Exploring the cost-effective strategy for introducing hydrogen by considering hydrogen supply infrastructure in detail

Takayuki Takeshita

Ritsumeikan Global Innovation Research Organization, Ritsumeikan University, Japan

Corresponding author: “Takayuki Takeshita” <taka-t@fc.ritsumei.ac.jp>

Abstract

In this paper, a global energy systems model representing hydrogen supply infrastructure in great detail is used to assess the economic competitiveness of hydrogen and to derive the cost-effective strategy for producing, transporting, and using hydrogen under a 400 ppmv CO_2 stabilization constraint. The major findings can be summarized as follows. First, hydrogen becomes one of the important final energy carriers in the second half of the century under the CO_2 constraint. Second, the large-scale use of hydrogen begins in the industrial sector. This is because this sector requires a small hydrogen distribution network and does not require the development of refueling stations, and because cheap hydrogen end-use technologies such as hydrogen-fired boilers and furnaces are available to this sector.

Keywords: Hydrogen supply infrastructure; Local hydrogen distribution; Climate stabilization

1. Introduction

Growing concerns over global climate change have prompted proposals for significant reductions in greenhouse gas emissions. A hydrogen-based energy system, the so-called “hydrogen economy” is regarded as one of the alternative energy supply options, which could make a substantial contribution to greenhouse gas reduction. To date, several model-based scenario studies have been carried out to assess the long-term role of hydrogen in clean and sustainable future global energy systems, notable examples being Barreto et al. (2003), IEA (2005), and van Ruijven et al. (2007).

It is widely recognized that the high cost of building infrastructure for hydrogen storage, transportation, distribution, and refueling is a major barrier to its widespread diffusion. This suggests the importance of modeling such hydrogen supply infrastructure explicitly when examining the potential role of hydrogen in energy systems. In this paper, a global energy systems model representing hydrogen supply infrastructure in great detail is used to assess the economic competitiveness of hydrogen and to derive the cost-effective strategy for producing, transporting, and using hydrogen under a 400 ppmv CO_2 stabilization constraint. This constraint corresponds to the most stringent (category I) climate stabilization target analyzed in the IPCC Fourth Assessment Report (Metz et al., 2007).

This paper is structured as follows. Section 2 describes the model used in this study with particular emphasis on the modeling of hydrogen supply infrastructure. Simulation results and discussion are presented in Section 3. Finally, Section 4 concludes.

2. Model description

2.1. Overview of the model

This analysis has been carried out with a regionally disaggregated global energy model with 70 regions (hereafter referred to as REDGEM70[1]). REDGEM70 is a bottom-up type, long-term global energy systems optimization model formulated as an intertemporal linear programming problem. Fig. 1 schematically illustrates the structure of REDGEM70. With a 5% discount rate, REDGEM70 is designed to determine the optimal global energy strategy (e.g., the optimal mix of technology options) from 2000 to 2100 at 10-year intervals so that total discounted energy system costs are minimized under constraints on the satisfaction of useful energy or energy service demands, the availability of primary energy resources, the market penetration rate of new technologies, and so forth. In the model, price-induced energy saving in end-use sectors, efficiency improvement in energy conversion sectors, fuel switching to less carbon-intensive fuels, and CO_2 capture and storage (CCS) in geologic formations are the four main options for CO_2 emissions reductions.

The 70 model regions are categorized into "energy production and consumption regions" and "energy production regions." While future useful energy or energy service demands are allocated to the 48 energy production and consumption regions, all the energy activities except final energy consumption are conducted in each of the two region types in the model.

Future trajectories for scenario driving forces such as population, gross domestic product measured in purchasing power parities (GDP_{ppp}), and end-use demands are based on the "Middle Course" case B developed by International Institute for Applied Systems Analysis (IIASA)/World Energy Council (WEC) (Nakicenovic et al., 1998). The evolution of transportation activity was estimated for each passenger/freight transportation mode mainly based on Victor (1990), Schafer and Victor (2000), Azar et al. (2003), and Fulton and Eads (2004).

Fig. 2 describes the distribution of energy system components in an energy production and consumption region of REDGEM70 from its conceptual center represented as the black-colored circle. As illustrated in this figure, REDGEM70 represents the spatial structure of this type of model region in detail and considers the entire supply chain of final energy carriers, which includes primary energy production, conversion into secondary energy, interregional energy transportation, energy storage, intraregional secondary energy distribution, and final energy supply at the retail site (e.g., refueling). To represent the economics of each of these final energy supply chains in a realistic manner, the model considers the capital and operating costs separately at each stage of the fuel supply chain (excluding resource extraction) by treating the corresponding infrastructure explicitly.

For example, in the case of centralized hydrogen production, hydrogen supply

---

[1] For a more detailed description of the REDGEM70 model, see Takeshita and Yamaji (2008).

infrastructure for light-duty vehicles consists of a hydrogen production system, hydrogen storage (to meet time varying demand and assure reliable supply), a delivery system to bring hydrogen from the production site to refueling sites, and a network of refueling stations to dispense hydrogen to vehicles (Ogden and Yang, 2005).

2.2. Modeling hydrogen production and storage

REDGEM70 includes nine centralized large-scale hydrogen production technologies and two decentralized small-scale hydrogen production technologies. Table 1 shows the data for hydrogen production technologies. Model inputs on plant capital costs vary by region by multiplying the reference capital cost data assumed for North America by a region-specific location factor (see Takeshita and Yamaji, 2006, for the location factor values).

