MSc Program
Renewable Energy Systems

Evaluating the viability and required market conditions for integrating renewable energy into the oil refining process via hydrogen

A Master's Thesis submitted for the degree of
“Master of Science”

supervised by
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Affidavit

I, **DAVID REID BA**, hereby declare

1. that I am the sole author of the present Master's Thesis, "EVALUATING THE VIABILITY AND REQUIRED MARKET CONDITIONS FOR INTEGRATING RENEWABLE ENERGY INTO THE OIL REFINING PROCESS VIA HYDROGEN", 74 pages, bound, and that I have not used any source or tool other than those referenced or any other illicit aid or tool, and
2. that I have not prior to this date submitted the topic of this Master's Thesis or parts of it in any form for assessment as an examination paper, either in Austria or abroad.

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Signature

Abstract

Following a raft of commitments made by major oil companies over the last 12 months to reach net-zero emissions targets, this paper will examine the viability of integrating renewable energy into the oil refining process through the replacement of a fossil fuel-based system for producing hydrogen with an electrolyser using renewable electricity. Hydrogen is an important chemical input in the refining process for road fuels and other oil products whose current production is overwhelmingly natural gas-based and, as such, makes a significant contribution to oil companies' emissions.

The topic is analysed first by establishing a realistic basis for cost comparison, as well as key assumptions regarding technology-specific performance characteristics, between the incumbent technology for hydrogen production and the renewable replacement route. From this point the analysis branches out into various scenarios, where the key price inputs influencing the economic viability of the replacement are allowed to diverge in a range of different ways. For some scenarios, financial support mechanisms of different kinds are assumed.

The viability of investing, as well as the cost of producing hydrogen, is assessed for each of these scenarios. Further points of comparison regarding investment viability and hydrogen production costs are also established by assuming price variables for some scenarios which correspond not to the main focus market (Europe), but instead to regions with superior price conditions for long-term renewable electricity supply contracts (the US and the Middle East).

The results of the analysis indicate that even favourable market price developments over the coming years struggle to yield any kind of viable investment in an electrolyser as a replacement for the incumbent technology. A consistent additional revenue stream in the form of a subsidy is required to achieve a viable investment case, given the inherent disadvantage for the replacement technology vs. the pre-existing system. Despite the relative difficulty in achieving a positive investment case, a number of the assessed scenarios do suggest low achievable levels for renewable hydrogen production costs, which may be improved further in the future. These should present a compelling alternative to fossil fuel-based production routes for new hydrogen production capacity in locations with the requisite pricing constellation.

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1 Introduction

The motivations for undertaking this analysis were borne from the specific circumstances of 2020 – a year which, for many industries, is likely to have represented a crucial turning point. The choice of topic was made mid-way through 2020, when Covid-19 dominated news headlines. Initial fears that the challenges presented by the Covid-19 pandemic would put the energy transition and broader decarbonisation efforts on ice proved to be fairly short-lived, and in fact the idea that economic recovery should be predicated on a low-carbon platform became almost a given. In this environment, the increasingly common pledges by businesses and governments to achieve 'net-zero' carbon emissions were welcomed, even if the path to this goal is unclear for many entities. Nowhere is this truer than in the case of the large-cap, integrated, international oil and gas companies. This analysis is motivated by an attempt to understand the (current) potential for emissions avoidance in one specific - albeit crucial - part of the oil supply chain. As such, it aims to offer some insight into one potential component of the broader roadmap needed to achieve 'net-zero' goals in energy supply.

The core objective of this paper is to assess the viability of incorporating renewable energy sources (RES) into the oil refining process, specifically via hydrogen production. Hydrogen is an important chemical input for the oil refining process, whose production is responsible for a significant share of the GHG (greenhouse gas) emissions from refining activities. This paper will establish a basis for comparing the production of hydrogen from RES, using electrolysis, with the most common method used currently, steam methane reforming (SMR), which uses natural gas as a feedstock. The aim is for this analysis to provide a good understanding of what kind of financial support schemes would be necessary to allow RES integration into oil refining via hydrogen in an economically viable way.

The analysis first describes the hydrogen market in broad terms as it stands currently, before describing the technologies which dominate production today as well as the alternative productions routes which make use of renewable energies. After establishing assumptions regarding performance for fossil-based and renewable hydrogen production methods and the metrics used to compare them, a range of market scenarios are described. These vary both by the level and type of financial support assumed for each, as well as their geographic location and by extension the level and number of variable market prices assumed. Observations and key takeaways based on the results of these scenarios are discussed in the final two chapters of this analysis.

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2 Some background on hydrogen production

Over the last twelve months, society has seen an unprecedented level of attention on carbon emissions from global economic activity. At the time of writing, the world is continuing to grapple with the challenges presented by the Covid-19 pandemic, even as the first vaccination efforts have commenced. However, contrary to some expectations, the unique challenges of 2020 do not appear to have slowed the momentum that has been building amongst governments, citizens and corporations to make a renewed push to mitigate anthropogenic GHG emissions as the effects of climate change become increasingly severe and commonplace.

In the corporate world in particular, 2020 has seen the issue of environmental, social and corporate governance (ESG), and carbon footprints in particular, take on a new urgency. This has been driven, to a large extent, by increased investor focus on these issues, and a broader perception that the share prices of companies with significant emissions profiles will suffer if steps are not taken to mitigate them. Arguably the most high-profile example of this trend has been the raft of commitments made by major oil companies to reach “net-zero” status by a certain point in the future (the most common date being set out is 2050). The first major European oil company to make a voluntary commitment of this kind was the Spanish-headquartered Repsol and, within just a few months, the largest European oil majors, including BP, Shell and Total had all followed suit.

In the intervening months, there has been much debate amongst analysts and observers over the exact nature of these targets. Differing methodologies for counting carbon and the issue of emissions *intensity*, as opposed to emissions in absolute terms, has left some room for interpretation. There is also no consensus on the definition of ‘net-zero’ as a term. As of late 2020, there is little in the way of concrete information about how these commitments will be met. However, there are commonalities between targets when it comes to emission scopes[1]. Scope 1 and 2 emissions make up a minority share of the total emissions profile for oil companies (IPIECA/API 2016:44) and have been allocated more aggressive targets than Scope 3 in company plans.

[1] A company’s emissions can be categorised in Scopes 1, 2 and 3. Scope 1 refers to direct emissions from sources belonging to or otherwise controlled by the company; Scope 2 refers to emissions associated with the production of materials or energy purchased from others but used by the company; Scope 3 refers to other indirect emissions which are located elsewhere in the value chain. In the case of an oil company, hydrogen produced on-site at a refinery qualifies as Scope 1; emissions related to hydrogen procured from a third party would be Scope 2. The emissions produced during the combustion of gasoline or diesel in the end-user’s vehicle would be Scope 3.

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Scope 1 and 2 emissions, as they relate to the oil companies, are concerned primarily with the extraction, transport and processing of raw materials. While there are many contributing factors to total emissions throughout the supply chain of oil-based fuels and products, the focus in this study will be on the processing segment. Specifically, and coinciding with renewed interest in a broader hydrogen economy - as exemplified in the publication by the European Commission (EC) of an ambitious hydrogen strategy in the summer of 2020[2] - this paper will address the GHG mitigation potential of hydrogen consumed by oil refineries via the integration of renewable energy systems.

There is good reason for this focus. While the EC strategy foresees the use of hydrogen as an energy carrier in myriad applications in the economy, there is a very strong case for addressing existing hydrogen supply and demand first. The existing dedicated (i.e. produced 'on-purpose', rather than as a by-product from another chemical or industrial process) hydrogen market is in the region of 70 million metric tonnes per year (IEA 2019:17). Figure 1 illustrates the extent to which this market is currently dependent on fossil fuels for feedstock, with the related carbon emissions exceeding the total national carbon emissions of several major economies[3]. Only a minor share of current hydrogen production qualifies as renewable.

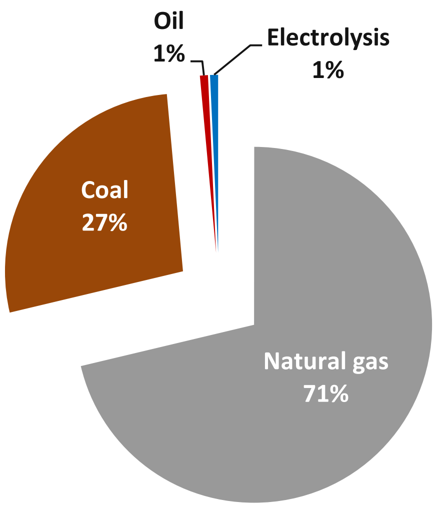

Figure 1 - Global dedicated H_2 production by feedstock; Source: IEA (2019, 37); own graphic

While there is a lot of hype around the potential proliferation of hydrogen applications in the future, most notably as an energy carrier for passenger transport and energy storage, the conversion of the refinery (and chemical) hydrogen market to renewable sources has many

2 EC report published July 2020, *A hydrogen strategy for a climate-neutral Europe* (see Bibliography)
3 It is estimated that hydrogen production is currently responsible for approximately 830 million tonnes of CO_2 emissions annually (IEA 2019: 37)

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potential advantages. Aside from the size of the emissions contribution generated by existing hydrogen production, switching hydrogen production for refinery and chemical inputs away from natural gas and coal would not require the same kind of prohibitively expensive infrastructure build-out which has long hampered the development of hydrogen as a transportation fuel. Maintaining a short supply chain from hydrogen production to consumption also allows for higher overall efficiency by avoiding conversions, and should allow for renewable hydrogen in existing applications to become competitive vs. fossil fuel options on an economic basis at a higher price point, and therefore more quickly, than applications where hydrogen does not currently have a meaningful share of the market.

For the purposes of pursuing ‘net-zero’ goals, switching away from fossil fuel-based ‘grey’[4] hydrogen to a renewable production route such as electrolysis could offer meaningful mitigation of Scope 1 emissions. While the share of Scope 1 in the total oil value chain - from well to refinery to end-user - makes up only a minority share, hydrogen production does nevertheless represent a significant share of these Scope 1 emissions. The share of process emissions related to hydrogen production is estimated to average around 15% in the modern crude oil refinery (IPIECA/API 2016: 43), but may be as high as 25% (EPA 2010: 9).

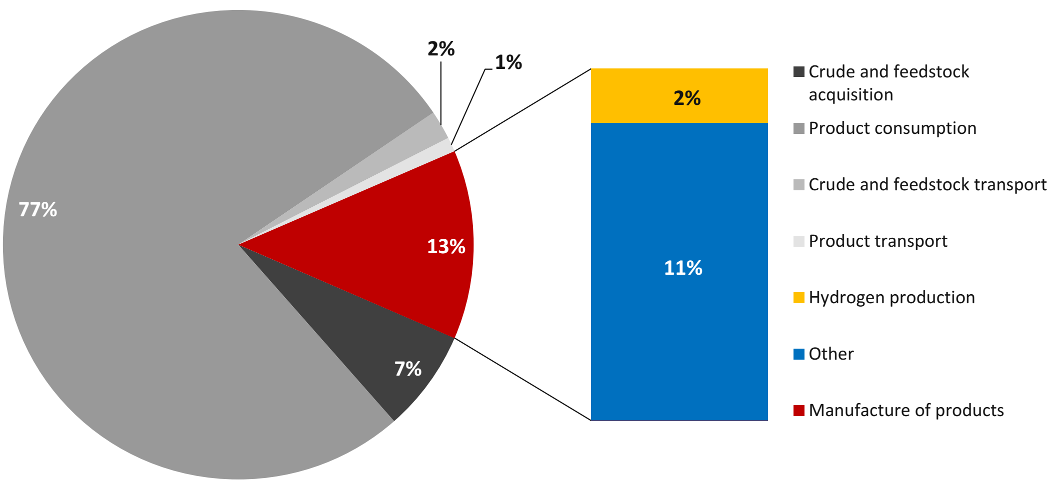

Figure 2 - Oil company emissions by category and hydrogen production contribution; Source: IPIECA/API 2016: 43, EPA 2010: 9; own graphic

For the purposes of this analysis, it is also important to have a basic overview of the nature of hydrogen consumption in an oil refinery. Hydrogen is produced as a by-product in some individual refining processes, with a typical and representative chain represented in Figure 3.

4 This term may be used in some sources to refer to hydrogen produced from a natural gas feedstock without any emissions mitigation technologies in place, such as CCUS (Peake 2018: 225)

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While on-site by-product output of hydrogen can be significant, and may account for up to one-third of the total hydrogen demand of the refinery (Srinivas 2014: 5) (and even more for integrated refineries that have access to by-product hydrogen from adjacent petrochemical facilities), there will always be a deficit of hydrogen which has to be met either with on-site, on-purpose supply; merchant supply[5]; or a combination of both. It is highly typical that the on-site production of hydrogen at a refinery falls short of the actual hydrogen quantity demanded (Philibert 2017: 95).

These volumes are significant; for a moderately-sized refinery with a nameplate capacity of 100,000 bpd of crude oil, the net requirement for hydrogen supply is estimated to be some 53 tonnes per day (Srinivas 2014: 6), or more than 17,000 tonnes per year assuming a utilization level of 90%. This equates to a carbon dioxide emission total of almost 165,000 tonnes annually[6] from the production of hydrogen alone, assuming this is produced using a natural gas feedstock.

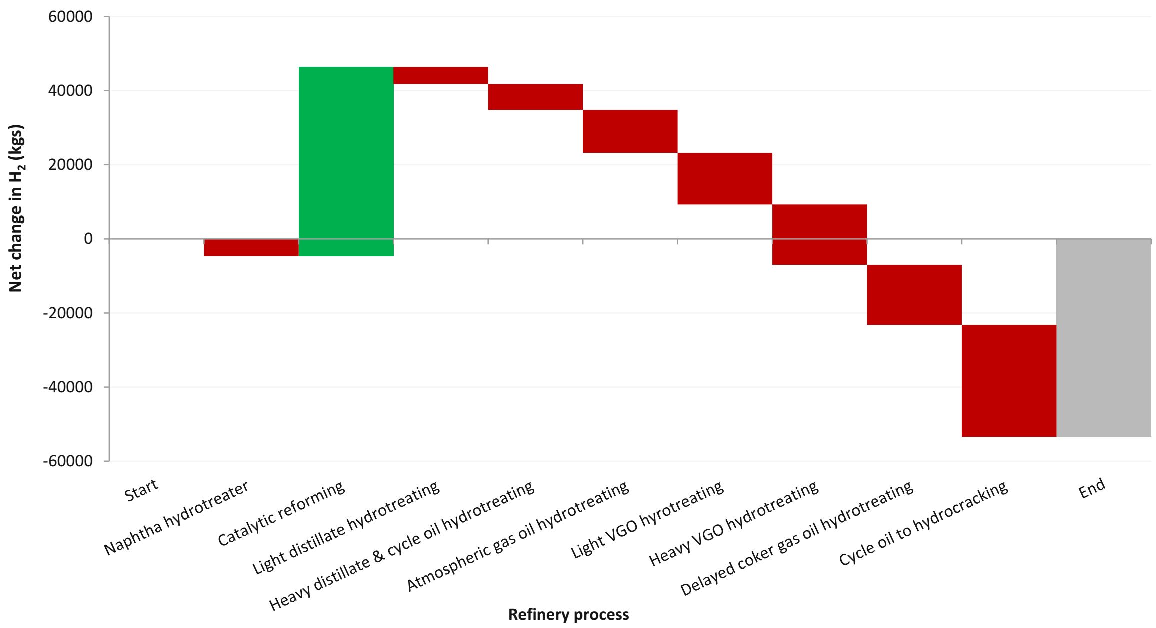

Figure 3 - Net consumption of H_2 by refining process; Source: own calculations based on Srinivas 2014: 6; own graphic

Additionally, it should be noted that hydrogen is a growth market, even disregarding the possibility that it will be used in increasing quantities in new applications in the future. Both oil and chemicals demand growth over recent years has been such that hydrogen demand has, by extension, registered a compound annual growth rate (CAGR) of some 3% between 1980

5 Hydrogen produced by a third party and purchased by the refinery operator (IEA 2019: 40)
6 Based on a 9.7:1 carbon emissions-to-hydrogen ratio (Subramani 2015: 490)

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and 2018 (PwC strategy& 2020: 2). Latterly, these increases have been increasingly driven by tightening regulations in many markets regarding the sulphur content of transportation fuel (hydrogen is an essential chemical feedstock in producing low-sulphur fuels which comply with these tighter specifications).

While the path of oil demand growth from this point has become a topic of intense debate due to the impacts of the Covid-19 pandemic, the oil space has an enormous volume of hydrogen demand whose emissions could potentially be abated. Moreover, while the focus of this analysis is renewable hydrogen in the context of oil refining, there are other significant and similar, short-supply chain demand areas for hydrogen (most notably the chemicals industry) that would be subject to many of the same economic conditions discussed here.

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3 Method of approach

This section will set out the approach taken in assessing the conditions required for an economically viable investment into renewable hydrogen (in the refining process). In 3.1, the most common current technology employed for hydrogen production at refineries and other hydrogen-consuming facilities, SMR, will be briefly discussed. While SMR is not the only method employed in industry to produce hydrogen, it is the most widely deployed. Here it will be important to establish the nature of this process, especially as regards efficiency and the ratio between natural gas feedstock and hydrogen output, for inclusion in the economic assessment which follows. These figures have been drawn first-hand from the manufacturers of modern SMR units and will be noted as such where appropriate.

Section 3.2 will address the basis for assessing the viability of a renewable hydrogen installation and the metrics used for comparison across different scenarios. Key input numbers, which are treated as fixed across different scenarios and in different regions, will be addressed in 3.3. The numerous parameters which vary by scenario/region are addressed in 3.4. There are a number of different support mechanisms that have been mooted for the development of a (renewable) hydrogen economy, and a brief overview of each can be found in 3.5.

3.1 Understanding the status quo for hydrogen production

SMR is the dominant technology at present for the production of hydrogen. This technology can make use of different feedstocks, but by far the most common is natural gas (methane). The natural gas serves as the chemical basis of the hydrogen output, as well as the fuel required for the reaction, which requires significant heat. The other main chemical input for the process is water, with modern SMR applications requiring around 6.6 litres per kg of hydrogen produced (EIGA 2019: 3). A simplified overview of the process chain and the associated chemical flows can be seen in Figure 4.

