FINAL REPORT

STUDY ON THE ECONOMICS OF THE GREEN HYDROGEN INTERNATIONAL SUPPLY CHAIN

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Executive Summary

Japan needs large amounts of hydrogen in order to decarbonize its energy system by 2050. As domestic resources for hydrogen are presumably limited in Japan, hydrogen will need to be imported. There is a variety of options for importing hydrogen, in terms of potential exporting countries and hydrogen resources. Japan has carried out or is currently carrying out demonstration projects for the establishment of international hydrogen supply chains with Australia, Brunei and Saudi Arabia, and forging dialogues on future collaboration with other countries like Argentina and Russia. Chile would also be a promising candidate as an exporter of hydrogen to Japan, as its renewable energy potential, including solar and wind power, is huge and its renewable energy costs are substantially low.

This study reveals the costs and carbon footprint across the whole green and blue hydrogen supply chains from potential suppliers to Japan; green hydrogen from Australia, Chile and the USA and blue hydrogen from Australia and Saudi Arabia.

When using liquified hydrogen or methylcyclohexane as the hydrogen carrier, the cost of green hydrogen from Chile is the lowest among green hydrogen supply chains and can also compete with blue hydrogen supply chains if the electrolyzer cost is reduced to a third of today's level, which is expected to be realized internationally by 2030. However, in the case of using ammonia as the hydrogen carrier, the cost of blue ammonia from natural gas of Saudi Arabia is the lowest. Assuming a carbon price of $100/t-$CO_2$ is imposed, Chilean green hydrogen by means of liquified hydrogen or methylcyclohexane becomes a more attractive option for Japan, as the carbon footprint of green hydrogen is much smaller than blue hydrogen, while the cost advantage of blue ammonia from natural gas still remains due to the lower production cost.

In order for green hydrogen to be even more attractive, production costs should be further reduced by, for example, elevating the capacity factor of electrolyzers through smoothing the power input by combining solar and wind. Another option would be employing electrolyzers, not only for producing hydrogen from renewable energy, but also as a grid service provider through demand response, which in turn will reduce the hydrogen production cost by remuneration from the grid services. If ammonia is selected as the hydrogen carrier for early-stage long-distance hydrogen transportation to Japan, green ammonia production technologies that can cope with variable input from renewable energy should be further developed.

However, it should be noted that possible applications of ammonia are rather limited, such as power generation and shipping fuels. For the decarbonization of the energy system, sectors such as industry and mobility bear crucial roles. Hydrogen transported in the form of liquified hydrogen or methylcyclohexane can contribute to decarbonization of these sectors.

In addition to green hydrogen exports, domestic hydrogen applications in the exporters should also be addressed, as these can help decarbonize the exporter's energy system and develop related-industries including fuel cell that are expected to contribute to mobility and stationary combined heat and power. Furthermore, it should also be remembered that storing hydrogen over long periods is much easier than storing electricity in batteries, thus giving hydrogen high potential for seasonal storage. This characteristic allows hydrogen to be a key mechanism for facilitating integration of higher shares of renewable energy into power grids that are isolated from the national grid system. Hydrogen will bear an important role in improving national energy security, securing a stable energy supply and enhancing resiliency in a decarbonized manner by stockpiling renewable energy.

From Japan's point of view, critical aspect other than hydrogen cost is energy security, which is often overshadowed by decarbonization discussions, despite its significance for Japan, as it depends heavily on energy supply from overseas. Green hydrogen promises to play a significant role in improving Japan's energy security by diversifying its energy supply resources, especially in geographical terms. For example, Chile's location in the APAC region can alleviate concerns over sea lane security. This study revealed that the shipping cost of hydrogen/ammonia does not have a significant impact on the overall supply cost, and thus the disadvantage of the long-distance transportation of hydrogen/ammonia to Japan is limited.

Collaboration between Japan and hydrogen exporters in establishing an international hydrogen supply chain and developing domestic applications of hydrogen will open windows of more concrete business opportunities. Areas for government to government cooperation and business matching, along with experience-sharing may be explored through in-depth discussions among stakeholders, including government, academia, businesses, and financial institutions. Such actions will eventually contribute to the development of the international hydrogen/ammonia market.

CHAPTER 1. BACKGROUND AND OBJECTIVES OF STUDY

Discussions on how Japan should procure hydrogen started in 2012, one year after the Great East Japan Earthquake. It was when Japan was faced with challenges in decarbonizing its energy system, especially its electric power system, given issues with nuclear power generation and difficulties in rapidly deploying renewable energy. Since then, Japan has been accelerating its efforts to procure affordable hydrogen from abroad. The Japanese government and private sector have recently been jointly negotiating with oil & gas and coal producing countries to import blue hydrogen. The then Prime Minister Suga's announcement of Japan's goal to achieve carbon neutrality in 2050 has increased the importance of hydrogen import and has thus added momentum to actions taken toward importing hydrogen.

In general, blue hydrogen is regarded inexpensive for the moment. However, blue hydrogen entails inherently challenging issues: the carbon footprint of blue hydrogen is larger than that of green hydrogen, international pressures on fossil fuel use is being strengthened, and blue hydrogen will not contribute to improving Japan's energy security if it is imported from the same oil & gas producing countries from which Japan currently imports fossil fuels. Given these challenges pertaining to blue hydrogen, green hydrogen is a promising alternative. For example, Chile has huge potential for green hydrogen production from renewable energy at the lowest cost in the world[1]. Furthermore, its geographical location in the APAC region, like Australia and the USA, will contribute to improving Japan's energy security through the diversification of hydrogen supply chains, avoiding heavy dependence on oil & gas producing countries.

This study will reveal the costs and carbon footprint across entire green hydrogen supply chains from potential suppliers to Japan and discuss their potential advantages, as well as the challenges to be addressed by comparison with blue hydrogen supply chains.

[1] "The Future of Hydrogen", IEA, 2019

CHAPTER 2. SCOPE OF STUDY AND METHODOLOGY

The green hydrogen resources considered in this report are solar photovoltaics and wind power. The green hydrogen producing countries addressed are Chile, Australia and the USA. For blue hydrogen, the resources considered are natural gas and coal and the producing countries are Saudi Arabia and Australia (Table 1).

TABLE 1. SCOPE OF HYDROGEN EXPORTING COUNTRIES AND RESOURCES

	Country	Resources for hydrogen
Green H_2	Chile	Solar PV and wind
	Australia	Solar PV and wind
	USA	Solar PV and wind
Blue H_2	Saudi Arabia	Gas
	Australia	Gas and coal

Note: Ammonia is included in hydrogen.

The hydrogen supply chain from the exporting country to Japan covers hydrogen production, domestic transportation in resource countries (hydrogen pipeline), conversion to hydrogen carriers, export ports, international shipping, receiving ports, and reconversion in Japan. Liquefied hydrogen (LH_2), methylcyclohexane (MCH) and ammonia (NH_3) have been selected as hydrogen carriers. This study assumes reconversion is not needed for liquefied hydrogen, but needed for MCH (dehydrogenation) and NH_3 (cracking). On the other hand, In Japan's strategy to achieve carbon neutrality, NH_3 has both the role of a hydrogen carrier and a clean fuel for power generation, either co-fired with coal or 100% NH_3 combustion. For this reason, the case in which the reconversion of NH_3 is unnecessary is also addressed.

