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Study on Demand and Supply Potential of Hydrogen Energy in ASEAN and East Asia – Phase 4

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Preface

Although it combusts like fossil fuels, hydrogen does not emit carbon dioxide. Hydrogen is expected to replace fossil fuels across the industry, transport, residential, commercial, and power sectors. Whilst fossil fuels – coal, oil, and gas – are prevalent, their consumption is projected to decrease because of anticipated high large demand for hydrogen until about 2050. Hydrogen is generated through reforming and gasification technologies and electricity, as well as through electricity using electrolysis equipment. Like electricity, hydrogen is classified as secondary energy and not indigenous energy such as coal, oil, and gas. Some countries have the advantage of domestic hydrogen production, whilst others must import it to meet substantial demand.

Phase 4 of the study (i) conducted economic and social analyses of the hydrogen supply network aimed at connecting hydrogen-producing and hydrogen-consuming countries in the East Asia Summit (EAS) region; (ii) assessed the current and future efficiency of hydrogen production; (iii) analysed the cost of hydrogen transport using liquid hydrogen; (iv) explored optimal solutions for hydrogen transport from production to consumption countries in the EAS region; and (v) conducted a dynamic study simulating hydrogen transport between hydrogen supply and demand countries, drawing on the results of phases 1 and/or 2.

Hydrogen is more expensive than existing low-carbon fuels and technologies such as natural gas and solar photovoltaic systems. However, innovative technology development and the scaling up of the hydrogen market size are anticipated, potentially making hydrogen more affordable by 2040–2050. This report describes the results of the five research points, aspiring to contribute to widespread adoption of hydrogen in the EAS region.

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List of Abbreviations and Acronyms

ASEAN	Association of Southeast Asian Nations
ASTRA	Assessment of Transport Strategies
CAPEX	capital expenditure
CCS	carbon capture and storage
CCUS	carbon capture, utilisation, and storage
CO	carbon monoxide
CO_2	carbon dioxide
CH_4	methane
EAS	East Asia Summit
FCV	fuel cell vehicle
FTE	full-time equivalent
GDP	Gross Domestic Product
H_2	hydrogen
H_2O	chemical symbol for water
IEA	International Energy Agency
JBIC	Japan Bank for International Corporation
kWh	kilowatt-hour
LASs	loading arm systems
LH_2	liquefied hydrogen
LHV	lower heating value
LNG	liquefied natural gas
MCH	methylcyclohexane
METI	Ministry of Economy, Trade, and Industry, Japan
NEDO	New Energy and Industrial Technology Development Organization
Nm^3	normal cubic metre
OPEX	operational expenditure
PEM	polymer electrode membrane

PSA	pressure swing adsorption
rpm	revolutions per minute
SMR	steam methane reforming
SOEC	solid oxide electrolysis cell
TPD	tonnes per day
US	United States
US$	United States dollar
¥	yen

Executive Summary

Like electricity, hydrogen (H_2) is classified as a secondary energy source. It is generally produced from fossil fuels through processes applying natural gas reforming and gasification for low-ranked coal. Renewable electricity from sources such as solar photovoltaic systems and hydropower plants can be used for water electrolysis to produce H_2. Efficiency is important in H_2 production. Current H_2 production technologies applying alkaline electrolysis technology have an efficiency of 50%–70%, whilst advanced technologies such as proton exchange membrane (PEM) electrolysers have an efficiency of 80%. Although the solid oxide electrolyser cell (SOEC) is not yet commercialised, it is anticipated to achieve an efficiency exceeding 90%. These trends suggest that ongoing technology development will likely lead to the commercialisation of SOEC electrolysers.

As a carrier, liquid H_2 has advantages in long-distance and large-volume transport. In the East Asia Summit region, China, Japan, and the Republic of Korea are predicted to emerge as big H_2 importers, whilst Australia, India, Indonesia, and Sarawak (Malaysia) are anticipated to be significant H_2 exporters. Liquid H_2 tankers are essential to establish a v supply chain network. Reducing costs associated with liquid H_2 transport, particularly in liquefaction, will be crucial.

We aim to identify the most efficient way to transport H_2 from exporting to importing countries using a linear programming model. The results indicate that China will import H_2 from Brunei Darussalam, Sarawak (Malaysia), and Viet Nam. Japan will source from Indonesia and Australia, whilst Korea will import from Indonesia, the Philippines, Viet Nam, and India. Singapore's imports will be from India (not Sarawak [Malaysia]) and Thailand will import from India (not Brunei Darussalam). If Singapore and Thailand opt to import H_2 from the nearest countries, such as Brunei Darussalam and Sarawak (Malaysia), their total H_2 transport cost would increase by 1.1% compared with the optimal results. Based on optimal H_2 transport results, we use a dynamic model to simulate transport from exporting to importing countries using H_2 tankers. According to the model, v-importing countries will need more than 70 tankers, each equipped with 12 storage tanks. Total capital costs for the tankers and storage tanks are estimated at US$36 billion, or a H_2 transport cost of US$0.036 per normal cubic metre.

The H_2 supply chain network will attract large investments and create jobs during construction and operation. The network will significantly reduce carbon dioxide (CO_2) emissions as H_2 is increasingly used across various sectors. However, in the initial stages of constructing the network, government subsidies will be needed to start H_2 supply (production and transport) and demand (consumption) projects.

Chapter 1

Economic and Social Impacts of Hydrogen Supply Chains in the East Asia Summit Region

1. Introduction

The Association of Southeast Asian Nations (ASEAN) Plan of Action for Energy Cooperation (APAEC) 2016–2025, Phase II (2021–2025) has set new targets for renewable energy. By 2025, the goal is to achieve 23% of total primary energy and 35% of total installed power generation capacity. APAEC Phase II highlights the role of hydrogen (H_2) and fuel cells in the low-carbon energy transition.

In 2021, the ASEAN Centre for Energy (2021) published its first policy research report: *Hydrogen in ASEAN – Economic Prospects, Development and Applications*. A three-phase road map for H_2 energy in ASEAN was proposed:

- Phase I (2020–2025). Countries with advantages in fossil fuel resources and existing infrastructure, such as gas pipelines and liquefied natural gas liquefaction plants, could consider developing capacities to produce and export grey H_2.
- Phase II (2026–2030). After capacity and infrastructure are built for grey H_2 production, shift to blue H_2 production and exports with the help of carbon capture and storage (CCS) or to carbon capture, utilisation, and storage (CCUS) if enhanced oil recovery opportunities exist.
- Phase III (2030 onwards). Green H_2 begins to dominate the scene and be used for domestic downstream energy applications and for export, facilitated by H_2 infrastructure in ASEAN Member States established during the previous two phases of H_2 export.

In formulating their climate change mitigation actions, European countries, the United States (US), Japan, and Korea have all made H_2 -related technologies and H_2 sourced from clean energy a pillar in their energy road maps and strategies (Li and Phoumin, 2022). The ongoing Russia–Ukraine conflict will push the world, especially Europe, to accelerate the development of low-carbon H_2 energy (European Commission, 2022). China is increasingly emphasising H_2 energy as a pillar of carbon neutrality (Li et al., 2022). As early as 2018, Australia announced its national H_2 road map (Bruce et al., 2018). New Zealand and India are working on their national H_2 road maps.

H_2 energy trade has been initiated within the East Asia Summit (EAS) region between Australia and Japan and between Brunei Darussalam and Japan. As of 2022, China had developed several large-scale green H_2 production projects, with an annual production capacity of 10,000–30,000 tonnes, especially in the north and northwest. Li and Tan (2021) explored the possibility of future H_2 energy trade between China, Mongolia, and other EAS countries. Australia, Brunei Darussalam, Malaysia, Indonesia, and New Zealand are the main suppliers of green and blue H_2 in the region (Economic Research Institute for ASEAN and East Asia [ERIA], 2022).

Given the accelerating development of the new energy sector, the study aims to provide policymakers with insights into the economic and social impacts associated with the establishment of H_2 energy supply chains. The study will do the following:

- Assess the fiscal impacts of developing H_2 energy supply chains, including H_2 in its various forms (gas and liquid), and its related transport and delivery pathways, such as liquid H_2 and liquid organic H_2 carriers such as methylcyclohexane.
- Estimate the scale of infrastructure investment required to develop H_2 energy supply chains, and the implications for direct job creation.
- Focus on environmental impact, particularly the reduction of carbon emissions enabled by H_2 energy, especially its applications in road transport and industry.
- Explore the implications for energy security.

The rest of the chapter is organised as follows. Section 2 reviews the literature on the economic and social impacts of H_2 supply chain and existing studies on H_2 energy development in the EAS region. Section 3 presents our methodology and main models. Section 4 summarises the input data. Section 5 discusses the results of our analysis. Section 6 concludes and presents policy implications.

2. Relevant Studies

The economic and social impacts of H_2 energy have been intensively discussed, focusing on developed economies such as the US, Canada, European countries, and Japan. Academic papers and research reports have explored the effects on investment, employment, economic output, and the fiscal burden of subsidies. However, studies, especially quantitative ones, on Asian economies, except for Japan and Korea, have been scarce.

2.1. Impacts on Investment and Employment

Wietschel et al. (2006) estimated the infrastructure investment required to develop a H_2 supply chain in 25 European Union countries. Total investment by 2030 amounts to 0.3% of the countries' gross domestic product (GDP). Köhler et al. (2010) applied an Assessment of Transport Strategies (ASTRA) model to the H_2 energy sector in Germany and found that it led to increased GDP, employment, and investment, and to growth in the electronics, chemical, mechanical, and automotive industries, amongst others.

The Argonne National Laboratory has developed an Excel-based JOBS H2 model to analyse jobs created, economic output, and earnings of H_2 refueling stations and their H_2 supply chain in California (Mintz et al., 2014). The study estimated that 90–330 jobs per year would be created by new H_2 refueling stations, whilst up to 1,120 jobs would be created to operate and maintain a total of 28 stations by 2023. A similar Excel-based JOBS FC model was also developed to analyse employment, economic output, and earnings derived from fuel cell applications for forklifts, telecommunication backup power, and prime power replacement in the US (Mintz et al., 2013).

Leguijt et al. (2021) presented a H_2 demand-driven model to estimate the job creation effects in the Netherlands, applying the employment factor approach. Demand for labour was split into two components: labour associated with investment in the supply chain and labour required to operate and maintain the supply chain. With projected demand for green H_2 reaching 2.11–4.93 million tonnes by 2050, the total one-off full-time equivalent jobs created would be 2,200–20,000 per year, whilst the total recurring full-time equivalent jobs created would be 14,200–72,600 per year. The estimate of one-off jobs considers only construction and installation and not manufacturing of equipment and materials.

The Government of Australia (2021) estimated that by 2050, clean H_2 exports could directly support 16,000 jobs and 13,000 more jobs from related construction work. The production of Australian H_2 for export and domestic use could generate more than US$50 billion in additional GDP by 2050.

2.2. Impacts on Fiscal Burden

Subsidies needed in the early stage of developing H_2 energy remain a heated issue. Through an environmental lens, the underpricing of pollution can be considered a market failure, which subsidies to H_2 technology are attempting to address. Some studies argued that directly pricing pollution would better tackle this failure. However, in certain circumstances, subsidising cleaner technologies is politically easier than raising taxes on polluting ones (Bridle and Beedell, 2021). Shasmi et al. (2021) argued that the corresponding economic value of carbon emission reduction resulting from the use of H_2 energy could be calculated by assuming a social cost of carbon dioxide (CO_2), such as current prices in a carbon emission trading scheme, to compensate for the positive externality of H_2 energy.

When considering technology diffusion and supply chain development, the government must provide specific financial incentives, such as subsidies and tax credits, not only to reduce the high costs at the early stage of development but also to mitigate the perceived risks of the investment involved (Trencher et al. 2020). Li et al. (2021) showed that government support for early investment in H_2 infrastructure could drastically accelerate the market penetration of H_2 energy and fuel cell technologies. Köhler et al. (2010)

indicated that some €200 million is needed to support the buildup of 500 H_2 refueling stations in urban areas, and €100 million more is needed to support the H_2 refueling stations along highways in Germany. However, subsidies aimed at boosting technological progress, technology adoption, and the early stages of the industry should be phased out at the appropriate time (Tibebu et al., 2022).

2.3. Impacts on the Environment and Energy Security

Shamsi et al. (2021) presented a macro simulation model to estimate the environmental and health costs avoided by the introduction of H_2 energy, especially in road transport in Canada. It was estimated that 1 kilogramme (kg) of H_2 energy used in road transport could reduce 11.09 kg of CO_2.

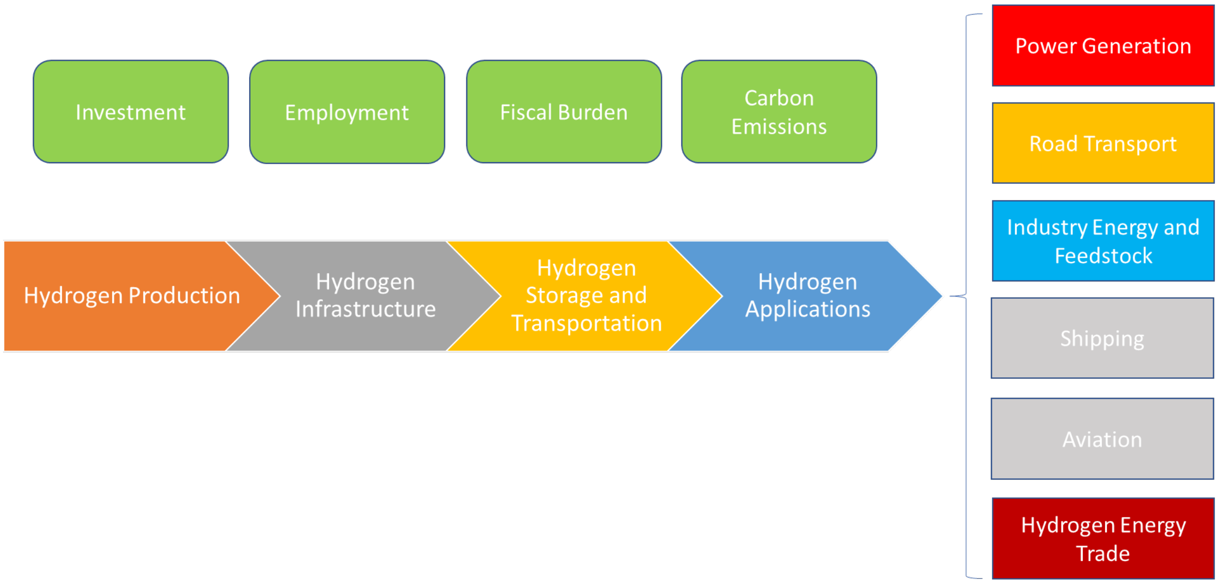
Razi and Dincer (2022) argued that green H_2 is essential for environmental preservation and energy security. Green H_2 serves as an energy storage solution for renewables, decarbonises key industries, replaces fossil fuels in transport, and blends with or replaces natural gas. Using the cases of China and Denmark, Ren et al. (2014) explored how developing H_2 pathways could impact the six dimensions of energy security. Al-Mufachi and Shah (2022) proposed that H_2 and fuel cells could decarbonise heat, thereby strengthening the energy security of countries such as the United Kingdom, which experience significant heat demand from industries and households. As H_2 replaces fossil fuels in power generation and transport, it helps reduce fossil fuel subsidies in certain countries.

The study aims to comprehensively and quantitatively analyse the economic and social impacts of developing H_2 energy in the ASEAN and EAS regions, especially the effects on investment, employment, carbon emissions, fiscal subsidies, and energy security.

3. Methodology and Models

Figure 1.1 presents the scope of the study, focusing on the H_2 supply chain to be developed in EAS countries, including ASEAN countries, by 2040. The scope includes examining H_2 production facilities; the infrastructure for transport, storage, and delivery of H_2; and the infrastructure for downstream application of H_2 energy. In estimating the carbon emission reduction effects of H_2 energy, the study focuses only on downstream applications, including power generation, road transport, industrial energy and feedstock uses, and international H_2 energy trade. Notably, applications of H_2 as fuel for shipping and aviation are excluded due to uncertainties regarding the adoption timeline of corresponding technologies and the lack of valid data in the literature.

Figure 1.1. Scope of the Study

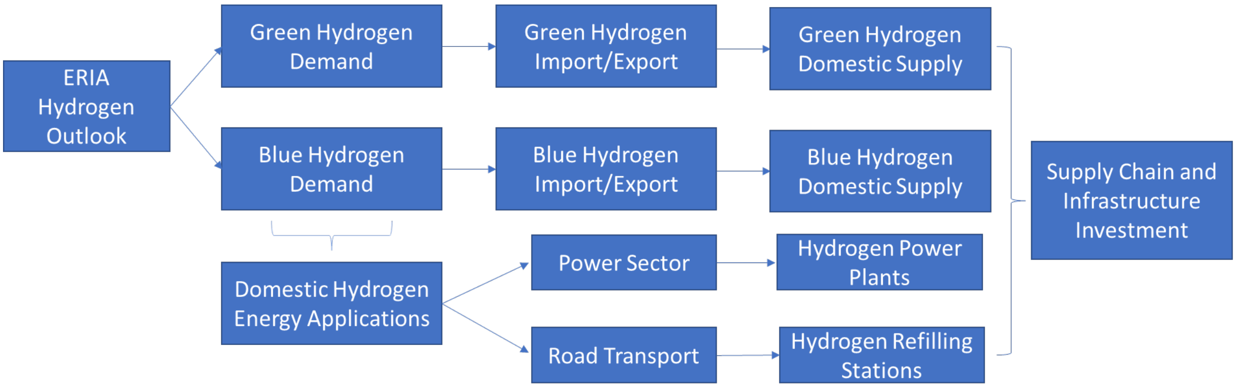


Sourc: Authors.

The analysis focuses on direct impacts of the development of H_2 energy infrastructure, the supply chain of H_2 energy, and the application of H_2 energy across various sectors. The analysis examines the effects on investment, fiscal subsidies, job creation, and carbon emission reduction.

The model is driven by H_2 demand (Figure 1.2). Domestic production and international trade of H_2 to meet the demand provide the basis for estimating the scale of the supply chain, from production to transport and storage, and eventually to delivery. The study covers H_2 infrastructure that connects the supply of H_2 to its downstream uses, such as H_2 power generation and v refilling stations. The study estimates the investment needed to build the supply chain system, along with the costs of the operation and maintenance of the system.

Figure 1.2. Demand-driven Model of Hydrogen Supply Chain and Infrastructure



ERIA = Economic Research Institute for ASEAN and East Asia.
Source: Authors.

Labour demand involves one-time jobs to build the supply chain and recurring jobs to operate and maintain it (Leguijt et al., 2021). The estimation is derived by dividing the country's corresponding labour costs by the average labour wage.

However, this analysis excludes induced impacts, such as those from expenditures by individuals and households that earn income from H_2 -related industrial and commercial activities and subsequently re-spend it. The study does not consider job losses in the conventional energy sector and its related energy applications.

4. Data and Assumptions

The projected demand and production figures for H_2 are derived from the ERIA H_2 studies, specifically the three phases of *Demand and Supply Potential of Hydrogen Energy in East Asia* (ERIA, 2019, 2020, and 2022). The capital cost and operation and maintenance costs of the H_2 supply chain are based on ERIA (2020), the ASEAN Centre for Energy (2021), Li and Taghizadeh-Hesary (2022), and Li et al. (2023) on the economic feasibility of H_2 energy in ASEAN and EAS countries.

Table 1.1 presents estimations for the demand and supply potential of H_2 in the EAS region in 2040. Our study adopts the demand potential outlined in the previous ERIA study. However, when estimating H_2 production, our assumptions deviate from the original estimations in ERIA (2022). We have adapted our assumptions based on announced government policies and the trends in national energy policies, especially on the reliance on natural gas imports.

Table 1.1. Hydrogen-producing Potential from Unused Energies Compared with Hydrogen Demand Potential in the East Asia Summit Region in 2040
(million normal cubic metres)

	Production Potential		Demand Potential	Self-sufficiency Rate from Previous ERIA Study		Self-sufficiency Assumptions in the Study
	Max	Min		Max	Min	
Australia	21,502	7,169	13,974	154%	51%	154%
Brunei Darussalam	1	1	1,775	0%	0%	0%
Cambodia	5	1	352	1%	0%	100%
China	1,204	395	163,408	1%	0%	95%
India	1,057	352	11,990	9%	3%	100%
Indonesia	1,501	500	44,807	3%	1%	100%
Japan			29,252	0%	0%	5%
Korea, Republic of			41,558	0%	0%	76%
Lao PDR	13	3	9	137%	34%	137%
Malaysia	42	16	24,034	0%	0%	100%
Myanmar	49	12	1,263	4%	1%	100%
New Zealand	3,370	1,123	1,065	317%	106%	317%
Philippines	49	16	4,551	1%	0%	100%
Singapore			15,098	0%	0%	1%
Thailand	192	63	12,993	1%	0%	70%
Viet Nam	85	29	3,668	2%	1%	100%
Total	29,070	9,681	369,796	8%	3%	

ERIA = Economic Research Institute for ASEAN and East Asia, Lao PDR = Lao People's Democratic Republic.
Source: Authors, based on ERIA (2022).

The share of a country's green H_2 production is assumed to be driven by the share of renewable energy in the primary energy mix by 2040 (ERIA, 2021). Similarly, the share of blue H_2 production is determined by the share of fossil fuels in the primary energy mix. The share of each H_2 production pathway is assumed to follow the pattern of shares of primary energy mix in 2040 (ERIA, 2021). To determine the corresponding share of solar and wind energy within the total renewable energy, we refer to the International Renewable Energy Agency (2020). The imports and exports of H_2 are assumed to follow ERIA (2020) estimations.

The estimation of the share of labour cost in total capital expenditure (CAPEX) and operational expenditure (OPEX) relies on data from the H2A models of the National Renewable Energy Laboratory, with labour wage data obtained from the International Labour Organization.

Subsidy rates are based on various sources of information, including government policy statements, research reports, and academic literature. All subsidy rates are assumed to decrease linearly until they are phased out by 2030.

Carbon emission reduction coefficients for H_2 applications in different sectors are obtained from the academic literature (Table 1.2). This study considers H_2 as energy storage for renewables only and power generation using green H_2 functions as peak generation. We do not assume that blue H_2 will be used to generate power, as it has low efficiency and uses fossil fuels. The application of green H_2 in the power sector does not reduce carbon emissions.

Table 1.2. Carbon Emission-reduction Coefficients of Hydrogen Energy Applied in Various Sectors

	Road Transport		Chemical Industry			Steel Manufacturing
	Gasoline Replacement (kg CO_2/kg H_2)	Diesel Replacement (kg CO_2/kg H_2)	Grey H_2 Replacement (NG) (kg CO_2/kg H_2)	Grey H_2 Replacement (Coal) (kg CO_2/kg H_2)	Gray Ammonia Replacement (kg CO_2/kg H_2 used in producing ammonia)	Replacing Coal (kg CO_2 per kg of H_2 used in DRI for steel)
Green Hydrogen	20.2	7.5	13	25	11.8	25.0
Blue Hydrogen	19.9	7.0	12.5	24.5	10.7	24

CO_2 = carbon dioxide, DRI = direct reduced iron, H_2 = hydrogen, kg = kilogramme, NG = natural gas.
Source: Authors, based on Li et al. (2023), Liu et al. (2020), Bhat and Garcia (2021), Yan et al. (2023), and Bhaskar et al. (2020).

Due to the lack of information to project the share of H_2 transport, storage, and delivery pathways in each country, the authors have arbitrarily assumed the shares to be the same across countries. A similar approach is adopted in projecting the share of H_2 energy uses in different downstream sectors (25% in transport, 15% in power generation, and 60% in industry). To some extent, the approach allows better comparability of results across countries. The model can be updated when better information becomes available.

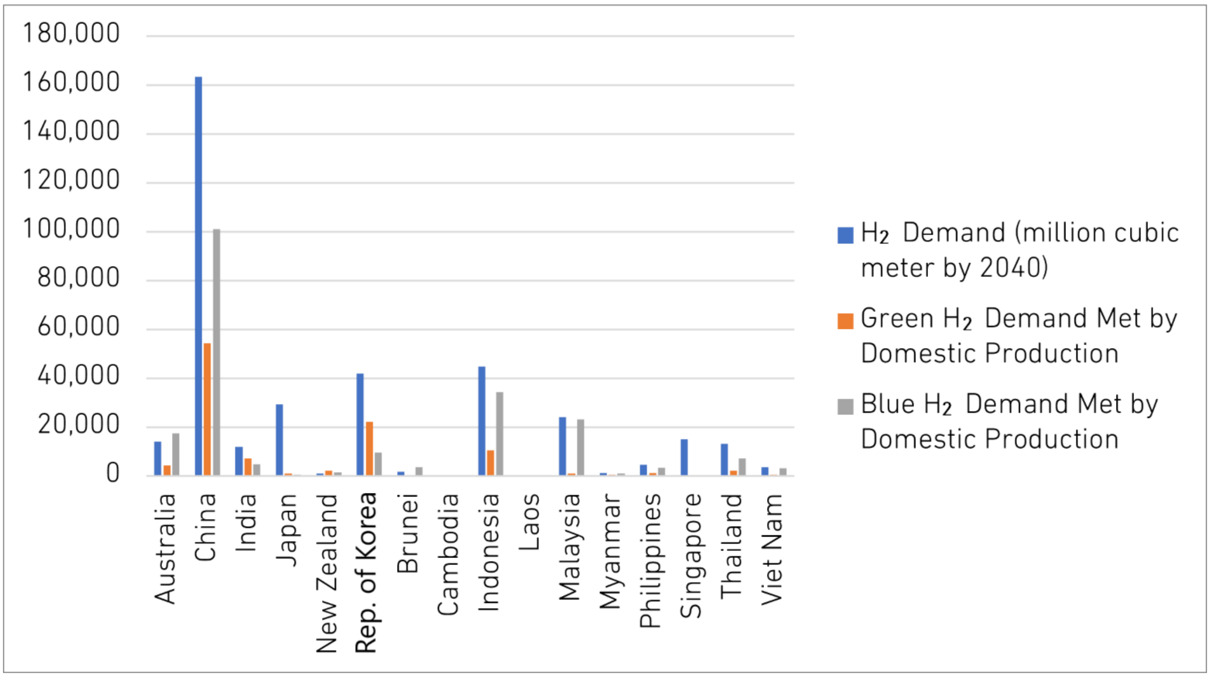
Estimations of the impacts of H_2 energy on energy supply security assume that v replaces imported and indigenously produced fossil fuels, according to the current share of imports and indigenous production in each country.

5. Analytical Results

5.1. Hydrogen Demand

By 2040, demand for H_2 energy is projected to be met by green and blue H_2, based on the share of fossil fuels and renewable energy anticipated in the ERIA energy outlook (Figure 1.3). In some countries, the total share of green and blue H_2 appears to be higher or lower than the total demand for H_2 energy due to projected H_2 exports or imports.

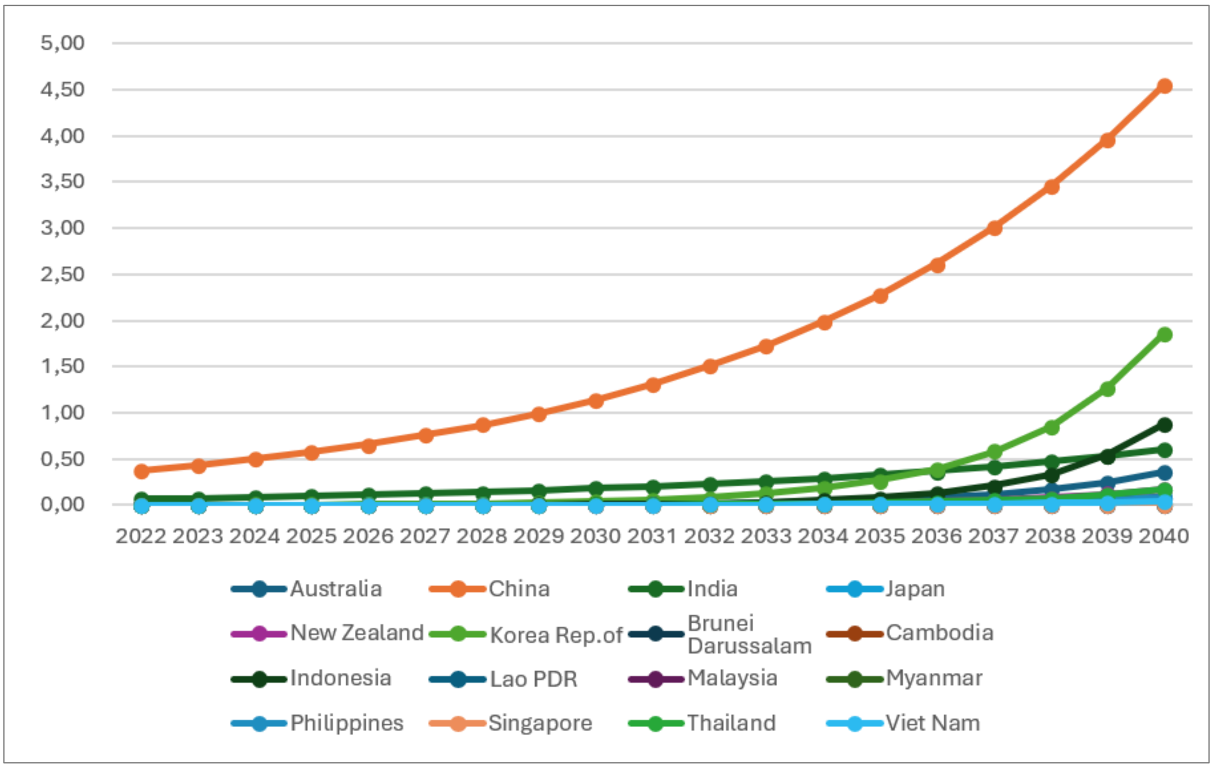
Figure 1.3. Hydrogen Demand of East Asia Summit Countries in 2040
(million cubic metres)



H_2 = hydrogen, Lao PDR = Lao People's Democratic Republic.
Source: Authors.

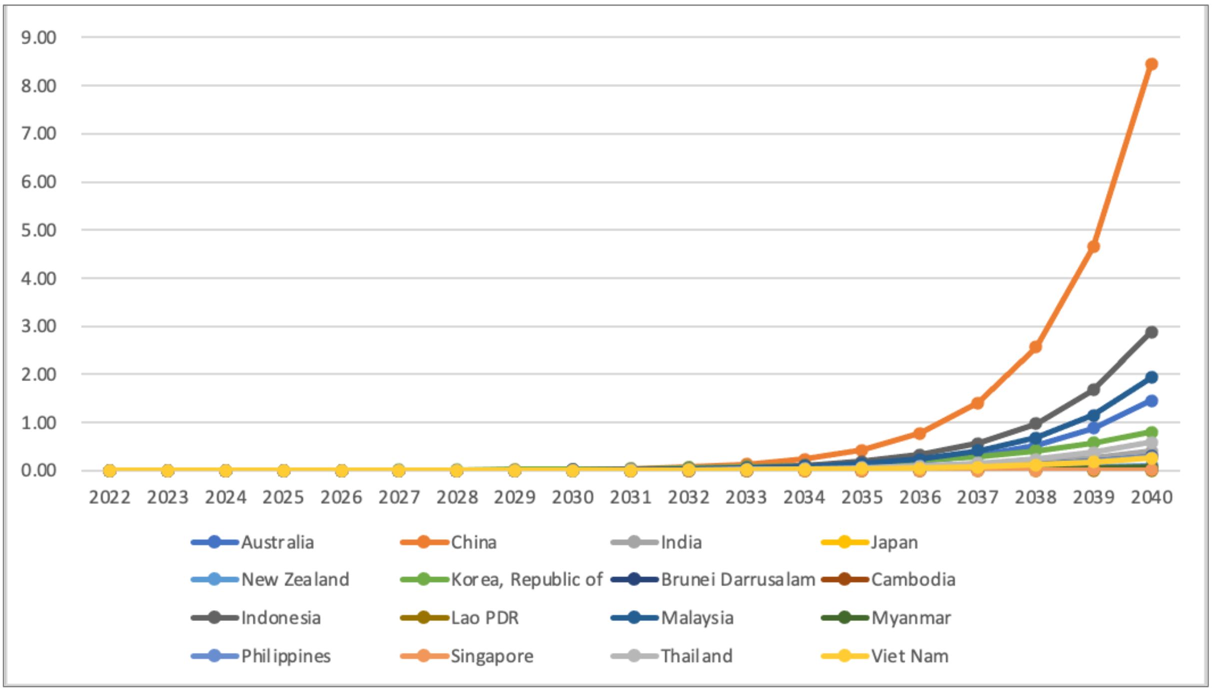
Until 2040, exponential growth is assumed for green and blue H_2 (Figures 1.4 and 1.5). Such trends have been typically observed in the development of renewable energy in the past few decades. By 2040, the production of blue H_2 is projected to be almost double that of green H_2.

Figure 1.4. Green Hydrogen Production Outlook by Country
(million tonnes)



Lao PDR =Lao People's Democratic Republic.
Source: Authors.

Figure 1.5. Blue Hydrogen Production Outlook by Country
(million tonnes)

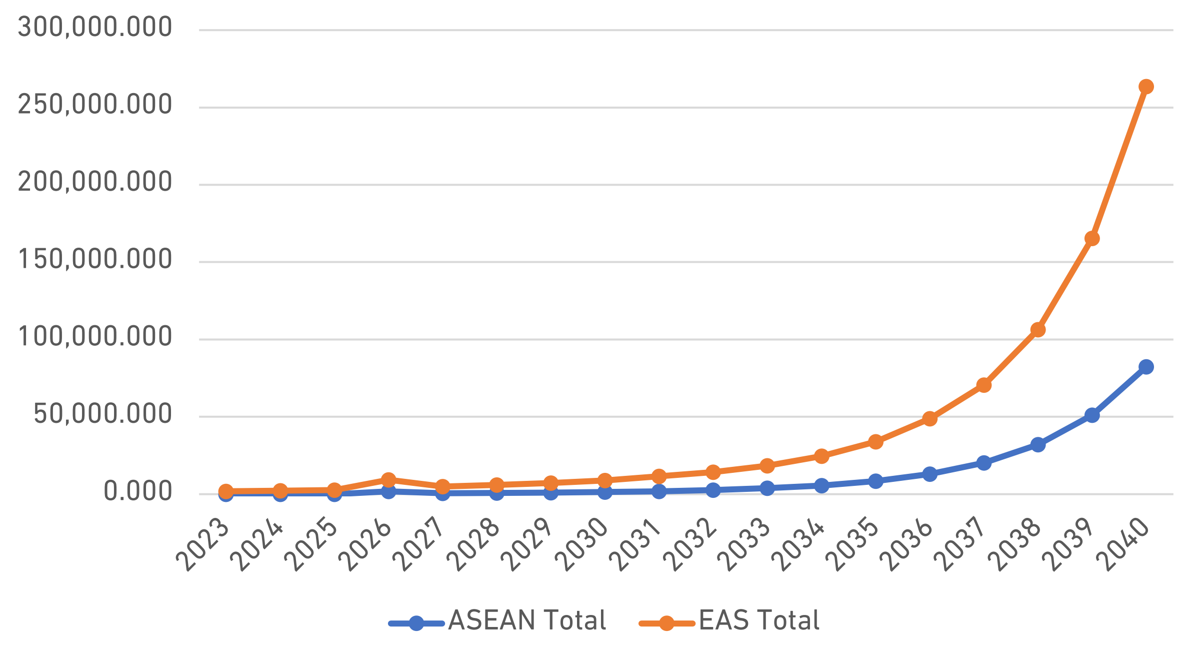


Lao PDR = Lao People's Democratic Republic.
Source: Authors.

5.2. Investment Costs

Figure 1.6 shows total capital investment in facilities and infrastructure of the H_2 supply chain in the ASEAN and EAS regions. In ASEAN, annual investment starts at some US$30 million in 2023 and expands to more than US$82 billion by 2040. In EAS, it starts at about US$1.9 billion and grows exponentially to more than US$263 billion by 2040.

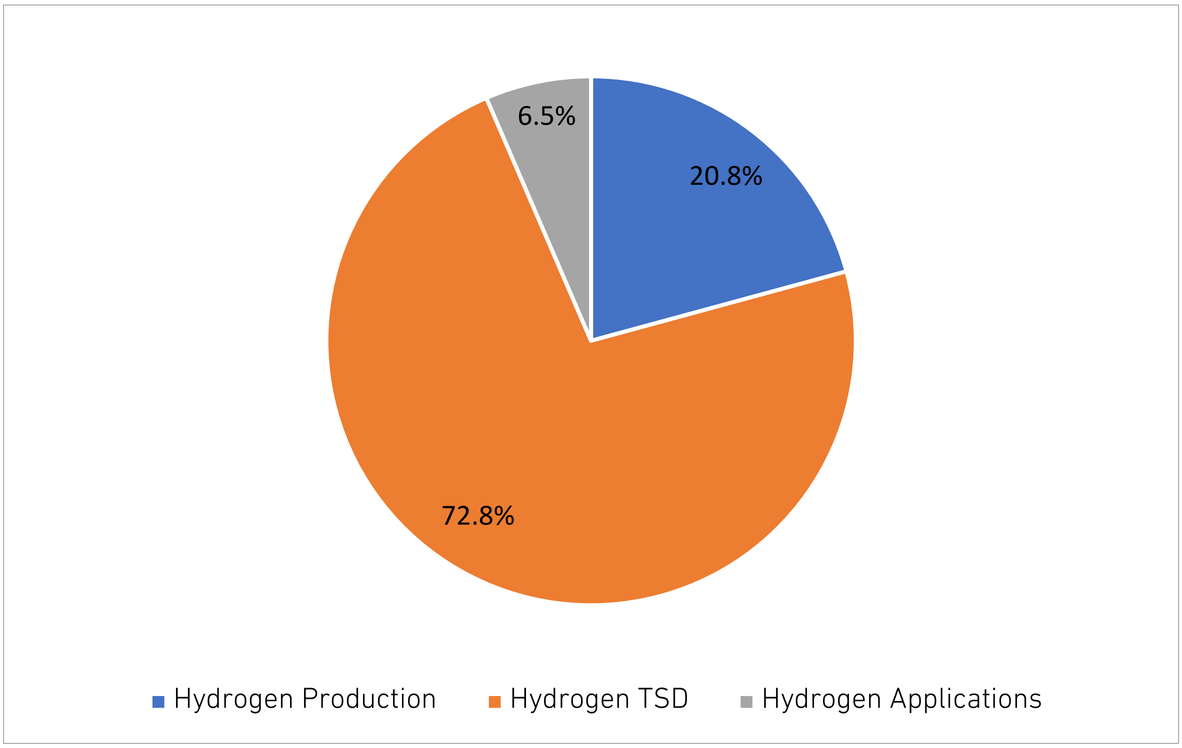
Figure 1.6. Capital Investment in the Hydrogen Supply Chain
(million US$)



ASEAN = Association of Southeast Asian Nations, EAS = East Asia Summit.
Source: Authors.

More than 70% of capital investment is allocated to infrastructure for the transport, storage, and delivery of H_2 (Figure 1.7). Roughly 21% goes to H_2 production facilities and the rest to investment in H_2 energy applications such as power generation and H_2 refilling stations. The total capital investment in 2040 in the EAS region amounts to US$263.5 billion in 2022 dollars. The projected EAS GDP by 2040 is US$81,474 billion in 2022 dollars. Thus, the investment in H_2 energy represents about 0.32% of EAS GDP in 2040. The investment required for H_2 energy appears to be affordable.

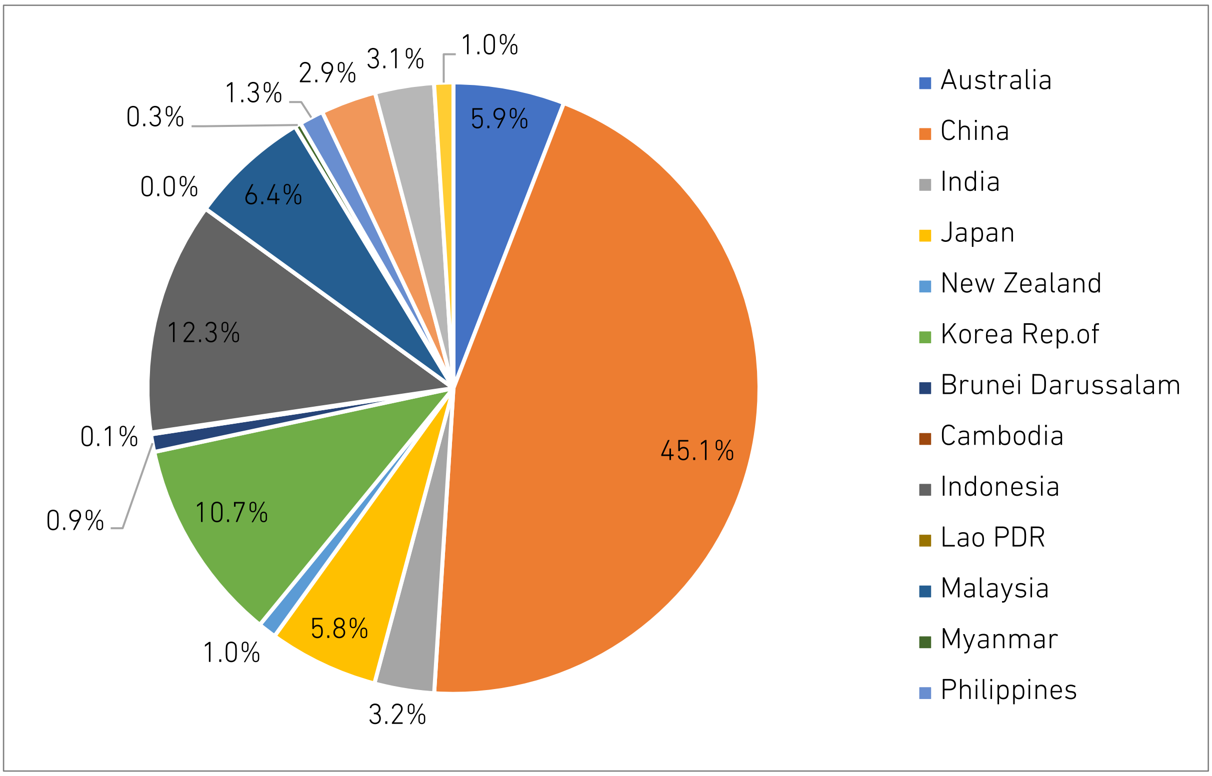
Figure 1.7. Hydrogen Infrastructure Investment by Type in the East Asia Summit Region, 2023–2040



TSD = transport, storage, and delivery.
Source: Authors.

China, Korea, and Japan represent more than 60% of all capital investment in H_2 energy in the EAS region (Figure 1.8). In the ASEAN region, Indonesia, Malaysia, Thailand, and Singapore appear to have substantial opportunities to invest in H_2 energy.

Figure 1.8. Hydrogen Infrastructure Investment by Country



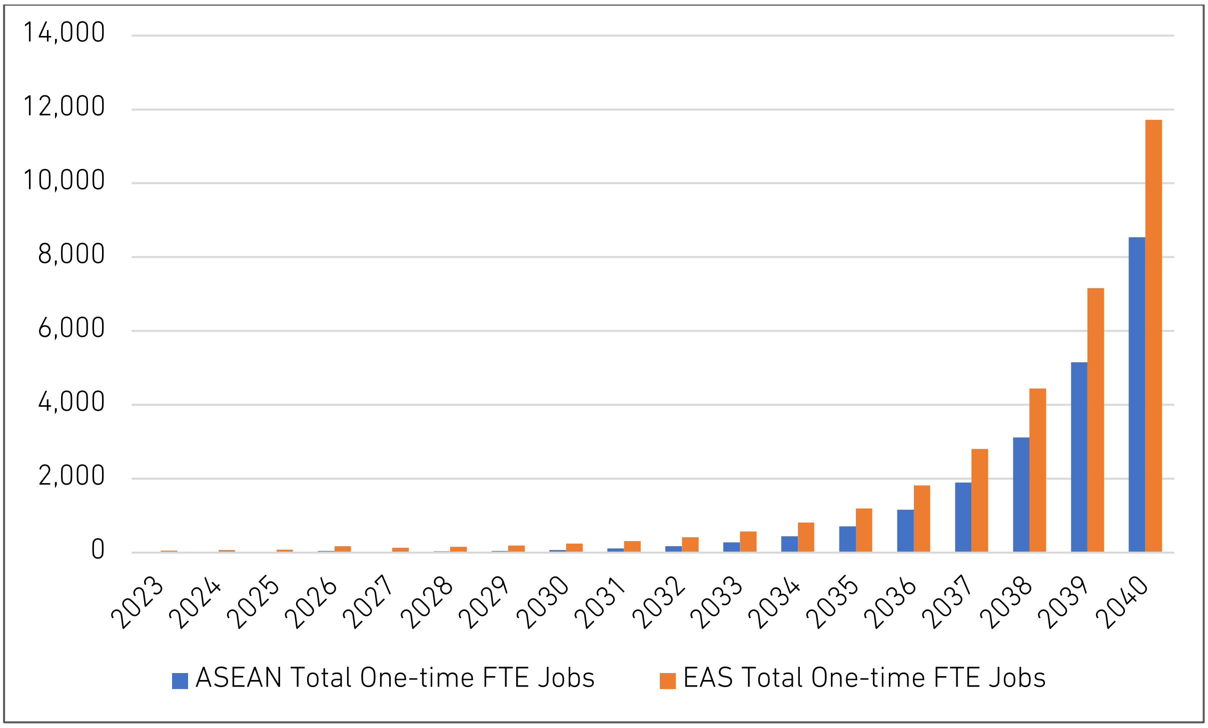
Lao PDR = Lao People's Democratic Republic.
Source: Authors.

5.3. Employment

The H_2 energy sector could create two types of jobs: one-time jobs related to construction of infrastructure and installation of facilities for the H_2 supply chain (Figure 1.9), and recurring jobs related to operation and maintenance of the H_2 supply chain (Figure 1.10). Both are estimated based on full-time equivalent (FTE) jobs.

Figure 1.9. Total One-time Full-time Equivalent Jobs Created by the Hydrogen Energy Sector in the Association of Southeast Asian Nations and the East Asia Summit Regions

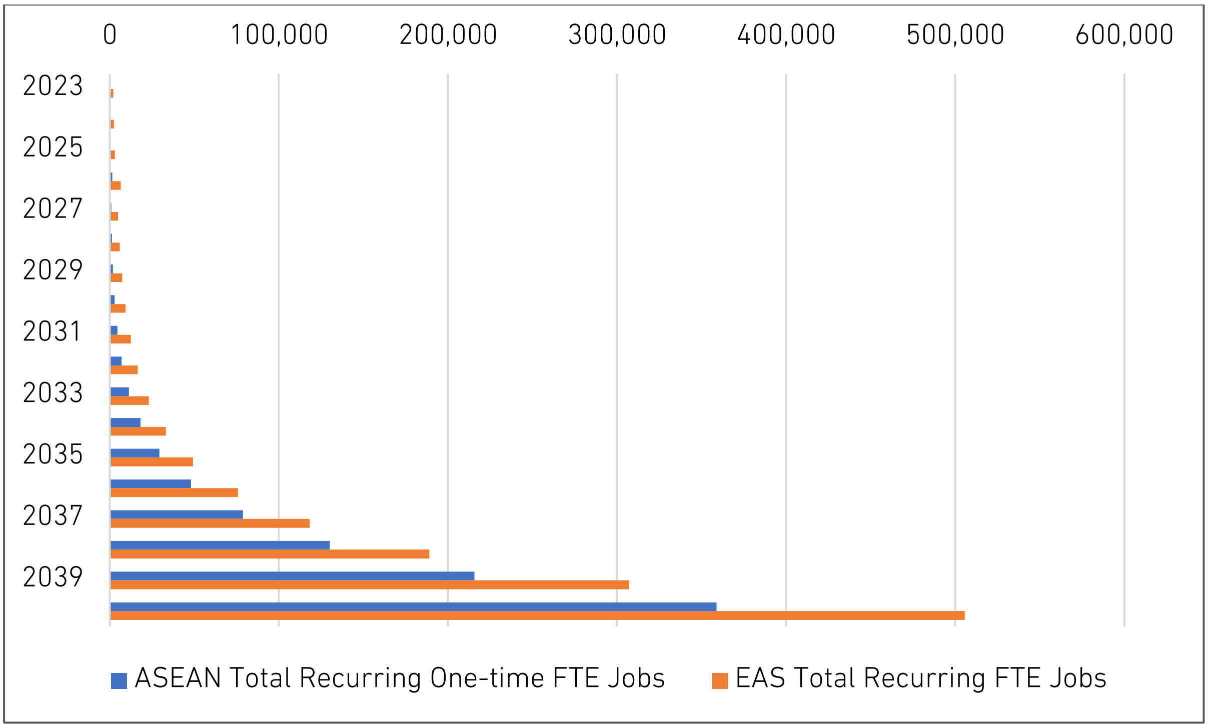
(thousands)



ASEAN = Association of Southeast Asian Nations, EAS = East Asia Summit, FTE = full-time equivalent.

Source: Authors.

Figure 1.10. Total Recurring Full-time Equivalent Jobs Created by the Hydrogen Energy Sector in the Association of Southeast Asian Nations and the East Asia Summit Regions



ASEAN = Association of Southeast Asian Nations, EAS = East Asia Summit, FTE = full-time equivalent.
Source: Authors.

In the EAS region, almost 12 million one-time FTE jobs could be created by 2040, and more than half a million recurring FTE jobs, with construction and installation requiring much more labour than the operation and maintenance of the H_2 supply chain. About 70% of H_2 energy jobs created in the EAS region go to ASEAN countries, despite non-ASEAN countries having much larger-scale H_2 energy, mainly because average wages are lower in ASEAN countries. Table 1.3 shows the two types of FTE jobs estimated in 2040 in each EAS country.

Table 1.3. One-time and Recurring Full-time Equivalent Jobs in 2040 in East Asia Summit Countries

Country	One-time FTE Jobs	Recurring FTE Jobs
Australia	91,192	3,675
China	2,258,883	107,713
India	554,442	25,146
Japan	77,984	2,842
New Zealand	15,268	577
Korea Rep. of	176,270	6,842
Brunei Darussalam	43,244	1,399
Cambodia	15,894	648
Indonesia	6,810,236	290,099
Lao PDR	262	10
Malaysia	681,623	26,599
Myanmar	117,684	4,256
Philippines	238,630	1,1210
Singapore	31,543	1,139
Thailand	398,365	14,534
Viet Nam	206,473	8,990.97

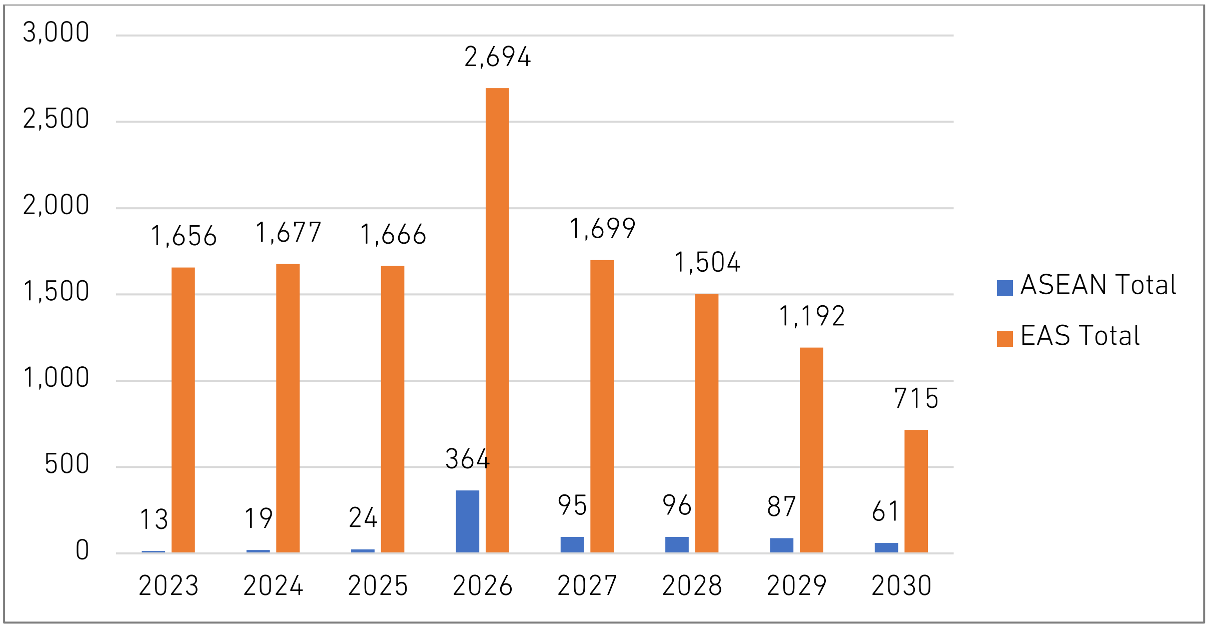
FTE = full-time equivalent, Lao PDR = Lao People's Democratic Republic.
Source: Authors.

5.4. Subsidies and Fiscal Burden

Subsidies are those allocated, depending on the announced policy of the country, to (i) H_2 production facilities (12%–30% of total CAPEX); (ii) H_2 transport, storage, and delivery infrastructure (30%–50% of total CAPEX); and (iii) H_2 energy production (US$1/kg–US$2.9/kg of H_2 produced). All subsidies are assumed to decrease linearly and to be phased out by 2030 (Figure 1.11). Most subsidies come from non-ASEAN EAS members.

