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CASCADE MINTS

CAse Study Comparisons And Development of Energy Models for INtegrated Technology
Systems

Part 1

Final Activity Report

Co-ordinated by: Nikos Kouvaritakis (ICCS-NTUA)

With contributions by:

P. Capros, V. Panos, L. Mantzos, M. Zeka-Paschou, V. Papandreou and E. Argiri, ICCS-NTUA (Greece)

M. Uyterlinde, H. Rösler, K. Smekens, G. Martinus, E. van Thuijl, B.C.C van der Zwaan and H.C. de Coninck, ECN (The Netherlands)

P. Criqui, S. Mima, P. Menanteau and E. Bellevrat, LEPII-EPE (France)

L. Schratenholzer, G. Totschnig, I. Keppo and K. Riahi, IIASA (Austria)

L. Szabó, P. Russ and W. Suwala, JRC-EU (Belgium)

S. Kypreos, P. Rafaj and D. Krzyzanowski, PSI (Switzerland)

C. Böhringer, A. Löschel, S. Jokisch, T. Mennel, H. Koschel and T. Hoffmann, ZEW (Germany)

W. Krewitt and S. Schmid, DLR (Germany)

M. Blesl, I. Ellersdorfer, M. Zürn and U. Fahl (IER), Germany

P. Zagame, F. Pratlong, P. Le Mouél and U. Gharbi, CRSA-ERASME (France)

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A. Introduction

CASCADE MINTS is a project that deals explicitly with the role of technical change and policies designed to promote it in enabling the evolution of the energy system towards sustainable paths. It is a modelling project that delivers enhanced quantitative tools and quantitative analysis with a potential for policy support.

A wide range of problems characterise the present energy system, including global and local pollution, resource depletion, security of supply concerns and doubts concerning the sustainability of present options in electricity production. CO2 capture and storage, renewable and nuclear energy forms have been widely recognised as important options in promoting sustainability (especially tackling climate change and improving security of supply). Part 2 of the CASCADE MINTS project brings together a number of the leading energy, economic and environmental modelling teams in Europe (together with some institutes in the US and Japan that are associated more loosely) with the aim to inform the debate on the prospects of transformation of the European and World energy system towards sustainability, while providing important analytical background for the formulation of energy and environmental strategy.

Fuel cells and the prospects for the transformation of the energy system by hydrogen as a carrier have in recent years attracted enormous interest from industry, policy makers and society at large. In many quarters this technological nexus is viewed as a panacea for solving the widest range of problems characterising the energy system. The analysis of an eventual transition towards a hydrogen economy requires an integrated analytical framework. Part 1 of the project undertakes the creation of such a framework that enables the analysis of the prospects of the hydrogen economy within the overall energy system in an unbiased fashion.

Following the structure of the project, this report is also divided into two parts. Table B.1-1 below provides a list of institutes and models participating in the CASCADE MINTS project.

Table A-1: List of participants

Participant name	Participant short name	Country	Model
Institute of Communication and Computer Systems of National Technical University of Athens	ICCS/NTUA	Greece	PRIMES
Energy Research Centre of the Netherlands	ECN	Netherlands	MARKAL
Centre National de la Recherche Scientifique	CNRS	France	POLES
International Institute for Applied Systems Analysis	IIASA-ECS	Austria	MESSAGE
Joint Research Centre	JRC-EU	Belgium	POLES
Paul Scherrer Institut	PSI	Switzerland	MERGE-ETL (Part 1)
Zentrum für Europäische Wirtschaftsforschung GmbH - Centre for European Economic Research	ZEW	Germany	PACE
Deutsches Zentrum für Luft – und Raumfahrt e.V. (German Aerospace Center)	DLR	Germany	
Universitaet Stuttgart*	USTUTT	Germany	TIMES-EE NEWAGE-W
Centrale Recherche S.A. *	CRSA/ERASME	France	NEMESIS

*Part 2 Only

Several non-European organisations participate in Part 2:

Institution	Institution short name	Country	Model	Researchers
Energy Information Administration of the U.S. Department of Energy (USA)	U.S. DOE/EIA	United States	NEMS	A.S. Kydes L. Martin
Research Institute of Innovative Technology for the Earth	RITE	Japan	DNE21	S. Fuminori F. Sano K. Akimoto T. Homma, T. Tomoda
National Institute for Environmental Studies	NIES	Japan	AIM	T. Hanaoka H. Tatsuya
International Energy Agency	IEA	International	ETP	D. Gielen F. Unander
Natural Resources Canada	NRCan	Canada	MAPLE	I. Hayhow

B. Hydrogen Technologies: Characterisation and Perspectives

B.1 Technology Characterisation and Prospects

(by W. Krewitt and S. Schmid)

B.1.1 Fuel cell technologies

Fuel cells are expected to be suitable for a wide range of applications (Table B-1). Transportation applications include vehicle propulsion and on-board auxiliary power generation. Portable applications include consumer electronics, business machinery, and recreational devices. Stationary power applications include stand-alone power plants, distributed generation, cogeneration, back-up power units, and power for remote locations. Within CASCADE MINTS, we focus on applications that might achieve a relevant share with respect to their overall energy consumption in a future energy system, i.e. stationary applications in power plants (mainly decentralised cogeneration), and vehicle propulsion.

There are several different fuel cell technology paths being pursued. These divide into low temperature and high temperature technologies. Low temperature technologies, including phosphoric acid (PAFC) and polymer electrolyte membrane (PEMFC) fuel cells, target transportation, portable power, and lower-capacity distributed power applications. High temperature technologies, including molten carbonate (MCFC) and solid oxide (SOFC) fuel cells, focus on larger stationary power applications, niche stationary and distributed power, and certain mobile applications (e.g. APU). A combination of technology developments and market forces will determine which of these technologies are successful. Currently, phosphoric acid fuel cells are the only commercially available fuel cells. While more than 200 units of the 200 kW PC25 fuel cell manufactured by UTC Fuel Cells are in operation around the world, UTC decided recently to stop the production of the PAFC fuel cell, because cost targets could not be achieved, and to focus on PEMFC development in the future.

The following sections provide a summary of the main characteristics of the different fuel cell types, the respective field of application, and a set of technical and economic data for different fuel cell systems and applications to provide technological background information for the CASCADE MINTS modelling workpackages.

Table B-1: Fuel cell technologies and their applications (ESECS, 2003)

			Polymer Electrolyte Fuel Cell (PEMFC)	Alkaline Fuel Cell (AFC)	Phosphoric Acid Fuel Cell (PAFC)	Molten Carbonate Fuel Cell (MCFC)	Solid Oxide Fuel Cell (SOFC)
Stationary-distributed	Grid sited	Central	○	○	○	●	●
		Distributed	○	○	○	●	●
	Customer sited cogeneration	Residential	●	⊙	○	○	●
		Commercial	●	⊙	●	●	●
		Light industrial	⊙	⊙	●	●	●
		Heavy industrial	○	○	●	●	●
Transportation	Propulsion	Light duty	●	○	○	○	○
		Heavy duty	●	○	⊙	⊙	⊙
	Auxiliary Power Unit	Light & heavy duty	●	○	○	○	●
Portable	Premium	Recreational, military	●	○	○	○	●
	Micro	Electronics, military	●	○	○	○	○

● likely; ⊙ under consideration; ○ unlikely

Stationary fuel cell systems

The following sections provide an overview on the state of the art and the current most relevant development paths with regard to stationary fuel cells. While there is still a considerable variety of competing fuel cell technologies, there are currently two main fields of application for stationary fuel cells: small scale house supply fuel cell heating appliances with a capacity of 1 to 5 kWel, and fuel cells of the 200 to 300 kWel class which can be used as a district heating CHP plant or for power and heat supply for commercial or industrial applications. It is possible that after a first successful market integration of high temperature fuel cells (MCFC, SOFC) of the 300 kWel class these technologies will expand towards the multi-Megawatt class.

All the fuel cell systems discussed below are in a very early phase of market introduction. The UTC 200 kW PAFC is the only stationary fuel cell system commercially available. Most of the other systems are currently tested in field trial programs, while for some fuel cell types there exist only first proof-of-concept demonstration plants. As a consequence, the availability of reliable data is poor. Taking into account the context of early market introduction, it is obvious that technical and economical data are quite sensitive, and thus in general a matter of confidentiality. It is difficult to assess to which extent specific data published by fuel cell manufacturers can be generalised or transferred into another context. Any data on current

investment cost is uncertain, and the information on the cost structure given by different manufacturers seems to be partly contradicting.

The data given in the following sections was compiled largely during a recent German research project on long term perspectives of stationary fuel cells in Germany (Krewitt et al. 2004). The technical data and cost data underlying the analysis were reviewed in a workshop that took place in June 2003 in Stuttgart, with participation from fuel cell manufacturers and utilities. Although the workshop did not claim to achieve an explicit agreement on each data set, workshop participants in general agreed to the basic database used in the project. We thus conclude that an updated version of the database elaborated in (Krewitt et al. 2004) is a sound basis for the future work in CASCADE MINTS.

It is difficult to derive reliable estimates on operation and maintenance costs from the current pilot and demonstration plants. We expect that O&M costs during the fuel cell market introduction phase are higher than those of a conventional CHP unit, but that on the long run O&M costs for the fuel cell system are lower because there are less moving components. We thus assume 'generic' O&M costs that are similar for all types of fuel cells, which are 5% of the investment costs per year during the early market introduction phase, and 2% of investment costs per year for a mature system.

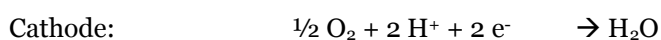
Based on the description of the individual fuel cell technologies, the final section of this chapter (see page 19) provides a summary of the main technical and economic data for each type of fuel cell which can be used as an input to the energy models in CASCADE MINTS. Some of the data which are required for a consistent characterisation of the fuel cell technology in the model are not always directly available from the data sources (e.g. availability, stack lifetime), and are thus specified based on expert judgement. As some of the models to be used in CASCADE MINTS might not differ between different fuel cell technologies for the same applications, section 0 suggests also the specification of two 'generic' fuel cells for small scale heating appliances, and for cogeneration units of the 300 kW-class.

Polymer electrolyte membrane fuel cells (PEMFC)

Basic mechanism and design

Polymer electrolyte membrane fuel cells (PEMFC) deliver high power density, which offers low weight, cost, and volume. The PEMFC system is thus seen as the system of choice for vehicular power applications, but is also being developed for smaller scale stationary power.

The electrochemical reactions are initiated by feeding hydrogen to the anode, which provides a proton, freeing an electron in the process that must pass through an external circuit to reach the cathode. The proton diffuses through the membrane to the cathode to react with oxygen and the returning electron:



PEMFCs consist of two platinum loaded porous electrodes and a proton conducting membrane pressed between them. The membrane, which acts as the electrolyte, is usually made of perfluorinated sulphonic acid polymer (Nafion). The back of the electrodes (the gasification layer) is made hydrophobic by coating with an appropriate material, such as Teflon. The individual cells in a stack are supported by a carbon sheet and separated by bipolar plates with integrated gas flow channels, in this type of cell normally made of carbon composite.

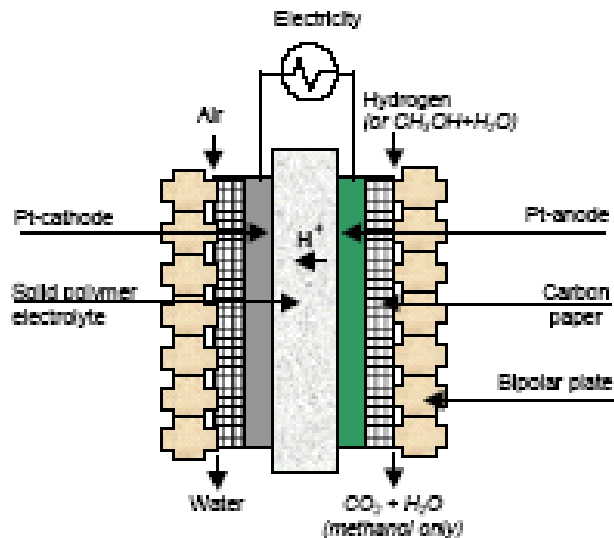


Figure B-1: Schematic representation of a PMFC

Because of the nature of the electrolyte membrane used, low-temperature operation of up to 80 °C is possible. The cell also is able to sustain operation at very high current densities. These attributes lead to a fast start capability and the ability to make a compact and lightweight cell. Other beneficial attributes of the cell include no corrosive fluid hazard. The disadvantage of the low operating temperature is that platinum catalysts are required to promote the electrochemical reaction. Carbon monoxide binds strongly to platinum sites at temperatures below 150 °C, so that only up to 100 ppm of CO can be tolerated with the platinum catalyst at 80 °C. Because reformed and shifted hydrocarbons contain about one percent of CO, a gas treatment to reduce the level of CO in the fuel gas is needed. The low temperature of operation also means that no significant contribution of waste heat from the fuel cell is available for any endothermic reforming process.

Fields of application

A variety of stationary PEM-fuel cell systems are being developed (see section 6 for mobile applications). Various manufacturers (including e.g. Buderus/IFC, HGC, IDATECH, Nuvera, Vaillant, Plug Power, Ballard, Viessmann) aim at small scale house supply cogeneration systems with a capacity of 1 to 5 kW_{el}. The fuel cell systems in general run on natural gas, and are equipped with a gas reformer integrated into the system. The systems are designed to operate to feed electricity into the utility grid ('virtual power plant').

Ballard Generation Systems developed a stationary PEMFC generator with a capacity of 250 kWel (P2B-PEM-FC). The system is designed to deliver power to the onsite power grid and to provide heat. A field trial programme with several units installed in the US and Europe was launched in 1999, and is expected to continue until 2004 (Ballard 2004).

Technical data

Table B-2 summarises the key technical data of PEMFC systems used for the two different types of application described above. Data are based on a review of technical data published from the various manufacturers. It should be noted that the electrical, thermal and overall efficiency depend on the intended application of the system (e.g. level of heat supply).

With regard to the house supply system, there are data available e.g. from the Vaillant's field trial programme in Europe, which is supported by the European Commission. The Vaillant system is based on a PEM-fuel cell provided by Plug Power. A total of 31 Vaillant fuel-cell heating appliances have been installed by now in several European countries and linked with each other via a control centre to analyse how fuel cells can be run as a virtual power plant. 13 units of a 4.7 kWel system ("EURO1" version) were installed in the first half of 2003, and the installation of further 43 units ("EURO2") started in November 2003. Measurement data from the EURO2 systems suggest that an electrical efficiency of up to 31 %, and a total efficiency of 88-89 % can be achieved. The lifetime of the stack is currently about 6,000 h, according to Vaillant a stack lifetime of 12,000 h seems to be realistic with an acceptable degradation (Klinder 2003). There are no published data available on the system's availability.

Measured data from the Ballard 250 kWel P2B-PEM-FC operated in Berlin since June 2000, which was the first system installed in Europe, indicate that an electrical net efficiency of 33 to 34 % was achieved, with a total efficiency of more than 70 % (Pokojski 2001). The target electrical efficiency of a pressurised system is 40 %. The availability of the first pilot plant during the first time of operation was still low. There are no data open to the public on stack degradation.

Economic data

The cost of the Plug Power 5 kWel fuel cell, which is used e.g. in the Vaillant system, is about 55,000 \$, the specific costs are thus 11,000 \$/kW (Fuel Cell Today 2002). Plug Power expects that still 4 to 7 years are required until a fuel cell heat appliance system is an economically viable option for the end-use customer. Since January 2001, Vaillant could reduce the manufacturing costs of its fuel cell system by 50 % within 1.5 years (Klinder 2002). Target costs for the Vaillant fuel cell heat appliance system are given as 1,500 €/kW.

Based on a detailed costs analysis, Siemens concludes that assuming a production volume of 50,000 units per year the costs for the individual components of a 5 kWel PEMFC system amount to at least 1,550 €/kW. It was assumed that the stack with 100 €/kW contributes to only about 6 % of the total system costs (Kabs 2002). Data from Viessmann indicate that the material costs for the current 2 kWel prototype are 6,100 €/kW if a product volume of 10,000 units per year is achieved, the material costs of the stack contribute

about 20% of the total material costs (Britz 2003). The reformer costs contribute to about 8 to 10% of the total costs.

The total cost of the Ballard 250 kW_{el} P2B-PEM-FC pilot plant which was put into operation in June 2000 in Berlin was about 3.8 Mill €, with about 5 % of the total costs allocated for planning and other services (Pokojski 2001). The specific system costs were thus about 14,000 €/kW_{el}. There are no data available on operation and maintenance cost.

According to (Schmidt et al., 2002), stack costs of around 30 \$/kW can be achieved in an automated mass production, leading to system costs of about 100 to 200 €/kW. We take this optimistic view as an indication of floor costs for small scale (1-5 kW_{el}) PEM-systems for house applications.

Table B-2: Technical data of PEMFC systems

		1-5 kW _{el} PEMFC fuel cell heat appliance		250 kW _{el} PEMFC	
		state-of-the-art	long term target	state-of-the-art	long term target
Performance data					
Electrical capacity	kW _{el}	1-5	1-5	250	250
Electrical net efficiency	%	28	32	35	42
Overall efficiency	%	80	90	76	84
Stack lifetime	h	10,000	40,000		40,000
Availability	%				
Fuel processing					
Fuel		natural gas		natural gas, biogas	
Reforming		steam reformer		Steam reformer	

Table B-3: Cost estimates for PEMFC systems

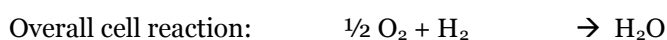
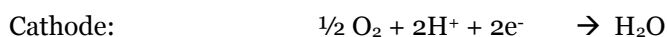
		1-5 kW _{el} PEM-fuel cell heat appliance system	250 kW _{el} PEMFC
Investment costs (system)			
Cost estimates for current demonstration plants	€ ₂₀₀₀ /kW _e	11,500	14,000
Long term target costs	€ ₂₀₀₀ /kW _e	1,500	
Share of stack costs	%	5-20 %	
Share of reformer costs	%	8-10	8-10
O&M fixed costs	%	2-5	2-5
	Invest./a		
O&M variable costs			

Phosphoric acid fuel cells (PAFC)

Basic mechanism and design

The phosphoric acid fuel cell (PAFC) is the only fuel cell technology that is in commercialisation. There are over 75 MW of demonstrators worldwide. Most of the plants are in the 50 to 200 kW capacity range, but also larger plants in the multi-MW range have been build, the largest plant operated until today achieved a capacity of 11 MW (Ichihara, Japan; operated by Tokyo Electric Power Company; today out of order).

The electrochemical reactions occurring in PAFCs are the same as in PEMFCs:



The electrochemical reactions occur on highly dispersed electrocatalyst particles supported on carbon black. Platinum (Pt) or Pt alloys are used as the catalyst at both electrodes. To achieve high cell performance, temperatures of about 200 oC and acid concentrations of 100% H₃PO₄ are commonly used today (EG&G 2000).

The porous electrodes are made from a mixture of the electrocatalyst supported on carbon black and a polymeric binder, usually PTFE, which binds the carbon black particles together to form a mechanically stable but porous structure, which is supported on a porous carbon paper substrate. The carbon paper serves as a structural support for the electrocatalyst layer, as well as the current collector. The composite structure consisting of a carbon black black/PTFE layer on carbon paper substrate forms a stable, three-phase interface in the fuel cell, with H₃PO₄ electrolyte on one side (electrocatalyst side), and the reactant gas environment on the other side of the carbon paper. A bipolar plate serves to separate the individual cells and electrically connect them in series in a fuel cell stack. Several designs for the bipolar plate and ancillary stack components are used by fuel cell developers. The bipolar plates used in early PAFCs consisted of s single piece of graphite with gas channels machined on either side to direct the flow of fuel and oxidant gases in adjacent cells. In new designs, consisting of multi-component bipolar plates, a thin impervious plate separates the reactant gases in adjacent cells in the stack, and separate porous plates with ribbed channels are used to direct gas flows. In a cell stack, the impervious plate is subdivided into two parts, and each joins one of the porous plates (EG&G 2000).

In PAFC stacks, provision must be included to remove heat generated during cell operation. Heat has been removed by either liquid or gas coolants that are routed through cooling channels located in the cell stack. Liquid cooling requires complex manifolds and connections, but better heat removal is achieved compared to air cooling. The advantage of gas cooling is its simplicity, reliability, and relative low cost, but the size of the cell is limited.

Fields of Application

The PAFC is available for commercial applications. UTC as the main manufacturer introduced the PC-25 200 kW_{el} system, the world's first commercially available fuel cell power plant, in 1991. Today, more than 250 units of the PC-25 have been delivered. These power plants operate independently or connected to the grid, partly as a co-generator with heat recovery, and it is used in numerous applications that require 'premium' power supply.

Technical data

Table B-4 summarises the technical data of the current PC25TM as specified by UTC Fuel Cells (UTC 2004). The efficiency of the system is high over a wide range of load settings. The standard PC25 delivers product heat to a heat exchanger designed to provide 60 °C hot water to customer loads, a high-grade heat option is also provided that makes approximately half of the power plant heat available at temperatures up to 120 °C. Overhaul after 40,000 h includes replacement or factory refurbishment of the stack. Experience with the PC25 C system shows that power plant availability is > 90% (King and McDonald 2003). The system is designed to run on natural gas or anaerobic digester gas.

As the costs of the PC25 system could not be reduced as required to achieve significant market penetration, UTC announced in 2002 to phase out the production of PAFC systems. As a consequence we do not report any long term technical development targets.

Table B-4: Technical data of PAFC system (UTC 2004), (King and McDonald 2003)

		state-of-the-art	long term target
Performance data			
Electrical capacity	kW _{el}	200	
Electrical net efficiency	%	37	
Overall efficiency	%	87	
Stack lifetime	h	40,000	
Availability	%	> 90	
Fuel processing			
Fuel		natural gas, anaerobic digester gas	
Reforming		steam reformer	

Economic data

UTC reported costs for the 200 kW_{el} PC25 unit to be approximately 850,000 \$, the specific costs for the installed system are thus about 4,250 \$/kW (UTC 2002). The cost of the PAFC power plant is approximately three times higher than required for significant market penetration. There is no unique component or system in the power plant that dominates the overall system costs. As mentioned above, in 2002 UTC announced to phase out the production of PAFCs because there is no realistic perspective to bring the costs down to the target costs, and to focus future fuel cell development activities towards the development of PEM-fuel cells.

As a consequence, we do not consider PAFCs as a priority technology for future developments, and we thus do not report technical data and target costs for future configurations.

Table B-5: Cost data for the PC25 fuel cell power plant (UTC 2002; own estimates)

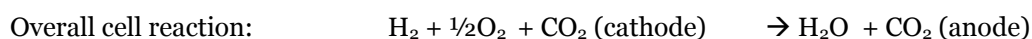
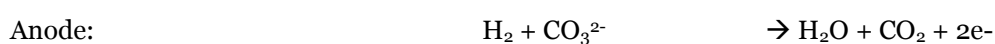
Investment costs (system)		
Current system costs	€ ₂₀₀₀ /kW _{el}	4,460
Long term target costs	€ ₂₀₀₀ /kW _{el}	
Share of stack costs	%	25
O&M fixed costs	% Invest./a	2-5
O&M variable costs		

Molten Carbonate Fuel Cell (MCFC)

Basic mechanism and system design

Currently several industrial corporations are actively pursuing the commercialisation of MCFCs, among them Fuel Cell Energy (FCE) in the US, MTU CFC Solutions (Germany) and Ansaldo (Italy) in Europe, and Hitachi in Japan. High operation temperature promotes conductivity of its molten carbonate electrolyte and for that reason noble metal catalysts are not required, which is one advantage of MCFCs over low-temperature fuel cells. Due to the high operation temperature heat at a high temperature level can be provided as a high quality by-product. On the other hand, the higher operating temperature places severe demands on the corrosion stability of cell components, particularly in the aggressive environment of the molten carbonate electrolyte.

In a MCFC, the electrolyte is a mixture of lithium and potassium carbonate salts which melt at the operating temperature of 650 °C. The electrolyte conducts carbonate ions (CO₃²⁻) from the porous NiO-cathode to the porous Ni-anode where they react with hydrogen to form water and carbon dioxide (Figure B-2). The CO₃²⁻ ions are replenished by reacting oxygen with carbon dioxide recycled from the anode. A CO₂ gas recycling system is needed to supply CO₂ from the anode chamber to the cathode chamber. The electrochemical reactions occurring in MCFCs can be summarised as follows:



High operating temperatures enable internal reforming, usually carried out with steam and promoted by a catalyst. Various concepts have been developed to use coal gas, biogas or liquid hydrocarbons as a fuel.

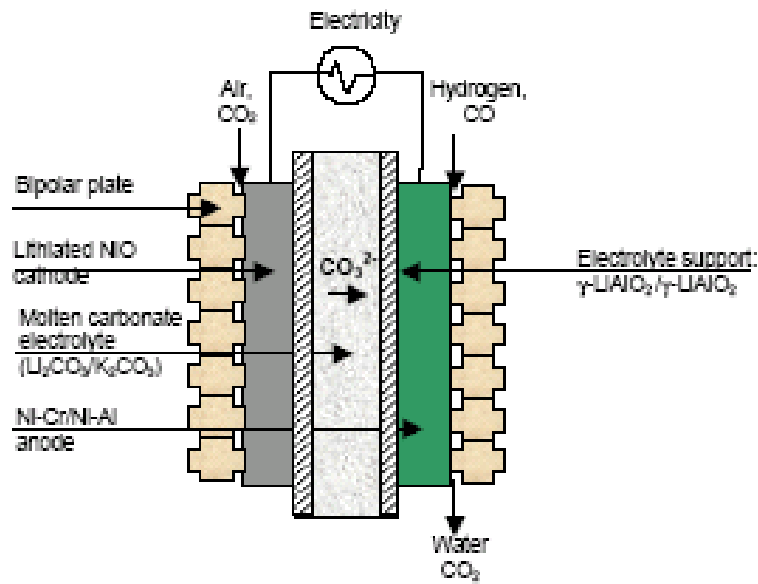


Figure B-2: Schematic representation of a MCFC



Figure B-3: The MTU 250 kW_{el} HotModule (MTU 2004)

Fields of application

While several years ago according to market requirements development of MCFC power plants aimed at the multi-MW class, currently the 250 kW class for decentralised combined heat and power production is close to commercialisation. The largest number of demonstration plants today is based on the 'HotModule' concept developed by MTU CFC Solutions (which is based on cells from FCE), with currently 14 systems installed. Some of them are operated to provide premium power supply and combined heat and power for hospitals, which is a quite challenging supply task in terms of reliability. We thus take the technical data of the HotModule as a reference. Future developments will include an up-scaling of the system (MTU

announced to produce a 1 MW system in 2006 (Berger 2003)), and the development of hybrid systems with a steam or gas turbine.

Technical data

Measurement data on the HotModule demonstration plants, which run on natural gas, confirm that the relatively high electrical efficiency of 47% could be reached (Berger 2003). We assume that the CHP unit achieves an overall efficiency of 83%, with depleted air available at a temperature of 400 °C. There are no public data on availability and on stack degradation, but it is reported that the stack lifetime is still one of the main challenges. Similar to other fuel cell manufacturers, the target for the stack lifetime is given as 40,000 h.

As development activities mainly focus on increasing the electrical efficiency, it is expected that future developments will lead to an increase of the electrical efficiency by 5 percent points to 52%, while the overall efficiency increases to 86%. It is expected that a future hybrid system which combines a MCFC with a steam turbine will achieve an electrical efficiency of 55 to 56%, with an overall efficiency of 90%.

Table B-6: Technical data of MCFC systems

		250 kW _{el} MCFC		hybrid MCFC with steam turbine	
		state-of-the art	long term target	2010 (?)	long term target
Performance data					
Electrical power	kW _{el}	250	250	1,000	1,000
Electrical net efficiency	%	47	52	55	56
Overall efficiency	%	83	86	90	90
Stack lifetime	h	<< 40,000	40,000		40,000
availability	%	80 (?)	90	(80)	90
Fuel processing					
Fuel		natural gas, biogas		natural gas, biogas	
Desulphurisation					
Reforming		internal reforming		internal reforming	

Economic data

The system costs of the HotModule 2, which was put into operation 1999, and was the first system which was operated by the customer, were 2.9 Mill €, which is equivalent to specific investment costs of about 12.000 €/kW. The cost of the HotModule installed at the Los Angeles Department for Water and Power (LADWP) headquarters in 2000 was reported to amount to 2.4 Mill \$ (MTU 2000). The stack costs are estimated to contribute about 30% of the total system costs. No data are available on operation and maintenance costs.

According to MTU, the target costs for a commercial product are below 1,250 €/kW. MTU expects to achieve this target once the production volume amount to 40 to 50 MW/a (Berger 2003), which is equivalent to the production of 160 to 200 systems per year.

Table B-7: Cost estimates for MCFC systems

		250 kW MCFC	1 MW hybrid MCFC with steam turbine
Investment costs (system)			
Cost estimates for current demonstration plants	€ ₂₀₀₀ /kW _{el}	12,000	
Long term target costs	€ ₂₀₀₀ /kW _{el}	<1,250	<1,250
Share of stack costs	%	30	30
O&M fixed costs	% Invest./a	2-5	2-5
O&M variable costs			

Solid Oxide Fuel Cells (SOFC)

Basic mechanism and system design

Solid oxide fuel cells (SOFC) have grown in recognition as a viable high temperature fuel cell technology. There is no liquid electrolyte with its attendant specific corrosion and electrolyte management problems. The operating temperature of > 800 °C allows internal reforming, promotes rapid kinetics with non-precious materials, and produces as a high quality by-product high temperature heat. The high temperature of the SOFC, however, places stringent requirements on its materials, both with regard to the stack and the balance of plant components. The development of suitable low cost materials and the low cost fabrication of ceramic structures are presently the key technical challenges facing SOFCs.

The SOFC cell consists of a solid ceramic electrolyte (yttria stabilised ZrO₂) pressed between a Ni/ZrO₂ cermet anode (usually stabilised with Y₂O₃) and a strontium-doped lanthanum manganite cathode. The ionic conduction in SOFCs is by oxygen ions. Carbon monoxide (CO) and hydrocarbons such as methane (CH₄) can be used as fuels in SOFCs.

A variety of system and stack designs has been proposed and is being developed to improve system performance and/or reduce costs. The most developed solid oxide fuel cell is the Siemens-Westinghouse tubular cell. A major advantage of this design is that relatively large single tubular cells can be constructed in which the successive active layers can be deposited without chemical or material interference with previously deposited layers. The support tube is closed at one end. The tubular approach with one closed end eliminates gas seals between cells. The oxidant gas is introduced via a central injector tube, and the fuel gas is supplied to the exterior of the closed-end tube. The fuel gas flows past the anode on the exterior of the cell and in a parallel direction to the oxidant gas. The spent gases are exhausted into a common plenum where the remaining active gases react and the generated heat serves to preheat the incoming oxidant stream. While one attractive feature of this design is that it eliminates the need for leak-free gas manifolding of the fuel and oxidant streams, the sealless tubular design results in a relatively long current path around the circumference of the cell interconnect, limiting performance. It is expected that a so-called High Power Density (HPD) flat-

tube design which is currently under development helps to overcome this limitations and increases the power density of the current cylindrical-tube cell design by a factor of two.

A bipolar or flat structure in contrast to the tubular concept permits a simple series electrical connection between cells without the need for external cell interconnections. Perpendicular current collection in a cell stack with a bipolar design should have a lower ohmic polarisation than the tubular configuration, and overall stack performance should be improved. However, gas leaks in a SOFC of bipolar configuration with compressive seals are difficult to prevent, and thermal stresses at the interface between dissimilar materials must be accommodated to prevent mechanical degradation of cell components.

If a SOFC is pressurised an increased voltage results, leading to improved performance (operation at 3 atmospheres e.g. increases the power output by ~ 10%). The expense of pressurisation is in particular justified by the ability to integrate the SOFC with a gas turbine which needs a hot pressurised gas flow to operate. Since the SOFC stack operates at 1000 oC it produces a high temperature exhaust gas. If operated at elevated pressure the exhaust gas becomes a hot pressurised gas flow that can be used to drive the turbine. By integrating a SOFC and a gas turbine, the pressurised air needed by the SOFC is provided by the gas turbine's compressor, the SOFC acts as the system combustor, and the exhaust from the SOFC drives the turbine, the compressor and the generator. This yields a hybrid cycle power system.

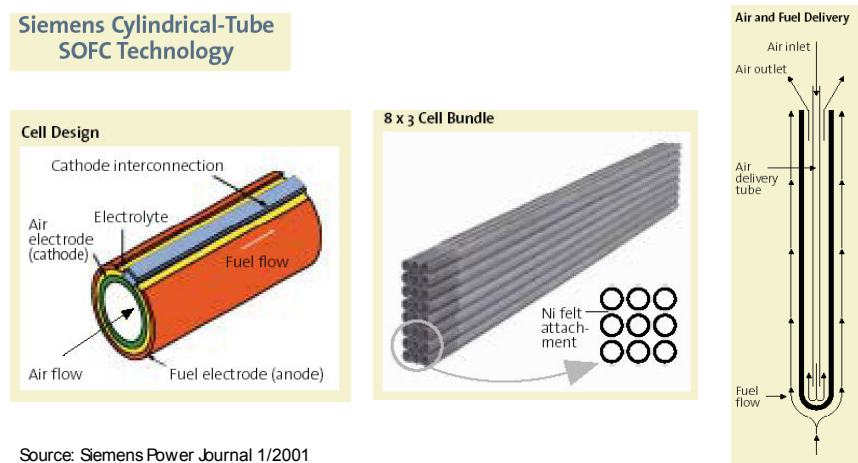


Figure B-4: The Siemens-Westinghouse tubular SOFC design (Bessette et al. 2001)

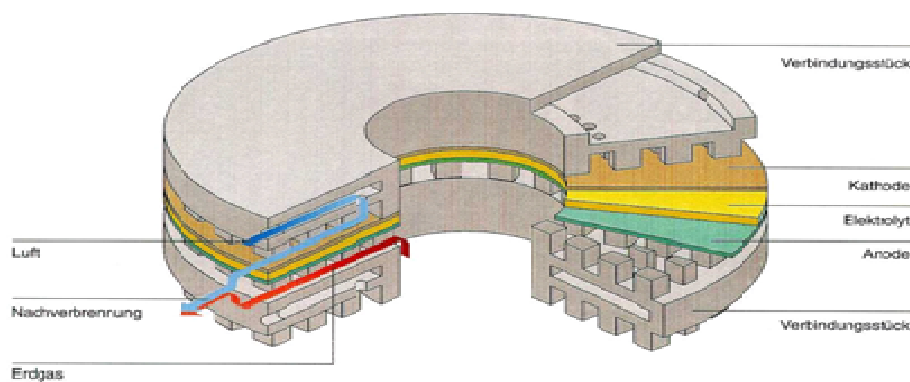


Figure B-5: The Sulzer Hexis planar SOFC design (Sulzer 2002)

Fields of Application

Current SOFC development aims primarily at stationary applications. The two main manufacturers which are closest to SOFC commercialisation developed two different SOFC concepts for different applications for the combined heat and power sector:

- The Sulzer Hexis system, which is based on the planar SOFC concept, generates 1 kW of electrical power and is intended to cover the thermal requirements of a one-family house. A modular auxiliary burner integrated into the system is switched on automatically on higher heat demand, thus the system replaces a conventional gas boiler. The system is designed for use with natural gas, it is operated in parallel to the grid.

Sulzer Hexis is commercialising the fuel cell system “HXS 1000 Premiere” with an energy contracting programme in close cooperation with utilities. A pre-series phase was launched towards the end of 2001. It is planned to manufacture a near-series product starting from the end 2004/beginning 2005.

- Siemens-Westinghouse is planning two major product lines based on the tubular SOFC concept. The first product will be a 250 kW cogeneration system operating at atmospheric pressure. The system will be a direct scale-up of a 100 kW demonstration plant, which was operated in the Netherlands since 1997, and later in Germany. The 250 kWel system will be followed by a pressurised SOFC/gas turbine hybrid system of approximately 500 kWel. A 220 kWel proof-of-concept hybrid system is operated at the University of California, Irvine. After initial production, larger systems are expected as well.

Current developments also aim at using small scale (1-10 kW) SOFCs as Auxiliary Power Units (APU) in vehicles and aircrafts. While this application might open up a potential high value mass market for fuel cells, it is not relevant in terms of installed capacity from the overall energy system’s perspective, so that we do not consider it in the context of CASCADE-MINTS. Research and development activities in this area might however accelerate the technical progress in SOFC research, thus resulting in spillovers that might affect the introduction of stationary applications.

Technical Data

The technical data of the relevant SOFC systems are summarised in Table B-8. Data from the pre-series phase of the Sulzer Hexis system indicate that an electrical net efficiency between 25 and 30 % were achieved. The development target is to achieve an electrical efficiency > 30 %, so that we assume a 32 % net electrical efficiency and a 90 % overall efficiency as a long term development perspective. The main problem of the per-series product is the high stack degradation, resulting in an average lifetime of the stack of only 2000 hours (Raak 2003). More than 90 % of the demonstration systems had an availability of more than 90 %.

There are currently two demonstration plants that can be used to get an indication of performance data of the Siemens-Westinghouse concept. A 100 kW_{el} SOFC cogeneration unit was first operated by EDB/ELSAM in the Netherlands, and was moved in 2001 to Essen, Germany for operation by RWE. The demonstration plant has been operated since more than 20,000 hours, and achieved an electrical efficiency of 46 %. According to information from Siemens, a stack lifetime of more than 80,000 hours seems to be achievable already now with the Siemens-Westinghouse tubular stack concept (as a conservative estimate, we assume a stack lifetime of 40,000 hours for current state-of-the-art).

The first SOFC/gas turbine hybrid system is operated by Southern California Edison at the University of California. As of January 2002 the system has operated for more than 900 hours and has demonstrated 53 % electrical efficiency (Siemens 2004). It is expected that hybrid systems with a capacity of 1 MW can achieve an electrical capacity of 60 % using simple small gas turbines. At the 2 to 3 MW capacity level with larger, more sophisticated gas turbines analysis indicates that electrical efficiencies of 70 % or more are possible. However, the construction of a 1 MW “Mega-SOFC” in Marbach (near Stuttgart, Germany) which was planned to be brought into operation in 2003, had to be cancelled; the ‘official’ reason was that there was no appropriate micro-gas turbine available, but there are also doubts on whether cost targets could have been achieved.

Table B-8: Technical data of SOFC systems

		1 kW _{el} SOFC single-family house application		250 kW _{el} atmospheric SOFC		pressurised hybrid SOFC	
		state-of-the-art	long term target	state-of-the-art	long term target	state-of-the-art	long term target
Performance data							
Electrical power (fuel cell)	kW _{el}	1	1	250	250	244	400
Gas turbine AC power	kW _{el}					65	100
Electrical net efficiency	%	28	32	47	49	58	60
Overall efficiency	%	80	90	80	85	80	85
Stack lifetime	h	2,000		40,000	100,000	40,000	100,000
availability	%	> 90					
Fuel processing							
Fuel		natural gas		natural gas, biogas		natural gas, biogas	
Desulphurisation		activated carbon					
Reforming		steam reformer or catalytic partial oxidation		internal reforming		internal reforming	

Economic data

Current cost estimates

The costs for the 100 kW Siemens-Westinghouse demonstration plant which was put into operation in the Netherlands in 1998 were estimated to about 100,000 €/kW_{el} by (Kuipers 1998). Investment costs for a today's demonstration plant are estimated by Siemens to 10,000 to 25,000 \$/kW. Costs for a first commercial market introduction shall be reduced to 6,000 \$/kW, and the long term target costs are 1,000 kW for a CHP unit, and 500 \$/kW for a small scale SOFC system (Kabs 2002), which we consider here as extremely optimistic. Based on the analysis of component costs, Siemens-Westinghouse expects that a turn-key-price of 1,300 \$/kW for a 1-3 MW hybrid system (SOFC/gas turbine) can be realised if series production of 50 units per year is achieved (George a. Bessette 1998). Tanaka et al. (Tanaka et al. 2000) however estimate the investment costs for a 1 MW pressurised hybrid system to 4,900 \$/kW. The costs for the stack are estimated to about 25 to 50 % of the total system costs, while the share of the gas turbine is about 35 %.

For planar concepts, prices for electrolyte-supported cells produced in batch wise series are in the range of 2,500 to 5,000 \$/kW, whereas the prices of prototypes of anode-supported cells are in the order of 12,000 \$/kW (Stöver et al. 2003). It is obvious that an order of magnitude cost reduction is still required to achieve commercially acceptable prices for the cells. Sulzer Hexis expects to reduce costs for the 1 kW_{el} HXS Premiere system to 3,600 CHF until 2010 (Sulzer Hexis 2001).

Table B-9: Cost estimates for SOFC systems

		1 kW family application	single- house unit	250 atmospheric kW CHP	500 pressurised hybrid CHP unit
Investment costs (system)					
Cost estimates for current demonstration plants	€ ₂₀₀₀ /kW _e	> 10,000		10,000-25,000	10,000-25,000
Target costs for market introduction	€ ₂₀₀₀ /kW _e	2,300		6,000	6,000
Long term target costs	€ ₂₀₀₀ /kW _e			~ 1,000	~ 1,000
Share of stack costs	%			20-50	20-50
O&M fixed costs	% Invest./a	2-5		2-5	2-5
O&M variable costs					

Cost reduction perspectives

In Siemens-Westinghouse tubular cells, the cost of powder for the cathode support structure dominates the material costs. Siemens is currently developing the so-called High-Power-Density (HPD)-tubes with a significantly higher power output per cell. It is expected that due to the new design the material costs can be

reduced up to 50% (Stöver et al. 2003). For planar cells, the material cost per kW is already low compared to tubular cells. Materials cost reduction is probably only achievable through the use of cheaper (more impure) raw materials, or due to the introduction of innovative cell designs, which however would require the development of a completely new technology (comparable e.g. with crystalline silicon PV cells versus the development of thin film PV cells).

A reduction of tubular fuel cell manufacturing costs can be achieved by replacing the expensive electrochemical vapour deposition (EVD) process for depositing thin electrode and electrolyte layers, e.g. by plasma spraying. In combination with the use of HPD-tubes and the use of cheap cathode powders, and assuming mass production of at least 200,000 cells per year (i.e. 20 MWel/a), it is expected that the cell target costs of < 250 \$/kWel might be reached (Stöver et al. 2003).

Large-scale manufacturing of planar SOFC components shows many similarities with manufacturing electronic components in the semi-conductor industry. Materials use of planar SOFC components are relatively small compared to tubular cells and manufacturing techniques such as tape casting and screen-printing are often cheap. However, in trying to reach the target costs, high volume manufacturing is probably not enough, but technical breakthrough will have to occur to further reduce manpower and material costs (Stöver et al. 2003). According to (Visco et al. 2003; Williams 2005), the cost goals of the US Solid State Energy Conversion Alliance (SECA) for planar solid oxide fuel cell systems are 400 \$/kW, resulting in stack target costs of 140 \$/kW. A recent modelling of SOFC stack costs by (Carlson et al. 2004), which is based on a detailed assessment of material and fabrication costs, suggests that stack costs of around 90 \$/kW can be achieved at a production volume of 250 MW per annum. From our point of view these cost targets should be considered as very optimistic. We suggest to use them in CASCADE as an indication of floor costs for the generic large cogeneration fuel cell unit, which thus is around 300 €/kW.

Current manufacturing capacity for tubular fuel cells at Siemens Westinghouse is in the order of 3-15 MWel/a. For planar cells, several companies have invested in manufacturing capacities, with a total installed capacity worldwide in the order of 3-30 MWel/a of semi-continuous production lines.

Other fuel cell technologies for stationary applications

In addition to the fuel cell technologies described above in detail, there are other fuel cell technologies that have been of importance in the past, or that are discussed as a future option. In the following we briefly discuss these fuel cell technologies, and we give some reasoning on why we do not include them as a promising option for further consideration in CASCADE MINTS:

Alkaline Fuel Cell (AFC). Like PEMFCs, alkaline fuel cells (AFC) are also low-temperature cells. They use an aqueous solution of potassium hydroxide (KOH) as the electrolyte, with concentrations ranging from 35-85 %, depending on the operating temperature. AFCs contain less noble metal catalyst material than

PEMFCs. A major operating constraint for AFCs is the requirement for low carbon dioxide concentrations in the feed oxidant stream.

Although AFCs were one of the first fuel cells to be developed and used mainly in space and military applications, the interest in this type of fuel cells has diminished over the years. AFCs were considered to be too costly for commercial applications, and there are no significant advantages over PEM-fuel cells, so that current R&D activities clearly favour PEMFCs for low temperature fuel cell applications. Several companies however are examining ways to reduce costs and improve flexibility.

Protonic Ceramic Fuel Cell (PCFC). This type of fuel cell is based on a ceramic electrolyte material that exhibits high protonic conductivity at elevated temperatures. PCFCs share the thermal and kinetic advantages of high temperature operation with molten carbonate and solid oxide fuel cells, but will not be able to use CO or hydrocarbons directly. Up to now there are no pilot applications from which any technical data of a future fuel cell system can be derived. The advantage over the well advanced MCFC and SOFC is not obvious.

Stationary fuel cells: summary of technical and economic data

The following Table B-10 provides a summary of the key technical and economic data of the various fuel cell technologies for stationary application to be used as an input into the CASCADE-MINTS database. Note that data refer to the use of natural gas as a fuel. If the energy system models require a more aggregated representation of stationary fuel cells, based on the detailed data of the different types of fuel cells Table B-11 suggests a specification of a generic small scale fuel cell heating application (1 to 5 kW_{el}) and a larger fuel cell cogeneration unit (200 kW_{el} to 5 MW_{el}).

Table B-10: Stationary fuel cells: summary of technical and economic characteristics

	Capacity	elect. efficiency %	overall efficiency %	availability %	plant lifetime (system/stack) a	investment costs € ₂₀₀₀ /kW _{el}	fixed costs % Invest./a	variable O&M costs
PEMFC								
1-5 kW _{el} house supply system								
‘today’	1-5	28	80	< 80	15/2	11,500	5	
2030	1-5	32	90	90	20/10		2	
250 kW _{el} system								
‘today’	250	35	76	< 80	15/2	14,000	5	
2030	250	42	84	90	20/10		2	
SOFC								
1-5 kW _{el} house supply system								
‘today’	1	28	80	80	15/1	10,000	5	
2030	1	32	90	90	20/10		2	
atmospheric SOFC, CHP unit								
‘today’	250	47	80	80	15/5	10,000	5	
2030	250	49	85	90	20/10		2	
pressurised hybrid SOFC								
‘today’	300	58	80	80	15/5	10,000	5	
2030	500	60	85	90	20/10		2	
PAFC								
PC25 200 kW _{el}								
‘today’	200	37	87	90	15/2	4,500	3	
MCFC								
250 kW _{el} system								
‘today’	250	47	83	80	15/3	12,000	5	
2030	250	52	86	90	20/10		2	
1 MW hybrid system								
2010 (?)	1,000	55	90	80	15/5		5	
2030	1,000	56	90	90	20/10		2	

Table B-11: Characterisation of ‘generic’ stationary fuel cells for CASCADE MINTS

Capacity		elect. efficiency	overall efficiency	availabilit y	lifetime (system/ stack) a	investmen t costs	fixed O&M costs	variable O&M costs	Floor costs
kW _{el}		%	%	%	a	€ ₂₀₀₀ /kW _{el}	% Invest./a		€ ₂₀₀₀ /kW _{el}
Small scale fuel cell heating appliance									
‘today’ 2030	1-5	28	80	80	15/2	11,000	5		
	1-5	32	90	90	20/10		2		150
Fuel cell cogeneration unit									
‘today’ 2030 (pressurised system)	200-500 (atmospheric system)	46	80	80	15/5	12,000	5		
	200-5,000 hybrid	58	87	90	20/10		2		300

Mobile Fuel cell systems for automotive application

Polymer Electrolyte Fuel Cell (PEFC) system

Basic mechanism

The basic mechanism of polymer electrolyte membrane fuel cells (PEFC) is described in section 1.1.1. on stationary fuel cell systems. For automotive applications PEFC can be applied also, however the main difference between stationary and automotive applications lies in the high degree of integration of system components in order to comply with the available space in a passenger car.

In order to operate a fuel cell stack in general, supplementary technical equipment is necessary. These equipment is composed of a stack cooling system, a cathode air supply compressor, sensors and control valves. In addition so called ancillary components or 'Balance of plant' (BOP) and efforts are needed to operate the fuel cell stack within an application: e.g. an electronic controller, a start-up battery, electrical equipment, safety equipment and system packaging. The figure below illustrates such a PEFC system with the stack and the surrounding controls.

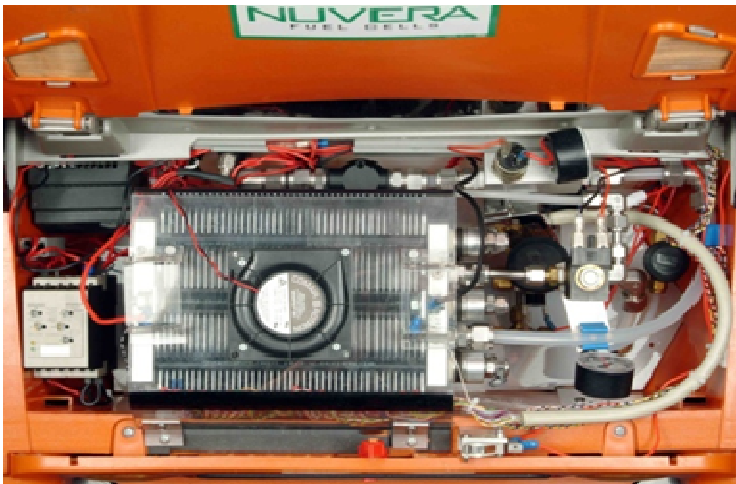


Figure B-6: 1.5 kW PEFC system (Source: DLR-FK)

Fields of application

Polymer electrolyte fuel cell stacks are preferably used in fuel cell engines which are designed to be easily integrated into electric vehicles. Today, most of the fuel cell demonstration vehicles are custom build with an individual integration of components in the vehicle. Development towards modularisation and system integration however is the way forward in the future in order to fit in the concept of automobile manufacturing.

Fuel cell engines typically consist of the system module, the stack module, a control unit, power distribution unit (PDU) and a cooling pump, as shown in Figure B-7 from Ballard. Ballard is today the world leader as a fuel cell system integrator.

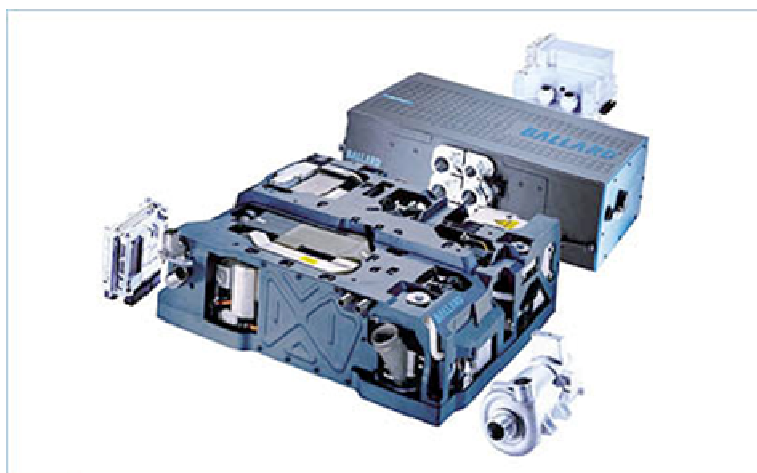


Figure B-7: Light duty fuel cell engine Xcellsis HY-80 from Ballard (Source: (Ballard 2004)).

To date a small fleet of fuel cell vehicles has been demonstrated (see Table B-12 for vehicles of the time 2001-2003). However no fuel cell vehicle is commercially available yet. The next generation of demonstration vehicles is expected to be introduced between 2005-2007. Commercially available fuel cell vehicles are expected to be manufactured after 2012. Market penetration however depends on several other factors like e.g. the existence of a hydrogen supply infrastructure.

Table B-12: Hydrogen fuel cell demonstration vehicles 2001-2003.

Car manufacturer	Fuell manufacturer	Cell Nr. demonstratio n projects	of Project	Year
Daimler Chrysler	Ballard	14	F-Cell (A - Class)	2002
Ford	Ballard	5	Advanced Focus FCV	2002
General Motors	Hydrogenics/GM	9	Diesel Hybrid Military truck	2003
Honda	Ballard	5	FCX	2002
Toyota	Toyota	10	FCHV-Bus2	2003
Nissan	Ballard/UTC	3	X-TRAIL (SUV)	2002
PSA Peugeot Citroen	Nuvera, H Power	2	Peugeot Fuel Cell Cab "Taxi PAC"	2001
BMW	UTC	2	BMW 745h	2001

Technical data

Polymer electrolyte fuel cell stacks

Considerable improvements in power densities have been achieved in PEFC stacks through reduction of electrolyte thickness and architectural control of the composite electrodes. Current research efforts are targeted on developing water-free membranes. This technology significantly reduces the system complexity and would result in lowering costs. A second target is to increase the operation temperature from at present 70°C to about 150-170°C. Higher operating temperatures result in higher efficiency and greater fuel flexibility due to enhanced electrode activity (Haile 2003). This would solve also currently existing problems with the

catalyst and help to reduce platinum loadings. State-of-the-art platinum loadings are 0.3 mg Pt/cm² for pure hydrogen as fuel, while for reformat 0.6 mg Pt/cm² are used (Rice 2004).

Reformers

Direct hydrogen allows for simpler system architecture but storage problems limit the operation range of vehicles. The use of small reformers to produce hydrogen onboard of FCVs could overcome this and omit major infrastructure changes and thus support the transition towards fuel cell propulsion at low costs. Onboard reformers convert a liquid (or other gaseous fuel) to hydrogen, however natural gas reforming is more difficult than liquid reforming, and therefore research has focused on liquids reforming so far. Methanol reforming is also possible, however to check whether reforming is economically a possibility at all, CASCADE focuses on gasoline reformers. It is also important to note that the funding for R&D of onboard fuel processing in the US has been recently severely reduced since it was judged uncertain if the technical goals can be reached until 2015. The independent review panel concluded, that due to the advanced state of competing technology (gasoline ICE/battery hybrids) on-board reforming technology does not offer clear advantages over hybrid vehicle technology available today (DoE Team Report, 2004). Table B-13 shows key technical data for gasoline reformers.

Table B-13: Technical data for gasoline reformers

Characteristics	Units	Status (2003)	Target for year		Ultimate target
			2005	2010	
Efficiency	%	78	78	80	>80
Power density	We/L	700	700	800	2,000
Specific power	W/kg	600	700	800	n.a.
Durability	hours	2000	4000	8000	8,000

Source: Thompson et al (2005), DoE Team Report (2004)

Economic data

Cost data for current PEFC stack

For automotive applications, it is still rather difficult to purchase a fuel cell stack with an electric power above 50 kW_{el} today. Stacks that are build in demonstration vehicles are mostly obtained through research co-operations. This technology cannot be purchased in the wholesale or retail market yet and therefore no clear price is available. Currently available information on the unit cost is thus not based on a “true” business calculation. Some indicative cost data of for fuel cells implemented in demonstration projects are summarised in Table B-14.

Table B-14: Cost data for PEFC stacks for molecular hydrogen.

Stack characteristics	Power kW net	Year	Units units year	Stack cost / T€	Cost €/kW _{el}
ZSW "Water cooled stack"	n.a.	n.a.	n.a.	30	n.a.
Ballard 70kW-Stack	37	2003	n.a.	230	6,000
Nuvera "Direct water stack"	10				7,000
Nuvera "Air cooled stack"	0.5			2	4,000
Smart Fuel Cell DMFC §	0.05			5	100,000
Föller H ₂ -System	0.08			5	63,000

Source: all data DLR-VC internal information. § methanol, all others hydrogen stacks

Cost data for current fuel cell engines

A fuel cell engine such as the Xcellsis HY-80 comprises the stack and the system equipment to run the fuel cell. The production volume of fuel cell engines from Ballard in 2003 was < 10 units with "costs" of about 37,000 US\$/kW. The term "costs" is here used in the sense of the expenses which have to be paid to suppliers for purchasing specialised components by the system integrator. This includes however not the accumulated expenses accruing from own research of Ballard. In 2004, the production volume is expected to be approximately 100 fuel cell engines. For this number of sales already cost reductions in one order of magnitude to 3,700 US\$/kW are anticipated (Anonymous 2004). Of the total costs only 40% are allocated to the stack manufacturing while the remaining 60% originate from system components.

Modelled cost projections for PEFC fuel cells

Total fuel cell module costs are projected by ADL (2001) to US\$ 181/kW for a PEFC-Stack with 50 kW_{el} (unit cell voltage 0.8V, power density 250 mW/cm²). These costs are driven by the membrane electrode assembly (MEA) (82%), while approx. 12% arise from the bipolare coolant plate and interconnect. Cost projections of several other authors lead to contributions of MEA in the range of 50-80% to the total cost of a PEFC-stack. This is due to the complicated manufacturing processes and the contribution of membrane and catalyst material cost.

Current carbon paper electrodes are thermoset resin impregnates carbon fiber paper moulded and graphitised at temperatures in excess of 2000°C. Typically, these electrodes are 0.2 – 0.3 mm thick, but provide the required electrical conductivity and structural strength (James 1999). Costs for such components are approx. 50 \$/m² at an annual production volume of 2000 m², but may potentially drop to 20 \$/m² provided further standardization and market introduction.

The configuration of the catalyst in the PEFC depends to a large extent on the type and quality of fuel used. Recent research has focused on CO-tolerant catalysts, which are needed at the Anode, if hydrogen contains residual CO from the reforming process. Pt-Ru catalysts are the state-of-the-art here.

Almost all of the membranes contain the toxic element fluor. Therefore, the manufacturing process needs dedicated precautions to protect the environment, which adds also to the total costs for such systems. Research on fluor-free membranes is currently under way (e.g. by AXIVA). However interim results are not yet available since such membranes are still in development (Gerl 2002).

Cost targets

To compete with existing automotive propulsion systems, fuel cell systems for vehicle application will have to reach costs between \$45 and \$60/kW with a lifetime of 3,000 to 5,000 hours (Freund 2003). Current costs of conventional power trains are in the order of 35 €/kW.

U.S. research programmes set several technical and economic targets in the past. The cost target of PNGV1 was ~50 US\$/kW. The successor of the PNGV U.S. DoE research programme is the FreedomCAR initiative. FreedomCAR differs from PNGV as its focus is petroleum free with emphasis on hydrogen fuel cells, and with a long-term vision with intermediate 2010 component technology goals (Garman 2002). Table B-15 presents cost targets of these research projects differentiated by years.

Table B-15: Cost targets for PEFC stacks and PEFC systems

Characteristics	Power kW net	Year of projection	Units projected		Cost US\$/kW _{el}	Reference
			units / year	units cumulative		
PNGV cost targets for fuel cell stacks (excl. subsystem)		1997	500,000	n.a.	200	ADL (2001)
		2000	500,000	n.a.	100	
		2004	500,000	n.a.	35	
FreedomCar cost targets for fc system including fuel reformer	n.a.	2010	n.a.	n.a.	45	FreedomCar (2005)
excl. storage tank	n.a.	2015	n.a.	n.a.	30	

Cost projections for PEFC fuel cell stacks

Kalhammer et al. (1998) prepared a view on ‘status and prospects of fuel cells as automobile engines’ for the State of California Air Resources Board. The panel concluded that a “stack cost target of approximately US\$1000 (US\$ 20/kW) may be achievable in large volume production (> 100,000 stacks per year)”. It was stressed, however, that only preliminary and incomplete cost projections were available.

In a multi-year research programme, Arthur D Little (2001) assessed the technology and the cost of a PEFC fuel cell system for automobiles, including a fuel processor system for hydrocarbon fuel. As the configuration of a fuel cell system for reformat is more complex, and therefore differs from a pure hydrogen fuelled system. Projections of ADL and others are summarised in Table B-16. Projections using learning curve methods are summarised in Table B-17.

¹ Partnership for a New Generation of Vehicles, former US research programme.

Table B-16: Technical cost projections of PEFC stacks

Stack characteristics	Power kW net	Units projected units / year	units cumulative	Cost US\$ / kW _e	Reference
(Not available)	50-60	>100,000	n.a.	60	Kalhammer (1998)
Hydrogen, 0.6 V, 1076 mA/cm ²	63	500,000	n.a.	20	Lomax (1998)
	56	10,000	n.a.	82	James (1999)
Pt 0.25 mg/cm ²		500,000	n.a.	19-28	Oei (2000)
Reformate; Pt 0.8 mg/cm ² , Ru	50	50,000	n.a.	181	ADL (2001)
Direct H ₂ , 0.6 V,	50	500,000	n.a.	~44	James (2002)
Reformate, 0.7 V, 400 mA/cm ² , 0.3 mg Pt/cm ² Cathode	50	500,000	n.a.	~150	James (2002)

Table B-17: Cost projections of PEFC stacks by learning curve

Stack characteristics	Power kW net	Year of Units projected projection	units / year	units cumulative	Cost US\$ / kW _e	Reference
n.a.		2010	25.000	50.000	167	Tsuchiya (2004)
n.a.		2015	200.000	500.000	79	Tsuchiya (2004)
n.a.		2020	2.000.000	5.000.000	15/38/145 [§]	Tsuchiya (2004)

§ Combination of scenarios with rapid, slow, moderate learning and high, medium, low power density.

Floor costs of PEFC stacks

Floor cost estimates for PEFC stacks are not given in literature. The lowest stack cost estimate reported is \$15/kW for the year 2020 at a cumulated production of 5 million by Tsuchiya (2004). Power density improvement would be essential for this scenario starting from 2 kW/m² to increase to 5 kW/m². Platinum loads are decreasing from today 0.4 mg/cm² to 0.05 mg/cm² and platinum costs are assumed constant at 35 €/g. We suggest to use 75% of this value as a minimum floor cost for pure hydrogen stacks, i.e. 11 €2000/kW_e. For reformate stacks, we assume a high level of improvement in reformer technology, and thus minimum floor costs of 15 €2000/kW_e.

Reformer costs

James (2002) estimates costs for reactor & peripherals to between US\$60/kW_{net} and US\$130/kW_{net} considering year 2001 technology with a focus on realistic and complete cost assessment without dramatic forward projections. Other cost estimates are in the same range, e.g. US\$65/kW_e (status 2/2004, DoE Team Report (2004)). Ultimate target costs are below US\$10/kW_e (cit. op.). We recommend to use ~ 5 €2000/kW_e as minimum floor cost for reforming.

Cost projections for PEFC fuel cell systems

System peripherals costs including turbo-compressors and power conditioners contribute considerably to the overall costs of a fuel cell engine. For a direct hydrogen system today the stack is estimated to 50 %-60 % of total system costs (James 2002). This ratio holds today also for a reformate system, as not only the reformer adds cost, but also the stack is more expensive due to higher catalyst loading. System costs for direct hydrogen and reformer systems are presented in Table B-18.

Table B-18: Technical cost near future projections of PEFC fuel cell systems

System characteristics	Power kW net	Units projected units / year	units cumulative	Cost € ₂₀₀₀ / kW _e	Reference
Direct H ₂ stack & peripherals, 0.6 V, no storage;	50	500,000	n.a.	~73	James (2002)
Stack, reactor & peripherals, 0.7 V, 400 mA/cm ² , 0.3/0.4 mg Pt/cm ² Cathode/Anode, no storage	50	500,000	n.a.	~241	James (2002)

Floor costs of PEFC systems

For the minimum floor costs of the ancillary system components like coolant-, fuel-, water- and air-loop, controls and misc. BoP we estimate 11 €/kW_{el} assuming that the ratio stack/system can be kept constant due to membrane developments which lower system effort. Together with the floor cost for PEFC stacks of 11 €₂₀₀₀/kW_{el} this will result in overall PEFC direct hydrogen system minimum floor cost of **22 €/kW_{el}**.

For minimum floor cost of fuel cell systems with gasoline reformer we sum up minimum costs of system components (~11 €₂₀₀₀/kW_{el}), floor cost for reformer systems (~5 €₂₀₀₀/kW) and floor cost of PEFC for reformat (~15 €₂₀₀₀/kW_{el}), resulting in overall floor costs of **31 €₂₀₀₀/kW_{el}**.

Technical and economic data on fuel cell stacks and systems are summarised in Table B-20.

B.1.2 Hydrogen engines for automotive application - Hydrogen production options

Basic mechanism

Hydrogen can be used as a fuel for internal combustion engines (H₂ICE). The combination of hydrogen as an energy carrier with proven and well understood engine technologies is seen as an ultimate near-term solution which could bridge the gap up to the full development of fuel cell vehicles. Combustion of H₂ in air produces water, non-methane volatile organic compounds and carbon monoxide below SULEV2 standard, but significant amounts of oxides of nitrogen. However given the inherent inefficiency of the internal combustion engine, H₂ICE will not be able to provide such substantial emission reductions ‘well-to-wheel’ and efficient energy use than a fuel cell powered vehicle.

The use of hydrogen as an engine fuel has been addressed on a rather limited basis with varying degrees of success over several decades (Karim 2003). Hydrogen can be applied in conventional spark ignited piston engines as well as in compression ignition engines of dual fuel type, homogenous charge compression

² California’s “Super Ultra Low Emission Vehicle” standard for tailpipe emissions.

ignition engines (HCCI) and engines where ignition is effected through surface or catalytic ignition (Karim 2003).

There are numerous positive features of hydrogen as an ICE fuel, mostly related to its high burning rates. However there are also some disadvantages and limitations. Engines fuelled with hydrogen suffer from reduced power output, due mainly to the very low heating value of hydrogen on volume basis (Karim 2003). A hydrogen engine when operated stoichiometrically needs to be 40-60% larger in size than for gasoline for the same power and torque output. Knock is seen as problem in SI engines caused by auto-ignition of unburned mixture of gas (Karim 2003) however seems to be solved by engine manufacturers. Due to the volatile nature of the gas, there are serious potential operational problems with uncontrolled pre-ignition and back-firing on the intake manifold, which need to be addressed.

High temperatures may lead to high emissions of oxides of nitrogen. NO_x emissions of 0.5 g/km are reported (RICARDO 2002) thus requiring a lean NO_x trap or other NO_x aftertreatment to meet EURO 4 and 5 standards.

Examples of application

Prototype vehicles using hydrogen internal combustion engines have been demonstrated in the past by BMW, DaimlerCrysler, Mazda and Ford. BMW certainly has put the highest effort in H₂ICEs, starting in 1979 and meanwhile presenting vehicles in the forth Generation (Scheuerer 2003). BMW presented a dual-fuel V12 hydrogen engine at IAA Frankfurt Motor Show 2003. DaimlerCrysler has stopped research on H₂ICE and switched to FC engines.

Mazda, the world's only manufacturer of rotary engines, has presented at the 2003 Tokyo Motor Show the hydrogen-powered version of the RENESIS as an example of a hydrogen-gasoline dual-fuel system (www.carpages.co.uk). The rotary engine can run on hydrogen with very little modification. It has the injection, compression, ignition and exhaust areas separated from each other so no pre-ignition of the gas occurs. Since the engine requires few modifications to run on hydrogen, it could enable production of a relatively low-cost hydrogen-powered alternative-fuel vehicle.

Technical data

From the demonstration vehicles and engines, some technical data are available. For general conclusions there is less information available. Some generic data for application in energy system models is summarized in Table B-19.

The BMW Group has presented a dual-fuel V12 hydrogen engine at the IAA Frankfurt Motor Show 2003. The 12-cylinder concept engine with a capacity of six litres yields 170 kW (231 HP) at 5500/min. The BMW 745h is powered by a 4.4-liter V8, featuring variable valve timing, variable intake runners, and a fully variable intake manifold. The 745h can use either hydrogen or premium unleaded gasoline. Running on hydrogen, the 745h produces 137 kW and can achieve a top speed of 214 km/h. The cruising range is 300 km. Added to the 645-km range of the normal fuel tank, the 745h can go 945 km between fill-ups (www.bmwworld.com).

The hydrogen-powered MINI features a possible new injection process in which super-cooled liquid hydrogen is injected into the intake ducts where it mixes with air before entering the cylinders for ignition. Previously, the liquid hydrogen was heated to ambient temperature before combustion (www.bmwworld.com). This measure lowers also NOx emissions (RICARDO 2002).

Ford's introduced the Model U concept SUV, including a hydrogen-fueled 2.3-liter, four-cylinder internal combustion engine (based on the 2.3-liter I-4 engine used in the Ford Ranger and European Ford Mondeo) that is supercharged and optimized to run on hydrogen. The powertrain is coupled with a hybrid electric transmission. The overall efficiency can reach 38 percent, which is 25 percent more fuel efficient than gasoline fueled ICE vehicles. The Model U was designed for mass production and affordability, and has a range of approximately 300 miles (Ford 2003)(www.carpages.co.uk).

Table B-19: 'Generic' technical data for H₂ internal combustion engines (dedicated engine).

		'dual-fuel'
Energy consumption	MJ/100 km	151 [*]
Average efficiency improvement [*]		
City cycles		+ 14% [§]
Highway cycles		+ 6% [§]
Range	km	++
Technical system lifetime	a	-as conventional-

[§] Ford P2000 demonstration vehicle results with 2.0 litre Zetec dedicate hydrogen engine (RICARDO 2002);

^{*} compared to gasoline engine; ++ depending on storage; ^{*} own calculation based on storage and range data.

Today's hydrogen IC engines do not achieve the specific power of conventional gasoline engines. The reason is that the volume of hydrogen in the combustion chamber is one third of a gasoline mixture and due to this charge loss the heating value of the total compound is lower. However with exterior mixture formation or high pressure injection with turbo charging fuel consumption of EURO IV calibrated turbo charged diesel engines are feasible (Pischinger 2005).

Economic data

Economic data on hydrogen internal combustion engines are scarce. Difiglio (2003) suggest additional cost in a range between of \$0-1,000 over conventional ICE. RICARDO (2002) used a reduction of 400 €2000 in their analysis for the year 2008 for an advanced H₂ICE compared to a Diesel engine with expensive fuel injection system. However at this stage already 800 € were include for the lean NOx trap (LNT) and a Diesel particle filter. RICARDO (2002) concludes also: "there would be a cost penalty due to the introduction of an LNT and addition of a boosting system".

Therefore we suggest until better data is available to use additional costs of 750 € compared to conventional gasoline engines due to the boosting system and LNT for energy system modelling. On the long run, no additional costs for the engine compared to a future diesel engine with supercharging can be assumed.

We don't see any significant changes on O&M fixed and O&M variable costs for the H₂ICE compared to conventional gasoline engines. Operation on hydrogen has no fundamental implications on cost, durability and recyclability of the engine (RICARD 2002).

Table B-20: Fuel cell systems for automotive application : summary of technical and economic characteristics and projections						
	plant (system/stack) a	lifetime costs € ₂₀₀₀ /kW _{el}	investment costs € ₂₀₀₀ /kW _{el}	floor cost € ₂₀₀₀ /kW _{el}	fixed costs	variable O&M costs
Direct H₂ PEFC						
Stack, 50 kW _{el}						
‘today’	2000		1800		n.a.	n.a.
2025	4000		38		n.a.	n.a.
2050	5000		24		n.a.	n.a.
....floor				11		
System, 50 kW _{el}						
‘today’	2000		3800		n.a.	n.a.
2025	4000		76		n.a.	n.a.
2050	5000		48		n.a.	n.a.
....floor				22		
PEFC with onboard reformer						
Stack, 50 kW _{el}						
‘today’	2000		2500		n.a.	n.a.
2025	4000		151		n.a.	n.a.
2050	5000		42		n.a.	n.a.
....floor				15		
System, 50 kW _{el} (incl. reformer)						
‘today’	2000		7750		n.a.	n.a.
2025	4000		199		n.a.	n.a.
2050	5000		74		n.a.	n.a.
....floor				31		
All system cost excl. onboard storage;						

B.1.3 Hydrogen production options - Hydrogen distribution

B.1.3.1 Options

Hydrogen is a high quality secondary energy carrier, not a primary fuel, and thus has to be produced from primary energy sources such as thermal or electric power. Hydrogen can be made from a variety of widely available feedstocks, including various fossil and renewable energy sources (Figure B-8). Today almost 50 % of hydrogen is produced by steam methane reforming, which for large scale hydrogen production is the most economical route. To comply with key sustainability targets (climate protection, protection of non-renewable resources), a future hydrogen economy will however be based on alternative hydrogen production options. The following sections review the current technical and economic status of hydrogen production technologies, taking into account their respective potential for future prospects for improvement.