Although centralized hydrogen production plants using fossil fuels or electricity can be constructed near a demand center, the location of those using renewable or nuclear energy (except biomass pellets and scrap lumber) is constrained by resource availability or safety concerns. Such siting characteristics are represented in the model in such a manner that the cost associated with intraregional hydrogen transportation from plants to demand centers is added in the cases of renewable and nuclear-based centralized plants.

Hydrogen produced and purified at centralized plants has to be either compressed or liquefied for interregional or intraregional transportation (see Takeshita et al., 2006, for a set of techno-economic parameters for compression, liquefaction, and regasification of hydrogen). For hydrogen storage at a centralized production plant, it is assumed that while 50% of the daily flow of compressed gaseous hydrogen (GH_2) needs to be stored, 200% of the daily flow of liquid hydrogen (LH_2) needs to be stored (Yang and Ogden, 2007). The cost of hydrogen storage at a centralized production plant was estimated to be US$$_{1990}$ 400/kg for compressed GH_2 and US$$_{1990}$ 30/kg for LH_2 (Yang and Ogden, 2007).

2.3. Modeling interregional energy transportation

Possible interregional energy transportation routes are given and specified between representative cities/sites in the 70 model regions. Interregional energy transportation costs were estimated for each energy carrier and for each transportation option (e.g., pipeline, rail, and ship) as a function of transportation distance (see Fig. 3). The share of capital costs in total interregional energy transportation costs was estimated to be 85% for pipeline transportation, 75% for tanker transportation of liquefied gaseous fuels, and 67% for rail transportation and ship transportation of the other energy carriers (Takeshita et al., 2006).

REDGEM70 then identifies the economically efficient evolution path of the interregional transportation of each energy carrier. The model also determines the need for infrastructure construction for each energy transportation option and each possible route at each point in time with existing infrastructure taken into consideration.

Following Fujii (1992) and NEDO (2000), bulk energy storage facilities at a coastal terminal with a capacity of storing a week’s supply of that energy are assumed to be required for interregional energy transportation. Hence, the model considers the capital costs of coastal bulk energy storage facilities for interregional energy transportation by treating the infrastructure explicitly.

For interregional hydrogen transportation, the model considers the three options: GH_2 pipeline transportation, LH_2 tanker transportation, and LH_2 rail transportation. As shown in Fig. 3, interregional hydrogen transportation is much more costly than the interregional transportation of the other energy carriers (except electricity); its actual cost is even higher due to the high costs and energy requirements needed for compression, liquefaction, and regasification.

2.4. Modeling intraregional secondary energy distribution and refueling

Fig. 4 shows the local distribution and refueling costs associated with supplying light-duty vehicles. It is implicitly assumed that local distribution of natural gas and GH_2 is made by pipeline and that solid and liquid fuels are distributed locally by truck, except that the distribution of LNG and LH_2 to airports is by pipeline or rail tanker. For the supply of LNG or LH_2 to aircraft, two possible pathways are considered: (1) the receipt of natural gas/GH_2 via pipeline at an airport boundary followed by natural gas/hydrogen liquefaction and LNG/LH_2 supply to aircraft and (2) the receipt of LNG/LH_2 via rail at an airport boundary followed by LNG/LH_2 supply to aircraft (Brewer, 1991, pp. 340-341). Based on Ogden (1999a), Azar et al. (2000), and Nam and Totschnig (2006), local pipeline distribution of GH_2 is assumed to be available only in urban areas, and rural areas are assumed to rely on trucking of LH_2 as a means of hydrogen introduction.

In addition to their temporal development, the model takes into account the site-specific feature of local distribution costs, in particular for gaseous fuels (Azar et al., 2000). Following the approach by Ogden (1999a), local distribution costs for natural gas, GH_2, and electricity are assumed to vary depending on the demand density (in fact, the length of each spoke of the distribution network for these secondary energy forms depends on the geographic concentration of the demand): they are estimated to be lower for urban areas where a geographically concentrated demand exists (Ogden, 1999a; van Ruijven et al., 2007). Following these studies, the local distribution costs are linked to the density of final energy demands in the model.

For the difference in the cost of local pipeline/transmission line distribution by end-use sector, it is assumed that a more extensive distribution system might be needed for applications in the residential/commercial sector than for those in the transportation sector (Ogden, 1999a) and that the industrial sector is located nearer to central production sites and requires a less complicated distribution system than the other end-use sectors (Nam and Totschnig, 2006). In the light of the degree of distribution of refueling points for each mode, ranging from centralized to completely decentralized, the model considers the cost difference between transportation modes as well: the cost of local pipeline/transmission line distribution is assumed to be 60% lower for aircraft, trains, and domestic freight ships, 40% lower for buses and medium-duty trucks, and the same for two- and three-wheelers and heavy-duty trucks relative to light-duty vehicles, while local distribution is assumed to be unnecessary for international ocean freight ships. These assumptions are based on the fact that centralized refueling is the norm for fleet vehicles, which include taxis, buses, and delivery trucks (Ogden, 1999b; Srinivasan et al., 1999; Azar et al., 2000; IEA, 2005). The resulting estimates of the cost of local hydrogen pipeline distribution are well comparable to the cost assumptions in the intermediate scenario developed by van Ruijven et al. (2007). In the case of solid and liquid fuels, for simplicity purposes, the cost of local distribution by truck or rail is assumed to be the same across all end-use sectors, because transportation distance has a small effect on their local distribution costs (Amos, 1998; Simbeck and Chang, 2002).

