Federal Foreign Office

H2 diplo HYDROGEN DIPLOMACY

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Synthesis Report

Study on the potential for Hydrogen in Nigeria

Federal Foreign Office

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Abbreviations and Acronyms

AEL	Alkaline water electrolysis
AFLH	Annual full load hours
ATR	Autothermal reforming
Bbl/d	Blue barrels per day
BEV	Battery electric vehicle
BF	Blast furnace
BOF	Basic oxygen furnace
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CCUS	Carbon capture utilisation and storage
CGH_2	Compressed gaseous hydrogen
CH_3OH	Methanol
CH_4	Methane
CIF	Climate Investment Funds
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPI	Corruption Perceptions Index
DAC	Direct air capture
DME	Dimethyl ether
DRI	Direct Reduced Iron
EAF	Electric Arc Furnace
ETP	Nigeria Energy Transition Plan
ETWG	Energy Transition Implementation Working Group
EU	European Union
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
GH_2	Green Gaseous hydrogen
GHG	Greenhouse gas
GHGe	Greenhouse gas emissions
GJ	Gigajoule
GoN	Government of Nigeria
GW	Gigawatt
H_2	Hydrogen
HVC	High value chemical
IEA	International Energy Agency

IEAGHG	International Energy Agency Greenhouse Gas R&D Programme
IPP	Independent Power Producer
kNm^3/hr	Thousand (or Kilo) normal cubic meters per hour
kt	kilotons
kTPA	Thousand (or Kilo) tonnes per annum
kWh	Kilowatt hour
kWp	Kilowatt peak
LCoH	Levelized cost of hydrogen
LCoE	Levelized cost of energy
LH_2	Liquid hydrogen
LHV	Lower heating value
LNG	Liquid natural gas
LNH_3	Liquid ammonia
LOHC	Liquid Organic Hydrogen Carrier
mmtpa	Million metric tonne per year
Mt	Million tons / megatons
MTBE	Methyl tertiary-butyl ether
MW	Megawatt
MWh	Megawatt hour
NETP	Nigeria Energy Transition Plan
N_2	Nitrogen
NH_3	Ammonia
nk	Not known
Nm^3	Normal cubic meter
O_2	Oxygen
OPEX	Operational expenditure
PEMEL	Polymer electrolyte membrane electrolysis
PEMFC	Proton exchange membrane fuel cell
PJ	Petajoule
PO	Partial oxidation
PPA	Power Purchase Agreement
PPI	Presidential Power Initiative
PSA	Pressure swing adsorption
PtL	Power-to-Liquid
PtX	Power-to-X
PV	Photovoltaic
RED	Renewable Energy Directive

RWGS	Reverse Water Shift reaction
SAF	Sustainable Aviation Fuel
SLNG	Synthetic liquid natural gas
SMR	Steam methane reforming
SNG	Synthetic natural gas
SOEL	Solid oxide electrolysis
tbpd	Thousand barrels per day
tcf	Trillion cubic feet
TFEC	Total final energy consumption
TOL	Toluol as a promising LOHC
TPA	Tonnes per year
TRL	Technological readiness level
TWh	Terawatt hour
WACC	Weighted average cost of capital
WGS	Water-gas-shift-reaction

1. Introduction

This “Study on the potential for Hydrogen in Nigeria” (hereafter, the study) was commissioned by the German-Nigerian Hydrogen Office, which is part of the Global H2-Diplo programme. The study took place over 2023 and its aims were to provide:

- an assessment of the current situation with regards to hydrogen use, and a basic overview of the relevant parts of the current energy sector;
- an investigation of the renewable energy resources, specifically solar and wind resources (using GIS mapping) in terms of potential production and economic costs (or LCoE) across Nigeria;
- a related investigation of the potential for production of green hydrogen and the costs of production (or LCoH) of green hydrogen across Nigeria;
- an assessment of the potential demand for or use of hydrogen within the different economic sectors utilising three different demand scenarios to 2060;
- an assessment of the related emission reductions (or emissions saved) under the different demand scenarios (based on the supply of green hydrogen);
- a comparison of supply costs with potential global competitors taking into account different transport costs, the prioritization of the most feasible transport options (e.g., ammonia vs. liquid hydrogen vs. LOHC vs. pipelines) for Nigeria based on costs, distance to key offtake regions and other relevant factors;
- an assessment of the potential production and costs (LCoH) and emission reduction potentials of blue hydrogen (compared to grey hydrogen produced from and within the natural gas sector without carbon capture, utilisation and storage (CCUS);
- conclusions and recommendations arising from the study’s investigation.

The overall study comprised four Work Packages (WP):

- Baseline and green production potential (WP1);
- Local demand and emissions reduction potential (WP2);
- International Competitiveness (WP3);
- Comparing green v blue hydrogen (WP4).

The data, assumptions and parameters to determine the LCoE and LCoH are provided in annexes.

For each of the four WP a report was prepared; the present report provides a synthesis of the four reports. More details can be found in each individual WP report.

2. Baseline and green hydrogen production potential

2.1 Energy Sector Overview

Nigeria's installed capacity includes 25 grid-connected plants in operation with a total installed capacity of around 12 GW and an available capacity of around 7 GW. Thermal-based generation installed capacity amounts to 8.5 GW and around 5 GW of available capacity. Hydropower installed capacity is at 2.1 GW with an available capacity of 1 GW. Plants are operated by privatized generation companies (GenCos), Independent Power Producers and the National Integrated Power Project (NIPP). Average generation capacity was around 5 GW in 2022 from 25 grid-connected power plants,[1] comprising 19 gas, 4 large hydro, and 2 gas/steam-powered plants. Hydropower generation fluctuates depending on the season. Table 1 sets out capacities and current status.

Table 1 : Power Plants

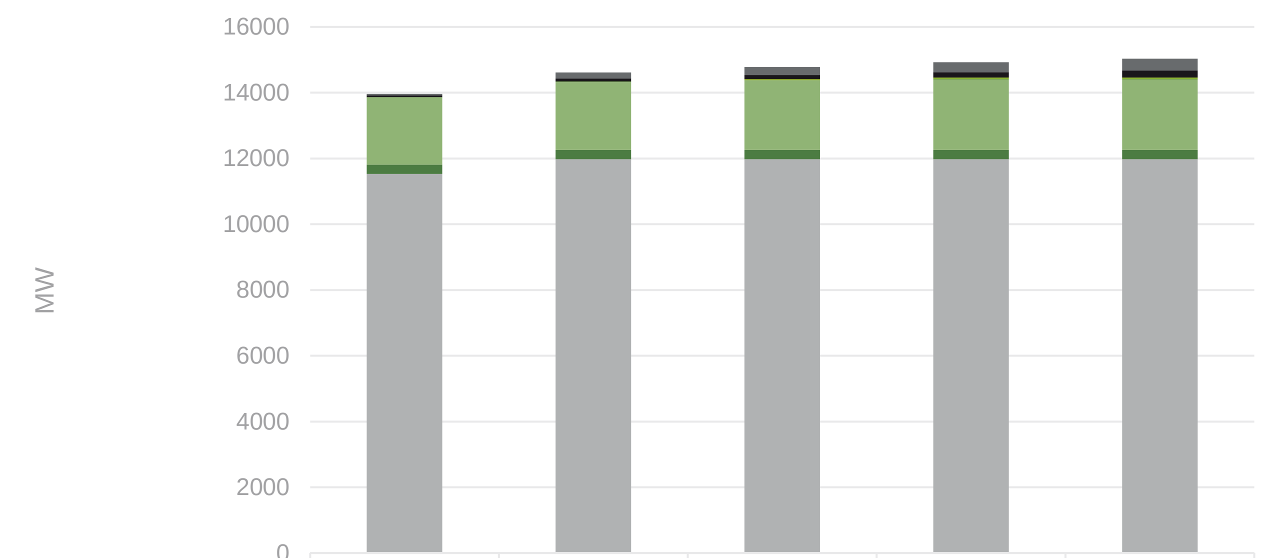
Power Plants	Type	Location	Established	Capacity (MW)	Status
Aba Power Station (IPP)	Gas	Abia State	2012	140	Operational
AES Barge (IPP)	Gas	Lagos State	2001	270	Non-operational
Afam IV-V(FGN)	Gas	Rivers State	1982 - 2002	977	Non-operational
Afam VI Power Station	Gas	Rivers State	2010	642	Partially
Alaoji Power Station (NIPP)	Gas	Abia State	2015	1,074	Partially
Azura Power Station (IPP)	Gas	Edo State	2018	450	Operational
Calabar Power Station (NIPP)	Gas	Cross River	2014	561	Non-operational
Egbema Power Station (NIPP)	Gas	Imo State	2013	338	Non-operational
Eleme	Gas	Rivers State	2006	75	Non-operational
Gbarain	Gas	Bayelsa State	2017	225	Operational
Geregu I Power Station	Gas	Kogi State	2007	414	Partially
Geregu II Power Station (NIPP)	Gas	Kogi State	2012	434	Partially
Ibom	Gas	Akwa Ibom	2009	190	Partially

[1] According to the latest report by NERC.

Power Plants	Type	Location	Established	Capacity (MW)	Status
Ihovbor Power Station (NIPP)	Gas	Edo State	2013	450	Partially
Okpai/Kwale-Okpai	Gas	Delta State	2005	480	Operational
Olorunsogo I Power Station	Gas	Ogun State	2007	336	Partially
Olorunsogo II Power Station (NIPP)	Gas	Ogun State	2012	675	Partially
Omoku I	Gas	Rivers State	2005	150	Operational
Omoku II	Gas	Rivers State	2012	225	Incomplete
Omotosho I Power Station	Gas	Ondo State	2005	336	Partially
Omotosho II Power Station (NIPP)	Gas	Ondo State	2012	450	Partially
Rivers IPP-A	Gas	Rivers State	nk	180	Operational
Sapele (NIPP)	Gas	Delta State	2012	450	Partially
Trans-Amadi	Gas	Rivers State	2004	136	Operational
Transcorp-Ughelli Power Station	Gas	Delta State	1966	900	Partially
Egbin Thermal Power station	GF-steam	Lagos State	1986	1,320	Partially
Sapele Power Station	GF-steam	Delta State	1981	1,020	Partially
Jebba Power Station	Hydro	Niger State	1984	540	Operational
Kainji Power station	Hydro	Niger State	1968	760	Operational
Shiroro Power Station	Hydro	Niger State	1990	600	Operational
Zamfara Power Station	Hydro	Zamfara State	2012	100	Operational

Source: Power Africa 2019, Oasdom 2020

Figure 1 below sets out the historic and current capacities while Figure 2 provides the target and estimated trajectory of renewable generation (as from a 2015 perspective).

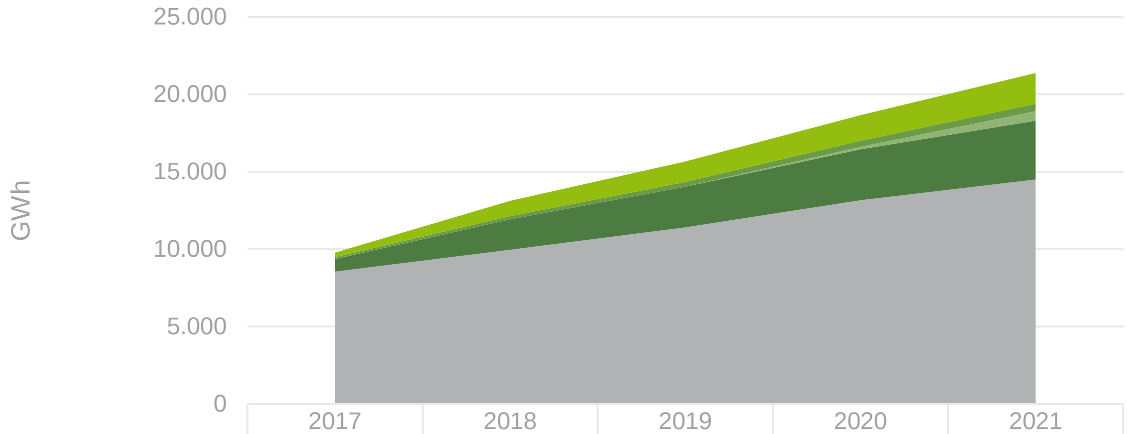


	2017	2018	2019	2020	2021
Biomass	50	180	240	300	360
Onshore Wind	50	90	130	170	210
Solar PV - Offgrid	0	0	28	28,3	28,3
Solar PV - Utility scale	15	19	22	25	29,1
Hydropower	2040	2062	2102	2142	2142
Coal fired plant	280	280	280	280	280
Gas plant	11529	11979	11979	11979	11979

Gas plant | Coal fired plant | Hydropower | Solar PV - Utility scale | Solar PV - Offgrid | Onshore Wind | Biomass

Source: Statista, www.nerc.org.ng ; https://hydropower-assets; Hydropower Status Report, 2018; Esi-africa, 2021; The Nation, 2019; Solar Report of Nigeria, 2021

Figure 1: Historic Fossil Fuel-based & Renewable Electricity Generation Capacity



	2017	2018	2019	2020	2021
Biomass	277	995	1.327	1.659	1.991
Onshore Wind	117	210	303	397	490
Solar - Off-grid	0	0	0	151	605
Solar - Utility scale	821	1.970	2.627	3.283	3.776
Hydropower	8.554	9.953	11.405	13.167	14.515

Hydropower · Solar - Utility scale · Solar - Off-grid · Onshore Wind · Biomass

Source: NREAP (2015 – 2030)

Figure 2: Renewable Generation

2.2 Planned expansion

Nigeria's capacity plans include an expansion of around 11 GW through the addition of six coal-fired power and nine gas plants by 2037. This expansion will provide sufficient baseload power in future. Nigeria has an estimated coal reserve of 2.8 billion metric tonnes.

Table 2: Planned Power Plants

Power plant	Type	Location State	Planned Commission	Capacity (MW)	Status
Itobe	Coal	Kogi	2023	1,200 (2,400)	To be commissioned
Tiga	Hydro	Kano	2023	10	To be commissioned
Zungeru	Hydro	Niger	2023	700	Added to the grid in May 2023
Ashama	Solar	Delta	2023	200	Proposed
Qua Iboe	Gas	Akwa Ibom	2025	540	Stalled
Mambilla	Hydro	Taraba	2030	3,050	Stalled
Okpai/Kwale-Okpai	Gas	Delta	2031	450	Planning
Totalfinaelf (Obitex)	Gas	Rivers	2031	420	Planning
Anambra state IPP	Gas	Anambra	2031	528	Planning
Knox	Gas	Kogi	2031	501	Planning
Delta state IPP	Gas	Delta	2032	500	Planning
Benco	Gas	Bayelsa	2033	700	Planning
Ashaka/TPGL	Coal	Gombe	2034	500	Planning
Ashaka	Coal	Gombe	2034	64	Planning
Nasarawa	Coal	Nasarawa	2034	500	Planning
Ramos	Coal	Delta	2034	1,000	Planning
Kaduna	Gas	Kaduna	2034	900	Planning
Fortune Electric	Gas	Cross River	2035	1,000	Planning
Benue	Coal	Benue	2037	1,200	Planning
Enugu	Coal	Enugu	2037	2,000	Planning
Gwagwalada	Gas	Abuja	2037	1,350	Planning

Source: Power Technology 2021, ESI Africa 2015, NS Energy Business, EnergyDay 2022, MyEngineers 2022, Qua Iboe

The main concern for the future expansion of gas-powered generation, however, is the availability of gas and the expansion of the gas pipeline network. Currently, most power plants are installed in the

Southern part near the oil and gas fields, while reliable and optimum expansion requires new power plants to be installed in other areas.

Table 3: Fossil Fuel Capacity Development Outlook (2022-2026)

MW	2022	2023	2024	2025	2026
Gas Stations	11,972	11,972	11,972	11,972	11,972
Coal fired Stations	280	1,480	1,480	1,480	1,480

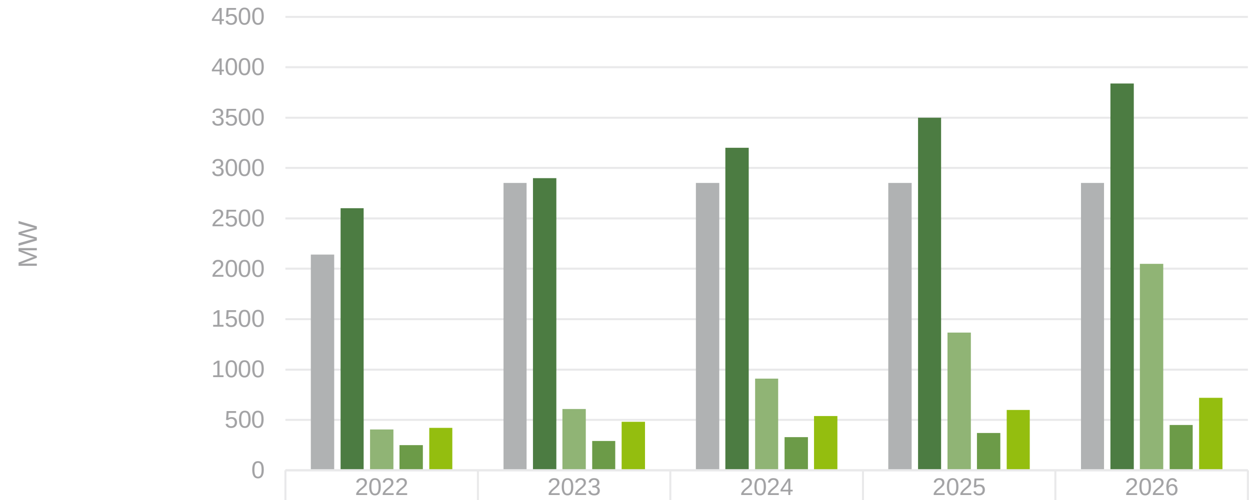
Source: Statista, Power Technology 2021

2.3 Renewable energy

The country had installed hydropower capacity of approximately 2GW up to 2019 which was increased with the commission of the 40 MW Kashimbila hydropower plant in Taraba State in 2019 and the 40 MW Dadin Kowa hydropower plant in Gombe in 2020. The hydropower generation capacity includes five additional small-scale hydropower plants, i.e., Gurara 1 (30 MW), Tiga (10 MW), Oyan (10 MW), Challawa (8MW), and Ikere (6 MW).

In terms of installed solar PV capacity (utility scale), the Rural Electrification Agency (REA) reports 15 MW in 2017, 19 MW in 2018, 22 MW in 2019, 25 MW in 2020 and 29.1 MW in 2021. Utility-scale solar PV will reach 500 MW by 2025 according to the Renewable Energy Masterplan and the estimated solar concentration potential of 427 GW. The mini-grid capacity in Nigeria was 28 MW in 2019, and 28.3 MW in 2021 based on the Solar Report of Nigeria, 2021 and the REA report of January 2023.

Between 2017 and 2021, there was no record of offshore wind farms. The Katsina state government initiated the construction of a 10 MW onshore windfarm in Rimi, Katsina state in 2005.



	2022	2023	2024	2025	2026
Hydropower	2142	2852	2852	2852	2852
Solar PV -Utlity Scale	2600	2900	3200	3500	3840
Solar PV - offgrid	405	608	911	1367	2050
Onshore Wind	250	290	330	370	450
Biomass	420	480	540	600	720

Hydropower Solar PV -Utlity Scale Solar PV - offgrid Onshore Wind Biomass

Source: NREAP (2015 – 2030)

Figure 3: Renewables Capacity Development Outlook (2022-2026)

Based on Nigeria's Renewable Energy Action Plan, NREAP (2015 - 2030) and the trajectory of hydropower in the overall energy mix, hydropower generation capacity is estimated to increase to 2,852 MW in 2023 with the commissioning of the 700 MW Zungeru hydro power plant in Niger State and the 10 MW plant in Kano. Solar Report of Nigeria (2021) estimates the total exploitable potential of hydropower at over 14,120 MW against the national target of reaching 8,218 MW by 2030. The potential for small hydro power is estimated at 3,500 MW.

If grid-connected utility solar PV reaches the 2030 target gradually, the estimated generation capacity is 2.6 GW, 2.9 GW, 3.2 GW, 3.5 GW and 3.8 GW between 2023 and 2026. Sun Africa will install 961 MWp across various states (Abuja, Kogi, Edo, Gombe, and Nasarawa) with a 443 MWh of utility-scale Battery Energy Storage System. The solar PV off-grid plan aims to bridge energy access to the unserved and underserved rural communities. With the effort of the Rural Electrification Agency establishing more mini-grid projects across rural communities at the rate of the NREAP (2015 – 2030), the estimated trajectory is an increase from 300 MW in 2022 to 700 MW in 2026. For instance, Husk Power Systems has secured funding of USD 750,000 from Germany's development finance institution DEG to set up eight community mini-grids in Nasarawa state each with a capacity of 50 kWp. The mini-grids are estimated to reduce 600 tons of CO_2 emissions by replacing over 100 diesel generators. The company plans to install 500 mini-grids in Nigeria by 2026.

The onshore wind renewable share is estimated as 250 MW, 290 MW, 330 MW, 370 MW and 450 MW between 2023 and 2026, while there are no records for offshore wind.

Nigeria has a substantial biomass potential of about 144 million tons per year. In rural areas, biomass is consumed as primary energy source. The Renewable Energy Division of the Nigerian National Petroleum Corporation (NNPC) has mapped out biomass opportunities. Plans include using sugarcane and cassava as key biomass raw materials and developing the automotive biofuels industry. According to NREAP, the estimated biomass share between 2023 and 2026 is 420 MW to 720 MW.

2.4 Natural gas reserves and gas production profile

Nigeria is the largest oil producer and holds the largest natural gas reserves in Africa. Given Nigeria's vast gas reserves and the relative advantages of gas as a cleaner source of energy for domestic use, its consumption has significantly increased. However, the majority of Nigeria's total natural gas output is either exported or injected again, with the remainder either used domestically or flared. Table 4 shows the past reserves and production.

Table 4: Reserves and production

tcf	2017	2018	2019	2020	2021
Gas Reserves	198.71[1]	199.09[1]	202[1]	203.16[2]	206.53[1]
Gas Production	1.0[3]	1.0[3]	1.01[3]	1.029073[4]	0.729616[4]
Total Gas Production	3.499695[5]	2.90914356[5]	3.04750733[5]	3.013640[5]	2.075474[4]

Source: 1. NUPRC Annual Conference Reports, 2. KPMG Nigeria Gas Sector Watch, October 2020, 3. NUPRC & PwC Analysis in “Evaluating Nigeria’s Gas Value Chain”; 4. NNPC Monthly Provisional Oil Utilization and Production Data, 5. NEITI Annual OGA Reports

Several challenges have impaired the progress of Nigeria’s natural gas sector. These have included, for example:

- a lack of adequate and reliable data on the country’s average oil and gas production;
- gas flaring and non-enforcement of the gas flaring levy by the Government of Nigeria;
- absence of gas gathering and distribution of infrastructure from the gas production field in the south to the growing markets in the western and northern parts of the country;
- a lack of local and international investors in the gas sector to boost gas utilization; and

- inadequate pricing in the downstream sector so reducing incentives for supply from the upstream sector.

The Minister of State for Petroleum has stated that the Government intended to increase its gas reserves from 206 trillion cubic feet to 600 trillion cubic feet.[2] The currently known reserves were "accidental discoveries" while looking for crude oil. The Government has declared gas as a transition fuel and intends to fully exploit its vast reserves to pave the way for net-zero carbon emissions in its energy mix.[3]

2.5 Hydrogen use

Industrial sectors in Nigeria with existing or possibly, future hydrogen supply and/or demand are refining, ammonia, methanol production and in the petrochemical and chemical sectors.

2.5.1 Oil refining

When hydrogen demand exceeds internal by-product production, additional hydrogen is typically produced using steam methane reforming of natural gas. The trend towards increased hydrogen consumption in refineries, in general, is related to the need for cleaner fuels, processing heavier crude oils, improving refinery efficiency, and meeting emissions regulations are expected to drive an overall increase in hydrogen consumption in refineries over time. There are now more efforts gathering pace to bring green hydrogen into play.

For example, while the EU's RED II[4] does not specifically mention green hydrogen, it includes provisions that indirectly encourage an increase in its production and deployment such as recognizing that electricity from renewable sources used for electrolysis (the process of producing hydrogen from water) is considered renewable energy, setting minimum targets for renewable fuels, which encompass sources like advanced biofuels and renewable hydrogen, establishing a certification framework for renewable and low-carbon fuels, referred to as "sustainable fuels", and allowing support schemes to promote green hydrogen.[5]

Green hydrogen is starting to be used to decarbonise refineries through projects such as REFHYNE in Germany – owing also to command-and-control instruments to drive greater decarbonisation through

[2] As started at the 23rd World Petroleum Congress (December 2021), USA.
[3] https://energytransition.gov.ng/ : Nigeria EnergyTransition Plan, NETP decarbonization strategy.
[4] RED II is the EU Renewable Energy Directive 2018 currently transposed by EU countries.
[5] These support schemes can consist of incentives, grants, tax breaks, and feed-in tariffs, which can be utilized to promote the production and deployment of green hydrogen.

low emissions fuel standards, so creating a high value market for green hydrogen and future fuel sulphur level reduction regulations which are predicated on the use of renewable hydrogen in the hydrotreating processes.

The current state of the oil-refining sector in Nigeria is rather desolate as existing state-owned refineries are idle. Consequently, there is no significant hydrogen on-site production in refining. However, the future may be different, planned or expected hydrogen production capacity within Nigeria is set out below, based on, at least in the short term, steam-methane reforming of natural gas. Table 5 shows the current and expected hydrogen needs.

Table 5: Current and Expected Hydrogen needs for Refining

Refineries	Company	Location	Capacity (bbl/d)	Approx H2 production (kNm3/hr)	Approx H2 production per year (kTPA)	Status
Private	Dangote Group	Lagos	650,000	485.55	379[6]	Expected to start full operations in late 2023 or 2024
State (NNPC)	Warri Refinery and Petrochemical Plant	Warri	125,000	93.37	73	At some point, it was operating at 30%, but now seems inoperative
State (NNPC)	New Port Harcourt Refinery,	Eleme, Port Harcourt	150,000	112.04	87	At some point, it was operating at 30% capacity, but now seems inoperative
State (NNPC)	Old Port Harcourt Refinery (PHRC)	Elesa-Eleme, Port Harcourt	60,000	44.82	35	Idle
State (NNPC)	Kaduna Refinery	Kaduna	110,000	82.16	64	Idle
Private	Akua-Ibom III	Akua Ibom	200,000	-	-	Expected to be commissioned in 2024
Private	Azikel Refinery	Bayelsa	12,000	8.96	7	Under construction

[6] Industry practice indicates that a 10 mmtpa refinery requires approximately 150,000 Nm3 per hour or more of hydrogen (digitalrefining.com). This requirement is satisfied two ways – through being a byproduct of the naptha reforming process within the refining stages or if this is insufficient, through further own production (eg an on-site hydrogen plant). The amount of hydrogen depends on various factors such as the size of the refinery, the type of crude oil being processed and the overall processes being used. Cleaner refineries processing medium-low sulphur crudes generally have sufficient catalytic reforming of naptha cuts for hydrotreating (where hydrogen is used to remove sulphur from crude oil). Nigerian crude oil is generally deemed good quality comprising light and medium heavy density with very low sulphur content (eg Bonny Light), so on that basis Nigerian refineries will need less hydrogen within the refining process compared to other refineries processing higher sulphur crudes. Refineries generally run 24 hours per day 365 days per year.

Refineries	Company	Location	Capacity (bbl/d)	Approx H2 production (kNm3/hr)	Approx H2 production per year (kTPA)	Status
Private	Ogbele Refinery (NDPR)	Rivers	11,000	8.22	6	Partially operational (targeting diesel for own consumption).
Private	Waltersmith Refining and Petrochemical Company	Imo	5,000	3.73	3	The phase one refinery (5000 bpd) started operations in November 2020.
There are also a number of illegal private refineries, but no data is provided						

Source: https://web.archive.org/web/20060213013744/http://www.nigeriabusinessinfo.com/nigerian-oil.htm
https://www.digitalrefining.com/article/1000044/hydrogen-generation-for-modern-refineries

As comparison, Germany's largest refinery is Wilhelmshaven Refinery (Hestya) at 300,000 bbl/d, producing half of Dangote Refinery's expected production. It is clear that total refinery hydrogen demand will be dominated by the Dangote plant.

Current total refinery hydrogen production capacity is nil at present but could be brought up along the range from 0 to around 650 kTPA over time if the state-owned refineries were to be fully rehabilitated and Dangote comes on line as planned, with Dangote accounting for over 58% of this capacity.

2.5.2 Ammonia

Nigeria is among the world's leading producers of nitrogen-rich fertilisers and exports to Ghana, Senegal, Uganda, and Kenya. In 2018, Nigeria produced 1.8 mmta of nitrogenous fertilisers, demonstrating strong growth. Since 2014, the sector has grown around 10% per year. Ammonia is a compound of nitrogen and hydrogen and has historically been produced using the Haber-Bosch process. Production is energy intensive consuming around 1.8% of the global energy output, the majority of which is for hydrogen production (methane reformation or coal gasification) and as a result is responsible for 500 MT/y CO_2e (1.8% of global emissions).

Traditionally the primary market for ammonia was fertilisers, with the market worth around 63 USD billion, with Russia historically the main exporter with around 12% of the market. However, with trading conditions changing there is likely a substantial opportunity for Nigeria to fill that market. As the world population increases, demand for ammonia as a fertiliser is expected to increase. Low-carbon ammonia is expected to increase its market size, as ammonia is a significant GHG emitter (so low carbon will be less emitting), in addition, low carbon ammonia can be produced using renewable energy sources which allows for greater integration of renewable energy into the ammonia production process, as well as the fact that ammonia has the potential to be used as a carrier of hydrogen, so can be easily converted back into hydrogen when needed, which makes low carbon ammonia an attractive option for energy storage, especially in situations where the direct storage or transportation of hydrogen is challenging.

Away from fertilizer production, ammonia can also be used as a low-carbon fuel in various applications, including transportation, power generation, and industrial processes. It has a high energy density and can be combusted in engines or used in fuel cells to produce electricity so making it a versatile energy carrier, so demand for ammonia is also expected to increase from new sectors, predominantly for shipping with ammonia (along with methanol) seen to be key to helping the global shipping to decarbonise. New uses also include as a method of transporting and storing hydrogen, with an ability, in the future to crack ammonia back to hydrogen but also co-fired in a coal power plant.[7] Ultimately ammonia could also be used in fuel cells to directly produce electricity. None of these applications is being used commercially today. An estimate of the operating companies, locations and hydrogen quantities utilized in ammonia production is tabulated below. Table 6 shows hydrogen demand for ammonia production.

Table 6: Hydrogen demand for ammonia production

Product	Company	Location	Capacity (KT product)	Approx. H2 production (kTPA)
Ammonia	Dangote Fertiliser Plant	Lekki Free Trade Zone, Lagos	1496	273
Ammonia	OCP Fertilizer Bulk Blending Plant	Kaduna	653	119
Ammonia	OCP (Morocco) Fertilizer Bulk Blending	Ogun	nk	nk
Ammonia	OCP (Morocco) Fertilizer Bulk Blending	Sokoto	nk	nk

Other companies involved in fertilizer and agro-allied production, sales and access to the products from outside Nigeria include Earthcare Nigeria, Golden Fertilizer Company, Nitromobil International Nigeria, Notore Chemical Industries, Bejafta Group, Matrix Fertilizer Ltd and PrimeGold Fertilizers and Chemical Industries. Specific data on Capacity and H2 production is not available.

[7] ThyssenKrupp, Air Liquide and Amogy are well-known manufacturers in the process of building or testing plants to decompose ammonia back to hydrogen (and nitrogen).

2.5.3 Methanol

Conventional methanol is produced by reforming natural gas and then converting the resulting syngas mixture (carbon monoxide and hydrogen), to pure methanol. Methanol is used as a feedstock to the industrial and consumer products market (~55% demand), and as an energy carrier and fuel substitute (~45% demand). Today, the main application of methanol is the feedstock for producing formaldehyde.

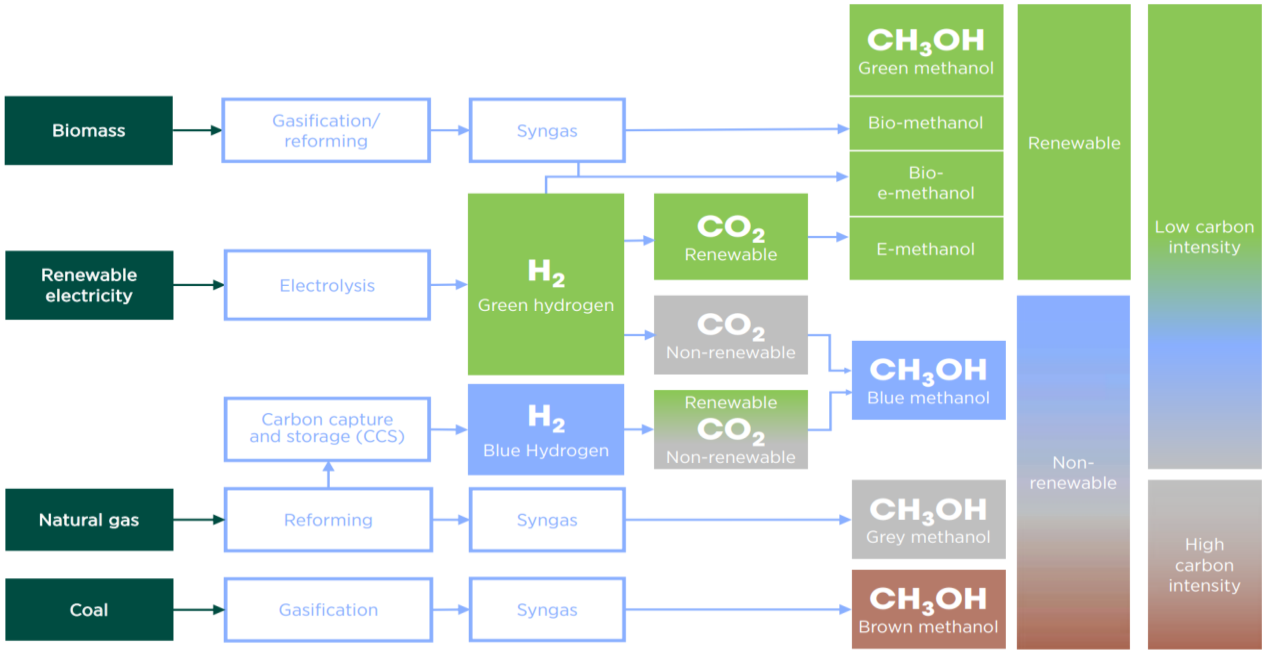
There has been an increase in the consumption of methanol for the production of dimethyl ether (DME) and Methyl tertiary-butyl ether (MTBE), which are a diesel alternative and gasoline additive respectively.

Renewable methanol is an ultra-low carbon chemical produced from sustainable biomass, often called bio-methanol, or from carbon dioxide and hydrogen produced from renewable electricity (referred to as e-methanol). In the latter process, the reformer unit in the conventional design is replaced with electrolytic hydrogen production and carbon-neutral carbon feed. Municipal solid waste (MSW) can also be used to produce methanol, with the biogenic content of the feedstock counting as producing renewable methanol.

