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Assessment of the seaborne supply chain costs of green hydrogen energy carriers with a focus on synthetic methane

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ABSTRACT

This study evaluates the international seaborne supply chain costs of fully renewable-based hydrogen energy carriers delivered from the Middle East to Japan, with particular emphasis on comparing synthetic methane with liquefied hydrogen, methylcyclohexane, and ammonia. A two-region, single-year, temporally detailed hydrogen supply model is employed to determine cost-optimal capacity sizing and hourly operations across the entire supply chain, while explicitly accounting for the hourly intermittency of variable renewable energy. The results indicate that synthetic methane is the second most cost-competitive carrier, at 6.2 USD per kgH_2, after the direct use of ammonia at 4.8 USD per kgH_2. Both synthetic methane and direct ammonia use avoid reconversion processes in the importing region, thereby reducing energy losses and associated costs. Synthetic methane further benefits from its compatibility with existing liquefied natural gas transportation technologies, which moderates transportation-related capital costs. The analysis confirms that the estimated costs are broadly applicable to other importing regions. In addition, the results indicate that innovative methane synthesis technologies could reduce the supply chain cost to 5.1 USD per kgH_2—nearly equivalent to the level of direct ammonia use. Nevertheless, the carrier faces institutional challenges related to CO_2 attribution, underscoring the need for internationally harmonized accounting rules for carbon capture and utilization.

1. Introduction

Green hydrogen—produced via water electrolysis using renewable electricity—is still expected to play a key role in achieving net-zero greenhouse gas emissions, despite its recent sluggish growth due to persistent barriers such as high costs, difficulties in securing demand, and an uncertain regulatory environment [1]. As a secondary energy carrier, the design of hydrogen supply chains—encompassing renewable electricity procurement, hydrogen production, transportation, and end use—is a critical challenge for integrating green hydrogen into existing energy systems. Hydrogen transportation particularly important because of hydrogen's low volumetric energy density, when cost-optimal sites for hydrogen production are located far from demand centers. For onshore transport to large-scale consumers, pipelines represent a mature option that enable the direct delivery of gaseous hydrogen. However, for countries with geographical constraints that hinder the construction of international pipelines (such as island nations including Japan), long-distance seaborne transportation of hydrogen energy carriers represents a more realistic solution. Among hydrogen energy carriers, the most frequently discussed are liquefied hydrogen, methylcyclohexane (MCH), and ammonia. In addition, synthetic methane—synthesized from hydrogen and CO_2—has attracted increasing attention among policymakers and industry stakeholders as a means of decarbonizing heat supply and power generation. A key advantage of synthetic methane is its compatibility with existing liquefied natural gas (LNG) infrastructure, enabling transportation, storage, and end use without major modifications while offering potential economic and deployment benefits.

Reflecting growing interest in synthetic methane, referred to as *e-methane* in Japan [2] or *e-NG* (Electric Natural Gas) by an international industry coalition [3], various demonstration projects have been implemented around the world. For example, projects in Europe include mobility applications in Germany since 2013 [4], natural gas pipeline injection in France since 2014 [5], and six projects primarily targeting decarbonization of the heavy-duty transport sector in Finland since 2021 [6]. In Japan, a public-private roundtable on promoting methanation, launched in 2021 [7], explores pathways for deploying synthetic

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Nomenclature

Abbreviations

AR7	Seventh Assessment Report
CCU	Carbon Capture and Utilization
CH_4	Methane
CO_2	Carbon Dioxide
DAC	Direct Air Capture
e-NG	Electric Natural Gas
H_2	Hydrogen
HT-DAC	High-temperature Direct Air Capture
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LCH_4	Liquefied Methane
LH_2	Liquefied Hydrogen
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LT-DAC	Low-temperature Direct Air Capture
MAC	Marginal CO_2 Abatement Cost
MCH	Methylcyclohexane
NH_3	Ammonia
NZE	Net Zero Emissions by 2050
O&M	Operation and Maintenance
Solar PV	Solar Photovoltaics
TOL	Toluene
VRE	Variable Renewable Energy

Units

$GtCO_2$	Billion ton of carbon dioxide
GW	Gigawatt
GWh	Gigawatt-hour
h	Hour
kgH_2	Kilogram of hydrogen
ktH_2	Thousand ton of hydrogen
ktTOL	Thousand ton of toluene
kW	Kilowatt
kW_e	Kilowatt (electricity basis)
kW_{prod}	Kilowatt (production basis)
kWh	Kilowatt-hour
kWh-gas	Kilowatt-hour (gas basis)
kWh_{H2}	Kilowatt-hour (hydrogen basis)
kWh_{heat}	Kilowatt-hour (heat basis)
kWh_{NH3}	Kilowatt-hour (ammonia basis)
kWh_{prod}	Kilowatt-hour (produced energy carrier basis)
LHV%	Lower Heating Value-based conversion efficiency
MJ	Megajoule
MMBtu	Million British thermal units (LHV basis)
MWh	Megawatt-hour
MWh_{heat}	Megawatt-hour (heat basis)
MWh_{prod}	Megawatt-hour (production basis)
PWh	Petawatt-hour
tCO_2	Metric ton of carbon dioxide
tH_2	Metric ton of hydrogen
$tLCH_4$	Metric ton of liquefied methane
tMCH	Metric ton of methylcyclohexane
tNH_3	Metric ton of ammonia
tTOL	Metric ton of toluene
t-water	Metric ton of water
USD	U.S. dollar (2024 value)

methane. Major Japanese city gas utilities are also conducting feasibility studies on international synthetic methane supply chains involving the United States [8,9], Canada [9], Malaysia [10,11], Australia [12], and the United Arab Emirates (UAE) [13].

From an academic perspective, many studies have assessed the economic and environmental performance of hydrogen energy carriers (see Section 2 for a literature survey). However, few studies have focused on the economics of entire hydrogen supply chains, encompassing hydrogen production, carrier conversion, storage, transportation, and reconversion. In particular, synthetic methane is not included in many existing entire-supply-chain assessments. Furthermore, no studies have investigated fully renewable-based hydrogen supply chains while explicitly considering the hourly intermittency of renewable energy for hydrogen production and carrier conversion processes. Therefore, this study conducts an economic assessment of fully renewable-based hydrogen supply chains with a focus on synthetic methane. We develop a hydrogen supply chain optimization model to estimate the cost-optimal supply chain configuration, hourly operations, and associated costs.

The remainder of this paper is organized as follows. Section 2 summarizes the existing research. Section 3 provides an overview of the model. Section 4 presents the simulation results. Finally, Section 5 summarizes the key findings and discusses directions for future research.

2. Literature survey

As synthetic methane is not yet a commercially mature technology, numerous techno-economic and environmental impact studies have focused on its production processes. Sayyah et al. [14] assess the life cycle environmental impacts of methanation processes, considering catalyst choice and electricity supply. Uddin et al. [15] conduct economic and environmental assessments of multiple methanation systems. Chirone et al. [16] evaluate an integrated CO_2 capture and methanation system, while Kadam et al. [17] proposes a novel system combining ammonia and synthetic methane production and show that environmental impacts are strongly influenced by electricity supply.

Beyond the production boundary, several studies have examined synthetic methane within power-to-gas systems for integrating variable renewable energy (VRE) into power grids [18–22]. Other studies have explored the role of synthetic methane in sector coupling through integrated operation of power and city gas networks to accommodate renewable energy [23,24]. While these studies emphasize the advantage of utilizing existing domestic city gas pipeline networks, the use of existing LNG seaborne transportation technologies remains relatively unexplored. Comparative assessments across hydrogen energy carriers are therefore necessary to evaluate whether the potential advantages of synthetic methane can be realized in international supply chains.

In assessments of international hydrogen supply chains, cost and carbon intensity are key metrics. First, with respect to cost, several studies have focused only on transportation, excluding hydrogen production and carrier conversion. Chen et al. [25] compare the shipping costs of liquefied hydrogen, ammonia, methanol, dibenzyltoluene, and MCH, finding methanol and ammonia to be the least costly. Johnston et al. [26] compare LNG, liquefied hydrogen, ammonia, methanol, and MCH under a transportation-only boundary and conclude that ammonia and methanol are the most cost-competitive, followed by synthetic methane. Kroon et al. [27] examine a broad set of hydrogen carriers—including hydrogen, ammonia, methanol, ethanol, synthetic methane, MCH, synthetic paraffinic kerosene, and formic acid—via pipeline and seaborne transportation. Hanssens et al. [28] present a techno-economic meta-analysis for seaborne hydrogen transportation, demonstrating that no single carrier is universally optimal. While these transportation-focused analyses provide useful insights, evaluating hydrogen import costs requires an integrated supply-chain assessment including production and carrier conversion. A comparative review of seaborne transportation studies [29] shows that transportation costs alone cannot identify an optimal carrier, underscoring the need for whole-supply-chain evaluation.

Although several studies have compared the economics of hydrogen energy carriers for entire international seaborne supply chains, synthetic methane has generally not been included as an option. The IEA [30] does not include synthetic methane in its carrier comparison analyses. Ishimoto et al. [31] compare only liquefied hydrogen and ammonia. Shin et al. [32] develop an export–import matrix covering 63 countries but limit their analysis to ammonia. Aditiya et al. [33] assess multiple carriers for a Malaysia–Japan route but exclude synthetic methane. On the other hand, Patha et al. [34] discuss renewable-based synthetic methane transport by LNG or gas pipeline from Chile, the UAE and Tunisia to Austria, but without comparison to alternative carriers. Al-Breiki et al. [35] analyze LNG, dimethyl ether, methanol, ammonia, and liquefied hydrogen, including production and transportation costs, but assume production from natural gas. As synthetic methane is an e-fuel derived from renewable hydrogen and CO_2, meaningful comparisons among carriers should be based on renewable energy sources rather than fossil fuels. Accordingly, cost comparisons of renewable-based hydrogen energy carriers—including synthetic methane—across the entire supply chain are required, encompassing not only transportation but also hydrogen production, carrier conversion, and reconversion processes.

