Chapter 1

Review of Hydrogen Production and Supply Cost

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Chapter 1

Review of Hydrogen Production and Supply Cost

This chapter reviews hydrogen production costs based on the study reports of the Advancement of Hydrogen Technologies and Utilization Project, which the New Energy and Industrial Technology Development Organization (NEDO), a government agency of Japan, has been conducting since 2014. There are two reports referred.

- ✔ Analysis and Development on Hydrogen as an Energy Carrier/Economical Evaluation and Characteristic Analyses for Energy Carrier Systems (2014–2015) (NEDO, 2014)
- ✔ Total System Introduction Scenario Research, Leading Technology Research and Development Project on Hydrogen Utilization (2016–2017) (NEDO, 2016)

These reports comprehensively studied the costs and energy inputs from hydrogen production to supply. However, the studies were conducted in FY2014 and FY2016[1] and, thus, do not reflect the latest technological trends.

The first NEDO report calculated the hydrogen supply chain cost in FY2014; however, it did not calculate the hydrogen production cost. In FY2016, the hydrogen production cost was calculated, and the hydrogen supply chain cost of FY2014 was combined to calculate the electricity generation cost and the supply cost to fuel cell vehicle (FCV). This chapter, therefore, reviews the cost of hydrogen according to the order of the NEDO reports.

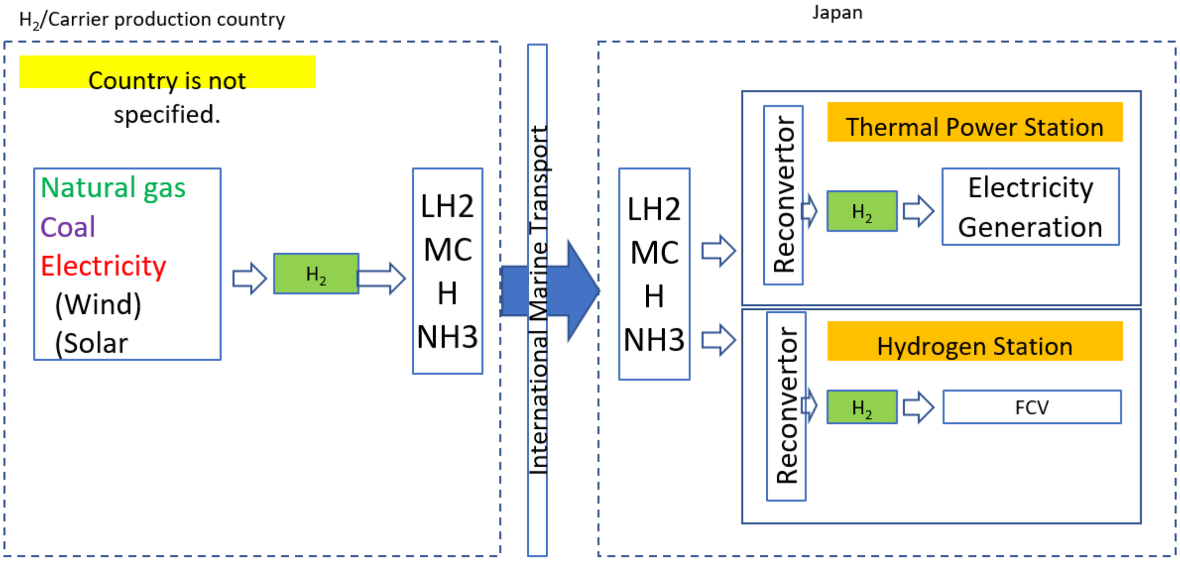
1. System Configuration

Figure 1.1 shows the outline of the NEDO study. This study aims to produce hydrogen in countries outside Japan, produce carriers for transporting hydrogen, import carriers into Japan by ship, and consume reconverted hydrogen in Japan.

Hydrogen production involves three processes: (i) natural gas steam reforming, (ii) coal gasification, and (iii) water electrolysis. The carriers for transporting hydrogen are liquified hydrogen (LH2), methylcyclohexane (MCH), and ammonia (NH3). Hydrogen is consumed at the hydrogen thermal electricity generation plant and FCV.

[1] Fiscal year of Japan: April–March.

Figure 1.1: System Configuration of the Study



Source: Author.

2. Hydrogen Supply for Electricity Generation

In this section, we review the hydrogen supply chain costs for hydrogen thermal electricity generation plants in different scenarios. First, we analyse the energy input to the supply chain, and then analyse the cost of the supply chain.

2.1. Scenario for hydrogen thermal electricity generation

The NEDO report (2014) created scenarios for a thermal power plant according to the scale of hydrogen imports and assumed an allowable imported hydrogen cost for the scenario to be realised. Allowable imported hydrogen cost includes hydrogen and carrier production costs, export terminal and loading costs, and shipping costs. Table 1.1 shows the allowable imported hydrogen cost for each scenario.

According to the NEDO report (2014), when the cost of imported hydrogen falls below ¥25–30/m^3, the utilisation of hydrogen will rapidly increase in the electricity generation sector; the total hydrogen demand, including from the industry and transport sectors, will increase significantly. If the imported hydrogen cost is ¥20/m^3, about 250 billion m^3 of hydrogen will be introduced.

Table 1.1: Scenario and Allowable Imported Hydrogen Cost

Scenario	Scale of Hydrogen Introduction	Allowable Imported Hydrogen Cost	
		2030	2050
Business-as-usual	No hydrogen import	–	–
Research and development (R&D)	Advances in R&D will lead to the introduction of fuel cell cogeneration, fuel cell vehicles (FCVs), and generation of hydrogen power.	¥40/m^3	¥30/m^3
Maximum introduction	The introduction and demand of fuel cell cogeneration, FCVs, and hydrogen power generation will be maximised. (Imported hydrogen accounts for about 15% of primary energy supply.)	¥30/m^3	¥20/m^3

Source: NEDO (2014).

2.2. Hydrogen supply cost for hydrogen thermal electricity generation plants

This section reviews the cost to supply hydrogen-to-hydrogen thermal electricity generation plants for each scenario based on the FY2014 NEDO report. The hydrogen supply chain consists of carrier production, hydrogen loading for exports, international marine transport, hydrogen unloading, regasification, dehydrogenation or ammonia decomposition, and domestic delivery for electricity generation plants by pipeline. In the FY2014 report, the hydrogen production cost for each process was not calculated. As mentioned earlier, the first NEDO report was studied in FY2014 and did not reflect the latest technological progress. Since the hydrogen production cost was studied in FY2016, the feedstock hydrogen cost in Table 1.2 is the allowable import cost minus the hydrogen supply cost outside Japan.

Table 1.2 and Figure 1.2 show the hydrogen supply cost for hydrogen thermal electricity generation.

LH2 has a high liquidation cost. In addition, loading and unloading costs are high because a dedicated freezing tank and loading and unloading equipment are required. On the other hand, regasification cost in Japan is unnecessary because sea water is used.

MCH has a high dehydrogenation cost. Ammonia (NH3) has a high ammonia synthesis cost and a decomposition cost.