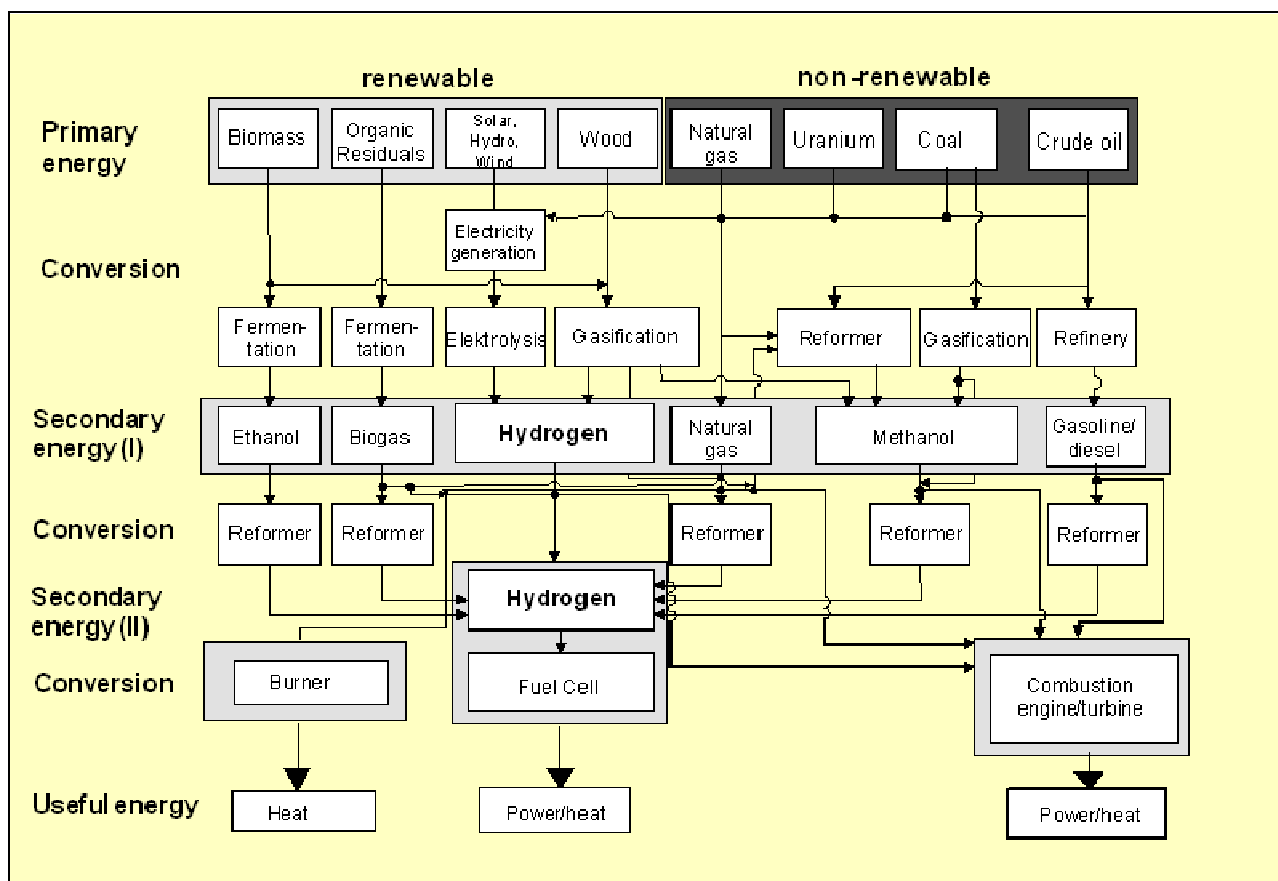


Figure B-8: Hydrogen production paths

Table B-21: Hydrogen production processes addressed

Feedstock	Production process
Electricity	Electrolysis - Alkaline electrolyser - Membrane electrolyser (PEM) - High temperature electrolyser (Solid Oxide Electrolyser Cell)
Natural gas	Steam methane reforming Pyrolysis (Kvaerner process) Solar methane reforming
Heavy fuel oil	Partial oxidation
Coal	Gasification - Gasification + Pressure Swing Adsorption (PSA) - Gasification + Pressure Swing Adsorption + CO₂-capture - Gasification + Hydrogen Separation Membrane Reactor (HSMR) + CO₂-capture
Biomass	Gasification Pyrolysis
Others	Photoelectrochemical water splitting Photobiological hydrogen production Thermochemical cycles

Note: All data in the following sections refer to the Lower Heating Value of Hydrogen!

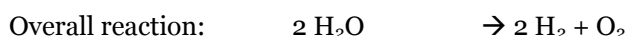
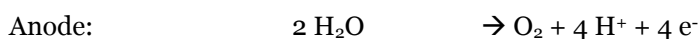
Hydrogen from Water

Electrolysis

Basic mechanism

Water is electrolysed in an electrochemical cell to produce hydrogen and oxygen. Water electrolysis was one of the main means of hydrogen production before the steam reforming process was introduced..

Water can be electrolysed by passing direct current (DC) through it in the presence of a suitable electrolyte, causing positively charged hydrogen ions to migrate to the negatively charged cathode, where they reduce to form hydrogen. Similarly, oxygen is formed at the positively charged anode. Chemically inert conductors such as platinum are used as electrodes to avoid unwanted reactions and the production of impurities in the hydrogen gas.



Three different process versions have been developed for electrolytic water dissociation:

- Alkaline water electrolyzers are in use commercially for long times. Alkaline electrolyzers work at atmospheric or low pressure (0-8 bar) or at pressure (up to 30 bar).

- Proton Exchange Membrane (PEM) electrolyzers (reverse reaction of PEM-fuel cell) use an organic membrane instead of alkaline aqueous solution, which leads to a significant volume reduction. PEM electrolyzers exhibit higher efficiency while operating at significantly higher current densities when compared to the advanced alkaline electrolyzers (but system costs are still very high, see below). Mitsubishi Corporation is developing a 'High-pressure Hydrogen Energy Generator' (HHEG), which is based on a proton exchange membrane stack in a high pressure vessel, which stores high-compressed hydrogen generated by electrolysis. The advantage of the system is that it produces high-pressure hydrogen by itself without the need for further compression.
- High-temperature steam electrolysis operates between 700 and 1000 °C, using oxygen ion-conducting stabilised ZrO₂-ceramics as an electrolyte (reverse reaction of Solid Oxide Fuel Cell). The water to be dissociated is entered on the cathode side as steam, which forms a steam hydrogen mixture during electrolytic dissociation (Winter and Nitsch 1988). The dissociation of steam theoretically requires less electrical energy than the dissociation of water. The energy required for water evaporation can be supplied by thermal energy and thus allows the use of various energy sources. The driving force for the development of the high-temperature electrolysis process in the 1980s was to use waste heat from high temperature nuclear reactors for hydrogen production, but most research activities were reduced significantly since then. Because of the improvements in Solid Oxide Fuel Cell technologies, there is a new interest in this technology, which can be combined with high temperature solar heat. Solid Oxide Fuel Cells (SOFC) used in electrolysis mode, called Solid Oxide Electrolyser Cells (SOEC), have the potential to become an efficient electrolyser technology.

Fields of application

Electrolysis is scaleable from few Nm³/h to several 10,000 Nm³/h, so that it can be used for decentralised on-site hydrogen production as well as for large scale centralised hydrogen plants. On-site hydrogen production can use existing electrical infrastructure and has the advantage that no additional infrastructure for hydrogen distribution is required. Due to their flexibility in operation (start and stop on demand) electrolyzers can support the load management in the electricity grid and thus facilitate the integration of fluctuating energy sources.

Because of the additional high temperature heat requirements from a nuclear reactor or a solar thermal facility, early process design studies for a high temperature steam electrolysis process assumed a hydrogen production capacity of several 10,000 Nm³/h (Dönitz 1988). A Solid Oxide Electrolyser Cell will be scaleable over a broad capacity range, thus also allowing the decentralised hydrogen production.

Technical data

As mentioned before, the capacity of electrolyzers is scaleable from small-scale on site hydrogen production to large-scale centralised hydrogen plants near the electricity source. The efficiency of the process is largely unaffected by the variation in size (EUCAR 2003), so that we do not have to differentiate between different size classes. The outlet pressure of commercially available pressurised electrolyzers range between 1.1 and 30 bar, and the efficiency ranges between 62 and 70 % related to the LHV of the delivered hydrogen (see e.g.

EUCAR 2003; Stuart Energy 2004; BOC 2004). Future long term developments are expected to result in an efficiency of close to 80 % (Dreier and Wagner, 2000).

Membrane electrolyzers are still in the development stage. A version is offered by Proton Energy Systems, USA, for the production of ultra-high purity hydrogen gas for industrial and laboratory applications, but the energy efficiency of 45 % is rather low (Proton 2004), and the lifetime of the stack is only 3 to 4 years. Mitsubishi Corporation recently announced the successful application of the 'High-pressure Hydrogen Energy Generator' (HHEG) prototype PERM-electrolyser (Mitsubishi 2004), producing hydrogen at a pressure of up to 350 bar without a compressor. The capacity of the prototype is 2.5 Nm³/h, and Mitsubishi plans to have a commercial product with a capacity of 30 Nm³/h and a pressure of 400 bar available in the next years. There are currently no data available on efficiency, stack lifetime, or costs of HHEG system.

Bench scale tests and a pilot plant design of a high temperature steam electrolysis process have been performed in the 1980s in particular in Germany, but research activities were slowed down (high costs, termination of the high temperature nuclear reactor programme in Germany). As discussed above, current research activities (e.g. at RISO, Denmark) on high temperature electrolysis focus on Solid Oxide Electrolyser Cells. The splitting of steam into hydrogen and oxygen at 1000 °C in a SOFC operated in the electrolysis mode has been successfully demonstrated in the laboratory (Jensen et al. 2003). The durability of the system is however limited, and much more work is necessary to achieve an acceptable lifetime of the cells.

Table B-22: Technical data of a high pressure electrolyser and a PEM electrolyser

		High pressure alkaline electrolyser		PEM electrolyser		High temperature steam electrolysis
		State-of-the-art	Long term target	State-of-the-art	Long term target	Long term target
Hydrogen output	Nm ³ /h	5-50,000	5-50,000	10	30	> 10,000
Electricity input	kW/kW _{H₂}	1.43	1.3	2		1.07
Steam input	kW/kW _{H₂}					0.2
Pressure	bar	30	100	1.4	400	
Efficiency ^{a)}	%	70	80	50		79
Technical system a		20	20			20
lifetime						
Stack lifetime	a			3-4	5	(80.000 h)

a)based on Lower Heating Value of hydrogen

Economic data

A summary of cost data for 100 MW scale plants built in the early 1990s suggest that the investment costs were in the range of ~600 \$₁₉₉₇/kW_{el} (Basye and Swaminathan 1997). Stuart Energy, one of the main manufacturers of alkaline electrolyzers, report capital costs for small scale systems with a capacity below 5 MW as 500 \$/kW_{el}, while the costs for larger systems (> 5 MW) are 400 \$/kW (Stuart Energy 2004). Additional system costs from connections, building, and other infrastructure are estimated to amount to about 15% of the electrolyser. Long term target costs of the US DOE for electrolyzers are given as 300 \$/kW (Myers et al. 2003), which we consider here as very optimistic. While (Angloher and Dreier, 2000) estimate that capital costs of a high pressure electrolyser will be reduced by 6% until 2025, we assume a long term cost reduction of 10 to 15%.

The O&M costs for electrolysis, apart from electricity, are small, as electrolysis plants are well automated. Electrode reactivation is normally carried out every five to seven years for alkaline electrolyzers. According to Stuart Energy the annual operation and maintenance costs amount to 2 % of the investment costs (Stuart Energy 2004).

Costs for PEM electrolyzers are currently a factor of about 3 higher than conventional alkaline electrolyzers. It is expected that due to spillovers from the development of PEM fuel cells – if manufacturers succeed to reduce fuel cell costs significantly – the competitiveness of PEM-electrolyzers might be enhanced in the future.

In the early phase of high-temperature steam electrolysis development, system target costs were estimated to amount to about 700 €₂₀₀₀/kW_{H₂} (Dönitz 1988). (Mogensen and Bagger al. 1998) estimate investment costs for a SOEC system to around 1,000 €/kW_{el}, which is well in line with the long term SOFC target costs (see section o). Because of the lower electricity demand of the high-temperature steam electrolysis, the competitiveness of the process over other electrolysis technologies gains from an increase in electricity costs.

Oxygen is the by-product of water electrolysis. Whether any credit can be taken for the oxygen produced depends very much on the oxygen demand in close proximity to the plant. In the context of CASCADE MINTS we do not consider a by-product credit for oxygen.

Table B-23: Economic data for a high pressure electrolyser and a PEM electrolyser

		High pressure electrolyser < 5 MW _{el}		High pressure electrolyser > 5 MW _{el}		PEM electrolyser		High-temp. steam electr.
		State-of-the-art	Long term target	State-of-the-art	Long term target	State-of-the-art	Long term target	Long term target
Investment cost electrolyser	€ ₂₀₀₀ /kW _{el}	525	450	420	360			
full system	€ ₂₀₀₀ /kW _{el}	600	510	480	410	1,565		1,000
Investment cost electrolyser	€ ₂₀₀₀ /kW _H	750	560	600	450			
full system	€ ₂₀₀₀ /kW _H	860	640	690	510	3,130		1,270
O&M fixed cost	% Invest./a	2	2	2	2	2		2
O&M variable cost								

Hydrogen from Fossil Fuels

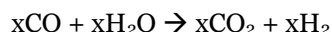
Natural gas steam reforming

Basic mechanism

Steam reforming of natural gas (SMR) is the most commonly used process for producing hydrogen in large quantities. Natural gas is reacted with steam at elevated temperatures ($> 800\text{ }^{\circ}\text{C}$) in the presence of a nickel catalyst. The reaction product (syn-gas) is a mixture of hydrogen and carbon monoxide:



The syngas from the reformer is cooled and fed to a water-gas shift reactor in which carbon monoxide reacts with steam over a catalyst to hydrogen and carbon dioxide:

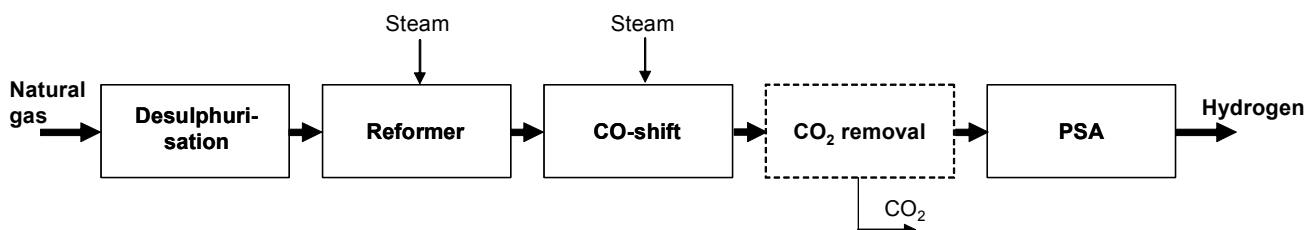


To achieve pure hydrogen, the gas is finally cleaned in a pressure swing absorption unit (PSA) (Figure B-9).

A novel concept called ‘Sorption Enhanced Reaction Process’ (SERP) aims at developing a more cost-effective steam methane reforming process. The reactants steam and methane are fed at $440\text{--}550\text{ }^{\circ}\text{C}$ into a reactor containing an admixture of reforming catalyst and an adsorbent for removing carbon dioxide from the reaction zone (Reijers et al. 2003, Hufton et al. 2000). The potential benefit from this process is the production of hydrogen at relatively high purity ($\sim 90\% \text{ H}_2$) directly from the reactor, thus leading to a reduction or even elimination of downstream hydrogen purification steps.

Möller et al. (Möller et al. 2004) suggest that fuel saving of up to 40 % can be achieved by using a solar reforming process, which provides process heat by solar energy. The off-gas, which is burnt to provide process heat in the conventional process, can be recycled, which increases the overall process efficiency and reduces CO_2 emissions. A concentrating solar system with a heliostat field and a solar tower is used to supply high temperature solar process heat. A first proof of concept solar volumetric reactor receiver has been tested (Möller et al. 2004).

Figure B-9: Schematic diagram of natural gas steam reforming



Fields of application

Today, hydrogen is produced industrially in large-scale steam reformers at rates in the order of 100,000 Nm³/h at high pressures (20-40 bar). Decentralised on-site production e.g. at a gas station or in a residential district requires small-scale SMR facilities with a production rate between 1,000 and 4,000 Nm³/h. Small scale stationary and mobile reformers which are developed as being part of a fuel cell package are not considered here.

Technical data

Table B-24 summarises key technical data for two steam reforming facilities of different size, which are considered as representative for small scale on-site hydrogen production, and for large scale industrial applications. As SMR is a well established and mature technology, the potential for technical improvement is limited. According to (Dreier and Wagner 2000) we assume that today's process efficiency of 67% (small scale) and 74% (large scale) (related to LHV of hydrogen) can still be slightly increased in the future.

Results from first Sorption Enhanced Reaction Process laboratory plants do not yet fulfil the expected performance objectives (Hufton et al. 2000), so that the potential for improvement is difficult to assess. We suggest to not consider this new process here as long as there is no further technical evidence that the theoretical targets can be met.

Technical data for the solar reforming process are based on a system design study by (Möller et al. 2004). The plant has a solar thermal capacity of 50 MW_{th}, and a hydrogen production rate of 50,000 Nm³/h. The current concept aims at a 'solar only' operation mode without storage for night time operation, resulting in only 2,000 full load hours per year. The system requires 0.25 Nm³ of CH₄ per Nm³ of H₂, and 0.32 kWh solarthermal energy per Nm³ of H₂, resulting in an overall reformer efficiency of 87 %.

Table B-24: Technical data for steam methane reforming (SMR) (Dreier and Wagner 2000, Möller et al. 2004)

			Small scale on-site SMR		Large scale SMR		Solar reformer
			State-of-the-art	Long term target	State-of-the-art	Long term target	Long term target
Capacity	natural gas	kW	4,500	4,275	405,000	385,000	125,000
Solar heat		kW					47,700
Hydrogen output		Nm ³ /h	1,000	1,000	100,000	100,000	50,000
Pressure		bar	16	16	30	30	
Efficiency ^{a)}		%	67	70	74	78	87
Technical lifetime	system	a	25	25	25	25	20
Utilisation time		h/a	8,000	8,000	8,000	8,000	2,000

^{a)} based on Lower Heating Value of hydrogen

Economic data

A literature review by (Basye and Swaminathan 1997) suggest capital costs for large hydrogen production plants (1.4 to 2.8 million Nm³/d) in the range of 160 to 490 \$₁₉₉₇/kW_{H₂}, indicating that economies of scale

plays an important role even in these large scale plants. More recent data from (Dreier and Wagner 2000) suggest capital costs of 335 €/2000/kW_{H2} for large scale steam methane reforming plants. Capital costs for decentralised small scale applications are significantly higher, and according to (Dreier and Wagner 2000) amount to 690 €/2000/kW_{H2} for the 1,000 Nm³/h reference plant. As the process of steam reforming is well established, (Angloher and Dreier, 2000) do not expect a substantial potential for further cost reduction. We assume that on the long term specific investment costs will be reduced by 5%.

A review of O&M costs from various studies in (Basye and Swaminathan 1997) suggests that normalised O&M costs for large scale plants are between 0.45 and 0.6 \$-cents₁₉₉₇/Nm³. We thus assume O&M costs of 0.55 Euro-Cent₂₀₀₀/Nm³, not including feedstock costs. There are no reliable data available on O&M costs for small scale facilities. As the operating costs for smaller SMR plants do not decrease with plant size and the raw material needs per unit of hydrogen produced remains similar, we assume the same O&M costs for all plant sizes.

The economics of a first Sorption Enhanced Reaction demonstration process were found to be non-competitive with conventional technology (Hufton 2000).

The costs of the solar natural gas reforming process were estimated by (Möller et al. 2004) to amount to 370 €/kW_{H2}, including the heliostat field, the solar tower and receiver, but not including the land cost. We consider the cost estimates of Möller et al., which are only slightly higher as the investment cost of a current large scale SMR plant, as a long term target. Annual O&M costs are estimated to amount to 7 % of the investment costs.

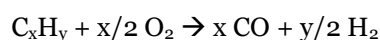
Table B-25: Economic data for a steam reformer system

		Small scale on-site SMR (1,000 Nm ³ /h)		Large scale SMR (100,000 Nm ³ /h)		Solar reformer
		State-of- the-art	Long term target	State-of- the-art	Long term target	Long term target
Investment cost	€/2000/kW _{H2}	690	655	335	320	370
O&M fixed cost	% Invest./a	5	5	2	2	5.5
O&M variable cost	€/2000/Nm ³	0.003	0.003	0.003	0.003	0.013

Partial oxidation of heavy oil

Basic mechanism

Partial oxidation is used in refineries for the conversion of residues (liquid, highly viscous hydrocarbons) essentially into hydrogen, CO, CO₂ and water. Heavy hydrocarbon's low volatility and often high sulphur content prevents using steam reforming. Instead, heavy hydrocarbons are transferred to hydrogen by partial oxidation, leading to an exothermic conversion of heavy fuel oil with oxygen:



Partial oxidation takes place at a temperature of 1300-1500 °C and a pressure of 30 to 100 bar without the need for a catalyst. The partial oxidation process is followed by a desulphurisation process, the CO-shift and

a final CO₂-removal (Figure B-10). In contrast to steam reforming, the partial oxidation process does not pose any specific requirements towards the quality of the feedstock.

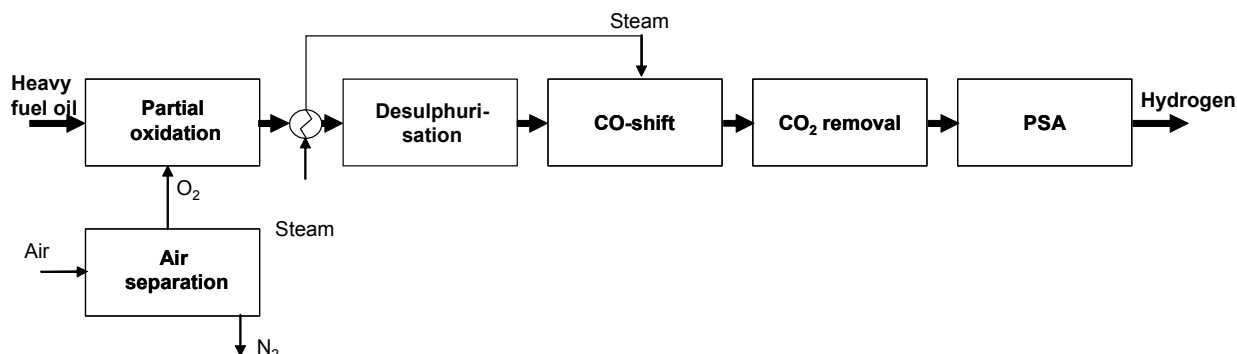


Figure B-10: Partial Oxidation process

Fields of application

Partial oxidation is not widely utilized for the production of hydrogen unless the only available feedstock is a heavy hydrocarbon. The process is most commonly considered for the production of carbon monoxide or for applications where the desired H₂/CO ratio is 1.6 - 1.8 or less. Partial oxidation is used in refineries for the conversion of residues (liquid, highly viscous hydrocarbons) essentially into hydrogen, CO, CO₂ and water. The products can be used as synthesis gas, fuel gas or feed for hydrogen recovery. Partial oxidation is relevant only for large scale hydrogen production.

Technical data

Partial oxidation of heavy hydrocarbons is a well established process based on the Texaco Gasification Process (TGP) (see e.g. EPA 1995) or the Shell Gasification Process (SGP) (see e.g. Heurich and Higman 1993). As a reference, we take technical data given by (Angloher and Dreier 2000) for a partial oxidation plant with a capacity of 100,000 Nm³/h hydrogen output. The data given in Table B-26 refer to a plant in which electricity covers about 5 % of the energy demand. As the primary energy for electricity generation is not considered when calculating the process efficiency it results in a higher efficiency compared to steam reforming.

Although partial oxidation is a well established process, it is expected that a further optimisation of system integration may result in a reduction of fuel input by 5 %, and a reduction of the electricity requirement by 10 %, leading to an improvement of the total efficiency from today 73 % to 77 % in the future.

Economic data

Capital costs for partial oxidation are higher than for steam reforming, while the feedstock price (heavy oil) is lower. Consequently, capital costs begin to contribute more to the overall production costs. Partial oxidation of heavy oil is a commercial process, so that cost estimates are based on considerable experiences. According to (Angloher and Dreier 2000), capital costs for a current heavy fuel partial oxidation plant are 500 €/2000/kW_{H₂}. They do not expect that capital costs can significantly be reduced in the future due to

technological improvements, but like in the case of steam reforming we assume a future 5% reduction of capital costs.

There are unfortunately no reliable data on O&M costs available. (Basye and Swaminathan 1997) report O&M costs of 1.9 \$₁₉₉₇/GJ based on a quite old study by (Steinberg and Cheng 1989), which are also quoted elsewhere throughout the relevant literature. We consider annual O&M costs in the range of 10 % of the capital costs as too high, and suggest to use fixed annual O&M costs of 5 % of total capital costs, which is more in line with similar facilities in the energy sector. Variable operation costs resulting from electricity consumption depend on the electricity costs. Assuming electricity costs of 5 ct/kWh, the electricity costs amount to 0.95 ct/Nm³H₂.

Table B-26: Technical data of a heavy oil partial oxidation plant (Angloher and Dreier 2000)

		State-of-the-art	Long term target
Capacity heavy oil	kW	390,400	370,900
Electricity requirement	kW	19,000	17,100
Hydrogen output	Nm ³ /h	100,000	100,000
Pressure	bar	50	50
Efficiency ^{a)}	%	73	77
Technical system lifetime	a	25	25
Utilisation time	h/a	8,000	8,000

^{a)} based on Lower Heating Value of hydrogen, does not take into account primary energy requirement for electricity input

Table B-27: Economic data of a heavy fuel partial oxidation plant (100.000 Nm³/h)

		State-of-the-art	Long term target
Investment cost	€ ₂₀₀₀ /kW _{H₂}	500	475
O&M fixed cost	% Invest./a	5	5
O&M variable cost	€ ₂₀₀₀ /Nm ³	0.0095	0.0085

Coal gasification

Coal continues to be a strategic indigenous primary energy source in a number of countries, and its global reserves and resources are abundant and more evenly distributed than oil or natural gas. Countries like China and India are likely to base the development of their energy systems, at least in the short and medium term, on indigenous coal resources. Clean-coal technologies - in particular when carbon capture and storage is applied - might play a complementary role to the decarbonisation of the energy supply mix and efficiency improvements in both the supply and demand sides (Yamashita and Barreto 2003). However, carbon capture technologies are currently under development and still face a number of challenges, in particular they must become less energy-intensive and more cost-effective. In addition, today we still know little about the storage potential of different reservoirs, their leakage characteristics and associated risks and costs.

Basic mechanism

Coal gasification is a process that converts solid coal into a synthetic gas composed mainly of carbon monoxide and hydrogen. Coal can be gasified in various ways by properly controlling the mix of coal, oxygen, and steam within the gasifier. There are also several options for controlling the flow of coal in the gasification section (e.g., fixed-bed, fluidized-bed, and entrained-flow systems). Most gasification processes being demonstrated use oxygen as the oxidizing medium.

Following (Gray and Tomlinson 2002), we consider two different coal gasification processes: The first one represents a conventional Texaco quench gasification system with acid gas removal and pressure swing adsorption (PSA) for hydrogen recovery (Figure B-11). The syngas can be cleaned of sulphur in a single-stage physical absorption unit called Selexol. For the CO₂ removal case, the Selexol unit consists of two absorbers, of which the first absorbs H₂S from the cooled syngas, and the second absorbs CO₂ from the desulfurised gas (Yamashita and Barreto 2003). The tail gas from the PSA unit is used to superheat steam for power production, excess electricity is fed into the grid. In this configuration 87 % of the feed carbon is sequestered (Gray and Tomlinson 2002).

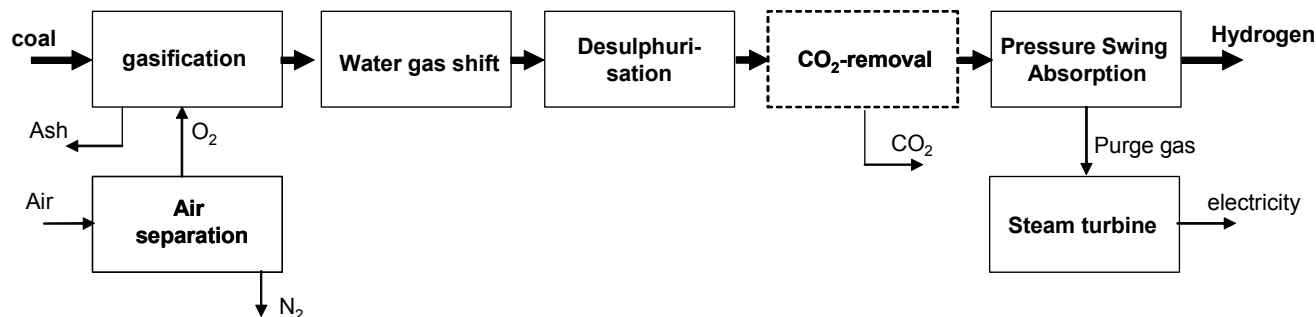


Figure B-11: Conventional coal gasification system (with/without CO₂ capture)

The second configuration is based on a high-temperature membrane device for hydrogen separation from the syngas (Klett et al. 2002). The high-pressure syngas produced in a slurry-feed gasifier is cleaned to remove particles and sulphur from the fuel gas stream. After adding steam, the pressurised syngas enters the hydrogen separation device (HSD) at the inside of the inorganic membrane tubes. The hydrogen separation membrane reactor serves both as a syngas shift reactor and a separation unit. The hydrogen produced from the HSD is 99.5 % pure. The CO₂-rich gas leaving the HSD goes to a gas turbine combustor with which oxygen is injected to convert CO and hydrogen to CO₂ and H₂O, respectively. The hot gas is expanded through a conventional gas turbine to produce electric power. The CO₂ product is cooled and dried to obtain CO₂ for sequestration.

Membrane technologies are at a very early R&D stage. Their introduction as a viable alternative will depend on the advances made in materials and on the development of the separation technologies (see Yamashita and Barreto 2003). It has to be ensured that the membrane systems are able to operate under the difficult conditions (high temperature/ pressure, chemical environment) of the coal gasification process. Because of the early development stage costs of membrane reactors and their future development are much more uncertain than those of other components.

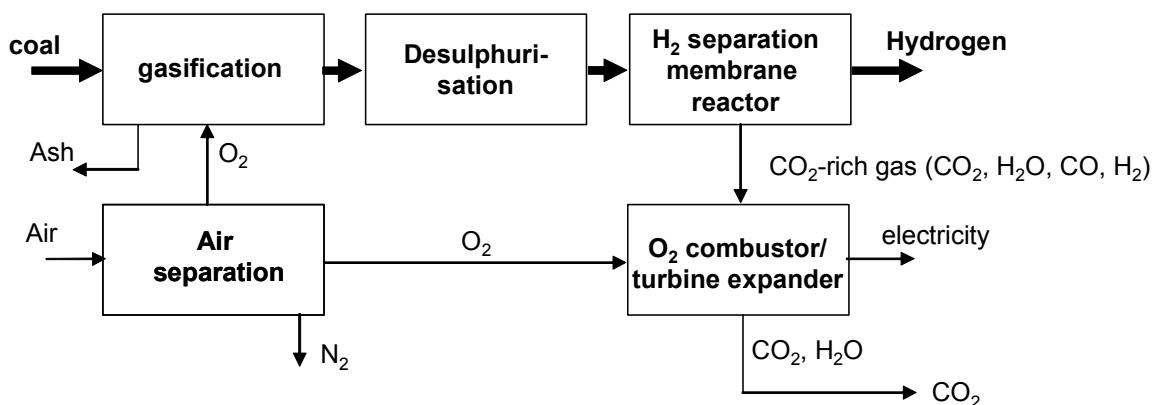


Figure B-12: Coal gasification system with a hydrogen separation membrane reactor and CO₂ capture

The Zero Emission Carbon (ZEC) concept proposed by Los Alamos National Laboratory is an integrated power production concept with a potential of achieving a high efficiency (Ziock et al. 2003). A hydrogasification process converts coal or other carbon feedstocks to a synthesis gas of mainly methane and hydrogen. This synthesis gas is reformed with steam at pressure and temperature to produce a relatively pure hydrogen stream through the use of a CaO carbonation reaction. The carbonation reaction removes the CO₂ and supplies energy needed to drive the reforming reaction. Electric power is produced from the product hydrogen in a solid oxide fuel cell, which needs to be especially designed for the coal-synthesis gas. A calcinations reaction, driven by process heat from the SOFC recycles the CaO and produces a stream of CO₂.

The installation of a ZEC pilot plant installation is planned in 2005/2006 (ZECA 2004). While the current ZEC concept aims at the integrated coal gasification and electricity generation, the process also offers the possibility to produce hydrogen and a 'pure' stream of CO₂ from any carbon fuel and water. First cost estimates published by ZECA Corporation address the integrated ZEC gasification and power plant process. Due to the very early stage of the development phase any data on costs and technical performance seem to be very indicative only. For the time being, we do not consider this process as a priority within CASCADE MINTS.

Fields of application

Coal gasification for hydrogen production is likely to be applied only for large scale centralised facilities. Current developments however mainly focus towards the optimisation and integration of the gasification process for electricity production in an IGCC power plant. Some authors support the idea of co-producing hydrogen and electricity from a coal gasification system, but the expected benefits from such a configuration remain vague.

Technical data

Table B-28 summarises the technical data of the three coal gasification processes considered. Data on the conventional state-of-the-art gasification process with PSA hydrogen separation are well in line with various references (e.g. Angloher and Dreier 2000, Klett et al. 2002). The overall efficiency of the process is reduced by about 4 %-points when CO₂ capture is introduced. A significant increase of the overall efficiency is

expected by substituting the conventional syngas treatment process by a hydrogen membrane separation reactor, some authors like e.g. (Klett et al. 2002) assume an even higher efficiency as the one given in Table B-28. As mentioned above, significant improvement of membrane technology and performance is still required to put this process into practice, so that we suggest to consider the data given in Table B-28 as indicative targets only which are still very uncertain.

Table B-28: Technical data of coal gasification systems for hydrogen production (based on Gray and Tomlinson 2001)

		State-of-the-art Gasification+PSA	Future	
			Gasification+PSA +CO ₂ capture	Gasification+HSMR ^{b)} +CO ₂ capture
Capacity hard coal	MW	800	800	(800)
Hydrogen output	Nm ³ /h	150,000	137,000	(178,000)
Electricity output	MW	20	27	(25)
CO ₂ removal efficiency	%		87	(100)
Efficiency ^{a)}	%	59	55	(70)
Tech. system lifetime	a	25	25	(25)
Utilisation time	h/a	8,000	8,000	(8,000)

^{a)} based on Lower Heating Value of hydrogen

^{b)} Hydrogen Separation Membrane Reactor

Cost data

According to (Gray and Tomlinson 2001), investment costs for the state-of-the-art gasification system with PSA are 890 €/kW_{H₂}, which is significantly higher than costs for a steam methane reformer or a heavy oil partial oxidation plant. Despite the lower feedstock costs, at current fuel prices coal gasification with its high capital costs is more expensive than the POX process of heavy fuels or hydrogen production from steam reforming. CO₂ capture leads to an increase of investment costs by about 30 % (not including costs for CO₂ disposal!). Klett et al. (Klett et al. 2002) estimate that the costs for a gasification plant with a hydrogen separation membrane reactor are in the same order of magnitude as the gasification plant with conventional syngas treatment, so that no extra costs for CO₂ capture would occur. Because of the early development stage of this process any cost estimates are very uncertain, and the estimates by (Klett et al. 2002) seem to be very optimistic. We suggest to not use these estimates until there is no further evidence for the technical feasibility of the process, but to keep in mind the remaining potential for further cost reduction resulting from the introduction of the membrane technology.

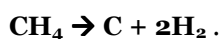
Table B-29: Economic data of coal gasification systems for hydrogen production (Gray and Tomlinson 2001; Klett et al. 2002)

		State-of-the-art Gasification+PSA	Future Gasification+PSA+CO ₂ capture
Investment cost	€ ₂₀₀₀ /kW _{H₂} , LHV	890	1140
O&M fixed cost	% Invest./a	5	5
O&M variable cost	€ ₂₀₀₀ /Nm ³	0.007	0.007

Pyrolysis

Process mechanism

Hydrocarbons can be converted to hydrogen without producing carbon dioxide, if they are decomposed at a sufficiently high temperature in the absence of oxygen. Methane can be ‘cracked’ for example in the presence of a catalyst such as carbon felt. Carbon black can either be sequestered or used further by a number of industries. This process has been developed commercially by the Norwegian firm KVAERNER ENGINEERING S.A. under the process name “Kvaerner Carbon Black and Hydrogen Process”. The raw materials for this process are hydrocarbon compounds that originate from a range of sources from light gases to heavy oil fractions. In a high temperature reactor, the temperature necessary for splitting hydrocarbons is supplied by a plasma burner that uses recirculated hydrogen from the process as plasma gas. The formula for the process using methane as a feed is



The main product of the Kvaerner process is carbon black, which is mainly used for making car tyres, and in the metallurgical industry. Traditional methods for producing carbon black only utilise 30-60 % of the raw material, while the Kvaerner process enables 100 % of the raw material to be used, leading to a significant reduction of environmental pollution. Hydrogen is considered as a by-product of the process. The current demand for carbon black is about 1 Mill. t/a in Europe, and 6 Mill. t/a world wide, with an expected increase in demand [Pehnt 2002]. A carbon black demand of 6 Mill. t/a is equivalent to a hydrogen production of about 160 PJ/a, which shows that the potential for hydrogen production is limited. Because of the environmental benefits of the process this potential however is worthwhile to be exploited.

Fields of application

A first commercial plant based on the Kvaerner process started operation in June 1999 in Canada. The plant was designed to initially produce 20,000 t/a of highest quality carbon black (to be expanded to up to 90,000 t/a). Hydrogen is considered as a by-product.

Technical data

A first pilot plant in operation since 1992 produced about 500 kg/h carbon black and 2,000 Nm³/h hydrogen from 1,000 Nm³/h natural gas and 2,100 kW_{el}. Another by-product is the production of about 1,000 kW high temperature steam. Considering all potential usable products, the plant works with almost 100 % efficiency, made up of 48 % hydrogen, about 10 % steam and 40 % carbon black.

The commercial plant put into operation in Canada in 1999 had an initial annual capacity of 20,000 tonnes of carbon black, which can be expanded to up to 90,000 t/a. As a by-product the plant produces 50 Mill. Nm³ per year (Kvaerner 1997). No data on plant efficiency and feedstock requirement are available. For the commercial plant, the hydrogen to carbon black ratio of the product stream seems to be significantly lower than for the pilot plant.

Due to the early phase of development a significant potential for technological improvement can be expected. As the overall efficiency is already almost 100 % (taking into account the use of all by-products), any technical improvement is likely to lead to a reduction of costs. Depending on the prices for the two main products, a further process optimisation might lead to changes in the carbon black to hydrogen ratio of the two output streams. It should be mentioned again that the potential for an increase in production capacity and thus for technological learning is limited.

Table B-30: Technical data of the Kvaerner process (Wurster and Zittel 1994; Kvaerner 1997)

		demonstration plant	State of the art
Hydrogen output	Nm ³ /h	2,000	6,300
Carbon black output	kg/h	500	2500
Feedstock (natural gas) input	Nm ³ /h	1,000	
Electricity requirement	kW	2,100	
Efficiency ^{a)}	%	48	
Technical system lifetime	a	20	20
Utilisation time	h/a	8,000	8,000

^{a)} related to Lower Heating Value of hydrogen output

Economic data

The costs for the first commercial plant built in Canada were about 43 Mill US\$ (Kvaerner 1997). Although hydrogen is considered as a by-product of the Kvaerner process, hydrogen production costs may be estimated by normalising the capital cost of the plant to the hydrogen output, resulting in 2,300 \$/kW_{H2} (2,600 €₂₀₀₀/kW_{H2}) (Table B-31), and considering carbon black as a by-product. The price for different grades of carbon black is in the range of 600 to 900 €/t (Chemical Market Reporter 2002), because of the high quality carbon black produced from the Kvaerner process we assume a price of 800 €/t. If in our context we consider hydrogen as the main product, 0.4 kg of carbon black are produced per Nm³ hydrogen, resulting in a credit for carbon black production of 0.32 €/Nm³_{H2}. There are no data available on O&M costs. We assume fixed annual O&M costs to amount to 5 % of the capital cost.

Table B-31: Economic data of a Kvaerner carbon black plant (Kvaerner 1997; own estimates)

		State-of-the-art	Long term target
Total investment cost	Mill. € ₂₀₀₀	49	
Specific investment cost	€ ₂₀₀₀ /kW _{H2}	2,600	
Credit for carbon black	€ ₂₀₀₀ /Nm ³ _{H2}	0.32	
O&M fixed cost	% Invest./a	5	
O&M variable cost	€ ₂₀₀₀ /Nm ³		

Hydrogen from biomass

Reducing the demand on fossil resources remains a significant concern for future energy supply. For the near- and mid-term, generating hydrogen from biomass may be the most practicable and viable renewable and potentially carbon neutral option for hydrogen production. Biomass has the potential to accelerate the

realisation if hydrogen as a major fuel of the future. Since biomass is renewable and consumes atmospheric CO₂ during growth, it can have a small net CO₂ impact compared to fossil fuels. Biomass gasification, however, is still in its infancy. Currently only a small number of demonstration facilities are in place and many issues must still be addressed before the technology can be expected to reach an adequate technical performance and hence become economically competitive. The yield of hydrogen is low from biomass since the hydrogen content in biomass is low, and also the energy content is low due to the 40 % oxygen content of biomass. The low yield of hydrogen on a weight basis might however be misleading, as the energy conversion efficiency has been demonstrated to be high (> 55% in the laboratory today).

Process for the production of hydrogen from biomass can be divided into three categories:

- Direct production routes (e.g. gasification)
- Conversion of storable intermediates, and
- Metabolic processing to split water via photosynthesis, or to perform the shift reaction by photo biological organisms.

The availability of biomass for competing utilisation is of course a critical issue in developing long term scenarios. A rough estimate provided by (IE, 2004) suggests that the total biomass potential in the EU-25 countries is about 6,600 PJ/a, including forest and industrial wood residuals, straw, and energy crops. (Frey et al. 2004) estimate the biomass potential in the EU-15 countries to amount to 7,000 PJ/a in 2050.

Biomass gasification and pyrolysis

Basic mechanism

Gasification is a two-step process in which a solid fuel is thermochemically converted to a low- or medium-energy-content gas (see also o). In the first reaction (pyrolysis), the dissociated and volatile components of the fuel are vaporised at temperatures as low as 600 °C. Included in the volatile vapours are hydrocarbon gases, hydrogen, carbon monoxide, carbon dioxide, tar, and water vapour. Because biomass fuels tend to have more volatile components (70-86 % on a dry basis) than coal (30 %), pyrolysis plays a larger role in biomass gasification than in coal gasification. Gas phase thermal cracking of the volatiles occurs, reducing the levels of tar. Char (fixed carbon) and ash are the pyrolysis by-products that are not vaporised. In the second step, the char is gasified through reactions with oxygen, steam, and hydrogen (Milne et al. 2002).

One gasification option is based on a low pressure, indirectly-heated gasifier, in which the heat necessary for the endothermic gasification reaction is supplied e.g. by hot sand circulating between the char combustor and the gasification vessel (Spath et al. 2003). After clean-up, the syngas is cooled so that it can be compressed to the pressure required for the pressure swing adsorption (PSA) unit. Following compression, the gasifier product gas is steam reformed and passed through a water-gas shift reactor to produce a gas concentrated in H₂ and CO₂. Finally, the hydrogen is purified in the PSA prior to storage and distribution (Figure B-13).

By including oxygen in the reaction gas the separate supply of energy is not required, but the product gas is diluted with carbon dioxide. An example of this process is the GTI High-Pressure Oxygen-Blown Gasifier (Bowen 2003). The major system components include biomass handling and drying, followed by gasification for which an air separation unit is required, hot gas clean-up, reforming, shift conversion, and hydrogen purification.

Makihira et al. (Makihira et al. 2003) suggest that from combining a biomass gasification system with carbon removal and sequestration technologies even a net removal of carbon from the atmosphere can be achieved, which might make sense from an economic point of view if the credit gained for CO₂-reduction from a CO₂ emission trading scheme compensates the extra costs for carbon capture.

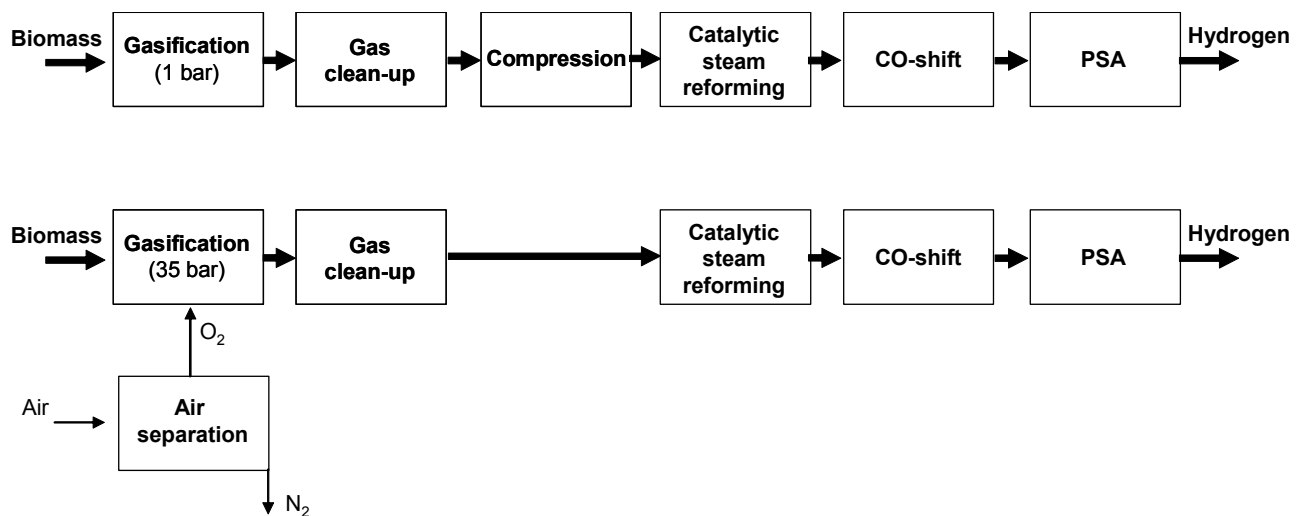


Figure B-13: Schematic diagram of biomass gasification options

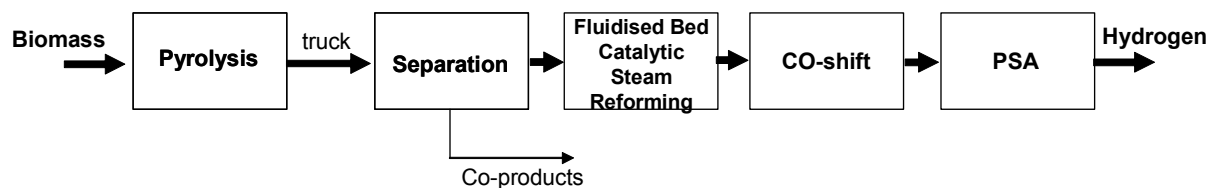
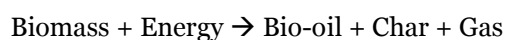


Figure B-14: Schematic diagram of hydrogen production from biomass pyrolysis

Instead of the direct gasification of biomass, a fast pyrolysis of biomass can be used to produce a liquid intermediate product called bio-oil, from which hydrogen can be produced in a steam reforming process after a co-product separation. Biomass is first dried and then converted to an oil by very quick exposure to heated particles in a fluidised bed:



The char and gases produced are combusted to supply heat to the reactor, while the product oils are cooled and condensed. Catalytic steam reforming of bio-oil takes place at a temperature of 750-850 oC over a nickel-based catalyst (Figure B-14).

The concept of fast pyrolysis combined with downstream steam reforming is expected to have advantages over the traditional gasification/water-gas shift technology. Bio-oil is much easier to transport than solid biomass, offering the possibility that bio-oil can be produced at smaller plants which are closer to the sources of biomass, such that lower cost feedstocks can be obtained. The bio-oil is then shipped by truck to the hydrogen production facility. It is more economical to produce bio-oil at remote locations and then ship the oil, since the energy density of bio-oil is higher than biomass (Spath et al. 2003). A second advantage is the potential production and recovery of higher-value co-products from bio-oil. The lignin-derived fraction can be separated from bio-oil and used as a phenol substitute in phenol-formaldehyde adhesives, while the carbohydrate-derived fraction is catalytically steam reformed to produce hydrogen. According to (Spath et al. 2003), the substitution of the current world wide consumption of phenol by a bio-oil based co-product translates in hydrogen production of about 60 million kg per year, thus the potential is significant.

At present, the amount of biomass-derived liquids available for reforming is rather limited, but a viable way to increase the production of hydrogen in a biomass-based plant could be co-reforming of pyrolysis liquid with natural gas, similar to co-firing of biomass with coal for power generation (Czernik et al. 2002).

Fields of application

Since biomass is low in density, the transportation costs for both the feedstock and the hydrogen must be balanced with the savings from employing economy of scale. In contrast to hydrogen production from fossil energy carriers, the size of a biomass gasification plant is limited by the regional availability of biomass feedstock. Economic operation is possible only if transportation costs are limited, which practically excludes the trans-regional transport of biomass. It is expected that future large, but decentralised biomass gasification plants will have a thermal capacity of around 25 MW_{th}, but depending on the specific context also larger facilities are possible.

Technical data

Technologies for hydrogen production from biomass are still in the R&D or demonstration phase and thus not yet commercially available. Milne et al. (Milne et al. 2002) provide a detailed overview on research activities in the field. Several authors provide technical characteristics of a future commercial plant configuration based on process simulation, which is based on the experience gained in demonstration processes as well as on the use of similar data from coal gasification processes.

State-of-the-art data given in Table B-32 refer to a projected small size biomass gasification plant described by (Angloher and Dreier 2000). The allothermic gasifier is operated at a pressure of 6 bar. Model simulations result in an overall plant efficiency of 69 %, suggesting that there is a potential for increasing efficiency by the further use of low-temperature process heat. It is assumed that the size of a future commercial application is around 25 MW_{th}, which is expected to achieve an efficiency of 72 %. Different studies suggest that due to differences in process design and biomass feedstock there is some variation in process efficiency, but data from (Spath et al. 2003) indicate that in general the differences in the overall process efficiency between systems operating with e.g. an indirectly-heated low pressure gasifier and a direct-fired high pressure gasifier are small. According to system design data from (Spath et al. 2003), the steam reforming of the bio-oil

produced from fast pyrolysis achieves an efficiency of 49%, while the overall efficiency with regard to the biomass feedstock is only 28%.

Table B-32: Technical data for biomass gasification (Angloher and Dreier 2000) and pyrolysis (Spath et al. 2003)

		Gasification		Pyrolysis
		State-of-the-art	Long term target	Long term target
Biomass feedstock ^{b)}	Mg/d	12	120	1,806 ^{c)} /1035 ^{d)}
Hydrogen output	Nm ³ /h	610	6,400	35,130
Electricity requirement	kW	160	1,500	
Efficiency ^{a)}	%	69	72	28 ^{c)} /49 ^{d)}
Technical system lifetime	a	20	25	25
Utilisation time	h/a	7,500	8,000	8000

^{a)} related to Lower Heating Value of hydrogen output; ^{b)} bone dry; heating value assumed to be 5 kWh/kg; ^{c)} refers to biomass feed-rate; ^{d)} refers to bio-oil feed-rate

Economic data

Data on investment costs of a future commercial biomass gasification system differ significantly. Based on data of a projected 2.5 MW_{th} demonstration plant, (Angloher and Dreier 2000) estimate investment costs to amount to 2,660 €/kW_{H₂}, which is at the upper end of cost data given in the literature. They expect that costs for a ‘small scale’ plant (25 MW_{th}, or 6,400 Nm³/h hydrogen production) are reduced to about 1,500 €/kW_{H₂} until 2025. Based on process simulation, Bowen (Bowen 2003) from the Gas Technology Institute estimates capital costs for the GTI gasification process between 850 \$/kW_{H₂} (feedstock: bagasse; hydrogen production: 350,000 Nm³/day) and 490 \$/kW_{H₂} (feedstock: switchgrass; hydrogen production: 1,650,000 Nm³/day). These estimates clearly are at the lower end of cost estimates published in the literature. Spath et al. (Spath et al. 2003) estimate investment costs for the GTI process to amount to 1,300 to 2,050 \$/kW_{H₂}, depending on the system’s capacity (12,000 Nm³/h and 58,000 Nm³/h, respectively). According to their estimates, the costs for a system with an endothermic, low pressure gasifier are slightly lower as for the GTI process.

While their seems to be a significant potential for reducing the investment costs by increasing the size of the gasification system, there is a trade-off with increasing transportation costs for the low density biomass feedstock. As discussed above, the cost-effective supply of biomass in most cases will limit the capacity of a biomass gasification system to a hydrogen production rate of 10,000 to 20,000 Nm³/h, while large scale gasification plants with a capacity of >> 20,000 Nm³/h hydrogen production are more likely to be an exception. On the other hand, because of the process similarities it is likely that on the medium term costs for a biomass gasification system, which can be operated a lower temperature as a coal gasifier, are at least similar to a current coal gasification system, and can be lower if developed further. We thus consider investment costs of about 900 €/kW_{H₂} as a reasonable estimate for future large scale gasification plants for hydrogen production, which is also well within the range of the various estimates from the literature discussed above.

Depending on the size of the facility, (Spath et al. 2003) estimate the capital costs for the bio-oil reformer to 510 to 535 \$/kW_{H₂}. These costs include the extraction of the bio-oil, the conversion of the carbohydrate-fraction to hydrogen, and the hydrogen purification, i.e. the costs of pyrolyzing the biomass is rolled into the

price of the bio-oil feedstock. Spath et al. assumed a pyrolysis bio-oil feed price of 0.12 \$/kg, but this price depends on a number of different parameters.

There are no data available on O&M costs for a biomass gasification system. In analogy to the coal gasification process we estimate annual O&M costs to amount to 7 %, and in the future to 6 % of the investment costs.

Table B-33: Economic data of biomass gasification systems for hydrogen production

		Gasification			Bio-oil reforming
		State-of-the-art (small scale demo plant)	Long term target		Long term target
			< 10,000 Nm ³ /h	>> 10,000 Nm ³ /h	
Investment cost	€ ₂₀₀₀ /kW _{H₂}	2,660	1,500	900	530 ^{a)}
O&M fixed cost	% Invest./a	7	6	6	6
O&M variable cost	€ ₂₀₀₀ /Nm ³				

^{a)} capital costs for bio-oil reformer, does not include costs for pyrolyzing biomass; bio-oil feed price is assumed to be 0.12 \$/kg (~7€/GJ)

Other methods for hydrogen production

The following sections summarise further processes for hydrogen production, which today are in a basic research phase and thus quite far away from a technical implementation. Although some authors already provide cost estimates for specific processes, we consider them as being highly unreliable, as there is still significant basic research required to understand and to set up a reliable technical process. This does not mean that some of these processes might not evolve further during the 50 years time horizon covered in CASCADE MINTS, but for the time being there is no basis for a sound technical and economic characterisation that is required to include these processes into the energy system models addressed in CASCADE MINTS.

Photoelectrochemical water splitting

Photoelectrolysis of water is the process whereby light is used to directly split water into hydrogen and oxygen. This can be achieved by illuminating a wet semiconductor device either directly or via dye sensitisation. Such systems eliminate the need for two separate systems regarding power generation and electrolysis, and hence offer the potential for cost reduction of electrolytically produced hydrogen compared with conventional two-step technologies. The direct production of hydrogen via water splitting by sunlight requires a light-harvesting device in conjunction with water-splitting catalysts. The necessary semiconductor-based light-sensitive device is similar to a PV solar cell.

For direct photoelectrochemical decomposition of water to occur, several key criteria of the semiconductor must be met: the semiconductor system must generate sufficient voltage to split water, the energetic of the semiconductor must overlap that of the hydrogen and oxygen redox reactions, the semiconductor must be

stable in aqueous electrolytes, and finally the charge transfer from the surface of the semiconductor must be fast enough not only to prevent corrosion, but also reduce energy losses due to overvoltage.

Research and development programs on Photoelectrolysis of water are in place in several countries such as the United States, Japan, Sweden or Switzerland. Photoelectrochemical hydrogen production is in an early stage of development, and it depends on a breakthrough in materials development. One of the main technical problems related to the use of photoelectrochemical cells is the stability of electrodes against corrosion. Research activities focus on the development of appropriate semiconducting materials and surface treatment to increase the semiconductor's stability. Amorphous silicon (Varner et al. 2002) or gallium based materials (Turner 2003 et al.) are being considered for this technology. Different coating options are analysed to increase the stability of the semiconductor.

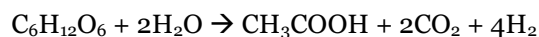
While the efficiency of the electrolysis in a photoelectrochemical system can be higher than in a conventional electrolysis due to the lower voltage required, theoretically the overall efficiency for photoelectrochemical water splitting is around 24 % (Winter and Nitsch 1988). System efficiencies of 10 to 12 % have been achieved in the laboratory, but these high efficiency systems have extremely short lifetimes (< 20 hours). A solar-to-hydrogen efficiency of 16%—the highest reported efficiency to date—was achieved using a tandem photo-electrochemical cell (IEA 2004a). The materials used in this cell are still too costly for this to be an economically competitive technology in the near term. A potential future system will likely be a compromise between efficiency and lifetime. Current research targets are to achieve a 10 % solar-to-hydrogen efficiency at a 10 year cell lifetime, with hydrogen production costs of 3 \$/kg (Turner 2003).

Assuming an efficiency of 5 to 10 %, the potential for hydrogen production with photoelectrochemical water splitting methods is comparable to that of solar cells combined with electrolysis. Today, with research still focused on the development of appropriate stable semiconductor materials, it is not possible to give a definitive statement about the technical feasibility or a possible point in time when such a system might become practical.

Biological hydrogen production

Green algae capture energy from sunlight. Under anaerobic conditions, the green algae produce a hydrogenase enzyme which produces hydrogen from water by a process known as bio-photolysis. The conditions must be carefully regulated, since the hydrogenase enzyme works in the dark phase and is sensitive to the presence of oxygen produced from photosynthesis. Basic research, which is progressing under the IEA Task 15 'Photobiological Production of Hydrogen' is still in a very early stage. The overall objective set out for the IEA Task 15 program is to '*sufficiently advance the basic and early stage applied science in this area of research to allow an evaluation of the potential of such a technology to be developed as a practical renewable energy source for the 21st century*' (IEA 2004b). Current laboratory work demonstrates the feasibility of using algal cultures to photoproduce hydrogen continuously for 3-4 days (Ghirardi et al. 2002). The major research challenges however still are to increase hydrogen production by a factor of at least 10, and to increase the solar energy conversion efficiency from 5 % to at least 10 % (Dutton 2002).

The second main biological pathway to hydrogen uses fermentation without the need for light. This is a dark, anaerobic process carried out by many species of bacteria, one of which (Clostridia) has been singled out for particular attention. The reaction involves a hydrogenase enzyme acting on carbohydrates to produce hydrogen and carbon dioxide (Dutton 2002):

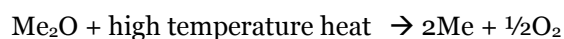


Laboratory studies have concentrated on pure microbial cultures, sterile feedstocks, and batch operation. Potential feedstocks include sugar cane or the organic fraction of municipal waste. The theoretical yield is 0.5 m³ H₂/kg carbohydrate, although this is yet to be achieved, largely because the reaction is hindered by increasing hydrogen concentration. Fermentative bacteria can multiply rapidly and produce high quantities of hydrogen, but the design and the operational parameters of the process are not yet well established, so that there is still basic research required to further understand and improve the process.

Hydrogen production from thermochemical cycle processes

Water can be split thermally only at very high temperatures above 2,000 K. To avoid materials problems occurring at these high temperatures, in contrast to direct thermal water splitting, thermochemical cycle processes utilise the coupling of several equilibrium reactions which in separate process steps and at different temperature levels permit the separate release of hydrogen and oxygen at temperatures of less than 1,200 K. Thermochemical cycles are Carnot-limited, for an upper temperature of 1,000 K and a lower temperature of 300 K the maximum theoretical efficiency is 88 %.

During the 1970/80ies, some 2,000 to 3,000 cycles have been ‘invented’ and analysed in theory (Wendt and Bauer 1988). After examining their feasibility with respect to reaction and process technology, only some 20 to 30 remained, some of which were examined in some detail as to their reaction technology. They were grouped in ‘families’ according to the respective working substances, such chlorides, oxides, metals sulfates or other elements with multiple valences common to the process of one family. High temperature process heat can be provided either from solar energy or from a high temperature nuclear reactor. As an illustrative example the following equations describe the high-temperature dissociation of a metal oxide to oxygen and metal, which is coupled to the low-temperature reaction of the same metal with water releasing hydrogen:



Theoretical calculations based largely on entropy balance considerations postulate that such thermochemical cycles shall not be limited to two reactions to achieve an attractive energy yield at an upper maximum temperature of 1,200 K, but must include more than two reactions operating at more than two separate temperature levels. This on the other hand implies complicated process engineering. In all cycles that use metal oxides, metal chlorides or metal sulfates as working materials, solids must be reacted, cooled or heated and circulated, leading to significant technical difficulties in process engineering. After some ten years of research and technical and economic analysis of process specific technical data, because of these problems further development work on this type of thermochemical cycles was virtually stopped.

In recent years, significant progress has been accomplished both in the field of materials science, and in the development of optical systems for large scale collection and concentration of solar energy, using solar tower and tower-reflector technology at power levels of several megawatts. These concentrating systems are capable of achieving power flux intensities equivalent to solar concentration ratios of 5000 suns and high by applying non-imaging secondary concentrators in tandem with the primary focusing heliostat field. Such high radiation fluxes correspond to temperatures exceeding 3,000 K and allow the conversion of concentrated solar radiation to thermal reservoirs at 2,000 K and above. Thus, the door was opened for the more efficient two-step thermochemical cycles for splitting water using solar energy (Steinfeld 2002; Palumbo et al. 2004). Several two-step water-splitting cycles based on metal oxides reactions have been proposed. Of specific interest is the solar thermochemical cycle based on ZnO/Zn redox reactions. The first endothermic step is the thermal dissociation of ZnO(s) into Zn(g) and O₂ at 2,300 K using concentrated solar energy. The second, exothermic step is the hydrolysis of Zn(l) at 700 K to form H₂ and ZnO(s), the latter separates naturally and is recycled to the first step:



Hydrogen and oxygen are derived in different steps, thereby avoiding the need for high-temperature gas separation. According to (Steinfeld 2002), a maximum exergy conversion efficiency of 29 % is achieved when using a solar cavity-receiver operated at 2,300 K and subjected to a solar flux concentration ratio of 5,000. Steinfeld estimate the costs of solar hydrogen produced in a large scale chemical plant equipped with a 90 MW_{th} solar reactor and a hydrogen production of 61 million kWh/a between 0.13 and 0.15 \$/kWh, thus suggesting might be competitive with other renewables-based routes for hydrogen production. However, currently there are only exploratory test carried out e.g. at PSI/ETH (Switzerland) on the dissociation of ZnO, and the economic feasibility strongly depends on the availability of an effective Zn/O₂ separation technique. The cost estimates by (Steinfeld 2002) thus are at least highly uncertain. Similar to the ‘old’-type of thermochemical cycle processes, the ZnO/Zn process has to face the challenge of handling large volume streams of solid materials for producing a relevant amount of hydrogen. Further development work is currently focused on solar chemical reactor modelling, and on designing a better quench method for recovering Zn. The benchmark against which the process has to prove its technical and economic viability in the future is hydrogen production from electrolysis with electricity from solar thermal power plants.

Summary: technical and economic characteristics of hydrogen production options

To provide a consistent set of input data to the CASCADE MINTS modelling activities, Table B-35 summarises the key technical and economic parameters of the various hydrogen production options discussed above. While the underlying literature in some cases indicates a broad range of different values, the present recommendations are based on a thorough analysis of the relevant literature, plausibility considerations, a discussion process with relevant experts, and expert judgement. It is recommended to carry

out some sensitivity analysis within the CASCADE MINTS modelling activities on key parameters that turn out to have a major influence on the final results.

The learning curve approach followed in CASCADE MINTS requires the specification of floor costs, which are difficult to derive for some of the technologies considered. For the other hydrogen production options, which in many cases are based on the further development of well established technologies, no bottom-up estimates of floor costs were available. For the purpose of the present study we assume that floor costs are around 75% of the given long term target costs, which in general is in line with very optimistic estimates of long term target costs. This assumption shall be revisited in a sensitivity analysis if the subsequent modelling will result in a strong influence of the assumed floor costs on the modelling results.

Table B-34: Floor cost estimates for hydrogen production options

	€/kWh ₂
Electrolyser	
- small scale on-site	480
- large scale	380
Steam methane reforming	
- small scale	490
- large scale	240
- Solar methane reforming	280
Heavy oil partial oxidation	360
Coal gasification	670
Biomass gasification	675
Bio oil reforming (from Pyrolysis)	400

Table B-35: Hydrogen production options: summary of technical and economic characteristics

	Capacity	Feedstock	Electricity input	Efficiency (based on H ₂ -LHV)	utilisation factor	system lifetime	investment costs	fixed O&M costs	variable O&M costs
	Nm ³ /h	kW/kW _{H2}	kW _{el} /kW _{H2}	%	%	a	€ ₂₀₀₀ /kW _{H2}	% Invest./a	€ ₂₀₀₀ /Nm ³
Electrolyser									
Small-scale on site									
‘today’	< 1,000		1.43	70	90	20	860	2	
2030	< 1,000		1.30	80	90	20			
Large-scale									
‘today’	> 1,000		1.43	70	90	20	690	2	
2030	> 1,000		1.30	80	90	20			
High temp. steam electrolysis									
2030	40,000	0.2 (steam)	1.07	79	90	20	(1,270)	2	
Steam methane reforming									
Small-scale on site									
‘today’	1,000	1.5 (nat. gas)		67	80	25	690		0.0055
2030	1,000	1.43 (nat. gas)		70	80	25			
Large-scale									
‘today’	100,000	1.35 (nat. gas)		74	90	25	335		0.0055
2030	100,000	1.28 (nat. gas)		78	90	25			
Solar methane reforming									
2030	50,000	0.83 (nat. gas)	(solar heat: 0.32)	87	0.23	20	370	7	
Heavy oil partial oxidation									
‘today’	100,000	1.3 (crude oil)	0.063	73	90	25	500	5	
2030	100,000	1.24 (crude oil)	0.057	77	90	25	500	5	
Coal gasification									
Gasification+PSA									
	150,000	1.78 (coal)	-0.044	59	90	25	890	7	
	137,000	1.95 (coal)	-0.066	55	90	25	1140	6	
Gasification+PSA+CO ₂ capture									
Gasification+HSMR	178,000	1.5 (coal)	-0.047	70	90	25	(895)	6	
Kvaerner Carbon Black process									
‘today’	6,300				90	20	2300	4	- 0.32 ^{a)}
2030					90	20			
Biomass gasification									
‘today’	610	1.37(biomass)	0.087	69	80	20	2,660	7	
2030	6,400	1.30(biomass)	0.078	72	90	25	900	6	
Biomass Pyrolysis/bio-oil reforming									
‘today’									
2030	35,130	2.04 ^{b)}		49	90	25	530 ^{c)}	6	

^{a)} credit for carbon black; ^{b)} pyrolysis bio-oil feed; ^{c)} capital costs for bio-oil reformer, does not include costs for pyrolyzing biomass

B.1.3.2 Hydrogen Delivery System and Infrastructure

[by W. Krewitt and S. Schmid (DLR)]

Hydrogen Storage

Liquefaction

Basic mechanism

The process to liquefy hydrogen is complex and energy intensive. Theoretically, about 14.2 MJ/kg H₂ have to be removed to cool hydrogen gas from 298 K (25°C) to 20.3 K and to condense the gas at 20.3 K and atmospheric pressure (Bossel, Elliasson et al. 2003; Quark 2004). Different thermodynamic processes are applied to cool hydrogen to very low temperatures and finally expand the gas in a Joule-Thompson valve or a cryogenic turbine.

Linde AG uses in the lower capacity range between 150 and 1000 l/h the helium process to cool the hydrogen. In the range of 1000 l/h up to 20,000 l/h a hydrogen Claude process with expansion and liquid nitrogen pre-cooling is used (Linde, web). Key components of the technical realisation of these processes are dry piston or oil injected screw recycle compressors, oil bearing turbo expanders, liquefier cold box, liquid nitrogen pre-cooling, multi-stage ortho-para conversion with up to 98% p-LH₂ and low temperature absorber for final purification.

The difference between Ortho and Para hydrogen is the orientation of their nuclear spin. It is important to transfer normal hydrogen (75% Ortho, 25% Para) completely into Para hydrogen (99.8%), because conversion releases energy higher than the heat of evaporation and thus contributes to boil-off in the storage vessel. Catalytic processes are used for ortho-para conversion.

Fields of application

Liquid hydrogen today is produced because of advantages in transportation. There are 10 hydrogen liquefaction plants in the U.S. with production rates of 5,400 to 32,000 kg/d (Drnevich 2003), and 3 plants in Europe with capacities of 5,000 kg/d (NL), 10,500 kg/d (FR) and 4,400 kg/d (DE) (Tzimas, Filiou et al. 2003).

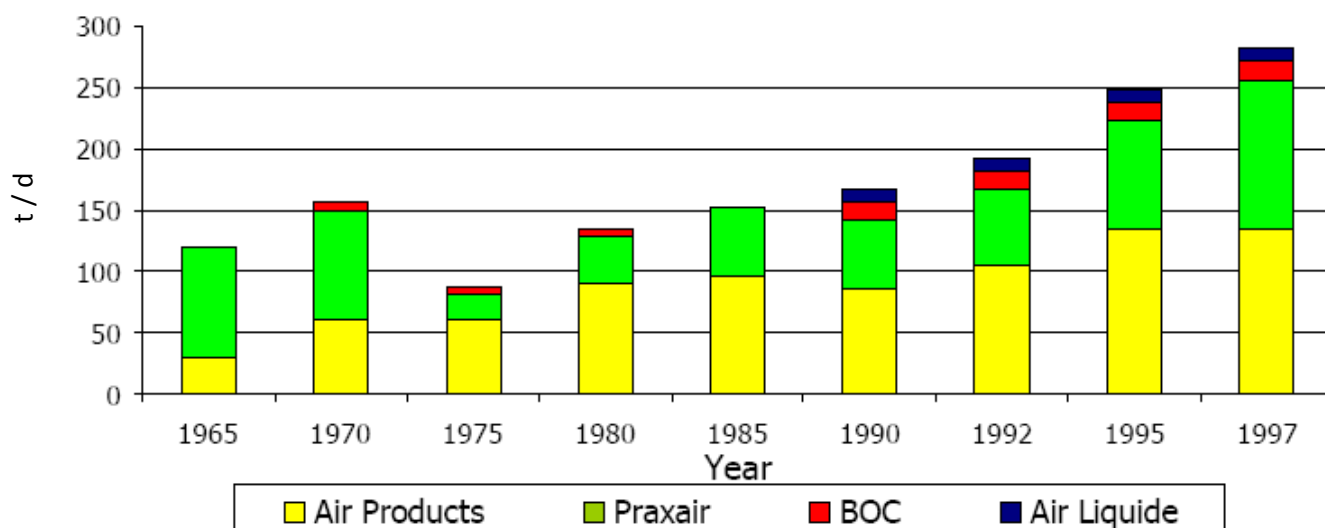


Figure B-17: North America liquid hydrogen capacity (Source: Drnevich (2003)).

