LCA of Power-to-X processes and applications in the residential sector

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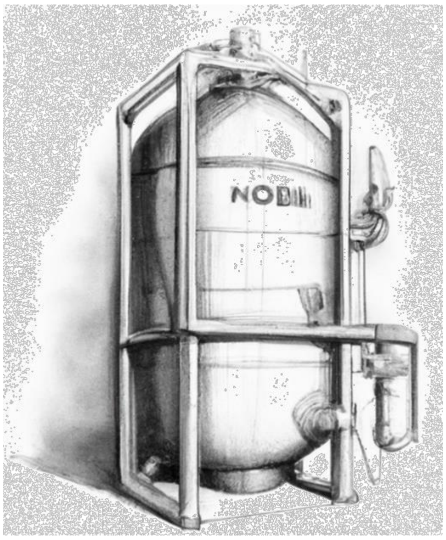

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Abbreviations

Emissions

CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
GHG	Greenhouse gas
HC	Hydrocarbon
N_2O	Nitrous oxide

Units

J	Joule
kg	kilogram
kWh	kilowatt-hour
MJ	megajoule

Other

ATR	Autothermal Reforming
CCS	Carbon Capture and Storage
CH	Switzerland
DAC	Direct Air Capture
DMFC	Direct Methanol Fuel Cell
GLO	World region (global)
GWP	Global Warming Potential
LCA	Life Cycle Assessment
LCI	Life Cycle Inventory Analysis
LCIA	Life Cycle Impact Assessment
MSWI	Municipal Solid Waste Incineration
RER	Region for geographical Europe
RES	Renewable Energy Sources
SMR	Steam Methane Reforming
SNG	Synthetic Natural Gas
TRL	Technological Readiness Level

Executive summary

Goal

The primary aim of this study is to model and provide life cycle inventories for delivering heat and electricity to residential areas and individual households by leveraging Power-to-X conversion processes, which can be used to provide liquid and gaseous fuels from (renewable) electricity. The outcomes of this study help to understand the environmental implications and efficiencies of various energy carriers and end-use technologies in residential settings and to compare the environmental performance of Power-to-X based heat and electricity supply to alternatives such as natural gas boilers or heat pumps operated with either the actual grid mix or a renewable electricity mix within a Swiss context on the level of single technologies, but not on a larger scale (i.e., as part of the energy system).

Method

To achieve this, the report explores the supply chains and establishes life cycle inventories of three energy carriers: hydrogen, synthetic natural gas (SNG), and methanol. The methodologies encompass modeling diverse end-use technologies, spanning from boilers to co-generation units and fuel cells, as well as the intermediary fuel processing steps, such as transmission, storage, and distribution (Figure 1).

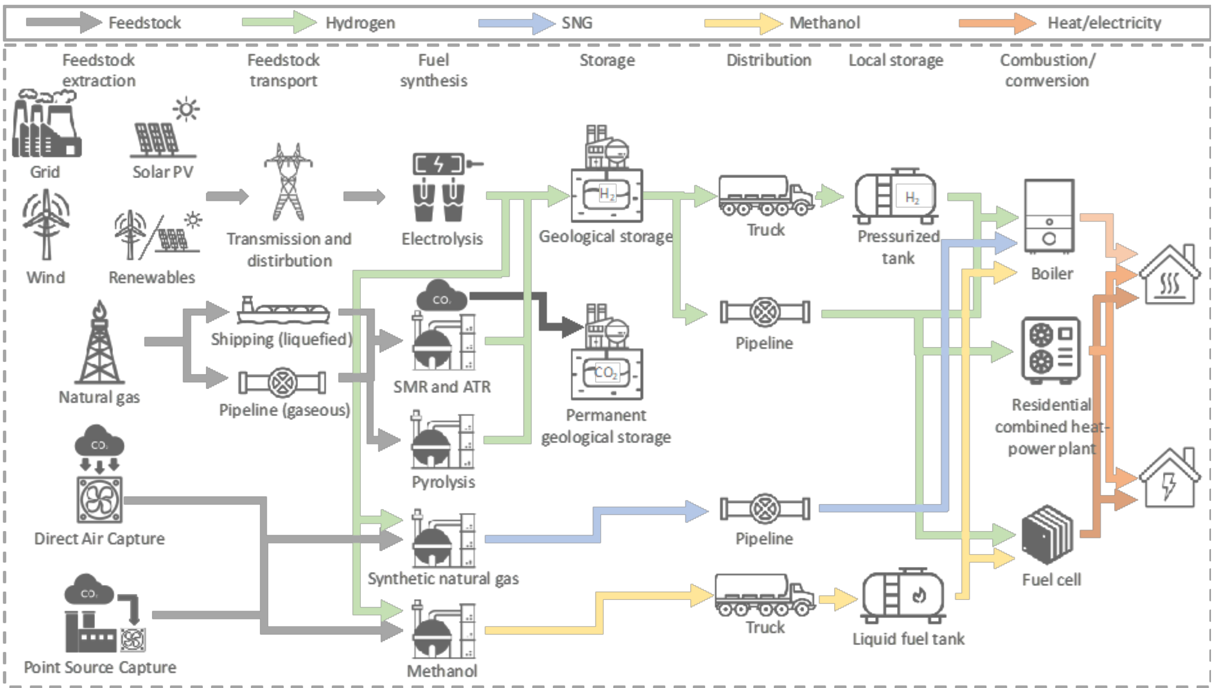

Figure 1 Schematic overview of investigated product systems and Power-to-X chains for residential heat and electricity supply.

As producing SNG and methanol from hydrogen requires CO_2, various sources for its supply are modeled.

The study provides the specifications and corresponding inventories to deliver transparent and comprehensive Life Cycle Inventory (LCI) datasets that link to the Life Cycle Assessment (LCA) database UVEK:2022 for further analysis.

Object of investigation

The focal point of our research is the heat and electricity supply chain specifications based on Power-to-X fuels and tailored to the residential sector in Switzerland. Given the increasing emphasis on sustainable energy solutions for residential sectors, these specifications are critical in today's context. More specifically, we compare supplying heat and electricity via the use of synthetic gas (i.e., hydrogen, synthetic natural gas) and liquid fuel (i.e., methanol) to incumbent technologies (i.e., air-water heat pump, wood, biomethane and natural gas boilers) concerning three environmental performance indicators: impacts on climate change (greenhouse gas (GHG) emissions), Cumulative Energy Demand (CED) and overall environmental impacts (using the Swiss eco-factors 2021 ("Umweltbelastungspunkte") according to the Ecological Scarcity method, version 2021).[1] Functional units (FU) used for the quantification of environmental burdens are "1 MJ of heat" (as produced), and "1 MJ of electricity" (as produced), respectively. When applying these FU to combined heat and power (CHP) generation systems (i.e., fuel cells and combustion-based CHP units), burdens are allocated according to the exergy contents of heat and electricity. In addition, the environmental performances of CHP units and fuel cells are evaluated with respect to their combined heat and power output ("1 MJ of heat and 0.22 kWh of electricity" in case of CHP; "1 MJ of heat and 0.167 kWh of electricity" in case of fuel cells).

Producing SNG and methanol using hydrogen from water electrolysis needs CO_2 as feedstock. This CO_2 can be captured from the atmosphere ("direct air capture", DAC) or from point sources such as cement or municipal waste incineration plants; the latter two represent cases of Carbon Capture and Utilization (CCU). In terms of LCA methodology and practices, different approaches regarding how to deal with such CCU processes exist. The captured CO_2 (partially of fossil, biogenic and geogenic origin, increasing the atmospheric CO_2 concentration when released during fuel combustion) is emitted by the end user of SNG or methanol, but it can be argued that these CO_2 emissions should nevertheless be assigned to the CO_2 point source as long as feedstock CO_2 is considered as a waste, which is currently the case in Switzerland. To provide a more comprehensive perspective in this context, LCA results for CCU-based fuels applying different accounting approaches are provided in a sensitivity analysis. Thereby, the effects of these different accounting approaches are shown and discussed in detail. Inventory data have been generated for all options and the decision on which inventories will be integrated into the UVEK LCI database is up to the Federal Office for the Environment (FOEN).

Purpose and intended use of this work

The main purpose of this Life Cycle Assessment is the compilation of life cycle inventories of Power-to-X based heat and electricity supply options in a Swiss context, to be added to the UVEK:2024 inventory database, in line with the respective data quality guidelines. The purpose of this report is to document these new inventories, modeling approaches, data sources used, and assumptions taken. Further, the report provides a technology-based comparison of the life-cycle environmental performance of these Power-to-X based heat and electricity supply options in comparison with conventional technologies ("benchmark, or reference technologies") on a microscale – based on impacts on climate change, (renewable and non-renewable) cumulative energy demand, and Swiss eco-factors 2021 according to the Ecological Scarcity method.

[1] Throughout this report, the terms "climate impacts", "impacts on climate change", "global warming potential impacts" and (life cycle) "greenhouse gas (GHG) emissions", all quantified using global warming potentials for a time horizon of 100 years according to IPCC 2013, will be used as synonyms.

Benchmark heat supply technologies selected are natural gas and biomethane boilers, a wood boiler, and a modern air-water heat pump operated with a) the current average Swiss grid electricity mix[2], and b) a renewable electricity mix that might represent the supply mix at the time the PtX supply chains and technologies would be operated. In terms of electricity supply, electricity from the grid (average and certified renewable, respectively), from a natural gas power plant and from photovoltaic roof-top modules represent the benchmark options.

This LCA is only addressing single technologies and their environmental performance from a current, attributional perspective and is not embedded in an energy system setting. Therefore, this LCA does not reflect any systemic aspects of introducing Power-to-X based heat and electricity supply options into the (Swiss) energy and economic system (on a large scale) and is thus not suitable as support in decision-making processes regarding large-scale market introduction of the synthetic fuels analyzed.

When interpreting the LCA results, it should be noted that options are being compared that are currently not at the same stage of development and some of which are not available in Switzerland. For example, hydrogen from natural gas pyrolysis and reforming with CO_2 capture and geological storage is not available today and it is uncertain whether this will ever be the case. Similarly, hydrogen from the – from an environmental perspective – “best case” production in Morocco is a theoretical option that may be available in the future; assumptions taken here regarding technical performances should be verified under real operation conditions. The same applies to synthetic methanol and synthetic natural gas, which are not (yet) commercially available products in Switzerland. This study makes no statement on how realistic and desirable it is for these energy sources to come onto the Swiss market at large scales in the coming years.

However, the aim of this work was to cover as broad a spectrum as possible of variants for hydrogen production and energy carriers based on it and to consider possible future options under optimistic framework conditions – mainly to gain an initial impression of the best possible potential environmental benefits despite all the uncertainties that exist, especially in the case of options that are not (yet) commercially available. And to be able to set the right priorities in the future development towards a climate and environmentally friendly heat supply for Swiss households.

Results

The LCA results for heat supply (Figures 2-5) illustrate that hydrogen technologies cause consistently lower impacts than synthetic natural gas or methanol among the explored heat and electricity supply options, as fewer and less elaborate processing steps are required.

Hydrogen production technologies (i.e., electrolysis, steam methane reforming, pyrolysis), feedstock type (e.g., electricity source, natural vs. liquefied gas, etc.), and allocation approaches (for combined heat and power generation units) emerged as pivotal across all impact categories. Both climate and overall environmental impacts of synthetic, electricity-based fuel use mainly depend on the source of electricity used for electrolysis, i.e., hydrogen production.

Using Carbon Capture and Storage (CCS) on natural gas-based hydrogen production pathways could reduce climate and the overall environmental impacts significantly in the future. However, this option still relies on foreign fossil resources as primary feedstock and the substantial reduction of climate and overall environmental impacts requires a) very low methane emissions along the natural gas supply chain, b) very high CO_2 capture rates at the

[2] Low voltage electricity supply from the grid according to the UVEK:2022 LCI database.

hydrogen production, and c) that the permanence of CO_2 storage is ensured. Further, CO_2 storage sites must be available.[3]

At the end of the supply and use chains, hydrogen-powered boilers, combined heat-power co-generation units (CHPs), and fuel cells consistently cause lower impacts compared to synthetic natural gas and methanol alternatives across the spectrum of impact categories addressed here. In terms of logistics, hydrogen delivery by truck causes additional greenhouse gas emissions related to leakages and on-site storage requirements, in addition to being unpractical because of the low volumetric density of the gas. Thus, supply via pipelines is the preferred option.

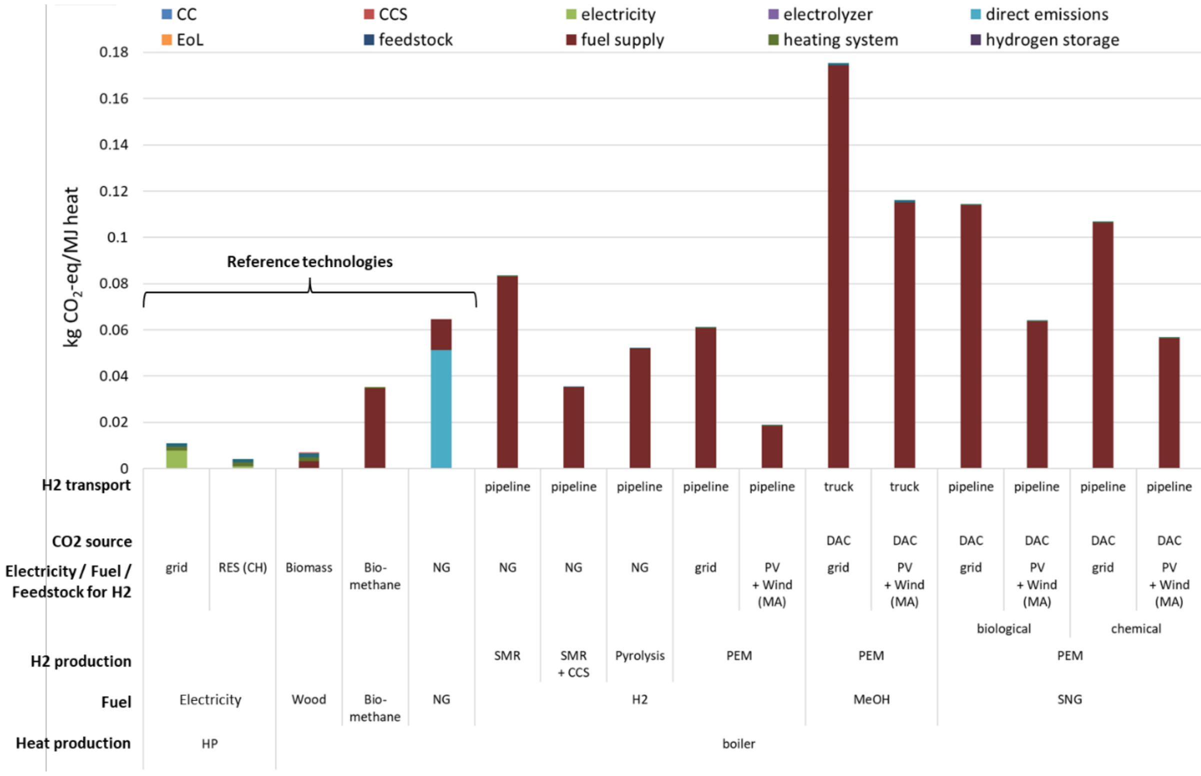

Figure 2 Life-cycle Global Warming Potential impacts for the supply of one megajoule of heat, in kg CO_2-eq./MJ heat, using IPCC's 2013 GWP 100-year impact assessment method. "RES" = Renewable Energy Sources". "HP" = air-water heat pump. "Wood" = wood chips-fired boiler. "Biomethane" = biomethane-fed boiler. "NG" = natural gas-fed boiler. "PEM" = Proton Exchange Membrane electrolysis. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "NG" = compressed natural gas. "RES (CH)": Swiss renewable electricity mix. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

The LCA results across all considered indicators show (Figure 61 to Figure 64) that renewables-based hydrogen-fed fuel cells and combined heat and power cogeneration units exhibit superior performance (i.e., lower scores) across all metrics on a per-megajoule basis of supplied heat when compared with natural gas reference systems.

[3] See (UVEK 2022) regarding the position of the Federal administration concerning hydrogen from natural gas with CCS.

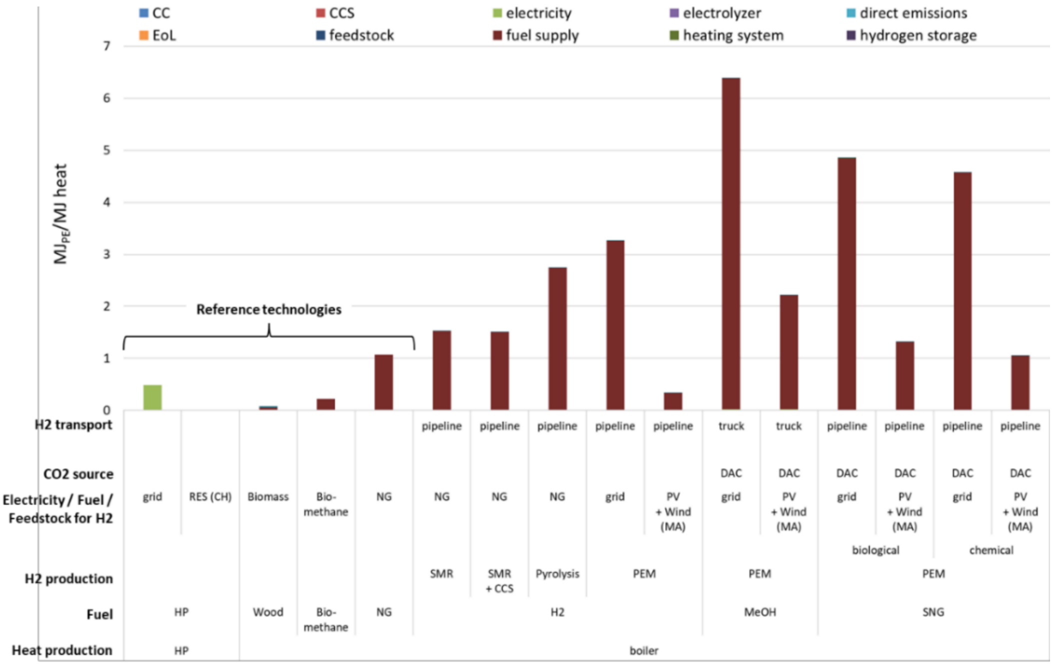

Figure 3 Life-cycle Cumulative Non-renewable Energy Demand, for the supply of one MJ of heat, in MJ of non-renewable primary energy (PE)/MJ heat. "HP" = air-water heat pump. "Wood" = wood chips-fueled boiler. "Biomethane" = biomethane-fed boiler. "PEM" = Proton Exchange Membrane electrolysis. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "DAC" = atmospheric CO_2 captured by Direct Air Capture. "CC" = CO_2 capture/sourcing. "CCS" = CO_2 capture and storage. "EoL" = End-of-Life. "NG" = natural gas. "RES (CH)": Swiss renewable electricity mix. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

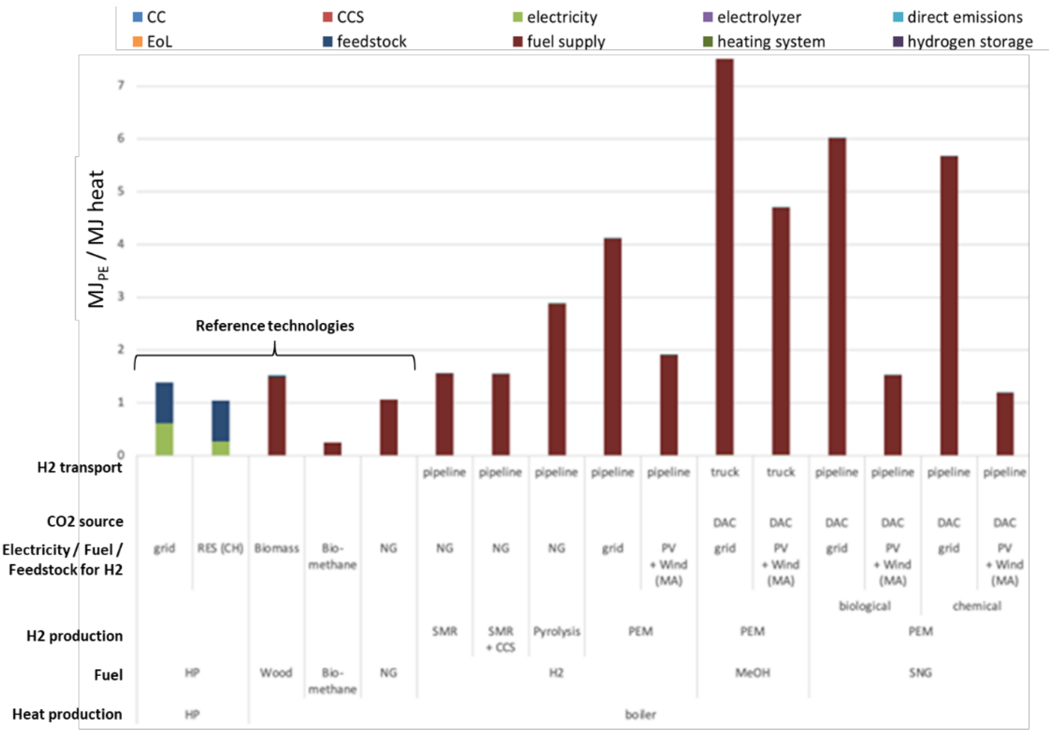

Figure 4 Life-cycle Cumulative Energy Demand (renewable and non-renewable), for the supply of one MJ of heat, in MJ of primary energy (PE)/MJ heat. "HP" = air-water heat pump. "Wood" = wood chips-fueled boiler. "Biomethane" = biomethane-fed boiler. "PEM" = Proton Exchange Membrane electrolysis. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "DAC" = atmospheric CO_2 captured by Direct Air Capture. "CC" = CO_2 capture/sourcing. "CCS" = CO_2 capture and storage. "EoL" = End-of-Life. "NG" = natural gas. "RES (CH)": Swiss renewable electricity mix. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

When comparing the impacts of such systems with an air-water heat pump ("HP"), the choice for the electricity to operate the heat pump is important for a consistent comparison across technologies. Heat supply using hydrogen produced with renewable sources should be compared with a heat pump also operated with electricity from renewables. Consistently, heat supply using hydrogen produced with grid electricity should be compared with heat pumps also operated with grid electricity. By performing these consistent comparisons, the hydrogen-fed boilers (and also fuel cell and CHP systems, see section "Life cycle impact assessment") present mostly higher impacts than the relevant reference cases (Figure 2 to Figure 5).

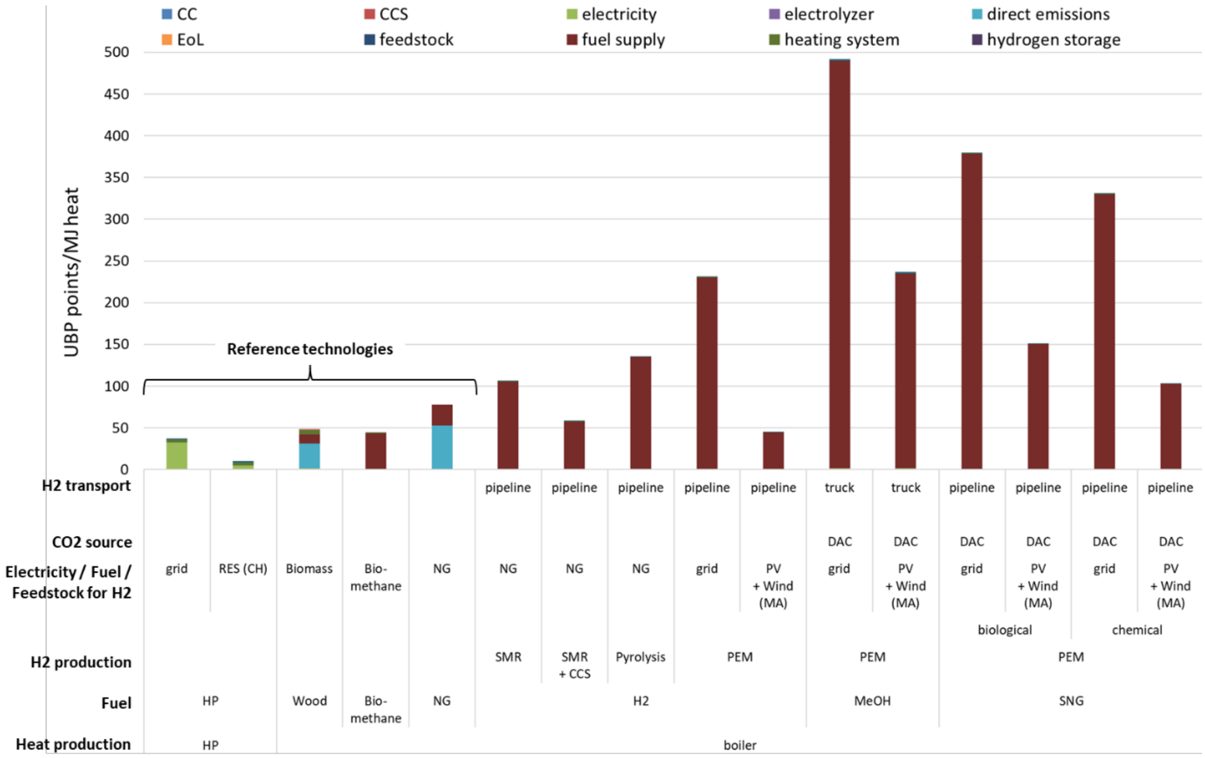

Figure 5 Life-cycle environmental impacts according to the Ecological Scarcity method for the supply of one MJ of heat, in UBP points/MJ heat. "HP" = air-water heat pump. "Wood" = wood chips-fueled boiler. "Biomethane" = biomethane-fed boiler. "NG" = natural gas-fed boiler. "PEM" = Proton Exchange Membrane electrolysis. "biological" = biological methanation. "chemical" = electrochemical methanation. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "RES (CH)": Swiss renewable electricity mix. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

When performing this same consistent comparison for the joint production of heat and electricity from these co-generation units, similar results can be observed (see Figure *6* to Figure 9). The "HP+grid mix" system causes lower impacts than the CHP unit operated with hydrogen produced with the grid mix and the "HP+renewable (RES)" system shows lower impacts than the alternative CHP operated with H_2 produced with renewable sources. Only when a heat pump operated with today's average grid mix is compared with a CHP unit operated with hydrogen produced with renewable power, the CHP unit causes lower impacts. However, this comparison would only be somehow relevant in case domestic (and European) renewable power generation capacities would be constrained, while large-scale hydrogen imports from regions with unconstrained renewable potentials (such as Morocco) could be realized.

Thus, the combination of a heat pump and renewable electricity represents the technology option generating the lowest environmental burdens (based on the indicators quantified) among the options compared in this report.

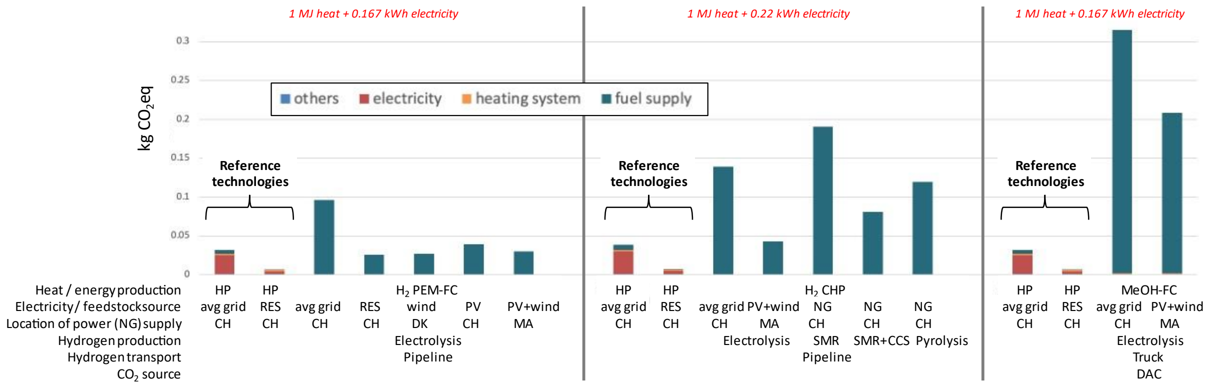

Figure 6 Life-cycle Global Warming Potential impacts of jointly producing heat and electricity from co-generation units. “H_2 PEM-FC” = hydrogen-fed fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. “H_2 CHP” = hydrogen-fed combined heat-power plant, providing 1 MJ of heat and 0.22 kWh of electricity. “MeOH-FC” = direct methanol fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. These three options are compared with counterparts, “HP + avg. grid electricity (CH)” and “HP + RES (CH)”, i.e., heat pumps which provide equivalent amounts of heat and electricity, either average Swiss grid power or from RES (for both HP operation and electricity supply). “RES = Renewable Energy Sources”; “pipeline/truck” refers to hydrogen transport; MA = Morocco; SMR = Steam Methane Reforming; CCS = Carbon Capture and Storage; DAC = Direct Air Capture of CO_2.

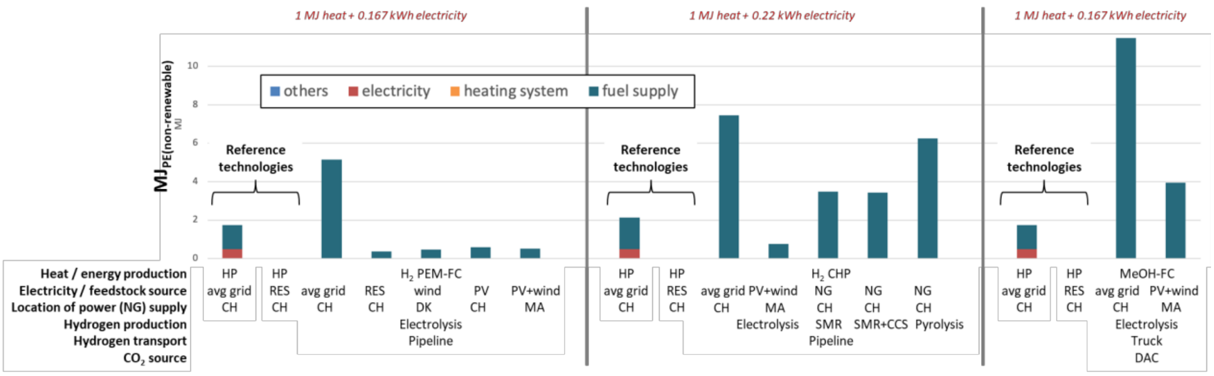

Figure 7 Life-cycle non-renewable Primary energy (PE) demand of jointly producing heat and electricity from co-generation units. “H_2 PEM-FC” = hydrogen-fed fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. “H_2 CHP” = hydrogen-fed combined heat-power plant, providing 1 MJ of heat and 0.22 kWh of electricity. “MeOH-FC” = direct methanol fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. These three options are compared with counterparts, “HP + avg. grid electricity (CH)” and “HP + RES (CH)”, i.e., heat pumps which provide equivalent amounts of heat and electricity, either average Swiss grid power or from RES (for both HP operation and electricity supply). “RES = Renewable Energy Sources”; “pipeline/truck” refers to hydrogen transport; MA = Morocco; SMR = Steam Methane Reforming; CCS = Carbon Capture and Storage; DAC = Direct Air Capture of CO_2.

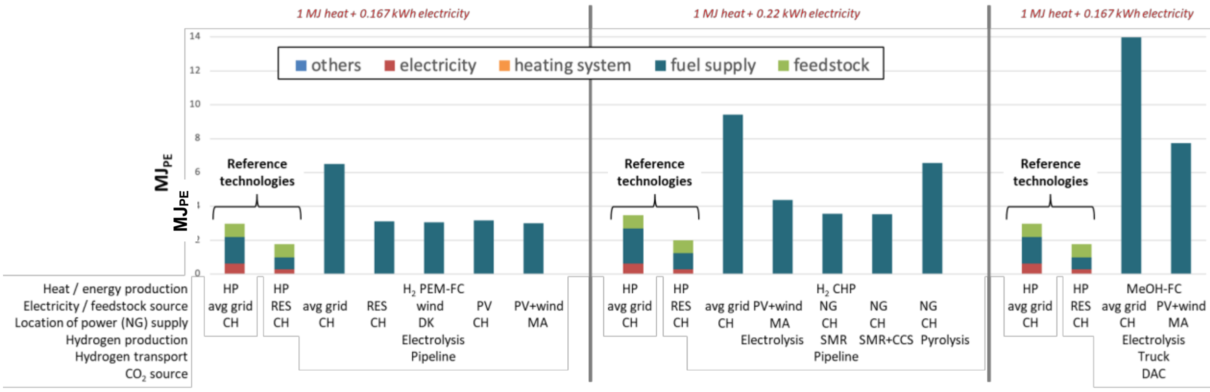

Figure 8 Life-cycle Cumulative Primary energy (PE) demand (renewable and non-renewable) of jointly producing heat and electricity from co-generation units. "H_2 PEM-FC" = hydrogen-fed fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. "H_2 CHP" = hydrogen-fed combined heat-power plant, providing 1 MJ of heat and 0.22 kWh of electricity. "MeOH-FC" = direct methanol fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. These three options are compared with counterparts, "HP + avg. grid electricity (CH)" and "HP + RES (CH)", i.e., heat pumps which provide equivalent amounts of heat and electricity, either average Swiss grid power or from RES (for both HP operation and electricity supply). "RES = Renewable Energy Sources"; "pipeline/truck" refers to hydrogen transport; MA = Morocco; SMR = Steam Methane Reforming; CCS = Carbon Capture and Storage; DAC = Direct Air Capture of CO_2.

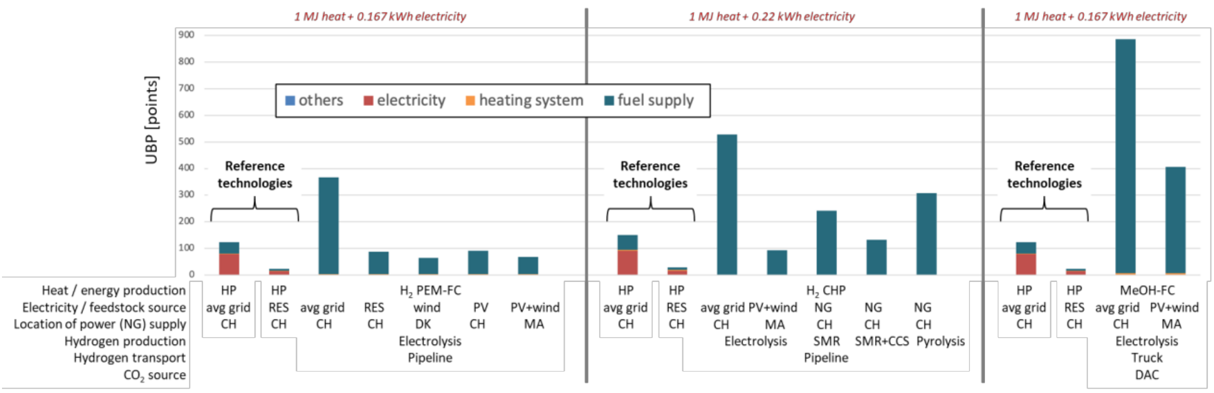

Figure 9 Life-cycle environmental impacts according to the Ecological Scarcity method of jointly producing heat and electricity from co-generation units. "H_2 PEM-FC" = hydrogen-fed fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. "H_2 CHP" = hydrogen-fed combined heat-power plant, providing 1 MJ of heat and 0.22 kWh of electricity. "MeOH-FC" = direct methanol fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. These three options are compared with counterparts, "HP + avg. grid electricity (CH)" and "HP + RES (CH)", i.e., heat pumps which provide equivalent amounts of heat and electricity, either average Swiss grid power or from RES (for both HP operation and electricity supply). "RES = Renewable Energy Sources"; "pipeline/truck" refers to hydrogen transport; MA = Morocco; SMR = Steam Methane Reforming; CCS = Carbon Capture and Storage; DAC = Direct Air Capture of CO_2.

Regarding further conversion of hydrogen to SNG or methanol and their use for heat supply: using CO_2 from a municipal solid waste incineration (MSWI) instead of DAC can reduce the climate impacts of methanol and SNG heating systems, if internally available waste heat can be used for CO_2 capture at the MSWI and if fuel use related CO_2 emissions are assigned to the MSWI plant. This setting – CO_2 from an MSWI plant for SNG production and allocation of fuel use related CO_2 emissions to the MSWI – represents the only viable option (compared to the direct use of hydrogen) in terms of climate impacts among all CCU options evaluated here. However, the GHG emissions are still much higher than those of heat from heat pumps and wood boilers. Further, it should be considered that biogenic CO_2 captured and used for fuel production in such CCU processes will finally be emitted to the atmosphere and can thus not generate so-called "negative emissions", while capturing and permanently storing this biogenic CO_2 would act as a carbon sink and thus qualify as "Carbon Dioxide Removal (CDR)".

Discussion

When assessing technologies or product systems, which are not yet commercially available, like power-to-X fuels for residential applications, the choice of the benchmark for comparing their environmental performance is central. In this project, various benchmark alternatives (namely wood and gas boilers as well as heat pumps operated with current average Swiss grid mix and renewable electricity sources, respectively) have been considered. Power-to-X based heat and electricity supply should be consistently compared with conventional counterparts: hydrogen-based solutions using renewable primary energy should in general be compared with heat pumps operated with renewable electricity, while systems relying on hydrogen produced using the grid mix should be compared with heat pumps using the grid mix as well. Such a comparison shows that hydrogen and electricity based SNG as well as methanol used for heat and electricity supply in the residential sector cause higher impacts than any of the comparable benchmark technologies.

In case of CHP units and fuel cells, which generate heat and electricity, the relatively low environmental burdens of heat from hydrogen based CHPs and fuel cells can be attributed to the exergy-based allocation of environmental burdens, which renders the environmental impacts of co-produced electricity roughly equivalent to those of the average Swiss grid electricity supply regarding Global Warming and overall environmental impacts according to the Ecological Scarcity method[4], but assigns comparatively low burdens to the heat. However, even when applying system expansion and comparing joint production of heat and electricity with the corresponding benchmark technologies, PtX systems cause higher impacts. The combination of heat from a heat pump exclusively operated with renewable electricity and renewable electricity supply clearly shows the lowest impacts using a system expansion approach.

Reliability of the new inventory data and thus uncertainties associated with LCA results basically reflect the technological development status of different processes. While, for example, water electrolysis can be considered as established process with lots of literature and industry data available and thus comparatively minor associated uncertainties with respect to electricity, fuel and material consumption, methane pyrolysis represents the other end of the spectrum of technological maturity and thus uncertainties. Information regarding the performance of hydrogen and methanol end use technologies is limited, as those currently do not represent common technologies. Also, synthetic hydrocarbon production using CO_2 from either the atmosphere or captured at point sources as well as autonomous hydrogen production via electrolysis entirely powered by intermittent renewables such as wind and PV power do not yet correspond to mature processes – performance data used for generating inventory data still need to be proven by operational units in practice.

From an environmental perspective, importing electricity-based fuels from regions, in which production can rely on high solar and wind power yields but are still not too far away allowing for hydrogen transportation via pipelines, seems to be beneficial compared to domestic production of such fuels in Switzerland. For hydrogen production, processes using natural gas with Carbon Capture and Storage might represent – based on the parameter settings applied in this analysis – environmentally sound alternatives to electrolysis using renewable electricity, provided the technology develops in the future (i.e., high CO_2 capture rates and low methane emission rates from natural gas supply can be ensured), and effectively captures and permanently stores CO_2 underground.

[4] Throughout this report, the term "(overall) environmental impacts" is used as synonym for "overall environmental impacts measured according to the Ecological Scarcity method" to improve readability.

Also using such hydrogen for residential heat supply causes higher climate and environmental impacts than a heat pump using renewable electricity.

Conclusions

The life cycle inventories developed in this report shed light on the environmental impacts of power-to-X supply chains and their subsequent use for heat and electricity supply in residential domains in Switzerland. Main conclusions are that power-to-X based hydrogen, synthetic natural gas, or methanol use require more non-renewable primary energy compared to air-water heat pumps, biomethane and wood chips boilers. This inefficiency is reflected in the two other indicators considered: Global Warming Potential and overall environmental impacts according to the ecological scarcity method. Even Power-to-X systems using 100% renewable electricity for hydrogen production with very low greenhouse gas emissions and overall environmental impacts show GHG emissions and environmental impacts higher than those caused by heat from heat pumps also operated with renewable electricity.

Recommendations

For stakeholders aiming for environmentally friendly energy solutions in residential areas, using liquid or gaseous synthetic fuels should be envisaged only when direct electrification of heating through heat pumps (preferably using renewable electricity) or use of wood from sustainable forestry is not feasible. Only if, in the future, both domestic and European renewable electricity generation capacities and sustainably harvested wood would become constrained resources and at the same time vast amounts of "clean" synthetic fuels could be imported from regions with high renewable energy potentials and yields, such fuels could also be considered. However, in general, the synthetic fuels should be primarily dedicated to applications where no relevant and easy to implement alternatives are available. A low temperature application to supply heat in the building sector cannot be considered as being one of those and furthermore, residential heat demand should be substantially reduced by energy efficient building envelops in the future. Therefore, we do not recommend using hydrogen and synthetic fuels for low-temperature heat supply in the residential sector from an environmental perspective.

As some of the technologies and process included in this work, such as methane pyrolysis, CO_2 supply via direct air capture or capture from industrial point sources, or hydrogen end-use technologies, are not yet fully commercialized, uncertainties regarding their environmental performance remain partially high due to lack of reliable data and thus, associated LCA results are less reliable than those for more mature technologies and processes such as hydrogen production from alkaline and PEM electrolyzers and SMR of natural gas. This needs to be considered when interpreting LCA results. Future work should, as soon as more reliable information would be available, focus on those processes.

Future work should also address an energy system perspective to provide decision support for potential large-scale implementation of power-to-X fuel supply and use on a city, cantonal or national level. This would require a combination of (energy) system analysis and LCA, in which a range of future scenarios regarding for example heat and electricity demand, resource constraints, and potential energy imports could be investigated. As such a perspective is currently missing, the results shown in this study shall not be used to support large scale investment decisions such as investments in power-to-X technologies and transport and storage infrastructures.

Readers seeking comprehensive details, specifications, life cycle inventories, and environmental performance (e.g., greenhouse gas emissions, Cumulative Energy Demand, and overall environmental impacts) may refer to the provided Data Object Identifier (DOI): https://doi.org/10.5281/zenodo.7955951. Additionally, these inventories are slated for inclusion in the forthcoming UVEK database update, enhancing their accessibility for diverse stakeholders.

Table of contents

1 Introduction

The quest to reduce the GHG emissions and other environmental burdens associated with on-site heat (and electricity) supply for residences has yielded significant advancements but continues to face several challenges. Key improvements include the development of highly efficient electric heat pumps powered by renewable electricity, the expansion of district heating systems powered by renewable and low environmental impacts energy sources, the harnessing of biomass-based gaseous fuels as an alternative to natural gas, and the use of solar thermal panels to provide hot water and complement other heating systems.

However, obstacles remain on the path to a complete phase-out of fossil energy carriers and eliminating associated climate impacts. Many homes still feature systems designed for fossil fuel heating, and replacing these with lower GHG emission (and, in general, more environmentally friendly) alternatives is often costly and disruptive. Home insulation, especially in older properties, is another issue, as poor insulation increases the heat needed and thus the cost and GHG emissions associated with heating.

Synthetic energy carriers like hydrogen, synthetic natural gas, and synthetic methanol (generated using electricity from renewable sources) have been identified as potential key players in reducing the emissions of GHG associated with energy supply in general, including residential heating. They can store energy from renewable sources and be used in systems initially designed for fossil fuels, reducing the need for infrastructure changes. Hydrogen can be produced from water using electrolysis powered by renewable electricity, used in fuel cells, or burned directly. Synthetic methane can be used in existing natural gas infrastructure, while synthetic methanol, produced from CO_2 and hydrogen, can be used as a heating fuel or in fuel cells.

Nevertheless, these technologies are still being developed and have not yet seen widespread deployment. Overcoming the challenges associated with their production, storage, and use requires significant research and development.

To ensure they provide a genuine advantage in terms of GHG emissions and other environmental burdens, it is essential to evaluate these options using life-cycle assessment (LCA), considering all the relevant phases of the heat (and electricity) value chain, notably the production of feedstock such as electricity, the synthesis, and distribution of the fuel, as well as its use at the consumer.

This report provides detailed life-cycle inventories (LCI) on the production, distribution, storage, and use of synthetic energy carriers for residential heat (and electricity) supply.

1.1 Goal and scope

This report aims to document all the energy and material resource inputs and associated output emissions related to the relevant life cycle phases of the supply chain of synthetic energy carriers for residential heating and co-generation systems to be further used for Life Cycle Assessment (LCA). The report represents the documentation of Life Cycle Inventories for complete PtX chains from the production of electricity-based energy carriers to their use for heat (and electricity) supply, including transport and storage.

The following Power-to-X fuels and associated use for heat and electricity provision in residential areas are considered:

- Heat from combusting a synthetic fuel in a home boiler (i.e., hydrogen, synthetic natural gas, and methanol),
- Heat and electricity from combusting a synthetic fuel in a small co-generation unit (i.e., hydrogen, synthetic natural gas, and methanol),

- Heat and electricity from chemically converting a synthetic fuel in a fuel cell system (i.e., hydrogen and methanol).

Heat distribution within buildings is not included. Variants for each main Power-to-X pathway are explored. Those are described in Table *1*.

*Table 1 Overview of LCI to be compiled to produce energy carriers. DAC: Direct Air Capture; MSWI: Municipal Solid Waste Incineration; *CO_2 from DAC, MSWI, and cement plant; **grid-connected and stand-alone configurations supplied with dedicated renewable power.*

(PtX-based) Energy carrier production	**Technology**		**Feedstock**
Hydrogen	Electrolysis**	Alkaline	Water, electricity
		Proton Exchange Membrane (PEM)	Water, electricity
		Solid Oxide electrolysis cells (SOEC)	Water, electricity
	Reforming	Steam / Autothermal reforming	Natural Gas (NG), Liquefied Natural Gas (LNG)
		Steam / Autothermal reforming with CCS	Natural Gas (NG), Liquefied Natural Gas (LNG)
	Pyrolysis		Natural Gas (NG), Liquefied Natural Gas (LNG)
Synthetic Natural Gas (SNG)	Methanation	Catalytic	H_2, CO_2*
		Biologic	H_2, CO_2*
Methanol		Catalytic	H_2, CO_2*

They are combined with several distribution and end-use options (Table *2* and Table *3*, respectively), yielding in total:

- 21 hydrogen production pathways (and 25 hydrogen supply datasets),
- 20 synthetic natural gas production pathways (and 20 supply datasets),
- 10 methanol production pathways (and 10 supply datasets),
- and 231 datasets representing end-uses (i.e., heat and electricity supply), of which 35 are considered as reference cases, and the remaining for the purpose of sensitivity analysis.

Table 2 Overview of storage and transport options to be included in the analysis.

Storage		
Hydrogen	Geological storage in sub-surface caverns	Capacity, pressure, and material specified in inventories
SNG	Above surface pressure vessel	Capacity, pressure, and material specified in inventories
Methanol	Above surface tank	Capacity and material specified in inventories
Transport		
Hydrogen	Pipeline	Distance, capacity, and material specified in inventories
	Truck	Distance and capacity specified in inventories
SNG	Pipeline	Equivalent to CNG pipeline
Methanol	Pipeline	Distance, capacity, and material specified in inventories

Table 3 Overview of end-use options for hydrogen, SNG, and methanol to generate heat (and electricity) in the residential sector. PEM: Proton Exchange Membrane; SOFC: Solid Oxide Fuel Cell; DMFC: Direct Methanol Fuel Cell.

Energy Carrier	Technology	Heat [MJ]	Electricity [kWh]
Hydrogen			
Combustion	Boiler	X	
	CHP	X	X
Conversion	Fuel cell PEM, SOFC	X	X
Methanol			
Combustion	Boiler	X	
Conversion	DMFC	X	X
SNG			
Combustion	Boiler	X	
	CHP	X	X

The resulting Life Cycle Inventories (LCI) have a Cradle-to-Grave scope. They encompass the following phases of the life cycle of the energy carrier:

- the provision of the feedstock,
- its synthesis,
- its regional transmission and distribution,
- its conversion into heat, and when relevant, electricity,
- as well as the provision of the heating system.

The assessed technologies are compared to reference alternatives ("benchmark technologies") to produce heat (and electricity), if relevant (i.e., when considering CHP or fuel cells). These alternatives are:

Heat:

- Natural fossil gas boiler
- Wood boiler
- Heat pump installed in a new building (COP=4.4.) operated with actual grid mix or renewable electricity (RES)

Electricity:

- Current Swiss grid mix (supply mix)
- Photovoltaic
- Renewable mix (RES)

The impacts of such reference technologies are taken from the KBOB list 2022, relying on the UVEK database as background.

Regarding the comparison with the heat pump references, the PtX scenarios relying on renewable electricity sources should be compared with systems relying on renewable sources, while the grid mix based scenarios should be consistently compared with hydrogen production using grid electricity as well.

This choice is made to ensure a meaningful and consistent comparisons between the reference technologies and the assessed PtX systems.

This report and associated datasets are established and reviewed according to ecoinvent v.2.0 methodology (Rolf Frischknecht et al. 2007). The reader may find the reviewer's assessment report under the section **Reviewer report**.

1.1.1 Functional unit

One megajoule of heat is the functional unit used for heat-supplying systems. Some of these systems co-produce electricity, in which case the functional unit of **one kilowatt-hour of electricity** is also considered. The units of megajoule for heat and kilowatt hour for electricity are chosen to align with current practices in LCA databases.

We extend the analysis to consider the multifunctionality of combined heat and power generation units and fuel cells, in which case the production of heat and electricity is considered altogether: 1 MJ of heat and 0.167 kWh of electricity for combined heat and power generation units, and 1 MJ of heat together with 0.22 kWh of electricity for fuel cells.

1.1.2 System boundary

The system boundary of the product systems generally encompasses the following Figure 10:

- The extraction, transformation, and transport of energy and material feedstock necessary to produce synthetic fuels ("Feedstock extraction" and "Feedstock transport"). This refers to the electricity or natural gas needed to produce hydrogen (and their respective supply chains) and the capture and purification of CO_2 to produce natural gas or methanol.
- The conversion of feedstocks into fuel ("Fuel synthesis"). Specifically, this entails the energy inputs to synthesize the fuel and the infrastructure (e.g., reactor, electrolyzer).
- The transmission of the fuel from the producer to the regional storage location.
- The regional fuel storage (e.g., tank, geological cavity). This is especially relevant for hydrogen distribution, where significant losses related to compression and storage may occur (also modeled).
- The fuel distribution ("Fuel distribution"). We refer here to the infrastructure and fuel transport operations required to distribute the fuel, such as pipelines and trucks regionally, the energy needed to condition the fuel for transport (e.g., compression, liquefaction) and related losses along the supply chain.
- The on-site storage, if relevant, and the infrastructure needed to combust or convert the fuel into heat and electricity (e.g., fuel cell stack and balance of plant, boiler, co-generation unit), as well as its decommissioning (e.g., end-of-life treatment). The potential benefits of material recycling (i.e., primary production avoidance), which may occur outside the system boundary, are not considered. However, any benefit from sourcing materials with a given recycled content is.

In general, the inventories are supposed to represent current or near-future processes and technologies, which are either currently available as commercial products or expected to enter the market soon (maybe except for methane pyrolysis, which faces technical and economic challenges).

End-use technologies represent operation in Switzerland. Supply chains for synthetic fuels include both domestic production and import from foreign production sites.

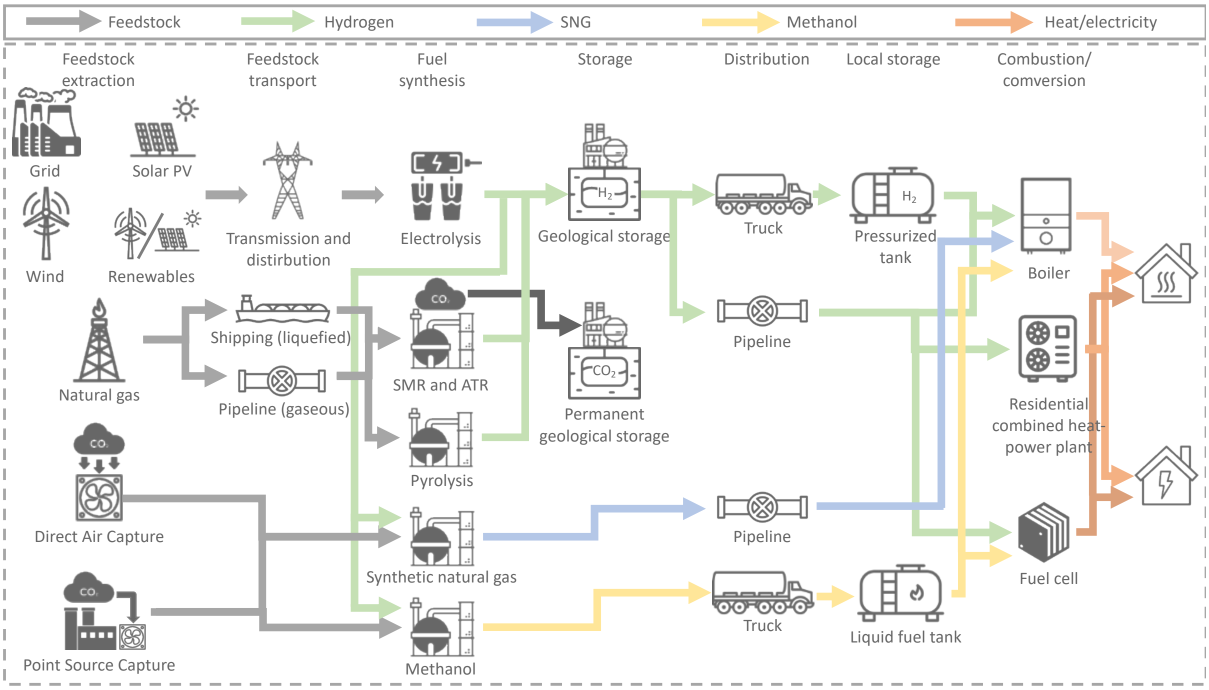

Figure 10 System boundary.

1.1.3 Purpose and intended use of this work

The main purpose of this LCA is the compilation of life cycle inventories of Power-to-X based heat and electricity supply options in a Swiss context, to be added to the UVEK:2024 inventory database, in line with the respective data quality guidelines. This report documents these new inventories as well as modeling approaches, data sources, and assumptions. The report also provides a technology-based comparison of the life-cycle environmental performance of these Power-to-X based heat and electricity supply options with conventional technologies on a microscale – based on impacts on climate change, (renewable and non-renewable) cumulative energy demand, and Swiss eco-factors 2021 according to the Ecological Scarcity method.