For NH_3 production this study assumes two conditions. If the hydrogen for NH_3 production comes from green hydrogen or hydrogen produced with brown coal + CCS, the study assumes hydrogen production and NH_3 conversion (Haber-Bosch process) separately (Figure 1). However, since the process of NH_3 production from natural gas is already a mature and widely-used technology, the study assumes hydrogen production and NH_3 production are integrated in the case of blue NH_3 production from natural gas (Figure 2).

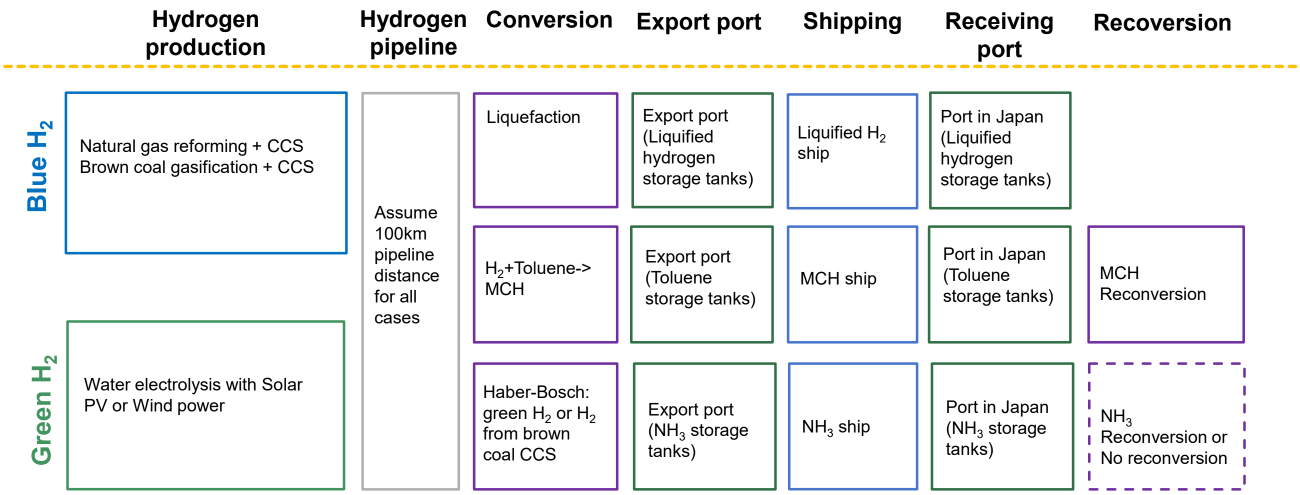


FIGURE 1. HYDROGEN SUPPLY CHAIN

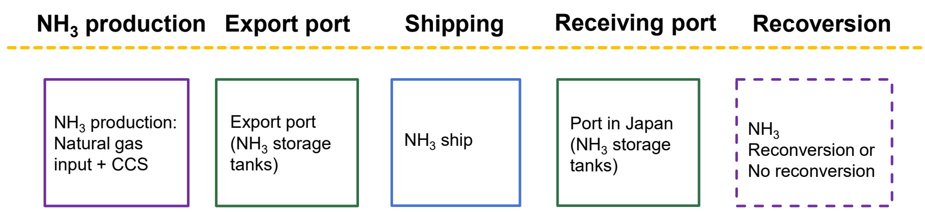


FIGURE 2. BLUE AMMONIA SUPPLY CHAIN WITH NATURAL GAS AS FEEDSTOCK

To compare the economics and GHG emission (CO_2 equivalent: CO_2eq) among different supply chains, this study assumed the same scale of hydrogen production for each supply chain: 225,000 tons of hydrogen production per year, which is equivalent to the annual volume of hydrogen to be used for 1 GW of hydrogen-fired gas turbine power generation. The study uses 2030 as the reference year for evaluating the economics and GHG emissions.

Hydrogen supply costs are impacted by many factors. Engineering details associated with each process of the hydrogen supply chain are not included within the scope of this study. The figures presented in this study only indicate one possible case under certain assumptions; and therefore, the hydrogen supply cost and GHG emissions of the hydrogen supply chain in a real case could be different from the study's evaluation results. However, the assumptions used in this study have been derived from reliable sources: IEA, government studies, etc.

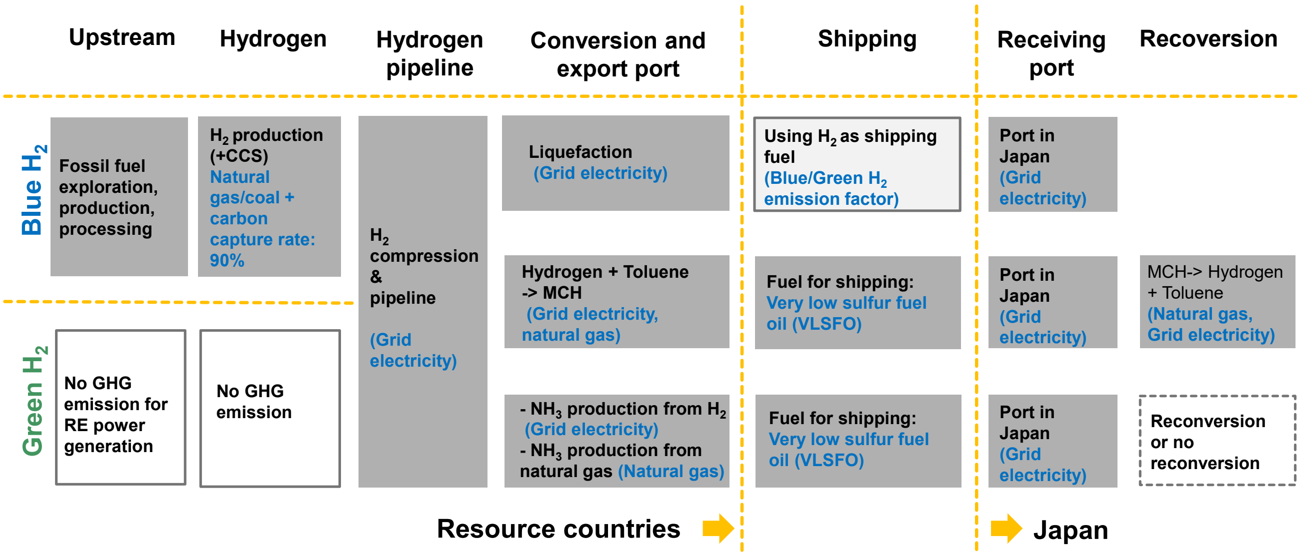


FIGURE 3. HYDROGEN SUPPLY CHAIN & GHG EMISSION EVALUATION FLOW AND EMISSION SOURCES FOR EACH PROCESS

This study will identify GHG emissions from the entire hydrogen supply chain (Figure 3). However, it should be noted that this does not mean that this study has conducted a life-cycle GHG (LCGHG) assessment that includes GHG emissions from the manufacturing process of all equipment and facilities across the supply chain. LCGHG assessments often complicate the interpretation of analysis results when international comparisons are involved. For the sake of simplicity and maintaining clear messages from analysis results, this study includes GHG emissions from the individual processes across the hydrogen supply chain. Upstream fugitive emissions also include methane, which is converted to CO_2 equivalent.

Chapter 3. Major findings

Based on the methodology above, the supply cost to Japan ($/kg-$H_2$) and the carbon footprint of green and blue hydrogen (kg-CO_2eq/kg-H_2) are compared among different supply chains.