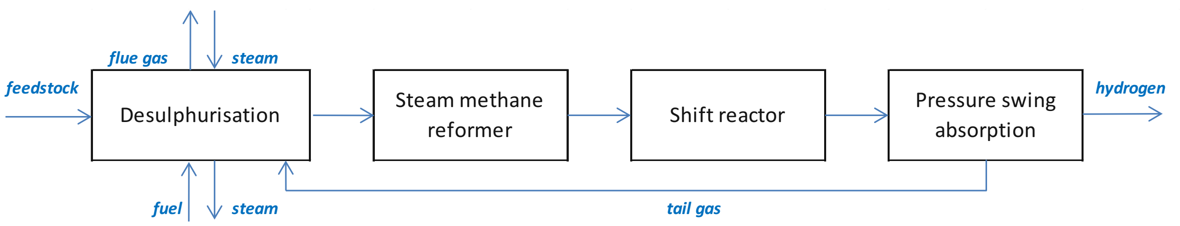

Figure 4 - SMR process for hydrogen production; Source: EIGA 2019: 1; own graphic

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Desulphurisation is required to remove impurities, predominantly sulphur, from the feedstock as these can damage the catalysts, which are used in steps two and three. These steps - the steam methane reforming step itself and the water-gas shift reaction - are the reactions that generate the hydrogen from the feedstock. The general reaction for steam methane reforming, which occurs at high temperatures of up to 1000°C, is indicated below:

$$CH_4 + H_2 0\ (+\ heat) \rightarrow CO + 3H_2 \qquad (1)$$

The steam methane reforming stage generates a mixture of hydrogen and carbon monoxide, sometimes known as product gas. The hydrogen yield is then further increased via the shift reaction. This reaction, described below, occurs at a significantly lower temperature.

$$CO + H_2 0\ \rightarrow CO_2 + H_2\ (+\ heat) \qquad (2)$$

As well as increasing the hydrogen yield from the natural gas feedstock, this reaction also generates a (concentrated) CO_2 stream which may be monetized if there is a demand outlet at hand for this by-product (as is often the case in chemicals manufacture). However, for oil refining facilities, this is often not the case, and this stream will not be considered in this analysis.

The key ratios for use in the economic assessment, including the natural gas feedstock required as well as the corresponding carbon emissions produced per unit of hydrogen output, can be found in 3.3.

3.2 Establishing a basis for comparing SMR and electrolysis

3.2.1 Technology options

The process described in 3.1 represents the incumbent technology in place for the provision of a large share of hydrogen consumed in a typical oil refinery. As such, an assessment of the economic viability of integrating renewable energy into this process will be measured against this baseline. Another route to hydrogen production that has garnered a lot of attention in recent years is to use SMR in combination with carbon capture, use, and storage (CCUS) technology. This route makes use of the same technology as described in 3.1, but enables reductions of up to 90% (IEA 2019: 40) of operating emissions vs. SMR without CCUS, leading to a significant - though notably not complete - abatement of GHG releases.

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While the CCUS production route for hydrogen may play an important role in the abatement of GHG emissions from hydrogen production in the coming years (EC 2020: 5), it does not eliminate the dependence on the fossil fuel feedstock, nor does it allow for the integration of renewable energy. To this end, electrolysis is the favoured option for comparison in this assessment. In a European context at least, this is also where much of the necessary subsidy focus will be, given the relative levels of envisaged investment in fossil-based hydrogen production with CCUS vs. renewable, electrolytic hydrogen (Barnes 2020: 14).

There are several different electrolysis technologies available. The two most prominent of these in commercial operation are alkaline electrolysis and proton exchange membrane (PEM). A third potential route to renewable hydrogen production via electrolysis, known as a solid oxide electrolysis cell (SOEC), has not yet reached a commercial stage. This method is, at present, prohibitively expensive compared to alkaline and PEM routes, and as such will not be considered in this analysis.

There are a number of key distinctions between alkaline and PEM electrolysers. Although alkaline has been commercialised for longer, PEM has rapidly become competitive and both electrical efficiency and reported specific investment costs have converged with those of alkaline electrolysis. Accordingly, PEM’s share of new installations has been growing rapidly in recent years, which is likely a result of greater economy-of-scale effects reflecting the trend towards increasing size for electrolysis units (IEA 2019: 45). Furthermore, commercial literature indicates that several major manufacturers’ PEM electrolysis units tend to exceed alkaline units in their hourly production capacity (Hydrogenics 2018: 10).

Additionally, PEM holds several advantages over alkaline technology when it comes to flexibility. This is reflected in wider operating ranges, including the ability to run in stand-by mode and to be ramped up above nominal capacity for short periods, up to as much as 200% of nameplate capacity (IRENA 2018: 19). Response time for adjusting utilization is also superior to that of alkaline units. All of these characteristics can represent advantages when pairing electrolysis technology with (variable) renewable electricity generation, particularly in an off-grid setup. While such an off-grid example is not considered in this analysis, superior flexibility should prove beneficial for an installation which is expected to run at a somewhat lower average utilization rate than the typical SMR facility. As such, PEM will serve as the technology for comparison in this analysis.

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Table 1 - Key characteristics for H_2 production technologies; Source: IEA (2019: 45), Subramani et al: (2015: 490)

	SMR	Alkaline Electrolyzer (ALK)	PEM electrolyzer
Efficiency (%)	70-85	63-70	55-65
System lifetime (years)	30	20+	15
Capacity (MW)	150-300	150 <	100 <
Emissions ($kgCO_2/kgH_2$)	9.7	0	0
Water consumption (l/kgH_2)	6.63	~9	~9
Specific investment costs (EUR/kW_e)	400-600	500-1400	900-1600

The efficiency of SMR has been reported as having even higher maximum values than noted here (EIA 2016: 1), though most sources place the maximum efficiency of such a system at around 85%. In any case, the feedstock-to-hydrogen conversion efficiency is significantly higher than that of electrolysis. A reasonable assumption of a 15-year lifespan for the PEM systems now being installed is based on a full load hours (FLH) profile of 5000, which will be discussed further in 3.2.2.1, and which will cover the investment horizon in this analysis. Finally, the CO_2 production ratios above should also be noted: per tonne of hydrogen produced, the SMR process generates close to 10 tonnes. In contrast, there are no operating carbon emissions from the electrolysis process.

3.2.2 Metrics for economic assessment of H_2 production routes

3.2.2.1 Levelized cost of hydrogen

Having determined the technologies to be compared in the analysis, econometric metrics have to be addressed. The goal of the exercise is to understand what market conditions would be necessary for renewable energy to be integrated into the oil refining process via hydrogen. Two key measurements will be employed here.

The first is to compare the levelized cost of hydrogen (LCOH), which assesses the average net present cost of producing a kilogram of hydrogen in a given setup over its entire lifetime. The calculation of the LCOH requires several inputs. These include capital costs, operating costs, a capital recovery factor, and the total amount of hydrogen produced over the lifetime of the installation.

The capital recovery factor is calculated as per below, where r is the effective interest rate and T is the number of annuities:

$$CRF = \frac{r \times (1 + r)^{T}}{(1 + r)^{T} - 1} \tag{3}$$

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For the purposes of this comparison, we can assume a value of 5% for the effective interest rate[7] which, over a 15-year investment horizon, would yield a capital recovery factor of 0.1 (or 10%).

The next element to be addressed is the operating costs component. Convention dictates that these costs are calculated as per the below, i.e. the sum of all costs related to the operation of the SMR or electrolysis unit, divided by the total amount of hydrogen produced over the installation's lifetime. The operating costs (C_B) is expressed as per the equation below, where C_{energy} is the cost of energy (electricity for electrolysis or natural gas in the case of SMR), C_{fixed} is the fixed cost associated with operating the hydrogen production unit, and C_{var} is other variable costs (carbon is included here in the case of SMR). $Q_{hydrogen}$ refers to the total lifetime output of hydrogen from the production unit:

$$C_B = \frac{C_{energy} + C_{fixed} + C_{var}}{Q_{hydrogen}} \tag{4}$$

Again, for the purposes of this example, the following values are assumed for the various components of the operating cost (for electrolysis):

- Cost of electricity (C_{energy}) at just over €24 per MWh[8] at an assumed 5000 FLH over 15 years;
- Fixed operating costs (C_{fixed}) at 5% of the initial investment cost, and other variable costs (C_{var}) at an additional 1%;
- An implied electrical efficiency of 64% for electricity/hydrogen conversion

These inputs yield an operating cost (C_B) component of €4.15/kgH_2. A summary of the calculations steps is provided below:

7 Otherwise referred to as weighted average cost of capital (WACC)
8 This is the average over 2019 of day-ahead green (guaranteed as renewably-sourced) power prices traded on EXAA and is treated as an energy cost only; actual delivered power price is significantly higher in the calculation due to grid fees and other associated costs

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Table 2 – Calculation summary for operating cost baseline; Source: own calculations

Electricity cost (€/MWh)	24.18	
> delivery factor, /45%	53.73	
> assumed FLH, x 5000	268,633.82	
> operating lifetime, x15 years	4,029,507.25	
> electrolyser capacity, x 5MW	**€ 20,147,536.27**	C_{energy}
Specific investment cost (€/kW$_{e}$)	1200	
> electrolyser capacity, x 5MW	6,000,000.00	
> fixed component, x 5%, x 15 years	**€ 4,500,000.00**	C_{fixed}
> variable component, x 1%, x 15 years	**€ 900,000.00**	C_{var}
Hydrogen output (kg/H_2/hr)	82	
>assumed FLH, x 5000	410,000	
> operating lifetime, x 15 years (kg)	**6,150,000**	$Q_{hydrogen}$
>sum costs / hydrogen output	**€ 4.15**	C_B

The remaining components for inclusion in the calculation of the full levelized cost can be seen below, where $\sum_{i}^{n} CC$ refers to the sum of capital (investment) costs and α refers to the capital recovery factor, as described above.

$$LCOH = \frac{\sum_{i}^{n} CC \times \alpha}{Q_{hydrogen}} + C_B \qquad (5)$$

Capital expenditure is accounted for as a product of the capital recovery factor discussed above, divided by the lifetime hydrogen output of the system. For this example, it is assumed that the specific cost of investment is €1200 per kW of capacity (equal to €0.09/kgH_2). This sums to €4.25/kgH_2[9], a figure which sits fairly centrally in the range of estimated H_2 production costs (Lambert 2020: 3) from electrolysis currently, which can nevertheless vary significantly.

9 Discrepancy due to rounding

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Table 3 - Calculation summary for capital cost baseline & LCOH; Source: own calculations

Specific investment cost (€/kW_e)	1200	
> electrolyser capacity, x 5MW	6,000,000.00	$\sum_i^n CC$
> x capital recovery factor 10%	600,000.00	
> / total hydrogen output (€/kgH_2)	0.098	
> add C_B (€/kgH_2)	**€ 4.25**	LCOH

This does not compare favourably with an equivalent calculation based on SMR technology. Making use of the following values for the purposes of a representative reference point, an SMR-based installation achieves an LCOH which significantly undercuts the electrolysis option:

- Cost of natural gas feedstock of €13.6[10] per MWh at an assumed 7000 FLH over 20 years;
- Fixed operating expense at 6% of the initial investment cost, and other variable costs at an additional 4% plus the cost of emitted carbon, which is here assumed to cost €30 per tonne;
- Specific investment costs are €600 per kW of capacity, with an implied electrical efficiency exceeding 70% for natural gas/hydrogen conversion

These inputs yield an LCOH of some €2.29 per kg/H_2. A summary of the calculations steps is provided below:

10 This is a conversion based on a price of €40 per 1000 therms

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Table 4 - Calculation summary for LCOH baseline from SMR; Source: own calculations

Specific investment cost (€/kW)	600	
> unit capacity, x 45MW	27,000,000.00	$\sum_{i}^{n} CC$
> x capital recovery factor 8%	2,160,000.00	
> / total hydrogen output (€/kgH$_2$)	0.02	
Hydrogen output (kg/H$_2$/hr)	820	
> assumed FLH, x 7000	5,740,000.00	
> operating lifetime, x 20 years (kg)	**114,800,000**	$Q_{hydrogen}$
> energy content of H$_2$ output (MJ)	16,301,600,000.00	
> req. natural gas feedstock (GJ)	22,822,240.00	
> req. natural gas feedstock (MWh)	6,340,018.27	
Natural gas cost (€/MWh)	13.65	
> delivery factor, /50%	**€ 27.30**	C_{energy}
> quantity x delivered price	**€ 173,106,300.94**	C_{fixed}
> fixed component, CC x 5%, x 20 years	32,400,000.00	
> variable component, CC x 4%, x 20 years	21,600,000.00	
> carbon emissions (mt), H$_2$ output x 9.7	1,113,560.00	
> carbon cost @ €30/mt	33,406,800.00	
> sum of variable costs	**€ 55,006,800.00**	C_{var}
> sum costs / hydrogen output (€/kgH$_2$)	**€ 2.27**	C_B
> add capital cost component (€/kgH$_2$)	**€ 2.29**	LCOH

This value, while substantially lower than the electrolysis value calculated previously, may be towards the upper end of actual SMR-based hydrogen production costs (in Europe, which may or may not explicitly include the cost of carbon), while average values in the US will certainly be significantly lower. Nevertheless, the scale of the challenge for renewable hydrogen to become competitive with SMR-based options is clear to see below:

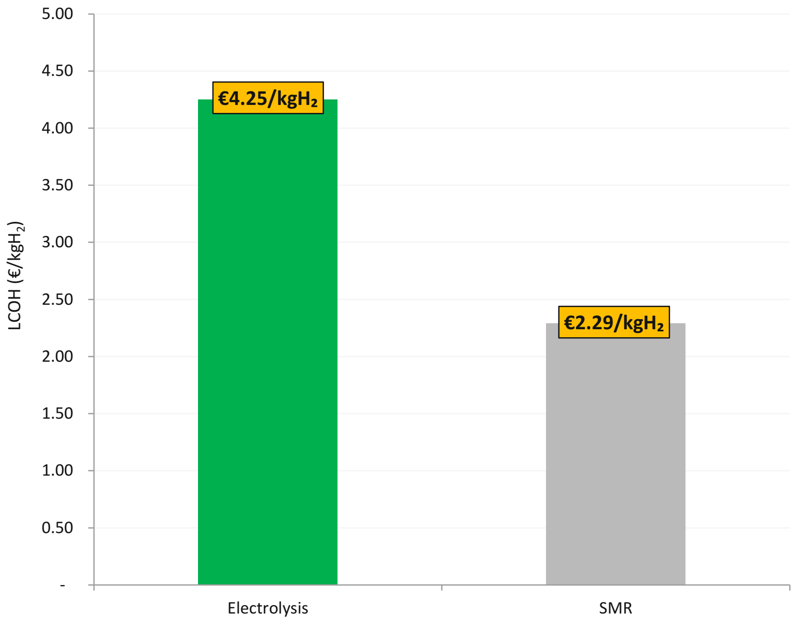

Figure 5 - Baseline LCOH comparison for electrolysis and SMR; own calculations

Given this discrepancy between the baseline values for electrolytic hydrogen vs. SMR-based hydrogen, it is useful to understand how the variability in the parameters included in equations (, (, and (can influence the LCOH value of the former. Taking the baseline value for electrolysis from above as a starting point, and performing a sensitivity analysis by adding increasing and decreasing increments at intervals of 5% out to a range of -40% to +40% indicates a very uneven skew between variables:

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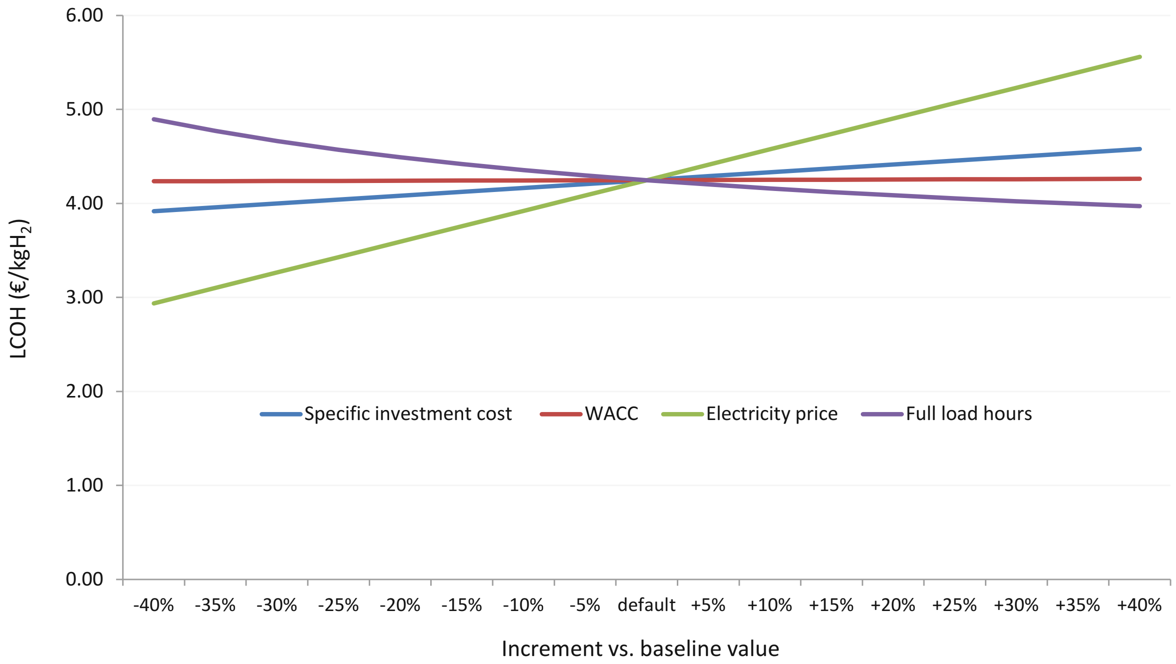

Figure 6 – Renewable LCOH sensitivity to variables (€/kgH_2); own calculations

Key observations from the sensitivity analysis as detailed in Figure 6:

