Chapter 4

The Potential and Costs of Hydrogen Supply

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Chapter 4

The Potential and Costs of Hydrogen Supply

1. Hydrogen Production Potential

1.1 Hydrogen Production Method

Hydrogen can be produced from any kind of primary energy, from fossil fuel to renewables; major hydrogen sources are shown in Figure 4.1.

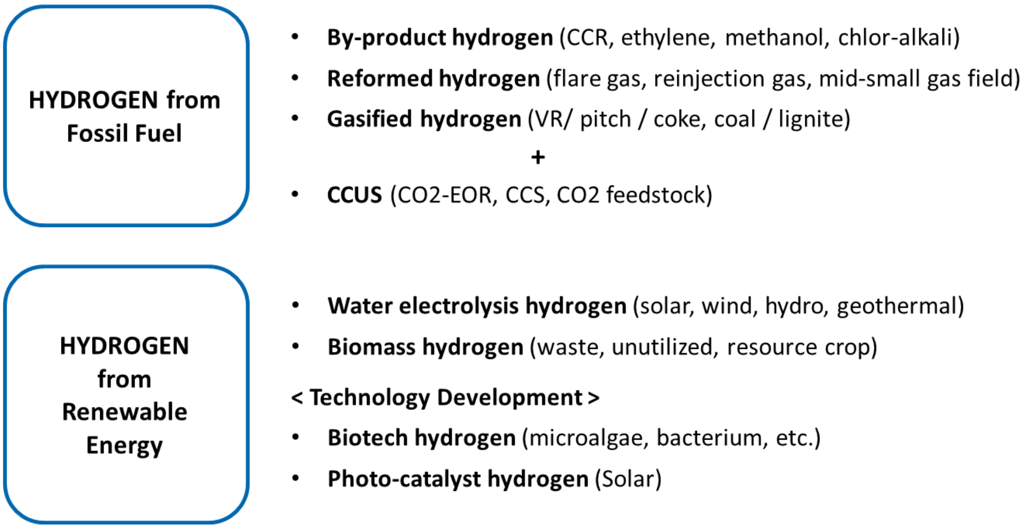
Three major fossil fuel production methods are listed: (1) by-product hydrogen utilising purification technologies, such as Pressure Swing Adsorption; (2) reformed hydrogen from gas flares, reinjection, and mid-small gas fields; and (3) gasified liquid (vacuum residue, pitch) and solid (coke, coal, lignite) hydrogen utilising gasification technology.

In addition, it is important to effectively manage the CO_2 that will be produced during hydrogen production. CO_2 can be captured and utilised for enhanced oil recovery or feedstock for chemical products or stored underground.

Renewable electricity, such as from solar, wind, hydro, and geothermal sources can be converted to hydrogen through water electrolysis, and biomass can also produce hydrogen via gasification.

In the future, new technology, such as biotechnology and photo-catalysts, will diversify and increase the options to produce hydrogen from renewables.

Figure 4.1 Hydrogen Production Methods



- **By-product hydrogen** (CCR, ethylene, methanol, chlor-alkali)
- **Reformed hydrogen** (flare gas, reinjection gas, mid-small gas field)
- **Gasified hydrogen** (VR/ pitch / coke, coal / lignite)

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- **CCUS** (CO2-EOR, CCS, CO2 feedstock)

- **Water electrolysis hydrogen** (solar, wind, hydro, geothermal)
- **Biomass hydrogen** (waste, unutilized, resource crop)

< Technology Development >

- **Biotech hydrogen** (microalgae, bacterium, etc.)
- **Photo-catalyst hydrogen** (Solar)

CCR = Conradson carbon residue, CCS = carbon capture and storage, CCUS = carbon capture, utilisation and storage, EOR = enhanced oil recovery, VR = vacuum residue.
Source: Author.

1.2. Hydrogen Production Cost

1.2.1. Key Assumptions

Key assumptions are made to calculate the costs of each hydrogen production method (technology and source), as shown in Table 4.1.

Table 4.1 Key Assumptions of Each Hydrogen Production Method

TECHNOLOGY	H2 SOURCE	Key Assumptions	Data Source
Reforming	Gas (Flare, Mid – small)	• Investment cost ($2,000/Nm3/h@2017, $1,650/Nm3/h@2040) • Efficiency (64%@2017, 83%@2040)	IEA report
Gasification	Lignite	• Investment cost ($10,000/Nm3/h@2017, $8,890/Nm3/h@2040) • Efficiency (42%@2017, 53 %@2040)	AIST report
CCUS	-	• CCS cost ($70/tonne@2015, $48/tonne@2040) • CO2 value ($20/ton@Best)	NCCS report
Gasification	Biomass	• Investment cost ($5,222/Nm3/h@2017, $4,700/Nm3/h@2040) • Efficiency (44%@2017, 50%@2040)	In-house data
Electrolysis	Solar, Wind, Hydro, Geothermal	• Investment cost ($5,936/Nm3/h@2017, $2,947/Nm3/h@2040) • Efficiency (79%@2017, 82%@2040)	IEA report IEEJ report

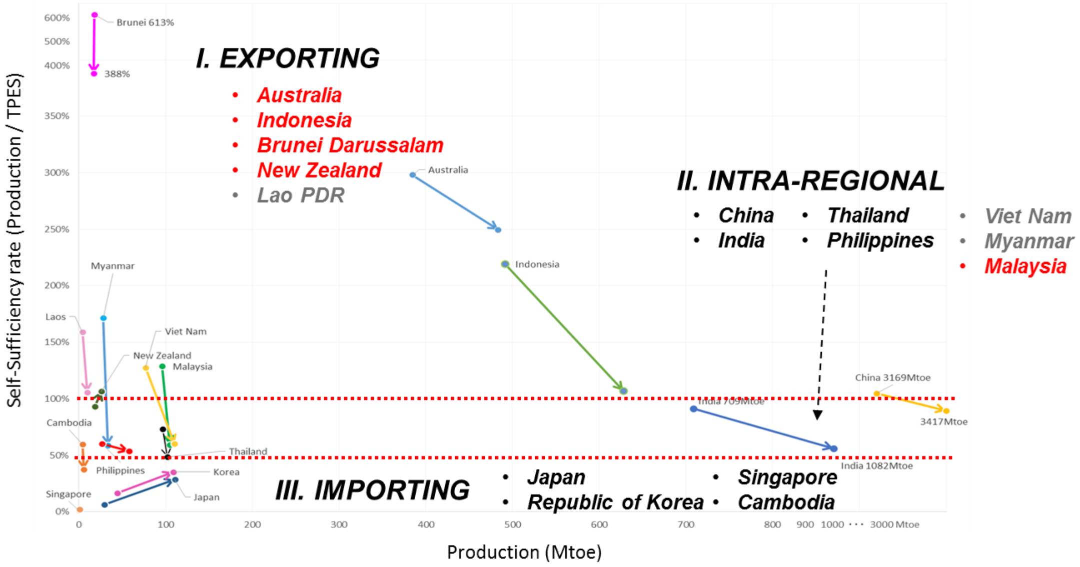
AIST = Association for Iron and Steel Technology, CCUS = carbon capture storage, IEA = International Energy Association, IEEJ = Institute of Electrical Engineers of Japan, NCCS = National Climate Change Secretariat.
Source: Author.

Using forecasted data of the energy balance between production and demand, including the hydrogen forecast, the 16 East Asia Summit (EAS) countries are categorised into three groups (Exporting, Intra-regional, Importing) to identify their positioning for hydrogen trading in 2040, as shown in Figure 4.2.

Addressing regional energy balance characteristics, Malaysia and Indonesia are divided into two regions each: In Malaysia 'Peninsular Malaysia' is the more demand-intensive region and 'Borneo' is the more supply-intensive region, while in Indonesia 'Eastern regions (Kalimantan, Natuna, Maluku, Papua, and Sulawesi)' is the more demand-intensive region and 'Java and Sumatra' is a demand-and-supply balanced region.

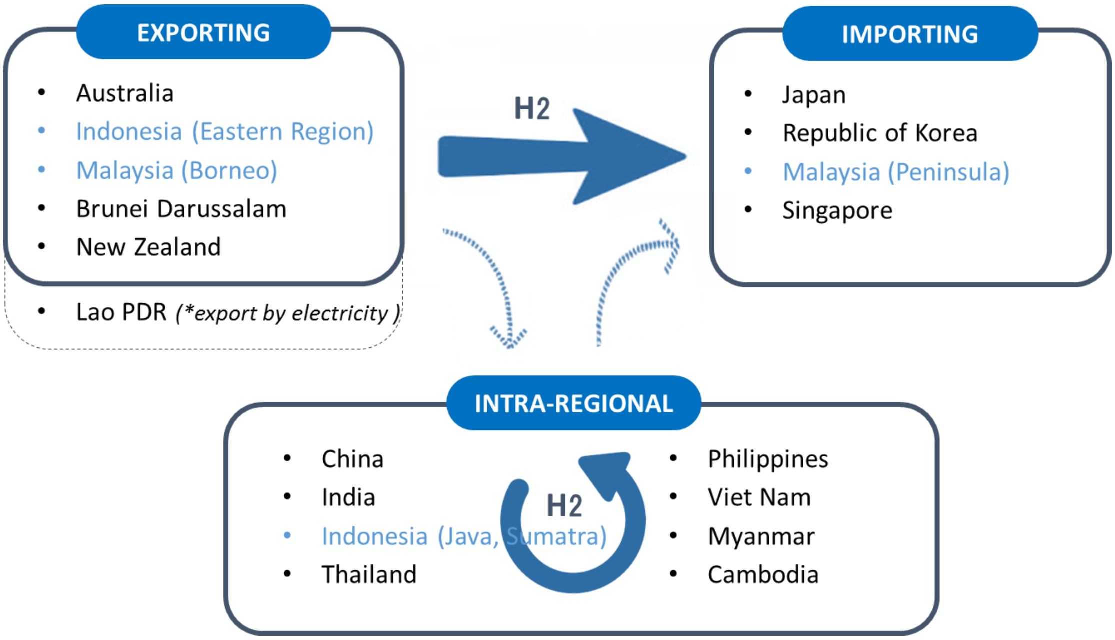
As the result, the supply-intensive 5 + 1 countries/regions will potentially be in a hydrogen 'Exporting' position, while the other four will be in the hydrogen 'Importing' group, and the remaining eight will be in the 'Intra-regional' group, as shown in Figure 4.3.

Figure 4.2 Self-Sufficiency Rate in Total Primary Energy Supply (2013–2040)



Mtoe = million tonnes of oil equivalent, TPES = total primary energy supply.
Source: Author; the data were customised based on Kimura and Phoumin, 2016.

Figure 4.3 Positioning for Hydrogen Trading



Source: Author.

1.2.2. Hydrogen Production Cost

Figure 4.4 compares the typical costs of hydrogen produced from fossil fuels and renewable energy in the Exporting group, with the same comparison presented for the Intra-regional group in Figure 4.5. The hydrogen costs are calculated based on public information from References [1].

The costs of each production technology are estimated in three scenarios, namely the Current scenario, the 2040 scenario, and the Best (New Tech or Future Tech) scenario. For the Exporting group, hydrogen production costs in 2040 ranked from low to high are in the order of 'Gas reforming', 'Water electrolysis (with stable power)', 'Biomass gasification', 'Lignite gasification', and 'Water electrolysis (with fluctuating power)'.

Hydrogen production will strongly depend on the price of feedstocks and process efficiency. The feedstock prices of each hydrogen production pathway for the three scenarios are presented in Table 4.2 for the Exporting group and Table 4.3 for the Intra-regional group.

Table 4.2 Feedstock Prices Applied to Evaluate Hydrogen Cost for Each Pathway (Exporting Group)

Hydrogen production pathway	Feedstock	Unit	Current	2040	Best
Steam reforming w/CCS	NG	US$/mmbtu	3.4	5.7	5.7
Alkaline electrolyser/stable power	Electricity	C/kWh	5.2	3.1	3.1
Lignite gasification w/CCS	Lignite	US$/tonne	39.8	55.7	55.7
Woody biomass gasification	Wood	US$/tonne	100	100	100
Alkaline electrolyser/fluctuating power	Electricity	C/kWh	8.0	2.5	N/A

CCS = carbon capture and storage, NG = natural gas.
Source: Author.

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[1] Environmental Energy Team (2014); Forestry and Forest Products Research Institute (2017); Fujimoto (2018); Ishii and Maruta (2018); Karimi and Shamsuzzaman (2014); Kato (2016); Korner (2015); Sayama and Miseki (2014); and Yamamoto (2018).

Table 4.3 Feedstock Prices Applied to Evaluate Hydrogen Cost for Each Pathway (Intra-regional Group)

Hydrogen Production Pathway	Feedstock	Unit	Current	2040	Best
Steam reforming w/CCS	NG	US$/mmbtu	5.9	9.9	9.9
Alkaline electrolyser/stable power	Electricity	C/kWh	5.2	3.1	3.1
Lignite gasification w/CCS	Lignite	US$/tonne	32.2	45.1	45.1
Woody biomass gasification	Wood	US$/tonne	100	100	100
Alkaline electrolyser/fluctuating power	Electricity	C/kWh	8.0	2.5	N/A

CCS = carbon capture and storage, NG = natural gas.
Source: Author.

In the case of production from fossil fuel sources, it is also required to assess the feasibility of carbon capture utilisation and storage (CCUS), reflecting the considerations on social acceptability, technology and economics.

CCUS consists of CCS and carbon capture and utilisation (CCU). CCS is cost-based activity and it is required to add its cost (CCS cost) to hydrogen production. CCU is value-based activity and it is required to deduct its value (CO_2 value) from hydrogen production.

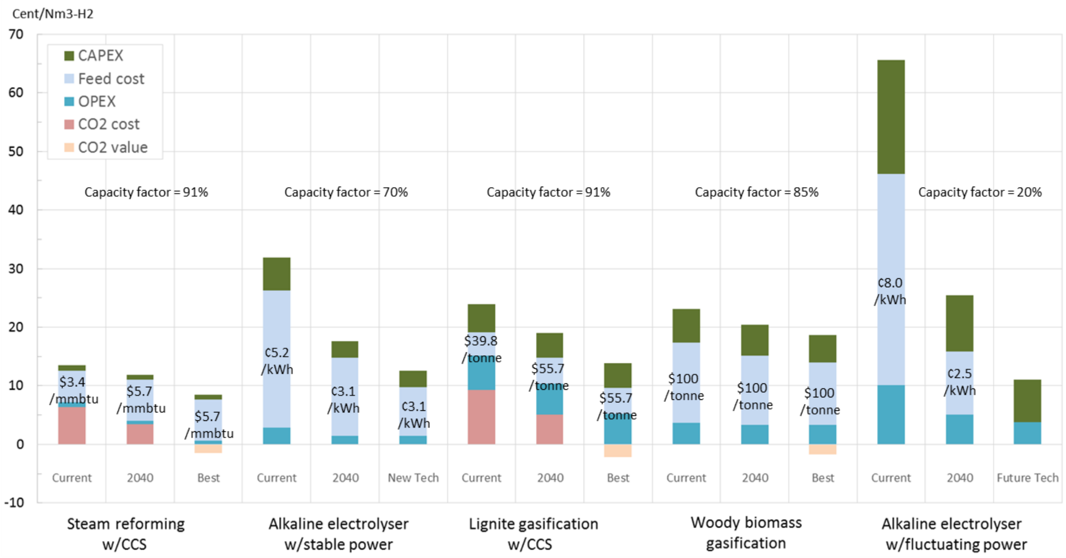
The capacity factor, CCS cost and CO_2 value used in the calculation of hydrogen production costs are shown in Table 4.4.