When methanol is used as a fuel, such as planned for shipping, it releases CO_2 back into the atmosphere. If the source of the CO_2 is biogenic, this overall process is considered carbon neutral from a lifecycle perspective, and hence also seen as an acceptable environmental solution. There is significant global debate though as to the acceptability of using fossil fuel-derived CO_2 as the feedstock for e-methanol production. Some people see this as a good thing to do, as at least the CO_2 emissions from the first combustion are re-used, halving total emissions from the combined first and second uses.

Others see this as unacceptable, as there are still substantial CO_2 emissions and there is a risk that re-using fossil fuel-derived CO_2 in this way "locks in" the original use of fossil fuels. The EU's view on this is moving towards allowing financial incentives for the use of fossil fuel-derived CO_2 for e-fuel production over the next decade as a short-term energy transition measure, but only to allow financial incentives for biogenic CO_2 use in the longer term. Within the shipping industry itself, Maersk has stated a clear preference for biogenic CO_2 as feedstock for e-methanol production. If Nigeria were to base its e-methanol production on biogenic CO_2, a key challenge for this renewable methanol production via electrolysis is sourcing significant biogenic CO_2 supply. The most attractive sources of biogenic CO_2 typically are fermentation processes, including bioethanol production. There is also potential for carbon capture of CO_2 from biomass-fired power production. A full list of eligible biogenic CO_2 sources comprise biomass combustion, biogas and landfill gas sites, ethanol fermentation, biodiesel production, agricultural waste decomposition, forest and land use, bio-based product production and aquatic and marine systems with CO_2 emissions emanating from all these sources.

Direct air capture (DAC) technology can be potentially used for e-methanol production, although the costs of DAC need to substantially drop to make this attractive. Figure 4 below shows the different production pathways for mainly low carbon methanol.



Source: IRENA, Innovation Outlook Renewable Methanol, 2021

Note - Renewable CO2: from bio-origin and through direct air capture (DAC), Non-renewable CO2: from fossil origin, industry
There is not a standard colour code for the different types of methanol production processes; this illustration of various types of methanol according to feedstock and energy sources is an initial proposition.

Figure 4: Main pathways of mainly low carbon methanol

Bio-methanol could be produced in Nigeria through the gasification of biomass sources, which would not require the production of hydrogen as an intermediate product. MSW could also be converted to bio-methanol via gasification in Nigeria, but again this is more of a separate pathway to renewable methanol outside of hydrogen production.

Nigeria can also consider e-fuel production using fossil fuel-derived CO_2, with the risk of there being no substantial export market for e-fuels produced from non-biogenic sources of CO_2. Due to the likely shortage of biogenic CO_2 in many countries, it may be that fossil fuel derived CO_2 does have a long-term future as a feedstock, just with a lower product premium. Table 7 shows current hydrogen demand for methanol production.

Table 7: Current Hydrogen Demand for Methanol Production

Technology	Company	Location	2020 Capacity (kTPA)	Approx. H2 production (kTPA)
Lurgi MegaMethanol™	Brass Fertilizer and Petrochemical Company	Bayelsa State	3400	722

2.5.4 Petrochemical and Chemicals Processes

Hydrogen is also produced as a by-product of several petrochemical and chemical processes, such as ethylene cracking, chlor-alkali, propane dehydrogenation (PDH), and dehydrogenation of ethylbenzene to styrene. Sometimes this hydrogen is sold in pure form as an industrial gas, sometimes burned as a fuel (typically saving natural gas use), or in some cases vented.

In Nigeria, by-product hydrogen is at present only at the Indorama Eleme Petrochemicals plant which is the largest producer of olefins and polyolefin plastics in West Africa, and only producer of polyolefins in the country. It comprises a mixed feed ethylene cracker plant, polyethylene plant producing HDPE and LLDPE and polypropylene plant. The main feedstock is natural gas liquids which is supplied by pipeline from a gas separation plant and is supplemented by propylene rich feed from a nearby refinery. There is no current production in Nigeria of Chlor-Alkali, PDH or Styrene.

The Raw Materials Research and Development Council (RMRDC) disclosed that in the last five years, Nigeria imported caustic soda valued at more than Naira 13 billion (~ Eur 26m) for use by manufacturing firms, oil and gas sectors. The need for PDH technology stems from the reality that, Nigeria currently has no refinery with operational fluid catalytic cracker nor sufficient steam crackers to meet an estimated propylene demand gap of about 140 KTA (2016/2017) despite propylene production at the Indorama Eleme Petrochemical plant.

Table 8: Hydrogen as by product of several petrochemical and chemical processes

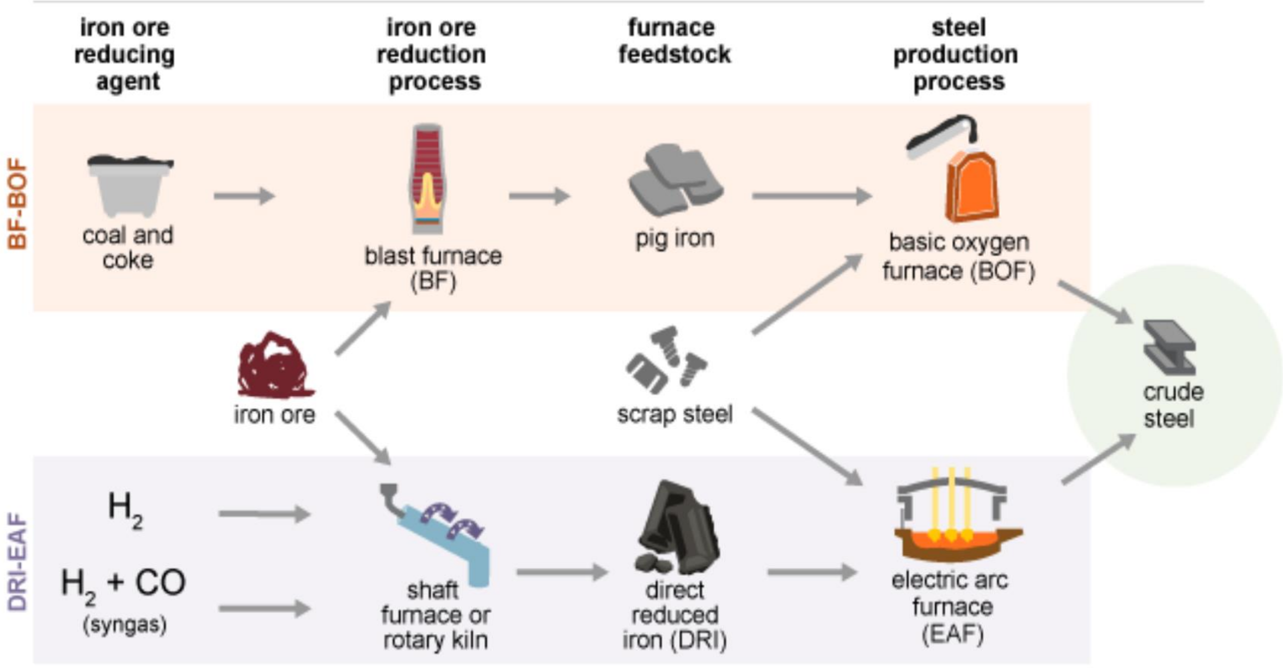
Processes	Company	Location	Capacity basis (KTA)	2020 Capacity (KT product)
Ethylene	Indorama Eleme Petrochemicals	Port Harcourt	Polyethylene - 320 (35%) Polypropylene -120 (37%)	440

2.6 Other sectors with hydrogen potential

A number of other sectors have potential use of hydrogen. These cover the iron and steel industry, marine transport, land transport and aviation.

2.6.1 Iron and steel

Figure 5 below shows the main two pathways of steel manufacturing, namely using the Blast Furnace (BF) and Basic Oxygen Furnace (BOF) route and the Direct Reduced Iron (DRI) and Electric Arc Furnace (EAF) route.



Source: EIA, Issues in Focus: Energy Implications of Potential Iron- and Steel-Sector Decarbonization Pathways, 2022

Figure 5: Main pathways of steel manufacturing

The BF-BOF route involves feeding iron ore, coke and fluxes (such as limestone) into a blast furnace to produce molten or pig iron, and then, in the BOF, high-purity oxygen is blown in oxidizing impurities in the molten iron and producing liquid crude steel. The DRI-EAF route, on the other hand, involves the direct reduction of iron ore in a direct reduction plant, followed by the use of Electric Arc Furnaces. The DRI plant converts iron ore pellets or lump ore into DRI, using the Midrex process. The DRI produced in the direct reduction stage is then utilized in Electric Arc Furnaces for further refining and steelmaking.

During the melting process, impurities and alloy additions are adjusted and refined by adding fluxes and alloys to achieve the desired steel composition.

Hydrogen can be used in the DRI-EAF route as reduction agents (replacing natural gas or syngases) in both stages. In the EAF, by injecting hydrogen into the EAF, it can react with any remaining impurities present in the molten iron, promoting further deoxidation and reducing the need for additional refining agents which also helps improve the quality of the steel produced and potentially, reduces emissions.

Overall, the BF-BOF process produces more emissions due to the reliance on coke as a reducing agent, the combustion process involved, the energy-intensive nature of the blast furnace, and the use of iron ore as the primary raw material. The DRI-EAF process, with its lower CO_2 emissions and energy requirements, represents a more environmentally friendly alternative for steel production.

In Nigeria, primary steel is no longer produced but used to be through the DRI process. In this process route, iron ore was reduced to sponge iron using syngas as the reductant. Natural gas is reformed into hydrogen and carbon monoxide. This is different from the blast furnace route that uses coal (converted to coke) as the main fuel. Electric arc furnaces then convert the DRI product to raw steel. The DRI route based on natural gas already offers a lower carbon pathway than the blast furnace route via coal and coke. Whilst the DRI process uses hydrogen as a reductant, it is important to clarify that the syngas used in this process cannot be directly replaced by hydrogen with carbon monoxide also playing an important role as a reductant. The industry has suggested that around 20% of the syngas could be replaced with hydrogen, however moving to a 100% hydrogen system would require a new shaft furnace to be installed as the endothermic nature of the H_2 reduction reactions affects the process heat balance. Table 9 shows that current DRI production is nil at present.

Table 9: Current Direct Reduced Iron (DRI) Production Capacity

Technology	Operator	Plant	Location	Capacity (mmpta)	Module	Product	Start Up	Status
MIDREX	Delta Steel Company	Delta Steel	Warri	1.02	2	CDRI	1982	Idle

Source: https://www.midrex.com/wp-content/uploads/Midrex-STATSbookprint-2020.Final_.pdf

2.6.2 Marine Transport

The marine shipping industry is a significant contributor to global GHG emissions. Heavy fuel oil is the most widely used fuel today followed by marine gasoil. In the near term, it is expected that marine gasoil and very-low sulphur fuel oil will be the predominant marine fuels provided that they can comply with IMO sulphur emissions restrictions. There are, however, other alternative fuels becoming available with lower emissions. These include both green methanol and green ammonia. However, how cost-competitive they will be compared to LNG remains an open question with some 2050 cost projections indicating LNG remaining more competitive although different positions over key assumptions (eg. gas prices) can change this. When used as a marine engine fuel, conventional methanol has 90-95% lower SO_x, 30-50% lower NOx, 5% lower CO_2 and 90% lower PM than a Tier II compliant HFO engine (Man Energy Solutions). When running with green methanol the SO_x and PM emissions would be negligible, and CO_2 emissions would have been offset by the CO_2 capture required during production in the case of blue methanol. Ammonia also has the key qualities of a low-carbon economy fuel – higher energy density than hydrogen as well as zero-carbon and sulphur-free emissions when combusted. There are currently no commercial ships running on blue or green ammonia out of Nigerian ports or indeed, anywhere else. However, ammonia storage and transport infrastructure are well developed globally with significant international trade, and ammonia's shipping routes are well established and there is a comprehensive network of ports globally able to handle ammonia shipments at a large scale, although such infrastructure will need to be grown as capacity is reached.

2.6.3 Land transport

Crude oil-based liquid fuels are energy-dense, cheap and abundant and can be handled safely and easily, for these reasons they have been dominant in the transportation industry. However, in the last decade, powering vehicles using electric motors and batteries has become increasingly popular, not only do these produce no NO_x, but they also have lower lifecycle GHG emissions and increasingly lower lifecycle cost. Hydrogen can provide an alternative to battery EVs, using a fuel cell to produce electricity, which then powers an electrical motor. Hydrogen vehicles have several strengths and weaknesses when compared to BEV – some of its advantages are range and refuelling time. In addition, in regions with poor existing electrical infrastructure, hydrogen can be transported to the region and stored. However, energy efficiency is roughly a third of battery Evs due to the efficiency of electrolyzers (currently around 70%) and fuel cells (<50%). There is no significant volume of hydrogen fuel cell vehicles in Nigeria. Due to the generally poorer cost competitive nature and energy efficiency of hydrogen fuel cell vehicles compared to battery EVs, they are only expected to be deployed where battery EVs are not suitable, there is actually refuelling infrastructure built or where there is poor availability of electricity. In time, these may include heavy-duty vehicles/buses which are required to drive long distances, mining vehicles (especially where flexibility is a key requirement), and long-distance trains (where demand makes it uncompetitive to electrify).

2.6.4 Aviation

The aviation sector is considered a sector that is difficult to decarbonise, as it is not suited for electrification, at least beyond short-haul flights. Hydrogen is seen as an option for decarbonising the sector either through being used as a building block in sustainable aviation fuel (SAF) or directly as hydrogen (but which would need significant redesigning of planes e.g. making wings shorter and the plane body longer). The most likely decarbonisation pathway for aviation is the widespread adoption of SAF, especially as it makes use of the existing infrastructure in terms of the aeroplanes themselves and airport refuelling logistics. Hence SAF is considered a drop-in replacement. There are many potential process pathways to produce SAF, only some of which involve the use of hydrogen.

2.7 Methodology for Renewable and Green Hydrogen production assessment

At this point, an assessment of the potential for renewable electricity generation and green hydrogen production was undertaken. For this purpose, both the costs (levelized cost of electricity - LCoE / hydrogen - LCoH) and the total quantities that can be produced were quantified. This quantification was based on a computer-based model that evaluates Nigeria's geospatial and meteorological data ("ERA5" dataset). The resolution of the spatial modelling is 0.25°, for both longitude and latitude In Nigeria, this corresponds to a distance of roughly 27 km between two vertically or horizontally neighbouring points. For the overall area of Nigeria, this results in about 2,000 data points. The methodical approach can be divided into four consecutive steps:

In the first step, the **site-specific hourly capacity factors** of the photovoltaic systems and the wind turbines is calculated. From the averaged capacity factors, the annual full load hours can subsequently be derived. This calculation is based on weather data from the open source ERA5 dataset, which is a reanalysis of the global climate and weather re-grided to a regular latitude-longitude grid of 0.25° provided in hourly time steps from 1979 onwards. For the sake of the computational power reduction, only one year, namely 2012 was chosen as the underlying weather year, identified next to 1989 as the most representative weather year for power system operation.

Based on the hourly capacity factor, the **costs for the generation of electricity (LCOE) from photovoltaics and wind energy** are determined. Since wind energy and photovoltaics have a particularly large scaling potential and are expected to provide the majority of renewable energy worldwide in the coming decades, the focus of the analysis is on these generation technologies. Literature data are used for the techno-economic parameters (e.g. CAPEX) of the wind energy and PV plants which are shown in the annex. The year of 2030 was chosen as the reference year for these techno-economic parameters, as a near-future time framework will give greater insight into progress on possible production and costs at a key milestone in the future adoption of hydrogen as an energy carrier and fuel.

The second step is to analyse the **availability of land in Nigeria that could be used for energy production**. To quantify the usable land area for the installation of photovoltaic and wind power plants as well as electrolyzers, the **land availability factor** of the sites is determined. The **land area classifications** provided by the Copernicus Server's Land Cover Classification dataset are used to determine the land availability factors. This dataset divides the land areas into 22 different classifications using a satellite-based evaluation with a resolution of 300 m in latitude and longitude steps. The classification is based on the Land Cover Classification System (LCCS) of the United Nations Food and Agriculture Organization. An overview of the land area classification, designation, and land availability allocation is listed in a table. As an example, the land area classification "grassland" is assigned an area availability factor of 90 % while for the land classification "urban area" the area availability factor is 0 %.

Based on the site-specific basic data determined in steps one and two, a **cost-optimized hydrogen production** is modelled in step three. In principle, a system for the production of green hydrogen via electrolysis can be supplied with the required electricity via either the public power grid or an off-grid stand-alone network. Thereby, green hydrogen production in off-grid systems shows several advantages, especially if emerging and developing countries are considered:

- No strain on the public power grid due to additional electricity transports
- Simple guarantee that electricity used for hydrogen production is fully renewable at all times – especially important in the context of possible exports
- Ensuring the additionality of the electricity used – it can be ruled out that renewable electricity potentially missing in the grid is replaced by fossil electricity

Therefore, for the investigations of this report, an off-grid system is considered which, in addition to the generation of renewable electricity and the electrolyzer, also includes the storage of electrical energy (battery storage) and hydrogen (pressurized storage). A linear optimization approach is chosen to identify the optimal combination of the mentioned system components. The key result of this modelling is the **site-specific, minimized hydrogen production costs**. 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. The techno-economic parameters of the system components are listed in the Annex 1 in Table 18 to Table 23.

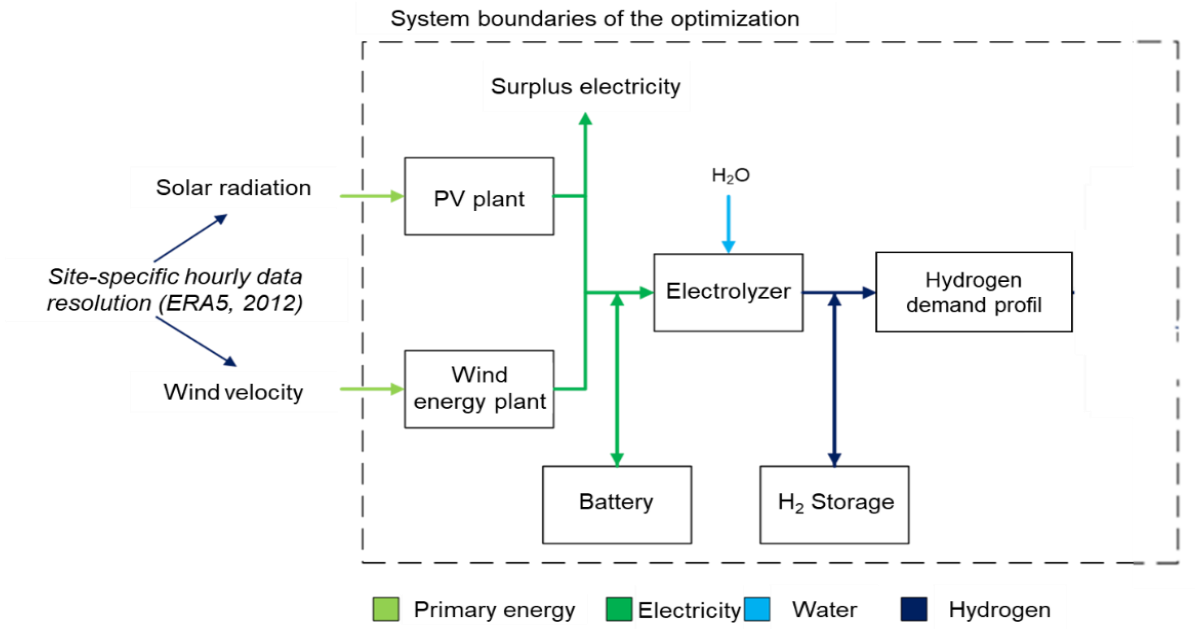


Figure 6: Components and Boundaries of the optimised System

The final step is to quantify the **annual technical hydrogen production potential.** For this purpose, the land availabilities determined in step two are connected with the site-specific hydrogen production costs from step 3. The site-specific, annual hydrogen production potential (kg_{H2}/km^2) can be determined by taking into account the annual full load hours (wind, photovoltaics, and electrolyzer), the specific land requirements per energy output unit of the respective technologies (photovoltaics, wind turbines, electrolyzer), and the site-specific land availability.

2.8 Determination of the Levelized Cost of Renewable Electricity and Green Hydrogen

2.8.1 Step 1: Levelized Cost of Renewable Electricity

The economic potential for electricity generation from wind and solar energy is usually determined by the site-specific LCoE. In turn, LCoE are largely determined by the site-specific mean wind velocity and/or solar radiation as well as the economic parameters of the corresponding plants (CAPEX, OPEX). In a first step, the annual full load hours (AFLH), can be calculated from the average wind speed and the solar radiation, which indicate the annual utilization of a plant at full load. Figure 7 shows the AFLH of wind turbines (top) and photovoltaics (bottom) in Nigeria. First, it can be seen that the availability of wind energy varies much more across the land area of Nigeria than the availability of solar energy. For both energy resources, the utilization potential increases strongly from south to north. In the far north of the country, both wind and photovoltaic power generation reach about 2,000 AFLH (max. 1,900 AFLH for photovoltaic, max. 2,200 AFLH for wind). However, solar power generation can still achieve about 1,200 AFLH even in southern Nigeria, while onshore wind turbines in unfavourable locations, especially in the southeast of the country, can only achieve 500 AFLH or less.

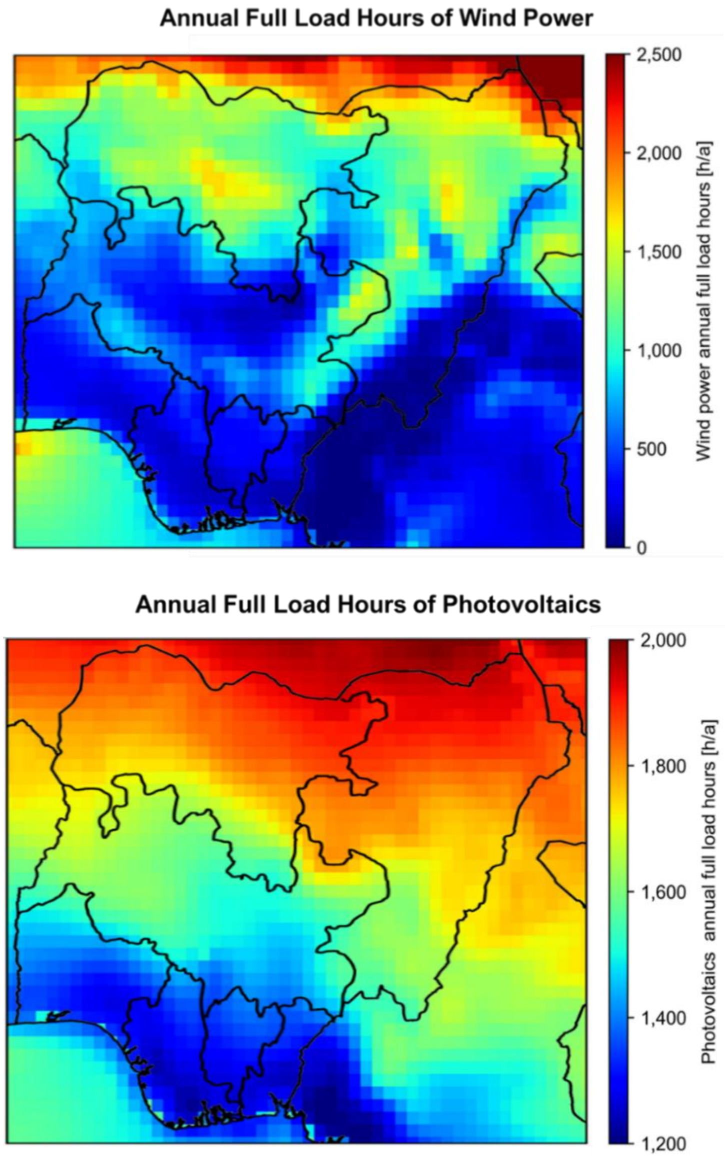
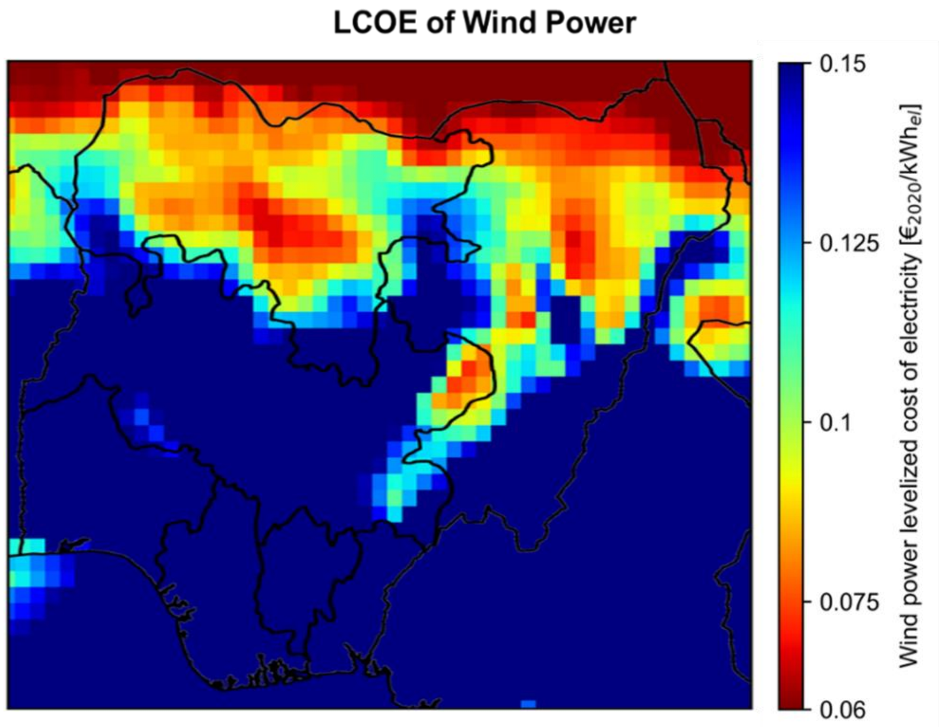


Figure 7: Annual Full Load Hours of Electricity Generation from Wind Power and Photovoltaics

Using the techno-economic parameters for photovoltaic systems and wind power plants (see Table 18 - Table 20), the LCoE can be derived from the AFLH. The LCoE of wind power and photovoltaics are shown in Figure 8.

All values refer to the techno-economic parameters expected in 2030 for the respective power generation systems. It becomes clear that electricity generation by means of photovoltaics has much lower LCoE than electricity generation with wind turbines.

The LCoE of wind power even at the best locations in the far north of the country is around 0.06 €/kWh. Other relatively windy regions can also be found in the central areas of the *North West* zone, e.g. northwest of the city of Kaduna, and in the *Plateau State (Jos Plateau)*. Here, LCoEs in the range of 0.07 €/kWh can still be achieved with wind power. Photovoltaic power generation is three to six times cheaper than wind turbine power generation in almost all regions of Nigeria. Particularly low LCoE of photovoltaics can be achieved in the north, where electricity generation can be realized at around 0.02 €/kWh. But even in central areas of Nigeria, the cost of photovoltaic power generation is still well below 0.03 €/kWh (e.g. *North Central* zone).



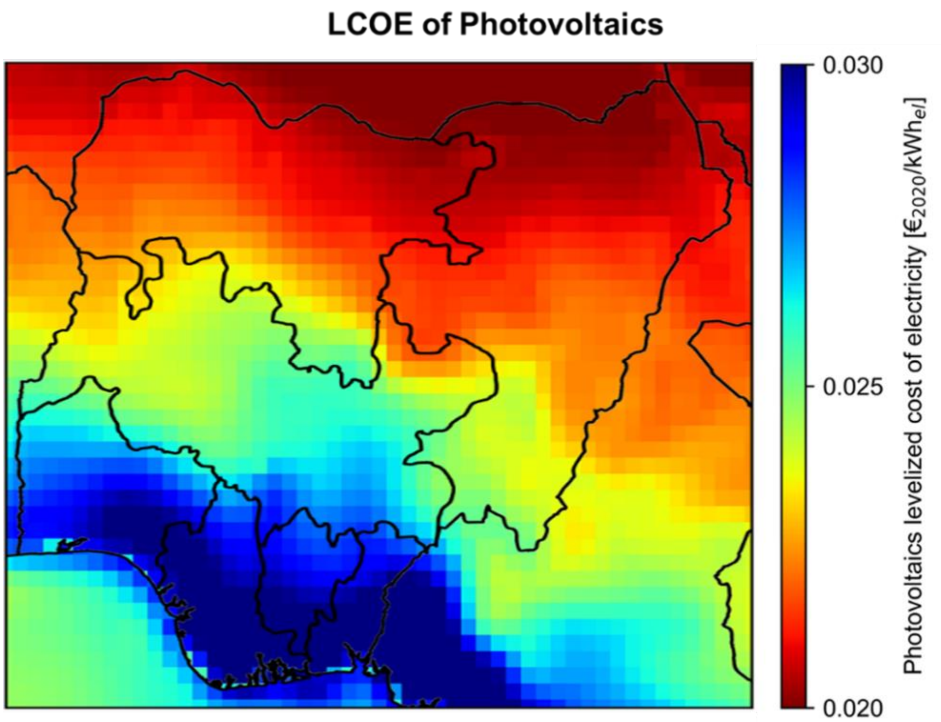


Figure 8: Levelized Cost of Electricity (LCoE) for Wind Power and Photovoltaics in 2030

Under a global comparison, Nigeria's potential for regenerative power generation from wind energy can be considered as relatively poor. For example, good onshore locations for wind turbines in Europe (e.g. northern Germany or Denmark) achieve AFLH of over 3,200, which can result in LCoEs of 0.04 €/kWh or less for the year 2030. By contrast, the sun-rich north of Nigeria in particular offers very good conditions for power generation using photovoltaics, compared with other countries. Thus, the 1,800 AVLH, which are reached throughout large parts of northern Nigeria, are only matched in Europe by southern Spain.

The resulting LCoE of photovoltaics in the range of 0.02 €/kWh is much lower than the LCoE that can be achieved with solar energy, for example, in Germany (0.03-0.04 €/kWh).

Table 1 summarizes the average AFLH as well as the resulting LCoE in the six geopolitical zones of Nigeria. In addition, the key figures of offshore wind energy in regions close to the coast are shown. Offshore wind energy use off the coast of Nigeria provides full load hours in the range of 1,100 to 1,200 per year. In the far west of Nigeria, on the border with Benin, the potential number of full load hours increases to almost 1,500. However, due to the higher investment and maintenance costs for offshore wind turbines, the realizable LCoE is significantly higher than comparable onshore sites, such as those located in northern Nigeria. It can be concluded that the use of offshore wind energy in Nigeria has no significant potential.

Table 10: Annual Full Load Hours and LCoE of Renewable Electricity Generation in the Geopolitical Zones

Region	Wind Energy		Photovoltaics	
	Average Annual Full Load Hours [h/a]	Average LCOE [€/kWh]	Average Annual Full Load Hours [h/a]	Average LCoE [€/kWh]
North-Central	670	0.17	1,540	0.025
North-East	960	0.12	1,830	0.021
North-West	1,100	0.10	1,810	0.021
South-East	440	0.26	1,340	0.029
South-South	460	0.25	1,290	0.030
South-West	510	0.22	1,450	0.027
Total (Onshore)	810	**0.14**	1,650	**0.024**
Offshore Locations	1,140	**0.18**	/	/

2.8.2 Step 2: Land Availability

As described above the assessment of the land available for renewable energy generation is based on the land classifications and the associated specific land availability factors. Figure 9 shows the results of the analysis of the available geospatial data.

It can be seen that land availability tends to increase from south to north. However, the variations are smaller than for the potentials for wind and solar energy use. While the calculated average land availability factor in the three northern zones is in the range of 0.25, the South-East and South-South zones only achieve an average land availability of 0.18 and 0.12, respectively (see Table 2). The differences in land availability between the north and the south are probably caused in particular by population density (much higher in the south) as well as biomass production (more forest land that cannot be used for energy production in the south).

In addition to this general distribution of land availability, Figure 9 shows two small-scale regions with a particularly high land use potential. Once this is the region between Ilorin town and Old Oyo National Park along the boundary between South West and North Central Zones. In addition, the area north of Abuja along the road to Kaduna also shows very high availability. In both of the mentioned regions, the analysis of the geospatial data indicates that there are larger areas with land availability between 0.5 and 1.

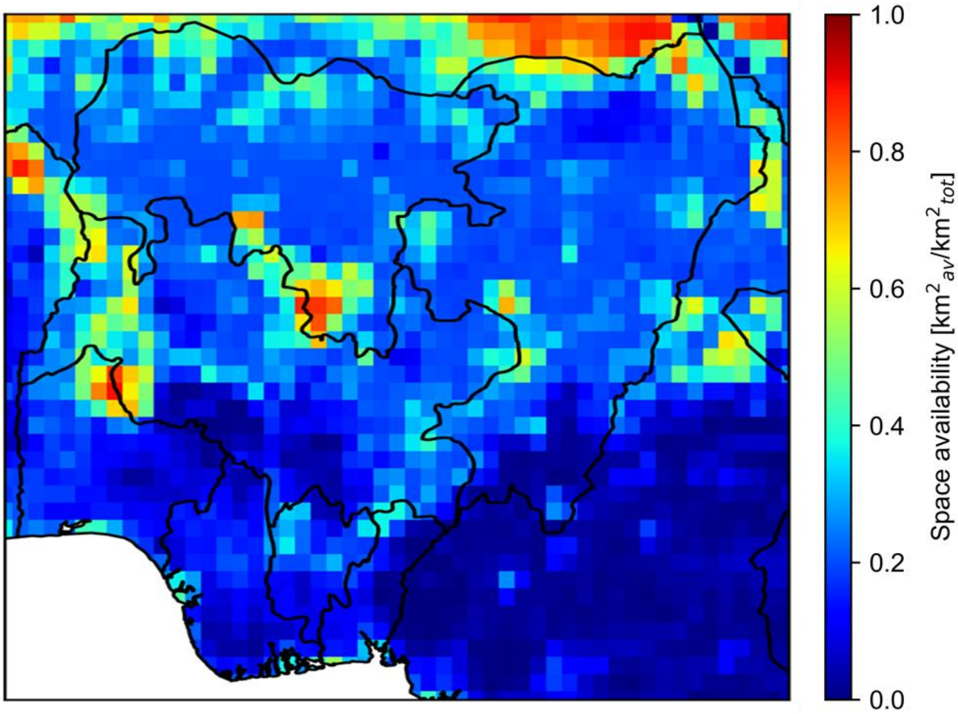


Figure 9: Available Space for Renewable Energy Generation

Table 11: Land Availability in the Geopolitical Zones

Region	Land Area [km²]	Average Land	Available Land area
North-Central	234,210	0.24	56,000
North-East	280,419	0.24	67,000
North-West	212,350	0.28	59,000
South-East	28,987	0.18	5,000
South-South	84,616	0.12	11,000
South-West	76,852	0.21	16,000
Total	917,434	0.23	~ 214,000

2.8.3 Step 3: Cost Optimized Production of Green Hydrogen

Figure 10 shows the minimum hydrogen production costs in Nigeria in 2030 resulting from the modelling of an optimized generation based on electricity from wind energy and photovoltaics. It is evident that production costs vary relatively widely across the area of Nigeria.

