Perspectives on Hydrogen in the APEC Region

June 2018

Asia Pacific Energy Research Centre

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PUBLISHED BY

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ISBN 978-4-931482-59-3

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Foreword

A wide variety of low-carbon technologies are needed to support the long-term reduction of CO_2 emissions. Hydrogen is one of those technologies, and its use being actively promoted in Japan in recent years, with the Ministry of Economy, Trade and Industry formulating the *Strategic Roadmap for Hydrogen and Fuel Cells* in 2014 (revised in 2016). In January 2017, the Hydrogen Council was formed, consisting of 13 global leading companies in the energy, transportation, and manufacturing industries, which announced they would strengthen efforts to transition to hydrogen-based energy. In Japan, the Ministerial Council on Renewable Energy, Hydrogen and Related Issues formulated a basic hydrogen strategy in December 2017 and a basic policy for establishing a hydrogen economy in Japan that was the first in the world. In other APEC economies, both China and the South Australia government formulated hydrogen roadmaps in April and September of 2017, respectively.

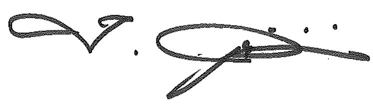
Even in the APEC region, there is a need to accelerate efforts to reduce CO_2 emissions, and the examination and verification of the possibility of introducing hydrogen technologies as new technology can be said to be a new attempt, in addition to existing low-carbon technologies. Distributing hydrogen within the APEC region also leads to the diversification of energy sources and relieves the uneven distribution of resources, which contributes to improving energy security within the region.

This project analyses the possibilities of hydrogen production, transport, and its use in the APEC region, and therefore makes recommendations on how hydrogen should be utilised.

Takato Ojimi

President

Asia Pacific Energy Research Centre



Acknowledgments

We appreciate those who have made inputs to this study report, which could not have been accomplished without the contributions of professionals, in particular those named below.

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Executive Summary

Hydrogen has garnered interest in recent years as a measure to counter climate change. The APEC region has abundant fossil fuels and renewable energy to act as sources to produce hydrogen, and the realisation of hydrogen production, transport, and use in the region is considered to be important not only for reducing CO_2 emissions but for also improving regional energy security. This study analyses the possibility of hydrogen production, the outlook for hydrogen demand, its economic viability in the APEC region, and discusses how hydrogen should be used in the region.

Based on scenario analysis, the demand for hydrogen in the entire APEC region in 2050 is 352 Mtoe, equivalent to 7% of the current primary energy supply. It is also expected to have the effect of reducing 1.2 Gt of CO_2 emissions, equivalent to 6% of the current level. From the perspective of energy security, while hydrogen does not offer a significant improvement in the energy self-sufficiency rate across the APEC region, relatively large improvements can be expected depending on the economy.

If hydrogen were distributed within the APEC region, economies with abundant fossil fuel and renewable energy resources, such as Australia, Canada, Chile, Indonesia, Mexico, New Zealand, Russia, and the United States, would be candidates as hydrogen-exporting countries, while other economies would be hydrogen importers.

When the focus is on using fossil fuels as a source for producing hydrogen, countries with fossil fuel resources and a large CCS potential are hydrogen-exporting economies. If hydrogen is produced from renewable energy, there is significant potential with solar power, since the cost of power generation has drastically fallen in recent years. In particular, solar power generation is relatively easy to do in economies like the United States, Australia and China that have vast tracts of land and plenty of sunlight for the inexpensive, large-scale production of hydrogen.

There are various options (of economies, technology) in the APEC region for the production of hydrogen, so competition to drive down the cost of hydrogen production can be expected. However, the most important issue is the creation of hydrogen demand. At present, there is almost no demand for hydrogen as an energy application. While fuel cell vehicles are expected to be the first application of hydrogen, it will take time for them to become popular since it is necessary to build large-scale infrastructure such as hydrogen fuelling stations.

Given this, introducing hydrogen power generation that can expect large-scale consumption is a very important element. Based on the analysis results of this study, in order for hydrogen power generation to compete with natural gas-fired and coal-fired power generation, all aspects of hydrogen, from its production to transportation, will have to become cheaper. And to produce hydrogen, it is vital that the costs of producing fossil fuels and renewable energies in hydrogen-exporting economies are further reduced. The transportation of hydrogen has challenges with the direction of technical development and issues that need to be sorted out to reduce costs based on the results of supply chain verification tests of liquefied hydrogen, methyl-cyclohexane, and ammonia currently being studied mainly in Japan.

In the APEC region, some of the joint research topics being considered through research of case studies introducing hydrogen and sharing outcomes in economies, include the development of hydrogen technologies, the economics of hydrogen production and transportation, the creation of hydrogen demand, and the study of the role of bilateral and multilateral hydrogen trade.

1. Current State of Hydrogen Technology

1.1. Technology Trends

1.1.1. Hydrogen Production

There are several technologies that can be used to produce hydrogen, and their basic characteristics are shown in Table 1.1 below. This section discusses production technologies that have a relatively high feasibility and are thought to play a central role, and outlines them, their trends, and the challenges they have.

Table 1.1 Hydrogen Production Technologies

	Status	Stability	CO_2 Emission	Cost
By-products of Industries	Practical	Depends on the primary products	Depends on the primary products	Depends on the primary products
Fossil Fuel Reforming	Practical	Stable	Without CCS, yes.	Relatively low
Electrolysis (Thermal Power)	Practical	Stable	Without CCS, yes.	Relatively low
Electrolysis (Renewable Power)	Practical	Variable (solar, wind)	No	Decreasing
Biomass Pyrolysis	Some difficulties	Not stable in certain areas	No (carbon neutral)	Relatively high
Thermochemical Water Splitting	R&D	Stable	Depends on heat source	Unknown
Hydrogen Producing Catalyst	R&D	Variable	No	Unknown

Source: NEDO (2014),[1] IEA (2015),[2] etc.

(1) Fossil Fuel Reforming

Of the various hydrogen production methods, fossil fuel reforming is already widely practised in Japan and elsewhere. In particular, steam methane reforming (SMR), which uses a reaction of fossil fuels (hydrocarbons) such as natural gas and high-temperature steam to generate hydrogen, is a large scale and stable method of hydrogen production. There is also a method of mixing fossil fuels with air and combusting it to generate hydrogen. This method is called partial oxidation (POX) because the reaction uses a limited amount of oxygen to prevent complete combustion. However, since the gas refined by POX has a low hydrogen purity and poor production efficiency, SMR is considered to be the practical method. In addition to fossil fuels, the steam reforming method can be applied to biomass and waste, but since there are various types of biomass and waste, each has their own properties, so it is necessary to consider the composition of facilities. Furthermore, there is also the challenge of ensuring a stable and inexpensive supply of biomass and waste to be used in the process.

Fossil fuel reforming is an established industrial method, and there are few technical issues with it. Therefore, in the meantime, it would be regarded as the primary method of producing hydrogen. However, the hydrogen production cost with this method is affected by price fluctuations in the fossil

1 NEDO, Hydrogen Energy White Paper, 2014.
2 IEA, "Technology Roadmap: Hydrogen and Fuel Cells," 2015.

fuel used as a feedstock. Moreover, the process emits carbon dioxide (CO_2), so if it is to be used as a low carbon energy (CO_2-free hydrogen), it is essential to develop it together with carbon capture and storage (CCS) technology. In this case, it is also necessary to consider its economic viability given the additional cost of CCS. Also, regional ubiquity becomes an issue since there are limited regions that produce fossil fuels and are suitable for CCS.

Unfortunately, there are few suitable sites for CCS in Japan, but advanced technology development and trials are being conducted by the Research Institute of Innovative Technology for the Earth (RITE) and other institutions. North America and Norway are global pioneers of CCS technology, especially in North America where large-scale CCS is already actively being carried out. However, in order to introduce CCS globally, it is essential not only to develop technologies but also to establish a certification mechanism that gives a low carbon value to fossil fuels to encourage its actual use.

(2) Electrolysis

This method electrolyses water to produce hydrogen and oxygen. The advantages of this method are that it does not require a special separation operation compared with producing hydrogen from fossil fuels, has few components in the generation system, and is easy to maintain. It is also possible to produce hydrogen from various energy sources by passing electricity through them. In particular, no CO_2 is generated if hydrogen is produced from electricity generated from renewable energy, such as solar and wind power, and accumulating surplus electric power as hydrogen can contribute to the further expansion of variable renewable energy, making them very promising energies.

Electrolysis is already an established technology, and about 8 GW[3] of facilities are in use worldwide. Commercial plants depend on electric power supplied from the grid, but in recent years, some electrolysis (Power-to-Gas, or PtG) using variable renewable energies such as solar and wind power, has also been deployed. PtG demonstrations are actively being conducted in Germany and Denmark where the proportion of the variable renewable power to the total power generation is large, and in Japan, the New Energy and Industrial Technology Development Organization (NEDO) is adopting PtG within its project to develop technologies for the creation of a hydrogen economy and development of hydrogen energy systems.[4]

Even though electrolysis itself is an established technology, low cost and high efficiency are required for commercial use in the future. To accomplish this, in addition alkaline electrolysis, which is membrane (PEM) electrolysis and solid oxide electrolysis are expected to be developed.[5] Also, if solar or wind power is used, their power generation costs have been decreasing in recent years, but since using them would mean using power with large fluctuations in output, it is necessary to improve

[3] Decourt, Benoît, Lajoie Bruno, Debarre, Romain and Soupa, Olivier, "Hydrogen-Based Energy Conversion: More than storage: system flexibility," SBC Energy Institute, 2014, p.48.
[4] NEDO website (http://www.nedo.go.jp/koubo/FF3_100144.html)
[5] IEA (2015), *op. cit.*, p.29.

the durability of facilities (electrolytic cell membranes and electrodes) and ensure the steady operation of auxiliary equipment.

(3) By-Product Hydrogen

Hydrogen generated as a by-product from various industrial processes may also be a promising supply source. Certainly, greenhouse gases, such as CO_2, are emitted during the manufacturing process, but as long as the production volume of the main product does not increase more than is necessary, this method can improve the efficiency obtained for a given emission. Major hydrogen sources in Japan are production of caustic soda (sodium hydroxide) and steelmaking. By-product hydrogen is also generated by oil refineries, but most of it is used for desulfurisation, and since its demand volume is increasing as higher quality for petroleum products is required, its external sale by this process is difficult not only in Japan, but for the rest of the world as well.[6][7] On the other hand, by-product hydrogen generated when caustic soda is produced by brine electrolysis is high in purity and is already being used for external sales. Also, hydrogen derived from steelmaking is partly being supplied to the outside. In Kitakyushu Hydrogen Town, for example, demonstrations are being conducted to supply by-product hydrogen generated from the Yawata Steel Works to neighbouring areas by pipeline.

Both sources already use established technologies, but since hydrogen is only a by-product, its supply depends on the amount of the primary products. In addition, when the generated hydrogen is of low purity, it is necessary to refine it with pressure swing adsorption or similar method, which requires additional cost. Furthermore, in the caustic soda industry, which is the dominant source of hydrogen, brine electrolysis technology by the gas diffusion electrode method, with its lower power consumption, is being advanced, but this method doesn't generate hydrogen. So, probably it may not be a source of hydrogen supply in the future.

(4) Thermochemical Water Splitting

Hydrogen can be obtained from water not only by electrolysis but also by thermochemical splitting. The process usually involves an ultra-high temperature of 4,000°C or higher, but with an IS process using an iodine (I) and sulfur (S) compound, the temperature can be lowered to about 900°C. It is also expected that this temperature can be further lowered to 650°C by combining the IS process with a separation membrane.[8]

High-temperature gas furnaces (nuclear-powered) have been considered as a necessary source of heat, and if this is realised, it is expected that a large amount of hydrogen can be stably produced

6 *Ibid.*, p.24.

7 The oil refining industry has introduced production equipment to make up for insufficient hydrogen, and by increasing the operation rate of the equipment, it will be able to produce hydrogen to be supplied externally. In this case, however, additional feedstock inputs are necessary, and this hydrogen cannot be regarded as a by-product. (*Cf.* Agency for Natural Resources and Energy materials)

8 NEDO (2014), *op. cit.*, p.115.

without generating any CO_2. In 2004, the Japan Atomic Energy Agency (JAEA) succeeded in continuously producing 30 NL/h of hydrogen for one week with the world's first IS process and is currently conducting research to expand the amount produced and ensure the soundness of the equipment. In Europe, the HYDROSOL project, research on the thermochemical water splitting using solar heat, is being conducted based on a framework programme for research of the European Union (EU). The latest project conducted until September 2017 is intended to demonstrate at least 3 kg of hydrogen production per week by constructing a 750 kWth scale facility in addition to examining chemical processes.[9]

Although neither method has been put to practical use, the common challenge is the development of an optimal chemical process and the securing of materials that can withstand high temperatures. In addition to this, when nuclear energy is used, there are the problems of having to ensure the safety of the reactor itself and the technology to safely connect the reactor and the hydrogen production system. With solar heat, the problems are with designing optimum light collectors and securing a location.

1.1.2. Distribution, Transport and Storage

Hydrogen is easier to store compared with electric power, so it is suitable for long-distance mass transport. However, since the amount of energy per volume is smaller than that of natural gas and other energies, it is necessary to transport it after compressing it to a high density. There are several transport and storage technologies, such as compressed hydrogen, liquefied hydrogen, hydrides, and hydrogen pipelines, and their basic characteristics are shown in Table 1.2. This section will outline each technology, their trends, and their challenges.

Table 1.2 Hydrogen Storage and Transportation Technologies

	Status	Capability for Long Duration Storage	Density	Efficiency	Capital Cost	Transportation Cost
Compressed Hydrogen	Practical	High	Relatively low	High	High	High
Liquefied Hydrogen	Practical	Low (due to boil-off)	High	Low	High	High
Organic Chemical Hydrides	R&D	High	High	Depends on waste heat recovery	Unknown	Low
Metal Hydrides	R&D	High	High volumetric density	Depends on waste heat recovery	Unknown	Low
Hydrogen Pipelines	Practical	–	Depends on the system	Efficient and stable	MP or LP: low HP: high	Low

Source: NEDO (2014), Decourt (2014), etc.

(1) Compressed Hydrogen

Hydrogen is compressed, filled in cylinders, and transported or stored. This technology is already in practical use worldwide and is deployed for industrial hydrogen (non-energy use) and hydrogen for fuel cell vehicles. Reliability is high as it is a mature technology, but high-pressure hydrogen has a

9 European Commission research grant program website (http://cordis.europa.eu/project/rcn/111501_en.html)

function that makes regular steel brittle, so it is necessary to use special alloys for storage containers. Also, depending on the pressure, the energy density per volume may be lower than other storage technologies.

Currently, hydrogen distributed for industrial use is about 15-20 MPa, but compressed to 35 MPa or 70 MPa for supplying to fuel cell vehicles, and storage at 87.5 MPa is internationally approved for fuelling stations that supply 70 MPa hydrogen.[10] Because of deregulation in Japan, new hydrogen stations established after FY2016 have been able to store hydrogen at 82 MPa by meeting the standards.

If the aim is for full-scale popularisation of fuel cell vehicles, which poses a promising demand for hydrogen, it will be necessary to reduce the cost of high-pressure compressors and high-pressure storage containers in particular. Measures to reduce the weight of compressed hydrogen containers and protection from hydrogen embrittlement are also important. In addition to the technological aspects, legal compliance is also critical. In Japan, amendments to the High-pressure Gas Safety Act, the Fire Service Act, and other laws are taking place in order to enable transport and storage in various forms.

(2) Liquefied Hydrogen

Since hydrogen liquefies at -253°C and reduces to 1/800 its volume,[11] the energy density per volume increases, allowing it to be transported and stored by container, truck, or other means. This technology has been used for rocket fuel since the late 1950s, but in recent years, the sales volume for general industry has also increased. However, considering the energy required for liquefaction and to keep hydrogen liquefied, its energy efficiency is lower than other technologies, and since 0.5–1.0% of the storage capacity is vaporised (boiled off) in a day, long-term storage is problematic.

In light of the above, insulation technology to prevent boil off, improving the energy efficiency in the liquefaction process, and reducing the cost of these technologies are issues for the deployment of hydrogen in the future. Integrated research is being conducted on the high-efficiency use of liquefied hydrogen (Integrated Design for Efficient Advanced Liquefaction of Hydrogen, or IDEALHY) under the EU framework programme for research (FP7) in which the amount of energy involved in liquefaction is theoretically reducible up to 6.4 MWh/t (as of 2007, it was 11.9 MWh/t).[12] Also, since liquefied hydrogen is treated as a high-pressure gas by law in Japan, it is necessary to optsimise regulations such as the High Pressure Gas Safety Act in the same way for compressed hydrogen.

(3) Hydrides

Hydrogen can also be transported and stored by adsorbing (hydrogenation) hydrogen to aromatic organic compounds, such as toluene, or some metal alloys, and separating (dehydrogenation) them as

[10] UNECE, Global technical regulation on hydrogen and fuel cell vehicles, ECE/TRANS/180/Add.13, 2013.
[11] NEDO (2014), *op. cit.*, p.123.
[12] Stolzenburg, Klaus and Mubbala, Ritah, "Hydrogen Liquefaction Report," IDEALHY, 2013, p.20.

necessary. The former are called organic hydrides while the latter are called metal hydrides. Both have the characteristic of 1) the ability to be repeatedly reused by combining hydrogenation and dehydrogenation, 2) the ability to be transported on existing transport systems as they can be handled at normal temperature and pressure after adsorption, 3) some energy consumption is required as heat is needed to cause the dehydrogenation reaction, and 4) time required for the dehydrogenation reaction.

There are various forms of organic hydrides, but the practical application of methyl-cyclohexane to toluene is expected from the viewpoint of safety and convenience. Both of these are general purpose chemicals and can be used with existing social infrastructure. In addition, hydrides can be compressed to 1/500 their volume[13] compared with their normal pressure state. Alloys such as lanthanum and magnesium are used for metal hydrides. Magnesium hydride (MgH_2) has an energy density per volume about three times[14] as high as that of liquid hydrogen, but since metal is used, it does not have a high density per weight. However, in recent years, JAEA researchers and others have created metal hydrides using a lightweight aluminium and copper alloy (Al_2Cu),[15] which is expected to solve this problem.

In the practical application of these technologies, not only cost reduction, but also deployment of easy-to-use dehydrogenation equipment is needed, since after being transported, hydrides require on-site dehydrogenation. It is also important to create measures to effectively use the waste heat generated during the dehydrogenation reaction and to improve energy efficiency.

(4) Hydrogen Pipelines

The same pipelines that transport natural gas can also be used to transport hydrogen. There are instances in Japan where pipelines are used to supply industrial hydrogen within a complex or to nearby facilities, as well as in Kitakyushu City, as previously mentioned, where by-product hydrogen generated at the steelworks is transferred to hydrogen stations and to demonstration fuel cell batteries for households. In addition, past surveys have confirmed that existing city gas supply pipelines can also be used to supply medium and low-pressure hydrogen without any problems.[16] The development of large-scale hydrogen pipelines is already in progress in Europe and the United States, and according to a survey conducted by the Department of Energy (DOE) in the United States, as of 2016, of the approximately 4,500 km of pipeline laid worldwide, approximately 2,600 km is in the United States, mainly in Texas and Louisiana, and 1,600 km has been laid in Germany, France, England, Belgium, and the Netherlands. Also, of the pipeline installed worldwide, approximately 1,900 km is owned by Air Liquide of France, and approximately 1,100 km is owned by Air Products of the United States.[17]

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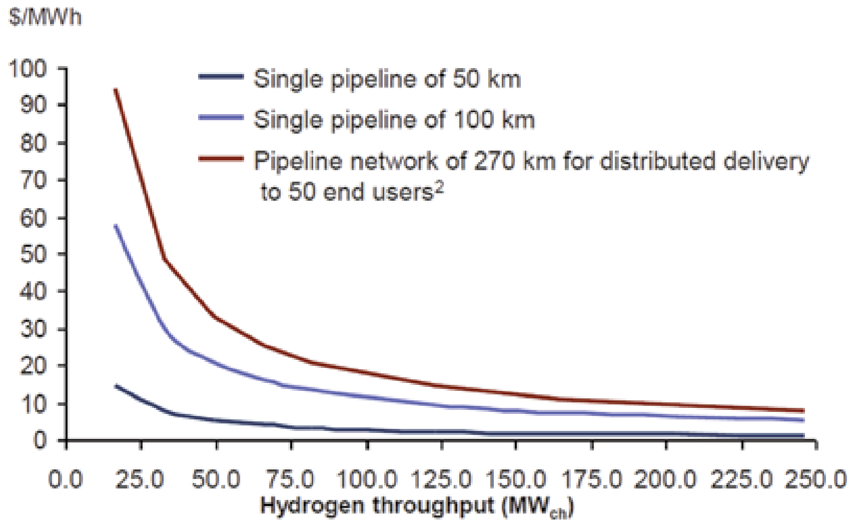
[13] NEDO (2014), *op. cit.*, p.126.
[14] *Cf.* Decourt (2014), *op. cit.*, p.68.
[15] Saitoh, Hiroyuki, Takagi, Shigeyuki, Machida, Akihiko *et al.*, "Synthesis and Formation Process Al_2CuH_x: A new class of interstitial aluminium-based alloy hydride," *APL Materials*, vol.1, no.3, 032113, 2013.
[16] The Japan Gas Association, "FY2015 Survey of Safety Technology for the Construction of a Hydrogen Pipeline Network (Comprehensive Survey)," Ministry of Economy, Trade and Industry, 2016, appendix p.5.
[17] Information published by Hydrogen Analysis Resource.

Although pipelines are an established technology, the cost of laying them is an issue. Although this can be mitigated by using existing pipelines, construction of new ones is critical, especially when considering the supply of high-pressure hydrogen. In the cost structure, since the initial cost accounts for a large proportion, efficiency of the life cycle cost can be improved by large-scale hydrogen supply as shown in Figure 1.1. However, due to this nature, there is the chicken or the egg issue[18] of needing large-scale hydrogen demand to promote the construction of a hydrogen pipeline, which is needed to promote the use of hydrogen.

Figure 1.1 Levelised Cost of Hydrogen Transported by Pipeline



Source: Decourt (2014), p.81.

1.1.3. Hydrogen Demand Sector

Hydrogen is expected to be used as a low-carbon energy in the future, but it is mainly used in the industrial sector at present. In 2011, of the approximately 53 Mt consumed globally, 27 Mt was for the production of ammonia and about 20 Mt was used in oil refining.[19] Therefore, in addition to these industrial hydrogen usage technologies, this section will explain the fuel cells and hydrogen power generation which are expected to be deployed in the future, and outline them, their trends, and their challenges.

(1) Ammonia Production

Ammonia is widely used as a feedstock for basic chemical products such as nitrogen fertiliser, chemical fibres, and nitric acid. Major producing countries are China, Russia, India, and the United States.[20] Of the various ways to produce ammonia, hydrogen is consumed by the direct reduction

[18] Decourt (2014), *op. cit.*, p.81.
[19] *Ibid.*, p.154.
[20] U.S. Geological Survey, *Mineral Commodity Summaries 2017*, 2017, p.119.

(Haber-Bosch process) of nitrogen. Currently, over 90% of the source of hydrogen is from reforming fossil fuels such as natural gas and coal.[21] In addition, although the Haber-Bosch method has been around for more than 100 years, other methods of synthesising ammonia under moderate conditions have been researched in recent years.

The basic application of ammonia has been described above, but it can also be used as a fuel that does not emit CO_2. In addition to being able to use the same existing distribution infrastructure as liquefied petroleum gas (LP gas) while in a liquid state close to normal temperature and pressure, it can be used as a hydrogen transport and storage technology since it is possible to separate hydrogen from ammonia by electrolysis or conduct dehydrogenation at a high temperature using a ruthenium catalyst. In this case, however, the supply of energy necessary for dehydrogenation is a problem. In addition, since ammonia has harmful properties both for humans and equipment that uses hydrogen (such as fuel cells), the hydrogen must be completely separated from ammonia.