Technical data

Data on specific energy consumption of liquefaction plants are summarised in Table B-48. Data on specific energy consumption of liquefaction plants. Energy consumption per kg of liquid hydrogen depends strongly on the size of the plant. A function for specific energy from the sources presented in Figure B-18 is proposed in equation (1).

Table B-48: Data on specific energy consumption of liquefaction plants.

Plant / example	Size class	Energy consumption	
		kWh _e /kg LH ₂	MJ/kg LH ₂
Linde, Ingolstadt (Production: 182 kg/h)	Medium	15 [#]	54
Best plants in the U.S. today	n.a.	10	36 [§]
Praxair plants in the US	n.a.	12.5 - 15.0 ^{\$}	45 - 54
Maximum expected for future plants with Helium/Neon as refrigerant	Large	7	25.2 [#]
Theoretical value	Large	3.9 [#]	14.2 [#]

Sources: [#] Quark (2004), [§] Bossel, Elliasson et al. (2003), ^{\$} Drnevich (2003)

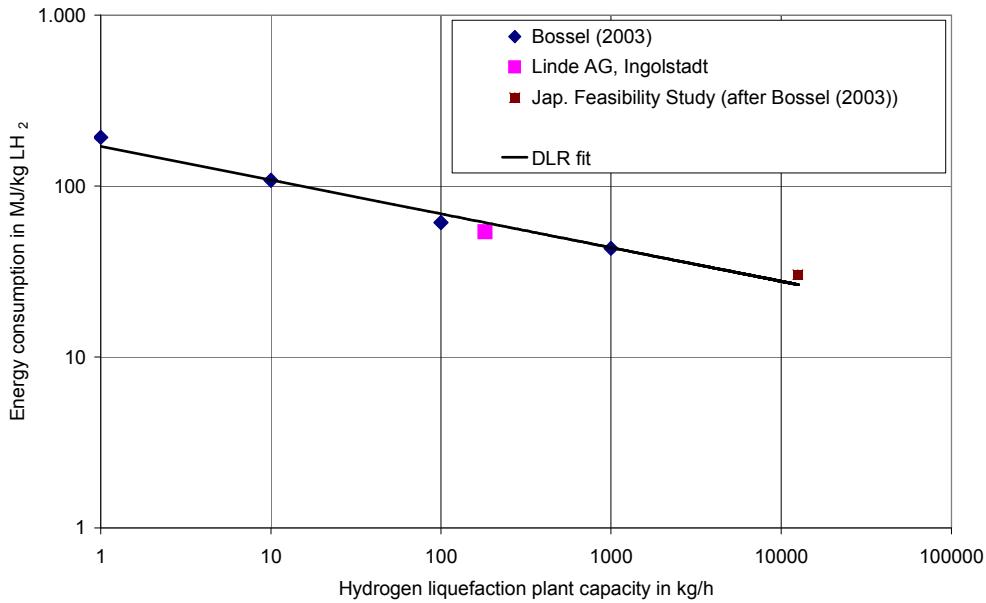


Figure B-18: Energy requirements for the liquefaction of hydrogen.

$$\text{Energy-consumption-for-liquefaction} = 170 \cdot \text{plantCapacity}^{-0.2} \text{ in MJ/kg LH}_2 \quad (1)$$

with the plant capacity in kg/h ($R^2=0.97299$).

Methods to decrease energy requirement are new compression and expansion technology, high speed centrifugal compressors and possibly expanders with new materials (Drnevich 2003). Drnevich also sees in the economies of scale a reduction potential for capital costs due to plant repeatability. Quark (2004) suggests an advanced process using a mixture of helium and neon as refrigerant. In his analysis, he finds an energy consumption of 6.5 kWh/kg (23.3 MJ/kg), and concludes that 7 kWh/kg LH₂ including auxiliary power use should be technical feasible. Completely new approaches for low temperature refrigeration are magnetic refrigerators and acoustic refrigerators. Magneto caloric cooling may reduce liquefaction energy to 5.0 kWh/kg (Dutton 2003).

Economic data

Costs for liquefaction are driven in the first place by capital costs (today: 63%), then energy costs (29%), and in the third place O&M (8%) (Drnevich 2003). Energy costs on the other hand are strong functions of the liquefier efficiency and less dependent on the production rate. In small plants, energy and non-energy costs are comparable. At large scale plants the energy costs become more important. Investment cost estimates are presented in Figure B-19. We derive from the given information the following equation on specific investment costs:

$$\text{Specific investment cost for liquefier} = 828,313 \cdot (\text{prod.capacity})^{-0.48} \text{ in } \text{€}2000/(\text{kg/h}) \quad (2)$$

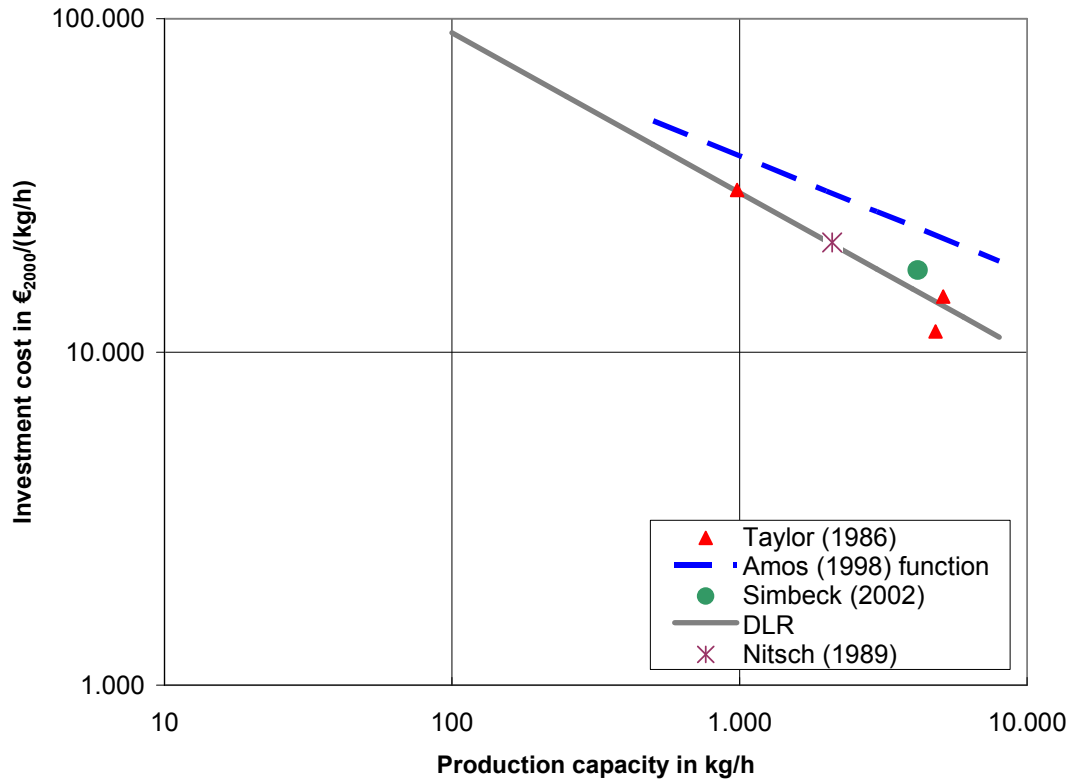


Figure B-19: Investment cost for liquefaction battery (excl. storage)

Table B-49: Cost estimates for liquefaction plants

		Small	Plants of 'today'	Large
Capacity	kg/h	100	1000	10,000
Investment cost	€ ₂₀₀₀ / (kg/h)	91,000	30,000	10,000
O&M	% Total cost/a		8 §	

§ Drnevich (2003)

Methods to decrease capital costs are to build larger scale plants (350,000 kg/h) and to use the effect of building multiple plants of the same design. The following challenges for more cost effective LH₂ production systems are (Drnevich 2003):

- System modularization for traditional sized units
- Larger scale equipment
- Higher efficiency compressors and expanders
- More efficient refrigeration
- Lower cost high-efficiency insulation

Table B-50: Hydrogen liquefaction: summary on technical and economic characteristic

Capacity		Electricity input	Cooling water	Efficiency §	Utilisatio n	System lifetime	Investment costs	O&M fixed costs	O&M variable costs
Nm ³ /h		kW _{el} /kg _{LH2}	m ³ /kg _{LH2}	%	%	a	€ ₂₀₀₀ /kW _L H ₂	% Invest./a	% Invest./a
Liquefaction									
Small-scale									
State-of-the-art	> 1,000	15	1,6	69	74	25	2,730	8	
Plants of ‘today’									
State-of-the-art	> 10,000	10	1,6	77	74	25	900	8	
Long-term-target	> 10,000	9	1,6	79	74	25			
Large plants									
Long-term-target	~ 100,000	7	1,6	83	74	25			

§ related to LHV

Automotive On-board hydrogen storage

Different storage systems are competing for hydrogen storage on-board of vehicles, characterised by the physical/chemical properties of the hydrogen: liquid, gaseous or chemically bound. Table B-51 gives an overview of the status and research target for on-board storage systems. The data relate to the tank system including material, valves, pipes, cooling etc.

Table B-51: Key data for on-board hydrogen storage

Characteristics	energy density		volumetric		specific cost
	gravimetric kWh/kg	kg H ₂ /kg	kWh/l	kg H ₂ /l	US\$ ₂₀₀₄ /kWh
Status 2004					
Gaseous H ₂ , 35 MPa	2.1	0,063	0.8	0,02	12
Gaseous H ₂ , 70 MPa	1.9	0,057	1.3	0,04	16 (13-24) [§]
Liquid hydrogen	2.0	0,060	1.6	0,05	6
Complex hydride	0.8	0,024	0.6	0,02	16
Chemical hydride	1.6	0,048	1.4	0,04	8
Targets					
2010	2.0	0,060	1.5	0,05	4
2015	3.0	0,090	2.7	0,08	2

Source: Bouza (2004)

Liquid hydrogen storage

Basic mechanism

Basic mechanisms are the same than for bulk storage. Liquid hydrogen is stored in a super-insulated vessel at -253°C.

Technical data

Some technical data for liquid hydrogen on-board storage systems are available from Linde. The CoolH₂ is double walled manufactured of stainless steel. The tank itself weighs 90 kg and has a volume of 68 l (net). The maximum pressure inside is 0.6 MPa (Tse 2003). Linde has developed recently a cooling system, which increases the time until boil-off starts to approx. 12 days (Linde AG 2003). This system uses cold hydrogen gas to liquefy air (-191°C), which is in turn used as a cooling agent for the tank. The boil-off rate is supposed to be less than 1%. To fill the tank, it takes less than two minutes.

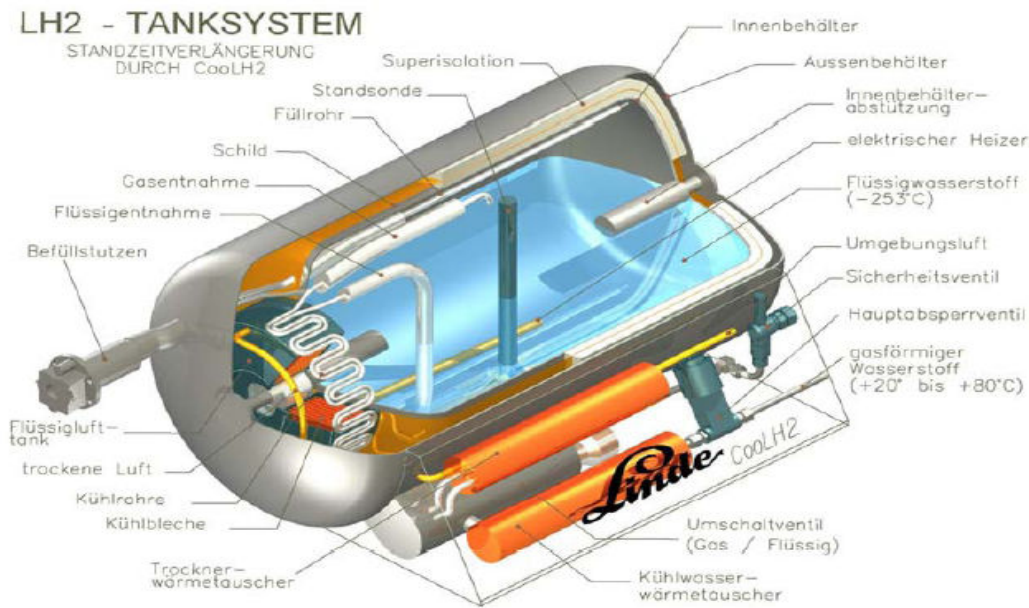


Figure B-20: Model of the advanced CoolH2 vehicle fuel tank for liquid hydrogen by Linde AG (Source: www.linde-gas.de)

Economic data

Costs for automotive liquid hydrogen storage are reported to 308 €/kWh (Grahl 2000). Assuming a volume of 70 l (Grahl 2000), this results to approximate investment costs of 50,000 €2000 for this kind of prototype tank system today.

There are no estimates of floor costs available.

Gaseous hydrogen storage

Basic mechanism

To store hydrogen on-board of automobiles in gaseous form is currently the most simplest, technically mature and cheapest storage method. Compressed H₂ tanks with pressures ranging from approx. 35 MPa up to approx. 70 MPa have been certified worldwide according to ISO 11439 (Europe), NGV 2 (U.S.), and Reijikijun Betten (Iceland) standards and approved by TÜV (Germany) and The High-Pressure Gas Safety Institute of Japan (KHK) (DoE 2003).

Lightweight pressure vessels, with minimum permeation losses, have been designed and fabricated. These vessels use lightweight bladder liners that act as inflatable mandrels for composite overwrap and as permeation barriers for gas storage. These tank systems have demonstrated 12 wt% hydrogen storage at 70 MPa (DoE 2004), together with a safety factor of 2.35 (158 MPa burst pressure) as required by the European Integrated Hydrogen Project specifications.

Economic data

Compressed hydrogen storage systems at 35 MPa are the only systems which are currently available commercially. Storage units for buses fabricated from carbon composites cost about US\$1000/kg H₂ (Burke 2005). However it seems unlikely that these systems can meet the technical goals for storage density by DoE. Cost data on gaseous on-board hydrogen storage are summarised in Table B-52.

Table B-52: Specific cost of compressed hydrogen tanks for automotive application.

Type	Pressure MPa	Specific Cost € ₂₀₀₀ /MJ
Steel	20	1 – 1.8
steel / FGR	20	1.7 – 2.5
alumin./ FGR	20	2.4 – 3.3
therm. Liner / FGR	20	-
therm. Liner / CF	20	3.1 – 3.8
polymer-lined cylinder	35	4.6
Carbon composite	35	8

Source: (Grahl 2000), (Lipman, Edwards et al. 2002)

Note: FGR – fiber glass wrapping, CF – carbon fiber wrapping.

Burke (2005) concludes that high pressure 70 MPa compressed gas seems to be the most satisfactory near term technology when factors like volume constraints and energy efficiency are taken into account. He also states that none of the storage technologies may reach less than US\$3/kWh H₂.

The cost of high strength aerospace grade carbon fibre is a major cost driver for 70 MPa tanks. Carlson (2004) concludes that due to the maturity of the carbon fibre industry it is unlikely to go down significantly and therefore limits the potential for cost reductions. In absence of any data of floor cost estimates we suggest to use as a minimum floor cost 75% of the 2015 DoE target at ~1,5 €/kWh.

Storage in Metal Hydrides

Basic mechanism

Hydrogen reacts at elevated temperatures with many transition metals and their alloys to form hydrides (Züttel 2003). The reaction is exotherm of the general form:



Hydrogen atoms are trapped in interstitial sites of the metal lattice, such as lattice defects, a vacancy or a line defect. Since adsorption of hydrogen increases the size of lattices, the metal is usually grounded to a powder in order to prevent the decrepitation of the metal particles (Hottinen 2001).

Interesting for technical applications are the metallic hydrides of intermetallic compounds, e.g. AB_xH_n, because the variation of the elements allows the properties to be tailored. All the reversible hydrides working

at ambient temperatures and atmospheric pressure consists of transition metals. The gravimetric hydrogen density is limited to < 3 mass% (Züttel 2003).

Economic data

The system for hydrogen storage in metal hydrides consist of the material itself, a pressure vessel and an integrated heat exchanger for cooling and heating during absorption and desorption (Amos, 1998). As the developments are in a laboratory phase, nothing is known about the cost of the equipment. Carpetis (1994) states that much of the capital cost is for hydride material itself. Amos (1998) starts his analysis with base costs for metal hydride of 2,200 €/2000/kg with a sizing exponent of 1.

Table B-53: Economic data for metal hydride storage

Size kg	Size Nm ³	Cost € ₂₀₀₀	Cost / kg € ₂₀₀₀ /kg	Source
n/a			2,100	Carpetis 1994 *
n/a			2,500 - 3,100	Carpetis 1994 *
0.036			70,900	Hydrogen Components Inc. 1997 *
			1,000 - 1,500	Oy 1992 *
8.9-890			1,700 - 2,100	Oy 1992 *
2.7			3,700 - 14,400	Zittel and Wurster 1996 *
0.089			7,100 - 26,000	Zittel and Wurster 1996 *
0.89			2,400 - 13,000	Zittel and Wurster 1996 *
8.9			2,600 - 9,700	Zittel and Wurster 1996 *
	1	400-1500		LBST
	10	200-750		LBST
	100	150-550		LBST

*cited from Amos (1998)

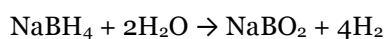
Storage in Metall Hydrides: Hydride Slurries

Basic mechanism

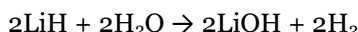
The limiting factor in the kinetics of hydrides is the conductivity of the heat needed in the sorption reactions of hydrogen. One way of solving this problem is to suspend the hydride powder in to an inert solution forming a pumpable slurry. An essential feature of this approach is the recovery and recycling of the spent hydride in centralised plants (Hottinen 2001).

Three approaches are discussed by DOE for hydrogen storage for automotive fuel cells (Milliken, Petrovic et al. 2002).

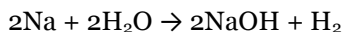
- Borax: 20-35% sol. Stabilized with 1-3% NaOH to form Borax in NaOH (Millenium Cell/DaimlerChrysler)



- Lithium hydride slurry, suspended in light mineral oil, is transformed with water into lithium hydroxide and pure hydrogen. A hydrogen capacity of 15.3% can be achieved with this reaction (Hottinen 2001) (“Thermopower”)



- Polyethylene-coated pellets, mechanically cut to expose Na (“Powerball”)



Economic data

Economic data on hydride slurries are presently not available to the authors.

Other forms of hydrogen storage for automotive applications

Zeolites

Zeolites are microporous inorganic compounds with an effective pore size of about 0.3 – 1.0 nm. The pore size is sufficient to permit the diffusion of some small molecules, such as hydrogen, under elevated temperatures and pressures. However most of the pores are smaller than the kinetic size of a hydrogen molecule in ambient temperature. Thus reducing the temperature the hydrogen is trapped into cavities of the molecular sieve host (Hottinen 2001).

The hydrogen storage capacity of zeolites is quite poor. At temperatures of 200 – 300 °C and pressures of about 100-600 bar about 0.1 – 0.8 wt% of hydrogen is adsorbed. The cyclic stability of zeolites has not been really studied. Ernst (1995) suggested that by applying sophisticated techniques of synthesis and modification there may be a potential in zeolites (Hottinen 2001).

For CASCADE MINTS, zeolites may not play a relevant role because of the poor storage capabilities.

Glass spheres

Glass spheres are small hollow glass micro-balloons whose diameter vary from 25 um to 500 um and whose wall thickness is about 1 um. The spheres are filled with hydrogen at high pressure and temperature of about 200 – 400°C. High temperature makes the glass wall permeable and the hydrogen is able to fill in. Once the glass is cooled down to ambient temperature, the hydrogen is trapped inside the spheres.

The hydrogen can be released by heating or crushing the spheres. The crushing naturally prevents the reuse of spheres. The storage capacity of spheres is about 5 –6 wt% at 200 – 490 bar (Hottinen 2001).

Chemically stored hydrogen

Hydrogen can be stored in chemical form, which is also a kind of storage. Examples are methanol CH₂OH, ammonia NH₃ and methylcyclohexane CH₃C₆H₁₂. In ambient condition, these compounds are liquid and

thus are good to handle. However the application of these NH_3 or $\text{CH}_3\text{C}_6\text{H}_{12}$ in large scale is unlikely because of environmental hazards (Hottinen 2001).

Hydrogen storage capacities of these chemical compounds are good

- 8.9 wt% for CH_2OH
- 15.1 wt% for NH_3
- 13.2 wt% for $\text{CH}_3\text{C}_6\text{H}_{12}$.

Hydrogen storage in carbon structures

Carbon nanotubes

A nanotube is a graphite sheet rolled up in a seamless cylinder with a diameter in a scale of nanometers. Hydrogen can be stored in nanotubes by chemisorption or physisorption. The mechanisms of how the hydrogen is trapped are not known accurately.

Recent experimental results on hydrogen uptake of single-walled nanotubes are promising. At 0.67 bar and 600 K about 7 wt% of hydrogen have been adsorbed and desorbed with a good cycling stability (Alleman, 2000).

The price of nanotubes is quite high. Depending on the manufacturer, the amount of nanotubes purchased, and the purity of nanotubes the price varies between 55 – 550 €/g.

Even though the price of nanotubes is still high, they have a good potential in storing hydrogen (Hottinen 2001).

Other forms of carbon (Hottinen 2001)

Storage in other forms of carbon is also known. There are graphite nanofibers, fullerenes and activated carbon. Graphite nanofibers are graphite sheets arranged in parallel, perpendicular or at angle rotation structure. One author reported high uptake of hydrogen, however others have not been able to reproduce the high results. More research will be necessary.

Fullerenes are synthesized carbon molecules usually shaped like a football, such as C_{60} and C_{70} . Fullerenes are able to hydrogenate, where approx. 6wt% of hydrogen can be adsorbed. Usually temperatures of over 400°C are needed to desorb the hydrogen. However one author claims this works also at 225°C . Besides, the cyclic stabilities have shown poor performance.

Bulky carbon with high surface area is called activated carbon, which is able to adsorb hydrogen in its macroscopic pores. However cryogenic temperatures and pressures of about 50 – 60 bar are needed.

Bulk storage of hydrogen

Liquid hydrogen storage

Basic mechanism

Storage of larger quantities of liquid hydrogen can either be necessary at liquefaction plants or at distribution centres, like e.g. fuelling stations. Hydrogen is only liquid at extreme low temperatures $\sim 20\text{ K}$ (-253°C) at 0,1 MPa. Therefore the storage vessel has to be of cold-resistant austenitic or alloy steels and non-metal materials. If there is any increase in temperature, hydrogen evaporates and increases the pressure in the vessel; this phenomenon is also called the boil-off. To avoid high pressures, the vessels are usually designed as open systems. To minimise boil-off, liquid storage systems are extremely insulated: vacuum insulation, vapor-cooled radiation shields and multi-layer insulation are applied to diminish conductive, convective and radiative heat transfer into the liquid. However, some losses are unavoidable, and the boil-off is apart from the costs the most significant factor.

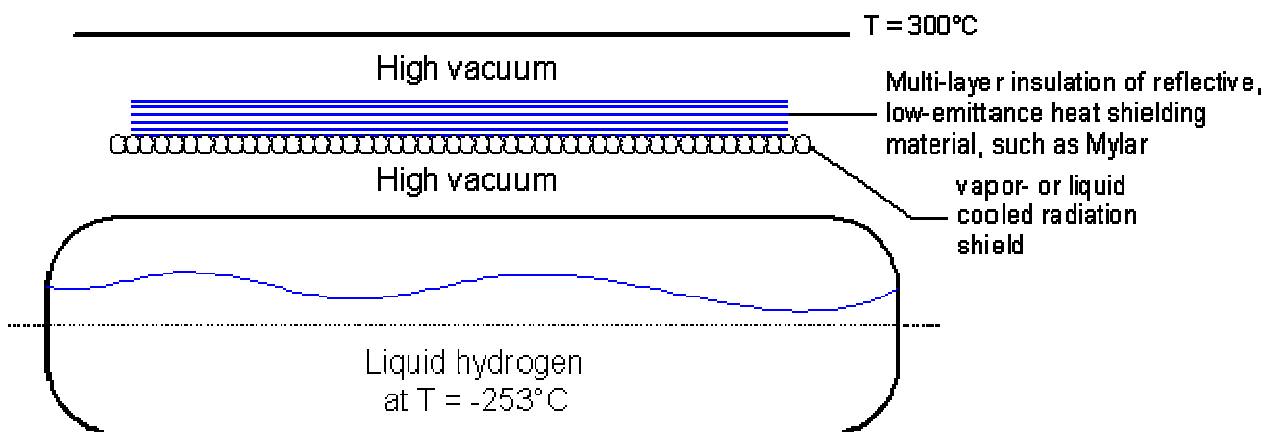


Figure B-21: Sketch of the insulation of a cryogenic tank for liquid hydrogen (according to (Hottinen 2001)).

Fields of application

Storage vessels for liquid hydrogen are state-of-the-art technology today. Large-scale applications are developed by the space programs in the U.S. and the USSR. NASA uses tanks up to $3.8 \times 10^3\text{ m}^3$ of about 22 m in diameter with a capacity of 230 t to store liquid hydrogen for the Space Shuttle, which burns 1535 m^3 (120 t) of liquid hydrogen per start. This is the largest known tank in the world (Tzimas, Filiou et al. 2003). For the 'Energia' space project with the "Buran" shuttle type spacecraft (1976-1988) several storages were built up to a total volume 8,300 m^3 (CRYOGENMASH 2004).

The commercial world market for cryogenic equipment is currently shared by just a few companies such as Linde AG (Germany), Air Liquide (France), Air Products, Praxair (U.S.A), British Oxygen Company (U.K.), Kobe Steel (Japan), and JSC Cryogenmash (Russia).



Figure B-22: Liquid hydrogen storage of Linde AG in Ingolstadt, Germany (Source: Schmidtchen (2003)).

Technical data

The boil-off rate is a function of size, shape and thermal insulation of the vessel. Therefore most vessels are spherical and thus minimize the surface area for the given volume. On the other hand, the bigger the volume, the lower the surface-to-volume ratio. Therefore boil-off for large vessels is generally lower than for smaller ones. Züttel (2003) provides average values for double-walled, vacuum-insulated spherical dewars of 50, 100 and 20,000 m³ volume to 0.4%, 0.2% and 0.06% respectively.

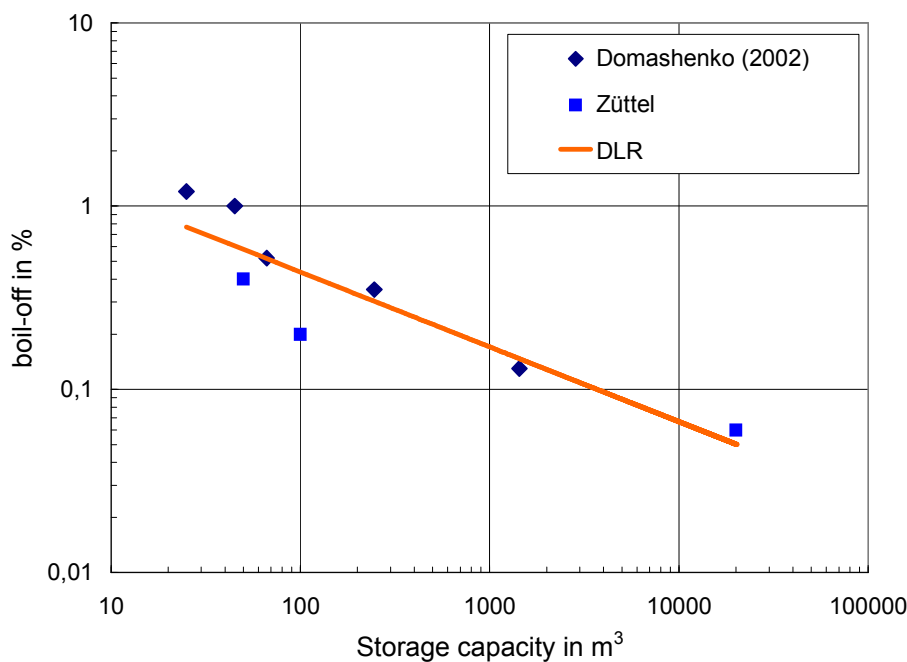


Figure B-23: Boil-off rate of large liquid hydrogen storage tanks.

Estimated storage densities of liquid hydrogen are in the range of 4.2 – 5.6 MJ/liter (Thomas und Keller 2003).

Storage can be built and used modular of the size of the largest tanks of ‘today’, or build larger. Storage volumes of approx. 60 m³ are appropriate to be used for local storage at filling stations or other consumers and therefore labelled ‘local’.

Table B-54: Technical data of liquid hydrogen storage tanks.

		‘Local’	Large/‘today’	Large/‘long-term’
Storage volume	m ³	60	3,000	100,000
Storage capacity	t	3.8	191	6,371
Thermal capacity	MWh _{th}	127	6,370	212,349
Technical system lifetime	a	30	30	30
Utilisation by volume	%	90	90	90
Utilisation by time [§]	h/a	8400	8400	
Evaporation loss (boil-off)	%	0,4	0,07	0,01

[§] Amos (1998).

Economic data

Costs for liquid hydrogen storage are often presented together with the liquefier costs in the literature. It should be noted that both cost items are presented separately here.

Costs for liquid storage are driven by the installation costs of the tank. In addition, interconnecting pipes, valves and pumps are needed. Capital costs per kg of installed capacity are summarised in Figure B-24. Until better data is available, the function for the total investment cost, adapted from Amos (1998) is recommended:

$$\text{Capital cost of liquid storage tank} = 23,445 \cdot \left(\frac{\text{capacity in kg}}{45} \right)^{0.7} \text{ in } \text{€}_{2000}$$

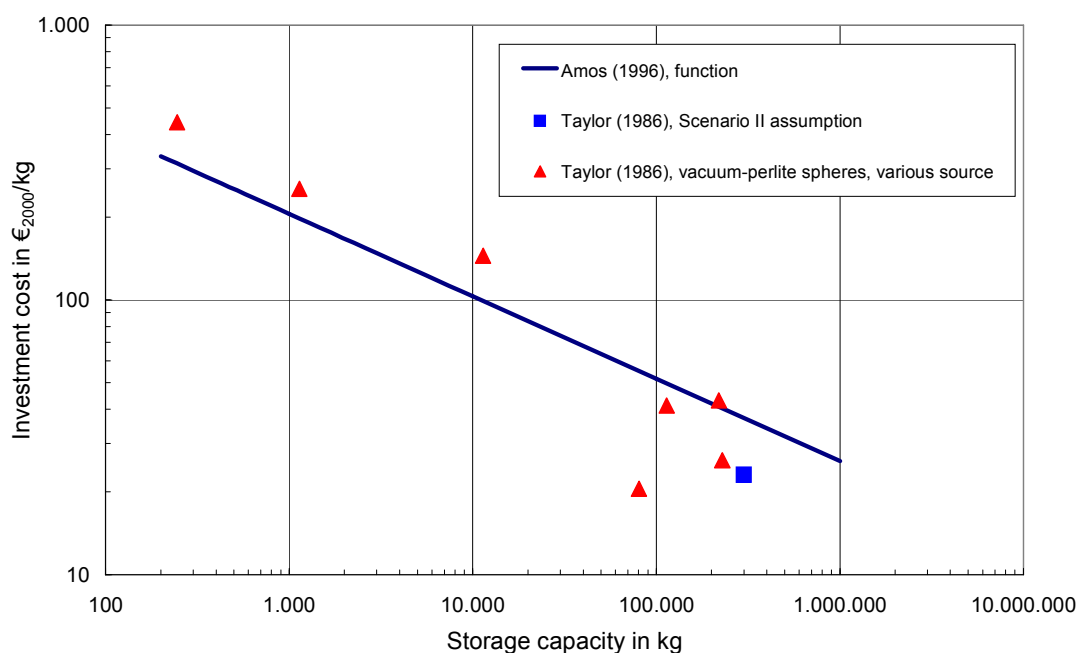


Figure B-24: Investment cost for the installation of liquid hydrogen tanks for bulk storage.

Again there are no data available for floor costs. As liquid hydrogen storage is a proven technology and considerable capacity has been installed already, however the number of installation sites world-wide would of course increase dramatically if used in a hydrogen economy. Therefore we suggest to use for modelling purposes 75% of current costs for minimum floor costs.

Specific investment costs depend on the size and the usage of the storage. Different scenarios are calculated and presented in Table B-55. Time-of-storage is defined as the time period liquid hydrogen can be derived from the storage at net production rate. The boil-off is calculated assuming steady-state where the boil-off rate depends only on the size and quality of the storage vessel (according to Amos (1998)). If the storage situated at a liquefaction plant, the cold gas due to boil-off would generally be taken back to the liquefier. At combined liquid-to-liquid and liquid-to-gas filling stations, it is used in the gas loop. In other case provisions might be taken to use the gaseous hydrogen differently. For future application, it might be possible to insulate the storage in addition with liquid nitrogen or air which however requires additional energy expenses.

Table B-55: Scenarios for liquid hydrogen storage utilisation

production flow-to-storage (incl. boil-off)	net production rate	Time of storage	Boil-off rate	Storage capacity	Storage capacity	net production rate	Invsetment cost	Cold gas back to liquefier or loss
kg/h	kg/h	d	%	m ³	kg	kW	€ ₂₀₀₀ /kW	kg H ₂ /h
10	10	1	1.55	4	240	333	227	0.15
101	100	1	0.52	37	2,400	3,333	114	0.52
1,002	1,000	1	0.18	373	24,000	33,333	57	1.77
10,006	10,000	1	0.06	3,729	240,000	333,333	29	6.01
10	10	2	1.12	7	480	333	369	0.22
101	100	2	0.38	75	4,800	3,333	185	0.75
1,003	1,000	2	0.13	746	48,000	33,333	93	2.56
10,009	10,000	2	0.04	7,459	480,000	333,333	46	8.68
10	10	8	0.58	30	1,920	333	973	0.45
102	100	8	0.20	298	19,200	3,333	488	1.56
1,005	1,000	8	0.07	2,983	192,000	33,333	244	5.33
10,018	10,000	8	0.02	29,835	1,920,000	333,333	123	18.09
11	10	30	0.31	112	7,200	333	2,455	0.90
103	100	30	0.11	1,119	72,000	3,333	1,230	3.13
1,011	1,000	30	0.04	11,188	720,000	33,333	617	10.71
10,036	10,000	30	0.01	111,880	7,200,000	333,333	309	36.42

Gaseous hydrogen storage in pressure vessels

Basic mechanism

Different types of pressure vessels are in operation today. Tube vessels can be operated at high pressure. Material characteristics limit the size of the tubes as the thickness of the walls grows with the physical volume of the vessel, so they are used on a modular basis. Today the most commonly used industrial storage method for hydrogen are cylindrical steel vessels with about 5 to 7 MPa. Approximately 6% to 7% of the stored energy is used to compress the hydrogen. High weight and space requirements for the vessel are general disadvantages of gaseous pressurized storage. For stationary applications, hydrogen might also be stored in gasometers as they were used in the past for fossil gases. The physical storage volume of a gasometer is approx. 350,000 m³ or even higher, however at low pressures.



Figure B-25: Pressure vessels applied for industrial hydrogen storage at 50 to 70 bar (left, (Belloni 2003)) and gasometer formerly used for hydrogen-rich gas storage (right, www.gasometer.de).

Technical data

High pressure tubes are commonly used to store hydrogen at pressures up to 20 MPa, e.g. at filling stations or for gaseous transport. Typically a bundle of tubes form the total storage capacity. Cylindrical steel vessels, operated at 5 to 7 MPa, are used today at approx. 100 to 150 m³ of physical volume. Larger volumes are operated at lower pressure. The size of cylindrical pressure vessels used at 2 MPa might not exceed 10,000 Nm³ today (IPTS), corresponding to a physical volume of 560 m³. Spherical pressure vessels are feasible at 0.6 to 2 MPa up to around 100,000 Nm³ (IPTS). Utilisation by time of this kind of stationary storage vessel is high: 360 d/a are reported by Taylor (1986). Technical lifetime is set to 22 years, equivalent to the depreciation time used by Amos (1996), but might be higher for spherical vessels operated at lower pressure.

Table B-56: Technical data of stationary gaseous hydrogen storage tanks.

		High pressure vessels (single tube)	Cylindrical pressure vessels	Spherical pressure vessels
Storage volume (phys. vol.)	m ³	~1.4	100 - 150	925 - 5600
Storage capacity	kg	~20	395 - 819	450 - 9,000
	Nm ³	~223	4,400 - 9,100	5,000 - 100,000
Pressure	MPa	20	5 - 7	0,6 - 2
Thermal capacity	MWh _{th}	0,67	13,2 - 27,3	
Technical system lifetime	a	22	22	>22
Utilisation by time [§]	h/a	8640	8640	8640

Source: Taylor (1996), IPTS (2004).

Economic data

The costs of compressed gas vessels increase with operating pressure and capacity. With increasing pressure, energy expenses for compression have to be taken into account. Simbeck (2002) provides cost data for

gaseous storage tubes depending on pressure. These tubes can be used stationary or mobile mounted on a trailer. The system however is modular and the capital costs are insensitive to scale (Taylor, 1986).

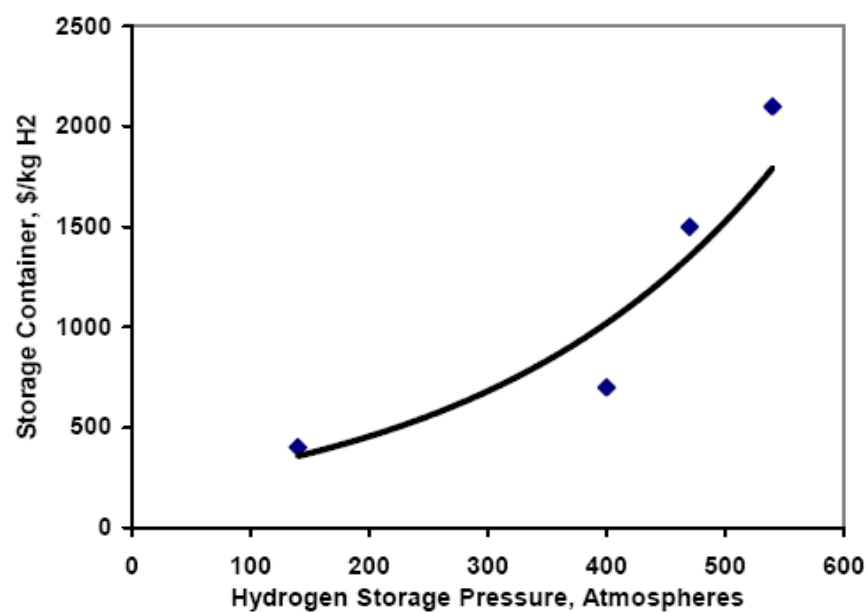


Figure B-26: Costs of compressed hydrogen tube vessels (Simbeck und Chang 2002).

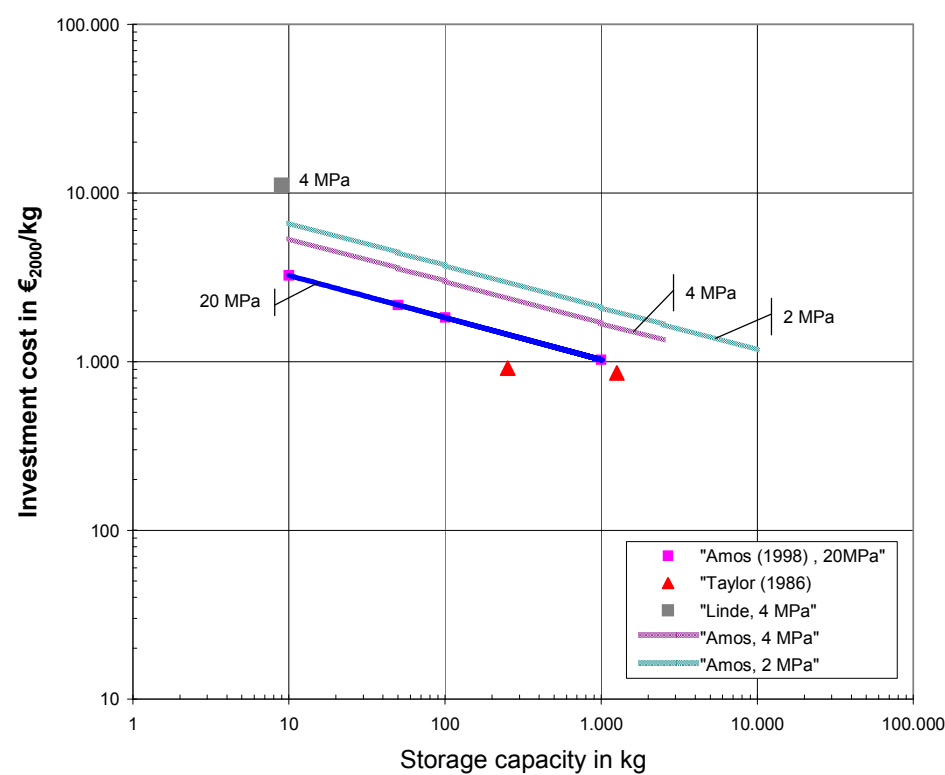


Figure B-27: Investment costs for hydrogen gaseous storage vessels from different sources.

There are no floor cost estimates for gaseous hydrogen storage available to the authors. As these systems are considered mature technology which are applied for all kind of industrial gases world wide, there might not be a big potential for cost reduction. Therefore for modelling purposes minimum floor costs of 90% of current cost estimates are considered.

Gaseous hydrogen storage underground

Basic mechanism

Gas can be stored underground under pressure in formations like (Taylor, Alderson et al. 1986):

- Depleted oil or gas fields
- Aquifers
- Excavated rock caverns
- Solution mined salt caverns.

Underground gas storage (UGS) technique is based on the simple principle which is as ancient as the geological traps which have held and confined gas and soil deposits deep under the ground or sea for millions of years all over the globe.

Fields of application

UGS can be used to store large quantities of hydrogen to balance demand with supply, i.e. in the case of fluctuating renewable energy. UGS for natural gas can be also used to store gaseous hydrogen. Today, there are over 600 underground natural gas storage facilities globally. The majority of these gas storage facilities are located in the US and Europe. 416 gas storage facilities are located in the US, while about 156 are in place in Europe. Rest remaining facilities are mainly located in Canada and Australia. Three fourths of the 615 gas storage systems are converted depleted storage fields due to their proven integrity and better economics (Airy 2004). The working volume is a percentage of the total physical capacity of the UGS and the deliverability represents the withdrawal capacity (volume per peak day) (Chachine und Guerrini 2000).

Table B-57: Characterisation of 134 underground gas storage facilities (UGS) in Europe

Type	No.	Working volume (1996) billion m ³	Deliverability (1996) million m ³ /day
Depleted field	72	142.2	1052.6
Aquifer	36	26.9	322.9
Salt cavern	19	6.3	251.5
Abandoned mine	2	0.1	1.5
Total	134	175.5	1628.5

Source: (Chachine und Guerrini 2000)

Economic data

Underground storage is probably the most inexpensive storage for large quantities of hydrogen. Capital costs depend on the suitability of the given formation.

Table B-58 illustrates investment costs for UGS facilities at a capacity of 100 million m³. According to the available data, we conclude that hydrogen storage in large quantities in aquifers and depleted is cheaper than in salt caverns. However, salt caverns are presently evaluated as the most reliable associate with the storage of the extremely volatile hydrogen regarding losses. Measurements of hydrogen losses in UGS facilities are not available.

Table B-58: Investment costs for UGS facilities at a capacity of 100x10⁶ m³

Type	Investment costs per working gas volume		Investment costs storage deliverability	
	€ ₂₀₀₀ /m ³		€ ₂₀₀₀ / m ³ /d	
	Europe	USA	Europe	USA
Aquifer	0.4 - 0.7	0.2 §	38.0 – 65.1	10.9
Depleted field	0.4 – 0.7	0.1	38.0 – 65.1	5.4
Salt cavern	0.8 – 1.1	0.3	7.6 – 10.9	2.2

Note: § Capacity: 500 10⁶ m³; Source: (Chachine und Guerrini 2000).

There is considerable experience with natural gas UGS world wide and the difference of development and organisation with hydrogen compared to natural gas will be minor despite of probably higher losses and higher investment for hydrogen compressors. Therefore we see no further potential for lower costs/floor cost

Table B-59: Hydrogen storage options: summary on technical and economic characteristic

Liquid hydrogen storage vessels for bulk storage	Capacity (phys. vol.) m ³	Thermal capacity MWh	Production rate, net kg/h	Time of storage ^e d	Boil-off % ^d	Cold gas back to loss kg/h	Utilisation factor ^s %	System lifetime a	Investment costs (floor) € ₂₀₀₀ /kW _{H₂}	O&M fixed costs % Invest./a	O&M variable costs € ₂₀₀₀ /Nm ³
Local storage											
Filling station											
Bulk storage of 'today'	~47	100	25	0,83	5	0.5	0.6	90	30	532 (400)	n.a.
State-of-the-art	~4,700	10,000	1,000	33,3	8	0.05	4.3	90	30	334 (250)	n.a.
Large-scale storage											
'2030'	~47,000	100,000	10,000	333,3	16	0.02	29.3	90	30		

Table B-60: Hydrogen storage options: summary on technical and economic characteristic

Gaseous pressure vessels for bulk storage	Capacity (phys. vol.) m ³	Thermal capacity MWh	Production rate, net kg/h	Time of storage d	Pressure MPa	Utilisation factor ^s %	System lifetime a	Investment costs € ₂₀₀₀ /kW _{H₂}	Floor costs € ₂₀₀₀ /kW _{H₂}	O&M fixed costs % Invest./a	O&M variable costs € ₂₀₀₀ /Nm ³
High pressure vessels											
'State-of-the-art', steel	1.5	0.7	0.5	2	20	98.6	22	3,800	3,400	n.a.	n.a.
Cylindrical vessels											
'State-of-the-art', steel	125	20	3	8	6	98.6	22	9,900	8,900	n.a.	n.a.
...Spherical vessels											
'State-of-the-art', steel	1,560	83	6.5	16	2	98.6	> 22	19,000	17,100	n.a.	n.a.

Table B-61: Hydrogen storage options: summary on technical and economic characteristic

Gaseous underground storage	Capacity (phys. vol.) m ³	Thermal capacity GJ	Storage rate MW	Electricity kWh/MWh	Cooling water kg/MWh	Utilisation factor ^s %	System lifetime a	Investment costs € ₂₀₀₀ /MW _{H₂}	O&M fixed costs % Invest./a	O&M variable costs % Fixed O&M
Salt cavern (dry mode)	2,000,000	21.580	617	45.3	1.400	36	>50	95,580	7%	8%

Hydrogen Delivery

Transport of hydrogen

Hydrogen road transport

Basic mechanism

Road transport of gaseous and liquid hydrogen is commonly applied in industry today. Special purpose vessels are mounted on trailers which are moved by conventional tractors. The transport capacity of both options is significantly different. Cryogenic tankers today are able to transport ca. 3.5 tonnes of hydrogen, which is about ten times more than the capacity of conventional gaseous hydrogen trailers. Compressed gaseous hydrogen tankers are limited in their capacity because of the height weight of today's pressure vessel technology.

It is likely to apply a different workflow to gaseous hydrogen road delivery compared to liquid delivery. While cryogenic tankers can be discharged similar to any other liquid fluid, the discharge of gaseous hydrogen takes more time. Therefore it is proposed to leave the trailers at the fuelling stations and use the vessel as storage (Simbeck und Chang 2002). This implies that the number of gaseous hydrogen trailers is at least doubled.

Fields of application

Cryogenic and gaseous tankers are commonly used to distribute hydrogen for industrial purposes in several cases. For example it is used if the pipeline capacity is not sufficient to supply enough hydrogen from centralised production, or as a backup supply in case of plant problems at the customer's site. In the future, road hydrogen transport might be used to supply hydrogen to refuelling stations or decentralised power plants. Figure B-28 shows an articulated train equipped for liquid hydrogen transport.



Figure B-28: Articulated train with semi-trailer equipped for liquid hydrogen; (source: Linde AG www.linde-gas.de).

Technical data

Technical data for today's liquid and gaseous hydrogen road transport vehicles are provided in Table B-62. Capacities of liquid and gaseous hydrogen transporters are limited by the maximum allowed gross weight of the vehicle on the road. This again is driven by the weight of the storage vessels mounted on the trailers, with an extreme dissatisfying ratio of 100-150 : 1 for gaseous trailer transport.

Unloading and loading is an important issue for short-distance delivery of hydrogen. It is generally faster for liquid hydrogen than for gaseous hydrogen. Liquid hydrogen flows in and out by gravity. Gaseous hydrogen is discharged section-by-section from the trailer and the whole procedure takes significant time. Therefore it is recommended to exchange trailers at the customer site and use the trailer as intermediate storage.

The load factor of the tankers is set to 0.5 referring to the net delivery as the tankers will always return empty to the central plant.

Table B-62: Technical data for hydrogen road transport

	Liquid hydrogen		Gaseous hydrogen	
Physical volume	53	m ³		
Capacity	3,500	kg/tanker	300	kg/tanker
Net delivery	3,370	kg/tanker	250	kg/tanker
Temperature	-235	°C	10	°C
Pressure (max)	-		16	MPa
Pressure (min)	-		3	MPa
Boil-off rate	0.3	%	-	
Load time	1	h [§]	2	h [§]
Unload time	1	h ^{§§}	3	h [§]
Fuel economy, 100% load (Diesel)	43.6	l/100 km	43.61	l/100 km
Fuel economy, empty (Diesel)	25.8	l/100 km	25.8	l/100 km
Average fuel economy (50%/50%)	34.7	l/100 km	34.7	l/100 km
Average speed for short-distance	60	km/h	60	km/h
Average speed for long-distance	80	km/h	80	km/h
Tanker availability	24	h	24	h
Load factor	0.5		0.5	
Technical lifetime	6	years	6	years

Note: 43.6/25.8/34.7 l/100 km equiv. 362/214/288 g/km Diesel (INFRAS 2004)

Source: § (Linde AG 2004)

Economic data

Import parameters for the economic evaluation of road hydrogen transport are utilisation of the vehicle by time and yearly mileage.

Table B-63 presents yearly average mileage per vehicle and time working for customers as the key variables for internal accounting. Short- and long-distance transport is distinguished. Short-distance is defined as when the delivery trip to the customer can be done within 8 hours of the working day. Long-distance transport is understood for distances which need more than a working day and where driver's breaks have a significant share on the overall transport time. The total workdays per year are assumed as 240 with 8 working hours per day. The time for load handling comprises loading and unloading the trailer as defined in

Table B-62. Average vehicle speeds are assumed for short-haul as 60 km/h and long-haul as 80 km/h (motorways).

Utilisation by time for short-distance is assumed between 0.6 and 0.8. The lower end is similar to for pre- and post haulage of intermodal transport, where the transport distance is comparable. Utilisation of 0.8 and higher is reached by long-distance road goods transport. Yearly mileage per truck and the time of vehicle usage presented here are recommended to break down fixed costs and estimate the variable costs per km. Break down of depreciation is also possible by time of utilisation which generally gives lower costs for low yearly mileage of vehicles compared to break down by kilometre only.

Table B-63: Scenario parameters for utilisation for gaseous and liquid, short- and long-distance hydrogen transport.

		Distance to customer km	utilisation by time	Time for driving h/trip	Time for handling h/trip	Yearly mileage of truck km/a	Time of utilisation § h/a
Gaseous hydrogen transport							
Short distance	No Exchange of trailers	25	0.60	0.83	5.0	9,900	1,200
		50	0.67	1.67	5.0	19,000	1,300
		100	0.73	3.33	5.0	34,000	1,400
		25	0.60	0.83	1.0	31,000	1,200
long distance	exchange of trailers	50	0.67	1.67	1.0	48,000	1,300
		100	0.73	3.33	1.0	65,000	1,400
		150	0.80	5.00	1.0	77,000	1,500
		200	0.80	5.00	2.5	77,000	1,500
		400	0.90	10.00	2.5	81,000	3,100
		800	0.95	20.00	2.5	115,000	3,300
		1600	1.00	40.00	2.5	126,000	3,500
		Liquid hydrogen transport					
Short distance		25	0.60	0.83	2.5	17,000	1,200
		50	0.67	1.67	2.5	31,000	1,300
		100	0.73	3.33	2.5	48,000	1,400
		150	0.80	5.00	2.5	61,000	1,500
long distance		200	0.80	5.00	2.5	77,000	1,500
		400	0.90	10.00	2.5	81,000	3,100
		800	0.95	20.00	2.5	115,000	3,300
		1600	1.00	40.00	2.5	126,000	3,500

Source: Own calculations, based on experience from RECORDIT. § Time for breaks for drivers are included

Data for accounting-sheet-calculations for road hydrogen transport are presented in Table B-64. For the transport sector the following general baseline assumptions are recommended: rate of capital return 8%, employer's salary 10% of fixed costs and contingencies 5% on variable costs per km (BVT 2004). Gross salaries for drivers are in the range of 1,600 € per month³ (short distance) to 2,000 € per month for long distance plus 500 € of expenses⁴ (long-distance only). In addition, associated employer outlays have to be added: 50% in Germany. Significant differences for costs for drivers throughout Europe are likely.

³ BVT (2004). Preisempfehlung Transport (PeTra), Bundesverband der Transport unternehmen.

⁴ ZEW, personal communication

Table B-64: Economic data for hydrogen road transport

	Liquid hydrogen		Gaseous hydrogen	
Capital cost				
Tractor	86,000	€	86,000	€
Trailer (undercarriage)	30,000	€	30,000	€
Storage vessel	400,000	€	80,000	€
Total (incl. tyres)	516,000	€	196,000	€
O&M fixed costs				
Cost for driver ⁺⁺	38,000	€/a	38,000	€/a
Insurance ^{##}	3000	€/a	3000	€/a
Circulation tax ^{\$}	3000	€/a	3000	€/a
Road charge	-	€/a	-	€/a
Overhead	7500	€/a	7500	€/a
Total	51,500	€/a	51,500	€/a
O&M variable costs				
Fuel cost [*]				
Maintenance (spare parts) ^{\$}	0.04	€/km	0.04	€/km
Maintenance oil	3%	of fuel costs	3%	of fuel costs
Tyres	3500	€ #	3500	€
Road tolls	-	€/km	-	€/km
Other				
Lifetime for depreciation tractor	5	years	5	years
Lifetime for depreciation trailer	6	years	6	years
Lifetime mileage tyres	40,000	km	40,000	km

Notes: * fuel costs are internal in CASCADE models and therefore not provided here. ++ here assumed 2,000 €/month gross salary, 13 months, 50% associated employer outlay. ## for German truck. \$ see also Sources: \$, # Gruppo Clas (2002), BVT (2004)

For short-distance liquid hydrogen transport with 48,000 km/a, and 1400 h of operation exemplary costs are calculated to 4 €/km with 2.6 €/km by fixed costs and 1.4 €/km by variable costs. For short-distance gaseous hydrogen transport with 65,000 km/a, and 1400 h of operation 1.7 €/km of fixed, 0.9 €/km of variable, and in total 2.5 €/km are estimated (capital costs for 2 trailers accounted). Long-distance transport estimates to 1.9 €/km (liquid, 115,000 km/a) and 1.4 €/km (gaseous/km). For comparison, long-haul road goods transport cost around 0,8 – 0,99 €/km today (Black, Seaton et al. 2002). Differences arise from the high investment cost for liquid trailers and the low utilisation for local transport. Transport by Eastern European companies might lower O&M fixed cost considerably.

Table B-65: Cost of hydrogen road transport (example calculation).

Transport scenario	Distance to customer km	yearly mileage of tanker km/a	Operating costs €/km	Net delivery capacity kg/tanker	Specific costs (floor) €/GJ
LH ₂ , short-distance	100	48,000	4.3	3,370	2.0 (1.6)
GH ₂ , short-distance	100	65,000	2.5	250	17
LH ₂ , long-distance	800	115,000	1.9	3,370	7.6 (6.5)
GH ₂ , long-distance	800	115,000	1.4	250	76

Floor cost

The main potential for lower investment costs for liquid and gaseous hydrogen transport is located in the storage vessel for liquid transport. Currently these are produced in very low volumes. For series production cost will certainly decrease. As a first estimate we suggest for the modelling to assume 75% of current investment cost for the trailer. This results in costs of 1.8 €/GJ for LH₂ short distance and 7 €/GJ for LH₂

long distance transport. If in addition the cost for the driver is reduce to 75% of current assumptions, the costs are 1.6 €/GJ and 6.5 €/GJ respectively. This might be justified to account for regional differences.

Table B-66: Circulation tax in European countries 1998 in €/year/truck

Country	Circulation tax	Country	Circulation tax
Austria	247	Poland	404
Denmark	475	Slovenia	-
France	976	Slovak Republik	1200
Germany	2997	Spain	150
Greece	382	Sweden	4000
Hungary	750	Switzerland	1742
Italy	628	United Kingdom	4719
Netherlands	1575		

Source: (Maas, Uitenboogaart et al. 2001)

Hydrogen ship transport

Basic mechanism

Liquid hydrogen may be transported overseas over several thousands of kilometres in large ships. Abe et al.(1998) start their conceptual study of hydrogen tank ships on the experience gained from liquid natural gas (LNG) ship technology. LNG tankers carry LNG below its boiling point of -163°C . The cryogenic tank system with insulation and tank support, the hull structural arrangement and the boil-off gas treatment are characteristics which are similar to those needed for liquid hydrogen ships. The main difference between LNG and LH₂ is the lower boiling point of LH₂ at -253°C . This increases the effort for insulation. Secondly, the density of LH₂ is much lower compared to LNG, which is an advantage for the construction of the tank system, however seems to be a disadvantage for hull design, immersion and maneuverability. It is assumed that the ship is propelled by hydrogen (e.g. fuel cell or H₂ burning engine). The insulation of the storage vessels is adjusted so that the amount of boil-off gas equals approximately the fuel need of the engine.



Figure B-29: Principle of cryogenic tankers with Moss tank system (left) and LNG ship as example for cryogenic tank ship (right) (Source: www.statoil.com).

Fields of application

Sea transport of liquid hydrogen might be applied to connect areas of high potentials of renewable energy to centres of high demand like e.g. Europa. This could be the case for solar thermal power plants in North Africa or hydrogen from large hydro power plants in Canada (see e.g. Nitsch 1989).

Technical data

Nitsch et al. (1989) derived scenarios for liquid hydrogen sea transport based on the work of Giacomazzi (1989). The ship reported is on the lower range of general ship sizes because the capacity of the liquid hydrogen storage system was kept similar to today's stationary systems. We take this as a small-scale application labelled 'today'. The study of Abe et al. (1998) showed that ships carrying up to 200,000 m³ of LH₂ are possible. Physical volumes of today's LNG carriers are in the same order of magnitude, e.g. LNG 147 (147,000 m³ phys. vol.) of Moss Maritime (2004). In contrast to stationary storage, the boil-off rate of 0.2-0.4%/day taken from Abe (1998) is not minimized, but rather designed to correspond to the fuel consumption of the propulsion system.

Table B-67: Technical data for hydrogen ship transport.

	Small-scale ('today')		Large-scale ('future')	
Physical volume	11,400	m ³	147,000	m ³
Capacity	810	t/tanker	10,500	t/tanker
Net delivery	750		9,718	t/tanker
Temperature	-235	°C	-235	°C
Spherical tanks	4		4	
Boil-off rate	0.03	%/day	0.2-0.4	%/day
Engine power	n.a.		80,000	HP
Ship speed	20	kt	21	kt
Propulsion efficiency			32	%
Load factor by time			0.5	
Technical lifetime	30	years	30	years

Economic data

Amos (1998) analysed container shipping in his study of hydrogen transportation, which has an advantage in inter-modal distribution chain to the customer. It is however less efficient for long-distance liquid hydrogen transport because the more complicated handling of the boil-off losses. Nitsch et al. (1989) give cost data for 'small-scale' liquid hydrogen tanker scenarios with investment cost of approx. 162 million €2000. For large-scale sea transport we consider information on conventional state-of-the-art LNG technology. Investment cost for LNG tankers are reported in the order of 1.5 billion NOK (Statoil 2004) which corresponds to 180 million Euro. Because of lack of further detailed information on the differential costs between LNG and LH₂ equipment, we suggest to use a scaling of 25% for the additional equipment needed to handle cryogenic temperatures of -253°C for liquid hydrogen (Christiansen, 2004).

For the transport of liquid hydrogen derived from solar thermal power plants in North Africa, the following scenario assumptions are used. Taken as a basis a distance of 3,330 km (e.g. Algier – Hamburg), and ship speeds of 28 km/h and 39 km/h, ‘small-scale’ and ‘large-scale’ respectively, 5 and 3,5 days per single trip are needed, resulting in 26 and 33 transport cycles per year. Net delivery of hydrogen would amount to 742 GWhth and 10,400 GWhth per year.

Table B-68: Cost estimates for liquefied hydrogen ship transport.

		Small-scale ('today')	Large-scale ('future')
Investment cost	€ ₂₀₀₀	162,000,000	225,000,000
Specific investment cost	€/MWh		
O&M fixed cost	% Invest./a	5	5
O&M variable cost	% Invest./a	4	4

Floor cost

As no detail bottom-up calculation of the investment cost for hydrogen ships is available, no estimate floor costs can be made. However it is as a bottom line the investment cost for LNG tankers can be used, i.e. multiplication by a factor 0.8.

Pipeline transport

Basic mechanism

Pipelines are effective for handling large flows. Along the piping in regular distances there is a compressor installed, which elevates the pressure in the pipe. The gas flows then from the high pressure end towards the low pressure end, loosing a certain amount of energy due to friction along the way. Hydrogen pipelines are in principle similar to natural gas pipelines. Because of the small size of the H₂ molecule, different valves and compressors have to be used. Embrittlement of steel due to H₂, i.e. H₂ induced cracking especially at high strength material and high pressures have to be taken into account. Nevertheless was recently a crude oil pipeline successfully converted to H₂ service (Air Liquide 2003).

Generally it seems to be advantageous to use the existing natural gas pipeline infrastructure for hydrogen in the future. This would avoid high investment costs for new, hydrogen dedicated pipelines.

Fields of application

Hydrogen pipelines are today in use in several areas of the US, Canada and Europe with a length of about 720 km in the US and about 1,500 km in Europe (Kruse, Grinna et al. 2002). Those pipelines primarily serve industrial purposes. Germany has a 210 km pipeline that has been operating since 1939, carrying 8,900 kg/h of hydrogen through a 0.25 m pipeline operating at 2 MPa (Amos 1998).

For a hydrogen economy, two different types of pipelines may be needed: a large capacity long distance system, and a local small capacity system to provide the link to hundreds of refuelling stations and customers.

Table B-69: Hydrogen pipelines in Europe

Name	Operator	Country	Length km	Pressure range bar
Rhine-Rhur pipeline	Air Liquide	Belgium, France, NL	966	10
		Germany	240	1.1 - 30
Leuna-Merseburg	Linde		100	2 – 2.5
Europoort	Air Products	NL	50	
Teeside	ICI	UK	16	5
Chemical Industry		Sweden	18	0.5 - 2.8

Source: (Wurster 2003)

Technical data

Hydrogen pipelines today are constructed of 0.25-0.30 m commercial steel and operate at 1-3 MPa with flows of 320-8,900 kg/h (Amos 1998). Natural gas pipelines for comparison are constructed of pipe as large as 2.5 m in diameter and have working pressure of 7.5 MPa (Hart, 1997). Air Liquide mentions, that gaskets and seals are more critical for hydrogen compared to natural gas (Air Liquide 2003) Higher strength Materials are more susceptible to hydrogen embrittlement than more ductile steel.

Natural gas pipeline can be used for hydrogen transport, depending on the pipe material, however because the hydraulic characteristics of hydrogen and natural gas are not the same, the transport capacity is different. Transporting hydrogen via an existing natural gas pipeline leads to a capacity de-rating of approximately 20-25% on a delivered energy basis. The same amount of energy requires increased compression to deliver the larger volume of gas. Therefore natural gas compressors will need to be replaced (Air Liquide 2003).

Leakage of hydrogen pipelines

Zittel and Altmann (1996) report about 0.1 % loss of gaseous hydrogen from the existing industrial hydrogen distribution grid in Germany. This is the only data on losses for dedicated hydrogen pipelines known to us.

For plausibility it is interesting to look at leakage of natural gas pipelines. Lelieveld et. al (2005) measured methane leakage from Russian natural gas long-distance pipelines and found them as high as 0.7% (with a range of 0.4-1.6%) including compressor stations, valve knots and machine halls. They also reported in addition 0.5-0.8% losses for the low pressure NG distribution networks from U.S. literature. Schultz et. al (2003) estimated a factor 3 higher leak rates if existing NG grids were used for hydrogen without further adaptations (such as new fittings or inline coating).

However for different reasons, e.g. embrittlement and safety, dedicated hydrogen pipelines are built of different materials and fittings compared to natural gas pipelines. Therefore it is likely that the leakage of natural gas pipelines can at least be met in spite of the more difficult situation with hydrogen, suggesting 1.7% as overall average (with a range of 0.9%-2.4%) for non-industrial hydrogen pipeline systems.

Economic data

Pipelines are capital intensive. Amos (1998) estimates hydrogen pipeline costs based on natural gas pipeline costs, stating that a large fraction of the pipeline is assumed for installation, probably also the right-of-way

(Simbeck und Chang 2002). Recent estimates for unit costs of hydrogen pipelines are given by Mintz (2002), differentiated by pipeline diameter and installation technology. Traditional cut and cover technology is about a factor of 1.2 more expensive than innovative trenchless technology (see Table B-70).

Cost data on 54 recent natural gas pipeline projects in the US for expanding or building natural gas pipelines in different regions are available from Tobin (2003). The values range from as low as 0.29 M€/km to 2.11 M€/km, resulting in a cross-average of 0,78 M€₂₀₀₀/km for project costs, i.e. incl. auxiliary equipment.

From the information given, we recommend for general calculations to use the average costs of both technologies given by Mintz (Table B-70).

Table B-70: Investment cost for hydrogen pipelines by pipe diameter and technology

Pipe diameter m	Cut – Cover € ₂₀₀₀ /km	Trenchless € ₂₀₀₀ /km	Average € ₂₀₀₀ /km
0.08	260,000	200,000	230,000
0.23	590,000	460,000	525,000
0.31	650,000	590,000	620,000
0.36	910,000	750,000	830,000
2.0	2,000,000 §	-	2,000,000

Source: § Nitsch (1989), others: Mintz (2002)

Compressors are needed in order to move the hydrogen in the pipeline, if the pressure at the central plant is not sufficient. They are sized depending on inlet and outlet pressure, and flow rate. Typically for natural gas, they are installed every 100-150 km (Voß 2001). In practise for all gases, the installation layout is an optimum problem of investment cost, operating costs and production rate. For diameter below optimum, the dominating costs are compressor capital and operating costs, for larger diameters than optimum, pipe total cost will prevail (Oney, Veziroglu et al. 1994).

Reciprocating compressors are most commonly used for hydrogen applications (Amos 1998). It is practical to power the compressors by hydrogen engines with a small amount of hydrogen taken from the pipeline, as it is done for natural gas pipelines. The given numbers below are based on a reciprocating compressor with gas engine including normal auxiliary equipment with purchase costs taken from Peters et al.(2003), adjusted for power by the methodology used in Amos (1998). This results in investment costs by size from 760 to 4,600 €₂₀₀₀/kW.

The major operating cost for hydrogen pipelines is compressor power and maintenance. Some hydrogen losses may occur in the piping network, but for natural gas piping systems, these losses are less than 1% (Hart, 1997 in Amos, 1998). Gas energy demand for compressor power is calculated for the exemplary layouts and can be used to estimate operation costs for compressing. The energy demand ranges from 0.01% to 4.5% of the transported energy.

Floor costs

Natural gas pipelines are considered a mature technology. Hydrogen pipelines will need adjustments at compressing stations and piping material, therefore will be more expensive at first. Therefore the investment costs for NG pipelines can be used as minimum floor costs. NG pipelines are roughly a factor 1.5 more

expensive than H₂ pipelines with trenchless technology (Mintz, 2002). We take this factor to estimate minimum floor costs of hydrogen pipelines.

Cost summary for pipelines

Cost data are summarized for several pipeline layouts for different purposes. 3 inch pipes are calculated representative for connecting pipes to fuelling stations, while large diameters may be used for long-distance pipelines. The inlet pressure of the compressor was set equal to the delivery pressure of 2 MPa. Therefore each section may be multiplied in order to cover greater distances. The compressor outlet pressure was calculated to overcome frictional losses, maintaining the given production rate. Energy demand is calculated from the adiabatic head for the given pressure delta, modelling hydrogen as real gas (Jacobsen, Penoncello et al. 1997). Compressor efficiency is set to 0.78 (Lüdtke 2004) and the gas engine efficiency is set to 0.33 (Peters, Timmerhaus et al. 2003).

Table B-71: Economic data for hydrogen pipelines (Delivery pressure 2 MPa)

Pipe diameter		Distance	Production rate	Energy demand for compressing	Energy demand gas engine	Pipeline capital cost	Compressor capital cost
in	m	km	Nm ³ /h	kW	kW	€2000/Nm ³ /h	€2000/Nm ³ /h
3	0.08	50	1,000	0.6	1.7	230	3.0
9	0.23	100	10,000	3.4	10.0	53	1.1
9	0.23	250	10,000	8.4	26.0	53	2.3
12	0.31	125	10,000	0.9	2.8	62	0.4
14	0.36	250	10,000	0.8	2.5	83	0.4
9	0.23	100	100,000	4,100	12,000	5.3	31.8
12	0.31	125	100,000	980	3,000	6.2	10.1
12	0.31	250	100,000	2,100	6,200	6.2	18.3
14	0.36	125	100,000	420	1,300	8.3	5.2
14	0.36	250	100,000	870	2,600	8.3	9.2
-	2	3300	4.2 10 ⁶	1.4 10 ⁶	5.1 10 ⁶		

Note.: numbers are rounded.

Table B-72: Transport of hydrogen: characterisation of ‘generic’ road transport scenarios.

Road transport	Net delivery kg	Transport distance km	Fuel use g/km	Yearly mileage km/a	Utilisation factor ^{\$}	System lifetime [%] a	Investment costs (floor) k€ ₂₀₀₀	Fixed O&M costs € ₂₀₀₀ /a	Variable O&M costs € ₂₀₀₀ /km
Liquid transport by road									
Short distance	3,370	100	288	66,000	0.73	6/10	516 (416)	52,000 *	0.20 *
Long distance	3,370	800	288	121,000	0.95	6/10	516 (416)	52,000 *	0.18 *
Gaseous transport by road									
Short distance ++	250	100	288	66,000	0.73	6/10	196	51,000 *	0.18 *
Long distance	250	800	288	121,000	0.95	6/10	196	51,000 *	0.16 *

++ with exchange of trailers at the filling station; \$ by kilometre; % tractor/trailer; * excl. capital cost, incl. labour, german case; * excl. fuel cost

Table B-73: Transport of hydrogen: characterisation of ‘generic’ sea shipping scenarios.