Figure 1.11. Total Subsidies for the Hydrogen Supply Chain in the Association of Southeast Asian Nations and East Asia Summit Regions

(million US$)



ASEAN = Association of Southeast Asian Nations, EAS = East Asia Summit.
Source: Authors.

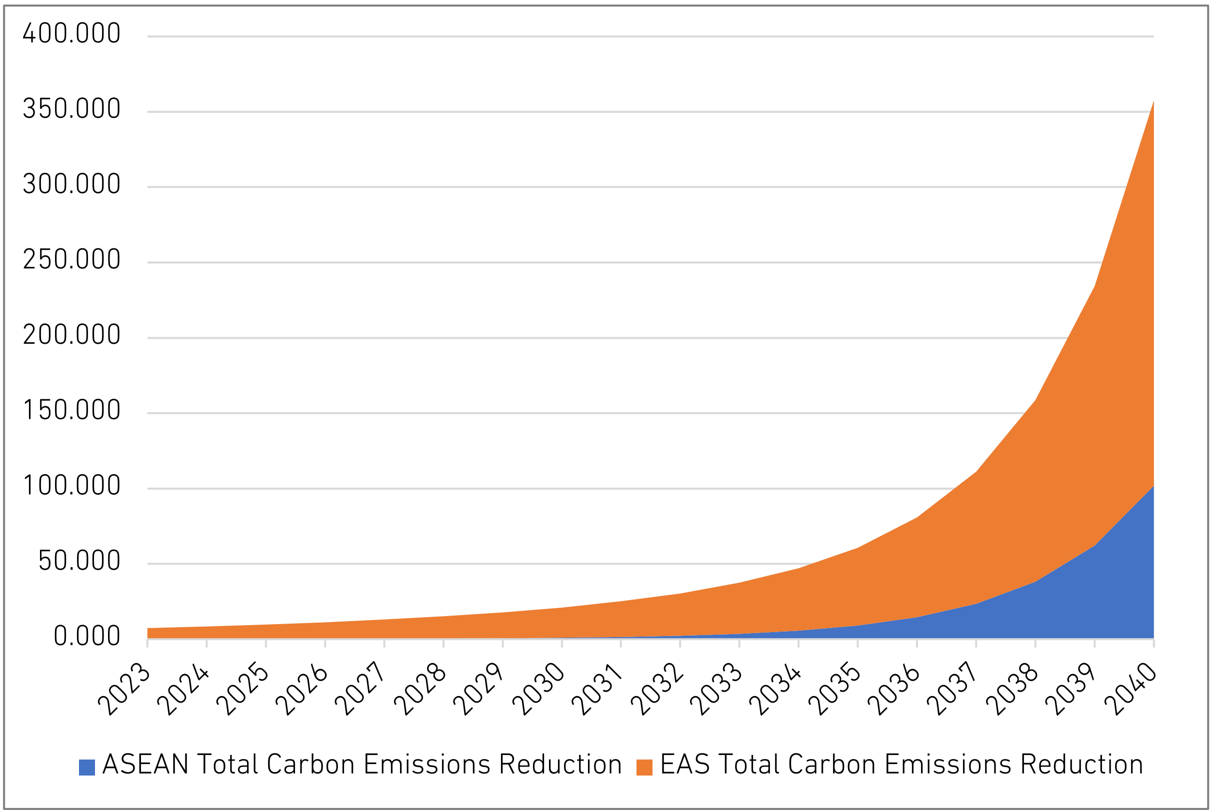
Total fiscal subsidies amount to US$12.8 billion in all EAS countries from 2023 to 2030, with ASEAN countries contributing US$759 million. According to World Bank data, the total nominal GDP of EAS countries in 2021 reached US$32,811 billion. Even without accounting for inflation, the fiscal subsidies to H_2 energy represent only 0.039% of GDP or 0.11% of government fiscal expenditure in the EAS region, based on the corresponding scale in 2021. The fiscal burden of subsidising H_2 energy should be in an acceptable range.

5.5. Carbon Emission Reduction

To ensure cross-country comparability of results and make the most of available data, the study assumes the same factors of carbon emission reduction by substituting conventional fuels with H_2 energy across the EAS countries (Table 1.2).

Figure 1.12. Association of Southeast Asian Nations and East Asia Summit Total Carbon Emission Reduction

(million tonnes)



ASEAN = Association of Southeast Asian Nations, EAS = East Asia Summit.

Source: Authors.

Carbon emissions could be reduced in the EAS region by some 358 million tonnes, 100 million tonnes more than in ASEAN countries (Figure 1.12). Applying the current European Emissions Trading System's carbon price of €85 per tonne, the economic value of carbon emission reduction in the EAS region in 2040 alone could reach more than €30 billion (about US$32 billion at US$1.06/€1.00). This figure is about 2.5 times the total fiscal subsidies (some US$12.8 billion) to support investment in and operation of the H_2 supply chain through early-stage development in 2023–2030.

5.6. Energy Security

The adoption of H_2 energy could significantly impact energy security, particularly in the context of green and blue H_2, as their production relies on a corresponding increase in the use of input energy or fuel. Following the 4As (availability, applicability, acceptability, and affordability) energy security framework (Li and Chang, 2019), three key indicators, mostly influenced by H_2 energy, have been selected: energy mix diversification, indigenous energy supply, and savings in fossil fuel imports.

Table 1.4. Impacts of Hydrogen Energy on Energy Security Indicators in East Asia Summit Countries

	Energy Mix Diversification	Indigenous Energy Supply (Self-sufficiency)	Savings in Fossil Fuel Imports
Australia	1.10%	1.44%	11.84%
China	0.46%	0.59%	2.30%
India	0.22%	0.14%	0.34%
Japan	0.11%	0.10%	0.24%
New Zealand	-0.52%	1.39%	6.23%
Korea, Rep. of	1.81%	4.08%	6.14%
Brunei Darussalam	-29.48%	0.00%	0.00%
Cambodia	-0.43%	0.44%	1.14%
Indonesia	0.34%	0.06%	0.56%
Lao PDR	18.37%	0.02%	0.06%
Malaysia	-0.18%	1.08%	0.54%
Myanmar	-0.01%	0.00%	0.00%
Philippines	0.22%	0.31%	1.74%
Singapore	-0.04%	0.02%	0.15%
Thailand	-2.79%	0.85%	1.61%
Viet Nam	0.04%	0.06%	0.23%

Lao PDR = Lao People's Democratic Republic.
Source: Authors.

Table 1.4 shows the following: (i) Positive changes in all three energy indicators are evident in 9 out of the 16 countries, indicating improvements in energy security. (ii) Negative changes occur only in the energy mix diversification indicator, specifically in Brunei Darussalam, Cambodia, Malaysia, Myanmar, Singapore, and Thailand. In these countries, the production of blue H_2 adds to the share of coal and natural gas, whilst the share of renewables remains insufficient. (iii) Indigenous energy production and savings in fossil fuel imports improve in all countries, except Brunei Darussalam and Myanmar, where the importation of fossil fuels is negligible.

6. Conclusions and Policy Implications

The study develops a demand-driven model for the H_2 energy supply chain in the EAS region, encompassing the ASEAN countries, Australia, China, India, Japan, Korea, and New Zealand. The model estimates necessary capital investment, number of jobs created, amount of reduction in carbon emissions, early-stage subsidies required, and impacts on key energy security indicators.

Based on the H_2 demand outlook and supply potential analysis in ERIA (2022), the production of green H_2 is projected at almost 9 million tonnes per year and of blue H_2 at almost 18 million tonnes per year by 2040 in the EAS region. Annual capital investment in the H_2 energy supply chain is forecast to reach more than US$263 billion by 2040 in the EAS region, with US$82 billion allocated to ASEAN. More than 70% of capital investment goes to infrastructure for H_2 transport, storage, and delivery. About 21% goes to H_2 production facilities, whilst the rest goes to investments in H_2 energy applications, such as power generation and H_2 refilling stations. Capital investment leaders in the EAS region include China, Korea, and Japan, whilst Indonesia, Malaysia, Thailand, and Singapore lead in ASEAN. The H_2 energy sector in the EAS region could create almost 12 million one-time FTE jobs by 2040 and more than half a million recurring FTE jobs. About 70% of jobs created in the EAS region's H_2 energy sector are attributed to ASEAN countries because of their lower average wages.

Such scales of capital investment and job creation would come at the cost of subsidies to be provided in the early stage of H_2 energy development. The study assumes that EAS countries need to subsidise the sector until 2030, with total fiscal subsidies amounting to US$12.8 billion across all EAS countries from 2023 to 2030. Of this sum, ASEAN countries contribute US$759 million. The total subsidies represent a mere 0.039% of EAS GDP, based on its 2021 scale, rendering the fiscal burden seemingly affordable.

The economic value of carbon emission reduction in 2040 alone would be 2.5 times the total fiscal subsidies required. The study estimates that about 358 million tonnes of carbon emissions could be reduced in the EAS region, 100 million tonnes more than in ASEAN countries. Applying the current European Emission Trading System (ETS) carbon price of €85/tonne, the economic value of the carbon emission reduction achieved in the EAS region in 2040 alone could reach more than €30 billion (about US$32 billion, at US$1.06/€1.00).

By introducing H_2 energy, most countries enjoy the benefits of better energy security. Improvements in indigenous energy supply and savings in fossil fuel imports are observed in all countries, except Brunei Darussalam and Myanmar, which remain energy self-sufficient. Whilst most countries diversify their energy mix, Brunei Darussalam, Cambodia, Malaysia, Myanmar, Singapore, and Thailand lag because blue H_2 production may intensify reliance on fossil fuels.

These results provide insights for policymaking:

(i) The substantial yet affordable capital investment required to develop H_2 energy is accompanied by a clear positive effect on job creation.
(ii) Supportive policies, including fiscal subsidies to develop the H_2 energy supply chain and downstream applications of H_2 energy, are necessary and affordable.
(iii) The substantial carbon emission reduction effect, the economic value of carbon emission reduction, and the positive impacts of H_2 energy on national energy security more than justify fiscal support, compensating for the positive externality of H_2 energy.
(iv) H_2 energy is recommended as a key pillar in the energy transition and for inclusion in the planning of national pathways to achieve carbon peak and carbon neutrality in member countries.
(v) Further research and development, economies of scale, and learning effects could help further reduce capital investment in the H_2 supply chain, especially in transport, storage, and delivery infrastructure.
(vi) International collaboration on optimising H_2 energy supply chains in the region could significantly reduce the costs of H_2 energy.

Chapter 2
Study on Energy Efficiency of Hydrogen Production

1. Introduction

Hydrogen (H_2) plays a key role in any industrialised society, being an essential component of many chemical processes. In 2020, global production of H_2 reached roughly 87 million tonnes, serving various uses such as oil refining, ammonia production (through the Haber process), methanol production (through carbon monoxide [CO] reduction), and as transport fuel. The H_2 generation market was expected to be valued at US$115.25 billion in 2017.

Using H_2 produced from unabated fossil fuels as an alternative to fossil fuels offers limited environmental benefits and, in many applications, can even lead to higher global emissions.

For H_2 to contribute significantly to the clean energy transition, it is critical to develop low-carbon H_2 production routes that can replace current production and, at the same time, expand production capacity to meet new demand.

2. Overview and Energy Efficiency Analysis of Hydrogen Production for Each Resource

Pure H_2 does not exist in nature but must be produced from resources such as natural gas, coal, and water. Synthesising H_2 requires energy. Ideally, the energy input equals the energy content of the synthetic gas. Whether through electrolysis, reforming, coal gasification, or other methods, H_2 production is a process of transforming energy – electrical energy or chemical energy from hydrocarbons – into chemical energy stored in H_2. Unfortunately, H_2 production is always associated with energy loss.

Four main resources drive commercial production of H_2: natural gas (accounting for 48% of the world's H_2 production), oil (30%), coal (18%), and electrolysis (4%). Fossil fuels are the dominant source of industrial H_2. Carbon dioxide can be separated from natural gas, with 70%–90% efficiency, for H_2 production, and from other hydrocarbons, with varying degrees of efficiency. Bulk H_2 is usually produced by steam reforming of methane or natural gas.

This chapter provides an overview of H_2 production methods and the efficiency of using natural gas, coal, and water electrolysis.

2.1. Reforming Technology for Natural Gas

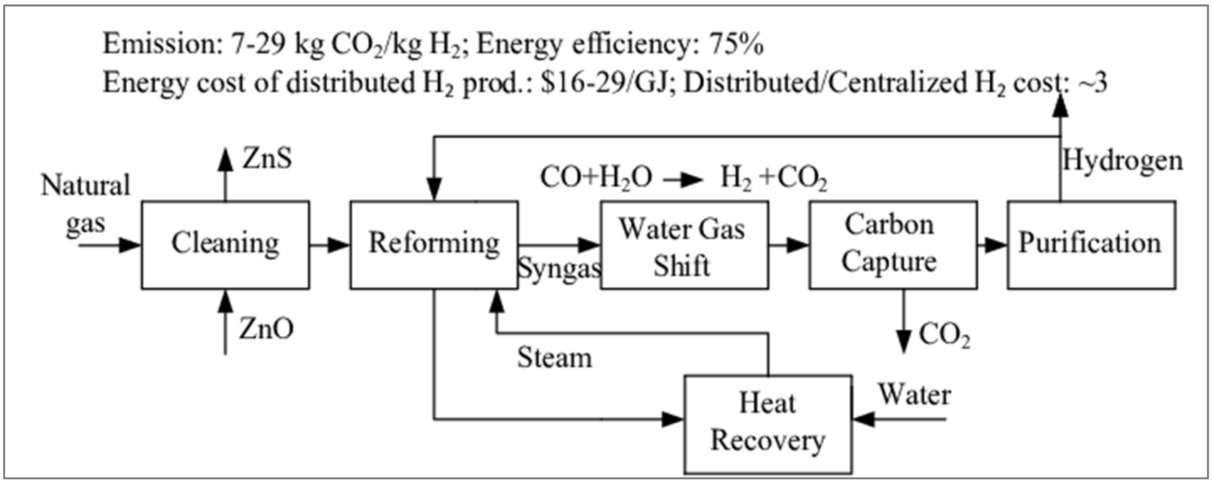
Conventional technologies, paired with carbon capture, utilisation, and storage (CCUS), are still the main methods of low-carbon H_2 production. They are likely to remain so in the short to medium term because their production costs are lower than those of other low-carbon technologies, such as water electrolysis. CCUS is attractive because it can reduce emissions from existing production capacity quickly through retrofits, enabling large-scale dispatchable H_2 production.

However, CCUS restricts the extent to which carbon emissions can be reduced, since high capture rates have associated economic penalties. It is impossible to eliminate 100% of CO_2 emissions generated in the process, as the best technologies available, yet to be demonstrated at scale, are limited to up to 97%–98% emission reductions. Upstream emissions impact the lifecycle footprint of H_2 produced from fossil fuels and CCUS.

Steam methane reforming (SMR) is a method of producing H_2 from natural gas, which is mostly methane (CH_4). It is the cheapest source of industrial H_2. Nearly 50% of the world's H_2 is produced using this method.

Figure 2.1 shows a flow diagram of H_2 production from natural gas (Matzen, 2015). However, to produce 1 kg of H_2, 7–29 kg of CO_2 is emitted. Thus, CCUS technology must be used, resulting in the further reduction of energy efficiency of the entire supply chain.

Figure 2.1. Hydrogen Production by Steam Reforming of Natural Gas



CO = carbon oxide, CO_2 = carbon dioxide, GJ = gigajoule, H_2 = hydrogen, H_2O = water, kg = kilogramme, ZnO = zinc oxide, ZnS = zinc sulfide.
Source: Matzen (2015).

Table 2.1 lists the world's large-scale projects producing H_2 from natural gas, as investigated by the International Energy Agency (IEA) (2021). Compared with processes using other resources, H_2 production using natural gas has extensive usage records and is inexpensive. The process is the most suitable for producing large amounts of H_2.

Table 2.1. Projects of Large-scale Hydrogen Production from Natural Gas

No	Project Name	Date Online	Status	Technology	Product	Announced Size	Nm^3-H_2/h	kt-H_2/y	t-CO_2 Capacity
1	Liberty South–Port Anthony		Concept	NG w CCUS	H_2	20 t H_2/d	93632.959	73.000	
2	Boryeong LNG Terminal	2025	Feasibility study	NG w CCUS	H_2	250 kt H_2/y	320660.818	250.000	1,200,000
3	H_2Teeside 1st phase	2027	Feasibility study	NG w CCUS	H_2	500MW - 1 million t CO_2/y	160112.360	124.830	1,000,000
4	H_2Teeside 2nd phase	2030	Feasibility study	NG w CCUS	H_2	1GW - 2 million t CO_2/y	160112.360	124.830	1,000,000
5	Sapio–Mantova	2016	Operational	NG w CCUS	H_2	1500 m3 H_2/h	1500.000	1.169	
6	Suncor Edmonton Refinery	2028	Feasibility study	NG w CCUS	H_2	300 kt H_2/y - 2Mt CO_2/y	384792.981	300.000	2,000,000
7	Project Jupiter (Gladstone)		Feasibility study	NG w CCUS	H_2	400t H_2/d	1872659.176	1460.000	
8	Keadby Hydrogen	2030	Feasibility study	NG w CCUS	H_2	1.2 GW	384269.663	299.592	
9	Pouakai–Taranaki–H_2	2024	Feasibility study	NG w CCUS	H_2	600t H_2/d	280898.876	219.000	
10	North Dakota Hydrogen Hub (former Great Plains Synfuel Plant)	2026	Feasibility study	NG w CCUS	H_2	310000t H_2/y	397619.414	310.000	

No	Project Name	Date Online	Status	Technology	Product	Announced Size	Nm^3-H_2/h	kt-H_2/y	t-CO_2 Capacity
11	H21 North of England	2035	Feasibility study	NG w CCUS	H_2	12.15GW H_2 - 20Mt CO_2/y	3890730.337	3033.369	20,000,000
12	Hynet Northwest, phase 1 (Essar Stanlow refinery)	2025	Feasibility study	NG w CCUS	H_2	3 TWh H_2/y	115437.894	90.000	828,657
13	Acorn Aberdeenshire	2024	Feasibility study	NG w CCUS	H_2	200MW - 0.4Mt CO_2/y	64044.944	49.932	400,000
14	H2morrow	2030	Concept	NG w CCUS	H_2	328000 m^3 H_2/h - 1.9Mt CO_2 captured	328000.000	255.722	1,900,000
15	Port Arthur	2013	Operational	NG w CCUS	H_2	1000000t CO_2/y - 151000m3 H_2/h	151000.000	117.726	1,000,000
16	Port Jerome	2015	Operational	NG w CCUS	H_2	100000t CO_2/y - 4500kg H_2/h	50000.000	38.982	100,000
17	Quest	2015	Operational	NG w CCUS	H_2	1000000t CO_2/y - 300 kt H_2/y		300.000	1,000,000
18	Air Products Net-Zero Hydrogen Energy Complex	2024	FID	NG w CCUS	H_2	1500t H_2/d - 3 Mt CO_2/y	667134.831	520.125	
19	H-Vision (phase 1)	2026	Feasibility study	NG w CCUS	H_2	900000t CO_2/y - 100 kt H_2/y	128264.327	100.000	900,000
20	H-Vision (phase 2)	2030	Feasibility study	NG w CCUS	H_2	2700000t CO_2/y - 300 kt H_2/y	256528.654	200.000	1,800,000
21	Hynet Northwest, phase 2	2030	Feasibility study	NG w CCUS	H_2	30 TWh H_2/y	1038941.050	810.000	6,995,124

No	Project Name	Date Online	Status	Technology	Product	Announced Size	Nm^3-H_2/h	kt-H_2/y	t-CO_2 Capacity
22	Hyundai Oilbank - Blue H_2 Ecosystem	2025	Feasibility study	NG w CCUS	H_2	100kt H_2/y	128264.327	100.000	

CCUS = carbon capture, utilisation, and storage; CO_2 = carbon dioxide; GW = gigawatt; H_2 = hydrogen; H_2/d = hydrogen per day; H2/h = hydrogen per hour; H_2/y = hydrogen per year; kg = kilogramme; Kt-H_2/y = kilotonnes hydrogen per year;M^3 = cubic metre; Mt = million tonnes; MW =megawatt; NG = natural gas; Nm^3-H_2/h = Normal cubic metre hydrogen per hour ; t-CO_2 = tonne-carbon dioxide; TWh H_2/y = terawatt hour hydrogen per year.
Source: International Energy Agency (2021).

2.1.1. Overview of Reforming Technology for Natural Gas

SMR is a method of producing H_2 from natural gas, which is mostly CH_4. It is the cheapest source of industrial H_2, contributing nearly 50% of the world's H_2 production. The process involves heating the gas to 700°C–1,100°C (1,292°F–2,012°F) in the presence of steam and a nickel catalyst. The resulting endothermic reaction breaks up the methane molecules and forms CO and molecular H_2. The CO gas can then be passed with steam over iron oxide or other oxides and undergo a water–gas shift reaction to obtain further quantities of H_2. The downside to the process lies in the major atmospheric release of carbon dioxide (CO_2), CO, and other greenhouse gases. Depending on the quality of the feedstock (natural gas, rich gases, naphtha, etc.), the production of one tonne of H_2 yields 9–12 tonnes of CO_2, a greenhouse gas that may be captured.

For this process, high-temperature steam (H_2O) reacts with CH_4 in an endothermic reaction to yield syngas:

$$CH_4 + H_2O \rightarrow CO + 3\ H_2$$

In the second stage, additional H_2 is generated through the lower-temperature, exothermic, water–gas shift reaction, performed at about 360°C (680°F):

$$CO + H_2O \rightarrow CO_2 + H_2$$

Essentially, the oxygen (O) atom is stripped from the additional water (steam) to oxidise CO to CO_2. The oxidation provides energy to maintain the reaction. Additional heat required to drive the process is generally supplied by burning some portion of the CH_4.

2.1.2. Energy Efficiency of Reforming Technology for Natural Gas

We referred to the International Energy Agency Greenhouse Gas R&D Programme (2017) to calculate the energy efficiency of H_2 production from natural gas.

This study evaluated the energy efficiency of a greenfield state-of-the-art SMR plant producing 100,000 Nm^3/hour of H_2 using natural gas as feedstock and fuel. The plant operates in a merchant plant mode, functioning as a standalone facility unintegrated into other processes within an industrial complex.

This study aims to access the following cases with and without carbon capture and storage (CCS):

(i) **Base case.** SMR plant equipped with feedstock pre-treatment, pre-reforming, high-temperature shift, and pressure swing adsorption (PSA) (Figure 2.2)
(ii) **Case 1A.** SMR with CO_2 capture from the shifted syngas using methyl diethanolamine (MDEA) (Figure 2.3)
(iii) **Case 1B.** SMR with burners firing H_2-rich fuel and CO_2 capture from the shifted syngas using MDEA (Figure 2.4)

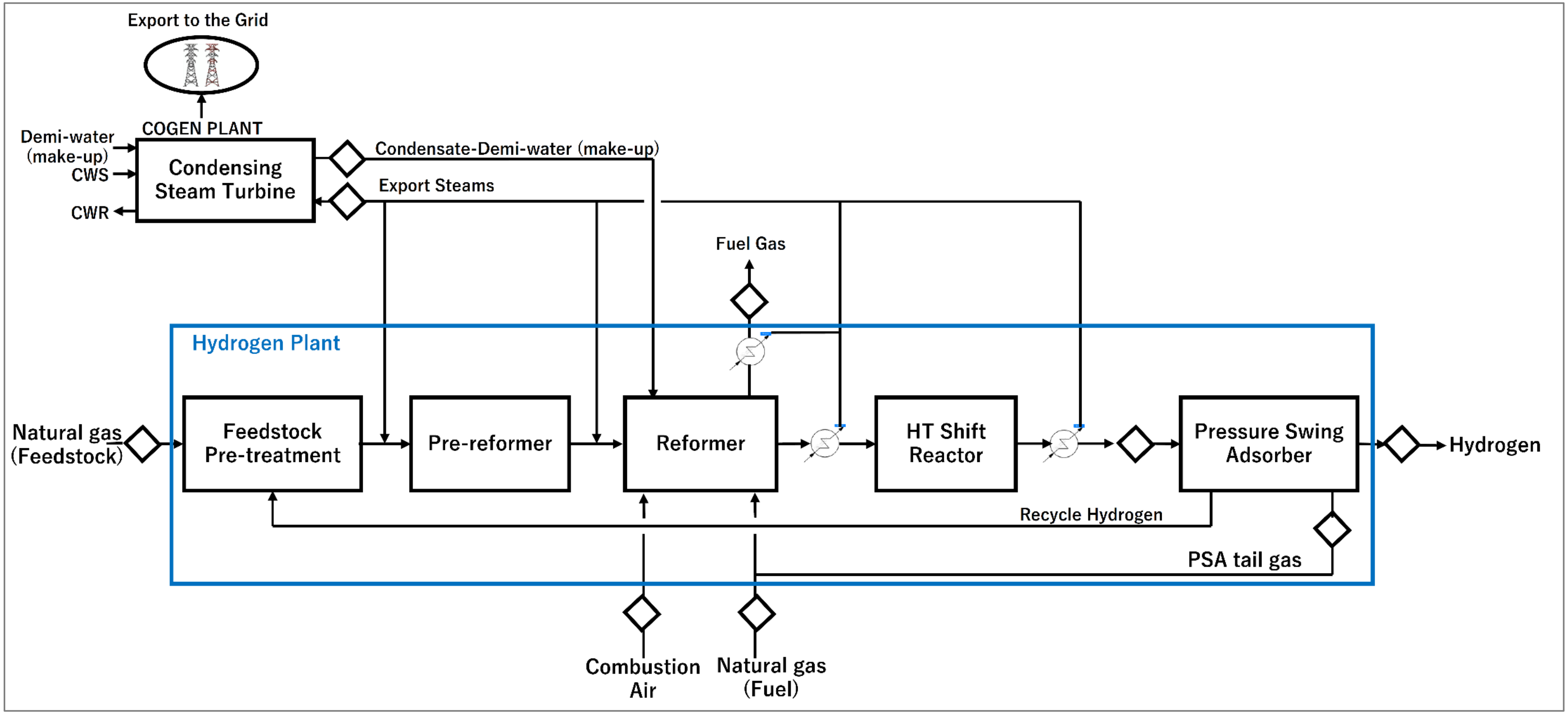
(iv) **Case 2A.** SMR with CO_2 capture from the PSA tail gas using MDEA (Figure 2.5)

(v) **Case 2B.** SMR with CO_2 capture from the PSA tail gas using cryogenics and membrane separation (Figure 2.6)

(vi) **Case 3.** SMR with CO_2 capture from the fuel gas using monoethanolamine (MEA) (Figure 2.7)

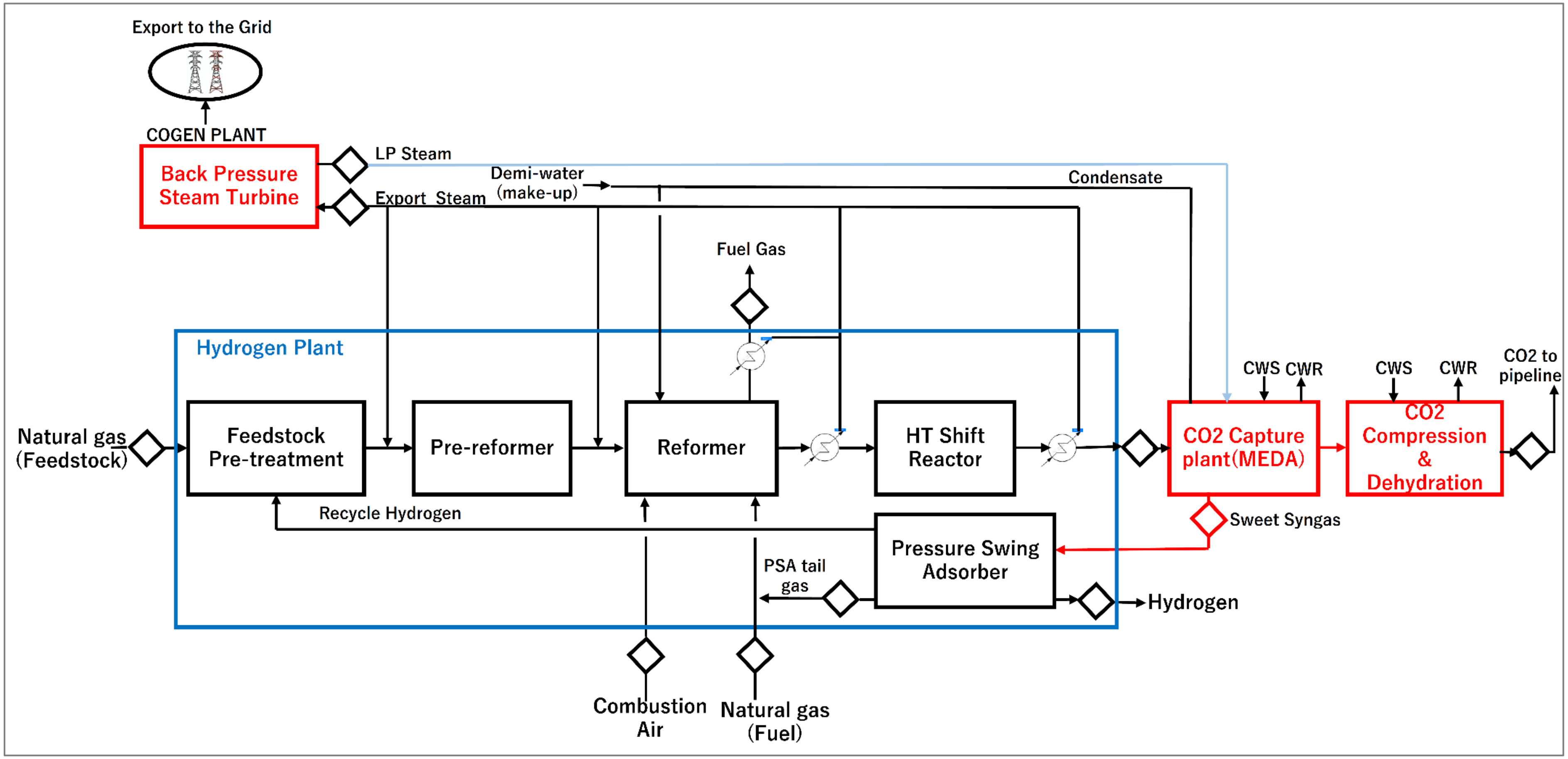
Figures 2.2–2.7 present a simplified block flow diagram, from the International Energy Agency Greenhouse Gas R&D Programme (2017), of the different cases of SMR plants evaluated in this study.

Figure 2.2. Base Case: Steam Methane Reforming Plant without Carbon Dioxide Capture, Producing 100,000 Normal Cubic Metres per Hour



COGEN = cogeneration, CWR = chilled water return, CWS = chilled water suppy, HT = high temperature, PSA = pressure swing adsorption.
Source: International Energy Agency Greenhouse Gas R&D Programme (2017).

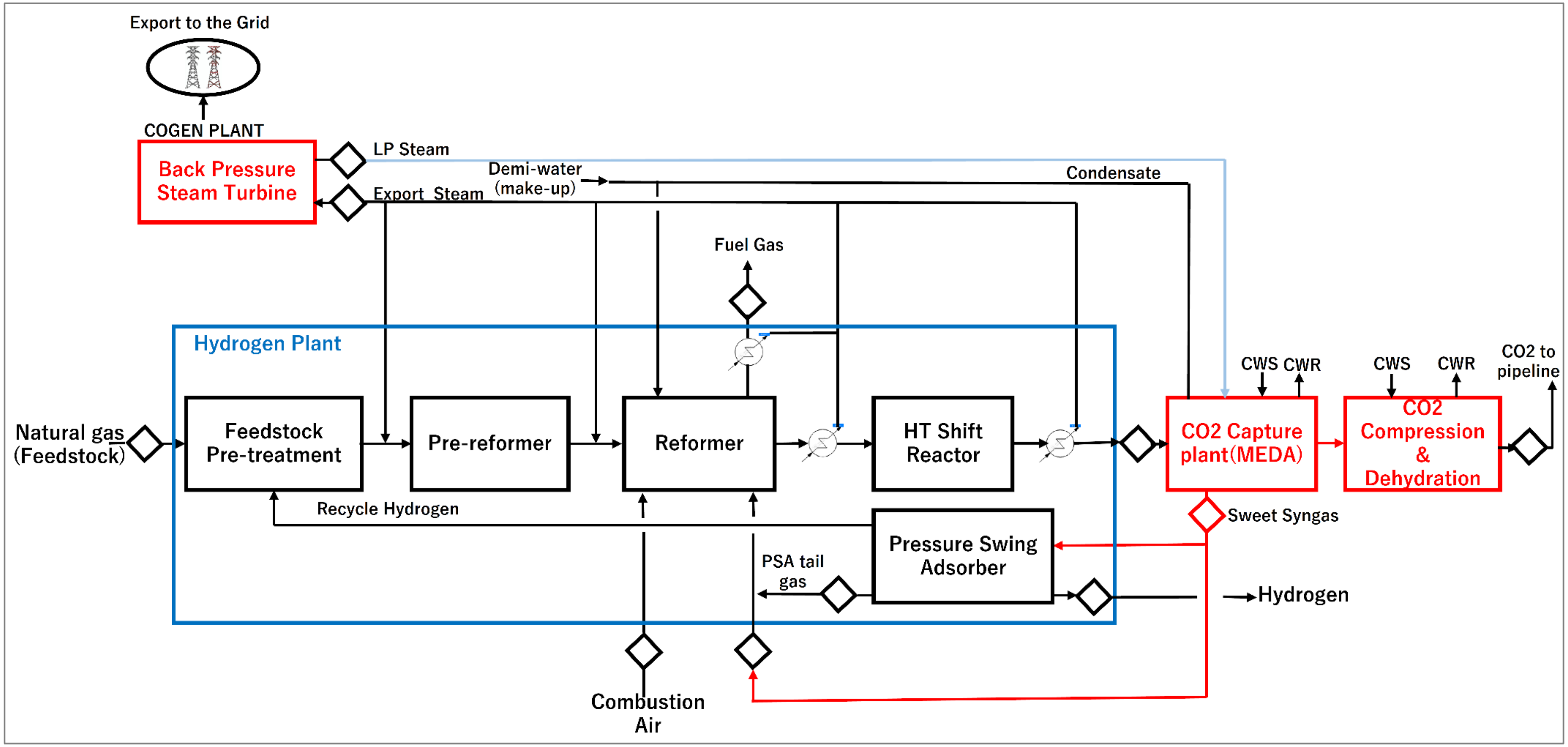
Figure 2.3. Case 1A: Steam Methane Reforming Plant with Carbon Dioxide Capture from Shifted Syngas Using Methyl Diethanolamine



CO_2 = carbon dioxide, COGEN =cogeneration, CWR = chilled water return, CWS = chilled water supply, HT = high temperature, LP = low pressure, MEDA = 3-methoxy-4,5-ethylenedioxyamphetamine PSA = pressure swing adsorption.

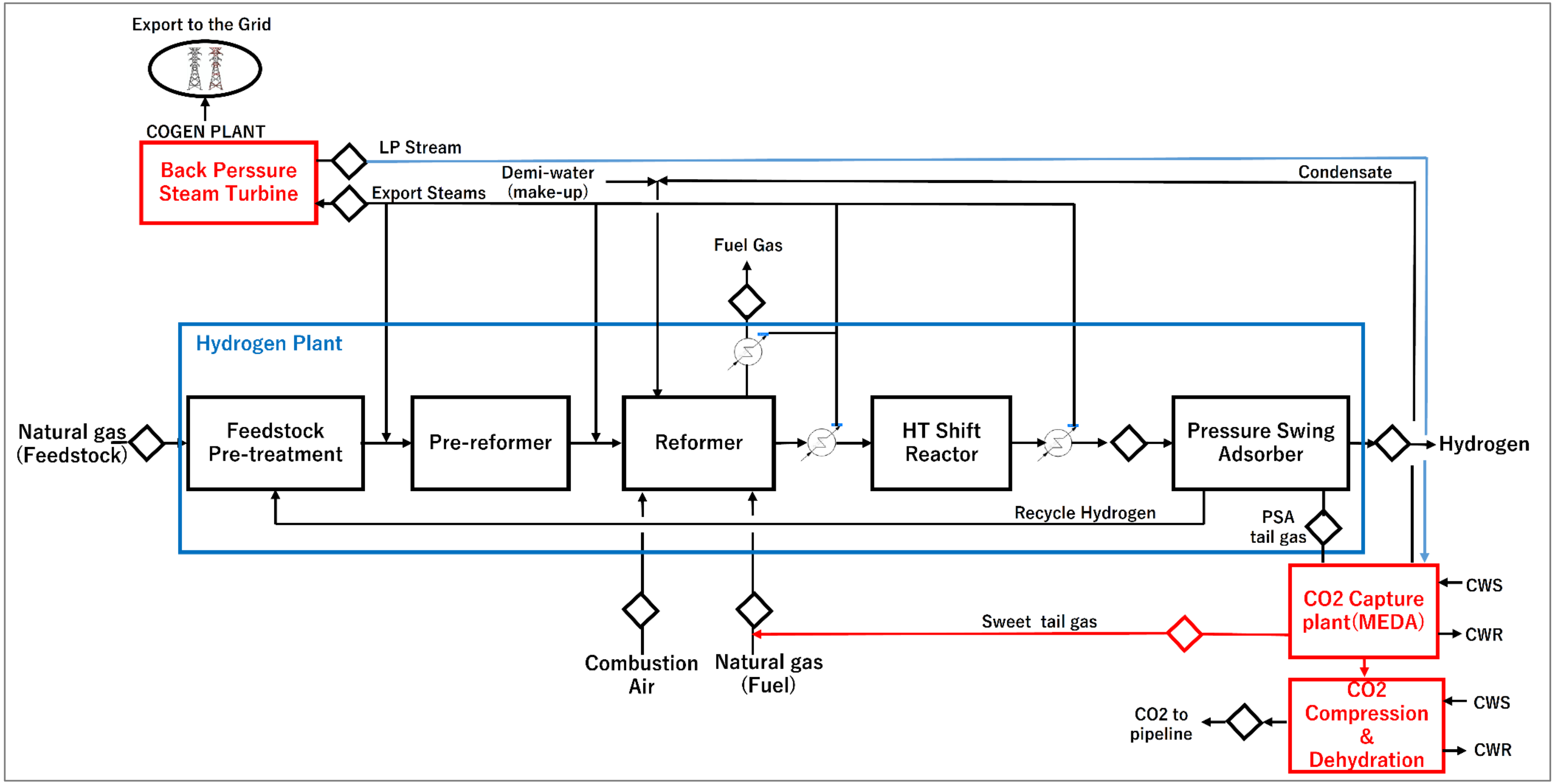
Source: International Energy Agency Greenhouse Gas R&D Programme (2017).

Figure 2.4. Case 1B: Steam Methane Reforming Plant with Hydrogen-rich Burners and Carbon Dioxide Capture from Shifted Syngas Using Methyl Diethanolamine



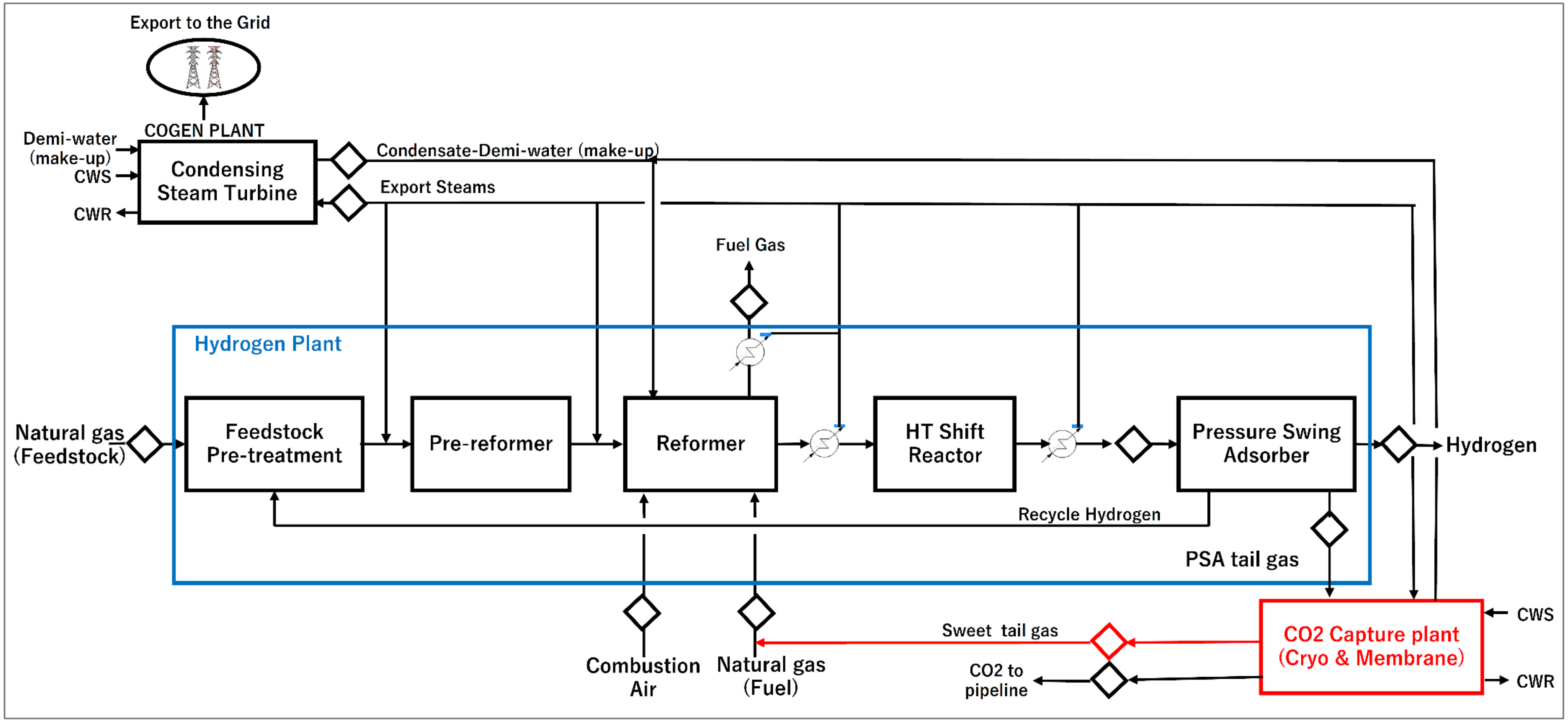
CO_2 = carbon dioxide, COGEN = cogeneration, CWR = chilled water return, CWS= chilled water supply, H_2 = hydrogen, HT = high temperature, LP = low pressure, MEDA =3-methoxy-4,5-ethylenedioxyamphetamine PSA = pressure swing adsorption.
Source: International Energy Agency Greenhouse Gas R&D Programme (2017).

Figure 2.5. Case 2A: Steam Methane Reforming Plant with Carbon Dioxide Capture from Pressure Swing Adsorption Tail Gas Using Methyl Diethanolamine



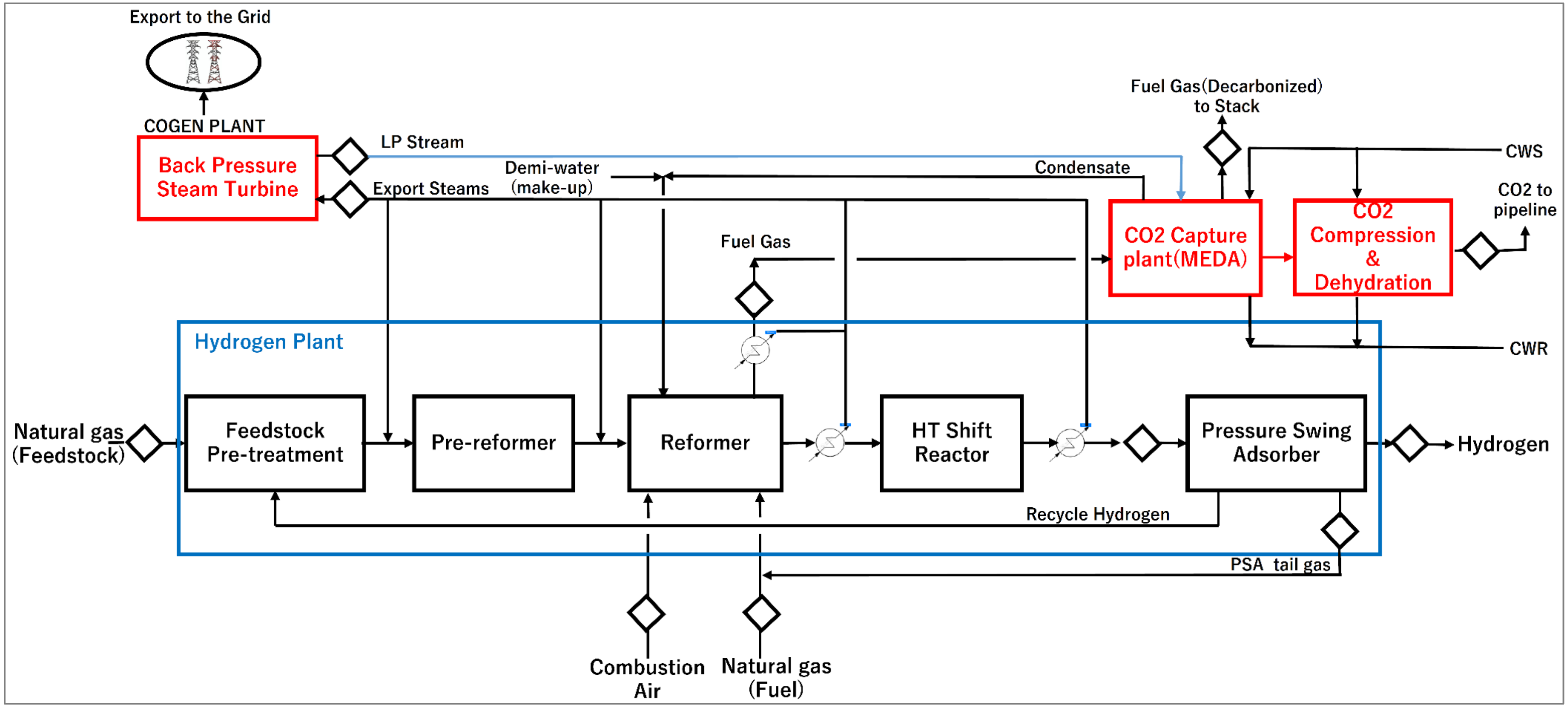
CO_2 = carbon dioxide, COGEN = cogeneration, CWR = chilled water return, CWS = chilled water supply, HT = high temperature, LP = low pressure, MEDA = 3-methoxy-4,5-ethylenedioxyamphetamine, PSA = pressure swing adsorption, SMR = steam methane reforming.
Source: International Energy Agency Greenhouse Gas R&D Programme (2017).

Figure 2.6. Case 2B: Steam Methane Reforming Plant with Carbon Dioxide Capture from Pressure Swing Adsorption Tail Gas Using Low Temperature and Membrane Separation



CO_2 = carbon dioxide, COGEN =cogeneration, CWR =chilled water return, CWS = chilled water supply, HT = high pressure PSA = pressure swing adsorption.
Source: International Energy Agency Greenhouse Gas R&D Programme (2017).

Figure 2.7. Case 3: Steam Methane Reforming Plant with Carbon Dioxide Capture from Steam Methane Reforming Flue Gas Using Methyl Diethanolamine



CO_2 = carbon dioxide, COGEN = cogeneration, HT =high temperature, LP =low pressure, CWR = chilled water return, CWS = chilled water supply, PSA = pressure swing adsorption.

Source: International Energy Agency Greenhouse Gas R&D Programme (2017).

Table 2.2. Calculation and Evaluation Results of Energy Efficiency of Hydrogen Production from Natural Gas

Case	Description	Inlet Stream (Natural Gas)					Outlet Stream (Hydrogen)			Export Power To The Grid (Mwe)	Energy Efficiency (%)		
		HHV of NG [4]			52.21	(MJ/kg)	HHV of H2[3]	141.18	(MJ/kg)				
		LHV of NG [3]			46.5	(MJ/kg)	LHV of H2[4]	119.96	(MJ/kg)				
		NG to Feedstock (kg/h)	NG to Fuel (kg/h)	Total Flow Rate (kg/h)	Total Energy Input HHV (MJ/h)	Total Energy Input LHV (MJ/h)	H_2 to B.L. (kg/h)	Total Energy in Product HHV (MJ/h)	Total Energy in Product LHV (MJ/h)		HHV	LHV (System total)	LHV (exclude 'Export Power to the Grid')
Base Case	SMR w/o capture	26,231	4,332	30,563	1,595,694	1,421,180	8,994	1,269,773	1,078,920	9.918	79.6%	75.9%	77.9%
Case 1A	CO_2 capture from shifted syngas using MDEA	26,262	5,300	31,562	1,647,852	1,467,633	8,994	1,269,773	1,078,920	1.492	77.1%	73.5%	73.8%
Case 1B	CO_2 capture from shifted syngas using MDEA with H_2 Rich Fuel Firing Burners	33,333	0	33,333	1,740,316	1,549,985	8,994	1,269,773	1,078,920	1.542	73.0%	69.6%	69.9%

Case	Description	Inlet Stream (Natural Gas)					Outlet Stream (Hydrogen)			Export Power To The Grid (Mwe)	Energy Efficiency (%)		
		HHV of NG (4)			52.21	(MJ/kg)	HHV of H2 (3)	141.18	(MJ/kg)				
		LHV of NG (3)			46.5	(MJ/kg)	LHV of H2 (4)	119.96	(MJ/kg)				
		NG to Feedstock (kg/h)	NG to Fuel (kg/h)	Total Flow Rate (kg/h)	Total Energy Input HHV (MJ/h)	Total Energy Input LHV (MJ/h)	H_2 to B.L. (kg/h)	Total Energy in Product HHV (MJ/h)	Total Energy in Product LHV (MJ/h)		HHV	LHV (System total)	LHV (exclude 'Export Power to the Grid')
Case 2A	CO_2 capture from PSA tail gas using MDEA	26,231	5,597	31,828	1,661,740	1,480,002	8,994	1,269,773	1,078,920	-1.070	76.4%	72.9%	72.7%
Case 2B	CO_2 capture from PSA tail gas using MDEA	26,231	4,264	30,495	1,592,144	1,418,018	8,994	1,269,773	1,078,920	0.284	79.8%	76.1%	76.1%
Case 3	CO_2 capture from flue gas using MEA	26,231	7,347	33,578	1,753,107	1,561,377	8,994	1,269,773	1,078,920	0.426	72.4%	69.1%	69.2%

CO_2 = carbon dioxide, h = hour, H_2 = hydrogen, HHV = higher heating value, kg = kilogramme, LHV = lower heating value, MDEA = methyl diethanolamine, MEA = monoethanolamine, MJ = megajoule, Mwe = megawatt electric, NG = natural gas, PSA = pressure swing adsorption.

Sources: International Energy Agency Greenhouse Gas R&D Programme (2017); and H_2 Hydrogen Tool, United States Department of Energy.

Table 2.2 shows the estimation results of the energy efficiency of each natural gas process. The energy efficiency of H_2 production from natural gas was calculated at about 76% without CCS (lower heating value standard) and 70%–74% with CCS.

2.2. Gasification Technology for Brown Coal and Bituminous Coal

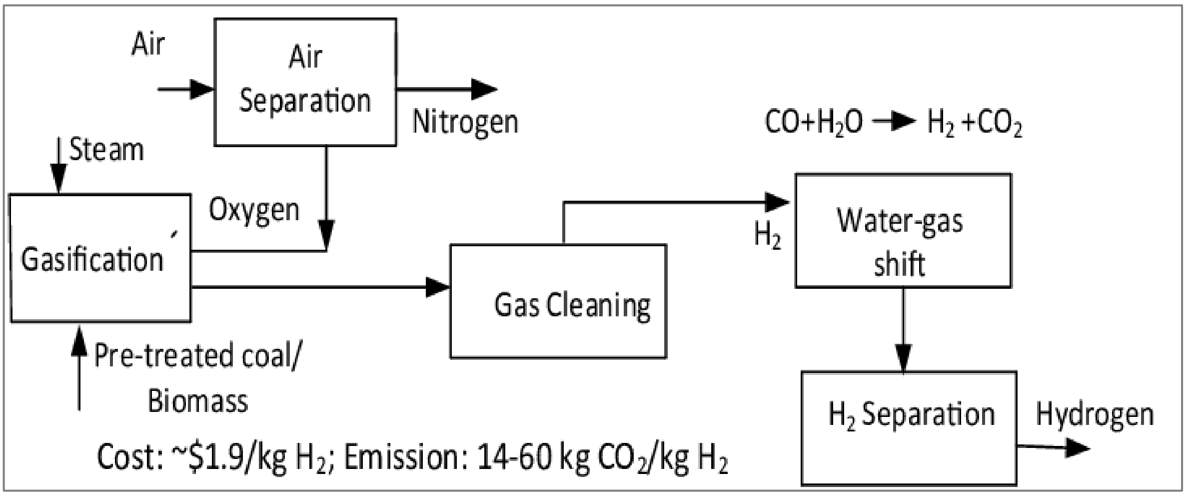
2.2.1. Overview of Gasification Technology for Brown Coal and Bituminous Coal

Coal gasification is used to produce H_2 from coal. The process uses steam and oxygen to break down molecular bonds in coal, forming a gaseous mixture of H_2 and CO. Extracting CO_2 and pollutants from gas derived through coal gasification is easier than from gas obtained from coal combustion. Another method of conversion involves low-temperature and high-temperature coal carbonisation.

Coke oven gas, made through pyrolysis (oxygen-free heating) of coal, contains about 60% H_2, along with methane, CO, CO_2, ammonia, molecular nitrogen, and hydrogen sulfide. PSA can separate H_2 from other impurities and is used by Japanese steel companies to produce H_2.

