Implemented by

Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH

The structures of the emerging international hydrogen trade

and their geopolitical implications

Imprint

Publisher	Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH Bonn and Eschborn, Germany Köthenerstr. 2-3 10963 Berlin Tel: +49 30 338424 186
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Date:	25.05.2023

On behalf of the Federal Foreign Office

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ATR	Autothermal Reactor
B2B	Business to Business
BMWK	Federal Ministry for Economic Affairs and Climate Action
BMZ	German Ministry for Economic Cooperation and Development
CAPEX	Capital Expenses
CBAM	Carbon Border Adjustment Mechanism
CCS	Carbon Capture and Storage
CCUS	Carbon capture and storage
CEF	Connecting Europe Facility
CF	Cohesion Fund
CfD	Contract for Difference
CIS	Commonwealth of Independent States
CO_2	Carbon Dioxide
CV	Calorific value
DAC	Direct Air Capture
DBT	Dibenzyltoluene
DFIs	Developing Financing Institutions
EOR	Enhanced Oil Recovery
ERDF	The European Regional Development Fund
EU ETS	EU Emission Trading System
EUAs	EU Allowances
FCEVs	Fuel-Cell Electric Vehicle
FID	Financial Investment Decision
GHG	Greenhouse Gas
H2	Hydrogen
H2Hubs	Regional Clean Hydrogen Hubs
IEEFA	Institute for Energy Economics and Financial Analysis
IIJA	Infrastructure Investment and Jobs Act
IPCEI	Important Projects of Common European Interest
IRA	Inflation Reduction Act
ITMOs	Internationally Transferred Mitigation Outcomes
JCM	Joint Crediting Mechanism
JKM	Japan Korean Marker
kWh	Kilowatt Hour
LCoE	Levelized Costs of Electricity
LHV	Lower Heating Value
LNG	Liquid Natural Gas
LOHC	Liquid Organic Hydrogen Carriers
MENA	Middle East and North Africa
N_2	Nitrogen
NBP	National Balance Point
NDC	Nationally Determined Contribution

NEC	N-ethylcarbazole
NIRs	National Inventory Reports
NYMEX	New York Mercantile Exchange
OPEX	Operating Expenses
PA	Paris Agreement
PEM	Proton Exchange Membrane
PRA	Price Reporting Agencies
PWh	Petawatt-hour
RFNBO	Renewable Liquid and Gaseous Fuels of non-Biological Origin
SCZone	Suez Canal Economic Zone
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolyser Cells
SPA	Sale and Purchase Agreement
TTF	Dutch Title Transfer Facility
UNFCCC	United Nations Framework Convention on Climate Change
WACC	Weighted Average Cost of Capital
WTI	West Texas Intermediate

Executive Summary

Executive Summary

The Paris Agreement has the ambitious long-term goal of limiting global warming to “well below” 2°C. But global greenhouse gas emissions are continuing to rise, and we have already exceeded 1°C of warming. Hydrogen produced with renewable electricity (‘green’ hydrogen) and its derivates, often summarized under the term “power to x” (PtX) and here subsumed under the term “hydrogen”, are expected to become key pillars for decarbonising hard-to-abate sectors and energy systems of fossil-fuel-dependent economies around the globe.

A global shift of energy demand away from oil, gas and coal towards green hydrogen will change global and regional energy markets and related geopolitical considerations. As major suppliers of fossil fuels may be replaced by “hydrogen superpowers” the balance of power among countries that are major energy producers could shift. On the one hand, new economic opportunities may emerge for countries with large renewable energy resources that have so far been unable to act as globally relevant energy suppliers due to a lack of fossil fuel resources, such as North African countries (Morocco, Tunisia, Egypt), and some countries in Sub-Saharan Africa as well as in Central- and South America. On the other hand, traditional oil and gas exporters, especially OPEC countries, must fear for their economic survival if they do not react in time. They favour and promote fossil fuel-based sources of hydrogen, in particular “blue” hydrogen; potentially with a vision to outcompete green hydrogen. From the point of view of energy importers, such as the EU and Germany, new options for making energy supply structures more sustainable and diversified arise.

This study intends to contribute to a better understanding of the possible structures of future international hydrogen trade. The aim is to identify and present the most likely scenarios of the design of the future global and regional hydrogen markets up to 2050 to enable market participants, regulators, and policymakers to assess the effects of different policy options on energy security, geopolitical implications, and sustainability.

Chapter 1

As of 2022, only 23 green hydrogen projects in the 5-30 MW scale have been operational. More and larger-scale green hydrogen projects are approaching FID but require a few more years to start production. Today, there is a limited market for grey hydrogen, but not yet a liquid market for green hydrogen. Project developers engage mainly in bilateral offtake contracts, with mostly undisclosed conditions. Key requirements for establishing hydrogen as a liquid commodity include: i) sufficient supply and demand, ii) standardisation of products and contracts, and iii) price transparency. The speed and depth of green hydrogen market development will depend on several factors, most importantly the availability of infrastructure (for production, transport and consumption), cost of production and transport, role and political preferences of different market players (government actors, large corporates, small private sector project developers), and policy instruments chosen to promote hydrogen market acceleration.

The historical development of energy markets – in particular oil and gas - shows that energy markets typically develop in a series of steps. Once technologies emerge that can utilize a new fuel, the creation of transport and distribution infrastructure becomes the key challenge. Often, governments have invested heavily and engaged in long-term contracts with suppliers (with fixed prices and quantities for several decades) to make new fuels widely available for private-sector consumption. Once the transport infrastructure is in place, standardisation becomes important to expand markets in geographical reach and liquidity. In the context of hydrogen, standardising benchmarks could develop related to its carbon content. With this in place and a sufficient number of producers, trade on exchanges and the development of derivatives such as futures and option contracts can evolve.

Based on these findings, we expect hydrogen trade to start with long-term contracts, initially emerging from local or regional “hydrogen valleys” driven by industry. Such hydrogen valleys allow cost reductions due to shared infrastructure. For the period until 2030, we expect long-term contracts (10-12 years) with fixed offtake conditions to dominate the market. There will be both government-to-government contracts (energy partnerships etc.) and private-sector contracts between energy suppliers and industry. Likely candidates are for hydrogen partnerships are EU-Africa (focus on green hydrogen), EU-Middle East (long-term: green; blue as transition), Japan-Middle East (long-term: green; blue as transition), Japan-Australia (focus on green), and – in the longer term – EU-Australia and Southern cone of South America-US (both with focus on green). Between 2030 and 2040, there will be significant progress towards standardisation and over-the-counter deals can be expected to steadily replace bilateral agreements. More players will be on the market and infrastructure/transport challenges lose importance, which together leads to more competition. A truly global hydrogen spot market will only materialize when/if significant oversupply emerges, and the supply chain components are converging to a worldwide standard.

Chapter 2

Until recently, blue hydrogen was considered significantly cheaper than green hydrogen. However, the increase of natural gas prices in 2022 due to the war in Ukraine makes this assumption at least questionable. Our calculations show that with 2022 prices, green hydrogen could already be the cheapest type of hydrogen in several world regions if production capacity was available. However, even under the conservative assumption that blue hydrogen is cheaper, it is important to consider the following:

1. Replacing fossil fuels with blue hydrogen will only lead to minor greenhouse gas benefits, because of low realistic CO_2 capture rates (50-90%) and additional energy requirements.
2. Green hydrogen production costs will mostly decline due to economies of scale, i.e., *if* there is a significant expansion of production capacities. Using blue hydrogen as an interim solution may hinder such investment.
3. Investment in *new* fossil-fuel-based hydrogen production has long lead- and lifetimes which would entail long-term lock-in effects that are not in line with the target of the Paris Agreement.

Despite those aspects, time-limited blue hydrogen deals between the EU and classical oil-/gas exporting countries (e.g., Middle East) may be an option to incentivise these countries to seriously embark in green hydrogen production. An essential pre-condition for such deals would be to define clear timelines (early 2030s) for a shift from blue to green hydrogen delivery.

Chapter 3

Our analysis shows that strict sustainability criteria can have significant effects on the global topography of hydrogen production. If a carbon threshold for embodied emissions is set at 3.4 $kgCO_2$-eq/kgH_2 (as defined by the EU), blue hydrogen would be ruled out in most cases. If water availability is defined as an additional criterion for sustainable hydrogen, several countries with low hydrogen production costs may not qualify any more. This applies to the Middle East and large parts of Africa. Rich countries in the Middle East could overcome such criteria by building large, renewable energy-driven water desalination capacities. This might not be an option for poorer countries e.g., in Africa.

Our analysis further concludes that certificate-based hydrogen trade (not physical hydrogen trade) would avoid the need to transport hydrogen over long distances and thus lower transportation costs and related technological challenges, as well as potential hydrogen leakage. However, there are several disadvantages: First of all, countries with a high green hydrogen production potential may not have sufficient application potential for hydrogen and the required infrastructure may be more difficult to finance than in existing industrial demand centres in the global north. In addition, it would not incentivise e.g. the EU industry to invest in and establish technological leadership.

Further, the international accounting rules for GHG emissions are of high importance regarding hydrogen trade. National Inventory Reports (NIRs) under the UNFCCC and the Paris Agreement apply the territory principle. They do not consider emissions related to the life cycle of a product or fuel. This means that the production of purely renewable hydrogen does not increase emissions of the producing country[1], but decreases emissions in the importing country – with the level of emission reductions depending on the fossil fuel(s) that is/are replaced. However, if grey, blue, or other forms of not 100% renewable hydrogen are produced, emissions in the producing country increase – putting at risk the country's national commitment to the Paris Agreement. In the importing country, emissions are reduced since the direct emission factor of hydrogen is zero regardless of the emission intensity of its production.

In cases where countries cooperate with a view to utilise (part of) the hydrogen in the producing country but allow the investing country to account for (part of) the emission reductions occurring in the producer country, Article 6 of the Paris Agreement can be applied.

Chapter 4

Recent studies suggest that the EU, Japan, and South Korea will become key importers of hydrogen, whereas Australia, the Middle East, North Africa, and South/Central America are commonly seen as major potential exporters – with varying market positions due to transport distances. China, India, and the US are expected to join the club of demand centres, but have the potential to become self-sustaining or even exporters depending on their political choices. In terms of hydrogen types, there already is an indication that the US and Japan are agnostic to colours, whereas the EU focuses on green hydrogen (but recently has opened the door for nuclear hydrogen). The Middle East has a clear preference for blue hydrogen, whereas export regions like Central/South America, North Africa and Australia have large resources for green hydrogen production.

[1] If also processing and transport are powered by renewable energies

Not all countries/regions will become similarly active due to varying investment capabilities and political preferences. For example, rich Gulf countries have the ability to invest both in blue and green hydrogen infrastructure (and benefit from existing energy infrastructures), whereas financial capacities in central/south America are limited, and even more so those in many African countries. In terms of transport distances, North Africa and the MENA region are well placed to serve Europe (MENA can serve East Asia as well). Australia, Southern Africa, and Latin America have high production potential but suffer from long transport distances and thus cost disadvantages.

What are the geopolitical implications? First, it needs to be acknowledged that the recent shift of geo-political attitudes from a cooperative, globalized world economy until the early 2010s to a more competitive, protectionist and fragmented one jeopardizes attempts to provide global public goods like mitigation of climate change. These conflicts could hamper the roll-out of hydrogen technologies, ranging from protectionism and market power for raw materials to conflicts about international trade routes. At the same time, hydrogen is a unique chance for energy importers to diversify their supply and minimize dependencies from a few dominant energy exporters. But this requires political dedication and significant investment. The following measures are recommended:

- **Establishment of strategic, long-term green hydrogen partnerships with selected countries**. This should include three key elements:
    - A dedicated government approach subsidizing green hydrogen infrastructure already in the very early stage. This includes support for scaled up electrolyser capacity, infrastructure for processing, transport, storage, and export.
    - 20-year supply contracts, building on the existing model of a green hydrogen partnership with Morocco. Similar partnerships could be envisaged with Argentina, Chile, Egypt, Mauritania, Namibia, Oman, Senegal, South Africa, Tunisia, and the UAE – all delivering green hydrogen.
    - A "prompt start" for hydrogen collaboration can be achieved by developing green hydrogen Art. 6 pilots, similar to what Japan has recently been pioneering in the context of the Japanese Crediting Mechanism (JCM).

- **Sustained political support and stable perspectives for green hydrogen demand in net-importer countries for at least the first decade of market environment volatility**. For the EU, this implies a coherent hydrogen import strategy with dedicated and financially strong instruments (Hydrogen Bank, H2Global). Further a political agreement on a clean hydrogen definition, as well as on industrial and trade policy priorities like CBAM is mandatory.

- **Consider partial openness for blue hydrogen for a limited, clearly defined time period.** It is clear that from an environmental point of view green hydrogen must be given absolute priority over blue hydrogen. At the same time, allowing blue hydrogen from *existing* oil/gas fields for a clearly defined time horizon can be a an approach to motivate Gulf countries to transition towards green hydrogen production. This could be done through long-term contracts defining total amounts of hydrogen to be delivered with shares of green hydrogen increasing over time. The exit year for blue hydrogen needs to be clearly defined. Contrary to this, blue hydrogen from new fields/operations should not be allowed due to long lead times and lock-in effects. Hence, blue hydrogen supply contracts could be negotiated but should be accompanied with a clear phase-out of blue hydrogen in the early 2030s.

- **Stable geopolitical environment and more cooperative international relations:** A global hydrogen market will only be possible within a cooperative world order**.** It is important for the EU to intensify regional cooperation schemes and to strengthen global governance institutions.

- In order to work against the prevailing protectionism, Germany should call for a **multilateral research collaboration** to advance key technological elements of the hydrogen supply chain.

Finally, it needs to be considered that one cannot expect a sudden change of global energy trade structure, but rather a gradual diversification along with a growing interaction of regional markets and more global trade relations toward 2050. Political dedication and willingness to make significant investments both domestically and in potential export countries over many years is a pre-condition for making a green hydrogen transformation a reality.

Zusammenfassung

Zusammenfassung

Das Pariser Klimaschutzabkommen hat das langfristige Ziel, die globale Erwärmung auf "deutlich unter" 2°C der vorindustriellen Temperaturen zu begrenzen. Die globalen Treibhausgasemissionen jedoch steigen weiter wodurch bereits mehr als 1°C Erwärmung überschritten wurden. Ein Hoffnungsschimmer ist der rasche Rückgang der Kosten für die Stromproduktion aus Solar- und Windenergie. Wasserstoff, der mit erneuerbarer Elektrizität produziert wird („grüner“ Wasserstoff) und seine Derivate, welche unter dem Begriff „Power to X“ (PtX) zusammengefasst und hier unter dem Begriff „Wasserstoff“ subsumiert werden, werden voraussichtlich zu zentralen Säulen für die Dekarbonisierung der schwer zu dekarbonisierenden (hard-to-abate) Sektoren fossiler Volkswirtschaften auf der ganzen Welt. Immer mehr Länder entwickeln grüne Wasserstoffstrategien.

Eine globale Verschiebung der Energienachfrage weg von Öl, Gas und Kohle hin zu grünem Wasserstoff wird die globalen und regionalen Energiemärkte und die damit zusammenhängende geopolitische Strukturen verändern. Da wichtige Lieferanten von fossilen Brennstoffen durch "Wasserstoff-Supermächte" ersetzt werden können, könnte sich das Kräfteverhältnis zwischen Ländern, speziell die großer Energieproduzenten, verschieben. Einerseits könnten sich neue, wirtschaftliche Chancen für Länder mit substanziellen erneuerbaren Ressourcen ergeben, die bisher aufgrund fehlender fossiler Ressourcen nicht als global relevante Energielieferanten agieren konnten. Hierzu zählen z.B. Nordafrikanische Länder (Marokko, Tunesien, Ägypten), einige Länder in Subsahara-Afrika, sowie Länder in Zentral- und Südamerika. Andererseits, müssen traditionelle Öl- und Gasexporteure, insbesondere OPEC-Länder, um ihr wirtschaftliches Überleben fürchten, wenn sie nicht rechtzeitig reagieren und auf nachhaltige Praktiken umsteigen. Einige bevorzugen und fördern momentan fossile Wasserstoffproduktionsrouten wie "blauen" Wasserstoff. Aus Sicht von Energieimporteuren wie der EU und Deutschland ergeben sich neue Möglichkeiten, ihre Energieversorgungsstrukturen nachhaltiger und diversifizierter zu gestalten.

Diese Studie soll dazu beitragen, ein besseres Verständnis für die möglichen Strukturen des zukünftigen internationalen Wasserstoffmarktes zu schaffen. Ziel ist es, die wahrscheinlichsten Szenarien für die Gestaltung der zukünftigen globalen und regionalen Wasserstoffmärkte bis 2050 zu identifizieren und darzustellen, um Marktteilnehmer, Regulierungsbehörden und politische Entscheidungsträger in die Lage zu versetzen, die Auswirkungen verschiedener Politikoptionen auf Energieversorgungssicherheit, geopolitische Implikationen und Nachhaltigkeit zu bewerten.

Kapitel 1

Im Jahr 2022 waren nur 23 grüne Wasserstoffprojekte mit Produktionskapazitäten von 5 bis 30 MW in Betrieb. Weitere grüne Wasserstoffprojekte mit größeren Kapazitäten stehen kurz vor der endgültigen Investitionsentscheidung, benötigen jedoch noch einige Jahre, um mit der Wasserstoffproduktion zu beginnen. Projektentwickler schließen heute hauptsächlich bilaterale Abnahmeverträge mit meist nicht veröffentlichen Bedingungen ab. Wesentliche Voraussetzungen um Wasserstoff als liquides Handelsgut zu etablieren sind: i) ausreichendes Angebot und Nachfrage, ii) Standardisierung von Produkten und Verträgen und iii) Preistransparenz. Die Geschwindigkeit der Entwicklung des Marktes für grünen Wasserstoff hängt von einer Reihe von Faktoren ab: der verfügbaren Infrastruktur (sowohl für Produktion als auch für Verbrauch), den Produktions- und Transportkosten, der Rolle und den politischen Präferenzen unterschiedlicher Marktteilnehmer (Regierungsakteure, große Unternehmen, kleine private Projektentwickler) und den von den wichtigsten Nachfragezentren gewählten politischen Instrumenten zur Beschleunigung des Wasserstoff ramp-ups. Regional unterschiedliche Wasserstoffproduktionskosten und verfügbare Transportoptionen (z.B. Pipelines versus Schifffahrt) werden einen erheblichen Einfluss auf die Entwicklung regionaler und internationaler Handelspartnerschaften haben.

Die historische Entwicklung von Energiemärkten - insbesondere von Öl und Gas - zeigt, dass sich Energiemärkte typischerweise in mehreren Schritten entwickeln. Sobald Technologien entstehen, mit welchen ein neuer Brennstoff genutzt werden kann, wird die Schaffung von Transport- und Verteilungsinfrastruktur zur Hauptaufgabe. Historisch haben Regierungen große Investitionen getätigt und langfristige Verträge mit Lieferanten geschlossen (feste Preise und Mengen über mehrere Jahrzehnte), um neue Brennstoffe für die Privatwirtschaft zur Verfügung zu stellen. Sobald die Transportinfrastruktur etabliert ist, wird die Standardisierung wichtig, um Märkte geografisch zu erweitern und die Liquidität zu steigern. Im Zusammenhang mit Wasserstoff könnten sich Benchmark-Standards im Zusammenhang mit dessen Kohlenstoffgehalt entwickeln. Mit dieser Grundlage und einer ausreichenden Anzahl von Produzenten kann der Handel an Börsen stattfinden und die Entwicklung von Derivaten wie Terminkontrakten und Optionsverträgen voranschreiten.

Basierend auf diesen Erkenntnissen erwarten wir, dass der Handel mit Wasserstoff mit langfristigen Verträgen beginnt, die zunächst aus lokalen oder regionalen "Hydrogen Valleys" entstehen. Solche Hydrogen Valleys ermöglichen Kosteneinsparungen durch gemeinsam genutzte Infrastruktur. Für den Zeitraum bis 2030 erwarten wir, dass langfristige Verträge (10-12 Jahre) mit festen Abnahmekonditionen den Markt dominieren werden. In diesem Zeitraum wird es sowohl öffentliche Verträge (z.B. Energiepartnerschaften zwischen Staaten) als auch private Verträge zwischen Energieversorgern und Industrie geben. Wahrscheinliche Kandidaten für Wasserstoffpartnerschaften sind EU-Afrika (Fokus auf grünem Wasserstoff), EU-Naher Osten (langfristig: grün; blau als Übergang), Japan-Naher Osten (langfristig: grün; blau als Übergang), Japan-Australien (Fokus auf grün) und - langfristig - EU-Australien und der südliche Teil des südamerikanischen Kontinents-USA (beide mit Fokus auf grünem Wasserstoff). Zwischen 2030 und 2040 wird es signifikante Fortschritte in Richtung Standardisierung geben, und es ist zu erwarten, dass außerbörsliche Geschäfte allmählich bilaterale Vereinbarungen ersetzen. Mehr Marktteilnehmer werden in den Markt einsteigen und Infrastruktur-/Transportprobleme werden an Bedeutung verlieren, was wiederum zu mehr Wettbewerb führt. Ein wirklich globaler Wasserstoff-Spotmarkt wird erst dann entstehen, wenn ein signifikantes Überangebot entsteht und die Transportketten global standardisiert werden.

Kapitel 2

Bis 2022 wurde angenommen, dass blauer Wasserstoff wesentlich kostengünstiger produziert werden kann als grüner Wasserstoff. Allerdings machten die steigenden Erdgaspreise im Jahr 2022, aufgrund des Krieges in der Ukraine, diese Annahme zumindest fraglich. Unsere Berechnungen zeigen, dass mit Preisen von 2022 grüner Wasserstoff bereits in mehreren Weltregionen die kostengünstigste Art der Wasserstoffproduktion sein könnte. Jedoch selbst unter der konservativen Annahme, dass blauer Wasserstoff günstiger ist, ist es wichtig, die folgenden Punkte zu berücksichtigen:

1. Die Substitution fossiler Brennstoffe durch blauen Wasserstoff führt nur zu geringfügigen Vorteilen in Bezug auf Treibhausgasemissionen, aufgrund geringer realistischer CO_2-Abscheideraten (50-90%) und des zusätzlichen Energiebedarfs.
2. Die Produktionskosten für grünen Wasserstoff werden größtenteils aufgrund von Skaleneffekten sinken, d.h. wenn es zu einer signifikanten Ausweitung der Produktionskapazitäten kommt. Die Verwendung von blauem Wasserstoff als Übergangslösung kann solche Investitionen behindern.
3. Investitionen in neue, auf fossilen Brennstoffen basierende Wasserstoffproduktionskapazitäten haben lange Vorlauf- und Lebenszeiten, was zu langfristigen lock-in Effekten führen kann. Diese würden die Erreichung des Ziels des Pariser Klimaabkommens stark erschweren.

Trotz dieser Aspekte könnten zeitlich begrenzte Deals für blauen Wasserstoff zwischen der EU und klassischen Öl- und Gasexportländern (z. B. dem Nahen Osten) eine Option sein, um diese Länder zur ernsthaften Beteiligung an der Produktion von grünem Wasserstoff zu motivieren. Eine wesentliche Voraussetzung für solche Vereinbarungen wäre die Festlegung klarer Zeitpläne (frühe 2030er Jahre) für den Übergang von blauem zu grünem Wasserstoff.

Kapitel 3

Unsere Analyse zeigt, dass strenge Nachhaltigkeitskriterien erhebliche Auswirkungen auf die weltweite Topografie der Wasserstoffproduktion haben können. Mit einem maximalen CO_2-Richtwert für Vorkettenemissionen von 3,4 kgCO2-eq/kgH2 (wie von der EU definiert), würde sich blauer Wasserstoff in vielen Fällen nicht mehr zur Zertifizierung qualifizieren. Wenn zusätzlich die Wasserverfügbarkeit als Kriterium für nachhaltigen Wasserstoff definiert wird, könnten sich mehrere Länder mit niedrigen Wasserstoffproduktionskosten nicht mehr qualifizieren. Dies gilt für den Nahen Osten und große Teile Afrikas. Wohlhabende Länder im Nahen Osten könnten diesen Kriterien durch den Bau großer, durch erneuerbare Energien betriebene, Entsalzungsanlagen gerecht werden. Diese Option steht ärmeren Ländern jedoch meist nicht zur Verfügung.

Zusätzlich wird gezeigt, dass der zertifikatbasierte Wasserstoffhandel (nicht der physische Wasserstoffhandel) den Transport von Wasserstoff über weite Strecken vermeiden würde und somit die Transportkosten und damit verbundene technologische Herausforderungen sowie potenzielle Wasserstoffleckagen reduzieren würde. Es bestehen jedoch mehrere Nachteile: Zum einen könnten Länder mit einem hohen Potenzial für die Produktion von grünem Wasserstoff möglicherweise nicht über ausreichende Anwendungsmöglichkeiten für Wasserstoff verfügen, und der erforderliche Infrastrukturaufbau könnte schwieriger zu finanzieren sein als in bestehenden industriellen Nachfragezentren im globalen Norden. Zusätzlich würden dementsprechend keine Anreize für die Industrie in der EU entstehen eigene Investitionen in Wasserstoffanwendungen zu tätigen und eine technologische Führungsposition einzunehmen.

Weiterhin sind internationale Rechnungslegungsregeln für Treibhausgasemissionen im Zusammenhang mit dem Wasserstoffhandel von großer Bedeutung. Nationale Inventarberichte (NIRs) gemäß der UNFCCC und dem Pariser Abkommen basieren auf dem Territorialprinzip. Sie berücksichtigen keine Emissionen, die mit dem Lebenszyklus eines Produkts oder Kraftstoffs zusammenhängen. Dies bedeutet, dass die Produktion von erneuerbarem Wasserstoff die Emissionen des produzierenden Landes nicht erhöht, sondern die Emissionen im Importland verringert – wobei die Höhe der Emissionsreduktionen von den ersetzten fossilen Brennstoffen abhängt. Wenn jedoch grauer, blauer oder andere Formen von nicht zu 100% erneuerbarem Wasserstoff produziert werden, steigen die Emissionen im produzierenden Land, und gefährden das nationale Engagement des Landes im Rahmen des Pariser Abkommens. Im Importland werden die Emissionen reduziert, da der direkte Emissionsfaktor von Wasserstoff unabhängig von der Emissionsintensität seiner Produktion null ist.

In Fällen internationaler Kooperation, in denen Teile des Wasserstoffs im Produktionsland verwendet werden, aber dem investierenden Land erlaubt wird, einen Teil der entstehenden Emissionsminderungen im Produktionsland im eigenen NIR zu verbuchen, kann Artikel 6 des Pariser Abkommens angewendet werden.

Kapitel 4

Aktuelle Studien zeigen, dass die EU, Japan und Südkorea zu wichtigen Importeuren von Wasserstoff werden, während Australien, der Nahe Osten, Nordafrika und Süd-/Mittelamerika allgemein als potenzielle Exportländer angesehen werden – mit unterschiedlichen Marktpositionen aufgrund der Transportentfernungen. China, Indien und die USA werden sich dem Kreis der Nachfragezentren anschließen, haben jedoch das Potenzial, abhängig von politischen Entscheidungen, autark oder sogar Exporteure zu werden. In Bezug auf die Wasserstoffarten gibt es bereits Hinweise darauf, dass die USA und Japan farbagnostisch sind, während sich die EU auf grünen Wasserstoff konzentriert (jüngst jedoch auch die Tür für nuklearen Wasserstoff geöffnet hat). Der Nahe Osten präferiert klar blauen Wasserstoff, während Exportregionen wie Zentral-/Südamerika, Nordafrika und Australien über große Ressourcen für die Produktion von grünem Wasserstoff verfügen.

Nicht alle Länder/Regionen werden, aufgrund unterschiedlicher Investitionsmöglichkeiten und politischer Präferenzen, in gleicher Weise aktiv werden. Zum Beispiel haben reiche Golfstaaten die Möglichkeit, sowohl in die Infrastruktur für blauen als auch für grünen Wasserstoff zu investieren (und von bestehenden Energieinfrastrukturen zu profitieren), während die finanziellen Kapazitäten in Zentral-/Südamerika sowie in vielen afrikanischen Ländern begrenzt sind. In Bezug auf Transportentfernungen ist die MENA-Region gut positioniert, um Europa zu versorgen (MENA kann auch Ostasien versorgen). Australien, Südafrika und Lateinamerika haben ein hohes Produktionspotenzial, leiden jedoch unter langen Transportentfernungen und damit verbundenen Kostennachteilen.

Welche geopolitischen Implikationen folgen daraus? Zunächst muss festgehalten werden, dass der jüngste Wandel der geopolitischen Einstellungen von einer kooperativen, globalisierten Weltwirtschaft bis in die frühen 2010er Jahre hin zu einer kompetitiven, protektionistischen und fragmentierten Welt den Versuch gefährdet, globale Ziele wie z.B. die Abschwächung des Klimawandels zu erreichen. Diese Konflikte könnten die Einführung von Wasserstofftechnologien behindern. Sie umfassen Protektionismus und Marktmacht hinsichtlich kritischer Rohstoffe bis hin zu Konflikten über internationale Handelsrouten.

Gleichzeitig bietet Wasserstoff den Energieimportländern eine einzigartige Chance, ihre Versorgung zu diversifizieren und ihre Abhängigkeit von wenigen dominanten Energieexporteuren zu minimieren. Dies erfordert jedoch politisches Engagement und erhebliche Investitionen. Es werden folgende Maßnahmen empfohlen:

- **Aufbau strategischer langfristiger grüner Wasserstoffpartnerschaften mit ausgewählten Ländern.** Dies sollte drei wesentliche Elemente umfassen:
  - Eine spezielle Regierungsstrategie zur Subventionierung der grünen Wasserstoffinfrastruktur bereits in einem sehr frühen Stadium. Dies umfasst die Unterstützung einer hochskalierten Elektrolyseurkapazität sowie die Infrastruktur für Verarbeitung, Transport, Lagerung und Export.
  - 20-jährige Lieferverträge, die auf dem bestehenden Modell einer grünen Wasserstoffpartnerschaft mit Marokko aufbauen. Ähnliche Partnerschaften könnten mit Argentinien, Chile, Ägypten, Mauretanien, Namibia, Oman, Senegal, Südafrika, Tunesien und den VAE in Betracht gezogen werden.
  - Ein "schneller Start" für die Wasserstoffkooperation kann durch die Entwicklung von grünen Wasserstoff-Artikel-6-Pilotprojekten erreicht werden, ähnlich wie Japan dies momentan im Rahmen des Japanischen Kreditmechanismus (JCM) vorantreibt.

- **Nachhaltige politische Unterstützung und stabile Perspektiven für die Nachfrage nach grünem Wasserstoff in netto-import Ländern für mindestens das erste Jahrzehnt des Markthochlaufes.** Für die EU bedeutet dies eine kohärente Wasserstoffimportstrategie mit dezidierten und finanziell starken Instrumenten (European Hydrogen Bank, H2Global). Des Weiteren ist eine politische Einigung über eine nachhaltige Wasserstoffdefinition sowie über industriepolitische und handelspolitische Prioritäten wie den CBAM erforderlich.

- **Teilweise Offenheit für blauen Wasserstoff für einen begrenzten, klar definierten Zeitraum in Betracht ziehen.** Aus umwelttechnischer Sicht muss grünem Wasserstoff absolute Priorität vor blauem Wasserstoff eingeräumt werden. Gleichzeitig kann die Produktion von blauem Wasserstoff aus bestehenden Öl-/Gasfeldern für einen klar definierten Zeitraum ein Ansatz sein, um Golfstaaten zu motivieren, den Übergang zur grünen Wasserstoffproduktion umzusetzen. Dies könnte durch langfristige Verträge erfolgen, die die Gesamtmenge des zu liefernden Wasserstoffs definieren, wobei der Anteil an grünem Wasserstoff im Laufe der Zeit steigt. Das Ausstiegsjahr für blauen Wasserstoff muss klar definiert sein. Im Gegensatz dazu sollte blauer Wasserstoff aus neuen Gasfeldern aufgrund der langen Vorlaufzeiten und Lock-in-Effekte nicht zugelassen werden. Daher könnten Lieferverträge für blauen Wasserstoff verhandelt werden, sollten aber mit einem klaren Ausstiegsszenario für blauen Wasserstoff bis Anfang der 2030er Jahre einhergehen.

- **Stabile geopolitische Umgebung und kooperativere internationale Beziehungen:** Ein globaler Wasserstoffmarkt wird nur in einer kooperativen Weltordnung möglich sein. Es ist wichtig, dass die EU regionale Kooperationsmaßnahmen intensiviert und globale Governance-Institutionen stärkt.

- Um dem vorherrschenden Protektionismus entgegenzuwirken, sollte sich Deutschland für eine multilaterale Forschungskooperation zur Weiterentwicklung wichtiger technologischer Elemente der Wasserstoff-Wertschöpfungskette einsetzen.

Abschließend muss berücksichtigt werden, dass man keinen plötzlichen Wandel des globalen Energiemarktes erwarten kann, sondern vielmehr eine schrittweise Diversifizierung zusammen mit einer wachsenden Interaktion regionaler Märkte und einer verstärkten globalen Handelsbeziehung bis 2050. Politisches Engagement und die Bereitschaft, über viele Jahre hinweg sowohl im Inland als auch in potenziellen Exportländern erhebliche Investitionen zu tätigen, sind eine wichtige Voraussetzung, um eine grüne Wasserstofftransformation zu realisieren.

00

Background

0. Background

Against the background of continuously high global emissions of greenhouse gases (GHG) and increasing pressure to act decisively in order to achieve international and national climate change mitigation objectives – in particular, the target to limit global warming to 1.5/2°C of the Paris Agreement under the United Nations Framework Convention on Climate Change (UNFCCC) -, so-called 'green' hydrogen and its derivatives are more and more becoming a beacon of hope.

The term "'green' hydrogen and its derivatives" refers to hydrogen-based fuels that are (predominantly) produced by using renewable electricity for water electrolysis and, if necessary, downstream processing for conversion into ammonia, methanol etc. (hereinafter: green power to fuel x, or "green PtX"). Green PtX can play a crucial role especially in sectors that cannot be decarbonized by direct electrification – such as many industrial processes (e.g., chemicals, steel, cement) or international transport.

If green PtX products become competitive with traditional fuels, particularly oil and gas, this has the potential to significantly impact geopolitics by transforming the global energy landscape and how countries generate and use energy. A breakthrough in green PtX would reduce the reliance on fossil fuels and increase the use of renewable energy. It would lead to a shift in the balance of power among countries that are major energy producers and would enhance the choices for countries that are consumers of energy. A transition of the global energy system away from fossil fuels such as gas, oil and coal towards green PtX could lead to a massive geopolitical shift. On the one hand, new economic opportunities may emerge for many countries that have so far been unable to act as globally relevant energy suppliers due to a lack of fossil fuel resources. Some of these countries could take a pole position in the production of green PtX due to the availability of renewable energy resources like high insolation and wind speed. On the other hand, traditional oil and gas exporters, especially OPEC countries, must fear for their economic survival if they do not react in time. They may try to step in with fossil fuel-based sources of hydrogen, in particular "blue" hydrogen applying carbon capture and storage (CCS) to grey hydrogen with a vision to outcompete green hydrogen. From the point of view of energy importers, such as the EU and Germany, new options for making energy supply structures more sustainable and diversified arise and could thus significantly reduce the vulnerability of such countries to disruptions in the supply of fossil fuels and increase energy security – which is a top political priority in view of the current Russia-Ukraine war.

Against this background, this study intends to contribute to a better understanding of the possible structures of future international hydrogen[2] trade to inform German and European hydrogen policy makers and stakeholders. It identifies and presents the most likely scenarios of the evolvement of the global hydrogen economy until 2050 to enable market participants, regulators and policymakers to assess different policy options, and to develop their positions, strategies and options for action accordingly.