Sea transport	Net delivery	Transport distance t km	Transport cycles t	Transport efficiency	Yearly mileage km/a	Utilisation factor	System lifetime a	Investment costs (floor) 10 ⁶ € ₂₀₀₀	Fixed O&M costs [*]	Variable O&M costs
Long-distance ‘small-scale’ [§]	742	3300	33		172,000	0.5	30	162 (123)	5	4
Long-distance ‘large-scale’ [§]	10,355	3300	26		218,000	0.5	30	225 (180)	5	4

[§]Transport scenario: Algier – Rotterdam; \$ by time: return trip empty; [‡]incl. 2,5% for insurance;

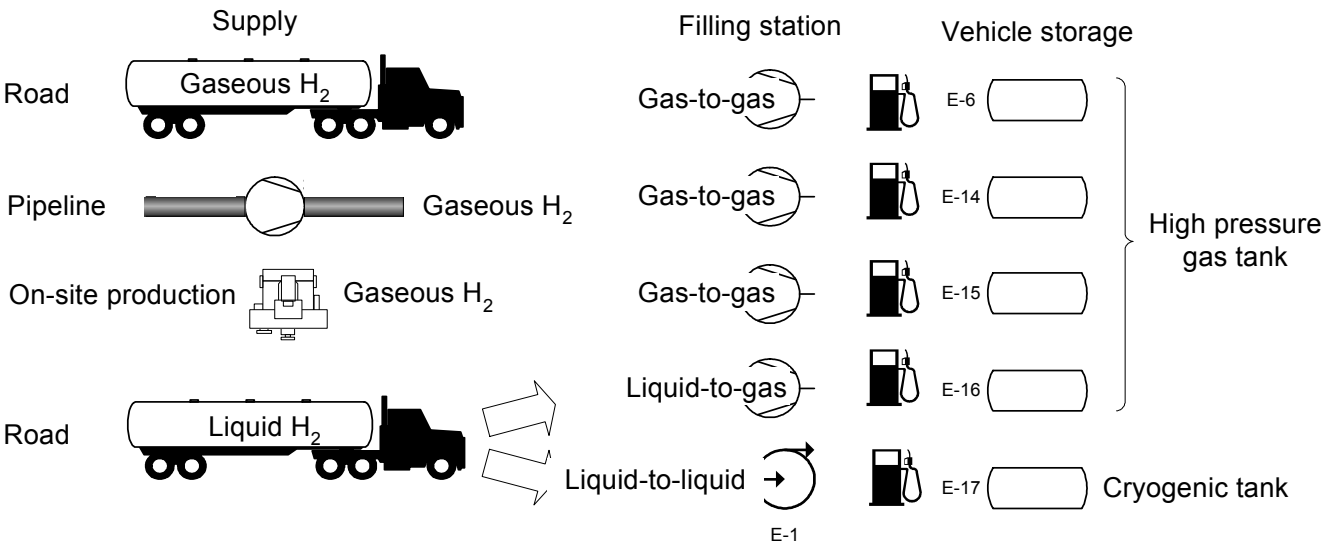
Table B-74: Transport of hydrogen: characterisation of ‘generic’ pipeline scenarios.

Pipeline	Capacity Nm ³ /h	Pipeline length km	Delivery distance km	Transport efficiency %	Utilisation factor %	System lifetime a	Investment costs (floor) € ₂₀₀₀ /kW _{CGH}	Fixed O&M costs % Invest./a	Variable O&M costs % Invest./a
Local connection	10,000	100	-		70	30	1,900 (1,300)	2,5	1
Distribution network, 4 arms	100,000	600	150		70	30	3,600 (2,400)	2,5	1
North Africa - Central Europe	4.17·10 ⁶	3,300	-	88,9	69 [§]	30	640 (430)	2,5	1

[§] depends on buffer storage at pipeline head;

Dispensing of hydrogen

The road transport sector may be supplied with hydrogen via hydrogen filling stations similar to today’s petrol stations. Hydrogen filling stations are provided with gaseous or liquid H₂ by road transport or gaseous H₂ by pipeline, or produce their hydrogen on-site. Looking at the potential need of the vehicles, liquid as well as gaseous hydrogen might be stored and used on board. As neither the form of supply nor demand is decided upon, the following combinations are conceivable:



There are major technical differences between hydrogen filling stations which are based on gaseous compared to liquid hydrogen. Therefore they are treated separately. The focus of this presentation is set on the filling station dispensing equipment itself and therefore does not include hydrogen production and delivery. This information can be drawn from other sections of this report.

Size of hydrogen filling stations

Data for four size classes of filling stations are presented, labelled ‘experimental’ (EXP), ‘small’ (S), ‘medium’ (M) and ‘large’ (L). Filling stations of size EXP corresponds e.g. to the Stuttgart filling station of the CUTE-project, serving 3 busses per day (~117 kg CGH₂/d). Size class L complies approximately with today’s petrol supply structure in Germany, taking into account the average number of vehicles per petrol station in Germany⁵. Dispensers are designed to meet peak demand at 3 times of the daily average rate (Simbeck und Chang 2002).

Table B-75 presents the characteristics of the filling stations by size class.

⁵ Based on 2,700 vehicles per petrol station in Germany 2002; 4.5 kg H₂ per refilling, 1 MJ/km energy consumption and 14,000 km annual mileage.

Table B-75: Size classes of hydrogen filling stations as analysed in the report.

		Experimental	Small	Medium	Large
Station design capacity	kg/d	150	300	600	1200
Station average daily rate [§]	kg/d	105	210	420	840
Station peak design rate	kg/h	19	38	75	150
Number of dispensers		1	2	3	6
Operation hours per day	h/d	12	15	18	24
Number of cars served (fleet)		325	650	1300	2600

[§] 70% utilisation of design rate

Gaseous hydrogen based filling stations

Basic mechanism

Gaseous hydrogen based filling stations provide compressed H₂ to be used in vehicles⁶. The hydrogen is provided at low pressure in the range of 1 to 16 MPa (electrolyser, steam reformer, pipeline, road tanker) to the dispensing system. Depending on the storage system of the vehicle, the gaseous H₂ has to be compressed to pressures above the pressure level of the on-board tank, e.g. today about 45 MPa for 35 MPa tank systems and in the future up to 88 MPa in order to fill a prospective 70 MPa tank system. Dispensers for compressed hydrogen work similar to those of natural gas stations.

Technical data

Different technical systems are used today for gas-to-gas filling stations. It is possible to avoid a high pressure storage vessel at low capacities with the utilisation of a booster compressor. Here, reciprocating compressors or membrane compressors are used. The dimensioning of the system depends also on the delivery pressure of the hydrogen to the station. An example configuration is given in Figure B-30. Technical data for different sized filling stations are given in Table B-76.

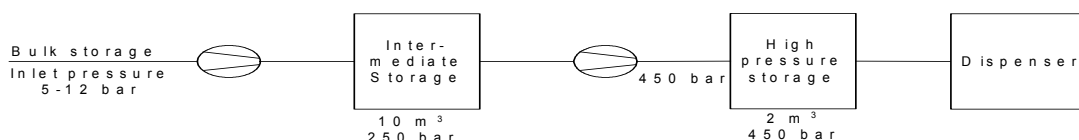


Figure B-30: Example configuration of a hydrogen gas-to-gas filling station of today (CUTE Project, BROCHIER (2003))

Table B-76: Technical data for gaseous H₂ based filling stations

		Experimental	Small	Medium	Large
Compressor power	kW	55	110	220	410
High pressure storage	kg	19	38	75	150
Technical system lifetime	a	15	15	15	15
Electricity use	kWh/kg	2.7	2.7	2.7	2.7

⁶ It is unlikely with today's technology, that gaseous H₂ based filling stations might be used for distributing liquid hydrogen due to the high effort for liquefaction without using the advantage of liquid transport offers.

Economic data

The main single technical components for cost calculations are: compressors, buffer storage and dispensers. Compressor costs are calculated from 2,100 €/kW at 100 kW with a sizing exponent of 0.8 and costs for buffer storage are estimated to 3,000 €/kg at 75 MPa (Simbeck und Chang 2002). Dispensers are taken at 16,000 €/dispenser for gaseous H₂. To the investment cost for technical components are added:

- general equipment: 25%
- engineering, permits and startup: 10%
- contingencies: 10%
- working capital, land, etc.: 7%

O&M fixed costs are assumed at 3.0% of investment p. a. and non-fuel O&M variable costs excluding energy costs at 0.5% of investment p. a..

Table B-77: Cost estimates for gaseous H₂ based filling stations

		Experimental	Small	Medium	Large
Investment cost	€	300,000	560,000	1,020,000	1,820,000
of which are					
CGH ₂ buffer storage		56,000	112,000	225,000	450,000
Compressor		130,000	226,000	393,000	647,000
Dispenser		16,000	32,000	48,000	96,000
Specific investment cost	€/ (kg/d)	2,000	1,870	1,700	1,500
O&M fixed cost	% Invest./a	3.0	3.0	3.0	3.0
O&M variable cost	% Invest./a	0.5	0.5	0.5	0.5

It is widely acknowledged that hydrogen dispensing is costly, however future target costs are rare. Uihlein set a target of \$400k/site for adding hydrogen to an existing filling station, considering all BP filling stations in the U.S. (Uihlein 2002).

Floor cost

As there is only a limited pool of bottom-up data for filling station cost estimates, we suggest again to draw comparisons to natural gas filling station. NG stations have investment costs starting with 180.000 (simple, dispenser, compression unit, piping etc.) to 1 M€. We assume a factor of 1.7 between NG and current hydrogen investment costs for estimation of minimum floor costs for hydrogen filling stations.

Liquid hydrogen based filling stations

Basic mechanism

Liquid hydrogen based filling stations can either provide liquid or compressed gaseous H₂ to vehicles, or both combined. The liquid hydrogen is provided by road tankers from the central liquefaction plant and is stored in cryogenic tanks at the station. For liquid dispensing, LH₂ is pumped into the vehicles tank as it is

done with gasoline or diesel, however specialised cryogenic filling equipment is needed. For gaseous dispensing, LH₂ is compressed to about 45 MPa (today) or 88 MPa (future) and subsequently vaporised.



Figure B.5: Tank robot at the liquid hydrogen filling station at Munich Airport (left) and a special cryogenic nozzle for liquid hydrogen (right) (Source: Linde).

Technical data

Table B-78 presents technical data for liquid hydrogen based filling stations. High pressure gas storage and pump-vaporizer unit are only needed for liquid-to-gas dispensing.

Table B-78: Technical data for liquid H₂ based filling stations

		Experimental	Small	Medium	Large
LH ₂ storage capacity	kg	1,050	2,010	4,200	8,400
LH ₂ storage capacity	m ³	15	30	59	119
High pressure storage §	kg	19	38	75	150
Pump-vaporizer unit §	kW	7	14	28	56
LH ₂ pump	kW/(kg/h)	0.8	0.8	0.8	0.8
Days of storage at design rate	d	7	7	7	7
Technical system lifetime	a	15	15	15	15

§ applicable only for liquid-gas stations.

Economic data

Liquid-to-gas

The main technical components for cost calculations are: liquid storage, pump-vaporiser unit and dispensers. Investment for liquid storage are estimated according to section 3.3.1.4, e.g. 205,000 € for 1000 kg LH₂ storage capacity. Costs for the pump-vaporiser unit are calculated after Simbeck (2002), e.g. 150,000 € at a design rate of 450 kg/d. Buffer storage are estimated to 3,000 €/kg at 75 MPa. Costs are adjusted for capacity at all items. Dispensers are taken at 16,000 €/dispenser for gaseous H₂.

Liquid-to-liquid

The main technical components for cost calculations are: liquid storage, pumping equipment and dispensers. Investment for liquid storage are estimated as above. Dispensers are estimated at 16,000 €/dispenser as for gaseous H₂ in the absence of information of liquid dispenser.

To the main technical component investment, the following system costs are added:

- general equipment: 25%
- engineering, permits and startup: 10%
- contingencies: 10%
- working capital, land, etc.: 7%

O&M fixed costs are assumed at 3.0% of investment p. a. and non-fuel O&M variable costs excluding energy costs at 0.5% of investment p. a..

Table B-79: Cost estimates for liquid H₂ based filling stations dispensing gaseous H₂

		Experimental	Small	Medium	Large
Investment cost, total	€	532,000	912,000	1,535,000	2,675,000
of which are					
LH ₂ storage	€	210,000	350,000	560,000	910,000
Pump-vaporizer unit	€	70,000	110,000	180,000	300,000
CGH ₂ buffer storage	€	56,000	112,000	225,000	450,000
Specific investment cost [§]	€/ (kg/d)	3,500	3,000	2,600	2,200
O&M fixed cost	% Invest./a	3.0	3.0	3.0	3.0
O&M variable cost	% Invest./a	0.5	0.5	0.5	0.5

[§] at station design capacity

Table B-80: Cost estimates for liquid H₂ based filling stations dispensing liquid H₂

		Experimental	Small	Medium	Large
Investment cost, total	€	380,000	623,000	1,003,000	1,672,000
of which are					
LH ₂ storage	€	210,000	350,000	560,000	910,000
Pumping	€	20,000	33,000	53,000	86,000
Specific investment cost [§]	€/ (kg/d)	2,500	2,100	1,700	1,400
O&M fixed cost	% Invest./a	3.0	3.0	3.0	3.0
O&M variable cost	% Invest./a	0.5	0.5	0.5	0.5

[§] at station design capacity

Floor costs

Due to the uncertainty in cost estimation for liquid filling stations it is even more difficult to estimate minimum floor costs here. LH₂ storage floor costs were previously estimated to 75% of today's cost. Pumping and pump-vaporizer will certainly cost less with growing numbers built. For CGH₂ storage only a small potential was estimated. It is also reasonable to assume that liquid hydrogen stations may certainly never cost less than today's gasoline filling stations. Applying 25% reduction on storage cost and 10% on other main technical components leads to an overall estimate of -18%.

Table B-81: Hydrogen dispensing options: characterisation of ‘generic’ filling stations

	Design capacity kg/day	Electricity use kWh/kg	Utilisation	Investment costs €/2000/(kg/d)	Floor cost €/2000/(kg/d)	Fixed costs % Invest./a	O&M % Invest./a	Variable O&M costs % Invest./a
Liquid-to-liquid								
Small-scale ‘today’	300	0.8	0.7	2,100	1,700	3		0.5
Large-scale ‘today’	1,200	0.8	0.7	1,400	1,100	3		
Liquid-to-gas								
Small-scale ‘today’	300	0.8	0.7	3,000	2,500	3		0.5
Large-scale ‘today’	1,200	0.8	0.7	2,200	1,800	3		
Gas-to-gas								
Small-scale ‘today’	300	2.7	0.7	1,900	1,100	3		0.5
Large-scale ‘today’	1,200	2.7	0.7	1,500	900	3		0.5

Costs of hydrogen production and supply

ased on the assumptions on energy prices and on the potential costs of CO₂-emissions given in Table B-82, Figure B-31 clearly shows that today natural gas steam reforming is the most economic option for producing hydrogen, followed by coal gasification and partial oxidation of heavy fuel oil. The costs for ‘green’ hydrogen produced by electrolysis using electricity from renewable energy sources today are still much higher. Biomass gasification still needs technical development before it can be considered as a reliable option for hydrogen production.

On the long term, this picture will change because of increasing prices of energy carriers, and the expected costs of CO₂ emission certificates. On the long term, the most economic renewable options for large scale electricity generation are offshore wind parks and concentrating solarthermal power plants. Until 2050, hydrogen production costs from electrolysis using electricity from these renewable energies will be compatible with natural gas steam reforming or coal gasification. Biomass gasification still is in an early stage of technology development, so that cost estimates are uncertain and depend on improvements in commercial scale production. In addition, the costs of hydrogen from biomass gasification very much depend on the availability of low cost biomass feedstock.

Carbon capture and storage technologies are in a very early – basically conceptual - stage of development, so that up to now there is very limited experience on reliable cost data. Figure B-32 shows the future maximum costs for carbon capture and storage, which still allow the production of hydrogen from natural gas steam reforming and coal gasification at competitive costs compared with hydrogen production from electrolysis using offshore wind electricity (base year 2050).

Table B-82: Assumptions on the future development of energy prices and carbon costs

		2000	2025	2050
Natural gas	€/GJ	2,91	4,84	8,72
Crude oil	€/GJ	4,44	5,33	9,76
Coal	€/GJ	1,4	1,7	2,4
Biomass	€/GJ	2,2	4,7	5,3
Electricity				
- wind offshore	ct/kWh	10,9	4,4	4,0
- solar thermal power plant with desalination facility	ct/kWh		5,8	3,8
Carbon costs	€/tCO ₂	-	25	50

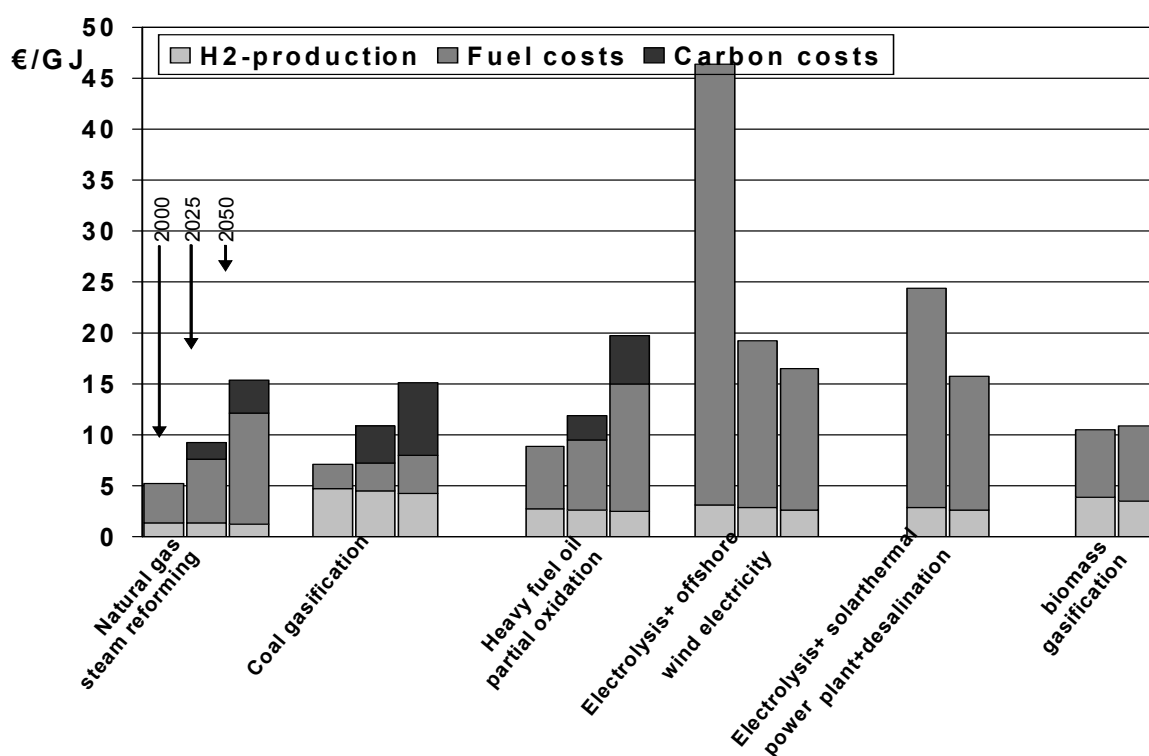


Figure B-31: Hydrogen production costs from different fuels

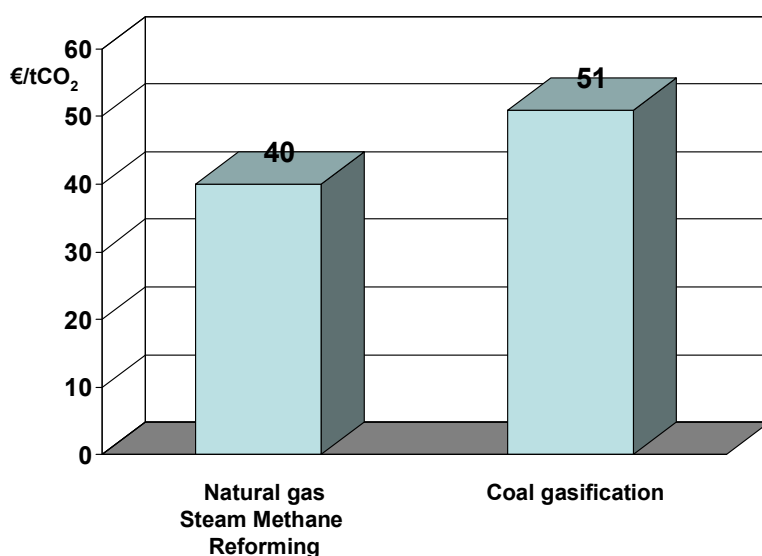


Figure B-32: Allowable CCS costs to achieve competitive hydrogen production costs, compared with hydrogen production from electrolysis with offshore wind electricity in 2050 (see Table B-82 for underlying assumptions) Hydrogen supply costs

It is commonly acknowledge that it is difficult and costly to deliver hydrogen to the customer (e.g. Uihlein (2002)). This section provides some selected scenarios by combining the infrastructure building blocks and giving some indicative cost data per unit hydrogen resulting from the cost data as of today. Lowering of costs can be expected in the future with a broad introduction of hydrogen to the energy sector. The evaluation of prospective future costs will be established in other working packages of the CASACADE MINTS project.

Table B-83: Scenarios for hydrogen supply by combination of different infrastructure blocks.					
Scenario	A	B	C	D	E
		Liquefaction	Liquefaction		Liquefaction
Long-distance transport				CGH ₂ Pipeline (3300 km)	LH ₂ Sea transport (3300 km)
Bulk-buffer-storage	Salt cavern	LH ₂	LH ₂	Salt cavern	LH ₂
Regional transport	CGH ₂ Pipeline (100 km)	LH ₂ road transport (100 km)	LH ₂ road transport (100 km)	Regional pipeline network	LH ₂ road transport (100 km)
Dispensing	CGH ₂ (35 MPa)	LH ₂ (liquid- liquid)	LH ₂ (liquid-gas)	CGH ₂ (35 MPa)	LH ₂ (liquid- liquid)

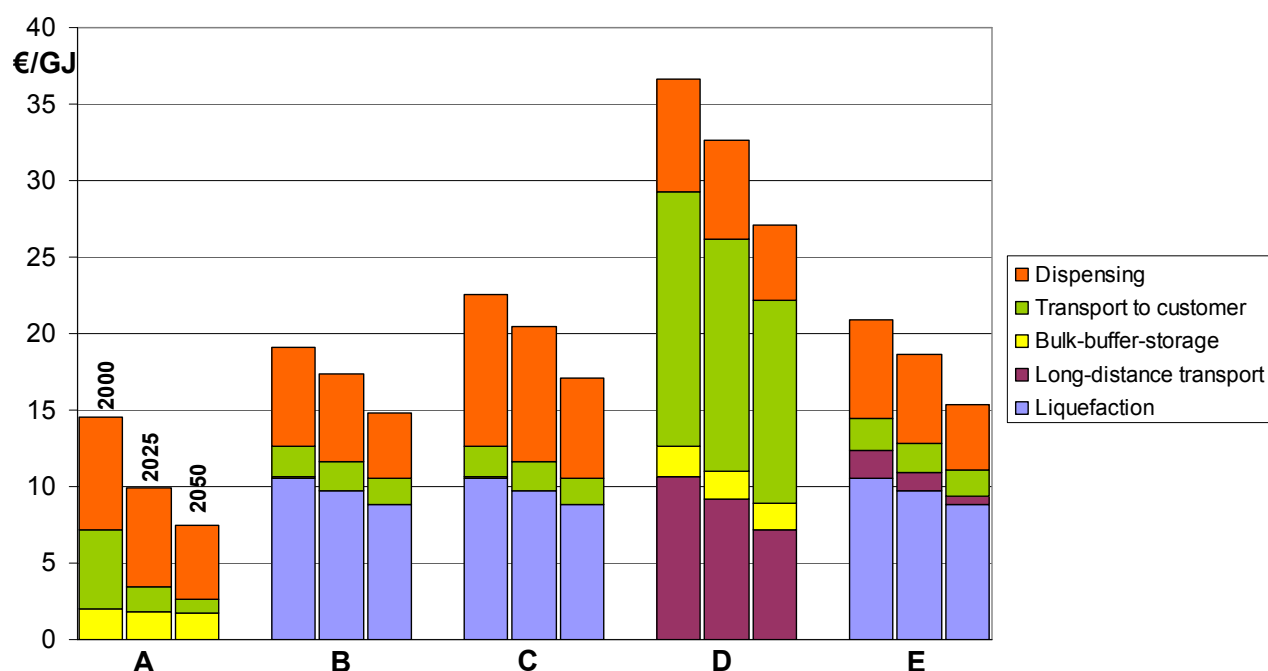


Figure B-33: Costs for different hydrogen supply scenarios (exemplary calculation)

Hydrogen properties

Density gaseous: 0.0899 kg/Nm³
liquid: 0.07079 g/cm³

Lower Heating Value (LHV)	Higher Heating Value (HHV)
10.79 MJ/Nm ³	12.75 MJ/Nm ³
3.00 kWh/Nm ³	3.54 kWh/Nm ³
120.00 MJ/kg	141.85 MJ/kg
33.33 kWh/kg	39.40 kWh/kg

B.1.3.3 Reference case for hydrogen distribution

[by S. Schmid (DLR), N. Kouvaritakis and V. Panos (ICCS-NTUA)]

This section describes a generic hydrogen storage and distribution network in a European context suitable for energy system models along with the necessary technical and economic data.

Introduction

A key element for the development of the overall hydrogen system is the hydrogen storage and delivery infrastructure. It is widely recognised that a future integrated hydrogen-based energy system would be particularly infrastructure intensive (more so than natural gas and electricity) and a great number of configurations are possible.

At present hydrogen is produced in a limited number of plants and is used for making chemicals or upgrading fuels. It is mainly stored as compressed gas or liquid, and the available technologies of today permit its distribution in gaseous or liquid form. The distribution system of today mainly consists of pipelines and trucks, with the latter being able to carry both gaseous and liquid hydrogen.

An overview of the available technologies of today for the storage and distribution of hydrogen shows the following:

- The storage of compressed gaseous hydrogen in tanks is the most mature technology, though the very low density of hydrogen is translated into inefficient use of space aboard a vehicle. On the other hand, liquid hydrogen takes up less storage volume than gas but requires cryogenic containers. Furthermore, liquefaction is a very energy intensive process and results in large evaporative losses.
- The distribution of hydrogen via pipelines is widely accepted as an efficient means to supply customer needs. On the other hand, hydrogen distribution via high-pressure cylinders and tube trailers has a limited range of 100-200 km from the production facility. Moreover, for long distance distribution hydrogen is usually transported in liquid form.

The CASCADE MINTS technology database contains several options for liquid or gaseous hydrogen storage and distribution, providing flexibility in the choice of the components for the future hydrogen infrastructure system. However, complete modelling of the hydrogen storage and distribution infrastructure system is a very complex task, since it is a “chicken-egg” problem; it is not possible to have infrastructure developments without demand and vice-versa. Therefore, a vision is needed about the future development of hydrogen infrastructure system, in which its main components will be identified and fully characterised in terms of their technical and economic performance.

In order to obtain a sense about the future hydrogen infrastructure, a combination of the gas supply and refined oil distribution networks can be the present analogue. In this sense, pipelines can distribute hydrogen to high-demand areas, and trucks or rail can distribute hydrogen to rural and other lower demand areas. On site hydrogen production and distribution facilities can be built where demand is high enough. Hydrogen can be stored either in gaseous or liquid form. However, given the high costs of liquid hydrogen delivery (mainly due to the liquefaction process), liquid hydrogen is more likely to be used in hydrogen fuelled vehicles, where its existence is indispensable, than in stationary applications.

General description of the reference case for H₂ distribution

The reference case for hydrogen distribution assumes an average EU region supplied with hydrogen around 2050. It represents a situation at the initial stages of a take-off of a hydrogen economy falling well short of maturity of such an economy. This is done on purpose because at this stage the economic performance of the network could play a crucial role in determining the extent of penetration of hydrogen as an energy vector.

The stylised configuration of the reference system is presented in Figure B-15. Table B-36 to Table B-38 present some key demographic information as well as hydrogen production and demand requirements for the reference area. According to Figure B-15, the key characteristics of the reference system are:

- A plant (A) of 400MWH₂ capacity but of unspecified type operating at 8000 hours per year (see also Table B-37). This is a high operation rate made possible by eventual storage capacity but especially by the fact that the overall load exhibits small seasonal variation (a small percentage of total demand goes to households).
- The plant is connected to a turnpike pipeline of a large diameter (which is 55km long within the territory under consideration and hence these 55km can be reasonably assumed to constitute cost attributions to the region) connecting it to other similar plants to the “north” and “south” of the region of examination (B). This pipeline is assumed to serve as a storage medium, a load management tool, and as emergency supply in cases of production disruption. The distance of the plant from the turnpike can be assumed to be negligible.
- A pipeline connects the plant to a stylised industrial zone (average distance 10km) containing, among other industrial installations, CHP plants using hydrogen and belonging to small to medium size energy intensive industries (but excluding very large scale process heat).
- Service stations absorbing more than half of the plant’s output are situated under at least two distinct conditions: rural stations along the roads crossing the region and urban service stations mostly concentrated on the outside ring of the urban area. The latter assumption stems from the difficulty to build large new pipeline networks in areas of high population density. It can be reasonably assumed that all rural stations will be supplied by truck.

- The distances indicated in the map are average distances from the plant to the consumer.

Figure B-15: Reference case for hydrogen storage and distribution in an average European Union area

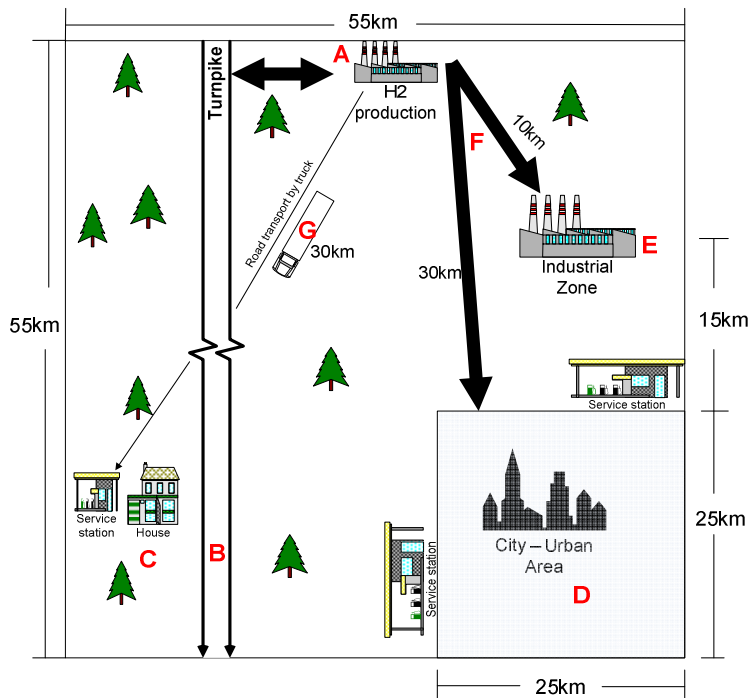


Table B-36: Demographic information of the area

Demographic information of the reference area		
Population	<i>inh.</i>	600000
Area	<i>km²</i>	3025
Population Density	<i>inh./km²</i>	198
Urban population	<i>inh.</i>	500000
Urban area	<i>km²</i>	625
Urban population density	<i>inh./km²</i>	800
Households/shops using H2 (urban)	<i>number</i>	18000
Households/shops using H2 (rural)	<i>number</i>	3000
Cars powered by hydrogen	<i>vehicles</i>	150000

Table B-37: Characterisation of the hydrogen production plant

Hydrogen production plant capacity	MW_{H_2}	400
Operating hours	$hours$	8000
Annual production	$ktoe$	275

Table B-38: Allocation of hydrogen demand

Hydrogen Demand - Total 275 ktoe			
	ktoe		
	Urban	Rural	Industrial zone
Industrial zone	-	-	80
Road transport	113	49	-
Residential/Commerce	28	5	-

Specification of infrastructure elements

The necessary infrastructure components for building the reference hydrogen storage and delivery network for the need to be identified and fully characterised in terms of their technical and economic performance in order to be used in energy system models. The discussion in this section will be structured around the key elements of Figure B-15.

Hydrogen production plant

The hydrogen plant is directly connected to the turnpike pipeline, which serves as an intermediate storage and load balancing tool. Therefore no additional storage systems are necessary at the plant site. For feeding the major demand into the pipelines and road transport, a pressure level of 3 MPa it is assumed.

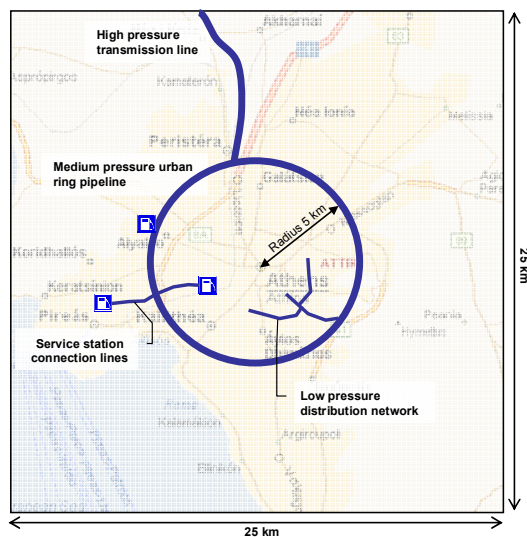
Dimensioning of pipelines

Detailed layout and engineering calculations are necessary in order to make the final design of hydrogen pipeline networks. At this stage, the design of the already existing natural gas pipeline system is followed. Starting with a constant energy flow through a pipeline with the same diameter as gas pipeline, by taking into account the lower volumetric energy density it turns out that roughly a factor of 3 higher gas velocities is needed. Compared with urban natural gas systems, it is necessary to use also increased pressures to compensate for this.

Urban pipeline system

In order to estimate investment cost, the urban pipeline system needs to be specified. In the style of natural gas networks, lines with different pressures, forming a pressure cascade, are introduced. The central element is a closed loop, stylised as a ring pipeline of 5 km radius. The ring is connected to the hydrogen production plant via a high pressure transmission line of 38 km (30 km extra-urban) + 8 km with urban area).

Figure B-16: Sketch of the layout of the urban hydrogen pipeline system



To ensure hydrogen supply through the pipeline system in all demand cases, it is necessary to estimate the peak demand of the different customers. The demand of the industrial area is set constant to 16 hours per day all year long. Peak demand of households is set to 10 kW. Peak demand of service stations adds up over all stations to 3,4 kg/s. The data is summarized in Table B-39.

Table B-39: Design capacities of pipeline network

	Annual Demand ktoe	Design capacity kg/s	Demand structure
Industrial area supply	80	1,33	16 h per day all year
Urban area supply	141	5,00	
of which			
Households/shops	28	1,50	All year peak demand: 10 kW per hh
Service stations	113	3,40	Supply service stations (50) at peak rate
Road transport	54	1,68	12 h per day, 5 days per week
Total hydrogen hub capacity	275	6,61	

High pressure transmission line

A high pressure transmission pipeline links the hydrogen plant to the urban city area. The pipeline is designed to meet a peak demand of 5 kg/s, including rudimentary consideration of line packing. The compressor inlet pressure is 3 MPa (hydrogen production) and the design delivery pressure at the ring is 6 MPa. The length of the transmission line is assumed to 38 km. The compressor power is calculated to 20 MW (~3 % of the delivered energy) at a diameter of 0.35 m. The heat of the hydrogen after compression is assumed to be used for other purposes.

Medium pressure urban ring pipeline

An urban ring pipeline for the distribution backbone to ensure a high delivery is assumed. For the size of an urban area of 25x25 km, 5 km of radius seem reasonable. The ring must support the peak demand of 2.5 kg/s in each branch, as it is assumed that the service stations are directly connected to the ring due to their high peak demand. The ring is operated at an average pressure of 2 MPa and with a diameter of 0.2 m.

Service stations connection lines

The service stations are connected directly to the ring pipeline at a peak design capacity of 0,067 kg/s. No additional compressors are assumed. Therefore a pipe with 0.1 m diameter at an average length of 2,000 m it is used. It is further assumed that 15 service stations are connected directly at the ring pipeline. In total 70 km pipeline for the service station connections are to be used.

Low pressure distribution network

Every customer – household or shop – has to be connected to the hydrogen grid. Throughout the whole scenario it is assumed that no natural gas pipelines can be used for the hydrogen distribution, which might be actually the case in some areas. To estimate the total length, the approach suggested by Castello et al. is used. According to this, natural gas networks show a linear relationship between the length of the distribution pipeline network and the number of natural gas consumers. The average length is 15.5 m per customer. There are 18,000 households/shops using H₂ in the reference case. The total length of the low pressure hydrogen distribution network thus calculates to 272 km (18,000 x 15.5 m). It is assumed 100 branches (180 customers) at 2,72 km length each and a design capacity to 0.015 kg/s. A pipe diameter of 0.02 m is assumed.

The reference number of urban inhabitants is 500,000, which means at an average size of 2.43 inhabitants per household (206,000 household in total) 8.7 % of the households are using hydrogen.

Industry supply

The pipeline which links the hydrogen production plant to the stylized industrial area is designed for 1.33 kg/s at delivery pressure of 6 MPa at the industrial customer. The diameter calculates to 0.15 m at an economic flow velocity of 30 m/s. The installed compressor power is 6.3 MW (3.9 % of the delivered energy is used for compression).

Turnpike pipeline

The Turnpike pipeline forms a part of a long distance transport pipeline system. It serves several tasks:

- Storage medium and load management tool, and
- Emergency supply in cases of production disruption.

At this stage, it is not possible to optimize the diameter of the turnpike pipeline as a function of storage, security and cost. In the absence of a very large storage in the hydrogen layout, it is assumed the upper limit of natural gas pipeline diameter of 1,500 mm operated at a maximum pressure of 7 MPa.

Summary on pipelines

The overall European average length of the natural gas transmission network (excluding UK data) is 2.2 m per customer {Castello, 2005 #874} (p. 99). However, it is not differentiated between high and medium pressure lines. The reference case for hydrogen storage and distribution infrastructure in total holds 21,000 customers which results in a transmission grid of ~69 km plus 55 km turnpike pipeline (which is justified for several reasons). Eventually this could be optimized by not connecting the hydrogen plant directly with the urban area (~30 km) but via the turnpike pipeline.

Table B-40: Pipeline specification

Pipeline	Design capacity kg/s	Diameter m	Pressure level MPa	Length [§] km
Turnpike pipeline	6.6	1.50	7	55
High pressure transmission (industry)	1.33	0.15	6	10
High pressure transmission (urban)	5.0	0.35	6	38
Medium pressure urban ring	2.5	0.20	2	31
Low pressure urban distribution network	0.015	0.02	1	272
Service station connection lines	0.067	0.1	2	70

§ Total length in reference case

Urban area service stations

To calculate the total investment on service stations, the number of hydrogen equipped stations has to be estimated. Today, there are around 2,500 to 3,500 cars operated per filling station in Europe. In the EU15, the average number of passenger cars per 1000 persons is ~450. Therefore in the reference case about 225,000 cars are operated and of this 150,000 hydrogen vehicles are owned by 600,000 inhabitants. This means 250 hydrogen cars per 1000 inhabitants. The diffusion of hydrogen powered cars is thus 56 %. According to the number of vehicles, assuming they were all conventional, there would be between 50 and 75 service stations located in the urban area.

The original layout of service station in deliverable D1.1 (ref B.1) would demand 129 filling stations of size class “large” in order to distribute ~40 Mio. kg hydrogen per year to cars. This layout was based on 6 dispensers (max. 27 kg H₂/h) and 10 min of occupation a dispenser per refuelling, including filling, shopping and payment. In the reference case it is estimated 2.5 MJ H₂ per km, which is based on the actual fleet energy use of today. The rather high energy use of 2.5 MJ H₂ per km needs ~13 kg of hydrogen storage capacity per vehicle to give a range of ~600 km per tank. This size of storage would be rather expensive today.

It seems unrealistic to increase the number of service stations due to hydrogen. Therefore it is assumed that 2/3 of all service stations are equipped with hydrogen i.e. 50 stations in the urban area. To distribute the

total amount of hydrogen, each station must sell ~ 2200 kg/d (daily average rate). Following the diurnal distribution of Praxair (in Simbeck, 2002), the peak demand then would be 242 kg/h in the late afternoon (0.067 kg/s). The average rate during 15 hours of selling is 147 kg/h or 24 kg/h per dispenser. According to this, each dispenser must be able to support 72 kg/h at peak rate (design rule of Simbeck et al. 2002). This goes well with 6 refills per hour, each 10 minutes, $6 \times 13 = 78$ kg/h.

Rural area: Hydrogen road transport

A rural population of 100,000 inhabitants and 250 hydrogen cars per 1000 inhabitants results in a hydrogen car fleet of 25,000 H₂ cars.

In order to deliver 49 ktoe of hydrogen per year, 21 service stations with the same sales than in the urban area (2,200 kg/d) are assumed.

Cost calculations

Pipeline

Cost calculations for hydrogen pipelines are based on experience from natural gas pipelines, which is extensive. This was already done in deliverable D1.1 (ref B.1) and goes in line with other authors, e.g. N. Parker (2005). Cost-breakdown was constructed from data from German industry and utilities. This led to percentages of total project costs as follows:

- Piping material: 40%
- Construction (labour): 33%
- Others (Planning, Right-of-way, environmental compensation measures): 27%.

This is close to another European study on hydrogen pipelines {Altmann, 2001 #921}, but slightly different from North American findings by Mendez {, 2005 #922}, who gets material less and labour more important.

Costs for piping material are derived from Peters et al. and from Zürich natural gas storage (DN 1500), and accounted for hydrogen use by 10%. It is unclear, if this is in fact necessary as embrittlement may be avoided by adding 150 vpm (volumes per million) of oxygen {Altmann, 2001 #921}. With smaller diameters, the cost for piping material sinks considerably {Peters, 2003 #629}. For urban areas, we therefore introduce a lower limit for construction and other costs.

For the high pressure transmission pipeline to the urban area, we assume compressing power of 20 MW, for the industry pipeline 6 MW. The cost model according to Amos {, 1998 #441} gives specific costs of 690 €/kW in this size class, thus investment cost of 18 million €2000 for compressing at the hydrogen plant are taken into account.

Table B-41: Pipeline investment cost per kilometer

Pipeline	Material	Construction	Other	Total project cost
Turnpike pipeline	489,000	403,000	330,000	1,222,500
High pressure transmission (industry)	65,000	54,000	44,000	162,500
High pressure transmission (urban)	275,000	227,000	186,000	687,500
Medium pressure urban ring	110,000	91,000	74,000	275,000
Low pressure urban distribution network				
Service station connection lines				

§ Total length in reference case

Storage

Since the turnpike pipeline is the only hydrogen storage option, no additional storage costs are assumed.

Service stations

50 stations are assumed in the urban area, each station with 6 dispensers, each designed to deliver 72 kg/h. Myers, D.B. (2002) in Weinert {, 2006 #926} reports costs of 21,517 \$2006/disp (~18,000 €/disp.). designed to deliver 76.33 kg/hr of hydrogen at a production volume of 250 units per year.

The buffer storage is designed to supply peak demand of 242 kg/h (6 x 72 kg/h) at 43 MPa at 3 consecutive hours. Investment cost at this pressure level are ~1,300 €/kg. The higher the storage volume is the lower the investment for the compressor can be. It is assumed 500 kg of storage volume resulting in a cost of the order of 655,000 €.

A rate of 200 kg/h of the compressor is considered to be sufficient. Compressor costs are ~1,577 €/kW which result in 647,000 Euro for the compressor. 7,411 kJ/kg of electricity is needed to compress the hydrogen from 20 MPa to 43 MPa (2,1 kWh/kg). The efficiency of the compressor is 80%. To the investment cost for technical equipment, 52% are added for general equipment, engineering, permits, contingencies and working capital as explained in deliverable D1.1 (ref B.1).

Table B-42: Cost estimates for gaseous H₂ based filling stations

		Large	Reference case
Investment cost	€	1,820,000	2,143,000
of which are			
CGH ₂ buffer storage		450,000	655,000
Compressor		647,000	647,000
Dispenser		6 x 16,000	6 x 18,000
O&M fixed cost	% Invest./a	3.0	3.0
O&M variable cost	% Invest./a	0.5	0.5

Rural road transport

The investment for trailers is double due to the assumption that the delivery of gaseous hydrogen to the rural service stations includes exchange of trailers because of time reasons.

Summary of cost calculations

Table B-43 summarises the calculations for delivering gaseous hydrogen to the final consumers.

For comparison, the delivery of liquid hydrogen is around 6.3€00/GJ in 2000 and 4.8€00/GJ in 2050 (however, the economics of liquid hydrogen improve substantially when rural delivery is considered).

Details about data and calculations are given in the Appendix.

Table B-43: Delivery costs of gaseous hydrogen to various end-use consumers

2000								
	Turnpike	High pressure	Medium pressure	Low pressure	Service station connection	Industry	Road transport	Total
Supply of Gaseous H ₂ at	€/GJ							
Urban service stations	0.88	0.78	0.21		0.51			2.38
Urban households	0.88	0.78	0.21	4.68				6.55
Rural service stations	0.88						5.53	6.41
Rural households	0.88						5.53	6.41
Industry	0.88					0.07		0.95

2050								
	Turnpike	High pressure	Medium pressure	Low pressure	Service station connection	Industry	Road transport	Total
Supply of Gaseous H ₂ at	€/GJ							
Urban service stations	0.74	0.50	0.18		0.43			1.84
Urban households	0.74	0.50	0.18	3.27				4.69
Rural service stations	0.74						5.07	5.81
Rural households	0.74						5.07	5.81
Industry	0.74					0.05		0.80

Appendix – Tables with analytical calculations of costs

In the following tables, the analytical calculations of the hydrogen storage and delivery are presented for both gaseous and liquid hydrogen.

Table B-44: Technical and economic characteristics of pipelines

PIPELINES																			
	all area				urban area												Industry		
	Turnpike all				High pressure pipe all urban				Medium pressure ring all urban				Low pressure network residential only					Service station connection transport sector only	
Customer	2000	2025	2050		2000	2025	2050		2000	2025	2050		2000	2025	2050		2000	2025	2050
Length	55	55	55	km	38	38	38		31	31	31		272	272	272		70	70	70
Diameter	1.5	1.5	1.5	m	0.35	0.35	0.35		0.2	0.2	0.2		0.02	0.02	0.02		0.1	0.1	0.1
Pipe capacity, design peak	23760	23760	23760	kg/h	18000	18000	18000		9180	9180	9180		72	72	72		241.2	241.2	241.2
Average energy delivered	275	275	275	ktoe/a	141	141	141		141	141	141		28	28	28		113	113	113
Transport efficiency (H2 loss)	99%	99%	99%		99%	99%	99%		99%	99%	99%		99%	99%	99%		99%	99%	99%
Transport efficiency (PQ compressor)					1.1%	1.1%	1.1%												
Progress as estimated from EViews	12.4	12.3	12.2		12.4	12.3	12.2		12.4	12.3	12.2		12.4	12.3	12.2		12.4	12.3	12.2
Investment cost	1356195	1294245	1139825	€/km	463701	442520	389722		300028	286323	252161		151985	134920	106323		259432	247581	218042
Overall investment cost	74590703	71183490	62650355	€	17620651	16815761	14809418		9300871	8876018	7816991		41339949	36698283	28919939		18160240	17330702	15262919
Technical lifetime	40	40	40	Years	40	40	40		40	40	40		40	40	40		40	40	40
Construction time	3	3	3	Years	2	2	2		2	2	2		2	2	2		2	2	2
Interest rate	6%	6%	6%	%	6%	6%	6%		6%	6%	6%		6%	6%	6%		6%	6%	6%
Decommission share	0.1	0.1	0.1		0.1	0.1	0.1		0.1	0.1	0.1		0.1	0.1	0.1		0.1	0.1	0.1
Discount rate	8%	8%	8%	%	8%	8%	8%		8%	8%	8%		8%	8%	8%		8%	8%	8%
Total investment cost	84056584	80216980	70646030	€	19300259	18418647	16221058		10187434	9722084	8562110		45280490	40196379	31676600		19891282	18982672	16717787
Annualised investment cost	7048999	6727009	5924387		1618523	1544591	1360301		854320	815296	718020		3797229	3377875	2556405		1668086	1591890	1401956
FOM cost	2101415	2005425	1766151	€	482506	460466	405526		254686	243052	214053		1132012	1004909	791915		497282	474567	417945
Load factor	98%	98%	98%	%	98%	98%	98%		98%	98%	98%		98%	98%	98%		98%	98%	98%
Total fixed cost	9337156	8910646	7847488	€	2143907	2045976	1801864		1131638	1079947	951095		5029838	4465086	3516694		2209559	2108629	1857042
VOM cost	840566	802170	706460	€	193003	184186	162211		101874	97221	85621		452805	401964	316766		198913	189827	167178
Specific energy cost (Hydrogen)	0.13	0.09	0.05	€/kWh	0.13	0.09	0.05		0.13	0.09	0.05		0.13	0.09	0.05		0.13	0.09	0.05
Energy cost	37.0	35.3	31.1	€/poe	32.7	27.3	20.8		8.7	8.3	7.4		195.8	173.8	137.0		21.3	20.3	17.9
Specific transportation cost	0.88	0.84	0.74	€/GJ	0.78	0.65	0.50		0.21	0.20	0.18		4.68	4.15	3.27		0.51	0.49	0.43

Table B-45: Road transport of gaseous hydrogen technical and economic characteristics

Road transport Gaseous H2				
		2000	2025	2050
Capacity	kg/tanker	250	250	250
Distance	km	30	30	30
Mileage	km/a	55000	55000	55000
	r-trips/a	916.7	916.7	916.7
Production rate net	GJ/a	27500.0	27500	27500
	MWh/a	7638.88889	7638.88889	7638.88889
	MW	0.9	1	1
	ktoe/a	1	1	1
Operating hours	h/a	8585	8585	8585
Overall inv cost	€/kW	344	324	284
Technical lifetime	Years	6	6	6
Construction time	Years	0	0	0
Interest rate		6%	6%	6%
Decommission share		0.0	0.0	0.0
Discount rate (%)		10%	10%	10%
Total investment Cost	€/Kw	354	333	292
Annualised investment cost	€/Kwy	81	77	67
FOM cost	€/Kwy	58	58	58
Availability factor	%	98%	98%	98%
Total Fixed Cost	€/kg	0.54	0.52	0.49
	€/kWh	0.0162	0.0157	0.0146
	€/GJ	4.5	4.3	4.0
	€/toe	188.6	182.1	169.2
Efficiency	lt/100km	34.7	34.7	34.7
VOM cost	€/Km	0.21	0.21	0.21
Diesel price	€/lt	0.87	0.87	0.87
Total variable cost	€	28154	28154	28154
	€/kWh	0.00368561	0.00368561	0.00368561
	€/GJ	1.02	1.02	1.02
	€/toe	43	43	43
Total delivery cost	€/kg	0.66	0.64	0.61
	€/kWh	0.02	0.02	0.02
	€/GJ	5.53	5.37	5.07
	€/toe	231.4	225.0	212.1

Table B-46: Hydrogen service stations technical and economic characterisation in €oo

		Gas to Gas urban service station			Gas to Gas rural service station			Liquid to Liquid urban service station		
		2000	2025	2050	2000	2025	2050	2000	2025	2050
Number of filling stations										
Total hydrogen demand in reference case	ktoe/a	50	50	50	21	21	21	50	50	50
	kgr/a	113	113	113	49	49	49	113	113	113
		39347000	39347000	39347000	16525740	16525740	16525740	39347000	39347000	39347000
Station average daily sales	kg/d	2200	2200	2200	2200	2200	2200	2200	2200	2200
Electricity use	KWh/kg	2.1	2.1	2.1	2.1	2.1	2.1	0.8	0.8	0.8
Investment cost per station	€	2100000	1864211	1395630	2100000	1864211	1395630	1930074	1713365	1282700
Specific cost	€/kgr/d	955	847	634	955	847	634	877	779	583
Overall investment cost in ref area	€	105000000	93210559	69781507	44100000	39148435	29308233	96503699	85668226	64134986
Other costs	€									
Technical lifetime	years	15	15	15	15	15	15	15	15	15
Construction time	years	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Interest rate		0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Decommission share		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Discount rate		0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Total investment cost	€	110548958	98136478	73469265	46430562	41217321	30857091	101603651	90195553	67524342
Annualised investment cost	€	12915384	11465240	8583381	5424461	4815401	3605020	11870308	10537505	7888838
FOM cost	€	387462	343957	257501	162734	144462	108151	356109	316125	236665
Availability factor	%	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Total fixed cost	€	13574333	12050201	9021308	5701220	5061085	3788950	12475936	11075133	8291330
Electricity price	€/KWh	0.046	0.037	0.028	0.046	0.037	0.028	0.046	0.037	0.028
Energy cost	€/kgr	0.10	0.08	0.06	0.10	0.08	0.06	0.04	0.03	0.02
VOM cost	€	64577	57326	42917	27122	24077	18025	59352	52688	39444
Total variable cost	€	3865497	3114588	2356521	1623509	1308127	989739	1507321	1217359	920817
Production cost	€/kgr	0.44	0.39	0.29	0.44	0.39	0.29	0.36	0.31	0.23
	€/KWh	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	€/GJ	3.7	3.2	2.4	3.7	3.2	2.4	3.0	2.6	2.0
	€/toe	155	134	101	155	134	101	124	109	82

B.2 Technology Database

B.2.1 Historical statistical evolution of technical and economic characteristics of technologies

[by W. Krewitt and S. Schmid]

Stationary fuel cells

Historical development of installed capacity

Time series for the world wide installed capacity of stationary fuel cells are derived from data provided by (fuelcells2000, 2004), which were checked as far as possible against other sources. There are some uncertainties with regard to the completeness of the data. There are also problems related to the time reference, as some data given by (fuelcells2000, 2004) refer to the recipient's financial year, and some to the year in which the fuel cell system was put into operation. These uncertainties seem to be acceptable with respect to the overall uncertainties we are facing in this field.

Figure B-34 shows the total installed capacity of stationary fuel cells by fuel cell type. First pilot- and demonstration plants were built since the mid 1980s, but more visible development took place only since 1990. The largest fuel cell power plant ever built – a 11 MW PAFC unit operated by TEPCO in Tokyo – was put into operation relatively early, and stopped operation in 1997. Further development oriented towards smaller units, the size of the PAFC PC25 system which was introduced into the market end of the 1980s was 200 kW. The PC25 system from UTC Fuel Cells was the first and so far only system commercially available, and thus for most of the time the PAFC technology clearly dominates the total installed capacity. In 2003 however the installed capacity of Molten Carbonate Fuel Cells exceeded the PAFC, which was mainly due to the large number of installations of the MTU HotModule in Germany. As current demonstration plants with PEMFC and SOFC fuel cells mainly aim at small scale house applications, the share of the installed capacity is small, although the number of installed systems is growing constantly.

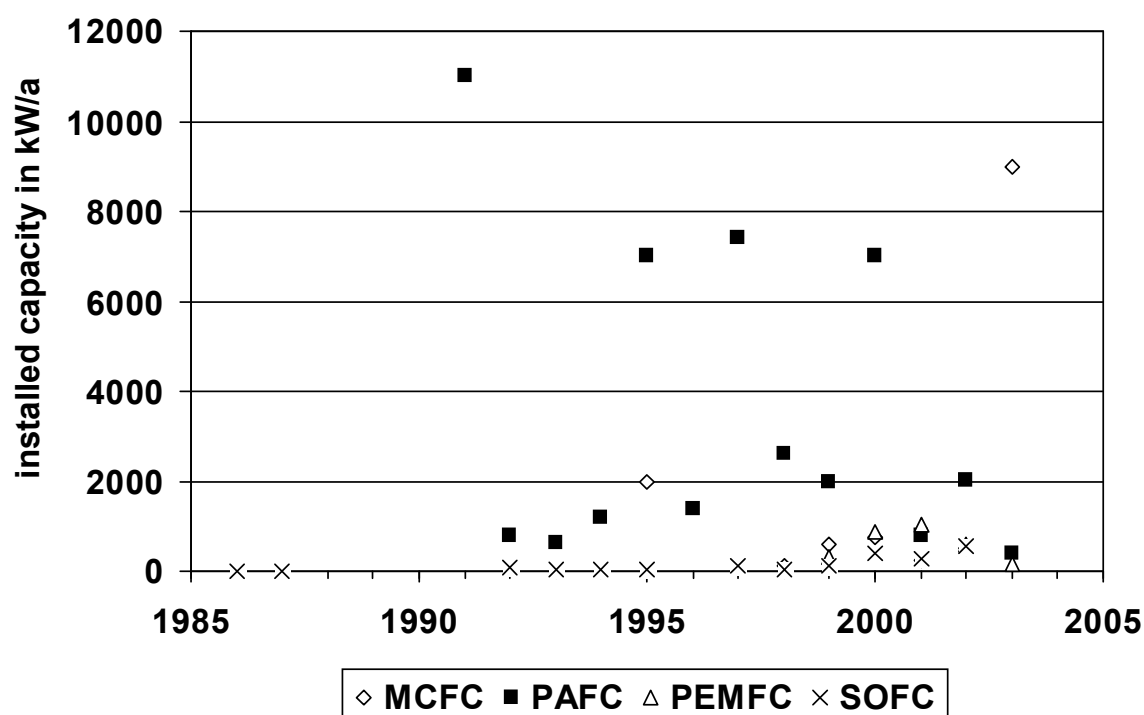


Figure B-34: Installed stationary fuel cell capacity, by fuel cell type

Table B-84: Development of world wide stationary fuel cell installations (fuelcells2000, 2004)

	all fuel cell types < 5 kW		all fuel cell types > 5 kW		PAFC	PEMFC	MCFC	SOFC
	total annual installed capacity (kW/a)	cumulated installed capacity (kW)	total annual installed capacity (MW/a)	cumulated installed capacity (MW)	annual installed capacity (kW/a)			
1986	0,4	0,4	0,04	0,04				0,4
1987	6	6,4						6
1989			0,2		200			
1991			11,0	11,2	11000			
1992			0,9	12,1	800			60
1993			0,7	12,8	650			20
1994			1,2	14,0	1200			20
1995			9,1	23,0	7000		2000	52
1996			1,4	24,4	1400			
1997			7,5	32,0	7400			125
1998			2,8	34,7	2600		100	52
1999	48	54	3,0	37,7	2000	298	600	125
2000	111	166	8,9	46,6	7000	860	750	400
2001	437	603	1,6	48,2	800	1012	250	
2002	379	981	3,0	51,2	2020	603	500	276
2003	181	1162	7,9	59,2	400	140	9010	570

The record of historical data is particularly poor for MCFC and SOFC fuel cells, which are considered as the most promising options for large scale stationary applications. On the other hand there are

quite some data available for more than a decade for PAFC fuel cells, but UTC Fuel Cells, the manufacturer of the currently only commercial fuel cell system, announced to abandon the PAFC technology because of problems to reduce costs. As uncertainties on the future technical and costs characteristics is much more uncertain than the difference between the different types of fuel cells, we suggested in D1.1 to specify to generic types of fuel cells to be used in the CASCADE MINTS models, a small scale fuel cell for house applications in the range of 1 to 5 kW, which will be most likely a PEMFC or a SOFC, and a large fuel cell with a capacity of 200 kW to 5 MW, which will be most likely a MCFC or a SOFC.

Following this distinction, Figure B-35 shows the development of small scale stationary fuel cell systems. It is obvious that a dynamic development started only late in the 1990s, when several field trials for fuel cell house applications were initiated in the US, in Europe and in Japan. Due to the early introduction of the PAFC PC25 system, for the large systems we can observe a continuous and steady increase in installed capacity since about 15 years now (Figure B-36). As discussed above, in this market sector we had a shift in the lead technology in the last year, as the MCFC exceeded the annual installation of the PAFC in 2003.

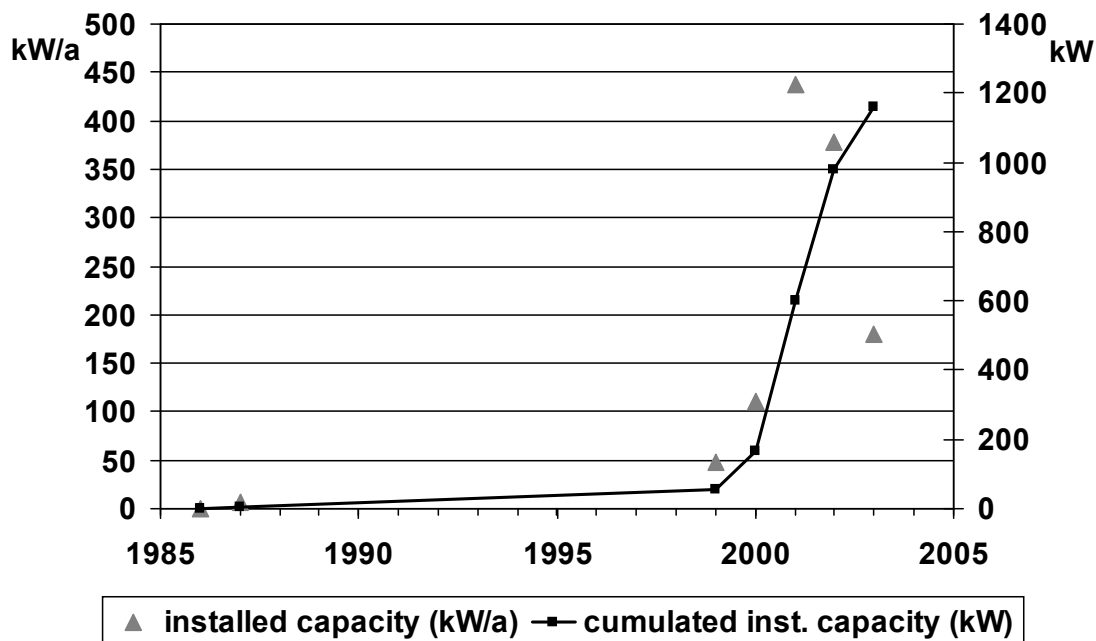


Figure B-35: Development of small scale (< 5 kW) stationary fuel cell installations

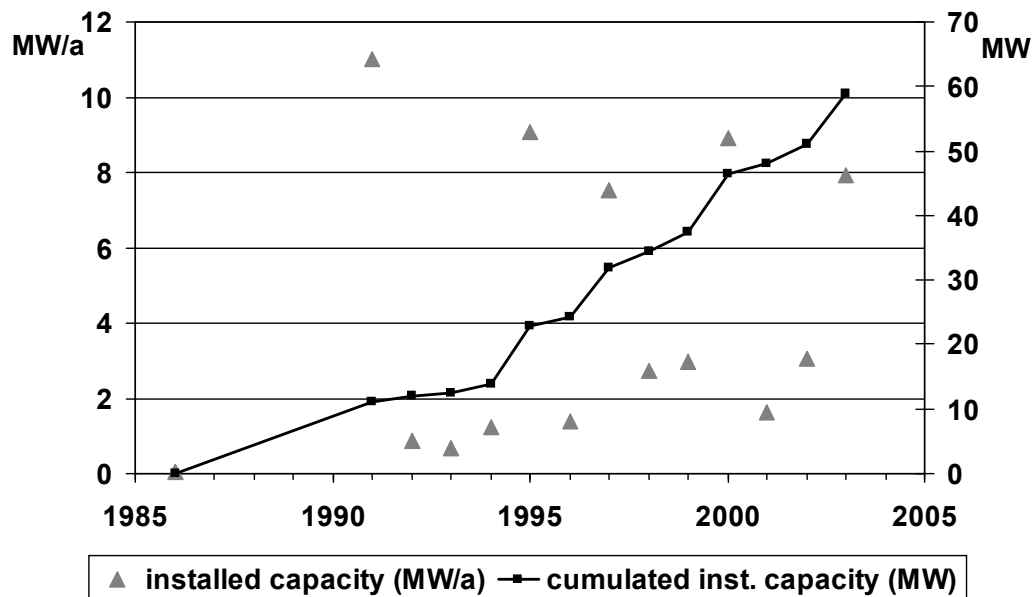


Figure B-36: Development of large scale (> 5 kW) stationary fuel cell installations

Development of fuel cell costs (stationary fuel cells)

As mentioned above, the PAFC PC25 system up to now is the only commercially available fuel cell system, so it is the only system for which market prices over a certain period of time are available. During an early market introduction phase, consumer prices however are not necessarily a good indicator for manufacturing costs (see below). Cost data for other fuel cell technologies are hardly available as for obvious reasons in general they are highly confidential. If cost data for specific demonstration projects are published, they should be considered as highly uncertain, as cost information during such an early development phase often is intended to convey a certain message (e.g. need for public support) to the policy, and in general cannot be validated. Keeping these limitations in mind, the following sections provide a compilation of cost data published in the literature. Like in the above section on the development of installed capacity we differ between 'small' and 'large' applications.

Small scale fuel cell house applications (< 5 kW)

As shown in Figure B-35, the installation of demonstration plants of small scale fuel cell house application system started only in recent years, so that there is no long term record of historical data available. Cost estimates of the PEMFC Plug Power 5 kW fuel cell systems, which is also the basis of the current Vaillant system, are about 11,000 €/kW (Fuel Cell Today, 2000). There are no cost data on the Sulzer Hexis 1 kW SOFC system open to the public, but estimates suggest that costs are significantly above 5,000 €/kW.

CHP-power plants (200 kW to 5 MW)

PAFC. The manufacturing costs of the initial UTC/ONSI PC25A model were above 1 Million US\$ (Whitaker, 1998), leading to specific costs of about 5,500 to 6,000 \$/kW. According to (Whitaker, 1998), the manufacturing costs were then reduced, dropping to about 3,000 \$/kW in 1997. The expectation towards a continuous decrease of production costs could however not be fulfilled, current customer price is about 4,250 \$/kW (UTC 2003), and we do not know to which extend this customer price is subsidised. According to (Whitaker, 1998), the PC25A model was sold at about one-half of its costs, and in spite of cost reductions the company's internal subsidies to the sales of the PC25 systems cumulated to roughly 50 Million US\$ between 1992 and 1998. In the meantime UTC Fuel Cells has announced to stop the further development of PAFC fuel cells and to shift focus to the PEMFC technology, as the potential for reducing costs was considered as being not sufficient to reach the target costs.

A major problem is that no cost data are available for pre-commercial systems. We should not consider the consumer price of the first PC25A systems as the starting point of the learning curve.

PEMFC. A small number of Ballard PEM fuel cells with a capacity of 250 kW have been installed since 1999 in the US and Europe. Published cost data are available only for the system which was installed 2000 in Berlin. Total costs of the system are estimated to amount to 3.8 Million €, which results in specific investment costs of 14,000 €/kW. There is no possibility to derive a reasonable time series from the few plants installed, which are similar and are assumed to have similar costs.

MCFC. The first field demonstration of a molten carbonate fuel cell power plant was a 2 MW generator that was put into operation in 1995 in the US. The total funding of the project was about 46.5 Million US\$ (Eichenberger, 1998), resulting in specific costs of about 23,000 US\$/kW. In recent years a number of the so called Hot Module, a MCFC with a capacity of 250 kW has been installed in Europe, in particular in Germany. The first HotModule system that was operated by a customer was put into operation 1999 in Bielefeld (Germany). Project costs were about 3.8 Mill. €, resulting in specific investment costs of 15,400 €/kW. Current cost estimates for a 250 kW HotModule are about 3 Mill € (12,000 €/kW).

SOFC. Costs for the 100 kW Siemens-Westinghouse SOFC which was put into operation in the Netherlands in 1998 were estimated to amount to 100,000 €/kW (Kuipers 1998), which is very high compared to long term target costs. It should be noted that the system was the first of its kind. There are no data available on the cost on the more recent proof-of-concept 220 kW hybrid system operated at the University of Californiy, Irvine.

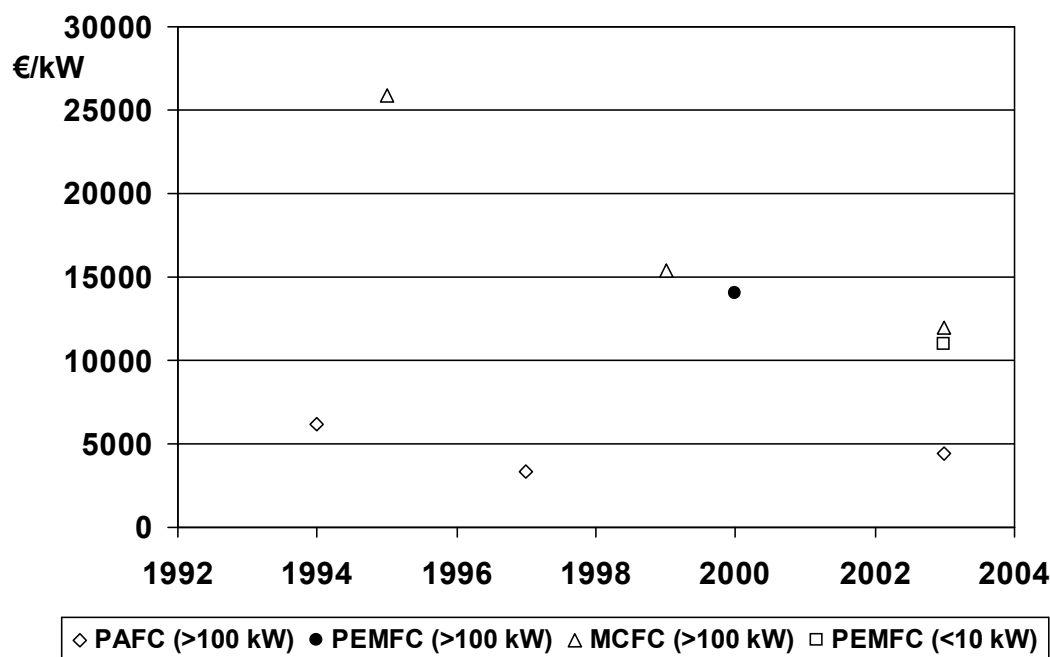


Figure B-37: Development of specific fuel cell production costs (excluding SOFC)

There are two main problems in making the cost data discussed above operational in the context of CASCADE, and use them as a basis for modelling the evolution of economic characteristics:

- Because of the specific technical characteristics we suggested to aggregate the different types of fuel cells into two generic classes, namely small scale fuel cell house applications (< 5 kW), and large CHP fuel cell power plants (200 kW to 5 MW). The record of historical data for the small scale systems however is absolutely insufficient (or better: non-existing) to provide a reliable basis for modelling a learning curve. At least for the historic perspective we thus suggest to assume the same technological learning in both categories, and use the full set of data on costs and cumulated capacity for one generic fuel cell only. The distinction between the small and large fuel cell systems shall however be maintained with regard to the technical characteristics.
- The four different fuel cell technologies (PAFC, PEMFC, MCFC, SOFC) are in very different technology development and market introduction phases, so that the aggregation into a single time series is not directly feasible. Important data points are missing for specific technologies, i.e. no costs data open to the public for the very early PAFC fuel cells; and consumer prices for the PAFC PC25 system are not considered as a good indicator for manufacturing costs, as there are indications that they were heavily subsidised.

As a consequence we suggest to not consider the data available for the Siemens-Westinghouse 100 kW-SOFC plant (one data point only, proof-of-concept facility) and the PAFC PC25 systems (costs

are likely to be significantly higher than consumer prices), so that we use only historic data on cost and capacity from the PEMFC and MCFC systems, leading to the development of costs over cumulated capacity as indicated in Figure B-38. This approach shall be reconsidered during a later phase of CASCADE-MINTS when we better understand the implications, and can do some sensitivity analysis, but for the time being it seems to be a reasonable starting point.

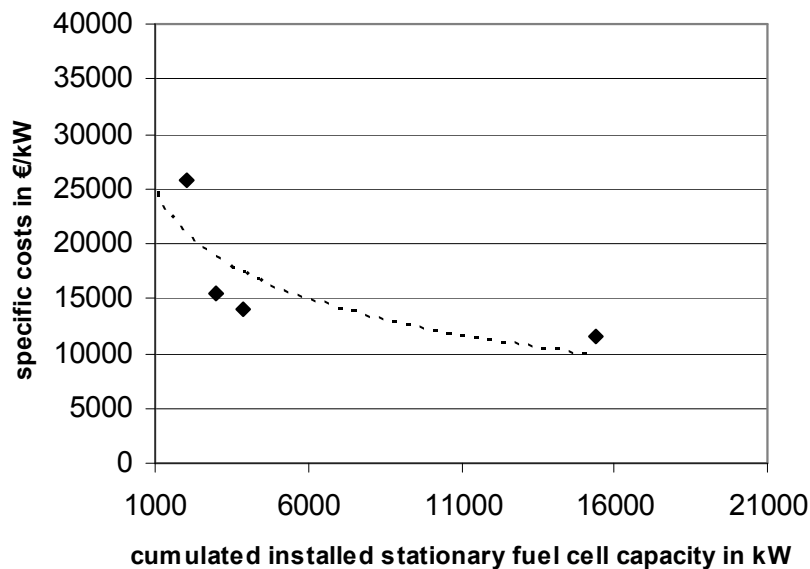


Figure B-38: Historical development of manufacturing costs of a generic stationary fuel cell as a function of cumulative capacity

Automotive Fuel Cells

Historical development of demonstration fuel cell vehicles

Recent surveys of fuel cell vehicles are presented by Cropper (2004) and Breakthrough Technologies (2004). Covered are passenger cars and road-going light commercial vehicles such as vans. At the end of 2004, Cropper estimates more than 500 vehicles which have been built ever. However within the 500 vehicles there are most probably a number of vehicles which were built as showcases and not as operational vehicles, so learning effects are probably very limited. Also included are the 60 F-Cell vehicles of DaimlerChrysler which are expected to be delivered end of 2004. In contrast, the Fuel Cell Vehicle World Survey 2003 (Breakthrough Technologies, 2004) estimates about 300 light duty FCVs which have been built worldwide.

