reactor	*years*	20			
Methanation capacity out - 10MW	*MWHHV-SNG*	5,50			
Methanation efficiency	*MWhHHV-SNG out/MWhHHV-H2 in*	79,4%			
Factory gate specific cost methanation reactor - 10MW	*€/MWHHV-SNG out*		1 500 000	1 000 000	700 000
Additional costs methanation reactor	*% cost methanation reactor*	50%			
Fixed O&M methanation - 10MW	*% cost methanation reactor/year*	7,5%			
Methanation H2 consumption	*Nm3H2/Nm3SNG*	4,0			
Methanation CO2 consumption	*Nm3CO2/NmSNG*	1,0			

[22] A slight improvement on the energy efficiency of electrolysis can be envisaged in the future (from 66 to 69 %) thanks to improvements on cell stack compactness and increased mutualisation of auxiliaries. The energy efficiency of methanation and methanol synthesis is fixed in the model as the theoretical energy efficiency of the chemical reactions involved (i.e. 79.4 % for methanation and 75.5 % for methanol synthesis).

Compression H2	Unit	Fixed	2015	2030	2050
Lifetime compressor H2	*years*	15			
Compressor H2 capacity out - 1MW	*MWHHV-H2*	0,69			
Compressor H2 capacity out - 10MW	*MWHHV-H2*	6,93			
Factory gate cost compressor H2 - 1MW	*€*		200 000	180 000	160 000
Factory gate cost compressor H2 - 10MW	*€*	1 135 723			
Additional costs compressor H2	*% cost compressor*	15,0%			
Fixed O&M compressor H2 10-60bar	*% CAPEX/year*	6,0%			
Power consumption compressor H2 10-60bar	*MWhe/MWhHHV-H2*	0,07			
Compression SNG	**Unit**	**Fixed**	**2015**	**2030**	**2050**
Lifetime compressor SNG	*years*	15			
Compressor SNG capacity out - 10MW	*MWHHV-SNG*	6			
Factory gate cost compressor SNG - 10MW	*€*	567 862			
Additional costs compressor SNG	*% cost compressor*	15,0%			
Fixed O&M compressor SNG 10-60bar	*% CAPEX/year*	6,0%			
Power consumption compressor SNG 10-60bar	*MWhe/MWhHHV-SNG*	0,02			
Pipeline H2 & SNG	**Unit**	**Fixed**	**2015**	**2030**	**2050**
Lifetime pipeline	*years*	35			
Pipeline capacity out - 1MW	*MWHHV-H2*	0,69			
Pipeline capacity out - 10MW	*MWHHV-H2*	6,93			
Pipeline length	*km*	1,00			
Fixed equipment CAPEX pipeline H2 @10 bar	*€*	50 000			
Variable equipment CAPEX pipeline H2 @10 bar	*€/km*	130 000			
Fixed equipment CAPEX pipeline H2 @60 bar	*€*	200 000			
Variable equipment CAPEX pipeline H2 @60 bar	*€/km*	300 000			
Fixed O&M pipeline	*% CAPEX/year*	2%			
Injection station H2 & SNG	**Unit**	**Fixed**	**2015**	**2030**	**2050**
Lifetime injection station	*years*	15			
Injection station capacity out - 1MW	*MWHHV-H2*	0,69			
Injection station capacity out - 10MW	*MWHHV-H2*	6,93			
Total equipment CAPEX distribution injection station - 1MW	*€*		600 000	480 000	360 000
Total equipment CAPEX distribution injection station - 10MW	*€*		700 000	560 000	420 000
Total equipment CAPEX transport injection station - 1MW	*€*		700 000	560 000	420 000
Total equipment CAPEX transport injection station - 10MW	*€*		900 000	720 000	540 000
Fixed O&M injection station	*%CAPEX/year*	8,0%			
Refueling station H2	**Unit**	**Fixed**	**2015**	**2030**	**2050**
Lifetime H2 refueling station	*years*	30			
H2 refueling station capacity out - 1MW	*MWHHV-H2*	0,69			
Total equipment CAPEX H2 refueling station - 1MW	*€*		3 000 000	1 800 000	1 620 000
Fixed O&M H2 refueling station - 1MW	*%CAPEX/year*	7,5%			
Power consumption H2 refueling station	*MWhe/MWhHHV-H2*	0,18			
Methanol synthesis	**Unit**	**Fixed**	**2015**	**2030**	**2050**
Lifetime methanol reactor	*years*	20			
Methanol reactor capacity out - 10MW	*MWHHV-MeOH*	5,23			
Methanol reactor H2 consumption	*kgH2/kgMeOH*	0,19			
Methanol reactor CO2 consumption	*kgCO2/kgMeOH*	1,38			
Methanol synthesis efficiency	*MWhHHV-MeOH out/MWhHHV-H2 in*	75,5%			
Specific factory gate cost methanol reactor - 10MW	*€/MWHHV-MeOH out*		1 500 000	1 000 000	700 000
Additional cost methanol reactor	*% cost methanol reactor*	50%			
Fixed O&M methanol reactor - 10MW	*%CAPEX/year*	7,5%			
Electrode boiler	**Unit**	**Fixed**	**2015**	**2030**	**2050**
Lifetime electrode boiler - 10MW	*years*	40			
Electrode boiler capacity out - 10MW	*MWth*	10			
Electrode boiler efficiency	*MWhth/MWhe*	99%			
Specific equipment CAPEX electrode boiler - 10MW	*€/MWth out*	90 000			
Fixed O&M electrode boiler - 10MW	*%CAPEX/year*	1,3%			