Northern areas

In the northern part of the country, production costs of less than 3.5 €/kg hydrogen can be realized in 2030. The minimum is reached at locations near the border triangle with Chad and Niger. Here, potential production costs of around €3.3/kg hydrogen can be achieved.

Southern areas

In the southern regions, by contrast, the minimum hydrogen production costs are typically higher than 4.5 €/kg.

Central areas

In the central areas of the country (*North-Central Zone*, southern part of *North-East Zone*, northern part of South-West Zone), the hydrogen production costs are typically between 3.9 and 4.3 €/kg. Production costs of less than 4 €/kg can be realized much further south in the *North-East Zone* than in the *North-West Zone*. This applies in particular to the border region with Cameroon, where it may be possible to achieve production costs below 4 €/kg up to the latitude of the town of Jimeta.

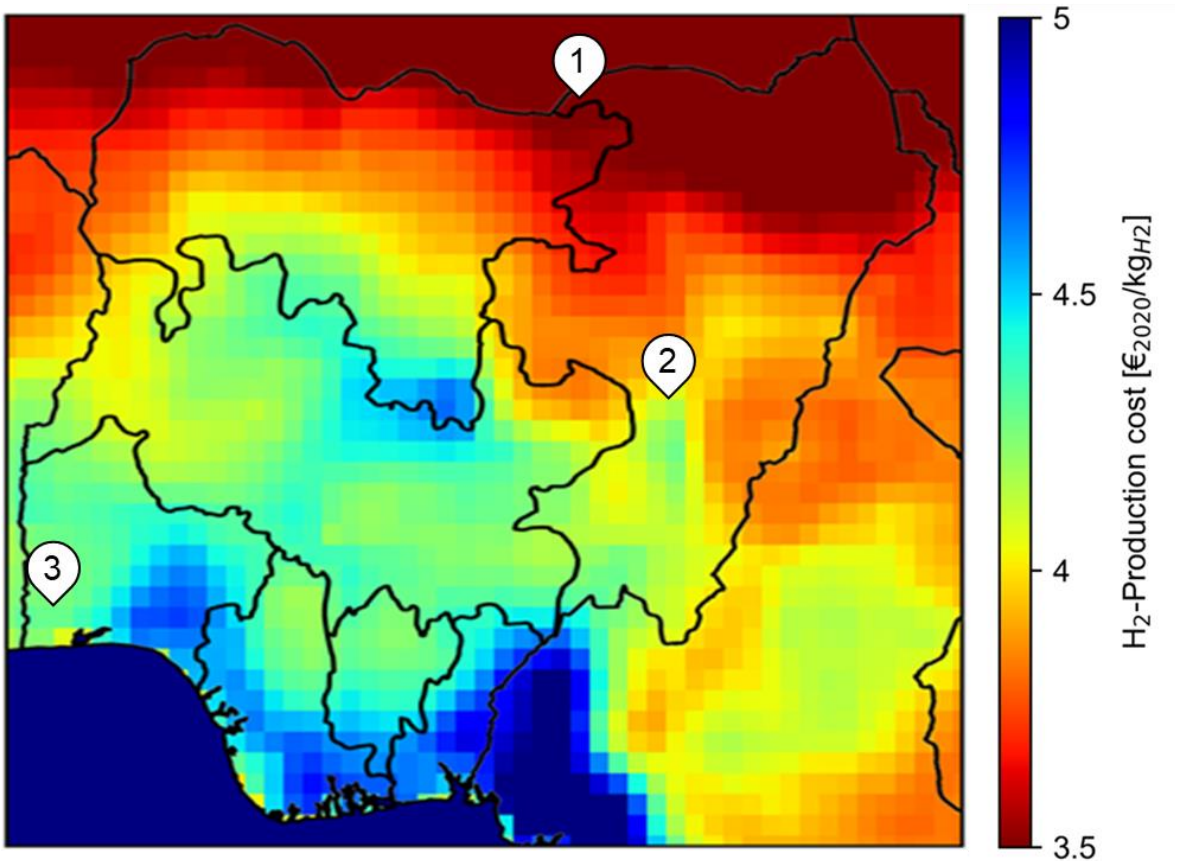


Figure 10: Onsite Hydrogen Production Cost in 2030

Table 12 also indicates that hydrogen production with offshore wind energy off the coast of Nigeria is not economically viable. Here, the production costs are on average more than 20 €/kg.

Table 12: Average Hydrogen Production Cost in the Geopolitical Zones

Region	Average H_2 production cost [€/kg_{H2}]
North-Central	4.2
North-East	3.7
North-West	3.8
South-East	4.4
South-South	4.7
South-West	4.5
Total	4.0
Offshore Locations	>20

The minimum hydrogen production costs depend primarily on the LCoE and the AFLH of renewable electricity generation as well as the techno-economic parameters of the additional system components (water supply, electrolyzer, compressor, energy storage).

Another factor may be the site-specific seasonality of renewable power generation. Despite these multiple dependencies, a relatively strong correlation between hydrogen production cost and the LCoE of photovoltaic power generation is shown for Nigeria. The reason for this is that an optimized system for generating green hydrogen from wind and solar energy in Nigeria relies exclusively on photovoltaic power generation at almost all locations, as it is shown in Figure 8 (bottom).

Wind energy does not play a role in cost optimized hydrogen production due to its high specific LCOE. The modelling performed also indicates the required ratio between the installed power generation capacity (as discussed, for all onshore sites in Nigeria exclusively photovoltaic) and the installed electrolysis capacity to enable hydrogen production at minimum cost (e. g., $kW_{renewables}$ per $kW_{electrolysis}$).

According to Figure 11 (top), the ratio of renewable power generation to electrolyzer capacity is between 2.3 and 3.3 in Nigeria. Thereby, at locations with a comparatively high number of AFLH (especially in the northern part of the country), less power generation capacity tends to be required than at locations with a lower number of AFLH. Such an oversizing of the power generation capacities is part of an optimized system, since in this way the utilization of the electrolyzer can be increased. At the same time, however, some of the electricity generated cannot be used and has to be curtailed - since an off-grid system was considered, this amount of electricity is not fed into the grid. Thus, oversizing of electricity generation always involves a trade-off between maximizing the utilization of the electrolyzer and minimizing the amount of electricity that is curtailed.

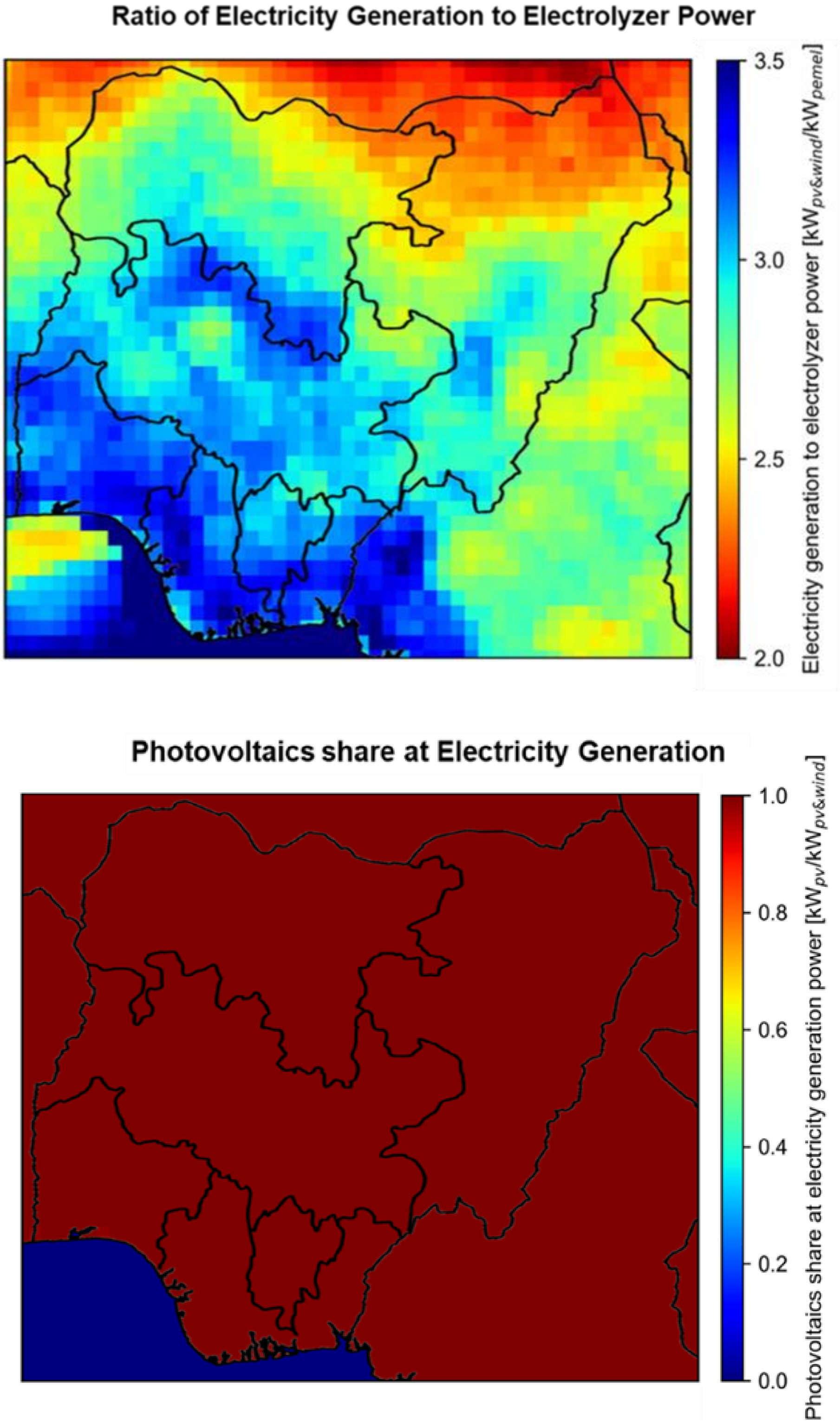


Figure 11: Characteristics of a cost-optimized System for Hydrogen Production

Detailed cost breakdown at exemplary sites

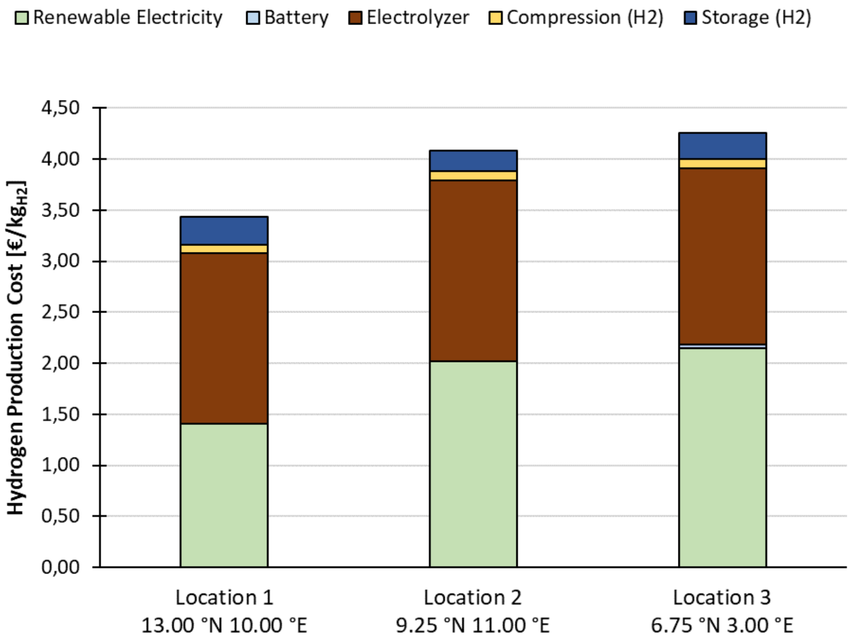
In the following, the composition of the onsite hydrogen production costs (see Figure 10) will be discussed. For this purpose, the three exemplary locations marked in Figure 10 will be examined in detail. Location 1 represents a site in northern Nigeria with hydrogen production costs of less than 3.5 €/kg. Location 2 is typical for the centre of the country, while Location 3 represents a coastal site with comparatively low hydrogen production costs within the three southern regions.

The breakdown of the hydrogen production costs (see Figure 12) shows that in all the cases examined, more than 90 % of the hydrogen production costs are determined by the electricity generation and the electrolyzer. The supply of electricity on the one hand site and on the other hand site the construction and the operation of the electrolyzer contribute almost equally to the overall hydrogen production costs. At Location 1, where photovoltaic electricity generation has particularly high AFLH, electrolyzer costs have a slight overweight. In contrast, at Locations 2 and 3, where the ALFH of PV is lower, the cost of providing electricity slightly predominates.

Furthermore, battery storage is only used at Location 3, but even here with comparatively low storage capacity. The capacity selected by the optimisation model is sufficient to supply the electrolyzer with electricity for about 3 hours. The costs for this battery storage have only a marginal influence on the total hydrogen production costs due to its small size.

In addition, it can be seen that a cost-optimized hydrogen production system in Nigeria generally seeks for an electrolyzer operation at 3000 AFLH. This capacity factor is essentially achieved by oversizing the PV power generation capacity relative to the electrolyzer capacity. Accordingly, the oversizing at Location 1 (factor 2.3) is significantly lower than at the other sites (factor 3.1 resp. 3.4) considered, as the PV-based power generation here has a higher AFLH. It can be assumed that an AFLH in the range of 3000 (+/- 150) is an optimal range for hydrogen production in Nigeria.

A further increase would most likely lead to a disproportionate increase in electricity costs, as even greater oversizing of PV capacity would be required, leading to more and more curtailed electricity. Less AFLH of the electrolysis could reduce the electricity costs, but would result in even higher costs for the electrolyzer (e.g., depreciation costs).



AFLH PV	1940	1650	1355
AFLH Electrolyzer	3140	2965	3030
Ratio PV/Electrolyzer	2,29	3,10	3,37

Figure 12: Cost breakdown for onsite Hydrogen Production at Exemplary Sites in 2030

2.8.4 Step 4: Technical Potential of Green Hydrogen

In a final step, the technical potential of hydrogen production from photovoltaics and wind energy is to be quantified. For this purpose, the mean hydrogen production potential in kg hydrogen per km^2 and year is first calculated for each analyzed data point described by the corresponding coordinates. Subsequently, the resulting hydrogen volume is linked to the minimum production costs previously determined at this data point. Finally, from the sum of all points, the total technical potential for hydrogen production can be calculated as a function of production costs (Figure 13).

It is shown that about **120 Mt hydrogen per year** can be produced in Nigeria at a cost of less than **4.5 €/kg hydrogen**. If **3.5 €/kg hydrogen** is defined as the maximum cost, the technical potential would still be around **40 Mt hydrogen per year**.

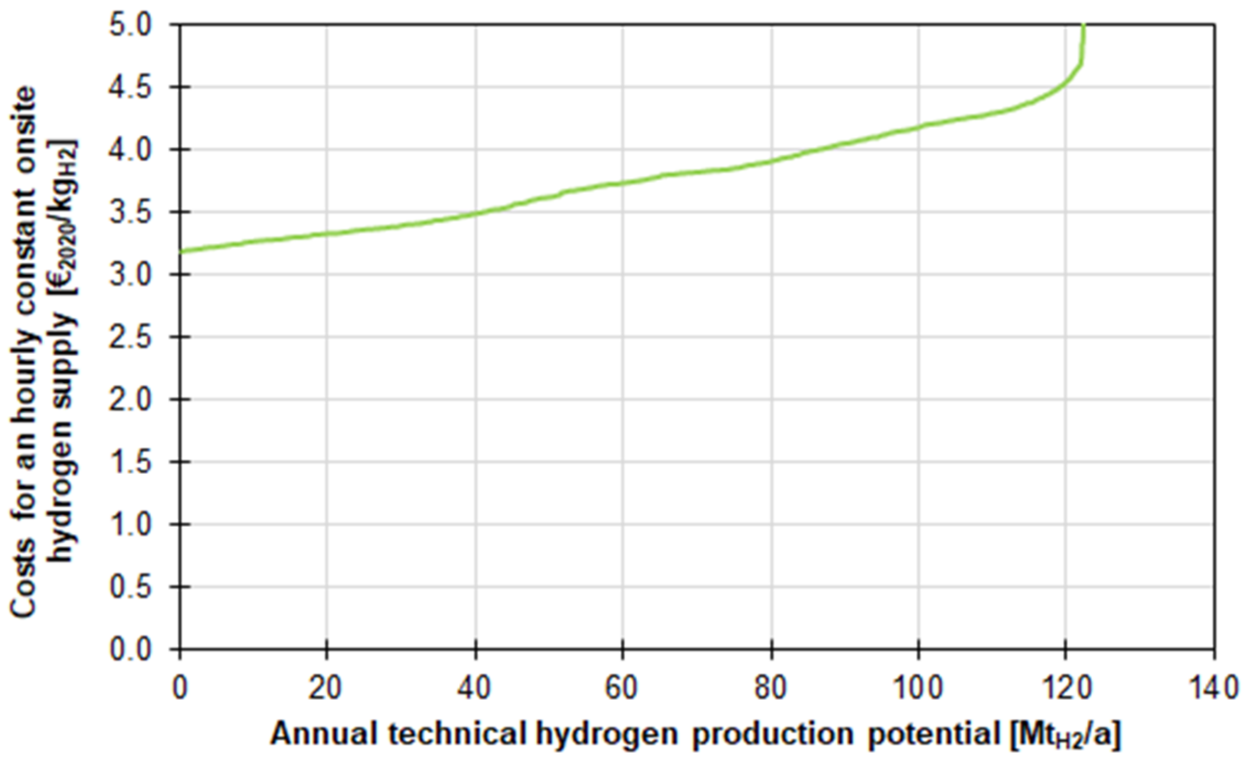


Figure 13: Technical Potential of Green Hydrogen Production in Nigeria

2.8.5 Excursus: Use of hydropower to produce green hydrogen

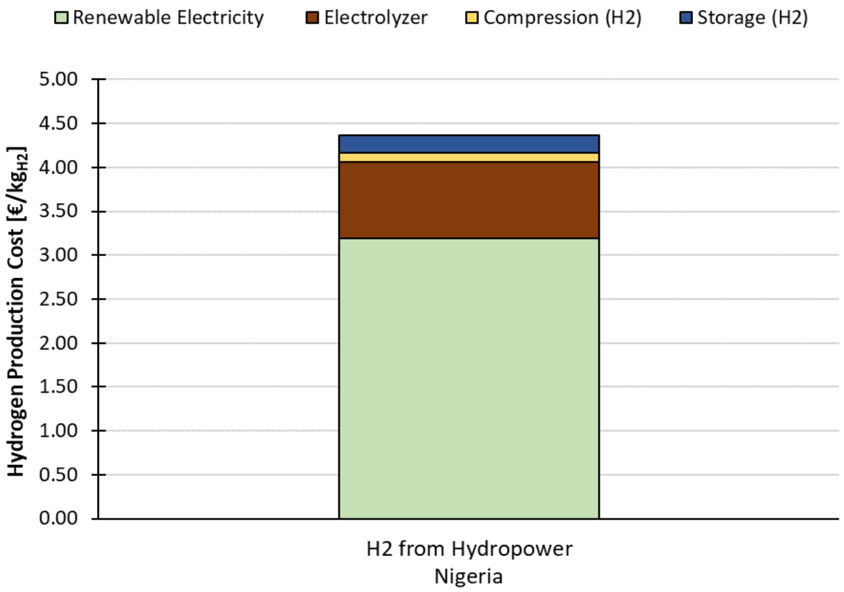
Based on data from IRENA, the total potential of hydropower (large and small) in Nigeria is about 27 GW, and at present, about 10% of the available total potential is being used. Various scenarios for the development of the Nigerian power system assume that between 13 and 15.5 GW of hydropower will be installed by 2050. Accordingly, the utilization rate would increase to over 50 %.

In principle, it should be presumed that the capacities needed to meet the national electricity demand are not available for hydrogen production. Direct use of electricity is more efficient and should therefore be prioritized, in addition, hydropower is generally capable of base-load operations. Correspondingly, a maximum of 10 GW hydropower is available for hydrogen production. However, it is questionable to what extent full exploitation of the potential could be realized in an ecologically sustainable manner.

If it is assumed that 5 GW hydropower with ~5,250 AFLH (based on data from IRENA for newly developed hydropower projects in Africa) would be available for hydrogen production, then the production potential of hydrogen is slightly below 0.8 Mt/a, which can be assessed against the potentials from photovoltaics and wind energy contained within Figure 13 above. It is also instructive to note that a LCoE of hydropower, based on IRENA for Africa 2015-2020, is estimated at around 0.065 €/kWh).

Based on the assumptions for the LCoE of hydropower and the corresponding AFLH, the costs for a hydrogen production based on hydropower can be calculated. In order to do so, it is also assumed that there is no oversizing of the hydropower plant, i.e., no electricity is curtailed.

Figure 14 shows the cost breakdown for a hydrogen production based on hydropower. Overall hydrogen production cost are around 4.4 €/kg, which is 25 % higher as hydrogen production with photovoltaics at best locations in the northern part of Nigeria. Due to the high availability of the hydropower the electrolyzer cost is significantly lower compared to a hydrogen production based on photovoltaics. However, the cost of supplying renewable electricity from hydropower is 1.5 to 2 times higher than the cost of PV electricity. The cost of hydrogen storage can be slightly reduced compared to generation with photovoltaics, since hydrogen production with hydropower is more continuous.



AFLH Hydropower	5250 h/a
LCOE Hydropower	0.065 €/kWh

Figure 14: Cost of Hydrogen Production based on Hydropower

3. Local demand and emissions reduction potential

3.1 Longlist of possible hydrogen applications in the Nigerian context

Currently, hydrogen is either to be used or is primarily used in the industrial sector. This includes the chemical industry, especially the synthesis of ammonia and methanol, iron and steel production, and the refining of oil. In the future, applications could also be developed in the agriculture, buildings, energy, and transport sectors. Table 13 below lists different hydrogen applications across the mentioned sectors with the various options subsequently described in detail.

Table 13: Longlist of possible hydrogen applications, based on [64–66,71, 75, 76, 79, 81]

Sector	Application
Agriculture	Traction
Buildings	Heat
	Cooking
Industry	Oil Refining
	Ammonia
	Methanol
	High value chemicals
	Iron and steel production
	Low-temperature heat (<100 °C)
	Medium-temperature heat (100-400 °C)
	High-temperature heat (>400 °C)
Power	Flexible power generation
	Backup power supply
	Off-grid-power-supply
	Co-firing in coal and gas plants
Transport	Light duty vehicles (Passenger road vehicles)
	Heavy duty vehicles - Buses/Coaches
	Heavy duty vehicles - Trucks
	Shipping
	Rail (Passenger trains and freight trains)

Sector	Application
	Aviation
	Forklifts
	Taxi fleets
	Motorcycles

3.1.1 Hydrogen in agriculture

The agricultural sector had a total final energy consumption (TFEC) of 8 PJ in 2015, accounting for 0.4 % of the Nigerian TFEC [82]. Figure 15 shows that energy is consumed mainly for irrigation and traction. Fossil diesel and gasoline are currently used almost exclusively as final energy sources. For irrigation, solar-powered systems are a competitive, greenhouse gas-neutral solution. Solar irrigation pumps already reach lower levelised costs of energy compared to conventionally used diesel and gasoline pumps [82]. Hydrogen could be used for traction applications. For example, the company Fendt showed a prototype of a first hydrogen-powered tractor recently [74].

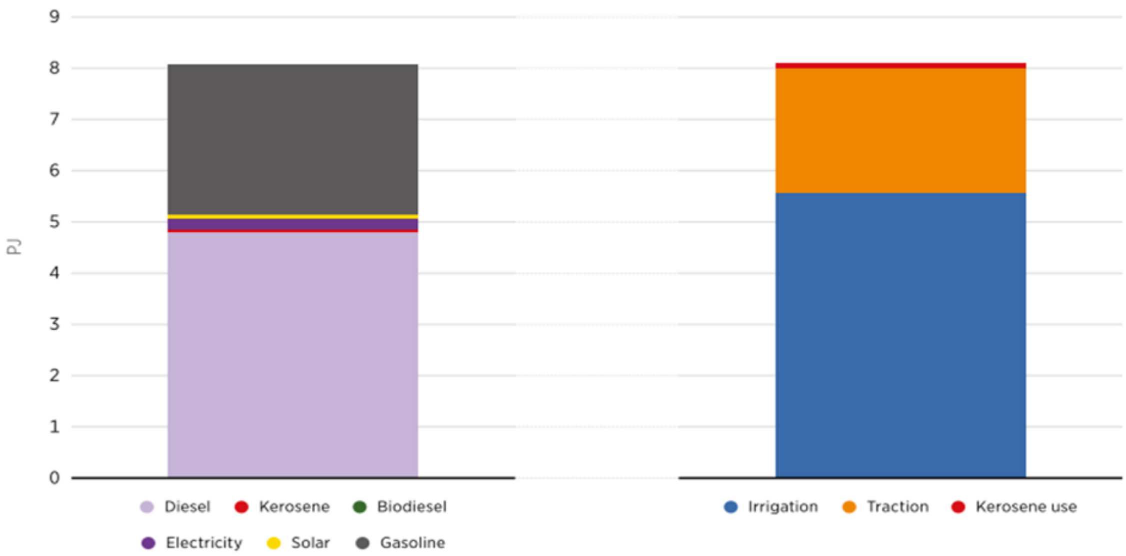


Figure 15: TFEC in agriculture, 2015 [82]

3.1.2 Potential for the utilization of hydrogen in the buildings sector

The buildings sector had a TFEC of 1324 PJ in 2015, accounting for 61.4 % of the Nigerian TFEC. The high share results mainly from the low level of development in the other sectors [23]. Over 75 % of the TFEC in the buildings sector originates from residential buildings. Therefore, residential buildings are the central focus of this segment [82]. As Figure 16 shows, the main part of the energy consumption results from cooking. The energy for cooking is mainly supplied by biomass. In addition, LPG, kerosene, and electric stoves are used [82].

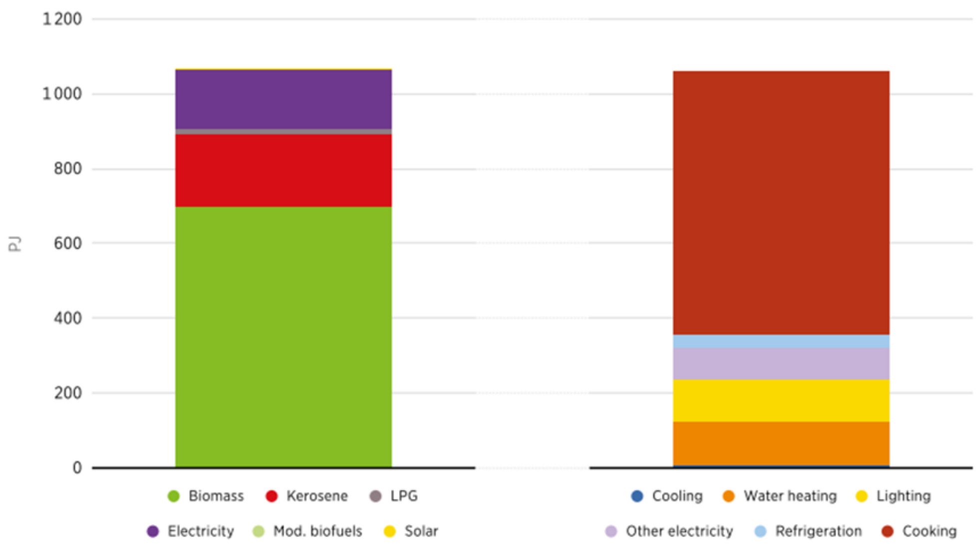


Figure 16: TFEC in residential buildings, 2015 [82]

Hydrogen can be used in buildings, but will most likely only be utilized in regions with existing natural gas distribution networks [71, 81]. As natural gas is not heavily used in the Nigerian buildings sector, this is not the case in the country's context. Furthermore, existing pipelines could require modifications for the distribution of hydrogen instead of natural gas.

- Hydrogen can be used as a **cooking fuel**. This option leads to high costs and requires complex technology as well as a high focus on safety [90]. A hydrogen-fuelled cook stove is currently being tested, but the technology is not market-ready [81].
- Hydrogen can be combusted to supply **heat** to residential and commercial buildings. This option is mainly looked at for the replacement of natural gas [68]. The heat demand in the buildings sector is low (see Figure 16) and natural gas is not heavily used in the country.
- The possibility of using hydrogen to supply **electricity** to buildings that are not connected to the public electricity grid is described in section: Options for the usage of hydrogen in the power sector.

3.1.3 Possible hydrogen applications in industry

The industry sector had a TFEC of 405 PJ in 2015, accounting for 19 % of the Nigerian TFEC [82]. As in the buildings sector, biomass is the main energy source utilized in industry. Right now, the industry sector is not well developed and needs a structural reform [82]. Despite this, Nigeria is already a large exporter of chemicals and could triple its chemicals production capacity by 2040 [77]. The energy consumption by different industries is shown in Figure 17. The main energy demand is located in the group "other industries" consisting of small and medium-sized businesses. The potential for the adoption of novel technologies with lower emission footprints or higher energy efficiencies is expected to be low [82] for this group. Therefore, the main focus of this work is set on cement, steel, fertilizer, and paper production.

Hydrogen can be used in industrial applications for different reasons [64]:

1. Hydrogen is a molecular constituent of the product and is used as a chemical feedstock, e.g. for ammonia (fertilizer industry) and methanol
2. Hydrogen takes part in reactions, but is not a part of the product, e.g. in the steel industry
3. Hydrogen is combusted to supply heat, e.g. in the cement and paper industry

The first application is responsible for the main part of the current hydrogen demand. That demand is primarily covered based on natural gas and coal or supplied as a by-product from other processes. Green hydrogen produced via electrolysis provides an option for an alternative, CO_2-neutral raw material source.

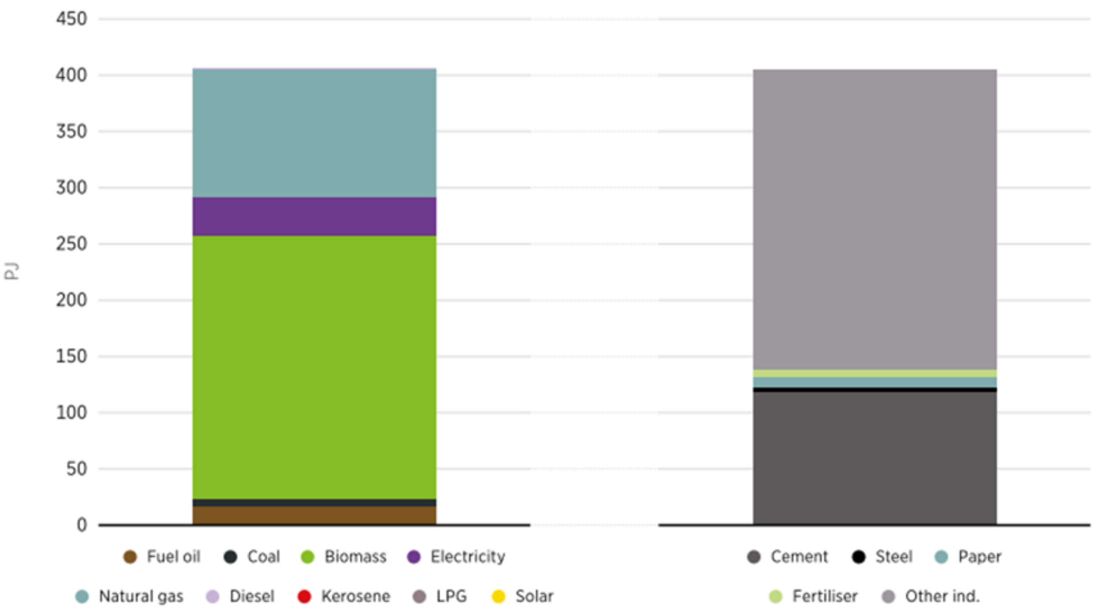


Figure 17: TFEC in industry in Nigeria, 2015 [82]

Hydrogen is needed to hydrocrack or hydrotreat crude oil to produce more valuable products such as fuels and to reduce the sulphur content of diesel fuel. The global hydrogen demand for **oil refineries** is expected to rise until 2040 and decline thereafter due to the declining importance of fossil fuels [64, 71], but a large demand is expected even after 2050 [79]. In the future, hydrogen will also be needed in refineries for upgrading biofuels and the production of synthetic fuels [81]. One-third of the required hydrogen in conventional refineries is generated as a by-product. The remaining amount could be supplied using green hydrogen [79]. Nigeria holds 2.1 % of global oil reserves (36.9 billion tonnes). The share of global crude oil production in 2021 was 1.8 % (77.9 million tonnes). With a refining capacity of 475 thousand barrels per day (tbpd), the country hosts 0.5 % of the world's refining capacity, but only 3 tbpd were refined in 2021 [67] because the available refineries are idle [72]. A new refinery with a capacity of 650 tbpd was constructed and is being commissioned in 2023 as mentioned in Chapter 2 [82,89].

Hydrogen is needed to produce **ammonia (NH_3)** using the Haber-Bosch-Process**.** Nitrogen, which is also required, is extracted from the air. Currently, hydrogen is generated using fossil fuels. From 2025 onwards, renewable NH_3 production with electrolysis-based hydrogen is expected to dominate all newly added capacity globally [83]. With a production of 1.1 million metric tons, Nigeria accounted for 0.73 % of global NH_3 production in 2021 [92]. NH_3 is mainly used as a precursor in the fertiliser industry. The demand is therefore coupled with agricultural production [71] and with the population [83]. The global NH_3 demand for fertiliser production is expected to rise from 156 million tons (Mt) in 2020 to 267 Mt in 2050 [83]. The Nigerian population is expected to grow from 218.5 million in 2022 to 378 million in 2050 [91]. As a result, the Nigerian demand for NH_3 will most likely increase significantly in the future, too. In addition, several other ammonia markets are expected to develop in the future, e.g. for the use as a shipping fuel or hydrogen carrier [83].

Similar to ammonia, hydrogen is needed as a feedstock for the synthesis of **methanol** [64]. In addition to hydrogen, carbon is also needed for methanol synthesis. Today, a fossil hydrocarbon such as coal or natural gas is used to supply hydrogen and carbon [81]. Changing the hydrogen feedstock would therefore imply that an alternative carbon source must be available.

- **High value chemicals** (HVCs), e.g. ethylene, propylene, or butadiene, are mainly used in plastics production. Conventional production is carried out using steam crackers for the cracking of long-chain hydrocarbons.
- Using a process called **Methanol-to-Olefins**, methanol can be converted to HVCs. Fossil-based methanol is used in China for the production of Olefins [94].

