sustainability

Article

Ammonia Production from Clean Hydrogen and the Implications for Global Natural Gas Demand

Deger Saygin [1,*], Herib Blanco [2], Francisco Boshell [2], Joseph Cordonnier [3], Kevin Rouwenhorst [4,5], Priyank Lathwal [6,7] and Dolf Gielen [2,6]

1 Faculty of Engineering and Natural Sciences, Sabanci University, Orta Mahalle, Tuzla, 34956 Istanbul, Turkey
2 International Renewable Energy Agency (IRENA), Innovation and Technology Center, Willy-Brandt-Allee 20, 53113 Bonn, Germany
3 Organisation for Economic Co-Operation and Development (OECD), Environment Directorate, 46 Quai Alphonse Le Gallo, 92100 Boulogne-Billancourt, France
4 Ammonia Energy Association, 77 Sands Street, Brooklyn, NY 11201, USA
5 Proton Ventures, Karel Doormanweg 5, 3115 JD Schiedam, The Netherlands
6 World Bank Group, 1818 H Street NW, Washington, DC 20433, USA
7 Belfer Center for Science and International Affairs, Harvard University, Cambridge, MA 02138, USA
* Correspondence: degersaygin@sabanciuniv.edu

Abstract: Non-energy use of natural gas is gaining importance. Gas used for 183 million tons annual ammonia production represents 4% of total global gas supply. 1.5-degree pathways estimate an ammonia demand growth of 3–4-fold until 2050 as new markets in hydrogen transport, shipping and power generation emerge. Ammonia production from hydrogen produced via water electrolysis with renewable power (green ammonia) and from natural gas with CO_2 storage (blue ammonia) is gaining attention due to the potential role of ammonia in decarbonizing energy value chains and aiding nations in achieving their net-zero targets. This study assesses the technical and economic viability of different routes of ammonia production with an emphasis on a systems level perspective and related process integration. Additional cost reductions may be driven by optimum sizing of renewable power capacity, reducing losses in the value chain, technology learning and scale-up, reducing risk and a lower cost of capital. Developing certification and standards will be necessary to ascertain the extent of greenhouse gas emissions throughout the supply chain as well as improving the enabling conditions, including innovative finance and de-risking for facilitating international trade, market creation and large-scale project development.

Keywords: green ammonia; blue ammonia; natural gas; energy security; energy transition

Citation: Saygin, D.; Blanco, H.; Boshell, F.; Cordonnier, J.; Rouwenhorst, K.; Lathwal, P.; Gielen, D. Ammonia Production from Clean Hydrogen and the Implications for Global Natural Gas Demand. *Sustainability* **2023**, *15*, 1623. https://doi.org/10.3390/su15021623

Academic Editor: Sohbet Karbuz

Received: 31 October 2022
Revised: 26 December 2022
Accepted: 4 January 2023
Published: 13 January 2023

1. Introduction

1.1. The Global Natural Gas Market Context and Prospects in the Energy Transition

Globally around 4 trillion cubic meters (m^3) of natural gas are produced and consumed every year. Gas consumption can be split equally between the energy end-use and the energy transformation sectors. Around 45% of the total gas supply is used for heating in industry and buildings, one third for electricity generation, 6% as feedstock for chemicals/plastics production and 3% as transport fuel. Finally, 12% is for own use in the energy industry and for use in other transformation processes [1]. Nearly three quarters of the gas produced is consumed nationally with only about a quarter of it traded internationally, through pipelines or as liquefied natural gas (LNG).

Future energy scenarios that investigate how a global net-zero emission pathway can be operationalized suggest that global gas output in 2050 will be between 20% and 65% lower than current levels [2–4].

1.2. The Importance of Natural Gas for Global Ammonia Production

Natural gas is utilized in the steam methane reforming (SMR) process to produce hydrogen which is subsequently combined with nitrogen to synthesize ammonia in the Haber-Bosch catalytic conversion process. Ammonia is the key raw material for nitrogen fertilizers such as urea and ammonium nitrate, which are critical for food supply chain. Today much of the ammonia production is based on natural gas (a total of ~183 million tons (Mt) ammonia was produced in 2020) where its production accounted for 20% of the total gas used as fuel and feedstock in the industry, representing 4% of the total final global natural gas consumption [1] (An average specific energy consumption (including the use of fossil fuels as feedstock) of 46 gigajoules (GJ) per tonne of ammonia was assumed [5] to produce 178 million tons (Mt) of ammonia in 2019 [6]). Ammonia production is typically concentrated in countries with low-cost hydrocarbon feedstock availability since energy and feedstock account for 40% to 70% of the total production cost (see Figure 1) [5]. Gas markets witnessed dramatic turmoil during the first half of 2022. The Ukraine crisis has resulted in one order of magnitude increase in gas prices in Europe from around Euro 20 to more than Euro 200 per megawatt-hour (MWh) [7], making energy price increase the largest contributor to region's record inflation [8]. This price hike during early 2022 has resulted in shuttering and curtailment of 50% of European ammonia manufacturing capacity [9,10]. Global spot prices for ammonia have increased significantly in 2022. From March 2017 to December 2020, ammonia prices stayed within United States dollars (USD) 200–400 per ton. But the price reached USD 1300 per ton in the first quarter of 2022 [11]. Average urea nitrogen fertilizer price increased from USD 230 per ton in 2019–2020 to USD 774 per ton April–June 2022 [12]. Consequently, rising fertilizer prices had a direct impact on food production and food prices. Due to these geopolitical developments, there is an increased interest in natural gas' non-energy use applications.

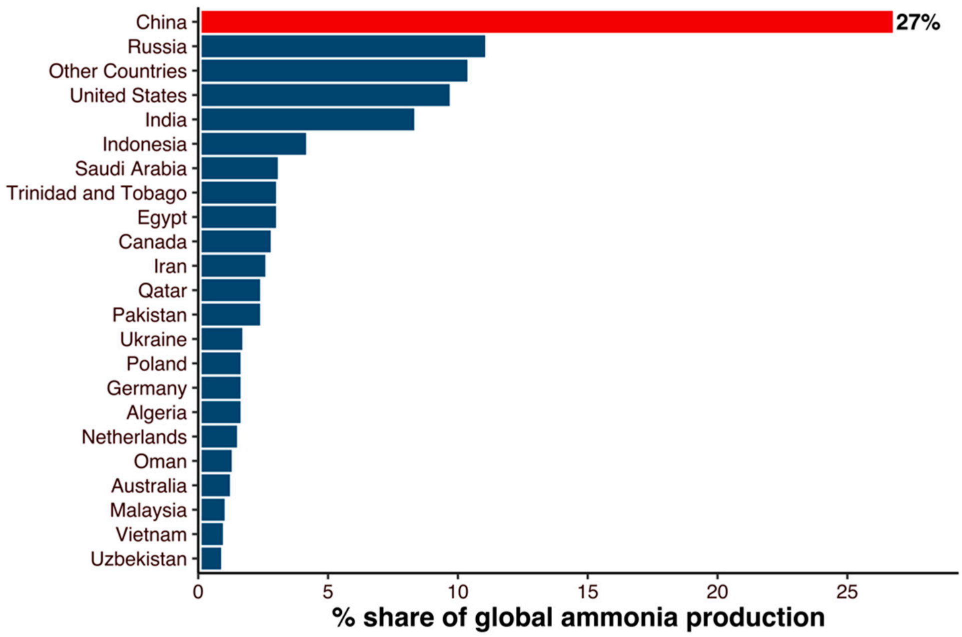

Figure 1. Country breakdown of global ammonia production, 2021. Source: [6].

1.3. The Role of Ammonia in the Emerging Hydrogen Economy

183 Mt of ammonia production requires around ~33 Mt hydrogen annually. Therefore, this makes ammonia a key commodity of the existing 94 Mt global hydrogen market. Alternative clean production processes for hydrogen are receiving attention from policy makers and industry actors as their costs have fallen in recent years [13]. Beyond its existing use as fertilizer, ammonia may be deployed as shipping fuel, as fuel in power generation,

and as hydrogen carrier. Ammonia may be the most economic and most efficient vector for intercontinental hydrogen shipping [14,15].

1.4. Scope and Objective of This Paper

In order to reduce dependency on natural gas and reduce risks of natural gas price shocks on the production costs of ammonia, there is a need to transition to low-carbon feedstocks. Typically, renewable power and electrification of heating are key drivers to reduce natural gas demand. However, in the context of ammonia production, this paper focuses on a specific aspect that has received far less attention: low-carbon alternatives for non-energy use of natural gas as a feedstock. In this context, this paper deals with ammonia produced from renewable power-based hydrogen (green ammonia) and from natural gas with CO_2 storage (blue ammonia) based on a technology and economic assessment of their potential and a discussion of their impact on the power system, international trade, and the environment.

The findings of this paper are discussed in perspective of a wide range of literature in the next sections whilst a brief review is presented here to pinpoint the paper's objective and value added. Green ammonia production potential and costs with different renewable power supply combinations have been assessed in detail at country level by [16]. Several other authors provided deep dive into country specific potential and costs [17–19]. This paper provides new analysis by distinguishing the economic situation between countries to provide a full comparison of the regional production costs of green ammonia with grey (natural gas-based steam methane reforming (SMR) route) and blue ammonia. Based on these findings, financing aspects are elaborated. Through an assessment of all three pathways, new insights are gained into blue ammonia's role in transition to widespread use of green ammonia which is to date not addressed. In this respect, this paper also builds on existing literature regarding the methane emissions from blue ammonia production and the related uncertainties that have been subject to debate [20]. Natural gas combustion results in the least amount of carbon dioxide (CO_2) emissions per unit of primary energy supply at around 56 kilogram (kg) per gigajoule (GJ). However, its production and transportation can entail significant methane emissions. This can range from ~30 and ~83 times the global warming potential (GWP) of CO_2 on a 100-year and 20-year time horizon, respectively [21]. In this paper, the GHG emission impact of all ammonia production pathways has been assessed based on review of available data from literature and a methane emission database from the International Energy Agency (IEA) [22]. This comparison is critical for crafting the policies needed in commercializing sustainable ammonia production pathways and the enabling conditions to develop international ammonia trade in view of its new markets and to complement other existing reviews [23]. The link between international trade and economic assessment of ammonia production pathways and their environmental impacts has not been fully made whilst several studies have assessed the supply chain and trade aspects in detail [24,25]. Finally, this paper stresses the importance of systems integration by coupling ammonia production with the power system and the need to think across the full supply chain, including its role for minimizing the capital costs of vertically integrated ammonia plants. For various countries the coupling of power system with ammonia production have been assessed [26,27]. However, the growing policy debate on additionality from hydrogen production in view of its potential impact on green hydrogen output and capital costs remain not fully covered.

This paper is organized as follows: Section 2 provides insights into the latest developments in green ammonia production. Section 3 provides an overview of the costs and the GHG emissions of various ammonia production options. Sections 4 and 5 discuss the energy system and policy implications of accelerated green ammonia deployment, respectively. Section 6 contains recommendations for policy makers how to create new ammonia markets with low-carbon alternatives to non-energy use of natural gas. The background data and the methodology of the analysis presented in this paper is provided in the Appendix A.

2. Latest Trends in the Global Ammonia Sector

Ammonia is one of the seven basic chemicals (Seven basic chemicals are high value chemicals (ethylene, propylene, butadiene, aromatics), ammonia, methanol, and carbon black) [28] and it is the second most produced chemical by mass after sulfuric acid. Nitrogen fertilizers such as urea and ammonium nitrate represented about 80% of the total ammonia market, and 2% of ammonia is directly applied in pastures. As such, ammonia sustains food supply for half of the global population. The remaining 20% of the global ammonia market was for industrial applications [5,29].

Existing ammonia markets are projected to increase by 20% to 2030. Overall ammonia demand is projected to increase 3–4-fold from 2020 levels in a 1.5 °C aligned scenario to 560–665 Mt per year by 2050 (see Table 1 and Figure 2). Availability of low-carbon ammonia production is expected to drive this market growth. The highest share of ammonia production from green hydrogen is according to the International Renewable Energy Agency's (IRENA) scenario which is estimated at 83% by 2050. In the same scenario, blue ammonia's share would be 11% with the remaining 6% estimated to be produced from fossil fuels with no carbon capture (see Table 1).

Table 1. Overview of global ammonia production estimates to 2050 aligned with a 1.5 °C compatible scenario.

Feedstock/Production Route	**[14]**	**[28]**	**[30] [1]**
	[Mt/Year]	**[Mt/Year]**	**[Mt/Year]**
Green hydrogen	550	400–450	387
Natural gas with CO_2 capture storage/use	75	-	152
Fossil fuel with CO_2 capture storage/use	-	-	-
Biomass and other thermochemical	-	100–150	17
Fossil fuel with no capture	40	100	-
Other	-	-	5
Total	665	650	561

[1] Data provided in this table refers to the "Lowest cost scenario" of the study. Note: According to the "Net Zero Emissions" scenario of [31], total annual ammonia production for current uses such as fertiliser is estimated to reach around 230 Mt by 2050 where near-zero emission routes would represent more than 90% of the total production. When new markets of ammonia are accounted for, such as its use as fuel for shipping and electricity generation, production reaches above 550 Mt per year.

One option to reduce emissions is controlled long-term storage of CO_2 in depleted oil and gas fields and in deep saline aquifers. Some view the production of blue hydrogen as an intermediate option for ammonia production that would allow utilizing the existing capacity until green ammonia commercializes. A total of above 5 Mt new ammonia capacity from 10 fossil fuel-based ammonia plants with carbon capture and storage (CCS) has been announced, of which 5 already operational [14]. In September 2022, QatarEnergy Renewable Solutions and Qatar Fertiliser Company have signed an agreement for the construction of the world's first large-scale blue ammonia plant to start operation in 2026 with a total annual production capacity of 1.2 Mt [32].