Table 4.4 Assumptions for Capacity Factor, CCS Cost and CO_2 Value

Hydrogen production pathway	Capacity factor (%)	CCS cost Current (US$/t-$CO_2$)	CCS cost 2040 (US$/t-$CO_2$)	CO_2 value Best case (US$/t-$CO_2$)
Steam reforming w/CCS	91.3	70.0	48.0	20.0
Alkaline electrolyser/stable power	70.0	NA	NA	NA
Lignite gasification w/CCS	91.3	70.0	48.0	20.0
Woody biomass gasification	85.0	NA	NA	20.0
Alkaline electrolyser/fluctuating power	20.0	NA	NA	NA

CCS = carbon capture and storage.
Source: Author.

Figure 4.4 Example of Large-Scale Hydrogen Production Cost (Exporting Group)

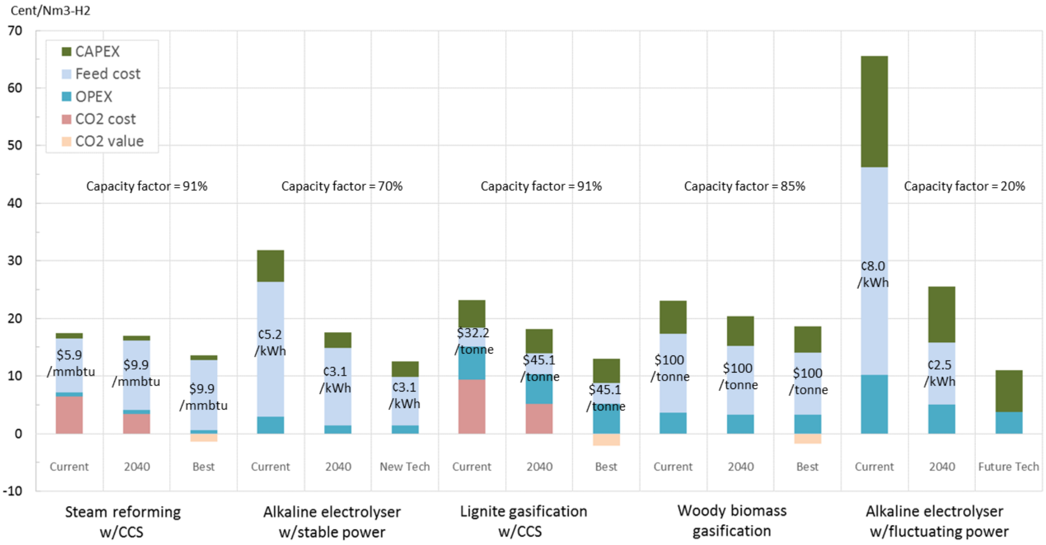


*1 : Feed Cost of Lignite gasification is based on FOB price in Exporting Group Countries.
*2 : CCS cost is based on $70/t-CO2 for current and $48/t-CO2 for 2040 (CCS/Utilization Singapore Perspectives).

CAPEX = capital expenditure, CCS = carbon capture and storage, FOB = free on board, OPEX = operating expenditure.
Source: Author.

Figure 4.5 shows the cost comparison of hydrogen produced from fossil fuels and renewable energy in the countries of Intra-regional Group. General trend of cost is same as the one in Exporting Group, and only costs of steam reforming and lignite gasification are different due to the difference of feedstock price between two groups.

Figure 4.5 Example of Large-Scale Hydrogen Production Cost (Intra-regional Group)



*1 : Feed Cost of Lignite gasification is based on FOT price in Intra-regional Group Countries.
*2 : CCS cost is based on $70/t-CO2 for current and $48/t-CO2 for 2040 (CCS/Utilization Singapore Perspectives).

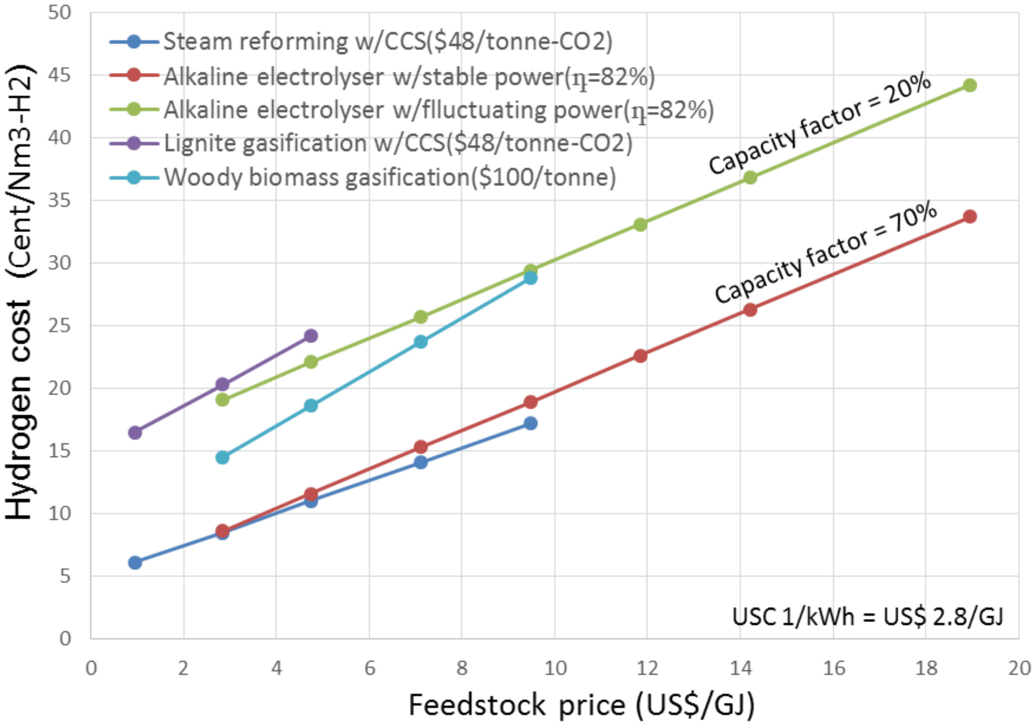
CAPEX = capital expenditure, CCS = carbon capture and storage, FOT = free on truck, OPEX = operating expenditure.
Source: Author.

1.2.3. Sensitivity Analysis

The sensitivity of hydrogen production costs to feedstock price changes is illustrated in Figure 4.6, which compares different hydrogen production costs using normalised feedstock prices as a variable parameter.

Hydrogen production cost by gas reforming is the most economical method. Water electrolysis with a high capacity factor (70%) plus a low feedstock price will enhance its cost competitiveness. Lignite gasification with CCS (US$48/tonne-$CO_2$) and woody biomass gasification shows same level of hydrogen production cost, and water electrolysis with low capacity factor shows the highest range of its cost.

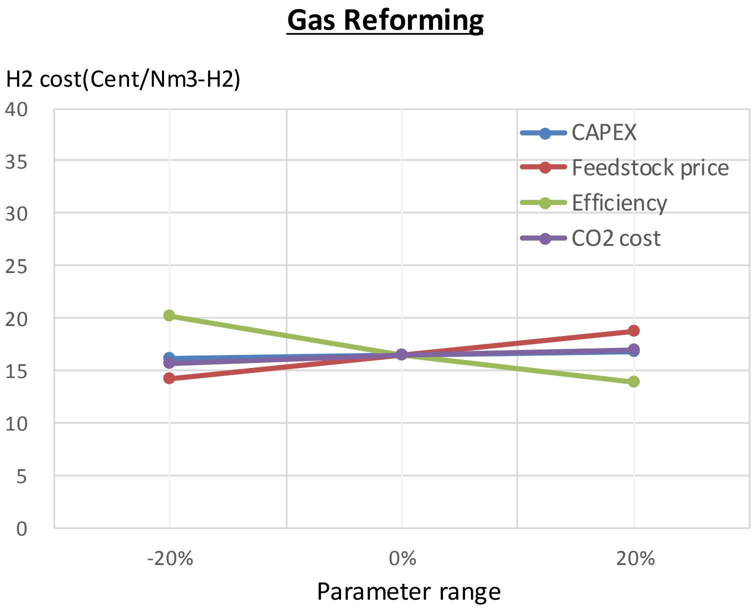
Figure 4.6 Sensitivity of Hydrogen Production Cost (2040) by Feedstock Price

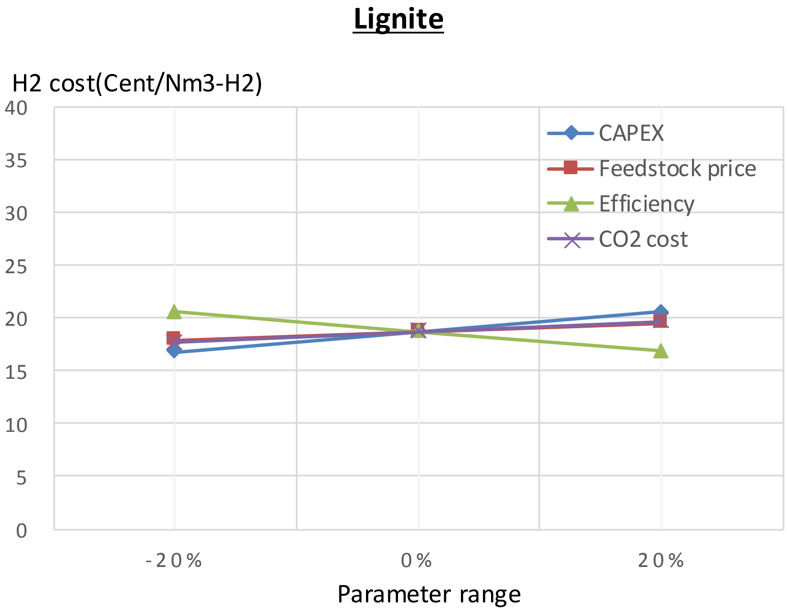


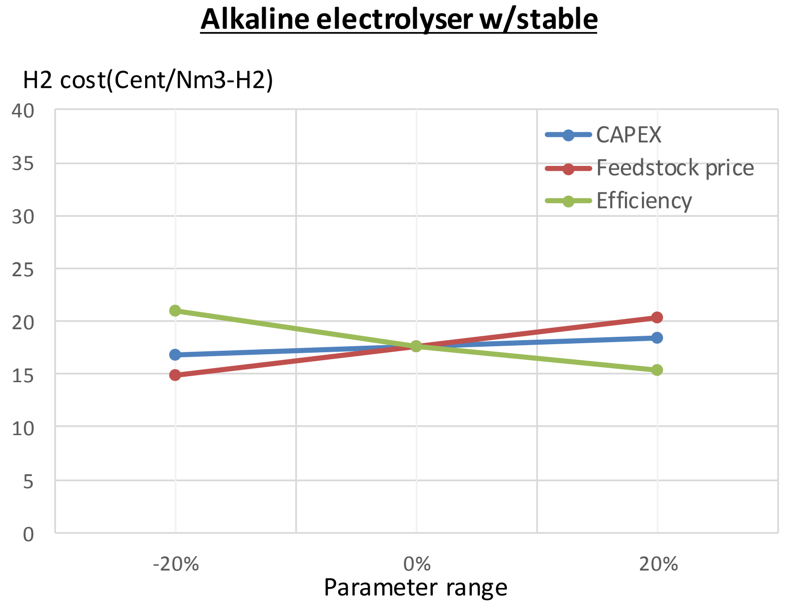
CCS = carbon capture and storage.
Source: Author.

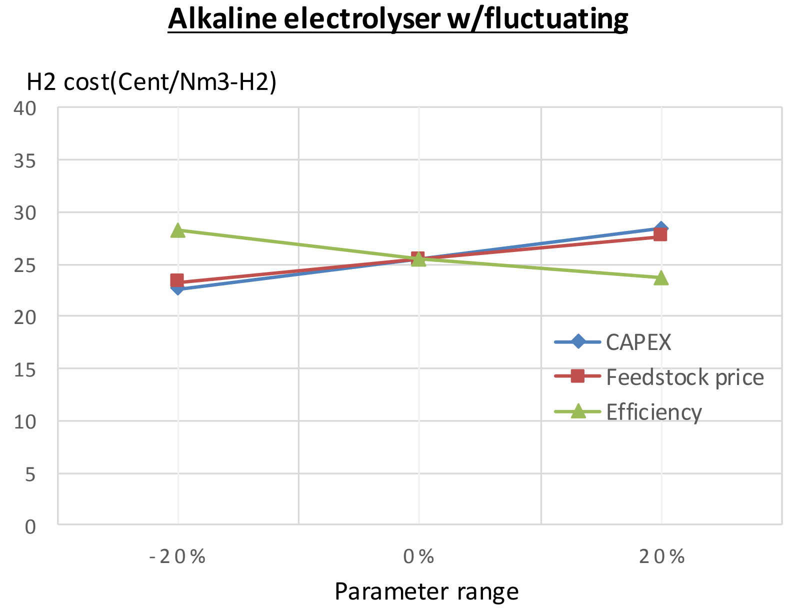
The sensitivity of parameters of 'CAPEX', 'Feedstock price', 'Efficiency', and 'CO_2 Cost' on the cost of each hydrogen production technology is illustrated in Figure 4.7. The parameters are varied by 20% higher and lower, relative to the base design condition. The conditions of technology development are assumed in the operation year of the production plants around 2040.

Figure 4.7 Sensitivity of Hydrogen Production Cost to Technical Parameters (2040)









CAPEX = capital expenditure.
Source: Author.

As for gas reforming, a +/- 20% change in feedstock price will lead to a variation of 4.6 Cent/Nm3-H_2; with lignite gasification, the same change will lead to a variation of 1.6 Cent/Nm3-H_2. On the other hand, a +/- 20% change in capital expenditure (CAPEX) will lead to a variation of 0.6 Cent/Nm3-H_2 for gas reforming and 3.8 Cent/Nm3-H_2 for lignite gasification. This means that the CAPEX of lignite gasification has a dominant effect on the hydrogen production cost compared to gas reforming. In the case of renewable energy, a +/-20% change in electricity price of stable power will lead to a variation of 5.4 Cent/Nm-H_2, while the case of fluctuating power, the variation is 4.4 Cent/Nm3-H_2. On the other hand, a +/- 20% change in CAPEX will lead to a variation of 1.6 Cent/Nm3-H_2 for stable power and 5.8 Cent/Nm3-H_2 for fluctuating power. This means that electricity price has a dominant effect on hydrogen production costs from renewable energy, and CAPEX of water electrolysers with fluctuating power will also largely affect hydrogen production cost.

The efficiency parameter has a reverse effect on the hydrogen production cost compared to the feedstock price, because an increase in efficiency causes a decrease in feedstock volume, which has a same effect on the production cost as the feedstock price.

1.3. Potential of Hydrogen Production Volume

1.3.1. Method of Estimation/Calculation

Hydrogen production volume is estimated for its potential together with a forecast as defined in Figure 4.8. Hydrogen production potential shows the technically feasible volume once geographical location, environmental conditions/constraints, etc. are considered. On the other hand, the hydrogen forecast shows the required hydrogen volume balanced with its expected demand in 2040, estimated as the total primary energy supply (TPES = demand x 1.5) of hydrogen. The ratio 1.5 is referred to the ratio between TPES and energy demand in Japan (Agency for Natural Resources and Energy, 2017).

Figure 4.8 Definitions of Hydrogen Production Potential and Forecast

Production Potential

Technically Feasible H2 Production Volume Potential in 2040

- Feasible land/area (excluding natural reserved, pasture, cropland and residential areas, etc.)
- Vicinity of coastal lines/ports in Exporting countries
- Feasible distance from populated area for inland transport in Intra-regional/Importing countries
- Balance between CO2 emissions from H2 production by fossil fuels and CO2 storage/usage potentials.
- Strong solar/wind (Solar : > 5kWh/m2, Wind : > 6m/s)

Production Forecast

H2 volume forecast to produce balanced with its TPES (demand x1.5) in 2040

- Exporting countries ('potentials' x 'introduction factor [as below]')
  by-product, gas reforming : 61%, stable RE : 29%
  biomass/lignite gasification : 5%, unstable RE : 1% below
- Intra-regional countries
  total production is 150% of total demand (Priority is lower cost H2.)
- Importing countries
  total production is all the potential H2 production.