This study considers two major cases for the economic evaluation of hydrogen supply chains. The difference between the two cases lies in the assumptions for the electrolyzer cost: $700/kW for the Base Case, and $336/kW for the Low Electrolyzer Cost Case (today's cost is $900/kW). The technology for blue hydrogen production is already mature and thus has limited potential for cost reduction. On the other hand, electrolyzers have much room for further cost reduction. However, there is much uncertainty involved with the cost reduction of electrolyzers, which is impacted by many factors, and therefore, this study considers two cases for future electrolyzer costs. In addition to these two cases, a case considering a carbon price under the Low Electrolyzer Cost Case is also included in order to analyze economic implications of carbon footprint differences.

3.1. Economics of hydrogen supply chain

Figure 4 shows the hydrogen supply cost for each supply chain. In case of NH_3, ammonia is assumed to be cracked into hydrogen so as to compare different hydrogen carriers at level playing field. Looking at LH_2 as hydrogen carrier, Chile_Wind ($4.8/kg-$H_2$) is the most competitive among green hydrogen supply chains, followed by Chile_PV ($5.1/kg-$H_2$) for the Base Case. Only green hydrogen from Chile_Wind can compete with blue hydrogen from Australia (AUS_CoalCCS and AUS gasCCS), while blue hydrogen from Saudi Arabia is the least expensive. If the electrolyzer cost is reduced by half (Low Electrolyzer Cost Case), the supply cost of green hydrogen from Chile (Chile_Wind and Chile_PV) can be curbed to $4.5/kg-$H_2$, which is lower than blue hydrogen from Australia ($4.8~4.9/kg-$H_2$), but still higher than Saudi_GasCCS ($4.1/kg-$H_2$).

Lower elyctrolyzer cost allows green hydrogen supply options to be more competitive than blue hydrogen. Not only green hydrogen from Chile, but also green hydrogen from Australia (AUS_PV) can be cheaper than blue hydrogen from Australia. However, green hydrogen production costs exhibit different sensitivity to electrolyzer costs due to the difference in renewable energy capacity factors. Electrolyzer CAPEX has less impact on hydrogen production cost when the capacity factor is higher.

The relative relationship among hydrogen supply costs of different supply chains using MCH as the hydrogen carrier is observed not to differ largely from that for LH_2. However, in the case of NH_3, the supply cost of green ammonia from Chile in the Low Electrolyzer Cost ($3.7~3.8/kg-$H_2$) case remains higher than that of blue ammonia from Saudi Arabia (Saudi_GasCCS: $2.8/kg-$H_2$) and Australia (AUS_GasCCS: $3.3/kg-$H_2$). As blue ammonia production from natural gas is a mature technology with optimized processes, the production cost of blue NH_3 from natural gas is lower than that of green NH_3 or of blue NH_3 produced from coal.

With regard to comparisons among different hydrogen carriers (LH_2, MCH and NH_3) for green hydrogen, MCH (ranging from \$3.7/kg-H_2 to 4.8/kg-H_2 for the Base Case and \$3.4/kg-H_2 to 4.2/kg-H_2 for the Low Electrolyzer Cost Case) is the most competitive option due to lower conversion costs and shipping costs for MCH (even if reconversion is included).

If ammonia is assumed to be directly used for power generation, either co-firing with coal-fired power plants or 100%-ammonia gas turbines[2], there is no need to crack ammonia into hydrogen at the import terminal, then the supply cost can be reduced. Figure 5 shows the ammonia supply cost without cracking (reconversion). The least expensive green NH_3 is \$2.9/kg-H_2 of Chile_wind and Chile_PV for the Low Electrolyzer Cost Case, which is cheaper than blue ammonia of AUS_coalCCS, while more expensive than the blue ammonia of Saudi_gasCCS.

When taking a closer look at the shipping cost, as Chile is located farthest from Japan among the countries addressed in this study, the longer transportation distance of hydrogen/ammonia may arise concerns of larger shipping costs. However, this study reveals that the shipping cost of hydrogen/ammonia accounts for a limited percentage of the whole supply cost; and therefore, the longer distance between Chile and Japan does not cause much disadvantage.

[2] 100%-ammonia gas turbines in fact can be regarded as 100%-hydrogen gas turbines that crack ammonia into hydrogen by exhaust heat from gas turbines, then the hydrogen is fed into gas turbines.

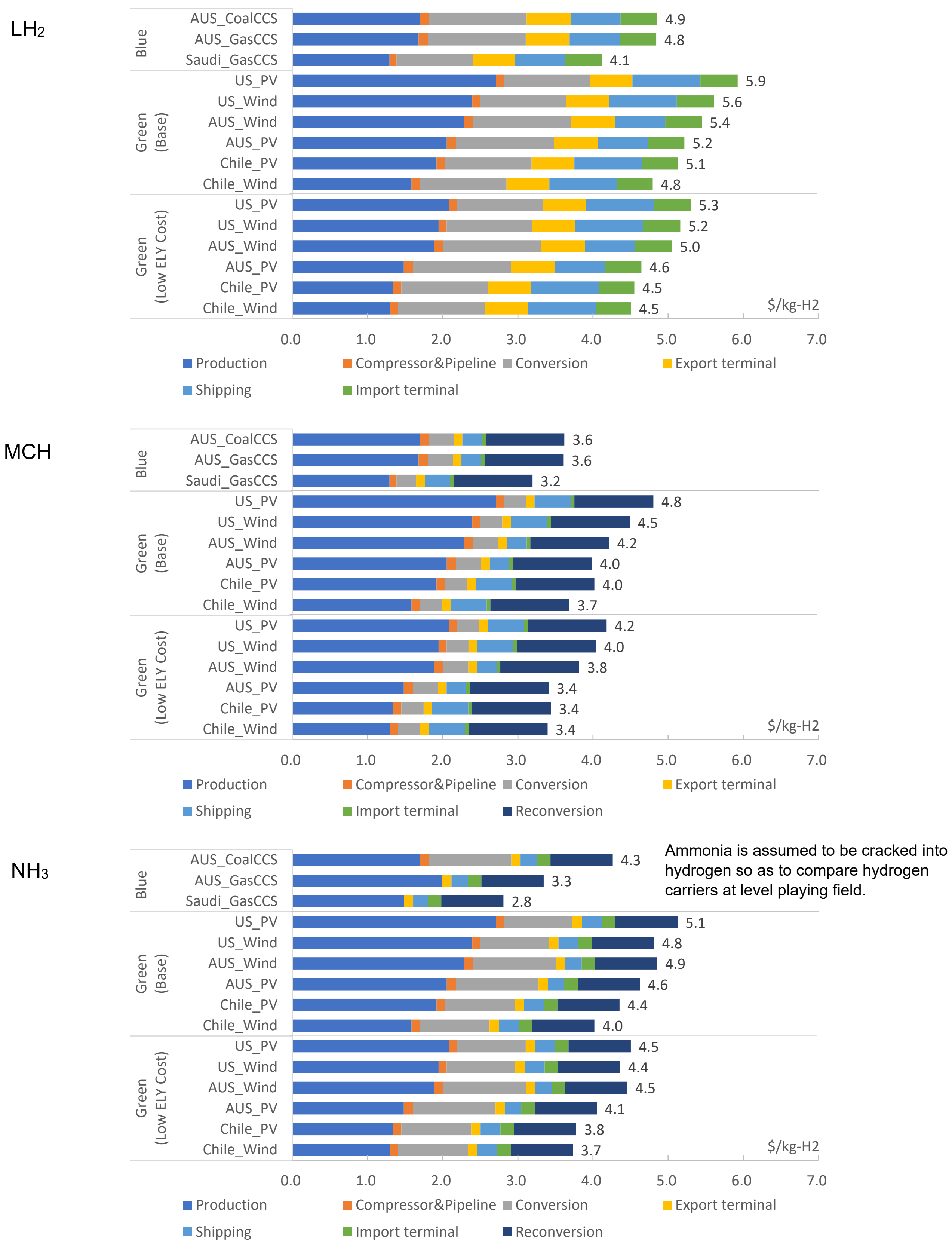


FIGURE 4. HYDROGEN SUPPLY COST

Note: "Base" stands for Base Case and "Low ELY Cost," for Low Electrolyzer Cost Case.