Second, regarding the carbon intensity of hydrogen energy carriers, regulatory benchmarks grounded in life cycle assessment (LCA), including the EU RFNBO (Renewable Fuels of Non-Biological Origin) Delegated Act [36] and Japan's Basic Hydrogen Strategy targets [37], are gaining global significance. These criteria include upstream, production, conversion, transportation, reconversion, and utilization. In the context of LCA of hydrogen energy carriers, Shin et al. [38] developed an LCA-based greenhouse gas (GHG) assessment framework for domestic and imported hydrogen pathways in South Korea, excluding synthetic methane. They recommend using renewable electricity for hydrogen conversion and reusing hydrogen to supply heat for endothermic reconversion reactions. Elhaus et al. [39] review LCA studies of renewable hydrogen imports and identify electricity carbon intensity as the dominant emissions driver. They further argue that meaningful emission reductions require both renewable-based hydrogen processing and the decarbonization of shipping fuels. Shin et al. [32] also suggest that using ammonia itself in the reconversion process can minimize CO_2 emissions.

LCA studies consistently show that fully renewable-based supply chains can minimize carbon intensity. Accordingly, systematic analysis is required to optimize facility capacities while explicitly accounting for renewable energy intermittency. However, few studies have incorporated this intermittency into analyses of hydrogen energy carriers. Shin et al. [32], focusing on ammonia, assume steady-state operation with higher capacity factor and determine the facility sizes heuristically, without explicitly accounting for renewable energy intermittency. Aditiya et al. [33] assume uniform hydrogen production costs across carriers and do not consider renewable energy intermittency. Patha et al. [34], focusing on synthetic methane, explore solar–wind capacity combinations for synthetic methane but exclude battery storage and treat methane storage capacity as exogenous. Otsuki et al. [40] and Kan et al. [41], comparing the economics and the carbon intensity of several hydrogen energy carriers, ignore renewable energy intermittency and treat the operational patterns of electrolytic hydrogen production and carrier conversion exogenously, potentially underestimating supply-chain costs. In reality, renewable energy intermittency lowers electrolyzer capacity factors and increases hydrogen costs, often requiring additional storage such as hydrogen storage and battery energy storage systems, which further raises overall system costs.

Against this background, we develop a cost-optimization linear programming model to investigate the economics of fully renewable-based international seaborne hydrogen supply chains, covering hydrogen production, carrier conversion, transportation, and reconversion. The model compares liquefied hydrogen, MCH, ammonia, and synthetic methane by explicitly accounting for VRE intermittency, associated mitigation measures—including battery storage, hydrogen storage, and carrier storage—and operational flexibility and constraints of electrolysis and carrier conversion processes. Furthermore, the study quantitatively evaluates the impact of technological innovations in synthetic methane production on overall supply chain costs.

3. Methods

The hydrogen supply chain model is based on the global energy system model developed by Otsuki et al. [42,43]. This study simplified the framework into a two-region model that focuses specifically on hydrogen production and seaborne transportation technologies. This section describes the model structure, case settings, and key assumptions. The Supplementary Material describes the mathematical formulations, and the model code used is available at [44].

3.1. Model structure

Fig. 1 illustrates the energy carriers, commodities, and technologies represented in the model (*NE_Hydrogen*). It is a single-year hydrogen supply model, formulated as a linear programming problem, encompassing renewable power generation, water electrolysis, and conversion to hydrogen energy carriers in the exporting region, as well as international seaborne transportation and reconversion to hydrogen in the importing region. The objective function is the total system cost, which consists of fuel costs, operation and maintenance (O&M) costs, and annualized capital costs in both regions. The installed capacities and hourly operations of the modeled technologies are optimized to meet exogenous gaseous fuel demand in the importing region. A discount rate of 8% is applied to annualize capital costs. All costs are expressed in 2024 USD.

The model incorporates explicit representations of green hydrogen production and transportation technologies, with all energy consumption in the system assumed to be met by renewable-based electricity and hydrogen energy carriers (see primary energy in Fig. 1). Accordingly, the analysis focuses on hydrogen supply chains with net-zero energy-related CO_2 emissions, providing insights into the economics of green hydrogen energy carriers in a deep decarbonization context. CO_2 emissions associated with the manufacturing and construction of supply chain facilities (e.g., renewable power plants) are not incorporated in this study, although this assumption is broadly consistent with the EU methodology for assessing greenhouse gas emission savings from low-carbon fuels [45].

In the model, hydrogen is produced via water electrolysis powered by renewable electricity, such as solar Photovoltaics (PV) and onshore wind turbines. These VRE sources can be combined with battery storage systems—when cost-effective—to smooth electricity inputs to water electrolysis. The modeled hydrogen energy carriers include liquefied hydrogen, MCH, ammonia, and liquefied methane. The assumed carrier conversion processes are hydrogen liquefaction, toluene hydrogenation for MCH, the Haber-Bosch process for ammonia, and the Sabatier reactions and methane liquefaction for synthetic methane. In addition, innovative methane synthesis processes are considered in Subsection 4.3.2. CO_2 input is required for synthetic methane production, and CO_2 is assumed to be supplied via direct air capture (DAC). More CO_2-rich exhaust gases from power plants and industrial processes may also serve as potential CO_2 sources. However, CO_2 procurement from such sources may face uncertainties due to the competition with CO_2 storage [46]. Furthermore, these fossil fuel-based power plants and industrial facilities may decline during the transition to a carbon-neutral society, constraining the deployment of CO_2 utilization technologies. Therefore, this analysis focuses on DAC, which avoids constraints associated with

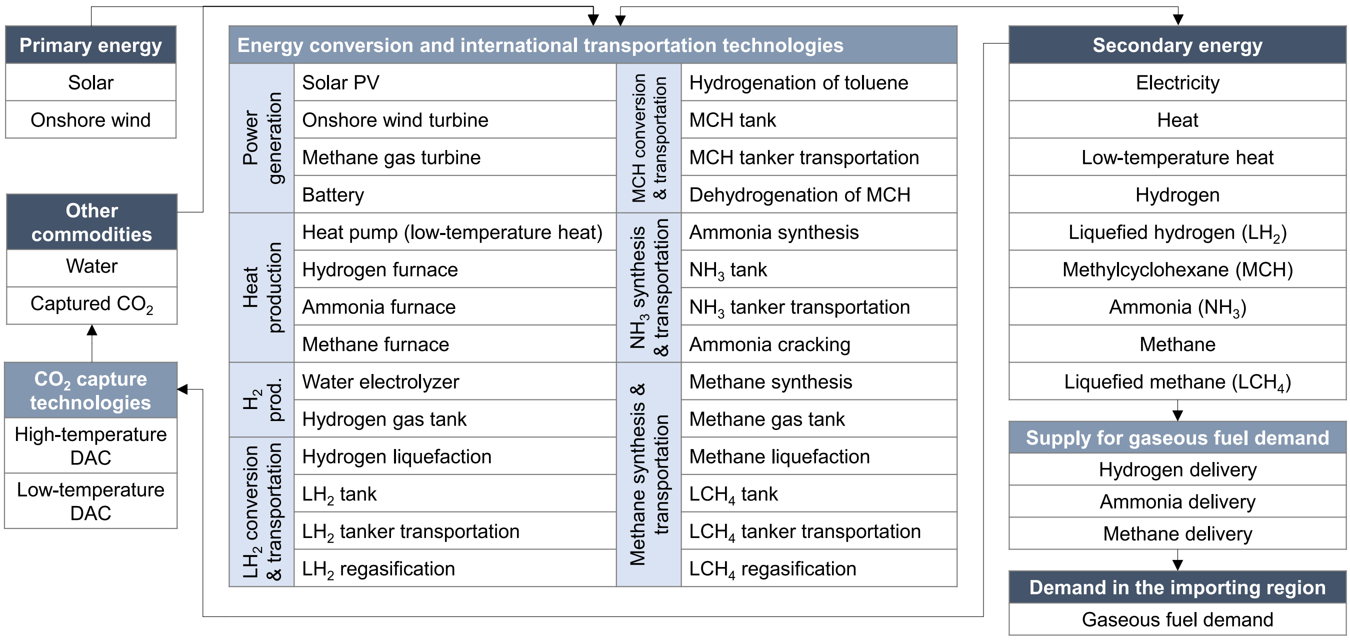

Fig. 1. Energy carriers, commodities, and technologies represented in the *NE_Hydrogen* model. Note: Prod. = Production.

geographical siting and CO_2 supply availability. Maritime tanker transportation is represented by tanker vessels and storage tanks at the loading and unloading terminals.

In the importing region, these energy carriers are either consumed directly (in the ammonia and synthetic methane supply chains) or reconverted into hydrogen (in the liquefied hydrogen, MCH, and ammonia supply chains). The reconversion processes include regasification for liquefied hydrogen, dehydrogenation for MCH, and cracking for ammonia. The gaseous fuel demand is assumed to be located near the import terminal; therefore, downstream distribution infrastructure costs are not considered in this study. Costs incurred up to the point of unloading at the import terminal are included in the objective function. Although not explicitly represented in the model, synthetic methane and reconverted hydrogen are expected to contribute to a wide range of applications, including power generation, industrial and building heat supply, and mobility. Direct use of ammonia is also expected to play a role in the electricity and industry sectors. From a combustion perspective, ammonia exhibits low reactivity and can produce fuel-NOx emissions due to its nitrogen content. However, several studies [47,48,49] indicate that these challenges can be mitigated through combustion control strategies, such as staged combustion, and confirm the technical feasibility of ammonia use in gas turbines and industrial furnaces.

