Support to REPowerEU Cyprus

Annex III of the Country Report: In-Depth support on priority areas

Accelerating the roll-out of renewable hydrogen

This project is funded by the EU via the Technical Support Instrument and implemented by Trinomics and its partner organisations, in collaboration with the European Commission. The views expressed herein can in no way be taken to reflect the official opinion of the European Union.

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Support to REPowerEU

Annex III to the Country Report

Cyprus

In association with:

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List of Acronyms / Abbreviations

AEL	Alkaline Electrolyser
AFID	Alternative Fuels Infrastructure
BAU	Business As Usual
BE	Battery Electric
BEV	Battery Electric Vehicle
BNEF	Bloomberg New Energy Finance
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilisation and Storage
CHP	Combined Heat and Power
CO	Carbon Monoxide
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CYSTAT	Cyprus Statistical Authority
DAC	Direct Air Capture
DOE	Department of Energy
DRI	Direct Reduced Iron
EAC	Electricity Authority of Cyprus
EC	European Commission
EEZ	Exclusive Economic Zone
ESC	Energy Systems Catapult
ETS	Emissions Trading System
EU	European Union
FC	Fuel Cell
FCEV	Fuel Cell Electric Vehicle
FOM	Fixed Operations and Maintenance
FSRU	Floating Storage & Regasification Unit
GHG	Greenhouse Gas
H2	Hydrogen
HFC	Hydrogen Fuel Cell
ICCT	International Council on Clean Transportation
IEA	International Energy Agency
JIVE	Joint Initiative for Hydrogen Vehicles
LCOH	Levelized Cost of Hydrogen
LNG	Liquified Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LPG	Liquified Petroleum Gas
MECI	Ministry of Energy, Commerce, and Industry
MIT	Massachusetts Institute of Technology
MTPA	Million Tonnes Per Annum
NACE	Statistical Classification of Economic Activities in the European Community

NECP	National Energy and Climate Plan
NG	Natural Gas
OPEX	Operating Expenditure
PEM	Proton Exchange Membrane
PLC	Public Limited Company
PV	Photovoltaic
REACH	Registration, Evaluation, Authorisation and Restriction of Chemicals
RED	Renewable Energy Directive
RO	Reverse Osmosis
SMR	Steam Methane Reform
SOEC	Solid Oxide Electrolyser
SPE	Solid Polymer Electrolyte
TCO	Total Cost of Ownership
TRL	Technology Readiness Level
TSO	Transmission System Operator
UK	United Kingdom
US	United States
USD	United States Dollars
WACC	Weighted Average Cost of Capital

Executive Summary

This report provides an analysis of the prospects for deployment of hydrogen in the Cypriot economy, reflecting the strong support envisioned in the EU Hydrogen Strategy and the REPowerEU initiative, and in light of the large uncertainties surrounding the technological and infrastructural development of this energy carrier.

We conducted an extensive review of techno-economic data, those provided by E3Modelling in the frame of this project as well as those more broadly available in the international literature. We took advantage of input from experts in the field and professionals with knowledge of actual costs in the market of Cyprus. We also benefited from very extensive interactions with national stakeholders through questionnaires and interviews described in Annexes I and II of the Country Report, respectively.

Our main finding is that although the Cypriot economy (with its small, isolated energy system without a robust industrial base) is less favourable for rapid and deep hydrogen deployment than other countries, and direct electrification is preferable in many cases, hydrogen may be appropriate for specific uses such as:

- In a small number of high-temperature industrial applications
- For heavy vehicles (trucks and buses)
- In industrial clusters utilizing hydrogen both in high-temperature industry and for heavy vehicles
- In the maritime and aviation sectors.

These findings have led to the definition of two scenarios – a ‘cautious’ and an ‘aggressive’ one – on the deployment of hydrogen by 2030 and 2050. The cautious scenario foresees almost no penetration of hydrogen in 2030. In the ‘aggressive’ scenario, which requires strong infrastructure investments and fast technological progress, hydrogen use is foreseen:

- In the cement industry, covering up to 10% of its energy needs if the infrastructure is available by 2030, and up to half of its energy needs by 2050;
- In the bricks and tiles (ceramics) industry after 2030;
- In trucks and buses, accounting for about 4% of total energy consumption in road transport and up to over 15% in 2050;
- In shipping and aviation, covering a very small fraction of fuel demand by 2030 and most of the fuel demand by 2050, in the form of hydrogen derivatives (ammonia for shipping and e-kerosene for aviation). These two sectors are projected to be the largest users of hydrogen in all scenarios for 2050, reflecting the role these industries play for Cyprus.

The above will require active policy interventions and substantial investments in a) renewable energy capacity, b) electrolysers for hydrogen production, c) balance-of-plant projects that can be substantial in the cases of hydrogen derivatives, and d) equipment and vehicles for the use of hydrogen in different sectors. The report has provided an estimate of the different costs associated with the two scenarios mentioned above; these costs, especially the long-term ones for 2050, have to be treated with caution as many of the technologies are at a low level of development and there is large uncertainty about the rate of technical progress (and the associated future cost reductions) as well as the actual costs of building all the infrastructure needed for the entire supply chain of hydrogen. The outcome of this report and the data that have been collected and used for the technoeconomic calculations shown here will provide input for the revision of the country’s National Energy and Climate Plan, which is due in a draft form in summer 2023, and the Long-Term Low-Emission Development strategy up to 2050.

1 Introduction

As mentioned in the main body of the report, Cyprus has requested for support in the following topics:

- Accelerating the roll-out of renewable hydrogen and other suitable forms of fossil-free hydrogen (Priority area nr 3), and
- Hydrogen solutions for the industrial sector and measures to enable the roll-out of these solutions in a socially fair manner (Priority area nr 7).

Due to the close topical proximity between the two priorities, the analysis on the industrial sector is embedded in this Annex as Chapter 3. Overall, this annex analyses the areas of in-depth support identified by Cyprus (points above) as confirmed in the inception phase, to the extent they are considered as realisable, realistic, and cost-effective options.

This report has benefited from input provided by Trinomics experts Luc Van Nuffel and João Gorenstein Dedecca.

2 Accelerating the roll-out of renewable hydrogen and other suitable forms of fossil-free hydrogen

2.1 The case for hydrogen deployment in Cyprus

2.1.1 Strategic priorities framework

The development of a roadmap for the introduction of renewable and low-carbon hydrogen (H_2) as an energy vector in the energy system of Cyprus is considered now a priority by the relevant governmental authorities, and for good reason: hydrogen has the capability to replace a lot of energy in processes that now rely on fossil fuels and their derivatives, if it is produced in a clean way that minimises (or eliminates) GHG emissions.

Hydrogen development in Cyprus can substantially contribute to the following areas:

- Gradual, but potentially deep reduction of reliance on imported fossil fuels, including those indirectly imported from Russia. This is tightly related to a more general increase in energy supply security.
- Decarbonisation of hard-to-abate energy end-use sectors, principally high-temperature (high-T) heat in industry and transportation applications that include heavy freight road transport, shipping, and aviation.
- Increased local employment opportunities in the production, storage, transportation, and end use hydrogen sectors, projected to be concentrated within Cyprus.
- Opportunity for Cyprus to position itself as a future hub of production and distribution of hydrogen, or hydrogen-based derivatives that might emerge as trade commodities.

There are several hurdles to overcome until this vision becomes reality however, some of which are quite tall and need to be identified as early as possible. The long list of challenges includes the following:

- High costs of production, especially for the clean varieties. These are coming down, but they remain high, sometimes several times higher than equivalent options via traditional fossil fuel routes based on historic fossil fuel prices. The effects of the pandemic supply chain issues and the global disruption in energy markets caused by the invasion of Ukraine by Russia have narrowed that gap.
- Several sub-systems and sub-components of the 'hydrogen economy' are still at lower stages of maturity. Some of them (e.g., ammonia combustion engines for ships) are essential for the quick transition to this model.
- The necessary financing, or co-financing, from private company balance sheets, project finance or special purpose vehicles cannot be easily accessed yet.
- The required engineering work and all the necessary permits should be able to be obtained within 3-4 years for a meaningful ramp up until 2030. This will be a challenge for Cyprus.
- Focus on investments should be weighing the probability of a swift hydrogen adoption in certain sectors that would require a degree of foresight and act decisively. For example, any Natural Gas pipelines laid in the next few years should be suitable for blending and future repurposing for dedicated hydrogen use.
- The regulatory framework for hydrogen must be drafted and put in place in time, otherwise any development will be hampered or even stalled.

For the uses of **H_2 in industry** in particular, the following should be considered:

- Even with production technologies in place and competitive costs, end uses (and users) of hydrogen should not be taken for granted. Cyprus is currently a country with a low industrial base, a mismatch between hydrogen's strongest merits and the country's reality. Any future opportunities need to be identified and cultivated at an early stage. Hydrogen should be delivered to an end-use that can absorb large quantities of the fuel (or a derivative) from a new source without major industrial dislocations and with guarantees of multi-year offtake. This can be a challenge for the local industry.
- There are no refineries in Cyprus, which currently constitutes a significant user base of hydrogen in other countries. A refinery was operating on the island between 1972 and 2004, when it ceased its operations. As Cyprus gradually decarbonises, local refining of petroleum products is not foreseen.
- Fertiliser plants represent another potentially large end use. Currently the needs in Cyprus are small, and the absence of fertiliser plants means that even if green ammonia was introduced, it would not displace any existing use of fossil fuels.
- Local users of steel as a raw resource are very limited in Cyprus. Considering building a steel mill and necessary infrastructure on the island, the export market should be carefully studied but there is no indication that this would succeed; steel plants are usually located close to their end use base.
- The chemicals sector – another potential user of hydrogen – is also absent with very low demand currently, except for pharmaceuticals where the processes are not compatible with the headlining advantages of hydrogen.

These topics are explored in more detail and are the subject of the next sections of this chapter.

2.1.2 Hydrogen opportunity for Cyprus

Cyprus' case as a destination for use and production of hydrogen is a particular one. On the one hand its geographical location and abundance of solar radiation make it a partially attractive option for renewable hydrogen production, where costs can be lower than in continental central and northern Europe. It is also a small country, which would benefit hydrogen use in the transport sector needing a less dense refuelling station network, and a country with busy port and airport facilities.

On the other hand, the industrial base of Cyprus – where most of the end users are forecasted to be concentrated – is very small, there are no natural gas pipelines to take advantage of and introducing hydrogen to the road transport sector eventually faces up against the more favourable case of direct electrification through Battery Electric Vehicles. Similarly, the buildings sector sees its highest energy demand in the summer due to cooling needs, which is not conducive to the deployment of hydrogen due to the complexity and efficiency penalties in its various stages of production, transportation, storage, and final use, and the fact that direct use of electricity (via heat pumps) is much more energy efficient than converting it to hydrogen for cooling purposes.

The concept of hydrogen valleys (i.e., the cross-sectoral integration of production and end uses of hydrogen in one physical location) and hydrogen use for islands is an attractive one for Cyprus. A notion that emerges in the rest of this report is that hydrogen is suitable for applications that are connected to industrial end uses (e.g., cement), the heavy vehicle transportation sector (freight and public transport) and perhaps some use in electricity generation and/or derivatives, all of which require large amounts of renewable electricity. Hydrogen valleys can be therefore conductive to this in areas where there is concentration of these production means and potential final uses, as is e.g., the area around the Vassiliko cement plant and power station.

2.2 Production overview

2.2.1 *Methods of production, costs, emissions, roles*

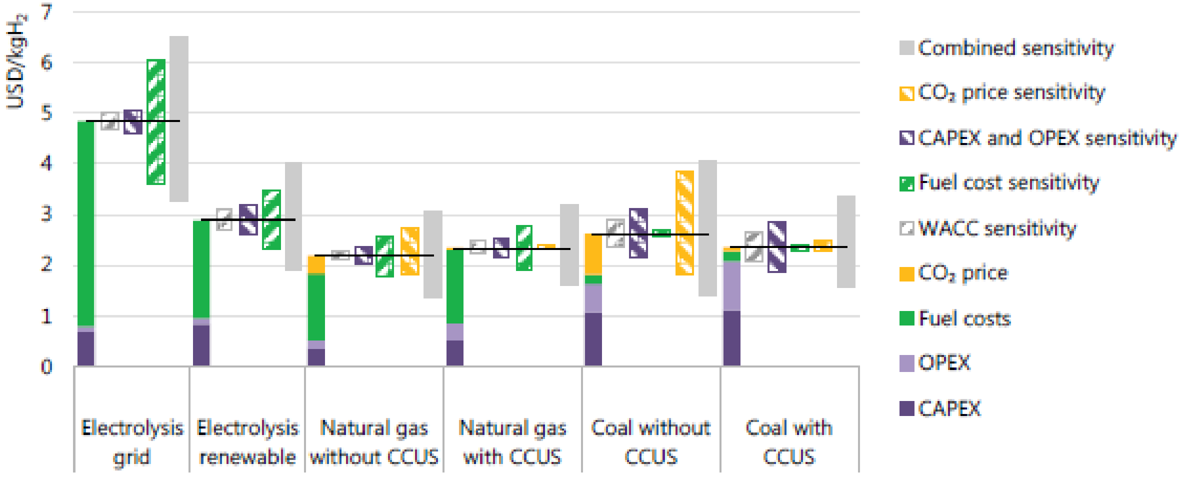
Hydrogen can be produced using several different methods with varying efficiencies and environmental impacts, typically classified into colours depending on the method and feedstock used. A summary of the different methods of producing hydrogen and emission levels, is given in Table 1. The EC accepts the term ‘renewable hydrogen’ to include electricity from renewables (such as PV and wind energy), as well as through the reforming of biogas (instead of natural gas) or biochemical conversion of biomass, if in compliance with sustainability requirements. Also, the term ‘clean hydrogen’ is used interchangeably.

Table 1: Hydrogen production methods and GHG emissions [1]

	Feedstock	Production via	Direct GHG emissions ($kgCO_2/kgH_2$)	Indirect GHG emissions ($kgCO_2/kgH_2$)
Using electricity	Renewable electricity	Electrolysis	-	*negligible*
	Grid electricity		-	<1-30 (depends on grid mix)
	Nuclear electricity		-	*negligible*
Using Fossil Fuels	Natural Gas	SMR	9-11	0.5-4
	NG or coal	SMR or coal gasification with CCS *often called blue H_2)	0.5-4	0.5-7
	NG	Pyrolysis	Solid carbon	0.5-5
	Biomass or biogas	Gasification or reforming with or without CCS	Possibility of <0 with CCS	1-3

An overall comparison of hydrogen production cost from each technology is presented in Figure 1 showing the average and best-case supply costs of hydrogen from renewables and fossil fuels according to [2]. Producing hydrogen from renewable electricity could potentially be a low-cost option, however this only applies in specific situations. While the overall cheapest option has traditionally been the production via natural gas in steam methane reformers (SMR), costs using fossil fuels as feedstock have been creeping upwards under supply chain constraints in the aftermath of the pandemic and – especially – after the invasion of Ukraine by Russia.

Figure 1: Hydrogen production cost from different technologies 2030 [4]



Notes: WACC = weighted average cost of capital. Assumptions refer to Europe in 2030. Renewable electricity price = USD 40/MWh at 4 000 full load hours at best locations; sensitivity analysis based on +/-30% variation in CAPEX, OPEX and fuel costs; +/-3% change in default WACC of 8% and a variation in default CO_2 price of USD 40/tCO_2 to USD 0/tCO_2 and USD 100/tCO_2. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

The most established - but not yet at large scale - technology used for producing **renewable** hydrogen is water electrolysis via renewable electricity. Using renewable electricity in electrolysers however is tied to significant efficiency penalties: a considerable portion of the energy is lost in the various stages of production even for the most efficient electrolysers, and a strong case can be made that electricity would be better used directly in several applications (e.g., in heat pumps for space heating and cooling, in Battery Electric Vehicles etc.). This is especially true in Cyprus where most electricity is still generated by fossil fuels: oil derivatives currently, natural gas when it becomes available. Yet, from a cost point of view, price parity for renewable hydrogen was expected by the end of the decade in renewable energy-rich areas of the world [3], but current fossil fuel prices have reduced the time until cost parity is reached even further. Cyprus is endowed with ample solar potential, but modest wind potential.

2.2.2 *Renewable Hydrogen*

While hydrogen can be produced with very low GHG emissions via either the biogas – reforming, biomass – gasification route or via nuclear electricity, renewable hydrogen usually refers to water electrolysers connected to renewable electricity generation units. Electrolysis requires an electricity source, electrodes, and a conductive electrolyte. There are three mature types of electrolysers in use today:

1. Alkaline Electrolysers (AEL)
2. Polymer electrolyte membrane (PEM) and
3. Solid oxide electrolysers (SOEC)

Alkaline electrolysers (AEL) are considered well advanced and can generate renewable hydrogen at substantial rates, with an operation energy efficiency ranging between 62% and 82%, and production capacity from 1 to 760 Nm^3/h. Approximately 9 litres of water are required to produce 1kg H_2. Oxygen is also produced as a by-product (8 kg) which could be used in other sectors, such as for medical uses [4]. Manufacturers now are focused on performance improvement, cost reduction and upscaling, and further developing pressurised system to better couple AEL with variable renewables and quick changes in input levels.

Electrolysis can take also place in an acid medium, a process known as **Proton Exchange Membrane (PEM)** or Solid Polymer Electrolyte (SPE) which does not require any electrolytic liquid. PEMs operate at a temperature of 80 ºC and 15 bar pressure, with a specific energy demand between 4.5 and 7 kWh/Nm^3H_2. The production capacity ranges between 0.06 and 30 Nm^3/h, and their efficiency between 67 and 82%. It is a mature technology, with the focus now being on cost reduction and restriction in the use of rare and expensive materials (like iridium and platinum) that could limit the large-scale expansion of PEM. The main advantage is the ability to ramp up and down very quickly, ably following the generation curves of renewables closely. A version of PEM using fewer exotic materials is **Anion Exchange Membrane (AEM) electrolysis**, still at earlier stages of development.

Solid oxide electrolysers (SOEC) operate at higher temperatures (600 – 1000 ºC) which allows for higher efficiencies compared to AEL and PEM methods by using part of the input heat to lower the energy demands for electrolysis. SOEs require a heat source for high temperature electrolysis, such as nuclear heat, solar thermal or geothermal systems. However, finding thermally stable and waterproof materials is a barrier. Currently SOEs are considered the least advanced electrolysis method, and while have reached commercialisation, their deployment at scale is still some distance away [5], [6].

2.2.3 *Electrolysis costs*

Several technical and economic factors affect the production costs from water electrolysis. Today, capital cost (CAPEX) is between 500 and 1,400 $\$/kW_e$ for AELs, between 1,000 and 1,800 $\$/ kW_e$ for PEMs, and estimated between 2,800 and 5,600 $\$/ kW_e$ for SOEs. Electrolyser stack has the largest share of CAPEX, 50% for AELs and 60% for PEMs and SOEC.

In the case of increased share of renewables in the electricity mix, surplus electricity may be available at a low cost, which could allow for producing hydrogen for direct use or for storing it for later use. However, in the case of low availability of surplus electricity (i.e., a low-capacity factor), the electrolyser economics look less favourable.

Christensen [7] has recently assessed the costs of electrolysers in the US and Europe under various scenarios of deployment (grid connection, dedicated renewable electricity based production and grid connection but using only renewable curtailed generation) and found that generation costs are generally higher than usually quoted in the literature due to the balancing costs that are usually omitted (e.g. compressors, localised storage etc.), and that they range from around $13/kg (median cost) in Europe today down to $7.7 in 2050 for grid connected H_2, and $19 today to about $10/kg in 2050 for dedicated production. These numbers were substantially higher than the production costs of SMR using natural gas, even if using CCS before the price hikes of 2022, they remain higher but the gap between them has narrowed.

Table 2: Techno-economic characteristics of electrolysers, adapted from [2] and [8]

	Alkaline			PEM			SOEC		
	Today	2030	Long-term	Today	2030	Long-term	Today	2030	Long-term

Electrical efficiency (%)	63-70	65-71	70-80	56-60	63-68	67-74	74-81	77-84	77-90
Operating T (ºC)	60-80			50-80			650-1000		
Load range (% of nominal load)	10-110			0-160			20-100		
CAPEX ($/kWe)	500 - 1400	400 - 850	200 - 700	1100 - 1800	650 - 1500	200 - 900	2800 - 5600	800 - 2800	500 - 1000

2.2.4 *Grey and blue hydrogen*

Grey hydrogen refers to the production from natural gas (see Table 1) and entails substantial CO_2 emissions [9]. Currently, the primary source of hydrogen is natural gas in the diesel purification, ammonia, and methanol industries utilising steam methane reformers (SMR). SMR happens in two steps, one taking place at high temperatures (steam reforming) in which the fuel is converted into a gaseous mixture after reacting with steam, and the second step occurring in lower temperatures in a shift reactor, in which the CO which is part of the synthesis gas reacts with H_2O to produce CO_2 and H_2 [5]. Some 75% of the annual global hydrogen production (70 Mt H_2) are attributed to natural gas production, 23% is attributed to coal, and the remaining 2% accounts to oil and non-renewable electricity. Currently the e=RES based hydrogen accounts for less than 1% of global production but it is projected to increase substantially. It is expected that SMR will retain its dominant status as the main technology for hydrogen production in the short and medium term due to its advantageous economics and the large number of units that are currently in operation [6], but this assumption is challenged by the extremely high fossil fuel prices experienced globally following the invasion of Ukraine by Russia.

The FSRU unit through which LNG will be imported into Cyprus is running into delays, projected to be operational be end of 2023 / beginning of 2024. The opportunity to have Natural Gas in Cyprus at that time presents a rather tempting proposition of using it to produce grey hydrogen, but this would i) generate a lot of emissions; ii) divert gas away from power generation and iii) potentially hinder electrification. In fact, relying on SMR for large scale H_2 production without CCS, will result in more emissions compared to the direct use of fossil fuels due to conversion efficiency losses. Also, SMR deployment with CCS is fraught with uncertainty around the availability of suitable geological formations in Cyprus and the low maturity of the tech.