Figure 2.8 shows a flow diagram of H_2 production from natural gas (Matzen, 2015). As 14–60 kg of CO_2 are emitted to produce 1 kg of H_2, it is essential to use carbon capture, utilisation, and storage technology, which reduces the energy efficiency of the entire supply chain.

Figure 2.8. Hydrogen Production by Steam Reforming of Coal



CO = carbon oxide, H_2 = hydrogen, H_2O = water, kg = kilogramme.
Source: Matzen (2015).

Table 2.3. Projects of Large-scale Hydrogen Production from Coal

No	Project Name	Date Online	Status	Technology	Product	Announced Size	$Nm^{3-}H_2/H$	$Kt-H_2/Y$	$T-CO_2$ Capacity
1	Sinopec Qilu Petrochemical CCS	2021	Under construction	Coal w CCUS	H_2	700kt CO_2 /y			700,000
2	Great Plains Synfuel Plant and Weyburn-Midale	2000	Operational	Coal w CCUS	CH4	3000000 t CO_2 /y			3,000,000
3	Sinopec Zhongyuan Oilfield EOR	2015	Operational	Coal w CCUS	Ammonia	100kt CO_2 /y			100,000
4	Changqing Oil Field EOR	2015	Operational	Coal w CCUS	MeOH	50kt CO_2 /y			50,000
5	HESC (Liquefied hydrogen energy supply chain)	2030	Feasibility study	Coal w CCUS	H_2	4.39 Mt CO_2/y - 770 tH2/d	360,487	281	4,390,000
6	Yanchang Integrated Carbon Capture and Storage Demonstration	2021	Under construction	Coal w CCUS	H_2	410000t CO_2/y			410,000
7	Wabash CarbonSAFE	2022	Under construction	Coal w CCUS	Ammonia	1650000t CO_2 /y			1,650,000
8	Pedirka Hydrogen Project		Concept	Coal w CCUS	H_2				

CCUS = carbon capture, utilisation, and storage; CH_4 = methane; CO_2 = carbon dioxide; $Kt-H_2/Y$ = kilotonnes hydrogen per year; MeOH = methanol; Mt CO_2/y = million-ton carbon dioxide per year; $Nm^{3-}H_2/H$ = normal cubic metre hydrogen per hour; T-Co_2 = ton of carbon dioxide; tH2/d = tonnes hydrogen per day; Y = year.
Source: International Energy Agency (2021).

2.1.2. Energy Efficiency of Gasification Technology for Brown Coal and Bituminous Coal

Table 2.4 shows the calculation and evaluation results of the energy efficiency of brown coal and bituminous coal. The energy efficiency of H_2 production from coal was calculated at 50%–69% with CCS (lower heating value standard) (Kawasaki Heavy Industries Corporation and New Energy and Industrial Technology Development Organization, 2010–2011; Center for Low Carbon Society Strategy, 2019; Liszka et al., 2012, 2019).

Table 2.4. Calculation and Evaluation Results of Energy Efficiency of Hydrogen Production from Coal

Case	Description	Inlet Stream (Coal)				Outlet Stream (Hydrogen)				Energy Efficiency (%)
		Calorific Value of Coal [5] (MJ/Kg)		Coal to Feedstock (Tonne/H)	Total Energy in Feedstock (MJ/H)	Calorific Value of H_2 (MJ/Kg)		H2 to B.L. (Tonne/H)	Total Energy in Product (MJ/J)	
Case1	Liquefied hydrogen energy supply chain Brown coal with CCS[1]	HHV	10.869	720	7,825,680	HHV[3]	141.18	37.4	5,280,132	67.5%
		LHV	8.99		6,472,800	LHV[4]	119.96		4,486,504	69.3%
Case2A	Brown coal with CCS[2]	HHV	-	1,776,000	-	HHV[3]	141.18	84,563	-	-
		LHV	11.5		20,424	LHV[4]	119.96		10,144	49.7%
Case2B	Bituminous coal with CCS[2]	HHV[4]	27.113	1,742,000	47,231	HHV[3]	141.18	200,858	28,357	60.0%
		LHV[4]	26.151		45,555	LHV[4]	119.96		24,095	52.9%
Case3	Brown coal with CCS[3]	HHV	-	-	-	HHV[3]	141.18	-	-	-
		LHV[8]	19.572		652.74	LHV[4]	119.96		392.82	60.2%

CCS = carbon capture and storage, HHV = higher heating value, LHV = lower heating value, MJ/H = megajoule per hour, MJ/kg = megajoule per kilogramme, tonne/H = tonne per hour.

[1] Kawasaki Heavy Industry (2010–2011).

[2] Center for Low Carbon Society Strategy Report (2019).

[3] Liszka et al. (2012).

2.3. Water Electrolysis Technology for Renewable Electricity

Three main types of electrolytic cells exist: alkaline electrolysis cells, polymer electrolyte membrane (PEM) cells, and solid oxide electrolysis cells (SOECs). The water electrolyser is a relatively mature technology that has long been used in certain industrial processes, such as the production of chlorine in the chlorine-alkali process (where H_2 is produced as a by-product). However, its use for dedicated H_2 production has not been widely adopted. The dedicated production of H_2 from electrolyser is 30 kilotonnes per year, accounting for up to 0.3% of all H_2 produced. As of 2020, about 8 gigawatts of electrolyser capacity had been installed worldwide, accounting for about 4% of global H_2 production.

Methods for producing H_2 without fossil fuels involve water splitting or breaking down the water molecule (H_2O) into its components – oxygen and H_2. When renewable energy powers the water-splitting process, the H_2 produced is sometimes called . Although conversion can be accomplished in several ways, all methods are more expensive than fossil fuel-based production.

2.3.1. Overview of Water Electrolysis Technology for Renewable Electricity

The alkaline electrolyser, the most mature electrolysis technology, has traditionally dominated the market because of its widespread deployment in the chlorine-alkali industry. For the dedicated production of H_2, however, many new projects are now opting for PEM designs, so their deployment in the past 3 years has surpassed that of the alkaline electrolyser.

Nevertheless, it is unclear which design will dominate the market as the technology scales up. Although alkaline electrolysis technology has the advantages of maturity and lower cost, the rapidly falling price of the PEM electrolyser, its smaller footprint, and its ability to deliver H_2 at high pressure (30–60 bars, compared with 1–30 bars for alkaline electrolysis) are compelling. The spillover technological advancements from PEM fuel cell development could further boost its appeal.

Projects involving high-efficiency SOECs are appearing, some aiming to scale up to 20 MW in the short term. Practically all the projects are in Europe and focus on producing synthetic hydrocarbons, encouraged by the potential adoption of quotas for synthetic fuels in aviation, as announced by the European Commission and supported by the governments of Germany and the Netherlands. The production of synthetic fuels is an interesting niche market for SOECs, since heat released in the synthesis reaction could be used in the SOEC electrolyser, which operates at high temperatures, eliminating the need for an external heat source.

A water electrolyser uses electricity to split water into H_2 and oxygen. It has 70%–80% efficiency, with 20%–30% conversion loss, whilst steam reforming of natural gas has a thermal efficiency of 70%–85%. The electrical efficiency of electrolysis is expected to reach 82%–86% before 2030, while remaining durable as progress continues at a pace.

Water electrolysis operates at 50°C–80°C (122°F–176°F), whilst steam methane reforming requires temperatures of 700°C–1,100°C (1,292°F–2,012°F). The difference between the two is the primary energy used: electricity for electrolysis and natural gas for steam methane reforming. Because they use water, which is readily available, electrolysis and similar water-splitting methods have attracted the interest of the scientific community. To drive down the cost of H_2 production, renewable sources of energy have been targeted for electrolysis.

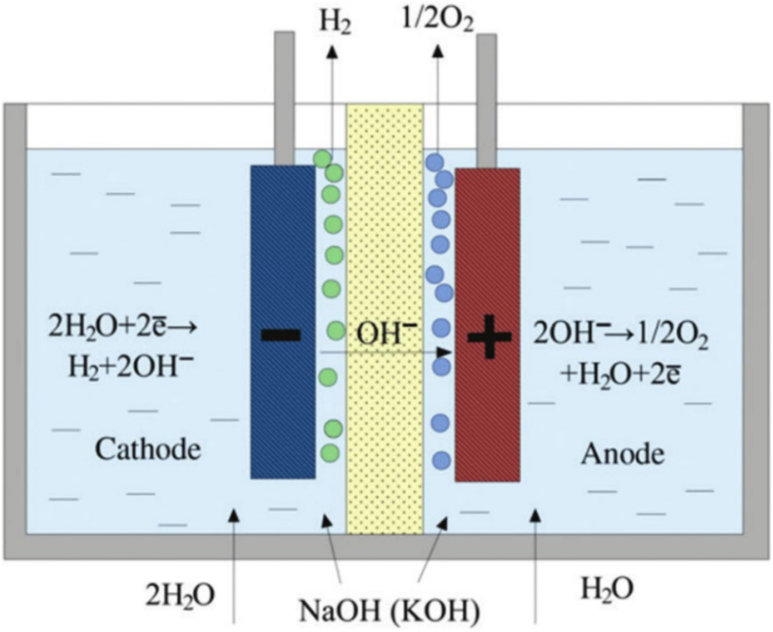
Traditionally, alkaline electrolysers, generally using nickel catalysts, are cheaper in terms of investment but less efficient. PEM electrolysers, generally using expensive platinum group metal catalysts, are more expensive but more efficient, can operate at higher current densities, and might be cheaper if H_2 production is large enough.

(a) Alkaline electrolyser

H_2 production by alkaline electrolyser is a proven technology with almost 90 years of operational experience.

The alkaline electrolyser has two electrodes operating in a liquid alkaline electrolyte solution of potassium hydroxide or sodium hydroxide. Separated by a diaphragm, the electrodes separate the product gases and transport the hydroxide ions from one electrode to the other. A recent comparison showed that state-of-the-art nickel-based electrolysers with alkaline electrolytes lead to competitive or even better efficiencies than acidic PEM water electrolysis with platinum group metal-based electrocatalysts (Figure 2.9 [a]).

Figure 2.9 (a). Schematic Diagramme of the Alkaline Electrolyser Cell



H_2 = hydrogen, O_2 = oxygen, H_2O = water, OH^- = hydroxide ions, e = electronic, NaOH = sodium hydroxide, KOH = potassium hydroxide

Source: Kamaroddin et al. (2018).

Table 2.5 (a) lists the world's largest H_2 production projects using alkaline water electrolysers.

Table 2.5 (a) Projects of Large-scale Hydrogen Production from Water Electrolyser (ALK Type, ≧1MW)

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	NM^3H_2/H	KTH_2/Y
					Type	Technology Comment	Renewable Type				
1	HYBRIT demo	SWE	2025	Under construction	ALK	Grid (excess renewable)		H_2	1 Mt iron/y	7,3751.988	57.500
2	CEOG	GUF	2022	Under construction	ALK	Dedicated renewable	Solar PV	H_2	15MW	3,260.870	2.542
3	Fukushima Hydrogen Energy Research Field	JPN	2020	Operational	ALK	Dedicated renewable	Solar PV	H_2	10 MW	1,923.077	1.499
4	Kokkola H_2 plant	FIN	2014	Operational	ALK	Other/Unknown		H_2	9MW	1,956.522	1.525
5	HYBRIT pilot	SWE	2020	Operational	ALK	Grid (excess renewable)		H_2	4.5MW	978.261	0.763
6	DEMO4GRID	AUT	2021	Under construction	ALK	Grid (excess renewable)		H_2	4MW	869.565	0.678
7	Hebei Jiantou Guyuan wind project - 1st phase	CHN	2020	Operational	ALK	Dedicated renewable	Onshore wind	H_2	4MW	869.565	0.678
8	Anglo-American Mining Truck	ZAF	2021	Under construction	ALK	Dedicated renewable	Others/Various	H_2	3.5MW	760.870	0.593

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	NM^3H_2/H	KTH_2/Y
					Type	Technology Comment	Renewable Type				
9	Hazira, Reliance, back-up hydrogen supply	IND	2005	Operational	ALK	Other/Unknown		H_2	680m³ H_2/h	680.000	0.530
10	Dahej, Reliance, back-up hydrogen supply	IND	2014	Operational	ALK	Other/unknown		H_2	444m³ H_2/h	444.000	0.346
11	Apex Energy, Rostock-Laage	DEU	2020	Operational	ALK	Grid (excess renewable)		H_2	2 MW	434.783	0.339
12	H_2RES - Orsted offshore wind	DNK	2021	Under construction	ALK	Dedicated renewable	Offshore wind	H_2	2MW	434.783	0.339
13	H_2 Logic 3 HRS with onsite electrolysis in Copenhagen	DNK	2013	Operational	ALK	Grid (excess renewable)		H_2	3x200 kg H_2/d	280.899	0.219
14	INGRID	ITA	2016	Operational	ALK	Other/unknown		H_2	1.15 MW	250.000	0.195
15	Wyhlen hydroelectric power plant	DEU	2020	Operational	ALK	Dedicated renewable	Hydropower	H_2	1 MW	217.391	0.169
16	Parnu refuelling station	EST	2019	Operational	ALK	Other/unknown		H_2	1 MW - 200m³ H_2/h	200.000	0.156
17	Aberdeen Conference Center	GBR	2018	Operational	ALK	Other/unknown		H_2	1MW - 200m³ H_2/h	200.000	0.156

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	NM^3H_2/H	KTH_2/Y
					Type	Technology Comment	Renewable Type				
18	RH2 Grapzow, Mecklenburg Vorpommern	DEU	2015	Operational	ALK	Dedicated renewable	Onshore wind	H_2	1MW - 200m^3 H_2/h	200.000	0.156
19	Hydrogen Valley South Tyrol - Bolzano, CHIC	ITA	2014	Operational	ALK	Other/unknown		H_2	1MW - 180m^3 H_2/h	180.000	0.140
20	Uniper/E-ON WindGas Falkenhagen Hydrogen Pilot Project	DEU	2013	Operational	ALK	Dedicated renewable	Onshore wind	H_2	1 MW - 180 m^3 H_2/h	180.000	0.140
21	vHyGO - 1st Facility for H_2 buses in Bouin (H2 Ouest)	FRA	2021	Operational	ALK	Dedicated renewable	Unknown	H_2	1MW - 300kg H_2/d	140.449	0.110

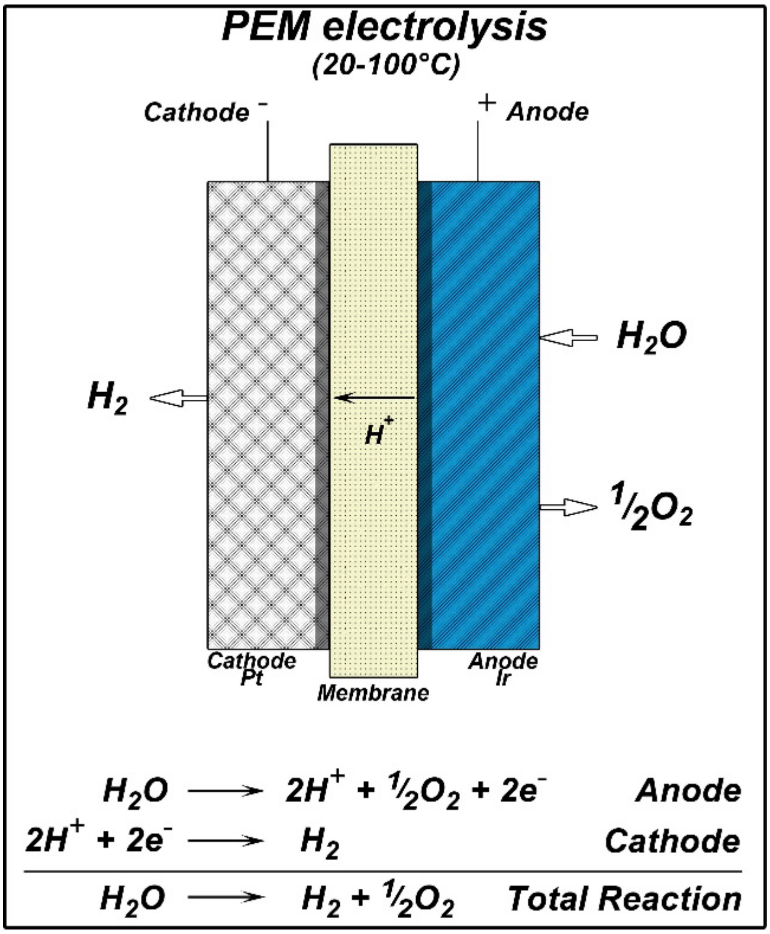
ALK = alkaline electrolysis, AUT = Austria, CHN = China, DEU = Germany, DNK = Denmark, EST = Estonia, FIN = Finland, FRA = France, GBR = Great Britain, GUF = French Guiana, H_2 = hydrogen, HRS = hydrogen refuelling station, IND = India, ITA = Italy, JPN = Japan, Kg = kilogramme, MW = megawatt, PV = photovoltaic, SWE = Sweden, ZAF = South Africa.
Source: International Energy Agency (2021).

(b) Proton exchange membrane electrolyser

In a PEM electrolyser, water undergoes electrolysis in a cell equipped with a solid polymer electrolyte. The polymer electrolyte conducts protons, separates product gases, and electrically insulates the electrodes. The PEM electrolyser was introduced to overcome the issues of partial load, low current density, and low-pressure operation currently plaguing alkaline electrolysis. The PEM electrolyser involves a proton-exchange membrane.

H_2 electrolysis with PEM offers rapid dispatchability and the ability to follow the energy output from renewables. This makes it an ideal choice for pairing with wind farms for low-carbon H_2 production or providing rapid response to the grid (Figure 2.9 [b]).

Figure 2.9 (b). Schematic of the Basic Operating Principle of a Polymer Electrolyte Membrane Electrolyser Cell



H_2 - hydrogen, O_2 = oxygen, H_2O = water, H^+= hydrogen ion
Source: Kamaroddin (2018)

Table 2.5 (b) lists the world's largest H_2 production projects using PEM water electrolyser.

Table 2.5 (b). Projects of Large-scale Hydrogen Production from Water Electrolyser (PEM Type, ≧1MW)

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	NM^3H_2/H	KTH_2/Y
					Type	Technology Comment	Renewable Type				
1	Candem County (GA), green power plant	USA	2022	Under construction	PEM	Dedicated renewable	Others/Various	H_2	15 t H_2/d	7022.472	5.475
2	Air Liquide Becancour	CAN	2020	Operational	PEM	Dedicated renewable	Hydropower	H_2	20MW - 8t H_2/d	3745.318	2.920
3	HySynergy, phase 1	DNK	2022	Under construction	PEM	Grid (excess renewable)		H_2	20MW	3846.154	2.999
4	Refhyne	DEU	2021	Operational	PEM	Other/unknown		H_2	10 MW	1923.077	1.499
5	Guangdong Synergy Hydrogen Power Technology Co. 2n phase	CHN	2021	Under construction	PEM	Dedicated renewable	Others/Various	H_2	9MW	1730.769	1.349
6	Wunsiedel Energy Park (Phase 1)	DEU	2022	Under construction	PEM	Dedicated renewable	Others/Various	H_2	8.75MW	1538.462	1.199
7	Unknown ITM peoject		2022	Under construction	PEM		N/A	H_2	8MW	1538.462	1.199
8	SoHyCal	ESP	2022	Under construction	PEM	Dedicated renewable	Solar PV	H_2	7.5MW	1442.308	1.124
9	H2FUTURE	AUT	2019	Operational	PEM	Grid (excess renewable)		H_2	6 MW	1153.846	0.900
10	Energiepark Mainz	DEU	2014	Operational	PEM	Dedicated renewable	Onshore wind	H_2	6 MW	1153.846	0.900

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	NM^3H_2/H	KTH_2/Y
					Type	Technology Comment	Renewable Type				
11	H&R Ölwerke Hamburg-Neuhof	DEU	2018	Operational	PEM	Grid (excess renewable)		H_2	5 MW	961.538	0.750
12	Chongli wind-solar Hydrogen Project - first phase	CHN	2021	Under construction	PEM	Dedicated renewable	Others/Various	H_2	1.7t H_2/d	795.880	0.621
13	Guangdong Synergy Hydrogen Power Technology Co. 1st phase	CHN	2019	Operational	PEM	Dedicated renewable	Unknown	H_2	4 MW	769.231	0.600
14	HRS Bremervörde - trains	DEU	2022	Under construction	PEM	Other/Unknown	N/A	H_2	1.6 t H_2/d	749.064	0.584
15	3 x 1250 kW projects in USA	USA	2000	Operational	PEM	Other/Unknown	N/A	H_2	3 x 1250kw	721.154	0.562
16	18x180 kW projects in USA	USA	2000	Operational	PEM	Other/Unknown	N/A	H_2	18x180kw	623.077	0.486
17	Markham Energy Storage, Ontario	CAN	2019	Operational	PEM	Grid (excess renewable)		H_2	2.5 MW	480.769	0.375
18	Wuppertal refuelling station	DEU	2020	Operational	PEM	Dedicated renewable	Others/Various	H_2	2.5MW - 500m^3 H_2/h	500.000	0.390
19	SALCOS - WindH2	DEU	2021	Operational	PEM	Dedicated renewable	Onshore wind	H_2	2 x 1.25MW - 450m^3 H_2/h	450.000	0.351

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	NM^3H_2/H	KTH_2/Y
					Type	Technology Comment	Renewable Type				
20	HAEOLUS	NOR	2021	Under construction	PEM	Dedicated renewable	Onshore wind	H_2	2.5MW - 500m3 H_2/h	500.000	0.390
21	Konin Power Plant, phase 1	POL	2022	Under construction	PEM	Dedicated renewable	Others/Various	H_2	2.5MW	480.769	0.375
22	Konin Power Plant, phase 2	POL	2022	Under construction	PEM	Dedicated renewable	Others/Various	H_2	5MW	480.769	0.375
23	Wind to gas Brunsbüttel	DEU	2018	Operational	PEM	Dedicated renewable	Onshore wind	H_2	2.4 MW - 450 m^3 H_2/h	450.000	0.351
24	Hydrospider - St Gallen	CHE	2020	Operational	PEM	Dedicated renewable	Hydropower	H_2	2 MW	384.615	0.300
25	SunLine Palms Springs	USA	2018	Operational	PEM	Other/Unknown	N/A	H_2	2MW	384.615	0.300
26	HRS TMB Barcelona	ESP	2021	Under construction	PEM	Dedicated renewable	Others/Various	H_2	2 MW	384.615	0.300
27	Duwaal	NLD	2021	Under construction	PEM	Dedicated renewable	Onshore wind	H_2	2MW	384.615	0.300
28	NEDO kofu city, Yamanashi Prefecture	JPN	2019	Operational	PEM	Other/unknown		H_2	1.5 MW	288.462	0.225
29	SunLine Transit Agency	USA	2018	Operational	PEM	Other/unknown		H_2	1.5MW	288.462	0.225

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	NM^3H_2/H	KTH_2/Y
					Type	Technology Comment	Renewable Type				
30	WindGas Hamburg-Reitbrook	DEU	2015	Operational	PEM	Dedicated renewable	Onshore wind	H_2	1.5 MW	288.462	0.225
31	Halcyon Power	NZL	2021	Under construction	PEM	Dedicated renewable	Others/Various	H_2	1.5MW - 250m^3 H_2/h	250.000	0.195
32	12 x 120 kW projects in USA	USA	2000	Operational	PEM	Other/Unknown	N/A	H_2	12x120kw	276.923	0.216
33	ITM-Sumitomo Coorp	JPN	2021	Under construction	PEM	Other/Unknown	N/A	H_2	1.4 MW	269.231	0.210
34	Leuchtturmprojekt Power-to-Gas Baden-Württemberg	DEU	2020	Operational	PEM	Dedicated renewable	Hydropower	H_2	1.3 MW	250.000	0.195
35	Hassfurt	DEU	2016	Operational	PEM	Grid (excess renewable)		H_2	1.25MW	240.385	0.187
36	Green hydrogen Project, Mohammad Bin Rashid Solar Park	ARE	2021	Operational	PEM	Dedicated renewable	Solar PV	H_2	1.25MW	240.385	0.187
37	Hydrogen Park South Australia - HyPSA	AUS	2021	Operational	PEM	Dedicated renewable	Others/Various	H_2	1.25MW	240.385	0.187
38	ARIES project	USA	2021	Under construction	PEM	Other/unknown		H_2	1.25 MW	240.385	0.187

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	NM^3H_2/H	KTH_2/Y
					Type	Technology Comment	Renewable Type				
39	HyBALANCE	DNK	2018	Operational	PEM	Dedicated renewable	Onshore wind	H_2	1.2 MW	230.769	0.180
40	HRS CMB Port of Antwerp	BEL	2021	Operational	PEM	Other/unknown		H_2	1.2 MW	230.769	0.180
41	eFarm (5 production sites in North Frisia)	DEU	2020	Operational	PEM	Dedicated renewable	Onshore wind	H_2	1.125 MW	216.346	0.169
42	Hydrogen plant - Orkney Islands - BIG HIT 2n phase	GBR	2020	Operational	PEM	Dedicated renewable	Onshore wind	H_2	1 MW	192.308	0.150
43	HRS CMB	BEL	2019	Operational	PEM	Other/unknown		H_2	1 MW	192.308	0.150
44	Windgas Haurup, 2nd phase	DEU	2021	Operational	PEM	Dedicated renewable	Onshore wind	H_2	1 MW	192.308	0.150
45	Lam Takhong Wind Hydrogen Hybrid Project-EGAT	THA	2018	Operational	PEM	Other/unknown		H_2	1MW - 200m^3 H_2/h	200.000	0.156
46	H2ORIZON	DEU	2018	Operational	PEM	Other/unknown		H_2	1 MW	192.308	0.150
47	P2G plant Erdgas Schwaben	DEU	2013	Operational	PEM	Other/unknown		H_2	1 MW - 180 m^3 H_2/h	192.308	0.150
48	Hystock (EnergyStock)	NLD	2019	Operational	PEM	Dedicated renewable	Solar PV	H_2	1 MW - 220m^3 H_2/h	220.000	0.172

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	NM^3H_2/H	KTH_2/Y
					Type	Technology Comment	Renewable Type				
49	NEL-Champaign-Urbana Mass Transit District	USA	2021	Operational	PEM	Other/Unknown		H_2	1 MW	192.308	0.150
50	H2Nodes, Parnu	EST	2019	Operational	PEM	Other/unknown		H_2	$185m^3$ H_2/h	185.000	0.144
51	4 projects of ITM in Australia	AUS	2018	Operational	PEM	Other/Unknown	N/A	H_2	4 x 0.25MW	144.231	0.112
52	H2Nodes, Riga	EST	2019	Operational	PEM	Other/unknown		H_2	$140m^3$ H_2/h	140.000	0.109

ARE = United Arab Emirates, AUS = Australia, AUT = Austria, BEL = Belgium, CAN = Canada, CHE = Switzerland, CHN = China, DEU = Germany, DNK = Denmark, ESP = Spain, EST = Estonia, GBR = Great Britain, H_2 = hydrogen, HRS = hydrogen refueling station, JPN = Japan, KTH_2/Y = kilotonnes hydrogen per year, m^3 = cubic metre, N/A = not applicable, NLD = The Netherlands, NM^3H_2/H = normal cubic metre hydrogen per hour , NOR = Norway, NZL = New Zealand, PEM = polymer electrolyte membrane, POL = Poland, PV = photovoltaic, THA = Thailand, USA = United States of America.
Source: International Energy Agency (2021).

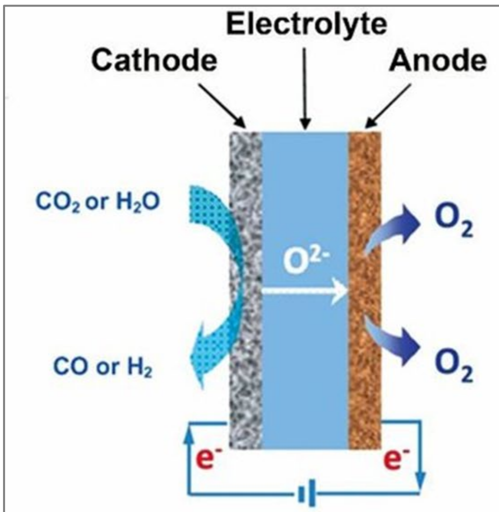
(c) High-temperature solid oxide electrolyser

A SOEC runs in regenerative mode using a solid oxide or ceramic electrolyte to achieve the electrolysis of water (and/or CO_2) to produce H_2 gas (and/or CO) and oxygen. The production of pure H_2 is compelling because it is a clean fuel that can be stored, making it a potential alternative to batteries, methane, and other energy sources. Electrolysis is the most promising method of H_2 production from water due to its high efficiency of conversion and required energy input, which is lower than that of thermochemical and photocatalytic methods (Wang et al., 2020) (Figure 2.9 [c]).

Despite being an immature production technology, SOEC has the potential to become a large-scale production method. A particular advantage of SOEC is its ability to harness industrial sources of waste heat, improving overall efficiency. If the energy cost of the waste heat is excluded from the calculation, SOEC electrical efficiencies can exceed 100%.

Demonstration cells are nowhere near the scale of PEM or alkaline electrolysis. Considerable development is required to produce a commercially ready, scalable system with an acceptable stack replacement life. Demonstration cells currently have a short life due to the high operating temperatures in the process.

Figure 2.9 (c). Typical Schematic of a Solid Oxide Electrolysis Cell and the Reaction Paths for Carbon Dioxide and Water Electrolyser



Cathode: $CO_2(g) + 2e^- \rightarrow CO(g) + O^{2-}$

$H_2O(g) + 2e^- \rightarrow H_2(g) + O^{2-}$

Anode: $2O^{2-} \rightarrow O_2(g) + 4e^-$

CO = carbon oxide, CO_2 = carbon dioxide, e^-= electron, g = gas, H_2 = hydrogen, H_2O = water.
Source: Wang et al. (2020).

Table 2.5 (c) lists the world's largest H_2 production projects using SOEC water electrolysers.

Table 2.5. (c) Projects of Large-scale Hydrogen Production from Water Electrolysers (SOEC Type)

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	Nm^3H_2/H	Kth_2/Y
					Type	Technology Comment	Renewable Type				
1	Multiphly	NLD	2022	Under construction	SOEC	Dedicated renewable	Unknown	H_2	2.6MW	684.211	0.533
2	Prairie Island	USA	2021	Demo	SOEC	Nuclear	N/A	H_2	1MW	263.158	0.205
3	GrInHy2.0	DEU	2020	Operational	SOEC	Grid (excess renewable)		H_2	0.72 MW - 200 m^3 H_2/h	200.000	0.156
4	Hypos - Sunfire	DEU	2019	Demo	SOEC	Other/unknown		H_2	0.18MW - 50 m^3 H_2/h	50.000	0.039
5	GrInHy	DEU	2017	Demo	SOEC	Other/Unknown		H_2	0.15MW - 37.5m^3 H_2/h	27.500	0.021
6	Naval Facilities Engineering Command, Engineering and Expeditionary Warfare Center	USA	2016	Demo	SOEC	Other/unknown		H_2	0.05MW	13.158	0.010
7	BOEING (rSOC Demonstrator)	USA	2015	Demo	SOEC	Other/Unknown		H_2	10m^3 H_2/h	10.000	0.008
8	REFLEX	ITA	2018	Operational	SOEC	Other/unknown		H_2	10m^3 H_2/h	10.000	0.008
9	Dresden	DEU	2015	Demo	SOEC	Other/Unknown		H_2	0.01MW	2.632	0.002

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	Nm^3H_2/H	Kth_2/Y
					Type	Technology Comment	Renewable Type				
10	Changwon Industrial complex	KOR	2022	FID	SOEC	Dedicated renewable	Solar PV	H_2			

DEU = Germany, FID = final investment decision, h = hour, H_2 = hydrogen, ITA = Italy, KOR = South Korea, Kth_2/Y = kilotonnes hydrogen per year, m^3 = cubic metre, MW = megawatt, NLD = The Netherlands, Nm^3H_2/H = normal cubic metre hydrogen per hour, SOEC = solid oxide electrolysis cell, USA = United States of America.

Source: International Energy Agency, 2021.

(d) Other electrolysers

Table 2.5 (d) lists the world's largest H_2 production projects using other electrolysers.

Table 2.5 (d). Projects of Large-scale Hydrogen Production from Water Electrolyser (Other electrolyser types)

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	NM^3H_2/H	KTH_2/Y
					Type	Technology Comment	Renewable Type				
1	New Jersey Resources Howell	USA	2021	Under construction	Other Electrolysis	Other/Unknown	N/A	H_2	50MW	11111.111	8.663
2	WIVA P&G Hydrogen Region	AUT	2025	Under construction	Other Electrolysis	Dedicated renewable	Others/Various	H_2	10t H_2/d	4681.648	3.650
3	Haiperer Wind Power Hebei - first phase	CHN	2020	Operational	Other Electrolysis	Dedicated renewable	Onshore wind	H_2	4.3 t H_2/d	2013.109	1.570
4	Hebei Jiantou Guyuan wind project - 2nd phase	CHN	2022	Under construction	Other Electrolysis	Dedicated renewable	Onshore wind	H_2	10MW	1304.348	1.017
5	PtG-Fehndorf	DEU	2021	Under construction	Other Electrolysis	Dedicated renewable	Onshore wind	H_2	2MW	444.444	0.347
6	Hysolar Green on Road - Nieuwegein	NLD	2021	Under construction	Other Electrolysis	Dedicated renewable	Solar PV	H_2	2MW	444.444	0.347
7	Hydrogen Mill	NLD	2022	Under construction	Other Electrolysis	Dedicated renewable	Onshore wind	H_2	2MW	444.444	0.347

No	Project Name	Country	Date Online	Status	Technology			Product	Announced Size	NM^3H_2/H	KTH_2/Y
					Type	Technology Comment	Renewable Type				
8	Lhyfe offshore electrolyser	FRA	2022	Under construction	Other Electrolysis	Dedicated renewable	Offshore wind	H_2	2MW	444.444	0.347
9	Power to Green H2 Mallorca - Phase 1	ESP	2021	Under construction	Other Electrolysis	Dedicated renewable	Solar PV	H_2	0.33kt H_2/y	423.272	0.330
10	HYPOS (several projects)	DEU	2019	Operational	Other Electrolysis	Other/Unknown		H_2	1.25MW	277.778	0.217
11	Hyoffwind Zeebrugge, 1st phase	BEL	2021	Under construction	Other Electrolysis	Dedicated renewable	Offshore wind	H_2	1MW	222.222	0.173
12	Northern Irish hydrogen project	GBR	2021	Under construction	Other Electrolysis	Other/unknown		H_2	1 MW	222.222	0.173
13	Hydrogenpilot Oosterwolde	NLD	2021	Under construction	Other Electrolysis	Grid (excess renewable)		H_2	1MW	222.222	0.173
14	Solar Global group headquarters, phase 1	CZE	2021	Under construction	Other Electrolysis	Grid (excess renewable)	N/A	H_2	0.7MW	155.556	0.121
15	Jemena Western Sydney - H2GO project	AUS	2021	Under construction	Other Electrolysis	Grid		H_2	0.5MW	111.111	0.087

AUS = Australia, AUT = Austria, BEL = Belgium, CHN = China, CZE = Czech Republic, DEU = Germany, ESP = Spain, FRA = France, GBR = Great Britain, KTH_2/Y = kilotonnes hydrogen per year, MW = megawatt, NLD = The Netherlands, NM^3H_2/H = normal cubic metre hydrogen per hour, PV = photovoltaic, USA = United States of America.
Source: International Energy Agency (2021).

2.3.2. Energy Efficiency of Water Electrolysis Technology for Renewable Electricity

The less energy used by a generator, the greater its efficiency; 100% efficient electrolysis would consume 39.4 kilowatt-hours per kilogramme (142 MJ/kg) of H_2 or 12,749 joules per litre (12.75 MJ/m^3). A practical electrolyser typically uses rotating electrolysis, where centrifugal force helps separate gas bubbles from water. Under 15 bar pressure, such an electrolyser may consume 50 kilowatt-hours per kilogramme (180 MJ/kg), with 15 kilowatt-hours (54 MJ) more if the H_2 is compressed for use in H_2 cars.

A conventional alkaline electrolyser has an efficiency rate of about 70%, but advanced versions have efficiency rates of up to 82%. Accounting for the higher heat value, as inefficiency via heat can be redirected back into the system to create the steam required by the catalyst, average working efficiencies for PEM electrolysers are about 80%, reaching 82% when using the most modern alkaline electrolysis.

Table 2.6 shows the calculation and evaluation results of the energy efficiency of three types of electrolysers (alkaline, PEM, and SOEC).

Alkaline electrolysers have already been commercialised because they are suitable for large-capacity facilities and are inexpensive. PEM electrolysers are the most widespread. SOEC electrolysers are the most energy-efficient (about 90%) and are expected to be commercialised.

Table 2.6. Calculation and Evaluation Results of Energy Efficiency of Hydrogen Production Using Water Electrolyser

Type	Project Name	Status	Inlet (Nominal Power Consumption/Stack) 1MWH=3600(MJ/H)		Outlet Stream (Hydrogen) 1kg=11.14nm^3 HHV OF H_2 141.18 (MJ/KG) LHV OF H_2 119.96 (MJ/KG)				Energy Efficiency (%)	Reference	
			Nominal Power Consumption/ Stack (MW)	Nominal Power Consumption/ Stack (MJ/H)	H2 Production (Nm^3/H)	H2 Production (Kg/H)	Total Energy In Product HHV (Mj/H)	Total Energy In Product LHV (Mj/H)	HHV	LHV	
Alkaline	Fukushima Hydrogen Energy Research Field (FH2R)	Operation	10.0	36,000	1,923.0	172.62	24,371	20,708	67.7%	57.5%	(1),(2),(3),(4),(5)
Alkaline	HYBRIT pilot	Operation	4.5	16,200	978.0	87.79	12,394	10,531	76.5%	65.0%	(6),(7),(8),(9)
Alkaline	HYBRIT demo	Under Construction	339.3	1,221,480	73,752.0	6,620.47	934,678	794,191	76.5%	65.0%	(6),(7)
Alkaline	GreenHydroChem Central German Chemical Triangle	Feasibility study	120.0	432,000	23,077.0	2,071.54	292,461	248,502	67.7%	57.5%	(10)
Alkaline	ETOGAS, Solar Fuel Beta-plant AUDI, Werlte (Audi e-gas)	Operation	6.0	21,600	1304.0	117.06	16,526	14,042	76.5%	65.0%	(11),(12),(13),(14),(15),(16)
Alkaline	ECB Omega Green biofuel project	Feasibility study	310.0	1,116,000	67391.0	6,049.46	854,063	725,693	76.5%	65.0%	(19),(20)
PEM	Air Liquide Becancour	Operation	20.0	72,000	3745.0	336.18	47,461	40,328	65.9%	56.0%	(21),(22)

Type	Project Name	Status	Inlet (Nominal Power Consumption/Stack) 1MWH=3600(MJ/H)		Outlet Stream (Hydrogen) 1kg=11.14nm^3 HHV OF H_2 141.18 (MJ/KG) LHV OF H_2 119.96 (MJ/KG)				Energy Efficiency (%)	Reference	
			Nominal Power Consumption/ Stack (MW)	Nominal Power Consumption/ Stack (MJ/H)	H2 Production (Nm^3/H)	H2 Production (Kg/H)	Total Energy In Product HHV (Mj/H)	Total Energy In Product LHV (Mj/H)	HHV	LHV	
PEM	HySynergy, phase 1	Under Construction	20.0	72,000	3856.0	346.14	48,868	41,523	67.9%	57.7%	(23),(24)
PEM	Siemens-Air Liquide Oberhausen, Phase 1	Feasibility study	10.0	36,000	1923.0	172.62	24,371	20,708	67.7%	57.5%	(25)
PEM	Refhyne	Operation	10.0	36,000	1923.0	172.62	24,371	20,708	67.7%	57.5%	(26),(27),(28)
PEM	H2FUTURE	Operation	6.0	21,600	1154.0	103.59	14,625	12,427	67.7%	57.5%	(29)
PEM	Energiepark Mainz	Operation	6.0	21,600	1154.0	103.59	14,625	12,427	67.7%	57.5%	(30),(31),(32),(33),(34),(35)
PEM	Murchison	Feasibility study	5,000	18,000,000	961,538.0	86,314.00	12,185,811	10,354,228	67.7%	57.5%	(36),(37),(38),(39),(40),(41)
SOEC	GrInHy2.0	Operation	0.72	2,592	200.00	17.95	2,535	2,154	97.8%	83.1%	(42),(43),(44)
SOEC	REFLEX	Operation	0.038	137	10.00	0.90	127	108	92.6%	78.7%	(45)
SOEC	Multiphly	Under Construction	2.60	9,360	684.00	61.40	8,669	7,366	92.6%	78.7%	(46),(47),(48),(49)
SOEC	Nordic Blue Crude	Feasibility study	20.0	72,000	5263.0	472.44	66,699	56,674	92.6%	78.7%	(17),(18)

Type	Project Name	Status	Inlet (Nominal Power Consumption/Stack) 1MWH=3600(MJ/H)		Outlet Stream (Hydrogen) 1kg=11.14nm³ HHV OF H_2 141.18 (MJ/KG) LHV OF H_2 119.96 (MJ/KG)				Energy Efficiency (%)	Reference	
			Nominal Power Consumption/ Stack (MW)	Nominal Power Consumption/ Stack (MJ/H)	H2 Production (Nm^3/H)	H2 Production (Kg/H)	Total Energy In Product HHV (Mj/H)	Total Energy In Product LHV (Mj/H)	HHV	LHV	
SOEC	E-CO2MET Raffinerie Mitteldeutschland	Demo	1.00	3,600	263.00	23.61	3,333	2,832	92.6%	78.7%	(50),(51),(52)
SOEC	Hydrogen Lab Leuna (phase 1)	Operation	1.00	3,600	263.00	23.61	3,333	2,832	92.6%	78.7%	(53),(54)

H_2 = hydrogen, HHV = higher heating value, LHV = lower heating value, MJ/H = megajoule per hour, MJ/KG = megajoule per kilogramme, MWH = megawatt per hour, PEM = polymer electrolyte membrane, SOEC = solid oxide electrolysis cell.

Sources (See Appendix): Asahi Kasei (2021); Toshiba (2020); Crolius, S. H. (2017); Science Direct (2018); Climate Adaptation Platform (2020); Korose, C. et al. (2019); Vattenfall (2019); Reuters (2020); BloombergNEF (2020); Steinmüller, H. (2014); Manuel Bailera et al. (2017); Gahleitner, G. (2013); Vartiainen, V. (2016); Iskov, H., N. Bjarne, and B. Rasmussen (2013); THEnergy (2020); Ihre Privatsphäre ist uns wichtig (2018); Sunfire (2017, 2019, 2021); Teesside Collective (2014); Sapp, M. (2020); Air Liquide Canada (2020);*The Canadian New* (2020); Bioenergy (2019); Nel (2019, 2021); Platts European Gas Daily (2021); Lymperopoulos, N. (2018); REFHYHE (2019, 2022), Fuel Cells and Hydrogen Joint Undertaking (n.d.); H2FUTURE (2021); ENTSOG (2021); Vartiainen, V. (2016); Iskov, H., N. Bjarne, and B. Rasmussen (2013); Mainz (2016, 2018); Siemens (2019); PV Magazine (2019); Mazengarb, M. (2020); Collins, L. (2020); GrlnHy20 (2021); Salzgitter (2020); Reflex (2020); Edwardes-Evans, H. (2020); Cordis (2020); Collins, L. (2020); De Laat, P. (2021); Hydrogen Central (2021); Alfred Wegener-Institut (2021).

3. Prediction of Energy Efficiency of Hydrogen Production by IEA (2019a)

Table 2.7 shows the energy efficiency forecasts by IEA (2019a).

According to the IEA (2019a)report, the energy efficiency of H_2 production from fossil fuels is expected to remain consistent (natural gas, 69%–76%; coal, 58%–60%) beyond 2030. Conversely, the energy efficiency of H_2 production through water electrolysis is expected to improve. It is predicted that by 2050, it will be as energy efficient as fossil fuels (64% today, 69% by 2030, 74% by 2050).

Table 2.7. Prediction of Energy Efficiency of Hydrogen Production by Resource

Technology	Parameter	Units	Today	2030	Long term
Water electrolysis	CAPEX	US$/kW$_e$	900	700	450
	Efficiency (LHV)	%	64	69	74
	Annual OPEX	% of CAPEX	1.5	1.5	1.5
	Stack lifetime (operating hours)	hours	95 000	95 000	100 000
Natural gas reforming	CAPEX	US$/kW$_{H_2}$	910	910	910
	Efficiency (LHV)	%	76	76	76
	Annual OPEX	% of CAPEX	4.7	4.7	4.7
	Emission factor	$kgCO_2/kgH_2$	8.9	8.9	8.9
Natural gas reforming with carbon capture	CAPEX	US$/kW$_{H_2}$	1 680	1 360	1 280
	Efficiency (LHV)	%	69	69	69
	Annual OPEX	% of CAPEX	3	3	3
	CO_2 capture rate	%	90	90	90
	Emission factor	$kgCO_2/kgH_2$	1.0	1.0	1.0
Coal gasification	CAPEX	US$/kW$_{H_2}$	2 670	2 670	2 670
	Efficiency (LHV)	%	60	60	60
	Annual OPEX	% of CAPEX	5	5	5
	Emission factor	$kgCO_2/kgH_2$	20.2	20.2	20.2
Coal gasification with carbon capture	CAPEX	US$/kW$_{H_2}$	2 780	2 780	2 780
	Efficiency (LHV)	%	58	58	58
	Annual OPEX	% of CAPEX	5	5	5
	CO_2 capture rate	%	90	90	90
	Emission factor	$kgCO_2/kgH_2$	2.1	2.1	2.1

Notes: 25-year lifetime and a 95% availability factor assumed for hydrogen production from natural gas and coal. Availability factors for electrolysis are based on the full load hours of electricity shown in following table. For water electrolysis, possible revenues from oxygen sales have not been considered in the cost analysis.

Sources: References in Table 1 of Chapter 2 for electrolysis IEAGHG (2014), "CO_2 capture at coal based power and hydrogen plants", IEAGHG (2017), "Techno-economic evaluation of SMR based standalone (merchant) hydrogen plant with CCS".

CAPEX = capital expenditure, CO_2 = carbon dioxide, $kgCO_2$ = kilogramme of carbon dioxide, kgH_2 = kilogramme of hydrogen, LHV = lower heating value, OPEX = operating expenditure.
Source: International Energy Agency (2019a).

Table 2.8 lists the future energy efficiencies of the three main water electrolysers (IEA, 2019b).

The energy efficiency of SOEC is expected to be the highest at 90%, followed by alkaline (80%) and PEM (74%).

In terms of CAPEX comparisons, alkaline is expected to emerge as the cheapest amongst the three electrolyses (US$700/kWe).

Table 2.8. Future Energy Efficiencies of the Three Main Water Electrolysers

	Alkaline electrolyser			PEM electrolyser			SOEC electrolyser		
	Today	2030	Long term	Today	2030	Long-term	Today	2030	Long term
Electrical efficiency (%, LHV)	63–70	65–71	70–80	56–60	63–68	67–74	74–81	77–84	77–90
CAPEX (USD/kW$_e$)	500 – 1400	400 – 850	200 – 700	1 100 – 1 800	650 – 1 500	200 – 900	2 800 – 5 600	800 – 2 800	500 – 1 000

CAPEX = capital expenditure, kWe = kilowatt electric, LHV = lower heating value, PEM = polymer electrolyte membrane, SOEC = solid oxide electrolysis cell.
Source: International Energy Agency (2019b).

4. Conclusion

H_2 production technologies are in various stages of development. Whilst some, such as SMR, have already been commercialised, others, such as the high-temperature thermochemical water-splitting, biological, and photoelectrochemical methods, are in the early stages of laboratory development and considered potential pathways for the long term.

Related research includes developing new H_2 delivery methods and infrastructure; improving carbon sequestration technology to minimise greenhouse gas emissions from coal-based H_2 production; and improving biomass growth, harvesting, and handling to reduce the cost of biomass resources used for H_2 production.

In this chapter, we calculated and evaluated the energy efficiency of H_2 production from the following sources, obtaining the estimation results for each energy efficiency (LHV base) on current commercial projects.

(i) H_2 production from natural gas (69%–76%)

(ii) H_2 production from coal (brown coal and bituminous coal) (53%–69%)

(iii) H_2 production from water electrolyser (alkali, PEM, SOEC) (56%–65%)

SOEC has not yet had a commercial project.

Fossil fuels, such as natural gas and coal, are the main sources of H_2 production because they are more efficient and cost-effective than water electrolysis using renewable energy.

Nevertheless, water electrolysers have recently and rapidly become widespread, and low-cost and high-efficiency water electrolysis is expected to be developed by 2030, leading to a significant increase in the share of H_2 production.

CO_2–free water electrolysers using renewable energy are expected to become the main source of H_2 production, projected to constitute 60%–70% or more in 2050. However, since H_2 is still expected to be produced from fossil fuels, the widespread adoption of highly efficient CCS technology is indispensable.

Chapter 3
Study on Forecast Hydrogen Transport Costs by 2050

1. Introduction

In Japan, carbon dioxide (CO_2)-free hydrogen (H_2) energy activity has been gaining momentum since the endorsement of the government's 6th Strategic Energy Plan in 2021, which identifies H_2 as an important energy solution.

Kawasaki Heavy Industries Corporation is developing world leading liquefied H_2 technologies to realise the H_2 society. These include liquefiers, cryogenic storage tanks, supply systems, liquefied H_2 carrier ships, and H_2 gas turbines. Kawasaki can contribute to decarbonisation by promoting international H_2 supply chains through H_2-related technologies.

In this chapter, liquefied H_2 (LH_2) transport cost is predicted from the difference in annual transport quantity and voyage distance.

2. Explanation of Liquefied Hydrogen Supply Chain

Demand for H_2, which has the potential to reduce CO_2 emissions, is expected to increase. To meet greatly increasing demand, it is essential to economically and reliably supply large quantities of H_2 to Japan, which requires developing a large-scale H_2 supply chain. To establish an LH_2 supply chain, Kawasaki has been working on technology demonstration towards commercialisation and the establishment of a cooperative consortium, and on technology and product development.

Marking the start of commercialisation of the LH_2 supply chain, a pilot-scale technical demonstration project entered its operation phase in fiscal 2020. H_2 is produced by gasifying and refining coal in Latrobe Valley, Victoria, Australia. The produced H_2 is then transported to a liquefaction and loading terminal in the Port of Hastings, where it is liquefied. Subsequently, the H_2 is transported via the world's first LH_2 carrier ship to Hy touch Kobe, the LH_2 terminal on Kobe Airport Island.

The pilot project will make it possible to source H_2 from overseas in the same way that liquefied natural gas (LNG) is today. H_2, which can be produced from renewable energy sources, is indispensable for realising a sustainable energy society and decarbonisation. Feasibility studies are underway in collaboration with several partner companies overseas to produce H_2 from renewable energy sources.

2.1. Concept of Liquefied Hydrogen Supply Chain

Figure 3.1 shows the conceptual diagram of Kawasaki's LH_2 energy supply chain. Kawasaki plans to produce H_2 overseas from affordable resources and transport LH_2 to Japan. The scheme is similar to the LNG supply chain.

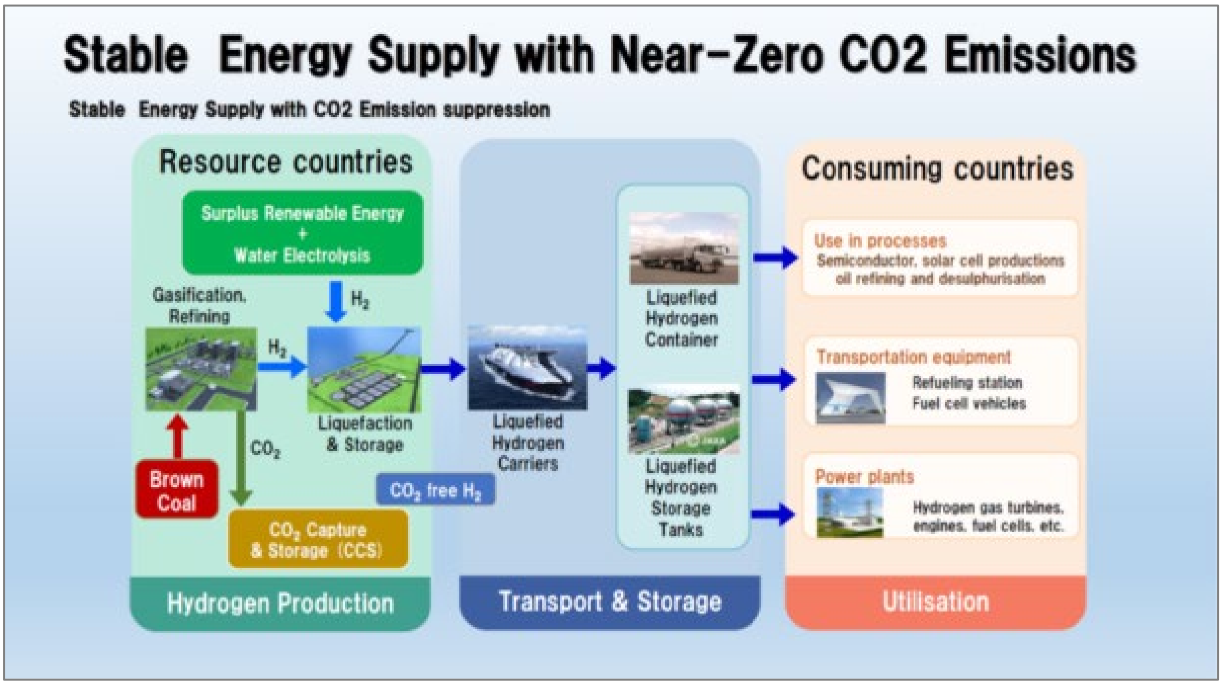
The method of producing H_2 enables the promotion of a CO_2-free H_2 supply chain worldwide. We are looking for a suitable location to produce H_2 at a reasonable cost from fossil fuels with carbon capture, utilisation, and storage (CCUS) or renewable energy such as solar, wind, or hydropower (Figure 3.2).