Table 1.2: Hydrogen Supply Cost for Hydrogen Thermal Electricity Generation Plants

Unit: US cent/m^3

Carrier	Scenario	Outside Japan							
		Hydrogen (Feedstock)	Carrier Production		Loading		International Marine Transport		(Subtotal)
		CAPEX + OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	Import Cost
LH2	R&D 2030	9.1	8.5	4.0	5.0	0.4	4.2		(36.2)
	R&D 2050	9.1	6.1	3.2	4.8	0.4	3.6		(27.2)
	Max 2050	7.3	2.9	3.1	2.7	0.3	1.8		(18.1)
MCH	R&D 2030	9.9	1.2	4.1	0.4	0.01	1.5	2.1	(36.2)
	R&D 2050	9.1	1.0	4.0	0.4	0.01	1.5	2.1	(27.2)
	Max 2050	7.3	0.9	4.0	0.4	0.01	1.5	2.1	(18.1)
NH3	R&D 2030	9.1	3.7	7.6	0.3	0.003	1.7	1.2	(36.2)
	R&D 2050	9.9	3.7	5.6	0.3	0.003	1.7	1.2	(27.2)
	Max 2050	7.9	3.4	2.2	0.3	0.003	1.7	1.2	(18.1)

Carrier	Scenario	Inside Japan						Total		
		Unloading		Dehydrogenation		Domestic Delivery				
		CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX	OPEX	CAPEX + OPEX
LH2	R&D 2030	7.1	0.2			0.5	0.7	25.2	5.3	39.6
	R&D 2050	6.7	0.2			0.5	0.7	21.6	4.4	35.2
	Max 2050	3.3	0.2			0.5	0.7	11.1	4.3	22.8
MCH	R&D 2030	1.3	0.02	3.6	11.6	0.5	0.7	8.4	19.0	36.8
	R&D 2050	1.3	0.02	3.3	8.3	0.5	0.7	7.9	15.2	32.2
	Max 2050	1.3	0.02	1.4	4.9	0.5	0.7	5.9	11.8	25.0
NH3	R&D 2030	1.7	0.02	2.4	5.6	0.5	0.7	10.3	15.2	34.6
	R&D 2050	1.7	0.02	2.4	5.6	0.5	0.7	10.3	13.2	33.3
	Max 2050	1.7	0.02	2.4	3.6	0.5	0.7	9.7	7.8	25.5

LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia, R&D = research and development.

Notes:

R&D 2030; R&D scenario 2030, allowable hydrogen import cost = ¥40/m^3

R&D 2050; R&D scenario 2030 and maximum introduction scenario 2030, allowable hydrogen import cost = ¥30/m^3

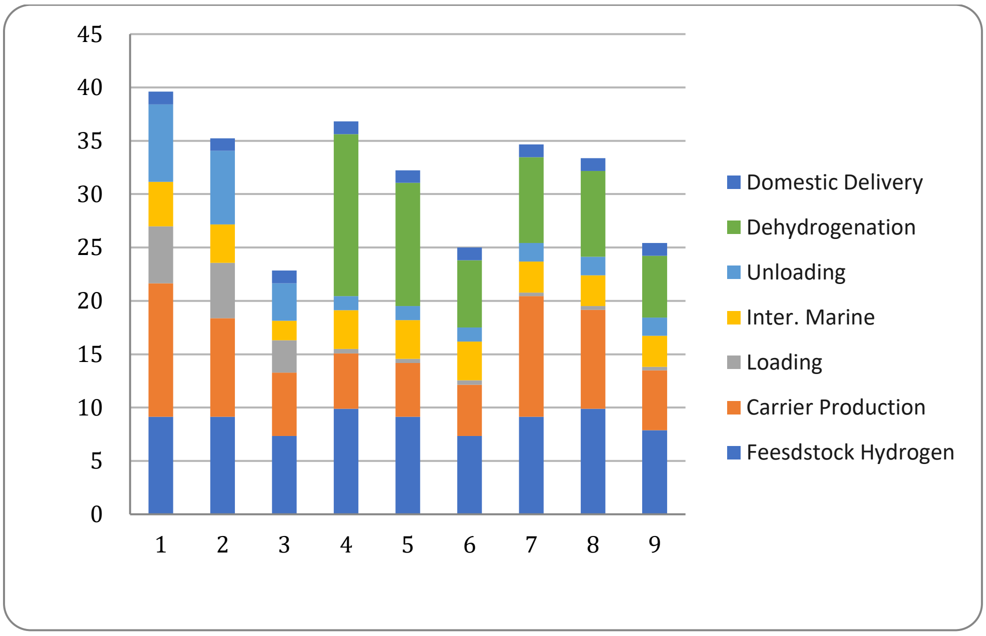
Max 2050; maximum introduction scenario 2050, allowable hydrogen import cost = ¥20/m^3

The same applies hereinafter.

Original currency is V. The cost is converted from V to US$ using the exchange rate, ¥110.4/US$ (average of 2018).

Source: NEDO (2014).

Figure 1.2: Hydrogen Supply Cost for Hydrogen Thermal Electricity Generation Plants



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia, R&D = research and development.
Source: NEDO (2014).

2.3. Cost of hydrogen production

This section reviews the hydrogen production cost based on the FY2016 report. The NEDO report assumed that hydrogen was produced overseas and imported to Japan, but the country of origin was not specified.

This section also analyses hydrogen production cost by natural gas steam reforming, coal gasification, and water electrolysis. Two types of electricity sources can be used in water electrolysis, solar PV and wind.

2.3.1. Assumptions of Hydrogen Production Cost

Table 1.3 shows the assumptions for the equipment for hydrogen production. The equipment will be constructed in countries other than Japan. Renewable energy–derived electricity input to water electrolysis is assumed to be supplied through the electricity grid and, hence, does not explicitly reflect the construction cost of renewable energy.

Table 1.3: Assumptions of Natural Gas Reforming Facility

Item	Description
Hydrogen production capacity	2.5 billion Nm3/y
Hydrogen production per hour	317,098 Nm3/h
Capacity factor	90%
Natural gas consumption (feedstock)	73.35 tonne/h
Natural gas consumption (fuel)	14.67 tonne/h
Electricity consumption	33,682.40 kWh/h
Cooling water	1,585 tonne/h
Pure water	379.90 tonne/h
Reforming	2 stages (3.0 MPa – 650°C, 3.0 MPa – 250°C)
Hydrogen gas treatment process	Moisture condensation + CO_2 recovery (rate of CO_2 recovery: 90%) + PSA (rate of hydrogen recovery: 85%)
Hydrogen output pressure	2.62 Mpa
CO_2 output pressure	15.3 Mpa
Natural gas specification	Das Island, UAE (C1: 75%, C2: 23%, C3: 2%)
Natural gas price	US$5/MMbtu
Electricity price (country of production)	¥5.6/kWh
Electricity price (Japan)	¥12.5/kWh

MPa = Megapascal, PSA = pressure swing absorption, UAE = United Arab Emirates.
Source: NEDO (2016).

Table 1.4: Assumptions of Coal Gasification Facility

Item	Description
Hydrogen production capacity	2.5 billion Nm^3/y
Hydrogen production per hour	317,098 Nm^3/h
Gasification process	Fluidised bed coal gasifier (5.6 MPa; 1,300°C)
Capacity factor	90%
Coal consumption (feedstock)	481.2 tonne/h
Electricity consumption	216,286 kWh/h
Reforming	2 stages (5.5 MPa – 650°C, 5.4 MPa – 250°C)
Hydrogen gas treatment process	Acid gas removal + PSA
Hydrogen output pressure	6.8 MPa
CO_2 recovery process	Exhaust gas desulphurisation + Decarboxylation (Amine method) + Dehydration + Compression
CO_2 output pressure	14.9 MPa

MPa = Megapascal, PSA = pressure swing absorption.
Note: Details of coal are not disclosed.
Source: NEDO (2016).