1. Specific investment cost, though substantial in the case of electrolysis and with an assumed starting point double that of the SMR route, has only a fairly minor effect on the final LCOH. Even with a 40% reduction in the specific investment cost (something that may be possible in the coming years due to economy of scale effects etc.) the LCOH is barely brought below €4/kgH_2.
2. WACC has an even more minimal impact on the variability of the LCOH, with a range between 3% and 7% equating to only a couple of euro cents' difference in final value.
3. FLH variability has a fairly substantial effect on the LCOH from electrolysis. While it should be pointed out that even a high FLH assumption of 140% of the baseline value at 7000 hours (equivalent to almost 80% utilization) serves to only just bring the LCOH value under the €4/kgH_2 threshold, a lower FLH value increases the LCOH substantially. This illustrates an important point regarding FLH: namely, that utilization above a certain threshold is crucial to achieving the best possible investment case. The additional benefit to the LCOH from a higher FLH decreases rapidly beyond the 4000-5000 FLH range, but a utilization value in this bandwidth is necessary to minimize the LCOH value and will be assumed for the purposes of the

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investment scenarios that follow. This effect is illustrated in the chart below, with both FLH and specific investment cost as variables[11]:

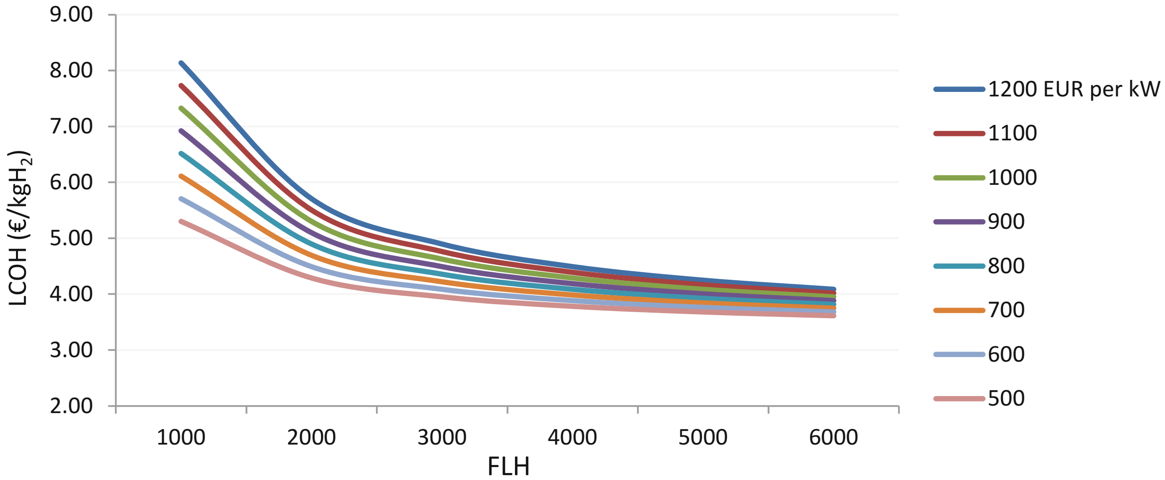

Figure 7 - Baseline LCOH sensitivity by FLH and specific investment cost (€/kW$_e$); own calculations

4. By far the most influential of the chosen factors on the actual LCOH value is the cost of electricity, with the sensitivity bounds of -40% and +40% from the price in the baseline value (just over €24 per MWh) translating into a range in LCOH values of more than €2.60/kgH_2. The highest LCOH value in the analysis, of more than €5.50/kgH_2, results from an electricity price (energy price) of just over €33 per MWh. This is a good illustration of how electricity prices generally have to be very competitive in order for renewable hydrogen to even come close to being competitive with SMR routes.

Given the outsize role of the electricity price in the LCOH from electrolysis, as described in both Figure 6 and Figure 8, this variable will serve as a key differentiating factor in the numerous investment scenarios that follow. By comparison, WACC and specific investment costs play comparatively minor roles in determining the level of the LCOH. As such, these are assumed at representative industry levels and/or minimum levels required to maximize investment viability and will be detailed fully in 3.3 along with other fixed assumptions.

11 Green line (Figure 7) illustrates original baseline reference

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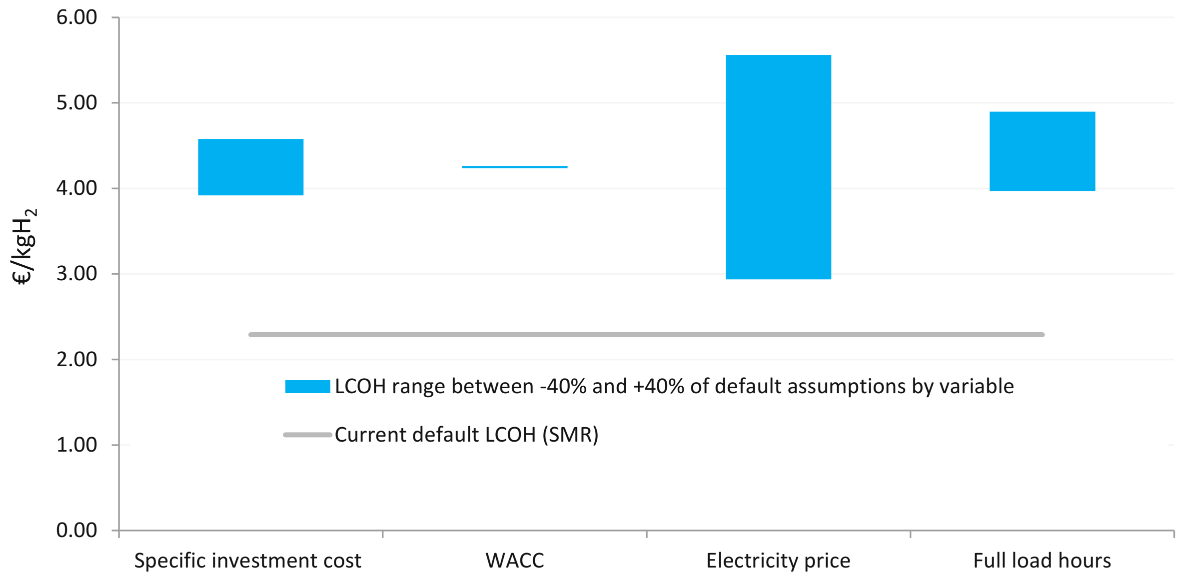

Figure 8 – LCOH sensitivity ranges and SMR benchmark (€/kgH_2); own calculations

As discussed above and illustrated in Figure 7, the benefit to the LCOH from higher FLH levels flattens out after a certain point. For the purposes of this analysis, that level will be defined at 5000 FLH per annum. Not only does this allow for the LCOH to occupy a lower bandwidth, it may also provide an advantage from an electricity price perspective if power is purchased from the grid and not generated off-grid or purchased under a fixed-price agreement of some kind, such as a power purchase agreement (PPA). This point is explored further in 0 and 4.2.

3.2.2.2 Net present value

The second key metric to be employed in this analysis will be the net present value (NPV). The purpose of this calculation is to assess the net benefit of a venture over a given period of time, by subtracting today's value of capital invested from today's value of all the projected net cash flows of the project over its lifetime. An important component of the NPV calculation is that it respects the time value of money, which is a function of the discount rate. From this perspective, a venture can be deemed worthy of investment (in isolation) if the NPV calculation yields a positive value (Kobialka 2020: 15).

$$NPV = \sum_{t=1}^{n} \frac{R_t}{(1+i)^t} \quad (6)$$

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In this notation, i represents the discount rate, and R represents the net cash flow during the given number of time periods (years), as denoted by t. While the relevant discount rate and the investment horizon will be common to all of the scenarios discussed in this analysis, the cash flows will change substantially between scenarios depending on the market conditions (the basis for which are discussed on a case-by-case basis in section 4).

It is important to note that, while the viability of an investment into electrolytic hydrogen production capacity will be assessed according to the NPV of each scenario, the basis of comparison will be an SMR system that is assumed to be installed already. This means that, for the purposes of this assessment, the "revenues" generated by the electrolyser are in fact the costs associated with running the SMR unit which are avoided by the renewable hydrogen production. As such, the scenarios in this assessment should illustrate whether - or with what level of support - electrolytic hydrogen production can be incorporated into a refining system while avoiding an economic disadvantage on the hydrogen produced via electrolysis that would otherwise be produced via SMR[12].

3.3 Assumptions for fixed inputs in assessed scenarios

As noted above, several of the inputs assumed for testing both the LCOH and the NPV of renewable hydrogen installations shall be fixed across scenarios. These assumptions will be made not only in order to reflect actual market and/or industrial conditions, but also to allow for reasonable comparison across scenarios. A list of all the fixed parameters assumed that are relevant for the calculations, as well as a brief rationale on each, is as follows:

- **Capital expenditure/specific investment cost**: this is estimated to play a relatively minor role in the LCOH of a given setup, though there is a wide range of values reported per kW of capacity in commercial and industrial literature. The assumption on this analysis is for **€1200 per kW** of nameplate capacity. This figure is in the middle of recent industry price indications, cited in Table 1, which will vary from setup to setup. The high figure can also be assumed to reflect some minimal infrastructure or setup adjustments that may be necessary to accommodate the installation of the electrolysis unit into the system (these are minimal however in relation to the cost of the electrolyser itself). Two scenarios are included where the specific investment cost deviates from this level and can be found in section 4. Any expectations of further price falls per kW for PEM capacity are not assumed in this assessment.

12 Given the volume of a typical refinery's hydrogen demand as discussed in 2, electrolysis can only realistically be expected to cover a minority share of hydrogen requirements in an average-sized oil refinery

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Furthermore, capital expenditure (capex) figures are assumed to be constant across regions, based on a limited number of established vendors for electrolyser units operating in international markets.

- **Full load hours**: these will be assumed at **5000 per year**, in order to achieve an optimum minimum level for the LCOH and for avoiding the highest levels of grid electricity prices, which will typically be found in the final 1000-2000 hours of the year (on an ordered-price basis).
- **Unit size**: assumed value common to all scenarios is for the installation of a **5MW-capacity** unit. This will allow for the displacement of a meaningful quantity of SMR-based hydrogen in each scenario. This figure refers to the unit's nominal power input. The nominal hydrogen flow for a unit of this size is 1000 Nm^3 per hour (Hydrogenics 2018: 5). As this refers to normal pressure and temperature conditions, this equates to approximately 82kg of hydrogen per hour. Based on the nominal power input and the nominal flow rate, an efficiency of 64% is implied between electricity input and the energy content of the produced hydrogen. This is towards the upper end of the current reported performance range for PEM technologies, as detailed in Table 1.
- **Electricity consumption**: for an electrolyser of this size and operating for the stated FLH value, annual consumption is an estimated **25,000 MWh**.
- **Natural gas consumption (for SMR)**: **a ratio of 1.4:1 natural gas feedstock-to-hydrogen output** (Azzaro-Pantel 2018: 93) is assumed. Specification and output of the SMR unit is based on commercial literature (Tudorache / Air Liquide 2018: 3). The natural gas-to-hydrogen ratio is equivalent to efficiency of more than 71%. This is at the lower end of the efficiency range currently reported for SMR technology according to the IEA as detailed in Table 1, but is likely to be more representative of the existing, installed industry average which will, on the whole, represent an older and less efficient fleet of SMR units.
- **Carbon emissions (for SMR): CO_2 emission per kg of H_2 is assumed to be 9.7kg** (Subramani 2015: 490). This ratio forms the basis of the assumed emissions output from the SMR unit which are avoided via electrolysis, and which are multiplied by the prevailing carbon price in each scenario and year in order to arrive at a saving, effectively a revenue, for the retrofitted electrolysis unit in each scenario vs. the incumbent SMR.
- **WACC** is assumed universally at **5%**.

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Summaries of the fixed assumptions as they relate to the performance of the electrolysis and SMR units, and which underpin the scenarios that follow, can be found in the below tables. Table 5 refers to the Hydrogenics HyLYZER® 1000 model:

Table 5 - Electrolyser unit performance summary, Source: Hydrogenics (2018: 8)

Output (m^3H_2/hour)	1000
(kgH_2/hour)	82
MW capacity	5
kgH_2/annum @5000 FLH	410000
Electricity demand (MWh) p/a	25000
Implied efficiency	64%

Implied efficiency as listed here is determined as the hourly nameplate H_2 output of the unit (82kg) (Hydrogenics 2018: 8) divided by the quantity of electrical energy required to run the unit for one hour (5 MWh). Corresponding figures for the SMR unit, the assumed incumbent technology, are listed below. The basis here is for a minimum applicable size for an SMR unit made available from Air Liquide, which is considerably larger in terms of nominal hydrogen flow than the average electrolysis unit:

Table 6 - SMR unit performance summary, Source: Air Liquide (2018: 3), Azzaro-Pantel (2018: 93)

Output (m^3H_2/hour)	10000
(kgH_2/hour)	820
kgH_2/annum @7000 FLH	5740000
Natural gas feedstock (MWh) p/a	317001
Carbon emissions (tonnes/annum)	55678
Implied efficiency	71.4%

Implied efficiency as listed here is determined as the hourly nameplate H_2 output of the unit (820kg, Air Liquide 2018: 3) divided by the quantity of natural gas feedstock required to run the unit for one hour (45 MWh).

For both the electrolysis and the SMR units used as the basis of the calculations in the scenarios that follow, no specific provision has been made for any replacement costs. The investment horizon for both (15 years) is assumed to be covered by lifetime operating hours of the respective units, as detailed in Table 1. General maintenance expenses are assumed to be covered by the assumptions for fixed costs, which are kept constant across scenarios. This expense has a nominal assumed annual increase of 1%, which is also kept constant across scenarios and regions.

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3.4 Market-based variables for assessed scenarios

A full list of the variables included in the calculation, as well as a brief description of each, can be found below (note that not all of the variables are relevant to each scenario). Further details on the specific figures assumed in each scenario and region is provided in 4. It should also be noted that all prices and costs are quoted in Euros (€), at an assumed conversion rate from the local currency, which is noted where relevant.

3.4.1 Capex

As detailed in 3.3, this is generally a fixed input with a couple of exceptions. The specific investment (per kW) cost is simply multiplied by 5000 to arrive at the total cost of the installation, which serves as the initial expense in the calculation of the LCOH and NPV values.

3.4.2 Natural gas price

This is the procurement price[13] for feedstock for the SMR unit. This will be one of the key variables, with different assumed starting levels for natural gas prices (depending on the region) and price development paths over the course of the investment lifetime. For each individual year, the quantity of natural gas feedstock "saved" by covering that portion of hydrogen demand via electrolysis is multiplied by the given price. This number then serves as revenue in the NPV calculation.

3.4.3 Electricity price

Otherwise referred to as the power price, this is the procurement price for the electricity input required by the electrolyser unit. As in the case of the natural gas feedstock, multiple starting levels and price paths are assumed. The quantity of electricity required to run the 5MW-capacity electrolyser for one hour is multiplied by the FLH, which is fixed at 5000 per year. This is the main expense for the renewable hydrogen. It should also be noted that the price assumption for electricity reflects the cost of acquiring renewably-sourced power, either from the grid or from a PPA arrangement.

3.4.4 PPA share

All scenarios incorporate the use of electricity from a PPA, albeit to varying extents. In each case, the share of total electricity demand covered by the PPA is specified, with the remainder of the demand purchased from the grid (at a higher price). The PPA share

13 Distinct from the energy price

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corresponds to a capacity factor for a solar or wind[14] facility supplying the unit which maxes out at or close to the best-reported capacity factors for the given technology in the given region. Some scenario, which include a higher PPA price reflecting an additional storage cost, are not bound by this limitation and are able to avoid grid purchases entirely.

3.4.5 **PPA price**

The share of the electrolyser's electricity demand met by the PPA is multiplied by the fixed price of electricity from that PPA (with the remainder assumed to be sourced from the grid). While PPAs are less prevalent in the European market, they are very popular and increasingly commonplace in the most dynamic PV-focused markets, such as the southern United States as well as the Middle East. PPAs feature heavily in the scenarios located in these regions for the assessment.

3.5 Support mechanism variables for assessed scenarios

Below is a list of the variable parameters included in the calculations that can be classified as subsidies. They comprise a variety of measures, some of which are already in operation and some of which have been mooted as potential routes to the development of a hydrogen economy more broadly.

With a sizeable renewable hydrogen capacity target of 6GW already outlined for 2024, it is foreseen that European governments will have to arrange competitive tenders for electrolysis projects at some point in the near future (Lambert 2020: 3). Given the current technology- and cost-based advantage enjoyed by SMR over electrolysis, as discussed in 3.2.2.1, financial support is a necessity. While no specific preference for the support mechanism has been set out at this stage, observers can speculate on multiple different routes, some of which are described here.

While these price and subsidy inputs apply first and foremost to the European market, where there has been the strongest demonstration so far of the political will to implement such policies, some are also included in selected non-European scenarios. Below is a brief description of each and/or their foreseen implementation and rationale:

3.5.1 **Carbon price**

The EU's Emissions Trading Scheme (ETS) is a union-wide cap-and-trade system for carbon emissions which was established in 2005 as a central pillar of the bloc's efforts to

14 Wind is the preferred option in central Europe, while PV is preferred in the US and Middle East scenarios

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reduce GHG emissions and mitigate the effect of economic activity on the environment[15]. The scheme requires any installation with a net heat excess above a given threshold to account for its GHG emissions via carbon credits. If an installation's emissions exceed its allocation of credits, additional volumes much be purchased from the market. The carbon price in this analysis is based on the traded price of (futures contracts[16] for) these allowances, and assumes that emissions reductions via the installation of an electrolysis unit would otherwise have to be covered by these additional purchases. As such, the carbon price, like natural gas costs, functions effectively as a revenue stream in the NPV calculation. As with the natural gas and electricity prices discussed above, various price paths are assumed for the price level of the European Union Allowance (EUA), or regional equivalent, in different scenarios. The historical development of the traded EUA price is illustrated in Figure 9 The higher market price in recent years informs the starting price for credits in the analysis of €30 per tonne CO_2 in year 1. Furthermore, the Market Stability Reserve (MSR), which gradually adjusts the number of credits auctioned off each year based on the volumes in circulation, is expected to support gradual price increases for carbon over the coming years[17].