To transport and store H_2 efficiently, the produced H_2 gas is liquefied. Subsequently, the LH_2 is loaded onto a special LH_2 carrier ship and transported to Japan.

H_2 is used for various purposes such as feedstock, fuel cell vehicles (FCVs), distributed power and heat generation, and large-scale utility power generation. A H_2 power station with a capacity of about 1 GW requires 220,000 tonnes of H_2 annually, equivalent to the total annual fuel for 3 million FCVs.

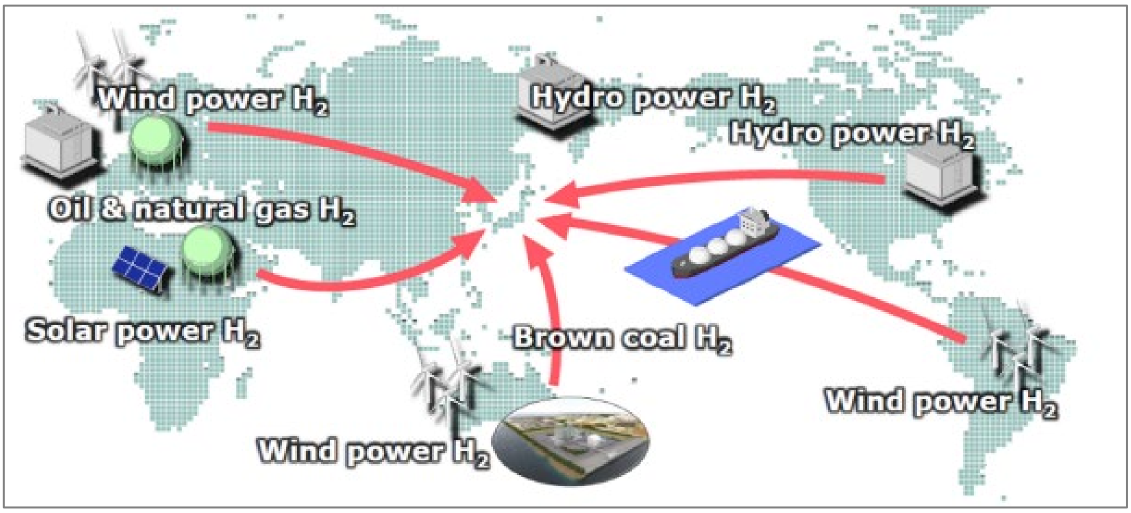
A large-scale CO_2-free H_2 supply chain is expected to bring down the cost of H_2 and make it competitive. This, in turn, can promote the deployment of FCVs, H_2 stations, and other H_2-energised equipment. We believe realising a large-scale supply chain will accelerate the development of the H_2 economy and contribute to a sustainable future.

Figure 3.1. Conceptual Diagramme of the Hydrogen Energy Supply Chain by Kawasaki Heavy Industries Corporation



CO_2 = carbon dioxide, H_2 = hydrogen.
Source: Authors.

Figure 3.2. Expected Carbon Dioxide–free Hydrogen Supply Chain

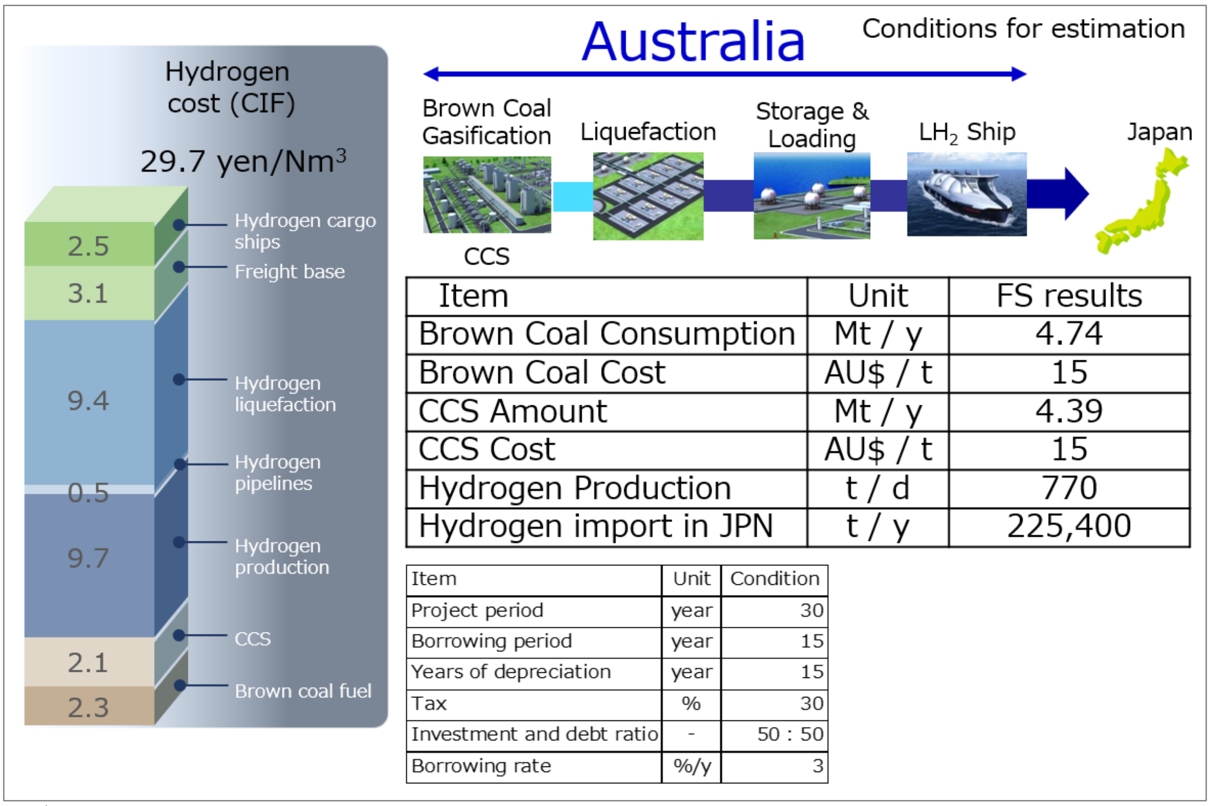


H_2 = hydrogen.
Source: Authors.

Kawasaki has calculated the costs for the H_2 supply chain in 2030 and the distant future (2050) (Nishimura et al., 2015; ERIA, 2019) (Figure 3.3).

The total cost of the LH_2 supply chain, under the following assumptions, is ¥29.7 per normal cubic metre [Nm^3]). H_2 liquefaction cost accounts for the highest ratio (¥9.4/Nm^3, 31.6%). Following closely are costs for H_2 production (¥5.5/Nm^3, 18.5%) and H_2 refining (¥4.2/Nm^3, 14.1%). The cost shares of liquefied H_2 marine transport (¥2.5/Nm^3, 8.4%) and carbon capture and storage (¥2.1/Nm^3, 3.7%) are relatively low.

Figure 3.3. Result of Cost Analysis (Cost, Insurance, and Freight Base) in the Liquefied Hydrogen Supply Chain



Item	Unit	FS results
Brown Coal Consumption	Mt / y	4.74
Brown Coal Cost	AU$ / t	15
CCS Amount	Mt / y	4.39
CCS Cost	AU$ / t	15
Hydrogen Production	t / d	770
Hydrogen import in JPN	t / y	225,400

Item	Unit	Condition
Project period	year	30
Borrowing period	year	15
Years of depreciation	year	15
Tax	%	30
Investment and debt ratio	-	50 : 50
Borrowing rate	%/y	3

AU$ = Australian dollar; CCS = carbon capture and storage; CIF = cost, insurance, and freight; JPN = Japan; LH_2 = liquefied hydrogen; Mt/y = million tonnes per year; Nm^3 = normal cubic metre; t/d = tonne per day; t/y = tonne per year.
Source: Authors.

2.2. Liquified Hydrogen

2.2.1. Characteristics of Liquefied Hydrogen Carrier

LH_2 is a clean and sustainable energy carrier and has been used mainly in industrial applications such as semiconductor manufacturing and specialised applications such as rocket fuel.

Figure 3.4 shows the advantages of an LH_2 carrier. The volume of LH_2 is 1/800 of gaseous H_2, making it highly efficient for transporting large quantities of H_2 overseas.

With a purity of 99.999% or higher, LH_2 can be directly supplied to fuel cells only by evaporating it without refining, a process that needs domestic energy. When burned, H_2 emits only water, not CO_2, contributing significantly to environmental conservation.

H_2 is non-toxic and has no greenhouse effect, making it an excellent substance in terms of health and safety.

The LH_2 supply chain resembles the liquefied natural gas (LNG) supply chain. Whilst LNG, which is distributed all over the world, was once very expensive, its affordability increased as distribution volumes increased over the years. Similarly, LH_2 may see its costs significantly reduced in the future. These factors are why we chose LH_2 as a carrier.

Figure 3.4. Advantages of Liquefied Hydrogen Carrier

LH_2 = liquefied hydrogen.
Source: Authors.

2.2.2. Comparison of Liquefied Hydrogen and Methylcyclohexane from the Viewpoint of Energy Efficiency

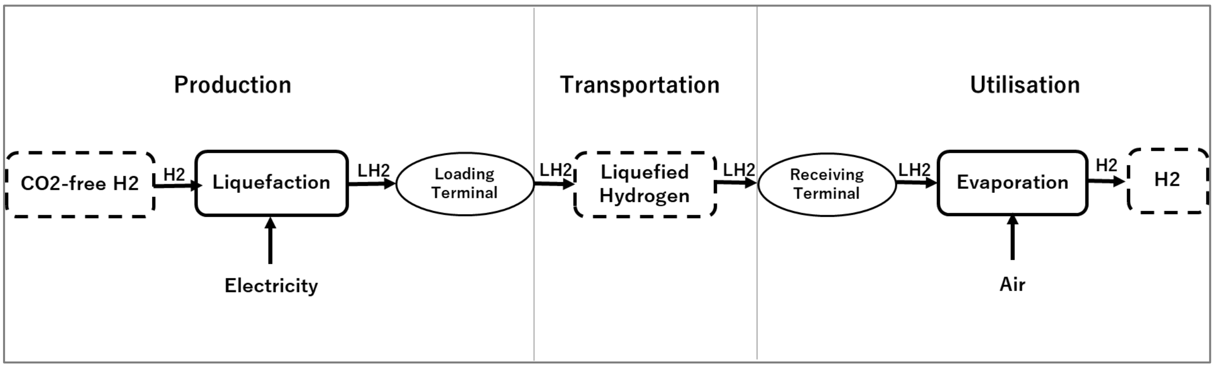
Amongst the many available technologies for H_2 carriers, two main technologies are receiving intensive attention from the Japanese government and industries: LH_2, and the toluene and methylcyclohexane (MCH) cycle.

The methods were chosen mainly for their H_2 storage capacity, technological maturity, carbon-free nature, and economic competitiveness, and the availability of supporting technology. Japanese companies have demonstrated the feasibility of these technologies on a large scale and for mass production.

In general, H_2 is produced from conversion of fossil fuels, by-products of steelmaking and chemical processes, and renewable energy sources. The H_2 is then stored and transported using several methods, including compressed and liquefied H_2, liquid organic H_2 carriers, and H_2 pipelines. H_2 can be converted through direct combustion, internal combustion engines, and fuel cells, or it can be blended into available pipeline gas for residential use. H_2 holds potential as fuel for FCVs and as a material for chemical industries.

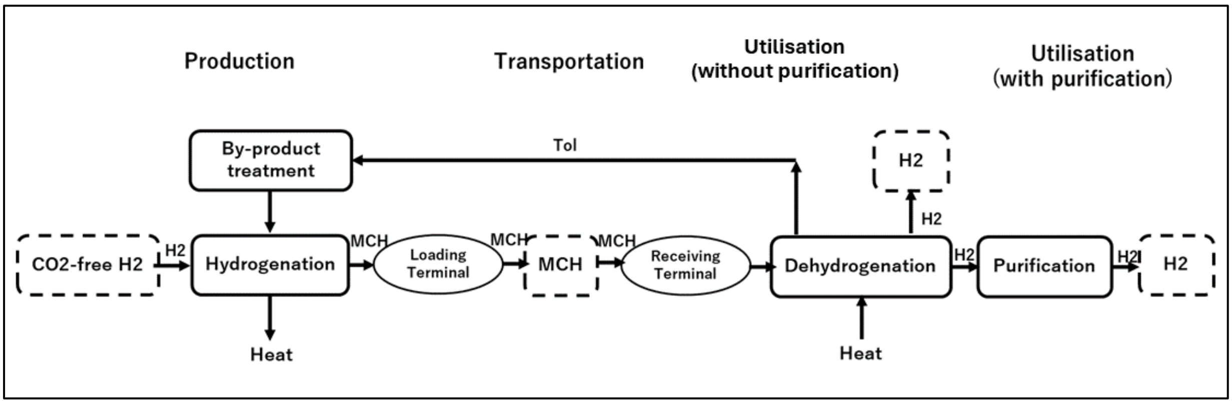
Figures 3.5 and 3.6 show the H_2 routes, covering production, transport, and utilisation, for each storage and transport method. In the liquefied H_2 process, produced H_2 is directly liquefied through cryogenic liquefaction. H_2 can be released through regasification, producing high-purity H_2. In H_2 storage using the toluene–MCH cycle, however, H_2 must be hydrogenated with the toluene on the production side (exothermic) and dehydrogenated from MCH on the utilisation side (endothermic). If high-purity H_2 is required (as for fuel cells), the released H_2 from MCH must be purified.

Figure 3.5. Hydrogen Stored in Liquefied Condition



CO2 = carbon dioxide, H2 = hydrogen, LH2 = liquefied hydrogen.
Source: Authors.

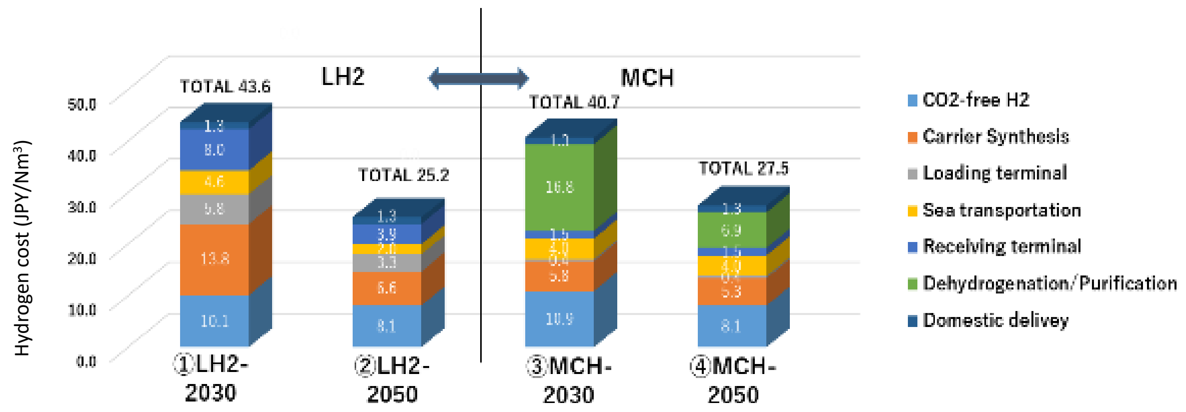
Figure 3.6. Hydrogen Stored through Hydrogenation and Dehydrogenation of Toluene– Methylcyclohexane



CO2 = carbon dioxide, H2 = hydrogen, MCH = methylcyclohexane.
Source: Authors.

Figure 3.7 shows projections of H_2 prices in Japan for 2030 and 2050. The assumed transport distance is about 10,000 kilometres (km), calculated from the H_2 producer (Australia) to the H_2 consumer (Japan). The expected amount of imported LH_2 is about 3.0×10^9 tonne per year signalling a large increase in imported LH_2 (New Energy and Industrial Technology Development Organization [NEDO] and International Energy Agency [IEA], 2016). Mature technologies, including cryogenic liquefaction, tank storage, and regasification technologies, can achieve the greatest price reductions for LH_2.

Figure 3.7. Forecast Hydrogen Price in Japan in 2030 and 2050



①Breakdown of hydrogen cost of liquefied hydrogen system (JPY/Nm3, R&D case for power generation 2030)
②Breakdown of hydrogen cost of liquefied hydrogen system (JPY/Nm3, maximum introduction case for power generation 2050)
③Breakdown of hydrogen cost of MCH system (JPY/Nm³, for power generation, research and development case 2030)
④Breakdown of hydrogen cost of MCH system (JPY/Nm³, for power generation, maximum introduction case 2050)

CO_2 = carbon dioxide, LH_2 = liquefied hydrogen, JPY = yen, MCH = methylcyclohexane, Nm^3 = normal cubic metre, R&D = research and development.
Sources: New Energy and Industrial Technology Development Organization and International Energy Agency (2016).

Table 3.1 shows the energy efficiency achieved by each storage method (carrier) covering production, transport, and utilisation. Liquefaction is used for LH_2 and hydrogenation for MCH (Aziz et al., 2019).

Energy efficiency during production involves changes in lower heating value that occur during conversion. Transport encompasses the entire transport process, including terrestrial and oceanic modes, and considers both the gaseous phase and storage forms of H_2. Therefore, transport efficiency tackles all losses, including leakage, heat loss, and phase changes. Utilisation involves the release of H_2 as a gas ready for further application and energy conversion. Further application comprises regasification of LH_2 and dehydrogenation of MCH, whilst energy conversion encompasses various technologies to harness energy from H_2, particularly to generate electricity.

LH_2 production is deficient due to energy-intensive cooling. MCH has an advantage in hydrogenation but has limitations in dehydrogenation. On the utilisation side, fuel cells are believed to perform better than combustion.

Table 3.1. Characteristics, Advantages, and Challenges Faced by Two Candidates (Liquefied Hydrogen and Methylcyclohexane) for Hydrogen Storage

Storage method	Production	Transportation	Utilisation	Total
Liquefied hydrogen(direct comb)	**58%**	**95%**	**55%**	**30%**
Liquefied hydrogen (fuel cell)	**58%**	**95%**	**60%**	**33%**
MCH(dehydrogenation, direct comb)	**95%**	**100%**	**26%**	**25%**

comb. = combustion MCH = methylcyclohexane.
Source: Aziz et al (2019).

The energy efficiency of LH_2 is 42%–44% and that of MCH is 34%–38% (Table 3.2) (NEDO and IEA, 2016).

Table 3.2. Results of Energy Efficiency Evaluation of Liquefied Hydrogen and Methylcyclohexane

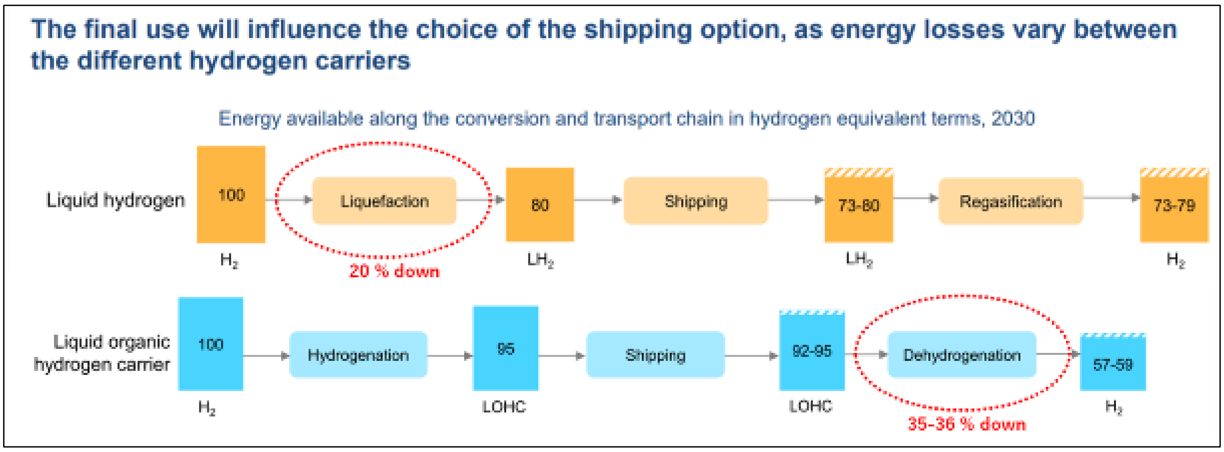
Case	Liquefied Hydrogen	Methylcyclohexane(MCH)
R & D case for power generation 2030	**42%**	**34%**
Power generation, maximum introduction case 2050	**44%**	**38%**

R&D = research and development.
Sources: New Energy and Industrial Technology Development Organization and International Energy Agency (2016).

IEA (2022) evaluates the conversion losses of LH_2 and liquid organic H_2 carriers (Figure 3.8). Within the LH_2 supply chain, the largest energy loss occurs during liquefaction (20 points down). Therefore, utilising the cold heat from LH_2 is important to offset future cooling energy losses.

In the case of liquid organic H_2 carrier (MCH), the largest energy loss is attributed to dehydrogenation (35 points down), despite minimal energy loss between hydrogenation and shipping. If MCH can be used without dehydrogenation, it will be a highly efficient energy carrier.

Figure 3.8. Conversion Losses of Different Hydrogen Shipping Options



H_2 = hydrogen, LH_2 = liquefied hydrogen, LOHC = liquid organic hydrogen carrier, NH_3 = ammonia.
Note: The numerical values depict the remaining energy content of H_2 throughout the supply chain, with a reference starting value of 100. This assumes that all energy needs at each stage are met by H_2 or H_2-derived fuel. The Haber-Bosch synthesis process includes energy consumption in the air separation unit. Boil-off losses from shipping are calculated based on a distance of 8,000 kilometres. In the case of LH_2, the dashed areas indicate energy recovery using boil-off gases as shipping fuel, corresponding to the upper-range numbers. For ammonia and liquid organic H_2 carrier, the dashed area represents the energy requirements for one-way shipping, which are factored into the lower-range figures.
Source: International Energy Agency (2022).

2.2.3. Main Equipment and Facilities for Liquefied Hydrogen Supply Chain

This section describes the equipment and facilities that are important for building an LH_2 supply chain. In Japan, the pilot demonstration has been completed.

In preparation for commercialisation in the second half of the 2020s, the development of large equipment – including LH_2 storage tanks, loading arm systems (LASs), liquefiers, and LH_2 pumps – alongside the construction of a commercial ship capable of transporting 160,000 m^3 liquefied hydrogen – has commenced. The initiative is being supported by the Japanese government and NEDO.

2.2.3. (a) Liquefied Hydrogen Carrier Ship[(6)]

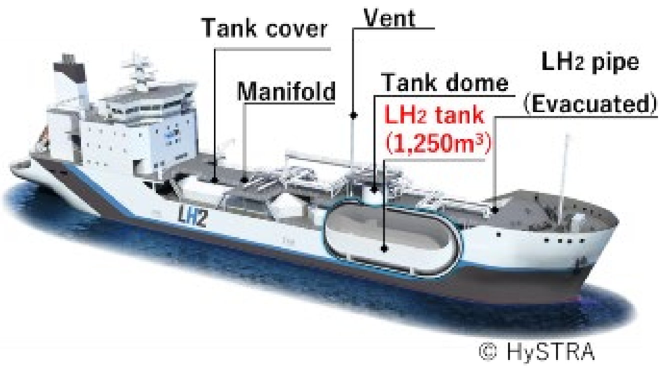
The LH_2 carrier ship transports LH_2, moving it from a resource country to Japan, a consuming country. LH_2 is highly convenient for transporting large amounts of H_2. Leveraging established technologies employed in constructing LNG marine carriers, along with expertise in land transport and LH_2 storage, Kawasaki has developed a novel cargo containment system using cryogenic technology to facilitate the marine transport of LH_2.

To date, the operational performance of large LH_2 transport tanks is unprecedented globally. Kawasaki has secured approval and a recommendation for the first time from the International Maritime Organization Maritime Safety Committee for the offshore carriage of LH_2 in bulk.

Figure 3.9 and Table 3.3 present an overview and specifications of an LH_2 carrier ship constructed for pilot demonstration. The installed ship features a 1,250 m^3 LH_2 storage tank, with a loading capacity of 75 tonnes at one time.

Kawasaki adapted the well-established electric propulsion system, using a diesel generator, to demonstrate the cargo containment system for LH_2. The company plans to use boil-off gas as a propulsion fuel in the first stages of commercial operation. This use of the boil-off gas system, derived from LNG carrier ships, could help reduce CO_2 emissions when applied to LH_2 carrier ships.

Figure 3.9. Outline of a Pilot Liquefied Hydrogen Carrier Ship



LH_2 = liquefied hydrogen, m^3 = cubic metre.
Source: Authors.

Table 3.3. Principal Particulars of a Pilot Liquefied Hydrogen Carrier Ship

Ship	
Principal Dimensions:	L X B X D (ab. 110m x ab.20m x ab.11m)
Gross Tonnage:	ab. 8,000
Propulsion System:	Diesel – electric[1)]
Speed:	ab. 13.0 knots
Flag State/Class:	Japan / Nippon Kaiji Kyokai (ClassNK)
Cargo Containment System[2)]	
Total Capacity:	ab. 1,250m³ (No. of Tank: 1)
Tank Type:	IMO Independent Tank Type C
Max. Design Pressure:	0.4MPaG
Min. Design Temperature:	-253 degree C (20K)
Insulation System:	Vacuum Multi-layer Insulation + Supplementary Kawasaki Panel insulation System
BOG Management:	Pressure Accumulation in the inner vessel in principle (BOG is not used for propulsion fuel)

L=length, B=breadth, D=depth, m^3=cubic metre, IMO=International Maritime Organization, K=kelvin, C=Celsius, MPaG=mega pascal gage, BOG=boil off gas
Notes:
1. The application of a diesel-electric propulsion system will provide an option to use generated electricity from accumulated boil-off H_2 gas.
2. Kawasaki Heavy Industry Corporation received approval in principle from Nippon Kaiji Kyokai (ClassNK) for carbon capture and storage in advance of this project based on the collaboration between ClassNK and Kawasaki in 2013. In 2016, Kawasaki evaluated and demonstrated the manufacturability and vacuum multi-layer insulation performance of a large-scale vacuum insulated tank. This involved fabricating a nearly full-scale mock-up tank, covering processes such as bending and welding a large stainless-steel tank and achieving the desired vacuum levels.

In preparation for commercialisation, Kawasaki initiated the design of an LH_2 ship with a capacity of 160,000 m^3 (comprising four tanks of 40,000 m^3 each), resembling the structure of an LNG ship capable of transporting about 10,000 tonnes in a single trip (Figure 3.10).

Figure 3.10. Large (16,000 cubic metres) Liquefied Hydrogen Carrier Ship (Cargo-carrying Capacity: 40,000 cubic metres × 4 tanks)

Source: Authors.

2.2.3. (b) Liquefied Hydrogen Cryogenic Storage Tank [7]

The LH_2 storage tank (Figure 3.11 [a]) is a spherical double-walled vacuum tank with a nominal geometrical capacity of 2,500 m^3. The tank receives and stores LH_2 transported from Australia, and then stores LH_2 transported by land from sites in Japan before subsequent loading onto LH_2 carriers.

To ensure prolonged storage of LH_2 with minimal evaporation loss, an LH_2 storage tank requires better thermal insulation than an LNG storage tank. Consequently, a vacuum insulation system was employed. Whilst the largest LH_2 storage tank in Japan, at the Tanegashima Space Centre, has a capacity of 540 m^3, our storage tank is designed to be at least four times larger. Kawasaki has implemented a perlite vacuum insulation system, augmenting thermal insulation by introducing perlite – a thermal insulation material – between the inner and outer spherical tanks and subsequently creating a vacuum (Figure 3.11 [b]).

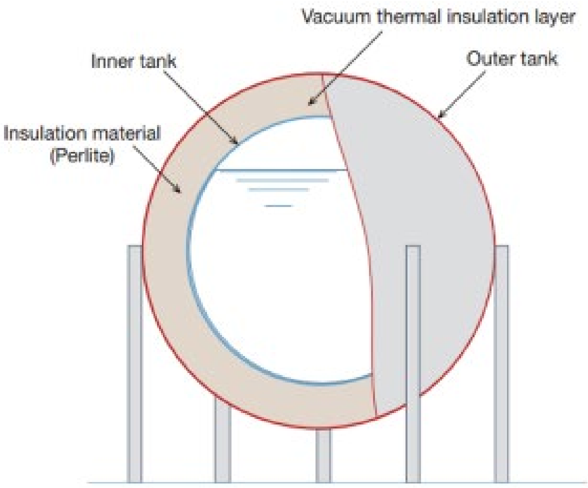
To accommodate larger sizes, Kawasaki has been studying the most suitable on-site manufacturing method for welding thick plate materials, favouring construction sites over factories. The company is optimising a plate-cutting plan to boost construction efficiency. This ongoing effort aims to accumulate expertise to manufacture similarly large tanks.

We have been studying the operational aspects of large tanks, including H_2 gas replacement before the recharge of LH_2 and the optimisation of tank cooling. These operations were successfully demonstrated in 2020.

Figure 3.11. Liquefied Hydrogen Cryogenic Storage Tank (Kobe Airport Island) in April 2020

Figure 3.11 (a). Liquefied Hydrogen Storage Tank

Figure 3.11. (b) Conceptual Diagramme of Vacuum



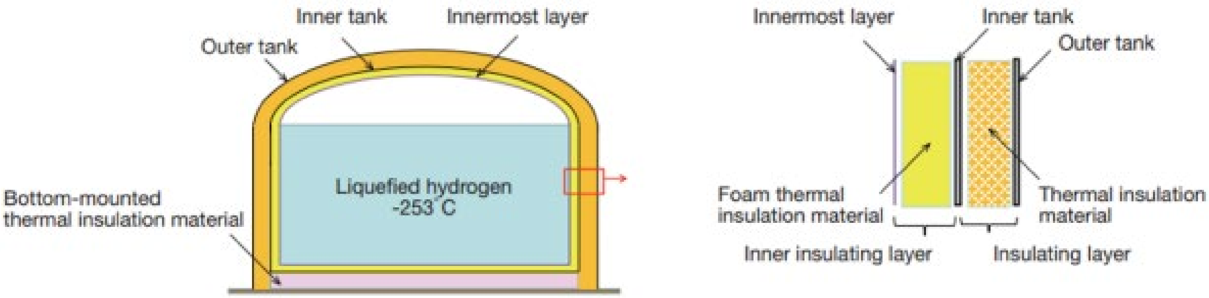
Source: Authors.

For a storage tank requiring tens of thousands of cubic metres, as would be essential at the commercial stage, creating an exceedingly thick outer tank poses difficulties, particularly in acquiring and manufacturing plate materials.

Hence, Kawasaki is developing a large-scale LH_2 storage tank with a novel structure, paving the way for commercialisation. The initiative is being undertaken as part of a grant project by NEDO: Development of Large-scale Equipment for the Transport and Storage of LH_2 and Equipment for LH_2 Unloading Terminals.

Under study is a flat-bottomed cylinder (Figure 3.12), which has higher volume efficiency than the spherical-shaped cylinder used for large LNG tanks. The design incorporates a non-vacuum structure, using H_2 gas at atmospheric pressure between the inner and outer tanks to prevent buckling caused by vacuum pressure, which is common in vacuum thermal insulation structures. We are considering applying gas barrier materials to the surfaces of thermal insulation materials to prevent the deterioration of the thermal insulation properties due to H_2 gas permeating the foam insulation materials. The concept of the structure is to repurpose existing LNG storage tanks, which will be effective as we gradually replace LNG with H_2 in the initial stages of a H_2-based society.

Figure 3.12. Structural Design of a Large-scale Tank



Source: Authors.

2.2.3. (c) Hydrogen liquefier [8]

H_2 liquefaction systems, which require advanced cryogenic technology, are an important factor in the global supply chain of LH_2.

Kawasaki has built Japan's first domestically developed commercial-scale liquefaction system that can liquefy about 5 tonnes of H_2 per day. Since the first successful liquefaction in 2014, Kawasaki has improved liquefaction efficiency by about 20% with its new liquefier and has demonstrated the reliability of the liquefier through long-term operation. Kawasaki has begun technical studies to further increase the size and efficiency of liquefiers (Figure 3.13, Figure 3.14).

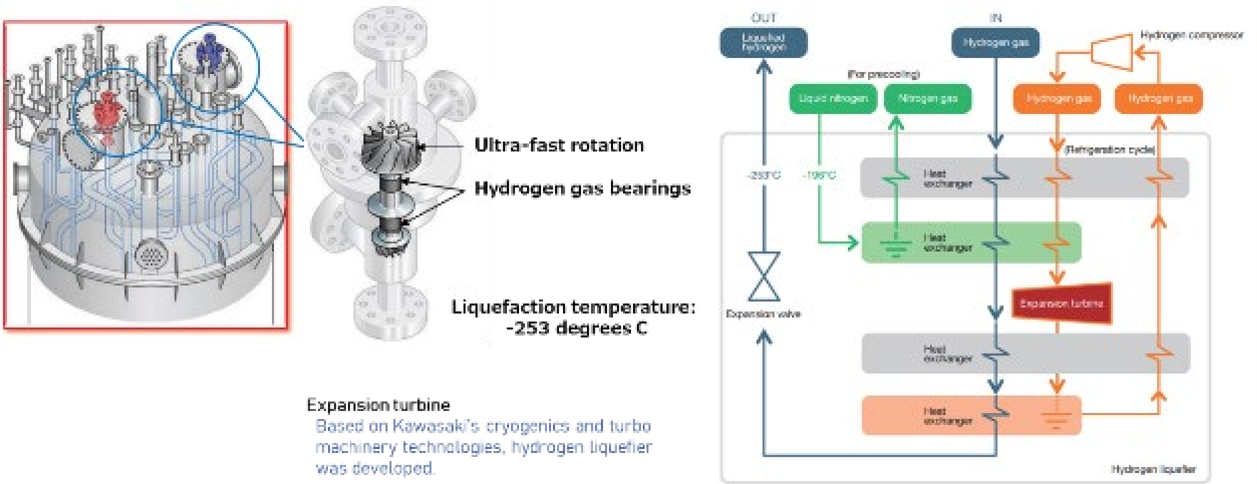
Liquefaction systems need advanced machinery technology to create expansion turbines capable of maintaining super high-speed rotation (>100,000 rpm). Kawasaki has successfully leveraged its expertise in diverse technologies, drawing from the motorcycle supercharger system and the gas turbine system.

Whilst natural gas liquefaction boasts large-scale and high-efficiency facilities, H_2 liquefaction plants operate at a capacity of about 5–25 tonnes per day (TPD). The primary challenge is to increase this capacity and improve efficiency.

Figure 3.13. Hydrogen Liquefier at the Harima Factory

Source: Authors.

Figure 3.14. Hydrogen Liquefier Structure and Schematic Process Flow Diagram



Hydrogen liquefier (upper part) and expansion turbine

Schematic process flow diagram of hydrogen liquefaction system

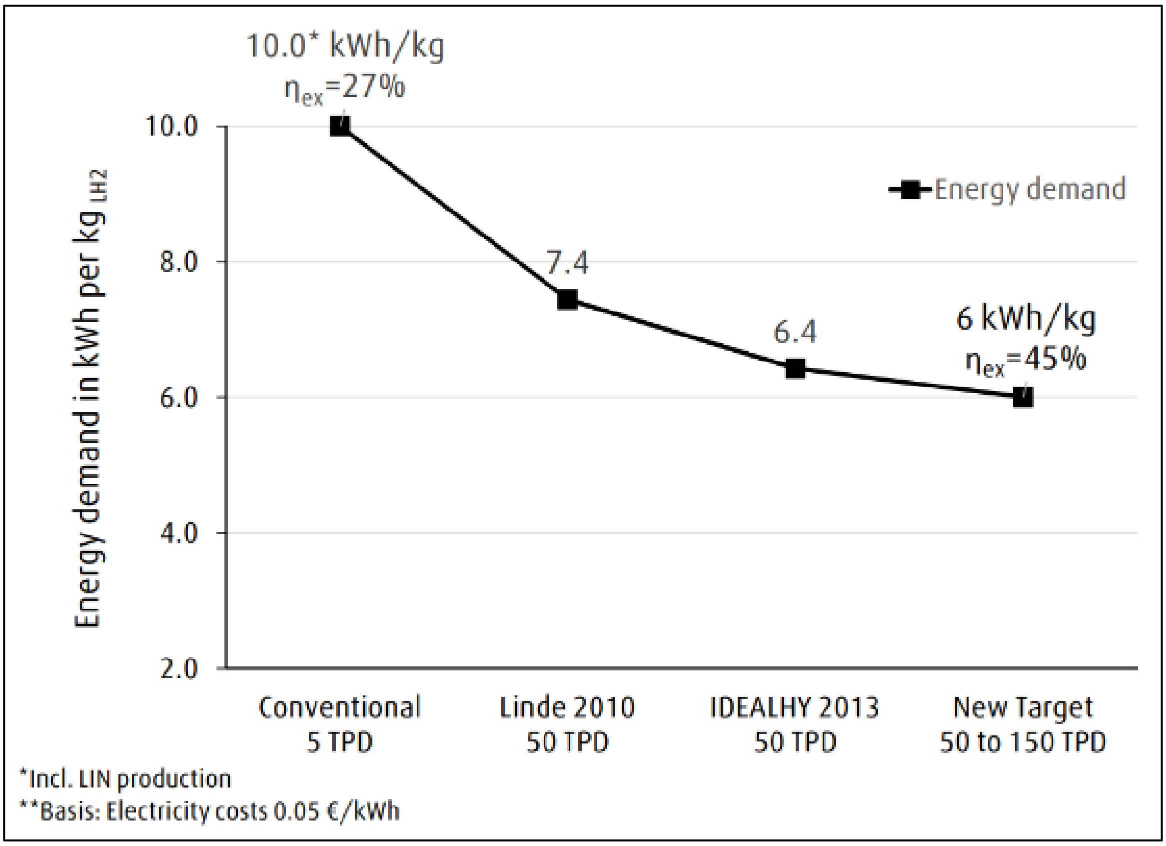
Source: Authors.

A conventional small liquefier (5 TPD) has a liquefaction efficiency of 27% (10.0 kilowatt-hour [kWh]/kilogramme [kg]) (Figure 3.15) (Cardella et al., 2016).

Expected larger liquefiers (50–100 TPD) in the future are anticipated to achieve an enhanced efficiency of 45% (6 kWh/kg). The improvement is attributed to the larger size of and advancements in liquefaction efficiency technology, making it 40% more efficient.

Boosting liquefaction efficiency, which accounts for the highest proportion of the LH_2 supply chain cost, will lead to a substantial reduction in the cost of the LH_2 supply chain cost, expediting the economical transport of large quantities of H_2.

Figure 3.15. Prior Concepts and New Objectives



kg = kilogramme, kWh = kilowatt hour, LH_2 = liquefied hydrogen, TPD = tonne per day.
Source: Cardella et al. (2017).

2.2.3 (d) Liquefied Hydrogen Loading and Unloading System[7]

Tokyo Boeki Engineering, Ltd. and Kawasaki have collaborated on building the world's first LAS for transferring LH_2 from a carrier ship to an onshore storage facility (Figure 3.16).

Because the temperature of LH_2 is lower than the liquefaction temperature of air, employing loading arms designed for LNG using earlier technology poses a fire risk. The reason is that, during LH_2 transfer, liquid oxygen may be generated on piping surfaces. To mitigate the risk, a structural design has been developed to deliver high thermal insulation performance and ensure safety.

The loading arm has three key features:

(i) A double-walled vacuum insulation structure that provides high thermal insulation performance. By providing a vacuum between the outer and inner pipes, a high level of insulation is achieved, maintaining the surface temperature of the outer pipe at close to the ambient temperature and precluding liquefied oxygen generation.

(ii) A highly flexible swivel joint for the piping that permits 360-degree rotation whilst maintaining high thermal insulation.

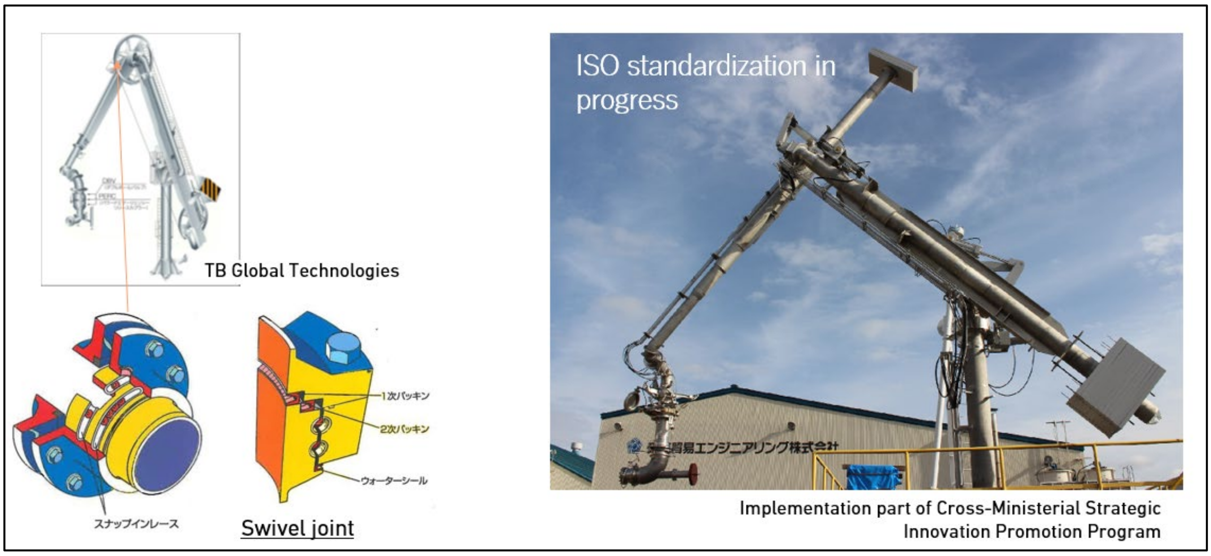
(iii) An emergency release system that safely interrupts LH_2 transfer in the event of an emergency.

Figure 3.16. Liquefied Hydrogen Loading and Unloading System

m^3 = cubic metre.
Source: Authors.

To accommodate the larger diameter requirements of a commercial LAS, considering factors such as installation area and weight, the primary method for tracking the swaying movement of a carrier involves adopting the swivel joint used in LNG terminals. In a joint development effort as part of the Strategic Innovation Promotion programme, we have manufactured an experimental LAS of this type (Figure 3.17) that aims to establish its position as an early mover in the development of loading arms for transferring liquefied hydrogen. Tokyo Boeki Engineering, Ltd., a major player in LAS used for LNG worldwide and a co-developer of this project, has confirmed that the LAS functions normally. Ongoing demonstration tests with LH_2 aim to complete the development.

Figure 3.17. Liquefied Hydrogen Loading Arm Systems for Commercial Use – Loading System: Swivel Joint Type



LNG = liquefied natural gas.
Source: Authors.

3. Study of Hydrogen Transport Cost in 2030

This section presents a study of transport costs associated with LH_2 carriers. We conducted a preliminary examination of H_2 transport costs, considering varying annual transport quantities (200,000, 600,000, 1,000,000 tonnes) and voyage distances (4,500, 10,000, and 15,000 km) using LH_2 carrier ships.

We predicted the H_2 transport cost at US cent/Nm^3 and US cent/Nm^3-km) in 2030. The calculations were based on a specific LH_2 transport carrier ship model with a capacity of 160,000 m^3, like those commercially used for LNG transport.

The analysis for 2030 considers the expected technological advancement, summarising the cost, capacity, and efficiency of LH_2 carrier ships.

3.1. Specifications of a Commercial Liquefied Hydrogen Carrier Ship

Table 3.4 presents the specifications of a commercial LH_2 carrier ship, designed to align with the scale of currently employed LNG carriers (160,000 m^3). The primary source of propulsion fuel for the LH_2 carrier ship is predominantly boil-off gas.

Table 3.4. Specifications of a Liquefied Hydrogen Carrier Ship

a) Principal Dimensions		d) Boil-off Gas	
Length overall	About 315.00 m	Designed	0.4%/day
Length perpendicular	300.00 m	e) Cargo Handling Equipment	
Breadth (mld.)	55.0 m	Cargo tank	4 sets
Depth (mld.)	28.0 m	Cargo pump	8 sets
b) Capacity		FG compressor	2 sets
LH_2 cargo tank	About 161,600 m^3	Cargo compressor	2 sets
Maximum LH_2 loading capacity	11.328 t/ship	Cargo heater	2 sets
Maximum LH_2 filling capacity	10,966 t/ship	Cargo vaporizer	1 set
Filling rate	96.8%	LH_2 vaporizer	1 set
c) Speed			
Service speed 1)	About 18.0 knots =33.3 km/h		

km/h=kilometre per hour, LH_2 = liquefied hydrogen, m = metre, m^3=cubic metre, mld = moulded, t/ship=tonne per ship, MCO =Multi-Canister Overpack.
Notes:
On draught of 9.5 m, at 90% MCO, with 21% sea margin.
At 90% MCO, based on H_2 gas of low calorific value of 121,000 kJ/kg.
At 90% MCO, based on marine gas oil of low calorific value of 42,700 kJ/kg.
H_2 gas fuel supply system is pending and not considered yet.
Assuming development of cargo-handling equipment is to be completed.
The design of the ship is under development and the content of the design report is not guaranteed. The information shown above is preliminary and for reference only and remains subject to change without notice.
Source: Authors.

3.1.1. Preconditions for Liquefied Hydrogen Transport Cost Calculation (Common)

Table 3.5 shows the preconditions (common) used to calculate LH_2 transport costs. The computations were executed using a specific type of LH_2 carrier (160,000 m^3, 40,000 m^3 x 4 tanks). We varied the voyage distance for three scenarios (4,500, 10,000, and 15,000 km) and annual transport quantities for three scenarios (200,000, 600,000, and 1,000,000 tonnes).

(a)–(e) Setting condition

A large commercial supply chain is assumed to start in 2030, involving large-scale importation of LH_2 to Japan.

Precondition for sea transport

LH_2 carrier ship: 160,000 m^3 commercial carrier ship (40,000 m^3 x 4 tanks)

Voyage distance: three scenarios (4,500, 10,000, and 15,000 km – one voyage)

Annual H_2 transport quantity: three scenarios (200,000, 600,000, and 1,000,000 tonnes)

Number of annual operating days: 330

Loading and unloading days: 4 days (total unloading and loading)

(f)–(i) Liquefied hydrogen carrier ship (Table 3.4)

(j) Project period

The project period is 30 years. However, as the continuation or termination of the business beyond 30 years has not yet been decided, dismantling and removal costs are not included.

(k) Borrowing rate

Considering the US 6-month London inter-bank offered rate (LIBOR) average over the past 5 years (2.66%), the Japan Bank for International Corporation (JBIC) US currency borrowing is estimated at 0.25 (bank fee) + 2.66 = 2.91%. The economic assessment will be conducted using a borrowing interest rate of 3%, considering the current accuracy of the economic examination of the commercial chain.

(l)–(m) Years of depreciation and tax

The H_2 chain model operator, being a local corporation, will be subject to local government tax laws. Adopting Australian government and companies' law and rules, a 15-year depreciation and fixed-rate depreciation will be implemented to reduce the tax costs at the beginning of the year. The tax rate used in Australia is 30%.

(n) Investment and debt ratio

Financing usually requires substantial investment and undergoes screening. According to JBIC, an international arm of Japanese policy-based financial institutions, a financial debt ratio of 50% is applied.

(o) Subsidy ratio

The subsidy ratio will be 0% to study the economic efficiency of the project.

(p) Exchange rate

This study uses an exchange rate of ¥110/US$1.00.

(q)–(s) Utility cost (electricity, water, nitrogen)

Typical costs used in previous feasibility studies were used.

Table 3.5. Preconditions for the Calculation of Liquefied Hydrogen Transport Cost (Common)

Items		Description
(a)	Liquefied hydrogen carrier ship (Table 3.4)	Commercial carrier ship (160,000 m^3) 40,000m^3 x 4 tanks
(b)	Hydrogen voyage distance	3 scenarios: 4,500, 10,000, 15,000 km
(c)	Annual hydrogen transport quantity	3 scenarios: 200,000, 600,000, 1,000,000 t
(d)	Number of annual operating days	330
(e)	Loading and unloading days	4
(f)	Fuel cost	US$1.136/kg
(g)	Number of crew	45
(h)	Maintenance fee	CAPEX x 0.01(1%)
(i)	Project period	30 years
(j)	Borrowing period	15 years
(k)	Years of depreciation	15 years
(l)	Tax	30%
(m)	Investment and debt ratio	50:50
(n)	Borrowing rate	3% per year
(o)	Subsidy ratio	0%
(p)	Exchange rate	¥110/US$1.00
(q)	Electricity	US$0.059/kWh
(r)	Water	US$2.42/t
(s)	Nitrogen	0.2US$/$Nm^3$

CAPEX = capital expenditure, km = kilometre, kWh = kilowatt hour m^3 = cubic metre, Nm^3 = normal cubic metre, t = tonne
Note: The electricity price (q) is used for liquefaction, export terminal, and import terminal.
Source: Authors.

3.1.2. Assumptions for Calculating Liquefied Hydrogen Transport Costs (for each case)

Assumptions for Variations in Voyage Distance and Annual Hydrogen Transport Quantity

Table 3.6 presents assumptions derived from the voyage distance and annual transport quantity, encompassing factors such as the number of LH_2 carrier ships, number of operational days, and the required annual voyage frequency for each case, as computed by the analysis.

Table 3.6 shows the following issues:

- The number of carrier ships is proportional to the voyage distance and the annual transport quantity.
- The number of voyage days is proportional to the voyage distance.
- The number of annual voyages (frequency) decreases in inverse proportion to the voyage distance.

Table 3.6. Assumptions Derived from Voyage Distance and Annual Hydrogen Transport Quantity

Case No	Voyage distance(km)	Liquefied hydrogen capacity(t/y)		Number of Carrier Ship	Voyage days	Loading/ Unloading days	Number of annual voyages(times)
		Export quantity	Import quantity				
Case-1	4,500	219,622	204,772	1	12	4	20.6
Case-2		658,865	614,315	3	12	4	20.6
Case-3		1,098,108	1,023,858	5	12	4	20.6
Case-4	10,000	234,263	204,563	2	26	4	11.0
Case-5		702,789	613,689	6	26	4	11.0
Case-6		1,171,315	1,022,815	10	26	4	11.0
Case-7	15,000	250,996	206,446	3	38	4	7.9
Case-8		752,988	619,338	9	38	4	7.9
Case-9		1,254,981	1,032,231	15	38	4	7.9

km = kilometre, t/y = tonne per year
Source: Authors.

3.1.3. Capital and Operational Expenditures of Liquefied Hydrogen Transport Considering Variations in Voyage Distance and Annual Transport Hydrogen Quantity

Table 3.7 shows the CAPEX and OPEX of LH_2 transport, considering the difference in voyage distance and annual transported H_2 quantity. The cost of LH_2 carrier ships is assumed to remain constant regardless of the number of ships constructed. Since the construction cost of the LH_2 carrier ships (160,000 m^3) remains consistent regardless of the number of ships, CAPEX increases almost in proportion to the voyage distance.

Table 3.7. Capital and Operational Expenditures of Liquefied Hydrogen Transport Considering Variations in Voyage Distance and Annual Hydrogen Transport Quantity

Case No	Voyage distance(km)	Liquefied hydrogen capacity(t/y)		CAPEX (M US$)	OPEX (M US$/y)
		Export quantity	Import quantity		
Case-1	4,500	219,622	204,772	455.0	19.8
Case-2		658,865	614,315	1,370.9	59.4
Case-3		1,098,108	1,023,858	2280.9	99.0
Case-4	10,000	234,263	204,563	910.0	43.6
Case-5		702,789	613,689	2730.0	130.9
Case-6		1,171,315	1,022,815	4,550.0	218.2
Case-7	15,000	250,996	206,446	1,370.9	68.3
Case-8		752,988	619,338	4,100.9	204.8
Case-9		1,254,981	1,032,231	6830.9	341.3

CAPEX = capital expenditure, km = kilometre, MUS$ = million US dollars, OPEX = operational expenditure, t = tonne, y = year.
Source: Authors.

3.1.4. Formula for Calculating Liquefied Hydrogen Transport Cost

The LH_2 transport cost was calculated from the equipment cost (CAPEX) and annual cost (OPEX).

