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Seaborne imports or domestic production? A techno-economic assessment of hydrogen-based energy carriers

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HIGHLIGHTS

- Techno-economic analysis of e-fuel and hydrogen imports versus domestic production.
- Integrating country-specific CAPEX and WACC of renewables and electrolyzer systems.
- Improved shipping cost models with ship selection specific to each hydrogen carrier.
- Importing electro-fuels for direct use is 12–22% cheaper than domestic production.
- Upscaling production or shortening distance enables cost-effective hydrogen imports.

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ABSTRACT

Hydrogen and electro-fuels play a crucial role in decarbonizing hard-to-abate sectors, while the comprehensive cost-effectiveness of their global trade driven by regional cost variations remains underexplored. This study presents a techno-economic assessment of importing hydrogen carriers (liquid hydrogen, liquid methane, methanol, ammonia, and liquid organic hydrogen carriers) via deep-sea shipping, compared with their domestic production. Incorporating country-specific capital expenditures (CAPEX) and weighted average cost of capital (WACC), the production costs of these hydrogen carriers are evaluated through cost-minimizing optimization of capacity configuration and operation strategy for wind-PV-grid hybrid energy systems. Additionally, this study improves shipping cost models by accounting for a comprehensive range of ship types and size categories specific to each hydrogen carrier. For the imports of electro-fuels from China to Sweden during 2025–2050, the levelized import costs of methane, methanol, and ammonia are 98–206, 93–204, and 93–126 EUR/MWh, respectively, which are 12%–22% lower than domestic production costs in Sweden. This cost advantage is attributed to lower country-specific CAPEX and WACC in China, while it comes with higher CO_2 emissions due to China's more carbon-intensive electricity grid. However, if electro-fuels require reconversion to hydrogen, the total import costs for all hydrogen carriers exceed the domestic hydrogen production costs. Moreover, if hydrogen production scale is doubled to 200 million kgH_2/year, or if shipping distance is reduced to less than 8000 nautical miles, importing liquid hydrogen could become cost-competitive with domestic production. Finally, uncertainty analysis reveals that overall costs are highly sensitive to CAPEX, WACC, and electrolyzer performance, highlighting the significance of accounting for these country-specific factors in global hydrogen trade.

Abbreviations: CAPEX, Capital expenditures; CO_2, Carbon dioxide; DAC, Direct air capture; DBT, Dibenzyl toluene; EU, European Union; LCOH, Levelized cost of hydrogen; LCOX, Levelized cost of *x*-fuel; LCH_4, Liquid methane; LH_2, Liquid hydrogen; LHV, Lower heating value; LNG, Liquefied natural gas; LOHCs, Liquid organic hydrogen carriers; LPG, Liquefied petroleum gas; MCH, Methylcyclohexane; MeOH, Methanol; NH_3, Ammonia; NPC, Net present cost; PV, Photovoltaic; WACC, Weighted average cost of capital.

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1. Introduction

Electro-fuels, synthetic fuels produced from electrolytic hydrogen and carbon dioxide (CO_2) or nitrogen [1], play a crucial role in decarbonizing hard-to-abate sectors such as aviation, long-distance shipping, heavy-duty trucks, iron and steel industries, chemical and petrochemical industries, etc., which heavily rely on fossil fuels and are challenging to directly electrify using renewable energy sources [2]. The European Union (EU) has introduced several policies to facilitate the deployment of hydrogen and electro-fuels. The *Renewable Energy Directive III (RED III)* [3] proposes to reach more than 29% share of renewable energy in final energy consumption in transport sector by 2030, including a 1%–5.5% share of renewable fuels of non-biological origin. The *e-fuels exemption* [4] stipulates that all new sales of CO_2-emitting vehicles will be prohibited by 2035, but those powered by electro-fuels could be exempt from this ban. Additionally, the *FuelEU Maritime* [5] and *REFuelEU Aviation* [6] aim to accelerate the alternative fuel transition in the transport sector by imposing carbon intensity limits or mandating minimum shares of renewable fuels.

The large-scale development of electro-fuels requires substantial amounts of renewable electricity, but the deployment of renewable energy projects is constrained by social/political acceptance, land availability, and resource potential [7]. For instance, European countries like Germany have increasing industrial energy demand but limited capacity for domestic renewable energy generation, so the demand shortage would rely on energy imports from other regions [8]. Additionally, Sweden cancelled 13 offshore wind projects due to military defense concerns [9], which may also lead to a shortage of domestic renewable electricity for electro-fuel production and necessitate energy imports. Furthermore, the levelized cost of energy for renewable systems varies significantly across regions, depending on resource endowment, regulatory frameworks, and capital costs. These regional cost disparities could foster the emergence of global electro-fuel trade [10].

Beyond their direct use in hard-to-abate sectors, electro-fuels such as methanol, methane, and ammonia can also serve as promising hydrogen carriers through reconversion processes [11]. Compared with electricity and gaseous hydrogen, electro-fuels are more suitable for large-scale storage and transportation due to their stable physicochemical properties. Another benefit of electro-fuels is that the transported cargo can be used as shipping fuel, thereby reducing fossil fuel consumption and transport-related life cycle greenhouse gas emissions [12]. Ammonia, methanol, and liquefied natural gas (LNG), have been traded globally for decades as fuels or chemical feedstocks [13], and large-scale shipping projects for these fuels are currently under construction [14]. The technical feasibility of liquid hydrogen (LH_2) shipping has also been demonstrated via the Suiso Frontier project between Australia and Japan [15]. In addition to electro-fuels, liquid organic hydrogen carriers (LOHCs) are also technically prospective choices for hydrogen transport. These organic compounds absorb and release hydrogen through reversible chemical reactions [16], which enables efficient long-distance transportation.

Despite established technical feasibility, the cost-effectiveness of importing hydrogen carriers remains a critical determinant in the development of global hydrogen trade. Although several studies have analyzed the techno-economics of hydrogen imports across various geographical regions, several critical research gaps need to be addressed. First, country-specific variations in capital expenditures (CAPEX) for energy sources and electrolyzers, which dominate hydrogen production costs, are not fully captured in existing techno-economic assessments. Second, detailed shipping cost models for various hydrogen carriers considering a comprehensive range of ship types and size categories are still lacking. Beyond these gaps, the cost-effectiveness of seaborne imports of hydrogen carriers from China to Europe, under different conditions of CO_2 costs, heat sources, and production scales, has not been systematically investigated.

The aim of this study is to evaluate the cost of importing hydrogen carriers (liquid hydrogen, liquid methane, methanol, ammonia, and LOHCs) from China to Sweden via deep-sea shipping, in comparison to domestic production in Sweden, across multiple time horizons. This study advances techno-economic assessments of global electro-fuel and hydrogen trade by introducing two novel contributions: (i) accounting for country-specific CAPEX and weighted average cost of capital (WACC) for renewables and electrolyzer systems to capture regional cost differences, and (ii) incorporating ship selection covering a comprehensive range of ship types and size categories into the techno-economic assessment to estimate transportation costs. This study addresses two key questions: *when importing electro-fuels and hydrogen is economically feasible over domestic production, and which hydrogen carrier pathway should be prioritized under different conditions?* These insights offer valuable guidance for industrial stakeholders in making business decisions and for policymakers in shaping development strategies.

1.1. Literature review

To comprehensively describe how this study addresses knowledge gaps in techno-economic assessments of global electro-fuel and hydrogen trade via seaborne shipping, a total of 27 relevant studies were systematically reviewed. Table 1 summarizes the key elements identified, including time horizons, shipping routes, energy sources, electro-fuel options, shipping models, country-specific conditions, optimization models, and uncertainty & sensitivity analysis.

(a) ***Time horizons***

19 out of the 27 reviewed studies focused exclusively on either the present condition or a single future scenario. Furthermore, Lee et al. [24], Moritz et al. [31] and Spatolisano et al. [39] examined both present and future scenarios to capture the evolving trends in techno-economic performance. In contrast, this study considers three different time horizons (2025, 2030, and 2050) to comprehensively reflect both short-term and long-term developments.

(b) ***Shipping routes***

Germany and Japan are frequently regarded as importing countries due to their high industrial energy demand and limited domestic renewable resources. In contrast, regions with abundant wind/solar resources and land availability, such as Australia, South America and North Africa, are widely discussed as potential exporters. However, despite accounting for 50% of global green hydrogen production capacity by the end of 2024 [43], China is rarely considered a hydrogen exporter. Notably, Song et al. [22] and Zhuang et al. [35] investigated exporting wind-based hydrogen carriers from China's offshore regions to Japan and other coastal Asian countries via short-distance shipping, with the findings highlighting the attractiveness of importing hydrogen from China. Beyond these efforts, this study explores the techno-economic competitiveness of exporting hydrogen and electro-fuels from China to Europe via deep-sea shipping.

(c) ***Energy sources***

Onshore/offshore wind and/or solar photovoltaic (PV) power are the primary energy sources for green hydrogen and electro-fuel production. However, their volatility and intermittency pose significant challenges to the stable operation of hydrogen production and electro-fuel synthesis, both of which require a minimum part-load threshold for continuous operation. Kim et al. [37] proposed the use of battery energy storage to mitigate this volatility, while operating in off-grid mode requires substantial battery capacity and results in prohibitively high production costs. In contrast, Pan et al. [44] highlighted that integrating renewable energy with the power grid is essential to ensure reliable and cost-effective hydrogen production. Therefore, this study adopts a

Table 1

Systematic overview of publications on techno-economic assessment of global electro-fuel and hydrogen trade, covering time horizons, shipping routes, energy sources, hydrogen carriers, shipping models, country-specific conditions, optimization models, and uncertainty & sensitivity analysis. It should be noted that this review excludes studies focusing on non-electro-fuel supply chains (e.g., blue or grey fuels) and the inland transport of hydrogen carriers.

Publications	Time horizons	Shipping routes	Energy sources	Hydrogen carriers	Shipping models	Country-specific conditions	Design & Operation optimization?	Uncertainty or Sensitivity?
Niermann et al. (2019) [16]	2017	Not specified; Distance: 5000 km	Not specified	DBT, MCH, MeOH, NEC, AB, FA, NAP	Oil tanker	Not specified	No	Sensitivity
Hank et al. (2020) [17]	2030	Morocco-Germany	Wind + Solar PV	LH_2, MeOH, NH_3, CH_4, DBT	LH_2-LH_2 carrier CH_4/NH_3-LNG carrier DBT, MeOH-Tanker	Not specified	No	Sensitivity
Eckl et al. (2021) [18]	2021	Portugal-Germany	Solar PV + Power grid	LH_2	Tanker	Hydrogen cost	No	Sensitivity
Hong et al. (2021) [19]	2019	Malaysia/ Indonesia/ Australia-Singapore	Power grid	LH_2, NH_3, MCH	Ship with different parameters	Hydrogen cost	No	Sensitivity
Niermann et al. (2021) [20]	2020	Algeria-Germany	Wind + Solar PV	LH_2, MeOH, MCH, DBT	Specific fuel consumption per tkm	Not specified	No	Sensitivity
Raab et al. (2021) [21]	2018	Australia-Japan	Not specified	LH_2, MCH, DBT	Ship with different parameters	Electricity price, Labor cost	No	Sensitivity
Song et al. (2021) [22]	2030, 2050	China-Japan	Offshore wind	LH_2, NH_3, MCH	Tanker with different parameters	Wind potential, Electricity price	Yes	Sensitivity
Johnston et al. (2022) [23]	2022	Australia-Rotterdam/ Venice/Tokyo/ Shanghai	Not specified	LH_2, CH_4, MeOH, NH_3, MCH	Ship with different parameters	Not specified	No	Sensitivity
Lee et al. (2022) [24]	2020, 2050	Australia-Korea	Grey/blue/green hydrogen	LH_2, MeOH, NH_3, MCH, DBT	Ship with different parameters	Not specified	No	Sensitivity
Zhang et al. (2022) [25]	2020	Saudi Arabia-China	Blue/Green hydrogen	MCH	Tanker	Not specified	No	Neither
Burdack et al. (2023) [26]	2030, 2050	Colombia-Asia/ Europe	Wind, Solar PV	LH_2	LH_2 Ship	Renewable potentials	No	Neither
Cui et al. (2023) [27]	2022	Not specified; Varying distances	Not specified	MeOH, NH_3	Shipping cost per tkm	Not specified	No	Sensitivity
Godinho et al. (2023) [28]	2030, 2040, 2050	Portugal-Netherlands	Not specified	MCH, DBT	Tanker with varying sizes	Electricity price	No	Uncertainty
Hampp et al. (2023) [29]	2030, 2040, 2050	Global-Germany	Onshore/offshore wind + solar PV	LH_2, NH_3, CH_4, MeOH, FT fuel	Ship with different parameters	Electricity price	Yes	Sensitivity
Meca et al. (2023) [30]	2021	Brazil-Spain Brazil-Netherlands Australia-Japan	Wind + Solar PV	LH_2, MeOH	LH_2-LNG carrier MeOH-tanker	Renewable potentials, Electricity price	No	Uncertainty
Moritz et al. (2023) [31]	2021, 2030, 2040, 2050	Global-Germany	Onshore/offshore wind + solar PV	LH_2, NH_3, CH_4, MeOH, FT fuels	LH_2-LH_2 carrier CH_4-LNG carrier NH_3-LPG carrier Liquids-Oil carrier	Renewable potentials, WACC	Yes	Sensitivity
Pfennig et al. (2023) [32]	2050	Global-Germany	Wind + Solar PV	LH_2, NH_3, MeOH, CH_4, FT diesel	Tanker with different parameters	Renewable potentials, Electricity price	Yes	Neither

(*continued on next page*)

Table 1 (*continued*)

Publications	Time horizons	Shipping routes	Energy sources	Hydrogen carriers	Shipping models	Country-specific conditions	Design & Operation optimization?	Uncertainty or Sensitivity?
Rezaei et al. (2023) [33]	2030	Australia-Japan	Solar PV + Power Grid	LH_2, NH_3, MeOH, MCH	Tanker with different parameters	Not specified	Yes	Sensitivity
Runge et al. (2023) [34]	2035	Global-Germany	Wind, Solar PV, Hydropower, Geothermal	LH_2, MeOH, FT diesel, DBT	Tanker with different parameters	Renewable potentials, Electricity price	Yes	Neither
Zhuang et al. (2023) [35]	2030, 2040, 2050	RCEP member trade	Offshore wind + Power grid	LH_2, NH_3, MCH	Ship with different parameters	Renewable potentials, Electricity price	Yes	Sensitivity
Kenny et al. (2024) [36]	2030	Chile/Namibia/ Morocco -Germany	Wind + solar PV	LH_2, NH_3	Shipping cost per tkm	Renewable potentials	Yes	Sensitivity
Kim et al. (2024) [37]	2040	Asia/EU/USA trade	Wind + Solar PV + Battery	LH_2	LH_2 fuel ship	Renewable potentials, Electricity price	Yes	Uncertainty
Peecock et al. (2024) [38]	2022	Canada-Netherlands	Not specified	LH_2, NH_3, DBT	Tanker with different parameters	Electricity price	No	Sensitivity
Spatolisano et al. (2024) [39]	2022, 2027	Not specified; Varying distances	Not specified	LH_2, NH_3, DBT, MCH	Tanker	Not specified	No	Sensitivity
Ta et al. (2024) [40]	2024	Vietnam-Japan/ Korea	Wind + Power grid	LH_2, NH_3, MCH	Ship with different parameters	Not specified	Yes	Sensitivity
Wolf et al. (2024) [41]	2050	Norway/Spain/ Morocco/ Australia-Germany	Wind + Solar PV	LH_2, DBT	LH_2-LNG carrier DBT-oil tanker	Renewable potentials, Electricity price, WACC	No	Sensitivity
Scheffler et al. (2025) [42]	2030	Australia-Germany Tunisia-Germany	Wind + Solar PV	NH_3, MeOH, CH_4, DBT	NH_3-LPG carrier CH_4-LNG carrier MeOH/DBT-Crude oil carrier	Renewable potentials, Electricity price	No	Sensitivity
This study*	2025, 2030, 2050	China-Sweden*	Onshore/Offshore Wind + Solar PV + Power grid	LH_2, NH_3, CH_4, MeOH, MCH, DBT	LH_2/CH_4-LNG tanker NH_3-Chemical/LPG tanker MeOH/MCH/DBT-Chemical/Crude oil tanker Varying sizes*	Renewable potentials, Electricity price, WACC, CAPEX of renewable and electrolyzer*	Yes	Both*

Abbreviations: LH_2: liquid hydrogen, CH_4: methane, NH_3: ammonia, MeOH: methanol, FT: Fischer-Tropsch, DBT: Dibenzyl toluene, MCH: Methylcyclohexane, NEC: N-ethylcarbazole, AB: 1,2-Dihydro-1,2-azaborine, FA: Formic acid, NAP: Naphthalene, RCEP: Regional Comprehensive Economic Partnership.

hybrid energy system configuration for electro-fuel production, which combines onshore/offshore wind, solar PV and the utility grid to enhance reliability and economic viability.