Benchmark heat supply technologies selected are natural gas and biomethane boilers, a wood boiler, and a modern air-water heat pump operated with a) the current average Swiss grid electricity mix, and b) a renewable electricity mix that might represent the supply mix at the time the PtX supply chains and technologies would be operated. In terms of electricity supply, electricity from the grid (average and certified renewable, respectively), from a natural gas power plant and from photovoltaic roof-top modules represent the benchmark options.

This LCA addresses single technologies and their environmental performance from a current, attributional perspective and is not embedded in an energy system setting. Therefore, this LCA does not reflect any systemic aspects of introducing Power-to-X based heat and electricity supply options into the (Swiss) energy and economic system (on a large scale) and is thus not suitable as support in decision-making processes regarding large-scale market introduction of the synthetic fuels analyzed.

When interpreting the LCA results, it should be kept in mind that options are being compared that are currently not at the same stage of development and some of which are not available in Switzerland. For example, hydrogen from natural gas pyrolysis and reforming with CCS is not available today and it is uncertain whether this will ever be the case. Similarly, hydrogen from the production in Morocco, which represents a “best case” from an environmental perspective, is a theoretical option that may be available in the future; assumptions taken here regarding technical performances should be verified under real operation conditions. The same applies to synthetic methanol and synthetic natural gas, which are not (yet) commercially available products in Switzerland. This study makes no statement on how realistic and desirable it is for these energy sources to come onto the Swiss market at large scales in the coming years.

However, the aim of this work was to cover as broad a spectrum as possible of variants for hydrogen production and energy carriers based on it and also to consider possible future options under optimistic framework conditions – mainly in order to gain an initial impression of the best possible potential environmental benefits despite all the uncertainties that exist, especially in the case of options that are not (yet) available. And also to be able to set the right priorities in the future development towards a climate and environmentally friendly heat supply for Swiss households.

1.2 Data sources and quality

Data sources for the various heat and electricity provision options differ. Table 4 presents an overview of the different data sources used.

Table 4 Overview of data sources.

	Feedstock	*Synthesis*	*Storage*	*Transmission, Distribution*	*Use*
Hydrogen					
AEC	Electricity LCIs (including photovoltaic electricity supply) for H_2 production via electrolysis are from the LCA database UVEK:2022 (lc-inventories 2018).	(Gerloff 2021b), combined with manufacturers data and from the IndWEDe project report (Now-gmbh 2020). Aggregated inventories for iridium supply from (Ifeu 2012).	(Wulf et al. 2018a) for storage. (Tsiklios, Hermesmann, and Müller 2022) for transmission pipelines.		Combustion of hydrogen based on datasets from UVEK:2022. For the chemical conversion: SOFC from UVEK, PEMFC from (Stropnik et al. 2022).
SOFC					
PEM					
ATR	LCI for natural gas and biomethane supply are from the LCA database UVEK:2022.	(Antonini et al. 2020)			
SMR					
Pyrolysis		(Al-Qahtani et al. 2021; Machhammer, Bode, and Hormuth 2016; Postels et al. 2016)			
CO_2					
DAC	(Qiu et al. 2022)				
Cement plant	(Meunier et al. 2020)				
MSWI	(Bisinella et al. 2021)				
SNG					
Catalytic		(Zhang et al., 2020)	Natural gas storage and pipeline LCI from UVEK:2022.		Natural gas boiler LCI from UVEK:2022.
Biological		(Energiforskning.dk 2014)			
Methanol		(Hank et al. 2019; Meunier et al. 2020)			Combustion of methanol based on datasets from UVEK(lc-inventories 2018). For direct methanol fuel cells (Notter et al. 2015; Glüsen, Müller, and Stolten 2020).

For all other purposes, the background data source is the life cycle inventory database the supply chain models link to (i.e., UVEK:2022). Additional data sources, such as boiler manufacturer specifications, are used for validation.

Table *5* lists some of this study's most critical assumptions or limitations.

Table 5 Summary of potentially critical model limitations or data quality issues.

	Use-related	Distribution	Inventory
Hydrogen	Data points on NOx emission factors for hydrogen combustion are scarce. The lifetime of electrolyzers depends on usage patterns, which are not well known.	On-site storage requirements depend on demand and delivery frequency, which are unknown.	Inventories for specific metals, such as rare earth elements, used in electrolyzers and fuel cells are not readily available in LCA databases or literature. For iridium, an aggregated inventory from IFEU had to be used.
SNG			CO_2 capture and biological and catalytic methanation of CO_2 are processes with relatively low TRL. Their efficiencies at scale are often extrapolated from demonstration projects.
Methanol	The use of methanol for residential heating purposes is not common in Europe. Hence, use-related data is challenging to obtain.		Synthetic methanol production is a process with a low TRL. Its efficiency at scale is not known.

Certain limitations in the established LCI due to a range of factors listed below need to be acknowledged, which points towards room for improvement as part of future work:

- Data Availability: Given the low level of deployment of these supply chains, obtaining reliable data is a significant issue (for example, the efficiency of the electrolysis process for hydrogen production, carbon capture rates, or emission data from the production and use of synthetic fuels). The limited data available might also not cover the complete variety of operating conditions these systems might encounter in the real world.
- Technology Maturity: As these technologies are still developing, the models considered in this report partially represent expected near-future technologies and come with uncertainty. They might be subject to further improvement when the technologies, as they will exist, will be deployed at scale. For instance, efficiencies could change as technologies improve. This is most relevant for methane pyrolysis, natural gas reforming with CCS, hydrogen storage, biological methanation, DAC and CCU processes.
- System Boundaries: The definition of system boundaries may influence the results in this life-cycle assessment (LCA) report. This includes notably whether the modelling of the supply of electricity-intensive synthetic fuels should include the transformational change on the electricity system of Switzerland, if produced domestically. These potential changes are currently not included.
- Assumptions: assumptions about the available source of energy (renewable or not), the efficiency of heating systems, the infrastructure used for transportation and storage, the frequency of hydrogen home deliveries can significantly affect the results.
- Geographical Variations: The environmental impact of producing synthetic fuels can vary greatly depending on the nature of the energy (e.g., average grid, hydroelectricity) and CO_2 feedstocks (e.g., biogenic, geogenic, fossil).
- Temporal Variations: Although not strictly considered in LCA, the availability of renewable power may not always align with the demand, affecting the system's overall efficiency and carbon intensity.
- End-of-Life Considerations: The treatment of the end-of-life phase can affect the life-cycle inventory performance. For example, the disposal, recycling, or reuse of fuel cell components or boiler equipment are aspects to consider.

1.3 General information – modeling

1.3.1 Overview

This section briefly describes common assumptions and modeling approaches for the synthetic fuel pathways presented in the report.

1.3.2 Fuel properties

The physical properties of the different energy carriers considered in this study are described in Table 6.

Table 6 Fuels characteristics.

Energy carrier	Density [kg/Nm^3]	LHV [MJ/kg]	LHV [kWh/kg]	Energy density [MJ$_{lhv}$/Nm^3]	CO_2 emission factor [kg CO_2/kg]	Source
Hydrogen	0.09	120	33.3	10.8	0	(The Engineering ToolBox 2003)
Synthetic natural gas	0.76	48	13.3	36.6	2.68	Assumed equivalent to natural gas (Emmenegger et al. 2007)
Methanol	792	20.0	5.55	12'355	1.37	(Althaus et al. 2007)

1.3.3 Supply chains and transport distances

Modeling infrastructure such as electrolyzers, reformers, pyrolyzers, reactors, on-site boilers, and fuel cells rely on global supply chains. Small co-generation units (i.e., 160 kWe) are assumed to be manufactured and assembled in Switzerland.

Transport operations from the regional storage to the assembly plant are added, following the distances and means of transport indicated in Table 4.2 p. 13 of the ecoinvent v.2 report (Rolf Frischknecht et al. 2007).

1.3.4 Losses

Hydrogen losses are considered throughout the supply chain. We refer to the UK government-commissioned report from (Frazer-Nash Consultancy 2022a) and the 2018 study from (Wulf et al. 2018a). The loss rates described in Table 7 are expressed as a percentage of the outgoing flow mass. For example, if a process supplies 1 kg of hydrogen with a loss rate of 0.18%, it requires 1.0018 kg of hydrogen upstream.

The mass of hydrogen lost through transmission and distribution by pipeline is specific to the distance the gas is transported over and the flow type (i.e., laminar flow when the leakage velocity is low and the hole size is small, turbulent flow otherwise). Here, we consider a leakage rate for *natural gas* pipeline transport of 0.019% of the mass transported per 1,000 km, as provided by (Faist Emmenegger et al. 2017) and used in UVEK:2022, which we multiply by the ratio between the mass flow rate of hydrogen and that of natural gas, assuming a laminar flow (i.e., optimistic case). This scaling factor is already given by (Frazer-Nash Consultancy 2022a) as 0.15. Hence, we obtain 0.00285% of the mass transported per 1,000 km. Note that volume-wise, the leakage rate of hydrogen is 20% superior to that of natural gas.

Despite hydrogen being clean burning, any leaked hydrogen released into the atmosphere may indirectly contribute to global warming by delaying the degradation of atmospheric methane. The following global warming potential for a time horizon of 100 years (GWP_{100}) of 11.6 kg CO_2-eq./kg H_2 has been suggested by (Sand et al. 2023).

For synthetic natural gas and methanol, we use the values considered in UVEK:2022 for natural gas and light fuel oil, respectively. Note that because we consider the production of synthetic natural gas and methanol fully integrated with hydrogen production, only the relevant loss rates from the hydrogen production process apply.

Table 7 Loss rates for the different steps in the hydrogen supply chain. The rates refer to the hydrogen mass.

Activity	Loss rate [% mass]	Source/remark
Electrolysis	0.24%	(Frazer-Nash Consultancy 2022a). Low estimate. Assumes the possibility of recombining the leaked hydrogen from venting and purging into water.
Steam Methane Reforming	0.25%	(Frazer-Nash Consultancy 2022a) estimate loss only when combined with CCS, as SMR without CCS is out of the scope of the analysis. We consider a similar loss when SMR is operated without CCS as well.
Auto-Thermal Reforming	0.25%	We apply a similar rate as for SMR, with and without CCS.
Pyrolysis	0.25%	(Frazer-Nash Consultancy 2022a) does not provide a loss rate for pyrolytic hydrogen production. Hence, we consider the rate as for SMR/ATR.
Regional storage (sub-surface cavern)	1% (loss) + 1.3% (used as cushion gas) – only 30% of the gas distributed is stored (Wulf et al. 2018b; European Commission 2022).	(Wulf et al. 2018a). Cushion gas is the portion of hydrogen needed but unused to maintain pressure in the cavity.
Transmission and distribution by pipeline	0.00285% per 1,000 km	Calculated from (Frazer-Nash Consultancy 2022a) and (Faist Emmenegger et al. 2017)
Transmission and distribution by truck	0.18% per day (considering an avg speed for European trucks of 60 km/h)	(Frazer-Nash Consultancy 2022a) for daily loss rates. (European Court of Auditors 2016) for the average speed of European trucks.
On-site storage (pressure vessel)	0.18% per day (multiplied by seven days since weekly deliveries)	
Boiler	0.5%	
CHP	0.5%	(Frazer-Nash Consultancy 2022a). Low estimate. For fuel cell systems, it assumes leaked hydrogen can be fully recombined. The loss rate in a CHP is not given it is deemed like that of a boiler.
Fuel cell	0.56%	

1.3.5 Multi-output activities

Dealing with multi-output activities mostly follows (Frischknecht et al. 2007), and exceptions have been agreed upon with FOEN and the reviewer of this work.

Combined heat and power generation activities are allocated according to the exergy content of their products, heat, and electricity – further details are provided in the specific sections of this report.

For a few selected activities, which generate by-products in small quantities or of limited economic value, a 100% allocation to the main product is implemented. This concerns hydrogen production via SMR, which generates minor amounts of electricity, and hydrogen production from methane pyrolysis with its by-product black carbon and water electrolysis, for which it is assumed that oxygen and heat are released into the atmosphere.

1.3.6 Dealing with CO_2 emissions from fossil carbon capture and utilization

Production of synthetic hydrocarbons such as synthetic natural gas and methanol using carbon dioxide (CO_2) from industrial point sources such as cement and municipal waste incineration plants and the subsequent use of these synthetic hydrocarbons as energy carriers or fuels (i.e., their combustion) represents a case of carbon capture and utilization (CCU).

As explained in (Treyer, Sacchi, and Bauer 2022), in case of using carbon dioxide from industrial point sources, there is a debate revolving at which point of the product systems the CO_2 emissions representing the captured CO_2 used as feedstock for fuel production should be accounted for. This issue arises because while the industrial point source capturing CO_2 has lower CO_2 emissions due to its capture process, the fuel user also wants to claim the use of "recycled" CO_2. Accounting for emission reductions associated with the same CO_2 molecule twice is not feasible.

Alternatively, a system expansion approach can be applied to such CCU processes – quantifying the environmental burdens of joint production of cement (and feedstock CO_2) at the cement plant and heat by the boiler using PtX fuel; or waste treatment by the MSWI plant (producing heat, electricity and feedstock CO_2) and heat generation by the PtX fuel boiler. However, such a system expansion approach for CCU processes does not allow for a quantification of product-specific environmental burdens of synthetic fuel production and use.

As product-specific environmental burdens of synthetic fuel production and use need to be quantified in the context of this analysis, the issue can be approached from three perspectives (also illustrated in Figure *11*):

- Fuel User's Perspective (100:0): The fuel user considers the CO_2 emitted as "recycled". In this view, the captured CO_2 stream represents a "waste", and a cement plant (or any industrial point source) shall bear the entire CO_2 emission burden, even with reduced own emissions, and the fuel user shall take the responsibility of capturing the CO_2 (and the associated environmental burdens). From this perspective, the CO_2 emissions at the cement plant would have occurred regardless of the fuel production and use, and the fuel user does not affect CO_2 source availability triggering additional CO_2 production unless demand surpasses supply.
- 50:50 Approach (50:50): To both the cement plant and fuel user 50% of the overall CO_2 emissions are attributed. Both are therefore assigned with 50% of the CO_2 captured and ultimately emitted, and the burden associated with capturing CO_2 is split equally between the two stakeholders. This represents the idea of using carbon (converted into CO_2) twice, once for cement production and once for fuel production. This approach could also be considered in line with the fact that from an overall system perspective including both CO_2 point source and CCU fuel consumer, overall system CO_2 emissions can be reduced by 50% at best.
- Industrial point source Perspective (0:100): By implementing carbon capture, the industrial point source reduces its direct CO_2 emissions. The fuel user is responsible for all emissions at the combustion point but is not assigned with any burdens associated with the carbon capture process. This acknowledges the actual CO_2 trajectory, with the industrial point source having fewer direct emissions. This perspective is relevant, especially if CO_2 is captured for storage or other permanent immobilization methods. However, a synthetic fuel producer would unlikely use CO_2 with full climate impacts attached.

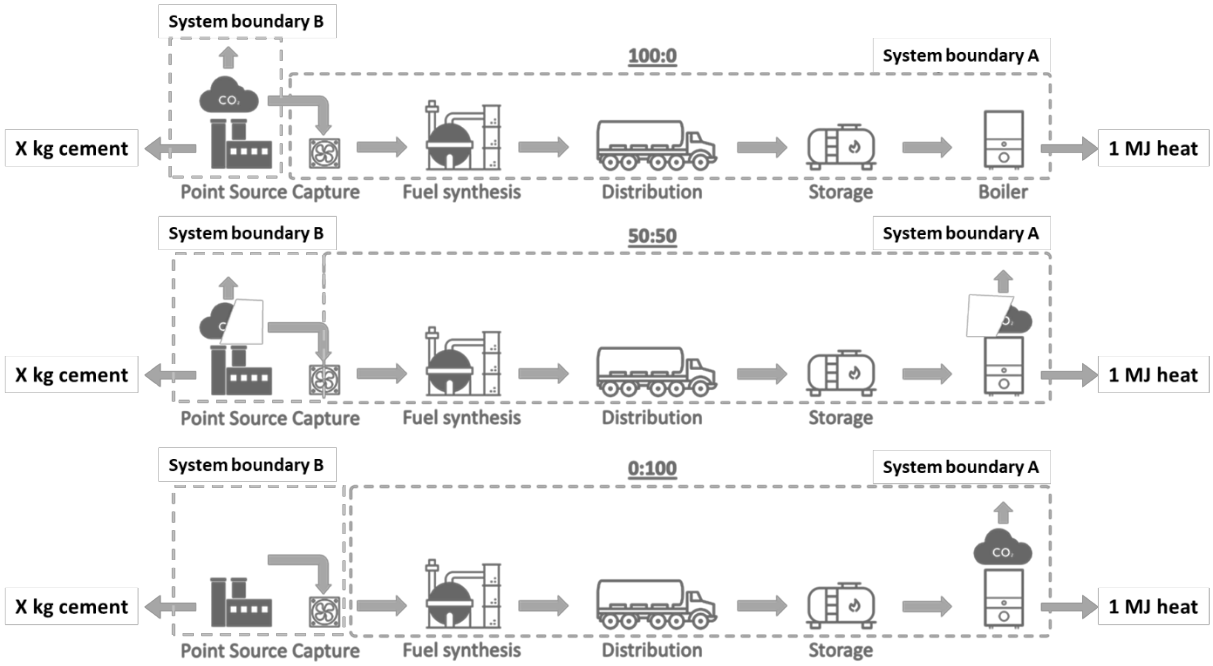

Figure 11 System boundaries definition according to CO_2 allocation approaches. 100:0 approach on top, where the captured CO_2, once emitted, is entirely assigned to the point source (system B, cement production) and CO_2 capture related burdens to the fuel end user (system A, heat production); 50:50 approach in the middle, where 50% of the captured CO_2 once emitted and 50% of the capture related burdens are assigned to both the fuel user and the point source; 0:100% approach at the bottom, where all captured CO_2 once emitted is assigned to the fuel user and the capture related burdens to the point source.

Synthetic natural gas and methanol supply and use datasets with these three approaches for CO_2 accounting are created. A sensitivity analysis section at the end of this report compares the results.

1.3.7 Supply chain specifications and datasets

This report and corresponding LCI datasets are available using the following Data Object Identifier: https://doi.org/10.5281/zenodo.7955951. The LCI datasets are also available through the update of the UVEK LCA database.

2 Hydrogen

2.1 Electrolysis

Water electrolysis is a process that uses electricity to split water into hydrogen and oxygen. Since this report only deals with water electrolysis, but no other electrolysis processes, we use the term “electrolysis” as equivalent for “water electrolysis”. The water splitting reaction occurs in an electrolyzer unit, which can range in size to accommodate different production scales. Various types of electrolyzers function differently based on their electrolyte material.

The electrolyte is a solid specialty plastic material in a **Polymer Electrolyte Membrane** electrolyzer (PEM). Water reacts at the anode to form oxygen and positively charged hydrogen ions (protons). The electrons flow through an external circuit, and the hydrogen ions selectively move across the PEM to the cathode. At the cathode, hydrogen ions combine with electrons from the external circuit to form hydrogen gas.

Alkaline electrolyzers (AEC) operate via hydroxide ions (OH-) transport through the electrolyte from the cathode to the anode, generating hydrogen on the cathode side. Newer approaches using solid alkaline exchange membranes (AEM) as electrolytes are also being explored.

Finally, **Solid oxide** electrolyzers (SOEC) use a solid ceramic material as the electrolyte that selectively conducts negatively charged oxygen ions (O_2-) at elevated temperatures. Steam at the cathode combines with electrons from the external circuit to form hydrogen gas and negatively charged oxygen ions. The oxygen ions pass through the solid ceramic membrane and react with the anode to form oxygen gas and generate electrons for the external circuit.

Note that such electrolyzers accept water or steam as input. Using steam reduces the electricity demand, allowing them to be combined with an excess heat supply.

We combine three sources of data to build the life-cycle inventories of electrolyzers:

1) the life-cycle inventories of (Gerloff 2021a), which provides detailed and scaled bills of materials for different electrolyzer types,
2) the summary report of the IndWEDe project (Now-gmbh 2020),
3) and a review of specifications of current electrolyzer models: the collected data is shown in Annex A, and average values per electrolyzer type are shown in Table *8*.

We use the life-cycle inventories of (Gerloff 2021a) to model the infrastructure (i.e., stack and balance of plant) while we consider the following parameters to model the operation phase:

- we consider the lifetime values reported in the IndWEDe report. Lifetime values reported from the manufacturers’ data are based on a small sample size, while (Gerloff 2021a) does not differentiate the lifetime across electrolyzer types.
- we consider the specific electricity consumption values reported in the IndWEDe report, although they agree with the manufacturer’s specifications. The IndWEDe project report, however, does not disclose the steam input for the SOEC electrolyzer when used in combination with steam. Hence, we collect that input from the manufacturers’ data instead, which also agrees with the steam input provided by (Gerloff 2021a).
- we use the average land occupation values from the manufacturers’ specification data, as it is missing from the inventories (Gerloff 2021a).
- and we use the average H_2 pressure level reported in the IndWEDe project report, although they agree with the manufacturers’ data.

Table 8 Average statistics based on manufacturers' data (see Annex A). SOEC electrolyzers can be operated with and without steam input. Using an input of steam reduces the electricity demand.

	AEC	PEM	SOEC	SOEC + steam
Sample Size	36	60	2	3
Spec. Electricity Demand [kWh/kg H_2]	53	52	46	39
Spec. Heat Demand [MJ/kg H_2]				16
Useful heat output [kW_{th}/kW_{el}]	0.27	0.17		
Electrical Efficiency [%, based on H_2 LHV]	64	65	72	84
Total Efficiency [%, based on H_2 LHV]	94	90	72	84
Space Requirement [m²/kW]	0.12	0.09	0.02	0.05
Stack Life [hours]	46'0	67'7		43'8
H_2 Pressure Level [bar]	23.2	34.5	1.2	2.3

This study considers each technology modeled as a 1 MW_{el} electrolyzer unit. The systems' parameters that are eventually considered are described in Table 9. These parameters align with the literature review performed by (Bauer (ed.) et al. 2022).

PEM electrolyzers rely on the use of iridium. LCI data for iridium mining and supply is neither available in the UVEK:2022 database nor in the scientific literature. Similarly to (Gerloff 2021a), aggregated emission inventories are extracted from the ifeu's Umweltprofile database (Ifeu 2012) to represent the mining and supply of iridium. The heat required by PEMC and SOEC electrolyzers is modeled with representative (fossil fuel-based) heat used in the petrochemical sector (as available in the UVEK:2022 database). For more information about the electrolyzers, the reader should refer to (Gerloff 2021a). The theoretical use of water per kg H_2 produced is 9 kilograms, as indicated in Table 9. However, this value is increased to 14 kilograms to reflect the technologies' current level of performance and the fraction of water reserved for cleaning or to compensate for evaporation caused by cooling (Simoes et al. 2021).

With a few exceptions, electrolyzer models on the market operate on 400 Volts of alternating current electricity, indicating that electricity supply can be modeled at low voltage – the International Electrotechnical Commission (IEC) considers medium voltage to start at 1,000 Volts.

Regarding land occupation and transformation, we assume the installation of the electrolyzer to take place in an industrial area. The annual land occupation is **calculated by dividing the land footprint of the electrolyzer by the annual hydrogen** production. The land transformation is calculated by dividing the land footprint of the electrolyzer by the lifetime production volume. The land footprint of the electrolyzer is calculated by multiplying the Space Requirement value from Table *8* with the electrolyzer's maximum power output.

Table 9 Specifications of electrolyzer units as modeled here.

	AEC	PEMC	SOEC	SOEC + steam	Source
Stack lifetime [hours]	55'000	45'000		20'000	IndWEDe
Stack lifetime [years]	7	5.5		2.5	IndWEDe, based on the lower estimate of 8,000 hours per year from manufacturers' data.
Balance of Plant lifetime [years]	Same as the system.				From the row below.
System lifetime [years]	27.5	20		20	IndWEDe

	AEC	PEMC	SOEC	SOEC + steam	Source
Stack replacement over the system's lifetime, excluding initial unit [unit]	3	3	7		Calculated.
Water demand [kg H_2O/kg H_2]	8.9, corrected to 14 to represent "real world" operation.				(Simoes et al. 2021)
Electricity demand [kWh/kg H_2]	51.8	54	42.3	39	IndWEDe for all cases, except SOEC + steam, based on manufacturers' data.
Electrical Efficiency [%, based on H_2 LHV]	64.50%	61.70%	78.70%	85%	From row above.
Steam demand [MJ/kg H_2]				16	Manufacturers' data.
Productivity [kg H_2/hour]	19.36	18.52	23.6		From row above.
KOH [kg/kg H_2]	0.0037				(Gerloff 2021a)
Operating temperature [°C]	60-80	50-80	650-1000		Manufacturers' data.
Operating pressure [bar]	~20	~30	~1		IndWEDe
Venting and purging loss [% mass]	0.24%				(Frazer-Nash Consultancy 2022b), low estimate.
Produced amount over system's the lifetime years [kg H_2]	4,259,200	2,963,200	3,776,000		Calculated based on the system's lifetime (fourth row and 8,000 hours of stack operation per year (from manufacturers' data) and hourly productivity.

Two primary hydrogen production datasets are described below and further analyzed in the Impact Assessment section of this report:

- PEM-based hydrogen production using Swiss grid electricity
- PEM-based hydrogen production operated by a Morocco-based hybrid power plant (Solar PV and Wind)

Additionally, alternative hydrogen production datasets are modeled using PEM electrolysis:

- PEM-based hydrogen production using a mix of renewable sources of electricity in Switzerland ("certified" electricity)
- PEM-based hydrogen production using Swiss photovoltaic solar power
- PEM-based hydrogen production using Swiss hydropower
- PEM-based hydrogen production using Danish wind power
- PEM-based hydrogen production using Morocco-based wind power
- PEM-based hydrogen production using Morocco-based photovoltaic solar power

Table 10 Life-cycle inventories for hydrogen production using PEM electrolysis with different electricity sources.

		hydrogen production, gaseous, 30 bar, from PEM electrolysis, from grid electricity/CH U	**hydrogen production, gaseous, 30 bar, from PEM electrolysis, from renewable electricity/CH U**	**hydrogen production, gaseous, 30 bar, from PEM electrolysis, from Swiss solar PV/CH U**	**hydrogen production, gaseous, 30 bar, from PEM electrolysis, from Swiss hydropower/CH U**	**hydrogen production, gaseous, 30 bar, from PEM electrolysis, from Danish wind turbines/DK U**	**Remark**
	Unit	1 kg	1 kg	1 kg	1 kg	1 kg	
Material and infrastructure inputs							
electrolyzer production, 1MWe, PEM, Stack/RER U	p	1.35e-06	1.35e-06	1.35e-06	1.35e-06	1.35e-06	Stack, 5.5 years lifetime.
electrolyzer production, 1MWe, PEM,	p	3.37e-07	3.37e-07	3.37e-07	3.37e-07	3.37e-07	BoP, 20 years lifetime.

		hydrogen production, gaseous, 30 bar, from PEM electrolysis, from grid electricity/CH U	hydrogen production, gaseous, 30 bar, from PEM electrolysis, from renewable electricity/CH U	hydrogen production, gaseous, 30 bar, from PEM electrolysis, from Swiss solar PV/CH U	hydrogen production, gaseous, 30 bar, from PEM electrolysis, from Swiss hydropower/CH U	hydrogen production, gaseous, 30 bar, from PEM electrolysis, from Danish wind turbines/DK U	Remark
Balance of Plant/RER U							
Water, deionised, at plant/CH U	kg	1.40e+01	1.40e+01	1.40e+01	1.40e+01	1.40e+01	A perfect reaction of H_2O results in 1 kg H_2 and 8 kg O_2 and needs 9 kg H_2O. Considering some losses, we assume 14 kg H_2O and 24 kg in arid climates (Simoes et al., 2021).
electricity, low voltage, at grid/kWh/CH U	kWh	5.40e+01					Electricity consumption with 61.7% eff.
electricity, low voltage, certified electricity, at grid/kWh/CH U	kWh		5.40e+01				Electricity consumption with 61.7% eff.
electricity, production mix photovoltaic, at plant/kWh/CH U	kWh			5.40e+01			Electricity consumption with 61.7% eff.
Electricity, hydropower, at power plant/CH U	kWh				5.40e+01		Electricity consumption with 61.7% eff.
Electricity, at wind power plant 2MW, offshore/OCE U	kWh					5.40e+01	Electricity consumption with 61.7% eff.
Steam, for chemical processes, at plant/RER U	MJ	1.01e+00	1.01e+00	1.01e+00	1.01e+00	1.01e+00	0.28 kWh heat needed/kg H_2
Occupation, industrial area	m2a	6.07e-04	6.07e-04	6.07e-04	6.07e-04	6.07e-04	Electrolyzer land footprint: (0.09 [m^2/kW]*1000[kW/MW])/(2963200[kg H_2 per lifetime]/20[years])
Transformation, from industrial area	m^2	3.04e-05	3.04e-05	3.04e-05	3.04e-05	3.04e-05	Electrolyzer land transformation: (0.09 [m^2/kW]*1000 [kW/MW])/2963200 [kg H_2]
Transformation, to industrial area	m^2	3.04e-05	3.04e-05	3.04e-05	3.04e-05	3.04e-05	Electrolyzer land transformation: (0.09 [m^2/kW]*1000 [kW/MW])/2963200 [kg H_2]
Emissions							
Oxygen		8.00e+00	8.00e+00	8.00e+00	8.00e+00	8.00e+00	
Hydrogen		2.40e-03	2.40e-03	2.40e-03	2.40e-03	2.40e-03	Hydrogen loss.
Waste treatment							
treatment of fuel cell stack, 1MWe, PEM/RER U	p	1.35e-06	1.35e-06	1.35e-06	1.35e-06	1.35e-06	Stack EoL
treatment of fuel cell balance of plant, 1MWe, PEM/RER U	p	3.37E-07	3.37E-07	3.37E-07	3.37E-07	3.37E-07	BoP EoL

2.1.1 PEM-based hydrogen production using Swiss grid electricity

Based on specifications from Table 9, the LCI presented in Table 10 and Figure *12* are considered. The dataset represents hydrogen production using PEM electrolysis powered by Swiss grid electricity. The electrolyzer system has a lifetime of 20 years, over which it will produce 2,963,200 kg of hydrogen.

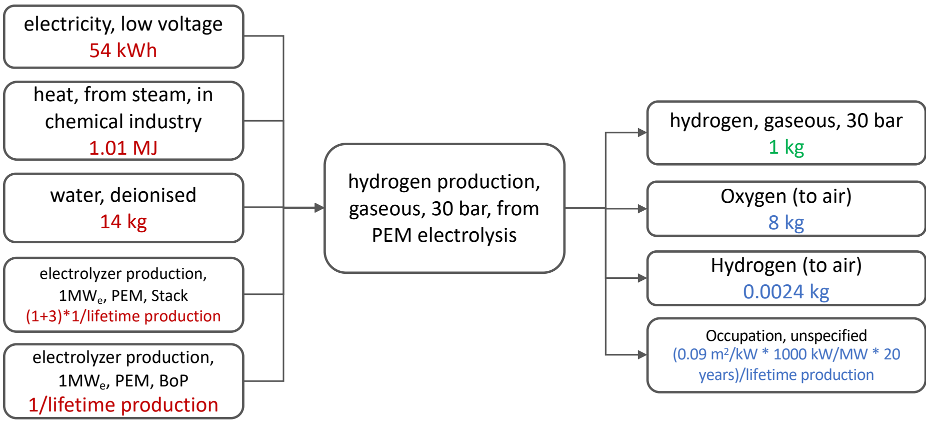

Figure 12 Schematic mass and energy balance for hydrogen production using PEM electrolysis. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

2.1.2 PEM-based hydrogen production using Swiss photovoltaic solar power

The LCI dataset is like that of hydrogen production using Swiss grid electricity, except that the supply of grid electricity is swapped for the supply of average Swiss photovoltaic electricity provided by the UVEK:2022 database, see Table 10. It is not an autonomous hydrogen production plant, and the dataset does not consider an individual energy storage capacity required for the smooth operation of the electrolyzer.

2.1.3 PEM-based hydrogen production using Swiss hydropower.

The LCI dataset is like that of hydrogen production using Swiss grid electricity, except that the supply of grid electricity is swapped for the supply of average Swiss hydroelectricity provided by the UVEK:2022 database, see Table 10. Note that it is not an autonomous plant, and the dataset does not consider the energy storage capacity required for a smooth operation of the electrolyzer.

2.1.4 PEM-based hydrogen production using Danish wind power

The LCI dataset is like that of hydrogen production using Swiss grid electricity, except that the supply of grid electricity is swapped for the supply of average electricity from offshore wind turbines. Note that the UVEK:2022 database does not provide a Danish wind turbine operation dataset. Hence, the dataset "Electricity, at wind power plant 2MW, offshore/OCE U" is used; see Table 10. This dataset considers a load factor of 30%, which is below Danish conditions (i.e., ~40%[5]).

2.1.5 PEM-based hydrogen production from an autonomous hybrid plant

Based on specifications from Table 9, a cost-optimization model building upon (Terlouw et al. 2023) is used to produce the LCI presented in Table 10. The dataset represents hydrogen production using PEM electrolysis, produced in an autonomous – i.e., not connected to the power grid – hybrid plant in central Morocco powered by local PV panels and onshore wind turbines, with average climate conditions for the country (Latitude: 21.6093, Longitude: -16.6012), pinpointed in red in Figure 13. The selected location is supposed to represent hydrogen production for import to Switzerland with very good site conditions in terms of

[5] https://turbines.dk/statistics/

renewable power generation yields, likely to represent a “best case” option in terms of environmental performance. This best-case scenario aims at quantifying the optimal environmental performance for H_2 production and use to be compared to the alternative technologies also operated under optimal condition (i.e., a heat pump operated with 100% electricity from renewable sources).

The hybrid plant has a lifetime of 30 years and produces 2.35 kilotons of hydrogen annually. It is assumed that 0.24% of the hydrogen mass produced is lost through venting and purging (Frazer-Nash Consultancy 2022a). Thirteen 2-MW onshore wind turbines are required, for a total capacity of 24.6 MW, with a lifetime of 20 years and a 50% load factor. This load factor is based on an estimate from https://www.renewables.ninja/, itself based on MERRA-2 reanalysis data – see Figure *14*. Twenty-eight 570-kWp ground-mounted PV units are considered, with a lifetime of 30 years and a 22% load factor, also based from an estimate from https://www.renewables.ninja/ -- see Figure *15*. To ensure a quasi-continuous operation, an NMC-811 stationary battery of 862 kWh capacity is considered, with a lifetime of 13 years. The process of optimizing the autonomous hydrogen production system involves determining the optimal Li-ion battery capacity for (hybrid) autonomous hydrogen production as well as the curtailment of solar PV and onshore wind. This problem is formulated as a mixed integer linear program. The constraints of the electrolyzer, solar PV, onshore wind, and the battery system are defined in (Terlouw et al. 2023). The hydrogen production systems are optimally designed based on annual cost (considering investment, O&M, and operation) considering 8760 timeslots (1 year). This allows considering the intermittent nature of solar PV and onshore wind, in addition to the possibility to curtail electricity and/or store electricity in a Li-ion battery. Thirty different global geographical locations are considered to obtain a curve fitting that allows on deciding on the battery capacity based on the amount of wind and solar PV installed globally. Note that the cost-optimization model suggests the installation of batteries only when the installation of photovoltaic panels becomes preponderant (and none when only wind power is used). This is because curtailment on wind turbines power production is more economical than installing energy storage capacity – this may however change in the future as battery cost will drop. A water requirement of 24 liters per kg H_2 is assumed because of losses due to cleaning, cooling, and significant evaporation (Tonelli et al., 2023). These parameters are summarized in

Table 11.

Figure 13 Location considered for the autonomous hybrid hydrogen plant.

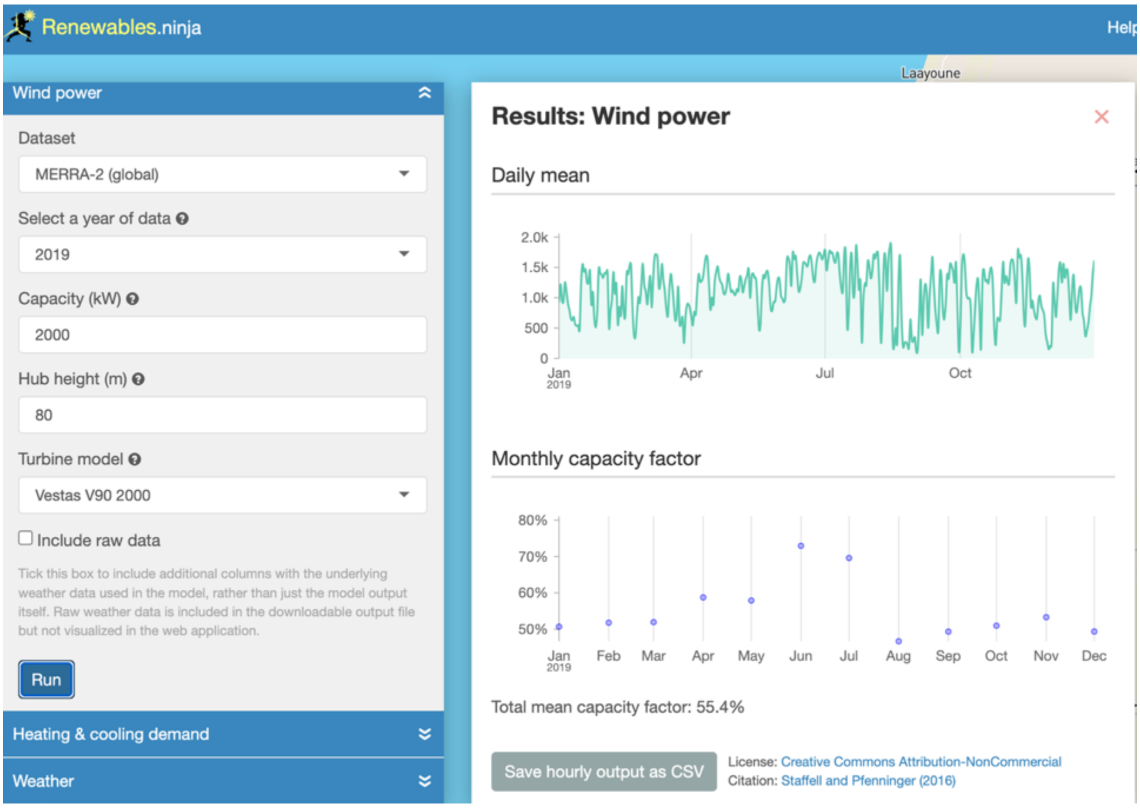

Figure 14 Seasonal and mean capacity factor for a 2-MW wind turbine at location Lat: 21.6093, Lon: -16.6012. (source: https://www.renewables.ninja/)

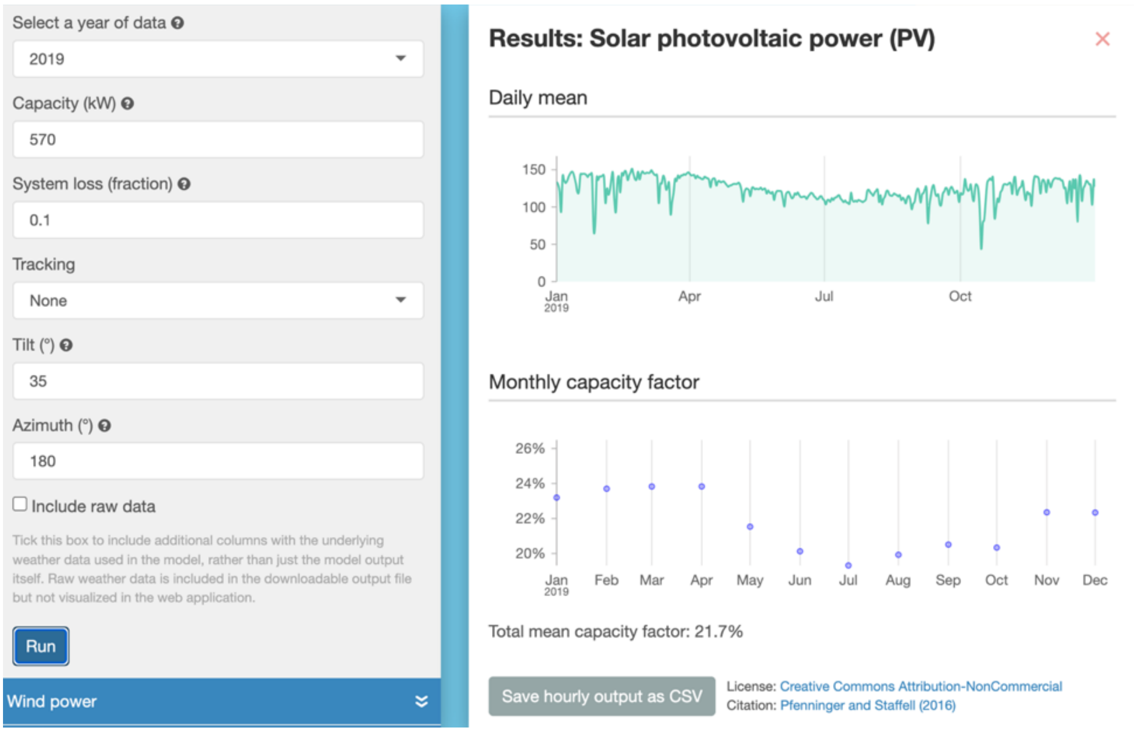

Figure 15 Seasonal and mean capacity factor for a 570-kWp open ground solar PV installation, at location Lat: 21.6093, Lon: -16.6012 (source: https://www.renewables.ninja/).

Table 11 Parameters for modeling an autonomous hydrogen production plant in Morocco.

	Hybrid plant (solar PV + Wind)	Solar PV only	Wind only	Remark
System lifetime [years]	30			
Annual production [kilotons]	2.35	1.37	2.86	
Electrolyzer installed capacity [MW]	26.2	14.4	37.3	It is scaled up from a 1-MW electrolyzer dataset.
Electrolyzer capacity factor [%]	57%	60%	50%	
Solar PV installed capacity [MW]	15.46	45.34		Scaled up from a 570 kWp ground-mounted PV panel dataset.
Solar PV load factor [%]	22%	22%		
Solar PV curtailment rate	13.8%	13.8%		
Onshore wind turbine installed capacity [MW]	24.6		33.3	Scaled up from a 2-MW onshore wind turbine dataset.
Onshore wind turbine load factor	50%		50%	
Onshore wind turbine curtailment rate	2.3%			
Energy storage capacity [kWh]	862	45,389	none	Based on an energy density of 0.2 kWh per kg of cell and

				0.14 kWh per kg of battery.

The life-cycle inventories are schematically described in Figure *16* and numerical values are provided in Table 12.

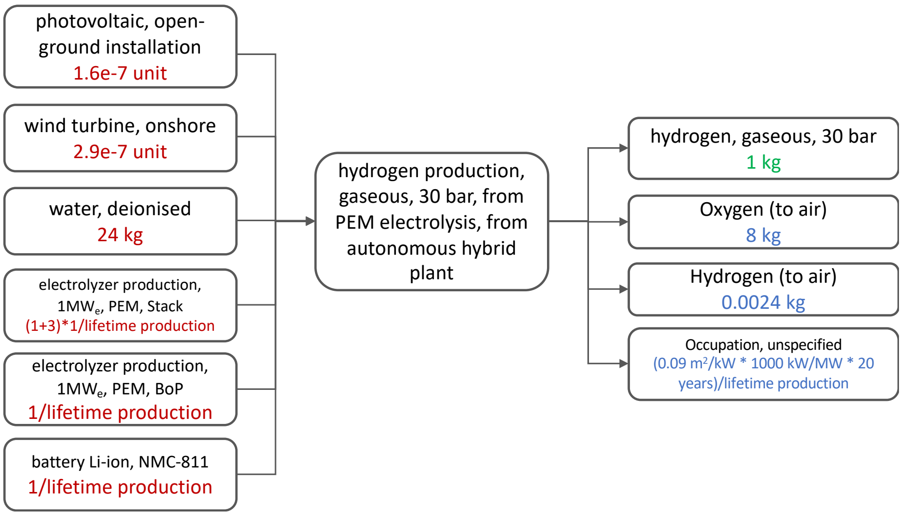

Figure 16 Schematic mass and energy balance for hydrogen production using PEM electrolysis in an autonomous hybrid plant. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

2.1.6 PEM-based hydrogen production using Morocco-based wind power

The LCI dataset is like that of hydrogen production in a Morocco-based hybrid plant, except that the input of solar PV is absent and compensated by an increase in electricity production capacity by wind turbines: nineteen 2-MW turbines are considered, for a total capacity of 33.3 MW, with a lifetime of 20 years and a 50% load factor. Other parameters used for modeling the dataset are summarized in Table 12.

2.1.7 PEM-based hydrogen production using Morocco-based solar power

The LCI dataset is like that of hydrogen production in a Morocco-based hybrid plant, except that the input of wind turbines is absent and compensated by an increase in electricity production capacity by solar PV panels: eighty 570-kWp ground-mounted PV units are considered, with a lifetime of 30 years, and a 22% load factor. Other parameters used for modeling the dataset are summarized in Table 12.

Flows representing the use of primary (kinetic) wind and solar (photonic) energy are added, similarly to their respective implementation in photovoltaic-based and wind-based electricity production datasets in the UVEK database.

Table 12 Life-cycle inventories for hydrogen production using PEM electrolysis in an autonomous plant in Morocco.

		hydrogen production, gaseous, 30 bar, from PEM electrolysis, from autonomous hybrid plant/MA U	**hydrogen production, gaseous, 30 bar, from PEM electrolysis, from autonomous solar-powered plant/MA U**	**hydrogen production, gaseous, 30 bar, from PEM electrolysis, from autonomous wind-powered plant/MA U**	**Remark**
	Unit	1 kg	1 kg	1 kg	
Material and infrastructure					
electrolyzer production, 1MWe, PEM, Stack/RER U	p	1.59e-06	1.50e-06	1.86e-06	Stack, 5.5 years lifetime.
electrolyzer production, 1MWe,	p	5.57e-07	5.27e-07	6.51e-07	BoP, 20 years lifetime.

		hydrogen production, gaseous, 30 bar, from PEM electrolysis, from autonomous hybrid plant/MA U	hydrogen production, gaseous, 30 bar, from PEM electrolysis, from autonomous solar-powered plant/MA U	hydrogen production, gaseous, 30 bar, from PEM electrolysis, from autonomous wind-powered plant/MA U	Remark
PEM, Balance of Plant/RER U					
Wind power plant 2MW, offshore, fixed parts/OCE/I U	p	2.61e-07		3.26e-07	Onshore wind installation with a lifetime of 20 years.
Wind power plant 2MW, offshore, moving parts/OCE/I U	p	2.61e-07		3.26e-07	Onshore wind installation with a lifetime of 20 years.
570 kWp open ground installation, multi-Si, on open ground/p/ES/I U	p	4.29e-07	2.17e-06		Ground-mounted system (considering degradation) with a lifetime of 30 years.
battery, rechargeable, prismatic, LiNCM, at plant/NO U	kg	1.89e-04	1.71e-02		Ground-mounted system (considering degradation) with a lifetime of 30 years.
Water, deionised, at plant/CH U	kg	2.40e+01	2.40e+01	2.40e+01	A perfect reaction of H_2O results in 1 kg H_2 and 8 kg O_2 and needs 9 kg H_2O. With losses, we assume 14 kg H_2O (24 kg in arid climate) (Simoes et al., 2021).
Energy inputs					
electricity, low voltage, at grid/kWh/CH U	kWh				Electricity consumption with 61.7% eff.
electricity, low voltage, certified electricity, at grid/kWh/CH U	kWh				Electricity consumption with 61.7% eff.
electricity, production mix photovoltaic, at plant/kWh/CH U	kWh				Electricity consumption with 61.7% eff.
Electricity, hydropower, at power plant/CH U	kWh				Electricity consumption with 61.7% eff.
Electricity, at wind power plant 2MW, offshore/OCE U	kWh				Electricity consumption with 61.7% eff.
Steam, for chemical processes, at plant/RER U	MJ	1.01e+00	1.01e+00	1.01e+00	0.28 kWh heat needed/kg H_2
Resources					
Occupation, unspecified, natural (non-use)	m^2a	3.83e-05	6.57e-05	3.15e-05	Electrolyzer land use: (0.09 [m2/kW]*1000[kW/MW])/(annual production [ktons/a]*1000[t/kt]*1000[kg/t])
Transformation, from unspecified, natural (non-use)	m^2	1.28e-06	2.19e-06	1.05e-06	Electrolyzer land transformation: (0.09 [m2/kW]*1000 [kW/MW])/(annual production [ktons/a]*30 [a]*1000[t/kt]*1000[kg/t])
Transformation, to industrial area	m^2	1.28e-06	2.19e-06	1.05e-06	Electrolyzer land transformation: (0.09 [m2/kW]*1000 [kW/MW])/(annual production [ktons/year]*30 [years]*1000[t/kt]*1000[kg/t])
Emissions					
Oxygen		8.00e+00	8.00e+00	8.00e+00	
Hydrogen		2.40e-03	2.40e-03	2.40e-03	Hydrogen loss.
Energy, solar, converted		4.30E+01	2.09E+02		
Energy, kinetic (in wind), converted		1.66E+02		2.09E+02	
Waste treatment					
treatment of fuel cell stack, 1MWe, PEM/RER U	p	1.59e-06	1.50e-06	1.86e-06	Stack EoL
treatment of fuel cell balance of plant, 1MWe, PEM/RER U	p	5.57e-07	5.27e-07	6.51e-07	BoP EoL

2.1.8 AEC- and SOEC-based hydrogen production using Swiss grid electricity

LCI datasets that represent hydrogen production using AEC and SOEC electrolyzers are modeled based on the specifications given in Table 9, and described in *Table 13*, Figure 17 and Figure 18. Additionally, an alternative to the SOEC-based hydrogen production dataset is created, where an input of steam is provided to reduce the electricity demand.

Table 13 Life-cycle inventories to produce hydrogen using AEC electrolysis with Swiss grid electricity.

		hydrogen production, gaseous, 20 bar, from AEC electrolysis, from grid electricity/CH U	**hydrogen production, gaseous, 1 bar, from SOEC electrolysis, from grid electricity/CH U**	**hydrogen production, gaseous, 1 bar, from SOEC electrolysis, with steam input, from grid electricity/CH U**	**Remark(s)**
	Unit	1 kg	1 kg	1 kg	
Material and infrastructure inputs					
electrolyzer production, 1MWe, AEC, Stack/RER U	p	9.39e-07			Stack, 5.5 years lifetime.
electrolyzer production, 1MWe, AEC, Balance of Plant/RER U	p	2.35e-07			BoP, 20 years lifetime.
electrolyzer production, 1MWe, SOEC, Stack/RER U	p		2.12e-06	2.12e-06	Stack, seven years lifetime.
electrolyzer production, 1MWe, SOEC, Balance of Plant/RER U	p		2.65e-07	2.65e-07	BoP, 20 years lifetime.
Potassium hydroxide, at regional storage/RER U	kg	3.70e-03			KOH input
Water, deionised, at plant/CH U	kg	1.40e+01	1.40e+01	1.40e+01	A perfect reaction of H_2O results in 1 kg H_2 and 8 kg O_2 and needs 9 kg H_2O. Considering some losses, we assume 14 kg H_2O (Simoes et al., 2021).
transport, freight, rail, electricity with shunting/tkm/CH U	tkm	2.22e-03			Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report.
transport, freight, lorry 16-32 metric ton, fleet average/tkm/CH U	tkm	1.85e-04			Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report.
electricity, low voltage, at grid/kWh/CH U	kWh	5.18e+01	4.23e+01	3.90e+01	Electricity consumption with 79% eff.
Steam, for chemical processes, at plant/RER U	kg	1.01e+00		5.76e+00	16 MJ heat needed/kg H_2
Resources					
Occupation, industrial area	m^2a	7.75e-04	1.06e-04	2.65e-04	Electrolyzer land footprint: (0.12 or 0.02 or 0.05 [m^2/kW]*1000[kW/MW])/(annual production [kg H_2 per lifetime]/27.5 or 20[years])
Transformation, from industrial area	m^2	2.82e-05	5.30e-06	1.32e-05	Electrolyzer land transformation: (0.12 or 0.02 or 0.05 [m_2/kW]*1000 [kW/MW])/annual production [kg H_2]
Transformation, to industrial area	m^2	2.82e-05	5.30e-06	1.32e-05	
Emissions to air					
Oxygen	kg	8.00e+00	8.00e+00	8.00e+00	
Hydrogen	kg	2.40e-03	2.40e-03	2.40e-03	Hydrogen loss.
Waste treatment					
treatment of fuel cell stack, 1MWe, AEC/RER U	p	1.35e-06			Stack EoL

		hydrogen production, gaseous, 20 bar, from AEC electrolysis, from grid electricity/CH U	hydrogen production, gaseous, 1 bar, from SOEC electrolysis, from grid electricity/CH U	hydrogen production, gaseous, 1 bar, from SOEC electrolysis, with steam input, from grid electricity/CH U	Remark(s)
treatment of fuel cell balance of plant, 1MWe, AEC/RER U	p	3.37E-07			BoP EoL
treatment of fuel cell stack, 1MWe, SOEC/RER U	p		2.12e-06	2.12e-06	Stack EoL
treatment of fuel cell balance of plant, 1MWe, SOEC/RER U	p		2.65E-07	2.65E-07	BoP EoL

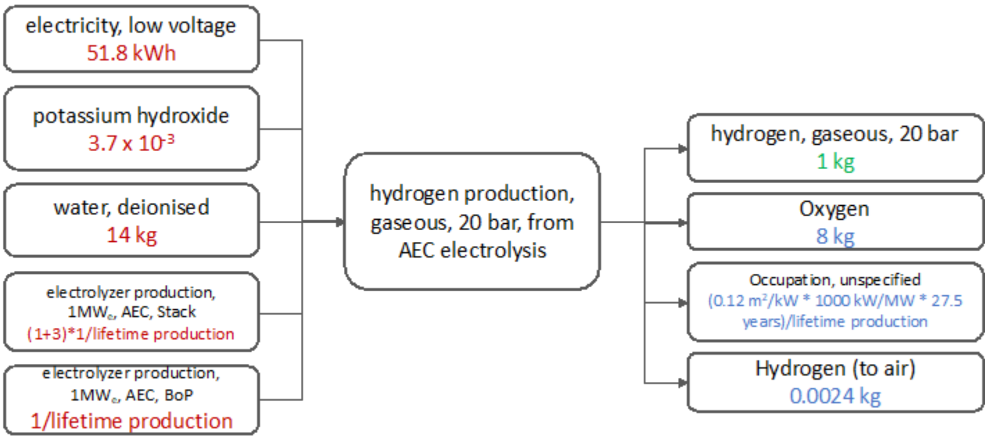

Figure 17 Schematic mass and energy balance for hydrogen production using AEC electrolysis. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

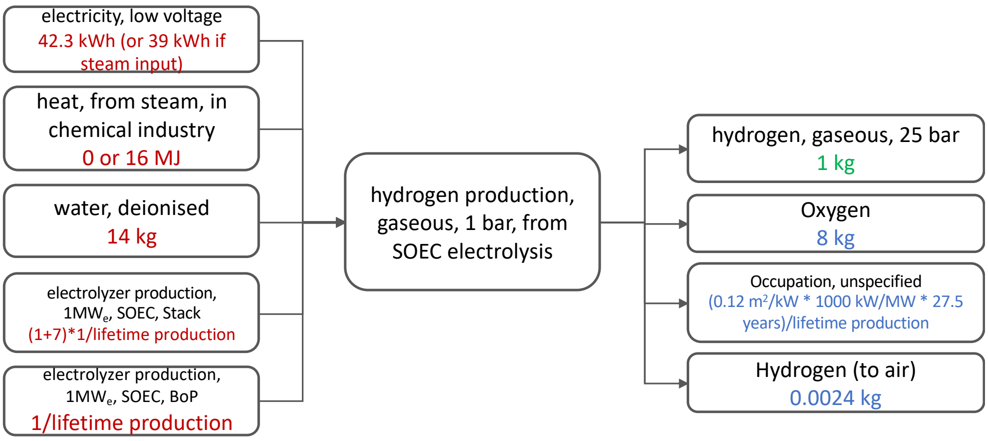

Figure 18 Schematic mass and energy balance for hydrogen production using SOC electrolysis. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

2.1.9 Uncertainty

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *14* for uncertainty estimation are considered.