The LH_2 transport cost is defined as follows and indicates the average cost during the project period:

$$\textit{Liquefied hydrogen transport cost} = \frac{\{\textit{CAPEX/Project period} + \textit{OPEX}\}}{\{\textit{Annual liquefied hydrogen import quantity}\}}$$

Where:

LH_2 transport cost: (US cent/Nm^3)

CAPEX: Equipment cost related to sea shipping (million US cent)

Project period: 30 years

OPEX: Annual expenses related to sea shipping (million US cent/year), including electricity, water, nitrogen, maintenance fee, labour cost

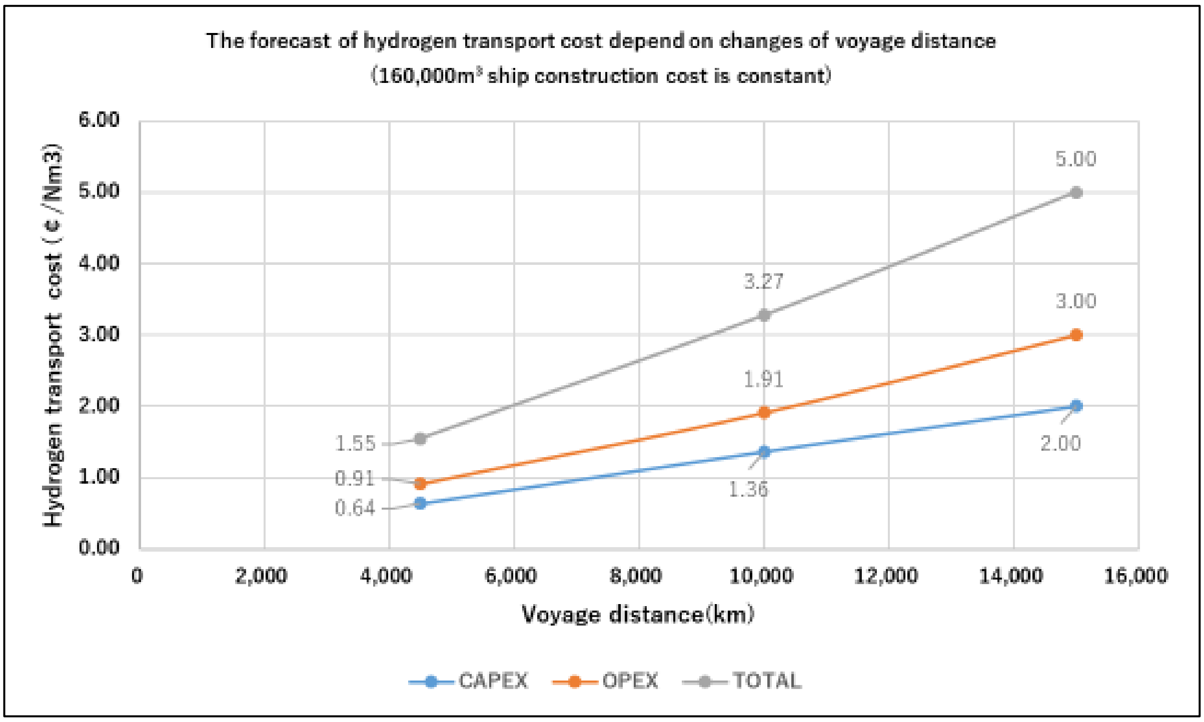
Annual LH_2 import quantity: (Nm^3 cost, insurance, and freight/year)

3.1.5. Results of the Hydrogen Transport Cost Study for Each Scenario

Table 3.18 (unit: US cent/Nm^3) and Table 3.19 (unit: US cent/Nm^3-km) show the predicted LH_2 transport costs in 2030.

Figure 3.18 illustrates that the LH_2 transport cost increases almost proportionally with the voyage distance. To reduce the cost of transporting LH_2, larger ships must be built and transport ship technology improved.

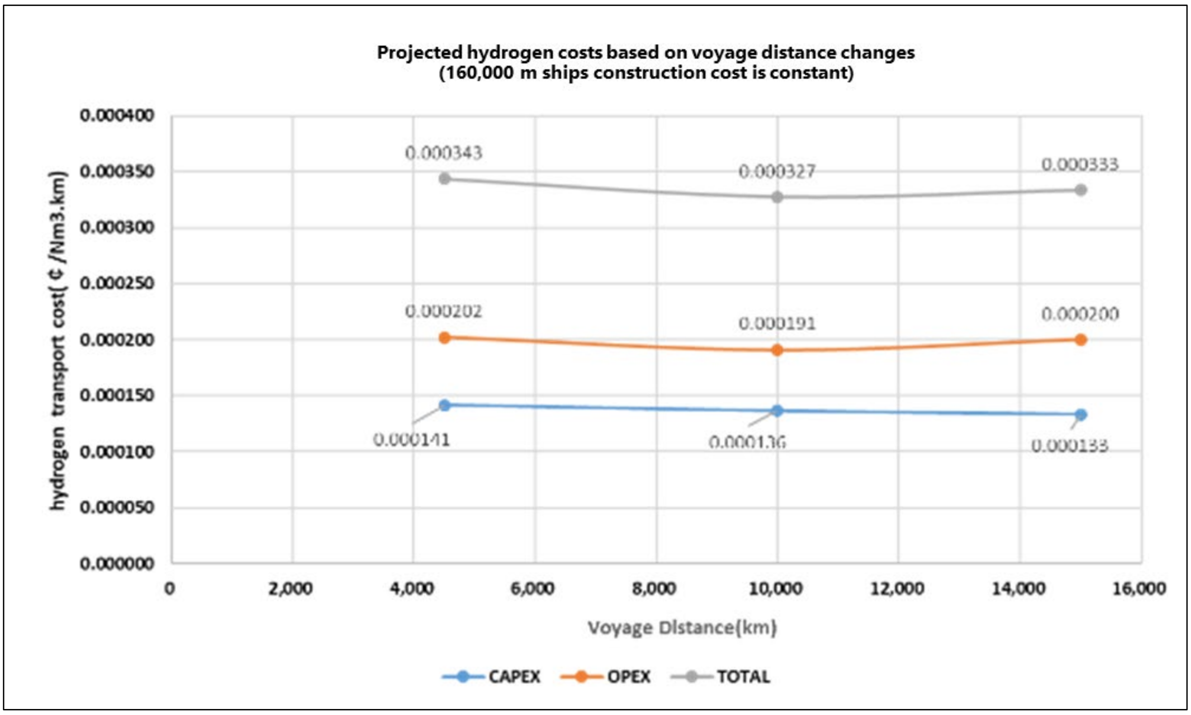
Figure 3.18. Liquefied Hydrogen Transport Cost Varied by Voyage Distance in 2030 (Unit US centnormal cubic metre)



¢ = US cent, km = kilometre, Nm^3 = normal cubic metre.
Source: Authors.

Figure 3.19 indicates that the LH_2 transport cost per unit of voyage distance remains nearly constant, at 0.000343US cent–0.000333US cent/Nm^3-km, irrespective of distance traveled.

Figure 3.19. Liquefied Hydrogen Transport Cost Disparity in 2030
(US cent/normal cubic metrw-kilometre)



¢ = US cent, CAPEX = capital expenditure, km = kilometre, Nm^3 = normal cubic metre, OPEX = operational expenditure.
Source: Authors.

3.1.6. Study Result of the Total Cost for the Liquefied Hydrogen Supply Chain (Case: 200,000 tonnes/year, 10,000 kilometres, 160,000 cubic metre ship)

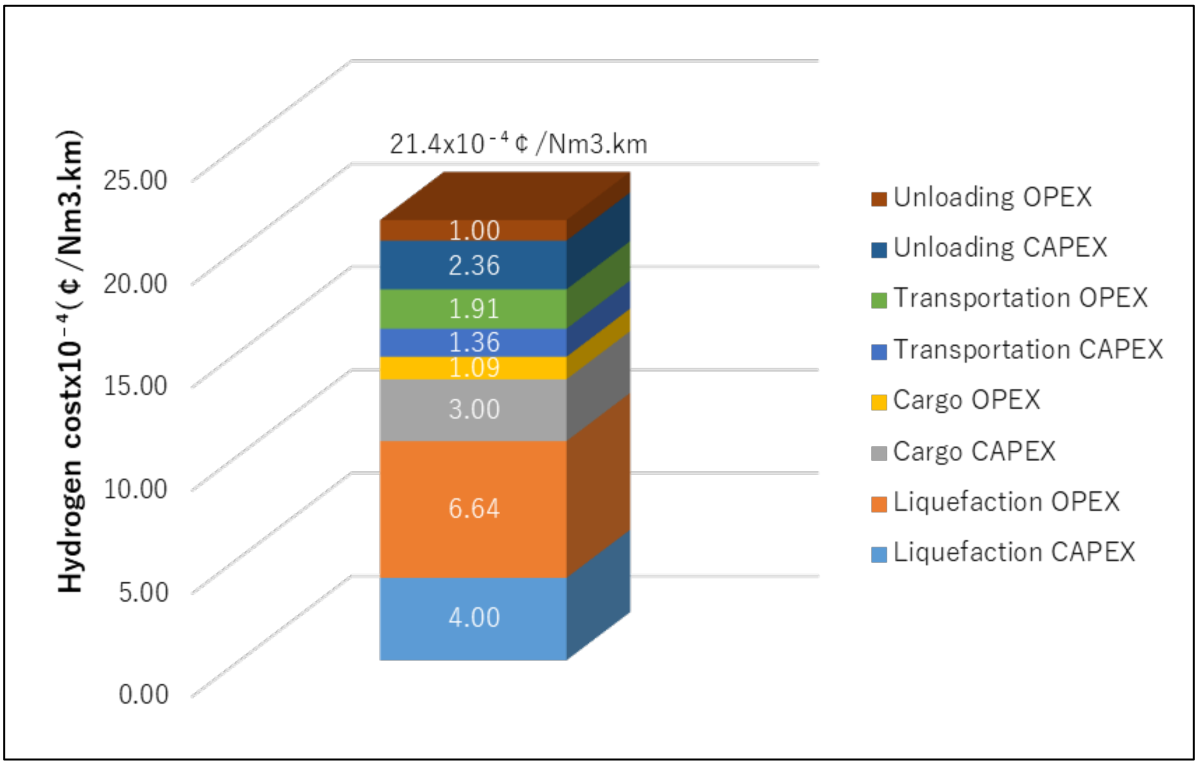
As a reference, we calculated a sample cost of the LH_2 supply chain in 2030, from the liquefaction process to the receiving terminal.

In this trial calculation, we studied a case of a ship with annual capacity of 200,000 tonnes per year and a voyage distance of 10,000 km.

The trial calculation showed that the LH_2 supply chain cost was 0.00214 US cent/Nm3-km and the total transport cost of LH_2 was 0.000327 US cent/Nm^3-km for OPEX and CAPEX (Figure 3.20).

Whilst the LH_2 supply chain cost is still relatively high in 2030, anticipated technological improvements and efficiency effects are expected to result in significant cost reductions, similar to the trajectory observed in LNG. About 30%–40% cost reduction is expected by 2040–2050.

Figure 3.20. Total Forecast Cost for the Liquefied Hydrogen Supply Chain in 2030 (US cent/normal cubic metre)



¢ = cent CAPEX = capital expenditure, km = kilometre, Nm^3 = normal cubic metre, OPEX = operational expenditure

Source: Authors.

3.2. Examination of Hydrogen Transport Costs in 2040–2050

We anticipate that reductions in LH_2 costs will follow a trajectory similar to that observed for LNG. We analyse the reductions in LNG transport costs up to the present day. Then we examine the LH_2 transport costs in the more distant future (2040–2050) based on the insights gained from the observed reductions in LNG costs.

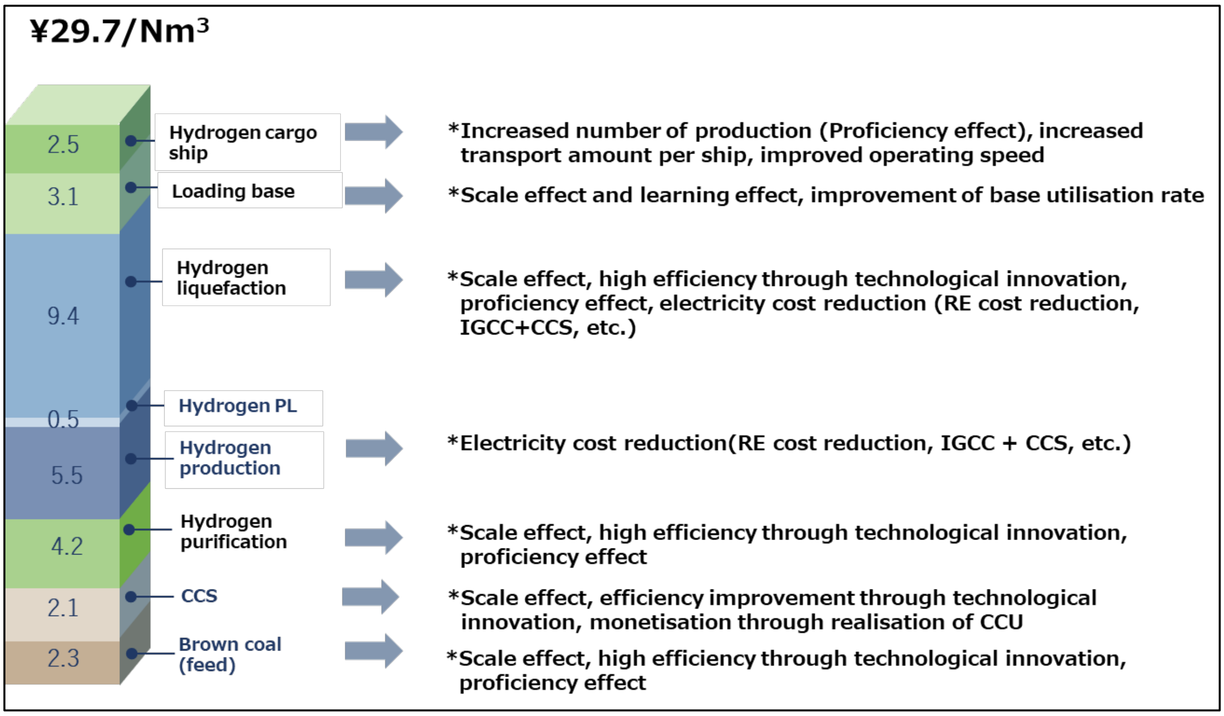
3.2.1. Possibility of Further Hydrogen Cost Reduction

The cost of H_2 in the LH_2 supply chain is estimated at ¥29.7/Nm^3 in the early stage of commercialisation in 2030. Now, we explore the potential reduction in H_2 costs, considering the possibility of further decreases in H_2 cost in the 2050s.

Figure 3.21 illustrates the potential for further reduction in H_2 costs in each process. Proficiency improvements in each process and the declining cost of electricity from renewable energy sources help reduce H_2 costs. The substantial demand for H_2, coupled with the benefits of scaling up, and high performance and efficiency of facilities, will significantly contribute to cost reduction. The rise in the number of voyages and the improvement in operating rates will help reduce H_2 costs in CAPEX and OPEX.

Regarding LH_2 transport costs, a significant cost reduction is anticipated with the construction of an increased number of LH_2 carrier ships. This expansion is poised to bring about proficiency effects, along with advancements in ship technology, including higher operating speeds, amongst other factors.

Figure 3.21. Potential Possibility of Further Reduction in Hydrogen Costs, 2040–2050



CCS = carbon capture and storage, CCU = carbon capture and utilisation, IGCC = integrated gasification combined cycle, Nm^3 = normal cubic metre, PL = pipeline, RE = renewable energy.
Source: Authors.

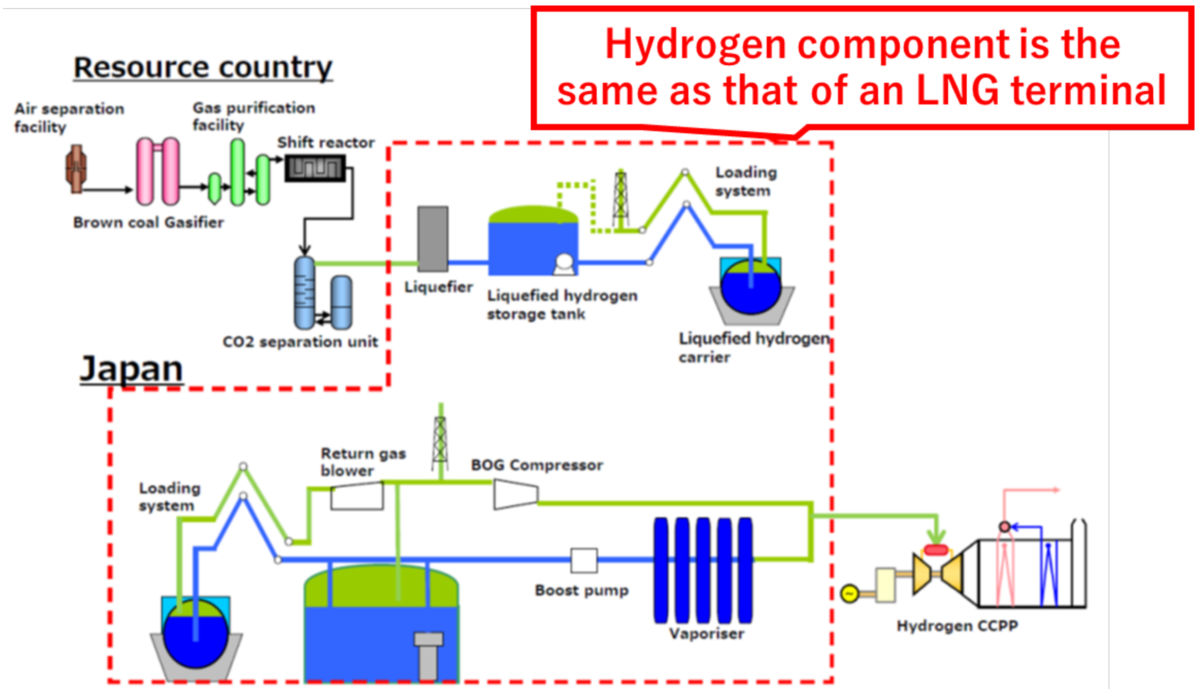
3.2.2. History of the Liquid Natural Gas Carrier Ship

Figure 3.22 illustrates the similarity of the LH_2 supply chain process to the LNG process. Drawing from this similarity, we posit that H_2 costs will be reduced in the same way as LNG costs. In this section, we researched the changes in LNG demand and cost, providing insights into prospective reductions in H_2 transport costs in 2040–2050.

Figures 3.23 (a) and (b) depict the cost evolution of LNG carrier ships (JBIC, 2006). In the 1960s, carriers with a capacity of 100,000 m^3 or less dominated the LNG market. As demand expanded, LNG carriers exceeding 150,000 m^3 became more prevalent from the 2000s onwards.

In contrast, the cost of an LNG carrier ship was US$280 million in the early 1990s. It subsequently decreased, falling to US$140 million–US$200 million in the 2000s or a 30%–50% cost reduction.

Figure 3.22. Brown Coal–derived Liquefied Hydrogen Supply Chain System

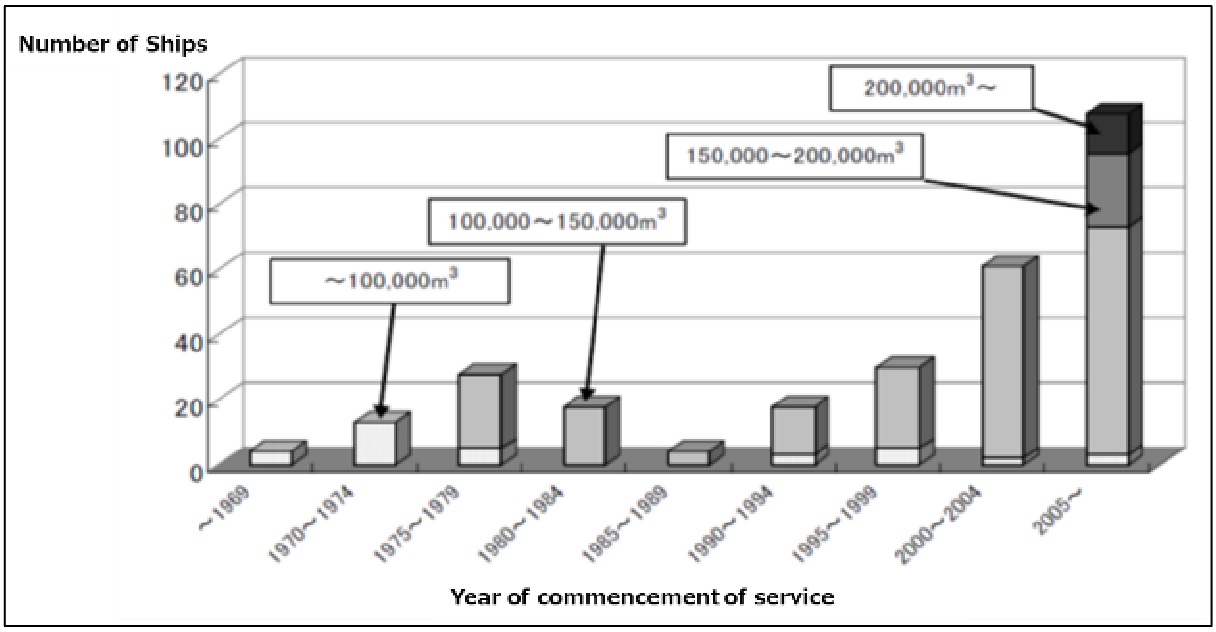


BOG = boil-off gas, CCPP = combined-cycle power plant, CO_2 = carbon dioxide, LNG = liquefied natural gas.

Source: Authors.

Figure 3.23. Cost Change in Liquefied Natural Gas Carrier Ships

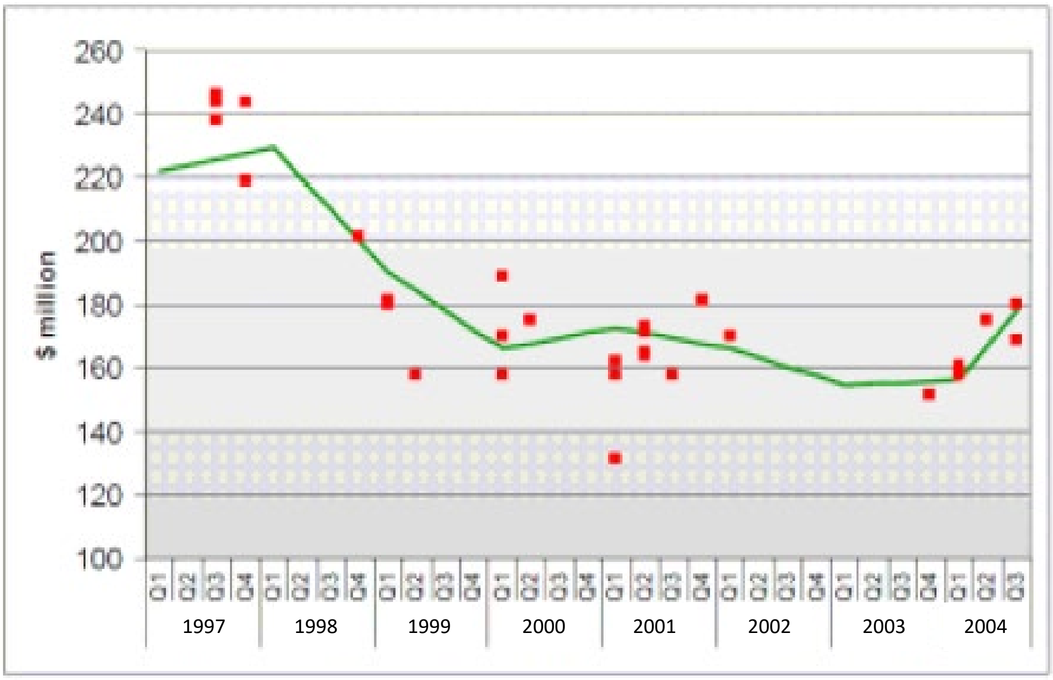
a) Annual Change in the Number and Capacity of Liquefied Natural Gas Carrier Ships



m^3 = cubic metre.

Source: Japan Bank for International Co-operation (2006).

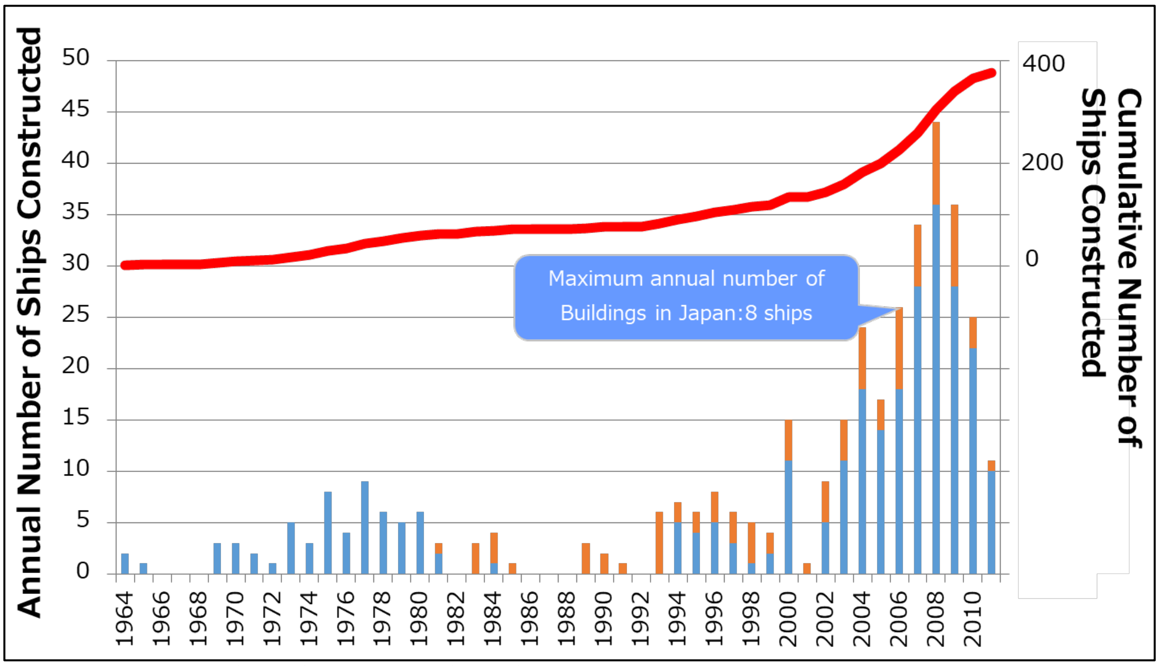
b) Annual Change in the Construction Cost of Liquefied Natural Gas Carrier Ships Since 1997



Source: Japan Bank for International Co-operation (2006).

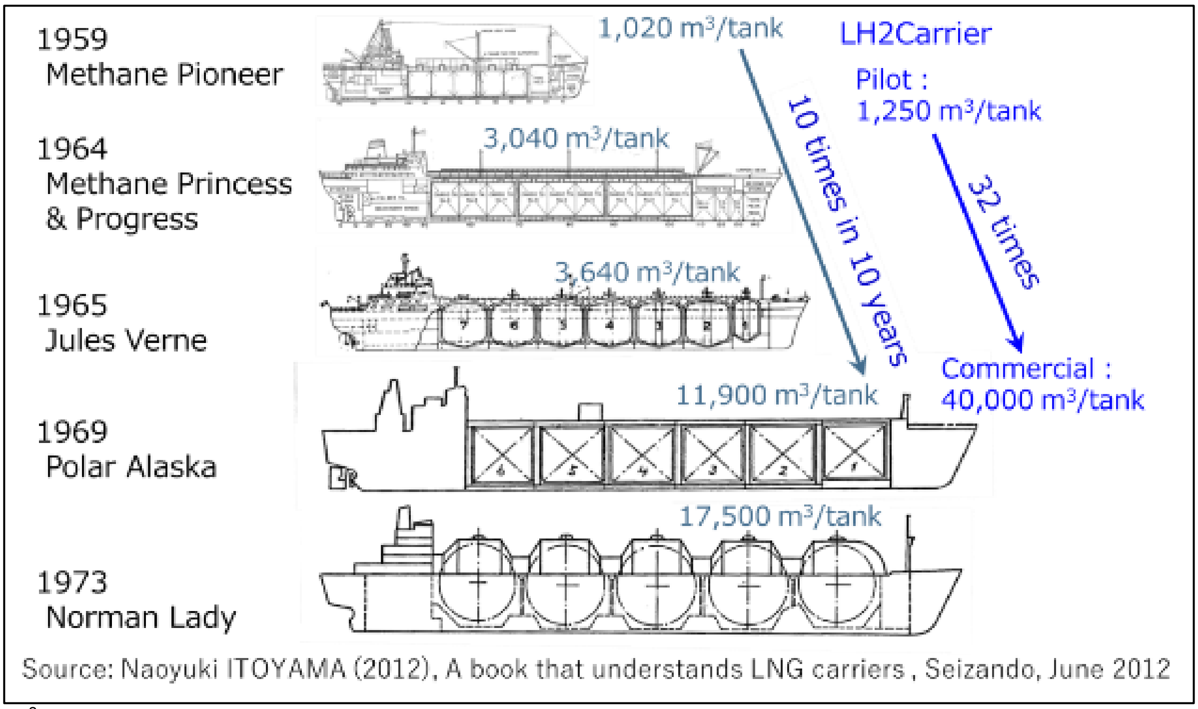
See Figures 3.24 and 3.25 on the history of LNG carrier ship construction (Itoyama, 2012).

Figure 3.24. Annual Number and Cumulative Total of Ships Constructed



Sources: Itoyama (2012), Seizando (2012).

Figure 3.25. History of Liquefied Natural Gas Carrier Ship Construction



m^3/tank=cubic metre per tank, LH_2=liquefied hydrogen
Source: Naoyuki Itoyama (2012).

3.2.3. Study Results on the Cost Reduction of Liquefied Hydrogen Carrier Ships, 2040–2050

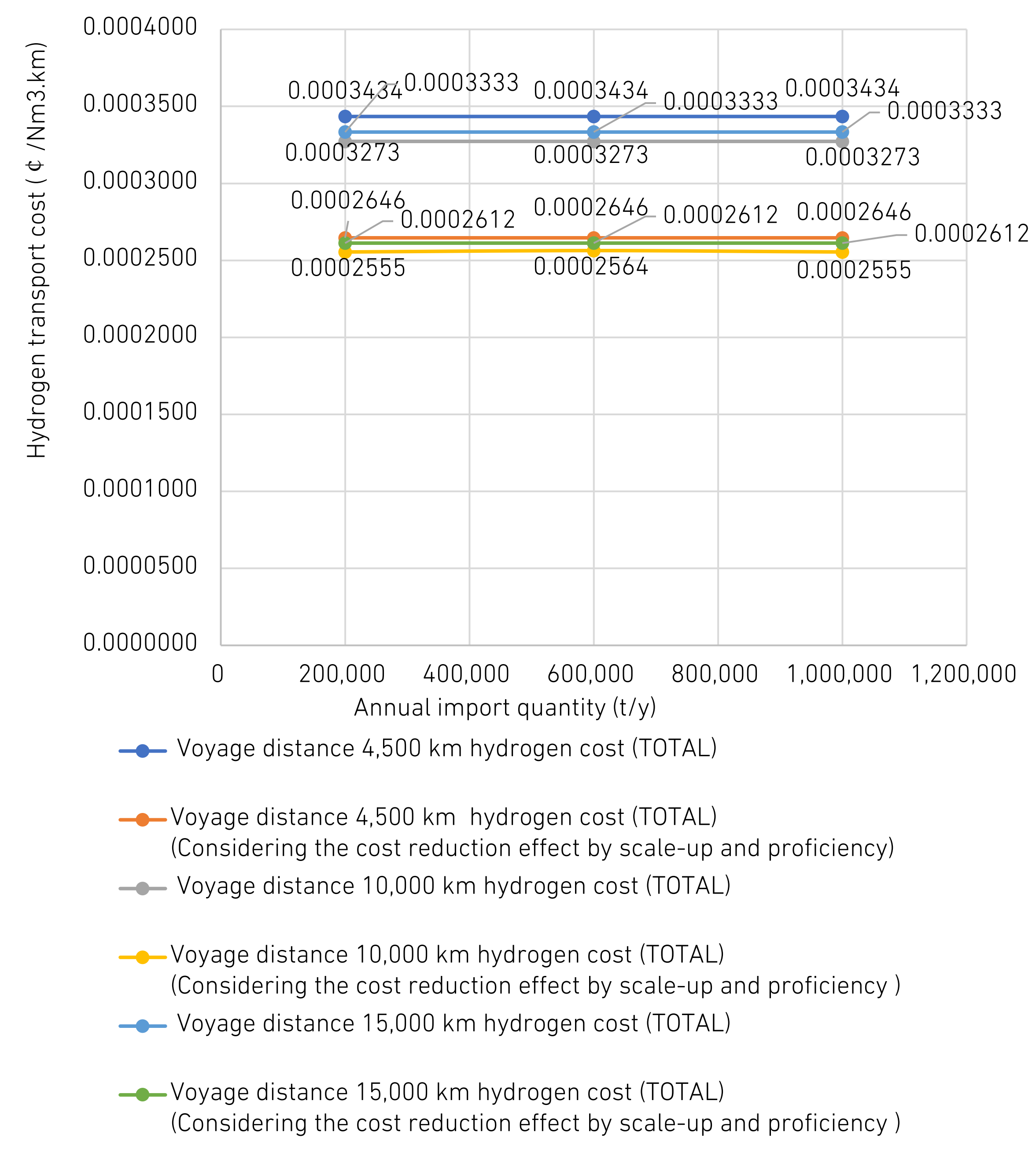
Using the relationship between LNG carrier ship demand and cost reduction, we studied the prospective reduction of LH_2 carrier ship costs.

The anticipated H_2 transport costs for 2040–2050 are calculated assuming a 40% reduction in the construction costs of LH_2 carriers due to economies of scale and proficiency effects from more construction.

Annual H_2 transport costs remain almost the same regardless of annual import volume (Figure 3.26).

However, should the commercial H_2 business start in 2030 and demand increase in 2040–2050, LH_2 transport costs are projected to be reduced by more than 20% compared with H_2 transport costs in 2030 (5.0 US cent/Nm^3 per 4,500 km, 3.27 US cent/Nm^3 per 10,000 km, 1,55 US cent/Nm^3 per 15,000 km).

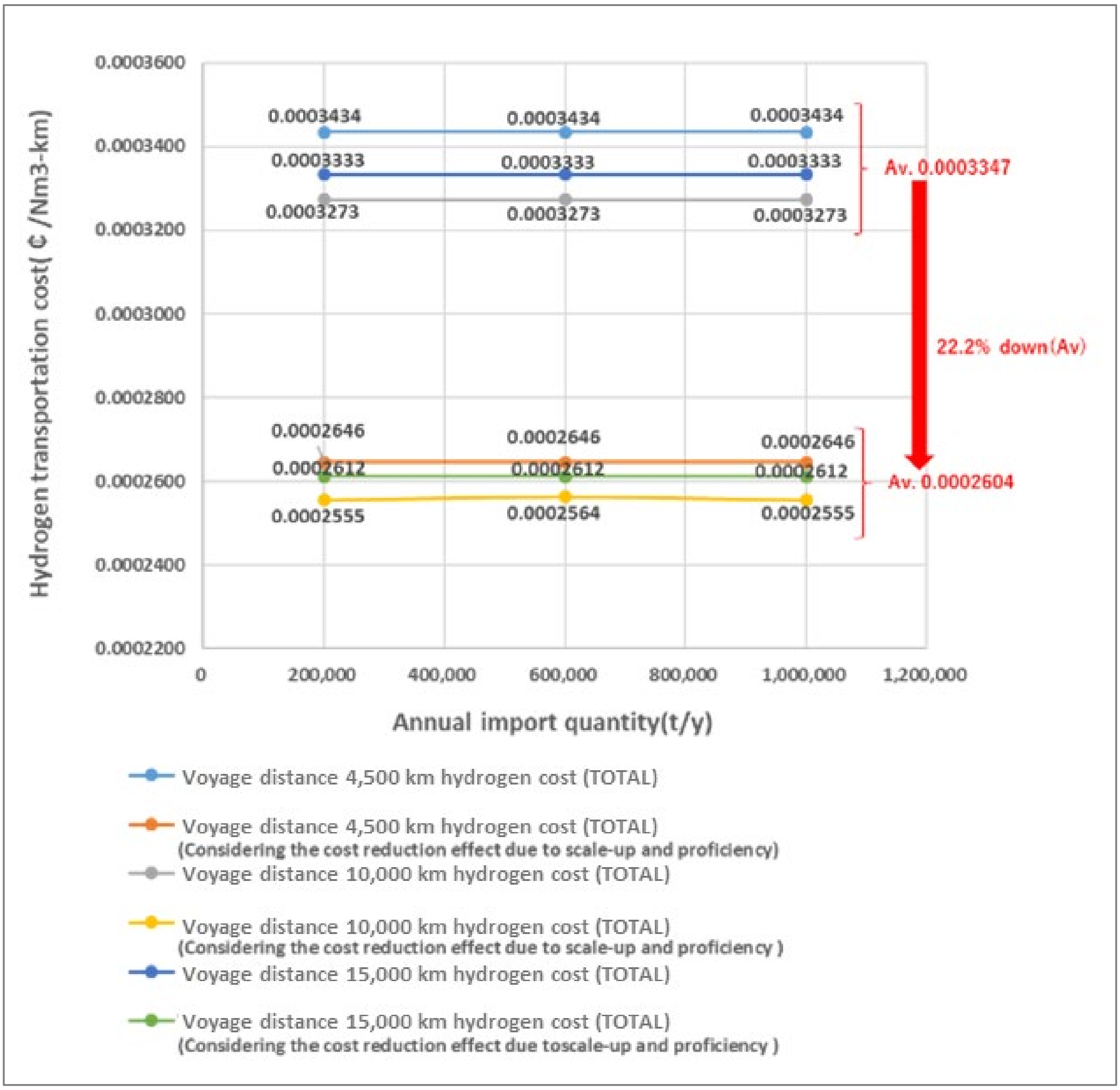
Figure 3.26. Liquefied Hydrogen Transport Costs Calculated from the Difference of Voyage Distance, 2040–2050
(US cent/normal cubic metre)



¢ /Nm^3 = US cent/normal cubic metre, km = kilometre, t/y=tonne per year.
Source: Authors.

Figure 3.27 illustrates the anticipated LH_2 transport cost per voyage distance in 2040–2050 and compares it with costs in 2030. The expected reduction in LH_2 costs in 2040–2050 is about 0.00026 US cent/Nm^3-km, reflecting a 20% decrease compared with costs in 2030.

Figure 3.27. Liquefied Hydrogen Transport Cost from the Difference in Voyage Distance, 2040–2050
(US cent/normal cubic metre)



¢ /Nm^3-km = US cent per normal cubic metre-kilometer, km = kilometer, Nm^3 = normal cubic metre. t/y=tonne per year.
Source: Authors.

The abovementioned H_2 transport cost aligns closely with estimates provided in the ERIA Reports, Phase 3 (ERIA, 2022). Achieving these reduced costs could pave the way for importing substantial amounts of H_2 in 2040–2050.

4. Conclusion

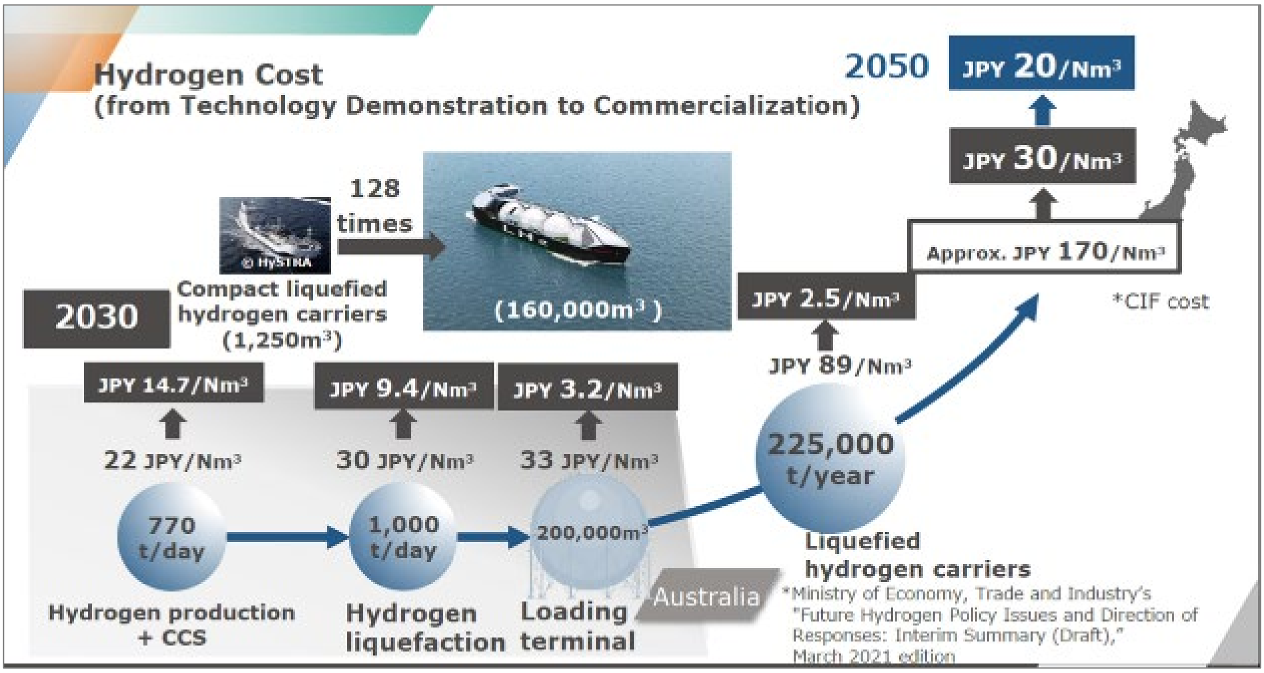
Considering the significant contributions of LH_2 energy to decarbonisation, energy security, economic development, and job creation, many countries are launching demonstration projects. Aligned with Japan's pioneering policies in this endeavour, Kawasaki has been at the forefront of developing and showcasing these technologies, making steady progress. Next, we aim to capitalise on these endeavours by engaging in business activities that actualise a H_2 economy, a prospect that some anticipate will materialise sooner than initially projected.

This chapter analysed LH_2 transport costs for 2020–2030 and 2040–2050. The study indicates a potential reduction of about 20%–30% in LH_2 transport costs, largely because of anticipated technology improvements.

Should the commercial H_2 business start in 2030 and demand increase in the 2050s, H_2 costs would decrease by 40% (about ¥20/Nm^3) compared with costs in 2030 (¥29.7/Nm^3) (Figure 3.28).

LH_2 transport costs are anticipated to drop by 20%–30% or more in 2040–2050 compared with costs projected for 2030.

Figure 3.28. Prediction of Hydrogen Costs by 2050



Approx = approximate, CCS = carbon capture and storage, CIF = cost insurance and freight, JPY = Japanese yen, m^3 = cubic meter, m^3 = cubic meter, t/y = ton per year, Nm^3 = normal cubic metre.
Source: Authors.

Chapter 4
Optimising Hydrogen Supply Routes by Minimising Cost

1. Introduction

1.1. Background

Hydrogen (H_2) production has two aspects:

H_2 can be produced from fossil fuel with carbon capture and storage and electrolysis technology using renewable energy. (ii) The potential for higher H_2 demand is significant.

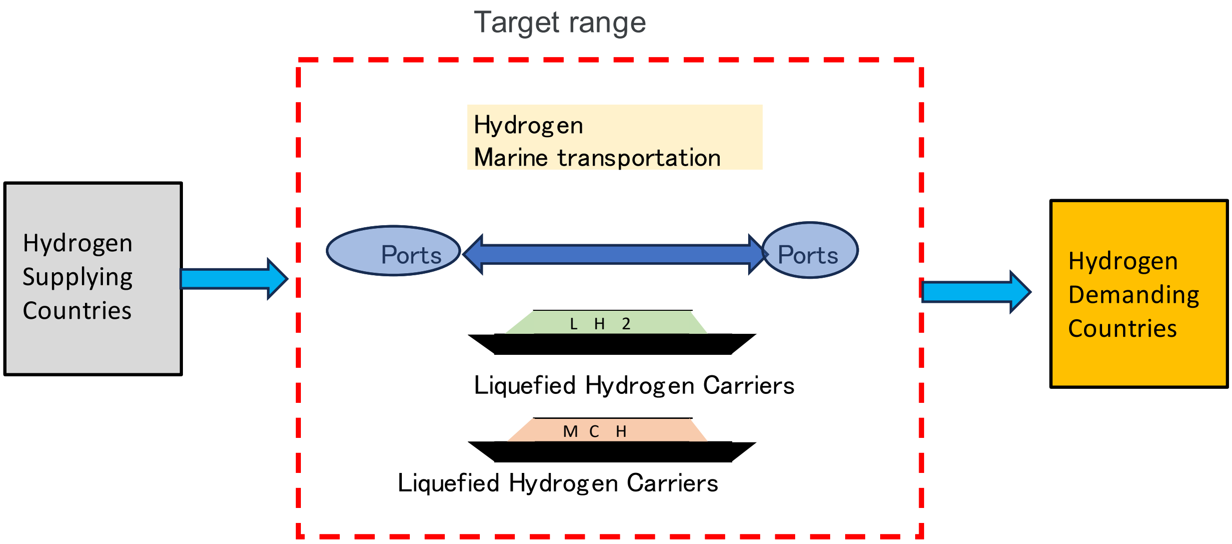
To fully harness the benefits of affordable H_2 consumption in the East Asia Summit (EAS) region, a suitable H_2 supply network must be established. A research assessment of the H_2 supply chain, applying linear programming and dynamic simulation models, is necessary.

1.2. Objectives and Procedures

The H_2 supply chain consists of production sites in H_2-supplying countries, marine transport, and consumption sites in countries with high demand. This study evaluates marine transport of the H_2 supply chain (Figure 4.1).

The study covers two types of hydrogen carriers: liquefied hydrogen (LH_2) and methylcyclohexane (MCH).

Figure 4.1. Hydrogen Supply Chain and Target Range



LH2 = liquefied hydrogen, MCH = methylcyclohexane.
Source: Authors.

Initially, the objective is to identify the optimal H_2 transport route from origin to destination by minimising H_2 transport costs, considering shipping and receiving amounts. Subsequently, based on the optimisation results, a dynamic simulation model will be developed to simulate H_2 transport from origin to destination using H_2 ships (Chapter 5). The major outcomes derived from the dynamic simulation model will encompass determining the required number of H_2 ships, determining the minimum capacity of H_2-receiving storage tanks, and estimating the necessary investment costs to integrate H_2 ships and receiving tanks into the infrastructure, thereby supporting the H_2 supply network.

2. Model Assumptions

2.1. Hydrogen Supply and Demand Countries

Based on the H_2-potential studies conducted in phases 1 and 2, the following countries and cities have been selected as H_2 shipping terminals:

- Brunei Darussalam: Bandar Seri Begawan
- Indonesia (Eastern): Tangguh
- Malaysia (Sarawak): Kuching
- Philippines: Manila
- India: Chennai
- Australia: Sydney
- New Zealand: Auckland

The following countries and cities have been selected as H_2-receiving terminals based on the H_2-potential studies of phases 1 and 2:

- Singapore: Singapore
- Thailand: Bangkok
- China: Tianjin
- Japan: Tokyo
- Republic of Korea: Seoul (Incheon)

The cities designated as both H_2-shipping and receiving terminals are shown in Figure 4.2.

Figure 4.2. Supply Countries and Demand Countries of Hydrogen

Source: Authors.

2.2. Assumptions for Hydrogen Shipping and Receiving Amounts

Tables 4.1 and 4.2 present the assumed H_2 shipping and receiving amounts for 2040. These figures are based on the H_2-potential studies conducted during phases 1 and 2.

Table 4.1. Assumptions of Hydrogen Shipping Quantities

No	Countries	Ports	Shipping Quantities	
			Mtoe/y	MNm^3/y
1	Brunei Darussalam	Bandar Seri Begawan	1.18	4,564
2	Indonesia	Tangguh	9.53	36,995
3	Malaysia (Sarawak)	Kuching (Borneo)	1.55	6,039
4	Philippines	Manila	1.40	5,438
5	Viet Nam	Hai Phong	4.50	17,478
6	Australia	Sydney	8.95	34,762
7	India	Chennai (east coast)	42.63	165,556
8	New Zealand	Auckland	0.73	2,816
Total			70.45	273,647

MNm^3/y = million normal cubic metres per year, Mtoe/y = million tonnes of oil equivalent per year
Source: Authors.

Table 4.2. Assumptions of Hydrogen Receiving Quantities

No	Countries	Ports	Shipping Quantities	
			(Mtoe/y)	(MNm^3/y)
1	Singapore	Singapore	0.84	3,275
2	Thailand	Bangkok	0.30	1,158
3	China	Tianjin	5.59	21,728
4	Japan	Tokyo	14.91	57,902
5	Rep. of Korea	Incheon	9.82	38,132
Total			31.46	122,194

MNm^3/y = million normal cubic metres per year, Mtoe/y = million tonnes of oil equivalent per year.
Source: Authors.

2.3. Distance from Origin to Destination

Table 4.3 shows the distances between H_2 shipping and receiving terminals.

Table 4.3. Nautical Distance Between Hydrogen Supply and Receiving Terminals

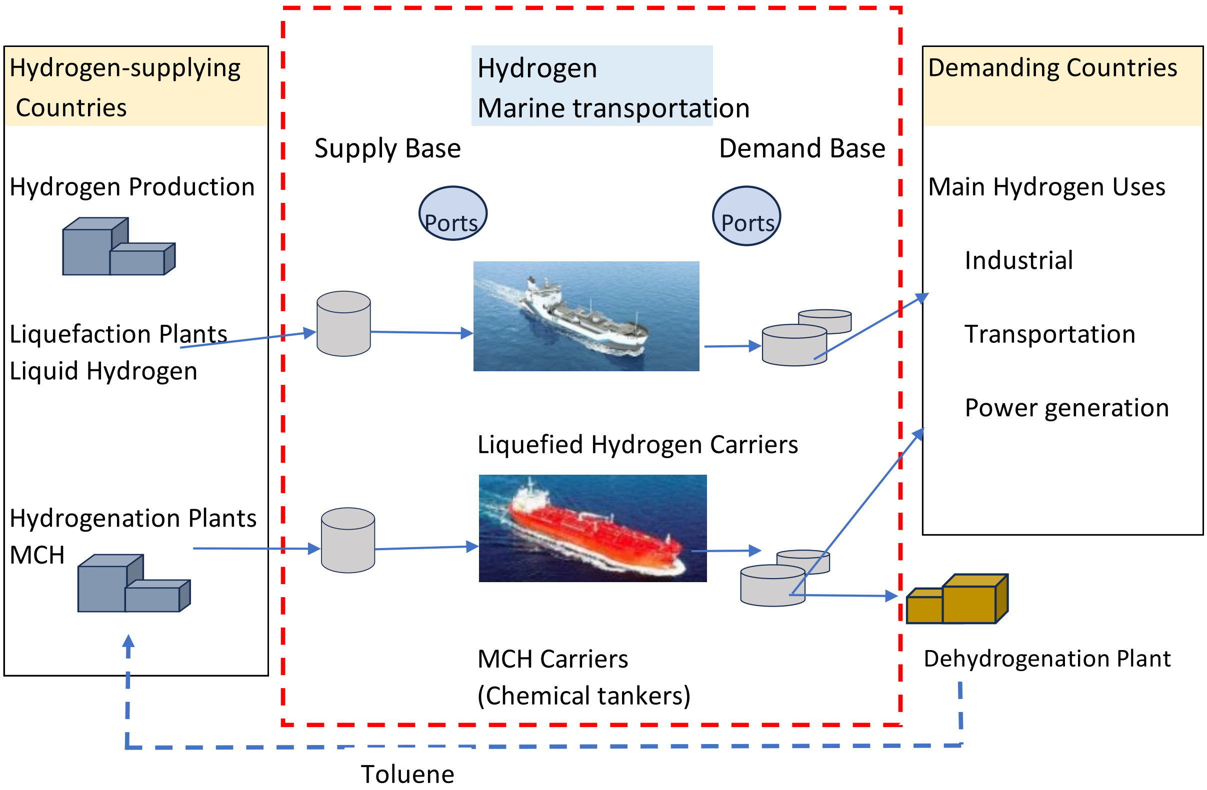
Hydrogen Supply Sites			Hydrogen Demand Sites				
		Countries	Singapore	Thailand	China	Japan	Korea
Countries	Ports	Ports	Singapore	Bangkok	Tianjin	Tokyo	Incheon
		No	21	22	23	24	25
Brunei Darussalam	Bandar Seri Begawan	11	1,447	2,054	4,667	4,536	4,318
Indonesia (Eastern)	Tangguh	12	7,578	8,179	5,653	5,013	5,214
Malaysia (Sarawak)	(Borneo): Kuching	13	1,002	1,729	5,043	5,009	4,688
Philippines	Manila	14	2,633	3,234	3,586	3,553	3,449
Viet Nam	Hai Phong	15	2,664	2,845	4,243	4,330	4,211
Australia	Sydney	16	7,893	10,056	9,707	7,722	9,268
India	Chennai (east coast)	17	3,274	4,842	8,743	8,740	8,679
New Zealand	Auckland	18	9,031	11,194	10,845	8,860	10,406

Source: Authors, based on Japan Navigating Officers' Association, World-wide Distance Chart inter-terminal data.

2.4. Hydrogen Transport Mode

H_2 can be industrially extracted from fossil fuels containing H_2 molecules or through water electrolysis. As H_2 is a gas, it is not readily suitable for transport in its natural state. Thus, two methods are employed to prepare it for transport: liquefaction by cooling it to –253° Celsius, resulting in LH_2, and dissolving it in toluene, yielding MCH. LH_2 is compressed to 1/800, necessitating specialised tankers for transport, whilst MCH, storable in rooms, can be transported by chemical tankers. Large tankers are being developed for both modes, but especially for LH_2 for mass transport by 2040. Henceforth, we will refer to the transport types as LH_2 and MCH. Figure 4.3 illustrates the H_2 supply chain and the scope of this study.

Figure 4.3. Image of Two Different Hydrogen Transport Models



Source: Authors, based on data from the Agency for Natural Resources and Energy; and Ministry of Economy, Trade, and Industry, Japan (2022).