Similar to the modeling of the interregional transportation of energy and CO_2, the model considers the capital and operating costs of local distribution and refueling separately by treating the infrastructure explicitly. The share of capital costs is assumed to be 85% for local pipeline/transmission line distribution, whereas the corresponding estimates are 33% for local truck distribution and 75% for refueling (Amos, 1998; Simbeck and Chang, 2002). Considering that the major expense is not the pipeline cost itself but installing the pipeline (Amos, 1998) and that installed pipeline capital costs are site specific (Ogden, 1999a), location factors were used to estimate the regional installed capital costs of pipelines and power transmission lines.

3. Results and discussion

3.1. Economic competitiveness of hydrogen under the climate stabilization constraint

Fig. 5 shows the evolution of the global final energy consumption under the 400 ppmv CO_2 stabilization constraint. Two findings are worth noting. First, under the stringent climate stabilization constraint, hydrogen becomes one of the important final energy carriers in the second half of the century. This implies that even if hydrogen supply infrastructure is modeled in detail, hydrogen becomes economically competitive under such a stringent climate stabilization constraint. Second, electricity, which competes with hydrogen, plays a major role throughout the century and has the largest share in the global final energy mix from 2070 onward. CO_2 mitigation technologies powered by electricity, such as heat pumps and plug-in hybrid vehicles (PHEVs), are economically highly attractive.

3.2. Cost-effective strategy for producing and transporting hydrogen under the climate stabilization constraint

Fig. 6 shows the global hydrogen production by source under the 400 ppmv CO_2 stabilization constraint, while Fig. 7 shows the global penetration rate of CO_2 capture technologies in large-scale energy conversion plants (to which CO_2 capture is assumed to be applicable). Biomass is a major source of global hydrogen production under the climate stabilization constraint. However, a constraint on sustainable biomass supply imposes a limit on the increase in the production of biomass-derived hydrogen. As a consequence, the production of natural gas-derived hydrogen grows sharply because of the low carbon content of natural gas and the low capital costs and high conversion efficiency of steam methane reforming plants.

As shown in Fig. 7, almost all the CO_2 generated from large-scale energy conversion plants is captured for sequestration in the second half of the century under the climate stabilization constraint. This is the reason why coal makes a very small contribution to global hydrogen supply (because CO_2 capture efficiency is assumed to be less than 91%) and why decentralized small-scale hydrogen production technologies are not selected.

Fig. 8 illustrates the global pattern of hydrogen production and transportation in 2060 and 2100 under the 400 ppmv CO_2 stabilization constraint. In 2060 and 2100, hydrogen production and consumption are evenly distributed around the world. It can be seen that pipeline transportation over short distances is an important means of interregional hydrogen transportation. In the year 2100, when the share of hydrogen increases further, natural gas becomes the main feedstock for hydrogen production, and LH_2 aircraft is selected, hydrogen liquefaction and LH_2 tanker transportation are done widely. A large part of the imported LH_2 is distributed locally to airports without being regasified to meet the demand for LH_2.

3.3. Cost-effective strategy for using hydrogen under the climate stabilization constraint

Fig. 9 shows the global final hydrogen consumption by sector under the 400 ppmv CO_2 stabilization constraint. Also shown are more disaggregated results. Contrary to the previous findings from Barreto et al. (2003) and van Ruijven et al. (2007), the large-scale use of hydrogen begins in the industrial sector, and hydrogen is not consumed in the residential/commercial sector. The main reason for this is that the cost of local hydrogen pipeline distribution to the industrial sector, which reflects the average distance from central hydrogen production sites to this sector, is estimated to be low. Another reason is that among the end-use sectors the industrial sector is expected to remain the largest consumer of natural gas worldwide, which would create the opportunity for hydrogen to replace natural gas. This implies that the sectoral difference in the requirement of an intraregional GH_2 distribution pipeline system has a significant impact on the competitiveness of hydrogen.

Furthermore, the heat generated from the direct combustion of hydrogen accounts for a large share of total industrial hydrogen energy use. The main reason for this is that direct hydrogen combustion technologies are assumed to have the same techno-economic characteristics as those of direct natural gas combustion technologies, i.e., a conversion efficiency of 90% on a higher heating value basis and capital costs of US$ 100/kW_{th} (Azar et al., 2003). By contrast, according to Makihira (2001) and IEA (2005), high-temperature stationary fuel cells using hydrogen as fuel gas such as solid oxide fuel cells (SOFCs) are estimated to have much higher capital costs (nine times as high as those of direct hydrogen combustion technologies even if their technological progress is considered) and a much shorter lifetime of about 10 years. This leads to the economic uncompetitiveness of high-temperature stationary fuel cells for applications in the industrial sector.

As regards the penetration of hydrogen in the transportation sector under the climate stabilization constraint, hydrogen use in this sector increases substantially, which is dominated by LH_2 aircraft and fuel cell-internal combustion engine hybrid (FCH) light-duty vehicles.

4. Conclusions

In this paper, the global energy systems model representing hydrogen supply infrastructure in great detail has been used to assess the economic competitiveness of hydrogen and to derive the cost-effective strategy for producing, transporting, and using hydrogen under the 400 ppmv CO_2 stabilization constraint. The model traces the entire hydrogen supply pathway from hydrogen production through dispensing to end users. The major findings obtained from these analyses can be summarized as follows.