Table 14 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertaint factor is applied (see Table 7.2 of (Rolf Frischknecht et al. 2007)).

	Reliability	**Completeness**	**Temporal correlation**	**Geographical correlation**	**Further technological correlation**	**Sample size**

PEM electrolysis	2	4	1	3	3	5
AEC electrolysis	2	4	1	3	3	5
SOEC electrolysis	2	4	1	3	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

2.2 Steam methane reforming (SMR)

Steam methane reforming is a process where methane from natural gas is reacted with steam to produce hydrogen, carbon monoxide, and a small amount of carbon dioxide. This reaction is endothermic, meaning it absorbs heat, and requires a high temperature (700–1000°C). A certain fraction of the natural gas consumed supplies this high-temperature heat. The overall reaction for steam methane reforming can be summarized as follows:

$$CH_4 + H_2O \leftrightarrow CO + 3H_2$$

The carbon monoxide can then be reacted with more steam to produce additional hydrogen and carbon dioxide in a process called the water-gas shift reaction.

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

The carbon dioxide and other impurities are then removed to leave pure hydrogen.

SMR is the most widely used large-scale technology for producing hydrogen today, besides its co-production associated with other industrial processes (Bermudez, Evangelopoulou, and Pavan 2022). It is efficient and well-established, but it does require a source of natural gas and results in greenhouse gas emissions. In this study, we also consider the association of Carbon Capture and Storage (CCS) to the SMR process, whereby the carbon in the flue gas is captured thanks to an amine-based pre-combustion capture unit. It is important to note that, unlike post-combustion capture units, the carbon emitted via emissions from the reformer furnace is not captured. Hence, the overall CO_2 capture efficiency (i.e., considering emissions from the reformer furnace) is about 65%.

The inventories for a 300 MW hydrogen plant sourced from (Antonini et al. 2020) are used for that purpose. These inventories consider the pre-combustion capture of CO_2 using Methyl diethanolamine (MDEA), with a 98% capture efficiency (only on the flue gas stream). Counterintuitively, SMR plants equipped with CCS need slightly less natural gas per unit of hydrogen produced (and at the same time do not produce excess electricity), as explained by (Antonini et al. 2020). The authors explain that “the more VPSA tail gas is burnt in the reformer furnace and the more CO_2 is captured, the less CO_2 will end in the furnace. Consequently, the heating value of the tail gas will be higher, and the furnace will require less additional fuel”. The plant’s specifications are described in Table 15.

Table 15 Specifications for a 300 MW SMR hydrogen plant, with and without CCS.

	SMR	SMR with CCS	Source
Lifetime [hours]	8’300 hours/year for 25 years		(Antonini et al. 2020)
Lifetime [years]	25 years		
Efficiency H_2/CH_4 (LHV) [%]	77.1%	77.9%	
Natural gas demand [m^3/kg H_2]	4.37	4.30	
Operating pressure [bar]	~25 bar		
Produced amount over 25 years [kg]	1’875’000		
Venting and purging loss [% mass]	0.25%		(Frazer-Nash Consultancy 2022b)

Two primary hydrogen production datasets are described below and further analyzed in the Impact Assessment section of this report:

- SMR-based hydrogen production using average Swiss natural gas.
- SMR-based hydrogen production using average Swiss natural gas with CCS.

Additionally, alternative SMR-based hydrogen production datasets are modeled using liquefied natural gas:

- SMR-based hydrogen production using liquefied natural gas.
- SMR-based hydrogen production using liquefied natural gas, with CCS.

2.2.1 SMR-based hydrogen production using natural gas, with and without CCS

Based on the specifications from Table *15*, the LCI datasets described in Table *16* and Figure *19* and Figure *20* are modeled. The SMR process co-delivers a small amount of electricity (1.2 kWh/kg H_2). For simplification, it has been decided not to consider it as a co-product requiring an allocation.

The capture, transport, and storage (CCS) of CO_2 are modeled after (Volkart, Bauer, and Boulet 2013). The inventories include the infrastructure and energy expenditure representing the capture of CO_2 adapted to a hydrogen plant. They also include the transport infrastructure (i.e., pipeline), compression over 200 km, and gas injection and storage at a depth of 1'000 m.

The hydrogen plant has a lifetime of 25 years and an annual production volume of 75 kilotons, or 1.875 million tons over 25 years (Antonini et al. 2020). The plant construction dataset is modelled based on UVEK's *Chemical plant, organics/RER/I U* and *Liquid storage tank, chemicals, organics/CH/I U*. The chemical plant dataset from the UVEK database considers a lifetime of the infrastructure of 50 years for the plant, with an annual production volume of 0.05 million tons, or 2.5 million tons over 50 years (Althaus et al. 2007). Hence, the hydrogen plant dataset considers 0.75 (1.875/2.5) units from *Chemical plant, organics/RER/I U.* The dataset representing the carbon dioxide capture and storage from a hydrogen plant *carbon dioxide storage, at hydrogen production plant, pre, pipeline 200km, storage 1000m/CH U* as well as that representing deep borehole drilling *drilling, deep borehole/CH U* are from (Volkart, Bauer, and Boulet 2013).

Direct emissions from the fuel combustion in the reformer furnace have not been the focus of the original study of the SMR dataset, which was more directed to investigating impacts on climate change and potential negative emissions using biomethane. Thus, the direct emissions from the furnace have been approximated by using the emissions to air from the activity "heat production, natural gas, at industrial furnace >100kW", scaled to kilogram of emissions per MJ of natural gas burned. Carbon dioxide emissions are not taken from that dataset, but instead modelled in the foreground depending on the various carbon capture system designs.

Table 16 Life-cycle inventories to produce hydrogen using SMR natural gas and liquefied natural gas.

		hydrogen plant construction, by methane reforming/CH U	**carbon dioxide storage, at hydrogen production plant, pre, pipeline 200km, storage 1000m/CH U**	**hydrogen production, steam methane reforming of natural gas, 25 bar/CH U**	**hydrogen production, steam methane reforming of natural gas, with CCS, 25 bar/CH U**	**hydrogen production, steam methane reforming of liquefied natural gas, 25 bar/CH U**	**hydrogen production, steam methane reforming of liquefied natural gas, with CCS, 25 bar/CH U**	**Remark(s)**
	Unit	1 unit	1 kg	1 kg	1 kg	1 kg	1 kg	
Material and infrastructure inputs								
Chemical plant, organics/RER/I U	p	0.75						

		hydrogen plant construction, by methane reforming/CH U	carbon dioxide storage, at hydrogen production plant, pre, pipeline 200km, storage 1000m/CH U	hydrogen production, steam methane reforming of natural gas, 25 bar/CH U	hydrogen production, steam methane reforming of natural gas, with CCS, 25 bar/CH U	hydrogen production, steam methane reforming of liquefied natural gas, 25 bar/CH U	hydrogen production, steam methane reforming of liquefied natural gas, with CCS, 25 bar/CH U	Remark(s)
Liquid storage tank, chemicals, organics/CH/I U	p	4.76						
transport, pipeline, long distance, carbon dioxide, with recompression/CH U	tkm		2.00e-1					
drilling, deep borehole/CH U	m		3.195					
Gas turbine, 10MWe, at production plant/RER/I U	unit		2.54e-11					
electricity, medium voltage, at grid/kWh/CH U			9.48e-3					
Diethanolamine, at plant/RER U	kg		3.40e-5					
hydrogen plant construction, by methane reforming/CH U	p			5.33e-10	5.33e-10	5.33e-10	5.33e-10	1/(25 years x 75 kilotons/year)
aluminium oxide, at plant/kg/RER U	kg			5.33e-04	5.33e-04	5.33e-04	5.33e-04	
Chromium oxide, flakes, at plant/RER U	kg			3.60e-05	3.60e-05	3.60e-05	3.60e-05	
Copper oxide, at plant/RER U	kg			3.62e-04	3.62e-04	3.62e-04	3.62e-04	
Magnesium oxide, at plant/RER U	kg			2.80e-05	2.80e-05	2.80e-05	2.80e-05	
Nickel, 99.5%, at plant/GLO U	kg			2.03e-04	2.03e-04	2.03e-04	2.03e-04	
Portafer, at plant/RER U	kg			3.12e-04	3.12e-04	3.12e-04	3.12e-04	
Quicklime, milled, packed, at plant/CH U	kg			4.80e-05	4.80e-05	4.80e-05	4.80e-05	
Sheet rolling, steel/RER U	kg			1.16e-05	1.16e-05	1.16e-05	1.16e-05	
Water, deionised, at plant/CH U	kg			7.54e+00	7.54e+00	7.54e+00	7.54e+00	
Zeolite, powder, at plant/RER S	kg			8.83e-04	8.83e-04	8.83e-04	8.83e-04	
Zinc oxide, at plant/RER U	kg			3.71e-04	3.71e-04	3.71e-04	3.71e-04	
carbon dioxide storage, at hydrogen production plant, pre, pipeline 200km, storage 1000m/CH U	kg				6.16e+00		6.16e+00	Captures 90% of the steam reforming reaction.
transport, freight, rail, electricity with shunting/tkm/CH U	tkm			1.44e-03	1.56e-03	1.44e-03	1.56e-03	Generic transport distances based on Table 4.2 of the ecoinvent v.2 Methodology report.
transport, freight, lorry 16-32 metric ton, fleet average/tkm/CH U	tkm			1.39e-04	1.49e-04	1.39e-04	1.49e-04	Generic transport distances based on Table 4.2 of the ecoinvent v.2 Methodology report.
natural gas, liquefied, at freight ship/m3/NAC U	m3			4.37e+00	4.30e+00			

		hydrogen plant construction, by methane reforming/CH U	**carbon dioxide storage, at hydrogen production plant, pre, pipeline 200km, storage 1000m/CH U**	**hydrogen production, steam methane reforming of natural gas, 25 bar/CH U**	**hydrogen production, steam methane reforming of natural gas, with CCS, 25 bar/CH U**	**hydrogen production, steam methane reforming of liquefied natural gas, 25 bar/CH U**	**hydrogen production, steam methane reforming of liquefied natural gas, with CCS, 25 bar/CH U**	**Remark(s)**
natural gas, liquefied, import from DZ/Europe without Switzerland U	m3					4.37e+00	4.30e+00	
Water, cooling, unspecified natural origin/m3	m3			3.80e-01	3.80e-01	3.80e-01	3.80e-01	
Emissions to air								
Acetaldehyde	kg			3.07e-08	2.80e-08	3.07e-08	2.80e-08	
Acetic acid	kg			4.60e-06	4.21e-06	4.60e-06	4.21e-06	
Benzene	kg			1.23e-05	1.12e-05	1.23e-05	1.12e-05	
Benzo(a)pyrene	kg			3.07e-10	2.80e-10	3.07e-10	2.80e-10	
Butane	kg			2.15e-05	1.96e-05	2.15e-05	1.96e-05	
CO_2, fossil	kg			8.92e+00	2.61e+00	8.92e+00	2.61e+00	
CO, fossil	kg			6.44e-05	5.89e-05	6.44e-05	5.89e-05	
Dinitrogen monoxide	kg			3.07e-06	2.80e-06	3.07e-06	2.80e-06	
Formaldehyde	kg			3.07e-06	2.80e-06	3.07e-06	2.80e-06	
Mercury II	kg			9.20e-10	8.41e-10	9.20e-10	8.41e-10	
Methane, fossil	kg			6.14e-05	5.61e-05	6.14e-05	5.61e-05	
Nitrogen oxides	kg			5.49e-04	5.02e-04	5.49e-04	5.02e-04	
PAH	kg			3.07e-07	2.80e-07	3.07e-07	2.80e-07	
Particulate Matter, < 2.5 um	kg			6.14e-06	5.61e-06	6.14e-06	5.61e-06	
Pentane	kg			3.68e-05	3.36e-05	3.68e-05	3.36e-05	
Propane	kg			6.14e-06	5.61e-06	6.14e-06	5.61e-06	
Propionic acid	kg			6.14e-07	5.61e-07	6.14e-07	5.61e-07	
Sulfur dioxide	kg			1.69e-05	1.54e-05	1.69e-05	1.54e-05	
Toluene	kg			6.14e-06	5.61e-06	6.14e-06	5.61e-06	
Hydrogen	kg			2.50e-03	2.50e-03	2.50e-03	2.50e-03	Loss

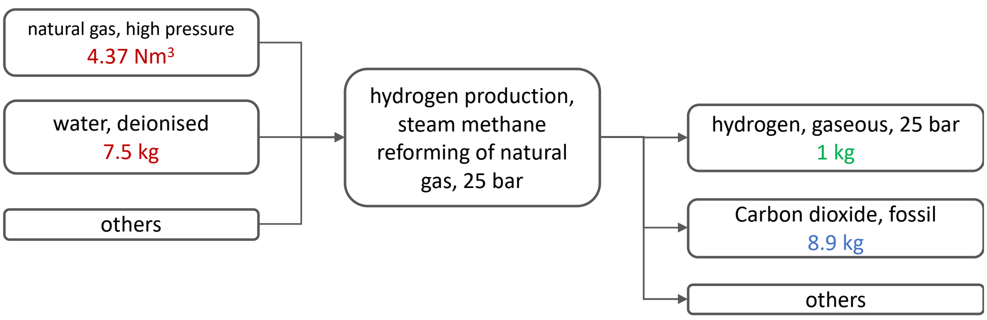

Figure 19 Schematic mass and energy balance for natural gas-based SMR hydrogen production. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

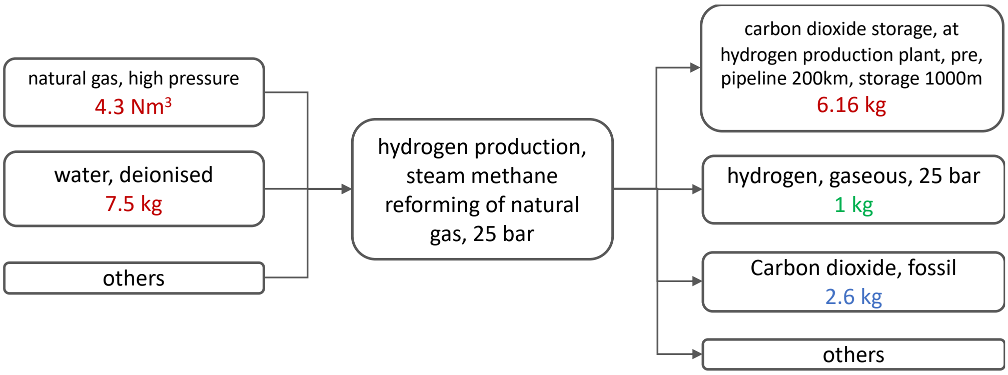

Figure 20 Schematic mass and energy balance for natural gas-based SMR hydrogen production with CCS. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

2.2.2 SMR-based hydrogen production using liquefied natural gas, with and without CCS

These datasets are like those described above, except for the natural gas input, which is replaced by “natural gas, liquefied, at freight ship/m3/NAC U”, provided by the UVEK:2022 database – see Table *16*.

2.2.3 Uncertainty

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *17* for uncertainty estimation are considered.

Table 17 Uncertainty factors used for uncertainty estimations. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	Completeness	Temporal correlation	Geographical correlation	Further technological correlation	Sample size
SMR	2	4	2	3	3	5
CCS	4	5	3	3	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

2.3 Auto-thermal reforming (ATR)

Autothermal reforming is a process for producing hydrogen from natural gas (methane) or other hydrocarbons. In the ATR process, natural gas, and steam (or water) are introduced to a reactor along with oxygen or air. Combustion and steam reforming co-occur in the same reactor, which is why the process is termed “auto-thermal”.

The overall reactions that occur in the ATR process include:

Combustion:

$$CH_4 + 2O_2 \leftrightarrow CO_2 + 2H_2O$$

Steam Reforming:

$$CH_4 + H_2O \leftrightarrow CO + 3H_2$$

The combustion reaction is exothermic (i.e., releases heat), while the steam reforming reaction is endothermic (i.e., absorbs heat). Hence, the heat from the combustion reaction provides the energy needed for the endothermic steam reforming reaction.

The resulting mixture of CO and H_2 from these reactions is then subjected to the Water-Gas Shift (WGS) reaction, where carbon monoxide reacts with water to produce more hydrogen and carbon dioxide:

Water-Gas Shift:

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

ATR has several advantages. It’s a well-established process and is currently one of the most efficient and effective ways to produce hydrogen at a large scale. It also allows for some CO_2 to be recovered and used, which can help mitigate the environmental impact.

However, there are also significant challenges with ATR. The major challenge is that, similarly to SMR, it produces fossil CO_2 as a byproduct due to the conversion of natural gas, contributing to greenhouse gas emissions.

Similarly to SMR, the inventories for a 300 MW plant from (Antonini et al. 2020) are used to model this technology. Compared to an SMR plant, which exhibits two primary sources of CO_2 emissions, an ATR shows only one source of emissions, which can be equipped with a CO_2 capture unit. Thus, the overall CO_2 removal rate of the ATR with CCS is much higher than that of the SMR plant with CCS represented here. Similarly to SMR plant, ATR plants equipped with CCS need slightly less natural gas per unit of hydrogen produced (and at the same time do not produce excess electricity), as explained by (Antonini et al. 2020).

Table 18 Specifications for a 300 MW ATR hydrogen plant, with and without CCS (Antonini et al. 2020).

	ATR	ATR with CCS	Source
Lifetime [hours]		8’300 hours/year for 25 years	(Antonini et al. 2020)
Lifetime [years]		25 years	
Yearly production [kt/year]		75	
Efficiency H_2/CH_4 (LHV) [%]	69.5%	76.6%	
Natural gas demand [m^3/kg H_2]	4.8	4.35	
Operating pressure [bar]	~25 bar		
Produced amount over 25 years [kg]		1’875’000	
Venting and purging loss [% mass]		0.25%	(Frazer-Nash Consultancy 2022b)

Two primary hydrogen production datasets are described below and further analyzed in the Impact Assessment section of this report:

- ATR-based hydrogen production using average Swiss natural gas.
- ATR-based hydrogen production using average Swiss natural gas, with CCS.

2.3.1 ATR-based hydrogen production using natural gas, with and without CCS

Based on the specifications from Table *18*, the LCI datasets described in

Table 19 and Figure *21* and Figure 22 are modeled. Note that the ATR process co-delivers a small amount of electricity (0.6 kWh/kg H_2) that we estimate too small to justify allocating the dataset inputs and emissions – hence not considered a co-product requiring an allocation. The capture, transport, and storage of CO_2 rely on the same set of inventories described in the previous section.

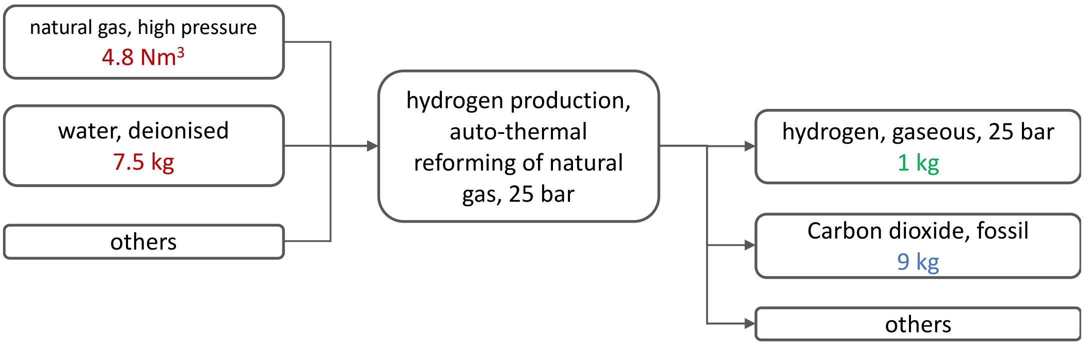

Figure 21 Schematic mass and energy balance for natural gas-based ATR hydrogen production. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Table 19 Life-cycle inventories for hydrogen production using ATR with natural gas.

		hydrogen production, auto-thermal reforming of natural gas, 25 bar/CH U	**hydrogen production, auto-thermal reforming of natural gas, with CCS, 25 bar/CH U**	**Remark(s)**
	Unit	1 kg	1 kg	
Material and infrastructure inputs				
hydrogen plant construction, by methane reforming/CH U	p	5.35e-10	5.35e-10	1/(25 years x 75 kilotons/year)
aluminium oxide, at plant/kg/RER U	kg	5.33e-04	5.33e-04	
Chromium oxide, flakes, at plant/RER U	kg	3.60e-05	3.60e-05	
Copper oxide, at plant/RER U	kg	3.62e-04	3.62e-04	
Liquid storage tank, chemicals, organics/CH/I U	p	2.55e-09	2.55e-09	
Magnesium oxide, at plant/RER U	kg	2.80e-05	2.80e-05	
Nickel, 99.5%, at plant/GLO U	kg	2.03e-04	2.03e-04	
Portafer, at plant/RER U	kg	3.12e-04	3.12e-04	
Quicklime, milled, packed, at plant/CH U	kg	4.80e-05	4.80e-05	
Sheet rolling, steel/RER U	kg	1.16e-05	1.16e-05	
Water, deionised, at plant/CH U	kg	7.54e+00	7.54e+00	
Zeolite, powder, at plant/RER S	kg	8.83e-04	8.83e-04	
Zinc oxide, at plant/RER U	kg	3.71e-04	3.71e-04	
Diethanolamine, at plant/RER U	kg		2.84e-04	

carbon dioxide storage, at hydrogen production plant, pre, pipeline 200km, storage 1000m/CH U	kg		8.34e+00	
transport, freight, rail, electricity with shunting/tkm/CH U	tkm	1.44e-03	1.61e-03	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report
transport, freight, lorry 16-32 metric ton, fleet average/tkm/CH U	tkm	1.39e-04	1.53e-04	
Energy inputs				
natural gas, at long-distance pipeline/m3/CH U	m3	4.80e+00	4.36e+00	
Resources				
Water, cooling, unspecified natural origin/m3	m3	3.80e-01	3.80e-01	
Emissions to air				
Carbon dioxide, fossil	kg	8.99e+00	5.88e-01	
Nitrogen oxides	kg	3.00e-03	3.00e-03	
Hydrogen	kg	2.50e-03	2.50e-03	Loss

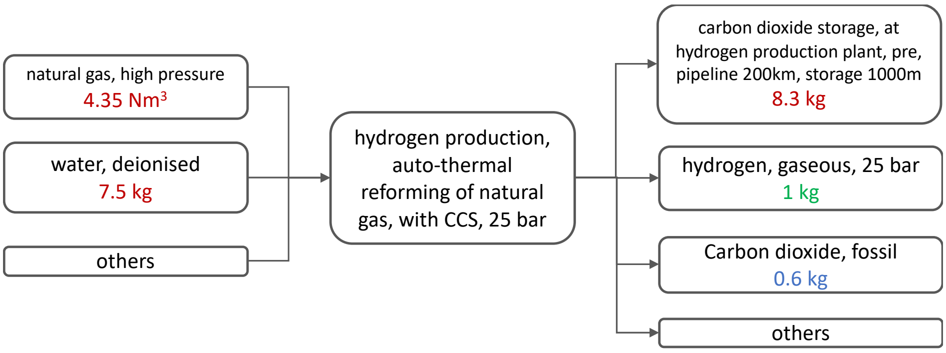

Figure 22 Schematic mass and energy balance for natural gas-based ATR hydrogen production with CCS. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

2.3.2 Uncertainty

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *20* for uncertainty estimation are considered.

Table 20 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	Completeness	Temporal correlation	Geographical correlation	Further technological correlation	Sample size
ATR	2	4	2	3	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

2.4 Methane pyrolysis

Hydrogen production from natural gas pyrolysis, also known as *methane pyrolysis* or *thermal decomposition*, is a promising method for producing hydrogen without the immediate release of carbon dioxide. In this process, methane (the primary component of natural gas) is heated to high temperatures, causing it to break apart into hydrogen and solid carbon so that:

$$CH_4 \leftrightarrow C + 2H_2$$

This process typically occurs at temperatures above 800°C. Solid carbon can produce materials like carbon fiber or carbon black (~3.9 kg solid carbon produced per kg H_2).

This dual-product approach could potentially provide a significant economic advantage. Low direct CO_2 emissions during the process make it potentially a more climate-friendly approach compared to SMR, which is the most widely used method for producing hydrogen from natural gas today, and which does produce CO_2 (Bermudez, Evangelopoulou, and Pavan 2022).

That said, there are still challenges to be addressed for this method of hydrogen production, including the need for significant energy input and the development of technology for handling and utilizing the solid carbon byproduct. There's ongoing research to overcome these challenges and make methane pyrolysis a viable large-scale method for hydrogen production.

This study uses the inventories from (Al-Qahtani et al. 2021) for the operational phase of a pyrolysis plant using a liquid-metal reactor, consolidated with inventories from (Postels et al. 2016) for modeling the reactor. The pyrolysis process requires an additional power requirement of 7.23 MWh_{el}/ton H_2. This amount accounts for the energy losses during heat recovery and the 2 MWh_{el}/ton H_2 compression power to compress pyrolysis hydrogen from 2 bar to 100 bar with three interim cooling stages.

Table 21 Specifications for a methane pyrolysis-based hydrogen plant

	Methane pyrolysis	**Source**
Annual operating time [hours]	8000	
Lifetime [years]	20	
Efficiency H_2/CH_4 (LHV) [%]	~51%	Average of (Al-Qahtani et al. 2021; Postels et al. 2016)
Natural gas demand [m^3/kg H_2]	6.57	
Operating pressure [bar]	100 bar	(Postels et al. 2016)
Operating temperature [°C]	~1'100	

2.4.1 Pyrolysis-based hydrogen production using average Swiss natural gas

Inventories based on specifications from Table *21* and described in Table *22* and Figure *23* are modeled. Even though there could be applications for solid carbon produced as a co-product in Switzerland in the future, which might represent long-term storage of CO_2 associated with climate benefits, it is considered a waste in the LCI compiled here. Hence, all the inputs and emissions associated with the pyrolysis process are attributed to hydrogen production. This differs slightly from the approach used in the study the inventories are sourced from, which gave an allocation factor superior to 95% for hydrogen production, based on the respective market values of the co-products.

Nevertheless, the inventories are considered low-quality since they are based on experimental studies scaled up to represent industrial conditions.

Table 22 Life-cycle inventories to produce hydrogen using pyrolysis of natural and liquefied natural gas.

		hydrogen production, gaseous, 100 bar, from methane pyrolysis/CH U	**hydrogen production, gaseous, 100 bar, from pyrolysis of liquefied natural gas/CH U**	**Remark(s)**
	Unit	1 kg	1 kg	
Material and infrastructure inputs				

		hydrogen production, gaseous, 100 bar, from methane pyrolysis/CH U	hydrogen production, gaseous, 100 bar, from pyrolysis of liquefied natural gas/CH U	Remark(s)
Palladium, at regional storage/RER U	kg	1.10e-05	1.10e-05	Infrastructure - membrane
Copper, primary, at refinery/GLO U	kg	7.33e-06	7.33e-06	Infrastructure - membrane
Chromium steel 18/8, at plant/RER U	kg	2.59e-03	2.59e-03	Infrastructure - heat exchanger
Tin, at regional storage/RER U	kg	3.36e-02	3.36e-02	Infrastructure - reactor
Chromium steel 18/8, at plant/RER U	kg	5.07e-04	5.07e-04	Infrastructure - filter
Silicon carbide, at plant/RER U	kg	4.20e-06	4.20e-06	Infrastructure - burner
Air compressor, screw-type compressor, 4 kW, at plant/RER/I U	p	6.36e-08	6.36e-08	Infrastructure - compressor
tap water, at user/kg/CH U	kg	8.08e+00	8.08e+00	
transport, freight, rail, electricity with shunting/tkm/CH U	tkm	2.20e-02	2.20e-02	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.01 kg over 3600.0 km.
transport, freight, lorry 16-32 metric ton, fleet average/tkm/CH U	tkm	1.84e-03	1.84e-03	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.01 kg over 300.0 km.
Energy inputs				
natural gas, at long-distance pipeline/m3/CH U	m3	6.85e+00		Initially, 4.86kg, then averaged with value from Postels et al., 2016, and converted to cubic meters.
natural gas, liquefied, at freight ship/m3/NAC U	m3		6.85e+00	Initially, 4.86kg, then averaged with value from Postels et al., 2016, and converted to cubic meters.
electricity, low voltage, at grid/kWh/CH U	kWh	7.23e+00	7.23e+00	
Emissions to air				
Carbon dioxide, fossil	kg	2.50e+00	2.50e+00	
Hydrogen	kg	2.50e-03	2.50e-03	Loss

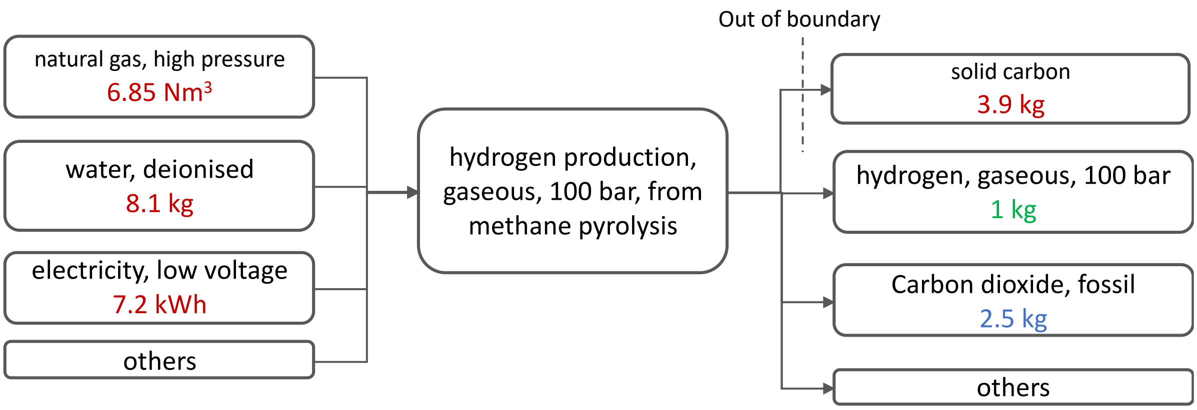

Figure 23 Schematic mass and energy balance for hydrogen production via methane pyrolysis. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

2.4.2 Pyrolysis-based hydrogen production using liquefied natural gas

These datasets are like those described above, except for the natural gas input, which is replaced by “natural gas, liquefied, at freight ship/m3/NAC U”, provided by the UVEK:2022 database – see Table *22*.

2.4.3 Uncertainty

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *23* for uncertainty estimation are considered.

Table 23 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	Completeness	Temporal correlation	Geographical correlation	Further technological correlation	Sample size
Methane pyrolysis	4	5	2	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

2.5 Transmission, storage, and distribution

Distances assumed for the transmission and distribution of hydrogen are presented in Table 24. The following sections explain the modeling aspects and inventories of the transmission, storage, and distribution steps. Hydrogen is transmitted to the regional storage by pipeline, regardless of the origin. We consider two distribution options for hydrogen: by low-pressure pipeline or truck in pressurized tanks.

Table 24 Distances assumed for transmission and distribution of hydrogen.

Transmission by	**pipeline**						**Remark**
Origin	*Switzerland*		*Morocco*		*Denmark*		
Distance from producer to regional storage [km]	250		2,500		1,300		For Morocco, the approximate distance was calculated using an online map calculator, considering a passage inland until Melila (MA) and an underwater section until Marseille (FR), completed by an inland section to the center of CH. For DK, the geodesic distance is used between the West coast of DK (e.g., Esbjerg, offshore installations) and the center of CH.
Distribution by	pipeline	truck	pipeline	truck	pipeline	truck	
Distance from regional storage to consumer [km]	250						A distance of 250 km is assumed between the regional storage and consumers for all delivery options.

2.5.1 Transmission

The transmission phase comprises transport from the hydrogen producer to a regional storage site (i.e., geological cavity, in this case) to be further available for dispatch to consumers (i.e., distribution). We consider only one transmission option: by pipeline.

2.5.1.1 Compression effort

The effort the compressor (i.e., assumed electric) must provide to condition the hydrogen for transmission is described in Table 25.

Table 25 Electric compression effort at the H_2 plant gate to 100 bar for pipeline injection. The formula for compression effort is from (Khan et al. 2021).

	Compression electricity [kWh/kg H_2]
Electrolysis, AEC (20 bar)	1.2
Electrolysis, PEM (30 bar)	0.88
Electrolysis, SOEC (1 bar)	4
Steam Methane Reforming (25 bar)	1.03
Auto-thermal reforming (25 bar)	1.03
Pyrolysis (100 bar)	0

2.5.1.2 Transmission by pipeline

Inventories for a hydrogen transmission pipeline are modeled after the work of (Tsiklios, Hermesmann, and Müller 2022). The pan-European hydrogen network, as envisioned by the literature, does not come to full capacity before 2040. In the meantime, it is believed it would consist of re-purposed natural gas transmission pipelines, circulating an increasing share of hydrogen (up to 20%) in the natural gas blend, as studies highlight the inadequacy of re-purposed natural gas pipelines to circulate pure hydrogen because of the embrittlement effect hydrogen has on steel.

In this study, we consider using dedicated hydrogen pipelines to circulate pure hydrogen. The inner layer of the pipeline is hot-dipped in an aluminum (55%wt) – zinc (43.3%wt) – silicon (1.6%wt) mixture to prevent corrosion and embrittlement. The other layers, from inner to outer, consist of steel, epoxy resin, copolymer adhesive, and high-density polyethylene. The pipeline specifications are described in Table 26.

According to the thermodynamic calculations of (Tsiklios, Hermesmann, and Müller 2022), pipelines with such diameter and flow rate require a 32-MW_{el} compressor operating at 28 MW every 125 km, with an isentropic efficiency of 80% and a mechanical-electric efficiency of 96%, which inventories are described in

Table 28.

On this basis, we derive the specifications described in Table *26* for the transmission pipeline, with inventories related to its manufacture, installation, and use presented in Table *22*.

Table 26 Pipeline and compression specifications for hydrogen transmission.

Transmission pipeline	
Lifetime [years]	40
Operating pressure range [bar]	16-100, 80 as reference
Annual operating hours [hours]	8,000
Hydrogen circulated per lifetime [Mt]	124.81
Mass flow [kg/s]	108.34
Outer diameter [m]	1.192
Inner diameter [m]	1.165
Inner coating layer [micro-m]	65
Steel layer [mm]	27.09
Epoxy primer [mm]	0.15
HDPE layer [mm]	3
Compressor	
Lifetime [years]	20

Number of compressors per 500 km [unit]	4
Pressure drop per 500 km [bar]	46.54
Compression capacity [MW]	32
Power consumption [MW]	27.7

Table 27 Life-cycle inventories to manufacture, install and use transmission and distribution hydrogen pipeline.

		transmission pipeline for hydrogen, dedicated hydrogen pipeline/CH U	**hydrogen transmission pipeline construction/CH U**	**hydrogen transmission pipeline installation/CH U**	**treatment of hydrogen transmission pipeline/CH U**	**Remark(s)**
	Unit	1 km	1 km	1 km	1 km	
Material and infrastructure inputs						
hydrogen transmission pipeline construction/CH U	km	1.00e+00				
hydrogen transmission pipeline installation/CH U	km	1.00e+00				
Building, hall, steel construction/CH/I U	m2		2.00e-01			manufacture
Building, multi-storey/RER/I U	m3		1.60e+01			manufacture
Drawing of pipes, steel/RER U	kg		7.91e+05			manufacture
powder coating, steel/RER U	m2		3.83e+03			manufacture
zinc coating for hydrogen pipeline/RER U	kg		4.46e+02			manufacture
extrusion, plastic film/RER U	kg		5.60e+03			manufacture
Steel, low-alloyed, at plant/RER U	kg		7.91e+05			manufacture
excavation, hydraulic digger, average/m3/CH U	m3			1.20e+03		installation
Excavation, skid-steer loader/RER U	m3			1.90e+04		installation
Sand, at mine/CH U	kg			2.28e+06		installation
transmission pipeline for hydrogen, dedicated hydrogen pipeline/CH U	km					Approximated by 99% downscaling of transmission pipeline.
Transport, freight helicopter, single-engine/hr/CH U	hr	2.60e+01				use and maintenance
transport, helicopter, single-engine, LTO cycle/p/CH U	p	1.04e+01				use and maintenance
transport, freight, rail, electricity with shunting/tkm/CH U	tkm		4.75e+05	1.20e+05		Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 791447.36 kg over 600.0 km.
transport, freight, lorry 16-32 metric ton, fleet average/tkm/CH U	tkm		3.96e+04	4.56e+04		Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 791447.36 kg over 50.0 km.
Transformation, from forest	m2	2.00e+03				
Transformation, to arable	m2	2.00e+03				
Transformation, from unknown	m2	2.49e+00				
Transformation, to industrial area, vegetation	m2	2.49e+00				
Occupation, construction site	m2 a	3.30e+03				
Water	m3	1.87E+02				
Emissions to air						
Water	m3	2.80e-02				
Emissions to water						
Water	m3	1.59e-01				
Waste treatment						
treatment of hydrogen transmission pipeline/CH U	km	1.00e+00				

		transmission pipeline for hydrogen, dedicated hydrogen pipeline/CH U	hydrogen transmission pipeline construction/CH U	hydrogen transmission pipeline installation/CH U	treatment of hydrogen transmission pipeline/CH U	Remark(s)
Disposal, natural gas pipeline, 0% water, to construction waste landfill/kg/CH U	kg				3.96e+05	end-of-life treatment
disposal, plastics, mixture, 15.3% water, to municipal incineration/kg/CH U	kg				2.73e+03	end-of-life treatment

Table 28 Life-cycle inventories to manufacture a 32MW compressor for hydrogen transmission pipeline, based on (Tsiklios, Hermesmann, and Müller 2022).

		compressor assembly for transmission hydrogen pipeline/RER U	Remark(s)
	Unit	1 unit	
Material and infrastructure inputs			
Building, hall, steel construction/CH/I U	m^2	2.00e-01	
Compressed air, average installation, >30kW, 7 bar gauge, at supply network/RER U	m^3	7.20e+03	
Metal working factory operation, average heat energy/RER U	kg	1.06e+05	
Lubricating oil, at plant/RER U	kg	2.15e+01	
Metal working factory/RER/I U	p	4.86e-05	
Metal working machine, unspecified, at plant/RER/I U	kg	4.19e+00	
Steel, low-alloyed, at plant/RER U	kg	2.21e+04	
Reinforcing steel, at plant/RER U	kg	6.98e+01	
Chromium steel 18/8, at plant/RER U	kg	9.54e+04	
Synthetic rubber, at plant/RER U	kg	3.60e-01	
transport, freight, rail, electricity with shunting/tkm/CH U	tkm	3.53e+04	
transport, freight, rail/tkm/RER U	tkm	1.91e+04	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 29649.66 kg over 644.0 km.
transport, freight, lorry 16-32 metric ton, fleet average/RER U	tkm	9.55e+03	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 26596.06 kg over 359.0 km.
transport, barge tanker/tkm/RER U	tkm	1.44e+01	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 21.5 kg over 670.0 km.
Energy inputs			
electricity, low voltage, production ENTSO, at grid/kWh/ENTSO U	kWh	3.92e+05	
Resources			
Water, cooling, unspecified natural origin/m3	m3	8.32e+01	
Emissions to air			
Water	m3	3.55e-02	
Emissions to water			
Water	m3	5.85e-02	
Waste treatment			
Recycling steel and iron/RER U	kg	4.67e+04	
Disposal, used mineral oil, 10% water, to hazardous waste incineration/CH U	kg	2.15e+01	

2.5.2 Regional storage

Large-scale hydrogen storage can be achieved in several ways, each with its benefits and challenges: geological, above-ground, liquid hydrogen, and chemical storage. It's important to note that the storage method is often determined by the intended use of the hydrogen, the volume to be stored, and the geographical and infrastructure conditions of the region. Globally, the infrastructure for large-scale regional storage would likely involve a combination of these methods tailored to the specific resources and needs of the area.

Natural underground formations such as salt caverns, aquifers, and depleted natural gas fields can be repurposed to store hydrogen, and these formations are geographically dependent and are not available everywhere. Geological hydrogen storage can be in various formations, including salt domes, porous media, and other geological structures. The feasibility of such storage depends on multiple factors, including the specific characteristics of the geological formation and the surrounding area and the technology available for managing such storage (Lawrence Livermore National Laboratory 2021).

Identifying possible candidate locations for geological hydrogen storage is out of scope, and we will simply assume that Switzerland has salt caverns for that purpose, even though a recent study suggests such caverns may not be located within the Swiss borders but nearby (Caglayan et al. 2020).

The inventories from (Wulf et al. 2018a) are used to model hydrogen storage in a salt cavern. They cover the solution mining of a 500'000 m^3 salt cavern, storing 4'000 tons of hydrogen annually at a pressure of 175 bar, with a 1% annual loss (or 0.01 kg/kg H_2 stored) and a service time of 40 years. There's also a 1.3% loss of the total hydrogen stored because a fraction of the gas volume stays unused as cushion gas. Additional specifications for the salt cavern considered are available in Table S7 in (Wulf et al. 2018a) and presented in Table *29*. We consider that only 30% of the hydrogen supplied needs be regionally stored. It aligns with the values considered in (Wulf et al. 2018b), but also with the current storage capacity-to-demand ratio for natural gas (European Commission 2022).

Table 29 Life cycle inventories for hydrogen storage in a geological cavity.

		geological hydrogen storage/CH U	**solution mining for geological hydrogen storage/CH U**	**Remark(s)**
	Unit	1 kg	1 kg	
Material and infrastructure inputs				
tap water, at user/kg/CH U	kg		3.12e+01	
solution mining for geological hydrogen storage/CH U	kg	1.00e+00		
Energy inputs				
electricity, low voltage, at grid/kWh/CH U	kWh	1.44E-01	9.38e-02	

As explained by (Wulf et al. 2018a), the large-scale storage of hydrogen in salt caverns is a new topic with little information to base inventories. Hence, these inventories must be considered minimal and relatively uncertain, focusing on operational expenditures rather than infrastructure requirements.

The electricity demand corresponds to the compression effort to inject hydrogen at a pressure of 170 bar from the hydrogen carrier (pipeline, truck, or train). When transported by truck or train, the outlet pressure is superior to the hydrogen injection pressure. Hence, the hydrogen is simply vaporized, and no compression effort is needed. However, when the hydrogen is transmitted by pipeline, the outlet pressure is around 70 bar, and the following compression effort is required: 0.64 kWh/kg H_2.

After storage, there's an additional electricity need of 0.144 kWh/kg H_2 for drying the hydrogen before injecting it into the distribution system (either a pipeline or the tank of a vehicle).

Finally, the pressure at the outlet of the hydrogen dryer drops to 50 bar, which implies further compression before distribution: either to 100 bar for distribution via pipelines (i.e., 0.5 kWh/kg H_2) or 500 bar for distribution by truck or train in pressurized tanks (i.e., 1.78 kWh/kg H_2).

2.5.3 Distribution

We consider two distribution options: by low-pressure pipeline or by truck. The reader should refer to Table *24* for distribution distances by means of transport.

2.5.3.1 Distribution by pipeline

Unfortunately, Tsiklios, Hermesmann, and Müller (2022) do not provide inventories for a hydrogen *distribution* pipeline. We derive the material requirements based on the dimensions of the transmission pipeline.

The distribution pipeline considered has an inner diameter of 100 mm. Hence, the wall thickness for the distribution pipeline, with an inner diameter of 100 mm, would be approximately 5 mm when scaled proportionally to the transmission pipeline's wall thickness (55 mm) and inner diameter (1,160 mm).

To determine the percentage difference in terms of the volume of material required for the two pipelines, we first need to compute the volume of material for each pipeline and then find the percentage difference.

For a cylindrical shell (like a pipeline wall), the volume *V* is given by:

$$V = \pi L(r_a^2 - r_b^2)$$

Where:

- *L* is the length of the pipeline
- r_a is the outer radius
- r_b is the inner radius

Given the wall thickness for each pipeline, the difference in material volume required between the transmission and distribution pipeline is defined by:

$$diff = (\frac{V_1 - V_2}{V_2}) \approx 0.99$$

Where:

- V_2 is the material volume of the distribution pipeline
- V_1 is the material volume of the transmission pipeline

Hence, a distribution pipeline with an inner diameter of 100 mm would require 99% less material than a distribution pipeline with an inner diameter of 1160 mm for the same pipe length. Therefore, we model the inventories of the distribution pipeline as a 99% downscaled version of the transmission pipeline, except for the 65-micrometer thick inner layer zinc coating, which we keep unchanged.

The cross-sectional area of the distribution pipeline, A_d, is given by:

$$A_d = \pi(\frac{D}{2})^2 = 78.54\ cm^2$$

And that of the transmission pipeline, A_t, is:

$$A_t = 10{,}660\ cm^2$$

With:

- *D* the inner diameter of the pipeline (100 mm)

The ratio of the capacities of the two pipelines, considering both area and pressure, can be expressed as:

$$ratio = \frac{A_d * P_d}{A_t * P_t}$$

We consider an operating pressure for the distribution pipeline that provides the same energy flow as current distribution pipelines for natural gas do. Low-pressure natural gas pipelines operate at 5 bar. The operating pressure for the hydrogen distribution pipeline can be determined by the following:

$$P_{H2} = P_{NG} * \frac{E_{NG}}{E_{H2}} = 19\, bar$$

With:

- E_{NG} = 36 MJ/m³ (for natural gas)
- E_{H2} = 10 MJ/ m³ (for hydrogen at standard conditions)

Hence, assuming an operating pressure for the distribution pipeline of 19 bar (i.e., like natural gas), the quantity circulated in the distribution pipeline over its 40 years lifetime, Q_d, can be defined as:

$$Q_d = \left(\frac{A_d * P_d}{A_t * P_t}\right) * Q_t \approx 0.22\, Mtons$$

With:

- A_d being the cross-sectional area of the distribution pipeline (calculated above)
- A_t being the cross-section area of the transmission pipeline
- P_d et P_t being the respective operating pressures of the distribution and transmission pipelines
- Q_t being the amount of hydrogen circulated through the transmission pipeline (i.e., 124 Mtons over 40 years)

On this basis, we derive the specifications described inTable *30* for the distribution pipeline. Finally, we do not consider any compression between the gas dryer outlet of the storage facility (50 bar) and the distribution pipeline since the latter is likely to require an inlet pressure lower than 50 bar.

Table 30 Pipeline specifications for hydrogen distribution.

Distribution pipeline (downscaled from transmission pipeline)	
Lifetime [years]	40
Operating pressure range [bar]	19
Annual operating hours [hours]	8,000
Hydrogen circulated per lifetime [Mt]	0.22
Mass flow [kg/s]	0.19
Outer diameter [m]	0.105
Inner diameter [m]	0.100
Inner coating layer [micro-m]	65
Steel layer [mm]	27.09 * (5/55) = 4.5
Epoxy resin layer [mm]	0.15 * (5/55) = 0.025
HDPE layer [mm]	3 * (5/55) = 0.5

Table 31 Life-cycle inventories to supply hydrogen via pipeline to the consumer.

		hydrogen supply, distributed by pipeline, produced by …	Remark(s)
	Unit	1 kg	
Material and infrastructure inputs			
hydrogen production, gaseous, XX bar, from …	kg	1.00e+00	Hydrogen input.
hydrogen production, gaseous, XX bar, from …	kg	6.90e-03	Hydrogen leak.
pipeline, hydrogen, low pressure distribution network /CH U	km	1.16e-06	0.22 Mton of hydrogen circulated over the pipeline's lifetime. Mass flow of 0.19 kg/second.
pipeline, hydrogen, high pressure transmission network /CH U	km	2.05e-09	124.81 Mton of hydrogen circulated over the pipeline's lifetime. Mass flow of 108.34 kg/second.
compressor assembly for transmission hydrogen pipeline/RER U	p	3.28e-11	Hydrogen compressor for transmission pipeline.
geological hydrogen storage/CH U	kg	3.06e-01	Geological cavity to store hydrogen. 30% of the supplied amount is stored.
Energy inputs			
electricity, low voltage, at grid/kWh/CH U	kWh	1.05e+00-4.24e+00	To compress the H_2 before and during transmission. The amount depends on the electrolyzer type.
electricity, low voltage, at grid/kWh/CH U	kWh	6.55e-01	To compress the H_2 before storage.
electricity, low voltage, at grid/kWh/CH U	kWh	1.45e-01	To compress the H_2 before and during distribution.
Emissions to air			
Hydrogen	kg	6.90e-03	Hydrogen leaks. Equal to losses.

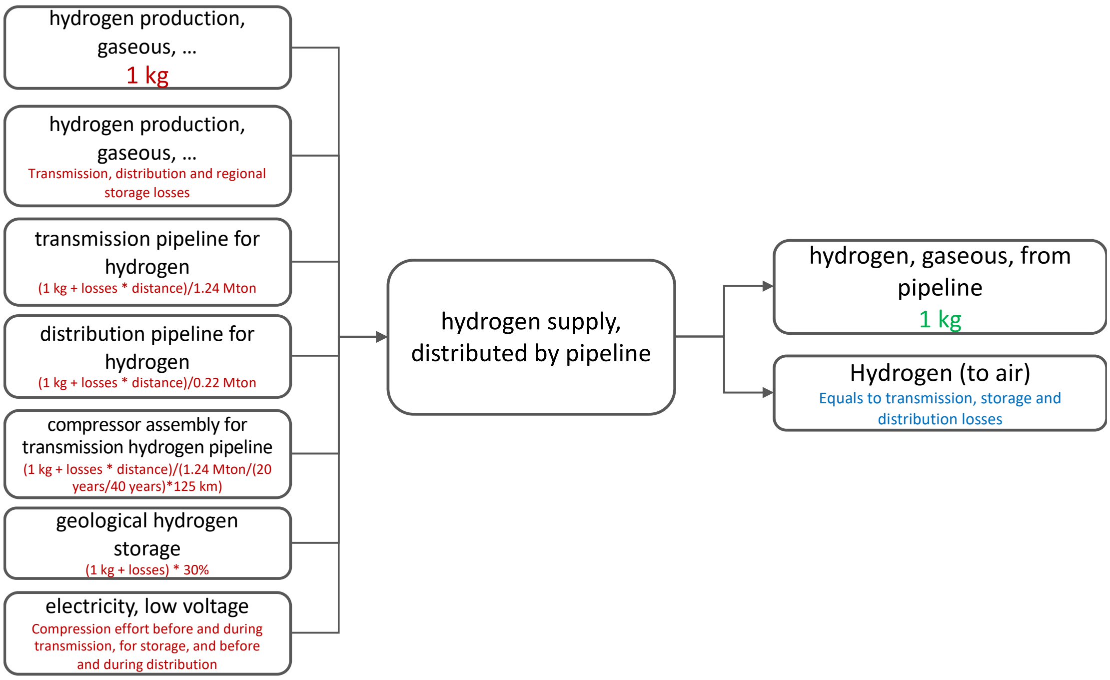

Figure 24 Schematic mass and energy balance for storing and distributing gaseous hydrogen via pipeline. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

2.5.3.2 Distribution by truck

Hydrogen's unique properties also pose specific technical challenges regarding storage and transport by truck and train. For instance, the transport vessel technology must be designed to contain this high-pressure gas and prevent potential leaks. Additionally, loading and unloading technologies also need to be considered. Transferring hydrogen to and from trucks or trains necessitates specialized equipment and safety procedures to ensure efficiency and safety.

However, these challenges are not solely technical but also extend to environmental considerations. Even with clean hydrogen production, using trucks for its transport can lead to environmental impacts, which can be reduced if these vehicles are powered by clean energy.

On the flip side, specific technological opportunities and advantages are associated with these modes of transport. For instance, the flexibility offered by trucks outpaces pipelines, and they can easily reach various locations without dependency on a fixed infrastructure.

However, road transport has its technological risks. Accidents, including those that could result in dangerous leaks or explosions, are inherent risks in hydrogen transportation.

The transport uses pressurized tanks at 500 bar (i.e., tube trailers). A 1.78 kWh/kg H_2 compression effort is considered to compress the gas from 50 bar at the outlet of the gas dryer to 500 bar for transport.

A dataset representing transport operated by a semi-trailer truck from UVEK:2022 is used for that purpose: *transport, freight, lorry, 32-40 metric ton, fleet average*. No infrastructure (e.g., pressurized tanks) is modeled besides those included in the datasets. However, (Wulf et al. 2018a) indicate that, due to the very low volumetric density of hydrogen (i.e., approximately 45 kg/m^3 at 500 bar), only 1,100 kg can be hauled on a 32-ton truck. Yet, in the transport dataset, the load factor considered is 11,600 kg for a vehicle weight of 17,000 kg. Therefore, we multiply the required transport activity volume (i.e., in ton-kilometer) by a factor of 10.55 to reflect a lower load factor – see Table 32. Note that the transmission part of the hydrogen supply chain is still performed by pipeline.