RE = renewable energy, TPES = total primary energy supply.
Source: Author.

Hydrogen production potential volume is calculated based on the preconditions shown in Table 4.5 for fossil fuels, and Table 4.6 for renewables.

Hydrogen from fossil fuels is calculated based on the material balance of the related processes, excluding the hydrogen consumed in the plant, and some portion of gas and lignite reserves (see Table 4.5).

Table 4.5 Preconditions to Calculate Production Potential (Fossil Fuel)

TYPE	H2 SOURCE	LOGIC	Data Source
By-product (Purification)	CCR, Ethylene, Propylene, Methanol, chlor-alkali electrolysis	• Calculate based on petro/chemical production capacity and process balance for existing/planned plants, excluding internal consumption • Calculate H2 export potential by using 10% of the potential.	Interview and site visit in Thailand and India
Gas (Reforming)	Flare gas, Mid - small gas field	• Calculate based on the process balance for flare gas, mid small-gas field, using typical gas composition. • 100% of flare gas and 21.4% of gas reserve(mid-small gas) for potential	NOAA IHS Energy UN Energy Statistic Year book 2015, BP Statistics, government statistics
Liquid/Solid (Gasification)	VR/pitch, Coke, Coal/Lignite	• Calculate based on the process balance, using typical VR and Lignite composition and production volume - VR/Coke: heavy oil percentage in the refinery production capacity - Lignite: 50% of lignite reserves	Heavy oil import rate from middle east (government statistics, ERIA, APEC data) 'Petro & Petro-chemical industry in Asia 2017', 'Petro-chemical industry in Asia 2018'
CCUS	CO2-EOR, CCS, CO2 feedstock	• Calculate expected reserve period based on the CO2 volume by H2 production from fossil fuel and CCS reserve potential.	GCCSI

APEC = Asia–Pacific Economic Cooperation, CCR = Conradson carbon residue, CCS = carbon capture and storage, EOR = enhanced oil recovery, ERIA = Economic Research Institute for ASEAN and East Asia, GCCSI = Global CSS Institute, IHS = IHS Markit, NOAA = National Oceanic and Atmospheric Administration, VR = vacuum residue.
Source: Author.

Hydrogen from renewable energy is calculated based on energy intensity, geographical conditions, and technical feasibility, including some economical perspectives, e.g. distance from the coastal lines, for each source, by using public information (see Table 4.6).

Table 4.6 Preconditions to Calculate Production Potential (Renewable Energy)

TYPE	H2 SOURCE	LOGIC	Data Source
Light Energy (Electrolysis)	Solar (PV, Solar thermal)	• Calculate based on the energy intensity, geographical conditions, technical and economical feasibility.	BNERI, CIEMAT, IRENA, Kaung Kyaw Say, Mot MacDonald, NREL, RED, SEDA, government statistics
Kinetic Energy (Electrolysis)	Wind	• Same as above	AWS, BNERI, Contact Energy, INWEA, IRENA, MOIT, Vortex
Kinetic Energy (Electrolysis)	Hydro	• Employ public data for technical, commercial feasible potential of hydro power in its rich resource and island countries (AUS, NZ, Indonesia, Malaysia-Borneo)	BNERI, Contact Energy, ERIA
Heat Energy (Electrolysis)	Geothermal	• Same as above (NZ, Indonesia)	Contact Energy, IEA, IRENA, government statistics
Biomass Energy (Gasification)	Waste, unutilised, Resource crop	• Calculate H2 production potential by using 60% of total biomass potential from public data (Remaining 40% is for biofuel)	BNERI, IEA, IRENA, NOAA (*sourced by IRENA (9))

AWS = AWS Truepower, BNERI = Brunei National Energy Research Institute, CIEMAT = Research Centre for Energy, Environment and Technology, ERIA = Economic Research Institute for ASEAN and East Asia, IEA = International Energy Agency, INWEA = Indian Wind Energy Association, IRENA = International Renewable Energy Agency, MOIT = Ministry of Industry and Trade, NOAA = National Oceanic and Atmospheric Administration, NREL = National Renewable Energy Laboratory, PV = photovoltaics, RED = Renewable Energy Development Programme, SEDA = Sustainable Energy Development Authority.
Source: Author.

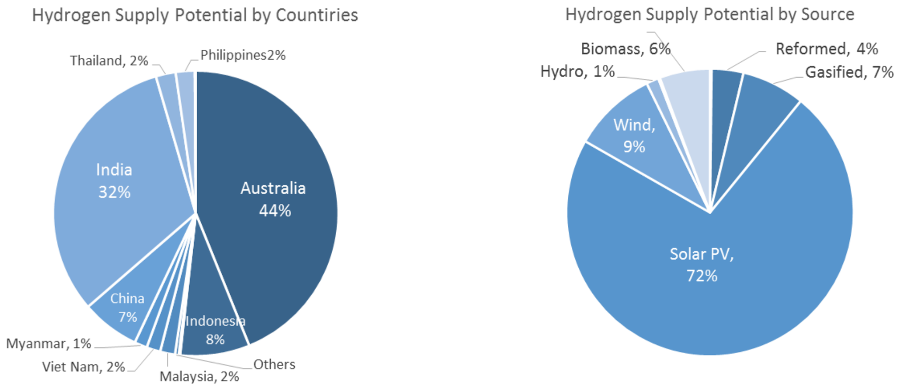
1.3.2. Hydrogen Production Potential

The total hydrogen supply potential across the EAS region is 1,876 Mtoe, with Australia accounting for 44%, followed by India with 32%, as shown in Figure 4.9.

Overall, renewable energy-derived hydrogen is assumed to account for almost 90% of the total of region's supply potential, with hydrogen from solar photovoltaics accounting for over 70%, followed by hydrogen from wind.

Amongst fossil fuel-derived hydrogen, supplies from gasification, mostly stemming from lignite, will account for 65% of the total, followed by reformed hydrogen with 33%, derived from flare gas, reinjection gas, and mid-small gas fields.

Figure 4.9 Hydrogen Supply Potential by Countries and Source



PV = photovoltaics.

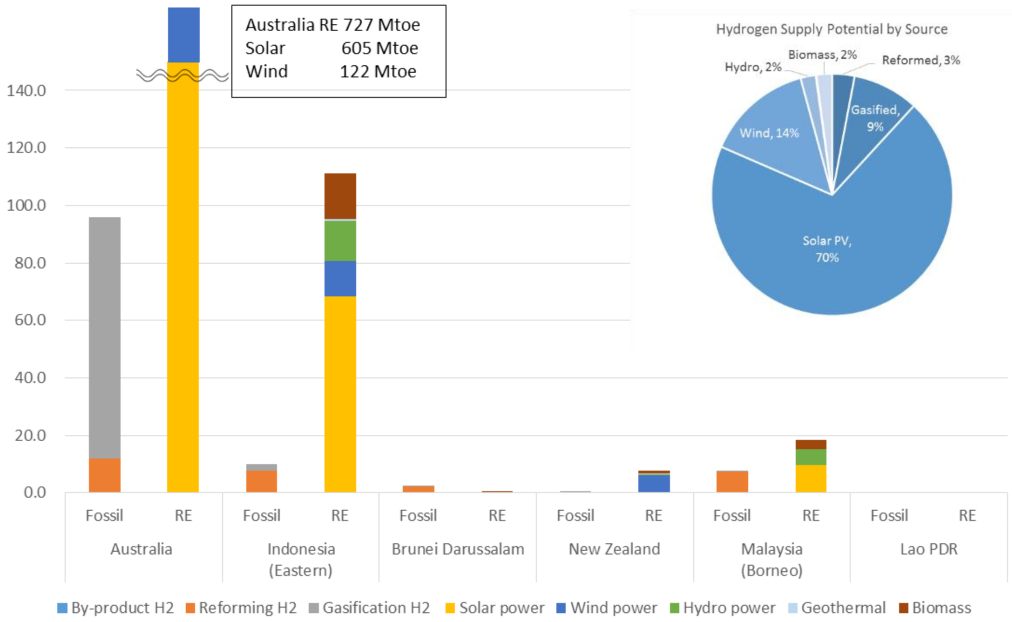
Source: Author.

The hydrogen supply potential in Exporting group countries can reach 982 Mtoe, with Australia accounting for 84%, followed by the Eastern regions of Indonesia, and then the Borneo region of Malaysia, as shown in Figure 4.10.

Renewable energy-derived hydrogen accounts for 88% of the group's supply potential, with photovoltaics (79%) taking the largest share, followed by hydrogen from wind with 16%. Fossil fuel-derived hydrogen mostly comes from lignite gasification, accounting for 74% of the total, followed by 25% of gas-reformed hydrogen.

As the largest supplier of hydrogen in the group, Australia has a potential of 823 Mtoe, mostly derived from photovoltaics, accounting for 74%, followed by wind with 15%. As the second-largest supplier, the Eastern regions of Indonesia has a potential of 121Mtoe, with photovoltaics taking the largest share at 57%, followed by biomass gasification at 13%, and then hydro and wind power. The Borneo region of Malaysia is the third-largest supplier at 26 Mtoe of hydrogen, with photovoltaics accounting for 37%, followed by gas-reformed hydrogen with 28%, then hydro with 21%.

Figure 4.10 Hydrogen Production Potential in 2040 (Exporting Group)



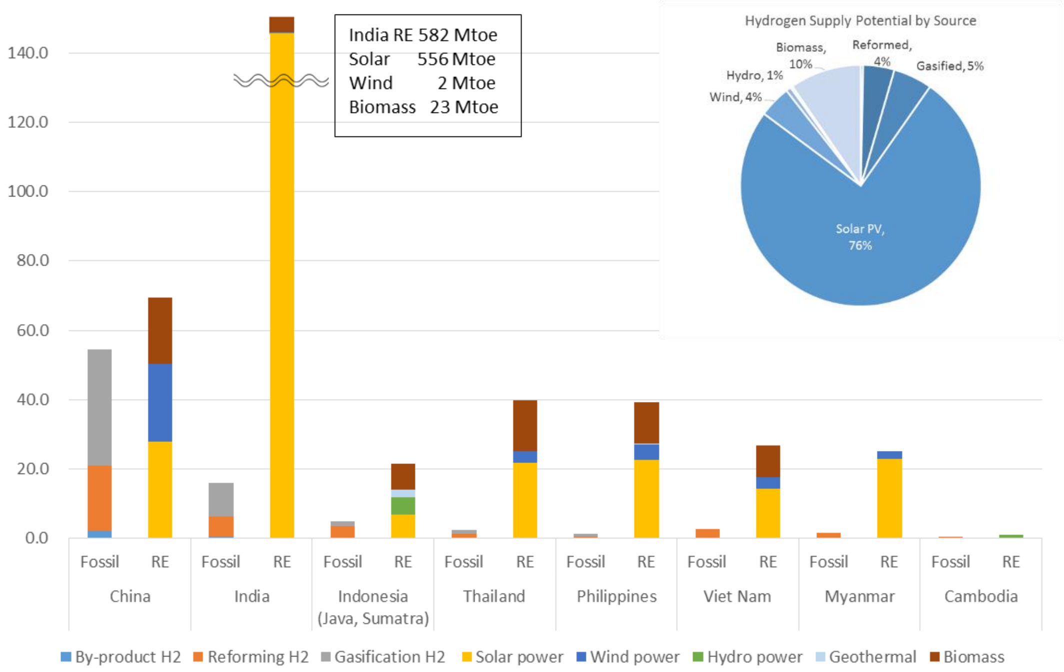
Lao PDR = Lao People's Democratic Republic, mtoe = million tonnes of oil equivalent, PV = photovoltaics, RE = renewable energy.
Source: Author.

Amongst Intra-regional group countries, the total of hydrogen supply potential can reach 890 Mtoe, with India accounting for 67%, followed by China at 14%, as shown in Figure 4.11.

Renewable energy-derived hydrogen accounts for 90% of the group's supply potential, with hydrogen from photovoltaics taking the largest share at 84%, followed by biomass gasification at 11%. Amongst fossil fuel-derived hydrogen, reformed gas accounts for 41%, followed by lignite gasification with 39%.

As the largest supplier of hydrogen in the group, India has the potential for 598 Mtoe, mostly derived from photovoltaics, accounting for 93%, followed by biomass. As the second-largest supplier, China has a potential of 124 Mtoe, mostly from photovoltaics (23%), followed by lignite gasification (19%) and then wind and biomass gasification. Thailand and the Philippines maintain the third position, showing a similar hydrogen portfolio, with photovoltaics accounting for almost the half of the potential, followed by biomass, then wind power.

Figure 4.11 Hydrogen Production Potential in 2040 (Intra-regional Group)

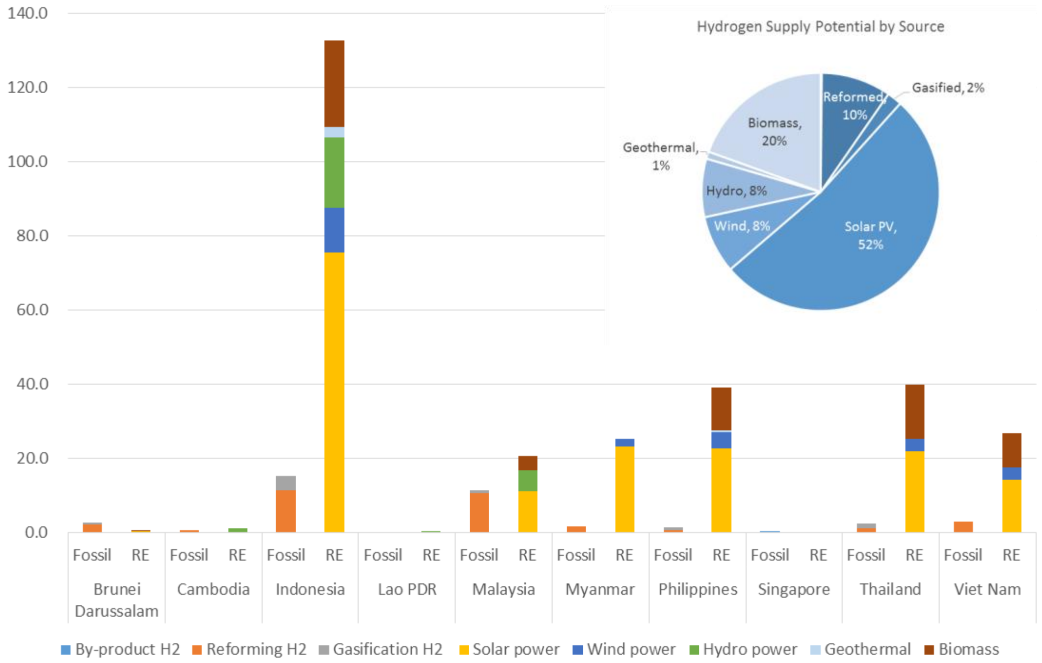


Mtoe = million tonnes of oil equivalent, PV = photovoltaics, RE = renewable energy.
Source: Author.

The Association of Southeast Asian Nations (ASEAN) region has the potential of 323 Mtoe of hydrogen, with Indonesia accounting for 46%, followed by Thailand and the Philippines, as shown in Figure 4.12.