(d) ***Design & operation optimization***

In the context of hybrid energy systems, the capacity configuration and operation strategy dramatically affect electricity and hydrogen production costs [45]. Specifically, decisions regarding the scale of renewable and electrolyzer capacity installations, electricity procurement from the grid, and the flexible operation strategy of electrolyzers within their operating range, directly determine the levelized production costs. Neglecting optimal energy system design can lead to overestimated cost assessments. However, only 10 out of the 27 reviewed studies incorporated design optimization into their cost evaluation. To improve the fidelity of techno-economic assessments, this study estimates production costs based on design & operation co-optimization models.

(e) ***Hydrogen carriers***

Liquid hydrogen, ammonia, methanol, liquid methane, and LOHCs including methylcyclohexane (MCH) and dibenzyl toluene (DBT), are frequently examined in the reviewed studies. Additionally, Pfennig et al. [32] included Fischer-Tropsch fuels among the electro-fuel options, but their techno-economic comparison revealed that the production costs of Fischer-Tropsch fuels were much higher than ammonia, methanol, and methane. Niermann et al. [16] conducted a techno-economic analysis of various LOHCs, including MCH, DBT, N-ethylcarbazole, 1,2-Dihydro-1,2-azaborine, formic acid and naphthalene, emphasizing MCH and DBT as the most cost-effective options. Given that this study primarily aims to examine the economic feasibility of importing hydrogen and electro-fuels via deep-sea shipping, currently unfavorable options are excluded from consideration. Therefore, this study focuses on six mainstream hydrogen carriers: liquid hydrogen, liquid methane, methanol, ammonia, MCH and DBT.

(f) ***Shipping models***

In the simplest approach, Niermann et al. [20], Cui et al. [27], and Kenny et al. [36] calculated shipping costs using unit cost values per tonne-kilometer (e.g., EUR/tkm). Other studies estimated shipping costs based on ship-related parameters tailored to different electro-fuels, such as cargo capacity, voyage speed, specific energy consumption, and vessel CAPEX, while ship type and size category were not specified. Moritz et al. [31] and Scheffler et al. [42] specified ship types for transporting different hydrogen carriers, such as LH_2 tankers, liquefied petroleum gas (LPG) tankers for ammonia, LNG tankers for methane, and crude oil tankers for methanol and DBT, but ship size categories were still not considered. In contrast, Godinho et al. [28] analyzed various tanker classes such as small tankers, Supramax, Panamax, and Aframax, with deadweights ranging from 27,300 to 105,000 t, while their analysis focused exclusively on a single ship type for LOHC transport. Although the selection of ship type and size directly influences shipping costs, no existing study comprehensively examines various ship types and size categories specific to the transportation of each hydrogen carrier. To bridge this knowledge gap, this study evaluates transportation costs across a comprehensive range of ship types and size categories, based on real ship specifications from the S&P maritime database [46] and the International Maritime Organization's classification criteria [47], with ship selection integrated into the techno-economic assessment.

(g) ***Country-specific conditions***

Regional differences in renewable energy potential and electricity prices are widely recognized as key drivers of global energy trade. Furthermore, Wolf et al. [41] and Moritz et al. [31] identified the country-specific WACC as another critical factor. WACC varies significantly across regions due to differences in socio-economic conditions, and it affects discounted costs across the entire supply chain, including production, storage and transportation. Raab et al. [21] considered country-specific labor costs in Australia and Japan when estimating operating expenditures, although labor only accounted for a minor share of the overall costs. However, the country-specific CAPEX for renewable and electrolyzer technologies has not been considered in previous literature.

The International Renewable Energy Agency reported that the weighted average CAPEX for onshore/offshore wind and solar PV projects in China was approximately 30% lower than in Europe and the United States in 2023 [48]. Similarly, BloombergNEF observed that the CAPEX of electrolyzers manufactured in China was 50% lower than those produced in Europe and the United States [49]. Since renewable and electrolyzer technologies account for the major proportion of total hydrogen production costs, country-specific CAPEX could play a critical role in regional cost differences and shapes global energy trade dynamics. Neglecting these CAPEX variations can substantially diminish the perceived potential for cost arbitrage in global trade, leading to an underestimation of the cost-competitiveness of import options. Therefore, this study addresses this knowledge gap and advances research on global hydrogen trade by explicitly incorporating country-specific CAPEX into the techno-economic assessment.

(h) ***Uncertainty & sensitivity analysis***

Uncertainty analysis is performed to understand how the uncertainties in input assumptions affect model outputs [50]. In contrast, sensitivity analysis aims to examine how variations in key input values affect model outputs individually, and to identify the most sensitive factors [50]. 20 out of the 27 reviewed studies conducted sensitivity analysis to explore the impact of various factors, such as production scale, shipping distance, CAPEX, WACC, electricity cost, voyage speed, fuel cost, and system lifetime. However, only three studies performed uncertainty analysis and none included both analyses. For instance, Godinho et al. [28] conducted an uncertainty analysis of cost parameters, including daily rates, port cost, tank storage cost, CO_2 price, and fuel cost. Meca et al. [30] considered uncertainty ranges across processes such as water electrolysis, hydrogen liquefaction, methanol synthesis, fuel storage, fuel transportation and reconversion. Kim et al. [37] integrated uncertainties in hourly supply and demand profiles into cost evaluations.

In this study, a comprehensive dataset is developed through an extensive literature review, incorporating base, pessimistic, and optimistic values for key techno-economic parameters across the entire supply chain and multiple time horizons. Based on this dataset, a sensitivity analysis is conducted to examine the individual impact of each parameter and identify the critical factors. Furthermore, an uncertainty analysis is performed to evaluate the combined impact of all parameters, thereby delivering a holistic techno-economic assessment.

2. Method

The overall research framework is illustrated in Fig. 1. Hydrogen is produced at the exporting terminal using hybrid energy sources, including onshore wind, offshore wind, solar PV, and the utility grid. Then, hydrogen is converted into various hydrogen carriers (liquid hydrogen, liquid methane, ammonia, methanol, MCH, and DBT) for large-scale storage and long-distance transport. The produced hydrogen carriers are transported by specific ship types to the importing terminal, where electro-fuels can be either used directly or reconverted into hydrogen, while LOHCs serve exclusively as carriers for hydrogen storage and transport. Electro-fuel production and reconversion

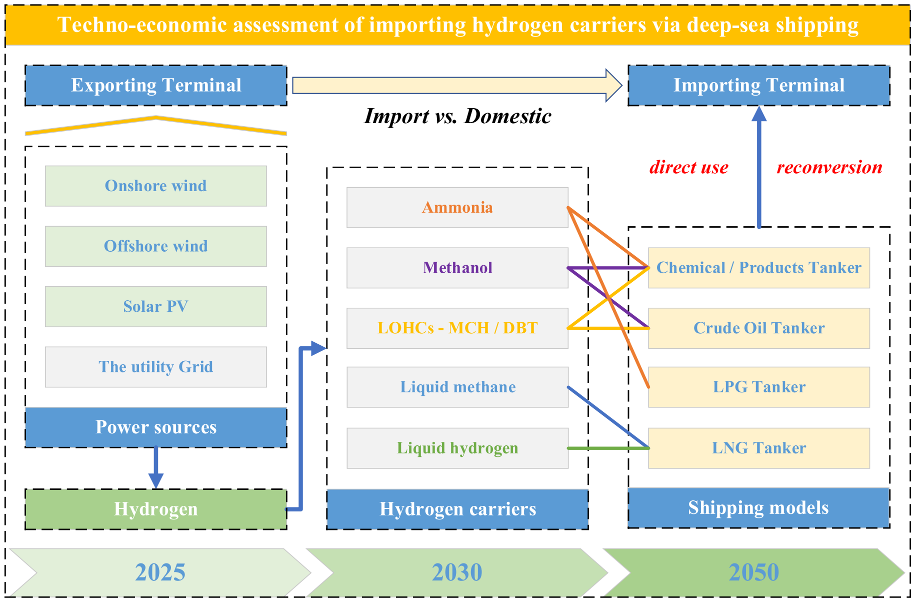

Fig. 1. Overall research framework of the techno-economic assessment of importing hydrogen carriers via deep-sea shipping.

facilities are assumed to be located near the terminals [51], so inland transportation costs are excluded. Considering the entire supply chain including production, storage, transportation, and reconversion if required, the levelized import costs of electro-fuels and hydrogen are compared with corresponding domestic production costs at the importing terminal. Multiple time horizons (2025, 2030, and 2050) are included to reflect present, near-term and long-term future scenarios, thus capturing the evolving dynamics of techno-economic performance.

2.1. System configurations

The system configurations of six hydrogen carrier pathways are shown in Fig. 2, including hydrogen production, electro-fuel synthesis, storage, shipping, reconversion, and end-user supply. Each pathway is described in detail below.

(a) ***Hydrogen baseline***

A hybrid electricity supply integrating wind-solar renewables and the utility grid is employed to enable reliable, flexible, and cost-effective hydrogen production, commonly referred to as "yellow hydrogen" [52]. An alkaline electrolyzer is applied due to its high technology readiness level and low capital cost [53]. A hydrogen buffer tank is incorporated to mitigate supply-demand mismatches between hydrogen production and electro-fuel synthesis, thus improving the system's operational flexibility. Due to its low volumetric energy density, hydrogen is further converted into hydrogen carriers for long-distance seaborne transport.

(b) ***Liquid hydrogen***

Liquid hydrogen is the most straightforward pathway to improve the volumetric energy density of hydrogen, but the liquefaction process (boiling point −253 °C) is highly energy-intensive (~10 kWh/kgH_2). Liquid hydrogen could be shipped globally in a similar manner to LNG [54]. However, given the limited availability of LH_2 tanker specifications, this study assumes that, starting from 2030, liquid hydrogen will be transported via newbuilt LH_2 tankers, which refer to the specifications of existing LNG tankers but require higher CAPEX due to stricter cryogenic conditions, and a higher boil-off rate (0.2% per day [55]). Furthermore, the boil-off hydrogen can be consumed as marine fuel in

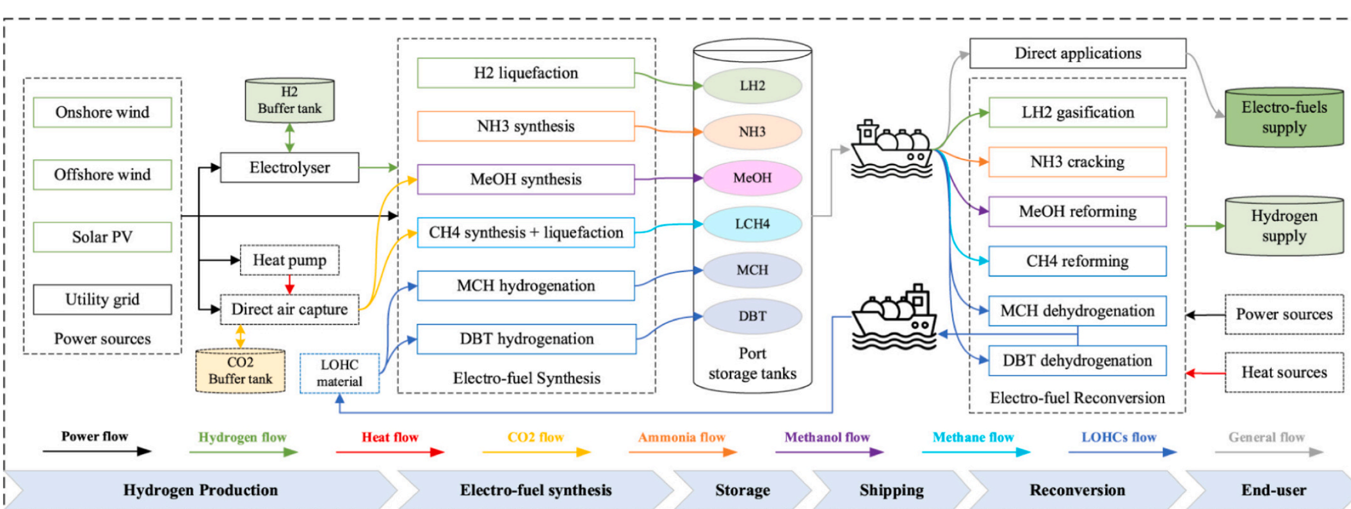

Fig. 2. System configurations of six hydrogen carrier pathways (LH_2, LCH_4, MeOH, NH_3, MCH, and DBT), including the entire supply chain of hydrogen production, electro-fuel synthesis, storage, shipping, reconversion if required, and end-user supply.

specialized hydrogen-fueled internal combustion engines.

(c) ***Ammonia***

Hydrogen can be combined with nitrogen sourced from air separation units to produce ammonia via the Haber-Bosch process. The ammonia pathway benefits from a mature technology readiness level and offers a higher volumetric energy density than liquid hydrogen, making ammonia a promising hydrogen carrier. The produced ammonia is assumed to be liquefied (−33 °C) by the cryogenic nitrogen feedstock [17], so separate liquefaction unit and additional cooling demand are not required. Ammonia can be transported via chemical/product tankers or LPG tankers, and it can be used as marine fuel with specialized engines [56]. Ammonia can be directly used in transport and agriculture sectors, or cracked into hydrogen for broader applications.