2.5. Cost Calculation

The transport costs for LH_2 and MCH were estimated by referencing the reports from 2021 and the results of the 2023 study (Table 4.4 and Figure 4.4).

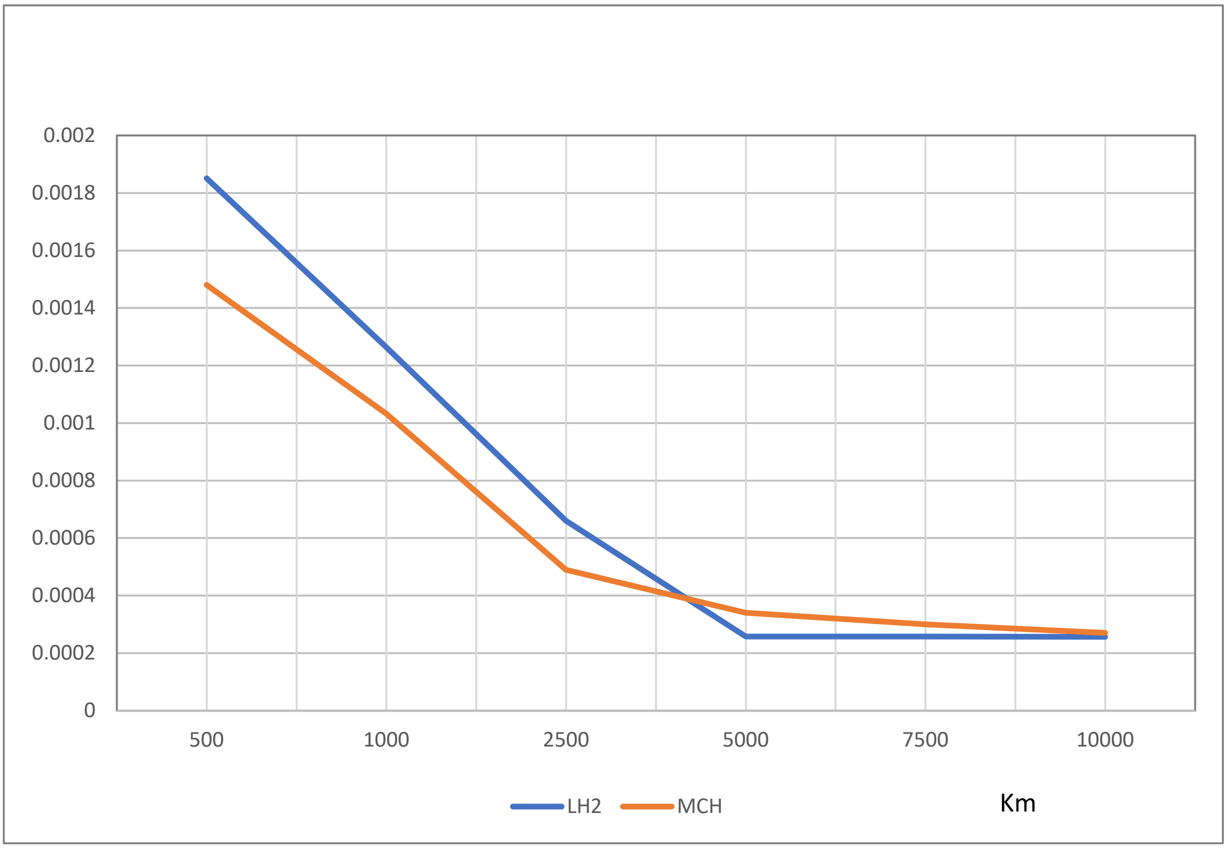
Costs due to distance between two points are calculated as varying in a straight line.

Table 4.4. Unit Price per Kilometre for Transporting 500,000 Normal Cubic Metres of Hydrogen

Mode	Unit type	Distance range					
	km	500	1,000	2,500	5,000	7,500	10,000
LH_2	Cent/(Nm^3-H2.km)	0,00185	0,00126	0,00066	0,00026	0,00026	0,00026
MCH	Cent/(Nm^3-H2.km)	0,00148	0,00103	0,00049	0,00034	0,00030	0,00027

LH_2 = liquefied hydrogen, MCH = methylcyclohexane, Nm^3 = normal cubic metre.
Source: Authors.

Figure 4.4. Unit Price per Kilometre for Transporting 500,000 Normal Cubic Metres of Hydrogen



km = kilometre, LH2 = liquefied hydrogen, MCH = methylcyclohexane.
Source: Authors.

3. Determining Hydrogen Transport Routes by Minimising Cost

3.1. Basic Concept of Linear Programming

The fundamental principle of linear programming is to identify H_2 transport routes that minimise costs, guided by an objective function, whilst adhering to specific constraints. Two are considered: shipping and receiving constraints. The objective function is outlined below:

- Objective function: $\Sigma\Sigma\Sigma Hijk \times Dij \times Tijk \Rightarrow$ Minimise

Where:

Hijk: H_2 transport amount (cubic metre) from i to j by mode k (MCH, LH_2)

Dij: distance (km)

Tijk: Transport cost (US$ per cubic metre-kilometre) from i to j by mode k (MCH, LH2)

i: H_2-shipping terminal

j: H_2-receiving terminal

k: transport mode 1=LH_2, 2=MCH

and there are following two constraints:

$\Sigma\Sigma Hijk =< \sum Si$ (j=1,...,n)

$\Sigma \sum Hijk = \sum Rj$ (i=1, ... m)

Si: Maximum shipping amount of H_2 at a shipping terminal i

Rj: H_2-receiving amount at a receiving terminal j

(1) Transport cost (US cent x km)

Before executing linear programming, we prepare the H_2 transport cost table, defined as US dollar per cubic metre using Tables 4.3 and 4.4 (see Table 4.5).

Table 4.5. Transport Cost

(US cent per cubic metre)

Port	No.		Singapore	Bangkok	Tianjin	Tokyo	Incheon
			21	22	23	24	25
(Brunei) Bandar Seri Begawan	11	LH_2	15,678	17,246	14,543	15,091	15,882
	11	MCH	12,601	13,378	16,800	16,685	16,448
Tangguh	12	LH_2	19,473	20,998	14,570	12,933	13,448
	12	MCH	22,663	23,871	18,630	17,034	17,549
(Borneo): Kuching	13	LH_2	12,647	16,774	13,010	12,923	14,450
	13	MCH	10,338	13,293	17,112	17,023	16,817
Manila	15	LH_2	16,827	17,539	17,416	17,444	17,511
	15	MCH	12,692	14,422	15,235	15,165	14,936
Hai Phong	16	LH_2	16,892	17,211	16,118	15,842	16,214
	16	MCH	12,791	13,352	16,353	16,463	16,311
Sydney	17	LH_2	20,273	25,743	24,861	19,839	23,753
	17	MCH	23,307	27,151	26,550	22,960	25,838
Chennai (east coast)	18	LH_2	17,545	13,724	22,426	22,418	22,264
	18	MCH	14,522	16,922	24,925	24,919	24,809
Auckland	19	LH_2	23,154	28,657	27,763	22,722	26,639
	19	MCH	25,434	30,224	29,282	25,134	28,096

LH_2 = liquefied hydrogen, MCH = methylcyclohexane.

Source: Authors.

(2) Upper limit of transport between shipping terminals and receiving terminals

Based on Tables 4.1 and 4.2 and Figure 4.4, we prepare the maximum amount of H_2 transport between a shipping terminal (i) and a receiving terminal (j). (Table 4.6)

Table 4.6. Upper Limits of Transport Volume between Shipping and Receiving Terminals

Port	No		Singapore 21	Bangkok 22	Tianjin 23	Tokyo 24	Incheon 25	Total
(Brunei) Bandar Seri Begawan	11	LH_2	0	0	21,728	57,902	38,132	117,761
		MCH	3,275	1,158	0	0	0	4,432
Tangguh	12	LH_2	3,275	1,158	21,728	57,902	38,132	122,194
		MCH	0	0	0	0	0	0
(Borneo): Kuching	13	LH_2	0	0	21,728	57,902	38,132	117,761
		MCH	3,275	1,158	0	0	0	4,432
Manila	14	LH_2	0	0	0	0	0	0
		MCH	3,275	1,158	21,728	57,902	38,132	122,194
Hai Phong	15	LH_2	0	0	21,728	57,902	38,132	117,761
		MCH	3,275	1,158	0	0	0	4,432
Sydney	16	LH_2	3,275	1,158	21,728	57,902	38,132	122,194
		MCH	0	0	0	0	0	0
Chennai (east coast)	17	LH_2	0	1,158	21,728	57,902	38,132	118,919
		MCH	3,275	0	0	0	0	3,275
Auckland	18	LH_2	3,275	1,158	21,728	57,902	38,132	122,194
		MCH	0	0	0	0	0	0
			3,275	1,158	21,728	57,902	38,132	

LH_2 = liquefied hydrogen, MCH = methylcyclohexane, MNm^3 = million normal cubic metres.
Source: Authors.

(3) Linear programming solution

Under the conditions specified in (1) and (2), we have identified the optimal H_2 transport routes (Table 4.6). The result is referred to as Case 1. In the scenario, Singapore and Thailand will receive H_2 from India, with Singapore utilising MCH and Thailand using LH_2. China will receive H_2 from Brunei Darussalam, Malaysia, and Viet Nam, all transported via LH_2. Japan will receive H_2 from Indonesia and Australia, whilst the Republic of Korea will receive H_2 from Indonesia, Viet Nam, and India as LH_2, and MCH from the Philippines. LH_2 will be the major H_2 transport mode in EAS region, especially for long distances.

We initially expected H_2 transport from Brunei Darussalam to Singapore and Thailand. If realised, China would need to import more H_2 from Viet Nam, thereby increasing the total H_2 transport cost. To explore alternative scenarios, we consider Case 2, aiming to realise H_2 transport between Brunei Darussalam, Malaysia, Singapore, and Thailand. Notably, no countries will receive H_2 from New Zealand in either case.

Table 4.6. Solution of Linear Programming (Case 1)

Case-1 Unconstrained

Unit： MNm^3/y

Port	No		Singapore	Bangkok	Tianjin	Tokyo	Incheon	Subtotal	Total of 2 types	Upper limit of Supply
			21	22	23	24	25			
(Brunei) Bandar Seri Begawan	11	LH_2	0	0	4,564	0	0	4,564	4,564	4,564
		MCH	0	0	0	0	0	0		
Tangguh	12	LH_2	0	0	0	23,140	13,855	36,995	36,995	36,995
		MCH	0	0	0	0	0	0		
(Borneo): Kuching	13	LH_2	0	0	6,039	0	0	6,039	6,039	6,039
		MCH	0	0	0	0	0	0		
Manila	14	LH_2	0	0	0	0	0	0	5,438	5,438
		MCH	0	0	0	0	5,438	5,438		
Hai Phong	15	LH_2	0	0	11,125	0	6,353	17,478	17,478	17,478
		MCH	0	0	0	0	0	0		
Sydney	16	LH_2	0	0	0	34,762	0	34,762	34,762	34,762
		MCH	0	0	0	0	0	0		
Chennai (east coast)	17	LH_2	0	1,158	0	0	12,486	13,644	16,918	165,556
		MCH	3,275	0	0	0	0	3,275		
Auckland	18	LH_2	0	0	0	0	0	0	0	2,816
		MCH	0	0	0	0	0	0		
			3,275	1,158	21,728	57,902	38,132	2,025,131,458		

Objective function

LH_2 = liquefied hydrogen, LP = linear programming, MCH = methylcyclohexane, MNm^3/y = million normal cubic metres per year.
Source: Authors.

3.2. Adding Transport Constraints (Case 2)

To facilitate the transport of H_2 between Brunei Darussalam, Sarawak (Kuching), Singapore, and Thailand, we revised Upper-limit Tables 4.5 to 4.7. We put maximum H_2 transport volume from Brunei Darussalam to China at 3,406 million cubic metres and from Sarawak (Kuching) to China at 2,764 million cubic metres (Table 4.7).

Table 4.7. Upper Limits of Transport Volume between Hydrogen Shipping Terminals and Receiving Terminals (Case 2)

Unit : MNm^3/Y

Port			Singapore	Bangkok	Tianjin	Tokyo	Inchon	
	No		21	22	23	24	25	Total
(Brunei) Bandar Seri Begawan	11	LH2	0	0	3,406	0	0	3,406
		MCH	3,275	1,158	0	0	0	4,432
Tangguh	12	LH2	3,275	1,158	21,728	57,902	38,132	122,194
		MCH	0	0	0	0	0	0
(Borneo) Kuching	13	LH2	0	0	2,764	0	0	2,764
		MCH	3,275	1,158	0	0	0	4,432
Manila	14	LH2	0	0	0	0	0	0
		MCH	3,275	1,158	21,728	57,902	38,132	122,194
Hai Phong	15	LH2	0	0	21,728	57,902	38,132	117,761
		MCH	3,275	1,158	0	0	0	4,432
Sydney	16	LH2	3,275	1,158	21,728	57,902	38,132	122,194
		MCH	0	0	0	0	0	0
Chennai (east coast)	17	LH2	0	1,158	21,728	57,902	38,132	118,919
		MCH	3,275	0	0	0	0	3,275
Auckland	18	LH2	3,275	1,158	21,728	57,902	38,132	122,194
		MCH	0	0	0	0	0	0
			3,275	1,158	21,728	57,902	38,132	

LH_2 = liquefied hydrogen, MCH = methylcyclohexane, MNm^3/y = million normal cubic metres per year.
Source: Authors.

(1) Linear programming solution (Case 2)

In Case 2, Brunei Darussalam is set to export H_2 to Thailand, whilst Sarawak (Kuching) will supply Singapore. China will increase H_2 imports from Viet Nam, and Korea will need to increase H_2 imports from India. This adjustment leads to a roughly 1% increase in objective function compared with Case 1.

Table 4.8. Solution of Linear Programming (Case 2)

Case-2 Constrained

Unit: MNm^3/y

Ports	No		Singapore 21	Bangkok 22	Tianjin 23	Tokyo 24	Inchon 25	Subtotal	Total of 2 types	Upper limit of supply
(Brunei) Bandar Seri Begawan	11	LH2	0	0	3,406	0	0	3,406	4,563	4,564
		MCH	0	1,157	0	0	0	1,157		
Tangguh	12	LH2	0	0	0	23,140	13,855	36,995	36,995	36,995
		MCH	0	0	0	0	0	0		
(Borneo): Kuching	13	LH2	0	0	2,764	0	0	2,764	6,039	6,039
		MCH	3,275	0	0	0	0	3,275		
Manila	14	LH2	0	0	0	0	0	0	5,438	5,438
		MCH	0	0	0	0	5,438	5,438		
Hai Phong	15	LH2	0	0	15,558	0	1,920	17,478	17,478	17,478
		MCH	0	0	0	0	0	0		
Sydney	16	LH2	0	0	0	34,762	0	34,762	34,762	34,762
		MCH	0	0	0	0	0	0		
Chennai (east coast)	17	LH2	0	0	0	0	16,919	16,919	16,919	165,556
		MCH	0	0	0	0	0	0		
Auckland	18	LH2	0	0	0	0	0	0	0	2,816
		MCH	0	0	0	0	0	0		0
			3,275	1,158	21,728	57,902	38,132	2,049,854,793		

Objective function

LH_2 = liquefied hydrogen, MCH = methylcyclohexane, MNm^3/y = million natural cubic metres per year.
Source: Authors.

Chapter 5
Dynamic Simulation Approach for Hydrogen Delivery

1. Basic Concept of the Simulation

Based on the optimal results of hydrogen (H_2) transport from H_2 production countries to consumption countries (Chapter 4), this chapter illustrates the dynamic simulation technique applied on a laptop screen. Sea transport serves as the primary mode, using two types of ships: chemical tankers for methlycyclohexsane (MCH) and liquefied H_2 (LH_2) ships for LH_2. The following are the major conditions of the dynamic simulation model:

(i) The simulation time axis operates on a minimum unit of 1 hour, covering 365 days.

(ii) H_2 tanker details include type of H_2, ship name, storage capacity, speed, and destination port.

(iii) Land storage at receiving ports includes capacity, current H_2 level, and criteria for tanker departure.

(iv) Route specifications define distances between origin and destination ports and tanker type.

(v) The location of H_2 shipping ports.

(vi) The location of H_2 receiving ports.

(vii) Loading and unloading time, waiting time, etc.

(viii) Preliminary maps and route maps.

2. Simulation Data Obtained from the Solution of Linear Programming

2.1. Concept of Domestic Diversification

In the linear programming model, we employ a straightforward concept of one port per one country, typically near its capital city. However, this approach proves unsuitable for the dynamic simulation due to severe congestion at the receiving port. Therefore, we adjust for countries such as China, Japan, and Korea. We assume four ports for Japan and three ports each for China and Korea, resulting in a reduction of H_2 imports to one-fourth at Tokyo port and one-third at Incheon and Tianjin ports.

2.2. Hydrogen Demand and Supply for Dynamic Simulation

Table 5.1 provides the maximum quantities of H_2 shipped by supplying countries, whilst Table 5.2 outlines the corresponding receiving amounts for recipient countries.

Table 5.1. Supply Capacity (Reposted)

No	Countries	Ports	Shipping Capacity	
			Hydrogen Equivalent Weight	Hydrogen Equivalent Capacity
			(Mtoe/y)	(MNm^3/y)
11	Brunei	Bandar Seri Begawan	1.18	4,564
12	Indonesia	Tangguh	9.53	36,995
13	Malaysia (Sarawak)	Kuching (Borneo)	1.55	6,039
14	Philippines	Manila	1.40	5,438
15	Viet Nam	Hai Phong	4.50	17,478
16	Australia	Sydney	8.95	34,762
17	India	Chennai (east coast)	42.63	165,556
18	New Zealand	Auckland	0.73	2.816
	Total		70.45	273.647

MNm^3/y = million normal cubic metres per year, Mtoe/y = million tonnes of oil equivalent per year.
Source: Authors.

Table 5.2. Hydrogen Receiving Volume by Port

No	Countries	Ports	Shipment Volume		0.5 Months	1 Month	1.5 Months
			(Mtoe/y)	(MNm^3/y)	(MNm^3/y)	(MNm^3/y)	(MNm^3/y)
21	Singapore	Singapore	0.84	3,275	136	273	409
22	Thailand	Bangkok	0.30	1,158	48	96	145
23	China	Tianjin	1.86	7,243	302	604	905
24	Japan	Tokyo	3.73	14,476	603	1,206	1,809
25	Korea	Incheon	3.27	12,711	530	1,059	1,589
	Total		10.01	38,861	1,619	3,238	4,858

MNm^3/y = million normal cubic metres per year, Mtoe/y = million tonnes of oil equivalent per year.
Source: Authors.

2.3. Assumed Tanker Types for Dynamic Simulation

H_2 is either liquid or MCH, each type requiring a suitable tanker. Four types of ships, including medium-sized ones, depending on transport volume and distance, were assumed.

Table 5.3. Types of Tanker

Type	Capacity (MNm^3/time)	Speed (km/h)
LH_2_L	128	30
LH_2_M	64	30
MCH_L	80	28
MCH_M	40	28

MNm^3 = million normal cubic metres, km/h = kilometre per hour.
Source: Authors, based on https://www.idemitsu.com/jp/tanker/fleet/vlcc.html

We assume the following rules for allocating MCH and LH_2 tankers to each route between H_2 shipping and receiving ports.

① 【Conditions for MCH vessels】

Distance < 5,000 km and transport volume < 5,000 million normal cubic metres (MNm^3) ⇒ MCH ship.

② 【Condition for LH_2 ship】

LH_2 ship if not meeting the criteria in ①

The size of the ship is determined by the amount of cargo transported.

2.4. Determining the Type and Number of Tankers

Following the aforementioned tanker allocation rules, Table 5.4 shows the types of hydrogen tankers allocated to each route between H_2 shipping and receiving ports.

The table shows the annual required transport volume (linear programming results) between the demand and supply sites, the number of transport days per voyage, and the required number of tankers (⑩). The items are noted below the table.

Table 5.4. Hydrogen Type and Transport Volume, Sailing Days, Required Number of Tankers

Demand Site	Supply Site	① Distance	② Hydrogen Type and Tanker Type	③ Quantity of Transport Required	④ Number of Trips	Actual Operation (considering distance)					Number of Tankers Required⑩	
						Operation Time ⑤	Total Days ⑥	Loading or Unloading ⑦	Number of Round Trip ⑧	Number of Times per Year⑨		
		(Km)		(MNm³)/Y	(Times /Y)	(H)	(days)	(days)	(days)	per tanker	Calculation	Actual
Singapore	Kuching	1,002	MCH_L	3,275	41	38.5	1.6	2	7.2	51	0.81	1
Bangkok	Brunei	2,054	MCH_M	1,157	29	79.0	3.3	2	10.6	34	0.84	1
Tianjin	Brunei	4,667	LH_2_L	1,135	9	155.6	6.5	2	17.0	22	0.41	1
Tianjin	Kuching	5,043	LH_2_M	921	7	168.1	7.0	2	18.0	20	0.36	1
Tianjin	Hai Phong	4,243	LH_2_L	5,186	41	141.4	5.9	2	15.8	23	1.75	2
Tokyo	Tangguh	5,013	LH_2_L	5,785	45	167.1	7.0	2	17.9	20	2.22	3
Tokyo	Sydney	7,722	LH_2_L	8,690	68	257.4	10.7	2	25.5	14	4.74	5
Incheon	Tangguh	5,214	LH_2_L	4,618	36	173.8	7.2	2	18.5	20	1.83	2
Incheon	Manila	3,449	MCH_L	1,813	23	123.2	5.1	2	14.3	26	0.89	1

Demand Site	Supply Site	① Distance	② Hydrogen Type and Tanker Type	③ Quantity of Transport Required	④ Number of Trips	Actual Operation (considering distance)					Number of Tankers Required⑩	
						Operation Time ⑤	Total Days ⑥	Loading or Unloading ⑦	Number of Round Trip ⑧	Number of Times per Year⑨		
Incheon	Hai Phong	4,211	LH_2_M	640	8	140.4	5.8	2	15.7	23	0.34	1
Incheon	Chennai	8,679	LH_2_L	5,640	44	289.3	12.1	2	28.1	13	3.39	4
Total	Total	51,297		38,860	350					266		22

*Brunei Darrusalam is abbreviated as Brunei.
Notes:
③ : Solution of linear programming by country (transport amount from production area to consumption area [MNm^3/year])
④ : Calculate the number of operations by ③ ÷ tanker transport volume
⑤ : Navigation time between two points
⑥ : Convert ⑤ to days
⑧ : Number of round-trip operation days
⑨ : Number of annual operations per vessel
⑩: Calculate the required number of vessels using (④/⑨)
Km = kilometre, LH_2 = liquefied hydrogen, MCH = methylcyclohexane, MNm^3/y = million normal cubic metres per year.
Source: Authors.

2.5. Supply- and Demand-side Storage

The storage capacity in H_2 shipping and receiving areas, the type of H_2 between supply and demand areas, the number of tankers, tanker capacity, and the number of berths in demand areas are presented below.

- ✓ Daily consumption is calculated by dividing annual consumption by 365, and withdrawals occur every day at 24:00.
- ✓ Therefore, initial inventory is necessary for storage, given as the initial value. The initial storage amount for Singapore and Bangkok was set at 0.5 month, whilst for Tianjin, Tokyo, and Incheon, it was 1 month.
- ✓ Tankers will depart upon reaching the specified lower storage limit.

These settings have been confirmed to function effectively in the simulation. Based on these rules, the initial storage amount, tanker type, and size for each route were configured as outlined below, and a simulation was executed.

Table 5.5. Storage Capacity at the Hydrogen Supply Site

Supply Storage	Unit	Brunei	Tangguh	Kuching	Manila	Hai Phong	Sydney	Chennai	Auckland
Initial value (Month)	Months	12	12	12	12	12	12	12	12
Capacity	Months	12	12	12	12	12	12	12	12
Maximum supply volume	MNm^3/Y	4.564	36.995	6.039	5.438	17.478	34.762	165.556	2.816

MNm^3/y = million normal cubic metres per year.
Source: Authors.

Table 5.6. Storage Capacity at the Hydrogen Demand Site

Demand Storage	Unit	Singapore	Bangkok	Tianjin	Tokyo	Incheon
Initial value	Months	0,5	0,5	1	1	1
Lower limit level	Months	0,5	0,5	1	1	1
Upper level	Months	1	1	1,5	1,5	1,5
Storage capacity	Months	1,5	1,5	1,5	1,5	1,5

Source: Authors.

Table 5.7. Number of Berths at the Hydrogen Demand Port

Number of Berths at Demand Site	
Departure Berths	Unloading Berths
1	2

Source: Authors.

3. Simulation Results

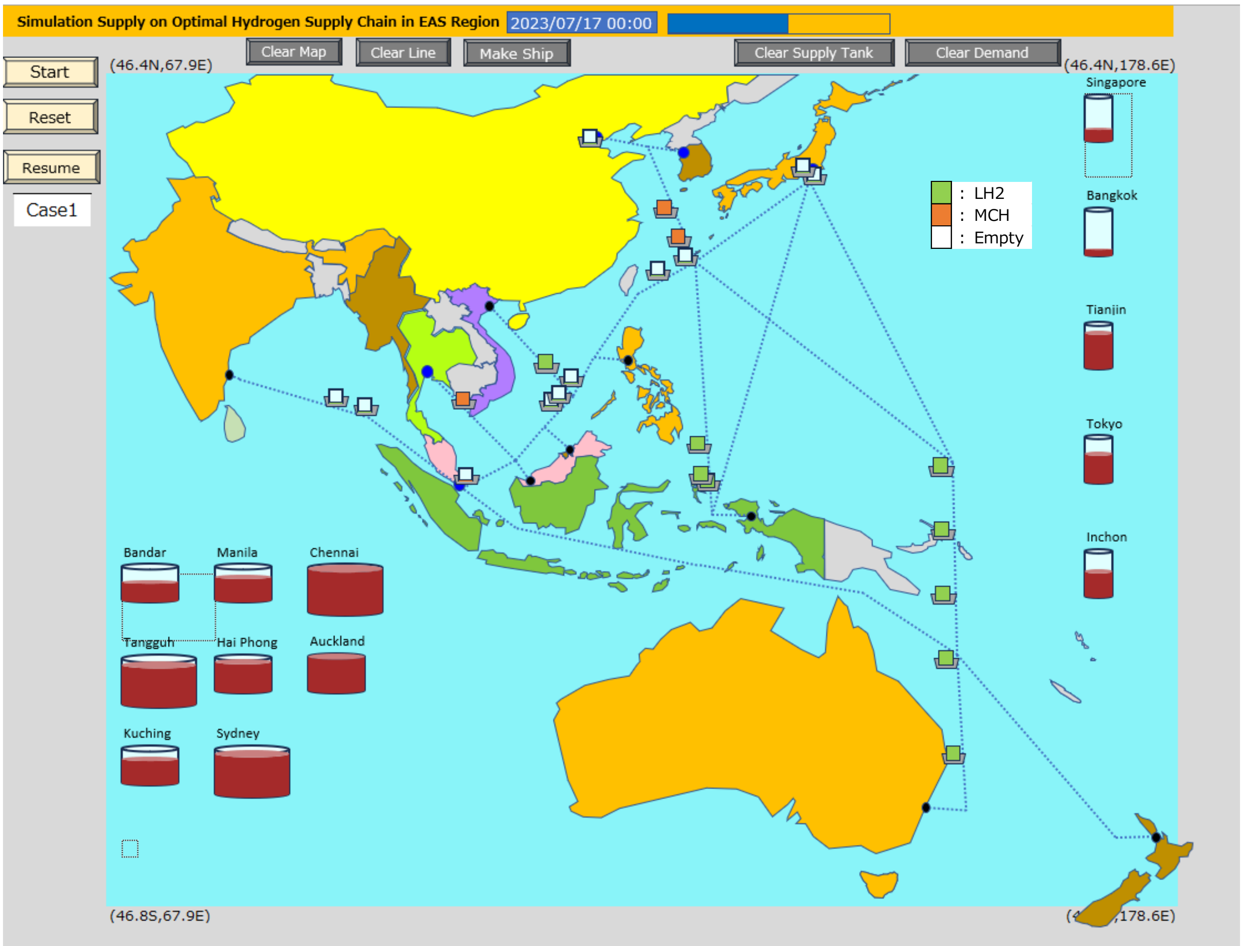
3.1. Simulation Screenshot

The simulation results are visualised through an animation, captured in the screenshot (Figure 5.1[1]). The screen focuses on the target area, depicting dotted lines across the sea representing the routes connecting supply and demand bases, forming a network. The eight countries listed in Table 5.1 serve as the supply bases, whilst the five countries listed in Table 5.2 are the demand bases, each with one port.

The tanker is represented in the shape of a ship, navigating the route at about 30 km/hour, with its movements coordinated in the simulation every hour. Tankers departing from the demand base arrive at the supply base with an empty status indicated by □ (white). Upon reaching the destination port, they load either LH_2 (green) or MCH (orange), and the color □ changes. Loading takes 2 days, after which the ship returns to the demand base. Unloading also takes 2 days.

The departure timing is contingent on the amount of remaining storage on land. If the timing is right, the tanker departs; otherwise, it waits. The storage tanks on both sides of the screen represent the supply base on the left and the demand tank on the right, showcasing changes in inventory levels due to loading and unloading.

Figure 5.1 (1). Simulation Screen (Overall View)

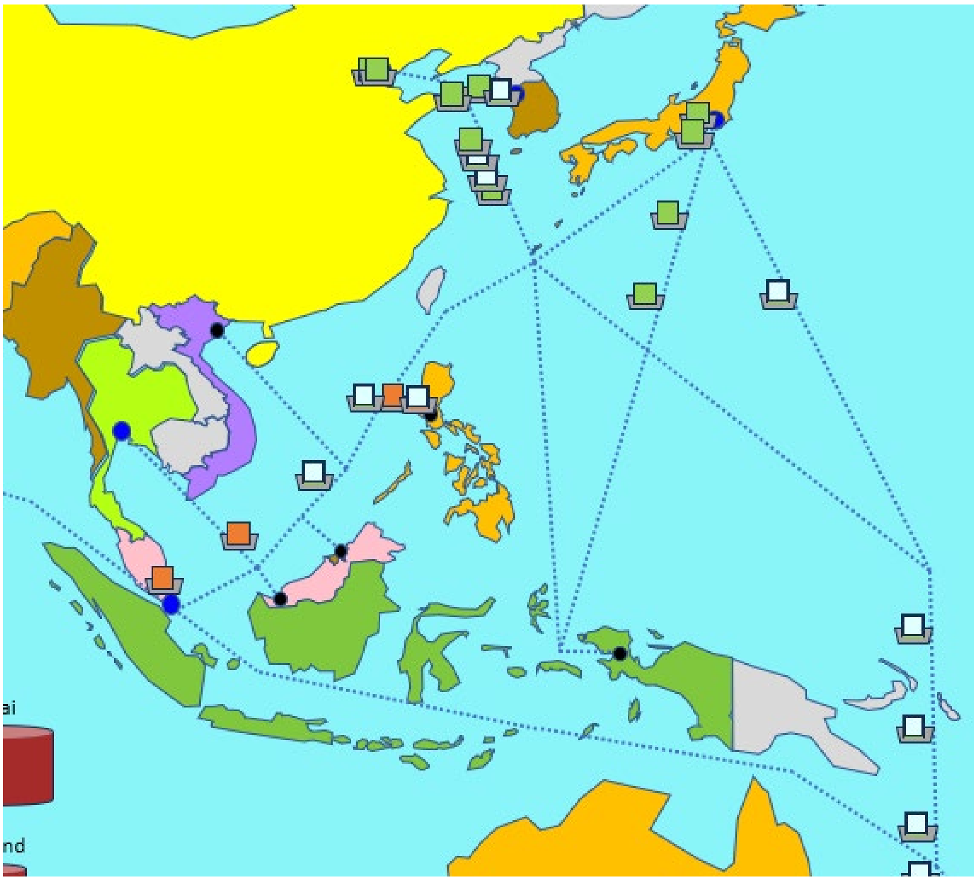


EAS = East Asia Summit, LH2 = liquefied hydrogen, MCH = methylcyclohexane.
Source: Authors.

Figure 5-1(2) illustrates status of the simulation:

- On the Tokyo–Sydney route, several empty tankers are in service, awaiting cargo pickup at Sydney.
- On the Tokyo–Tangguh route, several tankers loaded with LH_2 are in service.
- On the Incheon–Manila route, a tanker loaded with MCH has just departed Manila.
- In Singapore, a tanker carrying MCH from Kuching is in port.
- In Bangkok, a tanker carrying MCH from Brunei Darussalam is en route.

Figure 5.1 (2). Simulation Screen (Enlarged View)



Source: Authors.

3.2. Tanker Diagram and Storage Changes

Although the simulation ran for 365 days, the graph width limitations required truncating the storage fluctuation graph and tanker diagram at the 200-day mark. The portion of the graph beyond 200 days is replicated.

The simulation results indicated that the assumed initial storage value was set to full capacity. The optimal storage capacity was determined from the simulation results by calculating the difference between the maximum and minimum values.

The following are the assumptions for the storage tank at H_2-receiving terminals:

Singapore

Initial storage volume, maximum capacity, and tanker departure criteria are assumed below:

Table 5.8. Data for Simulation Assumptions, Singapore

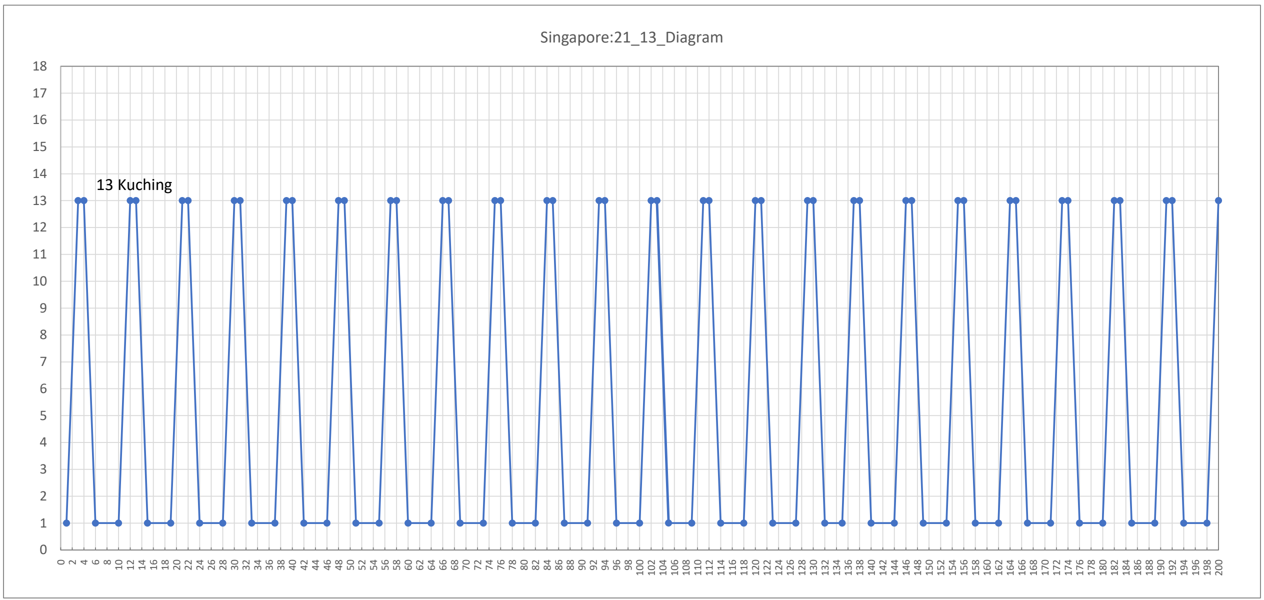
Storage					
Inventory Volume Initial Value		Maximum Capacity Initial Value		Tanker Departure Level	
(months)	(MNm3/y)	(months)	(MNm3/y)	(months)	(MNm3/y)
0.5	136	1.5	409	0.5	136

Tankers			
Supply Base	Numbers	Type	Unloading (MNm3/time)
13_Kuching	1	MCH_L	80

MNm^3/y = million normal cubic metres per year.
Source: Authors.

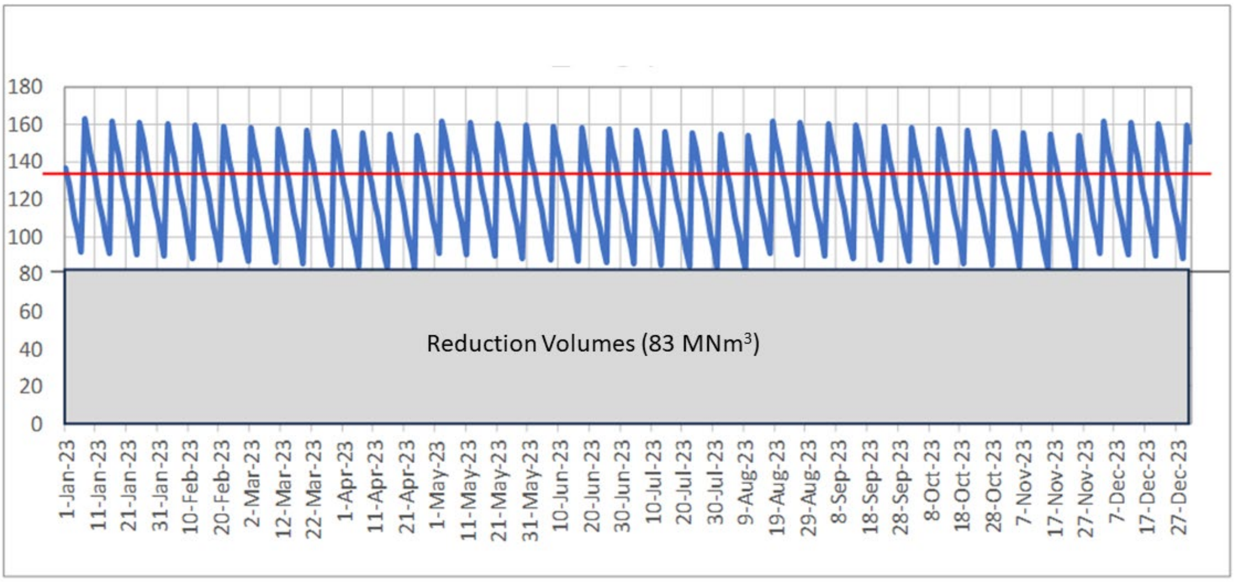
The supply port is 13 Kuching. The tanker is a large MCH (MCH_L) with a storage capacity of 80 MNm^3.

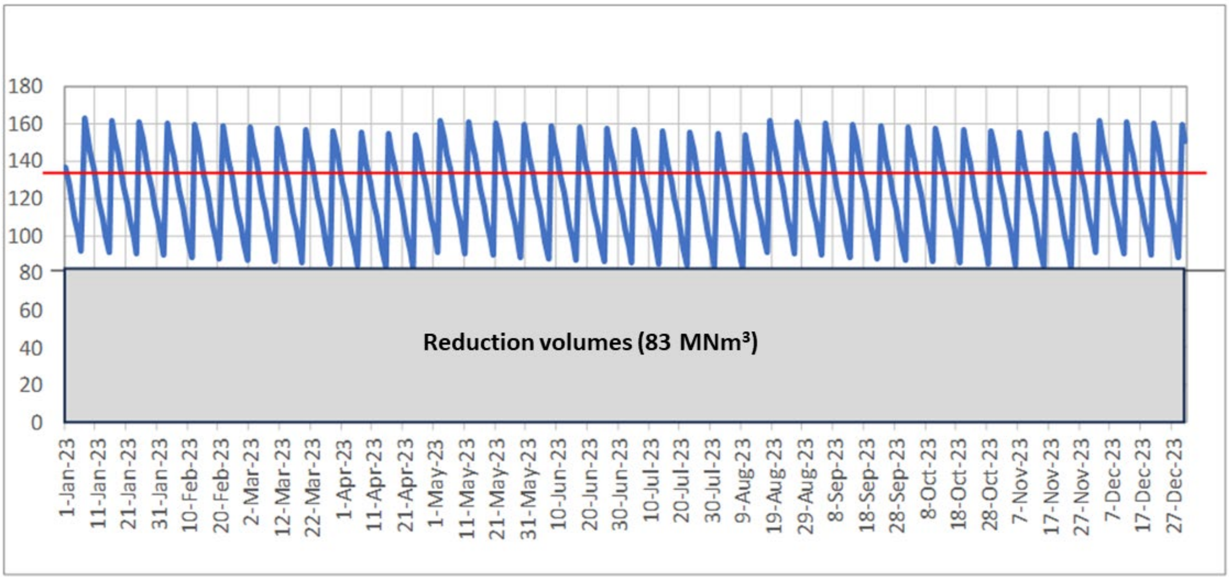
Figure 5.2. Tanker Diagramme, Singapore



Source: Authors.

Figure 5.3. Change in Land Storage Levels, Singapore





MNm^3 = million normal cubic metres.
Source: Authors.

Table 5.9. Storage Capacity Result

Storage Capacity Results			
Maximum Level	Mininum Level	Reduction Volume	Final Maximum Capacity
(MNm^3/Y)	(MNm^3/Y)	(MNm^3/Y)	(MNm^3/Y)
163	83	83	80

MNm^3/y = million normal cubic metres per year.
Source: Authors.

From the simulation results, the storage capacity was calculated as the difference between the maximum and minimum levels, resulting in 80 Mnm^3/year.

Bangkok

The initial storage values, maximum capacity, and tanker departure criteria are as follows:

- The supply port is 11 Brunei Darussalam.
- The tanker is a medium-sized MCH_M with a storage capacity of 40 MNm^3.

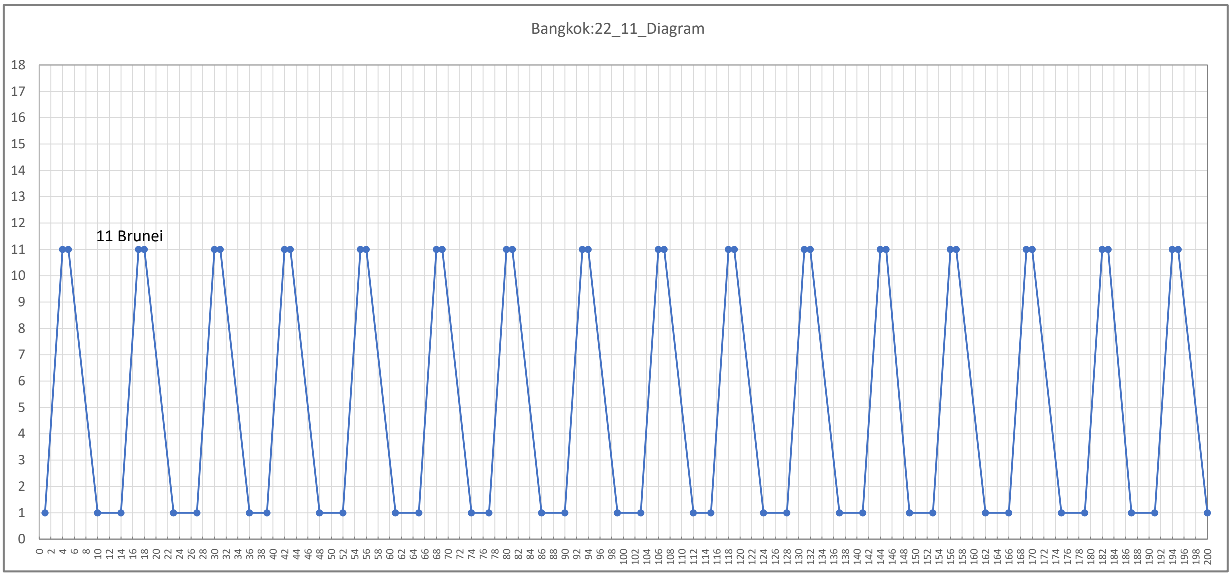
Table 5.10. Data for Simulation Assumptions, Bangkok

Storage					
Inventory Volume Initial Value		Maximum Capacity Initial Value		Tanker Departure Level	
(months)	(MNm^3/Y)	(months)	(MNm^3/Y)	(months)	(MNm^3/Y)
0.5	48	1.5	145	0.5	48

Tankers			
Supply Base	Numbers	Type	Unloading (MNm^3/time)
11 Brunei	1	MCH_M	40

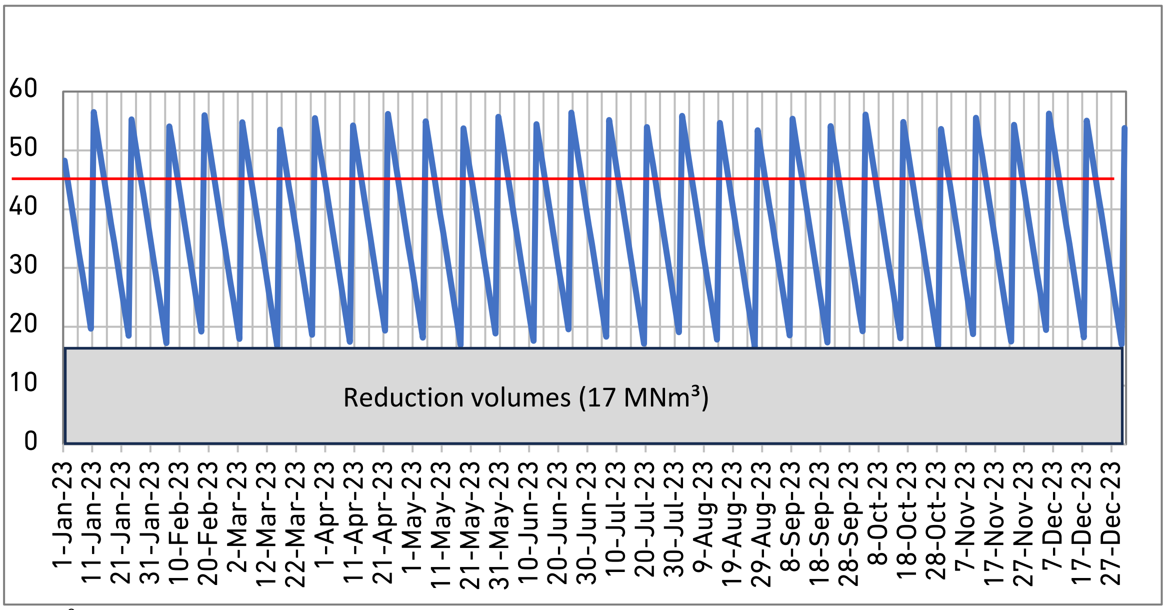
MCH = methylcyclohexane, MNm^3/y = million normal cubic metres per year.
Source: Authors.

Figure 5.4. Tanker Diagramme, Bangkok



Source: Authors.

Figure 5.5. Change in Land Storage Levels, Bangkok



MNm^3/y = million normal cubic metres per year.
Source: Authors.

Table 5.11. Storage Capacity Result

Storage Capacity Results			
Maximum Level	Mininum Level	Reduction Volume	Final Maximum Capacity
(MNm^3/Y)	(MNm^3/Y)	(MNm^3/Y)	(MNm^3/Y)
57	17	17	40

MNm^3/y = million normal cubic metres per year.
Source: Authors.

From the simulation results, the storage capacity is 40 MNm^3 per year, defined as the difference between the maximum and minimum levels.

Tianjin

The initial storage values, maximum capacity, and departure criteria for three supply ports are as follows: 11 Brunei Darussalam (LH2_L) x 1, 13 Kuching (LH2_M) x 1, 15 Hai Phon (LH2_L) x 2.

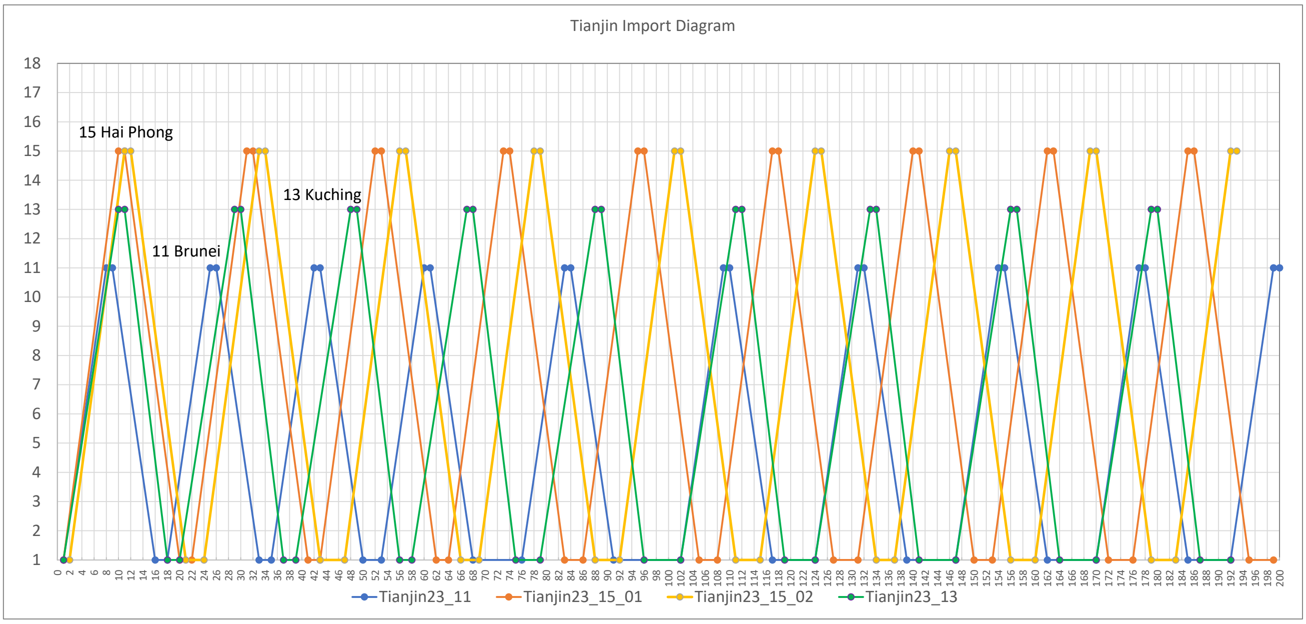
Table 5.12. Data for Simulation Assumptions, Tianjin

Storage					
Inventory Volume Initial Value		Maximum Capacity Initial Value		Tanker Departure Level	
(months)	(MNm^3/Y)	(months)	(MNm^3/Y)	(months)	(MNm^3/Y)
1	604	1.5	905	1	604

Tankers			
Destination	Numbers	Type	Unloading (MNm^3/time)
11 Brunei	1	LH_2__L	128
13 Kuching	1	LH_2__M	64
15 Hai Phon	2	LH_2__L	128

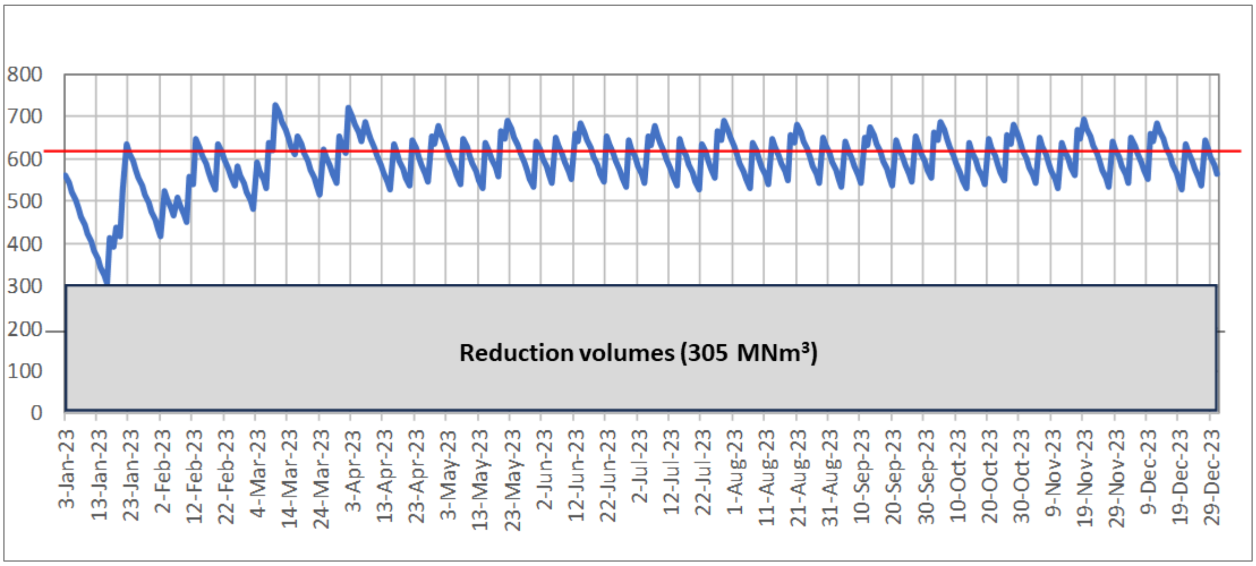
LH_2 = liquefied hydrogen, MNm^3/y = million normal cubic metres per year.
Source: Authors.

Figure 5.6. Tanker Diagramme, Tianjin



Source: Authors.

Figure 5.7. Change in Land Storage Levels, Tianjin



Source: Authors.

Table 5.13. Storage Capacity Results

Maximum Level	Mininum Level	Reduction Volume	Final Maximum Capacity
(MNm^3/Y)	(MNm^3/Y)	(MNm^3/Y)	(MNm^3/Y)
728	305	305	423

MNm^3/y = million normal cubic metres per year.
Source: Authors

Based on the simulation results, the storage capacity is calculated as the difference between maximum and minimum levels, resulting in a capacity of 423 Mnm^3/year.