(2) Oil Refineries

As mentioned in the previous section on “By-Product Hydrogen,” hydrogen is used for desulfurisation in the oil refining process. The amount of hydrogen required increases as the feedstock used for refining becomes heavier or as the quality (low environmental impact) required for the product becomes higher. Since by-product hydrogen accompanying refining is insufficient, it is currently additionally produced using fossil fuels as a feedstock. Therefore, similarly to the ammonia production described above, it becomes important for this sector in the future to supply low-carbon hydrogen at a cost comparable to conventional methods.

(3) Stationary Fuel Cells

In stationary fuel cell systems, hydrogen is created from fuels such city gas or LPG by a reformer, and electricity is generated by reacting hydrogen and oxygen (derived from the air) in the fuel cell stack. It is simply the reverse reaction of electrolysis. In this process, since the chemical energy of the fuel is directly converted into electricity without passing through thermal or mechanical energy, it is characterised as having a high power generation efficiency regardless of its scale.

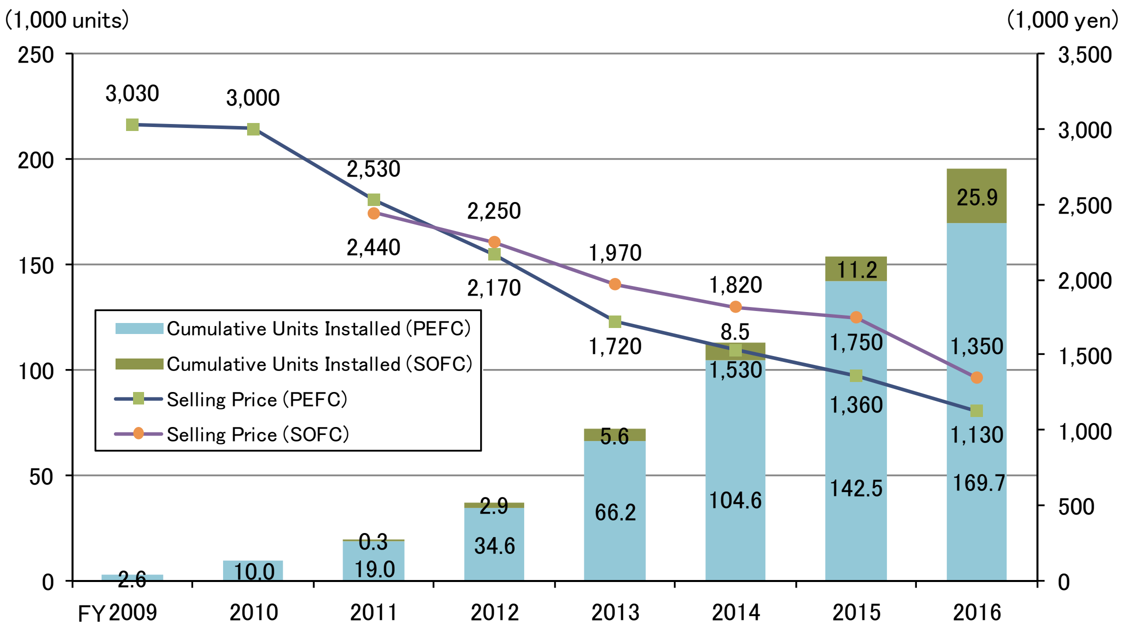
Although there are many different types of fuel cells depending on their electrolyte and fuel, development and deployment currently centers around polymer electrolyte fuel cells (PEFC) and solid oxide fuel cells (SOFC). PEFC has a high operating speed because of its low operating temperature and it is easy to reduce its size and weight because of its high power. With this in mind, PEFC is mainly used for home fuel cell cogeneration systems and fuel cell vehicles (FCV), which will be discussed later. Since the reaction in SOFC proceeds with ease, they do not need an expensive noble metal catalyst such as platinum. Because they have extremely high operating temperatures of 1,000°C, they

[21] Decourt (2014), *op. cit.*, p.161.

have been considered to be for large-scale plants, but in recent years, there has been progress in developing small-scale systems. In addition to these types, phosphoric acid fuel cells (PAFC) are also used but are for large-scale plants only.

In Japan, fuel cell cogeneration systems (0.7 kW) for households are collectively known as “Ene-Farm,” and are the first in the world to be sold to the general public with government subsidies since 2009. As shown in Figure 1.2, the number of installed units has steadily increased each year, with about 154,000 units (cumulative installation of about 108 MW) as of January 2016. In addition, their price has been decreasing as the technology develops. In particular, the selling price of polymer electrolyte fuel cells (PEFC) has dropped to less than half of its initial price as of January 2016. However, the *Strategic Energy Plan* passed by the Cabinet in 2014, sets targets of introducing 1.4 million units in 2020 and 5.3 million units in 2030, meaning that even the target for 2020 is about 10 times current levels. To achieve this goal, it is vital to cut costs so that it would be chosen by consumers without subsidies.

Figure 1.2 Cumulative Installed Units and Selling Price of Ene-Farm in Japan



Source: METI (2017),[22] p.59.

Although Japan leads other countries in the formation of a home fuel cell market, a project called “ene.field” is also making headway in Europe and aims to install 1,000 home fuel cell cogeneration systems for trials in 11 countries. In addition, the EU has adopted a solid oxide fuel cell (SOFC) demonstration project using biogas from sewage treatment plants in the framework programme for

[22] Ministry of Economy, Trade and Industry (Japan), *FY2016 Annual Report on Energy (Energy White Paper)*, 2017.

research (Horizon 2020). In the United States, more and more large-scale commercial and industrial fuel cells (several hundred kW to several tens of MW) using solid oxide (SOFC), molten carbonate (MCFC), phosphoric acid (PAFC), and others are being introduced, with a cumulative installed capacity of over 70 MW.[23]

As previously mentioned, although the theoretical energy efficiency of fuel cell systems is high, the efficiency is achieved only by simultaneously satisfying the demand for heat and electricity through cogeneration. Thus, careful consideration should be given to energy demand structures of the houses or offices, as to whether they are suitable for use. In addition, as of 2017, since commercialised stationary fuel cells produce hydrogen by reforming city gas or LP gas in their equipment, they are energy-efficient but emit CO_2. Regarding this issue, progress is being made in the development of a "pure hydrogen" stationary fuel cell that directly uses externally-supplied hydrogen in the equipment. CO_2 emissions can be reduced to almost zero by supplying this hydrogen from electrolysis created with renewable energy, and since pure hydrogen fuel cells can omit the reforming process of natural gas, it can lead to shorter start-up times and improved energy efficiency. In this case, however, there needs to be a different supply system from that for existing fuel cells.

(4) Fuel Cell Vehicles

A fuel cell vehicle (FCV) is a vehicle[24] that uses hydrogen supplied from a hydrogen station as fuel to generate power from a fuel cell that drives the motor using the generated electricity. Manufacturers have already started selling FCV passenger vehicles in Japan, the United States, Europe, South Korea, and elsewhere. In addition to passenger vehicles, fuel cells are also being introduced in scooters, large vehicles such as buses and trucks, industrial vehicles such as forklifts, and even ships. As of the end of September 2017, there are about 5,200 FCV passenger vehicles around the world, of which approximately 3,700 are the Toyota Mirai. The United States is ranked first in the number of vehicles by country with about 2,700 vehicles, followed by Japan with about 1,700 vehicles.[25] Some features of FCVs include: 1) they contribute to energy conservation and reduce CO_2 emissions because of their high energy efficiency, 2) a relatively short fuelling time, 3) long travel ranges of over 500 km,[26] and 4) reduce the dependency on oil as hydrogen because of a diverse range of energy sources.

The most important challenge for FCVs is to lower their price, which ranges from 60,000 to 100,000 USD.[27] Currently, the Mirai, the most prevalent FCV in Japan, costs about 7.2 million yen, which is much higher[28] than other passenger vehicles made by Toyota. At present, the national and local

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[23] DOE, *Fuel Cell Technologies Market Report 2015*, 2016, p.30.
[24] Additionally, there are automobiles that drive the engine by burning hydrogen, but here we deal only with FCVs that are thought to play a central role in the future use of hydrogen technology.
[25] Estimate from information published by Hydrogen Analysis Resource Center.
[26] According to the Toyota website (http://toyota.jp/mirai/performance/), the cruising range of the Mirai is about 650 km.
[27] IEA (2015), *op. cit.*, p.13.
[28] Compared on the Toyota website (https://toyota.jp/carlineup/?ptopid=menu).

governments provide subsidies for the purchase of an FCV. For example, one can be purchased for about 4.2 million yen[29] in Tokyo, but this is even expensive for a sedan. And independence from subsidies is vital for FCVs to be deployed widely. In addition to the price of the car itself, fuel production cost must also be lowered as the cost of fuel is an important factor for consumers in the decision to purchase. The current price of hydrogen for FCVs in leading cases is about 1,100 yen/kg, which is equivalent level to the fuel cost (per mileage) of a gasoline hybrid car.[30] Moreover, improving convenience is a problem directly connected to the consumers' decision making. To do this, it is vital to develop infrastructure such as hydrogen fuelling stations, meaning that it is necessary to develop technologies that enable inexpensive construction and to make legal preparations that allow smooth construction. To improve convenience, it is also important to expand the line-up of car models to meet the diverse needs of consumers.

(5) Hydrogen Power Generation

In addition to the above-mentioned fuel cells, energy can also be obtained by burning hydrogen to generate electricity, and some countries are studying how to introduce hydrogen into gas turbine power generation, which is the predominant means of thermal power generation. In general, existing plants can burn a mix of hydrogen and natural gas, and its introduction is being advanced in Japan and overseas. Also, turbines compatible with a mixed combustion rate of 50% or less with the integrated coal gasification combined cycle (IGCC) have already been commercialised.[31] On the other hand, power generation using only hydrogen is in the research and development stage, and a representative example is the 16 MW[32] demonstration plant operated by the Italian company Enel in Fusina (Venice), which has been in operation since 2009. In Japan, companies such as Mitsubishi Hitachi Power Systems and Kawasaki Heavy Industries are developing turbines that can handle dedicated hydrogen combustion and mixed combustion.

Although there is no CO_2 from burning hydrogen, nitrogen oxide (NO_x) is emitted from nitrogen in the air, which is a cause of air pollution and the greenhouse effect. Combustion in gas turbines in particular emits nearly double the amount of NO_x produced from natural gas combustion because of factors such as the fast combustion speed of hydrogen that causes unstable combustion, and high flame temperatures. To counter this, measures such as flame cooling by water injection and dilution of the fuel with an inert gas are being studied. Kawasaki Heavy Industries is working on developing a gas turbine combustion chamber that allows dedicated hydrogen combustion with low NO_x that uses a

[29] Tokyo Metropolitan Government Bureau of Environment website (https://www.kankyo.metro.tokyo.jp/energy/hydrogen/fcv.html)

[30] Iwatani Corporation press release, 14 November 2014.

[31] Decourt (2014), *op. cit.*, p.98.

[32] The output of hydrogen power generation itself is 12 MW, but 4 MW of output is obtained by using exhaust heat in an existing coal-fired power plant. (Enel, Press Release, August 14, 2009.)

micro hydrogen flame to suppress unstable combustion such as flashbacks .[33]

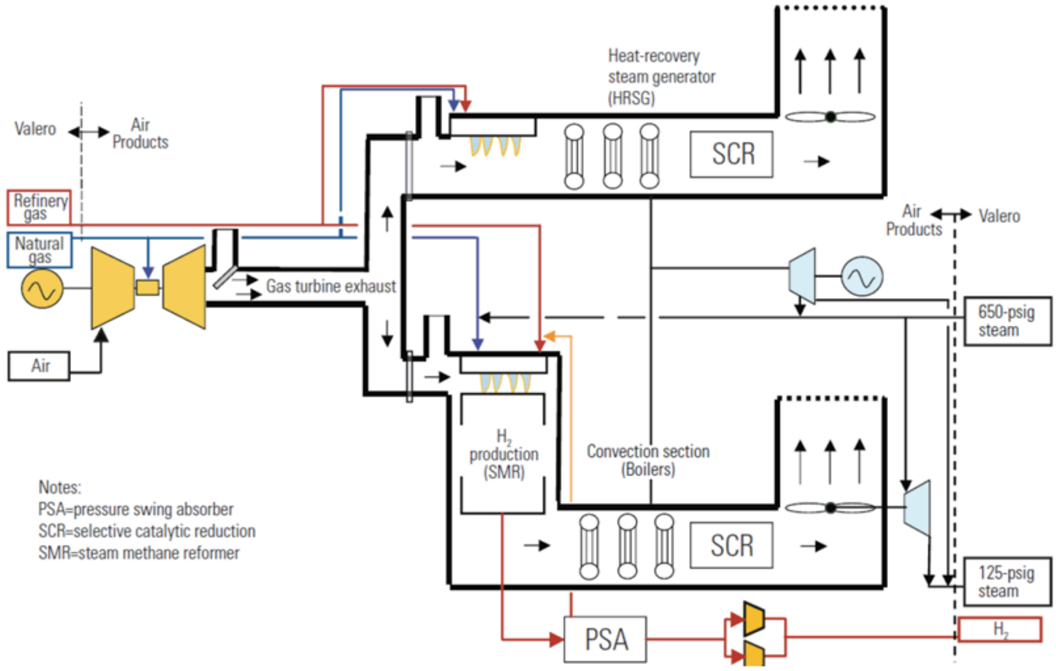
Although there are few practical cases, compared with stationary fuel cells, power generation from hydrogen (combustion) is expected to be cost-effective. Fuel cell plants have a structure that bundles a required number of stacks of a fixed size, whereas hydrogen power plants have the advantage of scale[34] in terms of the high efficiency and economy that comes from being designed large. However, this means that it loses the advantage of operating as a small-scale distributed power supply, and it must secure a large hydrogen supply for its size in order to obtain the benefits of a large-scale plant.

1.2. Leading Implementation Case Studies

1.2.1. Natural Gas Reforming + CCS (Texas, USA)

The US DOE adopted Air Products' Port Arthur II project in 2009 as one of its industrial CCS programs. Port Arthur II integrates natural gas cogeneration and hydrogen production using SMR, and since it was completed in 2007, it has supplied the nearby Valero Energy oil refinery with electricity (100 MW), steam (1.2 million lb/hr), and hydrogen (110 million SCF/d). Figure 1.3 shows the configuration of Port Arthur II's composite system.

Figure 1.3 Process Flow Diagram of Port Arthur II SMR Plant



Source: Air Products (cited by Santos (2015)

The CCS facility was completed in 2013, and the CO_2 captured is sent to the West Hastings oil field in Texas through a CO_2 pipeline owned by Denbury Resources and is used for enhanced oil recovery

33 Kawasaki Heavy Industries press release, 12 December 2015.
34 Decourt (2014), *op. cit.*, p.98.

(EOR). In October 2017 DOE announced that 4 million tons[35] had been captured and stored. Since the start of the program in 2009 until its end in September 2017, DOE provided a total of 284 million USD in support, with Air Products bearing 147 million USD.[36] It was reported that this cost of Air Products' side would be covered by selling CO_2 for EOR.[37] This case shows that EOR is a profitable option for commercial-based CCS.

1.2.2. Power-to-Gas (Falkenhagen, Germany)

As stated in section 1.1.1, electrolysis (PtG) using renewable electricity is regarded as a promising future method for producing CO_2-free hydrogen. Although PtG has not yet been put into practical use on a commercial scale, many demonstrative projects are being conducted in Germany. The demonstrations are premised on the fact that various measures are becoming important as the share of variable power supplies, such as solar and wind power, has rapidly increased in recent years and Germany is aiming for further introduction in the future, but construction of power transmission lines from the north, where power generation is concentrated, to the south, where demand is concentrated, is insufficient.[38] The gases produced by PtG can be used not only for power generation, but also for other purpose,[39] so it can be said to be a countermeasure for variable power sources that uses the entire energy system whereas interconnection in wide area and storage batteries are measures only within the power system. Currently, there are about 70 PtG demonstration projects (including those ended and being planned) in Europe, of which, about 40 are being conducted in Germany. However, the aim of about 10 of those projects is not to produce hydrogen, but to produce methane from the hydrogen.

Among the numerous PtG demonstration projects in Germany, "WindGas Falkenhagen" in Falkenhagen, Brandenburg, is one of the largest in Germany for hydrogen production purposes.[40] As shown in Figure 1.4, wind power generation not only exceeds the local electric power demand for much of the time in Falkenhagen, but also the fluctuation of power generation is wide, so some form of energy storage is required.

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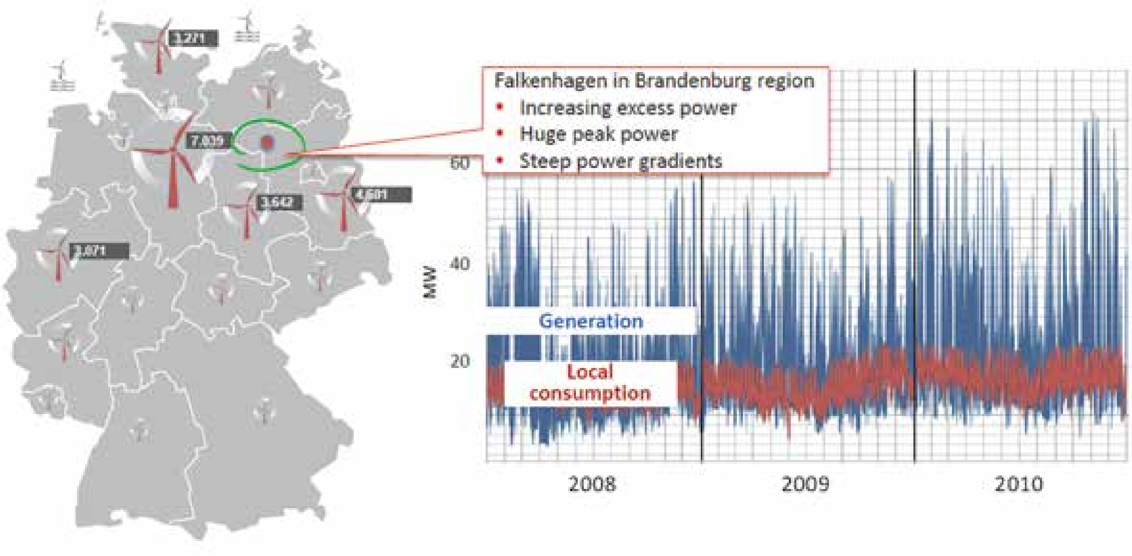
[35] DOE National Energy Technology Laboratory (NETL), 11 October 2017
[36] NETL website (https://www.netl.doe.gov/research/coal/project-information/FE0002381)
[37] Santos, Stanley, "Understanding the Potential of CCS in Hydrogen Production: Review of Current State-of-the-Art," Process Industry CCS Workshop (Joint IEA GHG & IETS Meeting), 2015.
[38] IEA, *Energy Policies of IEA Countries: Germany 2013 Review*, 2013, p.13.
[39] PtG not only produces hydrogen but also produces synthetic methane from its hydrogen and captured CO_2.
[40] Including those for methane production only, the synthetic gas fuel production project for Audi cars (6.3 MW plant capacity) in Werlte, Lower Saxony is the largest.

Figure 1.4 Project Context Falkenhagen: Regional Oversupply by Onshore Wind Capacities



Source: Schneider (2013)[41]

This project aims at demonstrating the production of hydrogen using surplus electricity from wind power in this area, and 2 MW of alkaline electrolysis equipment has been in operation since 2013. Among the multiple companies and organisations involved in this project, the Uniper operates the hydrogen production plant, which was separated from its parent company, E.ON, a major energy company in Germany. About 360 Nm^3/day[42] of the hydrogen produced is fed into the gas supply network operated by ONTRAS Gastransport and is provided for regular gas applications (power generation, heating, automobile fuel, etc.) without any problems.

Uniper and other companies have been steadily pursuing PtG demonstrations since then and started "WindGas Hamburg" in Hamburg from 2015 using the knowledge obtained at Falkenhagen. This project uses a 1.5 MW polymer electrolyte membrane (PEM) electrolyser, and provides the hydrogen produced to general consumers via a gas pipeline. Uniper also announced the construction of a new 1 MW plant in Falkenhagen in 2017. The plant is intended to produce methane, which is scheduled to be completed in 2018.[43]

1.2.3. Transport Technology (Demonstrative Projects in Japan)

When constructing a CO_2-free hydrogen supply chain in the APEC region in the future, it is essential to establish not only hydrogen production and usage technology, but also transport technology that can be used for import and export. Except for very few instances, no cases of importing and exporting

[41] Schneider, Günther, "Storage of Wind Power in Natural Gas Grids: "Power to Gas" Falkenhagen," European Gas Technology Conference, 2013.
[42] Uniper website (https://www.uniper.energy/storage/what-we-do/power-to-gas)
[43] Joint press release, 6 July 2017

hydrogen by sea could be confirmed,[44] and no leading implementation cases exist. But Japan, in recent years, has pushed forward with attempts to build a CO_2-free hydrogen supply chain by importing from other countries.

In 2016, Kawasaki Heavy Industries, Iwatani Corporation, Shell Japan, and Electric Power Development established the CO_2-free Hydrogen Energy Supply-Chain Technology Research Association (HYSTRA) and, using their strengths began to demonstrate technology for the gasification of lignite to produce hydrogen, long-range mass transportation and cargo handling of liquefied hydrogen for transportation and to identify issues facing commercialisation.[45] The lignite for producing hydrogen in this project is supplied by Australia and uses CCS to be CO_2-free.

In addition, Chiyoda Corporation, Nippon Yusen Kaisha, Mitsui & Co., and Mitsubishi Corporation established the Advanced Hydrogen Energy Chain Association for Technology Development (AHEAD) in 2017. The Association aims for a hydrogen import demonstration project[46] using organic hydride technology and will build a hydrogen plant (SMR) in Brunei and a dehydrogenation plant in Kawasaki, Kanagawa by 2019 to extract hydrogen from hydrides, and then start shipping hydrogen from Brunei by sea to customers in Japan from 2020.[47]

1.2.4. Fuel Cell Vehicles (California, USA)

California has one of the strictest zero emission vehicle (ZEV) regulations in the United States and is actively promoting electric vehicles and FCVs. As of September 2017, there were about 2,700 hydrogen-powered passenger vehicles[48] in the United States, with about 2,600 registered in the state of California.[49] At the same time, California deploys more hydrogen infrastructures than other states. 36 of the 43 hydrogen fuelling stations nationwide located in California as of October 2017.[50] (Figure 1.5 shows the distribution as of March 2017. The figure includes planned stations.)