Sources used for input data selection: [2][4][32][33][3][1][34][35][36][26] [37]

3.3 Calculated CAPEX of case studies

The total project CAPEX calculated for with the model is given for each case study and scenario in Table 2. The specific CAPEX is also given in €/kW_{el}-in.

Case study	Total project CAPEX	Specific CAPEX
Power-to-hydrogen for grid injection (1 MW_{el})	▪ 2015: 3,295,500 € ▪ 2030: 2,489,500 € ▪ 2050: 2,073,500 €	▪ 2015: 3,296 €/kW_{el}-in ▪ 2030: 2,490 €/kW_{el}-in ▪ 2050: 2,074 €/kW_{el} -in
Power-to-hydrogen for grid injection (10 MW_{el})	▪ 2015: 17,038,062 € ▪ 2030: 14,015,406 € ▪ 2050: 9,692,750 €	▪ 2015: 1,704 €/kW_{el} -in ▪ 2030: 1,402 €/kW_{el} -in ▪ 2050: 969 €/kW_{el} -in
Power-to-methane for grid injection (10 MW_{el})	▪ 2015: 30,741,773 € ▪ 2030: 23,268,547 € ▪ 2050: 15,874,391 €	▪ 2015: 3,074 €/kW_{el} -in ▪ 2030: 2,327 €/kW_{el} -in ▪ 2050: 1,587 €/kW_{el} -in
Power-to-hydrogen for mobility (1 MW_{el})	▪ 2015: 6,181,500 € ▪ 2030: 3,971,500 € ▪ 2050: 3,477,500 €	▪ 2015: 6,182 €/kW_{el} -in ▪ 2030: 3,972 €/kW_{el} -in ▪ 2050: 3,478 €/kW_{el} -in
Power to methanol for mobility (10 MW_{el})	▪ 2015: 29,799,950 € ▪ 2030: 22,636,728 € ▪ 2050: 15,485,875 €	▪ 2015: 2,980 €/kW_{el} -in ▪ 2030: 2,264 €/kW_{el} -in ▪ 2050: 1,549 €/kW_{el} -in
Power-to-heat for industry (10 MW_{el})	▪ 2015: 1,501,500 M€ ▪ 2030: 1,501,500 M€ ▪ 2050: 1,501,500 M€	▪ 2015: 150 €/kW_{el} -in ▪ 2030: 150 €/kW_{el} -in ▪ 2050: 150 €/kW_{el} -in

Table 2 – Calculated CAPEX of case studies

3.4 Input and assumptions used for products market price calculation

Input	Unit	Value	Sources	Comment/assumptions
2015 oil price	€/barrel	51.2		Spot price 01/04/2015
2030 oil price	€/barrel	98.11	[38]	IEA WEO new policies scenario
2030 CO_2 tax	€/t_{CO2}	100		Realistic figure regarding current trends on CO_2 tax increase in Europe.
Gasoline price in 2015 without taxes	€/L	0.53	[39] [40]	French production cost assumed representative of European production cost.
Gasoline price in 2030 without taxes	€/L	0.82	[39]	Calculated from the 2015 price and oil price variation with the assumption of oil price contributing to 60% of the production cost.
Share of taxes in final price of gasoline	%	60%	[39]	Value for France
2015 natural gas wholesale price	€/MWh_{HHV}	22		Spot price April 2015
2030 natural gas wholesale price	€/MWh_{HHV}	29.7	[38]	IEA WEO new policies scenario
Additional cost from wholesale and consumer price for natural gas	€/MWh_{LHV}	5	ENEA	ENEA analysis indicates typical value from 3 to 7 €/MWh_{LHV} for industrials depending on the contract.
Low spot price of ethanol	€/L	0.4	ENEA	Typical lower bound of spot prices in Europe
High spot price of ethanol	€/L	0.5	ENEA	Typical higher bound of spot prices in Europe
Additional cost of transport and delivery of ethanol at refuelling station	€/L	0.1	[39]	Assumed similar to the cost of transport and delivery of gasoline at refuelling station.
BioCNG low production cost	€/kg	1.1	ENEA	Include methanation plant, biogas upgrading and injection, gas transport and CNG station
BioCNG high production cost	€/kg	2.5	ENEA	Include methanation plant, biogas upgrading and injection, gas transport and CNG station
Biomethane low production cost	€/kg	0.9	ENEA	Include methanation plant, biogas upgrading and injection
Biomethane high production cost	€/kg	1.5	ENEA	Include methanation plant, biogas upgrading and injection