Hydrogen can serve as a reducing agent in the **steel industry**, replacing the reduction of iron ore via coke in a process called "direct reduction of iron" (DRI) [64]. A mixture of carbon monoxide and hydrogen is used in conventional DRI plants. DRI production using pure, potentially "green" hydrogen is at an early stage of development [81].

Industrial low-grade heat can be supplied using hydrogen, but direct electrification is the preferred option [75]. For the supply of **medium** (e.g. paper industry) and **high-grade heat** (e.g. cement production) hydrogen could be an option because direct electrification solutions suffer from material degradation [94].

The supply of heat employing hydrogen is most likely not a viable alternative for the **cement industry**. Carbon capture needs to be installed for the greenhouse gas-neutral production of cement regardless of the heat supply because 60 % of the CO_2 emissions are process-related. Therefore, the use of low-cost fossil fuels with carbon capture might be the preferred option [71].

3.1.4 Options for the usage of hydrogen in the power sector

As mentioned in the baseline section, the Nigerian power system consists of grid-connected and off-grid systems [82]. The installed capacity of grid-based systems in 2023 equals 13 GW, but only 4.5 GW of this capacity are available due to shortages in gas supply, water shortages, and unavailability of machines. Natural gas dominates the on-grid power supply. Off-grid generators running on diesel or gasoline are used by many households and business units due to the reliability issues of the public grid [82]. The high share of off-grid generators in the power system is illustrated in Figure 18.

The role of hydrogen in the power sector in the short term will be limited to blending into the gas grid on a global scale. Re-electrification of "green" hydrogen is expected to be the last application in the merit order [71]. The technologies needed for hydrogen-based electricity generation are commercially available today or under development. This includes reciprocating engines, gas turbines, and large-scale fuel cells [81]. An alternative to the use of pure hydrogen is co-firing in coal and gas plants [81].

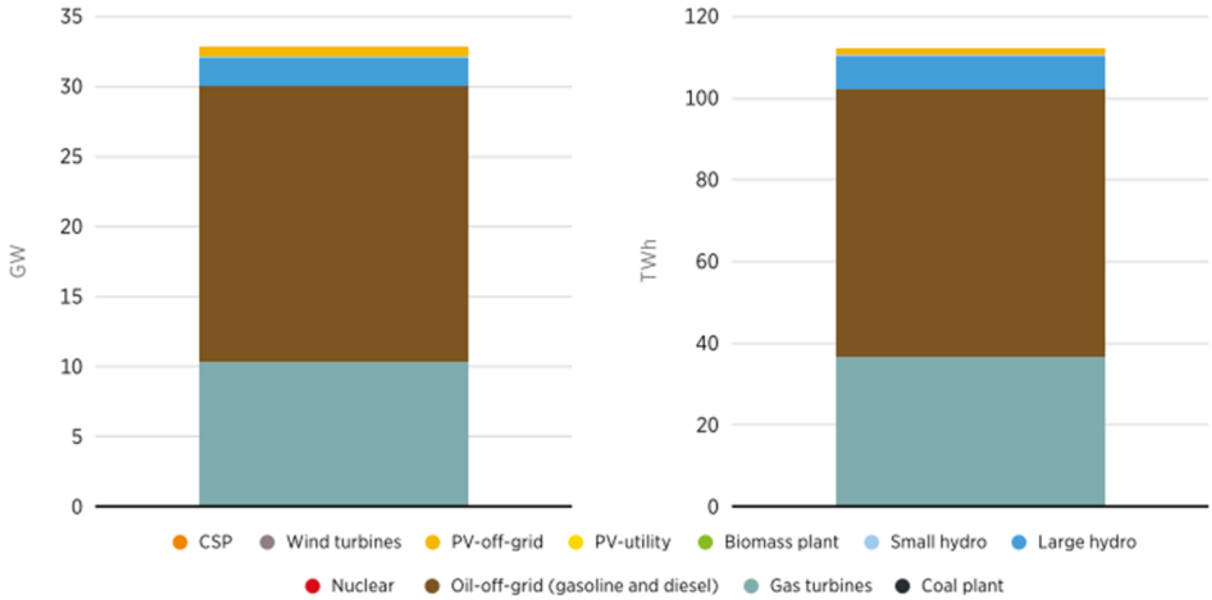


Figure 18: Installed electricity generation capacities (left) and total power generation (right) in 2015 [18]

Hydrogen can provide grid stability using **short-time storage** and grid reliability using **long-term storage** [68]. Considering the status of the electricity grid in Nigeria and the high effort for efficient storage of hydrogen (e.g. high-pressure tanks), these use cases are most likely not relevant in the near term.

Generating electricity using fuel cells or turbines is less efficient, compared to the direct utilisation of the electricity fed to the electrolyser [68]. The employment of hydrogen in the power sector results in high energy losses and storage demands [71].

Stationary electricity generation based on hydrogen should therefore be limited to special cases:

- **Off-grid-power supply:** A huge share of the power generation in Nigeria relies on gasoline and diesel used in off-grid-generators. These generators could be replaced by a system containing electricity generation utilizing photovoltaics, hydrogen generation via electrolysis, hydrogen storage, and a fuel cell. Such an off-grid-power supply does not require the delivery of diesel and gasoline via truck [68]. The build-up of solar/hydrogen-based mini-grids is an alternative to the expansion of the electricity grid and could provide households with access to electricity, especially in rural areas. One, potentially more cost-effective alternative to hydrogen-based systems, are off-grid solutions that work with battery storage.

- **Backup power:** Backup power is needed to sustain the operation of important infrastructure, e.g. in hospitals or data centres. Hydrogen could be used to fuel generators for backup power generation [75].

- **Flexible power generation:** Hydrogen can be used in turbines or large-scale fuel cells to provide flexible capacity and baseload power. Baseload power in Nigeria should be supplied by renewables, based on the high solar energy potential [75]. Combined cycle gas turbines could play a role in balancing the fluctuating renewables energy supply. This option needs hydrogen storage capacity and lacks from low efficiencies [75].

3.1.5 Possible hydrogen applications in the transport sector

The transport sector had a TFEC of 418 PJ in 2015, accounting for 20 % of the Nigerian TFEC [82]. Figure 19 illustrates that the main fuels used are gasoline and diesel. Private cars, taxis, and trucks are responsible for the highest shares of the TFEC. With 14 million vehicles, Nigeria's vehicle stock is the second highest in sub-Saharan Africa. By 2040, the vehicle stock could reach 37 million [77] as the transport sector is expected to grow in the future due to the predicted population growth and development of the economy [82].

As in other sectors, hydrogen can be directly used in the form of molecular hydrogen or indirectly for the production of liquid or gaseous fuels [66].

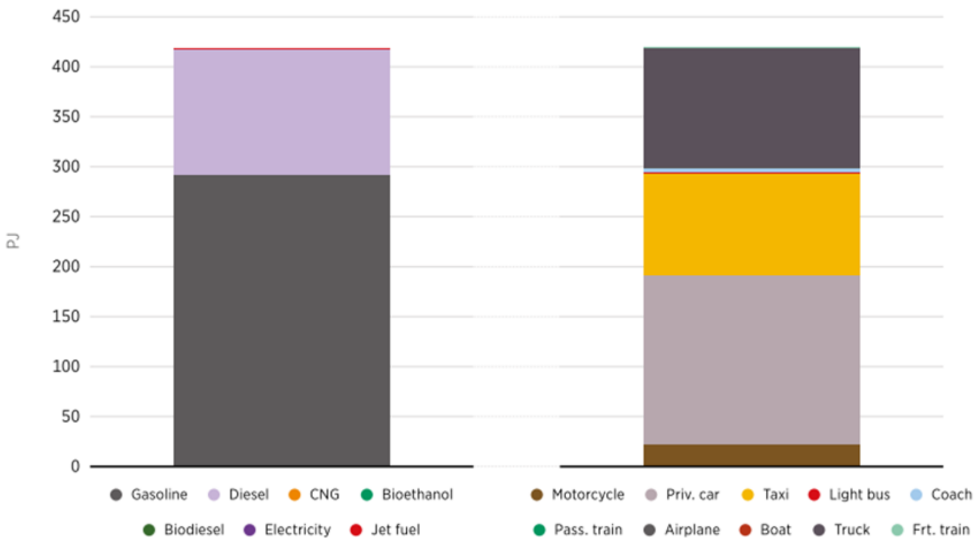


Figure 19: TFEC of the Nigerian transport sector in 2015 [82]

- Fuel cell **passenger vehicles** (fuel cell electric vehicles, FCEVs) contain an electric drivetrain powered by a proton exchange membrane fuel cell (PEMFC). FCEVs are only feasible for applications where long ranges above 400 km and/or short refuelling times are required. Otherwise, battery electric vehicles (BEVs) should be preferred [68] due to lower costs and higher efficiencies [71]. Therefore, the majority of passenger cars and light-duty vehicles are expected to be BEVs in a CO_2-neutral future [94]. Because **taxi fleets** require a centralised infrastructure and faster refuelling times, hydrogen is a promising fuel in this field [76].
- **Trucks** and **buses** powered by fuel cells may be the favoured decarbonisation option over BEVs because of their higher energy demand and the typical “back to base” routes [68].
  - Fuel cell electric buses offer ranges between 300 and 450 km. That results in operational flexibility comparable to currently used diesel-fuelled buses, while fuel cell buses do not emit air-polluting substances and offer lower noise emissions [66].
  - Hydrogen is an option for the decarbonisation of long-distance heavy-duty trucking because longer distances cannot be covered by currently available battery-powered trucks [71] due to the high costs and weights of the batteries as well as the long recharging times [75].
- Currently, hydrogen-powered **trains** use a PEMFC and offer travel distances of 1000 km and speeds in the range of 140 km/h [68]. Hydrogen-powered trains are presently only available for passenger transport. Freight trains are under development. Hydrogen-fuelled trains are a decarbonisation option for longer, low-frequency routes that are not yet electrified [75]. At the end of 2018, only 6 trains were operational in Nigeria. The majority of the railway network needs to be replaced. The government aims to revamp the system. Trains have a low relevance in Nigeria today but could become an important means of transport in the future [69, 82].
- Fuel cell-powered **marine applications** could be an option for smaller ferries with a “back to base” operation. For larger ships, synthetic fuels, ammonia and methanol are the preferred decarbonisation options. These options will create a demand for green hydrogen [68, 71], but ships do not play an important role in Nigerian transport right now as transport and travel using ships are badly developed [82].
- Direct use of hydrogen in **aviation** will be limited to alternative fuel cell applications in the near term, e.g. on-board power generation. A hydrogen-powered short- to medium-range aircraft is currently under development, but not expected to be available on the market until 2035 at the earliest. Aviation requires high power densities leading to the preference of synthetic fuels [68] which is also a future market for green hydrogen.
- Fuel cell **forklifts** can be used for material handling and are preferred over BEVs due to their higher speed of refuelling and lower cost of ownership [68]. Hydrogen-powered forklifts are currently being used in large numbers and are state of technology.

- Some prototypes of fuel cell-powered **motorcycles** have already been tested. The potential for hydrogen in this segment is low, as batteries are the favoured solution [66].

3.2 Identification of prioritized applications

3.2.1 Evaluation parameters for the identification of prioritized applications

In order to identify prioritized hydrogen applications which might have special relevance in the country in the future, three main factors are evaluated:

- Economic competitiveness;
- Technical feasibility;
- Relevance of the application in the context of the Nigerian energy system;

The **economic competitiveness** will be graded based on a literature survey and the evaluations in the previous sections.

The **technical feasibility** will be assessed based on the "technological readiness level" (TRL). In order to ensure a uniform evaluation, most of the TRL values are taken from the International Energy Agency (IEA) [80]. Hence, a TRL scale ranging from 1 to 11 is used in this work. Values obtained from other sources were converted to this scale.

The evaluation of the **relevance of the application in the context of the Nigerian energy system** is restricted by a lack of datasets regarding energy supply and demand at a state level [73]. For certain applications, the current demand cannot be assessed with sufficient accuracy, especially in the industrial sector. Additionally, the current status of industry and the power system as well as parts of the transportation sector could lead to a wrong evaluation. For example, the Nigerian rail system needs to be revamped. The energy demand for trains is therefore low today, but trains might become an important mean of transportation over the coming years.

As a measure of the relevance of the different applications, we therefore use the sectoral energy demand and CO2 emissions projection for 2050 as a **first step**. Thereby, we can identify the most important sectors for emission reductions as well as the introduction of greenhouse gas-neutral fuels such as hydrogen in the future.

In the **second step**, the other criteria will then be used to select the most promising applications within the individual sectors. The energy demand and emissions predictions are based on the "Planned energy scenario” in the IRENA “Renewable energy roadmap” for Nigeria [82]. This scenario implies that the current policies are carried on until 2050 [82]

It needs to be considered in the Nigerian context that applications requiring high investments by consumers generally have a lower potential due to the low purchasing power of the population of the country. Over 40 % of the population had an income below $400 per year in 2019 [95]. Therefore, large parts of the population will not be able to cover high capital outlays. This lowers the potential for clean technologies in sectors that mainly rely on private investments, e.g. residential buildings or private cars.

3.3 Assessing the relevance of applications in the context of the Nigerian energy system

The expected development of the Nigerian final energy consumption is shown in Figure 20. The TFEC is predicted to quadruple between 2015 and 2050. Industry and transport sectors show the fastest growth rate of their respective energy demand. Transportation overtakes the buildings segment as the sector with the highest consumption by 2035 [82]

Figure 21 shows that the expected CO_2 emissions rise steadily under current plans and policies. Total emissions increase from 119 Mt in 2015 to 516 Mt in 2050.

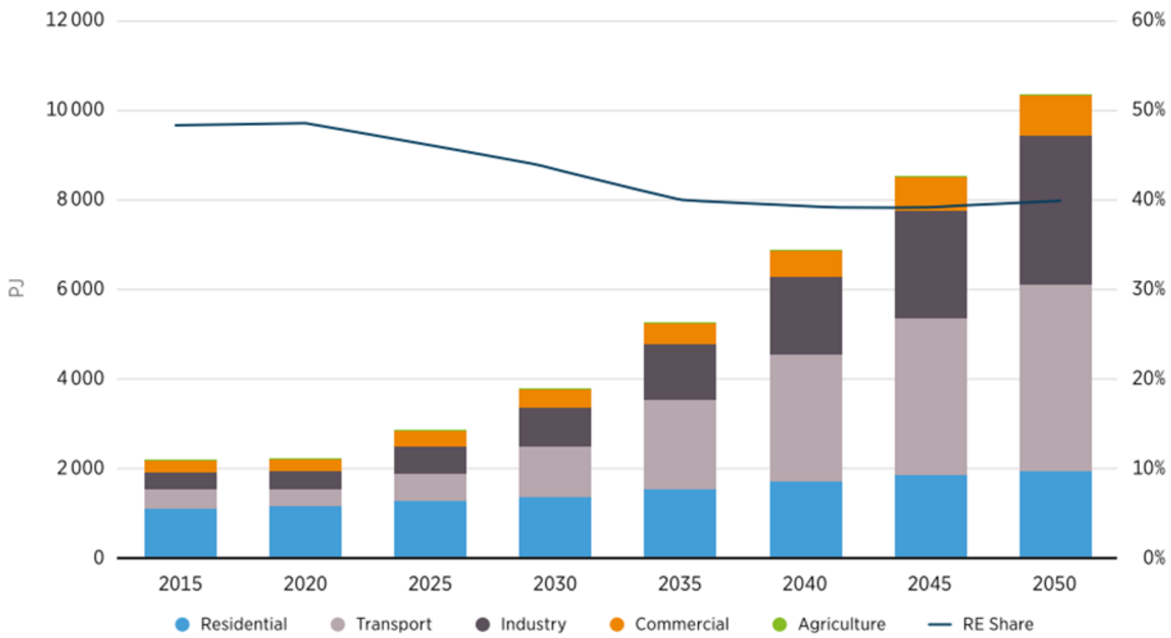


Figure 20: TFEC by sector and year based on current plans and policies, [82]

While the power sector accounted for the largest amount of emissions in 2015, the transport sector has the largest emissions footprint by 2030 [82]. The influence of the agriculture sector stays negligible. Emissions related to the segments buildings and industry show a steady increase, but at a much slower rate, compared to transport and power generation.

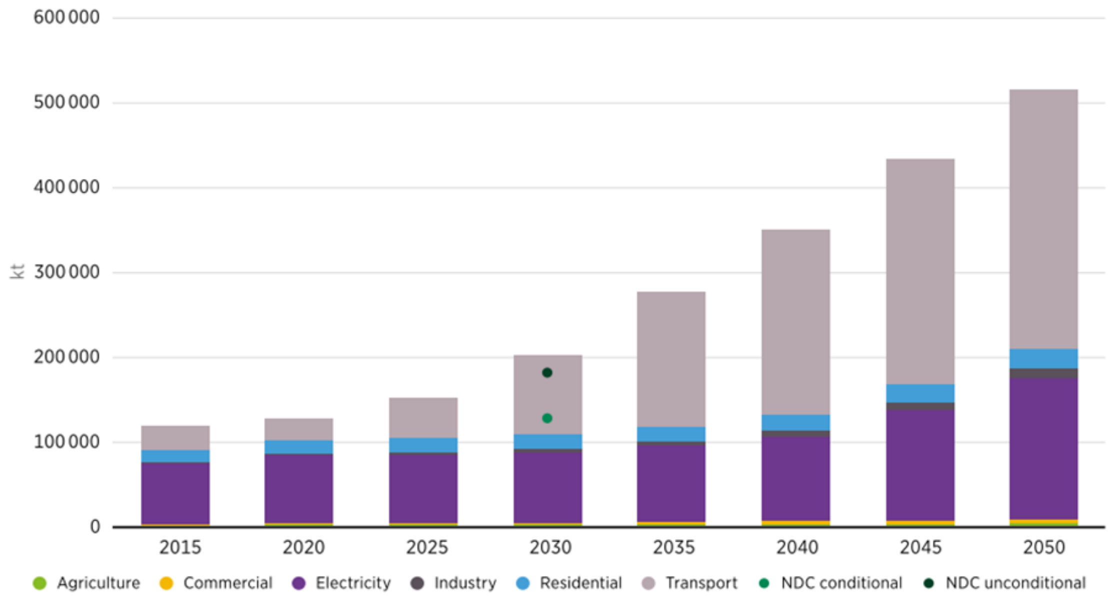


Figure 21: CO_2 emissions in kt by sector and year based on current plans and policies, [82]

By 2050, the transportation sector is predicted to account for over one-third of the TFEC and over 50 % of CO_2 emissions. Based on the predicted development of energy consumption and CO_2 emissions, the transportation sector therefore shows the largest potential and need for decarbonisation. Actions need to be taken regarding the power sector based on the share of CO_2 emissions, as the sector is expected to account for about one-third of the country's emissions. The industry and buildings sectors show a high predicted share of TFEC. Despite this, the CO_2 emissions are low, compared to transportation and power generation. Consequently, these sectors present a high potential demand for hydrogen and other sustainable energy supply options but have a lower importance regarding the decarbonisation of the energy system. The influence of the agriculture sector is negligible in terms of TFEC and emissions.

3.3.1 Evaluation scoring of different hydrogen applications

Table 14 shows the scoring of the considered applications regarding the different criteria.

Table 14: Scoring of the different hydrogen applications

Sector	Application	Relevance		Technical feasibility	Competitiveness in 2030	
		Sector CO_2 emissions	Sector TFEC	TRL	Vs. low carbon alternatives	Vs. conventional alternatives
Agriculture	Traction	0	0	4	-	-
Buildings	Heat	2	2	9	0	-
	Cooking			4	-	-
Industry	Oil Refining	1	3	9	+	+
	Ammonia			9	+	+
	Methanol			7	+	-
	High value chemicals			9	+	-
	Iron and steel production			6	+	+
	Low-temperature heat (<100 °C)			9	-	-
	Medium-temperature heat (100-400 °C)			9	0	-
	Paper (medium-temperature heat)			9	0	-
	High-temperature heat (>400 °C)			9	0	-
	Cement (high-temperature heat)			6	-	-
Power	Flexible power generation	3	4	7	0	-
	Backup power supply			7	+	-
	Off-grid power supply			7	0	-
	Co-firing in coal and gas plants			5	N.A.	N.A.
Transport	Light duty vehicles (Passenger road vehicles)	4	4	9	-	-
	Heavy duty vehicles - Buses/Coaches			9	+	+
	Heavy duty vehicles - Trucks			8	+	+
	Shipping			7	+	-
	Rail (Passenger and freight trains)			8	+	+
	Aviation			3	+	-
	Forklifts			11	+	+
	Taxi fleets			9	+	+

Sector	Application	Relevance		Technical feasibility	Competitiveness in 2030	
		Sector CO_2 emissions	Sector TFEC	TRL	Vs. low carbon alternatives	Vs. conventional alternatives
	Motorcycles			7	-	-

The values for TFEC and CO_2 emissions range between 0 and 4 with a value of 4 being assigned to the sector with the highest TFEC/emissions in 2050, i.e. the sector with the highest relevance. The power sector is not considered in TFEC but has a high primary energy consumption. Therefore, a value of 4 is assigned here. The competitiveness in 2030 is evaluated using a plus (better than alternatives), 0 (as good as alternatives) or – (worse than alternatives). The categorization is mainly based on studies carried out by Hydrogen Council and McKinsey [75, 76].

Based on the table, the total score of the applications can be calculated. The assigned values for emissions and TFEC are added together with values for the TRL and competitiveness.

The points for the TRL are assigned as follows:

- Concept (TRL 1-3): 0 points
- Prototype (TRL 4-6): 2 points
- Demonstration (TRL 7-8): 4 points
- Early adoption (TRL 9-10): 6 points
- Mature (TRL 11): 8 points

The scores regarding the competitiveness are awarded as follows:

- 0: 2 points
- -; N.A.: 0 points

Therefore, a maximum value of 8 points can be reached in each of the categories. Consequently, a maximum of 24 points can be achieved. The total points and the ranking of the applications are displayed in Table 15.

Table 15: Ranked longlist of hydrogen applications based on the total score

Application	Sector	Score
Forklifts	Transport	24
Heavy duty vehicles - Buses/Coaches	Transport	22
Taxi fleets	Transport	22
Heavy duty vehicles - Trucks	Transport	20
Rail (Passenger and freight trains)	Transport	20
Oil Refining	Industry	18
Ammonia	Industry	18
Shipping	Transport	16
Backup power supply	Power	15
Iron and steel production	Industry	14
High value chemicals	Industry	14
Light duty vehicles (Passenger road vehicles)	Transport	14
Off-grid power supply	Power	13
Flexible power generation	Power	13
Heat	Buildings	12
Methanol	Industry	12
Medium-temperature heat (100-400°C)	Industry	12
Paper (Medium-temperature heat)	Industry	12
Aviation	Transport	12
Motorcycles	Transport	12
Low-temperature heat (<100°C)	Industry	10
Cement (high-temperature heat)	Industry	10
Co-firing in coal and gas plants	Power	9
High-temperature heat	Industry	9
Cooking	Buildings	6
Traction	Agriculture	2

3.4 Shortlist of prioritized applications

The shortlist contains all applications achieving at least 75 % of the maximum score (24 points). The only exception are forklifts. It is not known how many forklifts are operated in Nigeria, and a potential can therefore not be estimated. Hydrogen-fuelled forklifts show a high maturity and can be used if the fuelling infrastructure is built at a site for the supply of trucks or trains, but a separate consideration will not be carried out.

Hydrogen applications that are located in the power sector are not present in the shortlist. In contrast to that, hydrogen shall play a role in the power sector according to the Nigerian Energy Transition Plan (ETP) [85]. The predicted utilization starts by 2040. That is in line with the evaluations in the previous segments. The power sector should be one of the last sectors in the green hydrogen merit order [71]. After implementing a hydrogen infrastructure for the supply of the prioritized sectors, hydrogen can be used in niche applications in other sectors. In the power sector, possible niche applications are backup power supply and flexible power generation. The majority of the power supply in Nigeria should rely on solar power, according to the ETP [85].

Table 16: Shortlist of prioritized hydrogen applications

Application	Sector	Score
Heavy duty vehicles - Buses/Coaches	Transport	22
Taxi fleets	Transport	22
Heavy duty vehicles - Trucks	Transport	20
Rail (Passenger and freight trains)	Transport	20
Oil Refining	Industry	18
Ammonia	Industry	18

3.5 Hydrogen demand scenarios

The prioritized applications are located in the transportation and industry sectors. The green hydrogen demand prediction for both sectors as well as the prioritized applications will be carried out in the following sections. A base scenario is constructed for every application. In addition, a more conservative and an ambitious scenario are considered.

3.5.1 Ammonia production

The hydrogen demand for the synthesis of ammonia in Nigeria is predicted based on the global ammonia demand projection by IRENA and AEA in the 1.5° scenario [83]. The global ammonia demand is forecasted to rise from 180 Mt in 2020 to 250 Mt in 2030 and 690 Mt in 2050. The demand in 2040 is determined via a linear interpolation, and the 2060 demand using a linear extrapolation. Nigerian production accounted for 0.73 % of the global ammonia production in 2022 [92]. It is assumed that this value will not change until 2060.

Based on these assumptions, total ammonia production (renewable and fossil-based) in Nigeria is assumed to develop as follows:

- 2030: 1.83 Mt/a
- 2040: 3.43 Mt/a
- 2050: 5.04 Mt/a
- 2060: 6.64 Mt/a

With the shares of renewable production, which depend on the scenario, and a specific hydrogen demand of 5.92 MWh_{H2}/t_{NH3} [84], the Nigerian hydrogen demand for the supply of renewable ammonia production can be calculated.

Ambitious scenario: Ammonia production increases rapidly after 2030. The production capacity consists therefore of a high share of new-build plants. New-build production facilities use the conventional Haber-Bosch-Process, and hydrogen is supplied via electrolysis. The share of the green synthesis route in total production capacity increases to 10 % in 2030, 70 % in 2040 and 100 % in 2060.

Base scenario: The electrolysis-based process is the main pathway chosen by ammonia producers. The adoption rate is based on the global shares of renewable production in the 1.5° scenario [83] and increases to 4 % in 2030 and 43 % in 2040. By 2060, 100% of ammonia production will use electrolysis-based hydrogen.

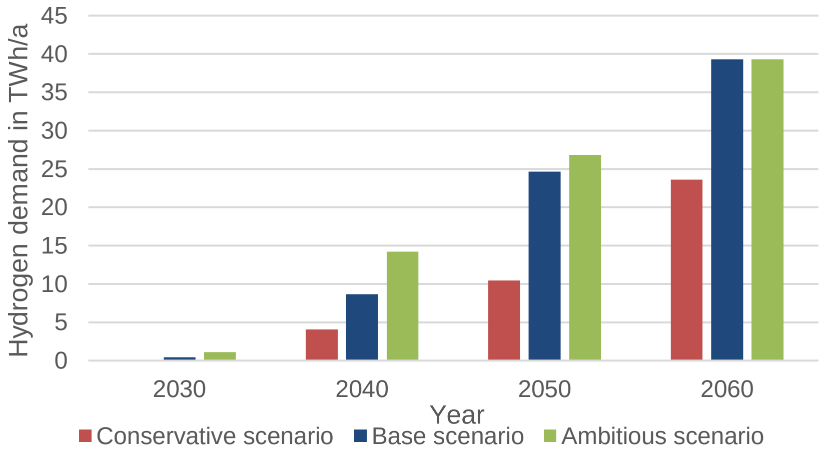


Figure 22: Development of predicted green hydrogen demand per year for ammonia production

Conservative scenario (ETP-scenario): Nigeria has natural gas reserves equal to 202 trillion standard cubic feet [82]. The available domestic natural gas is the main hydrogen source for ammonia production until 2050. The adoption rate of renewable electrolysis-based production increases from 0 % in 2030 to 20 % in 2040 and 60 % in 2060. The 2030 and 2050 adoption are based on the ETP. Natural gas-based production utilizes carbon capture and storage (CCS) to reduce CO_2-emissions in the ETP, but the so-produced blue hydrogen is not considered here [85].

Figure 22 shows the predicted development of the yearly hydrogen demand for ammonia synthesis. All scenarios have a low green hydrogen demand in 2030 but experience a significant increase starting by 2040. The ambitious and base scenarios require the same supply in 2060, as all production will be electrolysis-based in both cases. The ETP-based conservative scenario shows a significantly lower green hydrogen demand. The high adoption in the other cases is based on the expected competitiveness of green ammonia production in 2030 compared to conventional as well as alternative low-carbon production routes [76], while the ETP expects a high share of blue ammonia production.

3.5.2 Refineries

The hydrogen demand in oil refineries is predicted based on the assumption that the new build refinery (see [82]) with a 650 tbpd capacity is supplied using renewable hydrogen from 2030 onwards in varying shares in the different scenarios. Accordingly, the total hydrogen demand for oil refining remains constant between 2030 and 2060, despite the ETP predicting an increasing refining capacity between 2030 and 2050 [85]. The assumption of the constant refining capacity is made because of the expected decline in global oil demand starting in 2030 [71]. A specific hydrogen demand of 0.5 MWh_{H2}/t_{oil} is assumed [84].

Ambitious scenario: The hydrogen supply at the refinery is quickly changed to electrolysis-based. The adoption rate increases from 50 % in 2030 to 80 % in 2040 and 100 % in 2050.

Base scenario: The adoption rate of green hydrogen increases from 20 % in 2030 to 40 % in 2040 and 100 % in 2060.

Conservative scenario: The hydrogen supply is based on natural gas due to the domestic natural gas reserves. From 2040 onwards, a part of the replacement is carried out using electrolysis-based production. The adoption rate increases from 10 % in 2040 to 40 % in 2060.

Figure 23 shows the predicted development of the green hydrogen demand of the considered oil refinery. In the base scenario and in the ambitious scenario, a relevant demand for green hydrogen already arises in 2030. As in the ammonia industry, the base and ambitious scenarios have the same demand by 2060, since all hydrogen demand in both scenarios is met renewably at that time.

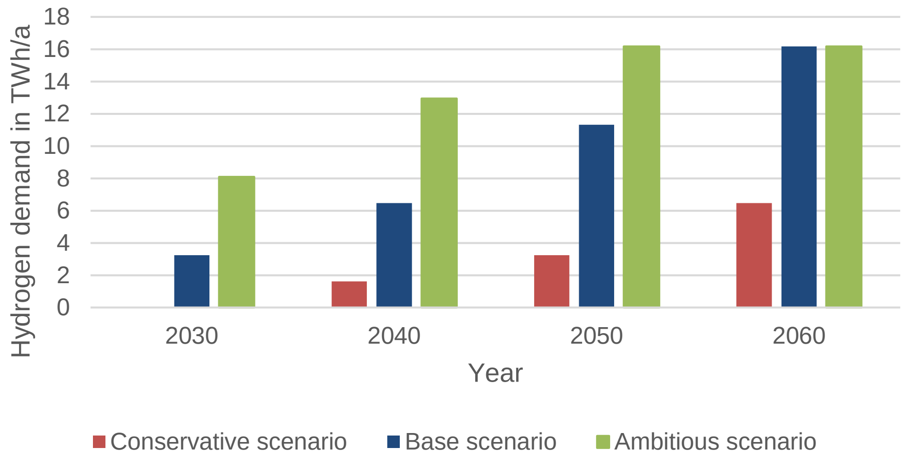


Figure 23: Predicted green hydrogen demand per year for oil refineries

3.5.3 Green hydrogen demand in the transport sector

In order to forecast the future green hydrogen demand of the Nigerian transport sector, we first project the development of the TFEC and the share of the different transport modes, especially the identified prioritized hydrogen applications in transportation. The prediction of the TFEC and shares of the different transportation modes is based on the “Planned energy scenario” by IRENA [82]. The 2060 TFEC is extrapolated linearly from the 2040 and 2050 values. A reliable demand projection for trains is not possible for Nigeria due to the status of the country’s railway system. The choice of the energy supply for trains is highly dependent on different factors, e.g. the topography, distances, usage frequencies and duration of trips [75]. Due to the uncertainties regarding the rail segment and trains not playing a relevant role in the IRENA scenario, this application will not be considered in the calculation of the green hydrogen demand.

The TFEC for the whole transport sector and the identified prioritized applications are shown in Figure 24. By 2060, buses, trucks and taxis are predicted to be responsible for 50 % of the TFEC in the transport sector. The energy use per km is assumed to be identical for fossil liquid fuels (diesel and petrol) and fuel cell systems. While fuel cells reach higher efficiencies at the moment, compared to internal combustion engines, fuel cells show a higher efficiency loss over their lifetime. In addition, the electric motor leads to higher losses, compared to a mechanical driveline used in diesel and petrol-fueled vehicles [93]. The TFEC will therefore not change significantly when hydrogen is used instead of fossil fuels. The hydrogen demand for the different applications can consequently be predicted based on the TFEC of the application and the adoption rate.

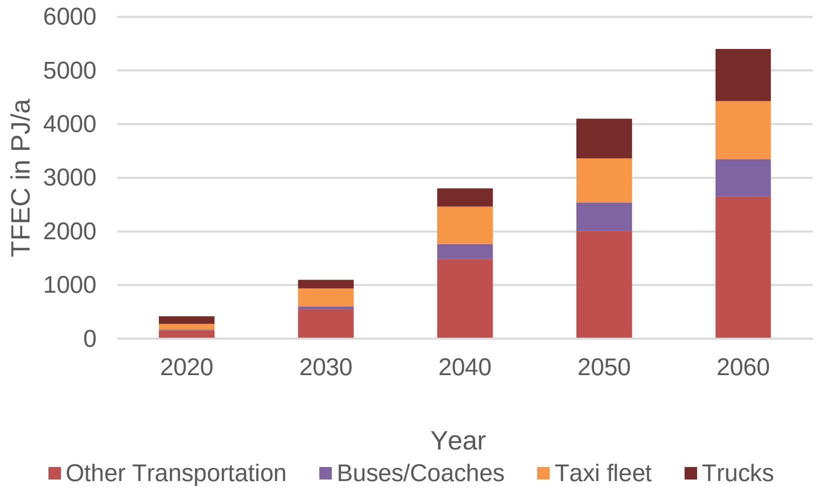


Figure 24: TFEC in the Nigerian transport sector from 2020 to 2060

Buses and trucks

Hydrogen-powered fuel cells will play a role in heavy-duty transportation in the future. Other decarbonisation options that most likely will be used are biofuels and battery electric solutions. The adoption scenarios for heavy-duty trucks and buses are based on a demand projection for heavy road freight carried out by Clean Hydrogen Joint Undertaking [70]

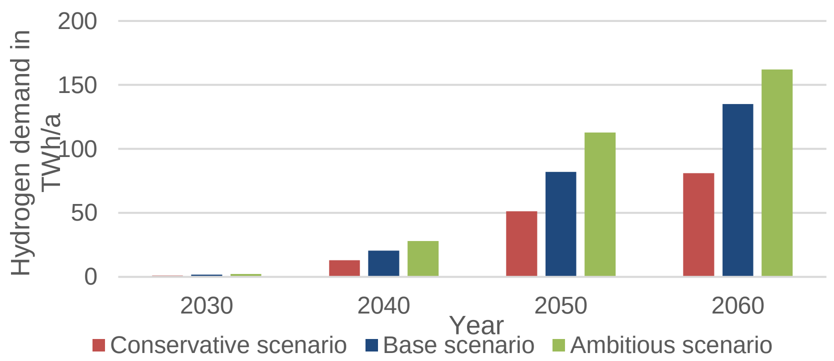


Figure 25: Predicted green hydrogen demand per year for trucks

Ambitious scenario: 60 % of heavy-duty vehicles will be powered by fuel cells in 2060. After 2030, an exponential increase in hydrogen-fuelled trucks and buses occurs. The hydrogen share in TFEC increases from 5 % in 2030 to 30 % in 2040.