Table 1.5: Assumptions of Water Electrolysis Facility

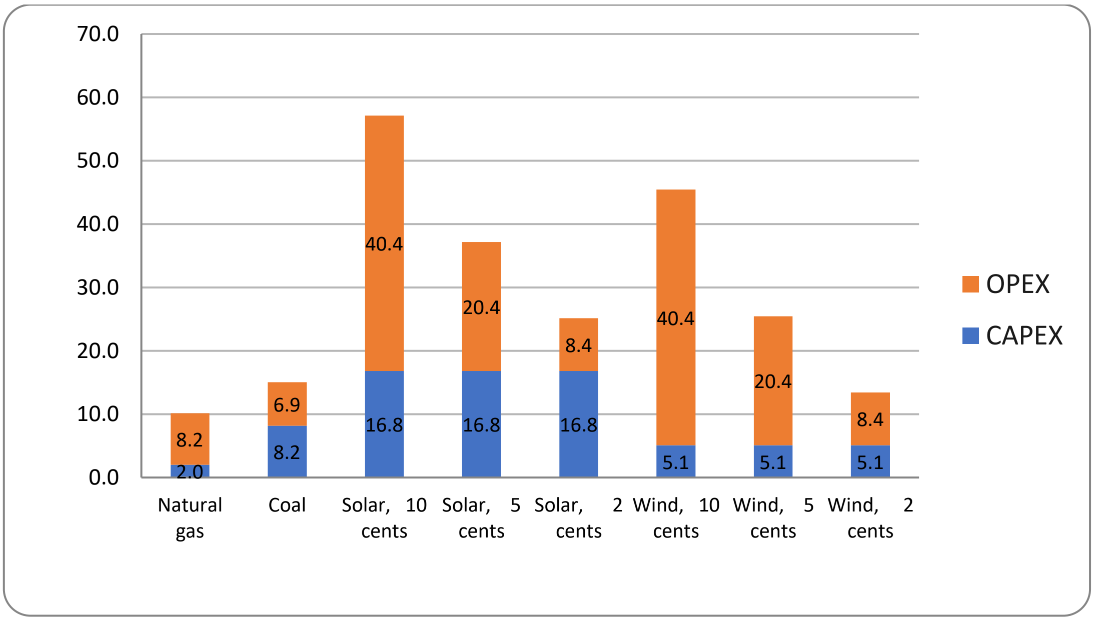
Item	Description
Process	Not specified
Unit electricity consumption	4 kWh/Nm^3-H_2
Unit water consumption	900 g/Nm^3-H_2
Unit equipment cost	¥200,000/Nm^3-H_2
Unit converter cost	¥60,000/Nm^3-H_2
Pure water cost	¥438.9/tonne
Unit pure water cost	¥0.4/m^3
Capacity factor (solar)	15%
Capacity factor (wind)	50%
Electricity price (renewable energy, feedstock)	US cents 10/m^3 US cents 5/m^3 US cents 2/m^3

Note: The construction cost of renewable generation plants is not included.
Source: NEDO (2016), Author.

2.3.2. Cost of hydrogen production

Figure 1.3 shows the cost of hydrogen production for each process. For water electrolysis, three cases of feedstock electricity price are assumed, i.e. US cents 10/kWh, US cents 5/kWh, and US cents 2/kWh.

Figure 1.3: Cost of Hydrogen Production, by Process



CAPEX = capital expenditure, Coal = coal gasification, Natural gas = natural gas steam reforming, OPEX = operating expense, Solar 10 cents = water electrolysis from solar power, electricity price is US cents 10/kWh, the same applies hereinafter.
Note: Original currency is ¥. The cost is converted from ¥ to US$ using the exchange rate ¥110.4/US$ (average of 2018).
Source: NEDO (2016), Author.

The cost of hydrogen production through natural gas steam reforming is US cents 10.1/m^3 and coal gasification is US cents 15.0/m^3. Due to 15% low capacity factor, solar-based water electrolysis costs US cents 25.19/m^3 even if we assume US cents 2/kWh of the feedstock electricity price. On the other hand, wind-based water electrolysis, which has a higher capacity factor of 50%, can expect US cents 13.4/m^3 when the feedstock electricity price is US cents 2/kWh. It is lower than the production cost adopting coal gasification.

2.4. Electricity generation cost

This section reviews the generation cost of hydrogen thermal electricity by adding the result of '1.2.2 Hydrogen supply cost for hydrogen thermal electricity generation plants' to '1.2.3 'Cost of hydrogen production'.

Table 1.6 shows the assumption of a thermal electricity generation plant.

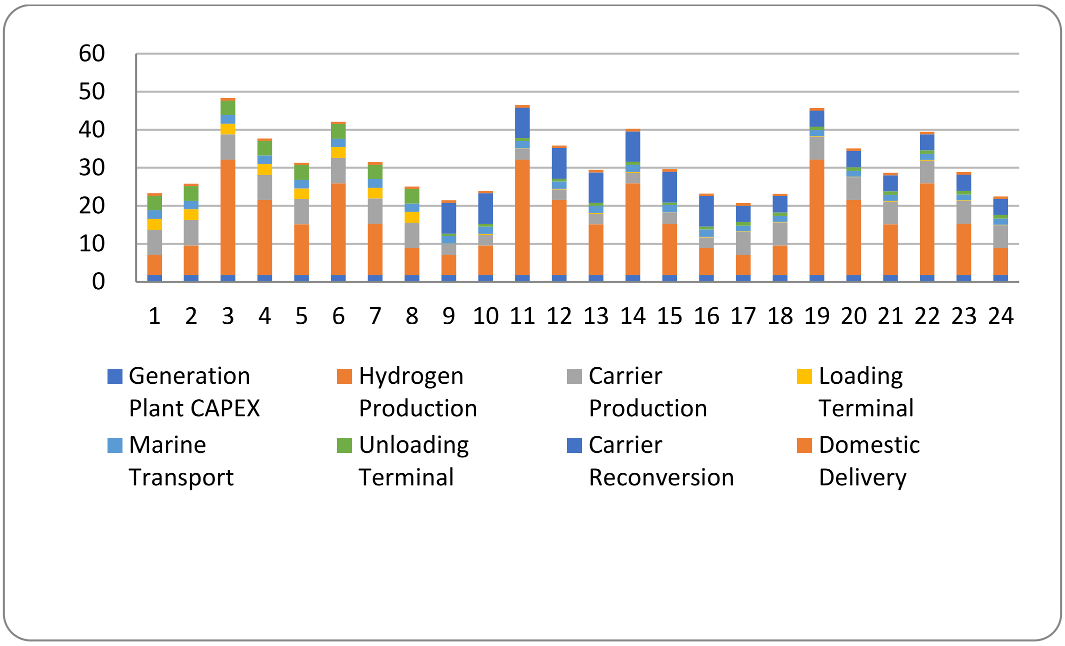
Table 1.6: Assumptions of a Hydrogen Thermal Electricity Generation Station

Item	Description
Capacity	720 MW
Unit construction cost	¥120,000/kW
Construction cost	¥86.4 billion
Thermal efficiency	63.0% at LHV
Rate of own use	2.0%
Hydrogen consumption	2.5 billion Nm3-H2/y (27.0 PJ/y)
Capacity factor	76.5%
Plant output electricity	4.7 TWh/y (16.9 PJ/y)

LHV = lower heating value.
Source: NEDO (2016).