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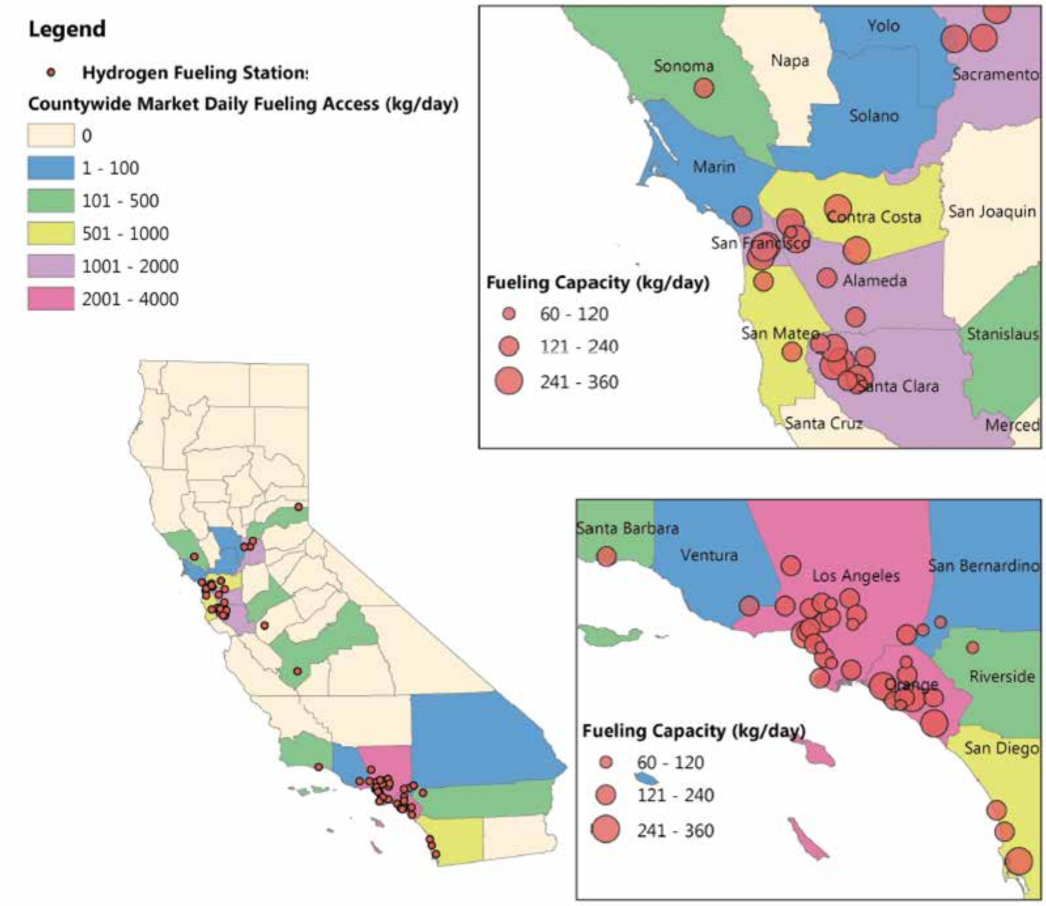
[44] For example, until the 1990's, the Euro-Quebec Hydro-Hydrogen Pilot Project was experimentally exporting hydrogen produced by Canadian hydroelectric power to Europe.
[45] Kawasaki Heavy Industries press release, 1 April 2016.
[46] AHEAD website (https://www.ahead.or.jp/organization.html).
[47] Mitsubishi Corporation press release, 27 July 2017.
[48] Although the majority are FCVs, those that burn hydrogen in internal combustion engines are also included.
[49] Estimate from information published by Hydrogen Analysis Resource Center.
[50] The number of hydrogen stations that are selling to the public. Including those targeting only specific customers, there are 64 in the United States, with 43 in California. (from information published by DOE, Alternative Fuels Data Center).

Figure 1.5 Existing and Planned Hydrogen Dispensing Capacity by County, as of 1 March 2017



Source: ARB (2017),[51] p.23.

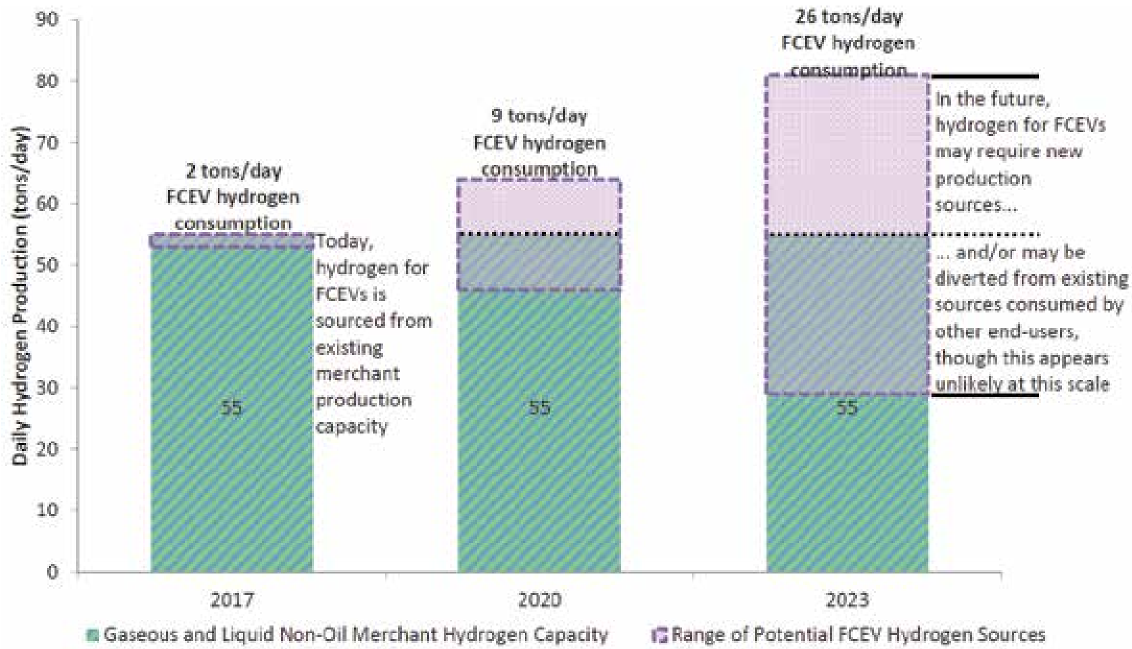
Founded in 1999, the California Fuel Cell Partnership (CaFCP) is a public-private platform aiming at deploying FCVs and hydrogen stations in the state. Currently, CaFCP includes major automobile manufacturers Toyota and Mercedes-Benz, major gas suppliers Air Liquide and Linde North America, as well as the California Energy Commission, the Air Resources Board (ARB), the federal Department of Energy (DOE), and the Environmental Protection Agency (EPA), and others. Support schemes for funding lie mainly with the California State Government. Subsidies for purchasing a ZEV (Clean Vehicle Rebate Project, or CVRP) and subsidies for the construction of hydrogen stations (GFO-15-605) are in place, which, as stated above, have been the most effective in the United States. Delays are expected in the actual introduction of ZEVs, however, as the roadmap released by CaFCP in 2012 targets 53,000 vehicles[52] and over 84 hydrogen stations[53] in 2017.

The ARB reports annually to the Energy Commission on FCVs in the state, the status of the spread

[51] ARB, "2017 Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development," 2017.
[52] Based on the results of surveying the forecast number of vehicles sold of each automobile manufacturer and aggregating them.
[53] CaFCP, "A California Road Map: Bringing Hydrogen Fuel Cell Electric Vehicles to the Golden State," 2012, p.20.

of hydrogen infrastructure, and its forecast, and proposes priority areas for hydrogen fuelling stations and the size of subsidy budgets based on their report. According to their report, in contrast to the above roadmap, the forecast number of FCVs will be 13,400 in 2020 and 37,400 in 2023. According to the ARB, hydrogen demand by FCVs in California is currently about 2 t/day (about 8 million Nm^3/year), which is covered by the supply from existing production plants, but based on the outlook for 2023, the demand for hydrogen will be about 26 t/day (about 105 million Nm^3/year), meaning that new production plants are needed to supply FCVs (Figure 1.6). Air Products announced in 2017 that it was able to sell hydrogen at fuelling stations in California for 9.99 USD/kg.[54] This is nearly the same price as Iwatani Corporation announced in 2014 (1.1.3, (4)).

Figure 1.6 Comparison of Projected Statewide Hydrogen Demand to Current In-State Non-Oil Merchant Hydrogen Production Capacity



Source: ARB (2017), p.69.

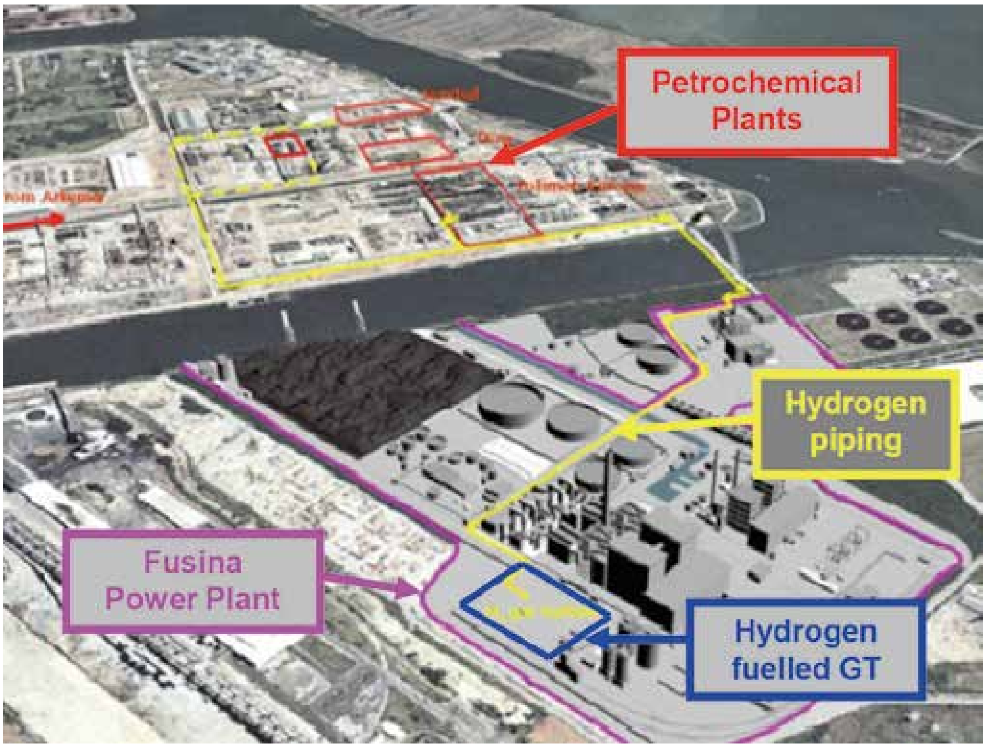
1.2.5. Hydrogen Power Generation (Fusina, Italy)

As stated in section 1.1.3, Enel is conducting a dedicated hydrogen combustion demonstration project in Fusina, Italy, which is the only one in the world. This hydrogen power plant consumes by-product hydrogen provided by nearby petrochemical plants. Before its construction, in this area, a consortium called "Hydrogen Park" conducted various kinds of demonstration projects for hydrogen utilisation technologies, and so it is a suitable site for a hydrogen plant. The total amount of capital cost of the plant is about 50 million euros, and its installed capacity is 16 MW (generation capacity by hydrogen is 12 MW, as well as an additional 4 MW generated through re-use of heated gas produced

[54] Air Products, Press Release, 6 March 2017.

by the hydrogen-fuelled turbine in the existing coal-fired plant). It consumes 1.3 t-H_2/day and generates 60 GWh of electricity.[55]

Figure 1.7 The Fusina Site



Source: Sigali (2011)[56]

1.2.6. Hydrogen Town (Kitakyushu City, Japan)

The Fukuoka Strategy Conference for Hydrogen Energy was established in Fukuoka Prefecture in 2004 where it has advanced the Fukuoka Hydrogen Strategy (Hy-Life Project) since then. This project is the only initiative in Japan that comprehensively promotes the development and spread of hydrogen energy with activities such as research and development, community demonstrations, human resource development, the building of a knowledge hub, and fostering of new industries. One of its community demonstration projects is Kitakyushu Hydrogen Town, established in 2011. The project uses by-product hydrogen generated from the Yawata Steel Works[57] and supplies it by pipeline to households, commercial facilities and public facilities to demonstrate the technology it uses. Figure 1.8 shows the primary destinations of the hydrogen supply. The demonstration of the hydrogen technology at the community level of this scale can be said to be the first trial in the world.

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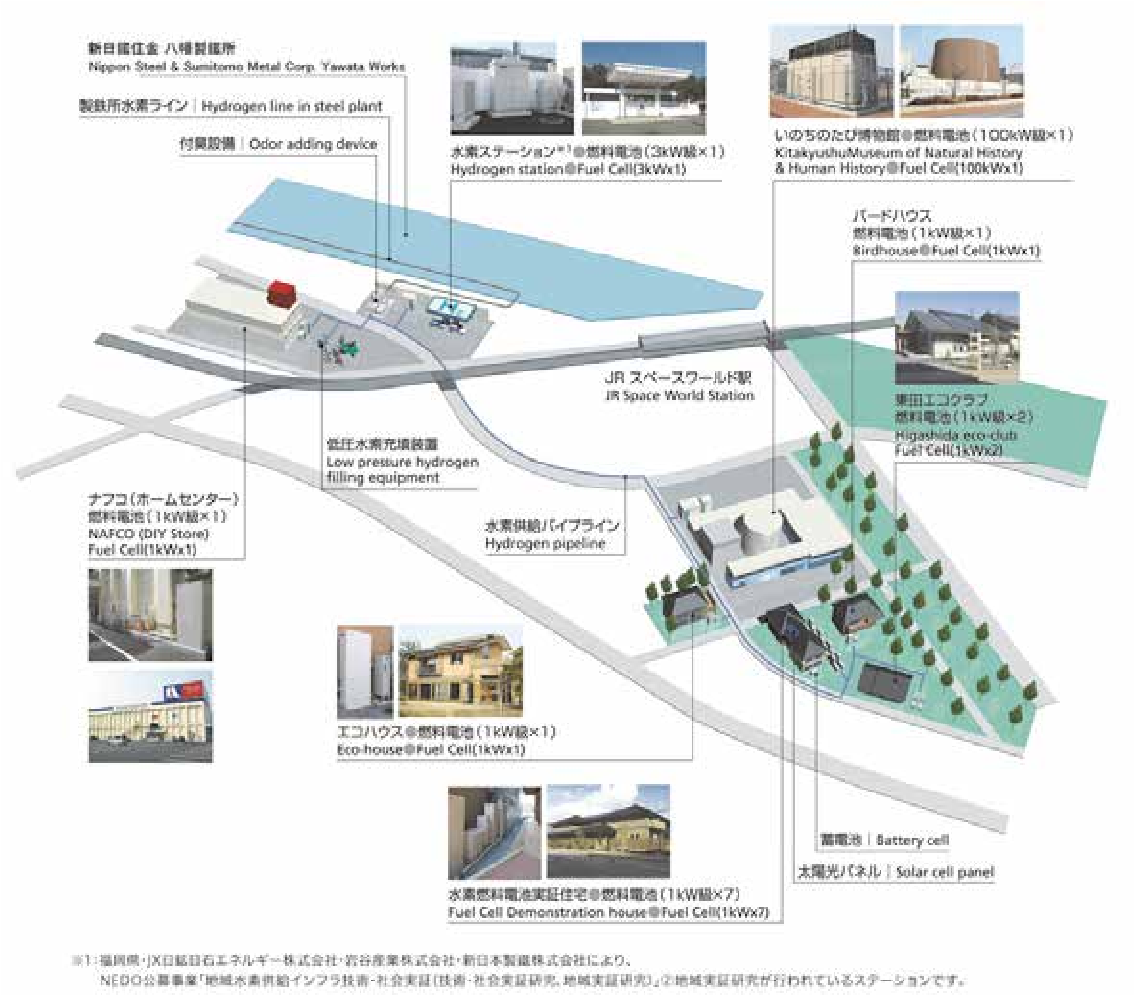
[55] Enel, Press Release, July 12, 2010.

[56] Sigali, Stefano, "Electricity from Hydrogen with Combined Cycles: The Fusina Project," Better Practice Exchange 2011, 2011.

[57] The steelworks owned by Nippon Steel & Sumitomo Metal started operations as a state-run steel works in 1901. Part of the original steel works is registered as a World Heritage site as "Sites of Japan's Meiji Industrial Revolution: Iron and Steel, Shipbuilding and Coal Mining."

Figure 1.8 Destinations of Hydrogen in Kitakyushu Hydrogen Town



Source: Saibu Gas website[58]

Specific demonstration items of the project include: (1) demonstration of hydrogen supply technology via a hydrogen pipeline, (2) demonstration of pure hydrogen fuel cells for multiple applications and for operation of multiple units, (3) demonstration of small vehicles using hydrogen as a fuel, (4) demonstration of supplying electricity from fuel cell vehicles to households (FCV2H), and (5) demonstration of small-area power adjustment at rental housing for the elderly. A breakdown of each item is as follows[59]:

(1) Demonstration of hydrogen supply technology via a hydrogen pipeline

- Laying approximately 1.2km of pipeline from a hydrogen station to a residential neighbourhood

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[58] http://www.saibugas.co.jp/profile/env_report/2014/technology/hydrogen.htm
Saibu Gas is a member of the Fukuoka Strategy Conference for Hydrogen Energy.

[59] Kitakyushu City, *Kitakyushu City Vision for a Hydrogen Society*, 2017, p.7.

- Identify operational issues related to the stable supply of hydrogen

(2) Demonstration of pure hydrogen fuel cells for multiple applications and for operation of multiple units

- Installation at apartment houses, businesses facilities and hydrogen fuelling stations
- Demonstration of pure hydrogen fuel cells and storage batteries connected to a solar power generation system

(3) Demonstration of small vehicles using hydrogen as a fuel

- Demonstration of small vehicles, such as forklifts and bicycles, powered by fuel cells

(4) Demonstration of supplying electricity from fuel cell vehicles to households (FCV2H)

- Supplying of electricity from a fuel cell vehicle to a house
- Demonstration as a new method of power levelling that contributes to reducing peak load
- Demonstration of the effect of power supply to public facilities (Kitakyushu Museum of Natural History & Human History) assumed to be evacuation shelters in times of disaster (V2L)

(5) Demonstration of small-area power adjustment at rental housing for the elderly

- Collaboration of community energy management system (CEMS) and Building Energy Management System (BEMS) in the "Higashida no Aikouen," housing facility for the elderly
- Conversion to hydrogen and storage in a tank when there is surplus electricity in the area, and when the demand increases, operation of fuel cells to supply electricity

Although the empirical research in Kitakyushu Hydrogen Town was completed in 2014, Fukuoka Prefecture and Kitakyushu City announced in 2016 their intention to restart the project.[60] They are planning to clarify the possibilities of using hydrogen at low cost through new demonstrations, such as technology to supply odourless hydrogen directly to households in urban areas.

The "Kitakyushu City Vision for Hydrogen Society" was announced in 2017, with the city setting the goal of creating a Kitakyushu hydrogen supply chain by around 2030. In addition to the Higashida district where the Kitakyushu Hydrogen Town project was held, the Vision designates the Hibikinada area as a "leading area" in which many energy-related facilities and port infrastructure are located. In that area, it aims to import hydrogen from overseas, produce it through LNG reforming and construct a storage and supply base for supplying Kyushu and other various parts of Japan.

[60] The Nihon Keizai Shimbun, 5 February 2016.

2. Analysis of the Possibility of Implementing Hydrogen in the APEC Region

2.1. Understanding the Supply Potential for CO_2-Free Hydrogen

We assume the options for supplying CO_2-free hydrogen to be coal gasification + CCS, natural gas reforming + CCS, and electrolysis using renewable energy (solar power, wind power, hydroelectric power). Table 2.1 shows the assumed hydrogen production options for each economy.

Table 2.1 Production Options of CO_2 Free Hydrogen in Each Economy

	Coal+CCS	Natural Gas+CCS	Wind (on-shore)	Solar PV	Hydro (available existing capacity)
Australia	●	●	●	●	
Brunei Darussalam					
Canada	●	●			●
Chile				●	
People's Republic of China	●		●	●	●
Hong Kong, China					
Indonesia	●			●	
Japan			●	●	
Republic of Korea			●	●	
Malaysia				●	
Mexico			●	●	
New Zealand	●		●		●
Papua New Guinea					
Peru					
The Philippines					
Russia	●	●			●
Singapore					
Chinese Taipei			●	●	
Thailand				●	
The United States	●	●	●	●	
Viet Nam			●	●	

The supply potential for hydrogen is based on the estimated amount of fossil fuel or renewable energy resources. We use existing evaluation cases to estimate amount of fossil fuel and renewable energy resources. The fossil fuel estimate uses recoverable reserves data compiled by BP.[61] Since there is no existing data on renewable energy resources assessments that covers APEC economies, the estimate uses official government announcements on renewable energy resources, the reports of international organisations and the authors' own estimation as sources. There are three approaches to

[61] BP Statistical Review of World Energy 2017a

assessing the potential of renewable energy: the resource potential of the physical quantity, the technological potential of what is technically developable, and the economic potential of what is economically rational. Additionally, it is necessary to be aware that the evaluation criteria for the potential of a renewable energy resource used in this calculation varies depending on the source of the data.

Table 2.2 Major Assumptions for Supply Potential Estimation

	Share of resource potential dedicated to hydrogen production	Convertion factor
Coal (lignite) + CCS	30% or CO2 storage potential, which is smaller	24.3 MJ/Nm3-H2
Natual gas + CCS	10% or CO2 storage potential, which is smaller	0.014 mmbtu/Nm3-H2
Wind and electrolyzation	10%	4.5 kWh/Nm3-H2
Solar PV and electrolyzation	10%	
Hydro power and electrolyzation	10% of existing capacity	

Note: Share of resource potential is assumed by authors.

Source: Conversion factor is from US DOE, Hydrogen and Fuel Cell Program.

It is unrealistic to use all fossil fuel and renewable energy resources to produce hydrogen. For hydrogen from renewable energy, the hydrogen supply potential is estimated on the assumption that 10% of renewable energy resources are used to produce hydrogen. For fossil fuels, the estimate preconditions are determined by considering the CO_2 sequestration potential. Possible CO_2 sequestration sites using CCS include depleted oil and gas fields, unused coal seams, and aquifers. Although aquifers have a very large CO_2 sequestration potential, this study limits CO_2 sequestration potential with CCS to depleted oil and gas fields and unused coal seams as further technical and economic reviews are needed to use aquifers as a reservoir.

On the other hand, progress by countries surveying the CO_2 sequestration potential of depleted oil and gas fields and unused coal seams has been uneven, and there are cases where various numbers have been reported even in the same country. This study bases the CO_2 storage sequestration potential of major countries summarised by the Institute of Energy Economics, Japan in the *Asia/World Energy Outlook 2016*. In the APEC region, the CO_2 sequestration potential of currently known depleted oil and gas fields and unused coal seams is limited. For example, the United States has a potential of 240-350 Gt of CO_2, but Australia is estimated to have a potential of about 20 Gt CO_2, while Russia and China have about 6.8 Gt and 2.2 Gt of potential respectively. We assume that 30% of lignite resources and 10% of natural gas resources will be used to produce hydrogen in economies with sufficient CO_2 sequestration potential. Economies with limited CO_2 sequestration potential are constrained by their estimated hydrogen supply potential, and where they possess both lignite and natural gas resources, the supply potential of CO_2-free hydrogen is estimated assuming the maximum utilisation of lignite resources and the maximum utilisation of natural gas resources.

Table 2.3 Hydrogen Supply Potential

Fossil fuel + CCS		Renewable		
Maximum utilization of Coal (lignite)	Maximum utilization of natual gas	Wind and electrolyzation	Solar PV and electrolyzation	Hydro power and electrolyzation
billion Nm3-H2		billion Nm3-H2/year		
21,526	25,166	866	6,933	43

Table 2.3 shows the supply potential for CO_2-free hydrogen estimated under the above conditions. By source, it is possible to supply 7,840 billion Nm^3 of hydrogen per year using 10% of the renewable energy resources (onshore wind power, solar power generation, and existing hydropower capacity) in the APEC region. In the hydrogen demand scenario analysis of the APEC region in section 2.2, hydrogen demand is 451 billion Nm^3/year in 2040 and 1,367 billion Nm^3/year in 2050 (see Table 2.8), indicating that there is a sufficient hydrogen supply in the APEC region to meet demand.