The most salient feature of the model is its hourly temporal resolution, which ensures hourly balances of the modeled energy carriers—such as electricity, hydrogen, liquefied hydrogen, MCH, ammonia, methane, and liquefied methane—throughout the year in both regions. This temporal resolution enables the model to capture the costs for managing the intermittency of VRE, including energy storage requirements and operational flexibilities of water electrolysis and carrier production plants. Based on hourly renewable power outputs, the model determines the hourly operation of water electrolyzers, carrier conversion plants, and DAC facilities. To follow VRE output variability, part-load operation of water electrolyzers would be necessary. However, downstream chemical processes—such as methane synthesis—are generally not designed for frequent shutdown and startup cycles. These operational constraints may necessitate large-scale buffer storage for hydrogen and methane to smooth input flows to subsequent carrier production processes. In addition, large-scale storage tanks at exporting terminals may become cost-effective for balancing seasonal variations in VRE output and shipping schedules. Accordingly, in addition to battery storage systems, this study endogenously incorporates compressed hydrogen and methane gas storage tanks, as well as liquefied hydrogen, MCH, ammonia, and liquefied methane storage tanks at the export and import terminals. The capacities of these storage technologies are determined through system-wide cost-optimization.

As described in the preceding paragraphs, the model encompasses various hydrogen energy carriers within a single optimization framework. To estimate the cost of each carrier, only the technologies relevant to each specific supply chain are selected and optimized (see the next subsection for detail).

3.2. Case settings and key assumptions

This study examines the economics of five hydrogen supply chains—the *CH4*, *LH2*, *MCH*, *NH3-R*, and *NH3-D* cases—by excluding technologies not relevant to each supply chain. For each case, the capacities and operations of the technologies indicated by thick marks in Table 1 are optimized, whereas those without such marks in the table are fixed at zero capacity. Hydrogen production and carrier conversion technologies are available only in the exporting region. All remaining technologies are included in all cases. For example, in the *CH4* case, hydrogen liquefaction, hydrogenation of toluene, and ammonia synthesis are excluded; consequently, the model is constrained to meet the fuel demand through the production and transportation of synthetic methane (Fig. 2a). This case-specific configuration enables the estimation of the cost-optimal design for each supply chain. Table 2 summarizes the key features of each supply chain. The *LH2* and *MCH* cases (Fig. 2b,c) assume liquefied hydrogen and MCH, respectively, as the hydrogen energy carriers. Both the *NH3-R* and *NH3-D* cases evaluate ammonia-based supply chains; however, they differ in the treatment of reconversion in the importing region. In the *NH3-R* case, ammonia is reconverted to hydrogen, whereas in the *NH3-D* case, ammonia is directly delivered to final demand without reconversion (Fig. 2d,e).

All supply chains assume the year 2050. The exporting region is assumed to be the Middle East, while the importing region is Japan. The seaborne transportation distance is assumed to be 12000 km. The scale of the supply chain—corresponding to the gaseous fuel demand shown in Fig. 1—is set at 261 ktH_2 per year, which is comparable to the assumed supply chain size in IEA [30]. This scale is equivalent to approximately 2.0% of Japan's city gas demand in 2023 [50].

Table 1
Available technologies in each case.

Case	Methane synthesis	Hydrogen liquefaction	Hydrogenation of toluene	Ammonia synthesis	Liquefied methane tanker transportation	Liquefied hydrogen tanker transportation	MCH tanker transportation	Ammonia tanker transportation	Methane delivery to the fuel demand	Hydrogen delivery to the fuel demand	Ammonia delivery to the fuel demand
CH4	✓				✓				✓		
LH2		✓				✓				✓	
MCH			✓	✓			✓			✓	
NH3-R				✓				✓		✓	
NH3-D				✓				✓			✓

Note: The capacities and operations of the technologies indicated by thick marks are optimized in each case, whereas those without such marks are fixed at zero capacity. All remaining technologies are also included across all cases.

Techno-economic assumptions for the modeled technologies—such as renewable power plants, water electrolyzers, DAC facilities, carrier conversion and reconversion plants, and seaborne transportation—are summarized in Subsection S.1.2 in the Supplementary Material. We refer to a wide range of journal papers and technical reports [1,30,40,50–62] for the techno-economic parameters. However, given the substantial uncertainties associated with future technological developments, sensitivity analyses are conducted in Subsection 4.3.1, focusing on cost and operational assumptions.

It should be noted that tankers transporting liquefied hydrogen, ammonia, and liquefied synthetic methane are assumed to use the respective carrier—including boil-off gas—as bunker fuel for propulsion, consistent with the focus on net-zero energy-related CO_2 supply chains (Subsection 3.1). In contrast, MCH tankers cannot use MCH as a propulsion fuel; therefore, ammonia-fueled tankers are assumed for MCH transportation, as illustrated in Table 2 and Fig. 2c. These losses and costs associated with bunker fuels are reflected in the supply chain cost estimates in this study.

4. Results and discussions

This section presents the key simulation results, including cost estimates of hydrogen energy carriers (Subsection 4.1) and installed capacities and operational profiles of renewable power generation and electrolyzers (Subsection 4.2). Subsection 4.3 conducts sensitivity analyses of techno-economic assumptions, innovative methane synthesis processes, and CO_2 attribution rules. Finally, Subsection 4.4 summarizes the limitations of this study.

4.1. Supply chain cost of hydrogen energy carriers

Fig. 3 and Fig. 4 depict the estimated supply chain costs and the overall efficiencies—defined as the ratio of delivered energy to the fuel demand to total renewable energy input—of each supply chain, respectively.

The Supply chain cost varies substantially across carriers (Fig. 3). The Direct use of ammonia (the *NH3-D* case) is estimated to be the most cost-competitive option, at 4.8 USD per kgH_2, whereas the *MCH* case is nearly twice as expensive, at 8.8 USD per kgH_2. This cost difference is largely attributable to hydrogen losses along the supply chain. In the *NH3-D* case, direct ammonia use avoids the additional energy inputs associated with reconversion processes such as ammonia cracking and hydrogen purification. In contrast, the *MCH* case requires significant heat input for the dehydrogenation process. To examine hydrogen supply chains with net-zero energy-related CO_2 emissions, this study assumes that a portion of the recovered hydrogen from MCH is consumed to supply heat for dehydrogenation (see the hydrogen furnace in Fig. 2c). This assumption reduces the overall efficiency of the *MCH* case and thus increases its supply chain cost. As shown in Fig. 4, the overall efficiency of the *MCH* case is estimated at 32%, which is lower than that of other carriers. The breakdown of energy losses in panels (b)-(f) indicates that reconversion processes contributed significantly to total energy losses. Similarly, the supply chain cost of the *NH3-R* case increases markedly relative to the *NH3-D* case, mostly due to the heat input for reconversion (Fig. 3 and panels (e)-(f) of Fig. 4). It should be noted, however, that waste heat from hydrogen end-use facilities may be available to offset part of this heat demand; the impact of such heat integration is quantified in the supplementary analysis presented in Subsection 4.3.1.

Synthetic methane (the *CH4* case) is estimated to be the second most cost-competitive hydrogen energy carrier, at 6.2 USD per kgH_2 (Fig. 3). Although this pathway requires CO_2 capture directly from the atmosphere—entailing additional capital costs and electricity consumption supplied by renewable power plants—synthetic methane can be used without reconversion processes, thereby avoiding energy losses. Moreover, transportation technologies for liquefied methane are already