Table 32 Life-cycle inventories to supply hydrogen via truck to the consumer.

		hydrogen supply, distributed by truck, produced by …	**Remark(s)**
	Unit	1 kg	
Material and infrastructure inputs			
hydrogen production, gaseous, XX bar, from …	kg	1.00e+00	Hydrogen input.
hydrogen production, gaseous, XX bar, from …	kg	2.36e-02	Hydrogen leak.
transmission pipeline for hydrogen, dedicated hydrogen pipeline/CH U	km	2.05e-09	124.81 Mton of hydrogen circulated over the pipeline's lifetime. Mass flow of 108.34 kg/second.
compressor assembly for transmission hydrogen pipeline/RER U	p	3.28e-11	Hydrogen compressor for transmission pipeline.
geological hydrogen storage/CH U	kg	1.02e+00	Geological cavity to store hydrogen.
transport, freight, lorry 16-32 metric ton, EURO 6/tkm/RER U	tkm	2.7e+00	Amounts multiplied by 10.55 to reflect a lower load factor than initially considered in the transport dataset (i.e., 1.1t against 11.6t).
Energy inputs			
electricity, low voltage, at grid/kWh/CH U	kWh	1.05e+00-4.24e+00	To compress the H2 before and during transmission. The amount depends on the electrolyzer type.
electricity, low voltage, at grid/kWh/CH U	kWh	1.82e+00	To compress the H2 before storage.
Resources			
Emissions to air			
Hydrogen	kg	2.36e-02	Hydrogen leaks. Equal to losses.

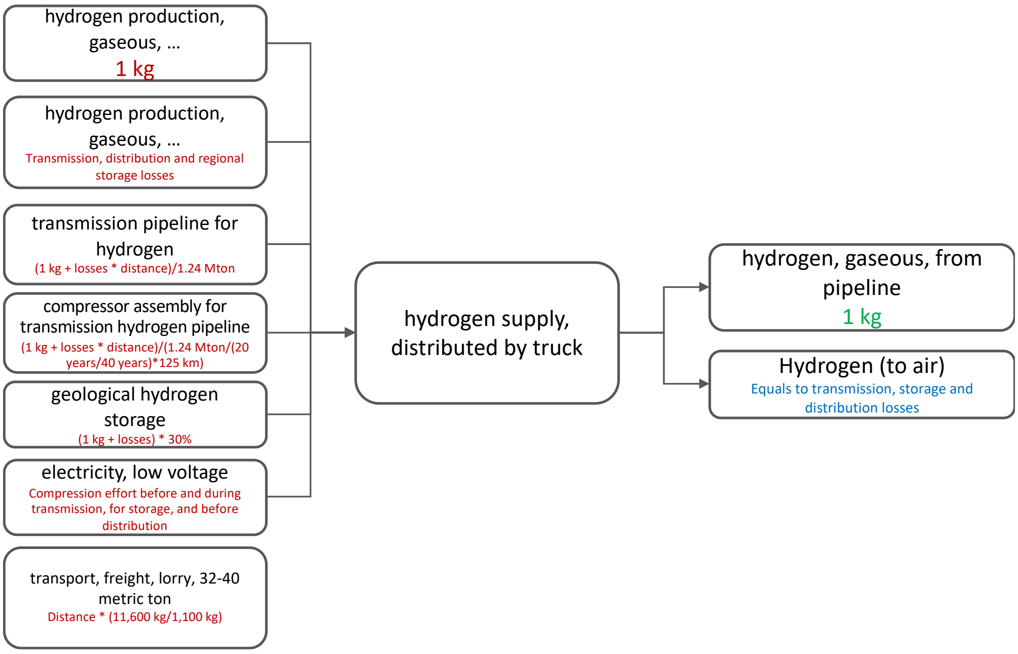

Figure 25 Schematic mass and energy balance for storing and distributing gaseous hydrogen via truck or train. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

2.6 On-site storage

On-site storage is considered for the cases where hydrogen is distributed by truck. Storing hydrogen effectively and safely requires specialized technologies. Hydrogen has a low energy density by volume, so it needs to be kept under high pressure, typically in the 200-500 bar range for residential applications, to have sufficient energy content. This necessitates the use of robust and high-pressure storage tanks.

We typically distinguish for types of hydrogen tanks, which characteristics are presented in Table 33.

Table 33 Compressed hydrogen tank types.

Type	**Material**	**Features**	**Pressure [bar]**
I	All-metal (steel or aluminum)	Cost-effective, common in industrial settings	200
II	Metal liner (usually aluminum) with filament windings	Balance between weight reduction and cost, added composite reinforcement	300
III	Metal liner with full composite overwrap	Lighter than Type I and II, higher safety due to robust composite overwrap	300-700
IV	Plastic liner with full composite overwrap	Lightest among all types, ideal for automotive and aerospace applications, high pressure capability	700

For stationary storage purposes, Type I or II tanks are preferred when weight is not a constraint, while Type IV tanks are usually reserved to mobile applications where weight and volume must be minimized. We create a dataset for the manufacture of a Type I steel tank. However, we also provide an alternative dataset using a Type IV tank, which is further analyzed for sensitivity purposes.

We use the technical specifications from a Type I hydrogen tank producer (Sino Energy Tech 2022): a 2’420 kg heavy steel tank for a volume of 2’320 liters, for storing hydrogen at a pressure of 200 bar, equivalent to 35 kg of hydrogen stored at 15 degrees Celsius.

We create a new dataset based on the existing dataset *Storage 10'000 l/RER/I* and adapt the amounts for steel, steel processing and transport activities accordingly, leaving the inputs for paint, chromium steel and aluminum unchanged, as described in Table *34*. We assume a lifetime of 20 years for this storage unit, owing to the hard-to-predict embrittlement effect of hydrogen on steel. We also increase the transport requirements proportionally to the change in the tank mass.

Table 34 Life cycle inventories to produce a high-pressure Type I hydrogen tank. Storage capacity of 35 kg.

		high pressure hydrogen storage Type I tank production/GLO U	**Remark(s)**
	Unit	1 p	Represents 35kg of storage capacity
Material and infrastructure inputs			
Alkyd paint, white, 60% in H2O, at plant/RER U	kg	4.2	
aluminium, primary, at plant/kg/RER U	kg	87.2	
Rock wool, at plant/CH U	kg	84	
Chromium steel 18/8, at plant/RER U	kg	3.7	
reinforcing steel, at plant/kg/RER U	kg	2420	
Welding, arc, aluminium/RER U	m	17.7	
Welding, arc, steel/RER U	m	15.4	
Sheet rolling, aluminium/RER U	kg	87.2	
Sheet rolling, steel/RER U	kg	2420	
transport, freight, lorry, fleet average/tkm/RER U	tkm	91.8	
transport, freight, rail/tkm/RER U	tkm	1296	
Resources			
Water, unspecified natural origin/m3	m^3	12.8	
Emissions to air			
Emissions to water			
Waste treatment			
disposal, mineral wool, 0% water, to construction waste landfill/kg/CH U	kg	84	
Treatment, pig iron production effluent, to wastewater treatment, class 3/CH U	m^3	10.2	

For the alternative option, a Type IV hydrogen tank is considered based on the inventories of (Wulf et al. 2018a), presented in Table *36*. The inventories represent a 120 kg heavy tank containing 10 kg of hydrogen at 500 bar, with a lifetime of 20 years. Because ~72 kg out of the 120 kg is carbon fiber, a material that is energy intensive to manufacture and yet not available from the UVEK:2022 database, inventories from the literature (Benitez et al. 2021) are used and presented in Table *35*.

Table 35 Life-cycle inventories to produce carbon fiber, weaved.

		polyacrylonitrile production (PAN), by polymerisation/RER U	**carbon fiber production, fiber coagulation, stretching, washing, sizing and drying/RER U**	**carbon fiber production, fiber relaxation/RER U**	**carbon fiber production, fiber winding and unwinding/RER U**	**carbon fiber production, exhaust gas treatment 1/RER U**	**carbon fiber production, exhaust gas treatment 2/RER U**	**carbon fiber production, fiber stabilization, carbonization, electrolysis and washing/RER U**	**carbon fiber production, fiber drying and sizing/RER U**	**carbon fiber production, weaved, at factory/RER U**
	Unit	1 kg	1 kg	1 kg	1 kg	1 kg	1 kg	1 kg	1 kg	1 kg
Material and infrastructure inputs										
Acrylic acid, at plant/RER U	kg	1.00E-02								
Acrylonitrile from Sohio process, at plant/RER U	kg	1.12E+00								
air separation, cryogenic/RER U	kg			9.96E-01						
Ammonium bicarbonate, at plant/RER U	kg							1.84E-02		
carbon fiber production, exhaust gas treatment 1/RER U	kg							3.32E+01		
carbon fiber production, exhaust gas treatment 2/RER U	kg							9.71E+00		
carbon fiber production, fiber carbonization (low temp)/RER U	kg							1.13E+00		
carbon fiber production, fiber relaxation/RER U	kg				1.00E+00					
carbon fiber production, fiber stabilization, carbonization, electrolysis and washing/RER U	kg								1.09E+00	
carbon fiber production, fiber winding and unwinding/RER U	kg							2.51E+00		
Compressed air, average generation, <30kW, 10 bar gauge, at compressor/RER U	m3		1.84E-02	2.30E-01	1.89E-01		9.28E-02	1.80E-01	2.78E-03	
Dimethyl sulfoxide, at plant/RER U	kg		1.08E-02							
Epoxy resin, liquid, at plant/RER U	kg								1.01E-02	
Ethylene glycol, at plant/RER U	kg		2.96E-04	5.00E-05				7.63E-03		
Methyl acrylate, at plant/GLO U	kg	5.00E-02	4.10E-02							
Natural gas, from medium pressure network (0.1-1 bar), at service station/CH U	kg						1.91e-01	1.98e-01		
Nitrogen, liquid, at plant/RER U	kg		1.61e-02					8.08E+00		
NOx retained, in SCR/GLO U	kg						9.90e-01			
polyacrylonitrile production (PAN), by	kg		1.02e+00							

		polyacrylonitrile production (PAN), by polymerisation/RER U	**carbon fiber production, fiber coagulation, stretching, washing, sizing and drying/RER U**	**carbon fiber production, fiber relaxation/RER U**	**carbon fiber production, fiber winding and unwinding/RER U**	**carbon fiber production, exhaust gas treatment 1/RER U**	**carbon fiber production, exhaust gas treatment 2/RER U**	**carbon fiber production, fiber stabilization, carbonization, electrolysis and washing/RER U**	**carbon fiber production, fiber drying and sizing/RER U**	**carbon fiber production, weaved, at factory/RER U**
polymerisation/RER U										
Potassium permanganate, at plant/RER U	kg		4.06e-02							
Silicone product, at plant/RER U	kg			5.00e-03						
tap water, at user/kg/RER U	kg							6.11E-01		
transport, freight, lorry 16-32 metric ton, fleet average/RER U	tkm	1.18E-01	1.01E-02	5.03e-02			9.54e-03	4.16e-01	1.02e-03	5.85e-02
transport, freight, rail/tkm/RER U	tkm	2.60E-01	5.72E-02	1.03e-01			1.91e-02	8.43e-01	6.09e-03	1.00e+00
Water, deionised, at plant/CH U	kg	7.65E-01	2.38E-01		1.02E-01			8.11E-05	2.51E-04	
Energy inputs										
electricity, low voltage, production ENTSO, at grid/kWh/ENTSO U	kWh	2.50e+00	1.03E+00	1.52E-01	1.59E-01	2.29e-02	2.62e-02	2.83E+01	6.25E-01	5.20e-01
Steam, for chemical processes, at plant/RER U	kg	1.94e+01	3.22E+00	3.56E-01				1.81E+00	1.31E-01	
Resources										
Emissions to air										
Argon	kg					1.26e-02				
Carbon dioxide, fossil	kg					1.63e-03	7.02e-01			
Nitrogen	kg					7.43e-03	3.44e+00			
Nitrogen oxides	kg						9.99e-03			
Water	m3		6.23e-07			2.07e-07	4.74e-07			
Emissions to water										
Waste treatment										
Treatment, sewage, to wastewater treatment, class 1/CH U	m3		1.14e-03							

Table 36 Life cycle inventories to produce a high-pressure Type IV hydrogen tank. Storage capacity of 10 kg.

		high pressure hydrogen storage tank/GLO U	**Remark(s)**
	Unit	1 p	Represents 10kg of storage capacity
Material and infrastructure inputs			
Sheet rolling, aluminium/RER U	kg	6.00e+00	
Aluminium alloy, AlMg3, at plant/RER U	kg	6.00e+00	
Sheet rolling, chromium steel/RER U	kg	9.00e+00	

Chromium steel 18/8, at plant/RER U	kg	9.00e+00	
carbon fiber production, weaved, at factory/RER U	kg	7.14e+01	
Epoxy resin, liquid, at plant/RER U	kg	3.06e+01	
Sheet rolling, copper/RER U	kg	9.00e+00	
Steel, low-alloyed, at plant/RER U	kg	9.00e+00	
transport, freight, rail/tkm/RER U	tkm	2.32e+01	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 19.3 kg over 1200.0 km.
transport, freight, lorry 16-32 metric ton, fleet average/RER U	tkm	4.83e+01	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 48.3 kg over 1000.0 km.
transport, barge tanker/tkm/RER U	tkm	7.14e+00	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 71.4 kg over 100.0 km.
Energy inputs			
electricity, low voltage, production ENTSO, at grid/kWh/ENTSO U	kWh	4.50e+00	

To determine the fraction of a storage tank to attribute per unit mass of hydrogen used, we need to estimate the need for hydrogen considering a heating period assumed to be six months per year and monthly deliveries, as described in

Table 37. We can infer the number of high-pressure hydrogen tanks needed on site.

Table 37 Hydrogen storage specifications, for Type I and IV storage tanks.

End-use technology	Boiler	CHP	Fuel cell, PEM	Fuel cell, SOFC
Power [kW_{th} + kW_{el}]	15	125 + 160	1.6 + 1	90 + 125
Total eff. (heat + el.)	111%	81%	95%	80%
Total cap. input-related [kW]	15	444	2.7	270
Annual operation [hours]	2,100	4,100	4,100	4,100
Annual heating [kWh]	34,860	820,000	6,560	369,000
Heating period [months/year]	6	6	6	6
Annual H_2 need [kg]	942	54,599	337	33,056
Monthly H_2 need [kg]	157	9100	56	5509
	Type I tank requirements			
35-kg H_2 storage tanks [unit]	5	260	2	158
H_2 storage tank lifetime [years]	20			
H_2 storage tank fraction per kg H_2 consumed [unit]	$2.65*10^{-4}$	$2.38*10^{-4}$	$2.97*10^{-4}$	$2.38*10^{-4}$
	Type IV tank requirements			
10-kg H_2 storage tanks [unit]	16	910	6	551
H_2 storage tank lifetime [years]	20			

End-use technology	Boiler	CHP	Fuel cell, PEM	Fuel cell, SOFC
H_2 storage tank fraction per kg H_2 consumed [unit]	8.49*10^{-4}	8.33*10^{-4}	8.90*10^{-4}	8.33*10^{-4}

Assuming a lifetime of 20 years for high-pressure tanks, we allocate the fraction of a tank needed per kg of hydrogen used in a boiler, CHP, or fuel cell by dividing the number of tanks over the total amount of hydrogen required over that period, which we include in the end-use dataset.

When a Type I storage tank is used, no additional compression effort is included, as the hydrogen is delivered at a pressure of 500 bar while the tank is designed to store hydrogen at a pressure of 200 bar. For Type IV tanks, a compression effort of 0.24 kWh/kg H_2 is included, considering a delivery pressure of 500 bar and a storage pressure of 700 bar. However, this electricity input is included in the end-use dataset, where the hydrogen is used for heat and electricity production.

It is important to note from

Table 37 that, because of the low volumetric density of compressed hydrogen, distribution by other means than pipeline seems challenging, as the need for weekly deliveries and on-site storage capacity becomes too important.

2.7 Combustion

Using hydrogen for home heating offers several potential advantages, such as reducing carbon dioxide and air pollutant emissions compared to using natural gas or fuel oil. Disadvantages include comparatively more complex fuel handling and infrastructure. When hydrogen is burned, the only byproducts are water vapor (H_2O) and traces of nitrogen oxides (NO_x), making it a relatively clean fuel source. When combusted in boilers or CHP, the formation of NOx is due to the high temperature of the flame, leading the nitrogen and oxygen contained in the air to combine to form nitric oxide (NO), which can then further react to form nitrogen dioxide (NO_2), collectively referred to as NO_x.

2.7.1 Boiler

Hydrogen boilers are being developed for home heating but have yet to enter the market. Therefore, reliable, and representative information is scarce. Today's primary focus is hydrogen-ready boilers, which can use a mix of natural gas and hydrogen, up to 20% hydrogen content. If a hydrogen supply network is introduced, these boilers could be adapted to work on 100% hydrogen (https://www.boilercentral.com/ 2023).

Examples of hydrogen-ready boilers include models from Viessmann and Worcester Bosch, which can be easily converted to work with 100% hydrogen in the future (https://www.boilercentral.com/2023).

In this study, we use the life cycle inventories of a conventional 15-kW natural gas home boiler from the UVEK database ("*natural gas, burned in boiler condensing modulating 15kW/MJ/CH U*") and adjust its efficiency and combustion emissions to represent pure hydrogen use, as described in Table 38. The combustion efficiency is set to 94% on a higher heating value basis according to the manufacturer's specifications on two hydrogen-ready boilers (Viessmann 2023; Worcester Bosch 2021, personal communication with Viessmann technical support), although no commercial instance of 100% hydrogen boiler exists at this moment (i.e., only 20%). To align with inventory modeling conventions, we express the efficiency based on the lower heating value of hydrogen, n_{LHV}, which yields:

$$n_{LHV} = \frac{n_{HHV} * HHV}{LHV} = 111\%$$

With:

- HHV equal to 141.8 MJ/kg
- LHV equal to 120 MJ/kg

An emission factor for NO_x emissions of 25 mg NO_x/kWh_{th} is from the technical specifications of a wall-mounted hydrogen-only prototype boiler, given as an upper limit (Hy4Heat 2021). In comparison, a 15 kW natural gas boiler has an emission factor of 65 mg NO_x/kWh_{th}, according to the *natural gas, burned in boiler condensing modulating 15kW* dataset of the UVEK database.

Table 38 Specifications for a 16.6-kW hydrogen-ready home boiler.

		Source/Remark
End-use technology	Boiler	
Energy carrier	Hydrogen	
Lifetime [years]	20	(Kägi et al. 2021)
Power input [kW]	15	
Power output [kW]	16.6	
Annual full load hours [hours]	2'100	
Annual heating [kWh]	34'860	Calculated from the two rows above.
Heat conversion efficiency [% HHV input]	94%	(Viessmann 2023; Worcester Bosch 2021)
Heat conversion efficiency [% LHV input]	111%	Calculated from the above row.
Annual heating period [months]	6	Assumption.
Annual H_2 need [kg]	942	Calculated from rows above.
Water emissions [kg/kg H_2 combusted]	9	Stoichiometry.
NO_x emissions [mg/kWh]	25	(Hy4Heat 2021). Emission factor originally refers to a kWh of thermal output.
Hydrogen loss [% mass]	0.5%	0.13% from the boiler, 0.33% from the pipework, rounded to 0.5% (Frazer-Nash Consultancy 2022a)

Five primary heat supply datasets are modeled based on specifications given in Table *38*. They are described below and are further analyzed in the Impact Assessment section of this report:

- heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid
- heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind from Morocco
- heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by SMR of natural gas
- heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by SMR of natural gas, with CCS
- heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by methane pyrolysis

The inventories are based on specifications given in Table *38* and described in Table *39*, for the pipeline supply option. The modelling is similar across the five hydrogen supply options and is schematically represented in Figure *26*.

Table 39 Life-cycle inventories for the combustion of grid-based electrolytic hydrogen in a boiler, supplied by pipeline.

		heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	**heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)**	**heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland**	**heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland**	**heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland**	**Remark(s)**
	Unit	1 MJ	1 MJ	1 MJ	1 MJ	1 MJ	
Material and infrastructure inputs							
gas boiler 15kW/RER/I U	p	4.41e-07	4.41e-07	4.41e-07	4.41e-07	4.41e-07	1/(Total cap. (input-related) [kW] * lifetime [y] * annual operation [h] * 3.6 [MJ/kWh])
chimney/CH/I U	m	8.82e-07	8.82e-07	8.82e-07	8.82e-07	8.82e-07	To evacuate the flue gases.
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	kg	7.51e-03					Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	kg	3.75e-05					((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)/CH U	kg		7.51e-03				Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)/CH U	kg		3.75e-05				((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U	kg			7.51e-03			Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U	kg			3.75e-05			((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U	kg				7.51e-03		Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U	kg				3.75e-05		((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U	kg					7.51e-03	Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)

		heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)	heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland	heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland	heat, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland	Remark(s)
hydrogen supply, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U	kg					3.75e-05	((1+storage loss)*(1+use loss)-1)*hydrogen input
Energy inputs							
electricity, low voltage, at grid/kWh/CH U	kWh	2.64e-03	2.64e-03	2.64e-03	2.64e-03	2.64e-03	To operate the boiler.
Resources							
Emissions to air							
Water	kg	6.76e-08	6.76e-08	6.76e-08	6.76e-08	6.76e-08	9kg of water produced per kg of H2 combusted.
Nitrogen oxides	kg	6.94e-06	6.94e-06	6.94e-06	6.94e-06	6.94e-06	Based on Greenstar 8000 Hydrogen-Ready specifications (25mg NOx/kWh).
Hydrogen	kg	3.75e-05	3.75e-05	3.75e-05	3.75e-05	3.75e-05	Hydrogen leakage.

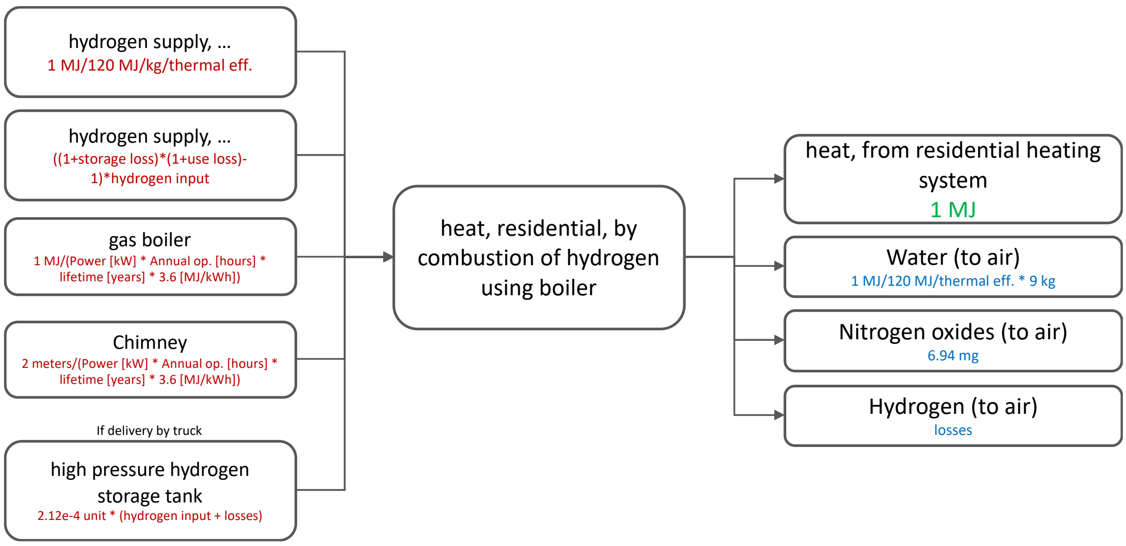

Figure 26 Schematic mass and energy balance for the combustion of hydrogen in a boiler. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Additionally, twenty alternative datasets are modeled:

- using different electrolyzer types: AEC, SOEC, and SOEC with steam input,
- using other hydrogen production methods: Auto-Thermal Reforming, with and without CCS,
- using different feedstock inputs: for electrolytic hydrogen, we consider the Swiss renewable electricity mix, Swiss solar power, Morocco-based solar power, Morocco-

based wind power, and Denmark-based wind power. For the SMR and pyrolysis options, we also consider liquefied natural gas from Algeria.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *40* for uncertainty estimation are considered.

Table 40 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	Completeness	Temporal correlation	Geographical correlation	Further technological correlation	Sample size
H_2 boiler	2	5	1	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

2.7.2 CHP

The second option based on the combustion of hydrogen considered in this study is using a small-scale co-generation unit. Data on conversion efficiency for hydrogen-fed co-generation units are challenging to find. We rely on the technical documentation of the co-generation unit Agenitor models from manufacturer 2G Energy AG (2G Energy AG 2022); see Table 41. The inventories for the CHP unit and related infrastructure are from the UVEK background database.

Table 41 Electrical and thermal efficiencies for hydrogen-fed CHP units from 2G Energy AG Agenitor models. Average values are used. Efficiencies are based on the lower heating value of hydrogen (personal communication with 2G Energy AG).

Model	Output		Efficiency		
	Electrical	Thermal	Electrical	Thermal	Total
agenitor 404c	115 kW	129 kW	37.70%	42.30%	80.00%
agenitor 406	170 kW	183 kW	39.00%	41.90%	80.90%
agenitor 408	250 kW	250 kW	40.20%	41.90%	82.10%
agenitor 412	360 kW	371 kW	40.50%	41.70%	82.20%
agenitor 420	750 kW	767 kW	39.80%	40.70%	80.50%
Average			39.40%	41.70%	81.00%

Co-generation units co-produce heat and electricity. We proceed to an exergy-based allocation to partition the inputs and outputs between the production of heat and electricity. We first calculate the heat exergy factor of the CHP unit, as described in Table 42, following the approach described in (Kägi et al. 2021). We consider a desirable indoor temperature of 20° C, an outgoing flow temperature of 60°C, and a return temperature of 60°C.

Table 42 Heat exergy factor for hydrogen-fed CHP unit.

		Remark
Flow temp. T_V [K]	333.15	Flow temperature (60°C)

Return temp. T_R [K]	308.15	Return temperature (35°C)
Ambient temp. T_U [K]	293.15	Ambient temperature (20°C)
Heat exergy factor	0.086	$\frac{\frac{T_R + T_V}{2} - T_U}{\frac{T_R + T_V}{2}}$

When the heat exergy factor is known, and assuming the exergy factor for electricity is 1, we calculate the allocation key to produce heat and electricity, as described in Table 43.

Table 43 Heat and electricity allocation keys for hydrogen-fed CHP unit.

		Remark
Heat exergy factor w_{ex}	0.086	
Heat efficiency n_{th}	41.7%	
Electricity efficiency n_{el}	39.4%	
Heat allocation key	8.3%	$\frac{(w_{ex} * n_{th})}{(w_{ex} * n_{th}) + (1 * n_{el})}$
Electricity allocation key	91.7%	Calculated from the row above.

The rest of the specifications for the hydrogen-fed CHP unit are described in Table 44.

Table 44 Specifications for a 160 kW-el hydrogen-fed CHP unit.

		Source/Remark
End-use technology	CHP	
Energy carrier	Hydrogen	
Lifetime [years]	20	(Kägi et al. 2021)
Power$_{th}$ [kW]	200	UVEK:2022
Power$_{el}$ [kW]	160	
Total cap. input-related [kW]	444	Calculated from rows above.
Heat conversion efficiency [% LHV input]	42%	(2G Energy AG 2022)
Electricity conversion efficiency [% LHV input]	39%	
Total eff. (heat + el.)	81%	Calculated from rows above.
Annual operation [hours]	4'100	(Kägi et al. 2021)
Annual heating [kWh]	820'000	Calculated from rows above.
Annual H_2 need [kg]	54'599	Calculated from rows above.

Manufacturer's specifications for Agenitor CHP models provide the maximum allowed emission factor for NO_x (i.e., <1.11 g NO_x per kg H_2 input (2G Energy AG 2022)), or approximately 1.55g NO_x/MJ of heat considering the CHP efficiency values above. Using this value is likely an overestimate considering that it is 225 times superior to the emission factor used for H_2 boilers (6.9mg NO_x/MJ (Hy4Heat 2021)). Hence, we use the NO_x emission factor for H_2 boilers.

Like boilers, we use the estimates from (Frazer-Nash Consultancy 2022a) and consider a 0.5% hydrogen loss.

Ten primary heat and electricity co-generation datasets are modeled based on specifications given in Table *44*. They are described below and are further analyzed in the Impact Assessment section of this report:

- heat and electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid
- heat and electricity, residential, by combustion of hydrogen using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind from Morocco
- heat and electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland
- heat and electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland
- heat and electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland

The inventories are based on specifications given in Table *44* and described in

Table 45. The modelling is similar across the ten heat and electricity supply options and is schematically represented in Figure *27* and Figure *28*.

Table 45 Life-cycle inventories for the heat supply via the combustion of grid-based electrolytic hydrogen in a CHP unit.

		heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	**heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)**	**heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland**	**heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland**	**heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland**	**Remark(s)**
	Unit	1 MJ	1 MJ	1 MJ	1 MJ	1 MJ	
Material and infrastructure inputs							
Cogen unit 160kWe, common components for heat+electricity/ RER/I U	p	6.51e-10	6.51e-10	6.51e-10	6.51e-10	6.51e-10	1/(Total cap. (input-related) [kW] * lifetime [y] * annual operation [h] * 3.6 [MJ/kWh])*allocation factor
Cogen unit 160kWe, components for electricity only/RER/I U	p	6.51e-10	6.51e-10	6.51e-10	6.51e-10	6.51e-10	1/(Total cap. (input-related) [kW] * lifetime [y] * annual operation [h] * 3.6 [MJ/kWh])*allocation factor
Cogen unit 160kWe, components for heat only/RER/I U	p	6.51e-10	6.51e-10	6.51e-10	6.51e-10	6.51e-10	1/(Total cap. (input-related) [kW] * lifetime [y] * annual operation [h] * 3.6 [MJ/kWh])*allocation factor

		heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)	heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland	heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland	heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland	Remark(s)
Lubricating oil, at plant/RER U	kg	9.46e-09	9.46e-09	9.46e-09	9.46e-09	9.46e-09	
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	kg	1.66e-03					Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	kg	8.31e-06					((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)/CH U	kg		1.66e-03				Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)/CH U	kg		8.31e-06				((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U	kg			1.66e-03			Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U	kg			8.31e-06			((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U	kg				8.31e-06		((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U	kg					1.66e-03	Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by	kg					8.31e-06	((1+storage loss)*(1+use loss)-

		heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)	heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland	heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland	heat, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland	Remark(s)
pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U							1)*hydrogen input
transport, freight, rail, electricity with shunting/tkm/CH U	tkm	3.12e-10	3.12e-10	3.12e-10	3.12e-10	3.12e-10	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.0 kg over 33.0 km.
transport, freight, lorry 16-32 metric ton, fleet average/tkm/CH U	tkm	3.12e-10	3.12e-10	3.12e-10	3.12e-10	3.12e-10	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.0 kg over 33.0 km.
Emissions to air							
Water	kg	1.50e-08	1.50e-08	1.50e-08	1.50e-08	1.50e-08	9kg of water produced per kg of H2 combusted.
Nitrogen oxides	kg	6.94e-06	6.94e-06	6.94e-06	6.94e-06	6.94e-06	Based on Greenstar 8000 Hydrogen-Ready specifications (25mg NOx/kWh).
Hydrogen	kg	8.31e-06	8.31e-06	8.31e-06	8.31e-06	8.31e-06	Hydrogen leakage.
Waste treatment							

Table 46 Life-cycle inventories for the electricity supply via the combustion of grid-based electrolytic hydrogen in a CHP unit.

		electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)	electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland	electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland	electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland	Remark(s)
	Unit	1 kWh	1 kWh	1 kWh	1 kWh	1 kWh	
Material and infrastructure inputs							
Cogen unit 160kWe, common components for heat+electricity/RER/I U	p	2.58e-08	2.58e-08	2.58e-08	2.58e-08	2.58e-08	1/(Total cap. (input-related) [kW] * lifetime [y] * annual operation [h] * 1 [kWh/kWh])*allocation factor
Cogen unit 160kWe, components for electricity only/RER/I U	p	2.58e-08	2.58e-08	2.58e-08	2.58e-08	2.58e-08	1/(Total cap. (input-related) [kW] * lifetime [y] * annual operation [h] * 1

		electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)	electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland	electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland	electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland	Remark(s)
							[kWh/kWh])*allocation factor
Cogen unit 160kWe, components for heat only/RER/I U	p	2.58e-08	2.58e-08	2.58e-08	2.58e-08	2.58e-08	1/(Total cap. (input-related) [kW] * lifetime [y] * annual operation [h] * 1 [kWh/kWh])*allocation factor
Lubricating oil, at plant/RER U	kg	1.04e-07	1.04e-07	1.04e-07	1.04e-07	1.04e-07	
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	kg	6.98e-02					Hydrogen input. 1 [kWh H2]/33.33 [KWh/kg H2]/ eff.(el)
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	kg	3.49e-04					((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)/CH U	kg		6.98e-02				Hydrogen input. 1 [kWh H2]/33.33 [KWh/kg H2]/ eff.(el)
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)/CH U	kg		3.49e-04				((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U	kg			6.98e-02			Hydrogen input. 1 [kWh H2]/33.33 [KWh/kg H2]/ eff.(el)
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U	kg			3.49e-04			((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U	kg				6.98e-02		Hydrogen input. 1 [kWh H2]/33.33 [KWh/kg H2]/ eff.(el)
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U	kg				3.49e-04		((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U	kg					6.98e-02	Hydrogen input. 1 [kWh H2]/33.33 [KWh/kg H2]/ eff.(el)
hydrogen supply, distributed by pipeline, produced by Pyrolysis using	kg					3.49e-04	((1+storage loss)*(1+use loss)-

		electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity grid/CH U	**electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)**	**electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland**	**electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland**	**electricity, residential, by combustion of hydrogen using CHP, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland**	**Remark(s)**
natural gas from Switzerland/CH U							1)*hydrogen input
transport, freight, rail, electricity with shunting/tkm/CH U	tkm	3.44e-09	3.44e-09	3.44e-09	3.44e-09	3.44e-09	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.0 kg over 33.0 km.
transport, freight, lorry 16-32 metric ton, fleet average/tkm/CH U	tkm	3.44e-09	3.44e-09	3.44e-09	3.44e-09	3.44e-09	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.0 kg over 33.0 km.
Emissions to air							
Water	kg	6.28e-07	6.28e-07	6.28e-07	6.28e-07	6.28e-07	9kg of water produced per kg of H2 combusted.
Nitrogen oxides	kg	2.50e-05	2.50e-05	2.50e-05	2.50e-05	2.50e-05	Based on Greenstar 8000 Hydrogen-Ready specifications (25mg NOx/kWh).
Hydrogen	kg	3.49e-04	3.49e-04	3.49e-04	3.49e-04	3.49e-04	Hydrogen leakage.
Waste treatment							
Disposal, used mineral oil, 10% water, to hazardous waste incineration/CH U	kg	1.04e-07	1.04e-07	1.04e-07	1.04e-07	1.04e-07	

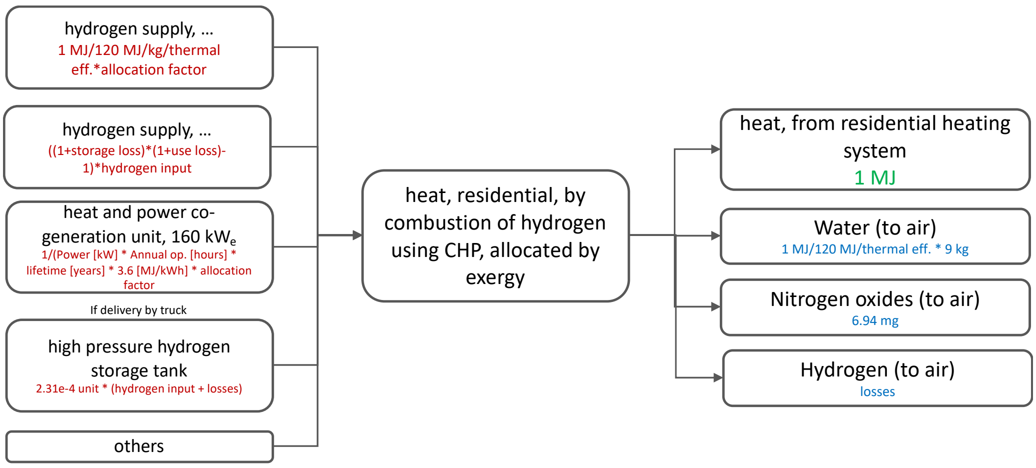

Figure 27 Schematic mass and energy balance for the heat supply via hydrogen combustion in a CHP unit. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

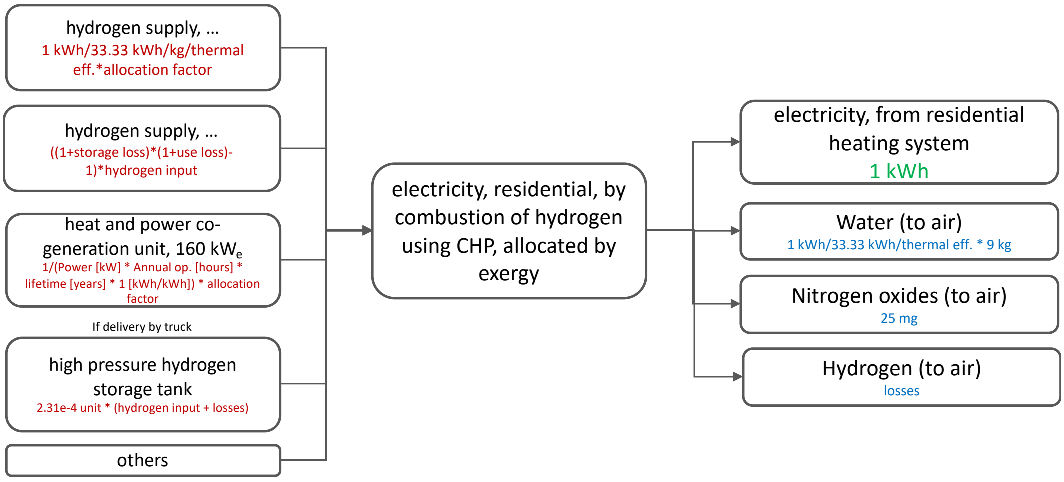

Figure 28 Schematic mass and energy balance for the electricity supply via hydrogen combustion in a CHP unit. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Additionally, forty alternative datasets are modeled:

- using different electrolyzer types: AEC, SOEC, and SOEC with steam input,
- using other hydrogen production methods: Auto-Thermal Reforming, with and without CCS,
- using different feedstock inputs: for electrolytic hydrogen, we consider the Swiss renewable electricity mix, Swiss solar power, Morocco-based solar power, Morocco-based wind power, and Denmark-based wind power. For the SMR and pyrolysis options, we consider liquefied natural gas from Algeria.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *47* for uncertainty estimation are considered.

Table 47 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	**Completeness**	**Temporal correlation**	**Geographical correlation**	**Further technological correlation**	**Sample size**
H_2 CHP	2	5	1	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

2.8 Conversion

Fuel cells, including those that utilize hydrogen as their fuel source, operate by converting chemical energy directly into electrical (and thermal) energy. They're often promoted for their high efficiency and low environmental impact, specifically when the hydrogen they use is produced from renewable sources. A hydrogen fuel cell could provide heat and electricity in a residential setting, making it a potentially versatile energy solution.

One of the key advantages of using a hydrogen fuel cell in the home is its potential for co-generation. In such a co-generation system, the fuel cell generates electricity, and the waste heat produced during this process is captured and used for heating. This can be a very efficient way to use the energy contained in the hydrogen, potentially leading to energy cost savings for the homeowner. Furthermore, since fuel cells operate silently and have no moving parts, they offer a quiet solution for home energy needs.

However, several technical challenges and drawbacks are associated with using hydrogen fuel cells for home heating. One major challenge is the current cost of fuel cells. While prices have decreased, fuel cells are still more expensive than traditional heating systems.

Regarding infrastructure, existing homes and buildings would likely need significant modifications to accommodate a hydrogen fuel cell system. These could include installing hydrogen storage tanks, modifying electrical systems to use the power generated by the fuel cell, and potentially altering the home's heating system to use the heat produced by the fuel cell. These modifications could add to the cost and complexity of installing a hydrogen fuel cell system.

Lastly, fuel cells, especially those using hydrogen, are relatively new and may pose unexpected maintenance challenges. While they have no moving parts, they still degrade over time. The stack, where hydrogen and oxygen combine to produce electricity, degrades and must be replaced periodically. This can add to the overall operating cost of a fuel cell system.

There are examples of small-scale fuel cell units running on hydrogen for residential heating. Panasonic has developed and commercialized household fuel cell systems. The Panasonic household fuel cell ENE-FARM, made commercially available in Japan in 2009, uses hydrogen from natural gas to generate electricity and hot water in homes (Panasonic 2021). This technology has also been introduced in Europe.

Panasonic also recently launched a pure hydrogen-type fuel cell in Japan that allows for the direct production of electricity from hydrogen with high efficiency. By connecting a hot water storage unit with the product, the heat generated from the fuel cell can be converted into hot water for use. Furthermore, more than 2'000 people in Panasonic's Sustainable Smart Town in Fujisawa, Japan, have been using home fuel cell systems since the town's inauguration in 2014 (Panasonic 2021).

2.8.1 PEM fuel cell

For this study, we consider the life cycle inventories from Stropnik et al. (2022), which describe a 1 kW_{el} PEM fuel cell system. They include the degradation of the fuel cells over time due to dynamic operation (i.e., intermittent use) at a rate of 0.88% voltage loss per 1'000 hours of use. Over 20'000 hours of use at a dynamic operation regime, the stack is replaced five times (a replacement every 3,800 hours of operation), as opposed to once if used continuously A replacement occurs when the voltage loss is superior to 10% relative to its initial value– while the Balance of Plant is not replaced. The platinum loading considered is 0.75 grams per kW_{el}. The life-cycle inventories for producing and assembling of a 1kWe PEM fuel cell system, designed for a 20,000-hour lifetime at a dynamic operation regime, are described in Table *49*.

Table 48 Specifications for a 1-kW_{el} PEM fuel cell system.

Energy carrier	**Hydrogen**	
End-use technology	Fuel cell, PEM	
Heat conversion efficiency [% LHV input]	50%	(Stropnik et al. 2022)
Electricity conversion efficiency [% LHV input]	45%	
Lifetime [years]	5	
Lifetime [hours]	20'000	
Fuel cell stack lifetime, at dynamic operational regime [hours]	3'800	
Fuel cell stack replacement [piece]	5 (plus original, 6)	
$Power_{th}$ [kW]	1.6	
$Power_{el}$ [kW]	1	
Total cap. input-related [kW]	2.7	Calculated from the rows above.

Total eff. (heat + el.)	95%	
Annual operation [hours]	4'100	(Kägi et al. 2021)
Annual heating [kWh]	6'560	Calculated from the rows above.
Annual heating period [months]	6	Assumption used for sizing of the hydrogen storage
Annual H_2 need [kg]	337	Calculated from the rows above.

Table 49 Life-cycle inventories for the assembly of a 1kW$_e$ PEM fuel cell system, designed for a 20,000-hour lifetime at a dynamic operation regime.

		fuel cell system assembly, 1 kWe, proton exchange membrane (PEM)/GLO U	**fuel cell stack production, 1 kWe, proton exchange membrane (PEM)/GLO U**	**fuel cell Balance of Plant production, 1 kWe, proton exchange membrane (PEM)/GLO U**	**Remark(s)**
	Unit	1 piece	1 piece	1 piece	
Material and infrastructure inputs					
fuel cell stack production, 1 kWe, proton exchange membrane (PEM)/GLO U	p	5.263E+00			The fuel cell stack is replaced five times over 20,000 hours.
fuel cell Balance of Plant production, 1 kWe, proton exchange membrane (PEM)/GLO U	p	1.000E+00			The BoP is not replaced over 20,000 hours.
Graphite, at plant/RER U	kg		4.500E+00		
Polyvinylidenchloride, granulate, at plant/RER U	kg		1.100E+00		
Injection moulding/RER U	kg		1.107E+00		
aluminium, production mix, at plant/kg/RER U	kg		3.000E-01	7.500E-01	
Aluminium product manufacturing, average metal working/RER U	kg		3.000E-01	7.500E-01	
Chromium steel 18/8, at plant/RER U	kg		1.000E-01	4.800E+00	
Steel product manufacturing, average metal working/RER U	kg		1.000E-01	4.800E+00	
Glass fibre, at plant/RER U	kg		1.000E-01		
polymer electrolyte membrane (Nafion) production/RER U	kg		7.000E-02		
Carbon black, at plant/GLO U	kg		8.000E-04		
Platinum, at regional storage/RER U	kg		7.500E-04		
Polyethylene, HDPE, granulate, at plant/RER U	kg			1.500E+00	
Cast iron, at plant/RER U	kg			8.000E-01	
Polypropylene, granulate, at plant/RER U	kg			2.500E-01	
transport, freight, rail/tkm/RER U	tkm		1.202E+00	1.470E+00	
transport, freight, lorry 16-32 metric ton, fleet average/RER U	tkm		9.028E-01	8.850E-01	
transport, barge tanker/tkm/RER U	tkm		1.470E-01	7.500E-02	
Energy inputs					
electricity, low voltage, production GLO, at grid/kWh/GLO U	kWh		1.690E+01	1.690E+01	

Like combustion-based co-generation units, exergy-based allocation keys for heat and electricity production must be calculated. The heat exergy factor of the PEM fuel cell system is described in Table 50, following the approach described in (Kägi et al. 2021). We consider the presence of a buffer water storage between the fuel cell and the heating system to adapt the outgoing flow temperature to the heat demand. Therefore, we use an outgoing flow temperature from the fuel cell system of 85°C, and a return flow temperature of 40°C, to calculate the exergy factor.

Table 50 Heat exergy factor for hydrogen-fed PEM fuel cell system.

		Remark
Flow temp. T_V [K]	358.15	Flow temperature (85°C)
Return temp. T_R [K]	313.15	Return temperature (40°C)
Ambient temp. T_U [K]	293.15	Ambient temperature (20°C)
Heat exergy factor	0.127	$\frac{\frac{T_R + T_V}{2} - T_U}{\frac{T_R + T_V}{2}}$

Given the heat exergy factor from Table 50, we obtain the allocation key to produce heat and electricity, as described in Table 51.

Table 51 Heat and electricity allocation keys for hydrogen-fed PEM fuel cell system.

		Remark
Heat exergy factor w_{ex}	0.127	
Heat efficiency n_{th}	50.0%	
Electricity efficiency n_{el}	45.0%	
Heat allocation key	12.3%	$\frac{(w_{ex} * n_{th})}{(w_{ex} * n_{th}) + (1 * n_{el})}$
Electricity allocation key	87.7%	Calculated from the row above.

Based on (Frazer-Nash Consultancy 2022a), we consider a 0.56% hydrogen loss from the fuel cell stack. This is a low estimate, assuming a system allowing the complete hydrogen recombination from purging and crossover venting, which is yet to be implemented on commercial models – otherwise, the loss could be as high as 1.36%.

Ten primary heat and electricity co-generation datasets are modeled based on specifications given in Table *48*. They are described below and are further analyzed in the Impact Assessment section of this report:

- heat and electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid
- heat and electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)
- heat and electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland
- heat and electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland
- heat, and electricity residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland

The inventories are based on specifications given in Table *44* and described in

Table 45. The modelling is similar across the ten heat and electricity supply options and is schematically represented in Figure *27* and Figure *28*.

Table 52 Life-cycle inventories for the heat supply via hydrogen conversion in a PEM fuel cell system.

		heat, residential, by conversion of hydrogen using electrolyzer, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	**heat, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM**	**heat, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U**	**heat, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U**	**heat, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U**	**Remark(s)**
	Unit	1 MJ	1 MJ	1 MJ	1 MJ	1 MJ	
Material and infrastructure inputs							
fuel cell system assembly, 1 kWe, proton exchange membrane (PEM)/GLO U	p	6.26e-07	6.26e-07	6.26e-07	6.26e-07	6.26e-07	Operational time of 20,000 hours at the power of 1 kWe. Due to the degradation effects, hydrogen consumption must be increased to always generate the power of 1 kWe. Because of the dynamic operational regime, five replacements of the PEMFC stack are included (lifetime of 3'800 hours per stack), while the BoP lasts the whole operational time.
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	kg	2.06e-03					Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th) * allocation factor
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	kg	1.15e-05					((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)/CH U	kg		2.06e-03				Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)/CH U	kg		1.15e-05				((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U	kg			2.06e-03			Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by pipeline, produced by Steam Methane	kg			1.15e-05			((1+storage loss)*(1+use loss)-1)*hydrogen input

		heat, residential, by conversion of hydrogen using electrolyzer, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	heat, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM	heat, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U	heat, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U	heat, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U	Remark(s)
Reforming using natural gas from Switzerland/CH U							
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U	kg				2.06e-03		Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U	kg				1.15e-05		((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U	kg					2.06e-03	Hydrogen input. 1 [MJ H2]/120 [MJ/kg H2]/ eff.(th)
hydrogen supply, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U	kg					1.15e-05	((1+storage loss)*(1+use loss)-1)*hydrogen input
Emissions to air							
Water	kg	1.85e-08	1.85e-08	1.85e-08	1.85e-08	1.85e-08	9kg of water produced per kg of H2 combusted.
Hydrogen	kg	1.15e-05	1.15e-05	1.15e-05	1.15e-05	1.15e-05	Hydrogen leakage.

Table 53 Life-cycle inventories for the supply of electricity via the conversion of hydrogen in a PEM fuel cell system.

		electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM	electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U	electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U	electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U	Remark(s)
	Unit	1 kWh	1 kWh	1 kWh	1 kWh	1 kWh	
Material and infrastructure inputs							
fuel cell system assembly, 1 kWe, proton exchange membrane	p	1.60e-05	1.60e-05	1.60e-05	1.60e-05	1.60e-05	Operational time of 20,000 hours at the power of 1 kWe. Due to the degradation effects, hydrogen consumption must be increased to

		electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	**electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM**	**electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U**	**electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U**	**electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U**	**Remark(s)**
(PEM)/GLO U							always generate the power of 1 kWe. Because of the dynamic operational regime, five replacements of the PEMFC stack are included (lifetime of 3'800 hours per stack), while the BoP lasts the whole operational time.
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	kg	5.84e-02					Hydrogen input. 1 [kWh H2]/33.33 [kWh/kg H2]/ eff.(el) * allocation factor
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	kg	3.27e-04					((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)/CH U	kg		5.84e-02				Hydrogen input. 1 [kWh H2]/33.33 [kWh/kg H2]/ eff.(el)
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)/CH U	kg		3.27e-04				((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/ CH U	kg			5.84e-02			Hydrogen input. 1 [kWh H2]/33.33 [kWh/kg H2]/ eff.(el)
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/ CH U	kg			3.27e-04			((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Steam Methane	kg				5.84e-02		Hydrogen input. 1 [kWh H2]/33.33 [kWh/kg H2]/ eff.(el)

		electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid/CH U	**electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Electrolysis, PEM**	**electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming using natural gas from Switzerland/CH U**	**electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/CH U**	**electricity, residential, by conversion of hydrogen using fuel cell, PEM, allocated by exergy, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/CH U**	**Remark(s)**
Reforming, with CCS using natural gas from Switzerland/ CH U							
hydrogen supply, distributed by pipeline, produced by Steam Methane Reforming, with CCS using natural gas from Switzerland/ CH U	kg				3.27e-04		((1+storage loss)*(1+use loss)-1)*hydrogen input
hydrogen supply, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/ CH U	kg					5.84e-02	Hydrogen input. 1 [kWh H2]/33.33 [kWh/kg H2]/ eff.(el)
hydrogen supply, distributed by pipeline, produced by Pyrolysis using natural gas from Switzerland/ CH U	kg					3.27e-04	((1+storage loss)*(1+use loss)-1)*hydrogen input
Emissions to air							
Water	kg	5.26e-07	5.26e-07	5.26e-07	5.26e-07	5.26e-07	9kg of water produced per kg of H2 combusted.
Hydrogen	kg	3.27e-04	3.27e-04	3.27e-04	3.27e-04	3.27e-04	Hydrogen leakage.

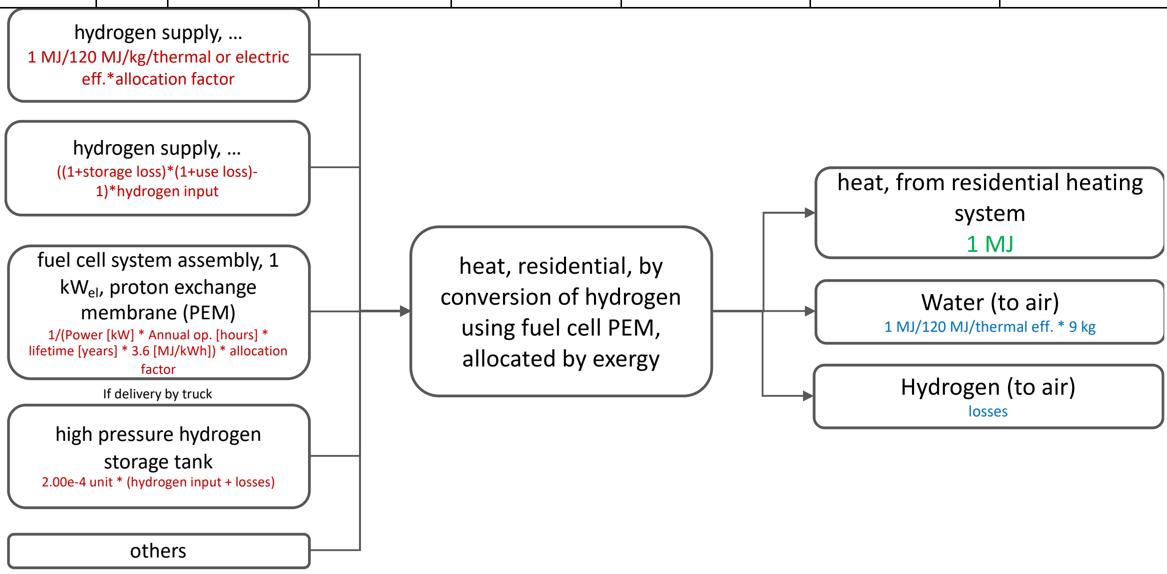

Figure 29 Schematic mass and energy balance for the heat supply via hydrogen conversion in a PEM fuel cell system. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

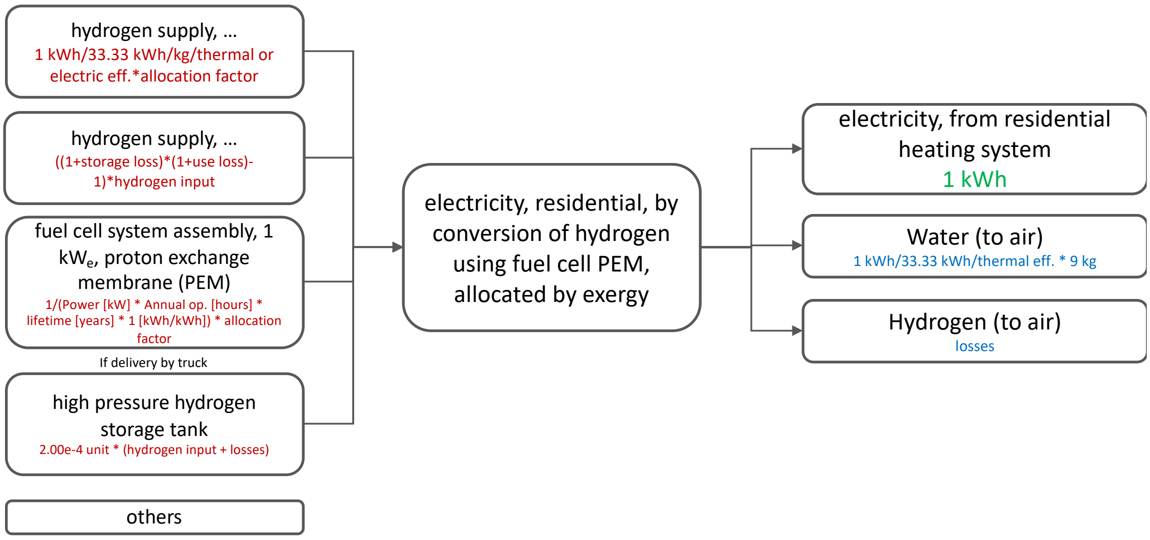

Figure 30 Schematic mass and energy balance for the electricity supply via hydrogen conversion in a PEM fuel cell system. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Additionally, forty alternative datasets are modeled:

- using different electrolyzer types: AEC, SOEC, and SOEC with steam input,
- using other hydrogen production methods: Auto-Thermal Reforming, with and without CCS,
- using different feedstock inputs: for electrolytic hydrogen, we consider the Swiss renewable electricity mix, Swiss solar power, Morocco-based solar power, Morocco-based wind power, and Denmark-based wind power. For the SMR and pyrolysis options, we consider liquefied natural gas from Algeria.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *54* for uncertainty estimation are considered.