Tokyo

The initial storage value, maximum capacity, and departure criteria for two supply ports are as follows: 12 Tanggu (LH2_L) x 3, 16 Sydnie (LH2_L) x 4.

Table 5.14. Data for Simulation Assumptions, Tokyo

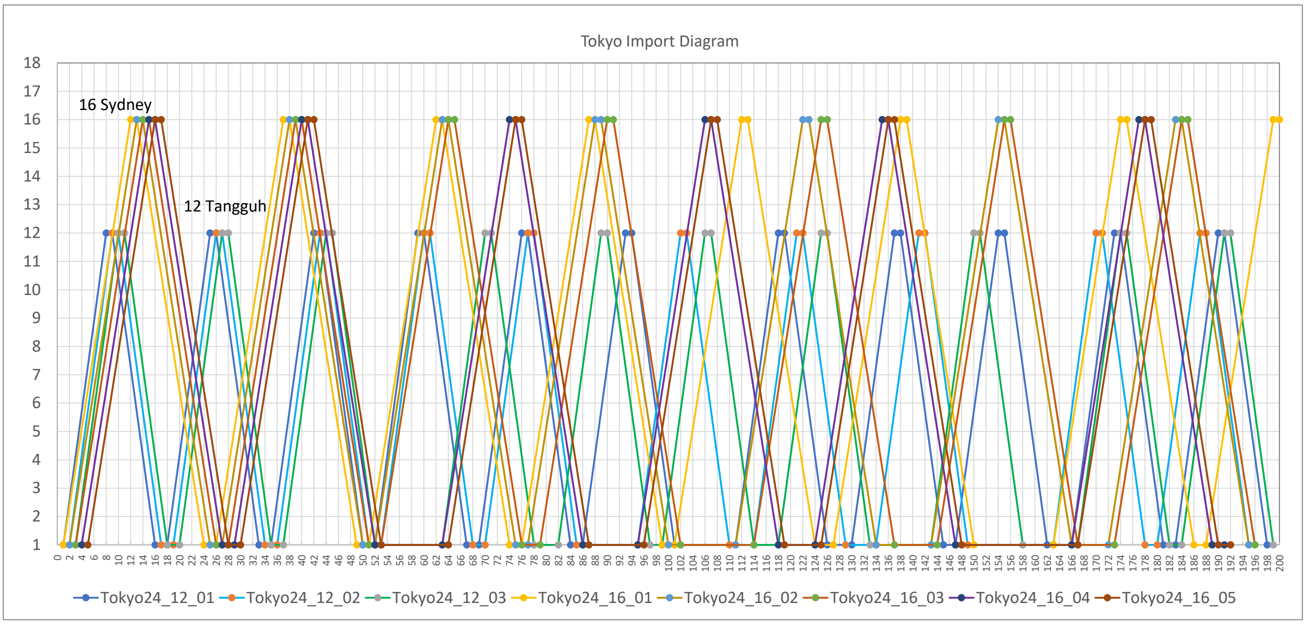
Storage					
Inventory Volume Initial Value		Maximum Capacity Initial Value		Tanker Departure Level	
(months)	(MNm^3/Y)	(months)	(MNm^3/Y)	(months)	(MNm^3/Y)
1	1206	1.5	1809	1	1206

Tankers			
Supply Base	Numbers	Type	Unloading (MNm^3/time)
12 Tangguh	3	LH_2__L	128
16 Sydney	5	LH_2__L	128

MNm^3/y = million normal cubic metres per year
Source: Authors.

In the case of multiple tankers, the initial fleet appears to be gradually collapsing.

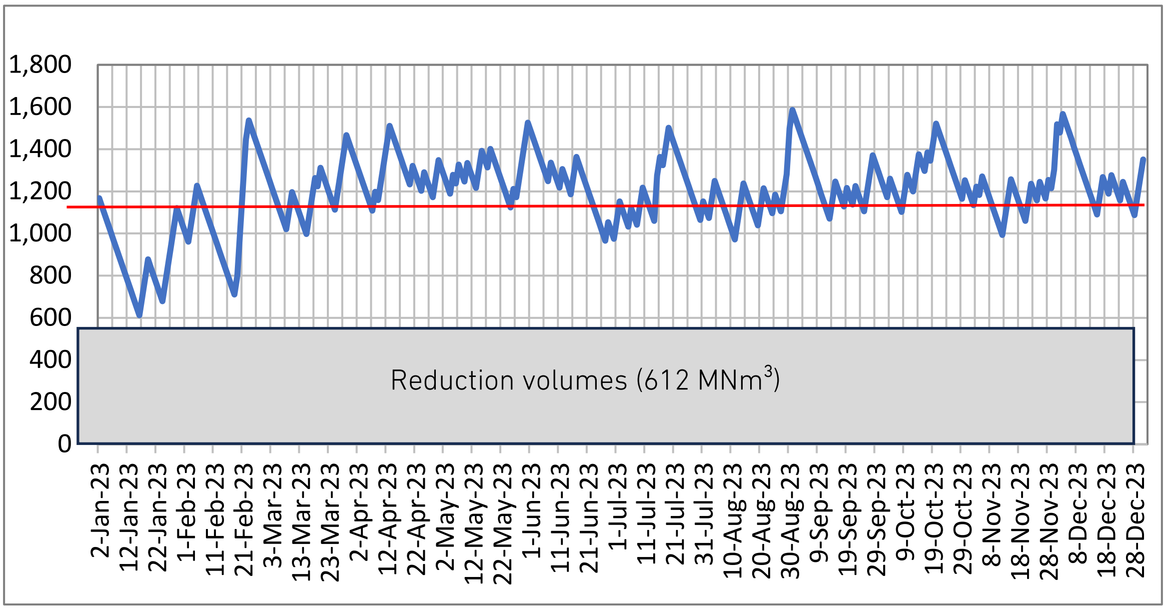
Figure 5.8. Tanker Diagramme, Tokyo



Source: Authors.

The long distance to Sydney creates a gap, resulting in a large amplitude.

Figure 5.9. Change in Land Storage Levels, Tokyo



Source: Authors.

Table 5.15. Storage Capacity Result

Storage Capacity Results			
Maximum Level	Minimum Level	Reduction Volume	Final Maximum Capacity
(MNm^3/Y)	(MNm^3/Y)	(MNm^3/Y)	(MNm^3/Y)
1,586	612	612	974

MNm^3/y = million normal cubic metres per year.
Source: Authors.

The storage capacity, as indicated by the difference between the maximum and minimum levels, is 974 Mnm^3/year.

Incheon

The initial storage value, maximum capacity, and departure criteria for four supply ports are as follows: 12 Tanggu (LH_2_L) x 2, 14 Manila (MCH_M) x 1, 15 Hai Phong (LH_2_M) x 1, 17 Chennai (LH_2_L) x 4.

Table 5.16. Data for Simulation Assumptions, Incheon

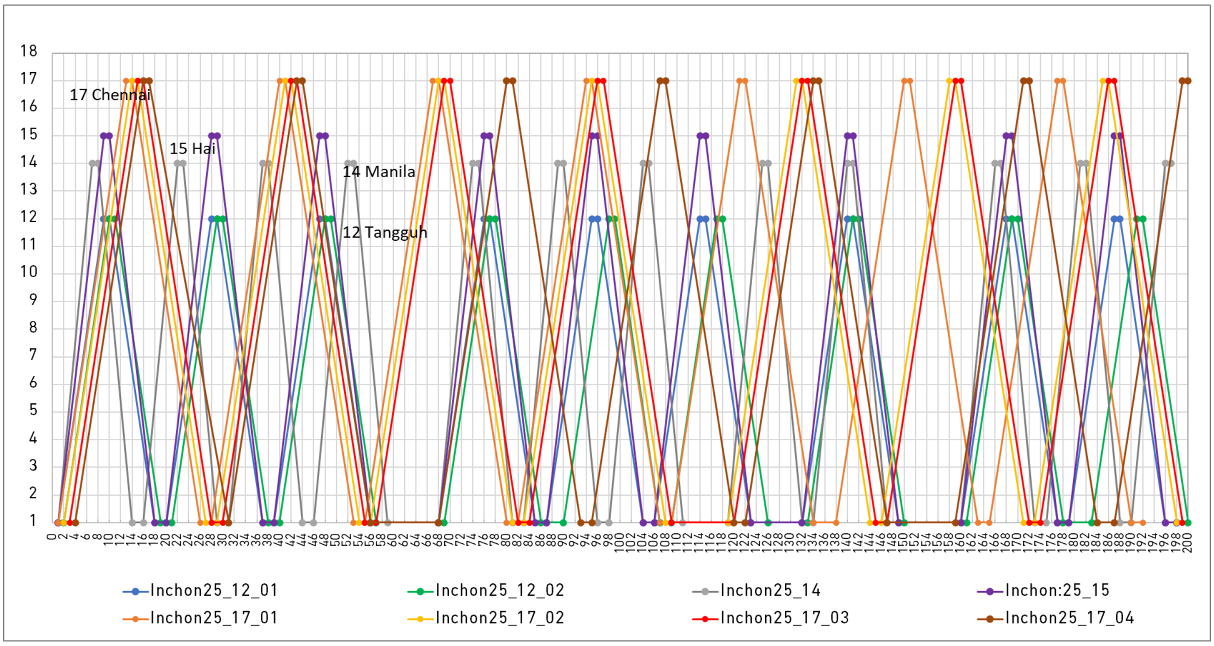
Storage					
Inventory volume initial value		Maximum capacity initial value		Tanker departure level	
(months)	(MNm^3/Y)	(months)	(MNm^3/Y)	(months)	(MNm^3/Y)
1	1,059	1.5	1,589	1	1,056

Tankers			
Supply Base	Numbers	Type	Unloading (MNm^3/time)
12 Tangguh	2	LH_2__L	128
14 Manila	1	MCL_M	80
15 Hai Phong	1	LH_2__M	64
17 Chennai	4	LH_2__L	128

LH_2 = liquefied hydrogen, MNm^3/y = million normal cubic metres per year.
Source: Authors.

The graphs overlap because there are four supply ports, but the initial fleet at 17 (Chennai) is gradually collapsing.

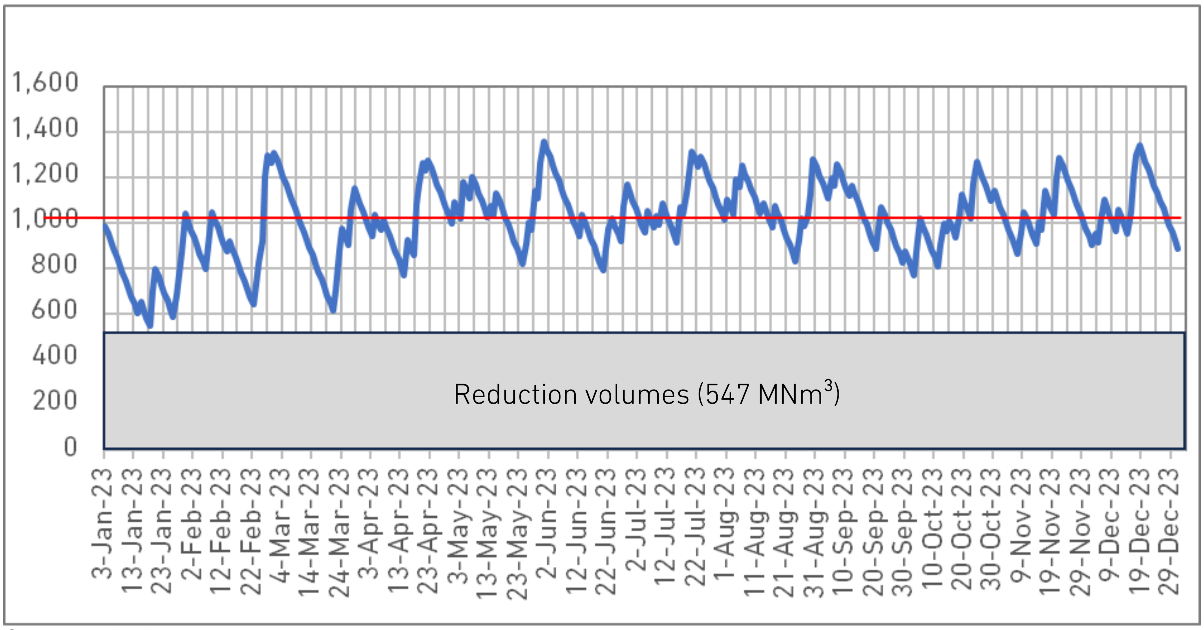
Figure 5.10. Tanker Diagramme, Incheon



Source: Authors.

Due to the long distance to Chennai, the navigation time is prolonged, resulting in a gap and a large amplitude. Whilst it fell below the initial value for about 2 months after the start, it stabilised around that level for an additional month.

Figure 5.11. Change in Land Storage Levels, Incheon



Source: Authors.

Table 5.17. Storage Capacity Result

Storage Capacity Results			
Maximum Level	Minimum Level	Reduction Volume	Final Maximum Capacity
(MNm^3/Y)	(MNm^3/Y)	(MNm^3/Y)	(MNm^3/Y)
1,359	547	547	812

MNm^3/y = million normal cubic metres per year.
Source: Authors.

The simulation results indicate that the storage capacity, calculated as the difference between the maximum and minimum levels, is 812 Mnm^3/year.

Summary of Simulation Results for Land Storage

Table 5.18 shows the simulation results for land storage, including volume and maximum, minimum, and average values of storage.

In ④, the total supply is derived from the cumulative amount unloaded by each tanker, and the total number of tanker operations. The evaluation index ⑥ is assessed by the ratio of annual storage input to annual consumption. A ratio of 1.0 for each consumption area indicates that the input amount is equivalent to annual consumption. The closer ⑥ is to 1.0, the more accurately the simulation model operates.

Table 5.18. Simulation Results for Land Storage (Summary)

Operational Status of Storage	Singapore	Bangkok	Tianjin			Tokyo		Inchon				Total
Initial Storage capacity (Months of demand)	1.0	1.0	1.5			1.5		1.5				
Initial Storage capacity (MNm^3/year)	273	96	905			1,809		1,589				4,672
Initial value of storage (Months of demand)	0.5	0.5	1.0			1.0		1.0				
① Initial value of storage (MNm^3/year)	136	48	604			1206		1059				
Level of tanker departures (MNm^3/year)	136	48	604			1206		1059				
Tanker Type	MCH_L	MCH_M	LH2_L	LH2_M	LH2_L	LH2_L	LH2_L	LH2_L	MCH_L	LH2_M	LH2_L	
Supply basees (Destination)	Kuching	Brunei	Brunei	Kuching	Hai Phong	Tangguh	Sydney	Tangguh	Manila	Hai Phong	Chennai	
Tannker unloading volumes (MNm^3/time)	80	40	128	64	128	128	128	128	80	64	128	
Number of tankers	1	1	1	1	2	3	5	2	1	1	4	22
Number of unloading operations (times)	41	29	16	16	32	52	62	30	21	15	47	
②Tanker unloading volumes (MNm^3/year)	3,280	1,160	2,048	1,024	4,096	6,656	7,936	3,840	1,680	960	6,016	38,696
Maximum level of storage (MNm^3/year)	163	57	728			1,586		1,359				

Operational Status of Storage	Singapore	Bangkok	Tianjin	Tokyo		Inchon		Total
Minimum level of storage (MNm^3/year)	83	17	305	612		547		
Final Maximum Storage Capacity (MNm^3/year)	80	40	423	974		812		2,329
③Stock at end of period (MNm^3/year)**	151	54	566	1,352		889		3,012
④Total supply (MNm^3/year) ①+②−③	3,265	1,154	7,206	14,446		12,666		38,737
⑤Annual consumption (MNm^3/year)	3,275	1,157	7,242	14,475		12,711		38,860
⑥Comparison ④ / ⑤	1.00	1.00	1.00	1.00		1.00		1.00

Notes:
*Maximum storage capacity calculated from simulation results.
**The inventory volume at the end of the year is the result of this simulation with a large initial input.
LH_2 = liquefied hydrogen, MCH = methylcyclohexane, MNm^3/y = million normal cubic metres per year.
Source: Authors.

3.3. Tanker Utilisation Rate

Operating ratios were calculated by tracking actual sailing, waiting, and processing time for each tanker based on the logs of the simulation results.

Tankers are marked with a symbol consisting of a departure and arrival point number, H_2 type (LH_2 or MCH), size (L or M), and a number.

The tanker operating ratio in the table is the operating time (in days) divided by the total time, including waiting time.

To find out the actual free time, the utilisation rate is created, calculated by dividing the operating time (in days) by 365 days, and is shown on the right side of the graph.

(1) Singapore

A single tanker (L type) transporting MCH from Kuching sails 41 times a year and has an operating rate of 90%. Including the waiting time, the tanker operates 365 days per year, signifying continuous daily operation.

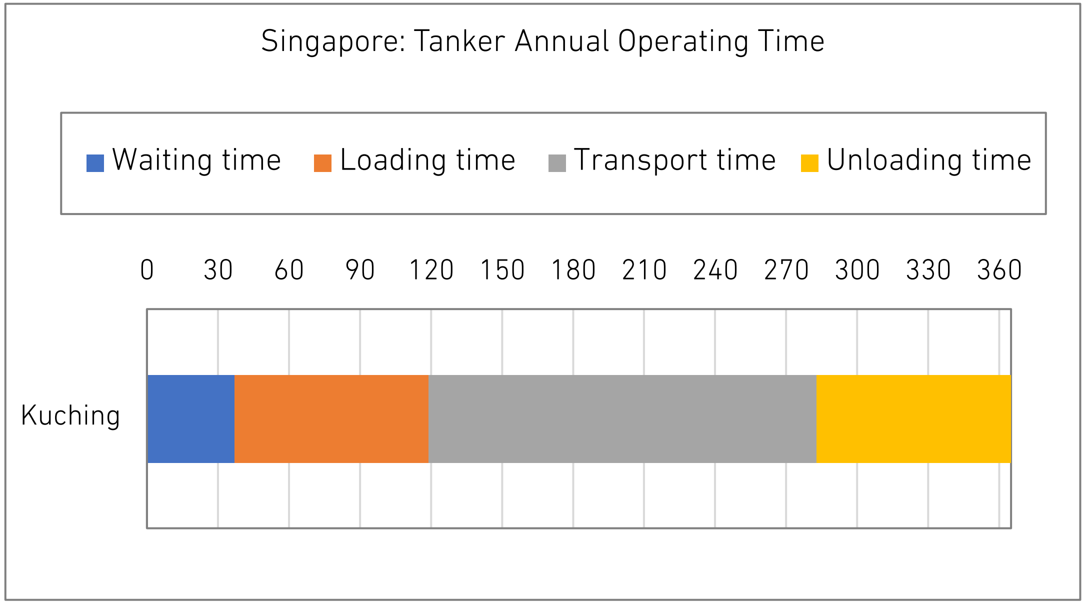
The graph on the right shows a consistent utilisation rate of 90% for 365 days, indicating that the only free time on this route is waiting time and that the operation is very tight.

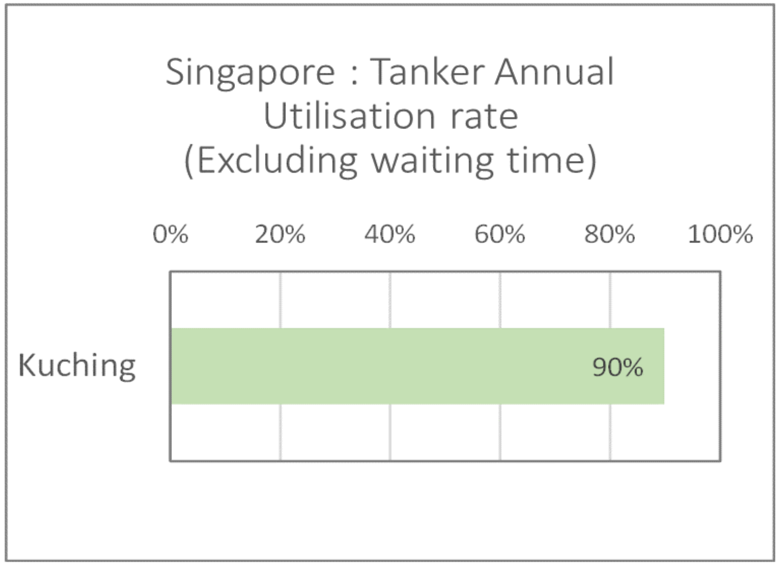
Table 5.19. Simulation Results for Tanker Utilisation Rate, Singapore

Supply Site	Tanker Number	Waiting Time for Shipment (days)	Loading Time (days)	Transport Time (days)	Unloading Time (days)	Operating Time (days)	Total Time (days)	Operating Ratio	Number of voyages (times)
Kuching	SHP_21_13_ML_01	37	82	164	82	328	365	90%	41
Kuching	Total	37	82	164	82	328	365	90%	41

Source: Authors.

Figure 5.12. Tanker Annual Operating Time and Utilisation Rate, Singapore





Source: Authors.

(2) Bangkok

A single tanker (M type) transports MCH from Brunei Darussalam, sailing 29 times a year and has an operating rate of 96%. Including waiting time, the tanker operates for 364 days per year, almost every day.

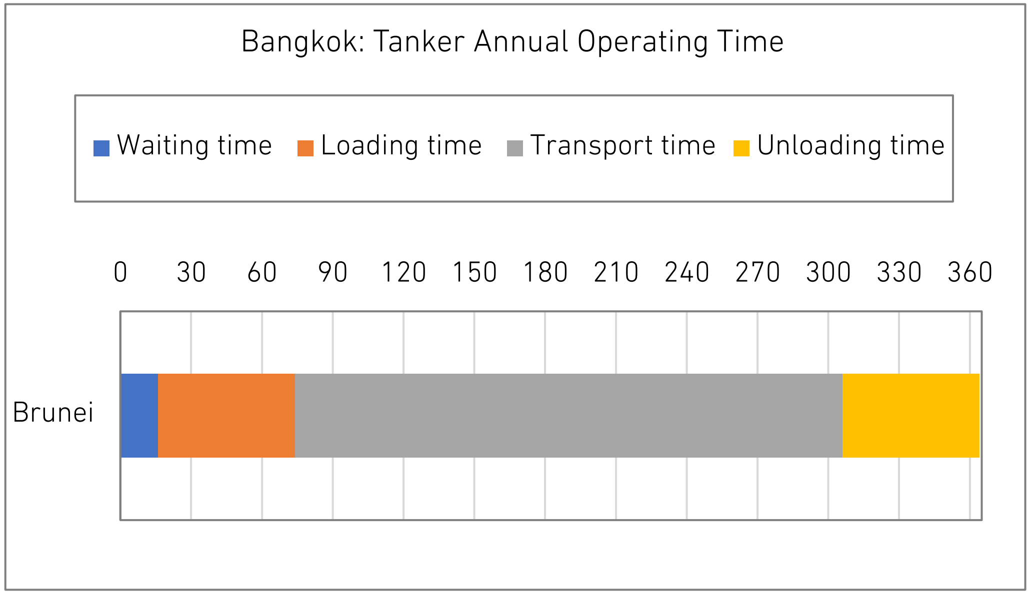
The graph on the right shows a nearly consistent utilisation rate for 95% for 365 days, indicating that the only free time on this route is waiting time and that the operation is very tight.

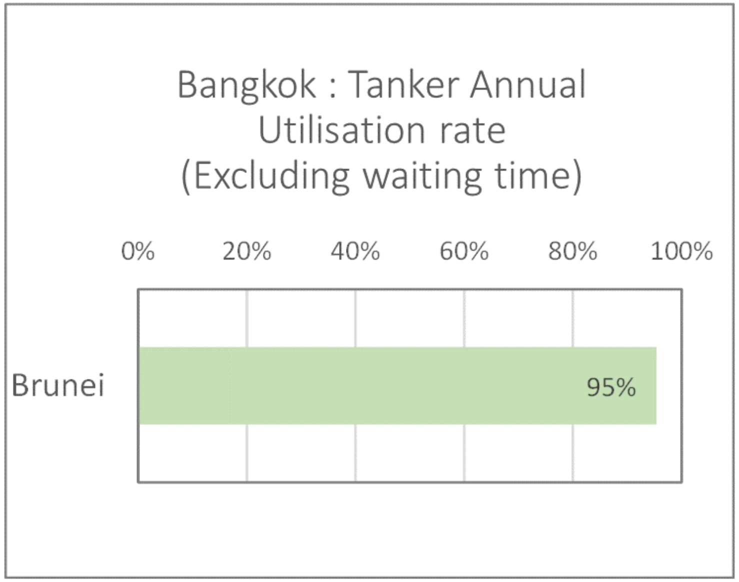
Table 5.20. Simulation Results for Tanker Utilisation Rate, Bangkok

Supply Site	Tanker Number	Waiting Time for Shipment (days)	Loading Time (days)	Transport Time (days)	Unloading Time (days)	Operating Time (days)	Total Time (days)	Operating Ratio	Number of Voyages (times)
Brunei	SHP_22_11_MM_01	16	58	232	58	348	364	96%	29
Brunei	Total	16	58	232	58	348	364	96%	29

Source: Authors.

Figure 5.13. Tanker Annual Operating Time and Utilisation Rate, Bangkok





Source: Authors.

(3) Tianjin

Tianjin has three routes, with tankers' operating ratio at 83% for the Brunei Darussalam route but at more than 90% for the other routes. The Hai Phong route has an operating time of 352 days and an operating ratio of 98%, which means that the tankers are in full operation.

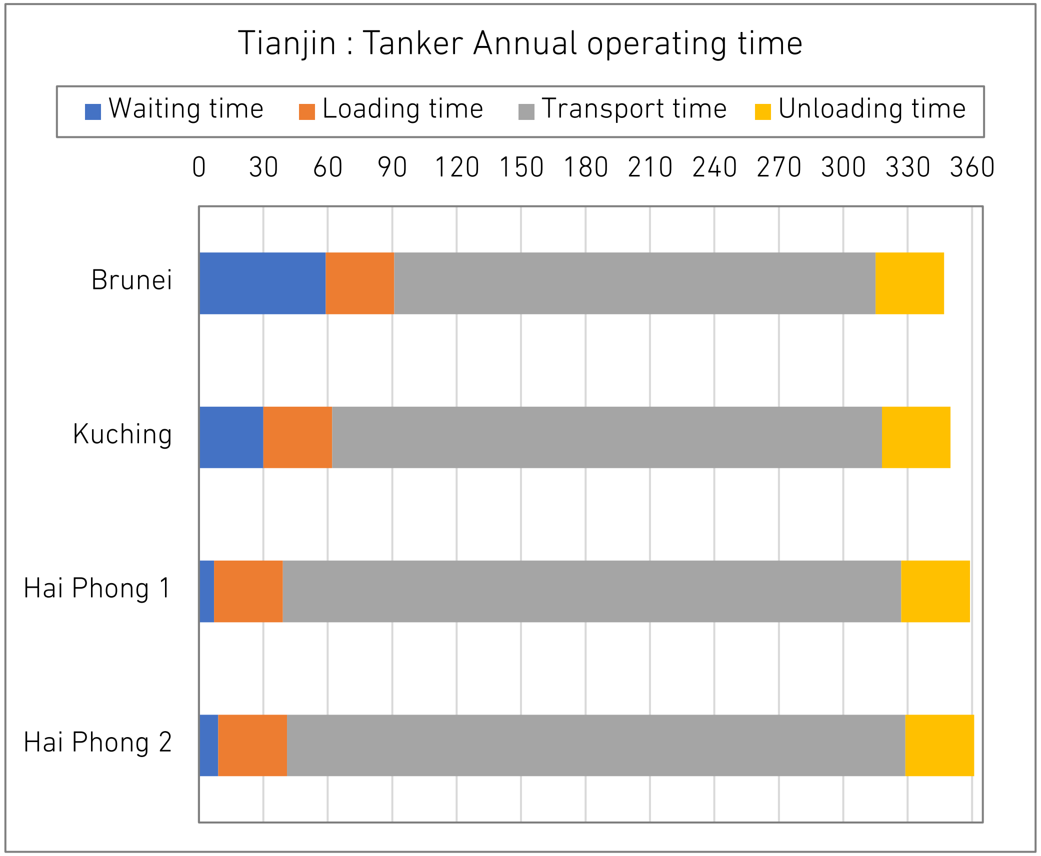
The tanker utilisation rate is very high at 96%, indicating that the route is operated with little margin.

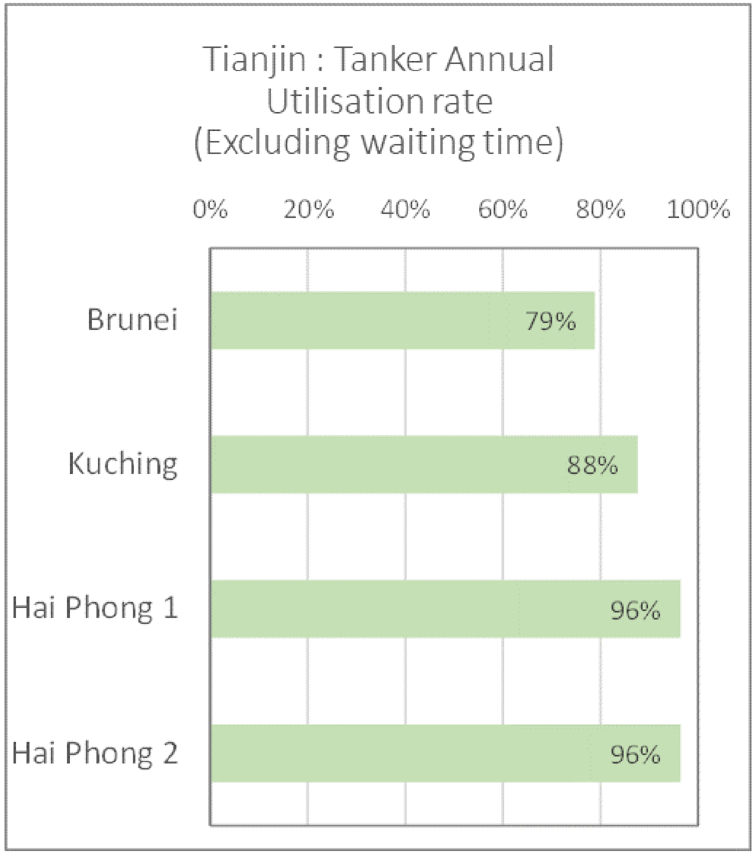
Table 5.21. Simulation Results for Tanker Utilisation Rate, Tianjin

Supply Site	Tanker Number	Waiting Time for Shipment (days)	Loading Time (days)	Transport Time (days)	Unloading Time (days)	Operating Time (days)	Total Time (days)	Operating Ratio	Number of Voyages (times)
Brunei	SHP_23_11_LL_01	59	32	224	32	288	347	83%	16
Kuching	SHP_23_13_LM_01	30	32	256	32	320	350	91%	16
Hai Phong	SHP_23_15_LL_01	7	32	288	32	352	359	98%	16
	SHP_23_15_LL_02	9	32	288	32	352	361	98%	16
Hai Phong	Interim Total	16	64	576	64	704	720	98%	32
	Total	105	128	1,056	128	1,312	1,417	93%	64

Source: Authors.

Figure 5.14. Tanker Annual Operating Time and Utilisation Rate, Tianjin





Source: Authors.

(4) Tokyo

Tokyo has two routes and as many as seven tankers. The operating ratio for the Tangguh route is 84%–90%. The breakdown of the ratio is high for the first tanker and slightly lower for the second and subsequent tankers. This discrepancy arises because one tanker departs first, resulting in longer waiting time for the following tankers.

The Sydney route has a fleet of six, resulting in an operating ratio of 86%–94%, with a waiting time of 23 days for the first tanker and 50 days for the tail tanker, resulting in a large difference between the first and tail tankers. The reason is that the simulation was conducted using the FIFO (first in, first out) operation. In actual operation, the operating ratio must be adjusted through operational management.

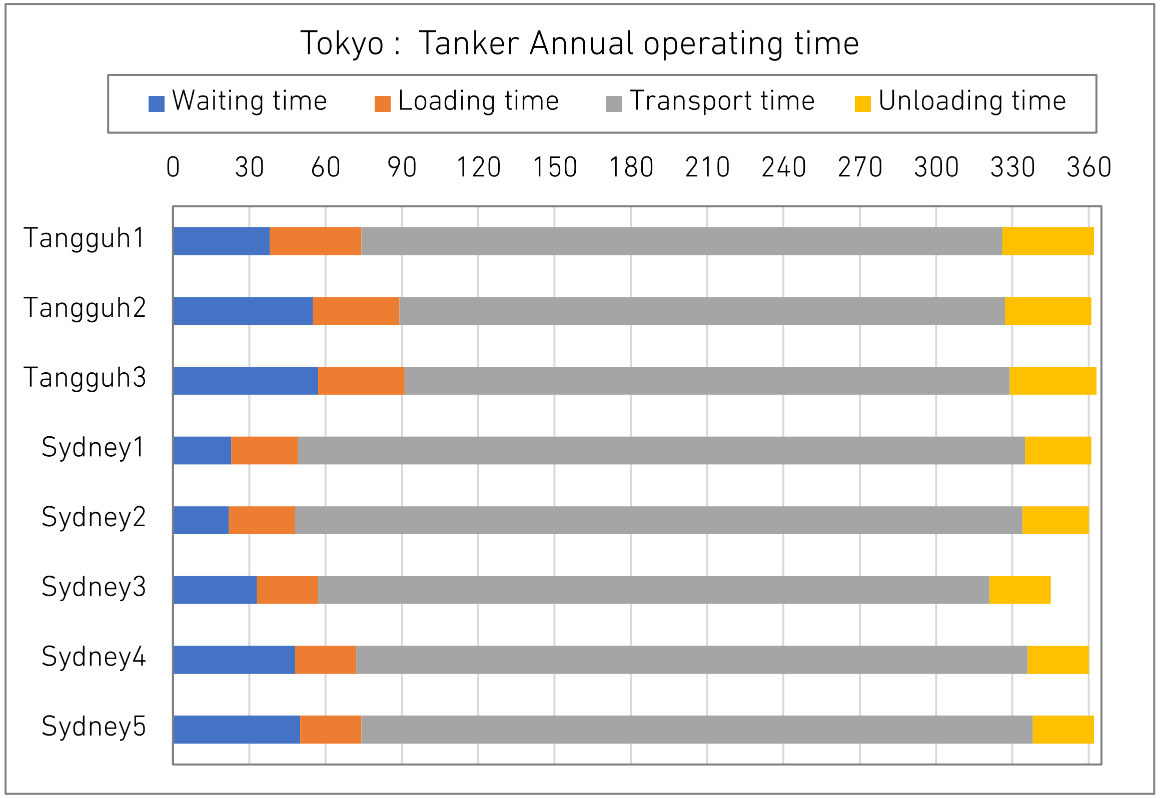
The utilisation rate is 85%–93%, indicating that the operating environment is severe.

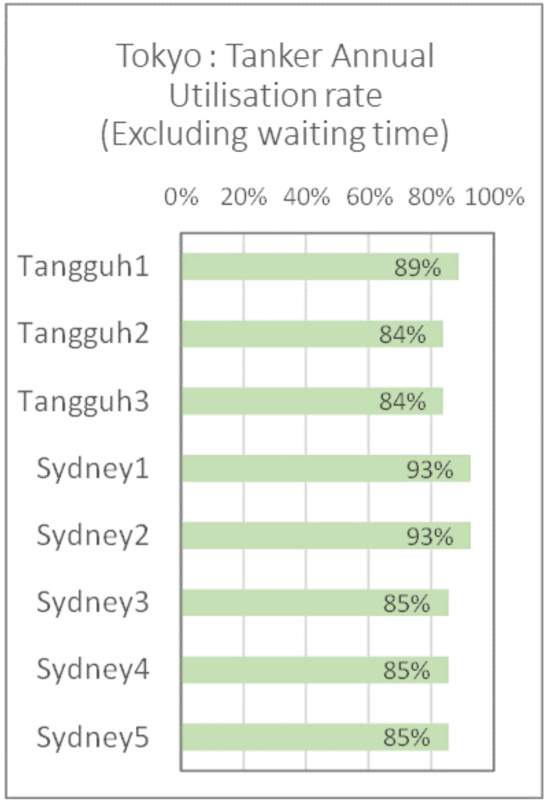
Table 5.22. Simulation Results for Tanker Utilisation Rate, Tokyo

Supply Site	Tanker Number	Waiting Time for Shipment (days)	Loading Time (days)	Transport Time (days)	Unloading Time (days)	Operating Time (days)	Total Time (days)	Operating Ratio	Number of Voyages (times)
Tangguh	SHP_24_12_LL_01	38	36	252	36	324	362	90%	18
	SHP_24_12_LL_02	55	34	238	34	306	361	85%	17
	SHP_24_12_LL_03	57	34	238	34	306	363	84%	17
Tangguh	Interim Total	150	104	728	104	936	1086	86%	52
Sydney	SHP_24_16_LL_01	23	26	286	26	338	361	94%	13
	SHP_24_16_LL_02	22	26	286	26	338	360	94%	13
	SHP_24_16_LL_03	33	24	264	24	312	345	90%	12
	SHP_24_16_LL_04	48	24	264	24	312	360	87%	12
	SHP_24_16_LL_05	50	24	264	24	312	362	86%	12
Sydney	Interim Total	176	124	1364	124	1612	1788	90%	62
	Total	326	228	2,092	228	2,548	2,874	89%	114

Source: Authors.

Figure 5.15. Tanker Annual Operating Time and Utilisation Rate, Tokyo





Source: Authors.

(5) Incheon

Incheon has four routes and a fleet of six. The operating ratio of the Tangguh route is 83%, and the waiting time is 60 days, providing some operational leeway.

The Manila route has an operating ratio of 93% and a short waiting time of 27 days, resulting in tight operations.

The Hai Phong route has an operating ratio of 83% and a waiting time of 61 days, giving it some leeway.

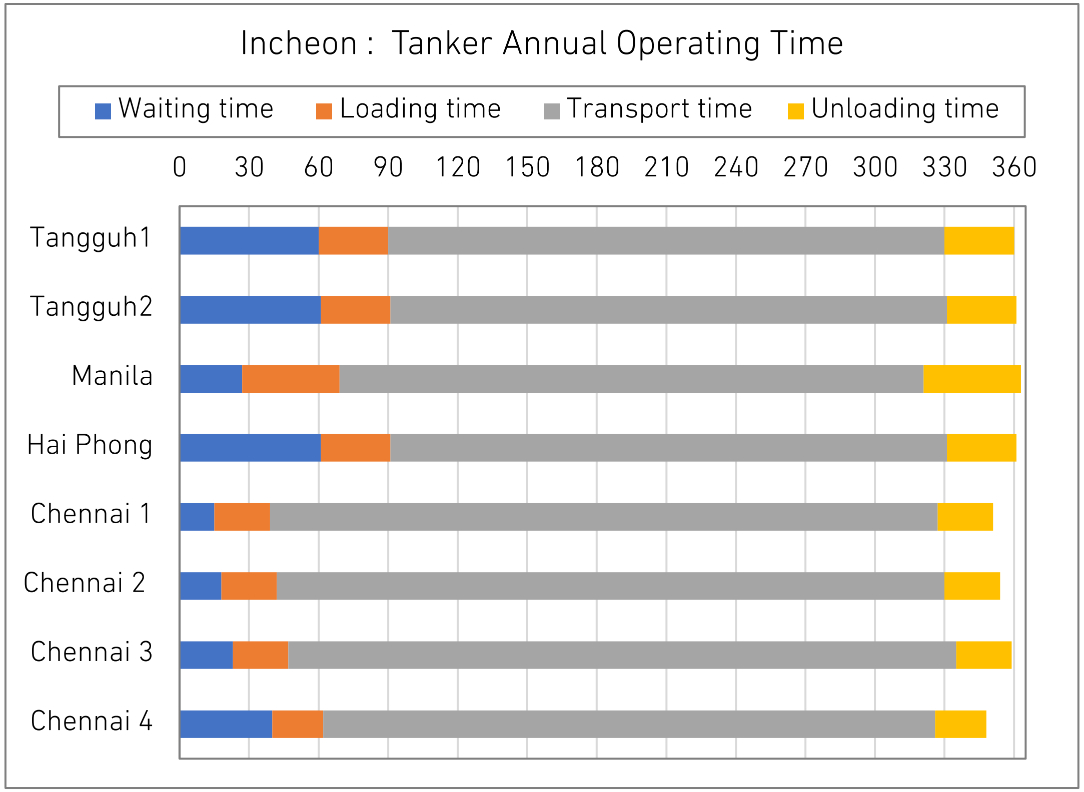
The operating ratio of the Chennai route is 89%–96%, with the first tanker having the highest at 96% and subsequent tankers having lower ones. The waiting time is 15–40 days and tends to increase over time.

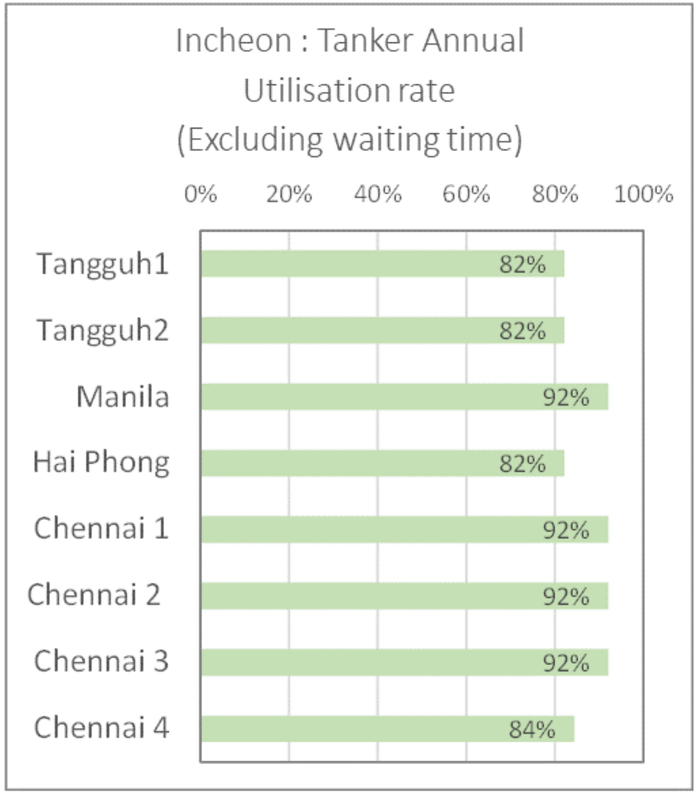
Table 5.23. Simulation Results for Tanker Utilisation Rate, Incheon

Supply Site	Tanker Number	Waiting Time for Shipment (days)	Loading Time (days)	Transport Time (days)	Unloading Time (days)	Operating Time (days)	Total Time (days)	Operating Ratio	Number of Voyages (times)
Tangguh	SHP_25_12_LL_01	60	30	240	30	300	360	83%	15
	SHP_25_12_LL_02	61	30	240	30	300	361	83%	15
Tangguh	Interim Total	121	60	480	60	600	721	83%	30
Manila	SHP_25_14_ML_01	27	42	252	42	336	363	93%	21
Hai Phong	SHP_25_15_LM_01	61	30	240	30	300	361	83%	15
Chennai	SHP_25_17_LL_01	15	24	288	24	336	351	96%	12
	SHP_25_17_LL_02	18	24	288	24	336	354	95%	12
	SHP_25_17_LL_03	23	24	288	24	336	359	94%	12
	SHP_25_17_LL_04	40	22	264	22	308	348	89%	11
Chennai	Interim Total	96	94	1128	94	1316	1412	93%	47
	Total	157	124	1,368	124	1,616	1,773	91%	62

Source: Authors.

Figure 5.16. Tanker Annual Operating Time and Utilisation Rate, Incheon





Source: Authors.

4. Forecast of Operational and Capital Expenditures

4.1. Land Storage Operational and Capital Expenditures

Figure 5.12 illustrates a tanker unloading H_2 into a onshore storage, the capacity of which is depicted as 230,000 kilolitres (kL).

Figure 5.17. Land Storage Image

Source: Tokyo Gas Engineering Solutions Co., Ltd. (2018) https://www.tokyo-gas.co.jp/Press/20181001-01.html.

1 Correlation graph of land storage size and construction cost

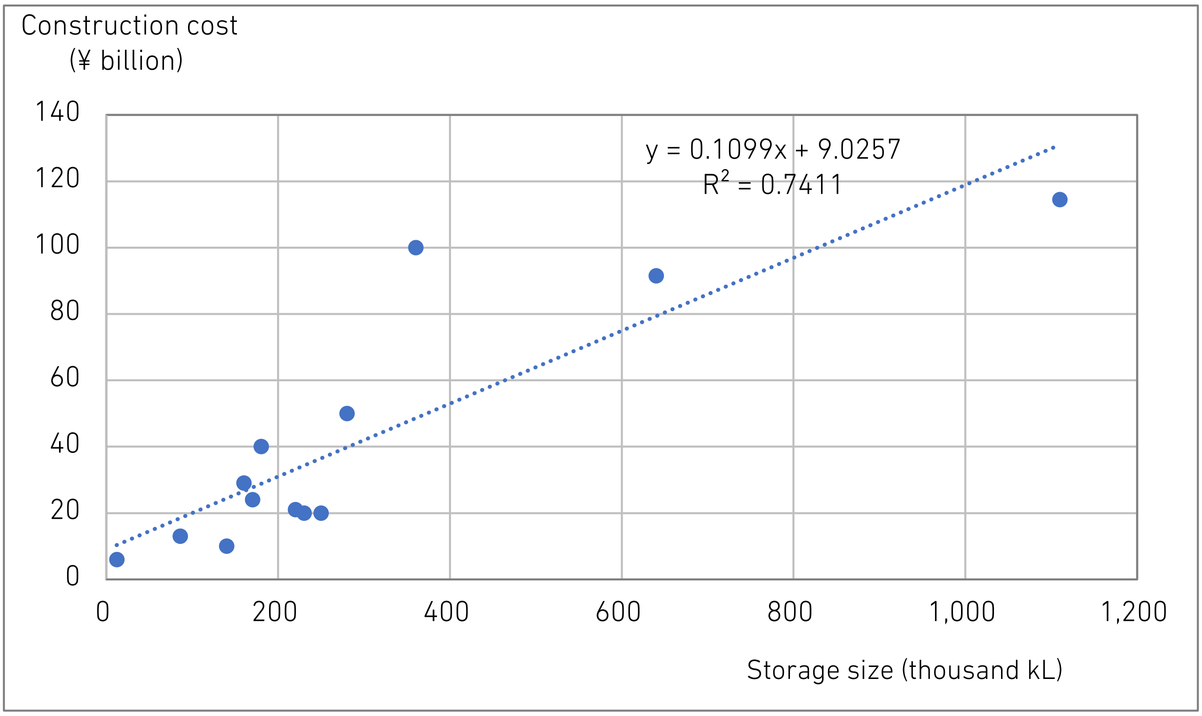
The correlation graph depicts the relationship of storage capacity and construction cost, using data on construction costs of liquefied natural gas (LNG) land storage in Japan. The regression equation, reflecting a linear relationship, is presented below:

$$y = 0.1099x + 9.0257 \text{ (Formula 1)}$$

x is the size of storage, given in kL

y is the construction cost of the storage (¥ billion).

Figure 5.18. Correlation Graph of Land Storage Size and Construction Cost



kL = kilolitre.

Note: Storage construction costs may include land acquisition, pipeline laying, and ancillary construction.

Source: Authors (2024).

The construction cost of LNG storage in the demand area is calculated using formula 1 and multiplying it by 1.5 to account for the higher internal pressure, advanced structure, and lower temperature needs in H_2 storage compared with LNG. For MCH storage, which does not require refrigeration equipment, the construction cost is assumed to be 20% of LNG storage cost. The yen display is converted to the US dollar (US$1 ≒ ¥130).

The number of storage units per country is specified in the middle of the table with assumed capacities of 100,000, 200,000, and 300,000 kL. The table provides values for CAPEX, converted to annual cost through a form of depreciation, and the combined OPEX and annual CAPEX + OPEX for storage. Annual CAPEX is calculated as 1/20 of CAPEX, and OPEX is set at 2.5% of CAPEX.

Table 5.24. Storage Type and Capacity, Capital and Operational Expenditures

Storage Items	Units	Singapore	Bangkok	Tianjin	Tokyo	Incheon*1		Total
Hydrogen Type		MCH	MCH	LH_2	LH_2	LH_2	MCH	
Storage capacity (Simulation Results)	MNm^3/year	80	40	423	974	703*	109*	2.329
LH_2: (1/800) MCH: (1/500) Unit:1000 kL	kL	160.000	80.000	528.750	1.217.500	878.540	218.335	3.083.126
Storage Composition	100,000 kL Storage		1		1	1	1	4
	200,000 kL Storage	1					1	2
	300,000 kL Storage			3	4	3		10
CAPEX (Refer to the table below)	Million US$	48	31	1.455	2.171	1.686	79	5.470
Annual CAPEX (1/20)	Million US$/year	2,4	1,6	72,8	108,6	84,3	4,0	274
OPEX (2.5% of CAPEX)	Million US$	1,20	0,78	36,4	54,3	42,2	2,0	137
Annual CAPEX + OPEX	Million US$/year	3,6	2,3	109,1	162,8	126,5	5,93	410

Note: *1: In Incheon LH_2 and MCH were prorated by the ratio of unloading volume CAPEX = capital expenditure, kL = kilolitre, LH_2 = liquefied hydrogen, MCH = methylcyclohexane, OPEX = operating expenditure.
Source: Authors.

The construction costs by capacity for LH_2 and MCH storage are as follows:

Table 5.25. Construction Cost of Storage

Type	100,000 kL	200,000 kL	300,000 kL	Remarks
LH_2 Storage (MUS$)	231	358	485	LNG Storage Cost× 1.5
MCH Storage (MUS$)	31	48	65	LNG Storage Cost× 0.2

KL = kilolitre, LH_2 = liquefied hydrogen, LNG = liquefied natural gas, MCH = methylcyclohexane, MUS$ = million US dollars.
Source: Authors.

Figure 5.19. Base with Abundant Land Storage

Note: The largest LNG terminal in Japan is in Sodegaura, Chiba Prefecture, with 35 storage units. Japan has about 230 large LNG storage facilities.
Source: Koshiji (2016)
https://www.doboku-watching.com/index.php?Kiji_Detail&kijiId=60.

4.2. Tanker Operational and Capital Expenditures

4.2.1. Tanker Capital Expenditure

Chemical tankers are classified according to their use and size. Coastal tankers are several thousand deadweight tonnes and large tankers reach 200,000 deadweight tonnes. Worldwide, there are 5,000 chemical tankers exceeding 10,000 deadweight tonnes.

(1) Reference example of an MCH chemical tanker

The shaded areas represent candidates for MCH tankers.

Table 5.26. Reference Materials for Methylcyclohexane Tankers

Tanker Classification	Deadweight Tonnes	Type	CAPEX Construction Price (MUS$)	Remarks
GP: General Purpose	10,000 – 24,999	Product Tankers	43	
MR: Medium Range	25,000 – 44,999	Panamax	43	
LR1: Large Range 1	45,000 – 79,999	Aframax	58	
LR2: Large Range 2	80,000 – 159,999	Suezmax	58	Reference for MCH_M construction cost
VLCC (Very Large Crude Carrier)	160,000 – 319,999	VLCC	120	Reference for MCH_L construction cost
ULCC (Ultra Large Crude Carrier)	320,000 – 549,999	VLCC		

MCH = methylcyclohexane, MUS$ = million US dollars.
Source: Authors, based on https://ja.wikipedia.org/wiki/%E7%9F%B3%E6%B2%B9%E3%82%BF%E3%83%B3%E3%82%AB%E3%83%BC

(2) Reference example of LH_2 tanker (LNG)

Table 5.27 refers to a large LNG tanker. A Korean shipyard received an order to build an LNG tanker valued at US$240 million.

Table 5.27. Reference Materials for Liquefied Hydrogen Tankers

Tanker Classification	Deadweight Tonnes (CBM)	Type	CAPEX Construction Price (MUS$)	Remarks
LNG Tanker (News in 2022)			240	Chosun Ilbo (contract value)
LH_2_L Tanker	160,000	LH_2	288	Above LNG Tanker x1.5x0.8 = 1.2 times price (estimation)
LH_2_M Tanker	80,000	LH_2	144	1/2 of L-type

CAPEX = capital expenditure, CBM = cubic metre, LH_2 = liquefied hydrogen, MUS$ = million US dollars, VLCC = very large crude carrier.
Source: Modified by Authors using *Chosun Ilbo* article for LNG tanker prices (article: 16 October https://www.chosunonline.com/site/data/html_dir/2022/10/14/2022101480106.html

4.2.2. Tanker CAPEX + OPEX

The construction costs of LH_2 and MCH tankers were estimated from various sources. The L-type LH_2, with a storage capacity of 160,000 cubic metres, is assumed to have a construction cost of US$288 million. The M-type LH_2 is assumed to be half the price of the L-type.

The L-type MCH, with a storage capacity of 160,000 cubic metres, is assumed to have a construction cost of US$120 million. The M-type MCH is assumed to be half the price of the L-type.

Table 5.28. Estimated Tanker Construction Cost

Tanker Type	Storage Capacity (cubic metre)	Converted to Gas (MNm^3)	Construction Price (MUS$)	Remarks
LH_2_L	160,000	128	288	Estimated to be 1.2 times the construction cost of an LNG tanker
LH_2_M	80,000	64	144	
MCH_L	160,000	80	120	Based on the construction cost of a chemical tanker
MCH_M	80,000	40	60	

LH_2 = liquefied hydrogen, MCH = methylcyclohexane, MNm^3 = million of natural cubic metres, MUS$ = million US dollars.
Source: Authors.