As a source of hydrogen, renewable energy accounts for 90% of the group's supply potential and photovoltaics takes the largest share at 58%, followed by biomass gasification at 22%, then wind and hydraulic power. Amongst fossil fuel-derived hydrogen, reformed hydrogen takes the largest share at 83%, followed by gasified hydrogen, as compared to the Java and Sumatra region.

Figure 4.12 Hydrogen Production Potential in 2040 (ASEAN)



Lao PDR = Lao People's Democratic Republic, PV = photovoltaics, RE = renewable energy.
Source: Author.

1.3.3. Hydrogen Production Forecast

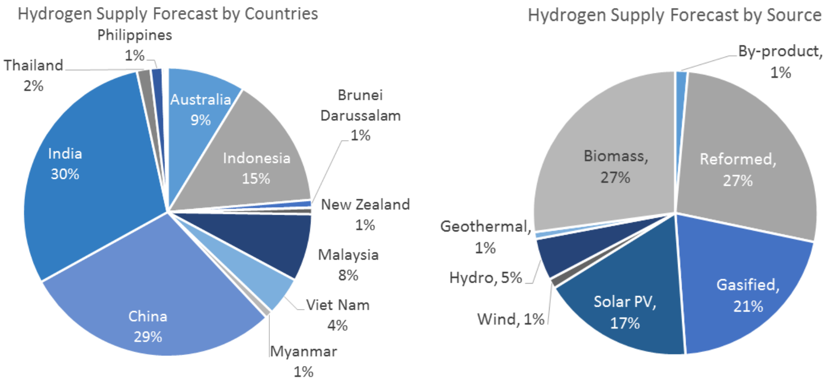
With rapid economic and demographic growth in the EAS region, along with global trends for renewables and decarbonisation, hydrogen is expected to play a key role in the transition away from fossil fuels through its mid- and long-term storable and transportable capability in this region.

In terms of the hydrogen supply forecast in 2040, the EAS region can reach 154 Mtoe, with India and China taking the largest share of around 30% each. They also have a high demand forecast themselves, with each able to satisfy its own domestic demand, as shown in Figure 4.13.

Indonesia (including Sumatra, Java, and other Eastern regions) and Australia will follow those countries in the majority of its hydrogen production being for export.

Regarding hydrogen sources, production derived from reformed gas and biomass will each account for 27%, followed by gasified liquids and solids.

Figure 4.13 Hydrogen Supply Forecast by Countries and Source



PV = photovoltaics.
Source: Author.

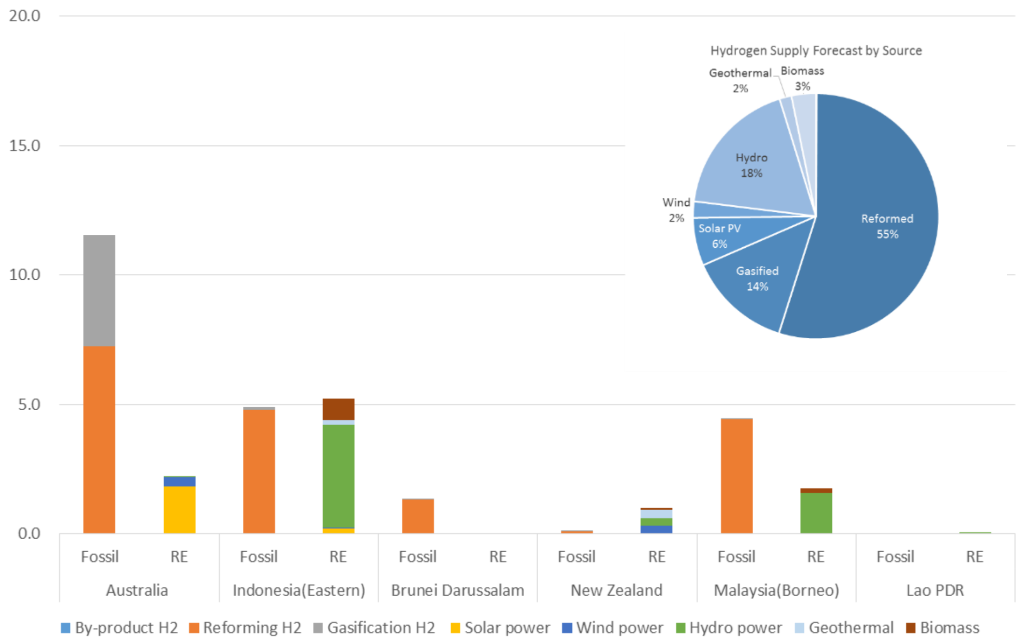
The hydrogen supply forecast in the Exporting group can reach 32.4 Mtoe in 2040, with Australia accounting for 42%, followed by the Eastern regions of Indonesia with 31%, then the Borneo region of Malaysia with 20%, as shown in Figure 4.14.

Fossil fuel-derived hydrogen shares 68% of the total supply forecast, including gas reforming and lignite gasification. It is necessary to investigate available locations and technology for CCUS, in case of hydrogen production from gas and lignite. The amount of hydrogen produced from flare gas and as a by-product is relatively small and is projected to be allocated for domestic supply or as an export supplement.

Hydro will take more than the half of the share of renewable energy-derived hydrogen, followed by photovoltaics with 20%. The volume of photovoltaic- and wind power-derived hydrogen will potentially increase as the result of innovations in water electrolysis.

Major hydrogen sources in Australia, the largest hydrogen-producing country in the Exporting group, consist of 53% gas, 31% lignite, and 13% photovoltaics. As the second-largest hydrogen-producing region, the Eastern regions of Indonesia will produce hydrogen mainly from gas, accounting for 47%, followed by hydro power with 39%, and biomass with 8%.

Figure 4.14 Hydrogen Production Forecast in 2040 (Exporting Group)



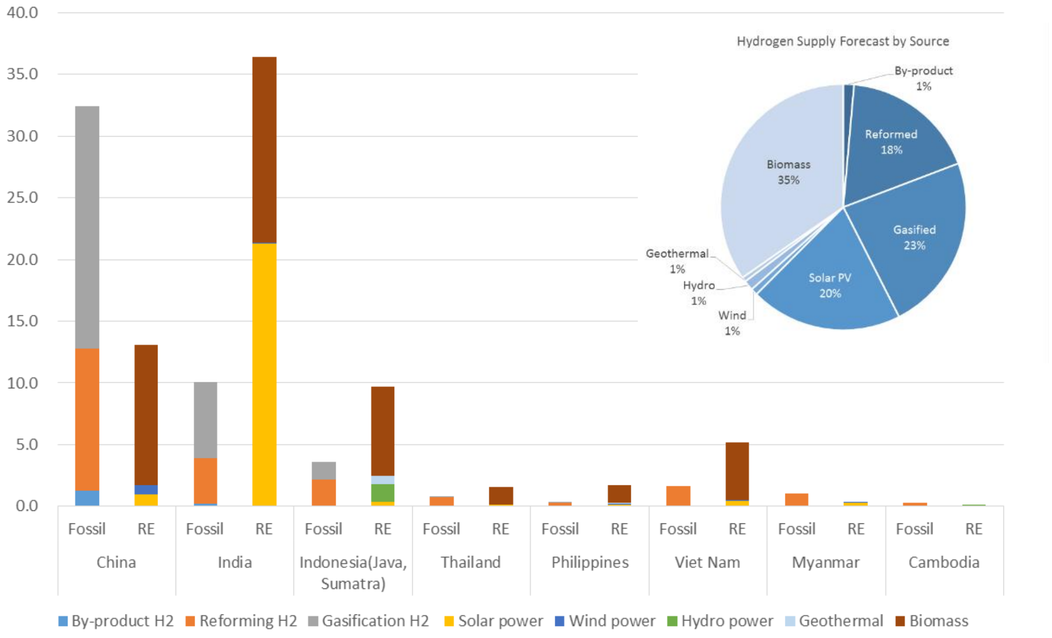
Lao PDR = Lao People’s Democratic Republic, PV = photovoltaics, RE = renewable energy.
Source: Author.

Amongst Intra-regional group countries, the hydrogen supply forecast can reach 118Mtoe in 2040, with India accounting for 39%, followed by China with 38%, as shown in Figure 4.15.

In terms of hydrogen source, renewables accounts for 57%, with biomass gasification taking more than the half of the share, followed by photovoltaics with 35%. Reformed hydrogen from mid-small gas fields accounts for 42% amongst fossil fuel-derived hydrogen, followed by lignite gasification with 40%.

As the largest supplier of hydrogen in this group, India shows a forecast of 47 Mtoe of hydrogen in 2040, mostly from renewables, with photovoltaics accounting for 46%, followed by biomass gasification with 32%. As the second-largest supplier, China shows a forecast of 45 Mtoe of hydrogen, mostly from lignite gasification, accounting for 31%, followed by biomass gasification and gas reforming with 25% each.

Figure 4.15 Hydrogen Production Forecast in 2040 (Intra-regional Group)



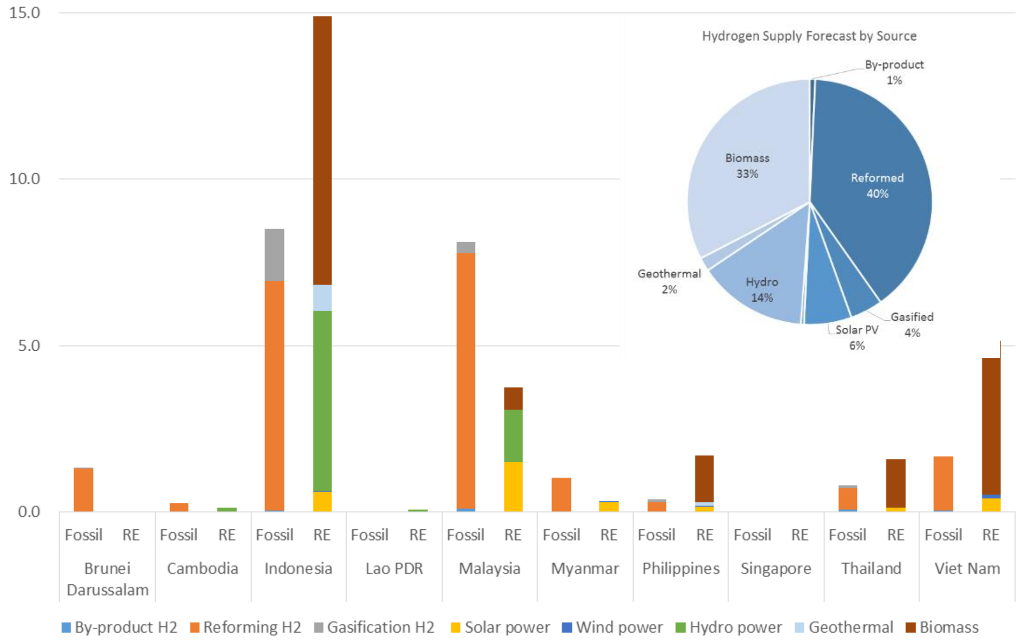
PV = photovoltaics, RE = renewable energy.
Source: Author.

The ASEAN region has a forecast of 50 Mtoe of hydrogen in 2040, with Indonesia accounting for almost the half of the share, followed by Malaysia with 24%, as shown in Figure 4.16.

Renewables derived hydrogen accounts for 56% of the total, with biomass gasification taking the largest share at 59%, followed by hydropower with 26%, then photovoltaics with 11%. Within fossil fuel-derived hydrogen, gas-reformed hydrogen accounts for the largest share with 89%. More research is needed about available location and technology for CCUS, in case of hydrogen production from gas and lignite.

As the largest supplier of hydrogen, Indonesia shows a forecast of 23 Mtoe of hydrogen, with biomass gasification accounting for 32%, followed by reformed hydrogen with 29%, then hydro with 23%. As the second-largest supplier, Malaysia has a forecast of 12 Mtoe, with gas-derived hydrogen taking the largest share at 65%, followed by hydro with 13% and photovoltaics with 13%.

Figure 4.16 Hydrogen Production Forecast in 2040 (ASEAN)



Lao PDR = Lao People's Democratic Republic, PV = photovoltaics, RE = renewable energy.
Source: Author.

1.3.4. Summary of Hydrogen Production: Potential vs. Forecast

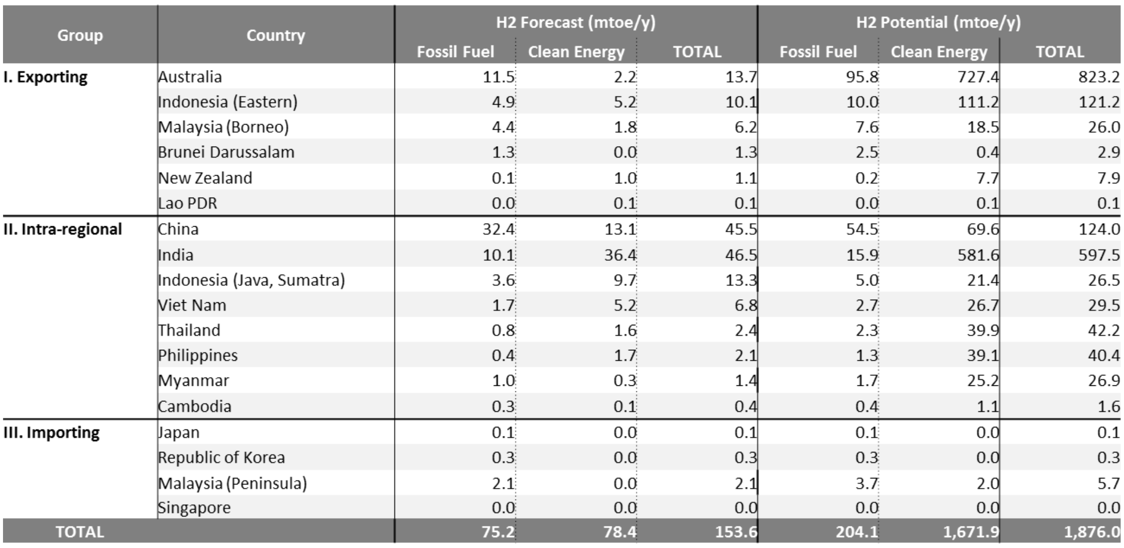
In general, hydrogen production potential, at 1,876 Mtoe, has enough volume to fulfil the forecast for 2040 of 154 Mtoe that will be balanced with expected demand. Exporting countries will cover the gap between supply and demand in Importing countries and Intra-regional countries will fulfil their own domestic demand, as shown in Table 4.7.

In Exporting countries, Australia will potentially be the largest hydrogen exporter in the EAS region, followed by Indonesia.

In Intra-regional countries, India and China have the largest hydrogen production potential.

Importing countries have less hydrogen production potential compared with demand; therefore, the hydrogen production forecast is equal to its potential.

Table 4.7 Hydrogen Production Potential and Forecast in 2040 (by Group)



Group	Country	H2 Forecast (mtoe/y)			H2 Potential (mtoe/y)		
		Fossil Fuel	Clean Energy	TOTAL	Fossil Fuel	Clean Energy	TOTAL
I. Exporting	Australia	11.5	2.2	13.7	95.8	727.4	823.2
	Indonesia (Eastern)	4.9	5.2	10.1	10.0	111.2	121.2
	Malaysia (Borneo)	4.4	1.8	6.2	7.6	18.5	26.0
	Brunei Darussalam	1.3	0.0	1.3	2.5	0.4	2.9
	New Zealand	0.1	1.0	1.1	0.2	7.7	7.9
	Lao PDR	0.0	0.1	0.1	0.0	0.1	0.1
II. Intra-regional	China	32.4	13.1	45.5	54.5	69.6	124.0
	India	10.1	36.4	46.5	15.9	581.6	597.5
	Indonesia (Java, Sumatra)	3.6	9.7	13.3	5.0	21.4	26.5
	Viet Nam	1.7	5.2	6.8	2.7	26.7	29.5
	Thailand	0.8	1.6	2.4	2.3	39.9	42.2
	Philippines	0.4	1.7	2.1	1.3	39.1	40.4
	Myanmar	1.0	0.3	1.4	1.7	25.2	26.9
	Cambodia	0.3	0.1	0.4	0.4	1.1	1.6
III. Importing	Japan	0.1	0.0	0.1	0.1	0.0	0.1
	Republic of Korea	0.3	0.0	0.3	0.3	0.0	0.3
	Malaysia (Peninsula)	2.1	0.0	2.1	3.7	2.0	5.7
	Singapore	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL		**75.2**	**78.4**	**153.6**	**204.1**	**1,671.9**	**1,876.0**

Lao PDR = Lao People’s Democratic Republic, Mtoe/y = million tonnes of oil equivalent per year.
Source: Author.