Figure 9 - EUA carbon futures contract price history; Source: investing.com, own graphic

15 As per the EC's own description of the scheme: https://ec.europa.eu/clima/policies/ets_en#Carbon
16 Otherwise referred to as EUA, acronym of *European Union Allowance*, the carbon emissions allowance futures contract traded on the Intercontinental Exchange (ICE)
17 As of late 2020, there is a broad market consensus for carbon prices to rise in the coming years, as per SP Global/Platts: https://www.spglobal.com/platts/en/market-insights/latest-news/coal/120320-analysts-see-eu-carbon-prices-at-eur56-eur89mt-by-2030

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3.5.2 Direct subsidy

The most straightforward way to encourage the development of renewable hydrogen production capacity would be for a government to guarantee a fixed sum payable to the operator of a facility per unit of hydrogen produced. It is possible that such an award would be allocated via a tendering process, such that an awarding body is able to maximize the amount of capacity and/or production of renewable hydrogen for a given amount of financial support. The fixed subsidy would in turn provide the necessary revenue stream required for a viable investment case. It could also carry the additional benefit of being applicable specifically to renewable hydrogen (and not low-carbon, fossil fuel-based hydrogen with CCUS, which is still likely to be able to undercut electrolysis on an LCOH basis for the foreseeable future).

3.5.3 Carbon Contract for Difference (CCfD)

An alternative to the direct, fixed amount subsidy, this support mechanism would be based in part on the carbon price dictated by the market, as discussed above. The idea is for a government or other entity providing support to guarantee a given carbon price, independent of the prevailing carbon price dictated by the market (Lambert). CCfDs are distinct from the direct (fixed) subsidy in that the CCfD adjusts to the market, and is intended to make up for the gap between the market and a carbon price level necessary to justify an investment in the renewable hydrogen capacity. In effect, a CCfD would inflate the revenue stream in the NPV calculation to ensure larger savings on carbon costs. It may also be more efficient from a subsidy perspective than a fixed subsidy regime.

3.5.4 Guarantee of Origin (GoO)

Another potential method of subsidizing renewable hydrogen production capacity would be to attach a specific value to the production of a unit of renewable hydrogen. This would serve as a tradeable certificate with a market value and would be distinct from any carbon-related mechanism such as the ETS. The generation and potential sale of such certificates could represent an additional revenue stream for a renewable hydrogen production facility. Due to the likely need for hubs or clusters to develop for renewable hydrogen production, GoO revenue streams are only assumed in selected scenarios from year 5 onwards.

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3.5.5 GoO traded share

The GoO would have a value per unit, while a facility which generates these certificates would have some flexibility in how many it sells into the market. This percentage share also functions as a variable in selected scenarios.

It should be noted that all of the market-based price assumptions (natural gas, grid electricity, carbon, GoOs) are assumed to change over the course of the investment period. Changes are listed annually, and are also expressed in terms of compound annual growth rate (CAGR). This is a convention reflecting the fact that all of the market-based price assumptions also serve as exchange products and investment vehicles for speculators. CAGR allows for the rate of growth (positive or negative) in a given commodity to be expressed as a percentage with respect to a given time period (in this case a universal 15-year investment horizon).

More details on these numbers per scenario, including the respective CAGR values for the various inputs, can be found in 4 and 0.

$$CAGR = \left(\frac{EV}{BV}\right)^{\frac{1}{n}} - 1 \tag{7}$$

In this equation, EV refers to the final price i.e. the value of the investment/asset/position at the end of the assessed period (of years), BV is the beginning price paid for the investment/asset/position at the beginning of the assessed time period, and n is the number of years.

As discussed above, there are also significant regional variations in the viability of investing in renewable hydrogen. This is a function of many factors: the potential for renewable electricity generation of different geographies, market prices for key inputs, financing conditions, and others. While the focus of this analysis is on the (central) European market such as Austria (0 and 4.2), comparisons will also be made with other regions that have exhibited excellent potential in terms of renewable electricity generation, and associated low PPA prices. The selected markets are the US (Texas) and the Middle East (UAE), both of which have seen significant build-out of PV capacity in recent years. Figure 10 illustrates the relative positioning of each market in terms of suitability for the development of renewable hydrogen resources:

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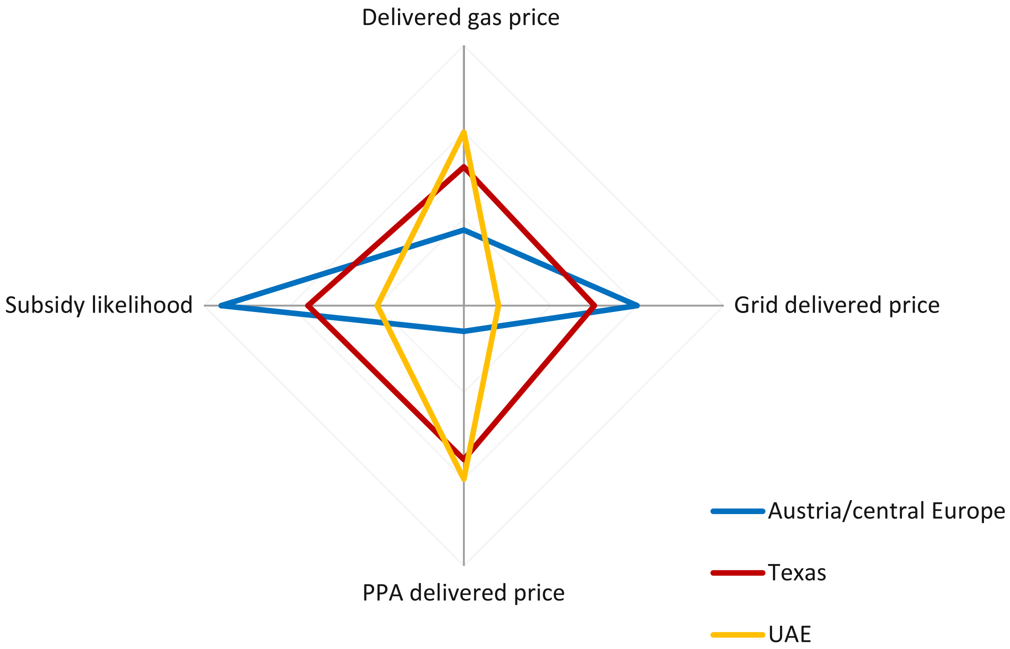

Figure 10 - Relative conduciveness to renewable H_2 by market; Source: own calculations based on EXAA, ICE, CME, ERCOT and Abu Dhabi Distribution Co. data, own graphic

Figure 10 describes the suitability of each market in terms of key characteristics: gas prices, electricity prices, PPA prices, and the subsidy environment. Shapes tracing closer to the outside of the chart area indicate a higher conduciveness to development. Market-based inputs are based on data from the most recently available full year[18], and the two less conducive regions are shown in relation to the most conducive. For example, in terms of the delivered grid electricity price, Europe has the most conducive market conditions of the three regions (lowest assumed price). Texas is 25% more expensive than this, while the UAE is 80% more expensive. Note that assumptions for subsidy likelihood are subjective. Europe is ranked most likely to subsidise, while the UAE is ranked least likely. Some additional rationale on these points is included in the respective scenario summaries in 4.

18 Sources for the data: ICE (European gas price proxy) , EXAA (Austrian wholesale electricity price), EEX (gas price comparison), CME (US natural gas), Electric Reliability Council of Texas ERCOT via EIA (Texas electricity prices), Abu Dhabi Distribution Co. / Dubai Electricity Authority / Al Ain Distribution Company via globalpetrolprices.com (UAE electricity and natural gas prices). Subsidy likelihood reflects own estimates.

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4 Documenting assessment parameters per scenario

This section provides a full description of each of the scenarios used in the assessment (in total there are 22), describing the level and rationale for the respective variable parameters. Fixed parameters in the calculations are as described in 3.3 unless otherwise stated. Summaries of the key economic metrics described in 3.2.2 are included in each of 4.1, 4.2, 4.3, and 4.4, with commentary to follow in 5 and 6.

4.1 European scenarios (unsubsidized)

The first group of scenarios do not assume any form of financial support. The starting prices for variables in year 1 of operation are similar in all scenarios, with differences mainly expressed via CAGR out to year 15 of the investment.

Some general comments on the assumptions for these scenarios:

- The grid electricity (energy) price has a starting point based on (green, renewable) Austrian electricity market data from 2019 sourced from Energy Exchange Austria (EXAA). The starting value for grid electricity (energy price) is drawn from the price curve shown in Figure 11. A lower bound is assumed to be the first hour that grid electricity is required (basis the FLH of the PPA installation). The upper end of the range is assumed to be the last hour in the curve that grid electricity is required (starting from 0). The price is simply the mean of these two bound values. In this way the assumed grid electricity price is adjusted depending on how much is purchased.
    - The "green" prices listed in Figure 11 refer to the price of the green electricity day-ahead product traded on EXAA since 2012. The product is distinct from "regular" - which is also illustrated below for reference - in that it is sourced exclusively from renewable electricity sources (specifically hydropower). The renewable source of the volumes traded via this EXAA product are guaranteed via the use of GoOs (Guarantees of Origin) and, as such, the product is an appropriate, physically-deliverable power procurement option for minimizing emissions related to the production of hydrogen in the European scenarios of this analysis.

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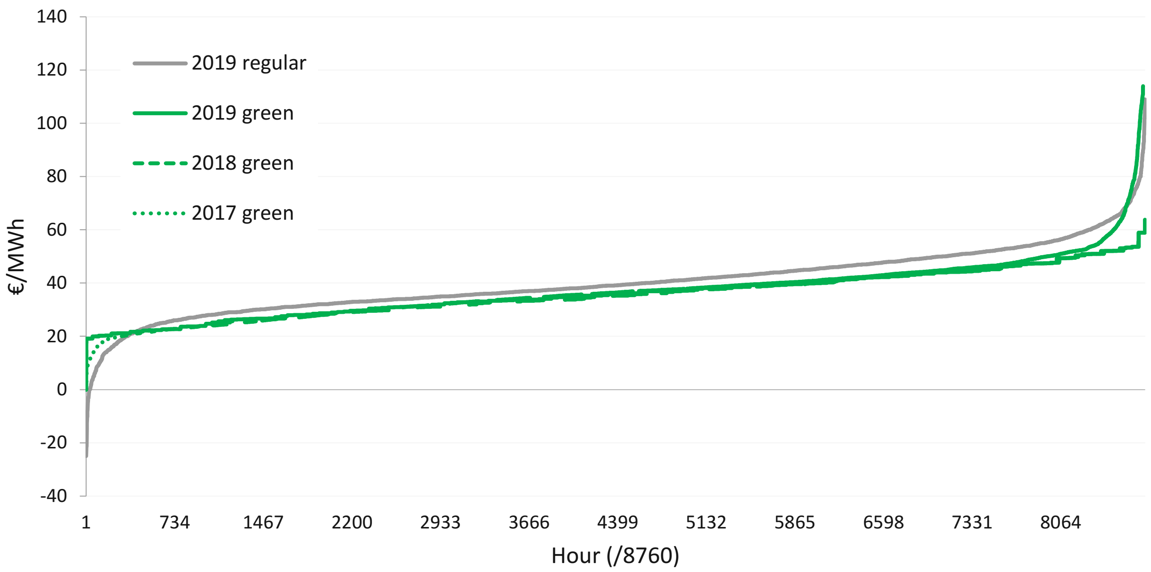

Figure 11 - Ascending day-ahead electricity prices by year (Austria); Source EXAA, own graphic

- Volatility in natural gas trading hubs over the last couple of years, and especially over the last 12 months, has been significant. The assumed starting price for natural gas is based on an average of monthly front-month contract settlements from a range of European trading hubs between Q4 2019 and Q4 2020, and is set at €13.7 per MWh which, on a delivered basis, is approximately €27.3 per MWh.
- Prices for both electricity and gas feeding into the calculations take the energy price in each case and divide these by a percentage factor to arrive at a higher value, which is assumed as the delivered price. This is in line with convention in Austria and other countries, where delivered prices include grid costs and other expenses, with the actual energy cost typically making up only a minority share of the final delivered gas/electricity price as can be seen in Figure 12 (this is for industrial customers):

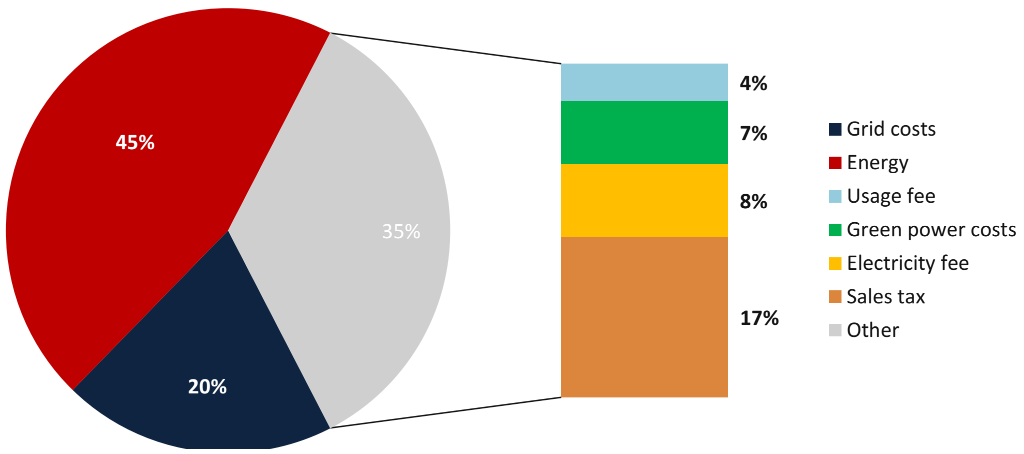

Figure 12 - Electricity price composition for industry (Austria); Source: e-control, own graphic

- The assumed starting price for carbon in year 1 will be €30 per tonne. This is close to the levels seen recently on the ICE exchange and as depicted in Figure 9. With expectation for the development of the MSR from this point, a price level which is close to the historical maximum (so far) can be seen as a reasonable baseline for this metric.
- PPA prices and shares are considerably less attractive in Europe than in the other regions. The price for PPA-sourced electricity in Europe is nevertheless lower than grid-sourced electricity, with a default level of approximately €38.5 per MWh (unless otherwise stated), which is fixed throughout the duration of the investment. The share of electricity consumption covered by the PPA is also lower in Europe than in the other regions, with assumptions that this will correspond to a capacity factor of an attached onshore wind facility no better than 24% in line with the regional average (Wind Europe 2020: 18), unless otherwise stated.

There are 7 scenarios in this European unsubsidized category. A summary of these can be seen in Table 7, with descriptions and economic metrics for each below. Additionally, a more comprehensive summary of all the inputs by scenario together with the assessed results can be found in 0 (see Figure 28).

Table 7 - European environment scenarios summary (unsubsidized); own parameters

	Default	Low capex	High spark	Low spark	PPA boost	Carbon rally	Supportive market + PPA boost
Grid start price	67.79	67.79	67.79	67.79	68.58	67.79	68.58
Gas start price	27.30	27.30	27.30	27.30	27.30	27.30	27.30
Carbon start price	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Investment/kWp	1200	900	1200	1200	1200	1200	1200
Gas CAGR	3%	3%	1%	5%	3%	2%	5%
Power CAGR	0%	0%	3%	-1%	0%	1%	-1%
PPA price	25	25	25	25	22	25	22
PPA share	42%	42%	42%	42%	50%	42%	50%
Carbon CAGR	4%	4%	4%	4%	4%	15%	10%
Direct subsidy	0	0	0	0	0	0	0
CCfD	0	0	0	0	0	0	0
GoO*	0	0	0	0	0	0	0
Traded share**	10%	10%	10%	10%	10%	10%	10%

**Guarantee of Origin value increases linked to carbon prices*

***of GoOs*

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4.1.1 *Default*

The *default* scenario includes all of the unadjusted base assumptions. Power prices from the exchange are assumed flat over the course of the investment due to increasing penetration of low-cost renewables in the system. Both gas and carbon prices appreciate moderately over time (see Figure 13). 4% CAGR on carbon converts to an average price of just over €40 per tonne over the course of the 15-year horizon.

NPV	**-€ 15,026,753.22**
Annuity	**-€ 1,447,711.78**
LCOH	**€ 4.42 /kgH_2**

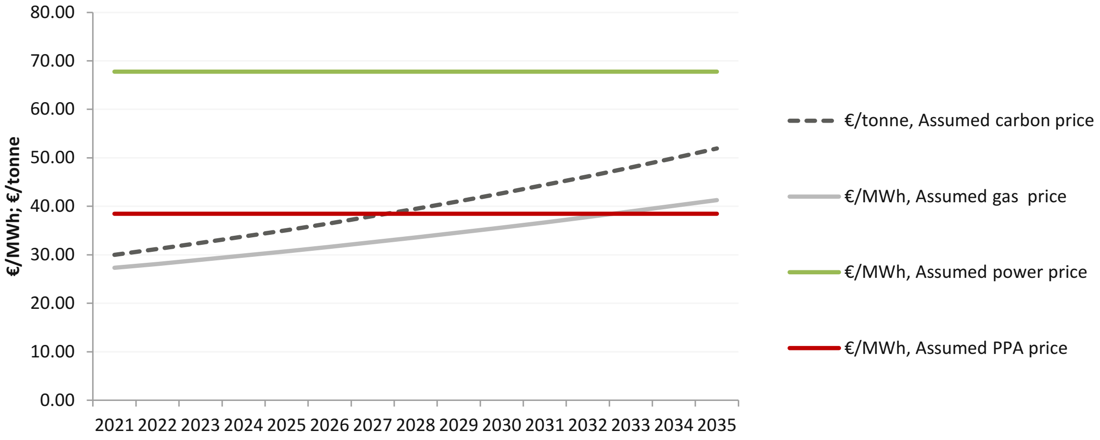

Figure 13 - Price development by variable (*default*, Europe); own calculations

4.1.2 *Low capex*

Default values are carried over. The only difference from the *default* values is the assumption of a lower cost of initial investment, which is set some 25% lower for the same nameplate capacity size. This is intended as an illustration of the difference that a potential fall in capex costs in electrolyser manufacturing costs would make to the investment viability of such a project.