Table 54 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	**Completeness**	**Temporal correlation**	**Geographical correlation**	**Further technological correlation**	**Sample size**
H_2 in PEMFC	1	5	1	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

2.8.2 SOFC fuel cell

For this study, we consider the life cycle inventories from the UVEK:2022 database, originally from (Primas 2007), which describes a 125 kW_{el} solid oxide fuel cell system. However, biomethane or natural gas are the fuels considered in the original publication. The system has an electrical efficiency of 47%, a thermal efficiency of 33%, for an overall efficiency of 80%.

Table 55 Specifications for a 125-kW_{el} SOFC fuel cell system.

		Source/Remark
Energy carrier	Hydrogen	
End-use technology	Fuel cell, SOFC	
Heat conversion efficiency [% LHV input]	33.0%	(Primas 2007)
Electricity conversion efficiency [% LHV input]	47.0%	
Lifetime [years]	20	
Power$_{th}$ [kW]	90	
Power$_{el}$ [kW]	125	
Total cap. input-related [kW]	270	Calculated from the rows above.
Total eff. (heat + el.)	80%	
Annual operation [hours]	4'100	(Kägi et al. 2021)
Annual heating [kWh]	369,000	Calculated from the rows above.
Annual heating period [months]	6	Assumption used for sizing of the hydrogen storage
Annual H_2 need [kg]	33'056	Calculated from the rows above.

Fifty datasets are modeled using different hydrogen production technologies and feedstocks, following the modelling principle schematically represented in Figure *31* and Figure *32*. However, none of those datasets are further discussed in this report. Their associated environmental impacts are considered as part of a sensitivity analysis.

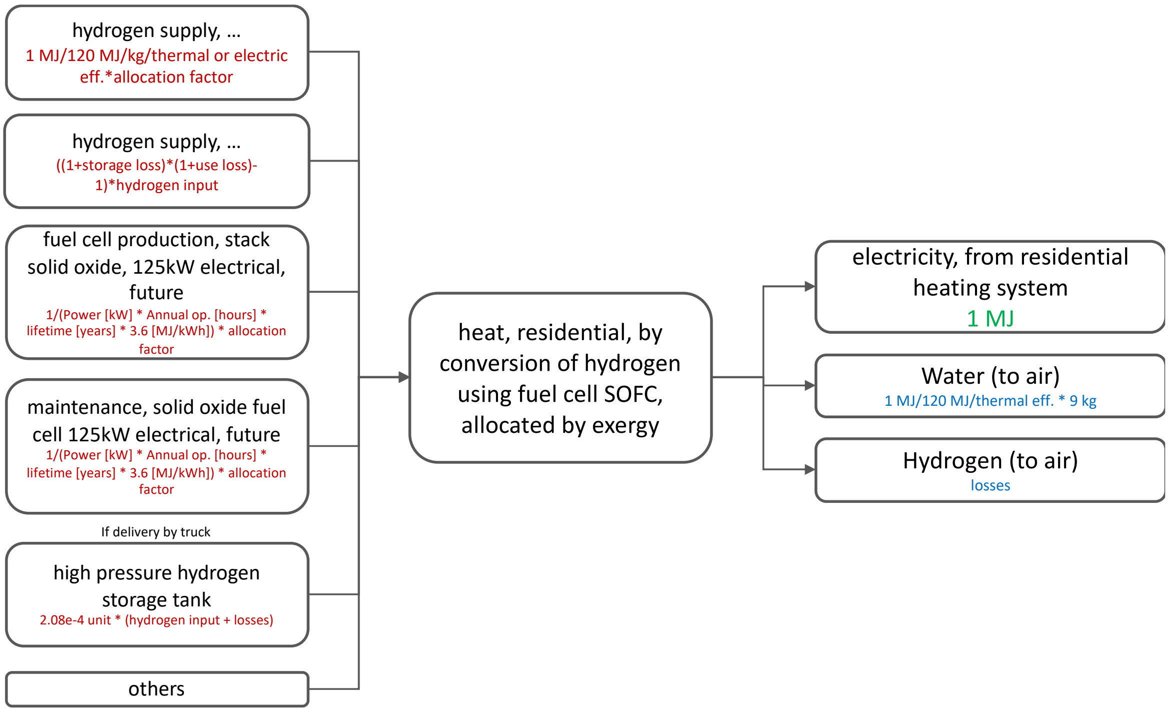

Figure 31 Schematic mass and energy balance for the heat supply via hydrogen conversion in a PEM fuel cell system. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

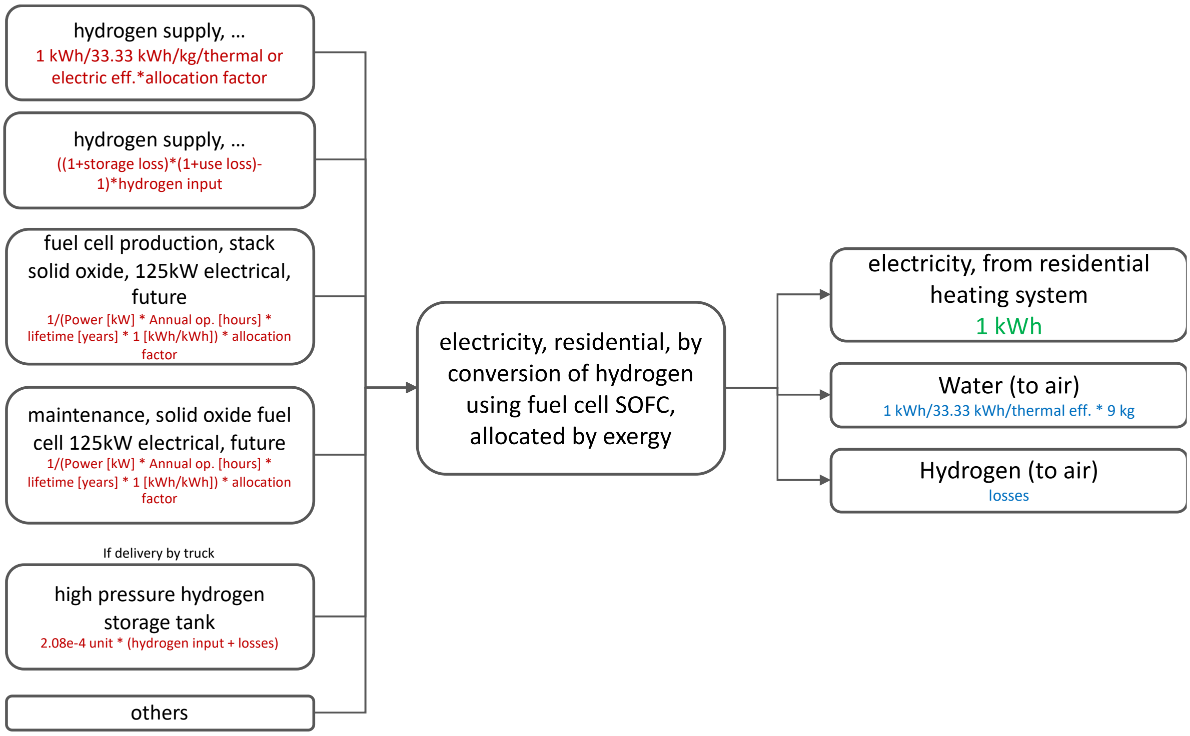

Figure 32 Schematic mass and energy balance for the electricity supply via hydrogen conversion in a SOFC fuel cell system. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *54* for uncertainty estimation are considered.

Table 56 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	**Completeness**	**Temporal correlation**	**Geographical correlation**	**Further technological correlation**	**Sample size**
H_2 in SOFC	1	5	1	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

3 Synthetic natural gas (SNG)

Synthetic natural gas (SNG), or substitute natural gas, can be produced from fossil fuels such as coal and oil or renewable sources such as biomass. The production of SNG involves a process called gasification followed by methanation.

Here is a simplified description of the process:

Gasification: The feedstock (e.g., biomass) is heated in a low-oxygen environment, which causes it to break down into a mixture of gases, primarily carbon monoxide (CO) and hydrogen (H_2). This mixture is often referred to as “syngas” or synthetic gas.

Cleaning and Purification: The syngas is then purified to remove contaminants and unwanted gases. The goal is to get a pure mixture of CO and H_2.

Methanation: The cleaned and purified syngas is then reacted over a catalyst to produce methane (CH_4), the primary component of natural gas. This process is exothermic. The reaction is as follows:

$$CO + 3H_2 \rightarrow CH_4 + H_2O$$

Gas Upgrading: The produced gas may need to be upgraded or adjusted to meet the specific requirements of the natural gas grid or the intended use. This could involve removing any remaining impurities, changing the calorific value, or adding odorants for safety.

In this study, we consider the production of SNG via:

- **Catalytic methanation**, where a stream of CO_2 sourced from various points (DAC, cement plant, MSWI plant) is converted to CO via RWGS and synthesized into CH_4 using H_2 from electrolysis, using a metal catalyst.
- **Biological methanation**, where microorganisms, typically archaea, convert CO2 (also sourced from various emission points) and H_2 into CH_4. The process can be seen as a biological form of the Sabatier reaction described above. Biological methanation has several potential advantages over catalytic methanation. For instance, it operates at lower temperatures and pressures, can handle gas streams with lower concentrations of hydrogen, and doesn’t require a physical catalyst, which can degrade over time. However, it also has challenges, including slower reaction rates and the need to maintain the health and activity of the microbial population.

3.1 CO_2 capture

Carbon capture technology, including direct air capture (DAC), represents a significant opportunity to reduce CO_2 emissions and mitigate climate change. Direct air capture is particularly promising as it is not limited by location and can potentially remove CO_2 from the atmosphere anywhere. However, it is penalized by low carbon dioxide concentrations in the atmosphere compared to industrial CO_2 point sources, as it results in a much higher energy demand for CO_2 capture.

On the other hand, cement plants and municipal waste incineration plants are significant sources of CO_2 emissions. Cement production accounts for around 8% of global CO_2 emissions. However, a large part, if not most, of the CO_2 emissions of cement and municipal waste incineration plants is of fossil or geogenic origin – see Table *57*. This implies that Carbon Capture and Usage from such industrial point sources to produce synthetic fuel leads to the release of CO_2 contributing to the long-term warming increasing of the atmosphere.

Table 57 Share of biogenic CO_2 in the different sources considered.

Carbon dioxide sources	Atmospheric/Biogenic share [% mass]	Remark/Source
DAC	100%	
MSWI	52%	Association of Swiss Operators of Waste treatment plants (VBSA 2020)
Cement plant	6%	18% of Switzerland’s cement plants’ fuel input is biomass-based, according to p.139 of Switzerland’s Greenhouse Gas Inventory 1990–2018 (INFRAS AG 2020). Two-thirds of Switzerland’s cement plants' CO_2 emissions are from lime calcination, which is geogenic. Here, we simplify by considering 18% of the remaining third (i.e., 6%), which also matches with the emission value found in the UVEK:2022 inventory dataset « clinker production » in Switzerland.

Using mono-ethanolamine (MEA) as a solvent for CO_2 capture is a well-established technology widely used in industrial applications. The process is quite effective; MEA can capture up to 90% of the CO_2 emissions from the exhaust gas of power plants or industrial processes. Despite the opportunities, significant challenges are associated with CO_2 capture using MEA. One of the main challenges is the high energy requirement for the regeneration of MEA after it has absorbed CO_2. This process typically involves heating the MEA to release the captured CO_2, which is energy-intensive and potentially counterproductive (i.e., emission-intensive) if the heat is not provided by a low-carbon source (e.g., excess process heat).

Direct air capture, while potentially promising, faces its own set of challenges. The concentration of CO_2 in the air is much lower than in the flue gases of power plants or industrial processes, making the capture process more complex and less efficient.

Table 58 describes the parameters considered to model the capture of CO_2 via Direct Air Capture, from MSWI and cement plants.

Table 58 Operational parameters for the different CO_2 capture options considered.

	DAC	MSWI		Cement plant		Remark
		Without heat recovery	With heat recovery	Without heat recovery	With heat recovery	
Inventories source	(Qiu et al. 2022)	(Bisinella et al. 2021)		(Meunier et al. 2020)		
Capture technology	Mono-ethanolamine (MDEA)					
CO_2 concentration in gas [ppm]	~418	105,000		204,000		
Heat requirement from dedicated heat source [GJ/ton CO_2 captured]	5.4	3.7	0.4	3.66	2.5	Optimistic heat recovery case values from (Bisinella et al. 2021) and (Gallego Dávila, Sacchi, and Pizzol 2023).
Electricity requirement [MWh/ton CO_2 captured]	0.5	0.1		0.07		
MEA degradation rate [kg/ton CO_2 captured]	3	4		1, corrected to 4		In (Meunier et al. 2020), a flash tank limits MEA loss via water evaporation. However, for a fairer basis of comparison, we align the MEA degradation rate with that of the MSWI case (i.e., 4 kg MEA/ton CO_2 captured).

The life-cycle inventories of the different carbon dioxide capture systems considered are described in Table *59*. Note that the original inventories provide the steam input in megajoules. We convert it to kilograms considering the specific steam enthalpy at 200°C and 6.5 bar (i.e., 2,796 kJ/kg), giving 0.36 kg/MJ.

Table 59 Life-cycle inventories of the different carbon dioxide capture systems.

		direct air capture system, sorbent-based, 100ktCO2/RER U	treatment of direct air capture system, sorbent-based, 100ktCO2/RER U	carbon dioxide, captured from the atmosphere, with a sorbent-based direct air capture system, 100ktCO2/CH U	carbon dioxide, captured at cement production plant, for subsequent reuse/CH U	carbon dioxide, captured at municipal solid waste incineration plant, for subsequent reuse/CH U	Remark(s)
	Unit	1 p	1 p	1 kg	1 kg	1 kg	
Material and infrastructure inputs							
Concrete, normal, at plant/CH U	m3	8.00e+03					civil engineering
Reinforcing steel, at plant/RER U	kg	9.42e+05					civil engineering
Concrete, normal, at plant/CH U	m3	6.00e+03					hall
Reinforcing steel, at plant/RER U	kg	5.48e+05					hall
Steel, low-alloyed, at plant/RER U	kg	1.20e+05					hall
Rock wool, at plant/CH U	kg	1.60e+04					hall
Steel, converter, unalloyed, at plant/RER U	kg	2.76e+05					collector containers
Chromium steel 18/8, at plant/RER U	kg	2.24e+05					collector containers
Rock wool, at plant/CH U	kg	1.00e+04					collector containers
Polyurethane, rigid foam, at plant/RER U	kg	1.20e+04					collector containers
Copper, primary, at refinery/GLO U	kg	1.00e+04					collector containers
aluminium, production mix, wrought alloy, at plant/kg/RER U	kg	1.60e+05					collector containers
Alkyd paint, white, 60% in H2O, at plant/RER U	kg	1.00e+04					collector containers
Chromium steel 18/8, at plant/RER U	kg	3.38e+05					process unit
Steel, low-alloyed, at plant/RER U	kg	2.80e+04					process unit
Polystyrene foam slab, at plant/RER U	kg	9.40e+04					process unit
Polyurethane, rigid foam, at plant/RER U	kg	1.00e+04					process unit
Copper, primary, at refinery/GLO U	kg	1.00e+04					process unit
Chromium steel 18/8, at plant/RER U	kg	2.20e+04					spare parts
Steel, low-alloyed, at plant/RER U	kg	1.20e+04					spare parts
amine-based silica production, for sorbent-based direct air capture system/RER U	kg			3.00e-03	4.00e-03	4.00e-03	operational
direct air capture system, sorbent-based, 100ktCO2/RER U	p			5.00e-10			System
Sodium hydroxide, 50% in H2O, production mix, at plant/RER U	kg				1.00e-04	1.00e-04	
tap water, at user/kg/RER U	kg				9.66e-03	9.66E-03	
transport, freight, rail, electricity with shunting/tkm/CH U	tkm	5.34e+05		1.80e-03	2.40e-03	2.52e-03	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.0 kg over 600.0 km.

		direct air capture system, sorbent-based, 100ktCO2/RER U	treatment of direct air capture system, sorbent-based, 100ktCO2/RER U	carbon dioxide, captured from the atmosphere, with a sorbent-based direct air capture system, 100ktCO2/CH U	carbon dioxide, captured at cement production plant, for subsequent reuse/CH U	carbon dioxide, captured at municipal solid waste incineration plant, for subsequent reuse/CH U	Remark(s)
transport, freight, lorry 16-32 metric ton, fleet average/tkm/CH U	tkm	3.16e+05		1.50e-04	2.00e-04	2.10e-04	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.0 kg over 50.0 km.
transport, barge tanker/tkm/RER U	tkm	1.72e+04					Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 21500.0 kg over 800.0 km.
Energy inputs							
electricity, low voltage, at grid/kWh/CH U	kWh			5.00e-01	6.90e-03	1.00e-01	operational
Steam, for chemical processes, at plant/RER U	kg			1.94e+00	1.32e+00 / 9.00e-01	1.40e+00 / 1.44e-01	With / without heat recovery from the plant.
Resources							
Carbon dioxide, in air	kg			1.00e+00			CO2 uptake
Emissions to air							
Ammonia	kg					1.00e-04	
Carbon dioxide, fossil	kg				1.03e-01	8.40e-02	CO2 leakage.
Carbon dioxide, biogenic	kg			2.10e-02	6.46e-03	9.10e-02	CO2 leakage.
Waste treatment							
treatment of direct air capture system, sorbent-based, 100ktCO2/RER U	p			5.00e-10			EoL
Disposal, building, concrete, not reinforced, to sorting plant/CH U	kg		2.94e+07				EoL
Disposal, building, reinforcement steel, to recycling/CH U	kg		2.14e+06				EoL
disposal, plastics, mixture, 15.3% water, to municipal incineration/kg/CH U	kg		1.16e+05				EoL
Recycling aluminium/RER U	kg		1.44e+05				EoL
Disposal, solvents mixture, 16.5% water, to hazardous waste incineration/CH U	kg		6.00e+06				EoL
disposal, copper, 0% water, to municipal incineration/kg/CH U	kg		2.00e+04				EoL
Disposal, mineral wool, 0% water, to inert material landfill/CH U	kg		2.60e+04				EoL

For all cases concerning the sourcing of CO_2 from a cement or MSWI plant, we produce three variants of the same supply chain, with different system boundaries reflecting the different allocation approaches described in Section 1.6.C.

This allocation issue does not concern the case where CO_2 is sourced from DAC.

3.1.1 Direct Air Capture (DAC)

This study uses the LCI of a solid sorbent-based CO_2 capture system (Qiu et al. 2022), which relies on data collected by Deutz and Bardow (Deutz and Bardow 2021) based on the demonstration pant of Climeworks in Iceland.

The LCI data represent a plant with an annual capacity of 100 kt CO_2/year and a lifetime of 20 years. The plant requires 5.4 MJ of heat per kg of CO_2 captured, which is coming as steam supplied by a mix of fuel oil and natural gas boilers, representing the European chemical industry practices according to the UVEK database. This assumption is critical, as it impedes the performance of DAC. Still, burden-free heat, such as excess heat, is constrained in supply and perhaps not available where needed. Another 0.5 kWh of electricity per kg CO_2 captured is required for ventilation. Finally, about 2% of the CO_2 initially captured leaks back into the atmosphere. The life-cycle inventories for the manufacture and use of the DAC system are presented in Table *59*.

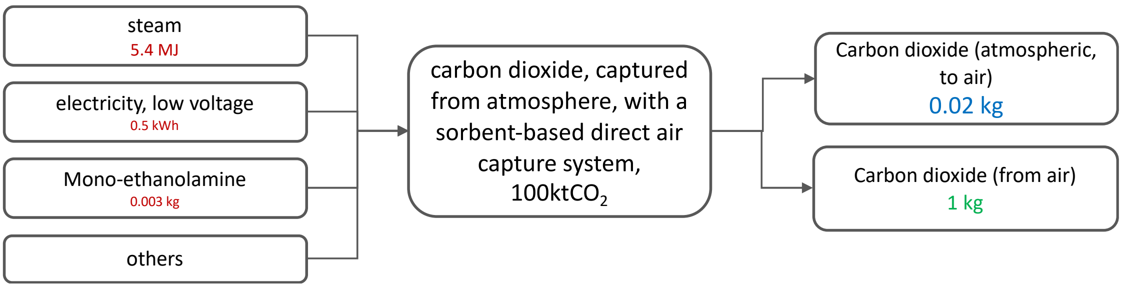

Figure 33 Schematic mass and energy balance for carbon dioxide capture using a sorbent-based direct air capture system. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *60* for uncertainty estimation are considered.

Table 60 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	**Completeness**	**Temporal correlation**	**Geographical correlation**	**Further technological correlation**	**Sample size**
DAC	1	5	1	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

3.1.2 Cement plants

The work of (Meunier et al. 2020) is used to model CO_2 capture from a cement plant for subsequent reuse. The facility, part of a synthetic fuel production chain, utilizes steam heat from excess heat generated by the synfuel conversion process and a heat-dedicated source to regenerate the sorbent.

Indeed, the heat requirement is initially discounted by 26% (i.e., from 3.66 GJ/ton CO_2 to 2.7 GJ) because the capture plant is integrated with a methanol production unit: the heat from the exothermic synthesis can be recovered to sustain the CO_2 capture process partly. Gallego Dávila, Sacchi, and Pizzol (2023) also look at methanol production from the CO_2 captured at a cement plant in Denmark. Based on the capture plant design, the energy demand can be reduced from 3.6 GJ/ton CO_2 to 2.5 GJ (i.e., -30%). However, this is only possible because the cement is already equipped with a heat recovery unit, which performs well thanks to the plant running a *wet process* (the kiln slurry is saturated in water), implying an important quantity of latent heat in the flue gas. Even then, the economic viability of such endeavor on existing plants is questioned (Hughes and Cvetic 2023), and the prospect of building new cement plants in Switzerland is unlikely. Hence, aside from a dataset with heat recovery considered (to the extent of 30% of the heat required by the capture plant), we also provide a dataset without it, because neither the presence of a heat recovery unit at the cement plant nor a high level of integration of the fuel plant are guaranteed. In the latter, we set the heat requirement from a dedicated source to 3.66 MJ/kg CO_2 captured.

As with DAC, such heat comes as steam supplied by a mix of fuel oil and natural gas boilers, representative of the practices in the European chemical industry. Alternatively, the heat could be provided by an industrial high-temperature heat pump in the future, reducing the energy input. This could prove interesting if the electricity carries low environmental impacts upstream. Water is also provided by the methanol production process, eliminating the need for an external source. CO_2 is captured using a chemical absorption-regeneration process with amines as the solvent (like DAC and MSWI-based carbon capture). The solution used is a 30 wt.% aqueous solution of MEA, a well-studied benchmark for industrial CO_2 capture. The CO_2 is pre-compressed to 2 bar for storage, with 10% released back into the atmosphere due to a 90% absorption rate.

The MEA loss makeup in (Meunier et al. 2020) is 1 kg MEA per ton of captured CO_2, which is lower than loss rates considered for DAC or CO_2 capture from an MSWI plant (3 and 4 kg MEA/ton CO_2 captured, respectively). This makeup rate offsets losses from thermal degradation only, as the loss of MEA via water evaporation is prevented by a flash tank. We changed it to 4 kg MEA/ton CO_2 captured to present a fairer basis for comparison with CO_2 capture via DAC or an MSWI plant.

The life-cycle inventories for the carbon dioxide capture system are presented in Table *59*. Note that neither infrastructure requirements nor the associated end-of-life treatment are included due to lack of information and the expected negligible associated environmental burdens.

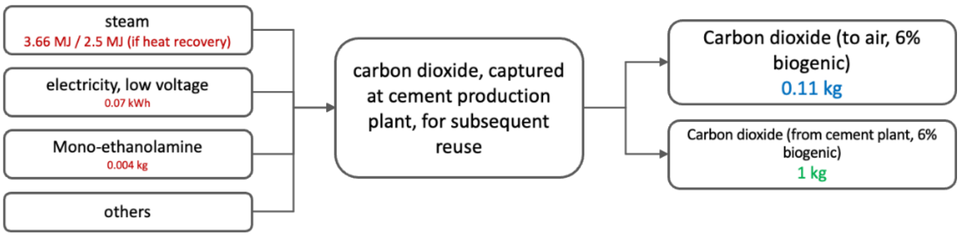

Figure 34 Schematic mass and energy balance for carbon dioxide capture from a cement plant using a sorbent-based capture system. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *61* for uncertainty estimation are considered.

Table 61 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	Completeness	Temporal correlation	Geographical correlation	Further technological correlation	Sample size
CC from cement plant	3	5	1	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

3.1.3 Municipal Solid Waste Incineration (MSWI) plants

The work of (Bisinella et al. 2021) is used to model CO_2 capture from an MSWI plant.

During the post-flue gas condensation, the gas is cooled and introduced to a reactor with a 30% MEA solution. This solution absorbs 85-90% of the CO_2 at 1 bar and temperatures between 25-50°C in an exothermic process. The CO_2-rich solution is then heated to 100-140°C, allowing CO_2 to desorb from the MEA in a stripper at 1-2 bars, leaving it as water vapor. The water is condensed from the CO_2 stream, and the CO_2 is compressed for transportation. The MEA is reused in the plant. Approximately 4 kg of MEA is used per ton of CO_2 (roughly like DAC), with some losses during stripping. Note that, unlike the carbon capture unit modeled at the cement plant, this unit is not equipped with a flash tank limiting the loss of MEA via evaporation. Sodium hydroxide (NaOH) is added during stripping, and about 4 kg of solid waste is produced per ton of CO_2 captured. The process also reduces the presence of other flue gas pollutants while NH_3 levels increase due to MEA degradation, which is considered out of scope.

The net heat requirement is 3.7 MJ/kg CO_2 captured. We produce two datasets: with and without heat recovery. In the latter, an optimistic case where 3.3 GJ out of 3.7 originate from the MSWI heat recovery unit is considered. According to Bisinella et al. (2021), when the carbon capture plant is amended to an existing MSWI plant, 40% of the recovered heat used by the capture plant cannot be rerouted to the district heating system (where it was initially destined to). This missing heat supply is not considered here but has to be considered on a case-specific basis including the environmental burdens originating from the alternative heat source substituting the missing heat from the MSWI with CO_2 capture. This loss can be reduced to 10% if the carbon capture plant is built together with the MSWI plant (i.e., full integration). As with DAC, such heat comes as steam supplied by a mix of fuel oil and natural gas boilers, representative of the practices in the European chemical industry.

The life-cycle inventories for the carbon dioxide capture system are presented in Table *59*. Note that neither infrastructure requirements nor the associated end-of-life treatment are included due to lack of information and the expected negligible associated environmental burdens.

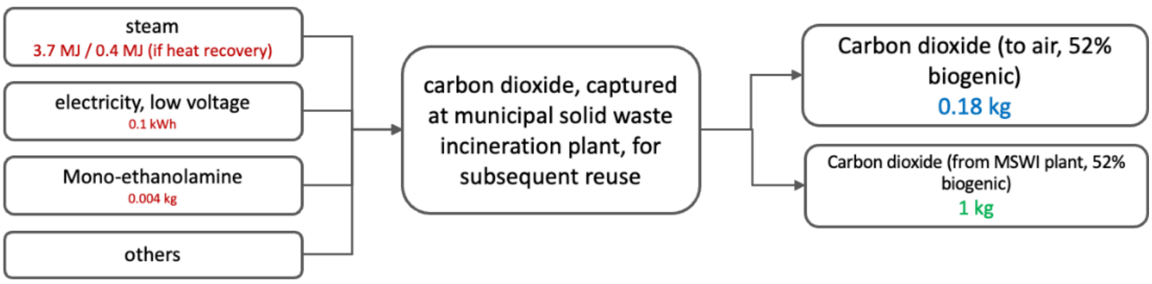

Figure 35 Schematic mass and energy balance for carbon dioxide capture from an MSWI plant using a sorbent-based capture system. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *62* for uncertainty estimation are considered.

Table 62 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	Completeness	Temporal correlation	Geographical correlation	Further technological correlation	Sample size
CC from MSWI plant	3	5	1	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

3.2 Hydrogen supply

For the following cases:

- methane, from (electrochemical or biological) methanation, with carbon from atmospheric CO_2 capture
- methane, from (electrochemical or biological) methanation, with carbon from cement plant
- methane, from (electrochemical or biological) methanation, with carbon from municipal waste incineration plant
- methane, from (electrochemical or biological) methanation, with carbon from atmospheric CO_2 capture, electricity from Swiss solar PV
- methane, from (electrochemical or biological) methanation, with carbon from atmospheric CO_2 capture, electricity from Swiss hydropower
- methane, from (electrochemical or biological) methanation, with carbon from atmospheric CO_2 capture, from Renewables mix

the production of hydrogen and synthetic natural gas is assumed to be located on the same site in Switzerland.

For the other cases, namely:

- methane, from (electrochemical or biological) methanation, with carbon from atmospheric CO_2 capture, hydrogen from autonomous hybrid plant
- methane, from (electrochemical or biological) methanation, with carbon from atmospheric CO_2 capture, hydrogen from autonomous solar-powered plant
- methane, from (electrochemical or biological) methanation, with carbon from atmospheric CO_2 capture, hydrogen from autonomous wind-powered plant
- methane, from (electrochemical or biological) methanation, with carbon from atmospheric CO_2 capture, hydrogen from Danish offshore wind turbines

we consider the logistics for supplying the hydrogen to Switzerland, thereby using hydrogen supply datasets while sourcing CO_2 and the methanation process remaining in Switzerland.

3.3 Catalytic methanation

The work of (X. Zhang et al. 2020) represents the electro-chemical methanation of H_2 and CO_2 into synthetic natural gas, using the so-called Sabatier reaction. The methanation process involves a bubbling fluidized bed reactor (BFB methanation) that converts CO_2 to CH_4 using a nickel-based catalyst. Following this initial conversion, a membrane gas separation separates and recycles any unreacted H_2 and CO_2. Additionally, water produced during methanation is separated via condensation, which shifts the thermodynamic equilibrium and allows for a higher conversion rate in a subsequent fixed-bed methanation reactor.

Hence, the Sabatier reaction, without considering any potential re-use of hydrogen from the water, is:

$$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O$$

The process requires 2.75 kg CO_2 and 0.5 kg H_2 to produce 1 kg CH_4, with a density of 0.717 kg/m^3 and a lower heating value (LHV) of 48 MJ/kg. We do not allocate the process expenditures between the production of synthetic methane and water. Finally, it is assumed this process is integrated with the production of hydrogen and the sourcing of CO_2 via DAC. This implies that little to no transport is considered except for ancillary materials (e.g., catalysts) and the absence of leakage during transport. This is also valid for cases where the CO_2 is sourced from point sources (i.e., cement plant, MSWI plant). This integrated configuration is optimal and represents a best-case scenario. Also note that no CO_2 losses during the methanation process are reported in the literature and were therefore left out from the process inventory.

In the cases where the CO_2 comes from an industrial point source (e.g., from a cement or MSWI plant), we develop three variants corresponding to the three allocation approaches described in Section I.C.6: 100:0, 50:50 and 0:100. Hence, depending on the allocation approach, none, half, or all of the carbon dioxide capture process input amount is considered – refer to Section I.C.6.

Table 63 Life-cycle inventories for the supply of synthetic natural gas via catalytic methanation.

		Sabatier reaction methanation unit construction/RER U	**production of nickel-based catalyst for methanation/RER U**	**methane, from electrochemical methanation, with carbon from atmospheric CO2 capture/CH U**	**methane, from electrochemical methanation, with carbon from cement plant/CH U**	**methane, from electrochemical methanation, with carbon from municipal waste incineration plant/CH U**	**Remark(s)**
	Unit	1 p	1 kg	1 kg	1 kg	1 kg	
Material and infrastructure inputs							
Chromium steel 18/8, at plant/RER U	kg	5.94e+03					
Polyethylene, HDPE, granulate, at plant/RER U	kg	6.60e+02					
Aluminium alloy, AlMg3, at plant/RER U	kg		8.10e-01				
Nickel, 99.5%, at plant/GLO U	kg		1.90e-01				
Sabatier reaction methanation unit construction/RER U	p			3.95e-07	3.95e-07	3.95e-07	
carbon dioxide, captured from atmosphere, with a sorbent-based direct air capture system, 100ktCO2/CH U	kg			2.75e+00			
carbon dioxide, captured at cement production plant, for subsequent reuse/CH U					2.75e+00 / 1.375e+00 / 0.00e+00		Amount depends on CO_2 allocation approach (100:0, 50:50 or 0:100).
carbon dioxide, captured at municipal solid waste incineration plant, for subsequent reuse/CH U						2.75e+00 / 1.375e+00 / 0.00e+00	Amount depends on CO_2 allocation approach (100:0, 50:50 or 0:100).

		Sabatier reaction methanation unit construction/RER U	production of nickel-based catalyst for methanation/RER U	methane, from electrochemical methanation, with carbon from atmospheric CO2 capture/CH U	methane, from electrochemical methanation, with carbon from cement plant/CH U	methane, from electrochemical methanation, with carbon from municipal waste incineration plant/CH U	Remark(s)
hydrogen production, gaseous, 30 bar, from PEM electrolysis, from grid electricity/CH U	kg			4.98e-01	4.98e-01	4.98e-01	
production of nickel-based catalyst for methanation/RER U	kg			8.37e-05	8.37e-05	8.37e-05	
transport, freight, rail/tkm/RER U	tkm	1.32e+03	2.00e-01	5.02e-05	5.02e-05	5.02e-05	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.5 kg over 400.0 km.
transport, freight, lorry 16-32 metric ton, fleet average/RER U	tkm	6.60e+02	1.00e-01	4.18e-06	4.18e-06	4.18e-06	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.5 kg over 200.0 km.

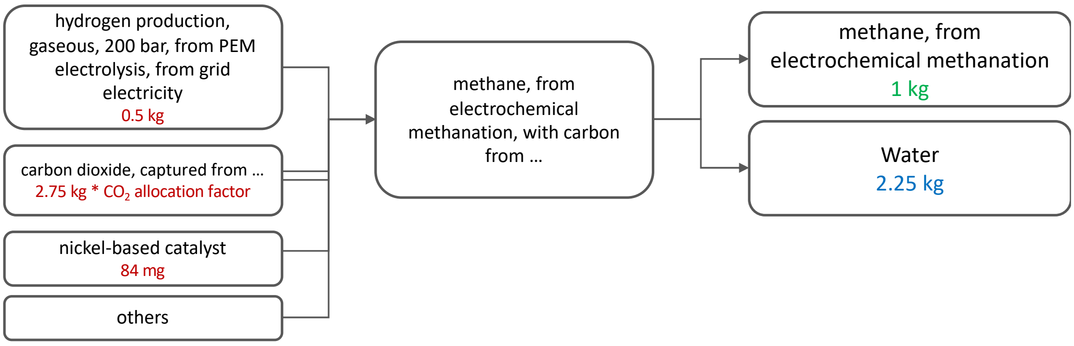

Figure 36 Schematic mass and energy balance to produce synthetic natural gas via catalytic methanation. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *64* for uncertainty estimation are considered.

Table 64 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	Completeness	Temporal correlation	Geographical correlation	Further technological correlation	Sample size
Catalytic SNG production	2	5	2	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

3.4 Biological methanation

In biological methanation, microorganisms known as methanogens convert carbon dioxide (CO_2) and hydrogen (H_2) into methane (CH_4) and water (H_2O). This process is also known as bio-methanation and occurs under anaerobic conditions (i.e., without oxygen).

Information and LCI about biological methanation are challenging to find. We consider the 2014 LCA report of a Denmark-based demonstration project called BioCat (Energiforskning.dk 2014) and validate it with input-output data from another demonstration plant in Germany (International Energy Agency (IEA) 2018).

The process of bio-methanation resembles that of the Sabatier reaction. Hence, for every kg of CH_4 produced, the system would consume approximately 2.75 kilograms of CO_2 and 0.5 kg of H_2 (i.e., like the catalytic pathway described above) and co-produce about 2.25 kilograms of water. The process expenditures are not allocated between the production of methane and water. The BioCat LCA document reports a production output of 51.3 kg CH_4 per full-load hour. The heat from the reaction is re-circulated at the wastewater treatment plant, hence not considered here. Electricity use of 60 kW at full load and 10 kW at standby operation levels are considered. The BioCat demonstration plant operated 3'000 full-load hours per year to capture the excess electricity production from wind turbines to use the electrolyzers (and the bio-methanation process).

Information regarding the infrastructure (i.e., reactor, facility) is missing. The overall quality of such a dataset is poor, but the requirements of CO_2 and H_2 should be correct. The life-cycle inventories are presented in Table *65*. Note that neither infrastructure requirements nor the associated treatment are included due to lack of information and the expected negligible associated environmental burdens.

In the cases where the CO_2 comes from an industrial point source (e.g., from a cement or MSWI plant), we develop three variants corresponding to the three allocation approaches described previously: 100:0, 50:50 and 0:100. Hence, depending on the allocation approach, none, half, or all the carbon dioxide capture process input amount is considered.

Table 65 Life-cycle inventory of the supply of synthetic natural gas via biological methanation.

		methane, from biological methanation, with carbon from atmospheric CO2 capture/CH U	**methane, from biological methanation, with carbon from cement plant/CH U**	**methane, from biological methanation, with carbon from municipal waste incineration plant/CH U**	**Remark(s)**
	Unit	1 kg	1 kg	1 kg	
Material and infrastructure inputs					
carbon dioxide, captured from atmosphere, with a sorbent-based direct air capture system, 100ktCO2/CH U	kg	2.75e+00			
carbon dioxide, captured at cement production plant, for subsequent reuse/CH U			2.75e+00 / 1.375e+00 / 0.00e+00		Amount depends on CO_2 allocation approach (100:0, 50:50 or 0:100).
carbon dioxide, captured at municipal solid waste incineration plant, for subsequent reuse/CH U				2.75e+00 / 1.375e+00 / 0.00e+00	Amount depends on CO_2 allocation approach (100:0, 50:50 or 0:100).
hydrogen production, gaseous, 30 bar, from PEM electrolysis, from grid electricity/CH U	kg	5.00e-01	5.00e-01	5.00e-01	
Ammonia, liquid, at regional storehouse/CH U	kg	1.62e-03	1.62e-03	1.62e-03	0,0833 kg Ammonia/full load hour.
transport, freight, rail, electricity with shunting/tkm/CH U	tkm	9.74e-04	9.74e-04	9.74e-04	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.0 kg over 600.0 km.
transport, freight, lorry 16-32 metric ton, fleet average/tkm/CH U	tkm	8.12e-05	8.12e-05	8.12e-05	Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.0 kg over 50.0 km.
Energy inputs					
electricity, low voltage, at grid/kWh/CH U	kWh	1.55e+00	1.55e+00	1.55e+00	60 kW at full-load, 10 kW at standby, 3000 full-load hours per year. 51.3 kg CH_4 /h at full load
Treatment, sewage, to wastewater treatment, class 1/CH U	m3	6.63e-01	6.63e-01	6.63e-01	34 m^3 of wastewater/full-load hour.

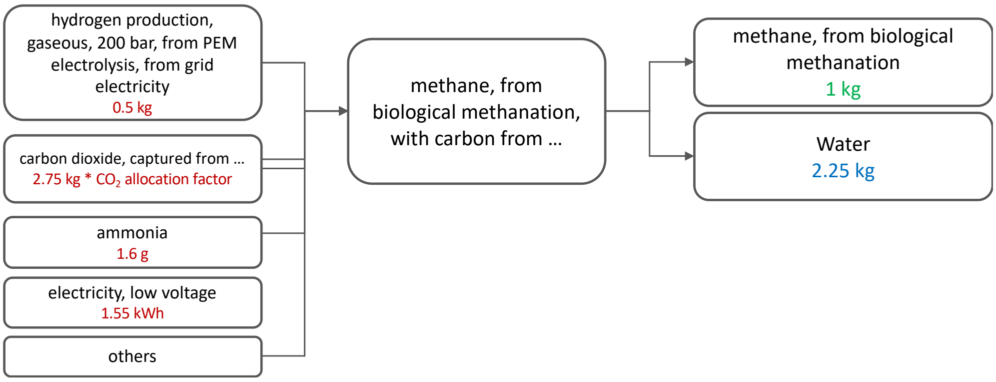

Figure 37 Schematic mass and energy balance to produce synthetic natural gas via biological methanation. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *64* for uncertainty estimation are considered.

Table 66 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	**Completeness**	**Temporal correlation**	**Geographical correlation**	**Further technological correlation**	**Sample size**
Biological SNG production	4	5	2	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

3.5 Distribution

3.5.1 Pipeline

To model the high and low-pressure transport of synthetic natural gas, we use the transmission and distribution datasets for natural gas from the UVEK:2022 database, initially provided by (Emmenegger et al. 2007), given the similar physical properties between natural and synthetic natural gas. Specifically, we consider:

- 3.84^{-8} km of high-pressure pipeline per m^3 of gas regionally distributed,
- 1.43^{-7} km of low-pressure pipeline per m^3 of gas delivered to the user.

These pipeline fractions already consider the average distance natural gas is transported in Switzerland in the high and low-pressure distribution systems, respectively.

We use the ratio between the volumetric (i.e., 40 MJ/Sm^3) and gravimetric (i.e., 48 MJ_{LHV}/kg) energy density of natural gas to derive the pipeline requirements for 1 kg of synthetic natural gas distributed.

Additionally, we consider the following leaked emissions:

- 0.69g per m^3 of gas transported at high-pressure (i.e., 0.08% mass-wise),
- 1.68g per m^3 of gas transported at low-pressure (i.e., 0.2% mass-wise),

as suggested by (Faist Emmenegger et al. 2017), totaling about 2.8g of synthetic natural gas leaked between the producer and the consumer.

We neglect other emissions initially present in the UVEK:2022 dataset for natural gas transport, as they are deemed specific to natural gas (i.e., emissions of butane, propane, NMVOC, and ethane). Carbon dioxide emissions during supply are multiplied by the carbon dioxide allocation factor, itself determined by the allocation approach (i.e., 0% for the 100:0 approach, 50% for the 50:50 approach, and 100% for the 0:100 approach).

Table 67 Life-cycle inventory of the supply of synthetic natural gas via pipeline to the consumer.

		synthetic natural gas from …	Remark(s)
	Unit	1 kg	
Material and infrastructure inputs			
methane, from …	kg	1.00e+00	Methane input.
methane, from …	kg	2.80e-03	Distribution (pipeline) losses and storage losses.
Pipeline, natural gas, high pressure distribution network/CH/I U	km	4.62e-08	SNG pipeline, based on the current Swiss CNG pipeline requirements in UVEK:2022. Lifetime of 40 years.
Pipeline, natural gas, low pressure distribution network/CH/I U	km	1.72e-07	SNG pipeline, based on the current Swiss CNG pipeline requirements in UVEK:2022. Lifetime of 40 years.
Energy inputs			
electricity, low voltage, at grid/kWh/CH U	kWh	2.82e-03	To compress the methane and inject it into the grid
synthetic natural gas from …	kg	1.3e-03	Self-consumption for compressors.
Emissions to air			
Carbon dioxide, fossil	kg	2.68 * 1.3e-3 * CO_2 fossil share * CO_2 allocation	2.68 kg CO_2/kg SNG. Emissions from compressors.
Carbon dioxide, biogenic	kg	2.68 * 1.3e-3 * CO_2 non-fossil share * CO_2 allocation	2.68 kg CO_2/kg SNG. Emissions from compressors.
Hydrogen sulfide	kg	5.97e-10	Adapted from UVEK:2022's natural gas supply dataset.
Methane, biogenic	kg	2.80e-03	Adapted from UVEK:2022's natural gas supply dataset.
Nitrogen	kg	1.81e-06	Adapted from UVEK:2022's natural gas supply dataset.

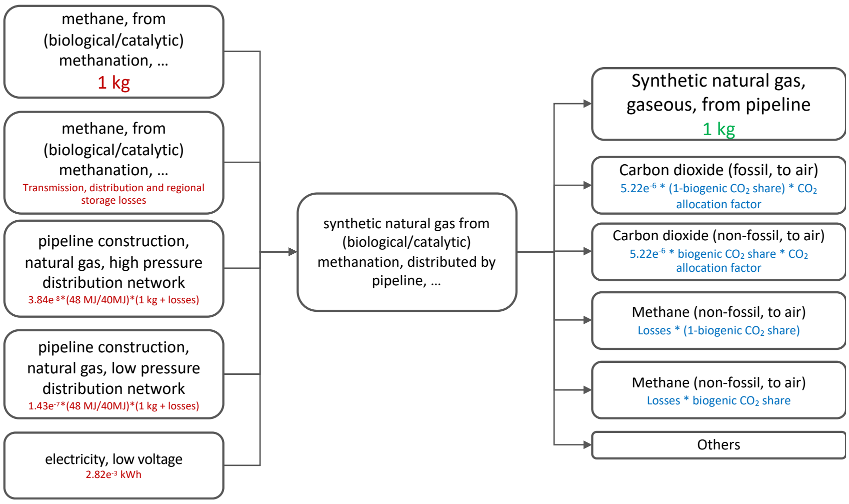

Figure 38 Schematic mass and energy balance for the storage and distribution of synthetic natural gas via pipeline. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

3.6 Storage

We do not consider any on-site storage solutions for users being delivered synthetic natural gas via pipelines.

3.7 Combustion

3.7.1 Boiler

Synthetic natural gas can be used in existing natural gas infrastructure, including home boilers. This means transitioning to SNG wouldn't require homeowners to replace their natural gas boilers. This ease of integration with existing infrastructure is a significant advantage of SNG over other forms of renewable energy (e.g., hydrogen).

In this study, we adapt the life cycle inventories of a conventional 16.4-kW natural gas home boiler from the UVEK database (Kägi et al. 2021) and adjust its combustion emissions, as described in Table 68: fossil air emissions in the original dataset (i.e., CO, CO_2, CH_4) are adapted to reflect the share of biogenic carbon in the gas. Emissions of propane and butane, specific to the combustion of natural gas, are removed. The other emissions, NMVOCs, particulate matter, etc., are preserved.

Table 68 Specifications for a 16.4-kW natural gas boiler using synthetic natural gas.

End-use technology	**Boiler**	
Energy carrier	SNG	
Lifetime [years]	20	(Kägi et al. 2021)
Power output [kW]	16.4	
Power input [kW]	15	
Annual operation [hours]	2'100	
Annual heating [kWh]	34'440	Calculated from the two rows above.
Heat conversion efficiency [% LHV input]	109.5%	The boiler can recover the latent heat of water evaporation from the moisture in the flue gas, leading to an efficiency value superior to 100% with respect to the LHV of SNG—efficiency from UVEK:2022's original CNG boiler dataset.
Annual SNG need [kg]	2'360	Calculated from rows above.

Four primary heat supply datasets are modeled based on specifications given in Table *68*. They are described below and are further analyzed in the Impact Assessment section of this report:

- heat, residential, by combustion of synthetic natural gas from biological methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from DAC
- heat, residential, by combustion of synthetic natural gas from biological methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA), and carbon sourced from DAC
- heat, residential, by combustion of synthetic natural gas from catalytic methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid, and carbon sourced from DAC
- heat, residential, by combustion of synthetic natural gas from catalytic methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA), and carbon sourced from DAC

The inventories are based on specifications given in Table *68* and described in Table *69*. The modelling is similar across the five heat supply options and is schematically represented in Figure *39*.

Table 69 Life-cycle inventories for the heat supply via the combustion of synthetic natural gas in a boiler produced by catalytic methanation, with CO_2 from cement plant and DAC and grid-based electrolytic hydrogen.

		heat, residential, by combustion of synthetic natural gas from biological methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from Cement plant/CH U	heat, residential, by combustion of synthetic natural gas from biological methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from MSWI plant/CH U	heat, residential, by combustion of synthetic natural gas from biological methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA) and carbon sourced from DAC/CH U	heat, residential, by combustion of synthetic natural gas from catalytic methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from DAC/CH U	Remark(s)
	Unit	1 MJ	1 MJ	1 MJ	1 MJ	
Material and infrastructure inputs						
gas boiler 15kW/RER/I U	p	4.41e-07	4.41e-07	4.41e-07	4.41e-07	1/(Cap. [kW] * lifetime [y] * annual operation [h] * 3.6 [MJ/kWh])
chimney/CH/I U	m	8.82e-07	8.82e-07	8.82e-07	8.82e-07	To evacuate the flue gases.
Energy inputs						
synthetic natural gas from biological methanation, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid, and carbon from Cement plant/CH U	kg	1.87e-02				Methane input. 1 [MJ SNG]/ 48 [MJ/kg SNG]/ eff.(th)
synthetic natural gas from biological methanation, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid, and carbon from MSWI plant/CH U	kg		1.87e-02			
synthetic natural gas from biological methanation, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA), and carbon from DAC/CH U	kg			1.87e-02		Methane input. 1 [MJ SNG]/ 48 [MJ/kg SNG]/ eff.(th)
synthetic natural gas from catalytic methanation, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid, and carbon from DAC/CH U	kg				1.87e-02	Methane input. 1 [MJ SNG]/ 48 [MJ/kg SNG]/ eff.(th)
synthetic natural gas from catalytic methanation, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA), and carbon from DAC/CH U	kg					Methane input. 1 [MJ SNG]/ 48 [MJ/kg SNG]/ eff.(th)
electricity, low voltage, at grid/kWh/CH U	kWh	7.34e-04	7.34e-04	7.34e-04	7.34e-04	To operate the boiler.
Emissions to air						
Acetaldehyde	kg	9.80e-10	9.80e-10	9.80e-10	9.80e-10	Adapted from UVEK:2022 natural gas-based heat dataset
Acetic acid	kg	1.47e-07	1.47e-07	1.47e-07	1.47e-07	Adapted from UVEK:2022 natural gas-based heat dataset
Benzene	kg	3.92e-07	3.92e-07	3.92e-07	3.92e-07	Adapted from UVEK:2022 natural gas-

		heat, residential, by combustion of synthetic natural gas from biological methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from Cement plant/CH U	heat, residential, by combustion of synthetic natural gas from biological methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from MSWI plant/CH U	heat, residential, by combustion of synthetic natural gas from biological methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA) and carbon sourced from DAC/CH U	heat, residential, by combustion of synthetic natural gas from catalytic methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from DAC/CH U	Remark(s)
						based heat dataset
Benzo(a)pyrene	kg	9.80e-12	9.80e-12	9.80e-12	9.80e-12	Adapted from UVEK:2022 natural gas-based heat dataset
Carbon dioxide, fossil	kg	4.9e-02 * CO_2 allocation factor	2.50e-02 * CO_2 allocation factor			Emissions based on fuel's fossil carbon content and allocation approach (100:0, 50:50 or 0:100)
Carbon dioxide, biogenic	kg	3.06e-03 * CO_2 allocation factor	2.71e-02 * CO_2 allocation factor	5.2e-02	5.2e-02	Emissions based on fuel's biogenic carbon content and allocation approach (100:0, 50:50 or 0:100)
Carbon monoxide, biogenic	kg	5.78e-06	5.78e-06	5.78e-06	5.78e-06	Adapted from UVEK:2022 natural gas-based heat dataset
Dinitrogen monoxide	kg	4.90e-07	4.90e-07	4.90e-07	4.90e-07	Adapted from UVEK:2022 natural gas-based heat dataset
Dioxin, 2,3,7,8 Tetrachlorodibenzo-p-	kg	2.94e-17	2.94e-17	2.94e-17	2.94e-17	Adapted from UVEK:2022 natural gas-based heat dataset
Formaldehyde	kg	9.80e-08	9.80e-08	9.80e-08	9.80e-08	Adapted from UVEK:2022 natural gas-based heat dataset
Mercury II	kg	2.94e-11	2.94e-11	2.94e-11	2.94e-11	Adapted from UVEK:2022 natural gas-based heat dataset
Methane, biogenic	kg	1.96e-06	1.96e-06	1.96e-06	1.96e-06	Adapted from UVEK:2022 natural gas-based heat dataset
Nitrogen oxides	kg	9.70e-06	9.70e-06	9.70e-06	9.70e-06	Adapted from UVEK:2022 natural gas-based heat dataset
PAH, polycyclic aromatic hydrocarbons	kg	9.80e-09	9.80e-09	9.80e-09	9.80e-09	Adapted from UVEK:2022 natural gas-based heat dataset
Particulate Matter, < 2.5 um	kg	9.80e-08	9.80e-08	9.80e-08	9.80e-08	Adapted from UVEK:2022 natural gas-based heat dataset
Pentane	kg	1.18e-06	1.18e-06	1.18e-06	1.18e-06	Adapted from UVEK:2022 natural gas-based heat dataset
Propionic acid	kg	1.96e-08	1.96e-08	1.96e-08	1.96e-08	Adapted from UVEK:2022 natural gas-based heat dataset

		heat, residential, by combustion of synthetic natural gas from biological methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from Cement plant/CH U	heat, residential, by combustion of synthetic natural gas from biological methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from MSWI plant/CH U	heat, residential, by combustion of synthetic natural gas from biological methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA) and carbon sourced from DAC/CH U	heat, residential, by combustion of synthetic natural gas from catalytic methanation using boiler, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from DAC/CH U	Remark(s)
Sulfur dioxide	kg	4.90e-07	4.90e-07	4.90e-07	4.90e-07	Adapted from UVEK:2022 natural gas-based heat dataset
Toluene	kg	1.96e-07	1.96e-07	1.96e-07	1.96e-07	Adapted from UVEK:2022 natural gas-based heat dataset
Emissions to water						
Nitrate	kg	1.27e-07	1.27e-07	1.27e-07	1.27e-07	Adapted from UVEK:2022 natural gas-based heat dataset
Nitrite	kg	2.94e-09	2.94e-09	2.94e-09	2.94e-09	Adapted from UVEK:2022 natural gas-based heat dataset
Sulfate	kg	4.90e-08	4.90e-08	4.90e-08	4.90e-08	Adapted from UVEK:2022 natural gas-based heat dataset
Sulfite	kg	4.90e-08	4.90e-08	4.90e-08	4.90e-08	Adapted from UVEK:2022 natural gas-based heat dataset

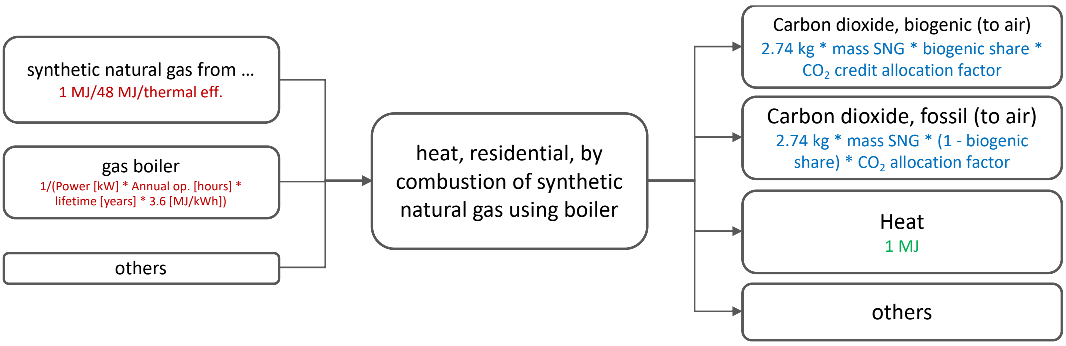

Figure 39 Schematic mass and energy balance for the heat supply via the combustion of synthetic natural gas in a boiler. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *70* for uncertainty estimation are considered.