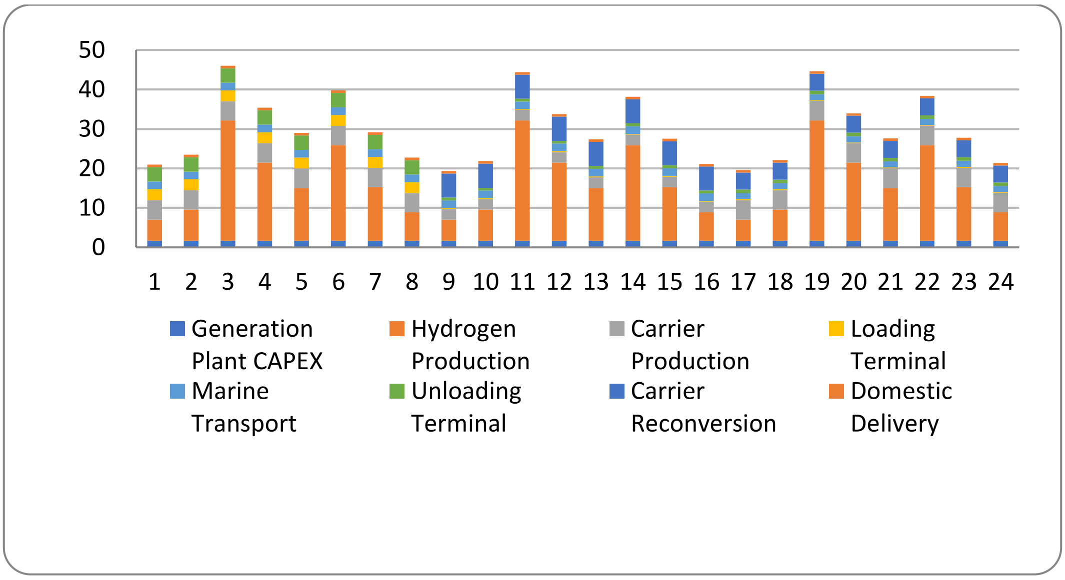
Figure 1.4 and Figure 1.5 show the electricity generation cost by carrier and hydrogen production process.

Figure 1.4: Electricity Generation Cost (R&D 2030 Scenario)



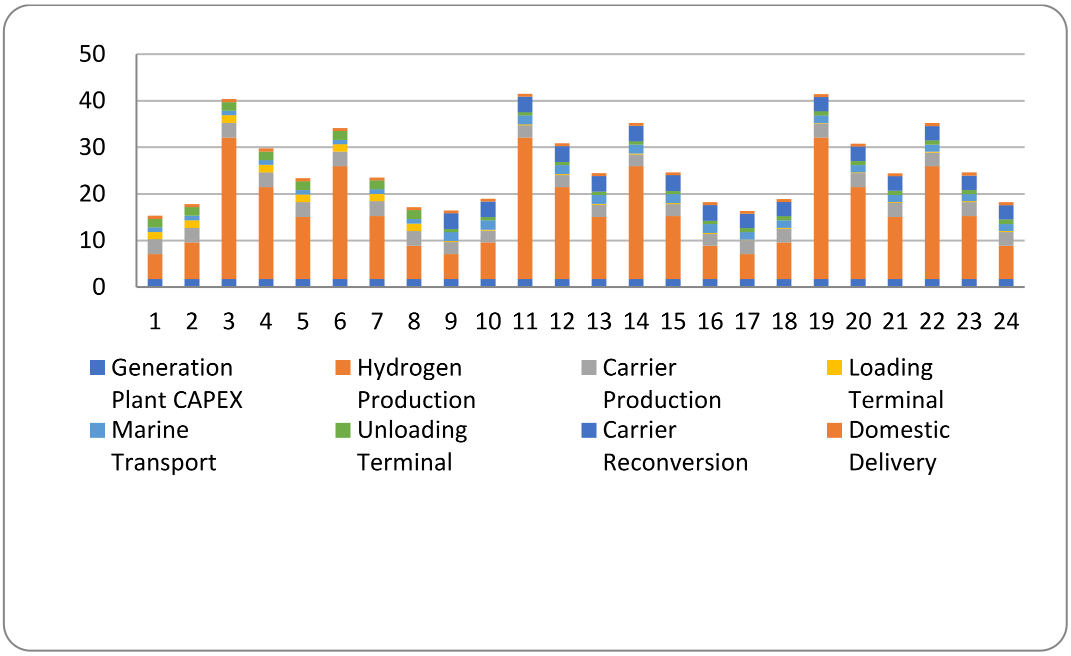
LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

Figure 1.5: Electricity Generation Cost (R&D 2050/Max 2030 Scenario)



LH2 = liquified hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

Figure 1.6: Electricity Generation Cost (Max 2050 Scenario)



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

2.5. Input fuel for hydrogen supply chain

This section reviews the outline of the hydrogen supply chain and the fuel input into each carrier.

2.5.1. Liquefied Hydrogen

Table 1.7 shows the supply chain of LH2 and the fuel to be inputted. Feedstock hydrogen is cooled to a liquefaction temperature or lower by the liquefaction machine and is transported to the dedicated LH2 tanks. At the loading site, LH2 is stored in tanks before shipment and delivered to tankers. The hydrogen boiled off in the loading tank is compressed by the boil-off gas (BOG) compressor, returned to the liquefier, and re-liquefied. LH2 is transported by dedicated tankers. It is assumed that BOG is used as fuel for LH2 tankers. After unloading and storage at the unloading site, reconverted gaseous hydrogen is pressurised by the compressor and then transported to the power plant by pipelines.

Table 1.7: Fuel Input for Hydrogen Supply Chain (LH2)

Source of Hydrogen	Fuel	Hydrogen Production	Liquefaction	Loading Storage	International Marine	Unloading	Vaporisation	Domestic Delivery
Natural gas	Electricity (Grid)	✓	✓	✓		✓		✓
	Natural gas	✓						
Coal	Electricity (Grid)	✓	✓	✓		✓		✓
	Coal	✓						
Water electrolysis	Electricity (Grid)		✓	✓		✓		✓
	Electricity (Res.)	✓						

Source: NEDO (2016).

2.5.2. Methylcyclohexane (MCH)

Table 1.8 shows the supply chain of MCH and the fuel to be inputted. The toluene/MCH system consists of hydrogenation equipment, storage equipment, international marine transportation, storage equipment at landing sites, dehydrogenation equipment (including hydrogen treatment), and domestic transportation. What differs from other systems is that after dehydrogenation, toluene (carrier) is loaded back into the hydrogen production country.