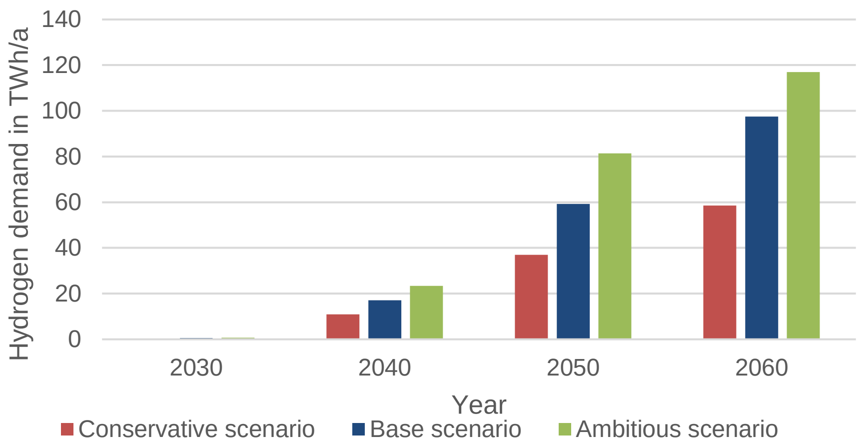


Figure 26: Predicted green hydrogen demand per year for buses

Base scenario: One-half of heavy-duty vehicles run on hydrogen-powered fuel cells by 2060. As in the ambitious scenario, an exponential increase in the hydrogen share is assumed. The adoption rate rises from 4 % in 2030 to 22 % in 2040.

Conservative scenario: 30 % of heavy-duty vehicles will be hydrogen-fuelled in 2060. As in the other scenarios, an exponential uptake is assumed after 2030, but at a lower rate. The hydrogen share increases from 2 % in 2030 to 14 % in 2040.

The predicted hydrogen demands for trucks and buses are shown in Figure 25 and Figure 26 respectively. As the same adoption rates are expected for both use cases, they show a similar progression. Trucks reach a higher total hydrogen demand due to their higher share in Nigerian TFEC.

Buses and trucks include a broad range of use cases, e.g. short-distance urban transportation and long-haul coaches for supra regional transportation in the case of buses or urban transportation and long-haul transportation for trucks [75]. These diverse applications lead to different requirements and therefore in all likelihood, to the use of different drivetrain technologies and energy sources in the future.

Taxi fleets

Taxi fleets show a more homogeneous operation and consequently a less diverse drivetrain mix. Therefore, the adoption rates will be based on the heavy-duty applications rate, but a faster increase and higher adoption rate of hydrogen-powered vehicles will be assumed.

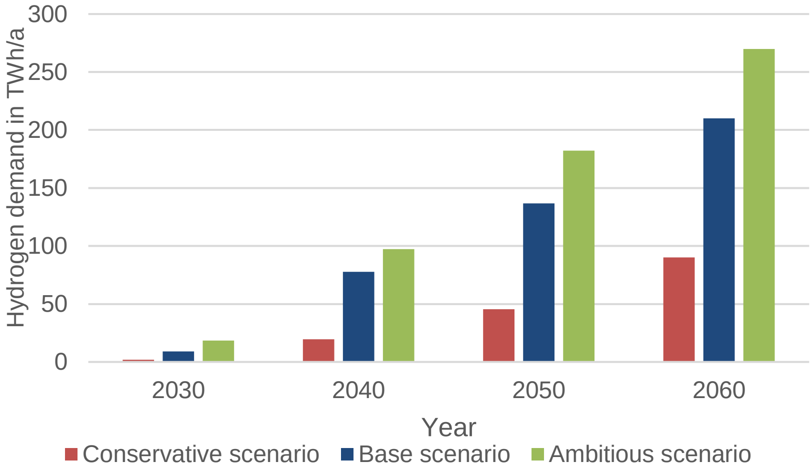


Figure 27: Predicted green hydrogen demand per year for taxi fleets

Ambitious scenario: Hydrogen is considered as the main fuel for taxi fleets. As other options, e.g. BEVs, will only be used for niche applications, 90 % of taxi fleets will be powered by fuel cells in 2060. After 2030, an exponential increase in hydrogen-fuelled taxis occurs. The hydrogen share in TFEC rises from 10 % in 2030 to 50 % in 2040.

Base scenario: By 2060, 70 % of the taxis will be FCEV. The adoption rate rises from 4 % in 2030 to 40 % in 2040.

Conservative scenario: Only 30 % of the taxis will be hydrogen-fuelled in 2060 because fossil fuels and/or other liquid fuels such as biofuels are still favoured. BEVs are used as a low-carbon option, too. The adoption of FCEV increases from 2 % in 2030 to 10 % in 2040.

Figure 27 illustrates the predicted growth of the hydrogen demand for the supply of taxi fleets. The adoption rates are based on the heavy-duty vehicle scenarios, therefore a similar trend is visible. Compared to trucks and buses, taxi fleets show the highest total hydrogen demand in the transport sector.

The assumed hydrogen adoption is mainly in line with the ETP. As recommended in the previous sections, the private cars sector should be decarbonized based on electric vehicles according to the ETP. BEVs, as well as hydrogen, are an option for the decarbonization of heavy-duty vehicles by electrification. The ETP sets the focus on BEVs, but hydrogen should play a role in certain applications and can support the goal of reaching a fully electrified vehicle fleet by 2060 [85].

3.6 Overall green hydrogen demand

Figure 28 shows the overall potential hydrogen demand of the applications studied in the different scenarios. By 2060, the demand is expected in the range between 260 and 500 TWh/a. Across all scenarios, approximately 90 % of the hydrogen demand is related to the transport sector. Within the transport sector, taxi fleets are the application with the largest potential hydrogen demand.

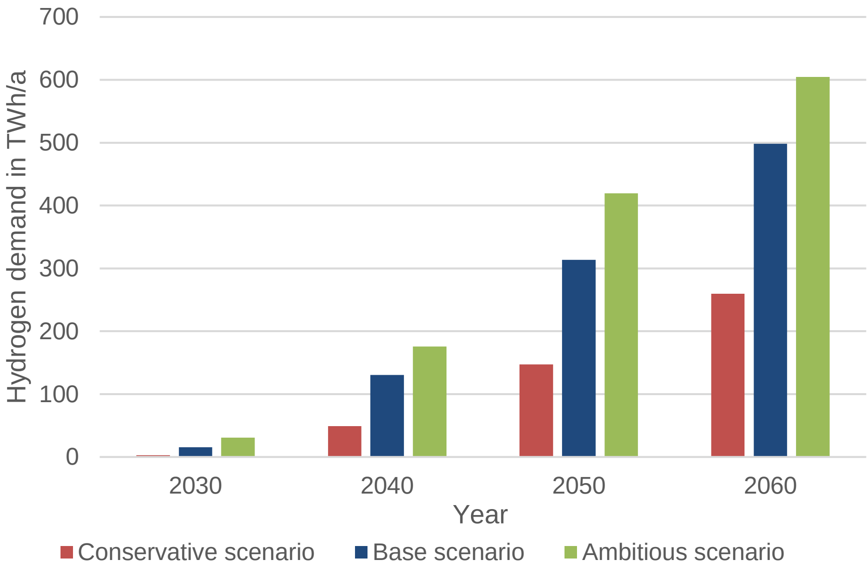


Figure 28: Overall predicted Nigerian green hydrogen demand per year

The industrial applications studied (ammonia production and petroleum processing) account for only a fraction of the hydrogen demand in the transport sector. In all the scenarios examined, the industry's hydrogen demand is only between 10 and 20 % of the hydrogen demand of the transport sector.

This is primarily due to the forecasted strong growth in energy consumption in the transport sector (see Figure 20). Although strong growth in energy demand is also projected for Nigeria's industrial sector, the variety of energy consumers limits the implementation of sustainable pathways like the adoption of hydrogen.

3.7 Emission reduction potential- Industry

3.7.1 Ammonia

To access the emission reduction potential for green ammonia production, the steam methane reforming-based Haber-Bosch-process using best available technology is assumed as the reference technology. This process has an emissions footprint of 1.6 t_{CO2}/t_{NH3} [88]. A production based on electrolysis and green electricity currently has a carbon footprint of 0.1 t_{CO2}/t_{NH3}. A reduction to 0 t_{CO2}/t_{NH3} is possible in the future [88]. The current status is used for the assessment of the emission reduction potential that is therefore equal to 1.5 t_{CO2}/t_{NH3}.

Figure 29 shows the emission reduction potential of green ammonia production. By 2060, the ambitious and base scenario yield the same result, because the green production route is the exclusively used route in both cases.

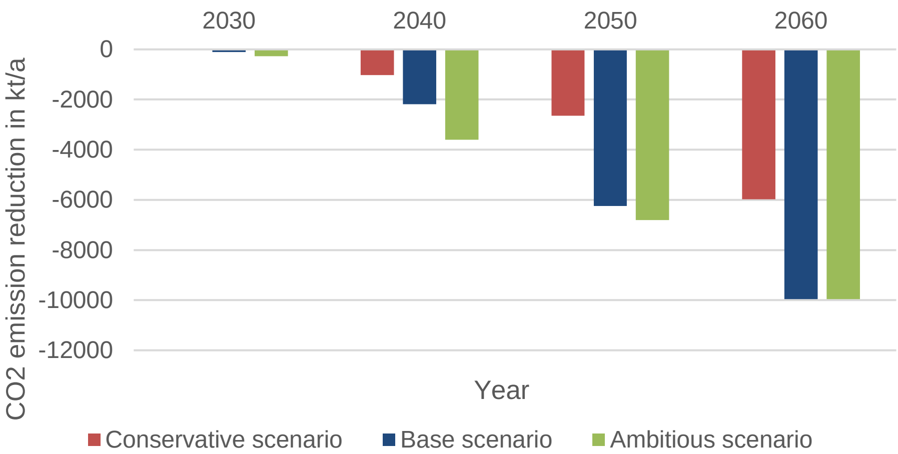


Figure 29: Emission reduction potential per year for green ammonia production

3.7.2 Oil refining

In the case of oil refineries, renewable hydrogen is a substitute for hydrogen supplied by steam methane reforming. A CO_2 emission reduction of 9 kg_{CO2}/kg_{H2} can be achieved [65]. This reduction is in line with the estimate of 0.27 t_{CO2}/MWh_{H2} used by Clean Hydrogen Joint Undertaking [70].

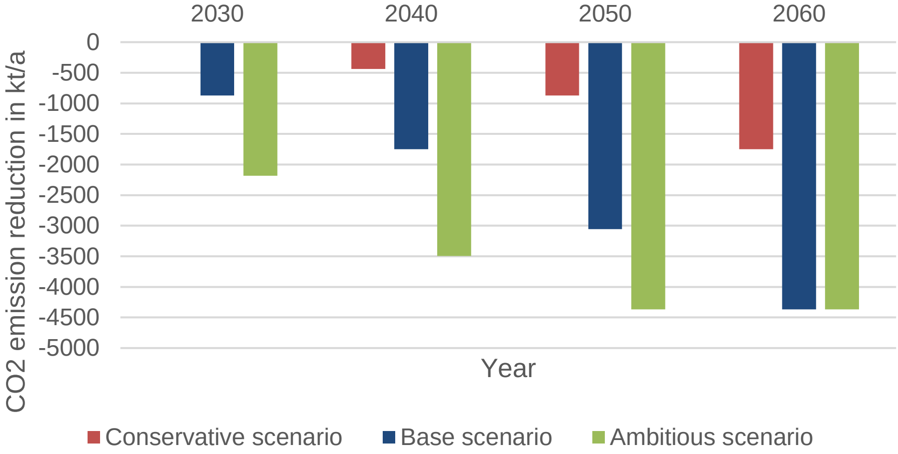


Figure 30: Emission reduction potential per year for oil refineries

The emission reduction potential for the application of renewable hydrogen in oil refineries is shown in Figure 30. In the ambitious scenario, the maximum potential is reached by 2050. The base scenario reaches the maximum reduction in 2060.

The possible emission reduction in the industry sector due to the use of renewable hydrogen in the ammonia industry and oil refining reaches a maximum value of 14,500 kt_{CO2}/a by 2060.

3.8 Emission reduction potential - Transport

For the transport sector, only the emissions from fuel consumption (direct emissions) will be considered. Therefore, the use of FCEV does not result in any emissions [70]. Taxis are assumed to use gasoline, while buses and trucks run on diesel. Gasoline leads to emissions equal to 67.99 $kg_{CO2}/GJ_{gasoline}$, Diesel to 72.66 kg_{CO2}/GJ_{diesel} [86]. The specific emissions are multiplied with the TFEC and the considered adoption rate for hydrogen-fuelled vehicles in order to calculate the emission reduction potential of the different applications.

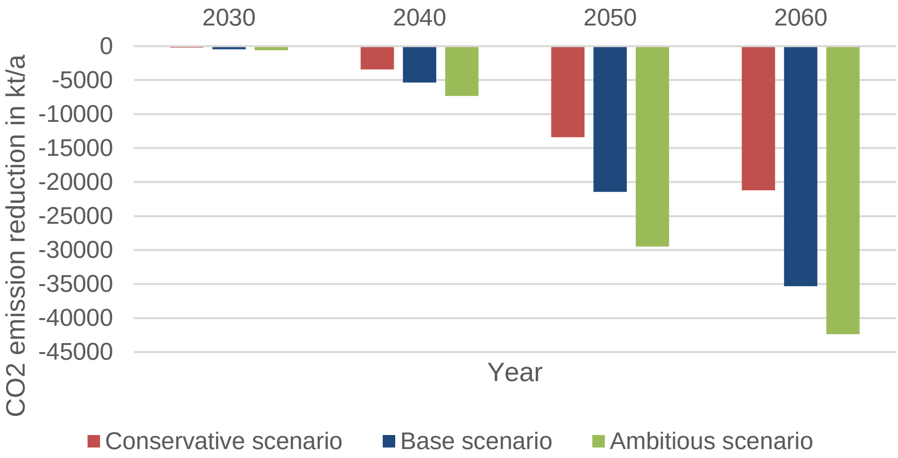


Figure 31: Emission reduction potential per year for trucks

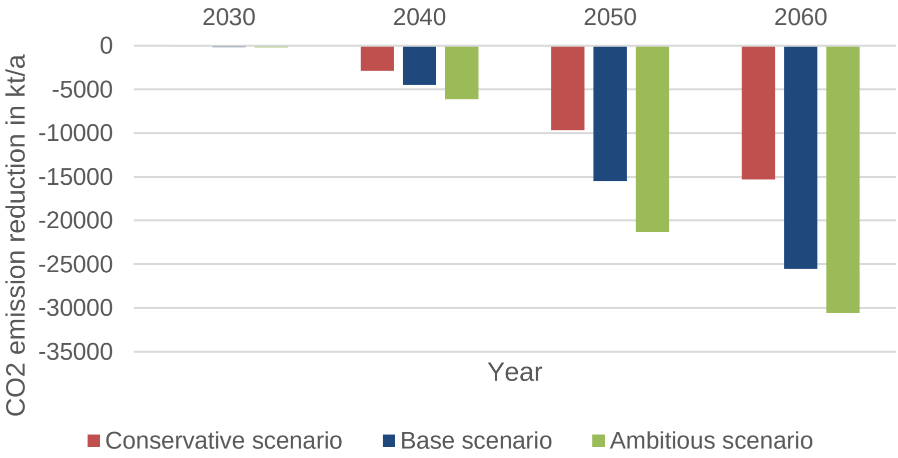


Figure 32: Emission reduction potential per year for buses

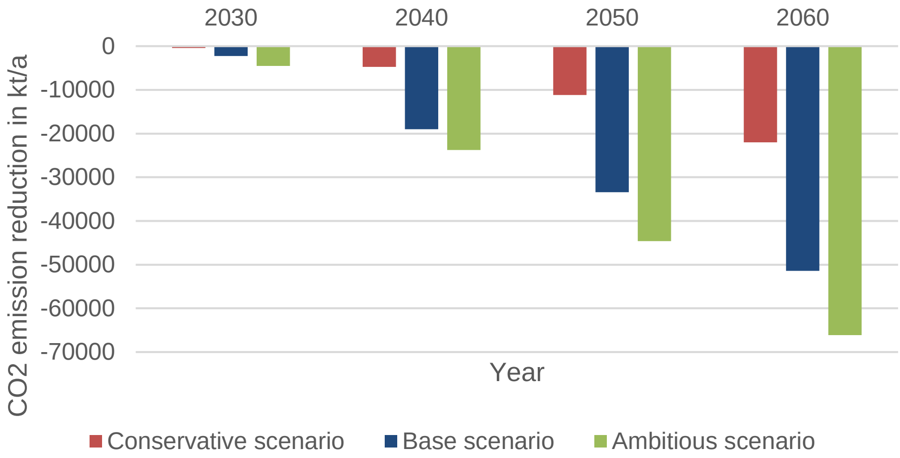


Figure 33: Emission reduction potential per year for taxi fleets

The emission reduction potentials for trucks, buses, and taxi fleets in the different scenarios are shown in Figure 31, Figure 32, and Figure 33. All three applications have a similar development across the scenarios with a constant increase starting after 2030. Taxi fleets offer the highest potential due to their high TFEC and adoption rate of hydrogen.

Across the considered applications, the yearly maximum emission saving potential reaches 140,000 kt_{CO2} in 2060. Compared to the transport-related yearly emissions predicted to 300,000 kt_{CO2} in IRENA's planned energy scenario by 2050 [82], approximately 50 % of the sector's emissions could be avoided by using hydrogen. The other half of the emissions should be avoided using alternative technologies, for example BEVs in the private cars segment. In the ETP is stated that all vehicles should be electrified by 2060. As FCEVs can be counted as electric vehicles, hydrogen adoption in the transport sector presents an option that can contribute to the ETP goals.

3.9 Overall emission reduction potential

Figure 34 shows the overall emission reduction potential for the three scenarios. The predicted yearly emission savings range between 66,000 and 155,000 kt_{CO2}/a by 2060. As with the hydrogen demand, approximately 90 % of the emission reduction is related to the transportation sector. Compared to the planned energy scenario predicted by IRENA, approximately one-third of Nigerian CO_2 emissions could be avoided by using hydrogen [82].

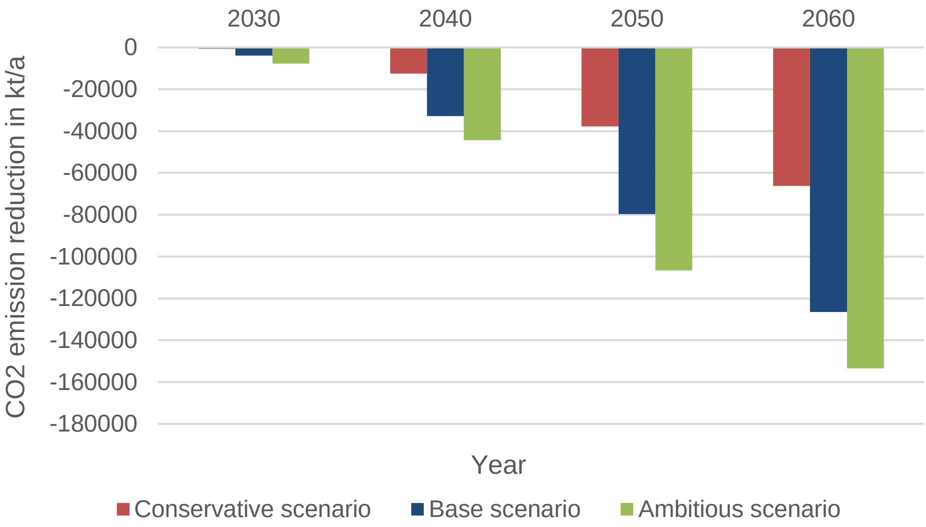


Figure 34: Overall emission reduction potential

4. International Competitiveness

4.1 Exports of H2 and PtX Products

Against the background of international agreements on climate protection and the cost decline for renewable energies, in particular for photovoltaic power generation, it can be assumed that global demand for fossil fuels will decline continuously in the coming decades. In contrast, it is expected that the supply of energy from renewable sources, mainly wind and solar energy, will increase sharply and become the central pillar of future energy supply. Thus, in its *Announced Pledges Scenario*, which assumes that all targets announced by governments are met, the International Energy Agency (IEA) projects that energy supply from oil, natural gas, and coal will be halved by 2050 [96]. Around half of global energy demand would then be met by renewable energies. Figure 35 shows the three different IEA scenarios.

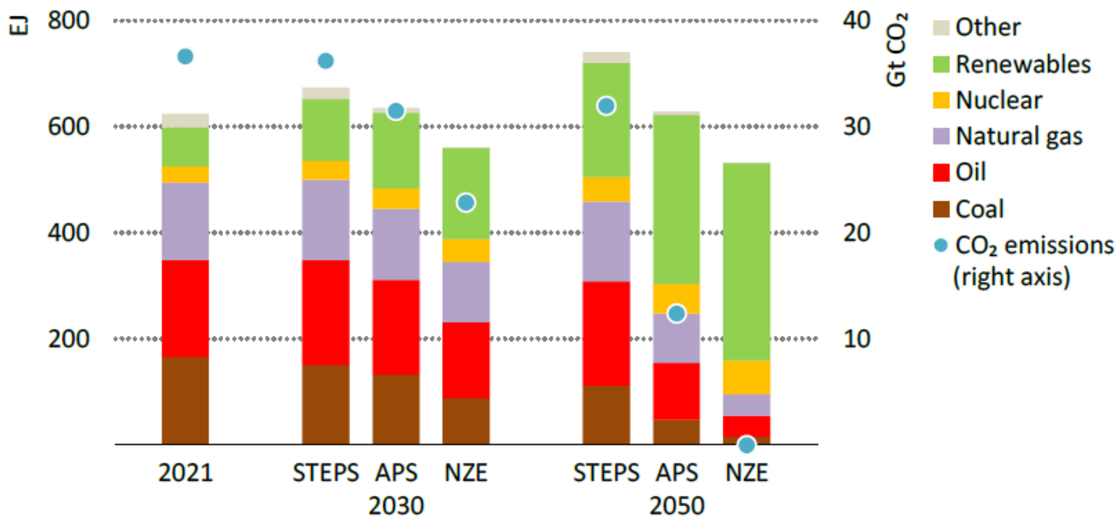


Figure 35: Total energy supply by fuel and CO_2 emissions in different scenarios developed by IEA [1]

STEPS = Stated Policies Scenario; APS = Announced; Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario

Nigeria's exports are currently critically dependent on fossil fuels, with over 90 % of exports relying on crude oil and natural gas in 2021 [97]. The expected decline in global demand for oil and natural gas therefore poses a potential risk to the country's further economic development unless measures are taken to reduce unilateral dependence.

4.2 Possible Supply Chains

Numerous investigations predict that an international market for renewable energy will emerge between 2030 and 2050 [98, 99]. While on a regional level (e.g. in Europe) some of this trade of renewable energies may be realized via the power grid, from today's perspective there is a strong indication that green energy carriers in liquid or gaseous form will also be transported by ship in the future. Green hydrogen and hydrogen-based Power-to-X (PtX) products are considered to be central energy carriers of an international market for green energy carriers due to their cross-sectoral application possibilities as well as their comparatively good storage and transportability. In this market, densely populated industrialized countries, which will most likely not be able to fully meet their energy needs through domestic renewables, will act as energy importers. Potential exporters are those countries that have particularly large potentials for the low-cost generation of large amounts of renewable energy - e.g. high land availability and high wind and/or solar supply.

For Nigeria, this forecasted development creates the opportunity to compensate for the expected loss of revenue from the fossil fuel business by exporting PtX products. Here, Nigeria competes with other countries and regions that may be exporters in an emerging global market for PtX products.

The export of hydrogen can be realized by means of various options. In all cases, a substantial increase in the volumetric energy density of the hydrogen is required. This chapter describes the main technological components of hydrogen supply chains.

Figure 36 shows the basic design of hydrogen supply chains. Depending on the conditioning option and the transport form, a carrier has to be supplied. In addition, some forms of transport can be used directly without reconversion - these are generally referred to as hydrogen derivatives (for details see Figure 38).

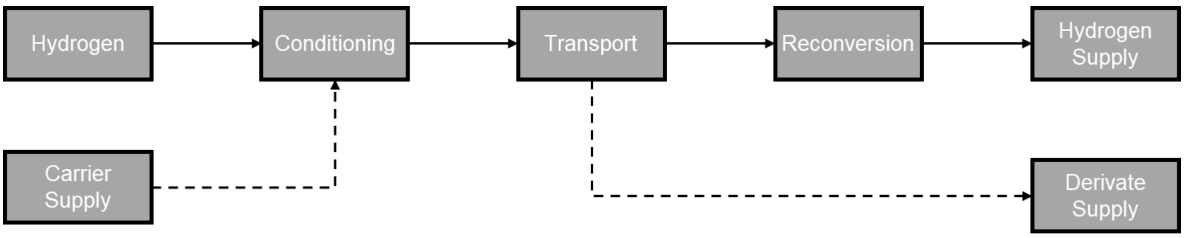


Figure 36: Basic components of a hydrogen supply chain

4.2.1 Conditioning

The conditioning of hydrogen can be divided into physical and material conditioning. In physical conditioning, hydrogen is compressed or liquefied and thus continues to exist as a pure element. In material conditioning, hydrogen is bonded to a carrier molecule. Liquid conditioned hydrogen options - liquid hydrogen, liquid organic hydrogen carrier (LOHC), methanol, ammonia, and liquid methane - are discussed for the seaway due to the high volumetric energy density required. Additionally, transport of compressed gaseous hydrogen via pipeline can be an option. Each of these hydrogen conditioning options has different gravimetric and volumetric energy densities and conditioning processes. The hydrogen conditioning options for transport purposes considered in this work are discussed below.

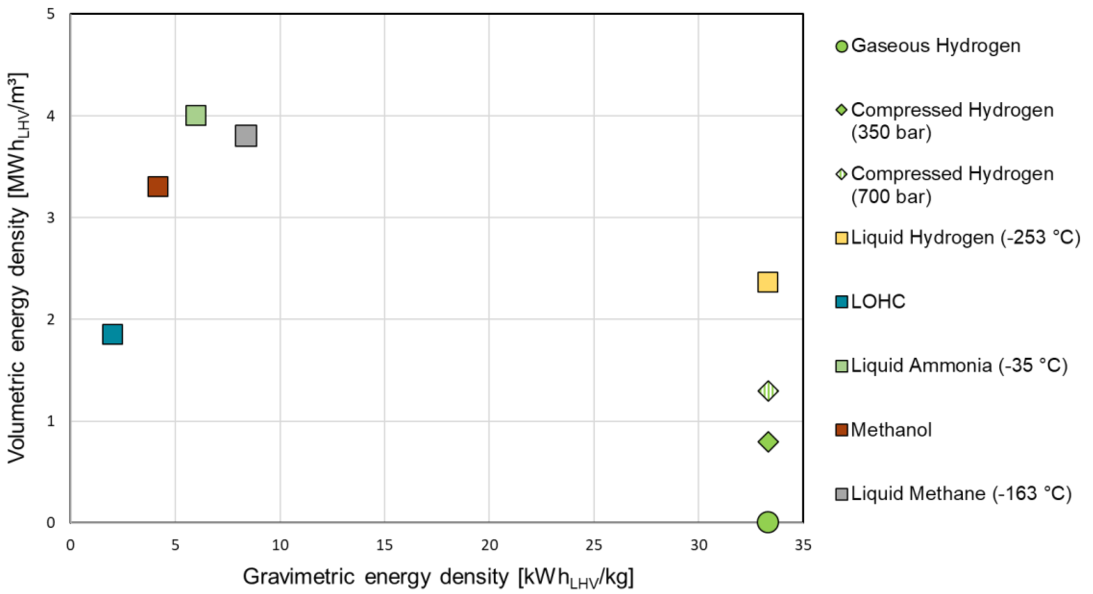


Figure 37: Energy densities of different conditioned hydrogen options

4.2.2 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 throughputs of 200 kg/h and pressure levels up to 1000 bar are already on the market. The possibility of arranging several compressors in series provides a high degree of flexibility. The overall efficiency depends on the type of compressor. The mechanical and electrical efficiency of reciprocating and ionic compressors is approximately 95 % and the efficiency of mechanical compressors is 65 to 88 %.

4.2.3 Liquid Hydrogen

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. The energy demand for liquefaction amounts to 20 to 30 % of the hydrogen's energy content. 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.

4.2.4 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 can be dissolved.

4.2.5 Ammonia

Ammonia is formed by the reaction of nitrogen 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 substance 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 nitrogen 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 is also discussed as a possible carbon-free fuel, especially for maritime applications [100]. Corresponding powertrains in which ammonia is converted into energy either in internal combustion engines or in fuel cells are currently under development [6]. Besides these direct use options ammonia can also be applied as a hydrogen carrier in a similar manner to LOHCs – which means that the hydrogen is dissolved after transport (and storage). Ammonia already becomes liquid at temperatures of -33 °C and, in this state, has a significantly higher storage density than liquid hydrogen.

4.2.6 Methanol

In terms of the underlying principle, the conversion of hydrogen into methanol is comparable to the conversion into ammonia. Methanol is an alcohol, which can be produced by combining hydrogen 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.

A variety of different processes can be applied to make use of the CO_2 bound in biomass. Thus, biogenic CO_2 is produced as a by-product in already established processes. Examples include the upgrading of biogas to biomethane and the production of bioethanol. Another approach to provide biogenic CO_2 may be the capture from flue gas resulting from biomass combustion. If the use of biogenic CO_2 is considered, it must be taken into account that medium- to long-term availability of sustainably provided biomass is currently unclear.

The Direct Air Capture (DAC) technology can be used to capture CO_2 from the atmosphere. The ambient air is passed through an absorption unit that binds the CO_2. As soon as the absorbent is saturated, the CO_2 is redissolved and is available as a pure stream. In principle, DAC technology is already available today, but it has a very high energy requirement (electrical and especially thermal) and a considerable space requirement. For the supply of larger quantities of CO2 by means of DAC, further technological development is required to reduce energy requirements and investment costs.

Methanol has a wide range of applications. For example, it is used to produce fuels or processed into plastics. In the future, green methanol is expected to play a key role as a feedstock for a defossilized industry. Methanol is also seen as a potential fuel for mobility sectors that are difficult to electrify, such as shipping. 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 additional effort.

4.2.7 Methane / Synthetic Natural Gas

Synthetic natural gas (SNG), which consists essentially of methane, represents another possibility for converting hydrogen into a flexible, easy-to-transport energy carrier. Catalytic methanation is the chemical conversion of hydrogen to methane. The reaction (Sabatier process) can take place with carbon monoxide (CO) as well as with CO_2. Methane synthesis on the basis of CO is an established process and has been used for decades, in particular for the gasification of coal on a large industrial scale. The largest plants of this type achieve outputs in the GW range. Methanation with CO_2, on the other hand, has so far only been realized on a pilot and demonstration scale. If green hydrogen is converted into SNG, the existing infrastructure for the international transport of fossil liquid natural gas (LNG) can in principle be used for the transport (liquefaction plants, LNG tankers, export and import terminals). However, as with green methanol, a sustainable CO_2 source is needed to provide relevant quantities of green SNG.

4.3 Transport

In principle, hydrogen and PtX products can be transported by pipeline or by ship. While seaborne transport makes sense for liquid energy carriers (liquid hydrogen, ammonia, methanol, LOHC, and LNG), export by pipeline is an option primarily for gaseous hydrogen.

4.3.1 Transportation via ships

There are already a number of possibilities for transporting hydrogen derivatives via ship. For example, tankers that are currently used to transport crude oil and crude oil products like diesel and gasoline can also be used to transport LOHCs or methanol. Liquid ammonia and LNG are currently transported in large quantities with corresponding tankers, too. Existing infrastructures and technologies could also be used 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. However, shipping of liquid hydrogen could be an option in future international hydrogen trade. The storage of large quantities of cryogenic hydrogen on ships is currently a technological challenge, that is being researched intensively. The first dedicated tanker for the transport of liquid hydrogen was built by Japanese company Kawasaki in 2020. After completion of the test operation, hydrogen produced in Australia shall be transported to Japan with the help of this ship.

4.3.2 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 (eg. hydrogen embrittlement). One possible approach to prevent damage to converted pipelines is to apply internal pipe coatings made of hydrogen-impermeable plastic.

In a transition phase, blending hydrogen with natural gas may also be an option for pipeline-based transportation. Current research and testing indicate that hydrogen blends between 10 and 20% should be feasible for natural gas pipeline operations without major adjustments in most cases. When hydrogen is blended to natural gas the additional effort for the recovery of the pure hydrogen has to be taken into account.

4.4 Reconversion

If hydrogen is not transported in a gaseous state, reconversion might be required. Thus, in a LOHC-based supply chain, recovery of the hydrogen is required in all cases. In the case of ammonia, methanol and methane, direct use is possible; if the energy is required in the form of pure hydrogen, reconversion is necessary.

4.4.1 Liquid Hydrogen

The reconditioning of liquid hydrogen to gaseous hydrogen is relatively simple, since only an evaporation unit is required. The amount of energy required for regasification is negligible, since ambient heat is usually sufficient to evaporate the liquid hydrogen. In addition, the hydrogen in liquid hydrogen supply chains usually meets the very highest purity requirements (5.0 quality),since impurities can be separated with little effort during the liquefaction process due to the higher boiling and freezing points.

4.4.2 Liquid Organic Hydrogen Carriers – LOHCs

The hydrogen bound in the LOHC carrier medium can be released from the LOHC in an endothermic reaction – the dehydrogenation process. The dehydrogenated LOHC medium must then be transported back to the hydrogenation site, usually the site of energy production. For the commonly discussed LOHC carrier mediums, high amounts of thermal energy are required for this dehydrogenation process. Typically, these are in the range of 10 to 15 kWh/kg$_{H2}$ at a temperature level of more than 300 °C, which thus corresponds to about 30 to 40 % of the bound energy content of the hydrogen. The efficiency of hydrogen storage and/or transportation systems using LOHCs depends on whether the heat required 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.

Unlike the physical hydrogen conditioning options (hydrogen transport via pipeline or in its liquid form), the hydrogen released from the LOHC still needs to be purified, which can result in additional hydrogen losses of up to 5% or more. An advantage of most LOHCs over other transportation options is that they are not flammable or explosive even in the hydrogenated form, so there are fewer safety requirements to meet during storage and transportation.