First, hydrogen becomes one of the important final energy carriers in the second half of the century under the 400 ppmv CO_2 stabilization constraint. Hydrogen and electricity compete as substitute energy carriers in some end-use sectors (e.g., PHEV or FCHV). For other uses, their differing properties give one or the other an advantage (e.g., hydrogen preferred by aviation, and electricity preferred by the residential/commercial sector).

Second, biomass is a major source of global hydrogen production. However, a constraint on sustainable biomass supply imposes a limit on the increase in the production of biomass-derived hydrogen. As a consequence, the production of natural gas-derived hydrogen grows sharply because of the low carbon content of natural gas and the low capital costs and high conversion efficiency of steam methane reforming plants. Almost all the CO_2 generated from large-scale energy conversion plants is captured for sequestration in the second half of the century.

Third, pipeline transportation over short distances is an important means of interregional hydrogen transportation. In the year 2100, when the share of hydrogen increases further, natural gas becomes the main feedstock for hydrogen production, and LH_2 aircraft is selected, hydrogen liquefaction and LH_2 tanker transportation are done widely.

Fourth, large-scale use of hydrogen begins in the industrial sector because the cost of local hydrogen pipeline distribution to the industrial sector is estimated to be low. The heat generated from the direct combustion of hydrogen accounts for a large share of total industrial hydrogen energy use. This is because direct hydrogen combustion technologies are assumed to have the same techno-economic characteristics as those of direct natural gas combustion technologies and because high-temperature stationary fuel cells using hydrogen as fuel gas are estimated to have much higher capital costs and a much shorter lifetime of about 10 years.

References

Amos, W.A., 1998. Costs of storing and transporting hydrogen. Report No. NREL/TP-570-25106, National Renewable Energy Laboratory, Golden, CO.

Azar, C., Lindgren, K., Andersson, B.A., 2000. Hydrogen or methanol in the transportation sector? Report no. KFB-Rapport 2000:35, KFB, Stockholm, Sweden.

Azar, C., Lindgren, K., Andersson, B.A., 2003. Global energy scenarios meeting stringent CO_2 constraints – cost-effective fuel choices in the transportation sector. Energy Policy 31, 961-976.

Barreto, L., Makihira, A., Riahi, K., 2003. The hydrogen economy in the 21st century: a sustainable development scenario. International Journal of Hydrogen Energy 28, 267-284.

Brewer, G.D., 1991. Hydrogen aircraft technology. CRC Press, Boca Raton, FL.

Fujii, Y., 1992. The evaluation of CO_2 mitigation options in energy systems. Ph.D. thesis, Department of Electrical Engineering, The University of Tokyo (in Japanese).

Fulton, L., Eads, G., 2004. IEA/SMP model documentation and reference case projection. IEA, Paris.

IEA (International Energy Agency), 2005. Prospects for hydrogen and fuel cells. IEA, Paris.

Makihira, A., 2001. Medium- and long-term demand and supply prospects for fuel cells. Interim Report on the TEPCO-IIASA Collaborative Study, International Institute for Applied Systems Analysis, Laxenburg, Austria.

Metz, B., Davidson, O., Bosch, P., Dave, R., Meyer, L. (Eds.), 2007. Climate Change 2007: Mitigation. Cambridge University Press, New York, NY.

Nakicenovic, N., Grubler, A., McDonald, A. (Eds.), 1998. Global Energy: Perspectives. Cambridge University Press, Cambridge.

Nam, K.Y., Totschnig, G., 2006. Economic assessment on the role of world hydrogen economy and its supply options. Paper presented at the International Energy Workshop 2006, Cape Town, South Africa, June 27-29, 2006.

NEDO (New Energy and Industrial Technology Development Organization), 2000. Project for the introduction of natural gas-derived DME in Sichuan Province in China. Report No. T99064, NEDO, Tokyo (in Japanese).

Ogden, J.M., 1999a. Prospects for building a hydrogen energy infrastructure. Annual Review of Energy and the Environment 24, 227-279.

Ogden, J.M., 1999b. Developing an infrastructure for hydrogen vehicles: a Southern California case study. International Journal of Hydrogen Energy 24, 709-730.

Ogden, J.M., Yang, C., 2005. Implementing a hydrogen energy infrastructure: Storage options and system design. Report No. UCD-ITS-RR-05-28, Institute of Transportation Studies, University of California, Davis, CA.

Schafer, A., Victor, D.G., 2000. The future mobility of the world population. Transportation Research Part A 34, 171-205.

Simbeck, D.R., Chang, E., 2002. Hydrogen supply: cost estimate for hydrogen pathways –scoping analysis. Report No. NREL/SR-540-32525, National Renewable Energy Laboratory, Golden, CO.

Srinivasan, S., Mosdale, R., Stevens, P., Yang, C., 1999. Fuel cells: reaching the era of clean and efficient power generation in the twenty-first century. Annual Review of Energy and the Environment 24, 281-328.

Takeshita, T., 2009. A strategy for introducing modern bioenergy into developing Asia to avoid dangerous climate change. Applied Energy, forthcoming.

Takeshita, T., Yamaji, K., 2006. Potential contribution of coal to the future global energy system. Environmental Economics and Policy Studies 8, 55-88.

Takeshita, T., Yamaji, K., 2008. Important roles of Fischer-Tropsch synfuels in the global energy future. Energy Policy 36, 2791-2802.

