Just Transition in a Renewable Energy Riche Environment

Potential Role of Green Hydrogen

Knowledge Product
& Cases Studies

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AFRICAN DEVELOPMENT BANK GROUP

CIF CLIMATE INVESTMENT FUNDS

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List of Abbreviations and Acronyms

AEL	Alkaline water electrolysis
AFLH	Annual full load hours
AfDB	African Development Bank
CAPEX	Capital expenditure
CGH_2	Compressed gaseous hydrogen
CH_3OH	Methanol
CIF	Climate Investment Funds
CO_2	Carbon Dioxide
CPI	Corruption Perceptions Index
EU	European Union
GH_2	Gaseous hydrogen
H_2	Hydrogen
IEA	International Energy Agency
kWh	Kilowatt Hour
kWp	Kilowatt Peak
LH_2	Liquid hydrogen
LNH3	Liquid ammonia
LOHC	Liquid Organic Hydrogen Carrier
N_2	Nitrogen
NDC	Nationally Determined Contributions
NH_3	Ammonia
OPEX	Operational expenditure
PEMEL	Polymer electrolyte membrane eletrolysis
PPP	Public Private Partnership
PtL	Power-to-Liquid
PtX	Power-to-X
PV	Photovoltaic
RWGS	Reverse water gas shift reaction
SOEL	Solid oxide eletrolysis
TOL	Toluol as a promising LOHC

Executive Summary

The study at hand aims at proposing an preliminary framework that encourages the deployment of green hydrogen in three preselected African countries. The three countries were selected in consulta-tion with the African Development Bank (AfDB) after screening 29 African member countries under the Climate Investment Fund (CIF). Several criteria were considered covering the following aspects:

- Geographical spread; Northern, Eastern, Western, Central and Southern Africa
- Availability of different renewable energy resources
- Technical aspects for green hydrogen e.g. water availability and salt cavern locations
- Existence of renewable energy power systems and infrastructure

Several filtration processes have been conducted using a dedicated list of selection criteria. As a re-sult, **Egypt, Kenya and Ghana** were finally selected. The analysis in each country establishes an adequate knowledge product to contribute to longterm strategies to achieve low carbon and climate resilient development. It considers specific characteristics of renewable energy resources and generation mix, barriers and opportunities of green hydrogen production, presence of a relatively well-developed fossil energy system (e.g. already existing natural gas grid) and possible influence on green hydrogen production and transport, possible technology pathways for production of green hy-drogen and it's derivate: Power-to-X (PtX) or Power to Liquids (PtL) products and finally hydrogen production costs and their future trends.

The successful combination of production, transport, storage and utilisation of green hydrogen is es-sential for a secure, sustainable and economical energy supply in the future. The three cases studies have been accordingly preceeded by a generalized model of green hydrogen supply chain that will be commonly applied on the three countries. The technology costs in the hydrogen supply chain electrolyzer are elaborated in the annex. The cost estimates based on the extensive desk research and references as mentioned in the annex. It should be noted that especially the costing information carries some level of uncertainty as none of the proposed plants are realised nor under planning.

An optimization model has been utilized to determine the hydrogen production costs and the optimal configuration of a respective plant. The objective of the model is to minimize the location-specific hydrogen production cost using water electrolysis powered with available renewable resources in each country; photovoltaics, onshore wind power, geothermal energy or hydropower by determining the optimal system configuration. The assumptions used in the model regarding the techno-economic parameters of the components refer to the year 2030.

As a result, the Consultant developed case studies represent different pathways and options of green hydrogen production. Each case study illustrates: i) the renewable energy resources of that can be allocated to hydrogen production. ii) the supply and production of green hydrogen and the renewable energy required. iii) technical evaluation hydrogen production and its derivates and other PtX products, iv) basic design of possible plants. v) processing steps, storage potential, energy flow and ef-ficiencies and the overall supply costs.

1. Egypt as a Hydrogen Exporter

The case study of Egypt proposed Hydrogen (H_2) as a product. The installed renewable capacities of solar and wind power plants produce 695 GWh annually. From this amount of electricity, approximate-ly 12,175 t of green H_2 (equivalent to 406 GWh) can be generated. Since energy losses occurs along the H_2 supply chain (e.g. during electrolysis) and part of the electricity produced is not used (excess energy), the amount of energy stored in the H_2 is inevitably less than the amount of electricity pro-duced. t . With a 100 MW PEM electrolyser, the resultant specific production capacity is of a specific production capacity of 2.0 t/h and 6050 annual full load hours (AFLH).

The selected site for H_2 production is located south-east of Cairo on the Gulf of Suez. This location has a high potential for both wind and solar power. The close proximity to the coast of the Red Sea is an elementary advantage with regard to the necessary water supply for electrolysis. Furthermore, there is already a well-developed infrastructure and an existing (natural gas) pipeline system. Due to the availability of salt caverns, the H_2 can be stored very cost-effectively. An electricity storage facili-ty is not required. The selected H_2 storage capacity amounts 1390 t.

The H_2 production cost equals to 2.7 €/kg.H_2 which is equivalent to **0.08 €/kWh.H_2**. The estimated supply cost equals to **0.1 €/kWh.H_2.**

2. Kenya as an Ammonia Exporter

In Kenya, Ammonia (NH3) is proposed as a final product. Beside solar and wind energy potential, Kenya has a high potential for the use of geothermal energy in green hydrogen (ammonia) production. Electricity from geothermal energy can already be purchased from the public grid. The selected loca-tions for using wind energy are in the region around Lake Turkana. A wind farm already exists on the south coast in the Loiyangalani District. An area close to the Lake Turkana wind farm was chosen as the best possible location for green hydrogen production.

With a 100 MW AEL electrolyser, ammonia can be produced with a specific production capacity of 2.0 t/h and 7600 annual full load hours (AFLH). The cryogenic nitrogen (N_2) purification process is chosen for the extraction of pure N_2 from ambient air and the Haber-Bosch process for the production of NH_3. According to this setting, the total production potential equals to 86,800 t of green NH3 that can be produced annually from the 15,300 t of H_2 provided. The total energy demand for the supply of 86,800 t of green NH3 (~451 GWh) is 966 GWh. Around 937 GWh of this amount is generated from PV, wind and geothermal energy.

The H_2 storage capacity is 17 t and is thus significantly less than 50 % of the maximum daily output of the electrolyser. The reasons for the low installed storage capacity are presumably the high specif-ic costs of H_2 storage in pressure gas tanks and the availability of continuous grid electricity.

The NH_3 production cost equals to 2.23 €/kg.H_2 which is equivalent to 0.07 €/kWh.H_2. The estimated supply cost equals to 0.12 €/kWh.H_2.

3. Ghana as a PtL Fuels Producer

Ghana has a relatively even potential for solar energy nationwide. Electricity from hydropower is an-other option for the use of renewable energy sources and can be purchased from the public electricity grid. An area east of Accra was chosen as a potential site for PtL fuel production. This location already offers good infrastructure and easy access to the electricity grid. Furthermore, the proximity to the coast offers short national transport distances for future export.

PtL (Power-to-Liquid) fuel is proposed as a product for this case study. With a 100 MW AEL electro-lyser of a specific production capacity of 2.0 t_(H_2)/h and 3200 annual full load hours (AFLH). The raw materials for the production of PtL fuels are H_2 and CO_2. Around 341 GWh are generated annually by the installed PV plant and 33 GWh of electricity from hydropower is annually purchased from the public grid. From the 6,500 t of H_2 provided, about 13,100 t of PtL fuel (~157 GWh) can be produced annually.

The H_2 storage capacity is 13 t and is thus significantly less than 50 % of the maximum daily output of the electrolyser. The reasons for the low installed storage capacity are presumably the high specif-ic costs of H_2 storage in pressure gas tanks and the availability of continuous grid electricity.

The PtL production cost equals to 2.95 €/kg.H_2 which is equivalent to 0.09 €/kWh.H2. The estimated supply cost equals to 0.16 €/kWh.H_2.

1. Introduction

The overarching objective of this assignment is to raise the awareness of Green Hydrogen within the AfDB network to investigate and analyse various options to contribute to longterm strategies to achieve low carbon and climate resilient development. In this context, the report at hand brings a greater clarity of the potential of green hydrogen in Africa. It also develops the knowledge to support AfDB in its role of the Just Transition Initiative to establish the framework of green hydrogen deployment and contribution to long-term strategies to achieve low carbon and climate resilient development.

Three African countries of rich renewable energy resources have been selected under this assignment: Egypt, Kenya and Ghana. The selection process has been based on various criteria to ensure the diversity of the selected countries in terms of their geoghrapicsal spread, renewable energy resources, hydrogen technical aspects as well as existence of renewable energy power systems and infrastructure.

The three countries show high potential for the production of green hydrogen. The report will accordingly describe the case study for each country to present a green hydrogen energy system. all the necessary background information's on various possibilities for the production, storage and transport of green hydrogen are explained. An optimisation model is utilised to determine the hydrogen production costs and the optimal configuration of a corresponding plant. Furthermore, a scenario for the export of hydrogen based green energy is evaluated. For each country, a particularly promising export scenario is selected on the basis of the country specific conditions and the supply costs are calculated. The three case studies are as follows:

1. Egypt as a Hydrogen Exporter
2. Kenya as an Ammonia Exporter
3. Ghana as a PtL Fuels Producer

The following chapters pave the way towards the case studies through a general explanation of green hydrogen supply chain (chapter 2), which is common along all case studies. This covers its main stages; feedstock, electrolysis and logistics. The optimization model will then be proposed to estimate the optimum hydrogen production as well as calculate its supply cost. Finally, the case studies are presented for each country explaining renewable energy resources, hydrogen production and its derivates, proposed electrolysis plants, processing steps, storage potential, energy flow and efficiencies and the overall supply costs.

The following sections provides a brief overview on hydrogen global status, potential applications in various sectors, potential production of green hydrogen and common barriers and opportunities of green hydrogen production.

1.1 Hydrogen Global Status

Hydrogen is used almost exclusively as a material. In 2020, the hydrogen amount used worldwide was around 90 million tonnes. The annual demand has increased by 50% in the last twenty years [1]. As shown in the left pie chart of Figure 1, the majority of the global hydrogen demand comes from crude oil refining and the chemical industry. Annually, crude oil refineries consume almost 40 million tonnes of hydrogen as feedstock and reactants or as an energy source. Around 45 million tonnes of hydrogen are used every year in the chemical industry, where hydrogen is mainly deployed to produce ammonia and methanol. While ammonia is a central feedstock for the production of fertilisers, methanol is further processed into a variety of downstream products. For example, methanol is used as a raw material for the production of many types of glue or resins. Hydrogen use in the production and processing of metals contributes 5% to the global hydrogen demand.

Hydrogen in its molecular form rarely occurs in nature and is chiefly found in chemical bonds. Therefore, production processes are necessary to yield pure hydrogen. Both different primary materials and different processes are used to generate hydrogen. The hydrogen used today is almost exclu-sively produced from fossil raw materials, apart from a few exceptional cases. As highlighted in the right pie chart of Figure 1, most of the globally produced hydrogen originates from natural gas (about 48 %). Hydrogen production from coal amounts to 18 %, and 30 % of dedicated hydrogen produc-tion is from oil. The remaining 4 % is produced from electricity via water electrolysis [1, 2].

Hydrogen can be used in a variety of applications. Basically, a distinction can be made between its energetic application and its use as a material. In material use, the chemical properties of the hydrogen molecule are exploited in the form of reactions with other chemical elements. Thus, hydrogen can be used to form new chemical compounds together with other elements or to change the composition and properties of existing compounds. On the other hand, hydrogen can be used to generate energy. Here, the chemical energy bound in the hydrogen is converted into electricity and/or heat.

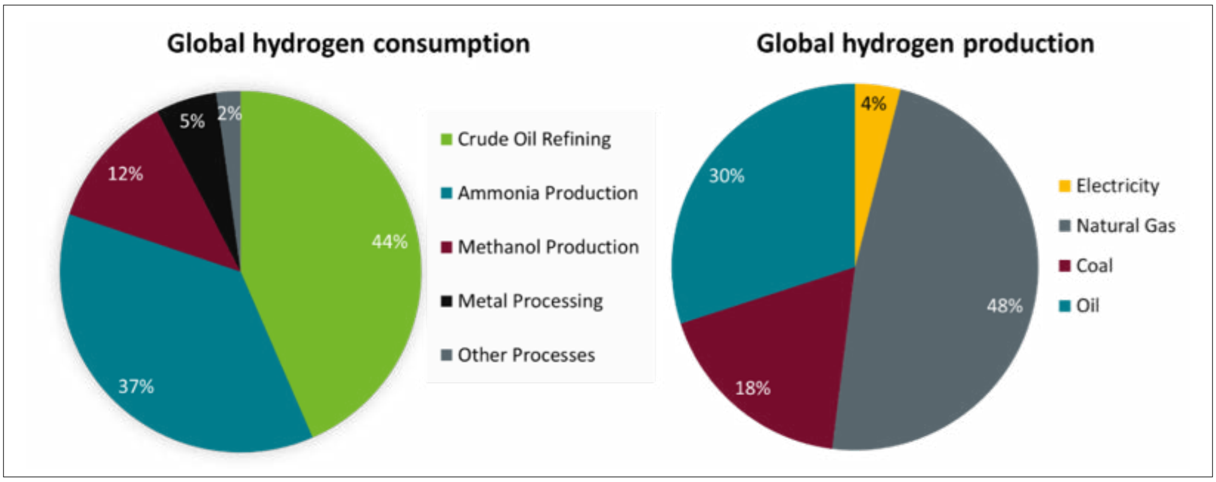

Figure 1: Shares on global hydrogen consumption and production
Left: Share of the most important applications in today's global hydrogen consumption [1]
Right: Share of primary energy sources used for today's global hydrogen production [2]

1.2 Hydrogen Applications in Various Sectors

As international climate protection goals are to be achieved, fossil energy sources will have to be al-most completely replaced by greenhouse gas-neutral energy sources within the next few decades. In addition to the use of biomass and the direct use of renewable electricity, green hydrogen will most likely play a central role in the substitution of fossil energy carriers. The following table shows areas of application in which green hydrogen can replace fossil fuels in the future. The various applications are classified into the three sectors:

- Mobility
- Industry
- Electricity and Heat

Hydrogen-powered vehicles can be used in almost all areas of the transport sector. While battery electric vehicles is preferably suitable for short distances, fuel cell mobility or mobility using synthetic fuels will tend to be used for heavier vehicles and longer ranges.

Nowadays in the industrial sector, fossil raw materials are not only used as energy sources, but also as basic materials in many processes. Examples of this are the production of plastics, which is largely based on crude oil, or the production of fertilisers, which requires natural gas. Green hydrogen plays a crucial role in the transformation of the industrial sector towards climate neutrality.

The provision of electricity and heat is responsible for a large proportion of the total CO_2 emissions. The chemical energy stored in hydrogen can be converted into heat and electricity using direct combustion or fuel cell technology. If green hydrogen is used, heat and electricity are climate neutral.

		APPLICATION OF HYDROGEN	STATUS OF DEVELOPMENT	LONG-TERM DEVELOPMENT POTENTIALS
MOBILITY SECTOR	AVIATION	•Production of PtL-fuels as aviation fuel •H_2 as aviation fuel	•The use of H_2 will require new aircraft systems •Airbus is currently researching various H_2 aircraft concepts •PtL production not yet used on a large scale	•Direct combustion of H_2 (short and medium-haul flights) •H_2 fuel cell (FC) aircraft •Increased use of SAF for longer-haul flights
MOBILITY SECTOR	SHIPPING	•Ammonia as fuel •H_2 as fuel	•Announcement that the first 100% ammonia-fuelled marine engines will be available as early as 2023 and that ammonia retrofit packages for existing ships will be offered from 2025 •Since the early 2000s, coastal and short-range vessels with H_2 FC power have been demonstrated	•H_2-based fuels for large oceangoing vessels (ammonia as a fuel for combustion engines) •H_2-powered FC ships: Passenger ship, ferries, roll-on/ roll-of vessels, tugs
MOBILITY SECTOR	RAIL TRANSPORT	•PtL fuel •H_2-powered FC train	•H_2 and FC technologies are already being used for rail transport in some countries •Worldwide, interest in H_2 trains is growing •Various stages of development and deployment for passenger trains, H_2 trams, line-haul and switching locomotives	•In areas where the direct electrification of lines is difficult or too expensive, the use of Rail applications with FC offer a high potential for decarbonisation
MOBILITY SECTOR	ROAD TRANSPORT	•H_2-powered FC electric vehicles - cars	•H2-powered passenger cars have been under development for several decades •Although some car manufacturers, especially from Asia, are offering FC passenger cars as series models, their number on the roads has been small up to now.	•A significant increase in FC cars is to be expected •More major car manufacturers are developing prototypes •Expansion of H_2 filling stations must increase significantly at the same time
MOBILITY SECTOR	ROAD TRANSPORT	•H_2-powered FC electric vehicles – Trucks	•H_2 driven trucks have so far only been produced as prototypes for use in pilot projects. •Various concepts are currently being developed for storing H_2 on board of the truck •The Hyundai Xcient Fuel Cell is the only H_2 powered truck that is already in use in larger numbers	•Higher ranges can currently be achieved with FC vehicles than with battery-electric alternatives
MOBILITY SECTOR	ROAD TRANSPORT	•H_2-powered FC electric vehicles - busses	•Several manufacturers (e.g. Van Hool, Solaris) offering series-production vehicles	•A significantly increase can be assumed in the coming years
INDUSTRY SECTOR	STEEL MAKING	•Direct reduced iron (DRI) process for steel production	•The direct reduction of iron ore with the help of H_2, though, has not yet been realised on an industrial scale. Various steel manufacturers have announced pilot projects and expect to be able to produce climate-neutral steel using H_2 by 2030 at the latest	•The combination of H_2-based direct reduction and electric arc furnance makes it possible to produce steel exclusively based on renewable energies. However, the electricity demand of this production route (for the production of the green H_2 and the operation of the electric arc furnace) is enormously high

	REFINERY	•Removing impurities (desulphurisation process) •Conversion of long-chain hydro-carbons (heavy oils) into short-chain hydrocar-bons (light oils) (hydrocracking process)	•Large use of grey H_2 but no large-scale use of green H_2	•Replacement of grey H_2 with green H_2 •Conversion of the production process to e-fuels based on green H_2
	CHEMICAL INDUSTRY	•Ammonia production (e.g. for fertilisers) •Methanol production (e.g. for glue or resins)	•Methanol and ammonia are nowadays produced almost exclusively from grey H_2 based on natural gas	•Replacement of grey H_2 with green H_2 •Green methanol production may lead to an increased demand for methanol in the future to replace many oil and gas based feedstocks. Ethylene and propylene are, for example, starting materials for the production of a large number of plastics. The use of green methanol can completely eliminate crude oil and natural gas in the chemical industry sector
ELECTRICITY AND HEAT	**GENERATION OF PROCESS HEAT**	•Green H_2 to provide process heat, especially at a high-temperature level	•No large-scale use of green H_2	•H_2 can be combusted directly in appropriate burners or heating boilers •Under certain circumstances, the use of high-temperature FC (SOFC) is also possible, which at least enable the provision of heat at a temperature level of up to 700 °C
	ENERGY STORAGE	•H_2 gas turbines and FC power plants can be used for the large-scale reconversion of H_2 into electricity	•Gas turbines currently used in combined cycle power plants are partly able to operate with H_2 contents of maximum 30 % in the natural gas. Turbines that can run on pure H_2 are not yet available in the MW power range. Companies such as Siemens Energy and Kawasaki are working on the development of such H_2 turbines. For the use of FC power plants for the large-scale reconversion of H_2, the existing systems must be scaled up	•When H_2 is converted back into electricity, part of the energy is necessarily released in the form of heat, regardless of whether turbines or fuel cells are used. This waste heat can be extracted via a water circuit and used as process heat, for heating of residential buildings (district heating) or to heat drinking water. This principle is called combined heat and power (CHP)
	HEAT SUPPLY FOR BUILDINGS	•The application of green H_2 is an option to replace fossil natural gas and to reduce greenhouse gas emissions in the building sector	•FC heating systems are already offered by various suppliers and are mostly based on PEM fuel cells	•H_2 can be mixed with natural gas and burned in gas condensing boilers connected to the pipeline network. Provided the necessary adaptation of the infrastructure (e.g. pipelines and heating systems), a gradual increase in the proportion of H_2 in natural gas is conceivable •H_2 can also take place in stationary, decentralised FC heating systems for domestic energy supply

Table 1: Overview of potential hydrogen applications in different sectors [IEA, 2021: Global Hydrogen Review 2021]

1.3 Potential of Green Hydrogen

In the course of global efforts to mitigate climate change and the accompanying advancing defossili-sation (i.e., the substitution of fossil raw materials), the importance of hydrogen produced in a green-house gas-neutral way is likely to increase in the future. Thereby, green hydrogen - i.e., hydrogen pro-duced from renewable electricity by means of electrolysis - offers the best prerequisites for a timely scaling of production while at the same time minimising greenhouse gas emissions.

On the one hand, green hydrogen can substitute grey hydrogen in existing applications. On the other hand, in the course of increased sector coupling, green hydrogen can also be increasingly used as a greenhouse gas neutral energy carrier in the future, for example, in the mobility sector.

For the cross-sector, medium-term development of the hydrogen market, various ramp-up scenarios were created within the scope of this study. Figure 2 shows that the demand for green hydrogen is likely to be subject to dynamic growth in the coming decades. In a progressive scenario, the demand for green hydrogen could almost reach the volume of today's hydrogen consumption as early as 2030. Even in a conservative scenario, by 2045 at the latest, the demand for green hydrogen will ex-ceed the current consumption of fossil-based hydrogen. Green hydrogen is becoming a relevant en-ergy carrier in the global energy mix, which will find its way into many sectors.