NPV	**-€ 12,533,256.54**
Annuity	**-€ 1,207,482.61**
LCOH	**€ 4.16 /kgH_2**

4.1.3 *High spark*

High spark refers to a market environment where power prices become increasingly expensive relative to the natural gas price. Power CAGR over the 15 years is set at 3%,

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assuming a much-faster-than-anticipated electrification of multiple applications in the economy (by year 15, the price for delivered grid energy appreciates to more than €100 per MWh). Meanwhile, natural gas price increases are much gentler, with a CAGR of only 1%. Development of the respective price inputs over time can be seen in Figure 14. This is an example of a market environment which is substantially less conducive to the replacement of SMR-based hydrogen production with electrolysis.

NPV	**-€ 18,061,572.70**
Annuity	**-€ 1,740,093.23**
LCOH	**€ 4.99 /kgH_2**

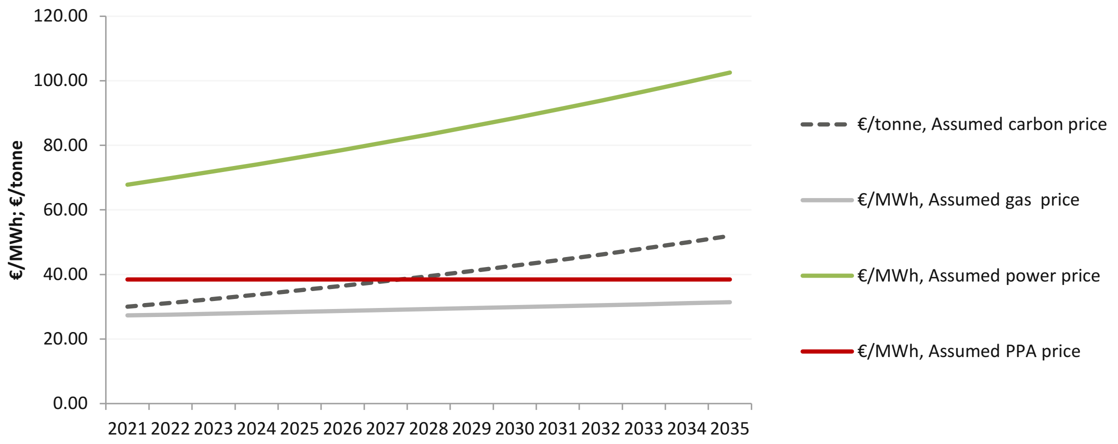

Figure 14 - Price development by variable (*high spark*, Europe); own calculations

4.1.4 *Low spark*

Essentially the reverse of the prior scenario, *low spark* denotes an environment where electricity prices are weak relative to those for natural gas. This scenario includes a CAGR of 5% for natural gas. This significantly increases the savings possible on feedstock purchases with the installation of an electrolysis unit. Furthermore, an accelerating deployment of low-cost renewables into the system actually drives a decrease in the cost of grid electricity over time, with a CAGR here of -1%. This leaves electricity and natural gas prices within sight of one another on a delivered per-MWh basis by the end of the 15-year cycle.

NPV	**-€ 13,343,365.11**
Annuity	**-€ 1,285,530.32**
LCOH	**€ 4.26 /kgH_2**

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4.1.5 *PPA boost*

This scenario envisions better-than-expected conditions for the PPA included in the project. A more competitive environment here means that the fixed price paid for the PPA-sourced electricity is lower than in the other scenarios (a €3 per MWh, or 12%, relative discount), while a higher assumed capacity factor for the PPA-associated onshore wind facility is also able to meet a higher share of the installation’s electricity demand (50% in this scenario vs. 42% in the *default* assumptions). This is associated with a slightly higher assumed starting price for the non-PPA electricity demand, though the growth rates for electricity, gas, and carbon are unchanged.

NPV	**-€ 13,921,466.02**
Annuity	**-€ 1,341,225.88**
LCOH	**€ 4.16 /kgH_2**

4.1.6 *Carbon rally*

This scenario envisions the most dramatic price change in the market occurring in carbon. A combination of more stringent tightening efforts by the European Commission via the MSR in order to accelerate emissions abatement efforts, as well as much more widespread speculation on rising prices for carbon amongst institutional and retail investors, puts carbon CAGR at 15%. This drives the carbon price to more than €200 per tonne by the end of year 15 (see Figure 15). Associated with this much higher carbon price is weaker growth in natural gas prices (CAGR 2%) relative to the *default* assumptions due to weaker demand, with faster electrification driving up power prices faster than in the *default* scenario (CAGR 1%).

NPV	**-€ 14,272,878.70**
Annuity	**-€ 1,375,081.78**
LCOH	**€ 4.59 /kgH_2**

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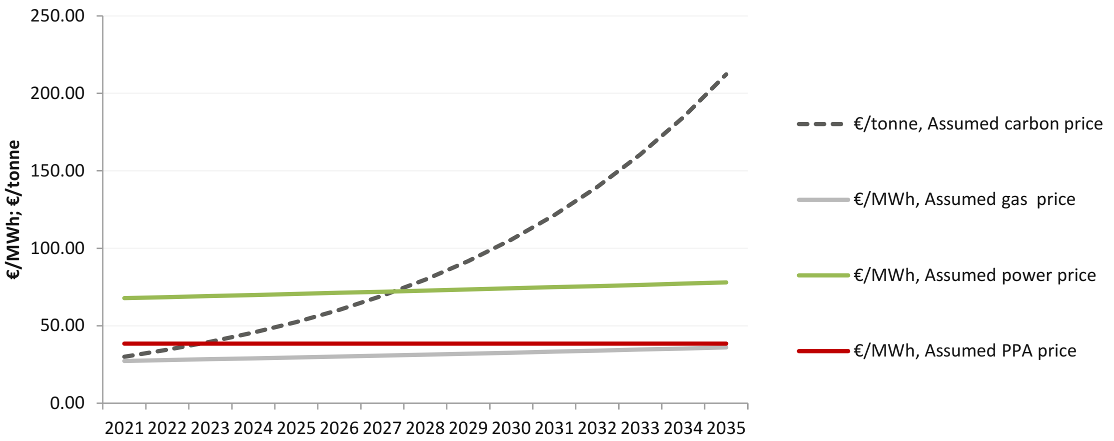

Figure 15 - Price development by variable (*carbon rally*, Europe); own calculations

4.1.7 *Supportive market + PPA boost*

The final non-subsidized scenario for the European market envisages a combination of some of the supportive elements from the prior scenarios. This scenario assumes the more attractive conditions in the PPA market than the *default* scenario (€22 per MWh fixed price on PPA-sourced power, along with a higher capacity factor, which allows for the PPA to cover 50% of the installation's electricity consumption) as well as more conducive conditions in the market for renewable hydrogen production. This includes the assumption for increasingly expensive natural gas (CAGR 5%) relative to electricity (CAGR -1%).

NPV	**-€ 11,501,418.60**
Annuity	**-€ 1,108,072.98**
LCOH	**€ 4.02 /kgH_2**

4.2 European scenarios (subsidized)

This second group of European scenarios assumes various forms of financial support that underpin the NPV of the investment into the electrolyser. Assumptions on costs of delivery and starting prices for the various inputs are the same as in the non-subsidized scenarios described above.

There are seven scenarios in this European subsidized category. A summary of these can be seen in Table 8, with descriptions and economic metrics for each below. Additionally, a more comprehensive summary of all the inputs by scenario together with the assessed results can be found in 0 (see Figure 29).

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Table 8 - Europe environment scenarios summary (subsidized); own parameters

	Fixed subsidy	Fixed subsidy, supportive market	Market-based subsidy	Market-based subsidy, supportive market	Market-based subsidy + GoO revenue	Market-based subsidy + GoO higher revenue	Initial investment subsidized
Grid start price	67.79	67.79	67.79	67.79	67.79	67.79	67.79
Gas start price	27.30	27.30	27.30	27.30	27.30	27.30	27.30
Carbon start price	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Investment/kWp	1200	1200	1200	1200	1200	1200	0
Gas CAGR	3%	5%	3%	5%	3%	3%	3%
Power CAGR	0%	-1%	0%	-1%	0%	0%	0%
PPA price	25	25	25	25	25	25	25
PPA share	42%	42%	42%	42%	42%	42%	42%
Carbon CAGR	4%	10%	4%	10%	4%	4%	4%
Direct subsidy	4	4	0	0	0	0	0
CCfD	0	0	345	305	345	345	0
GoO*	0	0	0	0	1	1.75	0
Traded share**	10%	10%	10%	10%	10%	40%	10%

**Guarantee of Origin value increases linked to carbon prices*

***of GoOs*

4.2.1 *Fixed subsidy*

This scenario assumes a straightforward, fixed level of financial support for the installation payable per unit of hydrogen produced renewably, set at €4/kgH_2 for the full duration of the investment's 15-year horizon. That is the sole form of support in this scenario, and other assumptions regarding starting prices and CAGR for the various inputs remain unchanged from the *default* scenario above. Figure 16 illustrates the assumptions for this scenario over the investment horizon, with both market power prices and the per-unit subsidy remaining fixed throughout (the subsidy in this scenario does not adjust to the market).

NPV	**€ 1,995,885.96**
Annuity	**€ 192,288.22**
LCOH	**€ 4.42 /kgH_2**

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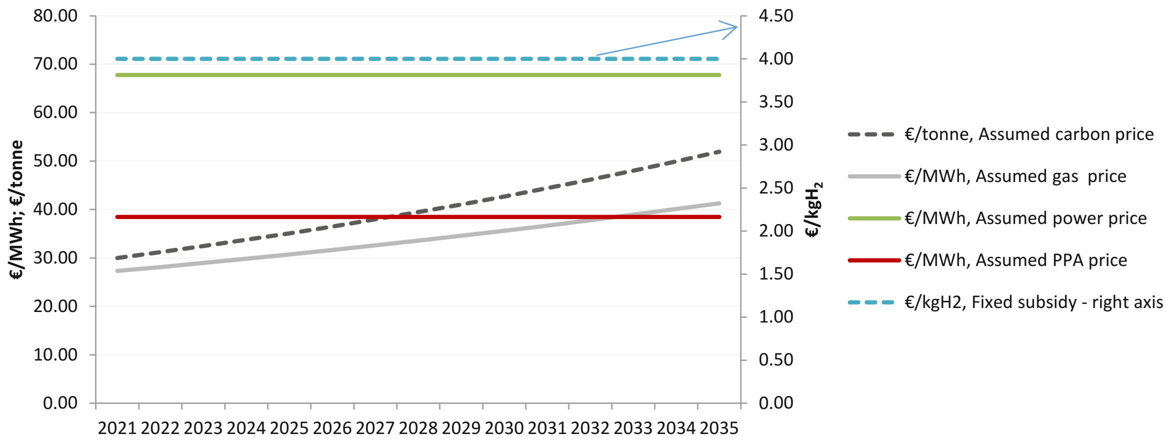

Figure 16 - Price development by variable (*fixed subsidy*, Europe); own calculations

4.2.2 *Fixed subsidy, supportive market*

This scenario envisions the same level of fixed support provided to the installation per unit of renewable hydrogen produced as in the prior scenario of (€4/kgH_2), but with market conditions which are more supportive of the investment than those in the *default* scenario. This includes the faster appreciation of natural gas prices, with a CAGR of 5%, and a decrease in power prices on average (CAGR -1%). As noted above, there is no mechanism in this subsidy scheme to adjust to the fact that the market is here providing a more conducive – and potentially profitable – environment for the investment.

NPV	**€ 4,492,373.84**
Annuity	**€ 432,805.57**
LCOH	**€ 4.26 /kgH_2**

4.2.3 *Market-based subsidy*

This scenario makes use of a subsidy which adjusts to the prevailing market conditions; the CCfD included here is designed to make up the shortfall between the market conditions and the levels required for an investment to be economically viable. If this is to be set up and arranged in advance, it requires an assumption to be made for the carbon price (the differential between abatement cost and the market price is the compensation paid out by the subsidy provider). With the same market assumptions for gas and electricity as the *default* scenario, but with a CAGR expectation of 10% for carbon, the investment would require a CCfD of almost €345 per tonne of CO_2 in order to return a positive NPV. However, in this scenario, the carbon price does not appreciate in line with expectations, managing a CAGR of only 4% over the investment lifetime.

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NPV	**-€ 785,187.71**
Annuity	**-€ 75,646.78**
LCOH	**€ 4.42 /kgH_2**

4.2.4 *Market-based subsidy, supportive market*

In this scenario, the CCfD is decided on ex-post, when the cost of abatement is known. Here, carbon prices on the market rise more aggressively, managing CAGR of 10%. Meanwhile, market prices for natural gas and electricity also move in favour of electrolysis economics, posting CAGR of 5% and -1% respectively. In this environment, a smaller CCfD of €303.54 per tonne of CO_2 can be calculated as the support level required to ensure the NPV of the project is not negative. The CCfD level is rounded up to an even €305 per tonne of CO_2, representing a 12% reduction vs. the CCfD cost of the prior scenario and yet returning a moderately positive NPV.

NPV	**€ 60,104.17**
Annuity	**€ 5,790.57**
LCOH	**€ 4.26 /kgH_2**

4.2.5 *Market-based subsidy + GoO revenue*

This scenario assumes the inclusion of the pre-agreed CCfD at €345 per tonne of CO_2 and also includes an additional, unrelated revenue stream coming from the generation of GoOs from year 5 onwards. The starting value assumed for the GoO is €1/kgH_2 produced, with a CAGR for the certificate of 4% translating into a final-year value of €1.47/kgH_2. With 10% of the total generated certificates sold into the market, the GoOs represent just over €50,000 of revenue for the installation each year. Other market prices – natural gas, electricity and carbon– are the same as the *default*.

NPV	**-€ 442,387.03**
Annuity	**-€ 42,620.58**
LCOH	**€ 4.42 /kgH_2**

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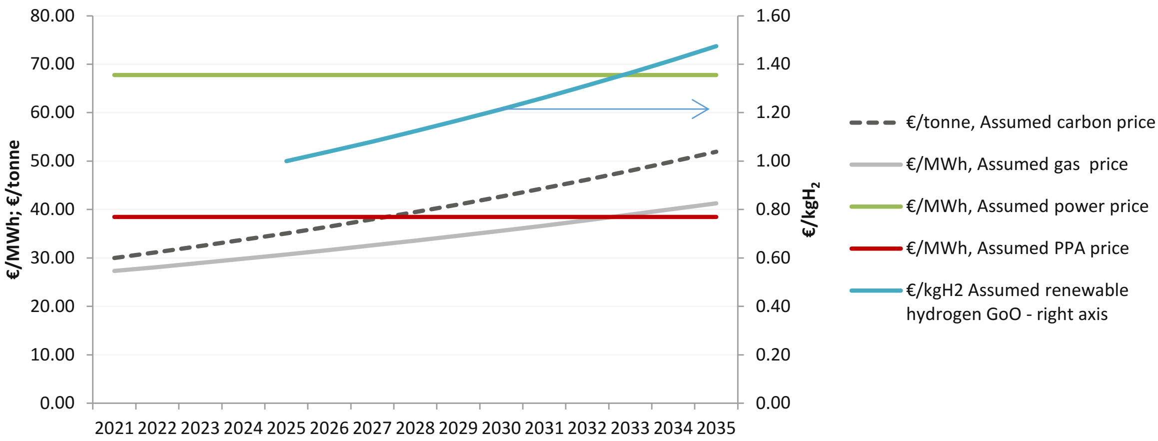

Figure 17 - Price development by variable (*market-based subsidy + GoO revenue*); own calculations

4.2.6 *Market-based subsidy + higher GoO revenue*

This scenario also assumes the €345 per tonne of CO_2 CCfD and the same natural gas, electricity and carbon price development as the *default* scenario, but assumes a larger revenue stream from the sale of GoO certificates. Here, the GoO revenue is also introduced in year 5 of the investment, when hubs and clusters for renewable hydrogen are better developed. However, the assumed starting price is higher in this case at €1.75/kgH_2 and CAGR for the certificates is 4%. Additionally, the refinery is assumed to be in a position to be able to sell a significantly higher share of the certificates that it generates, placing 40% into the market. This means GoO-related revenue in this scenario is expanded considerably, to more than €350,000 each year that GoOs are generated and sold. While the LCOH is unchanged vs. the prior scenario, the NPV of the investment is considerably improved.

NPV	**€ 1,614,417.11**
Annuity	**€ 155,536.64**
LCOH	**€ 4.42 /kgH_2**

4.2.7 *Initial investment subsidized*

The final scenario in this region assumes the same market prices as in the *default* scenario, and does not include any of the production- or market-based support schemes that have featured in the other subsidized scenarios. Instead, the financial support here comes in the form of reimbursement for the costs of the initial investment. As such, there are no cash flows to speak of in year 0 of the investment as the initial costs have been removed.

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NPV	**-€ 5,052,766.48**
Annuity	**-€ 486,795.08**
LCOH	**€ 3.38 /kgH_2**

[19]

4.3 United States scenarios

As a point of comparison with the scenarios in 4.1 and 4.2, this section assesses the viability of the same project in the market environment of Texas in the United States. The market conditions taken into consideration in this assessment are considerably different here than in Europe. Furthermore, Texas is home to a large share of the total US oil refining fleet, and is the largest state emitter of carbon in the entire US. This, combined with excellent potential renewable electricity development, especially PV, makes Texas a highly relevant potential market for the development of renewable hydrogen capacity.

The scenarios for Texas include both subsidized and non-subsidized options. The starting points for market price variables in year one of operation are similar in all scenarios, with differences mainly expressed via CAGR out to year 15 of the investment, and in the PPA conditions available to the installation (the PPA concept is significantly more developed and widespread in Texas and some other US states than in the European market as of 2020).

Some general comments on the assumptions for these scenarios:

- For the sake of simplicity of comparison, all prices in assumptions are listed in Euro (€). Conversions have been made where necessary from the local currency at an average exchange rate against the Euro encapsulating at least 3 months of historical data (as of December 2020).
- The grid electricity (energy) price has a starting point based on ERCOT data as cited by the Energy Information Administration (EIA) for 2019, which states that day-ahead prices for electricity on the wholesale market averaged close to €35 per MWh, which has been assumed at a higher starting point for year 1 of the investment based on the upwards trend of recent years. As in the European examples from the previous section, a delivery cost factor has to be assumed. This is set at the same 45% factor that has been used in Europe, giving a final electricity start price of just under €85 per MWh. Default CAGR for power is set at 0%.