Takeshita, T., Yamaji, K., Fujii, Y., 2006. Prospects for interregional energy transportation in a CO_2-constrained world. Environmental Economics and Policy Studies 7, 285-314.

van Ruijven, B., van Vuuren, D.P., de Vries, B., 2007. The potential role of hydrogen in energy systems with and without climate policy. International Journal of Hydrogen Energy 32, 1655-1672.

Victor, D.G., 1990. Liquid hydrogen aircraft and the greenhouse effect. International Journal of Hydrogen Energy 5, 357-367.

Yang, C., Ogden, J., 2007. Determining the lowest-cost hydrogen delivery mode. International Journal of Hydrogen Energy 32, 268-286.

Table 1

Data for hydrogen production technologies[1]

	Conversion efficiency (%, LHV basis)			Capital cost US$$_{1990}$/toe-fuel/year		
	2000	2050	2100	2000	2050	2100
Offsite hydrogen production technologies						
Coal gasification	64.0	72.5	72.5	941	680	680
Partial oxidation of fuel oil	71.0	72.8	72.8	631	557	557
Steam methane reforming of natural gas	79.2	81.2	81.2	361	319	319
Biomass gasification	60.6	68.7	68.7	934	675	675
Black liquor gasification	53.6	60.8	60.8	1319	953	953
Electrolysis of water using grid AC power	68.2	69.9	69.9	880	777	777
Electrolysis of water using solar, wind, hydro, or nuclear DC power	71.0	72.8	72.8	676	597	597
Iodine-Sulfur thermochemical water splitting cycle using nuclear heat	45.0	51.0	51.0	732	585	585
Iodine-Sulfur thermochemical water splitting cycle using solar heat	56.0	63.4	63.4	2684	2143	2143
Onsite hydrogen production technologies						
Steam methane reforming of natural gas	72.8	74.6	74.6	1625	1434	1434
Electrolysis of water using grid AC power	68.2	69.9	69.9	1977	1745	1745

Sources: Takeshita and Yamaji (2008); Takeshita (2009).

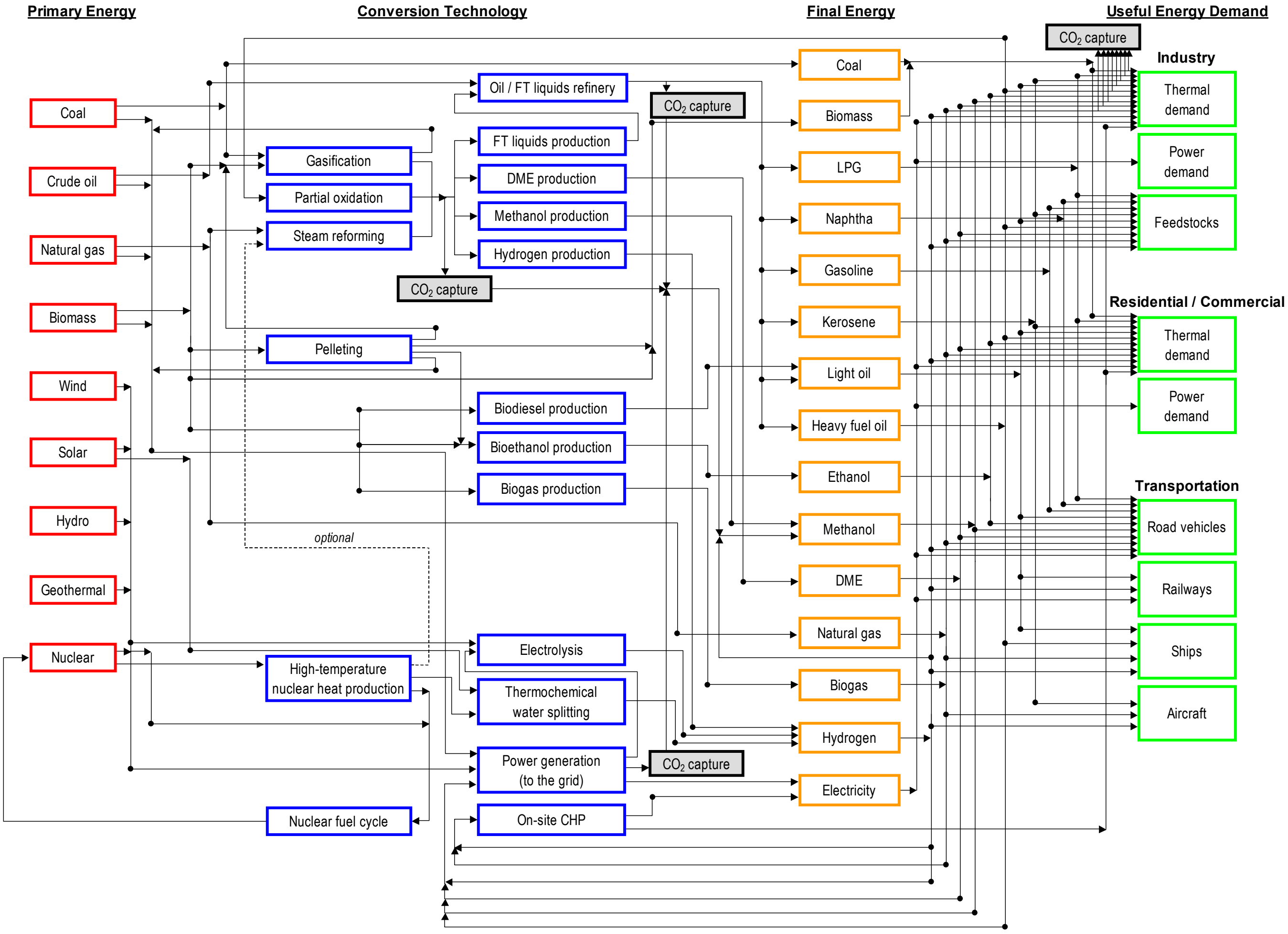

Fig. 1. Schematic representation of the structure of REDGEM70.