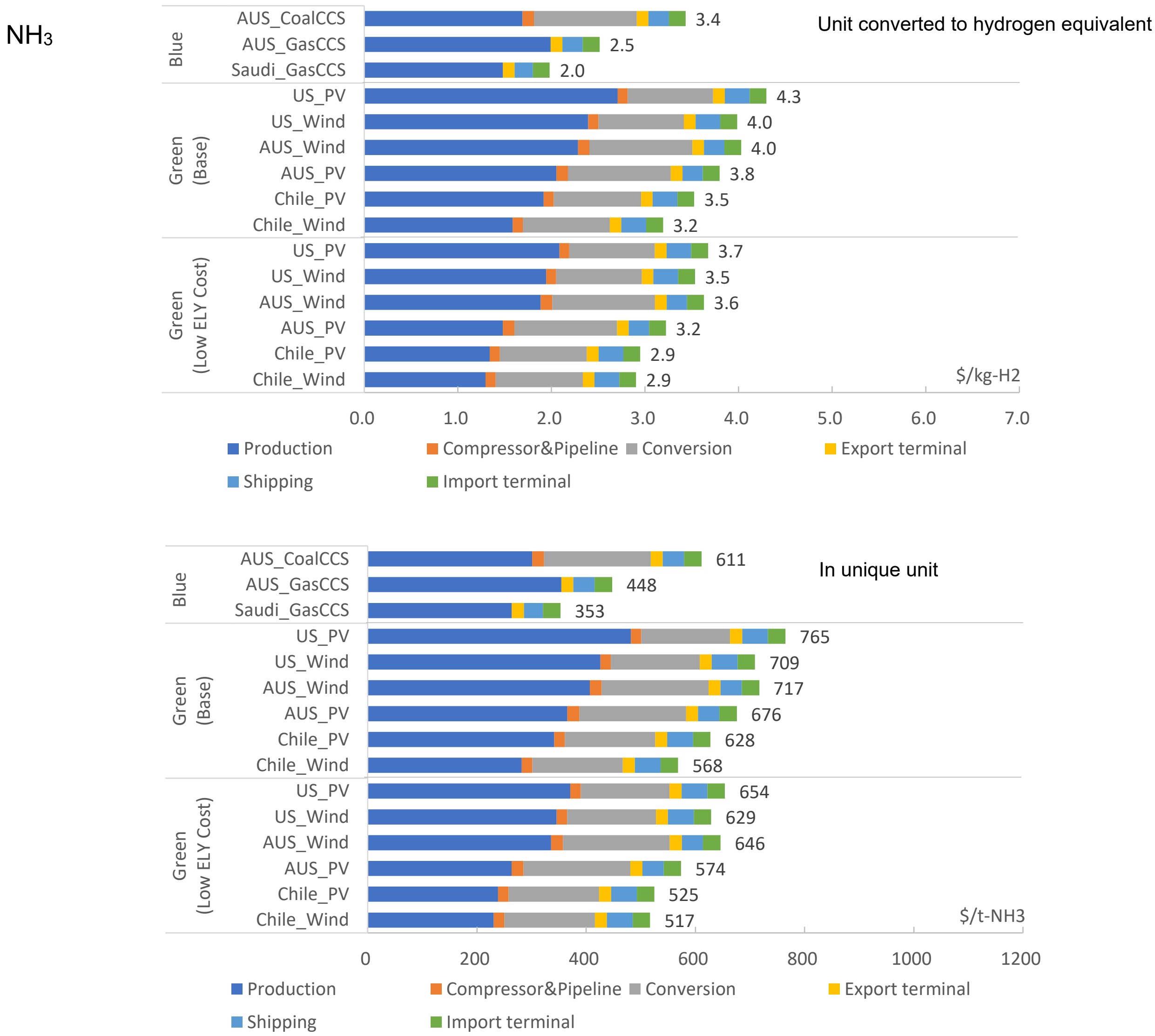


FIGURE 5. AMMONIA SUPPLY COST (WITHOUT CRACKING)

Note: "Base" stands for Base Case and "Low ELY Cost," for Low Electrolyzer Cost Case.

3.2. Economics of Hydrogen Supply Chain Including Carbon Footprint

The carbon footprint of each hydrogen supply chain is shown in Figure 6. As with the economics of hydrogen supply, the carbon footprint of hydrogen supply chain is affected by many factors. In general, the green hydrogen supply chain exhibits smaller carbon footprint than that of blue hydrogen due to lower GHG emissions from the hydrogen production process. However, GHG emissions associated with other processes also constitute a large part total GHG emissions from the hydrogen supply chain. For example, the conversion processes of LH_2 and NH_3 are electricity intensive. This study assumes that the electricity input for conversion comes from the grid, and as a result in countries with lower grid emission factors[3], such as Chile, the conversion process involves lower GHG emissions. Furthermore, since the study assumes that 90% of GHG emissions associated with blue NH_3 production is captured, in some cases, the blue NH_3 supply chain can involve less GHG emissions compared even to green NH_3 (from the US and Australia) .

With regard to comparisons among different hydrogen carriers (LH_2, MCH and NH_3), LH_2 exhibits the lowest carbon footprint due partly to the fact that hydrogen is used for driving the shipping while others are assumed to be driven by heavy fuels, and partly to the fact that reconversion process is not needed. If ammonia is assumed to be cracking-free (reconversion-free), its carbon footprint can be reduced.

[3] Grid emission factor is calculated based on the expected power generation mix of 2030. The power generation mix is derived from published literature.