19 The LCOH listed for the *Initial investment subsidized* scenario is from the perspective of the investor, as the initial costs of the investment have not been included in the calculation. If these are included, the LCOH is €4.42 per kgH_2

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- By contrast, natural gas prices are assumed somewhat lower than in the European market. An assumed exchange price for Henry Hub natural gas of €3 per mmBtu – which is some way above where futures contracts have been trading in the US market on average over the last couple of years – converts to a wholesale gas price of approximately €10.50 per MWh. Again, assuming the same grid cost factor (for gas) of 50% that had been seen in Europe, this converts to a delivered starting natural gas price of just under €21 per MWh – significantly lower than in Europe. Default CAGR for natural gas is set at 3%.
- As there is currently no federal, EU-style cap-and-trade scheme in place for carbon in the US, the default assumption for the Texas scenarios is for no cost to be attached to the carbon emissions associated with SMR-based hydrogen production (and therefore no savings to be made on this front from a partial switch to electrolytic hydrogen production). The default scenario also does not foresee such a scheme being introduced at any point during the investment horizon. However, three of the US scenarios do assume that a carbon cap-and-trade scheme is introduced for the middle of the decade, with carbon prices effective from year 5 of the investment. The starting price is set at the level of the default European price at the same point in time (just over €35 per tonne, based on a starting price of €30 and a CAGR of 4%).
- More expensive default values for electricity and less expensive default values for natural gas, combined with the lack of a carbon pricing scheme, do not appear especially conducive to renewable hydrogen investment in Texas. It should also be noted that, as discussed in 3.3, capital cost assumptions are the same here as in the other regions. However, the PPA environment is considerably different to Europe. A realistic estimate for the price of PPA contract available for this analysis in Texas would be for €15 per MWh[20]. Delivered costs, based on a smaller grid cost assumption than for the grid-sourced electricity (70% vs. 45%) gives a delivered PPA power price of just over €21 per MWh. Furthermore, the PPA arrangement, even in the default Texas scenario, is able to cover a larger share of the electrolyser's power requirement, due to a higher assumed capacity factor for the associated PV plant. This capacity factor is in line with the best reported capacity factors for modern PV

20 PPA fixed prices have continued to set new record lows in the southwestern United States over 2020, with the $15 (USD) per MWh barrier undercut recently by the Hecate project located in Santa Teresa in New Mexico (company information). At late-2020 conversion rates, equivalent to €12-13 per MWh

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plants in the US[21], which can reach up to 28% in the best-performing locations in states such as Texas and Arizona.

- An additional PPA option has been included in some of the US scenarios, namely the inclusion of storage. While this involves a higher assumed average price for the delivered electricity than the non-storage PPA option due to cost of additional infrastructure, the average cost is still significantly lower than purchasing electricity from the grid. Accounting for the same assumed transport factor as in the pure PPA option, a €25 per MWh PPA + storage option converts to a delivered PPA + storage price of almost €36 per MWh. However, the inclusion of storage means that the PPA source is able to meet all of the electricity requirements of the 5MW electrolyser[22], with this option allowing for electricity purchases from the grid to be avoided altogether.

There are a total of five scenarios in the Texas category. A summary of these can be seen in Table 9, with descriptions and economic metrics for each listed below. Additionally, a more comprehensive summary of all the inputs by scenario together with the assessed results can be found in 0 (see Figure 30).

Table 9 - United States environment scenarios summary; own parameters

	Default	Best available PPA	Best available PPA + carbon rally	Best available PPA + EU-level subsidy + carbon rally	Best available PPA + supportive market + carbon
Grid start price	84.44	84.44	84.44	84.44	84.44
Gas start price	20.94	20.94	20.94	20.94	20.94
Carbon start price	0.00	0.00	0.00	0.00	0.00
Investment/kWp	1200	1200	1200	1200	1200
Gas CAGR	3%	3%	3%	3%	5%
Power CAGR*	0%	0%	0%	0%	-1%
PPA price**	21.43	35.71	35.71	35.71	35.71
PPA share***	50%	100%	100%	100%	100%
Carbon CAGR	4%	4%	15%	15%	4%
Carbon 2025 price	0	0	35.1	35.1	35.1
Direct subsidy	0	0	0	4	0

**Power price changes not relevant in those scenarios which are entirely PPA-based*

***Higher of the two price levels includes storage; effective when when PPA share is 49% and above*

21 Based on EIA form 860 data, which summarises electric generator information at power plants with 1MW and above of capacity. Link to the data: https://www.eia.gov/electricity/data/eia860/

22 The size of the PPA-associated PV installation is assumed to be significant in scale (30+ MW capacity), in line with recent development trends in the state which see installations providing electricity for a single large customer, or multiple customers with smaller offtake requirements

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4.3.1 *Default*

The *default* scenario includes all of the base assumptions as described above. The starting delivered power price is €84.44 per MWh; the starting gas price is €20.94 per MWh. The *default* scenario does not put a price on carbon emissions. The associated PPA price is €21.94/MWh, which is fixed for the duration of the investment. This arrangement is assumed to cover 50% of the electrolyser's electricity demand, and this corresponds to a capacity factor of 28.5% for the associated PV facility. There are no assumptions of financial support for the installation in this scenario.

NPV	**-€ 19,622,308.16**
Annuity	**-€ 1,890,458.06**
LCOH	**€ 4.70 /kgH_2**

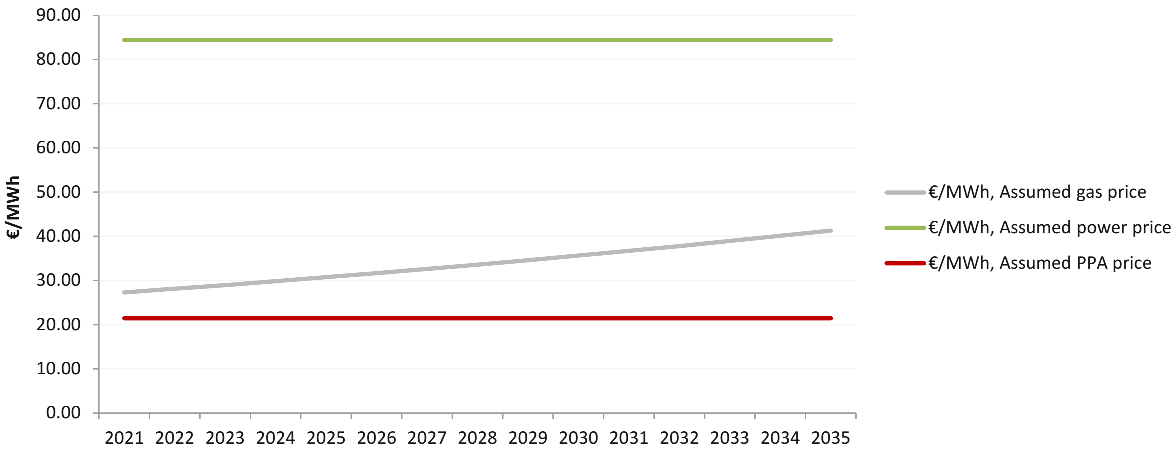

Figure 18 - Price development by variable (Texas, *default*); own calculations

4.3.2 *Best available PPA*

This scenario reflects the same market as in the *default* scenario, but with superior PPA coverage. The assumed PPA price per MWh here is €35.71. However, unlike the *default* scenario, which still relies on the grid for 50% of its electricity needs, this higher-cost PPA allows grid-sourced power to be completely avoided. As in the *default*, there is no financial support available or price attached to carbon emissions.

NPV	**-€ 13,299,778.36**
Annuity	**-€ 1,281,331.07**
LCOH	**€ 3.21 /kgH_2**

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4.3.3 *Best available PPA + carbon rally*

This scenario takes the full PPA integration of the prior scenario and adds the assumption of a carbon price on top. This serves as additional revenue for the electrolyser installation as they represent savings that are made vs. SMR-based production. The scenario assumes that the US introduces a federal cap-and-trade, EU-style scheme for carbon emissions starting from the beginning of year 5 of the investment horizon. The price of carbon, starting at just over €35 per tonne, is also assumed to appreciate rapidly in this scenario in the period following the scheme's introduction, with a CAGR of 15% driving the value of US carbon to more than €140 per tonne by the end of year 15[23].

NPV	**-€ 11,324,294.11**
Annuity	**-€ 1,091,008.40**
LCOH	**€ 3.21 /kgH_2**

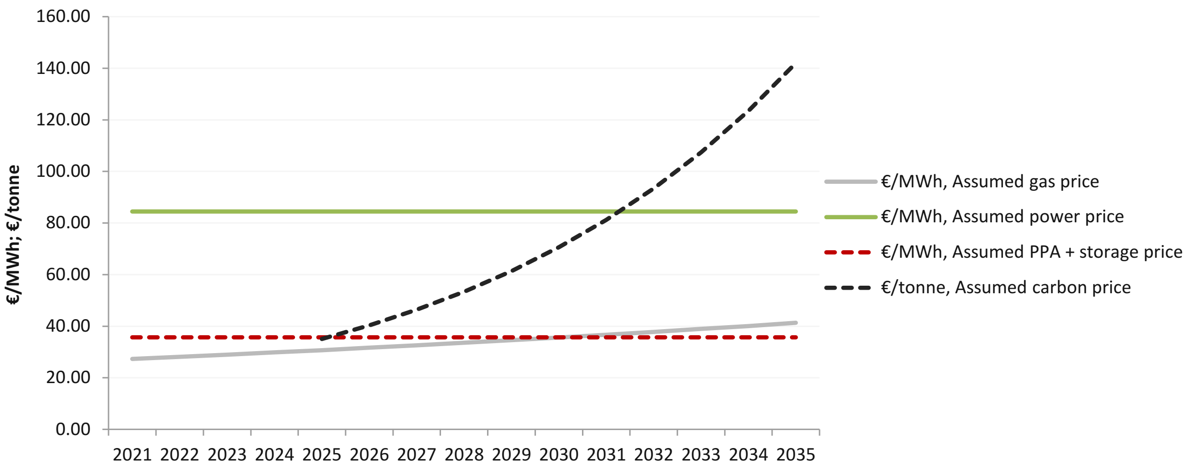

Figure 19 - Price development by variable (Texas, *best available PPA + carbon rally*); own calculations

4.3.4 *Best available PPA + EU-level subsidy + carbon rally*

This scenario maintains the PPA conditions from the previous cases (100% coverage at a fixed price of €35.71 per MWh), as well as the carbon price conditions (introduction of a federal scheme in year 5, which then posts CAGR of 15% over the remainder of the investment horizon). In addition, the scenario assumes that a fixed subsidy is introduced specifically to encourage the production of renewable hydrogen, and which does not

23 The €35 per tonne value is the year 5 value of EU carbon assuming CAGR of 4% (*default* scenario).

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adjust to the market. This is set at a fixed level of €4/kgH_2, the level of the fixed price subsidy seen in several European-based scenarios in 4.2.

NPV	**€ 5,698,345.07**
Annuity	**€ 548,991.60**
LCOH	**€ 3.21 /kgH_2**

4.3.5 *Best available PPA + supportive market + carbon pricing*

This scenario also maintains the PPA conditions from the previous cases (100% coverage at a fixed price of €35.71 per MWh), and carbon pricing is introduced at the beginning of year 5 of the investment – albeit with a lower assumed CAGR of 4%. This sees the value of carbon in the region rise to more than €50 per tonne by the end of the installation's 15-year investment horizon. At the same time, this scenario assumes that the market prices for the different inputs develop in a way that is more conducive to an investment in renewable hydrogen, with natural gas prices rising faster (CAGR 5%) than in the *default* scenario and electricity prices actually showing negative growth over the same time period (CAGR -1%).

NPV	**-€ 11,319,536.91**
Annuity	**-€ 1,090,550.08**
LCOH	**€ 3.21 /kgH_2**

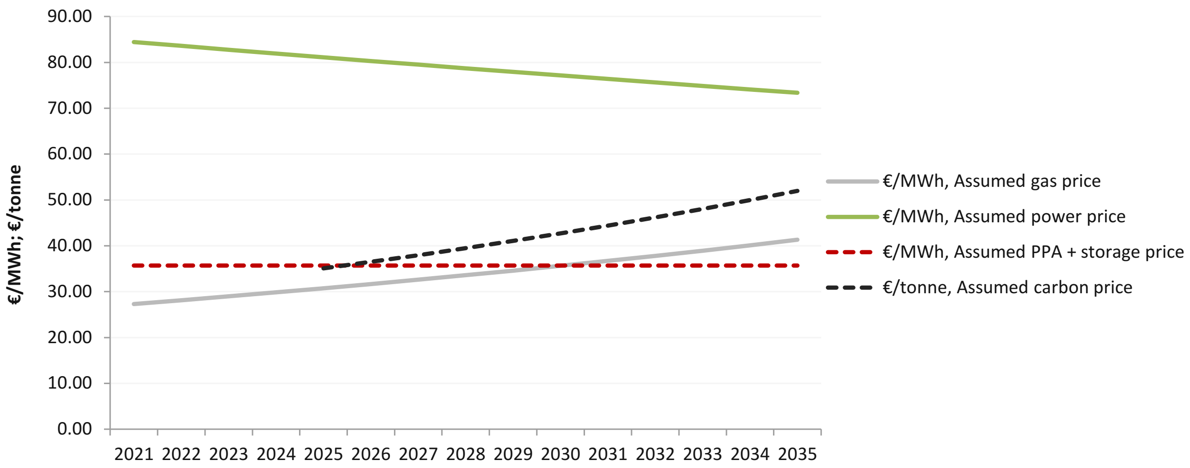

Figure 20 - Price development by variable (Texas, *best available PPA + supportive market + carbon pricing*); own calculations

4.4 Middle East scenarios

As a further point of comparison with the scenarios detailed in 4.1, 4.2 and 4.3, this section documents model results for the same project in a United Arab Emirates (UAE) market

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environment. The prevailing market conditions are again considerably different than in Europe, with a substantially different price constellation. The UAE, as a major oil producer, is also home to a large volume of crude oil refining capacity with significant GHG contributions, while also holding significant PV potential. These factors make the UAE a highly relevant candidate for assessing the viability of renewable hydrogen investments.

The scenarios for the UAE include both subsidized and non-subsidized options. The starting points for market price variables in year 1 of operation are the same in all scenarios, while CAGR for these inputs is also assumed at the same level across scenarios. PPA coverage, and by extension PPA price, varies. Carbon costs are not assumed in any of these scenarios.

Some general comments on the assumptions for these scenarios:

- For the sake of simplicity of comparison, all prices in assumptions are listed in Euro (€). Conversions have been made where necessary from the local currency at an average exchange rate against the Euro encapsulating at least 3 months of historical data (as of December 2020).
- The grid electricity price is based on reported final distributed electricity costs[24] for industrial customers in the UAE. The price listed is a reported final price, and does not include any assumed delivery factor as was the case for the US and Europe examples. Industrial electricity demand in the largest emirates (Abu Dhabi and Dubai) is met by only a small number of utilities, and the assumed price represents a weighted average of the utilities' prices based on population size.
- The natural gas price assumption for the UAE is slightly lower than that of the US. Over the past two years the reported price of natural gas in the country, according to various sources[25], has averaged below AED[26] 10 (per mmBtu). This has typically converted to less than €2.50. Converting this value to MWh, and assuming the same delivery/grid cost factor as in the Europe and US scenarios of 50%, yields a starting value just short of €17.50 per MWh.
- The PPA price assumption for the UAE is significantly lower than that in Europe. Based on the level of PPAs agreed recently in the country[27], the power-only price

24 Based on information from three distribution companies via globalpetrolprices.com (see 18)
25 Thomson Reuters Datastream; The Wall Street Journal; World Bank (via Index Mundi)
26 Abbreviation for the UAE Dirham
27 Recent PPAs agreed in the country have (substantially) undercut the level assumed in the analysis. The Al Shafra project, developed by the Abu Dhabi Power Corporation, announced a PPA price which at late-2020 conversion rates equates to €11 per MWh (company information)

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assumed available for the duration of the project is €13.50 per MWh. With an assumed grid cost factor of 70%[28], the assumed delivered PPA price comes in below €20 per MWh.

- As in the US scenarios, there is also an assumed value in the latter UAE scenarios for a higher PPA price which also includes the cost of storage and which allows for grid purchases of electricity to be avoided. The increase in cost (vs. PPA without storage) is assumed at the same level as in the US[29] as this is a technology cost, thereby bringing the delivered PPA + storage fixed price to just over €32 per MWh.
- No carbon or other operating subsidy is assumed in the UAE scenarios. The only subsidy provision foreseen here is an up-front subsidy on the cost of the initial investment in the final scenario.

There are a total of three scenarios in the UAE category. A summary of these can be seen in Table 10, with descriptions and economic metrics for each listed below. Additionally, a more comprehensive summary of all the inputs by scenario together with the assessed results can be found in 0 (see Figure 29).

Table 10 - Middle East environment scenarios summary; own parameters

	Default	Best available PPA	Best available PPA + subsidized capex
Grid start price	122.00	122.00	122.00
Gas start price	17.45	17.45	17.45
Investment/kWp	1200	1200	500
Gas CAGR	3%	3%	3%
Power CAGR	0%	0%	0%
PPA price*	19.29	32.14	32.14
PPA share	52%	100%	100%

**Higher price includes storage*

4.4.1 *Default*

The *default* scenario for the UAE assumes the starting values and CAGRs for the various inputs as described above. The electricity costs for the electrolyser unit are 48% exposed to the market price, which is assumed at the €122 per MWh for the duration of the project (CAGR 0%). The PPA power-only cost is lower, with coverage of 52% of electricity

28 This is assumed at the same level as that of Texas, and slightly cheaper than in Europe (65%)
29 This is a market-representative price increase of 67% from power-only to power-plus-storage

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demand corresponding to a capacity factor of just under 30%[30]. The investment in these market conditions does not make any savings on the carbon side as there is no assumption for a price to be attached to emissions at any point during the investment.

