Techno-economic assessment of hydrogen energy in the electricity and transport sectors using a spatially-disaggregated global energy system model

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Hydrogen (H_2) receives much attention to mitigate climate change and strengthen energy security. This study analyzed the economic viability of H_2 energy with a focus on the electricity and transport sectors, employing a spatially-disaggregated global energy system model. The simulated period is from 2015 to 2050. The results suggest that, in addition to strict CO_2 regulation policies, significant cost reductions of H_2 production technologies would be prerequisite to accelerate H_2-fueled power generation globally. By contrast, deployment of fuel-cell vehicle appears more sensitive to vehicle price, rather than the H_2 supply costs. Among H_2 production processes, gasification of coal and reformation of natural gas, combined with carbon capture and storage, are estimated to be cost-efficient, implying opportunities for H_2 trade between coal and gas resource countries and energy consumers. Yet, again, improved economics are necessary for maritime H_2 transportation, including liquefied H_2; otherwise, H_2 trade would be limited to pipeline. If maritime H_2 trade becomes economically viable, natural gas and coal in Australia could be competitive feedstock for Japan. Long-term policies to support research and development are crucial to commercialize H_2 supply system.

Keywords : Hydrogen power generation, Fuel cell vehicle, Energy carriers, Energy system model, Climate change mitigation

1. Introduction

Energy-related CO_2 accounts for a large part of the global greenhouse gas emissions; therefore, to achieve the 2 degrees Celsius target in the Paris Agreement, the energy system needs to be significantly decarbonized while taking into consideration energy security and economic viability. Hydrogen gains great attention from the security and environmental perspectives as it can be produced from a wide range of energy resources in a low-carbon manner. Japan possesses world-class hydrogen-related technologies, and the Japanese government has indicated that the country will lead the world in realizing a hydrogen-based society.[1)] Based on this background, this study discusses the economic viability of hydrogen, with a focus on the Electricity and Transport sectors, for achieving the long-term global climate target. We employ a spatially-disaggregated global energy system model to explicitly consider the costs related to global hydrogen supply, including production, trade and consumption processes.

The characteristics of this study can be summarized into the following three points: (1) It develops a bottom-up spatially-disaggregated energy system model to consistently analyze the global energy supply-demand balances and assess the cost-competitiveness of various low-carbon technologies; (2) It analyzes the location of hydrogen production and transportation infrastructure by using the spatially-detailed model (totaling 363 nodes, which is by far detailed compared to the major existing models (around 11~100 nodes); and, (3) It undertakes a comprehensive review of hydrogen-related technologies focusing on hydrogen carriers as well as electricity and transport sectors. With regard to the third point, the modeled hydrogen carriers are liquefied hydrogen, ammonia, methanol, and methylcyclohexane (MCH); the modeled hydrogen power generation technologies are hydrogen turbine, fuel cells, ammonia-fired, and methanol-fired technologies; and the modeled transport technology is hydrogen fuel cell vehicles (FCV).

The concept design and economic assessment for hydrogen energy systems have been carried out for many years, beginning with the WE-NET Project[2)]. There also have been techno-economic assessments[3) 4) 5) 6)]. Compared to these existing analyses, the novelty of this study includes the following two points: (1) analysis of hydrogen supply-demand considering spatial factors (such as hydrogen production sites and hydrogen transportation infrastructure) in detail, and (2) analysis of economic conditions to accelerate the deployment of hydrogen-related technologies.

2. Research Methodology

2.1 Framework for evaluation

This study develops a spatially-disaggregated global energy system model, with reference to Reference [7)] (**Fig. 1**). The number of nodes in the world is 363. The analysis period is from 2015 to 2050, with five representative years (2015, 2020, 2030, 2040, and 2050). The duration of each representative year is three years for 2015, eight years for 2020, and one term of 10 years for 2030 to 2050. The model is a linear programming model that explicitly considers the energy production, conversion, and consumption processes. The objective function is the discounted total system cost (assumed discount rate of 5%), consisting of energy production, conversion, transportation, and storage, and energy-saving costs. The constraints of the model include energy resource limits, energy demand and supply balances, and CO_2 emissions regulations. This model is built as a large-scale mathematical

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programming problem, with 294 million constraints and 148 million variables. For greenhouse gases, this model only calculates energy-related CO_2 emissions.