However, if 30% of lignite resources and 10% of natural gas resources are used in the major fossil fuel producing economies of the APEC region and limited to a realistic CO_2 sequestration potential, the supply potential of CO_2-free hydrogen from fossil fuels is about 21,526 to 25,166 billion Nm^3. Incidentally, as the survey on CO_2 storage potential progresses, the hydrogen supply potential can be expected to expand.

2.2. Hydrogen Demand Scenario Analysis

This section estimates the future hydrogen consumption (demand) under certain assumptions and evaluates the potential of hydrogen use in the industrial, transport, and power generation sectors. The basic approach common to all three sectors uses future energy demand forecasts of Asia-Pacific Economic Cooperation (APEC) member economies already conducted by the Asia-Pacific Energy Research Centre (APERC) as a base and considers the possibility of substituting fossil fuel demand with hydrogen. However, since the private (commercial and residential) sector has a diverse and dispersed small-scale form of use compared with other sectors and development of supply infrastructure for them becomes a bottleneck, its impact on overall demand is considered to be small, so it is not included in the estimate of this research aiming to evaluate the demand at the APEC regional level.

2.2.1. Industrial Sector

In the industrial sector, its composition, such as fuels and applications, differs depending on the type of industry, and there are parts that can be substituted for by hydrogen and parts that cannot. In this regard, the Institute of Energy Economics, Japan (IEEJ) has already estimated the energy consumption structure and the possibility of substituting hydrogen in each industry in Japan using the Ministry of Economy, Trade and Industry's Current Survey of Energy Consumption.[62] Therefore, we assume here that the energy consumption structure of the same industry is the same in any country and estimate the total demand of APEC by applying the Japanese estimations by IEEJ to other member economies.

(1) Substitutability in Japanese Industrial Sectors

By using the Current Survey of Energy Consumption, the energy consumption structure in Japan's industrial sectors can be classified into four types of fuel (coal, oil, natural gas, and by-products) and five kinds of applications (for boilers, for cogeneration, for feedstock, for direct heating and for other applications). According to the study by the IEEJ mentioned above, Table 2.4 outlines the substitutability of fuels and applications (see notes below table for exceptions).

Next, of the theoretically substitutable fuels and applications, we consider the proportions that can be replaced by hydrogen in the forecast year. In this research, we assume that hydrogen substitution is gradually started from around 2030, and 15% of substitutable fuels and applications in 2040 and 30% in 2050 are replaced with hydrogen.[63] Table 2.5 shows the hydrogen substitution rate for each industrial sector for each type of fuel (with no consideration of the application) with that assumption.

Table 2.4 Substitutability of Energy Demand in Industrial Sector by Hydrogen

<table>
<tr><th></th><th>For Boilers</th><th>For Cogeneration</th><th>As Materials</th><th>For Direct Heating</th><th>For Other Purposes</th></tr>
<tr><td>Coal</td><td colspan="2">Substitutable[*1]</td><td rowspan="4">Not Substitutable</td><td colspan="2">Substitutable[*1]</td></tr>
<tr><td>Oil</td><td colspan="2">Substitutable</td><td colspan="2">Substitutable</td></tr>
<tr><td>Natural Gas</td><td colspan="2">Substitutable[*2]</td><td colspan="2">Substitutable[*2]</td></tr>
<tr><td>By-Products, etc.</td><td colspan="2">Not substitutable</td><td colspan="2">Not substitutable</td></tr>
</table>

Note:

*1: Coal demand in "Iron and Steel" and "Ceramics, Clay and Stone" industries is not substitutable by hydrogen because production process of these industries is established so that coal utilisation is indispensable.

*2: Hydrogen as substitute for natural gas is supposed to be supplied through existing pipelines. So hydrogen substitutes 50 vol.% (24 cal.%) of its demand at the maximum.

*3: All of the energy demand in "Petroleum products" industry is not substitutable by hydrogen for the same reason as "Iron and Steel" and "Ceramics, Clay and Stone" industries. Thus, our scenario excludes entirely this industry from estimation.

Source: AIST (2014).

[62] National Institute of Advanced Industrial Science and Technology (AIST), *FY2013 Report on Total System Introduction Scenario for the Development of Renewable Energy Storage and Transport Technology*, 2014. Estimates referred to in the text were carried out by IEEJ under the charge of AIST.

[63] The future energy consumption of fuels by application is estimated by the authors based on actual consumption in the Current Survey of Energy Consumption.

Table 2.5 Hydrogen Substitution Rate for Each Industrial Sector in 2040 and 2050

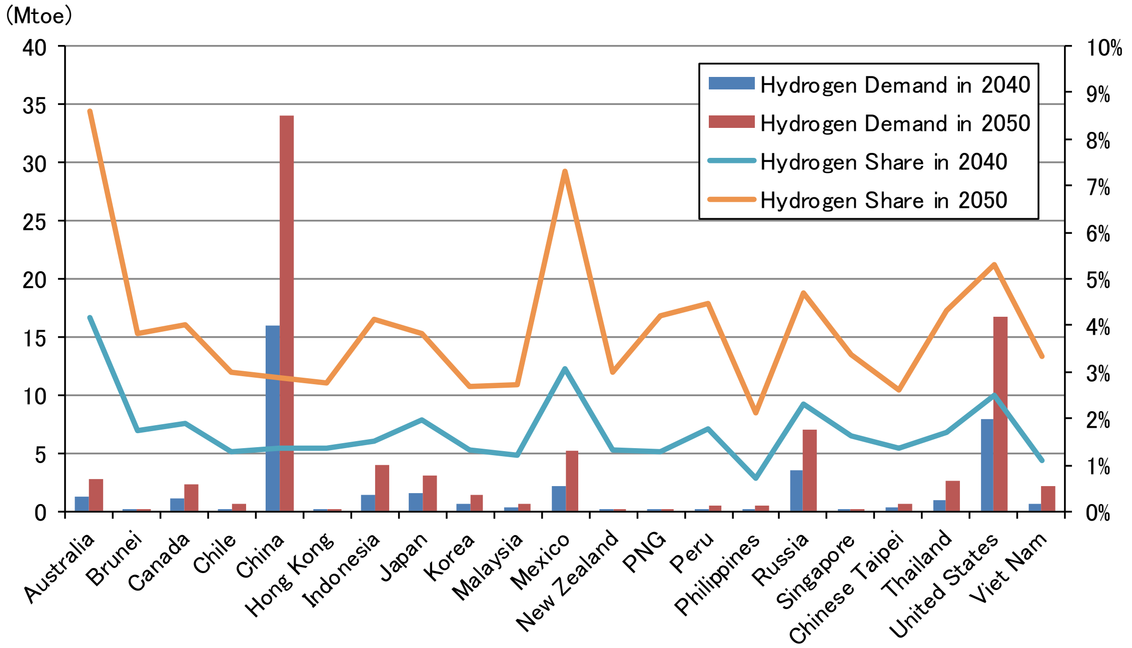
		Iron and Steel	Chemical and Petrochemical	Non-metallic Minerals	Machinery	Paper, Pulp and Printing	Non-ferrous Metals	Others
2040	Coal	0.0%	2.5%	0.0%	6.0%	12.9%	13.4%	2.0%
	Oil	8.3%		12.2%				
	Natural Gas							
	By-Products, etc.	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2050	Coal	0.0%	5.0%	0.0%	11.9%	25.7%	26.8%	4.0%
	Oil	16.5%		24.3%				
	Natural Gas							
	By-Products, etc.	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Note:
- Some of the industries in Japanese statistics are integrated so that they would correspond to the classification by APERC Outlook.
- "Others" is calculated by the average of all the industries excluding "Petroleum products" that is not supposed to be substitutable by hydrogen. (Please see the note no.3 of Table 2.4.)

(2) Demand for Entire APEC Region

The hydrogen substitution potential (%) by industry and fuel was estimated based on (1) above. The substitution potential is applied to the future energy demand in the industrial sectors of each member economy estimated by APERC (2016),[64] and Figure 2.1 shows the estimated hydrogen demand potential of each member economy. The totals for all of APEC are 39,047 ktoe in 2040 (1.7% of the final energy consumption of the industrial sector for that year) and 84,994 ktoe in 2050 (3.7% of the final energy consumption of the industrial sector for that year).

Figure 2.1 Hydrogen Energy Demand in Industrial Sector of APEC Economies and Its Share



64 APERC, *APEC Energy Demand and Supply Outlook 6th Edition*, 2016. Also includes estimates by the authors.

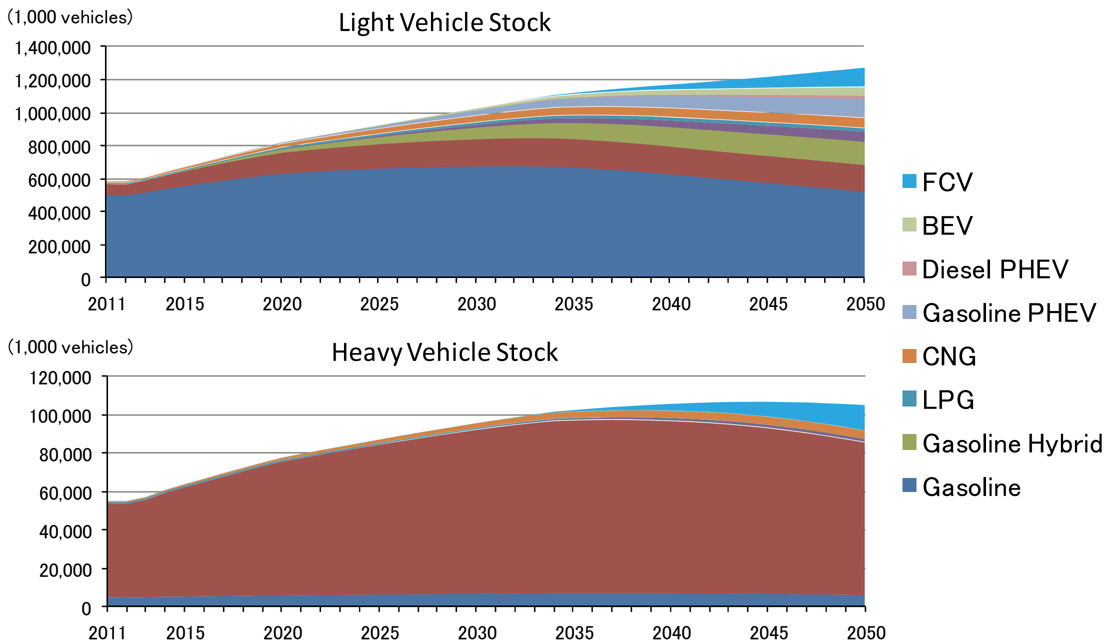
2.2.2. Transport Sector

Based on the outlook (BAU scenario) for the purchase of light and heavy vehicles in member economies estimated by APERC, we believe a portion of new vehicles sales every year can be replaced by fuel cell vehicles (FCV) in the transport sector. Under this assumption, we determined the total vehicle stock each year according to the number of estimated new vehicles sales and calculated the total energy demand by applying the fuel consumption (annual energy consumption) by vehicle model estimated by APERC.

(1) Vehicle Stock Estimate

Considering the technological feasibility and the motivation to deploy FCVs given by environmental restrictions, we assume that light vehicles powered by gasoline and heavy vehicles powered by gasoline or diesel can be substituted by FCVs. Motorcycles are not included as a candidate for FCV substitution in this estimate since their proportion in the transport sector's total energy demand is relatively small and the introduction of FCV models into the market is delayed compared with passenger vehicles. The substitution rate of FCVs versus the number of new vehicle sales would increase at a constant pace from 2031 and is assumed to be 15% in 2040 and 30% in 2050 as in the industrial sector. Based on these assumptions, we estimate the number of new vehicles sold in each member economy and apply the rate at which aging vehicles are scrapped that is equivalent to the APERC estimation, and arrive at the total stock of light vehicles and heavy vehicles across APEC shown in Figure 2.2. According to this result, the ratio of FCVs to the total vehicle stock in 2050 is 8.9% for light vehicles and 12.5% for heavy vehicles.

Figure 2.2 Light and Heavy Vehicle Stock in APEC Economies



(2) Energy Demand Estimate

The yearly vehicle stock of each member economy was estimated in (1) above. Using these numbers, energy demand in the transport sector can be obtained by applying the APERC-estimated fuel efficiency by vehicle model and annual travel distance and totalling the results. Figure 2.3 shows the trends in the whole APEC region, and Figure 2.4 shows the data by economy for 2040 and 2050. Since these are total values of the transport sector, they include not only the total light vehicle and heavy vehicle demand, but also the energy demand by motorcycles (not substituted by FCV). Hydrogen energy demand across the APEC region was 32,691 ktoe in 2040 (2.1% of the final energy consumption in the transport sector for that year) and 130,277 ktoe in 2050 (8.5% of the final energy consumption in the transport sector for that year).

Figure 2.3 Final Energy Consumption in Transport Sector of APEC Economies

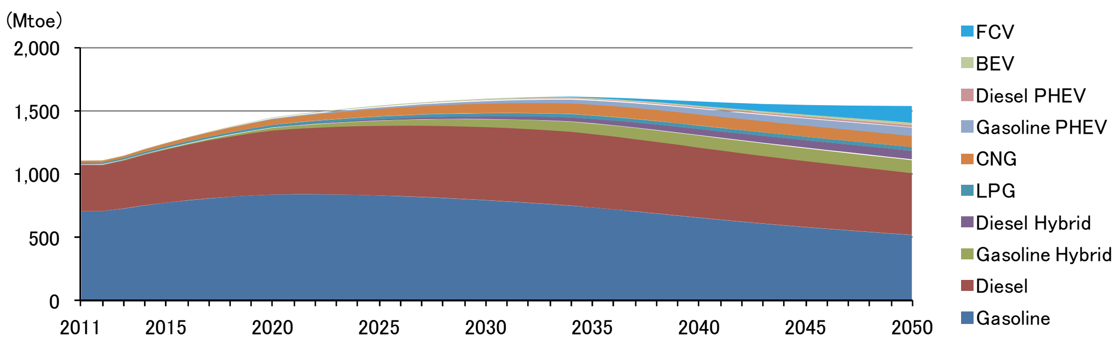
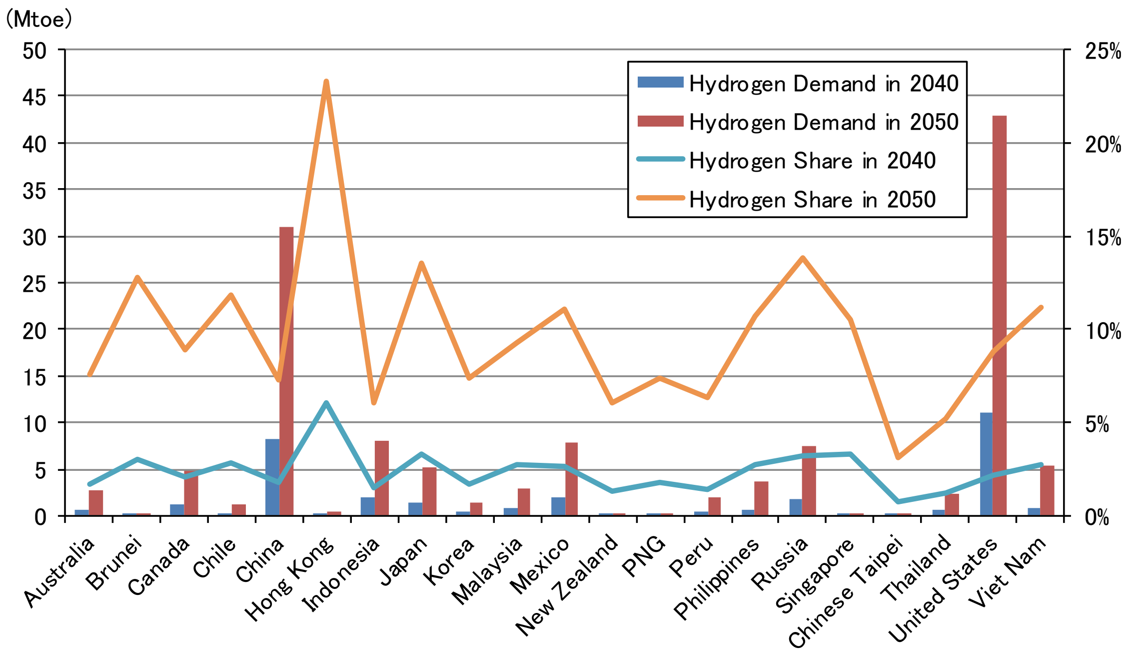


Figure 2.4 Hydrogen Energy Demand in Transport Sector of APEC Economies and Its Share



2.2.3. Power Generation Sector

In the power generation sector as well, we believe that a portion of new coal and gas thermal power generation will be replaced by hydrogen to reduce CO_2 emissions, and the amount of new thermal power plants in the future is based on the APERC estimation (BAU scenario). In addition, the assumptions for the estimation are based on the "lower hydrogen scenario" by the IEEJ (2016).[65]

(1) Assumptions

As stated in section 1.1.3, the usage of hydrogen in the power generation sector can be roughly divided into stationary fuel cells and hydrogen (thermal) power generation, but stationary fuel cells

[65] Institute of Energy Economics, Japan, *Asia/World Energy Outlook 2016.*

that have begun to spread and are expected to continue to do so for the foreseeable future are not a so-called "pure hydrogen type" of generation, but that reform natural gas supplied to the system to obtain hydrogen. Energy demand by this type of fuel cell should be regarded as natural gas demand and is not included in the estimation of hydrogen demand in this research.

Substituting the base load power supply of thermal power generation with hydrogen power generation means that the supply of hydrogen needs to be large-scale and stable, and since electrolysis using the excess electricity from the fluctuating output of renewable energy is not suitable for this, we assume that hydrogen should be supplied by fossil fuel reforming. However, from the viewpoint of reducing CO_2 emissions, fossil fuel reforming should be combined with carbon capture and storage (CCS). However, if CCS is available in all economies, there is no motivation to introduce hydrogen power because fossil fuel power generation can be used in each economy without CO_2 emission regardless of hydrogen utilisation. Therefore, we assume that CCS is not available in all economies and that economies where CCS is not available (non-CCS economies) import CO_2-free hydrogen from economies where CCS is available (CCS economies) to generate power. CCS economies can use CO_2-free thermal power generation in their own economy for the above reasons. Future discussions of CCS should take into consideration the amount of CO_2 that can be stored, but at present as there is no internationally authorized data on storage potential for each economy, and we only judge whether CCS is available or not in each economy being based on information published to date. Since additional information will likely be released concerning the feasibility and potential storage amounts, it is necessary to pay careful attention to such information and respond flexibly in future research.

Finally, as with the IEEJ (2016) "lower hydrogen scenario" the proportion of thermal power generation replaced by hydrogen power generation in non-CCS economies is basically set to 50% of newly installed capacity after 2035.[66] However, as assumed above, hydrogen used for power generation will be covered by imports from CCS economies, so it is difficult to imagine that economies that have abundant coal and natural gas resources depend on hydrogen imports, abandoning their own resources. Therefore, as for economies with less than 50% dependence on imports (100% minus self-sufficiency rate (%), with the self-sufficiency rate based on APERC estimation) of each resource as of 2040, we apply its import dependency rate as the substitution rate[67]. Table 2.6 summarises the CCS and non-CCS economies, the self-sufficiency rate of energy resources in 2040 for each economy, and the substitution rate calculated taking each into consideration.

[66] Japanese Ministry of Economy, Trade and Industry announced in 2016 the *Strategic Roadmap for Hydrogen and Fuel Cells* (revised) stated that the full-scale introduction of commercial hydrogen power generation will proceed from around 2030, which is consistent with the IEEJ scenario that assumes its introduction will progress in APEC from 2035 (leaving whether Japan will lead aside).

[67] According to the estimation of this research, it is assumed that the substitution rate in the industrial and transport sectors increases in stages from 0%, whereas the substitution rate of each economy in the power generation sector is uniformly applied from 2035 to 2050. The difference is consistent with the fact that if a hydrogen power plant is constructed as a substitute for a thermal power plant, the scale of the plant should be above a certain level, and that it is difficult to imagine that they will gradually increase like some plants of the manufacturing industry and some new vehicles sales.

Table 2.6 CCS Possibility, Self-Sufficiency and Hydrogen Substitution in APEC Economies

	CCS	Self-Sufficiency in 2040		Substitution by Hydrogen	
		Coal	Gas	Coal	Gas
Australia	Yes	100%	100%	0%	0%
Brunei	Yes	n.a.	100%	0%	0%
Canada	Yes	100%	100%	0%	0%
Chile	No	1%	17%	50%	50%
China	No	86%	57%	14%	43%
Hong Kong	No	n.a.	n.a.	50%	50%
Indonesia	Yes	100%	53%	0%	0%
Japan	No	n.a.	3%	50%	50%
Korea	No	1%	0%	50%	50%
Malaysia	No	5%	88%	50%	12%
Mexico	No	79%	98%	21%	2%
New Zealand	Yes	100%	100%	0%	0%
PNG	No	n.a.	100%	50%	0%
Peru	No	11%	100%	50%	0%
Philippines	No	22%	49%	50%	50%
Russia	Yes	100%	100%	0%	0%
Singapore	No	n.a.	n.a.	50%	50%
Chinese Taipei	No	n.a.	1%	50%	50%
Thailand	No	16%	16%	50%	50%
United States	Yes	100%	100%	0%	0%
Viet Nam	No	31%	51%	50%	49%

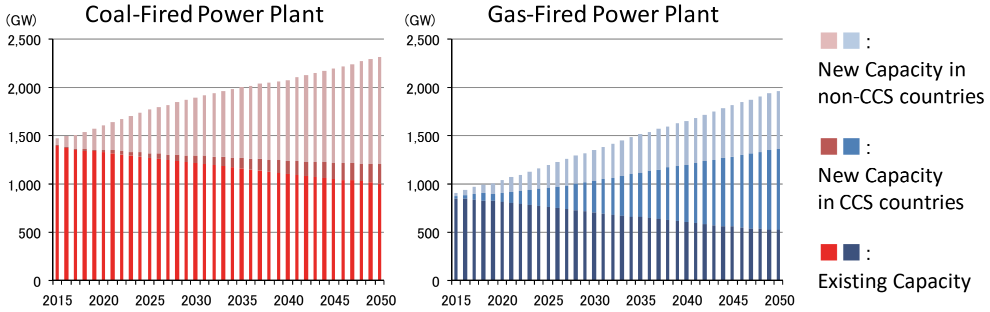
Source: IEEJ (2016) and APERC (2016).

(2) Energy Demand Estimation

Based on APERC's outlook for the construction of new thermal power generation plants and retirement of existing ones, newly installed capacity is divided into CCS economies and non-CCS economies as shown in Figure 2.5. The amount of electricity generated by hydrogen can be obtained using the substitution rate for each economy shown in Table 2.6 for the equivalent amount of electricity generation by the new capacity in non-CCS economies. Figure 2.6 summaries the results and shows the trend in the amount of electricity generated in the APEC economies. According to the results, the amount of electricity generated by hydrogen in all of APEC would be 294 TWh in 2040 (1.2% of total power generation for that year) and 903 TWh in 2050 (3.4% of total power generation for that year). Furthermore, when we assume the generating efficiency of hydrogen is 57%,[68] then the required energy input of hydrogen is 44,371 ktoe in 2040 and 136,293 ktoe in 2050. Figure 2.7 shows the results by economy.