In the ASEAN region, Indonesia will potentially be the largest hydrogen exporter, and Malaysia will follow, as shown in Table 4.8.

Thailand, the Philippines, Viet Nam, and Myanmar have enough hydrogen production potential to fulfil their forecast in 2040, which will be balanced with their expected demand.

Lao PDR has a large hydropower potential for export due to its inland location, and potentially can utilise hydrogen to store or absorb seasonal or mid-long-term supply variations.

Table 4.8 Hydrogen Production Potential and Forecast in 2040 (by ASEAN and Others)

Group	Country	H2 Forecast (mtoe/y)			H2 Potential (mtoe/y)		
		Fossil Fuel	Clean Energy	TOTAL	Fossil Fuel	Clean Energy	TOTAL
I. ASEAN	Brunei Darussalam	1.3	0.0	1.3	2.5	0.4	2.9
	Cambodia	0.3	0.1	0.4	0.4	1.1	1.6
	Indonesia	8.5	14.9	23.4	15.0	132.6	147.6
	Lao PDR	0.0	0.1	0.1	0.0	0.1	0.1
	Malaysia	6.5	1.8	8.3	11.2	20.5	31.7
	Myanmar	1.0	0.3	1.4	1.7	25.2	26.9
	Philippines	0.4	1.7	2.1	1.3	39.1	40.4
	Singapore	0.0	0.0	0.0	0.0	0.0	0.0
	Thailand	0.8	1.6	2.4	2.3	39.9	42.2
	Viet Nam	1.7	5.2	6.8	2.7	26.7	29.5
TOTAL (ASEAN)		20.6	25.7	46.3	37.2	285.7	322.9
II. Others	Australia	11.5	2.2	13.7	95.8	727.4	823.2
	China	32.4	13.1	45.5	54.5	69.6	124.0
	India	10.1	36.4	46.5	15.9	581.6	597.5
	Japan	0.1	0.0	0.1	0.1	0.0	0.1
	Republic of Korea	0.3	0.0	0.3	0.3	0.0	0.3
	New Zealand	0.1	1.0	1.1	0.2	7.7	7.9
TOTAL (Others)		54.6	52.7	107.3	166.9	1386.3	1553.1
TOTAL		75.2	78.4	153.6	204.1	1671.9	1876.0

ASEAN = Association of Southeast Asian Nations, Mtoe/y = million tonnes of oil equivalent per year.
Source: Author.

2. Hydrogen Transportation

2.1. Hydrogen Transportation Method and Portfolio

Hydrogen transportation methods consist of transportation modes and hydrogen carriers.

Typical transportation modes include ships, railways, road freight, and pipelines. Major hydrogen carriers are liquid hydrogen (LH_2), ammonia (NH_3), organic hydride (MCH), and compressed hydrogen (CH_2), as shown in Figure 4.17.

Hydrogen can be liquefied at -253 °C and the volume of hydrogen gas will be converted to 1/800 as liquid, the technology for which has already been commercialised in smaller local hydrogen supply chains. However, LH_2 has an energy-intensive liquefaction process and boil-off loss should be considered.

Hydrogen can also be transported as NH_3, which is already produced and transported globally, with the volume of hydrogen gas being converted to 1/1,300 liquid. However, NH_3 is toxic and transporting hydrogen requires dehydrogenation technology.

Finally, hydrogen can be transported as a chemical by reacting it with Toluene to form MCH, which is transported as a liquid under ambient conditions using existing infrastructure. MCH converts hydrogen gas to 1/500 liquid and requires relatively higher temperature for dehydrogenation.

Figure 4.17 Hydrogen Transportation Method

< Transportation mode >

- **Ship transportation**
  Liquid H2 tanker, Chemical tanker, Container vessel, Barge, etc.
- **Railway transportation**
  Freight train, Container train, etc.
- **Truck transportation**
  Liquid H2 truck, Chemical / Gasoline tank truck, Tube trailer for compressed gas, etc.
- **Pipeline transportation**
  Hydrogen gas pipeline, Natural gas pipeline, etc.

< Hydrogen Carrier >

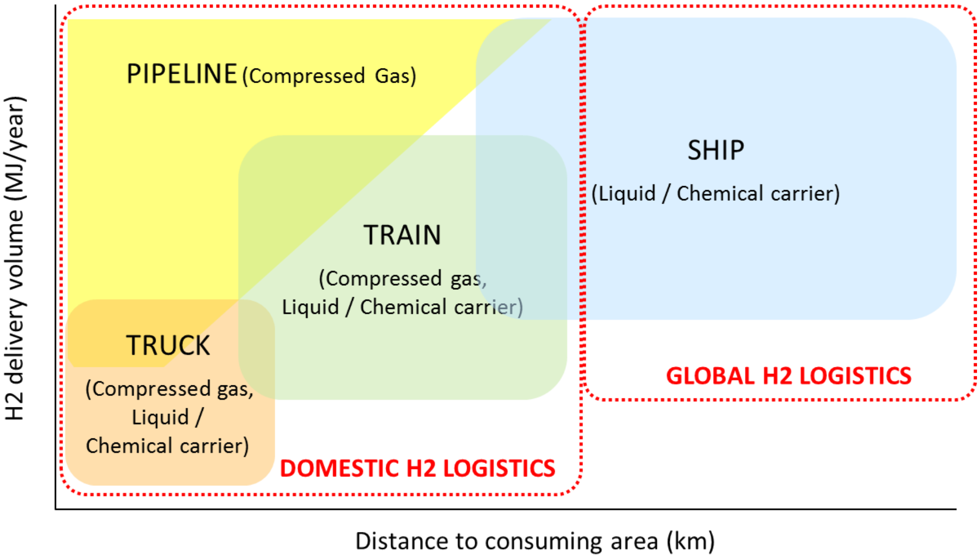
	Liquid Hydrogen (LH2)	Ammonia (NH3)	Chemical Hydride (MCH)	Compressed Hydrogen (CH2-700MPa)
Molecular Weight	2.0	17.0	98.2	2.0
H2 Content (wt%)	100	17.8	6.2	100
Volumetric H2 Density (kg-H2/m3)	70.8	121.0	47.4	39.6
Boiling Point (deg-C)	-253	-33.4	101	-
H2 Release Enthalpy Change (kJ/mol-H2)	0.9	30.6	67.5	-
Others	- High purity - Low energy to be pressurised	- High H2 density - Direct combustion	- Liquid at ambient - Utilize existing oil infrastructure	- Widely used in existing market

Source: Author.

Transportation modes and hydrogen carriers can be selected and combined based on the hydrogen delivery volume, distance and characteristic of each transportation mode/carrier, as shown in Figure 4.18.

Global hydrogen logistics will use tanker ships for long-distance transportation, and domestic hydrogen logistics will combine ships, rail, trucks, and pipelines with proper carriers depending on delivery volume and distance.

Figure 4.18 Image of Hydrogen Logistics Portfolio



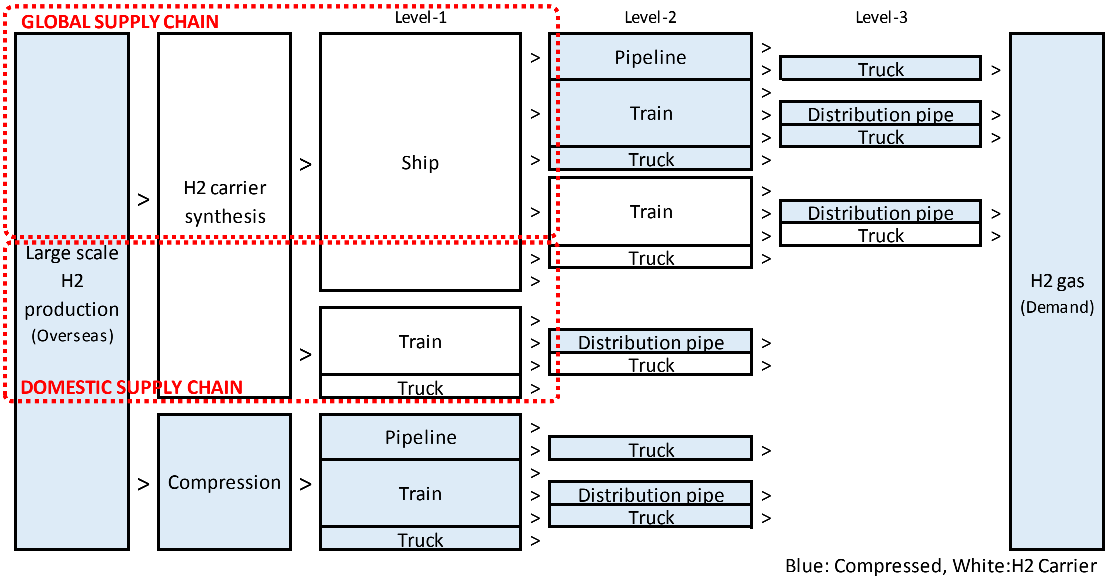
Source: Author.

Several hydrogen logistics scenarios can be drafted via the combination of transportation modes/hydrogen carriers and volume of hydrogen production/demand.

This study analyses the case of large-scale hydrogen production with larger concentrated demand for global supply chains and smaller distributed demand for domestic supply chains, as shown in Figure 4.19.

To consider the flexibility of hydrogen logistics networks, especially in early stages of hydrogen commercial deployment, this study focuses on interchangeable modes of transportation, such as ships, trains, and trucks.

Figure 4.19 Hydrogen Logistics Scenario for Large-scale Production



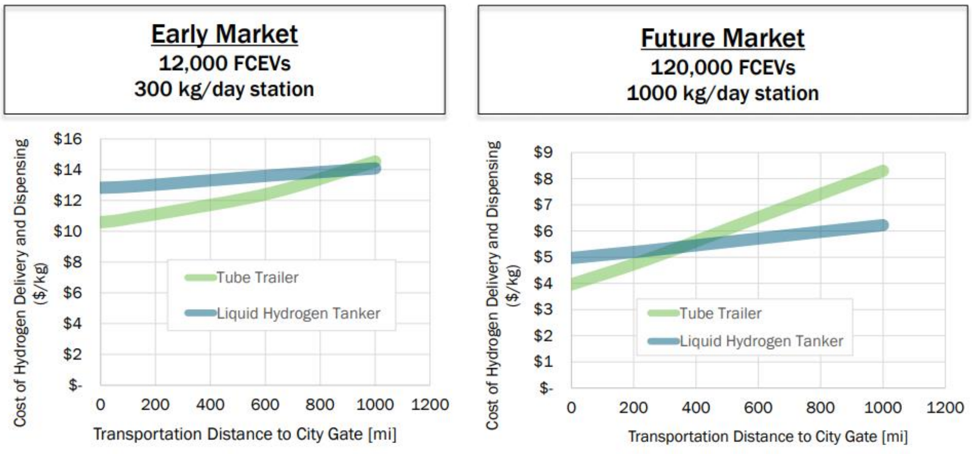
Source: Author.

2.2. Hydrogen Transportation Cost

The study includes three hydrogen transportation pathways, LH_2, NH_3, and MCH. The transportation cost (not including the cost of carrier synthesis from H_2 gas to carrier and H_2 regeneration from H_2 carrier to gas) dependency on the transportation distance (km) for the selected carriers is shown in Figure 4.21 to Figure 4.23.

In general, CH_2 transportation is more economical for shorter transportation distances and smaller volume, as compared with other hydrogen carriers. Figure 4.20 compares the hydrogen delivery cost between CH_2 and LH_2 by transportation distance and volume.

Figure 4.20 Example of Hydrogen Delivery Cost of CH_2 and LH_2 (US Department of Energy)

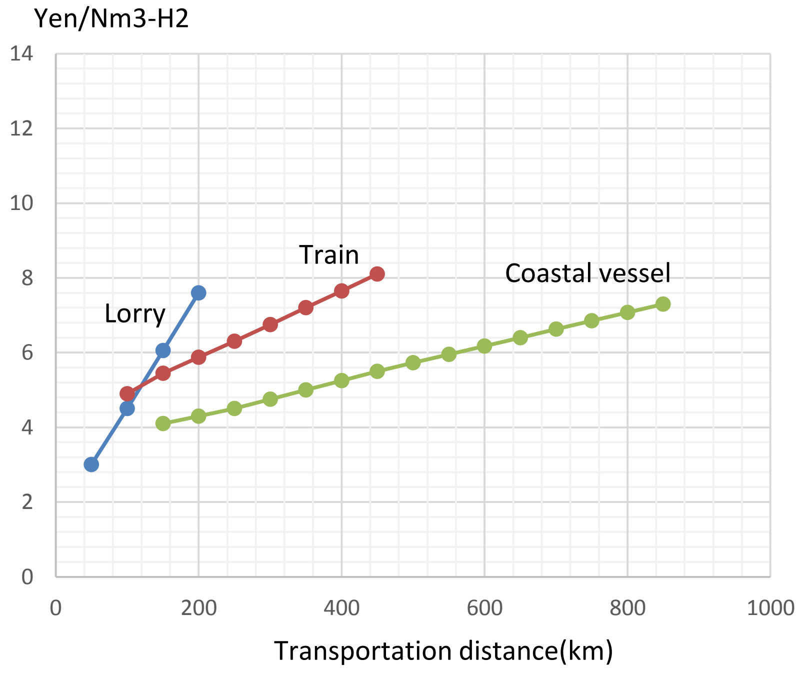


FCEV = fuel cell electric vehicle.
Source: Elgowainy (2018).

2.2.1. *Hydrogen Transportation by Liquid Hydrogen (LH_2)*

The transportation cost of LH_2 appears relatively high, as the cost of cryogenic equipment is much higher than other carriers. A transportation distance of around 100km is a reverse point between trucks and trains. Coastal vessels have the cheapest transportation cost above 100km.

Figure 4.21 General Transportation Costs by Truck, Train, and Ship (LH_2)

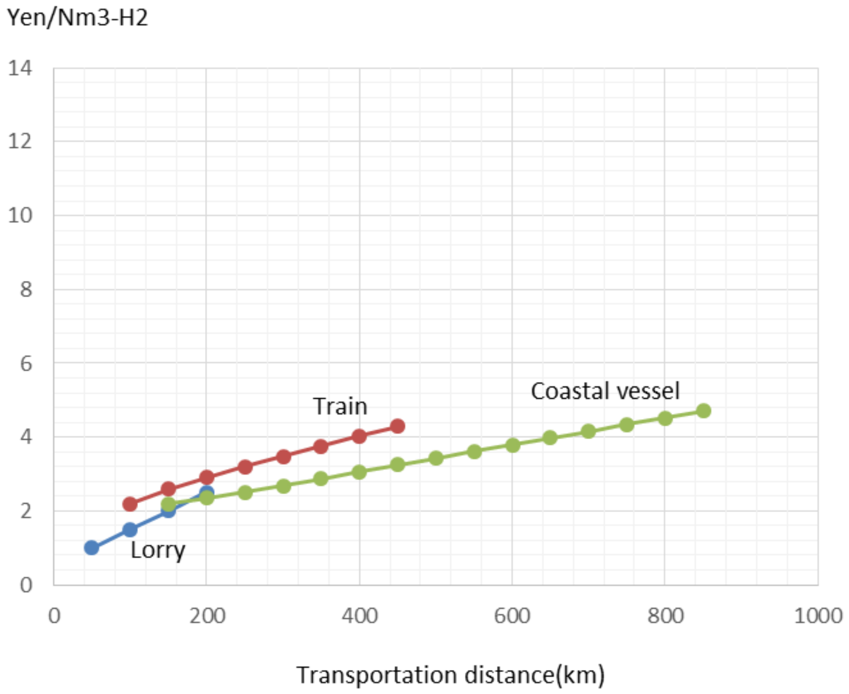


Note: The data were customised based on Institute of Applied Energy (2016).
Source: Author.