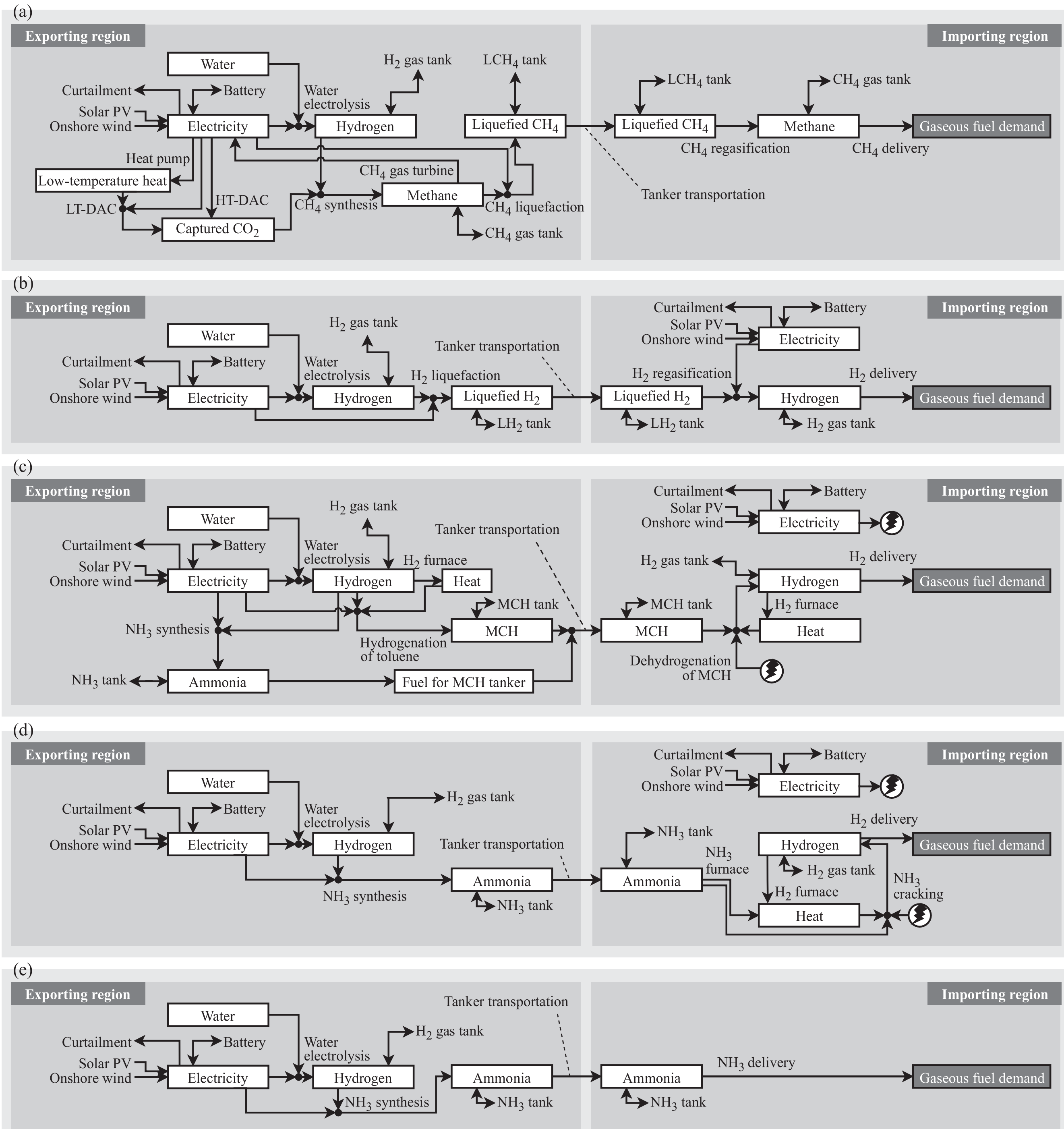

Fig. 2. Schematic diagram of the five supply chains in this study. (a): The *CH4* case, (b): The *LH2* case, (c): The *MCH* case, (d): The *NH3-R* case, (e): The *NH3-D* case.

commercialized through existing LNG supply chains, which helps constrain overall costs. Liquefied hydrogen follows synthetic methane and ammonia with cracking. The *LH2* case shows the highest overall efficiency among the carriers (Fig. 4); however, the chain faces higher transportation costs due to the capital-intensive cryogenic infrastructure, including specialized tankers and storage tanks at export and import terminals. Improving the economics of this cryogenic infrastructure is therefore a key challenge for establishing liquefied hydrogen as a cost-effective energy carrier. Compared to existing studies [30,63], the relative cost competitiveness of liquefied hydrogen, ammonia with cracking, and direct ammonia use is broadly consistent. Yet, care should be taken when comparing results across studies, as underlying assumptions and methodologies may differ.

From the perspective of supply chain cost composition, hydrogen production processes and intermittency management measures—including renewable power generation, water electrolysis, and associated energy storage (e.g., batteries and hydrogen gas tanks)—dominate the total supply chain cost. The aggregated share of these components ranges from 52% in the *LH2* case to 70% in the *NH3-D* case. This finding highlights the importance of procuring low-cost renewable

Table 2
Summary of each supply chain.

		CH4	*LH2*	*MCH*	*NH3-R*	*NH3-D*
Exporting region	Power generation	Solar PV, onshore wind turbines, and battery. In the *CH4* case, synthetic methane gas turbines are also available.				
	Hydrogen production	Water electrolysis and hydrogen gas tank				
	CO_2 capture	Direct air capture	–	–	–	–
	Carrier conversion	Methane synthesis and liquefaction	Hydrogen liquefaction	Hydrogenation of toluene	Ammonia synthesis	
International transportation		Methane-fueled tanker	Hydrogen-fueled tanker	Ammonia-fueled tanker	Ammonia-fueled tanker	
Importing region	Reconversion	Methane regasification	Hydrogen regasification	Dehydrogenation of MCH	Ammonia cracking	–
	Power generation	Solar PV, onshore wind turbines, and battery. In the *CH4* case, synthetic methane gas turbines are also available.				
	Heat production	–	–	Hydrogen furnace	Hydrogen furnace and ammonia furnace	–
Gaseous fuel demand		Methane	Hydrogen	Hydrogen	Hydrogen	Ammonia

Note: The installed capacities and operations of the listed technologies are determined through system-wide optimization.

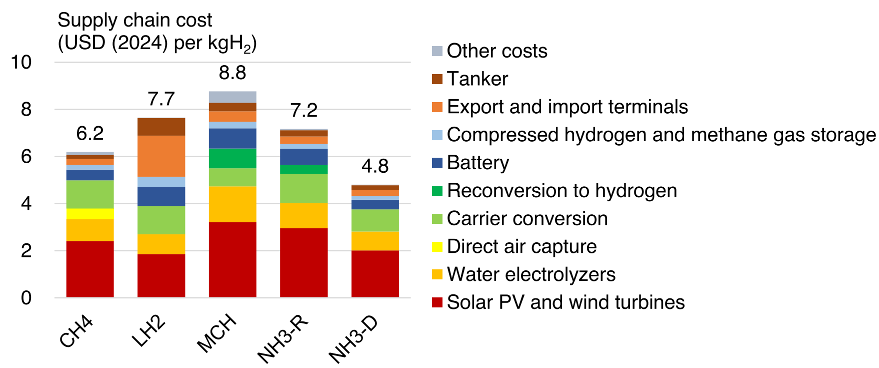

Fig. 3. Estimated supply chain costs. Note: Each cost component, except for “Other costs,” represents the fixed costs of the corresponding technology. "Export and import terminals" include storage costs at the terminals. “Other costs” include toluene mark-up costs in the *MCH* case and variable operating costs in all cases.

energy and advancing water electrolysis technologies across all carriers. Our temporally detailed analysis indicates that batteries and hydrogen storage costs account for 12%–16% of the total cost in each supply chain. These costs arise primarily from the need to manage the intermittency of renewable electricity and the resulting variability in hydrogen production (see Subsection 4.2 for examples of hourly operations). These energy storage costs are non-negligible in the production of green hydrogen energy carriers.

In the Basic Hydrogen Strategy of 2017, the Japanese government set a target to reduce the hydrogen import costs to 20 JPY per Nm^3-H_2 by 2050 [37], which is about 2.5 USD per kgH_2, assuming a 2017 exchange rate (1 USD = 113 JPY) and GDP deflator adjustments from 2017 to 2024. None of the supply chains considered in this study achieve this target. Even the *NH3-D* case—the lowest-cost option in our analysis—is 1.9 times higher than the targeted level. Subsection S.2.2 of the Supplementary Material further discusses the cost competitiveness of these hydrogen energy carriers through comparisons with natural gas prices, indicating that carbon prices or other financial mechanisms equivalent to 530–1100 USD per tCO_2 are necessary for these carriers to become cost-competitive with natural gas priced at 10 USD per MMBtu. The lower end of this range corresponds to direct ammonia use, while the higher end corresponds to MCH. Synthetic methane requires approximately 740 USD per tCO_2. These results underscore the economic challenges of deploying green hydrogen carriers and the need for continued technological development to reduce costs.

4.2. Installed capacity and cost-effective operation of hydrogen production and carrier conversion technologies

Although the assumed fuel demand is identical across supply chains, the installed capacities of renewable power generation and water electrolyzers vary substantially across cases due to differences in overall system efficiency (panel (a) in Fig. 5). In the *LH2* case, the cost-effective installed capacity of solar PV and onshore wind is estimated at 8 GW, together with 3 GW of water electrolyzers, whereas the *MCH* case requires 12 GW of renewable power generation and 5 GW of electrolyzers to compensate for higher energy losses along the supply chain. For synthetic methane, the combined capacity of solar PV and onshore wind turbines reaches 9 GW, accompanied by 3 GW of electrolyzers. Such large-scale renewable capacity deployment is necessary to realize these supply chains, even though the analyzed scale corresponds to only 2.0% of Japan’s city gas demand in 2023. As of December 2025, Japanese city gas utilities target supplying about 50–90% of city gas demand with synthetic methane or biogas by 2050 [64]. Achieving this target through synthetic methane alone would require a much larger deployment of renewable capacity if the *CH4* case were scaled up linearly.

Mid-load and flexible operation of electrolyzers and carrier production technologies, combined with energy storage, is critical to cost-effective production of green hydrogen energy carriers. The cost-optimized annual capacity factor of water electrolyzers ranges from 50% to 61% (panel (a) in Fig. 5), reflecting the need to manage the intermittency of VRE. For example, hourly electricity balances in the *CH4* case show that electrolyzer operation closely follows the output of solar and wind power (see “Water electrolysis” in panel (a) of Fig. 6). This operational pattern leads to pronounced hourly variability in hydrogen production, which is accommodated through ramping operations of carrier production technologies (see the example of methane synthesis in panel (b) of Fig. 6).