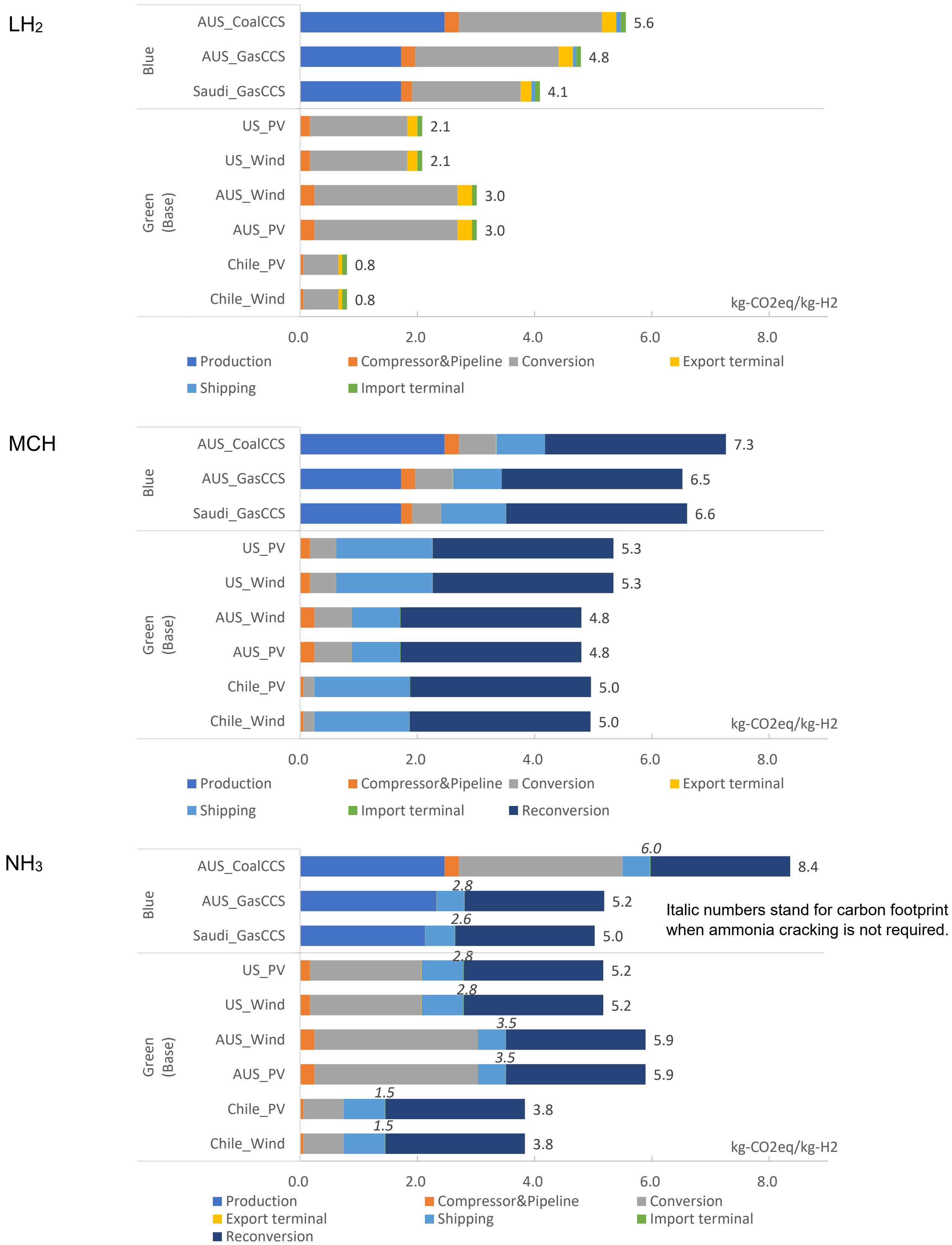


FIGURE 6. CARBON FOOTPRINT (GHG EMISSION) OF HYDROGEN SUPPLY CHAIN

In the GHG emissions evaluation of the supply chain, fugitive GHG emissions associated with fossil fuel exploration and production are also included. However, due to a lack of reliable information, this study applies the calculated average fugitive emissions factor of coal mining and natural gas systems (exploration, production, and processing) in the United States to all cases. The U.S.' average emission factor has been calculated based on the U.S. Environmental Protection Agency's GHG emissions report[4] and statistics for natural gas[5] and coal production[6]. Upstream GHG emissions are dependent on case-specific factors and further studies will be required to evaluate the emission more correctly and precisely.

With more and more countries committed to carbon neutrality and considering placing a price on GHG emissions, GHG emissions associated with the hydrogen supply chain could translate into economic costs. To see how the carbon cost, if introduced[7], can impact the economics of hydrogen supply, the study assumed a carbon cost of \$100/t-CO_2 to be added to the hydrogen supply chain (Figure 7) and ammonia supply chain (Figure 8). Adding a carbon price results in higher hydrogen supply costs for both green hydrogen and blue hydrogen. However, the carbon cost associated with blue hydrogen is larger than that of green hydrogen. Therefore, when a carbon cost is considered, green hydrogen from Chile (Chile_Wind and Chile_PV) for the Low Electrolyzer Cost Case can compete with the cheapest blue hydrogen from Saudi Arabia in the case of LH_2 and MCH. However, when the hydrogen carrier is NH_3, the cost of green ammonia from Chile remains higher than blue ammonia from Saudi Arabia (Saudi_gasCCS) and Australia (AUS_gasCCS).

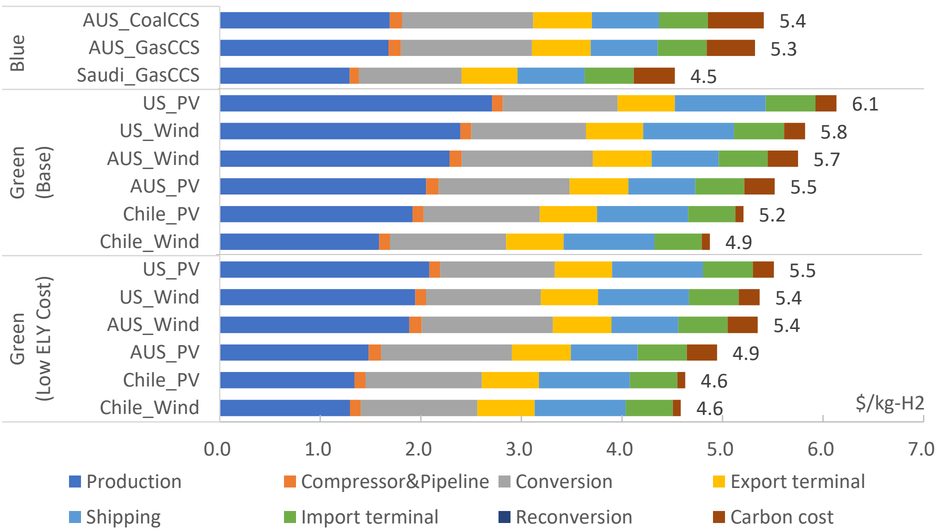
[4] United States Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019, https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-main-text.pdf?VersionId=wEy8wQuGrWS8Ef_hSLXHy1kYwKs4.ZaU

[5] Natural gas production data from U.S. Energy Information Administration (EIA): https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FPD_mmcf_a.htm

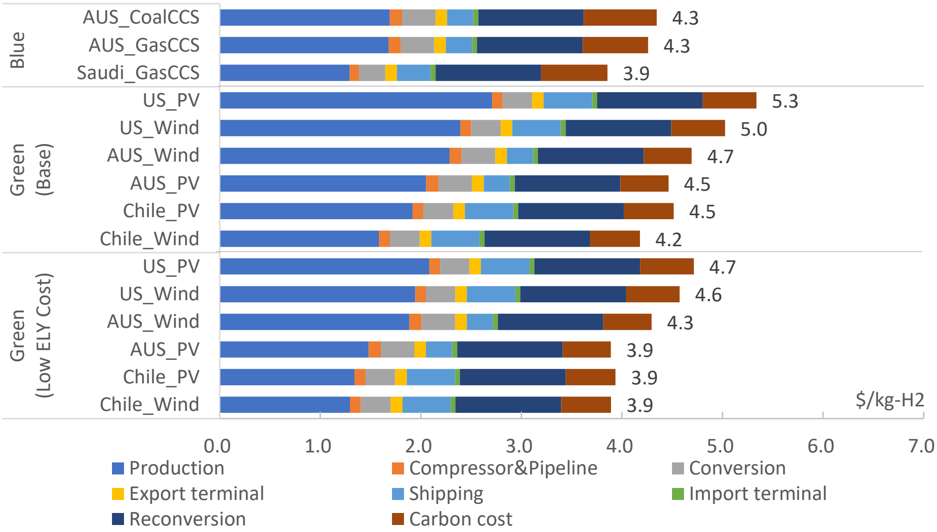
[6] Coal production data is also in the same EPA report

[7] This report stands neutral with regard to Japan's policy decision on carbon price. Carbon cost of \$100/t-CO_2 is assumed purely for the purpose of economic analysis to take into account carbon footprint differences.