Low-carbon hydrogen is technically grey hydrogen coupled with CCS. It is expected to play a role in the early stages of energy transition and could help hydrogen market grow. CCS offers potentially a lower-emission pathway for using hydrogen and can alleviate the pressure on the capacity of renewable electricity required to generate renewable hydrogen [10], but it must be seen with scepticism: its deployment is contingent to fluctuations of fossil fuel prices, its reliance on the continuation of the economic model based on fossil fuel extraction and exploitation, the potential lack of social acceptance, the relatively low capturing efficiency (right now in the mid-50%, expected to rise and reach 85-95%) and the elevated costs. Overall, carbon emissions from blue hydrogen production can be driven down substantially, but not eliminated, and there are questions on the true magnitude, management, and containment of upstream emissions (especially methane). Cyprus' potential to store CO_2 in geological formations is still unknown.

2.2.5 Other production methods

Other production methods, such as "turquoise" hydrogen, referring to the process of producing hydrogen from natural gas via pyrolysis, are in various stages of development. In this process the carbon content of methane is transformed into carbon black, a solid that's far easier to store than CO_2. This also provides an additional potential revenue stream due to an already existing – but presently rather small - market. Nevertheless, turquoise hydrogen is still at a pilot stage [9][1].

Other low emission methods for hydrogen production that use biomass or biogas as feedstock can still be considered green, especially if combined with CCS (in which case they can even produce negative emissions). This report does not focus on these methods, and they will not be discussed in detail.

2.2.6 Water feedstock needs, desalination, and water purification

The issue of water availability should not be seen as a triviality. In island locations with restricted access to freshwater, and no guaranteed supply during periods of low rainfall, emissions-free desalination should be the preferred route. Xevgenos et al. [12] reported that in 2017 Cyprus produced 68.7 million m^3 of desalinated water, all from Reverse Osmosis (RO) plants connected to the main electricity grid. For every kg of green H_2 the demand for water would be around 15kg [13], [14], (around 9 kgH_2O/kgH_2 for the alkaline electrolyser, plus losses, treatment, and cleaning of equipment), which would mean an additional load on the electricity grid for desalination [15].

2.3 Costing methodology

2.3.1 Water electrolysis

This study is tailored to the local conditions in Cyprus but takes cues from international literature as guidance. What is presented below is not meant as a guide to investors; any individual project will have its own costing profile and specific requirements.

It is generally accepted that the levelized cost of renewable hydrogen production (LCOH) currently falls broadly within the range of €5-15 /kgH2, depending on location (see sec. 2.2.1). In this exercise we look at production costs based on a LCOH calculation for 2030 and 2050. Table 3 presents a comprehensive list of assumptions for estimating the LCOH for Cyprus, under three different production models:

a. In a dedicated, off-grid production facility
b. Using curtailed electricity only, and
c. Using renewable hydrogen produced by utilising guarantees of origin regarding the green credentials of the electricity used for the electrolysis.

The dedicated production model a. assumes a renewable electricity installation that is dedicated to the electrolyser and is optimised for delivering as many full load hours as possible based on data in [2] assuming a locale for the Middle East. It is the simplest method of production, and the one assumed to

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[1] It is however quickly gaining attention e.g., see [11].

be the default option in the rest of this report. Land costs are based on real project data from existing PV systems in Cyprus, and the full load hour estimation takes into account the ratio of PC/electrolyser size to minimise the LCOE based on analysis found in [16]. The CAPEX for a PV system in Cyprus is estimated at 0.60 €/Wp in 2030 and 0.40 €/Wp in 2050 based on estimations in [17].

Option b. (from curtailed generation) proves to be much more costly that the rest since the reduced load hours of operation use are not generating enough hydrogen to pay for the CAPEX of the electrolyser. Economics improve as curtailment increases however, the LCOH becomes equal to the dedicated production when curtailment rates reach around 30% for 2030 and around 19% for 2050. We should add here that this option is in principle more energy and cost-efficient than alternative measures to avoid/reduce curtailment such as demand response, storage of electricity etc., so it should not be dismissed outright.

The model using dedicated grid supply c. assumes that renewable electricity (properly certified, when this will be allowed) is provided to the electrolyser at a specific, predefined rate per kWh (in this case it is assumed to be €0.10/kWh, but this is subject to volatility given the fluctuation of electricity generation costs in Cyprus because of the global rise in costs). Doubling of this rate results in roughly doubling of the LCOH.

In the numerical assumptions presented in Table 3 below, the Weighted Average Cost of Capital (WACC) for Cyprus is set at 7.5%, a number that reflects project risk. The generally accepted WACC for renewable electricity projects is around 6% [1], while green hydrogen projects are usually placed a little higher due to the increased complexity and relative immaturity of the technology e.g., see [18], and [19].

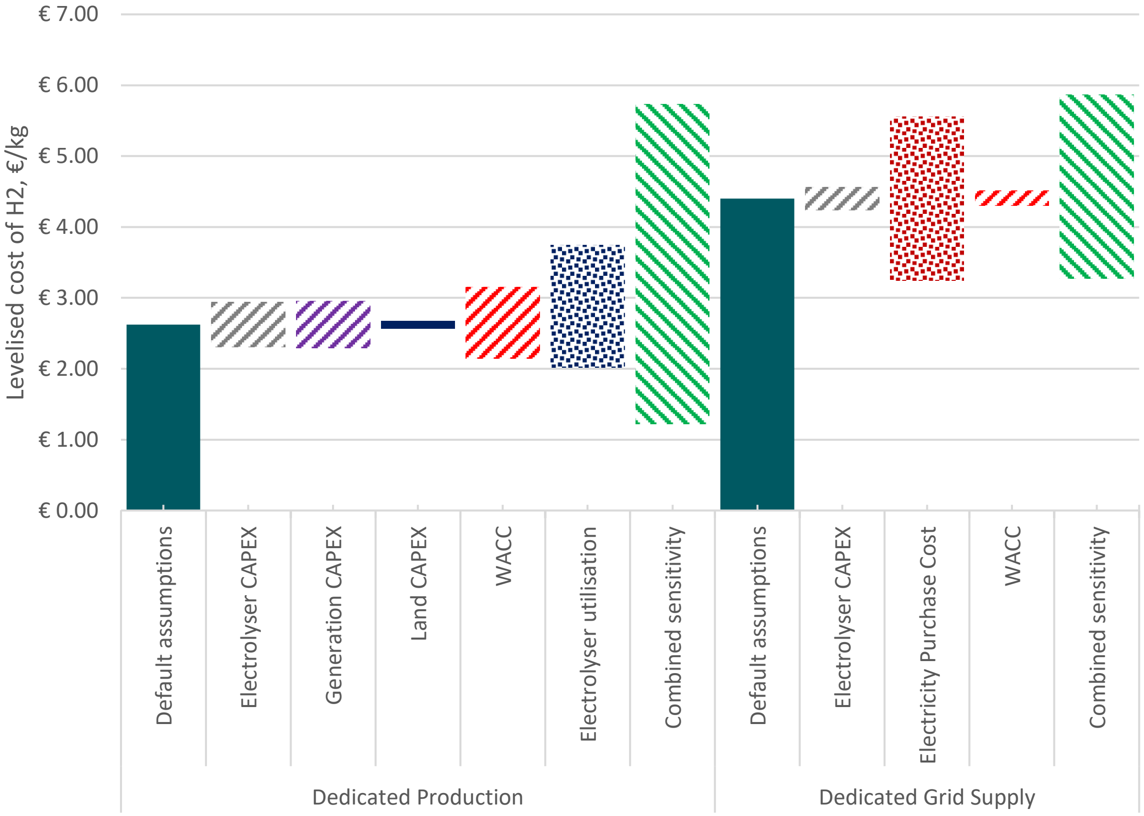
Table 3: Technoeconomic assumptions for renewable hydrogen production using PV

Input	2030	2050	2030	2050	2030	2050
	Dedicated Production		From Curtailed Generation		Dedicated Grid Supply	
Analysis assumptions						
WACC	7.50%					
Analysis period	20					
Land cost (€/m^2)	5	6	0			
Electrolyser						
Efficiency	48.25	45	48.25	45	48.25	45
Sizing Ratio (PV/electrolysis)	0.7					
CAPEX (€/kWe)	600	230	600	230	600	230
Annual OPEX (% of CAPEX)	1.5%					
Other BoP costs (% of electrol.CAPEX)	20%					
Water demand (kg/H_2kg)	15					
Water treatment costs (€/m^3)	0.17	0.15	0.17	0.15	0.17	0.15
Electrolyser annual full load hours	2,560	2,700	128	216	5,000	
Electrolyser Capacity Factor	29.2%	30.8%	1.5%	2.5%	57.1%	
Electricity Generation						
Curtailment Rate	N/A		5%	8%	N/A	
CAPEX (€/Wp)	0.60	0.40	0		N/A	

OPEX (€/kW-yr)	15	14	0		N/A	
Electricity tariff (€/kWh)	N/A		N/A		€0.08	€0.06
Output						
Calculated Discount Factor	9.81%					
Calculated LCOH (€/kgH2)	**€ 2.62**	**€ 1.42**	**€ 21.01**	**€ 4.45**	**€ 4.40**	**€ 2.90**

Figure 2 shows a sensitivity analysis of the dedicated production and grid supply cases using the default assumptions seen in Table 3. The dedicated production can be influence by a multitude of factors and the final combined variation is quite wide, be the largest uncertainty is with the electrolyser utilisation that has the capacity to significantly influence the final cost. Raising this number for a given location usually involves opting for a different electrolyser tech (PEM and SOEC tend to tolerate swings in input power better than alkaline) or combining the supply with storage to stabilise its output. The dedicated grid supply final levelized cost largely depends on the cost of input electricity, much less on other factors.

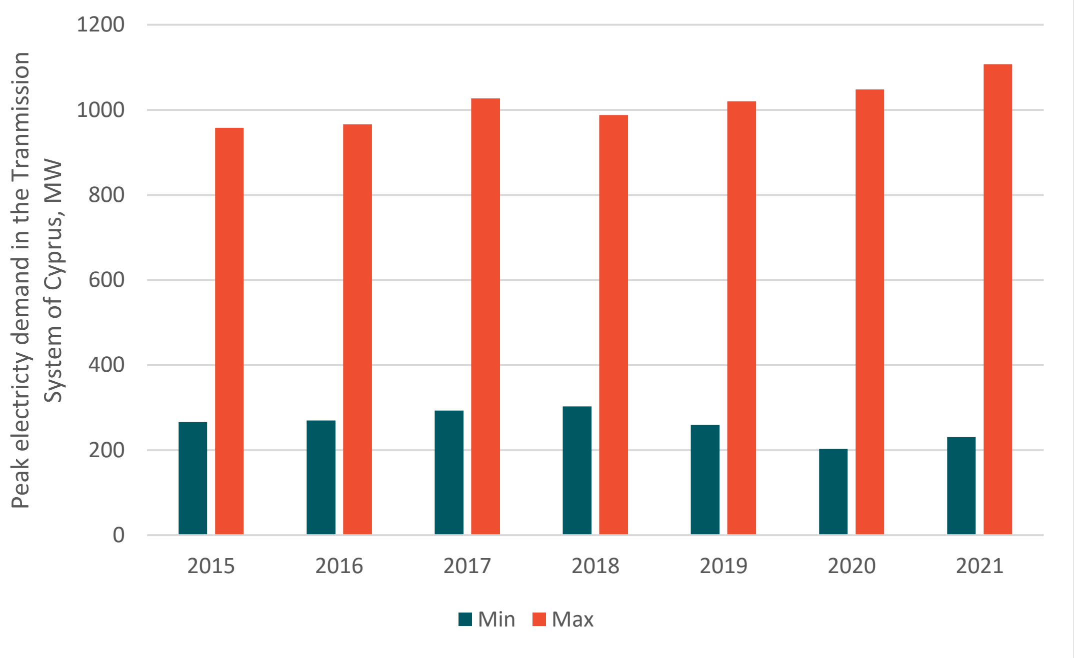
Figure 2: Sensitivity analysis of hydrogen production in Cyprus for dedicated production and grid supply. Notes: WACC = weighted average cost of capital. Assumptions refer to an electrolysis system in Cyprus in 2030 connected to a 50MWp PV source. Default assumptions as per Table 3. Sensitivity analysis based on +/-30% variation in electrolyser, land, and generation CAPEX, +/-3% change in default WACC of 7.5% and a variation in electrolyser utilization and electricity purchase costs (applicable to the dedicated grid supply case) of +/-30%.



2.3.2 *Storage of hydrogen*

While short term-storage is dealt with in the section discussing transportation (3.7.2), long-term storage can potentially play a role in balancing the power system in the periods with high electricity demand. Theoretically this is a solution that can provide system balancing, by offering services such as energy time shift, and balancing demand and supply through storing excess electricity generated by renewables released when required, e.g., using gas turbines. Even though electricity demand and generation from solar-based technologies is closely matched in the high demand periods (typically in the warmer parts of summer days), the dispatch of long-term storage will alleviate the very large gap between low and high demand periods, as seen in Figure 3.

Figure 3: The minimum and maximum electricity load values in the transmission system in Cyprus for the years 2015-2021. Note that the minimum has dipped during the pandemic years (2020 and 2021), while the maximum is on an upward trajectory. Maxima take place in the afternoon during the summer (typically the last 10 days of July or the first 10 of August at the height of the touristic season that coincides with very high air-conditioning demand) and minima occur during the night at either the spring or autumn. *Data source: Cyprus Transmission System Operator*.



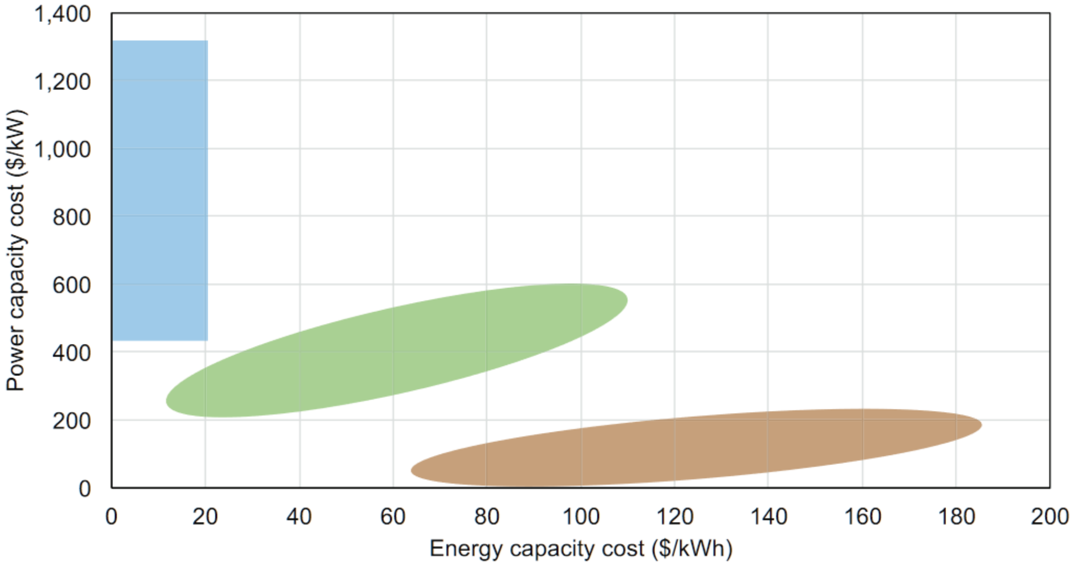
Compared to other options, such as batteries, hydrogen can theoretically be stored for long periods even up to months, whereas batteries can only be used for hourly or weekly needs. Also, it can have a much higher scale in terms of capacity, reaching GWh or even TWh. In a recent study, Cyprus was found that it *"could assess the potential contribution of deploying hydrogen in the frame of security of energy supply and to address the challenge of balancing electricity supply and demand in a system with a high share of variable renewable energy"* [20].

Hydrogen can also offer ancillary services to the grid via fuel cells and electrolysers, such as congestion mitigation, reduction of negative price incidences, frequency control, voltage control and black start. Transmission and distribution line congestion might occur in power systems and power-to-hydrogen conversion and subsequent hydrogen storage – like other types of energy storage – can be used to mitigate it. It has the major benefit of a low response time (seconds) which can make it particularly attractive [21], even though it is not a short as what can be achieved with battery storage.

This issue however is resting on the availability of suitable storage sites. Underground storage in aquifers (depleted deposits of natural gas and oil) or salt caverns are considered as the main options for large-scale hydrogen storage in the medium and long term. Approximately 75% of the underground storage is in depleted deposits, with salt caverns taking great interest lately due to their stability and imperviousness of their walls of salt caverns. Such sites could hold a volume range between 100,000 and 1,000,000 m^3 at maximum 200 bar. There are some additional technical challenges such as tightness of boreholes and the transfer capacity of the surface installation. Cyprus does not however have salt caverns or depleted hydrocarbon reservoirs (yet) to utilise for long-term storage. A dedicated study that would investigate the potential for geological storage of both CO2 and Hydrogen is required to assess this option with certainty. Without such data (and strong indications that there are none, see [22]), this study assumes that storing hydrogen in such a way is not an option. Other options for storage through derivatives are not considered in this report.

Based on technoeconomic data found in the most recent MIT report on storage [23], storing hydrogen in geological formations has a low cost per unit of energy, but a high one per unit of power (see Figure 4).

Figure 4: The blue region includes technologies with low energy capacity and high power capacity costs, such as pumped hydro, thermal and hydrogen storage tech. Li-ion batteries fall in the brown area, while flow batteries occupy the green area in the middle. Source [23].



The technology to convert H_2 back into electricity exists but is still at early stages of development. IEA [24] reports that the hydrogen content in reciprocating gas engines can easily reach 70% without too many modifications, and higher blending ratios (even pure hydrogen) have undergone successful testing. The main technical challenge involves the tackling the issue of greatly increased NOx emissions associated with the higher flame temperatures during the combustion of hydrogen. Currently systems that are negotiating this problem introduce substantial efficiency penalties, but it is expected that these hurdles will be eventually overcome. Several projects (mainly in Asia) have also attempted to use ammonia in turbines mainly as an add-on to coal firing plants (a case that's not relevant to Cyprus), and there are R&D projects that attempt to mature the use of ammonia in turbines directly. Mitsubishi claims to have such a system ready for commercial deployment by 2025 [24].

While fuel cells for the automotive industry saw rapid maturity since the 1990s, the technology is untested at the scales required to provide bulk electricity (see section 2.3.3). Using hydrogen in a blended mix with Natural Gas would allow it to be burned in a Steam Turbine, but the blending ratio currently must be capped at around 5%-10% due to the embrittling properties of hydrogen on steel pipes. Pure hydrogen in thermal power plants is untested and considered to be several years – in not decades away, even though it has attracted considerable attention from large engineering firms, see section below.

Table 4: Technoeconomic assessment for hydrogen storage costs

Tech		Now	2030	2050
In tanks	CAPEX (€/MWh)	8,230	7,900	7,200
	FOM (€/MW-yr)	82	79	72
	Efficiency	96%	96%	96%
Underground	CAPEX (€/MWh)	1,210	1,200	1,180
	FOM (€/MW-yr)	30	29	27
	Efficiency	93%	93%	93%

2.3.3 Use in thermal power generation

Hydrogen can be used directly for combustion, but the industry of Hydrogen-Fuelled Gas Turbines (HFGTs) is still at a nascent stage of development [25]. The authors state that ‘*certain existing natural gas-fired gas turbines can operate with a blend of hydrogen and natural gas, but there are very few that can be fuelled exclusively with hydrogen. This is primarily because the flame length of hydrogen is much longer than natural gas – this longer flame length leads to the production of NOx, a local air pollutant*’.

IEA [24] has examined this area in some detail in a 2021 report on the role of low-carbon fuels in the energy transition, with an extensive discussion on hydrogen co-firing. In summary:

- Clean H_2 and NH_3 are emerging fuel options for co-firing. Retrofitting facilities with CCUS for both fossil fuel generation and blue hydrogen is one of the options.
- Using hydrogen in turbines is already a common practice in industry, but at smaller scales than what is required for large scale thermal generation of electricity. For now, firing blended H_2 with Natural Gas does not require a lot of modifications to existing power generation infrastructure, but is restricted by the ability of pipelines to transfer a richer hydrogen blend than the usually quoted 5-10%.
- Co-firing of NH_3 and coal is also gaining attention, but this is not relevant to Cyprus.

This report will therefore not consider the use of hydrogen in power generation in any of the scenarios examined, as described in the passages below.

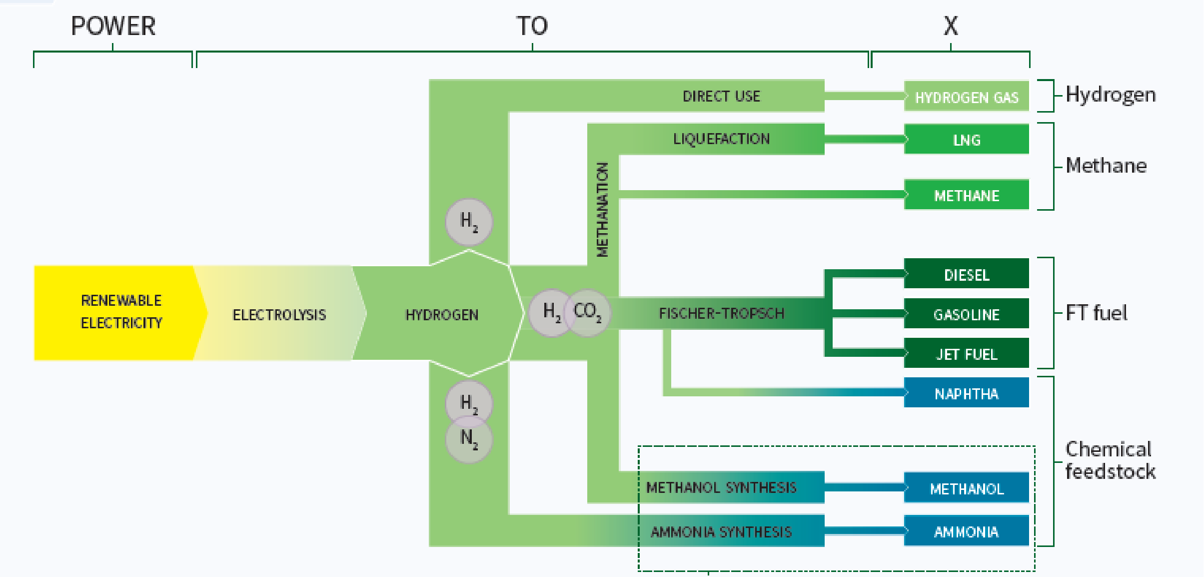
3 Accelerating the deployment of innovative hydrogen-based solutions and cost-competitive renewable electricity in industrial sectors

This section investigates the industrial base for Cyprus concentrated in distinct industrial areas, area of operation and temperature range. This classification assists in organising and directing the discussion towards areas that hydrogen deployment is in place to make a substantial difference. Throughout the following analysis, two scenarios are used to project the penetration of hydrogen in the Cypriot industrial sector, as follows:

- **Cautious**: Hydrogen is introduced usually at a later stage, and in sectors where it is projected to help with decarbonisation. This scenario assumes minimal or no top-down quota for H_2 generation and use in Cyprus
- **Aggressive**: Hydrogen is seen as a primary decarbonisation option from early on, and its adoption is accelerated earlier and in more depth. *This should be treated as a really ambitious scenario, whose realization critically depends both on the amount of infrastructure investments to be implemented and on assumptions about strong technical progress along the entire renewable hydrogen supply chain.*

One of the main levers of promotion for green hydrogen is its suitability to gradually replace fossil energy in processes that require high temperatures, and which now mainly rely on fossil fuels. Globally, the principal candidates mentioned are the use in refineries, the production of steel and other high-T applications, various applications within the chemical industry, as well as the production of synthetic fuels. All these are usually grouped under the ‘Power-To-X’ moniker, where the power is supplied by renewable electricity to produce green hydrogen, and then used via different routes to serve various industries (see Figure 5).