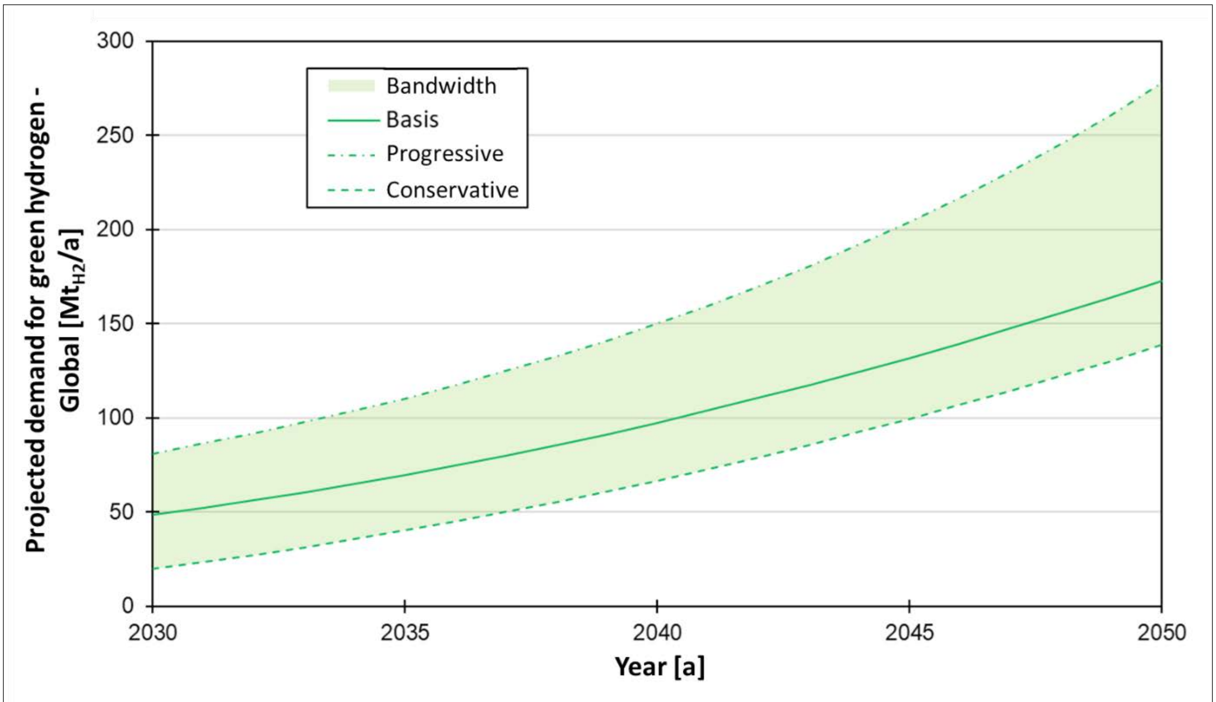

Figure 2: Forecasted development of global green hydrogen demand
Values are based on an evaluation of [3-8]

The shares of individual sectors respectively applications in the future consumption of green hydrogen are currently difficult to forecast. Still, it is considered almost certain that large quantities of hydrogen will be needed in the chemical industry and steel making to enable climate neutral production. In these fields of application, hydrogen based solutions represent the only viable option for the complete substitution of fossil raw materials. Furthermore, future climate neutral electricity systems, which primarily use fluctuating renewable energies such as wind and photovoltaics, will, in all likelihood, rely on green hydrogen as a long-term storage medium. In contrast, there are sectors, for example, mobility and heating, where it is not yet possible to predict the extent of future hydrogen use. Hydrogen based solutions can be used in these areas but, in many cases, compete with direct electric solutions (e.g., fuel cell electric vehicles vs. battery electric vehicles).

Against the background of the foreseeable market development, many countries have developed strategies and plans in recent years to initiate the rampup of a hydrogen economy. Figure 3 provides an overview of the countries' activities regarding the development of national hydrogen strategies. By June 2021, 12 countries and the European Union (EU) had published national hydrogen strategies. In another 19 countries, corresponding strategies were being developed.

The published hydrogen strategies show that the countries have different priorities in developing the hydrogen economy. Countries such as Germany, Japan and the Netherlands, for example, are focusing on importing green hydrogen in order to use it to reduce greenhouse gas emissions in their economies. On the other side, countries such as Chile, Australia and Morocco are focusing primarily on the opportunities that can arise from the export of green hydrogen [9]. In the African context, Egypt and Morocco have published their hydrogen strategies. In addition, potential national strategies are currently being prepared several other countries.

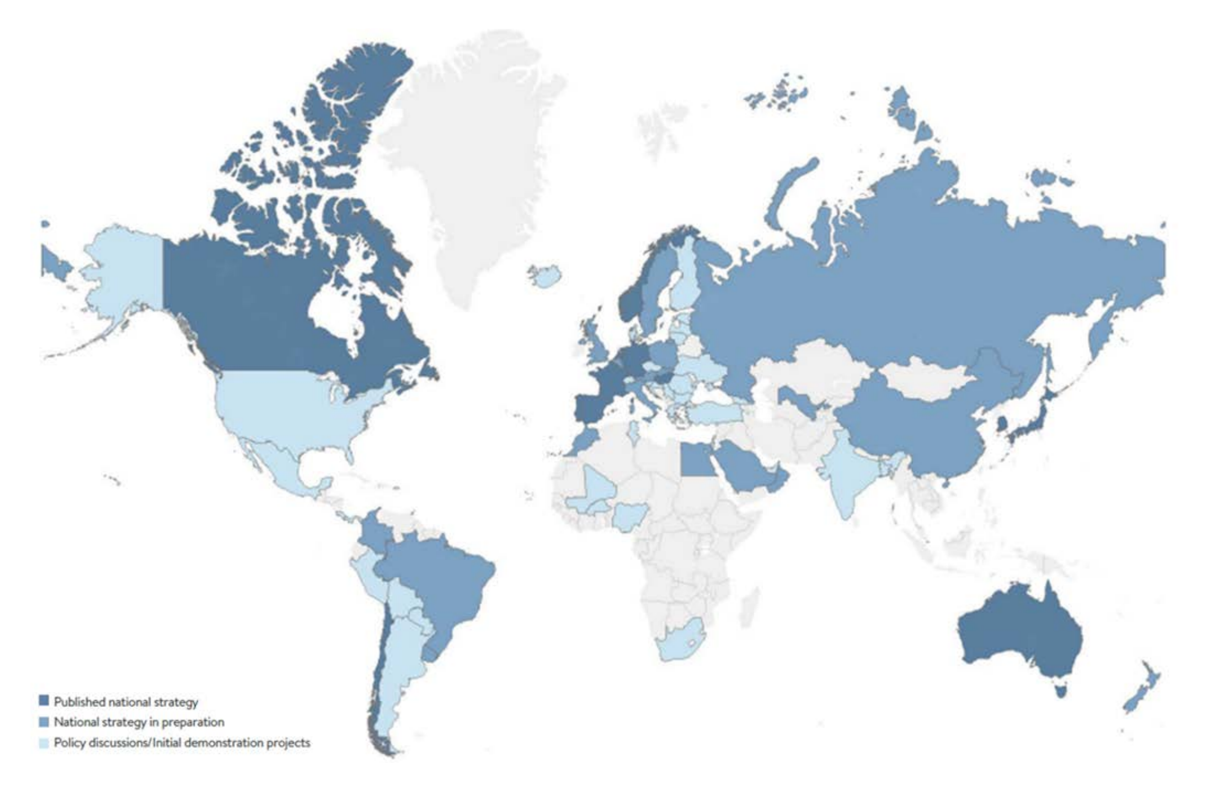

Figure 3: Overview of activities worldwide towards national hydrogen strategies, status 06/2021 [9]

1.4 Barriers and Opportunities of Green Hydrogen Production

In order to achieve climate neutrality as prescribed in the Paris Agreement, the energy supply of all sectors must almost completely be switched over to renewable energy sources. To achieve this goal renewable, greenhouse gas neutral gaseous and/or liquid energy carriers are needed in addition to green electricity. This applies in particular to industries and applications in which battery electric solutions can only be used to a limited extent or not at all due to technical limitations. Green hydrogen can be used in almost all sectors and thus offers the possibility of making renewable electricity available for use cases in which the implementation of direct electric solutions is questionable or impossible. Ex-amples are:

- Use as a fuel for heavy duty vehicles, such as trucks, busses, or trains,
- Use as a fuel in smaller marine applications, such as ferries or river boats,
- Use as a coal substitute for the reduction of iron ore in steel production,
- Use as an energy carrier for the supply of heat, especially high temperature heat for certain indus-trial applications,
- Use as an energy storage medium for stabilising power grids with highly fluctuating supply of electricity from renewable energies.

Beyond that, there are some applications in which green hydrogen derivatives are likely to be used in the future. This means that the hydrogen is not used directly, but is first processed into another ener-gy carrier or raw material:

- Green ammonia as a feedstock for a greenhouse gas-neutral fertiliser industry,
- Green methanol as a feedstock for the chemical industry,
- Green Power to Liquid (PtL) fuels for aviation and shipping,
- Liquid hydrogen as fuel for aircraft.

A detailed overview of possible applications for hydrogen and their potential can be found in Table 1.

In addition to the opportunities that green hydrogen offers on the user side with regard to the substitution of fossil energy sources and the reduction of greenhouse gas emissions, economic opportunities can also arise from the production of green hydrogen. Thus, countries can reduce their dependence on fossil energy imports with the help of green hydrogen.

Furthermore, new opportunities for exporting energy are opening up for renewable energy rich coun-tries. It is currently assumed that densely populated industrialised countries with a high energy demand (e.g. Japan, the EU states or China) will still be dependent on energy imports in a future without fossil fuels. Therefore, it is highly likely that a global market for renewable energy will emerge within the next decades. In such a market, industrialized countries with a high demand for energy would import energy from regions that have a promising availability of renewable energies such as wind and solar and thus relatively lowcost green energy. Since gaseous and liquid energy carriers (i.e. energy rich molecules) can be transported over longer distances much more easily, with less loss and more flexibly than electrical energy (i.e. as electrons), from today's perspective there is much to sug-gest that this potentially developing global renewable energy market will likely be based on green hydrogen and/or its derivatives. Countries that have particularly good conditions for the production of such renewable secondary energy carriers due to their geographical location (i.e. high regenerative energy supply) and largely unused land potential have the opportunity to act as exporters of green energy on the world market in the future.

The development of an (exportoriented) hydrogen economy can contribute to economic development and growing prosperity in African countries. Thus, local value creation can be supported sustainably through the development of green hydrogen production and export capacities as well as the associated services. Investments in capacities for renewable electricity generation and hydrogen production, but also transport or storage infrastructure strengthen the exporting countries and thus improve their global competitiveness. In African countries that currently export fossil fuels, new, climate neutral sources of income can emerge and gradually replace less sustainable business models.

In addition to the opportunities arising from the export of hydrogen, investments in green hydrogen can also help to increase the stability and security of the national energy supply. For instance, many African countries currently lack a reliable electricity supply. Investment in green hydrogen can help overcome the lack of reliable electricity supply by accelerating the deployment of renewable energies. Thus, investments in green hydrogen inevitably lead to improvements in national, regional, and local condi-tions for renewable electricity generation. These conditions include, for example, the necessary know how and infrastructure in the respective African country. Finally, successfully implemented green hydrogen projects ensure that the development of a reliable national energy supply based on renewable energies can subsequently be realized much more easily.

In some regions of Africa, not only a secure energy supply but also a reliable supply of clean water is not guaranteed at all times. If planned and implemented in the right way, investments in green hydrogen can also improve the water supply in these regions. Thus, the freshwater required for green hydrogen production should always be supplied via seawater desalination, especially in arid regions. This is particularly true since seawater desalination accounts for only a negligible share of total hydrogen supply costs (see Chapter 4.3). To improve the water supply of the local population, the desalination plant, for example, can be planned slightly larger than necessary in the planning of plants for the production of green hydrogen. This excess capacity can then be used to supply the population with clean freshwater.

The described opportunities arising from the production and use of green hydrogen and its deriva-tives are contrasted by a number of challenges in terms of setting up the required value chains. Some of the key challenges are described below.

Additional costs in the supply of green hydrogen
In the vast majority of applications, the use of green hydrogen is currently still associated with considerable additional costs compared to the use of fossil fuels. This applies in particular to the com-parison with grey hydrogen produced from natural gas. The production cost for grey hydrogen, which is currently mainly used in industrial processes, is usually less than 2 €/kg. Even under favourable conditions, the production costs of green hydrogen are currently at least two to three times higher. To close this gap, firstly the production costs for green hydrogen must be significantly reduced. The most important cost drivers for green hydrogen are usually the electricity supply costs and the in-vestment costs for the electrolyser. While the costs of generating electricity from renewable energies (in particular wind and PV) are already low today and are expected to decrease further in the future, further efforts must be made to reduce the manufacturing costs of electrolysers.

Lack of financial value of the "green" properties of hydrogen
So far, there is no internationally approved, universally valid system for certifying the green properties of hydrogen. As a result, there are currently no decisive financial incentives for potential end users to use green instead of grey hydrogen. In order to be able to establish effective financial incentives for the use of green hydrogen in the long term, it is essential as a first step to develop and apply criteria for the certification of green hydrogen. Initially, this can be done on an intergovernmental level, but in the long term, internationally approved regulations should be strived for.

Supply of fresh water for electrolysis
Electrolysis currently requires treated freshwater, which, depending on the production site, may be an insufficiently available resource in African countries. Such water shortages, which are intensified by the climate crisis, can lead to distribution conflicts in water supply, especially in arid areas. When planning hydrogen production projects, it must be ensured that the provision of the required water does not worsen the general supply at the respective location. As described above, integration of seawater desalination into the hydrogen production system is one way

to counteract water shortages. However, care must be taken to develop suitable concepts for the environmentally friendly use/disposal of the residues resulting from seawater desalination (brine).

Infrastructure for transport and storage of hydrogen

Hydrogen has a very low volumetric energy density. For this reason, transport and storage pose a particular challenge. In principle, various technological options are available for the safe and economical transport of hydrogen. However, suitable transport infrastructure, such as roads, railways or pipe-lines, must be available to enable the establishment of a hydrogen supply chain. In less developed countries in particular, it can be assumed that a large proportion of these transport routes will have to be newly constructed. If the hydrogen or hydrogen derivative is to be exported by ship, a suitable port infrastructure must also be available or newly constructed. If the respective region already has a well developed infrastructure for the storage and transportation of fossil fuels, such as oil or natural gas, it may be possible to use interfaces when establishing hydrogen supply chains. This is especially true if the hydrogen produced is further processed into derivatives that have similar properties to fossil fuels. Examples are methanol or liquid organic hydrogen carriers (LOHC). Further explanations of the various options for transporting and storing hydrogen can be found in section 2.3.

Qualified staff

The construction and operation of hydrogen production plants and the generation of the required electricity require the availability of qualified staff. Especially against the background of the desired strengthening of local value chains through export-oriented hydrogen projects (see above), at least part of the required labour force should come from the respective production countries. Therefore, hydrogen projects should always be accompanied by campaigns to build up local know how especially if these projects are localised in developing or emerging countries.

Lack of acceptance in the absence of benefits for the local population

Investments in the development of renewable energy and hydrogen production capacities are not necessarily accompanied by benefits for the local population. If there are only few benefits for the local population, acceptance in the production countries can decline and the sustainable implementation of corresponding projects can be endangered. Especially in countries where a secure and affordable energy supply is lacking, exportoriented hydrogen projects can promote energy poverty. To counteract this, the planning of hydrogen production projects should always include the use of parts of the newly built capacities to generate renewable electricity for the energy supply of the local population. Efforts should also be made to ensure that investments in decentralised energy supply structures are not pushed back by large scale hydrogen projects.

2. Green hydrogen supply chain

The knowledge product of this assignment is developing various scenarios for the deployment of green hydrogen in Egypt, Kenya and Ghana, to contribute to long-term stratigies to achieve low carbon and climate resilient development. Before explaining each case study in details, this chapter explains the technologies required for the hydrogen supply chain, including their costs, their technological key figures and their future market trends. As some of the technologies are not currently produced on an industrial scale (both in terms of size and number), the techno economic parameters listed in this chapter as well as in the annex always refer to the year 2030. These information are key to understand the discussions in the following chapters.

The successful combination of production, transport, storage and utilisation of green hydrogen is a fundamental basis for a secure, sustainable and economical energy supply in the future. As shown in Figure 4, Electricity from renewable energy sources is, along with water, the central raw material for the production of green hydrogen. The electricity generated from the renewable energies is fed into the general electricity grid (use of public power grid or direct connections are possible) and can thus be used for hydrogen production. A distinction is made between three different processes for hydrogen production: Water electrolysis, methane steam reforming and methane pyrolysis. Natural gas is required for both methane steam reforming and methane pyrolysis.

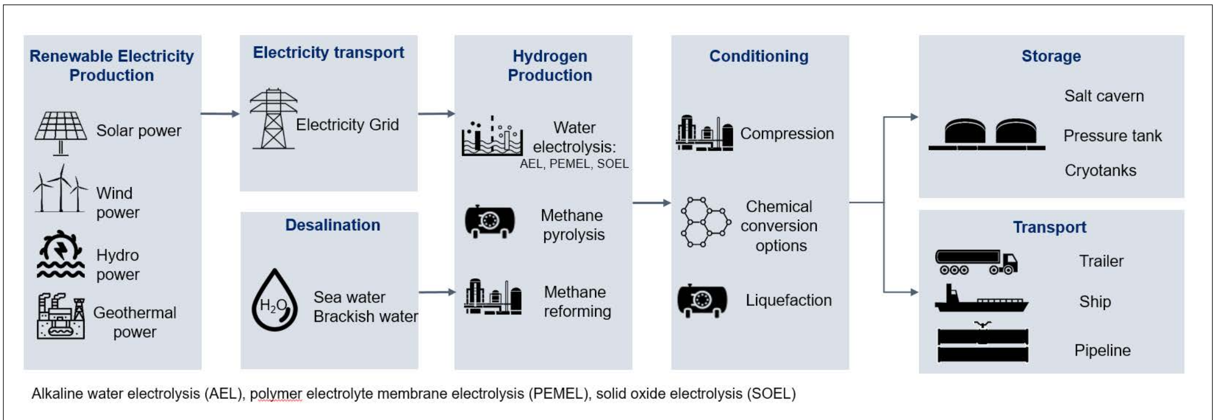

Figure 4: Green hydrogen supply chain

In addition to the significant greenhouse gas emissions from the natural gas supply chain, the pro-duction of hydrogen with steam methane reforming produces further carbon dioxide emissions. For these reasons, only water electrolysis for the production of hydrogen is considered in the case studies elaborated in this report. If the hydrogen needs to be transported between the locations of production and utilization, usually a specific conditioning is necessary. The reason for this is the low volumetric energy content of gaseous hydrogen.

In the following sections, both the different technology options for electrolytic hydrogen production and the hydrogen transport options are presented accordingly.

2.1 Feedstock

Electrolysers use electricity to split water into hydrogen and oxygen. To ensure green hydrogen production, the required electricity must be generated from renewable energies.

2.1.1 Water treatment - Desalination

In order to prevent fresh water resources, which are limited, especially in arid areas, from being strained by hydrogen production plants, the treated water required for electrolytic hydrogen production should be provided by means of sea or brackish water desalination. Such plants are state of the art and available on the market. They are also available for relatively small capacities and only require electrical energy. Reverse osmosis processes are of particular relevance here.

2.1.2 Renewable energy

For climate-neutral hydrogen production, the electricity needed for electrolysis must be generated from renewable energy sources. Renewable energy is energy that is inexhaustibly available or is renewed relatively quickly. For green hydrogen production, the renewable energy potentials of geothermal energy, hydropower, solar energy and wind energy are taken into account in these case studies.

In order to exploit the full potential of green hydrogen production, different renewable energy sources are considered in each of the three countries. The yield of these energy sources and thus the costs and land use efficiencies depends strongly on the geographical location. Exemplary indicators could be: Sunshine hours per year, average wind velocities as well as the availability of rivers that can be used for electricity generation. Considering the geographical spread is therefore essential, as dif-ferent regions in Africa have differ-ent characteristics regarding the availability of renewable energies. The initial focus in this context is on the technical feasibility.

Wind Energy

Wind is a renewable, clean energy resource and therefore one of the best solutions to deliver relatively cheap electricity. Wind energy is deemed to be one of the most promising renewable energy sources due to its worldwide availability as well as its level of technological development. Wind tur-bines can be used to generate green electricity in all climate zones. Often, a distinction is only made between wind energy use on land (onshore) and at sea (offshore). The average wind speed of a site plays a key role in the search for suitable areas for the construction of wind energy plants. The higher the average wind speed of a site, the higher the utilisation of the wind turbine and the lower the specific electricity generation costs.

Solar Energy

Solar energy will play a major role for the production of green hydrogen in the future. Especially in ar-id regions, which have high solar irradiation and low cloud formation, the potential for utilising solar energy is high. The use of solar energy by means of photovoltaic systems is characterized by particu-larly low electricity production costs and a high degree of decentralized operation. However, it should be noted that solar energy cannot be produced continuously due to dark periods. For a permanent supply of electricity, temporary storage resources must be used.

Hydropower

Hydropower, as opposed to wind and solar power, can be used to generate electricity from renewable energy sources on a continuous basis. Due to the high annual hours of use, the hydrogen production plants can be operated at a high utilisation rate. However, the use of hydropower is highly dependent on the geographical availability of suitable rivers. In addition, the ecological consequences resulting from the necessary damming of rivers must always be taken into account when further exploiting hydropower.

Geothermal Energy

Geothermal energy refers to the thermal energy stored in the earth's crust. Comparable to hydropower, geothermal energy can only be used to generate electricity at certain locations but enables a con-stant supply of renewable electricity and thus a high utilisation of hydrogen generation plants.

2.2 Hydrogen production – Water electrolysis

There are three main types of electrolysis: alkaline water electrolysis (AEL), polymer electrolyte mem-brane electrolysis (PEMEL) and solid oxide electrolysis (SOEL). Regardless of the particular process, the principle of water electrolysis is identical. Water is split into hydrogen and oxygen in a molar ratio of 2 to 1 by supplying electrical energy:

$$H_2O \rightarrow H_2 + 0{,}5\ O_2$$

Alkaline water electrolysis
Alkaline electrolysis (AEL) is the oldest and currently most widely used water electrolysis process. In AEL, the two half-cells are filled with a aqueous potassium hydroxide solution, which serves as an electrolyte. Typical operating temperatures are between 60 and 80 °C with a pressure in a range of up to 30 bar [10]. The technology is known, already established and relatively cheap. Large AEL plants have already been commercially realized with capacities of up to 6 MWel, equivalent to 3 t/d [11].

Polymer electrolyte membrane electrolysis
Proton exchange membrane electrolysis (PEMEL) is a relatively new process. The first PEMEL plants were developed about 25 years ago. In the electrolysis cells, the anode and cathode are firmly connected to the proton exchange membrane (PEM), which assumes the function of both the separator and the electrolyte. The PEMEL is a low temperature electrolyser with operating temperatures in the range of 50 to 80 °C and a maximum output pressure of hydrogen between 30 and 80 bar [10, 11]. Due to its low ramp up times and good characteristics in partial load operation, the PEMEL is predes-tined for operation in combination with volatile renewable energy sources.

High-temperature electrolysis
High temperature solid oxide cell electrolysis (SOEL) is based on the integration of high temperature heat. Instead of liquid water, overheated water vapour is introduced into the electrolytic cell, which reduces the need for electrical energy. SOEL electrolysers have so far only been offered by a few manufacturers and in significantly smaller size classes than the AEL and PEMEL. The SOEL technology is not yet mature and still in research stage [11]. Hence, the SOEL is not considered further in this case study.

Due to the differences in structure, functioning and technological maturity, the electrolysis technologies have specific characteristics in terms of their application. Table 2 provides an overview of these differences of hydrogen production via AEL and PEMEL.

	ALKALINE ELECTROLYSER	PEM ELECTROLYSER
SPECIFIC ADVANTAGES	•Established technology •No noble metal in catalysts •Relatively low investment costs •High availability and long lifetime	•High voltage efficiency •Operates well at partial load •Suitable for operation in combination with fluctuating renewable energies •Suitable for high pressure operation
DISADVANTAGES	•Dynamic operation •Cleaning of hydrogen efforts additional effort	•High demand of noble metals •Low durability •High investment cost

Table 2: Hydrogen production via water electrolysis

Both the AEL and the PEMEL are expected to see significant technological improvements in the coming years due to the anticipated ramp up of the global market for green hydrogen. In order to quantify and illustrate these developments, a meta study was conducted. The key findings of this meta-study in terms of system costs and efficiencies are shown in Figure 5 and Figure 6. A strong cost reduction and a slight increase in efficiency can be therefore expected.