Table 70 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	Completeness	Temporal correlation	Geographical correlation	Further technological correlation	Sample size
SNG boiler	1	5	1	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

4 Methanol

Methanol is a liquid with a higher volumetric energy density at ambient conditions than gaseous fuels like hydrogen. This characteristic facilitates storage and transportation, a logistical advantage particularly beneficial in a residential setting.

Its combustion exhibits superior characteristics compared to conventional heating fuels. The complete combustion of methanol yields carbon dioxide and water, with negligible quantities of particulates, sulfur dioxide (SO_2), and nitrogen oxides (NO_x). These pollutants are typically associated with the combustion of fossil fuels and contribute to air pollution and the formation of acid rain.

With certain adjustments, utilizing methanol in existing light fuel oil boilers may be feasible, reducing the need for entirely new infrastructure. This would involve modifications to the burner system to accommodate the different combustion characteristics of methanol and possibly adding vegetable oil to prevent pump failures (Hayden, Braaten, and Palmer 1981). Methanol-based boilers are already used in some provinces of China (Huo et al. 2021).

However, potential challenges and risks are also associated with its use as a heating fuel. Indeed, methanol is a potent neurotoxin and can be harmful if ingested, inhaled, or absorbed through the skin. Also, it has a low flash point and is highly flammable, necessitating stringent safety measures during storage and handling.

Finally, despite its higher energy density than hydrogen (i.e., 22'700 vs. 10 MJ/Nm^3), methanol's lower heating value is less than fuel oil's (i.e., 19.9 vs. 43 MJ/kg). Therefore, a greater volume of methanol would be required to deliver the same quantity of heat, impacting the overall system efficiency, and potentially influencing the economic viability of methanol heating systems.

4.1 Synthesis

The synthesis of methanol from a source of non-fossil CO_2 and a source of non-fossil hydrogen is a way to produce renewable methanol. This process can be called "green methanol" production or "power-to-methanol".

Methanol production involves the reaction of CO_2 and H_2 to produce methanol (CH_3OH) and water (H_2O). The chemical reaction can be written as follows:

$$CO_2 + 3H_2 \leftrightarrow CH_3OH + H_2O$$

This process generally requires a catalyst to facilitate the reaction and is typically carried out under high pressure and temperatures. A commonly used catalyst for this reaction is a copper, zinc oxide, and alumina mixture.

This methanol can then be used as a fuel in various applications, including residential heating.

4.2 CO_2 capture

The CO_2 used in this process can come from any source. Still, we consider CO_2 captured from the atmosphere or a cement and MSWI plant, respectively, for which the inventories and assumptions are described in earlier sections. In the cases where the CO_2 comes from an industrial point source (e.g., from a cement or MSWI plant), we develop three variants corresponding to the three allocation approaches described in Section I.C.6: 100:0, 50:50 and 0:100.

4.3 Hydrogen and CO_2 supply

For the following cases:

- methanol, produced with hydrogen from Electrolysis, PEM using water and electricity from grid, and carbon from DAC,
- methanol, produced with hydrogen from Electrolysis, PEM using water and electricity from grid, and carbon from cement plant,
- methanol, produced with hydrogen from Electrolysis, PEM using water and electricity from grid, and carbon from municipal waste incineration plant,
- methanol, produced with hydrogen from Electrolysis, PEM using water and electricity from Swiss solar PV, and carbon from DAC,
- methanol, produced with hydrogen from Electrolysis, PEM using water and electricity from Swiss hydropower, and carbon from DAC,
- methanol, produced with hydrogen from Electrolysis, PEM using water and electricity from Renewables mix, and carbon from DAC,

The production of hydrogen, the sourcing of CO_2 and methanol are assumed to be located on the same site, in Switzerland.

For the other cases, namely:

- methanol, produced with hydrogen from autonomous hybrid plant and carbon from DAC,
- methanol, produced with hydrogen from autonomous solar-powered plant and carbon from DAC,
- methanol, produced with hydrogen from autonomous wind-powered plant and carbon from DAC,
- methanol, produced with hydrogen from Danish offshore wind turbines and carbon from DAC,

we consider the logistics for supplying the hydrogen to Switzerland, thereby using hydrogen supply datasets, while the sourcing of CO_2 and the synthesis of methanol remain in Switzerland.

4.4 Methanol production

We use the life-cycle inventories from (Hank et al. 2019), who modeled the production of synthetic methanol to produce Oxymethylene Dimethyl Ethers, a possible alternative to diesel fuel. The methanol production process (incl. synthesis and distillation) consists of one adiabatic reactor with a volume of 12.6 m³ and one isothermal reactor with a volume of 8.0 m³.

The estimated steel demand for the process is 44.2 tons and estimates for BE (enameled borosilicate glass) and enamel demand amount to 56.7 tons and 12.5 tons, respectively. In addition, the steel demand for 19 heat exchangers is estimated at 26.4 tons. Hank et al. (2019) obtained these estimates from CAD models and industry communication.

The hardware material demand for compressors, pumps, distillation, flash units, and other chemical plant equipment was estimated based on secondary data from the UVEK:2022 background processes.

Stoichiometrically, methanol (CH_3OH) synthesis requires the following masses of CO_2 (m_{CO2}) and H_2 (m_{H2}):

$$m_{CO2} = \frac{44}{32} \times 1000 = 1375\ g$$

$$m_{H2} = \frac{3 \times 2}{32} \times 1000 = 187.5\ g$$

With:

- The molecular mass of CO_2 being 44 g/mol
- The molecular mass of H_2 being 2g/mol

- And the molecular mass of CH_3OH being 32 g/mol.

However, in practice, inefficiencies may cause these amounts to differ from the stoichiometric requirements. We consider the amounts of CO_2 and H_2 required per kg of methanol synthesized from several studies. This review is originally provided in (Sarp et al. 2021) and presented in Table 71. Accordingly, we use the average values of 1.446 and 0.192 kilograms of CO_2 and H_2 respectively, per kilogram of methanol synthesized.

Table 71 Review of carbon dioxide and hydrogen requirements per kilogram of methanol.

Study	CO_2 [kg/kg MeOH]	H_2 [kg/kg MeOH]	MeOH Output [ton/year]	Reactor Scale
(Hank et al. 2019)	1.690	0.138		
(Matzen and Demirel 2016)	1.431	0.190	35'295	
(Pérez-Fortes et al. 2016)	1.460	0.200	481'800	Conv. Plants
(Al-Kalbani et al. 2016)	1.374	0.189	547'500	Conv. Plants
(Hoppe, Thonemann, and Bringezu 2018)	1.370	0.190		
(Tremel et al. 2015)	1.370	0.189	34'600	
(González-Garay et al. 2019)	1.450	0.190	440'000	100 m3
(H. Zhang et al. 2019)	1.500	0.254	121'667	Conv. Plants
(Jouny, Luc, and Jiao 2018)	1.370		36'500	DOE H2A Base Model
Average	**1.446**	**0.192**		

The synthesis of methanol is an exothermic process. Steam energy is necessary for the distillation columns (3.5 MJ/kg methanol, according to Hank et al (Hank et al. 2019)): representative steam heat used in the chemical sector is used, which comprises a mix of natural gas and light fuel oil boilers. Finally, a common catalyst made of zinc, copper, and aluminum is used at 33 milligrams per kilogram of methanol (Hank et al. 2019).

Table 72 Life-cycle inventories for the synthesis and distillation of methanol, produced with electrolytic hydrogen and CO_2 from DAC.

		reactors, distillation columns and heat exchangers for methanol production/CH U	**methanol synthesis, hydrogen from electrolysis, CO2 from DAC/CH U**	**methanol synthesis, hydrogen from autonomous hybrid plant, CO2 from DAC/CH U**	**methanol distillation, hydrogen from electrolysis, CO2 from DAC/CH U**	**methanol distillation, hydrogen from autonomous hybrid plant, CO2 from DAC/CH U**	**Remark(s)**
	Unit	1 piece	1 kg	1 kg	1 kg	1 kg	
Material and infrastructure inputs							
Chromium steel 18/8, at plant/RER U	kg	4.42e+04					Steel for reactors and distillation columns
Chromium steel 18/8, at plant/RER U	kg	2.64e+04					Steel for reactors and distillation columns
Enamelling/RER U	kg	2.08e+04					Enameling, based on 600 grams of powder coating per square meter.
tap water, at user/kg/CH U	kg		6.88e+01	6.88e+01			
Zinc oxide, at plant/RER U	kg		7.93e-06	7.93e-06			
Copper oxide, at plant/RER U	kg		2.11e-05	2.11e-05			
aluminium oxide, at plant/kg/RER U	kg		3.96e-06	3.96e-06			
hydrogen production, gaseous, 30 bar, from PEM electrolysis, from grid electricity/CH U	kg		1.92e-01				

		reactors, distillation columns and heat exchangers for methanol production/CH U	**methanol synthesis, hydrogen from electrolysis, CO2 from DAC/CH U**	**methanol synthesis, hydrogen from autonomous hybrid plant, CO2 from DAC/CH U**	**methanol distillation, hydrogen from electrolysis, CO2 from DAC/CH U**	**methanol distillation, hydrogen from autonomous hybrid plant, CO2 from DAC/CH U**	**Remark(s)**
hydrogen supply, distributed by pipeline, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA)/CH U	kg			1.92e-01			
carbon dioxide, captured from atmosphere, with a sorbent-based direct air capture system, 100ktCO2/CH U	kg		1.45e+00	1.44e+00			
Air compressor, screw-type compressor, 300 kW, at plant/RER/I U	p		1.68e-08	1.68e-08			
methanol synthesis, hydrogen from electrolysis, CO2 from DAC/CH U	kg				1.00e+00		
methanol synthesis, hydrogen from autonomous hybrid plant, CO2 from DAC/CH U	kg					1.00e+00	
Chemical plant, organics/RER/I U	p		2.00e-10	2.00e-10	2.00e-10	2.00e-10	
reactors, distillation columns and heat exchangers for methanol production/CH U	p		7.42e-10	7.42e-10	7.42e-10	7.42e-10	
tap water, at user/kg/CH U	kg				7.73e+01	7.73e+01	
transport, freight, rail, electricity with shunting/tkm/CH U	tkm		1.82e-05	1.82e-05			Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.0 kg over 1400.0 km.
transport, freight, lorry 16-32 metric ton, fleet average/tkm/CH U	tkm		1.65e-06	1.65e-06			Generic transport distances are calculated based on Table 4.2 of the ecoinvent v.2 Methodology report. Distribution: 0.0 kg over 150.0 km.
Energy inputs							
electricity, low voltage, at grid/kWh/CH U	kWh		3.03e-01	3.03e-01			
Steam, for chemical processes, at plant/RER U	kg				1.37e+00	1.37e+00	
Emissions to air							
Carbon dioxide, biogenic	kg				1.30e-01	1.30e-01	
Carbon monoxide, biogenic	kg				1.65e-06	1.65e-06	
Hydrogen	kg				2.50e-02	2.50e-02	Hydrogen leakage
Waste treatment							
Treatment, sewage, to wastewater treatment, class 1/CH U	m3		6.88e-02	6.88e-02	7.73e-02	7.73e-02	

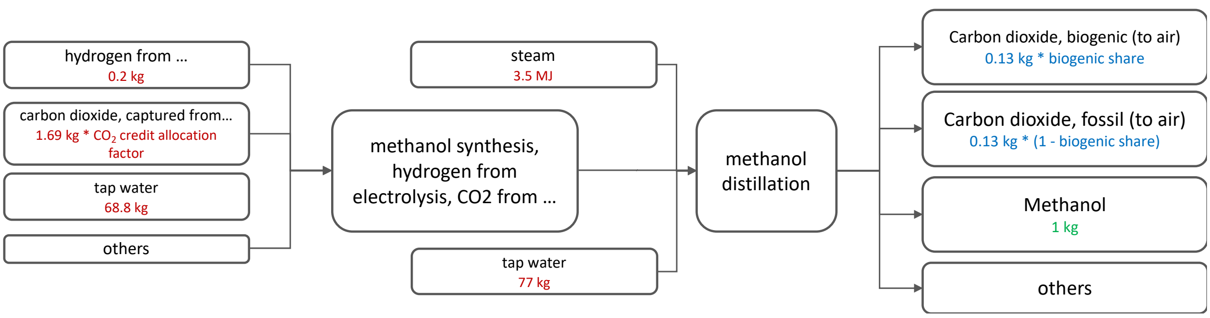

Figure 40 Schematic mass and energy balance to produce methanol. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *64* for uncertainty estimation are considered.

Table 73 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	Completeness	Temporal correlation	Geographical correlation	Further technological correlation	Sample size
H_2 boiler	2	5	2	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

4.5 Distribution

The UVEK:2022 dataset for the regional storage of liquid chemicals is used to represent the regional storage of methanol, adjusting for the transport distance by truck to and from the regional storage location (i.e., 250 km each segment).

Like the methanol distribution dataset of the UVEK:2022 database (*Methanol, at regional storage/CH U*), no losses are considered during distribution. The life-cycle inventories for the distribution of methanol to the consumer are described in

Table 74.

Table 74 Life-cycle inventories to supply methanol via truck to the consumer.

		methanol supply, produced with hydrogen from Electrolysis, PEM using water and electricity from grid, and carbon from DAC/CH U	methanol supply, produced with hydrogen from Electrolysis, PEM using water and electricity from Solar PV + Wind (MA), and carbon from DAC/CH U	Remark(s)
	Unit	1 kg	1 kg	
Material and infrastructure inputs				
methanol distillation, hydrogen from electrolysis, CO2 from DAC/CH U	kg	1.00e+00		Methanol input.
methanol distillation, hydrogen from autonomous hybrid plant, CO2 from DAC/CH U	kg		1.00e+00	Methanol input.
Liquid storage tank, chemicals, organics/CH/I U/RER/I U	p	2.63e-10	2.63e-10	Adopted from the UVEK:2022 dataset for methanol distribution.
transport, freight, lorry 16-32 metric ton, fleet average/RER U	tkm	5.00e-01	5.00e-01	

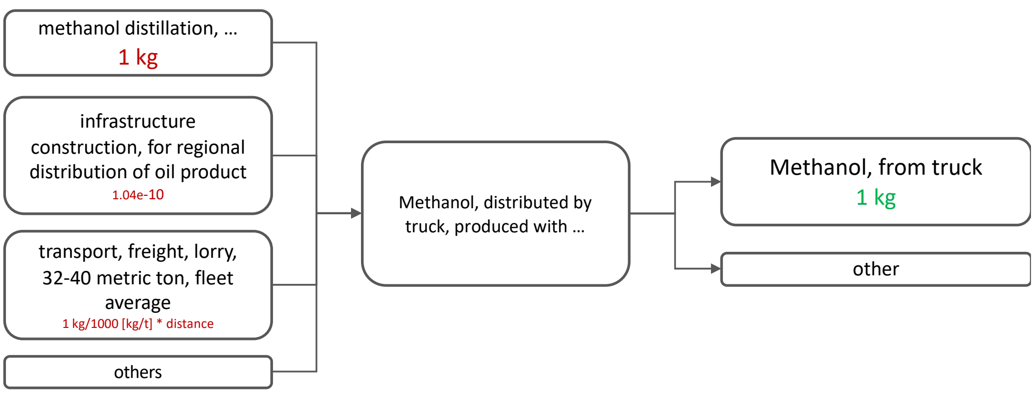

Figure 41 Schematic mass and energy balance for the storage and distribution of methanol via truck. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

4.6 Storage

Storage needs are based on the oil storage input requirements in the UVEK dataset for heat supply from a 10-kW light fuel oil boiler.

4.7 Combustion

Methanol and light fuel oil are used in various applications, including boilers for heating. However, their chemical properties, combustion characteristics, and environmental impacts differ. Methanol has a higher oxygen content compared to diesel (about 50% by weight), which can lead to more complete combustion. This means that, under ideal conditions, burning methanol can be more efficient and reduce emissions mass-wise compared to burning light fuel oil.

4.7.1 Boiler

The UVEK dataset for heat generation, using a 9-kW light fuel oil boiler, is used as basis. The boiler manufacture dataset and lifetime are from (Jungbluth, Wenzel, and Christoph Meili 2018). As with the other end-use datasets, the annual number of hours of heating are obtained from (Kägi et al. 2021) for a boiler of a similar size. A 90% thermal efficiency is used, as reported by the Methanol Institute for industrial boilers (Methanol Institute 2020). Hence, the intake of fuel in the dataset is adjusted accordingly. The specifications of the boiler are described in Table *75*.

Table 75 Specifications for a 9-kW methanol boiler, adapted from a light fuel oil boiler.

		Source/Remark
End-use technology	Boiler	
Energy carrier	Methanol	
Lifetime [years]	20	(Jungbluth, Wenzel, and Christoph Meili 2018)
Power input [kW]	10	
Power output [kW]	9	Calculated based on Power input and efficiency.
Annual operation [hours]	2’100	(Kägi et al. 2021)
Annual heating [kWh]	18’900	Calculated from the two rows above.
Heat conversion efficiency [% LHV input]	90%	(Methanol Institute 2020)
Annual heating period [months]	6	Assumption.
Annual methanol need [kg]	3,780	Calculated from rows above.

When burned completely, methanol (CH_3OH) produces CO_2 and water. In contrast, light fuel oil, a complex mixture of hydrocarbons, has other pollutants like unburnt hydrocarbons, particulate matter, NO_x, and SO_x due to impurities in the fuel and the combustion conditions. A white paper on methanol from IRENA indicates that the combustion of methanol reduces SO, PM, and NO_x emissions by 99%, 95%, and 60-80%, respectively, relative to combusting fuel oil, when used in ships (IRENA 2021). The Methanol Institute reports a minimum of 75% reduction for all three air pollutant emissions when used in boilers, compared to natural gas (Methanol Institute 2020). Therefore, all air pollutants emissions initially contained in the light fuel oil boiler dataset are removed, except for CO, CO_2, NO_x, and $PM_{2.5}$. Emissions of CO_2 are calculated stoichiometrically; emissions of CO are left unchanged, and, by lack of more specific values, the emissions of NO_x and $PM_{2.5}$ are reduced by 75% relative to the values for the light fuel oil boiler.

Life-cycle inventories for the heat supply from the combustion of methanol in a boiler are presented in Table *76*.

Table 76 Life-cycle inventories for the heat supply via the combustion of methanol produced with CO2 from DAC and electrolytic hydrogen.

		heat, residential, by combustion of methanol using boiler, distributed by truck, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from DAC/CH U	**heat, residential, by combustion of methanol using boiler, distributed by truck, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA) and carbon sourced from DAC/CH U**	**Remark(s)**
	Unit	1 MJ	1 MJ	
Material and infrastructure inputs				
oil boiler 10kW/p/CH/I U	p	6.61e-07	6.61e-07	1/(Cap. [kW] * lifetime [y] * annual operation [h] * 3.6 [MJ/kWh])
oil storage 3000l/p/CH/I U	p	4.41e-07	4.41e-07	Adapted from UVEK:2022 light fuel oil-based heat dataset
chimney/CH/I U	m	2.64e-06	2.64e-06	Adapted from UVEK:2022 light fuel oil-based heat dataset
Energy inputs				
methanol, produced with hydrogen from Electrolysis, PEM using water and electricity from grid, and carbon from DAC/CH U	kg	5.56e-02		Methanol input. 1 [MJ]/ 19.9 [MJ/kg methanol]/ eff.(th)
methanol, produced with hydrogen from Electrolysis, PEM using water and electricity from Solar PV + Wind (MA), and carbon from DAC/CH U	kg		5.56e-02	Methanol input. 1 [MJ]/ 19.9 [MJ/kg methanol]/ eff.(th)
electricity, low voltage, at grid/kWh/CH U	kWh	2.73e-03	2.73e-03	To operate the boiler.
Emissions to air				
Water	kg	6.25e-08	6.25e-08	1.125kg water per kg methanol
Carbon dioxide, biogenic	kg	7.62e-02	7.62e-02	Adapted from UVEK:2022 light fuel oil-based heat dataset
Carbon monoxide, biogenic	kg	9.00e-06	9.00e-06	Adapted from UVEK:2022 light fuel oil-based heat dataset
Nitrogen oxides	kg	6.88e-06	6.88e-06	Emission factors for light fuel oil were reduced by 75% to consider using methanol.
Particulate Matter, < 2.5 um	kg	1.25e-07	1.25e-07	
Waste treatment				
Treatment, condensate from light oil boiler, to wastewater treatment, class 2/CH U	m3	9.83E-06	9.83E-06	Adapted from UVEK:2022 light fuel oil-based heat dataset
Disposal, hazardous waste, 25% water, to hazardous waste incineration/CH U	kg	4.15E-06	4.15E-06	Adapted from UVEK:2022 light fuel oil-based heat dataset

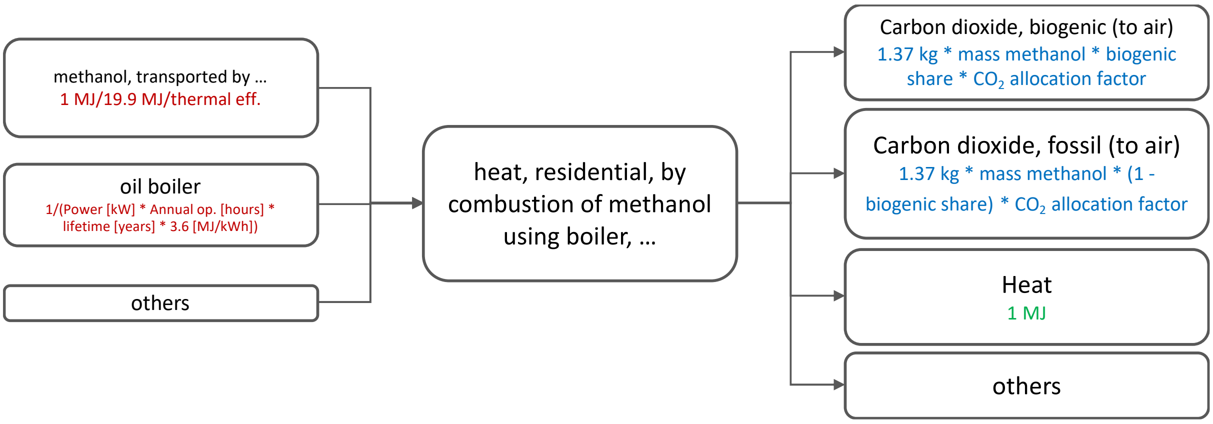

Figure 42 Schematic mass and energy balance for the combustion of methanol in a boiler. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *70* for uncertainty estimation are considered.

Table 77 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	Completeness	Temporal correlation	Geographical correlation	Further technological correlation	Sample size
H_2 boiler	1	5	1	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

4.8 Conversion

4.8.1 Fuel cell

Direct Methanol Fuel Cells (DMFC) are a subtype of proton-exchange membrane fuel cells (PEM) specifically designed to use methanol as a fuel source.

In a DMFC, methanol is oxidized directly at the anode to produce CO_2, protons, and electrons. The protons then move across the proton-exchange membrane (the PEM) to the cathode, while the electrons are forced to travel through an external circuit, generating electricity. At the cathode, oxygen from the air combines with protons and electrons to form water, typically released as water vapor.

One of the critical advantages of DMFCs over other types of fuel cells is that they can operate at relatively low temperatures (typically around 60-90°C), simplifying cooling and allowing for a compact design. However, DMFCs also have some challenges. One of the main problems is that methanol can cross over from the anode to the cathode through the PEM, which decreases efficiency and can lead to cell degradation over time.

As for their application, DMFCs have primarily been used in small portable devices (like laptops and mobile phones) and some transportation applications. They can also be used for residential heating as part of a combined heat and power (CHP) system. In a CHP system, the heat produced by the fuel cell during operation is used to heat water or air for the home, while the electricity generated can be used to power appliances and lights.

For this study, we consider the life cycle inventories from (Stropnik et al. 2022), which describe a 1 kW_{el} PEM fuel cell system – DMFCs are, from a hardware viewpoint, similar to PEMFCs

(Hartnig et al. 2008). Over 20’000 hours of use, the stack is replaced five times when the voltage loss is superior to 10% relative to its initial value– while the Balance of Plant is not replaced. The platinum loading considered is 0.75 grams per kW_{el}. We use the thermal and electrical conversion efficiencies measured by (Glüsen, Müller, and Stolten 2020) for a DMFC, which includes efficiency losses due to methanol permeating the membrane (i.e., methanol crossover).

Table 78 Specifications for a 1-kW_{el} DMFC fuel cell system.

		Source/Remark
Energy carrier	Hydrogen	
End-use technology	Fuel cell, DMFC (PEM)	
Heat conversion efficiency [% LHV input]	50%	(Glüsen, Müller, and Stolten 2020)
Electricity conversion efficiency [% LHV input]	30%	
Lifetime [years]	5	(Stropnik et al. 2022)
$Power_{th}$ [kW]	1.667	
$Power_{el}$ [kW]	1	
Total cap. input-related [kW]	3.3	Calculated from the rows above.
Total system eff. (heat + el.)	80%	
Annual operation [hours]	4’100	(Kägi et al. 2021)
Annual heating [kWh]	6’835	Calculated from the rows above.
Annual H_2 need [kg]	2’460	Calculated from the rows above.

Like combustion-based co-generation units, exergy-based allocation keys must be calculated for heat and electricity production from DMFC.

The heat exergy factor of the DMFC fuel cell system is described in Table *79*, following the approach described in (Kägi et al. 2021). We consider the presence of a buffer water storage between the fuel cell and the heating system to adapt the outgoing flow temperature to the heat demand. Therefore, we use an outgoing flow temperature from the fuel cell system of 85°C, and a return flow temperature of 40°C, to calculate the exergy factor.

Table 79 Heat exergy factor for a DMFC fuel cell system.

		Remark
Flow temp. T_V [K]	358.15	Flow temperature (85°C)
Return temp. T_R [K]	313.15	Return temperature (40°C)
Ambient temp. T_U [K]	293.15	Ambient temperature (20°C)
Heat exergy factor	0.127	$\dfrac{\frac{T_R+T_V}{2}-T_U}{\frac{T_R+T_V}{2}}$

Given the heat exergy factor from Table *79*, we obtain the allocation key to produce heat and electricity, as described in Table *80*.

Table 80 Heat and electricity allocation keys for methanol fed DMFC fuel cell system.

		Remark
Heat exergy factor w_{ex}	0.127	
Heat efficiency n_{th}	50.0%	

Electricity efficiency n_{el}	30.0%	
Heat allocation key	17.4%	$\frac{(w_{ex} * n_{th})}{(w_{ex} * n_{th}) + (1 * n_{el})}$
Electricity allocation key	82.6%	Calculated from the row above.

The life-cycle inventories for the supply and heat and electricity via the conversion of methanol in a direct methanol fuel cell system are described in Table *81*.

Table 81 Life-cycle inventories for the supply, heat, and electricity via the conversion of methanol in a direct methanol fuel cell system.

		heat, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from DAC/CH U	**heat, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA) and carbon sourced from DAC/CH U**	**heat, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from Cement plant/CH U**	**electricity, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from DAC/CH U**	**electricity, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA) and carbon sourced from DAC/CH U**	**electricity, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from Cement plant/CH U**	**Remark(s)**
	Unit	1 MJ	1 MJ	1 MJ	1 kWh	1 kWh	1 kWh	
Material and infrastructure inputs								
methanol, produced with hydrogen from Electrolysis, PEM using water and electricity from grid, and carbon from DAC/CH U	kg	1.74e-02			4.95e-01			Methanol input. 1 [MJ]/ 19.9 [MJ/kg methanol]/ eff.(th)* allocation factor, in case of heat supply. Methanol input. 1 [kWh]/ 5.5 [kWh/kg methanol]/ eff.(el)* allocation factor, in case of electricity supply.
methanol, produced with hydrogen from Electrolysis, PEM using water and electricity from Solar PV + Wind (MA), and carbon from DAC/CH U	kg		1.74e-02			4.95e-01		Methanol input. 1 [MJ]/ 19.9 [MJ/kg methanol]/ eff.(th)* allocation factor, in case of heat supply. Methanol input. 1 [kWh]/ 5.5 [kWh/kg methanol]/ eff.(el)* allocation factor, in case of electricity supply.
produced with hydrogen from Electrolysis, PEM using water and electricity from Solar PV + Wind (MA), and carbon from Cement plant/CH U	kg			1.74e-02			4.95e-01	Methanol input. 1 [MJ]/ 19.9 [MJ/kg methanol]/ eff.(th)* allocation factor, in case of heat supply. Methanol input. 1 [kWh]/ 5.5 [kWh/kg methanol]/ eff.(el)* allocation factor, in case of electricity supply.
fuel cell system assembly, 1 kWe, proton exchange membrane (PEM)/GLO U	p	1.21e-06	1.21e-06	1.21e-06	2.06e-05	2.06e-05	2.06e-05	Operational time of 20,000 hours at power of 1 kWe. Due to the degradation effects, hydrogen consumption must be increased to generate the power of 1 kWe consistently. Because of the dynamic operational regime, five replacements of the PEMFC stack are included (lifetime of 3'800 hours per stack), while the BoP lasts the whole operating time.
oil storage 3000l/p/CH/I U	p	4.41e-07	4.41e-07	4.41e-07	4.41e-07	4.41e-07	4.41e-07	Adapted from light fuel oil-based heat production dataset.
Emissions to air								
Water	kg	1.96e-02	1.96e-02	1.96e-02	5.57e-01	5.57e-01	5.57e-01	1.125kg water per kg methanol
Carbon dioxide, fossil	kg			0.00e+00 / 1.13e-02 / 2.25e-02			0.00e+00 / 3.20e-01/ 6.40e-01	1.372 kg CO_2 per kg methanol * CO_2 allocation factor, if relevant.

		heat, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from DAC/CH U	heat, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA) and carbon sourced from DAC/CH U	heat, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from Cement plant/CH U	electricity, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from DAC/CH U	electricity, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from Solar PV + Wind (MA) and carbon sourced from DAC/CH U	electricity, residential, by conversion of methanol using fuel cell, DMFC allocated by exergy, distributed by truck, produced by Electrolysis, PEM using water and electricity from grid and carbon sourced from Cement plant/CH U	Remark(s)
Carbon dioxide, biogenic	kg	2.39e-02	2.39e-02	0.00e+00 / 7.02e-04 / 1.4e-03	6.80e-01	6.80e-01	0.00e+00 / 2.00e-02 / 3.99e-02	1.372 kg CO_2 per kg methanol * CO_2 allocation factor, if relevant.

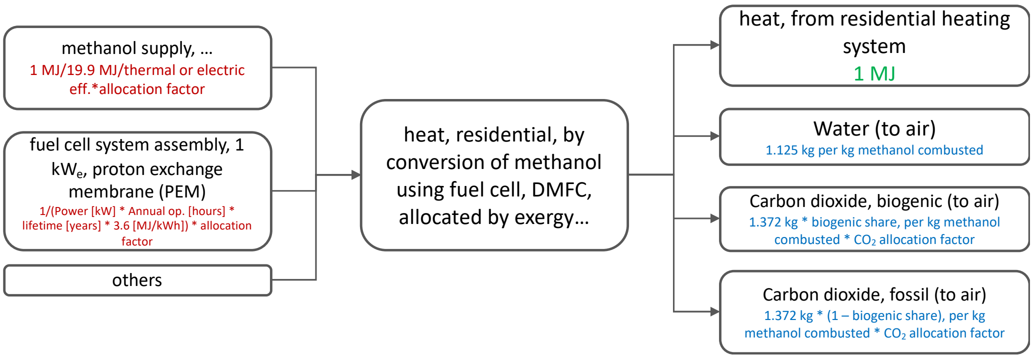

Figure 43 Schematic mass and energy balance for the heat supply via the conversion of methanol in a direct methanol fuel cell. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

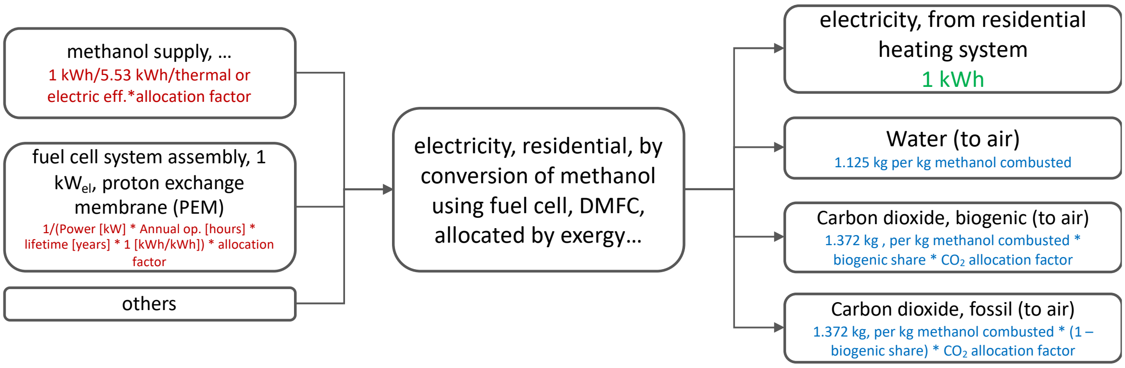

Figure 44 Schematic mass and energy balance for the electricity supply via the conversion of methanol in a direct methanol fuel cell. Red numbers represent material, energy, or infrastructure input amounts. Blue numbers represent incoming and outgoing biosphere flows. The green number is the amount of the reference flow of the process.

Referring to Section 7.3 of (Rolf Frischknecht et al. 2007), the pedigree matrix factors described in Table *70* for uncertainty estimation are considered.

Table 82 Uncertainty factors used for uncertainty estimation. Note that the scores apply to all data points of the dataset. In addition, a flow-specific basic uncertainty factor is applied (see Table 7.2 of (Frischknecht et al. 2007)).

	Reliability	Completeness	Temporal correlation	Geographical correlation	Further technological correlation	Sample size

H_2 boiler	2	5	1	2	3	5

Additionally, basic uncertainty factors listed in Table 7.2 of (Rolf Frischknecht et al. 2007) are applied to the relevant technosphere and biosphere flows.

5 Life cycle impact assessment

This section provides the life-cycle impact assessment scores for the following indicators:

- **Global Warming Potential (100 year), 2013**: This indicator expresses the impact of emissions of different greenhouse gases (GHGs) on climate change. It is a relative measure comparing the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide. The "100-year" component indicates the timescale over which the effects are considered.
- **Ecological Scarcity 2021**: Ecological scarcity is a method used in LCA to measure the environmental impact of resource extraction and emissions. This method quantifies the environmental impact based on the principle of 'distance-to-target'. The greater the distance from the current state to an environmentally acceptable state (the target), the higher the ecological scarcity. Refer to (BAFU 2021) for further information.
- **Cumulative Primary Energy Demand (CED)**: This measures the amount of primary energy directly and indirectly used in the life cycle of a product or service (Frischknecht et al. 2015). The CED in general encompasses all energy sources (renewable and non-renewable) and can help assess energy efficiencies of products or processes. Often, one distinguishes between renewable, non-renewable and overall CED.

The first sub-section presents the results per energy carrier (i.e., hydrogen, methanol, synthetic natural gas), carbon dioxide capture and heat and electricity production options. It is followed by a sub-section presenting sensitivity analyses, where main datasets are benchmarked against alternative options for heat and electricity supply. A third sub-section benchmarks the results of co-generation units (i.e., which produce both heat and electricity) against the combined supply of heat and electricity from Swiss grid electricity (average mix and certified renewables only).

When interpreting the LCA results, it should be kept in mind that options are being compared that are currently not at the same stage of development and some of which are not available in Switzerland. For example, hydrogen from natural gas pyrolysis and reforming with CCS is not available today and it is uncertain whether this will ever be the case.[6] Similarly, hydrogen from the production in Morocco, which represents a "best case" from an environmental perspective, is a theoretical option that may be available in the future; assumptions taken here regarding technical performances should be verified under real operation conditions. The same applies to synthetic methanol and synthetic natural gas, which are not (yet) commercially available products in Switzerland. This study makes no statement on how realistic and desirable it is for these energy sources to come onto the Swiss market at large scales in the coming years.

5.1 Main results

5.1.1 Hydrogen production

The life-cycle Global Warming Potential impacts per "kilogram of hydrogen, as produced at the production unit" (representing the functional unit), are shown in Figure *45*.

Results are shown alongside those for hydrogen produced by light ends and methane cracking («Crack.» in Figure *45*, *Hydrogen, cracking, APME, at plant/RER* in the UVEK:2022 database), an endothermic process performed in the polymers industry, to obtain a range of

[6] See (UVEK 2022) regarding the position of the Federal administration concerning hydrogen from natural gas with CCS.

chemicals such as naphtha and hydrogen, as well as hydrogen co-produced from the electrolysis of sodium chloride – so-called the chlore-alkali process – (“Diaph.” in Figure *45*, *Hydrogen, liquid, diaphragm cell, at plant/RER* in the UVEK:2022 database). Note that LCA results for those two processes, which do not represent dedicated hydrogen production processes as opposed to those newly modeled within this study, are comparatively low, as most environmental burdens are allocated to other products jointly generated.

For the Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) methods, particularly with natural gas (both gaseous and liquefied), greenhouse gas emissions are comparatively high. These emissions emphasize the environmental challenges tied to these traditional hydrogen production methods. The liquefied natural gas option presents higher emissions due to additional processing steps (e.g., liquefaction) and losses along the supply chain. The possible integration of Carbon Capture and Storage (CCS) solutions can lead to (substantial) reductions of GHG emissions, but still relies on fossil resources and on non-domestic energy resources (UVEK 2022). Substantial reductions of GHG emissions and also overall environmental impacts will require a) very low methane emissions along the natural gas supply chain, b) very high CO_2 capture rates at the hydrogen production, and c) that the permanence of CO_2 storage is ensured. Further, CO_2 storage sites must be available. All these elements would need to be ensured in the future. Methane pyrolysis (and the variant using liquefied natural gas) presents a different picture. While they, too, have a considerable “carbon footprint”, it is predominantly encapsulated under the "others" category, which, in this case, refers to the gas supply and associated methane losses. Emissions, though present, are considerably reduced compared to the reforming methods without CCS.

Water electrolysis, as a method, branches out into several types: PEM, AEC, and SOEC, representing different electrolyzer technologies. Across these, the electricity source emerges as a significant determinant of life-cycle greenhouse gas emissions, mainly when the electricity is sourced from conventional grids. This finding underscores the imperative of harnessing renewable or low-carbon electricity for electrolysis. The carbon footprint dramatically diminishes when the electricity is derived from renewable sources, with Swiss hydropower, wind and PV power in Morocco, and Danish wind turbines standing out as particularly well-performing hydrogen supply options. While the electrolyzer component consistently adds to the emissions across these methods, its exact contribution fluctuates based on the specific method and conditions. Notably, in the SOEC electrolysis method incorporating steam input, steam emerges as a major contributor, introducing an additional layer of environmental consideration. This option only makes sense when coupled with a burden-free steam input (e.g., from industrial excess heat) when using relatively low-carbon electricity.

On the other hand, End-of-Life (EoL) treatment and water supply have a relatively benign impact. While these factors warrant attention, they might not be at the forefront when strategizing to minimize the carbon footprint and overall environmental impacts of hydrogen production.

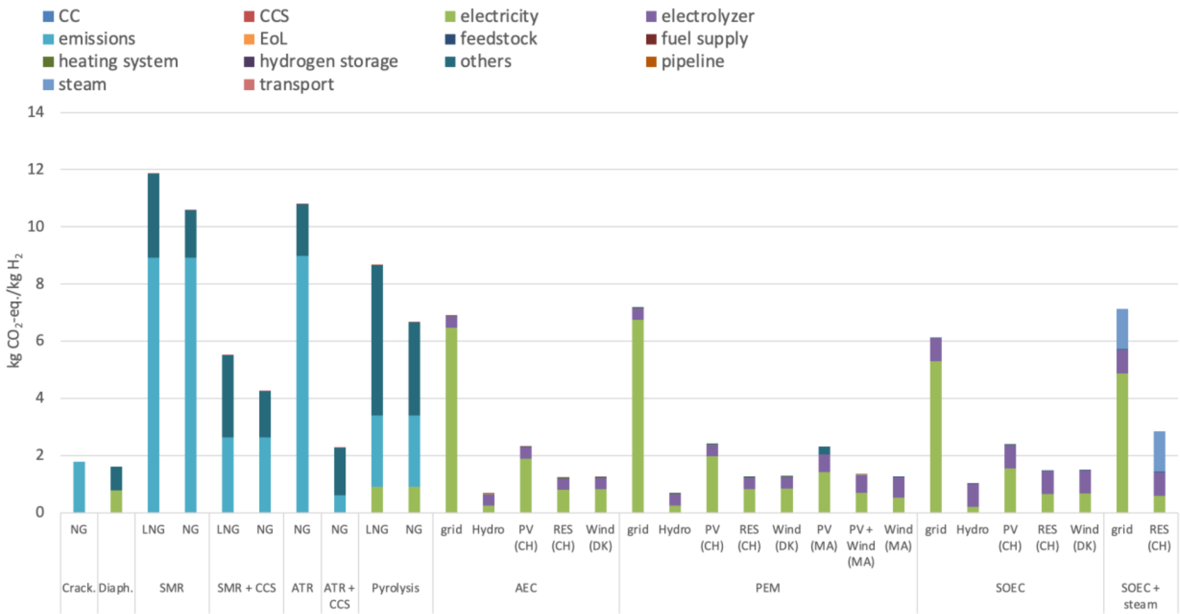

Figure 45 Life-cycle Global Warming Potential impacts per kilogram of hydrogen produced. Note that the outlet pressure differs across technologies. Hence, these results are not strictly comparable since they may require further compression. "Crack." = catalytic cracking of methane. "Diaph." = diaphragm cell, from chlore-alkali process. "SMR" = Steam Methane Reforming of natural gas. "SMR + CCS" = Steam Methane Reforming of natural gas with Carbon Capture and Storage. "ATR" = Auto-Thermal Reforming of natural gas. "AEC" = Alkaline Electrolysis Cell. "PEM" = Proton Exchange Membrane. "SOEC" = Solid Oxide Electrolysis Cell. « SOEC + steam" = Solid Oxide Electrolysis Cell with steam input. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

The life-cycle Cumulative Energy Demand per kilogram of hydrogen produced is shown from Figure *46* and Figure *47*. The electricity supply is the most contributing aspect of electrolytic hydrogen production options, with the Swiss grid option faring the highest CED. For the other options, most of the primary energy is drawn from natural gas extraction, refining, and supply.

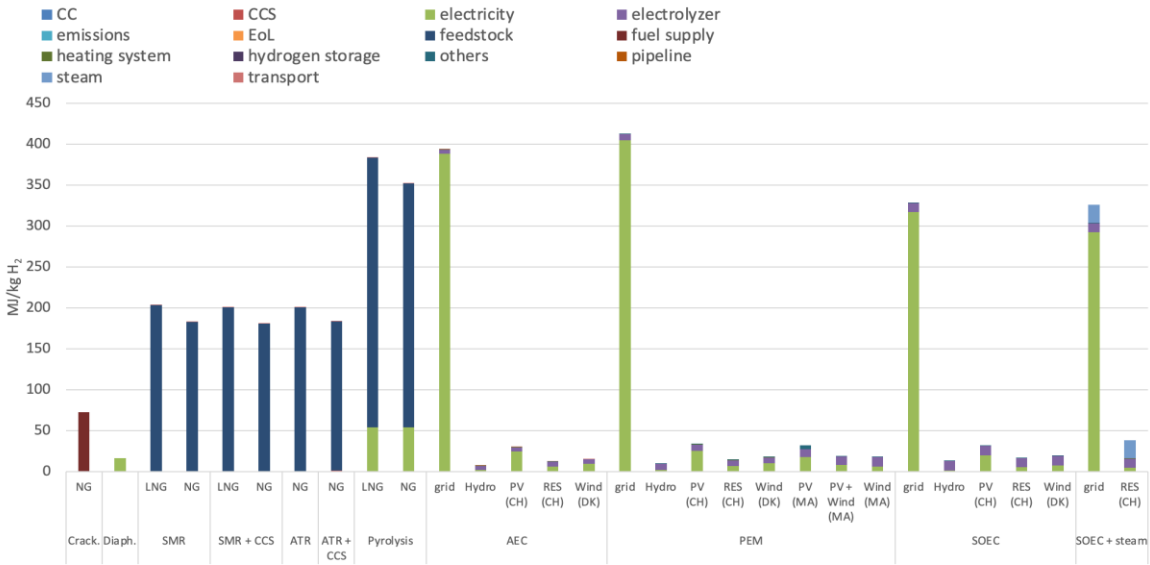

Figure 46 Life-cycle Cumulative Non-renewable Energy Demand per kilogram of hydrogen produced. "Crack." = catalytic cracking of methane. "Diaph." = diaphragm cell, from chlore-alkali process. "SMR" = Steam Methane Reforming of natural gas. "SMR + CCS" = Steam Methane Reforming of natural gas with Carbon Capture and Storage. "ATR" = Auto-Thermal Reforming of natural gas. "AEC" = Alkaline Electrolysis Cell. "PEM" = Proton Exchange Membrane. "SOEC" = Solid Oxide Electrolysis Cell. « SOEC + steam » = Solid Oxide Electrolysis Cell with steam input. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

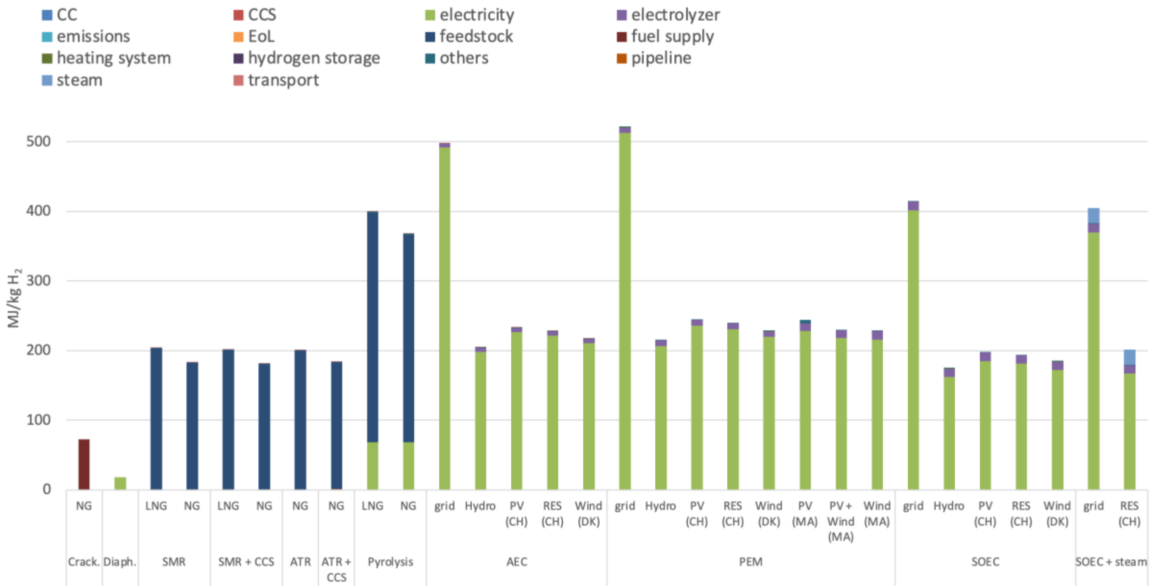

Figure 47 Life-cycle Cumulative Primary Energy (PE) Demand (renewable and non-renewable) per kilogram of hydrogen produced. "Crack." = catalytic cracking of methane. "Diaph." = diaphragm cell, from chlore-alkali process. "SMR" = Steam Methane Reforming of natural gas. "SMR + CCS" = Steam Methane Reforming of natural gas with Carbon Capture and Storage. "ATR" = Auto-Thermal Reforming of natural gas. "AEC" = Alkaline Electrolysis Cell. "PEM" = Proton Exchange Membrane. "SOEC" = Solid Oxide Electrolysis Cell. « SOEC + steam » = Solid Oxide Electrolysis Cell with steam input. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

The overall environmental life cycle impacts per kilogram of hydrogen produced are described in Figure *48*. Unlike Global Warming Potential impacts, electrolytic hydrogen production options using grid electricity perform only marginally better than natural gas-based ones without CCS, considering uncertainties in data. However, alternative electricity sources (e.g., hydropower, photovoltaic power) help reduce impacts substantially.

The production of hydrogen by methane cracking («Crack.») or Diaphragm cell («Diaph.») perform rather well compared to other options, but these are not dedicated production pathways for hydrogen: a significant share of the process burdens are allocated to other co-products (e.g., naphtha for methane cracking, and chlorine and sodium hydroxide from the electrolysis of sodium chloride).

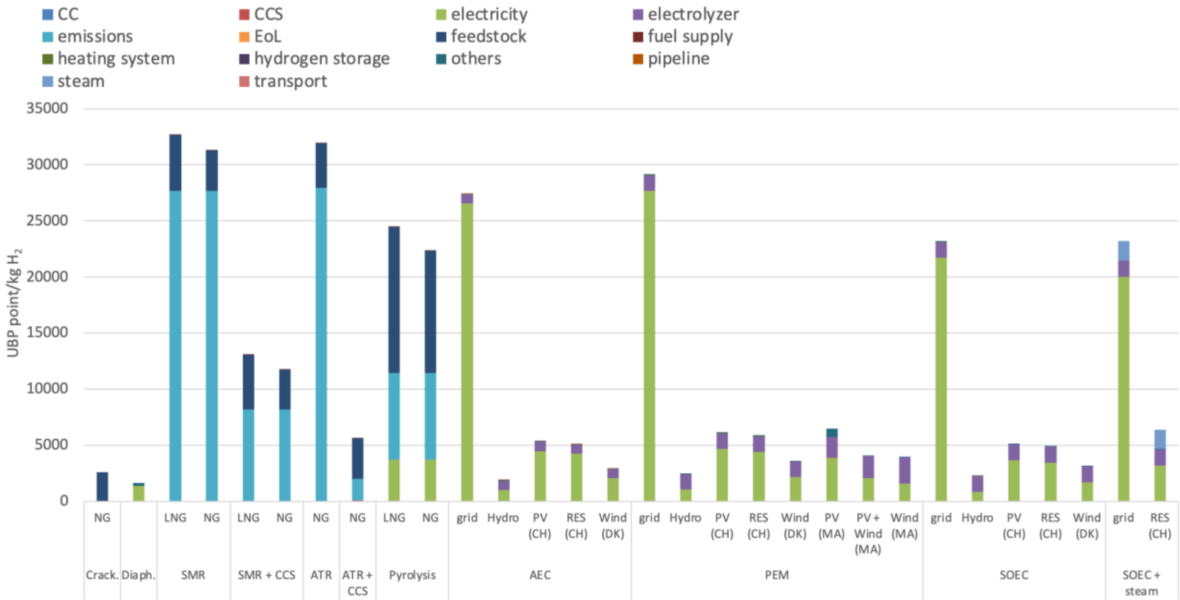

Figure 48 Life-cycle environmental impacts according to the Ecological Scarcity method (version 2021) per kilogram of hydrogen produced. "Crack." = catalytic cracking of methane. "Diaph." = diaphragm cell, from chlore-alkali process. "SMR" = Steam Methane Reforming of natural gas. "SMR + CCS" = Steam Methane Reforming of natural gas with Carbon Capture and Storage. "ATR" = Auto-Thermal Reforming of natural gas. "AEC" = Alkaline Electrolysis Cell. "PEM" = Proton Exchange Membrane. "SOEC" = Solid Oxide Electrolysis Cell. « SOEC + steam » = Solid Oxide Electrolysis Cell with steam input. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

5.1.2 Carbon sourcing

The life-cycle Global Warming Potential impacts per "kilogram of carbon dioxide captured", representing the functional unit, are shown in Figure *49*. The nature of the steam used to regenerate the sorbent matters most. A burden-free steam input for the DAC unit can decrease impacts by 80% compared to fossil-based steam supply. Inversely, using low-carbon electricity does not deliver significant reduction benefits given how little electricity contributes to the total. Heat recovery (HR) at the cement and MSWI plant reduce the demand for external heat sources and thus reduce GHG emissions of CO_2 capture (and other environmental impacts) accordingly. The fact that heat recovery reduces the amount of heat (and potentially electricity) available for other purposes, e.g., district heating networks, has not been considered here and in the LCI provided. However, this need for alternative heat (electricity) supply and associated environmental burdens must be considered if the missing energy from cement or MSWI plants needs to be substituted by other energy sources.