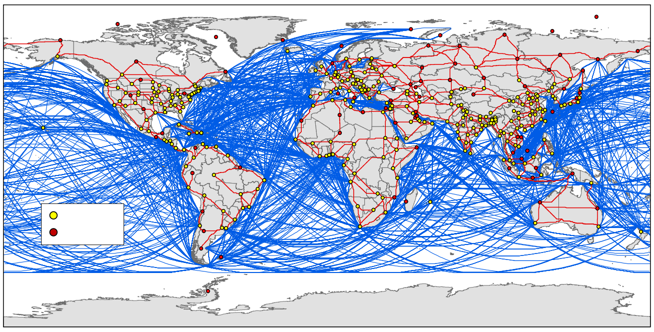


Fig. 1 Regional division and energy transportation routes

Detailed regional divisions enable the model to analyze the regional characteristics of energy demand and supply as well as the economic viability of long-distance energy transportation. We selected the regional divisions considering energy resources endowments, energy consumption structure, and geopolitical and socioeconomic perspectives including the level of economic development. The model has two types of nodes: city node and supply node. City nodes have energy demand, while energy production, conversion and storage facilities can be installed at the both types of nodes. As for temporal resolution, a different resolution is applied to the electricity and non-electricity sectors. For the electricity sector, the model balances demand and supply, taking into account seasonal typical load curves (One calendar year is divided into 64 time slots = 4 representative seasonal days × 8 time slots/Representative days × 2 weather patterns). The non-electricity sector only balances annual demand and supply. Two weather patterns include “fine day” and “cloudy day” to incorporate the variability of solar power generation. Energy resources and technologies in this model are summarized in **Table 1**. Energy supply technologies are modeled using a bottom-up approach based on engineering data. Hydrogen production technologies include the gasification of coal and oil, steam reforming of natural gas, shift reaction of carbon monoxide, and water electrolysis. Note that this model formulates shift reaction separately from gasification and steam reforming processes to optimize the synthesis gas consumption (the synthesis gases produced through gasification or steam reforming processes can also be used for methanol synthesis and dimethyl ether synthesis, in addition to shift reaction). This model considers two types of CO_2 capture technologies: pre-combustion for gasification plants and integrated gasification combined cycle (IGCC) power generation plants, and post-combustion for other thermal power generation plants. CO_2 capture facilities can be equipped with new power plants and gasification plants, as well as retrofitted to existing plants in this model. As for demand-side technologies, we employ a top-down approach, with the exception of passenger vehicles and trucks. This model considers five types of energy demand (solid fuel, gaseous fuel, liquid fuel, electricity and commercial heat) and two types of service demand (passenger transportation demand and freight transportation demand). The definition of commercial heat is based on the world energy balances published by the International Energy Agency (IEA).

Table 1 Modeled energy carriers and technologies

Primary energy	Crude oil, Natural gas, High grade coal, Low grade coal, Nuclear, Solar, Wind, Hydro, Black liquor, Wooden biomass, Energy crop, Bagasse
Secondary energy	Electricity, Hydrogen (=H_2), Gasoline, Diesel, Other oil products, Syn. oil, Ammonia (=NH_3), Methanol (=MeOH), Ethanol, Dimethyl ether (=DME), Methylcyclohexane (=MCH), Carbon monoxide, Commercial heat
Final demand	Electricity, Solid fuel, Gaseous fuel, Liquid fuel, Passenger road transport, Freight road transport, Commercial heat
Energy trade	Crude oil (pipeline, tanker), Gasoline (tanker), Diesel (tanker), Natural gas (pipeline, LNG tanker), High grade coal (rail, ship), H_2 (pipeline, liquefied H_2 tanker), MeOH (pipeline, tanker), MCH (tanker), NH_3 (rail, tanker), CO_2 (pipeline), Electricity (High voltage transmission)
Transformation	***Power generation***: Coal-fired, IGCC, Gas turbine, Gas combined cycle, Oil-fired, Nuclear, Solar PV, Wind, Hydro, Biomass-fired, H_2-fired, Fuel cell, NH_3-fired, MeOH-fired, Pumped hydro, Battery ***H_2 production***: Coal gasification, Natural gas reforming, Oil gasification, Shift reaction, Water electrolysis ***Other***: MeOH synthesis, Methane synthesis, Nitrogen separation, NH_3 synthesis, H_2 separation from NH_3, Hydrogenation of Toluene, Dehydrogenation of MCH, DME synthesis, H_2 liquefaction, H_2 regasification, Oil refinery, Natural gas liquefaction, Natural gas regasification. Biomass liquefaction, coal boiler, Gas boiler, Oil boiler
Carbon capture & storage	***Capture***: Post-combustion at power plants (except for IGCC), Pre-combustion at gasification plants and IGCC plants ***Storage***: Enhanced oil recovery, Depleted gas well, Aquifer, Enhanced coal bed methane recovery
Vehicle (passenger, freight)	Gasoline vehicle (internal combustion engine [=ICE], hybrid, plug-in hybrid), Diesel vehicle (ICE, hybrid), CNG vehicle (ICE, hybrid), Electric vehicle, H_2 fuel cell vehicle
Vehicle fueling	Gas station, CNG station, H_2 station, EV charging station

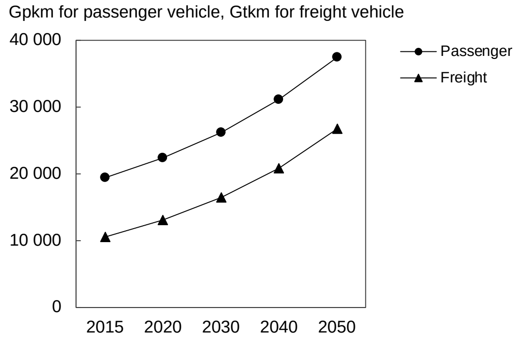
2.2 Key assumptions

2.2.1 Final demand

Fig. 2a shows the global passenger and freight transportation demand, and **Fig. 2b** shows final energy demand excluding the vehicle transportation demand. We estimated passenger and freight transportation demand referring to References[8) 9) 10)]. Final energy demand assumptions (solid fuel, gas fuel, liquid fuel, electricity, commercial heat) are based on the reference scenarios in IEEJ Outlook [8)].