Table 1.8: Fuel Input for Hydrogen Supply Chain (MCH)

Source of Hydrogen	Fuel	Hydrogen Production	Hydrogenation	Loading Terminal	International Marine	Unloading Terminal	Dehydrogenation	Domestic Delivery
Natural gas	Electricity (Grid)	✓	✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas	✓	✓					
	Fuel oil				✓			
Coal	Electricity (Grid)	✓	✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas		✓					
	Fuel oil				✓			
	Coal	✓						
Water electrolysis	Electricity (Grid)		✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas		✓					
	Fuel oil				✓			
	Electricity (Res.)	✓						

MCH = methylcyclohexane.
Source: NEDO (2016).

2.5.3. Ammonia (NH3)

Table 1.9 shows the supply chain of NH3 and the fuel to be inputted. The NH3 system consists of nitrogen production equipment (air separator), NH3 synthesis, NH3 storage equipment, international marine transportation, storage equipment at unloading sites, NH3 decomposition equipment (including hydrogen treatment), and domestic transportation.

Table 1.9: Fuel Input for Hydrogen Supply Chain (NH3)

Source of Hydrogen	Fuel	Hydrogen Production	Ammonia Synthesis	Loading Terminal	International Marine	Unloading Terminal	Ammonia Decomposition	Domestic Delivery
Natural gas	Electricity (Grid)	✓	✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas	✓	✓					
	Fuel oil				✓			
Coal	Electricity (Grid)	✓	✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas		✓					
	Fuel oil				✓			
	Coal	✓						
Water electrolysis	Electricity (Grid)		✓	✓		✓	✓	✓
	City gas						✓	
	Natural gas		✓					
	Fuel oil				✓			
	Electricity (Res.)	✓						

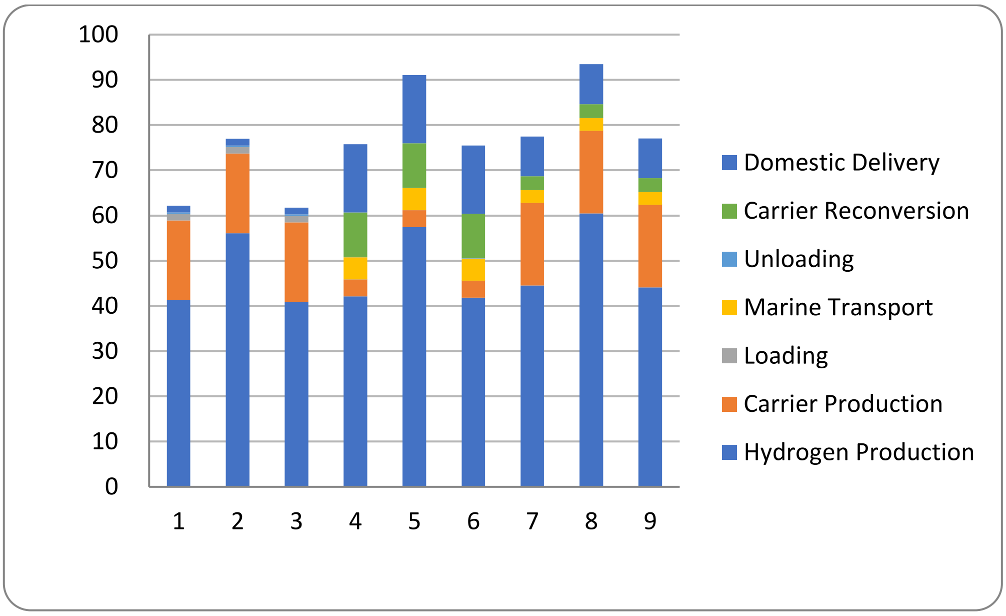
NH3 = ammonia.
Source: NEDO (2016).

2.6. Energy input for hydrogen supply chain

This section reviews the energy input to the hydrogen supply chain analysed in the NEDO report. However, since the NEDO report was done in FY2016, it did not reflect the latest technological progress.

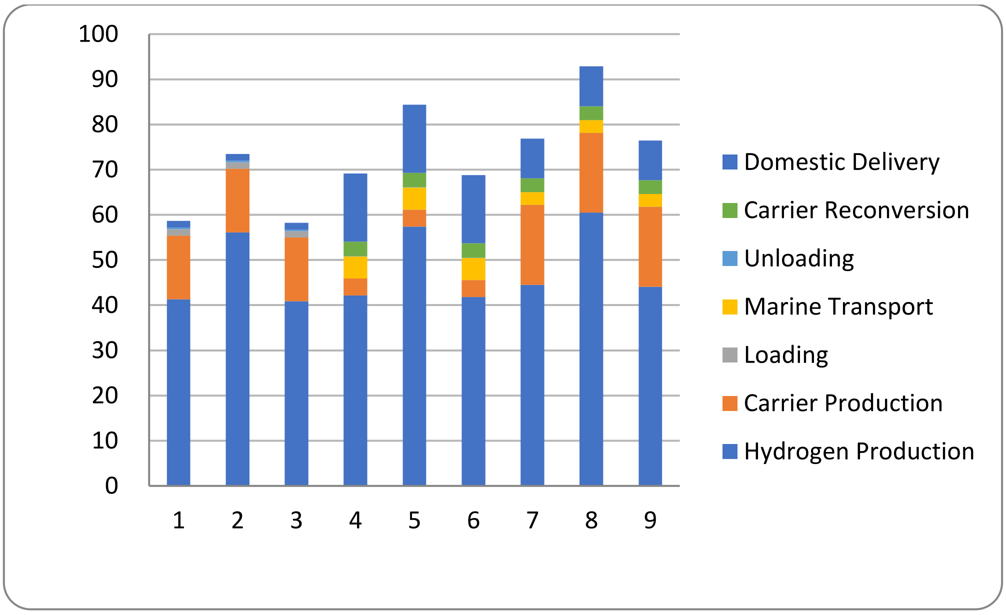
Figure 1.7 shows the required energy to supply 2.5 billion m^3 per year of hydrogen to hydrogen thermal electricity plants by scenario. LH2 requires a large amount of energy for carrier production (liquefaction). Unlike LH2 and NH3, MCH does not require a large amount of energy for carrier production; however, it requires a large amount for dehydrogenation and domestic delivery in Japan. Like LH2, NH3 requires a large amount of energy for carrier production (NH3 synthesis) and for domestic delivery.

Figure 1.7: Energy Input for Hydrogen Supply Chain (R&D 2030 Scenario)



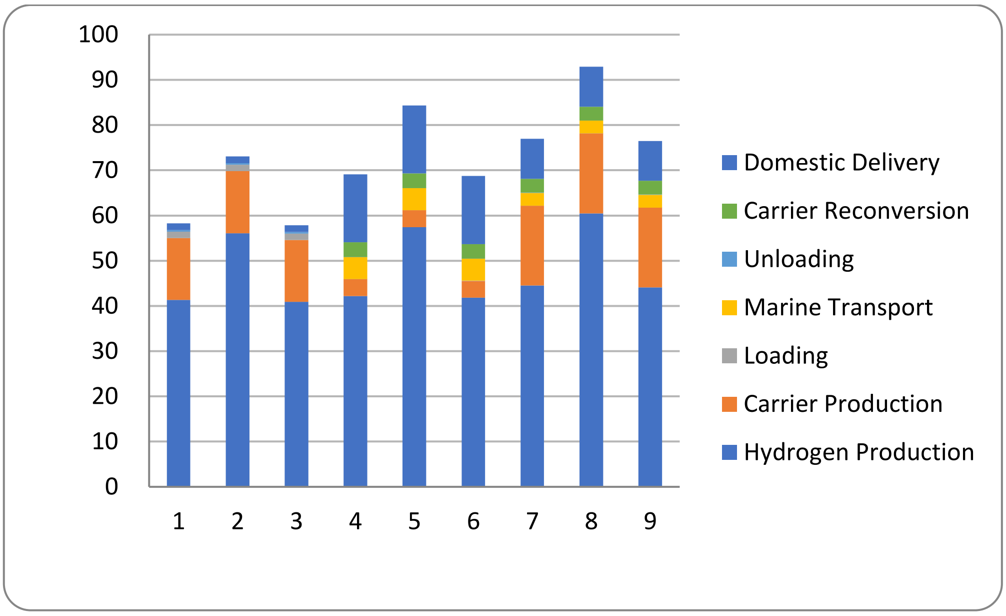
LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016).