[68] Although sufficient data on the accurate generating efficiency of hydrogen power has not been confirmed, but since it is expected that the constituent elements such as equipment will be close to those of LNG-fired power generation, the report by the power generation cost verification working group of the Ministry of Economy, Trade and Industry of Japan adopted the figures equivalent to the generating efficiency of LNG-fired power generation in 2030. (Power Generation Cost Verification Working Group, *Report on Analysis of Generation Costs, etc. for Subcommittee on the Long-term Energy Supply- demand Outlook*, 2015, p.47.)

Figure 2.5 Existing and Newly Installed Capacity of Thermal Power Plants in APEC Economies (No Hydrogen Scenario Estimated by APERC)



Source: APERC (2016) including unpublished data.

Figure 2.6 Electricity Generation in APEC Economies

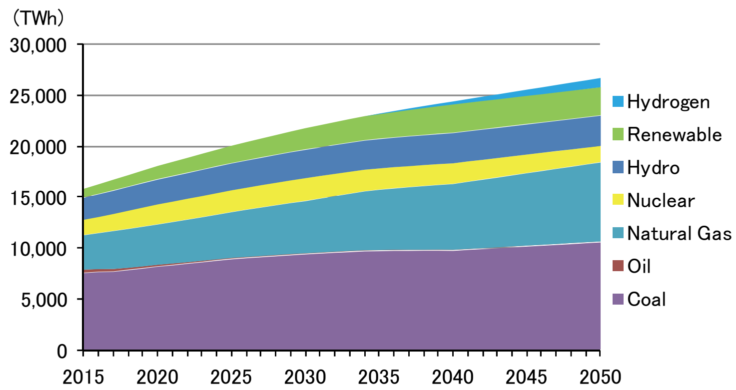
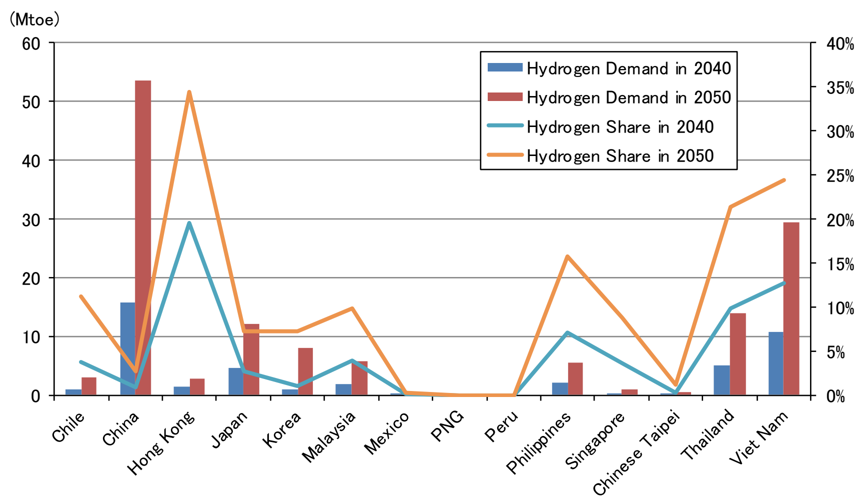


Figure 2.7 Hydrogen Energy Demand in Electricity Sector of APEC Economies and Its Share



Note:

· CCS economies are excluded.

· "Share" in this chart means share of hydrogen in total electricity generation.

2.2.4. Summary of Hydrogen Demand

As described above, we estimated the potential demand for hydrogen energy based on assumed scenarios for the industrial, transport and power generation sectors. These are summarised in Table 2.7, and converted into gas volume in Table 2.8.

Table 2.7 Hydrogen Energy Demand in APEC Economies (in ktoe)

(ktoe)

	Hydrogen Demand in 2040				Hydrogen Demand in 2050			
	Industry	Transport	Electricity	Total	Industry	Transport	Electricity	Total
Australia	1,343	608	0	1,951	2,769	2,664	0	5,433
Brunei	3	16	0	20	8	67	0	74
Canada	1,130	1,199	0	2,329	2,376	4,762	0	7,138
Chile	263	291	909	1,462	600	1,151	3,153	4,904
China	15,925	8,229	15,730	39,883	33,958	30,973	53,435	118,366
Hong Kong	14	119	1,444	1,577	28	481	2,837	3,346
Indonesia	1,468	1,933	0	3,401	4,028	7,987	0	12,015
Japan	1,571	1,486	4,561	7,617	3,035	5,255	12,098	20,389
Korea	691	421	1,099	2,212	1,384	1,466	8,071	10,921
Malaysia	326	745	1,931	3,002	728	2,841	5,873	9,442
Mexico	2,206	1,971	117	4,294	5,276	7,935	357	13,569
New Zealand	71	55	0	126	162	227	0	389
PNG	47	26	0	74	154	164	0	318
Peru	198	400	0	598	498	1,976	0	2,474
Philippines	182	625	2,101	2,908	539	3,665	5,592	9,796
Russia	3,492	1,805	0	5,296	7,046	7,483	0	14,529
Singapore	123	59	378	560	255	166	956	1,377
Chinese Taipei	322	76	125	522	616	283	482	1,381
Thailand	1,024	587	5,160	6,771	2,585	2,446	13,935	18,966
United States	7,934	11,131	0	19,065	16,777	42,904	0	59,681
Viet Nam	716	908	10,817	12,441	2,170	5,384	29,504	37,058
APEC Total	39,047	32,691	44,371	116,109	84,994	130,277	136,293	351,563

Table 2.8 Hydrogen Energy Demand in APEC Economies (in billion Nm^3)

(billion Nm^3)

	Hydrogen Demand in 2040				Hydrogen Demand in 2050			
	Industry	Transport	Electricity	Total	Industry	Transport	Electricity	Total
Australia	5	2	0	8	11	10	0	21
Brunei	0	0	0	0	0	0	0	0
Canada	4	5	0	9	9	19	0	28
Chile	1	1	4	6	2	4	12	19
China	62	32	61	155	132	120	208	460
Hong Kong	0	0	6	6	0	2	11	13
Indonesia	6	8	0	13	16	31	0	47
Japan	6	6	18	30	12	20	47	79
Korea	3	2	4	9	5	6	31	42
Malaysia	1	3	8	12	3	11	23	37
Mexico	9	8	0	17	21	31	1	53
New Zealand	0	0	0	0	1	1	0	2
PNG	0	0	0	0	1	1	0	1
Peru	1	2	0	2	2	8	0	10
Philippines	1	2	8	11	2	14	22	38
Russia	14	7	0	21	27	29	0	56
Singapore	0	0	1	2	1	1	4	5
Chinese Taipei	1	0	0	2	2	1	2	5
Thailand	4	2	20	26	10	10	54	74
United States	31	43	0	74	65	167	0	232
Viet Nam	3	4	42	48	8	21	115	144
APEC Total	152	127	172	451	330	506	530	1,367

2.3. Effect on CO_2 Emission Reduction from Expanded Implementation of Hydrogen

Here, assuming that the hydrogen demand scenario described in section 2.2 is realised and the demand is covered by CO_2-free hydrogen, we estimate how much of a CO_2 emission reduction can be expected compared with the base scenario (BAU scenario by APERC (2016)). We estimated the amount of hydrogen substituting for fossil fuels in section 2.2. Here, on the other hand, being based on the amount of fossil fuels substituted, we obtain the amount of CO_2 that should have been emitted if the fossil fuels were used.

2.3.1. Industrial Sector

In the industrial sector, the rate of substitution by hydrogen was set for future coal, oil and natural gas consumption, and we estimated the hydrogen demand. The amount of fossil fuels substituted for by hydrogen and the amount of CO_2 that was expected to be emitted by the fuels is shown in Table 2.9. It is expected that hydrogen would reduce emissions by 243 Mt-CO_2 throughout APEC in 2050.

Table 2.9 Reduction of Energy Consumption and CO_2 Emission in Industrial Sector

	2040			2050			2040	2050
	Coal	Oil	Natural Gas	Coal	Oil	Natural Gas	CO_2	
	ktoe						$Mt\text{-}CO_2$	
Australia	116	233	993	198	453	2,118	4	7
Brunei	0	3	0	0	8	0	0	0
Canada	45	266	819	96	549	1,731	3	6
Chile	2	209	51	4	464	131	1	2
China	8,165	3,232	4,528	15,273	5,885	12,801	53	109
Hong Kong	0	13	1	0	26	2	0	0
Indonesia	120	431	917	329	1,035	2,664	4	11
Japan	397	648	526	747	1,159	1,129	5	9
Korea	9	113	570	12	207	1,165	2	3
Malaysia	33	136	157	63	304	361	1	2
Mexico	0	596	1,610	0	1,250	4,026	6	13
New Zealand	9	31	31	18	87	57	0	0
PNG	0	47	0	0	154	0	0	0
Peru	13	124	61	25	294	180	1	1
Philippines	43	131	7	133	379	27	1	2
Russia	7	430	3,056	10	915	6,121	9	17
Singapore	3	93	27	5	194	56	0	1
Chinese Taipei	142	90	90	267	158	191	1	2
Thailand	29	678	317	55	1,707	823	3	7
United States	222	568	7,144	292	1,086	15,399	19	41
Viet Nam	498	192	26	1,433	661	76	3	8
APEC Total	9,851	8,265	20,931	18,960	16,974	49,060	114	243

Note:

· Emission factor of each energy source is based on IPCC (2006).[69]

2.3.2. Transport Sector

In the transportation sector, we set an FCV substitution rate for the number of new gasoline vehicles (heavy-duty vehicles only) and diesel vehicles sold in the future and calculated the vehicle stock (circulating) by fuel type and used it to estimate hydrogen demand. Table 2.10 shows the amount of demand for each vehicle fuel substituted by hydrogen for FCVs and the amount of CO_2 that was expected to be emitted by the fuels. The substitution is expected to reduce emissions by 405 $Mt\text{-}CO_2$ throughout APEC in 2050.

[69] Intergovernmental Panel on Climate Change (IPCC), *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, vol.2, 2006.

Table 2.10 Reduction of Energy Consumption and CO_2 Emission in Transport Sector

	2040		2050		2040	2050
	Gasoline	Diesel	Gasoline	Diesel	CO_2	
	ktoe				Mt-CO_2	
Australia	601	287	2,410	1,233	3	11
Brunei	10	4	39	15	0	0
Canada	1,165	613	4,071	2,489	5	20
Chile	156	131	589	465	1	3
China	5,124	2,125	20,743	6,450	21	80
Hong Kong	13	38	48	154	0	1
Indonesia	1,535	935	6,014	3,461	7	28
Japan	821	376	2,681	1,345	4	12
Korea	196	161	715	430	1	3
Malaysia	192	178	658	726	1	4
Mexico	1,770	528	6,606	2,018	7	25
New Zealand	42	35	164	147	0	1
PNG	27	28	164	149	0	1
Peru	206	340	950	1,550	2	8
Philippines	285	193	1,550	1,042	1	8
Russia	1,203	234	4,658	887	4	16
Singapore	41	56	100	150	0	1
Chinese Taipei	64	40	222	151	0	1
Thailand	205	367	767	1,525	2	7
United States	9,253	5,080	32,757	20,811	43	160
Viet Nam	290	679	1,720	3,367	3	15
APEC Total	23,199	12,429	87,627	48,565	106	405

Note:

· Emission factor of each fuel is based on IPCC (2006).

2.3.3. Power Generation Sector

In the power generation sector, we set a hydrogen power generation substitution rate with respect to the amount of electricity generated by new coal and gas-fired power generation plants expected to be built in the future by non-CCS economies and calculated the amount of the electricity generated by hydrogen and the amount of input energy needed for it. Table 2.11 shows the fuel demand for each power source replaced by hydrogen power generation and the amount of CO_2 that was expected to be emitted by them. A reduction of 598 Mt-CO_2 in emissions throughout APEC can be expected in 2050. Also, in this scenario, CCS economies can capture and store all CO_2 emissions from their own thermal power plants (and therefore do not introduce hydrogen power generation), so it is thought that all emissions in the power generation sector can be reduced. Including the reduction effect by CCS, emission reductions across APEC would be 3,352 Mt-CO_2 in 2040 and 4,087 Mt-CO_2 in 2050.

Table 2.11 Reduction of Energy Consumption and CO_2 Emission in Electricity Sector

	2040		2050		2040		2050	
	Coal	Gas	Coal	Gas	By Hydrogen	By CCS	By Hydrogen	By CCS
	ktoe				Mt-CO_2			
Australia						137		139
Brunei						3		6
Canada						70		85
Chile	1,263	0	4,383	0	5		17	
China	10,744	8,200	36,498	27,856	62		211	
Hong Kong	0	1,646	0	3,234	4		8	
Indonesia						479		644
Japan	1,852	3,270	5,076	8,541	15		40	
Korea	1,058	319	7,745	2,364	5		36	
Malaysia	2,256	444	6,938	1,289	10		31	
Mexico	0	139	0	425	0		1	
New Zealand						4		7
PNG	0	0	0	0	0		0	
Peru	0	0	0	0	0		0	
Philippines	2,666	331	7,177	827	11		30	
Russia						575		662
Singapore	0	402	0	1,019	1		2	
Chinese Taipei	89	60	340	234	0		2	
Thailand	2,683	3,778	7,066	10,316	20		52	
United States						1,888		1,946
Viet Nam	15,414	0	42,043	0	61		167	
APEC Total	38,025	18,591	117,265	56,103	195	3,157	598	3,489

Note:

・Emission factors for the reduction by hydrogen are based on IPCC (2006).

Source: APERC (2016) and estimation by authors

2.3.4. Summary of Effects of CO_2 Emission Reductions

As described above, we estimated the effect of reducing CO_2 emissions for industrial, transport and power generation sectors based on the hydrogen introduction scenario. Table 2.12 summarises the results. Although CCS accounts for majority of the reduction effect in both 2040 and 2050, hydrogen alone can be expected to reduce emissions by 1,246 Mt-CO_2 by 2050. However, its effect is regionally unique, with great differences among China (400 Mt-CO_2), the United States (200 Mt-CO_2), Viet Nam (190 Mt-CO_2) and other economies. Therefore, whether hydrogen utilisation technology will promptly deploy in these economies, will strongly influence the magnitude of the effect obtained by introducing hydrogen energy. While all sectors are important for China, emphasis should be placed on the transport sector in the United States and the power generation sector in Viet Nam. It can be said that for the CCS technology critical to realising its potential in the power generation sector, it is important to advance its development in the United States where more than 50% (1,946 Mt-CO_2) of its effect is concentrated.

Table 2.12 Reduction of Energy-Related CO_2 Emission from APEC Economies

(Mt-CO_2)

	2040				2050			
	Industry	Transport	Electricity	CCS (Electricity)	Industry	Transport	Electricity	CCS (Electricity)
Australia	4	3	0	137	7	11	0	139
Brunei	0	0	0	3	0	0	0	6
Canada	3	5	0	70	6	20	0	85
Chile	1	1	5	0	2	3	17	0
China	53	21	62	0	109	80	211	0
Hong Kong	0	0	4	0	0	1	8	0
Indonesia	4	7	0	479	11	28	0	644
Japan	5	4	15	0	9	12	40	0
Korea	2	1	5	0	3	3	36	0
Malaysia	1	1	10	0	2	4	31	0
Mexico	6	7	0	0	13	25	1	0
New Zealand	0	0	0	4	0	1	0	7
PNG	0	0	0	0	0	1	0	0
Peru	1	2	0	0	1	8	0	0
Philippines	1	1	11	0	2	8	30	0
Russia	9	4	0	575	17	16	0	662
Singapore	0	0	1	0	1	1	2	0
Chinese Taipei	1	0	0	0	2	1	2	0
Thailand	3	2	20	0	7	7	52	0
United States	19	43	0	1,888	41	160	0	1,946
Viet Nam	3	3	61	0	8	15	167	0
APEC Total	114	106	195	3,157	243	405	598	3,489

2.4. Improvement in Energy Security from Expanded Use of Hydrogen

In the previous section, we estimated the alternative fuel demand based on the hydrogen introduction scenario for the industrial, transport and power generation sectors, but section 4 will analyse the extent energy security in each economy and the APEC region improves by expanding the use of hydrogen in these sectors.

Table 2.13 shows the decreasing demand for coal, oil and natural gas, and their proportions in each economy, in 2040 due to the expanded introduction of hydrogen. Fossil fuel demand for all of APEC is reduced by 131 Mtoe, and by economy, China (42 Mtoe), the United States (22 Mtoe) and Viet Nam (17 Mtoe) account for 60% of the reduction. By fuel, the use of coal (48 Mtoe), oil (44 Mtoe) and natural gas (40 Mtoe) are reduced.

In terms of the reduction ratio in fuel demand, the ratios for natural gas in Hong Kong, China (24%), and coal in Viet Nam (15%), Chile (8%), Thailand (7%), the Philippines (7%) and Malaysia (6%) are large. For the total of fossil fuels, it is Hong Kong, China (26%), Viet Nam (17%), the Philippines (15%), Thailand (14%) and Chile (10%). For all of APEC, the demand for fossil fuels is expected to be reduced by 4.5% because of the expanded introduction of hydrogen.

Table 2.13 Reduction of Energy Demand from APEC Economies in 2040

	Total fossile fuel reduction				Share of reduction in TPES				
						Total			
		Coal	Oil	Gas			Coal	Oil	Gas
	(Mtoe)					(%)			
Australia	2.2	0.1	1.1	1.0	1.6	4.6	0.4	2.2	2.0
Brunei	0.0	0.0	0.0	0.0	0.4	2.2	n.a.	2.2	0.0
Canada	2.9	0.0	2.0	0.8	0.9	3.2	0.5	2.1	0.6
Chile	1.8	1.3	0.5	0.1	2.8	10.3	7.6	2.1	0.7
China	42.1	18.9	10.5	12.7	0.9	4.3	0.8	1.4	2.1
Hong Kong	1.7	0.0	0.1	1.6	14.0	26.4	0.0	2.2	24.2
Indonesia	3.9	0.1	2.9	0.9	0.7	2.5	0.1	1.6	0.8
Japan	7.9	2.2	1.8	3.8	1.9	7.0	2.0	1.3	3.7
Korea	2.4	1.1	0.5	0.9	0.8	3.3	1.3	0.6	1.5
Malaysia	3.4	2.3	0.5	0.6	2.3	8.6	6.4	1.2	1.0
Mexico	4.6	0.0	2.9	1.7	1.5	3.7	0.0	2.6	1.2
New Zealand	0.1	0.0	0.1	0.0	0.6	3.2	1.0	1.4	0.8
PNG	0.1	0.0	0.1	0.0	0.8	1.8	n.a.	1.8	0.0
Peru	0.7	0.0	0.7	0.1	1.3	3.7	1.2	2.2	0.3
Philippines	3.7	2.7	0.6	0.3	3.6	14.5	6.9	2.0	5.6
Russia	4.9	0.0	1.9	3.1	0.6	1.8	0.0	1.1	0.7
Singapore	0.6	0.0	0.2	0.4	1.9	6.5	2.0	1.0	3.5
Chinese Taipei	0.6	0.2	0.2	0.1	0.5	1.8	0.5	0.5	0.7
Thailand	8.1	2.7	1.2	4.1	3.2	14.1	7.1	1.3	5.7
United States	22.3	0.2	14.9	7.1	1.0	2.9	0.1	2.0	0.7
Viet Nam	17.1	15.9	1.2	0.0	7.5	16.7	14.9	1.6	0.2
APEC Total	131.3	47.9	43.9	39.5	1.2	4.5	1.4	1.6	1.4

Next, we see how much each economy's energy security improves because of the reduction in fuel demand by changes in fossil fuel dependency and the self-sufficiency rate (Table 2.14, Table 2.15, and Table 2.16). The expanded introduction of hydrogen reduces fossil fuel dependency of the whole APEC from 82% by 1.2%. By economy, Hong Kong, China is reduced from 99% to 85% by 14% and Viet Nam is reduced from 85% to 77.5% by 7.5%. The Philippines, Thailand, Chile and Malaysia see a reduction of 2% to 3%.

In the change of the self-sufficiency rate, the self-sufficiency rate of oil is expected to improve by 1.3 points and natural gas by 1.3 points for all of APEC. By economy, the rate of improvement in the self-sufficiency rate of coal is relatively high in Viet Nam, the Philippines and Thailand; for oil, it is high in the United States and Peru; and for natural gas, it is high in the Philippines, China, Mexico and Thailand.

Table 2.16 shows the extent to which net imports by subtracting the domestic production from each economy's primary domestic supply in 2040 would be reduced by the expanded introduction of hydrogen. Negative values for net imports mean net exports, while positive values of the impact on net imports mean an increase in net exports because of domestic supply reductions. Economies that can significantly reduce net imports with the expanded introduction of hydrogen include: Viet Nam (coal: 22% decrease), the Philippines (coal: 9% decrease), Thailand (coal: 8% decrease, natural gas: 7% decrease), Viet Nam and Hong Kong, China (natural gas: 24% decrease), Chile (coal: 8% decrease) and China (coal: 6% decrease, natural gas: 5% decrease).