Table 3 – Input on the price of products and cost of fuel taxes

Fuel and vehicle type	Unit	Fuel consumption (current)	Future fuel consumption (2030)	Comment
Gasoline in an ICE car	L/100km	5	4	
Ethanol in an ICE car	L/100km	7.7	6.1	Similar energy consumption than for gasoline in an ICE car
Pure methanol for blending with gasoline and use in an ICE car	L/100km	10.2	8.2	Similar energy consumption than for gasoline in an ICE car
BioCNG in a CNG car	Nm^3/100km	6.5	6.5	
Hydrogen in a fuel cell car	Kg/100km	1	1	

Table 4 – Assumptions on the fuel consumption of light duty vehicles

3.5 Sensitivity analysis on other parameters than load factor

3.5.1 Analysis

The sensitivity analysis is performed on the LCOX for each case study with two types of variations around nominal values used for input parameters in the model for the 2015 scenario:

- A +/-10 % variation on each input parameter,
- A range variation on each input parameter.

The +/-10 % variation allows for the analysis of the inherent sensitivity of parameters. The range variation uses low and high values corresponding to an uncertainty margin on the nominal value chosen in the model. This uncertainty margin can be derived from uncertainties on technology performance or cost or from different possible project configurations (e.g. HV line or pipeline length to electric or gas grid).

Besides nominal values specific to technology blocks, the following common nominal parameters have been used for the analysis:

- Load factor : 6000 hour/year,
- Electricity price: 20 €/MWh,
- WACC: 8 %.

Detailed results of the sensitivity analysis are later presented in the form of tornado charts for each case study. We first propose a review of the key findings of the sensitivity analysis.

1. Variations on the costs of technologies under development (injection station, hydrogen refuelling station, methanation and methanol synthesis) can significantly modify the LCOX.

As shown in Table 5, range variations on the CAPEX and OPEX of technologies currently not commercial can significantly impact the LCOX (up to 19 % for the refuelling station). This reveals a high uncertainty on such values due to the lack of feedback from commercial plants operating these technologies.

Type of parameter	Technology/block	Range (Low/Nominal/High)	Variation on LCOX
CAPEX	Injection station (distribution)	500/600/700 k€ for H_2 injection (1 MW_{el})	-4 % to +4 %
CAPEX	H_2 refueling station	2/3/4 M€ for 1MW_{el}	-19 % to +19 %
CAPEX	Methanation reactor (without integration costs)	1200/1500/1700 €/kW_{out}	-8 % to +5 %
CAPEX	Methanol synthesis (without integration costs)	1200/1500/1700 €/kW_{out}	-7 % to +5 %
O&M	H_2 refuelling station	6 %/8 %/10 % of CAPEX (with integration costs)	-8 % to +8 %
O&M	Methanation reactor	6 %/8 %/10 % of CAPEX (with integration costs)	-5 % to +5 %
O&M	Methanol synthesis	6 %/8 %/10 % of CAPEX (with integration costs)	-5 % to +5 %

Table 5 – Results of the sensitivity analysis on the costs of technologies under development

2. Variations on input consumption and price impact all case studies concerned but are controlled.

Table 6 gives the results of the sensitivity analysis on energy efficiency of the electrolysis block and on the price of CO_2.

A variation of 5 percentage points in the electrolyzer efficiency can modify the LCOX of power-to-hydrogen case studies by 7 to 8 %. It is thus critical to properly assess the actual efficiency of an electrolyzer. The nominal value set in the model (66 % of efficiency including power consumption of electrolyzer auxiliaries) is derived from feedback of alkaline electrolyzer manufacturers and can be considered realistic.