Although there is virtually no green ammonia production, it is gaining momentum. In fact, in the early 1920s, ammonia was produced from alkaline electrolyzers fed with electricity from hydropower [33]. By the 1960s, these plants were outcompeted by cost competitive natural gas. Today, early-stage green ammonia projects typically have small annual production capacities (<0.1 Mt) due to demand uncertainty. As of May 2022, more than 60 green ammonia plants have been announced [14]. In less than 5 years, most of these plants are planned from a combination of wind and solar energy, with a combined annual capacity of 2–3 Mt/year of ammonia. The output would be utilized in existing and new ammonia markets. Announced projects for renewable ammonia currently add up to 34.1 Mt/year by 2030, mainly in places with very low-cost wind and solar energy [34]. Other sources estimate much higher levels at 83 Mt green ammonia production to be commissioned by 2030 [35]. There are many early adopters and movers towards investing in green ammonia plants from publicly listed fertilizer companies in Australia, Europe, Saudi Arabia, and the United States [36]. At the same time, several large-scale ammonia plants are being planned or under construction in emerging and developing economies, such as in the Middle East and Africa to be realized in the next few years [37–40].

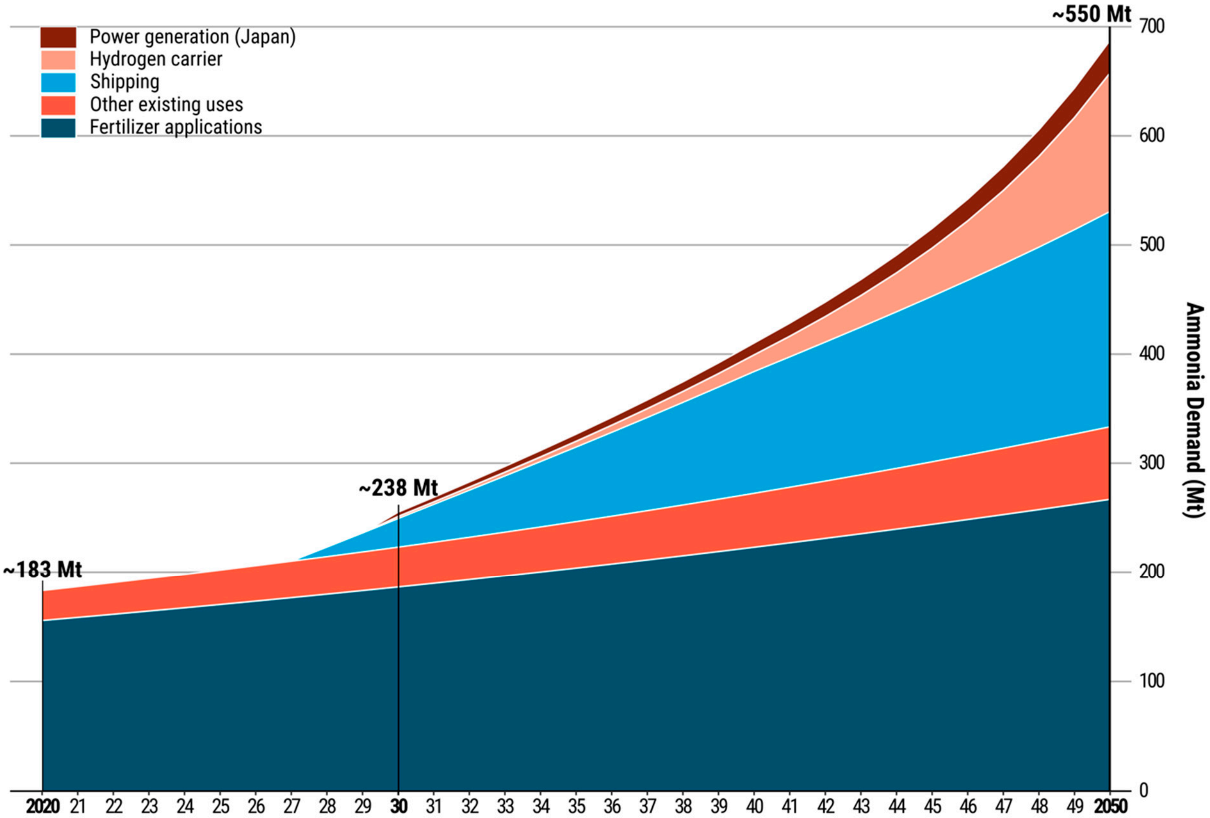

Figure 2. Expected ammonia demand up to 2050 for a 1.5 °C compatible scenario according to the IRENA. Source: [14].

Intercontinental hydrogen shipping will be essential to utilize its potential. It is likely that hydrogen will be converted to other products to facilitate shipping. Liquefaction, use of liquid organic hydrogen carriers (LOHC), or conversion to hydrogen derived products such as ammonia, methanol, steel, and synthetic fuels are options [41]. Each additional conversion step means losses, thereby increasing the costs per unit of energy; however, ammonia is regarded as an economically viable option for shipping where up to 100 Mt ammonia per year could be used for this purpose by 2050. Currently, 65 active vessels operate as an ammonia carrier (excluding liquefied petroleum gas (LPG) vessels that can switch to ammonia) [42]. One key distinction of ammonia is that it liquefies at −33 °C and atmospheric pressure as opposed to hydrogen that needs to be chilled to temperatures lower than −253 °C for liquefaction [43]. As a result, ammonia shipping is much easier and less costly than hydrogen shipping. The liquefaction of hydrogen with current technologies is energy intensive, requiring more than one-third of its lower heating value [44]. The hydrogenation and de-hydrogenation of liquid organic hydrogen carriers is still at a low maturity phase [41]. While some of the shipped ammonia could be directly consumed, including the production of materials that were initially targeted by green hydrogen, some will be reconverted to hydrogen ('cracked') upon delivery.

New ammonia markets are being developed for commercialization in 2024 [45]. For instance, recently, ammonia is considered a prospective fuel for oceangoing vessels [46].

Ships typically have lifetimes of 20–25 years or longer, implying vessels should be able to employ ammonia by 2030 to meet their ambitious net GHG emission reduction target of 50% by 2050 compared to 2008 [47]. As of the first quarter of 2022, more than 40 ship technology projects with ammonia have been announced [35,48]. An opportunity exists to retrofit LNG ships with ammonia [49]. Estimates show that ammonia could represent by between 20% and 99% of the total projected fuel mix of the shipping industry by 2050 [46,50,51].

Ammonia can also be used as fuel in power plants. Japan has included ammonia option alongside hydrogen in its power sector transition roadmap to achieve 50–60% co-firing with ammonia by 2050 with the first implementation and demonstration to materialize by 2024 in a 1-gigawatt (GW) coal-fired power plant at 20% rate [52]. This would result in a total ammonia demand of 30 Mt for Japan by 2050 which would all be imported [53,54]. Besides Japan, Republic of Korea has initiated a demonstration program to operationalize the co-combustion of ammonia in over half the country's coal-fired power plants by 2030 [55].

3. Technical, Economic and Greenhouse Gas Emission Estimates of Ammonia Production Pathways

3.1. Energy Use and Greenhouse Gas Emissions of Ammonia Production

Green ammonia production requires 30–36 GJ electricity per ton ammonia with the range depending on electrolyzer efficiency that range between 62% and 83% according to literature (see Table 2). About 85–90% of all energy demand is related to hydrogen production requiring about 50–55 kWh electricity per kg hydrogen. The remaining energy demand is for air separation, hydrogen compression, and ammonia synthesis [16,17,56–59]. The slightly lower energy consumption of the SMR route compared to electrolysis is due to more efficient hydrogen production and greater heat integration across the process.

Provided that all electricity is sourced from renewable power, green ammonia is emission free (The production of renewable power equipment that requires steel and other materials is currently produced from a mix of renewable and fossil fuels and other upstream production processes result in GHG emissions in today's situation. This results in a wide range of cradle-to-factory gate emissions for green ammonia production from as low as 0.2 to 1.3 tons of CO_2-eq/t ammonia [60–62]. Although outside of the cradle-to-factory gate system boundaries of the data presented in this paper, when transport emissions are considered, up to an additional 0.2 tons of CO_2-eq/t ammonia could be emitted [60]). Gas- and coal-based ammonia production emits CO_2 from the combustion of fuels from as low as 1.51 t CO_2-eq/t ammonia from the efficiency SMR route to as high as 6.18 t CO_2-eq/t ammonia from less efficient coal gasifiers. In addition to these direct CO_2 emissions, there are indirect emissions related to electricity supply for hydrogen and nitrogen production as well as for ammonia synthesis which can be up to 1.05 t CO_2-eq/t ammonia [5]. Additional GHG emissions occur from gas production and operations, and they include emissions from energy for extraction, vented CO_2, methane emissions from pipelines and LNG, upstream embedded emissions, and fugitive methane, and downstream, during storage, transport, and distribution. On average, it is estimated that a total of 0.015 tons CO_2-equivalent (CO_2-eq) per GJ gas production has been emitted in 2018 in various countries, equivalent to 32% of the carbon content of natural gas (A GWP of 30 tons of CO_2 per 1 ton methane is assumed for 100 years). Based on data from [63], it is estimated that about 60% of these additional GHG emissions were methane related from upstream and downstream gas operations and another 40% is related to energy for extraction and vented CO_2. When expressed in tons of ammonia production, upstream and downstream methane emissions could contribute another 0.42 t CO_2-eq/t ammonia on average with a wide range of 0.19–2.40 t CO_2-eq/t ammonia, on a 100-year GWP horizon. These would raise SMR-based grey ammonia's total GHG emissions from on average 1.51 t CO_2-eq (direct CO_2 emissions related only to gas use) to a range of 2.29–4.27 t CO_2-eq/t ammonia (all emissions cradle-to-factory gate) (see Table 2).

Production of blue ammonia is estimated to reduce these total emissions by 16–45% to between 1.26 and 3.59 t CO_2-eq/t ammonia, but this is still far from carbon neutral production even at high CO_2 capture rates as assumed in this paper at 90% (Current industry practice from Canada shows an average annual capture rate of around 80% [64]). This is explained by the large share of remaining emissions from electricity use for ammonia production and the indirect GHG emissions from gas use that are not captured (In this paper, an average GHG emission reduction of 51% is estimated for blue hydrogen (5.55 t CO_2-eq/t H_2) compared to grey hydrogen (11.38 t CO_2-eq/t H_2) production. These estimates are comparable with the findings from other studies [65–68]. However, there is a large difference with the estimates of [20] where the authors estimated only 9–12% GHG emissions reduction, explained by the higher GHG emissions that occur from the gas needed for CCS. The difference between this paper and the estimates of [20] is explained by three main factors where in this paper (i) a higher capture rate of 90% is assumed [69] as opposed to 65% (flue gas capture) and 85% (SMR process capture) capture rates, (ii) a GWP of 30 tons of CO_2 for 100 years per 1 ton methane is assumed [63] as opposed to 86 tons for 20 years, and (iii) 40% lower methane emissions from upstream and downstream gas operations and energy for extraction of 0.021 tons methane is estimated based on data from [63] as opposed to 0.035 tons fugitive methane emissions per ton of natural gas). There are additional emissions from the generation of heat and electricity for the CCS process. Abating methane emissions across the gas value chain by replacing existing equipment and improving operational techniques can provide additional emissions reductions [70]. Based on the methane emission reduction potential data according to the IEA [71], there is an estimated potential of up to an additional 16% GHG emissions reductions compared to blue ammonia production where methane emissions are unabated.

The cost of capture and storage of CO_2 emitted from the SMR burners is much higher because of low CO_2 concentration in the flue gas. Therefore, oxygen-based systems such as the new autothermal reforming (ATR) technology that avoids the use of such burners is better suited for CCS as the process combines hydrogen production and heating in a single reactor, resulting in a single concentrated CO_2 stream [72]. This decreases the cost of CO_2 capture and increases the effective capture rate to more than 90% where ATR can be combined with a pre-combustion carbon-capture technology [73,74]. Without CCS, the ATR route has comparable total energy consumption with the SMR. With CCS blue ammonia (ATR) route's total energy consumption is estimated at 29 GJ/t which is less than the blue ammonia (SMR) route of 33 GJ/t ammonia thanks to the ease of capturing emissions [14]. Blue ammonia (ATR) route is estimated to emit 0.65–0.70 t CO_2-eq/t ammonia (including 0.46 t CO_2-eq/t ammonia methane emissions) [75]. This results in total GHG emissions mitigation of 57–82% compared to grey ammonia.

Table 2. Overview of energy use and GHG emissions of ammonia production.

Production Pathway	**Energy Use (GJ/t Ammonia)**	**Cradle-to-Factory Gate CO_2 Equivalent (t CO_2-eq/t Ammonia)**	**Ammonia Type**	**References**
Coal Gasification	56–64	Fuel: 5.32–6.18	Grey	Fuel use and related CO_2 emissions [76]
SMR and ATR (without CCS)	28–36	Fuel: 1.51–2.02 Electricity: 0–1.05 Methane: 0.19–2.40 Total: 2.29–4.27	Grey	Fuel use and CO_2 related emissions: [77–81] Electricity and methane: See Appendix A for background data
SMR + CCS	33	Total: 1.34–3.68	Blue	See Appendix A for background data
ATR + CCS	29	0.65–0.70	Blue	[14,75]

Table 2. *Cont.*

Production Pathway	Energy Use (GJ/t Ammonia)	Cradle-to-Factory Gate CO_2 Equivalent (t CO_2-eq/t Ammonia)	Ammonia Type	References
Renewables + Electrolyzer	30–36 (electricity)		Green	Own estimate based on [16,17,56–59]

Notes: Absolute methane emissions reported by the [82] related to gas pipelines and LNG facilities, offshore gas and onshore gas operations (fugitive and vented) as well as other emissions from oil and gas operations and satellite detected large leaks by country have been converted to per GJ gas specific emissions for each country as a ratio of the total methane emissions (assuming a 30 GWP of methane) and the total gas production. For the blue ammonia (SMR) route, post-combustion capture CO_2 technology is assumed to have a 90% capture rate and total heat and electricity requirement of 2.5 GJ and 0.4 GJ per ton of CO_2 captured, respectively. Additional heat and electricity are generated by individual gas boiler and gas-fired power plant operating with 90% and 40% conversion efficiency, respectively. This has a total energy penalty of 10 percentage points over the hydrogen production system efficiency (reducing the total efficiency from 86% to 76% based on lower heating value) [69]. Methane abatement technologies could offer estimated methane emissions reduction potential of more than 40% based on data available from [82]. Country specific electricity generation emissions have been estimated based on data from [1] by considering the generation from both stand-alone power plants and combined heat and power plants. Based on stoichiometry of ammonia production reaction, it is assumed that 1 ton of ammonia production requires 178 kg hydrogen and 822 kg nitrogen. See Appendix A for additional details of the background data and the methodology.