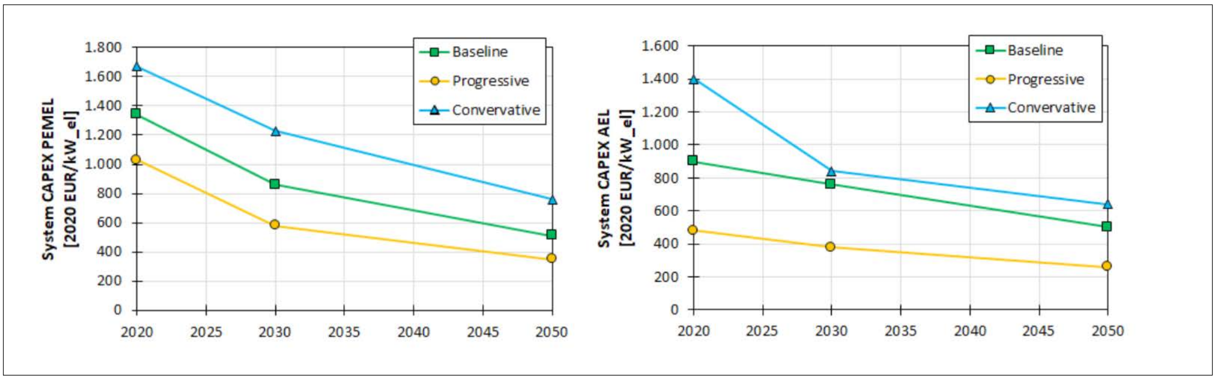

Figure 5: Expected development of system CAPEX for PEMEL and AEL [10, 12-22]

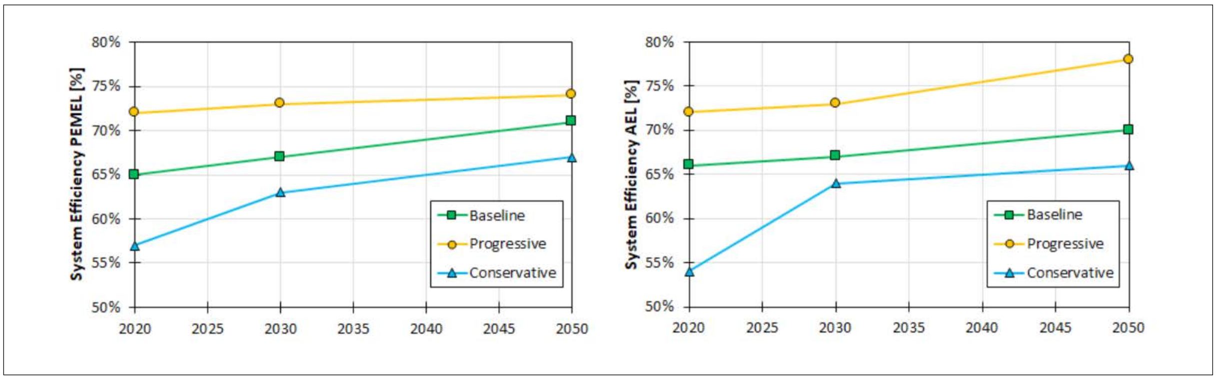

Figure 6: Expected development of system efficiencies (based on LHV) for PEMEL and AEL [10, 12-22]

A detailed breakdown of the techno-economic parameters of the electrolytic technologies can be found in the appendix (Table 9). These values are used in chapters 5,6 and 7 for the quantitative assessment of the respective supply chains.

2.3 Hydrogen logistics

Storage and transport are essential to enable a constant supply of green hydrogen. Especially against the background of a global hydrogen market, transport is of particular importance. The following sections present the various possibilities for storing and transporting hydrogen.

2.3.1 Conditioning

For an economic hydrogen storage and transport, hydrogen must be conditioned due to its very low volumetric energy density. The energy content of hydrogen can be increased in a variety of ways. In addition to the compression or liquefaction of the hydrogen, there are various chemical conversion options, such as methanol or ammonia. An alternative option is the use of LOHC (Liquid Organic Hy-drogen Carrier). Figure 7 demonstrates the energy densities on different hydrogen storage options

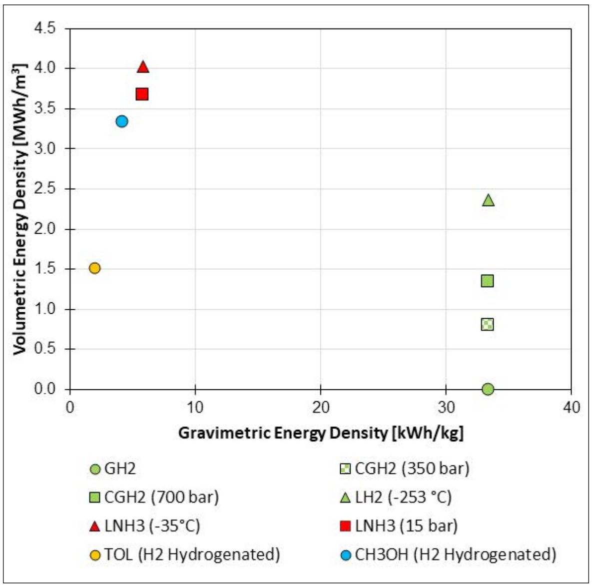

Figure 7: Dependence of different energy densities on different hydrogen storage options

GH_2	–	Gaseous hydrogen
CGH_2	–	Compressed gaseous hydrogen
LH_2	–	Liquid hydrogen
LNH3	–	Liquid ammonia
TOL	–	Toluol as a promising LOHC
CH_3OH	–	Methanol

Compression

The easiest way to increase the volumetric energy density of hydrogen is compression. Depending on the application, different types of compressors, e.g. mechanical compressors and turbo compressors, are used. The compression of hydrogen is well established. Compressors of high performance with through puts of 200 kg/h and pressure levels up to 1000 bar are already on the market [23]. The possibility of arranging several compressors in series provides a high degree of flexibility [24]. The overall efficiency depends on the type of compressor. The mechanical and electrical efficiency of reciprocating and ionic compressors is approximately 95% [25] and the efficiency of mechanical compressors is 65 to 88% [26].

Liquefaction

Due to the very low volumetric energy density of gaseous hydrogen, it can hardly be transported in vessels over long distances at reasonable cost, even if it is compressed. Therefore, liquefaction is necessary; this increases the volumetric energy density of hydrogen many times over to more than 2 000 kWh/m³. Since hydrogen only changes into the liquid phase at about 253 °C, the liquefaction process is technically complex and energy intensive. Liquefaction plants are correspondingly capital intensive. In order to keep the costs arising from liquefaction as low as possible, the corresponding plant should be utilised as much as possible. Hydrogen liquefiers have been built for decades and have reached a high degree of technological maturity.

Liquid Organic Hydrogen Carriers – LOHCs
Hydrogen can react with other elements or certain compounds to form new chemical compounds. LOHC storage systems are based on the chemical bonding of hydrogen to a liquid carrier medium, the LOHC. The hydrogen is bound to the LOHC in a so called exothermic hydrogenation reaction, i.e., heat is released during that reaction. By binding the hydrogen to the LOHC, not only the volumetric energy density can be strongly increased, but also the handling can be decisively improved. LOHC are comparable to crude oil in many properties and can be stored and transported as a liquid in conventional vessels, even in a hydrogen-saturated state.

If the hydrogen is to be used after storage or transport, it must be dissolved. For this dehydrogenation reaction to proceed and the hydrogen to be released, the LOHC must be heated. The efficiency of hydrogen storage and/or transportation systems using LOHCs depends on whether the heat re-quired for the hydrogen release has to be generated separately for this purpose. By using surplus heat from other industrial processes, so-called waste heat, the overall efficiency can be significantly improved.

Ammonia

Ammonia is formed by the reaction of nitrogen (N_2) and hydrogen and is one of the most widely produced chemicals in the world. It is mainly used in the production of fertilizers and is therefore a sub-stance that is crucial for feeding the world's population. Nowadays, the Haber-Bosch process is usually used for the production of ammonia. In this process, in addition to N_2 extracted from the air, grey hydrogen is commonly used as a starting substance. However, hydrogen from renewable energy sources can also be used to produce green, climate neutral ammonia.

In addition to its direct use as a basic chemical, ammonia can also be applied as a hydrogen carrier in a similar manner to LOHCs. Ammonia already becomes liquid at temperatures of -33°C and, in this state, has a significantly higher storage density than liquid hydrogen. Nonetheless, both the Haber Bosch process and the redissolution of hydrogen, which is necessary if the ammonia is not used directly, are energy intensive processes. In relation to the energy content of the hydrogen stored in the ammonia, the losses can be over 30 %.

Methanol

In terms of the underlying principle, the storage of hydrogen in the form of methanol (CH_3OH) is comparable to the storage in ammonia. Methanol is an alcohol, which can be produced by combining hy-drogen with a carbon rich gas. Today, methanol is of major importance as feedstock for the chemical industry. While methanol production is currently mostly based on the use of fossil natural gas (which includes both hydrogen and carbon), in the future green hydrogen can be the feedstock for methanol production. In addition, the production of climate neutral methanol also requires green carbon dioxide (CO_2), which can, for example, come from biomass or be captured directly from the air.

Methanol has a wide range of applications in industry. For example, it is used to produce fuels or processed into plastics. In addition, similar to ammonia, the use of methanol as a hydrogen carrier is also being discussed. It must be taken into account that additional energy is required for methanol production and the hydrogen redissolution. The extraction of the required green CO_2 also means addi-tional effort.

Power-to-Liquid fuel

Power-to-Liquid (PtL) refers to the production of liquid fuels from electricity, water and CO_2. The use of additional renewable energy sources is crucial for a greenhouse gas reduction contribution. The PtL process is not yet used on a large scale, but it potentially enables fuel supply from regeneratively generated electricity for those sectors that cannot operate without liquid fuel. For this purpose, a synthesis gas is first produced from H_2 and CO_2. A typical process here is the reverse water gas shift re-action (RWGS). The best known and most widely used approach for the production of liquid fuels from this synthesis gas is the subsequent Fischer Tropsch synthesis. The product is a synthetically produced fuel that can significantly reduce CO_2 emissions, provided that the production process is designed sustainably.

2.3.2 Storage

Large storage facilities will be an essential component of a future hydrogen infrastructure. Thus, the energy demand can also be reliably covered at the beginning of the heating season or during periods of weather related reduced generation of renewable energies.

Pressure tank

Like natural gas, hydrogen can be stored in pressure tanks. Pipe storage, as a large volume tank, reach pressures up to 100 bar, while spherical tanks have a pressure range up to 200 bar [27]. Gener-ally, Pressure tanks are mature, and losses are not stated in the literature [28].

Salt cavern

Many salt caverns are already used for the storage of crude oil and natural gas and will also play an important role in the future for large scale storage of hydrogen. An average cavern with a diameter of 60 m, a height of 300 m and a filling pressure of 175 bar has a capacity of 100 million Nm^3. This corresponds to an energy quantity of 300 GWh for hydrogen storage [29]. Depending on the depth and geological parameters, storage pressures between 50 to 200 bar are common [30]. In addition to the large storage potential in terms of quantity, salt caverns offer a safe and loss free hydrogen storage.

Cryotanks

Liquid hydrogen can be stored and transported in special vessels. Such cryotanks represent the state of the art. Due to the very low temperatures of the liquid hydrogen, these cryotanks must be very well insulated. Nevertheless, the entry of heat into the tank system can never be completely prevented, which inevitably leads to the evaporation of parts of the liquefied hydrogen. The resulting pressure increase in the tank can only be absorbed by the cryotank to a certain extent. For this reason, parts of the gaseous hydrogen must be drained off after a certain time (socalled boil off losses). Alternatively, the tank can be coupled with an appropriate cooling unit that compensates for the heat input. However, this requires an additional external energy source.

The storage and transportation of ammonia, methanol and LOHCs are widely known from the logistics of the chemical industry and represents the state of the art. Accordingly, the existing infrastructure for fossil, crude oil based fuels can be used.

2.3.3 Transport

Depending on the aggregate state of the hydrogen, the geographical conditions and the transport distance, two typical transport options will be considered in the following case studies. Only large scale export is relevant for the case studies, according to which transport by trailer plays a subordinate role.

Transportation via ships
There are already a number of possibilities for transporting hydrogen derivatives via ship. For exam-ple, tankers that are currently used to transport fossil oil can also be used to transport LOHCs or PtL fuels by ship. Liquid ammonia and methanol are currently transported in large quantities with corresponding tankers, too. Existing infrastructures and technologies could also be used here if these energy carriers become established as a storage and transport medium for green hydrogen. Pure hydrogen is currently not transported by ship on a large scale. The transport of gaseous hydrogen via ship is not a promising option due to the limited transport volumes and is therefore not expected to play a major role in the future. The transportation of hydrogen by ship is technically possible for longer distances when pipelines cannot be considered. Because of its low energy density relative to volume, gaseous hydrogen is best converted into a liquid with a higher energy density before being loaded onto a ship.

Transportation via pipelines
Due to the relatively low conditioning effort (no energy intensive liquefaction or bonding to carrier medium), hydrogen transport by pipeline is a particularly attractive option. Already today, pipelines are used to transport (grey) hydrogen between industrial sites. Hydrogen pipelines usually run at operating pressures between 10 and 100 bar. Since the operating pressure must be maintained to ensure gas transport, the compression of the hydrogen plays a central role. Besides the construction of new pipelines, the conversion of existing natural gas pipelines can also be considered for pipeline-based hydrogen transport. With such a rededication, it must be ensured that the hydrogen cannot permeate the wall of the pipeline. In the long term, permeation would lead to the destruction of the pipeline (hydrogen embrittlement). One possible approach to prevent damage to converted pipelines is to apply internal pipe coatings made of hydrogen-impermeable plastic.

Figure 8 summarises the different transport options for hydrogen, and its derivatives, and Table 3 compares them with regard to the most important characteristics. A detailed breakdown of the tech-no-economic parameters of the different options for conditioning, storage and transportation can be found in the appendix (Table 10 - Table 15). These values are used in chapters 4,5 and 6 for the quan-titative assessment of the respective supply chains.

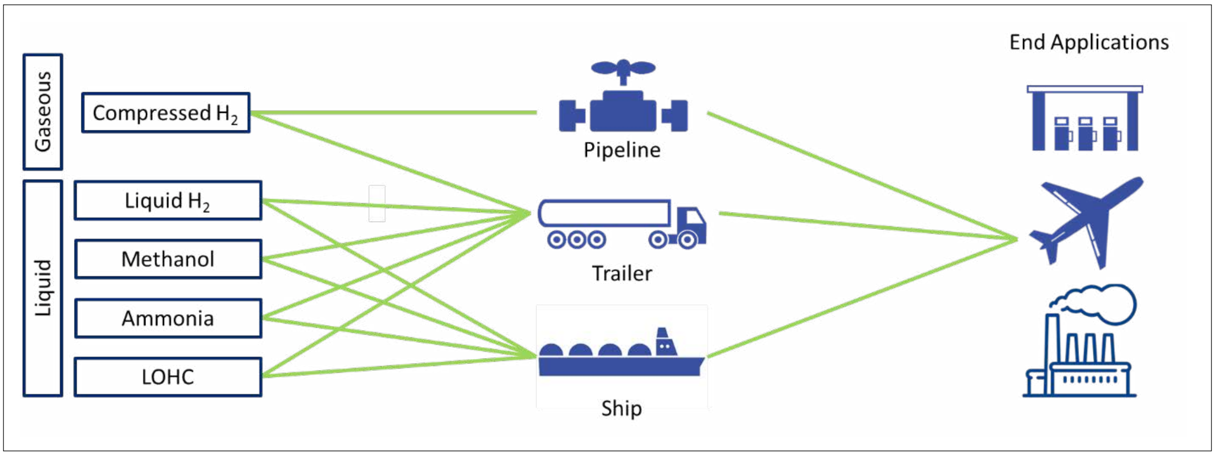

Figure 8: Hydrogen transport options

	COMPRESSED GASEOUS HYDROGEN	LIQUID HYDROGEN	LOHC	METHANOL (CH_3OH)	AMMONIA (NH3)(LIQUID)	PTL FUELS
Storage conditions	•Different pressure levels, usually 700 bar maximum •Ambient temperature	•Ambient pressure •-253 °C	•Ambient conditions	•Ambient conditions	•-33 °C and ambient pressure •or: •9 bar and ambient temperature	•Ambient conditions
Volumetric energy density	0.8 MWh/m^3 (at 350 bar)	2.4 MWh/m^3	1.8 MWh/m^3	3.3 MWh/m^3	4.0 MWh/m^3	10 MWh/m^3
Energy demand conditioning*	0.04 kWh/ kWh_{H2} (at 350 bar)	0.20-0.25 kWh/kWh_{LH2}	0.35-0.40 kWh/kWh_{H2}	0.15-0.17 kWh/ kWh_{CH3OH} **	0.05-0.07 kWh/ kWh_{NH3} **	0.08-0.10 kWh/kWh_{PtL} **
Energy loss during transport	Pipeline transport: 1.5-2 % per 1000 km	0.2-0.4 % per day	No losses	No losses	No losses	No losses
Advantages	•Low energy demand for conditioning •High purity of H_2	•High energy density •High purity of hydrogen •Low reconditioning effort	•High energy density at ambient conditions •Easy handling in existing infrastructure	•High energy density at ambient conditions •Easy handling in existing infrastructure •Use of "pure" CH_3OH in existing markets possible	•High energy density at moderate conditions •Use of "pure" NH3 in existing and new markets possible •Handling in existing infrastructure possible	•High energy density at ambient conditions •Use in existing mobility markets •Easy handling in existing infrastructure
Disadvantages	•Low volumetric energy density •Missing global infrastructure •Pipelines needed for transregional transportation	•High energy input for liquefaction •Boil off losses •Missing global infrastructure	•Very high energy demand for redissolution of H_2 •High investment cost for carrier material	•Supply of green CO_2 necessary •Very high energy demand for redissolution (if used as H_2 carrier)	•Toxic substance •Very high energy demand for redissolution (if used as H_2 carrier) •Low purity of redissoluted H_2	•Supply of green CO_2 necessary •H_2 redissolution not feasible

* excludes provision of $H_2/CO_2/N_2$
** excludes redissolution of H_2

Table 3: Comparison of different transport options for hydrogen

2.3.4 Indicative comparison of different transport options

If the costs of the various hydrogen transport options are to be compared, the entire supply chain must always be taken into account, especially conditioning. For example, when considering the transport of hydrogen using LOHCs, the additional cost of bonding the hydrogen to the carrier medi-um and the cost of redissolving the hydrogen must always be taken into account.

Figure 9 provides an overview of the costs of hydrogen transport using various options. The transport distance is taken as 4000 km. It becomes clear that hydrogen transport by pipeline has sig-nificantly lower costs than the other options. However, it must be taken into account that gaseous hydrogen is assumed to be supplied at the point of consumption. If liquid hydrogen or a derivative is demanded instead of gaseous hydrogen, the supply costs can differ significantly.

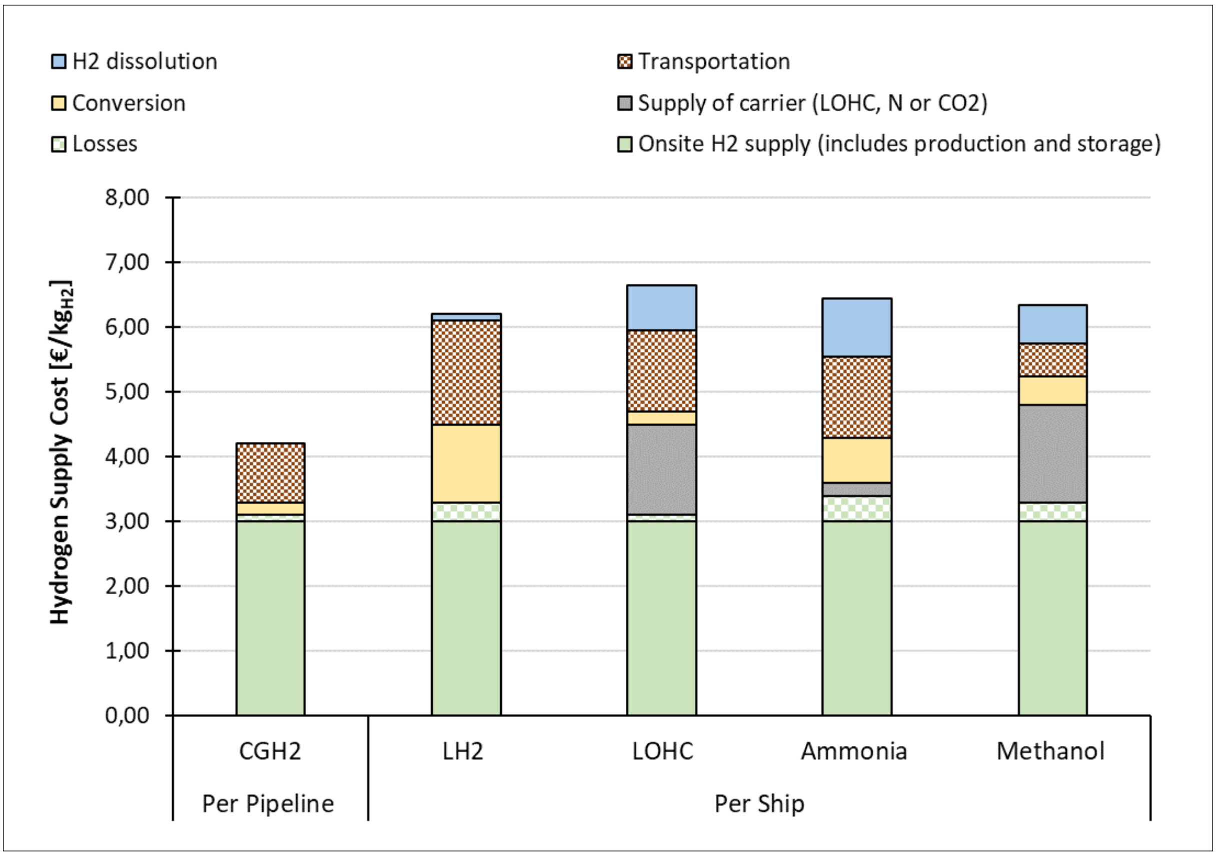

Figure 9: Indicative comparison of different options for the transport of hydrogen

3. Hydrogen Supply Cost

This chapter explains the model adopted to estimate the hydrogen supply cost in the three case studies. The Consultant utilized an optimisation model, developed at Hamburg Univeristy of Technology, to determine the hydrogen production costs and the optimal configuration of a respective plant. The objective of the model is to minimize the location specific hydrogen production cost using water electrolysis powered with available renewable resources in each country; photovoltaics, onshore wind power, geothermal energy or hydropower by determining the optimal system configuration. Hydrogen production cost serve as a target that must be minimized covering the costs of:

- Renewable power supply
- Storage for electricity
- Water electrolysis
- Hydrogen compression
- Hydrogen storage

3.1 Optimised Hydrogen Production

The hydrogen supply system consists of, on the one hand, the production of hydrogen in the selected countries (Egypt, Kenya and Ghana) and, on the other hand, the transport of the produced hydrogen or respective derivatives to promising sales markets. The overall system is shown Figure 10.