Figure 5: Simplified Power-To-X schematic. Source: LUT University (2020)



3.1 The industrial sector in Cyprus

3.1.1 *Spatial Planning of the Cyprus Industry*[2]

In total there are 13 industrial areas, 85 industrial zones and 62 craft zones in Cyprus. There are also several industrial premises all over Cyprus with a special permit of operation issued by the municipalities and communities, located outside industrial and craft zones and areas.

Food production is the most important activity with the greatest contribution to industrial added value (22.1%). Other important activities in terms of economic output and employment are the production of pharmaceutical products, beverages production, production of other non-metal mineral products, manufacturing of metal products, and processing of wastewater.

3.1.2 *Classification of Industrial Areas and Industrial Zones in Cyprus*

3.1.2.1 Industrial areas

Industrial areas in Cyprus became a necessity mainly due to the high price of urban plots, the lack of suitable land for setting up industries, the decentralised nature of industrial units, the very high cost of production, the absence of modern facilities, and the presence of industrial units within residential districts.

By creating these areas, industries are now concentrated in clusters. The acquisition of the necessary land is done by the government, which also provides the required infrastructure along with the necessary facilities. The space is finally offered to interested entrepreneurs at a low rent.

Based on data series provided by MECI, for the needs of this report, the total number of industries per industrial area are presented in Table 5 below.

Table 5: Cyprus Industrial Areas and Number of Industries (MECI, 2022)

Industrial Area	Total number
ΑΓΙΟΣ ΑΘΑΝΑΣΙΟΣ/AGIOS ATHANASIOS	157
ΑΘΗΕΝΟΥ/ATHIENOU	30
ΑΡΑΔΙΠΠΟΥ/ARADIPPOU	47
ΑΡΑΔΙΠΠΟΥ - ΒΙΟΜΗΧΑΝΙΚΗ ΚΑΙ ΕΜΠΟΡΙΚΗ/ ARADIPPOU INDUSTRIAL AND COMMERCIAL	45
Β' ΠΑΦΟΥ - ΑΓΙΑ ΒΑΡΒΑΡΑ/ Β' PAPHOS – AGIA VARVARA	46
ΕΡΓΑΤΕΣ/ERGATES	83
ΚΟΚΚΙΝΟΤΡΙΜΙΘΙΑ/KOKKINOTRIMITHIA	23
ΛΑΡΝΑΚΑΣ/LARNACA	84
ΛΕΜΕΣΟΥ/LIMASSOL	98
ΜΕΣΟΓΗ/ MESOGI	40
ΣΤΡΟΒΟΛΟΥ/ STROVOLOS	62
ΥΨΩΝΑ/YPSONAS	140
ΦΡΕΝΑΡΟΣ/FRENAROS	47
Grand Total	**902**

For better illustration of the data provided in the Table 5 above, Map 1 shows the location of the Cyprus Industrial Areas and Map 2 shows the total number of industries per industrial area.

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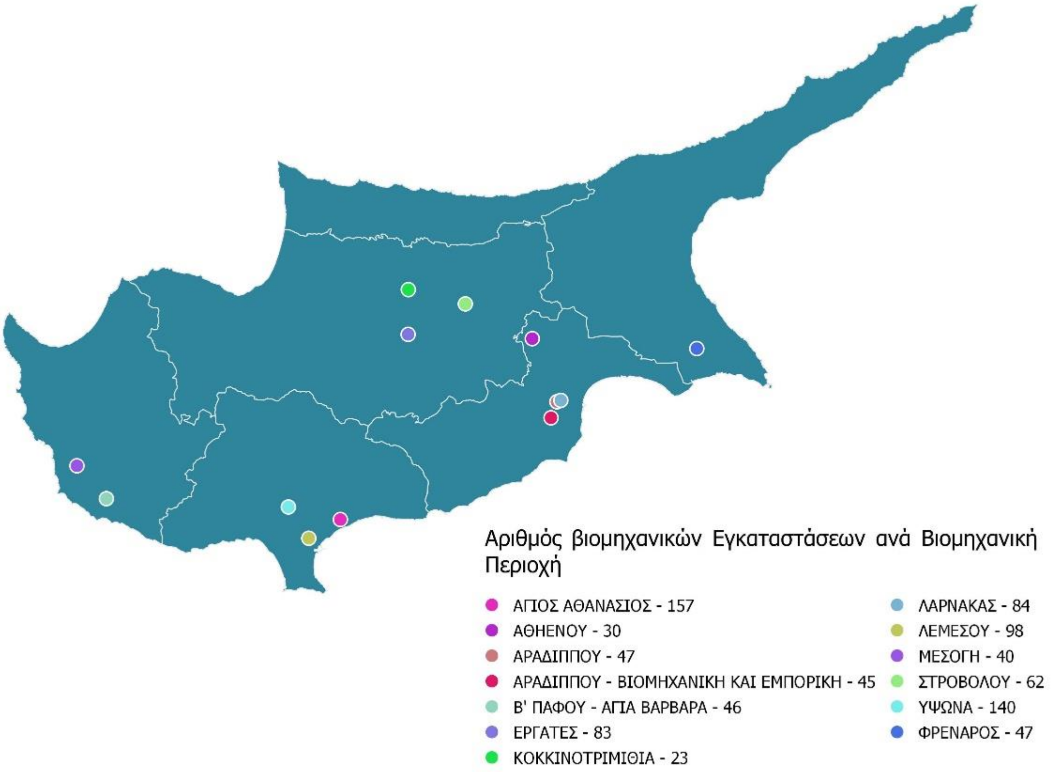
[2] See the relevant document of MECI: NEA ΒΙΟΜΗΧΑΝΙΚΗ ΠΟΛΙΤΙΚΗ 2019-2030 & ΣΧΕΔΙΟ ΔΡΑΣΗΣ 2019-2022.pdf

Map 1: Cyprus Industrial Areas (Cyl, ideopsis, 2022)

Map 2: Number of Industries per Industrial Area in Cyprus (Cyl, ideopsis, 2022)



To classify the 902 industrial units of Cyprus, the NACE rev. 2 classification was used. The number of these units per NACE code is provided in Table 6. Most industries fall under category C – Manufacturing.

Table 6: Cyprus Industrial Areas and Number of Industries (Cyl, ideopsis, 2022 based on MECI data)

NACE code	Number of industries
C - Manufacturing	671
E - Water supply; sewerage; waste management and remediation activities	13
F - Construction	8
G - Wholesale and retail trade; repair of motor vehicles and motorcycles	61
H - Transporting and storage	60
J - Information and communication	5
K - Financial and insurance activities	1
L - Real estate activities	6
M - Professional, scientific, and technical activities	13
N - Administrative and support service activities	7
S - Other services activities	2
P - Education	1
N/A	39
I - Accommodation and food service activities	1
Grand Total	**902**

3.1.2.2 Industrial zones

The Industrial zones are a measure of general spatial policy in Cyprus, defined in places where there are possibilities for concentrated industrial development. Industrial zoning serves a dual purpose: On the one hand the industrial units are concentrated in predetermined areas where measures are taken for the organized provision of common infrastructure services, while on the other it is possible to separate industry from residential, tourist, archaeological and rural areas, where industrial units are prohibited. The industrial zones also include zones with high levels of noise, such as the industrial zones of Geri-Dali, Aradippou, Moni, etc. Although industrial zones cannot have the size, layout, infrastructure, and facilities of industrial areas, yet industrial zone design is constantly being improved.

The industrial zones of Cyprus are currently located in the following areas:

- NICOSIA: Latsia (3), Lakatamia, Kokkinotrimithia, Engomi, Pallouriotissa, Tseri, Geri - Dali, Dali.
- LIMASSOL: Limassol, Agios Athanasios, Moni.
- LARNACA: Aradippou, Larnaca port – (ex. Refinery), Larnaca (2).
- PAPHOS: Paphos - Konia, Anatoliko, City (2).
- AMMOCHOSTOS: Deryneia (2), Paralimni (2), Sotira, Frenaros (2), Avgorou.

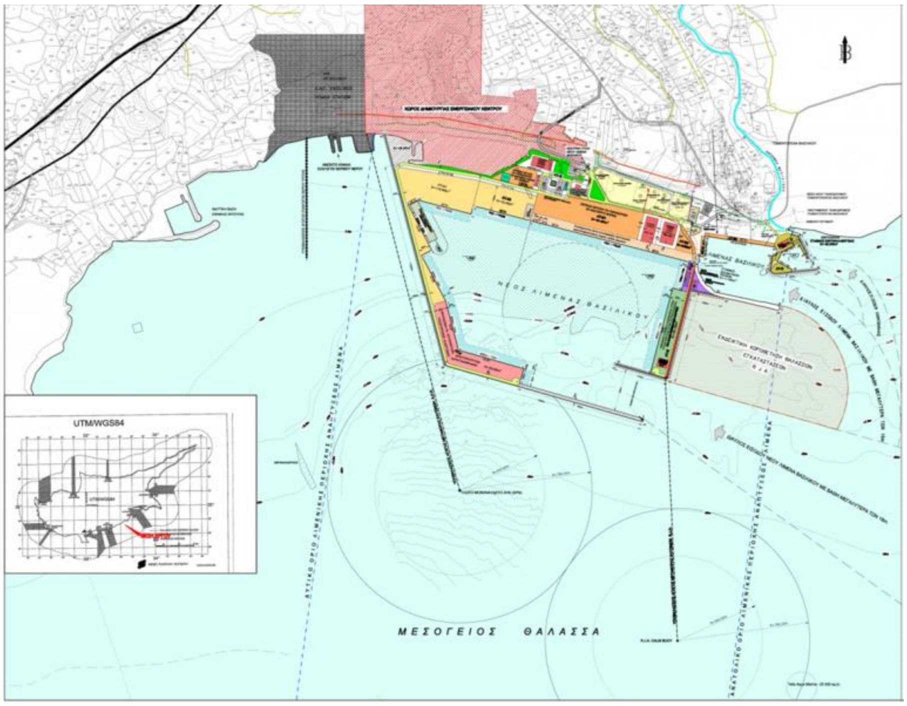
3.1.3 Revised Spatial Development Plan of Vassilikos Area

In April 2022, the final draft Master Plan for the Vassilikos Area and the relevant Strategic Environmental Assessment were completed and submitted to the Department of Environment. The revised Master Plan will include the projects and uses / activities that are planned to be implemented in the area of Vassilikos and which have not been taken into account in the existing Master Plan or there are changes in their design / location.

The main objectives of the Master Plan for the Vassilikos area are the following:

- The provision of a framework that will allow its optimal industrial development area for the next 30 years.
- Allocating land and providing a framework for storage hydrocarbons and other energy-related industries, natural gas and related infrastructure.
- Land allocation (Liquefied Natural Gas Zone - LNG) for LNG facilities, considering the potential discovery of significant additional natural gas reserves in the Cyprus Exclusive Economic Zone (EEZ) and in general in the Eastern Mediterranean.
- The Evaluation of existing and planned port facilities (including the proposed extension of the Port of Vassilikos) in relation to land-based activities and other commercial and industrial and energy related activities.
- Providing a framework for upgrading or developing new facilities in Vassilikos area.
- The optimal industrial development of the Vassilikos area giving particular importance to the social and environmental aspects and in matters of safety, security, and risk.

Figure 6: Vassilikos industrial area (source: https://www.roganassoc.gr/project/masterplan-for-the-port-of-vasilikos/)



In the area of Vassilikos there are currently the following **main facilities:**

- Vassilikos cement manufacturing and Vassilikos port
- EAC power station, marine facilities (Single Point Mooring, Water intake, thermal outfall)
- Military base and military port
- Liquid fuel Storage Facilities (Petrolina, VTTV and ELPE/ Yugen)
- VTTV jetty
- Archirodon port
- Skyra Vasa (has a temporary installation permit)
- Aquaculture facilities

The plan for the Vassilikos Industrial area is to accommodate additionally the following:

- The construction of a natural gas liquefaction unit with a capacity of up to five LNG trains (5 MTPA/train),
- Petroleum and liquid gas (LPG) storage facilities, and
- Industries related to natural gas (petrochemical industries).

These plans are in line with the obligations and plans of the country as they are presented in the NECP submitted at the end of 2019, but will be revisited in the preparation of the next version of the strategy report due for 2023.

3.2 Possible Hydrogen Industrial Users in Cyprus

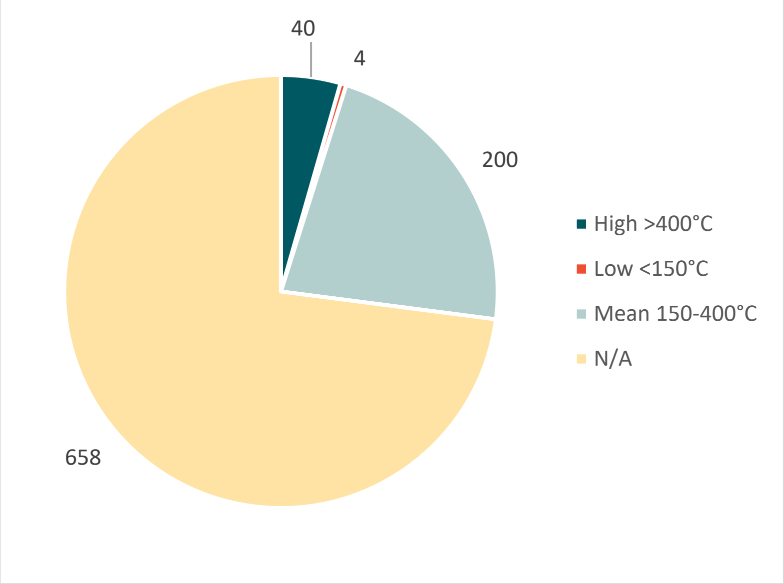
As a first estimate of hydrogen requirements in industrial uses, industrial activities were divided into three temperature ranges (High, Medium, Low), as presented in Table 7.

Table 7: Temperature bands classification for industrial units in Cyprus (Cyl, ideopsis, 2022)

Temperature bracket	Industry
High temperatures >400 °C	Ceramics
	Cement
	Aluminium extrusion and processing
	Copper mining
	Glass and steel[3]
Medium Temperature 150-400 °C	Publishing and printing
	Paper
	Plastics
	Textiles
	Tobacco
	Food
	Pharmaceuticals
Low Temperature <150 °C	

Based on the above classification, all industrial units in Cyprus have been allocated to the three temperature ranges (High, Medium, Low), as presented in Figure 7.

Figure 7: Number of Cyprus Industries per temperature range (Cyl, ideopsis, 2022)



Based on the geographical location of industries per industrial area, the number of industries per industrial area and temperature range were identified and are presented in Table 8 and Map 3. The 40 industrial units that are classified as 'high temperature' belong to NACE C – Manufacturing.

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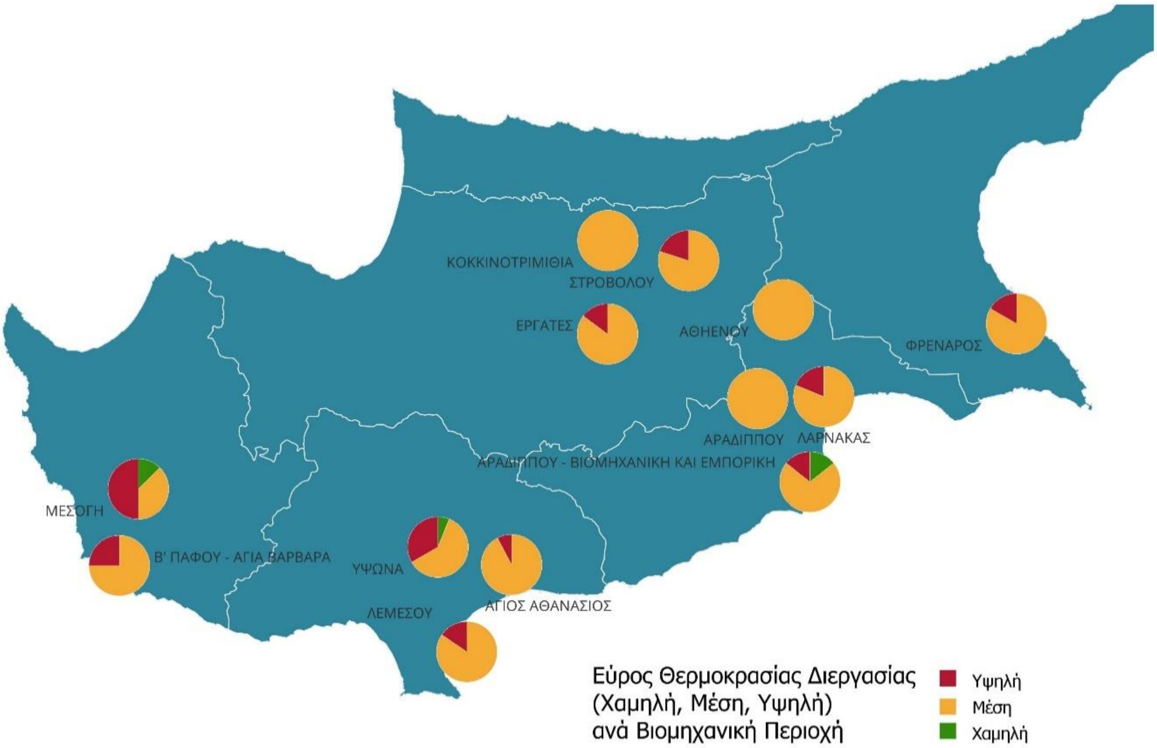
[3] Discussed as potential industrial units in the future only.

Table 8: Industrial units by temperature band and industrial area in Cyprus (CyI, ideopsis, 2022)

Industrial Area	Mean 150-400°C	High >400°C	Low <150°C	N/A	Grand Total
ΑΓΙΟΣ ΑΘΑΝΑΣΙΟΣ/AGIOS ATHANASIOS	48	4		105	157
ΑΘΗΕΝΟΥ/ATHIENOU	9			21	30
ΑΡΑΔΙΠΠΟΥ/ARADIPPOU	8			39	47
ΑΡΑΔΙΠΠΟΥ - ΒΙΟΜΗΧΑΝΙΚΗ ΚΑΙ ΕΜΠΟΡΙΚΗ/ ARADIPPOU INDUSTRIAL AND COMMERCIAL	5	1	1	38	45
Β' ΠΑΦΟΥ - ΑΓΙΑ ΒΑΡΒΑΡΑ/ B' PAPHOS – AGIA VARVARA	3	1		42	46
ΕΡΓΑΤΕΣ/ERGATES	23	4		56	83
ΚΟΚΚΙΝΟΤΡΙΜΙΘΙΑ/KOKKINOTRIMITHIA	9			14	23
ΛΑΡΝΑΚΑΣ/LARNACA	13	3		68	84
ΛΕΜΕΣΟΥ/LIMASSOL	33	6		59	98
ΜΕΣΟΓΗ/ MESOGI	3	4	1	32	40
ΣΤΡΟΒΟΛΟΥ/ STROVOLOS	16	4		42	62
ΥΨΩΝΑ/YPSONAS	20	11	2	107	140
ΦΡΕΝΑΡΟΣ/FRENAROS	10	2		35	47
Grand Total	**200**	**40**	**4**	**658**	**902**

Map 3: Temperature bands classification for industrial units and per industrial area in Cyprus (CyI, ideopsis, 2022)



3.3 Identification of needs for medium and high temperature heat in the Cypriot industry

The following passages expand on the possibility of using hydrogen in selected industrial units in Cyprus following the classification shown in Chapter 3.2. We present options for high, medium, and low heat, and additionally investigate the principal derivatives that we deem relevant to Cyprus in the long term: Ammonia and methanol.

3.3.1 High-T industries

3.3.1.1 Ceramics

Deployment of hydrogen in the ceramics industry is another case of use of combustible fuel in a gas furnace, but it should come as no surprise that the switch to hydrogen in existing systems will lead to wide-ranging changes, and even then some key considerations remain [26]:

- Hydrogen's high calorific value in relation to its mass, but low in relation to its volume leads to higher volume flows (fuel pressures) in a furnace. The shorter dwell time leads to poorer heat transfer and therefore to a less efficient heat exchange.
- In comparison to conventional fuels, hydrogen has a high adiabatic flame temperature. This leads to a less homogeneous heat distribution that cause thermal wear. In addition, temperature peaks lead to a significant increase in levels of nitrogen oxides (NOx) in the exhaust gas.
- Hydrogen is a good reducing agent, and at high temperatures it can attack oxide ceramic furnace materials in the long term, thereby causing chemical wear.
- The increased proportion of water vapor can lead to increased condensation in cooler zones. In connection with higher proportions of NOx in the exhaust gas, this can also cause corrosion.