In addition to flexible operation, all supply chains rely on energy storage technologies, including battery systems and hydrogen gas tanks. The combined storage capacity ranges from about 8–15 GWh across cases (panel (b) in Fig. 5). These battery systems enable electrolyzers to

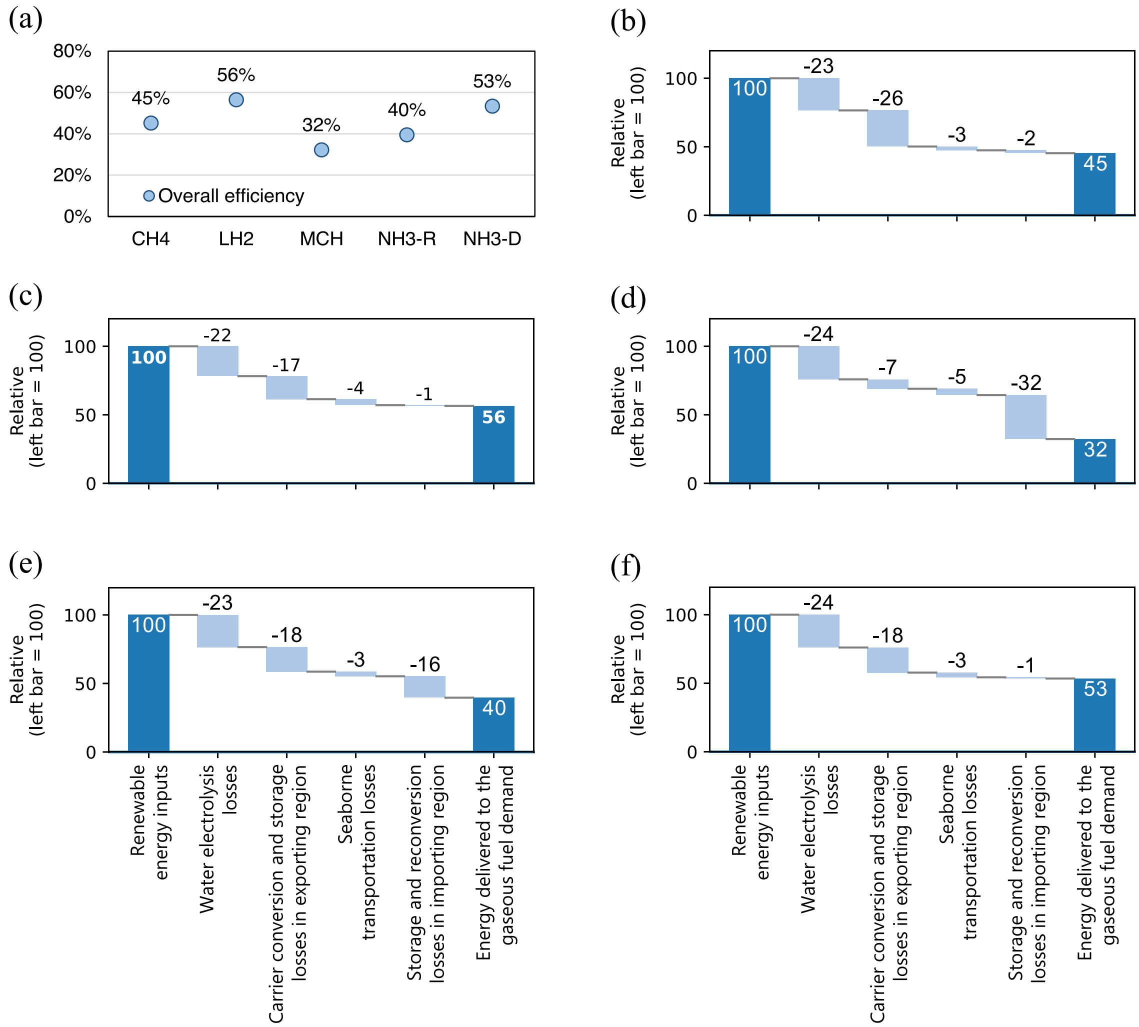

Fig. 4. Overall efficiency and breakdown of energy losses for each hydrogen supply chain. (a): Overall efficiency, (b): Energy losses in the *CH4* case, (c): Energy losses in the *LH2* case, (d): Energy losses in the *MCH* case, (e): Energy losses in the *NH3-R* case, (f): Energy losses in the *NH3-D* case. Note: See panels (e) and (f) for the horizontal-axis labels that apply to panels (b)-(d). Due to rounding, the sum of renewable energy inputs and losses may not exactly equal the energy supplied to the fuel demand.

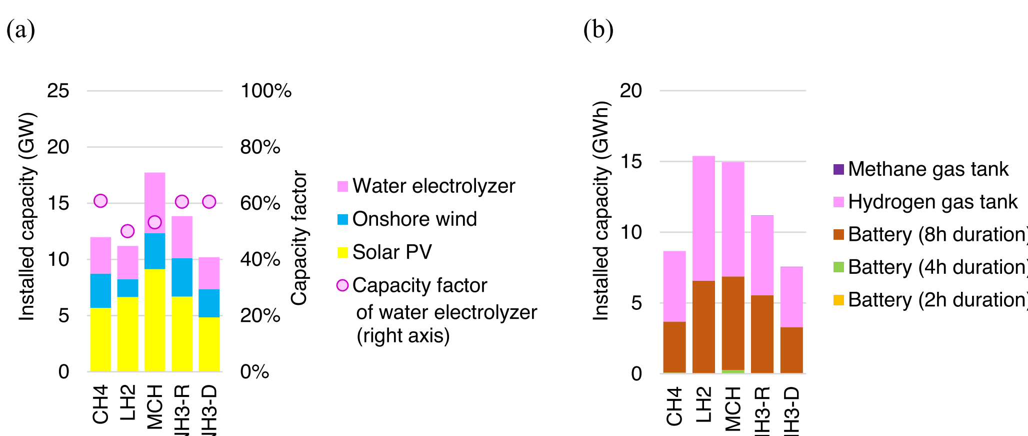

Fig. 5. Installed capacity of selected technologies. (a): Renewables and water electrolyzers, (b): Battery, compressed hydrogen and methane gas tanks.

effectively maintain their capacity factors and minimum output levels through daily charge-discharge cycles. As illustrated in panel (c) of Fig. 6, electricity is charged into batteries during daytime hours with high solar PV output and discharged at night to compensate for reduced generation. This battery operation allows electrolyzers to run continuously throughout the day and mitigates degradation due to shutdown events. Similarly, hydrogen gas tanks enable carrier production processes to maintain the assumed minimum output level of 30% of

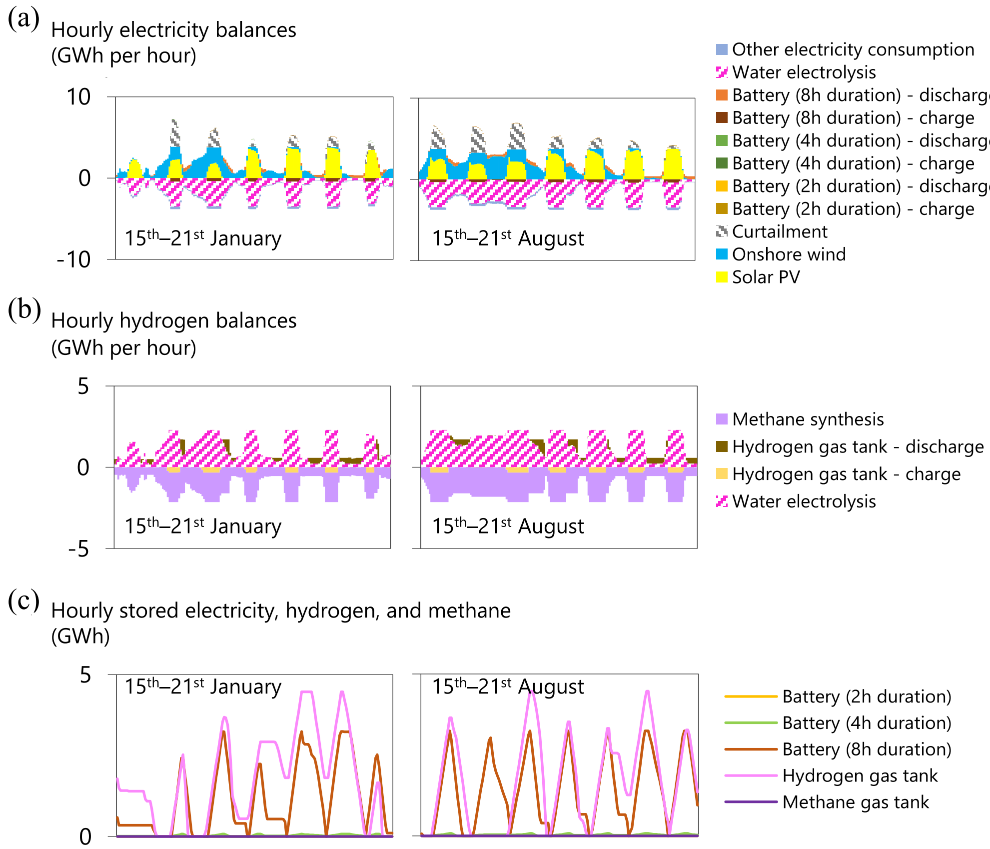

Fig. 6. Hourly balances of electricity, hydrogen, and stored energy in the exporting region in a week in January and August, the *CH4* case. (a): Hourly electricity balances, (b): Hourly hydrogen balances, (c): Hourly stored electricity, hydrogen, and methane. Note: Positive values in panels (a) and (b) indicate electricity and hydrogen production, respectively, while negative values are consumption.

nominal capacity (see the Supplementary Material for operational parameters). This role of storage is further confirmed in Subsection 4.3.1 through a supplementary analysis of minimum output constraints, which shows that higher minimum output requirements necessitate larger storage capacities.

Panel (a) of Fig. 6 also indicates that a portion of VRE is curtailed. In the model, curtailment is selected when it is more cost-effective than additional investments in technologies such as water electrolyzers and battery storage systems. Further expansion of these technologies could result in low capacity factors, thereby increasing the overall supply chain cost.

4.3. *Sensitivity analysis*

The cost estimates presented in this study depend on a range of future techno-economic and institutional assumptions. To assess the impacts of these uncertainties, this subsection conducts sensitivity analyses focusing on cost and operational assumptions (Subsection 4.3.1) and innovative methane synthesis technologies (Subsection 4.3.2). Subsection 4.3.3 discusses the impacts of CO_2 attribution rules on synthetic methane. In addition, Subsection S.2.3 presents a supplementary analysis of energy-related CO_2 emissions from each supply chain.