Beside the techno-economic parameters of the individual components (CAPEX, OPEX, lifetime, efficiencies), the optimisation of hydrogen production is mainly based on location-specific weather data.

In the annex, all techno-economic parameters which were used are summarised. In order to calculate the hourly capacity factor of the photovoltaic systems, the site specific hourly solar irradiation, tem-perature, albedo and wind speed are required. To calculate the hourly capacity factor of the wind power plants, location specific parameters, namely the wind speed and the roughness index, are needed. The location specific weather data required are taken from the ERA5 data set. The ERA5 data set is a reanalysis for the global climate and weather with a regular latitude-longitude grid of 0.25 degrees. The capacity factors of the photovoltaic systems and the wind power plants are basis for optimising the electrolytic hydrogen production.

A linear optimization approach is chosen to identify the location specific optimal combination of renewable power supply (photovoltaics and wind power plus geothermal energy or hydropower, if available), battery, electrolyser, compressor and hydrogen storage. The costs of all selected components are summed up in an objective function. The components available for selection depend on the used technologies shown in Figure 9 within the model boundaries.

Specific constraints are implemented to ensure that the given physical restrictions are met. For example, the energy and mass flows must be balanced for every hour. Thus, the energy flow is described as the balance of the electricity supply (output of installed renewable electricity generation technologies and the battery) and electricity demand (demand of the electrolyser, demand of the compressor and battery feed). The linear optimization takes place via the Python library PuLP.

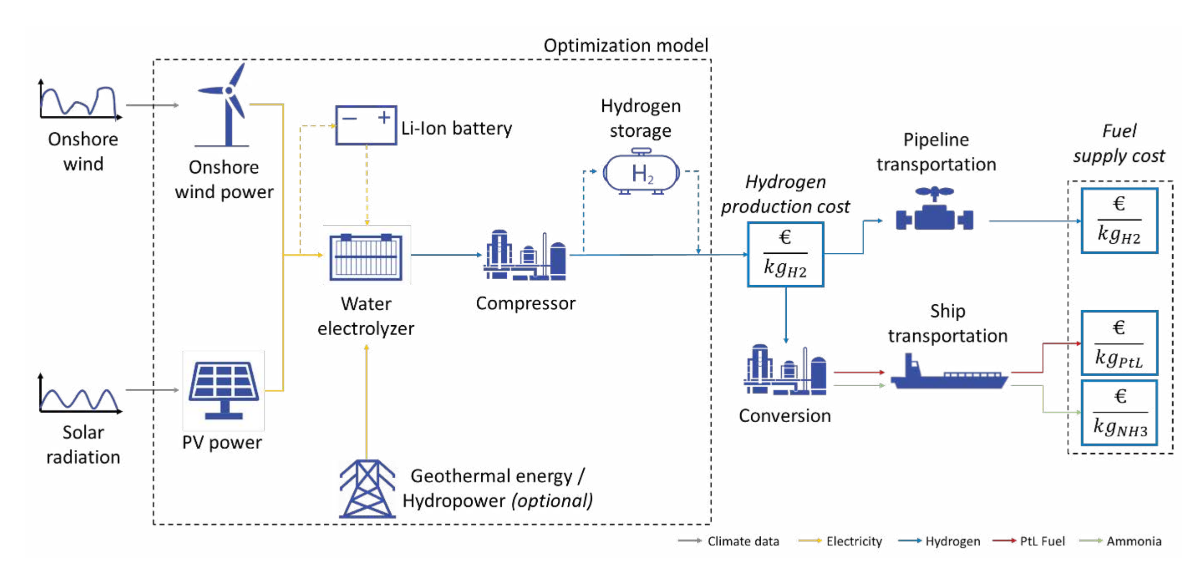

Figure 10: Overview of the analysed supply chain and the model for optimised hydrogen supply

3.2 Calculation of Hydrogen Supply Cost

Within the framework of the case studies, one scenario for the export of hydrogen-based green energy will be assessed for each of the African countries under consideration. The different export scenarios are mainly defined by the transport distance and the transported energy carrier. One possible energy carrier for transport is the hydrogen itself. Other transport options are derivatives such as ammonia, methanol or PtL fuels. For every country, a particularly promising export scenario is selected based on the country-specific conditions.

The fuel supply cost $c_{(fuel,supply)}$ include hydrogen production cost $c_{(H2,production)}$ as well as fuel transportation cost $c_{(fuel,transport)}$. If the hydrogen is exported in the form of a derivative, the costs for the conversion c_conversion are also taken into account.

$$c_{(fuel,supply)}=c_{(H2,production)}+c_{conversion}+c_{(fuel,transport)} \quad (1)$$

The conversion costs c_conversion include the capital and operating costs for the plant to produce the respective derivative. The operating costs contain the costs for providing the electrical and thermal energy required for the conversion process. Furthermore, for the production of methanol and PtL fuels, green CO_2 must be provided in addition to hydrogen. If ammonia is used as an energy carrier, N_2 must be supplied. Therefore, the CO_2 resp. N_2 supply costs must also be taken into account when calculating the conversion cost.

The transport costs c_(fuel,transport) depend on the chosen transport technology. Pipelines are a cost-effective option for transporting gaseous hydrogen over long distances. However, the use of pipelines is limited by technical limitations (e.g., no oceans can be crossed). The transportation cost via a pipeline consists of two parts. First, the sum of the capital and operating cost for the pipeline must be considered. In addition, the cost for intermediate compression to maintain the pressure level is included. If methanol, ammonia or PtL fuel is exported, transport by ship is a suitable option. In this case, the investment costs for the required ships are taken into account, as well as the operating costs, which, in addition to maintenance costs, include crew and fuel costs, amongst others.

Further constraints and assumptions for the calculation of the hydrogen production cost and fuel supply cost:

• The assumptions used in the model regarding the techno economic parameters of the components refer to the year 2030. All applied parameters refer to large scale plants. Possible scaling effects (reduction of specific costs when building larger plants) are not taken into account.

• Taxes, incentives, and country specific cost differences, e.g., in the interest rate, are not considered.

• For the model based cost optimised hydrogen supply, the installed electrical power of the electrolyser is assumed to be 100 MW. The size of the electrolyser serves as an anchor for the design of the entire hydrogen supply plant. All other components, such as renewable energy plants and hydrogen storage facilities, are dimensioned according to the optimisation approach described.

• All model components are considered static. Process specific dynamics, such as start up processes or partial load behaviour, are not considered. It is assumed that load fluctuations can be absorbed by the modular design of the components. This applies particularly to electrolysis, where the individual stacks can be ramped up and down as required for load control.

• 2019 is chosen as the reference year for the weather data used as the basis for calculating the hourly capacity factor of the photovoltaic (PV) and wind energy plants.

• As a major constraint for the optimisation, the coverage of an hourly constant hydrogen demand is defined in the model. In concrete terms, this means that the amount of hydrogen supplied by the modelled production plant is the same every hour of the year. The coverage of a baseload hydrogen demand is possible. The volatility in electricity generation resulting from the fluctuating supply of renewable energies is thus absorbed by the storage systems (battery and/or hydrogen storage).

• A possible commercialization of the by-products of electrolytic hydrogen production is not considered in the model. While commercial use of the oxygen produced is conceivable for example, in the health sector or for wastewater treatment a reasonable use of the waste heat seems rather less realistic due to the low temperature level (usually a maximum of 60 °C is possible). This is especially true for Africa, where the demand for low temperature heat is low due to climatic conditions.

•Neither transportation cost nor transmission losses for transporting the electricity from the power supply technology to the electrolyser site are considered in the calculation of the levelized cost of electricity at the hydrogen production site

• The local/regional transport of all educts (hydrogen, CO_2, N_2, derivates) at the point of production, for example, from the CO_2 point source to the PtL production plant, is not taken into account for the cost calculation.

4. Case study 1
Egypt as a Hydrogen Exporter

The first case study aims to investigate Egypt's potential in terms of green hydrogen production and export. The approach to this case study follows the following steps. First, the components of a suit-able supply chain are identified based on the regional conditions in Egypt. This initially involves identifying a suitable location for setting up a production plant. Second, a suitable sales market is identified for possible export of the hydrogen produced. Accordingly, a range of possible transport options is identified, from which an alternative is selected that is conceivable and advantageous for connecting Egypt with the selected export market. Finally, the cost model approach (as presented in Chapter 2) is applied to examine the identified supply chain through proposing a possible design of an exemplary demonstration plant, then estimating the energy supply costs and the overall efficiency expected for a realization in 2030.

4.1 Availability of Renewable Energy Resources in Egypt

A preliminary assessment of renewable energy resources is estimated, which can be used for green hydrogen production in Egypt. For this purpose, the results of the country selection process are used. With a mean wind power density for the 10% windiest area of 663 W/m2 and a specific photo voltaic power output of 5.35 kWh/kWp per day, Egypt has a high potential for wind energy as well as for solar energy [31, 32]. Therefore, both renewable energy sources are taken into account in the site identification for the green hydrogen production in Egypt. Figure 11 clearly shows that the potential for the use of solar energy is very high throughout the whole country, whereas the wind energy poten-tial is very unevenly distributed. By far, the highest potential for use of (onshore) wind power is on the shores of the Gulf of Suez.

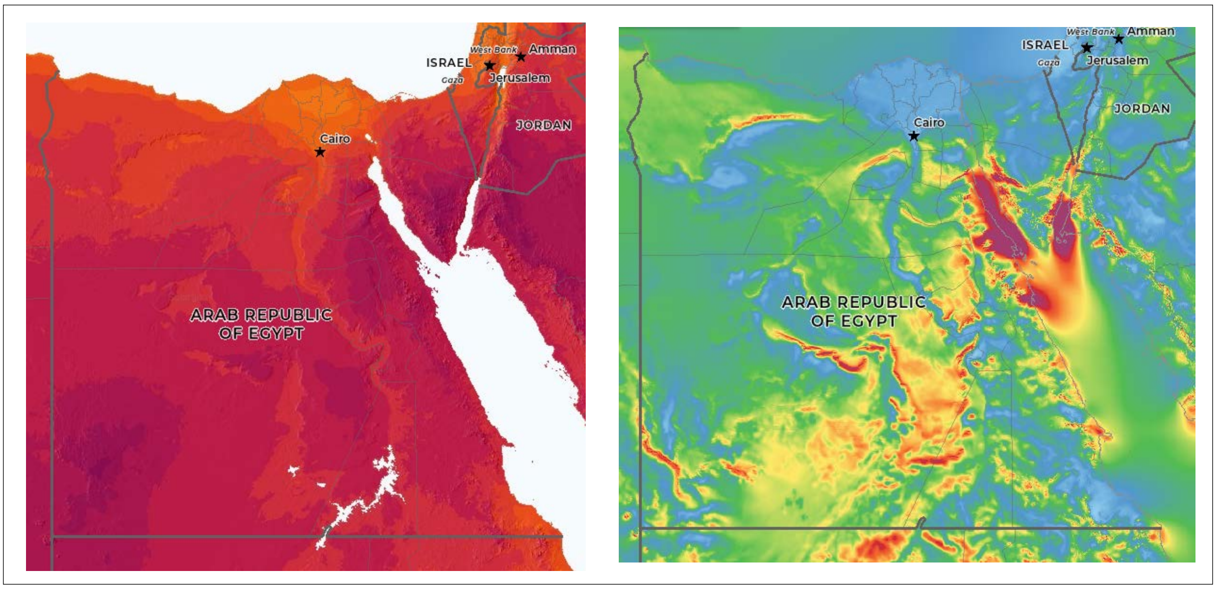

Figure 11: Solar and wind map of Egypt [31, 32]

In 2019, the total amount of energy generated from renewable sources was approximately 18,300 GWh per year, and the share of renewable electricity in total power generation was around 9.4 % [33]. While most of the renewable electricity was generated by hydropower, the first projects utilising wind and solar energy to produce electricity have recently been realised in Egypt.

A wind park on the shores of the Gulf of Suez and the Benban solar park are two examples for existing, recently built renewable energy plants. The 250 MW wind park, located 30 km northwest of the town of Ras Ghareb, generates over 1,000 GWh of green electricity annually [34].

The Benban Solar Park currently consists of 41 PV plants stretching over 37 km. The park is located in the southeast of the country, about 50 km north of Aswan. The solar park has been connected to the Egyptian electricity grid since 2019 and currently produces 930 GWh per year [35]. The two locations of the discussed renewable energy plants are shown in Figure 12.

In order to take the potential of hybrid green hydrogen plants (electrolysis powered by onshore wind and solar PV energy) into account, this case study examines a location near the existing wind farm at Ras Ghareb, as the potential for both solar

Figure 12: Locations of the Benban solar park and the Zafarana wind park at the Gulf of Suez [36]

and wind power is very high there. Furthermore, the selected site is in close proximity to the coast of the Red Sea. This is an elementary advantage with regard to the necessary water supply for electrolysis. Additionally, the well developed infrastructure be-tween the Red Sea coast and the Nile and the existing natural gas pipeline system are beneficial elements for a good hydrogen production site.

4.2 Further Processing Steps

To elaborate exporting of hydrogen, a complete supply chain is outlined, including suitable transport options for exporting the hydrogen produced at the selected site in Egypt. If pure hydrogen is required by the customer, the transport of pure hydrogen is generally preferable compared to the transport as a chemically bound variant, as conversion losses can thus be avoided. Due to Egypt's geographic location, the proximity to the promising European sales market is given. Due to the limited potential for renewable energy sources, there are some import-dependent countries in Europe where probably not enough hydrogen can be produced domestically. Presumably, a relevant hydrogen demand will arise in Central Europe in the near future.

In the supply chain examined in this case study, the gaseous hydrogen will be transported to Europe via pipelines. Several studies confirm that for large quantities and medium distances of up to 5000 km, the most cost effective option for hydrogen transport is via pipelines [37-44].

With regard to other possible transport options, it is questionable whether Egypt has a high potential for biomass as a CO_2 source due to its arid climate. The CO_2 required for hydrogen transport via methanol or the further processing into PtL fuels can also be drawn directly from the environment, but this is very cost intensive. The export as liquid hydrogen, ammonia or bound to a LOHC by ship is conceivable but has significantly higher energy losses than transport by pipeline. Figure 13 shows the considered hydrogen supply chain for Egypt.

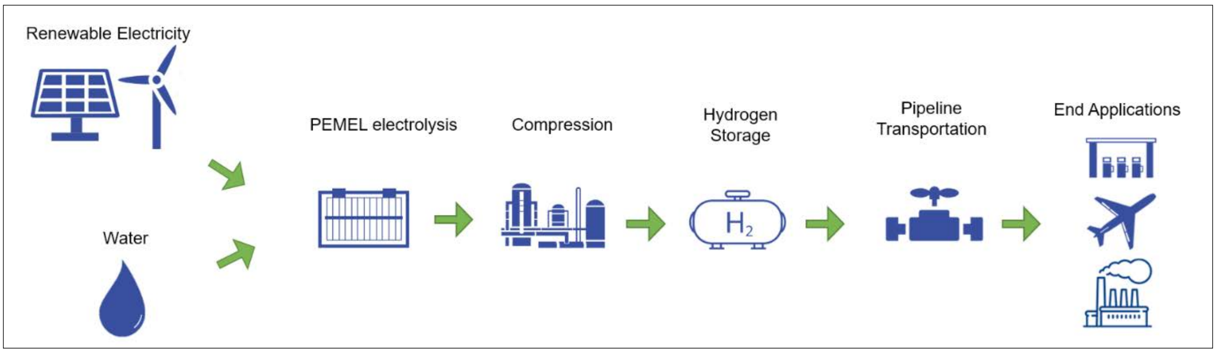

Figure 13: Hydrogen supply chain in Egypt

A major advantage for hydrogen exports to Europe is the large hydrogen pipeline network through Europe, which is already being planned with the "European Hydrogen Backbone" project as shown in Figure 14. The "Hydrogen Backbone" will enable hydrogen transport within Europe and realises the import of hydrogen from Northern Africa. In the current planning, the connection of Egypt to the net-work has not yet been taken into account. However, as the country selection has shown, Egypt has a very high potential for green hydrogen production, so a connection might be attractive for Europe if the corresponding production capacities are built up in Egypt [45].

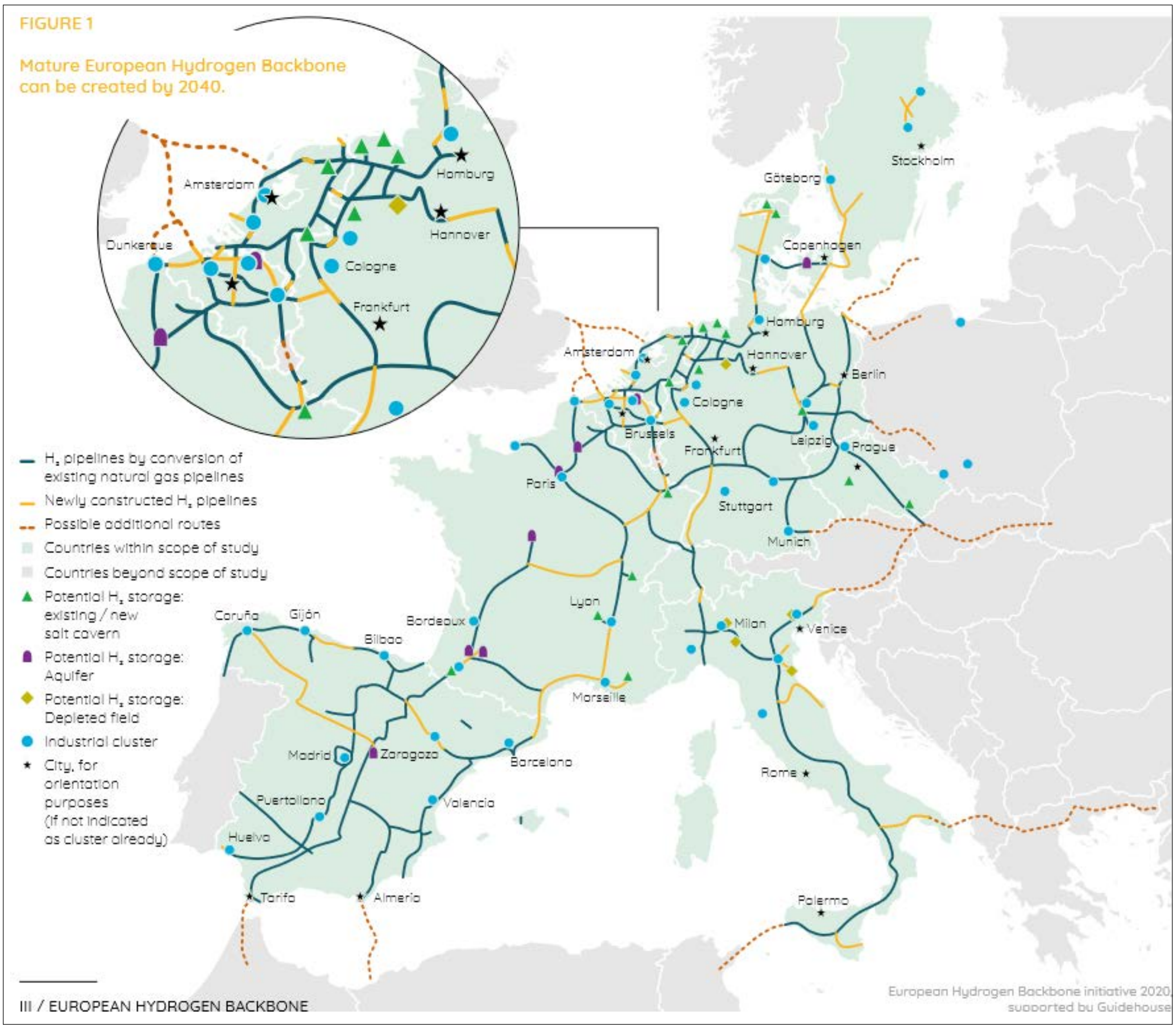

Figure 14: European hydrogen backbone [45]

4.3 Results – Hydrogen Production in Egypt and Supply to Central Europe

The modelled results for hydrogen production in Egypt and the supply of the produced hydrogen to Central Europe are explained as follows with regard to the dimensioning of the individual supply chain components. For this purpose, the plant design optimised for minimum hydrogen supply costs is presented first. Subsequently, the energy input along the supply chain, the resulting efficiency and the composition of the hydrogen supply costs are discussed. All values shown refer to the techno-economic parameters of the supply chain components forecasted for 2030.

4.3.1 Renewable Energies

Table 4 shows the most important key figures for renewable electricity generation for the cost optimised, continuous supply of compressed hydrogen at the site under consideration. An electrolyser with an installed capacity of 100 MW is used as design parameter for dimensioning the renewable energy plants. The electricity required for hydrogen transport via pipeline is not part of the optimisation and is accordingly not supplied via the power generation plants shown in Table4.

To achieve the minimum hydrogen supply costs, the available renewable energies, onshore wind and PV power, are oversized. This means that the total installed capacity of PV and wind exceeds the installed electrolyser capacity. The factor of oversizing in the optimised plant configuration at the con-sidered location is about 2.

The optimal ratio of installed wind and solar energy is almost 1 to 1, with a slight preponderance of onshore wind power. One consequence of oversizing is the occurrence of excess energy, which describes the situation where, when the production of renewable electricity is particularly high, part of the generated power cannot be used and can therefore be curtailed.

In the plant configuration modelled here, the total output of renewable energies is over 100 MW when only the installed wind turbines (106 MW) are running at full load. If the PV modules (91 MW) also generate energy during such very windy weather phases, the total output can quickly reach over 100 MW. Since the electrolyser can only take 100 MW, part of the power cannot be used and is regulated down (= excess energy). In the modelled case, 85 MWh of the generated electricity annually is not used and arises as excess energy. The costs arising from the generation of excess energy are contrasted by cost savings resulting from the high utilisation of the electrolyser. High utilisation of the electrolyser lowers the hydrogen production costs, as the specific CAPEX costs (€ per kg of hydrogen produced) decrease with increasing utilisation.

	INSTALLED CAPACITY [MW]	AFLH [H/A]	SHARE OF SUPPLIED ELECTRICITY [GWHGWH$_{DEMAND}$]	ELECTRICITY COST [€/MWH]
ONSHORE WIND POWER	106	4580	70 %	25
PHOTOVOLTAIC POWER	91	2310	30 %	18

Table 4: Parameter of the renewable energy generation for the supply of 100 MW electrolysis[a]

[a] All data refer to the year 2030.

The low modelled levelised cost of electricity (LCOE) of 25 €/MWh for onshore wind energy and 18 €/MWh PV solar energy indicate a good site selection for hydrogen production. Current projects show that LCOE between 2 and 3 €/MWh are realistic and can already be achieved today at preferred sites. Due to the higher number of full load hours compared to PV energy, the share of onshore wind energy of total electricity provided (70 %) is higher than its share of installed generation capacity (54 %). Due to the availability of salt caverns at the considered location, the hydrogen can be stored very cost effectively, so that the model does not choose electricity storage facilities at this location.