[2] In the remainder of this study, the term "hydrogen" always encompasses PtX products. The specific terms will only be used when a specific differentiation is required.

Chapter 1 analyses the expected contractual and financial forms of hydrogen trading in the emerging international hydrogen market, starting from today's situation where there is a (limited) market for grey hydrogen, but not yet a liquid market for green hydrogen. It identifies relevant parameters influencing future market structures and summarises lessons that can be learned from the historical development of other energy markets, in particular oil and gas. Chapter 2 evaluates the relevance of different hydrogen production technologies – in particular "blue" and "green" hydrogen. Until recently, blue hydrogen has been assumed to come at significantly lower production costs than green hydrogen, but recent gas price increases are changing the picture. In addition, the climate benefits of blue and green hydrogen are compared, indicating that blue hydrogen only results in limited benefits in some use cases. Also, the relevance of lock-in effects is addressed. These are all important aspects that need to be considered when making decisions for or against certain hydrogen colours. Chapter 3 evaluates the positive or negative impacts resulting from different types of sustainability criteria on supply volumes and supplier topography. In addition, the pros and cons of hydrogen certificate trading compared to physical hydrogen trade are discussed qualitatively in terms of avoided transport cost/emissions, local use potential and investment requirements, as well as innovation push and technology leadership. In addition, the consequences of both physical and certificate-based hydrogen trading for international climate commitment of both exporting- and importing countries are evaluated. Chapter 4 summarises the expected global and regional hydrogen trade structures in the short, medium, and long-term and discusses the geoeconomic implications. A particular focus is on energy supply security and the roles of key supply and demand regions. In a final step, recommendations are derived for the EU and Germany on how to facilitate the global green hydrogen market acceleration and enhance energy supply security.

01

Analysis of expected contractual and financial forms of hydrogen trading in the emerging international hydrogen market

1. Analysis of the expected contractual and financial forms of hydrogen trading in the emerging international hydrogen market

There is a wide range of possible hydrogen market structures, ranging from short-term bilateral or intermediary-brokered contracts to exchange-based commodity trading. In addition, hydrogen trade agreements can be part of governmentally driven, political energy partnerships. Global hydrogen markets might show similar developments as fossil fuel markets in the past. However, there is one difference to fossil fuel markets: the value of the hydrogen product is not only defined by its physical properties but also by its environmental benefits that differ according to production and transport processes. Therefore, not only up- and midstream costs are relevant for hydrogen trade, but also the monetized climate change mitigation and other environmental benefits.

This chapter summarises today's contractual and financial forms of hydrogen trade, differentiated by grey and green hydrogen; then analyses key parameters influencing the expected forms of hydrogen trade, and then reviews the historical evolvement of oil, gas and coal markets. This information is used to derive an assessment of the likely contractual and financial forms of hydrogen trade.

1.1. Today's contractual and financial forms of hydrogen trading

Hydrogen can be produced by a variety of different processes, each of the associated with different feedstock, energy requirements and greenhouse gas emission (GHG) intensities. The color-coding is not internationally standardised[3] and provides highly simplified categories. In addition, the different processes have strongly varying technology readiness levels (TRLs), meaning that some of them are not yet available for large-scale hydrogen production. Box 1 summarises the most relevant hydrogen colours. The report will focus on green, blue, and grey hydrogen, as those are readily available for commercial use.

Looking at today's hydrogen markets, one needs to differentiate between "grey" hydrogen that is already produced at large-scale, and other colours of hydrogen which as of today are produced in globally marginal quantities only (see box below and a more detailed discussion in Annex).

[3] For example, the H2Bulletin defines 9 hydrogen colours (H2 Bulletin 2023), whereas the US national grid operator sees only 7 colours (National Grid 2023).

Box 1: Overview of the main “colours” of hydrogen

- **Grey hydrogen:** Grey hydrogen production refers to the traditional method of producing hydrogen from fossil fuels, such as natural gas, coal, or oil. This method is often called "grey" because it is associated with high carbon emissions and pollution, which can have negative environmental impacts.
- **Blue hydrogen**: Blue hydrogen production is a method that aims to mitigate the environmental impacts of grey hydrogen by capturing and permanently storing the CO_2 emissions produced during the production process.
- **Green hydrogen**: Green hydrogen production is a method that uses renewable energy sources to produce hydrogen through electrolysis of water.
- **Purple hydrogen**: Purple hydrogen production refers to using a combination of nuclear power and heat in chemo-thermal electrolysis of water.
- **Pink hydrogen**: Pink hydrogen production refers to the use of nuclear energy to produce hydrogen through electrolysis. This method is currently not widely used but constitutes a readily available technology that is even eligible in the EU RED framework.
- **Turquoise hydrogen**: Turquoise hydrogen refers to the thermal splitting of methane via methane pyrolysis. The side product carbon is obtained in solid form which eliminates the requirement of carbon capture from air. However, the technology is not

Most of the production of grey hydrogen today is captive and often a by-product of the production of another ‘core’ product. There are a few industrial complexes with some merchant production of grey hydrogen, and only a few end users usually dependent on a single supplier. As there is not a broad market but rather bilateral trading, no price indices comprehensively reflecting supply and demand patterns exist (IRENA 2022a). S&P Global Commodity insight is one of the few available price indexes for hydrogen, but it estimates the production costs (not trading prices) of hydrogen from Steam Methane Reforming (SMR), blue hydrogen for some regions and – where already available green hydrogen (S&P Global 2022) [4]. Another available price index for hydrogen is E-Bridge’s Hydex &HydexPlus (E-Bridge 2023). However, this tool is a spot price index that is based on the marginal cost of hydrogen production for grey, blue, and green hydrogen. It is important to note, the costs shown in this index do not consider capital, transport, and distribution costs, which have a high influence on total prices. (E-Bridge 2023).

Green hydrogen trading is still in its infancy. According to the hydrogen insights report by McKinsey (2023), more than 1000 green hydrogen projects (with a rated electrolyser capacity of at least 1MW) and a total investment volume of over USD 320bn through 2030 have been *announced* recently, but only projects worth USD 29bn have reached financial investment decision (FID) or are under construction or operational. Globally, only 23 green hydrogen projects are operational according to the latest IEA hydrogen project database (IEA 2022b). By far the biggest share of those projects is located in OECD-countries. Most of them are in the 5-30 MW electrolyser capacity scale. Projects currently in planning phase also aim for larger scales (100 MW+), but it will take some more years until they will be in operation. These numbers show that today the volumes produced globally are rather marginal. Also, the demand side for green hydrogen is still close to zero. No liquid market can develop if both the supply- and demand side are nearly non-existent.

[4] Partially includes blue hydrogen, depending on production hubs.

So as of today, green hydrogen producers and project developers have to search for and identify buyers on a case-by-case basis. Product requirements (e.g., maximum carbon intensity of production, approach for determining/verifying this) have to be defined in negotiations, and typically bilateral offtake agreements are negotiated. This causes high transaction costs and investor/operator uncertainty. Currently, there is only one publicly known case where a dedicated merchandising agent has been assigned with the marketing/sales of to-be-produced green ammonia – this is for the multi-GW project NEOM, backed by large corporates in Saudi Arabia (Air Products 2022).

Based on interviews with green hydrogen project developers[5], a study recently commissioned by H_2Global (Baez et. al. 2023) finds that the key challenges associated with planning, financing, and implementing hydrogen today are:

- Non-existence of price premiums for green hydrogen compared to conventional hydrogen (private sector demand side);
- Challenges to sign long-term offtake contracts - which are required not only to plan revenues of the investment, but which constitute a key success factor for securing financing both from private financial institutions / banks and from developing financing institutions (DFIs);
- Uncertainty about future prices and price premiums for green hydrogen.
- Lack of / insufficient scope of public support schemes; and
- Lack of uniform definition of “green” hydrogen, and uncertainty about buyers’ requirements (e.g., EU RED).

The lack of reliable off-takers willing to pay adequate prices has been mentioned as a particularly relevant market barrier.
On the positive side, governments in many world regions are introducing support schemes aiming to accelerate market development. The most prominent and already operational example is the pricing mechanism of the H_2Global foundation that applies a double-auctioning system to buy green hydrogen internationally (with a price premium compared to grey hydrogen) and sells it domestically at a competitive price. The price differential is backed by funds of the foundation financed by the German government. Funding source of the first H_2Global window is the German Federal Ministry for Economic Affairs and Climate Action (BMWK). Other funding bodies as the Dutch government may join (Hydrogen Economist 2022).

The H_2Global mechanism is designed to allow different funding windows. Aligned to the specific objectives of the funding body, certain priorities/requirements can be defined for each window. This provides flexibility regarding the promoted product type (e.g., hydrogen, ammonia, methanol, jet fuel) and the geographical focus of origin (e.g., Europe, a specific country, or global award procedure). Also, windows may differentiate product requirements and sustainability criteria for production, transport, and offtake (H2 Global Stiftung 2022). The first tender for green ammonia was published by the implementing body HINT.CO in late 2022. In terms of contract types, the H_2Global mechanism will engage in bilateral contracts with a duration of up to 10 years and firm offtake conditions.

[5] Characteristics: at least 10MW electrolyser capacity, FID reached, located in non-OECD-countries.

Other governmental initiatives to promote low-carbon hydrogen include among others the US Clean Hydrogen Production Tax Credit as part of the Inflation Reduction Act (launched 2022), the Indian National Hydrogen Strategy (launched in 2023) and the PtX Development Fund and PtX Growth Fund launched by the German Ministry for Economic Cooperation and Development (BMZ) and the Federal Ministry for Economic Affairs and Climate Action (BMWK) end 2022 and operated by KfW (KfW 2022). These initiatives will be highly relevant to mobilize green hydrogen production domestically through tax incentives (US), subsidies (India) and financing mechanisms such as equity investments/loans/grants (KfW 2022). They will therefore not affect contractual structures of international hydrogen trade directly. Therefore, they are not explored in more detail.

1.2. Key parameters influencing the expected contractual and financial forms of hydrogen trading

Key requirements for establishing a liquid market for any commodity include:

- **Sufficient supply and demand** as enablers for large-scale production and, cost reduction resulting from economies of scale. Over time, increasing competition will lead to a price reduction.
- **Price transparency**; and
- **Standardisation of products and related contracts**. Such standardisation can be related to GHG intensity (production, processing /conversion, transport, storage, re-conversion), but also to product qualities. Contracts can be standardized according to geographical characteristics (see discussion of the history of markets for different fuels and forms of energy in section 0).

Besides these aspects, a number of other parameters can be expected to have a significant impact on the contractual and financial forms of hydrogen trading, namely:

i) The physical properties of hydrogen product types, which influence the possible **modes of transport** and associated costs and GHG emissions – thus influencing regional market volumes and trading partners;

ii) **Availability of infrastructure** – such as ports and distribution grids - to connect producers and users. Establishing the required infrastructure will take time and require significant investment. A starting point can be local networks that gradually expand to regional, national, and international supply chains. The optimal contractual forms for hydrogen trading will change between the initial stage where no infrastructure is available and the full availability of infrastructure;

iii) **Type of market players**: public actors have different contractual and financial options compared to private companies, small hydrogen project developers and industry consumers from various sectors;

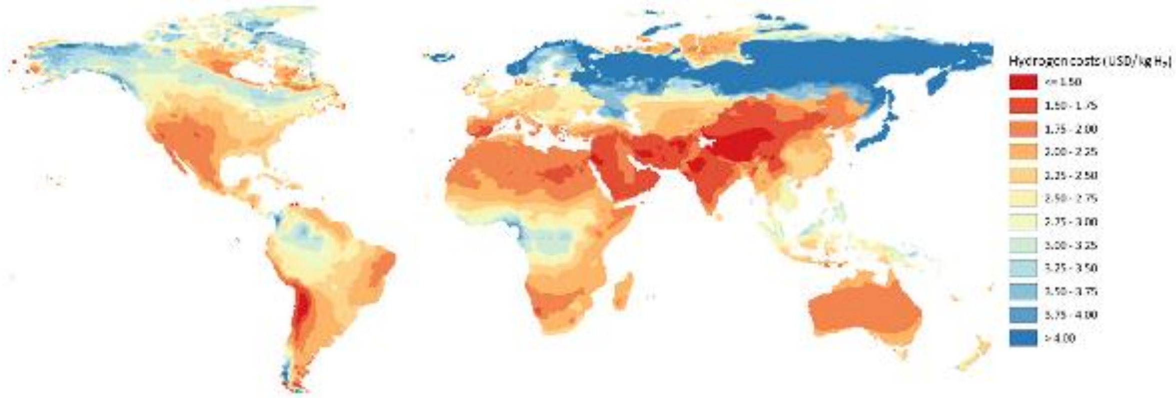
iv) **Political visions and preferences** of key market players, which can reach from aiming to transform to real hydrogen economies (e.g., Japan) to use hydrogen only for selected hard-to-abate sectors; and

v) **Policy instruments** chosen to mobilize supply and demand as well as provide infrastructure providers with planning certainty.

These parameters will be assessed in the following sub-chapters.

1.2.1. Hydrogen product type and transport options

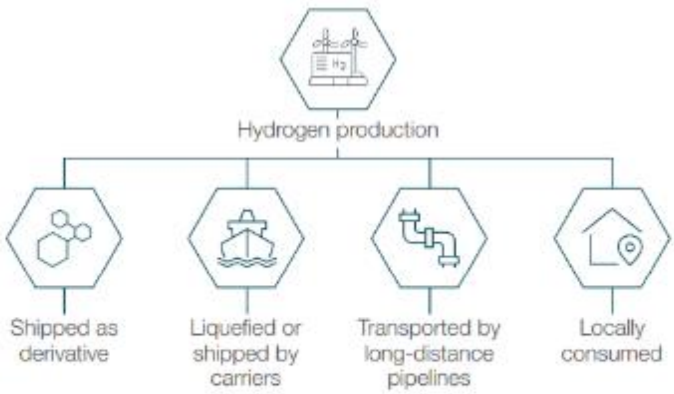
Figure 1: *Green hydrogen costs in 2050*



Source: *IEA (2021), p.126.*

The main hydrogen demand centres are expected to be Europe, North America, and South-East-Asia (McKinsey 2022). Figure 1 shows the expected green hydrogen production costs across the world in 2050. It can easily be derived that future demand centres are not located in regions where green hydrogen can be produced at the lowest cost; hence it will be necessary to transport the fuels over long distances. As can be seen in Figure 2 there are four main options for gaseous hydrogen: It can be consumed locally/regionally or it can be transported in gaseous form through pipelines, in liquid form via ships, or processed to derivates like i.e., Liquid Organic Hydrogen Carriers (LOHC) and ammonia and then be shipped over long distances. All these transport forms have various advantages and disadvantages which will be explained in detail in the following.

Figure 2: *Modes of transport*



Source: *Hydrogen Council, McKinsey & Company (2022).*

- **Gaseous hydrogen**: when hydrogen is produced it is typically obtained in gaseous form at up to 30 bars. The main challenge of gaseous hydrogen transport is its very low energy density. Even compressed to 700 bar, gaseous hydrogen has an energy density of approximately 1,265 kWh/m^3 (IEA 2021). For comparison, diesel has a volumetric energy density of approximately 10,000 kWh/m^3. The only economically feasible mode for transporting gaseous hydrogen over long distances is transport via pipelines. The transport by ships would either require large vessels to compensate for the low density of it or would require high compression pressures which both would lead to very high costs. Also, for larger hydrogen volumes pipelines become economically more attractive which can be seen in Figure 3. Hydrogen is transported in pipelines at pressures between 40-80 bars. To keep this pressure constant over the complete transmission distance, compressors are needed along the way. Due to the lower volumetric energy density of hydrogen compared to natural gas, the power demand for compression is approximately 3-4 times higher. This increased energy demand represents approximately 1.5-2% of the energy content of the transported hydrogen for every 1000 km. There are two options when considering pipelines for hydrogen transport: Repurposing existing natural gas pipelines or constructing new ones specifically for hydrogen. Repurposing can decrease capital costs by 65-94% compared to building new pipelines (Guidehouse 2020; HyWay 2021; Re-Stream 2021). However, only very few of the 1.4 million km of natural gas pipelines can be repurposed. There are various aspects which have to be considered when repurposing pipelines. The most important ones are the type of steel and the compression technology. Molecular hydrogen can diffuse through steel and reduce its ductility, toughness, and tensile strength, increasing its chance to failure. Building new pipelines would require massive investment and time to build especially for the offshore pipeline networks, which is why this option is only viable in the mid- to long-term future. Another problem is possible hydrogen losses during transportation. The losses can occur as a leakage from the pipe and/or valves, permeation through steel, and other operational losses. Even at a loss of a few per cent during transportation, the climate change mitigation benefit could be severely curtailed (Ocko and Hamburg 2022). Finally, pipeline construction for intercontinental transport is not feasible (i.e., South America to Europe) (IRENA 2022a).

Instead of transporting gaseous hydrogen, one can transport liquid hydrogen, LOHC and ammonia. There are also carbon-containing carriers such as methanol and methane. For these products carbon sources needs to be obtained from sustainable and renewable sources. The one option is obtaining the carbon from the air with direct air capture (DAC). But according to a recent study by IRENA the cost of using DAC outweighs the benefits of using these products during transport (IRENA 2022a). Therefore, they are not included in this report.

- **Liquid hydrogen** which can be produced using a commercially available technology has a volumetric energy density of 2357 kWh/m^3 and is obtained by the liquefication of hydrogen (IEA 2021, IRENA 2022a). The biggest issue for this option is the extremely low temperature of -253°C needed for liquefication, requiring special cryogenic technology. Theoretically, hydrogen can be liquified using 10% of its lower heating value (LHV). But today liquefaction requires 30-36% of hydrogen energy content (IRENA 2022a). The best available technology requires about 10 kWh of electricity/kg H_2 (WSU 2021). Further losses can occur due to boil-off. The boil-off is a term describing the losses of gas during transportation or storage due to evaporation of the cargo. The boil-off ratio depends on the tank size but on average 0.1% to 0.3% loss occurs per day (Berstad et al., 2022). Any such loss also reduces the GHG mitigation benefits (Ocko and Hamburg 2022). There are also some advantages of using liquid hydrogen. The reconversion to gaseous hydrogen only requires very minor amounts of energy (0.6 kWh/kg H_2) (IRENA 2022a). So, if the exporting region has low renewable energy cost this can lead to overall low transport costs. Another advantage is that liquefied hydrogen is extremely pure and there is no need for purification systems at the import location. Finally, liquefaction is a carbon free technology, if the energy required is obtained from 100% renewable sources (IRENA 2022b).

- **LOHC** are liquid organic compounds which can bind high amounts of hydrogen molecules through hydrogenation and release them at relatively low energy demand (Umicore 2022). There are various LOHCs with different advantages and disadvantages. For example, benzyltoluen has little to no health hazard and no flammability issue, but it requires high temperatures to be synthesized. Although it is hard to single out one prominent LOHC, the most popular currently are N-ethylcarbazole (NEC) and dibenzyltoluene (DBT) (Southall, Lukashuk 2021). LOHC have a slightly higher volumetric energy density than gaseous hydrogen (700 bar), approximately 1577 kWh/m^3. The biggest advantage of LOHC is that they can be transported like oil using existing infrastructure. However, they have several disadvantages compared to other transport mediums. One major disadvantage is that the dehydrogenation process to release hydrogen at the import location requires significant energy. The dehydrogenation requires temperatures of up to 400°C. For the dehydrogenation to hydrogen approximately 25-35% of hydrogen energy equivalent (33.3 kWh/kg H_2) is needed (IRENA 2022d). Lastly, only about 4 to 7% by weight of transported products contains hydrogen which in fact increases overall cost.

- **Ammonia** (NH_3) can be used as both, a hydrogen carrier or a product as a feedstock or fuel. Generally, ammonia is produced via the Haber-Bosch process from nitrogen (N_2) and hydrogen (H_2) gases. The process involves reacting the gases at high temperature (around 400-450°C) and high pressure (approximately 150 bars) in the presence of a catalyst, usually iron. The reaction is exothermic, meaning it releases heat, and is typically performed in a continuous flow reactor, a fully mature technology applied at large scale. In 2020, 183 Mt ammonia was produced globally (UCGS 2021): 72% using natural gas, and less than 1% using renewables (IRENA 2022e). The nitrogen used in the Haber-Bosch process is typically obtained from air-by-air separation units. Ammonia is already traded globally; 10% of the global production with Europe being the largest importer of ammonia with 4.4. Mt/yr. Liquid ammonia has the highest volumetric energy density – 4,042 kWh/m^3 -of the presented four hydrogen carriers discussed in this section, 1,800 times higher than the energy density of atmospheric hydrogen. This makes it a very promising candidate for hydrogen transport. For long distances ammonia is generally transported via ships in liquid form. The liquefaction of ammonia requires significantly less energy than the liquefaction of hydrogen since its boiling point is significantly higher. It can be liquefied at 20°C at 7.5 bar or -33°C at 1 bar (European Commission 2007). However, even though the ammonia synthesis is not very energy intensive requiring 10% of hydrogen energy equivalent, the reconversion to hydrogen (ammonia cracking) has a high energy demand, approximately 30% of hydrogen energy equivalent (European Commission 2007). However, as noted before, there are various applications where ammonia can be used directly. Lastly, ammonia is a toxic and corrosive agent which requires additional safety procedures.

The energy consumption for different types of hydrogen and its derivatives for transport is summarized in Table 1.

Table 1: *Energy consumption of four types of hydrogen and its derivatives for transport*

	Energy density kWh/m^3	Energy consumption for conversion kWh/kgH_2	Energy consumption for reconversion kWh/kgH_2	GHG emissions at German grid emissions factor kg CO_2/kg H_2(eq)	Total energy losses % of LHV[6] of hydrogen
Gaseous hydrogen	1,265	-	-	11.6	1% + 2%/1,000km
Liquid hydrogen	2,357	10	0.6	15.3	30-36%[7]
LOHC	1,577	1.1 – 2.5 Depends on Product	9-12 Depends on Product	15.44	28-42%
Ammonia	4,042	4.3	10	16.6	30-43%[8]

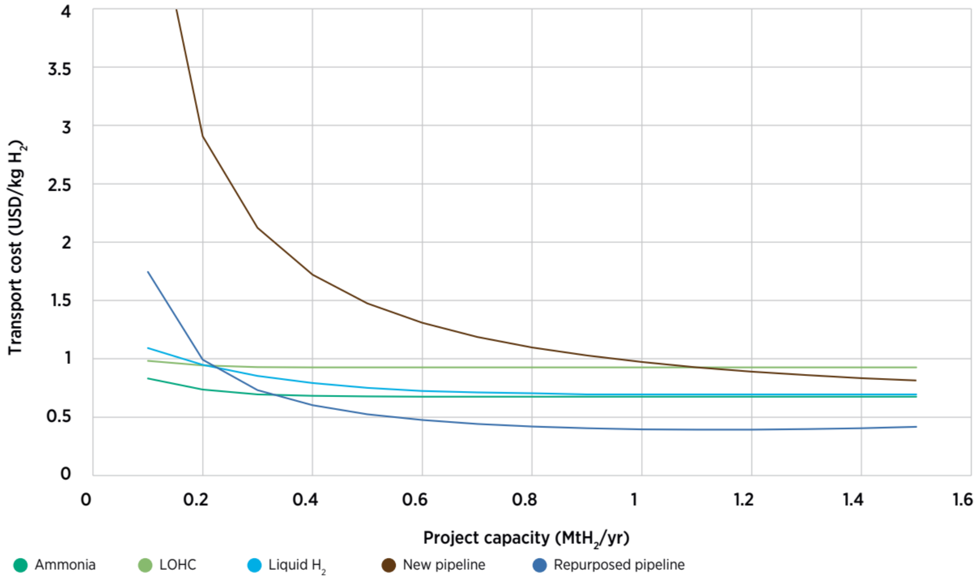
Source: IRENA (2022b)

Shipping large quantities of hydrogen results in significant GHG emissions. Although there is currently a push toward carbon free propulsion technologies, most of the ships today are using fossil fuels which result in higher GHG emissions compared to pipeline transport. Generally, 0.0089 kg CO_2 is emitted per tonne-kilometre of ship transport (US DoT 2019, EU Parliament 2022). However, this value is an overall average. There are significant differences depending on the type of ship that is being used, type of fuel that is used and boil-off losses could heavily change this value. Figure 3 and Figure 4 show the costs for different PtX transport scenarios. Both figures include all relevant initial CAPEX like PtX terminals and the construction costs for new pipelines.

Figure 3 shows different transport scenarios and compares these options from a cost point of view for a fixed distance of 5,000 km (IRENA 2022b). For a project capacity smaller than 0.2 MtH_2/year, ammonia is the most feasible option followed by liquid hydrogen and LOHC respectively. Repurposed pipelines only become a feasible option with higher capacities and building new pipelines would only make sense against using LOHC carrier at very high transport capacities. It is also important to notice that pipelines lead to the largest cost decrease with increasing transport capacity.

[6] LHV refers to lower heating value (33.3 kWh/kgH_2).
[7] The boil-off losses as discussed above are not included here.
[8] Ammonia synthesis and cracking are included in the losses.

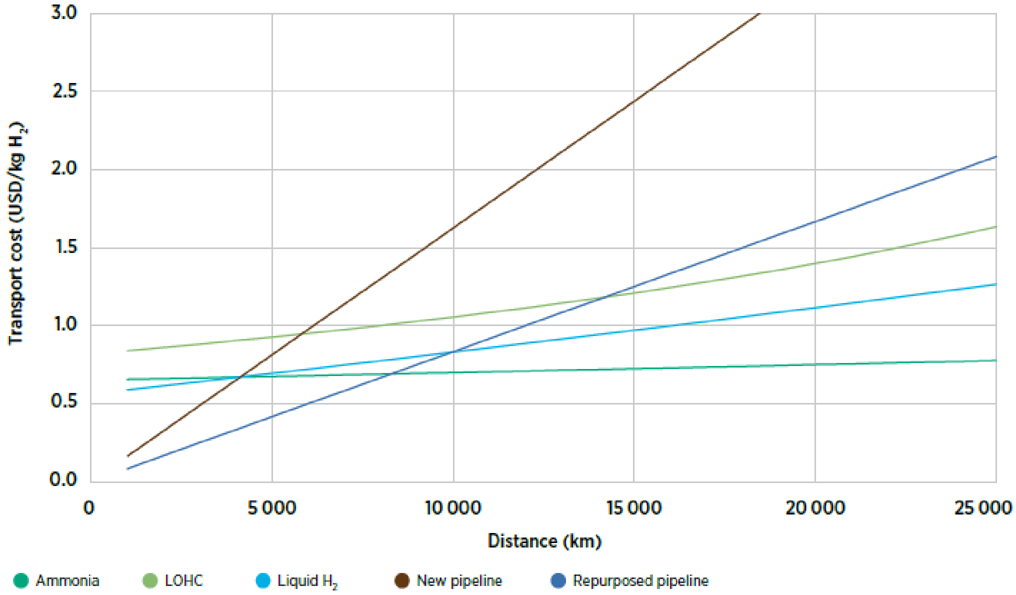
Figure 3: *Transport costs for different types of hydrogen and its derivates and transport options as a function of project size for a fixed distance of 5000km*



Source: *IRENA (2022b), p.125.*

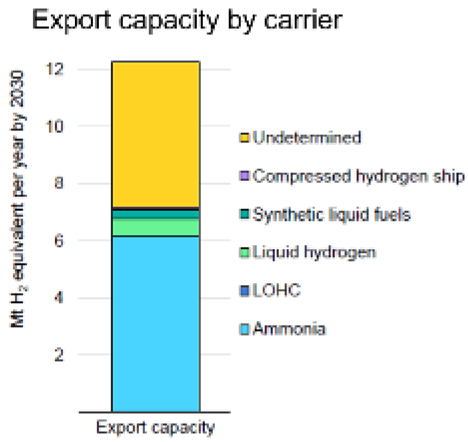
Figure 4 compares the effect of distance for the projects with a capacity of 1.5 MtH_2/year. It can be deducted that for **short distances both pipeline options are most favourable**. With increasing distance though, the cost of using pipeline increases faster than the other transport options. For shorter distances the fixed cost for a pipeline is relatively small and only compression of hydrogen is impacting the cost. Since pipelines do not require very large pressure (40-80 bar) the initial costs are lower. On the other hand, transport by ships - regardless of the distance travelled - has the same infrastructure requirements: conversion steps, storage, port facilities etc. Since the costs of ammonia increase to a limited extent with transport distance, **for long distances, ammonia becomes the cheapest option.**

Figure 4: *Transport costs of different hydrogen and transport options as a function of distance for a fixed project size of 1.5 MtH_2/year*



Source: *IRENA (2022b), p.126.*

Figure 5: H_2 export capacity by hydrogen / derivative type in 2030



Source: IEA (2022c), p.166.

Combining the information from the two graphs, it can be concluded that liquid hydrogen and LOHC should only be considered for short distances and small capacities. Even then LOHC is still not feasible compared to ammonia transport, but liquid hydrogen can be a viable option for shorter distances. Pipelines make the most economical sense for high capacities and low distances. **For transport capacities of 1.5 MtH_2/yr even new pipelines are the most feasible option.** However, it should be noted that it is not possible to construct pipelines in all regions. Geopolitical implications of pipelines are significant, as the current situation in Europe shows. Thus, wherever pipelines are not economically attractive or not desirable, ammonia is the best alternative. Ammonia is already produced, traded and stored globally on a large scale, making it a well-known and mature technology. In 2020 183 Mt ammonia was produced (UCGS 2021). Its relatively low costs and the high maturity of transport technologies **make ammonia the most promising candidate for future long-distance hydrogen transport**. This is also reflected in the export-focused hydrogen projects planned for the 2030-time horizon whose vast majority has selected ammonia ((IEA 2022c, see Figure 5.

1.2.2. Availability of infrastructure and investment capacities

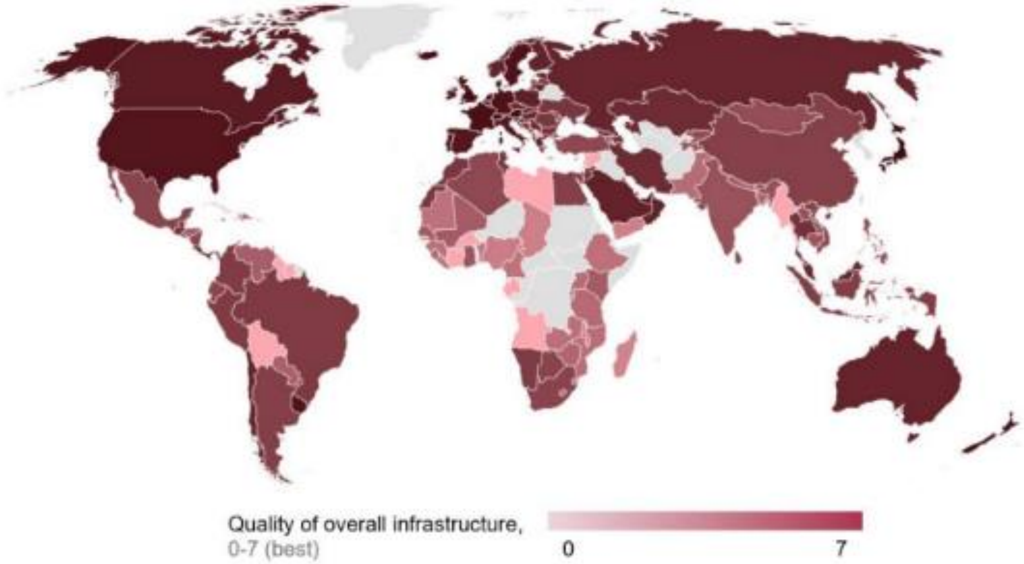
As the preceding discussion has shown, infrastructure requirements will be huge for any of the chosen transport modes. The availability of infrastructure and the ability to quickly ramp it up through large investments will be key factors to consider in order to identify potential suppliers and develop actual trade streams. This is particularly relevant for more costly infrastructure options such as pipelines. Access to capital markets, which is a function of credit rating and will determine the cost of capital, will be a key factor. Energy companies and investors will need a secure and stable environment and long-term agreements to secure returns and minimize risks. As of today, this seems easier to be achieved in importing than in exporting countries. For any of the hydrogen expansion scenarios currently discussed, infrastructure will be a major bottleneck.

Based on the 1.5 °C Scenario by IRENA, in 2050 about 25% of the global hydrogen production will be traded internationally (18.4 EJ/yr). It is foreseen that about 55% of this share will be transported in mostly retrofitted pipelines and 45% mostly in the form of ammonia by ship. It is expected that only 11% of the overall investments of a minimum of 4 trillion USD in hydrogen infrastructure (including power generation) until 2050 will be directed to the international trading infrastructure. About 30% of this trading infrastructure will be invested in pipelines and the remaining 70% in (re)conversion plants and shipping infrastructure (IRENA 2022b).

Compared to today's fuel transport infrastructure, costs will be higher due to hydrogen's corrosive effect on some metals, which requires better quality pipeline material and more careful monitoring to prevent leaks and explosions. Ammonia, which is a toxic, highly caustic, highly corrosive, and water-seeking chemical requires better-built and better-monitored ships. Meanwhile, the number of ammonia shipping vessels needs to rapidly increase along with ammonia cracking infrastructure at import ports or floating/offshore ammonia production facilities. Similarly, significant investments in hydrogen-fuelling infrastructure would be necessary for scaling up adoption in transportation systems.

Consequently, the ability of countries to quickly ramp up infrastructure needs is to be considered as one of the key factors- along with production and transport costs (see above) and resource and water availability (see section 0) to identify possible trade partners and routes. De Blasio (2020, p.25) uses the Global Competitiveness Index to rank countries regarding their infrastructure. While he sees the US, Norway, Australia or even Morocco as having high infrastructure potential, key potential hydrogen supplying countries in South America, North and Sub-Saharan Africa and Southeast Asia would be infrastructure constrained.

Figure 6: *Infrastructure quality worldwide in 2019*



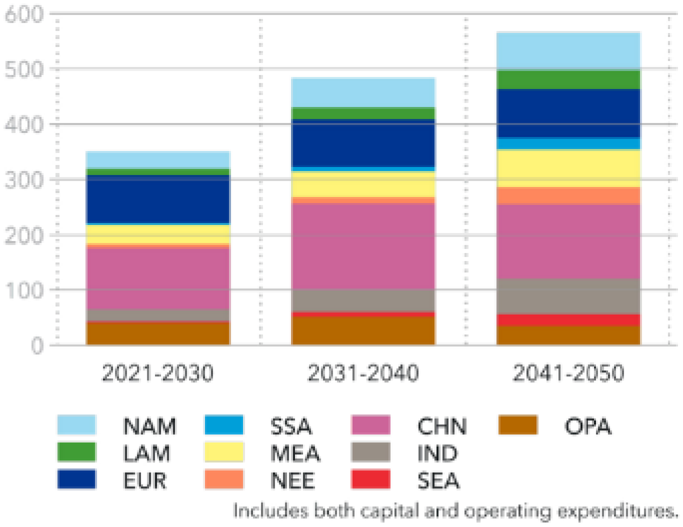
Source: *De Blasio, Pflugmann (2020), p.24.*

It should be noted that the evaluation of a country's infrastructure potential also includes considerations on financial variables (e.g., access to capital markets, credit rating, and cost of capital). The geographic distribution of capital and investment flows should hence be also factored in.

Currently, capital is not flowing as smoothly into hydrogen projects as in renewable energies, notwithstanding the unprecedented interest in hydrogen. By 2030 global investments in hydrogen, including both capital and operating expenditures, are expected to reach roughly 350 billion USD worldwide. These investments are concentrated in three high-demand areas, namely China, Europe, and North America. MENA and Australia may become the leading investment targets as exporter hubs (see Figure 7). India is aiming to attract close to 100 billion USD of investment by 2030 on its path to becoming self-reliant by 2047; see Chapter 4.3.1 (Koundal 2023).