3.2. Production Costs of Ammonia

Today's cost of producing green ammonia is estimated to range from United States dollars (USD) 400 to USD 1670 per ton ammonia (global average USD 730/t ammonia) with the assumption that renewable power will be generated and supplied on site by dedicated wind and solar energy plants (see Figure 3) (Background data and methodological details to estimate the production costs of ammonia from various routes are provided in the Appendix A. The impacts of sale/purchase of electricity from/back to the grid and the subsequent impact on the greenhouse gas emissions are excluded from this analysis assuming that there is sufficient and optimized renewable power capacity for ammonia production at all hours synthesis takes place). In few countries that offer a combination of good solar and wind resources and favorable economic conditions (cost of capital < 8%), the cost of producing green ammonia is estimated at USD 400/t ammonia (e.g., Australia, some Middle Eastern countries). This is cost competitive with grey ammonia production. In this paper (see Appendix A), the choice was made to reflect the current differences in the cost of capital between countries [83], therefore the cost of capital has a profound effect over renewable electricity generation costs. In these countries, the estimated production cost of green hydrogen is around USD 2/kg, which accounts for on average 86% of the total green ammonia production cost. Other studies show that this production cost level can be achieved in more countries by 2030 [84,85]. In countries with less favorable economic conditions (8–15% cost of capital) or low capacity factors, estimated ammonia production costs vary between USD 500 and USD 800 per ton (e.g., South Asia, Western Europe, North Africa). In countries characterized by high cost of capital (>15%), but with relatively high-capacity factors, production costs reach USD 1000 per ton and above (e.g., Sub-Saharan Africa). These findings are comparable with those from other studies (e.g., [16,86]). A study by [84] showed that the tipping point for green ammonia at production costs of around USD 400/t ammonia is found with power plant capacity factors below 25% when compared with dispatchable sources including fossil fuels, biomass and systems retrofitted with post-combustion CCS.

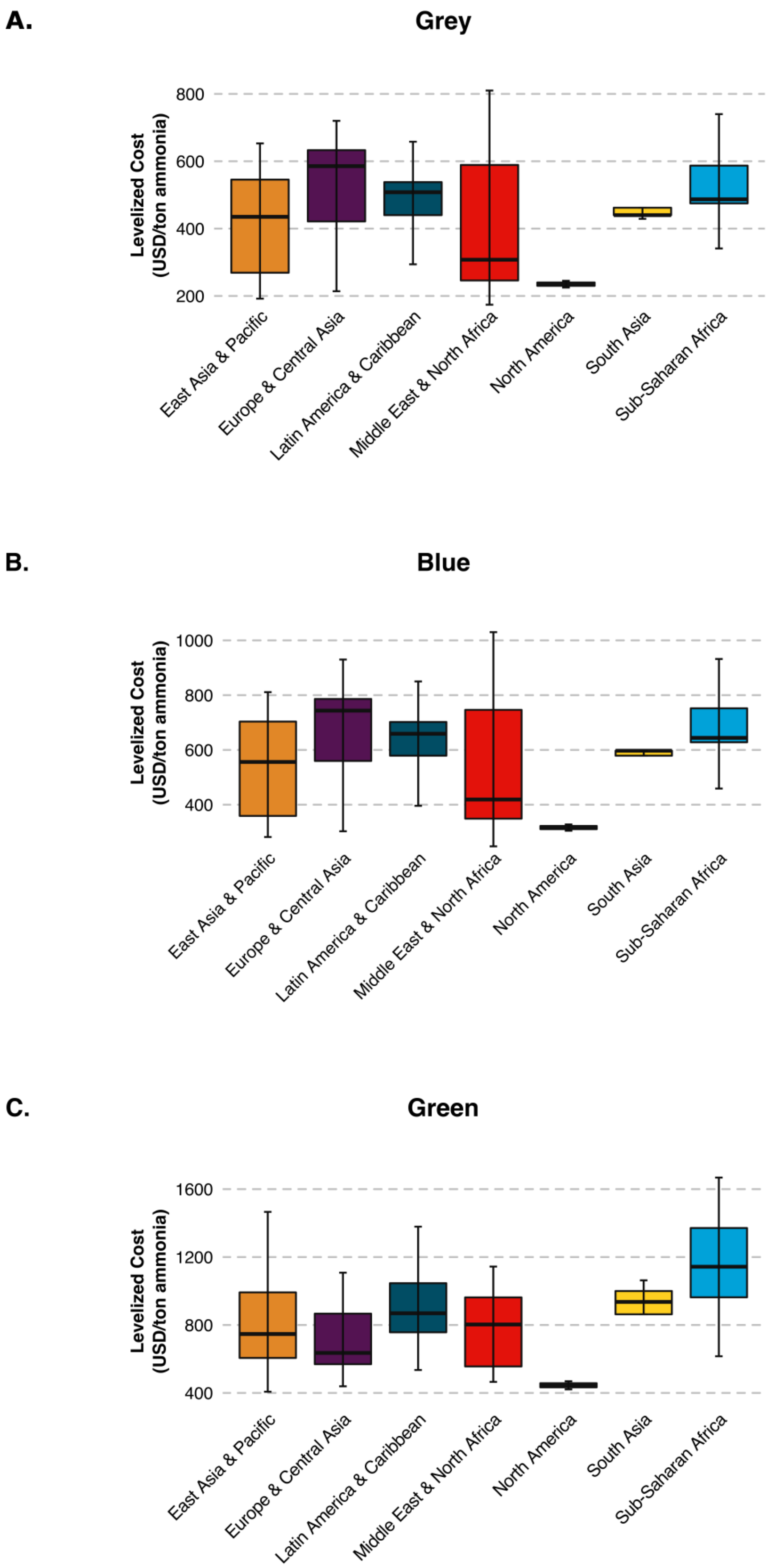

Figure 3. (**A**–**C**). Estimated current production costs of grey, blue and green ammonia. The whiskers in the figure represent 95% confidence intervals and the black line inside the box represents the median production cost for the region, respectively. Note: see Appendix A for background data and methodology. By-product oxygen from air separation is not valued.

The estimated green ammonia production cost is three to four times higher than the estimated grey ammonia production cost that ranges between USD 175 and USD 810 per ton ammonia based on a gas price range of USD 1–15/GJ (global average production cost is estimated at USD 470 per ton). Energy costs account for just below 60% of the total grey ammonia costs, split between 45% gas and 13% electricity and are the determining factor of both grey and blue final production costs where there is a linear relationship between them (see Figure A1). Electricity's share is considerable, particularly in regions with high industrial electricity prices. Overall, hydrogen production cost is estimated to account for 70% of the grey ammonia total production cost where in natural gas producing countries with low gas prices (USD 1–2/GJ) the estimated production cost of hydrogen from the SMR route is USD 1/kg hydrogen and below which compares with a production cost of above USD 2/kg hydrogen in high gas price countries (>USD 10/GJ). By comparison, global average blue ammonia (SMR) is estimated at around USD 600 per ton.

Green ammonia production cost is characterized by a 78% share of capital costs of renewable power technologies and electrolyzers (see Figure A2). A combination of high gas prices, low discount rates or low capital costs of electrolyzers can enhance competitive green ammonia production (see Figure A1).

For the global average, a gas price of USD 8/GJ and a 10% cost of capital were assumed. At USD 17/GJ gas price, the cost of producing grey ammonia is equal to the average global green ammonia production cost. At a 2% cost of capital, green ammonia production is cost competitive with grey ammonia at USD 400/t. In regions with good wind and solar resource potential with renewable electricity generation costs of USD 2.5 cents per kWh and more than a 50% reduction in the electrolyzer capital costs (from USD 750 to USD 350/kW), green ammonia production cost is estimated at USD 400/t. Indeed, the choice of the electrolyzer technology has impacts on electricity demand and the final production cost. The analysis presented in this paper assumes alkaline electrolyzer technology for hydrogen production close to the low end of its electricity consumption range (50–78 kWh/kg hydrogen) and the average of its current capital cost range (USD 500–1000/kW). Polymer electrolyte membrane (PEM) electrolyzers have similar electricity demand but come with a much smaller facility footprint and operate with higher current density and output pressure. Current capital cost of PEM electrolyzers are, however, higher than alkaline ranging between USD 700 and USD 1400 per kW. Assuming PEM electrolyzer use, the estimated green ammonia production cost would increase from USD 726 to USD 810 per ton due to higher capital requirements. Solid oxide systems are much more efficient with an average electricity demand of 50 kWh/kg hydrogen, but they are still at development phase. One can argue that in the future the gap in capital costs of electrolyzers and renewable power between regions will close with technological learning and the cost of capital and the risk associated with building new technologies will also decrease across the world [87]. Different electrolyzer technology costs are projected to converge towards similar costs of less than USD 200–300/kW and electricity demand below 40 kWh/kg hydrogen by 2050 [88]. The combination of these reductions would make green ammonia cost competitive with today's grey ammonia production costs. The future cost of producing green ammonia should then be largely driven by renewable energy resource quality and any differences that may remain in the cost of capital due to non-technology risks.

4. Discussion of System Implications and Technical Constraints in Utilizing Green Ammonia

4.1. Interactions with the Power System

To increase production of ammonia by a factor of four by 2050, the energy system impacts need to be understood. The 560–665 Mt of green ammonia to be produced by 2050 would be estimated to need up to 1100 GW electrolyzer capacity and 2300 GW of renewable generation capacity to supply up to 5500 terawatt-hour (TWh) per year electricity. This equals to a fifth of today's global electricity generation.

The typical production capacity of an ammonia plant is on average 1000 tons per day which would require 1.5 GW co-located renewable power capacity. The total capital cost of such system would range between USD 5 to 7 billion per Mt of annual ammonia production capacity. This roughly translates up to USD 4 trillion investments across the green ammonia value chain between now and 2050 assuming today's technology costs. According to Figure 4, renewable power and electrolyzers would have the largest contribution to the total capital cost requirements.

In case variable solar and wind power are used, it is critical to identify sites where both have complementary production profiles. In many coastal desert locations, temperature differences in the evening and at night cause high wind speeds. This complements the sunshine during the day. The combination yields high-capacity factors for electrolyzer operation, e.g., up to about 70%. It is therefore no surprise that first proposed green ammonia plants are in desert locations such as in Red Sea area, Oman and Australia. Therefore optimal design of renewable power capacity and generation is essential to reduce ammonia plant investment costs. Particularly important is ensuring additionality to prevent the use of existing renewable power plants for green hydrogen production that are initially built to decarbonize the power system [89].

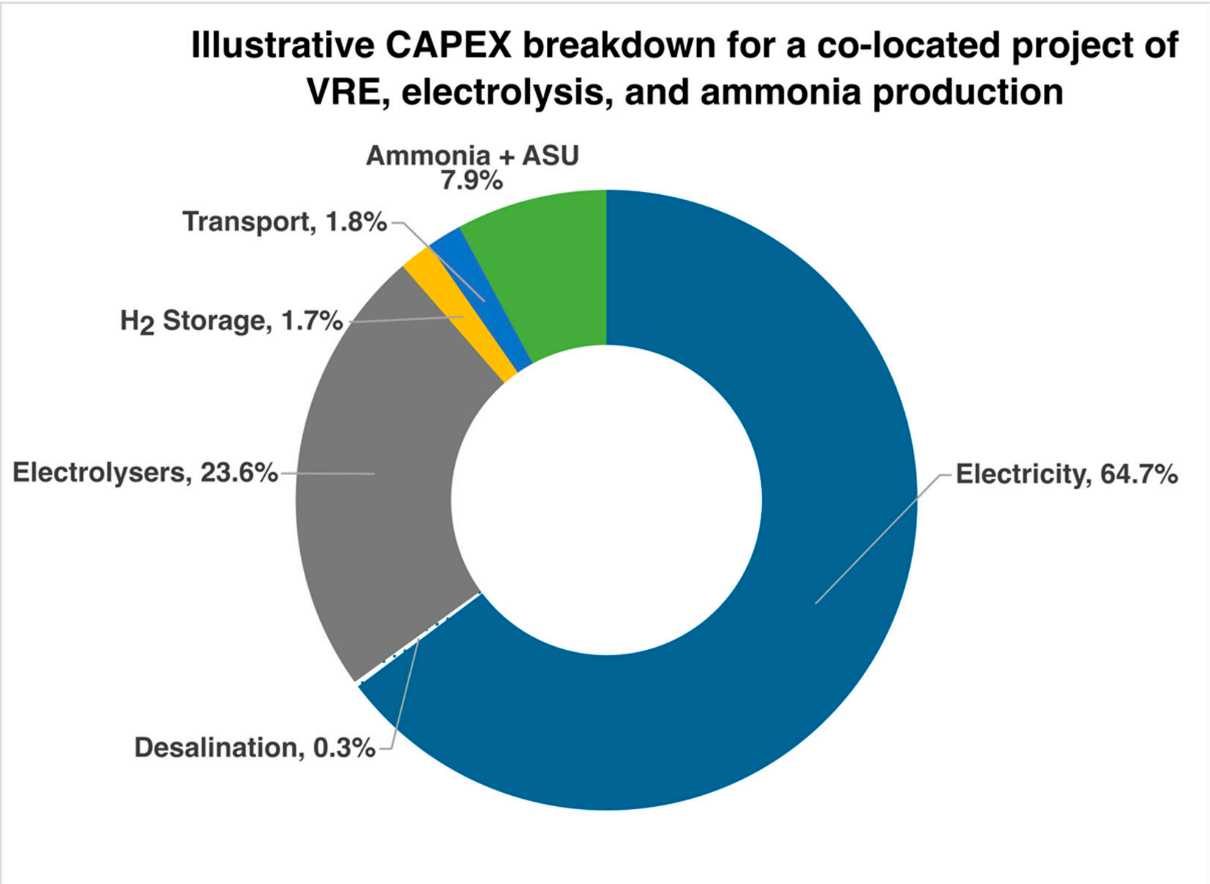

Figure 4. Breakdown of total investments of a co-located renewable energy, electrolyzer, and green ammonia plant. Note: For the higher end of the range USD 7 billion splits to USD 4.7 billion for renewable power plants, USD 0.02 billion for desalination, USD 1.6 billion for electrolysers, USD 0.1 billion for hydrogen storage, USD 0.1 billion for transport, and USD 0.5 billion for the ammonia synthesis plant and the air separation unit.