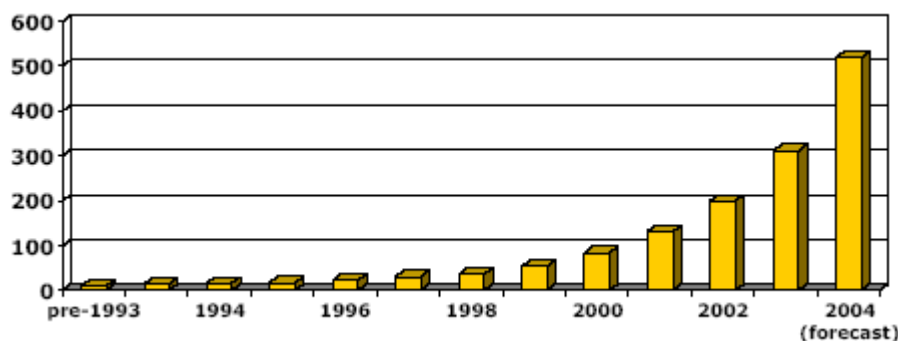


Figure B-39: Light duty vehicles built, cumulative (Cropper, 2004)

For the first time in the history of FCV a significant number of vehicles of the same type are or has been built in the years 2003 and 2004. These are 33 Citaro Busses produced by EVOBUS (DaimlerChrysler) for the EU-project CUTE (27 busses), the Sustainable Energy Program (STEP) of Western Australia (3 busses) and the ECTOS project (Ecological City Transport System) of Iceland (3 busses). There is also the first small series of 60 F-Cell light duty vehicles by DaimlerChrysler to be delivered 2004 or early 2005.

In order to update the given statistics, we have analysed the different sources and present the installed fuel cell capacity in automotive applications in Figure B-40 (by year) and Figure B-41 (cumulative). Here, we did not distinguish between types of fuel cells or light or heavy duty vehicles, as for “learning by doing” or “learning by producing” most probably the same effects apply, no matter what size the fuel cell system has. Almost all vehicles use PEFC systems. Perhaps the only exception in the last year has been the alkaline fuel cell (AFC) powered Lada built by Russia’s AvtoVaz (Cropper 2004). If the numbers are used on a fuel cell technology level (e.g. PEFC, AFC etc.) these FCV should be separated.

We expect that the installed capacity of fuel cells in vehicles is lower than the actually produced capacity, as there are in general problems with stacks and a number of spare stacks are produced and used in the projects. Unfortunately there is no data available on the actual number of stacks produced. As explained in Del 1.1, not only the fuel cell stack itself causes a significant fraction of the cost, but also the system design. For gaining experience in system design, all installed fuel cell power in vehicles (cars, busses, ships) above a certain power range might be cumulated.

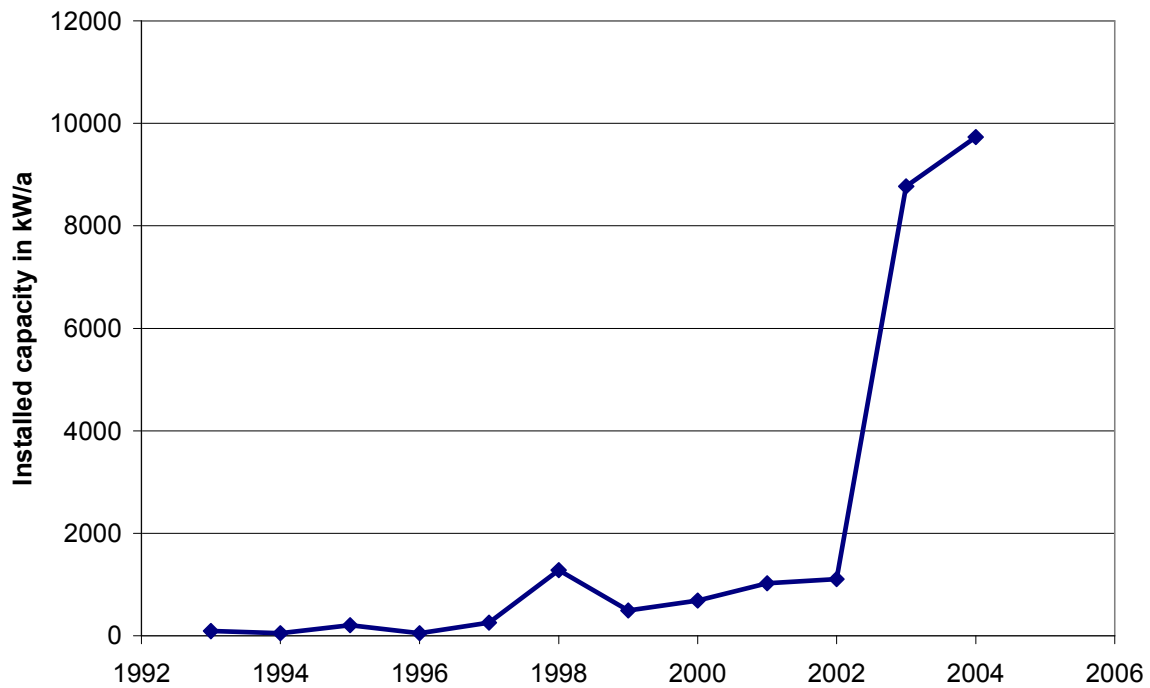


Figure B-40: Automotive fuel cell installations in demonstration vehicles by year (light duty vehicles and busses, all kind of fuel cells, hydrogen as primary or secondary fuel) (Own data DLR-IFK).

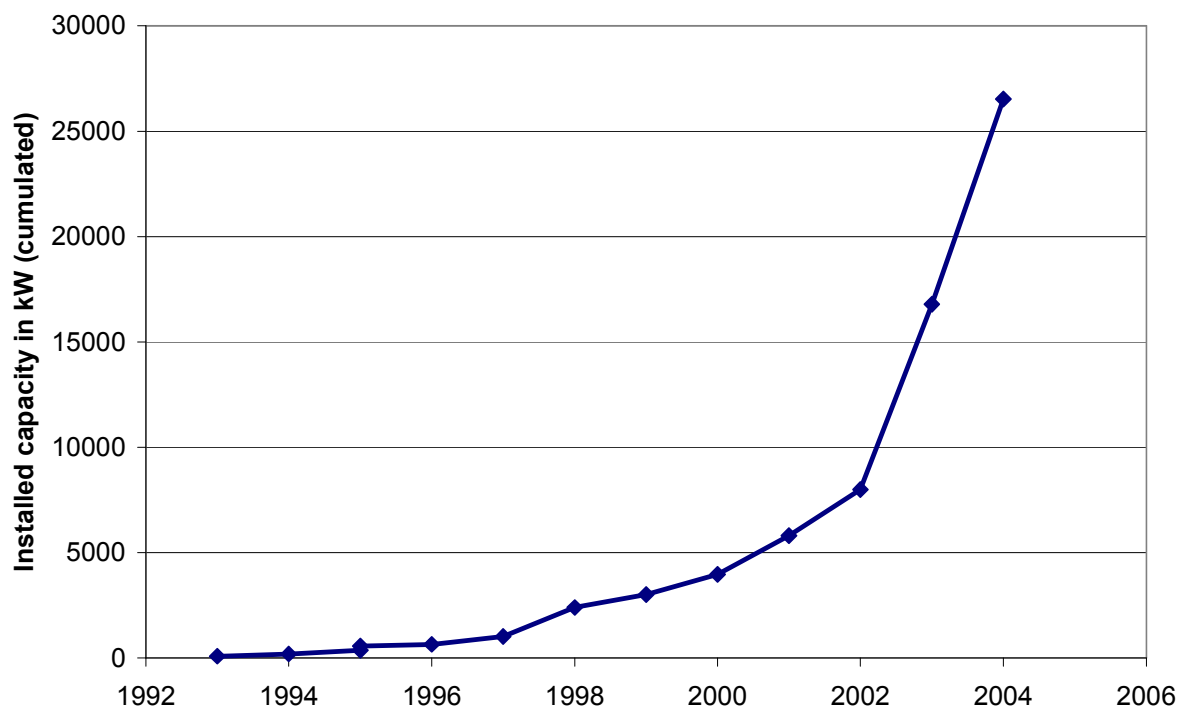


Figure B-41: Automotive fuel cell installations in demonstration vehicles, cumulated (light duty vehicles and busses, all kind of fuel cells, hydrogen as primary or secondary fuel) (Own data DLR-IFK).

Short-comings in data about built fc-stack capacity for automotive applications

- Only „official“ numbers available and power installed in demonstration vehicles
- No data about „additional“ stacks delivered (e.g. CUTE-project: there are spare stacks for exchange in case of problems)
- No data on number of stacks build for internal use

Cumulative mileage of FCVs

Another indicator for “learning” is the cumulative mileage the vehicles have been operated. The time series data on mileage and performance is incomplete. The earlier vehicles covered relative small distances. E.g. NECAR 5 in the year 2002 covered a distance a distance of 5 250 km between San Francisco and Washington on Methanol. DaimlerChryslers Hermes Sprinter travelled in the first test year a distance of 16.000 km (www.daimlerchrysler.com). The FCHV-4s of Toyota have covered at the end of 2002 about 110 000 kilometres cumulative (Toyota, 2002). The GM HydroGen vehicles have so far covered a distance of approximately 175 000 kilometers during the tough series of trials and bench tests (www.gmeurope.com). The ZEBus at the 13 month test run 6 848 km. CUTE and ECTOS busses have run 300 000 km by 30th July 2004.

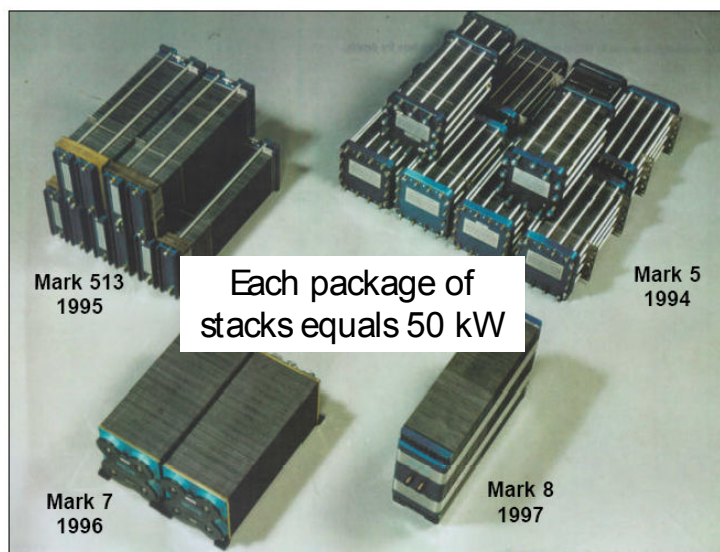


Figure B-42: Historical development of power density in fuel cell stacks for automotive application (Source: Lamm 2002)

Development of automotive fuel cell system costs

In the past the fuel cell stack was considered the most challenging element in a fuel cell system, with design targets reflecting solely the performance of the stack itself. Meanwhile the other system components have moved in foregrounds, even when considering costs.

“True” cost data for fuel cell stacks and fuel cell systems, for today as well as for the past, are scarce and lack the true market background. This is particular the case for the automotive power range of 50 to 200 kW_e.

For the PEFC stack costs of 3 000 to 7 000 EUR/kW and PEFC systems cost between 7 000 (AIR LIQUIDE/NUVERA) to 15 000 (BALLARD) EUR/kW at the prototype level are quoted (<http://www.leg.ensieg.inpg.fr>).

We have presented in Deliverable 1.1 the volume effect on the Xcellsis HY-80 light duty fuel cell engine. With a production volume of less than 10 units in 2003, costs of 37 000 US\$/kW were quoted. For 2004 with an assume volume of 100 units, costs of 3 700 US\$/kW were expected (Anonymous, 2004). This costs are defined as the money which has to be paid by the system integrator to the suppliers, including the stack manufacturer. These costs certainly do not include expenses for research and development and do not break even.

The only data available to establish a link between fuel cell costs and volume produced in the past are data about Ballard fuel cells. Figure B-43 shows the cumulative installed capacity of Ballard stacks in fuel cell vehicles (cars and busses) together with cost estimates. The use for the deduction of learning factors is however very limited because only in 2004 the first small series of stacks were produced. Before 2004, the production was on a complete laboratory scale. Moreover, this data lacks the actual cumulative capacity ever produced as mentioned before, as only the “official” numbers for demonstration vehicles are available and not those of stacks produced for testing. Possibly, the cumulative capacity is twice as high as presented. Referring to the size effect shown in Figure B-42, the learning component by “new and improve generations of technology” has certainly a higher share than “learning how to operate existing equipment more efficiently” as related to mass production.

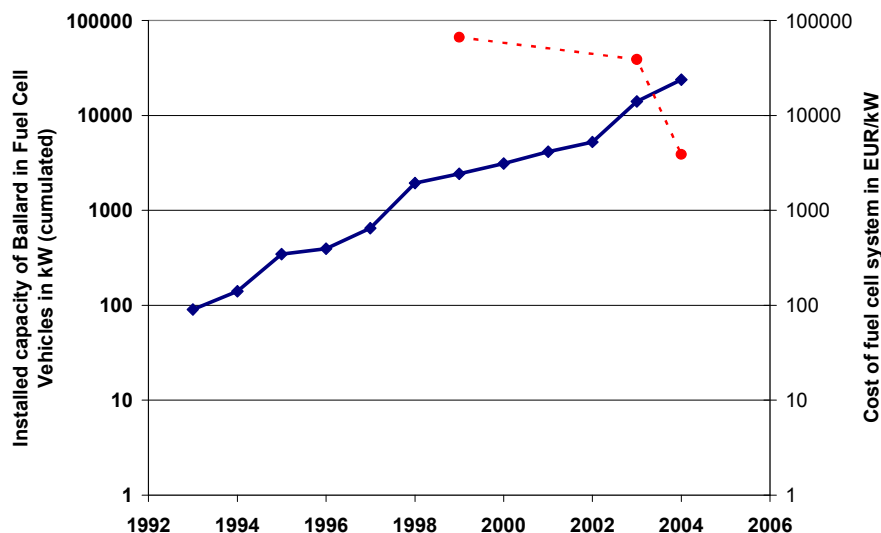


Figure B-43: Development of light duty engine capacity with Ballard stacks and corresponding cost estimates.

Some more historic cost estimates are shown in Figure B-44. The cost numbers by Siemens in 1993/94 and Ballard 1999 are consistent and show, that the costs in the past have been around 60000 Euro/kw. The cost estimates for the Xcellsis HY-80 light duty fuel cell engine are of a slightly different quality as they include air supply, water management and compressor costs on top of the stack costs.

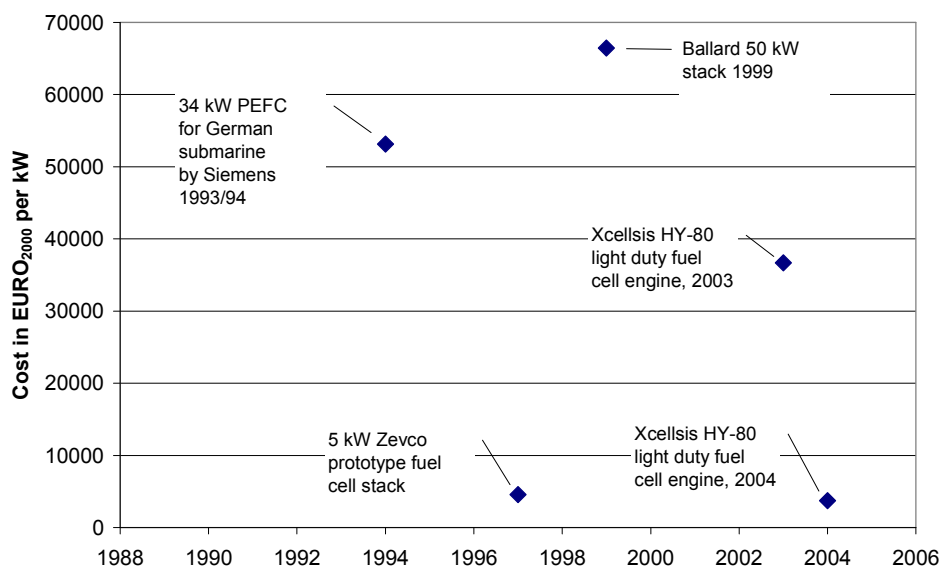


Figure B-44: Some given cost numbers for fuel cell stacks and fuel cell engines. (Source: Hydrogen & Fuel Cell Letter 1993-2002, Anonymous 2004).

Costs of hydrogen fuel cell busses from several projects in the past and today are shown in Figure B-45. The cost estimates are related to the vehicle itself except for the Citaro FC bus, where 2 years of service is included in the amount. The project costs were about a factor of 5 to 7 higher than the costs for the busses.

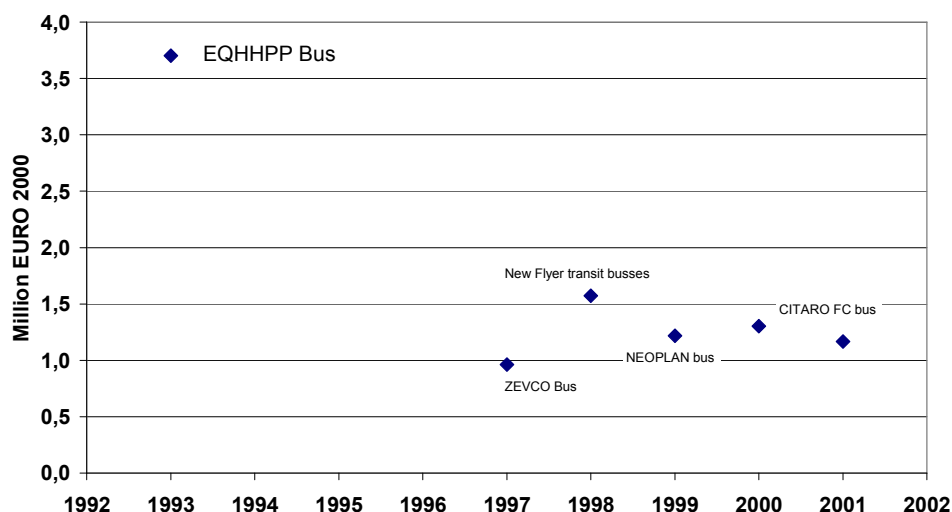


Figure B-45: Estimated costs for fuel cell busses (Source: Hydrogen & Fuel Cell Letter 1993-2002).

Hydrogen production technologies

Historical development of installed capacity

Several hydrogen production technologies are well established since decades now. The first MW-scale electrolyser was put into operation in Norway in 1929, using electricity from a hydro power plant. A hydrogen pipeline network in the German Ruhrgebiet area exists since the 1930s. Industrial scale production of hydrogen started in the beginning of the last century. Historical data records on the hydrogen production volume, or on the respective share of specific production technologies are not available for this very early phase of industrial hydrogen production.

Current annual world wide hydrogen production amounts to about $600 \cdot 10^9 \text{ Nm}^3$ per year (6,500 PJ/a), which is equivalent to only 1.5% of global primary energy demand. Nearly half of the hydrogen is used for non-energy application in the chemical industry (mainly for ammonia production), about 20% in the petroleum industry for fuel refining and the production of synthetic fuels (indirect energy use), and the rest (mainly contaminated hydrogen from industrial processes) is directly used for industrial process heat production.

Today about 60% of the hydrogen is directly produced by steam reforming of natural gas and naphtha and by partial oxidation of heavy oil. The rest is a by-product from the petroleum industry and petrochemical industry, and other industries. As a large share of the hydrogen is used internally and not traded on a market, any data on total hydrogen production are rough estimates with a relatively high uncertainty. We can trace back historical data on world wide hydrogen production until 1986 (Wurster and Zittel, 1994), while data for Germany are at hand back until 1976 (Winter and Nitsch, 1988). These data show that there was little variation over time in the dominating sources from which hydrogen was produced (mainly heavy oil partial oxidation and natural gas steam reforming). As in CASCADE we strive for quantitative historical information on the cumulated installed capacity as a basis for describing technological learning, an attempt is made to extrapolate the data back to the beginning of industrial hydrogen production, using an S-curve fit (Figure B-46). Although this approach obviously is a bit speculative, we are confident that it at least provides a reasonable working assumption. As we are looking back at more than 80 years of experience with a large cumulated hydrogen production capacity, the derived learning curve will not be too sensitive against changes related to our assumptions with regard to the early days of industrial hydrogen production.

From the time series of annual hydrogen production given in Figure B-46, we can derive the time series of annually installed new capacity (Figure B-47) and the total cumulated capacity, by using the technology specific availability factors and technical lifetime as described in the CASCADE-D1.1 report. This time series of cumulated capacity is used as an input to the CASCADE TECHSdb database.

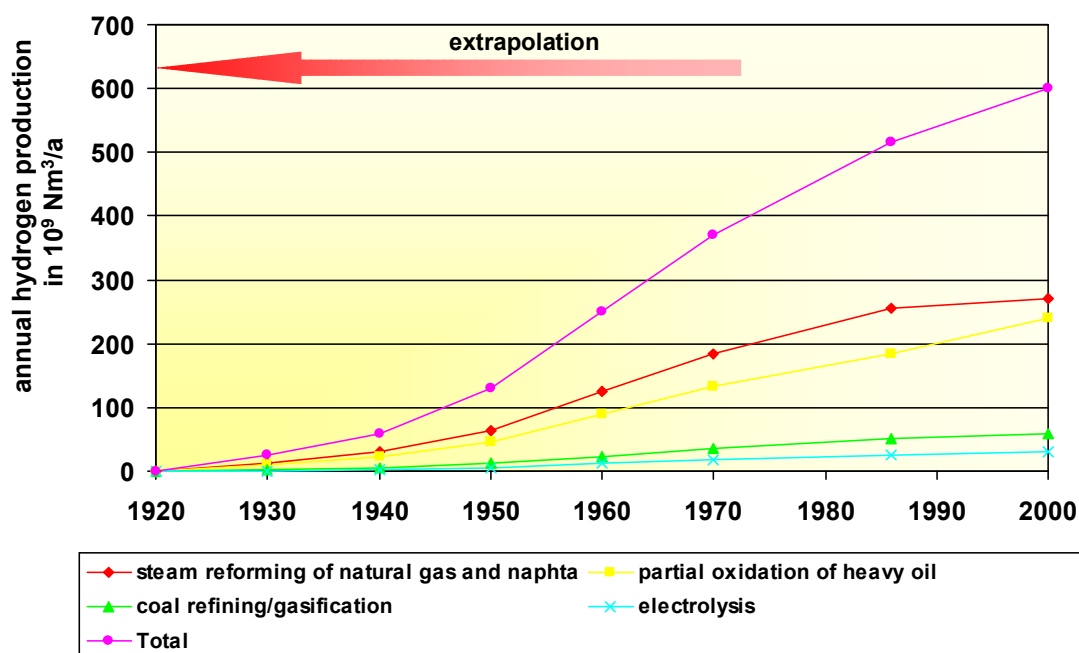


Figure B-46: Development of world wide hydrogen production

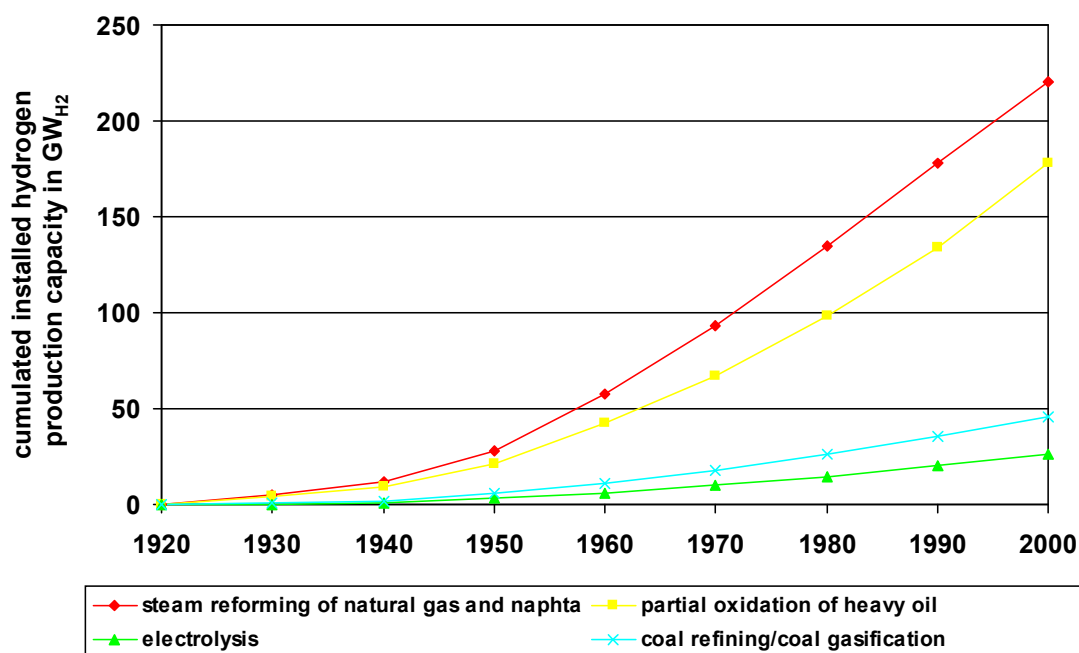


Figure B-47: Estimated development of world wide hydrogen production capacities

Development of costs of hydrogen production technologies

Historical cost data are derived from a literature survey. Reliable cost data are available since the early 1980s, so that we can cover a time span of about 25 years. There is however some uncertainty

related to the cost data used in the analysis, as data sources do not always refer to the year in which a specific installation was put into operation, in these cases we use the year of publication as the reference year. In addition there is some significant variation in the specific investment costs due to differences in the process design (e.g. plant size), which makes a direct comparison difficult. As far as possible we used data only for the same size-class of a specific technology, which however reduces the amount of data points.

Table B-85: Historical cost data for hydrogen production technologies

Source	Year	Plant size Nm ³ /h	Specific capital costs in € ₂₀₀₀ /kW _{H₂} (LHV)
Natural gas steam reforming			
Schulze a. Gaensslen, 1984	1983	100,000	342
Steinberg a. Cheng, 1989	1989	120,000	346
IKARUS, 1994	1994	100,000	355
Gaudernack et al. 1996	1996	120,000	346
Dreier a. Wagner, 2000	2000	100,000	336
Heavy oil partial oxidation			
Schulze a. Gaensslen, 1984	1983	100,000	653
Steinberg a. Cheng, 1989	1989	110,000	706
IKARUS, 1994	1994	100,000	796
Dreier a. Wagner, 2000	2000	100,000	500
Coal gasification			
Schulze a. Gaensslen, 1984	1983	100,000	810
Steinberg a. Cheng, 1989	1989	110,000	1094
Dreier a. Wagner, 2000	2000	100,000	890
Electrolysis			
Nitsch (1989) (based on data from Lurgi)	1981	>10,000	1190
	1986	>10,000	1181
	1987	>10,000	1207
	1988	>10,000	1067
Audus et al., 1996	1996	278,000	985
Thomas, 1997	1997	23,650	754
Dreier a. Wagner, 2000	2000	> 10,000	690

Figure B-48 summarises the development of investment costs over time for the different hydrogen production technologies, while Figure B-49 shows the cost development against the cumulated

installed capacity, thus giving an indication of the technological learning over the last 20 to 25 years. Data available for natural gas steam reforming consistently indicate that the specific investment costs were nearly constant (with an only very marginal decline), which is not surprising as natural gas steam reforming is a well established and mature technology. Investment costs for heavy oil partial oxidation facilities show an increase until 1995, but more recent data suggest that there is a further potential for cost reduction. Data for coal gasification show slightly increasing capital costs over time and also over cumulated capacity, but it should be noticed that only three data points were available. The cumulated capacity of coal gasification plants is relatively small compared to steam reforming and partial oxidation. Capital costs for electrolyzers were reduced by about 40% since 1980.

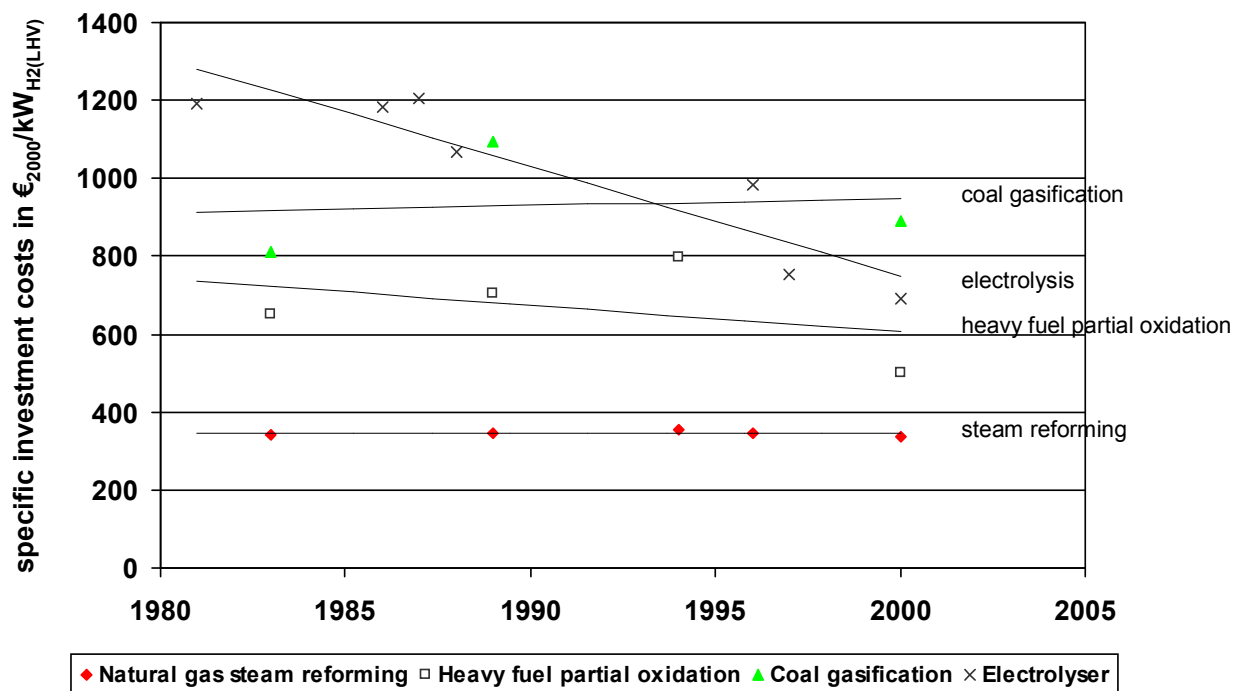


Figure B-48: Development of specific investment costs over time for different hydrogen production technologies

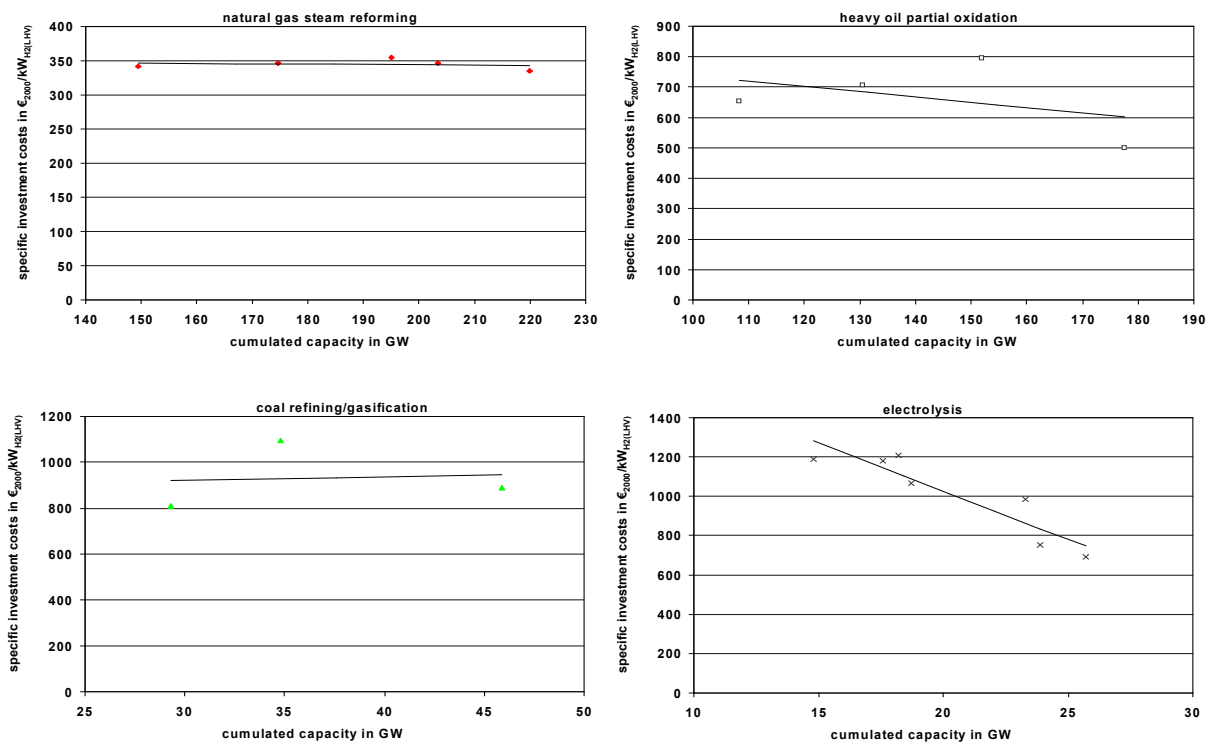


Figure B-49: Development of specific investment costs over cumulated installed capacity for different hydrogen production options

Hydrogen Storage Options

Liquefaction

Time series of historic data on hydrogen liquefaction capacity in North America is shown in Figure B-50. The capacity has increase in 25 years from 1975 to 2000 by about a factor 3 to 4. Unfortunately no corresponding cost data is available.

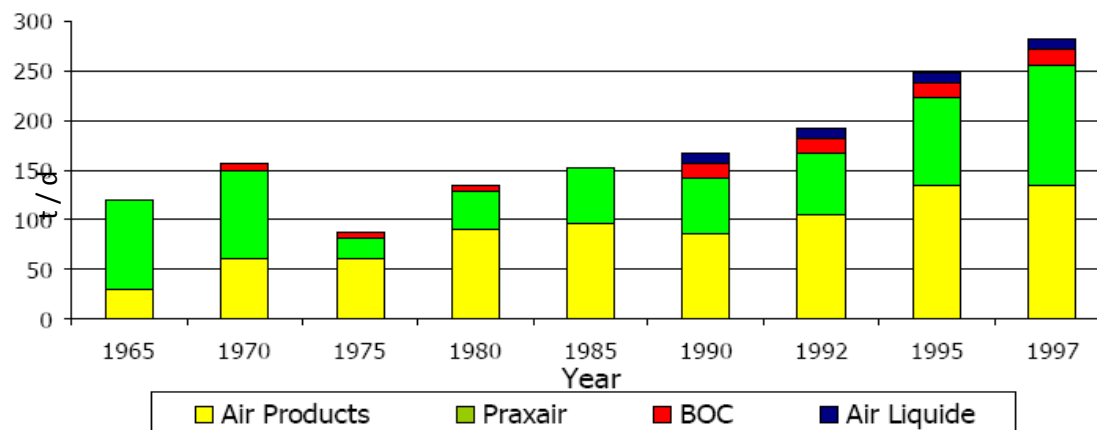


Figure B-50: Time series of North America liquid hydrogen capacity (Source: Drnevich (2003)).

Hydrogen Delivery Infrastructure

Hydrogen Pipelines

A steady increase in volume of hydrogen delivered in pipelines can be observed world-wide. Starting from data given by J. Ogden (cited by Science Applications International Corporation (2004)), we have updated the data with recent sources, mainly by Praxair and BOC. The extrapolation of the data gives a rough picture of the present volume of hydrogen delivered in pipelines (Figure B-51).

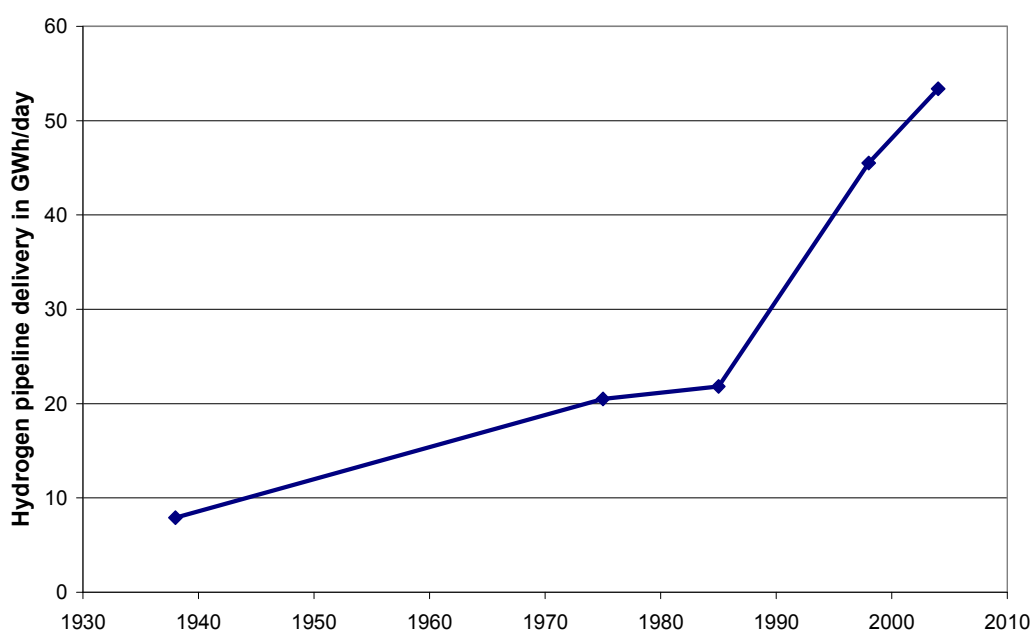


Figure B-51: Time series data of hydrogen delivered through pipelines world-wide (Source J. Ogden, Praxair);

Table 5.1: Hydrogen pipelines in Europe (taken from Deliverable 1.1)

Name	Operator	Country	Length km	Pressure range bar
Rhine-Rhur pipeline	Air Liquide	Belgium, France, NL	966	10
		Germany	240	1.1 - 30
Leuna-Merseburg	Linde		100	2 – 2.5
Europoort	Air Products	NL	50	
Teeside	ICI	UK	16	5
Chemical Industry		Sweden	18	0.5 - 2.8

Source: (Wurster 2003)

Filling stations

Hydrogen filling stations were built in the past at research laboratories and were most often used only for a short time. The number has significantly increased after the year 2000. The cumulative number of liquid and compressed hydrogen stations built world wide are given in Figure B-52 and Figure B-53. Corresponding costs are not available.

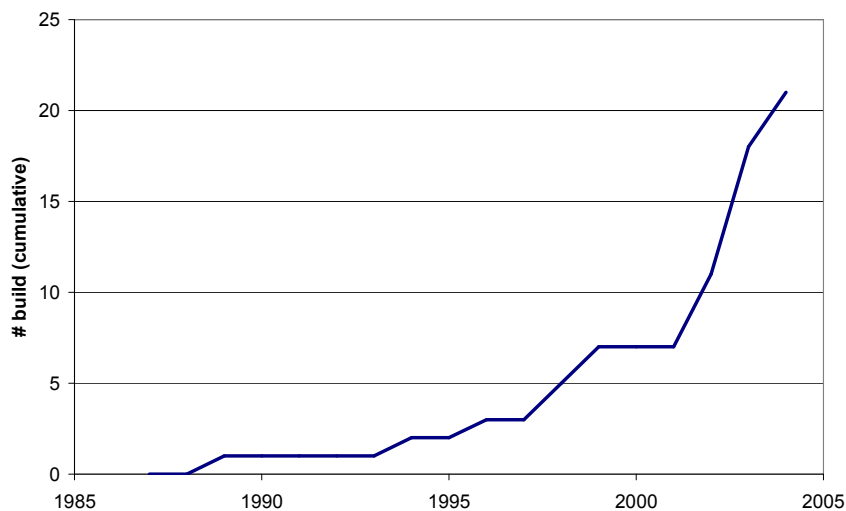


Figure B-52: Cumulative number of worldwide build liquid hydrogen based filling stations.

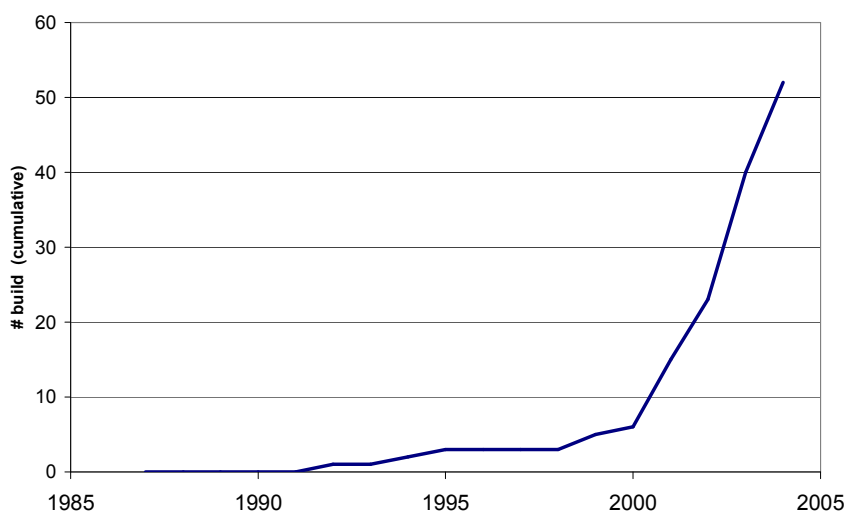


Figure B-53: Cumulative number of worldwide build compressed hydrogen based filling stations.

ANNEX

Table B-86: Historical development of specific investment costs and cumulated capacity for stationary fuel cells and hydrogen production options

	Fuel cell < 5 kW				Fuel cell > 5 kW				H2 from Nat.Gas Steam Ref.				H2 from part. oxid. heavy oil				H2 from coal refining/gasification				H2 from electrolysis			
	INV	CGERD	CBERD	CAP	INV	CGERD	CBERD	CAP	INV	CGERD	CBERD	CAP	INV	CGERD	CBERD	CAP	INV	CGERD	CBERD	CAP	INV	CGERD	CBERD	CAP
	€2000/kW	€ 2.000	€ 2.000	MW	€2000/kW	€ 2.000	€ 2.000	MW	€2000/kW	€ 2.000	€ 2.000	MW	€2000/kW	€ 2.000	€ 2.000	MW	€2000/kW	€ 2.000	€ 2.000	MW	€2000/kW	€ 2.000	€ 2.000	MW

Results of a literature survey on historic data on fuel cell costs

1993

The grad total spent so far on the project (Euro-Quebec, EQHHPP) is about 45 million ECU/ Can. \$ 69.75 million / US \$ 54 million

Most 50 percent cost shared. Some 50 European and 20 Canadian partners.

The average cost for each bus project is about ECU 2.5 million (US\$ 3 million)

Fuel Cell Letter 1993/11

Energy Partners Inc. rolls out green car; Total development costs about \$3.4 million

Fuel Cell Letter 1993/11

1994

GM Study says that PEM FCs cost about the same as IC.

Total costs of PEM ECE projected to be \$46/kW (peak) / \$65/kW (continuously operating)

Detailed cost projections

Stack \$1752

Fuel processor \$1077

Heat rejection/water management \$195

Fuel Cell Letter 1994/5

80 PEM FCs at \$3000 sold. 20 watt version. Price reduction in Mass production: 90%

Fuel Cell Letter 1994/6

Siemens Submarine PEM Cell

Hannover EXPO 2000: Siemens developed a prototype of an new PEM fuel cell module for German navy submarine during 1993/1994.

Oxygen/Hydrogen 34 kW (50kW Peak) "the ball park price" DM 2 million (US\$ 1.47 million) per module or about US\$ 44.000 pro kW

Fuel Cell Letter 1995/5

1996

Daimler-Benz outlay for current projects (NECAR Series) around \$200-233 million

Almost no help from Bonn government

“Another indicator that Daimler-Benz is into fuel cells for the long haul was the large amount of money spent on the NECAR II minivan. The total outlay for the current projects was in the triple digit millions of Deutsche Mark” One public relations executive hinted the total was around DM 300-350, (US\$ 200-233 million) from internal company funds. Fuel Cell Letter 1996/6

1997

At the moment, a 5 kW ZEVKO prototype fuel cell stack for a vehicle goes for about \$20,000, or \$4000/kW. Fuel Cell Letter 1997/12

Zevco bus projects: One bus will cost about \$ 845,000

1998

UCS report estimates overall savings by a hydrogen fc bus \$ 180,000 /lifetime compared to a diesel. For natural gas fc bus \$51,000

“Current prototype fuel cell busses are expensive: standard diesels average about \$240,000 while CNG busses cost between \$287,00 and \$311,000, depending whether it’s a low-floor or a high-floor model.”

“Each of the three New Flyer transit busses equipped with Ballard PEM fuel cells [...] cost \$1.4 million each, plus fuel budget \$900,000 for all three for the two-year test period, plus other costs. The total cost of the entire two-years test package is \$9,6 million”

Fuel Cell Letter 1998/5

Zevcos Millenium Taxi costs about \$4,100 more than the standard diesel powered version.

Lifetime costs \$ 85,000 compared to \$ 134,000 for standard diesel version.

Fuel Cell Letter 1998/8

1999

A 50 kW Ballard stack total price is \$3 million – about \$60,000/kW. Fuel Cell Letter 1999/1
In his Chairman's Address, Marcus Nurdin, Managing Director of the World Fuel Cell Council, noted that the cost of fuel cells has dropped 10 fold in the past decade. .. The Cost of fuel cells used in demonstration projects in early 1990's averaged \$5.000 per kW. The NECAR program [...] and other activities have radically reduced fuel cell costs. DaimlerChrysler estimates, for example, that the fuel cell system used in NECAR 4 was \$545 per kW. ... mass production of MEA could cut costs to \$10 to \$15 per kW Fuel Cell Letter 1999/11
NEOPLAN bus project: Total costs of the bus itself was about \$1.1 million. Cost of the Entire project was about \$ 5.4 million. Fuel Cell Letter 1999/11

2000

Citaro bus Project: Bus itself costs \$1.2 million. Diesel version cost 1/4 or 1/5 of that. Hydrogen fueling infrastructure cost between \$100,000 and \$1 million. Fuel Cell Letter 2000/5
Bavaria I Bus Project: The MAN Bus featuring a Siemens PEM Fuel Cell had total project costs of \$6.2 million, with a 50% contribution from the ministry. Bavaria II Bus Project: Proton Motor/Neoplan Bus total project Costs: \$ 1.15 million. Fuel Cell Letter 2000/6

2001

The GEF (Part of UNDP) expects 40 -50 FC buses will be delivered and deployed at a total cost of about \$130 million to major cities and capitals with air pollution problems. Fuel Cell Letter 2001/2
DaimlerChrysler Citaro Bus Project: One Bus Costs about \$1.1 Million, approximately 5 times the cost of a conventional bus. Price includes 2 year service package. Fuel Cell Letter 2001/4
Media report that the price for a FCHV-4 (Toyota) would be about \$79,000 Fuel Cell Letter 2001/7

B.2.2 The TECHPOL database

[by P. Menanteau (LEPII-EPE)]

Introduction

The TECHPOL database provides reliable data on the costs and performance of representative supply and demand energy technologies to be used in the Cascade project for energy simulation exercises. It is used to collect and organise the quantitative information provided by the different partners in the Cascade project on new energy technologies, including hydrogen production, transport and distribution and use.

The TECHPOL database is built on past experience with technology data collection developed during former European research projects (such as Sapient / Sapientia) and on a specific and detailed work carried out by LEPII and DLR on hydrogen energy technologies.

Former work realised within European research projects and new developments on hydrogen production technologies has allowed establishing reference values on costs and performance for key power and hydrogen generation technologies including capture and storage, and transportation technologies.

These data are used by the different models in the Cascade projects to simulate the evolution of the global energy system. Even if technological progress is endogeneous in the energy models the data are estimated up to 2050 in order to provide estimations on costs and performance for the key energy technologies in the case of specific scenarios with assumed accelerated technical progress or breakthroughs for example.

The database is provided under an excel format that includes a standardized calculation procedure for electricity / hydrogen levelised production costs for three time periods: 2000, 2025, 2050. It allows comparing the combined effects of different factors that may influence production cost and facilitates a more accurate assumption of the future evolution of key parameters (such as investment cost, efficiency, variable or fixed O&M).

In the following section, the content and structure of the database is presented. A detailed presentation of the content of the common technology database used within the Cascade-Mints project with specific technological trajectories up to 2050 can be found in the section D.1.2.

Content of the common technology database

In the TECHPOL database, around 50 different generic technologies are considered. These technologies are divided into 4 main categories:

- Power production technologies
- Hydrogen production technologies
- Technologies for H² transport and distribution

- Transportation technologies (vehicle cars)

For each technology, different set of data on costs and performance are provided including, overnight investment costs, lifetime, operation and maintenance costs, efficiency, availability, etc. All the data necessary to calculate a levelised electricity/hydrogen production costs are provided. This allows to calculate and compare the production costs for each technology on the basis of an agreed methodology and common assumptions (discount rate, load factor, etc.) and to improve the cross-consistency of the large number of hypothesis which are further integrated in the modelling process.

Furthermore, floor costs are provided for each technology as required by the two factors learning curve approach. They represent the ultimate cost that can be reached by the technology when learning process is achieved and the technology has exploited all scale and series effects to attain its ultimate performance.

Centralised power generation

Centralised power generation includes both fossil and nuclear electricity production. The main fossil fuel power generation technologies are considered:

- conventional boilers firing solid, liquid or gaseous fuels,
- standard and advanced (super / ultra critical) coal-fired steam power plants,
- new clean-coal technologies (integrated gasification and combined cycle)
- combustion turbines with simple or combined cycle using natural gas or oil.

Three of these technologies are also considered with capture and storage devices. The nuclear power technologies covers conventional and advanced (4th generation) nuclear power reactors.

Table B-87: Key technologies for centralised / large scale power generation

Technology	Fuel	CC & Sequ.	Acronyms
Steam boiler	Fuel	W/O	OCT
Steam boiler	Natural Gas	W/O	GCT
Steam boiler	Coal	W/O	CCT
Steam boiler	Brown Coal	W/O	LCT
Super Critical Pulverised	Coal	W/O	PFC
Super Critical Pulverised	Coal	W	PSS
Gas Turbine	Natural Gas	W/O	GGT
GT Combined Cycle	Fuel	W/O	OGC
GT Combined Cycle	Natural Gas	W/O	GGC
GT Combined Cycle	Natural Gas	W	GGs
Integrated Gasification CC	Coal	W/O	ICG
Integrated Gasification CC	Coal	W	CGS
Nuclear Power (conv.)			NUC
Nuclear Power (adv.)			NND

A far as coal powered generation is concerned, conventional pulverized coal plants operating at subcritical conditions (CCT) have been included but new coal plants which operate at supercritical conditions are

progressively entering the market. These new supercritical pulverized coal plants (PFC) have been added to reflect state of the art technology. Integrated gasification plants (ICG) which offer environmental benefits and increased efficiency are considered for the near future.

Gas combustion turbines are divided in two subcategories, simple cycle gas turbines (GGT) which are used mainly for peak electricity production, and combined cycle gas turbines (GGC) which are considered as the reference technology for electricity production in most countries.

Conventional nuclear reactors are described under the "NUC" category that takes into account ongoing evolutions of existing designs in nuclear power plants (EPR type reactors). New, intrinsically secure, nuclear power reactors (Fast Breeder Reactors, Gas / Sodium cooled fast reactors, etc.) known as 4th generation reactors are regrouped in a separate category (NND) to reflect the fact that these developments are not expected in the middle term. If costs and performance of fossil fuelled and conventional nuclear reactors are well known, this is not the case for new nuclear designs ; assumptions have been made according to the expectations of the Generation IV international forum that these plants would be competitive with conventional reactors in 2050.

Carbon capture technologies

The deployment of low GHG emitting fossil fuelled power plants is the condition for exploiting existing fossil energy resources while controlling the increase of GHG emissions. For that reason, CO₂ capture technologies have been introduced for the principal fossil power plants:

- pulverised coal,
- integrated coal gasification plants
- gas powered combustion turbines (combined cycle).

After a close examination of the capture cost of CO₂ in the literature, it has been decided to keep three different capture options for electricity production (post capture for coal and gas and pre capture for coal gasification). As far as pulverized coal and gas turbines are considered, the capture of CO₂ takes place after combustion (PSS, GGS). Pre-combustion capture is possible with coal integrated gasification combined cycle power plants (CGS).

Carbon capture technology has also been introduced on biomass gasification power plants. This is not necessary as biomass combustion is not considered to emit net GHG if the whole plant cycle is considered but it may be cost-effective to introduce carbon capture in the perspective of GHG emission trading.

Distributed or renewable power generation

Key decentralised technologies include both small and large renewable power generation units and fossil distributed production systems including conventional cogeneration units and fuel cells (Table B-85).

Table B-88 : Key technologies for decentralised or renewable power generation

Technology	Fuel	CC & Sequ.	Acronyms
Large Hydro			HYD
Micro Hydro			SHY
Wind Power / on shore			WND
Wind Power / off shore			WNO
Concentrating Solar Power			SPP
Photovoltaics			DPV
Biomass (conv.)			BF2
Biomass gasification			BGT
Cogeneration (industrial)			CHP
Fuel cell (small)	Hydrogen		HFCs
Fuel cell (large)	Hydrogen		HFCI
Fuel cell (small)	Natural Gas		GFCs
Fuel cell (large)	Natural Gas		GFCI

Hydraulic power plants are divided in two broad categories : large hydro (HYD) refers to large-scale hydro power stations, either run-of-river or storage plants and micro hydro (SHY) to small units of less than 10 MW of installed capacity.

Off-shore and on-shore wind power technologies that present different technical and economic characteristics are described as separate technologies.

As far as solar power is considered, two basic solar energy technologies have been included: building integrated PV systems and solar thermal plants. The concentrating solar power category (SPP) is a generic technology as different technologies (parabolic troughs and central receivers) are still competing for base load production of electricity. The deployment of this technology is limited to highly insulated regions (south of Europe, Australia, south of USA for example). Photovoltaics (DPV) category covers small distributed power generating units which may be integrated in new buildings. As photovoltaic modules can benefit from lower insulation, its potential deployment is much wider than concentrating technology.

Two categories have been considered among biomass power production technologies, t: direct combustion or co firing (BF2) of solid biomass (either wood or waste) associated to a steam cycle for the production of electricity and biomass gasification (BGT) associated with a gas turbine or a combined cycle to produce electricity.

In the database, different fuel cell technologies have been considered for mobile and stationary applications resulting in differing performance, costs and progress rhythm for technologies. For stationary applications, low temperature PEM fuel cells have been introduced for small residential or tertiary applications in buildings and high temperature MCFC or SOFC units for large systems in industry. These systems can be fuelled directly with hydrogen or with natural gas through a reformer. Both of them are supposed to produce heat and power simultaneously.

Hydrogen production

Hydrogen can be produced from fossil or renewable fuels and from electricity. Seven different hydrogen production technologies are considered in the TECHPOL database (Table B-86) :

- gas steam reforming with the option of solar steam reforming,
- coal gasification,
- heavy oil partial oxidation,
- biomass gasification
- water electrolysis

These technologies can be considered as more "conventional" technologies even if they have reached totally different maturity levels.

Thermochemical cycles (nuclear and solar) are more prospective technologies but they may represent possible future solutions for H₂ production in the very long term.

Gas steam reforming and water electrolysis are state of the art technology. Technical and economic performance is known for present technologies but these characteristics may change in the future if significant change in scale and related economies are possible.

Coal gasification, biomass gasification, and partial oxidation are still in a development stage in the sense that their deployment is still very limited. As a consequence, present costs and performance may vary according to the sources and future performance is more uncertain compared to state of the art technology.

Thermochemical cycles (nuclear and solar) are clearly futuristic technologies, with no real reliable technical and economic data being available. The data provided in the database about thermochemical cycles should therefore be considered at best as rough provisional estimations and most often as target costs.

Gas steam reforming, coal and biomass gasification and heavy oil partial oxidation are also considered with capture and storage option.

Table B-89 : Key technologies for hydrogen production

Technology	Fuel	CC & Sequ.	Acronyms
Gas Steam Reforming	Natural Gas	W/O	GSR
Gas Steam Reforming	Natural Gas	W	GSS
Solar Steam Reforming	(Natural Gas)	W/O	SMR
Coal Gasification	Coal	W/O	CGA
Coal Gasification	Coal	W	CGS
Heavy Oil Partial Oxydation	Oil	W/O	OPO
Heavy Oil Partial Oxydation	Oil	W	OPS
Biomass Gasification (small)	Biomass	W/O	BGAs
Biomass Gasification (large)	Biomass	W/O	BGAI
Biomass Gasification (large)	Biomass	W	BGS
Biomass Pyrolysis	Biomass	W/O	BPY
Solar Thermochemical cycle			SHT
Nuclear Thermochemical cycle			NHT
Water Electrolysis	Electricity (grid)		WELs
Water Electrolysis	Electricity (grid)		WELI
Water Electrolysis	Nuclear		WEG
Water Electrolysis	Wind		WEW

Storage and delivery

A new part has been added in the database following the work carried out by DLR on the technologies for hydrogen storage and delivery. In this file four main groups of technology have been considered: liquefaction of hydrogen, storage tanks, transport technologies (both road transport, sea transport and pipelines) and filling stations.

Liquid hydrogen is considered because of advantages in transportation. Capital costs and energy consumption for liquefaction have been provided.

Different types of devices are presented for bulk storage of hydrogen. Today cylindrical steel vessels are commonly used for gaseous industrial storage. For stationary applications, hydrogen might also be stored in gasometers as they were used in the past for fossil gases. Hydrogen is also stored in vessels that are state of the art technology for liquid storage. This storage of large quantities of liquid hydrogen can be necessary at liquefaction plants or at distribution centres, like e.g. fuelling stations.

Technologies for road transport of gaseous and liquid hydrogen are described. The road transport uses conventional trailers with specific vessels but the transport capacity of both options is significantly different (much more important for cryogenic tankers than conventional gaseous hydrogen trailers). Liquid hydrogen can also be transported overseas in tank ships similar to LNG tankers.

At least hydrogen filling stations are described similar to conventional fuel stations. These stations are provided with gaseous or liquid hydrogen by road transport (trailers) or gaseous hydrogen pipelines. These

two options are described separately as they are major technical differences between filling stations based on gaseous or liquid hydrogen.

Pipelines are effective for handling large flows. Along the piping in regular distances there is a compressor installed, which elevates the pressure in the pipe. The gas flows then from the high pressure end towards the low pressure end, losing a certain amount of energy due to friction along the way. Hydrogen pipelines are in principle similar to natural gas pipelines. Because of the small size of the H₂ molecule, different valves and compressors have to be used. Embrittlement of steel due to H₂, i.e. H₂ induced cracking especially at high strength material and high pressures have to be taken into account. Nevertheless was recently a crude oil pipeline successfully converted to H₂ service (Air Liquide 2003). Generally it seems to be advantageous to use the existing natural gas pipeline infrastructure for hydrogen in the future. This would avoid high investment costs for new, hydrogen dedicated pipelines.

Table B-90: Key technologies for hydrogen storage and distribution

Liquefaction			
	Liquefaction	small	
	Bulk storage,	medium	
	Large scale storage,	large	
Storage tanks			
	Local storage,		
	Bulk storage,		
	Large scale storage,		
	High pressure vessel (20 MPa)		
	Cylindrical vessel (6 MPa)		
	Spherical vessel (2 MPa)		
Transport			
	Pipeline local		
	Pipeline distribution network,		
	Pipeline, high capacity		
	Road transport	Liquid	
	Road transport	Gas	
	Sea transport		
Distribution			
	Filling station	Liquid	exp.
	Filling station	Liquid	small
	Filling station	Liquid	medium
	Filling station	Liquid	large
	Filling station	Liquid/gas	exp.
	Filling station	Liquid/gas	small
	Filling station	Liquid/gas	medium
	Filling station	Liquid/gas	large
	Filling station	Gas / gas	exp.
	Filling station	Gas / gas	small
	Filling station	Gas / gas	medium
	Filling station	Gas / gas	large

Transport technologies

At least, five different motorisation are considered in the TECHPOL database for road passenger transport (Table B-87) :

- conventional internal combustion engine vehicles,
- pure electric vehicles,
- hybrid vehicles,
- hydrogen powered internal combustion engine vehicles
- fuel cell hybrid vehicles fuelled with hydrogen (gaseous or liquid) or gasoline.

Conventional internal combustion engine vehicles are supposed to evolve under the CO₂ constraint resulting in a slight decrease of vehicles weight and an improvement in unit fuel consumption.

An hybridisation of conventional ICE with electric powered wheel drive is considered. The resulting fuel consumption would be 20-25% lower than conventional ICE (2025) which can be considered as a rather conservation scenario.

Pure electric vehicles are also included in the database with very low unit consumption but only smaller urban electric vehicles have been considered with limited performance in terms of range.

Hydrogen powered internal combustion engine vehicles are included in the database as an alternative to fuel cell vehicles (assumption that no breakthrough in fuel cells will occur). Present fuel consumption of H₂ ICE would be higher compared to the gasoline vehicle, due to non-adapted engines. For the future, the consumption is similar to conventional vehicles

As far as fuel cell vehicles are considered, a higher capacity is need compared to thermal engines because higher peak power is needed to reach similar performances. Considering that it is cheaper to add a battery and to install a smaller fuel cell stack instead of powering the vehicle only with a fuel cell, hybrid configurations are considered for fuel cell vehicles.

Table B-91 : Key demand-side technologies / energy intensive sectors

Technology	Fuel	Acronyms
Fuel cell	Hydrogen (gas)	
Fuel cell	Hydrogen (liquid)	
Fuel cell	Gasoline	
Thermal	Hydrogen (gas)	
Fuel cell	Hydrogen (liquid)	
ICE (conv.)	Gasoline	
Hybrid	Gasoline	
Electric	Electricity	

Update of the common database

An updating process of the common information database has been engaged within the work package 1.5. The update of the database has been performed through a continuous interacting process with the other partners in the project, a process that is difficult to describe in details. In the following section we just mention some of the important modifications that have been introduced in the database.

Electricity Production Technologies

The most important issue on power production technologies was referring to the estimation of operation and maintenance costs. In the first version of the database, fixed O&M costs were estimated as a constant percentage of investment when it would be preferable to consider them independently of investment to take account of a real evolution in operation and maintenance costs. The update of fixed O&M costs has also allowed reconsidering the variable O&M costs for electricity production technologies.

Fixed O&M

The update of O&M costs has begun with an analysis of the information available in the literature. Unfortunately, there is limited information on the future evolution of O&M cost in power production technologies. As far as non fuel O&M costs are concerned, (IEA – NEA, 1998) ⁷ and (EIA, 1999)⁸ consider that labour productivity increase and non-labour improvements are likely in liberalised markets. However the potential for further cost reduction is not clear particularly in developing countries where at the same time labour productivity and labour costs should increase.

Without further information we have estimated that O&M fixed costs for mature technologies would decrease at a limited rate (5% / 25 yrs) ; a rate that is similar to previous decrease considered in SAPIENTIA database. Potential for cost decrease is supposed to be larger for emerging technologies (25% / 25 yrs) which is also in line with previous assumptions in the SAPIENTIA project.

Variable O&M costs

For the reasons mentioned above, non labour O&M costs (variable O&M) are supposed to decrease slightly in the future ; in the absence of information we have estimated the rate of decrease to be 10% / 25 yrs for mature technologies and 50% for emerging technologies (NND).

Carbon capture and storage options

In the database six different CO₂ capture options were considered resulting in six different €/annual tonne of CO₂ captured costs. The question was raised whether it would be possible to limit the number of CO₂ capture options to two main options: post-combustion capture for coal and gas and pre-combustion capture

⁷ Projected costs of generating electricity – Update 1998

⁸ Issues in Midterm Analysis and Forecasting 1999

(to be used in electricity production from coal and biomass gasification and in hydrogen production technologies).

As far as storage costs are concerned the idea to introduce a marginal supply cost curve for CO₂ storage was suggested.

CO₂ capture

After a close examination of the capture cost of CO₂ in the literature, it has been decided to keep three different capture options for electricity production (post capture for coal and gas and pre capture for coal gasification).

As far as H₂ production is concerned, it has been suggested to use one pre-capture technology for all technologies (incremental investment costs: 22-16-17 €/m³d). Accordingly only one technology has been kept for capture (H₂ production) in the database: the techno-economic parameters used are the ones that were initially provided for steam methane reforming.

Nevertheless it does not allow to reach a unique capture cost of CO₂ expressed in €/tCO₂ as it was requested. The cost of CO₂ captured being the result of a calculation that uses H₂ production cost with and without capture it is mathematically impossible to reach a unique cost of CO₂ captured with one set of specifications for all technologies.

In conclusion, costs of CO₂ captured expressed in €/tCO₂ will not be the same for the different H₂ production technologies, even if the technology used for CO₂ capture is the same.

This conclusion is consistent with the data found in different papers in which cost of CO₂ captured (expressed in €/tCO₂) differs for methane steam reforming and coal gasification.

CO₂ sequestration

As requested, CO₂ storage marginal cost curves have been provided by the LEPII reflecting increasing access cost to reservoirs and differentiated potentials according to the different regions. These figures are based on former work realised by IPTS based on ECOFYS data.

Biomass gasification with CO₂ capture

The introduction of a capture option on biomass gasification for the production of electricity may result in negative electricity production costs when CO₂ taxes are very high given the high rate of capture and relatively low cost for capture and storage. In order to avoid this behaviour it was suggested to examine a possible modification in the technical and economical characteristics of CO₂ capture for biomass gasification or a revision of the calculation procedure for electricity production with biomass gasification.

As a conclusion of our investigations, it has been proposed not to revise the characteristics of CO₂ capture for biomass gasification but to introduce biomass supply cost curves that will allow to compensate the decreasing electricity production cost when CO₂ tax is increasing.

H² production technologies

As for electricity production technologies, O&M costs have been revised for hydrogen production in order to keep their evolution independent of investment costs. The former selection of hydrogen production technologies has also been revised following discussions with the project partners.

Operation and Maintenance costs

Fixed O&M costs for H² production technologies are provided in the DLR report but except for steam methane reforming, O&M costs are estimated as a percentage of investment. No variable O&M costs are provided for hydrogen production technologies (Table B-35).

Rough estimates of fixed O&M costs evolution have been provided with the following rules:

- Fixed O&M for 2000 are estimated according to DLR's report as a percentage of investment (except for immature technologies which are not supposed to be on the market until 2025 – for these technologies, FOM for 2025 are DLR's estimates as a percentage of investment)
- As H² production technologies are relatively new technologies and pressure to reduce operating costs not so important yet, it is estimated that a potential for O&M costs reduction exists (higher than potential for electric power plants) ; basic rate of decrease is 10 %/25 yrs and high rate is 50 %/25 yrs (for emerging or experimental technologies ; ie, thermochemical cycles and advanced electrolysis).
- Long term estimates (2030) are considered for the year 2025

No variable O&M costs has been provided because of the huge uncertainty of this estimate given the immaturity of most hydrogen production technologies ; this does not have any consequence on global production costs as Fixed O&M reflect total O&M costs.

HT thermochemical cycle

Even if it is considered as a futuristic option, assumptions regarding costs, performance and floor cost was required. As no real reliable technical and economic data are available on thermochemical cycles, these estimations should be considered as provisional.

The estimation of floor costs for nuclear thermochemical cycle is based on (Schultz, 2003) and refers to the production of H² from nuclear energy using a modular helium reactor and a Sulphur-Iodine (S-I) H² production cycle.

Clustering

A link has been introduced in the database between gas steam reforming and solar methane reforming which are similar technologies. The investment cost for solar methane reforming is considered as the sum of a methane steam reforming unit and a specific solar system. A specific link has also been introduced in the efficiency of solar methane reforming with the efficiency of gas reforming.

Similarly technical and economic characteristics of Nuclear – electrolysis and Wind – electrolysis have been adjusted as follows to reflect the combination of independent technologies.

Transport technologies

Several modifications have been introduced to the capacities and costs of vehicles.

Engine costs

The cost of ICE engine is increasing over time because of increasing effort for emission after-treatment and improvements in unit fuel consumption due to CO₂ restrictions (from 20 €/kW to 32 €/kW).

The cost of electric engine (incl. power electronics) is estimated to decrease from 27 €/kW to 12 €/kW for fuel cell vehicles.

The cost of the hybrid vehicle is introduced in the database as a function of costs of ICE and electric engines.

Electric and ICE engine capacities

The capacity of electric engines for battery only electric vehicles has been reconsidered: the new figure 60 kW corresponds to a smaller urban vehicle with lower performance in terms of range.

The capacity of ICE vehicle is supposed to decrease slightly in the future as the weight of the vehicles will decrease a little - even under light CO₂-restrictions.

The capacity of fuel cell vehicles is larger than the capacity of thermal engines because higher peak power is needed to reach similar performances.

Cost of batteries for electric and hybrid cars

Costs of batteries are approximately inversely proportional to their specific energy expressed in W/Wh. The differentiation between pure electric and hybrid electric batteries is significant and should be kept. A rule of thumb for clustering the technology is to divide the cost of the batteries for full hybrid vehicles by a factor of 2 compared to the cost of batteries for electric vehicles.

Liquid and gaseous H₂ storage

Costs of on board gaseous and liquid storage for vehicles have been reintroduced in the database in reference to the figures provided by DLR.

Efficiencies of ICE, hybrid and electric cars

Former inconsistencies in vehicle fuel consumption between LEPII and DLR have been solved after a discussion with S. Schmidd with the following results:

	ICE	H ² ICE	Hybrid	Electric	FC hybrid gasol.	FC hybrid H ²
2000	257	321	161	20	122	84
2025	180	180	153	17	98	70
2050	162	162	145	15	78	60

Table B-92 : fuel consumption of vehicles(MJ/100 km)

Fuel cells

Generic fuel cell for mobile / stationary applications

In the database, different fuel cell technologies have been considered for mobile and stationary applications resulting in differing performance, costs and progress rhythm for technologies which present clear similarities. In order to preserve a coherent evolution in the performance of stationary and mobile fuel cells, the possibility to limit the number of fuel cell technologies has been considered.

Finally it has been decided to keep three technologies in the database for stationary (large and small) and mobile applications, but the stack costs have been re-estimated so as to solve the inconsistencies that previously existed (very high initial costs with very low costs in 2025 for mobile FC – lower initial costs for stationary applications but higher costs in 2025).

The idea to consider mobile and stationary fuel cells as a unique technology has been rejected (because of totally different lifetime targets). The differentiation between 'small' (low temperature PEM) and 'large' (high temperature MCFC or SOFC) stationary application has been kept and just as between the stack costs for pure hydrogen and reformat systems.

As a consequence, there are still differences in total FC costs in the database between large and small, on the one hand, mobile and stationary applications, on the other, but the stack costs have been re-estimated in order to avoid inconsistencies and to facilitate introduction of clustering rules between stack costs.

Stationary FC

Several modifications have been made in the database on stationary fuel cells, including improvement of O&M costs, introduction of explicit reformer efficiency and cost, and floor costs.

Concerning fixed O&M costs, data have been provided in DLR's report. Given the limited experience to date with fuel cells it has not been possible to differentiate between fixed and variable O&M costs. As a consequence we have introduced only fixed O&M in the database with autonomous technical progress (5% of investment cost in 2000 and 2% in 2050) as an approximation of O&M costs.

Reformer cost are calculated as a difference between hydrogen fuel cells and gas fuel cells investment costs. As agreed the reformer is integrated in large FC systems and does not induce any additional cost.

The reformer efficiency is estimated in reference to the figures provided by W. Krewitt as the difference in electric efficiency between natural gas and hydrogen fuel cells ; the efficiencies differ according to the size of the reformer : 92% for small reformers and 95% for large ones.