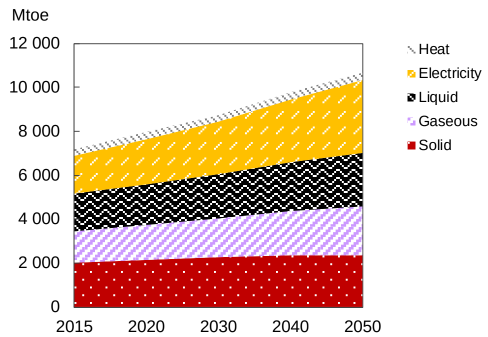
2.2.2 Fossil fuel resources

Fig. 3 illustrates the aggregated global fossil fuel supply curves in this study. We estimated fossil fuel resources, with reference to reserves[11] and undiscovered resources[12]. Assumptions for production costs are based on References[13,14]. See Section 2.2.3 for costs for transportation, such as tankers, pipelines and liquefaction plants.



(a) Road transport

(Note: Gpkm=109 passenger-km, Gtkm=109 ton-km)



(b) Other sectors

Fig. 2 Assumed global final demand

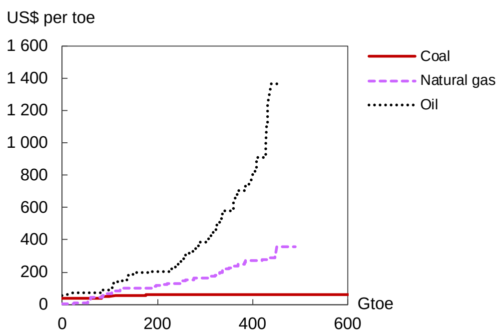


Fig. 3 Assumed global production cost curves for fossil fuels

2.2.3 Energy conversion and transportation

Assumptions for power generation technologies are based on Reference [15,16], and hydrogen production costs rely on Reference [17,18]. Detailed assumptions for 2050 are summarized in Table 2-**Table 3**. Installed capacity for energy conversion technology (except for pumped hydro storage) is determined through cost-optimization. Pumped hydro in this study is fixed at the current installed capacity. We also impose upper and lower capacity limits for nuclear power plants considering policy directions and social factors in each country. For example, aggregated global nuclear capacity is set at an upper limit of 766GW and lower limit of 138GW.

As for hydrogen transportation, this model considers hydrogen pipeline and hydrogen carriers, including liquefied hydrogen (tanker), MCH (tanker), ammonia (rail and tanker), methanol (pipeline and tanker). Economic assumptions for these carriers are based on the "2030 research and development case" from Reference [18] (**Fig. 4**). Note that this figure includes the costs for converting hydrogen into carriers and *vice versa*, such as liquefaction and regasification costs for liquefied hydrogen, ammonia synthesis and hydrogen separation costs for ammonia, hydrogenation and dehydrogenation costs for MCH, and methanol synthesis and reforming costs for methanol. Cost assumptions for liquefied natural gas (LNG) are also illustrated in this figure as a reference. Maritime transportation of hydrogen carriers is relatively expensive compared to LNG tanker; this is mainly due to the costs for hydrogen conversion (i.e., liquefaction plant costs). It also should be noted that electricity costs (for liquefaction of natural gas and hydrogen) and heat costs (for dehydrogenation of MCH) are assumed to be 50US$/MWh and 470US$/Mtoe, respectively, in **Fig. 4**; yet, in model calculation, these costs are estimated endogenously.

Table 2 Assumptions for power plants in 2050

Technology	Capital cost [US$/kW]	Efficiency [%]
Coal-fired	750-2500	42-46
IGCC	900-2900	46-50
CCGT	550-1100	58-61
Nuclear	2000-6600	--
Solar PV	720-1450	--
Wind	1100-2170	--
Hydro	1220-6400	--
Biomass-fired	1500-2340	35
H_2-fired	550-1100	55
NH_3-fired	550-1100	55
MeOH-fired	550-1100	55
Fuel cell	2500	60
Electrolyzer	870	80
Pumped hydro	570-1560	75
Battery	1200	85

Note: Efficiency indicates cycle efficiency for pumped hydro and battery, while conversion efficiency for other plants. The ranges indicate the minimum and maximum values among the nodes.

Table 3 Cost assumption for H_2 production process in 2050

Process	Annualized capital cost [US$/toe/year]
Coal gasification	98
Natural gas reforming	120
Shift reaction	8

Note: Capital costs are expressed as cost per unit of inputs (e.g., coal gasification indicates the cost per 1 toe of coal inputs). See Table 2 for electrolyzer cost.