Figure 5 depicts an illustrative daily case to show the impact of renewable power supply over green hydrogen production when electricity is produced on site at all hours from a co-located stand-alone renewable power plant (Figure 5A–C) and when grid-connected electricity is supplied (Figure 5D–F). For the sake of simplicity, in this paper the assumption was made to source electricity from stand-alone systems dedicated for green hydrogen production as shown in Figure 5A. Total capital cost and daily hydrogen production (tons per day) have been used as indicators to show economic viability (In optimum design of real projects, the assessment presented in this illustrative case should be carried out for the entire lifetime of projects at an hourly resolution. Additionally, each one of these options should be evaluated in view of their potential impacts on green ammonia production costs [90] besides total capital costs).

In the case where all electricity need is generated on site, renewable power plants are generally designed with some degree of overcapacity (see green dashed lined) to ensure electricity demand of the electrolyzer (see red dashed line) is met at all hours with no disruptions (Figure 5A). While this ensures 100% green hydrogen production, it requires significant investments and may only be possible in cases when there is a renewable energy investor to co-finance the project or an established power market and/or guaranteed consumer for the hydrogen producer to sell any surplus power. Adjusting the capacity of the electrolyzer and the power plants can optimize the total capital costs and the load factor of the electrolyzer. In that case, the power plant has a lower generation capacity, thereby reducing green hydrogen output and reducing the economic viability of the system as electrolyzer is operated with lower capacity factors (Figure 5B). This can be overcome by installing on-site energy/hydrogen storage and store power and/or hydrogen during times when there is surplus power and utilize these during shortage of renewable power supply (Figure 5C). However, energy/hydrogen storage must be designed carefully in view of the choices for renewable power supply and the electrolyzer capacity since it can have a high contribution to the upfront investment costs.

In the case where a share of the total electricity need is supplied from the grid, the non-renewable electricity share can be offset with the surplus renewable power generated on site which will depend on renewable energy capacity, the electricity mix in the grid at that time as well as on the accounting methodology for green hydrogen eligibility. Additionally, green hydrogen output will decrease when renewable power capacity is lower (compare Figure 5D with Figure 5E). Grid-connected electricity could allow for higher utilization rates of the electrolyzer capacity, however, to ensure production of hydrogen is green, demand must be coupled with supply at all hours. Depending on the hour of the day, supplying electricity from the grid could also be very expensive. Tradeoff between grid electricity price, high-capacity factors of electrolyzers and green hydrogen output need to be carefully assessed.

In zones where there is a significant renewable generation surplus, grid-connected electrolyzers could procure renewable power from the grid which may otherwise be curtailed or utilized by energy storage systems and other users. However, availability of curtailed power may be insufficient, and it may be more cost effective to utilize it with other flexibility options. Alternatively, a renewable energy power purchase agreement (PPA) with other electricity suppliers can be signed to increase renewable electricity supply to complement the sourcing from on-site renewable electricity capacity (see Figure 5F). The electricity supplier may have a business case if power can be sold at more times instead of only for several hours for complementing the renewable power supply shortages. Thus, PPAs for few hours could be expensive.

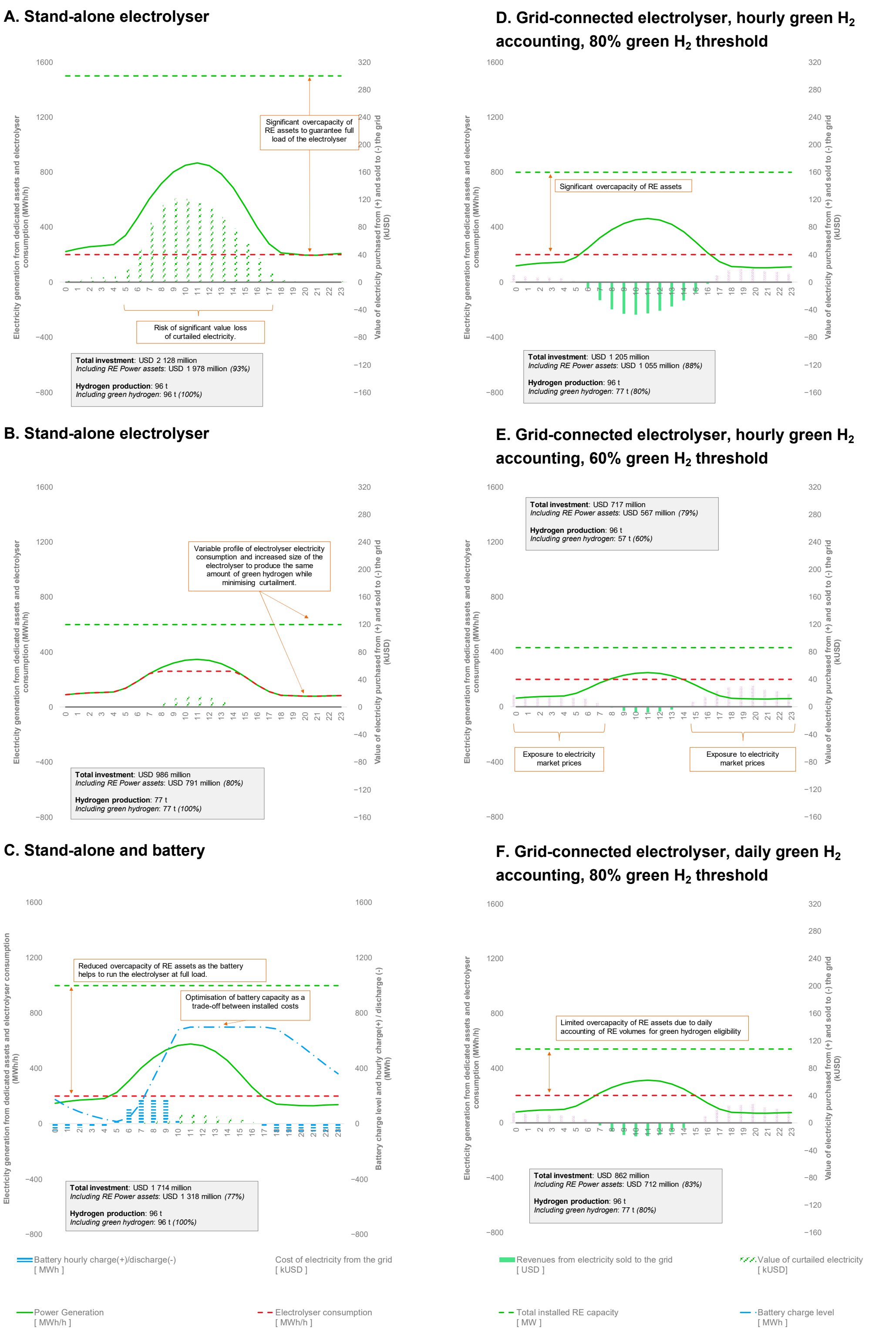

Figure 5. Impact of stand-alone and grid-connected power supply on green hydrogen production. Notes: Illustrative charts showing the operation in a single day. Hydrogen production is expressed in tons per day. Capital costs of solar PV, onshore wind and offshore wind have been assumed as USD 800, USD 1800 and USD 3740 per kW, respectively. Li-ion battery capital cost is USD 350/kWh and electrolyser capital cost is USD 750/kW. Electricity prices for self-consumption/PPA and grid average have been assumed as USD 62 and USD 162 per kWh.

4.2. Ammonia Production Aspects

Cost effective green ammonia production will require an optimum system operation. The ammonia synthesis reactor operates continuously at elevated temperatures of above 400 °C to maintain a high rate of reaction. While the heat of reaction is sufficient to realize the required process temperatures, the heat management of the reactor is critical to maintain this, which is impacted by the temperature of the system inlet and outlet feeds. With variable renewable energy supply, the steady-state operation and recycle loops (essential to feed the unreacted reactants back to the reactor) may be adversely impacted because green hydrogen supply can be intermittent. It will be important to understand the flexibility of reactors and the operational limitations to avoid interruptions, shutdowns, overheating and most importantly catalyst damage that is prone to reactor temperature [91].

Hydrogen storage may be needed between the electrolyzer and ammonia synthesis reactor. Low-cost solutions can be offered by underground storage at salt caverns, aquifers, and depleted gas fields. These options provide large and safe capacity for storage [92]. The salt cavern option is proven with years of experience that offers safe and fast cyclic storage at various sites [93]. Caverns can be up to 2 km deep and offer up to 1 million m^3 volume [94]. The Teesside in the United Kingdom operated by SABIC since 1972 stores in total 210,000 m^3 hydrogen at 45 bar across three sites. In the United States, more than 1.7 million m^3 hydrogen is stored in another three salt caverns [95]. The world's largest project for storing hydrogen in two salt caverns with a total capacity of 0.3 TWh in central Utah has started in June [96]. More research and development is needed to assess the geological feasibility whereas new pilot and demonstration projects can help to commercialize hydrogen storage in gas fields and aquifers [97]. Several pilot projects are underway in Austria (SunStorage) [98] and in Argentina (HyChico) [99] to utilize gas fields for hydrogen storage but availability of underground salt deposits is limited only to certain regions in the world [100]. Trials in gas fields have pointed to technical constraints such as the chemical and bacteriological reactions, alterations in the mechanical and permeability properties of the reservoir due to interaction with hydrogen, and the embrittlement of hydrogen [101]. Additionally, aquifers and depleted hydrocarbon reservoirs need to have good reservoir properties for injection and good quality cap rock to prevent migration of stored gas. In aquifers, hydrogen injection causes the formation of gas-liquid mixture which affects the withdrawal process. Additionally, undetected leakages (migration) and reactivity of hydrogen with reservoir minerals are other issues that warrant attention. Overall, these hydrogen storage options still have lower technology readiness level and require more research for commercialization [102].

Ammonia production efficiency ranges between 57% and 69% which is a fraction of the ammonia lower heating value and the total electricity demand to produce ammonia (30–36 GJ). Nevertheless, the cycle efficiency of using ammonia as a hydrogen carrier is lower at about 49% considering the value chain from renewable energy input for hydrogen production and synthesis of ammonia to its cracking (see Figure 6 for conversion of 1 kWh electricity to ammonia). Although the conversion of hydrogen to ammonia and to convert it back to hydrogen may initially be regarded inefficient and costly due to storage, transport, and cracking steps, it is currently economically the most feasible transport way since hydrogen is difficult to ship. Estimates show that it is 25–70% cheaper to produce, store, transport and crack ammonia to hydrogen compared to the liquefied hydrogen route [41]. Additionally, there is transportation infrastructure available for ammonia logistics today, which is not the case for hydrogen [103,104]. Losses from hydrogen to ammonia make up a small share of the total losses in ammonia production where in large-scale plants at least 99% of the produced hydrogen is converted to ammonia [105]. Technically, cracking is the most challenging step in the value chain. This reconversion step called ammonia cracking requires net energy of 1 GJ/t ammonia, equivalent to about 5% of ammonia's total energy content. Besides reconversion energy, there are thermal energy losses in the cracker of 4–7% when accounting for this 15% hydrogen loss in cracking, more than 5 GJ/t ammonia is needed [106], resulting in an overall efficiency on a H_2 mass basis of about 75% [107]. Potential areas of research for commercializing ammonia cracking are the development of efficient catalysts (determined by the heat requirements and the subsequent process temperatures), hydrogen purification with membranes and PSA & associated heat integration with the ammonia cracker reactor, and novel reactor technologies that are more efficient and flexible [108].

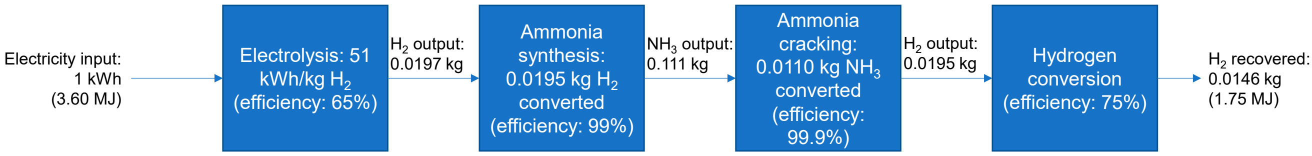

Figure 6. Cycle efficiency of using ammonia as an energy carrier.

Another aspect for green hydrogen production is that solar and wind produce DC electricity, which is converted into AC electricity and subsequently again reconverted into DC electricity for electrolysis. Significant energy losses and cost increases occur because of these conversions. If such conversion steps can be avoided, this could reduce the overall systems cost significantly. When accounting for such losses and all other energy inputs in the green ammonia value chain, the efficiency decreases to about 28% since about 0.745 MJ additional energy is needed during the conversion of 1 kWh electricity to 1.75 MJ recovered hydrogen (see Figure 6):

- About 2% of the total electricity input is consumed at the inverter control system (0.072 MJ)
- Compression of hydrogen requires 4.32 MJ/kg hydrogen (0.085 MJ to compress 0.0197 kg hydrogen) [107]
- Nitrogen production (0.091 kg nitrogen is required for the equivalent amount of hydrogen compressed) requires 265 kWh/kg nitrogen electricity (0.087 MJ)
- Ammonia synthesis requires 600 kWh/t ammonia (0.238 MJ)
- Transport of ammonia over a 3000 km distance requires 0.936 MJ/kg ammonia (0.103 MJ)
- Cracking and purification steps require 0.4 kWh/kg ammonia (0.159 MJ) [107]

The losses due to limited efficiency of electrolyzers are compensated by the characteristics of the electrified ammonia production process. Various electrolysis processes produce hydrogen at different pressures. This determines the need for additional compression [109]. Instead of steam turbines, compressors are powered with efficient electric motor systems. Electrolysis and ammonia production can provide flexibility services that facilitate variable renewable energy (VRE) integration. Although start/stop flexibility of ammonia synthesis reactors is limited, electrolysis process can react much quicker than the heat integrated methane reforming process, offering additional benefits [105]. At the same time, attention is needed to manage the complex operation of electrolyzers that may require additional energy, thereby reducing the overall system efficiency. Typically, the whole installation needs to be flushed with nitrogen after a standstill and before a gradual restart for security reasons, which results in additional energy demand to produce additional nitrogen. This also impacts the flexibility of the electrolyzers since continuous operation even at low levels helps to avoid such security measures. During the electrolysis process, excess heat is produced and ventilated without any recovery. This creates cooling demand that reduces the system efficiency. Systems especially overheat when they operate with high loads [103]. Heat recovery systems can reduce the additional energy demand for cooling [110].