For the time horizon 2040 and 2050, investments would accelerate first in China and then Latin America, while Africa would continue to lag behind. India is expected to grow continuously.

Figure 7*: Global expenditures for production of hydrogen and its derivatives by region (billion USD/year)*



Source: *DNV (2022), p.26.*

1.2.3. Types of market players

The various market players have different market priorities and contractual and financial options. The following paragraphs introduce the most relevant archetypes of market players: the interests and action options of different types of players that will be involved in international hydrogen trading are discussed. **Governments** typically pursue national political agendas. They can engage in strategic energy partnerships (e.g., Germany - Morocco) that can lay the foundation for future hydrogen contracts both on the governmental level and with the private sector. In order to facilitate private investments, they can provide governmental guarantees and securities with high creditworthiness as well as direct subsidies for infrastructure investments. Also, governments can easily engage in long-term commitments regarding both prices and volumes; and the former does not necessarily have to be competitive but can be higher in order to reach non-monetary goals such as energy security. Thus, governments are likely to accept multi-decadal contracts with other governments, or private hydrogen suppliers and users. Governments may involve public financial entities and other state agencies as intermediaries (e.g., bilateral development banks such as KfW; or development agencies such as GIZ; or intermediary that bring suppliers and consumers together such as the Hydrogen Intermediary Company GmbH (HINT.CO) by H2Global Foundation).

State-owned energy suppliers are prevalent in countries with a weak private sector and a strong role of fossil fuel exports (e.g., Saudi Aramco) and typically follow the political agenda of their governments. They often are characterised by strong liquidity and financial reserves, high creditworthiness, and can be easily supported with governmental guarantees and securities and thus can easily finance strategic investments in new energies and infrastructure. They also engage in long-term commitments, but typically the engagement has a stronger economic focus than those of purely governmental players and, hence, prices should be competitive. However, strategic considerations can allow for initial losses. They are likely to actively consider different colours of hydrogen production depending on the political and commercial attractiveness. Contracts can be of long- or short-term nature and can be signed with governments, or industrial hydrogen consumers.

Multilateral institutions: International development banks and energy-related institutions can play important facilitative roles in the international hydrogen market. The banks can serve as catalysts for large-scale financing programmes while institutions like IEA and IRENA can provide the analytical background for specific market design parameters.

Private international energy companies (e.g., BP, Shell, Total Energies) follow their corporate objectives and goals - which may be different from the political priorities of their home countries. Large corporates typically are able to finance hydrogen investments off-balance sheet or through project finance – often in collaboration with financial institutes. They engage in medium to long-term commitments (prices & volumes), and the engagement is typically profit-oriented with possible strategic components. Contracts are typically B2B, but partnerships with (semi-) governmental actors are possible.

Small hydrogen project developers actively identify green hydrogen projects that are close to economic viability. Currently, they aim to implement project scales of up to 120 MW electrolyser capacity. But they have limited means to finance investments off-balance sheet or through project finance as they do not have significant financial reserves. Hence, they regularly require governmental support in the form of guarantees, grants, or offtake agreements. Contracts are typically B2B, and project developers are seeking long-term offtake-agreement to minimise their risks. As of today, there is only a limited number of these actors, and they are characterised by innovative approaches and business ideas.

Private industries from various sectors (chemicals, steel, transport, etc.) that aim to reduce their own carbon footprint or to produce carbon-neutral products (e.g., steel) and **public entities** can become key drivers of hydrogen demand. They have to invest in their own infrastructure to enable their production to use hydrogen or its derivatives and have to source hydrogen. As of today, the market only sees a few early movers, often sectoral industry leaders. Often, pilot projects are implemented with public support or as part of large-scale energy programmes such as the ‘important projects of common European interest’ (IPCEIs) in the hydrogen sector.

1.2.4. Political visions of future energy systems influencing hydrogen trade

Countries with dedicated “hydrogen visions” can be expected to actively engage in hydrogen market design and acceleration. With regards to hydrogen users (and potentially importers), one can differentiate between those countries that i) have the vision to transform national energy systems to “green hydrogen economies” and those that ii) aim to promote hydrogen market acceleration regardless of the colour of hydrogen production (i.e., where cost is the main driver).

The former category can be expected to establish strategic *green hydrogen partnerships* with suppliers exclusively for renewable hydrogen, with the objective to drive supplier countries’ investments in this technology. Besides the international engagement, these countries can be expected to support their domestic industry in switching from fossil fuels to green hydrogen. This can be done by various policy instruments such as grants, financial incentives, carbon pricing schemes, etc. In addition, investments in domestic infrastructure – hydrogen ports, grids, distribution systems, and hydrogen fuel stations – may be taken. This can be done most cost-effectively when starting off with “local hydrogen valleys”, i.e., clusters of hydrogen users where the infrastructure is supported by the state that expands geographically over time. These countries can be expected to engage in long-term offtake contracts with suppliers of green hydrogen, which can lead to dedicated market acceleration. Depending on the political priorities and concerns, countries may prioritize new market players (e.g., Africa, South America, Australia) or traditional oil/gas exporters. The former can open new economic possibilities for countries that did not benefit from large fossil fuel reserves in the past but may require more investment in infrastructure and national know-how. The latter can help oil-/gas-exporting countries to diversify their economies and to adjust their income structures sustainably.

Consumers with a vision to promote hydrogen market acceleration regardless of the hydrogen colour can be expected to engage in partnerships that promise the lowest cost of hydrogen supply. In other words, these players may engage in medium- to long-term contracts for blue hydrogen as long as there is a cost advantage to green hydrogen and can thus counteract the intention of the former country group. Once green hydrogen has become more cost-competitive, they may change suppliers. Japan currently seems to follow this strategy, also see Chapter 4.

On the side of hydrogen producers (and potentially exporters), one can differentiate between those groups of stereotype-countries that i) have a vision to become green hydrogen exporters and those that ii) aim to promote blue hydrogen. Countries with a vision to become green hydrogen exporters typically engage in strategic investments of large-scale green hydrogen production in combination with the required renewable energy capacities, and processing/transport/storage infrastructure including ports and pipelines. This will require substantial governmental support. Countries with existing oil-/gas-processing infrastructure (e.g., Middle East) are expected to need less investments than countries without existing oil/gas infrastructures (e.g., Sub-Saharan Africa countries). Countries with a vision to promote blue hydrogen use may do this as a means to stick to their classical business, or for “buying time” to become a leading exporter of green hydrogen. For these countries, it is comparatively easy to combine enhanced oil recovery (EOR)- and CCS activities that have been planned anyway with blue hydrogen production. Investing in greenfield[9] CCS activities specifically for green hydrogen production is more unlikely as the exploration of appropriate sub-surface storage sites as well as the preparation and implementation of new CCS sites requires substantial lead times (5-10 years) and investment, which constitutes a key risk for creating stranded assets (i.e. if cost-reduction of green hydrogen production happens faster than new CCS-sites are operational for blue hydrogen production). Importantly, also those countries may do large-scale strategic investments in green hydrogen production infrastructure in parallel.

[9] The term greenfield refers to new installations (not refurbishment/adjustment of existing installations).

1.2.5. The impact of policy instrument choice on international hydrogen trade

The types of policy instruments chosen by governmental players to support the build-up of hydrogen infrastructure as well as the production of specific colours of hydrogen will impact the contractual forms of hydrogen trade. Some instruments will lead to direct, long-term contracts between private companies and governmental agencies whereas others will incentivise certain types of private sector contracts, either short- or long-term, depending on the design of the policy instruments. In the following, we highlight examples from the current policy landscape while differentiating between i) instruments that support the production or use of green hydrogen, and ii) instruments supporting infrastructure investments.

1. Policy instruments supporting the production or use of green hydrogen

Direct price incentives for (green) hydrogen production have recently been in the focus of policymakers. As mentioned in section 1.1 above, a leading example of a price subsidy through a contract for difference (CfD) is the **H_2Global Mechanism** of the German government, aiming to bridge the gap between (high) production cost and (low) willingness to pay for green hydrogen by consumers through a double-auctioning mechanism and governmental funding making up the difference. Such **Contracts for Difference** schemes incentivise investment in renewable hydrogen by providing project developers facing high upfront costs and long lifetimes with direct protection from uncertain or volatile wholesale prices, and they support consumers to start switching from fossil fuels to green hydrogen. The bilateral contracts are typically signed between governmental agents and hydrogen suppliers and buyers and are long long-term (10-15 years) contracts with fixed prices and volumes.

Another important policy instrument type is **carbon pricing**, which internalizes costs of GHG emissions for emitters and thus can help to spur investment in low-carbon technological innovation and fuels. Carbon pricing instruments include **carbon taxes and emissions trading systems**, such as the EU Emission Trading System (EU ETS) - creating incentives to reduce emissions where it is most cost-effective to do so. In most trading systems, the government sets an emissions cap for one or more sectors, and covered companies are allowed to trade emissions allowances (IEA 2020). This also applies to the EU ETS: installations must monitor and report their greenhouse gas emissions and submit the corresponding number of EU allowances (EUAs) to their national authorities. One EUA corresponds to one metric ton of CO_2 equivalent. Current EUA prices are around 90 USD. If the corresponding quantities of EUAs are not submitted, the operator must pay a penalty and submit the missing EUAs. This instrument can be a significant lever in developing low-carbon hydrogen technologies since various sectors that might use hydrogen to decarbonize their operations are covered under the EU ETS (EU Commission 2021a). Relevant examples are power plants, the chemical industry, steel mills and maritime transport. Additionally, the EU Parliament has agreed to create a new, separate emissions trading system for the buildings and road transport sectors. Replacing fossil fuels with green hydrogen can lead to significant GHG reductions which in turn can have significant economic benefits under the EU ETS. For example, replacing 1 MWh of grey ammonia with green ammonia would lead to revenues from the EU ETS of more than 45 USD or 11.44 USD/kgH_2. Since the EU ETS only considers scope 1 emissions, embodied emissions of grey or blue hydrogen are not directly priced under this policy instrument. This makes the current EU ETS regulations not a perfect fit for incentivizing green hydrogen production. However, the current EU ETS rules are extremely complex with different allocation rules for grey hydrogen and green hydrogen. Grey production plants can apply for free allocation according to the hydrogen benchmark (based on the top-10 efficient SMR-plants) and have to surrender EUAs according to their real emissions (i.e., most efficient plants would not face extra costs through the EU ETS). In contrast to this, green hydrogen production is not eligible for free allocations and does not have to surrender EUAs (because electricity consumption does not lead to direct emissions at the production site). Nevertheless, electricity prices may be higher due to the EU ETS. The exact impact needs to be determined individually for each green hydrogen production site, as it depends on the details of electricity consumption (dedicated RE versus grid connection) and the underlying power-purchase agreements (PPAs). However, those regulations are currently under discussion within the EU Commission. Regarding the contractual form of hydrogen trading, the EU ETS incentives direct, private-sector contracts between hydrogen producers and consumers.

While the EU ETS covers emissions released in EU countries, the EU's **Carbon Border Adjustment Mechanism (CBAM)** applies to goods produced outside of the EU. The CBAM is part of the EU's "Fit for 55" package and will impose a financial cost on the carbon content of goods imported into the EU from 2026 onwards. This ensures that imports are subject to similar carbon pricing as domestic products and that EU-based companies do not shift production sites to countries without carbon pricing. The CBAM Certificate (CBAMC) price corresponds to the average weekly auction price for an EU emissions trading allowance. In contrast to EUAs CBAMCs cannot be traded. Among other products, hydrogen, ammonia, and steel imports will be covered by the CBAM with further extensions possible. Due to this policy instrument, hydrogen produced with low or even zero embodied emissions will significantly benefit compared to fossil-fuel-based alternatives. This signals hydrogen producers outside the EU to direct their investments towards green hydrogen technologies. With current EU ETS prices, blue hydrogen importers would need to buy CBAMCs. This mechanism could close the current cost gap between green and fossil fuel-based hydrogen. Regarding the contractual form of hydrogen trading, the CBAM also incentives direct, private-sector contracts between hydrogen producers and consumers.

The **Inflation Reduction Act of 2022 (IRA)** is a US law that aims to curb inflation by - among other things -investing in domestic energy production while promoting clean energy. Within the IRA an estimated 369 billion USD will be spent over the next 10 years on energy security and climate change. A key component of the IRA is a series of tax credits designed to accelerate the deployment of clean energy technologies such as green hydrogen. The new bill gives tax credits to US hydrogen producers. A hydrogen producer can receive 0.6 to 3 USD per kilogram H_2, depending on the carbon intensity of the produced hydrogen. The maximum carbon intensity to receive the lowest tax credit is 4 $kgCO_2/kgH_2$, the benchmark for receiving the maximum tax credit is 0.45 $kgCO_2$-eq/kgH_2 Upstream emissions (well-to-gate) are considered for the carbon intensity calculations (BlueGreen Alliance 2022). Even though the regulation only targets national producers, it is expected to have a significant effect. First of all, because 3 USD/kgH_2 is a strong price signal which almost immediately brings green and “greenish” hydrogen to price parity with fossil fuel-based hydrogen. Furthermore, North America may become one of the main hydrogen consumers with an expected demand of approximately 117 Mt in 2050, which shall be met mainly by domestic/regional production. This can lead to a significant uptake of green hydrogen production and a rapid development in the technology supply chain. From a contractual point of view, a focus on B2B contracts can be expected.

Besides financial support schemes for green hydrogen production, countries may also choose to introduce **sustainability requirements for hydrogen** that go beyond carbon intensity. As we discuss in detail in chapter 3, such criteria may refer to water availability, land conflicts and other political- and social indicators. Depending on their design, such sustainability requirements could have a strong impact on the eligibility of suppliers. For example, if the EU would define water availability as a strong criterion, and renewable-based water desalination was not accepted as a remedy, then significant parts of Africa and the Middle East would disqualify as suppliers for the EU. At the same time, from a supplier's point of view, such criteria may make the EU less attractive as an off-taker market.

2. Policy instruments supporting infrastructure investments

The widespread use of hydrogen requires comprehensive infrastructure. Depending on production and use patterns, the following infrastructure may be required: hydrogen pipelines for the import, transmission and distribution of gaseous hydrogen, import ship terminals including processing/reconversion stations for ammonia, hydrogen fuel stations for fuel-cell electric vehicles (FCEVs), etc. Due to their scale, such generic investments cannot be taken by the private sector alone; and access to a suitable infrastructure is a key requirement for the transformation of energy systems to hydrogen. Countries leading the hydrogen transition are expected to substantially support infrastructure investments. Therefore, different policy instruments can be used.

The EU for example has a wide range of support mechanisms and policy instruments that can support the establishment of the required hydrogen infrastructure, such as the **Connecting Europe Facility (CEF)** funding mechanism or **IPCEI (Important Projects of Common European Interest)** funds.

CEF is a funding instrument that supports the development of energy infrastructure, including alternative fuels infrastructure, in the European Union (The European Hydrogen Backbone (EHB) Initiative 2022). The CEF provides grants, loans, and guarantees to support the development of infrastructure projects in the areas of transport, energy, and digitalization. To support an infrastructure project with CEF funds the following criteria must be met (European Parliament 2021):

1. The project must contribute towards achieving the EU's energy and climate objectives such as helping decarbonization of the energy system or deployment of alternative renewable fuels (renewable hydrogen or PtX products).
2. The project must be technically and economically feasible. The project should have a real benefit and cost analysis for the timespan of the project.
3. The project must serve the public interest. It should either contribute to the security of the energy supply (i.e., the creation of hydrogen pipelines within Europe), support the deployment of alternative fuels, or promote the integration of energy markets.
4. The project must have a cross-border dimension to be eligible for CEF funding, meaning it must involve a minimum of two EU member states.

When these criteria are met CEF can fund any project up to 50% of its capital expenditure (CAPEX) costs (EU Commission 2021a).

Just like CEF, IPCEI is also a funding instrument that aims to fund the development of cross-border projects that can boost the union’s competitiveness, strategic importance, and sustainability (European Parliament 2020). The IPCEI provides a framework for EU Member States to collaborate and jointly support the development of key projects in areas such as research and development, innovation, and infrastructure. The funding for an IPCEI is provided by the participating Member States, who pool their resources and jointly finance the project. The financing can take the form of grants, loans, guarantees, equity investments, or a combination of these instruments. The amount of funding provided by each Member State is proportional to its share of the project's benefits, risks, and costs. Unlike CEF, IPCEI can cover all eligible costs of the project. The maximum permitted aid is determined via the so-called “funding gap”. This refers to the difference between positive and negative cash flow over the lifetime of an investment (EU Commission 2021b)[10].

For transforming the transport sector, availability of hydrogen fuel stations is crucial. Today, there are only 161 operational refuelling stations in the EU and UK, mainly focused on Western Europe and 95 of these are located in Germany[11] (Clean Hydrogen Partnership 2021). This means a huge fuel station ramp-up is required. CEF and IPCEI can be used to fund refuelling station projects but there are other funds available to support the ramp-up process.

The European Regional Development Fund (ERDF) is a financial instrument of the European Union (EU) that aims to reduce regional disparities in terms of economic development and employment across the EU. The ERDF has been in operation since 1975 and has supported a wide range of projects, including infrastructure development, research and innovation, environmental protection, and support for small and medium-sized enterprises. Just like ERDF, Cohesion Fund (CF) also provides support to less-developed EU regions, more specifically, regions with GDP per capita below 90% of the EU average (EU Commission 2021c). ERDF and CF have targets of 30% and 37% toward energy transition which could include hydrogen infrastructure networks.

Another important financial instrument is the Horizon Europe Funds[12]. EU's research and innovation funding program for the period 2021-2027, with a total budget of 102.5 USD billion. The program can also support energy, environment, and transport projects which include hydrogen infrastructure projects. Horizon Europe has already funded a hydrogen infrastructure project named Hydrogen Mobility Europe 2[13].

In short, most of today’s support schemes for building a hydrogen infrastructure in Europe are direct subsidies. Typically, grant contracts will be awarded to industry players by the EU or Member States, and cover the period required for building the infrastructure.

In conclusion, effective policy instruments supporting both production of hydrogen and establishment of required infrastructure will be key to facilitating market development. The availability and scope of

[10] Article 4, 4.1 (33)
[11] Website provided by H2Mobility that shows current refueling stations in Europe (H2 Live 2023).
[12] Already supported Hydrogen infrastructure with Hydrogen Mobility Europe 2 project (European Commission 2021d).
[13] The project brings together 7 EU countries and the UK. The project demonstrates the system benefits achieved by using electrolytic hydrogen solutions in grid operations and conducts a large-scale market test of hydrogen refueling infrastructure, and passenger and commercial fuel cell electric vehicles operated in real-world customer applications. In total it supports a total of 1000 vehicles and 20 new refueling stations.

such policy instruments in different regions will also impact the region's ability to become a key player in international hydrogen trade. So far, Europe, the US, India, South Korea, Japan, Chile and Australia have been at the forefront of introducing hydrogen policies. Gulf cooperation countries have promising conditions for green hydrogen. As a result, their hydrogen strategies and policies are in the process of development and they are expected to incorporate strategies in a fast manner (KPMG 2023). – An evaluation of the effectiveness and impact of these policies goes beyond the scope of this study; but it already becomes clear that policy makers carefully watch each other and aim to remain 'competitive'. For example, the US IRA act has fuelled fears in Australia that renewable energy production capacities will be 'redirected' to the US (away from Australia) due to more attractive benefits (Hart, 2023; Cranston 2023).

1.3. Historical energy market development: analogies for international hydrogen trade

Over the last 200 years, international energy markets have evolved as new forms of tradable energy. The nature of the fuel/energy carrier has been crucial for market design. Any natural type of energy will come in diverse forms that are more or less difficult to transport and use. Over time, transportation technologies evolve and become more efficient, e.g., the shift from ship to pipeline transportation, or the development of highly efficient long-distance transmission lines for electricity. Often, the processing of fuels has allowed generating of a denser form that can be transported at a lower cost, as has been the case for liquid natural gas (LNG).

An international market for a specific fuel has historically developed in a series of steps. It starts with the emergence of technologies that can utilize the fuel. Often, such technologies have a military function, as has been the case with the oil-fuelled warships of the British Navy in the early 20th century (Dahl 2000). Here, the state has an interest to ensure secure fuel supply. It will directly invest in sourcing and try to control the entire value chain. Once the technology finds uses outside of the military due to becoming competitive with "incumbent" fuels, the market broadens. The need to invest in supply infrastructure remains, especially if a whole new supply chain needs to be built. This leads to a market built on (mostly bilateral) long-term contracts, where prices and quantities are fixed for up to several decades. The secure cash flow allows investments into infrastructures that are amortized over long periods. However, markets need standardization to increase their geographical reach and liquidity. This standardization is usually happening at a regional scale through a benchmark contract referring to a specific type of fuel. Such benchmarks typically develop several decades after the initial emergence of the market in regions where there is a high number of suppliers for a specific fuel type that is abundantly available, with sufficient competition between suppliers as well as demand sources to drive liquidity. Also, the main infrastructures for fuel transport already need to be in place. This then allows trade on exchanges and the development of derivatives such as futures and option contracts. Currently, no form of energy is traded truly globally.

The first form of internationally traded energy was fuelwood, but this trade has been rather small in volume and never generated any benchmark contract (Hillring and Trossero, 2006). Coal has been traded internationally since the late 19th century and over the last decades two key markets with different dynamics have developed: the Atlantic and the Pacific Basin (Fernandez 2022). Coal characteristics such as moisture, ash and sulphur content, as well as volatile matter, present a much wider variety than those of other fossil fuels, with four main types recognized: anthracite, bituminous coal, sub-bituminous coal and lignite. The market is differentiated into “thermal” and “coking coal”. From around 2011 on, there has been a growing segmentation of thermal coal trade by quality, with price spreads varying widely (Fernandez 2022). Calorific value (CV) is used as the main parameter for differentiation. Private Price Reporting Agencies (PRAs), Argus, S&P Global Platts and IHS Markit compete to report so-called “price markers”. Three such markers have traditionally been used for standard traded coal with a CV of 6,000 kcal/kg coal “net as received” – at the ports of the Netherlands and Belgium, at the South African port Richards Bay and at the Australian port of Newcastle. Since the 2010s, further markers have been added for the Chinese port of Guangzhou and a lower CV of 5,500 kcal/kg (Fernandez 2022). The Atlantic market is essentially spot while the Pacific market was traditionally dominated by long-term contracts, but the share of the latter has fallen from 90% to 50% in about a decade. Japanese power plant operators still prefer long-term contracts in order to have the security of supply. Derivatives trading has emerged since the late 1990s and become significant since the mid-2000s, first in the Atlantic basin and since the mid-2010s also in the Pacific.

Coking coal markets that essentially involve Australia on the supplier side and Japanese and Chinese steel producers on the demand side were dominated by long-term contracts until the late 1990s, but now spot trades which are linked to a price index make up over 50% of contracts (Fernandez 2022).
The international trade of oil can be traced back to the early 20th century. After the Second World War, international oil markets were largely controlled by an oligopoly of a few large oil companies, mostly from the US and North-Western Europe that agreed on a geographical distribution and an absence of competition as market shares were pegged to the value achieved in 1928. “By 1950, the[se companies, called] ‘Seven Sisters’ owned 70% of the world refining capacity outside the Communist block and North America, almost 100% of the pipeline networks and over 60% of the world’s privately owned tanker fleet. They priced crude oil using ‘posted prices’ [i.e. fixed, pre-defined prices] to maximise their revenues within their vertically integrated systems” (Imsirovic 2022). This system was undercut by independent oil companies until the 1970s, and further weakened by the turmoil of the oil crises during the 1970s and early 1980s, which led to the emergence of spot trading on exchanges around 1980. By 1987, 60% of oil traded according to spot market prices (Imsirovic 2022, p. 336). The international oil market is now famous for its extremely high liquidity. Oil derivatives trade in far greater volumes than physical oil. In August 2019 on a single day, a volume equivalent to over two months of global oil production was traded (Imsirovic 2022, p. 327), but still more than half of the latter is delivered on long-term contracts. Despite significant differences in oil types regarding specific gravity and sulphur content, since the early 1980s just three global benchmarks have emerged: Brent in Europe, West Texas Intermediate (WTI) in the US and Dubai/Oman for Asia. Brent was driven by massive differences between officially posted OPEC and spot market prices in the aftermath of the second oil shock of 1979. Abundant production of North Sea oil, “underpinned by English law, with standardised csontracts, no destination restrictions and tax advantages in ‘spinning’ or ‘churning’ the cargoes”, led to the emergence of a transparent and liquid spot market (Stern and Imsirovic 2020, p. 4). After the abolition of US oil price regulation in 1981, a WTI futures contract was introduced by the New York Mercantile Exchange (NYMEX) in March 1983, with a generally accepted location for physical trades at an intersection of major pipelines (Stern and Imsirovic 2020, p. 5). Dubai was able to become the Asian benchmark due to its liberal economic structure which allowed foreign oil companies to invest into production facilities

and trade the oil freely. In 1985–87, a time of a massive oversupply in the global oil market, Japanese trading houses and US-based refiners started entering the Dubai market. In 1988 important OPEC countries in the Gulf region switched from controlled oil pricing to the spot market and chose the available Dubai infrastructure for their trade towards Asia (Fattouh 2012).

Interestingly, such benchmarks which are driven by price reporting agencies (PRAs) like Platts and Argus as in the coal market case persist even after the source has been exhausted, as is the case for Dubai (Fattouh 2012) and will shortly be for Brent. In the Dubai case, Platts tried to maintain the viability of Dubai as a global benchmark by allowing the delivery of Omani oil against Dubai contracts. Despite a low liquidity of the actual contract, this was successful due to the interest of key exporters to retain the pricing base. Another reason was "the deep financial layers that have emerged around Dubai and which have linked Dubai to the highly liquid Brent complex" (Fattouh 2012, p. 5), which are expressed through highly intricate swap structures between Brent and Dubai.

WTI had a difficult period between 2005 and 2015 as US shale oil production increased and generated domestic oversupply, but exports were prohibited. The price of WTI decoupled from the other international benchmarks and key Arabian exporters stopped applying the benchmark. Only the lifting of the US export ban in 2015 enabled WTI to regain its global status (Stern and Imsirovic 2020, p. 6). A wide range of derivatives including 'swap spreads', forwards or futures, 'contracts for differences' as well as exchange for physical flows to arbitrage relative price movements ensures the oil market is truly global.

Natural gas markets are probably the best analogy for hydrogen markets. Natural gas is a low-density, dangerous commodity that needs a highly developed and costly transport infrastructure. Gas markets have been more regionalized than oil markets. This is because gas transport was traditionally more expensive than oil transport because it was primarily transported through pipelines before technologies developed during the 1960s to liquefy gas and transport it in specially designed ships (Jensen 2004).

In the late 19th and early 20th century, gas derived from coal was an important energy source for lighting and cooking in the early industrialized countries. This "town gas" was produced and distributed in local networks. In the 1960s, a massive natural gas discovery in the Netherlands led to a conversion of the domestic energy system from coal to gas within less than a decade without any state intervention, as natural gas was cheaper and much more convenient than coal. Likewise, the UK transitioned from coal to gas after large gas discoveries under the North Sea in the 1970s. Norway developed a large pipeline-based export infrastructure from the 1970s onwards, followed by the Soviet Union during the 1980s, and Algeria from the 1980s onwards. Historically, pricing for international gas supply contracts was done through long-term contracts pegged to the oil price, as gas initially was a by-product of oil production and served as an alternative to oil combustion in power plants and industry (Jegourel 2016). "Gas suppliers had to allocate substantial investment in production and transportation, and gas buyers often had to invest a lot in distribution networks. Appliances geared towards gas had to be adopted downstream by industrial residential and commercial users, often with the help of the State. The gasification of entire countries carried hefty costs. Strong guarantees were thus needed by both suppliers and buyers and oil—by its liquid, global, traded nature—offered stronger guarantees than a nascent commodity" (Hafner and Luciani 2022, p. 383). The emergence of LNG trading has changed this situation. International LNG trading in significant volumes started in the 1970s first in the Atlantic, and subsequently in the Pacific. The US LNG market collapsed in the late 1970s and only re-emerged in the late 1990s, while the Japanese and European markets expanded continuously: Supply initially came mostly from Southeast Asia and Algeria; Qatar entered the market only in the late 1990s (Jensen 2004, p. 9).

Given that characteristic of the early LNG market are quite similar to those of future hydrogen markets, we take a deep dive into the contract structures, building on Jensen (2004, p. 15ff). Initially, LNG investments could only be triggered through an elaborate system of risk sharing designed by a long-term Sale and Purchase Agreement (SPA) with a duration of 20 or more years, with the buyer assuming the volume risk and the seller the price risk. Most contracts feature a ‘plateau’ volume to be reached after a ‘ramp-up’ period. The buyer would have to take a minimum of 90% of his annual contract quantity or pay a penalty. The price would usually be bound to the oil price. Initially, buyers were limited to government monopolies or franchised energy utilities in industrialized countries, while oil companies (see the section on oil markets above) would act as sellers. Due to the high creditworthiness of these counterparts, financing conditions would be favourable. Contractual delivery was always specified either at the start or the end of the tanker route, never beyond. Ownership of tankers varied but a specific ship would be assigned to a specific contract, often also due to transport systems having unique characteristics and lacking harmonization. Sometimes ships would idle for decades if there was a problem with the SPA they were assigned to (Jensen 2004, p. 45). On the margins of the SPA markets, short-term markets developed to cover excess supply or demand since the 1990s. These became the seed of the spot market to emerge in the phase of market deregulation.

Once transport infrastructure was sufficiently mature and homogeneous, a competitive market for transportation capacity developed as tanker operators were able to easily switch between suppliers. Deregulation in the buyer markets was achieved when governments required LNG terminal operators to provide access to any entity wanting to unload LNG there. With free market competition among buyers and sellers emerging, it became crucial to hedge risks. Since the 1990s, and fully since the mid-2000s a competitive natural gas market reacting on supply and demand in a region, a so-called “hub”, has emerged (Hafner and Luciani 2022, p. 380), mainly driven by the explosion of shale gas production in the US that established the Henry Hub benchmark in the US and the UK National Balance Point (NBP) and Dutch Title Transfer Facility (TTF) in Europe. Derivatives such as futures, options and swaps developed rapidly in the US and EU natural gas markets and then made an inroads into the LNG market. Pirrong (2014, p. 8) proclaimed that “The shift away from oil-based pricing can be made, will be made, and must be made”. However, Jegourel (2016) pointed to the serious oversupply of natural gas globally in the 2010s driven by a more rapid penetration of renewable energy than anticipated, driving the emergence of the spot LNG market. In the same vein, Jensen (2004, p. 51) stressed that financial derivatives are unable to mobilize multi-billion-dollar LNG investments and indeed a decade later (Pirrong 2014, p. 8) only 20% of transactions had shifted to the spot market. Also, where new transport infrastructure has been needed, a ‘ship-or-pay’ agreement is applied, where a bidding process is used to allocate transport capacity and the selected transport users pay long-term fixed fees on the investment, regardless of whether they use the transport capacity. While around 2017 the Henry Hub benchmark started to become a global benchmark for gas trading due to the emerging role of the US as a swing producer for LNG (Sider and Matthews 2017), and in East Asia the Platts LNG Japan Korean

Marker (JKM) became a key benchmark (Bennett 2019), driven by supply surplus (Stern and Imsirovic 2020, p. 15). Pratt (2022) sees no full convergence of the LNG market towards a spot market. In 2021, international LNG and pipeline-bound natural gas each made up about half of the market volume (IEA 2022b, p. 78, 86). An interesting trend in Europe is the replacement of the NBP hub previously driven by strong UK North Sea gas production, robust consumption, and supportive market regulation by TTF due to more indexation of gas contracts in northwest Europe to a gas benchmark denominated in Euro (Bennett 2019, p. 30). While the aftermath of the Ukraine war will reduce the share of pipeline-routed international gas trades currently dominated by Russia, in the long term a mix of pipeline and LNG markets will develop depending on the competitive characteristics of costs of pipeline vs ship transport. A “pipeline-ship transport frontier” can be expected where the cost of the pipeline and ship-based LNG transport becomes equal.

1.4. Synthesis: expected contractual and financial forms of hydrogen trading

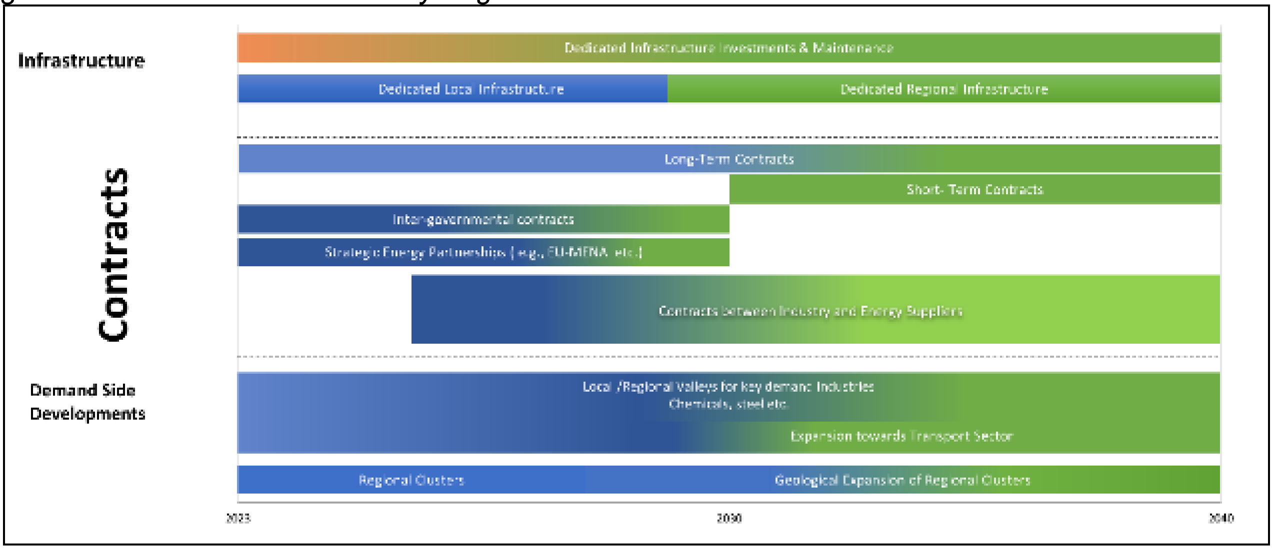
Summing up the historical experiences with energy markets, particularly the natural gas, LNG and oil markets, we would expect a start with long-term contracts for the evolving trade of hydrogen. This is due to the heavy need for infrastructure investment for hydrogen production as well as the transport infrastructure including pipelines, tankers, and terminals. For gaseous hydrogen, its low density of hydrogen and related transport challenges are likely to lead to strongly regionalized markets defined by the renewable energy base. For long-distance transport the best option today is ammonia (in the future potentially liquified hydrogen transport) which can be shipped but in much lower quantities than by pipelines.

Overall, we expect the hydrogen markets to start with **regional clusters**. Local or regional hydrogen valleys driven by industry can ignite demand and benefit from cost reductions from shared infrastructure such as local/regional hydrogen grids supplied with a combination of domestic and imported hydrogen. One can already observe the establishment of such clusters, for example, the evolvement of the European Hydrogen Backbone (EHB) in the western part of Europe, with dedicated import terminals in the Netherlands, Germany, the UK, and France. The regional grid is supposed to supply industrial centres (e.g., Ruhr area) and single installations (e.g., steel plants). The EHB initiative consists of a group of 31 private-sector energy infrastructure operators, aiming to create a pan-European hydrogen transport infrastructure by 2040, requiring an estimated total investment of 86 USD-154 USD billion (EHB, 2022). Industry sectors expected to be demand drivers until the early-mid 2030s are the chemical sector/fertiliser production (ammonia), steel (hydrogen), refineries (hydrogen) and potentially industries with a high demand for industrial heat. These regional clusters will expand geographically over time. The transport sector can be connected in line with infrastructure investments in hydrogen fuel stations.