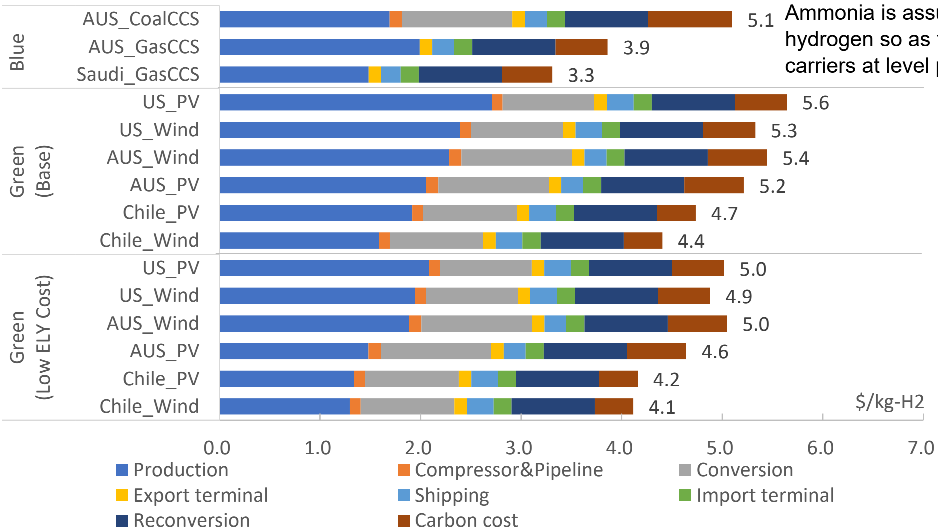
LH_2



MCH



NH_3



Ammonia is assumed to be cracked into hydrogen so as to compare hydrogen carriers at level playing field.

FIGURE 7. HYDROGEN SUPPLY COST INCLUDING CARBON COST

Note: The carbon price is assumed to be \$100/t-CO_2.

NH3

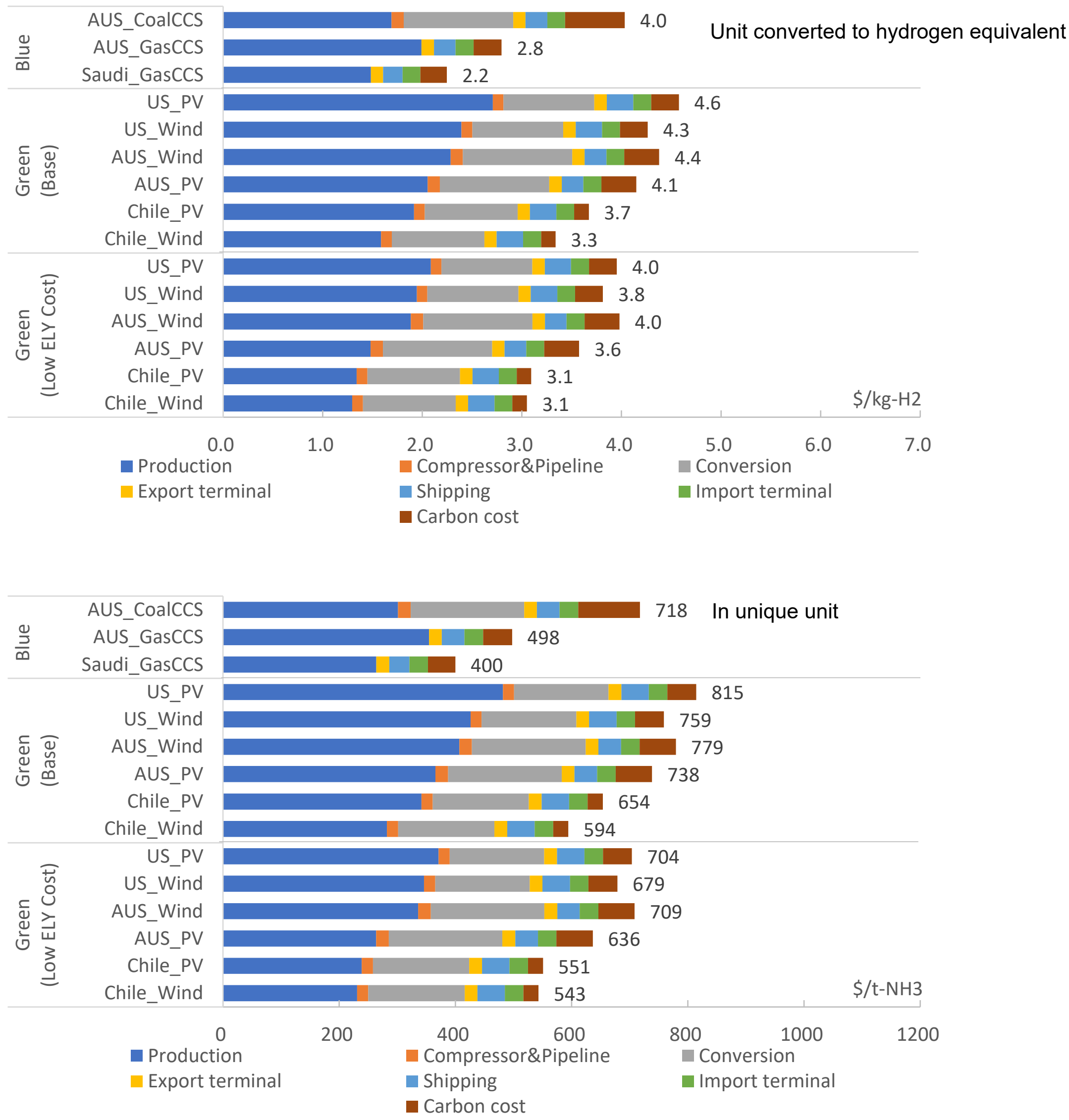


FIGURE 8. AMMONIA SUPPLY COST INCLUDING CARBON COST (WITHOUT CRACKING)

Note: The carbon price is assumed to be $100/t-$CO_2$.

3.3. Issues in Analyses

It should be noted that there are uncertainties in the assumptions made in this study (See Appendix). For example, blue hydrogen/ammonia is assumed to be produced with an additional cost for CCS with a carbon capture rate of 90%. This can be realized in steam methane reforming of gas for blue hydrogen. However, in the case of blue ammonia, the current carbon capture rate for the entire blue ammonia production from gas is, in general, 50% to 60%[8]. Hence the assumption for blue ammonia may be too optimistic. If a carbon capture rate of 90% is sought for all blue ammonia production, costs could be higher. On the other hand, in terms of green ammonia production, this study assumes the same process as blue ammonia production from gas. However, the large-scale and constant operation assumed for this process is not appropriate for variable input from renewable energy. To realize green ammonia production costs of the same level as blue ammonia, technology development for coping with variable input is necessary.

[8] 70% of CO_2 emissions come from the main (intensive) process and 30% from the remaining (distributed) process. Therefore, if the carbon capture rate of the main process is assumed to be 90%, the whole capture rate will be around 60%.