During green ammonia production, 1.4 tons of oxygen is produced as a by-product per ton of ammonia arising from the electrolysis and air separation steps. High purity oxygen can be used in several markets, including niche applications in the medical sector as well as in industrial processes, such as nitric acid plants in downstream fertilizer facilities, the steel industry and electricity generation, provided that green ammonia is produced in proximity with other oxygen using production processes thus making it case specific. Using pure oxygen helps to improve the efficiency of the process since combustion temperature is higher and CO_2 capture is easier as it has a higher partial pressure in the combusted gas mixture [105]. So far this oxygen potential is not utilized in plant designs, it may offer further optimization potential. In fact, oxygen could be used in the ATR-based blue hydrogen production processes.

5. Discussion of Prospects for Green Ammonia Trade and Required Policies

5.1. Prospects for International Trade

The capacity to store ammonia seasonally and the high maturity of its transportation and distribution technologies yield a viable pathway compared to other hydrogen shipping options. Moreover, shipping ammonia has the advantage of requiring the lowest total amount of capital for a fixed hydrogen capacity, about 20% lower than the total investment needed for liquid organic hydrogen carriers and 50% lower than for liquid hydrogen [41]. Currently more than 10% of all ammonia production is globally traded using pipelines and ships [41]. In a 1.5 °C aligned climate scenario, ammonia trade is estimated to grow by nearly 25 times [2] with its trade for hydrogen transport alone to reach 127 Mt by 2050 [14].

The prospect for green ammonia trade as a hydrogen carrier will be driven by the production cost difference between regions and the cost of transportation. The estimated production cost difference is a factor between 1.4 and 2.2 times for countries with good economic conditions, but with differences in the capacity factors of wind and solar energy (e.g., Australia versus Italy and Japan, respectively), equivalent to USD 175–450 per ton ammonia (see Section 3). By comparison, the production cost difference is close to the high end of this range between countries with similar quality wind and solar energy resources, but with different economic conditions (e.g., Australia versus Egypt). As the disparity in economic conditions widen, the production cost difference increases up to USD 1000 per ton or about 4 times between countries (e.g., Australia versus most sub-Saharan Africa countries).

This analysis suggests that green ammonia production can start in countries with good renewable energy resource availability and favorable economic conditions such as in Australia and the United States. The renewable electricity generation cost in these countries are close to the low end of the estimated range of USD 2–12 cents per kWh (global average: USD 4.6 cents per kWh). The future cost difference in green ammonia production will be driven by renewable energy resource quality or the capacity factors of power plants, as the differences between the capital cost of equipment and the cost of capital are expected to narrow over time. At the same time, investment decisions are being taken by emerging and developing economies for new green hydrogen and green ammonia plants. Based on their credit rating, these countries are, however, characterized by high cost of capital in this paper, implying high green ammonia production costs. In reality, the risks associated with high cost of capital can be overcome through private investors who are willing to pay for a high equity share and the availability of concessional finance provided to countries through specific programs or special de-risking measures [111]. Thus, if enabling conditions and financing can be secured to ensure low cost of capital (see Section 5.2), large-scale green ammonia production can also begin in India, Middle East and North Africa, and Latin America. In that sense, green ammonia opens the opportunity to tap into remote low-cost renewable energy potentials. Therefore, in the long-term, the largest economic potential of hydrogen and ammonia supply is found in Sub-Saharan African and Latin American countries with opportunities in parts of Asia as well (e.g., the Middle East).

The additional cost parameters that impact ammonia import are shipping and cracking costs, which depend on the technology choice and its development. The cost of producing green hydrogen from renewables is projected to drop below USD 1/kg H_2 for most regions by 2050. Over the same time frame, the cost of shipping ammonia is projected to decline by one order of magnitude, from USD 8/kg H_2 for today's pilot projects to USD 0.8/kg H_2 for large-scale projects. Three-quarters of this decline is explained by economies of scale, followed by the decline in the cost of capital (from 15% to 5%) and technology learning. Hydrogen can be delivered at a cost of USD 1.5–2/kg H_2 with green ammonia, highlighting that the future prices offered by various exporters could be very similar. Future trade will therefore also be defined by other factors such as energy security, availability of infrastructure, existence of trade routes and country relationships. Indeed, transportation costs of ammonia remain much lower than the gap in production costs, both between production routes, and between countries for a given route [41]. Therefore, the location of future ammonia plants will also depend on the appetite of consumers for low-carbon ammonia at regional and global level and on trade policies.

Building new ammonia trade routes can use the significant experience that exists with ammonia shipping. There exists infrastructure in over 120 ports that could be used for ammonia trade. Ammonia is typically shipped in LPG carriers with around 170 ships present with the capability of carrying ammonia. Besides carrying LPG and other similar products, 40–65 of these ships permanently carry ammonia [42,112]. Transport and handling of ammonia can be done easily through the existing distribution network of fossil fuel-based ammonia, where ammonia is usually transported in liquid form. This also includes the use of pipelines for instance used in the United States [24]. There are already protocols in place for the health and safety regulations of ammonia transport, and a complete value chain has been established comprising, for instance, component manufacturers, spare part suppliers, ammonia sensors, and detector vendors. However, there are concerns related to storage and transportation of hydrogen using ammonia due to its toxic characteristic. It is possible to overcome this barrier by storing ammonia in a solid (e.g., metal ammines, ammonium carbonates or urea) and by using leak-proof infrastructure [113].

5.2. Required Policies and Enabling Conditions

There are two pillars in establishing such a policy framework, namely, (1) to establish national and sectoral plans for ammonia, and (2) to improve the enabling conditions to realize them. This section discusses these based on literature that has addressed the various aspects of developing such decarbonization strategies for industrial products [5,114–116].

5.3. Climate and Environment

The climate and environmental impacts of ammonia production must be at the core of ammonia development strategies. The analysis presented in this paper has shown that in defining green and blue ammonia, carbon neutrality is not a given. The cradle-to-factory gate blue ammonia (SMR) emissions are estimated to range from 1.27 to 3.59 t CO_2-eq/t ammonia whereas green ammonia emissions could be around 0.40 t CO_2-eq/t ammonia. From the perspective of avoiding stranded assets [117] and minimize impact on production costs, the industry may favor blue ammonia as a first option given its production costs are only about 25% higher than grey ammonia. This option becomes more favorable when the total methane emissions from the gas industry could be mitigated. Although mitigation of these emissions is an early opportunity for the energy sector, the gas industry has been slow to act, and mitigation has been challenging due to lack of measuring and reporting frameworks. Few studies attempted to quantify the country-level emissions, even in the case of large emitters such as the United States [118] and there are even larger uncertainties about gas transport emissions such as from LNG ships [119]. Additionally, methane and indirect GHG emissions of the gas industry show large uncertainty depending on the methodology and assumptions. Data collection, measurement, assessment, and reporting methodology require improvements. It is equally important to assess the impact of captured CO_2 used for enhanced oil recovery and the production of urea or methanol along the full life cycle, since these options lead to release of CO_2 back to the atmosphere.

Besides GHG emissions, the availability and use of water is another aspect of green ammonia production. Ammonia from electrolysis requires about 1.6 tons water feedstock/t ammonia, with additional water required for cooling and support systems. By comparison, the SMR route requires around 0.6 tons [43]. Wherever possible, the use of desalinated sea water must be prioritized. The use of alternative sources such as wastewater can be explored as well [120]. As pure water is needed for the electrolysis, purification technologies warrant attention. Water availability could affect the green hydrogen supply potential in regions such as the Middle East [121]. Thus, the impacts of natural resource requirement as well as the environmental and climate impacts of hydrogen geological storage will need to be better understood. Other sustainability criteria will need to be considered, including availability of land, scarcity of certain metals, and impacts on the global nitrogen cycle.

5.4. Innovation Policies

The enabling conditions to improve the feasibility to invest in green ammonia include actions across technology innovation, policy instruments and financing. Innovation is needed to continue cost reductions and minimize the energy losses across the green ammonia value chain of production. Research and development is required to reduce the additional ammonia requirements during reconversion, e.g., when ammonia is used to carry hydrogen, and reconvert back to purified hydrogen for importing regions. Alternatively, partial cracking technologies or even fully ammonia-fed technologies can be developed, reducing the overall energy requirement. To minimize methane emissions from blue ammonia production, simple technology solutions such as frequent leak detection and repair, emission technology standards, and controlling and allowing for venting only under certain circumstances need to be prioritized to ensure blue ammonia can be deployed in tandem with green ammonia [22].

5.5. Regulations for Market Creation and Growth and Financing

The required policy instruments include a wide range of options. Creating local markets and ensuring sustainability of production will require accurate characterization and definitions of blue and green ammonia. Using these definitions, the pillar to facilitate international trade will be to develop certification and standards. Ammonia is currently transported as a chemical, but in will also be a zero-carbon fuel and hydrogen carrier in the future. Methodologies will need to be developed to trace the life cycle GHG emissions associated with all stages of ammonia value chain–production, transport, and conversion processes for different ammonia types. Besides including quantitative criteria (e.g., emissions, water use), qualitative criteria should also be incorporated depending on the region under consideration. Ensuring consistency in the methodological aspects across countries such as spatial and time boundaries, data, treatment of co-products, as well as socio-economic aspects will be critical. Interoperability will be needed to minimize differences in criteria and thresholds between different countries, thereby eliminating risks related to uneven progress of creating new markets and emissions mitigation. Ammonia standards must strike a balance between guaranteeing the production of green hydrogen production for decarbonization and incentivizing innovation and capacity deployment.

There will be a need to understand how to design and implement production targets, production quotas, green public procurement, and other regulatory approaches to create new ammonia markets and reshape existing ones, where examples of their role for low-carbon steel and cement have already been explored [122]. Business and country partnerships facilitate project development and market creation, and they accelerate innovation [111]. New demand creation incentives for green hydrogen can accelerate ammonia trade, but separate trade policies may be needed to deal with the individual ammonia products that compete with grey ammonia and fossil fuels, as well as the hydrogen transport options in view of their varying costs and GHG emission performances.

Market-based instruments and financing approaches will be needed to materialize on the nearly USD 4 trillion investment needed across the green ammonia value chain between today and 2050. For the first large-scale projects, availability of mature value chain and existing market will be critical which is one of the underlying reasons why green ammonia projects are an early opportunity. Yet, green ammonia is still perceived as a risky investment because of its high capital costs, and therefore the first projects will require higher equity share [19] and first movers would be willing to pay for a premium for green ammonia [26]. Economies of scale will reduce costs and mid- to long-term contracts can ensure demand among other measures as discussed earlier. Creation of a sustainable green ammonia market will rely on market-based instruments instead of subsidies and support, thereby requiring de-risking mechanisms and eliminating factors that create financial risks to investors. This requires understanding of the existing barriers and the parameters that can drive down the costs across the value chain. The reduction of renewable power and electrolyzer costs are essential to ensure cost competitiveness. This may require multiple actors to partner since it may be challenging for a single actor to cover the costs across the entire value chain. Many of the announced green ammonia projects feature company partnerships including a supplier of green electricity, green hydrogen producer and the consumers/off-takers of green hydrogen and its products. Direct financial support and viability gap funds can reduce the upfront capital costs of first projects. The operation and maintenance costs of green ammonia production will require market-based policy approaches to improve the enabling conditions. Reduction of fossil fuel subsidies, creation of carbon markets and carbon contracts for differences could be helpful means to create a level playing field for green ammonia [34].

Unless alternatives for green hydrogen supply through infrastructure and imports become available at lower cost, green hydrogen may require long-term subsidies. A better understanding of the cost of hydrogen infrastructure and import options as well as efficient subsidy frameworks will be needed [123]. Grants, investments, loans, or loan guarantees, intermediate secured buyer of auctioned projects, are possible instruments to finance future green ammonia projects, where their role should be assessed case by case by engaging both the international and local financial actors. The availability of infrastructure such as loading and unloading port facilities will be one of the criteria to determine suitable trade routes. Therefore, infrastructure investments will be needed as well, where public private partnerships can play a role.

6. Conclusions

This paper has provided an overview of ammonia market projections based on various scenarios and assessed the energy, climate, and cost impacts of realizing those markets with a view on the power system implications and the required policies for facilitating international trade. As part of national and sectoral net-zero emission targets, the role of green and blue ammonia should be further defined as ammonia has the potential to reduce future non-energy use of gas. Green ammonia presents an early market opportunity for green hydrogen deployment and to decarbonize hard to abate sectors such as chemicals processing, petrochemicals, agriculture, energy, maritime shipping, and long-haul freight operations. Although ammonia represents about 4% of the global gas market today, this share may increase as ammonia demand picks up with growth in these end-use sectors and economic growth in developing countries.

This work summarizes existing knowledge on low-carbon ammonia production and adds value by comparing the different available ammonia production pathways. Further, the research study elaborates the energy system integration issues of green and blue ammonia production, their environment impacts, as well as the required policies and financing aspects to facilitate their market deployment and international trade. The findings presented in the paper may be detailed and studied further at the level of projects in various regions globally for designing and deploying cost-effective ammonia plants. The ammonia efficiency assessment should be expanded with the embedded energy in the production and supply equipment through the development of indicators such as energy return on investment. These assessments can help to prioritize the key enabling conditions that should be advanced on as well as innovative project finance. As this paper stresses, ammonia is moving from viable technology to full scale deployment, yet while green ammonia is likely to reach cost competitiveness in the coming decades, its deployment can be in tandem with blue ammonia. In deployment of blue ammonia, gas supply security has gained importance while countries must urgently act to reduce CO_2 and methane emissions from their gas operations. Ammonia can play a key role in decarbonizing the gas sector due to its ease of transportation and its relatively high energy content per unit of weight. Certification and standards built on internationally acknowledged methodologies and that consider ammonia's energy requirements, emissions, and other environmental impacts across its full value chain will be essential.

Author Contributions: Conceptualization, H.B., F.B., K.R. and D.G.; Methodology, D.S., H.B., K.R. and D.G.; Formal analysis, H.B., J.C. and K.R.; Data curation, D.S., J.C. and K.R.; Writing—original draft, D.S. and J.C.; Writing—review & editing, H.B., F.B., K.R., P.L. and D.G.; Supervision, D.G.; Project administration, D.G. All authors have read and agreed to the published version of the manuscript.