NPV	**-€ 24,555,553.52**
Annuity	**-€ 2,365,738.20**
LCOH	**€ 5.63 /kgH_2**

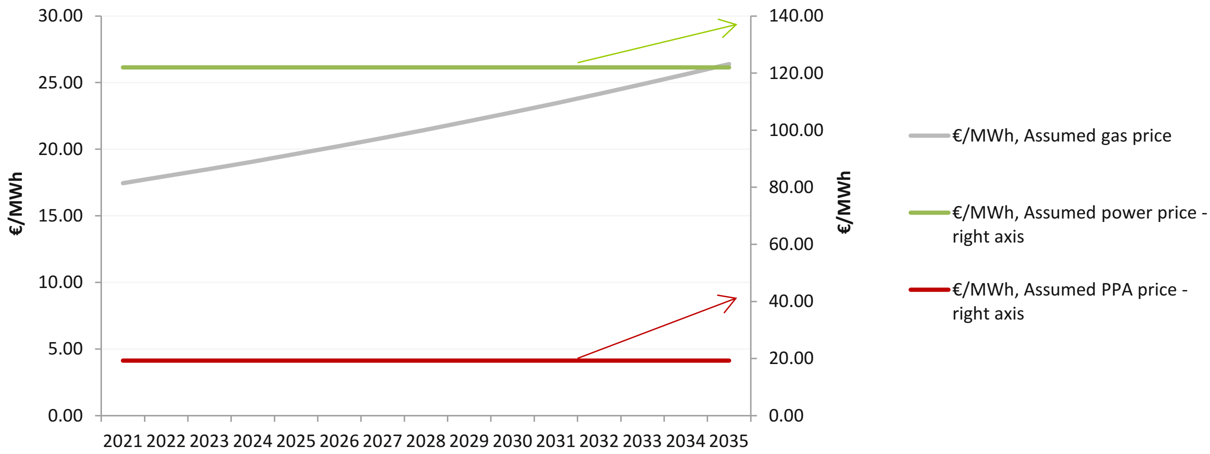

Figure 21 - Price development by variable (UAE, *default*); own calculations

4.4.2 *Best available PPA*

This scenario is exposed to the same market conditions as the *default*, but avoids exposure to the high grid electricity cost due to full coverage from the PPA. This is associated with the higher PPA price level, reflective of a representative assumption for an agreement of this type in the country. Carbon costs do not factor into the calculation as no price is attached to them, which means that natural gas prices are the only market variable relevant in this case (representing the savings potential for avoided natural gas feedstock purchases). An assumed CAGR of 3% means this revenue increases substantially over time, with a price of more than €26 per MWh reached by year 15.

NPV	**-€ 13,363,316.54**
Annuity	**-€ 1,287,452.49**
LCOH	**€ 3.00 /kgH_2**

30 This is in line with the best-performing PV installations globally (Peake 2018: 145)

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4.4.3 *Best available PPA + subsidized capex*

This final scenario retains the market and PPA conditions of the preceding scenarios, but includes a subsidy for initial construction and installation of the electrolyser unit. As noted in the summary seen in Table 10, the per-kW specific investment cost is reduced to €500 from the investor's perspective (an effective discount of almost 60% vs. the default), with the balance assumed to be covered by the government. The government may opt to provide specific support to the development of renewable hydrogen without introducing a broader, more all-encompassing scheme such as cap-and-trade on carbon which may be seen as an untenable burden on key parts of the national economy.

NPV	**-€ 7,545,157.61**	
Annuity	**-€ 726,917.74**	
LCOH	**€ 2.39**	**/kgH_2** [31]

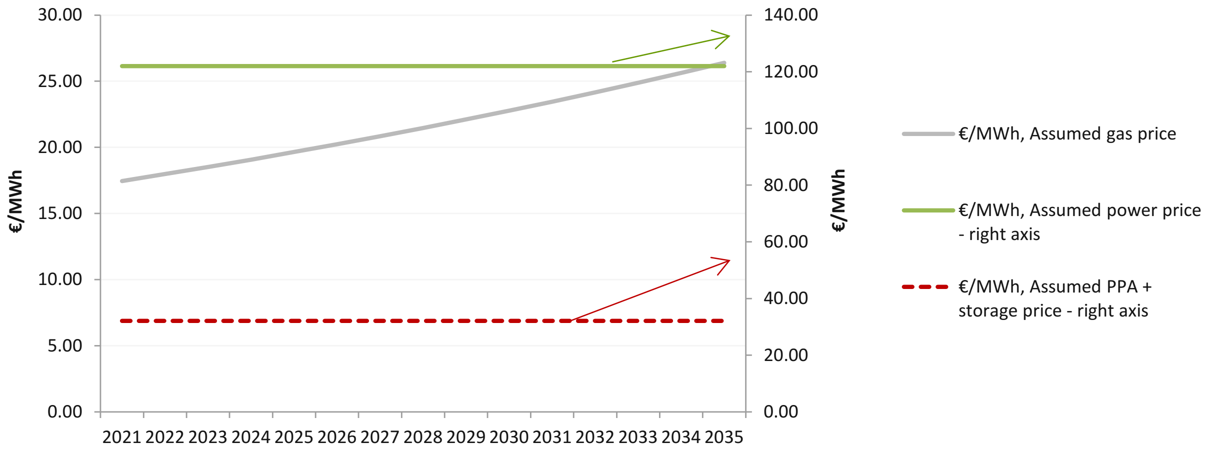

Figure 22 - Price development by variable (UAE, *best-available PPA + subsidized investment*); own calculations

31 Note that this €2.39 value is from the investor's perspective, but not the genuine cost of production as the capex cost is still paid for (see 6). In reality this scenario shares the best available LCOH in the Middle East group with the *Best available PPA* scenario, at an even €3 per kgH_2

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5 Summary of scenario outcomes

This section will summarise the results of the individual scenarios by the various markets that have been detailed in 4.1, 4.2, 4.3 and 4.4. A broader comment on the differences between regions as well as broader conclusions and takeaways from the exercise is to be found in 6.

5.1 Europe (scenarios 1-7, unsubsidized)

The first group of scenarios are all unsubsidized and returned a complete set of negative NPVs (note that the chart in Figure 23 is ordered by the calculated NPV level, from lowest to highest). The magnitude of these negative values is significant, indicating that, under the assumed conditions, renewable hydrogen remains some distance from representing a viable investment for this application.

There was a significant range exhibited between the weaker and stronger scenarios. Unsurprisingly the *high spark* scenario, with a combination of relatively higher electricity prices and low natural gas prices, provides the single most challenging environment. The calculated LCOH in this scenario, at just short of €5/kgH_2, is amongst the highest of any scenario assessed and looks unrealistically expensive compared to representative SMR-based LCOH levels as discussed in 3.1.

The *carbon rally* scenario, which assumed a price for emissions of more than €200 per tonne CO_2 by year 15, represents only a moderate improvement in NPV terms vs. the *default* (and even brings back a slightly higher LCOH)[32]. The *PPA boost* and *low spark* scenarios represent further minor improvements vs. the *default*, though both retain massive negative NPVs. Notably, the *low capex* scenario, which assumes a significant reduction in the specific investment cost of the electrolyser[33], also does not yield a meaningful improvement in NPV terms vs. the *default*, while the LCOH in this scenario is only 6% lower than in the *default* scenario at €4.16/kgH_2.

The most investment-conducive scenario in the assessment of the non-subsidized options is the *supportive market* + *PPA boost* scenario (relatively high natural gas costs, cheaper electricity, and more expensive carbon combined with an optimistic assumption for a lower PPA price with a higher share of demand covered). This scenario is the

32 This is due to lower natural gas prices and higher power prices associated with the carbon rally

33 As noted in section 5.1, this assumes a fall in prices vs. the default of 25% in the per-kW cost of the unit by the time of purchase

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strongest in the group in both NPV and LCOH terms, albeit far from anything even resembling a viable investment scenario.

Common to all of the scenarios in the European unsubsidized group is a negative cash flow profile during the operating years. All but one of the scenarios exhibit this trait throughout the course of the investment, with only the *supportive market + PPA boost* showing movement into positive operating cash flow by the end of the 15-year investment cycle. This indicates that the price constellation on average over the course of the investment would have to be close or superior to these end-cycle conditions from a much earlier point in order to present a viable investment case, potentially in combination with a more drastic decline in the specific investment cost.

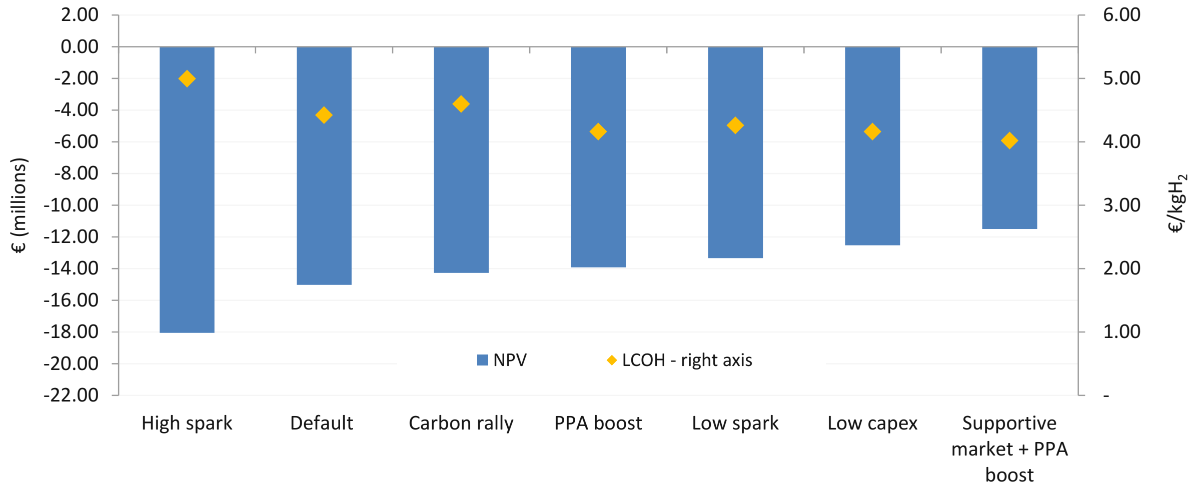

Figure 23 - Summary of results for Europe (1-7); own calculations

5.2 Europe (scenarios 8-14, subsidized)

The second group of scenarios present a much more conducive pricing constellation for the installation of a renewable hydrogen unit in a refinery as each of them includes financial support in one form or another. Compared to the first group, the range of NPVs on these subsidized scenarios is large and, though the group as a whole does average in positive NPV territory, three of the seven assessments come back negative. This is again a strong indication that the required conditions for this application to present a viable investment case are narrow and well-defined.

The essential obstacle to positive investment scenarios in Europe (i.e. the general lack of a positive operating cash flow profile over the course of the unit's lifetime) is well illustrated in the weakest case amongst the subsidized group, which is the *Initial investment subsidized* scenario. Here it was assumed that the upfront costs of installation

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were taken on by a subsidy provider, and yet the negative NPV returned in this assessment is substantial.

A group of investment scenarios, namely *market-based subsidy*, *market-based subsidy + GoO revenue*, and *market-based subsidy + supportive market*, all returned NPVs close to parity. This is not a huge surprise, given that the nature of the market-based subsidy (CCfD) is such that it makes up the difference between the prevailing carbon price and the actual cost of cutting emissions. As the market-based subsidy adjusts to the assumed conditions, differences between the NPVs of these scenarios is attributable to differences in market prices for electricity and gas, as well as the additional, unrelated revenue generated by the sale of GoOs.

While the *market-based subsidy, supportive market* scenario returned a small negative NPV, the remaining three scenarios – *market-based subsidy + higher GoO revenue*, *fixed subsidy*, and *fixed subsidy + supportive market* stood out as viable investments. The better performance of the scenarios in this analysis is of course tied to the level of the subsidy - an even €4/kgH_2 throughout - which represents a good share of the total baseline LCOH from electrolysis discussed earlier in this analysis in 3.2.2.1. Adjusting this figure lower in the model quickly brings the NPV back into negative territory.

Regarding LCOH values, it should be noted that the subsidized and unsubsidized groups averaged out at the same values as one another (€4.37/kgH_2). Furthermore, the subsidized group brought back only two discrete LCOH values. This illustrates an important distinction between the investment case and the actual cost of renewable hydrogen production, which will be addressed further in 6.

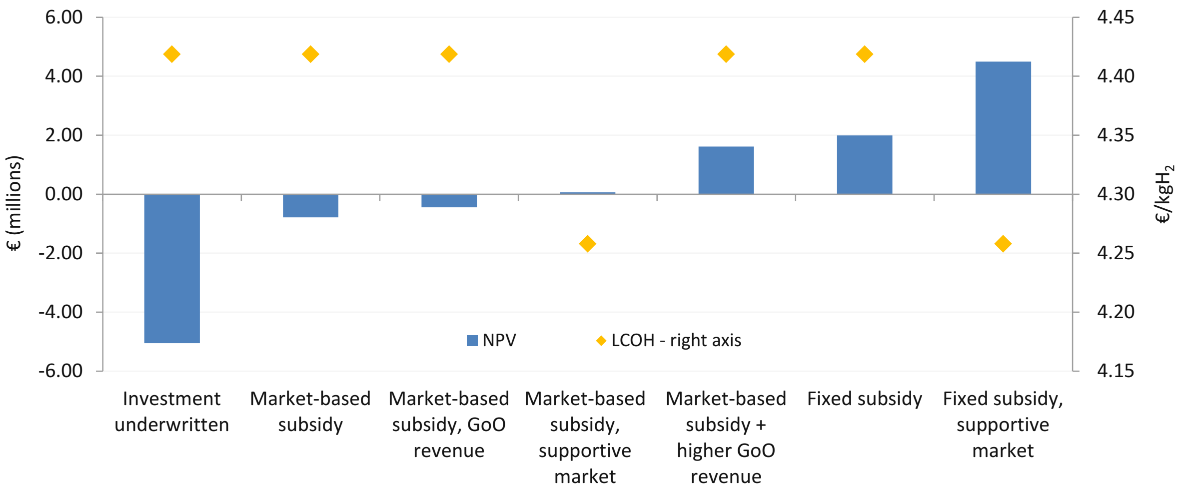

Figure 24 - Summary of results for Europe (8-14); own calculations

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5.3 United States

The analysis results for Texas, using a distinct set of assumptions for market and PPA prices, bore some strong resemblances to the Europe-based assessments. Of the five scenarios considered, a positive NPV was only returned in one case (the only one to include a subsidy). In this regard, the investment case looks to be non-viable without financial support, much as it appears to be Europe. However, the significantly lower LCOH values returned in the Texas vs. Europe does offer some strong indications for the potential for this application in the future, which will be discussed further in 6.

The *default* investment scenario in Texas is even weaker than the equivalent in the European example, as the superior PPA conditions were cancelled out by smaller savings on natural gas purchases, higher electricity prices from the grid, and a lack of pricing for carbon emissions. The integration of the best-available PPA options brought back a significant improvement in the NPV vs. the *default*. There was little difference in the NPV of the *best-available PPA* + *carbon rally* and *best-available PPA* + *supportive market*, both of which remained deeply in negative territory.

Much like the trend which was identified in the European scenarios, a majority of those assessments in Texas were simply unable to return a positive cash flow profile through the operation phase. There was a trend towards this as the market price constellation became more conducive towards the end of the investment cycle but, as in Europe, for unsubsidized assessments in Texas, this would have to be achieved much earlier to enable a positive investment scenario without support for this application.

The sole assessment to yield a positive NPV in Texas was the *best-available PPA* + *EU-level subsidy* + *carbon rally*. This scenario represents a convergence of conducive conditions which, at present, cannot be expected to materialise in the market – requiring both a direct and an indirect form of support. Nevertheless, the scenario does illustrate that the Texas market would likely prove even more conducive to the production of renewable hydrogen than the European market if the same subsidy support were available to both.

Further underlining this point are the LCOH values for Texas. While there were only two discrete values returned for five scenarios, a median value of €3.21/kgH_2 represents a significant reduction in cost (-20%) vs. the best-performing European scenario. From this perspective, Texas does represent a more competitive environment for the production of renewable hydrogen than central Europe/Austria – a point which would be of direct

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relevance if electrolytic hydrogen were to be encouraged by governments/regions by auction systems, as is the case today with a wide range of renewable electricity generation projects.

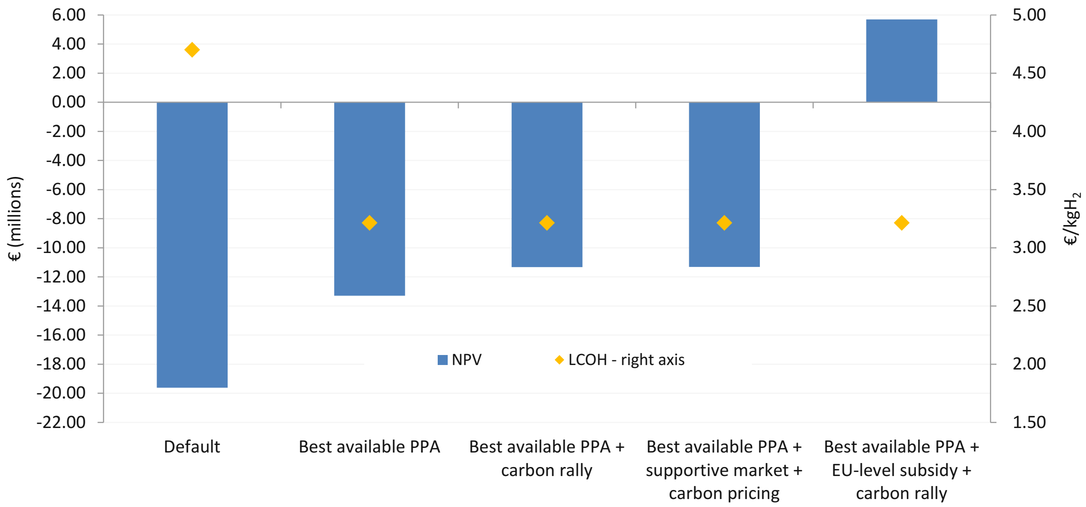

Figure 25 - Summary of results for the United States; own calculations

5.4 Middle East

The final assessed region in the analysis did not yield a single positive investment case (it should be noted that the UAE scenario group was the only one not to include a subsidy during the operation phase of the electrolyser). In general, poor investment cases - despite the extremely low PPA price assumptions thanks to exceptional regional PV potential - are attributable to both the relative lack of savings potential from very low natural gas costs, as well as the lack of a subsidy and/or carbon price.