4.4.3 Ammonia

If the green ammonia is not to be used directly in the importing country, it can be split into its elements hydrogen and nitrogen in an endothermic reaction – the ammonia cracking. During the hydrogen purification necessary after recovery, high hydrogen losses occur, which are between 10 and 30 % depending on the purification process. In addition to these hydrogen losses, the energy demand of the process must also be considered; in particular for meeting the heat demand of the cracking. In an optimised process, the heat demand could be at least partially covered by burning the hydrogen that is lost during purification. In the case of ammonia, the carrier molecule (nitrogen) can be obtained comparatively inexpensively (< 0.15 €/kg$_{H2}$ bound in ammonia) via an air separation unit due to the high nitrogen concentration in air of around 78 % by volume. Therefore, the nitrogen is released into the atmosphere after hydrogen separation and is not transported back to the synthesis site.

4.4.4 Methanol

Like ammonia, methanol can either be used directly (for example in the chemical industry or as a fuel for shipping) or split into its feedstock components. Methanol cracking is an endothermic reaction and thus, as with LOHCs, heat is required at a temperature level of around 300 °C. In addition, there is a demand for electrical energy for the subsequent hydrogen purification - for which hydrogen losses of about 15 % are reported. Thus, for the entire hydrogen recovery process, about a quarter of the energy bound as hydrogen has to be used for reconditioning. In contrast to LOHCs, the carrier molecule - carbon dioxide - is not transported back to the conditioning site in most of the concepts discussed, but released into the atmosphere. For such a concept, the use of sustainable CO_2 is elementary to realize a green hydrogen supply chain.

4.4.5 Methane / Synthetic Natural Gas

Also in the case of SNG, in addition to direct use, recovery of the combined hydrogen is possible in principle. The cracking of methane (currently mostly as Natural Gas) to obtain hydrogen is state of the art and is currently usually realized via the so-called Steam Methane Reforming (SMR). However, in the context of SNG-based hydrogen supply chains, the use of the innovative Autothermal Reforming (ATR) is often discussed. Unlike in the case of the SMR, in the ATR the supply of the heat required for the process and the actual cracking take place in the same reactor. In the process, around 30 % of the energy stored in the methane is not transferred to the hydrogen. The CO_2 produced can be captured comparatively easily and efficiently in the ATR, which is advantageous, for example, for concepts that envisage a CO_2 sequestration or cycle. In addition, energy losses due to heat transport limitations can be avoided. As described previously, several options are available for exporting hydrogen or PtX products generated in Nigeria.

4.5 Supply Cost

Figure 38 shows the supply chains examined and their key technological components. As mentioned above, hydrogen supply chains based on ammonia, SNG or methanol can supply either the derivatives / PtX products themselves or pure hydrogen. The reconversion of the derivative into hydrogen is therefore an optional component of these supply chains.

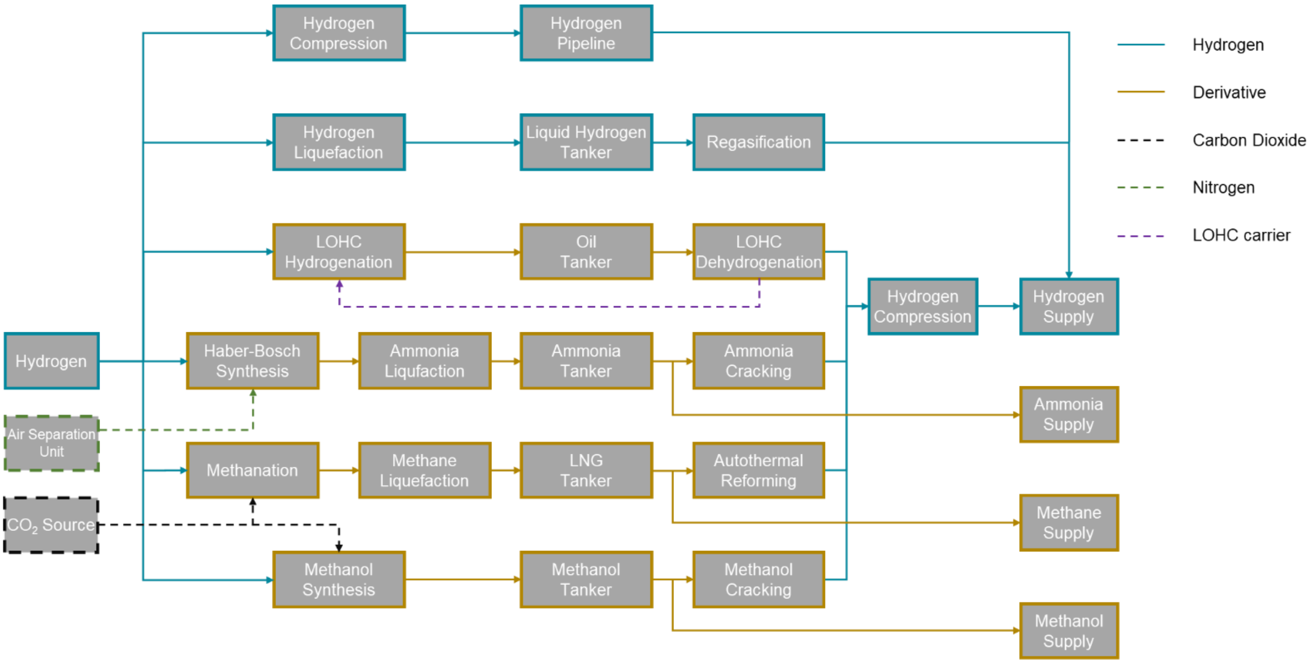


Figure 38: Different hydrogen supply chains for export purposes

To ensure comparability, a supply of pure hydrogen is considered for the following comparison of the different supply chains. For the supply chains based on ammonia, methanol and LOHCs, a differentiation is made. In all cases, thermal energy is required for the recovery of hydrogen from the carrier. For the evaluation of the corresponding pathways, two possibilities of heat supply are considered in each case. The *"external heat"* case assumes the use of externally supplied energy (e.g. in the form of locally available waste heat at the import site). In the *"internal heat"* scenario, part of the energy stored in the derivative in the form of hydrogen is used to provide the required thermal energy.

As already mentioned, CO_2 is required for the conversion of hydrogen to methanol and SNG. Unlike an ammonia-based supply chain, where the required carrier material (nitrogen) can be supplied comparatively easily via an air separation unit, CO_2 supply is not trivial. Renewable, i.e. non-fossil, CO_2 is necessary to enable climate-neutral, energy supply. For the following analysis, two different options for sustainable CO_2 supply are considered. In the *"Biomass"* case, it is assumed that the required CO_2 can be captured from a biogenic source. One possibility for this would be the bioethanol production, in which biogenic CO_2 is produced in large quantities as a by-product. In the "Onsite DAC" scenario, it is assumed that no biogenic source is available and that Direct Air Capture (DAC) technology is used instead. The DAC process can be used to capture CO_2 from atmospheric air.

4.5.1 Total Supply Cost

The economic evaluation of different hydrogen supply chains is influenced by some basic assumptions. For the calculation carried out here, a scenario is defined with the following boundary conditions and assumptions:

- For all export pathways, the supply of gaseous hydrogen in 3.5 quality (corresponding to a purity ≥ 99.95 %) at a pressure level of 100 bar in Germany is investigated.
- The distance for the transport of the energy vector by ship from Nigeria to Germany is assumed to be 9,200 km. The transport distance for hydrogen export by pipeline is assumed to be 7,000 km;
- The reference year for all techno-economic and ecological technology parameters is 2030.
- All monetary values are related to the average euro value of the year 2020. The real weighted average cost of capital (WACC) is assumed to be 6 %;
- For the continuous hydrogen supply in Nigeria, specific costs of 3.5 €/kg_{H2} are assumed. In addition to the electrolyzer and a seawater treatment plant, the system required for this also includes intermediate hydrogen storage and the necessary compression between the electrolyzer (40 bar operating pressure) and the storage facility;
- It is assumed that all processes that are not directly related to the hydrogen production in Nigeria (e.g. syntheses, reconversion processes, DAC) can rely on a constant supply of renewable electricity. Based on findings of [102], the costs of this electricity supply are assumed to be 0.08 €/kWh_{el} in Nigeria and 0.1 €/kWh_{el} in Germany. For a constant heat supply, which is necessary for the CO_2 supply by means of DAC as well as some hydrogen reconversion processes, 0.04 €/kWh_{th} (Nigeria) and 0.08 €/kWh_{th} (Germany) are assumed;
- The hydrogen losses that occur anyway during the reconversion and purification of hydrogen can be used to (partially) provide the heat required for this process;
- For the SNG- and Methanol-based supply chains, it is assumed that in the *"Onsite DAC"* scenario 80% of the waste heat generated during methanation resp. methanol synthesis can be used for CO_2 supply via DAC;
- Biogenic CO_2 can be supplied at a specific cost of 50 €/t_{CO2} (relevant for "Biomass" scenario in SNG- and Methanol-based supply chains) (own assumption for different biogenic sources, based on [103,104]);
- Nitrogen supply for ammonia synthesis is provided by in-situ air separation;
- Benzyltoluene is considered as LOHC;
- The SLNG tanker can be powered by boil-off gas. Re-liquefaction of the resulting boil-off gas (0.16 % per day) is not considered. Also in the case of ship transport of liquid hydrogen, resulting boil-off gas (0.5 % per day) is used as propulsion energy;

- All other tankers (ammonia, methanol, LOHC) are powered by a renewable fuel. The supply costs for this fuel are 0.11 €/kWh$_{LHV}$ (own assumption based on [105,106] for a mix of Bio-LNG and SNG).

Figure 39 shows the cost of the import options investigated. The total cost is divided into the segments defined below:

- *H2 Production - Excl. Losses*: Cost in the export region for the supply of hydrogen to Europe.
- *H2 Production - Only Losses*: Cost effort to cover the additional hydrogen demand caused by losses in the supply chain (e.g. boil-off losses, energy conversion losses).
- *Storage*: Costs due to (intermediate) storage
- *Conversion - Excl. Carrier*: Costs incurred by the respective conversion step (e.g. liquefaction, methanol synthesis, Haber-Bosch process) to convert the hydrogen into its transport state. The costs that may arise for the provision of the carrier (CO_2, nitrogen) are considered separately.
- *Conversion - Only Carrier*: Cost to provide the hydrogen carrier (CO_2, nitrogen).
- *Transportation*: Costs incurred in transporting the energy vector (liquid hydrogen or derivative).
- *Reconversion - Excl. Heat*: Costs incurred by the specific reconversion step (e.g. ATR, ammonia cracking) excluding the costs for heat supply (separate segment).
- *Reconversion - Only Heat*: Cost of heat supplied externally in the specific reconversion step. For scenarios with internal heat provision, heat provision is part of *H2 Supply - Only Losses*.
- *Final Compression*: Cost to compress the hydrogen to 100 bar following the reconversion step.

In the examined scenario, costs between 6 and 7 €/kg$_{H2}$ can be expected for a hydrogen supply between Nigeria and Germany in 2030. Generally, the total supply costs are dominated by cost related to hydrogen production in Nigeria. In most cases, the hydrogen production in Nigeria, including the compensation of losses along the supply chain, causes more than 65 % of the total costs. Based on this, it can be stated that the minimization of hydrogen production costs is of particular relevance for low supply costs in export scenarios. As shown earlier, hydrogen production costs are usually largely determined by the electricity supply costs, the investment costs (CAPEX) of the electrolysis system and its utilization (annual full load hours).

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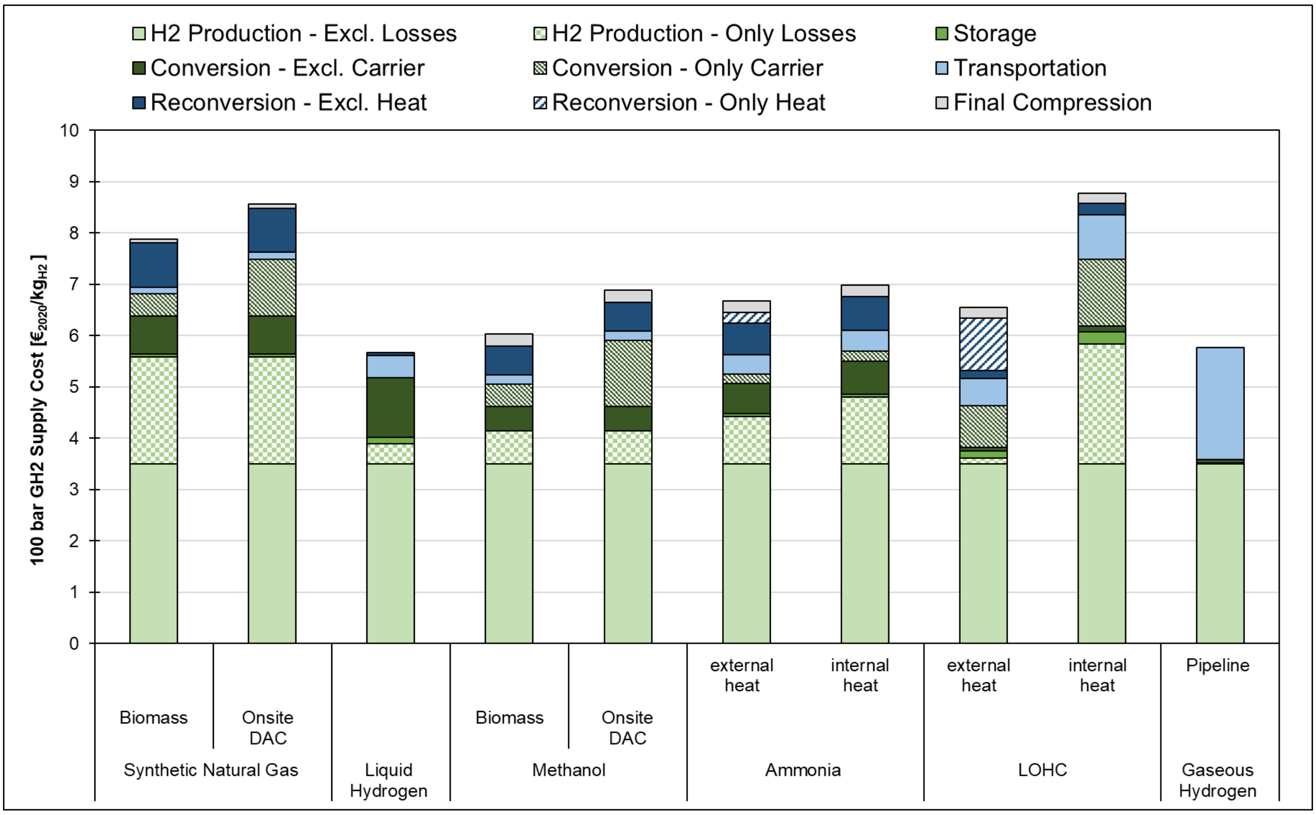

Figure 39: Specific costs of hydrogen supply between Nigeria and Germany with different export options

** All values shown assume a transport distance of 9,200 km (ship transport of Synthetic Natural Gas, Liquid Hydrogen, Methanol, Ammonia and LOHC) resp. 7,000 km (pipeline transport of Gaseous Hydrogen).*

A comparison of the different supply chains shows that in the examined scenario, supply via liquid hydrogen has the lowest total costs with slightly less than 6 €/kg$_{H2}$. A liquid hydrogen-based supply chain is characterized, in particular, by low hydrogen losses. Notable hydrogen losses occur only during ship transport (boil-off). At more than 1.1 €/kgH2, hydrogen liquefaction (*Conversion - Excl. Carrier*) contributes significantly to the hydrogen supply costs. The liquefaction costs consist of about half of the electricity costs and the other half of investment and maintenance costs. Unlike the other supply chains studied, reconversion incurs very little cost in a liquid hydrogen supply chain as regasification can be implemented easily and with almost no additional energy input.

The different hydrogen supply chains based on methanol and ammonia have specific costs of between 6 and 7€/kg$_{H2}$. In the case of ammonia, comparatively high hydrogen losses occur, in particular due to the complex purification of the hydrogen necessary after ammonia cracking. If no external heat source is available at the point of import, additional hydrogen must be used to provide heat, which leads to additional losses. In addition, Figure 39 shows that the required nitrogen (*Conversion - Only Carrier*) can be provided at low cost. Accordingly, providing the carrier material is significantly less expensive for ammonia-based supply than for the other transport options that bind hydrogen to a carrier material (SNG, Methanol & LOHC).

The reconversion of methanol to hydrogen and CO_2 requires, among other things, the use of thermal energy. However, the available literature suggests that the hydrogen losses occurring anyway during methanol cracking and hydrogen purification are sufficient to cover the total thermal energy demand of the process. Therefore, Figure 39 does not distinguish between external and internal heat sources for the methanol-based supply chain. On the contrary, it can be seen that the losses along the supply chain are relatively low. This is particularly due the comparatively low-loss conversion and reconversion processes. Accordingly, few hydrogen losses have to be compensated by additional hydrogen to be produced. It also becomes apparent that the costs of a methanol-based hydrogen supply in the scenario studied are strongly dependent on the availability of a biogenic CO_2 source. If the CO_2 has to be captured from the air using the DAC process, the total supply cost increases by about 1 €/kg_{H2}.

Exporting hydrogen produced in Nigeria in the form of SNG has significantly higher costs than the previously discussed options. The high energy losses in the conversion processes (methanation and ATR) are particularly disadvantageous here. The costs incurred for transportation are lowest for SNG-based exports, as LNG tankers are already established on the market and have very high capacities. In addition, as in the case of methanol-based supply, the use of biogenic CO_2 results in significantly lower costs than the use of DAC technology.

The costs of LOHC-based hydrogen supply are decisively determined by the way in which the required dehydrogenation heat (*Reconversion - Only Heat*) is provided. If an external (waste) heat source can be used in the importing country, the supply costs are around 6.5 €/kg_{H2}. If the required heat has to be provided internally and transported along the supply chain, the costs add up to almost 9 €/kg_{H2} and are thus significantly higher than the supply costs of all other options. The comparatively high costs of supplying the hydrogen carrier (Benzyltoluene in this case) are also striking. One reason for this is that the system ties up a large quantity of the carrier and the corresponding capital to be spent on its acquisition.

Hydrogen export from Nigeria to Germany would require the construction of a correspondingly long pipeline connection (7,000 km assumed). Figure 39 shows that such a pipeline would cause significantly higher transportation costs than the investigated ship-based options. In addition to the investment and maintenance costs for the pipeline, the energy used to recompress the hydrogen along the pipeline also contributes to the transportation costs. However, export by pipeline does not require conversion of the hydrogen. Accordingly, all associated cost components are omitted. In the scenario examined, the costs of a hydrogen export by pipeline are around 6 €/kg$_{H2}$ and thus in the range that can also be expected for supply chains based on liquid hydrogen and methanol (CO_2 from biomass).

4.5.2 Influence of Transport Distance on Hydrogen Supply Cost

In addition to the specific export scenario examined earlier, the influence of the transport distance to be covered on the total costs of hydrogen supply incurred in the importing country is examined. Figure 40 shows the total supply cost for an export of hydrogen from Nigeria depending on transportation distance and refers to the costs of providing pure hydrogen in the importing country.

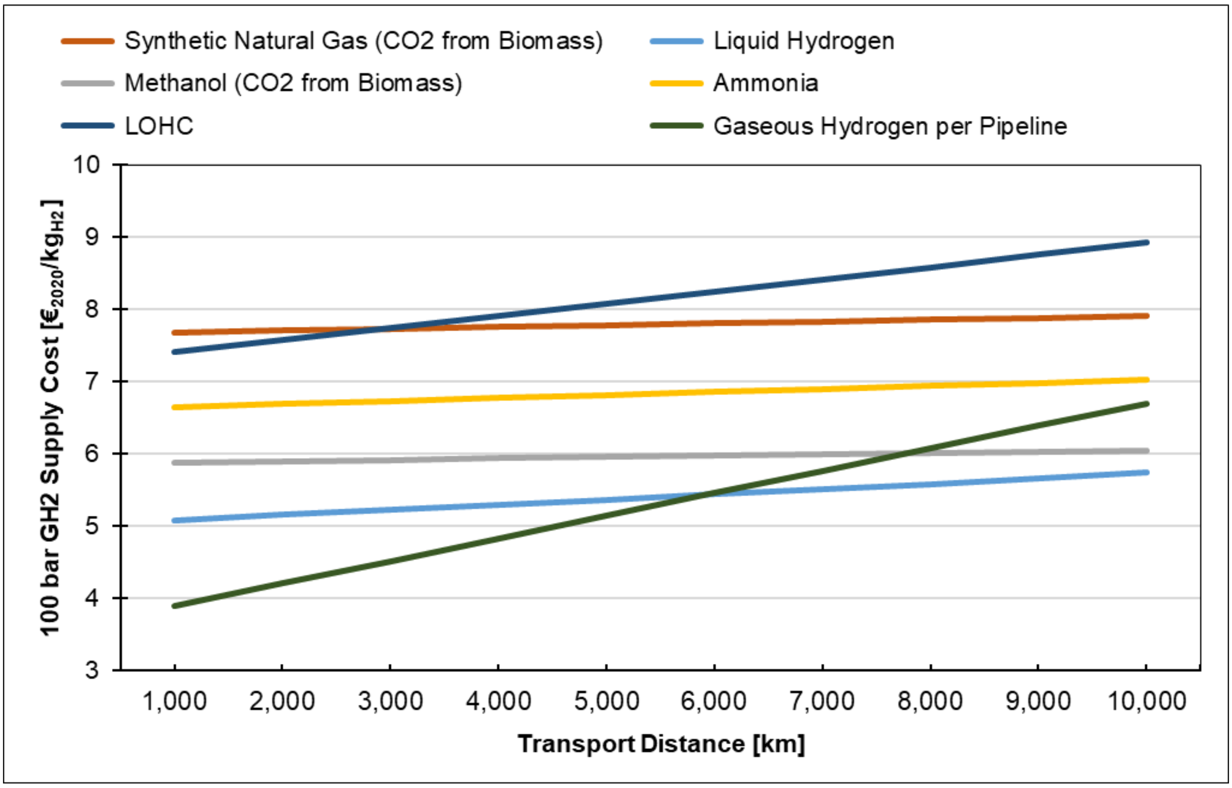

Figure 40: Hydrogen supply costs for different supply chains as a function of the distance to be covered

** For the supply chains based on ammonia and methanol, hydrogen redissolution is assumed with the use of an internal heat supply (see Figure 39).*

Figure 40 illustrates that transportation distance has very little impact on supply costs when hydrogen is converted to another chemical energy carrier (SNG, ammonia or methanol). In these cases, increasing the distance merely results in the need for more ships and more ship fuel. The influence of these parameters on the total costs is very small, since the tankers for transporting SNG, methanol and ammonia are already in use today and correspond to the state of the art. If the hydrogen is exported in its liquid form, the transportation distance has a slightly larger impact on the total cost. The reason for this is, on the one hand, that liquid hydrogen tankers are currently still under development and will in all likelihood remain comparatively expensive in the future. Accordingly, an increase in the number of ships required will result in a higher cost increase than in the case of the previously discussed options. On the other hand, in a liquid hydrogen-based supply chain, also the energy losses depend on the transport distance, since the longer the transport takes, the more boil-off occurs. An even higher dependence on the transport distance is observed for hydrogen export by means of LOHCs. In this case, longer transport distances lead to a higher total amount of the carrier material (here Benzyltoluene) tied in the system while the amount of energy provided remains the same. Accordingly, the acquisition of the carrier material causes additional costs, which increase sharply with increasing transport distance. Moreover, due to the comparatively low volumetric energy density of hydrogen-loaded LOHC, the number of ships required, which increases with the transport distance, has a greater impact on the total supply cost than in the other cases.

Hydrogen export by pipeline shows the highest dependence on transport distance among all supply chains investigated, and the costs resulting directly from transport account for a particularly large share of the total supply costs. In the case of pipelines, the transport costs are strongly affected by the distance to be covered, since both the material input and the energy input for recompression are directly dependent on the distance.

Against the background that an international market for hydrogen and hydrogen-based PtX products currently does not exist, a conclusive assessment of Nigeria's chances to act as an exporter on this (potential) market is difficult. However, in addition to numerous socioeconomic factors, such as the availability of labor or political stability, some techno-economic indicators also play a role in assessing Nigeria's competitiveness as hydrogen / PtX exporter. In this chapter, we focus on criteria that are likely to have an important impact on the price at which Nigeria will be able to offer its PtX products on the world market. Based on the analyses conducted earlier, the three criteria discussed below are identified as crucial to the price of Nigeria’s products and thus the country’s competitiveness as an exporter in an international market for hydrogen and PtX products.

4.6 Onsite hydrogen production cost

In chapter 2, an optimization model for Nigeria was used to determine a minimum hydrogen production cost of slightly less than 3.5 €/kg$_{H2}$ using wind energy and photovoltaics. These minimal costs are achieved exclusively in the sun-rich north of the country. When comparing Nigeria with countries that are potential competitors in the future market for green hydrogen and PtX products, the conditions for

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renewable power generation are decisive. Other relevant factors for the hydrogen production costs such as the techno-economic parameters of the electrolyser or the CAPEX of the PV and wind power plants are determined via the world market and differ only marginally, if at all, between the different regions.

Figure 41 shows the onsite hydrogen production costs projected in 2030 for Europe, Northern Africa, and the Middle East. The same model and framework assumptions were used that have been applied to calculate the minimum hydrogen production costs in Nigeria in the range of 3.5 €/kg$_{H2}$. It can be seen that the cost of onsite hydrogen production in African countries bordering the Sahara and in the Arabian Peninsula is generally of the same order of magnitude. Thereby, some regions, such as Western Sahara, parts of Algeria and Oman, have slightly lower hydrogen production costs of around 3 €/kg$_{H2}$ than the most attractive regions in Nigeria. Hydrogen production in Nigeria would thus be about 17 % more expensive than in these advantaged regions.

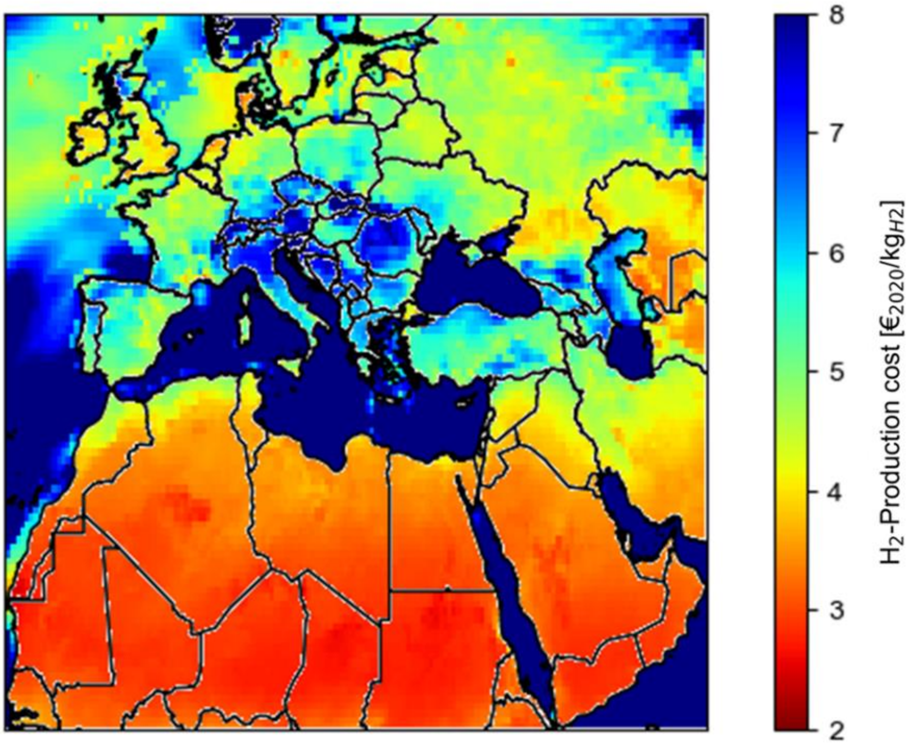

Figure 41: Onsite Hydrogen Production Cost in 2030 for Europe, Northern Africa, and the Middle East

Other studies also come to similar conclusions. One example is the calculation by the management consultancy PWC. PWC's results for country-specific hydrogen production costs in 2030 are shown in Figure 42. For hydrogen production costs in Nigeria, a range of 2.50 to 2.75 €/kg$_{H2}$ is indicated here. On the Arabian Peninsula as well as in Algeria and Egypt, slightly lower hydrogen production costs of

2.25 to 2.5 €/kg$_{H2}$ can be achieved according to PWC. This results in a relative cost premium of around 10 % for hydrogen production in Nigeria.

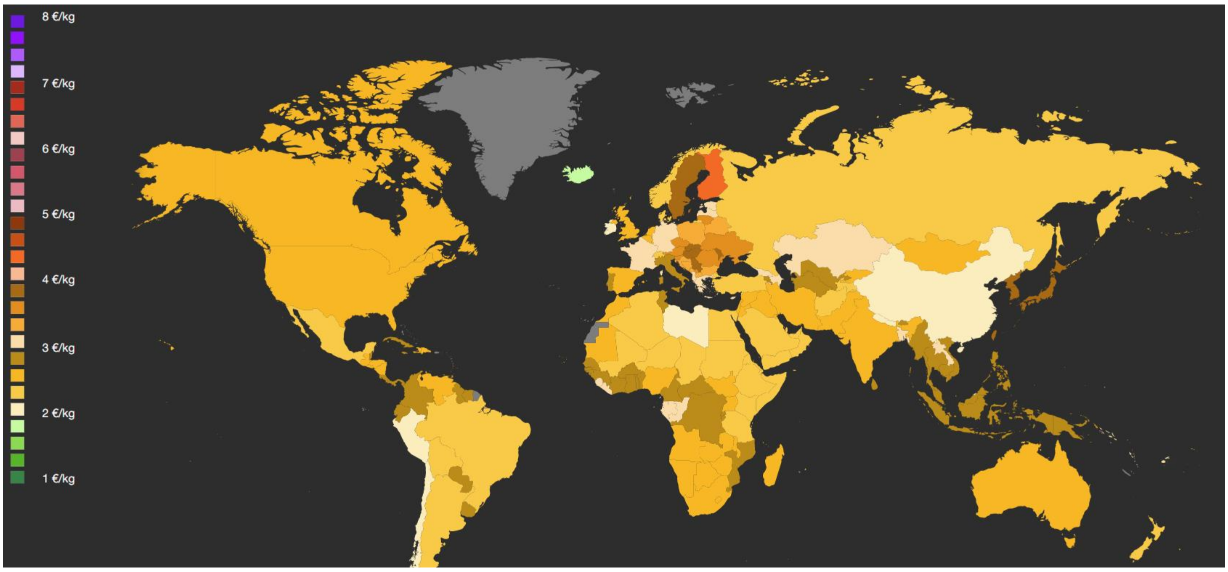

Figure 42: Country-specific Hydrogen Production Cost in 2030, according to PWC [107]

4.7 Proximity to emerging import markets

As shown earlier, pipeline import is a promising option for the supply of pure hydrogen in countries with high import demands. Especially if the transport distance is less than 3,000 km, it can be assumed that significantly lower supply costs can be realized with pipelines than with ship-based import. Short transport distances also tend to be advantageous for an import by means of liquid hydrogen. For an assessment of Nigeria's future competitiveness as a hydrogen exporter, it may therefore also be relevant which distances have to be covered to supply regions with a large import demand.

As an example for a prediction of a future international hydrogen trade, Figure 43 shows a forecast by the IEA [96] for the development of the global hydrogen market by 2050. Markets that are expected to have a high demand for the import of hydrogen as PtX products are, in particular, the EU as well as Japan and Korea. In the Asian region, China could become an importer too, although complete self-sufficiency also seems possible. All other regions are projected to be able to fully meet their hydrogen and PtX demand through domestic supply and could potentially become exporters in addition. Nigeria tends to be in a disadvantageous geographic location for supplying hydrogen to Europe and Asia. For example, for the supply of Europe with hydrogen, it is likely that transportation costs from Northern Africa will be lower than those from Nigeria. This is particularly valid against the background that a pipeline connection of Northern Africa to a future European hydrogen grid is being envisaged within the framework of the so-called "*European Hydrogen Backbone*" [108]. It is not anticipated that a ship-based hydrogen supply from Nigeria would be competitive with such a pipeline supply.

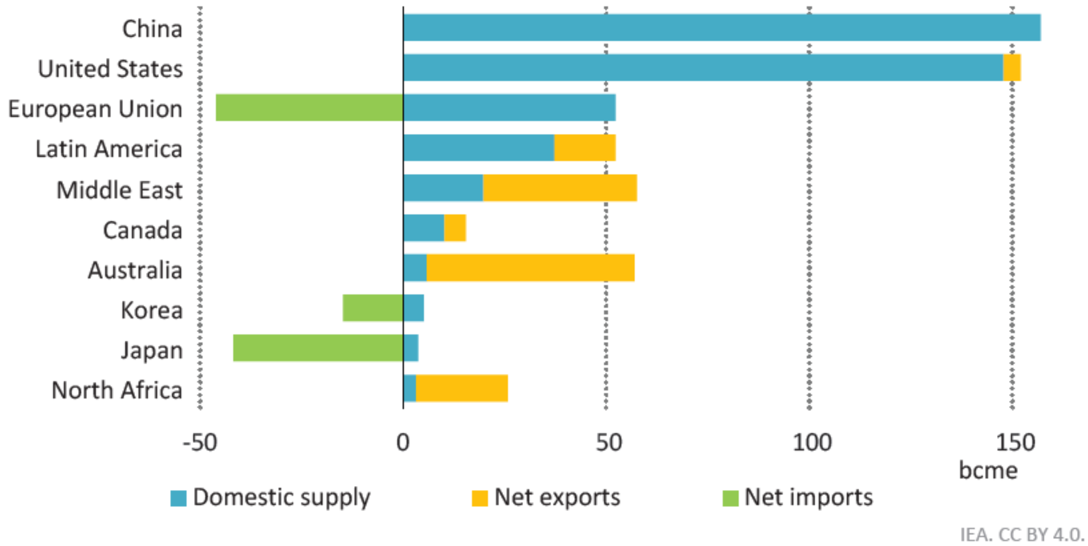

Figure 43: Domestic supply and trade of hydrogen of different regions by 2050 in the "Announced Pledges Scenario" of the IEA [96]

Also for the supply of the foreseen import markets in the Asian region, there is a potential export country in Australia, which is significantly closer to the sales markets than Nigeria. Accordingly, declarations of intent and an initial pilot project already exist for hydrogen transport from Australia to Japan. In this pilot project, the hydrogen is transported in liquid form by ship. Especially in the case that liquid hydrogen supply chains can be realized on a large scale in the future, it can be assumed that Australia is in an advantageous position compared to Nigeria in terms of supplying the Asian markets with hydrogen.