4.3.1. *Costs, efficiency, and operational parameters*

This subsection examines the impacts of several key factors, including renewable electricity cost, water electrolyzer cost and efficiency, direct air capture cost and efficiency, discount rate, seaborne transportation distance, minimum output levels and ramping capabilities of carrier conversion technologies, and heat supply for the reconversion process (Table 3). We first focus on renewable electricity and

Table 3
Assumptions for sensitivity analysis regarding cost, efficiency, and operational parameters.

	Assumptions
Capital cost of solar PV and onshore wind turbines in the Middle East	*Default (Def)*: 225 USD/kW for solar PV and 1188 USD/kW for wind turbines; *RE-H*: 338 USD/kW and 1782 USD/kW; and *RE-L*: 113 USD/kW and 594 USD/kW, respectively, for solar PV and wind turbines
Capital cost of water electrolyzers	*Def*: 564 USD/kW_e; *WE-H*: 845 USD/kW_e; and *WE-L*: 282 USD/kW_e
Efficiency of water electrolyzers	*Def*: 74%; *WE-LE*: 62%; and *WE-HE*: 86%
Capital cost of direct air capture in the *CH4* case	*Def*: 319 USD/(tCO_2/year) for low-temperature direct air capture system and 356 USD/(tCO_2/year) for high-temperature direct air capture system. *DAC-H*: 50% higher costs than the *Def* condition; and *DAC-L*: 50% lower costs than the *Def* condition
Efficiency of direct air capture in the *CH4* case	*Def*: See Subsection S.1.2 for the assumed energy inputs; *DAC-LE*: 50% higher energy inputs than the *Def* condition; *DAC-HE*: 50% lower energy inputs than the *Def* condition
Discounted rate	*Def*: 8% for the entire supply chain; *DR-H*: 13%; *DR-L*: 3%
Seaborne transportation distance	*Def*: 12000 km; *Dist-S*: 6000 km; *Dist-L*: 18000 km
Hourly minimum output of carrier conversion technologies	*Def*: 30% of nominal load; and *Min*: 90% of nominal load
Maximum ramp-up and -down rates of carrier conversion technologies	*Def*: 100%/h each; and *Rmp*: 10%/h each
Heat input for the reconversion process in the *MCH* and *NH3-R* cases	*Def*: Supplied by delivered hydrogen or ammonia; and *WstH*: Supplied by waste heat from the end users

water electrolyzers, as they constitute the largest cost component across all supply chains (Fig. 3). The *RE-H* condition assumes a 50% increase in the capital costs of solar PV and onshore wind turbines for all supply chain cases, whereas the *RE-L* condition assumes a 50% cost reduction. Similarly, the *WE-H* and *WE-L* conditions examine variations in the capital cost of water electrolyzers, while the *DAC-H* and *DAC-L* conditions focus on direct air capture plants. We also examine the impacts of efficiency in the *WE-HE*, *WE-LE*, *DAC-HE*, and *DAC-LE* conditions.

The default discount rate is 8% in this study; this sensitivity analysis assumes a lower discount rate (3%) under the *DR-L* condition and a higher discount rate (13%) under the *DR-H* condition. With respect to seaborne transportation, the previous subsection assumes a distance between the Middle East and Japan (12000 km). This supplementary analysis considers a 50% longer distance (18000 km) under the *Dist-L* condition and a 50% shorter distance (6000 km) under the *Dist-S* condition. These distance assumptions provide insights into the supply chain costs for exporting-importing region pairs.

The *Min* and *Rmp* conditions examine uncertainties associated with

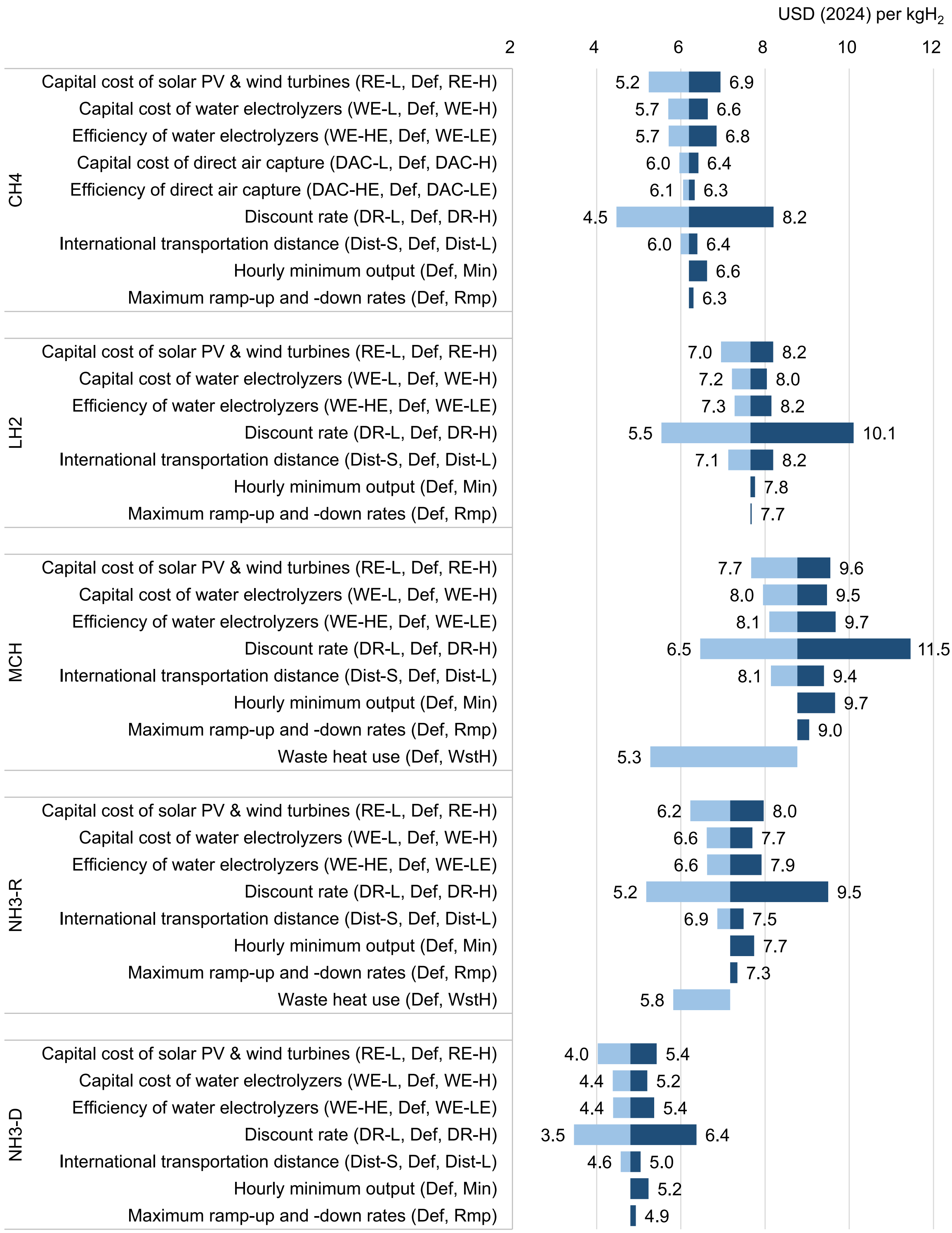

Fig. 7. Impacts of cost, efficiency, and operational assumptions on the supply chain costs.

assumptions on minimum output levels and ramping capabilities of carrier conversion technologies, such as methane synthesis, methane liquefaction, hydrogen liquefaction, toluene hydrogenation, and ammonia synthesis. Both conditions are more conservative than the default settings. The analysis of heat supply (the *WstH* condition) is applied only to the *MCH* and *NH3-R* cases, in which heat consumption during the reconversion process significantly reduces overall supply chain efficiency. In this case, all heat requirements for MCH dehydrogenation and ammonia cracking are assumed to be supplied by waste heat from hydrogen end users, such as industrial facilities, at no additional cost. This hypothetical condition quantifies the maximum potential benefit achievable through waste heat utilization.

Fig. 7 illustrates the changes from the default assumptions under each sensitivity condition. Among the sensitivity conditions, the discount rate has the largest impact in four cases, as it affects the annualized capital costs across the entire supply chain. For example, the *CH4* case is estimated at 4.5 USD per kgH_2 under the *DR-L* condition, 28% lower than the default case, while the supply chain cost reaches 8.2 USD under the *DR-H* condition. However, it should also be noted that the relative competitiveness among the carriers is largely unchanged; the *CH4* remains the second most cost-competitive carrier under both conditions.

Renewable energy costs have relatively large impacts across all carriers, followed by electrolyzer efficiency and cost. Under the *RE-L* and *RE-H* conditions, supply chain costs change by about −16% to + 13% relative to the default condition, depending on the carrier. The *NH3-D* case—which is estimated to be the most cost-competitive carrier under the default assumptions—improves to 4.0 USD per kgH_2 under the *RE-L* condition. Its CO_2 emission reduction cost to replace natural gas priced at 10 USD per MMBtu decreases to 410 USD per tCO_2. For synthetic methane, the supply chain cost is estimated at 5.2 USD per kgH_2 under the *RE-L* condition, corresponding to a CO_2 emission reduction cost of about 590 USD per tCO_2. Capital costs and efficiency of direct air capture have relatively modest impacts on the *CH4* case. Interestingly, the impacts of DAC efficiency are estimated to be smaller than those of capital costs, despite the energy-intensive nature of direct air capture. This is likely due to the highly efficient heat supply system assumed for DAC. In this study, low-temperature DAC (LT-DAC) appears to be a cost-effective option for supplying CO_2 in the *CH4* case. LT-DAC is equipped with a highly efficient heat pump system—with an assumed coefficient of performance of 3.7—for CO_2 regeneration. This contributes to reducing electricity consumption and mitigating the sensitivity of the results to DAC efficiency. As depicted in Fig. 8, the electricity consumption of DAC accounts for only 6% of the total electricity consumption in the *CH4* case; water electrolyzers dominate electricity consumption, resulting in a larger impact of electrolyzer efficiency than that of DAC efficiency.