This is exemplified most clearly in the *default* scenario for the UAE, which actually represented the lowest NPV of any scenario considered in the entire analysis. The *best available PPA,* which avoided grid electricity purchases completely, represents a significant improvement over the *default* result, but nevertheless brings back an NPV deep in negative territory. The superior conditions for PV-based electricity generation, while impressive, simply do not appear capable of displacing an incumbent technology economically in this application without additional incentives.

The investment case was further improved in the *best available PPA + subsidized capex* scenario, in which the initial investment was reduced by almost 60% vs. the *default*. While this represents a significant outlay on the part of the subsidy provider, it is also not sufficient to bring back a positive NPV.

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Despite this, the most competitive LCOH values of the entire analysis were to be found in the UAE scenarios. Given that there is no applicable carbon price for the region, this would bring the LCOH from electrolysis within €1/kgH_2[34] of an SMR-based production cost, based on the cost assumptions from 3.2.2.1. This would make the UAE highly competitive vs. other markets for developing renewable hydrogen capacity in a new, standalone investment.

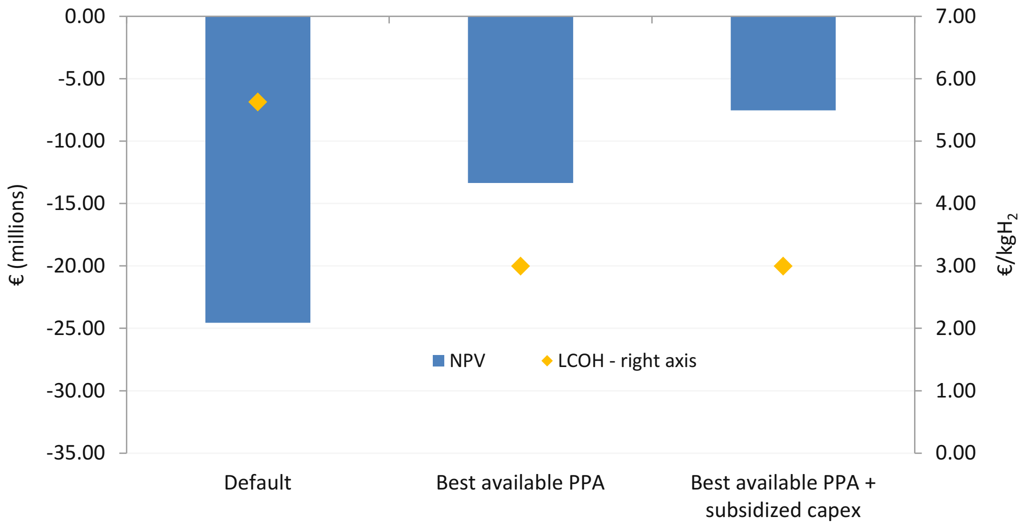

Figure 26 - Summary of results for the Middle East; own calculations

[34] The most competitive LCOH in the UAE of (€3/kgH_2) vs. baseline from 4.2.2.1 (€2/kgH_2, excluding the cost of carbon emissions but based on European commodity prices)

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6 Conclusions

This section will address the major observations and takeaways from the scenarios described in 4 and summarised in 5. Key observations regarding the variable inputs into the model, as well as regional differences and the role of the various financial support schemes, are discussed below. The section will then conclude with some thoughts for the future, as regards the development of this application for renewable hydrogen and suggestions for avenues of further research.

Key observations

On the whole, the integration of renewable hydrogen for this application is generally difficult to justify from a purely economic perspective. This is reflected in the fact that, of the 22 investment scenarios examined, only five of these returned a positive NPV and as such a viable proposition. The five scenarios which managed positive NPVs all had financial support attached, and none (out of a total of 13) of the non-subsidized scenarios returned a positive NPV.

As had been illustrated in Figure 10, the three regions examined each have their own strengths and weaknesses when it comes to their conduciveness to the economic installation of an electrolyser in an oil refinery. Despite this, there was a good distribution of the investment cases by region (see Figure 27 below). Of the three regions, the Middle East was the only one *not* to register a positive investment case. However, it is also the only region not to benefit from any kind of financial support in the operational phase.

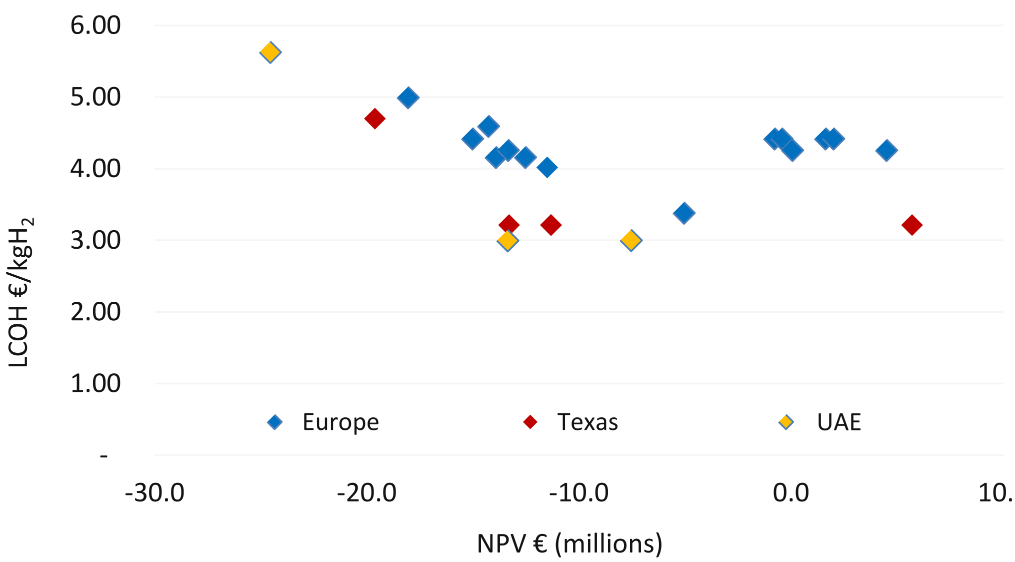

Figure 27 - Summary of investment scenarios; own calculations

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The primary focus as far as this exercise is concerned is the NPV of each scenario. After all, the core objective laid out at the outset was to evaluate the viability for RES to be integrated into the oil refining process in an economical way. With this in mind, the assessments made in this analysis demonstrate very clearly that, at this point in time, ongoing financial support of some kind is a necessity for a viable investment in this application.

It should be reiterated at this point that installing an electrolyser to partially replace *pre-existing* SMR units puts renewable hydrogen at an inherent disadvantage. In other words, SMR and electrolysis are not competing on a level playing field in this context as SMR is already installed. Investment costs for SMR do not play a role, and the installation of the electrolyser - with the associated capital costs - has to make its investment case purely on the basis of the “savings” that it can offer.

There is no non-subsidized, market-based price constellation envisioned that can allow such an investment case to form. Even those scenarios describing the most conducive pricing environments for the production of hydrogen from renewable electricity over natural gas fall short here[35]. On this point, it should also be noted that even a very aggressive increase in carbon pricing (CAGR of 15%) from the starting point of €30/mt over the investment lifetime (which takes the carbon price in year 15 to more than €200/mt) does not make any real dent in the inherently disadvantaged position of the venture.

Instead, a running financial support has to be included. Ongoing financial support needs to be specified here, as scenarios which included either reduced capital costs or a fully subsidized installation also failed to demonstrate viable investment cases[36]. As such, it is somewhat difficult to see how market prices alone can incentivize uptake in this application, given that even sizeable reductions in the cost of electrolysis technology would be unlikely to meaningfully change the investment cases for these scenarios.

More extreme pricing developments than those shown in the scenarios can of course be assumed, but there is no market consensus out there at present for more conducive conditions (for example, even more expensive natural gas and carbon). A combination of further reductions in specific investment costs for electrolysis technology *and* more conducive pricing conditions may merit a reassessment in the future, but again it is unlikely that this could be sufficient to deliver a viable investment case.

35 *Best available PPA* + *carbon rally* (US) and *Supportive market* + *PPA boost* (Europe) scenarios in particular include market price constellations which are especially conducive to the installation

36 The best example of this being the *Best available PPA* + *subsidized capex* scenario in the UAE

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For the five scenarios which generated positive NPVs, the following internal rates of return (IRR) were calculated (see Table 11). This was done using the formula below, where C_t represents net cash inflows during the period t, C_0 refers to the cost of the initial investment, and T is the total number of time periods:

$$0 = NPV = \sum_{t=1}^{T} \frac{C_t}{(1 + IRR)^t} - C_0 \tag{8}$$

Table 11 – IRR values for positive investment scenarios; Source: own calculations

	Europe				US
	Market-based subsidy, supportive market	Market-based subsidy + GoO higher revenue	Fixed subsidy	Fixed subsidy, supportive market	Best available PPA + EU-level subsidy + carbon rally
IRR	0.1%	2.9%	4.0%	7.5%	9.9%

From an investment perspective, it is likely that only the two strongest cases here, *Fixed subsidy, supportive market* (Europe) and *Best available PPA + EU-level subsidy + carbon rally* (US) would be considered for progression as their IRRs exceed the assumed cost of capital (5%).

While the selection of the market conditions for the scenarios here are to some extent arbitrary (albeit anchored to realistic, market-based starting points), the fact that the best IRR value is to be found in the US market does underline an important observation from the analysis - namely the important distinction between the NPVs of the scenarios and their LCOH values. The LCOH, unlike the NPV calculation, provides an indication only of the relative cost of producing hydrogen in a given environment. In this regard, both the US (average LCOH of €3.51/kgH_2) and the Middle East (average LCOH of €3.87/kgH_2) performed better than the European environment (which posted an average LCOH of €4.37/kgH_2). Though there was not a single registered positive NPV for the Middle East, the region did register the lowest individual LCOH value of all the scenarios considered (in 2 out of the region's 3 scenarios). While these values are not sufficiently low to make the investment case in this assessment, they should be a key consideration for the future and potential further research.

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The way forward & questions for further research

The ideal candidate for the integration of renewable hydrogen into the oil refining system would be an environment which combines a high-cost operation of the incumbent technology (i.e. high-cost natural gas) with cheap renewable electricity to run the electrolyser and, ideally, a high price on the carbon emissions generated by SMR. None of the environments assessed in this analysis are ideal matches for these criteria. Nevertheless, the best-performing scenarios in the assessment did begin to approach the SMR baseline on an LCOH basis, and these appear to provide the most promising routes for the economic production of renewable hydrogen.

For example, the *Best available PPA* and *Best available PPA + subsidized capex* in the Middle East returned LCOH values of €3.00/kgH_2. All of the Texas-based scenarios, save for the *default* scenario, were almost as competitive, each posting LCOH values of €3.21/kgH_2. The model indicates that significant further reductions to these numbers are possible with further declines in the specific cost of the electrolyser. The model indicates that, were the specific cost of the electrolyser to fall to same level as that of the SMR unit, the LCOH for the strongest Middle Eastern scenarios would fall to less than €2.50/kgH_2. This could easily undercut an SMR-based LCOH in Europe if the carbon price rises from the default €30/mt level to just €50/mt[37]. Further improvements to the efficiency shortfall in competitively-priced electrolysis technology vs. SMR would of course accelerate this process and, given the relative speed of development on this front, it is possible that an updated analysis would yield significantly improved results even within next 18-36 months.

What should also be noted is that the quantity of hydrogen production assumed in this analysis still only accounts for the minor share of the demand for a refinery of moderate size (just over 2% of demand for a 100,000 bpd-capacity facility, assuming 90% utilization). For a more sizeable installation with greater potential for GHG emissions abatement, there may be additional benefits from economy of scale which may present an improved investment case relative to those discussed in this analysis, but may also bring with it higher associated risk.

Whether or not electrolytic hydrogen is able to compete on an economic basis with all or a share of SMR-based hydrogen production in the broader system of a new-build refinery is also a question which would require further research. In this case, the question of which method is used to produce hydrogen would be one component of a much larger and more complex theoretical economic viability assessment which would depend on the ability of a

37 On average over the investment lifetime

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refinery as a whole to generate a viable investment case when accounting for all materials flows in and out of the refinery as well as between a large number of processing units.

Ultimately, a company's decision to adopt renewable hydrogen production into their refining process - as part of a wider goal to reach net-zero emissions - may depend on how the costs of doing so compare with other options for mitigating GHG emissions. There are many places along the oil supply chain where mitigation is possible, each with varying costs of avoiding emissions (i.e. on a €/mtCO_2-abated basis). It is possible that a large majority, or even all, of these options fail to represent viable investments on an individual, isolated basis. In such an environment and in the pursuit of emissions abatement, switching to renewable, emissions-free hydrogen may present a compelling case for oil companies with facilities in the most favourable locations.

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List of acronyms, units and abbreviations

API	American Petroleum Institute
bpd	Barrels per day
CAGR	Compound annual growth rate
CCfD	Carbon contract for difference
CCUS	Carbon capture, use and storage
CO_2eq.	Equivalent carbon dioxide
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
ESG	Environmental, social, and corporate governance
ETS	Emissions Trading Scheme
EUA	European Union Allowance
EXAA	Energy Exchange Austria
FLH	Full load hours
GHG	Greenhouse gas
GoO	Guarantee of Origin
IPIECA	(formerly) International Petroleum Industry Environmental Conservation Association
IRR	Internal rate of return
LCOH	Levelized cost of hydrogen
MMBtu	Million British thermal units
MSR	Market Stability Reserve
mt	Metric tonne
MWh	Megawatt-hour
NPV	Net present value
PEM	Proton exchange membrane
PPA	Power purchase agreement
RES	Renewable energy sources
SMR	Steam methane reforming
SOEC	Solid oxide electrolysis cell
WACC	Weighted average cost of capital

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List of equations

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Appendices

Scenario Summary	Default	Low capex	High spark	Low spark	PPA boost	Carbon rally	Supportive market + PPA boost
Changing Cells:							
Investment_cost	1200.00	900.00	1200.00	1200.00	1200.00	1200.00	1200.00
NatGas_CAGR	3%	3%	1%	5%	3%	2%	5%
Carbon_CAGR	4%	4%	4%	4%	4%	15%	10%
Power_price	0%	0%	3%	-1%	0%	1%	-1%
PPA_value	25	25	25	25	22	25	22
PPA_share_of_demand	42%	42%	42%	42%	50%	42%	50%
Subsidy	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CCfD	0	0	0	0	0	0	0
GoO_start_price	0	0	0	0	0	0	0
Traded_share	10%	10%	10%	10%	10%	10%	10%
Result Cells:							
NPV	-15,026,753	-12,533,257	-18,061,573	-13,343,365	-13,921,466	-14,272,879	-11,501,419
LCOH	4.42	4.16	4.99	4.26	4.16	4.59	4.02

Notes: Current Values column represents values of changing cells at time Scenario Summary Report was created. Changing cells for each scenario are highlighted in gray.

Figure 28 - Scenario summary (Europe 1-7, non-subsidized); own calculations

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Scenario Summary	Fixed subsidy	Fixed subsidy, supportive market	Market-based subsidy	Market-based subsidy, supportive market	Market-based subsidy, GoO revenue	Market-based subsidy + higher GoO revenue	Initial investment subsidized
Changing Cells:							
Investment_cost	1200.00	1200.00	1200.00	1200.00	1200.00	1200.00	0.00
NatGas_CAGR	3%	5%	3%	5%	3%	3%	3%
Carbon_CAGR	4%	10%	4%	10%	4%	4%	4%
Power_price	0%	-1%	0%	-1%	0%	0%	0%
PPA_value	25	25	25	25	25	25	25
PPA_share_of_demand	42%	42%	42%	42%	42%	42%	42%
Subsidy	4.00	4.00	0.00	0.00	0.00	0.00	0.00
CCfD	0	0	345	305	345	345	0
GoO_start_price	0	0	0	0	1	1.75	0
Traded_share	10%	10%	10%	10%	10%	40%	10%
Result Cells:							
NPV	1,995,886	4,492,374	- 785,188	60,104	- 442,387	1,614,417	- 5,052,766
LCOH	4.42	4.26	4.42	4.26	4.42	4.42	3.38

Notes: Current Values column represents values of changing cells at time Scenario Summary Report was created. Changing cells for each scenario are highlighted in gray.

Figure 29 - Scenario summary (Europe, 8-14, subsidized); own calculations

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Scenario Summary	Default	Best available PPA	Best available PPA + carbon rally	Best available PPA + EU-level subsidy + carbon rally	Best available PPA + supportive market + carbon pricing
Changing Cells:					
Investment_cost	1200.00	1200.00	1200.00	1200.00	1200.00
NatGas_CAGR	3%	3%	3%	3%	5%
Power_price	0%	0%	0%	0%	-1%
PPA_value	21.43	21.43	21.43	21.43	21.43
PPA_share_of_demand	50%	100%	100%	100%	100%
Carbon_CAGR	4%	4%	15%	15%	4%
Carbon_2025_price	0.00	0.00	35.10	35.10	35.10
Subsidy	0.00	0.00	0.00	4.00	0.00
PPA_storage_value	35.71	35.71	35.71	35.71	35.71
Result Cells:					
NPV	- 19,622,308	- 13,299,778	- 11,324,294	5,698,345	- 11,319,537
LCOH	4.70	3.21	3.21	3.21	3.21

Notes: Current Values column represents values of changing cells at time Scenario Summary Report was created. Changing cells for each scenario are highlighted in gray.

Figure 30 - Scenario summary (Texas); own calculations

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Scenario Summary	Default	Best available PPA	Best available PPA + subsidized capex
Changing Cells:			
Investment_cost	1200.00	1200.00	500.00
NatGas_CAGR	3%	3%	3%
Power_price	0%	0%	0%
PPA_value	19.29	32.14	32.14
PPA_share_of_demand	52%	100%	100%
Result Cells:			
NPV	- 24,555,554	- 13,363,317	- 7,545,158
LCOH	5.63	3.00	2.39

Notes: Current Values column represents values of changing cells at time Scenario Summary Report was created. Changing cells for each scenario are highlighted in gray.

Figure 31 - Scenario summary (UAE); own calculations

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