The impact of the price of CO_2 on the LCOX is limited given the ranges chosen. If free CO_2 is considered, the LCOX can be reduced by 5 % for the power-to-methane case and by 10 % for the power to methanol case. However sources of free CO_2 (biomethane plants) would become scarce if power-to-gas and power to liquids markets grow. Free CO_2 is then an opportunity to reduce the LCOX but should not be used as a standard case.

Type of parameter	Technology/block	Range (Low/Nominal/High)	Variation on LCOX
Energy efficiency	Electrolyzer	61 %/66 %/71 %	-7 % to +8 % for H_2 cases -4 % to +4 % for SNG & MeOH cases
CO2 price	Methanation	20/50/80 €/t_{CO2}	-3 % to +3 %
CO2 price	Methanol synthesis	80/100/120 €/t_{CO2}	-3 % to +3 %

Table 6 – Results of the sensitivity analysis on energy efficiency and the price of CO_2

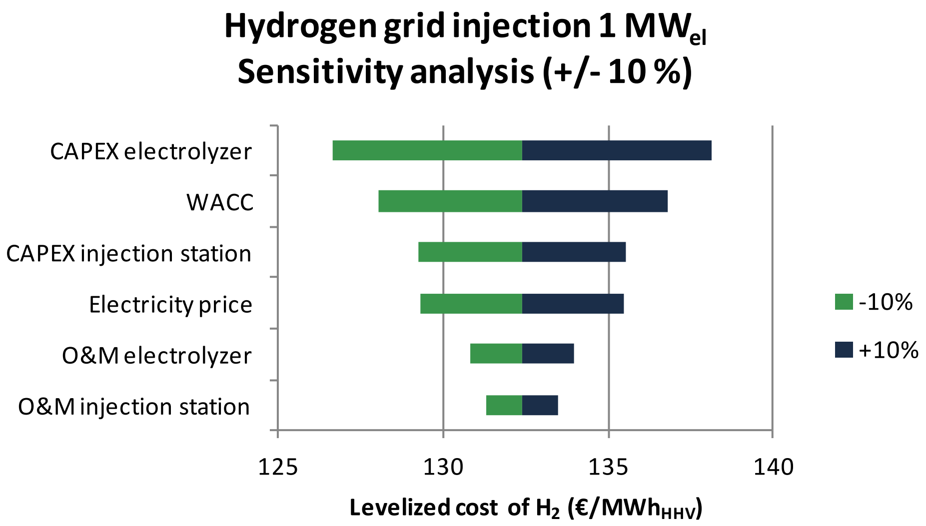
3. Long distances to power grid and gas grid can rapidly increase costs.

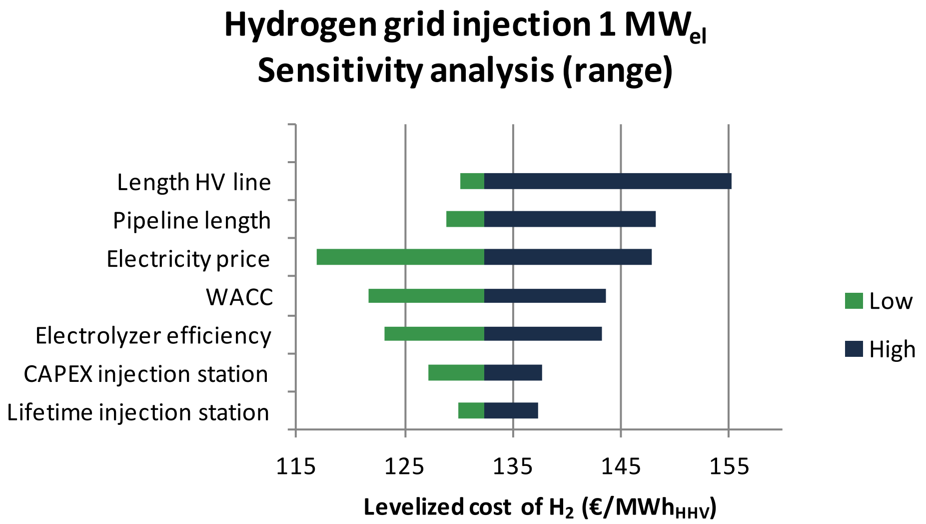
Table 7 gives the results of the sensitivity analysis on HV line and gas pipeline length. These parameters are sensitive for small scale capacities (1 MW_{el}) and depend on the project configuration. A plant located at 10 km from the power grid or the gas grid and with a small production capacity (1 MW_{el}) will be highly impacted by the CAPEX of HV line or pipeline. With a nominal value set at 1 km for both HV line and gas pipeline the potential for cost reduction is low.