When new plants are constructed, the above criteria can be considered by changing the furnace geometry and selecting suitable lining materials. These factors however also make upgrading existing gas boiler infrastructure more complex and expensive.

Brick-making plants and the use of hydrogen in kilns is a very low TRL activity. HyBrick[4] is a project between UK researchers and local industry that investigates brick quality, integrity, and aesthetics, but results are not expected until the mid-2020s, with commercialisation coming later. Similarly, a feasibility study commissioned by Brickworks[5], an Australian company, has not published results yet. The direct electrification of the sector using electrical heating elements was examined by Kamps et al. [27] and they found that *the use of electrical heating elements for firing bricks and ceramic roof tiles will not be sufficient because the heat and/or radiation can't reach the core of the piled stones*. Also, adding hydrogen to a NG burner is theoretically possible up to 20%, but untested for the ceramics industry.

The costs for such an update cannot be ascertained with confidence, especially in what concerns 2050. Table 9 shows the set of assumptions employed for the penetration of hydrogen in the ceramics industry, where we do **not see the integration of hydrogen-fired kilns in the brick manufacturing of**

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[4] HyBrick

[5] Brickworks Launches its Hydrogen Feasibility Study | Brickworks

the existing plants in Cyprus for 2030, while the aggressive scenario assumes that **50% of the current energy consumption in the sector will be covered by such kilns in 2050**. The BoP costs are set at 30% of the electrolyser CAPEX to account for intermediate infrastructure such as compressors and transmission, as well as the equipment required to upgrade the facilities to use hydrogen.

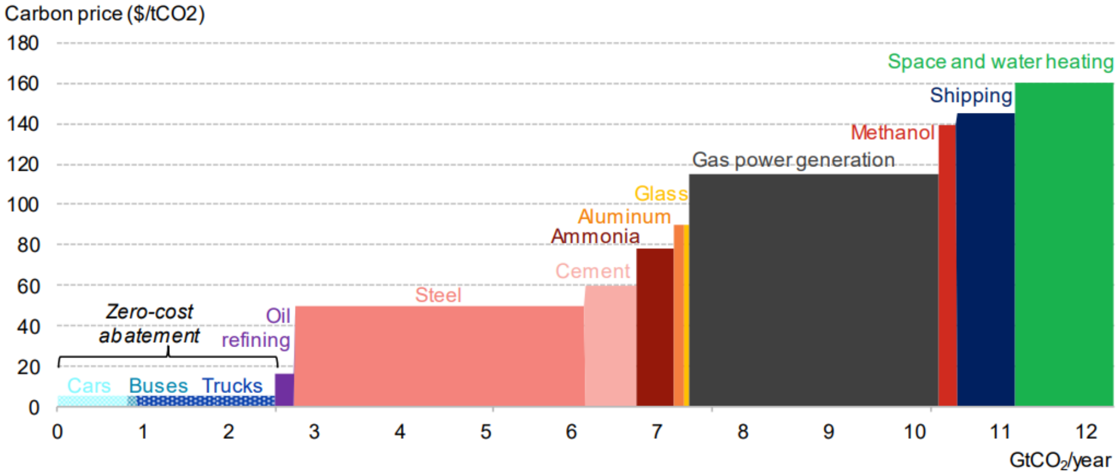
Table 9: Cost and penetration assumptions for hydrogen penetration in the Ceramic Industry

2030 Energy use (ktoe)	2050 Energy use (ktoe)	Scenario 1: Cautious *H2 penetration in 2030*	Scenario 1: Cautious *H2 penetration in 2050*	Scenario 2: Aggressive *H2 penetration in 2030*	Scenario 2: Aggressive *H2 penetration in 2050*
10	8	0%	0%	0%	50%
H2 required (MWh)		0	0	0	46,101
Electricity required (MWh)		0	0	0	62,242
PV capacity (MWp)		0	0	0	23
Costs (€m)					
Generation		0	0	0	9.2
Electrolysis		0	0	0	3.7
BoP		0	0	0	1.1
Total		**0**	**0**	**0**	**14**

3.3.1.2 Cement

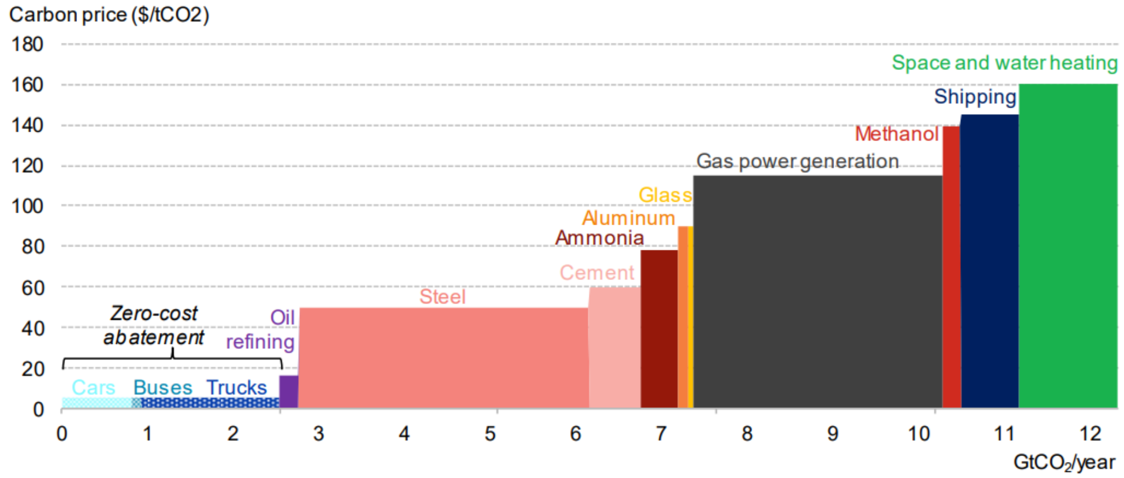
Cyprus has one cement factory rated at 2Mt of cement production annually, located on the south coast of the island near the city of Limassol. It has been operating for more than 50 years and has undergone several upgrades, including port facilities for importing raw materials and exporting clinker and cement. According to the national emissions inventory, it currently accounts for about 10% of total national greenhouse gas emissions.

Globally, cement accounts for 8% of global emissions [28], and is in great need for decarbonisation. As shown in Figure 8: Marginal carbon abatement cost curves from using $1/kg hydrogen for emission reductions, by sector in 2050. Source: BNEF (2020)



, BNEF [29] has calculated that a carbon price of $60/tCO₂ would be required for green hydrogen to break even for supplying heat to the cement industry, a price that has already been exceeded within the EU. The recent invasion of Ukraine by Russia however has caused global hydrocarbon prices to skyrocket and hence the rapid switch to alternative fuels is imperative; yet this period is not a sound basis to make long-term projections on as prices can fluctuate considerably. This also does not mean that any switch will happen across the whole industrial landscape right away in this pricing environment; switching to a new fuel requires more upfront costs and infrastructural upgrades, as noted by IEA [2].

Figure 8: Marginal carbon abatement cost curves from using $1/kg hydrogen for emission reductions, by sector in 2050. Source: BNEF (2020)



Recent literature also points out that the processes in the production of cement cannot be simply cleaned up with the use of renewable energy or efficiency improvements [30]. This is because the majority (60%) of the industry's CO_2 emissions do not originate from energy use, but from the very manufacture of cement from limestone. A recent analysis by Chatham House [28] underlines that more than 50% of cement emissions are the by-product of a chemical reaction, and such emissions cannot be reduced simply by changing fuel sources or increasing the efficiency of cement plants.

In very simple terms, clinker, a major constituent of cement is manufactured by breaking down limestone into calcium and CO_2, and (for now) the principal option of cement makers is to capture and store this CO_2 (via a CCS route like in other carbon-emitting industries) instead of concentrating on the high-T processes that could be potentially replaced by hydrogen boilers. The reduction of emissions by fuels switching is one of the tools of the industry, but for now the efforts are concentrating around the use of biomass for the high-T processes, that can gradually be replaced by hydrogen. Other publications e.g., [31]-[33] note that in the case of the cement industry novel, low-carbon cement formulations are expected to provide decarbonization options **that take precedence** over the use of an alternative heating fuel like hydrogen, at least in the short to medium term. Commercialisation therefore **is not expected before 2030** due to low maturity, uncertain costs, the likelihood of needing fundamentally redesigned plant and the slow turnover of existing systems [34].

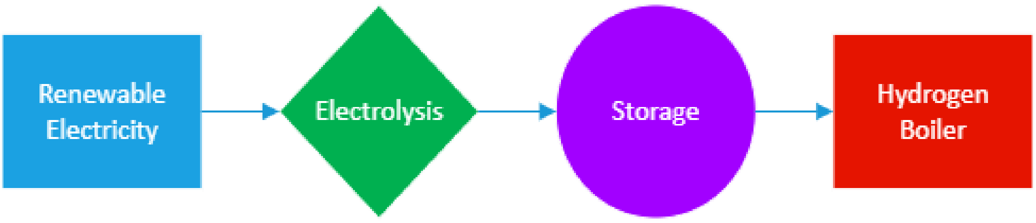
The following table maps the probable steps towards the cement sector decarbonisation, and the role that renewable hydrogen might play in the long term.

Table 10: Cement sector decarbonisation pathways, adapted by Griffiths et al. [31]

Near Term	Medium Term	Long term	Possible synergies
• CCUS (via mineralisation) • New formulations (use of calcined clay, alkali binders, • Re-use and waste upcycling (unhydrated cement recycling)	• CCUS (via calcium looping, chemical absorption, oxy-fuelling, silica adsorption, direct separation, partial chemical absorption) • New cement production pathways (advanced grinding) • New formulations (calcium silicates) • Renewable energy (concentrated solar) replacement of fossil fuels	• CCS (membrane separation) • New cement process operations (electrolyser decarbonation prior to clinker production) • New formulations (magnesium oxides) • Renewable and low-carbon hydrogen for high-temperature processes • Direct electrification	• Solar thermal energy storage • Hydrogen clustering with other industrial end users • Hydrogen synergies with refuelling hubs for heavy vehicles • Possible utilisation of CO2 (from the CCS process) with renewable H2 for methanol production

The cement sector is especially relevant for Cyprus since there is a local plant already in operation (the Vassiliko Cement Works PLC[6]). Based on the short analysis above, the cautious scenario does not see any hydrogen penetration for the cement industry either in 2030 or 2050, where the industry is projected to focus mostly on the measures mentioned above, perhaps even with the inclusion of CCS, which would have to be proven viable. In the aggressive scenario, these percentages are 10% and 50% respectively (Table 11). For 2030 this would imply a co-firing of hydrogen with other liquid hydrocarbons, whereas in 2050 the assumption is that there will be a switch to hydrogen-fired boilers for both storage, clinker and cement production. Figure 9 is a simplified illustration of the process.

Figure 9: Simplified flow of hydrogen for substituting fossil fuels in a cement production process



Costs for such a transition are very difficult to estimate, as there are no projects of sufficient size for the cement industry and the TRL of the process is very low. Some pilot projects have started to appear that aim at integrating renewable hydrogen in various steps of cement production, even by using the e-fuel route instead of direct use of H2 in boilers[7]. While we are mainly focussing on the costs associated with the rest of the hydrogen supply chain, the costs for upgrades and new facilities are only indirectly estimated from the costs of a new cement plant with mature technologies today, estimated at around €20k/t[8]. We assume that in the case of 10% penetration in the aggressive scenario of 2030 this will take place via injecting H_2 into existing infrastructure with moderate upgrades, costed at €1,000/t. In the aggressive 2050 scenario where we see 50% switch to hydrogen boilers, this is costed at €10,000/t, under the assumption that a lot of existing infrastructure (e.g., office spaces, land, commodity networks etc.) are already in place. Table 11 and

Figure 10 illustrate the above estimates.

The decision to cap the penetration of the aggressive scenario to 50% instead of 100% is related to the existing investment that the Vassiliko plant has recently made in adding an incinerator of municipal

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[6] Vassiliko Cement Works Public Company Ltd - Home

[7] An overview of some of these projects can be found here: Cement producers explore hydrogen to tackle emission - H2 Bulletin

[8] E.g., see Cement Factory Cost | How Much Does It Cost To Start A Cement Plant? (cement-plants.com)

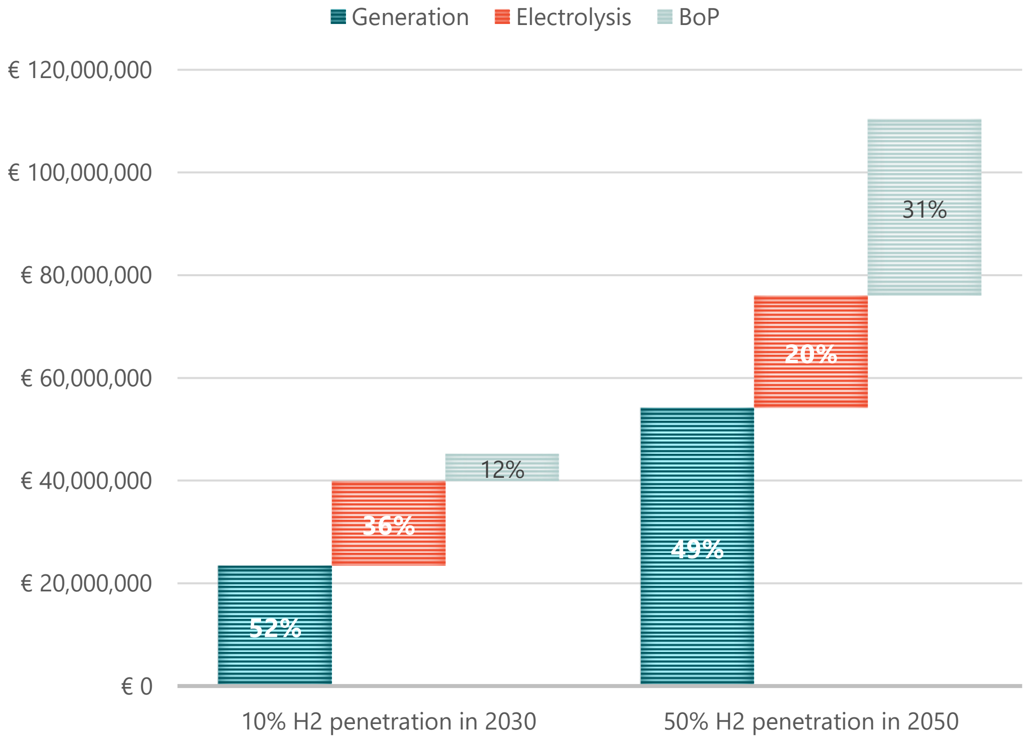
waste that covers about half of its thermal needs. It is not known with certainty if this infrastructure will be retained until 2050, but even if this is not, assuming a 100% decarbonisation via hydrogen may not be realistic, as other options exist.

An exhaustive study into all steps required for switching to hydrogen is beyond the scope of this report and may be explored at a later stage.

Table 11: Hydrogen penetration and supply costs for the Vassiliko cement plant in Cyprus.

2030 Energy use (ktoe)	2050 Energy use (ktoe)	Scenario 1: Cautious		Scenario 2: Aggressive	
		H2 penetration in 2030	*H2 penetration in 2050*	*H2 penetration in 2030*	*H2 penetration in 2050*
60	47	0%	0%	10%	50%
H2 required (MWh)		0	0	69,151	270,843
Electricity required (MWh)		0	0	100,106	365,675
PV capacity (MWp)		0	0	39	135
Costs (€m)					
Generation		0	0	23.4	54.1
Electrolysis		0	0	16.4	21.8
BoP		0	0	5.2	34.3
Total		**0**	**0**	**45.1**	**110.3**

Figure 10: Hydrogen investment costs in the cement sector

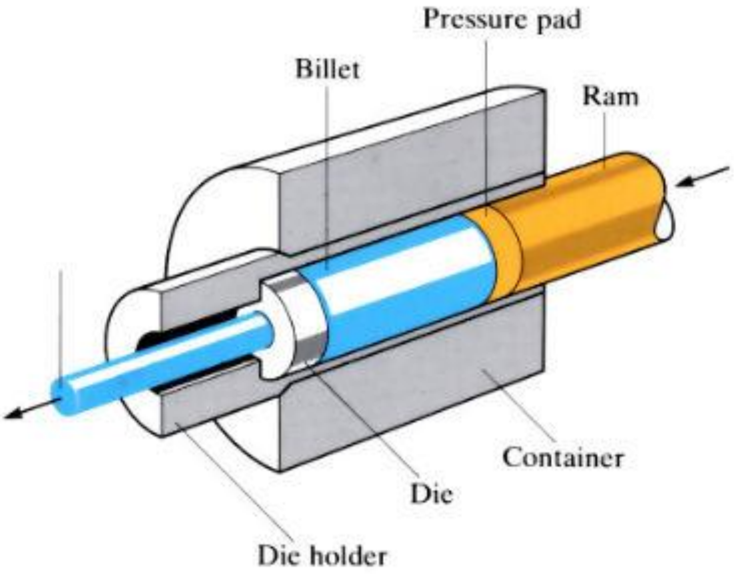


3.3.1.3 Aluminium extrusion and processing

Aluminium smelting is a very energy-intensive process by which aluminium is extracted from Al_2O_3, which is itself extracted from aluminium ore. While there are aluminium industries in Cyprus, the energy intensity of smelting is an immaterial consideration for Cyprus that does not possess such a plant, nor does it have ready access to aluminium ore deposits. The local industry is engaged in *aluminium extrusion* (Figure 11), a process that involves the creation of market-ready products based on aluminium, that can happen at temperatures between 350-500ºC for hot extrusion, or at room temperature for cold.

Hot extrusion uses steel moulds through which aluminium billets are pressed thought using a hydraulic press and come out on the other end in the desired shape. Hydrogen's use in burners to heat up the steel moulds would be the obvious application, but at this temperature range it would be an inefficient process. It's an area of industrial research that has not attracted attention and **is not considered relevant to the future of aluminium industries in Cyprus**. Hydrogen is therefore not foreseen to play a role in extrusion processes that are more likely to follow a direct electrification pathway.

Figure 11: Forward hot extrusion of aluminium billets. Source: Open University[9]



3.3.2 *Medium-T industries and low-T industries*

Industries with processes in the two lower temperature brackets (see Table 7) are not foreseen to be decarbonised using renewable hydrogen. This is a view that is corroborated by several publications from across the board of the academic, policy maker and industrial stakeholder space [19], [31], [35]-[41]. The central argument articulated in [36] is that "*with respect to industry, it is important to focus on subsectors where hydrogen is a 'no-regret' option, i.e. no decarbonisation option with higher cost -effectiveness is available*". While this study does not perform an exhaustive analysis of every potential low- and medium-heat application in Cyprus, international literature indicates that direct electrification using renewable electricity will be the preferred, but not only, solution instead of hydrogen.

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[9] Hot extrusion - OpenLearn - Open University

3.3.3 Shipping (ammonia and methanol)

There is intense interest in the use of hydrogen and its derivatives in shipping. As a fuel used directly, hydrogen fuel cells have been demonstrated on several coastal and short-distance vessels since the early 2000s, but none are yet commercially available, even though the commercial operation of fuel cell ferries has tentatively begun in 2021 in the United States and Norway. Most hydrogen-fuelled vessels currently under demonstration or planned for deployment in the next few years are passenger ships, ferries, roll-on/roll-off ships, and tugboats, typically with fuel cell power ratings of 600 kW to 3 MW. A recent EU partnership aims to build a hydrogen ferry with 23 MW of fuel cell power. Past and ongoing projects span both gaseous and liquid onboard hydrogen storage [42].

Due to the low volumetric density of hydrogen (whether in gaseous or liquid form), direct use of hydrogen will be limited to short- and medium-range vessels, especially those with high power requirements that cannot be met through battery electrification. Recent developments resulted in demonstration projects gradually moving towards commercialisation with vessels using liquid H_2 onboard doing commercial routes in Norway[10]. A recent study by the International Council on Clean Transportation (ICCT) [43] found that 99% of shipping voyages made on a popular China-US route can be made with hydrogen by replacing only 5% of cargo capacity with space for liquified H_2; the same could be achieved by adding one more refuelling stop to the route.

3.3.3.1 Ammonia

Ammonia (NH_3), predominantly used to produce nitrogen fertilisers, accounts for 2% of global final energy demand and around 1% of energy-related and process CO_2 emissions from the energy sector [19]. Ammonia has almost twice as much energy as liquid hydrogen by weight and nine times the energy density of lithium-ion batteries, but one third that of diesel (per volume), while storage and handling are tricky – it’s also highly toxic and is associated with serious nitrous oxide (N_2O) emissions. Using renewable hydrogen for ammonia production is still not at full maturity [19]. Pilot and pre-commercial projects that exist in various parts of the world are for the most part examining the substitution of ‘grey’ ammonia with electrolytic one as fertiliser feedstock, but the process is the same for port facilities that would be relevant for Cyprus, since no fertiliser plants exist.