2.2.2. Hydrogen Transportation by Ammonia (NH_3)

The transportation cost of NH_3 shows relatively lower dependency on the distance. Also, the cost difference amongst three modes is the smallest.

Figure 4.22 General Transportation Costs by Truck, Train, and Ship (NH_3)

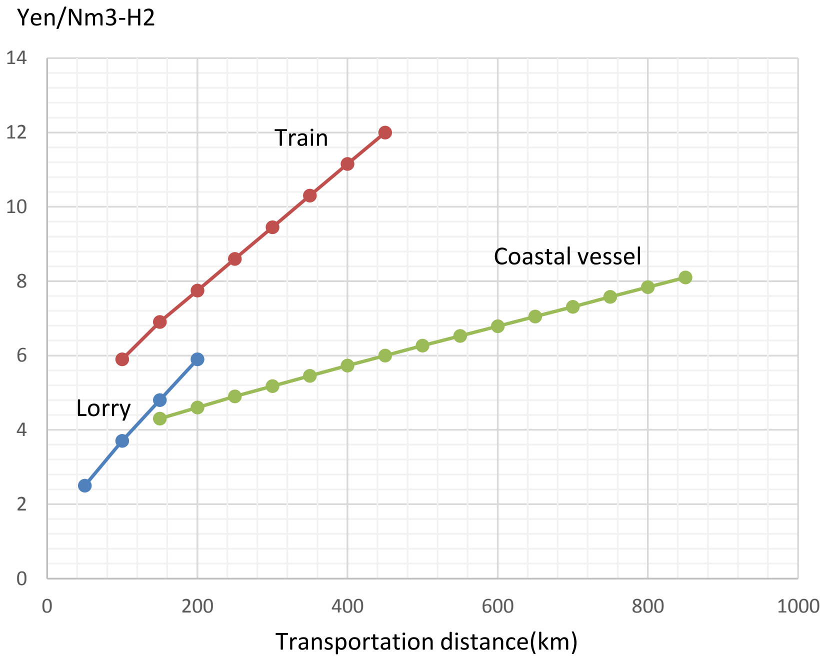


Note: The data were customised based on Institute of Applied Energy (2016).
Source: Author.

2.2.3. Hydrogen Transportation by Chemical Hydride (MCH)

MCH shows transportation costs as high as those of LH_2, because MCH has less hydrogen content per weight compared to other carriers. The transportation distance of around 120km is a reverse point between truck and coastal vessel.

Figure 4.23 General Transportation Costs by Truck, Train, and Ship (MCH)



Note: The data were customised based on Institute of Applied Energy (2016).
Source: Author.

3. Hydrogen Supply Chain and Its Cost

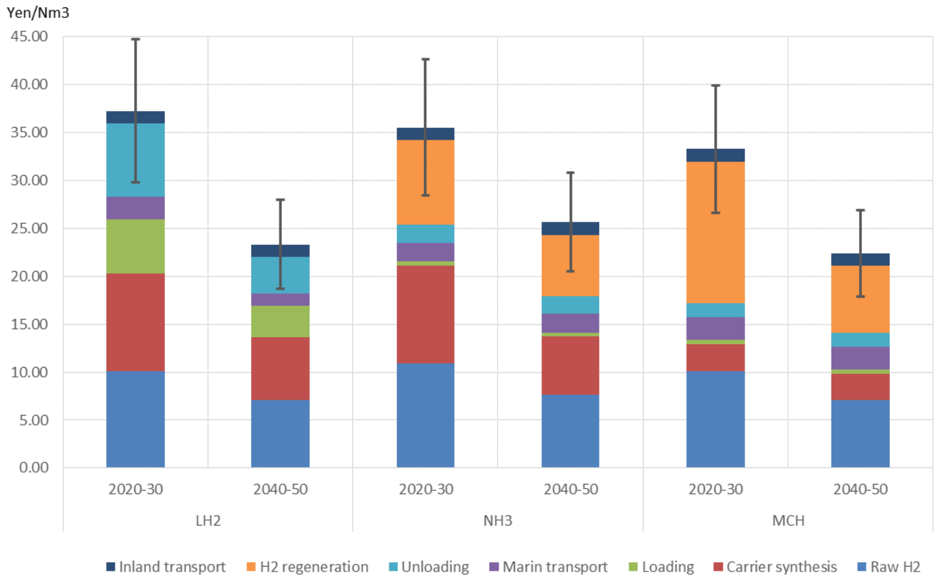
3.1. Global Hydrogen Supply Chain Cost

Figure 4.24 shows an example of global hydrogen supply cost for large-scale production (2.5 billion Nm^3/year) to Japan from exporting countries in this region in 2020–30 and 2040–50, respectively.

For the cost components of global hydrogen supply chains, marine transportation is minor for all carriers; carrier synthesis and unloading are major components of the LH_2 supply chain, carrier synthesis and H_2 regeneration are major components of the NH_3 supply chain, and H_2 regeneration is a major component of the MCH supply chain.

Each hydrogen carrier has merit and technical challenges, and requires continuous technology development to accelerate cost reductions. In developing the hydrogen transportation infrastructure, it is also necessary to consider the balance between the future goals and the longer-term uncertainties of technological achievement.

Figure 4.24 An Example of Global Hydrogen Supply Cost to Japan (5,400 km)

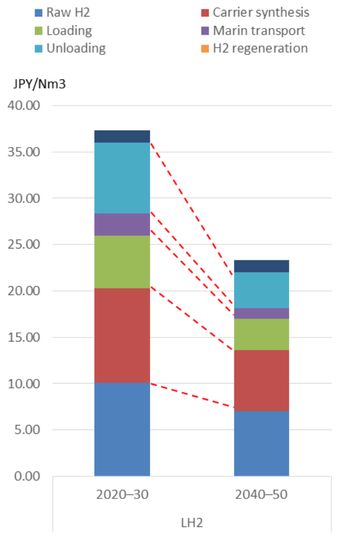


Note: The data were customised based on Institute of Applied Energy (2016).
Source: Author.

3.1.1. *LH_2 Cost Reduction Scenario*

Key points for reducing the cost of LH_2 transportation are to achieve higher liquefaction performance, minimisation/utilisation of boil-off gas, and upscaling, as shown in Figure 4.25.

Figure 4.25 Cost Down Scenario of Liquid Hydrogen (LH_2)



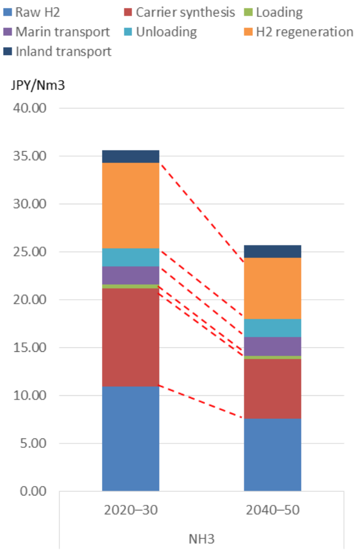
Process	Cost down scenario
H2 regeneration	• Large scale LH2 vaporiser (~400 tonne/d class)
Unloading	• Large scale LH2 tank with lower BOG (200,000m3 with BOR 0.1%/d) • Effective utilization of cold heat of LH2 • Larger & efficient LH2 loading arm
Marine transportation	• Large sized LH2 transportation vessel (with minimum BOG)
Loading	• Larger & efficient LH2 loading arm • Large scale LH2 transfer pump (~3,000m3/h) • Higher efficiency of BOG compressor
Carrier synthesis	• Higher efficiency of liquefaction process (Liquefying machine of 100-300 tonne/d with power consumption < 0.60 kWh/Nm3)

BOG = boil-off gas, BOR = boil-off rate, JPY = Japanese yen,
Note: The data were customised based on Institute of Applied Energy (2016).
Source: Author.

3.1.2. *NH_3 Cost Reduction Scenario*

Key points for reducing NH_3 transportation costs are to achieve higher ammonia synthesis performance, development of NH_3 decomposition technology, and upscaling, as shown in Figure 4.26.

Figure 4.26 Cost Down Scenario of NH_3



Process	Cost down scenario
H2 regeneration	• Develop Larger & efficient NH3 decomposition technology and plant (2,400 tonne/d class)
Unloading	• Large-scale NH3 storage tank (50,000 tonne class)
Marine transportation	• Large-scale NH3 transportation vessel (38,000 m3 class)
Loading	• Large-scale NH3 storage tank (50,000 tonne class)
Carrier synthesis	• NH3 synthesis plant with higher efficiency (1,600 tonne/d class, post Haber–Bosch process)

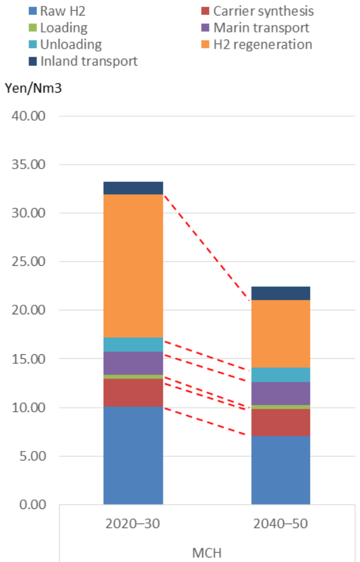
Note: The data were customised based on Institute of Applied Energy (2016).

Source: Author.

3.1.3. *MCH Cost Reduction Scenario*

Key points for reducing the cost of MCH are to achieve higher dehydrogenation performance, effective utilisation of hydrogenation process heat, and upscaling, as shown in Figure 4.27.

Figure 4.27 Cost Down Scenario of MCH



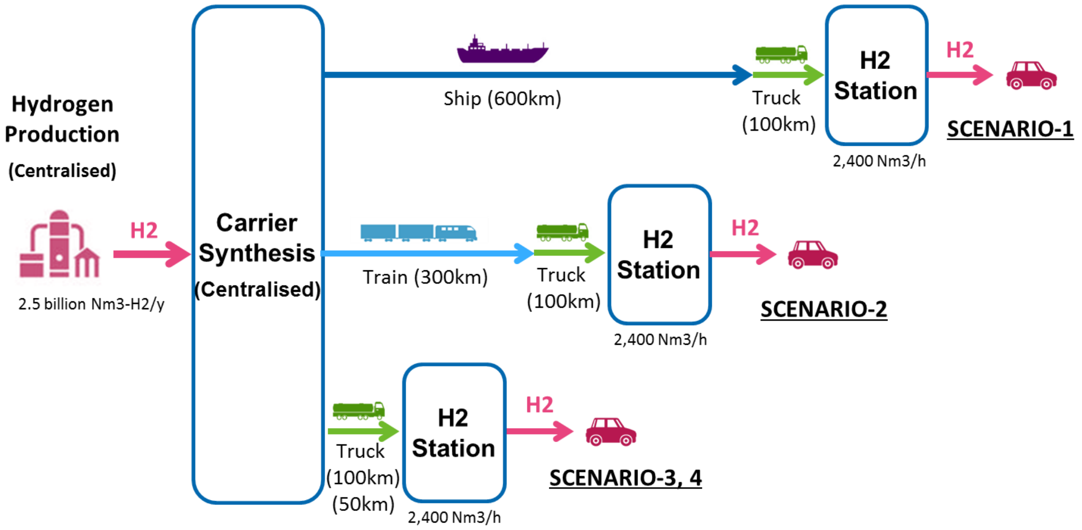
Process	Cost down scenario
H2 regeneration	• Larger scale dehydrogenation (DHG) plant (>1,000,000Nm3/h) • Decreasing in reaction temperature • Higher performance of DHG catalyst • Integration of DHG reaction with exhaust heat
Unloading	
Marine transportation	• Large scale transportation vessel (100,000m3 class - chemical tanker)
Loading	
Carrier synthesis	• Larger scale hydrogenation (HGN) plant (>1,000,000Nm3/h) • Effective utilization of process heat from HGN

Note: The data were customised based on Institute of Applied Energy (2016).
Source: Author.

3.2. Local Hydrogen Supply Chain Cost

To understand each technological step in local hydrogen supply chains, Figure 4.28 applies the following four scenarios to study the costs from large-scale production sites (2.5 billion Nm^3/year) to refueling stations by each carrier (LH_2, NH_3, and MCH).

Figure 4.28 Typical Scenarios for Local Hydrogen Supply Chain



Source: Author.

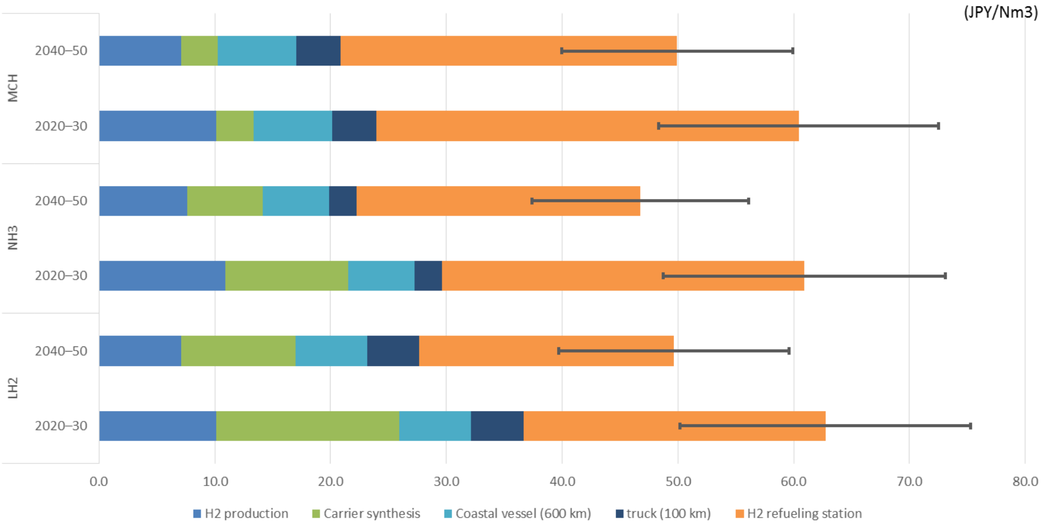
The cost of large-scale hydrogen production (raw hydrogen) and synthesis for each carrier is taken from Figure 4.24. Each carrier is synthesised using different processes, i.e. hydrogen liquefaction, ammonia synthesis and hydrogenation of Toluene. Also, each carrier uses each regeneration process, that is, liquid hydrogen vaporisers, ammonia decomposition, and dehydrogenation of MCH. These processes will be customised to improve energy efficiency for 2040–2050.

3.2.1. Local Hydrogen Supply Chain Cost of Scenario-1 (Ship + Truck)

Figure 4.29 shows an example of the costs of a local hydrogen supply chain using the selected carriers. The costs include the use of large-scale hydrogen production and carrier synthesis, coastal vessel transport of 600km, truck transport of 100km, and hydrogen refuelling stations (scenario-1). In 2020–2030, the costs for MCH and NH_3 will be lower than LH_2 and the cost of NH_3 is expected to be the lowest in 2040–2050.