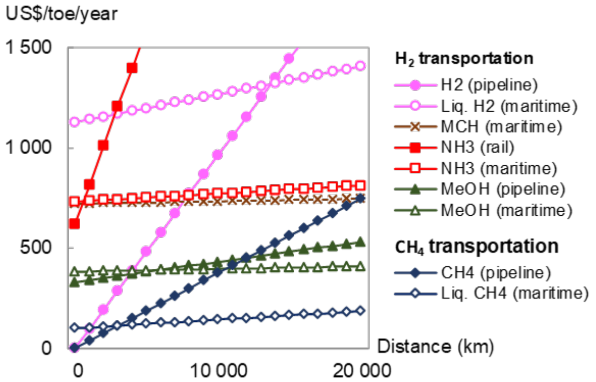


Fig. 4 Cost assumption for hydrogen and natural gas transportation

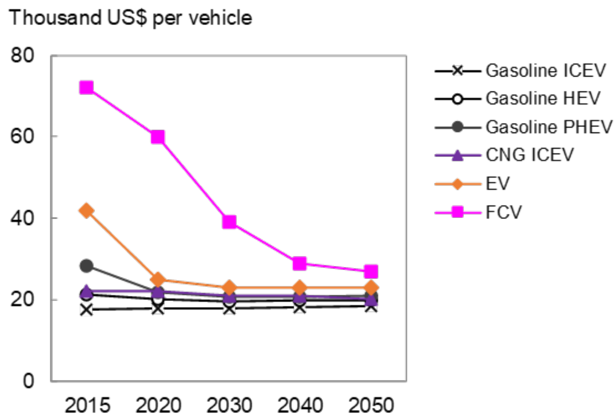


Fig. 5 Cost assumption for passenger vehicle

2.2.4 Passenger and freight vehicle

Assumed vehicle types are summarized in **Table 1**, and the assumptions for vehicle costs are shown in **Fig. 5**. In estimating vehicle cost in the future, this study broke down each vehicle into key components (engines, motors, batteries, fuel cell systems, etc.) and predicted the costs for each component based on Reference [19) 20)]. Fuel economy for each type of vehicle is estimated referring to Reference [21)]. We assume that fuel economy of ICEV, HEV, and FCV improves by 20% from 2015 to 2050[22)] while that of EV remains at the current level.

In addition to vehicle cost, this model considers the cost for filling facilities (**Table 1**). For hydrogen stations, one station is assumed to be built for every 900 units of FCV, based on the 2030 target in Reference [23)]. Assumed construction cost per station is 3 million US$ in 2015 and 2 million US$ after 2030.

2.3 Scenario Setting

This study analyzed two scenarios (Base scenario, 2-degree scenario). Both scenarios consider global CO_2 emission constraints (**Fig. 6**). The constraint for the former scenario is based on the "Reference scenario" in the IEEJ Outlook[8)], where the global annual emissions increase to 12Gt-C/year by 2050 (+37% compared to 2015). The constraint for the 2-degree scenario is based on the "2 degree scenario" in IEA ETP2017[25)]; global emissions are assumed to be reduced to 2.9Gt-C/year by 2050 (-67% compared to 2015). The 2-degree scenario in this study also imposes constraints on the emissions in developed countries (the emissions in each G8 country are assumed to be equal or lower than emissions from 2015 up till 2020, and reduced linearly by 80% from 2020 to 2050). Note that the emissions pathway in IEA ETP2017 [25)] includes energy and industrial CO_2. We estimated the emissions constraint for the 2-degree scenario (**Fig. 6**) by estimating future industrial process emissions and deducting it from the ETP2017 pathway.

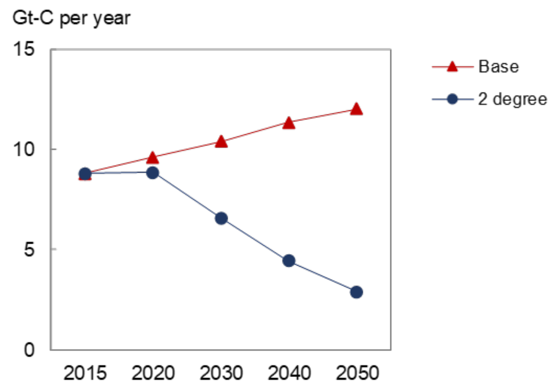


Fig. 6 Constraint on global energy-related CO_2 emissions

3. Results and Discussion

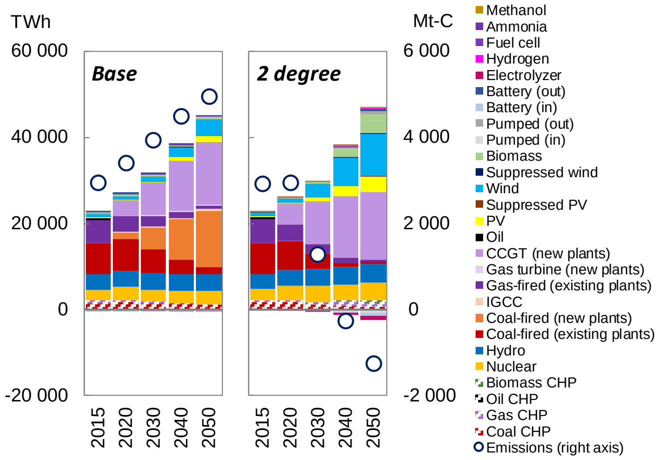
3.1 Long-term Feasibility of Introducing Hydrogen Energy

3.1.1 Electricity/transport sectors

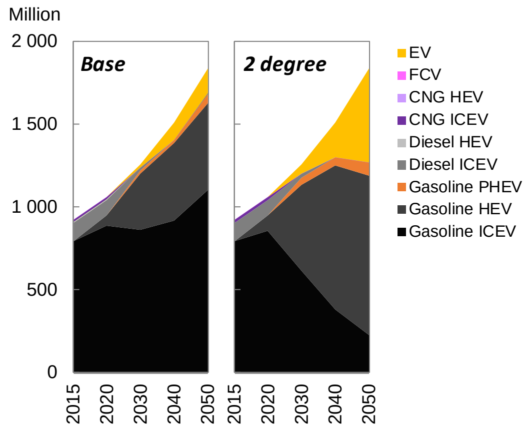
To begin with a description of the outcome, the use of hydrogen as fuel for power generation and automobiles is limited in either scenario (**Fig. 7a-b**). To accelerate the use of hydrogen in these sectors, significant level of cost reduction would be necessary as discussed in Section 3.2.