For the **period until 2030,** we expect long-term contracts (10-12 years) to dominate between producers and off-takers to reflect investment cycles and the cost-reduction potential of electrolysers. There will be both government-to-government contracts (energy partnerships etc.) and private-sector contracts between energy suppliers and industry. In addition, strategic energy partnerships may be initiated as geopolitical measures. Depending on the political priorities of key demand centres, likely candidates are EU-Africa (focus on green hydrogen), EU-Middle East (long-term: green; blue as transition), Japan-Middle East (long-term: green; blue as transition), Japan-Australia (focus on green), and – in the longer term – EU-Australia and Southern cone of South America-US (both with focus on green). In this period, we expect mainly bilateral contracts with individually agreed, fixed offtake (volumes/prices) conditions. Between the early **2030s and 2040,** there will be significant progress towards standardisation – in terms of carbon characteristics and potentially sustainability labels – and OTC deals steadily replacing bilateral agreements. Also, more flexibility in contract duration can be expected, with shorter terms possible. Also, more players will be on the market and infrastructure/transport challenges losing importance, which all leads to more competition in the markets.

In contrast to the oil (and partially natural gas) market, benchmarks will not be linked to the physical characteristics of the fuel but to the regional abundance of the energy driving hydrogen production, mostly renewable but probably also fossil if linked to CCS. The first large hydrogen market could be built around a Dubai solar / CCS benchmark in the 2030s, competing with Australian solar. The first market could serve both Europe and Asia; the latter would focus on East Asian demand. As transport options become cheaper over time and the infrastructure will start to become amortized, over two to three decades a shift to a more liquid market with more regional benchmarks driven by regions with huge renewable energy supply far from major demand centres is likely – we may see Patagonia wind[14] and North American West Coast Tidal[15] as new benchmarks for the American market and East Siberian tidal[16] for the Asian market in 2050. A full hydrogen spot market will only materialize if a significant oversupply emerges, and the transport chain components are converging to a worldwide standard. In the long run, competition between pipeline and ship-bound hydrogen trading will emerge; the shares of each market segment will depend on the relative costs.

Figure 8*: Schematic evolution of hydrogen trade structures until 2040*



Legend: Blue colours are present in the beginning meaning the blue hydrogen will be more dominant in the beginning. However, after 2030 green hydrogen will start being more dominant.

Source: *Authors, based on IRENA (2022a), p.82.*

[14] Technical wind power potential in Patagonia is estimated at over 200 GW (Labriola 2005), with plant load factors as high as 60% (Armijo and Philibert 2020).

[15] The tidal current potential of Cook Inlet in Alaska alone is estimated at 18 GW; for Alaska as a whole at 47 GW (Georgia Tech Research Corporation 2011, p.26). In the Canadian inlets near Vancouver Island potential has only partially been explored but certainly exceeds 2 GW (Sutherland et al. 2007) and probably 4 GW (Tarbotton and Larson 2006).

[16] According to Wikipedia (2022), the tidal power potential of Penzhin bay in the Okhotsk Sea reaches 87 GW.

02

Relevance of different hydrogen production technologies in the emerging international hydrogen market

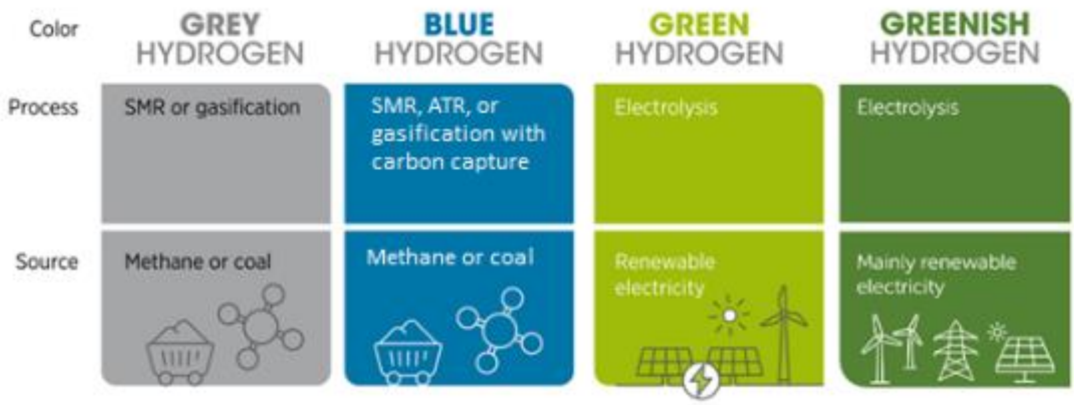
2. Relevance of different hydrogen production technologies in the emerging international hydrogen market

2.1. Characteristics of grey, blue, and green hydrogen

Today various technologies for the production of hydrogen are available. A strongly simplifying colour scale is normally used in order to describe the different production pathways for hydrogen, see Box 1.

As mentioned in Chapter 1.1, this study focuses on the three most prominent ones, i.e., grey, blue, and green hydrogen. In addition, we introduce a new category: “greenish hydrogen” – which is hydrogen produced mainly but not exclusively with renewable electricity. This category is highly relevant in practice because electrolyser operators may opt for a grid connection and running electrolysers with grid electricity in times when no PV/wind is available. This can increase the utilisation rates of electrolysers and improve the economic attractiveness of a project. In order to ensure significant environmental benefits of “greenish hydrogen”, maximum GHG thresholds associated with its production should be defined. In its RED regulation, the EU currently defines this threshold at around 3.4 kg CO_2/kg H_2, whereas the Green Hydrogen Organisation promotes a significantly lower value of 1 kg CO_2/kg H_2 (Green Hydrogen Organisation, 2023). Details on the production processes, the respective embodied GHG-emissions and required raw materials of each of these four hydrogen types can be found in the Annex.

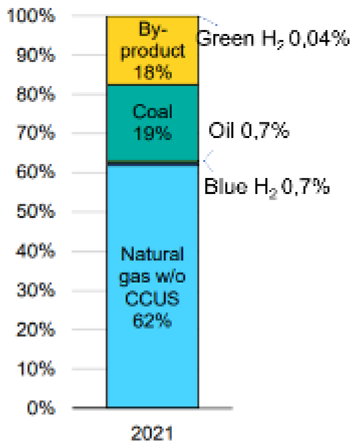
Figure 9: *Hydrogen production types discussed in this study*



Source: *Authors, based on IRENA (2022d).*

In 2021, the majority of the world's hydrogen demand was met by fossil fuel-based hydrogen without carbon capture and storage (CCUS) ("grey hydrogen"). The total global production amounted to 94 million tonnes of hydrogen (Mt H_2) with associated emissions of approximately 900 Mt CO_2. Natural gas without CCUS accounted for 62% of global hydrogen production. Hydrogen production from coal accounted for 19% of total production in 2021 and was mainly located in China. Also, limited amounts of oil (less than 1%) were used to produce hydrogen. Another production route is as a by-product of naphtha refining, which accounted for 18% ("white hydrogen"). These by-products are mostly used for other refinery processes such as hydrocracking and desulphurization. In 2021, green and blue hydrogen production accounted for less than 1 million tons (0.7%) of total global production, with almost all of it being produced from fossil fuels with CCUS. Only 35 kt H_2 was produced from electricity via water electrolysis. However, the amount of hydrogen produced via water electrolysis, while still small, increased by almost 20% compared to 2020, indicating an increasing deployment of water electrolysers. During the year 2021, the installed electrolyser capacity rose by another 70% which reflects the foreseen exponential growth of this auspicious technology (IEA 2022).

Figure 10: Total global production shares of H_2 production processes in 2021



Source: IEA (2022c), pg.71.

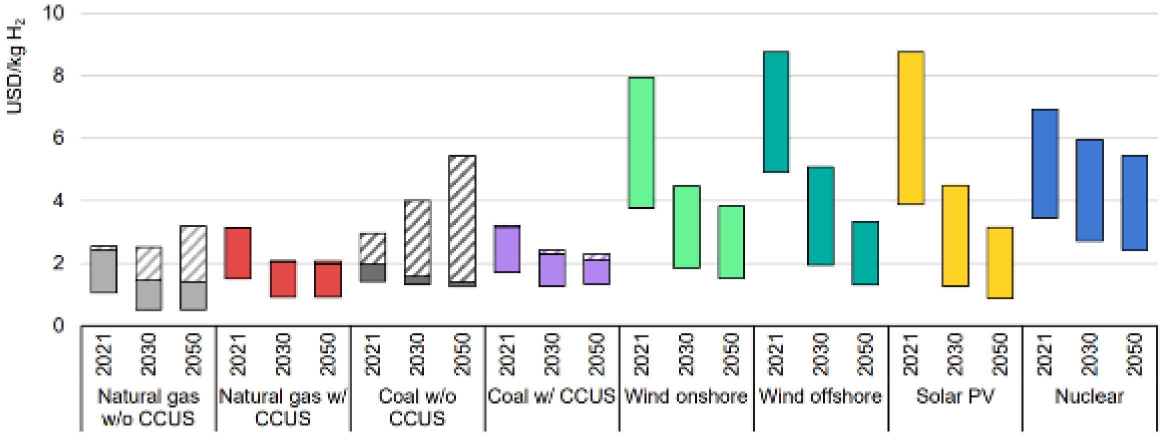
2.2. Drivers of grey, blue, and green hydrogen investments

Generally, it can be noted that the amount of "green", "blue" and "grey" hydrogen products produced and consumed is mainly a function of the following key parameters:

2.2.1. Cost of hydrogen production

As can be seen in Figure 11, in 2021 the cost of producing blue or green hydrogen was higher than grey hydrogen production in most regions. The typical cost range for hydrogen production in 2021 was 1.0-2.5 USD per kilogram for grey hydrogen; 1.5-3.0 USD per kilogram for blue hydrogen, and 4.0-9.0 USD per kilogram for green hydrogen. However, the war in the Ukraine has increased concerns about energy security, leading to physical constraints on natural gas supplies in Europe and a significant rise in natural gas prices. This has heavily affected the economics of producing hydrogen from natural gas. At prices of 0.93-1.68 USD/m^3 observed in June 2022 in European gas markets, hydrogen production costs from unabated natural gas at 4.8-7.8 USD per kilogram are up to three times higher than in 2021 (IEA 2022c). With these natural gas prices, the costs for hydrogen from natural gas with CCS are in the range of 5.3-8.6 USD per kilogram. **Considering those prices, green hydrogen could already be the cheapest option for producing hydrogen in many regions if production capacity was available.** The high price volatility for fossil fuels, makes it hard to predict how grey/blue hydrogen prices will evolve in coming years and when green hydrogen will reach cost parity with higher emission hydrogen production technologies.

Figure 11*: Hydrogen production costs for different energy sources*[17]



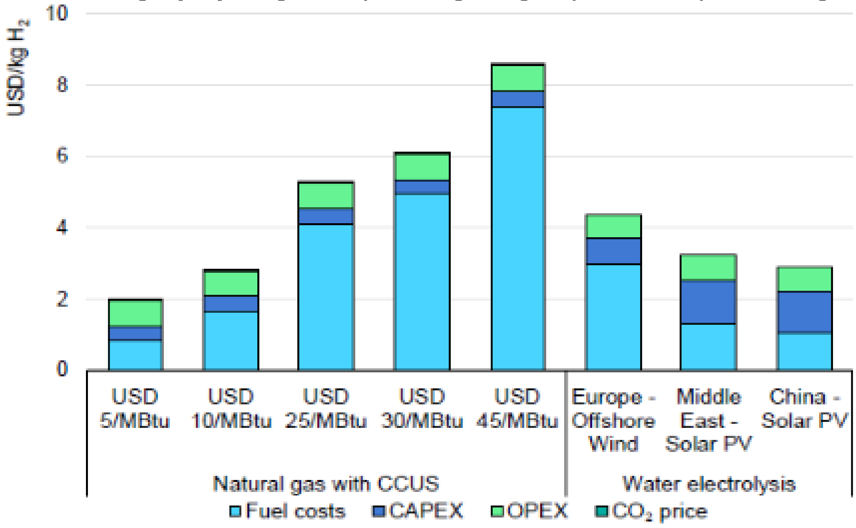
Notes: Ranges of production cost estimates reflect regional variations in costs and renewable resource conditions. The dashed areas reflect the CO_2 price impact, based on CO_2 prices ranging from USD 15/tonne CO_2 to USD 140/tonne CO_2 between regions in 2030 and USD 55/ tonne CO_2 to USD 250/ tonne CO_2 in 2050.

Source: *IEA (2022c), p.92.*

A typical cost breakdown for different hydrogen colours can be seen in Figure 11. The most important factors influencing the production costs for green hydrogen are, as noted in chapter 2.1, CAPEX (including cost of capital) and OPEX (mainly electricity costs). Especially levelized costs of electricity (LCOE) and weighted average cost of capital (WACC) strongly depend on the project location. LCOE are influenced by the share of renewable resources in the grid of consideration (or the CAPEX of dedicated RE if there is no grid-connection), while WACC mainly depends on economic and market conditions in the host country (IRENA 2022c). The production costs for blue and grey hydrogen are mainly driven by gas prices and, to a far lesser extent, by CAPEX and OPEX for the respective production facilities. At average European gas prices of 2022, the gas feed stock makes up approximately 70% of the overall production costs of blue hydrogen (Flora and Jaller-Makarewicz 2022). This ratio is even higher for grey hydrogen since CAPEX and OPEX are further reduced compared to blue hydrogen production facilities. Figure 12 shows the production costs of grey hydrogen depending on gas prices compared to average green hydrogen production costs in various regions. With an average gas price of 0.75-0.93 USD/m^3 green hydrogen production powered by offshore wind in Europe would already be cheaper than blue or even grey hydrogen production. The projected significant price decrease for electrolyser CAPEX to less than 537 USD/kW until 2030 as projected by IEA (2022) would support this cost benefit further. According to the to a recent study by IEEFA, blue hydrogen projects are at great risk of becoming stranded assets due to the high volatility of fossil fuel prices (IEEFA 2022).

[17] The CO_2 emissions from blue hydrogen and the resulting carbon pricing in this figure is based on a 95% CO_2 capture rate.

Figure 12*: Levelized cost of grey hydrogen depending on gas price compared to green hydrogen*



Source: IEA (2022c), p.93.

2.2.2. Greenhouse gas emission intensity

The emission intensity for different hydrogen production routes can vary greatly as can be seen in the following table. These embodied emissions of hydrogen may have a crucial impact on the future demand for different types of hydrogen. Embodied emissions of hydrogen can impact demand (buyer sensitivity to embodies emissions), achievable prices and have reputational impacts.

It must be noted that the emission intensity depends significantly on the system boundary chosen. Especially upstream (extraction, processing, and transport of natural gas) and downstream emissions (transport emissions) can have a significant effect on the overall embodied emissions. As noted, upstream emissions from grey and blue hydrogen can lead to embodied emissions of up to 5.2 $kgCO_2/kgH_2$. As can be seen in Table 2, which shows production emissions as well as upstream emissions, in some cases blue hydrogen production can have similarly high embodied emissions as grey hydrogen which brings the ecological benefit of this technology into question. The carbon capture rate (CC-rate) of blue hydrogen is the factor influencing emission intensities of blue hydrogen. Studies show that the carbon capture rate is generally altering between 50% to 90% (Duscha and Riemer 2022).

Table 2*: Carbon intensity of different hydrogen production technologies*

Grey hydrogen	Blue hydrogen (50-90% capture-rate)	Green and greenish hydrogen
10.9 – 14.2 $kgCO_2/kgH_2$	3.1 – 9.2 $kgCO_2/kgH_2$	0 – n.d. $kgCO_2/kgH_2$

Source: Authors.

The European Union for example has put strict regulations on the carbon intensity of hydrogen. It defines Renewable hydrogen as: i) It derives its energy content from renewable sources other than biomass; and ii) achieves a 70% GHG emission reduction compared to fossil fuels. Low-carbon hydrogen is defined as hydrogen with an energy content that is derived from non-renewable sources, and that meets a GHG emission reduction threshold of 70% compared to fossil-based hydrogen. This can be translated to an emission intensity threshold of approximately 3.4 $kgCO_2/kgH_2$ (EU Commission

2022a). Hence it would be technically very challenging to reach this threshold with blue hydrogen (if upstream emissions are considered), and thus makes the European market almost inaccessible for this type of hydrogen.

Further, low embodied emissions can entail economic benefits for hydrogen consumers or producers. There are various low-carbon hydrogen subsidy schemes in place which lead to increasing positive opportunity costs with decreasing embodied emissions. One example is the Inflation Reduction Act (IRA) in the USA. It gives tax incentives for low-carbon hydrogen production between 0.60 USD/kgH_2 to up to 3 USD/kgH_2. The lower the carbon intensity is, the higher the tax credit. The maximum carbon intensity receiving the lowest tax incentive is 4 kgCO_2/kgH_2 including upstream emissions and downstream emissions [18]. (Resources of the Future 2022) Another example is the carbon border adjustment mechanism (CBAM) of the EU, which is still under development. CBAM will internalize costs for embodied carbon emissions for imported hydrogen and hydrogen derivates. Due to these instruments, the ecological benefit of green hydrogen compared to other production technologies will be internalized and reflected in economic benefits.

Carbon intensity or the specific production route of hydrogen can be decisive for consumers when selecting hydrogen suppliers / products. Products based on green or low-carbon hydrogen can bring beneficial marketing effects to companies and can help them achieving corporate net-zero targets. The reputational benefit may lead to a “green premium”. Especially in the steel sector, this trend already becomes visible. The additional costs caused by the production of green steel potentially can be passed on to customers as it is done with the increased costs for e.g., organic food. For instance, the CEO of Anglo American Anesan Naidoo mentioned that “Green steel is a niche market because it’s fairly new, but it will eventually become a license to operate.” (Perrine 2022) Further, increased public pressure on companies for good environmental performance can further push hydrogen consumption to green.

Generally, it can be noted that blue hydrogen may serve as an interim solution due to the currently lower production costs compared to green(ish) hydrogen in most locations. It is important to note though that green hydrogen production costs will only decline due to economies of scale, *if* there is a significant expansion of production capacities. Hence, large-scale investment in green hydrogen is required to achieve cost-reductions in the mid-term; and using blue hydrogen as an interim solution may hinder such investment. Additionally, investment in *new* fossil-fuel based hydrogen production has long lead- and lifetimes which might entail long-term lock-in effects. Finally, due to the high embodied emissions of blue hydrogen, real GHG-benefits only occur for some use cases – such as replacement of coal in difficult to replace sectors such as steel production or the replacement of grey ammonia or grey hydrogen in the chemical industry. Replacing e.g., natural gas by blue hydrogen may effectively not lead to emission reductions. The replacement of coal with 100% green hydrogen in the steel sector can reduce emissions by approximately 1 tCO_2/MWh of hydrogen used. 1 MWh of grey hydrogen has embodied emissions of 0.3 tCO_2/MWh, while replacement of natural gas leads to emissions of 0.2 tCO_2/MWh. Blue hydrogen can have embodied emissions of up to 0.22 tCO_2/MWh. Thus, its application

[18] In this context this refers to “[…]the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, From feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.”

would only reduce emissions significantly in the replacement of coal; other applications would only entail minor emission reductions or might even have a negative climate impact.

2.2.3. Security of supply

For producing large amounts of green hydrogen, mainly three things are needed: Sufficient electrolyser capacities, sufficient renewable energy capacities to power them, and sufficient water resources for electrolysis. Currently, the market is confronted with supply chain issues regarding electrolysers. This is mainly due to limited electrolyser production capacity. Another problem is the scarcity of raw materials (especially noble metals) for the electrolyser production. But with new technologies like i.e., AEM electrolysers – which do not need any rare materials – this issue might be solved in the mid-term (IRENA 2022d). The second critical input factor is sufficient renewable energies. A rapid and massive ramp-up of those technologies is needed. It is essential to have a supportive regulatory framework in place, to have a sufficient supply of rare earths like e.g., Neodymium for wind turbines, to have sufficient land availability and finally technological know-how at the specific project location.

For producing blue hydrogen, the main input needed is natural gas and access to a substantial, cheap and long-term possibility to store the captured CO_2. Natural gas is subject to strong price fluctuations especially in gas importing countries, which could be recently observed during the gas crisis in Europe. This high volatility leads to high risks for significant, long-term investments required to develop blue hydrogen projects. According to Bloomberg Energy News "with blue Hydrogen, it is go-big or go-home. A typical project costs USD 500 million to build, and there is not much scope to go smaller because the technology only works at large scale." (Bloomberg 2021).

2.3. Expected production and market shares of grey, blue and green hydrogen

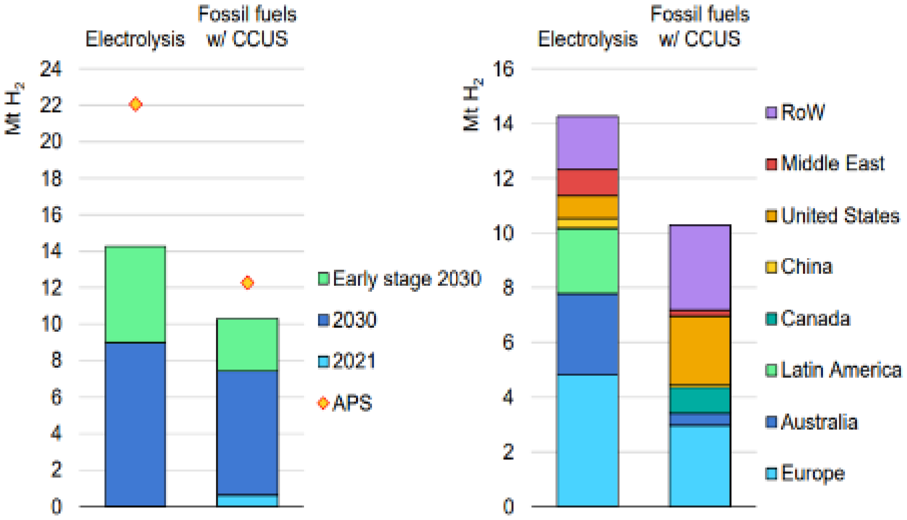
As previously mentioned, hydrogen is currently produced almost entirely from fossil fuels (gas and coal) or as a by-product of chemical processes. Despite high growth rates[19], the global market share of green or blue hydrogen is currently less than 1% but is bound to grow rapidly in the coming years (IEA 2022). The exact extent of its use is unclear, but estimates suggest hydrogen could make up anywhere from 10% to 20% of global energy consumption in a low-carbon energy system (DNV 2022). In this study the expected market share for green and blue hydrogen production for 2030 will be based on the hydrogen project database by the IEA. Since big-scale hydrogen projects have long lead times, most projects which will be operational at this time are already in the planning stage and thus included in the project database. Forecasting the development for 2040 and beyond is significantly more uncertain due to the various driving factors influencing the future development which are listed in the previous chapter. There are multiple studies projecting hydrogen production development until 2050 of which we have selected six scenarios.

[19] In 2021, low-emission hydrogen production grew by 9%. Good 200 MW of electrolysers went into operation in 2021, including 160 MW in China and like. 30 MW in Europe (IEA 2022c).

2030

According to the hydrogen project database, annual green and blue hydrogen production can reach 24 Mt in 2030 if all current projects are completed. The development stage of these projects varies with 68% in advanced planning including 4% being under construction or having reached FID. 32% are still in the early planning stage.

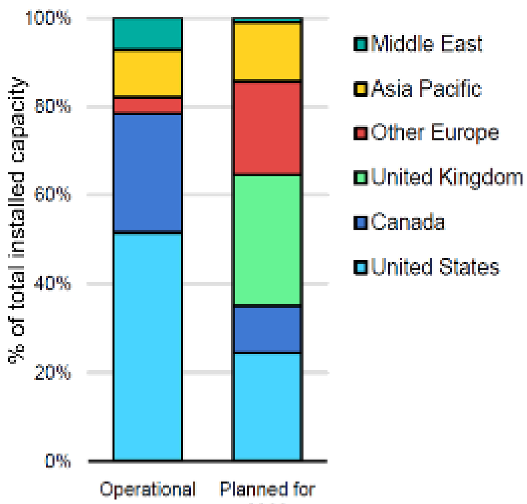
Figure 13: *Green and blue hydrogen production in 2030*



Source: *IEA (2022c), p.72.c*

As of January 2021, more than 50 new projects involving CCUS had been announced. If these projects are successful, it is estimated that by 2030, approximately 80 Mt CO_2 could be captured from hydrogen production, with around 50 Mt coming from dedicated facilities for producing merchant hydrogen or ammonia. The production of blue hydrogen from facilities equipped with CCS is projected to reach 11 Mt in 2030. However, as of August 2022, less than 10 of these projects had reached FID or were already operational (IEA project database) Additionally, it is uncertain if recent increases in natural gas prices will delay planned investment decisions in the near future, particularly in Europe. Most projects in the pipeline are focused on hydrogen or ammonia production for merchant use.

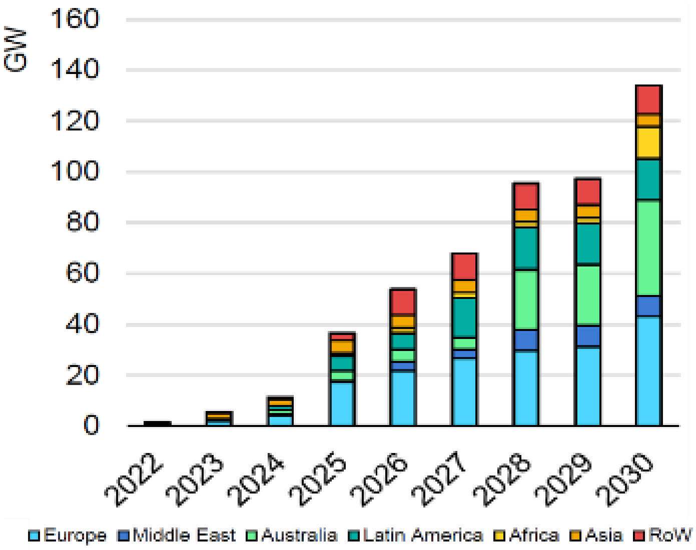
Figure 14: Blue hydrogen production by region (in % of total)



Source: IEA 2022c, p.89.c

In Europe, blue hydrogen production is growing, particularly in the United Kingdom and the Netherlands, driven by industrial decarbonization programs. Most of these facilities are being built near industrial clusters as these areas can serve as potential demand centres for hydrogen and also provide opportunities for sharing the cost of CO_2 transport and storage infrastructure with other emitters. Approximately half of the announced capture capacity is being developed as part of CO_2 transport and storage hubs for multiple industrial sources, with about 80% located in Europe and about 15% in Canada (IEA 2022c). Figure 14 shows the current blue hydrogen production capacity as well as the project pipeline.

Figure 15: Installed electrolyser capacity by region



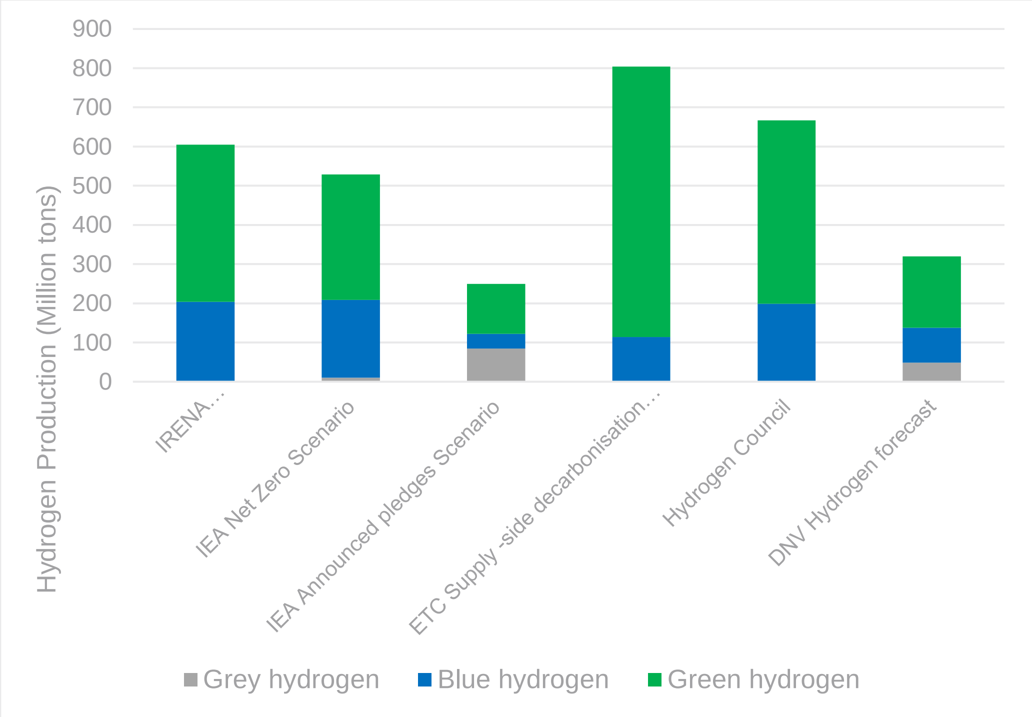
Source:IEA (2022c), p.77.)

By the end of 2022, global electrolysis capacity has exceeded 1 GW which is nearly three times the 2021 level. Globally, there are approximately 460 electrolyser projects under development or construction. Approximately 40% of this capacity is being developed in China and a third in Europe. IEA (2022c) expects an increase in global electrolyser capacity to up to 134 GW in 2030. However, so far only 175 of these projects are under construction or have reached FID, representing about 9.5 GW. As can be seen, Europe and Australia are leading the way in hydrogen production using water electrolysis. Green hydrogen production in Europe could reach nearly 5 Mt. Australia plans to export hydrogen to high-demand centres in Asia and could reach a production capacity of 3 Mt (28 %) by 2030. Additionally, Latin America (12%), the Middle East and Africa are also expected to produce large amounts of electrolytic hydrogen for export to Europe and Asia.

2050

There are multiple studies projecting the amount and market share of different production routes of hydrogen in 2050. A summary graph can be seen in Figure 16. For this study, we selected six scenarios in order to give a range of the current forecasts and show the high uncertainty regarding this topic.

Figure 16: *Hydrogen production projections for 2050 for different scenarios*

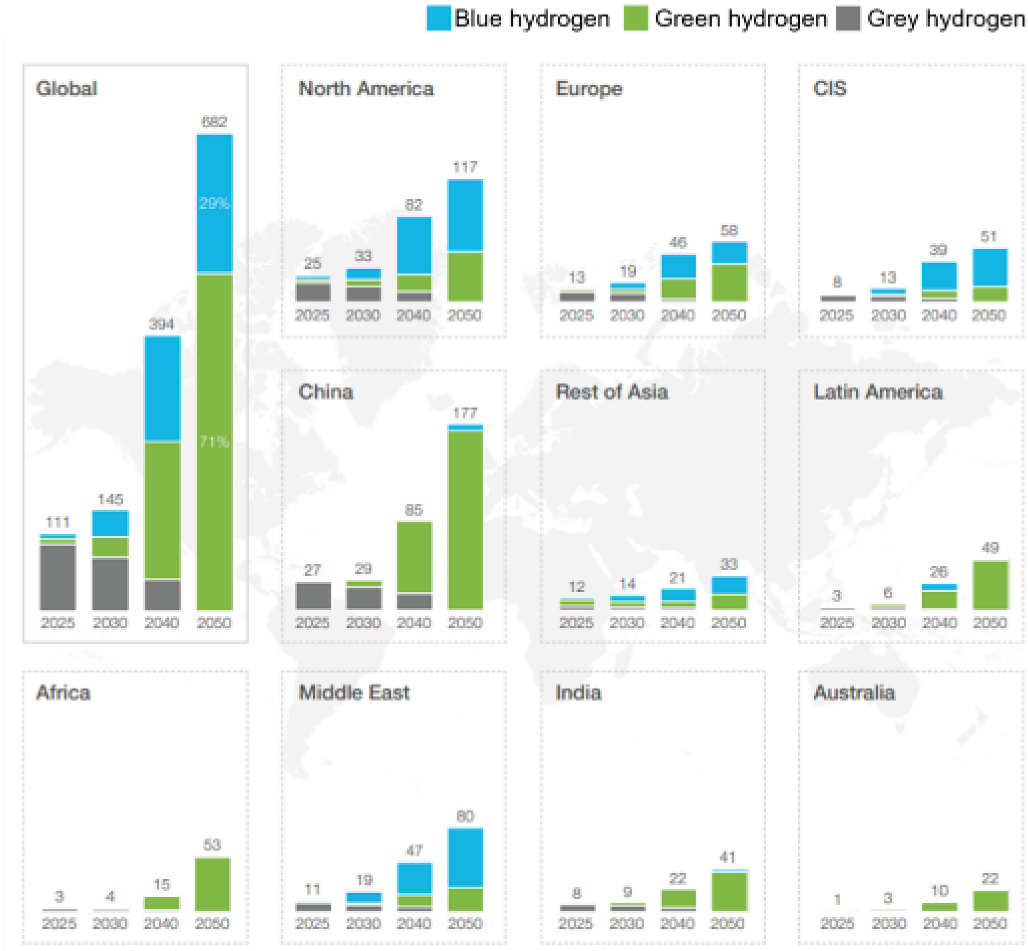


Source: *Authors, based on ETC (2021); Hydrogen Council (2021); IRENA (2021); IEA (2021); DNV (2022)*

The overall projected global hydrogen production capacity in 2050 ranges from approximately 250 Mt/yr in the APS (Announced Pledges Scenario) by the IEA to more than 800 Mt/yr in the decarbonization scenario by the ETC meeting between 6% and 22% of the final energy demand. Even though there are significant variations in the expected production routes, 4 out of 6 studies foresee a complete phase out of fossil-based hydrogen production routes without CCS. Further, all studies predict a dominance of green over blue hydrogen. Between 51% and 86% of the global hydrogen production will be met by green hydrogen. To produce the predicted amounts of green hydrogen, between 5 and 27 PWh of renewable energy production will be necessary. To put this in comparison, in 2021 approximately 8.3 PWh of renewable electricity have been generated globally.

For a deeper analysis of the specific market shares of hydrogen types we chose the prediction by the Hydrogen Council which can be seen in Figure 17. This study was selected since their production forecast lays well within the average of all presented studies and show disaggregated numbers for production regions and timespans.

Figure 17: *Expected blue and green hydrogen market shares for different regions (in million tons per annum)*



Source: *Hydrogen Council (2022), p.21.*

By 2050 grey hydrogen will be phased out and the global ratio of green to blue hydrogen will be approximately 70:30. However this ratio differs strongly by geography: China, Africa, India, Australia, and Latin America are projected to produce hydrogen exclusively from renewable sources, while the other regions will produce a significant part via the blue production route. Especially regions which are currently major natural gas producers like North America, the Middle East and Commonwealth of Independent States (CIS), will produce the major share of the overall production based on fossil fuels with CCS in order to further benefit from their natural gas resources until 2050 and beyond. For Europe it is foreseen that in 2050 approximately 60% of the 58 Mt hydrogen will be green and 40% blue hydrogen (Hydrogen Council 2022). As previously stated, these figures should be taken with a grain of salt, as even small changes in policy or production technologies could lead to significant changes in the global market.