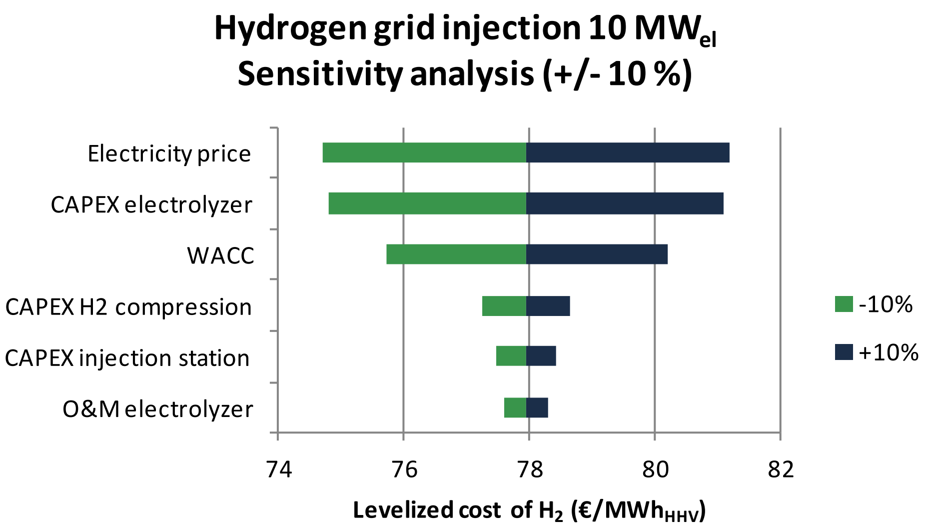
Type of parameter	Technology/block	Range (Low/Nominal/High)	Variation on LCOX
Length	HV line	0/1/10 km	-2 % to +17 % for H_2 1 MW_{el} -1 % to +10 % for H_2 mobility
Length	Gas pipeline	0/1/5 km	-3 % to +12 % for H_2 1 MW_{el} -1 % to +5 % for H_2 10 MW_{el}

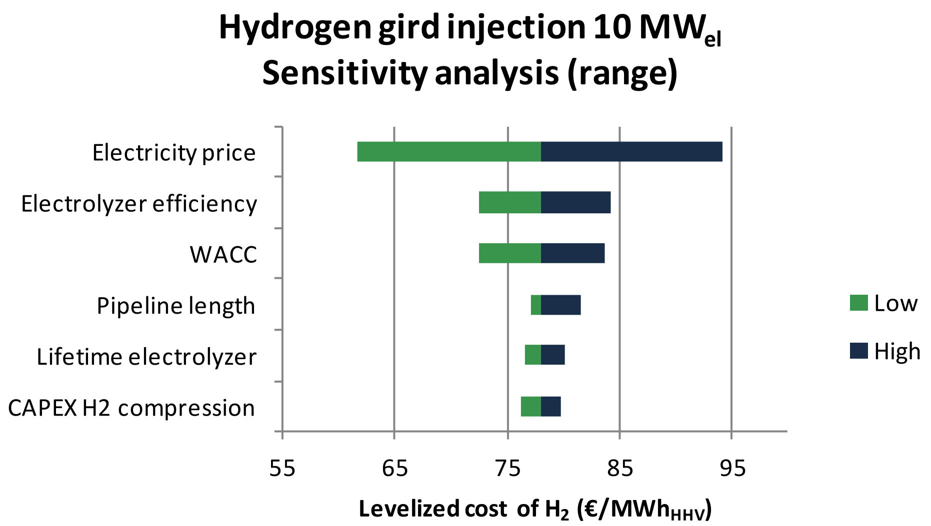
Table 7 – Results of the sensitivity analysis on HV line and gas pipeline