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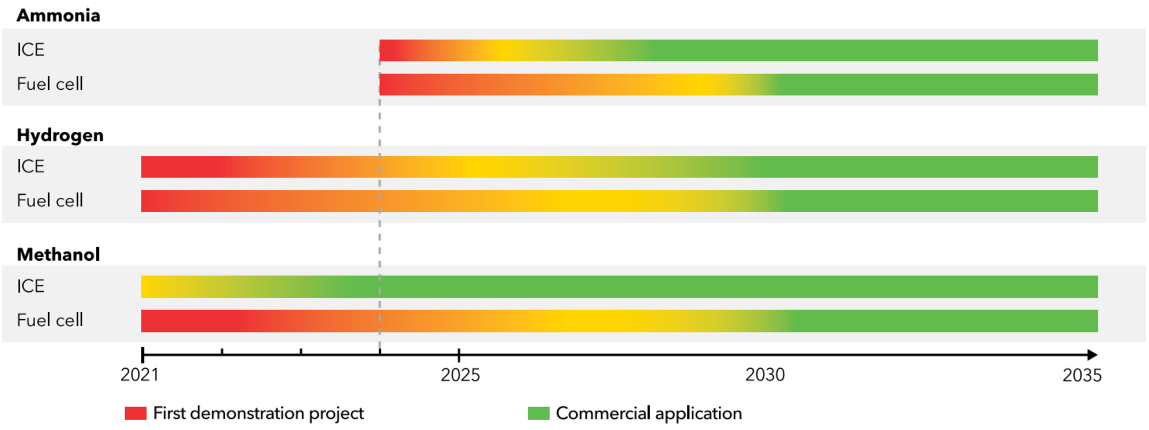
[10] World’s First Liquid Hydrogen-Powered Vessel Wins Ship Of The Year Award (fuelcellsworks.com)

Figure 12: Estimated timeline for expected availability of alternative maritime fuel technologies. Source: [44]

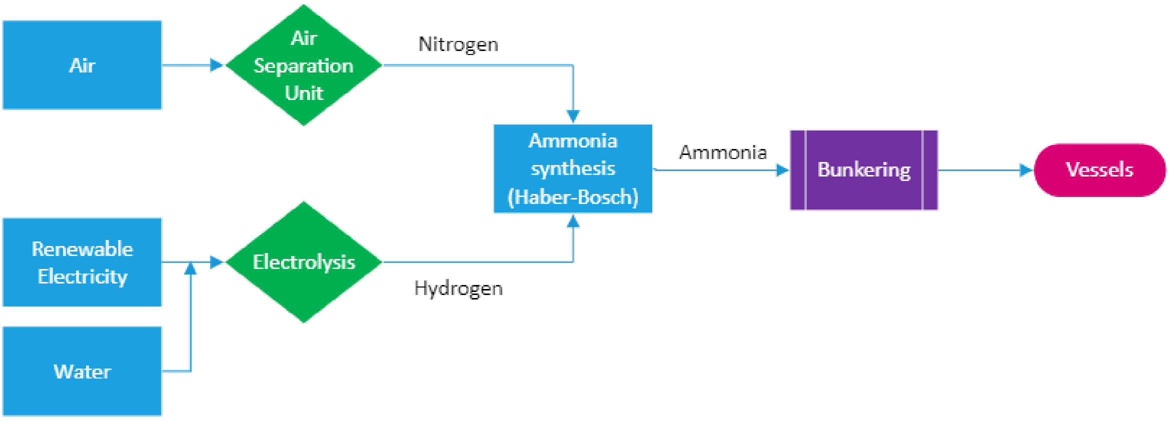


Key: Internal combustion engine (ICE)

183Mt of ammonia were produced globally in 2021, of which 72% is from natural gas, 22% from coal, 5% from oil and less than 1% from renewables [45]. Currently, 10% of production is globally traded, using pipelines and more than 70 LPG tankers with cargo capacities from 2 500 t to 40 000 t [46]. Ammonia's role as a tradeable commodity is therefore established and mature in many parts of the world using a supply chain that is familiar to many port authorities.

Using renewable hydrogen for ammonia production is still not at full maturity [19]. Pilot and pre-commercial projects that exist in various parts of the world are for the most part examining the substitution of 'grey' ammonia with electrolytic one as fertiliser feedstock, but the process is the same for port facilities that would be relevant for Cyprus, since no fertiliser plants exist. Despite this, ammonia is generally considered one of the primary options for bunker fuel decarbonisation resting on a combination of steps that are already established (see Figure 13).

Figure 13: Primary conversion steps for producing renewable ammonia



<u>Ammonia Projected Demand</u>

Demand in ammonia in this report deals **with its use in the shipping sector as bunker fuel only** and does not consider the production of renewable (green) ammonia for other uses, or its transportation in vessels as cargo. As a result, the costs reported in this section are related only to the synthesis of ammonia using renewable hydrogen, its bunkering and use in vessels.

As bunker fuel, it can be used in internal combustion engines to eliminate vessel CO_2 emissions, or in ammonia fuel cells. Solid oxide fuel cells (SOFCs) can use NH_3 directly and have a high efficiency (40-60%), but lack power density and load response capability, and are expensive (> USD 1,650/kW) [47]. On the other hand, major industry stakeholders have announced plans to make 100% ammonia-fuelled maritime combustion engines available as early as 2023 and to offer ammonia retrofit packages for existing vessels from 2025, where internal combustion engines fuelled by pure ammonia are expected to be commercially available by 2024 [48]. Wartsila (a technology and equipment company serving the maritime and energy markets) is developing a platform for LNG ships that could be used to be used interchangeably with ammonia; they claim that this is the best way to prepare vessels for a possible conversion. This report assumes that the uptake of NH_3 in vessels as engine fuel will follow the combustion pathway.

Assuming an engine efficiency of 50% [45], Table 12 presents the results of a theoretical penetration of ammonia as bunker fuel in 2030 and 2050 in Cyprus.

Table 12: Projections for fuel oil and ammonia use in shipping as bunker fuel in Cyprus. Data for petroleum sales to ships for years 2018-21 from CYSTAT (2022). Numbers in blue are projections. The cautious scenario does not foresee and use of ammonia in shipping, while the aggressive scenario in 2030 assumes a penetration 10%, and 100% in 2050. The quantities for ammonia are based on a specific energy ratio between diesel and NH_3 of 2.45. Generation and electrolysis cost assumptions presented earlier in the report. Overnight investment assumptions for ammonia via electrolysis from [2].

Fuel	2018	2019	2020	2021	2030		2050	
					Cautious	Aggressive	Cautious	Aggressive
Gasoil for marine use	117,778	123,756	119,096	113,321				
Light fuel oil	0	0	157,620	140,508				
Heavy fuel oil	165,656	146,312	674	0				
Total Fuel Oils (Gasoil + Light Fuel Oil, tonnes)	**283,434**	**270,068**	**277,390**	**253,829**	300,000	270,000	350,000	70,000
Total NH_3 (tonnes)					0	73,548	0	686,452
Electricity consumption (synthesis, MWh)						80,903		686,452
Electricity consumption (electrolysis, MWh)					0	644,284		5,834,839
Hydrogen required (tonnes)						45,692		236,358
Hydrogen required (MWh)						1,507,850		7,877,820
PV Capacity (MWp)						252		2,161
Costs (€m)								
Generation					0	151	0	864
Electrolysis					0	105	0	347
Overnight investment					0	70	0	522
Total					**0**	**326**	**0**	**1,734**

Costs

Costs for the use of ammonia as bunkering fuel are broken down in three main categories: The costs for producing renewable hydrogen, the costs for synthesising NH_3, and the auxiliary costs for storage, port terminal and bunkering.

IEA [2] combines the electrolyser and synthesis infrastructure costs in one for both 2030 and 2050, and is the source of costing data used in this report for ammonia. The other cost categories are included in the ‘overnight investment’ row.

3.3.3.2 Methanol

Methanol (CH_3OH or CH_4O) is an organic chemical compound that can be synthesised using hydrogen and a carbon source, typically via CO_2 hydrogenation; it is one of the main derivatives discussed relevant to the energy transition. It is a liquid hydrocarbon with a huge existing market size (over 100Mt, [45]), and a very low price compared to other Liquid Organic Hydrogen Carriers (LOHCs).

Methanol has also been demonstrated as a fuel for the maritime sector and is relatively more mature than hydrogen and ammonia. Given its compatibility with existing maritime engines, methanol could be a near-term solution to reduce shipping emissions, but question marks remain on the source of carbon for the synthesis of the methanol molecule [49]. Several engineering firms operating in the shipping sector claim that a commercially available engine for vessels using methanol shall be available by the end of 2023.

A common limitation of carbon-containing carriers is the availability of a sustainable carbon source. Direct air capture (DAC) currently has a cost of several hundred dollars per tonne and is unproven beyond pilot projects. Using captured CO_2 from a CCS facility in an industrial or electricity unit will ‘transfer’ the carbon content to the hydrogen carrier that will eventually find its way again in the atmosphere, rendering this option non-renewable. A different option is a biogenic source of carbon, but land and water availability are major concerns for Cyprus, and hence methanol’s sourcing of carbon for an island location like Cyprus is not considered viable and is not examined further in this report. Deeper examination of the potential to use methanol for shipping could be the subject of deeper, more specialised analysis.

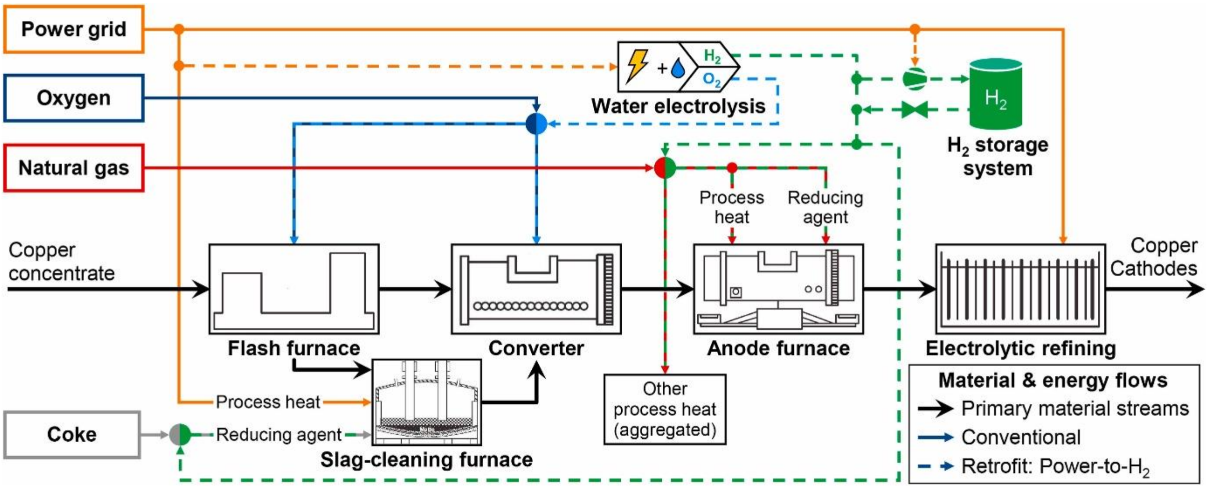
3.4 Noteworthy possible industrial units of the future

3.4.1 Copper mining

Cyprus has a long-standing tradition with mining copper, being a major exporter of ore in antiquity. Mining and extraction is already an ongoing activity at the Skouriotissa mines site, but there is renewed interest to exploiting copper deposits around the village of Apliki in the Pitsilia region, with contracts for resource base establishment and extraction already in place.

Röben et al [50] have recently investigated the cost effectiveness of such a transformation for copper mining in Germany. They found that using a power-to-H_2 approach (i.e., the use of renewable electricity and electrolysers) would result in a high CO_2 abatement cost of around €200/tCO_2-eq, considerably higher than other less costly options that should be pursued first from an energy system point of view.

Figure 14: Flowsheet of copper production process retrofitted with Power-to-H_2 technology to supply hydrogen as both a reducing agent, and to supply high-temperature process heat for Germany. Source: [50].



Future reductions in costs could potentially make this a more attractive proposition, but recent industry reviews e.g., [51] suggest hydrogen boilers are not yet proven for copper smelting and processing, and are not considered yet prime candidates for the industry's decarbonisation. Several pilot projects in the last few years concentrate in the replacement of fossil fuels used in high-tonnage vehicles (e.g., extraction trucks) operating in a mine. The challenge for this transition again is the merits of direct electrification both in the mining processes and its use in vehicles, as seen in the section on transportation.

Hydrogen for copper mining is therefore not considered an option with a high enough upside to feature on this roadmap.

3.4.2 *Steel*

Steel is the premier industry proposed for decarbonisation via hydrogen across the world. It figures in nearly every decarbonisation roadmap for industrialised regions, where hydrogen is considered the primary option to replace processes that require high temperatures, typically served by fossil fuels.

Steel needs a cleaner way to separate the oxygen from iron ore to make Direct Reduced Iron (DRI) as an intermediate step when using hydrogen [52], and the high-quality ore deposits required are rare [3]. The hypothetical supply chain of steel production for Cyprus would have to involve importing iron ore of sufficient quality and produce steel locally.

For Cyprus to consider the production of 'green steel' many things would have to line up for it to succeed: First, Cyprus would have to establish itself as an economical steel exporting hub to countries of the region. As of 2022, countries with sufficiently large industrial base of the region include Israel, Turkey, and Egypt. All of these would be hard markets to reach, for different reasons each. Secondly, there would need to very generous governmental support that would need to also include the whole value chain of steel production – supporting the building of a steel mill, subsidising the imports of iron ore and exports of steel, all these for no local industries with demand for steel. And then global conditions would have to favourable as well: Carbon would need to be priced high (as it is projected to be under the European Emissions Trading System), and that global decarbonisation efforts are intensified.

This study **does not therefore foresee the development of a steel industry** in Cyprus for the reasons mentioned above.

3.4.3 Glass industry

The glass industry is responsible for about 3.1% of emissions in Europe [53], and like the other high-T industries appearing in this report and in hydrogen literature, it is one of the candidate sectors that is being discussed for decarbonising using hydrogen. When NG prices are low the feasibility of such a transformation seemed unlikely, but the price hikes of 2021/2022 have renewed the interest in this option.

From a technical point of view hydrogen seems to be compatible with existing infrastructure, save for some concerns about NOx generation [54]. The question for Cyrus however is not on technical maturity, but on the possible demand for glass industry in the future, under any pf the scenarios. Considering that such a transformation is not yet a mainstream idea and the fact that local demand cannot justify such investments, the probability of a glass smelting industry in Cyprus is considered very low and hence not considered in this report.

3.5 Forecasted Hydrogen use in the Cypriot industry

E3Modelling has provided the country team with a range of projections on the consumption of hydrogen in Cypriot industrial sectors. The overall demand forecast picture can be found in the Appendix, Table 24. The ‘other industries’ row reports a calculated need for 5-15 GWh, whereas Table 13 below puts this number at 69 GWh for 2030 and 588 for 2050. It’s worth noting that all the hydrogen in this analysis is projected to serve the cement industry, without which demand would be zero. E3M did not provide any forecast for 2050.

Table 13: Overview of projected use of hydrogen in industry in Cyprus

	Industry	2030 Energy use projections (ktoe)	2050 Energy use projections (ktoe)	Scenario 1: Cautious				Scenario 2: Aggressive			
				H2 penetration in 2030		H2 penetration in 2050		H2 penetration in 2030		H2 penetration in 2050	
				%	tonnes	%	tonnes	%	tonnes	%	tonnes
High temperatures >400 °C	Metal (aluminium)	0	0	0%		0%		0%		0%	
	Ceramics	10	8	0%	0	0%	0	0%	0	50%	1,397
	Glass										
	Quarrying	0	0								
	Cement	60	47	0%	0	0%	0	10%	2,095	50%	8,207
Medium Temperature 150-400 °C	Publishing and printing	0	0								
	Paper	0	0								
	Plastics	0	0								
	Textiles	0	0								
	Tobacco	0	0								
	Food	0	0								
	Pharmaceuticals	0	0								
Low Temperature <150 C	*(all)*	0	0	0%		0%		0%		0%	
Total (tonnes)					**0**		**0**		**2,095**		**9,604**
Total (GWh)					**0**		**0**		**69**		**317**

3.6 Concluding notes

In all the industrial cases, supporting the switch of industries that use high-T heat to green hydrogen would usually mean passing through their additional costs to their final customers, something that may not be an option at this early stage, especially for a country with a relatively small industrial base and a small market unable to absorb price hikes.

There is also another trend that may run counter to the future use of liquid fuels for high-T applications: the direct use of electricity. A recent publication by Madeddu et al. [55] summarised the latest developments and found that over 70% of the current industry-related emissions in the EU can be eliminated by the direct use of electricity through the use of current technologies, while 99% of those emissions can be eliminated by technologies in development, mostly high-T heat pumps. Whether this happens and to which extent will heavily depend on the costs of green electricity production and the cost of fossil fuels and carbon emissions, as well as the upfront costs for making the changes in the industrial processes.

3.7 Other end uses

3.7.1 Domestic use in buildings (heating and cooling)

Fuel cell systems

Hydrogen in the domestic and commercial sectors is projected to develop using Fuel Cells that can be in a micro-CHP or mini-CHP configuration. Micro-CHP technologies are usually used as a heating solution in single flats, or houses while the mini-CHP systems are usually installed in apartment buildings or commercial buildings, operating to optimise either most of the electricity demand or most of the heat demand. The main disadvantage of the CHP fuel cell heating system is the high upfront cost. A new micro-CHP fuel cell heating system with an electricity output of 1kW and heat output of 1.45kW would cost around €25. If CHP is utilised in electricity-led mode, the remaining heat requirement needs to be covered by an additional heating system such as a hydrogen boiler. These work in a similar way to existing gas boilers and are expected to be able to achieve high efficiencies, like those of current natural gas boilers.

The penetration of hydrogen in the domestic sector however is facing an uphill struggle, as heat pumps have emerged as the dominant heating and cooling option powered by electricity. Currently, heat pumps are standard, mature, off-the-shelf technology that can be purchased now, and they are cheaper than fuel cell heating systems, while at the same time being able to provide cooling. The cost for an air source heat pump and its installation is around €12k with strong downward trends [57].

Another option is the blending of H_2 in Natural Gas pipelines. This is a way to decrease the carbon content of the fuel delivered (if the blended H_2 is green), but the ability of NG pipelines to transport blended fuel is limited to about Up to 5% by volume used in buildings or industrial processes without major investments [40] If however that 5% is a hard cap, then the real blending quantities in a year are likely to be less, since there won’t be constant supply of renewable hydrogen to the network if generation relies on the temporal generation profile of renewables. To achieve a constant blend, hydrogen storage would be required that will drive costs up.

Since however Cyprus does not have an existing gas pipeline network to leverage on, any new pipeline project should be able to carry hydrogen in any blending ratio, even in pure form. Such a pipeline network would have to be built using higher grade alloys or high purity steel employing smooth welds to allow for the higher pressures (typically 65 to 100bar) required to increase the calorific flow. Alternatively, plastic (polyethylene) pipes can be built, but these allow pressures only up to 30bar.

There are some cases of buildings with high electricity and heat load demands (such as hotels) for which hydrogen Fuel Cells have emerged as a competitive option[11]. This needs to be investigated further, but Cyprus is dominated by cooling demand (which is not a very good fit with a fuel cell), even though electricity is expensive. It is therefore **not considered a prime candidate location for the development of hydrogen FC and boiler systems** and calculations will not assume demand in these sectors because:

1. Direct electrification via heat pumps is forecasted to be more energy efficient, less expensive and more mature at an earlier stage; and
2. There is very limited heating demand, and hence the main use of FC systems in heating mode is mostly redundant. Heat pumps on the other hand can work in dual mode of both heating and cooling, the main need during the summer months in Cyprus.

3.7.2 *Road transportation*

Passenger cars

Hydrogen passenger vehicles garnered a lot of attention a few decades ago when the engineering advances in fuel cells made the use of compressed hydrogen onboard vehicles a possibility. Hydrogen Fuel Cell (FC) cars became commercially available in 2014 but only around 26,000 such cars were sold by the year 2020 since their sales first began [58]. The market penetration of these vehicles has not been very deep mainly because as a source of work, fuel cells are only 60% efficient (considerably less than electric motors), they are quite more complex, and building a hydrogen refuelling station is also very costly.

There are still fewer than 20,000 heavily subsidised hydrogen FC vehicles on the roads globally, served by around 400 almost exclusively publicly funded hydrogen filling stations [59]. A few commercial passenger cars exist in the market today, albeit restricted to Japanese and Korean automakers (Toyota, Hyundai, and Honda), spurred on by domestic hydrogen support policies. Vehicles of this size exhibit low round-trip efficiencies, essentially restricted by physics, since there are several unavoidable steps between the energy source and motive energy at the wheels: Any renewable energy that acts as a feedstock (typically solar or wind) must be converted to electricity to drive the electrolyser, then compressed (or liquefied), transported, stored, reconverted to gaseous form, converted back to electricity through the on-board fuel cell, and finally converted to mechanical energy through an electric motor. **The final energy at the wheels is around 30% of what was generated,** a fact that should prioritise investment in BEVs, if one would conform with the ‘energy efficiency first’ principle of the EC. The general position of the EC is that hydrogen utilisation in passenger cars is not considered a priority.

We therefore **do not expect hydrogen to play a role in the energy transition of the passenger vehicle sector in Cyprus**, considering the advances Battery Electric Vehicles (BEVs) and associated

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[11] E.g., the Radisson Blu Hotel in Frankfurt

infrastructure have made in the last few years. The main current drawbacks of BEVs (limited range and prolonged charging times) are partially negated by the short distances drivers usually travel, and hence hydrogen for passenger cars in not considered a solution that is explicitly modelled in this study.

Buses

Public transportation in Cyprus is served only by buses and therefore only those are discussed in this subsection. Hydrogen Fuel Cell (HFC) buses have been developed and trialled in Europe for more than a decade through various prototype vehicles or demonstration projects to test large fleets in the field. A key challenge of the commercialisation of HFC buses relates to the high ownership costs, as well as the high hydrogen infrastructure costs. The production costs for 12-metre hydrogen fuel cell buses are still much higher than standard diesel and electric buses. As in 2017, the purchase cost for such a bus was around €1m, while the cost for a battery electric bus was around €450k, and the cost of a standard diesel bus was around €250k. [60], [61]. These costs are expected to fall as the annual production numbers increase. ICCT Europe estimated that FCEV trucks in Europe will have a retail price at just under €400,000 in 2022, and projects the cost to fall to around €220,000 per vehicle by 2030 [62].

Pre-commercial demonstration projects in place currently in Europe, such as the Joint Initiative for hydrogen Vehicles across Europe (JIVE) and JIVE 2 project, will pave the way to commercialisation by addressing the issues of high upfront vehicle costs, which together with infrastructure are the main barriers for the adoption of HFC buses. The overall objective of these initiatives is to unlock economies of scale through the large-scale deployment of vehicles and infrastructure in different cities in Europe. Thus, by the end of the projects, the costs for the HFC buses are reduced enough so they are commercially viable for the bus operators to include them in their fleet without the need for a subsidy aiming at a maximum price of €625k for a standard (12-metre) HFC bus thanks to economies of scale [63], [64]. The overall price of FC buses is expected to fall to around €325k by the year 2030 as the cost of the components of the FC powertrains such as the fuel cells, hydrogen tank and battery, drop significantly. However, as those buses have not been manufactured yet in large-volume series, it is difficult to estimate the related costs precisely.