Table 2.14 Share of total primary energy supply by fuel in BAU and change of the share in Hydrogen Scenario

		Share of Total primary energy supply in BAU								Change of the share			
		Fossil Fuel				Non Fossil Fuel				Fossil Fuel			
			Coal	Oil	Gas		Nuclear	Hydro	Other renewables		Coal	Oil	Gas
Australia	100	90	19	36	35	10	0	1	9	−1.6	−0.1	−0.8	−0.7
Brunei	100	100	0	16	84	0	0	0	0	−0.4	0.0	−0.4	0.0
Canada	100	74	3	31	40	26	7	13	6	−0.9	0.0	−0.6	−0.3
Chile	100	74	26	37	11	26	0	5	21	−2.8	−1.9	−0.8	−0.1
China	100	80	51	16	13	20	5	3	12	−0.9	−0.4	−0.2	−0.3
Hong Kong	100	99	20	24	56	1	0	0	1	−14.0	0.0	−0.5	−13.5
Indonesia	100	74	20	32	21	26	0	1	25	−0.7	0.0	−0.5	−0.2
Japan	100	87	28	34	25	13	5	2	6	−1.9	−0.5	−0.4	−0.9
Korea	100	77	28	28	21	23	19	1	3	−0.8	−0.4	−0.2	−0.3
Malaysia	100	92	24	29	39	8	0	2	6	−2.3	−1.5	−0.3	−0.4
Mexico	100	91	4	38	50	9	0	1	8	−1.5	0.0	−1.0	−0.6
New Zealand	100	52	4	32	16	48	0	10	39	−0.6	0.0	−0.5	−0.1
PNG	100	84	0	47	37	16	0	2	14	−0.8	0.0	−0.8	0.0
Peru	100	87	2	52	33	13	0	7	6	−1.3	0.0	−1.1	−0.1
Philippines	100	74	38	30	6	26	0	1	25	−3.6	−2.6	−0.6	−0.3
Russia	100	87	10	21	56	13	9	2	1	−0.6	0.0	−0.2	−0.4
Singapore	100	98	0	59	39	2	0	0	2	−1.9	0.0	−0.6	−1.3
Chinese Taipei	100	95	40	36	20	5	0	0	4	−0.5	−0.2	−0.2	−0.1
Thailand	100	83	15	39	29	15	0	0	15	−3.2	−1.1	−0.5	−1.6
United States	100	87	11	33	43	13	5	1	7	−1.0	0.0	−0.7	−0.3
Viet Nam	100	85	47	32	7	14	2	3	9	−7.5	−7.0	−0.5	0.0
APEC Total	100	82	31	25	26	17	5	2	10	−1.2	−0.4	−0.4	−0.4

Table 2.15 Self-sufficient rate in BAU and Hydrogen Scenario

		BAU Scenario			Hydrogen Scenario			Hydrogen − BAU		
		Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil	Gas
Australia	100.0	100.0	12.3	100.0	100.0	12.6	100.0	0.0	0.3	0.0
Brunei	100.0	n.a.	100.0	100.0	n.a.	100.0	100.0	n.a.	0.0	0.0
Canada	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0
Chile	29.2	1.5	2.7	16.7	1.6	2.7	16.9	0.1	0.1	0.1
China	77.0	85.7	34.9	56.8	86.4	35.4	58.0	0.7	0.5	1.2
Hong Kong	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Indonesia	100.0	100.0	20.8	52.8	100.0	21.2	53.3	0.0	0.3	0.4
Japan	14.4	n.a.	0.5	3.1	n.a.	0.5	3.2	n.a.	0.0	0.1
Korea	23.2	1.2	0.9	0.4	1.2	0.9	0.4	0.0	0.0	0.0
Malaysia	57.0	5.2	46.7	88.3	5.5	47.2	89.3	0.4	0.5	0.9
Mexico	100.0	78.7	100.0	97.8	78.7	100.0	99.0	0.0	0.0	1.2
New Zealand	86.6	100.0	31.6	100.0	100.0	32.0	100.0	0.0	0.5	0.0
PNG	76.8	n.a.	0.0	100.0	n.a.	0.0	100.0	n.a.	0.0	0.0
Peru	100.0	10.9	39.2	100.0	11.1	40.1	100.0	0.1	0.9	0.0
Philippines	37.4	22.0	1.4	49.4	23.6	1.5	52.3	1.6	0.0	2.9
Russia	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0
Singapore	2.2	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Chinese Taipei	4.8	n.a.	0.0	1.2	n.a.	0.0	1.2	n.a.	0.0	0.0
Thailand	26.2	16.1	10.3	16.5	17.3	10.4	17.5	1.2	0.1	1.0
United States	96.9	100.0	77.4	100.0	100.0	79.0	100.0	0.0	1.6	0.0
Viet Nam	32.7	31.0	0.2	51.3	36.4	0.2	51.4	5.4	0.0	0.1
APEC Total	92.2	100.0	75.3	91.8	100.0	76.5	93.1	0.0	1.3	1.3

Table 2.16 Impact of Net Import by introduction of Hydrogen in 2040

	Net Import in BAU (Mtoe)				Impact of Net Import in Hydrogen Scenario (%)		
		Coal	Oil	Gas	Coal	Oil	Gas
Australia	−293	−287	45	−51	0.04	−2.5	2.0
Brunei	−23	n.a.	−12	−11	n.a.	0.1	n.a.
Canada	−294	−26	−224	−43	0.2	0.9	1.9
Chile	46	17	23	6	−7.7	−2.1	−0.8
China	1082	343	476	264	−5.5	−2.2	−4.8
Hong Kong	12	2	3	7	n.a.	−2.2	−24.2
Indonesia	−115	−314	143	56	0.04	−2.0	−1.6
Japan	351	115	138	98	−2.0	−1.3	−3.9
Korea	224	81	82	60	−1.3	−0.6	−1.5
Malaysia	64	34	23	7	−6.7	−2.2	−9.0
Mexico	−69	2	−74	3	n.a.	3.9	−53.4
New Zealand	3	−2	5	n.a.	0.4	−2.1	n.a.
PNG	3	0	6	−3	n.a.	−1.8	n.a.
Peru	−19	1	19	−39	−1.4	−3.5	0.2
Philippines	64	30	31	3	−8.9	−2.0	−11.0
Russia	−733	−141	−405	−187	0.00	0.5	1.6
Singapore	31	0	19	12	−2.0	−1.0	−3.5
Chinese Taipei	102	43	38	21	−0.5	−0.5	−0.7
Thailand	178	32	87	60	−8.4	−1.4	−6.9
United States	66	−62	165	−37	0.4	−9.0	19.3
Viet Nam	153	74	72	8	−21.6	−1.6	−0.3

3. Economic Analysis of Hydrogen Supply in the APEC Region

3.1. Assumptions on Hydrogen Supply Scenario

The assumptions for the hydrogen supply scenario include identifying the hydrogen supply sources and the technical options in the hydrogen supply chain.

3.1.1. Assumptions on Hydrogen Importing/Exporting Economies

In order to identify the hydrogen supply sources, it is necessary to identify exporting and importing economies. By comparing the hydrogen demand forecast estimated in the previous chapter with the estimate results of supply potential, hydrogen exporting and importing economies can be classified according to the following criteria, taking into consideration the estimated results of the cost of hydrogen production described later:

- ✓ Importing economy: An economy that does not produce hydrogen domestically (Brunei; Hong Kong, China; Papua New Guinea; Peru; the Philippines and Singapore) and an economy that has insufficient potential to economically produce hydrogen domestically (China; Japan; Korea and Chinese Taipei)
- ✓ Exporting economy: An economy where the potential to supply inexpensive hydrogen greatly exceeds domestic hydrogen demand (Australia; Canada; Chile; Indonesia; Mexico; New Zealand; Russia and the United States)
- ✓ Non-importing/exporting economy: An economy with both limited domestic hydrogen potential and domestic hydrogen demand (Malaysia; Thailand and Viet Nam)

Economies with fossil fuel resources and CO_2 sequestration potential can introduce thermal power generation + CCS, so there is no need to produce hydrogen for power generation from fossil fuels + CCS. Also, supplying domestic hydrogen created from renewable energy as a fuel for hydrogen generation is not subject to this study as converting renewable energy into hydrogen and using the hydrogen for power generation results in large energy losses because of multiple conversion processes. In other words, when considering the supply source of hydrogen, we only consider imported hydrogen as a supply source for power generation.

Table 3.1 Assumptions on Hydrogen Importers and Exporters in the APEC Region

	Domestic production	Import	Export
Australia	●		●
Brunei Darussalam		●	
Canada	●		●
Chile	●		●
People's Republic of China	●	●	
Hong Kong, China		●	
Indonesia	●		●
Japan	●	●	
Republic of Korea	●	●	
Malaysia	●		
Mexico	●		●
New Zealand	●		●
Papua New Guinea		●	
Peru		●	
The Philippines		●	
Russia	●		●
Singapore		●	
Chinese Taipei	●	●	
Thailand	●		
The United States	●		●
Viet Nam	●		

3.1.2. Assumptions on Hydrogen Supply Chain

The hydrogen supply chain is comprised of hydrogen production, transport and storage. Table 2.1 shows the assumptions for hydrogen production technology in each economy. As described in section 1.1.2, various options are being studied for the transport and storage of hydrogen. For example, compressed hydrogen, liquefied hydrogen, methyl-cyclohexane and ammonia can be considered energy carriers, while pipelines, trailers, ships and railroads are transport means.

In this study, we select liquefied hydrogen as an energy carrier since it is relatively easy to obtain cost data and other information for it. When the source of hydrogen is domestic hydrogen, the hydrogen supply chain consists of hydrogen production, liquefaction, domestic delivery and storage. Hydrogen delivery to the final demand destination differs depend on whether the economy is an importing or exporting economy. In a hydrogen importing economy, we select liquid hydrogen trucks as the domestic means of delivering hydrogen (Figure 3.1). In a hydrogen exporting economy, assuming a domestic hydrogen pipeline (described later), domestic transport of hydrogen is via a pipeline from the production plant to a secondary base that liquefies hydrogen, and then delivers the liquefied hydrogen from there to the final demand destination by liquid hydrogen trailers (Figure 3.2).

Figure 3.1 Hydrogen Supply Chain when Supply Source is Domestic Hydrogen for Non-exporting Economies

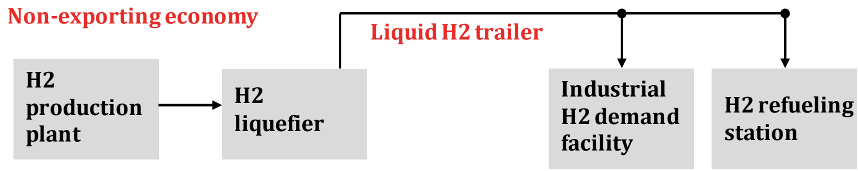
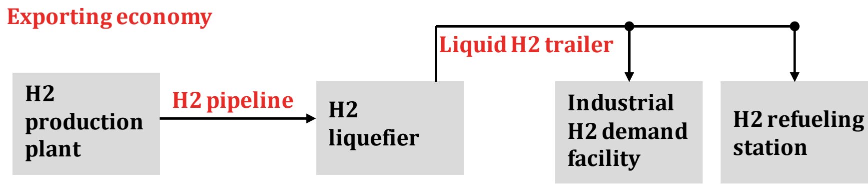
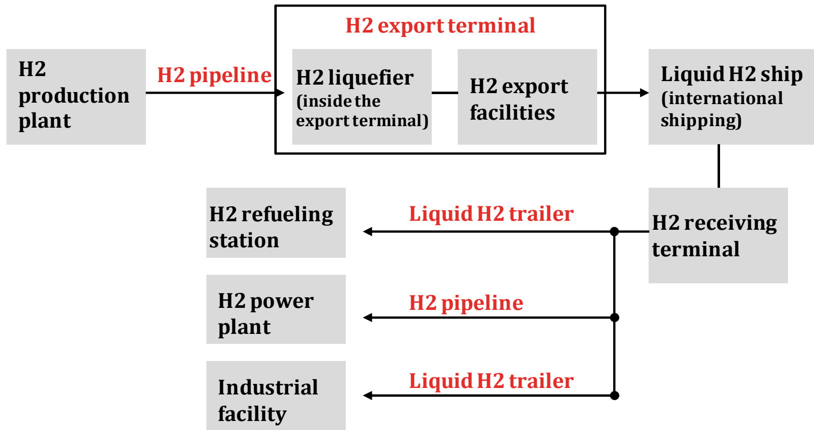


Figure 3.2 Hydrogen Supply Chain when Supply Source Is Domestic Hydrogen for Exporting Economies



On the other hand, if the supply source of hydrogen is imported hydrogen, the configuration of the hydrogen supply chain becomes complicated. It includes the production, transport, storage, export terminals and international transport of hydrogen in exporting economies as well as hydrogen receiving terminals and transport and storage in importing economies. It is assumed that hydrogen is transported from the production plant to the loading terminal via pipeline and that hydrogen is liquefied at the hydrogen loading terminal. Liquefied hydrogen is transported to a hydrogen receiving terminal in the importing economy by a liquid hydrogen ship and delivered to the final demand destination. Liquid hydrogen trailers are assumed to deliver hydrogen in importing economies, similar to the domestic hydrogen mentioned above. When hydrogen is used for hydrogen power generation, it is assumed that the hydrogen power plant is adjacent to the hydrogen receiving terminal and that the hydrogen is supplied to the pipeline.

Figure 3.3 Hydrogen Supply Chain when Supply Source Is Import Hydrogen



3.2. Estimate Prerequisites

The unit cost of hydrogen cost in each process of the hydrogen supply chain is calculated from items such as the cost of the facilities (initial investment), the cost of maintenance and operation, the cost of financing and the cost of utilities (cost of electricity, water, etc.):

Unit Cost of Hydrogen（$/Nm3）＝ Levelised CAPEX ＋ Levelised OPEC ＋ Levelised Financing Cost ＋ Utility Cost

The equation for calculating the levelling cost is as follows:

$$\text{Levelized Cost} = \frac{\text{Total Present Value of a Specific Cost}}{\sum_{t=1}^{n} \frac{\text{Annual Volume of Hydrogen}}{(1 + \text{Discount Rate})^{(t-1)}}}$$

where "n" is the assumed to be the useful life of the applicable facilities.

The estimate of the cost of the hydrogen supply requires the cost of facilities, the cost of maintenance and operation, the cost of financing and the cost of utilities, such as feedstock and fuel in each process of the supply chain, as well as technical preconditions that include the process efficiency of each process and the facility utilisation rate. In this study, we refer to the leading research conducted by the US DOE,[70] The Institute of Applied Energy,[71] Kawasaki Heavy Industries[72] and others to make assumptions about costs and technical specifications.

3.2.1. Hydrogen Production

(1) Assumptions about Hydrogen Production Technology

Table 3.2 shows the preconditions for the production capacity of the hydrogen production plant, facility utilisation rate, initial investment cost, cost of maintenance and operation, energy efficiency of hydrogen production, and other items. Although the same assumptions are used for each economy, the facility utilisation rate of hydrogen from renewable energy is limited by the facility utilisation rate of renewable energy power generation, so it varies depending on the economy (the facility utilisation rate of hydrogen production plants using renewable energy is assumed to be the same as the facility utilisation rate of power generation from renewable energy).

70 US DOE Hydrogen and Fuel Cell Program. Analysis files could be retrieved from https://www.hydrogen.energy.gov/h2a_analysis.html#h2a_project

71 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.

72 Kawasaki Heavy Industry (2015). "Investigation of Improvement of a Value Chain of Hydrogen Production from Australian Low Rank Coal." Research commissioned by NEDO.

Table 3.2 Preconditions for Hydrogen Production Technologies

	Coal Gasification	Gas SMR	Electrolyzer
Capacity (ton H2/year)	89,964	138,476	18,250
Operation hours per year (hours)	6,132	7,008	-
Fossil fuel input (MJ/kg-H2)	271	164	-
Electricity input (kWh/kg-H2)	4.38	0.69	50.2
Water input (m3/kg-H2)	0.011	0.018	0.015
CAPEX (million $)	499	240	44
Non-fuel O&M (million $/year)	39	39	4
CO2 emission ratio (kg-CO2/kg-H2)	25	9	0

Source: US DOE, Hydrogen and Fuel Cell Program; Kawasaki Heavy Industry, "Investigation of Improvement of a Value Chain of Hydrogen Production from Australian Low Rank Coal" (research commissioned by NEDO); and various other sources.

Assumptions concerning technical specifications, the cost of facilities, the cost of maintenance and operation and CO_2 emission coefficients for hydrogen production technology use the values discussed in the "Hydrogen and Fuel Cell Program"[70] of the US DOE. The consumption of electricity in coal gasification plants is estimated based on research[72] by Kawasaki Heavy Industries. Also, we assume that the facility utilisation rate of hydrogen production plants using fossil fuel + CCS is 70%. In practice, the cost of facilities and other costs vary depending on the economy, but to simplify the calculation, the assumption shown in Table 3.2 (excluding the facility utilisation rate of the hydrogen production plant using renewable energy) is applied to each economy.

(2) Assumptions about CCS

The preconditions shown in Table 3.2 do not include the cost of CCS or the power consumption of CO_2 injection. Although the cost of transporting and storing CO_2 is different in each economy, the cost analysis of CCS is outside the scope of this research, so we assume the same CO_2 pipeline and storage site specifications for each economy (Table 3.3). Estimates of the cost of CCS and power consumption of CO_2 injection are based on the methods presented by D. Steward, T. Ramsden, and J. Zuboy (2012),[73] and David L. McCollum and Joan M. Ogden (2006).[74] The power for CCS is supplied from the grid. Power consumption in CCS depends on the amount of CO_2 generated when hydrogen is produced. If the specifications are for a hydrogen production plant using fossil fuels + CCS, which this study is examining, the power consumption associated with CO_2 injection is 1.7 kWh/kg-H_2 for coal and 0.7 kWh/kg-H_2 for natural gas.

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[73] D. Steward, T. Ramsden, J. Zuboy (2012). "H2A Central Hydrogen Production Model, Version 3 User Guide (DRAFT)". US DOE, Hydrogen and Fuel Cell Program.
[74] David L. McCollum, Joan M. Ogden (2006). "Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity." UCD—ITS—RR—06-14. Davis, CA: Institute of Transportation Studies, University of California, Davis.

Table 3.3 Major Assumptions for CO_2 Pipeline and CO_2 Sequestration Site

Parameters	Assumptions
CO2 capture process outlet pressure (inlet pressure for compression, psia)	14.7
Outlet pressure desired (Mpa)	15
Terrain Type	<20 Mountainous
CO2 pipeline length (km)	161 (100 miles)
Depth of injection well (m)	1,524
CO2 pipeline cost (1,000$/km)	450
Capital cost for site screening and evaluation (million $/per well)	1.9
Other CAPEX (e.g. CO2 compressor)	depends on CO2 flowrate
Non-fuel O&M factor for CO2 pipeline	2.5%
Non-fuel O&M factor for others	4.0%

Source: D. Steward, T. Ramsden, J. Zuboy (2012); David L. McCollum, Joan M. Ogden (2006).

(3) Feedstock and Utilities Costs

The unit price of inputs, such as coal, natural gas, water and electricity, used to produce hydrogen differ depending on the economy. As shown in the previous chapter, since it is assumed that hydrogen demand in the APEC region will see a full-scale expansion after 2030, it is assumed that large-scale production of hydrogen will be introduced after 2030, and that the unit price of feedstocks and utilities will also be at 2030 price levels.

Using current costs as a base, the production cost of coal and natural gas in 2030 is estimated by referring to the medium and long-term outlook for international energy prices projected in *Asia/World Energy Outlook 2016*.

The cost of the water supply uses industrial water in each economy. Since the price level of water varies depending on the region, even in the same economy, the average price level of the representative city or region is assumed as a precondition for the estimate.

Electricity consumed by coal gasification, natural gas reforming and CCS are assumed to be supplied from the grid. It is therefore necessary to estimate the level of grid electricity prices in 2030. We estimate the future electricity price level based on the current electricity price level and the future average cost of generating electricity (APERC estimate). The price level of electricity differs depending on the type of contract and power consumption, but we estimate the average value for each economy based on various information.

Table 3.4 Assumptions for Feedstock and Utility Input

	Coal		Natural gas	Water cost	Utility electricity Tariff
	Heat value (kcal/kg)	2030 cost level ($/ton)	2030 cost level ($/mmbtu)	Cost ($/ton)	2030 cost level ($/kWh)
Australia	2,750	12.6	6.0	1.5	0.095
Brunei Darussalam					
Canada	3,583	29.6	3.6	2.7	0.075
Chile				1.3	0.103
People's Republic of China	3,200	35.3		0.6	0.092
Hong Kong, China					
Indonesia	2,690	17.2		0.6	0.082
Japan				1.5	0.111
Republic of Korea				0.6	0.046
Malaysia				0.8	0.103
Mexico				0.9	0.065
New Zealand	3,583	29.6		0.9	0.087
Papua New Guinea					
Peru					
The Philippines					
Russia	3,200	35.3	1.7	0.4	0.020
Singapore					
Chinese Taipei				1.1	0.096
Thailand				0.5	0.079
The United States	3,583	29.6	5.4	1.0	0.068
Viet Nam				0.6	0.086

Source: Kawasaki Heavy Industry (2015);[75] Australian Energy Council; Canadian Energy Research Institute; Inner Mongolia Coal Trade Centre; NEDO Research Presentation Material; US DOE; IEA, "Energy Prices &Taxes;" Indonesia MEMR; and various publicly accessible information and expert interviews.

(4) Cost of Renewable Energy

As mentioned, we assumed that large-scale production of hydrogen will be introduced from around 2030, so we assume the generation cost of electricity from renewable energy necessary for the production of renewable energy hydrogen will be the cost in 2030. The future cost of renewable energy is estimated from current facilities costs, maintenance and operating costs, the facility utilisation ratio and future cost reduction savings (IRENA (2016),[76] Fraunhofer ISE (2015),[77] Agora Energiewende (2017).[78] The values for generation costs have been adjusted in some economies with reference to the selling price.

[75] Kawasaki Heavy Industry (2015). "Investigation of Improvement of a Value Chain of Hydrogen Production from Australian Low Rank Coal." Research commissioned by NEDO.
[76] IRENA (2016). The Power to Change: Solar and Wind Cost Reduction Potential to 2025.
[77] Fraunhofer ISE (2015). "Current and Future Cost of Photovoltaics. Longterm Scenarios for Market Development, System Prices and LCOE of Utility-Scale PV Systems."
[78] Agora Energiewende (2017). "Future Cost of On-shore Wind."

Table 3.5 Renewable Power Generation Cost

	Future Solar PV Generation Cost ($/kWh)	Future On-shore Wind Generation Cost ($/kWh)	Future Hydro Generation Cost ($/kWh)
Australia	0.038	0.049	
Brunei Darussalam			
Canada			0.034
Chile	0.027		
People's Republic of China	0.029	0.044	0.033
Hong Kong, China			
Indonesia	0.040		
Japan	0.058	0.066	
Republic of Korea	0.070	0.085	
Malaysia	0.040		
Mexico	0.031	0.041	
New Zealand		0.051	0.034
Papua New Guinea			
Peru			
The Philippines			
Russia			0.055
Singapore			
Chinese Taipei	0.056		
Thailand	0.038		
The United States	0.030	0.050	
Viet Nam	0.041	0.057	

3.2.2. Hydrogen Storage and Transport

We used preconditions concerning the transport and storage of hydrogen being studied by the US DOE,[79] Kawasaki Heavy Industries[80] and The Institute of Applied Energy.[81] Table 3.6 summarises the major assumptions regarding costs, technical specifications and operational patterns relating to hydrogen pipelines (including compressors), hydrogen liquefiers, hydrogen loading terminals, liquefied hydrogen ships, hydrogen receiving terminals, and liquefied hydrogen trailers.

To simplify calculation, the transport distances of hydrogen pipelines and liquefied hydrogen trailers are the same for each economy and are 97km[82] and 50km, respectively. The distance of international transport depends on a combination of the export destination and import destination. Also, since the assumed specifications for hydrogen loading terminals, liquefied hydrogen ships and hydrogen receiving terminals are one model for calculating the unit price of hydrogen, they are not related to the capacity of a hydrogen production plant.

The cost of liquefied hydrogen receiving terminals is cited from results of economies that have already been studied.[83] Otherwise, costs are estimated with the preconditions shown in Table 3.6.

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79 US DOE Hydrogen and Fuel Cell Program. Analysis files could be retrieved from https://www.hydrogen.energy.gov/h2a_analysis.html#h2a_project

80 Kawasaki Heavy Industry (2015). "Investigation of Improvement of a Value Chain of Hydrogen Production from Australian Low Rank Coal." Research commissioned by NEDO.

81 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.

82 Assumes the same value (60 miles) as the calculation model of the US DOE.

83 The cost of liquefied hydrogen receiving terminals and domestic delivery in Japan, and the domestic delivery cost of hydrogen in the United States have already been calculated by previous research.

Table 3.6 Hydrogen Delivery and Storage

Parameter		Unit	Value
Pipeline	Compressor capacity per unit	kg-H2/day	194,070
	Number of compressor installed	units	5
	Number of compressor in operation	units	4
	Pipeline length	km	79
	Capex of compressor	$/unit	9,703,764
	Capex of pipeline	$/km	399,779
	Non-electricity running cost factor	% of Capex/yr	8%
	Total power load	kW	19,500
Liquefier	Liquefier capacity	kg/day	50,000
	Liquefier unit installed	units	16
	Liquefier efficiency	kWh/kg-H2	6.4
	Capex per liquefier package	$/package	8,016,195
	Non-electricity running cost factor	% of Capex/yr	3.6%
Export terminal	Liquid H2 storage tank capacity	m3	50,000
	Units of storage tanks	units	4
	Power load	kW	6,000
	Total Capex	$	878,192,867
	Non-electricity running cost factor	% of Capex/yr	1.9%
International shipping	Tanker size	m3/tanker	40,000
	Units of tanker per ship	units per ship	4
	Boil-off Gas (BOG) rate	%/day	0.2%
	Speed	km/h	30
	Loading/unloading days in total	days	4
	Capex per ship	$/ship	413,072,845
Receiving terminal	Liquid H2 storage tank capacity	m3	51,000
	Units of storage tanks	units	6
	Power intensity	kWh/kg-H2	0.2
	Total Capex	$	1,484,583,803
	Non-electricity running cost factor	% of Capex/yr	3.6%
Liquid H2 trailer	Trailer capacity	kg-H2/trailer	1,416
	Trailer life	years	13
	Average speed	km/hour	58
	Total time for loading and unloading	hours	6.5
	Capex per trailer	$/trailer	413,073

Source: US DOE; Kawasaki Heavy Industry; The Institute of Applied Energy.