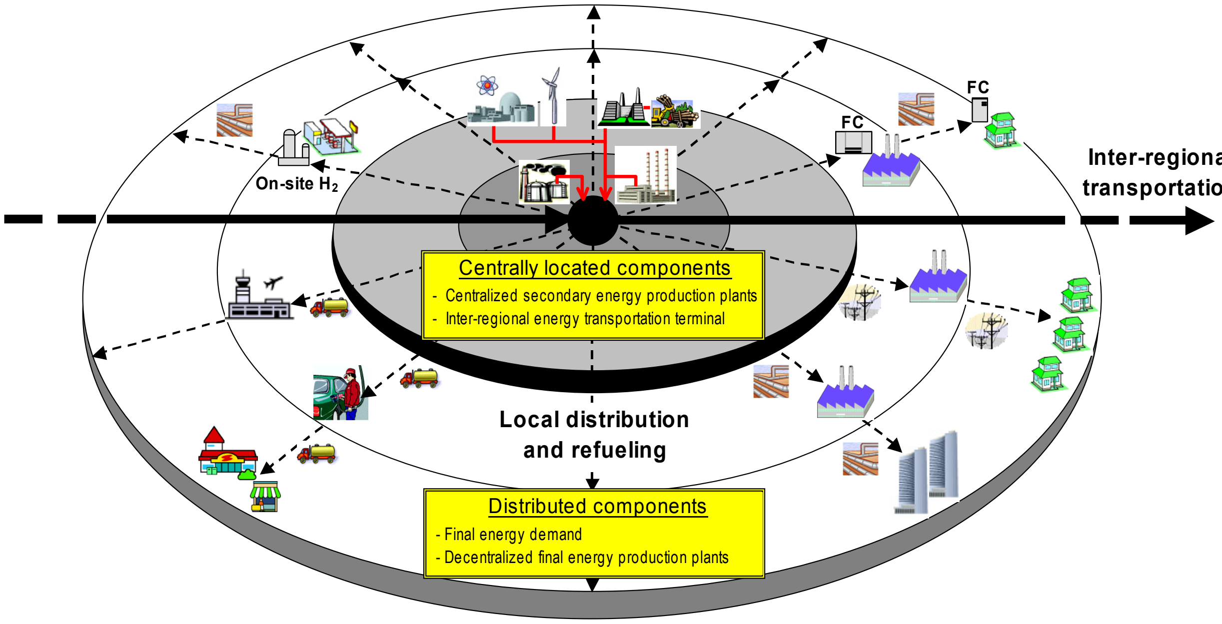

Fig. 2. Spatial structure of energy production and consumption regions in REDGEM70.

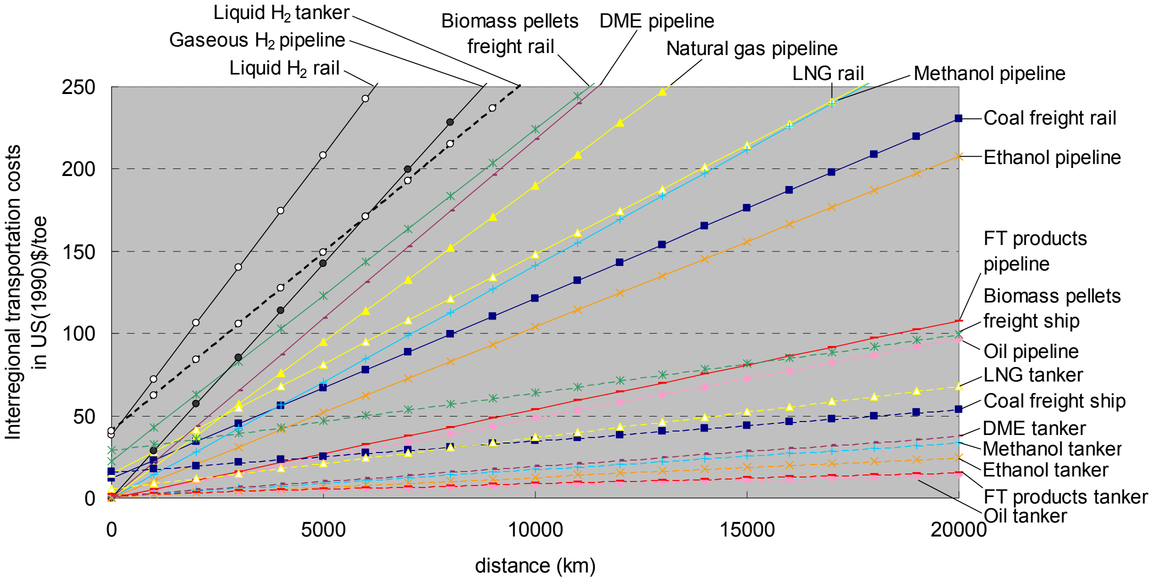

Fig. 3. Interregional energy transportation costs as a function of transportation distance.