Sensitivity to seaborne transportation distance varies by carrier (see the *Dist-L* and *Dist-S* conditions). Synthetic methane and ammonia supply chains are relatively insensitive to transportation distance, suggesting that the estimated costs are broadly applicable to other importing regions. The *LH2* and *MCH* cases exhibit much stronger sensitivity to distance assumptions. In the *LH2* case, cost changes are primarily driven by the capital costs of tankers. Liquefied hydrogen tankers are assumed to be more expensive than those for other carriers—about five times higher than liquefied methane tankers on an energy-transport basis. Longer transportation distances increase the number of tankers required, resulting in significant cost impacts. In the *MCH* case, multiple factors—including tanker costs, initial toluene costs, and fuel consumption for tankers—jointly affect supply chain costs under the *Dist-L* and *Dist-S* conditions. For example, under the *Dist-L* condition, the total amount of start-up toluene loaded onto each tanker increases by about 40% (in metric tons) relative to the default condition, reflecting the larger number of tankers required. In addition, longer transport distances also increase ammonia fuel procurement costs for MCH tankers (such as the costs for additional renewable power generation, water electrolysis, and ammonia production).

Regarding operational parameters of carrier conversion technologies, minimum output constraints have a larger impact on supply chain costs than hourly ramping capabilities. Costs increase under less flexible operating conditions, such as higher minimum output requirements and limited hourly ramping capability. In particular, supply chain costs rise markedly under the *Min* condition across all cases, as higher minimum output levels necessitate substantially larger energy storage capacities to maintain stable operation throughout the year, even during periods of reduced VRE output. In the *CH4* case, installed energy storage capacity more than triples from the default to the *Min* condition (Fig. 9). In contrast, the *Rmp* condition results in only modest cost changes across cases. It should be noted, however, that when no ramp-up or ramp–-down operations are allowed, the supply chain costs exceed those under the *Min* condition. These results suggest that a certain degree of operational flexibility—such as minimum output levels of 30% of nominal capacity and hourly ramping capability of around 10%—is critical to curbing hydrogen supply chain costs.

Heat supply assumptions substantially influence the economics of *MCH* and *NH3-R* cases. For the *MCH* case, supply chain costs decrease by about 40%, from 8.8 USD per kgH_2 under the default condition to 5.3 USD per kgH_2 under the *WstH* condition. The *NH3-R* case also shows a cost reduction of about 20%. With access to low-cost, carbon-free heat for reconversion processes, both cases become cost-competitive options for green hydrogen supply, even cheaper than the *CH4* case. For further discussion, Subsection S.2.3 considers the use of natural gas for heat supply. Although natural gas–based heat results in CO_2 emissions, it can contribute to reducing overall supply chain costs.

4.3.2. Innovative methane synthesis technologies

Innovative carrier production technologies, such as direct electrosynthesis of MCH and ammonia, are under development to improve the economics of hydrogen energy carriers. For methane synthesis, several high-efficiency processes have been proposed, including co-electrolysis of water and CO_2 using solid oxide electrolysis cells, as well as low-temperature Sabatier and hybrid water electrolysis technologies. This subsection examines the supply chain costs of these innovative methane synthesis technologies, shown red in Fig. 10. Assumptions for cost, efficiency, and operational parameters are summarized in Subsection S.1.2 in the Supplementary Material. Cost and efficiency parameters are

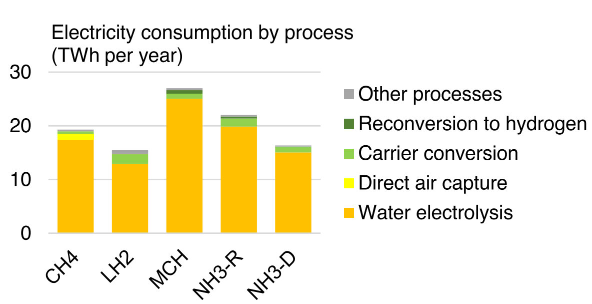

Fig. 8. Electricity consumption by process in each hydrogen supply chain.

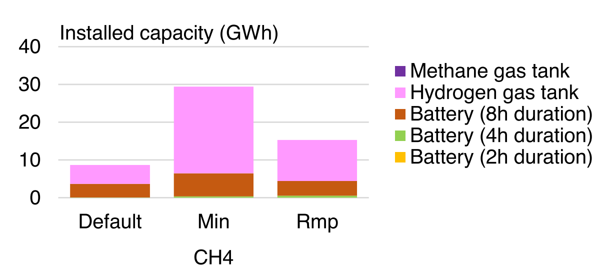

Fig. 9. Installed capacity of energy storage technologies under the *Min* and *Rmp* conditions in the *CH4* case.

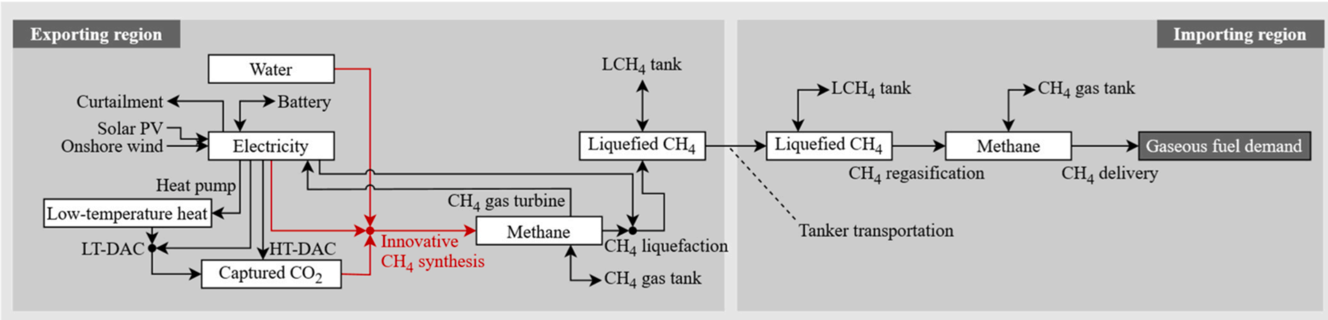

Fig. 10. Innovative methane synthesis supply chain.

based on [40] and [65]. Due to limited publicly available information on their operational characteristics, two contrasting assumptions regarding operational flexibility are considered: a high flexibility case (the *CH4-I-HF* case), characterized by high ramping capability and low minimum output constraints, and a low-flexibility case (the *CH4-I-LF* case), characterized by limited ramping capability and higher minimum output constraints.

The results highlight that high conversion efficiency, combined with operational flexibility, is critical to reducing the overall supply chain costs of innovative methane synthesis. As shown in Fig. 11, with the adoption of innovative technologies, the *CH4-I-LF* case achieves a cost of 5.7 USD per kgH_2. This represents a cost reduction of about 9% relative to the conventional process. Although improved conversion efficiency reduces renewable electricity inputs, the limited operational flexibility results in installing relatively large battery storage capacities to smooth VRE inputs to the methane synthesis process, largely offsetting the efficiency gains. In contrast, the high operational flexibility assumed in the *CH4-I-HF* case allows the innovative methane synthesis process to closely follow VRE output profiles. This flexibility reduces the need for battery storage investments, as variability in methane production can instead be absorbed by liquefied methane storage tanks at the export terminal, which are assumed to be much cheaper than battery storage (see Subsection S.1.2). As a result, the estimated supply chain cost decreases to 5.1 USD per kgH_2, which is nearly equivalent to that of the *NH3-D* case (4.8 USD per kgH_2).

4.3.3. CO_2 attribution rules

From an institutional perspective, the commercial deployment of liquefied hydrogen, MCH, and ammonia does not appear to pose major regulatory or emission accounting challenges. In contrast, synthetic methane raises unresolved issues related to CO_2 attribution. Specifically, synthetic methane re-emits CO_2 upon combustion at the point of use, while ambiguity remains regarding whether these emissions should be attributed to the original CO_2 emitter (or the location where CO_2 is captured from the atmosphere) in the exporting region or to the end user of synthetic methane in the importing region. Attributing CO_2 to the end users may discourage synthetic methane imports, as the importing region cannot explicitly claim the emission reduction benefits. Similar attribution challenges also arise for other carbon capture and utilization (CCU) technologies, such as Fischer–Tropsch liquid fuels and methanol. Against this background, as of 2026, international efforts to establish standardized accounting rules for CCU are ongoing. For instance, within the IPCC, the outline for the Methodology Report on Carbon Dioxide Removal Technologies and Carbon Capture, Utilization, and Storage—to be developed under the Seventh Assessment Report (AR7) cycle—was finalized in 2025 [66].

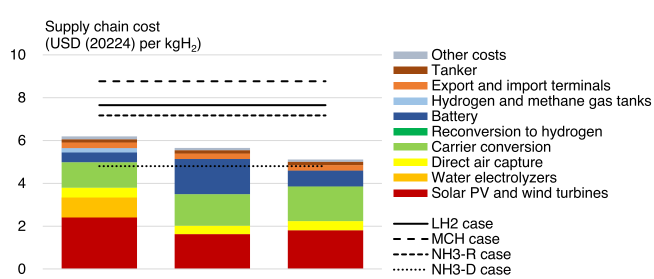

Fig. 11. Supply chain costs of innovative methane synthesis.