4.3.2 Hydrogen Production and Storage

As already explained, an electrolyser with 100 MW is specified for hydrogen production. The 100 MW electrolyser serves as a dimensioning factor for optimising all other supply chain components. Due to the high fluctuation in the electricity supply from wind and solar energy exclusively, the optimisation of hydrogen production at the location under consideration is based on a PEM electrolyser. As described in Section 2.2, PEM electrolysers are better suited for direct coupling with fluctuating renewable energies than alkaline electrolysers due to their higher flexibility. At full capacity, an electrical load of 100 MW roughly corresponds to a specific production capacity of 2.0 t H2/h.

The optimised plant configuration shown in Figure 14 leads to around 6050 annual full load hours (AFLH) for the electrolyser. The compression corresponds to the maximum specific output respectively to the power of the electrolyser with 2 t H2/h. In terms of the use of a hydrogen storage facility to ensure a continuous hydrogen supply (cf. Section 3.2), the selected site profits from the availabil-ity of salt caverns, which enable significantly cheaper storage than pressure tanks. Accordingly, the hydrogen storage capacity selected in the cost optimal plant configuration is relatively high at 1390 t. An explanation of the resulting production and supply costs shown in Figure 15 is provided in Chapter 4.3.4.

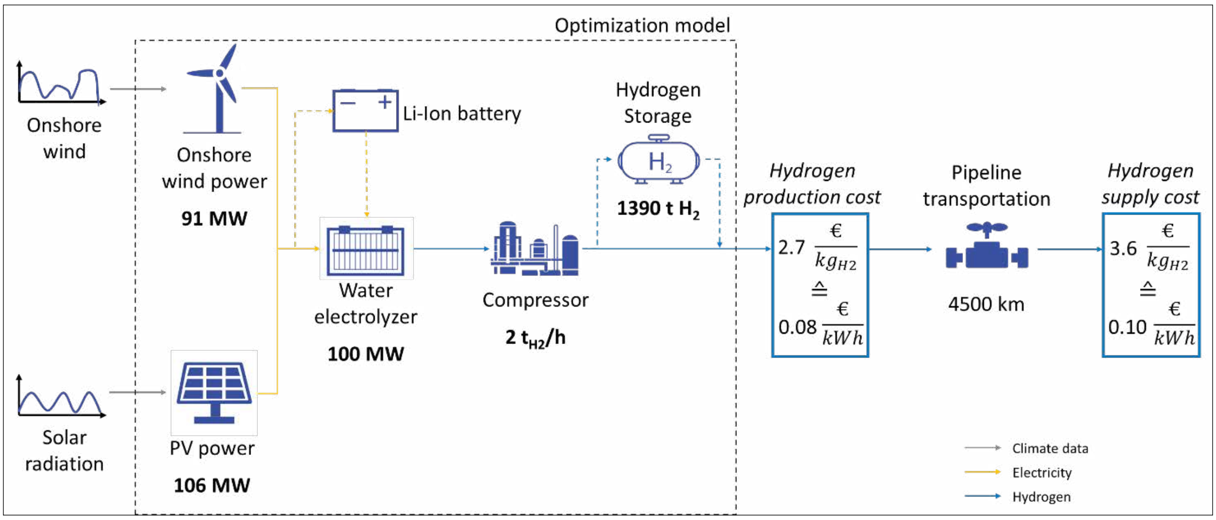

Figure 15: Optimized system configuration for hydrogen production at the selected site in Egypt

4.3.3 Energy Flow and Efficiencies

Figure 16 shows the annual energy flows of the optimized system configuration (see Figure 14). Based on the weather year 2019, around 695 GWh are generated annually by the installed PV and wind energy systems. Approximately 12 % (85 GWh) of the electricity generated cannot be used by the system and is curtailed as excess energy. The majority of the energy supplied to the system is used for electrolysis. The energy demand for compression plays a subordinate role in the overall pic-ture, at around 5 GWh per year. Only about 0.5 GWh per year is needed to desalinate the water re-quired for electrolysis. Therefore, desalination is negligible as an energy consumer and is not listed in Figure 15.

The largest energy losses occur during electrolysis (~200 GWh). These energy losses are determined by the electrolysis efficiency and are generated mainly as waste heat. Therefore, the electrolysis's ef-ficiency is the decisive parameter for the overall efficiency of hydrogen supply in the outlined scenario. While the use of waste heat (see Table 4) from electrolysis is conceivable in areas with low ambient temperatures (e.g., in Europe or North America), this appears to be less feasible in countries with a low heat demand, such as Egypt.

Compression does not change the amount of energy stored in the hydrogen. Therefore, the energy used for compression can be considered a loss. During the transport of the gaseous hydrogen from Egypt to Central Europe, the pipeline's operating pressure must be maintained. Due to the very long transportation distance (assumption for calculation: 4,500 km), the energy input for intermediate com-pression is relatively high in the considered case. The energy required for intermediate compression occurs along the transport route and is therefore not part of the optimised system. Instead of the electricity generated by the wind and PV plants installed at the site in Egypt, grid electricity is used for intermediate compression.

It is assumed that no hydrogen losses occur during compression, storage and pipeline transport. Therefore, the amount of hydrogen produced in Egypt can be provided in Central Europe. Based on the weather year 2019, around 12,175 tonnes of hydrogen can be produced at the site under consid-eration with a 100 MW electrolyser embedded in the outlined plant configuration. Taking into account the excess energy, the overall efficiency is nearly 56 %. If the excess energy is excluded, the overall efficiency of hydrogen supply rises to around 63%.

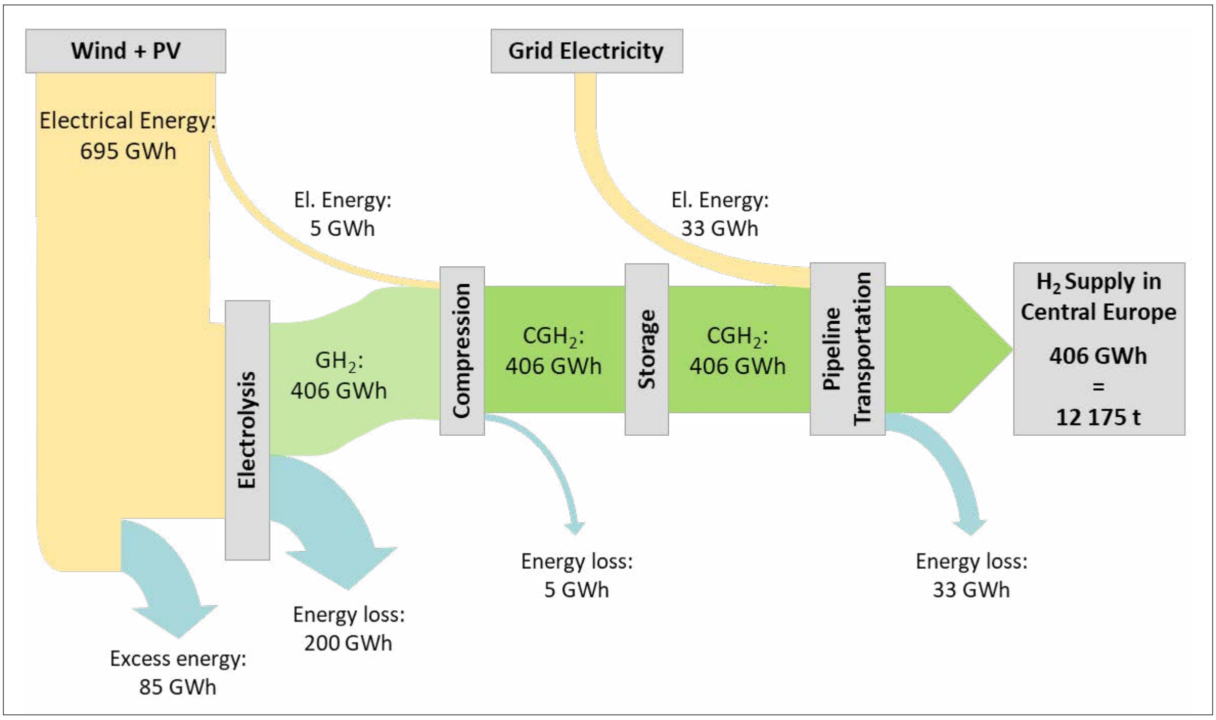

Figure 16: Annual energy flows of the optimized system configuration for Egypt

4.3.4 Hydrogen Supply Cost

Under the selected assumptions, hydrogen production costs of 2.7 €/kg can be expected at the examined location in Egypt in 2030. For a possible transport of the produced hydrogen by pipeline to Central Europe (transportation distance of 4,500 km assumed), an additional cost of about 0.9 €/kg arises. Thus, the resulting hydrogen supply costs are 3.7 €/kg. This corresponds to 0.11 €/kWh.

Figure 17 shows the composition of hydrogen supply costs. Listed are the production costs resulting from the supply of renewable electricity (91 MW PV, 106 MW wind onshore), the costs for the construction and operation of the electrolyser (100 MW), the compressor (2 tH_2/d) and the hydrogen storage (1390 t) as well as the water supply costs. For the hydrogen supply in Central Europe, transporta-tion costs have to be added. The transportation costs include the costs for the construction and operation of the pipeline and the costs for the supply of the grid electricity required for the intermediate compression of the hydrogen. New construction or redevelopment of roads or ports etc. were not considered in this case study.

It becomes clear that the costs of generating renewable electricity play a central role. At around 1.3 €/kg, the costs for the construction and operation of PV and onshore wind energy plants account for almost half of the hydrogen production costs (without transportation). However, electrolysis also represents a substantial share, accounting for around one third of hydrogen production costs. The costs for desalination and supply of water play a minor role at 0.03 €/kgH_2. Also, the costs for the construc-tion and operation of the compressor are comparatively low.

One reason for this is that the pressure difference between the hydrogen supplied by the electrolyser (50 bar) and the salt cavern storage (100 bar) is only 50 bar. If the hydrogen is required at a higher pressure level, for example, for use in the mobility sector, the costs for compression increase.
Storage costs contribute around 0.5 €/kgH_2 to the overall supply cost. In this regard, it should be noted that the availability of salt caverns significantly reduces storage costs. The specific expenses for hydrogen storage in pressure tanks are several times higher than storage in salt caverns.

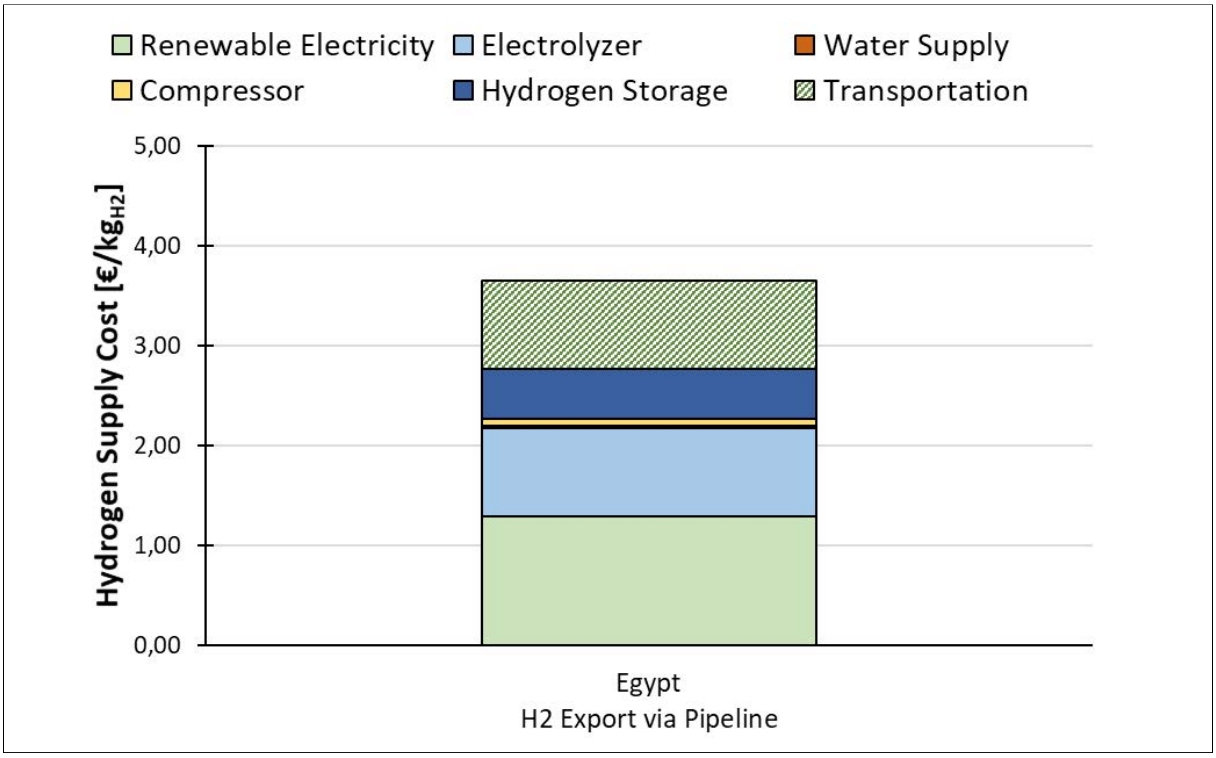

Figure 17: Composition of hydrogen supply costs for the selected location in Egypt

5. Case study 2
Kenya as an Ammonia Exporter

The second case study aims to investigate Kenya's potential in terms of green energy production and export. In a first step, the components of a suitable supply chain are identified based on the regional conditions in Kenya. This initially involves identifying a suitable location for setting up a hydrogen production plant as well as potentially available renewable energy sources. Secondly, a suitable sales market for a potential export of the produced hydrogen or its derivatives is identified, and a corresponding conceivable and advantageous transport option from Kenya is selected. Finally, both the design of the individual components and the identified supply chain will be investigated. For this pur-pose, the approach explained in Chapter 3 is applied in Section 5.3 and a possible design of an ex-emplary demonstration plant is presented.

5.1 Availability of Renewable Energy Resources in Kenya

Referring to the results of the country selection process, Kenya shows an increased potential for wind, solar and geothermal energy. Therefore, all three renewable energy sources are taken into ac-count in the site identification for green hydrogen production in Kenya.

Figure 18 clearly illustrates that the region around Lake Turkana has a very high wind energy potential. Here, the average power density for the 10 % windiest area in this region is about 1900 W/m^2. With a size of 365 wind turbines, the Lake Turkana Wind Park is located in the Loiyangalani District. The indi-vidual wind turbines have a capacity of 850 kW. The wind farm is connected to the Kenyan national grid via a 435 km long transmission line [46].

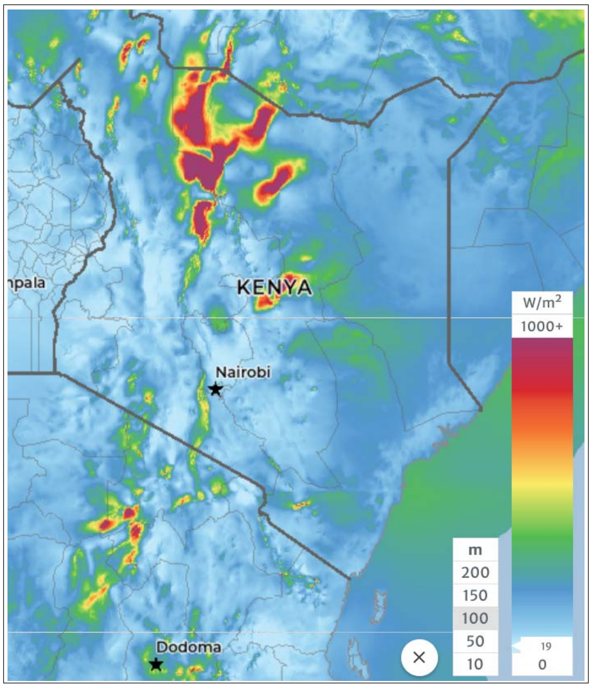

Figure 18: Wind map of Kenya [32]

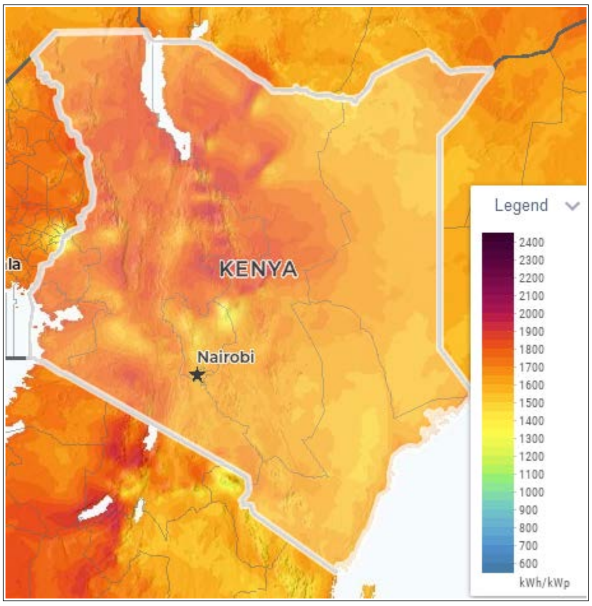

Figure 19: Solar map of Kenya [31]

Figure 19 shows that solar energy is nationwide available and furthermore there is increased irradiation especially around Lake Turkana and the Rift Valley. Currently, the installed capacity of PV power plants is more than 100 MW. The largest solar park, the Garissa Solar Power Plant, has an installed capacity of 55 MW. Further solar plants are already being planned for the future [47].

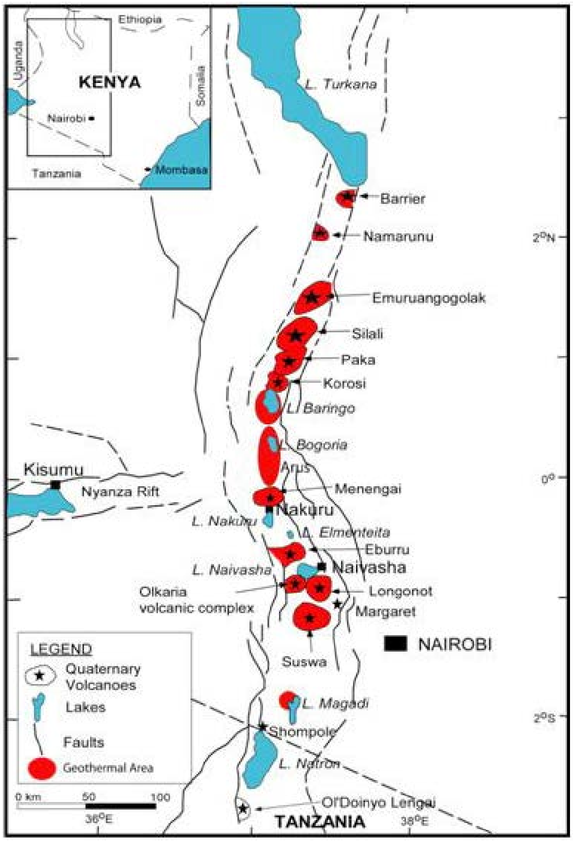

Figure 20: Geothermal resource map of Kenya [48]

Additionally, Kenya has an increased potential for geothermal energy. The geothermal resources come from Africa's Great Rift Valley with an estimated potential of between 7 000 MW to 10 000 MW spread over 14 prospective sites. Figure 20 shows the geothermal resource map of Kenya [48].

Many geothermal plants are already permanently installed and others are being planned. These five stakeholders, among others, are involved in the exploration of Kenya's geothermal resources [48]:

• GDC: Geothermal Development Company
• AGIL: African Geothermal International Limited
• KenGen: Kenya Electricity Generating Company
• ODCL: Oserian Development Company Limited
• AGL: Akiira Geothermal Limited

Due to the availability of the generated electricity from geothermal energy via the national grid for hy-drogen production, an area close to the Lake Turkana wind farm was chosen as the best possible location for this case study. In this area, the wind and solar potentials are very high. The selected loca-tion is shown in Figure 21.

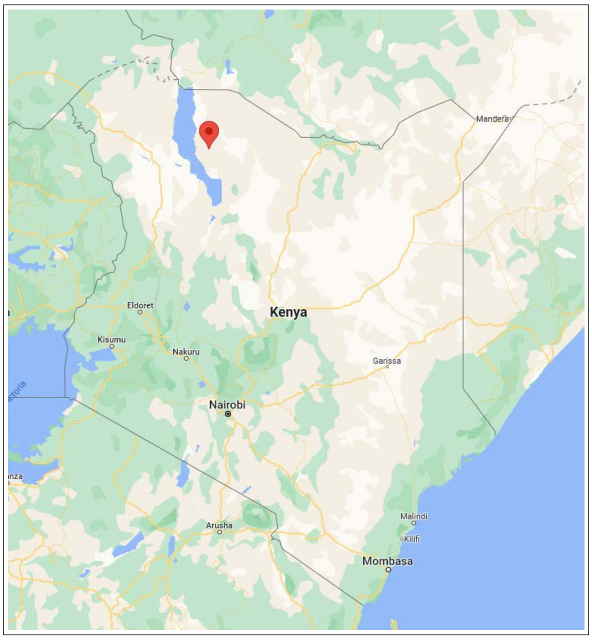

Figure 21: Selected Location for the hydrogen production in Kenya [36]

5.2 Further Processing Steps

As already explained in the previous section, the renewable energy for green hydrogen production in this case study will be obtained from wind power, solar power and geothermal energy. This chapter shows one example of a potential complete supply chain, including one suitable transport option. Due to Kenya's geographical location, the Asian region, e.g., Japan, is a potential sales market.

Japan is one of the populous industrialized countries with high energy demand. In order to steadily reduce the fossil energy demand, imports from regions that have a high potential for production of cheap green energy are necessary.

In principle, transporting pure hydrogen is always preferable to transporting it as a chemically bound variant, as this avoids conversion losses. Due to the long distance and the resulting lack of pipeline infrastructure, transport via ship is considered for the following calculations. However, boil off losses during the transport of liquid hydrogen by ship increase significantly with increasing transport distances.

Liquid ammonia is a promising hydrogen carrier, as it can be transported with high energy densities at moderate conditions (pressure and temperature). The transport of ammonia is already established on the world market, as ammonia is a raw material for fertilisers. In addition, ammonia can be used as a fuel in the mobility sector or split again (so called ammonia cracking) to generate hydrogen. Especially in Japan, the development of a transnational market for green ammonia is currently being driven forward. Therefore, this case study examines the export of green ammonia from Kania to Japan. Figure 22 shows the ammonia supply chain under consideration.

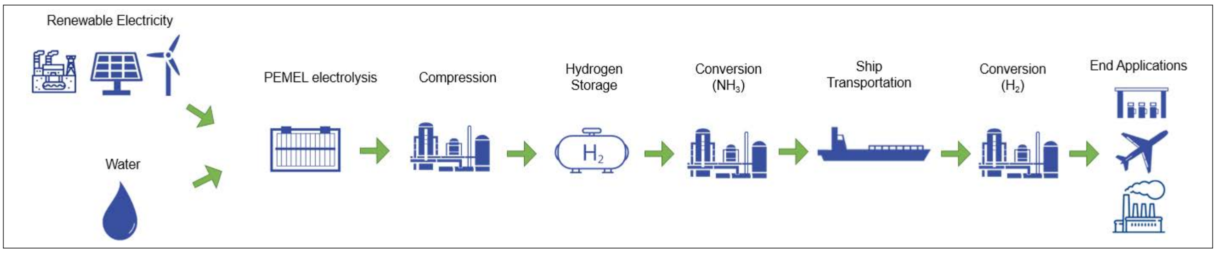

Figure 22: Ammonia supply chain in Kenya

5.3 Results - Production of Green Ammonia in Kenya and the Supply to Japan

In this chapter, the modelled results for a cost optimised production of green ammonia in Kenya and its supply to Japan are presented with regard to the dimensioning of the individual supply chain components. The central component of a plant for the production of green ammonia is the electrolytic hy-drogen production. Therefore, the design of a plant optimised for minimum hydrogen supply costs is presented first. In the following sections, the energy input along the overall ammonia supply chain, the resulting efficiency and the composition of the ammonia supply costs are discussed. All values shown refer to the techno economic parameters of the supply chain components forecasted for 2030. Furthermore, the optimisation is based on the weather data for the year 2019.