The advantages of the HFC buses over the BE buses is that they perform like traditional diesel buses. The current range of the HFC buses, up to 450km, is sufficient to cover the expected daily mileages of long-range bus segments and they can be refuelled in less than 10 minutes. The refuelling stations are likely to be in or close to the bus depot, eliminating the need for roadside charging infrastructure, and (in the case of Cyprus) close to an industrial / port cluster that would be utilizing hydrogen for other end uses.

Although there are a variety of factors that influence the choice of technology, such as the cost of acquiring buses and operating them[12], refuelling time and vehicle range, the total cost of ownership (TCO) is ultimately what matters the most to bus fleet operators. Cost analysis available in the literature shows that fuel cell technologies would be as suitable option for the decarbonisation of long-range bus segments. In bus segments with short ranges, BEVs are expected to become the most energy efficient and competitive low carbon alternative [65]. Accounting for the fact that the average daily mileage of buses in Cyprus is only around 150km, hydrogen is hence not considered as the most suitable decarbonisation option for the bus sector in Cyprus.

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[12] Operational costs include vehicle maintenance and fuel cost which depends on the production, transmission costs, as well as the infrastructure cost for refuel or charging.

Heavy-duty road transport

In contrast to HFC buses, hydrogen-powered heavy-good vehicles (HGVs) have begun on-road demonstrations in the last couple of years but are still low in production levels to enable a commercial market. A detailed survey on trial and demonstration projects with HGVs is available by Ruf *et al*. [66]. Currently, due to low prototype production volumes, the production cost for HFC HGVs is high. Successful commercialisation and market integration of HFC HGVs will depend on lowering their TCO and dealing with the lack of sufficient refuelling infrastructure for HFC HGVs. Likewise, BE HGVs face limitations regarding the charging time requirements as well as the battery weight and price, which constraint their range and payload. Nevertheless, BE HGV progress benefits from industry experience in smaller vehicle segments such as passenger cars and light-duty vehicles which have a head start of several years over HFC powertrains [66], [67]. Therefore, the technological readiness of BE HGVs is higher compared to HFC HGVs, with the former being at a pre-series stage demonstrated in operational environments, while the latter being at a prototype stage demonstrated in relevant environments [66].

Currently, there is very limited field data on zero-emission powertrains for HGVs, i.e., BEV and HFC. There is big uncertainty around predicted performance and cost developments of the vehicles, which are mainly based on assumptions and limited data from the prototypes or small-scale demo phases. Therefore, industry knowledge needs to be verified in first demonstrations and early commercial deployments.

Several studies comparing the TCO of the alternative powertrains have shown that the most economical solution for zero-emission HGVs is the electric powertrain since the vehicle purchase cost, as well as the infrastructure cost for fuel cells is significantly higher compared to the alternative electric powertrains [68]–[71]. However, some studies have shown that fuel cell vehicles might be more cost-competitive compared to electric HGVs with a battery range of 800km [72], [73].

According to the data used in a recent project by the UK Energy Systems Catapult (ESC), on average rigid HGVs cover 242km daily and articulated HGVs 412km daily Freight [70]. Since articulated HGVs cover longer distances compared to rigid HGVs, as expected, the powertrain costs of the former will be higher compared to the latter due to bigger batteries and bigger hydrogen fuel tanks. In 2025, the CAPEX of an average rigid electric HGV and an average rigid fuel cell HGV is projected to be around €100k and €207k respectively, while the cost for a baseline diesel powertrain is expected to be around €78k. For the same year the CAPEX of an average electric articulated HGV and an average articulated fuel cell HGVs is projected to be around €163k and €255k respectively, while the cost for a baseline diesel articulated powertrain is expected to be €82k. The study reached the conclusion that, based on today’s assumptions, expected market developments and the foreseeable technology cost reductions, **battery electric long-haul trucks and those using an overhead catenary infrastructure are likely going to be the most cost-effective pathway to replace the vast majority of today's diesel-powered vehicle fleet and, eventually, reach zero well-to-wheel road freight GHG emissions by 2050.**

In Cyprus, the distances HGVs cover are much lower than what HGVs cover in most other European countries, and hence the above conclusion will be even more pronounced for a smaller country. This does not however disqualify this option outright, as there are conditions that can be engineered to be favourable for HGVs, e.g., the co-development of infrastructure with industrial clusters and port facilities that will require hydrogen in the future. Also, the total cost of ownership for both buses and

HGVs is declining and combined with falling costs of key equipment (predominantly the power train), would make for a compelling option for a decarbonised fleet.

Figure 15: Simplified supply chain for hydrogen delivery and use for heavy duty road transportation

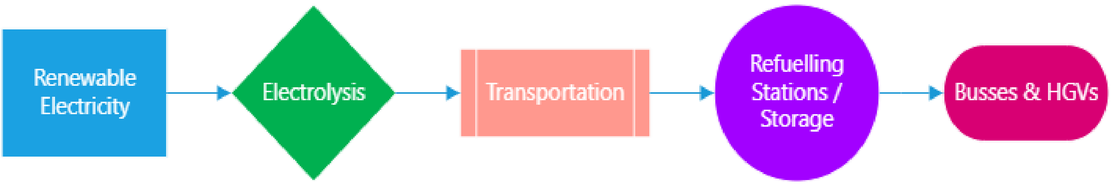


Table 14 shows the results from a theoretical penetration of hydrogen in public transport and freight fleets in Cyprus in 2030 and 2050 under the usual scenarios – cautious and aggressive. Data for the assumptions on fuel use in these sectors are taken from internal modelling data used for the NECP for Cyprus calculations, and the energetic conversion between diesel and H_2 is assumed to be based on an ICE engine efficiency of 42% in 2030 and 44% in 2050, and 60% and 65% for H_2 respectively.

Table 14: Assumptions and results for the penetration of renewable hydrogen in the public and freight transport sectors.

	2030		2050	
	Cautious	Aggressive	Cautious	Aggressive
Consumption of fossil fuels in Public Transport (PJ)	1.704		0.000	
Consumption of fossil fuels in Freight Transport (PJ)	6.812		5.043	
Public Transport conv. to H2	0%	20%	10%	50%
Freight Transport conv. to H2	0%	10%	10%	50%
Public Transport (H2 PJ)	0	0.2385	0.0000	0.0000
Freight Transport (H2 PJ)	0	0.4768	0.3414	1.7070
Public Transport (H2 MWh)	0	66,262	0	0
Freight Transport (H2 MWh)	0	132,449	94,832	474,161
Public Transport (H2 tonnes)	0	2,008	0	0
Freight Transport (H2 tonnes)	0	4,014	2,874	14,369
Renewable electricity required (MWh)	0	287,662	128,036	640,181
PV Capacity (MWp)	0	112	47	237
Costs (€m)				
Generation	0	67.4	19	94.8
Electrolysis	0	18.1	19.9	38.1
Fleet	0	161.5	66.3	331.6
Refuelling infrastructure	0	41.2	19.6	59
Total	**0**	**288.3**	**124.8**	**523.6**

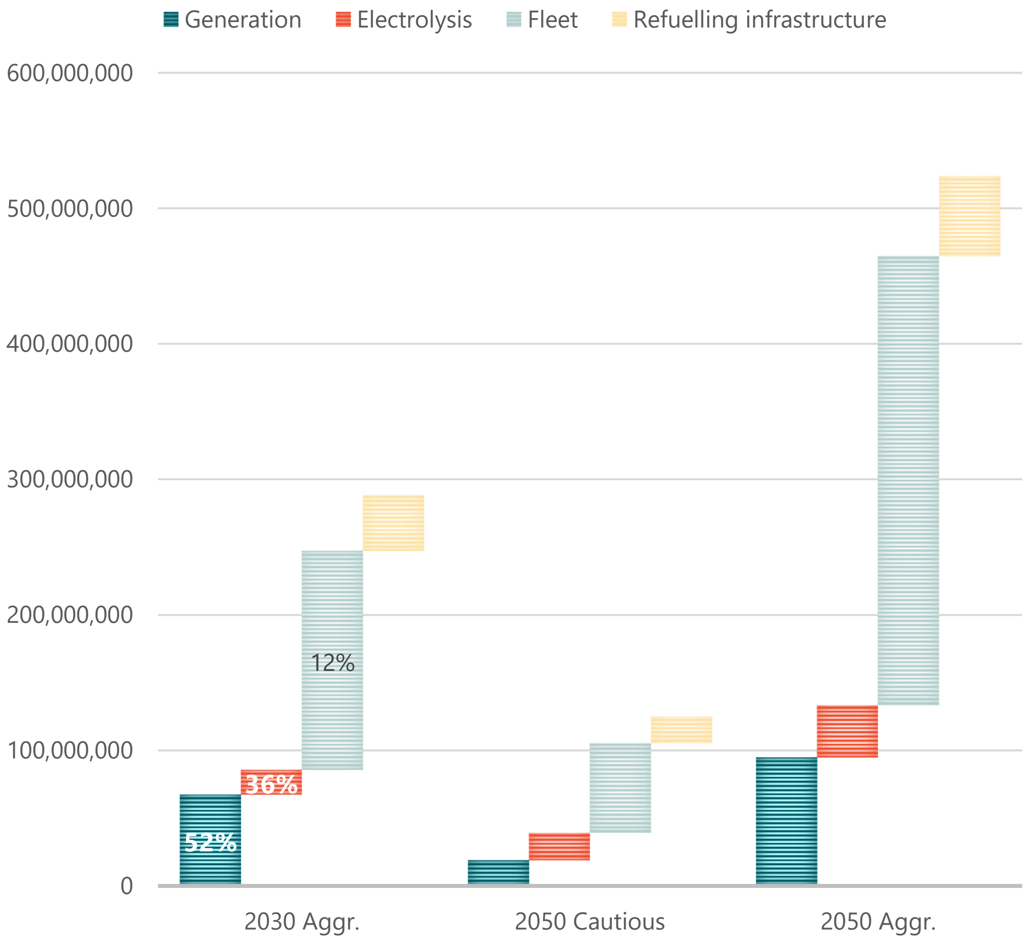
The cost assumptions for the fleet are based on a FCEV vehicle cost data of €220,000 for 2030 and €150,000 for 2050 found in Basma et al. [62]. Refuelling costs and capacities are based on a 2021 US

DOE factsheet [74]. The analysis assumes that 16 new refuelling stations will be needed in 2030 with a capacity of 1,000 kgH_2/d in 2030 and 28 such stations of 1,400 kgH_2/d in 2050. These are shown in Table 15, and the resulting investment costs are illustrated in Figure 16.

Table 15: Full set of assumptions for public and freight hydrogen-based transport sector in Cyprus

	2030		2050	
	Cautious	Aggressive	Cautious	Aggressive
Total distance (km)	0	73,433,360	44,210,769	221,053,847
Hydrogen Buses and Trucks Specific Energy Consumption (kgH2/100km)	8.2	8.2	6.5	6.5
Yearly km travelled by 1 vehicle (km)	100,000	100,000	100,000	100,000
Total vehicles (buses and trucks)	0	734	442	2,211
Cost per vehicle	€ 220,000	€ 220,000	€ 150,000	€ 150,000
Fleet cost	€ 0	€ 161,553,392	€ 66,316,154	€ 331,580,770
Refuelling station capacity (kgH2/day)	1,000	1,000	1,400	1,400
Refuelling stations	0	16	6	28
Refuelling Cost (kgH2/d)	€ 2,500	€ 2,500	€ 2,500	€ 1,500
Total refuelling station costs	€ 0	€ 41,243,394	€ 19,682,877	€ 59,048,630
Cost per station	€ 0	€ 2,500,000	€ 3,500,000	€ 2,100,000

Figure 16: Hydrogen investment costs in the Public and Road Freight sector



3.7.3 *Airports and aviation*

Hydrogen for use in aircraft has long been touted as one of the possible technologies to decarbonise the aviation sector. There is a lot of activity both from start-ups and from mainstream manufacturers of airplanes (e.g. [75]) for a future that heavily relies on renewable hydrogen. The economics however are not favourable at the moment: assuming advances in propulsion technology, higher compression containers and solution of issues of storage of liquid H_2 onboard, a switch to hydrogen would result in price increases in the range of 10-60% per passenger, depending on size of aircraft [76]. Yet, it is believed that 2030 may be the cut-off point where the use of liquified H_2 in pressurised cryogenic tanks can become economical, but only for short-haul flights (i.e., covering distances under 1,500 km). Decarbonisation of the sector must address the long-haul flights, which account for over 80% of its emissions. The European Commission in its recent transport vision document [77], envisages large commercial hydrogen planes to be ready by 2035.

The industry is not relying only on pure hydrogen using cryogenic tanks for propelling aircraft. A dominant trend in the attempts to decarbonise the aviation sector is the use of synthetic fuels (also called ‘electrofuels’), that are derived from the reaction of renewable hydrogen with CO_2, either from waste gas or from direct air capture as recently reported by Boeing and CSIRO [78]. It is argued by several industries of the sector that the cost of these fuels remains high (in the order of 8 times that of kerosene), but these will eventually fall and be de-risked after 2030, settling at a level of around 1.5-2 times that of conventional fuels. It is thus more prudent, according to them, to adopt a staggered blending of these fuels with traditional jet fuel until their complete adoption by 2050. These scenarios are favourable to the aviation industry as it stands now, since few changes will need to happen in aircraft, engine, and airport design [79].

For Cyprus, flights that serve the usual destinations departing the island are mostly travelling towards Europe, mainly Greece, Russia (pre-invasion), and the UK. In the case of Greece, the major urban centres (Athens for the most part, but also Thessaloniki) are within the 1,500km range, as are the numerous holiday destinations in the Aegean and Ionian seas. The UK that traditionally has business, education and family ties with Cyprus is well outside this range and cannot be served by such planes in the short and medium term.

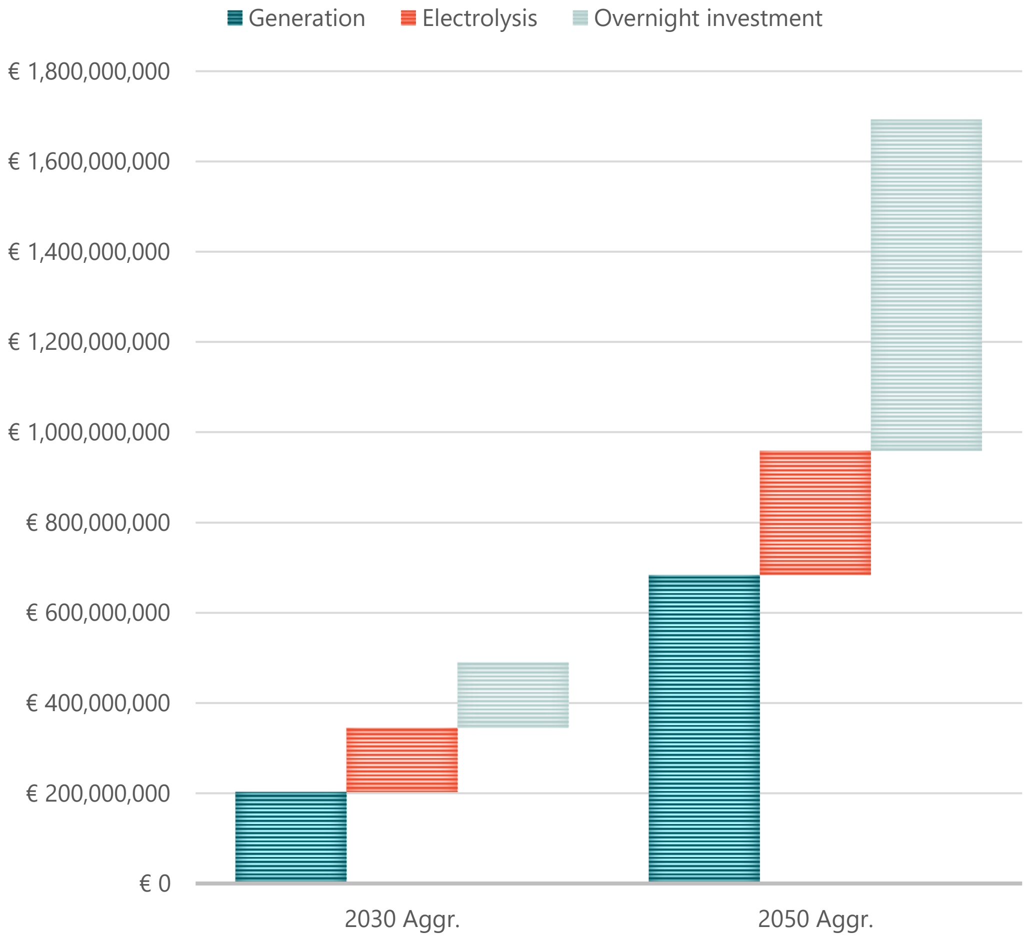
A different approach to the use of hydrogen in aviation is the establishment of a refuelling hub in Cyprus for hydrogen planes that will link flights between Europe and the Middle East. Increased research activity in the area has been happening in the last few years, mostly in the re-design of airports for the safe and effective utilisation of hydrogen in airport facilities (incl. refuelling of aircraft), the upstream H_2 value chain (storage, transportation, distribution), and the decarbonisation of peripheral airport systems using renewable hydrogen (e.g., aircraft ground service equipment, logistics equipment, etc.). Facilities for renewable hydrogen production could be located close to the airport to minimise these associated costs.

As with the discussion about methanol, the challenge lies with the source of carbon for the hydrocarbon synthesis. Table 16 shows the quantities that would be required to replace a certain percentage of aviation fuel with e-kerosene derived from renewable hydrogen, and Figure 17 illustrates the associated investment costs. A detailed study on the merits of e-fuels for an isolated energy system and the source of carbon through synergies with other emitters (e.g., power stations) may be needed to weight the costs and benefits of such an approach, which is beyond the scope of this report.

Table 16: Projections for hydrogen requirements and costs for replacing 10% in 2030 and 50% in 2050 in the aggressive scenario of the aviation fuel delivered to customers in Cyprus. Data for past sales are from CYSTAT (2022), Techno-economic data have been provided by E3Modelling in the frame of this project. Overnight costs include infrastructure for sourcing the necessary carbon for the fuel synthesis and are taken from [80].

Fuel	2018	2019	2020	2021	2030		2050	
					Cautious	Aggressive	Cautious	Aggressive
Aviation kerosene	311,432	297,780	93,077	152,510	350,000	315,000	400,000	400,000
Total e-kerosene (tonnes)						35,000		200,000
e-kerosene (MWh)						427,000		2,440,002
Hydrogen required (MWh)						597,800		3,416,003
Electricity required (MWh)						865,403		4,612,065
PV Capacity (MWp)						338		1,708
Costs								
Generation (€million)						202.8		683.2
Electrolysis (€million)						141.9		275
Overnight investment (€million)						145.3		734.5
Total (€million)						**490.1**		**1,692**

Figure 17: Investment costs in synthesizing e-kerosene



Aside from this analysis, there is intense discussion in EU circles about the implementation and the mandated blending ratios of e-fuels in upcoming EU legislation that will concern aviation in the frame of the “Fit-for-55” policy package. If a specific target is indeed implemented, then a minimum amount of e-kerosene originating from renewable hydrogen will be required to be supplied to all aircraft in airports within the EU. This is both an obligation and an opportunity for Cyprus. In addition, the latest expansion of the EU ETS to fully include the aviation sector will impact pricing of the fuels and might disadvantage nations that overly rely on aircraft for travelling purposes. There is discussion at the time of writing (December 2022), as part of the negotiations among EU bodies on the amendments to the ETS Directive and the adoption of Regulation ReFuelEU Aviation, to provide some incentives for a degree of exemption from this impact for isolated and island locations that use renewable e-fuels. This aspect should also be considered by national authorities as it could offer an economic incentive to fuel suppliers to tank with e-kerosene, even beyond the minimum blending requirements, in Cypriot airports.

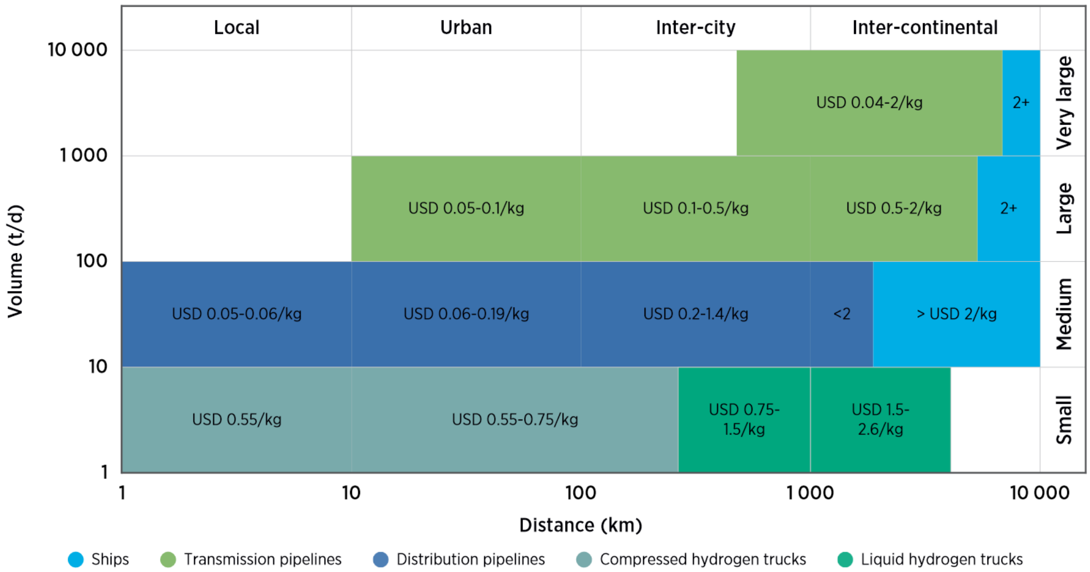
3.7.4 Transport and distribution of hydrogen, Imports, and exports

3.7.4.1 Overview

The most appropriate mode for transporting hydrogen depends on the distance and the volumes involved. The chart in

Figure 18 shows the appropriate mode of transportation based on these two parameters: smaller volumes and short distances are better served on land by trucks carrying compressed[13] hydrogen, but for longer terrestrial destination liquefaction should be preferred[14]. Distribution and transmission pipelines are the preferred mode for short and medium distances but larger volumes, with ships becoming the best option over bodies of water and long travel distances, usually via a hydrogen derivative such as ammonia [45].