Funding: This researched received no external funding.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: The background data used in this study is available in Appendix A.

Acknowledgments: The authors would like to thank three anonymous reviewers for their valuable comments.

Conflicts of Interest: The opinions expressed in this paper are those of the authors and do not necessarily reflect the official views of the Organisation for Economic Co-operation and Development (OECD) or of the governments of its member countries. The opinions expressed in this paper are those of the authors and do not net necessarily reflect the official views of the Ammonia Energy Association or Proton Ventures. The opinions expressed in this paper are those of the authors and do not net necessarily reflect the official views of the Sabanci University. The opinions expressed in this paper are those of the authors and do not necessarily reflect the official views of The World Bank or of the governments of its member countries. The authors declare no conflict of interest.

Appendix A

	Unit	**Assumed Value**	**References**
	Hydrogen production		
CAPEX: SMR	USD/kW	910	[124–126]
CAPEX: Electrolyzer	USD/kW	750	[127]
CAPEX: CCS	USD/t CO_2/year	300	[69]
CAPEX: Onshore wind	USD/kW	1150–3000	[128,129]
CAPEX: Offshore wind	USD/kW	2300–6300	
CAPEX: Solar PV	USD/kW	600–1750	
CAPEX: Gas boiler	USD/kW	500	[130]
OPEX: SMR	% of CAPEX	4.7	[124,125]
OPEX: Electrolyzer	% of CAPEX	2.5	[127]
OPEX: CCS	% of CAPEX	7	[69]
OPEX: Renewable power	% of CAPEX	2.5	[128,129]
Gas boiler OPEX	% of CAPEX	3	[130]
Capacity factor: SMR	%	90	[124,125]
Capacity factor: Electrolyzer	%	50	[127]
Capacity factor: CCS	%	90	[69]
Capacity factor: Onshore wind	%	28–38	[128–131]
Capacity factor: Offshore wind	%	38–57	
Capacity factor: Solar PV	%	12–23	
Capacity factor: Gas boiler	%	90	[132]

	Unit	Assumed Value	References
SMR gas input Feedstock Fuel	GJ/t H_2	140.7 15.4	[133]
SMR steam Import Export	GJ/t H_2	25.9 37.2	
SMR electricity	GJ/t H_2	1.14	
Electrolyzer efficiency	%	65	[127]
Electrolyzer water demand	l/kg H_2	15	
CCS steam	GJ/t CO_2 captured	2.5	[69]
CCS electricity	GJ/t CO_2 captured	0.4	[69]
CCS capture rate	%	90	[69]
Gas-fired power plant efficiency	%	30–90	Assumption
Gas boiler efficiency	%	90	Assumption
Emission factor of natural gas	tons CO_2/GJ	0.056	
Emission factor of grid electricity	g CO_2/kWh	0–1050	Estimated based on data from [1]
Average methane emissions from natural gas	t CO_2-eq/GJ	0.015	Estimated based on data from [1,22,63,71,82]
GHG emission reduction potential of methane abatement measures	%	Up to 16%	Estimated based on data from [1,71]
	Nitrogen production		
CAPEX: cryogenic air separation	USD/t N_2/h	1,500,000	[56]
OPEX: cryogenic air separation	% of CAPEX	2	
Electricity	kWh/t N_2	265	[134]
Capacity factor	%	90	Assumption
	Ammonia synthesis		
CAPEX: ammonia synthesis	USD/t NH_3/h	3,450,000	[17]
OPEX: ammonia synthesis	% of CAPEX	2	
Electricity for synthesis	kWh/kg NH_3	0.65	[16,57]
	Utility prices		
Natural gas price	USD/GJ	1–10	Assumption
Grid electricity	USD/kWh	0.014–0.108	Assumption
LCOE onshore wind	USD/kWh	0.037–0.228	Estimated based on above parameters
LCOE offshore wind	USD/kWh	0.052–0.215	
LCOE Solar PV	USD/kWh	0.038–0.142	
Water price	USD/L	0.001	Assumption
	Annuity factor		
Long-term interest rate (2019–2021)	%	−0.5–10	[135]
Country credit ratings (August 2022)	-	-	[136]
Discount rate	%	5–22	Estimate
Economic lifetime of equipment	Years	25	Assumption

Levelized cost of producing hydrogen, electricity and ammonia are estimated based on Equation (A1)

$$LCOX_{i,c} = \frac{\alpha \times I_i + E_{i,c} + O_i}{X_i} \tag{A1}$$

where $LCOX_{i,c}$ is the levelized cost of production (in USD per unit of energy/chemical) from technology i in country c, α is the annuity factor in years^{-1} (estimated as $r_c/(1-(1+r_c)^{-L})$, r_c is the discount rate in country c (in %) and L is the economic lifetime (in years)), I_i is the initial investment cost of technology i (in million USD, CAPEX)), X_i is the annual energy/chemical production from technology i (estimated as the product of production capacity and the capacity factor), E_i is total annual energy costs (electricity, gas etc), and O_i is total other costs of technology i (all in million USD/year, OPEX).

CO_2 avoidance cost of post-combustion CCS has been estimated based on Equation (A2)

$$COA_c = \frac{\alpha \times IC + EC + OC}{CO2} \tag{A2}$$

where COA_c is the levelized cost of avoiding CO_2 (in USD per ton of CO_2) in country c, α is the annuity factor in years^{-1} (estimated as $r_c/(1-(1+r_c)^{-L})$, r_c is the discount rate in country c (in %) and L is the economic lifetime (in years)), IC is the initial investment cost of carbon capture technology (in million USD, CAPEX)), $CO2$ is the annual CO_2 avoided i (estimated as the product of CO_2 emissions and the capture rate minus total CO_2 emissions from electricity and heat supply to the carbon capture process), EC is total annual energy costs related to the carbon capture process (electricity, gas), and OC is total other costs of carbon capture (all in million USD/year, OPEX).

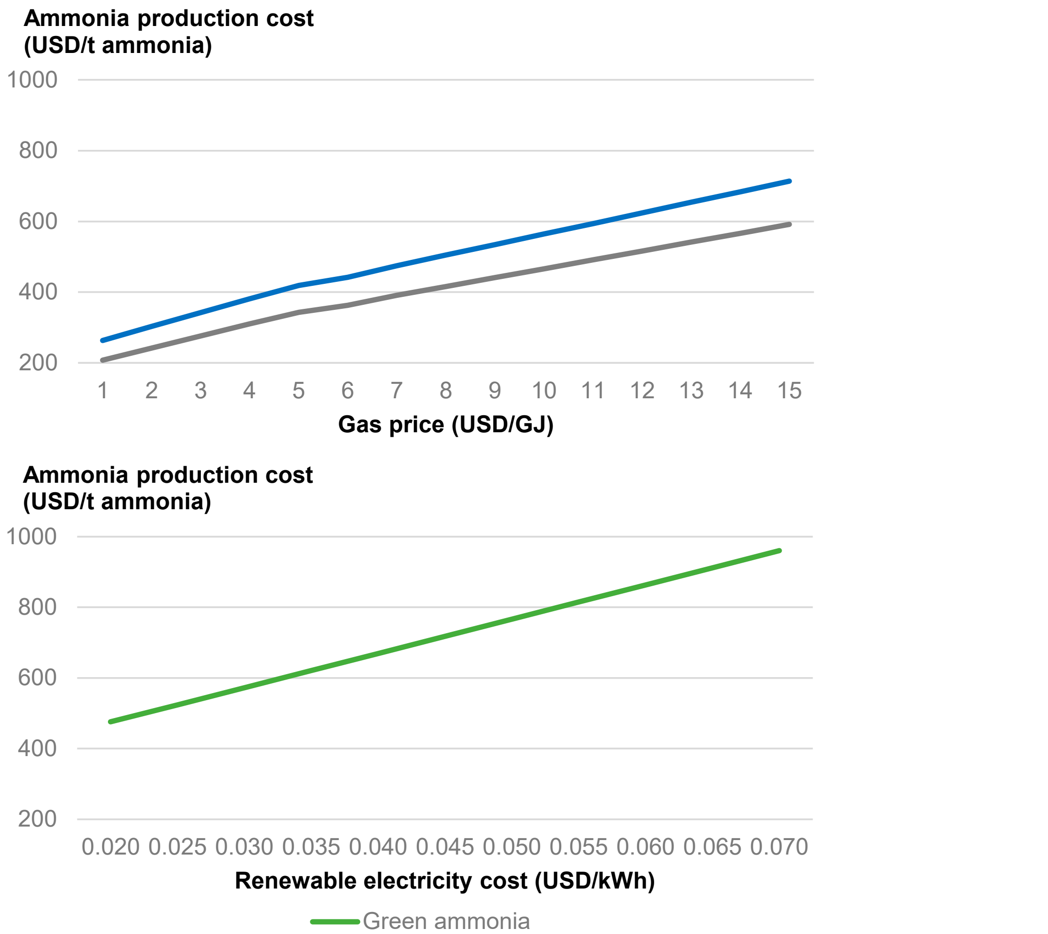

Figure A1. Estimated ammonia production costs as a function of gas and electricity prices. Note: Estimates assume a 10% cost of capital.

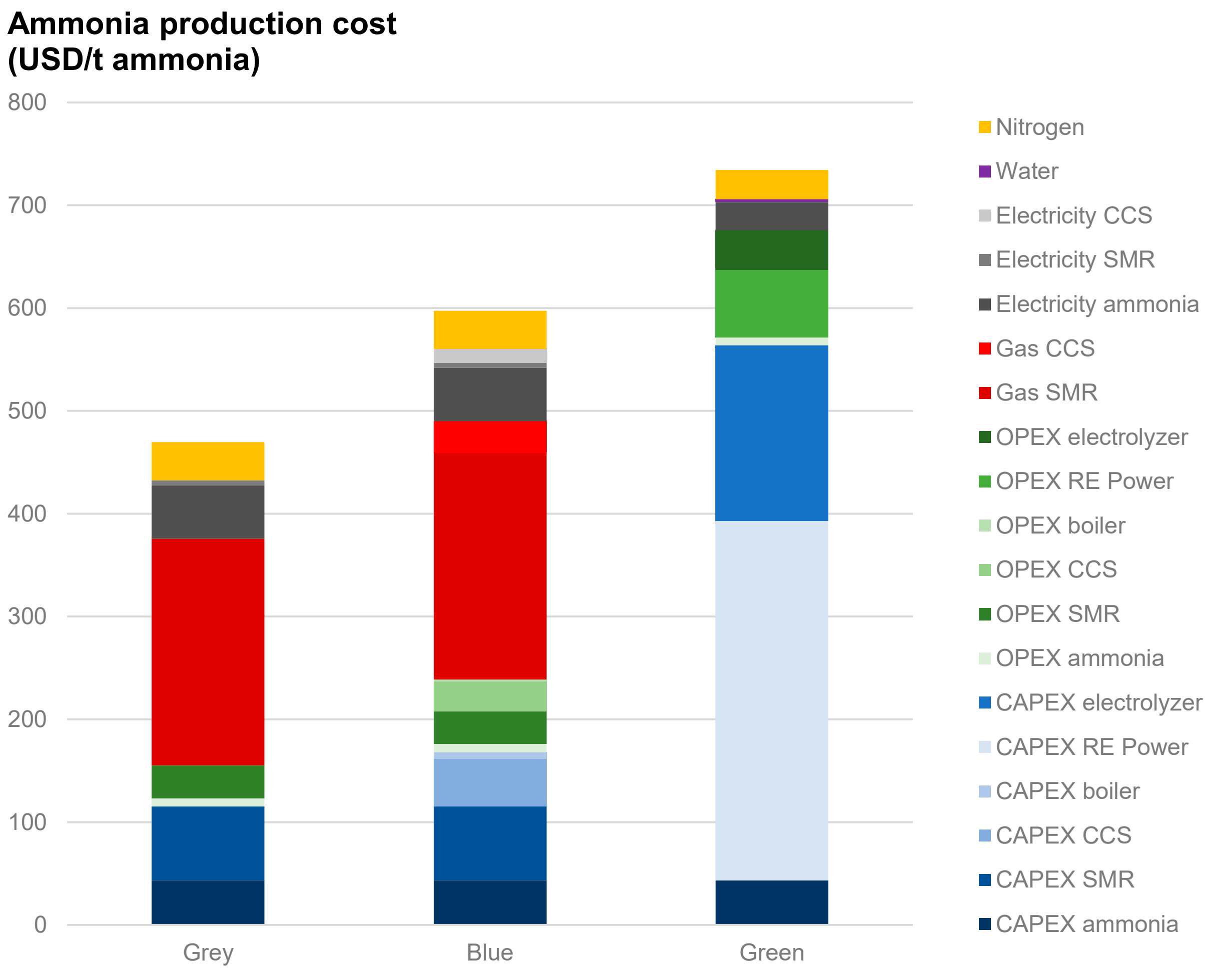

Figure A2. Breakdown of the average global ammonia production costs. Note: By-product oxygen from air separation is not valued.

References

1. OECD/IEA. *World Energy Balances Overview*; International Energy Agency: Paris, France, 2021.
2. IRENA. *World Energy Transitions Outlook: 1.5 °C Pathway*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2022.
3. OECD/IEA. *World Energy Outlook 2021*; International Energy Agency: Paris, France, 2021.
4. Riahi, K.; Schaeffer, R.; Arango, J.; Calvin, K.; Guivarch, C.; Hasegawa, T.; Jiang, K.; Kriegler, E.; Matthews, R.; Peters, G.; et al. Mitigation Pathways Compatible with Long-Term Goals. In *Climate Change 2022: Mitigation of Climate Change*; Shukla, P., Skea, J., Slade, R., Khourdajie, A.A., Diemen, R., McCollum, D., Pathak, M., Some, S., Vyas, P., Fradera, R., et al., Eds.; Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change; Cambridge University Press: Cambridge, UK; New York, NY, USA, 2022.
5. OECD/IEA. *Ammonia Technology Roadmap*; International Energy Agency: Paris, France, 2021.
6. USGS. Nitrogen Statistics and Information. 2022. Available online: https://www.usgs.gov/centers/national-minerals-information-center/nitrogen-statistics-and-information (accessed on 29 November 2022).
7. Dempsey, H.; Ivanova, P. *European Gas Prices Soar after Russia Deepens Supply Cuts*; Financial Times: London, UK, 2022.
8. OECD. Why Governments should Target Support Amidst High Energy Prices. Available online: https://www.oecd.org/ukraine-hub/policy-responses/why-governments-should-target-support-amidst-high-energy-prices-40f44f78/ (accessed on 30 June 2022).
9. OECD/IEA. *Gas Market Report, Q3-2022*; International Energy Agency: Paris, France, 2022.
10. Lawson, C. Europe Nitrogen Capacity Closure and Cost Tracker. Available online: https://www.crugroup.com/knowledge-and-insights/insights/2022/europe-nitrogen-capacity-closure-and-cost-tracker (accessed on 25 August 2022).
11. IAMM. Why are Ammonia Prices so High in 2022? Available online: https://www.iamm.green/ammonia-prices/ (accessed on 26 June 2022).
12. The World Bank. World Bank Commodities Price Data (The Pink Sheet). Available online: https://thedocs.worldbank.org/en/doc/5d903e848db1d1b83e0ec8f744e55570-0350012021/related/CMO-Pink-Sheet-September-2022.pdf (accessed on 2 September 2022).