The black line on the right-hand edge of each cumulative bar shows an accuracy range of ±20%.

Figure 4.29 An Example of Local Hydrogen Supply Chain Cost (Scenario-1)



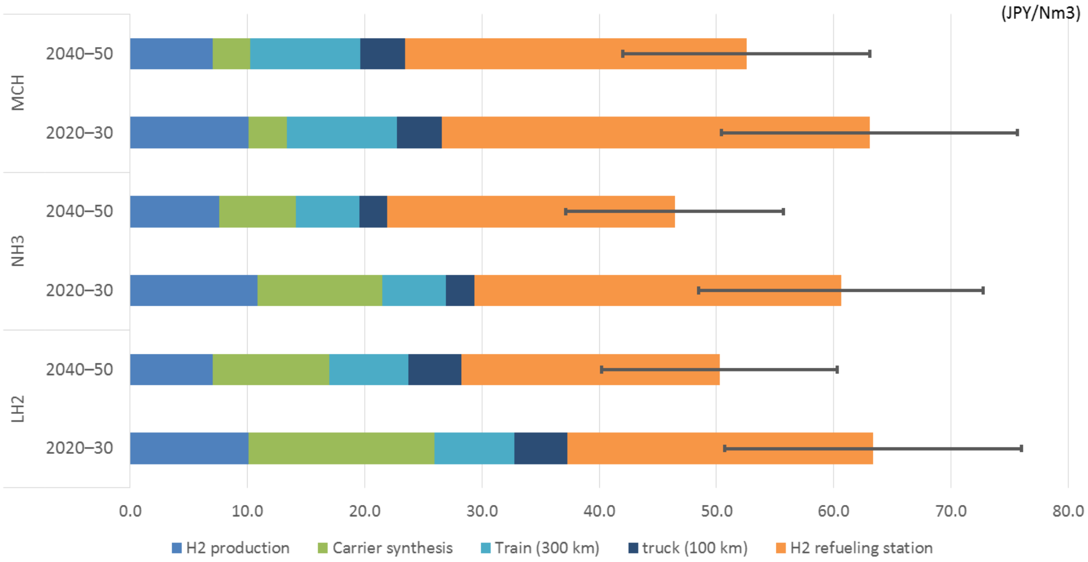
Note: The data were customised based on the Institute of Applied Energy (2016).
Source: Author.

3.2.2. Local Hydrogen Supply Chain Cost of Scenario-2 (Train + Truck)

In Figure 4.30, the costs include the use of large-scale hydrogen production and carrier synthesis, train transport of 300km, truck transport of 100km, and hydrogen refuelling stations (scenario-2).

The costs of MCH and LH_2 are the same and NH_3 also shows the lowest cost in 2020–2030 and 2040–2050.

Figure 4.30 An Example of Local Hydrogen Supply Chain Cost (Scenario-2)



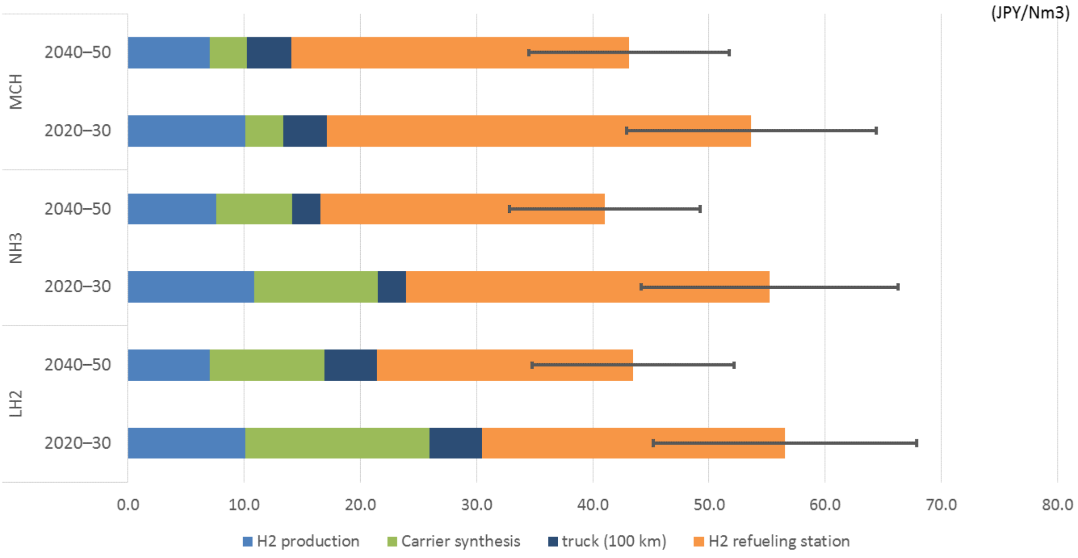
Note: The data were customised based on the Institute of Applied Energy (2016).
Source: Author.

3.2.3. Local Hydrogen Supply Chain Cost of Scenario-3 & 4 (Truck)

In Figure 4.31, the costs include the use of large-scale hydrogen production and carrier synthesis, truck transport of 100km and hydrogen refuelling stations (scenario-3). The costs are in the order of MCH, NH_3, and LH_2 from the lowest in 2020–2030, and NH_3 will be the lowest cost in 2040–2050.

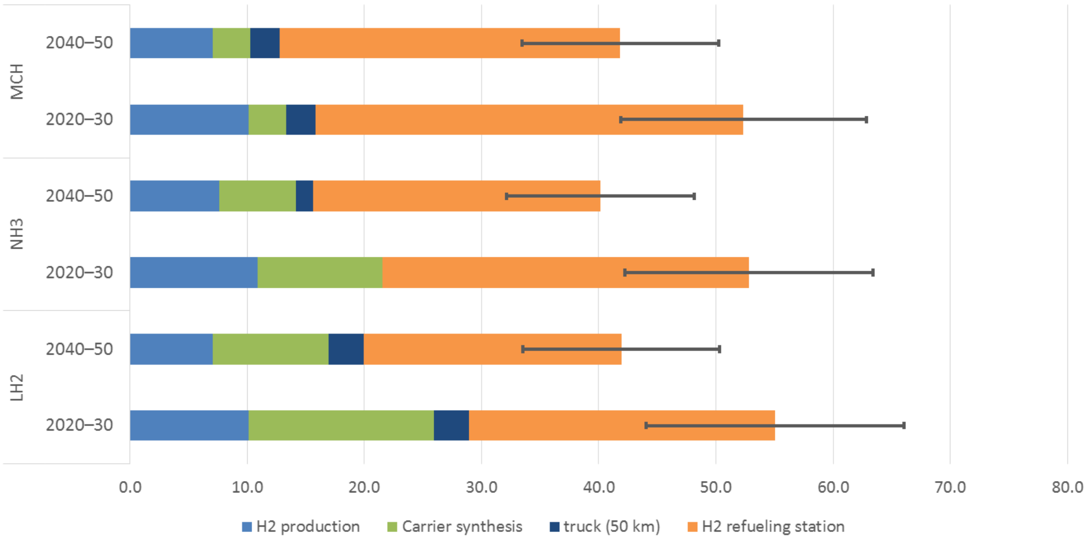
Figure 4.32 shows same transportation scenario with 50km truck transport (scenario-4). The costs of the selected carriers are the same trend of scenario-3.

Figure 4.31 An Example of Local Hydrogen Supply Chain Cost (Scenario-3)



Note: The data were customised based on the Institute of Applied Energy (2016).
Source: Author.

Figure 4.32 An Example of Local Hydrogen Supply Chain Cost (Scenario-4)



Note: The data were customised based on the Institute of Applied Energy Report.(8)
Source: Author.

Summary

3.3. Hydrogen production and transportation

3.3.1. Hydrogen supply and demand balance in the EAS region

Hydrogen demand and supply in the EAS region is expected to be well balanced between ‘Exporting’ and ‘Importing’ and inside ‘Intra-regional’ countries in 2040. Exporting countries have enough potential to export to Importing countries, and Intra-regional countries have also enough potential, though some countries will require imports depending on the demand growth.

Table 4.9 Summary of Hydrogen Production and TPES in 2040 (by Group)

Group	Country	H2 TPES (mtoe/y)			H2 Production (mtoe/y)		Difference (F-S3)
		Scenario 1	Scenario 2	Scenario 3	Forcast	Potential	
I. Exporting	Australia	1.5	3.5	5.7	13.7	823.2	8.0
	Indonesia (Eastern)	0.9	2.0	3.3	10.1	121.2	6.8
	Malaysia (Borneo)	0.3	0.7	1.2	6.2	26.0	5.0
	Brunei Darussalam	0.1	0.1	0.2	1.3	2.9	1.1
	New Zealand	0.1	0.3	0.5	1.1	7.9	0.6
	Lao PDR	0.0	0.0	0.1	0.1	0.1	0.0
II. Intra-regional	China	11.8	27.7	45.5	45.5	124.0	0.0
	India	13.4	29.3	46.5	46.5	597.5	0.0
	Indonesia (Java, Sumatra)	3.5	8.0	13.3	13.3	26.5	0.0
	Viet Nam	2.0	4.3	6.8	6.8	29.5	0.0
	Thailand	0.7	1.5	2.4	2.4	42.2	0.0
	Philippines	0.6	1.3	2.1	2.1	40.4	0.0
	Myanmar	0.3	0.8	1.4	1.4	26.9	0.0
	Cambodia	0.1	0.2	0.4	0.4	1.6	0.0
III. Importing	Japan	3.7	8.4	13.3	0.1	0.1	-13.1
	Republic of Korea	2.7	5.8	8.9	0.3	0.3	-8.7
	Malaysia (Peninsula)	1.2	2.9	4.8	2.1	5.7	-2.7
	Singapore	0.2	0.5	0.7	0.0	0.0	-0.7
TOTAL		**43.3**	**97.3**	**157.1**	**153.6**	**1,876.0**	**-3.6**

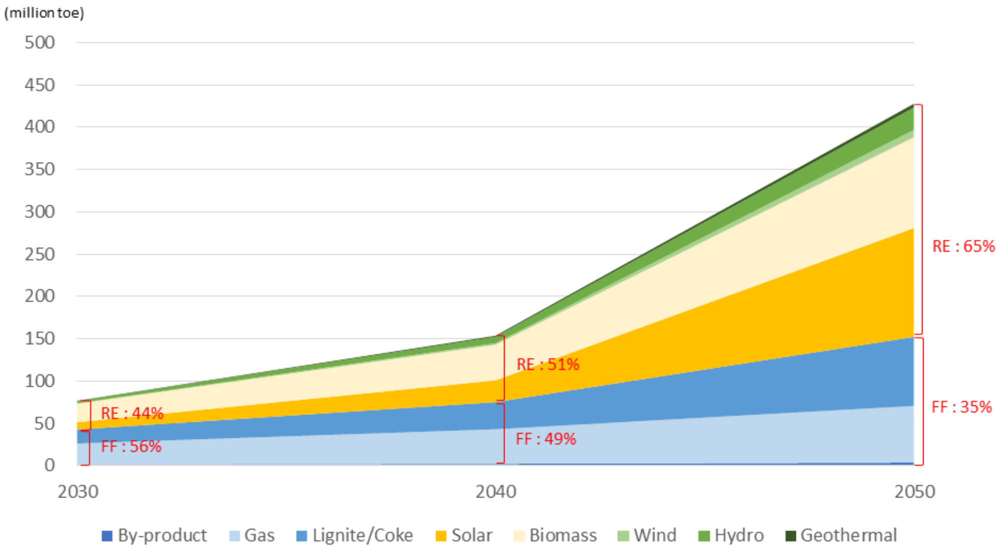
Lao PDR = Lao People’s Democratic Republic, TPES = total primary energy supply.
Source: Author.

3.3.2. Transition of hydrogen production sources

Our forecast shows that a major hydrogen source will be from fossil fuels with stable hydro/geothermal and partial solar/wind, mainly for local consumption in early stages. Sources will largely shift to abundant renewable energy as the result of technological development, as shown in Figure 4.33.

The supply potential from economical hydrogen sources, such as gas or stable renewable energy, is limited, and hydrogen from abundant solar, wind, biomass, lignite/coal will increase, along with technological improvements for each hydrogen production method, including water electrolysis and CCUS.

Figure 4.33 Image of Hydrogen Production Source Transition in the EAS Region



EAS = East Asia Summit, FF = fossil fuels, RE = renewable energy.
Source: Author.

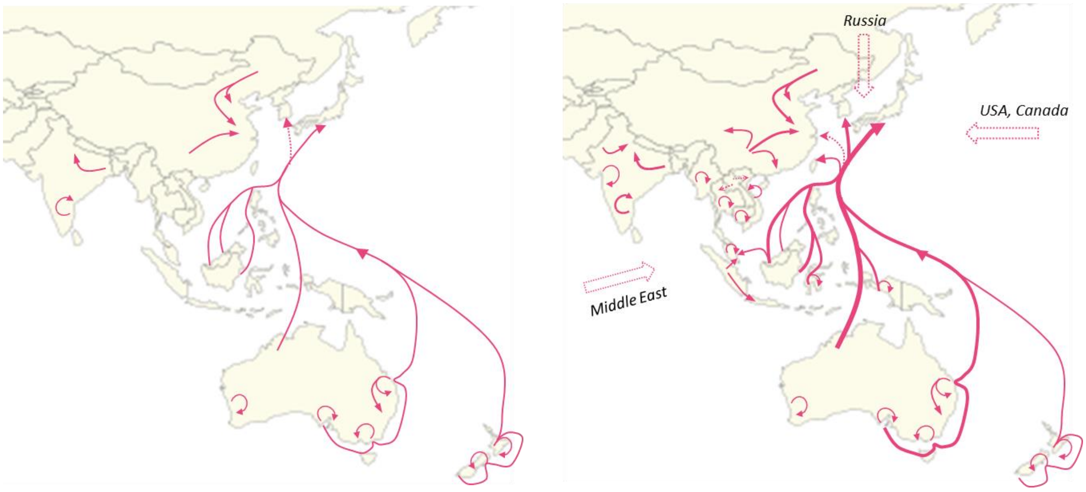
3.3.3. Global hydrogen supply chain and its network in the EAS region

This study envisions that, in the early stage (2020–2030), global trading of hydrogen from exporting countries to Japan, Republic of Korea, and local supply chains in China, India, and some other countries will be started.

Those supply chains are expected to be widely spread out in the EAS region, and linked to an eventual global hydrogen energy network, including trading to other countries outside this region, in 2040–2050.

Figure 4.34 shows images of the future hydrogen trade flow in the EAS region.

Figure 4.34 Image of Hydrogen Trade Flows in the EAS Region



2020–2030

2040–2050

Source: Author.