5.3.1 Renewable Energies

Table 5 shows the most important key figures for renewable electricity generation for the continuous supply of compressed hydrogen at the site under consideration. The figures listed result from the model-based optimisation and describe the system configuration that enables hydrogen supply at minimum cost. An electrolyser with an installed capacity of 100 MW is used as a design parameter for dimensioning the renewable energy plants. The supply of the required N_2, the ammonia synthesis via Haber-Bosch process and the transport of the green ammonia from Kenya to Japan are not part of the optimised hydrogen supply. Accordingly, the supply of the energy required for these process steps is not covered by the capacities shown in Table 5.

	INSTALLED CAPACITY [MW]	AFLH [H/A]	SHARE OF SUPPLIED ELECTRICITY [GWH/ GWH_{DEMAND}]	ELECTRICITY COS[€/MWH]
ONSHORE WIND POWER	106	5066	59	22
PHOTOVOLTAIC POWER	107	2151	25	19
GEOTHERMAL POWER VIA GRID	Max. 100	8760	15	70

Table 5: Parameter of the renewable energy generation for the supply of 100 MW electrolysis [a]

[a] All data refer to the year 2030.

In the case under consideration, electricity from onshore wind energy, photovoltaics and geothermal energy is available for the production and compression of hydrogen. While the key figures for elec-tricity supply from wind and solar energy are derived from site-specific weather data, it is assumed that electricity from geothermal power can be purchased from the public electricity grid. Respectively, a continuous supply of electricity from geothermal energy at 70 €/MWh (includes typical electricity generation costs for geothermal energy and grid usage fees) is included in the model as a further electricity supply option. Although the supply of electricity from geothermal energy is significantly more expensive than PV or wind energy, the advantages are considerable. A permanent base load and thus security of supply is guaranteed. Furthermore, with an efficiency of almost 100 %, the tech-nology for using geothermal energy is highly efficient and only requires a small amount of land.

With 22 €/MWh for onshore wind energy and 19 €/MWh for PV, the location under consideration has excellent conditions for generating cheap renewable electricity. Especially for wind energy, with over 5,000 annual full load hours, a degree of utilisation is achieved that is unusually high for onshore loca-tions. The validity of the key figures determined for wind energy use is confirmed by the real data of the Lake Turkana wind farm, located near the analysed location. The operator states an utilisation rate of 70 % for the park, which has been in operation since 2018. That would correspond to even more than 6,000 annual full load hours [46].

Under the selected constraints, the optimal ratio of installed wind and solar energy to achieve the min-imum hydrogen supply cost is almost 1 to 1. In total, just over 100 MW each of onshore wind energy and PV are installed. The oversizing factor (installed renewable energy capacities against installed electrolyser capacity) is slightly over two. Due to the significantly higher utilisation, onshore wind en-ergy (59 %) contributes a much higher share to the total electricity supply than PV (25 %). The remain-ing 15 % of the electricity used for electrolysis and hydrogen compression is purchased from the grid for 70 €/MWh and originates from geothermal energy. Batteries for storing electrical energy are not part of the system for cost-optimised hydrogen supply.

5.3.2 Hydrogen Production and Storage

Since electricity from geothermal energy is available for hydrogen production at all times, an alkaline electrolyser was selected for optimising the hydrogen supply. As described in Chapter 2.2, alkaline electrolysers have slightly less operational flexibility (which is less important if continous electricity supply is available) than PEM electrolysers, but are expected to be the most affordable electrolysis technology in 2030. At full capacity, an electrical load of 100 MW roughly corresponds to a specific production capacity of 2.0 t H2/h.

The optimised plant configuration shown in Figure 23 leads to an extraordinarily high load factor of the electrolyser of around 7,600 annual full load hours. The amount of hydrogen produced annually is around 15,300 t. The installed compression capacity corresponds to the maximum specific output re-spectively to the power of the electrolyser with 2.0 t H2/h.

The hydrogen storage capacity selected by the model is only 17 t and is thus significantly less than 50 % of the maximum daily output of the electrolyser. Reasons for the low installed storage capacity in the cost optimal plant design especially compared to the results of the case study for Egypt are most likely the high specific costs of hydrogen storage in pressure gas tanks and the availability of continuous grid electricity.

5.3.3 Production of Green Ammonia

For ammonia production, N_2 is needed in addition to hydrogen. Various technologies are available for the extraction of pure N_2 from ambient air, of which cryogenic N_2 purification is the most commonly used process. For the production of ammonia in the Haber-Bosch process, an almost loss-free pro-cess is assumed. Accordingly, 0.82 kg of N_2 and 0.18 kg of hydrogen are needed to produce one kg of ammonia. For the supply chain examined in this case study, this translates into a total of around 86,800 t of green ammonia that can be produced annually from the 15,300 t of hydrogen provided. Approximately 71,200 t of N_2 are required. Based on literature values, it is assumed that the large scale supply of N_2 (includes separation from the air plus compression) is possible at 30 €/t and has an energy demand of 110 kWh/t.

5.3.4 Energy Flow and Efficiencies

Figure 24 shows the expected annual energy flows of the optimised system configuration (see Figure 22). Based on the weather year 2019, around 768 GWh are generated annually by the installed PV and wind energy systems. Close to 18 % (137 GWh) of the electricity generated by the PV and wind energy plants cannot be used and is curtailed as excess energy. In addition to electricity from wind and PV, 134 GWh from geothermal energy are purchased via the grid to supply the electrolyser and hydrogen compressor. Taking into account the electricity consumed by hydrogen compression (5 GWh), the amount of energy fed into the electrolyser in the reference year amounts to 759 GWh. Only about 0.6 GWh per year are needed to desalinate the water required for electrolysis. Therefore, water supply is negligible as an energy consumer and is not listed in Figure 23.

In addition to hydrogen supply, N_2 supply, ammonia synthesis, and ammonia transport by ship also require energy. The total annual energy demand for the supply of the required N2 quantity (71,200 t) is almost 8 GWh. For the Haber-Bosch synthesis, 27 GWh are needed. It is assumed that grid electricity from geothermal energy, is used to supply both of these processes. An additional 29 GWh of fuel energy are needed per year to transport the ammonia produced to Japan by ship.

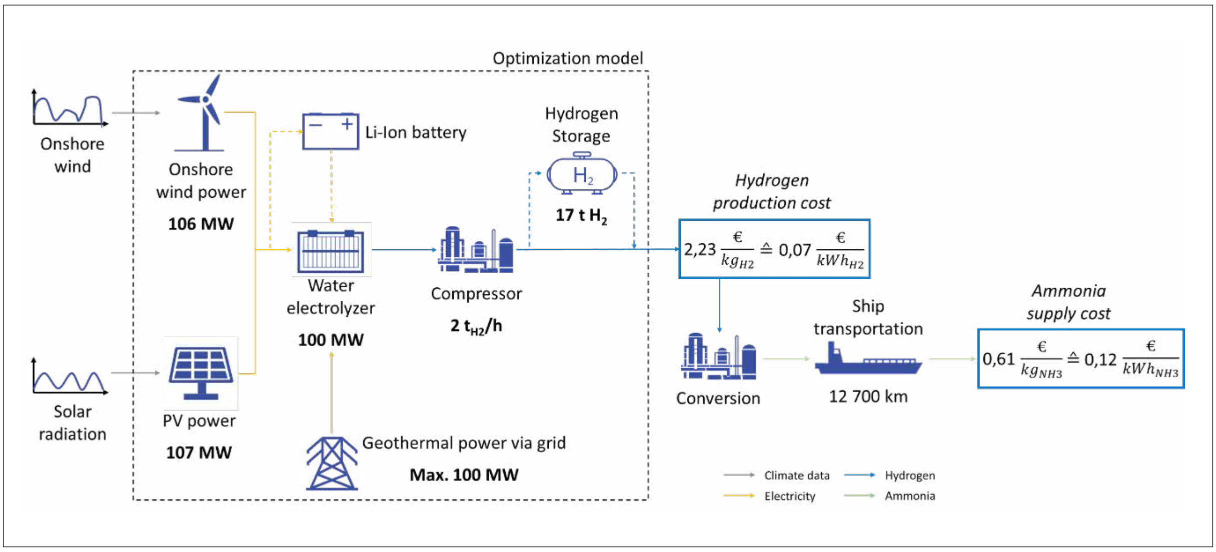

Figure 23: Optimized system configuration for hydrogen production at the selected site in Kenya

Taking all process steps into account, the total energy demand for the supply of 86 800 t of green ammonia (~451 GWh) is 966 GWh. This corresponds to an energy efficiency of close to 47 %. If the excess energy is neglected, the overall efficiency rises to around 54 %.

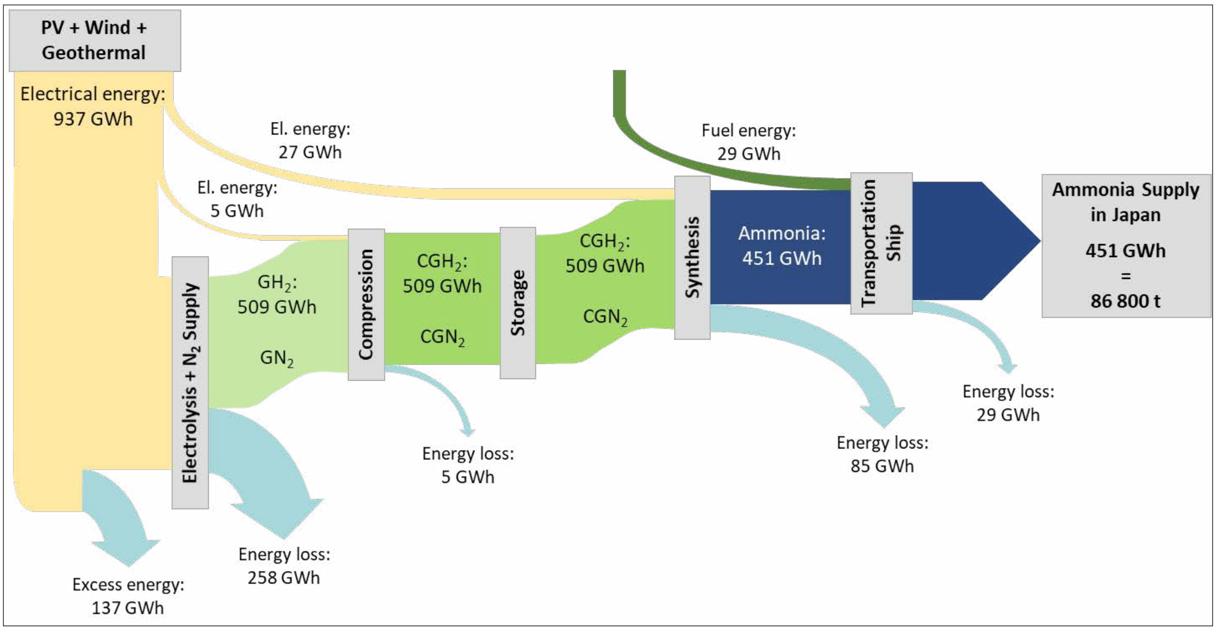

Figure 24: Annual energy flows of the optimized system configuration for Kenya

The analysis of the energy flows shows that the electrolytic hydrogen production essentially deter-mines the total energy demand of the ammonia supply. Thus, over 90 % of the total energy used is used for electrolysis. At the same time, the majority of the energy losses that occur along the supply chain can be attributed to electrolysis (258 GWh). These energy losses are essentially determined by the electrolysis efficiency and are largely generated as waste heat. Further notable energy losses re-sult from ammonia synthesis. While it is difficult to use the waste heat from the electrolyser (<80 °C), the waste heat from the Haber-Bosch synthesis is easier to exploit for subsequent use due to its higher temperature level (>300 °C). Although the distance between the production site and the supply location is high in the outlined scenario with over 12,000 km, the energy input for transportation has only a small influence on the overall energy balance.

5.3.5 Ammonia Supply Cost

Under the selected assumptions, green ammonia production costs in the range of 0.52 €/kg can be achieved at the examined location in Kenya in 2030. The additional costs caused by the transport of the ammonia by ship to Japan (transport distance of 12,700 km assumed) are slightly below 0.1 €/kg. Thus, the resulting ammonia supply costs in Japan are approximately 0.6 €/kg. This corresponds to 0.12 €/kWh.

The ammonia supply costs consist of different components. Central is the site-specific cost for the supply of the required green hydrogen, which is determined with the help of the optimisation model described in section 5.3 "Results - Production of Green Ammonia in Kenya and the Supply to Japan". The hydrogen supply costs include the costs for the supply of renewable electricity (106 MW onshore wind, 107 MW PV and geothermal power via grid), the construction and operation of the electrolyser (100 MW) as well as the hydrogen compressor and storage tank. Additionally, there are the costs for the provision of the N_2, the construction and operation of the fuel synthesis unit and the transportation of the green ammonia to Japan. The transport costs include the depreciation costs for the acquisition of the corresponding tanker and the operating costs, including fuel costs. New construction or redevelopment of roads or ports etc. were not considered in this case study.

Figure 25 shows that hydrogen supply costs are the largest cost component. Overall, their share of the ammonia supply costs in the examined case is around 65%. It is noticeable that, in contrast to the case studies for Ghana and Egypt, the specific costs for the generation of the required electricity (0.28 €/kg_{NH3}) are significantly higher than the costs for the construction and operation of the electrolyser (0.09 €/kg_{NH3}). The reason for this is the extraordinarily high load factor of the electrolyser. On the one hand, this leads to very low specific investment costs for the electrolyser. On the other hand, a high utilisation of the electrolyser goes hand in hand with a relatively large amount of excess ener-gy, which in turn leads to rising costs for the electricity supply.

The supply of N_2, as well as the water required for electrolysis, plays a subordinate role in the overall costs. Also, the costs for storage and compression are low. The relatively low costs for hydrogen storage (especially in comparison to Case Study 1, Figure 16) can be explained, among other things, by the fact that the storage capacities installed as part of the cost optimised hydrogen supply are low at 17 t of hydrogen (see Figure 22). The costs arising from the Haber Bosch synthesis and the transportation costs are each in the range of 0.1 €/kg. Compared to the transport of PtL fuel examined in the case study for Ghana, it is noticeable that the transport of ammonia has a significantly higher share of the total supply costs. This is mainly due to the fact that the energy density of (liquid) ammonia (3.2 kWh/l) is much lower compared to PtL fuel (10 kWh/l). Accordingly, ammonia transport requires a larger volume.

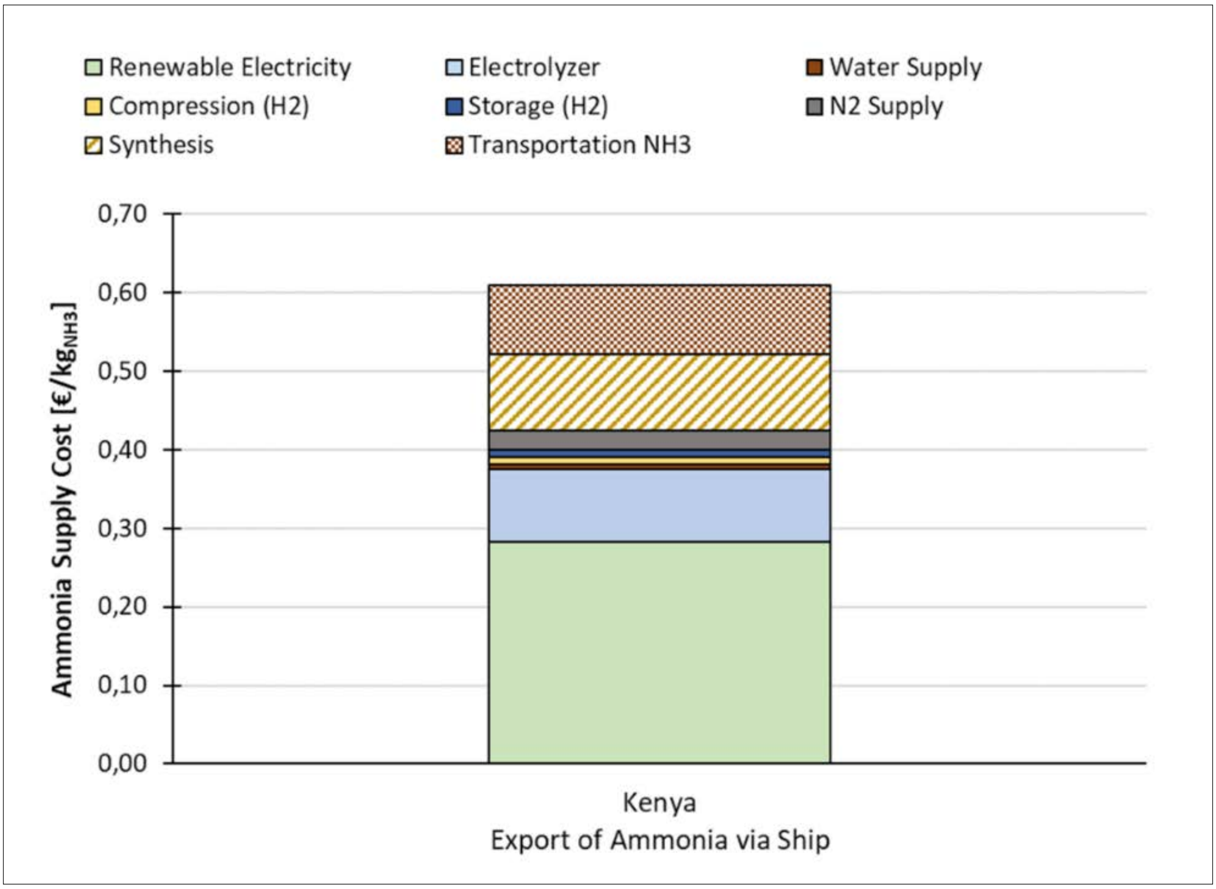

Figure 25: Composition of hydrogen supply costs for the selected location in Kenya

6. Case study 3
Ghana as a PtL exporter

The third case study aims to investigate the potential of Ghana for the production and export of green energy. In a first step, the components of a suitable supply chain are identified based on the regional conditions in Ghana. This initially involves identifying a suitable location for setting up a hydrogen production plant as well as potentially available renewable energy resources. Secondly, a suitable sales market for a potential export of the produced hydrogen or its derivatives is identified, and a corresponding conceivable and advantageous transport option from Ghana is selected. Finally, both the design of the individual components and the identified supply chain will be investigated. For this purpose, the approach explained in Chapter 3 is applied in Section 6.3, and a possible design of an exemplary demonstration plant is presented.

6.1 Availability of Renewable Energy Resources in Ghana

This chapter is about a preliminary assessment of renewable energy resources that can be used for hydrogen production in Ghana. The Wind Atlas map (Figure 26) clearly shows no increased potential for wind power in Ghana. Only north of the capital Accra is a narrow area extending to the north of Kumasui with an increased power density between approximately 300 W/m^2 and 800 W/m^2 at a high of 100 m. In the Ningo Prampram district, around 60 km east of Accra, an onshore wind farm with a total capacity of 225 MW is being planned for 2023. The development of the Ayitepa wind farm has already been completed and is currently in the financing phase. With a size of up to 75 wind turbines, approx. 600 GWh 700 GWh of energy are to be produced annually. The site was chosen as it offers good and consistent wind conditions due to its openness and relative flatness. Furthermore, the existing good infrastructure, low environmental requirements and easy grid access are advantageous for the construction of a wind farm [49, 50].

The Solar Atlas map shows that Ghana has a relatively even potential for solar energy nationwide. In the north of the country as well as on the coast in the greater Accra area, there is a slight increase in solar resources.

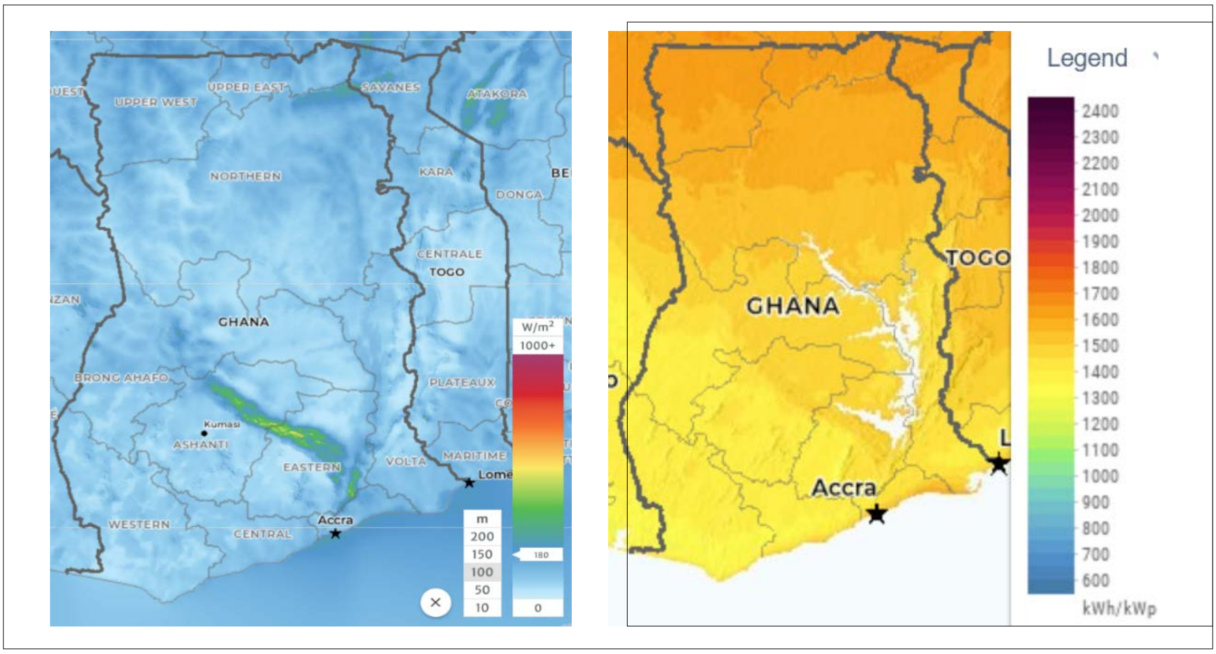

Figure 26: Wind and solar map of Ghana [31, 32]

The existing electricity generation in Ghana is dominated by two power plants. The Kpong and Akosombo hydropower plants supply about 70% of the national electricity. According to current data, the Akosombo power plant (912 MW) is the largest hydroelectric dam built in Ghana and supplies up to 58% of Ghana's electricity. With an average flow of 1160 m^3/s, the annual design energy of the 160 MW Kpong hydro electric power plant is about 1000 GWh. Both power plants are located on the Volta River below Lake Volta, 80 km from the city of Accra. The lower reaches of Akosombo form the up per reaches of Kpong [51].