The results and discussions in Subsections 4.1–4.3.2 and S.2.2 implicitly assume that CO_2 re-emissions are attributed to the exporting region; captured and re-emitted CO_2 are offset within the exporting region, and synthetic methane is treated as a fuel with net-zero energy-related CO_2 emissions in the importing region. However, the detailed methodological treatment of CCU awaits completion of the forthcoming IPCC report and may differ from the assumptions adopted in this study. This subsection therefore examines the impacts of a more conservative attribution framework on synthetic methane supply chain costs, particularly from the perspective of importing region. Under this framework, re-emitted CO_2 is counted as emissions of the importing region and is assumed to be offset—for example, by procuring carbon offset credits from domestic sources, the exporting region, or other markets—in order to maintain net-zero energy-related CO_2 emissions. The associated offset cost (see the horizontal axis in Fig. 12) is added to the synthetic methane supply chain, denoted as the *CH4-A* case. This estimate can be interpreted as the synthetic methane supply chain costs borne by the importing region under the conservative attribution framework. For comparison, Fig. 12 also presents natural gas import costs combined with carbon offset costs. The natural gas import costs shown in the figure are broadly comparable to Japan's LNG import prices from 2010 to 2024, which ranged from 9.8 USD to 24.5 USD per MMBtu [67,68]. This study assumes the same amount of carbon content between synthetic methane and natural gas.

The results indicate that the cost competitiveness of synthetic methane depends strongly on the CO_2 attribution rule and carbon offset costs. The *CH4-A* case becomes less economically attractive than the

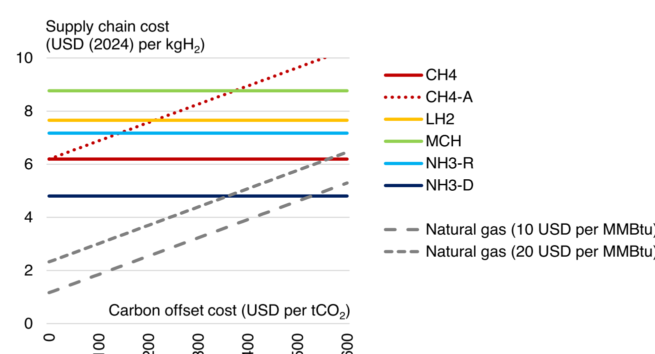

Fig. 12. Supply chain costs including carbon offsets under a conservative CO_2 attribution framework.

NH3-R case at an offset cost of 150 USD per tCO_2 and less attractive than the *LH2* case at 220 USD per tCO_2. More importantly, the figure implies that the conservative attribution framework would render synthetic methane economically uncompetitive relative to natural gas; for example, compared with natural gas priced at 20 USD per MMBtu, the *CH4* case—which attributes re-emitted CO_2 to the exporting region—becomes more cost-competitive at an offset cost of 570 USD per tCO_2. In contrast, natural gas is estimated to remain cheaper than the *CH4-A* case under all offset cost assumptions; in other words, synthetic methane is unlikely to be a cost-effective option for the importing region under the conservative attribution framework. These results imply that re-emitted CO_2 needs to be attributed to the original emitter (or the locations where CO_2 is captured) for synthetic methane to remain economically attractive for the importing region.

4.4. Limitations of this study and discussions on social implementation

This study develops a novel hydrogen supply model designed to capture operational characteristics expected under commercial deployment conditions. By explicitly integrating multiple energy storage technologies—namely battery systems, compressed hydrogen gas tanks, and energy carrier storage tanks—into the hydrogen supply framework, the model addresses the critical challenge of renewable energy intermittency and provides a more realistic and robust representation of future hydrogen supply chain. Nevertheless, the current assumptions regarding hourly minimum output levels and maximum ramp-up and ramp-down rates for water electrolysis and energy carrier synthesis remain simplified. These assumptions underscore the need for further refinement as empirical evidence and technological experience accumulate. In particular, although innovative methane synthesis technologies are actively under development, they remain at an early stage of technological maturity. As a result, data on their cost structures and operational characteristics are highly limited, necessitating iterative model updates as research and development progress.

Also, the model does not fully account for economies of scale across all system components. While battery storage systems and water electrolyzers are generally considered to exhibit limited scale economies, other components—such as hydrogen storage systems, energy carrier storage facilities, carrier conversion plants, and maritime transport vessels—are expected to benefit significantly from scale effects. In practical applications, for example, when large storage capacities are required, hydrogen gas tanks—where economies of scale apply—may be favored over battery systems. This substitution could lead to system configurations different from those identified in the present analysis. This limitation reflects an inherent constraint of linear programming-based approaches, and incorporating economies of scale remains an important direction for future research.

Finally, this analysis—bounded at the point of unloading in Japan—identifies direct ammonia use as the lowest-cost option among the assessed supply chains. However, ammonia requires careful handling during production, storage, and seaborne transportation, and safety constraints may limit the feasibility of widespread urban distribution, restricting ammonia use primarily to power generation and industrial applications near unloading ports. In contrast, synthetic methane offers distinct advantages in downstream utilization. It can supply gas-fired power plants located near unloading terminals and be distributed to a wide range of end users through existing city gas networks. For inland demand, liquefied hydrogen, MCH, and ammonia would generally require truck-based transportation and conversion of end-use equipment, whereas synthetic methane can leverage existing infrastructure and appliances. This compatibility with established systems may confer an additional cost advantage that extends beyond the scope of the present supply chain boundary.

5. Conclusion

This study assesses the international seaborne supply chain costs of fully renewable-based hydrogen energy carriers—including liquefied hydrogen, MCH, ammonia, and synthetic methane—from the Middle East to Japan. A two-region, single-year, temporally detailed hydrogen supply model is employed to consistently evaluate cost-optimal capacity sizing, hourly operational feasibility, and resulting supply chain costs for these carriers. Particular attention is given to synthetic methane—both the conventional Sabatier-based process and innovative methane synthesis technologies—as this carrier has attracted increasing interest from policymakers and industry for decarbonizing natural gas systems while maintaining compatibility with existing city gas and LNG infrastructure. The modeling framework and detailed assessment of synthetic methane mark the novelty of this study. The optimization results provide three key findings regarding the economics of synthetic methane.

First, the results indicate the cost competitiveness of synthetic methane. Under the default assumptions of this study, the supply chain cost of synthetic methane produced via the Sabatier reaction is estimated at 6.2 USD per kgH_2, making it the second most cost-competitive option after the direct use of ammonia (4.8 USD per kgH_2). In comparison, the corresponding costs are 8.8 USD per kgH_2 for MCH, 7.7 USD per kgH_2 for liquefied hydrogen, and 7.2 USD per kgH_2 for ammonia reconversion. Synthetic methane and direct use of ammonia avoid reconversion processes and the associated energy losses in the importing region, contributing to their favorable economics. Synthetic methane further benefits from its compatibility with existing LNG transportation technologies, which curbs capital costs for transportation infrastructure compared with other carriers. The sensitivity analysis also confirms that synthetic methane is relatively insensitive to assumed transportation distance, suggesting that the estimated costs are broadly applicable to other importing regions. Furthermore, innovative methane synthesis technologies are estimated to reduce the supply chain cost to 5.1 USD per kgH_2—nearly equivalent to the level of direct ammonia use.

Second, operational flexibility—such as part-load operation with frequent ramp-up and ramp-down—of electrolyzers and carrier conversion technologies is critical to reducing the costs of green hydrogen energy carriers, including synthetic methane. Under less flexible operating conditions, supply chain costs increase substantially because additional energy storage capacity is required to ensure stable operation under VRE output. Operational flexibility is particularly important for innovative methane synthesis processes. Under limited flexibility, even with the adoption of innovative technologies, the supply chain cost remains at 5.7 USD per kgH_2—9% lower than the conventional process cost. This is because the need for large VRE-buffering storage capacities offsets the efficiency gains of advanced technologies. Enhancing operational flexibility reduces the supply chain cost to 5.1 USD per kgH_2, as highlighted in the previous paragraph, and therefore represents a key research priority for future methane synthesis technologies.

Third, the synthetic methane faces institutional challenges related to CO_2 attribution. Attributing CO_2 emissions to the re-emission stage would render synthetic methane economically and environmentally uncompetitive relative to natural gas, highlighting the importance of international efforts to establish standardized accounting rules for CCU.

Finally, we identify three priorities for future research on the economics of hydrogen energy. First, domestic delivery costs should be examined. The scope of this study is bounded at the point of unloading at the import terminal, as incorporating domestic delivery would introduce substantial complexity—such as accounting for spatial distributions of end users and their technical characteristics, including compatibility with existing energy infrastructure in buildings and industrial facilities. Nevertheless, these end-use conditions are critical for real-world deployment, and future studies should extend the system boundary to the point of use. Second, from a methodological perspective, mixed-integer programming approaches are needed to explicitly represent economies of scale, as discussed in Subsection 4.4. Third, liquid synthetic fuels—such as Fischer–Tropsch fuels and methanol—are also attracting increasing attention from policymakers and industry. Future research should therefore evaluate the economics of these fuels to achieve a more comprehensive understanding of hydrogen energy carriers.

CRediT authorship contribution statement

Takashi Otsuki: Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Investigation, Funding acquisition, Formal analysis, Data curation, Conceptualization. **Tatsuya Hagita:** Writing – original draft, Validation, Methodology, Investigation. **Yoshiaki Shibata:** Writing – review & editing, Writing – original draft, Supervision, Conceptualization.

Declaration of Generative AI and AI-assisted technologies in the writing process

During the preparation of this work the authors used ChatGPT 5.2 in order to improve the readability and language of the manuscript. After using this tool/service, the authors reviewed and edited the content as needed and takes full responsibility for the content of the published article.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.tegy.2026.100015.

Data availability

The model code and input data used in this study are available at reference [44].

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