Figure 18: Hydrogen transport cost based on distance and volume. Source: [45], adapted from [81].



The following table, adapted from [45] with added context for Cyprus, shows the state-of-the-art of the considerations for various transportation modes of hydrogen. This is directly influencing the import and export options of the island

Table 17: Major advantages and disadvantages of potential hydrogen carriers for Cyprus

Carrier	Pros		Cons	
	++	+	--	-
Ammonia (NH_3)	- Already produced at scale - Low transport losses - High energy density	- Can be used directly in destination (e.g., fertiliser plants - Easy to liquefy (compared to LH2)	- Cracking has high energy consumption and high heat requirements - Cracking infrastructure very sparse in Cyprus' vicinity	- NH_3 synthesis quite energy intensive - Ship engines using ammonia not yet fully commercialised - High NOx emissions (requires flue gas treatment) - Toxic and corrosive
Liquid hydrogen	- Easy regasification at destination - Guaranteed carbon-free	- No need for purification and destination	- Very high losses (30-40%) for liquefaction process - Boil-off (0.05-0.25% per day)	- Available only at small scales

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[13] Typical pressures are 70-100 bar for transport by pipeline and 350-700 bar for road transport applications (350 bar mostly for buses and trucks and 700 bar for passenger vehicles)

[14] Liquefaction of hydrogen happens at very low temperatures (around 20 – 21 K) where the volumetric density can reach 70.8 kg/m^3 but storing hydrogen in liquid form is time and energy consuming as there are losses inherent in the process that can reach 45% of the energy content of the H_2 itself.

Carrier	Pros		Cons	
	++	+	--	-
	transportation (if via green H2) - Liquefaction already commercial (but not at massive scale)		during shipping and storage - Hydrogen-powered ships are not yet available	
LOHC	- Easy transportation using existing infrastructure - Low capital costs		- High (25-35%) energy consumption for dehydrogenation - Requires high-temperature heat (150-400°C) for dehydrogenation - Only 4-7% of the weight of the carrier is hydrogen	- Potential emissions in various stages not easy to control
Gaseous hydrogen (via pipeline)	- Transport and storage are proven at a commercial scale - Existing network can be repurposed to hydrogen	- No conversion is required (only compression)	- Gas network non-existent in Cyprus - Cost increases significantly for offshore pipelines - Storage of pure hydrogen in geological formations in unproven and possibly unavailable for Cyprus	- Not all the pipeline materials are suitable for hydrogen - Blending with NG only brings modest emissions reductions, and high GHG mitigation costs

3.7.4.2 Transportation via pipeline

Bulk transportation of hydrogen via pipeline is the preferred method for large volumes and large (but not intercontinental) distances (

Figure 18). The larger the volume the better option a pipeline is, as the material costs required to construct the pipe scales up less rapidly compared to the carrying capacity of the pipe. The principal option in locations with a mature NG distribution and transmission network is to repurpose NG pipelines, but his is not an option for Cyprus that does not possess any. Blending is also not a possibility as of now for the same reason and is an option with significant potential downsides such as limited CO_2 reduction potential, potentially low tolerance of blends in end users, a high mitigation cost, regulatory uncertainty, and a purity cost in case H_2 needs to be separated from the blend.

Transporting hydrogen in dedicated pipes is already mature business with 4,600 km of such infrastructure already in existence in North America and Europe [45]. The transportation of hydrogen in pipelines in a marine environment poses an additional challenge however and is around 2.5 and 3 times more expensive than land-based ones. Table 18 is a list of calculations for exporting 20,000 tonnes of Hydrogen in 2030 (in the aggressive scenario) and 100,000 tonnes in 2050. The pipeline diameter is calculated using data from [82], and the specific cost is an average of several studies aggregated and reported in [45], after applying a multiplier of 2.5 to account for the cost of laying pipelines on the seabed.

Table 18: Projections for costs of hydrogen via pipeline exports to the island of Crete.

Fuel	2030		2050	
	Cautious	Aggressive	Cautious	Aggressive
H2 exports planned (tonnes)	0	20,000	0	100,000
Hydrogen required (MWh)	0	660,000	0	3,300,000

Electricity required (MWh)	0	955,446	0	4,455,446
PV Capacity (MWp)	0	373	0	1,650
Production Costs (€m)				
Generation		234		660
Electrolysis		157		266
Pipeline Costs				
Flow (kg/s)		0.63		3.17
Pipeline diameter (cm)		12		28
Distance (km)		700		700
Specific cost (€/km)		1,300,000		2,500,000
Pipeline costs (€m)		910		1,750
Total (€million)	**€ 0**	**1,291**	**€ 0**	**2,676**

3.8 Overall assessment

Table 19 below is an assessment by the authoring team of the production and end use pathways considered revenant for Cyprus. Based on the analysis of these topics in the paragraphs and sections above, an overall grade of suitability for Cyprus is proposed (in the last column of the table) on a scale of A (high probability of success) to E (very low probability of success). The column titled ‘T/E calculations’ refers to technoeconomic calculations that quantitatively support the roadmap.

Table 19: Assessment table of production and end use pathways of hydrogen in Cyprus

Product / End use	Carrier	T/E calculations?	Possible synergies	Overall grade
Hydrogen	Renewable Electricity (green H2)	Yes	*(all end use sectors)*	A
	Natural Gas Steam Methane Reforming (Grey H2)	No	*(all end use sectors)*	E
	NG SMR with CCS (Blue H2)	No	*(all end use sectors)*	D
Shipping	Green Ammonia	Yes	Trucking at port / industrial clusters / power generation / fertilisers	A
	Methanol	No	Trucking at port / chemicals	D
Aviation	Synthetic fuels	Yes	Industrial clusters, port facilities, refuelling stations for Heave Good Vehicles	C
Power generation	Hydrogen	No	Trucking / industrial clusters	D
	Green Ammonia	No	Port facilities	E

Product / End use	Carrier	T/E calculations?	Possible synergies	Overall grade
Industry	Cement	Yes	Trucking at port / industrial clusters	C
	Steel	No	Trucking at port / industrial clusters / Export green steel / feed local and regional industry?	D
	Glass	No	Trucking at port / industrial clusters	D
	Aluminium extrusion	No	Industrial clusters	E
	Copper Mining	No	Hydrogen trucks	D
	Ceramics	Yes	Trucking at port / industrial clusters	C
Buildings	Fuel Cell Systems	No	Transportation	E
	NG Blending	No	Industrial clusters / use in port facilities	E
Transportation sector	Heavy Goods Vehicles and Buses	Yes	Industrial clusters / ports	B
	Passenger Cars	No	Other fuels stations / EV chargers / Domestic sector	D
Export/import and hydrogen transmission and distribution	As ammonia	Yes	Trucking at port / industrial clusters / Power Generation / Fertilizers	B
	As Liquified H2	No	Trucking at port / industrial clusters	C
	Via LOHC	No	Trucking at port / industrial clusters	D
	Via terrestrial and undersea pipelines	Yes	Trucking at port / industrial clusters	C

Table 20: Overall quantities and costs for the introduction of Hydrogen into the Cypriot economy. Costs include all hydrogen generation infrastructure as well as the necessary costs for each end use. They generally do not include transportation and storage costs.

	H2 demand 2030 (MWh)		H2 demand 2050 (MWh)		H2 cost 2030 (€million)		H2 cost 2050 (€million)	
End use	Cautious	Aggressive	Cautious	Aggressive	Cautious	Aggressive	Cautious	Aggressive
Industry (existing)								
Metal (aluminium)								
Ceramics	0	0	0	46,101	€ 0	€ 0	€ 0	€ 14
Cement	0	69,151	0	270,843	€ 0	€ 0	€ 45	€ 110
Publishing and printing								
Paper								
Plastics								
Textiles								
Tobacco								
Food								
Pharmaceuticals								
Industry (possible future)								
Copper mining								
Steel								
Glass								
Shipping								
Ammonia	0	1,507,850	0	7,799,822	0	326	0	1,734
Methanol								
Transport Sector								
Public Transportation	0	66,262	0	0	0	288	124	523

Freight Road Transport	0	132,449	94,832	474,161				
E-Fuels & Aviation	0	597,800	0	3,416,003	0	490	0	1,692
Other								
Power Generation (blending)								
Power Generation (dedicated)								
Buildings								
Export		660,000		3,300,000	0	1,290	0	2,675
Total	**0**	**3,033,512**	**94,832**	**15,306,929**	**0**	**2,395**	**170**	**6,750**

3.9 Supporting policy and activity

EU legislation is affecting the deployment of a variety of hydrogen applications, production, storage, transport, distribution etc. The corresponding legislative acts have direct or indirect impact on hydrogen projects. Often, the projects are included within the scope of a wider regulatory area, covering health and safety, labour law and environmental law. An important number of these legislative acts are source of obligations to project developers and operators.

The major part of the EU legislation relevant to the production, storage, transportation, and distribution of hydrogen is presented in the following table. Additionally, the legislation related to the use of hydrogen as a fuel and the refuelling infrastructure is included. To this, one has to consider additional legislative measures that are still under discussion at EU level, most notably i) the gas package and ii) the delegated act on the rules that will govern the requirements for hydrogen to be certified as renewable.

Table 21: Main Directives and Regulations Governing Hydrogen in Cyprus

Directives and Regulations at the EU Level
Directive 2012/18/EU on the control of major-accident hazards involving dangerous substances (so-called SEVESO Directive) ** Annex I, Part 1, establishes Hydrogen as a dangerous substance and lists the quantity of hydrogen for the application of lower-tier requirements (≥ 5t) and upper-tier requirements (≥ 50t).*
Directive 2014/34/EU on the harmonisation of the laws of the Member States relating to equipment and protective systems intended for use in potentially explosive atmospheres (recast) (so-called ATEX Equipment)
Directive 1999/92/EC on minimum requirements for improving the safety and health protection of workers potentially at risk from explosive atmospheres (so-called ATEX Workplace)
Council Directive 98/24/EC on the protection of the health and safety of workers from the risks related to chemical agents at work
Directive 2010/75/EU on industrial emissions (integrated pollution prevention and control) (IED)
Directive 2004/35/CE on environmental liability regarding the prevention and remedying of environmental damage ** The Directive applies to the production to Hydrogen by reference to Annex I, point 4.2 of Directive 2010/75/EU on industrial emissions*
Directive 2011/92/EU on the assessment of the effects of certain public and private projects on the environment (EIA Directive)
Directive 92/43/EEC on the conservation of natural habitats and of wild fauna and flora
Directive 2009/147/EC on the conservation of wild birds
Regulation 1272/2008/EC on classification, labelling and packaging of substances and mixtures (so-called CLP regulation)
Directive 2014/68/EU on the harmonisation of the laws of the Member States relating to the making available on the market of pressure equipment
Directive 2014/94/EU on the deployment of alternative fuels infrastructure (AFID)
Directive 2014/29/EU on simple pressure vessels
Directive 2008/68/EC on the inland transport of dangerous goods
Directive 2010/35/EU o on transportable pressure equipment
Commission Regulation (EU) No 453/2010 on the Registration, Evaluation, Authorisation and Restriction of Chemicals (so-called REACH)

Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources (RED II)
Directive 98/70/EC relating to the quality of petrol and diesel fuels
Directive (EU) 2015/652 on laying down calculation methods and reporting requirements pursuant to Directive 98/70/EC
Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (Recast)
Directives and Regulations at the National Level
Health and Safety (Tackling Risks of Large-Scale Accidents Related to Hazardous Substances) Regulations of 2015 (Κ.Δ.Π. 347/2015)
Urban Planning and Spatial Planning (Large-Scale Accidents Related to Hazardous Substances) Regulations of 2017 (Κ.Δ.Π. 76/2017)
Health and Safety (Minimum Requirements for the Protection of Persons at Work from Dangers from Explosive Atmospheres) Regulations of 2002 (Κ.Δ.Π. 291/2002)
Equipment and Protective Systems Intended for Use in Potentially Explosive Atmospheres Regulations 2016 (Κ.Δ.Π. 199/2016)
Environmental Impact Assessment of Certain Projects Law (N. 127(I)/2018)
Nature and Wildlife Protection and Management Law of 2003 (N.153(I)/2003)
Industrial Emissions (Integrated Pollution Prevention and Control) Laws 2013 to 2021 (N.127(I)/2021)
Locational Policy for Renewable Energy Sources Projects
Promotion and Development of Alternative Fuels Infrastructure Law of 2017 (N. 59(I)/2017)
Promotion and Encouragement of the Use of Renewable Energy Sources Law of 2022 (N. 107(I)/2022)
Specifications, Sustainability Criteria and Reduction of Emissions of Fuels Law of 2022 (N. 106(I)/2022)

3.10 Investment priorities and supporting policy

This section provides a summary of investment needs based on the scenario development presented in the previous chapters, accompanied by a mapping of the regulatory landscape for hydrogen in Cyprus now, and a separate section on regulatory proposals to accelerate the realisation of the vision outlined above.

3.10.1 Infrastructural needs

The results in this section are based on the generation and electrolysis assumptions presented in par. 2.2. The total generation, electrolysis and overnight investment costs are presented in Table 22.

Table 22: Total investment costs per scenario

	H2 cost 2030 (€million)		H2 cost 2050 (€million)	
	Cautious	Aggressive	Cautious	Aggressive
Generation	0	645	42	2,366
Electrolysis	0	423	36	952
Overnight Investments	0	1,328	91	3,432
Total	**0**	**2,395**	**170**	**6,750**

A more complete breakdown per sector is shown in Table 20 and Figure 19. The required quantities of hydrogen are illustrated (for the aggressive scenario only) in Figure 20. Evidently most of the projected demand is in ammonia and e-fuels, fuels that will be used in the maritime and aviation sectors, both being crucial for Cyprus, but also difficult to decarbonise. Overall amount of H_2 is substantial, but it’s only 0.5% of the pan-EU REPowerEU quota for 2030 (at 20Mt).

Figure 19: Overall forecasted investments

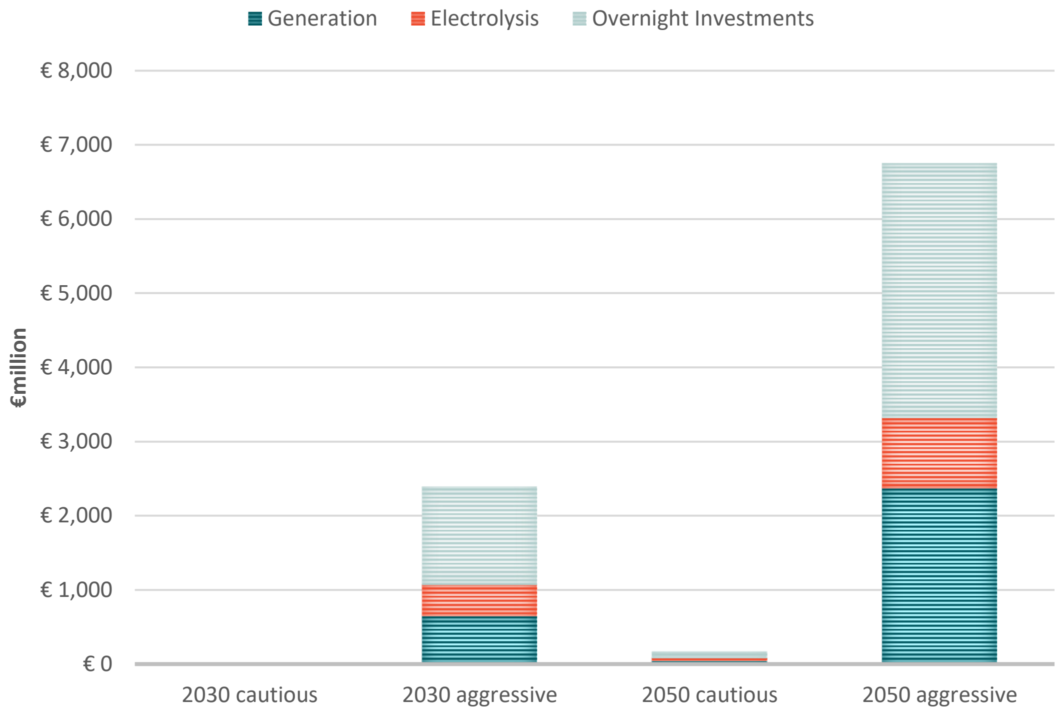
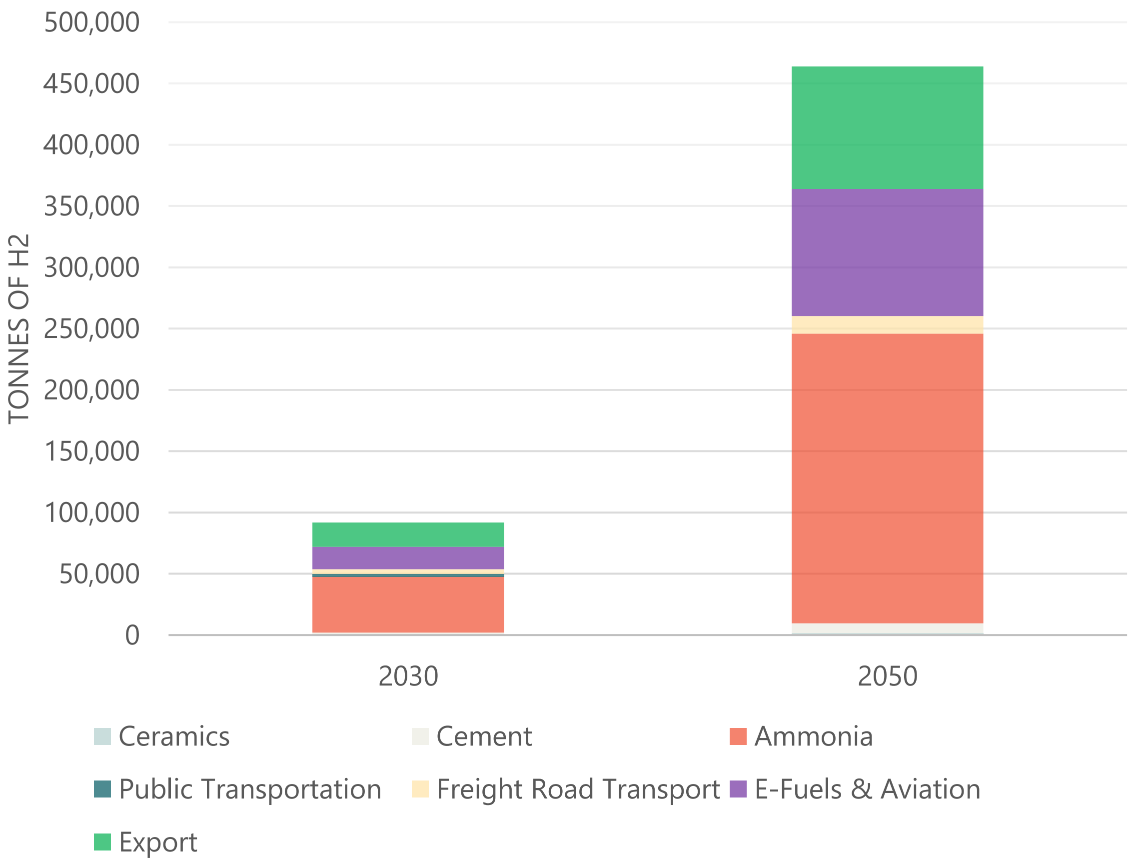
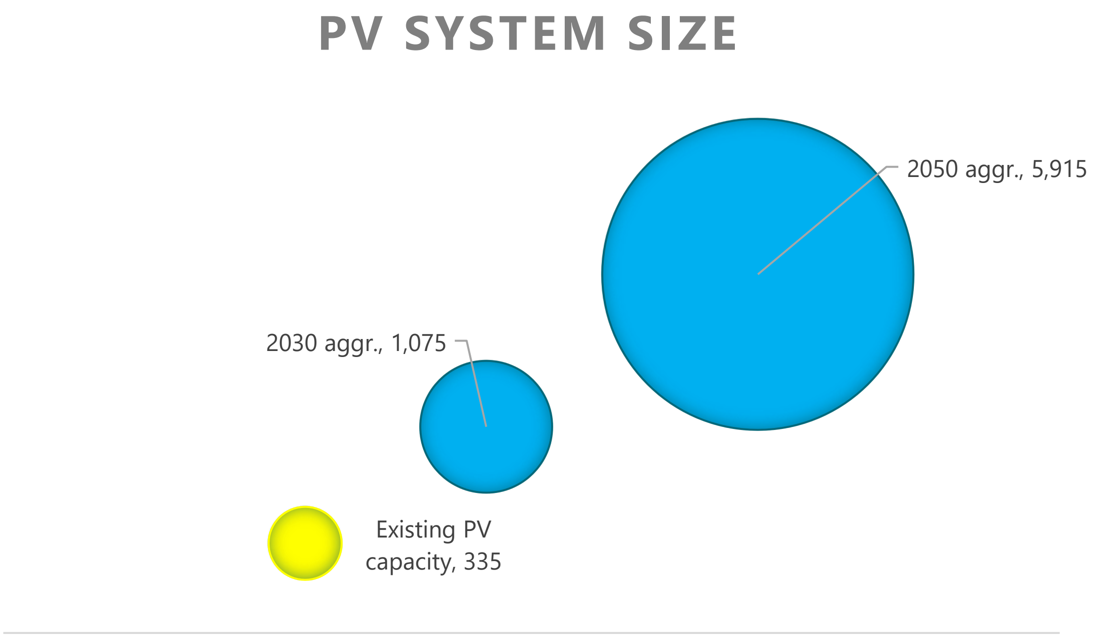


Figure 20: Tonnes of Hydrogen required in the aggressive scenario



The overall installed electricity generation capacity that such investment would require based on generation via PV is shown in Figure 21.