Note that solid sorbent-based DAC units, which work at lower temperature levels than the liquid solvent counterpart, could be coupled in the future to a high-temperature heat pump to provide the needed heat input – in which case, using low-carbon electricity to operate the heat pump would be more beneficial. This is what is shown in Figure *49* with the additional two cases (i.e., “DAC (PV)” and “DAC (RES)”), where a high-temperature heat pump with a coefficient of performance of 2.5 is used together with a mix of renewable and solar photovoltaic electricity, respectively.

Using a fossil-based steam input, as considered here, makes little sense as the equivalent of 50-60% of the CO_2 captured is released back in the form of indirect greenhouse gas emissions.

Figure *50* to Figure *51* indicate that most of the primary energy to capture CO_2 are the fossil fuels required to generate the steam.

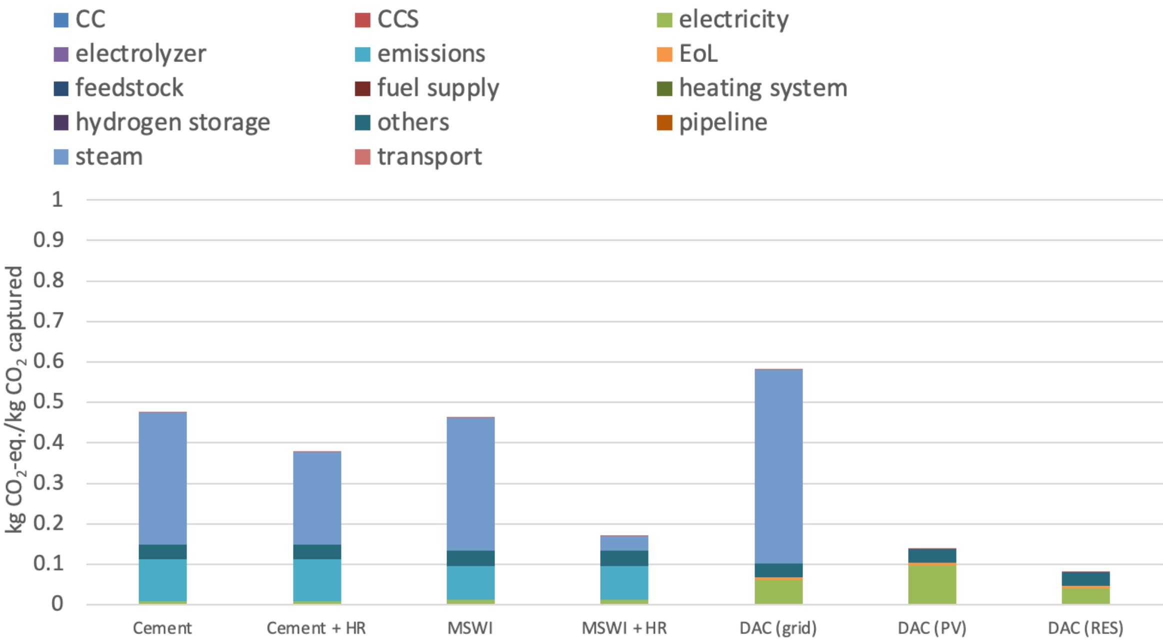

Figure 49 Life-cycle Global Warming Potential impacts per kilogram of CO_2 captured. Note that steam is here provided by a mix of fossil fuel-based industrial furnaces. “DAC” = atmospheric carbon dioxide captured by Direct Air Capture. “Cement” = carbon dioxide captured at cement plant. “Cement + HR” = carbon dioxide captured at cement plant with use of recovered process heat. “MSWI” = carbon dioxide captured at municipal solid waste incineration plant. “MSWI + HR” = carbon dioxide captured at municipal solid waste incineration plant with use of recovered process heat. “CC” = carbon dioxide capture/sourcing. “CCS” = carbon dioxide capture and storage. “EoL” = End-of-Life.

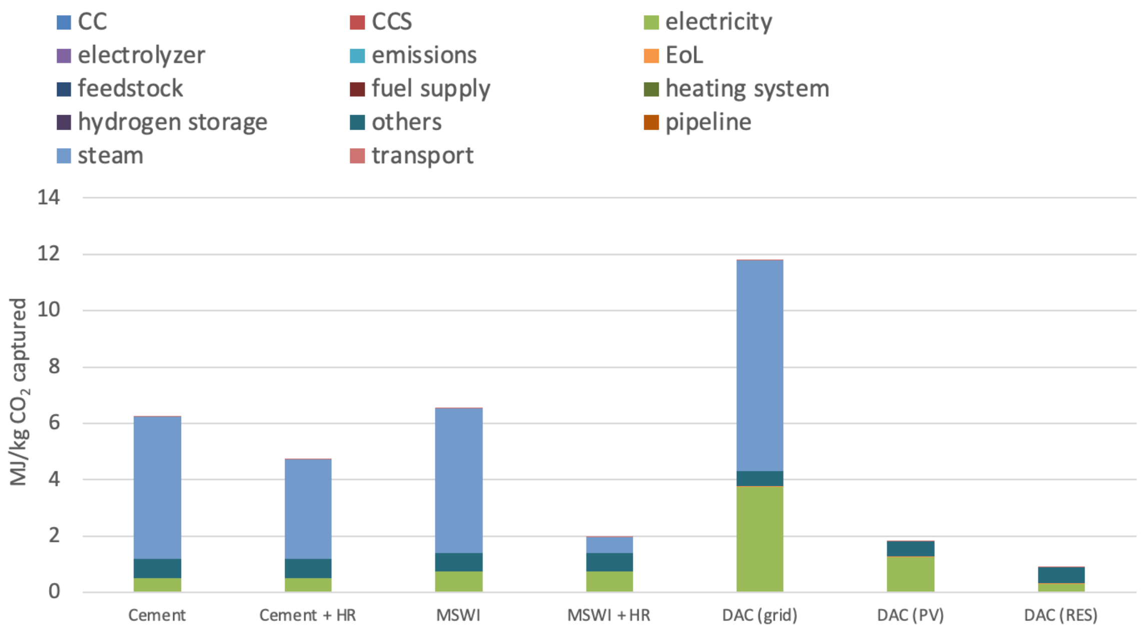

Figure 50 Life-cycle Cumulative Non-renewable Energy Demand per kilogram of CO_2 captured Note that steam is here provided by a mix of fossil fuel-based industrial furnaces. “DAC” = atmospheric carbon dioxide captured by Direct Air Capture. “Cement” = carbon dioxide captured at cement plant. “Cement + HR” = carbon dioxide captured at cement plant with use of recovered process heat. “MSWI” = carbon dioxide captured at municipal solid waste incineration plant. “MSWI + HR” = carbon dioxide captured at municipal solid waste incineration plant with use of recovered process heat. “CC” = carbon dioxide capture/sourcing. “CCS” = carbon dioxide capture and storage. “EoL” = End-of-Life.

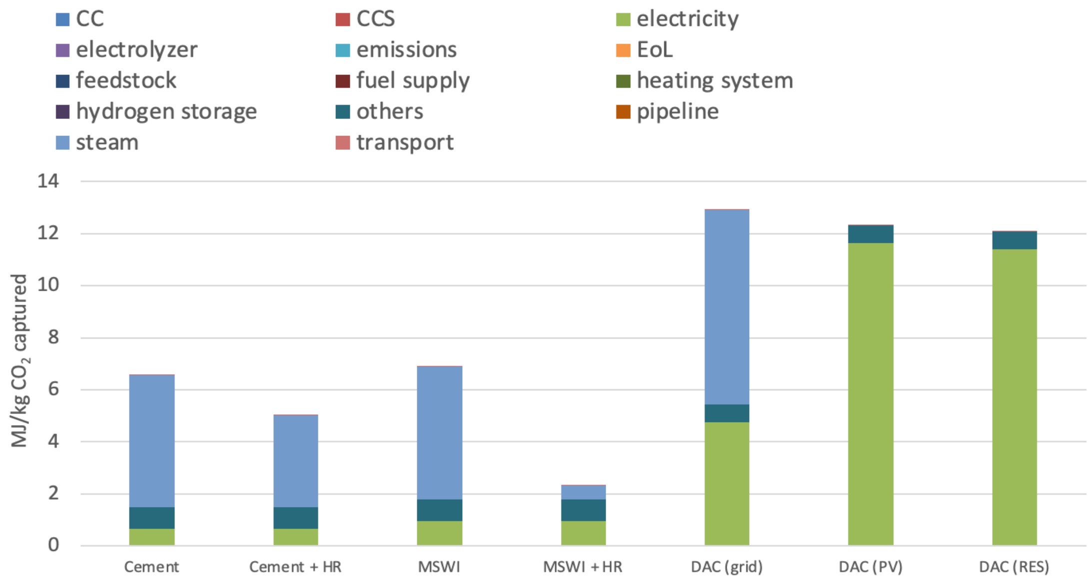

Figure 51 Life-cycle Cumulative Primary Energy (PE) Demand (renewable and non-renewable) per kilogram of CO_2 captured. Note that steam is here provided by a mix of fossil fuel-based industrial furnaces. “DAC” = atmospheric carbon dioxide captured by Direct Air Capture. “Cement” = carbon dioxide captured at cement plant. “Cement + HR” = carbon dioxide captured at cement plant with use of recovered process heat. “MSWI” = carbon dioxide captured at municipal solid waste incineration plant. “MSWI + HR” = carbon dioxide captured at municipal solid waste incineration plant with use of recovered process heat. “CC” = CO_2 capture/sourcing. “CCS” = CO_2 capture and storage. “EoL” = End-of-Life.

Finally, Figure *52*, which shows overall environmental impacts, indicates that a third of the impacts from capturing CO_2 from point sources stems from the “leakage” of fossil CO_2 during capture.

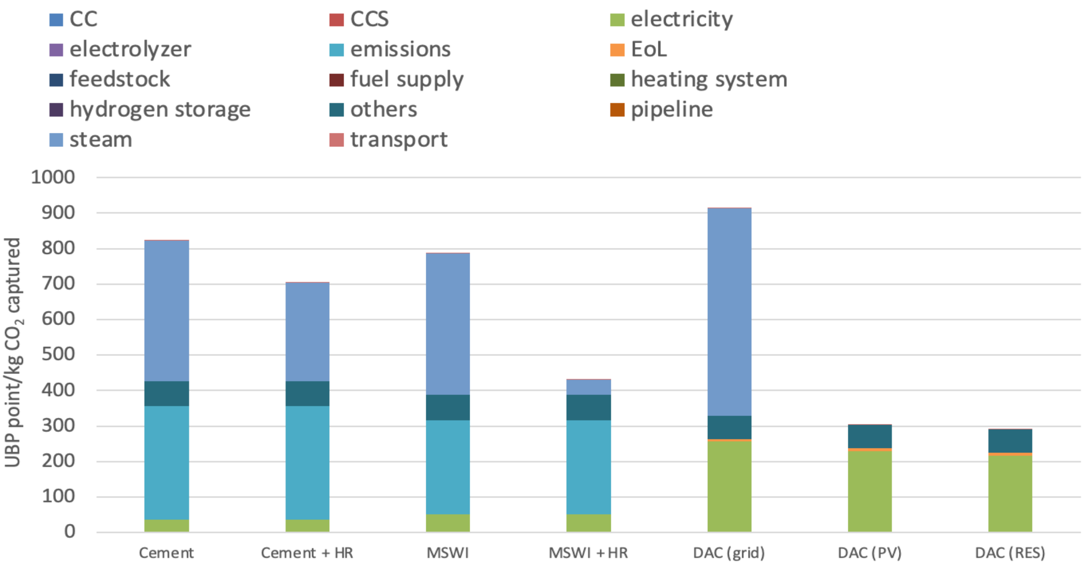

Figure 52 Life-cycle overall environmental impacts per kg of CO_2 captured according to the ecological scarcity method. Steam is here provided by a mix of fossil fuel-based industrial furnaces. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "Cement" = carbon dioxide captured at cement plant. "Cement + HR" = carbon dioxide captured at cement plant with use of recovered process heat. "MSWI" = CO_2 captured at municipal solid waste incineration plant. "MSWI + HR" = CO_2 captured at municipal solid waste incineration plant with use of recovered process heat. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life.

5.1.3 Synthetic natural gas production

The life-cycle Global Warming Potential impacts per kilogram of synthetic natural gas, as produced (representing the functional unit), are shown in Figure *53*. For reference, results are shown alongside those for supplying a kilogram of natural gas, delivered at low pressure at the consumer («NG», *natural gas, low pressure, at consumer/CH* in the UVEK:2022 database). Note that these results do not include the combustion of the fuel and are therefore not supposed to be directly compared, as it is necessary to consider the use phase of the life cycle (i.e., emissions from combusting the fuel) to draw meaningful conclusions. Comparisons of environmental impacts per kg synthetic versus natural gas must therefore not be performed.

The electrochemical methanation pathway scores consistently lower. The biological pathway is penalized by higher use of electricity and impacts associated with wastewater treatment (i.e., the process releases 34 m^3 of wastewater per full-load hour of operation, or about 30 liters per kilogram of gas produced) – however, this may be due to uncertain inventory data. Using the 100:0 allocation approach, capture at point sources (from a cement or MSWI plant) leads to similar GHG emissions as the atmospheric CO_2 capture option ("DAC"). On the other hand, using a 0:100 allocation approach favors the point source capture options. Here again, no complete conclusions can be drawn without considering all relevant life-cycle phases.

Figure 54 to Figure *55* indicate that the sourcing of hydrogen is a significant source of renewable and non-renewable primary energy demand. Finally, while Figure *56*, showing the life-cycle Ecological Scarcity impacts, indicates better performance for the electrochemical pathway options, the CO_2 sourcing option does not determine the results.

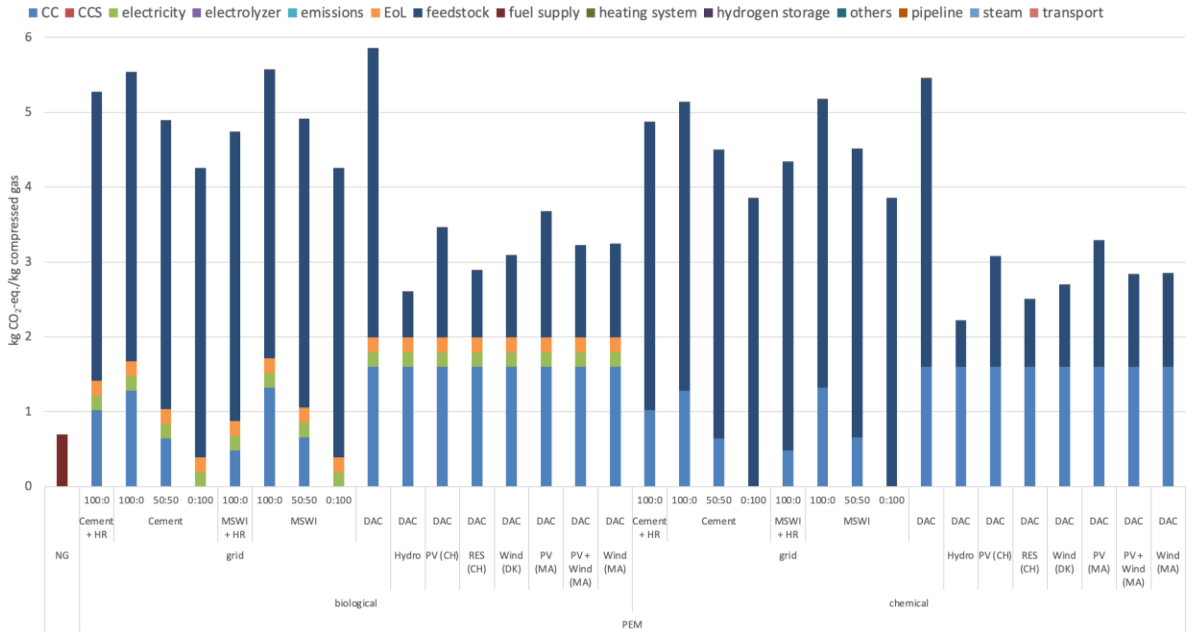

Figure 53 Life-cycle Global Warming Potential impacts per kilogram of synthetic natural gas produced. "NG" = natural gas, low pressure, at consumer. "PEM" = Proton Exchange Membrane. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "Cement" = carbon dioxide, captured at cement plant. "Cement + HR" = carbon dioxide captured at cement plant with use of recovered process heat. "MSWI" = carbon dioxide, captured at municipal solid waste incineration plant. "MSWI + HR" = carbon dioxide captured at municipal solid waste incineration plant with use of recovered process heat. "100:0" = carbon dioxide emissions allocated to emitter. «50:50» = carbon dioxide emissions allocated equally between emitter and fuel producer. «0:100» = carbon dioxide emissions allocated entirely to fuel producer. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production. These results do not include the combustion of the fuel.

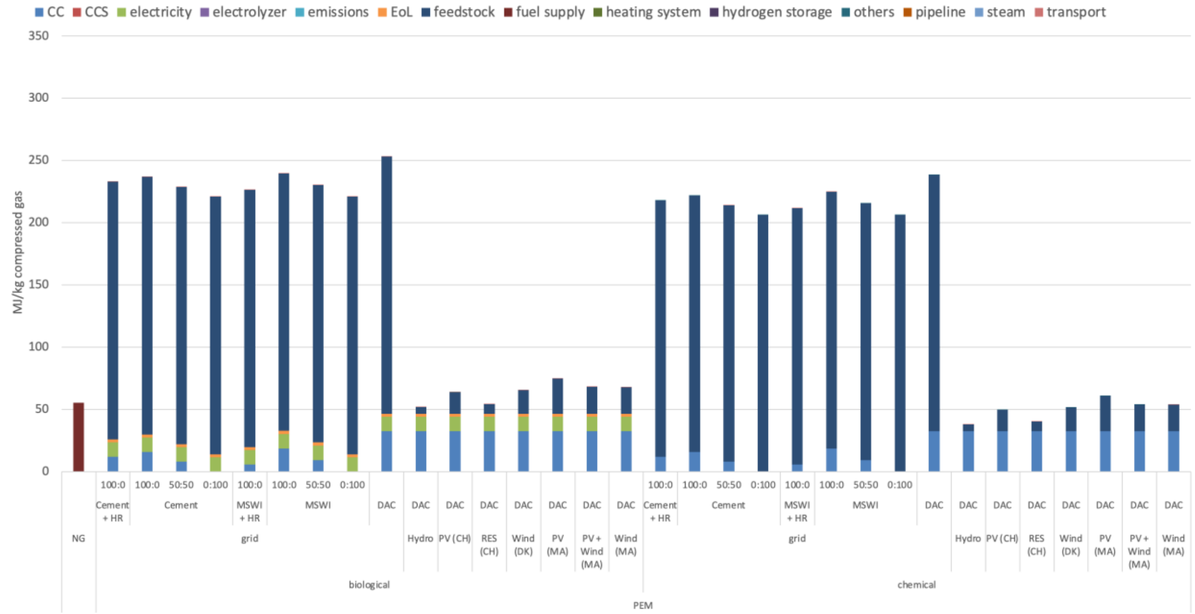

Figure 54 Life-cycle Cumulative Non-renewable Energy Demand per kilogram of synthetic natural gas produced. "NG" = natural gas, low pressure, at consumer. "PEM" = Proton Exchange Membrane. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "Cement" = carbon dioxide, captured at cement plant. "Cement + HR" = carbon dioxide captured at cement plant with use of recovered process heat. "MSWI" = carbon dioxide, captured at municipal solid waste incineration plant. "MSWI + HR" = carbon dioxide captured at municipal solid waste incineration plant with use of recovered process heat. "100:0" = carbon dioxide emissions allocated to emitter. «50 :50» = carbon dioxide emissions allocated equally between emitter and fuel producer. «0:100« = carbon dioxide emissions allocated entirely to fuel producer. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

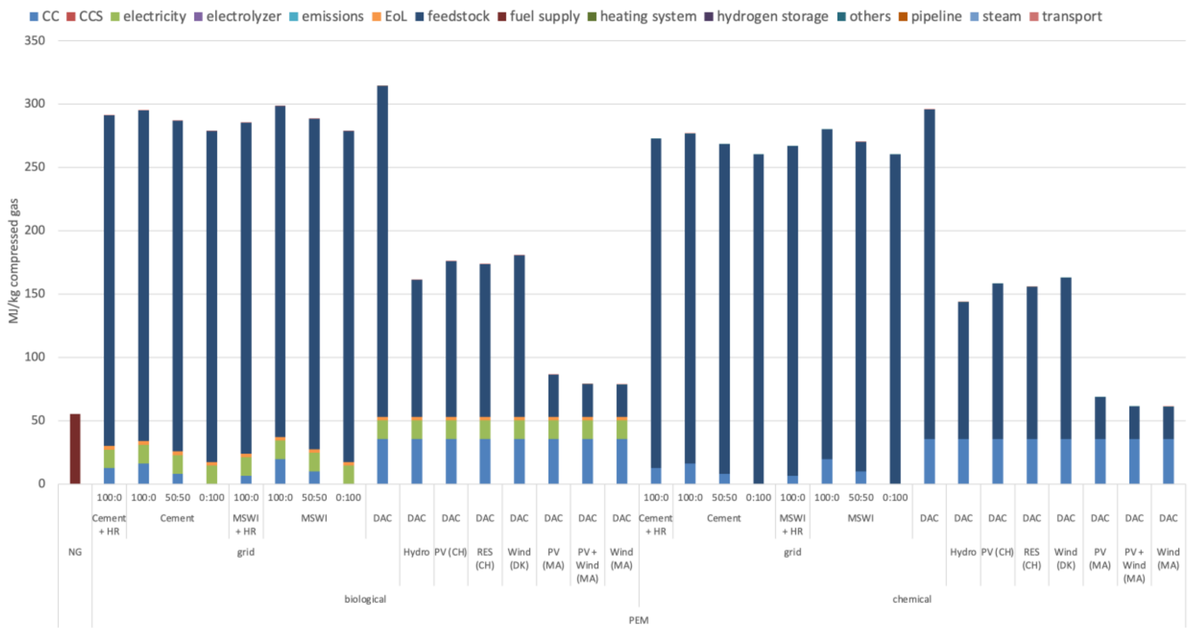

Figure 55 Life-cycle Cumulative Primary Energy (PE) Demand (renewable and non-renewable) per kilogram of synthetic natural gas produced. "NG" = natural gas, low pressure, at consumer. "PEM" = Proton Exchange Membrane. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "Cement" = carbon dioxide, captured at cement plant. "Cement + HR" = carbon dioxide captured at cement plant with use of recovered process heat. "MSWI" = carbon dioxide, captured at municipal solid waste incineration plant. "MSWI + HR" = carbon dioxide captured at municipal solid waste incineration plant with use of recovered process heat. "100:0" = carbon dioxide emissions allocated to emitter. «50:50» = carbon dioxide emissions allocated equally between emitter and fuel producer. "0:100" = carbon dioxide emissions allocated entirely to fuel producer. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

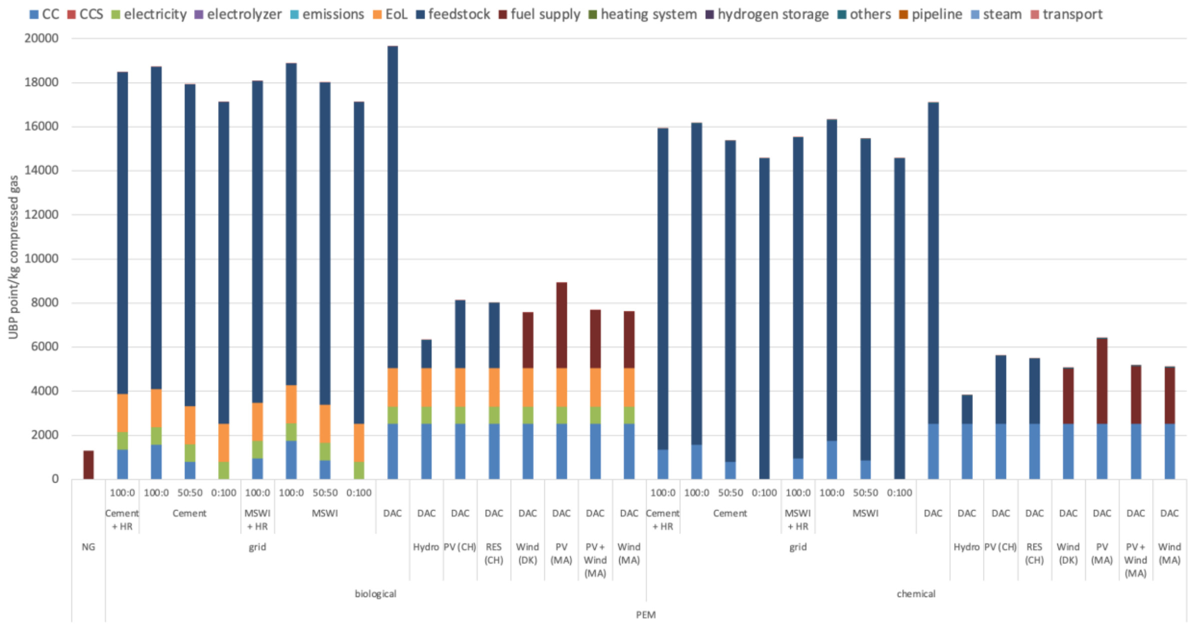

Figure 56 Life-cycle overall environmental impacts per kilogram of synthetic natural gas produced according to the ecological scarcity method. "NG" = natural gas, low pressure, at consumer. "PEM" = Proton Exchange Membrane. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "Cement" = carbon dioxide, captured at cement plant. "Cement + HR" = carbon dioxide captured at cement plant with use of recovered process heat. "MSWI" = carbon dioxide, captured at municipal solid waste incineration plant. "MSWI + HR" = carbon dioxide captured at municipal solid waste incineration plant with use of recovered process heat. "100:0" = carbon dioxide emissions allocated to emitter. «50:50» = carbon dioxide emissions allocated equally between emitter and fuel producer. «0:100« = carbon dioxide emissions allocated entirely to fuel producer. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production. These results do not include the combustion of the fuel.

5.1.4 Methanol supply

The sourcing of hydrogen and CO_2 dominates the Global Warming Potential impacts of methanol production, see Figure *57*. Results are shown alongside those of producing methanol from biomass («Biomass», represented by the dataset methanol*, from synthetic gas, at plant* in the UVEK:2022 database) and natural gas («NG», represented by the dataset *methanol, at plant* in the UVEK:2022 database).

Like SNG, it is necessary to consider the use phase of the life cycle (i.e., emissions from combusting the fuel) to draw meaningful conclusions. Comparisons of environmental impacts per kg synthetic methanol versus methanol from natural gas must therefore not be performed.

Using alternative low-carbon electricity sources substantially reduces the impacts of hydrogen sourcing. The steam input can also represent a non-negligible share of the total impacts.

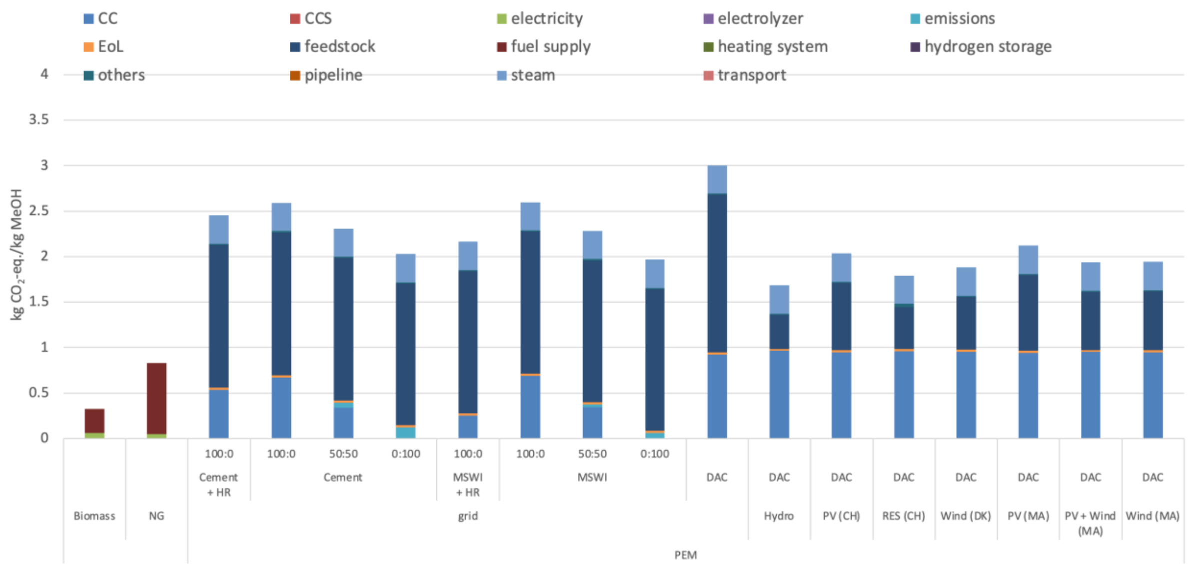

Figure 57 Life-cycle Global Warming Potential impacts per kilogram of methanol produced. "Biomass" = methanol produced from wood chips. "NG" = methanol produced from natural gas. "PEM" = Proton Exchange Membrane. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "Cement" = carbon dioxide, captured at cement plant. "Cement + HR" = carbon dioxide captured at cement plant with use of recovered process heat. "MSWI" = carbon dioxide, captured at municipal solid waste incineration plant. "MSWI + HR" = carbon dioxide captured at municipal solid waste incineration plant with use of recovered process heat. "100:0" = carbon dioxide emissions allocated to emitter. « 50:50 » = carbon dioxide emissions allocated equally between emitter and fuel producer. « 0:100« = carbon dioxide emissions allocated entirely to fuel producer. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production. These results do not include the combustion of the fuel.

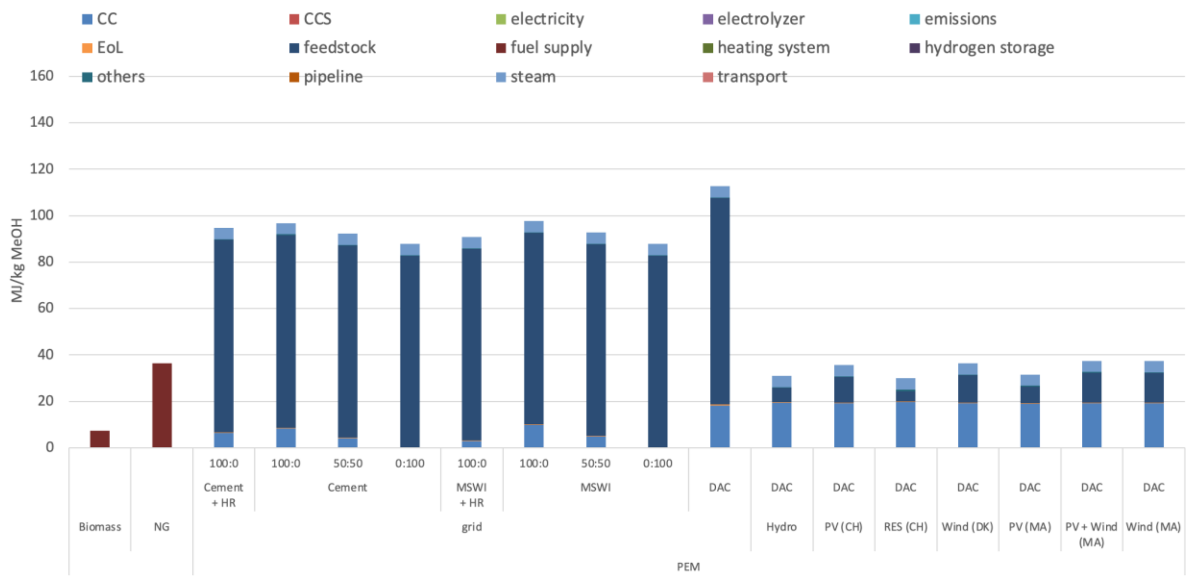

Figure 58 Life-cycle Cumulative Non-renewable Energy Demand per kilogram of methanol produced. "Biomass" = methanol produced from wood chips. "NG" = methanol produced from natural gas. "PEM" = Proton Exchange Membrane. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "Cement" = carbon dioxide, captured at cement plant. "Cement + HR" = carbon dioxide captured at cement plant with use of recovered process heat. "MSWI" = carbon dioxide, captured at municipal solid waste incineration plant. "MSWI + HR" = carbon dioxide captured at municipal solid waste incineration plant with use of recovered process heat. "100:0" = carbon dioxide emissions allocated to emitter. « 50:50 » = carbon dioxide emissions allocated equally between emitter and fuel producer. « 0:100« = carbon dioxide emissions allocated entirely to fuel producer. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

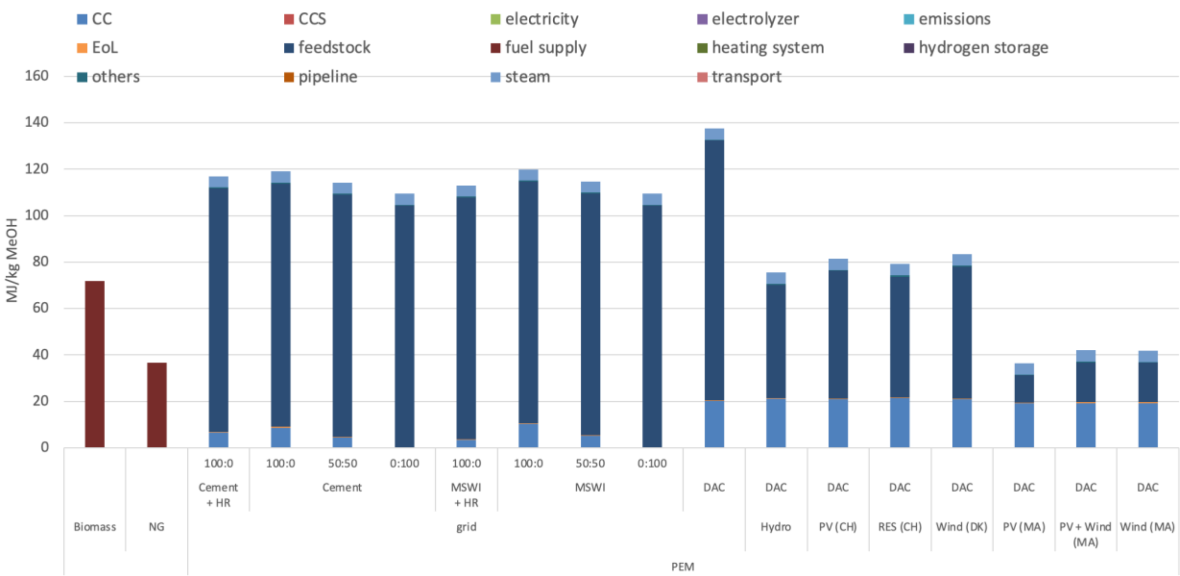

Figure 59 Life-cycle Cumulative Primary Energy (PE) Demand (renewable and non-renewable) per kilogram of methanol produced. "Biomass" = methanol produced from wood chips. "NG" = methanol produced from natural gas. "PEM" = Proton Exchange Membrane. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "Cement" = carbon dioxide, captured at cement plant. "Cement + HR" = carbon dioxide captured at cement plant with use of recovered process heat. "MSWI" = carbon dioxide, captured at municipal solid waste incineration plant. "MSWI + HR" = carbon dioxide captured at municipal solid waste incineration plant with use of recovered process heat. "100:0" = carbon dioxide emissions allocated to emitter. «50:50» = carbon dioxide emissions allocated equally between emitter and fuel producer. «0:100» = carbon dioxide emissions allocated entirely to fuel producer. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production.

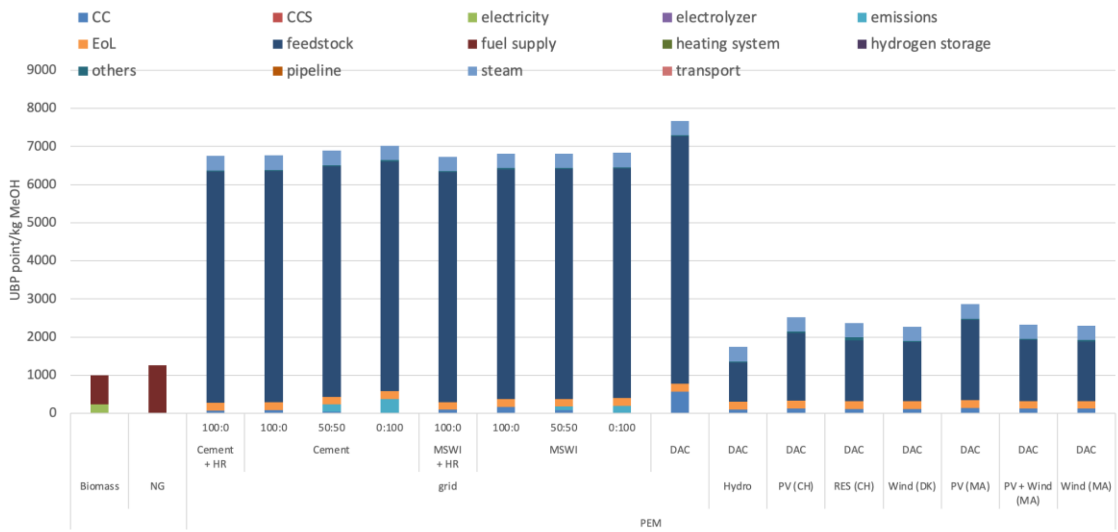

Figure 60 Life-cycle overall environmental impacts per kilogram of methanol produced according to the ecological scarcity method. "Biomass" = methanol produced from wood chips. "NG" = methanol produced from natural gas. "PEM" = Proton Exchange Membrane. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "Cement" = carbon dioxide, captured at cement plant. "Cement + HR" = carbon dioxide captured at cement plant with use of recovered process heat. "MSWI" = carbon dioxide, captured at municipal solid waste incineration plant. "MSWI + HR" = carbon dioxide captured at municipal solid waste incineration plant with use of recovered process heat. "100:0" = carbon dioxide emissions allocated to emitter. «50:50 » = carbon dioxide emissions allocated equally between emitter and fuel producer. «0:100» = carbon dioxide emissions allocated entirely to fuel producer. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "LNG" = liquefied natural gas. "NG" = compressed natural gas. "grid" = electricity from the Swiss grid. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Hydro" = Swiss hydropower. "PV" = Swiss solar photovoltaic power. "RES" = mix of Swiss-based renewable energy sources. "Wind" = wind power. "Wind (MA)" = Morocco-based autonomous wind power-based hydrogen production. "PV (MA)" = Morocco-based autonomous solar power-based hydrogen production. "PV + Wind (MA)" = Morocco-based autonomous wind and solar power-based hydrogen production. These results do not include the combustion of the fuel.

5.1.5 Heat supply

This section shows the life-cycle impacts of heat supply options. These options are compared to reference technologies, which specifications are described in Table 83.

Table 83 Main specifications for the reference technologies for heating

Name (in figures)	Dataset name	Description	Energy carrier	Power [kW]	Efficiency [%, LHV]	Source
HP - grid	heat, at heat pump, air-water, 15kW, CH electricity, in new building/MJ/CH	Air-water heat pump, installed in a new building in Switzerland.	Electricity from the Swiss grid.	15	440% (CoP ~4.4)	(Kägi et al. 2021)
HP - RES (CH)	heat, at heat pump, air-water, 15kW, certified electricity, in new building/MJ/CH	Air-water heat pump, installed in a new building in Switzerland.	Electricity from a mix of renewable energy sources.	15	440% (CoP ~4.4)	
Boiler – Wood	heat, softwood chips from forest, at furnace 50kW/MJ/CH	Wood chips furnace, in Switzerland	Wood chips, from soft wood.	50 kW	84%	
Boiler - Biomethane	heat, biomethane, at boiler cond. modulating 15kW/MJ/CH	Home boiler fed with biomethane, in Switzerland.	Biomethane.	15 kW	109%	
Boiler - NG	heat, natural gas, at boiler condensing modulating 15kW/CH	Home boiler fed with natural gas, in Switzerland.	Natural gas.	15 kW	109%	

Figure 61 shows the life-cycle Global Warming Potential impacts of heat supply options using hydrogen, SNG, and methanol, in kilogram of CO_2-eq. per "megajoule heat output" (representing the functional unit).

Results are shown alongside those of heat from a 15 kW air-water heat pump operated with either average electricity or renewable power from the Swiss grid in a new building ("HP", represented by the dataset *heat pump, air-water, 15 kW, in new building* from the UVEK:2022 database), heat from a boiler fed with wood chips ("Wood", represented by the dataset *heat, softwood chips from forest, at furnace 50kW* in the UVEK:2022 database), heat from a 15 kW biomethane boiler ("biomethane", represented by the dataset *heat, biomethane, at boiler condensing modulating 15kW* from the UVEK:2022 database) as well as heat from a 15 kW natural gas-fed boiler ("boiler – NG", represented by the dataset *heat, natural gas, at boiler condensing modulating 15 kW* from the UVEK:2022 database).

Among all heat supply options compared, the heat pump using Swiss renewable power causes the lowest climate impacts as well as the lowest overall environmental impacts, as it uses renewable power in the most efficient way. Among the non-conventional heat supply pathways modeled in this work and in case environmental burdens of joint heat and electricity generation are allocated according to exergy content of these products (as per default in this work), hydrogen-based CHP and fuel cell options score consistently better (i.e., cause lower GHG emissions and overall environmental burdens) than those using a boiler due to the exergy allocation, which assigns a relatively high share of burdens to the co-produced electricity. Methanol and synthetic gas options score consistently worse. Compared to using natural gas in a 15-kW condensing boiler, most hydrogen-based options perform better, except for SMR-based heat supply from a boiler. Finally, the heat options using electrolytic hydrogen from the Moroccan-based autonomous plant (representing a "best case" in terms of renewable yields and thus environmental burdens) or those using SMR-based hydrogen with CCS also show higher impacts than the associated reference technology (heat pump operated with renewables).

It is important to note the penalty when supplying the hydrogen by truck (Figure *61*): accentuated gas losses and the requirements in on-site storage lead to a 20-25% increase in greenhouse gas emissions compared to pipeline hydrogen transport.

Applying a global warming characterization factor for hydrogen emissions due to leakage of 11.6 kg CO_2-eq./kg H_2 for a 100-year time horizon (GWP_{100}), as suggested by (Sand et al. 2023), would increase results related to impacts on climate change by 2-4%. This is insufficient to change the ordinal rank of the options presented above.

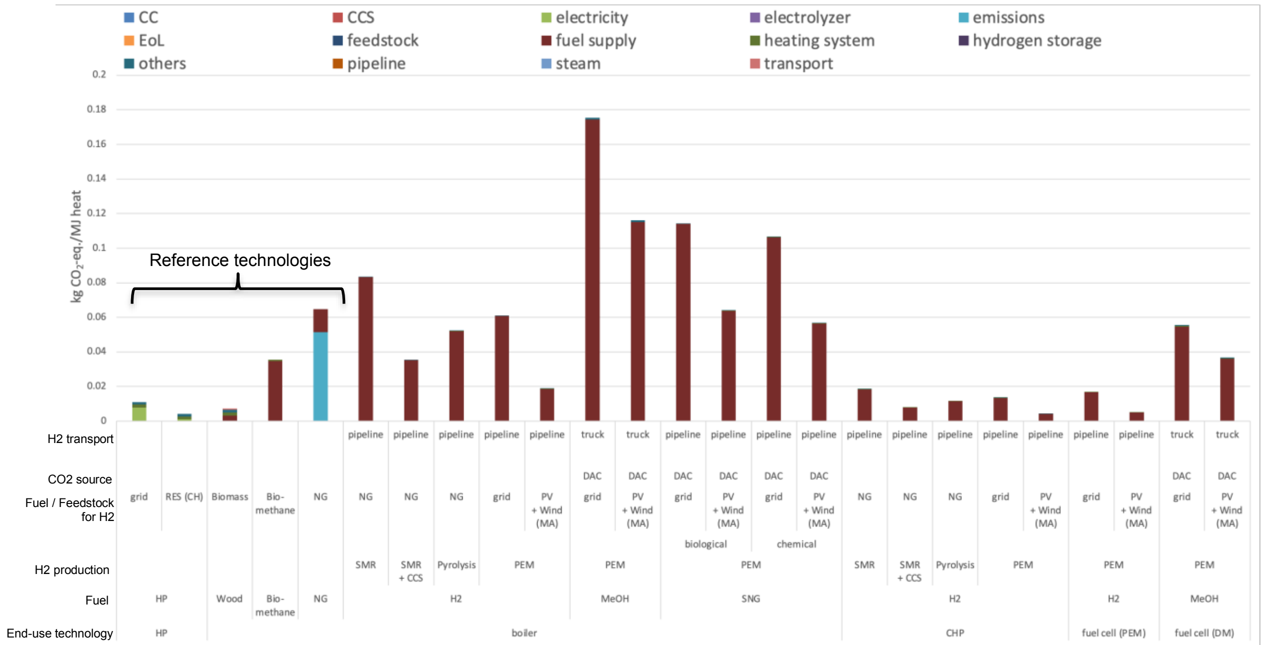

Figure 61 Life-cycle Global Warming Potential impacts per megajoule of heat supplied. "HP" = air-water heat pump. "Wood" = wood chips-fueled boiler. "NG" = natural gas. "PEM" = Proton Exchange Membrane. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "RES (CH)": Swiss renewable electricity mix. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "Wind" = wind power. "PV + Wind (MA)" = Morocco-based autonomous PV and wind power-based hydrogen production.

Figure 63 indicates that using SMR-based hydrogen in a boiler requires about 1.6 megajoules of primary energy per megajoule of heat supplied. This number increases to 4, 6, and 8 megajoules when using electrolytic hydrogen, synthetic natural gas, and methanol, respectively, rendering the energy chain relatively inefficient. In comparison, the air-water heat pump only requires 0.6 megajoules of energy per megajoule of geothermal energy transferred.

The overall environmental life cycle impacts in Figure *64* indicate that hydrogen from electrolysis in a CHP or fuel cell yields a score higher than that of an air-water heat pump operated with renewable electricity. These scores are heavily driven by the allocation approach chosen (i.e., based on exergy in this case), discussed in the next sections.

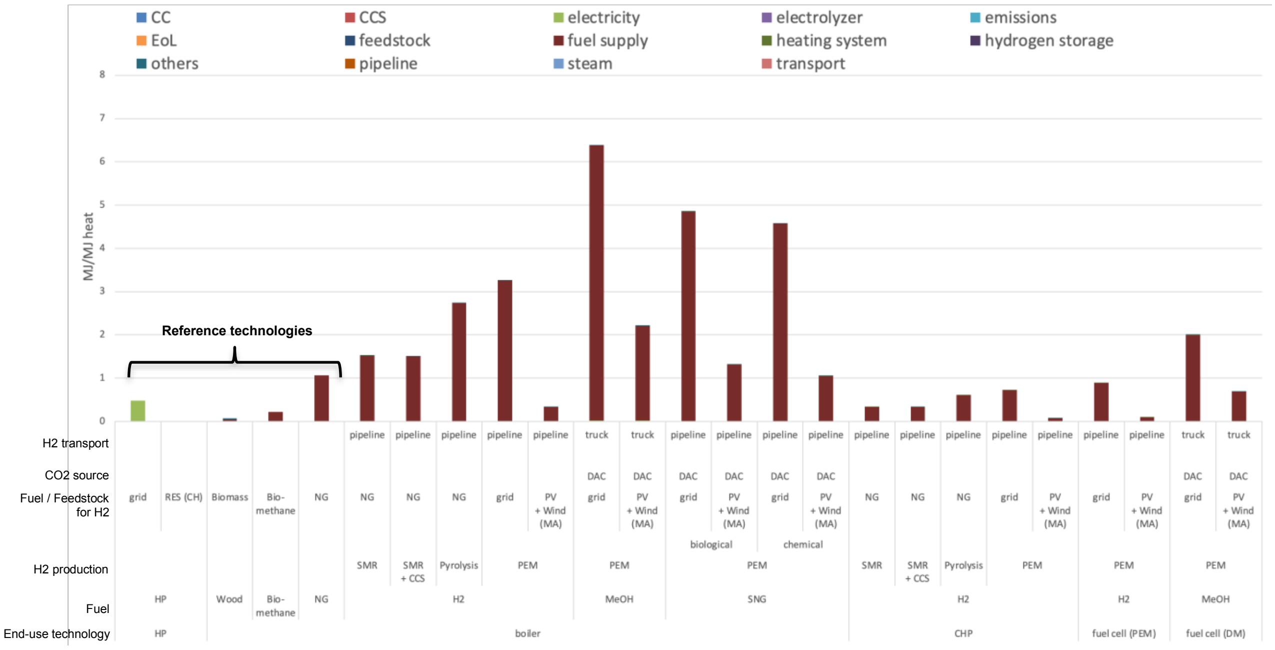

Figure 62 Life-cycle Cumulative Non-renewable Energy Demand per megajoule of heat supplied. “HP” = air-water heat pump. “Wood” = wood chips-fueled boiler. “NG” = natural gas. “PEM” = Proton Exchange Membrane. “biological” = biological methanation. “chemical” = electrochemical methanation. “grid” = Swiss grid electricity. “RES (CH)”: Swiss renewable electricity mix. “DAC” = atmospheric carbon dioxide captured by Direct Air Capture. “CC” = carbon dioxide capture/sourcing. “CCS” = carbon dioxide capture and storage. “EoL” = End-of-Life. “Wind” = wind power. “PV + Wind (MA)” = Morocco-based autonomous PV and wind power-based hydrogen production.

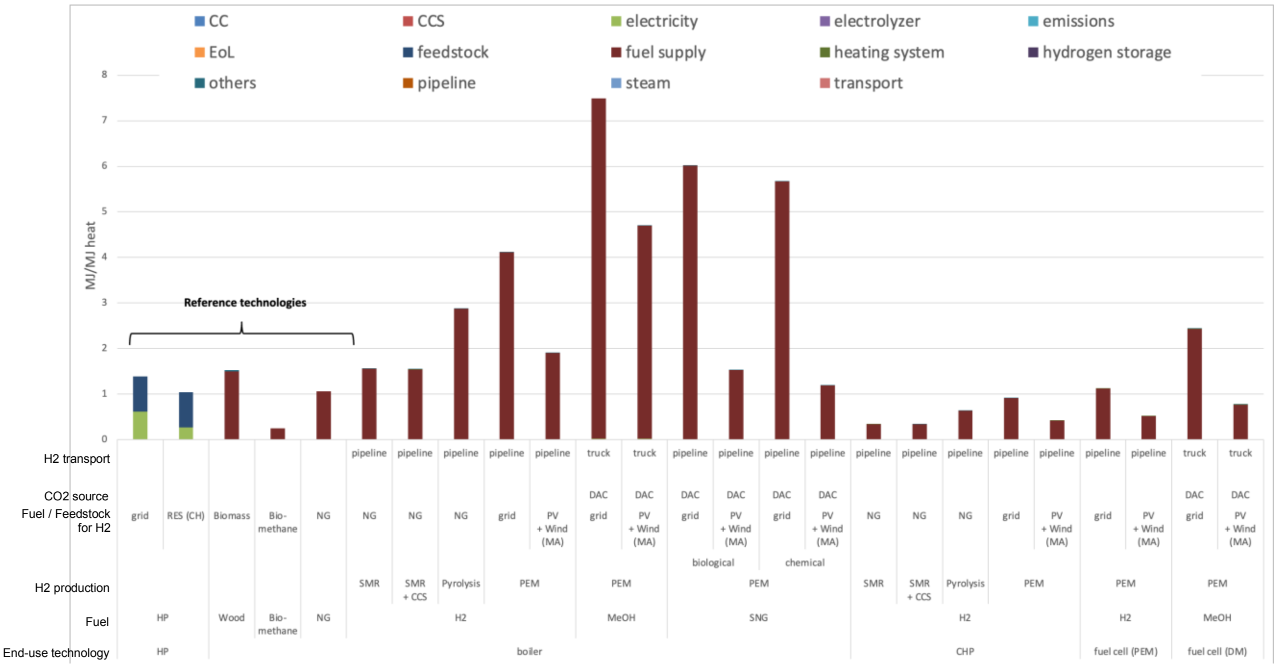

Figure 63 Life-cycle Cumulative Primary Energy (PE) Demand (renewable and non-renewable) per megajoule of heat supplied. “HP” = air-water heat pump. “Wood” = wood chips-fueled boiler. “NG” = natural gas. “PEM” = Proton Exchange Membrane. “biological” = biological methanation. “chemical” = electrochemical methanation. “grid” = Swiss grid electricity. “RES (CH)”: Swiss renewable electricity mix. “DAC” = atmospheric carbon dioxide captured by Direct Air Capture. “CC” = carbon dioxide capture/sourcing. “CCS” = carbon dioxide capture and storage. “EoL” = End-of-Life. “Wind” = wind power. “PV + Wind (MA)” = Morocco-based autonomous PV and wind power-based hydrogen production.