(d) ***Methanol***

Hydrogen can react with CO_2 to produce methanol based on the methanol synthesis process. CO_2 is assumed to be sourced from solid sorbent-based direct air capture (DAC), which reduces atmospheric carbon intensity and is less constrained by geographical conditions. The power demand of DAC is supplied by the hybrid energy systems, and low-temperature heat is supplied via heat pumps. A CO_2 buffer tank is integrated to improve the operational flexibility of DAC and synthesis units. Methanol is also a promising hydrogen carrier due to its high volumetric energy density and liquid state under ambient conditions, which facilitates efficient storage and transport [8]. Methanol can be transported via chemical/product tankers or crude oil tankers, and it can also be used as marine fuel with adjusted engines [56]. Methanol can be directly used in the transport sector, or reconverted to hydrogen via steam methanol reforming.

(e) ***Liquid methane***

Hydrogen can alternatively be converted to methane by reacting with CO_2 based on the Sabatier process. Compared to methanol, the liquid methane pathway requires a separate liquefaction unit to make it suitable for storage and transport, as it has lower boiling point (−162 °C). Liquid methane can be efficiently transported using well-established LNG tankers, and the boil-off methane (0.1% per day [55]) is already used as a mature marine fuel. Similar to ammonia and methanol, methane can be either directly used or reconverted into hydrogen via steam or autothermal methane reforming [42].

(f) ***LOHCs (MCH and DBT)***

MCH is based on the reversible reactions between toluene ($C_6H_5CH_3$) and MCH (C_7H_{14}), with a loaded hydrogen content of 6.2%. Similarly, DBT is based on the reversible conversion between H0-DBT ($C_{21}H_{20}$) and H18-DBT ($C_{21}H_{38}$), also with a loaded hydrogen content of 6.2%, but has different conversion and reconversion rates compared with MCH. Toluene, which is widely applied and produced at scale, is less expensive compared to H0-DBT, while the hydrogenation and dehydrogenation processes for MCH are more energy-intensive than DBT due to different reaction thermodynamics [16]. Specifically, the dehydrogenation temperature of MCH and H18-DBT is 300–350 °C and 270–320 °C, respectively, with corresponding reaction enthalpies of ~68 and 64 kJ/molH_2 [57]. Both MCH and DBT can be transported via chemical/product tankers or crude oil tankers, and the onboard dehydrogenation of LOHCs to produce hydrogen as marine fuel is not considered. Notably, the LOHC materials (toluene and H0-DBT), after being dehydrogenated at the importing terminal, are transported back to the production site for circular reuse. In contrast, tankers transporting liquid hydrogen, ammonia, methanol, and liquid methane are assumed to return with empty cargo holds, carrying only ballast water.

2.2. Production optimization model

The production optimization model is developed to evaluate the levelized production cost of various hydrogen carriers, based on cost-minimizing optimization of capacity configuration and operation strategy for energy systems [58]. The generalized optimization model for various pathways, including the objective function, decision variables and constraints, is concisely formulated as follows. Subsequently, the optimization problems are solved by linear mathematical programming based on the YALMIP-Gurobi solver [59].

(a) ***Objective function and decision variables***

The objective function of the optimal design and operation for various pathways is to minimize the levelized cost of *x*-fuel production (including liquid hydrogen, liquid methane, methanol, ammonia, MCH, and H18-DBT), expressed as:

$$F_{\mathrm{obj}} = \min LCOX_{\mathrm{P}}\left(C_{\mathrm{WP}}, C_{\mathrm{PV}}, C_{\mathrm{P2H}}, C_{\mathrm{H2X}}, P_{\mathrm{WP}}(t), P_{\mathrm{PV}}(t), P_{\mathrm{grid}}(t), P_{\mathrm{P2H}}(t), P_{\mathrm{H2X}}(t)\right) \tag{1}$$

where F_{obj} denotes the objective function, $LCOX_{\mathrm{P}}$ is levelized cost of *x*-fuel production, expressed in EUR/MWh based on lower heating value (LHV), C_{WP}, C_{PV}, C_{P2H} and C_{H2X} (in MW) are sizing decision variables, representing the installed capacity of onshore/offshore wind power, solar PV power, power-to-hydrogen (P2H) electrolyzer, and hydrogen-to-*x*-fuel (H2X) synthesis units, respectively, and $P_{\mathrm{WP}}(t)$, $P_{\mathrm{PV}}(t)$, $P_{\mathrm{grid}}(t)$, $P_{\mathrm{P2H}}(t)$ and $P_{\mathrm{H2X}}(t)$ (in MWh) are operating decision variables, representing the hourly power output of renewables and grid, as well as the hourly power input to electrolyzer and *x*-fuel synthesis units.

The levelized cost of *x*-fuel production is defined as the net present cost (NPC) divided by the discounted fuel output over its life cycle, described as:

$$LCOX_{\mathrm{P}} = \frac{NPC_{\mathrm{Production}}}{\sum_{n=1}^{N_{\mathrm{life}}} M_{x\text{-fuel}} \Big/ (1+WACC)^{n-1}} \tag{2}$$

where $NPC_{\mathrm{Production}}$ is the NPC associated with production, $M_{x\text{-fuel}}$ (in kg or $\mathrm{MWh_{LHV}}$) is the predefined annual production scale of *x*-fuel. In this study, the hydrogen production scale is consistent across various pathways, while the *x*-fuel production scale varies depending on their loaded hydrogen content and conversion rate, N_{life} is the lifetime of the overall system, consistently taken as 20 years in the study [60], and *WACC* is the country-specific weighted average cost of capital, used as the discount rate to estimate the present value of future cash flows.

The NPC of production consists of the NPC of each asset, including onshore/offshore wind power, solar PV power, electrolyzer, *x*-fuel synthesis units, and buffer storage tanks, as well as the total grid electricity and water costs, described as:

$$NPC_{\mathrm{Production}} = NPC_{\mathrm{WP}} + NPC_{\mathrm{PV}} + NPC_{\mathrm{P2H}} + NPC_{\mathrm{H2X}} + NPC_{\mathrm{tank}} + NPC_{\mathrm{grid}} + NPC_{\mathrm{water}} \tag{3}$$

The NPC of system assets consists of capital expenditures (CAPEX), life cycle operating expenditures (OPEX), replacement expenditures (REPEX), and salvage values (SV) [61–63], in which OPEX, REPEX, and SV are discounted to the present value using the WACC, and all of them depend on the CAPEX and the lifetime of each component, briefly described as:

$$NPC_i = CAPEX_i + OPEX_i + REPEX_i - SV_i, i \in \{\mathrm{WP}, \mathrm{PV}, \mathrm{P2H}, \mathrm{H2X}, \mathrm{tank}\} \tag{4}$$

(b) ***Constraints***

The supply-demand energy balance constraint, to ensure that the power supply from wind, solar, and grid equals the power demand of electrolyzer and x-fuel synthesis units, is formulated as:

$$P_{\mathrm{WP}}(t) + P_{\mathrm{PV}}(t) + P_{\mathrm{grid}}(t) = P_{\mathrm{P2H}}(t) + P_{\mathrm{H2X}}(t) \tag{5}$$

The production requirement constraints, to ensure that the annual hydrogen and x-fuel production targets are satisfied, are formulated as:

$$\frac{\sum_{t=1}^{T} P_{\mathrm{P2H}}(t)}{\eta_{\mathrm{P2H}}} \geq M_{\mathrm{H_2}}, \frac{\sum_{t=1}^{T} P_{\mathrm{H2X}}(t)}{\eta_{\mathrm{H2X}}} \geq M_{x\text{-fuel}} \tag{6}$$

where M_{H2} (in kg or $\mathrm{MWh_{LHV}}$) is the predefined annual hydrogen production scale, η_{P2H} and η_{H2X} are the specific energy consumption of electrolyzer and x-fuel synthesis units, respectively, expressed in kWh per kg of hydrogen or x-fuel produced, and t and T are the time resolution and time horizon of the operation optimization, taken as 1 h and 1 year, respectively.

The operating range constraints, defining the flexible operating range of energy conversion units, including electrolyzer and x-fuel synthesis, are formulated as:

$$C_{\mathrm{P2H}} \times \sigma_{\mathrm{P2H}} \leq P_{\mathrm{P2H}}(t) \leq C_{\mathrm{P2H}}, C_{\mathrm{H2X}} \times \sigma_{\mathrm{H2X}} \leq P_{\mathrm{H2X}}(t) \leq C_{\mathrm{H2X}} \tag{7}$$

where σ_{P2H} and σ_{H2X} are the minimal part-load operating thresholds of the electrolyzer and x-fuel synthesis units, respectively.

2.3. Shipping model

The shipping model is developed to evaluate the costs of transporting hydrogen carriers from the production site to the importing terminal, primarily including vessel costs, fuel consumption costs and port storage costs. Vessel costs depend on the ship type, ship size, and the number of ships required, which is determined based on the hydrogen carrier pathway, annual production scale, cargo capacity, shipping distance, and voyage speed. Fuel consumption costs are calculated using the specific energy consumption, shipping fuel option, and the total shipping distance. Port storage costs are directly linked to the hydrogen carrier pathway and ship size, under the assumption that the port storage capacity matches the ship cargo capacity. All these cost components are closely related to the ship type and size category, which vary in CAPEX and technical specifications such as cargo capacity, deadweight, engine power, maximum and average voyage speed. Therefore, ship selection is a critical factor for accurately evaluating shipping costs and avoiding underestimation of the cost-effectiveness of importing hydrogen and electro-fuels.

The levelized cost of x-fuel imports is defined as the total NPC associated with production and shipping divided by the life cycle delivered x-fuel to the importing terminal, expressed as:

$$LCOX_{\mathrm{IM}} = \frac{NPC_{\mathrm{Production}} + NPC_{\mathrm{Shipping}}}{\sum_{n=1}^{\mathrm{N_{life}}} \left(M_{x\text{-fuel}} - AFC_{x\text{-fuel}}\right) \Big/ (1+WACC)^{n-1}} \tag{8}$$

$$NPC_{\mathrm{Shipping}} = NPC_{\mathrm{Vessel}} + NPC_{\mathrm{Fuel}} + NPC_{\mathrm{Port}} \tag{9}$$

where $LCOX_{\mathrm{IM}}$ (in EUR/MWh) is the levelized cost of x-fuel imports, NPC_{Shipping} is the NPC associated with shipping, including the cost of vessel, fuel and port storage, and $AFC_{x\text{-fuel}}$ (in MWh) is the annual fuel consumption of x-fuel used as marine fuel.

Consistent with Eq. (4), the NPC of both vessel and port storage includes CAPEX, OPEX, REPEX, and SV. The CAPEX of vessel depends on the number of ships required, and the engine type corresponding to marine fuel option, formulated as:

$$CAPEX_{\mathrm{Vessel}} = N_{\mathrm{Ship}} \times \left(CAPEX_{\mathrm{Base}} + CAPEX_{\mathrm{AltEngine}} - CAPEX_{\mathrm{BaseEngine}}\right) \tag{10}$$

where $CAPEX_{\mathrm{Vessel}}$ is the CAPEX of the vessel itself, N_{Ship} is the number of ships required, and $CAPEX_{\mathrm{Base}}$ is the base CAPEX per vessel. If x-fuel is used as marine fuel, the CAPEX of base engine ($CAPEX_{\mathrm{BaseEngine}}$) should be replaced with that of an alternative engine ($CAPEX_{\mathrm{AltEngine}}$).

The number of ships required is based on the number of shipments required and the maximum number of shipments allowed per year. The required shipment depends on the ship cargo capacity and the volume of transported x-fuel, while the maximum allowed shipment is limited by the ship voyage speed, formulated as:

$$N_{\mathrm{Ship}} = \left\lceil \frac{N_{\mathrm{Shipment}}}{365/(T_{\mathrm{sail}} + T_{\mathrm{load}})} \right\rceil, N_{\mathrm{Shipment}} = \left\lceil \frac{M_{x\text{-fuel}}/\rho_{x\text{-fuel}}}{C_{\mathrm{Cargo}}} \right\rceil \times 2 \tag{11}$$

where N_{Shipment} is the number of round-trip shipments, T_{sail} and T_{load} are the days spent on sailing at sea and loading/unloading at port, $M_{x\text{-fuel}}$ (in kg) is the annual x-fuel production, $\rho_{x\text{-fuel}}$ (in kg/m^3) is the density of x-fuel, and C_{Cargo} (in m^3) is the cargo capacity per ship, constrained by both cargo volume and deadweight.

The NPC of fuel consumption depends on the life cycle consumed (bio-)diesel and its market price, formulated as below. Notably, x-fuel used as marine fuel is not included in the fuel consumption costs but instead deducted from the total quantity of delivered fuels.

$$NPC_{\mathrm{Fuel}} = \sum_{n=1}^{\mathrm{N_{life}}} \frac{\pi_{\mathrm{diesel}} \times AFC_{\mathrm{diesel}}}{(1+WACC)^{n-1}} \tag{12}$$

where π_{diesel} (in EUR/MWh) is the price of marine diesel or biodiesel, used either as shipping fuel or as pilot fuel, which refers to a small quantity of fuel injected into dual-fuel engines to improve combustion performance [12], and AFC_{diesel} is the annual fuel consumption of (bio-)diesel.

The annual fuel consumption depends on the shipping distance, the specific energy consumption, and the power consumption of the auxiliary engine and boiler, in which the specific energy consumption is calculated based on admiralty law [64], formulated as:

$$AFC = D_{\mathrm{Shipping}} \times N_{\mathrm{Shipment}} \times \frac{P_{\mathrm{MainEngine}} \times \left(V_{\mathrm{avg}}/V_{\mathrm{max}}\right)^3}{\eta_{\mathrm{powertrain}} \times V_{\mathrm{avg}}} \times (1+\mathrm{FOA}) \tag{13}$$

$$AFC_{x\text{-fuel}} = AFC \times (1-\omega_{\mathrm{diesel}}), \mathrm{AFC}_{\mathrm{diesel}} = AFC \times \omega_{\mathrm{diesel}} \tag{14}$$

where D_{Shipping} is the shipping distance per shipment, $P_{\mathrm{MainEngine}}$ is the main engine power, V_{avg} is the average voyage speed, V_{max} is the maximum voyage speed, $\eta_{\mathrm{powertrain}}$ is the powertrain efficiency, FOA is the average power consumption factor of the auxiliary engine and boiler relative to the main engine, and ω_{diesel} is the proportion of (bio-)diesel consumed, taken as 5% when used as pilot fuel and 100% when used as the exclusive marine fuel, respectively [12].

In the scenario of hydrogen imports, reconversion processes including additional reconversion costs, and hydrogen losses are further incorporated into the supply chain. The generalized model for hydrogen imports via various hydrogen carriers is formulated as:

$$LCOH_{\mathrm{IM}} = \frac{NPC_{\mathrm{Production}} + NPC_{\mathrm{Shipping}} + NPC_{\mathrm{Reconversion}}}{\sum_{n=1}^{\mathrm{N_{life}}} R_{\mathrm{X2H}} \times \left(M_{x\text{-fuel}} - AFC_{x\text{-fuel}}\right) \Big/ (1+WACC)^{n-1}} \tag{15}$$

where $LCOH_{\mathrm{IM}}$ (in EUR/$\mathrm{MWhH_2}$) is the levelized cost of hydrogen imports, $NPC_{\mathrm{Reconversion}}$ is the NPC associated with the reconversion processes, primarily including the costs of reconversion facilities and electric/thermal energy consumption at the importing terminal, and R_{X2H} is the reconversion rate from x-fuel to hydrogen. In this study, the scale of reconversion facilities is assumed to be equivalent to the scale of the synthesis unit.