Chapter 4. Recommendations

4.1 Potential hydrogen demand in Japan

Under the Green Growth Strategy[9], Japan seeks to create hydrogen demand of 3 million tons in 2030 and 20 million tons in 2050[10]. Commercial vehicles, including fuel cell (FC) trucks and hydrogen-powered ships will be introduced through 2030. In the power sector, stationary fuel cells and small-scale hydrogen turbines will be locally introduced in the short term, with an aim to install large-scale hydrogen gas turbines in around 2030, when a commercially viable hydrogen supply chain has been established globally. Pilot projects to decarbonize manufacturing processes using clean hydrogen will be continued through 2030.

During the transition to a hydrogen economy, fuel ammonia will be first used for co-firing at existing coal-fired power plants[11]. To this end, the demonstration project in Chubu-area is expected to be completed around 2025. Therefore, Japan will need to rely on ammonia imports to decarbonize its fuel supply in the short to medium term.

In the industry, commercial and household sectors, fossil fuels will be replaced with hydrogen for heat demand by installing either hydrogen burners/boilers for industrial use or fuel cells and boilers for commercial and residential use, as well as through newly built pipeline distribution of hydrogen or through delivery of synthetic methane produced from hydrogen by the existing city gas pipeline. Given limited domestic resources, clean hydrogen imports will be key to mainstreaming hydrogen in Japan.

While it is true that Japan needs to import hydrogen, it should be noted that Japan's energy security cannot be improved if hydrogen is imported from the countries from which Japan is currently importing fossil fuels. In this sense, green hydrogen from for example Chile promises to play a significant role in improving Japan's energy security through diversifying its energy supply resources, especially in terms of its geographical location in the APAC region, which can alleviate concerns over sea lane security. The longer distance between Chile to Japan compared to other hydrogen/ammonia supply chains may arise concerns of larger shipping costs. However, this study reveals that the shipping cost of hydrogen/ammonia does not have a significant impact on the overall supply cost, Therefore, the disadvantages of the longer-distance transportation of hydrogen/ammonia from Chile to Japan is limited.

From the viewpoint of hydrogen carriers, this study has found that MCH is the most competitive option due to lower conversion costs and shipping costs for MCH even if reconversion is included. If it is assumed that NH_3 does not need reconversion (cracking) to hydrogen, NH_3 is the less expensive option through 2030. However, it should be noted that possible applications of ammonia are rather limited, such as power

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[9] Ministry of Economy, Trade and Industry (2020) *Green Growth Strategy Through Achieving Carbon Neutrality in 2050*, https://www.meti.go.jp/english/press/2020/pdf/1225_001b.pdf

[10] Domestic hydrogen demand for large-scale power generation is estimated to be 5-10 million tons per year. Around 6 million tons will be needed to fuel commercial vehicles such as FC trucks, and 7 million tons, for green steel.

[11] For example, if 20% co-firing is implemented at all coal-fired thermal power plants in Japanese major power companies, an estimate of about 10% of CO_2 emissions from the domestic electric power sector will be reduced.

generation and shipping fuels. In fact, Japan aims to use ammonia first for co-firing with coal-fired power generation where toxic ammonia can be centrally managed and controlled. If ammonia is to be used for distributed applications, such as industrial heat or fuel cells, the process of ammonia cracking to hydrogen will be required; and this may result in raising the supply cost. Hence, attention should be paid to the fact that ammonia can be used only for rather limited applications, while Japan needs hydrogen for other sectors as well, including high temperature industrial heat demand and mobility. For these applications, hydrogen imported by means of MCH and LH_2 can be candidates. Selection of hydrogen carriers should be discussed based on hydrogen applications.

4.2 Enabling the hydrogen economy in Green Hydrogen Exporters

According to the economic analysis herein of hydrogen exports to Japan, the prices of green hydrogen are still higher than Japan's target price, which is JPY30/Nm^3-H_2[12] in 2030 and JPY20/Nm^3-H_2[13] beyond 2030[14]. However, potential reductions in hydrogen shipping costs are heavily dependent on future developments in LH_2 and MCH technologies in Japan. Furthermore, ammonia shipping technology has almost reached maturity. Hence, further reductions in overall costs to meet Japan's target will call for lower green hydrogen production costs in producing countries.

Specific measures to reduce costs of green hydrogen production from electrolyzers should be established. Points that should be highlighted are how the power inputs to electrolyzers can be smoothed and how electrolyzers can be employed as grid service providers. This study assumed solar PV and wind separately as sources of green hydrogen/ammonia. However, in reality, smoothed power input to electrolyzer from a combination of solar PV and wind can be an option, thus contributing to elevating the capacity factor of electrolyzers and leading to lower hydrogen production costs. To make this happen, the optimal power supply from a combination of solar PV and wind should be identified, taking account of geographical location. Another option to improve the capacity factor of electrolyzers may be using grid electricity. This would involve optimizing the electrolyzer operation pattern to minimize the hydrogen production cost based on two factors: the power procurement cost and capacity factor. By expanding the operating capacity of electrolyzers at during the hours when the wholesale power price is low (i.e. when the share of renewable electricity is high), and *vice versa*, the hydrogen production cost can be minimized and the use of renewable electricity can be maximized. However, it should be noted that the carbon footprint of hydrogen depends on the power generation mix. Above all, electrolyzers can be used for LFC

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[12] USD3/kg-H_2 = USD0.47/kg-NH_3
[13] USD2/kg-H_2 = USD0.31/kg-NH_3
[14] Hydrogen and Fuel Cell Strategy Council (2019) *The Strategic Road Map for Hydrogen and Fuel Cells - Industry-academia-government action plan to realize a "Hydrogen Society" –* (https://www.meti.go.jp/english/press/2019/pdf/0312_002b.pdf)

(Load Frequency Control) through demand response. This will allow electrolyzer costs to be compensated by providing grid services, thus leading to reducing hydrogen production cost.

In addition to the measures above, cost reductions in green hydrogen production can be pursued by advancing production technology development. However, scaling up electrolyzer capacity should be accompanied by increased domestic application. The domestic use of hydrogen will also contribute to decarbonizing the energy system of green hydrogen exporters. Increased demand in the industrial, transport and household sectors may enable the achievement of economies of scale. Formulating a roadmap for domestic applications and thus presenting policy direction will facilitate the uptake of such technologies.

Furthermore, it should also be remembered that storing hydrogen over long periods is much easier than storing electricity in batteries, thus giving hydrogen high potential for seasonal storage. This characteristic allows hydrogen to be a key mechanism for facilitating integration of higher shares of renewable energy into power grids that are isolated from the national grid system. Hydrogen will bear an important role in improving national energy security, securing a stable energy supply and enhancing resiliency in a decarbonized manner by stockpiling renewable energy.

4.3 Potential areas of collaboration between Japan and Exporters

Various solutions can be explored through bilateral cooperation and other forms of collaboration among various players in Japan and green hydrogen exporters. Channels for cooperation should be sought across the entire supply chain, covering hydrogen production, transport, storage and application.

As one of the first countries in the world that formulated a hydrogen strategy and roadmap, Japan can offer its support in designing a roadmap for hydrogen deployment in green hydrogen exporters. Clear political will promises to attract foreign investment in target areas.