13. Gielen, D.; Bazilian, M.D. Critically exploring the future of gaseous energy carriers. *Energy Res. Soc. Sci.* **2021**, *79*, 102185. [CrossRef]
14. IRENA. *Innovation Outlook: Renewable Ammonia*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2022.
15. EU. *Assessment of Hydrogen Delivery Options*; European Union: Brussels, Belgium, 2021.
16. Fasihi, M.; Weiss, R.; Savolainen, J.; Breyer, C. Global potential of green ammonia based on hybrid PV-wind power plants. *Appl. Energy* **2021**, *294*, 116170. [CrossRef]
17. Armijo, J.; Philibert, C. Flexible production of green hydrogen and ammonia from variable solar and wind energy: Case study of Chile and Argentina. *Int. J. Hydrog. Energy* **2020**, *45*, 1541–1558. [CrossRef]
18. Guerra, C.F.; Reyes-Bozo, L.; Vyhmeister, E.; Caparros, M.J.; Salazar, J.; Clemente-Jul, C. Technical-economic analysis for a green ammonia production plant in Chile and its subsequent transport to Japan. *Renew. Energy* **2020**, *157*, 404–414. [CrossRef]
19. Salmon, N.; Bañares-Alcántara, R. Green ammonia as a spatial energy vector: A review. *Sustain. Energy Fuels* **2021**, *5*, 2814–2839. [CrossRef]
20. Howarth, R.W.; Jacobson, M.Z. How green is blue hydrogen? *Energy Sci. Eng.* **2021**, *9*, 1676–1687. [CrossRef]
21. Forster, P.; Storelvmo, T.; Armour, K.; Collins, W.; Dufresne, J.-L.; Frame, D.; Lunt, D.; Mauritsen, T.; Palmer, M.; Watanabe, M.; et al. 2021: The Earth's Energy Budget, Climate Feedbacks, and Climate Sensitivity. In *Climate Change 2021: The Physical Science Basis*; Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, Cambridge and New York; Cambridge University Press: Cambridge, UK, 2021; pp. 923–1054.
22. OECD/IEA. *Methane Emissions from Oil and Gas*; International Energy Agency: Paris, France, 2021.
23. Al-Aboosi, F.Y.; El-Halwagi, M.M.; Moore, M.; Nielsen, R.B. Renewable ammonia as an alternative fuel for the shipping industry. *Curr. Opin. Chem. Eng.* **2021**, *31*, 100670. [CrossRef]
24. Allman, A.; Daoutidis, P.; Tiffany, D.; Kelley, S. A framework for ammonia supply chain optimization incorporating conventional and renewable generation. *Process Syst. Eng.* **2017**, *63*, 4390–4402. [CrossRef]
25. Salmon, N.; Banares-Alcantara, R.; Nayak-Luke, R. Optimization of green ammonia distribution systems for intercontinental energy transport. *iScience* **2021**, *24*, 102903. [CrossRef]
26. Zhao, H.; Kamp, L.M.; Lukszo, Z. The potential of green ammonia production to reduce renewable power curtailment and encourage the energy transition in China. *Int. J. Hydrog. Energy* **2022**, *47*, 18935–18954. [CrossRef]
27. Sagel, V.N.; Rouwenhorst, K.H.R.; Faria, J.A. Renewable Electricity Generation in Small Island Developing States: The Effect of Importing Ammonia. *Energies* **2022**, *15*, 3374. [CrossRef]
28. Saygin, D.; Gielen, D. Zero-Emission Pathway for the Global Chemical and Petrochemical Sector. *Energies* **2021**, *14*, 3772. [CrossRef]
29. Patonia, A.; Poudineh, R. *Global Trade of Hydrogen: What is the Best Way to Transfer Hydrogen over Long Distances?* Oxford Institute for Energy Studies: Oxford, UK, 2022.
30. MPP. *Making Net-Zero Ammonia Possible: An Industry-Backed, 1.5oC-Aligned Transition Strategy*; Mission Possible Partnership, 2022.
31. OECD/IEA. *Net Zero by 2050*; International Energy Agency: Paris, France, 2021.
32. Pekic, S. QatarEnergy to Build 'World's Largest Blue Ammonia Facility. 2022. Available online: https://www.offshore-energy.biz/qatarenergy-to-build-worlds-largest-blue-ammonia-facility/ (accessed on 18 January 2022).
33. Rouwenhorst, K.H.; Travis, A.S.; Lefferts, L. 1921–2021: A Century of Renewable Ammonia Synthesis. *Sustain. Chem.* **2022**, *3*, 149–171. [CrossRef]
34. IRENA. *Global Hydrogen Trade to Meet the 1.5 °C Climate Goal: Part I—Trade Outlook for 2050 and Way Forward*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2022.
35. Argus Media. *Ammonia Market Update and CFR NW Ammonia Swaps—A New Risk Management Tool*; Argus Media: London, UK, 2022.
36. Thomas, W. Fertilizer Industry Takes Leap of Faith on Green Ammonia. Available online: https://www.crugroup.com/knowledge-and-insights/insights/2021/fertilizer-industry-takes-leap-of-faith-on-green-ammonia/ (accessed on 25 June 2021).
37. Rai-Roche, S. 'World's Largest Green Ammonia Plant' Planned for South Africa, Set to go Live in 2025. 2022. Available online: https://www.pv-tech.org/worlds-largest-green-ammonia-plant-planned-for-south-africa-set-to-go-live-in-2025/ (accessed on 18 January 2022).
38. Atchison, J. Total: Renewable Ammonia Production in Egypt. 2022. Available online: https://www.ammoniaenergy.org/articles/total-renewable-ammonia-production-in-egypt/ (accessed on 26 May 2022).
39. Construction Review Online. US$ 10.69bn Committed to Hydrogen & Green Ammonia Production Project in Guelmim-Oued Noun, Morocco. 2022. Available online: https://constructionreviewonline.com/news/us-10-69bn-committed-to-hydrogen-green-ammonia-production-project-in-guelmim-oued-noun-morocco/ (accessed on 29 January 2022).
40. Atchison, J. Scatec Joins ACME's Oman Green Ammonia Project. 2022. Available online: https://www.ammoniaenergy.org/articles/scatec-joins-acmes-oman-green-ammonia-project/ (accessed on 8 March 2022).
41. IRENA. *Global Hydrogen Trade to Meet the 1.5 °C Climate Goal: Part II—Technology Review of Hydrogen Carriers*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2022.
42. Hatfield, O. Country Traded Ammonia Logistics and Storage, Present and Future. In Proceedings of the Ammonia Energy Conference 2021, Boston, MA, USA, 9–11 November 2021.
43. Ghavam, S.; Vahdati, M.; Wilson, I.G.; Styring, P. Sustainable Ammonia Production Processes. *Front. Energy Res.* **2021**, *9*, 580808. [CrossRef]

44. Wu, S.; Salmon, N.; Li, M.M.-J.; Banares-Alcantara, R.; Tsang, S.C.E. Energy decarbonization via green H_2 or NH_3? *ACS Energy Lett.* **2022**, *7*, 1021–1033. [CrossRef]
45. NYK. Demonstration Project Begins for Commercialization of Vessels Equipped with Domestically Produced Ammonia-Fueled Engine. Available online: https://www.nyk.com/english/news/2021/20211026_03.html (accessed on 26 October 2021).
46. IRENA. *A Pathway to Decarbonize the Shipping Sector by 2050*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2021.
47. IMO. Initial Imo Strategy on Reduction of GHG Emissions from Ships. Available online: https://wwwcdn.imo.org/localresources/en/OurWork/Environment/Documents/Resolution%20MEPC.304%2872%29_E.pdf (accessed on 13 April 2018).
48. Kilemo, H.; Montgomery, R.; Leitão, A.M. *Mapping of Zero Emission Pilots and Demonstration Projects*; Getting to Zero Coalition: Copenhagen, Denmark, 2022.
49. Lloyd's List. Ammonia Retrofits for LNG-Fuelled Ships to Pick Up in 2030s. Available online: https://lloydslist.maritimeintelligence.informa.com/LL1135669/Ammonia-retrofits-for-LNG-fuelled-ships-to-pick-up-in-2030s (accessed on 4 February 2021).
50. Mallouppas, G.; Ioannou, C.; Yfantis, E.A. A Review of the Latest Trends in the Use of Green Ammonia as an Energy Carrier in Maritime Industry. *Energies* **2022**, *15*, 1453. [CrossRef]
51. Baresic, D. Ammonia as A Ship Fuel: Transition Pathways. In Proceedings of the Ammonia Energy Conference, Orlando, FL, USA, 12–14 November 2019.
52. Atchison, J. JERA Targets 50% Ammonia-Coal Co-Firing by 2030. Ammonia Energy Association. Available online: https://www.ammoniaenergy.org/articles/jera-targets-50-ammonia-coal-co-firing-by-2030/ (accessed on 21 January 2022).
53. METI. *Transition Roadmap for Power Sector*; Ministry of Economy, Trade and Industry: Tokyo, Japan, 2022.
54. Brown, T. Japan's Road Map for Fuel Ammonia. Available online: https://www.ammoniaenergy.org/articles/japans-road-map-for-fuel-ammonia/ (accessed on 25 February 2021).
55. Atchison, J. South Korea Sets Targets for Hydrogen & Ammonia Power Generation. Available online: https://www.ammoniaenergy.org/articles/south-korea-sets-targets-for-hydrogen-ammonia-power-generation/ (accessed on 24 November 2021).
56. Ikäheimo, J.; Kiviluoma, J.; Weiss, R.; Holttinen, H. Power-to-ammonia in future North European 100 % renewable power and heat system. *Int. J. Hydrog. Energy* **2018**, *43*, 17295–17308. [CrossRef]
57. Nayak-Luke, R.; Bañares-Alcántara, R.; Wilkinson, I. "Green" Ammonia: Impact of Renewable Energy Intermittency on Plant Sizing and Levelized Cost of Ammonia. *Ind. Eng. Chem. Res.* **2018**, *57*, 14607–14616. [CrossRef]
58. Rivarolo, M.; Riveros-Godoy, G.; Magistri, L.; Massardo, A.F. Clean Hydrogen and Ammonia Synthesis in Paraguay from the Itaipu 14 GW Hydroelectric Plant. *ChemEngineering* **2019**, *3*, 87. [CrossRef]
59. Gomez, J.R.; Baca, J.; Garzon, F. Techno-economic analysis and life cycle assessment for electrochemical ammonia production using proton conducting membrane. *Int. J. Hydrog. Energy* **2020**, *45*, 721–737. [CrossRef]
60. Bicer, Y.; Dincer, I.; Zamfirescu, C.; Vezina, G.; Raso, F. Comparative life cycle assessment of various ammonia production methods. *J. Clean. Prod.* **2016**, *135*, 1379–1395. [CrossRef]
61. Singh, V.; Dincer, I.; Rosen, M.A. Life Cycle Assessment of Ammonia Production Methods. In *Exergetic, Energetic and Environmental Dimensions, London, Ed.*; Academic Press: New York, NY, USA, 2018; pp. 935–959.
62. Liu, X.; Elgowainy, A.; Wang, M. Life cycle energy use and greenhouse gas emissions of ammonia production from renewable resources and industrial by-products. *Green Chem.* **2022**, *22*, 5751–5761. [CrossRef]
63. OECD/IEA. *The Oil and Gas Industry in Energy Transitions*; International Energy Agency: Paris, France, 2020.
64. Government of Alberta. *Quest CO2 Capture Ratio Performance*; Government of Alberta: Edmonton, AB, Canada, 2020.
65. Bauer, C.; Treyer, K.; Antonini, C.; Bergerson, J.; Gazzani, M.; Gencer, E.; Gibbins, J.; Mazzotti, M.; McCoy, S.T.; McKenna, R.; et al. On the climate impacts of blue hydrogen production. *Sustain. Energy Fuels* **2022**, *6*, 66–75. [CrossRef]
66. Dong, Z.Y.; Yang, J.; Yu, L.; Daiyan, R.; Amal, R. A green hydrogen credit framework for international green hydrogen trading towards a carbon neutral future. *Int. J. Hydrog. Energy* **2022**, *47*, 728–734. [CrossRef]
67. Noussan, M.; Raimondi, P.P.; Scita, R.; Hafner, M. The Role of Green and Blue Hydrogen in the Energy Transition—A Technological and Geopolitical Perspective. *Energies* **2021**, *13*, 298. [CrossRef]
68. Timmerberg, S.; Kaltschmitt, M.; Finkbeiner, M. Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas—GHG emissions and costs. *Energy Convers. Manag.* **2020**, *7*, 100043. [CrossRef]
69. Saygin, D.; Broek, M.; Ramirez, A.; Patel, M.K.; Worrell, E. Modelling the future CO_2 abatement potentials of energy efficiency and CCS: The case of the Dutch industry. *Int. J. Greenh. Gas Control.* **2013**, *18*, 23–37. [CrossRef]
70. OECD/IEA. *Curtailing Methane Emissions from Fossil Fuel Operations—Pathways to a 75% cut by 2030*; International Energy Agency: Paris, France, 2021.
71. OECD/IEA. *Methane Tracker 2020*; International Energy Agency: Paris, France, 2020.
72. IEAGHG. *Reference Data and Supporting Literature Reviews for SMR Based Hydrogen Production with CCS.*; IEA Greenhouse Gas R&D Programme: Cheltenham, UK, 2017.
73. KBR. *KBR Purifier™/PurifierPlus™ Process: A Superior Technology for Blue Ammonia Production*; KBR: Houston, TX, USA, 2022.
74. Liu, N. *Increasing Blue Hydrogen Production Affordability*; Hydrocarbon Processing: Houston, TX, USA, 2021.
75. Hydrogen Council. Hydrogen Council. Hydrogen Decarbonization Pathways. In *A Life-Cycle Assessment*; Hydrogen Council: Brussels, Belgium, 2021.