2.4. Boundary conditions

China is identified as a promising energy exporter due to the favorable economics of its renewable energy systems and the world's largest hydrogen production plants in operation [65]. In contrast, Sweden has the motivation to import energy carriers elsewhere, driven by increasing

Table 2
Country-specific economic parameters for Sweden and China in 2025, 2030, and 2050, under base, pessimistic, and optimistic scenarios.

CAPEX (EUR/kW)	2025		2030		2050	
	Sweden	China	Sweden	China	Sweden	China
Onshore wind[a]	1390 (960–1940)	860 (700–1220)	1240 (830–1870)	770 (610–1180)	980 (620–1610)	610 (460–1010)
Offshore wind[a]	2750 (2200–4190)	2070 (1320–2820)	2080 (1500–3820)	1570 (900–2580)	1460 (1100–2290)	1100 (660–1540)
Solar PV[a]	640	590	510 (470–570)	470 (430–520)	290 (250–370)	270 (230–340)
Electrolyzer[b]	1750	900 (660–1140)	1460 (1390–1530)	760 (520–1000)	1010 (980–1020)	520 (370–660)
WACC[c]	4.2% (3.2%–6.1%)	3.5% (2.5%–6.1%)	4.2% (3.2%–6.1%)	3.5% (2.5%–6.1%)	4.2% (3.2%–6.1%)	3.5% (2.5%–6.1%)

[a] The country-specific CAPEX values for onshore/offshore wind and solar PV in 2025, along with their associated uncertainty ranges, are retrieved from [48]. The values for 2030 and 2050 are extrapolated from the 2025 values based on projected trends provided by NREL [69]. The onshore/offshore wind CAPEX values in Sweden are based on the European average.

[b] The country-specific CAPEX values for electrolyzer in 2025 are retrieved from [43]. The values and associated uncertainty ranges for 2030 and 2050 are derived from the 2025 values following the projected trends provided by TNO, based on different learning rates [70]. These values for Sweden are based on the European average.

[c] The country-specific WACC data for 2025–2050 are retrieved from [48], based on the average across various renewable energy projects (onshore wind, offshore wind, and solar PV) during 2021–2023. In this study, the power supply and the electrolyzer are assumed to be integrated within a single investment project, so a unified system-level WACC is applied to all assets and technology-specific WACC differences are not included [71]. Furthermore, uncertain future variations of WACC are also not considered in this study.

Table 3
Characteristics of power sources in Stenungsund Port, Sweden and Zhanjiang Port, China, including renewable capacity factors and grid electricity tariffs.

Indicators	Stenungsund, Sweden	Zhanjiang, China
Average capacity factor of onshore wind power[a]	31.1%	23.7%
Average capacity factor of offshore wind power[a]	40.6%	25.3%
Average capacity factor of solar PV power[a]	12.1%	16.2%
Average electricity tariff of power grid (EUR/MWh)	67.7[b]	84.7[c]
Maximum electricity tariff (EUR/MWh)	133.3[b]	189.4[c]
Minimum electricity tariff (EUR/MWh)	15.3[b]	29.1[c]

[a] Renewable power output data for these two ports, including onshore wind, offshore wind and solar PV power, are collected from the Renewables.ninja platform [72].

[b] The electricity tariff in Sweden consists of wholesale spot prices and grid fees. Wholesale spot prices in Stenungsund Port, Sweden (January–December 2024) are collected from the IEA Real-Time Electricity Tracker [73]. Grid fees are estimated at 18 EUR/MWh, sourced from a Swedish energy company Ellevio [74].

[c] Peak-valley electricity prices for industrial users under agency purchase mode in Zhanjiang Port, China (July 2023–June 2024) are sourced from the official government website [75].

energy demand but relatively limited domestic renewable energy projects. Based on the World Ammonia Map [66] and LNG terminals over the world [67], Zhanjiang Port, China and Stenungsund Port, Sweden are selected as the exporting and importing terminals, respectively, with an estimated shipping distance of approximately 10,050 nautical miles. Furthermore, the annual baseline hydrogen production scale is assumed to be 100 million kgH_2/year for all pathways.

Table 2 presents the country-specific economic parameters for China and Sweden across three different years under three uncertainty scenarios (base, pessimistic, and optimistic). The integration of these country-specific CAPEX and WACC into the techno-economic assessment represents one of the key contributions of this study. Based on *IRENA renewable power generation costs in 2023* [48], China has much lower CAPEX for renewable technologies than Sweden, especially for onshore/offshore wind power. Similarly, the CAPEX for electrolyzers in China is currently nearly half that in Europe [43]. Furthermore, future CAPEX values are projected to decline due to factors such as economies of scale, technological progress, and learning effects [68].

Table 3 summarizes the characteristics of power sources at the two terminals. Regarding renewable energy potential, both onshore and offshore wind resources in Stenungsund Port, Sweden outperform Zhanjiang Port, China, while solar resource presents an opposite pattern. Additionally, the electricity tariff of the power grid in Stenungsund is lower than that in Zhanjiang.

Fig. S1 and **Fig. S2** (in Supplementary Information) show the annual profiles of hourly capacity factors for renewables, and electricity tariffs of the utility grid at these two ports. **Fig. S3** illustrates their daily electricity tariff profiles across four representative months.

Table S1 shows the techno-economic parameters for the production, storage, and reconversion of various hydrogen carrier pathways for 2025, 2030, and 2050, with base, pessimistic and optimistic values capturing the uncertainties of each parameter.

Table S2 presents the technical specifications and costs for various ship types and size categories, including chemical tankers, LPG tankers, LNG tankers and crude oil tankers, with ship sizes ranging from 0 to 50,000 cbm to 200,000+ cbm or 10,000–20,000 dwt to 200,000+ dwt.

Table S3 outlines shipping schemes including ship types and fuel options for various pathways across three different time horizons. In 2025, shipping liquid methane, ammonia, and methanol is technically feasible, with methane already used as a marine fuel in LNG tankers. From 2030 onward, the seaborne transport of liquid hydrogen and LOHCs, as well as specialized engines for various electro-fuels are assumed to become technically viable. By 2050, marine diesel is assumed to be fully replaced by biodiesel due to increasingly stringent environmental regulations.

Table S4 shows the physical properties and cost parameters of electro-fuels, fossil fuels and biofuels, including lower heating value, density, volumetric energy density, along with uncertainties in the prices of fossil and bio-based fuels.

3. Results

This section presents cost and CO_2 emission comparisons of importing electro-fuels and hydrogen from China to Sweden versus domestic production. It then extends the case study via generalization analyses of production scales and shipping distances. Finally, uncertainty and sensitivity analyses are performed to identify the most critical factors and to quantify the variability of the results.

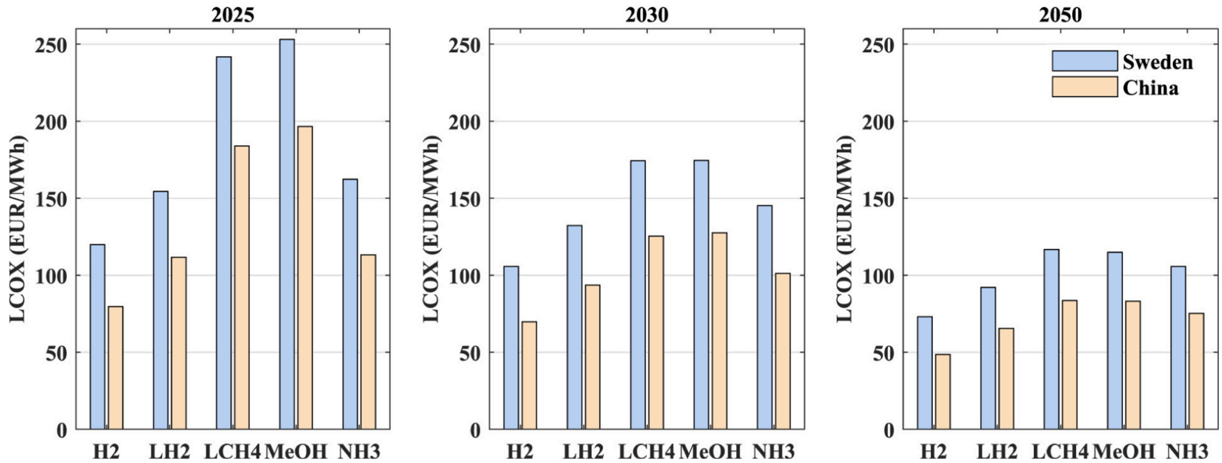

Fig. 3. Levelized production costs of hydrogen and electro-fuels in Stenungsund Port, Sweden and Zhanjiang Port, China, in 2025, 2030, and 2050.

3.1. Production cost comparison

Fig. 3 compares the production costs of hydrogen and electro-fuels in Stenungsund Port, Sweden and Zhanjiang Port, China across three different years. In 2025, the levelized production costs ($LCOX_P$) of hydrogen, liquid hydrogen, ammonia, liquid methane, and methanol in China are 80, 112, 123, 184, and 197 EUR/MWh, respectively, which are 40–58 EUR/MWh (22%–34%) lower than the corresponding costs in Sweden. The cost advantage of China is primarily attributed to lower CAPEX for renewables and electrolyzers, along with a lower WACC. As CAPEX values are projected to decline in 2030 and 2050, LCOX values will decrease by 10%–31% in 2030 and 35%–55% in 2050. Among the electro-fuel pathways, methane and methanol exhibit the largest cost reductions, primarily due to the assumption of significant cost reduction in DAC [76]. Moreover, China consistently maintains a cost advantage over Sweden, although the LCOX gap is expected to narrow from 36 to 49 EUR/MWh in 2030 to 24–33 EUR/MWh in 2050.

Fig. 4 presents the cost and energy breakdown of the hydrogen baseline in China and Sweden across three different years. In 2025, the cost of onshore wind power for hydrogen production is 23 EUR/MWh in China and 37 EUR/MWh in Sweden, contributing 40% and 52% of the energy supply, respectively, owing to the abundant wind resources available in both regions. Moreover, China relies more heavily on solar PV power due to its better solar potential and lower CAPEX. In contrast, Sweden purchases more electricity from the utility grid, benefiting from lower electricity tariffs, and its grid electricity cost is 18 EUR/MWh higher than China. As the CAPEX of solar PV declines in 2030 and 2050, its deployment in Sweden becomes increasingly cost-effective, while its contribution remains lower than onshore wind power. Another key driver of regional differences is the electrolyzer cost, with 50% lower electrolyzer CAPEX in China independently reducing the levelized cost by 11–18 EUR/MWh, highlighting the significance of incorporating country-specific electrolyzer CAPEX. Notably, offshore wind power is consistently excluded by the cost-minimizing optimization model in both regions, as it is outperformed by onshore wind power, which offers comparable capacity factor (e.g. 31.1% vs. 40.6%) but significantly lower CAPEX (e.g. 1390 EUR/kW vs. 2750 EUR/kW), as shown in Table 2 and Table 3.

Fig. 5 shows the production cost breakdown of various electro-fuel pathways in China across three different years, offering further insight into cost differences among electro-fuels. The production costs of methane and methanol in 2025 are substantially higher than other electro-fuels due to the high CO_2 cost sourced from DAC. Methanol is the most expensive option, as its synthesis reaction requires more CO_2 feedstock than methane. As the cost of DAC is assumed to decline in 2030 and 2050, the production costs of methanol and methane are

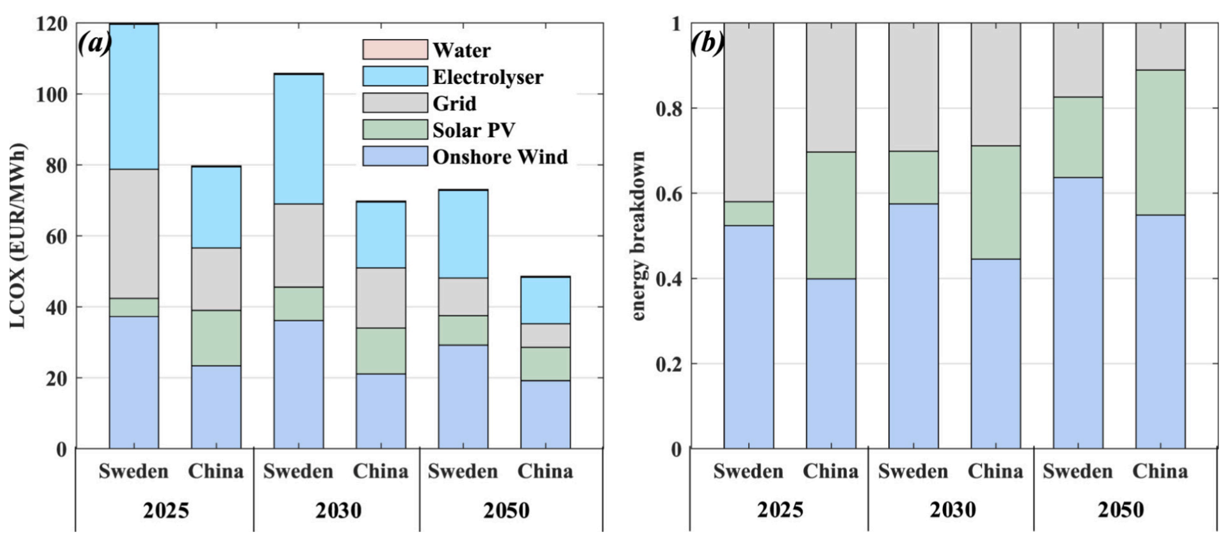

Fig. 4. Cost and energy breakdown of the hydrogen baseline in Stenungsund Port, Sweden and Zhanjiang Port, China, in 2025, 2030, and 2050: (a) levelized cost breakdown, and (b) energy supply breakdown, considering the hydrogen production scale at 100 million kgH_2/year. Note that the cost proportion of the water source is non-zero but negligible (<1%).