Figure 27: Selected PtL production site in Ghana [36]

An area east of Accra was chosen as a potential site for hydrogen production in this case study. This location already offers good infrastructure and easy access to the electricity grid. Furthermore, the proximity to the coast offers short national transport distances for future export.

6.2 Further Processing Steps

As already explained in the previous chapter, the renewable energy for green hydrogen production in this case study will be obtained from solar power, wind power and hydropower. This chapter shows one example of a potential complete supply chain, including a suitable transport option. Due to Gha-na's geographical location, North America is a potential sales market for green energy. PtL fuels are a promising option for the export of green energy.

PtL fuels are important in the transport sector for achieving the goals of the Paris Climate Agreement. In principle, CO_2 emissions in the transport sector must be drastically reduced. At the same time, however, the global transport of goods and people must continue to be guaranteed. Heavy transport, air traffic and shipping cannot operate without the high energy density of liquid fuels. With the PtL concept, climate-neutral liquid fuels can be produced with electric current from renewable energy sources (power). In addition to renewable electricity, green CO_2 is needed.

The CO_2 will be extracted directly (so-called direct air capture) or indirectly (via biomass) from the at-mosphere. This means that the CO_2 emitted during the use of e-fuels is previously taken from the air, which closes the CO_2 cycle and thus makes the fuel CO_2 neutral. An essential prerequisite for green PtL production is the availability of green hydrogen. The green hydrogen produced in this case study will therefore serve as a feedstock for PtL production.

As the North American region is an established market in global trade and CO_2-neutral transport is be-coming increasingly important, this case study examines the shipping of PtL fuels produced in Ghana to North America. Figure 28 shows the supply chain under consideration.

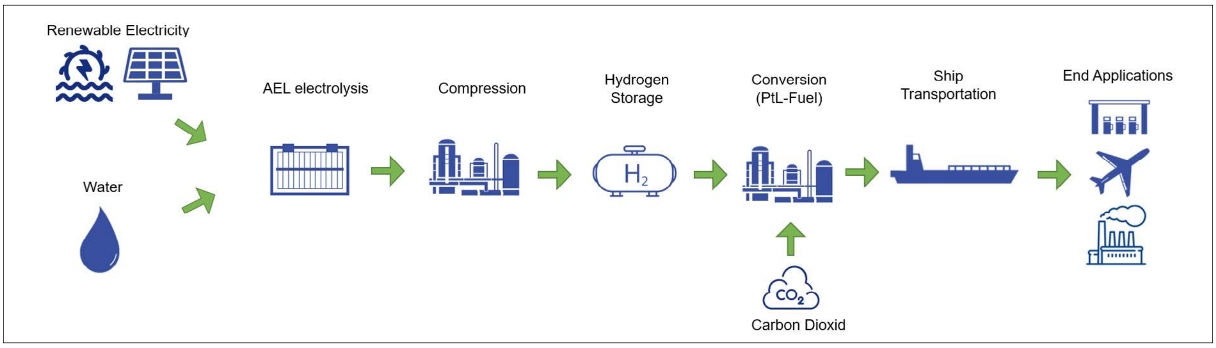

Figure 28: PtL supply chain in Ghana

6.3 Results - Production of Green PtL Fuels in Ghana and their Supply to North America

In this chapter, the modelled results for a cost optimised production of green PtL fuels in Ghana and the supply of the produced fuels to North America are presented with regard to the dimensioning of the individual supply chain components. The central component of a plant for the production of PtL fuels is electrolytic hydrogen production. Therefore, the design of a plant optimised for minimum hy-drogen supply costs is presented first. The following sections discuss the energy input along the overall PtL supply chain, the resulting efficiency, and the composition of the PtL supply costs. All values shown refer to techno economic parameters of the supply chain components forecasted for 2030. Furthermore, the optimisation is based on the weather data for 2019.

6.3.1 Renewable Energies

Table 6 shows the most important key figures for renewable electricity generation for the continuous supply of compressed hydrogen at the site under consideration. The figures listed result from the model-based optimisation and describe the system configuration that enables hydrogen supply at minimum cost. An electrolyser with an installed capacity of 100 MW is used as a design parameter for dimensioning renewable energy plants. The capture and compression of the required CO_2, the fuel synthesis via Fischer Tropsch process, and the fuel transport are not part of the optimised hydrogen supply. Accordingly, the supply of energy required for these process steps is not covered by the capacities shown in Table 6.

In this case study, electricity from onshore wind energy, PV and hydropower is available for the pro-duction and compression of hydrogen. While the key figures for electricity supply from wind and solar power are derived from site specific weather data, it is assumed that electricity from hydropower can be purchased from the public electricity grid. Respectively, a continuous supply of electricity from hydropower at 60 €/MWh (includes typical electricity generation costs for hydropower and grid usage fees) is included in the model as a further electricity supply option.

Table 6 clearly shows that the conditions for the use of wind energy at the chosen location are poor. Thus, the annual full load hours (AFLH) for onshore wind energy are only around 1,700. Accordingly, the calculated levelised cost of electricity (LCOE) of wind energy is very high at 66 €/MWh and three times greater than the LCOE of PV electricity generation. Even the use of hydropower via the public electricity grid, which is not subject to any weather related fluctuations in availability, shows lower specific costs than onshore wind energy.

The poor conditions in Ghana for the use of wind energy result in onshore wind turbines not being part of the plant configuration that features minimum hydrogen supply cost. The installed PV capaci-ty, which generates electricity at 23 €/kWh at the investigated site, is therefore all the greater. A total of 193 MW is installed, supplying 91 % of the electricity for the electrolyser and the compressor. The remaining 9 % of the electricity used for electrolysis and hydrogen compression is purchased from the grid for 60 €/MWh and originates from hydropower. Batteries for storing electrical energy are not part of the system for cost optimised hydrogen supply.

	INSTALLED CAPACITY [MW]	AFLH [h/a]	SHARE OF SUPPLIED ELECTRICITY [GWH/GWH_{DEMAND}]	ELECTRICITY COS[€/MWH]
ONSHORE WIND POWER	0	1,702	0 %	66
PHOTOVOLTAIC POWER	193	1,763	91 %	23
GEOTHERMAL POWER VIA GRID	Max. 100	8,760	9 %	60

Table 6: Parameter of the renewable energy generation for the supply of 100 MW electrolyser [a]

[a] All data refer to the year 2030.

The modelled plant design shows that minimum hydrogen supply costs, and thus also minimum PtL fuel supply costs, require oversizing of the installed renewable energy plants. The oversizing factor (installed renewable energy capacities against installed electrolyser capacity) is in the range of two. The excess energy resulting from oversizing corresponds to around 14 % (51 GWh) of the electricity generated annually (for further explanations on oversizing and excess energy, see Case Study for Egypt).

6.3.2 Hydrogen Production and Storage

Since electricity from hydropower is theoretically available for hydrogen production at all times, an al-kaline electrolyser was selected for optimising the hydrogen supply. As described in Chapter 2.2, alkaline electrolysers have slightly less operational flexibility (which is less important if continous electricity supply is available) than PEM electrolysers, but are expected to be the most affordable electrolysis technology in 2030. At full capacity, an electrical load of 100 MW roughly corresponds to a specific production capacity of 2.0 t H2/h.

The optimised plant configuration shown in Figure 29 leads to around 3,200 annual full load hours (AFLH) for the operation of the electrolyser. The amount of hydrogen produced annually is thus around 6,500 t. The installed compression capacity corresponds to the maximum specific output respectively to the power of the electrolyser with 2.0 t H_2/h. The hydrogen storage capacity selected by the model is only 13 t and is thus significantly less than 50 % of the maximum daily output of the electrolyser. Reasons for the relatively low installed storage capacity in the cost optimal plant design especially compared to the results of the case study for Egypt are most likely the high specific costs of hydrogen storage in pressure gas tanks and the availability of continuous grid electricity.

6.3.3 Production of PtL Fuel

The raw materials for the production of liquid PtL fuels, which takes place in a three stage process, are hydrogen and CO_2. In the reverse water gas shift (RWGS) reaction, CO_2 is first converted to car-bon monoxide. During this conversion, hydrogen is "consumed". To produce one kg of carbon mon-oxide (CO), about 0.07 kg of hydrogen and 1.6 kg of CO_2 are needed. In a second step, the Fischer Tropsch synthesis, one kg of the so called syncrude is produced from 0.33 kg of hydrogen and 2.2 kg of CO. The syncrude, a mixture of different hydrocarbons, is finally processed in the refinery into the desired PtL product (e.g. jet fuel). For this study, it is assumed for simplicity that exactly one kg of the desired PtL product can be produced from one kg of syncrude. In terms of the modelled mass balance of the PtL fuel supply chain, this translates into around 13,100 t of PtL fuel can be produced annually from the 6,500 t of hydrogen provided. This requires approximately 45,500 t of CO_2. For the operation of the synthesis plant consisting of the RWGS reactor, the Fischer Tropsch synthesis and the refinery unit, an operation with 8 000 h/a (full load) is assumed. Therefore, a continuous CO_2 supply must also be ensured in addition to the constant hydrogen supply, which is guaranteed by the modelled plant configuration (see Figure 29). Accordingly, it is assumed that the plant for capturing CO_2 from a biogenic point source (for example, biogas or bioethanol plant) operates at 8000 h/a (full load).

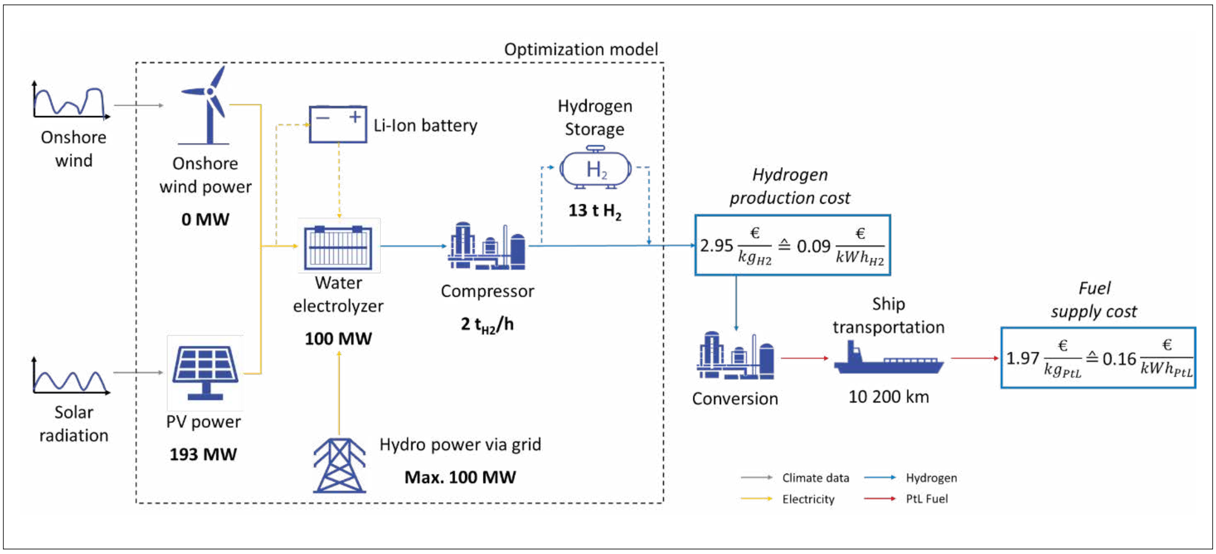

Figure 29: Optimized system configuration for hydrogen production at the selected site in Ghana

6.3.4 Energy Flow & Efficiencies

Figure 30 shows the expected annual energy flows of the optimised system configuration (see Figure 28). Based on the weather year 2019, around 341 GWh are generated annually by the installed PV plant. Close to 15 % (51 GWh) of the PV electricity cannot be used and arises as excess energy. In addition to the electricity from PV, 33 GWh of electricity from hydropower is annually purchased from the public grid to supply the electrolyser and the hydrogen compressor. Taking into account the electricity consumed by hydrogen compression (2 GWh), the amount of energy fed into the electrolyser in the reference year amounts to 321 GWh. Only about 0.3 GWh per year are needed to desalinate the water required for electrolysis. Therefore, desalination is negligible as an energy consumer and is not listed in Figure 30.

To determine the total energy demand of PtL fuel production, in addition to hydrogen supply, the supply of CO_2 and the fuel synthesis itself must also be taken into account. In the context of CO_2 supply, both capture (0.5 GWh) and compression (4 GWh) require electricity. A total of around 11 GWh of electricity is needed for fuel synthesis, of which the RWGS accounts the largest share. To ensure continuous operation of the synthesis plant and steady CO_2 supply, it is assumed that grid electricity from hydropower, which is available at all times, is used to supply these processes.

Taking into account, all the process steps mentioned, the total electricity demand of PtL fuel produc-tion in the scenario under consideration is 339 GWh. If the excess energy is also considered, this results in a total energy supply of 390 GWh, as shown in Figure 30. Additionally, 4 GWh of fuel energy is needed to transport the PtL fuel produced to North America. A special feature of the PtL process is the possible internal use of waste heat. As shown in Figure 30, it is assumed that part of the waste heat generated in the Fischer Tropsch synthesis can be used to cover the heat demand of the CO_2 capture unit (29 GWh). If the thermal energy required for CO_2 capture has to be provided externally, the total energy demand increases accordingly.

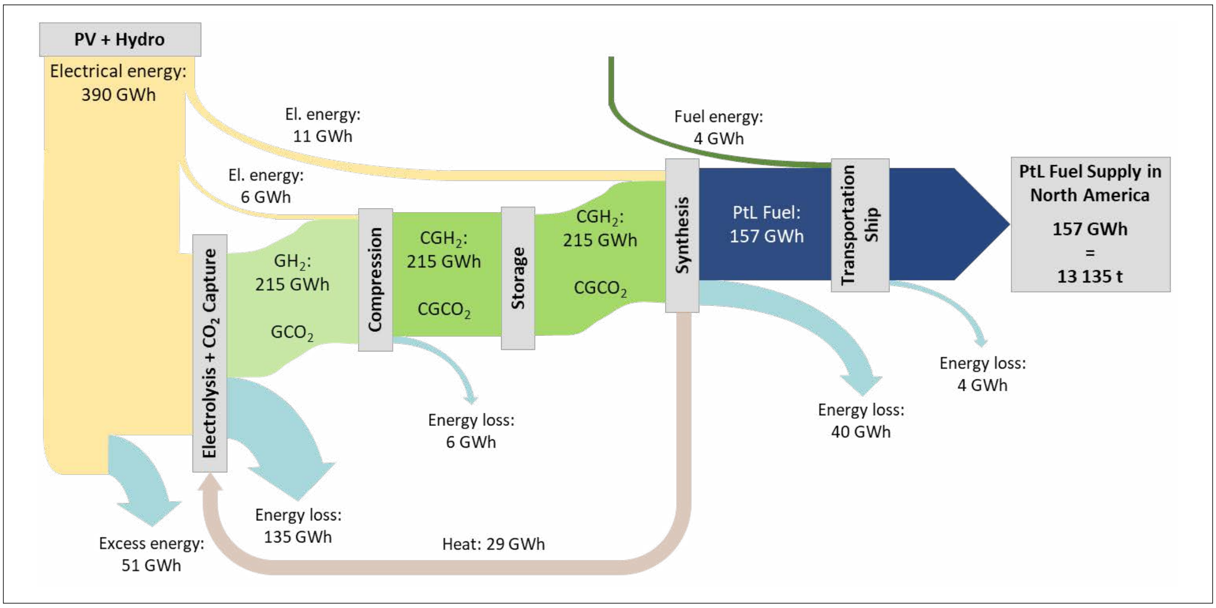

Figure 30: Annual energy flows of the optimized system configuration for Ghana

The comparison of the different process steps shows that hydrogen supply via electrolysis is deci-sive for the total energy input of PtL fuel production. Over 90 % of the total energy used is consumed by electrolysis. At the same time, the largest energy losses occur during hydrogen production (135 GWh). These energy losses are essentially determined by the electrolysis efficiency and are largely generated as waste heat. The efficiency of the electrolysis is, therefore, the decisive parameter for the overall efficiency of hydrogen supply in the outlined scenario. While the use of waste heat from electrolysis may be conceivable in areas with low ambient temperatures (e.g., in Europe or North America), this appears to be less feasible in countries with a low heat demand, such as Egypt.

Further energy losses occur in particular during fuel synthesis (40 GWh). These energy losses occur mainly in the form of waste heat, too. Although the distance between the production site and the sup-ply location is high in the outlined scenario with over 10,000 km, the energy input for transportation has only a minimal influence on the overall energy balance.

Based on the weather year 2019, around 13,135 tonnes of PtL fuel with an energy content of 157 GWh can be produced at the site under consideration with a 100 MW electrolyser embedded in the outlined plant configuration. Taking into account the excess energy, the overall efficiency is approximately 40 %. If the excess energy is neglected, the overall efficiency of PtL fuel supply rises to around 46 %.

6.3.5 Fuel Supply Cost

Under the selected assumptions, PtL fuel production costs in the range of 1.87 €/kg can be expected at the examined location in Ghana in 2030. The additional costs caused by transporting the PtL fuel by ship to North America (transport distance of 10,200 km assumed) are low and in the range of 0.1 €/kg. Thus, the resulting PtL fuel supply costs in North America are approximately 1.97 €/kg. This cor-responds to 0.16 €/kWh.

Figure 31 shows the composition of PtL fuel supply cost. Listed are the costs for the supply of re-newable electricity (193 MW PV and hydro power via grid), for the construction and operation of the electrolyser (100 MW) and the CO_2 capture unit, for the compression and storage of hydrogen and CO_2, the water supply costs as well as the costs for the construction and operation of the fuel syn-thesis unit.

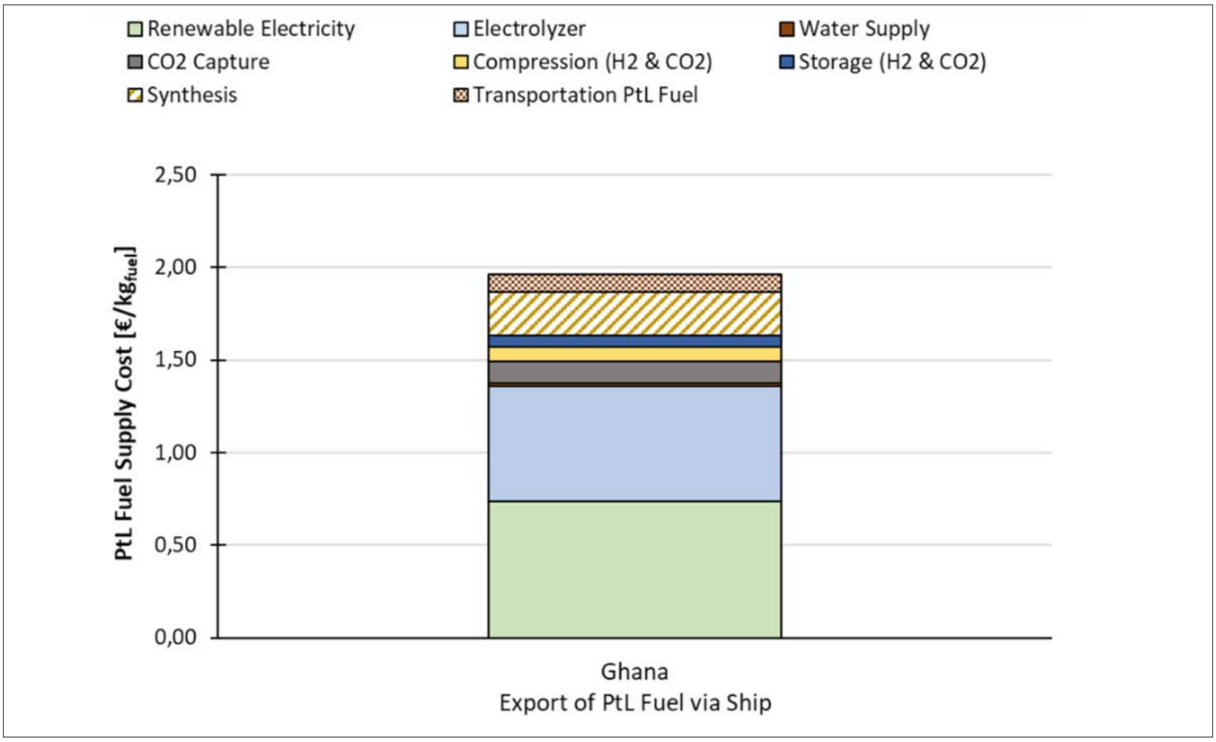

Figure 31: Composition of hydrogen supply costs for the selected location in Ghana

For the supply of the PtL fuel in North America, transportation costs have to be added. The transportation costs include both, the depreciation costs for the acquisition of the corresponding tanker as well as the operating expenses, including fuel costs. New construction or redevelopment of roads or ports etc. were not considered in this case study.

Despite the large number of process steps, electrolysis and the provision of renewable electricity for hydrogen supply (electrolysis & hydrogen compression) account for the majority of overall fuel supply costs at around 70 %. This leads to the conclusion that the availability of low-cost renewable electricity with a high number of annual full load hours is the decisive criterion for selecting a suitable site for low cost PtL fuel production. High utilisation of the electrolyser enables lower specific electrolysis costs (see Egypt case study).

Another relevant cost factor is the synthesis plant for producing the liquid fuel from hydrogen and CO_2, which contributes around 0.25 €/kg PtL fuel to the total costs. At 0.12 €/kg PtL fuel, the costs for providing the CO_2 required for fuel synthesis are comparatively low in the analysed scenario. In this regard, it should be noted that the costs for CO_2 capture would be significantly higher if instead of a biogenic point source (e.g., biogas or bioethanol plant), capture from the atmosphere (the so-called direct air capture process) had been considered. Other studies have shown that the PtL supply costs can increase by up to 20 % if no biogenic point source is available, mainly due to the high in-vestment costs for direct air capture plants. If the heat required for CO_2 capture cannot be provided internally via the waste heat from Fischer Tropsch synthesis, this also leads to higher fuel supply costs.

The storage of hydrogen and CO_2, the provision of treated water for electrolysis and the transport of the produced PtL fuel by ship account for a small share of the total supply costs only, with a maxi-mum of 0.1 €/kg fuel each. The relatively low costs for hydrogen storage (especially in comparison to Case Study 1, Figure 16) can be explained, among other things, by the fact that the storage capacities installed as part of the cost-optimised hydrogen supply are low at 13 t of hydrogen (see Figure 29).


Hydrogen

7. Conclusion

In the context of this project, three case studies were conducted to investigate the potential for the production and export of green energy from three different African countries. Egypt, Kenya and Ghana were previously identified through a specific country selection process. In each case study, a selected example of a green hydrogen supply chain was examined. The reference year was 2030. In a first step, the components of a suitable supply chain were identified on the basis of the regional conditions. First, a favourable location for the construction of a green hydrogen production plant were defined. Secondly, a suitable sales market for a possible export of the produced hydrogen or respective derivate was identified and a correspondingly conceivable and advantageous transport option was selected.