76. Ma, D.; Hasanbeigi, A.; Chen, W. *Energy-Efficiency and Air-Pollutant Emissions-Reduction Opportunities for the Ammonia industry in China*; Lawrence Berkeley National Laboratory: Berkeley, CA, USA, 2015.
77. Appl, M. *Ammonia: Principles and Industrial Practice*; Wiley-VCH: Weinheim, Germany, 1998.
78. Worrell, E.; Phylipsen, D.; Einstein, D.; Martin, N. *Energy Use and Energy Intensity of the U.S. Chemical Industry*; Ernest Orlando Lawrence Berkeley National Laboratory: Berkeley, CA, USA, 2000.
79. European Commission. *Large Volume Inorganic Chemicals—Ammonia, Acids and Fertilisers*; Joint Research Centre: Brussels, Belgium, 2007.
80. Noelker, K.; Ruether, J. Low-Energy Ammonia Production: Baseline Energy Consumption, Options for Energy Optimization. Dusseldorf, Germany. 2011. Available online: https://ucpcdn.thyssenkrupp.com/_legacy/UCPthyssenkruppBAIS/assets.files/download_1/ammonia_2/low_energy_consumption_ammonia_production_2011_paper.pdf (accessed on 15 April 2022).
81. Brown, T. *Innovations in Ammonia*; US DOE, Hydrogen & Fuel Cell Technical Advisory Committee: Washington, DC, USA, 2018.
82. OECD/IEA. Methane Tracker Data Explorer. 2022. Available online: https://www.iea.org/articles/methane-tracker-database (accessed on 1 June 2022).
83. Egli, F.; Steffen, B.; Schmidt, T.S. Bias in energy system models with uniform cost of capital assumption. *Nat. Commun.* **2019**, *10*, 4588. [CrossRef]
84. Cesaro, Z.; Ives, M.; Nayak-Luke, R.; Mason, M.; Bañares-Alcántara, R. Ammonia to power: Forecasting the levelized cost of electricity from green ammonia in large-scale power plants. *Appl. Energy* **2021**, *282*, 116009. [CrossRef]
85. Nayak-Luke, R.M.; Banares-Alcantara, R. Techno-economic viability of islanded green ammonia as a carbon-free energy vector and as a substitute for conventional production. *Energy Environ. Sci.* **2020**, *13*, 2957–2966. [CrossRef]
86. Pozo, C.A.; Cloete, S. Techno-economic assessment of blue and green ammonia as energy carriers in a low-carbon future. *Energy Convers. Manag.* **2022**, *255*, 115312. [CrossRef]
87. Bogdanov, D.; Child, M.; Breyer, C. Reply to 'Bias in energy system models with uniform cost of capital assumption'. *Nat. Commun.* **2019**, *10*, 1–2. [CrossRef] [PubMed]
88. IRENA. *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5 °C Climate Goal*; IRENA Publications: Abu Dhabi, United Arab Emirates, 2020.
89. Stones, J. MEPs Vote to Remove Additionality Principle for Renewable Hydrogen Production. Available online: https://www.icis.com/explore/resources/news/2022/09/14/10805502/meps-vote-to-remove-additionality-principle-for-renewable-hydrogen-production/ (accessed on 14 September 2022).
90. Longden, T.; Beck, F.J.; Jotzo, F.; Andrews, R.; Prasad, M. 'Clean' hydrogen?—Comparing the emissions and costs of fossil fuel versus renewable electricity based hydrogen. *Appl. Energy* **2022**, *306*, 118145. [CrossRef]
91. Cheema, I.; Krewer, U. Operating envelope of Haber–Bosch process design for power-to-ammonia. *RSC Adv.* **2018**, *8*, 34926–34936. [CrossRef]
92. Zivar, D.; Kumar, S.; Foroozesh, J. Underground hydrogen storage: A comprehensive review. *Int. J. Hydrog. Energy* **2021**, *46*, 23436–23462. [CrossRef]
93. Toktarova, A.; Göransson, L.; Johnsson, F. Design of Clean Steel Production with Hydrogen: Impact of Electricity System Composition. *Energies* **2021**, *14*, 8349. [CrossRef]
94. Muhammed, N.S.; Haq, B.; Shehri, D.A.; Al-Ahmed, A.; Rahman, M.M.; Zaman, E. A review on underground hydrogen storage: Insight into geological sites, influencing factors and future outlook. *Energy Rep.* **2022**, *8*, 461–499. [CrossRef]
95. Hévin, G. Underground Storage of Hydrogen in Salt Caverns; Paris, France. 2019. Available online: https://energnet.eu/wp-content/uploads/2021/02/3-Hevin-Underground-Storage-H2-in-Salt.pdf (accessed on 26 August 2022).
96. Power, M. US DOE Closes $504.4 Million Loan to Advanced Clean Energy Storage Project for Hydrogen Production and Storage. Available online: https://power.mhi.com/regions/amer/news/20220609 (accessed on 9 June 2022).
97. Gessel, S. Underground Hydrogen Storage; Geneva, Switzerland. 2021. Available online: https://unece.org/sites/default/files/2021-04/09_Serge_van_Gessel-Hydrogen_Storage_and_UNFC-UNECE_RM_Week-2021.pdf (accessed on 26 August 2022).
98. RAG Austria A.G. *Underground Sun Conversion—Renewable Gas Produced to Store Solar and Wind Power*; RAG Austria AG: Vienna, Austria, 2018.
99. HyChico. Underground Hydrogen Storage. 2018. Available online: http://www.hychico.com.ar/eng/underground-hydrogen-storage.html (accessed on 26 August 2022).
100. Blanco, H.; Faaij, A. A review at the role of storage in energy systems with a focus on Power to Gas and long-term storage. *Renew. Sustain. Energy Rev.* **2018**, *81*, 1049–1086. [CrossRef]
101. Perez, A.; Pérez, E.; Dupraz, S.; Bolcich, J. Patagonia Wind—Hydrogen Project: Underground Storage and Methanation. Zaragoza, Spain. 2016. Available online: https://hal-brgm.archives-ouvertes.fr/hal-01317467/document (accessed on 26 August 2022).
102. Kruck, O.; Crotogino, F. *Benchmarking of Selected Storage Options*; KBB Underground Technologies GmbH: Hannover, Germany, 2013.
103. Patonia, A.; Poudineh, R. *Cost-Competitive Green Hydrogen: How to Lower the Cost of Electrolysers?* Oxford Institute for Energy Studies: Oxford, UK, 2022.
104. Service, R.F. Ammonia-a renewable fuel made from sun, air, and water—Could power the globe without carbon. *Science* **2018**. [CrossRef]
105. Smith, C.; Hill, A.K.; Torrento-Murciano, L. Current and future role of Haber–Bosch ammonia in a carbon-free energy landscape. *Energy Environ. Sci.* **2022**, *13*, 331–344. [CrossRef]

106. Giddey, S.; Badwal, S.; Munnings, C.; Dolan, M. Ammonia as a Renewable Energy Transportation Media. *ACS Sustainable Chem. Eng.* **2017**, *5*, 10231–10239. [CrossRef]
107. Ishimoto, Y.; Voldsund, M.; Neksa, P.; Roussanaly, S.; Berstad, D.; Gardarsdottir, S.O. Large-scale production and transport of hydrogen from Norway to Europe and Japan: Value chain analysis and comparison of liquid hydrogen and ammonia as energy carriers. *Int. J. Hydrog. Energy* **2020**, *45*, 32865–32883. [CrossRef]
108. Morlanés, N.; Katikaneni, S.P.; Paglieri, S.N.; Harale, A.; Solami, B.; Sarathy, S.M.; Gascon, J. A technological roadmap to the ammonia energy economy: Current state and missing technologies. *Chem. Eng. J.* **2021**, *408*, 127310. [CrossRef]
109. Frattini, D.; Cinti, G.; Bidini, G.; Desideri, U.; Cioffi, R.; Jannelli, E. A system approach in energy evaluation of different renewable energies sources integration in ammonia production plants. *Renew. Energy* **2016**, *99*, 472–482. [CrossRef]
110. Ottosson, A. *Integration of Hydrogen Production via Water Electrolysis at a CHP Plant—A Feasibility Study*; Lulea University of Technolog: Lulea, Sweden, 2021.
111. Cordonnier, J.; Saygin, D. *Green Hydrogen Opportunities for Emerging and Developing Economies*; OECD Publishing: Paris, France, 2022.
112. Egerer, J.; Grimm, V.; Niazmand, K.; Runge, P. *The Economics of Global Green Ammonia Trade—"Shipping Australian Wind and Sunshine to Germany"*; Elsevier: Erlangen, Germany, 2022. [CrossRef]
113. Lan, R.; Irvine, J.T.; Tao, S. Ammonia and related chemicals as potential indirect hydrogen storage materials. *Int. J. Hydrog. Energy* **2012**, *37*, 1482–1494. [CrossRef]
114. Rissman, J.; Bataille, C.; Masanet, E.; Aden, N.; Zhou, W.M., III; Elliott, N.; Dell, R.; Heeren, N.; Huckestein, B.; Cresko, J.; et al. Technologies and policies to decarbonize global industry: Review and assessment of mitigation drivers through 2070. *Appl. Energy* **2020**, *266*, 114848. [CrossRef]
115. Nilsson, L.; Bauer, F.; Ahman, M.; Andersson, F.; Bataille, C.; Can, S.R.; Ericsson, K.; Hansen, T.; Johansson, B.; Lechtenböhmer, S.; et al. An industrial policy framework for transforming energy and emissions intensive industries towards zero emissions. *Clim. Policy* **2021**, *21*, 1053–1065. [CrossRef]
116. OECD. *Framework for Industry's Net-Zero Transition: Developing Financing Solutions in Emerging and Develoing Economies*; OECD Publications: Paris, France, 2022.
117. Saygin, D.; Rigter, J.; Caldecott, B.; Wagner, N.; Gielen, D. Power sector asset stranding effects of climate policies. *Energy Sources Part B Econ. Plan. Policy* **2019**, *14*, 99–124. [CrossRef]
118. Warner, E.; Steinberg, D.; Hodson, E.; Heath, G. *Potential Cost-Effective Opportunities for Methane Emission Abatement*; The Joint Institute for Strategic Energy Analysis: Golden, CO, USA, 2015.
119. Balcombe, P.; Heggo, D.A.; Harrison, M. Total Methane and CO_2 Emissions from Liquefied Natural Gas Carrier Ships: The First Primary Measurements. *Environ. Sci. Technol.* **2022**, *56*, 9632–9640. [CrossRef]
120. Newborough, M.; Cooley, G. Green hydrogen: Water use implications and opportunities. *Fuel Cells Bull.* **2021**, *2021*, 12–14.
121. IRENA. *Global Hydrogen Trade to Meet the 1.5 °C Climate Goal: Part III—Green Hydrogen Cost and Potential*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2022.
122. Hasanbeigi, A.; Nilsson, A.; Mete, G.; Fontenit, G.; Shi, D. *Fostering Industry Transition through Green Public Procurement: A "How to" Guide for the Cement & Steel Sectors*; LeadIT: Stockholm, Sweden; UNIDO: Vienna, Austria; CEM: Paris, France, 2021.
123. George, J.F.; Müller, V.P.; Winkler, J.; Ragwitz, M. Is blue hydrogen a bridging technology?—The limits of a CO2 price and the role of state-induced price components for green hydrogen production in Germany. *Energy Policy* **2022**, *167*, 113072. [CrossRef]
124. Al-Qahtani, A.; Parkinson, B.; Hellgardt, K.; Shah, N.; Guillen-Gosalbz, G. Uncovering the true cost of hydrogen production routes using life cycle monetization. *Appl. Energy* **2021**, *281*, 115958. [CrossRef]
125. OECD/IEA. Global Average Levelised Cost of Hydrogen Production by Energy Source and Technology, 2019 and 2050. 2020. Available online: https://www.iea.org/data-and-statistics/charts/global-average-levelised-cost-of-hydrogen-production-by-energy-source-and-technology-2019-and-2050 (accessed on 5 August 2022).
126. Parkinson, B.; Balcombe, P.; Speirs, J.; Hawkes, A.; Hellgardt, K. Levelized cost of CO_2 mitigation from hydrogen production routes. *Energy Environ. Sci.* **2019**, *12*, 19–40. [CrossRef]
127. IRENA. *Green Hydrogen Cost Reduction*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2020.
128. IRENA. *Renewable Power Generation Costs in 2021*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2022.
129. IRENA. *Renewable Power Generation Costs 2020*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2021.
130. The World Bank. Global Solar Atlas. 2022. Available online: https://globalsolaratlas.info/map?c=11.609193,8.4375,3 (accessed on 5 August 2022).
131. The World Bank. Global Wind Atlas. 2022. Available online: https://globalwindatlas.info/en (accessed on 5 August 2022).
132. Saygin, D.; Gielen, D.J.; Draeck, M.; Worrell, E.; Patel, M.K. Assessment of the technical and economic potentials of biomass use for the production of steam, chemicals and polymers. *Renew. Sustain. Energy Rev.* **2014**, *40*, 1153–1167. [CrossRef]
133. Spath, P.L.; Mann, M.K. *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming*; National Renewable Energy Laboratory: Golden, CO, USA, 2001.
134. Rouwenhorst, K.H.; Ham, A.G.; Mul, G.; Kersten, S.R. Islanded ammonia power systems: Technology review & conceptual process design. *Renew. Sustain. Energy Rev.* **2019**, *114*, 109339.

135. OECD. Long-Term Interest Rates. 2022. Available online: https://data.oecd.org/interest/long-term-interest-rates.htm (accessed on 5 August 2022).
136. Trading Economics. Credit Rating. 2022. Available online: https://tradingeconomics.com/country-list/rating (accessed on 5 August 2022).