4.8 Availability of a sustainable, low-cost carbon source

Due to the comparatively large distances to potential sales markets, transport options with a low sensitivity to distance are particularly suitable for exporting hydrogen / PtX products from Nigeria. In addition to ammonia, this also applies to the export of methanol and SNG. Supply costs for options that involve the conversion of hydrogen to a hydrocarbon such as methanol or SNG are highly dependent on the availability of a sustainable, low-cost carbon source. Accordingly, the sufficient availability of biomass as a source for biogenic carbon may, under certain conditions, represent a competitive advantage for a country in the future. The prerequisite for this is that sustainable use of this biomass is ensured. Figure 44 shows that Nigeria, due to its geographical location, generally has a high biomass potential compared to other frequently discussed hydrogen exporters like the countries in Northern

Africa or the Middle East. Due to the climatic conditions, the south of the country in particular is expected to have a high biomass utilization potential. Examples for potentially usable biomass resources are biowaste, energy crops (e.g. corn, sugar cane), agricultural residues and timber waste. Correspondingly, a possible value chains could envisage the transport of green hydrogen from the sun-rich North to the South, where further processing into hydrocarbons could take place with the biogenic CO_2 available there. Biogenic CO_2 occurs in a variety of processes in which biomass is converted into energy or a biogenic energy carrier. The processes that currently have the greatest potential for CO_2 provision are biogas and bioenthanol production as well as biomass combustion. Therefore, the realisation of a holistic concept could, in addition to the export of green hydrocarbons, for example, also include the supply of biogenic energy, which is produced anyway in the context of the harvesting of biogenic CO_2, for the domestic market.

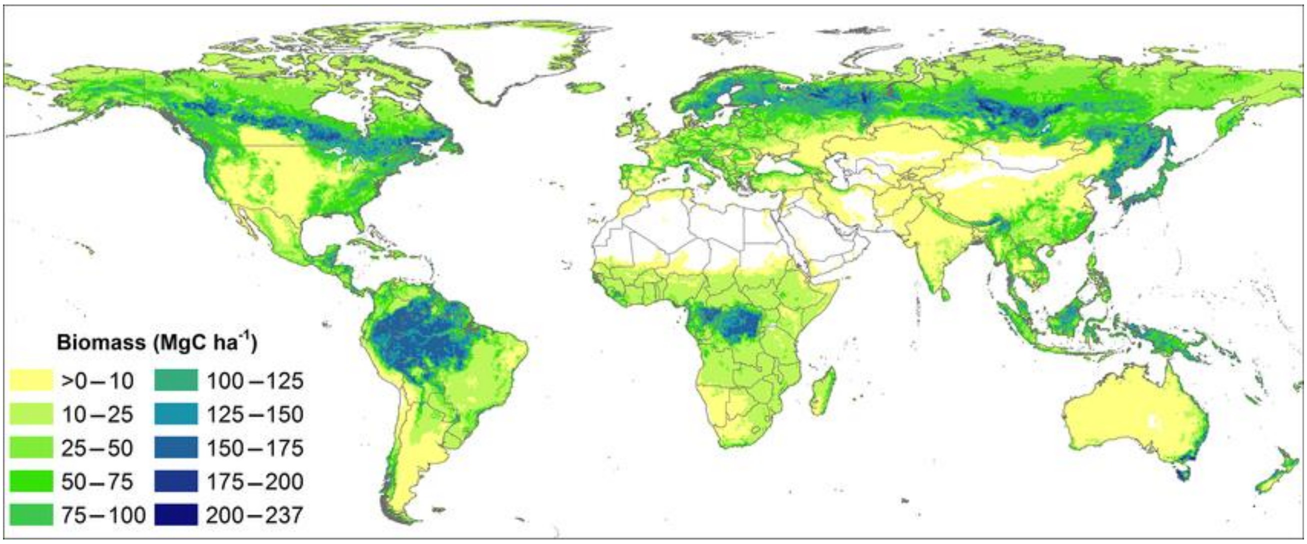

Figure 44: Estimated Global Carbon Biomass [109]

4.9 Competitiveness as an exporter of hydrogen and PtX products

Initial assessments indicate, based on the data available, that Nigeria is not expected to be a front-running exporter in the emerging international market for hydrogen and PtX products as the cost of hydrogen production is expected to be 10 to 20 % higher than in the top international competitors. If northern Nigeria cannot be developed for energy production in the medium term for security reasons, this gap would increase further. In addition, Nigeria is comparatively far away from the regions that are expected to have the greatest import demand. This results in potentially higher transportation costs, especially if options will become available for supplying demand centers that have low transportation costs over short distances (e.g., pipelines and liquid hydrogen tankers).

However, a locational advantage of Nigeria may arise from the potentially good availability of biomass, which might be utilized as a source for green carbon. The combination of good renewable energy resources for hydrogen production on the one hand and good biomass availability on the other hand is only found in a few competing countries. In the context of PtX products, such an availability of biomass is an advantage, especially for the provision of green hydrocarbons and transport distance also plays a subordinate role for the supply costs of such products, which additionally benefits Nigeria's competitiveness.

The role of methanol in a climate-neutral energy system may go far beyond that of a pure hydrogen carrier. Thus, it is expected that green methanol will become a basic component of a defossilized future chemical industry and serve as a feedstock for a variety of products (e.g., plastics, paints). Due to its good transportability, it can be assumed that an international market for green methanol will be emerging. Against the background of the initial situation described in this chapter, Nigeria's chances of entering this future market as a highly competitive exporter of green methanol are particularly good.

5. Comparing green v blue hydrogen

In this penultimate chapter, an evaluation is undertaken of blue hydrogen or hydrogen supplied by SMR with, at least, carbon capture, utilisation and storage (CCUS) regarding its economic and ecological performance, compared to green hydrogen production. Previous assessments have focused on green hydrogen production which will play an important role in the future, while currently, production routes based on natural gas dominate the global hydrogen production with a share of 62 % in 2021 [138]. Hydrogen production from fossil fuels leads to significant carbon emissions. By equipping hydrogen production facilities based on fossil fuels with carbon capture technologies, the emissions could be lowered significantly.

Besides this so-called “blue hydrogen”, “turquoise hydrogen” is another route for fossil-based hydrogen production with reduced emissions. In this case, a methane pyrolysis is employed. An electrical plasma provides a high temperature sufficient to split methane into hydrogen and carbon, with the latter being produced in a solid form. Currently, no commercial-scale production facilities exist. Due to the low TRL, this option will not be considered further. [128, 137, 138]. Low-emission hydrogen production based on natural gas could be important to reduce emissions of existing production plants and could play a role in regions with abundant natural gas resources [138]. This is the case for Nigeria, as the country's natural gas reserves in Nigeria total 202 trillion cubic feet which is equal to about 3% of global reserves [143, 150].

5.1 Production of blue hydrogen from natural gas

The production of blue H_2 is based on fossil resources. The conventional processes, reformation of natural gas and gasification of coal, are equipped with CCS [151]. The required emission reductions for a production to be labelled as blue are not regulated. A 60% reduction has been proposed, but the European Union is currently aiming for at least a 90% reduction [141]. Here, the natural gas-based pathway and technologies needed for blue hydrogen production is examined. In the first step, the different routes that can be used to supply hydrogen based on natural gas are presented while the second segment presents the technology that is needed to carry out the CCS.

5.2 Hydrogen supply based on natural gas

Three different processes that can be used to produce hydrogen based on natural gas are currently available: the endothermal steam methane reforming (SMR, Technological readiness level (TRL) 9), the exothermal partial oxidation (PO, TRL 7-9) and the autothermal reforming (ATR, TRL 7-9) that combines SMR and PO [129,141]. The hydrogen produced by these technologies is commonly referred to as grey hydrogen. Currently, SMR is the most extensively used method for the production of grey hydrogen [130 138, 141]. A purification of the natural gas is carried out in front of SMR and ATR to remove catalyst poisons, e.g., sulphur, and can be carried out upstream of a PO reactor [129, 139]. Syngas, a mixture containing mainly hydrogen and carbon monoxide (CO), is the product of the three processes. The composition of the syngas depends on the feedstock and the employed process. To derive pure hydrogen, purification is required [139].

5.2.1 Partial oxidation (PO)

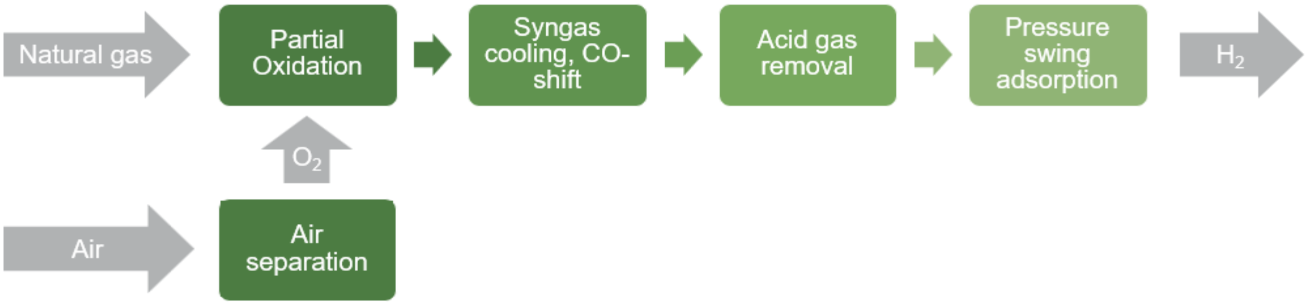

Figure 45: Process scheme for the partial oxidation of natural gas, based on [139,145]

Partial oxidation is mainly used to process low-quality and solid feedstocks [13]. If natural gas is utilised as a feed, methane (CH_4) reacts with pure oxygen (O_2) and forms carbon monoxide (CO) and H_2 [135]:

$$CH_4 + \frac{1}{2}O_2 \rightarrow CO + 2H_2 \quad (1)$$

In parallel or immediately after the oxidation reaction, the water-gas-shift-reaction (WGS) (Eq. (3)) and methane reforming reaction (Eq. (2)) take place [135]. The reactions are carried out under pressures in the range of 3-12 MPa and high temperatures (1250-1500 °C) or lower temperatures of about 950 °C in presence of a catalyst [135, 151]. After the oxidation, a sequence of cooling down, gas purification and shift reaction takes place [135].

5.2.2 Steam methane reforming (SMR)

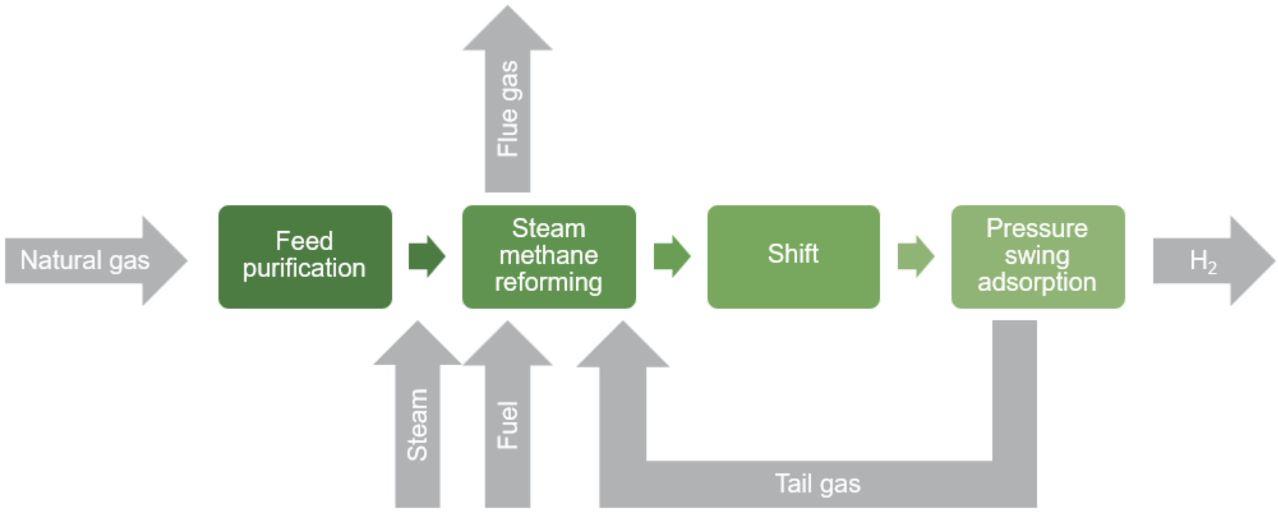

Figure 46: Process scheme for the steam methane reforming of natural gas, based on [138]

Sulphur components are removed from the feed stream, which is then preheated. After that, steam is added. CH_4 and pure steam react in an endothermal reaction and form a mixture of H_2 and CO [129, 135]:

$$CH_4 + H_2O \rightleftarrows CO + 3H_2 \quad (2)$$

The exothermal WGS (Eq. (3)) occurs simultaneously [9]:

$$CO + H_2O \rightarrow CO_2 + H_2 \quad (3)$$

The reactions take place at pressures in the range of 1.5-3.0 MPa and high temperatures (800-900 °C) in catalyst-filled tubes. The overall process requires a supply of heat carried out by indirect heating of the outside of the tubes. Heat is provided by an external furnace [127, 135, 139].

In the next step, the remaining steam and CO are converted into H_2 and carbon dioxide (CO_2) in a high-temperature shift reaction. The high-temperature shift conversion is followed either by a pressure swing adsorption (PSA) or by a low-temperature shift reaction in the so-called classical process. If the classical process is chosen, the remaining impurities are removed with a CO_2-scrubber and a methanation [129, 135]. In the case of a PSA, the impurities are collected in the tail gas which is burnt to supply heat to the reforming reaction. Additional fuel is burnt as well. As the PSA route is the standard for pure H_2 plants, this option will be the one covered in this work [135, 138, 139].

About 40 % of the CO_2 production of the overall process results from the burning of additional fuel to heat the reaction. The rest of the CO_2 emissions originate from the reforming and shift reactions and can be recovered from a stream with a high CO_2 concentration. Potentially, low-emission electricity could be used to supply heat to the SMR process in the electrified steam reforming process (TRL4). In this case, only the emissions from the reforming itself, available in one stream with a high CO_2 concentration, would be left to capture [138, 139, 141].

5.2.3 Autothermal reforming (ATR)

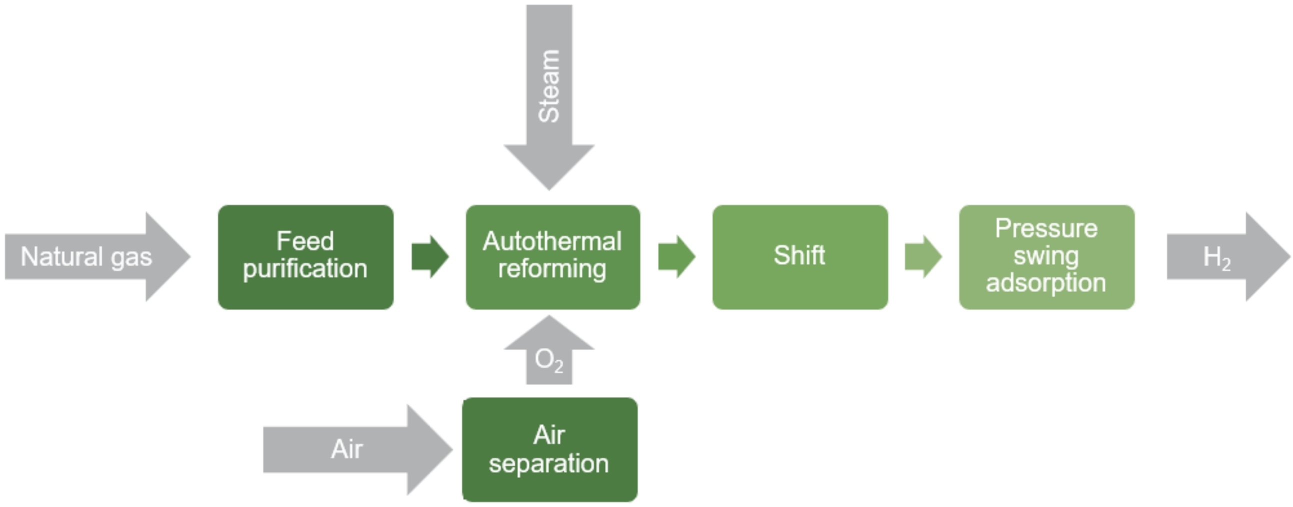

Figure 47: Process scheme for the autothermal reforming of natural gas, based on [138]

PO and SMR are combined in this process. The PO supplies heat for the endothermal reforming. To achieve that, natural gas, steam and pure O_2 or air are fed simultaneously to the reformer. Temperatures of 1000 °C and pressures in the range of 30-50 bar are employed. The PSA tail gas is burned and the resulting heat is used to preheat the feed [139]. All CO_2 produced in the ATR process is available in one stream with a high CO_2 concentration [12]. The commercial-scale experience of the process is currently limited [151]. Furthermore, the ATR leads to high costs and requires a more complex purification [129].

5.3 Carbon capture and storage for blue hydrogen production

Carbon capture, utilisation and storage (CCUS) is a process chain involving the capture of CO_2 from point sources or the air and its permanent storage or utilisation as a feedstock [138]. The focus here is set on the capture from point sources, namely hydrogen production facilities, and permanent storage.

The carbon is separated in the reforming process. SMR plants currently in operation achieve CO_2-capture rates of around 60%. Capture rates between 90 and 100% could be achieved in the future

[130]. ATR plants with CCUS are not available right now, but the targeted capture rates of planned facilities are in the range of 95-99% [138].

Carbon capture can be carried out with three different systems: a pre-combustion, a post-combustion or an oxyfuel combustion capture. The latter is only employed in power plants and will not be covered here [139, 141, 149]. In a post-combustion process, the CO_2 is captured from the flue gases coming out of the combustion section, e.g., from the furnace in the steam reformer. Other reaction products and inerts are also present in the flue gas stream. Therefore, the CO_2 concentration in the stream is low (10-15 vol%). The pressure is nearly atmospheric [139]. Post-combustion capture is the favoured option for retrofitting of existing plants in most cases [141]. In a pre-combustion process, the CO_2 is removed from the raw syngas. Higher CO_2 concentrations and pressures lead to more favourable separation conditions, compared to the post-combustion process [139, 149]. The possible process options for the pre- or post-combustion capture are absorption, adsorption, membrane and cryogenic processes, with absorption being the most widespread choice and therefore the main focus of this work. In this case, the CO_2 is washed out by a solvent that needs to be regenerated. In adsorption processes, CO_2 bonds to the solid surface of the adsorbent in a pressure or temperature swing adsorption process. In cryogenic processes, low temperatures lead to liquefaction and consequently to the separation of CO_2. Membrane processes are under development. A selective membrane is used in this case to separate CO_2 from gaseous streams [133, 139, 141].

5.3.1 CO_2 capture in SMR/ATR plants

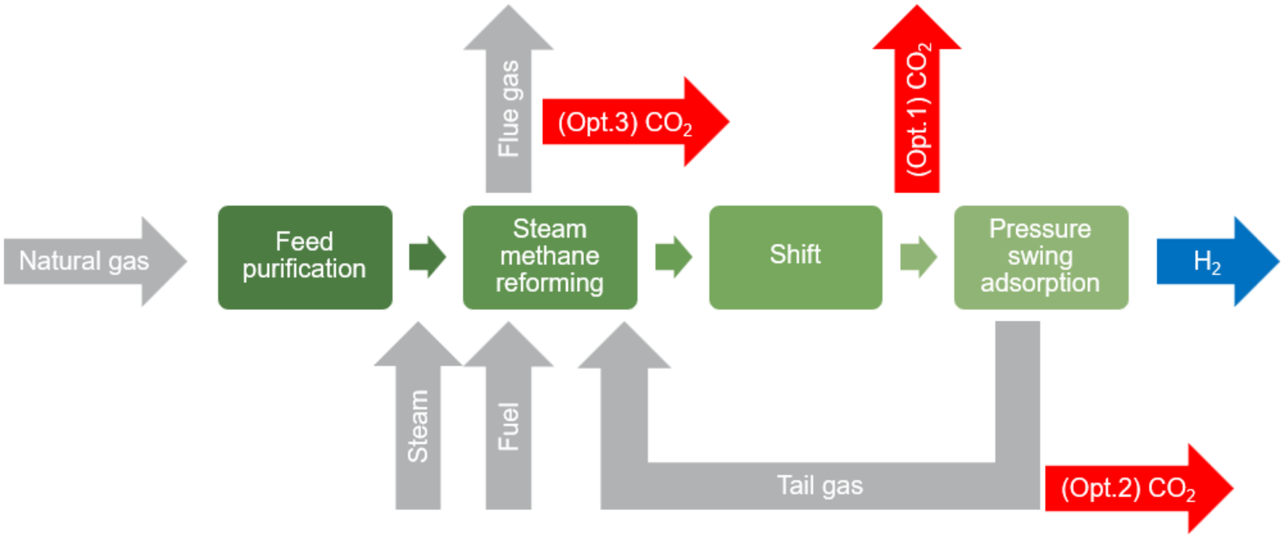

Figure 48: Locations for CO_2 removal in a SMR plant, based on [138]

In a SMR plant with one shift reactor and a PSA, CO_2 can be separated at three different locations [127, 139, 141]:

- **After the shift reaction/ at the PSA inlet (pre-combustion, Opt.1 in Figure 48):** About 90% of total emissions can be captured for ATR-plants. In the case of a SMR process, a post-combustion capture is needed to capture the emissions from the flue gas. Consequently, only 60% of the overall emissions can be captured.
- **PSA tail gas (pre-combustion, Opt.2 in Figure 48):** About 55% of total emissions can be captured.
- **SMR flue gas (post-combustion, Opt.3 in Figure 48):** About 90% of total emissions can be captured.

The capture from the PSA tail gas shows worse economics, compared to the other two options, and will therefore not be considered. The pre-combustion capture at the PSA inlet is a standard process, as it is needed in several industrial processes, e.g., ammonia production, while the post-combustion CCS can be favourable for retrofits. It is possible to capture emissions at more than one location. For example, if capture is carried out at the PSA inlet and from the SMR flue gas, 96% of the total emissions can be captured [139, 141].

The main energy demand in a CO_2-capture process originates from the heat needed to regenerate the solvent. Current energy consumptions are in the range of 2.5-3.2 GJ/$t_{CO2\ removed}$ [139].

5.3.2 CO2 capture in PO plants

As sulphur does not need to be removed before the PO, sulphur components are present in the syngas. This leads to additional requirements regarding the CO_2 removal, mainly influencing the solvent selection. As CO_2 and sulphur components are present in the solvent, an additional separation is necessary. Apart from that, CO_2 capture in PO plants is comparable to SMR/ATR plants [139].

5.4 Transport and storage

The transport of the captured CO_2 from the production facility to the storage site can be carried out by road tankers, pipelines and ships. The favourable option for a certain case is determined by the volumes that need to be transported, the distances that need to be covered and the lifetime of the plant. Pipelines are expected to be the most viable option in the context of blue hydrogen production. CO_2 is transported in liquid or supercritical conditions or as a dense phase fluid, as transport as a gas is not economically viable. In the case of pipelines, temperatures and pressures are in the range of 13-44°C and 85-150 bar. After transport, CO_2 could be utilized or needs to be stored [133, 144, 145]. The utilization of captured CO_2 should only be carried out for “green” CO_2 in the future. Therefore, the focus will be set on storage.

Three different CO_2 storage technologies can be distinguished: geological, mineral and ocean storage. The global CO_2 storage capacity is expected to be in the range of 13,000 Gt [133].

Long-term storage in geological formations, e.g., depleted oil and gas fields, is the most proven method and accounts for about 2% of the global storage capacity. Other options include unmineable coal beds and saline aquifers. Most of the options do not reach a TRL of 7. Enhanced oil recovery is an exception here and reaches a TRL of 9. CO_2 is injected into an oil reservoir and increases the pressure in the reservoir to enable the extraction of residual oil. In this case, it needs to be ensured that the CO_2 is retained after the injection. Retention rates for enhanced oil recovery projects show a high variation between 28-96% [133, 142, 144, 145]. Geological storage sites need to fulfil several requirements, e.g., regarding the porosity and sealing capability. The feasibility of a storage site is furthermore determined by the distance from the CO_2 source, the storage capacity and the leakage potential. Commercial-scale experience regarding the long-term storage of CO_2 in geological formations is currently limited. Therefore, the long-term environmental impact of large-scale storage sites cannot be determined with sufficient reliability [144, 145]. Deep ocean storage is an option that will probably be limited due to environmental concerns, e.g., due to the acidification of seawater. The TRL of deep ocean storage is 2 [133, 144, 145].

In the case of mineral storage, CO_2 reacts with alkaline earth metals and forms carbonate minerals. The TRL for this option is in the range 2-6 [133].

5.5 Levelized cost of blue hydrogen production

Different aspects will be considered to evaluate the overall process, i.e., the energy consumption, the economics of the production and the emissions related to the production. As SMR is the most widespread technology for natural gas-based hydrogen production, the following analysis will only cover this option. Most of the evaluations are based on different studies carried out by the International Energy Agency Greenhouse Gas R&D Programme (IEAGHG). These studies refer to a production in the Netherlands [139–141]. As there is no specific data available for Nigeria, it is assumed that the results can be transferred to Nigeria with sufficient accuracy.

The economic viability of a CCS system is determined by the following aspects [141, 146]:

- Flow rate of flue gas/syngas
- CO_2 partial pressure
- CO_2 recovery rate
- Energy requirement

Existing studies report that a capture rate between 55-90% of the overall process CO_2 emissions increases H_2 costs by 20-60% [127]. The majority of the additional costs for the CCS system are related to the CO_2 capture itself, with transport and storage being responsible for about 20-30% of the CCS system costs [141]. The hydrogen production costs result from capital and operating expenditures.

Capital costs
The capital costs include the investment cost for the SMR plant, a power island to generate electricity from excess steam, a CO_2 capture and compression as well as utilities and balance of plant equipment. The latter contains, among others, the cooling water system, flare system, buildings and interconnections [140].

Operating costs
Operating costs contain payments for labour, operation and maintenance, fuel and feedstock, CO_2 transport and storage as well as catalysts and chemicals. A revenue for the sale of excess electricity generated by the power island is included here as well [140].

Based on the capital and operating costs shown in Table 13 the LCoH as well as the CO_2 avoidance cost are calculated. The results shown in Table 13 are in line with several other studies [141, 151].

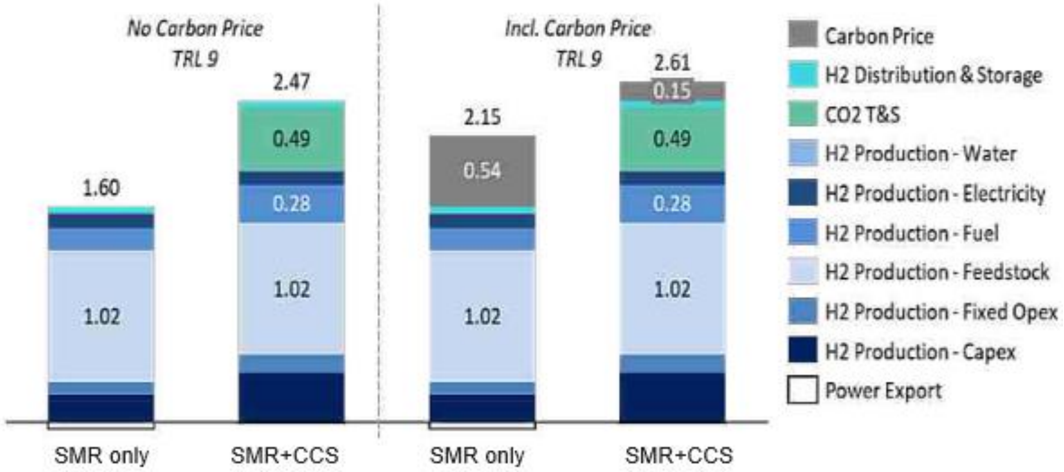

Figure 49: LCoH in €/kg for SMR without CCS and with CCS (90% capture rate), Carbon price: 9.53 €/t, [141]

Figure 49 gives an overview of the different cost components influencing the LCoH and enables a good estimation of the influence of each component. The feedstock (natural gas) is responsible for a high share of the overall costs. If CCS is used, CO_2 transport and storage results in high costs as well. Together with the plant CAPEX, these two components are responsible for over 74% of the LCoH in the case of SMR+CCS [141].

The same can be seen in Figure 50. For the comparison with the green production route, the Gateway 2 costs are the most relevant. As H_2 distribution is only responsible for a small part of the overall costs, this aspect can be neglected in further analysis [141].

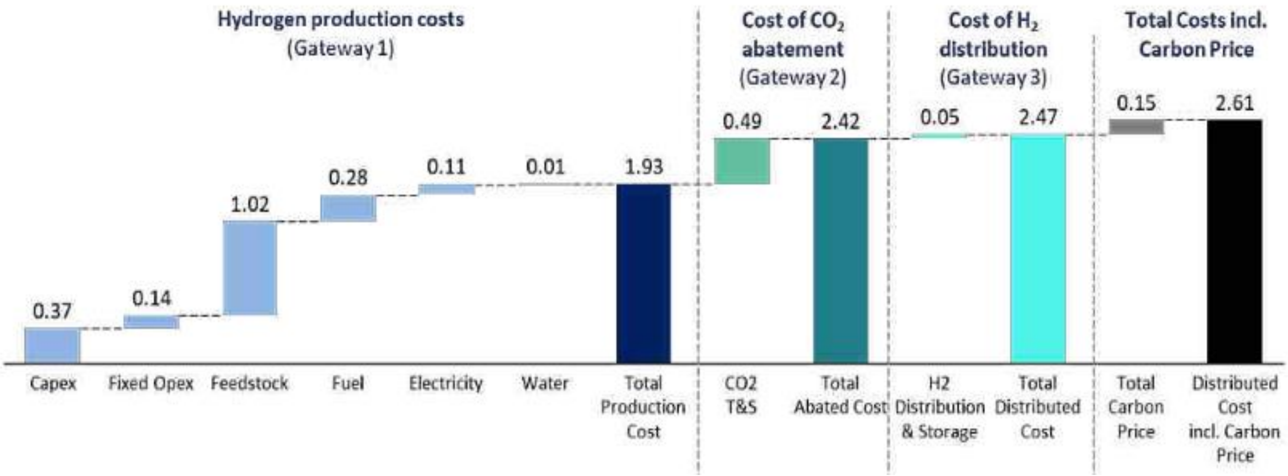

Figure 50: LCoH for SMR with CCS (90% capture rate) in the Netherlands in €/kg, [141]

Without a carbon price, the cost of SMR-based H_2 without CCS is expected to increase to 1.75 €/kg by 2050, compared to 1.60 €/kg as shown in Figure 49, due to increasing feedstock prices. Even though the gained experience in this timespan will most likely lead to decreasing CO_2 capture, transport and storage costs, the LCOH for the SMR+CCS pathway will therefore not be lowered significantly. 2.28 €/kg is the expected LCOH in 2050 with a 5% learning rate. If a carbon price is employed, blue production could be cheaper than the grey pathway by 2050 [141]. PO and ATR production are not covered in detail here but reach similar results [141].

5.6 Emissions related to blue hydrogen production

Emissions related to blue hydrogen production originate from the production, processing and transportation of natural gas, the SMR process, the generation of heat and high pressures and the supply of energy for the CCS [136]. Besides CO_2, other substances influencing the environment are emitted during natural gas-based hydrogen production, e.g., volatile organic compounds, CH_4, nitrous oxide and sulphur oxides. Due to the additional energy demand for the CCS, blue hydrogen leads to higher emissions of CH_4 as well as nitrous and sulphur oxides, compared to production without CCS. In addition to the influence on global warming, expressed by the global warming potential, acidification and impacts on humans, among others, are relevant environmental aspects that need to be considered [151]. In the scope of this analysis, the carbon footprint of blue production will be used to assess the environmental impact [141].

Several studies have assessed the greenhouse gas (GHG) emissions of natural gas-based hydrogen production. The GHG emission values found in different estimations are shown in Figure 51.

Across these studies, a significant emission reduction can be achieved by equipping hydrogen production plants with CCS. The capture rates assumed in the estimations are in the range of 71-92% [149]. While all studies considered in Figure 51 expect a significant decrease in GHG emissions can be achieved by CCS technologies, a recent study by Howarth and Jacobson suggests the actual emission reduction may be lower (in the range of 10-20%) [136].

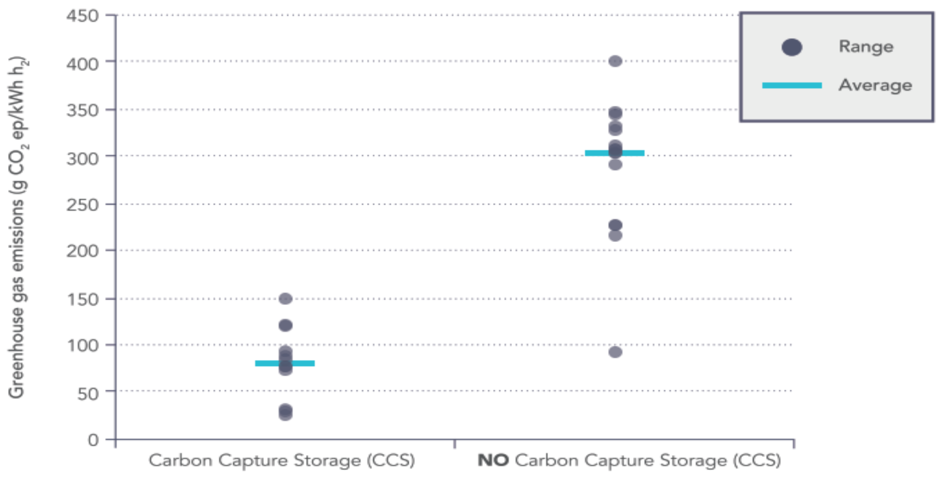

Figure 51: Estimates of GHG emissions related to natural gas-based H2 production, [149]

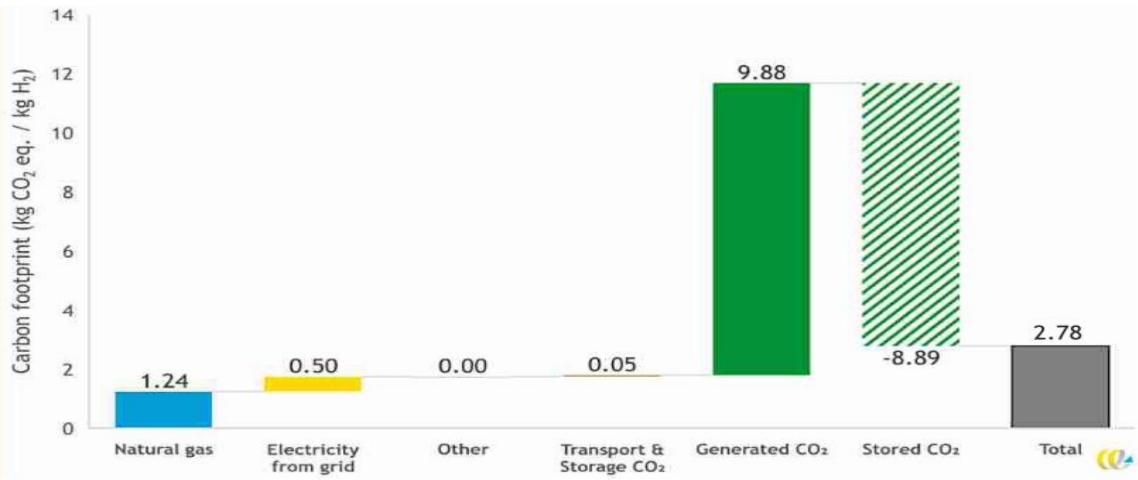

Figure 52: CO2 footprint of blue H2 production by SMR+CCS (90% capture rate) in the Netherlands in 2020, [15]

The supply of natural gas to the reforming plant causes significant emissions – about 25% of the overall process emissions, in the case that no CCS is executed. Therefore, the values below 71 g_{CO2eq}/kWh_{H2} shown in Figure 51 are not relevant, as supply chain emissions are not considered here [23], even though natural gas production and transport have the highest influence on the emissions of the SMR+CCS pathway [16]. Other processes leading to GHG emissions are for example the water supply and CO_2 transport and storage [15].