Mobile FC

The fuel cell engine capacity has been split into stack power and electric power. The capacity of the electric engine is 90 kW decreasing to 80 kW in 2050 ; the capacity of the stack is supposed to be lower because of the hybrid configuration : 70 kW decreasing to 60 kW in 2050. The cost of the electric engine has been added to the vehicle cost just as the cost of the electric storage with the following assumptions: 1.3 kWh cap in 2000 decreasing to 1.0 kWh in 2050.

B.2.3 R&D expenditure database

[by S. Mima (LEPII-EPE)]

This task deals with the construction of a database containing time series for R&D expenditure regarding Hydrogen, Fuel Cells and Carbon Sequestration. This is an essential element of information for the estimation of the two-factor learning curve relationships, themselves constituting a privileged way, although not the unique one, through which R&D effort is translated in technology improvement. Data on public R&D are obtained for OECD countries (which are assumed to undertake the bulk of the effort) through a systematic survey of the available information : different publications (particularly IEA « Hydrogen&Fuel cells : review of national R&D Programs »), IEA, CORDIS and FERD databases.

In order to understand current and future energy technology dynamics, it is however important to characterise also the private efforts, which are much more difficult to identify. In order to obtain reasonable estimates the use of indirect methods using CORDIS and FERD databases was necessary. Then cumulative research is also examined for a set of key technologies, and considered as a “proxy” for accumulated knowledge for each technology.

Target and Tasks

In recent years, fuel cells and to a lesser extent other hydrogen economy related technologies have benefited from public R&D support and have attracted growing private R&D interest in developed economies. The corresponding data on R&D efforts – although not so long in time and not traced in existing generic statistical sets – are essential for the model’s technology dynamics mechanisms, enabling them to perform R&D policy simulations in a dynamic environment.

Based on initial work performed in the TEEM and SAPIENT projects of the EU DG Research, the SAPIENTIA project under the 6th RTD Framework Program develops some efforts for including hydrogen and related technologies in the Technology database.

The key finding of the TEEM and SAPIENT project had been a prerequisite for the endogenisation of technical change in large energy sector models in order to simulate the combined impacts of the experience processes and that of the R&D efforts on the technologies' costs and/or performances. In order to combine the “learning by doing” and “learning by searching” effects, the concept of “Two Factor Learning Curves” (TFLC) had been developed and used in simulations with the POLES model (see corresponding Chapters in the special issue of the International Journal of Global Energy Issues V14, N°1-4, 2000).

As a reminder, the basic equation used for the Two Factor Learning Curve in the POLES model and SAPIENTIA project modelling exercises is of the following form:

$$\text{COST}_i = k * (\text{CUMGERD}_i + \text{CUMBERD}_i)^a * (\text{CUMCAP}_i)^b$$

where:

COST_i is the cost of technology i in constant money,

CUMGERD_i the cumulative Government Energy R&D (exog.),

CUMBERD_i the cumulative Business Energy R&D (endog.),

a the “learning-by-research elasticity”,

CUMCAP_i the cumulative installed capacity (endog.),

b the “learning-by-doing elasticity”.

In order to improve the approach and further increase the reliability of the estimates of the TFLC it has been decided in the CASCADE-MINTS project to develop a database gathering data on the cost of the key hydrogen and related technologies (i.e. the 18 technologies considered in the POLES model: 9 hydrogen production, 4 fuel cells, 5 carbon sequestration) and to the key explanatory variables considered in the TFLC i.e.: cumulative capacities, cumulative government energy R&D (GERD) and cumulative Business energy R&D (BERD).

The construction of public and private R&D regarding Hydrogen, Fuel Cells and Carbon Sequestration intended to :

provide a more reliable description and estimation of TFLC parameters for H₂ Production, Storage, Transport & Distribution, Fuel Cells and CCS,

develop a full set of consistent data for the key variables in the TFLC i.e. GERD, BERD complementary to Cost-Cap data with a technology disaggregation deriving from POLES but also adapted to other models and allowing new modelling on infrastructures

Survey of available information, in particular existing estimations on Government New Energy Technologies R&D and make a consistent treatment of different sources.

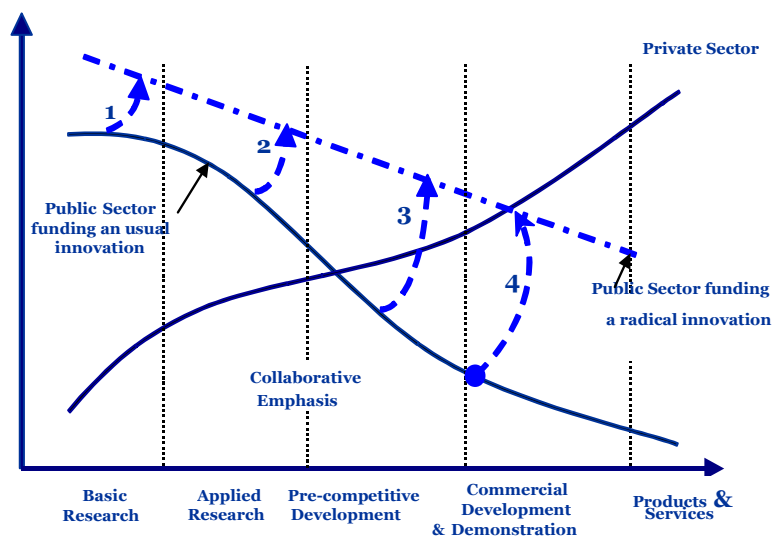
Problems raised by new technologies

Most of hydrogen, fuel cell and CCS programs correspond to disruptive technologies, so longer and larger basic research is required, since the creation of new scientific knowledge should be supported by the development of new scientific disciplines or sub-disciplines. The applied research stage should also be longer and more costly because of the requirement to develop new practical devices and new artefacts that are initially characterised by low performances and which require continual adaptations in order to improve their key functionality. Radical innovations require also a high public support for demonstration, market-entry and infrastructure investments (hydrogen networks and storage), while in the case of incremental innovations the costs incurred by these activities are comparatively less important and entirely supported by private investment. So public/private partnerships are necessary to speed up the cost reduction process by accelerating early market development and reduce lead time to commercial operations in order to avoid the 'valley of death' risk.

The following figure shows that the ratio of GERD to BERD may be changing over time, according to the maturity of each technology. Thus there are difficulties to estimate this ratio for the future for hydrogen and related technologies.

Figure B-54 : The initial GERD / BERD ratio is probably higher for H2 and FC programs than for other emerging technologies (all BERD in Public Private Partnership programs)

R&D Investment



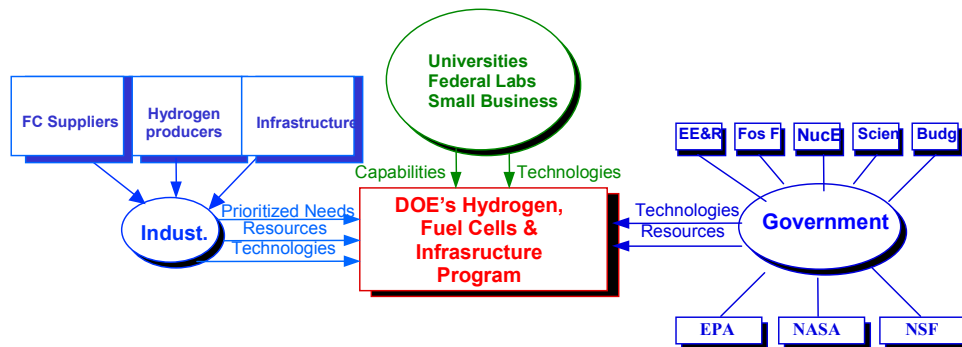
Source : Bernard Bourgeois, LEPII-EPE

There is no doubt that fuel cell technologies may be included in the 'radical innovation' category, and as such could benefit from higher than usual public support. But, they have a more than 130 years history, with many ups and downs. How long should they continue to benefit from public support? We do not tackle that issue, but we argue that if a major environmental innovation is needed to make the likely transition from the 'old' energy system mainly based on carbon fossil energy resources to a 'new' system mainly based on renewable, nuclear and hydrogen energy sources, then fuel cell technology is among the major forthcoming innovations to be supported. We do not try to develop the consequences of this statement and the new relevant mix of

policy instruments within that perspective. But we assume that without this new public and societal involvement, technological advances will be insufficient to overcome the currently inferior overall performance of fuel cells with respect to the mainstream existing technologies.

Furthermore, hydrogen, fuel cells and CCS programs are based on complex networking RD architectures with overlapping of GERD and BERD money (eg. DOE's Hydrogen, Fuel Cells & Infrastructure Program, or NHP⁹) and an increasing share of international partnerships (eg. IEA Collaboration).

Figure B-55 : Overlapping of Public and Private R&D for the Hydrogen, Fuel Cells & Infrastructure Technologies Program



Source : LEPH-EPE



Source: IEA/EET

⁹ “The New Hydrogen Project (NHP) in Japan, not only ties together a number of METI’s ongoing and new programs, but it integrates the development of fuel cell, hydrogen production, and hydrogen transportation and storage technologies concurrently with the implementation of demonstration programs, vehicle sales, construction of refuelling infrastructure, establishment of codes and standards, and a general push to enlarge the consumer market for fuel cells and fuel cell vehicles” (IEA, 2004).

In this framework it is difficult to elaborate a general methodology for a consistent treatment of the available information. Therefore we tried to collect each published particular R&D data concerning hydrogen, fuel cells and CCS.

Construction of R&D expenditure (private/public) database principles and methodologies

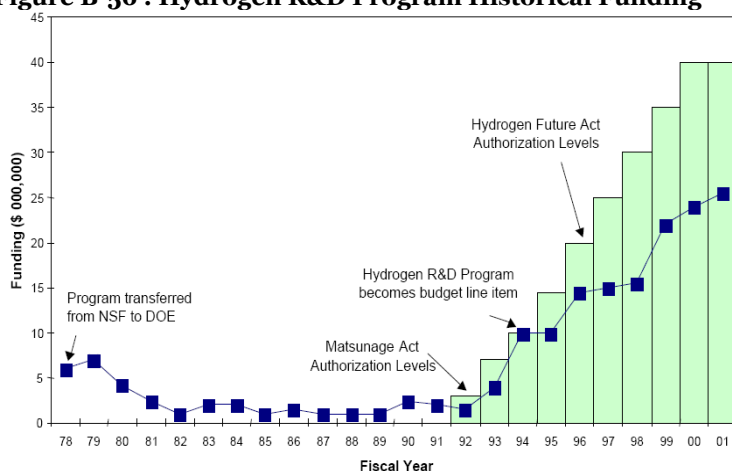
Survey of available information

Recently, top-level decision-makers in OECD Member countries have pointed to hydrogen and fuel cells as key technologies to contribute to energy supply security and environmental protection in the mid-long term. Actions and investments are backing up these statements. A vast amount of information was reported in response to the IEA's HCG survey questionnaire published in "Hydrogen&Fuel cells : review of national R&D Programs", but a consistent description of the structure of HFC GERD/BERD spending for each type of technology is very difficult to construct.

United States

In the United States, Hydrogen R&D Programs are identified since 1978. The following figure shows a regular increasing trend of the historical funding :

Figure B-56 : Hydrogen R&D Program Historical Funding



Source : http://www.h2net.org.uk/PDFs/RN_2/US%20Hydrogen%20Prog_mod.pdf

In the past few years, DOE has lead a heavily-funded, wide-ranging program, with national laboratories, universities, other federal agencies and industry partners to overcome critical technical barriers to fuel cell commercialization. Current R&D is also focused on the development of reliable, low-cost, high-performance fuel cell system components for transportation and buildings applications.

Fuel cell R&D responsibilities at DOE, have included research on SOFC and MCFC with a FY 2003 funding of US\$47 million, of which approximately \$11.5 million is allocated towards the Vision 21 projects that develops clean central station generation technologies. The remainder is allocated to technologies that are more focused on distributed generation applications. A key activity is the Solid State Energy Conversion Alliance

(SECA), a partnership between DOE, the National Laboratories, and industry to develop and demonstrate planar solid oxide fuel cells for distributed generation applications. DOE also develops fuel cell technologies with an emphasis on the PEM fuel cell for both stationary and transportation applications.

The FreedomCAR partnership between DOE and USCAR (a pre-competitive research organization consisting of General Motors, Ford and DaimlerChrysler) is the vehicle through which PEM fuel cells are being developed for use. DOE also has the responsibility for developing PEM fuel cells for portable and distributed generation applications as well as the technologies required for the hydrogen energy infrastructure that is important in the long-term for large scale use of PEM fuel cells.

The FY 2003 budget allocation for the integrated DOE program was US\$92 million, split between PEM fuel cell R&D (\$54million), and hydrogen production, infrastructure, and storage R&D (\$38 million). The DOE budget in the FY 2004 has increased 60%, with more important increase for hydrogen then for fuel cells. The total request for Hydrogen fuel initiative for the FY 2005 attains \$173 million, while the total request of the Department of Energy for FreedomCAR and Hydrogen Fuel Initiative is \$1.7 billion for the whole period 2005-2008 period.

In the following table is presented not only the historical funding of the Department of Energy for FreedomCAR and Hydrogen Fuel Initiative but also the estimates of government Hydrogen and Fuel cell R&D made by the fossil energy coal and nuclear program, in the basic energy sciences and by the department of transportation. It also appears that DOD makes also some efforts in this direction.

Table B-93 : Estimations on Government Hydrogen and Fuel cell R&D (in millions of dollars)

Hydrogen Initiatives	FY 99 Approp.	FY 00 Approp.	FY 01 Approp.	FY 02 Approp.	FY 03 Approp.	FY 04 Approp.	FY 05 Request
Hydrogen technology							
Hydrogen Production & Delivery	9.0	13.4	14.8	11.2	11.2	22.6	25.3
Hydrogen storage				6.1	10.8	29.4	30.0
Safety, Codes & standards utilisation				4.5	4.5	5.9	18.0
Education and Cross-Cutting analysis	2.2	2.5	3.1	1.4	1.9	5.7	7.0
Infrastructure Validation	10.9	8.8	9.0	5.7	9.7	18.4	15.0
Total Hydrogen technology	22.0	24.6	26.9	28.9	38.1	82.0	95.3
Fuel Cell Technology							
Transportation systems				7.5	6.2	7.5	7.6
Distributed energy systems				5.5	7.3	7.4	7.5
Stack Component R&D				12.6	14.8	25.2	30.0
Fuel Processor R&D				20.9	23.5	14.8	13.9
Technology validation				0	1.8	9.9	18.0
Technical Support				0.2	0.4	0.4	0.5
Total Fuel cell technology				46.7	53.9	65.2	77.5
Total (Energy/EERE-Hydrogen Fuel Initiative)				75.6	92.0	147.2	172.8
					Actual*	Enacted**	Request
Energy/EERE FreedomCar					152	155	169
Energy/Fossil Energy (coal)					2	5	16
Energy/Nuclear					2	6	9
Energy/Basic Energy Sciences					0***	0***	29
Departement of Transportation					0	0.6	0.8
Total****					180	249	319

Source : Elaborated according http://www.h2net.org.uk/PDFs/RN_2/US%20Hydrogen%20Prog_mod.pdf,
<http://www.eere.energy.gov/hydrogenandfuelcells/mypp/pdfs/appendix.pdf>,
http://www.ctfuelcell.uconn.edu/fcic/pdf/fcic_program_oral_p2.pdf,
<http://www.house.gov/science/hearings/full04/mar03/charter.pdf>

Note : * Reflects funding for baseline activities that the Hydrogen Fuel Initiative (HFI) augments and/or redirects. 2004 was the first year for the HFI, 2003 was the first year for FreedomCAR.

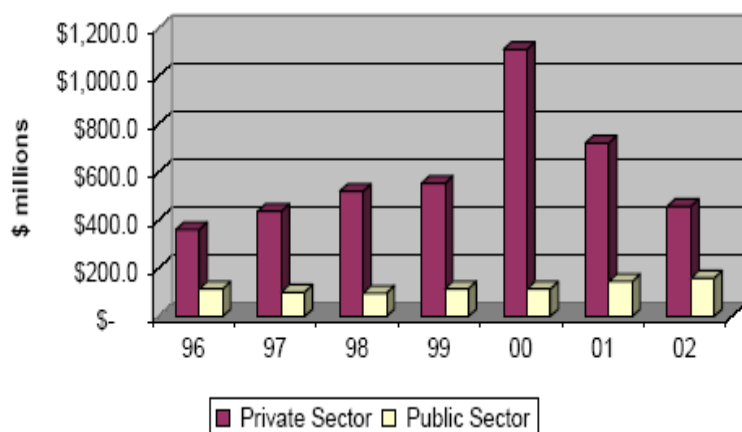
** Reflects rescissions, general reductions, and other adjustments included in relevant 2004 appropriations.
 *** Base funding for hydrogen-related activities in Basic Energy Sciences was roughly \$8 million in 2003 and 2004. These activities have been reoriented and expanded to support the goals of the President's HFI in 2005.
 **** Columns do not add due to FreedomCAR and HFI funding overlaps and rounding.

Industry participation

Although exact numbers on industry involvement are proprietary, the major automobile companies have invested billions of dollars in R&D and demonstrations of fuel cell vehicles. General Motors alone had spent \$1 billion as of June 2003, and estimated that its total investment by 2010 could triple (<http://www.house.gov/science/science/hearings/fullo4/mar03/charter.pdf>, p. 7).

The following figure shows, through an estimate of the funding of the US Fuel Cell Industry a much higher R&D effort made by the private sector for the Fuel Cell technologies than the public sector. While the public effort seems to be flat during the period 1996-2002, private sector attains in 2000 more than \$1 billion, although it decreases after to \$400 million in 2002.

Figure B-57 : Estimated Funding of the US Fuel Cell Industry



Source : <http://www.fuelcells.org/info/charts/economicstudy.pdf>

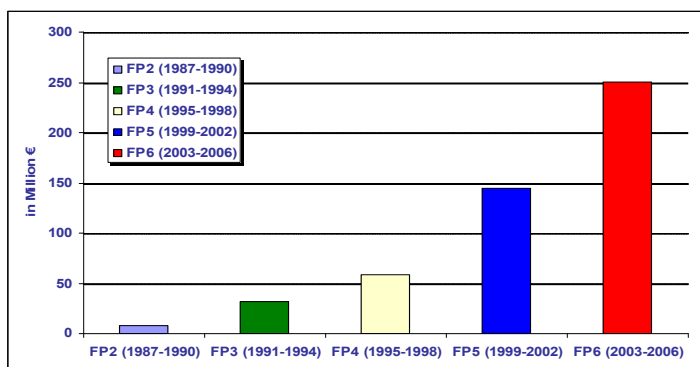
European Union

The EC contribution on hydrogen and fuel cells research within FP5 has been of the order of €145 million. Recently EU launched a new hydrogen and fuel cell initiative with some €100 million of EU funding, matched by an equivalent amount of private investment. Further calls for R&D will pump €300 million of public and private investment into the sector (of which €150 million EU funding). These projects represent the initial phase and form a basis for the large scale “Quick Start” initiative for hydrogen production and use. The “European Growth Initiative” earmarks an indicative €2.8 bn public and private funding for these partnerships over the next ten years. The Commission is thus helping to implement the ambitious vision of the European Hydrogen and Fuel Cell Technology Platform¹⁰.

¹⁰ Source :

<http://www.fuelcelltoday.com/FuelCellToday/CommonServices/PrinterFriendlyPage/0,1872,Type%3DNews%26RecordID%3D4159,00.html>

**Figure B-58 : Estimations on Government Fuel Cell/Hydrogen Technologies R&D : EC (in million €)
(Demonstration and Research)**



Source : Elaborated from Angel PEREZ SAINZ Miami, November 2003,
http://www.h2net.org.uk/PDFs/Programmes_2003/Borthwick_H2NET_Novo3.pdf

The EU funding is matched by an equivalent amount of private investment.

Besides EU funding, Member States' funding is often important. For instance, Germany has funded RD&D in H₂/FCs since 1974. The total German annual budget for H₂ and FC R&D (Estimates) stands as follows :

	Mio €
Fed. Ecomic Min. (BMWA)	7-10
Fed. Research Min. (BMBF)	5-15
State Programmes	15-20
From EC Programmes	10-15
Industry ??	(several 100 Mio €!)
Total	40-60 +??

Source : Helmut Geipel, Hanns-Joachim Neef, 2003¹¹

In addition to its National Program, Germany has very strong Länder Programs, i.e. programs in their Federal States :

- Bavaria - 75 M€ (30 M€ 1997-03)
- Baden-Wurttemberg - 5-6 M€/y
- North-Rhine Westphalia - 77 M€ (40 M€ until 2003)
- Further activities in Saxony, Saarland, Mecklenburg-Vorpommern

A new H₂ vision is under definition to be prepared by the Federal Ministries, Federal States, industry and research organisations to be unveiled by the end of 2004.

¹¹ Hydrogen :1974 until 2000 : 60 mio € for more than 100 RD&D projects (examples: thermo-chemical production of H₂, Hot Elly, Hysolar, Baysolar, ...). After 2000 : 10 mio € for demonstration of H₂ infrastructure for fuel cell busses.

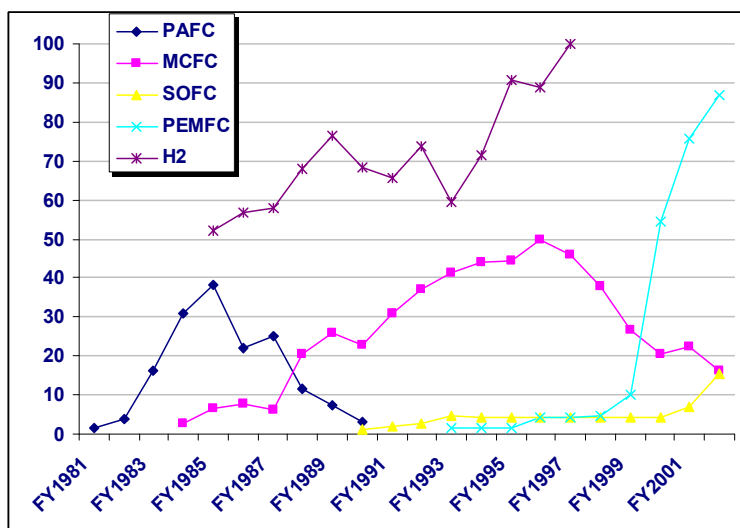
FC : Until 2000 : 100 mio € for more than 100 projects (examples : MCFC, SOFC, PEM, DMFC, cross-cutting issues)
 After 2000: 68 mio € for additional projects. In addition: funding for National Research Centres more than 50 mio € until 2002.

Japan

The Japanese R&D budget for fuel cells and hydrogen has tripled since 1995, reaching \$ 200 million per year in 2002. The New Hydrogen Project (NHP) extends the work initiated during the seminal, 10-year, JPY1.8 billion WE-NET program, which initially focused R&D on core technologies necessary for establishing a hydrogen infrastructure (e.g., electrolysis, liquefaction, storage) and then later on the utilization of hydrogen and construction of fuelling stations.

METI Budget on PEFC Systems attained ¥ 5.3 - 5.1 B¹², for MCFC and SOFC ¥ 3.3-3.6 B (high-efficiency, large-scale FC systems), for Micro FCs ¥ 0 -0.2 B (DMFCs for portable applications, PCs, phones), for Li ion Battery for FCVs: ¥ 1-2 B (high power/efficiency and long-lifetime batteries for supplementary power), in demo Projects ¥ 2.5-3.9 B (FCV on-road demos including H₂ refuelling stations or stationary FC demos with co-generation). Some ¥ 0 - 4.5 B goes to Basic H₂ Technology and Safety. Concerning the establishment of codes, standards, regulations and test methods for FCs (the Millennium Project) are spent ¥ 3.1-3.9 B. The total Budget attained ¥ 22B(2002) - 31B(2003) equal to € 235 M (Haug, 2004, p. 17).

Figure B-59 : Budget of Fuel Cell Project in NEDO (in millions of \$)



Source : Toshiaki ABE Toshiaki ABE, NEDO, 2003 for FC, <http://www.worldenergy.org/wec-geis/global/downloads/et21/japtab1.pdf> for hydrogen.

Other OECD and non-OECD countries (Canada, Italy, UK, China) either have R&D programmes in place, or are expanding their investments; small countries (such as Iceland and Singapore) are already committed to introducing hydrogen and fuel cells in their electricity and end-use sectors. This emphasis is echoed in the private sector, where investments in hydrogen technology have grown in recent years, leading to technology development and demonstration projects for stationary and mobile fuel cells, as well as for hydrogen fuelling facilities for fuel-cell-powered vehicles.

¹² 1 ¥ = 0.01 \$

Canada allocates in Research and Development \$ 10M/yr, to the Institute for Fuel Cell Innovation \$ 20M and \$ 23M for Hydrogen Refueling Demonstration. Recent Federal Investment (five year) \$ 215M (Haug, 2004, p. 11).

CORDIS and FERD databases

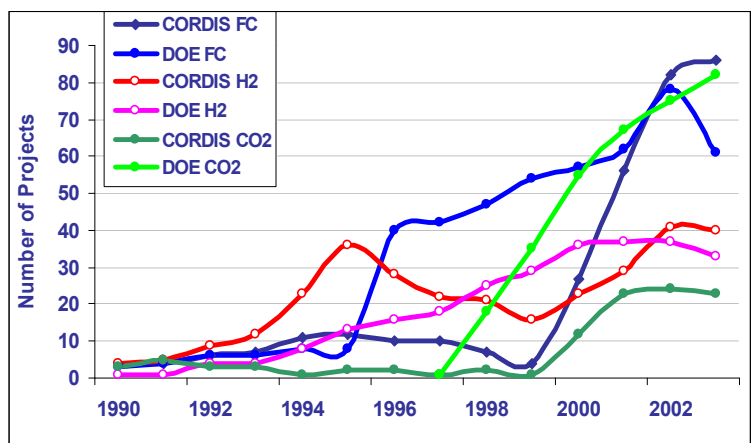
Data comparison and compatibility treatment are the keystones for the development of Public and Private R&D regarding Hydrogen, Fuel Cells and Carbon Sequestration. In absence of detailed energy technologies in IEA databases an endeavour has been performed through CORDIS and DOE energy programs databases in order to develop comparable treatment of Public and Private R&D database regarding Hydrogen, Fuel Cells and Carbon Sequestration. These databases also provide some information on BERD as most projects are Public-Private. A further refinement of BERD may be derived from an on-going study on patents.

In order to use these databases, an important preliminary work had to be carried out. At the beginning a codification of projects according to the set of CASCADE-MINTS technologies was needed. Then the treatment of EU/DOE multi-period funding, by year and by technology BERD is calculated as the difference of sum of project costs and public (EU/DOE) funding. The elaboration has been done according the following framework :

Technology	Start Date	End Date	Project Cost	Public Funding	1990	1991	1992			2004
Hydrogen production										
Project 1										
Project 2										
....										
Hydrogen storage										
Project 1										
Project 2										
....										

CORDIS concerns 10116 energy projects with data since 1987 while FERD include 2356 energy projects registered by DOE with data since 1991. Excluding the projects that have no data concerning the project and funding costs, the year by year and by technology structure is presented in the following figure :

Figure B-60 :Number of Projects :



FC have the most important number of projects in both of databases, however CORDIS displays a higher increase of the number of the projects in the last years. CORDIS and FERD have registered comparable number of projects for hydrogen while DOE have 3 times more projects for CCS than CORDIS.

Figure B-61 : Total Project Cost

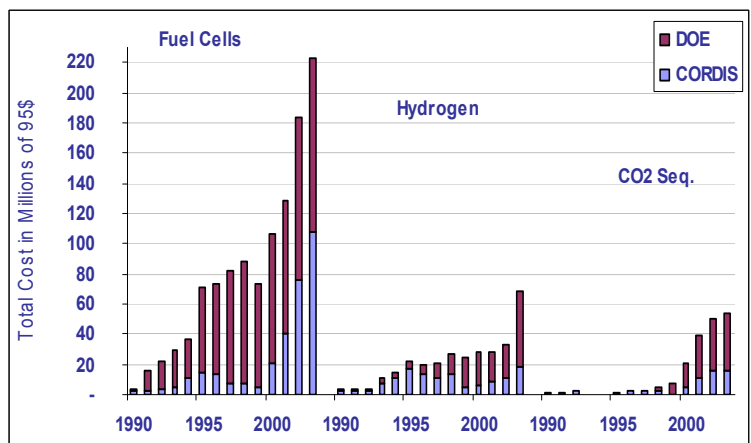


Figure B-62 : Public Funding

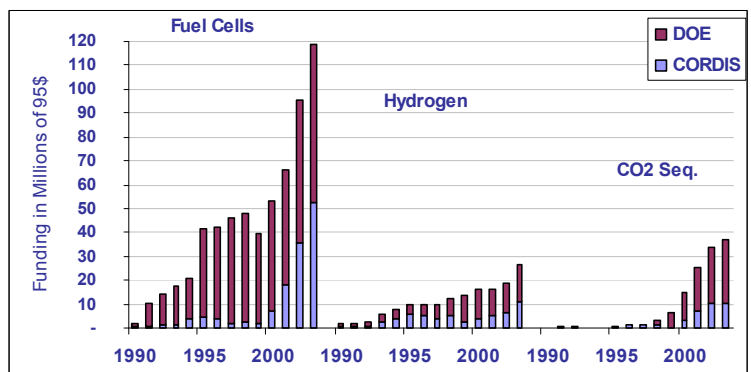
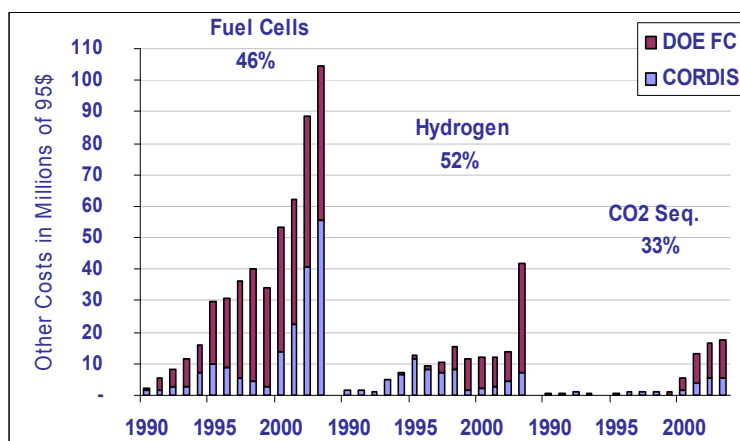


Figure B-63 : Other Costs represent 33 to 52% of the total project costs



Assesment of the approach :

Strong Points : the global consistency of figures is guaranteed by the nature of the data sets, the links between them and the consistency of the treatments.

Weak points :

- Although Cordis is improving the data provided, many problems persist :better key-word research must be available ;
- A better identification of other costs (private, public) is necessary ;
- No identification of Member States' public funding is possible up to now, while this public funding is often important.
- FERD has no more archive data, it is limited only in active projects;
- No equivalent data has been found up to now for Japan

Available data are not sufficiently detailed and the link with individual technologies for modelling is hard to establish. Moreover the structure of ERD projects is changing with increasing networking and Public Private Partnerships. The challenge is to create some degree of consistency while using the different sets of data in accordance with the Two Factor Learning Curves structure, as a minimum pre-requisite for endogenous technology.

Improvements in Cordis and FERD databases and common IEA – EU working in R&D issues may be very important in the future for better disaggregation of R&D by technology and by source of funding.

The energy GERD portfolio, structure and trends by main technology

The following analyses have been produced on the basis of the IEA energy R&D statistics which present the GERD for each member state and about forties technologies or budget categories. The analysis deal with the G7 countries, and in a first step identifies the total budget split into six categories: conservation, renewable, fossil energy, power generation, nuclear, other. Hydrogen, fuel cell and Carbon capture and sequestration

research do not figure in the AIE nomenclature of R&D expenditures separately. The OECD-IEA working group on RD statistics plans to introduce more detail on H2 in 2005 enquiry....

GERD time-series provide a comprehensive view of energy RD, in spite of uncertainties attached to total spending and categories. Triggered by the need for more clarity and comprehensiveness OECD and EUROSTAT agreed to work together to set up a practical framework¹³. There are for eg. quite different interpretations among European IEA member countries of what demonstration should include. The question about the right cut-off point between demonstration and deployment in research projects remains thorny. So far, according to reports from member states 10 – 30% of total research is accounted for demonstration. Consistency should be maintained between Eurostat and IEA data in order to minimise the discrepancy between their definitions.

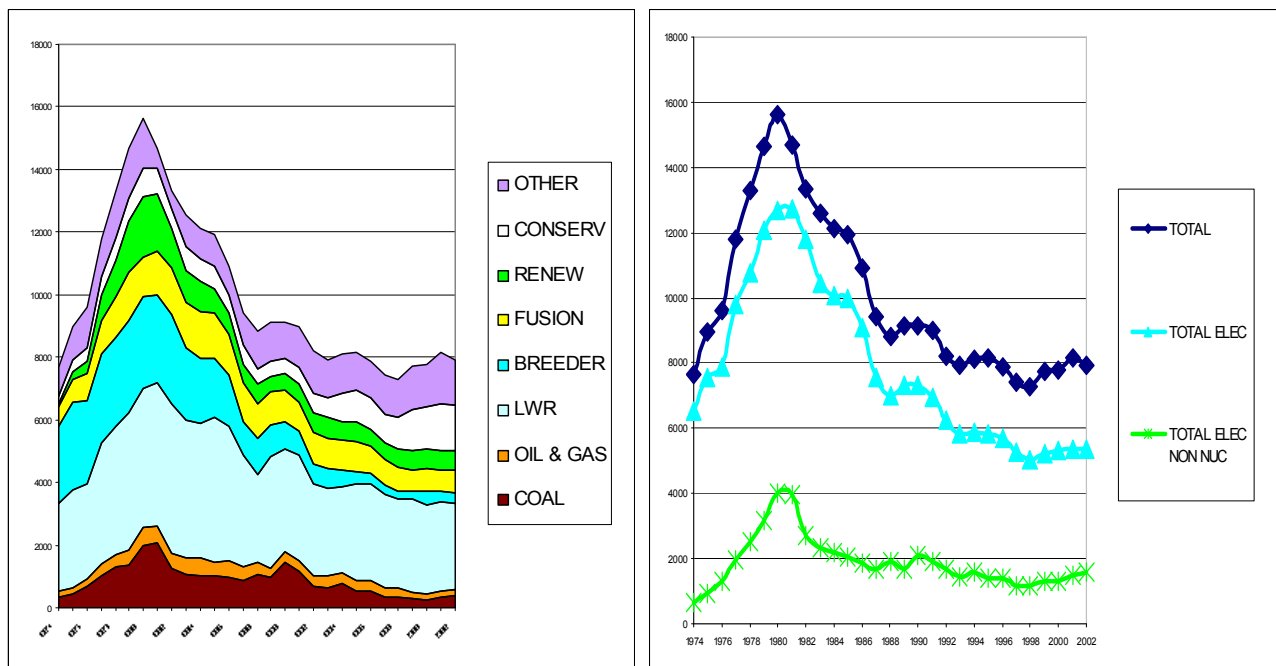
However, taking into account that Hydrogen, fuel cell and Carbon capture and sequestration research are included in “Other” category and using the vast amount of information collected a particular assessment of H₂, FC and CCS R&D (although without a full desegregation among technologies), is included in the AIE GERD time-series.

Yearly GERD of the G7 countries increased drastically in the seventies from less than 6 billions dollars (\$90) in 1974 two more than 12 billions in 1980 as shown in Figure B-62. Of that total, the nuclear technologies (LWR, breeder, fusion...) represent almost two third. From 1980 to 1998, the GERD expense has experienced a continuous decline, with three periods of particularly marked reductions: from 1980 to 1984 for renewable and fossil, from 1986 to 1988 for nuclear and from 1990 to 1993 for almost all categories, except energy conservation and renewables. This leads to a total spending of not more than 8 G\$/yr, with nuclear technologies representing half of the total and less than one fourth for non-nuclear electricity.

¹³ However many questions remain open :

- Should EU-sponsored R&D projects be included in country R&D statistics (in some countries they account for nearly half of the energy R&D expenditures)? How to deal with R&D in connection to education and training? One could at least consider including post-graduate students.
- The new questionnaire should also collect information on the structure of public financing of energy R&D (which public financing organisation provides the money?).
- A new regulation by the EC will form the new legal framework for action. Countries will have to deliver R&D data, but only down to chapter level (one figure for energy). Despite the clear relationship to R&D, market deployment is kept out of R&D statistics.
- A big update of the questionnaire would destroy the comparability of the IEA data series in time.
- Frascati manual recommends to exclude demonstration from research expenditure while IEA includes it. The IEA will continue to include demonstration, member states will be asked to indicate separate figures on group level. Demonstration is currently treated very differently among member states and despite existing rules some of them don't indicate demo figures at all. Thus it seems unlikely that stricter obligations would be accepted.
- Another discussion is the treatment of multi-annual projects. The practice in the countries is not harmonised, while Sweden distributes the budget over the number of project years (for the IEA data), other countries assign it to the first year.
- Many countries do not retrospectively change budget data into expenditures.

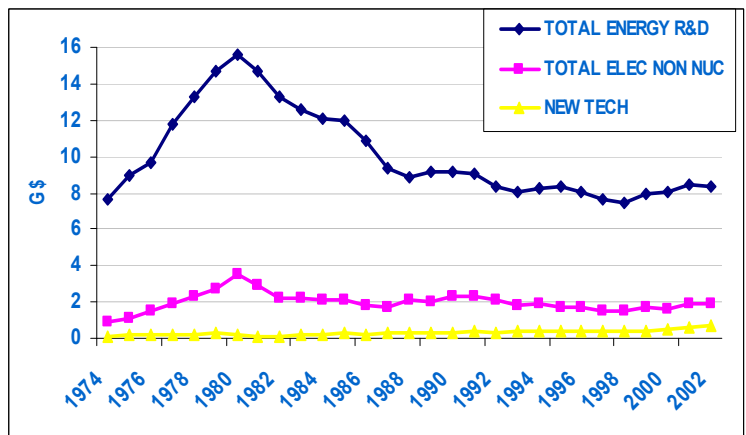
Figure B-64: Energy GERD of the G7 countries by main category (10⁶ \$95)



Source: from IEA Energy R&D statistics

New technologies are growing from zero to less than 5% of total public energy R&D budget.

Figure B-65 :Government Energy RD



Taking into account the available information we have estimated the following world public and private R&D expenditures for Hydrogen, SFC, MFC, FCV and CCS technologies.

Figure B-66 : Public R&D expenditure database

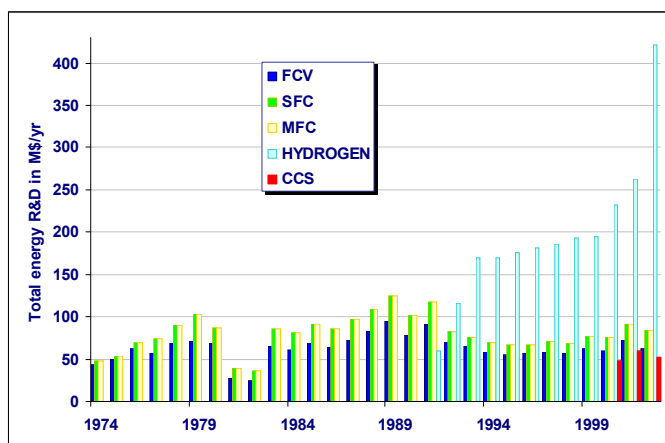
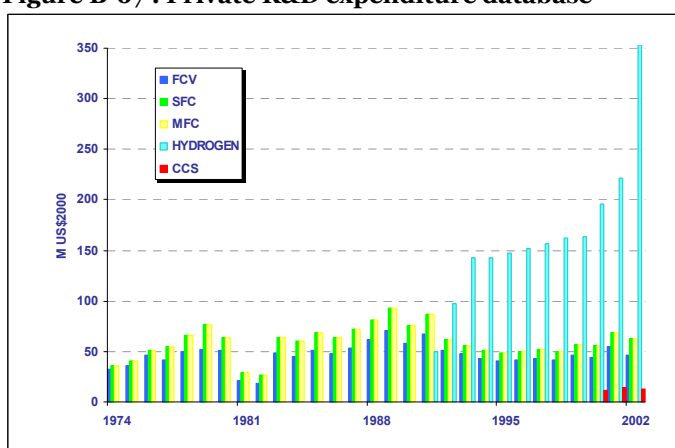


Figure B-67 : Private R&D expenditure database

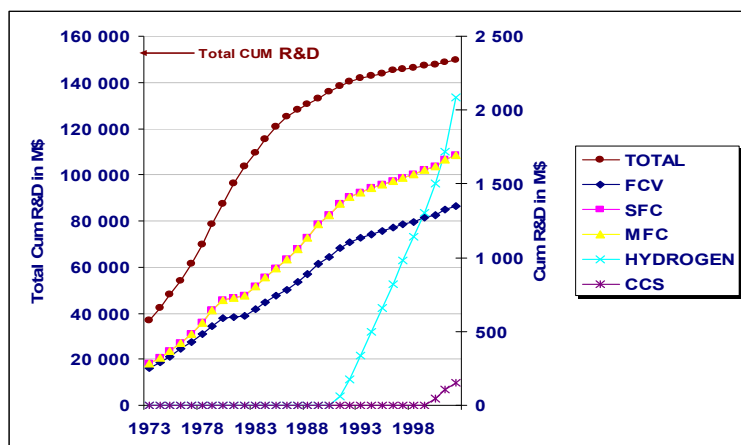


Cumulative GERD as a proxy for the stock of knowledge

In order to explain technology dynamics and improvements, it is also relevant to refer to cumulative R&D spending, considered as a proxy variable for the accumulated stock of scientific and technological knowledge gained from basic research. Two methodological difficulties arise when assessing this variable: the first one relates to the initial value of cumulative research and the second one to the necessity of taking into account a “scrapping rate” for technological. As concerns initial cumulative research, it has been assumed in this analysis that R&D expenses have increased linearly between a hypothetical starting year 1974, the first date with real data for hydrogen and fuel cells found in literature. By lack empirical indications for the energy technologies and for the simplicity of the analysis, the “scrapping rate” has been taken 3%.

The profiles of cumulative research by main technology category, in Figure B-68 show that total cumulative R&D spending rises at 150 billions \$2000 in 2002, while cumulative GERD for Hydrogen and related technologies represent only 7 billions \$2000 in 2002, although it increases very rapidly by the end of the period.

Figure B-68: Cumulative GERD for Hydrogen and related technologies (106 \$95)



Conclusion

This survey shows basic needs to improve energy R&D statistics. Particularly it is necessary to have more disaggregated nomenclature of energy R&D statistics and improvement of the data reliability and comparability.

C. Model Extensions to represent Hydrogen Economy Configurations

C.1 Modeling Technology Dynamics: Basic Tools

C.1.1 Spillovers

[by K. Smekens and H. Rösler (ECN)]

Introduction

This chapter describes the establishment of the technology cluster matrix for modeling purposes in the Cascade Mints project. This technology matrix is used for modeling technology spill-over and learning effects, which are included in the some of the models participating in this project. Technology learning and technology cluster matrices are extensively treated in the TEEM, SAPIENT and SAPIENTIA projects, see for instance (Seebregts et al, 1999).

Briefly, a technology cluster is the group of technologies that share a common component. A technology can belong to different clusters when it is composed of different components, e.g. a natural gas combined cycle (NGCC) is part of the clusters gas turbine, recovery boiler and steam turbine. The common component or so called key-component is assumed to be the learning technology and each component has its own learning

curve specifications and costs (or ETL costs). For modeling purposes, investments in technologies consist of the corresponding investments in the learning components present in this technology and costs of non-learning components, the so called non-ETL cost. These latter costs can be constant or variable over time, but are exogenously determined. The investments in the learning technologies are distributed through a capacity factor, which is the link between the learning component and the technology. For example, the power capacity of a NGCC is for 67% attributable to the gas turbine and for 33% to the steam turbine. This means that key component entry in the cluster matrix for the gas turbine in a NGCC is 0.67 and the steam turbine entry is 0.33.

Using this approach, the technologies described in the D1.1 report by DLR (ref B.1) have been split up component by component. The resulting cluster matrices are presented in this chapter.

Fuel Cell technologies

Stationary applications

The Information Base on Fuel Cells and Hydrogen Technology Options (ref B.1) identifies different types of fuels cells that can, depending on the type of fuel cell, be used in fuel cell systems from small scale applications on household size to large scale industrial CHP plants.

In Table C-1 the characteristics of the four key-components are given. Initial investment cost is derived from Table C-1 from (ref B.1), whereas the initial installed capacities in 2000 are taken from Table B-84 in the Working paper for Task B.2.1 (ref B.2.1). The progress ratios have been taken from the SAPIENTIA project. Since large scale applications of CHP are combined with a gas turbine or and steam turbine and both technologies can also be seen as learning components these are also considered here. Data for the gas turbine and steam turbine come from the SAPIENTIA project (Martinus et al, 2005).

Table C-1 Specifications key-components for stationary H2 and FC end-use technologies

	PAFC	PEMFC	Reformer stat. PEMFC	forMCFC	SOFC	Gas turbine	Steam turbine
Initial Investment cost [€2000/kWe]	1115	2500	1000	3600	3600	420	300
Progress ratio	0.80	0.80	0.80	0.80	0.80	0.87	0.99
Initial cumulative capacity [MWe]	41.25	1.16	1.16	3.45	0.86	31900	250000

The cluster matrix in Table C-2 describes the cost composition of different fuel cell systems into the ETL costs of the key-components and the non-ETL cost part. Costs provided for the ETL part, are only given for the first year available since ETL costs for future years are scenario dependent. These future model dependent costs are mentioned in the table by MR (Model Result). The total costs for future years are also not given, they exist of an estimated non-ETL part and the results of the learning costs for the fuel cell multiplied by the factor in the matrix. This factor takes into account the fact that fuel stacks have a shorter lifetime than the technology application as such, e.g. 2 versus 15 years for a PEMFC in residential application, implying that during the lifetime of the technology, the stack needs to be replaced $15/2=7.5$ times. The costs of the replacements over the life time of the whole system are included in the initial investment cost of the

application when it is installed. This may not correspond completely with reality and lead to an overemphasis of the initial investment, but this is a well accepted approach in large energy system modelling with endogenised learning (TEEM, Sapien).

As an example from Table C-2, the costs of a 1 kWe residential PEMFC is reported in (ref B.1) to be 11500 €/kWe. In the cluster matrix the component cost is 2500 €/kWe for the FC, 1000 € for the reformer and the non-ETL cost is 8000 €/kWe, summing up to the same value. Now, seen the shorter lifetime of the stack (2 years compared to 15 years), 7.5 replacements are needed, so instead of 2500 €, $7.5 \times 2500 = 18750$ € for the stack and 1000 € for the reformer are added to the non-ETL cost, summing up to 27750 €/kWe for a system that will last 15 years. For technologies that use a combination of fuel cells and gas or steam turbine, the capacity share of each is also incorporated in this factor. E.g. the 1 MWe MCFC system has 800 kWe MCFC capacity and 200 kWe of gas turbine capacity. Assuming that the gas turbine has the same life time as the system, the cluster matrix entry is 0.2 for the gas turbine and as explained above with the shorter life time of the FC, an entry of $15/5 \times 0.8 = 2.4$ for the MCFC.

For modeling purposes, as (ref B.1) contains different data for different years, it is advisable to work with generations of technologies, in this case two generations are obvious, one at the initial year (2000 or 2010) and one for 2030. Each modeller also has to judge whether to allow for technology jumps, i.e. waiting for the more efficient technology (with lower non-ETL costs) to become available without having invested in the more expensive and less efficient first applications. In practice this would mean to go for the 2030 option without deploying the 2000/2010 option first. Allowing this would make the component artificially more attractive since the model would ignore the first expensive and technologically immature applications.

The PAFC fuel cell application could be left out of the model because (ref B.1) states that there will be probably no further research or implementation of the kind of fuel cell. Its development happened in the past so it could be taken up in the historical experience and capacity built-up.

Table C-2 Cluster matrix for stationary H2 and fuel cell end-use technologies

Capacity	Generation	Investment cost (DLR)	PAFC	PEMFC	Reformer stat. PEMFC	forMCFC	SOFC	Gas turbine	Steam turbine	Non-ETL costs	Total model investment cost
	[year]	[€2000/kWe]	[kW/kW]	[kW/kW]	[kW/kW]	[kW/kW]	[kW/kW]	[kW/kW]	[kW/kW]	[€2000/kWe]	[€2000/kWe]
Residential heat appliance	PEMFC	1 kW	2000	7.5	1					8,000	27,750
			2030	2	1					1,200	MR*
			2050	2	1					150	MR
	5 kW	11,500		7.5	1					8,000	19750
			2030	2	1					1,200	MR
Small CHP LT PEMFC			2050	2	1					150	MR
	250 kW	14,000		7.5						11,500	18750
			2030	2						1,500	MR
Small CHP LT PAFC	200 kW	4,500								3,350	5,580
			2030	2						3,350	MR
Small CHP HT MCFC	250 kW	12,000				5				8,400	26,400
			2030			2				1,050	MR
Large CHP HT MCFC with steam turbine 2010	1 MW	12,000				2.4			0.2	9,000	17,700
			2030			2			0.2	1,100	MR
Residential heat appliance SOFC	1 kW	10,000					15			8,400	62,400
			2030				2			800	MR
Small CHP HT SOFC	250 kW						3			14,000	24,800
			2030				2			3,900	MR
Large CHP HT SOFC with gas turbine	300 kW							0.2		15,000	23,724
	500 kW						2	0.2		4,000	MR

*MR: model resul

A more generic approach to stationary fuel cell application would reduce this matrix to a few technologies. The principle is the same, but with less detail, e.g. no specific fuel cells. It is up to the different model teams to decide how much detail they introduce in their models.

For this generic approach, it is also assumed that the Balance of System (BoS) cost will be endogenised, having the same learning rate as the fuel cell. In order to balance the more expensive early applications, they receive a BoS factor higher than 1. It is expected that this factor will become 1 for later applications. The fact that also the BoS is learning, means that the applications are built up exclusively from learning components.

In Table C-3 the characteristics of more generic key-components are given. The reduced technology matrix considering only three stationary fuel cell application is given in Table C-5.

Table C-3 Specifications for generic stationary H₂ and FC end-use technologies

	FC	Reformer	BoS FC	Gas turbine
Initial investment costs [€2000/kWe]	3500	1000	6500	420
Progress ratio	0.8	0.8	0.8	0.87
Initial cumulative capacity [MWe]	46.72	46.72	46.72	31900

Mobile applications

While the description of stationary applications is quite extensive, for automotive applications only private cars are mentioned in (ref B.1), although FC applications can appear in other transport modes as well. These are already mentioned in the matrix assuming also PEMFC for propulsion and with an estimated capacity and costs (taken from material from the ECN contribution to the SAPIENTIA project). Apparently only direct H₂ fuelled transports are foreseen, no on board reforming of liquid hydro-carbons is mentioned.

The key-components used in mobile applications are described in Table C-4. Data for PEMFC have been taken from (ref B.1) and (ref B.2.1), while liquid H₂ mobile storage is further described in “**Hydrogen storage options and transport structures**” below.

Table C-6 gives the technology matrix for mobile use of fuel cells and direct hydrogen end-use in an internal combustion engine.

Table C-4 Specifications key-components for mobile H₂ and FC end-use technologies

	PEMFC	Reformer for mobile PEMFC	Gaseous H ₂ mobile storage tank	Liquid H ₂ mobile storage tank	ICE otto/ diesel
Initial investment cost	2500 €/kW	130 €/kW	3 €/GJ	6.5 €/GJ	45/67 €/kW
Progress ratio	0.8	0.8			0.82/ 0.90
Initial cumulative capacity	1.16 MWe	0.1 MWe			5.00E+08

Table C-5 Cluster matrix for generic stationary H2 and FC end use technologies

	Capacity	Generation [year]	FC [kW/kW]	Reformer [kW/kW]	BoS FC [kW/kW]	Gas turbine [kW/kW]
Residential heat appliance FC	1-5 kW _e	2000 2030	7.5 2	1 1	1 1	
CHP FC	200-500 kW _e	2000 2030	3 2		1.27 1	
CHP FC HT pressurised	200-5000 kW _e	2000 2030	2.4 1.6		2 1	0.2 0.2

Table C-6 Cluster matrix for mobile H2 and FC end-use technologies

	PEMFC	Reformer for mobile PEMFC	Gaseous H2 tank	mobile storage	Liquid H2	ICE otto/ diesel
	[MW/1000 vehicles]	[MW/1000 vehicles]	[TJ/1000 vehicles]	[TJ/1000 vehicles]	[MW/1000 vehicles]	
FC medium private car	50		600			
FC medium private car with reformer	50	50				
FC van	75		800			
FC bus	150					
FC truck	400					
FC ship	900				1 900 000	
H2 ICE dual fuel otto private car					600	127.5*
H2 ICE dual fuel diesel private car					600	105

* assumed 50 % higher than standard ICE (see ref B.1)

Hydrogen production

The hydrogen production technologies are described in (ref B.1), with a focus on already known technologies. Zero emission concepts are not treated although for long term modelling, these could play a role and they could combine learning components like a gasifier and SOFC which are already present in some models. As no data are available yet, they are also not included in the clustering matrix, which is given in Table C-9.

Not all production technologies are suited for clustering, this does not mean however that they cannot have learning effects. However, the establishment of single technology learning curves falls outside this task. Some of them are mentioned in the table, with an ETL cost of zero because no specific learning component was identified.

The technology data of the H₂ production technologies mentioned in Table 3.15 of (ref B.1) were converted to more common units for H₂ production, namely GJ instead of kW. The conversion factors used are given in Table C-7.

Table C-7 Conversion factors

kW to GJ	8760 x 3600 / 1E6	31.536
Nm ³ /h to GJ/year	10.79 x 8760 /1000	94.520
GJ to MWh	1/3.6	0.278

This means that for instance cost data originally expressed in €2000/kWe are divided by 31.536 in order to present them in €2000/GJ. Values in €/GJ are the same as for M€/PJ.

Table C-8 presents the key components used in hydrogen production. Data for technologies other than fuel cell are mainly based on data collected in the SAPIENTIA project (Martinus et al, 2005). Table C-9 gives the clustering matrix for hydrogen production technologies.

Table C-8 Specification key-components

	PEMFC	Steam turbine	Electrolyser	SMR	CCS	Gasifier	Wind turbine	Nuclear reactor
Initial investment costs [€/kWe]	2500	300	600	315	430	800	1100	1430
Progress ratio	0.8	0.99	0.8	0.98	0.9	0.9	0.9	0.99
Initial cumulative capacity [MWe]	1.16	250000	23000	160000	210	1000	5000	118000

In Table C-9, the H₂ production technologies are expressed in GJ (or PJ) production capacity per year and the learning components which are spilling over from the power sector are expressed in GWe, the entries in the cluster matrix may require some explanation. Over a one year period, an electrolyser of 1 kWe could theoretically produce 8760 kWh H₂, which is equal to 31.536 GJ H₂. This means that in order to produce 1 GJ H₂, only 1/31.536 or 0.032 kWe electrolyser would be needed.

For the CCS components, in addition to the kWe to GJ conversion, another factor has been added to take into account that the capture technologies do not capture 100% of the CO₂ from the flue or synthetic gas, for gas an capture efficiency of 90% has been assumed, for coal 88%.

Furthermore, a couple of the gasification production technologies have an additional output of electricity fed by superheated steam from the hot tail gases from the absorber. This means that the power output, originally expressed in MWe per plant has to be converted as kWe per GJ H₂ production. Table 3.8 in (ref B.1) gives the plant data on which the cluster matrix entries for the three technologies are based: e.g. 150,000 Nm³/h H₂ output from a coal gasification plant corresponds to an annual production of 14.2 PJ H₂ (or 14.2 million GJ) while electricity output amounts to 20,000 kWe, this results in a matrix entry of 20,000/14.2 million kWe/GJ or 0.001 for the steam turbine component for this particular H₂ production plant.

Table C-9 Cluster-matrix for H2 production technologies

	Available from	Total costs		PEMFC	Steam turbine	Electrolyser	SMR	CCS	Gasifier	Wind turbine	Nuclear reactor	Non-ETL costs
		[M€ / PJ/a]	[M€ / PJ/a]		[GW / PJ/a]	[GW / PJ/a]	[GW / PJ/a]	[GW / PJ/a]	[GW / PJ/a]	[GW / PJ/a]	[GW / PJ/a]	[M€ / PJ/a]
Small, local electrolyser	2000	27				0.032						8
Large electrolyser	2000	22				0.032						3
PEM based electrolyser	2000	325	0.1268									8
HTS based electrolyser	2020	40										40
SMR small, local	2000	22					0.032					12
SMR large	2000	11					0.032					1
Direct solar	2020	12										12
SMR small with CO2 capture	2000	372)					0.032	0.035				121)
SMR large with CO2 capture	2000	262)					0.032	0.035				11)
Direct solar with CO2 capture	2020	272)						0.035				121)
Coal gasification	2000	28			0.001				0.032			2
Coal gasification HSMR	2030	28			0.001				0.032			2
Coal gasification with CO2 capture	2020	432)			0.002			0.036	0.032			21)
Biomass gasification	2010	84							0.032			59
Biomass gasification with CO2 capture	2020	1002)						0.036	0.032			591)
Wind + electrolysis	2020	632)				0.032				0.032		8
Nuclear + electrolysis	2020	762)				0.032					0.032	11
Biomass pyrolysis	2030	17										17

1) Same Non-ETL costs as technology without CO2 capture. 2) Non-ETL part + ETL part

Hydrogen storage options and transport structures

Storage

H2 storage can occur in several places in the hydrogen chain, there is the larger scale intertemporal storage between e.g. liquefaction and distribution or large scale underground storage as part of a H2 dispatching system. Besides these options, H2 storage is also necessary in filling stations and in vehicles. Most storage options are assumed to be stand alone technologies given the large difference in size. Therefore, no cluster matrix has been developed. However, for local storage (filling stations and vehicles) some spill-over can be included. The costs for liquid H2 storage as given in (ref B.1) have been interpolated as illustrated in Figure C-1. For the storage capacities used in the technologies to be modeled, the left hand side of the curve is to be used. For the capacities used in filling stations, the formula would suggest an average cost of about 1000 €/GJ, for a single GJ (a car has a storage capacity of 0.6 GJ) the cost would be around 6500 €/GJ.

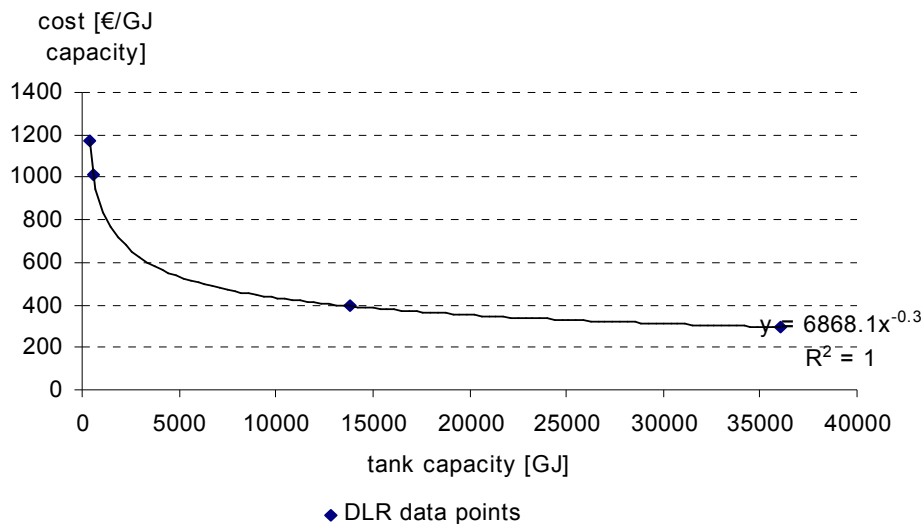


Figure C-1 Curve for liquid H2 storage tanks based on data points from (ref B.1)

Table C-10 presents the key components for H2 storage technologies.

Table C-10 Specifications key-components H2 storage

	Gaseous H2 storage	Liquid H2 storage
Initial investment cost [€/GJ]	25,000	1,000
Progress ratio	0.90	0.90
Initial cumulative capacity [TJ]	1	0.01

In the information base (ref B.1) a number of filling stations types are distinguished, both in scale (small, medium and large) as well as is fuel type (gaseous, liquid or liquid-to-gas). For each of these types, the storage component is given below, together with the station costs. The non-ETL part is taken to be the difference between the overall costs as given by DLR and the costs of the learning storage component(s). As

mentioned above, since an average cost for storage is assumed, the calculated costs for the storage are slightly underestimated for smaller stations, but slightly overestimated for large stations: for a small liquid H2 filling station the given costs are 0.350 M€ for the storage whereas the calculated value is 0.240 M€.

Table C-11 Cluster matrix for H2 filling station

	Total costs [M€/filling station]	Gaseous storage [GJ filling station]	H2Liquid storage storage/-[GJ filling station]	H2Non-ETL costs storage/-[M€/filling station]
Small filling stations gas H2	0.560	4.6		0.446
Medium filling stations gas H2	1.020	9		0.795
Large filling stations gas H2	1.820	18		1.370
Small filling stations liquid H2	0.623		240	0.383
Medium filling stations liquid H2	1.003		500	0.503
Large filling stations liquid H2	1.672		1000	0.672
Small filling stations liquid-to-gas H2	0.912	4.6	240	0.557
Medium filling stations liquid-to-gas H2	1.535	9	500	0.810
Large filling stations liquid-to-gas H2	2.675	18	1000	1.225

H2 transportation

For H2 transport, two major options appear from the document: pipelines and truck transport of H2. For pipelines, 3 categories are elaborated: a local network, a distribution network and a large connection Africa-Europe. The latter falls out of scale to be useful for learning effects, only 1 or 2 of such connections would be exploited. For the other two, the learning effects actually take place in the pipeline manufacturing industry, not as such in the laying. Furthermore, the differences in distance and flow for both networks make it hard to model them with a common component. The pipeline options could be modeled as separate learning technologies, i.e. without spill-over. H2 transport by truck can occur in liquid or gaseous form. For both options, the cluster matrix is given in Table C-13. The overall costs are slightly different from what was quoted in (ref B.1) because in the cluster matrix below, the diesel engine is also included as learning component and becomes hence part of the ETL cost.

Table C-12 Specifications key-components H2 truck transport

	Mobile storage	gaseous H2 Liquid H2 storage	Diesel engine
Initial investment cost	3000 €/GJ	1000 €/GJ	67 €/kW
Progress ratio	0.90	0.90	0.93
Initial cumulative capacity	1 TJ	0.01 TJ	500000 GW

The storage component of both trucks, liquid and gaseous, is determined from the net load capacity which is 3370 kg liquid H2 and 250 kg gaseous H2 resp. per truck. From previous projects, the engine capacity of a generic truck is estimated to be 400 kW (Martinus et al, 2005).

Table C-13 Cluster matrix for H2 transport by truck

	Total investment costs [k€/truck]	Mobile gaseous H2 storage [GJ / truck]	Liquid H2 storage [GJ / truck]	Diesel engine [kW/truck]	Non-ETL cost [k€/truck]
Liquid H2 truck	511.2		404.4	400	80
Gaseous H2 truck	196.8	30		400	80

C.1.2 Two Factor Learning Curves specification and estimation

[by N. Kouvaritakis and V. Panos (ICCS-NTUA)]

This section presents the specification and estimation of the learning curve equations for endogenising as much as possible the technological progress in the TECHPOL database.

Introduction

In determining the cost and technical performance of technologies the learning by experience has already been recognised as an important factor in traditional technology dynamics. However, it is also widely accepted that the R&D can contribute directly to technological improving. In order to address the main questions of R&D efficacy in the penetration of hydrogen in the energy system, it is clear that R&D must figure explicitly in the specification of the technology dynamics. For this reason two factor learning curve mechanisms have been adopted, which recognise learning attributed to research effort (learning-by-research) and learning arising from the experience gained through technology uptake (learning-by-doing).

The work in CASCADE MINTS was based on the previous experience from the SAPIENTIA project. In the context of the project, two factor learning curves have been estimated for the hydrogen related technologies (supply, storage, distribution and end-use), the CO₂ carbon capture filter (post-combustion and pre-combustion) and for passenger private cars. For the electricity and steam production technologies the two factor learning curves used are those from the SAPIENTIA project Table C-14 summarises the technologies for which two factor learning curves have been estimated.

The main aim of the current specification of the two factor learning curves was to capture with as few parameters as possible a set of desired properties, including:

- Endogenisation of as much of the technological progress reported in the CASCADE MINTS common information base as possible, by incorporating both learning by experience and learning by research.
- Constraint the learning mechanism to technical possibilities as they emerge from perspective analysis. This means that the progress of a particular technical economic characteristic (such as the capital cost) cannot go beyond a notional absolute limit, which in the current document is called “floor”.
- Incorporate “clustering” as much as possible, which is essential for a rapid modelling transformation of energy system. In most cases, the “clustering” was performed by analysing the deliverable D1.1 (ref B.1). However, when there was no clear indication from D1.1 (ref B.1) on how to form clusters of technologies, “weak clustering” was introduced (see section “The notion of “weak” clustering”)

Table C-14: Technologies for which TFLC equations have been estimated in the context of CASCADE MINTS

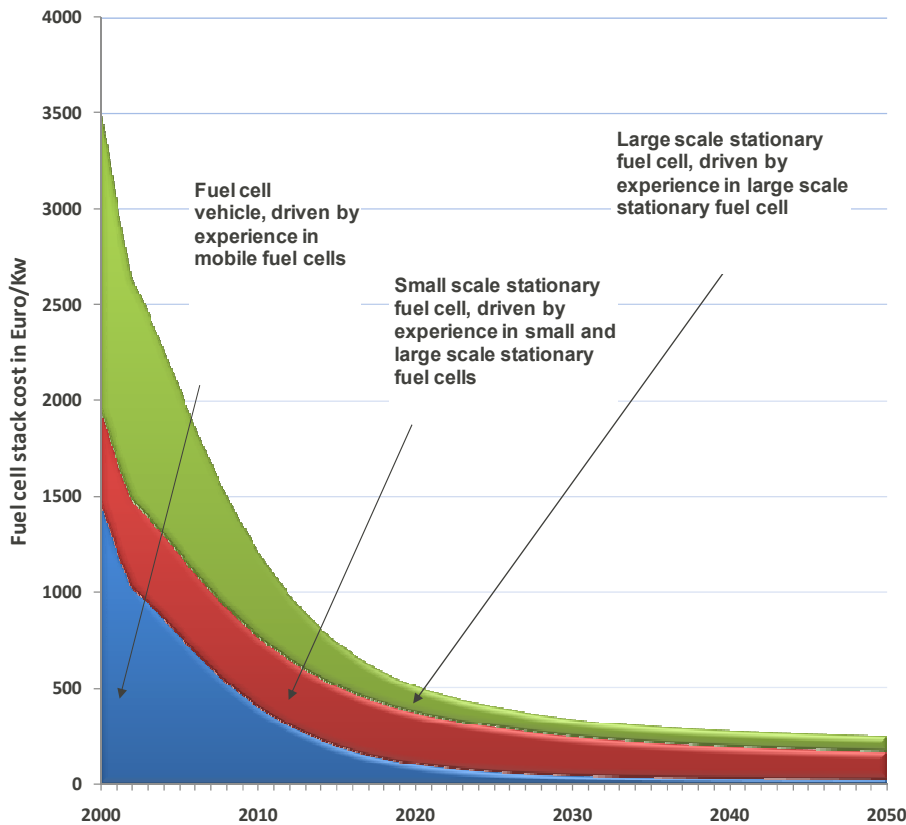
Hydrogen production technologies Gas Steam Reforming Solar Methane Reforming Coal Gasification Gasifier component Biomass Gasification (Small scale) Biomass Gasification (Large scale) Biomass Pyrolysis Biomass Handling component High Temperature Thermochemical cycle component Large Scale Electrolyzer Oil Partial Oxidation	Hydrogen infrastructure Liquid hydrogen on board storage Gaseous hydrogen on board storage Liquid hydrogen storage vessel in trucks Gaseous hydrogen storage vessel in trucks Liquid hydrogen storage in service stations Gaseous hydrogen storage in service stations Large scale liquid hydrogen storage Low pressure pipelines Other service stations costs not related to storage
Fuel cells Mobile fuel cells with/without reformer Large scale stationary fuel cells with/without reformer Small scale stationary fuel cells with/without reformer	CO2 capture technologies Post combustion CO2 capture in Gas Turbine Combined Cycle Post combustion CO2 capture in Supercritical coal Pre combustion CO2 capture in Coal Gasification for electricity production Pre combustion CO2 capture for hydrogen combustion
Passenger cars Gasoline ICE cars Hybrid cars Hydrogen ICE cars Pure electric vehicles	Other technologies On board reformer Small scale reformer in stationary fuel cells Batteries for electric motors

A particular problem that emerged during the estimation of the TFLC equations was the unavailability of historical data on capacity installation for the majority of the technologies. The only historical data used in the estimation process were the historical R&D expenditures and base year technology performance as reported in the common information base. The installed equipment was derived from PROMETHEUS (in deterministic mode) baseline, using the characterisation and the prospects of the technologies from the common information base as well as projections of R&D expenditures technology as they elaborated by E3M-Lab. In order to derive the stochastic properties of the estimators, the experience gained from other similar TFLC estimations in the SAPIENTIA project was used. As a consequence the process adopted is better characterised as calibration rather than estimation and its results are highly dependent on a host of assumptions related to the technology performance projections and PROMETHEUS model results on technology uptake.

The notion of “weak” clustering

This form of clustering does not identify individual components, which learn separately (eg. steam turbines, boilers, gasifiers, etc.) but it uses a whole technology as the basis for other similar (and probably more complex) technologies. The TFLC equations for technologies, which are “structured” from the basic technology, capture the additional, specific to the technology only, progress of a particular technical-economic characteristic. This connection is identified as “weak” because the largest part of the improvement of the technologies belonging to such a cluster is specific to each technology and independent of the progress of the basic technology.

Figure C-2: Illustration of “weak” clustering in fuel cell stack cost



An example of “weak” clustering is presented in Figure C-2, which illustrates the case of the capital cost of mobile and stationary fuel cell stacks. The basic technology in this “weak” cluster is the mobile fuel cells stack, the cost of which is driven by the experience in mobile fuel cells and the common R&D expenditures to all fuel cells. The two factor learning curve for the small scale stationary fuel cell stack operates at the “additional” cost, which is driven by the experience in small and large scale stationary fuel cells and the common R&D expenditures to all fuel cells. The “additional” cost is defined as the difference between the small scale fuel cells stack cost and the mobile fuel cells stack cost. Finally the additional cost of large scale fuel cells stack is driven by experience in large scale fuel cells and the common R&D expenditures to all fuel cells.

This “weak” cluster ensures that the cost reduction of mobile fuel cells stack will pass through to the small scale stationary fuel cells and finally to the large scale stationary fuel cells. However, despite the diffusion of learning, the connection is weak in the sense that the largest part of the progress in the cost of each stack type is independent of the other types.

General algebraic specification of a two factor learning curve

The general algebraic specification is presented for the capital cost of a technology, but it is applied to all technical-economic characteristics. Let i be a technology and $C_{i,t}$ be the capital cost of the technology at time t . Let $K_{i,t}$ be the installed capacity of technology i at time t and $R_{i,t}$ be the cumulative R&D (both government

and business energy R&D) spent on technology i at time t . Then the general formulation of the TFLC equation is:

$$C_{i,t} = C_{i,t-1} \left(\frac{cl_{i,t-1}}{cl_{i,t-2}} \right)^{a_{i,t} \cdot caplm_{i,t}} \cdot \left(\frac{R_{i,t-1}}{R_{i,t-2}} \right)^{b_{i,t} \cdot rdlm_{i,t}} \quad (1)$$

$$cl_{i,t} = \sum_{j=1}^{n_i} w_{i,j} \cdot K_{j,t} \quad (2)$$

$$y_{i,t} = \frac{-floor_i}{|floor_i - C_{i,t-1}| + z} \quad (3)$$

$$a_{i,t} = capelfac_i \cdot e^{s_i \cdot y_{i,t}} \cdot d_{i,t} \quad (4)$$

$$b_{i,t} = rdelfac_i \cdot e^{s_i \cdot y_{i,t}} \cdot d_{i,t} \quad (5)$$

$$d_{i,t} = \begin{cases} 0, & C_{i,t-1} < floor_i \\ 1, & C_{i,t-1} \geq floor_i \end{cases} \quad (6)$$

$$caplm_{i,t} = \begin{cases} 0, & K_{i,t-1} \leq caplmt_i \\ 1, & K_{i,t-1} > caplmt_i \end{cases} \quad (7)$$

$$rdlm_{i,t} = \begin{cases} 0, & R_{i,t-1} \leq rdlmt_i \\ 1, & R_{i,t-1} > rdlmt_i \end{cases} \quad (8)$$

In the above specification, $cl_{i,t}$ is the cluster associated to technology i and n_i is the number of technologies participating in cluster cl . Each technology has a specific weight in the cluster, denoted with $w_{i,j}$, where j are the technologies participating in cluster associated with technology i . Usually the weights are equal to 1. Equation (2) calculates the total installations of all technologies participating in cluster cl .