In the electricity sector, coal-fired power generation remains as a dominant fuel in the Base scenario. Variable renewable energy (VRE, such as wind and solar power generation) shows a gradual increase from 2030-2040, driven by the construction cost reductions and rising fossil fuel prices. In the 2-degree scenario, by contrast, it becomes necessary to significantly reduce coal-fired generation after 2020 and accelerate low-carbon power sources to achieve the CO_2 reduction regulation. Various low-carbon technologies (such as wind power, solar power, biomass, natural gas-fired power generation) grow in the global aggregated mix although regional mix varies, reflecting local resource endowments and costs (Appendix 1). Regionality would be an important factor for designing low-carbon system in a cost-efficient manner. Note that CO_2 capture for natural-gas and biomass-fired generation contributes to preventing CO_2 from being emitted into the atmosphere. CO_2 emissions in the power generation sector is largely reduced from 2015 to 2050. Although hydrogen turbines are also introduced in the 2-degree scenario, its share of power generation remains modest, at just 0.8% of the global generation share (total global installed capacity is 133GW) even in 2050. Ammonia-fired generation and methanol-fired generation are also introduced by 2050; yet, installed capacity are 10GW and 1GW, respectively, and do not have a significant impact on global power demand and supply.

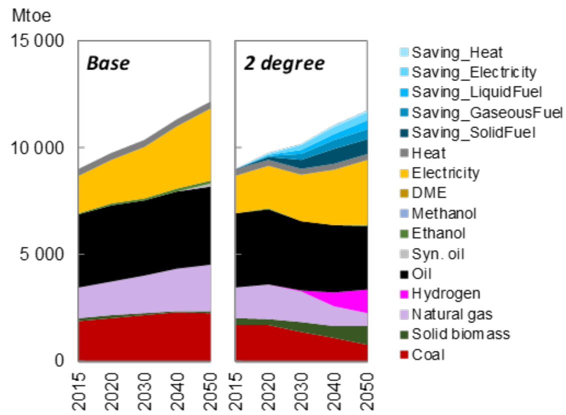
In the passenger vehicle stock, hybrid and electric vehicles grow in both scenarios, driven by vehicle price reductions (**Fig. 7b**). The transition to electric vehicles is significant in the 2-degree scenario, with EV reaching approximately 30% of global passenger vehicle stock in 2050. Another interesting point is that hybrid vehicles remain as the main technology even under the latter scenario. Gasoline HEV accounts for 50% of global passenger vehicle stock in 2050; and, similarly for freight vehicles, diesel hybrid trucks largely grow, reaching approximately 90% of global stock by 2050. This would be because of higher fuel economy compared to conventional ICEV and relatively cheaper vehicle prices compared to EV or FCV (**Fig. 5**). These results imply that petroleum-based HEVs remain as a cost-competitive option by 2050. However, it should be noted that the vehicle choice in this model is based on economic viability, and other consumer preferences (such as brand, travel distance, etc.) are not taken into consideration. Also, our model is a partial equilibrium model, which is not able to analyze the impact of vehicle choice on the whole economy. Future work should include these factors to discuss the future vehicle market from various perspectives.



(a) Global power generation and electricity emissions



(b) Global passenger vehicle stock



(c) Global final energy consumption

Fig. 7 Simulation results under the Base and 2 degree scenarios

3.1.2 Final energy consumption excluding automobiles

Our model assumes that natural gas or hydrogen can satisfy gaseous fuel demand, and natural gas dominates in the Base scenario (natural gas part in **Fig. 7c**). By contrast, alternative fuel use (hydrogen), combined with energy saving, grows in the 2-degree scenario, reaching 65% of total gaseous fuel consumption in 2050. This result implies that hydrogen could be an important option in the end-use sector (except for vehicles), such as heat supply by hydrogen boilers and city gas mixed with hydrogen; future study needs to examine the cost-competitiveness of hydrogen for other types of demand.

3.1.3 Hydrogen production and transportation

The cost-optimal hydrogen production processes in the 2-degree scenario are estimated to be coal gasification and natural gas reforming and shift reaction of carbon monoxide, together accounting for 95% of global hydrogen production processes in 2050. Most hydrogen is produced near demand centers, and hydrogen pipeline dominates hydrogen transportation infrastructure. Ammonia and methanol transportation appeared in the latter scenario in 2050; yet, they make up just 7% of global hydrogen carrier trade (on heat content basis). Maritime transportation of liquefied hydrogen and MCH are also estimated to be limited.

3.2 Sensitivity analysis for the cost assumptions of hydrogen-related technologies

The implication of Section 3.1 is that there are economic challenges for hydrogen carriers as a fuel in the electricity and transport sectors. In this section, therefore, we conduct a sensitivity analysis on hydrogen production and transportation costs as well as passenger FCV prices, with the aim of assessing the cost reductions required for boosting market penetration.