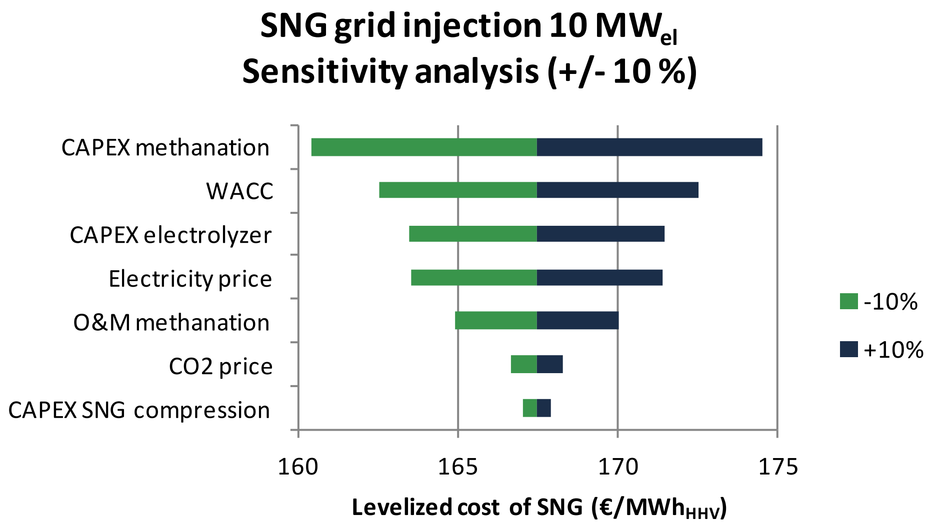
3.5.2 Tornado charts of power-to-gas for grid injection