The estimated learning parameters are denoted as $capelfac_i$ for learning by experience and $rdelfac_i$ for learning by research (equations (4) and (5)). However, as the capital cost approaches asymptotically the floor cost, these parameters have to be reduced in order to slow down the learning process. Thus, the learning parameters applied in equation (1) are the reduced parameters $a_{i,t}$ for learning by experience and $b_{i,t}$ for learning by research.

The mechanism for reducing the estimated parameters and slowing down the learning process is implemented in equations (3)-(6). Equation (3) calculates the variables $y_{i,t}$, which represents the “distance” of the capital cost of the technology i from the corresponding floor $floor_i$, and it is used in equations (4) and

(5). The constant z in equation (3) is introduced in order to avoid zero denominators. This constant is equal to 1 for all technical-economic characteristics except efficiencies and efficiencies losses (for CO₂ capture technologies) in which it is equal to 0.1.

The learning process is not activated below a threshold either on capacity or on cumulative R&D. This assumption is necessary for the new, and currently non-existent, technologies in order to avoid learning when only demonstration versions of these technologies exist in the first years of the forecast. In this way, the instability in learning arising from an excessive reliance on initial conditions (data and forecasts) is avoided. The limits are denoted as $caplmt_i$ and $rdlmt_i$ for learning by experience and learning by research respectively and they are used in equations (7)-(8) which calculate the corresponding binary variables $caplm_{i,t}$ and $rdlm_{i,t}$ used in equation (1).

Moreover, in order to ensure that the learning process will stop in those cases in which the capital cost is lower than the floor cost, a binary variable $d_{i,t}$ is introduced in equations (4) and (5), which is calculated according to equation (6). Finally, in equations (4)-(5) there is also a saturation coefficient, s_i , which regulates the speed at which saturation is reached.

Technology classification for the Two Factor Learning Curves

In the context of the specification and estimation of the two factor learning curves, the technologies have been classified into clusters, either weak or not. This section presents a brief description of the various clusters identified by taking into account the specificities of the technologies. In the figures of this section, the base component of each cluster is marked using the yellow color.

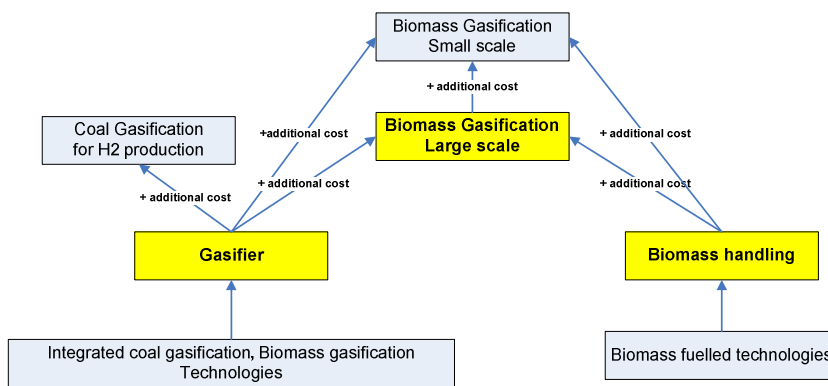
Hydrogen production technologies

For all hydrogen production technologies, two factor learning curves following the formulation (1)-(8) were estimated covering their capital costs, fixed o&m costs and efficiencies. During the estimation process a set of clusters have been formed by taking into account the specificities of the various hydrogen production options as follows:

- Hydrogen production from steam reforming: this weak cluster includes the gas steam reforming and the solar methane reforming technologies. The basic component of this cluster is the gas steam reforming. Two factor learning curves have been estimated for the gas steam reforming and for the specific to solar methane reforming technology technical economic characteristics. For the basic technology, the gas steam reforming, the installed capacity includes also the installations of solar methane reforming. The learning by research elasticity is applied to the specific to each technology R&D expenditures.
- Hydrogen production from gasification: this weak cluster includes all the technologies for hydrogen production based on the gasification process (Figure C-3). Two components are the base technologies for this cluster: the “gasifier” component, which is the base technology for all gasification options and the “biomass handling” component, which is the base technology for all

biomass fuelled technologies. However, these components were not introduced in the TECHPOL database at the first place so their improvement has been derived by extracting information from the common database. Moreover, the R&D expenditures directed to these new components, are formed from the R&D directed to gasification and to biomass fuelled technologies. As in all weak clusters, the learning by experience elasticity for the base components includes the installations of all technologies which depend on these components.

Figure C-3: Weak clustering between coal and biomass gasification for hydrogen production



Hydrogen production from thermochemical cycle process: this is a form of “perfect” cluster, where the technical and economic characteristics of some technologies are directly related to the corresponding characteristics of other technologies. In this cluster, the technical and economic characteristics of the “thermochemical cycle process” component are directly combined with the corresponding characteristics of a solar thermal or a 4th generation nuclear plant for electricity production in order to form the solar high temperature thermochemical cycle and nuclear high temperature thermochemical cycle processes. In this context, two factor learning curves have been estimated only for the “thermochemical cycle” component, using the cumulative installations of solar and nuclear high temperature plants and the sum of their R&D expenditures.

Hydrogen production from electrolysis: this is another form of perfect clustering, where the technical and economic characteristics of the large scale electrolyser are combined with the corresponding characteristics of a nuclear power plant or a wind turbine to form technologies based on hydrogen production from electrolysis using nuclear or wind electricity. Two factor learning curves were estimated only for the large electrolyser, which also can be considered as a stand alone technology for hydrogen production operating with grid electricity.

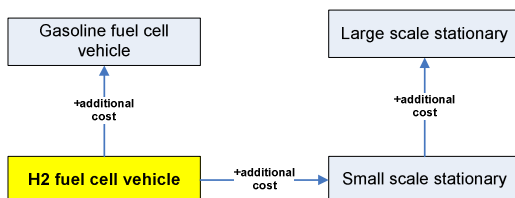
Other hydrogen production options (not clustered to any technology): this group includes the hydrogen production from partial oxidation of oil and biomass pyrolysis options, which cannot be clustered with any of the rest hydrogen production technologies. However, two factor learning curves have been estimated only for oil partial oxidation, since biomass pyrolysis equations have been already estimated in the SAPIENTIA project.

Fuel cell technologies

Since fuel cells are considered to be a key technology for the penetration of hydrogen in energy final demand sectors, effort has been made to endogenise the progress of as many technical-economic characteristics as possible. For this purpose, separate two factor learning curves were estimated for stack and system costs, efficiencies, stack lifetimes, hydrogen storage and reformers. The two factor learning curves are considered both fuel cells for mobile and stationary applications. The R&D expenditures used in the learning by research elasticity is common for all technical economic characteristics either considering stationary or mobile applications. On the other hand, the learning by experience elasticity for the basic technology of a weak cluster is applied to the sum of the cumulative installations of all technologies participating in the cluster, while for the rest of the cluster technologies uses the individual for each technology installations. The clusters for fuel cells are:

Stack costs: the weak cluster for fuel cell stack costs is presented in Figure C-4. The basic technology is the stack used in fuel cell vehicles without onboard reformer. Two factor learning curves were estimated for the basic component and for the additional costs of the rest of the components forming the weak cluster. A property that this scheme has is that in the early stages, where installations are small and the R&D is the main driver for the technological progress, the cluster between mobile and stationary fuel cells is stronger and big improvements in mobile fuel cells are passed on to the stationary varieties. On the other hand, in longer term when mobile fuel cells improve sufficiently, the progress in stationary fuel cells becomes independent. This conforms to the views expressed in deliverable D1.1 (ref B.1).

Figure C-4: Cluster for fuel cells stack cost



System cost: the progress in the system cost between mobile and stationary fuel cells is considered to be independent. For mobile fuel cells, the two factor learning curve for system cost takes into account the stock of fuel cells vehicles. On the other hand, for the stationary fuel cells a weak cluster is formed with the the small scale fuel cells system cost as the base component. Two factor learning curves were estimated for the base component and the additional cost of the large scale stationary fuel cell system.

Reformer cost: the reformers of mobile and small scale stationary fuel cells are considered to be independent. In order to estimate two factor learning curves, the R&D expenditures directed to large scale gas steam reforming were used for the cost reduction of stationary and onboard

reformers. This implies that the only connection between the onboard and stationary reformers is the common R&D expenditures

Stack lifetime: separate two factor learning curves were estimated for the stack lifetime for small scale and large scale stationary applications, assuming no clustering.

Efficiencies: the efficiency of mobile fuel cells is assumed to be improved independently from the efficiency of the stationary applications. In this way, two separate clusters were identified; one for mobile fuel cells and the other for the CHP stationary small or large scale fuel cells. The only connection between these two clusters is the common R&D expenditures, which are used in the two factor learning curve equations. For mobile fuel cells, one two factor learning curve equation was estimated endogenising the improvement of the efficiency of the fuel cell vehicle without reformer; the overhead of the onboard reformer is considered to be constant over the time. On the other hand, since the stationary fuel cells are CHP plants, two separate two factor learning curves were estimated: one for their total efficiency (i.e. taking into account the efficiency for electricity generation and the efficiency for heat production), and another one for electricity generation efficiency. For total efficiency of the stationary applications, a weak cluster was formed. According to the clustering scheme, the small and large scale applications without onsite reformer have the same total efficiency. This efficiency is the basic component of the cluster. The presence of reformer in small scale applications causes a loss of 4% in their total efficiency, while in large scale applications it causes a loss of around 3%. On the other hand, there is no clustering between small and large scale fuel cells for the electricity generation efficiencies. Their improvement is considered to be independent and separate TFLC equations have been estimated for fuel cells without reformer. The overhead of the reformer in electricity generation efficiencies is assumed to be constant and it is the one used in the common information base.

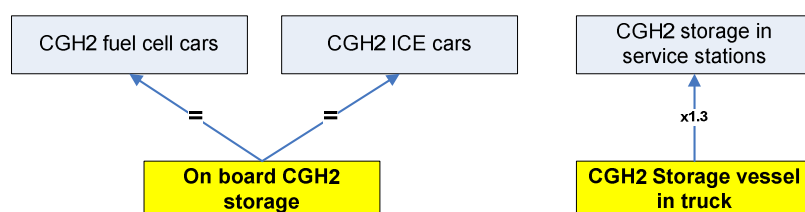
Fixed o&m costs: In the common information base the fixed o&m costs are expressed as percentage of system and stack cost. This percentage is the same for small and large scale fuel cells with or without reformer. Thus, one TFLC equation has been estimated for the progress of fixed o&m costs, which applies to all stationary fuel cells.

Hydrogen storage and distribution infrastructure technologies

The hydrogen infrastructure technologies considered in the estimation are the ones identified in the reference case for hydrogen distribution (see section....). The TFLC equations capture the progress in capital costs only (including decommissioning shares, investments during construction etc.), since the fixed and variable operating and maintenance costs are expressed in the database as constant percentages of the investment cost. In the R&D database, and consequently in the R&D outlook, total R&D expenditures for hydrogen transportation and hydrogen storage are identified, which have been used in the TFLC equations for the corresponding technologies. In addition, clustering has been introduced as much as possible in the form of “weak” clustering, since there was no explicit indication from deliverable D1.1 (ref B.1).

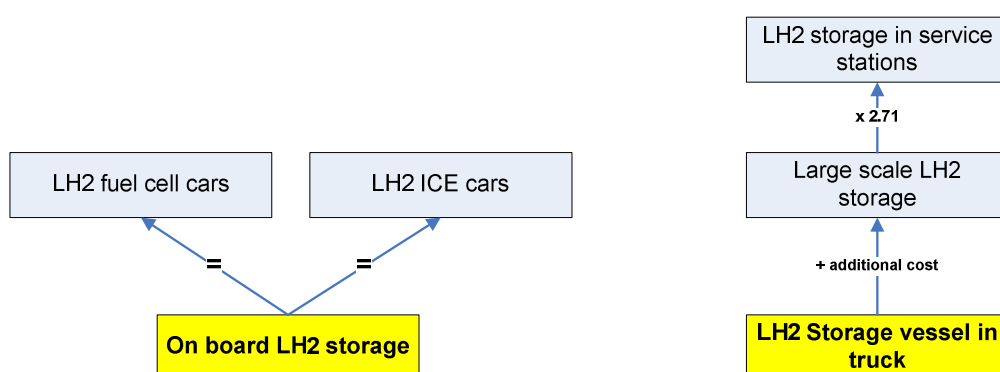
- Pipelines: The capital cost reduction of the low pressure urban network pipelines has been endogenised by a TFLC equation. The learning by experience parameter operates on the final consumption of hydrogen in the residential sector, while the R&D expenditures are the common R&D expenditures on all hydrogen transportation technologies.
- Storage of compressed gaseous hydrogen: Two separate clusters for CGH₂ storage are considered, one for the on-board storage in passenger cars and the another one for the CGH₂ storage in truck vessels and service stations, as described in Figure C-5. All TFLC equations use the common R&D directed to all hydrogen storage technologies.

Figure C-5: Cluster for gasous hydrogen storage options



Liquid hydrogen storage options: Two individual weak clusters, one for on-board storage in passenger cars and one for the rest of the liquid hydrogen storage options identified in the reference system for hydrogen distribution, are considered in the estimation of the TFLC equations. The clusters are presented in Figure C-6. The liquid hydrogen storage vessel used in trucks forms a cluster with the large scale liquid hydrogen storage and the liquid hydrogen storage in service stations.

Figure C-6: Clustering for liquid hydrogen storage options



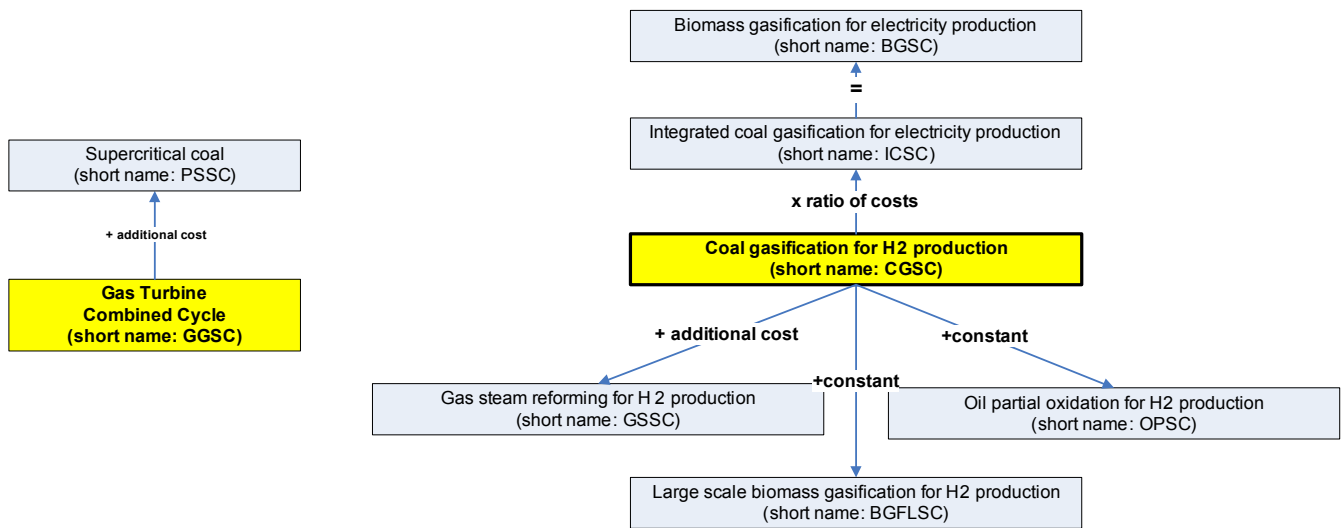
CO₂ capture technologies

In the common information base, the technical and economic performance of the different types of CO₂ capture filters is considered to be independent leading to inconsistencies in the learning process of similar CO₂ capture options. To overcome this situation, in the two factor learning curve estimation process, two weak clusters were identified which are kept independent: one cluster for all post combustion CO₂ capture options and another one for all pre-combustion CO₂ capture options. The R&D expenditures in CO₂ capture

technologies have been summed up, so that only two R&D spending options are distinguished one for post-combustion CO₂ capture and another one for pre-combustion CO₂ capture. The estimated two factor learning curve equations consider capital costs, fixed o&m costs and efficiency losses and follow the formulation (1)-(8).

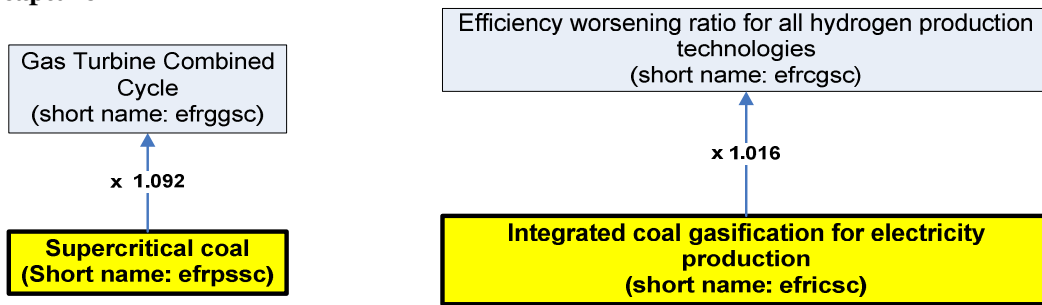
For capital costs, the two clusters for post-combustion and pre-combustion CO₂ capture are shown in Figure C-7. In the post-combustion CO₂ capture cluster the basic component is the option applied to gas turbines combined cycle, while in the pre-combustion CO₂ capture the basic component is the option applied to coal gasification for hydrogen production. Two factor learning curves were estimated for the basic component in each cluster and the additional cost of the rest of the options participating in each cluster.

Figure C-7: Post-combustion (left) and pre-combustion (right) clusters for CO₂ capture



For efficiency losses due to the application of the CO₂ capture filter, the clusters for post-combustion and pre-combustion capture are shown in Figure C-8. Two factor learning curves have been estimated for each of the basic components in each cluster only. Perfect clustering is applied between the basic components and the rest of the technologies participating in each cluster. For example, according to the clustering scheme, the efficiency worsening ratio for all CO₂ capture filters applied to hydrogen production technologies is 1.016 times greater than the corresponding ratio of the filter applied to integrated coal gasification for electricity production.

Figure C-8: Post-combustion (left) and pre-combustion (right) clusters for efficiency losses due to CO₂ capture



Finally for fixed o&m costs, separate two factor learning curves were estimated for each one of the CO₂ production options identified in the technology database.

Passenger cars

Despite the two factor learning curves for mobile fuel cells stack and system costs, onboard hydrogen storage and fuel cell vehicles efficiency, learning equations have been also estimated for a set of technical and economic characteristics of passenger cars. More specifically, two factor learning equations have been specified and estimated for:

Engine capacity: For fuel cells and internal combustion engines separate two factor learning curves were estimated for each one of the engine types, using in the learning by experience parameter the stock of the cars of the corresponding engine.

Electricity engine cost: The reduction in electricity engine cost is captured by a two factor learning curve, which uses a weighted sum (according to engine size) of the stock of all types of passenger cars including an electric engine, namely hybrids, fuel cells and pure electric vehicles. The R&D used in the two factor learning curve is the total R&D expenditures directed to electric and hybrid vehicles.

Electric batteries cost: The two factor learning curve equation for electric batteries cost reduction uses a similar approach as the two factor learning curve for electric engine cost. Thus, the cluster is formed from the weighted sum of all “electric” vehicles (hybrids, fuel cells, pure electric) and uses the R&D expenditures directed to batteries.

Fuel efficiency (for all cars other than fuel cells): Regarding the efficiency of internal combustion engine cars (conventional, hybrid and hydrogen) as well as the efficiency of electric cars, it should be noted that many gains are not directly attributed to the engines themselves. For example decreases in weight and improved aerodynamics are likely to benefit all vehicles (conventional and non-conventional). In this context, the progress of fuel efficiencies is independent for each vehicle type. Two factor learning curves were estimated for internal combustion engine cars (which also uses the R&D directed to conventional cars) including

conventional and hydrogen, and for hybrid and electric cars (which uses the R&D directed to hybrid and electric vehicles).

Fixed o&m costs: Two factor learning curve equations have been estimated for fuel cells and hydrogen internal combustion engine fixed o&m costs.

For a number of technical economic characteristics of passenger cars perfect clustering was assumed, so no two factor learning curves were estimated for them. The perfect clusters are:

Mobile fuel cells stack capacity: Perfect clustering is assumed between stack and engine capacity. Stack capacity is assumed to be the 77% of engine capacity, thus no separate two factor learning curve is required.

Batteries storage capacity of fuel cell vehicles: The storage capacity of batteries in fuel cell vehicles is related to their engine size and to their efficiency improvement. This relationship provides perfect clustering with the engine capacity and efficiency improvement, removing the need for a separate two factor learning curve.

On board hydrogen storage capacity: Similarly, the capacity of on-board hydrogen storage required for the hydrogen fuelled vehicles (including both fuel cells and ICE cars), is directly associated to the engine size and the fuel efficiency of the vehicle.

Appendix: Summary table of learning parameters

The following table summarises the learning parameters for all two factor learning curves equations estimated in the context of CASCADE MINTS project:

	Learning by experience	Learning by research
HYDROGEN PRODUCTION		
<i>Capital cost</i>		
Gas steam reforming	-0.0197	-0.0105
Solar methane reforming	-0.0396	-0.0751
Gasifier	-0.0202	-0.1005
Coal gasification	-0.0491	-0.2298
Large scale biomass gasification	-0.0108	-0.0193
Small scale biomass gasification	0.0000	-0.3285
Biomass handling	-0.1971	0.0000
Thermochemical cycle	-0.0168	-0.0445
Large scale electrolyser	-0.0266	-0.0553
Oil partial oxidation	-0.0065	-0.0135
<i>Fixed cost</i>		
Gas steam reforming		
Capacity < Capacity threshold	0.0000	-0.0177
Capacity >= Capacity threshold	-0.0733	0.0000
Solar methane reforming	-0.0126	-0.0166
Coal gasification	-0.0127	-0.0363
Large scale biomass gasification	-0.0238	-0.0441
Small scale biomass gasification	-0.0235	-0.0396
Solar high temperature	-0.0992	-0.3364
Nuclear high temperature	-0.0502	-0.3640
Large scale electrolysis	0.0000	0.0000
Capacity < Capacity threshold	0.0000	-0.0472
Capacity >= Capacity threshold	-0.1066	0.0000
Oil partial oxidation	-0.0067	-0.0453
<i>Efficiencies</i>		
Gas steam reforming	0.0130	0.0227
Solar methane reforming	0.0033	0.0028
Large scale electrolysis	0.0099	0.0399
Oil partial oxidation	0.0033	0.0175
FUEL CELLS		
<i>Stack cost</i>		
H2 mobile fuel cells stack cost	-0.0193	-3.9279
Gasoline mobile fuel cells stack cost	-0.1277	-1.3614
Small scale stationary fuel cells stack cost	-0.0824	-1.5473
Large scale stationary fuel cells stack cost	-0.2567	-4.2534
<i>System cost</i>		
Mobile fuel cells system cost	-0.0295	-8.8617
Large scale stationary fuel cells system cost	-0.0970	-3.2599
Small scale stationary fuel cells system cost	-0.1894	-3.8630
<i>Reformer cost</i>		
Small scale stationary fuel cells reformer cost		
Capacity < Capacity threshold	0.0000	-0.8146
Capacity >= Capacity threshold	-193.1954	0.0000
Mobile fuel cells reformer cost		
Capacity < Capacity threshold	0.0000	-1.7341
Capacity >= Capacity threshold	-2.1309	0.0000
<i>Lifetime</i>		
Small scale stationary fuel cell stack lifetime	0.0000	7.9056
Large scale stationary fuel cell stack lifetime	0.0000	7.3261
<i>Efficiency</i>		
Mobile fuel cell efficiency		
Capacity < Capacity threshold	0.0000	0.1866
Capacity >= Capacity threshold	0.0540	0.0000
Small scale stationary fuel cell without reformer total efficiency		
Capacity < Capacity threshold	0.0000	0.4210
Capacity >= Capacity threshold	0.0021	0.0000
Large scale stationary fuel cell without reformer electricity efficiency		
Capacity < Capacity threshold	0.0000	0.8144
Capacity >= Capacity threshold	0.0038	0.0000
Small scale stationary fuel cell without reformer electricity efficiency		
Capacity < Capacity threshold	0.0000	3.5870
Capacity >= Capacity threshold	0.0070	0.0000
<i>FOM</i>		
All stationary fuel cells fixed o&m percentage to system and stack cost	-0.0644	-0.2639
All mobile fuel cells fixed o&m percentage to total cost of vehicle	-0.0389	-0.3817
H2 INFRASTRUCTURE		
Low pressure urban pipelines	-0.0102	-0.0407
On-board gaseous hydrogen storage option	-0.0772	-0.9468
Gaseous hydrogen storage vessel in trucks	-0.0548	-0.0425
On-board liquid hydrogen storage option	-0.0422	-0.2657
Liquid hydrogen storage vessel in trucks	-0.0404	-0.0565
Large scale liquid storage	-0.0651	-0.0355
CO2 CAPTURE		
<i>Capital cost</i>		
Post-combustion CO2 capture in Gas Turbine Combined Cycle (capital cost)	-0.0574	-0.0597
Post-combustion CO2 capture in Supercritical coal (capital cost)	-0.0645	-0.0998
Pre-combustion CO2 capture in coal gasification for H2 production (capital cost)	-51.9868	-30.6597
Pre-combustion CO2 capture in gas steam reforming for H2 production	0.0000	-0.0915
Pre-combustion CO2 capture in integrated coal gasification for electricity production	0.0000	0.0000
Capacity < Capacity threshold	0.0000	-0.0452
Capacity >= Capacity threshold	-0.1446	0.0000
<i>Efficiency</i>		
Post-combustion CO2 capture efficiency worsening ratio	0.0086	0.0143
Pre-combustion CO2 capture efficiency worsening ratio	0.0000	0.0450
<i>FOM</i>		
Post-combustion CO2 capture fixed o&m cost for supercritical coal	-167.5405	-27.2655
Post-combustion CO2 capture fixed o&m cost for gas turbines combined cycles	-0.0708	-0.0309
Pre-combustion CO2 capture fixed o&m cost for gasification in electricity generation	0.0000	-0.0634
Pre-combustion CO2 capture fixed o&m cost for H2 production technologies	-0.0069	-0.0109
PASSENGER CARS		
<i>Engines</i>		
Fuel cell vehicles engine capacity	-0.0187	0.0000
Internal combustion engine capacity	-6.0336	0.0000
Electric engine cost	-0.0782	-0.2148
<i>Batteries</i>		
Electric vehicle batteries cost	-0.0485	-0.2316
<i>Efficiencies</i>		
Internal combustion engine efficiency	0.5817	0.3795
Hybrid engine efficiency	0.0291	0.0184
Electric engine efficiency	0.0338	0.0885
<i>FOM</i>		
Hydrogen ICE cars fixed o&m cost ratio	-0.0314	0.0000

C.2 Model extensions to represent Hydrogen Technology Configurations

C.2.1 World Partial Equilibrium Model: POLES

[by P Criqui and S Mima (LEPII-EPE)]

Overview

The interest on identification of feasible strategies for the transition to cleaner sustainable energy systems has never been stronger. In this framework decarbonised energy carriers are presented as one of the most promising solutions not only for emissions reductions but also for the shift from the continued dependency on oil.

Hydrogen and carbon capture and sequestration are proposed as most promising options. But, these technologies are not enough advanced and because of the large variations of key parameters, the economics of hydrogen production and delivery, and of CO₂ storage is difficult to be estimated with certainty. However the difference in uncertainty between hydrogen and CO₂ capture in one side and other new technologies or improved existing technologies is a relevant issue for policy makers to decide for long term R&D developments. That's why some model extensions were necessary to better take into account hydrogen economy configurations.

The modelisation of the hydrogen economy (section 2) begins with demand side. Hydrogen is supposed to be used through fuel cells which have better efficiency than conventional engines either in stationary or in mobile uses. In order to not exclude some possible niche market uses, thermal hydrogen vehicle is also considered as part of hydrogen demand. The way how the hydrogen demand is calculated is described in the 2.2.1 section. A second important step for the presentation of the hydrogen economy in the POLES model has been the completion of the dataset characterizing the Hydrogen production technologies. Standardization of data collected from different studies has been necessary to provide a satisfactory description of the constant and variable costs of hydrogen production (see chapter B 2.2).

The satisfaction of the hydrogen demand is supposed to be realised through 14 possible hydrogen production technologies. The competition between them through the unit production cost is described in the 2.2.2 section. Given that transport and delivery costs strongly impacts the development of H₂, the calculation of their costs concern a particular section. The storage and delivery cost of hydrogen is related to four principal drivers : the kind of the application, the production rate, the delivery distance, and the storage time. Given that often these factors are dependent on each other, modelling of storage and delivery cost represented many difficulties. For eg. the hydrogen production strategy greatly affects the cost and method of storage and delivery. In the case of a centrally hydrogen production, the transport distances and longer time of storage

increase cost significantly. Distributed production at the point of use eliminates the transportation costs but results in higher production costs because the economy of larger scale production is lost. So, the hypothesis of a semicentrally production which reduces the distance and the related costs seemed more judicious.

There is a growing consensus in the global scientific community on the need to control CO₂ emissions to mitigate the problem of global climate change problem. Capture and sequestration of CO₂ is being proposed as a medium term solution that can allow continued use of conventional fossil-fuel resources over the next century without significantly contributing to global carbon emissions from electric power and hydrogen generation (and, potentially, other industrial sources). However some important uncertainties hang over the sequestration of the CO₂ : long term stability of sequestration options, the available potential, public awareness and acceptability. These uncertainties affects the fact whether CO₂ capture and sequestration is a good strategy or not. For that reason, one of the most interesting extensions of the model is the taking into account of the CCS. So, after a general overview of the CCS in the world and the problems connected to the geological storage potential and CO₂ transportation, it is presented a description of the CCS in the POLES model.

The project includes other important features concerning the introduction of low emission technologies in the transport and building sectors¹⁴ which are introduced through activities in other research projects (WETO H₂).

The extension and revision of the key variables and parameters of the POLES model allows to produce a reference image of the world energy system to 2050, with the corresponding outcomes in terms of prices and demand for the key primary sources.

Improvements in POLES Hydrogen module

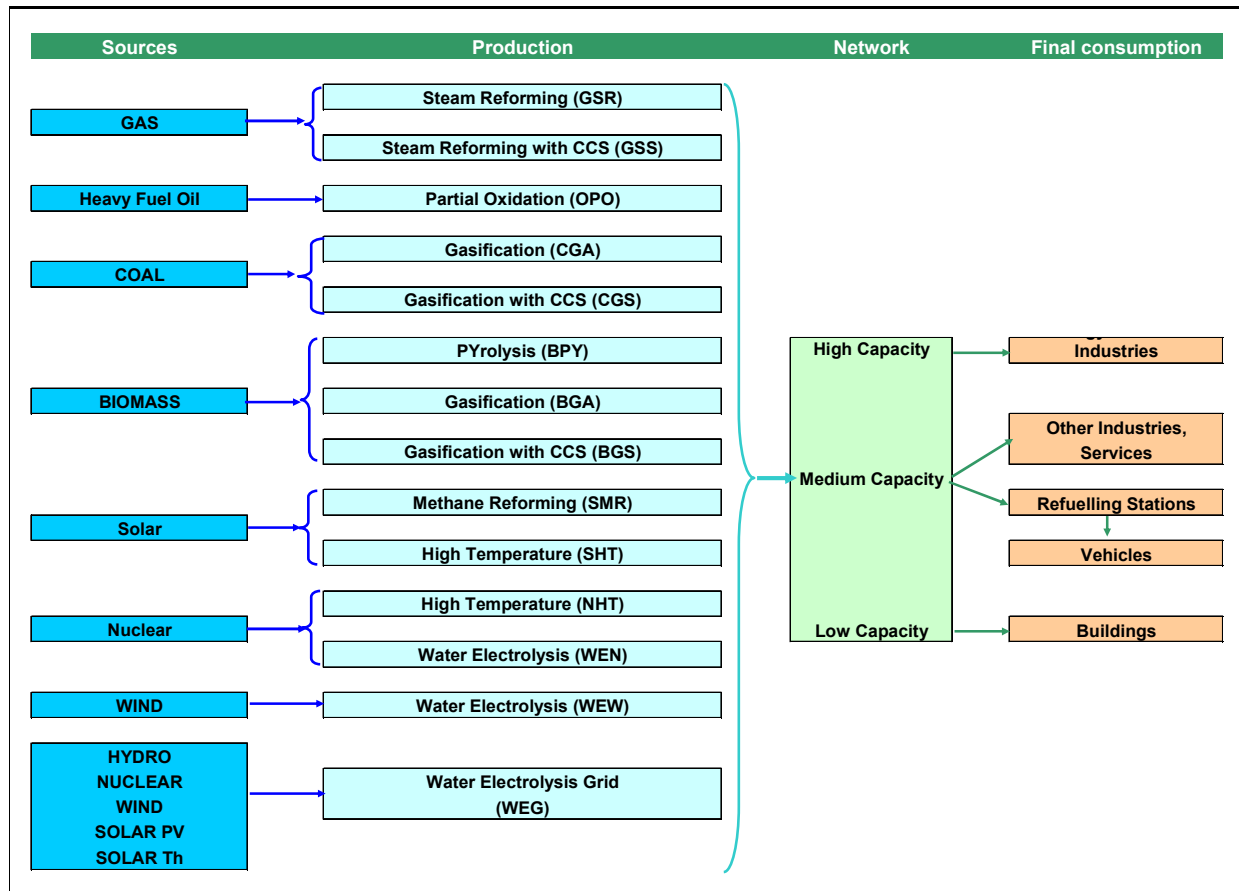
Besides the update of the entire technology database (Hydrogen production and demand technologies) significant improvements in the hydrogen and carbon capture and sequestration modules have been introduced in the past six months.

In this report we summarize the most significant changes performed sine the previous report.

¹⁴ Low Emission Buildings consume approximately half the total energy of a conventional building and may be used in retrofiting ; Very low Emission Buildings consume about one fourth of conventional building

Hydrogen module

Figure C-9 : The hydrogen economy in the POLES model



Hydrogen final consumption

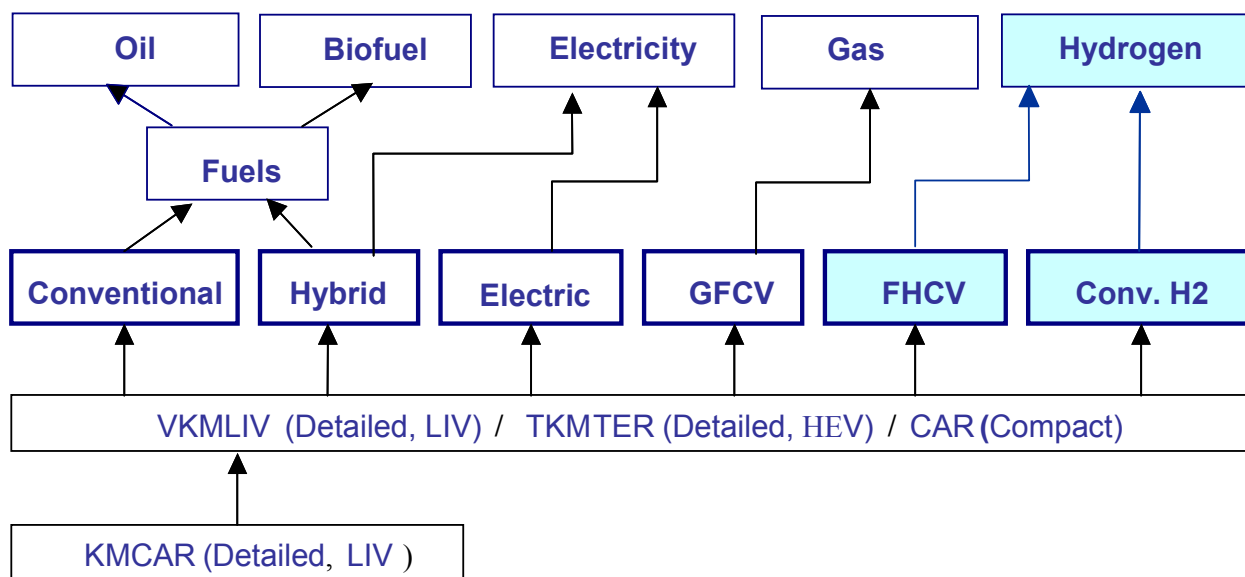
As underlined in the previous report, total Hydrogen demand is the result of two components: demand in stationary uses for power and heat generation with no CO₂ emissions at end point and transport uses through clean and no-emission vehicles. Stationary uses concern correspond to fuel-cells for distributed electricity in cogeneration (HFC) which compete both with other distributed (CHP, DPV, GFC) electricity production electricity and with the supply of electricity from network (ELN). Furthermore, in order to take into account the value of the heat production from CHP and stationary fuel-cells, this value is subtracted from the fuel costs of distributed electricity production.

Endogenised Base Market Shares (MT variables in POLES) are introduced as a function of the relative costs of the different options, network or distributed. Effective market shares progressively adjust in time to Base Market Shares

Hydrogen demand in transport

As far as transport is concerned six categories of vehicles, including low or zero emission vehicles, are distinguished in the POLES model as illustrated in Figure 2. The role of hydrogen is represented by the blue rectangles, which means that hydrogen is used in hydrogen fuel-cell vehicles but also through direct injection in conventional engines. These two categories of hydrogen cars are in competition with conventional, hybrid, electric and gasoline fuel cell vehicles.

Figure C-10 : Hydrogen and inter-technology competition in the transport sector



The corresponding inter-technology competition, which is translated into market shares for the vehicles.km (passengers and goods) depend on the total cost of each vehicle (investment + operation + energy) under a scraping rate constraint for existing equipments.

$$\text{Total Veh. Cost (incl. Mrkup)} = \text{Engine cost} + \text{Storage} + \text{Reformer} + \text{Body}$$

New production technologies to be considered

As a result of the work performed in work package T 1.5.2 “Identification and characterisation of hydrogen production/distribution options”, some changes in the choices of the hydrogen production technologies have been necessary. For example, given that Hydrogen from Coal Partial Oxidation and Hydrogen from Coal Partial Oxidation with CCS have been considered as options without any broad prospect for development, they have been removed from the model. Conversely, technologies considered as more promising in the future [Hydrogen from Heavy Fuel Oil Partial Oxidation (OPO), Hydrogen from Coal Gasification (CGA), Hydrogen from Coal Gasification with CCS (CGS), Hydrogen from Biomass Gasification (BGA), Hydrogen from Biomass Gasification with CCS (BGS), Hydrogen from Solar Methane Reforming (SMR)] have been added to the H₂ production technology portfolio.

Table C-15 : Portfolio for hydrogen production technologies in the POLES model

1	Hydrogen from Gas Steam Reforming	GSR
2	Hydrogen from Gas Steam Reforming with CCS	GSS
3	Hydrogen from Heavy Fuel Oil Partial Oxidation	OPO
4	Hydrogen from Coal GASification	CGA
5	Hydrogen from Coal Gasification with CCS	CGS
6	Hydrogen from Biomass GASification	BGA
7	Hydrogen from Biomass Gasification with CCS	BGS
8	Hydrogen from Biomass PYrolysis	BPY
9	Hydrogen from Solar Methane Reforming	SMR
10	Hydrogen from Solar thermal High-temperature Thermolysis	SHT
11	Hydrogen from Nuclear thermal High-temperature Thermolysis	NHT
12	H2 from Water Electrolysis dedicated Nuclear power plant	WEN
13	H2 from Water Electrolysis dedicated Wind power plant	WEW
14	H2 from Water Electrolysis baseload electricity from Grid	WEG

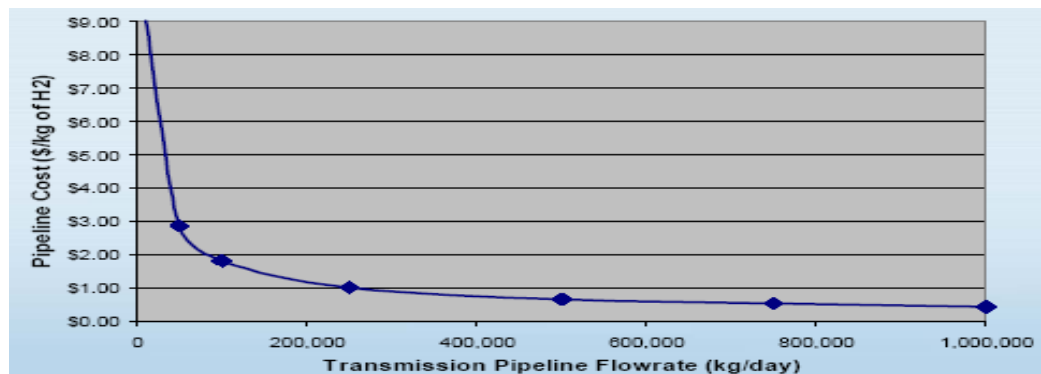
Enhanced modelling of the hydrogen delivery system

Key variables in the hydrogen delivery system

The delivery system is defined as the whole set of equipments between the H₂ production plant and the nozzle of a dispenser including: compression or liquefaction, H₂ storage, H₂ distribution in trucks or pipelines. Delivery and storage costs strongly impact the development of H₂ and deserve a careful treatment in the modelling system. Delivery costs are strongly dependent from: the size and density of the demand, the configuration and patterns chosen for the infrastructures, the choice of the technologies and many other parameters such as the flowrate, distance, refuelling station size ...An example is provided in

Figure C-11 for the order of magnitude of the impact of the flowrate effect on the pipeline cost.

Figure C-11 : Example of Flowrate Effect on pipeline cost



Hydrogen Delivery in POLES

From exogenous hypotheses on unit size, by plant category and time horizon and given the endogenous production mix the model calculates:

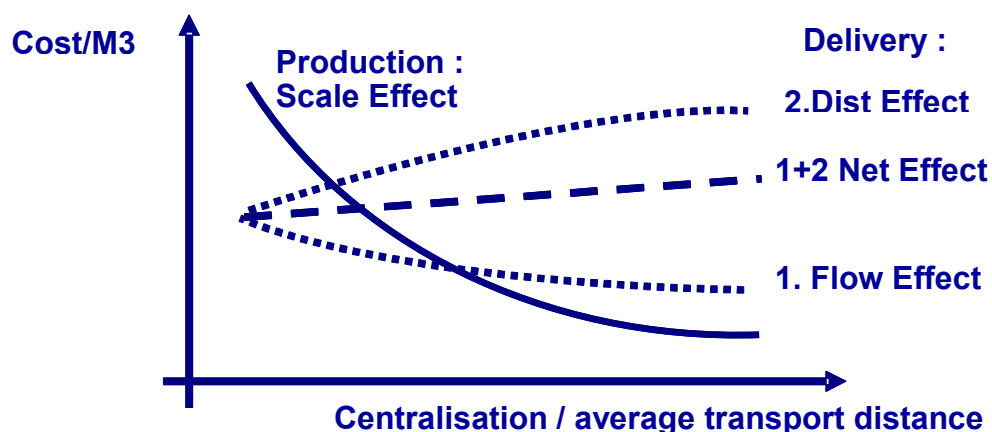
1. the average unit size
2. the average transport distance
3. the H2 transport cost (in a two factor cost equation) to be added to production cost

$$\ln(y) = a_1 \cdot \ln(\text{flow}) + a_2(\text{distance}) + a_0$$

Exogenous distribution costs are also added, according to the type of final market (stationary industry, building, transport).

Their impact in the delivery cost is sketched in Figure C-12.

Figure C-12 : Hydrogen Transport and Delivery in POLES



In other words five key drivers govern the dynamics of H2 Delivery costs in POLES:

1. The positive link between the unit size (by plant type and average unit capacity by country) and the typical delivery distance (small plant deliver on a small distance).
2. The positive (linear cost increase) impact of the distance on delivery cost.
3. The negative (cost decreasing) impact of the average unit capacity/transportation flow on delivery cost.
4. The increasing size of large units in time.
5. Autonomous technological progress in delivery technologies.

Transport and delivery costs for high (TDHHNC) and low (TDHLNC) network capacity are calculated as the sum of the transport (THHNC) and distribution cost, differentiated for high (DHHNC) and low (DHLNC) network capacity, and taking into account a technological progress ratio (TRHD = -0.02).

$$TDHHNC_{[ALLC]} = (THHNC_{[ALLC]} + DHHNC_{[ALLC]}) * (1+TRHD)^{(Time-2000)}$$

$$TDHLNC_{[ALLC]} = (THHNC_{[ALLC]} + DHLNC_{[ALLC]}) * (1+TRHD)^{(Time-2000)} \quad (\text{in EUROS99/toe})$$

For this project the distribution cost is calculated exogenously (DHHNC_[ALLC] = 100 ; DHLNC_[ALLC]=200 in EUROS99/toe) while the equation of hydrogen transport cost is presented below.

$$THHNC_{[ALLC]} = \exp(\ln(FLOW\ COUNTRY_{[ALLC]}) * FLOE_{[ALLC]} + \ln(DISTANCE_{[ALLC]}) * (DISTE_{[ALLC]} + CHHNC_{[ALLC]}) * 350) \quad (\text{in EUROS99/toe})$$

Where :

The flow of hydrogen by country is the sum of the flow of each hydrogen production technology :

$$FLOW\ COUNTRY_{[ALLC]} = \text{SUM}(FLOW_{[ALLC, HYDRPLANTS!]}) \quad (\text{in kg/h})$$

FLOE_[ALLC] = -0.2 is the flow elasticity.

The distance for each country :

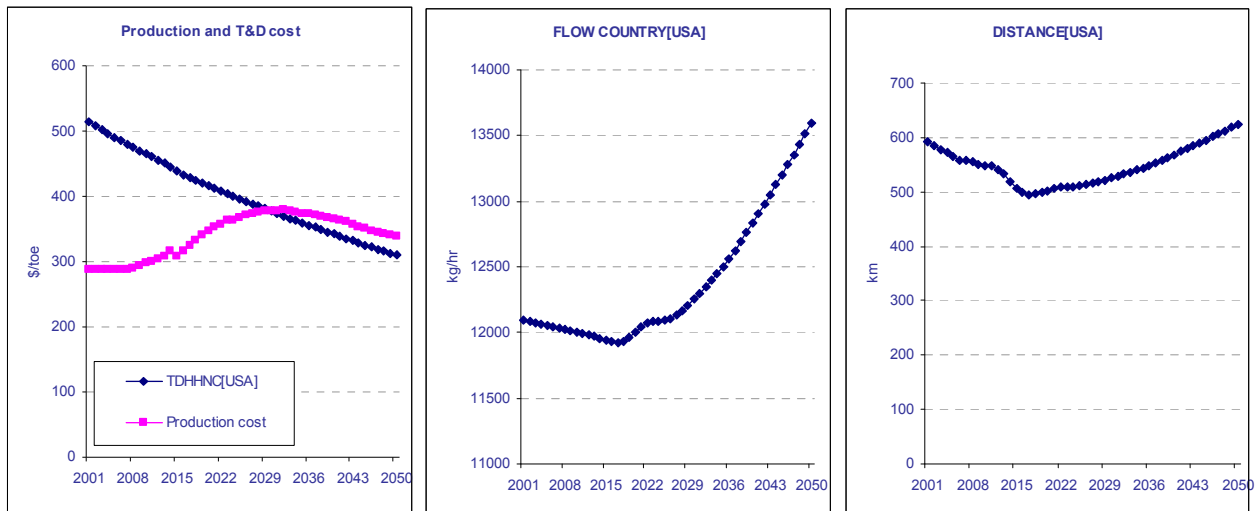
$$DISTANCE_{[ALLC]} = \text{SUM}(SHPWH\ DLY_{[ALLC, HYDRPLANTS!]} * a * (CAPOPT_{[HYDRPLANTS!]})^b)$$

$$DISTE_{[ALLC]} = 0.15$$

$$CHHNC_{[ALLC]} = 1.09$$

Technology trend : TRHD = -0.012

Figure C-13 : Eg. Impact of the flow rate, distance and technological progress (2%/year) in the Hydrogen Production and Delivery Cost in USA



In the example provided for the USA the increase in the flow rate and in the average distance of hydrogen delivery results a cut of two of the hydrogen delivery cost.

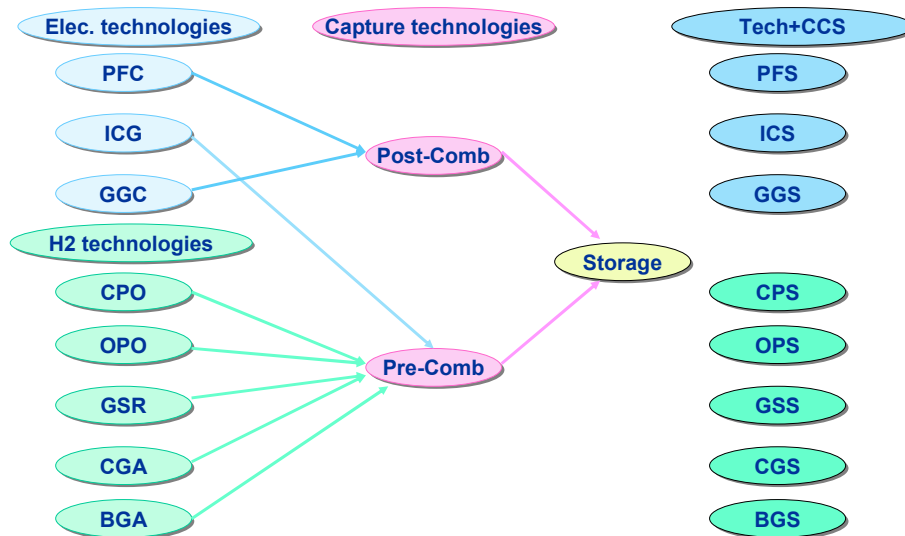
Improvements in POLES CCS module

Improvements have been introduced during this period with the taking into account of new technologies of capture and sequestration and with the insertion of marginal costs for transport and storage of the CO₂ captured. In the following sections we describe the selection of the technologies that can be combined with CCS, the successive stages in the simulation of carbon capture and sequestration and the key outputs of the module.

Introduction of CS technologies

In the CASCADE-MINTS version of the POLES model we describe CCS while retaining three electricity technologies and five hydrogen technologies, among which oil partial oxidation with CCS (OPS), coal gasification with CCS (CGS) and biomass gasification with CCS (BGS) are newly added options :

Figure C-14 : CCS technologies in POLES



PFC + CS => PFS Pressurized Supercritical with Sequestration

ICG + CS => ICS Integrated Coal Gasification with Sequestration

GGC + CS => GGS Gas powered Gas turbine in combined cycle with Sequestration

CPO + CS=> CPS Coal Partial oxidation with Sequestration

OPO + CS=> OPS Heavy Oil Partial oxidation with Sequestration

GSR + CS=> GSS Gas Steam reforming with Sequestration

CGA + CS=> CGS Coal Gasification with Sequestration

BGA + CS=> BGS Biomass Gasification with Sequestration

Capture and storage cost

The simulation of the competition of technologies with and without sequestration imposes the taking into account of the costs of capture, transport and storage of the CO₂. The cost of capture tends to be the dominant item for current technology. The corresponding hypotheses concerning the components of the capture costs are presented in TECHPOL part of this report.

The cost of transport and storage of the CO₂ captured is a function of the amount of CO₂ being shipped and of the distance; the cost of storage is a function of the storage capacity, which varies from one country to the other and across the different types of reservoirs. These drivers have been taken into account through marginal storage cost curves provided by the IPTS.

Investment costs for the technologies with sequestration are the sum of investment cost of the technology without sequestration, of the capture and of the transport-storage cost, all converted in €/kwh in the case of

the electric technologies and in €/m³d for hydrogen. For example, the investment cost of CGS (coal gasification with sequestration) is calculated as :

$$ACINH_{[ALLC,CGS]} = ACINH_{[ALLC,CGA]} + ACIN1_{[ALLC,CGSC RD]} + STORAGE COSTH_{[ALLC,CGS]}$$

The investment cost takes into account two factor learning curves, which are distinct for the capture and for the storage of CO₂. Currently the investment cost of the technologies with capture and sequestration may be 70-80 % more expensive than the corresponding technologies without sequestration. Overall efficiencies are also around 10% lower. Because of more equipment is needed for compression, injection ... the fixed costs for Operation and Maintenance are supposed to be 10% higher than for technologies without sequestration.

The unit cost of hydrogen production by coal gasification with sequestration is the sum of fixed and variable cost :

$$PRODCOSTH_{[ALLC,CGS]} = ACFCH_{[ALLC,CGS]} + ACVCH_{[ALLC,CGS]} \quad (\text{in EUROS99/toe})$$

The variable cost of the technology with sequestration can be impacted by the quantity of carbon sequestered. The increase in the quantity on the one hand decreases the cost through flowrate effect but on the other hand, limitations in the capacity for underground storage imply that the marginal cost for transport and storage increase with cumulative storage.

$$ACVCH_{[ALLC,CGS]} = (ACVOH_{[ALLC,CGS]} + \frac{ETCOAL_{[ALLC,INDUS]} * (1 - KSCOALH_{[ALLC,CGS]}) + CPSCOAL_{[ALLC,INDUS]}}{ACEFH_{[ALLC,COAL]}}) + STORAGE COSTH_{[ALLC,CGS]} \quad (\text{in EUROS99/toe})$$

Carbon stored by sequestration

Total carbon stored by the sequestration can be calculated :

$$CARBONST_{[ALLC]} = \left(\frac{EP_{[ALLC,GGS]}}{ACEF_{[ALLC,GGS]}} * KSGAS_{[ALLC,GGS]} + GAFINHYDR_{[ALLC]} * KSGASH_{[ALLC,GSRI]} \right) * \\ CARBON CONTENT_{[GAS]} + \\ \left(\frac{EP_{[ALLC,PSS]}}{ACEF_{[ALLC,PSS]}} * KSCOAL_{[ALLC,PSS]} + \left(\frac{EP_{[ALLC,CGS]}}{ACEF_{[ALLC,CGS]}} * KSCOAL_{[ALLC,CGS]} + \right. \right. \\ \left. \left. SOFINHYDR_{[ALLC]} * KSCOALH_{[ALLC,CPO]} \right) * CARBON CONTENT_{[COAL]} \right)$$

The carbon stored by sequestration in world level each year (in k*tC) is:

$$CARBONST WRD = \sum_{ALLC} CARBONST_{[ALLC]}$$

Reductions of emissions by sequestration

In order to take into account the sequestration in the reductions of emissions, the corresponding emissions are corrected by a sequestration coefficient (KS) which vary according energy sources and technologies. For instance carbon emissions from hydrogen sector (in ktC) are:

$$EM\ CARBON\ TOT\ HYDR_{[ALLC]} = \sum_{FUEL} EM\ CARBON\ HYDR_{[ALLC,FOSSILFUEL]}$$

Where:

$$EM\ CARBON\ HYDR_{[ALLC,GAS]} = GAFINHYDR_{[ALLC]} * (1-KSGAS) * CARBON\ EMF\ HYDR_{[ALLC,GAS]}$$

$$EM\ CARBON\ HYDR_{[ALLC,COAL]} = SOFINHYDR_{[ALLC]} * (1-KSCOAL) * CARBON\ EMF\ HYDR_{[ALLC,COAL]}$$

where : KSGAS, KSCOAL- sequestration coefficient (87%).

The total sequestration cost

To calculate the sequestration cost by ton of carbon stored, first we calculate the total sequestration cost (€99) for each technology as the difference between the production cost of the technology with sequestration and the corresponding one without, multiplied by the production of the hydrogen or electricity by the technology with sequestration.

$$SEQCOSTH_{[ALLC,CPS]} = \frac{ACFCH_{[ALLC,CPS]} - ACFCH_{[ALLC,CPO]}}{ACAFH_{[ALLC,CPS]}} + \frac{ACVCH1_{[ALLC,CPS]} - ACVCH1_{[ALLC,CPO]}}{KSGASH_{[ALLC,CPO]} * \frac{CARBON\ CONTENT_{[COAL]}}{ACEFH_{[ALLC,CPS]}}}$$

$$SEQCOSTH_{[ALLC,OPS]} = \frac{ACFCH_{[ALLC,OPS]} - ACFCH_{[ALLC,OPO]}}{ACAFH_{[ALLC,OPS]}} + \frac{ACVCH1_{[ALLC,OPS]} - ACVCH1_{[ALLC,OPO]}}{KSGASH_{[ALLC,OPO]} * \frac{CARBON\ CONTENT_{[OIL]}}{ACEFH_{[ALLC,OPS]}}}$$

$$SEQCOSTH_{[ALLC,GSS]} = \frac{ACFCH_{[ALLC,GSS]} - ACFCH_{[ALLC,GSR]}}{ACAFH_{[ALLC,GSS]}} + \frac{ACVCH1_{[ALLC,GSS]} - ACVCH1_{[ALLC,GSR]}}{KSGASH_{[ALLC,GSR]} * \frac{CARBON\ CONTENT_{[GAS]}}{ACEFH_{[ALLC,GSS]}}}$$

$$SEQCOSTH_{[ALLC,CGS]} = \frac{ACFCH_{[ALLC,CGS]} - ACFCH_{[ALLC,CGA]}}{ACAFH_{[ALLC,CGS]}} + \frac{ACVCH1_{[ALLC,CGS]} - ACVCH1_{[ALLC,CGA]}}{KSGASH_{[ALLC,CGA]} * \frac{CARBON\ CONTENT_{[COAL]}}{ACEFH_{[ALLC,CGS]}}}$$

$$SEQCOSTH_{[ALLC,BGS]} = \frac{ACFCH_{[ALLC,BGS]} - ACFCH_{[ALLC,BGA]}}{ACAFH_{[ALLC,BGS]}} + \frac{ACVCH1_{[ALLC,BGS]} - ACVCH1_{[ALLC,BGA]}}{KSGASH_{[ALLC,BGA]} * \frac{CARBON\ CONTENT_{[BIOM]}}{ACEFH_{[ALLC,BGS]}}}$$

$$\begin{aligned}
SEQCOST_{[ALLC,PSS,DURATION]} &= \frac{ACFC_{[ALLC,PFS]} - ACFC_{[ALLC,PFC]}}{LOADS_{[DURATION]} * ACAF_{[ALLC,PFS]}} + \\
&\quad \frac{ACVC1_{[ALLC,PFS]} - ACVC1_{[ALLC,PFC]}}{KSGAS_{[ALLC,PFS]} * \frac{CARBONCONTENT_{[COAL]}}{ACEF_{[ALLC,PFS]}}} * factor \text{ ktGWh} * 1000 \\
SEQCOST_{[ALLC,ICS,DURATION]} &= \frac{ACFC_{[ALLC,ICS]} - ACFC_{[ALLC,ICG]}}{LOADS_{[DURATION]} * ACAF_{[ALLC,ICS]}} + \\
&\quad \frac{ACVC1_{[ALLC,ICS]} - ACVC1_{[ALLC,ICG]}}{KSGAS_{[ALLC,ICS]} * \frac{CARBONCONTENT_{[COAL]}}{ACEF_{[ALLC,ICS]}}} * factor \text{ ktGWh} * 1000 \\
SEQCOST_{[ALLC,GGS,DURATION]} &= \frac{ACFC_{[ALLC,GGS]} - ACFC_{[ALLC,GGC]}}{LOADS_{[DURATION]} * ACAF_{[ALLC,GGS]}} + \\
&\quad \frac{ACVC1_{[ALLC,GGS]} - ACVC1_{[ALLC,GGC]}}{KSGAS_{[ALLC,GGS]} * \frac{CARBONCONTENT_{[GAS]}}{ACEF_{[ALLC,GGS]}}} * factor \text{ ktGWh} * 1000 \\
&\hspace{20em} (\text{in EUROS99/tc})
\end{aligned}$$

The unit sequestration cost

The unit sequestration cost (in EUROS99/tC) is computed as following :

SEQCOST WRD = IF CARBONST WRD = 0, THEN 0

$$\text{ELSE } \frac{\sum_{ALLC, Techseq} SEQCOST[ALLC!, Tech seq]}{CARBONST WRD * 1000}$$

Conclusions

H2 and CCS modelling in the CASCADE-MINTS version of POLES now include new R&D DB, a new set of H2 production technologies, new exogenous technology cost/performance DB and a full description of the delivery systems. These new developments improve the capabilities of the POLES model for exploring the many facets of the deployment of hydrogen and CCS systems in a greenhouse gas constrained world. With the current set of hypotheses, the results describe a very limited development of H2. This lead to H2

deployment scenarios through the introduction of technological breakthroughs for hydrogen, with contrasted “Technology Stories” and “R&D scenarios”.

C.2.2 European Partial Equilibrium Model: PRIMES

[by V. Papandreou (ICCS-NTUA)]

In the context of the model development for PRIMES (PRIMES-H₂) under WP1.1, ICCS/NTUA has concentrated on detailed modelling of the hydrogen economy for present EU15 and New Member States. This involved the development of a detailed Reference Energy System (RES) with inclusion of hydrogen demand and supply processes and links. The new RES was coded into GAMS and linked with demand side formulation of the PRIMES model.

The new Reference Energy System

The new RES of PRIMES represented eleven hydrogen production technologies according to the definitions given in the ‘Common Information Base’ under WP1.5. In addition a number of other technologies were added related to decentralized (‘forecourt’) hydrogen production (e.g. small scale electrolysis or other energy sources like methanol, ethanol, gasoline, LPG, diesel). Moreover the production of methanol and ethanol from biomass was also modelled in detail in the separate PRIMES biomass sector.

Regarding the end use technologies, the transport sector of the PRIMES demand model has been enriched by the update of techno-economic representation of hydrogen technologies for road and rail transport. For the residential and industrial sectors, stationary H₂ and natural gas fuel cells, along with direct combustion of hydrogen/natural gas mixture were introduced and/or updated. These technologies were applied to specific electricity and heat demand (water, space, cooking etc) in the residential and tertiary sector and specific electricity and steam\heat demand for industrial processes in the industrial sector. Table C-16 gives an overview of the new technologies that were added in the different sectors.

The representation of the delivery infrastructure included both the transportation of hydrogen, ethanol or methanol, either through a pipeline network (gaseous hydrogen and hydrogen/gas mixture) or via trucks (gaseous or liquid form, metal hydrides etc) and the hydrogen storage stations for gaseous hydrogen, liquid hydrogen and gas/liquid hydrogen. In the later cases the compression or liquefaction processes have also been modelled.

Transport	Industrial	Residential
H2 FC (cars, trucks, busses, trains)	H2 FC stationary	H2 FC stationary
Methanol FC (cars, trucks, busses, trains)	H2 ICE	Natural Gas FC stationary
H2 ICE (cars, trucks, busses)	Natural Gas FC stationary	H2 ICE
Ethanol ICE (cars, trucks, busses)	Methanol FC stationary	

Table C-16: The new technologies introduced in the existing sectors of PRIMES

The Hydrogen Supply model

The hydrogen supply model is a process based representation of the hydrogen supply sector. It formulates the economics of the production processes of hydrogen and the expansion of process plants and infrastructure. Capacity use and expansion is represented as a full vintage model with endogenous investment. Dynamics of technology improvement is fully tracked through the vintages of process units.

As shown in Figure C-15, twenty one hydrogen production technologies have been included in total, with primary resources ranging from traditional fossil fuel to nuclear and renewable energy. The primary resources are either primary fuels, e.g. in the case of Well Gas or Oil Reforming, or secondary fuels produced by another sub-model of the PRIMES model, e.g. the refinery sub-model. In the first case the primary energy production is formulated through an upwards slopping supply function representing the intertemporal rent-seeking management of an exhaustible resource, while in the latter the price is the result of the optimisation problem of the sub-model. Ultimate indigenous resources are exogenous. A similar upwards slopping supply function is used to formulate the supply of imports but also the supply of primary renewable and waste energy sources. In this case the supply function represents the increasing unit cost associated with the exploitation of the potential of renewables.

The option of carbon capture and storage (CCS) is possible for some of the hydrogen production processes. This choice is also introduced to the model and the technologies that can be combined with CCS are listed in Table C-17.

The complete process of supplying hydrogen to the end user, including the production, possible import and final distribution of hydrogen to the market, is modelled as a network with the nodes representing the processing units or the transportation-distribution methods and the links between them representing the flows of energy forms. The model is seeking to minimise total delivery cost subject to demand and technical constraints.

Let t be the set of projection time periods, n the set of process units, f the set of the various energy forms and tt , nn and ff be the alias sets. Symbol $Q_{n,f,nn,tt,t}$ denotes the flow of energy form f from unit n built in tt to unit nn at year t . The mapping sets of input and output energy forms of a unit n are denoted by $fin(n,f)$ and $fout(n,f)$.

Technologies with CCS	
Coal gasification with syngas	Heavy Oil partial oxidation
Coal gasification with membrane	Heavy Oil reforming
Coal supercritical gasification	Heavy Oil gasification with syngas
Gas reforming	Heavy Oil gasification with membrane

Table C-17: List of technologies with CCS option

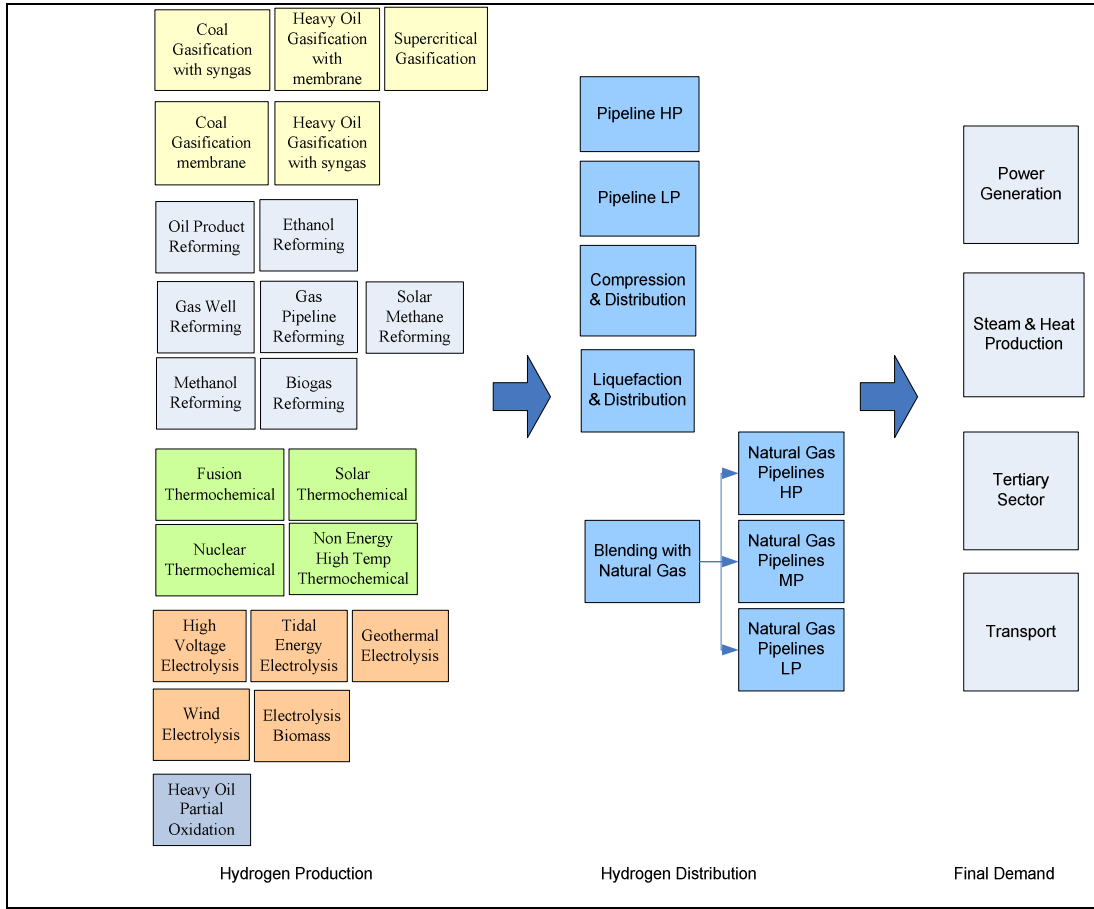


Figure C-15 Graphical representation of the hydrogen supply sector in PRIMES

The primary source supply curve is given by the following logarithmic expression:

$$P_{f,t} = a_{f,t} + b_{f,t} \cdot \sum_{n \in \text{exn}(n,f)} \sum_{nn \in \text{fin}(n,f)} Q_{n,f,nn,tt,t} + c_{f,t} \cdot \log\left(1 - \frac{\sum_{n \in \text{exn}(n)} \sum_{nn \in \text{fin}(n,f)} Q_{n,f,nn,tt,t}}{Q_{\max_{f,t}}}\right)$$

$$\forall f \in \text{primf}(f)$$

where $\text{primf}(f)$ is the sub-set of primary energy forms, $\text{exn}(n,f)$ is the sub-set of primary production units-processes that produce f , $P_{f,t}$ is the price of the primary fuel f , $a_{f,t}$, $b_{f,t}$ and $c_{f,t}$ are the supply curve parameters and $Q_{\max_{f,t}}$ is an exogenously defined maximum supply quantity. Note that $\sum_{n \in \text{exn}(n,f)} \sum_{nn \in \text{fin}(n,f)} Q_{n,f,nn,tt,t}$ gives the total primary fuel output. A similar expression is used to formulate the importation of energy forms.

A resource constraint for the indigenous primary production is given by:

$$\max_{f,t} \geq \sum_{n \in \text{exn}(n,f)} \sum_{tt \leq t} Q_{n,f,nn,tt,t} \geq \min_{f,t} \quad \forall f$$

The energy equilibrium through every process unit can be written as:

$$\sum_{f \in \text{fin}(n,f)} \sum_{nn \in \text{fout}(nn,f)} \sum_{tt \leq t} Q_{nn,f,n,tt,t} = \text{hrt}_{n,tt} \cdot \sum_{ff \in \text{fout}(n,ff)} \sum_{nn \in \text{fin}(nn,ff)} \sum_{tt \leq t} Q_{n,ff,nn,tt,t} \quad \forall n,tt$$

where $\text{hrt}_{n,tt}$ is the vintage depended heatrate of the process unit.

The range of yield shares per output for each unit is specified exogenously, yet the specific output is an endogenous decision of the model. This is introduced in the model by the following constraint:

$$\text{blom}_{n,f,tt,t} \geq \frac{\sum_{nn \in \text{fin}(nn,f)} Q_{n,f,nn,tt,t}}{\sum_{ff \in \text{fout}(n,ff)} \sum_{nn \in \text{fin}(nn,ff)} Q_{n,ff,nn,tt,t}} \geq \text{blox}_{n,f,tt,t} \quad \forall n, f, tt, t \in \text{map}_o(n, f, tt), tt \leq t$$

where blom_f and blox_f is the minimum and maximum output shares per energy form respectively and $\text{map}_o(n, f, tt)$ is the mapping set of units n , output forms f and vintage tt .

A similar constraint is introduced for the inputs in each unit:

$$\text{blim}_{n,f,tt,t} \geq \frac{\sum_{nn \in \text{fin}(nn,f)} Q_{n,f,nn,tt,t}}{\sum_{ff \in \text{fout}(n,ff)} \sum_{nn \in \text{fin}(nn,ff)} Q_{n,ff,nn,tt,t}} \geq \text{blix}_{n,f,tt,t} \quad \forall n, f, tt \in \text{map}_i(n, f, tt), tt \leq t$$

with blim_f and blix_f denoting the minimum and maximum input share per energy form, e.g. hydrogen and natural gas blending in the grid. Set $\text{map}_i(n, f, tt, t)$ is a mapping set of unit n , input forms f and vintage tt .