3.2.1 Sensitivity analysis for hydrogen production and transportation costs

Based on the assumptions of the 2-degree scenario, additional analysis is carried out on five cases related to hydrogen production and transportation costs. Specifically, the construction costs of hydrogen production facilities (gasification reactor, reformer, and electrolyzer) and the production and transportation facilities for liquefied hydrogen and MCH (hydrogen liquefaction and gasification plants, liquefied hydrogen tankers, toluene hydrogenation and MCH dehydrogenation plants, port facilities) are drawn up for 2015-2050 based on the following hypothetical situations: (1) No changes (HRef); (2) 30% reduction (H30%red); (3) 50% reduction (H50%red); (4) 70% reduction (H70%red); and (5) 90% reduction (H90%red). Construction costs are assumed to be fall linearly in situations (2) to (5) (the assumptions for the HRef case are the same as the 2-degree scenario in Section 3.1). This study does not assume any cost reductions for ammonia and methanol as their production and maritime transportation technologies are relatively matured. We also do not assume cost reductions for hydrogen pipeline. The assumed hydrogen transportation cost in 2050 in the H90%red case is shown in **Fig. 8**. Compared to **Fig. 4**, we can see larger cost reductions for liquefied hydrogen than MCH. This is because construction costs dominate liquefied hydrogen while variable costs are the main components for MCH.

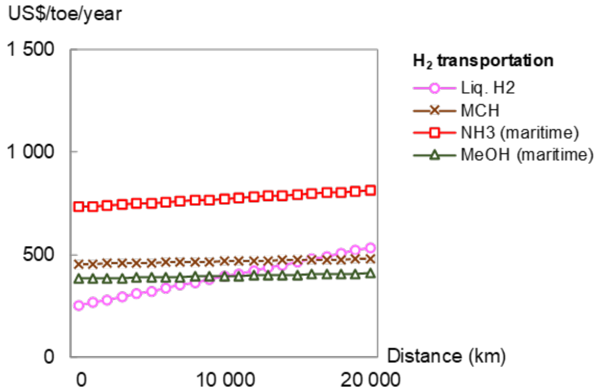


Fig. 8 Annualized cost assumption for maritime hydrogen transportation in 2050 under the H90%red case

Hydrogen use grows significantly in the power generation sector under lower “hydrogen supply cost” cases (**Fig. 9**). Share of hydrogen-fired in 2050 increases to 3% of global power generation in the H50%red case, and 10% in the H90%red case. It also grows in Japan, reaching 12% in 2050 in the H90%red case. Average global hydrogen price in 2050 (weighted average price based on hydrogen consumption at each node) is estimated to be 680US$/toe (0.18US$/Nm^3) in the HRef case, and falls to 540US$/toe (0.14US$/Nm^3) in the H90%red case. In contrast, deployment of passenger FCV is limited regardless of hydrogen production and transportation costs. FCV may not be economically rational, although FCV price reductions have already been incorporated (**Fig. 5**). This point is considered separately in Section 3.2.2.

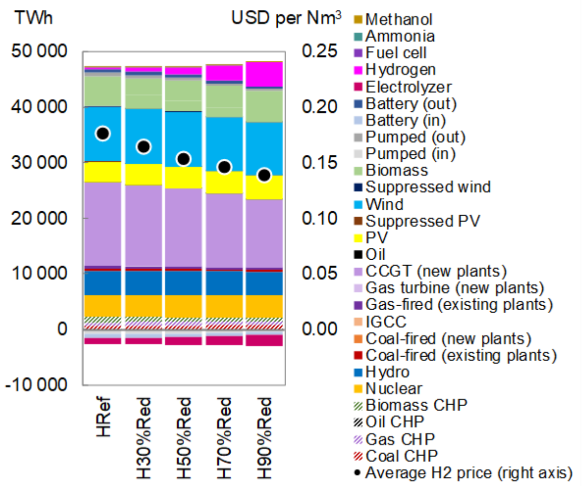


Fig. 9 Global power generation and weighted-average hydrogen price in 2050 under the H_2-cost variant cases

3.2.2 Sensitivity analysis for the vehicle price of fuel cell vehicles (passenger vehicles)

This section conducts an additional analysis of the vehicle price: four FCV prices in each of the cases in Section 3.2.1 (therefore, total 20 cases are examined: 5 cases of hydrogen production and transportation costs × 4 cases of FCV vehicle prices). The assumption for FCV vehicle prices is the same as **Fig. 5** until 2040, while the following assumptions are set for 2050: (1) 27,000 US$/unit (FcvRef); (2) 22,000 US$/unit (Fcv22k$); (3) 21,000 US$/unit (Fcv21k$); (4) 20,000 US$/unit (Fcv20k$). The assumption for (1) is the same as **Fig. 5**; for (3), it is assumed that FCV prices fall to the same level as EV by 2050; for (4), it is assumed that they fall to the level of gasoline hybrid vehicles (HEV).