Figure 1.8: Energy Input for Hydrogen Supply Chain (R&D 2050/Max 2030 Scenario)



LH2 = liquified hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016).

Figure 1.9: Energy Input for Hydrogen Supply Chain (Max 2050 Scenario)



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016).

2.7. Energy efficiency of delivered hydrogen and generated electricity

Table 1.6 presents the assumptions of a thermal plant.

The calculation for hydrogen efficiency and electricity efficiency is as follows:

$$Energy\ efficiency\ of\ delivered\ hydrogen\ =$$

$$Delivered\ hydrogen\ (2.5\ billion\ m3, 27\ TJ)\ /Energy\ input\ for\ hydrogen\ supply\ chain$$

$$Energy\ efficiency\ of\ generated\ electricity =$$

$$Generated\ electricity\ (17\ TJ)/Energy\ input\ for\ hydrogen\ supply\ chain$$

Table 1.10 shows the energy efficiency of hydrogen and electricity for each carrier and scenario. However, the calculation did not reflect the latest technological progress as it was done in FY2016.

For carriers, LH2 has the highest energy efficiency, followed by MCH and NH3. Looking at the feedstock of hydrogen production, natural gas and electricity from renewable source (solar and wind) have the highest energy efficiency, followed by coal.

Table 1.10: Energy Efficiency of Delivered Hydrogen and Generated Electricity, %

Carrier	Process	Scenario					
		R&D 2030		R&D 2050/Max 2030		Max 2050	
		Hydrogen	Electricity	Hydrogen	Electricity	Hydrogen	Electricity
LH2	Natural gas	43	27	46	29	46	29
	Coal	35	22	37	19	37	23
	Renewables	44	27	46	29	47	29
MCH	Natural gas	36	22	39	24	39	24
	Coal	30	19	32	20	32	20
	Renewables	36	22	39	25	39	25
NH3	Natural gas	35	22	35	22	35	22
	Coal	29	18	29	18	29	18
	Renewables	35	22	35	22	35	22

LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016).

3. Hydrogen Supply for FCVs

This section reviews hydrogen supply for FCVs. From hydrogen production to unloading hydrogen carrier in Japan, the supply chain is the same as electricity generation, and the difference is domestic delivery.

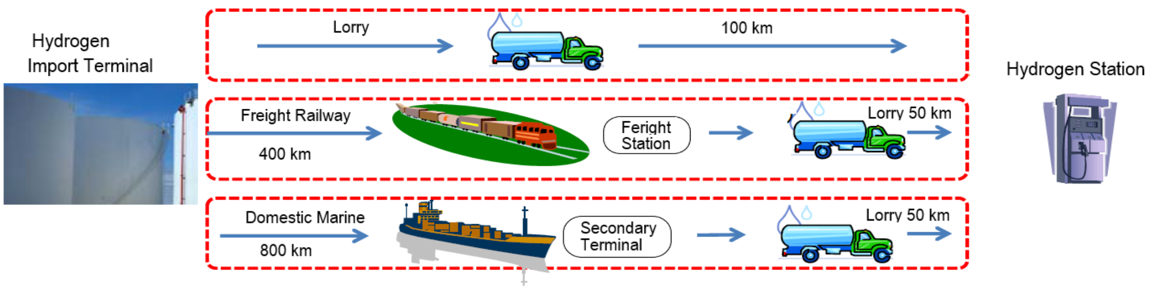
3.1. Hydrogen supply chain for FCVs

Domestic delivery for the FCV system is assumed as follows. The hydrogen carrier is transported from the hydrogen import terminal to the hydrogen station and stored. The hydrogen carrier is reconverted to gaseous hydrogen at the station. Gaseous hydrogen is compressed and supplied to the FCVs.

Figure 1.10 shows how hydrogen is transported from the hydrogen import terminal to the hydrogen station. The following three transport modes are assumed.

Mode 1: Lorry 100 km
Mode 2: Rail 400 km + Lorry 50 km
Mode 3: Domestic marine 800 km + Lorry 50 km

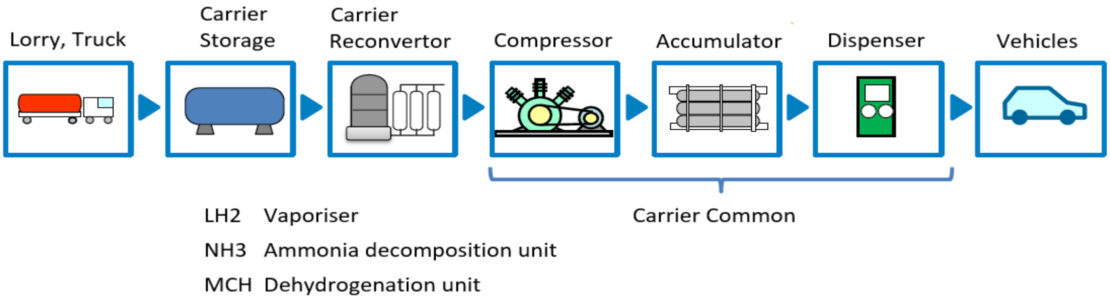
Figure 1.10: From Hydrogen Import Terminal to Hydrogen Station



Source: NEDO (2014).

Figure 1.11 shows the image of the hydrogen station. The hydrogen station consists of equipment that receives and stores hydrogen carriers, equipment that reproduces hydrogen from carriers, compressor, accumulator, and dispenser (including pre-cooling). The equipment of carrier storage and carrier re-converter differ, depending on the carrier. Compressor, accumulator, and dispenser are common equipment for carriers.

Figure 1.11: Equipment of Hydrogen Station



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016).

3.2. Hydrogen supply cost for FCVs

Hydrogen stations are expected to have three sizes (Table 1.11).