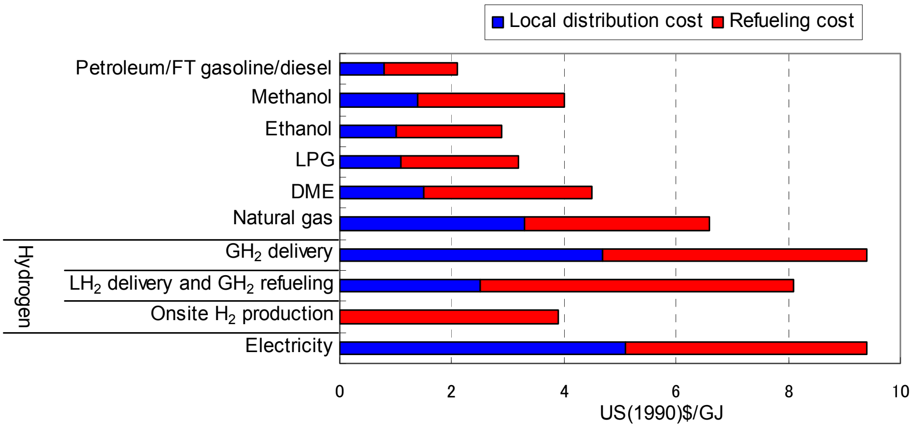

Fig. 4. Local distribution and refueling costs associated with supplying light-duty vehicles.

Note: These values are the estimated world averages for the year 2000.

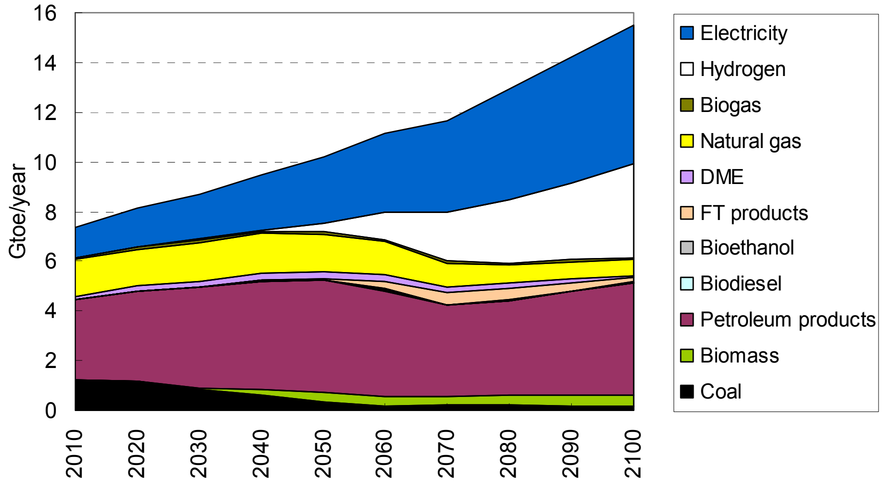

Fig. 5. Global final energy consumption under the 400 ppmv CO_2 stabilization constraint.

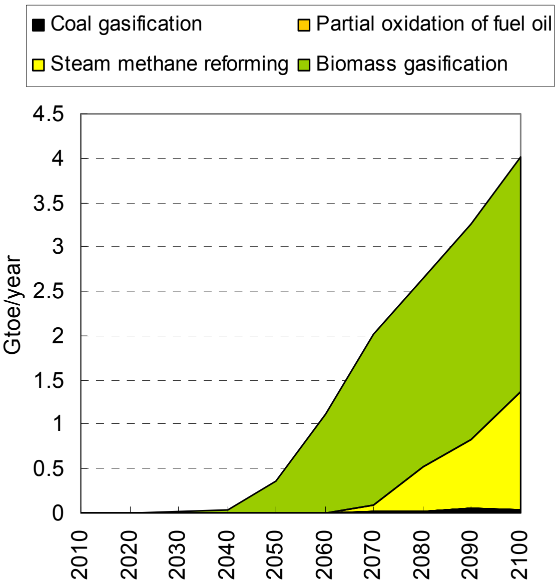

Fig. 6. Global hydrogen production by source under the 400 ppmv CO_2 stabilization constraint.

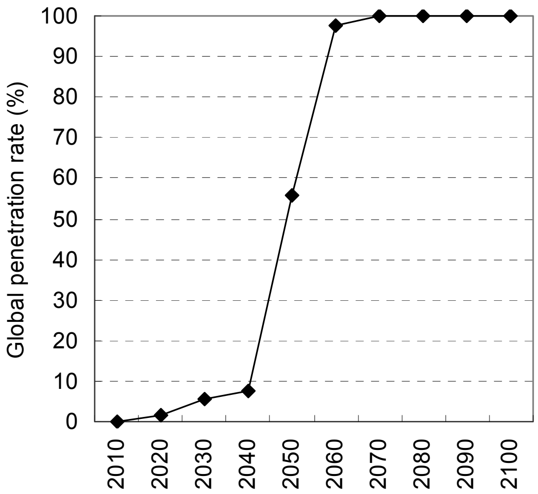

Fig. 7. Global penetration rate of CO_2 capture technologies in large-scale energy conversion plants under the 400 ppmv CO_2 stabilization constraint.