3.2.3. Other Prerequisites

Table 3.7 summarises other preconditions used for estimating the cost of the hydrogen supply. In order to simplify the calculation, similar assumptions are made for each economy regarding the discount rate, project loans, depreciation period, tax rate, and other factors.

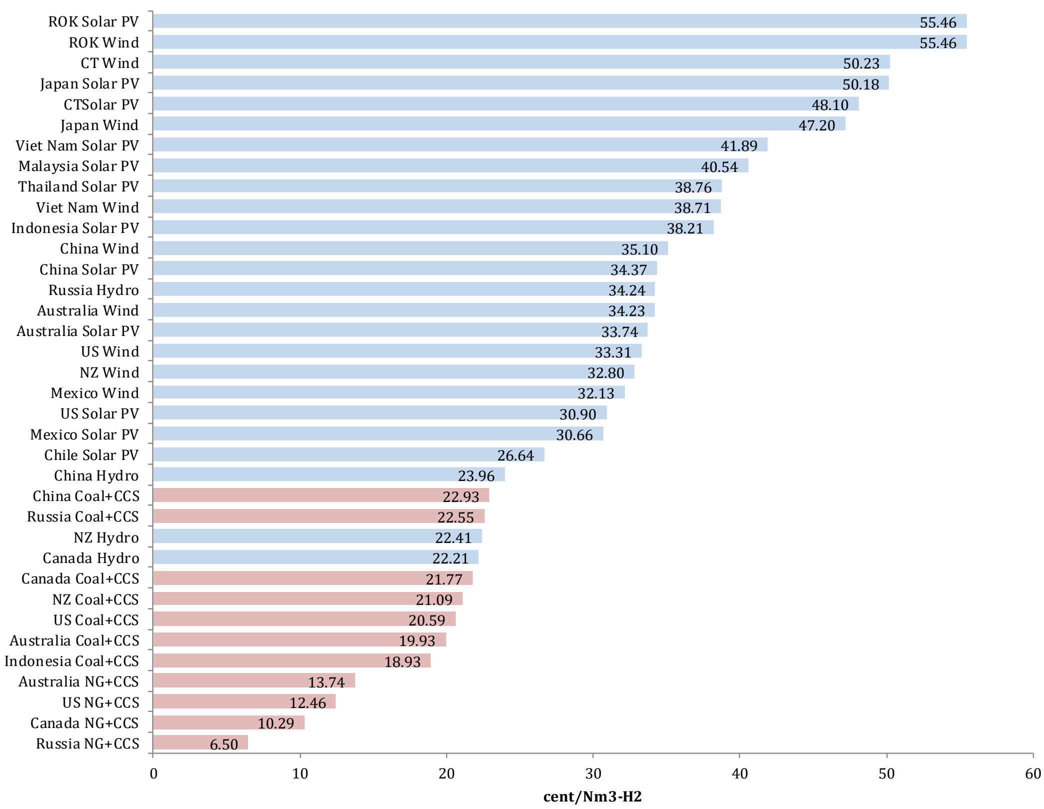
Table 3.7 Other Assumptions for Calculating Hydrogen Supply Cost

Parameter	Assumption
Discount rate (%)	5%
Share of equity (%)	100%
Share of debt (%)	0%
Interest rate (%)	5%
Loan repayment period (years)	10
Depreciation period (years)	15
Tax rate (%)	1.4%

3.3. Production Cost of Hydrogen

Figure 3.4 shows the estimate of the cost of CO_2-free hydrogen production in the APEC region based on the above preconditions. The cost of hydrogen production has a broad range of 7 cents/Nm^3-55 cents/Nm^3. The cost of hydrogen production from fossil fuel + CCS is 7 cents/Nm^3-23 cents/Nm^3, whereas the cost of hydrogen production from renewable energy is 22 cents/Nm^3-55 cents/Nm^3. The cost of manufacturing hydrogen from hydroelectric power generation is comparable to that of hydrogen created with fossil fuel + CCS.

Figure 3.4 Production Cost of CO_2 Free Hydrogen in APEC Region



Note: ROK: Republic of Korea; CT: Chinese Taipei; NZ: New Zealand.

Looking at the breakdown of the production cost (Figure 3.5), since the cost of lignite fuel is inexpensive, the ratio of the cost of fuel (lignite) to the unit cost of hydrogen production by coal + CCS is as low as 30% or less. On the other hand, with hydrogen produced from natural gas + CCS, the ratio of the cost of fuel (natural gas) reaches 40% to 70%. With hydrogen produced from renewable energy (Figure 3.6), the share of the cost of fuel (electricity from renewable energy) per unit production cost of hydrogen is affected by the cost of renewable energy generation and the facility utilisation rate of the production plant. Although the cost estimate of the same electrolysis equipment is assumed for each economy, the levelled facilities cost per unit cost of hydrogen production differs according to the facility utilisation rate of the plant.

Figure 3.5 Breakdown of Hydrogen Production Cost by Fossil + CCS

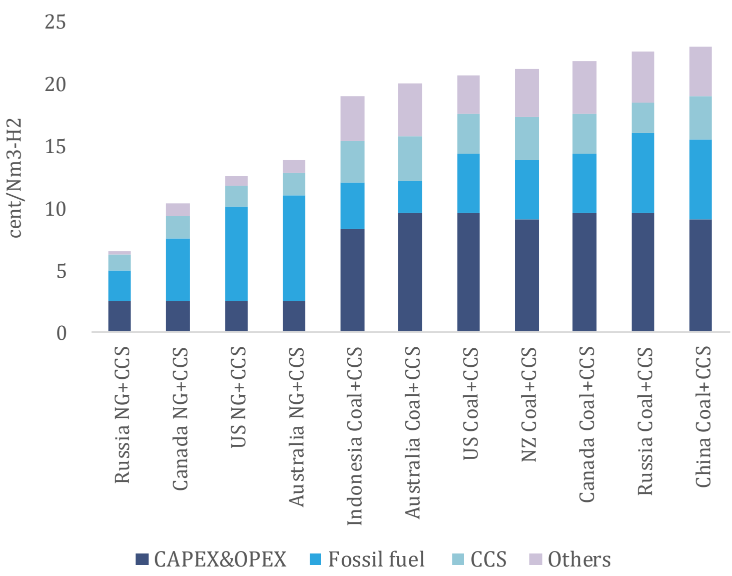
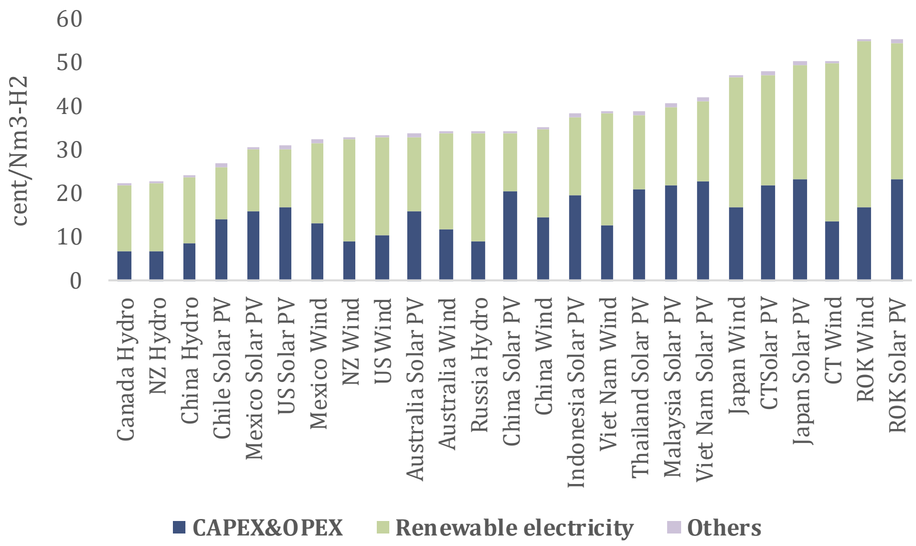


Figure 3.6 Breakdown of Hydrogen Production Cost by Renewable + Electrolysis



3.4. Study of the Economic Viability of Hydrogen Supply

We analyse the economic viability of the hydrogen supply for Japan, China and the United States. Japan and China are assumed to be hydrogen-importing economies, but we also consider domestically-produced hydrogen. We assess the economic viability of the hydrogen supply assuming the following two cases:

① Comparison of the target price of the hydrogen supply required for the cost of hydrogen power generation to be equivalent to competing thermal power generation, and analysis of the economic efficiency of imported hydrogen; and

② Comparison of fuel costs when using domestically-produced hydrogen and imported hydrogen as fuel for FCVs and the supply cost of domestic hydrogen and imported hydrogen.

The source of supply for the United States, an exporter of hydrogen, only considers domestic hydrogen. As discussed in section 3.1.1, it is assumed that no hydrogen power generation is introduced in hydrogen-exporting economies. We therefore assess the economic viability of the hydrogen supply of the United States when domestic hydrogen is supplied as a fuel for FCVs.

3.4.1. Japan

(1) Hydrogen Power Generation

The cost of supplying hydrogen (imported hydrogen) for hydrogen power generation is composed of the cost of producing hydrogen, the cost of transport and storage in the exporting country, the cost of international transportation and the cost of the domestic receiving terminal and domestic delivery.

The costs up to the international transportation of hydrogen are estimated based on the assumptions in Table 3.6, and the costs up to the receiving terminal and delivery to a hydrogen power station are the values considered in the leading research by The Institute of Applied Energy.[84]

Since hydrogen power generation does not emit CO_2, it is necessary to consider the environmental cost of thermal power generation, namely, the cost of CO_2 emission countermeasures when verifying its competitiveness with thermal power generation. In this study, the cost of CO_2 countermeasures for thermal power generation that assumes a carbon price of 0-100 USD/t-CO_2 is added to the cost of thermal power generation (values do not consider the cost of carbon) calculated by the Power Generation Cost Verification Working Group[85] as of 2030 to find a competitive target price of hydrogen that can compete with. According to the results of the calculation, the hydrogen supply cost for hydrogen power generation to compete with coal-fired power needs to be 16-27 cents/Nm^3 or less, 17-22 cents/Nm^3 or less to compete with LNG power generation and 44-53 cents/Nm^3 or less to compete with oil-fired power generation. Table 3.8 shows the major preconditions.

[84] 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.

[85] *www.enecho.meti.go.jp/committee/council/basic_policy.../cost_wg/.../006_05.pdf*

Figure 3.7 Hydrogen Supply Cost for Power Generation and Required Hydrogen Fuel Price for Competing with Fossil Fuel Thermal Power Generation (Japan)

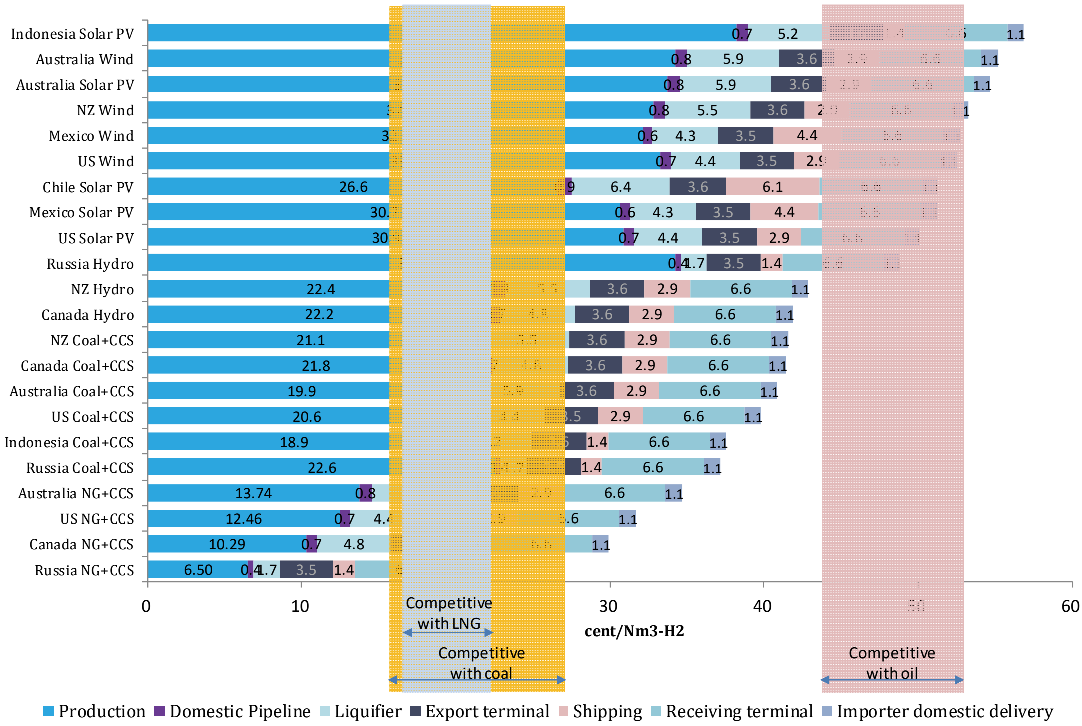


Table 3.8 Major Preconditions for Calculation of Hydrogen Target Price (Japan)

Hydrogen power generation	
CAPEX ($/kW)	991
OPEX ($/kWh)	0.005
Thermal efficiency	57%
Capacity factor	80%
Assumed financial life (years)	40
Fossil fuel thermal power generation cost without carbon cost (cent/kWh)	
Coal fired thermal power	10.7
LNG fired thermal power	11.1
Oil fired thermal power	27.3
Average CO2 emission ratio for fossil fuel thermal power in Japan (kg-CO2/kWh)	
Coal fired thermal power	0.67
LNG fired thermal power	0.32
Oil fired thermal power	0.52

Note: Thermal efficiencies used for estimation of average emission ratio for fossil fuel thermal power generation were: Coal, 48%; LNG, 57%; Oil, 48%

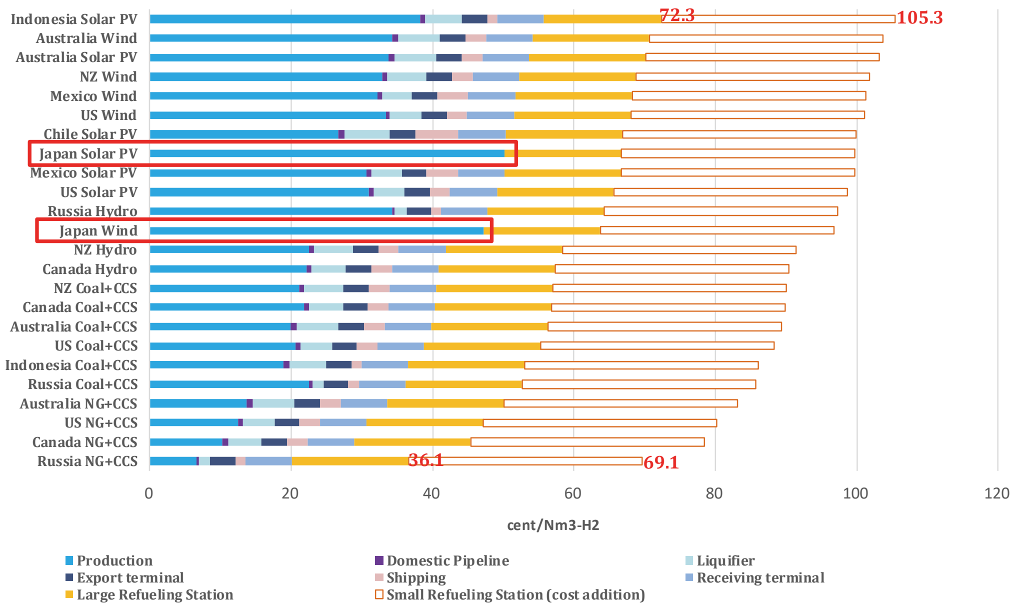
Source: expert interview; Power Generation Cost Estimation Working Group Report; Energy Data Modelling Center (IEEJ), Handbook of Japan's & World Energy & Economic Statistics; authors' estimation.

The plant delivery price for importing CO_2-free hydrogen from the APEC region to Japan and supplying it to a hydrogen power plant is 21-57 cents/Nm^3 (Figure 3.7). If no consideration is given to environmental costs (the cost of CO_2 countermeasures), the hydrogen supply cost must be 17 cents or less for hydrogen power generation to compete with coal-fired power generation and LNG-fired power generation. It is difficult for CO_2-free hydrogen in the APEC region to realise this target price as of 2030. If the carbon price is 100 USD/t-CO_2, the required price level rises to 22-27 cents/Nm^3. The source of CO_2-free hydrogen that can meet this price level is only hydrogen produced by Russian natural gas + CCS. Further reduction in the cost of the hydrogen supply is required to expand supply sources.

(2) FCV Fuel Cost Comparison of Domestic and Imported Hydrogen

It is necessary to consider the cost of hydrogen fuelling stations when calculating fuel cost for FCVs. The cost of hydrogen stations varies widely depending on their scale. According to leading research by The Institute of Applied Energy,[86] the levelised facility cost of a small-scale hydrogen station with a hydrogen supply capacity of 300 Nm^3/h or less is about 60 yen/Nm^3 (energy carriers include liquefied hydrogen and domestic delivery), and a supply capacity of 1,200 Nm^3/h or more is calculated to be about 20 yen/Nm^3. Figure 3.8 shows the supply cost of CO_2-free hydrogen to fuel FCVs, which is added to the hydrogen supply cost calculated above.[87]

Figure 3.8 Hydrogen Fuel Cost for FCV (Japan)



[86] 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.

[87] The import cost up to domestic delivery and domestic CO_2-free hydrogen supply cost.

If a small hydrogen station[88] is used, the cost of supplying CO_2-free hydrogen for FCVs is 69-105 cents/Nm^3. As the size of the hydrogen station grows with the spread of FCVs, the supply cost of CO_2-free hydrogen drops to 36-72 cents/Nm^3 because of lower unit costs related to maintenance and operation of the station.

Assuming that the price of a gasoline-powered vehicle is 2 million yen (16,523 USD), the price of gasoline is 150 yen/l (1.24 USD/L), the fuel consumption of both gasoline-powered vehicles and FCVs is 17 km/L-gasoline and 17 km/L-gasoline (11.7 km/Nm^3-H_2), and that the annual distance driven is 10,000 km, if the price of an FCV becomes equal to that of a hybrid vehicle (3 million yen, or about 24,784 USD), the cost of CO_2-free hydrogen is 11 cents/Nm^3 in order for the life cycle cost of an FCV to be equivalent to that of a gasoline vehicle. The price of FCVs, the cost of hydrogen and the cost of hydrogen stations must be simultaneously reduced if FCVs are to compete with gasoline vehicles.

Looking at the hydrogen supply cost for hydrogen stations, although hydrogen produced from domestic renewable energy is more expensive than imported hydrogen manufactured from inexpensive foreign fossil fuels + CCS, it is comparable to the cost of imported hydrogen manufactured overseas from renewable energy.

3.4.2. China

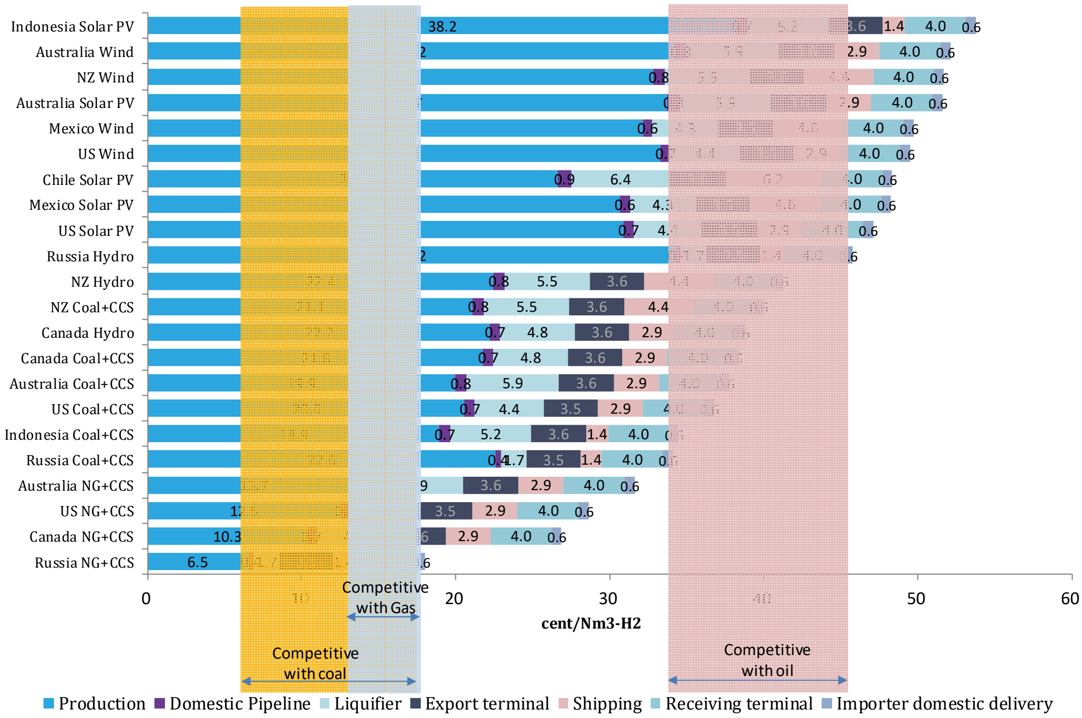
(1) Hydrogen Power Generation

Since imported hydrogen is used for hydrogen power generation in China, the costs related to the production and transport of hydrogen in hydrogen-exporting economies are the same as those for Japan. International transportation costs are estimated by the distance they are transported to China. Given the difference in cost between China and Japan's LNG receiving terminals, the pipeline cost to a hydrogen receiving terminal in China and the adjacent hydrogen power plant is calculated as being 60% that of Japan.

Like Japan's case, the price of carbon is assumed to be 0-100 USD/t- CO_2 and is used to calculate the hydrogen supply cost required for hydrogen generation to compete with competitive thermal power generation. The power generation efficiency of hydrogen power plants is the same level as that of natural gas power generation in China, and other conditions are the same as those in Japan. Table 3.9 shows the major assumptions of thermal power generation in China.

[88] The supply capacity is 300 Nm^3/day or less.

Figure 3.9 Hydrogen Supply Cost for Power Generation and Required Hydrogen Fuel Price for Competing with Fossil Fuel Thermal Power Generation (China)



China's imported CO_2-free hydrogen plant delivery price is about 18-54 cents/Nm^3, which is slightly cheaper than Japan. On the other hand, since the cost of fossil fuel thermal power generation in China is low, the cost of generating hydrogen gas is equal to that of thermal power generation, so the cost of supplying CO_2-free hydrogen is also less expensive than Japan. If no consideration is given to environmental costs (the cost of CO_2 countermeasures), the cost of the CO_2-free hydrogen supply required for it be equivalent to coal-fired power is 6 cents/Nm^3 and 12 cents/Nm^3 or less for it to be equivalent to LNG-fired power, which is significantly lower than the supply cost of imported hydrogen. On the other hand, using imported hydrogen created from fossil fuel + CCS as a fuel for hydrogen power generation can compete with oil-fired power generation. If the price of carbon is assumed to be 100 USD/t-CO_2, the CO_2-free hydrogen supply cost required for hydrogen power generation to be as competitive as that of coal-fired and LNG-fired power generation is 17-18 cents/Nm^3 or less. Although the cheapest hydrogen supply source may reach this price level, further hydrogen supply cost reductions are required to improve the economic viability of hydrogen power generation.