Table 1.11: Scenario of Scale of Hydrogen Station

	Scenario		
	Small	**Medium**	**Large**
Hydrogen sales	300 Nm^3/h	Ave. 830 Nm^3/h Max. 1,200 Nm^3/h	Ave. 1,240 Nm^3/h Max. 2,400 Nm^3/h
(Gasoline sales equivalent)	(100 KL/month)	(200 KL/month)	(300 KL/month)
Number of visitors (Peak hour)	8 vehicles/h 2 dispensers	15 vehicles/h 3 dispensers	22 vehicles/h 4 dispensers
Number of visitors (Monthly)	4,000 vehicles	8,000 vehicles	12,000 vehicles

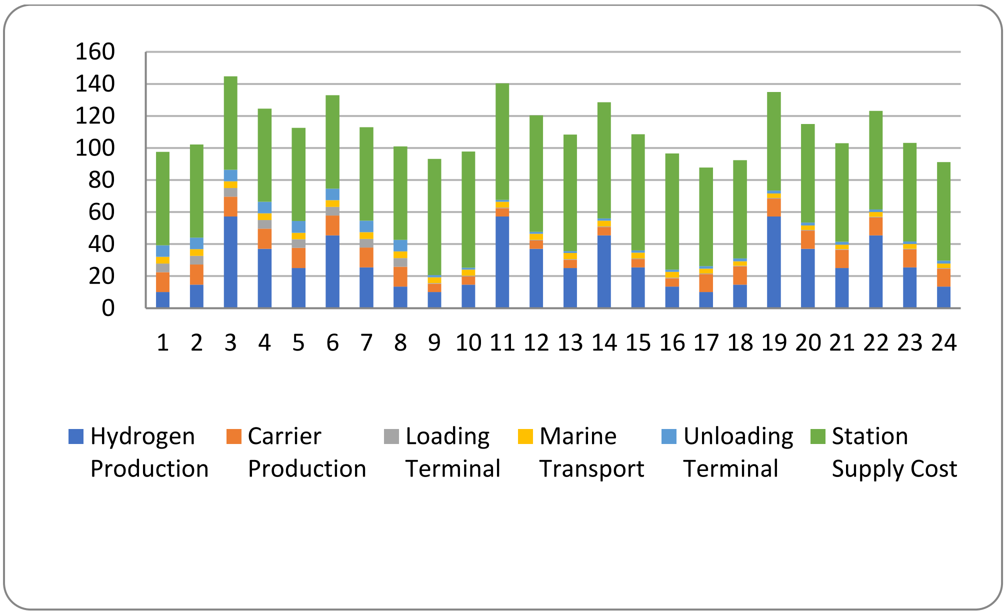
Source: NEDO (2016).

Figure 1.12 shows the hydrogen supply cost (up to dispenser) for FCVs. Hydrogen production and supply costs (up to unloading) are the same as electricity generation. The comparison of the scenario names for electricity generation and for FCVs is as follows:

For Electricity Generation		For FCVs
R&D 2030	→	Small
R&D 2050/Max 2030	→	Medium
Max 2050	→	Large

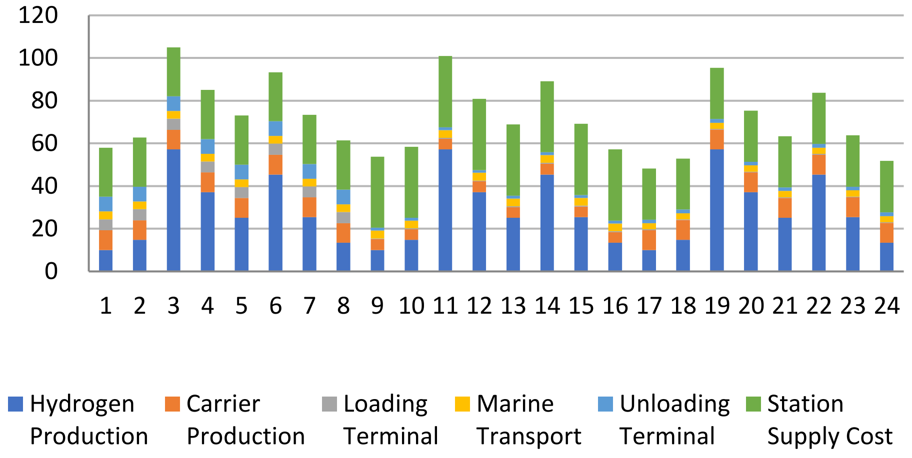
Figure 1.13 shows the hydrogen supply cost at a dispenser when the transport mode is 'Lorry 100 km'. In the figure, station supply cost is the sum of transporting hydrogen carrier from the hydrogen import terminal to the hydrogen station, storing it, reproducing hydrogen from the carrier, and sending it to the dispenser.

Figure 1.12: Hydrogen Supply Cost at a Dispenser (Small Scale)



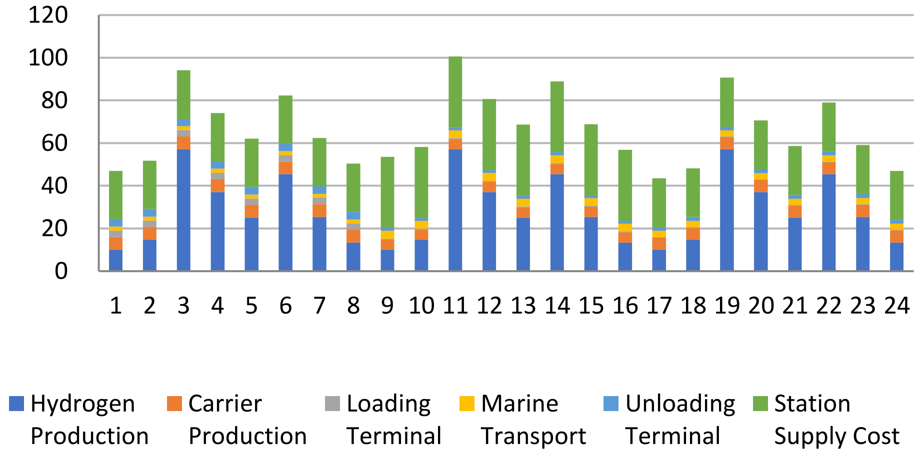
LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

Figure 1.13: Hydrogen Supply Cost at a Dispenser (Medium Scale)



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

Figure 1.14: Hydrogen Supply Cost at a Dispenser (Large Scale)



LH2 = liquefied hydrogen, MCH = methylcyclohexane, NH3 = ammonia.
Source: NEDO (2016), Author.

4. Price Comparison

This section compares the electricity generation cost shown in subsection 1.2.4 on electricity generation cost and the supply cost to FCVs shown in subsection 1.3.2 on hydrogen supply cost for FCVs with the existing system.

4.1. Electricity generation

Table 1.12 shows the assumptions for estimating the levelised cost of electricity generation (LCOE) for different technologies and fuel.