03

Expected effects of different hydrogen certification schemes on the structure of the emerging international hydrogen market

3. Expected effects of different hydrogen certification schemes on the structure of the emerging international hydrogen market

Certification plays a crucial role in establishing any industry, especially in the case of the emerging hydrogen trade. The certification of hydrogen and its derivates would include information regarding compliance with regulatory requirements and would facilitate the verification via data on sustainability criteria. Those criteria include the embodied carbon emissions or the renewable energy content which would allow consumers to differentiate certified products from less green alternatives. A uniform, reliable and transparent certification of the greenhouse gas intensity (kg CO_2/kg H_2) of hydrogen or its derivatives is essential to achieve national or corporate climate policy goals. Additionally, other environmental, social or governance criteria e.g., water footprint or land use regulations could further increase the scope of sustainable hydrogen certification. Including sustainability criteria in product, certificates is crucial to making low-carbon or renewable hydrogen a desirable commodity. The certification of hydrogen enables industries to promote their products as sustainable products. This results in consumer demand for certified products, providing incentives for long-term investments and assurance of the low-carbon or environmentally friendly status of the product. Moreover, certificates enhance the accuracy of supply chain carbon accounting, which is vital for businesses and industries that may face carbon credits or taxes. The emergence of multiple hydrogen certification schemes, both voluntary and mandatory, has created confusion regarding the definition of low-carbon and renewable hydrogen. The varying technical criteria, including emissions threshold and accounting methodology, can result in different interpretations of the same label, such as "green hydrogen". Additionally, these schemes may also include non-comparable environmental, social, and governance criteria. As a result, there is currently no universally recognized hydrogen certification scheme suitable for international trade. The development of a standardized, globally recognized certification scheme would greatly benefit the industry by providing clarity and facilitating international trade (IRENA and RMI 2023).

In recent months, various organizations have proposed different certification standards – e.g., the *International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) and the Green Hydrogen Organization (IPHE 2021)*. The UK's *Department of Energy and Climate Change* already published a green hydrogen standard in 2015 (Department of Energy and Climate Change 2015); and the EU is currently elaborating delegated acts under the Renewable Energy Directive (RED) defining the standards for recognizing the 'green property' of hydrogen. The legislation has been in public consultation and negotiation in the last months and is expected to be formally adopted by summer 2023.Further standards are in the works.

Table 3: *Standards and regulations defining low-carbon hydrogen or its derivatives*

Region/Body	***Reference***	***Threshold/labels***
United States – Build Better Act	*Hydrogen from natural gas*	*40% GHG reduction (2 $kgCO_2/kgH_2$)*
EU - Taxonomy for sustainable activities	*Fossil fuel for transport (94 gCO_2/MJ)*	*73.4% GHG reduction (3 $kgCO_2/kgH_2$)*
EU - CertifHy	*Hydrogen from natural gas*	*60% lower than reference (36.4 gCO_2/MJ)*
EU - Hydrogen and decarbonized gas package	*Fossil natural gas*	*70% GHG reduction*
United Kingdom – Renewable Transport Fuel Obligation	*Transport fuels*	*55-65% GHG reduction*
IPHE, Greet, I-RECISO	-	*Does not define thresholds, but covers methodology to quantify emissions*
Smart Energy Council (Australia)	-	*Renewable*
Ammonia Energy Association	-	*Low-carbon ammonia*
World Business Council for Sustainable Development	*Hydrogen from natural gas*	*Reduced carbon from hydrogen production (< 6kg $kgCO_2/kgH_2$), low carbon (<3 $kgCO_2/kgH_2$), ultra-low caron (<1 $kgCO_2/kgH_2$)*
China – Hydrogen Alliance	*Coal*	*Low carbon (< 14.51kg $kgCO_2/kgH_2$), clean and renewable (<4.9 $kgCO_2/kgH_2$)*
Green Hydrogen Organisation (GH2)	*Green Hydrogen*	*Close to zero (<1 kg CO_2/kgH_2)*
TÜV SÜD	*Hydrogen from natural gas*	*60% lower than reference (36.4 gCO_2/MJ)*

Sources: *Authors, based on IRENA (2022a); Green Hydrogen Organisation (2022).*

The problem is that these standards are neither uniform nor globally binding, which leads to uncertainties on both the producer and consumer side. For example, some standards are limited to Scope 1 emissions, while most take *Scope 1 and 2* into account; and still others would like to include Scope 3 emissions in the medium term or introduce further sustainability criteria.

In this section, possible trade-offs between i) hydrogen certification focused exclusively on climate benefits and ii) hydrogen certification geared towards broader sustainability issues are analysed. The key question is: "What effects can be expected from more narrow or broader certification requirements?" on the hydrogen ramp-up?"

3.1. Trade-offs between strict sustainability criteria and the speed of the international ramp-up of the hydrogen market

3.1.1. Historical analogies from carbon markets

While the Clean Development Mechanism (CDM) formally had the twin goal of contributing to sustainable development and generating emissions credits that can be used to reach the emission targets of industrialized countries under the Kyoto Protocol, the requirements regarding sustainable development co-benefits were left to each host country. The main reason for this was the prerogative to exercise national sovereignty regarding the definition of sustainable development. This led to severe criticism by NGOs and media regarding the lack of sustainable development co-benefits of many projects, and outright damage generated by certain projects, such as hydropower or forestry projects leading to the displacement of people without adequate compensation. This criticism led to the elaboration of a sustainable development tool with an elaborate set of criteria that could be voluntarily applied by CDM project developers. Already in the mid-2000s, NGOs had founded the “Gold Standard” certification body which required multiple stakeholder consultations and compliance with a set of safeguards for sustainable development. Under the Gold Standard, monitoring and verification of sustainable development co-benefits is mandatory.

CDM credits from Gold Standard accredited projects have commanded a significant price premium compared to other CDM credits; in the period of absence of demand for “normal” CDM credits whose price fell to a few cents, Gold Standard credits could still be sold for 3.2-5.4 USD. The price premium was significantly higher than the difference in transaction costs between the normal CDM and the Gold Standard procedure. On the voluntary carbon market, Gold Standard credits have been in high demand; they hold a market share of approximately 15% of the total of approximately 1 billion credits issued to date. Especially in the period when the voluntary market demand emanated from companies who really cared for their reputation the price premium for Gold Standard credits reached 2.2-3.2 USD. As demand for voluntary credits soared from 2018 onwards, the price premium declined because more and more companies engaged in the market who just wanted to buy any offset credit. Recent scandals in the market linked to credits from avoided deforestation under the Verra label – which has been dominating the voluntary market - may lead to an increase of the price premium as demand focuses on high quality credits again. This historical experience shows that especially in times of an oversupply in low quality credits, the price premium for credits with high sustainable development co-benefits will increase. In a situation of a “gold rush” with a demand surplus sustainability co-benefits generate less attention, and the price premium may vanish to a large extent.

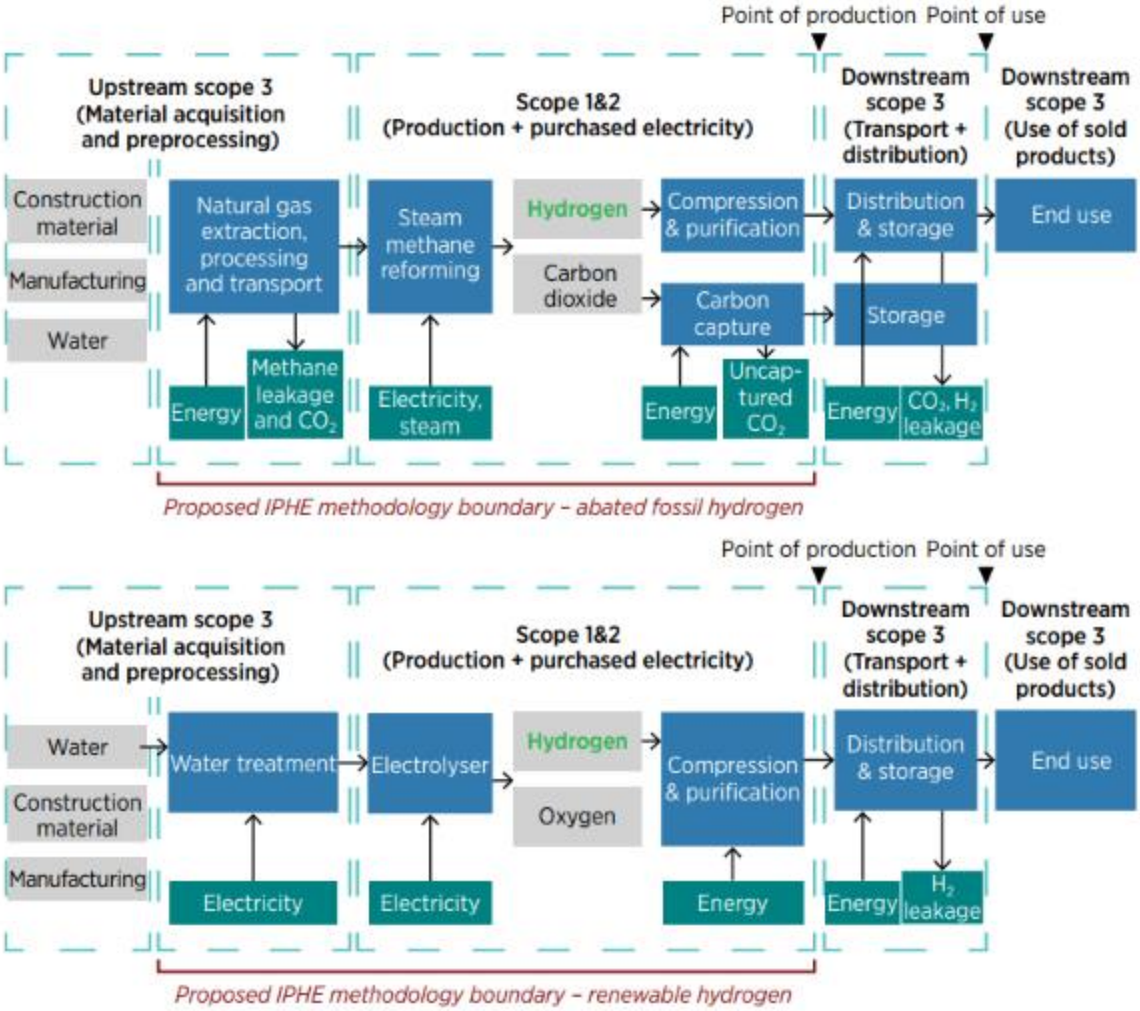
3.1.2. Impacts of comprehensive sustainability requirements on hydrogen market ramp up

In this chapter, three theoretical cases regarding hydrogen certification schemes are used to investigate their potential impact on the future global hydrogen market. The first case only defines a threshold for the carbon footprint of the hydrogen (derivative). The second case investigates the effects of adding water availability and land use conflicts as certification parameters. The third case adds regional and local development opportunities as an additional criterion.

Case 1 – Certification of GHG-intensity

While the use of hydrogen does not lead to direct GHG emissions, emissions can occur during hydrogen production, transportation, and other upstream and downstream processes depending on the type of hydrogen. The upstream processes include electricity generation, extraction of fossil fuels, and fugitive emissions while downstream emissions refer to transport emissions and leakages of greenhouse gases. The carbon intensity of hydrogen can vary significantly depending on the scopes taken into consideration. Some certification schemes only focus on production emissions, others also include upstream and downstream emissions. For this study, we want to showcase the effect of the certification scope by varying the scope of the embodied emission calculations. Case 1.1 only considers scope 1 emissions, case 1.2 additionally includes emissions from scope 2 and 3. Figure 18 shows the different scopes which can be taken into consideration for the emission calculation of hydrogen production.

Figure 18: *Different scopes for GHG-calculations of hydrogen production*



Notes: IPHE = International Partnership for Hydrogen and Fuel Cells in the Economy.

Source: *IRENA&RMI (2023), p.16.*

One of the most prominent examples for hydrogen certification schemes is CertifHy. It sets a carbon intensity threshold of 4.36 kg CO_2/kg H_2 produced including upstream emissions (CertifHy 2022). For this study a theoretical certification scheme with a carbon intensity threshold of 3.4 $kgCO_2/kgH_2$ as defined by the European Union for RFNBOs is used (DA 28, EU). For hydrogen production, 9 kg CO_2/kgH_2 is used as reference value for grey hydrogen (IEA 2021). To assess the consequences of this certification scheme, carbon capture rates of 50% and 90% are assumed. Green hydrogen production does not entail any CO_2-emissions if only scope 1 are considered.

Table 4 shows that, even with upstream and downstream emissions excluded, blue hydrogen with a capture rate of 50% is too carbon intensive for the set carbon threshold and would thus not be eligible for certification. A minimum carbon capture rate of 63% would be necessary to be eligible for certification. Furthermore, grey hydrogen is above the threshold limit. Therefore, it will not be considered in further analysis.

Table 4. *Results of case 1.1 - GHG-emissions of hydrogen production (Scope 1).*

Hydrogen type	Production related emissions ($kgCO_2$-eq/kgH_2)	Within GHG-threshold (<3.4 $kgCO_2$-eq/kgH_2)?
Grey hydrogen	9	**No**
Green hydrogen	-	**Yes**
Blue hydrogen with a 50% capture rate	4.5	**No**
Blue hydrogen with a 90% capture rate	0.9	**Yes**

Source: *Authors*

For case 1.2, scope 2 and 3 emissions are included. A recent IEA study shows that upstream emissions for natural gas-based hydrogen can add 1.9-5.2 kgCO2-eq/kgH2 (IEA 2021). For the calculations in this report, the global average of 2.7 kgCO2-eq/kgH2 is applied. The electricity supply for green hydrogen production can indirectly generate emissions if fossil fuel-based electricity is used. Further emissions can occur during transportation. On average 8.9 g CO2-eq are emitted for 1 tkm of hydrogen transport. Additionally, boil-off/leakages can occur during transport which is already mentioned in Chapter 1.2.1. However, these losses depend on time spent at sea and this can change due to various reasons from weather to long waiting queues in strategic locations. Therefore, the boil-off/ leakage losses are not included in these calculations. Chosen distances are selected strategically. The distance of 8,000 km covers all possible transport routes from North Africa to Germany. 20,000 km covers the longest possible transport distances, i.e., Australia to Germany. The results for case 1.2 can be seen in Table 5.

Table 5: Results of case 1.2 – GHG-emissions (Scope 1, 2 and 3)

Hydrogen type /emissions in $kgCO_2/kgH_2$	Production related emissions	Upstream emissions	Downstream emissions (transport)	Total emissions	Within the GHG- threshold of <3.4 $kgCO_2$?
Green hydrogen, transport distance 8,000 km	-	-	0.07	0.07	Yes
Green hydrogen, transport distance 20,000 km	-	-	0.18	0.18	Yes
Blue hydrogen, 50% capture rate, transport distance 8,000 km	4.5	2.7	0.07	7.27	No
Blue hydrogen, 50% capture rate transport distance 20,000 km	4.5	2.7	0.18	7.38	No
Blue hydrogen, 90% capture rate transport distance 8,000 km	0.9	2.7	0.07	3.67	No
Blue hydrogen 90% capture rate transport distance 20,000 km	0.9	2.7	0.18	3.78	No

Source: Authors

Table 5 shows that only green hydrogen imports are eligible if the described carbon threshold is applied. Blue hydrogen would only be eligible with 90% capture rates and very low upstream emissions. For example, if the upstream emissions are reduced to 2.4 kg CO_2/kg H_2, transport distances of up to 8,000 km would be within the threshold limits. With upstream emissions of only 2.3 kg CO_2/kg H_2, all blue hydrogen-producing countries could qualify for certification and export to Germany.

For local production in Germany, transport emissions are assumed to be zero. However, since national renewable energy capacities are not sufficient to meet the country's hydrogen demand in the short- and medium term, there is – in some cases – the need to use additional grid electricity. With a grid emission factor of 0.349 kg CO_2/kWh (Statista 2022), a maximum of 24% of German grid electricity can be used to stay within this threshold.

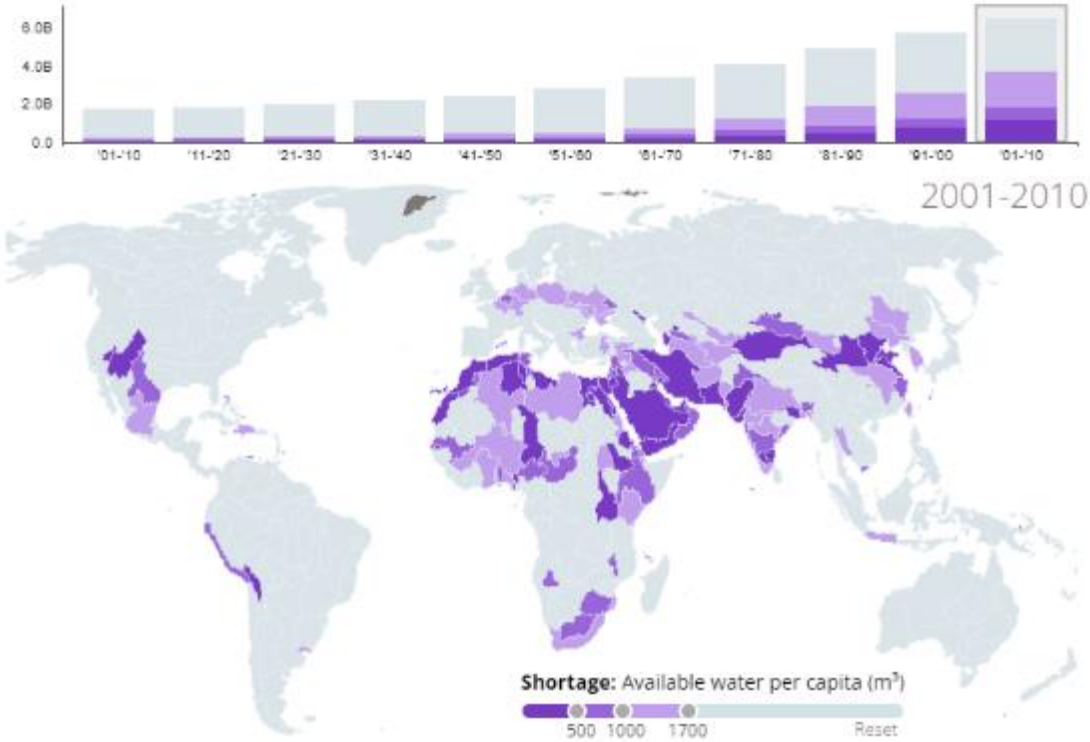
In conclusion, if scope 2 and 3 emissions are considered and the carbon threshold is set to 3.4 kg CO_2/kg H_2 only green hydrogen would be eligible to be certified with average upstream emissions for blue hydrogen. To qualify for certification, most blue hydrogen producers would have to significantly reduce upstream emissions. If grid electricity is used for electrolysis, already low amounts of fossil-based electricity would lead to the surpassing of the set carbon threshold. This shows the high importance of ramping up renewable electricity generation when planning to produce green/greenish hydrogen.

Case 2 – Water availability

In addition to carbon intensity, case 2 defines water availability in regions of hydrogen production as additional sustainability criteria. "The Green Hydrogen Standard" developed by GH2 (Green Hydrogen Organisation) mentions the importance of water availability. The certificate *requires a publicly accessible evaluation of the project's utilization of water and the project's approach to wastewater treatment and water pollution (Green Hydrogen Organisation 2022)*. There is another certification scheme by the Climate Bond Initiative (CBI). This initiative does not give quantitative numbers but mentions that water availability needs to be considered while planning hydrogen production projects (Climate Bonds Initiative 2022).

For this report, data from the water availability atlas is used. For water shortage, the "water stress index" will be applied. This index defines water scarcity in terms of the total water resources available to the population of a region. If the amount of freshwater is less than 1,700 m^3 per person per year, the region experiences water stress, if this value is below 1,000 m^3, it is defined as water scarcity and if the value is below 500 m^3, is called absolute water scarcity (Global Water Forum 2012, Falkenmark 1989). Figure 19 shows that the MENA region is either in absolute or normal water scarcity. Apart from the MENA region, East and West Africa as well as South Africa experiences water shortages. Further, certain parts of the Indian subcontinent experience at least water stress with the western parts even experiencing water scarcity. Moreover, the northern part of the Black Sea region and some parts of Europe are under water stress. Furthermore, some parts of central Asia as well as northern China have similar issues. In South America, coastal provinces of Peru and around the Atacama Desert are in water scarcity. In North America, the Texas-New Mexico-Chihuahua (TX-NM-CHIH) region has absolute water scarcity, water scarcity and water stress respectively. If the certification scheme would only define regions without water shortage as eligible for hydrogen production, none of the above-mentioned countries would qualify for certification. Some of the countries in these areas have been identified by Europe as potential major hydrogen producers for import due to the low costs for renewable energies.

Figure 19: *Water shortage map and global population living in water shortage*



Source*: Water and Development Research Group, International Institute for Applied Systems Analysis (2023).*

Figure 19 only shows freshwater availability. However, it is possible to desalinate seawater to produce green hydrogen. For the desalination process, several aspects need to be considered. These include the additional cost for desalinating water and the energy required for this process. For electrolysis approximately 20 l of water is required to produce 1 kg of hydrogen (IRENA 2020). The cost of water desalination can vary between 0.011 USD/kg H_2 – 0.03 USD/kg H_2 (Rebecca et al. 2021). The required energy for desalination of seawater by reverse osmosis is in the range of 2.5- 4.0 kWh/m^3 or 0.05 – 0.08 kWh/kg H_2 (Pinto 2020). This could result in additional emissions if the required electricity is obtained from fossil fuels. For example, if coal is used to generate electricity for water desalination, it can result in additional emissions of approximately 0.052-0.084 kg CO_2/kgH_2.

Case 3 – Social impacts

In order to examine the effects of a hydrogen certification scheme including all relevant sustainability criteria, the overall social and environmental performance of hydrogen production is included as additional criteria. These criteria include social as well as further environmental impacts like protection of wildlife, biodiversity, and waste management. Some of these aspects are considered in the GH2 standard (Green Hydrogen Organisation 2022).

- Are the social and environmental impacts of new projects fully considered?
- Does the project comply with international human rights standards and are human rights promoted?
- Has a good faith effort to engage key stakeholders and communities actively been undertaken?

- Have key stakeholders and communities been provided with the information and potential opportunities to engage in project activities?
- Does the local/regional/national community benefit from the project i.e., does it support local/regional/national value creation?

In order to monitor these additional requirements, the project developer would need to demonstrate his compliance within a publicly available report covering all the aforementioned points. Only if all requirements are considered, met and verified, the produced hydrogen would qualify for certification. These additional criteria do not lead to a categorical exclusion of certain technologies, countries, or regions but compliance with this set of requirements would have to be monitored on a case-by-case basis.

3.1.3. Conclusions: effects of quality requirements on global hydrogen market ramp-up and trade

Stringent sustainability criteria can be expected to have significant effects on the topography of hydrogen production and trade. Details depend not only on the criteria themselves but also on the extent to which such criteria are applied.

Impact on hydrogen production

If all global demand centres consistently apply stringent sustainability criteria or other quality requirements for hydrogen, then a significant market power results that impacts global production and origin of supply.

If a carbon threshold for embodied emissions is set to 3.4 $kgCO_2$-eq/kgH_2 and only scope 1 emissions are considered, green as well as blue hydrogen (with carbon capture rates > 62%) qualify. If scope 2 and 3 emissions are considered, blue hydrogen with a carbon capture rate of even 90% would be excluded due to the high average upstream emissions. To meet the carbon threshold target, blue hydrogen producers would need to reduce upstream emissions to a maximum of 2.4 $kgCO_2$-eq/kgH_2. This would either exclude several natural gas providers from the emerging hydrogen market or would create the necessity to better manage supply chain emissions. Transport emissions have a rather minor impact on the overall embodied emissions with less than 0.01 $kgCO_2$-eq/kgH_2 per 1,000 km transport distance[20].

If water availability is defined as an additional criterion for sustainable hydrogen, several countries with very low LCoE for hydrogen production might not qualify any more - if only freshwater resources are considered. However, desalination of seawater, if run by renewable energies, could become a solution for water scarcity problems, since it only results in a marginal increase of hydrogen prices and energy demand. Hence, if regions with water scarcity like e.g., the MENA region wants to become major hydrogen producers a massive upscale of desalination technology and corresponding renewable energy capacities will be necessary[21].

[20] However, it is important to mention again, these emissions do not contain boil-off/leakages. As explained earlier, these additional emissions occur specifically to the cases and can be affected by different situations.
[21] The actual costs of water desalination depend on the cost of electricity. The energy demand ranges between 2.5-4.0 kWh/m^3. Depending on the exact location, and LCoE, desalination cost can change significantly. As an example, taking the global average LCoE of 0.065 USD/kWh would result in additional 0.16-0.26 USD/m^3 water desalinated (IRENA 2022f).

The effects of adding further sustainability criteria – e.g., no land conflict, and other social and environmental criteria – cannot be estimated easily and would require further research. Essentially, verification need to happen on a case-by-case basis.

Impact on hydrogen trade

If only some global demand centres, such as the EU, apply stringent sustainability criteria or other quality requirements for hydrogen, the question arises if the EU has enough market power to impact hydrogen production, or if the EU becomes a less interesting export market for suppliers that will then look for alternative off-takers will less stringent requirements?

In Early 2023, the EU defined the globally most stringent requirements related to the carbon intensity of hydrogen; see discussion of the Renewable Energy Directive in chapter 1.2.5. Theoretically, this means that the EU could be less attractive for hydrogen exporters than other world regions, e.g., Southeast Asia. Interviews held with various hydrogen project developers (partially summarised in Baez et. al., 2023), however, indicate that this is not the case. As of today, hydrogen producers from various world regions (Middle East, MENA, South America) view the EU as an attractive export market. They had been waiting for clarity on the final carbon intensity standards according to RED because their strategy is to plan new hydrogen projects in a manner that meets RED requirements (Anonymous interview, 2022). This gives a strong indication of the attractiveness of the EU as a hydrogen market despite stringent - but achievable – carbon standards.

The situation may of course change if the EU defines additional sustainability requirements that are hard/impossible to achieve. If, as a hypothetical scenario, the EU would define sufficient natural water availability as a requirement (and would not allow for renewable-based water desalination), several relevant supply regions – MENA, Middle East, large parts of Africa – would be excluded. In such a scenario, one can expect the Middle East to re-focus their hydrogen trade strategy on Southeast Asia (probably with less stringent carbon requirements), whereas a ramp-up of green hydrogen production in MENA and other parts of Africa would become highly uncertain due to the lack of trade partners in relative proximity. – One may argue that in such a scenario, the EU may increase domestic green hydrogen production e.g., in Spain and Portugal (Copernicus 2022; Euronews 2023), but the severe periods of drought and related water scarcity for these reasons make it questionable if such sustainability requirements can be met.

To conclude: today's carbon intensity requirements defined by the EU support the global ramp of green hydrogen production and are not expected to have a negative impact on hydrogen trade. However, if additional and hard-to-achieve sustainability requirements are added, this picture might change.

Furthermore, as of September 2022, nearly 50% of worldwide water desalination is occurring in the MENA region. Not only are desalination processes using fossil fuels, but also more than 60% of the water is used for municipal applications (Sayed et al. 2022). Which means additional production plants are required to prevent any use conflicts.

3.2. Consequences of the separation of hydrogen certificate trading and physical hydrogen trading

Recently, there have been discussions about whether hydrogen certificate trading should be made possible independent of a physical hydrogen supply. A potential advantage is that a greater climate benefit may be achieved by saving energy-intensive transport over long distances. Reduced transport costs and more favourable renewable energy potential can also lead to earlier competitiveness of green hydrogen.

But there are also disadvantages that need to be considered. In some countries, particularly less developed ones, the demand side for green hydrogen may be rather limited – simply because no large-scale heavy industry exists as in the case of industrialized countries. It may be more difficult to create this demand, and governments and industry in less developed countries may have fewer financial resources to invest in technology transitions (e.g., making steel plant or the transport sector ready for green hydrogen). Last but not least, a pure certificate-based hydrogen trade would reduce incentives for industry e.g., in Europe to take own investments. Thus, chances to create technology leadership would be reduced. A combination of physical and certificate trading may be a feasible option but requires more detailed and country-specific analysis. The advantages and disadvantages of hydrogen certificate trading are summarized in Table 6.

Table 6: *Advantages and disadvantages of hydrogen certificate trading*

Advantages	**Disadvantages**
Electrolysers can be operated in locations with optimal RE sources, and low RE electricity costs	Countries with high RE-potential may not have large demand / use-potential for hydrogen: • E.g., heavy industry as in EU
Reduced need for international transport of hydrogen lowers: • Required energy (processing, transport, storage, re-conversion), • Costs • GHG-emissions	Investment in local demand required – may be more difficult to finance than in existing industrial demand centres: • E.g., build industry / make industry ready for hydrogen use in Africa more challenging than e.g., in EU
	Does not give incentive for industry in EU to take own investments in green hydrogen production/use.
	No technological leadership / push for innovation in EU

Source: Authors

Another important aspect is that international accounting rules under the UNFCCC need to be considered. The most important aspects and questions are:

- Accounting of purely balance-sheet traded green hydrogen against national emission targets. How is national offsetting carried out for international trade and how can double counting be avoided?
- Who oversees international trade according to uniform rules?

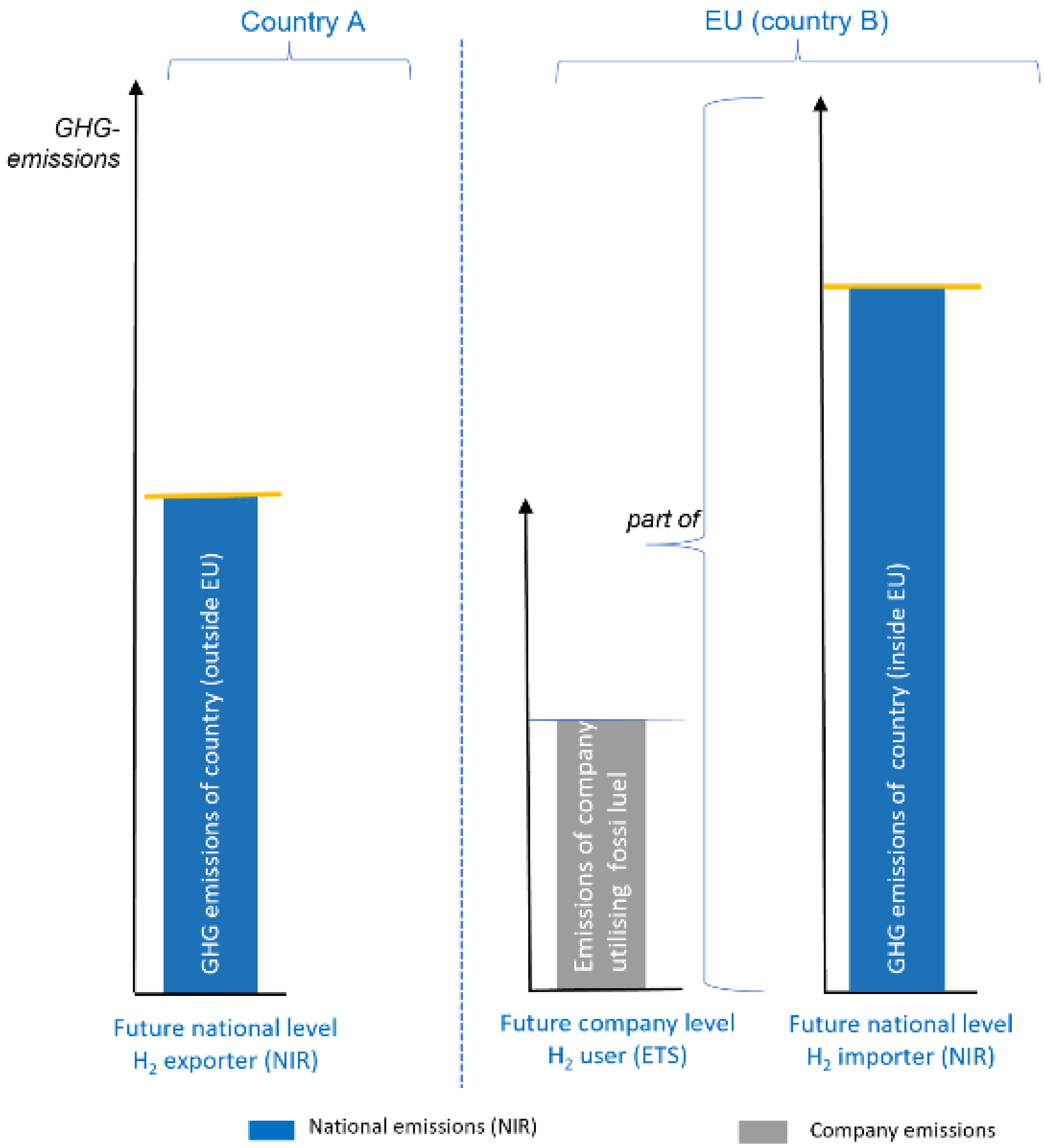
National inventories under the UNFCCC and the Paris Agreement account for actual greenhouse gas emissions on the territory of a state. They do not account for emissions related to the life cycle of a product. Therefore, activities that influence emissions levels in other countries need to be accounted for through cooperative approaches under Article 6 of the Paris Agreement.
This means that emissions related to the production of fuels are accounted for in the country where the fuel production is taking place. For example, fugitive methane emissions linked to oil production in Saudi Arabia are accounted for in the Saudi inventory. Likewise, emissions from the use of these fuels are accounted for in the fuel importing country.

3.2.1. Accounting of physical hydrogen trading in national inventories

Before looking at the impact of hydrogen certificate trading on national emission inventories, the impacts of physical hydrogen trading on national inventories are analysed from the point of view of hydrogen exporters and importers (country level). The discussion also includes impacts on corporate emission (targets), e.g., under the EU ETS.

Figure 20 visualises GHG emissions accounting according to the rules for National Inventory Reports (NIRs) of countries under the Enhanced Transparency Framework of the Paris Agreement valid from 2024 – both for future hydrogen-producers/exporters and importers/consumers -, and 'verified emission inventories' on company level (e.g., under EU ETS). This base-case scenario summarises emission levels resulting from the use of fossil fuels prior to hydrogen production and trade. The left-hand side shows the emissions level of the country that is planning to export hydrogen into the EU, while the right-hand side shows the emissions level of the importing country. The latter includes the emissions of a private sector player in the EU that would import hydrogen.