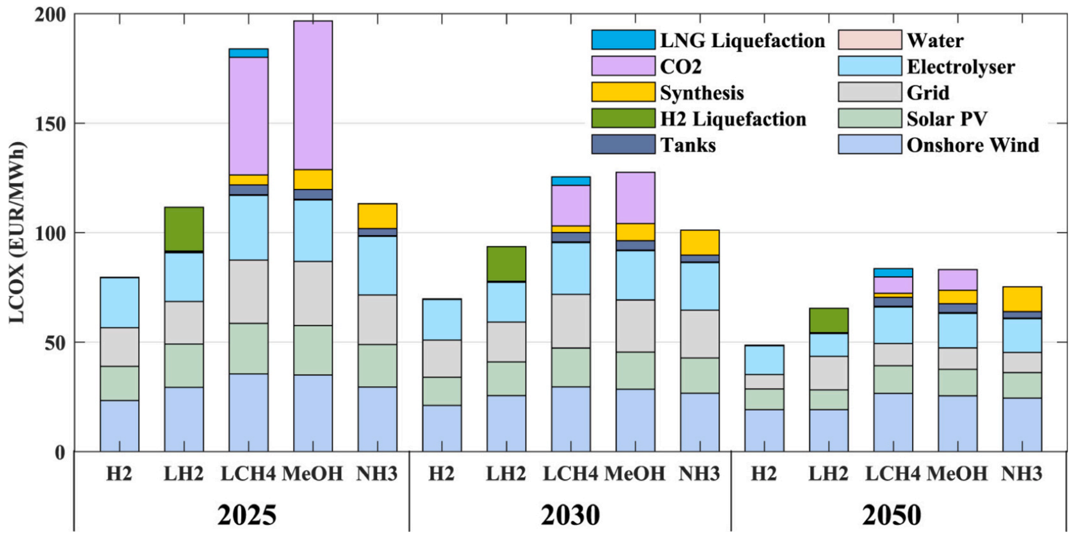

Fig. 5. Levelized production cost breakdown of various electro-fuel pathways in Zhanjiang Port, China, in 2025, 2030, and 2050, considering the hydrogen production scale at 100 million kgH_2/year. Note that the cost proportion of the water source is non-zero but negligible (<1%).

expected to converge with other electro-fuels. Detailed cost projections under varying CO_2 price scenarios are presented in **Fig. S4**. Additionally, liquid hydrogen has a higher total production cost than ammonia, as the hydrogen liquefaction is more energy- and capital-intensive than ammonia synthesis. However, the ranking of energy-based levelized production costs does not necessarily align with that of total production costs, due to differences in the heating values of electro-fuels under the same hydrogen production scale. For instance, although liquid hydrogen has higher total production costs than ammonia, it delivers a lower levelized production cost, as the energy content of 1 kg of hydrogen (33.3 kWh) is higher than that of 5.6 kg of the produced ammonia (29 kWh).

3.2. Import cost of electro-fuels

The previous section indicates that the production costs of all electro-fuels in Zhanjiang Port, China are consistently lower than those in Stenungsund Port, Sweden, primarily due to China's lower CAPEX and WACC. However, whether importing electro-fuels is more cost-effective than domestic production also depends on shipping costs.

Considering the scenario of using electro-fuels directly, Fig. 6 compares the levelized import costs of various electro-fuels from China to Sweden with the corresponding domestic production costs across three different years. In 2025, the levelized import costs of methane, methanol, and ammonia are 206, 204, and 127 EUR/MWh, respectively, which are still 36–49 EUR/MWh (15%–22%) lower than the domestic production costs in Sweden, even with shipping costs included. In 2030 and 2050, importing methane, methanol, and ammonia remains more cost-effective than domestic production, although the cost differences narrow over time. However, importing liquid hydrogen is more expensive than its domestic production. Furthermore, ammonia consistently maintains the lowest import costs among all electro-fuels over the three years, implying that ammonia could be prioritized as an economically favorable option for global electro-fuel trade. The cost advantage of ammonia imports primarily stems from its low production cost due to less energy- and capital-intensive feedstock and synthesis processes, along with its moderate shipping cost enabled by less shipment requirement and lower storage cost than liquid hydrogen, owing to ammonia's higher boiling point and higher volumetric energy density.

Fig. 7(a) illustrates the relative contributions of the production and transport stages to total import costs of electro-fuels. The shipping costs of liquid hydrogen, liquid methane, methanol, and ammonia account for

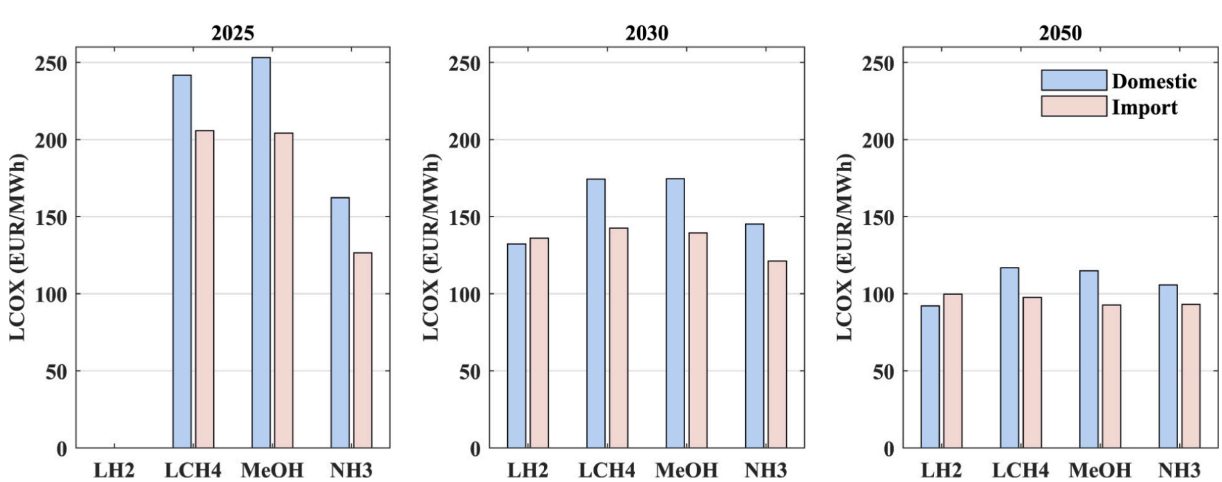

Fig. 6. Levelized import costs of various electro-fuels from Zhanjiang Port, China to Stenungsund Port, Sweden versus domestic production costs, in 2025, 2030, and 2050.

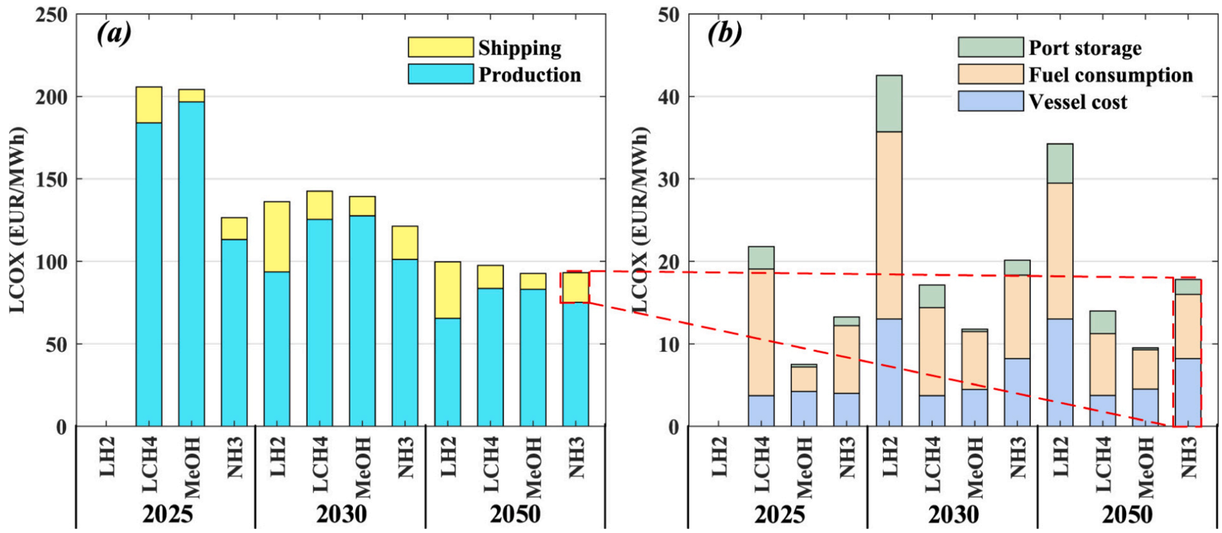

Fig. 7. Breakdown of levelized import costs for various electro-fuels from Zhanjiang Port, China to Stenungsund Port, Sweden, in 2025, 2030, and 2050, including (a) relative contributions of production and transport to the total import costs, and (b) shipping cost breakdown by vessel cost, fuel consumption, and port storage.

31%–34%, 11–14%, 4%–10%, and 10%–19% of their respective total import costs. Despite the lowest production costs, liquid hydrogen is the most expensive import option in 2050, due to significantly higher shipping costs (32–42 EUR/MWh) than other electro-fuels (8–22 EUR/MWh). This is because its low volumetric energy density results in more shipment and higher fuel consumption. Additionally, the storage and transport of liquid hydrogen require strict cryogenic conditions due to its extremely low boiling point and high boil-off rate, increasing the costs of vessel construction and port storage. In contrast, methanol has the lowest shipping costs due to its relatively high volumetric energy density and its liquid state under ambient conditions, leading to less shipments required as well as lower costs associated with vessels and storage tanks.

Fig. 7(b) further presents the detailed shipping cost breakdown, including vessel cost, fuel consumption, and port storage. On average, fuel consumption accounts for 54% of total shipping costs, followed by vessel cost (36%) and port storage (10%), highlighting fuel consumption as the primary contributor. Notably, the shipping cost breakdown shows pronounced differences among different electro-fuels. For instance, in 2025, fuel consumption represents 70% of the total shipping costs for liquid methane (15 EUR/MWh), while vessel cost constitutes only 17% (4 EUR/MWh). In contrast, vessel cost accounts for 56% of total shipping costs for methanol, despite remaining the same cost at 4 EUR/MWh, and fuel consumption at 3 EUR/MWh constitutes 40%.

The substantial gap in fuel consumption costs between methane and methanol shipping is attributed to the fuel option assumptions, in which methane and diesel are used as the main marine fuel for transporting methane and methanol in 2025, respectively, and the production cost of methane (184 EUR/MWh) is significantly higher than diesel price (65 EUR/MWh). Similarly, the shipping costs of methanol and ammonia in 2030 are higher than in 2025, as a portion of these electro-fuels is assumed to be used as marine fuels to replace conventional fossil fuels from 2030. Overall, this trend reflects the economic and environmental trade-off between electro-fuels and fossil fuels, where achieving lower carbon emissions in the shipping sector results in higher costs.

Fig. 8 illustrates the shipping cost breakdown for various electro-fuels across different ship types and size categories. It clearly shows that shipping costs vary significantly with different ship types and sizes, highlighting the necessity of incorporating ship selection into techno-economic assessments. Generally, larger ships with higher cargo capacity result in fewer shipments and low fuel consumption, but incur higher vessel and port storage costs. In contrast, smaller ships exhibit the opposite characteristics, with more frequent shipments but lower vessel and port storage costs. In addition to cargo capacity, shipping costs also depend on a vessel's specific energy consumption, which is determined by technical specifications such as engine power and voyage speed.

For shipping liquid hydrogen and liquid methane, the 50,000–99,999 cbm LNG tanker (N3), with a cargo capacity of 78,360 cbm and a specific energy consumption of 0.66 MWh/km, is the most cost-effective ship option across all years, with 2%–95% lower levelized shipping costs than other ship sizes. Unlike the 100,000–199,999 cbm LNG tanker (N2) which incurs higher vessel and port storage costs, and the 0–49,999 cbm LNG tanker (N4) which suffers from extremely high vessel and fuel consumption costs due to too small cargo capacity, the medium-sized N3 achieves an optimal balance among the costs of vessel, fuel consumption and port storage.

For methanol transport, the 120,000–199,999 dwt crude oil tanker (O2), with a cargo capacity of 156,000 dwt and a specific energy consumption of 0.62 MWh/km, is consistently the best ship option, benefiting from the balance among the three major shipping cost components. Notably, the 20,000–59,999 dwt (O5) and 10,000–19,999 dwt crude oil tanker (O6) are not viable for methanol transport in 2025, as their limited fuel capacity cannot sustain such long-distance travel. However, these smaller ships become feasible in 2030 and 2050, as methanol cargo is assumed to serve as marine fuel and the available cargo capacity is sufficient to support long-distance voyages.

Furthermore, the 50,000–99,999 cbm LPG tanker (P2), with a cargo capacity of 78,570 cbm and a specific energy consumption of 0.73 MWh/km, is the most cost-effective ship option for ammonia transport in 2025, while the 100,000–199,999 cbm LPG tanker (P1), with a cargo capacity of 144,060 cbm and a specific energy consumption of 0.82 MWh/km, becomes the preferred option in 2030 and 2050. This shift is driven by the assumption that ammonia will serve as marine fuel to replace cheaper fossil fuels from 2030, thus increasing the cost proportion of fuel consumption in total shipping costs. Therefore, minimizing fuel consumption becomes the top priority in ship selection, so P1 with larger cargo capacity and lower fuel consumption achieves lower total shipping costs compared to the smaller P2.

3.3. Import cost of hydrogen

Considering the scenario of reconverting electro-fuels to hydrogen, Fig. 9 compares the import levelized cost of hydrogen (LCOH) for various hydrogen carriers with domestic hydrogen production costs. With the reconversion costs included, the import LCOH for 2025–2050 is 100–136 EUR/MWhH_2 via liquid hydrogen, 138–280 EUR/MWhH_2 via

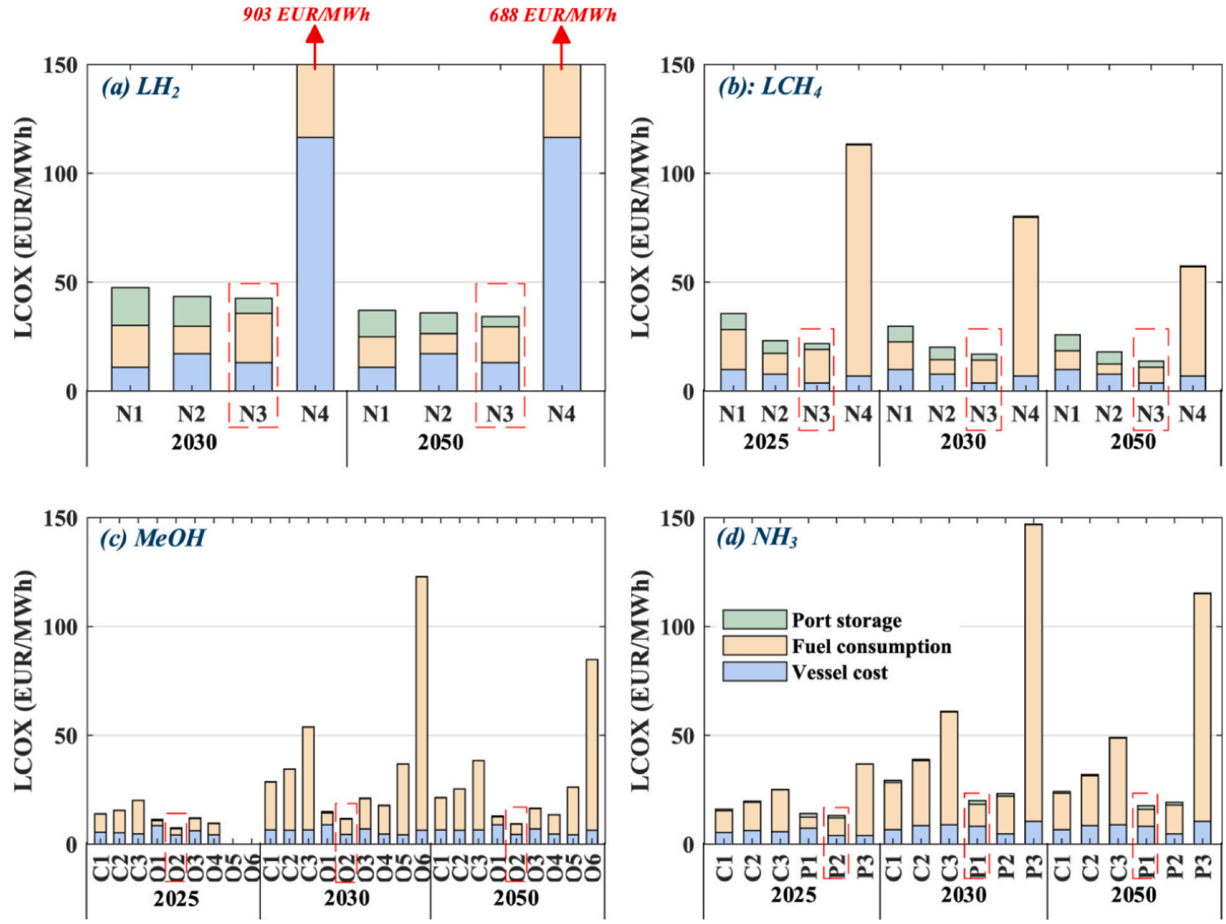

Fig. 8. Shipping cost breakdown for various electro-fuels across different ship types and size categories: (a) liquid hydrogen, (b) liquid methane, (c) methanol, and (d) ammonia. Red dashed rectangles show the ship type with the lowest costs. The LCOXs of LH_2 shipping via N4 in 2030 and 2050 are 903 and 688 EUR/MWh, respectively, which are not fully shown as they are significantly higher than the magnitude of other ship options. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Note: Techno-economic specifications for different ship types and size categories are provided in Table S2. Detailed results of shipping cost breakdown are listed in **Table S6**.

liquid methane, 133–262 EUR/MWhH$_2$ via methanol, 123–160 EUR/MWhH$_2$ via ammonia, 129–158 EUR/MWhH$_2$ via MCH, and 110–140 EUR/MWhH$_2$ via DBT, all of which are higher than the domestic LCOH (73–120 EUR/MWhH$_2$ for hydrogen and 92–154 EUR/MWhH$_2$ for liquid hydrogen). These results suggest that hydrogen imports are less cost-effective than domestic hydrogen production.