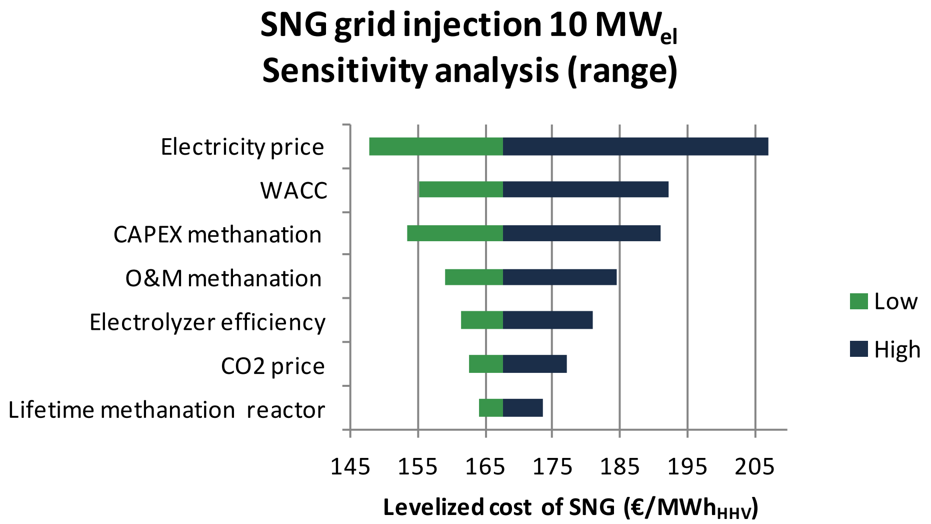




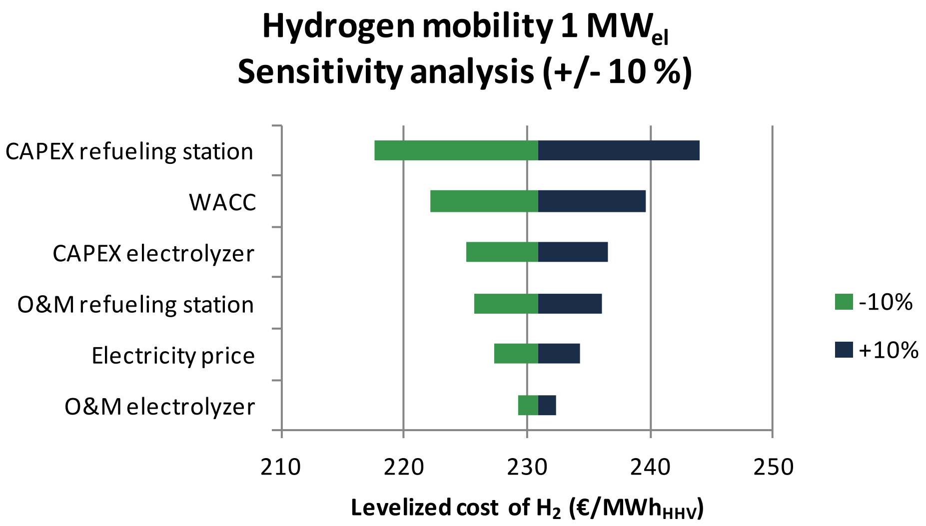


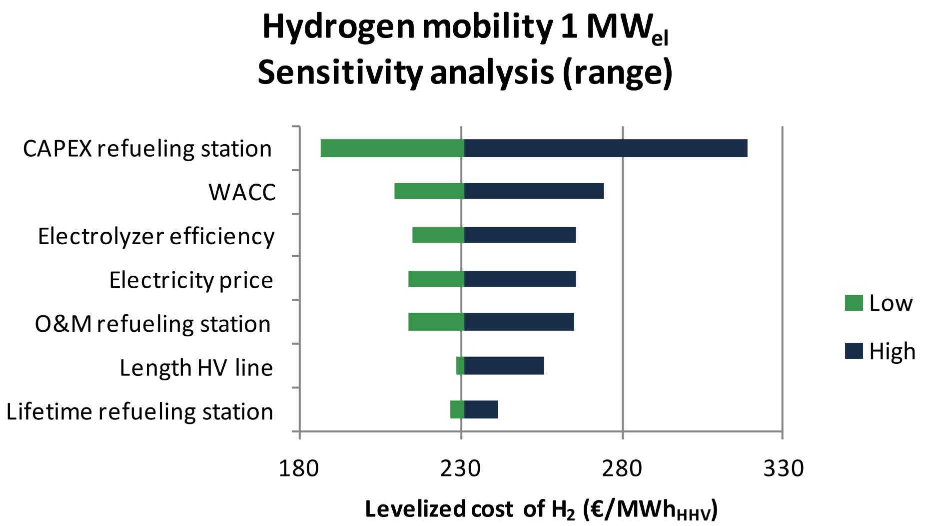

Hydrogen gird injection 10 MW_{el}
Sensitivity analysis (range)
Electricity price
Electrolyzer efficiency
WACC
Pipeline length
Lifetime electrolyzer
CAPEX H2 compression
Low
High
55
65
75
85
95
Levelized cost of H_2 (€/MWh_{HHV})

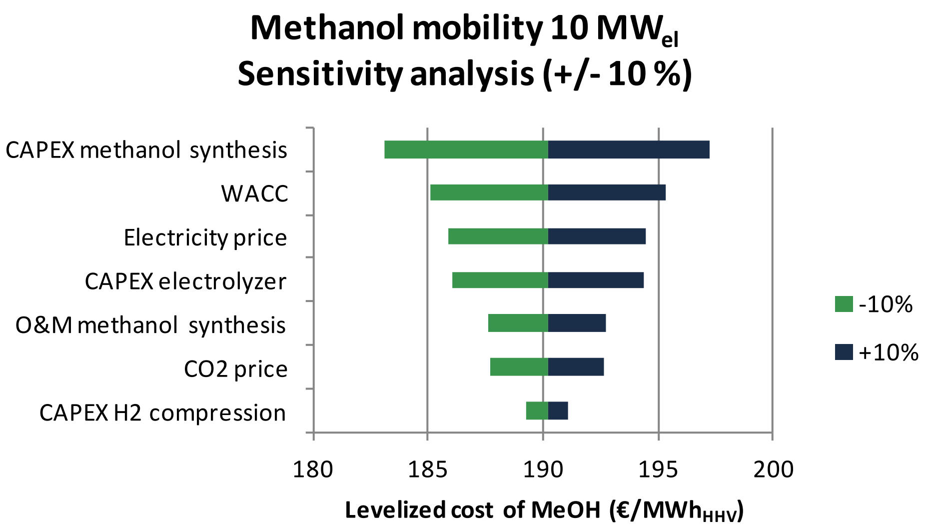

SNG grid injection 10 MW_{el}
Sensitivity analysis (+/- 10 %)
CAPEX methanation
WACC
CAPEX electrolyzer
Electricity price
O&M methanation
CO2 price
CAPEX SNG compression
-10%
+10%
160
165
170
175
Levelized cost of SNG (€/MWh_{HHV})