Figure 52 provides an overview of the impact of the different process steps leading to GHG emissions. The emissions originating from the natural gas supply cannot be abated by the CCS unit in the reforming process. Here, methane leakages occurring during the production and transport of natural gas are included. Even a 100% capture rate would consequently not enable zero-emission hydrogen production. The group "Other" contains the supply of water and the treatment of wastewater and has a negligible influence [141].

5.7 Performance of blue hydrogen production

Table 13 shows the influence of different CCS options on the performance of the overall SMR process. Three different cases, based on the IEAGHG study [140], are compared:

- Base case: SMR plant (with high-temperature shift and PSA), without CCS
- Case 1: SMR plant with absorption CO_2 capture (after shift conversion/ pre-combustion)
- Case 2: SMR plant with absorption CO_2 capture (from flue gas/ post-combustion)

Table 17: Parameters for the production of H_2 via SMR with and without CCS, based on [140]

	Unit	Base case	Case 1	Case 2
CO_2 emissions				
CO_2 capture rate	%	0	55.7	90
Specific CO_2 emissions	kg/Nm^3_{H2}	0.8	0.4	0.1
Energy consumption				
Natural gas consumption	MJ/Nm^3_{H2}	14.2	14.7	15.6
Change in natural gas consumption	%	0	+3.3	+9.9
Economic evaluation				

CO_2 emissions	Unit	Base case	Case 1	Case 2
Total plant costs - specific	€/(Nm³/h)	1,600	2,000	3,000
Increase in plant costs	%	0	+18	+78.6
Operating cost per year	€/(a(Nm³/h))	724	855	964
Increase in operating costs	%	0	+18	+33
LCOH	€/kg	1.3	1.5	1.8
Increase in LCOH	%	0	+18	+44
CO_2 avoidance cost	€/t_{CO2}	-	47.1	69.8

In addition to a base case without a CCS, a 55% and a 90% emission reduction are analysed. The emissions associated with grey and blue production shown here are in line with the estimations in the literature shown in Figure 51 [140, 149].

As the comparison of Case 1 and Case 2 shows, a higher capture rate leads to lower process emissions but comes with an energy and cost penalty. The estimated energy penalty of adding CCS to a SMR plant is in the range of 5-14% [149]. Adding a CCS leads to additional capital and operating costs as well. The overall cost penalty is in the range of 18-44%. A newer analysis, executed by the IEAGHG, estimates an even higher LCoH (see Figure 49 and Figure 50) and a higher cost increase for a 90% capture rate (+54.3%), compared to the values in Table 13 [140, 141].

Increasing the capture rate from 90 to 99% leads to an emission reduction of 8% and an increase in energy consumption equal to 10% [141].

5.8 Comparison of green and blue hydrogen production in Nigerian context

5.8.1 Gas reserves

Detailed information regarding the distribution of natural gas reserves in the country is not available. Figure 53 shows that the majority of the natural gas fields, as well as the natural gas pipelines, are located in the southern part of Nigeria. As the map was generated in 2014 [134], probably not all fields and pipelines are depicted here, but the map is sufficient to give a first overview of the natural gas system in Nigeria. Based on the location of the existing natural gas fields, the southern part of the country shows the highest potential for blue hydrogen (H_2) production and application. The existing pipelines connect the fields and could be used to transport the natural gas to a H_2 production facility. Possibly, pipelines could be retrofitted for the distribution of the produced H_2 as well.

In the northern part of the country, a more decentralised green production should be the favourable option at least for the domestic supply, as the needed infrastructure for the distribution of natural gas and/or H_2 is reduced.

Figure 53: Nigerian Oil and Gas fields [134]

5.8.2 Emissions related to hydrogen production

In the scope of this analysis, only electrolysis-based hydrogen production supplied by renewable electricity will be considered as a green pathway. As for the GHG emissions of natural gas-based hydrogen production, several estimates for electrolysis-based production are available. While the emissions related to the natural gas-based pathways shown in Figure 51 are mainly in the range of 288-347 g_{CO2eq}/kWh_{H2} without CCS and 23-150 g_{CO2eq}/kWh_{H2} with CCS, electrolysis-based production leads to GHG emissions between 24-788 g_{CO2eq}/kWh_{H2}. The upper limit is for grid electricity, while purely renewable-based production reaches significantly lower values, as shown in Figure 54 [149].

The estimations for solar PV, the most relevant case in the Nigerian context, are well in the range of blue hydrogen production. Blue production reaches an even lower average, but the average of the blue production is decreased by some studies not considering supply chain emissions and therefore estimating values that are not comparable to green production. In addition, it needs to be considered that the quality of renewable resources determines the GHG emissions of the electrolysis pathway. For example, lower solar irradiation leads to the installation of a bigger PV park. Dimensions of electrolyser and storage capacities are influenced by the availability of renewable resources as well. As the emissions of electrolysis-based production based on renewables mainly result from the production and installation of the components, higher installed capacities lead to higher emissions. As Nigeria holds high-quality solar resources, it can be expected that emissions from solar-based production are at the lower end of the range depicted in Figure 54.

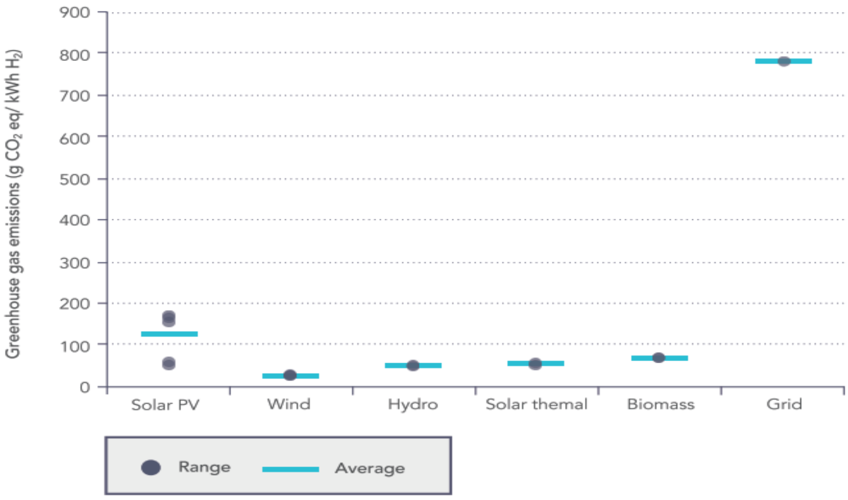

Figure 54: Estimations of GHG emissions related to electrolysis-based H_2 production, [23]

Consequently, green production will most probably reach lower emissions, compared to natural gas-based production equipped with CCS. In addition, the supply chain emissions of the green pathway are expected to decrease significantly in the future, as fossil-based energy supply in the production of renewable generation technologies and electrolysers is replaced by low-carbon options [149].

Furthermore, green production itself does not lead to the emission of other pollutants. This is important, as nitrous oxide, sulphur components, volatile organic compounds, particulate matter and methane are emitted by blue production [151].

5.9 Other criteria

5.9.1 Potential Customers

While some countries, e.g., Japan and China, are expected to rely on blue and green hydrogen, other countries have a preference for green hydrogen. Furthermore, different countries state in their national hydrogen strategy that they want to use blue hydrogen, but only for a limited time [131, 147]. While green hydrogen will be accepted by all possible importers, the export market for blue hydrogen could therefore be limited in the future.

5.9.2 Water consumption

As 60 million people do not have access to drinking water [152], water consumption is a relevant parameter in the context of the country. Green H_2 production requires about 10-15 litres of water per kilogram of H_2. The water demand of blue H_2 production is in the range of 24-38 litres per kilogram of H_2, depending on the chosen feedstock and process [147,151].

5.9.3 Process efficiency

Blue and green H_2 reach comparable overall process efficiencies, but the green route has a higher ceiling in this regard. While a SMR plant equipped with CCS could improve the efficiency from the currently reached 65% to 74% in the future, an electrolysis-based route could improve from 67% to 81% or even 92% if a high-temperature electrolysis is employed [130].

5.9.4 Fluctuating renewable energy supply

As the power generation by solar and wind power plants is variable, the H_2 supply could fluctuate as well. The supply can be smoothed, but additional investments are required, e.g., for batteries. Blue production can be based solely on natural gas and therefore ensure a stable supply. As green production in Nigeria can reach high full load hours, this factor is not as relevant in the country's context [138].

5.9.5 Economics

Figure 55 shows the predicted development of H_2 costs in the future for blue H_2 based on coal and natural gas as well as green H_2. The current blue H_2 cost estimation of 1.5-3 $/kg is in line with the estimations given in the literature [141, 151]. The same holds for the green H_2 cost estimation of 2.5-4.5 $/kg. The cost of natural gas-based production without CCS is in the range of 1-2.5 $/kg [145, 151]. The predicted development shows that green H_2 production costs will decline continuously until 2050 and the green route will reach cost parity with blue H_2 by 2030. Blue H_2 production costs are not predicted to experience a significant decline [145, 147]. Currently, a renewables-based H_2 production in Nigeria could achieve LCoH between 3.5-4.7 €/kg.

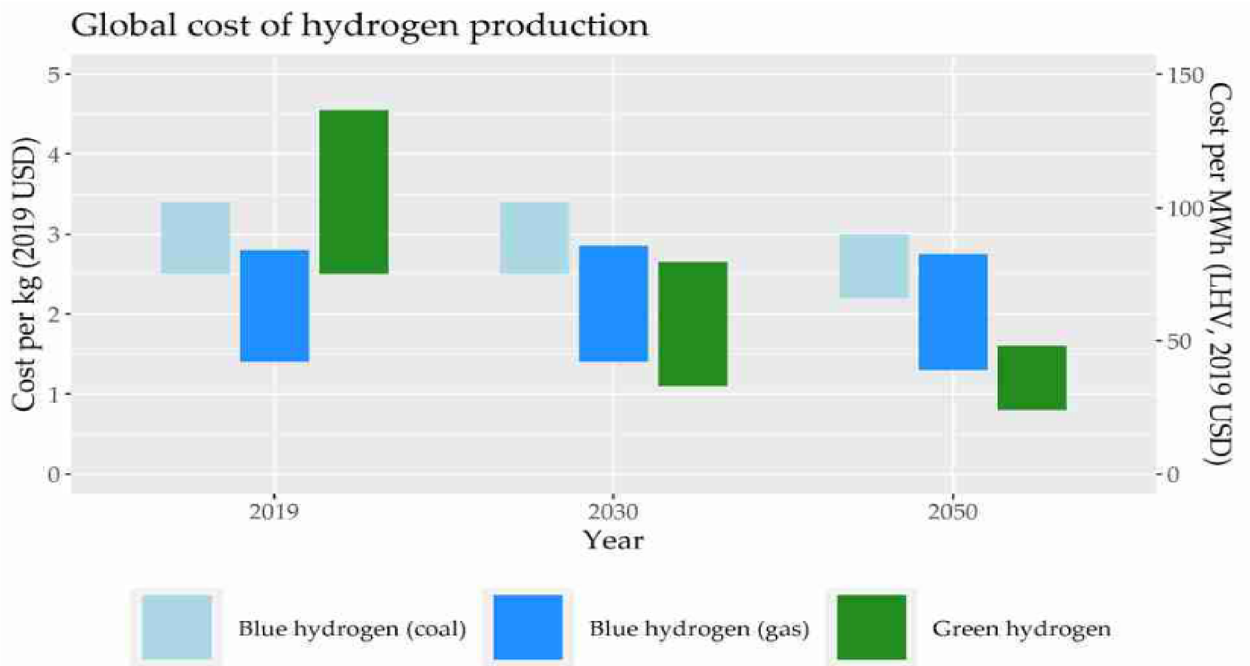

Figure 55: Predicted development of H_2 costs for different pathways, [147]

5.9.6 Feedstock

Blue H_2 production is based on natural gas or coal, with natural gas being the focus of this report [132, 151]. These fossil resources are not available in infinite quantities. Furthermore, the feedstock price is subject to fluctuation, influencing the economics of H_2 production [151]. Green production just requires water and electricity. The aspect of water consumption was already covered. Renewables-based electricity is produced from resources that cannot be depleted and is only limited by space requirements and the quality of renewable resources. A dependence on fossil fuel prices does not exist.

5.9.7 Gas distribution infrastructure requirements

In the case of green H_2, only a H_2 infrastructure is needed. As green production can be carried out in a decentralised way, the size of the required distribution network can be minimized, but a more developed distribution network could lead to lower storage capacities and lower supply costs. Blue production requires a natural gas infrastructure from the gas fields to the reforming plants and a H_2 infrastructure from the reforming plants to the end users. As the natural gas fields are mainly located in the southern part of the country, a nationwide H_2 distribution network would be required to supply the whole country based on blue H_2. If the hydrogen should be exported, this is not as relevant due to the ports being located in the southern part as well. In addition to the hydrogen distribution, a CO_2 infrastructure is needed for the transportation of captured CO_2 from the plant to the storage site [147]. Therefore, green production is favourable regarding the needed gas transport infrastructure, especially for the supply of the northern part of Nigeria.

5.9.8 CO_2 storage

Green production does not require CO_2 storage. In the case of blue production, on the other hand, the CO_2 needs to be stored after the capturing process. Currently, geological storage is not a state-of-the-art technology and long-term storage is immature on a commercial scale [149, 153]. In addition, further research would be needed to identify if and where possible storage locations are located in the country.

5.9.9 Technological readiness level

Blue H_2 production based on SMR equipped with CCS currently reaches a TRL of 8. While the existing experience in the field of natural gas-based H_2 production is an advantage of blue production, the long-term storage of CO_2 is still not state-of-the-art [147]. ATR without CCS reaches a TRL in the range of 7-9, while PO achieves a higher maturity and has a TRL of 9 [141]. PO-based blue H_2 production has a TRL of 7 [141]. Electrolysis-based H_2 production has a TRL of 9 in the case of the low-temperature electrolysers, while high-temperature electrolysis reaches a TRL of 5-6 [148].

6. Conclusions and recommendations

A roundup of the main areas covered and issues explored can concluded from both the supply, demand, the sources of hydrogen, cost perspectives and capacity building support.

6.1 Supply side

Nigeria has good prerequisites for the low-cost production of “green” hydrogen; this is true, in particular, for the sun-rich northern part of the country. In 2030 hydrogen production costs in the range of 3.5 € per kg are realistic, taking into account the current forecasts for investment costs (e.g. PV modules and electrolyzers). In principle, the site-specific costs for hydrogen production continuously increase the further south the site is located. However, there are also regions in central Nigeria where hydrogen production is possible at less than 4 € per kg (e.g. in Plateau, Taraba, Adamawa). Based on the results of the modeling performed in this study, cost-minimized hydrogen production in Nigeria involves oversizing renewable electricity generation capacity by a factor of 2.2 - 3.2. Only PV is used to supply electricity to the electrolyzer.

In order to enable large-scale “green” hydrogen/PtX production in Nigeria, a favorable environment must be created. This includes for example investment security, a clear and solid legal framework, and sufficient transport infrastructure. As an initial step on the way to large-scale hydrogen/PtX production, demonstration projects are essential. In order to prepare and accompany successful demonstration projects, feasibility studies should be carried out. In these feasibility studies, the findings of this study should be specified for a concrete, previously defined framework. In addition, feasibility studies should tackle remaining issues regarding the specific project realization.

In particular, the construction of PV systems to generate the necessary electricity for hydrogen/PtX production requires a considerable amount of space. Suitable land needs to be identified. Here, the surface analysis carried out in this study can be an initial indication, but must be expanded by further factors (e.g. land ownership, access to transport infrastructure, safety within the region).

For the supply of the water required for hydrogen production, a pipeline transport of desalinated seawater was assumed in this study. While such a solution can be part of a minimum-cost configuration for large-scale hydrogen production, alternative water supply concepts will most likely have to be developed for the first demonstration projects. Special care must be taken to ensure that natural freshwater resources are not exploited in an unsustainable manner.

6.2 Demand side

The planning of concrete projects for the production of hydrogen must always include the utilization of the generated hydrogen. In all likelihood, an export is only feasible at a later stage when larger volumes are produced. Therefore, for initial demonstration projects, it must be examined in which concrete applications in the economy can "green" hydrogen be used.

Across the main economic sectors (agriculture, buildings, power, transport, industry etc), priorities appear to be where hydrogen is needed as a basic material, e.g. ammonia synthesis, and in applications where hydrogen is the best option for decarbonisation, such as parts of the transport sector. Energy demand is expected to rise significantly over the next decades and the transport sector will become a sector with the highest energy requirements and CO_2 emissions by 2030 and should therefore become the prioritized field for the introduction of more efficient and/or sustainable technologies and fuels. Hydrogen can be a promising option for the decarbonisation of heavy-duty vehicles such as trucks and buses, taxi fleets, certain train lines and forklifts.

The industrial sector is currently inadequately developed and the status of the sector limits the hydrogen potential, however, promising applications for green hydrogen are in the supply of ammonia for fertilizer production and oil refining. The ammonia industry could become an important market for green hydrogen, as the country already hosts a significant production capacity and expected population growth could lead to further increases in fertiliser demand and with a concomitant production expansion. Using green hydrogen in these prioritized applications could lead to CO_2 emission savings of up to 155,000 $ktCO_2/a$. The emission savings are related to the transport and industry sectors, which are two of the five key sectors identified in the ETP [85]. Using green hydrogen can therefore contribute to the goals of the ETP, and if hydrogen is used in the prioritized applications, the infrastructure and experience regarding hydrogen usage could lead to the exploitation of other applications, leading to a higher hydrogen demand and higher emission reduction potentials.

When realizing projects for hydrogen/PtX production, attention should be paid to incorporating the needs of local people and generating benefits for them at an early stage. For example, plants for regenerative power generation or water treatment could be planned to supply both the hydrogen production plant and local communities. Concepts that allow the public to participate directly in the revenues from hydrogen/PtX production should also be examined.

6.3 Sources

All production processes of hydrogen produce GHG emissions except for green hydrogen. Producing blue hydrogen produces emissions originating mainly from the supply of natural gas. In addition, not all of the CO_2 generated during the synthesis gas generation production can be captured, and other substances that are harmful to the environment are also emitted eg methane leaks and purposeful emissions, e.g. venting [136], and also, regarding the need for water, blue hydrogen has a larger water footprint which is an important point where water availability is an issue. However, the country possesses significant natural gas resources and therefore potentially access to cheap natural gas.

6.4 Costs

Based on the methodology applied in this study, the minimum “green” hydrogen production cost in Nigeria are expected to be 10 to 20 % higher compared to top international competitors like Mauretania, Saudi Arabia or Algeria. Other works come to similar results [154, 155]. For a possible export of “green” energy, Nigeria should therefore focus on PtX products respectively hydrogen derivatives, whose supply costs are greatly influenced not only by hydrogen production costs, but also by other country-specific factors.

In all likelihood, an international market for "green" hydrocarbons will emerge in the coming decades. Important examples of "green" hydrocarbons with growing demand are PtL fuels, which are indispensable for climate-neutral long-haul shipping and aviation, and methanol, which is needed for a fossil-free chemical industry. For competitive production of such "green" hydrocarbons, the supply of renewable, low-cost carbon is essential. Sustainable biomass can be an economic carbon source, hence Nigeria's good biomass availability is a potential advantage over other regions for the production of "green" hydrocarbons. It is therefore recommended that the future development of Nigeria as an exporter of "green" PtX products should focus on "green" hydrocarbons. To this end, future actions should involve developing concepts for accessing sustainable biomass as a carbon source for the production of "green" hydrocarbons. Holistic concepts should be developed that, in addition to carbon supply for PtX production, also include the efficient use of biomass, for example as an energy source to meet the domestic demand.

The cost of producing “blue” hydrogen based on Nigerian natural gas reserves is projected to be around 3 €/kg, taking into account data from current literature. However, natural gas-based hydrogen production with high carbon capture rates as well as safe underground CO_2 storage have not yet been realized on a large scale. The technical challenges result in great uncertainties for the production of "blue" hydrogen, both in terms of medium-term realisation and the expected production costs. Therefore, before concrete plans can be made for the production of "blue" hydrogen in Nigeria, the development of the necessary technologies in international projects (currently being pursued primarily in Norway, Australia and Great Britain) must be observed. Furthermore, the general availability of suitable deposits for CO_2 storage in Nigeria must be ensured.

6.5 Capacity building support

The realization of competitive hydrogen and PtX production, the integration of hydrogen into the national energy system and the establishment of supply chains that enable the export of PtX products are highly complex tasks. To successfully accomplish these tasks and ensure that the Nigerian economy and population benefit sustainably from the development of a hydrogen/PtX economy, a large number of highly qualified people are needed. Accordingly, a focus should be placed on the successful implementation of capacity-building measures in the coming years.

7. Annex 1: RE and Green Hydrogen production and cost assumptions and data

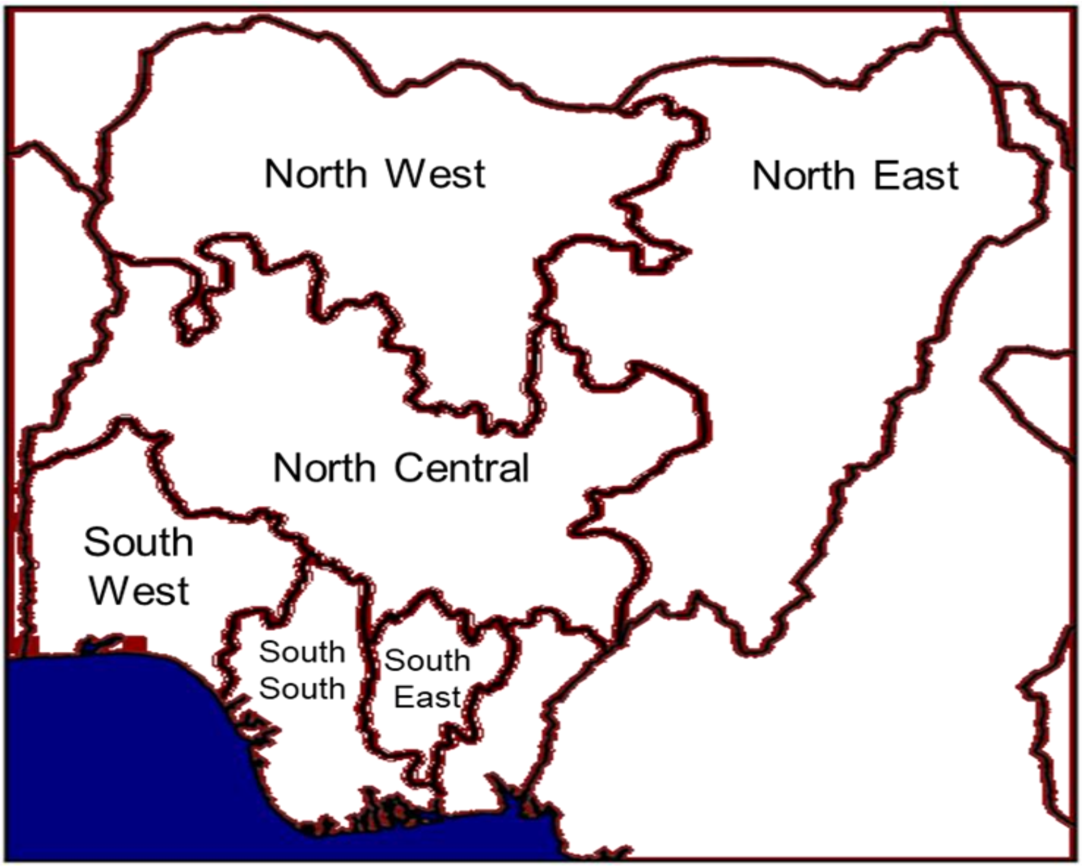

Figure 56: Geopolitical zones

Table 18: Techno-economic parameter of photovoltaic system [1–17]

Parameter	Unit	2030
Depreciation period	a	30
CAPEX	$€_{2020}$/kW	374
Cover glass losses	%	10
Degradation losses	%	5
Surface demand	m^2/kW	62
Line losses	%	2
Mismatch losses	%	0,8
OPEX	$\%_{CAPEX}$/a	2,7
Self-shadowing losses	%	2
Standard test efficiency	%	21,7
Transformation losses	%	0,9
Availability	%	100
Pollution losses	%	3,5

Table 19: Techno-economic parameters of the onshore wind power plant [6–9, 11, 13–15, 17–24]

Parameter	Unit	2030
Shadowing losses	%	92
Depreciation period	a	25
CAPEX	$€_{2020}$/kW	1.088
Space requirement	m^2/kW	170
OPEX	$\%_{CAPEX}$/a	2,4
Parking efficiency [a]	%	96
Parking efficiency	m	110
Availability [b]	%	96

a. Includes transmission line losses, degradation effects and losses due to icing;
b. Includes forced and planned downtime

Table 20: Techno-economic parameters of the offshore wind power plant [6–9, 11, 13–15, 17–24]

Parameter	Unit	2030
Shadowing losses	%	94
Depreciation period	a	25
CAPEX (ground mounted) [a]	€$_{2020}$/kW	1.822
CAPEX (floating) [b]	€$_{2020}$/kW	2.691
Space requirement	m^2/kW	178
OPEX	%$_{CAPEX}$/a	2,4
Parking efficiency [c]	%	96
Parking efficiency	m	150
Availability [d]	%	95

a. up to 50 m sea depth

b. from more than 50 m sea depth

c. Includes transmission line losses, degradation effects and losses due to icing;

d. Includes forced and planned downtime

Table 21: Techno-economic parameters of the electrolyzer [6, 22, 25–46]

Parameter	Unit	2030
Depreciation period	a	20
CAPEX	€$_{2020}$/kW$_{el}$	743
Efficiency	kWh$_{H2,lhv}$/kWh$_{el,in}$	0,68
OPEX	%$_{CAPEX}$/a	3,5
Water demand	kg$_{H2O}$/kg$_{H2}$	10
Water costs [a]	€$_{2020}$/m$^3_{H2O}$	2,6
Operating pressure	bar	50

a. based on water desalination by reverse osmosis, neglecting water transport costs

Table 22: Techno-economic parameters of the hydrogen compressor [6, 47–54]

Parameter	Unit	2030

Depreciation period	a	15
CAPEX	€$_{2020}$/(kg$_{H2}$/h)	1.780
Efficiency [a]	kWh$_{ideal}$/kWh$_{real}$	0,79
OPEX	%$_{CAPEX}$/a	5
Outlet pressure	bar	150
Hydrogen losses	kg$_{H2,loss}$/kg$_{H2}$	0,005

a. Energy demand of real compression in relation to isothermal compression

Table 23: Techno-economic parameters of the energy storage options available in the model [6, 16, 40, 46, 51, 52, 54–63]

Parameter	Unit	2030
Lithium ion battery		
Depreciation period	a	15
CAPEX	€$_{2020}$/kWh	153
Efficiency a	kWh$_{in}$/kWh$_{out}$	0,87
OPEX	%$_{CAPEX}$/a	3
Pressurized storage (hydrogen)		
Depreciation period	a	30
CAPEX	€$_{2020}$/(kg$_{H2}$)	462
Average storage pressure	bar	100
Maximum storage pressure	bar	200
OPEX	%$_{von\ CAPEX}$/a	2
Hydrogen losses	kg$_{H2,loss}$/kg$_{H2}$	0
Salt cavern storage (hydrogen)		
Depreciation period	a	30
CAPEX	€$_{2020}$/(kg$_{H2}$)	46
Average storage pressure	bar	100
Maximum storage pressure	bar	200

OPEX	$\%_{CAPEX}/a$	2
Hydrogen losses	$kg_{H2,loss}/kg_{H2}$	0

8. Annex 2: International competitiveness assumptions and data

Table 24: Techno-economic parameter of conditioning processes

	Unit	SNG (Methani-sation)	LH_2 (Lique-faction)	CH_3OH (Methanol-synthesis)	NH_3 (Haber-Bosch)	LOHC (Hydroge-nation)
Reference size	t_{H2}/d	500	500	500	500	500
CAPEX	M€	300 [15–17]	672 [18–20]	137 [21–23]	428 [24, 25]	67 [18, 26]
OPEX	$\%_{CAPEX}/a$	4 [17, 21]	4 [18, 27]	4 [21, 28]	4 [25]	4 [29]
Depreciation period	a	20 [15, 30]	30 [27]	20 [15]	20 [15]	20 [15]
Electricity demand	$kWh_{el}/kg_{Derivat}$	0.08 [22]	7.40 [27]	3.69 [22, 28]	0.312 [15, 31, 32]	0.24 [28, 33]
Waste heat	$kWh_{th}/kg_{Derivat}$	-1.97 [34]	–	-0.28 [22, 28]	-1.12 [31]	-9.90 [28, 33]
H_2 demand	$kg_{H2}/kg_{Derivat}$	0.505 [15, 34]	1	0.12 [35]	0.176 [31]	1
Additional H_2 loss	%	0	1.65 [27]	0 [35]	0	0.55 [28, 33]
N_2 demand	kg_{N2}/kg_{NH3}	–	–	–	0.824 [31]	–
CO_2 demand	kg_{CO2}/kg_{SNG}	2.750 [15, 34]	–	7.333 [35]	–	–
Energy demand N_2 supply	kWh_{el}/kg_{N2}	–	–	–	0.108 [24]	–
Energy demand CO_2 supply (DAC)	kWh_{el}/kg_{CO2}	0,225 [15, 36]	–	0.225 [15, 36]	–	–
	kWh_{th}/kg_{CO2}	1.5 [15, 36]	–	1.5 [15, 36]	–	–

Table 25: Techno-economic parameter SNG-Liquefaction

	Unit	SNG-Liquefaction
Reference size	t_{H2}/d	500
CAPEX	M€	87 [3, 22, 37]
OPEX	$\%_{CAPEX}/a$	4 [38]
Depreciation period	a	25 [38]
Losses	%	0.1 [39]
Electricity demand	$kWh_{el}/kg_{Derivat}$	0.56 [4, 37, 38]

Table 26: Techno-economic parameter storage

	Unit	SNG	LH_2	CH_3OH	NH_3	LOHC
CAPEX	M€	4.4 [37, 40]	33 [33]	0.5 [33, 41]	2.2 [16, 42]	20 [33, 41]
OPEX	$\%_{CAPEX}/a$	2 [40]	3 [18, 41]	2 [33]	2 [16]	2 [33]
Depreciation period	a	30	30 [33]	30 [33]	30	30 [33]
Losses	%	0.5 [43]	0.07 [33]	0	0.03 [16]	0

Table 27: Techno-economic parameter ship transportation

	Unit	SNG	LH_2	CH_3OH	NH_3	LOHC
Payload	t/ship	75,500 [3]	11,000 [41]	13,750 [41]	53,000 [41]	6,300 [41]
CAPEX	M€/ship	214 [15]	387	83 [41, 44]	79 [16, 41]	83 [41, 44]
OPEX	$\%_{CAPEX}/a$	4 [45]	4 [41]	4 [41]	4 [41]	4 [41]
Depreciation period	a	25 [45]	25 [44]	25 [44]	25 [44]	25 [44]
Fuel demand	kWh/km	0 [a]	0 [a] [41]	920	700 [41]	920 [41]
Boil-off losses	%/d	0.16 [45]	0.5 [46]	0	0.024	0 [41]
Average speed	km/h	30 [15]	33 [47]	30	30 [41]	30 [41]
Filling losses	%/load	–	1.3 [41]	–	–	–
De/Loading + Waiting Time	h/load	54 [44]	54 [44]	54 [44]	54 [44]	54 [44]
Utilization	h/a	8,000	8,000 [44]	8,000	8,000 [44]	8,000 [44]

[a] It is assumed that boil-off losses can be used as fuel.

Table 28: Techno-economic parameter hydrogen pipeline

	Unit	Hydrogen Pipeline
Reference size (diameter)	mm	500
CAPEX	M€/km	1.3 [48]
OPEX	$\%_{CAPEX}/a$	5 [48]
Depreciation period	a	40 [48]
Energy demand intermediate compression	$kWh_{el}/(kg_{H2}*km)$	0.0006 [48]
Losses	%/km	0 [48]

Table 29: Techno-economic parameter reconversion processes

	Unit	SNG (ATR)	LH_2 (Regasification)	CH_3OH (Methanol-cracking)	NH_3 (Ammonia-cracking)	LOHC (Dehydrogenation)
Reference size	t_{H2}/d	500	500	500	500	500
CAPEX	M€	604 [13, 16, 49, 50]	2 [18]	83 [28, 51–54]	250 [41, 55, 56]	58 [18, 26]
OPEX	$\%_{CAPEX}/a$	3 [13]	3 [18]	4 [28]	4 [41]	4 [29]
Depreciation period	a	20 [13]	10 [18]	20 [28]	20 [15]	20 [18, 29]
Electricity demand	$kWh_{el}/kg_{Derivat}$	2.133 [49, 57]	0.5 [33, 58]	4.20 [28]	3.38 [41, 59]	1.09 [33, 41, 59]
Heat demand	$kWh_{th}/kg_{Derivat}$	0	0	0 [a, b] [60–62]	2.1 [a] [41]	12.5 [15, 41, 59]
Derivate demand	$kg_{Derivat}/kg_{H2}$	3.0 [49, 50]	1	9.80 [c] [63]	7.08 [c] [64]	1.0204 [c] [33, 41]
O_2 demand	%	3.0 [49]	–	–	–	–
Electricity demand for O_2 supply	kg_{N2}/kg_{NH3}	0.29 [65, 66]	–	–	–	–
CO_2 capture rate	kg_{CO2}/kg_{SNG}	91 [13, 49, 50]	–	94	–	–
H_2 outlet pressure	bar	36 [49]	100 [58]	1	1 [55]	2 [33]

[a] Losses occurring during cracking can be used to provide part of the heat energy for cracking.

[b] The losses that occur anyway are sufficient to completely cover the heat energy demand.

[c] Includes losses incurred during NH_3 and CH_3OH cracking as well as LOHC dehydrogenation and downstream hydrogen purification.

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Impressum

Als Bundesunternehmen unterstützt die GIZ die deutsche Bundesregierung bei der Erreichung Ihrer Ziele in der internationalen Zusammenarbeit für nachhaltige Entwicklung.

Herausgeber:
Deutsche Gesellschaft für
Internationale Zusammenarbeit (GIZ) GmbH

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Autor/Verantwortlich/Redaktion etc.:
Name, Ort

Design/Layout etc.:
indigo Komunikationsdesign, Berlin

Fotonachweise/Quellen:
Fotograf/in, Bildagentur oder GIZ Mitarbeiter/in (GIZ/Name)

Die GIZ ist für den Inhalt der vorliegenden Präsentation verantwortlich.