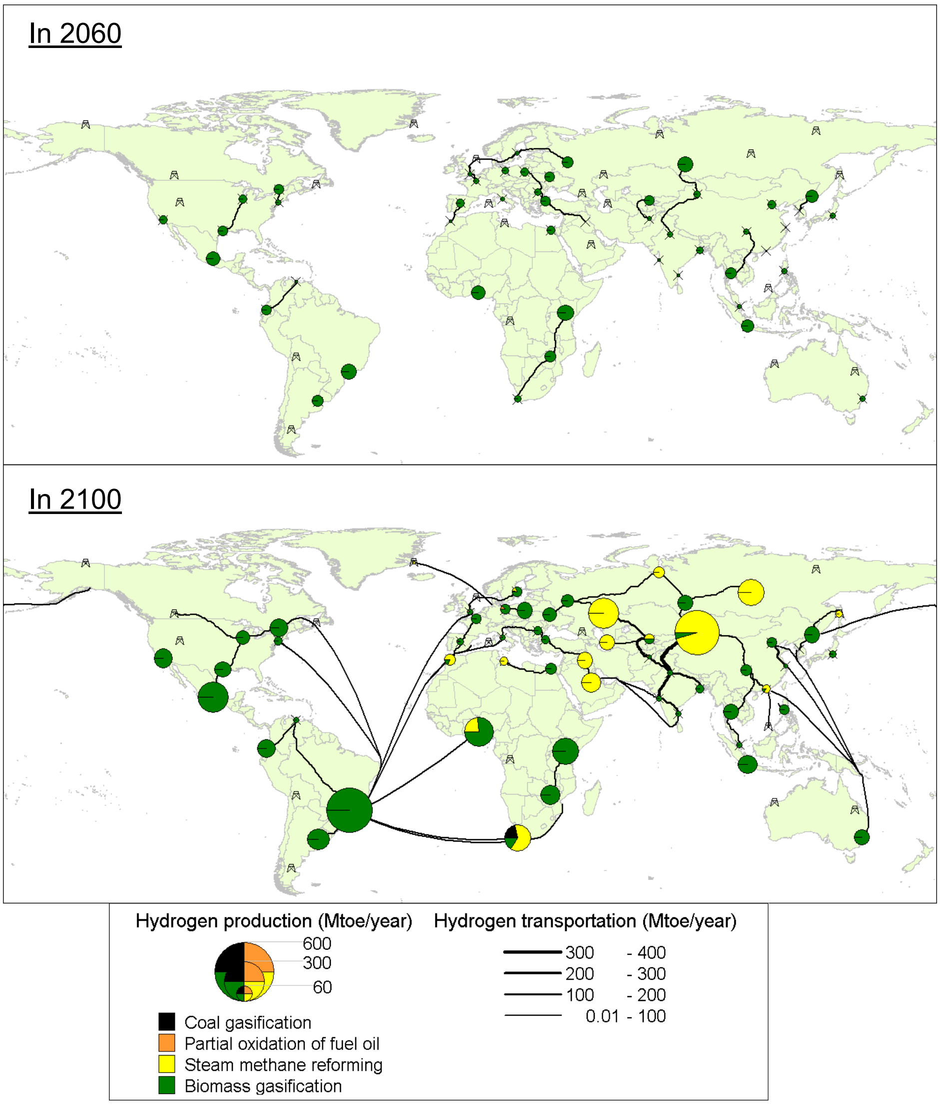

Fig. 8. Hydrogen production and transportation under the 400 ppmv CO_2 stabilization constraint for the years 2060 and 2100.

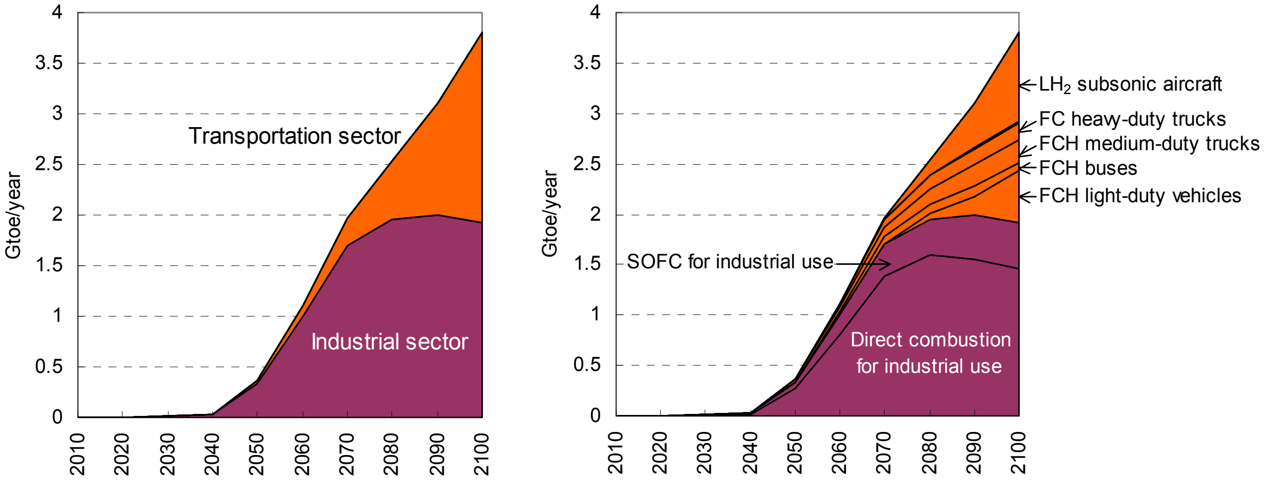

Fig. 9. Global final hydrogen consumption by sector under the 400 ppmv CO_2 stabilization constraint.