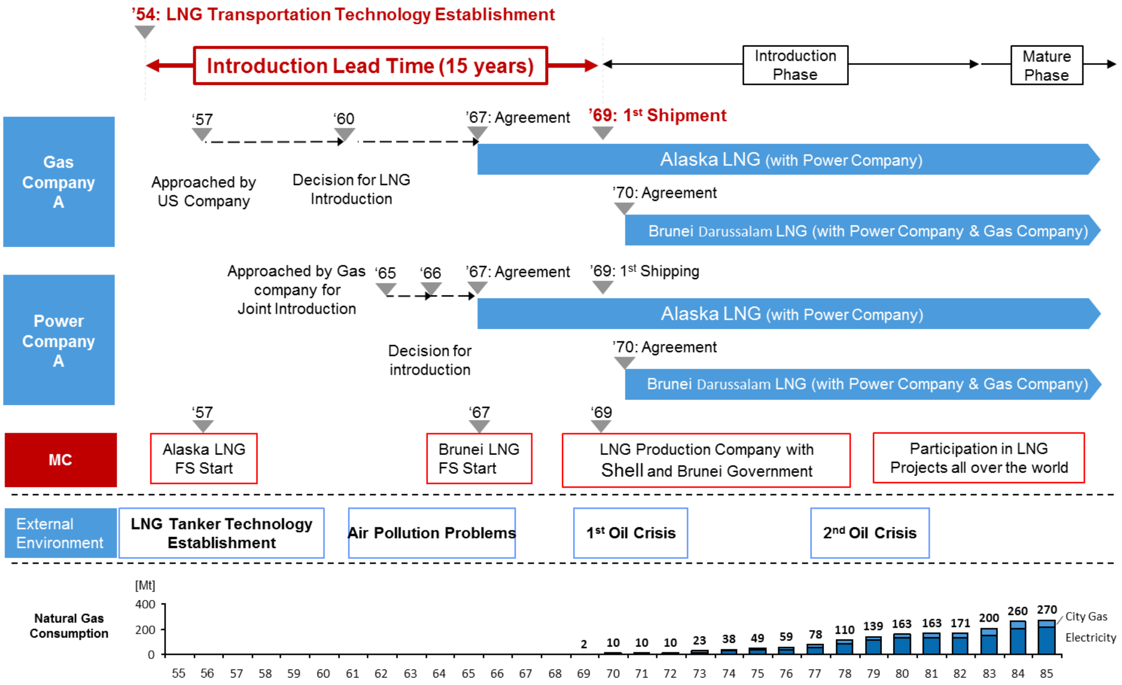
3.4. Hydrogen market creation

3.4.1. History of LNG imports to Japan

In the case of the LNG business, it took 15 years for the first LNG shipment to be made once the transportation technology was established in 1954, and over 30 years to mature the market, as shown in Figure 4.35.

Hydrogen will also be assumed to take time to develop, penetrate, and mature its market.

Figure 4.35 History of LNG Import Business to Japan



FS = feasibility study, MC = Mitsubishi Corporation, LNG = liquefied natural gas.
Source: Mitsubishi Corporation.

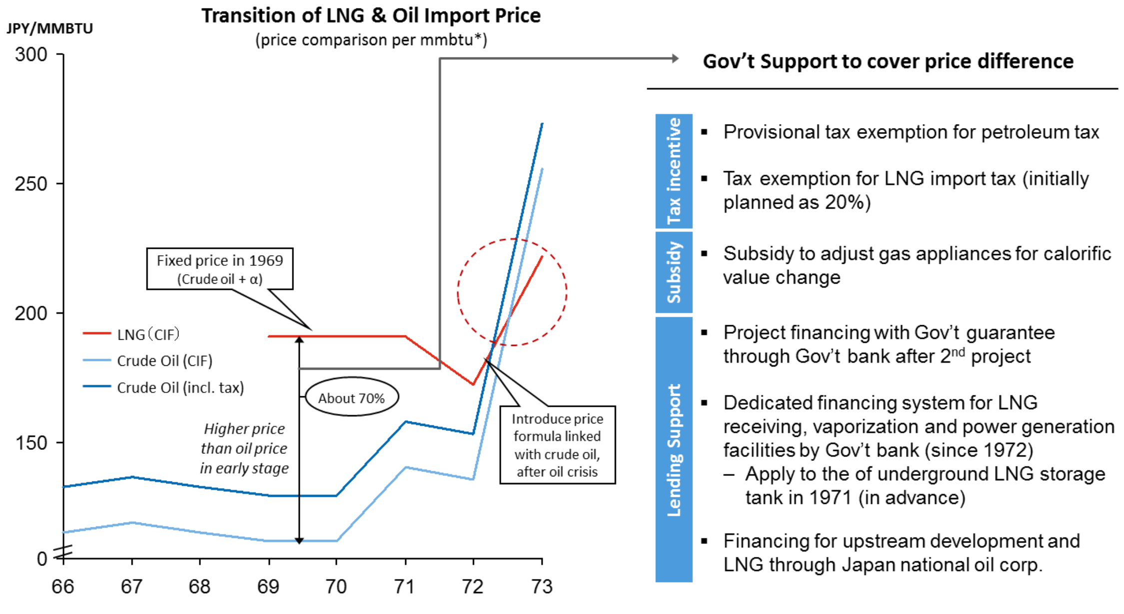
3.4.2. *History of LNG import prices to Japan*

LNG was introduced to improve air pollution in Japan; however, the price was quite high compared to the oil price in the 1960s and early 1970s, before the oil crisis.

Under this circumstance, the Japanese government introduced LNG, including tax incentives, a subsidy, and lending support.

This means that government support is one of the key areas to introduce hydrogen into the market, especially in early stages.

Figure 4.36 History of LNG and Oil Import Prices to Japan



Gov't Support to cover price difference

- Provisional tax exemption for petroleum tax
- Tax exemption for LNG import tax (initially planned as 20%)
- Subsidy to adjust gas appliances for calorific value change
- Project financing with Gov't guarantee through Gov't bank after 2nd project
- Dedicated financing system for LNG receiving, vaporization and power generation facilities by Gov't bank (since 1972)
  – Apply to the of underground LNG storage tank in 1971 (in advance)
- Financing for upstream development and LNG through Japan national oil corp.

* Not consider the difference of power generation efficiency by each fuels

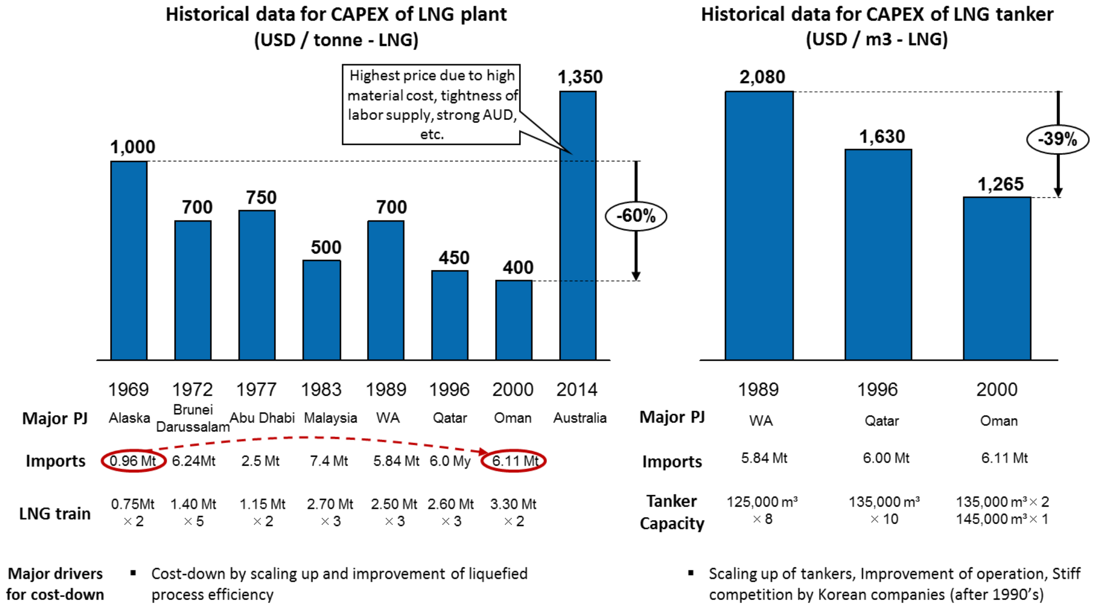
CIF = cost insurance freight, JPY = Japanese yen, LNG = liquefied natural gas.
Source: Mitsubishi Corporation.

3.4.3. History of LNG production and transportation cost

LNG production and transportation costs have been reduced by technological developments and upscaling over the last 30 years.

These are the same key factors for reducing hydrogen supply chain costs.

Figure 4.37 History of LNG Plant and Tanker Costs



AUD = Australian dollar, CAPEX = capital expenditure, LNG = liquefied natural gas, PJ = project, WA = Western Australia.
Source: Mitsubishi Corporation.

3.5. Hydrogen policy implications

3.5.1. Hydrogen policy implications in the EAS region

Proposed policy implications regarding the global hydrogen market and supply chain in the EAS region are shown in Figure 4.38.

National approaches, including strategies, government support, and awareness programmes, will develop hydrogen in each country, and regional approaches will enhance the interconnection and trading between each country in this region.

Figure 4.38 Hydrogen Policy Implications in the EAS region

National Approach

1. **National hydrogen strategy and roadmap**

Develop technical, marketing, and business strategy to introduce hydrogen into the national energy market.

2. **Government support**

Introduce financial support (tax incentives, subsidy, lending support, etc.) and market mechanisms (carbon trading, etc.) in early stages..

3. **Awareness programme**

Enlighten the key organisations and public to have common understandings of the meanings, benefits, and challenges of introducing hydrogen into the market.

Regional Approach

1. **Standardisation** (refer to next two pages)

Develop standard to evaluate/label carbon reduction value of hydrogen, and define hydrogen price/volume unit for global trading and statistics, and develop technology/safety standard in this region.

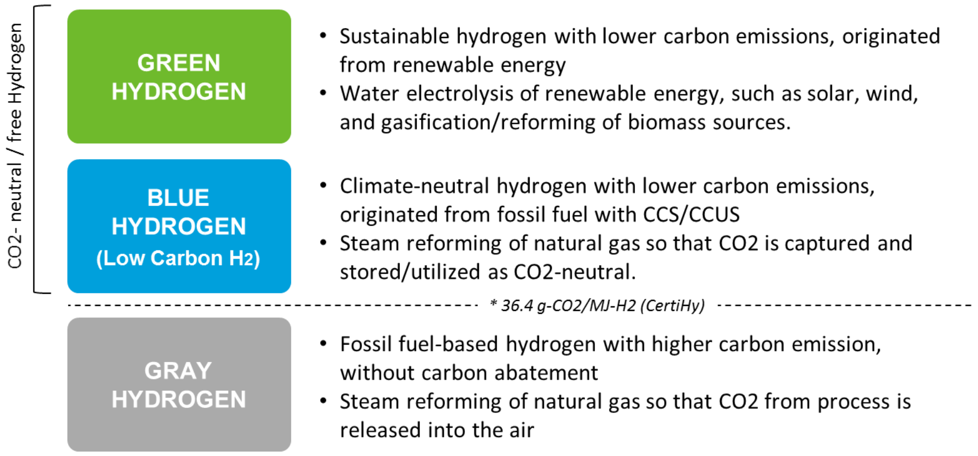
EAS = East Asia Summit.
Source: Author.

3.5.2. Example of standardisation-1 (Carbon reduction value)

Low carbon emissions is one of the key values of hydrogen, making it necessary to set up international standards to evaluate/define carbon reduction values for global trading.

The EU introduced a hydrogen certification system that is categorised into three groups based on their sources and CO_2 emissions. This will be a valuable reference to establish the standard in this region and to align with other regions.

Figure 4.39 Definition of Green/Low-Carbon Hydrogen in EU



- Sustainable hydrogen with lower carbon emissions, originated from renewable energy
- Water electrolysis of renewable energy, such as solar, wind, and gasification/reforming of biomass sources.

- Climate-neutral hydrogen with lower carbon emissions, originated from fossil fuel with CCS/CCUS
- Steam reforming of natural gas so that CO2 is captured and stored/utilized as CO2-neutral.

- Fossil fuel-based hydrogen with higher carbon emission, without carbon abatement
- Steam reforming of natural gas so that CO2 from process is released into the air

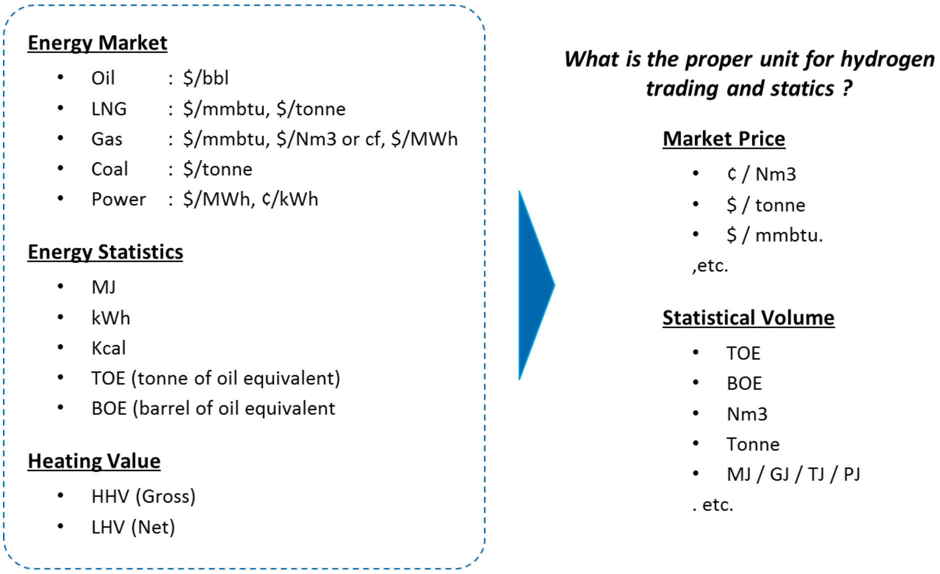
CCS/CCUS = carbon capture and storage/carbon capture, utilisation, and storage, EU = European Union.
Source: Hinichio and Hinichio (2016); GasTerra (2018).

3.5.3. *Example of standardisation-2 (Trading & statistic unit)*

At present, there is no global hydrogen market, and unified trading and statistical units are not available.

It is necessary to define hydrogen price/volume unit for its global trading and statistics that are commonly utilised and understood in this region.

Figure 4.40 Trading and Statistic Unit for Hydrogen and Other Energy



Energy Market

- Oil : $/bbl
- LNG : $/mmbtu, $/tonne
- Gas : $/mmbtu, $/Nm3 or cf, $/MWh
- Coal : $/tonne
- Power : $/MWh, ¢/kWh

Energy Statistics

- MJ
- kWh
- Kcal
- TOE (tonne of oil equivalent)
- BOE (barrel of oil equivalent)

Heating Value

- HHV (Gross)
- LHV (Net)

What is the proper unit for hydrogen trading and statics ?

Market Price

- ¢ / Nm3
- $ / tonne
- $ / mmbtu.

,etc.

Statistical Volume

- TOE
- BOE
- Nm3
- Tonne
- MJ / GJ / TJ / PJ

. etc.

Source: Author.

3.6. Conclusion

3.6.1. *Shift hydrogen source from fossil fuel to renewable energy, and expand its network widely in the EAS region*

- There are enough potentials to supply hydrogen to satisfy demand in this region, including trading from exporting countries to importing countries.
- In early stages, the major hydrogen source will be fossil fuels with hydrogen from stable hydro/geothermal; this will largely shift to abundant renewable energy, such as solar, wind, biomass as the result of technological and market development.
- Hydrogen supply chains will be assumed to start from exporting countries to Japan, Republic of Korea, with some local supply chains in China, India, and will expand its network globally and locally in this region in 2040–2050.

3.6.2. *It is important to start actions now to develop a hydrogen market in the EAS region*

- As shown by the history of LNG, it will take time to build the hydrogen market in this region.

- To meet the CO_2 abatement target (two-degree scenario) of the Paris Agreement, it is quite important to start actions now vis-à-vis R&D/technology development in hydrogen supply/utilisation, investment for hydrogen infrastructure, and collaborating with countries in this region.

3.6.3. Government support is one of the key drivers, especially in early stages

- Intensive support from governments shows the future vision regarding funding and market support mechanisms, R&D promotion, awareness programmes, etc.
- In addition, it is important to develop a standard for hydrogen trading globally in this region, including proper energy trading and statistical units and carbon reduction values.

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