Table 3.9 Major Assumptions for Fossil Fuel Thermal Power in China

Fossil fuel thermal power generation cost without carbon cost (cent/kWh)	
Coal fired thermal power	5.6
Natural Gas fired thermal power	9.7
Oil fired thermal power	24.1
Average CO2 emission ratio for fossil fuel thermal power in Japan (kg-CO2/kWh)	
Coal fired thermal power	0.72
Natural Gas fired thermal power	0.36
Oil fired thermal power	0.71

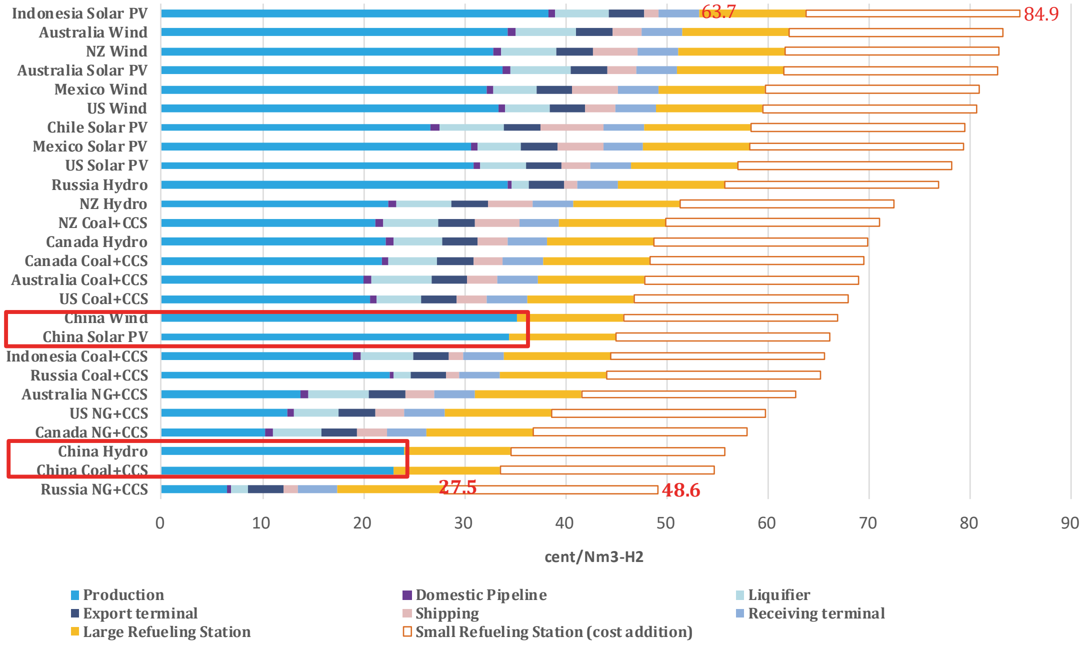
Note 1) Fossil price input for power generation cost: Natural gas, 2RMB/m^3; Diesel: 4.3RMB/L. Cost for coal fired power generation is based on benchmark price set by the government.
Note 2) Thermal efficiencies used for estimation of average emission ratio for fossil fuel thermal power generation were: Coal, 45%; LNG, 50%; Oil, 35%;
Source: Handbook of Japan's & World Energy & Economic Statistics; Various other sources from internet, and authors' estimation.

(2) FCV Fuel Cost Comparison of Domestic and Imported Hydrogen

It has been reported[89] that the cost to build a hydrogen fuelling station with a supply capacity of 464 Nm^3/h (1,000 kg/day) in China is approximately RMB 15 million (approximately 2.4 million USD). According to the previously-mentioned leading research[90] by The Institute of Applied Energy, the capital investment in Japan required for a hydrogen station with a hydrogen supply capacity of 300 Nm^3/h or less is about 2.45 million USD and compared with the construction cost per hydrogen supply capacity, the cost in China is 64% that of the cost in Japan. Therefore, assuming that the levelised facilities costs for a hydrogen station (including domestic delivery costs) in China is 64% that of Japan, we set two patterns for stations the same way as in Japan and estimated the cost of FCV fuel in China (where CO_2-free hydrogen is the supply source in the APEC region), which is shown in Figure 3.10.

[89] http://www.360doc.com/content/17/0130/13/40048856_625427939.shtml
[90] 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.

Figure 3.10 Hydrogen Fuel Cost for FCV (China)



If using a small hydrogen station in China, the CO_2-free hydrogen supply cost for FCVs is 49-85 cents/Nm^3. As the size of the hydrogen station grows with the spread of FCVs, the cost drops to 28-64 cents/Nm^3. In China, the price of gasoline vehicles and gasoline is cheaper than in Japan, so if the price of an FCV is set to the same conditions as in Japan, the CO_2-free hydrogen supply cost required to be competitive with gasoline vehicles is less than 11 cents/Nm^3. Currently in China, the government offers generous subsidies for hydrogen stations (there are cases where the subsidy from the Central People's Government is RMB 4 million/location, with local government subsidies of up to RMB 5 million/location), and even if the subsidies are included, the hydrogen supply cost for FCVs is 20 cents/Nm^3 or more at the lowest, so further reductions to hydrogen fuel costs are required to compete with gasoline vehicles.

Also, looking at the hydrogen supply cost to the hydrogen stations in Figure 3.10, it can be seen that in China, domestic CO_2-free hydrogen has cost competitiveness comparable to imported hydrogen.

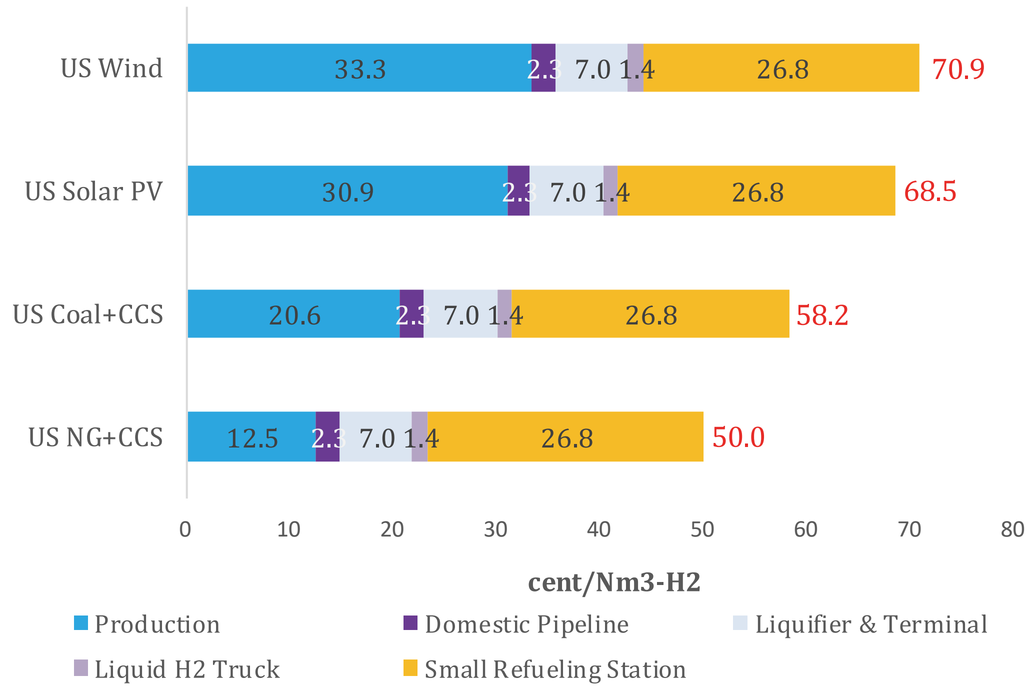
3.4.3. USA

The United States, an exporter of hydrogen, only has domestically-produced hydrogen as a source, so the introduction of hydrogen power generation is not considered. In other words, we assess the economic viability when domestically-produced hydrogen is supplied to fuel FCVs.

As a result of calculating hydrogen production costs and liquefaction costs in the previous section, the cost of domestic delivery to hydrogen stations and the cost of the hydrogen station use the values considered in the Hydrogen Delivery Scenario Analysis Model of the Department of Energy (DOE).

According to US DOE estimate, the domestic delivery cost of hydrogen is about 3.7 cents/Nm^3 (pipeline cost is 2.3 cents/Nm^3 and liquefied hydrogen tanker truck cost is 1.4 cents/Nm^3). In addition, the unit cost of small hydrogen stations in the country is about 26.8 cents/Nm^3, which is considerably lower than Japan.

Figure 3.11 Hydrogen Fuel Cost for FCV (US)



The fuel supply cost of CO_2-free hydrogen for FCVs in the United States is 50-71 cents/Nm^3. The price of gasoline vehicles and FCVs, as well as the fuel consumption of FCVs are the same as Japanese case, and assuming that the price of gasoline is 64 cents/L,[91] the average gasoline vehicle fuel consumption is 13.6 km/L (32 MPG[92]), the average annual distance driven of a passenger vehicle is 18,226 km (11,325 miles[93]), the cost of CO_2-free hydrogen for FCVs in order for it to be equivalent in the life cycle of a gasoline vehicle is 14.6 cents/Nm^3. Although it is possible to produce inexpensive CO_2-free hydrogen domestically in the United States, when supplying it as fuel for FCVs, the cost reductions of the entire hydrogen supply chain need to be considerably reduced to compete with gasoline vehicles.

91 US DOE EIA.
92 US EPA.
93 US DOE Hydrogen Delivery Scenario Analysis Model.

4. Interviews Held Abroad

4.1. Victorian Government Office

Date: 9 January 2018

Location: Melbourne, Australia

Interviewee: Trent Harkin (Technical Manager, CarbonNet Project)

<u>Overview of the CarbonNet Project and its present situation</u>

- CarbonNet is a project to transport CO_2 emitted from multiple facilities in the Latrobe Valley (one of the world's leading lignite-producing regions), situated southeast of Melbourne, about 100 km by pipeline to the Gippsland Basin further east and sequester it in the ocean floor there. The project aims to evaluate the stability of sequestration and to investigate the possibility of commercialisation of CCS in the future. Kawasaki Heavy Industries and others are participating in the CarbonNet Project with hydrogen production facilities derived from lignite.
- In Australia, CCS demonstration projects are also taking place in Otway (Victoria) and the Gorgon Gas Field (Western Australia).
- Gippsland was chosen because its geology is suited for sequestration. It was deemed that its ease of storage outweighed the benefits of enhanced oil recovery (EOR).
- In July 2017, the Victorian state government issued a statement on coal policy. It announced the goal of accomplishing the CarbonNet Project along with reducing the CO_2 emission intensity rate from coal and others.
- The total cost of capture and sequestration depends on the technology for the emission source, which is 30-50 AUD/t-CO_2. While producing hydrogen is comparatively cheap, if it captured from power generation or steel making, it becomes more expensive because of the difficulty in capturing it.

<u>Future developments for the CarbonNet Project</u>

- Since the project's launch in 2007, the Australian government and the Victoria state government have borne all costs of the CarbonNet Project. Risks will gradually be reduced by establishing technology and feasibility, and costs are scheduled to be shifted to private equity investment (in the form of CCS "usage fees") after 2020. (Thermal power generation) producers are expected to be the main investors because of emission controls imposed on new power plants.
- Although it is true that the cost of renewable energy is falling rapidly, the CarbonNet Project believes that coal-derived hydrogen (with CCS) will be cheaper in Victoria in the long run.
- Both national and state level regulations affect CCS. Whether existing regulations and actual CCS implementation are compatible is being confirmed through the CarbonNet Project.
- It is also important to promote understanding for local governments and other groups. In addition to actively disclosing information about CCS technology, the Project is also assessing the impact

on fishery resources in response to concerns from fishermen.

4.2. Global CCS Institute Headquarters

Date: 9 January 2018

Location: Melbourne, Australia

Interviewees: Alex Zapantis (General Manager, Commercial)
Chris Consoli (Senior storage advisor)
Lawrence Irlam (Senior advisor of economic and policy work program)

Global trends in CCS

- Originally founded by the Australian government, the Global CCS Institute is currently an independent group of experts that provides information and recommendations to member companies and governments. The latest information on CCS in the world is summarised in the 2017 edition of their report (issued in November 2017).
- Of 37 large-scale CCS projects around the world (including those in the initial stage), eight are underway in China. (While the United States and others have been similarly assessed before) It can be asserted that China now has a great CCS potential. However, it should be noted that the numerical value of the storage potential may be modified as exploratory drilling progresses.
- Australia's CarbonNet can be assessed as a perfect example of connecting sources of CO_2 source to reservoirs. The costs of transporting CO_2 and storing it are low, so it can be expected to play a role as a CCS hub.
- Major oil companies have the knowledge and equipment necessary for underground development and can also be expected to increase oil production with EOR, so the development of CCS is becoming an opportunity to consider. However, the availability of EOR depends on the geology and the components of petroleum.

Hydrogen derived from CCS

- The Institute recognize that the combination of CCS and hydrogen will be an important part of the new low carbon economy and industry.
- Analysis by University College London shows that CCS is indispensable for achieving the IEA's 2°C scenario. According to this analysis, about 25% of hydrogen production in 2050 would come from fossil fuels and CCS.
- Currently, both CCS and hydrogen are expensive, but solar and wind power were also once expensive. How to mitigate risk through policy support during the initial stage of introduction and promote investment is the key to its spread.
- There is certainly CCS potential in China, but there are doubts as to whether it can assumed it can

be used to manufacture hydrogen from oil and export it to Japan. Until now, China has consumed nearly all of its oil near the production area, and no export infrastructure is in place.

- To begin with, China needs fossil fuels for itself, which makes it difficult to produce hydrogen for export. From this perspective, the major candidates for export may be Australia or Indonesia. However, Indonesia does not disclose any relevant data, and its storage potential is unclear.

4.3. The Commonwealth Scientific and Industrial Research Organization Queensland Centre for Advanced Technologies

Date: 10 January 2018

Location: Pullenvale (on the outskirts of Brisbane), Australia

Interviewees: Michael Dolan (CSIRO[94] gasification process team leader)
David Harris (Research Director, Low Emissions Technologies and head of QCAT[95])
Attilio Pigneri (The Hydrogen Utility（H2U）CEO, chair of AAHE[96])
John Blackburn AO (Defense and national security systems consultant)
Tim Owen (Ampcontrol,[97] energy consultant)

<u>CSIRO and its activities</u>

- CSIRO is a national research institution. It has numerous laboratories in Australia and conducts research in various fields.
- It is studying electrolysis with renewable energy and the gasification of lignite as a source of hydrogen.
- Dolan and colleagues are researching technology to separate hydrogen from ammonia as a hydrogen carrier for research on hydrogen production by electrolysis and fuel cells operating at high temperature conducted at the Melbourne laboratory.
- To separate hydrogen from ammonia, a bundle of tubular metal membranes with a diameter of 10mm is used. The membrane is made of a vanadium alloy, which is considerably less expensive than palladium ones used in previous research. This facility can produce (separate) 15 kg/day of hydrogen with greater than 99.99998% purity, which can be used in fuel cells. CSIRO plans to use ammonia left over from separation for power generation.
- In collaboration with Toyota Motor Corporation and Hyundai Motor Corporation, CSIRO are

[94] Commonwealth Scientific and Industrial Research Organisation.
[95] Queensland Centre for Advanced Technologies.
[96] The Australian Association for Hydrogen Energy.
[97] It provides technologies and services for a wide range of electric power businesses such as the construction of transmission and distribution facilities, maintenance of power quality, safety management and coal mining for companies all over the world. Of its services, it also deals with hydrogen technologies as one option for integrating renewable energies into the power grid.

conducting a demonstration test to supply hydrogen purified in CSIRO laboratories to FCVs. In this project, trucks with tanks and dispensers transport they hydrogen to customers.

・CSIRO is planning to improve cost reductions in the future to establish a manufacturing system for hydrogen separation facilities and wants to receive orders from private enterprises.

・In addition to technical problems, there are also inadequacies in regulation as to what kind of state and quantities of ammonia, a hazardous substance, can be transported and stored. With respect to this, given that the population densities of Japan's urban areas is high and that it is subject to earthquakes, CSIRO wants to use the answer Japan will provide as a point of reference.

[We were given a tour of a (small scale) coal gasification facility and a hydrogen separation facility]

<u>H2U activities and the Australian energy market</u>

・H2U is promoting the introduction of FCVs and hydrogen stations in the pre-commercial stage in various parts of Australia. It has so far built hydrogen stations in Moreland (Melbourne) and Keswick (Adelaide). Linde and other gas supply companies, and automobile manufacturers including Toyota are partners.

・The FCV market is in the early stages, and H2U is targeting their introduction in public services such as buses and garbage trucks, and small-scale networks (such as airport shuttle services).

・Hydrogen can fully play a role in the storage of renewable energy. For example, southwestern Australia has the best wind conditions in the country, but no transmission grid is in place. However, at present, things like coordination with markets has not been established, so there is no incentive to use hydrogen in that sense.

・Batteries and electrolysers, which are measures for variable power supplies, behave differently. They can very effective when used appropriately.

・In addition to the rapid increase in electricity rates in Australia, the price of gas is not stable, and long-term contracts are also difficult to establish. This situation is expected to increase interest in hydrogen in the country.

<u>Policies in Australia</u>

・Australia is in a position to be an energy exporter for East and Southeast Asian countries such as Japan. This could lead to Japan reducing its dependency risk on the Middle East.

・The Australian government and the Australian Renewable Energy Agency (ARENA) have also shown a strong interest in systematic measures for hydrogen and the export of energy, and have started large-scale support for research and development.

・The Ministry of Economy, Trade and Industry in Japan has also indicated its intention to strengthen partnerships with Australia through the construction of a long-term hydrogen society.

・Aside from the policy perspective, hydrogen is the focus of attention in Australia where energy prices are high. However, the FCV market is in a chicken or the egg situation as to whether the spread of FCVs should come first or the spread of hydrogen supply infrastructure should be first.

・One of the problems is that policies at the state government level (be they conservative or liberal) are strongly influenced by lobbying from fossil fuel companies, and there is no clear government leadership. Because of this, even when it is necessary to make changes that cannot be made with market forces, measures tend to be delayed.

・Australia has never been exposed to existential threats such as in Asia and European countries. This cultural background can be said to be a factor in delaying responses to problems. This has also led to a weak interest in security issues (including energy).

4.4. Unitec Institute of Technology

Date: 11 January 2018

Location: Auckland, New Zealand

(Interview was conducted in Auckland outside the university)

Interviewee: Jonathan Leaver (Associate Professor or Engineering)

Akihiro Watanabe (Professor, Kanagawa University)

The use of hydrogen in New Zealand

・It is not as aggressive as in Australia, but the export of hydrogen is being considered in New Zealand. At least one Japanese company is conducting a feasibility assessment. Promising sources are hydroelectric and geothermal electrolysis, but there is little room for development in hydropower and geothermal resources are limited. If the aluminium smelter at the southern tip of the South Island is closed, there is a possibility that surplus power can be used to produce hydrogen. There are also gas fields, so CCS may be an option.

・In Unitec's energy model, all hydrogen is used in New Zealand's transport sector. At present, however, there are (1) no clear prospects for its introduction or promotion, (2) fuel cells have low energy densities and are not suitable for large vehicles, (3) there is only one hydrogen fuelling station in the country and no demonstration project can be started, and (4) there is the problem of the high costs of electrolysis (but is still cheaper than production in Japan).

・Recently, there are growing expectations for electric vehicles, but it is not enough to bring them to the market as it is predicted that the cost of storage batteries will stop falling after 2020 and that the technologies for existing vehicles will improve.

・FCVs are not the only solution. We should think about electric vehicles and their proper use, starting with forklifts and other such vehicles.

Japan's hydrogen energy policy

- Japan’s Abe government has announced it will use hydrogen energy, will probably become a promising hydrogen buyer, especially for Australia.
- If the renewable energy in Australia’s desert region is to be factored in as a source of hydrogen, the Japanese government will need to have dialogues with not only the Australian government but also with Aborigines.

Assessment of hydrogen demand and supply potential in the APEC region implemented in this project

- The estimate itself is very useful and interesting. Under the present situation where there is little data, we can also understand that various elements are being simplified and thought about. There are problems, however.
- We think the cost of electrolysis is underestimated in supply costs.
- It is reasonable to estimate hydrogen demand under a fixed scenario being based on APERC’s model, but we notice that the price of FCVs and other factors are not taken into consideration in the transport sector, for example.

5. How Hydrogen Should be Used in the APEC Region

Based on scenario analysis in this study, the demand for hydrogen in the entire APEC region in 2050 is 352 Mtoe, equivalent to 7% of the current primary energy supply. Looking at the breakdown, the power generation sector and the transportation sector each account for slightly less than 40%, while the rest is in the industrial sector. It is also expected to reduce 1.2 Gt of CO_2 emissions, equivalent to 6% of current CO_2 emissions.

From the perspective of energy security, while hydrogen does not offer a significant improvement in the energy self-sufficiency rate across the APEC region, relatively large improvements can be expected in some economies.

If hydrogen were distributed within the APEC region, economies with abundant fossil fuel and renewable energy resources, such as Australia, Canada, Chile, Indonesia, Mexico, New Zealand, Russia and the United States, would be candidates for hydrogen-exporting countries, while other economies would be hydrogen importers.

When the focus shifts to using fossil fuels as a source for producing hydrogen, economies with fossil fuel resources and a large CCS potential are hydrogen-exporting economies. However, it should be noted that this study covers only depleted oil and gas fields for CCS potential. If aquifers are included in the CCS potential, China can also be a hydrogen exporter as its CCS potential is comparable to that of the United States.

If hydrogen is produced from renewable energy, there is significant potential with solar power, as the cost of power generation has drastically fallen in recent years. In particular, solar power generation is relatively easy to do in economies like the United States, Australia and China that have vast tracts of land and plenty of sunlight for the inexpensive, large-scale production of hydrogen. In Australia in recent years, the study of the concept of manufacturing hydrogen from renewable energy such as solar power generation and exporting it to other countries has been started.

There are various options (economies, technology) for the production of hydrogen, so competition to drive down the cost of hydrogen production can be expected. On the other hand, no conclusion has been reached regarding the transport of hydrogen as to which of the current methods being studied - liquefied hydrogen, methyl-cyclohexane and ammonia - is the most suitable. Therefore, we will have to wait until around 2020 when the supply chain demonstration tests with Japan and other countries begin.

However, the most critical issue is the creation of hydrogen demand. At present, there is almost no demand for hydrogen as an energy application. While fuel cell vehicles are expected to be the first application for hydrogen, it will take time for them to become popular since it is necessary to build large-scale infrastructure such as hydrogen stations. Also, the spread of electric vehicles has expanded in recent years and has also affected trends in competing vehicles. Also, the annual hydrogen consumption per fuel cell vehicle (assuming an annual distance travelled of 10,000 km) is only 1,000 Nm^3, equivalent to the consumption of 2 billion Nm^3 of hydrogen from a 1 GW hydrogen power plant with 2 million vehicles on the road. Therefore, the introduction of hydrogen power generation that can expect large-scale consumption is a very important key.

Based on the analysis of this study, the cost of supplying hydrogen for hydrogen power generation is extremely high, and in order for hydrogen power generation to compete with natural gas-fired and coal-fired power generation, all aspects of hydrogen, from its production to transportation, will have to become cheaper. To produce hydrogen, it is vital that the costs of producing fossil fuel and renewable energy in hydrogen-exporting economies are further reduced. As described above, based on the results of the Japanese demonstration test in around 2020, there are challenges with the direction of technical development and challenges that need to be sorted out to reduce costs for the transport of hydrogen.

Future research topics being considered through research of case studies introducing hydrogen and sharing outcomes in economies include the development of hydrogen technologies, the economics of hydrogen production and transportation, the creation of hydrogen demand, and the study of the role of bilateral and multilateral hydrogen trade.

PUBLISHED BY

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ISBN 978-4-931482-59-3

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