Fig. 10(a) shows the relative contributions of production, shipping, and reconversion to the overall import LCOH for various hydrogen

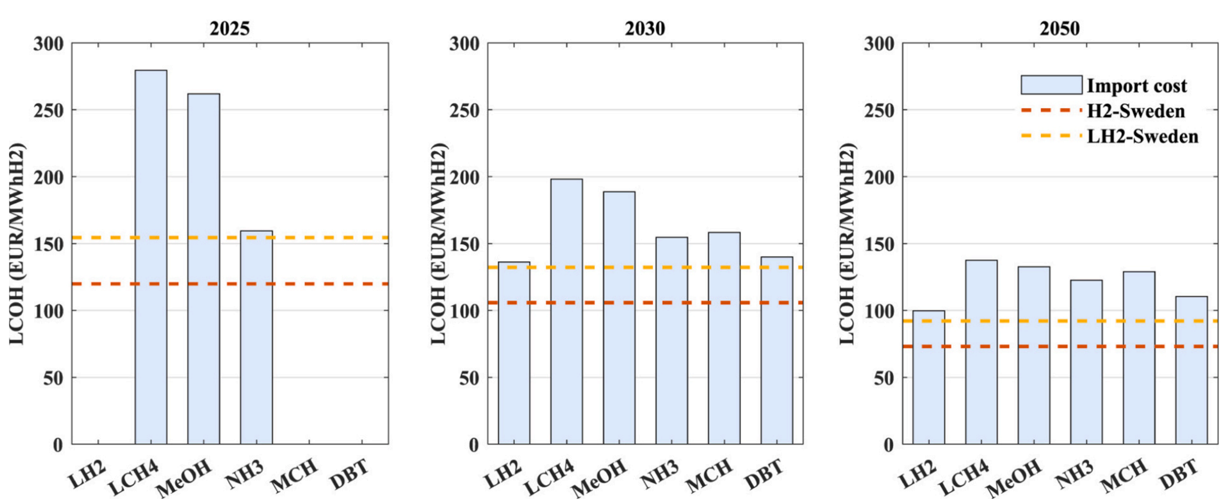

Fig. 9. Import LCOH for various hydrogen carriers from China to Sweden, shown as bars, compared with domestic production costs of hydrogen (H_2-Sweden) and liquid hydrogen (LH_2-Sweden), indicated by dashed lines, in 2025, 2030, and 2050.

Note: shipping costs for LOHCs using different ship options are detailed in **Fig. S5**, and the overall cost breakdown for various hydrogen carriers is shown in **Fig. S6**.

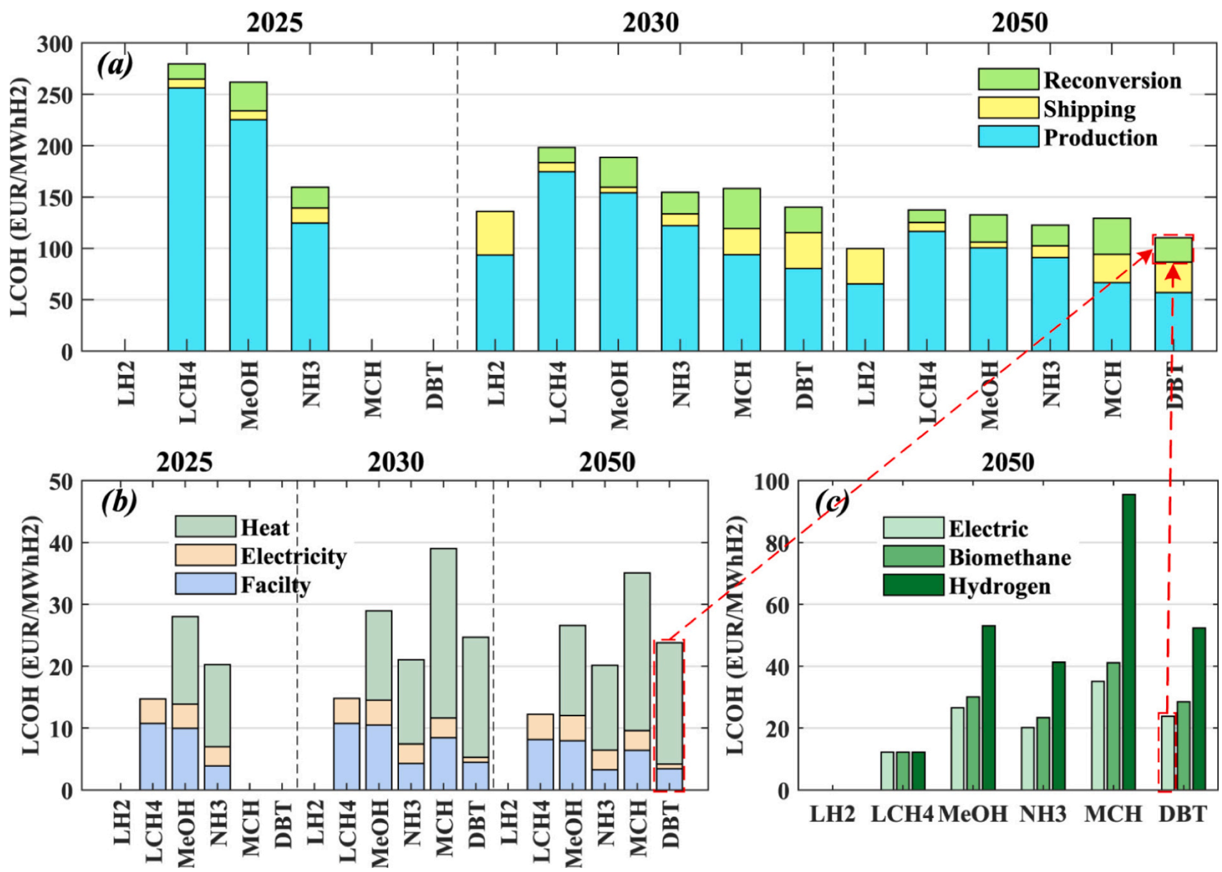

Fig. 10. Import LCOH breakdown for various hydrogen carriers from China to Sweden in 2025, 2030, and 2050. (a) overall cost breakdown of production, shipping and reconversion based on electric boilers, (b) reconversion cost breakdown including facility, electricity and heat components based on electric boilers, and (c) reconversion cost comparison based on different heating sources, where "Electric", "Biomethane" and "Hydrogen" represent electric boilers using electricity, gas boilers using biomethane, and gas boilers using reconverted hydrogen, respectively.
Note: the efficiency of electric boiler and gas boiler is taken as 0.98 and 0.78, respectively [42].

carriers. The reconversion costs and proportion during 2025–2050 are 12–15 EUR/MWhH_2 (5%–9%) for methane, 27–29 EUR/MWhH_2 (11%–20%) for methanol, 20–21 EUR/MWhH_2 (13%–16%) for ammonia, 35–39 EUR/MWhH_2 (25%–27%) for MCH, and 24–25 EUR/MWhH_2 (18%–22%) for DBT. Although importing methane, methanol, and ammonia for direct use is more cost-effective than domestic production, these electro-fuels are not cost-competitive for hydrogen transport due to their high additional reconversion costs and reconversion hydrogen losses. Among them, liquid methane as a hydrogen carrier exhibits the highest LCOH, as the reconversion rate from methane to hydrogen (~80%$_{LHV}$) is significantly lower than that of ammonia (91%$_{LHV}$) and methanol (87%$_{LHV}$) [42], leading to lower delivered hydrogen. In contrast, liquid hydrogen without reconversion becomes the most promising carrier for global hydrogen trade, followed by DBT with low reconversion losses [77].

Fig. 10(b) further presents the reconversion cost breakdown for various hydrogen carriers, including the facility, electricity, and heat components. Except for methane via autothermal reforming, the heat component accounts for the largest proportion of reconversion costs, ranging from 50% for methanol to 82% for DBT. Particularly, the dehydrogenation processes of LOHCs require substantial heat demand (12–14 kWh$_{th}$/kgH_2), so identifying a cost-effective heat source for reconversion is a key opportunity to improve their overall cost-effectiveness.

Additionally, Fig. 10(c) compares the reconversion costs based on different heating sources, including electric boiler, gas boiler using either biomethane or reconverted hydrogen. Reconversion costs using electric boilers are 20%–22% lower than gas boilers with biomethane, and 60%–84% lower than gas boilers with hydrogen, implying that it is inefficient to consume valuable imported hydrogen merely to supply heat for its own reconversion. Instead, the imported hydrogen should be prioritized for hard-to-abate sectors where its role is non-substitutable.

3.4. Generalization analysis

The abovementioned results are based on an annual hydrogen production of 100 million kgH_2/year and a shipping distance of 10,050 nautical miles from Zhanjiang Port, China to Stenungsund Port, Sweden, indicating that hydrogen imports are not cost-effective compared to domestic production. However, variations in production scale and shipping distance can significantly affect transport costs and the overall import costs. Accordingly, this study further generalizes these impacts on the cost-effectiveness of seaborne hydrogen imports versus domestic production, providing a more comprehensive perspective and identifying opportunities for profitable hydrogen imports.

Fig. 11(a) shows the import LCOH for various hydrogen carriers versus domestic LCOH across varying annual hydrogen production scales, ranging from 10 to 1000 million kgH_2/year. At an annual hydrogen production of 10 million kgH_2/year, the import LCOH through all hydrogen carriers is higher than domestic production costs and significantly higher than those at larger production scales. This indicates that small-scale hydrogen and electro-fuel production is not cost-effective for long-distance trade. The import costs gradually decrease with the increase of production scale, as larger scales lead to higher vessel utilization factors and lower shipping costs. The comparative patterns observed at 50 million kgH_2/year are consistent with the

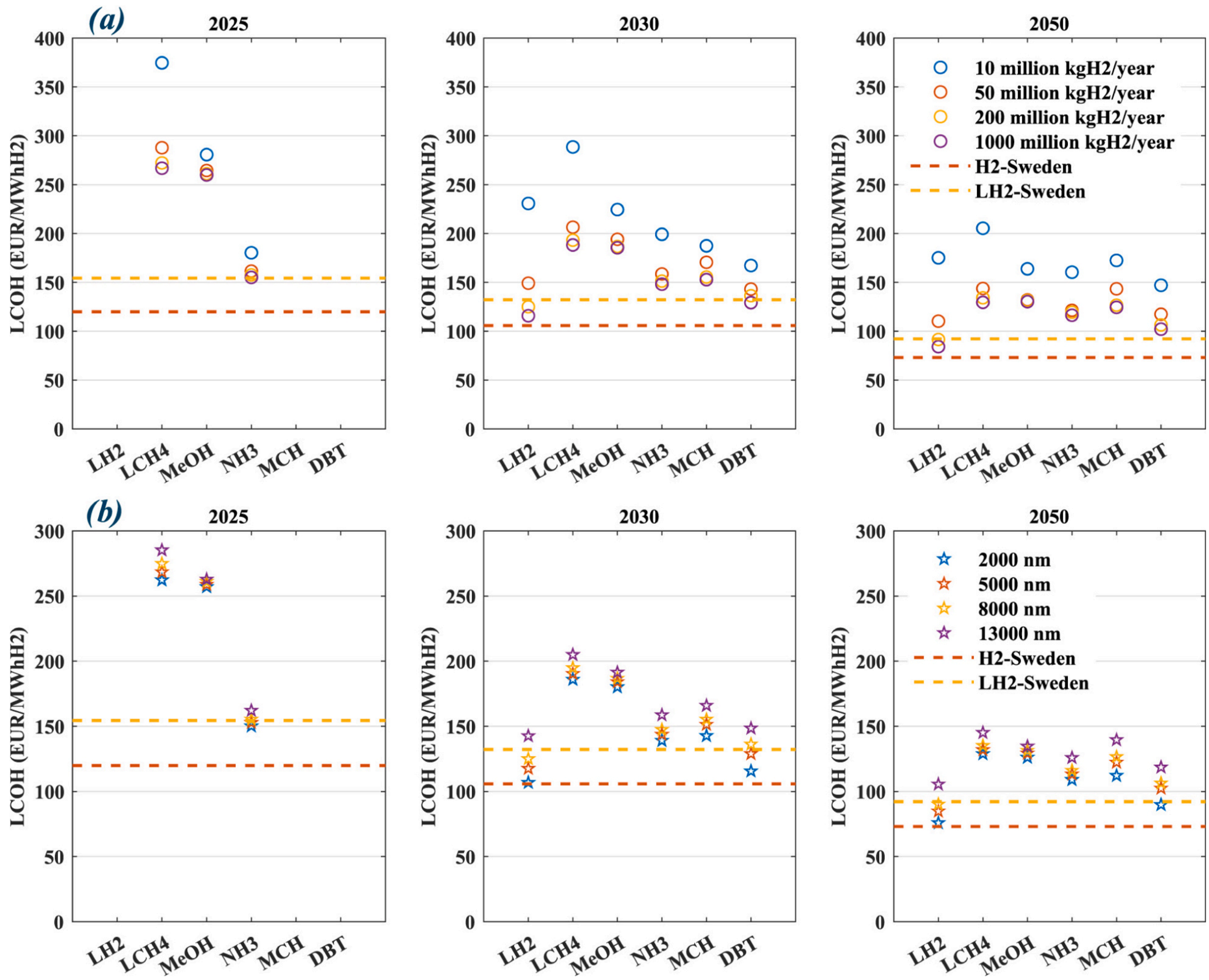

Fig. 11. Import LCOH for various hydrogen carriers from China to Sweden, versus domestic LCOH of hydrogen (H2-Sweden) and liquid hydrogen (LH2-Sweden), in 2025, 2030, and 2050, across (a) varying hydrogen production scales: 10, 50, 200, and 1000 million kgH_2/year, and (b) different shipping distances: 2000, 5000, 8000, and 13,000 nautical miles (nm).

baseline case. Notably, at production scales of 200–1000 million kgH_2/year (at least twice the baseline), the import costs of liquid hydrogen become lower than its domestic production costs in 2030 and 2050. Therefore, these generalized results suggest that scaling up production is a potentially feasible solution to improve the cost-effectiveness of hydrogen imports.