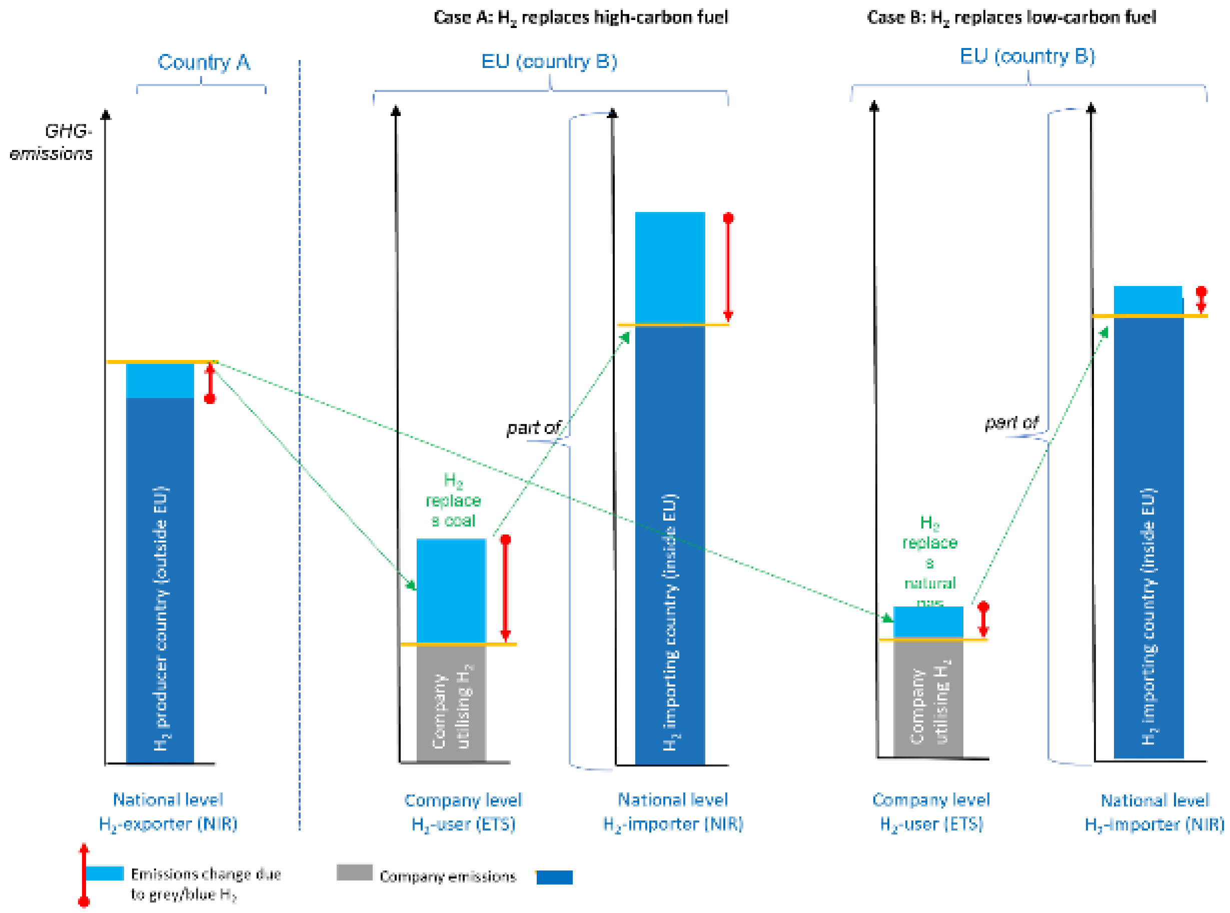
Figure 20: *Baseline case for fuel consumption and related GHG-emissions*



Source: *Authors*

For future hydrogen trade, we differentiate two main scenarios. In case 1 – visualised in Figure 21 – we assume that hydrogen is not produced with 100% renewable energies and, hence its production increases GHG-emissions in the exporting country. Emissions of the importing country are reduced but the reduction depends on the baseline fuel used. Exact numbers depend on the emission factor of the baseline fuel. For example, if coal is replaced, CO_2-emissions will be reduced by approx. 95 kg/GJ. If natural gas is replaced, CO_2 emissions are reduced by 56 kg/GJ (DEHST, 2022) if one assumes same efficiencies.

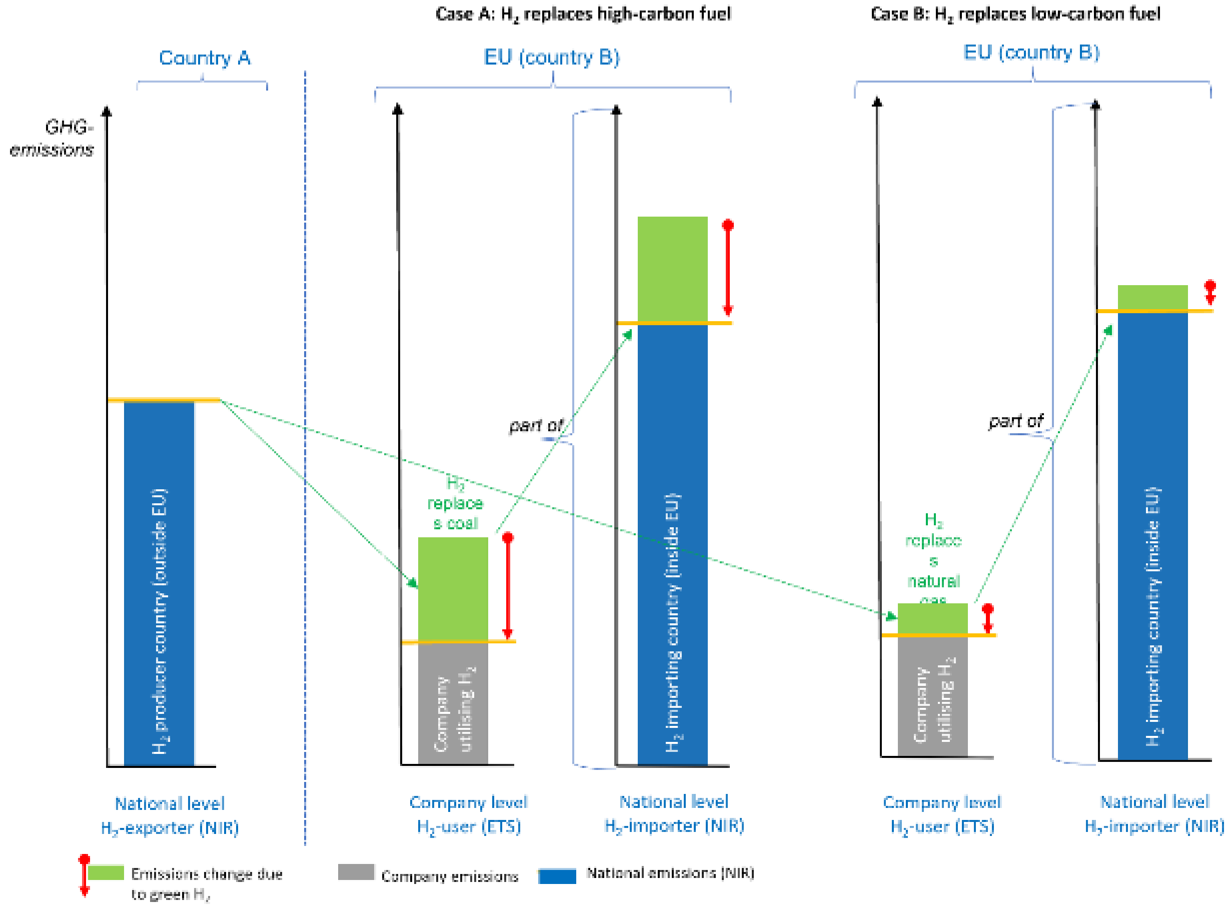
Figure 21: *Effects of physical blue/grey hydrogen trade on national GHG inventories in the exporting and importing country*



Source: *Authors*

In case 2 (Figure 22), we assume that hydrogen is produced by 100% renewable energies. In this case, the national emissions of the producing country are not increased. Emissions of the importing country are reduced but also in this case, the reductions depend on the baseline fuel used.

Figure 22: *Effects of physical green hydrogen trade on national GHG inventories in the exporting and importing country*

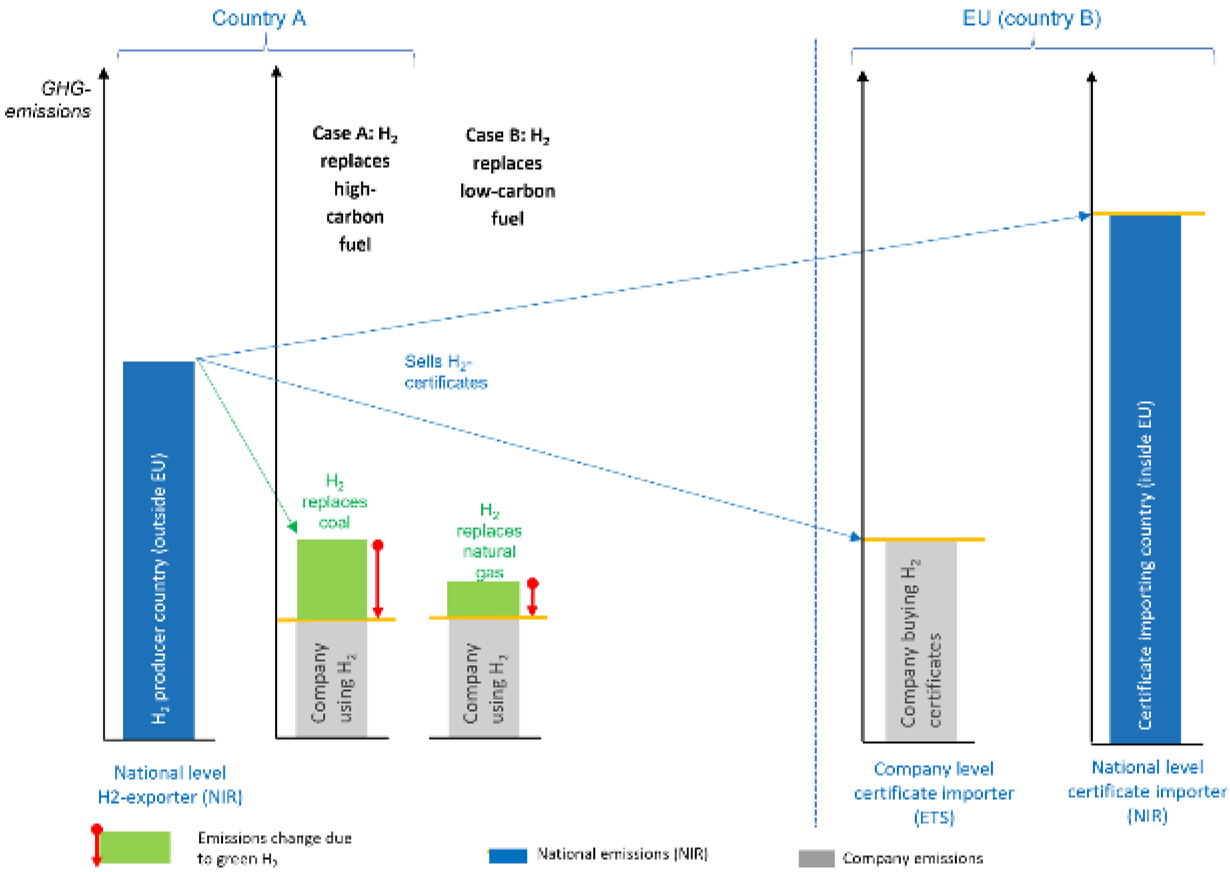


Source*: Authors*

3.2.2. Accounting of hydrogen certificate trading in national inventories

If hydrogen certificates are traded instead of physical hydrogen, the following situation results for NIRs.

Figure 23: *Effects of blue/grey hydrogen certificate trade on national GHG inventories*



Source: *Authors*

The production of blue or grey hydrogen initially increases emissions of country A. If the hydrogen is used e.g., by industry in country A, this reduces emissions again. The exact balance depends on the baseline fuel that has been used in industry and is replaced by the hydrogen. For example, if hydrogen replaces coal, this leads to a higher reduction than replacing gas. This means that a hydrogen certificate always needs to be accompanied by an assessment on the emissions intensity of the baseline fuel(s) – which means that a project-specific assessment is possible. This can easily become complex, in particular if the hydrogen produced in country A has different use cases, or use cases change over time. – In the country that buys hydrogen certificates (country B), national inventory emissions will remain unchanged because there is no physical effect.

If country A produces 100% green hydrogen, the positive effect on the national emissions inventory will be higher. All other principles described in the previous paragraph remain valid.

Example:

If Germany finances green hydrogen production in Morocco and the green hydrogen is not exported to Germany but used within Morocco, the German emissions inventory does not change, while Moroccan emissions are reduced compared to a baseline of continued fossil fuel use. In such a context, Germany and Morocco should engage in **collaboration under Article 6.2 or 6.4 of the Paris Agreement**. Such collaboration allows the generation of emission credits Internationally Transferred Mitigation Outcomes (ITMOs) for the emission reduction from the baseline emissions level. These emission credits can then be accounted towards the German emissions inventory. A precondition for such accounting is a bilateral agreement between Morocco and Germany on the baseline methodology to use. If the mechanism under Article 6.4 is to be applied, a proposal for a baseline methodology needs to be submitted to the Article 6.4 Supervisory Body which then assesses the methodology and can require changes before formally approving it. This means that any transfer of hydrogen credits between countries should be "mirrored" by an ITMO transaction under Article 6. Unilateral agreements can be made between the countries, but credibility may be lower due to a lack of UNFCC supervision.

It should be noted that the current emission target of the EU for 2030 (the Nationally Determined Contribution, NDC) does not allow to account for Article 6 credits. This is not an international rule, but a unilateral decision of the EU and can thus be changed by unilateral decision, if desired.

3.2.3. Who is responsible for overseeing global trade of H_2 credits?

As discussed above regarding the example of hydrogen certificate trading between Morocco and Germany, a full accounting of these certificates under the Paris Agreement requires consistency with the rules defined under Article 6.4. While formally, issuance of ITMOs through a bilateral agreement under Art. 6.2 will also be possible, following the Article 6.4 rules will be perceived as more credible because these rules have been internationally set and are administered in a highly transparent way.

Therefore, the generation of certificates should always be accompanied by a submission of the activity as an Article 6.4 activity. Once Article 6.4 Supervisory Body issues Article 6.4 Emission Reductions (A6.4ERs) for the activity, the host country of the green hydrogen activity needs to decide whether to authorize these emission reductions as ITMOs. If so, a corresponding adjustment in the host country's emissions inventory will take place. If not, the A6.4ERs will become "mitigation contributions" and can only be used for fulfilment of the host country NDC. While it is currently contested whether the mitigation contributions can be traded internationally, for example in the context of the voluntary carbon market, it is clear that they cannot be used against the NDCs of other countries

04

Expected topography of the emerging international hydrogen market and geopolitical implications

4. Expected topography of the emerging international hydrogen market and geopolitical implications

The topography of the emerging hydrogen trade and its market structure will be influenced by several correlated factors. The key parameters, as discussed in detail in chapters 1.2 and 2.2, are:

- Hydrogen production, transport, and storage costs;
- Infrastructure availability - both on the producer and consumer side -, and availability of financial resources to make required investments;
- Political visions of future energy systems, and;
- Policy instruments are chosen.

Some research has already been conducted, mainly focusing on the first parameter, but in a few cases, also considering some of the other parameters. In the following paragraphs, we will summarize the most recent findings. Subsequently, we will analyse the initial positioning of the major demand and supply regions, both in terms of technological preferences (green versus blue hydrogen) and political trade partner preferences. By doing so, we aim to sketch up a potential topography of hydrogen trade and the evolution of the market structure at two different stages, 2023-2030 and 2030-2050. In a last step, we analyse the expected implications for the security of supply, supply flexibility and cost risks.

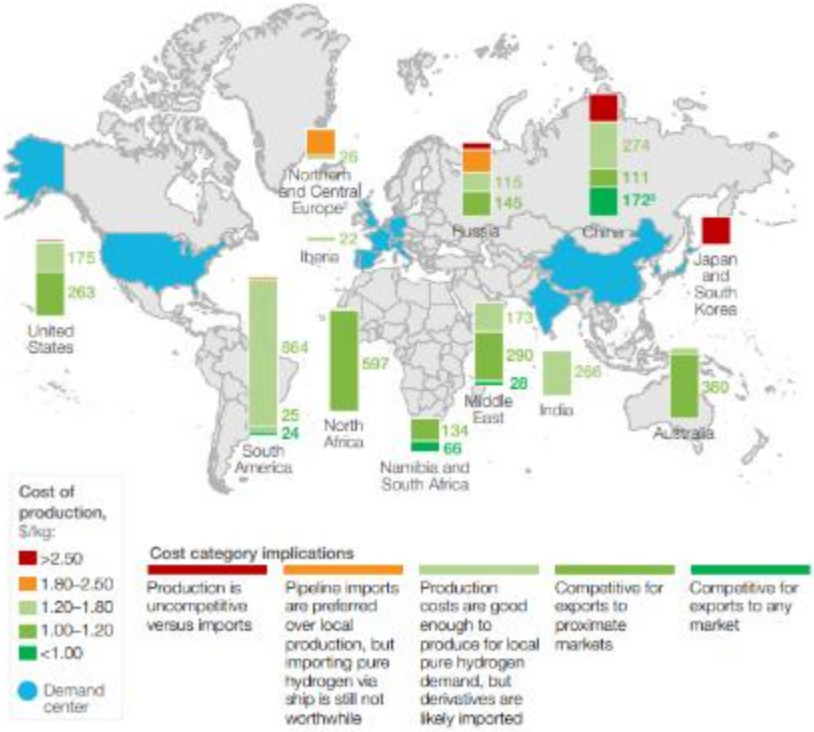
4.1. Findings of recent studies and reports

This chapter summarises and compares studies by various international organizations. Due to their high credibility & comprehensiveness studies from Hydrogen Council, IRENA and DNV are selected.

Figure 24 summarises findings from the Hydrogen Council, showing the mismatch between production and demand locations for hydrogen. In other words, high-demand locations such as Europe, China, India, and the US are not always the most cost-competitive locations for hydrogen production. In particular, Europe and Japan have very limited potential for cost-competitive green hydrogen production which increases their need for hydrogen trade. This results from mainly three factors. First, the levelized costs of production vary depending on the local renewables' potential and costs. Second, the availability of other feedstock materials, such CO_2 availability for synthetic fuels, differs across regions. Finally, countries differ regarding workforce availability and cost, local stability, and the country's risk classification for financial instruments.

According to these findings, renewable energy supply potential will be insufficient to cover hydrogen demand in China, India, Japan, and the EU to substitute fossil energies. In contrast to this, countries like Russia, Australia, Algeria, Qatar, Saudi Arabia, Canada, and the US have more renewable energy than necessary to satisfy their own hydrogen demand and thus could export green hydrogen. However, the future situation strongly depends on the policy choices of countries. For example, if China gives high political priority to ramp up domestic hydrogen production, the country has the potential to become self-sufficient or even an exporter of green hydrogen. This will be discussed in more detail below.

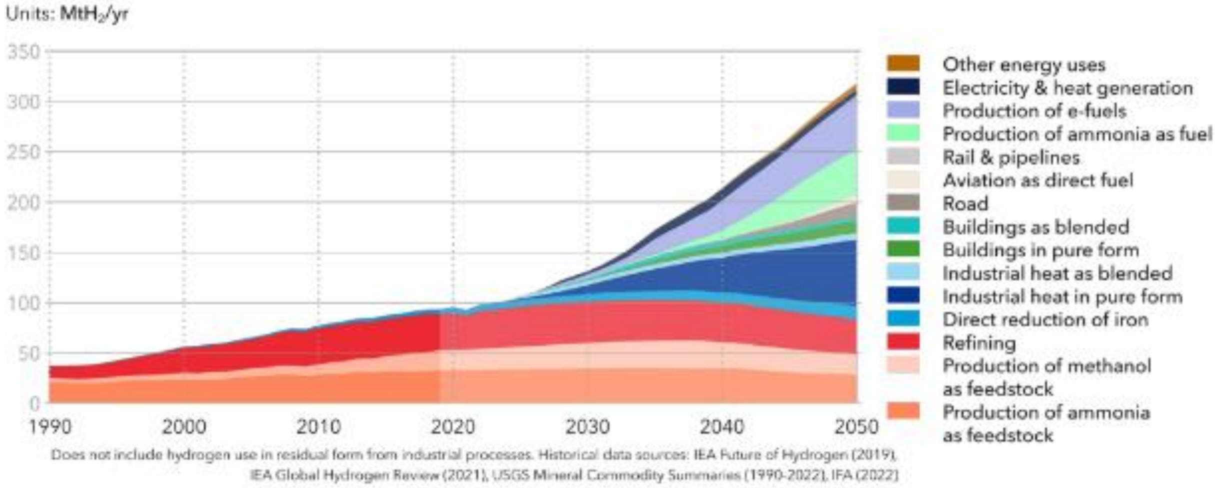
Figure 24: *Hydrogen production potential in million tons per annum in 2050*



Source: *Hydrogen Council (2022), p.12*

Figure 25 shows that currently most of the world's hydrogen demand is used in non-energy-related sectors: mainly in the production of ammonia and methanol as feedstock and in the refining/chemical sectors. Also, demand from the steel sector slowly begins to develop. From the mid-2020s onwards, other industry sectors, the building sector and the production of e-fuels are expected to phase in, creating additional demand. By 2050, industrial demand will result from i) replacing grey hydrogen with green hydrogen, ii) using hydrogen as a primary fuel source (and not mainly as feedstock) and iii) novel uses for hydrogen e.g., in the production of e-fuels.

Figure 25: *Global hydrogen demand by sector (Mt H_2/yr)*

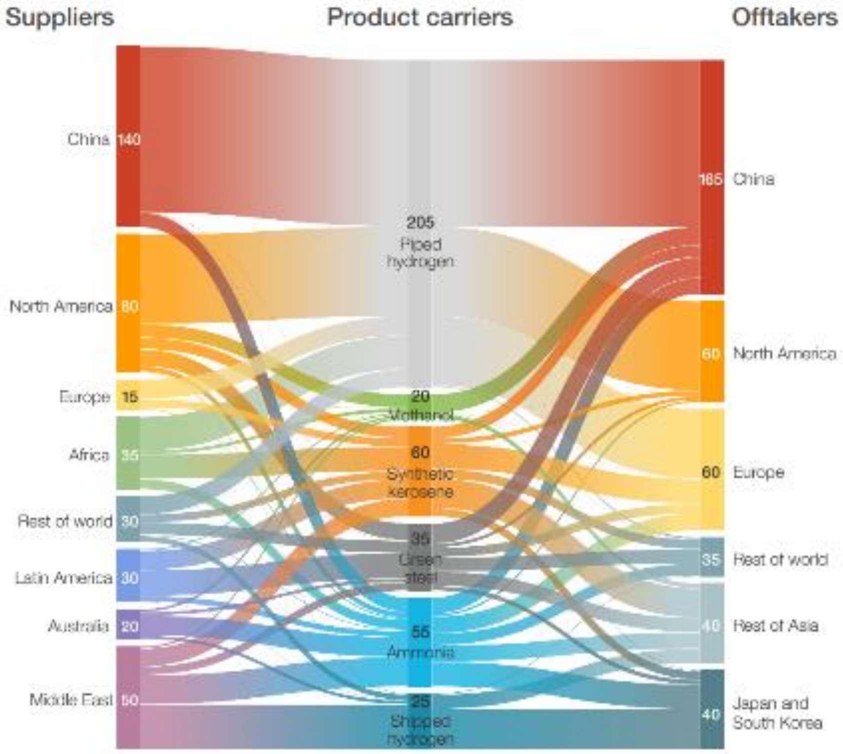


Source: *DNV (2022), p.71.*

Figure 25 also shows that the use of grey hydrogen will start to diminish after 2030. This can be attributed to a decline in fossil fuel production. By 2040, the energy application of hydrogen is expected to be on a similar level to the non-energy applications of hydrogen. By 2050, hydrogen will be mainly (up to 70%) used as an energy source (DNV 2022).

The Hydrogen Council (2022) expects that by 2050, regions specialize in certain types of hydrogen production. This will result in new trade and transport routes. China and the US are expected to make use of domestic hydrogen pipelines for transporting large hydrogen volumes. Europe is expected to import a significant portion of its hydrogen demand by pipelines from Africa; complemented by domestic pipelines for intra-European transport. Synthetic kerosene and ammonia transported by ship are expected to have the second and third-largest import share. Australia, the Middle East, and China are foreseen to be the largest ammonia exporters. Africa, Latin America, and the Middle East are expected to become the largest exporters of synthetic kerosene. Hydrogen trade by ship will dominate the route the Middle East to Japan and South Korea. Methanol will mainly be traded from North America to China; see Figure 26.

Figure 26: *Global hydrogen interregional long-distance supply by 2050 in Mt/yr*

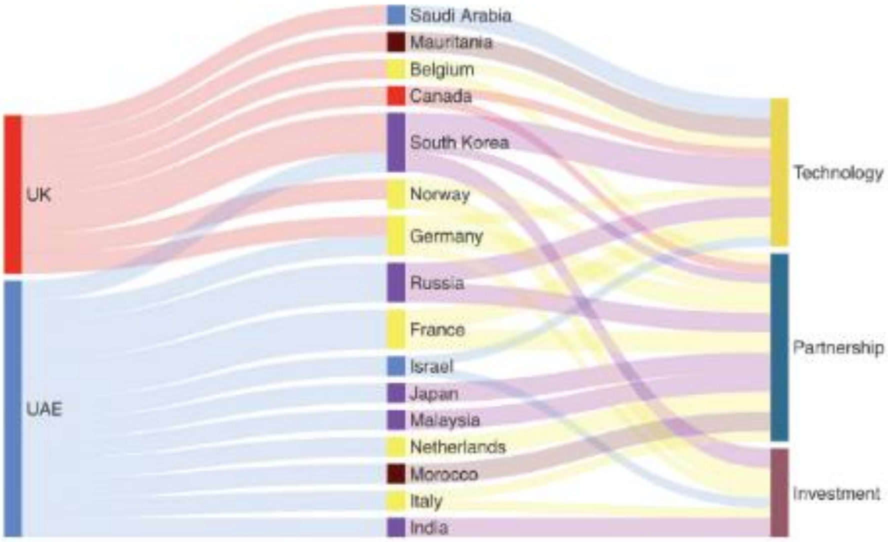


1. Excludes local production and distribution.

Source: *Hydrogen Council (2022), p.20.*

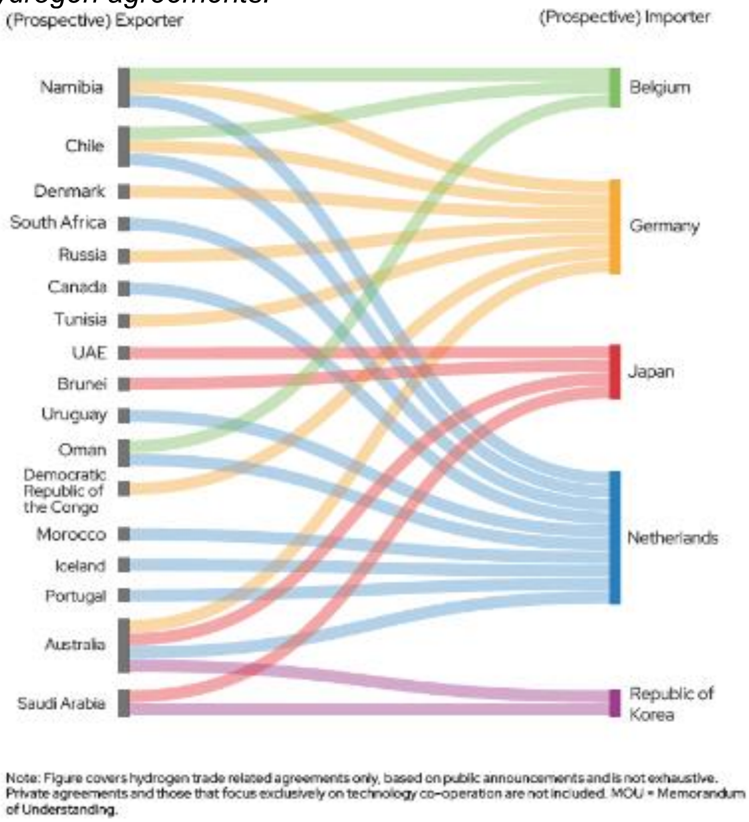
The World Green Economy Organization (2022) expects trade partnerships to be shaped by proximity of supply-and-demand centres. Already, dozens of Memorandums of Understanding have been signed between prospective exporters and importers, as shown in the non-exhaustive list in Figure 27. Many of these agreements are bilateral agreements at the governmental level (see Figure 28), which can facilitate private-sector initiatives. They tend to explore potential trade synergies, investment opportunities, and technical and economic feasibility studies, with some agreements looking at joint R&D initiatives.

Figure 27: *Hydrogen MOUs signed between the UAE, UK and other countries*



Source*: World Green Economy Organization (2022), p.21.*

Figure 28*: Bilateral hydrogen agreements.*



Source: *IRENA (2022d), p.77.*

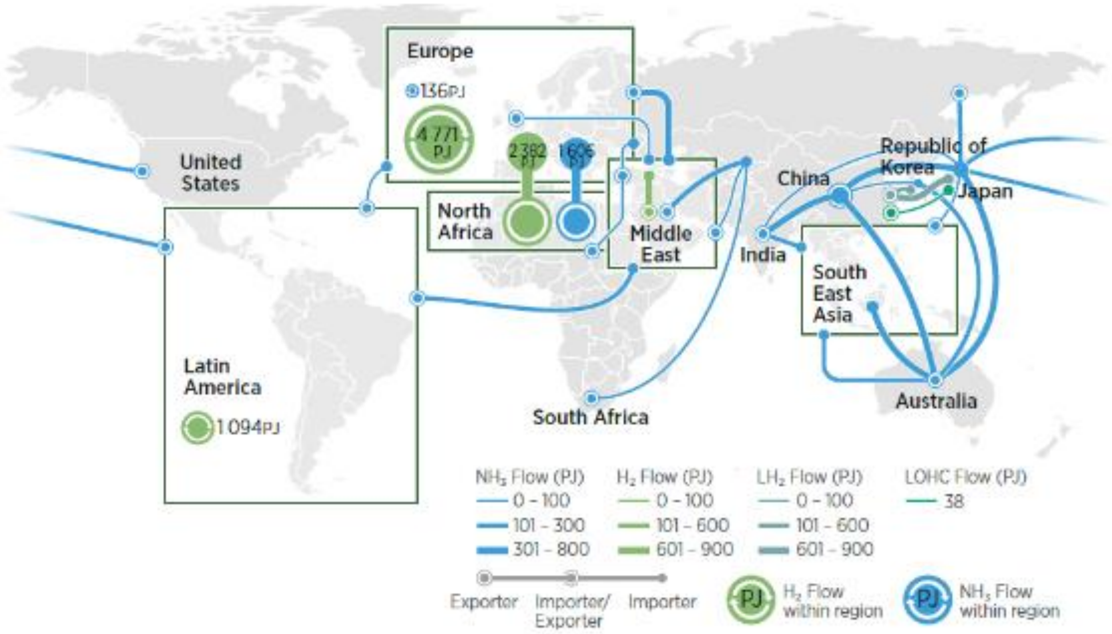
Figure 29 summarises the forecast for global hydrogen trade in 2050 by IRENA (2022d), considering the previously discussed[22] bilateral agreements and national hydrogen strategies. IRENA expects a major increase in trade between North Africa and the Middle East towards Europe; and another main trade cluster between Australia and Asia – mainly Japan, China, and South Korea. Some of these

[22] Canada, Chile, Germany, Italy, Japan and Spain have mentioned bilateral relations in their respective hydrogen strategies.

countries have existing energy trade relationships, for instance, Japan and Saudi Arabia for crude oil trade. This is expected to facilitate the initial phases of bilateral hydrogen trade.

IRENA expects approximately 18 EJ/year of hydrogen and hydrogen derivates to be traded. 55% of this trade will be achieved by hydrogen pipelines, 40% will be achieved by ammonia shipping and 5% will be liquid hydrogen. The ammonia trade roughly equals 7.4 EJ/year, 25 times larger than today's global ammonia trade. Ammonia is expected to cover most of the long-distance trading (IRENA 2022d).

Figure 29: *Global expected hydrogen trade map in 2050*



Source: *IRENA (2022e), p.236.*

Putting those studies in comparison, all studies expect Europe, the US, India, China, Japan and South Korea to be major demand regions. DNV suggests that the OPA region (Australia, Japan, South Korea, and New Zealand) as a whole will require imports (DNV 2022). It should be noted, though, that the report does not specify which countries in the region are expected to become net importers or exporters. All studies agree that the Middle East will become a main exporting region.

Key differences between the studies are related to the role of India and China. DNV expects India to rely on imports, whereas Hydrogen Council suggests the country will meet its own hydrogen demand by domestic production. In the case of China, different views exist on whether the country will focus on becoming self-sufficient or taking an exporter role. More details can be found in Table 7.

Table 7: *Status of countries/regions as net exporters and importers in different reports*

Country/Region	Seen as net-exporter by	Seen as net-importer by	Seen as self-supplier by:
Australia	Hydrogen Council, IRENA		
China	DNV, Hydrogen Council, IRENA		Brown, Grünberg (2022), Nakano, 2022
EU		DNV, Hydrogen Council, IRENA	
India	IRENA	DNV	Hydrogen Council
Japan		DNV, Hydrogen Council, IRENA	
Latin America	IRENA		
Middle East	Hydrogen Council, DNV		
North Africa	IRENA		
OPA-region		DNV	
Russia	Hydrogen Council		
Spain	IRENA		
South Africa	IRENA		
South Korea		DNV, Hydrogen Council, IRENA	
Sub-Saharan Africa	Hydrogen Council		
USA	DNV, Hydrogen Council, IRENA		

Sources: DNV (2022), Hydrogen Council (2022), IRENA (2022b), Brown, Grünberg (2022); Nakano(2022)

4.2. Geopolitics and hydrogen

The term 'geopolitics' has historically been used to cover both the political and economic aspects of competition between nations, through violent as well as peaceful means. Specifically, the geopolitics of energy has been highly relevant since the industrial revolution. The control of fossil energy resources in different geographic locations has helped to shape temporal and spatial patterns of power and wealth (Van de Graaf, Sovacool, 2021). This control can relate to flows of energy resources, their prices, and the infrastructure to manage flows.

For the economic aspects of this renewed geopolitical competition, the term '**geoeconomics'** (Luttwack, 1999) has been rediscovered to stress the pre-eminence of the economic aspects of the current geopolitical competition (Blackwill and Harris, 2016)[23]. In more general terms, geoeconomics can be defined as the use of economic instruments (instead of military control) to promote and defend national interests, and to produce beneficial geopolitical results; and the effects of other nations' economic actions on a country's geopolitical goals without recurring to military means (Blackwill and Harris, 2016; Luttwack, 1990).

The emergence of new technologies and forms of energy can re-define and redistribute power among supply and demand centres. It can for example reduce power of incumbents and increase power of players that were previously irrelevant. The rise of Arabia from being an irrelevant backwater of world politics to a key region due to the discovery of oil in the 1930s illustrates this process.
In general terms, global geopolitical relationships have a key impact on energy market development. A multilateral world order with well-functioning institutions and global governance mechanisms will facilitate free energy flows, open and liberalised markets and a level playing field. Opposed to this, a non-cooperative international environment with competing powers typically implies non-cooperative, protectionist behaviour of states that can lead to geo-political (mis-)use of energy resources- and infrastructure control and price politics.

Fostered by globalization and embedded in the setting of the post-cold war liberal economic world order, a clear trend towards commodification and tradability of fossil resources has been visible between the 1980s and the financial crisis of 2008/2009. During this period of increasing globalization, interdependencies have grown also in the energy sector, in terms of trade flows, market and physical infrastructure. For example, the globalisation of fossil energy trade has contributed to the integration of the former soviet space and Russia as a major fossil fuel producer into global energy markets and international economic institutions. Technological changes like the US's shale oil and gas revolution did not only reshape the gas and oil markets but also re-equilibrated geopolitical relations between producing and consuming countries. The growing interdependencies of markets and the concept of energy supply security saw a paradigm change from state to market: economic efficiency, cost calculations and open, liberalised markets would allow for economic affordability, timely investments, and uninterrupted supplies - rather than military means and direct resource and supply chain control (Van de Graaf, Sovacool, 2021). Consequently, the role of private or business actors - i.e., energy corporations - became more relevant compared to the role of the state as a market actor.

Since the financial crisis of 2008/2009 shattered the belief in unfettered globalization, the Arab Spring and the subsequent upheaval in the Middle East contributed to the increasing fragmentation of markets. Moreover, the ascent of increasingly authoritarian regimes (China, Turkey, Russia, Brazil and to some extent India and the US under the Trump Administration) led to the revival of the concept of a strong state and of unfettered competition in every sector, including the military. This was exacerbated by the COVID-19 pandemic which almost brought the energy markets to their knees, leading to negative prices in the world oil market, a phenomenon never seen before in a global energy market. Compounded by the Ukraine war, political attention is increasingly given to self-reliance, greater energy independence, supply chain resilience, and protectionism.