Table 1.12: Assumptions of Hydrogen Price Comparison for Electricity Generation (LCOE)

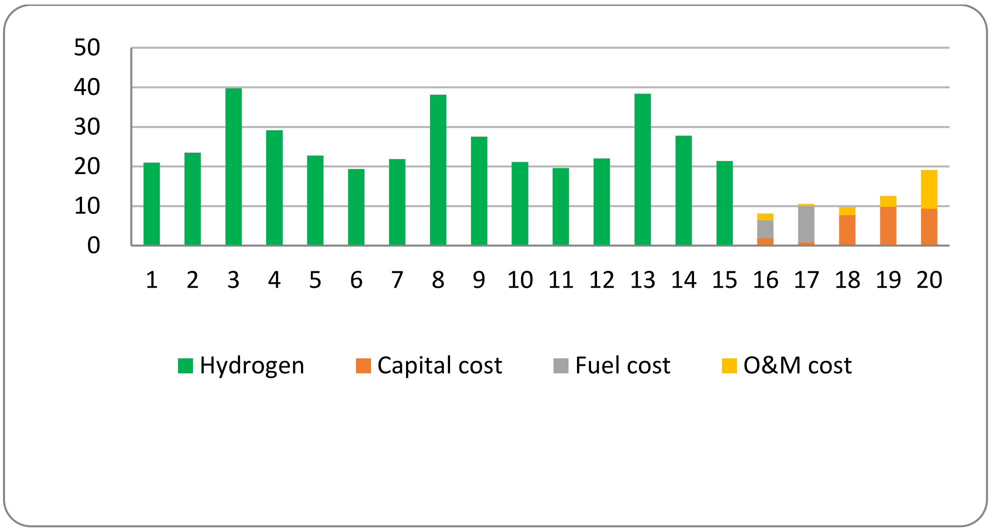
Item	Description
Plant site	Japan
Hydrogen production process	Natural gas steam reforming Coal gasification Water electrolysis (wind)
Thermal (Coal)	Capacity: 800 MW, Capacity factor: 70% Thermal efficiency (2030): 48% at HHV Construction cost: ¥250,000/kW Operation years: 40 years Coal price (2030): US$133.45/tonne
Thermal (Natural gas)	Capacity: 1,400 MW, Capacity factor: 70% Thermal efficiency (2030): 57% at HHV Construction cost: ¥120,000/kW Operation years: 40 years Natural gas (LNG) price (2030): US$751.22/ton (US$14.1/MMBtu)
Conventional Hydro	Capacity: 12 MW, Capacity factor: 45% Construction cost: ¥640,000/kW Operation years: 40 years
Wind (Onshore)	Capacity: 20 MW, Capacity factor: 20% Construction cost: ¥252,000/kW Operation years: 20 years
Solar (Commercial scale)	Capacity: 2 MW, Capacity factor: 14% Construction cost: ¥222,000/kW Operation years: 30 years

HHV = higher heating value, LCO = levelised cost of electricity.

Source: Electricity Generation Cost Verification Working Group, METI, May 2015.

Figure 1.15 compares the LCOE of hydrogen thermal power generation in the R&D 2050/Max 2030 scenario and conventional technologies.

Figure 1.15: Comparison of LCOE



LCOE = levelised cost of electricity, LH2 = liquified hydrogen, MCH = methylcyclohexane, NH3 = ammonia, O&M = operations and maintenance.
Note: Scenario = R&D 2050/Max 2030.
Source: NEDO (2016), Author.

4.2. Hydrogen supply for FCVs

This section compares hydrogen prices to fuel FCVs with regular gasoline prices (for conventional gasoline engine vehicles) and electricity prices (for battery electric vehicles). Since hydrogen (gaseous), gasoline (liquid), and electricity have different units, we will compare the consumption amount for 100 km driving. Comparison is made only for fuel costs, excluding vehicle costs and taxes.

Table 1.13 shows the assumptions for prices and vehicles for comparison.

Table 1.13: Assumptions of Hydrogen Price Comparison for Fuel Cell Vehicles

Item	Description
Location	Japan
Hydrogen production process	Natural gas steam reforming
Hydrogen carrier	Liquified hydrogen (LH2)
Transport mode	Lorry 100 km
Types of vehicle	Fuel cell vehicle Conventional gasoline-engine vehicle Battery electric vehicle
Hydrogen price at dispenser	Hydrogen supply cost + ¥5/m^3 of station charge
Regular gasoline price	¥80.0/L (Japan, 2018, tax is excluded)
Electricity price for household	¥24.059/kWh (Japan, 2018, tax is excluded) (Battery is assumed to be charged at the driver's house.)

Source: IEA (2019).

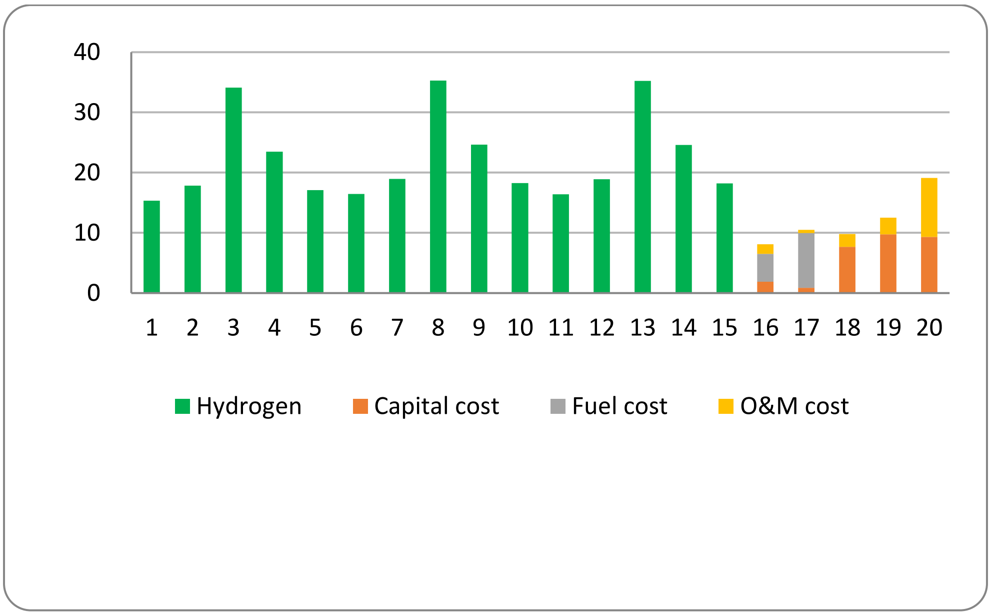
4.2.1.Selected Vehicles

Type	Vehicle	Fuel Mileage	Fuel Consumption (100 km driving)
FCV	Toyota Mirai	7.59 km/m^3 (JC08)	13.2 m^3
Gasoline	Toyota Land Cruiser	6.7 km/L (JC08)	14.9 L
	Toyota Crown 2.0L	12.8 km/L (JC08)	7.8 L
	Toyota Corolla 1.8 L CVT	14.6 km/L (WLTC)	6.8 L
	Toyota Vitz 1.0 L	20.8 km/L	4.8 L
	Toyota Vitz Hybrid 1.5 L + motor	34.4 km/L	2.9 L
BEV	Nissan Leaf 62 kWh	458 km (WLTC)	13.5 kWh
	Nissan Leaf 40 kWh	322 km (WLTC)	12.4 kWh
	Tesla Model 3 55 kWh	409 km (WLTP)	13.4 kWh
	Tesla Model 3 75 kWh	499 km (WLTP)	15.0 kWh
	Tesla Model S 100 kWh	610 km (WLTP)	16.4 kWh

BEV = battery electric vehicle, FCV = fuel cell vehicle, JC08 = one of the methods in Japan to calculate the fuel economy of vehicles, WLTC = worldwide harmonised light vehicles test cycle.
Source: Manufacturers' website.

Figure 1.16 compares the fuel costs for 100 km driving. Other costs, such as vehicle costs and taxes, are excluded.

Figure 1.16: Fuel Cost for 100 Km Driving



Note: Cost other than fuel expenditure is excluded.
Source: Author.