Fig. 11(b) shows the import LCOH for various hydrogen carriers versus domestic LCOH across different shipping distances. Generally, shorter shipping distances reduce fuel consumption and improve vessel utilization efficiency, leading to lower shipping costs. When the shipping distance is 2000 nautical miles (e.g., Morocco to Sweden), 5000 nautical miles (e.g., the United States to Sweden), and 8000 nautical miles (e.g., Argentina, India, or South Africa to Sweden), importing liquid hydrogen becomes more cost-effective than its domestic production in 2030 and 2050. Notably, DBT-based and ammonia-based hydrogen imports are also cost-competitive with domestic production at shipping distances of 2000–5000 nautical miles. However, when the shipping distance increases to 13,000 nautical miles (e.g., North China, or Australia to Sweden), none of the hydrogen carriers are cost-effective compared to domestic production.

Overall, long shipping distances hinder the cost-effectiveness of importing hydrogen from China to Sweden. In contrast, sourcing hydrogen from countries, such as Morocco, which benefit from both shorter shipping distances to Sweden and abundant renewable energy potential, could be another viable solution to improve the economics of hydrogen imports.

3.5. CO_2 emissions assessment

Fig. 12 presents the equivalent CO_2 emission of importing electro-fuels and hydrogen from China to Sweden compared to domestic production. The CO_2 emissions of producing various hydrogen carriers in China in 2025 are 360–540 gCO_2eq/kWh, varying with their total electricity consumption, while the figures for Sweden are only 40–60 gCO_2eq/kWh, owing to significantly higher carbon intensity of China's power grid (670 gCO_2eq/kWh) than Sweden's power grid (26 gCO_2eq/kWh). However, with the ongoing low-carbon transition of China's power grid, the CO_2 emissions of hydrogen carrier production in China in 2030 and 2050 will decline to 260–360 gCO_2eq/kWh and 60–115 gCO_2eq/kWh, respectively, narrowing the emission gap with the Sweden case. Moreover, transporting and reconverting hydrogen carriers also lead to additional CO_2 emissions, though these are comparatively lower than the production stage.

The emission gap between seaborne imports and domestic production within the EU may influence the cost-effectiveness of importing hydrogen and electro-fuels, according to the Carbon Border Adjustment Mechanism [78], which is the EU's tool to put a fair price on carbon emitted during the production of carbon-intensive goods that are

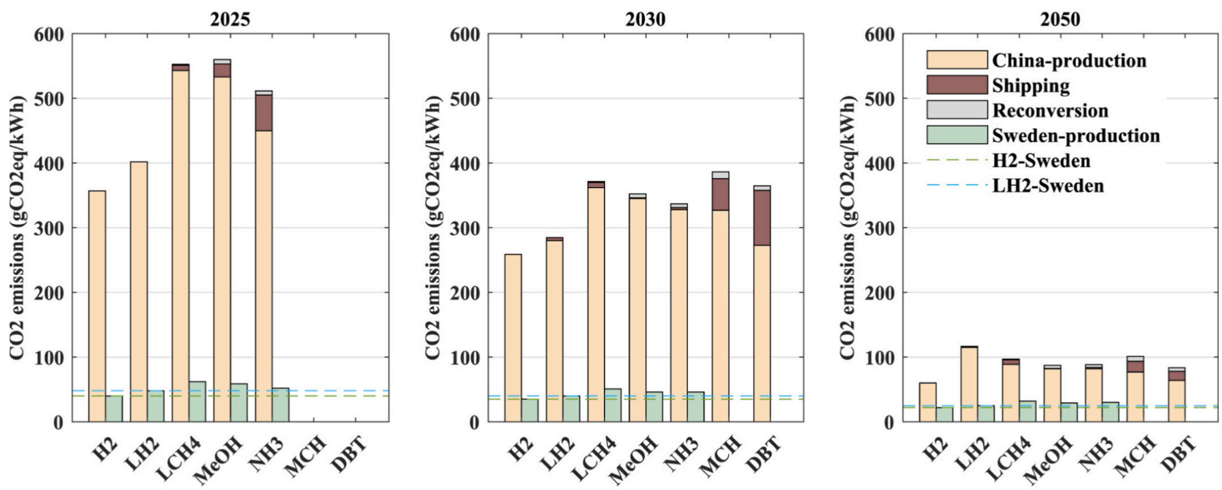

Fig. 12. CO_2 emissions (gCO_2eq/kWh) of importing hydrogen carrier from China to Sweden, compared to domestic production of hydrogen (H2-Sweden) and liquid hydrogen (LH2-Sweden).
Note: the method for CO_2 emissions evaluation, along with the carbon intensity of each energy source used in hydrogen carrier production, and the emission factors for fuel consumption during shipping, are presented in **Table S5**.

entering the EU. If this carbon price is implemented in 2025 and exceeds 75–100 EUR/tCO_2, importing electro-fuels from China could become more expensive than domestic production in Sweden. Furthermore, as the emission gap narrows over time, the carbon price thresholds for cost-effective imports in 2030 and 2050 will increase to 85–120 EUR/tCO_2 and 230–420 EUR/tCO_2, respectively.

3.6. *Uncertainty & sensitivity analysis*

Uncertainties are inherent across the entire energy supply chain, including production, storage, transport and reconversion, particularly when evaluating future scenarios. These uncertainties encompass a wide range of factors, such as the cost of power generation technologies, the technical and economic performance of energy conversion units, new-built ship costs, and electricity/fuel prices. Incorporating these uncertainties into techno-economic assessment is essential to avoid biases caused by fixed assumptions and parameters, thus providing more comprehensive and robust results to support informed and resilient decision-making by stakeholders.

Fig. 13 presents the levelized cost ranges of importing electro-fuels and hydrogen, versus their domestic production, accounting for the joint effects of all uncertainties. The import LCOH ranges across all hydrogen carriers are 115–390 EUR/$MWhH_2$ in 2025, 100–300 EUR/$MWhH_2$ in 2030, and 70–220 EUR/$MWhH_2$ in 2050. The uncertainties enable the import LCOH to deviate from the benchmark values, as shown in Fig. 9, by 72%–138% in 2025, 69%–155% in 2030, and 66%–168% in 2050, respectively. In 2025, using ammonia as hydrogen carrier could be more cost-effective than domestic hydrogen production in optimistic scenarios. By 2030 and 2050, all hydrogen carriers could outperform domestic liquid hydrogen or hydrogen production in the most optimistic scenarios. Furthermore, importing methane, methanol, and ammonia for direct use remains cost-effective under most scenarios.

Fig. 14 illustrates the variation ranges of levelized cost of hydrogen imports attributed to individual parameter uncertainties. Uncertainties in onshore wind CAPEX, system-level WACC, electrolyzer efficiency and CAPEX, LOHC material costs, and reconversion rates result in significant cost variations, ranging from −13% to +14%, highlighting that these parameters are the most decisive factors in determining the cost-effectiveness of hydrogen imports. Specifically, increasing the WACC from 4.2% to 6.1% in 2030 raises the overall import LCOH by 13.4%, while decreasing it from 4.2% to 2.5% reduces the LCOH by 5.7%. It must be acknowledged that the feasible uncertainty ranges for each parameter across different time horizons are derived from existing literature, so the variation ranges caused by each parameter depend on not only their inherent sensitivity but also the data availability.

Fig. 15 further demonstrates how individual parameter uncertainties, excluding those associated with universal assets, affect the relative cost-effectiveness among different hydrogen carriers, and between seaborne hydrogen imports and domestic production. In 2025, if the reconversion rate of ammonia increases from 0.141 to 0.16 kgH_2/$kgNH_3$, ammonia-based hydrogen imports become more cost-effective than domestic liquid hydrogen production. In 2030, decreasing the CAPEX of hydrogen liquefaction from 32,400 to 25,300 EUR/(kgH_2/h) enables liquid hydrogen imports to be more cost-effective than domestic production, while lowering the DBT material cost from 2 to 1.3 EUR/kg enables it to outperform liquid hydrogen, although it remains more expensive than domestic production. In 2050, increasing the reconversion rate of methanol and MCH enables them to outperform ammonia, while all hydrogen carriers are less cost-effective than domestic production under individual uncertainties.

4. Discussion and conclusion

Recognizing the growing interest in global hydrogen trade, this study conducts a comprehensive techno-economic assessment of importing electro-fuels and hydrogen carriers (liquid hydrogen, liquid methane, methanol, ammonia, MCH, and DBT) from Zhanjiang Port, China to Stenungsund Port, Sweden via deep-sea shipping, compared with domestic production across present and future time horizons (2025, 2030, and 2050). Notably, country-specific CAPEX and WACC for renewables and electrolyzer systems, as well as the selection of ship type and size category specific to each hydrogen carrier are incorporated into the techno-economic assessment.

The study shows that, although Sweden holds superior wind potential and lower electricity prices, the production costs of all electro-fuels in China are lower than those in Sweden across all time horizons. This is primarily due to higher country-specific CAPEX and WACC for Sweden. Thus, this study highlights that the regional differences in renewable energy potential and electricity price alone are not decisive in determining hydrogen production costs, while country-specific CAPEX and WACC for renewable and electrolyzer systems are equally critical.

Including transport costs, importing ammonia, methane, and methanol from China for direct use is more cost-effective than domestic production in Sweden, indicating that China's production cost advantages are sufficient to offset long-distance shipping costs. In contrast, due to the low volumetric energy density and costly cryogenic storage

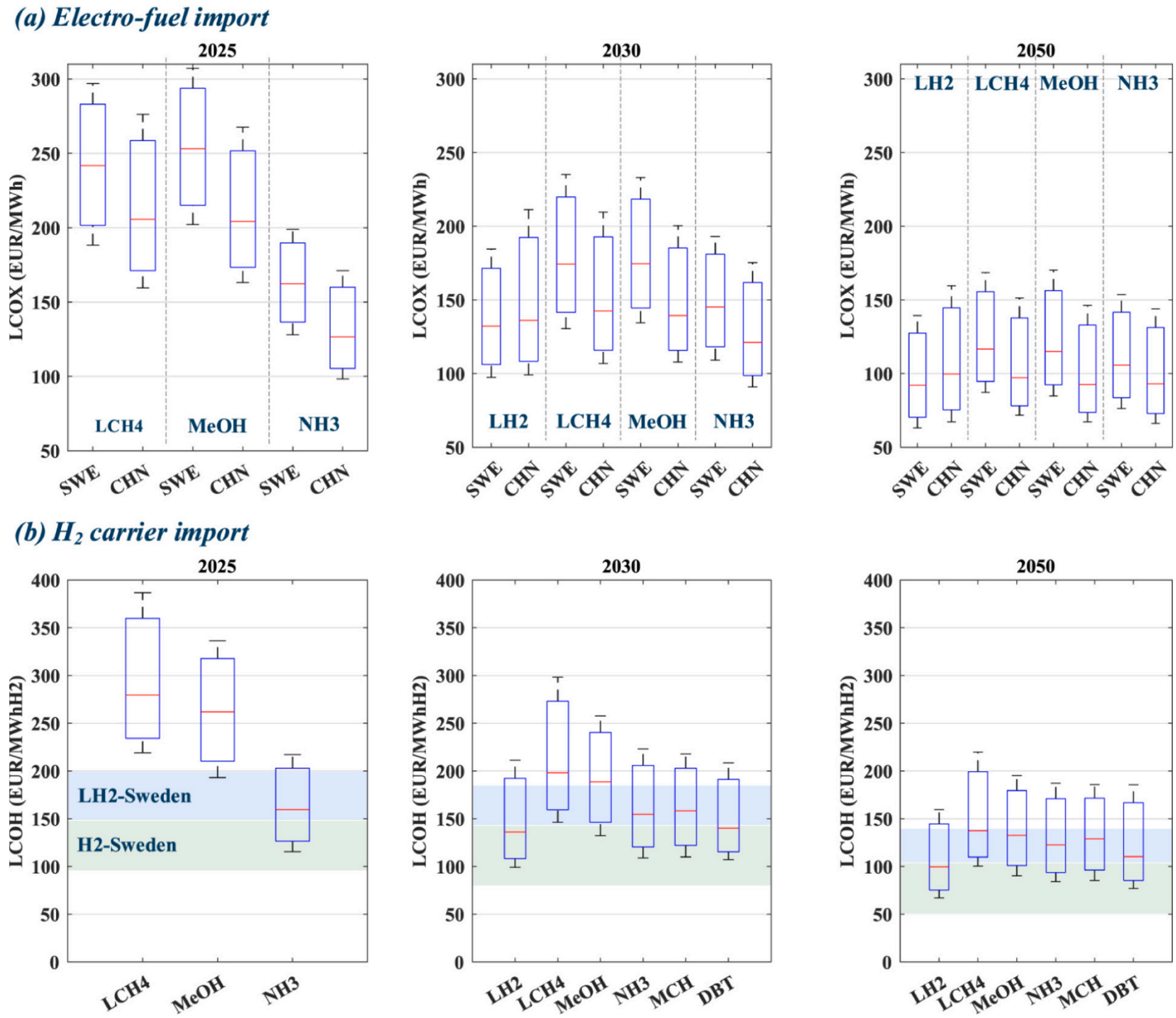

Fig. 13. Levelized cost ranges for (a) importing electro-fuels from China to Sweden, versus their respective domestic production, and (b) importing hydrogen carriers from China to Sweden, versus the domestic production of hydrogen (H2-Sweden) and liquid hydrogen (LH2-Sweden), in 2025, 2030, and 2050, accounting for the joint effects of all uncertainties.

conditions for liquid hydrogen, importing liquid hydrogen results in higher costs than domestic production in Sweden. However, the liquid hydrogen pathway offers the advantage of negligible additional cost and conversion losses for re-gasification compared to the chemical reconversion processes required for other electro-fuels [20], making it more favorable for hydrogen import applications.

Among the electro-fuel options, ammonia exhibits the lowest import cost, consistent with the findings of Hank et al. [17], Pfennig et al. [32], and Johnston et al. [23]. The cost advantage of ammonia over carbon-based electro-fuels (methane and methanol) is due to the significantly lower cost of nitrogen feedstock sourced from air separation units, compared to CO_2 feedstock from DAC. However, the cost-competitiveness of carbon-based electro-fuels could improve under several scenarios: (i) large-scale deployment of DAC projects results in rapid cost reductions via learning effects, (ii) cheaper and fossil-free carbon sources like CO_2 from bioenergy with carbon capture (BECC) are available [79], and (iii) CO_2 from the reconversion of methane and methanol could be captured and recycled to production sites for reuse [42].