Finally, both the design of the individual components and the overall supply chain were examined. Based on a possible design of an exemplary demonstration plant, production efficiencies and supply costs were calculated. The Figure 32 shows the countries of the individual case studies and their respective export regions. In the first case study, the production of green hydrogen in Egypt and the supply to Central Europe was examined. The production of green ammonia in Kenya and the shipping to Japan was elaborated in the second case study. The third case study explored the production of green PtL fuels in Ghana and their supply to North America. Table 7 below summarises the main aspects of all the case studies.

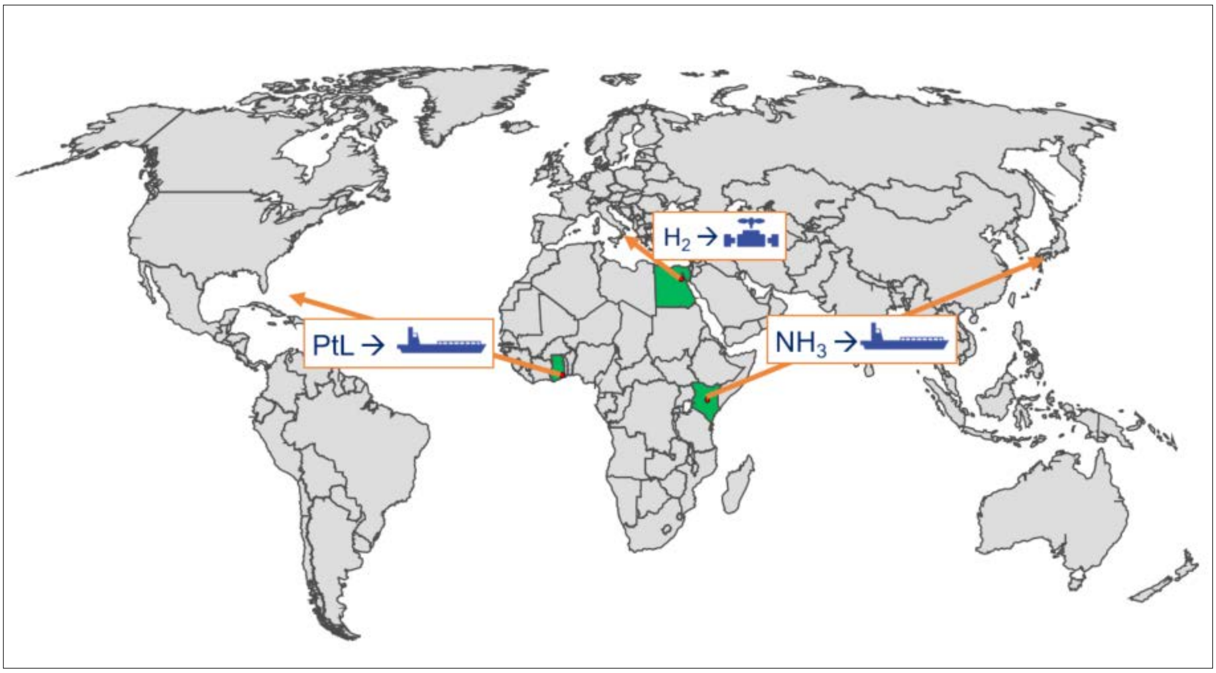

Figure 32: Overview of the considered production locations and their export regions

	EGYPT (2030)	KENYA (2030)	GHANA (2030)
PRODUCT	**HYDROGEN (H_2)**	**Ammonia (NH3)**	**PtL fuel**
PRODUCTION SITE	The selected site for H_2 production is located south-east of Cairo on the Gulf of Suez. This location has a high potential for both wind and solar power. The close proximity to the coast of the Red Sea is an elementary advantage with regard to the necessary water supply for electrolysis. Furthermore, there is already a well-developed infrastructure and an existing (natural gas) pipeline system.	In addition to wind and solar energy, Kenya also has a high potential for the use of geothermal energy. Electricity from geothermal energy can already be purchased from the public grid. While the potential for using solar energy is relatively evenly distributed across the country, the best locations for using wind energy are in the region around Lake Turkana. A wind farm already exists on the south coast of Lake Turkana in the Loiyangalani District. An area close to the Lake Turkana wind farm was chosen as the best possible location for green hydrogen production.	Ghana has a relatively even potential for solar energy nationwide. Electricity from hydro-power is another option for the use of renewable energy sources and can be purchased from the public electricity grid. An area east of Accra was chosen as a potential site for PtL fuel production. This location already offers good infrastructure and easy access to the electricity grid. Furthermore, the proximity to the coast offers short national transport distances for future export.
			
SHARE OF SUPPLIED ELECTRICITY [GWh/ GWh_{demand}]	• Onshore wind power: 70 % • Photovoltaic power: 30 %	• Onshore wind power: 59 % • Photovoltaic power: 25 % • Geothermal power via grid:15%	• Photovoltaic power: 91 % • Hydropower via grid: 9 %
ELECTROLYSER	100 MW PEM electrolyser with a specific production capacity of 2.0 t_(H_2)/h and 6050 annual full load hours (AFLH).	100 MW AEL electrolyser with a specific production capacity of 2.0 t_(H_2)/h and 7600 annual full load hours (AFLH).	100 MW AEL electrolyser with a specific production capacity of 2.0 t_(H_2)/h and 3200 annual full load hours (AFLH).
PRODUCTION	Based on the weather year 2019, around 695 GWh are generated annually by the installed PV and wind energy systems. Considering energy losses and excess energy over the entire supply chain, around 12,175 t of H_2 (~406 GWh) can be produced with a 100 MW PEM electrolyser.	For NH_3 production, N_2 is needed in addition to hydrogen. The cryogenic N_2 purification process is chosen for the extraction of pure N2 from ambient air and the Haber-Bosch process for the production of NH3. For this supply chain, this translates into a total of around 86,800 t of green NH3 that can be produced annually from the 15,300 t of H_2 provided. Approximately 71,200 t of N_2 are required. The total energy demand for the supply of 86 800 t of green NH3 (~451 GWh) is 966 GWh. Around 937 GWh of this amount is generated from PV, wind and geothermal energy.	The raw materials for the production of PtL fuels are H_2 and CO_2. The synthesis plant consist of the RWGS reactor, the Fischer-Tropsch synthesis and the refinery unit. Based on the weather year 2019, around 341 GWh are generated annually by the installed PV plant and 33 GWh of electricity from hy-dropower is annually purchased from the public grid. From the 6,500 t of H2 provided, about 13,100 t of PtL fuel (~157 GWh) can be produced annually. This requires about 45,500 t of CO_2

	EGYPT (2030)	KENYA (2030)	GHANA (2030)
PRODUCT	HYDROGEN (H_2)	Ammonia (NH3)	PtL fuel
H_2 STORAGE	Due to the availability of salt caverns, the H_2 can be stored very cost-effectively. An electricity storage facility is not required. The selected H_2 storage capacity amounts 1390t.	The H_2 storage capacity is 17 t and is thus significantly less than 50 % of the maximum daily output of the electrolyser. The reasons for the low installed storage capacity are presumably the high specific costs of H_2 storage in pressure gas tanks and the availability of continuous grid electricity.	The raw materials for the production of PtL fuels are H_2 and CO_2. The synthesis plant consist of the RWGS reactor, the Fischer-Tropsch synthesis and the refinery unit. Based on the weather year 2019, around 341 GWh are generated annually by the installed PV plant and 33 GWh of electricity from hydropower is annually purchased from the public grid. From the 6,500 t of H_2 provided, about 13,100 t of PtL fuel (~157 GWh) can be produced annually. This requires about 45,500 t of CO_2.
H_2 PRODUCTION COSTS	$2.7 \frac{€}{kg_{H_2}} \triangleq 0.08 \frac{€}{kWh_{H_2}}$	$2.23 \frac{€}{kg_{H_2}} \triangleq 0.07 \frac{€}{kWh_{H_2}}$	$2.95 \frac{€}{kg_{H_2}} \triangleq 0.09 \frac{€}{kWh_{H_2}}$
SALE MARKET FOR EXPORT	H_2 supply to Europe	NH_3 supply to Japan	PtL fuel supply to North America
MEAN OF TRANSPORT FOR EXPORT	Pipeline	Ship	Ship
SUPPLY COSTS	$3.6 \frac{€}{kg_{H_2}} \triangleq 0.10 \frac{€}{kWh_{H2}}$	$0.61 \frac{€}{kg_{NH_3}} \triangleq 0.12 \frac{€}{kWh_{NH3}}$	$1.97 \frac{€}{kg_{PtL}} \triangleq 0.16 \frac{€}{kWh_{PtL}}$
OVERALL EFFICIENCY	• 56 % (excess energy included) • 63 % (excess energy is excluded)	• 47 % (excess energy included) • 54 % (excess energy is excluded)	• 40 % (excess energy included) • 46 % (excess energy is excluded)

Annex A: **Parameters used in the modelling**

PARAMETER	WATER SUPPLY	UNIT
H_2O desalination cost	2.62	€/m^3H_2O
H_2O desalination electricity demand	3.10	kWh_{el}/m^3H_2O
H_2O transportation cost	0.55	(€/m^3H_2O)/100 km
H_2O transportation electricity demand	0.45	(kWh_{el}/m^3H_2O)/100 km

Table 8: Water supply by reverse osmosis desalination and pipeline transport[a] [52-59]

PARAMETER	UNIT	Alkaline electrolyser	PEM electrolyser
Technology Readiness	TRL	9	8
CAPEX	€/kW_{el}	760	860
OPEX	$\%_{CAPEX}/a$	2.5	3.5
Depreciation	a	25	20
System efficiency[b]	%	67	67
H_2O demand	kg_{H2O}/kg_{H2}	13	13

Table 9: Hydrogen production via water electrolysis[a] [10, 13-17, 19, 60- 62]

[a] All data refer to the year 2030.
[b] System efficiency based on the LHV ($kWh_{H2.LHV}/kWh_{el,input}$)

PARAMETER	UNIT	Compression	Liquefaction
Technology Readiness	TRL	9	8
Reference scale	$t_{H2/d}$	6	100
CAPEX	M€	0.7	195
OPEX	$\%_{CAPEX/a}$	5	4
Depreciation	a	15	30
Energy demand	kWh_{el}/kg_{H2}	0.31[b]	7.4

Table 10: Compression and liquefaction of hydrogen[a] [63-66]

[a] All data refer to the year 2030.
[b] Calculation for inlet pressure of 50 bar and outlet pressure of 100 bar

PARAMETER	UNIT	AMMONIA PRODUCTION
Technology Readiness	TRL	9
Reference scale	t_{NH3}/d	18
CAPEX	M€	109
OPEX	$\%_{CAPEX/a}$	4
Depreciation	a	20
Electricity demand	kWh_{el}/kg_{NH3}	10
H_2 demand	kg_{H2}/kg_{NH3}	0.18
N_2 demand	kg_{N2}/kgNH3	0.82
N_2 supply, cost	€/kgN_2	0.03
N_2 supply, energy demand	kWh_{el}//kgN_2	0.11

Table 11: Ammonia production[a] [67-70]
[a] All data refer to the year 2030

PARAMETER	UNIT	RWGS	FischerTropsch synthesis[b]
Technology Readiness	TRL	7	9
Scale	$t_{PtL/d}$	10	10
CAPEX	M€	0.83	3.5
OPEX	$\%_{CAPEX/a}$	4	4
Depreciation	a	5	30
Electricity demand	kWh_{el}/kg_{PtL}	0.63	0.2
Heat demand	kWh_{th}/kg_{PtL}	0.62	-3.8
H_2 demand	kg_{H2}/kg_{PtL}	0.15	0.33
CO_2 demand	kg_{CO2}/kg_{PtL}	3.5	/

Table 12: PtL fuel production[a] [71-75]

[a] All data refer to the year 2030.
[b] Includes refinerey

PARAMETER	UNIT	CGH_2 tank	CGH_2 cavern	LH_2 tank	NH_3 tank	PtL tank
Technology Readiness	TRL	9	7	8	9	9
CAPEX	€/kg_{fuel}	460	46	33	13	2
OPEX	$\%_{CAPEX/a}$	2	2	2.7	2	2
Depreciation	a	30	30	30	30	30
Storage pressure	kWh_{el}/kg_{H2}	100	100	1	1	1
Fuel loss	%/d	0	0	0.1[b]	0.03	0

Table 13: Storage of compressed gaseous H_2 (CGH_2), LH_2, NH_3 and PtL fuel[a] [10,63, 64, 68, 76-83]

[a] All data refer to the year 2030.
[b] Based on large scale liquid hydrogen storage, in the case of small scale storage systems (e.g., vehicle tanks), losses can be significantly higher due to poor surface to volume ratio

PARAMETER	UNIT	LH_2 ship	NH_3 ship	PtL Ship
Technology Readiness	TRL	6	9	9
Maximum Payload	t/ship	11,000 LH_2	53,000 NH_3	20,500 PtL
CAPEX	M€/ship	387	79	30
OPEX	$\%_{CAPEX/a}$	4	4	4
Depreciation	a	25	25	25
Fuel demand	kWhPtL/km	0[b]	690	300
Fuel loss	%/d	0.25[c]	0	0

Table 14: Transportation of LH_2, NH_3 and PtL fuel by ship [a] [10, 40, 81, 84-86]]

[a] All data refer to the year 2030.
[b] Boil-off losses assumed as fuel and therefore no additional fuel demand
[c] Additional hydrogen losses during loading of 1.3 % per load

PARAMETER	UNIT	CGH_2 PIPELINE
Technology Readiness	TRL	8
Scale (Pipeline diameter)	mm	1,400
CAPEX	M€/$km_{Pipeline}$	6.58
OPEX	$\%_{CAPEX/a}$	5
Depreciation	a	40
Electricity demand for intermediate compression	$kWh_{el}/(kg_{H2}$ 100km)	0.06
H_2 loss	$kg_{H2}/(kg_{H2}$ 100 km)	0
Operating pressure	bar	100

Table 15: Transportation of compressed gaseous H_2 (CGH_2) via pipeline [a] [10, 88]

[a] All data refer to the year 2030.

Annex B: **Just Transition dimensions**

This Annex sets out the principles and framework underpinning the Just Transition concept, which is still more a vision or process, rather than an end-point, to facilitate greater representation, greater equality, greater equity for communities, but in particularly, marginalized groups, within a transition dynamic. In this case the situation relates to the energy transition underway encapsulating the emergence of new technologies and energy carriers to achieve wider aspirations of net zero or carbon neutrality economies in the coming decades.

7.1 Defining the Just Transition

The concept has its antecedence in the context of a different environment, continent and era. Today, it is viewed as a process to achieve more equitable distribution of costs within the wider climate change goals. Work within AFDB remains underway to agree a definition[1]. As on its website, the Bank defines the "Just Transition concept as a framework for facilitating equitable access to the benefits and sharing of the costs of sustainable development such that livelihoods of all people, including the most vulnerable, are supported and enhanced as societies make the transition to low carbon and resilient economies. A Just Transition affirms Africa's right to development and industrialization based on the Paris Agreement-negotiated language of equity and the principle of common but differentiated responsibilities and respective capabilities, in the light of different national circumstances".[2]

7.2 High Level principles

This framework advances three principles as underpinning a just transition towards an environmentally sustainable economy and society: procedural justice, distributive justice and restorative justice. The principles are drawn from literature on the just transition[3] and international best practice guidelines [4].

7.2.1 Procedural Justice

Here, workers, communities, and small businesses must be empowered and supported in the transi-tion, with them defining their own development and livelihoods.

At a State policies or Government level this means:

• assisting the Egyptian, Kenyan and Ghanian communities to understand what the just transition entails, specifically, and discuss points of agreement and disagreement openly and transparently.

• supporting worker and community organisations (unions, civics, advocacy groups, etc.) in the three countries to participate actively in just transition policy-making processes ensuring de-cisions are made in their best interests and allow them to take advantage of opportunities.

• collaborating actively with a range of stakeholders, through inclusive and participatory decision making structures, allowing each to play to their respective strengths, fostering a more dynamic, competitive, diversified, and equitable economy.

• supporting the design and implementation of just transition projects, as proposed by individuals and communities in affected areas.

[1] In December 2021, AFDB did launch a Just Transition Initiative, supported by the Climate Investment Funds, and with consultations with African stakeholders is aiming to build a consensus around a working definition that can be ef-fectively implemented.
[2] https://www.afdb.org/en/topics-and-sectors/initiatives-partnerships/climate-investment-funds-cif/just-transition-initiative
[3] Cahill, B. M. Allen. 2020. Just Transition Concepts and Relevance for Climate Action. Washington, D.C.: Center for Strategic and International Studies (CSIS) and McCauley, D. and Heffron, R. 2018. "Just transition: Integrating cli-mate, energy and environmental justice." Energy Policy (119)
[4] International Labour Organization (ILO). 2015. Guidelines for a just transition towards environmentally sustainable economies and societies for all. Switzerland

7.2.2 Distributive Justice

The risks and opportunities resulting from the transition must be distributed fairly, taking account of gender, race, and class inequalities. It is essential that impacted workers and communities do not carry the overall burden of the transition, and the costs of adjustment are borne by those historically re-sponsible for the problem.

At a State or Government level, it encompasses:

• equipping the Egyptian, Kenyan and Ghanian citizens with skills, assets, and opportunities to participate in industries of the future, with particular attention on impacted groups, the poor, women, people with disabilities, and the youth.

• Implementing transformative national economic and social policies that clearly consider how benefits and burdens will be distributed (this includes clear indication of where jobs are gained, where jobs are lost, and the quality and longevity of future employment).

• Increasing provincial and local capacity (both resources and skills) to promote local econom-ic development.

• ensuring corporate responsibility to support a green and inclusive economy.
An effective just transition demands an understanding of the working people and communities that are:

• negatively impacted by climate change i.e., when their lives and livelihoods are directly impacted by droughts, floods, and other extreme weather events or other long-term climate impacts (e.g. food security risks, water scarcity);

• negatively impacted by the sectoral shifts in response to climate change i.e., when their means of securing income and work are tied to high-emissions industries that are phased out over time;

• negatively impacted by the development and buildup of green hydrogen (comprising projects investments and operational projects in due course)

7.2.3 Restorative Justice

Restorative Justice relates to historical damages against individuals, communities, and the environment that should be addressed, with a particular focus on rectifying or ameliorating the situations of harmed or disenfranchised communities. It is about redress: healing people and the land, which is an immediate need for many communities.

At a State or Government level this means:

• acknowledging the health and environmental impacts to communities in fossil fuel impacted areas, and supporting all citizens rights to a healthy environment.

• Shifting away from resource intensive sectors and fossil fuels to improve ecosystems with community ownership and stewardship, improve energy security and eliminate energy poverty, and create opportunities for rehabilitation of degraded land, water systems, the improvement of biodiversity as well as related employment opportunities.

• creating a more decentralised, net zero emissions economy, which allows for greater economic inclusion, ownership, and participation, especially for women and the youth.

• Remedying past harms by building on, and enhancing, existing mechanisms such as equitable access to environmental resources

7.3 Aligning the Just Transition Process with Country Specifics

Africa is very diverse across the compass points, not least with different energy and fuel mixes, dif-ferent infrastructure expansion needs, investment requirements, financing options available and energy policy priorities as well as NDC targets and scenarios. The type of issues to be addressed there fore depend on the "country context", for example, taking into account:

• if any, the size and extent of a coal mining sector and related workforce

• the type of fuels used in power generation whether coal is the predominant source

• the sources of the Renewable Energy sector whether hydro based or with significant wind and solar plants

• the mix and ownership of the RE sector whether large private companies or PPPs or community driven RE projects

• the extent to which significant petrochemical and agri-industrial sectors exist

• the extent to which grey hydrogen is used in these sectors (eg. refining and producing ammonia and methanol)

7.4 Moving from State and Government to project level

Along with international obligations or steers, the main drivers behind Just Transition, generally, are States and Governments who establish the enabling frameworks and instruments. These frameworks include policies, legislation, acts, regulations, rules and other standards cutting across many sectors and issues including:

• energy, transport, water, agriculture, industry, heath, finance and the environment

• labour and community rights,

• social protection, and so on.

As an item of investigation, developing projects, as such, would need to comply with the myriad of Just Transition promoting policies, laws, regulations and standards.

The technologies, in this context, are renewable energy sources (eg hydropower, solar and wind, among others) and the case studies have, clearly, well-established RE sectors either benefiting from large hydropower resources (Ghana), significant wind and solar resources (Egypt) or geothermal resources (Kenya), while the energy carrier is hydrogen. In many African countries, at this time, there will be no significant production of grey (let alone, green) hydrogen although Egypt is an exception with well established hydrogen-sourced iron, steel, cement and petrochemical sectors.

The development of Green Hydrogen projects (principally powered by Renewable Energies) can be viewed through the "lens" of an African relevant Just Transition process which will also be, in the frame of the case studies' conditions, less about transitioning away from coal but rather about using it to tackle poverty, inequality, gender discrimination and unemployment so as to improve lives.

The project initiators, owners or operators have responsibility and interest to ensure that projects are supported by all key stakeholders, the local community and the Just Transition process affords them a mechanism to participate and shape the development, commissioning, operation and eventual de commissioning of the projects.

In and of itself, Renewable Energy technologies and the supply chain of Green Hydrogen are neither just nor unjust but their equity and justice implications must be considered. A part of the implementation of the Just Transition process is therefore to consider and to answer in the affirmative key questions set out below. These are by no means exhaustive. Behind the issues will be a need for specific actions (eg polcies and measures) on the areas addressed by interested parties, including Governments, civil society organisations and project operators.

		EGYPT AS A HYDROGEN EXPORTER	KENYA AS AN AMMONIA EXPORTER	GHANA AS A PTL FUELS PRODUCER
	CARBON NEUTRALITY AND THE ENVIRONMENT			
12.	Do the plans and projects synchronize with national-level decarbonization strategies (and NDCs)?	●●●	●●●	●●●
1.3	Have comprehensive decarbonization plans been prepared?	●●●	●●●	●●●
1.4	Are the environmental impacts of the proposed just transition Green Hydrogen projects adequately assessed?	●●●	●●●	●●●
1.5	Has an assessment been prepared of the environmental impacts of the industries being phased out?	●	●	●
	SOCIO-ECONOMIC IMPACTS			
2.1	Will new skills, training or re-training be undertaken for those impacted, the poor, the youth, women, and jobseekers to seize opportunities offered by the new technologies (RE and Green Hydrogen)?	●●●	●●●	●●●
2.2	Will employment opportunities be secured for people losing their jobs?	●	●	●
2.3	Are the issues of various vulnerable groups being addressed?	●●●	●●●	●●●
2.4	Do the Green Hydrogen projects significantly address the issues faced by women?	●●●	●●●	●●●
2.5	Do the Greem Hydrogen projects address the needs of the young?	●●●	●●●	●●●
2.6	Has economic redevelopment actually been ensured?	●●	●●	●●
	PUBLIC PARTICIPATION			
3.1	Has an inclusive participatory process been ensured (so no one is left behind)?	●●●	●●●	●●●
3.2	Have relevant stakeholders with a quieter voice been included in the process?	●●●	●●●	●●●
3.3	Has local capacity been developed to ensure a more inclusive process?	●●●	●●●	●●●
3.4	Has a good Green Hydrogen project selection process been ensured?	●●●	●●●	●●●
3.5	Has good governance over the implementation phase been ensured?	●●●	●●●	●●●

Legend: Contextual Importance: three: high, two: medium, one: low

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