Hydrogen transport and energy carrier technologies, as well as port infrastructure technologies are important areas for collaboration between Japan and green hydrogen exporters. In addition to realizing future exports of green hydrogen to Japan, collaboration should be sought in the domestic application of hydrogen as an option for decarbonizing the domestic energy system. Some proposed areas for collaboration are, as aforementioned, harnessing electrolyzers for smoothing the increased fluctuation caused by the integration of solar PV and wind power into the power grid. In Japan, such technologies are currently being tested in several demonstration projects, including the Fukushima Hydrogen Energy Research Field (FH2R), which aims to balance supply and demand in the power grid while establishing low-cost green hydrogen production technology.[15]

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[15] NEDO (2020) “The world's largest-class hydrogen production, Fukushima Hydrogen Energy Research Field (FH2R) now is completed at Namie town in Fukushima” Press release (March 7, 2020) (https://www.nedo.go.jp/english/news/AA5en_100422.html)

Regarding ammonia production, Harber-Bosch process was originally designed for constant operation and large-scale production. However, technologies for ammonia production based on variable input from renewable energy is currently being developed in Japan. Sharing these experiences would be promising areas of cooperation.

Other potential areas of cooperation include decarbonizing the final energy demand (industry, residential and transport sectors), by promoting the hydrogen application in the industry and the use of commercial and residential stationary fuel cells, as well as deploying fuel cell vehicles and hydrogen fueling networks to support them.

It should also be noted that while hydrogen plays an important role for decarbonization, the carbon footprint of hydrogen is a critical issue. Japan and hydrogen exporters should collaboratively lead international discussions on standards for hydrogen carbon footprint. It is also expected that the development of hydrogen/ammonia and fuel cell technologies through collaboration between Japan and hydrogen exporters can contribute to the development of relevant international markets.

Collaboration will open windows of more concrete business opportunities. Areas for government to government cooperation and business matching may be explored through workshops and in-depth discussions among stakeholders, including government, academia, businesses, and financial institutions.

APPENDIX: MAJOR ASSUMPTIONS

For hydrogen production, this study uses the same assumptions as in IEA's "The Future of Hydrogen"[16] (2030 cost assumptions). However, for green hydrogen production, this study considers two cases. The base case assumes an electrolyzer CAPEX of $700/kW in 2030 (IEA), and the low-cost case assumes an electrolyzer CAPEX of $336/kW based on interviews with global electrolyzer manufacturers, as reported by the Ministry of Energy, Chile.

The study also uses figures provided in IEA's "The Future of Hydrogen" for the cost evaluation of hydrogen liquefaction, MCH conversion and reconversion, NH_3 production, hydrogen shipping, and hydrogen export/receiving ports. However, since this study treats hydrogen production and NH_3 production as separate processes in the cases of green hydrogen and blue hydrogen production with coal, this study also uses NH_3 conversion cost estimations from the Institute of Applied Energy's report[17].

Feedstock cost assumptions have a significant impact on hydrogen production costs. and since this study applies the same cost and technical specification assumptions to all the countries, the differences in hydrogen supply cost and carbon footprint among the countries addressed are largely attributable to the country-specific differences in feedstock and fuel costs and emission factors (Table A1).

Projections of future renewable power generation costs or fossil fuel costs are not included within the scope of this study. For Chile, the renewable power generation cost and capacity factor for 2030 was provided by the Ministry of Energy of Chile. For Australia, assumptions for the future cost and capacity factor have been derived from a study by the Australian national science agency, CISRO[18]. For the United States, the data for renewable power generation is from EIA's annual energy outlook study[19].

Shipping distance is another important factor that affects hydrogen supply costs. Assumptions of shipping distances is shown in Table A2. For Chile, since solar PV resources are located in the northern part of the country and wind resources in the south, the study considers two different ports: one in the North and the other in the South.

As mentioned above, for the CAPEX of blue hydrogen production, this study uses IEA's assumptions, in which the CCS cost is already incorporated in the overall CAPEX. According to IEA's assumptions, CAPEX for hydrogen production with natural gas reforming will have a nearly 50% markup with CCS compared with no CCS ($910/kW$_{H2}$ without CCS and $1,360/kW$_{H2}$ with CCS (2030)), and 4% markup for coal gasification ($2,670/kW$_{H2}$ without CCS and $2,780/kW$_{H2}$ with CCS (2030)). For blue NH_3 production from natural gas, CCS results in 28% CAPEX cost increase ($905/ton-$NH_3$ without CCS and $1,260/ton-$NH_3$ with CCS).

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[16] IEA (2019), The Future of Hydrogen, IEA, Paris https://www.iea.org/reports/the-future-of-hydrogen

[17] The Institute of Applied Energy (2016). "*Research on the introduction scenario of an energy carrier total system / Cost analysis of energy carrier technologies, Impact evaluation of long term global energy supply and demand, Development of scenario on hydrogen technologies and utilization*." Research commissioned by NEDO.

[18] Graham, P., Hayward, J., Foster J. and Havas, L. 2021, *GenCost 2020-21: Final report*, Australia.

[19] U.S. EIA, "*Levelized Cost of New Generation Sources in the Annual Energy Outlook 2021*", https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

TABLE A1. MAJOR ASSUMPTIONS ON FEEDSTOCK AND FUEL COSTS AND EMISSION FACTORS

<table>
<tr><th rowspan="2"></th><th colspan="2">Grid Electricity</th><th colspan="2">PV</th><th colspan="2">Wind</th><th colspan="3">Natural gas</th><th colspan="2">Coal</th><th colspan="2">Very low sulfer fuel oil (VLSFO)</th><th>Water</th></tr>
<tr><th>Price ($/kWh)</th><th>Emission factor (kg-CO2/kWh)</th><th>LCOE ($/kWh)</th><th>Capacity factor</th><th>LCOE ($/kWh)</th><th>Capacity factor</th><th>Price ($/mmbtu)</th><th>Combustion emission factor (kg-CO2-eq/mmbtu)</th><th>Upstream emission factor (kg-CO2/mmbtu)</th><th>Price ($/ton)</th><th>Upstream emission factor (kg-CO2-eq/ton)</th><th>Price ($/ton)</th><th>Emission factor (kg-CO2/MJ)</th><th>Price ($/ton)</th></tr>
<tr><td>Chile</td><td>0.07</td><td>0.10</td><td>0.017</td><td>32%</td><td>0.021</td><td>64%</td><td>5.2</td><td rowspan="5">53.1</td><td></td><td></td><td></td><td rowspan="4">400</td><td rowspan="4">0.078</td><td>0.5</td></tr>
<tr><td>Australia</td><td>0.09</td><td>0.40</td><td>0.019</td><td>32%</td><td>0.031</td><td>46%</td><td>6.2</td><td>4.4</td><td>16.2</td><td>74.03</td><td>1.5</td></tr>
<tr><td>US</td><td>0.07</td><td>0.27</td><td>0.031</td><td>29%</td><td>0.031</td><td>41%</td><td>4.2</td><td></td><td></td><td></td><td>1.0</td></tr>
<tr><td>Saudi Arabia</td><td>0.05</td><td>0.30</td><td></td><td></td><td></td><td></td><td>4.0</td><td>4.4</td><td></td><td></td><td>0.03</td></tr>
<tr><td>Japan</td><td>0.17</td><td>0.42</td><td></td><td></td><td></td><td></td><td>8.5</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

TABLE A2. ASSUMPTIONS ON SHIPPING DISTANCE

Resource country	Port in Resource country	Port in Japan	Distance (nautical miles)
Chile (North)	Mejillones, Antofagasta	Yokohama	9,192
Chile (South)	Cabo Negro, Magallanes		9,259
Australia	Melbourne		4,907
US	Houston (via Panama canal)		9,254
Saudi Arabia	Ras Tanura		6,593

Source: https://sea-distances.org/

Contact: report@tky.ieej.or.jp