[23] However, we would like to stress an authoritative definition of geoeconomics is lacking to date and its differentiation from geopolitics is seen as challenging by many.

As a result, **a fragmented and more regionalized world (energy) economy is becoming more and more likely;** the post-Cold War international (economic) world order based on win-win partnerships, liberal governance and open market seems long past. Liberal Western systems are on the defensive, while aggressive state capitalist authoritarian systems are on the rise.

Whether calls for energy transition, triggered by the climate crisis, can bring back a more cooperative approach to energy markets remains to be seen. While energy resource concentration is declining due to the rise in renewable energy[24], the technological complexity and infrastructure investment requirements grow. In this context, competition to control the complex technologies and infrastructure networks will become more intense.

(Green) hydrogen represents a case in point. As the potential for (green) hydrogen production and leadership in industrial applications is distributed unequally around the globe, both industrialized countries and developing countries have a chance to position themselves. For industrialised net energy importers like the EU, a successful hydrogen market ramp up is not only conducive to net-zero ambitions but could help mitigate asymmetrical dependencies and limit the possibility to use energy resources as power tools. But in this emerging phase of the market, there is a strong need to invest heavily in infrastructure, to build long-term contractual relations, and to negotiate multilateral agreements on contract standardization and certification.

However, countries like the United States, China or India could favour protectionist and state-backed industrial policies to emerge as frontrunners in future green hydrogen markets and lead either in hydrogen production or in industrial applications, such as ammonia, methanol, and steel production. Moreover, as hydrogen trade will also highly depend on hardware trade flows for components – from solar panels and wind turbines to electrolysers as well as required raw materials – , new asymmetrical dependencies might move along the value chain. While countries dominating parts of the value chain – for instance China – might be very interested in further exporting renewable energy technology components notwithstanding geopolitical tensions, the logic of geopolitical and global technological competition might at time still change their priorities or incentives. China's announced ban on the export of silicon wafer used to make solar panels is the most recent example: the ban is aimed at securing China's technological dominance in the segment by reducing the development of alternative supply-chain ecosystems anywhere in the world (Yeh, 2023).

Furthermore, some developing countries with adequate resources for green hydrogen production and highly related economic activities could have an incentive on both exporting hydrogen and upgrading along value chains and attracting green hydrogen-based industries. By doing so, they could compete with import-dependent industrial powers for jobs and market shares. This could be the case for Morocco or Thailand; when it comes to green steel production, or Indonesia for green ammonia (Eicke, De Blasio, 2022). They could also try to use hydrogen to adjust their economic model to accommodate regional and more global geopolitical power shifts (reduce dependence on China, balance between the West and more authoritarian regimes, emerge as regional leader).

[24] Currently, a third of global power capacity is now based on renewables with the cost of electricity from photovoltaic solar panel falling by 77% between 2010 and 2018 (IRENA, 2019)

Thus, a transition in existing value chains will give rise to new markets and geopolitical dynamics and dependencies, however whether states will seek to strengthen their position as trade and/or technological “hubs“in the emerging international hydrogen economy by cooperative or non-cooperative means, will also depend on the current regional and global geopolitical environment shaping their political priorities.

4.3. (Geo-)political environment and hydrogen policy

Along with production costs, transport and infrastructure readiness, resources and water availability as well as investment capabilities (all discussed in section 0), key parameters defining the topography of hydrogen trade, will be the political priorities set by supply and demand regions. In the following, we discuss the geopolitical environment and geopolitical considerations shaping hydrogen policies, and their potential evolvement over time.

An early and clear political orientation to increase hydrogen applications of a key demand region, and to favour a particular technology/colour will have major impacts on the market design and the topography of the trade partners. First movers on the demand side may have an advantage compared to other demand centres regarding the choice of potential suppliers and can thereby influence the producers’ topography. However, preferences and priorities on the supply side will also have a strong influence on the hydrogen world trade map. Two sets of questions should be considered: A first set of questions refers to the current oil and gas-producing and exporting countries. Can they be incentivized to invest in green hydrogen production, or will they try to engage in the market through a focus on blue or grey hydrogen, which will be easier for them due to lower investment needs? Will a concerted push by all major demand sources be required to convince current fossil exporters or will it be sufficient if only the EU prioritizes green hydrogen? A second set of questions relates to potential green hydrogen exporters: how will these countries position themselves along the green hydrogen value chain, what will be their political bargaining power, will they be able to choose among different demand centres or will they strive to keep hydrogen production local in order to foster domestic industrialization?

4.3.1. Demand centres: Europe, US, China, India, Japan, and Korea

Among the three identified major international demand centres, Europe and the US are currently leading in terms of hydrogen policy packages and support for kick-starting hydrogen production, establishing industrial hydrogen clusters, and promoting cost-competitiveness of low-carbon technologies.

Europe

We first look at the considerations that drive EU hydrogen policies. Traditionally, the EU has positioned itself as a global leader in the effort to mitigate climate change and has focused on green hydrogen to date. At the EU level, the Green Deal Package represents a potentially powerful tool to deliver climate neutrality and the transformation of the energy system, but it still needs to be fully operationalized. Also, worth mentioning is the categorisation of nuclear energy-based hydrogen (pink hydrogen) as a Renewable Fuel of Non-Biological Origin (RFNBO) under the Renewable Energy Directive (RED) (EU Commission, 2023), which opens the door for additional countries potentially becoming exporters of “renewable” hydrogen as per RED (e.g., Finland, Ukraine, China). Geopolitical considerations are becoming increasingly important in addition to climate policy aims. The need to diversify supply sources and suppliers and to increase the resilience of the EU's energy supply chains after the outbreak of the Ukraine war is one major reason. Furthermore, a renewed interest in traditional industrial policy to secure technology leadership and prevent the erosion of industrial capacities has emerged more recently (Green Deal Industry Plan). This comes against the backdrop of the perceived technological-industrial onslaught by the US and China. Reducing dependencies from fossil fuels goes along with the ambition to shape a new post-fossil energy system where dependencies can be better managed, and vulnerabilities minimized. Towards 2030, the EU aims at scaling up electrolysis capacity, decarbonizing hard-to abate sectors, build up infrastructure and promote hydrogen for new uses: it has set very high (though hard to achieve in the given timeframe) targets for hydrogen production and import (EU Commission 2022b, p.7-10.), aiming at more than 120 GW installed electrolyser capacity by 2030 (EU Commission 2022b Annex; Ansari et al. 2022) for domestic production. The goal is to both produce and import 10 Mt green H_2 by 2030 (EU Commission 2022b, p.7). Due to the geopolitical pressures, blue hydrogen has been considered a valid bridge towards a green hydrogen future, but the drawbacks discussed in chapter 2 must be considered.

The Ukraine war and the break-up in the relation with Russia essentially force the EU to focus its short-term hydrogen sourcing strategy toward its southern neighbours while pushing for a rapid global market ramp-up to diversify sources over time.

Several European countries have their own strategies and targets, though, reflecting their different position on the future hydrogen market (exporter or importer) and their different political preferences (autarky vs diversification, technological innovation vs technological preservation). The most prominent example is France. The country prioritizes nuclear based hydrogen production due to the large share of nuclear energy in its electricity mix. Paris is also rather sceptical about a global or even continental hydrogen market and bets on technological self-reliance. The United Kingdom and the Netherlands are relying, at least for the transition phase, on blue hydrogen, and are open to trade while Italy and Spain are betting big on green hydrogen, with Italy also increasingly open to blue. While Spain's and Germany's strategies are complementary and aligned in terms of hydrogen trade, Italy remains more ambiguous on its future role as final consumer, or transit/export country (EWI, 2021). Germany for its part further prefers green hydrogen in the long-term but is more recently cautiously opening to blue, whereas only for a limited period of time.

Consequently, the development of a universally accepted EU strategy has been slow as the protracted struggle for a definition of clean hydrogen and the slow approval of IPCEIs show.

The US

The United States have been a climate policy laggard but after the election of President Biden are now targeting net zero GHG emissions by 2050. The US Hydrogen Strategy and the Hydrogen Energy Earthshot target cost reduction for clean hydrogen by 80% to 1 USD/kgH_2. The US takes a **largely technology-open approach to hydrogen**, focusing on advancing production of both low-carbon (blue) hydrogen and electrolysis based on renewable and nuclear electricity. Demand is expected to develop at state and province level, with a major focus on mobility solutions. State and regional activity around low-carbon hydrogen has been ramping up in the United States since the Infrastructure Investment and

Jobs Act (IIJA), which appropriated 8 billion USD for the development of at least four Regional Clean Hydrogen Hubs (H2Hubs) across the country. Proposed hubs are betting big on hydrogen for heavy industry and long-haul transportation (CSIS 2022).

The US multi-technology push for clean hydrogen is not only driven by climate considerations, but it has primarily an industrial and geopolitical dimension, which reflects the US peculiar position in the international economic and financial system and the challenges it faces, particularly its systemic rivalry with China and the growing industrial-technological competition with both China and Europe seen as a threat to the US' "innate" technical leadership. The Inflation Reduction Act (IRA) of 2022 is a key example of this strategy. The Act is openly protectionist, aiming to make the US less reliant on foreign suppliers by providing financial incentives to locate factories and produce goods in the US. While the IRA has a clear domestic-industrial dimension, it is also embedded in the USA peculiar and dominant position as technology leader. As a result, an "America first" industrial policy and security considerations to increase supply chains resilience and diminish external dependencies from both suppliers and foreign markets shape the US's support for clean hydrogen.

China

In the macro-region of the Indo-Asia-Pacific, where the major concentration of demand centres can be found, China is the third major demand source, and could become the biggest of the "prosumers" who both consume and produce hydrogen. Already, it is the largest hydrogen producer and consumer worldwide. However, only 1% of hydrogen was produced from renewable energy in 2020 (Quitzow et al., 2023). Given the massive expansion of solar and wind power in China over the last 15 years, with annual solar PV ramp up being close to 100 GW, China is seen by many as a key player in the green hydrogen supply[25]. However, the Chinese hydrogen strategy is **clearly technology agnostic and aiming at leadership in key technologies**, including for export-oriented industries like transport vehicle manufacturing. The 14th Five Year Plan sees hydrogen as a frontier industry area, and hydrogen is expected to have a 5% share in final energy consumption by 2030 and 10% by 2050. China aims to develop 10 GW of installed electrolysers capacity by 2025 for 0.1-0.2 Mt green hydrogen according to the latest Medium and Long-term Plan for the development of a Hydrogen Economy, and 35 GW by 2030, to reach more than 500 GW by 2050. Selected local governments have more ambitious short-term targets, mostly built around efforts to build fuel cell vehicle industries, while the steel and chemical industry should only gradually be decarbonized. Consequently, as fuel cell vehicles remain the most prominent target sector, China's focus at this stage is largely on technology, industrial systems and policy environment related to the manufacturing of fuel cells and electrolysers, with pure hydrogen production and transport emerging only gradually as priorities. Only after 2035 China plans to apply hydrogen in different hard-to-abate industries. While it remains unclear how demand for green hydrogen will be supported, recent studies (Quitzow, et al. 2023, pp. 57-58; Brown, Grünberg, 2022, Nakano, 2022) come to slightly more differentiated results than the DNV; Hydrogen Council or IRENA reports. The preliminary conclusion is that China does not appear to be positioning itself as a large-scale importer or exporter of (green) hydrogen yet, favouring domestic hydrogen production and self-reliance, at least in the early stage (until 2030). The reason is that given China's current vast consumption of (grey) hydrogen, overcapacity is currently no issue. Because of the current gap between its overall

[25] It should be noted that the arid characteristics and long distance from the sea for most of the Chinese territory attractive for renewable energy supply makes water availability a major constraint for Chinese green hydrogen production.

demand for hydrogen and low-carbon production capacity, it is unlikely that China will become a major exporter of green hydrogen, nor is this planned in its national policy. However, this situation may change in the longer-term if China produces champions in related technologies along the value chain who are capable of mass-producing green hydrogen. In this case, they might both cover the growing domestic demand in the hard to abate sectors and export green hydrogen, or China might decide to prioritize export over mass-adoption for commercial use. Ultimately, China's geopolitical environment and domestic development also dictates its future position on the hydrogen market: amid growing tensions with the US and decoupling attempts from the West, China bets big on minimizing external dependencies while increasing foreign dependencies on own technologies and exports. With its state-funded programs Made in China 2025 (The State Council of The People's Republic of China 2015) and China Standard 2035 (Xinhua News Agency 2021) and the principle of a dual circulation economy, China is attempting to reduce its dependence on advanced economies and develop strategic autonomy along the entire supply and value chain, in down, mid and upstream, from raw material extraction and refining to research and development, industrial production and assembly, market ramp-up and export. This ambition translates in the hydrogen sector as well: China already dominates electrolyser production and raw materials refining while striving for technological and industrial supremacy in fuel cell vehicles. China might be tempted to use market dominance more geopolitically to strengthen asymmetric dependencies, exert coercive power or gain market shares in hydrogen-producing countries.

India

India's motives to promote hydrogen are largely driven by industrial and energy security considerations, and climate policy goals take a back seat. India can also be characterized as a "prosumer". Indian Prime Minister Narendra Modi has set the goal of "energy independence" by 2047, the hundredth anniversary of India's political independence. The strategy calls for 50% of electricity demand to be met by renewable energy by 2030 and surplus electricity from renewable energy to be used for the production of green hydrogen for domestic use (Giri 2022). India's Hydrogen Strategy aims to make the country a **hub for hydrogen technology manufacturing**. India has set up a National Hydrogen Mission and allocated 2.3 billion USD until 2020, starting with 36 million USD in 2023 (Mongabay 2023). India's demand for hydrogen is forecast to approximately double from current values to reach 9 Mt by 2030 to be satisfied by domestic production, of which 5 Mt would be green hydrogen. While the main customers for hydrogen are currently oil refineries and fertilizer plants, demand is expected to expand to the transportation and power generation sectors as well as in the steel industry from the second half of the 2020s onwards, when production costs for green hydrogen are expected to fall (Giri 2022, p.3). Consequently, green hydrogen, is projected to become the mainstream in the future, but only ramp-up by 2040 (Giri 2022, p.4). In line with the energy independence strategy, India aims to reduce imports to a minimum, while producing green hydrogen at low cost could contribute to global production expansion. Geopolitically, greater production independence and only limited hydrogen imports represent a priority to reduce dependencies both on China and on Africa/the Gulf.

Japan and Korea

In the Asia Pacific region, Japan and Korea are the major expected demand centres. Both have national strategies in place to reach net zero by 2050 and Japan has actually been a frontrunner, publishing the world's first national hydrogen strategy in 2017 (Ministry of Economy, 2017). Japan sees hydrogen as a key pillar of a high-tech strategy for energy transition, aiming at a highly diversified import strategy from overseas, particularly the Gulf and Australia. Japan has already signed multiple deals with potential exporters and is the first country in the world that has embarked on Article 6 collaboration for green hydrogen sourcing through its Joint Crediting Mechanism (JCM), with New Zealand (Carbon Pulse 2023), Australia and Indonesia (Marubeni 2022)

For both countries, pivoting to hydrogen is key to decarbonization. However, energy supply diversification imperatives and industrial-technological supremacy loom large in the hydrogen strategies of both countries, leading to **technology-agnostic strategies**. Korea targets a mix of grey, blue, and green hydrogen toward 2030, with demand (roughly 3 Mt) still entirely covered by imports in 2030. By 2050, Korea will still be largely reliant on hydrogen imports (12 Mt imports vs only 7 Mt produced domestically) (Green Energy Strategy Institute et al. 2022, p.15).

Japan and Korea support domestic uptake for hydrogen, with sectoral targets for industry and particularly for vehicles/transportation. Japan's motives are quintessentially geopolitical, given its difficult security and geopolitical environment (territorial disputes with China, China's growing influence in Southeast Asia, China's backward integration in Japan's industrial value chains and Japan's dependency on lengthy energy supply chains). The risk of energy supply disruptions dictates Japan's pragmatic and holistic approach to hydrogen. In fact, a key part of its strategy is to build a comprehensive international supply chain and to control it from manufacturing to storage, transport and use of hydrogen to increase supply chain resilience and energy security while increasing its geopolitical space of manoeuvre vis-à-vis China. Japan's pre-eminence in Southeast Asia's industrial value and supply chains might indirectly contribute to local demand increase for green hydrogen in Southeast Asia, particularly for the production and export of green steel, in the long-term.

All in all, all major potential hydrogen demand centres share motives which go well beyond climate policy and related net-zero commitments.

Table 8: *Expected demand centres, position on the market and geopolitical priorities*

Expected demand centers	Expected position on the market	(Geo)political priorities & hydrogen policy
EU, Japan and Korea	**Net importers:** **EU:** can produce large hydrogen volumes but cannot cover the expected demand. Different intra-European priorities make a coherent strategy hard to implement. **Japan and Korea:** have only limited potential to produce hydrogen, heavily dependent on imports. Have clear strategies	**EU:** Climate goals still highly prioritized but geopolitical motives adds to them. Moderately technological-agnostic, Industrial Policy and Energy Supply Security + Technological leadership+ **Japan and Korea:** Strong technological agnostic, Energy Supply Security and Diversification, Technology leadership in the energy transition, Control of the entire value chains to reduce dependencies on Gulf and China
USA, China, India	**Potential game change prosumers** **US, China:** relatively free to decide whether to pursue domestic self-sufficiency or participate in hydrogen trade (import, export, trading hub). Technology leader **India: striving** to become technology-manufacturing hub, **limited imports, producing green hydrogen at low cost could contribute to global production expansion**	**USA:** Support for multiple hydrogen-technologies, including nuclear. Retain technological leadership, pursue decoupling from China. **China:** clearly technology agnostic and aiming at leadership in key technologies, H2 not yet a priority for vast domestic consumption; but focus on domestic production, rather than on large-scale importer or exporter of (renewable) hydrogen. It might misuse market dominance more geopolitically to strengthen asymmetric dependencies, exert coercive power or gain market shares in hydrogen-producing countries. **India:** Geopolitical priority is greater production independence and only limited hydrogen imports to reduce dependencies both on China and on Africa/the Gulf. Green technologies are prioritized. Limited Blue H2 imports from Gulf, Russia might be an option. **Common to all** • Climate policy and net-zero commitments are at various level not principal motivation anymore

		• Moving from “green-only” to more technology-agnostic strategies • Growing relevance of industrial policy and energy security considerations • Uncooperative regional and global geopolitical environment- especially in North Africa/ continental Eurasia (Ukraine War) and Asia-Pacific (China’s dominance and decoupling strives, US-China competition) - dictates H2 priorities also for demand centres

Source: Authors

The role of industrial policy and energy security has become prominent over the last two years, meaning that the focus on green hydrogen that had characterized earlier strategies has been pushed aside in favour of technology-agnostic strategies. By focusing on hydrogen, ambitions include preserving or achieve technology supremacy, retaining or build up industrial-manufacturing capacity and secure energy supply in an increasingly conflictual and competitive geopolitical environment. While the US, China and India are likely to emerge as prosumers, and in the longer-term free to decide whether to pursue domestic self-sufficiency or participate in hydrogen trade as exporters, Europe and Asia-Pacific, i.e., Japan, Korea and (in the longer term, after 2030) Southeast Asia, will remain largely or entirely dependent on imports. Moreover, almost every demand centre has its own political preferences when it comes to the hydrogen colour, with the European Union being the least technology-open, and Japan and Korea the more pragmatic and agnostic.

4.3.2. Expected producers: MENA, the southern hemisphere, continental Eurasia

Potential hydrogen producing and exporting regions can be grouped into three macro regions: Middle East and North Africa (MENA), the three Southern Hemisphere regions Australia, Southern Africa and Latin America, and continental Eurasia, including Russia/Eastern Europe and Central Asia.

Middle East and North African countries can be potential global hydrogen suppliers and industrial users. However, across the region technological priorities, economic strengths, governance, policy frameworks, and geopolitical orientations vary greatly and require a by-country differentiation. The countries of North Africa, spanning from Morocco to Egypt, have enormous solar and wind resource potential. IRENA estimates (IRENA 2022g) the installable capacities as 2,792 gigawatts (GW) for solar and 223 GW for wind in North Africa alone – which is more than 12 times the total installed electricity generation capacity in Africa and more than two and a half times Europe’s entire electricity capacity in 2021. The countries are strategically located between Europe and Sub-Saharan Africa and maintain solid political and economic links with European states and businesses. The region could become an important player in clean energy value chains. While the potential for green hydrogen is high in terms of costs reduction and renewable availability, challenges such as governance problems, water scarcity in inland areas and infrastructure constraints might prove to be key negative factors. In addition to costs, resources and infrastructure, policy frameworks for hydrogen and geopolitical situation needs to be factored in.

In the case of North Africa, fossil resources are poor, but sun- and wind-rich Morocco has already published its hydrogen strategy and bets big on Europe as final destination for green hydrogen. Algeria and Egypt are all working on developing their own strategies. In Algeria, due to its status as prime natural gas exporter, hydrogen does not figure high on the political agenda. Conversely things are evolving differently in Egypt. Shortly after the UNFCCC COP 2022 hosted in the country, the Government has announced an ambitious national green hydrogen strategy to be launched by the end of 2022 to turn Egypt in a regional hub for green hydrogen However, the strategy has yet to be finalized and published (see below).

Morocco is the country combining the highest potential in terms of costs, infrastructure and resources, with the most advanced policy framework and the highest expected investments (8 billion USD by 2030, 75 billion by 2050) (DNV, 2022, p. 42). It has already ramped up its renewable electricity generation capacity massively over the last decade. Morocco's priorities are clearly aligned with the European demand centres in its direct proximity. Morocco's Green Hydrogen Roadmap, published in 2021, targets a 4% share of global hydrogen demand by 2030, prioritizing export to Europe. This would require the construction of 6 GW of new renewable capacity. Domestic use plans include transport, fertilizers and raw materials (feed stock). Infrastructurally, Morocco is at the centre of electricity interconnectors linking Spain and Europe with the rest of the region as North Africa's national electricity systems are also interconnected, meaning that the technical preconditions are in place to ramp up intra-regional electricity trade. In October 2022, the EU has signed with the country its first Green Partnership, and Germany has a green hydrogen partnership since 2020. Morocco could also be a bridge to West African green hydrogen exporters such as Senegal.

However, the geopolitical situation around Morocco and Algeria remains tense: In fact, territorial disputes at the border between the two countries have resurfaced, as have tensions about the long-disputed territory of Western Sahara which Morocco occupied in 1975. And Western Sahara is undoubtedly one of the most politically controversial and legally challenging questions as much of the phosphate and other minerals that could fuel Morocco's clean energy industrial supply chains, as well as a large share of the solar and wind power generation for green hydrogen production potential, is located in Western Sahara. Actually, German diplomatic relations with Morocco were frozen for two years which delayed concrete action on the green hydrogen partnership. Likewise, diplomatic conflicts with Spain and France could only recently be solved.

Algeria has enormous potential for green and blue hydrogen, owning to both its renewable resources and its gas reserves. But it is currently focusing on maximizing natural gas export revenues and does not really focus on transitioning its export model. At best it sees green hydrogen as a niche technology to compete with Saudi-Arabia. There are so far only vague plans and no clear policy framework for technological push and demand pull (Clean Technica, 2022). Governance in Algeria has traditionally been problematic and renewable energy development has been inexistent. Algeria could have an advantage in producing and exporting blue hydrogen, but given the high natural gas prices, its new role as one of the major EU's suppliers, and the high dysfunctionality of its gas sector, it currently lacks incentives for committing to blue hydrogen. Conversely, while the Government is in fact working on a hydrogen strategy, it has been quite silent about the role export might play in it.

Egypt is a complicated case due to political forces pulling into different directions. Governed by an autocratic president with a penchant for costly prestige projects, Egyptian plans have to be taken with "a grain of salt". Renewable energy development has been patchy, with a recent GW scale PV plant showing that large projects can be successfully implemented. As the country is profiling itself as a natural gas exporter to Europe, producing and exporting green hydrogen was only a niche priority until recently. Things have changed last year, with the Government following a technology-open approach, including both blue and green hydrogen, and targeting Europe specifically, before and during the UNFCCC COP27 hosted by Egypt. There, Egypt announced ambitious plans to become a hub for green hydrogen production and export. To achieve capturing 8% of the global hydrogen market, Egypt has also announced the creation of a green hydrogen plant in the Suez Canal Economic Zone (SCZone) and signed several agreements and cooperation protocols with nine developers in the renewable energy sector at a value of 83 billion USD (Salah 2022). The strategy is jointly developed with the EBRD. However, its publication has been delayed. According to a first draft- the scale-up phase is expected only by the late 2030s. Water scarcity remains a major barrier for green hydrogen. Egyptian perspectives for becoming a blue hydrogen hub would be much greater in the short- to mid-term, due to the development of offshore gas fields, gas supplies from Israel and depleted sandstone reservoirs in Egypt's Nile Delta, which are potentially suitable for CCS (Ruseckas, 2022). Geopolitically, gas cooperation with Israel has been at the core of Egypt-Israeli rapprochement and thus would speak in favour of a blue hydrogen approach. But security risks in resource-rich regions of the Egypt's Sinai Peninsula, Western Desert and Nile region should not be underestimated.

Generally, for the entire North African region, the attempt to reduce exposure to the EU's CBAM mechanism and the prioritization of electricity exports could lead to a lower availability of green hydrogen for export, particularly in Morocco.

While North Africa could almost exclusively supply Europe, the Gulf could emerge as a core of the global hydrogen trade swing producer in the new global topography of hydrogen trade, given its strong oil and gas trade links to far flung world regions as well as high renewable electricity potential and gas reserves that would drive both green and blue hydrogen supply (Michaelowa et. al., 2019). The countries of the Gulf Cooperation Council (GCC) are mapping out agendas to kick-start a hydrogen economy, taking generally a technological-agnostic stance. Historically, these countries, especially the UAE and Saudi Arabia, have been able to decide and implement large infrastructural investment in a very short period, and thus can easily become hydrogen supply frontrunners if sufficient political will exists. The countries have also full public coffers given huge revenues due to the high oil and gas export prices since the outbreak of the Ukraine war. Especially Saudi-Arabia, the United Arab Emirates (UAE) and to a lesser degree Oman are pursuing ambitious plans to supply both Europe and Asia-Pacific with low-carbon and green hydrogen. Numerous declarations of intent have been signed, and the first large-scale projects are under way (Ansari 2022). Saudi Arabia is working on a hydrogen roadmap. It is currently demonstrating blue ammonia value chains projects with shipments to Japan and is planning one of the largest projects with 4 GW of green hydrogen at the new city of NEOM. However, its major focus is on blue hydrogen as part of the country's vision of a circular carbon economy. Oman's National Hydrogen Strategy (2021) pursues blue and green hydrogen, targeting 10 GW by 2030 and 30 GW by 2040, but in a first stage only for domestic use, while the UAE' s Hydrogen Leadership Roadmap (2021) targets a 25% share of the global low-carbon/hydrogen and derivatives market by 2030 and exports to both Europe and Asia. First supply agreements with Japan and South Korea for blue ammonia have been signed. As the last decades have shown, the UAE's, particularly Dubai's, ability to diversify into new economic sectors cannot be overestimated. Given past lacklustre experiences with large projects in Oman, the Omani strategy should be seen as a declaration of interest, not (yet) a serious bid for participation in the global market.

In contrast to the described neighbours, Qatar- one of the biggest LNG exporters worldwide- has no plans for producing hydrogen but bets big on LNG exports with which importers could produce blue hydrogen abroad (Ansari, 2022). While Qatar has good CCS potential (Hodge 2022), and the State-owned giant Qatar Energy aims to target CCS technology to capture over 11 million t per annum of CO_2 by 2035, priority is given to cleaner LNG production rather than to the production of blue hydrogen (Ugal 2022).

For the Gulf countries, hydrogen would allow diversification without jeopardizing the prevalent governance model. Since the hydrogen economy blends into the institutional and fiscal framework of the petroleum industry, it is primarily a chance for the GCC economies to maintain current economic and political power structures with a top-down, highly centralized approach suited to their autocratic forms of governance. This is essentially a corporatist, favouring large-scale utility energy model. The emphasis on technology and innovation and the focus on low-carbon "development" points to energy 'addition' rather than energy transition. An important caveat regarding the Gulf's strategy is that often large projects announced with great fanfare do not materialize. Moreover, potential for destabilization through events in Iran and unrest on the GCC's northern flank should not be underestimated.

Historically strong relations with East Asia and a growing Chinese presence will ensure that the region does not become a hydrogen "backyard" of the EU, even in case of a more open and long-term preference for blue hydrogen by the EU. However, transport challenges may limit the Gulf countries' ability to export green hydrogen at similar scale as they currently export oil/gas.

In the **Southern Hemisphere**, Australia could emerge as a major global export champion and has already been a frontrunner in hydrogen strategies and related policies, as well as concrete private sector action. Australia has a huge solar electricity potential but suffers from water stress in its inland areas. Australia's National Hydrogen Strategy (2019) targets clean hydrogen (blue and green) production and becoming an export hub in renewable and low-carbon hydrogen and ammonia. Australia's different regions also have regional targets for hydrogen use (e.g., 10% hydrogen blending in the gas network by 2030) and production, as well as concrete funding programmes. The government is investing 320 million USD in Clean Hydrogen Industrial Hubs. Its Renewable Energy Agency has provided 40 million USD in support for R&D in green hydrogen and ammonia projects.

Australia's insular and remote position at the conjunction of the Pacific and the Indian Ocean generates a disadvantage regarding transport costs. Due to this, economic conditions to emerge as a global hydrogen superpower, i.e. able to trade with all major demand centres, including Europe, might not emerge before 2050: a significant fall in transport cost due to competitive shipping solutions for long-distance hydrogen trade or a significant drop in hydrogen production costs – Henceforth, while Germany bets on hydrogen cooperation with Australia e.g. as the *HyGate Incubator for German-Australian hydrogen cooperation in technology and innovation* Programme (Australian Government Department of Climate Change, Energy, the Environment, and Water 2021), the country is in the mid-term best suited to supply Japan and Korea. The choice comes also as Australia faces a complicated geopolitical environment, as China remains both Australia's major trading partner and an increasing geopolitical menace, with a trade war embroiling the two countries since early 2020, mainly resulting from China's retaliation for Australia's decision to join the US-sponsored security alliance QUAD. Canberra's and Japan's interests are aligned in creating resilient energy supply chains centred on "clean hydrogen" which diminish trade dependencies from respectively the Middle East/Russia and China. Japan is already active in the Australian hydrogen supply and value chain, for both green and blue, while the Australian hydrogen strategy openly targets Japan as main export destination. (Akimoto 2022). The pilot JCM project under Article 6 of the Paris Agreement between Australia and Japan was already mentioned above.

Moving west across the Indian Ocean, **Southern Africa**[26] remains a region of vast untapped potential. Particularly South Africa and Namibia could emerge as hydrogen producer and exporters (IRENA 2022e). Although renewable electricity resources are abundant, there are several factors hindering the rapid development of hydrogen production for export. These include water constraints, an insufficient infrastructure, energy poverty that prioritizes domestic renewable electricity consumption, and a lack of robust regulatory instruments. A notable exception here is South Africa, which aims for renewable hydrogen exports targeting 4% of global market share by 2050 and a slow but constant increase of electrolyser capacities to 15 GW by 2040. With the exception of South Africa, no country in Southern Africa has dedicated support programs, only low funding schemes nor CCS policies. Hydrogen projects here are likely to advance only in the long-term, if supported through international funding and bilateral government offtake agreements. Namibia and South Africa could tap into a 10–22 Mt hydrogen export market mostly directed to the Japanese, South Korean and Southeast Asian markets (Green Hydrogen Organisation 2022, African Green Hydrogen Alliance, p.23.). This adds political instability of some key transit countries, autocratic regimes and divided international geopolitical loyalties, with China capitalizing on infrastructure, investments, political connections with local elites, institutional ties with the African Union and growing raw materials imports reinforcing path-dependencies in fossil and mineral-rich countries.

Latin America would have the potential to become another major production and exporting hub. Traditionally, Latin American countries, especially in the Southern Cone have prospered on revenues from commodity export, with Chile for saltpetre and copper, and Argentina for meat and other agricultural resources. So, there is a good understanding of harnessing commodity export markets. In

[26] In Central Africa, there is a vast untapped hydropower potential. The famous Inga site near the mouth of the Congo River alone could yield over 40 GW. However, governance problems have so far prevented exploitation of this potential, and this is unlikely to change.

Argentina and Chile, there is huge untapped wind and solar power potential amounting to several hundred GW. Several countries are developing hydrogen strategies, with Chile's National Green Hydrogen Strategy being the most concrete. The country aims at becoming a global export hub and reach 25 GW installed capacity by 2030. While demand will come from the mining industry and heavy transport, the principal focus is on exporting hydrogen. In June 2022, the Argentine government unveiled the 2030 National Low-Emission Hydrogen Strategy, aiming at 5 GW electrolysis capacity by 2030 (GH2, 2022). Already today, some large-scale projects are being developed, e.g., a 120MW (electrolyser capacity) green ammonia project in Paraguay to be expanded to 420MW capacity, benefiting from excess hydropower capacities (ATOME n.d.).

However, limited public funding means foreign investments are required. Governance challenges need to be overcome; countries of the Southern Cone have recently been shaken by social movements denouncing persistent inequalities. Latin America has the potential to become an important player in global hydrogen trade, but this will require a clear political vision and collaboration and the long-term engagement of all relevant national and international stakeholders (IEA 2022d).

Finally, **continental Eurasia**, mainly consisting of Russia, Ukraine, and Central Asia, presents on paper major opportunities for blue (and turquoise) hydrogen and- to a less extent- for green hydrogen production and export. Proximity to the European and Asian market would make the region a natural swing producer. Before the Ukraine war, Russia (Westphal, Zabanova 2021) and Ukraine had major aspirations in tapping into the potential of the European hydrogen market, while Central Asia remained largely marginal. The war has reshaped flows, partnerships priorities and opportunities. Ukraine still features prominently in the EU's hydrogen import plans and the Ukrainian Hydrogen Strategy draft (December 2021) aimed at renewable hydrogen exports building on the existing pipeline infrastructure. Until 2030, Ukraine planned 7.5 GW of exports to the EU. However, uncertainties about the war outcome and the presence of Russian occupation troops in the renewable energy-rich east and southeast mean, that Ukraine might re-enter the hydrogen equation in the second half of the 2030s. Before the war, Russia was working on a roadmap for (blue and turquoise) hydrogen development for the period 2021-2024 with the aim to preserve the country's leading role as a global energy exporter. Russia's export plans include hydrogen shipments of 2 Mt/year by 2035 and 15 -50 Mt/year by 2050. The end goal of 50 Mt/year would be equivalent to around 160 Bcm/year of natural gas, the entire amount of natural gas Russia sold to Europe before the war. After the outbreak of the war, Russia will fall out as an (hydrogen) partner for Europe for the time being, while the implementation of these plans largely depends on Russia's fiscal capabilities and the outcome of the war. However, the geopolitical break-up with Europe, which seems long-term, leaves Russia with the only option of the Eastern Asian markets that could tap into the immense renewable electricity resources of Eastern Siberia and Kamchatka (hydro, tidal and geothermal). Japan, which has frozen cooperation with Russia in several sectors- is still involved in the Sakhalin II LNG project and might resume plans to work with Russia's Rosneft and Novatek on hydrogen and ammonia, as well as CCS, once the war is over. In a technology-open scenario, Russia might play a role in the Asian Pacific hydrogen trade- as well as in bilateral trade with India, at some point around 2040, while less so in an "only green" scenario. Central Asia is emerging as a partial alternative for hydrogen exports to Europe, and national strategies for hydrogen in Uzbekistan and Kazakhstan are set to be approved with a focus on green and low carbon hydrogen. Solar potential is high while water constraints are relevant in these regions. Infrastructure constraints, Russia's role as major transit territory for pipelines to Europe, would however leave Central Asia largely dependent on a complex logistics to reach other countries outside the region. The region lacks a regulatory and policy framework for hydrogen.