For tanker OPEX (Appendix), we assumed that the LH_2 tanker comprises 12% of CAPEX and the MCH tanker 9%. The construction cost of tankers, categorised by location of demand, is shown below.

(1) Singapore

The tanker is an L-type MCH, with a construction cost of US$120 million. If the annual cost of the tanker is 1/20 of CAPEX, then the annual cost of the tanker is US$6 million. The OPEX is assumed to be 16% of the construction cost (CAPEX), which is US$19 million. Therefore, the annual CAPEX + OPEX is US$25.2 million.

Table 5.29. Tanker Operational and Capital Expenditures, Singapore

Demand Sites	Supply Sites	Tanker CAPEX				Tanker OPEX
		Tankers Type	Number of Tankers	Construction Price MUS$	Annual Cost (1/20) MUS$/Year	Operating Costs MUS$/Year
21 Singapore	13 Kuching	MCH_L	1	120	6	10.8
Singapore	Annual CAPEX+OPEX (MUS$ /year)					16.8

CAPEX = capital expenditure, MCH = methylcyclohexane, MUS$ = million US dollars, OPEX = operating expenditure.
Source: Authors.

(2) Bangkok

The tanker is an M-type MCH, with a construction cost of US$60 million. Assuming that the annual cost of the tanker is 1/20 of CAPEX, the annual cost of the tanker is US$3 million. Annual CAPEX + OPEX is US$12.6 million.

Table 5.30. Tanker Operational and Capital Expenditures, Bangkok

Demand Sites	Supply Sites	Tanker CAPEX				Tanker OPEX
		Tankers Type	Number of Tankers	Construction Price MUS$	Annual Cost (1/20) MUS$/Year	Operating Costs MUS$/Year
22 Bangkok	11 Brunei	MCH_M	1	60	3	5.4
Bangkok	Annual CAPEX+OPEX (MUS$ /year)					8.4

CAPEX = capital expenditure, MCH = methylcyclohexane, MUS$ = million US dollars, OPEX = operating expenditure.
Source: Authors.

(3) Tianjin

The fleet consists of three L-type and one M-type LH_2 tankers. The construction cost is US$1,008 million and the annual CAPEX is US$50 million. Annual CAPEX + OPEX is US$171.4 million.

Table 5.31. Tanker Operational and Capital Expenditures, Tianjin

Demand Sites	Supply Sites	Tanker CAPEX				Tanker OPEX
		Tankers Type	Number of Tankers	Construction Price MUS$	Annual Cost (1/20) MUS$/Year	Operating Costs MUS$/Year
23 Tianjin	11 Brunei	LH2_L	1	288	14	34.6
	13 Kuching	LH2_M	1	144	7	17.3
	15 Hai Phong	LH2_L	2	576	29	69.1
Tianjin	Total		4	1,008	50	121.0
Tianjin	Annual CAPEX+OPEX (MUS$ /year)					171.4

CAPEX = capital expenditure, LH_2 = liquefied hydrogen, MUS$ = million US dollars, OPEX = operating expenditure.
Source: Authors.

(4) Tokyo

The fleet consists of eight LH_2 L-type tankers. The total construction cost is US$2,304 million and annual CAPEX is US$115 million. Annual CAPEX + OPEX is US$391.7 million.

Table 5.32. Tanker Operational and Capital Expenditures, Tokyo

Demand Sites	Supply Sites	Tanker CAPEX				Tanker OPEX
		Tankers Type	Number of Tankers	Construction Price MUS$	Annual Cost (1/20) MUS$/Year	Operating Costs MUS$/Year
24 Tokyo	12 Tangguh	LH_2_L	3	864	43	103.7
	16 Sydney	LH_2_L	5	1,440	72	172.8
	Total		8	2,304	115	276.5
Tokyo	Annual CAPEX+OPEX (MUS$ /year)					391.7

CAPEX = capital expenditure, LH_2 = liquefied hydrogen, MUS$ = million United States dollars, OPEX = operating expenditure.
Source: Authors.

(5) Incheon

The fleet consists of six L-type LH_2 tankers, one M-type LH_2 tanker, and one L-type MCH tanker. The total construction cost is US$1922 million and annual CAPEX is US$100 million. Annual CAPEX + OPEX is US$338.6 million.

Table 5.33. Tanker Operational and Capital Expenditures, Incheon

		Tanker CAPEX				Tanker OPEX
Demand Sites	Supply Sites	Tankers Type	Number of Tankers	Construction Price MUS$	Annual Cost (1/20) MUS$/Year	Operating Costs MUS$/Year
25 Incheon	12 Tangguh	LH_2_L	2	576	29	69.1
	14 Manila	MCH_L	1	120	6	14.4
	15 Hai Phong	LH_2_M	1	144	7	17.3
	17 Chennai	LH_2_L	4	1,152	58	138.2
Incheon	Total		8	1,992	100	239.0
Incheon	Annual CAPEX+OPEX (MUS$ /year)					338.6

LH_2 = liquefied hydrogen, MCH = methylcyclohexane, MUS$ = million US dollars.
Source: Authors.

(6) Total

There are eight supply sites, one of which is not in use, and five demand sites. The total number of tankers required to meet demand is 22. The 22 tankers include 17 LH_2_L, 2 LH_2_M, 2 MCH_L, and 1 MCH_M. The total construction cost of the tanker fleet was US$5,484 million, with an annual cost of US$274 million. The annual CAPEX + OPEX is US$926.9 million.

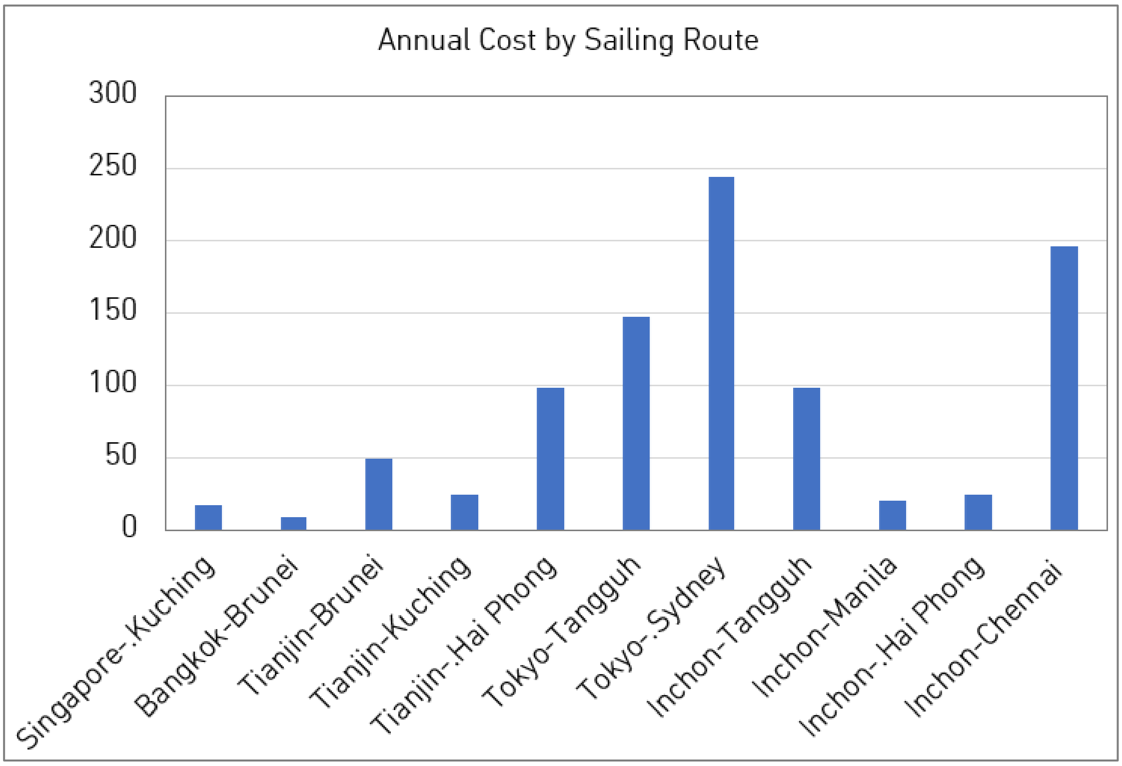
Table 5.34. Total Tanker Operational and Capital Expenditures

Demand Sites	Supply Sites	Tanker CAPEX				Tanker OPEX	CAPEX+OPEX
		Tankers Type	Number of Tankers	Construction Price (MUS$/year)	Annual Cost (1/20) (MUS$/year)	Operating Costs (MUS$/year)	Annual Cost (MUS$/year)
21 Singapore	13 Kuching	MCH_L	1	120	6	10.8	16.8
	Total		1	120	6.0	10.8	16.8
22 Bangkok	11 Brunei	MCH_M	1	60	3	5	8.4
	Total		1	60	3.0	5.4	8.4
23 Tianjin	11 Brunei	LH_2_L	1	288	14	34.6	49.0
	13 Kuching	LH_2_M	1	144	7	17.3	24.5
	15 Hai Phong	LH_2_L	2	576	29	69.1	97.9
	Total		4	1,008	50.4	121.0	171.4
24 Tokyo	12 Tangguh	LH_2_L	3	864	43	103.7	146.9
	16 Sydney	LH_2_L	5	1,440	72	172.8	244.8
	Total		8	2,304	115	276.5	391.7
25 Incheon	12 Tangguh	LH_2_L	2	576	29	69.1	97.9
	14 Manila	MCH_L	1	120	6	14.4	20.4
	15 Hai Phong	LH_2_M	1	144	7	17.3	24.5
	17 Chennai	LH_2_L	4	1,152	58	138.2	195.8
	Total		8	1,992	100	239.0	338.6
	Grad Total		22	5,484	274	652.7	926.9

CAPEX = capital expenditure, LH_2 = liquefied hydrogen, MCH = methylcyclohexane, MUS$ = million US dollars, OPEX = operating expenditure.
Source: Authors.

Figure 5-20 shows the annual tanker costs (annual CAPEX + OPEX) by route. The Tokyo–Sydney route has the highest annual cost at US$245 million with five tankers. The Incheon–Chennai route has the second-highest annual cost at US$196 million with four tankers.

Figure 5.20. Tanker Annual Operational and Capital Expenditures



Source: Authors.

The total number of voyages for the entire route is 361, the volume unloaded is 38,696 MNm^3, and the voyage distance (round trip) is 3,662,302 km. To put this in perspective, the Earth's circumference is about 40,075 km, which means that the tankers have travelled a total distance of about 91 times around the Earth.

Table 5.35. Tanker Transport Results and Costs by Country

Countries	Number of Voyages Times	Unloading Volume MNm^3/Year	Cruise Distance (Round Trip) Kilo metres	CAPEX		OPEX	CAPEX+OPEX	CAPEX+OPEX per Unload Volume US$/$Nm^3$
				Construction Price MUS$	Annual Cost 1/20 of CAPEX MUS$/Year	Annual Cost 12% of CAPEX MUS$/Year	Annual Cost MUS$/Year	
Singapore	41	3,280	82,164	120	6	11	16.8	0.0051
Bangkok	29	1,160	119,132	60	3	5	8.4	0.0072
Tianjin	64	7,168	582,272	1,008	50	121	171.4	0.0239
Tokyo	114	14,592	1,478,880	2,304	115	276	391.7	0.0268
Incheon	113	12,496	1,399,854	1,992	100	239	338.6	0.0271
Total	361	38,696	3,662,302	5,484	274	652.7	926.9	0.0240

CAPEX = capital expenditure, MNm^3 = million natural cubic metres, MUS$ = million US dollars, Nm^3 = natural cubic metres, OPEX = operating expenditure.

Source: Authors.

4.3. Expansion of Simulation Results

The simulation used one port to represent a demand country. However, in countries with high demand such as China, Japan, and Korea, concentrating all demand in one port yields an unrealistic result. Therefore, the simulation was scaled down to fit the demand of one port. In the scaled-down version, China was assumed to be one-third, Japan one-fourth, and Korea one-third. Using these results, the calculation was expanded to determine investment and operating costs for more realistic results.

The enlargement coefficients are as follows:

Table 5.36. Enlargement Coefficient

Countries	Enlargement Coefficient
Singapore	1.00
Thailand	1.00
China	3.00
Japan	4.00
Korea	3.00

Source: Authors.

(1) Tanker (enlarged version)

In the enlarged version, the simulation results are multiplied by an enlargement factor. As a result, CAPEX is US$18,396 million, which is 3.4 times higher than the simulation result.

Table 5.37. Enlarged Total Tanker Operational and Capital Expenditures

Countries	CAPEX	Anual CAPEX (1/20)	Annual OPEX	Annual CAPEX+OPEX	Enlargement Coefficient
	Million US$	Million US$	Million US$	Million US$	
Singapore	120	6	11	17	1,00
Bangkok	60	3	5	8	1,00
Tianjin	3.024	151	363	514	3,00
Tokyo	9.216	461	1.106	1.567	4,00
Incheon	5.976	299	717	1.016	3,00
Total	18.396	920	2.202	3.122	

Source: Authors.

After the enlargement, the number of tankers was rounded up to the nearest whole number, which was 70, or about 3.2 times the number of tankers in the simulation.

Table 5.38. Number of Tankers After the Enlargement

Countries	Simulation	Enlargement	Enlargement Coefficient
Singapore	1	1	1.00
Bangkok	1	1	1.00
Tianjin	4	12	3.00
Tokyo	8	32	4.00
Incheon	8	24	3.00
Total	22	70	

Source: Authors.

(2) Storage (enlarged version)

The enlarged storage version is the simulation results multiplied by an enlargement coefficient. The resulting CAPEX is US$18,423 million, which is 3.4 times higher than the simulation case.

Table 5.39. Enlarged Total Storage Operational and Capital Expenditures

Countries	CAPEX	Annual CAPEX (1/20)	Annual OPEX (2.5%)	Annual CAPEX + OPEX	Enlargement Coefficient
	Million US$	Million US$	Million US$	Million US$	
Singapore	6	0,3	0,2	0	1,00
Bangkok	3	0,2	0,1	0	1,00
Tianjin	454	22,7	11,3	34	3,00
Tokyo	1.843	92,2	46,1	138	4,00
Inchon	896	44,8	22,4	67	3,00
Total	3.202	160,1	80,1	240	

CAPEX = capital expenditure, OPEX = operating expenditure.
Source: Authors.

3.4. Investment Amount for Storages and Tankers (Enlarged Version)

(1) Initial investment in the EAS region (enlarged version)

The capital and operating costs for the entire EAS region are US$36,819 million.

Table 5.40. Initial Investment Amounts for Storages and Tankers

Unit: MUS$

Countries	Storage CAPEX	Tanker CAPEX	Total
Singapore	48	120	168
Bangkok	31	60	91
Tianjin	4,365	3,024	7,389
Tokyo	8,684	9,216	17,900
Inchon	5,295	5,976	11,271
Total	18,423	18,396	36,819

CAPEX = capital expenditure, MUS$ = million US dollars.
Source: Authors.

(2) Annual costs of hydrogen storage and tankers (enlarged version)

Annual costs of H_2 transport are estimated at $1,382 million for storage and $3,122 million for tankers, for a total of $4,504 million. The total annual CAPEX + OPEX per unloading volume is $0.0369 per normal cubic metre (Nm^3) for all routes combined.

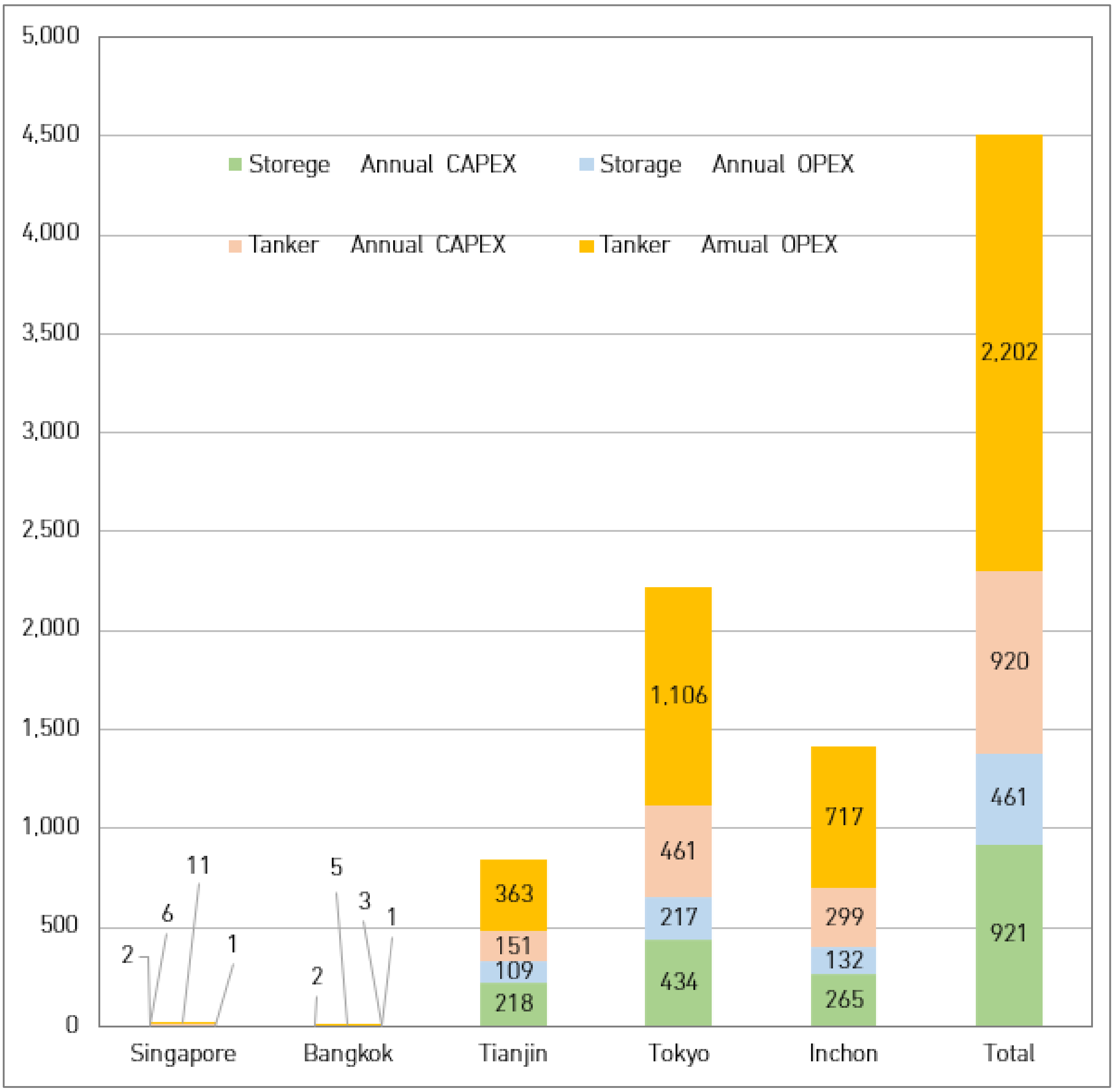
Table 5.41. Annual Costs for Storages and Tankers (Enlarged Version)

Unit: MUS$

Countries	Storage			Tanker			Total Annual Costs	Expected Unloading Volume MNm³/Year	Cost/Nm³ US $
	Storage Annual CAPEX	Storage Annual OPEX	Total	Tanker Annual CAPEX	Tanker Annual OPEX	Total			
Singapore	2	1	4	6	11	17	20	3,275	0.0062
Bangkok	2	1	2	3	5	8	11	1,158	0.0093
Tianjin	218	109	327	151	363	514	841	21,728	0.0387
Tokyo	434	217	651	461	1,106	1,567	2,218	57,902	0.0383
Inchon	265	132	397	299	717	1,016	1,413	38,132	0.0371
Total	921	461	1,382	920	2,202	3,122	4,504	122,194	0.0369

CAPEX = capital expenditure, MUS$ = million US dollars, MNm^3 = million normal cubic metres, OPEX = operating expenditure.
Source: Authors.

Figure 5.21. Annual Capital and Operational Expenditures for Storages and Tankers (Enlarged Version)



CAPEX = capital expenditure, OPEX = operating expenditure.
Source: Authors.

(3) Calculation of OPEX

The report mentioned above calculates shipping costs for an ocean-going tanker with a deadweight capacity of 50,000 tonnes. The ratio of ship costs (including fuel costs) to ship acquisition costs (CAPEX) was calculated to be 12%. This ratio was then applied to LH_2 tankers.

For MCH transport, a 21,000-tonne ocean-going tanker was assumed, prompting a recalculation of costs for each item. The ratio of ship costs (including fuel costs) to ship acquisition costs (CAPEX) was calculated to be 9%. This ratio was then applied to MCH tankers.

Table 5.42. Ratio of Ship Costs (Including Fuel Costs) to Ship Acquisition Costs (Capital Expenditure)

Items		LH_2 Tanker	MCH Tanker
Basic items	Tanker acquisition price ①	9.790.000	6.490.000
Ship expenses	Crew fee	345.600	288.000
	Repair costs	190.000	126.000
	Ship equipment cost	47.500	31.500
	Lubricant cost	48.800	20.500
	Insurance fee	39.200	26.000
	Miscellaneous expenses	49.000	32.500
	Ship owner fee	134.600	52.450
	Total annual expenses	854.700	576.950
	Fuel cost	348.479	36.780
	Total ②	1.203.179	613.730
Ratio to CAPEX ②/①		12%	9%

CAPEX = capital expenditure, LH_2 = liquefied hydrogen, MCH = methylcyclohexane.
Source: Authors, based on NEDO (2020) https://www.nedo.go.jp/content/100930227.pdf.

Chapter 6
Conclusions and Recommendations

1. Conclusions

1.1. Chapter 1

The chapter analyses the anticipated economic and social impact of the hydrogen (H_2) supply chain in the East Asia Summit (EAS) region. According to the H_2 study phases conducted in fiscal years 2019 and 2020, the 16 EAS countries are categorised into two groups: those that export H_2 and those that import H_2. Thus, establishing an H_2 supply chain network to connect these countries is indispensable. The projected capital investment needed to support H_2 trade in the EAS region until 2040 is estimated at about US$260 billion. The investment goes to H_2 carrier ships, H_2 storage tanks, and loading and unloading facilities at H_2 shipping and receiving terminals. It includes H_2 production facilities and H_2 utilisation facilities such as H_2 power plants and refueling equipment. The development of the H_2 supply networks is expected to create jobs, which consist of one-time full-time equivalent (FTE) of 12 million employees who will construct H_2 supply network facilities. A recurring FTE of 0.5 million employees will be engaged in the operation and maintenance of H_2 transport by 2040.

In the initial stages of H_2 trade in the EAS region, government subsidies may be needed to increase H_2 demand and supply volume. About US$13 billion in subsidies will be required until 2030 but they will be shouldered by developed countries in the EAS region, including Malaysia, Singapore, and Thailand.

1.2. Chapter 2

H_2, unlike fossil fuels, does not occur naturally. It must be produced utilising sophisticated technologies from fossil fuels, water, biomass, and other resources. The chapter analyses H_2 production efficiency, focusing on (i) reforming of natural gas, (ii) gasification of low-ranked coal, and (iii) water electrolysis.

In the case of (i), H_2 production efficiency is estimated at 76% without carbon capture and storage (CCS) and 70%–74% with CCS. Despite its high efficiency, natural gas is considered a crucial transitional fuel to gradually reduce coal power generation, making its direct use still essential.

In the case of (ii), however, where low-ranked coal and lignite are utilised, efficiency is estimated at 50%–69% with CCS. Despite its lower production efficiency, case (ii) is recommended for H_2 production due to its utilisation of low-ranked coal with low heat content.

Case (iii) applies electrolysis technologies using alkaline electrolyser, proton exchange membrane (PEM) electrolyser, and solid oxide electrolysis cell (SOEC) electrolyser. The alkaline technology, currently available, has production efficiency of about 70%. PEM, an advanced type of alkaline technology, is expected to reach efficiency of 80%–82%. Whilst SOEC is not currently commercialised, its efficiency is expected to reach around 90%.

1.3. Chapter 3

Liquefied H_2 (LH_2) is one of the H_2 carriers and has a compression ratio from gas to liquid of about 800 times under –253° Celsius. Thus, a LH_2 ship needs special storage tanks that are thicker than liquefied natural gas (LNG) tanks. The superiority of LH_2 becomes evident when considering long-distance and high-volume H_2 transport. LH_2 transport needs at least large-scale LH_2 ships such as LNG ships and storage tanks at receiving terminals.

Based on assumptions of H_2 volume of 200,000 tonnes per year, 10,000 km of transport distance, and 160,000 m^3 ship capacity, the estimated H_2 transport cost in 2030 is pegged at US$0.00214 per Nm^3–kilometre (km). Liquefaction costs account for 50% of the total H_2 transport cost. Thus, we expect innovative liquefaction technology and substantial increase in LH_2 demand to contribute a remarkable reduction of H_2 transport costs by 2050.

1.4. Chapter 4 and Chapter 5

The H_2 supply network in the EAS region will consist of H_2-exporting and H_2-importing countries. Referencing the H_2 potential reports of phases 1 and 2, eight EAS countries are selected as exporting countries: Australia, Brunei Darussalam, India, Indonesia, Sarawak (Malaysia), New Zealand, the Philippines, and Viet Nam. Five EAS countries are selected as importing countries: China, Japan, Korea, Singapore, and Thailand. Our first objective involves determining the optimal H_2 transport routes between exporting and importing countries, applying the linear programming method. The optimisation yields the following results:

- China imports H_2 from Brunei Darussalam, Sarawak, and Viet Nam.
- Japan imports H_2 from Indonesia and Australia.
- Korea imports H_2 from Indonesia, the Philippines, Viet Nam, and India.
- Singapore imports H_2 from India.
- Thailand imports H_2 from India.

The results reveal intriguing patterns: Singapore and Thailand opt not to import H_2 from their nearest neighbours, Brunei Darussalam and Sarawak, respectively. No country imports H_2 from New Zealand because it is farther away than other exporting countries. To explore alternative scenarios, we investigated the Brunei Darussalam–Thailand and

Sarawak–Singapore routes. However, the objective function, representing total H_2 transport cost, registers a 1.1% increase over the base case.

Based on the optimal results of H_2 transport between the exporting and importing countries in the EAS region, we simulated H_2 transport on a personal computer. The simulation showed that, to support the H_2 supply network in 2040–2050, 70 LH_2 tankers, including 5 chemical tankers and 10 LH_2 storage tanks, are required. If we convert the physical number to capital cost, US$18.4 billion per tanker and storage tank will be needed. As a result, H_2 transport cost is estimated at US$0.037/Nm^3 in 2040–2050.

2. Recommendations

We recommend the following:

- SOEC technology should be quickly commercialised for green H_2 production. Its high efficiency (more than 90%) promises substantial reduction in H_2 production costs.
- The H_2 supply chain network in the EAS region is expected to have an economic impact. It includes large investments in network infrastructure connecting H_2-exporting and H_2-importing countries, an increase in employment during construction and operations, and a remarkable reduction in carbon dioxide emissions through the aggressive use of H_2.
- During the initial stages of network development, government subsidies are deemed indispensable to initiate H_2 supply and demand projects.
- Given the forecast large H_2 demand in East Asia (China, Japan, and Korea) and large H_2 production in the southern part of the EAS region (Australia, Brunei Darussalam, India, Indonesia, the Philippines, Sarawak [Malaysia], and Viet Nam), long-distance and big-volume H_2 transport routes are foreseen. LH_2 will emerge as the preferred carrier, with a critical focus on cost reduction, especially in the liquefaction process.
- Envisioning H_2, instead of fossil fuels, as the main fuel in the EAS region by 2040–2050 for carbon neutrality suggests demand for about 70 H_2 tankers and more than 10 large H_2 storage tanks in the receiving countries. H_2 transport cost is projected at US$0.037/Nm^3. As the cost is still high, efforts to reduce the capital costs of H_2 tankers and storage tanks remain imperative.

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Appendix 1

Appendix Table 2.6

Reference List for Table2.6

No	Project Name	Description	HP Address
(1)	Fukushima Hydrogen Energy Research Field (FH2R)	Asahi Kasei presentation (2021), Asahi Kasei efforts to realise a carbon-neutral society, The 22nd Hydrogen Fuel Cell Strategy Council (2 March 2021).	https://ak-green-solution.com/assets/pdf/brochure.pdf https://www.asahi-kasei.com/jp/news/2020/ze200403.html Ref1) https://hydrogen2023.nedo.go.jp/wp-content/uploads/2023/06/B2-6.pdf
(2)		Toshiba presentation (2020), Fukushima Power-to-gas Hydrogen Project.	https://www.nedo.go.jp/content/100899755.pdf Ref1) https://www.global.toshiba/ww/news/energy/2020/03/news-20200307-01.html Ref2) https://www.nedo.go.jp/news/press/AA5_101293.html
(3)		Crolius, S. H. (2017), Renewable Hydrogen in Fukushima and a Bridge to the Future., Ammonia Energy Association.	https://www.ammoniaenergy.org/articles/renewable-hydrogen-in-fukushima-and-a-bridge-to-the-future/
(4)		Green Car Congress (2020), Fukushima Hydrogen	https://www.greencarcongress.com/2020/03/20200308-fh2r.html

No	Project Name	Description	HP Address
		Energy Research Field (FH2R) completed in Japan; aiming for low-cost green hydrogen production; P2G	
(5)		Green Hydrogen (2018), Construction Begins on Fukushima Hydrogen Energy Research Field., Fuel Cells Bulletin, Science Direct	https://www.sciencedirect.com/science/article/abs/pii/S1464285920300894

No	Project Name	Description	HP Address
(6)	HYBRIT pilot&Demo	Climate Adaptation Platform (2020), Green Steel Plant A Boon for Carbon Zero Steel Production.	http://www.hybritdevelopment.com/articles/three-hybrit-pilot-projects https://climateadaptationplatform.com/green-steel-plant-a-boon-for-carbon-zero-steel-production/ https://group.vattenfall.com/press-and-media/pressreleases/2019/hybrit-sek-200-million-invested-in-pilot-plant-for-storage-of-fossil-free-hydrogen-in- lulea https://www.reuters.com/article/us-sweden-steel-hydrogen/swedens-hybrit-starts-operations-at-pilot-plant-for-fossil-free-steel- idUSKBN25R1PI Ref1) https://www.hybritdevelopment.se/en/ Ref2) https://www.sciencedirect.com/science/article/pii/S277273782100002X Ref3) Sustainable Horizons(2022) Hybrid Water Electrolysis: A New Sustainable Avenue for Energy-Saving Hydrogen Production Ref4) https://nelhydrogen.com/press-release/nel-asa-receives-4-5-mw-electrolyzer-purchase-order-for-fossil-free-steel-production/ Ref5)https://www.bu.edu/igs/files/2021/01/E-Anderson_Nel-LT-ELY-Overview_BU-ISE_ITIF-Wkshp_20210127.pdf Ref6)https://nelhydrogen.com/ Ref7)https://nelhydrogen.com/wp-content/uploads/2024/01/Electrolysers-
(7)		Korose, C. et.al. (2019), University of Illinois, Wabash CarbonSAFE.	
(8)		Vattenfall (2019), HYBRIT orders Norwegain	

No	Project Name	Description	HP Address
		electrolyzers for fossil free steel production in Luleå	Brochure-Rev-D-1.pdf Ref8)https://www.hybritdevelopment.se/en/hybrit-demonstration/ Ref9)https://www.hybritdevelopment.se/en/a-fossil-free-development/direct-reduction-hydrogen-pilotscale/
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(10)	GreenHydroChem Central German Chemical Triangle	BloombergNEF (2020), Hydrogen Economy Outlook. Key Messages.	https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf Ref1)https://juser.fz-juelich.de/record/906356/files/Energie_Umwelt_561.pdf
(11)	ETOGAS, Solar Fuel Beta-plant AUDI, Werlte (Audi e-gas)	Endbericht(2014) Energieinstitut an der Johannes Kepler Universität Linz. Power to Gas – eine Systemanalyse. Markt- und Technologiescouting und –analyse. Endbericht. 2014.	https://www.ea.tuwien.ac.at/fileadmin/t/ea/projekte/PtG/Endbericht_-_Power_to_Gas_-_eine_Systemanalyse_-_2014.pdf https://www.researchgate.net/publication/272476549_Power_to_Gas_-_eine_Systemanalyse_Markt-_und_Technologiescouting_und_-analyse Ref1)https://pureadmin.unileoben.ac.at/ws/portalfiles/portal/2239502/AC14537345n01.pdf
(12)		Manuel Bailera et al., (2017), Power-to-gas projects review: Lab, pilot, and demo plants for	https://www.sciencedirect.com/science/article/abs/pii/S1364032116307833

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(13)		Gahleitner, G. (2013) , Hydrogen from renewable electricity: an international review of power-to-gas pilot plants for stationary applications , Science Direct	https://www.sciencedirect.com/science/article/abs/pii/S0360319912026481 Ref1) https://www.scirp.org/reference/referencespapers?referenceid=2997534
(14)		Vartiainen, V. (2016), 'Screening of Power-to-Gas Projects', Master's Thesis.	https://lutpub.lut.fi/handle/10024/123485 Ref1) https://lutpub.lut.fi/bitstream/handle/10024/123485/diplomityo_vartiainen_vesa.pdf?sequence=2&isAllowed=y
(15)		Iskov, H. N. Bjarne, and B. Rasmussen (2013), Global screening of projects and technologies for Power-to-Gas and Bio-SNG.	https://dokumen.tips/documents/global-screening-of-projects-and-technologies-for-power-screening-of-projects.html
(16)		THEnergy (2020), Operating hydrogen electrolysers	https://www.th-energy.net/english/platform-hydrogen-applications/flagship-projects-generation-electrolyzers/

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(17)	Nordic Blue Crude	Ihre Privatsphäre ist uns wichtig (2018),	https://www.poerner.at/en/media/pressemitteilung/news/e-crude-klimaneutraler-erdoelersatz-aus-co2-wasser-und-oekostrom/?tx_news_pi1%5Bcontroller%5D=News&tx_news_pi1%5Baction%5D=detail&cHash=685eb0b65e1ede82f72fca3fd907fe90.
(18)		Sunfire (2017), First Commercial Plant for the Production of Blue Crude Planned in Norway.	https://www.sunfire.de/en/news/detail/first-commercial-plant-for-the-production-of-blue-crude-planned-in-norway Ref1) 2017_sunfire_PR_Nordic-Blue-Crude%20.pdf Ref2) https://energiforsk.se/media/26740/technology-review-solid-oxide-cells-2019-energiforskrapport-2019-601.pdf
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(20)		Sapp, M. (2020), 'ECB signs contract with government for Paraguayan Omega Green project', The Digest.	https://www.biofuelsdigest.com/bdigest/2020/09/16/ecb-signs-contract-with-government-for-paraguayan-omega-green-project/
(21)	Air Liquide Becancour	Air Liquide Canada (2020), Bloucher	https://www.airliquide.com/group/press-releases-news/2019-02-25/air-liquide-invests-worlds-largest-membrane-based-electrolyzer-develop-its-carbon-free-hydrogen https://thecanadian.news/2020/12/08/air-liquide-has-started-industrial-production-of-green-hydrogen-in-becancour/. https://www.airliquide.ca/news-and-events. Ref1) https://engineering.airliquide.com/sites/engineering/files/2022-09/technohandbook11oct.pdf Ref2) https://engineering.airliquide.com/technologies/renewable-hydrogen Ref3) https://engineering.airliquide.com/sites/engineering/files/2022-09/brochurehydrogenpp_0.pdf Ref4)https://cordis.europa.eu/docs/projects/files/ENK5/ENK5-CT-2001-00536/103966621-6_en.pdf Ref5) https://www.canadianconsultingengineer.com/wp-content/uploads/gravity_forms/26-

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(26)	Refhyne	Lymperopoulos, N. (2018), European Developments in Electrolyser Technology,	https://www.waterstofnet.eu/_asset/_public/powertogas/Conference/4-Nikolaos-Lymperopoulos_-FCH-JU.pdf Ref1) http://itm-power.com/products/ Ref2) https://cea.hal.science/cea-02558095/document

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		Technical and Economic Outlook.	
(27)		REFHYHE (2019)	https://www.refhyne.eu/about/ Ref1) https://cordis.europa.eu/project/id/779579 Ref2) https://cordis.europa.eu/project/id/779579/reporting
(28)		FCH EUROPA (2022), Fuel Cells and Hydrogen Joint Undertaking, REFHYNE Project (2022)	https://www.fch.europa.eu/project/clean-refinery-hydrogen-europe
(29)	H2FUTURE	H2FUTURE (2021)	https://www.h2future-project.eu/ Ref1) https://www.h2future-project.eu/technology Ref2) https://task37.ieabioenergy.com/wp-content/uploads/sites/32/2022/03/3-Verbund-H2Future_Paulnsteiner.pdf Ref3) https://www.siemens-energy.com/global/en/home/products-services/product-offerings/hydrogen-solutions.html
(30)	Energiepark Mainz	ENTSOG (2021), European Power-to-Gas platform–Power-to-Gas demo database.	https://www.entsog.eu/power-gas Ref1) https://www.frontiersin.org/articles/10.3389/fenrg.2020.00191/full Ref2) https://cea.hal.science/cea-02558095/document Ref3) https://www.sciencedirect.com/science/article/abs/pii/S0360319917300083 Ref4)

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(31)		Vartiainen, V. (2016), 'Screening of Power-to-Gas Projects', Master's Thesis	https://lutpub.lut.fi/handle/10024/123485 Ref1) https://lutpub.lut.fi/bitstream/handle/10024/123485/diplomityo_vartiainen_vesa.pdf?sequence=2&isAllowed=y
(32)			
(33)		Benedikt Stefansson (2017), CO2-to-methanol: Nordic technology with global application	https://www.nordicenergy.org/wp-content/uploads/2017/11/CO2-to-methanol_Nordic-technology-with-global-application-Benedikt-Stefansson.pdf
(34)		Mainz (2017), Technical data about the Energiepark (2017)	https://www.energiepark-mainz.de/en/technology/technical-data/
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(36)	Murchison	Bloomberg (2019), Siemens Backs Mega Green Power Hydrogen Project in Australia (2019)	https://www.bloomberg.com/news/articles/2019-10-08/siemens-backs-mega-green-power-hydrogen-project-in-australia Ref1)https://www.aimspress.com/article/doi/10.3934/energy.2022052
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(38)		PV Magazine (2019), Siemens backs 5 GW green	https://www.pv-magazine.com/2019/10/08/siemens-backs-5-gw green-hydrogen-plan-for-australia/

No	Project Name	Description	HP Address
		hydrogen plan for Australia.	
(39)		Mazengarb, M. (2020), Massive 1000MW "baseload" wind, solar and hydrogen plant pitched for NSW, RENEW ECONOMY (2020)	https://reneweconomy.com.au/massive-1000mw-baseload-wind-solar-and-hydrogen-plant-pitched-for-nsw-16049/ Ref1) https://www.solarchoice.net.au/blog/massive-1000mw-baseload-wind-solar-and-hydrogen-plant-pitched-for-nsw/ Ref2) https://reneweconomy.com.au/tag/solar-2/page/6/ Ref3) https://assets.cleanenergycouncil.org.au/documents/resources/reports/clean-energy-australia/clean-energy-australia-report-2021.pdf
(40)		PV Magazine (2019), Danish fund backs 5 GW Australian renewable hydrogen project'.	https://www.pv-magazine.com/2020/11/17/danish-investment-fund-backs-5-gw-australian-renewable-hydrogen-project/ Ref1) https://www.pv-magazine-australia.com/2020/11/17/danish-investment-fund-backs-5000-mw-wa-renewable-hydrogen-project/ Ref2) https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/May/IRENA_Innovation_Outlook_Ammonia_2022.pdf
(41)		Collins, L. (2020), 'Global green-hydrogen pipeline exceeds 250GW — here's the 27 largest gigawatt-scale projects', Recharge	https://www.rechargenews.com/energy-transition/global-green-hydrogen-pipeline-exceeds-250gw-heres-the-27-largest-gigawatt-scale-projects/2-1-933755

No	Project Name	Description	HP Address
(42)	GrlynHy2.0	Nel (2021), Receives purchase order for 2 MW PEM electrolyser	https://news.cision.com/nel-asa/r/nel-asa--receives-purchase-order-for-2-mw-pem-electrolyser,c3339141. Ref1) https://mb.cision.com/Main/115/3339141/1411842.pdf Ref2) https://nelhydrogen.com/ Ref3) https://nelhydrogen.com/wp-content/uploads/2024/01/Electrolysers-Brochure-Rev-D-1.pdf
(43)		GrInHy2.0(2021) GREEN INDUSTRIAL HYDROGEN	https://www.green-industrial-hydrogen.com/ Ref1) https://salcos.salzgitter-ag.com/de/grinhy-20.html Ref2) https://cordis.europa.eu/project/id/700300 Ref3) https://www.sunfire.de/files/sunfire/images/content/Produkte_Technologie/factsheets/SUNF_17028_GrInHy.pdf Ref4) https://multiplhy-project.eu/Documents/Workshop%20on%20Advanced%20PtG%20and%20PtL%20Technologies%20High-Temperature%20Electrolysis_Posdziech.pdf Ref5) https://www.salzgitter-ag.com/en/newsroom/press-releases/details/worlds-largest-high-temperature-facility-commences-trial-operation-in-salzgitter-14588.html
(44)		GrlnHy2.0 (2021), Sunfire-delivers-the-worlds-largest-high-temperatur-electrolyzer-to-salzgitter-flachstahl	https://www.green-industrial-hydrogen.com/project/news/sunfire-delivers-the-worlds-largest-high-temperatur-electrolyzer-to-salzgitter-flachstahl Ref01)https://salcos.salzgitter-ag.com/de/grinhy-20.html

No	Project Name	Description	HP Address
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Appendix 2

East Asia Summit First Working Group Meeting on Hydrogen

27 December 2022

The Economic Research Institute for ASEAN and East Asia (ERIA) conducted the first working meeting on Hydrogen (H_2) Study Phase 4 virtually on 27 December 2022. The meeting aimed to share and consolidate the findings of East Asia Summit (EAS) hydrogen research studies to be conducted in 2022–2023. The meeting was open for comments and feedback from EAS members that had served as study objects. Under ERIA's coordination, the study included (i) Social and Economic Impact to be Brought by H_2 Supply Chain in the EAS Region, by Dr. Yanfei Li; (ii) Production Efficiency of H_2 Production, by Kawasaki Heavy Industries Corporation; (iii) Forecast of H_2 Transport Cost of LH2, by Kawasaki; (iv) Seeking Optimal H_2 Supply Chain in EAS Region, by ERIA; and (v) Dynamic Simulation Approach to Represent H_2 Transport on PC Screen, by ERIA.

The first study, focusing on the economic and social impact of H_2, aimed to estimate the investment scale for the H_2 supply chain in the region, employment as a derived economic-social factor of investment, fiscal burden as required support during early-stage investment, carbon emission reduction potential due to application of H_2 in the region, energy security resulting from adding H_2 to the energy mix, and reduced reliance on imported energy sources. The scope of the H_2 supply chain studied covered the stage of H_2 production, infrastructure, storage and transport, and several applications. Road transport, the chemical industry, and steel manufacturing, will all be utilising H_2. Fiscal burden discussions will touch upon subsidies for capital expenditures (CAPEX) and operating expenditures (OPEX), whilst energy security implications will adopt the 4A framework (acceptability, applicability, availability, and affordability).

Mr Shintaro Onishi from Kawasaki outlined the study plan for energy efficiency in H_2 production. The study will predict the potential of each production process based on the resources and technologies used, including natural gas (natural gas reforming), coal (brown coal and bituminous coal for gasification), and water (water electrolysis). Kawasaki shared the outline of the study on estimated liquified H_2 transport, covering the basic concept of liquefied H_2 supply chain, its characteristics, loading and unloading systems, and transport costs in 2030, and total costs for certain case studies and assumptions.

H_2 transport cost was estimated using a statistical and dynamic approach by Mr Shigeru Kimura, ERIA's Special Advisor on Energy Affairs, together with Mr Setsuo Miyakoshi, logistics consultant. The study will use data assumptions based on technical factors such as ship speed, ship and H_2 tank prices, and LH_2 tank prices. On the computer screen, dynamic simulations will represent H_2 transport between origins and destinations in the EAS region.

EAS 2nd Hydrogen Phase 4 Working Group Meeting

Virtual Meeting system, 17 April 2023

The Economic Research Institute for ASEAN and East Asia (ERIA) conducted the second working meeting on Hydrogen Study Phase 4 virtually on 17 April 2023. This meeting aim to share and consolidate the progress of research results within hydrogen study phase 4 and opened for comments and feedbacks from EAS region members as study objects. Under this study, ERIA conducted four research studies: (1) Social and economic impact to be brought by hydrogen supply chain in EAS region by ERIA, (2) Analysis on hydrogen production efficiency by KHI, (3) Estimation of LH2 transportation cost by KHI, (4) Optimal solution of hydrogen transportation between EAS countries by ERIA and (5) Dynamic simulation of hydrogen transportation.

The big picture is that hydrogen era is arriving in EAS region. As we have already big project of hydrogen is happening in Asia countries, almost industries should prepare for adapting hydrogen as potential source of energy. Policy makers and all actors in this sector must have references regarding the economic and social impacts of establishing hydrogen energy supply chain. Therefore, Dr Yanfei Li from ERIA conducted research covering four main aspects: (1) estimating the scale of infrastructure investment required, (2) fiscal impacts of developing hydrogen energy supply chain, (3) environmental impacts focusing on the carbon emissions reduction of its applications in the road transport and industry sectors, and (4) implications on energy security.

Shintaro Onishi from Kawasaki Heavy Industries, LTD.(KHI) presented the study on energy efficiency of hydrogen production. The focus of the study is initially predicting the future potential of each production process based on resource and future production efficiency. Hydrogen production resources considered in this study include natural gas (natural gas reforming method), coal (brown coal and Bituminous coal for gasification method), and water (water electrolysis method). Following the production efficiency study, KHI also shared the estimated liquified hydrogen transportation costs by taking into account annual transportation quantity and voyage distance and focusing on seaborne/marine transportation way. The future hydrogen cost is predicted to decrease as the reduction cost of LNG.

The estimation of hydrogen transportation cost was also carried out with statistic and dynamic approach by Shigeru Kimura, Special Advisor on Energy Affairs, ERIA together with logistic consultant, Setsuo Miyakoshi. The study took several assumptions, including Singapore, Thailand, China, Japan, and Korea as the hydrogen destination countries while ASEAN countries such as Brunei, Indonesia, Malaysia, Myanmar, Philippines, Vietnam, Australia, India, and New Zealand as the supply countries. In this study, based on the potential of hydrogen production in each supplier countries, how many ships needed, and the capacity of tanks will be analysed. The readiness of port infrastructure should also been considered to receive and handle hydrogen ships arrival and departure.

Appendix 3

East Asia Summit Hydrogen Workshop

Kobe, Japan, 18 October 2022

The East Asia Summit (EAS) Hydrogen (H_2) Workshop, organised by the Economic Research Institute for ASEAN and East Asia (ERIA) and the Institute of Energy Economics, Japan (IEEJ), with support from the Ministry of Economy, Trade, and Industry (METI), Japan, was held on 18 October 2022. Whilst considering issues and challenges surrounding H_2 technology development, the workshop noted that the H_2 policies of EAS countries, especially those of H_2 technology frontrunners such as Japan, play a crucial role in achieving a carbon-neutral society by 2050 by pioneering the creation of optimal H_2 supply networks in the EAS region and setting up a conducive environment for H_2 business.

Ms Hino Yukari, Director of Advanced Energy Systems and Structure Division, Hydrogen and Fuel Cells Strategy Office, Agency for Natural Resources and Energy, METI, Japan, emphasised the importance of H_2 for decarbonisation. She said that even from an energy security standpoint, shifting to clean energy to attain carbon neutrality would result in the rapid increase in the significance and function of H_2. Noting the replacement of fossil fuels in the power sector's ultimate energy consumption, she added that the potential for H_2 demand would be enormous. To reduce H_2 supply cost, she said innovation in technological development and scaling up H_2 demand are necessary.

Mr Shigeru Kimura, ERIA's Special Adviser on Energy Affairs, focused on the H_2 demand forecast in the Association of Southeast Asian Nations (ASEAN) region. Presenting the low-carbon energy transition scenario, he explained that six ASEAN countries would tap H_2 for final use and power generation until 2050 to achieve carbon neutrality. He cited three things necessary to enhance the deployment of H_2: progress of H_2 technology on the supply and demand sides; clear government policy; and holding of regional and international conferences, seminars, and workshops to increase common understanding of H_2.

Mr Emanuele Bianco, Programme Officer of the International Renewable Energy Agency, discussed the H_2 trading considerations covering the technical potential for producing green H_2 and the strategy, as well as plans and agreements, to expand networks of H_2 trade routes. He elaborated on stated policy framing in H_2 strategic documents and policies as well as green H_2 policy priorities.

Mr Hiroki Yoshida, Deputy Director of Hydrogen and Fuel Cells Strategy Office, Agency for Natural Resources and Energy, Ministry of Economy, Trade, and Industry, Japan, presented Japan's vision of a H_2 economy and ways to achieve it. He said that Japan has designated H_2 production as a priority for the Green Growth Strategy, and that the country is attempting to further introduce H_2 and decrease its cost through the green innovation fund and other initiatives.

The workshop closed with remarks from Prof Jun Arima, Senior Policy Fellow for Energy and Environment of ERIA, who underscored the importance of resolving the current energy crisis and pursuing ambitious carbon neutrality goals. He stated that in September 2022, the EAS Energy Ministerial Meeting acknowledged the significance of achieving a realistic energy transition by utilising a variety of alternative and emerging low-carbon technologies, such as fuel ammonia; H_2; biomass; clean coal technology; and carbon capture, and utilisation, and storage. He said that ERIA and IEEJ are conducting cost-optimal road map technology optimisation scenarios to attain carbon neutrality in the ASEAN region by 2060. The analysis emphasised the importance of H_2 and ammonia as crucial technologies for achieving carbon neutrality by 2030.

Appendix 4

Introductory Workshop on Hydrogen-Potential Study of Demand and Supply Sides for Cambodia

22 December 2022

The Economic Research Institute for ASEAN and East Asia (ERIA) and the Institute of Energy Economics, Japan (IEEJ) hosted a virtual workshop on 22 December 2022 on the demand and supply potential of H_2 in Cambodia. The objective was to emphasise the importance of H_2 as a potential energy source contributing to the 2050 carbon neutrality target. Attending institutions from Cambodia included the Directorate General of Petroleum at the Ministry of Mines and Energy.

In his opening remarks, Mr Victor Jona, Undersecretary of State, Ministry of Mines and Energy, pointed out the nation's obligations to maintaining socio-economic stability and ensuring an adequate and sustainable energy supply to accelerate the energy transition towards decarbonisation and carbon neutrality. He emphasised the need to prioritise the development of renewable energy resources; minimise the environmental impact associated with development; and seek new clean energy technologies such as carbon capture, utilisation, and storage and H_2 energy technology. He stressed that introducing H_2 potential through workshops and studies on demand and supply of H_2 potential in Cambodia is an important step in advancing the national energy transition.

Along with economic growth, projected electricity demand until 2050 is expected to peak at 6.3%, followed by oil demand at 4.8%. According to the business-as-usual (BAU) estimation, gas power generation (from coal to gas) will continue to dominate with a 55% share in 2050. Power generation in the alternative policy scenario will be lower than in BAU, at 16%, because of the promotion of energy efficiency and conservation and renewable energy. In the low-carbon energy transition with carbon neutrality, the power sector will achieve decarbonisation by applying carbon capture and storage (CCS) for thermal power plants and increasing renewable energy development. Carbon dioxide emissions are predicted to increase fivefold from 2019 to 2050, with oil being the highest emitter, followed by gas and coal. Cambodia's decarbonisation will then be achieved by electrification in the final sector, especially battery electric vehicles and CCS for thermal power plants.

H_2 as an energy source is new to Cambodia. Introduction of H_2 development and basic knowledge of H_2 production will be beneficial for the government of Cambodia as a benchmark to start exploring further H_2 potential in their country and how it can contribute to the national energy plan to achieve net zero target.

Appendix 5

Introductory Workshop on the Demand and Supply Potential of Hydrogen in the Lao People's Democratic Republic

10 April 2023

The Economic Research Institute for ASEAN and East Asia (ERIA) and the Institute of Energy Economics, Japan (IEEJ) hosted the virtual workshop on 10 April 2023. The objectives were to emphasise the importance of hydrogen (H_2) as a potential energy source, contributing to the target of achieving carbon neutrality by 2050. Participating institutions from the Lao People's Democratic Republic (Lao PDR) included the Ministry of Energy and Mines (MEM), the Alternative Energy Division at the Renewable Energy and New Materials Institute, and the Electrical Construction and Installation, State Enterprise of Lao PDR.

Mr Khamso Kouphokham, Permanent Secretary of MEM, said that the Lao PDR has huge hydropower potential. As the leading source of renewable electricity globally, hydropower is well suited to producing green H_2. Produced using decarbonised electricity and water through electrolysis, green H_2 is set to be an important component of the transition to net-zero carbon economies. The surplus supply of hydropower presents a great opportunity for the Lao PDR to produce green H_2 not only for domestic consumption but also for export to neighbouring countries.

To realise this potential, policy and regulatory frameworks must be updated to deploy H_2 services and infrastructure at the required scale. The study on H_2 potential demand and supply can help the Lao PDR prepare for development, planning, and policy improvement of the energy sector, focusing on H_2. The Lao PDR needs to pay more attention to basic knowledge about H_2 production and utilisation as the first step to tapping H_2 as a domestic energy source. As the Lao PDR will host the Association of Southeast Asian Nations Ministry of Energy Meeting in 2024, the H_2 study can be shared and further analysis can help in adapting the study results to the Lao PDR's needs.