For hydrogen carrier scenarios where all electro-fuels need to be reconverted to hydrogen, all import options in base cases are more expensive than domestic production, due to the high additional costs and hydrogen losses associated with reconversion. In line with the findings of Hong et al. [19], Moritz et al. [31], and Kenny et al. [36], this study also suggests that importing electro-fuels for direct use is more economically attractive than importing hydrogen. However, a key challenge lies in the currently limited demand for the direct use of electro-fuels, primarily due to their low technology readiness levels. Transport sectors such as aviation and shipping are expected to become major consumers of electro-fuels [56], underscoring the importance of research & development in technologies like ammonia- and methanol-fueled internal combustion engines and fuel cells. These advancements are essential to support the transition towards fossil-free alternative fuels.

To generalize the findings from the specific case study and identify opportunities for cost-effective hydrogen imports, this study further investigates the impacts of varying production scales and shipping distances on the cost-effectiveness of hydrogen imports. Production scale is influenced by region-specific factors such as land availability and renewable energy potential, while shipping distance depends on the exporting country and the shipping route. These generalized insights reveal that both scaling up production to 200 million kgH_2/year and shortening shipping distances to below 8000 nautical miles are feasible strategies for reducing overall import costs, potentially making liquid- and DBT-based hydrogen imports cost-competitive with domestic production.

Variations		2025		2030		2050	
Components	**Uncertainty Parameters**	**Pessimistic**	**Optimistic**	**Pessimistic**	**Optimistic**	**Pessimistic**	**Optimistic**
Electricity sources	CAPEX_onshore wind	5.96%	-4.44%	7.43%	-5.49%	10.62%	-7.99%
	CAPEX_offshore wind	0.00%	0.00%	0.00%	0.00%	0.00%	-0.05%
	CAPEX_PV	0.00%	0.00%	1.35%	-1.06%	3.12%	-2.08%
	Electricity price	0.00%	0.00%	1.92%	-0.49%	3.41%	-1.05%
	WACC	13.89%	-5.58%	13.35%	-5.67%	13.71%	-6.21%
Electrolyser	Energy consumption	4.01%	-2.76%	4.07%	-2.86%	3.84%	-2.72%
	CAPEX	5.00%	-5.07%	5.43%	-5.84%	4.58%	-5.09%
DAC	Energy consumption	0.00%	-4.35%	1.14%	-0.52%	0.30%	-0.43%
	CAPEX	0.00%	0.00%	0.00%	-1.20%	0.00%	-0.63%
H2 Liquefaction	Energy consumption	NA	NA	2.73%	-2.01%	1.50%	-1.82%
	CAPEX	NA	NA	4.13%	-3.18%	2.76%	-5.16%
	CAPEX_LH2 tank	NA	NA	3.42%	-1.72%	2.34%	-2.18%
NH3 Synthesis	Conversion rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Energy consumption	0.00%	-0.70%	0.00%	-0.73%	0.00%	-0.76%
	CAPEX	0.00%	-1.62%	0.00%	-1.83%	0.00%	-2.33%
	CAPEX_NH3 tank	0.16%	0.00%	0.29%	0.00%	0.36%	0.00%
MeOH Synthesis	Conversion rate	0.46%	0.00%	0.45%	0.00%	0.43%	0.00%
	Energy consumption	1.09%	-0.02%	1.46%	-0.04%	1.73%	-0.03%
	CAPEX	0.00%	-0.74%	0.00%	-0.96%	0.00%	-1.06%
	CAPEX_MeOH tank	0.15%	-0.02%	0.18%	-0.05%	0.21%	-0.04%
CH4 Synthesis	Conversion rate	1.04%	-2.99%	1.01%	-2.90%	0.98%	-2.82%
	Energy consumption	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	CAPEX	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	CAPEX_CH4 tank	1.03%	-0.25%	1.46%	-0.35%	2.11%	-0.51%
CH4 liquefaction	Energy consumption	0.41%	-0.41%	0.53%	-0.54%	0.63%	-0.63%
	CAPEX	1.20%	0.00%	1.68%	0.00%	2.43%	0.00%
DBT hydrogenation	Conversion rate	NA	NA	1.72%	-1.40%	1.66%	-2.37%
	Energy consumption	NA	NA	0.03%	-0.25%	0.03%	-0.27%
	CAPEX	NA	NA	0.00%	-0.97%	0.00%	-0.70%
MCH hydrogenation	Conversion rate	NA	NA	0.00%	0.47%	0.00%	-2.55%
	Energy consumption	NA	NA	0.19%	-0.27%	0.09%	-0.19%
	CAPEX	NA	NA	0.00%	-0.48%	0.00%	-0.45%
NH3 Reconversion	Reconversion rate	0.00%	-10.66%	0.00%	-10.56%	0.00%	-10.30%
	Energy consumption	3.36%	0.00%	3.58%	0.00%	4.61%	0.00%
	CAPEX	0.50%	0.00%	0.57%	0.00%	0.55%	0.00%
MeOH Reconversion	Reconversion rate	0.00%	-13.38%	0.00%	-12.79%	0.00%	-12.21%
	Energy consumption	0.00%	-0.57%	0.00%	-0.84%	0.00%	-1.21%
	CAPEX	0.18%	0.00%	0.26%	0.00%	0.29%	0.00%
CH4 Reconversion	Reconversion rate	0.00%	-4.21%	0.00%	-4.12%	0.00%	-4.06%
	Energy consumption	0.91%	0.00%	1.32%	0.00%	1.94%	0.00%
	CAPEX	3.53%	0.00%	4.98%	0.00%	5.45%	0.00%
DBT dehydrogenation	Reconversion rate	NA	NA	3.74%	-0.89%	3.61%	-0.86%
	Energy consumption	NA	NA	2.75%	-0.30%	3.56%	-0.38%
	CAPEX	NA	NA	0.00%	-0.72%	0.00%	-0.70%
	CAPEX_DBT tank	NA	NA	0.10%	0.00%	0.50%	0.00%
	CAPEX_DBT material	NA	NA	2.70%	-4.08%	11.33%	-4.14%
MCH dehydrogenation	Reconversion rate	NA	NA	0.00%	-9.28%	0.00%	-9.01%
	Energy consumption	NA	NA	1.26%	-1.16%	1.45%	-1.45%
	CAPEX	NA	NA	0.00%	-4.45%	0.00%	-4.18%
	CAPEX_MCH tank	NA	NA	0.69%	-0.24%	0.42%	-0.49%
	CAPEX_MCH material	NA	NA	0.93%	-0.92%	1.14%	-1.05%
Ship	CAPEX	0.64%	-0.42%	1.58%	-1.06%	2.09%	-1.40%
	Fuel price	0.72%	-0.48%	0.76%	-0.51%	1.74%	-2.08%

Fig. 14. Variation ranges in the levelized cost of hydrogen imports attributed to individual parameter uncertainties under pessimistic and optimistic settings, in 2025, 2030, and 2050. Variations related to universal assets, including electricity sources, electrolyzer, and ship, are derived from the average variation across all hydrogen carriers. Variations associated with each synthesis and reconversion unit are based on the respective hydrogen carriers.

Regarding the uncertainties included in the techno-economic assessment, this study considers optimistic and pessimistic values for key parameters across the entire supply chain, including energy supply, hydrogen production, electro-fuel synthesis, shipping, and reconversion. However, several uncertainties are not fully captured, including the inter-annual variability of renewable energy potential and electricity tariffs, the technical feasibility and safety risks of large-scale liquid hydrogen storage and transport, as well as hard-to-anticipate uncertainties embedded in assumptions about future scenarios, especially those related to emerging technologies such as DAC, LOHCs, and LH_2 tankers. Although this study indicates that, in the future, liquid hydrogen is likely to become a relatively less expensive option for global

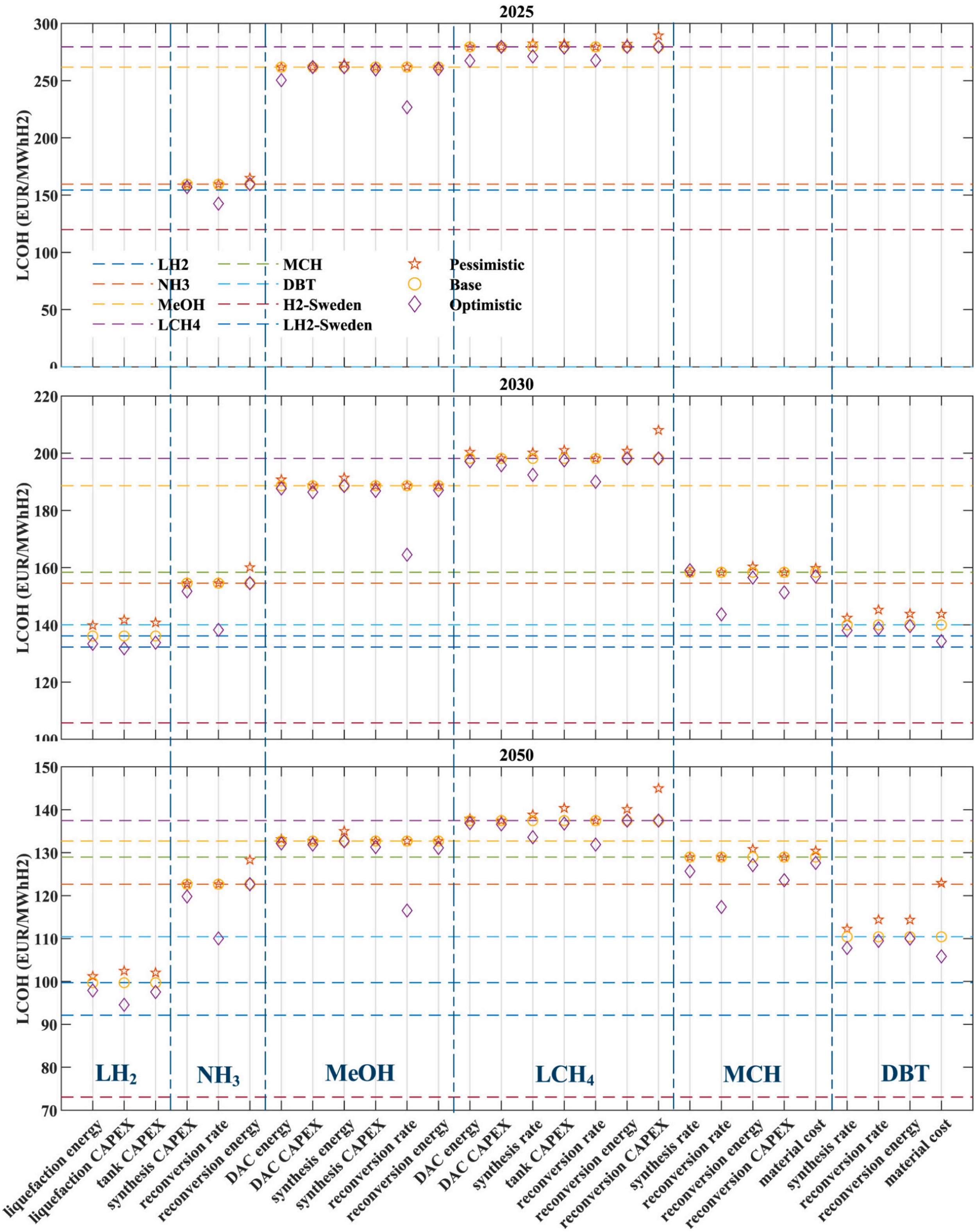

Fig. 15. Variations in the levelized cost of hydrogen imports for each hydrogen carrier resulting from individual parameter uncertainties, in 2025, 2030, and 2050. Three different markers indicate the levelized costs under pessimistic, base, and optimistic parameter settings, respectively, while dashed lines represent the benchmark values of hydrogen imports and domestic production. The circular markers representing the base levelized costs of each hydrogen carrier are always on their respective dashed lines. This figure illustrates how individual parameter uncertainties shape the relative cost-effectiveness ranking among hydrogen carriers, as well as between seaborne hydrogen imports and domestic production.

hydrogen trade compared with other hydrogen carriers, its practical viability and cost-effectiveness will hinge on whether large-scale LH_2 tankers can reach technical maturity from 2030. Additionally, the economic competitiveness among various hydrogen carriers, and between seaborne imports and domestic production, could evolve differently with uncertainties in future technological progress. For instance, efficiency improvement and cost reduction for hydrogen liquefaction, DAC, and dehydrogenation reactions could reshape the relative cost-effectiveness of liquid hydrogen, methane and methanol, and LOHCs, respectively. It is worth mentioning that the primary objective of techno-economic assessments for future scenarios is not to accurately forecast the future, but rather to offer comprehensive and evidence-based insights that support more informed and resilient decision-making by stakeholders.

Regarding the overall techno-economic assessment, several potential revenues and costs, that are not fully considered in this study, may affect the cost-effectiveness of hydrogen imports. During the process of water electrolysis, oxygen is generated as a by-product, which can be collected and sold to sectors such as healthcare and chemical industries. Additionally, electro-fuel synthesis releases substantial amounts of waste heat via exothermic reactions, which can be recovered and sold to industrial and heating end-users. Revenues from both oxygen sales and waste heat utilization could offset electro-fuel production costs. Moreover, this study reveals that importing hydrogen carriers from China leads to higher CO_2 emissions than domestic production in Sweden, due to China's more carbon-intensive electricity grid and shipping-related emissions. According to the Carbon Border Adjustment Mechanism, importing goods into the EU may need to pay for the embedded carbon emissions generated during production [78]. EU Emissions Trading System (EU ETS) also claims that vessels calling at EU ports need to pay for their CO_2 emissions [80]. These emission-related costs could have a significant impact on the economic feasibility of global hydrogen trade, which warrant further in-depth investigation.

Another limitation of the study is that it does not differentiate between electrolyzer technologies such as proton exchange membrane (PEM) and solid oxide electrolysis cell (SOEC), since realistic country-specific cost data is currently only available for alkaline electrolyzers [49]. Variations in investment costs, hydrogen production efficiency, and operational characteristics across different electrolyzer technologies significantly affect the overall system configurations and hydrogen production costs [60], and hence the overall cost-effectiveness of global hydrogen trade. Additionally, this study assumes a unified system-level WACC and does not fully capture potential technology-specific WACC differences among assets such as wind power, solar PV power, and electrolyzer. Incorporating technology-specific WACC could affect the relative cost-effectiveness of different assets and the cost-optimal system configurations, which can be further explored when more technology-specific WACC data for hydrogen projects become available.

CRediT authorship contribution statement

Yi He: Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Selma Brynolf:** Writing – review & editing, Validation, Supervision, Resources, Funding acquisition, Conceptualization. **Fayas Malik Kanchiralla:** Writing – review & editing, Validation, Software, Methodology, Formal analysis, Data curation. **Maria Grahn:** Writing – review & editing, Validation, Supervision, Resources, Funding acquisition, Conceptualization.

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. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2026.127627.

Data availability

Data will be made available on request.

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