Figure 21: Relative size of PV capacity (in MWp) required to fulfil the aggressive scenarios.



This capacity would require 21 km^2 of land used for PV in 2030 and between 820,000 and 1,370,000 m^3 of feedstock water, based on requirements between 9 and 15 kg of freshwater per kg of H_2 produced. In 2050 however these numbers potentially rise to 102 km^2 of land used for PV, (equivalent to around 2% of the Republic's total land surface) and would need between 4 to 7 million m^3 of freshwater as feedstock. For comparison, annual production of treated wastewater[15], which is a resource that could be used to a large extent to produce renewable hydrogen, amounts to 11-13 million m^3.

3.11 Possible Follow up activities

This study has examined three different generation methods (see par. 2.2) based on a technoeconomic model that is geared towards large systems with electrolyser stacks over 1 MWe each. While in general terms appropriate, this approach lacks the necessary nuance to adequately inform policy makers for production costs using a mixture of renewables (typically PV and wind), does not factor in other types of RES (e.g., Concentrated Solar Power), and only makes blanket assumptions of the BoP costs such as storage and transportation infrastructure. For the purpose of highlighting the costs in 2030 and in 2050 this study is adequate, but a more detailed approach should be taken in a detailed roadmap setting. In addition, more electrolyser technologies should be examined (primarily PEM, but also SOEC that could be relevant for deploying with systems producing renewable heat).

Also, the model only informs about potential end uses via a dedicated, off-grid supply of renewable electricity. This should in the future be contrasted with the technoeconomic merits of supplying

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[15] See data from the Cyprus Water Development Department.

hydrogen using the grid, an approach that is more probable to be popular in the beginning of adoption but will very quickly face sizing constraints due to the sheer size of RES installations required to serve the potential end uses. Figure 21 shows the relative installed capacity of PV installations (using the assumptions in this report) that for 2030 are roughly equal to the total capacity of the electricity grid in Cyprus. This is clearly a cause for concern as this much RES production would have to be balanced by baseload generation and storage, something not considered in this study. The situation is even more pronounced in 2050.

The various storage solutions should also be investigated with more technoeconomic detail both in molecular hydrogen (either in gaseous form, compressed or liquefied) or in derivatives, principally ammonia and/or methanol. Other storage media such as metal hydrides and Liquefied Organic Hydrogen Carriers (LOHCs) should also be investigated with the same levels of detail. Moreover, Cyprus needs a systematic and rigorous survey of geological formations that would be suitable for hydrogen (and CO_2) storage, such as salt caverns and depleted aquifers since there are no hydrocarbon reservoirs to take advantage of yet. This survey of storage media should be followed up an optimisation of the full load hours at the energy system level by balancing electricity storage vs. storing hydrogen.

On the topic of Heavy Goods Vehicles and public transportation via buses, a full Total Cost of Ownership (TCO) analysis should be performed that would compare BEV, diesel, and hydrogen trucking in Cyprus. This should be accompanied by cost and benefit calculations that would consider not only the cost for deploying a certain solution, but also health benefits accruing from zero emission vehicles, and reduction in emissions in general.

The two sectors with the largest projected potential use (aviation and shipping) are examined in the detail required for the needs of this report. A more thorough examination for each however would require a closer look at the potential decarbonization alternatives and the role hydrogen may play in each. For example, the aviation sector can be decarbonized with renewable e-fuels, biofuels, direct use of renewable hydrogen (liquified or compressed), or even aircraft using batteries. These options can be contrasted in a more comprehensive and detailed manner. Similarly, the shipping sector faces options such as the use of ammonia, methanol, direct use of liquified hydrogen and even batteries. All these carry a long list of benefits, drawbacks and trade-offs that can be investigated in more detail for Cyprus.

Finally, the hydrogen technoeconomic modules and a more complete energy system based on hydrogen should be included in the OSeMOSYS model that the Cyprus Institute maintains and runs for the planning needs of Republic. This would allow deeper analyses that would include all other parts of the system, scenario building and running, and a more informed policy support and briefing on the potential penetration of hydrogen in Cyprus built on a cost optimisation model.

4 Summary and Conclusions

This report provides an overview of the prospects for deployment of hydrogen in the Cypriot energy system, reflecting the strong support envisioned in the EU Hydrogen Strategy and the REPowerEU initiative, and in light of the large uncertainties surrounding the technological and infrastructure development of this energy carrier, and in particular taking into account the specificities of Cyprus. After an extensive review of techno-economic data (including those provided by E3Modelling in the frame of this project as well as those more broadly available in the international literature), input from experts in the field, and interactions with national stakeholders, the following conclusions can be drawn:

- Small, isolated energy systems without a robust industrial base and without an existing natural gas infrastructure are a much less favourable case for rapid and deep hydrogen deployment.
- Because of the high renewable energy (mainly solar) potential of Cyprus, direct electrification by using low-cost renewable electricity is expected to be more energy and cost efficient than using hydrogen (produced via electrolysis) in low- and medium-temperature industrial processes as well as for satisfying the heating and cooling demand in the residential, public buildings and tertiary sectors.
- Electrification of passenger road transport is also expected to be more energy and cost efficient, than using hydrogen for this purpose, in particular in Cyprus where the distances are limited.
- However, hydrogen (or its derivatives) may be appropriate for other uses (such as in industrial clusters utilizing hydrogen in high-temperature industrial processes and for heavy-duty road vehicles, and in the maritime and aviation sector). Hydrogen is also an adequate option as feedstock for industrial processes, but Cyprus does not (yet) have such industries on its territory.

These findings, summarised in Table 23, have led to the definition of two preliminary scenarios – a ‘cautious’ and an ‘aggressive’ one – on the deployment of hydrogen by 2030 and 2050. The cautious scenario foresees almost no penetration of hydrogen in 2030. According to the ‘aggressive’ scenario, which has as a pre-requisite both strong infrastructure investments and fast technological progress, hydrogen use could evolve:

- In the cement industry, covering up to 10% of its energy needs if the infrastructure is available by 2030, and up to half of its energy needs by 2050;
- In the bricks and tiles industry after 2030;
- In trucks and buses, accounting for about 4% of total energy consumption in road transport and up to over 15% in 2050;
- In shipping and aviation, covering a very small fraction of fuel demand by 2030 and most of the fuel demand by 2050, in the form of hydrogen derivatives (most likely ammonia for shipping and e-kerosene for aviation).

The above will require active policy interventions and substantial investments in a) renewable energy capacity, b) electrolysers for hydrogen production, c) balance-of-plant projects that can be substantial in the cases of hydrogen derivatives, and d) equipment and vehicles for the use of hydrogen in the concerned sectors. The report provides an estimate of the different costs associated with the two scenarios mentioned above; these costs, especially the long-term ones for 2050, have to be treated with caution as many of the technologies are at present still at a low level of development and there is large uncertainty about the rate of technical progress (and the resulting potential future cost reductions) as well as the actual costs of building all the infrastructure needed for the entire supply chain of hydrogen.

In our report we have also reviewed the current regulatory environment. Based on that review, the findings mentioned above, and the outcome of the stakeholder consultation described in Chapter 4.2 and Annexes I and II of the Country Report, we are proposing two reforms and three investments to enable the launch of hydrogen production and use in Cyprus, in line with the REPowerEU priorities. These are described in Chapter 3.3 of the Country Report.

The outcome of this report and the data that have been collected and used for the technoeconomic calculations shown here will provide input for the revision of the country's National Energy and Climate Plan, which is due in a draft form in June 2023.

Table 23: Summary Table of end uses and intermediate processes for Hydrogen in 2030 and 2050 in Cyprus

	Renewable Hydrogen production				Storage and Transportation			End use infrastructure			
End use	Electricity Generation	Electrolyser	H2 Storage	Transportation	Conversion infrastructure	Derivative storage	Upgrades of existing infr.	Hydrogen Boiler	Fuel Cell	Refuelling stations	New vehicles / vessels
Industry (existing)											
Metal (aluminium)											
Ceramics	🟩	🟩	🟩				🟩	🟩			
Cement	🟩	🟩	🟩				🟩	🟩			
Publishing and printing											
Paper											
Plastics											
Textiles											
Tobacco											
Food											
Pharmaceuticals											
Industry (possible future)											
Copper mining											
Steel											
Glass											
Shipping											
Ammonia	🟩	🟩			🟩	🟩	🟩			🟩	🟩
Methanol	🟩	🟩			🟩	🟩				🟩	🟩
Transport Sector											
Public Transportation	🟩	🟩	🟩	🟩			🟩			🟩	🟩
Freight Road Transport	🟩	🟩	🟩	🟩			🟩			🟩	🟩
E-Fuels & Aviation	🟩	🟩			🟩	🟩	🟩			🟩	🟩
Other											
Power Generation (blending)	🟩	🟩		🟩			🟩				
Power Generation (dedicated)	🟩	🟩	🟩	🟩			🟩	🟩	🟩		
Domestic Sector											
Export	🟩	🟩	🟩	🟩							

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Appendix: A) Data received from E3M; B) Techno-economic calculations used in this report, available as Excel sheets

A) Data received from E3M

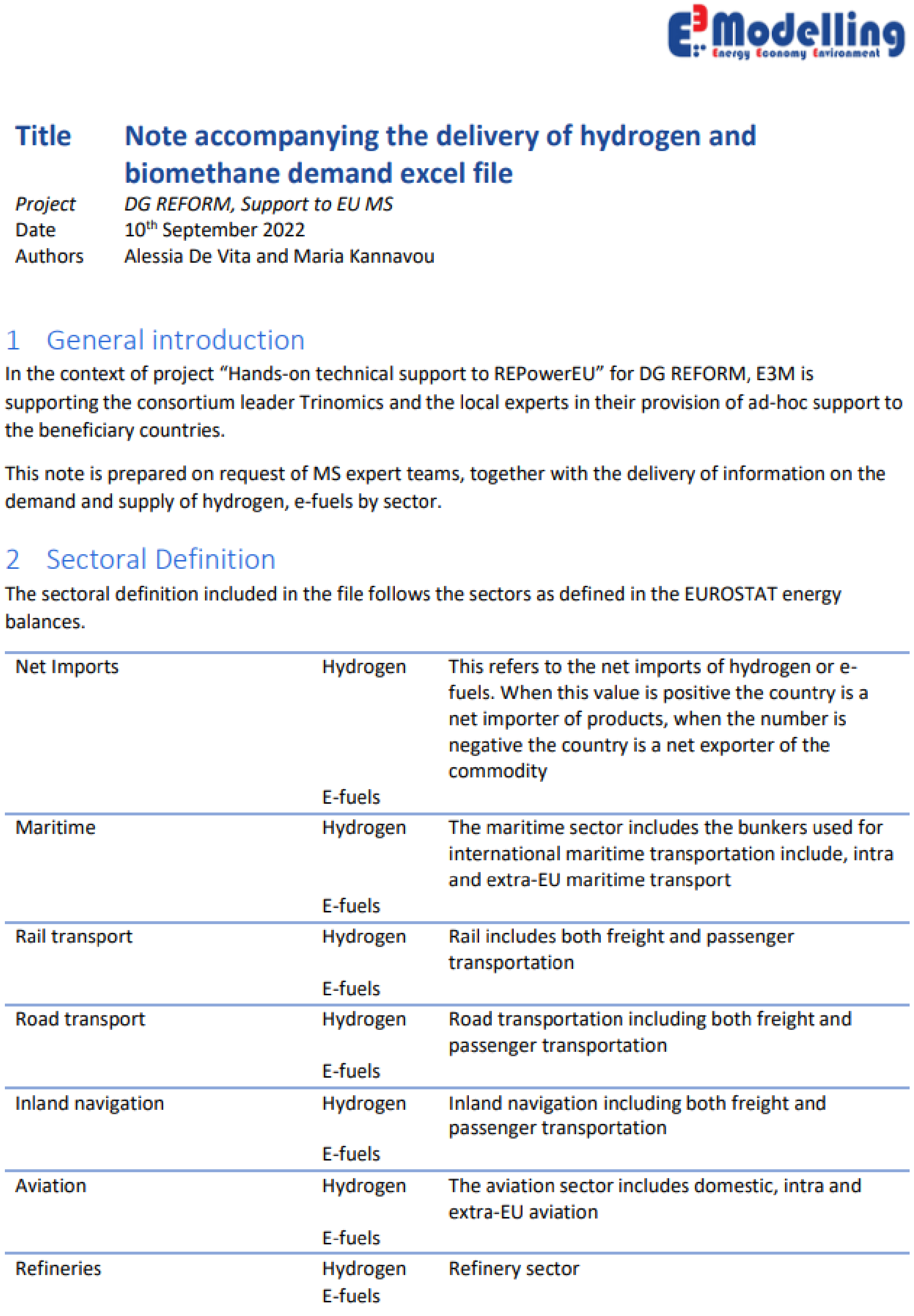
Table 24: Demand Projection for Hydrogen in Cyprus according to E3M

Hydrogen and e-fuels balance (GWh)

		2025	2030
Net Imports	Hydrogen		0 - 50
Maritime	Hydrogen		
	E-fuels		
Rail transport	Hydrogen		
	E-fuels		
Road transport	Hydrogen		35 - 80
	E-fuels		10 - 40
Inland navigation	Hydrogen		
	E-fuels		
Aviation	Hydrogen		
	E-fuels		30 - 50
Refineries	Hydrogen		
	E-fuels		
Power sector	Hydrogen		
	E-fuels		
Industry	Hydrogen		5 - 15
	E-fuels		
Iron & Steel	Hydrogen		
	E-fuels		
Chemicals incl. petrochemicals	Hydrogen		
	E-fuels		
Ammonia	Hydrogen		
	E-fuels		
Other industries	Hydrogen		5 - 15
	E-fuels		
Domestic Sector*	Hydrogen		
	E-fuels		
Input to E-fuels	Hydrogen		60 - 130
Total demand	**Hydrogen**		**100 - 225**
Total system	**Hydrogen**		**100 - 175**

Installed Capacity (MW)	
Electrolyser	**25 - 44**
E-methanation & E-liquids	**13 - 29**

** Hydrogen consumption in the domestic sector is through the blending of hydrogen in gas distribution. The blending shares are lower than 5% vol.*



Title	**Note accompanying the delivery of hydrogen and biomethane demand excel file**
Project	*DG REFORM, Support to EU MS*
Date	10th September 2022
Authors	Alessia De Vita and Maria Kannavou

1 General introduction

In the context of project "Hands-on technical support to REPowerEU" for DG REFORM, E3M is supporting the consortium leader Trinomics and the local experts in their provision of ad-hoc support to the beneficiary countries.

This note is prepared on request of MS expert teams, together with the delivery of information on the demand and supply of hydrogen, e-fuels by sector.

2 Sectoral Definition

The sectoral definition included in the file follows the sectors as defined in the EUROSTAT energy balances.

Net Imports	Hydrogen E-fuels	This refers to the net imports of hydrogen or e-fuels. When this value is positive the country is a net importer of products, when the number is negative the country is a net exporter of the commodity
Maritime	Hydrogen E-fuels	The maritime sector includes the bunkers used for international maritime transportation include, intra and extra-EU maritime transport
Rail transport	Hydrogen E-fuels	Rail includes both freight and passenger transportation
Road transport	Hydrogen E-fuels	Road transportation including both freight and passenger transportation
Inland navigation	Hydrogen E-fuels	Inland navigation including both freight and passenger transportation
Aviation	Hydrogen E-fuels	The aviation sector includes domestic, intra and extra-EU aviation
Refineries	Hydrogen E-fuels	Refinery sector

Power sector	Hydrogen E-fuels	Power generation incl. steam heat production
Industry	Hydrogen E-fuels	
Iron & Steel	E-fuels Hydrogen	
Chemicals incl. petrochemicals	E-fuels Hydrogen	
Ammonia	E-fuels Hydrogen	
Other industries	E-fuels Hydrogen	
Domestic Sector*	Hydrogen E-fuels	Incl. Residential, services and agriculture
Input to E-fuels	Hydrogen	Amount of hydrogen required as feedstock for the production e-fuels
Total demand	**Hydrogen**	Total demand for hydrogen including final energy demand, refineries, other energy branch and power sector
Total system	**Hydrogen**	Domestic production of hydrogen.

Electrolyzer	MW	Domestic electrolyser capacity
E-methanation & E-liquids	MW	Capacity for the production of e-fuels

All hydrogen mentioned in this table is hydrogen from electrolysis. Hydrogen produced from Steam Methane Reforming (SMR) within industrial sites -e.g. in ammonia production or in refineries, is not included in this table.

The refinery sector is expected to be a first mover of hydrogen consumption; the use of green hydrogen in refineries allows to help achieve the transport targets both in terms of GHG emission intensity (RED proposal) and for the RFNBO target.

3 Methodology to derive the data

The data provided represents ranges of hydrogen and e-fuel consumption in the context of the Fit for 55 and REPowerEU context.

The initial analysis for the Fit for 55 context as published in the Impact Assessments of July 14th 2021, uses the Reference scenario 2020 international fuel prices as a baseline (these can be found here: https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en).

The international fuel prices used for the purposes of the REPowerEU analysis can be found in the staff working document of the REPowerEU Communication.

The ranges represent different effectiveness of the Fit for 55 and REPowerEU policy implementation.

The numbers provided are not in any way to be seen as prescriptive, but are the result of an analysis looking in a top-down (not country specific) manner to the implementation of EU wide policies and national circumstances. National legislation is taken into account in the Reference scenario, key changes in national legislation (e.g. relating to nuclear or coal developments) have also been reflected.

Table 25: Hydrogen Technoeconomic Data according to E3M

	SEC - Natural gas	SEC - Electricity	SEC - hydrogen	Overnight investment cost (EUR per kW-output or per vehicle)		Variable and emissions cost (EUR/MWh-output)		Total cost (EUR/MWh-output)	
				Currently	*Long-term*	*Currently*	*Long-term*	*Currently*	*Long-term*
Transportation									
Road transport (passenger vehicles)			0.83	54100	29000				
Road transport (busses)			8.2	60100	32000				
Road transport (Heavy good vehicles 7-16tn)			3.3	300000	115000				
Road transport (Heavy good vehicles 16-32tn)			5.1	375000	147000				
Aviation			2300	160	145				
Shipping (via ammonia)			27	10.23	9.9				
Shipping (via methanol)			27	10.23	9.9				
H2 storage									
Hydrogen Storage in salt caverns / depleted reservoirs				5000	4000	3	2		
Liquefied Hydrogen storage in tanks		1.33		8000	6000	4	3		
Production of synthetic fuels (excl. additional costs related to compression, liquefaction, transportation etc.)									
Production of Hydrogen (electrolysis)		1.32		920	440	80	84	91	89
Production of hydrogen (NG SMR)	1.33	0.095		540	490	42	87	52	98
Production of hydrogen (NG SMR with CCS)	1.33	1.095		1900	850	47	155	89	132
Production of Synthetic Liquids (diesel, gasoline, kerosene)			1.4	1600	950	50	38	250	130
Dedicated hydrogen network for cross-border hydrogen trade									
on-shore pipelines				2700	2200			10.5	13.1
off-shore pipelines				4600	3400			19.6	24.2

SEC: specific energy consumption
vkm: vehicle-kilometre (one vehicle transported a distance of one kilometre)
pkm: passenger-kilometre (one passenger transported a distance of one kilometre)

Title Note accompanying the delivery of the investment table provided
Project *DG REFORM, Support to EU MS*
Date 20th September 2022
Authors Alessia De Vita and Maria Kannavou

1 General introduction

In the context of project "Hands-on technical support to REPowerEU" for DG REFORM, E3M is supporting the consortium leader Trinomics and the local experts in their provision of ad-hoc support to the beneficiary countries.

This note is prepared on request of Trinomics and others to accompany the investment tables provided in the start of this project.

2 General scope of data delivered

The data was provided with the following notes:

1. The data contained in this file is representative for investments in a RePowerEU context; they should serve as basis of further calculations, discussions and training.
2. The data does not, in any way, represent a recommendation from E3-Modelling or from the European Commission to investment suggestions.
3. The data was computed ad-hoc by E3-Modelling for the exclusive use under the inception phase of the project "Support to RePowerEU" led by Trinomics.

3 Methodology to derive the data

The data provided represents a computed magnitude of investments in the RePowerEU context. The data is provided by sector and uses within the sectors.

The data includes both private and public investment: it provides information about the magnitude of overall investments.

This implies that the values are inclusive of investments for a context where the Fit for 55 policies – as proposed by the Commission on July 14th 2021- would be met in combination with the RePowerEU measures as published in May 2022.

3.1 Context

The economic context used is that as published in the Reference scenario report:
https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en.

The investments are indicative for fuel price ranges between the ones used in the analysis for the Fit for 55 context as published in the Impact Assessments of July 14th 2021, which use the Reference scenario 2020 international fuel prices and a context where higher international fuel prices are considered.

Exemplary of higher fuel prices considered are published in the staff working document of the REPowerEU Communication.

The numbers provided are not in any way to be seen as prescriptive. They are the result of an analysis looking in a top-down manner to the implementation of EU wide policies taking into account national circumstances. National legislation is taken into account in the Reference scenario, key changes in national legislation announced until April 2022 (e.g. relating to nuclear or coal developments) have also been reflected.

4 Purpose and use examples

As delivered: the values provided are of representative nature to understand the order of magnitudes and the relations of investment requirements between sectors.

The investments are representative of a context where the key EU legislation (Energy Efficiency Directive, Renewable Energy Directive, Effort Sharing Regulation) is effectively implemented allowing the overall targets for Energy Efficiency, Renewables and Greenhouse Gas emission reductions to be met at EU level.

The investment numbers show e.g. at EU level that large investments are required in the building sector (residential and services): approximately 25% of EU wide investments would need to take place in these sectors. These include both investments in renovation, equipment replacement (which will come up for replacement anyway or is prematurely scrapped), new constructions (only small part of investments) as well as appliances.

While a lot of focus in Member State legislation is provided to supply side investments and in new fuel infrastructure (primarily hydrogen), these represent for the EU only 2% of projected representative investments.

These numbers represent all investments public and private as well as investments required to replace aging equipment.

Member State local experts can use this table to understand whether there are the necessary measures in place to support such investments.

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