Simulation results suggest that deployment of FCV appears more sensitive to vehicle price, rather than the H_2 supply costs (Fig. 10). For example, in the FcvRef and Fcv22k$ cases, deployment of FCV is estimated to be limited regardless of hydrogen production and transportation costs. By contrast, FCV grows in the Fcv21$ and Fcv20$ cases; particularly in the Fcv20$ case, global FCV stock reaches 480 million in 2050 even under the HRef condition. This would be because vehicle costs dominate FCV's lifecycle cost (Appendix 2). In summary, to accelerate the use of hydrogen as a fuel for passenger vehicles, it would be necessary to decrease FCV price, at least, equivalent to EV prices (as indicated in the Fcv21k$ case). The Government of Japan sets out the goal of realizing vehicle prices with the same level of price competitiveness as hybrid vehicles by 2025[23]. FCV may grows significantly if its price declines to the level of HEV as illustrated in the Fcv20k$ case.

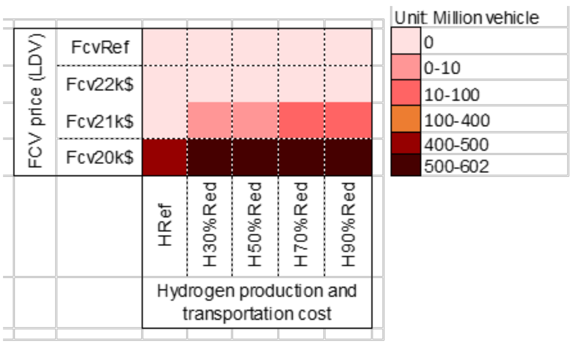


Fig. 10 Global FCV stock in 2050 under H_2-cost and FCV price variant cases

3.2.3 Hydrogen production and transportation trends in the sensitivity analysis cases

Similar to the 2-degree scenario in Section 3.1, fossil fuels account for a large part of the raw materials for hydrogen across all the sensitivity analysis cases. For example, **Fig. 11** shows the hydrogen production volume for 2050 in the H90%red & Fcv20k$ case (hydrogen supply cost falls by 90%, and FCV price is 20,000 US$/unit), coal gasification, natural gas reform and shift reaction contribute to 95% globally. There are high expectations for water electrolysis as a measure to manage excess generation from variable renewables; yet the simulation results show a relatively low market share, implying economic challenges. The cost-optimal hydrogen raw material varies depending on local resource availability. In Europe, East Asia, and Russia, coal is the main raw material. In contrast, natural gas is used in the Middle East and North Africa. In the United States, natural gas reform is used in the Gulf of Mexico region, while coal gasification dominates in other regions. In Australia, both natural gas and coal in east coast are estimated to be cost-competitive resources.

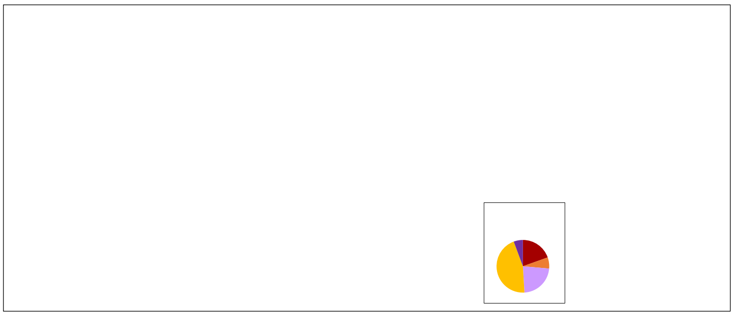


Fig. 11 H_2 production in 2050 under the H90%red & Fcv20k$ case

As for maritime hydrogen transportation, signification cost reductions would be necessary. Pipeline transportation accounts for 90% of global hydrogen trade under the HRef~H70%red cases (regardless of FCV prices). Maritime transportation of liquefied hydrogen grows under the condition of H90%red. For example, in the H90%red & Fcv20k$ case, the traded liquefied hydrogen increases to 184Mtoe (713 billion Nm^3) in 2050 globally, accounting for 40% of total hydrogen carrier trade (the rest of the traded hydrogen carriers was through pipeline). In liquefied hydrogen trade, energy consumers such as Japan and India become the main importers, while coal and natural gas resource countries such as Australia, Qatar, and Indonesia become exporters. For Japan, natural gas in Australia, Papua New Guinea, and Alaska, U.S., as well as low-grade coal in Australia, are estimated to be cost-competitive hydrogen raw materials (**Fig. 11- Fig. 12**). In addition, hydrogen produced from natural gas and coal in Sakhalin (through pipelines) could be competitive resources.

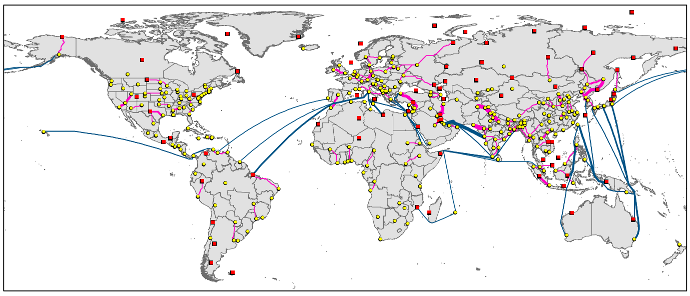


Fig. 12 H_2 pipeline and liquefied H_2 trade in 2050 under the H90%red & Fcv20k$ case