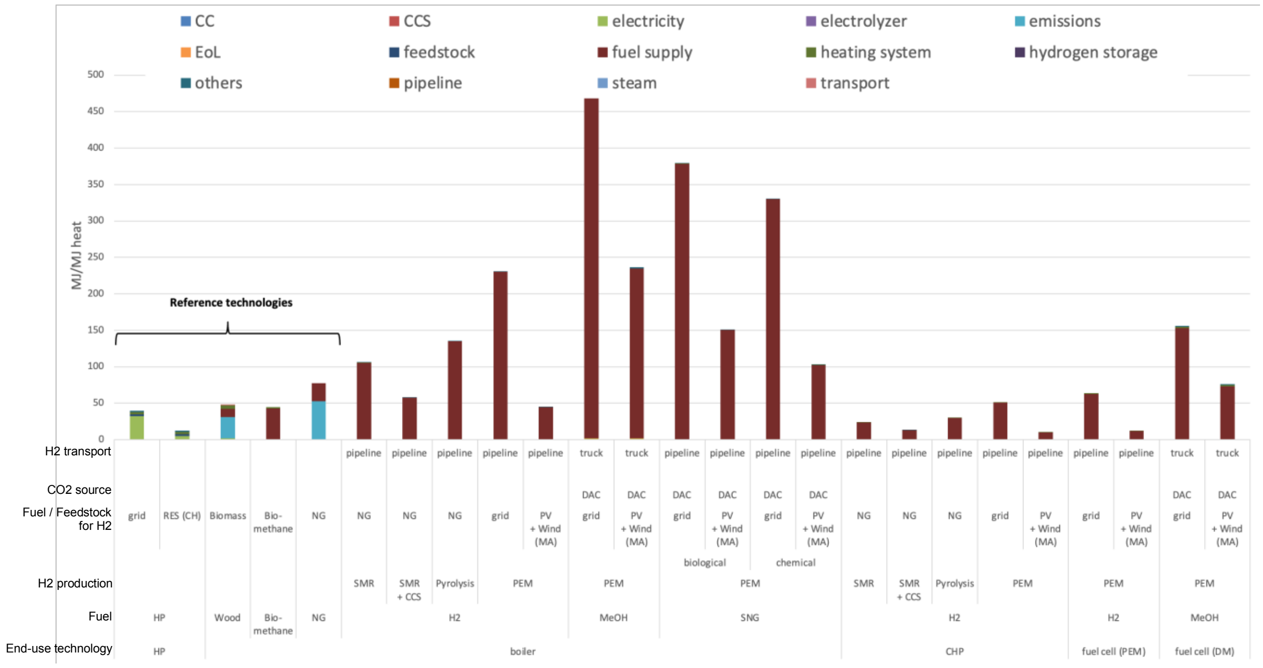

Figure 64 Life-cycle overall environmental impacts according to the ecological scarcity method per megajoule of heat supplied. "HP" = air-water heat pump. "Wood" = wood chips-fueled boiler. "NG" = natural gas. "PEM" = Proton Exchange Membrane. "biological" = biological methanation. "chemical" = electrochemical methanation. "grid" = Swiss grid electricity. "RES (CH)": Swiss renewable electricity mix. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "Wind" = wind power. "PV + Wind (MA)" = Morocco-based autonomous PV and wind power-based hydrogen production.

5.1.6 Electricity supply

This section shows the life cycle impacts of electricity supply. The options are compared to reference technologies, which specifications are described in Table 84.

Table 84 Main specifications for the reference technologies for electricity supply

Name (in figures)	Dataset name	Description	Energy carrier	Source
grid	electricity, low voltage, at grid/kWh/CH U	Low voltage electricity, supplied by the Swiss grid.	Electricity.	(Krebs and Frischknecht 2021)
RES	electricity, certified eletricity/kWh/CH	Low voltage electricity, supplied by the Swiss grid, representing average certified electricity.	Electricity.	(Krebs and Frischknecht 2021)
NG	Electricity, natural gas, at power plant/DE	Electricity, high voltage, supplied by a natural gas power plant, in Germany.	Electricity.	(Emmenegger et al. 2007)
PV (CH)	electricity, production mix photovoltaic, at plant/kWh/CH	Electricity produced by Swiss average photovoltaic installations.	Electricity.	(R. Frischknecht et al. 2020)

Figure 65 shows the life-cycle Global Warming Potential impacts for the electricity production options relying on hydrogen and methanol-based fuel cells or CHPs, per "kWh of electricity at the power plant" (representing the functional unit). Results are shown alongside those of average electricity from the Swiss grid ("grid", represented by the dataset *electricity, low voltage, at grid* from the UVEK:2022 database), electricity from Swiss photovoltaic power ("PV (CH)", represented by the dataset *electricity, production mix photovoltaic, at plant* from the

UVEK:2022 database) and from a natural gas-fed power plant in Germany ("NG", represented by the dataset *electricity, natural gas, at power plant* from the UVEK:2022 database). Electricity from PV modules is chosen here as representative for renewables in Switzerland, as PV exhibits the by far largest potential for further domestic renewable power generation. PV electricity causes (slightly) higher GHG emissions and overall environmental impacts than electricity from wind and hydropower in Switzerland and can thus be considered as conservative choice for the purpose of this comparison.

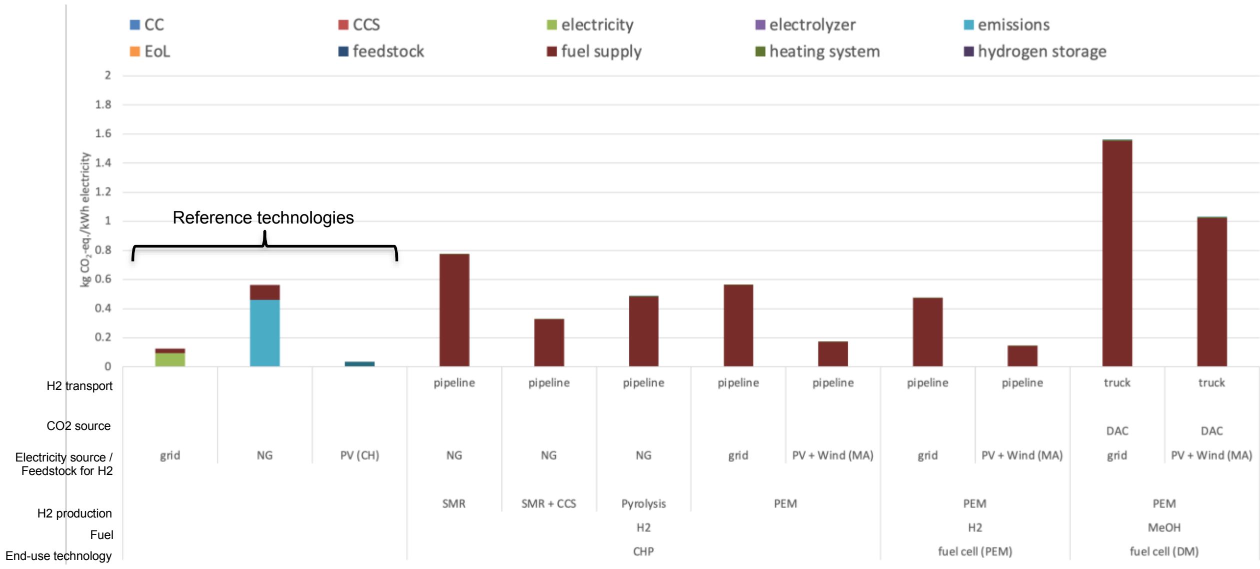

Figure 65 Life-cycle Global Warming Potential impacts per kilowatt hour of electricity supplied. "grid" = Swiss grid electricity. "NG" = natural gas-fired power plant. "PV (CH)" = Swiss solar photovoltaic power. "PEM" = Proton Exchange Membrane. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "NG" = natural gas. "Wind" = wind power. "PV + Wind (MA)" = Morocco-based autonomous PV and wind power-based hydrogen production.

All hydrogen and methanol-based options score several folds higher than solar photovoltaic electricity in Switzerland, some even surpassing the impacts of natural gas-based electricity. Hydrogen and methanol-based options, also those based on renewable power, cause higher GHG emissions than average grid electricity as well. On the one hand, this is an effect of the comparatively low energy efficiency of electricity-based hydrogen and methanol production (Figure 66 and Figure 67); on the other hand, this is also driven by the exergy-based partitioning between the production of heat and electricity, which assigns comparatively large shares of overall impacts to electricity.

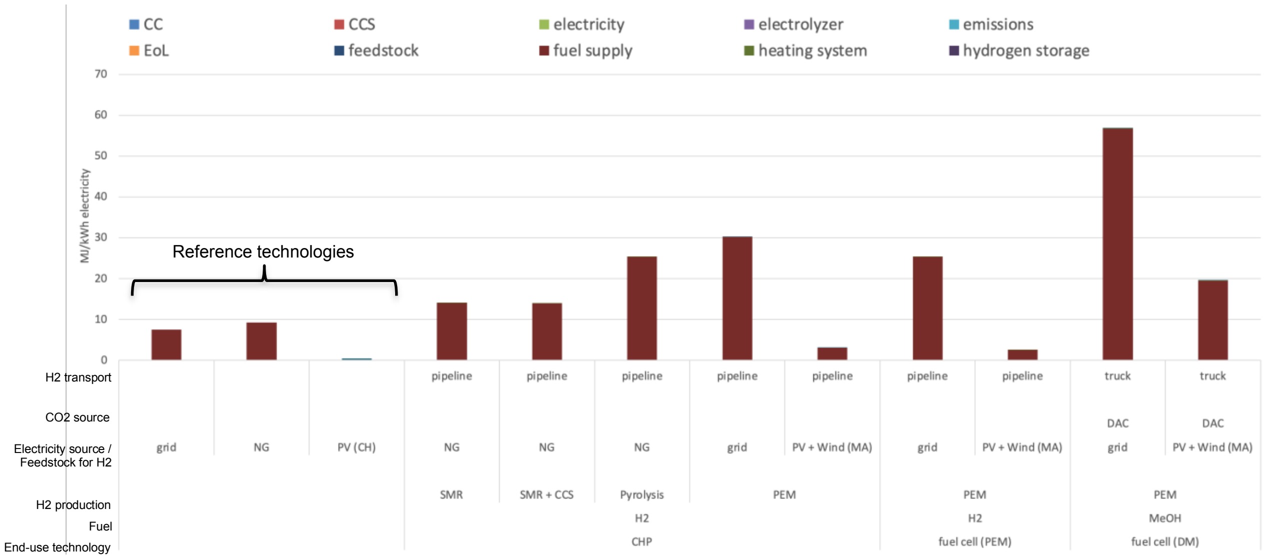

Figure 66 Life-cycle Cumulative Non-renewable Energy Demand per kilowatt hour of electricity supplied. "grid" = Swiss grid electricity. "NG" = natural gas-fired power plant. "PV (CH)" = Swiss solar photovoltaic power. "PEM" = Proton Exchange Membrane. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "NG" = natural gas. "Wind" = wind power. "PV + Wind (MA)" = Morocco-based autonomous PV and wind power-based hydrogen production.

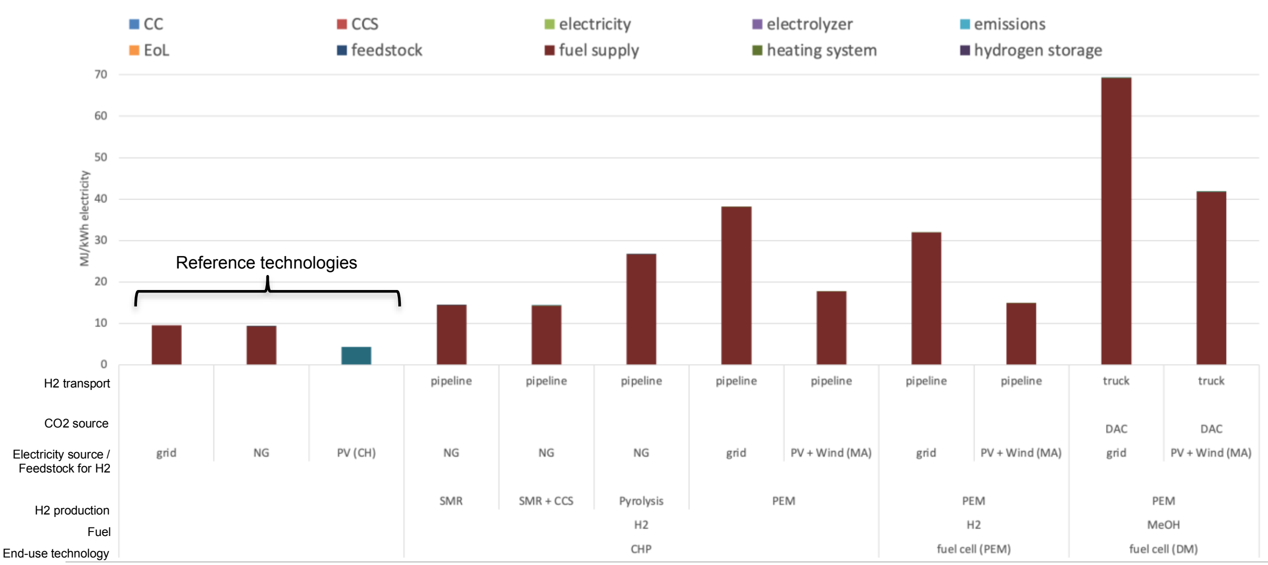

Figure 67 Life-cycle Cumulative Primary Energy (PE) Demand (renewable and non-renewable) per kilowatt hour of electricity supplied. "grid" = Swiss grid electricity. "NG" = natural gas-fired power plant. "PV (CH)" = Swiss solar photovoltaic power. "PEM" = Proton Exchange Membrane. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "NG" = natural gas. "Wind" = wind power. "PV + Wind (MA)" = Morocco-based autonomous PV and wind power-based hydrogen production.

In terms of overall environmental impacts, also PV causes the lowest scores (Figure 68), a factor of four to five below the hydrogen CHP and fuel cell with imported hydrogen produced with renewable electricity in Morocco (representing a "best case" option in terms of environmental burdens).[7] These hydrogen options cause slightly less impacts than the average Swiss grid electricity mix.

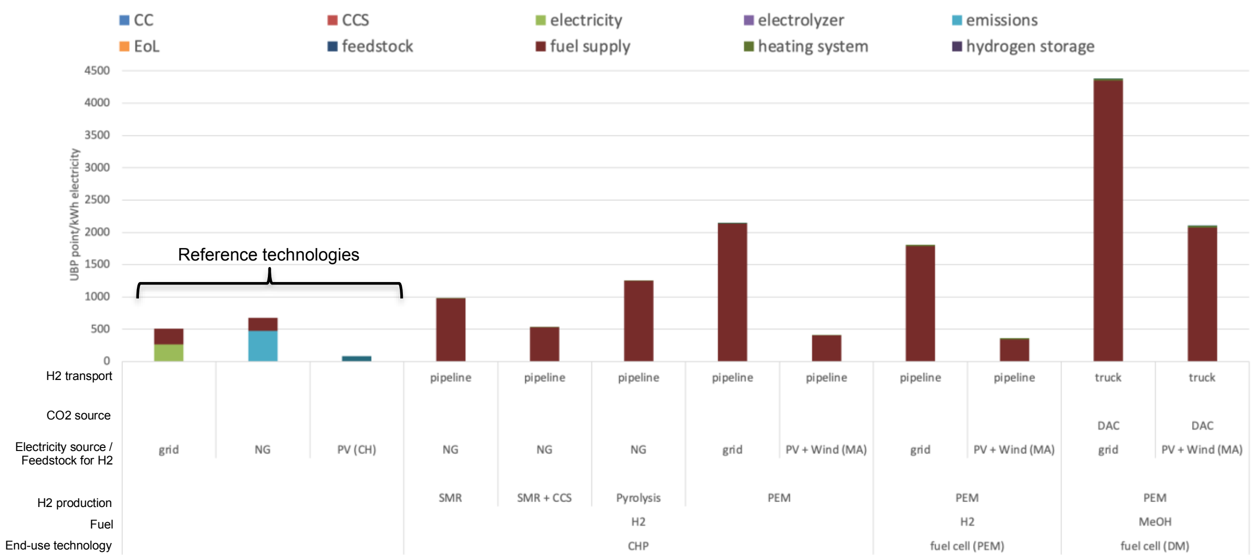

Figure 68 Life-cycle overall environmental impacts according to the ecological scarcity method per kilowatt hour of electricity supplied. "grid" = Swiss grid electricity. "NG" = natural gas-fired power plant. "PV (CH)" = Swiss solar photovoltaic power. "PEM" = Proton Exchange Membrane. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life. "NG" = natural gas. "Wind" = wind power. "PV + Wind (MA)" = Morocco-based autonomous PV and wind power-based hydrogen production.

5.2 Sensitivity analyses

A sensitivity analysis comparing all boiler-based options in terms of life-cycle Global Warming impacts per megajoule of heat is shown in Figure 69.

Results are shown alongside a number of reference technologies: heat from an air-water 15 kW heat pump operated with the Swiss grid in a new building ("HP", represented by the dataset *heat pump, air-water, 15 kW, in new building* from the UVEK:2022 database), heat from a heating boiler fed with wood chips ("Wood", represented by the dataset *heat, softwood chips from forest, at furnace 50kW* in the UVEK:2022 database), heat from a 15 kW biomethane boiler ("biomethane", represented by the dataset *heat, biomethane, at boiler condensing modulating 15kW* from the UVEK:2022 database) as well as heat from a natural gas-fed 15 kW boiler ("boiler – NG", represented by the dataset *heat, natural gas, at boiler condensing modulating 15 kW* from the UVEK:2022 database). Their specifications are described in Table 83.

From Figure 69 one can conclude that:

- The delivery of hydrogen by truck causes significantly more GHG emissions than hydrogen transport per pipeline due to increased losses during distribution as well as the need for an on-site storage tank.
- The effect of considering a Type I or Type IV hydrogen storage tank for the truck delivery options seems negligible.

[7] This best-case scenario aims at quantifying the optimal environmental performance for hydrogen production in comparison to alternative technologies also operated under optimal conditions (i.e., a heat pump operated with 100% electricity from renewable sources).

- The electrochemical methanation process to produce synthetic natural gas seems to cause less GHG emissions than its biological counterpart. However, this may be due to uncertain inventory data for biological methanation.
- The CO_2 allocation approach for SNG and methanol-based options (see section 1.3.6) is important when the CO_2 sourced is primarily of a fossil nature (i.e., from a cement plant). When the fossil share in the CO_2 is only close to 50%, such as in the case of CO_2 from an MSWI plant, the CO_2 allocation approach has less effect on the GHG emissions. In the case where the CO_2 is sourced from an MSWI plant and the heat needed for CO_2 capture must be provided by fossil external sources, the differences in GHG emissions due to different CCU approaches are close to zero. This is because the amount of fossil CO_2 emissions assigned to the fuel end-user (i.e., the physical emitter) in case of a 100:0 allocation of CCU related CO_2 emissions is almost exactly equivalent to the GHG emissions caused by fossil heat supply for the CO_2 capture process.
- The use of recovered process heat to capture the CO_2 to produce methanol and synthetic natural gas can help decrease GHG emissions on a megajoule heat basis from 5% (i.e., capture at the cement plant) to 15% (i.e., capture at the MSWI plant). Thus, in terms of climate impacts, the use of CO_2 from a MSWI plant with heat recovery for CO_2 capture is the preferred option among all CCU cases included in this analysis. Overall climate impacts of heat from SNG boilers using CO_2 of such an origin and assigning the fuel use related CO_2 emissions to the fuel producer ("0:100 allocation" with CO_2 emissions from fuel use assigned to the CO_2 point source) are indeed slightly below those of hydrogen boilers, which use hydrogen from electrolysis and delivered by truck to the end user.
- Overall and based on most options analyzed here, the direct use of hydrogen should – from a climate impact perspective – be prioritized, as heat production from SNG and methanol boilers causes higher GHG emissions, independently of whether fossil CO_2 emissions from SNG or methanol combustion are assigned to the fuel user or the CO_2 point source (in case of CO_2 sourcing from MSWI and cement plants). The only exception from this general conclusion is the case in which CO_2 is captured at an MSWI plant with internally provided heat: due to the comparatively high share of biogenic CO_2 emissions and the potential to use almost 100% internally provided waste heat for the CO_2 capture process ("heat recovery"), burning SNG with CO_2 from such MSWI plants (but assigning the associated CO_2 emissions to the MSWI plant) causes slightly less GHG emissions than pure hydrogen combustion product systems, in which hydrogen is delivered by truck and stored in small-scale tanks at the household level.

Figure 69 Life-cycle Global Warming Potential impacts per MJ of heat supplied for all boiler-based options, in addition to reference options. All cases where the hydrogen is supplied via a PEM electrolyzer ("PEM") use Swiss grid electricity. "NG" = natural gas-fed boiler. "Wood" = wood-fired boiler. "HP" = air-water heat pump powered with Swiss grid electricity. "pipe." = hydrogen transport by pipeline. "truck" = hydrogen transport by truck. "PEM" = Proton Exchange Membrane fuel cell or electrolyzer. "ATR" = Auto-Thermal Reforming of natural gas. "SMR" = Steam Methane Reforming of natural gas. "bio." = biological methanation. "chem." = electrochemical methanation. "DAC" = atmospheric carbon dioxide captured by Direct Air Capture. "Cement" = carbon dioxide, captured at cement plant. "MSWI" = carbon dioxide, captured at municipal solid waste incineration plant. "100:0" = carbon dioxide emissions allocated to emitter. "50:50" = carbon dioxide emissions allocated equally between emitter and fuel producer. "0:100" = carbon dioxide emissions allocated entirely to fuel producer. "CC" = carbon dioxide capture/sourcing. "CCS" = carbon dioxide capture and storage. "EoL" = End-of-Life.

5.3 System expansion

This section shows the life-cycle impacts of co-generation heat and power options. These options are compared to a basket of reference technologies, which specifications are described in Table 85.

Table 85 Main specifications for the reference technologies for heating

Name (in figures)	Dataset name	Description	Energy carrier	Power [kW]	Efficiency [%, LHV]	Source
HP - grid	heat, at heat pump, air-water, 15kW, CH electricity, in new building/MJ/CH	Air-water heat pump, installed in a new building in CH.	Electricity from the Swiss grid.	15	440% (CoP ~4.4)	(Kägi et al. 2021)
HP - RES (CH)	heat, at heat pump, air-water, 15kW, certified electricity, in new building/MJ/CH	Air-water heat pump, installed in a new building in CH.	Electricity from a mix of renewable sources.	15	440% (CoP ~4.4)	
avg grid CH	electricity, low voltage, at grid/kWh/CH U	Low voltage electricity, supplied by the CH grid.	Electricity.			(Krebs and Frischknecht 2021)
RES CH	electricity, certified eletricity/kWh/CH	Low voltage electricity, supplied by the CH grid, representing the average supply of certified electricity.	Electricity.			

Figure 70 shows the life-cycle Global Warming Potential impacts of jointly producing heat and electricity for co-generation options, Figure 71 and Figure 72 non-renewable and overall cumulative primary energy demand, respectively, and Figure 73 overall environmental impacts according to the ecological scarcity method. The impacts of the combined heat and electricity production from co-generation units (i.e., hydrogen fuel cells and CHP units, and methanol fuel cells) are compared to the impacts of providing the same reference flows with an air-water heat pump (operated with average Swiss grid electricity or Swiss renewable electricity (RES)) and electricity from the Swiss grid (average or certified renewables only). Thus, the functional unit is a combination of heat and electricity supply, specifically for each production unit. For CHPs, this amounts to 1 MJ of heat and 0.167 kWh of electricity, while it amounts to 1 MJ of heat together with 0.22 kWh of electricity for more efficient fuel cells.

The system providing heat with a heat pump operated with renewable electricity and additional renewable electricity supply causes the lowest greenhouse gas emissions and overall environmental impacts. Both climate and overall environmental impacts of hydrogen options are at least three to four times higher. The hydrogen fuel cell is more efficient than the CHP unit and therefore causes lower climate and overall environmental impacts. Whether renewable electricity (PV) in Switzerland is used or hydrogen is produced in regions with higher renewable yields and imported via pipeline only results in minor differences in terms of GHG emissions and overall impacts. Converting hydrogen further and using electricity-based methanol in a fuel cell can (as shown here, without heat recovery) lead to an increase of climate and overall environmental impacts by a factor of around two to three. Using average Swiss grid electricity instead of renewable power – directly and for hydrogen production – increases both climate and overall environmental impacts by a factor of around three to five.

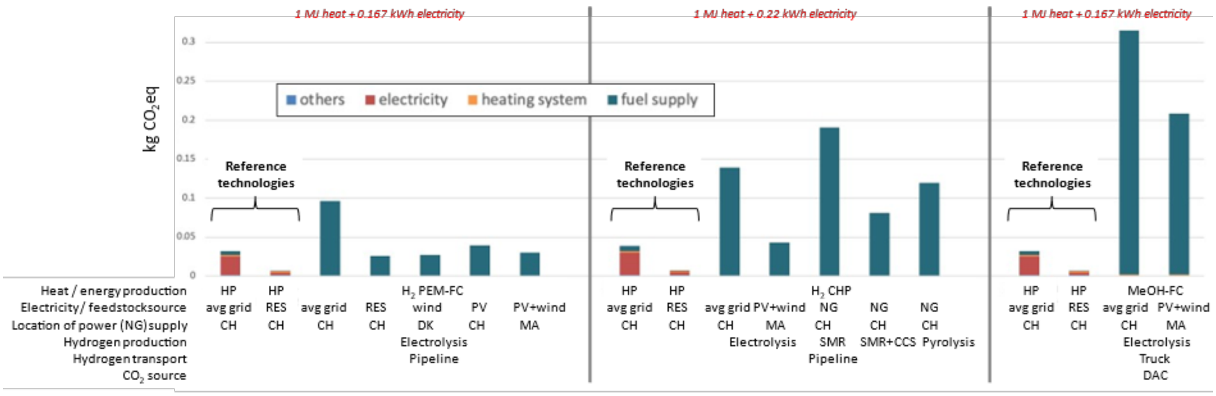

Figure 70 Life-cycle Global Warming Potential impacts of jointly producing heat and electricity from co-generation units. “H_2 PEM-FC” = hydrogen-fed fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. “H_2 CHP” = hydrogen-fed combined heat-power plant, providing 1 MJ of heat and 0.22 kWh of electricity. “MeOH-FC” = direct methanol fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. These three options are compared with counterparts, “HP + avg. grid electricity (CH)” and “HP + RES (CH)”, i.e., heat pumps which provide equivalent amounts of heat and electricity, either average Swiss grid power or from RES (for both HP operation and electricity supply). “RES = Renewable Energy Sources”; “pipeline/truck” refers to hydrogen transport; MA = Morocco; SMR = Steam Methane Reforming; CCS = Carbon Capture and Storage; DAC = Direct Air Capture of CO_2.

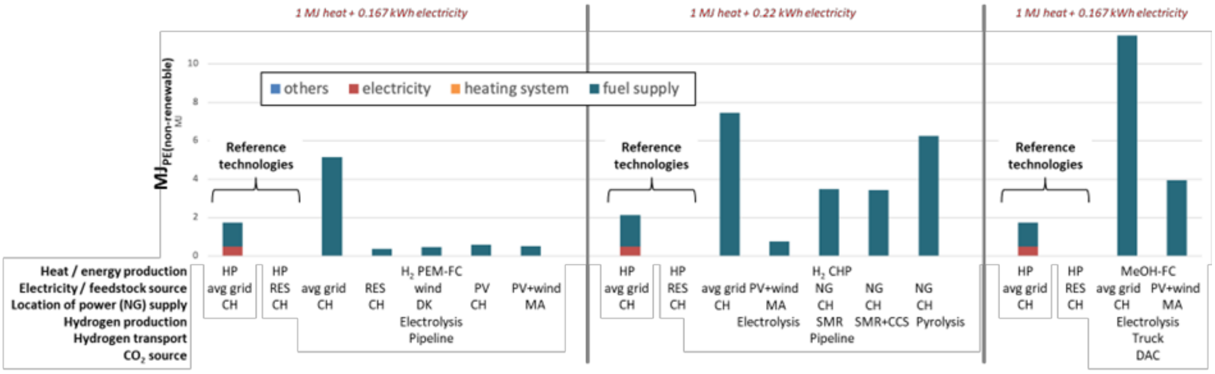

Figure 71 Life-cycle non-renewable Primary Energy (PE) Demand of jointly producing heat and electricity from co-generation units. "H_2 PEM-FC" = hydrogen-fed fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. "H_2 CHP" = hydrogen-fed combined heat-power plant, providing 1 MJ of heat and 0.22 kWh of electricity. "MeOH-FC" = direct methanol fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. These three options are compared with counterparts, "HP + avg. grid electricity (CH)" and "HP + RES (CH)", i.e., heat pumps which provide equivalent amounts of heat and electricity, either average Swiss grid power or from RES (for both HP operation and electricity supply). "RES = Renewable Energy Sources"; "pipeline/truck" refers to hydrogen transport; MA = Morocco; SMR = Steam Methane Reforming; CCS = Carbon Capture and Storage; DAC = Direct Air Capture of CO_2.

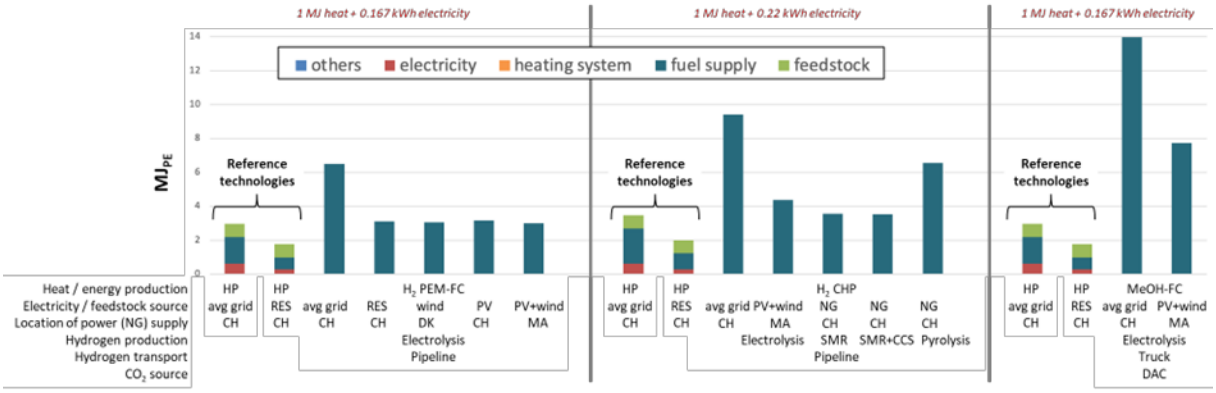

Figure 72 Life-cycle Cumulative Primary Energy (PE) Demand (renewable and non-renewable) of jointly producing heat and electricity from co-generation units. "H_2 PEM-FC" = hydrogen-fed fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. "H_2 CHP" = hydrogen-fed combined heat-power plant, providing 1 MJ of heat and 0.22 kWh of electricity. "MeOH-FC" = direct methanol fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. These three options are compared with counterparts, "HP + avg. grid electricity (CH)" and "HP + RES (CH)", i.e., heat pumps which provide equivalent amounts of heat and electricity, either average Swiss grid power or from RES (for both HP operation and electricity supply). "RES = Renewable Energy Sources"; "pipeline/truck" refers to hydrogen transport; MA = Morocco; SMR = Steam Methane Reforming; CCS = Carbon Capture and Storage; DAC = Direct Air Capture of CO_2.

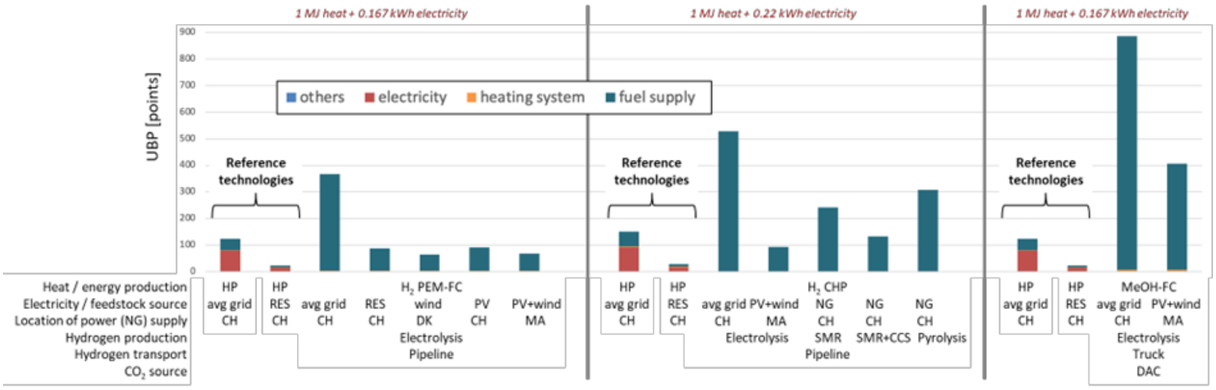

Figure 73 Life-cycle environmental impacts according to the Ecological Scarcity method of jointly producing heat and electricity from co-generation units. "H_2 PEM-FC" = hydrogen-fed fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. "H_2 CHP" = hydrogen-fed combined heat-power plant, providing 1 MJ of heat and 0.22 kWh of electricity. "MeOH-FC" = direct methanol fuel cell, producing 1 MJ of heat and 0.167 kWh of electricity. These three options are compared with counterparts, "HP + avg. grid electricity (CH)" and "HP + RES (CH)", i.e., heat pumps which provide equivalent amounts of heat and electricity, either average Swiss grid power or from RES (for both HP operation and electricity supply). "RES = Renewable Energy Sources"; "pipeline/truck" refers to hydrogen transport; MA = Morocco; SMR = Steam Methane Reforming; CCS = Carbon Capture and Storage; DAC = Direct Air Capture of CO_2.

All system specifications, life cycle inventories, and environmental indicator results (i.e., Global Warming, Cumulative Energy Demand, and Ecological Scarcity 2021) are available via the following Data Object Identifier (DOI): https://doi.org/10.5281/zenodo.7955951. These inventories link to the UVEK:2022 database in the format ecoSpold1[8], and will also be made available with the UVEK database update.

[8] https://ecoinvent.org/the-ecoinvent-database/data-formats/ecospold1/

6 Conclusions

Modeling considerations and assumptions for generating life cycle inventories for power-to-X supply chains and associated heat and electricity supply in residential areas in a current Swiss context have been presented. The new inventories of these power-to-X systems have been used to compare the environmental performance of such options for residential heat and power supply with conventional technologies such as heat pumps, natural gas, biomethane, and wood boilers as well as natural gas-based hydrogen systems. The environmental performance has been assessed based on impacts on climate change (greenhouse gas emissions), cumulative energy demand and overall environmental impacts according to the Ecological Scarcity method.

Energy carriers addressed in this study include hydrogen, synthetic natural gas (SNG) and methanol – all three of them produced via water electrolysis and in case of SNG and methanol subsequent synthesis with CO_2 from the atmosphere or industrial point sources. Further hydrogen production options, namely methane reforming with and without CCS as well as methane pyrolysis have been included. Water electrolysis includes both hydrogen production in Switzerland and abroad, namely Denmark and Morocco, where large potentials for wind (and PV) power with high yields are available. Hydrogen and synthetic hydrocarbons could be imported from such locations in the future. Energy carrier transport and storage options include transport by truck and pipeline and storage in salt caverns and residential tanks. End-use technologies for hydrogen, SNG, and methanol include small-scale boilers, fuel cells and combined heat and power generation (CHP) units.

The technological maturity of the Power-to-X product systems and other hydrogen production options vary, which influences uncertainties and thus the reliability of LCA results. The uncertainties associated with new inventory data basically reflect the technological development status of the different processes as known today. While, for example, water electrolysis can be considered as an established process with lots of literature and industry data available (see Annex A) and thus comparatively minor associated uncertainties, methane pyrolysis represents the other end of the spectrum of technological maturity and thus higher uncertainties. Also, autonomous hydrogen production via water electrolysis, purely powered by intermittent renewables, has not yet been implemented on the market and the operational performance assumed to compile inventory data still needs to be proven. This difference in reliability of LCA results due to the lack of a common technology maturity must be considered when interpreting the LCA results.

Characterized LCA results show that for most heat and electricity supply options, hydrogen production technology, feedstock type used, and allocation approaches determine results across all impact categories most. In general, hydrogen-fed boilers, CHPs, and fuel cells cause lower GHG emissions, cumulative energy demand and overall environmental impacts than synthetic natural gas and methanol options, as additional processing steps for SNG and methanol production reduce energy efficiency and increase environmental burdens. Further, CO_2 supply can – depending on its origin and the way it is captured – add substantial burdens.

Regarding heat supply options, all hydrogen boiler options cause higher GHG emissions than heat pumps in Switzerland – the hydrogen option with the lowest climate impacts (hydrogen produced in Morocco from wind and PV power at an optimal site, imported to Switzerland) causes about two times higher GHG emissions than the heat pump operated with the average Swiss grid mix and five times higher emissions than a heat pump operated with a Swiss renewable mix. Overall environmental impacts of the “cleanest” hydrogen boiler option are in the same range as those of the heat pump operated with the current grid mix. When considering renewable electricity to operate the heat pump, all hydrogen options have higher overall environmental impacts. CHP and fuel cell systems fed with hydrogen from electrolysis produced with renewable electricity show lower scores than current air-water heat pumps operated with the Swiss grid mix and higher impacts when considering heat pumps operated with renewable sources regarding Global Warming and overall environmental impacts. This is mainly due to the exergy-based allocation for combined heat and power generation, assigning low fractions of burdens to the heat, but comparatively high shares of burdens to electricity, yielding electricity comparable to the current average Swiss grid electricity supply concerning Global Warming and environmental impacts.

Applying a system expansion approach, which can be used to compare environmental burdens of joint heat and power generation with heat from heat pumps (operated with the average grid mix or a renewable source) and electricity from the grid or from renewable sources show similar trends: the hydrogen alternatives based on grid mix cause higher impacts than the combination “heat pump + grid mix”; and the hydrogen alternatives based on renewables also cause higher impacts than the reference combination “heat pump (operated with renewables) and renewable electricity”.

Regarding CCU fuels, i.e., SNG and methanol produced from hydrogen and CO_2 captured at cement and MSWI plants, few key factors determine the LCA results: the biogenic share of CO_2, the heat source for the CO_2 capture and the approach for assigning CO_2 emissions due to fuel combustion to either the fuel end user or the CO_2 point source, where CO_2 is captured. Within this analysis, only using CO_2 captured at an MSWI plant with heat recovery for CO_2 capture for SNG production and heat production using this SNG in a boiler (and assigning combustion related CO_2 emissions to the MSWI plant) can generate heat with a climate impact similar or slightly below direct hydrogen combustion in a boiler (with hydrogen produced via water electrolysis powered by the same electricity source in both cases).

Based on the LCA results of this study, some general conclusions can be provided:

- Hydrogen is – in comparison with SNG and methanol – the preferred electricity-based energy carrier from a purely environmental perspective. In practice, hydrogen is more difficult to store and transport than these alternatives, which requires more changes in terms of infrastructure.
- Again, from a purely environmental perspective, differences between domestic hydrogen production via water electrolysis and import from countries with higher renewable power yields are rather small, as long as electricity from renewables is used. However, potentials for renewable power generation in Switzerland are limited.
- Using hydrogen for residential heat and electricity supply in Switzerland has higher impacts than the reference technologies when the comparison is consistent (i.e., hydrogen relying on renewables is compared to heat pumps operated with renewable electricity or hydrogen produced with the average grid mix is compared to heat pumps operated with the same grid mix). Moreover, from an energy efficiency perspective – i.e., using limited renewable potentials in the most efficient ways – even such renewable-based hydrogen cannot be considered as a preferred option.

As the scope of this study is limited to the analysis of the environmental burdens of power-to-X based heat and electricity supply options in an isolated way on a microscale (applying a so-called “attributional LCA approach”) not considering any system effects, such effects (e.g., regarding resource shortages or limitations, substitution effects, etc.) are not reflected. To address such issues potentially associated with introducing Power-to-X based heat and electricity supply options into the (Swiss) energy and economic system, it is recommended to broaden this limited, technology-centered perspective and to address such systemic impacts, i.e., climate and overall environmental impacts of power-to-X based heat and electricity supply in Switzerland as part of the overall energy system. Scenario-based energy system models linked with LCA could be used for this purpose. Doing so would allow to consider limited renewable potentials as well as changes in heat and electricity demand and specific production and demand profiles over the year and to identify the preferred options for hydrogen and synthetic fuel use versus alternatives in general.

Due to these limitations, the LCA results provided in this report are not suited for decision support on a macroscale, for example regarding the introduction of Power-to-X fuels for heating purposes on cantonal or national level and quantification of the resulting environmental implications without an energy system analysis.

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Annex A

Commercial electrolyzer models' specifications.

Manufacturer	Model	Electrolysis type	Maximum power consumption [kW]	Voltage consumption [V]	Type of current [V]	Space requirement [m²]	Max. system availability [hours/year]	Spec. electricity demand [kWh/Nm³ H2]	Spec. electricity demand [kWh/kgH2]	Useful heat output [kW]	Electrical efficiency [%]	Total efficiency [%]	Stack life [h]	H2 pressure level [bar]	H2 quantity [kg/h]
Enapter	EL 2.1	AEC	2.4	230	AC	0.3		4.8	53.8		62.5		30000	35	0.45
H2 Core Systems GmbH	HydroCab Indoor 2.0 Nm3/h	AEC	10	400	AC/ DC	1	8700	4.8	53.8	2	62.5	92.5	35000	35	0.18
H2 Core Systems GmbH	HydroCab Outdoor 2.0 Nm3/h	AEC	10	400	AC/ DC	1	8700	4.8	53.8	2	62.5	92.5	35000	35	0.18
H2 Core Systems GmbH	HydroCab Indoor 4.5 Nm3/h	AEC	22	400	AC/ DC	2	8700	4.8	53.8	5	62.5	92.5	35000	35	0.4
H2 Core Systems GmbH	HydroCab Outdoor 4.5 Nm3/h	AEC	22	400	AC/ DC	2	8700	4.8	53.8	5	62.5	92.5	35000	35	0.4
ostermeier H2ydrogen Solutions GmbH	EO.05	PEM	7	400	AC	3	8500						35000	20	0.1
ostermeier H2ydrogen Solutions GmbH	EO.10	PEM	14	400	AC	3	8500						35000	20	0.2
ostermeier H2ydrogen Solutions GmbH	EO.15	PEM	20	400	AC	3	8500						35000	20	0.3
ostermeier H2ydrogen Solutions GmbH	EO.20	PEM	27	400	AC	3	8500						35000	20	0.4
ostermeier H2ydrogen Solutions GmbH	EO.25	PEM	33	400	AC	3	8500						35000	20	0.5
H2 Core Systems GmbH	HydroCab Indoor 9.0 Nm3/h	AEC	43	400	AC/ DC	4	8700	4.8	53.8	11	62.5	92.5	35000	35	0.8
H2 Core Systems GmbH	HydroCab Outdoor 9.0 Nm3/h	AEC	43	400	AC/ DC	4	8700	4.8	53.8	11	62.5	92.5	35000	35	0.8
iph Hähn Gmbh	EL20	PEM	105	400	AC	7	8600							30	1.75
Kyros Hydrogen Solutions GmbH	Kyros Electrolyzer 50	PEM	60	400	AC/ DC	7	8650	4.8	53.8	10	62.5		80000	40	0.89
Kyros Hydrogen Solutions GmbH	Kyros Electrolyzer 100	PEM	120	400	AC/ DC	7	8650	4.8	53.8	20	62.5		80000	40	1.78

Manufacturer	Model	Electrolysis type	Maximum power consumption [kW]	Voltage consumption [V]	Type of current [V]	Space requirement [m²]	Max. system availability [hours/year]	Spec. electricity demand [kWh/Nm³ H2]	Spec. electricity demand [kWh/kgH2]	Useful heat output [kW]	Electrical efficiency [%]	Total efficiency [%]	Stack life [h]	H2 pressure level [bar]	H2 quantity [kg/h]
H2 Core Systems GmbH	HydroCab Indoor 18.0 Nm3/h	AEC	86	400	AC/ DC	8	8700	4.8	53.8	22	62.5	92.5	35000	35	1.6
H2 Core Systems GmbH	HydroCab Outdoor 18.0 Nm3/h	AEC	86	400	AC/ DC	8	8700	4.8	53.8	22	62.5	92.5	35000	35	1.6
iph Hähn Gmbh	EL40	PEM	210	400	AC	14	8600							30	3.5
H-TEC SYSTEMS GmbH	ME100/350	PEM	330	400	AC	14	8322							30	4.23
H-TEC SYSTEMS GmbH	ME450	PEM	1000	400		52.8		4.7	53	170	62.9	90		30	260
Kyros Hydrogen Solutions GmbH	Kyros Electrolyzer 200	PEM	240	400	AC/ DC	14	8650	4.8	53.8	40	62.5		80000	40	3.56
Kyros Hydrogen Solutions GmbH	Kyros Electrolyzer 300	PEM	360	400	AC/ DC	14	8650	4.8	53.8	60	62.5		80000	40	5.34
Kyros Hydrogen Solutions GmbH	Kyros Electrolyzer 450	PEM	540	400	AC/ DC	14	8650	4.8	53.8	90	62.5		80000	40	8.01
Kyros Hydrogen Solutions GmbH	Kyros Electrolyzer 600	PEM	720	400	AC/ DC	14	8650	4.8	53.8	120	62.5		80000	40	10.68
AVX/KUMATEC Hydrogen GmbH & Co. KG	PEM-40-100	PEM	110	400	AC	15	8410	4.67	52.3		64.2		80000	40	1.8
AVX/KUMATEC Hydrogen GmbH & Co. KG	PEM-100-25	PEM	28	400	AC	15	8410	4.9	54.9		61.2		50000	100	0.45
H2 Core Systems GmbH	HydroCab Indoor 36.0 Nm3/h	AEC	173	400	AC/ DC	16	8700	4.8	53.8	43	62.5	92.5	35000	35	3.2
H2 Core Systems GmbH	HydroCab Outdoor 36.0 Nm3/h	AEC	173	400	AC/ DC	16	8700	4.8	53.8	43	62.5	92.5	35000	35	3.2
iph Hähn Gmbh	EL80	PEM	420	400	AC	27	8600							30	7
H-TEC SYSTEMS GmbH	ME450/1400	PEM	1400	568	AC	28	8322							30	18.9
Kyros Hydrogen Solutions GmbH	Kyros Electrolyzer 750	PEM	900	400	AC/ DC	28	8650	4.8	53.8	150	62.5		80000	40	13.35
Kyros Hydrogen Solutions GmbH	Kyros Electrolyzer 1000	PEM	1200	400	AC/ DC	28	8650	4.8	53.8	200	62.5		80000	40	17.8

Manufacturer	Model	Electrolysis type	Maximum power consumption [kW]	Voltage consumption [V]	Type of current [V]	Space requirement [m²]	Max. system availability [hours/year]	Spec. electricity demand [kWh/Nm³ H2]	Spec. electricity demand [kWh/kgH2]	Useful heat output [kW]	Electrical efficiency [%]	Total efficiency [%]	Stack life [h]	H2 pressure level [bar]	H2 quantity [kg/h]
Kyros Hydrogen Solutions GmbH	Kyros Electrolyzer 1500	PEM	1800	400	AC/DC	28	8650	4.8	53.8	300	62.5		80000	40	26.7
Kyros Hydrogen Solutions GmbH	Kyros Electrolyzer 2000	PEM	2400	400	AC/DC	28	8650	4.8	53.8	400	62.5		80000	40	35.6
Kyros Hydrogen Solutions GmbH	Kyros Electrolyzer 150	PEM	180	400	AC/DC	28	8650	4.8	53.8	30	62.5		80000	40	2.67
Enapter	AEM Multicore	AEC	1058	400	AC	29.7		4.8	53.8		62.5		35000	35	18.75
AVX/KUMATEC Hydrogen GmbH & Co. KG	PEM-40-1000	PEM	1100	400	AC	30	8410	4.87	54.6		61.6		80000	40	18
elogen	E200	PEM	1000	400	AC/DC	45	8322	4.4	49.3						18
Hydrogenics (Cummins Inc.)*	HySTAT 10	AEC	115		AC	54		4.9	54.9					10	0.88
Hydrogenics (Cummins Inc.)*	HySTAT 15	AEC	155		AC	54		4.9	54.9					10	1.33
Hydrogenics	HySTAT 30	AEC	275		AC	54								10	2.67
iph Hähn Gmbh	EL220	PEM	1155	400	AC	55	8600							30	20
elogen	E500	PEM	2500	400	AC/DC	60	8322								45
Ecoclean GmbH	EcoLyzer P200	AEC	1000	10	AC	70	8568	4.8	53.8	330	62.5	95.5	70000	1	16.82
Hydrogenics (Cummins Inc.)	HySTAT 60	AEC	550		AC	89		5.2	58.3					10	5.42
Hydrogenics	HySTAT 70	AEC	675		AC	89								10	6.67
Hydrogenics	HySTAT 100	AEC	800		AC	89								10	8.96
elogen	E1000	PEM	5000	400	AC/DC	90	8322	4.4	49.3						90
AVX/KUMATEC Hydrogen GmbH & Co. KG	EcoLyzer A300	AEC	1500	10	AC	105	8410	4.5	50.4	495	66.7	99.7	80000	30	25.23
Ecoclean GmbH	EcoLyzer A600	AEC	3000	10	AC	105	8568	4.5	50.4	990	66.7	99.7	80000	30	50.46
Ecoclean GmbH	EcoLyzer P400	AEC	2000	10	AC	105	8568	4.8	53.8	660	62.5	95.5	70000	1	33.64
PlugPower Inc.	5MW ELECTROLYZER	PEM	5000		AC	120								40	90
elogen	E2000	PEM	10000	400	AC/DC	180	8322	4.8	53.8						180

Manufacturer	Model	Electrolysis type	Maximum power consumption [kW]	Voltage consumption [V]	Type of current [V]	Space requirement [m²]	Max. system availability [hours/year]	Spec. electricity demand [kWh/Nm³ H2]	Spec. electricity demand [kWh/kgH2]	Useful heat output [kW]	Electrical efficiency [%]	Total efficiency [%]	Stack life [h]	H2 pressure level [bar]	H2 quantity [kg/h]
Hydrogenics (Cummins Inc.)	HyLyzer 200	PEM	788		AC	198		3.95	44.3		75.9			30	17.96
Hydrogenics (Cummins Inc.)	HyLyzer 250	PEM	988		AC	198		3.95	44.3		75.9			30	22.46
Hydrogenics (Cummins Inc.)	HyLyzer 400	PEM	1580		AC	198		3.95	44.3		75.9			30	35.92
Hydrogenics (Cummins Inc.)	HyLyzer 500	PEM	1975		AC	198		3.95	44.3		75.9			30	45
elogen	E3000	PEM	15000	400	AC/DC	270	8322	4.8	53.8						270
green-H2-systems	green Electrolyzer gEL400	PEM	2000	400	AC	300	8600	4.5	50.4		66.7		80000	35	36
green-H2-systems	green Electrolyzer gEL600	PEM	3000	400	AC	300	8600	4.5	50.4		66.7		80000	35	54
Sunfire GmbH*	Sunfire-HyLink SOEC	SOEC	2475		AC	300		3.6	40.3		80			1	67.5
elogen	E4000	PEM	20000	400	AC/DC	360	8322	4.8	53.8						360
green-H2-systems	green Electrolyzer gEL800	PEM	4000	400	AC	400	8600	4.5	50.4		66.7		80000	35	72
green-H2-systems	green Electrolyzer gEL1000	PEM	5000	400	AC	400	8600	4.5	50.4		66.7		80000	35	90
Sunfire GmbH*	Sunfire-HyLink Alkaline	AEC	10481		AC	450		4.7	52.7		63.8		90000	30	200.7
elogen	Indoor	PEM		400	AC/DC		8322								
H2 Core Systems GmbH	Multicore MC 225/450	AEC	504	400	AC			4.8	53.8	165	62.5		35000	35	9.3
H2 Core Systems GmbH	Multicore MC450	AEC	1008	400	AC			4.8	53.8	330	62.5		35000	35	18.7
HIAT gGmbH	PURIFIER	PEM	2					5	56.0		60		40000	40	0.05
HIAT gGmbH	CUSTOMIZER	PEM	13					5	56.0		60		40000	40	0.23
HIAT gGmbH	SUPPLIER	PEM	35					5	56.0		60		40000	40	0.63
HIAT gGmbH	STORAGER	PEM	100					5	56.0		60		40000	40	1.79
Hoeller Electrolyzer GmbH	Prometheus S Stack	PEM	120	300	DC			4.83	54.1		62.1		80000	40	1.9

Manufacturer	Model	Electrolysis type	Maximum power consumption [kW]	Voltage consumption [V]	Type of current [V]	Space requirement [m²]	Max. system availability [hours/year]	Spec. electricity demand [kWh/Nm³ H2]	Spec. electricity demand [kWh/kgH2]	Useful heat output [kW]	Electrical efficiency [%]	Total efficiency [%]	Stack life [h]	H2 pressure level [bar]	H2 quantity [kg/h]
Hoeller Electrolyzer GmbH	Prometheus L Stack	PEM	1.8	616	DC			4.85	54.3		61.9		80000	40	27.8
Hydrogenics (Cummins Inc.)	HyLyzer 1000	PEM	5375		AC			4.3	48.2		69.8			30	90
ITMPower	HGAS1SP	PEM	700	400	AC									20	11
ITMPower	HGAS2SP	PEM	1390	11000	AC									20	22
ITMPower	HGAS3SP	PEM	2350	11000	AC									20	36
ITMPower	HGASXMW	PEM	10070	11000	AC									20	168.75
McPhy Energy S.A.	Piel Baby	AEC	3											1	0.04
McPhy Energy S.A.	Piel P	AEC	9											2.5	0.14
McPhy Energy S.A.	Piel M	AEC	26											2.5	0.4
McPhy Energy S.A.	Piel H	AEC	60											8	0.9
McPhy Energy S.A.	McLyzer 10-30	AEC	50		DC			4.5	50.4		66.7			30	0.9
McPhy Energy S.A.	McLyzer 20-30	AEC	100		DC			4.5	50.4		66.7			30	1.8
McPhy Energy S.A.	McLyzer 100-30	AEC	500		DC			4.5	50.4		66.7			30	9
McPhy Energy S.A.	McLyzer 200-30	AEC	1000		DC			4.5	50.4		66.7			30	18
McPhy Energy S.A.	McLyzer 400-30	AEC	2000		DC			4.5	50.4		66.7			30	36
McPhy Energy S.A.	McLyzer 800-30	AEC	4000		DC			4.5	50.4		66.7			30	72
PlugPower Inc.	1MW ELECTROLYZER	PEM	1000	400	AC			4.49	50.3		66.8		80000	40	18
PlugPower Inc.	ALLAGASH ELECTROLYZER STACK 50	PEM		64									80000		4.5
PlugPower Inc.	ALLAGASH ELECTROLYZER STACK 200	PEM		260									80000		18
PlugPower Inc.	MERRIMACK ELECTROLYZER STACK 10	PEM		54									80000		0.9

Manufacturer	Model	Electrolysis type	Maximum power consumption [kW]	Voltage consumption [V]	Type of current [V]	Space requirement [m²]	Max. system availability [hours/year]	Spec. electricity demand [kWh/Nm³ H2]	Spec. electricity demand [kWh/kgH2]	Useful heat output [kW]	Electrical efficiency [%]	Total efficiency [%]	Stack life [h]	H2 pressure level [bar]	H2 quantity [kg/h]
PlugPower Inc.	MERRIMACK ELECTROLYZER STACK 30	PEM		163									80000		2.7
Siemens Energy	Silyzer 300 Minimalbeispiel	PEM													100
Siemens Energy	Silyzer 300 Maximalbeispiel	PEM													2000
thyssenkrupp Uhde Chlorine Engineers *	20 MW module	AEC	18000		DC			4.5	50.4		66.7			0	360

Reviewer’s report