Table 9: *Potential production centres, position on the market, geopolitical priorities*

Production centres	Position on the market	(Geo) political priorities and h
Middle East (Saudi Arabia, UAE, Oman, Qatar) **North Africa (Morocco, Algeria, Egypt)**	Exporter of blue and green hydrogen.	Gradual economic diversification while preserving own political-economic model fossil fuel producers, Modernisation and technological-industrial competition with neighbouring countries to secure regional leadership. Balance among divided loyalties West and China (especially Gulf)
Southern Hemisphere Australia **Sub-Saharan Africa (Namibia, South Africa)** **Latin America (Chile, Argentina)**	Exporter of blue and green hydrogen, with expected growing local demand. Transport and logistics are an issue. Large potential, but only South Africa has clear targets and political-regulatory conditions to emerge as an exporter in the long run. Transport and logistics are an issue. Producer and exporter of green hydrogen and also hydrogen products in the long run. Geographic remoteness and limited public funding	Reducing existing geopolitical dependencies (AU-China) plus strengthening existing historical trade and diplomatic ties (Australia-Japan) Divided loyalties between the West and China and existing geopolitical dependencies (China-Africa) or already largely oriented toward Asian off-takers (Namibia, South Africa toward Japan, Korea) Balance among divided loyalties and concurring influence West-China. Look to Asia and Europe
Continental Eurasia (Ukraine, Russia, Central Asia)	Potential major producers of blue and green hydrogen in the long-term (especially Russia, Ukraine).	Divided loyalties between the West and China and existing geopolitical dependencies

Production centres	Position on the market	(Geo) political priorities and h
	Limited chances to participate in hydrogen trade in the short term.	Gradual economic diversification while preserving own political-economic model CE fossil fuel producers), Modernisation and technological-industrial competition with neighbouring countries

Source: Authors

Summing up, the topography of potential exporting countries is characterized by a **high volatility in terms of motivations and priorities.** All countries share a pragmatic approach toward climate policy goals while the hydrogen priorities are strongly shaped by the economic and productive structure of the country, the socio-economic and industrial priorities, and the regional geopolitical environment. Generally, a vast number of potential suppliers is endowed with both renewable and fossil sources and takes a technology-open approach. Fossil-poor but renewable-rich countries generally have a more export-oriented strategy and aim at integrating in the green industrial value chain by increasing their local content. Fossil fuel producing countries in the MENA region and in continental Eurasia are mainly driven by their desire to attract investments to diversify their economies while preserving their own economic model. In almost every region, tense geopolitical relations on territorial issues, competition for regional leadership and divided loyalties toward external great powers (Europe, US, China) influence hydrogen policies.

4.4. Expected market structure and topography of the hydrogen trade in 2030, 2040 and 2050

Combining the factors analysed throughout this study, we can draw a first partial conclusion on the future market structure for different colours of hydrogen and on the geographic trade flows.

Period 2023-2030

Since some major demand centres are geographically distinct from major production centres, particularly in the first stage (2023-2030), production and transport costs, as well as government-backed, large-scale infrastructure investments will be critical to determine the attractiveness of production sites. Due to differences in these parameters, different hydrogen types/colours will influence the geography of trade, production, and supply. Importing countries will be in search of the largest possible number of suppliers to create redundancies and diminish dependencies (e.g., Africa/South America as competition for Middle East/Russia) while producing countries will not only align their strategies to the demand centres in their proximity (band-wagoning) but also seek to balance between different off-takers, not all necessarily located in their geographic proximity. In this stage, political preferences and geopolitical priorities will play a significant role in co-defining the market structure.
In this first stage, the major demand centres in Europe, North America, and East Asia (see IRENA 2022a) will work with selected suppliers to create the first rudimentary trade relations. In parallel, China

and the United States will each presumably form a strong – largely self-sufficient – pole, having renewable electricity generating and CCS locations on their territory, technology openness, and know-how as well as the required industries. In this early stage, India will presumably focus on scaling up own technological manufacturing capacities, with demand for green hydrogen still low. Conversely, Europe and East Asia – their technological leadership notwithstanding – will greatly rely on imports. Particularly for net importers, it seems essential to establish logistics chains early on and to work on the emergence of a "commodity" market.

Europe can be expected trying to kick-start a global trade network already in an early stage. However, it will presumably end up focusing largely on North Africa, the Gulf and potentially Eastern Europe. Conversely, East Asia is likely to focus on the triangle Australia-Gulf-Asia Pacific. Largely uncertain will remain the role Southeast Asia. Particularly Malaysia and Indonesia might play as regional producer and exporter. While the countries are targeting Singapore, Japan, and Korea as final destination, they are not yet ready for a rapid ramp-up.

The wild cards of the market will be Latin America – which could deliver to both North America or Europe – and Southern Africa, which could serve all demand centres. However, these locations would suffer from a transport cost disadvantage compared to the other suppliers. Also, the Gulf states can be considered wild cards, being able to deliver to Europe and Asia, but also facing longer transport distances.

During this early stage, in absence of standardization of product specifications and contracts and internationally standardised certification, political decisions are needed to tackle the "chicken or egg" dilemma: Supply and demand must be aligned, and the logistics in between, that is, transport and storage, should be free of bottlenecks. Volatility will characterize the market environment in terms of off-takers, price-building mechanisms, hydrogen quantities and types (hydrogen derivatives) and qualities ("colours").

Assuming a persisting non-cooperative geopolitical environment, in the short to mid-term, regional crisis and instability might have a major impact on the hydrogen topography as well, contributing to determining the final preferences.

Against this backdrop, for Europe in this early stage, realistic options for a diversified market might be scarce. In North Africa, the number of producers might be restricted to one (Morocco) or only few (Egypt, Algeria) depending on Europe's technological and "colour" preferences. Moreover, the willingness of European states to invest political, diplomatic, and financial resources in countries with authoritarian political regimes and uncertain security environments (Egypt, Algeria) and to accept their preferences and conditions determines its options. In a green scenario, Morocco will be the obvious first- and only choice until 2030. This, however, only assumes Morocco's interest is aligned with Europe's (CBAM and priority given to hydrogen rather than electricity imports plus support for Morocco's geopolitical ambitions). In the case of a more open approach toward blue hydrogen, Algeria and Egypt might offer greater chances for a faster scale-up of production and imports, but these will not come without a major and broader political, diplomatic, and financial engagement in the broader region.

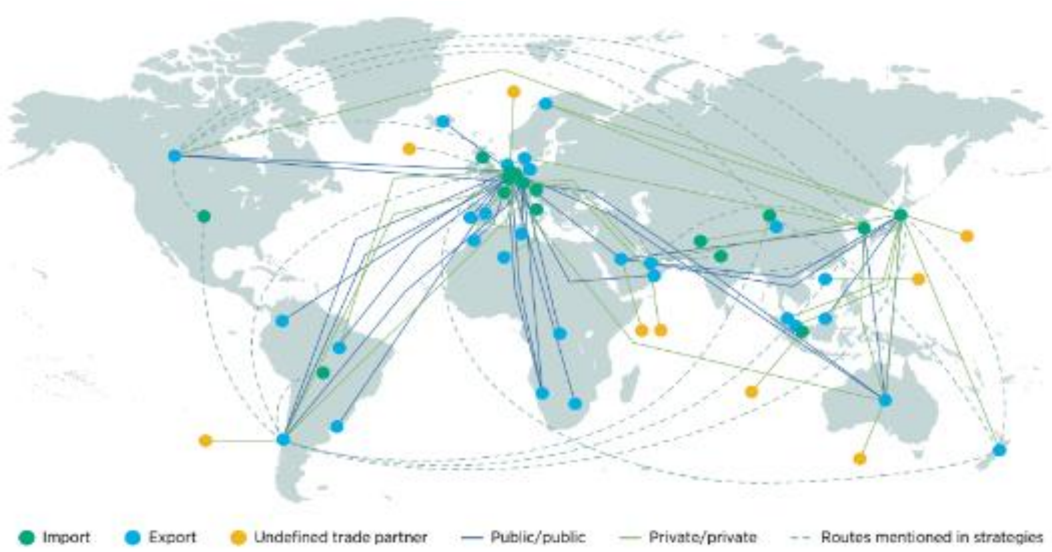
A similar picture offers the Gulf, where a more agnostic approach, could contribute to expand the number of potential partners already in the early stage. By 2030 both UAE and Qatar could indeed deliver on their promises, if Europe were to accept both green and blue hydrogen supplies, including derivatives. Conversely, a narrower preference for green could further reduce the partner options and decisively orient the Gulf toward traditional off-takers in Asia, if particularly Japan and Korea will still rely on Gulf countries in the early market stage. The more so, considering that transport constraints might limit the Gulf's country's ability to export substantial volume of green hydrogen to Europe.

Continental Eurasia remains a black box. Russia will be out of the hydrogen equation for geopolitical reasons, while Central Asia-i.e., Kazakhstan and maybe Uzbekistan still in a very early stage of development and many unresolved questions (water resource scarcity and water management conflicts, transport-logistic remoteness, low share of installed renewable energy capacity, growing domestic demand for gas and scarce incentives to invest in blue hydrogen production vs exporting natural gas). Conversely, a green hydrogen partnership with Ukraine could become a key pillar of reconstruction measures and commitments, also considering Ukraine clear commitment to integrate with Europe. It seems however unrealistic that Ukraine's reconstruction will be completed, and the country pacified before the end of the decade.

Generally, at an early stage, a major role is to be played by states and governments not only in defining rudimentary trade relations. Government-to-government deals and strategic energy partnerships will be needed to secure supply and stabilize demand. Meanwhile, it needs a major diplomatic-political and financial effort to stabilize regions with volatile security environments and ongoing bilateral or multilateral conflicts potentially impacting hydrogen supplies.

Only under these circumstances, mainly bilateral contracts with individually agreed, fixed offtake (volume/prices) conditions can be expected toward the end of the decade.

Figure 30: *Bilateral trade announcements for global hydrogen trade until March 2022*



Source*: IRENA (2022a), p.23.*

Period 2030-2040

In the second stage (2030-2040), the market will eventually cluster in macro-regions as infrastructure matures. We might experience growing standardization, OTC deals, clear standards on colour, including carbon content and sustainability labels and a wide array of both long-term and short-term agreements. Market maturity will bring more players on the market, generating more competition in production, while demand will grow due to improved infrastructure and greater conversion of industry production to green hydrogen compatibility.

For Europe, more players in the market for green hydrogen might materialize especially in North Africa (Egypt), the East (Ukraine, to a less extent Kazakhstan), and the Gulf (Saudi Arabia). Pipelines from Morocco, Egypt, and potentially Ukraine would be supplemented with derivatives shipped from the Gulf. Largely pipeline-bound transport and bilateral contracts with fixed tariffs and volumes would reduce supply flexibility and increase risks related to the political stability of the supplying countries. However, building long-distance pipelines takes time, while shipping requires an accelerated development of logistics and infrastructure.

From a European perspective, this development assumes not only market maturity but also the EU's ability to coherently align single EU members' preferences as well as in terms of a coherent and effective foreign energy and security policy. The persisting interest of developing countries in exporting molecules and derivatives instead of moving up the hydrogen value chain and competing with industrialized countries for jobs and industrial re-location will also be a key factor.

Period 2040-2050

In the third stage 2040-2050, in particular towards 2050, as a result of declining transportation costs and growing pipeline-shipping competition, demand growth and infrastructure build-up, mature and liquid regional markets, while still largely concentrated in three blocks – North America, Europe-Eastern Europe Africa/Middle East and Latin America-Indo-Asia-Pacific, might start interconnecting, with trade

in hydrogen derivatives playing a similar role as today's LNG trade connecting regional gas markets. At this stage, some Latin American countries like Chile, Argentina, and Brazil, as well as swing producers like Namibia, Southern Africa and Australia might enter the equation and position themselves as important complementary suppliers also for Europe. While for Europe these countries will hardly emerge as major suppliers, they will contribute to diversifying supplies and build redundancies.
This scenario could decrease but not rule out inter-regional market competition interwoven and influenced by geopolitical competition among the regional blocks or major power if the world order remains competitive and less open to international multilateral cooperation.

4.5. Geopolitical implications of the expected topography of hydrogen trade

Our analysis shows that future geopolitical realities of net hydrogen importers like Europe/Germany (as well as East Asian economies) might not be too different from today's situation, as energy import dependencies may continue, but risks and vulnerability will get less due to a stronger differentiation of energy import sources. However, this will require proactive management of markets and minimization of geopolitical risks particularly through dedicated government support of infrastructure.

First, the sketched topography of the hydrogen market shows, that – while potentially many producers might emerge in the long-term -, in the short to mid-term (2023-2040) a limited number of producers might come to dominate regional markets. On the one side, it is highly unlikely that these producers will create a small cartel of suppliers to leverage hydrogen as an instrument of political pressure or to set prices and production volumes. When it comes to producers of green hydrogen, Europe and Germany face a different set of risks: in an early stage of the market (2023-2040), producers will presumably be concentrated in North Africa, the Gulf region and – developing more slowly due to the Ukrainian war, Eastern Europe.

Non-economic costs, such as diplomatic and political efforts to stabilize and secure supplies, need to be factored in and may justify subsidies for infrastructure development to get supply from other regions like Latin America and Southern Africa.

For example, assuming that the European states overcome their differences and prioritize major green hydrogen imports, the geopolitical environment in the direct eastern and southern neighbourhood will significantly limit Europe's options. Aligning different technological and political preferences of both European off-takers and North African producers along the trade corridor North Africa-Mediterranean-Europe might prove particularly challenging. For instance, in this green scenario, with Morocco emerging as the only potential and realistic supplier in the 2020s, political strings might come attached to any partnership with the country.

While Morocco prioritizes exports to Europe and aims at a 4% share of exports, it has ambitions to use hydrogen to decarbonize its own economy and foster green industries (ammonia, fertilizers, green steel). This might create direct competition with European producers and reduce the amount of hydrogen available for export. Furthermore, Morocco could conversely privilege electricity exports over hydrogen. Geopolitically, Morocco could try to exploit its dominant market position to drag Europe- or single European countries- on its side in its conflict with Algeria on the West Sahara. In this case, Europe would be forced to intervene more directly to stabilize the Morocco-Algeria relation.

In a longer-term perspective (2040-2050), the emergence of a more mature market, underpinned by global, cross-border value chains, can offer greater supply flexibility, and lessen dependencies on few, and geographically concentrated producers. This includes particularly producers from the Southern Hemisphere (Argentina, Australia, Chile, Namibia).
While greater flexibility via shipping would create needed redundancies, such a diversification would also mean a more complex supply chain and risk management. This would come at cost: first, the emergence of new elongated maritime shipping routes for hydrogen across the Indian Ocean, the West African coast and across the Southern Atlantic increase the security premium amid growing hybrid warfare risks at sea. Maritime risks vary from piracy near coastlines to acts of sabotage, espionage and attacks on ships and maritime infrastructure like pipelines carried out by state actors. In a worst-case-scenario and in the presence of persisting geopolitical competition between the US and China as well as in the absence of a collective security provision mechanism, it cannot be ruled out that at this stage the US might not have the financial capacity or the political will to use its naval presence to secure the sea lines of communications. In this case, securing this "public good" might be the task of single major importers dependent on these routes[27]. Second, dependencies on new choke points like the Panama Canal, could add to the already existing ones in Malacca and Hormuz.

In the case of Australia, a like-minded partner with the potential to emerge as a major supplier, the country's own connections with the world will continue to rely on sea lines of communication. If the region's seas will remain congested and contested and the geopolitical situation between China and the US worsens or escalate, we can assume that many regional countries like China, Japan, India, and Southeast Asian nations will continue to invest in advanced naval and civil maritime capabilities. States as well as terrorists and other criminals might use the relatively porous maritime boundaries of the Indo–Pacific as transit routes. Secure hydrogen exports, this will require greater diplomatic, political, and military engagement in the region by the European Union alone or in tandem with the United States, which at the current stage cannot be taken for granted.

Conversely, if the topography of producing countries includes both green and blue hydrogen, this technological mix will certainly increase the number of suppliers and create additional flexibility. In this scenario, for example, the Gulf, as well as –in the very long-term- Russia might still play an important, though not dominating role. Moreover, "the potential for centralized production and distribution of hydrogen offers opportunities to co-opt segments of the fossil fuel industry into the energy transition and throw a lifeline to petrostates" (Van de Graaf et al. 2020). This potential could not only be politically leveraged in order to maintain at least the minimum commitment of oil exporters to the Paris Agreement but also to guarantee political stability and avoid destabilizing intra-regional competition. However, in this scenario, blue hydrogen supplies, particularly via pipeline, might strengthen or replicate old fossil path dependencies (including potentially massive CO_2-emissions) while the additional diversification will come with additional complexification of trade and diplomatic relations, calling for a greater European and German engagement at regional and global level.

[27] For possible scenarios concerning the future of the US Security umbrella for the Sea Lines of Communications see Andrews-Speed, Len (2016).

Generally, it should be noted that geopolitics– rather than cost calculations and economic rationality- might especially motivate the positioning of the two major prosumers the US and China on the future hydrogen market. With both growing production but also demand potential and massive ability to provide subsidies, the US and China might at any date decide to enter the market as either importers, exporters, or trading hubs. Their motives might vary from increasing geopolitical influence, to securing political loyalty or cementing industrial-technological superiority.

4.6. Synthesis and recommendations

The shift from a cooperative, neoliberal, globalized world economy to a competitive, conflictual, protectionist and fragmented world order starting in the late 2000 has accelerated with the COVID-19 pandemic and Russia's invasion of Ukraine. This shift jeopardizes attempts to provide global public goods like mitigation of climate change.

Under pessimistic assumptions, these conflicts could hamper the roll-out of hydrogen technologies, ranging from protectionism and market power for raw earths and materials required for electrolyser- and PV-installations (a large share of global resources are located in China) to conflicts about international maritime trade routes for hydrogen.

At the same time, low-carbon hydrogen is a unique chance for energy importing countries to diversify their supply and minimize dependencies from a few dominant energy exporters while at the same time reducing detrimental climate impacts. A truly global hydrogen market with a more diversified suppliers' topography - i.e., a larger number of suppliers - can help to minimise geopolitical risks for Europe's and Germany's supply security[28]. But this requires political dedication and significant investment - both politically and financially. For diversifying global green hydrogen supply chains and for increasing energy supply security, Europe and Germany should undertake the following:

- **Establishment of strategic, long-term green hydrogen partnerships with selected countries**. This should include three key elements:
- A dedicated government approach to **subsidizing green hydrogen infrastructure** already in the very early stage. This includes support for scaled up electrolysers' capacities, which can help move hydrogen projects faster from pilot to test to production stage in a greater number of supply countries. In addition, infrastructure for processing, transport, storage, and export requires financial commitments.
    - **20-year supply contracts**, building on the existing model of a green hydrogen partnership with Morocco. Similar partnerships could be envisaged with Argentina, Chile, Egypt, Mauritania, Namibia, Oman, Senegal, South Africa, Tunisia, and the UAE – all delivering green hydrogen.
    - Acknowledging that a typical drawback of energy partnerships is their long lead-time, a "**prompt start"** for hydrogen collaboration can be achieved by developing **green hydrogen Art. 6 pilots**, similar to what Japan has recently been pioneering in the context of the Japanese Crediting Mechanism (JCM).

[28] At the same time, it needs to be considered that a more diversified hydrogen market will require a continued management of risks along elongated supply chains and management of political partnerships with a wider array of countries.

- **Sustained political support and stable perspectives for green hydrogen demand in net-importer countries for at least the first decade of market environment volatility**. For the EU, this implies a coherent hydrogen import strategy with dedicated and financially strong instruments (Hydrogen Bank, "H2Global at European level") to align European off-takers and extra-European suppliers. This includes both a political agreement on a clean hydrogen definition, on standards and certification, as well as an agreement on industrial and trade policy priorities (molecules vs electrons vs hydrogen products like green steel) as well strategic clarity about CBAM's impact on its own energy-intensive industries and on decarbonisation paths in supply countries.
- **Consider partial openness for blue hydrogen for a limited, clearly defined time period.** The pros and cons of blue hydrogen have been discussed in detail in the previous sections, and it is clear that green hydrogen must be given absolute priority. At the same time, allowing blue hydrogen from existing oil/gas fields for a clearly defined time horizon (e.g., max. 10 years) can be a geopolitical means to motivate Gulf countries to transition towards green hydrogen production. This could be done through long-term contracts defining total amounts of hydrogen to be delivered with shares of green hydrogen increasing over time. The exit year for blue hydrogen needs to be clearly defined. Contrary to this, blue hydrogen from new fields/operations should not be allowed due to long lead times and lock-in effects. - Hence, blue hydrogen supply contracts could be negotiated with Saudi Arabia and other Gulf countries but should be accompanied by a clear phase-out of blue and a transition to green hydrogen in the early 2030s.
- **Political pragmatism:** striving to build green hydrogen alliances around high standards is important but might reduce the number of potential suppliers. Especially attaching political conditionalities (for example nature of the regime) to hydrogen cooperation might prove counterproductive and be at odds with the desire to speed up market ramp-up *and* have a diversified supplier's topography. A country-specific analysis and strategy is essential.
- **Stable geopolitical environment and more cooperative international relations:** finally, a more diversified hydrogen market will only nurture by levelling the playing field and allowing different supply centres to compete under similar conditions. A global hydrogen market with multilateral agreements will be only possible in presence of a cooperative world order with multilateral governance mechanisms working at both regional and global level**.** Yet, against the backdrop of regional fragmentation and global competition, it is important for the EU to intensify regional cooperation schemes in the short- to mid-term and strengthen global governance institutions in the mid to long-term**.** New regional governance mechanisms must be established or upgraded at least in the supply centres of North- and Sub-Saharan Africa and the Gulf region. Central Asia may also be considered. Each country needs a tailored approach and bilateral hydrogen partnerships. In addition, hydrogen diplomacy should be also multilateral and embedded in a broader effort to strengthen multilateral and regional energy governance mechanisms via multi- and plurilateral governance platforms.
- In order to work against the prevailing protectionism, Germany should call for a **multilateral research collaboration** to advance key technological elements of the hydrogen supply chain and pledge a significant sum as a "bait". Such a program should build on experiences gained in the multilateral program for development of nuclear fusion (ITER).

Annex – Overview of common “hydrogen colours”

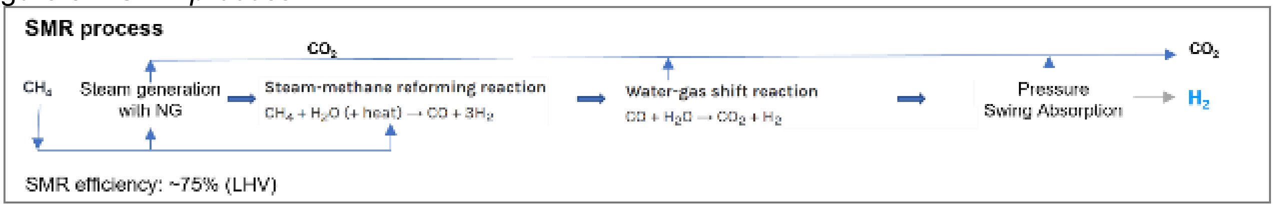
Annex – Overview of common “hydrogen colours”

Grey hydrogen is produced from fossil fuels, such as natural gas or coal. Hydrogen produced from coal or gas uses well-established technologies and by far dominates global hydrogen production. The process of producing grey hydrogen involves the use of steam methane reforming (SMR) and coal

Grey hydrogen

gasification. In gasification, coal or other carbon-based materials are heated in the absence of oxygen to produce a mixture of gases, including hydrogen. In SMR, natural gas is reacted with steam to produce hydrogen and carbon dioxide. This process can take place in a conventional SMR reactor or in an auto thermal reactor (ATR). Both of these processes release CO_2 as a by-product, (Oni et al. 2022). SMR is an endothermic reaction and requires significant amounts of energy, (~2.25 kWh per m^3 hydrogen) providing the necessary heat and pressure for the reaction. Generally, this energy is supplied from natural gas which further increases the GHG-emissions intensity of grey hydrogen. SMR as well as ATR release approximately 9 $kgCO_2$-eq / kg H_2 produced. Additionally, the upstream processes like extraction, processing and transportation of natural gas used in the process can contribute an additional 1.9-5.2 kg of CO_2-eq per kg of hydrogen produced, with a global average of 2.7 kg CO_2eq/kg H_2 (IEA 2021). The SMR process can be seen in Figure 31.

Figure 31: *SMR process*



Source*: Authors*

The ATR reaction is very similar with the only difference that natural gas oxidation and the SMR take place in the same at the same location.

Blue hydrogen

Blue hydrogen is produced by using natural gas as a feedstock, but with parts of the resulting CO_2 captured and stored. In the CCS process, CO_2 is separated from the hydrogen and parts of it is captured and stored underground or used in industrial processes (Oni et al. 2022). Most blue hydrogen plants built today have carbon capture efficiencies of less than 50%. Maximum theoretical capture rates for the SMR process in the range of 80-90%. In order to achieve even higher capture rates, ATRs need to be applied which entail higher costs and energy demands. Capture rates from commercial projects are rarely reported. Theoretical estimates are often considered too optimistic, and many demonstration projects have faced delays or failed to meet expectations. (Riemer and Duscha 2022) Currently there are only two plants in operation attempting commercial scale production: Quest in Alberta, Canada and Air Products in Port Arthur, Texas. The effective CO_2 capture rate at the Air Products plant is less than 40%. Shell's Quest blue hydrogen plant in Alberta emits more carbon than it captures. This reflects the general difficulties with CCS technology and the potentially high remaining GHG-emissions (IEEFA 2022). Blue hydrogen is often considered a "transitional" form of hydrogen, as it can help reduce greenhouse gas emissions while the infrastructure for green hydrogen (produced from renewable sources) is developed (IRENA 2019).

The production of blue hydrogen involves three main steps: natural gas steam methane reformation, carbon capture and compression, and hydrogen purification. Steam methane reformation is the process of breaking down natural gas into hydrogen and CO_2 by using steam. Parts of the CO_2 is then captured using CCS technologies such as amine absorption or membrane separation. The compressed CO_2 is then stored underground or used for industrial purposes (Howarth & Jacobson 2021). Storing CO_2 underground has been demonstrated by large-scale projects, but currently there is more emphasis on utilizing captured CO_2 rather than just storing it[29]. The main use for captured CO_2 is in enhanced oil recovery (EOR), helping to increase oil production in mature oil reservoirs. If captured CO_2 is not stored but utilized, in most applications, it is reemitted to the atmosphere after relatively short periods of time (IRENA 2019).

The use of blue hydrogen as a fuel source has several benefits. It can help reduce greenhouse gas emissions by capturing and storing CO_2, which can help in the transition to a low-carbon economy. Additionally, blue hydrogen can be produced using existing natural gas infrastructure, which can be a cost-effective way to produce hydrogen until the cost of green hydrogen production decreases. Furthermore, blue hydrogen gives traditional gas suppliers the possibility to continue their current economic models, which is particularly relevant for economies highly dependent on gas exports (IRENA 2019).

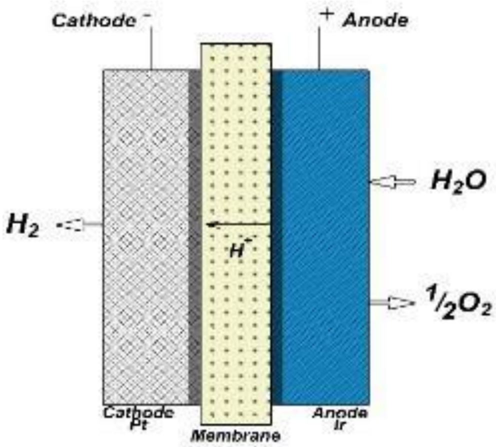
However, blue hydrogen also has its drawbacks. The production of blue hydrogen requires the extraction and use of natural gas, which can lead to negative environmental and social impacts. Additionally, there are concerns about the long-term storage of CO_2. Current industrially applied CCS technologies have capture rates of approximately 50-90 % (Howarth and Jacobson 2021). Considering the additional energy required for CO_2 processing, transport and storage and the methane emissions during NG extraction, results in total GHG emissions of 3.6 $kgCO_2/kgH_2$ to 9.2 $kgCO_2/kgH_2$. Therefore, it is crucial to minimize and account for upstream emissions when considering the use of blue hydrogen in order to reflect the correct environmental impacts. These embodied CO_2 emissions are significant and as discussed in chapter 3.1.2 entail that blue hydrogen would not be considered an RFNBO within the European Union. Furthermore, blue hydrogen does not contribute to increasing renewable energy production and does not help to decarbonize power generation (IEA 2021). Finally, investing in CCS for fossil fuels could divert limited financial resources away from the deployment of renewable energy (IRENA 2019). For those reasons blue hydrogen should only be considered a transitional technology on the way to a sustainable future.

[29] Then, the CO_2 is not stored permanently, but storage periods depend on the product use. It can range from a few weeks (e.g. carbonated drinks) to several years (e.g. buildings).

Green hydrogen

Green hydrogen is produced through the electrolysis of water using renewable energy sources such as solar and wind power. This process does not produce any greenhouse gas emissions, making it a clean and sustainable alternative to traditional hydrogen production methods. In electrolysis, a direct current is applied to the electrodes in the electrolyser, which causes water to split into hydrogen and oxygen. The hydrogen is collected at the cathode while the oxygen is released at the anode (IEA 2022).

Figure 32: Schematic of PEM electrolyser



Source: Wikipedia (2020).

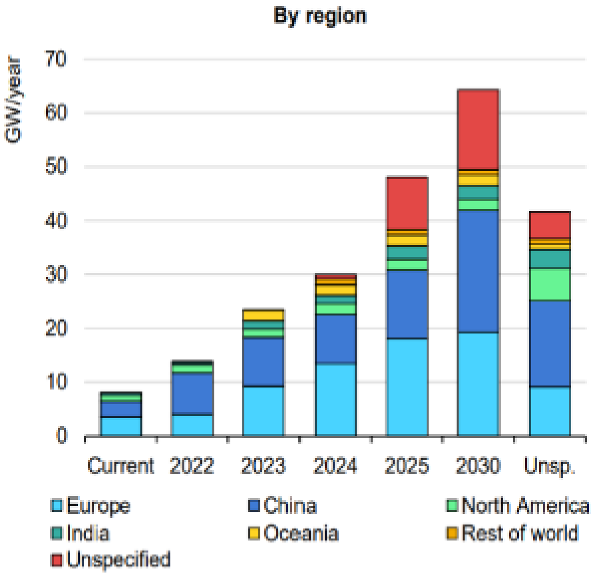
The production of green hydrogen is still relatively expensive compared to traditional hydrogen production, but costs are rapidly decreasing as technology improves and economies of scale are achieved. There are various electrolyser technologies with various advantages and disadvantages.

The most mature technology is the alkaline electrolyser (Abad & Dodds 2020). An alkaline electrolyser uses an alkaline solution, typically potassium hydroxide (KOH), as the electrolyte. The main advantages of this technology are the relatively low CAPEX (500 – 1000 USD/kW), its high durability (60,000 h) and that no noble metals are needed for the catalytic reaction at the electrodes (IRENA 2020). Disadvantages of alkaline electrolysers include the low current density as well as the necessity to only use ultra-pure water (Mohammadi & Mehrpooya 2018). Another mature electrolyser technology is the Proton Exchange Membrane (PEM). PEM electrolysers use a proton exchange membrane as the electrolyte. PEM electrolysers have several advantages, such as relatively longer lifetime fast response time, and the ability to operate at high pressures. The average lifetime ranges between 50,000 – 80,000 hours (IRENA 2020). They are relatively compact and lightweight, making them well-suited for portable and mobile applications. Additionally, they are more tolerant to impurities in the feedwater than alkaline electrolysers. They have similar efficiencies like alkaline electrolysers with voltage efficiencies of 50% - 68% (IRENA 2020). However, PEM electrolysers also have some disadvantages, such as high cost, and the need to use noble metals at the anode (iridium) and the cathode (platinum) (Zhang et al. 2022). CAPEX of PEM electrolysers ranges between 700 – 1400 USD/kW. While platinum is already a very rare element on earth which leads to high costs, iridium is even more limited. Currently, there are only 2 major exporters of iridium in the world – South Africa and Haiti – with total global production of approximately 7500 kg/yr. With an iridium demand of approximately 1-2.5 kg/MW PEM electrolyser, it would only be possible to install around 7.5 GW of electrolysers per year. Hence iridium could pose a substantial bottleneck to the ramp-up of this technology. IRENA estimates that there is only enough iridium to increase electrolyser capacity by approximately 30-75 GW in the next decade. This falls short of the goal to install 350 GW in order to meet the projected demand for green hydrogen in 2030 (EPO & IRENA 2022).

Another bottleneck for the rapid upscale of PEM-electrolysers is the limited production capacities. According to expert interviews current lead times for electrolyser range from 12-18 months (Baez et. al. 2023). There are other electrolyser technologies like Solid Oxide Electrolyser Cells (SOEC) or Anion-Exchange-Membrane Electrolyser (AEM) but both technologies are still on lower Technology Readiness Level (TLR) and not produced on an industrial scale. (IEA 2022c)

In 2021, the world's electrolyser manufacturing capacity was about 8 GW annually, with Europe and China representing 80% of this capacity. According to company statements, the global manufacturing capacity for electrolysers could reach 65 GW per year by 2030. Currently, alkaline electrolysers make up 60% of the global manufacturing capacity, due to its maturity compared to PEM. By 2030, it is projected that alkaline electrolysers will continue to dominate with 64% of the manufacturing capacities, followed by PEM electrolysers at 22% and SOEC electrolysers at 4% (IEA 2022c).

Figure 33: Electrolyser production capacity by region until 2030



Source: IEA (2022c), p.80

Costs for green hydrogen production can vary strongly. This variation is mostly dependent on the costs for renewable electricity (OPEX), and CAPEX. According to a study by Jeffers at al. (2021), costs for hydrogen production are composed out of approximately 69% OPEX (53% electricity) and 31% for CAPEX. This shows the high importance of the right location for large scale green hydrogen production: the cost of electricity is decisive.

When hydrogen is produced exclusively by renewable energies, green hydrogen is essentially carbon free. However, using only small amounts of fossil fuel-based electricity can lead to significant embodied emissions that need to be considered in its environmental impacts (greenish hydrogen). If for example hydrogen is produced 100% from grid-electricity in Germany (grid emission factor 349 gCO_2/kWh (UBA 2021)), 1 kg of hydrogen would have embodied emissions of approximately 18 kg CO_2 which is almost double the GHG amount of grey hydrogen production. Hence, a massive upscale of green hydrogen production has to be accompanied by a respective upscale of renewable energy capacities. In order to meet the current global hydrogen demand with green hydrogen, more than the complete annual electricity generation of the European Union (3600 TWh) would have to be produced by additional RE capacities (IEA 2021). Thus, some people have been speaking of “greenish” hydrogen when the electricity is coming from a grid that is not 100% renewable.

Greenish hydrogen

In the context of this study, we define ‘greenish hydrogen’ as hydrogen that has been produced by electrolysis, where the majority of electricity use to operate electrolysers is renewable, but where some grid-electricity has been used. This can be expected to happen to optimize electrolyser operation (maximization of utilization rates) and minimize production cost. In order to ensure significant environmental benefits of “greenish hydrogen”, maximum GHG-thresholds associated with its production should be defined. In its RED regulation, the EU currently defines this threshold at around 3.4 kg CO_2/kg H_2, whereas the Green Hydrogen Organisation promotes a significantly lower value of 1 kg CO_2/kg H_2 (Green Hydrogen Organisation, 2023).

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