4. Conclusion

This study developed a global energy system model with detailed spatial resolution, and analyzed the cost-competitiveness of hydrogen as a fuel in the electricity and transport sectors. The detailed spatial resolution enables the model to explicitly consider the costs related to hydrogen supply chain, ranging from production, transportation and consumption. The simulated period is from 2015 to 2050. The results suggest that, in addition to strict CO_2 regulation policies, significant cost reductions of H_2 production technologies would be prerequisite to accelerate H_2-fueled power generation globally. By contrast, deployment of fuel-cell vehicle appears more sensitive to vehicle price, rather than the H_2 supply costs. Among H_2 production processes, gasification of coal and reformation of natural gas, combined with carbon capture and storage, are estimated to be cost-efficient, implying opportunities for H_2 trade between coal and gas resource countries and energy consumers. Yet, again, improved economics are necessary for maritime H_2 transportation, including liquefied H_2; otherwise, H_2 trade would be limited to pipeline. If maritime H_2 trade becomes economically viable, natural gas and coal in Australia could be competitive feedstock for Japan. Long-term policies to support research and development are crucial to commercialize H_2 supply system.

Future research includes further modeling of hydrogen-related technologies, such as end-use technologies in industry and buildings sectors (hydrogen reduction steelmaking, hydrogen boilers, etc.). Improvement in the temporal resolution is also important. Explicit modeling of variable renewables, as well as exploring the conditions to boost the deployment of "renewable hydrogen" would be interesting research agenda.

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Appendix 1. Power composition in the main regions in 2-degree scenario

Fig. A1 illustrates the power generation mix in 2050 for the main regions in the 2-degree scenario. Power generation mix largely varies by regions. For example, in China and India, nuclear power as well as renewable energy (especially solar and wind power) play an important role. In Russia and Latin America, biomass contributed to 30% of generation mix. In Russia, biomass CHP (cogeneration) grows to satisfy both electricity and heat demand. On the other hand, in the United States, Middle East and North Africa, and Southeast Asia, natural gas-fired equipped with CCS significantly increased. CO_2 is stored at depleted gas wells and aquifers in these regions. In Japan, solar and wind power (104GW and 14GW respectively in 2050), as well as natural gas-fired with CCS contributed to reduce emissions. Annual CO_2 captured amounts to 48Mt-C/year (180 million tCO_2/year） in 2040, and 57Mt-C/year (210 million tCO_2/year） in 2050.

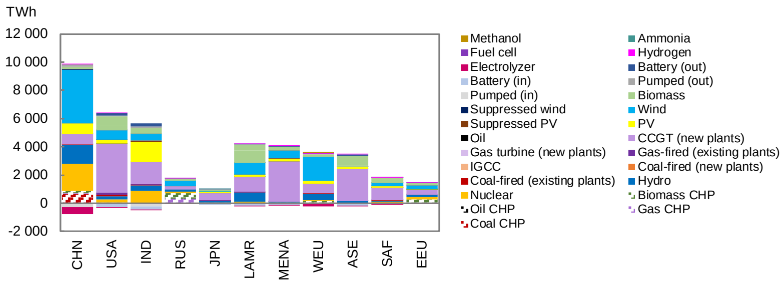

Fig. A1 Regional power generation mix in 2050 under the 2 degree scenario. Regional groupings are as follows: CHN = China, USA = United States, IND = India, RUS = Russia, JPN = Japan, LAMR = Latin America, MENA = Middle East and North Africa, WEU = Western Europe, ASE = ASEAN, SAF = Sub-Saharan Africa and EEU = Eastern Europe.

Appendix 2 Cost structure of FCVs (passenger vehicles)

According to our estimation which focuses on FCV's vehicle price and fuel costs, vehicle price dominates the total life cycle cost as illustrated in **Fig. A2**. The following assumptions were made in this estimation. Annual driving distance is 10,000 km, vehicle lifespan is 10 years, and fuel efficiency is 105km/kg-H_2 （9.4km/Nm^3） [24]. Vehicle and hydrogen prices for FCVs are assumed to follow three patterns (FCV prices of 70,000 US$/unit, 30,000 US$/unit, 20,000 US$/unit, and hydrogen prices of

1US\$/Nm^3, 0.3US\$/Nm^3, and 0.1US\$/Nm^3). In **Fig. A2**, the case of FCV price of 70,000 US\$/unit and hydrogen price of 1US\$/Nm3 is shown as “V70F1” for example.

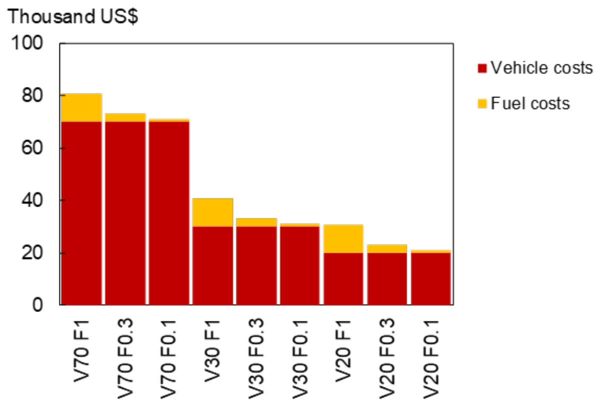

Fig. A2 Vehicle costs and life-cycle fuel costs for FCV under H_2 price and vehicle price variant assumptions. The “V70F1” assumes, for example, 70 thousand US\$ for FCV price and 1 US\$/Nm^3 for hydrogen price.

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