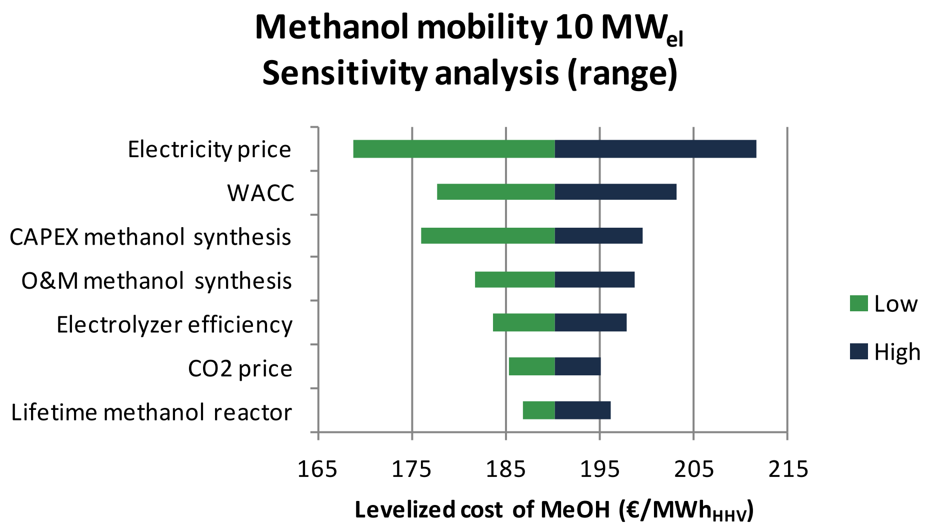

SNG grid injection 10 MW_{el}
Sensitivity analysis (range)
Electricity price
WACC
CAPEX methanation
O&M methanation
Electrolyzer efficiency
CO2 price
Lifetime methanation reactor
Low
High
145
155
165
175
185
195
205
Levelized cost of SNG (€/MWh_{HHV})

3.5.3 Tornado charts of power-to-gas /liquid for mobility

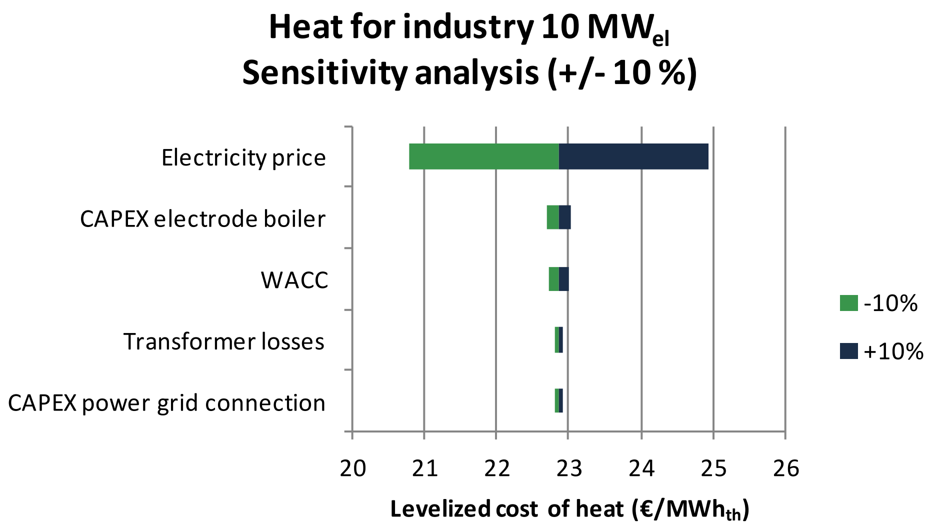


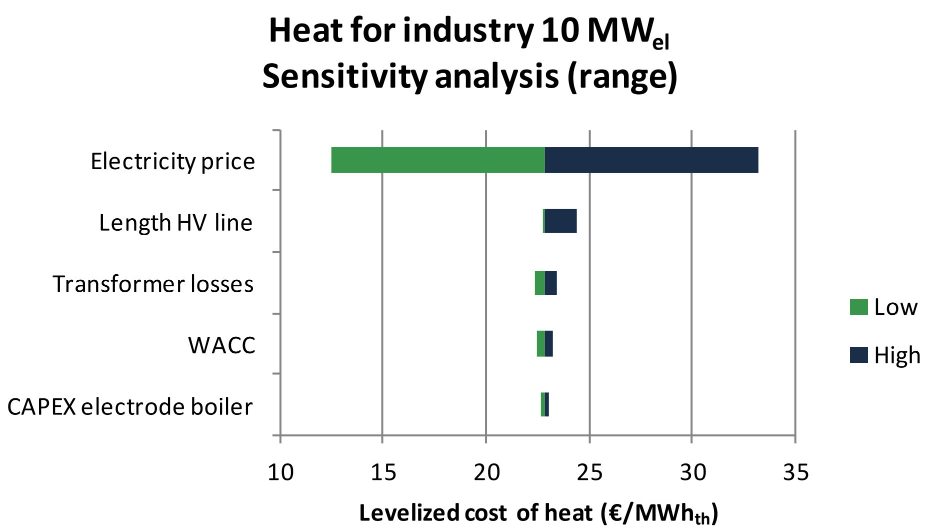






3.5.4 Tornado charts of power-to-heat for industry





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- Energy storage
- CO_2 Capture & storage
- Hydrogen & Fuel cells
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- Social acceptability

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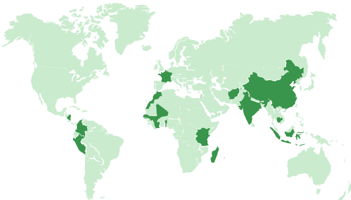

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