The capacity constraint is expressed for every unit-vintage combination as:

$$\sum_{f \in \text{fout}(n,f)} \sum_{nn \in \text{fin}(nn,f)} \sum_{tt \leq t} Q_{n,f,nn,tt,t} \leq \text{util}_{n,tt,t} \cdot \text{CAP}_{n,tt,t} \quad \forall n, \forall tt \leq t$$

where $\text{util}_{n,tt,t}$ is the utilisation parameter of the unit and $\text{CAP}_{n,tt,t}$ is the capacity at time t of unit n built in tt given by:

$$\text{CAP}_{n,tt,t} = (\text{capexog}_{n,tt} - \text{scrap}_{n,tt,t}) + \text{INV}_{n,tt} \cdot \text{surv}_{n,tt,t} \quad \forall n, \forall tt \leq t$$

with $\text{capexog}_{n,tt}$ denoting the exogenous capacity of unit n with vintage tt , $\text{scrap}_{n,tt,t}$ is the exogenous known scrapping, $\text{INV}_{n,tt}$ is the endogenous investment at time tt and $\text{surv}_{n,tt,t}$ is an exogenously defined surviving index that gives the proportion of the investment done in time $tt \leq t$ that survives in period t .

The wholesale supplier has to satisfy specific demand for hydrogen derived from the rest of the supply modules (e.g. power and steam) and the demand module.

$$\sum_{n \in f_{out}(n,f)} \sum_{nn \in demn(nn)} \sum_{tt \leq t} Q_{n,f,nn,tt,t} \geq \sum_{ds} demand_{ds,f,t} \quad \forall f \in f_{inf}(f)$$

with ds being a set denoting the different demand sectors (demand model or other supply sub-models), $demn(n)$ the demand node of the energy sub-model, $f_{inf}(f)$ the sub-set of final fuels and demands, f,t the demand of fuel f from sector ds .

The emission produced by each process n are given by:

$$EM_{n,pl,tt,t} = emfac_{n,pl,tt,t} \cdot \sum_{f \in f_{out}(n,f)} \sum_{nn \in fin(nn,f)} Q_{n,f,nn,tt,t} \quad \forall n, \forall pl, \forall tt \leq t$$

with $EM_{n,pl,tt,t}$ being the emission of pollutant pl from process unit n of vintage tt at time t and $emfac_{n,pl,tt,t}$ is the relevant emission factor per unit of output from the process.

The total cost of the supply sector is given by the following expression:

$$\begin{aligned} & \sum_{t \geq tt} (capcost_{n,tt,t} + fixcost_{n,tt,t}) \cdot [(capexog_{n,tt} - scrap_{n,tt,t}) + INV_{n,tt} \cdot surv_{n,tt,t}] \\ & + varcost_{n,f,tt,t} \cdot Q_{n,f,nn,tt,t} + emcost_{pl,t} \cdot \sum_n \sum_{tt < t} EM_{n,pl,tt,t} \geq 0 \end{aligned}$$

where $varcost_{n,f,tt,t}$ is the variable cost of process unit n built in tt with output f at time t , $capcost_{n,tt,t}$ and $fixcost_{n,tt,t}$ is the annuity and fixed costs respectively, paid in time t for a process unit built in time tt and $emcost_{pl,t}$ is the cost of emitting pollutant pl (e.g. carbon tax).

The adoption of CCS in hydrogen production is modelled as an endogenous decision, formulated as the option of an auxiliary equipment or additional process. The idea is that the process plant may either be constructed as it is or combined with a carbon capture process but in the later case additional capital, fixed and variable costs as well as increase in the overall heatrate of the process will have to be met. On the other hand the CO₂ emissions from the process will be highly reduced.

An additional capacity constraint is introduced:

$$\sum_{f \in f_{out}(n,f)} \sum_{tt < t} AQ_{n,f,tt,t} \leq util_{n,tt,t} \cdot ACAP_{nn,tt,t} \quad \forall n, \forall tt \leq t$$

with $AQ_{n,f,tt,t}$ being the flow of the energy form f through the hydrogen production process n built in tt at time t that is coupled with CCS and $ACAP_{nn,tt,t}$ being the capacity of the plant. Two additional constraints are necessary to restrict the value of $AQ_{n,f,tt,t}$ and $ACAP_{nn,tt,t}$:

$$\sum_{f \in f_{out}(n,f)} \sum_{tt < t} AQ_{n,f,tt,t} \leq \sum_{f \in f_{out}(n,f)} \sum_{nn \in fin(nn,f)} \sum_{tt < t} Q_{n,f,nn,tt,t} \quad \forall n, \forall tt \leq t$$

$$ACAP_{nn,tt,t} \leq CAP_{nn,tt,t} \quad \forall n, \forall tt \leq t$$

The increase of the heatrate is implemented by adding the following expression to the right part of the energy equilibrium constraint:

$$ahrtn,tt \cdot \sum_{f \in f_{out}(n,f)} \sum_{tt < t} AQ_{n,f,tt,t}$$

where ahrtn,tt is the increase of the heatrate (reduction of efficiency) of the process due to the adoption of the additional CCS process.

The reduction of CO₂ emissions is modelled likewise by adding $aemred_{n,CO_2,tt} \cdot \sum_{f \in f_{out}(n,f)} \sum_{tt < t} AQ_{n,f,tt,t}$ to the

left part of the emission equation, with aemredn,tt being a negative parameter expressing the relative reduction of the emission factor of CO₂.

C.2.3 Perfect Foresight World Energy Model (Very Long Term): MESSAGE

[by G. Totschnig and I. Keppo (IIASA)]

To fulfill the tasks of CASCADE MINTS Part 1, substantial extensions to the MESSAGE model were made. One of our main targets was to implement endogenous technological learning of the technologies relevant to the hydrogen (H₂) economy. Two important aspects of the new endogenous learning methodology will be described below in more detail. The first aspect is the modeling of learning spillovers among technologies with similarities—the learning of one technology leads to technological progress in technologies that are, to some extent, related. This spillover effect is modeled using technological subcomponents and clustered learning (see below C.2.3.1; compare also C.1.1). The second aspect described in more detail is the implementation of endogenous two-factor learning (2FL) into the MESSAGE model (see below C.2.3.2).

The four-region version of IIASA's global MESSAGE model (covering countries of the Organisation for Economic Co-operation and Development [OECD]; Asia; Latin America + Africa + Middle East; and the reforming economies) was used for this study. The CASCADE MINTS TECHPOL database (based on the WP 1.5 results) was used to completely update the MESSAGE data specifications for the production of hydrogen, the hydrogen reference system, and electricity production.

A further important change was the complete renewal and detailed modeling of the transport sector. The description of the transport sector, previously only stylized, was split into passenger car transport, air transport, and other (mainly freight) transport, including a detailed description of 14 different passenger car technologies, which now comprise:

- Internal combustion cars using gasoline, natural gas, methanol, and ethanol;
- Internal combustion cars, with an electric battery hybrid system using gasoline, natural gas, methanol, ethanol, and hydrogen;
- Fuel cell cars using hydrogen, gasoline, natural gas, and methanol; and

- The electric passenger car.

The technological data for these 14 car technologies are based on the CASCADE MINTS TECHPOL database (see B.2.2) and on Turton and Barreto (2007). The transport demand for the three transport sectors is based on the ERIS model (Turton and Barreto, 2007) using a B2 scenario. Details of the clustering in the car transport sector can be found below in C.2.3.1.

C.2.3.1 Implementation of endogenous learning spillovers in MESSAGE using clustering and subcomponents

In MESSAGE, technologies are defined by inputs, outputs, investment costs, efficiencies, fixed and variable operation and maintenance costs, plant factors, plant lifetime, emission coefficients, and other parameters. All these parameters can be given as a time series to reflect improvements with time. This is also called **exogenously** defined learning. For the technologies relevant to the hydrogen economy an **endogenous** two-factor learning approach was implemented. This means that the technological characteristics and costs do not automatically improve with time, but only as a result of R&D spending decisions taken by the model (learning by research [LBR]) and model decisions leading to an increasing number of technology installations (learning by doing [LBD]). The costs and the characteristics in a certain time period depend on the evolution of the model run and are not exogenously given. See the definition of the two-factor learning curves in C.1.2. In the following, the term “learning” always refers to endogenous two-factor learning.

An example illustrating the topic of spillovers is shown in Table C-18 . It can be seen from Table C-18 that different car types have common parts. For example, many advanced car systems contain a hybrid system. Thus, technological learning of one car type will have effects on cars with related parts.

Table C-18. The endogenous learning parts of passenger cars, as implemented in MESSAGE.

	Mobile Fuel Cell System	Hybrid System	Mobile Nat. Gas / Methanol Reformer	Mobile Gasoline Reformer	H2 Storage
Conv. Gasoline Car					
Conv. Natural Gas Car					
Conv. Methanol Car					
Conv. Ethanol Car					
Gasoline Battery Hybrid Car		x			
Natural Gas Battery Hybrid Car		x			
Methanol Battery Hybrid Car		x			
Ethanol Battery Hybrid Car		x			
Hydrogen Battery Hybrid Car		x			x
Gasoline Fuel Cell Car	x	x		x	
Natural Gas Fuel Cell Car	x	x	x		
Methanol Fuel Cell Car	x	x	x		
Hydrogen Fuel Cell Car	x	x			x
Electric Car		x			

The implementation of spillovers and 2FL in MESSAGE is straightforward, provided that a technology is modeled with only one learning component. In that case, all the technologies with the same component make up a cluster. All technologies in the cluster have one common R&D spending variable and contribute to the

common cumulative installations of the cluster. The common cumulative installations and the cumulative spending of the common R&D variable are used to calculate the cost of the learning component using the two-factor learning curve (2FLC, defined in C.1.2). The TECHPOL database (see B.2.2) is used to calculate the cost of the non-learning parts. If the results are added together, the total technology cost for all members of the cluster is obtained.

Let us consider, for example, hybrid cars. All hybrid cars are assumed to have the same generic hybrid system onboard, which consists of a 50 kW electric engine/generator and a 1.5 kWh high-output power battery (twice the cost of the low-output power battery given in C.1.2; see also hybrid car in B.2.2). Using the 2FLC for the electric engine and the battery as defined in C.1.2 and a markup factor of 1.7445 (see B.2.2), the costs for the generic hybrid system can be calculated (see Table C-19).

Table C-19. Costs for the generic hybrid system (referred to as hybrid subcomponent) given for different cumulative installed capacities and cumulative spent R&D. The hybrid system is defined as having a 50 kW electromotor/generator, a 1.5 kWh high-output power battery, and a 1.7445 markup factor. The values in the column and row headers are the CRDi and CCLj levels used, as defined below in C.2.3.2.

Model cumulative installed hybrid cars [mioCars]:	0	56	233	1165	6991
Model cumulative spent R&D on hybrids[M\$90]:	Generic hybrid system cost [USD90/car]				
2817	3522	2978	2732	2471	2213
36000	1927	1647	1509	1372	1237
154000	1425	1224	1129	1089	1052
250000	1264	1091	1013	1021	997

The conversion rates used were 1 euro99 = 0.7199 USD90 and 1 USD2000 = 0.6892 USD90. According to B.2.2 the gasoline battery hybrid car without hybrid system costs a constant 12,699 USD90. Adding this to Table C-19 leads to a total investment cost for a gasoline battery hybrid car, as given in Table C-20.

Table C-20. Total investment cost for a gasoline battery hybrid car for different cumulative installed capacities and cumulative spent R&D. The values in the column and row headers are the CRDi and CCLj levels used, as defined below in C.2.3.2.

Model cumulative installed hybrid cars [mioCars]:	0	56	233	1165	6991
Model cumulative spent R&D on hybrids[M\$90]:	Gasoline battery hybrid car inv. cost [USD90/car]				
2817	16191	15646	15401	15139	14881
36000	14596	14316	14178	14040	13906
154000	14093	13892	13797	13758	13721
250000	13933	13760	13681	13690	13666

Another example is the electric car. The electric car without an electric engine and battery costs 11,186 USD90 (see B.2.2). According to the TECHPOL database (see B.2.2) the 30 kWh low-power, high-capacity battery and the 60 kW electric engine of the electric car cost about 5.7 times more than the generic hybrid system. Adding 5.7 times the costs in Table C-19 to 11,186 gives the total investment cost of the electric car for different cumulative installed capacities and cumulative spent R&D. In this way the cost matrices needed for the endogenous 2FL (see C.2.3.2) are calculated for all the technologies that are part of the hybrid cluster.

These technologies are listed in Table C-21. The hybrid subcomponent is part of the cluster because fuel cell cars are defined as having the hybrid system as a subcomponent (see Table C-21). As the electric car contains a battery and an electric engine worth 5.7 times more than the generic hybrid system, the electric car contributes to the common cumulative installations by a multiplicative factor of 5.7 (see Table C-21). All other hybrid cars have a factor of 1 and contribute directly to the common cumulative installations.

The learning of the technologies in a cluster depends on one common R&D spending variable and on the common cumulative installations. However, the technologies are allowed to have, and usually do have, different costs, efficiencies, and technological characteristics. Each technology may also contribute to the common cumulative installations by a different factor (note factor 5.7, above, for the electric car).

If a technology is modeled with more than one independently learning part, then the costs of the most important learning part remain with the technology and define the cost matrix as just described. The costs of the other learning parts are deducted from the total technology cost and included in the cost of a subcomponent that is used by the main technology. For example, the hydrogen battery hybrid car has the hybrid system and the hydrogen fuel tank as learning parts. The hydrogen battery hybrid car is then split into two MESSAGE technologies. The main MESSAGE technology, “hydrogen battery hybrid car main part,” includes the cost of the hybrid system and the rest of the car but not the cost of the hydrogen storage fuel tank. The second MESSAGE technology created is “1 kg H₂ mobile hydrogen storage tank,” and includes the cost of 1 kg of H₂ storage only. As TECHPOL specifies that a hydrogen battery hybrid car should have 13 kg of H₂ storage, MESSAGE is programmed in such a way that for each “hydrogen battery hybrid car main part” installed in the model, 13 installations of “1 kg H₂ mobile hydrogen storage tank” are also installed. When the model builds the main technology, it is also required to build the specified amount of subcomponents. The main technology and the subcomponent can then be part of different clusters (see Table C-21) and show independent learning behavior and spillovers.

Another example is the hydrogen fuel cell car. The fuel cell system, the hybrid system, and the mobile hydrogen storage are defined as independently learning parts. To model the hydrogen fuel cell car, three MESSAGE technologies are used: the “hydrogen fuel cell car main part” technology, which includes the costs of the fuel cell, 6 times the “1 kg H₂ mobile hydrogen storage tank” technology for each car, and 1.3 times the “hybrid system car subcomponent” technology—TECHPOL defines a hydrogen fuel cell car as having a 6 kg hydrogen tank and a hybrid system that is 1.3 times larger than in a gasoline battery hybrid car. The subcomponents are defined as having an investment cost, which changes according to the specific 2FLC, and a lifetime (the same as the main technology), but no other technological characteristics. They merely bear costs.

The main technology has all the characteristics of the original technology as inputs, outputs, efficiencies, fixed and variable operation and maintenance costs, plant factors, etc. Changes to the main technology are a reduction of the investment costs by the cost of the subcomponents and additional parameters specifying how much of a subcomponent needs to be installed with the main component. All these parameters can be made learning for the main technology.

In the present installation of 2FL in MESSAGE, the following technology parameters are implemented as 2FL (for details see C.2.3.2):

- Investment costs;
- Efficiency;
- Fixed operation and maintenance costs;
- Variable operation and maintenance costs;
- Plant factor (defining the annual availability/use of a technology); and
- Required amount of subcomponents to be installed per unit of main technology.

An example of the variation in the amount of subcomponents required is the hydrogen fuel cell car, one subcomponent of which is mobile hydrogen storage. The investment costs of the “1 kg H₂ mobile hydrogen storage tank” subcomponent are given in USD90 per kilogram of hydrogen. As the efficiency of the hydrogen fuel cell car improves with learning, the car’s required hydrogen tank size reduces from 6 kg to 4.2 kg hydrogen. Thus, the amount of subcomponent required (kg hydrogen storage) changes from 6 kg to 4.2 kg. The technologies, clusters, and subcomponents used for the implementation of the endogenous two-factor learning in MESSAGE are listed in Table C-21.

Table C-21. Implementation of the endogenous two-factor learning in MESSAGE. The endogenous learning technologies, clusters, and subcomponents used are provided.

Technology	Endogeneous learning		Subcomponent 1	Subcomponent 2
	properties	Cluster		
Hydrogen fuel cell car	full 2FL	Mobile FC	Hybrid subcomp.	Mobile H2 storage subcomp.
Gasoline fuel cell car	full 2FL	Mobile FC	Hybrid subcomp.	Gasoline reformer subcomp.
Methanol fuel cell car	full 2FL	Mobile FC	Hybrid subcomp.	Nat. gas/alcohol reformer subcomp.
Natural gas fuel cell car	full 2FL	Mobile FC	Hybrid subcomp.	Nat. gas/alcohol reformer subcomp.
Mobile fuel cell stack subcomp.	full 2FL	Mobile FC		
Stationary H2 fuel cell CHP	full 2FL	Stationary FC		Mobile fuel cell stack subcomp.
Stationary nat. gas fuel cell CHP	full 2FL	Stationary FC		Mobile fuel cell stack subcomp.
Gasoline reformer subcomp.	full 2FL	Mobile reformer		
Nat. gas/alcohol reformer subcomp.	full 2FL	Mobile reformer		
Steam methane reformer H2 plant	full 2FL	SMR		
Solar methane reformer H2 plant	full 2FL	SMR		
Mobile H2 storage subcomp.	full 2FL	Stand alone		
Hybrid subcomp.	full 2FL	Hybrid		
Gasoline battery hybrid car	full 2FL	Hybrid		
Natural gas battery hybrid car	full 2FL	Hybrid		
Ethanol battery hybrid car	full 2FL	Hybrid		
Methanol battery hybrid car	full 2FL	Hybrid		
Hydrogen battery hybrid car	full 2FL	Hybrid		Mobile H2 storage subcomp.
Electric car	full 2FL	Hybrid		
Electrolyzer H2 plant	full 2FL	Stand alone		
Gasifier subcomp.	full 2FL	Gasifier		
Coal gasification H2 plant	full 2FL	Gasifier		
Biom. gasification H2 plant	full 2FL	Gasifier		Biomass handling subcomp.
Biomass handling subcomp.	1FL	Stand alone		
IGCC	Exogenous learning		Gasifier subcomp.	
Biomass gasification power plant	Exogenous learning		Gasifier subcomp.	Biomass handling subcomp.
Biomass power plant	Exogenous learning			Biomass handling subcomp.

Table C-21 summarizes how endogenous two-factor learning is implemented in MESSAGE using 6 clusters and 3 independent standalone learning (sub)technologies (for details, see C.2.3.2). Seventeen technologies

and 6 subcomponents are fully 2FL. One subcomponent is 1FL. Three exogenous learning technologies have 2FL subcomponents.

As specified in the definitions of the 2FLC (see C.1.2), there is only one common “FC” R&D spending variable for the clusters of “stationary fuel cells” and “mobile fuel cells,” and there is only one common “reformer” R&D spending variable for the “steam methane reformer” (SMR) and “mobile reformer” clusters. The mobile fuel cell stack subcomponent is a special case. According to definitions of the 2FLC, one cost component of the stationary fuel cell combined-heat-and-power (CHP) plants is equal to the mobile fuel cell stack. But, on the other hand, the stationary fuel cell CHP plants do not contribute to the “mobile FC” cluster, which is why the mobile fuel cell stack subcomponent learns together with the “mobile FC” cluster but does not contribute (factor = 0) to the common cumulative installations of the “mobile FC” cluster.

C.2.3.2 Implementation of endogenous two-factor learning (2FL) in MESSAGE

In section C.2.3.1 we described how the modeling of learning spillovers was implemented into the MESSAGE model using clusters, standalone technologies, and subcomponents. In this section we describe in detail how the two-factor learning curve formulation (as defined in C.1.2) for these clusters, standalone technologies, and subcomponents was implemented into MESSAGE.

The idea behind using 2FLCs is that technological learning and cost reductions should not be given as exogenous input time series, but should result from the evolution of the model itself. If a technology is used excessively in one model scenario run, then its characteristics should improve, while if the same technology is not used in some other model scenario run, its characteristics should remain static. The 2FLCs describe how the different technological parameters improve with experience (learning by doing) and with research (learning by research). As a measure of experience, the 2FLCs given in C.1.2 use the cumulative installed capacity $K(t)$ and as a measure of research, the cumulative spent R&D $R(t)$.

One main characteristic of a technology are the investment costs. The two-factor learning curve (2FLC, as defined in C.1.2) formula for the investment costs can be rewritten as:

$$Cost(t) = F(K(t), R(t)) \quad (1)$$

As MESSAGE is a large linear optimization model it is not possible to model a continuous change of technology characteristics depending on the endogenously achieved cumulative installed capacities or R&D spending. This would result in a nonlinear model which would not be easy to solve. But it is possible to have changing costs and technology parameters as endogenous results using discrete learning steps and mixed integer programming. Thus, instead of implementing the 2FLC as a continuous function (see Equation [1]), the 2FLC is implemented into MESSAGE as a matrix with discrete learning steps (see Table C-19 and Table C-20).

As the solution times of mixed integer programs are very long, the number of learning technologies and the number of learning steps must also be limited so that the model can be solved sufficiently accurately within a reasonable time. Endogenous one- factor learning (“learning by doing”) modeled with mixed integer

programming is a known option in MESSAGE. New in section C.2.3.1 was the introduction of subcomponents to model spillovers on a more accurate basis and in this section the implementation of two-factor learning in MESSAGE.

The idea behind 2FLC implementation in MESSAGE is that if a technology T is made a 2FL technology, then the single technology T is replaced by a whole set of technologies. Each technology in the set represents the same technology, but with characteristics that are changed because of different LBD and LBR levels.

To reduce the model solution time for each 2FL cluster or standalone technology, 4 levels of cumulative spent R&D $R(t)$ and 5 levels of cumulative installed capacity $K(t)$ were defined. If all the combinations are included, this gives a set of 20 ($= 4 \times 5$) technologies T_{ij} ($i=0..3, j=0..4$) which replace the original technology T. The T_{00} technology is the initial technology before learning occurs. The technologies T_{ij} with indices $j=1..4$ are the same technology after certain levels of LBD have occurred. The technologies T_{ij} with indices $i=1..3$ are the same technology after certain levels of LBR have occurred. MESSAGE is programmed in such a way that a specific level of cumulative installations needs to be reached before the technologies for all technologies with a specific column index j can be installed by the model and become active. Similarly, for each row index i , a specific level of cumulative R&D needs to be spent on this technology before the technologies with this index can be installed by the model and become active. Thus, at the beginning, only the technology T_{00} is allowed to be active. At higher levels of learning, more and more of the technologies T_{ij} are allowed to be active. From all the technologies T_{ij} that are allowed to be active, MESSAGE will, of course, always choose the most advanced technology, as this technology will have the lowest cost and highest efficiencies. As all the 20 technologies T_{ij} ($i=0..3, j=0..4$) are implemented in MESSAGE as full technologies, all aspects of the original technology T can be made learning, for example, the investment cost, efficiency, fixed/variable operation and maintenance costs, and any other parameter of the technology T. One simply has to define a set of technologies T_{ij} ($i=0..3, j=0..4$) with improved characteristics.

The relations used in MESSAGE to define when a certain technology T_{ij} is allowed to be installed by the model and to become active are given below:

In MESSAGE, technologies are usually modeled using capacity and activity variables. The capacity variable of a technology T is denoted by Y_T and represents the annual new installed capacity of that technology in Gigawatts (GW). Let the activity variable be denoted by A_T and represent the annual output produced in Gigawatt years (GWyr). Let the lifetime of the technology T be denoted by τ . There is then a capacity relation in MESSAGE ensuring that the output in time period p is not higher than the total installed capacity CT in that time period can produce:

$$AT(p) < Plantfactor \cdot CT(p) \quad (2)$$

The total installed capacity CT is the sum over all new installed capacities in the past up to the lifetime of the technology:

$$CT(p) = \sum_{q=(p-\tau-1)}^p (YT(q) \cdot length(q)), \quad (3)$$

where $YT(p)$ represents the annual new installed capacity in period p and $length(p)$ the length of the time period in years. Ten-year time periods are used in this study. Unless $YT(p)$ has been positive in the past, the technology T cannot become active and produce an output AT .

Now let CRD1 to CRD3 levels of cumulative spent R&D be used to define 3 different states of learning by research for the cluster to which technology T belongs. Let CCL1 to CCL4 be levels of cumulative installed capacity used to define 4 different states of learning by doing for the same cluster. Then let the technology T be replaced by a set of technologies T_{ij} ($i=0..3$, $j=0..4$) with improved characteristics, where the characteristics of technology T_{ij} represent the technology T after learning due to a cumulative spent R&D of CRD i and after learning due to a cumulative installed capacity of CCL j .

For the investment cost $InvC_{ij}$ of technology T_{ij} , the 2FLCs, as defined in C.1.2, are used to calculate the costs. In Equation (4) the recursively defined 2FLC of C.1.2 is given in an integral representation. A difference is that the “+1” term of the 2FLC given in C.1.2 is removed, as it leads to the possibility that the learning curve could go below the floor. In most cases, the “+1” term makes a difference of less than 1%.

$$\int_{InvC_{00}}^{InvC_{ij}} \frac{e^{\left(\frac{s \cdot floor}{C - floor}\right)}}{C} dC = rdelfac \cdot \ln\left(\frac{CRD_i}{CRD_{2000}}\right) + capelfac \cdot \ln\left(\frac{CCL_j}{CCThre}\right) \quad (4)$$

CRD2000 is defined as the cumulative spent R&D up to the year 2000, CCThre as the threshold of cumulative installed capacity after which LBD is effective (see C.1.2), and $InvC_{00}$ as the initial cost before learning. The initial costs are assumed to be the costs in 2000 (see C.1.2). The parameters CRD i and CCL j were defined above, and the parameters s , $floor$, $rdelfac$ $capelfac$ are defined in the definition of the 2FLC in C.1.2. The investment costs $InvC_{ij}$ are then calculated by solving the integral in Equation (4) for the upper bound.

For the sake of simplicity, a different approach was used for the other technology parameters such as efficiency, plant factor, fixed/variable operation and maintenance costs, or amount of subcomponents needing to be installed per unit of main technology. If one of these parameters is assumed to be learning, then the initial value and the final value after full learning for this parameter was taken from TECHPOL or C.1.2 and then Equation (5) was used to calculate the parameter value $Para_{ij}$ for the technology T_{ij} :

$$Para_{ij} = \frac{InvC_{ij} - InvC_{34}}{InvC_{00} - InvC_{34}} \cdot (Para(2000) - Para(Final)) + Para(Final), \quad (5)$$

where $InvC_{34}$ represents the investment costs after a cumulative spent R&D of CRD3 and after learning due to a cumulative installed capacity of CCL4. Thus, $InvC_{34}$ is the investment cost after full 2FL (see Table 5). Equation (5) shows that the parameters progress at the same pace as the investment costs from initial to final values. That way, for each T_{ij} ($i=0..3$, $j=0..4$), the improved technology characteristics are calculated and then T_{ij} is implemented in the MESSAGE code.

Table C-22. The initial cost in 2000, the cost after full mixed integer learning (called InvC34 above), and the floor cost of different representative learning technologies.

	Units	Initial Cost	Cost after full MIP learning	Floor Cost
Veh. FC Comp. of the H2 FC car	USD90 / car	2743556	2867	1631
Stationary fuel cell CHP	USD90 / kW	7438	553	169
H2 steam methane reformer	USD90 / kW	264	210	189
Gasoline Car Reformer	USD90 / kW	5747	6.2	6.2
Mobile H2 Storage	USD90 / kgH2	577	60	44
Generic Hybrid Component	USD90 / car	3522	997	995
H2 Electrolyser	USD90 / kW	487	281	261
Gasifier Component	USD90 / kW	461	276	216
Biomass Handling	USD90 / kW	288	136	108

In the following we explain the relations that control the activity of the technologies T_{ij} which are dependent on endogenously achieved learning.

Table C-23. Scheme showing which of the relations R1 to R3 and D1 to D4 acts on which technology T_{ij} .

			Relation D1: LBD level CCL_1	Relation D2: LBD level CCL_2	Relation D3: LBD level CCL_3	Relation D4: LBD level CCL_4
		T00	T01	T02	T03	T04
Relation R1:	R&D level CRD_1	T10	T11	T12	T13	T14
Relation R2:	R&D level CRD_2	T20	T21	T22	T23	T24
Relation R3:	R&D level CRD_3	T30	T31	T32	T33	T34

The relations D1 to D4 control which “column” of technologies (index $j = 1$ to 4) can become active, while the relations R1 to R3 control which “row” of technologies (index $i = 1$ to 3) can become active. This is illustrated in Table C-23.

The relations $D_j(p)$ ($j = 1 \dots 4$) are defined as:

$$\sum_{i=0}^3 Y_{T_{ij}}(p) < M \cdot DB_j(p) \quad (6)$$

There is one relation D_j for each time period p , where $Y_{T_{ij}}(p)$ is the annual new installed capacity of technology T_{ij} in period p and $DB_j(p)$ is the activity variable of a binary technology. M is a number defined so that M is larger than any possibly expected annual new installation of technology T . M was set at 100,000 in this study. This relation means that if the binary output $DB_j(p)$ is 0, then for the technologies in this relation there can be no new installation in this period p . If $DB_j(p) = 1$, then the model is free to make new installations for the technologies in this column.

A binary technology is defined here as having infinite lifetime and as always being active once it is installed. The binary technology is modeled using the activity variable $DB_j(q)$ and the capacity variable $YDB_j(p)$. $YDB_j(p)$ is not defined as annual new installations, as in the case of normal technologies, but as the new installed capacity in the period p .

The relations for defining a binary technology are:

$$DB_j(p) = \sum_{q=2000}^p YDB_j(q) \text{ and } \sum_{q=2000}^p YDB_j(q) \leq 1, YDB_j(p) \text{ is binary.} \quad (7)$$

$DB_j(p)$ is defined as a normal variable, and $YDB_j(p)$ is defined as a binary variable for the CPLEX optimizer. If a binary technology is installed in one time period p (i.e., $YDB_j(p) > 0$ for a specific p) then the output is $DB_j(q) = 1$ for all time periods $q \geq p$ and $DB_j(q) = 0$ for all time periods $q < p$.

The relations R_i ($i = 1 \dots 3$) are defined as:

$$\sum_{j=0}^4 YT_{ij}(p) < M \cdot RB_i(p) . \quad (8)$$

The definitions are similar to those described above, and $RB_i(p)$ is the activity variable of a binary technology.

Thus, the relations R_i ($i=1 \dots 3$) and relations D_j ($j=1 \dots 4$) define which of the 20 technologies T_{ij} ($i=0..3$, $j=0..4$) can be active. The relations are controlled by the activity variables $RB_i(p)$ and $DB_j(p)$ of binary technologies.

Only 7 variables (4 YDB_j + 3 YRB_i) defined as binary for the CPLEX optimizer are needed to control the 20 technologies T_{ij} in this 2FL implementation. For a one-factor learning implementation (5 technologies, 1 initial + 4 advanced LBD levels), 4 binary variables would still be needed. Thus, despite the fact that the number of technologies replacing the original technology T increases from 5 T_j ($j=0..4$) for 1FL to 20 for T_{ij} ($i=0..3$, $j=0..4$) for 2FL, the number of binary variables increases only from 4 to 7. This is important because the running time depends on the number of binary variables.

If technology T is not a standalone technology but part of a cluster C , then Equations (6) and (8) actually include all the cluster technologies into the sum, as all technologies of a cluster C are affected by the same binary variables:

$$\sum_{T \in C} \sum_{i=0}^3 YT_{ij}(p) < M \cdot DB_j(p) \text{ and } \sum_{T \in C} \sum_{j=0}^4 YT_{ij}(p) < M \cdot RB_i(p) \quad (9)$$

In the following, we present the equations that connect the cumulative installed capacity and the cumulative spent R&D to these binary technologies.

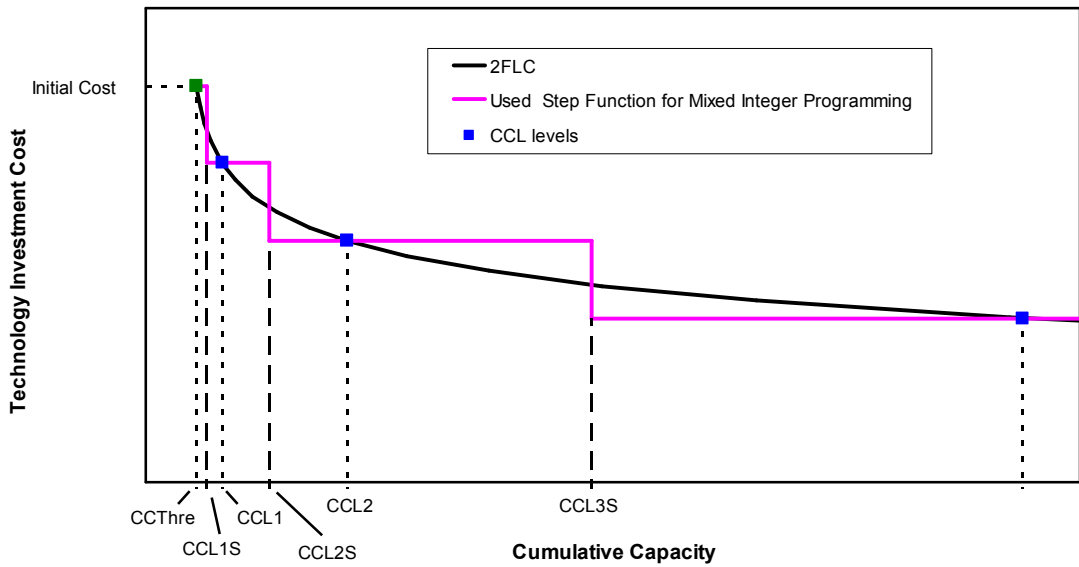


Figure C-16. Relation of the switching level CCL_jS to the cumulative installed capacity levels CCL_j .

First, for each cumulative R&D level $CRDi$ and for each cumulative installed capacity level CCL_j , a corresponding switching level $CRDiS$ and CCL_jS has to be defined. In Figure C-16 the investment cost reduction due to learning by doing is depicted schematically as a black line. The initial investment cost is marked with a green square. The blue squares mark the investment costs $InvC_{ij}$ corresponding to the cumulative installed capacity levels $CCL_j (j=1..4)$ as defined in Equation (4) for technology T_{ij} . If the technologies T_{ij} (representing the technology performance due to a cumulative R&D of $CRDi$ and a cumulative installed capacity of CCL_j) were enabled only after the corresponding CCL_j level was achieved, then the technology T_{ij} would be always more expensive than it should be according the continuous 2FLC (blue line in Figure C-16). If the model enables the technology T_{ij} at some level CCL_jS before it reaches CCL_j , then the technology will first be lower in cost than the continuous 2FLC and, after reaching the level CCL_j , higher in cost. Thus, the investment cost of the enabled technologies T_{ij} would behave like the purple step function in Figure C-16. The investment cost of the enabled technologies will be sometimes cheaper and sometimes more expensive than it should be, according to the continuous 2FLC. If the switching levels (CCL_iS) are chosen properly, then the cumulative installation costs up to CCL_3 would be similar if the investment costs behaved as defined by the continuous 2FLC or if the costs followed the steps defined by CCL_jS and $InvC_{ij}$. In other words the integral from $CCThre$ to CCL_3 over the black line is the same as the integral over the purple step function; as the value of the integral is the cumulative investment cost, it is clearly desirable for the cumulative investment costs of the (step) approximation to be close to the continuous 2FL estimate. What cannot be easily incorporated into the optimal selection of the switching level CCL_jS is the effect of a 5% discount rate. The discount rate makes costs less expensive for the model in the far future than in the near term. Thus, the step behavior will also distort the cumulative cost even if the integral is the same as over the continuous 2FL curve.

This was the motivation for the following definitions:

$$CCL_1S = \sqrt[1.76]{CCThre^{0.76} \cdot CCL_1} \text{ and } CCL_jS = \sqrt[1.76]{CCL_{j-1}^{0.76} \cdot CCL_j} \text{ for } j = 2, 3, 4 \quad (10)$$

The switching levels CCLjS are defined as a weighted geometric mean of the corresponding CCLj levels. This simple formula turned out define close to the optimal switching points.

Relating YDBj(p) to the cumulative installed capacity:

Now we calculate the cumulative installations required on each learning step: $DS_j = CCL_jS - CCL_{j-1}S$, where CCLoS is the cumulative installed capacity in 1990 and CCL1S to CCL4S are the switching levels (as defined above). For example, DS2 is the number of cumulative installations needed on the first improved LBD level to achieve the second improved LBD level.

For each j (j=1..4) and each period p a relation is defined as:

$$\sum_{q=1990}^p \sum_i Y_{T_{ij-1}}(q) \geq DS_j \cdot YDB_j(p). \quad (11)$$

This means that the cumulative installations on the learning-by-doing level (j-1) must be greater than or equal to DSj, before YDBj(p) can be 1. If the technology T is not a standalone technology but part of a cluster C, then Equation (12) also includes a sum over all technologies in the cluster that contribute to the cumulative installations of the cluster with some factor f(T) (see factor 5.7, above, for electric cars):

$$\sum_{T \in C} \left[f(T) \cdot \left(\sum_{q=1990}^p \sum_i Y_{T_{ij-1}}(q) \right) \right] \geq DS_j \cdot YDB_j(p). \quad (12)$$

Relating YRBi(p) to the cumulative spent R&D:

Switching levels CRDiS are defined as a weighted geometric mean by:

$$CRD_1S = \sqrt[1.76]{CRD_{2000}^{0.76} \cdot CRD_1} \text{ and } CRD_iS = \sqrt[1.76]{CRD_{i-1}^{0.76} \cdot CRD_i} \text{ for } i = 2 \text{ and } 3. \quad (13)$$

For each i (i = 1..3) and each period p, a relation is defined as:

$$CRD_{2000} + \sum_{q=2000}^{p-1} SPT(q) \geq CRD_iS \cdot YRB_i(p), \quad (14)$$

where CRD2000 is the cumulative spent R&D up to 2000, SPT(p) is the R&D spending variable for technology T in the period p, CRDiS is the switching level defined above, and YDBj(p) is the binary variable (YDBj(p) has values 0 or 1). The R&D spending in time period p is defined as having a cost-reduction effect

only in the next time period $p+1$. Thus, $CRD_{2000} + \sum_{q=2000}^{p-1} SPT(q)$ is the cumulative spent R&D having an effect in time period p . The equation means that $YRBi(p)$ can be equal to 1 only if

$$CRD_{2000} + \sum_{q=2000}^{p-1} SPT(q) \geq CRDiS. \quad (15)$$

In other words, once the cumulative spent R&D is larger than or equal to the required R&D level $CRDiS$, then $YRBi(p)$ can be = 1 and $RBi(p) = 1$, and then the technologies T_{ij} ($j = 1 \dots 4$) of relation R_i can be active.

This R&D relation works as desired: depending endogenously on the model R&D spending decisions $SPT(p)$, in the time period when the cumulative spent R&D is larger than or equal to the R&D level $CRDiS$, a version of the technology T is activated, which reflects this state of learning by research.

To sum up: relations (12) and (14) connect the cumulative installed capacity and the cumulative spent R&D to the binary variables YDB_j and $YRBi$, and these binary variables enable those technologies in the technology matrix T_{ij} that reflect the state of 2FL learning.

As presented in the previous section, the 2FL is implemented in MESSAGE using clusters, standalone technologies, and subcomponents (see Table C-21). Each cluster has one common R&D spending variable. A description of how R&D budget limitations are defined is left open. In MESSAGE several 2FL operation modes were implemented:

If there are different technology clusters (see Table C-21) C_k , each of which, independently, is 2FL, then a common R&D budget time series $B(p)$ can be specified and the model set to optimize endogenously which cluster to spend the available R&D budget on for each time period. The budget constraint is then defined as $\sum_k SPC^k(p) < B(p)$, where $SPC_k(p)$ is the R&D spending variable on the technology cluster C_k . There is only one spending variable for each cluster.

It can be defined that the R&D spending budget is unlimited but that each euro spent on R&D in the time period p has a cost entry of one euro in the objective function for the time period p . The result is that the model will spend the R&D only if this results in lower costs worth more than the R&D spent. As the cost entries in the objective function are discounted by 5%, the model will also try to optimize the timing of the R&D so that the R&D is only spent just before the respective technology is needed.

A combination of the two above points. The R&D spending can be limited and have a cost entry in the objective function.

Exogenous R&D spending time series $SPC_k(p)$ are supplied for each cluster and the model is solved as a one-factor learning problem, where on each LBD step, the costs improve with time because of the exogenously given R&D spending time series (see below Table C-24).

Combinations of the above are also possible. Some technology clusters may be defined as having a common budget, whereas other clusters have a predefined budget time series, and others have free spending with costs.

These cases will be called operation modes 1–5 of the MESSAGE 2FL code. Cases 1–3 are full 2FL implementations with endogenous optimization of the R&D spending, whereas case 4 is a 2FL implementation with exogenously given R&D spending and is, in fact, a modified 1FL using two-factor learning equations and the given R&D spending time series to calculate the cost improvements with time on each learning-by-doing step (see below Table C-24).

Table C-24. Cost matrix for gasoline battery hybrid cars (a technology of the hybrid cluster) used in MESSAGE for the baseline scenario. The baseline scenario uses the exogenously given R&D spending outlook values given in Table C-25. Compare also Table C-20. The values in the column headers are the CCLj levels used, defined above.

		CCL0	CCL1	CCL2	CCL3	CCL4
Model cumulative installed hybrid cars [mioCars]:		0	56	233	1165	6991
R&D spending outlook for hybrids[M\$90]:	Year	Gasoline battery hybrid car inv. cost [USD90/car]				
2817	2000	16191	15646	15401	15139	14881
6552	2010	15594	15145	14943	14721	14513
12342	2020	15147	14782	14603	14418	14240
20396	2030	14856	14539	14377	14223	14066
30364	2040	14671	14372	14233	14087	13948
41834	2050	14531	14257	14130	13996	13867
54850	2060	14423	14167	14047	13924	13819
69083	2070	14340	14100	13984	13866	13796
84342	2080	14274	14046	13932	13824	13778
100413	2090	14223	14001	13897	13803	13764
117087	2100	14186	13967	13865	13796	13755

The data for the R&D outlook to 2050 are supplied with the definition of the 2FLC in D.1.3. The data were aggregated for the 10-year time periods used in this MESSAGE model, and quadratic extrapolation was used to extend the outlook to 2100 (see Table C-25 and Figure C-17). The R&D outlook for gasifiers and biomass handling was calculated as a weighted sum, as defined in C.1.2. The hybrid R&D outlook is a sum of the battery and hybrid + electric outlooks. The reformer outlook is the sum of the gas steam reformer and the solar reformer outlook.

Table C-25. Outlook for the cumulative R&D spending (million USD90) up to, but not including, the year given as column header for the clusters, as defined in Table C-21.

	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Fuel cell	22088	29864	45002	66263	92913	124921	160984	200688	243310	288173	334598
Mobile H2 storage	82	505	1912	4732	9614	16926	27264	41111	58980	81380	108824
Hybrid System	2817	6552	12342	20396	30364	41834	54850	69083	84342	100413	117087
Gasifier	1378	2307	4017	6522	9598	12688	15838	18673	20962	22456	22904
Electrolyzer	164	808	1874	3300	5056	7131	9468	12044	14823	17772	20857
Reformer	450	2307	5331	8144	11643	15111	18466	21545	24154	26112	27235

In the definitions of the 2FLC, there is only one common “fuel cell” R&D spending variable for the clusters “stationary fuel cell” and “mobile fuel cells,” and there is only one common “reformer” R&D spending variable for the clusters “steam methane reformer” (SMR) and “mobile reformer.”

If the MESSAGE model is run in 2FL operation mode 4 (baseline scenario, see D.2.1.4; see technology story scenarios, D.3.2.4) then no definition of learning by research levels CRDi is required, as the exogenous R&D outlook and the 2FL input matrices defined as in Table C-24 are used for the code. Only if 2FL operation modes 1 to 3 are used is the definition of learning by research levels CRDi needed. In that case the R&D budget of a cluster is not restricted to the R&D outlook of that cluster but to the total R&D spending of all clusters sharing the budget time series (in the case of mode 1) or is unlimited (mode 2). Thus, there is a competition and the possibility of a cluster exceeding its own R&D budget.

Keeping this in mind, the learning-by-research levels for a cluster were selected roughly in accordance with the guidelines given below:

CRD1 was selected so that the cumulative R&D spending outlook for this cluster exceeds the CRD1S switching level in 2030.

CRD2 was selected so that the cumulative R&D spending outlook for this cluster exceeds the CRD2S switching level in 2090.

CRD3 was selected so that if this cluster had 4 times the R&D spending assigned in the R&D outlook, the cumulative R&D spending would exceed the CRD3S switching level in 2060.

These guidelines were adapted for each cluster as appropriate. For example, the steam methane reformer (SMR) 2FLC showed only little response on R&D, according to the above guidelines. Keeping in mind the total R&D budget of all clusters, the R&D levels chosen for the SMR were higher.

The learning-by-doing levels CCLj for a cluster were selected so that the final switching level CCL4S of cumulative installed capacity can be reached until 2100 if the technology is widely introduced into the respective market in around 2030. The intermediate levels are chosen so that, in the case of LBD only, the costs are reduced by the same amount with each step. For the hybrid cluster cost matrices, this equal reduction step size for LBD is not strictly accurate (Table C-19, Table C-20 and Table C-24), as the investment cost matrix is the sum of two 2FLCs (electric engine 2FLC + battery 2FLC); moreover, as the LBD levels generating equal cost reductions for each step for the electric engine 2FLC do not result in even cost reduction steps for the battery 2FLC, the sum also shows uneven cost reductions.

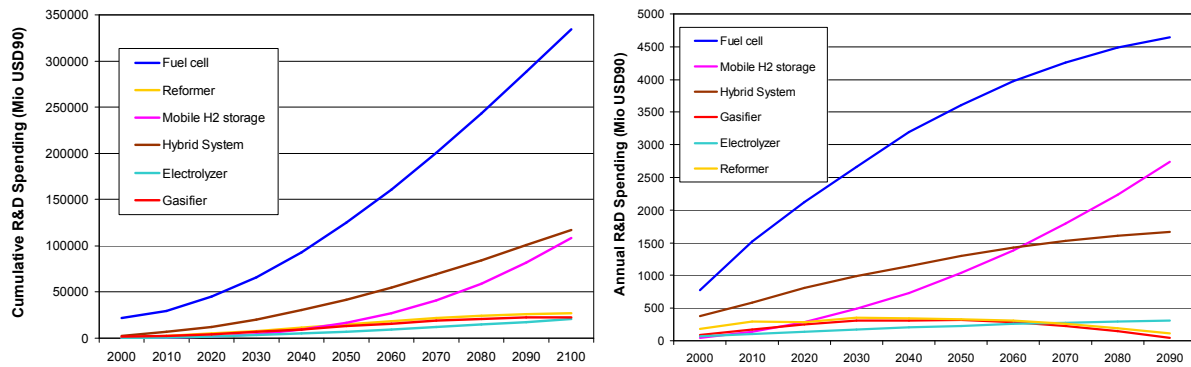


Figure C-17. The graph on the left shows the cumulative R&D spending outlook for the clusters, as defined in Table C-21. The data are the same as in Table C-25. The graph on the right shows the corresponding annual R&D spending values.

To make a 2FL run, the MESSAGE model needs a list of all technologies, as well as their corresponding clusters, to be made endogenously learning. For each 2FL technology (see Table C-21) the model needs the switching levels CRDiS, CCLjS, the investment cost matrix in the form of Table C-20 and Table C-24 and, for each learning parameter of each learning technology, the initial and final values (see Equation (5)). Further, for each cluster, the 2FL operation mode has to be defined (see definition above). All this data is included in an input text file. A UNIX shell file and the UNIX program AWK are used to automatically replace each 2FL technology T with a set of 20 technologies T_{ij} ($i=0..3$, $j=0..4$) and to add the relations described before governing the 2FL process according to the input data. The shell file then starts the MESSAGE matrix generation (resulting in an approximately 30 MB matrix) and the mixed integer optimization using CPLEX. Usually, a 2FL run is optimized for 24 hours on one 750 MHz Spark V9 processor of a Sun Fire 880 server. The runs were then continued for another 24 hours to confirm that the optimal solutions were indeed found and that the solution did not change. The optimal solution was often found even within 12h.

C.2.4 Perfect Foresight Integrated Assessment Model: MERGE-ETL

[by S. Kypreos (PSI)]

Model Development

The analysis for CASCADE-MINTS, part I (CMI), has been done using a project specific version of MERGE Integrated Assessment Model (IAM) that “provides a framework of thinking about climate change management proposals”. The PSI version, called MERGE-ETL, developed during the 5th Framework Programme of DG Research and the Swiss NCCR project on “Climate variability and risk”, allows considering different endogenous technological learning (ETL) options to describe fossil fuels, renewables and nuclear energy including carbon capture and disposal options. It is therefore appropriate to highlight aspects of optimal emission control trajectories of carbon dioxide and other greenhouse gases and technology dynamics. What was not included before refers to an explicit treatment of transportation technologies, the

production of synthetic fuels and hydrogen and their infra-structures and the concept of clusters where spillovers among key technology components (i.e., gasifiers, gas turbines, fuel cells, battery systems, etc.) can be explicitly modeled.

The objective of CMI related work described herein was to modify and extend the present version of MERGE-ETL to address, in more details, the processes and technologies related to hydrogen economy on a global level and explain the way this new model dimension substitutes for the aggregate representation of energy markets available now. After completion of the modeling extension, the description of the hydrogen related technologies with endogenous learning needed to represent technology dynamics will follow. The model is then used to elaborate on different scenarios concerning the hydrogen economy, defining among others, the trade-off between the hydrogen economy and environmental policies.

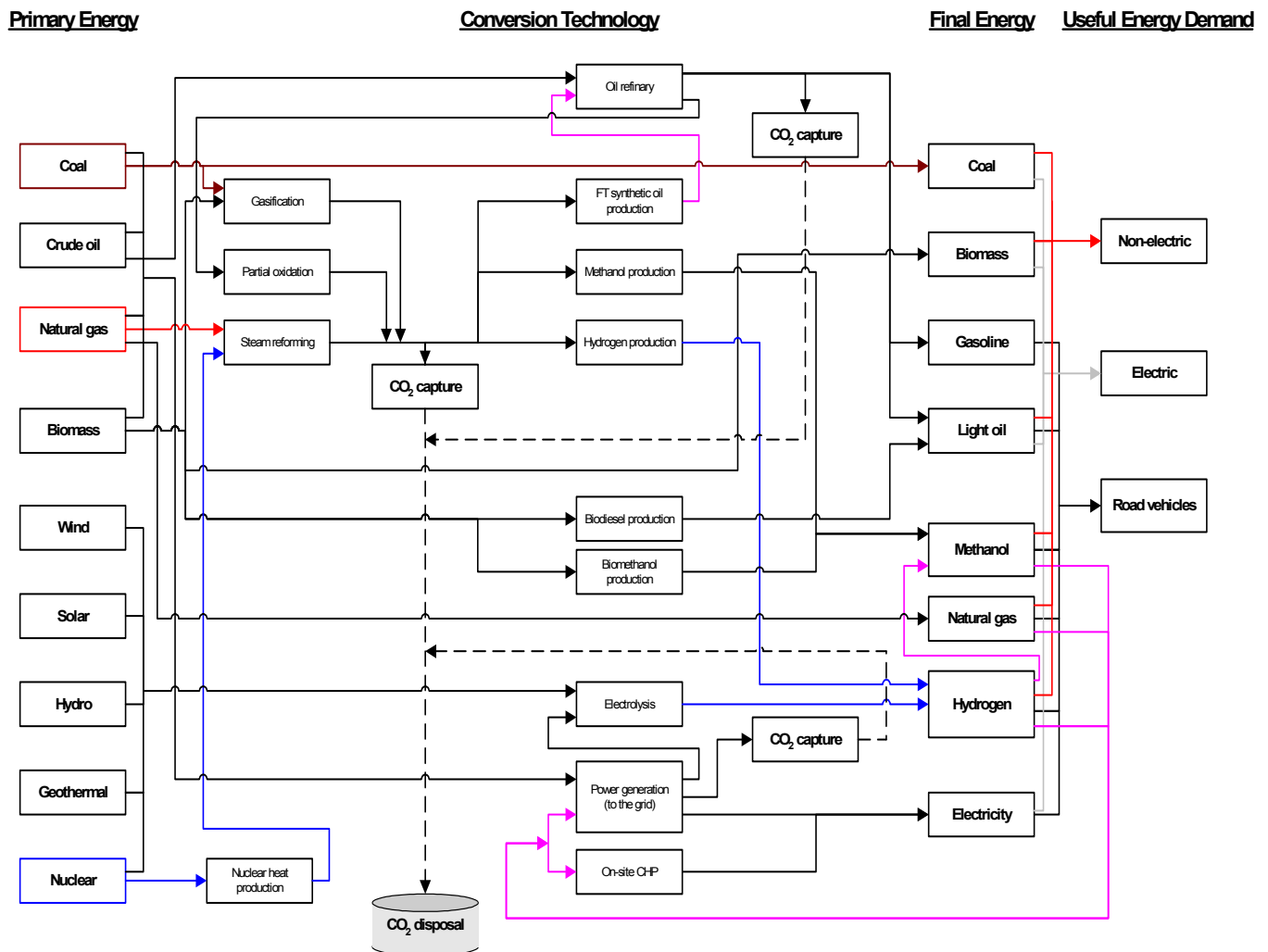
The model extension takes place in the bottom-up part of MERGE, called ETA, which represents the energy supply system and the power generation. ETA defines a least cost solution for each scenario for the demand of electric and non-electric energy use. Fossil fuels are viewed as exhaustible resources while there are limits in the availability and introduction of low cost renewable resources like hydropower etc. Penetration constraints are applied on new technologies like synthetic fuels and carbon free backstop technologies.

We have extended the technological options to generate hydrogen by different sources like fossil fuels, bio-fuels, nuclear energy and renewables. The so-produced hydrogen will be used for either electricity production or to cover end-use demands. CO₂ sequestration options can be also included for hydrogen production based on fossil fuels or biomass.

As hydrogen is a secondary energy carrier, the production and its use related to electricity generation and the end-use markets has to be represented in MERGE together with a set of competing conventional and alternative technological options. Also, the demand for these end-use markets has to be defined in a consistent way with the demands for electric and non-electric energy. These two demands i.e., for electric and non-electric energy are defined by a production function based on a constant elasticity of substitution (CES) formulation between the energy and the value-added aggregate. We will then represent the specific end-use demands by the relative change of the baseline demands that takes into consideration income variations and the change in the relative price of energy services.

Figure C-18 is a schematic representation of the Reference Energy System (RES) of MERGE describing what it has been explained before.

Figure C-18: The Reference energy system of MERGE



Market demand for personal transportation

The private transportation is introduced as an independent sector that consumes part of the non-electric energy to satisfy the demand for mobility¹⁵. The demand for mobility is based on the constant time and budget constraint that allows distributing the total mobility to different modes of transport when the per capita income increases or the cost per unit of mobility changes.

The market demands considered here are overall demands for transportation, in terms of passenger kilometres ([P-km]). As Person-km's depend on the load factor of each specific mode and type of transportation technology, appropriate load factors have to be considered based on statistical information. In

¹⁵ The alternative possibility was to consider demands for energy services and express them with a CES function as in MARKAL-MACRO. But, to keep the model changes simple, we have formulated the reference demands for private mobility to be part of the non-electric demands following their baseline developments.

the presented work, the main focus was laid on personal transportation, which includes Personal Vehicles (personal cars) and Buses and is calculated as suggested by Schafer and Victor, 2000.

The concept of Travel Time Budget (TTB) indicates that world-wide, citizens spend an average, fixed amount of around 1 hour a day for commuting. This includes work-office travel, as well as vacation-travel, household trips, etc. The estimated TTB includes travel by different modes of transport – ranging from bipeds, personal automobiles to public transport and airplanes. Additionally, it has been noticed that the preference of citizens to travel with specific modes of transport is dependant on the income measurement (GDP/capita). Hence, citizens of countries with high GDP/capita level tend to use faster and more expensive modes of transport (for example airplanes), while citizens from lower-income countries use slower modes.

In this study, a modified version of Schafer and Victor equations were coded in GAMS. The overall demand for transportation, as a function of GDP/capita is defined as presented in Figure C-19, Eq. 1.

$$TV_t = \log\left(\frac{GDP_t}{G} - H\right) \cdot GDP_t^{E \cdot F} \quad \text{Eq. 1}$$

Where:

TV Overall demand for passenger transportation [passenger km]

t Time index

GDP GDP/capita, for the reference development expressed in USD [USD'95]

G,H,E,F constants defined by econometric analysis (Schafer and Victor 2000) adopted for the GAMS code

Then, the overall transportation demands for specific modes are obtained in forms of percentage shares, as described in the following equations:

$$S_{\text{Rail}}(t) = I * \left(\frac{1}{(TV(t) - J)^K} - \frac{1}{(240000 - J)^K} \right) \quad \text{Eq. 2}$$

With:

SRail Share of railroad transportation [%],

I,J,K constants (Schafer and Victor 2000) adopted for the GAMS code

$$S_{\text{HighSpeed}}(t) = S * 10^{e(-T*(TV(t)-U))} + V \quad \text{Eq. 3}$$

SHighSpeed Share of high speed transport (airplanes and ultra fast trains) [%]

T,U,V,S constants (Schafer and Victor 2000) adopted for the GAMS code

$$S_{\text{Bus}}(t) = \frac{BK}{(TV(t) - TV_{\text{Bus}}(1990))^{BM}} + BC - S_{\text{Rail}}(t) \quad \text{With:} \quad \text{Eq. 4}$$

S_{Bus} Share of bus transportation [%]
BK,BM,BC constants (Schafer and Victor 2000) adopted for the GAMS code

$$S_{\text{PersonalVehicle}}(t) = 1 - S_{\text{Bus}}(t) - S_{\text{Rail}}(t) - S_{\text{HighSpeed}}(t) \quad \text{Eq. 5}$$

With:

S_{PersonalVehicle}: Share of personal cars [%]

Although we explain the equations for all modes of transport, MERGE-ETL concentrates only on the part related to the personal transport by cars (Figure C-19).

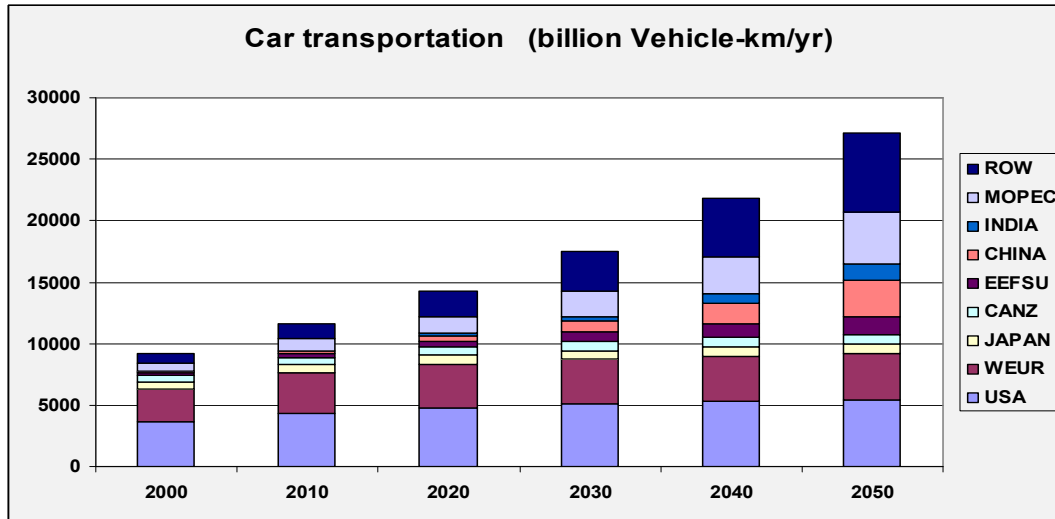


Figure C-19: Demand projection is given billion vehicle km for the B2 SRES scenario, based on the model of A. Schafer, as modified by Hal Turton (2006). In this case, the industrialized world moves to faster modes of transport while the rest of the regions increase mobility following the population and economic growth developments. Global mobility is increasing by almost a factor of three, mostly in the now less developed countries.

Alternative formulation of learning based on TFLC

Technological learning describes how the specific cost of a given technology is reduced through the accumulation of knowledge. This learning process evolves either from manufacturing and operation of the technology (LBD) or through the allocation of research-and-development expenditures to that technology (LBS). A learning curve relates the specific cost incurred by a given technology to one or more factors describing the accumulation of knowledge related to that technology.

Depending on the scope, alternative formulation of MERGE for the CASCADE-MINTS project have been elaborated and applied in the course of the project:

- The first option formulates a relatively simple TFLC problem, as a non-convex and non-linear problem and excludes, through a careful choice of initial bounds and terminal conditions, local

optimal solutions, as shown by Manne and Barreto (2004). In such case, CONOPT-3 can solve directly MERGE to define an optimal but deterministic RD&D-portfolio for new technologies. This approach is only applied for a limited set of technologies with endogenous learning properties. The RD&D budget is endogenous and becomes a function of the objectives we like to realize.

- An alternative approach to define the TFLC problem has been proposed by Kouvaritakis and Panos, (2005) for CASCADE-MINTS introducing technology clusters with gradually reducing learning rates as technologies approach their floor cost. This formulation of learning functions well when applied in simulation models with expectations but not with optimization models of perfect foresight like MERGE¹⁶.
- The third approach follows pre-specified RD&D budgets, a-priori allocated to technologies (e.g., as in the EU project Sapiencia). In this methodology, the model will simulate first, the technology uptake in the markets and it will quantify a set of indicators describing different sustainability objectives. This is a Monte-Carlo method that defines the mean, the variance and the co-variance matrices of indicators describing different sustainability objectives per technology. Finally, with a stochastic budget allocation algorithm, decisions concerning RD&D allocation can be re-defined based on an objective function to be maximized and a set of constraints to be satisfied with a given probability.

There are also alternative possibilities to apply directly MERGE-ETL or the specific transportation sub-model TREDa (Kryzanowski, Kypreos, Barreto, 2007), in either a stochastic analyses (SA) or in a Monte-Carlo risk assessment framework, not followed in the work described herein, but discussed here to highlight potential alternatives for future work¹⁷.

In the following section we are describing the MERGE-ETL formulation that defines a deterministic endogenous budget allocation and the version of MERGE-ETL finally followed for the CASCADE-MINTS project.

¹⁶ An effort has been undertaken to apply the method of Kouvaritakis and Panos in MERGE with partial success. The method is based on an **iterative** and **heuristic** MERGE version, as described in the final PSI report for SAPIENTIA; it works well for simple models with a few competing technologies having the LBD and LBS options hard-coded. Applying the heuristic approach with the full scope technological options as needed for CASCADE-MINTS in MERGE we obtain unstable results. The proposed solutions are oscillating between alternative options (e.g., either a HFC car with liquid hydrogen, or a HFC car with gaseous hydrogen become optimal) when the number of iterations changes.

¹⁷ It is quite feasible based on MERGE (but with a reduced regional complexity) to apply Monte Carlo methods defining a set of probability density functions (pdf) for uncertain inputs like the climate sensitivity, economic growth and the learning performance and select among others, the market penetration of the systems in investigation as well as the distribution profile of RD&D support needed by technology under different policy constraints (Kypreos 2007).

Alternatively, a stochastic analysis (Bahn et al. 2006) can define “first act then learn” (ATL) policies in MERGE that take into account the uncertainties prevailing the climate change effect. In that case, one tries to define the appropriate policy concerning the level and timing of actions (i.e., act now) in order to hedge against climate change assuming that the uncertainty will be resolved in the future, e.g., after 2030. We could formulate then RD&D budgets for different technological options to be endogenous to climate policy within this hedging framework.

The TFLC with endogenous budget specifications

In the energy sector, R&D constitutes a fundamental factor for the successful introduction of advanced supply and end-use technologies and the achievement of economic, safety and environmental goals. Therefore, it is important to study the main mechanisms by which R&D investments contribute to cost and performance improvements of individual technologies of the energy system.

The section describes the formulation of endogenous technological learning in MERGE, using the TFLC formula (e.g., with Learning -by- Doing and Learning -by- Searching components). In the two-factor learning curve, the cumulative production of a technology (output) is used as a proxy for the accumulation of experience that affects the generation cost of a given technology. Similarly, the knowledge stock, defined as the accumulation of a depreciated annual R&D spending, is used to determine cost reductions attendant LBS processes.

Examples of this interaction have been described by Neij (1999) for the case of wind turbines and Watanabe (1995, 1999). The latter performed an analysis of the role of public and private R&D expenses and industrial production in the competitiveness of solar photovoltaic in Japan. Our formulation of the knowledge stock follows Watanabe and Kouvaritakis (2000).

The learning curve for the generation cost $GC_{k,t}$ (in € per MWh for electric or € per GJ for non-electric) of a technology **k** is then defined as:

$$GC_{k,t} = a \cdot CP_{k,t}^{-\beta} \cdot KS_{k,t}^{-\gamma} \quad \text{Eq. 6}$$

with the knowledge stock $KS_{k,t}$ estimated as the depreciated sum of annual **AR&D** spending,

$$KS_{k,t} = KS_{k,t-1} \cdot (1-s) + AR \& D_{k,t} \cdot ypp_t \quad \text{Eq. 7}$$

where *s* is the depreciation factor (e.g., 5 percent per year) and **ypp** the number of years per period. The parameter *a* can be calibrated by applying equation (Eq. 6) for the initial point ($GC_{k,0}$, $KS_{k,0}$, $CP_{k,0}$) of the learning curve, while the parameters **β** and **γ** are learning indices. The latter define the speed of learning and are derived from econometric analysis and are alternative expressions to the learning ratio. The learning ratio **lr** is the rate at which the generating cost declines each time the cumulative capacity doubles, while **lrs** is the rate at which the cost declines each time the knowledge stock doubles. The relation between **β**, **γ**, **lr** and **lrs** can be expressed as follows:

$$1 - lr = 2^{-\beta} \quad \text{and} \quad 1 - lrs = 2^{-\gamma} \quad \text{Eq.}$$

The model assumes that both "learning" and "knowledge" diffuse to the entire world and create positive externalities. For the introduction of LBD and LBS options and of subsidies or learning investments, a few new variables and equations are defined. The new variables refer to the annual research and development (**AR&D**) spending, the knowledge stock (**KS**) and the amount of subsidized production (**SPE**). The cumulative production of electricity (**CPE**) is based on the annual generation of unsubsidized **PE**, and subsidized electricity **SPE**.

$$CPE_{k,t} = CPE_{k,t-1} + (PE_{k,t} + SPE_{k,t}) \cdot ypp_t \quad \text{Eq. 9}$$

The functional form of the learning curve is coded directly as a non-linear and non-convex formulation in MERGE according to equation (6 & 7), which is based on the cumulative production and the knowledge stock relative to the starting year. The CONOPT3 optimizer defines directly the global optimal solution in the case of a number of LBD technologies per market once the level of penetration is confined based on the assumed annual expansion rates, and bounds are defined that exclude local optimum solutions [Manne & Barreto, 2004].

$$\frac{GC_{k,t}}{GC_{k,0}} = \left(\frac{CPE_{k,t}}{CPE_{k,0}} \right)^{-\beta} \cdot \left(\frac{KS_{k,t}}{KS_{k,0}} \right)^{-\gamma} \quad \text{Eq. 10}$$

The budget of the economic production variable **Y** of MERGE is formulated in different ways. In the case that we apply **AR&D** spending for learning technologies as decision variables we consider the AR&D and the "learning investments" in the use of output (or budget) constraint of the model.

$$Y_{rt} = C_{rt} + I_{rt} + EC_{rt} + NTX_{rt} + A \& RD_{rt} \quad \text{Eq. 11}$$

C represents consumption, **I** investments, **EC** the energy cost that includes the cost of subsidies and **NTX** the trade of a numeraire good.

We also assume that learning technologies will be available in 2010 under sufficient RD&D support, while their penetration rates will increase. Annualized RD&D investments reduce consumption, [i.e., they are included in equation (11)] and are introduced only when enough benefits are generated to compensate for the cost of research and development. In other words, the induced benefits of the cost reduction for energy production should be greater than the discounted and cumulative cost of R&D. Finally, it is important to notice that the production associated to learning investments in the electric and non-electric markets (i.e., **SUPE** or **SUPN**) contributes to the balance of electricity or of the primary-energy use, correspondingly. The user can restrict the penetration of learning investment by expansion bounds and let the model free to identify optimal AR&D levels to support new technologies under different mitigation policies.

MERGE-ETL with Exogenous RD&D for CASCADE-MINTS

As explained before, the second model formulation for CASCADE-MINTS assumes pre-specified levels of AR&D spending to estimate the market uptake of technologies and some scenario indicators that describe the efficiency of the RD&D spending, if desired.

In that application both the reference RD&D budget will be known as well as the change of the budget allocation in form of an exogenous scenario specification. This could trigger another cost reduction with some benefits measured as changes in the performance indicators associated to his modified budget. The key equation describing the generation cost GC, for the reference or the scenario budget is follows (R superscript refers to the reference case, S to a scenario):

$$\frac{GC_{tj}^R}{GC_{0,j}} = \left(\frac{CPE_{tj}^R}{CPE_{0,j}} \right)^{-\beta} \cdot \left(\frac{KS_{tj}^R}{KS_{0,j}} \right)^{-\gamma} \quad \text{Eq. 12}$$

Applying Eq. 12 for the case with known R&D-scenario spending, we have:

$$GC_{tj}^S = GC_{0,j} \cdot \left(\frac{CPE_{tj}^S}{CPE_{0,j}} \right)^{-\beta} \cdot \left(\frac{KS_{tj}^S}{KS_{0,j}} \right)^{-\gamma} \equiv P_{jt}^S \cdot \left(\frac{CPE_{tj}^S}{CPE_{0,j}} \right)^{-\beta} \quad \text{Eq. 13}$$

This is a simple NLP formulation with CPE_{tj}^S acting as the decision variable while the cost parameter P_{jt}^S , is estimated with the help of the technology database applying equation 13b:

$$P_{jt}^S = \left[\frac{SC_{0,j} \cdot crf_j + fixom_{jt}}{lf_j * 8760} + varom_{jt} \right] \cdot \left(\frac{KS_{tj}^S}{KS_{0,j}} \right)^{-\gamma} \quad \text{Eq. 13b}$$

P_{jt}^S is technology, scenario and time specific and defines the initial cost data included in TECHPOL related to the specific cost per technology. Thus, the information needed to define the parameter P_{jt}^S is the capital recovery factor **crf**, the initial specific costs and the fixed and variable O&M cost and the load factor while the depreciated RD&D knowledge stock is a scenario related parameter.

Another cost item is the systems efficiency. The fuel cost is endogenously defined out of the resource supply curve and the technical efficiency of a technology.

In the case of technology clusters the cumulative production term $\left(\frac{CPE_{ij}^s}{CPE_{0j}}\right)^{-\beta}$ will take into consideration

the production of all technologies contributing to power generation and/or to secondary fuel production in the global energy system that belong to the same key technological subsystem, e.g., all hydrogen fuel cells.

Finally the technology dynamics formulation of MERGE assumes that for new technologies an initial development phase is considered where R&D alone is responsible for the cost reduction to the levels assumed in TECHPOL-EURO2000 between the years 2000 and 2025. We can then calibrate the model such that an appropriate LBS elasticity reduces the cost to the one given in that database for the reference R&D budget. Afterwards the TFLC formulation is applied as explained in Eq. 13. Finally, the compromise followed in CASCADE-MINTS is formulated as follows:

$$GC(KS) = GC_{2000} \cdot \ln\left(\frac{KS_t}{KS_0}\right)^{-\gamma_1} \quad 2000 \leq t \leq 2025$$

$$GC_t = ILC_{25} \cdot \ln\left(\frac{cc_t}{cc_0}\right)^{-\beta} \cdot \ln\left(\frac{KS_t}{KS_0}\right)^{-\gamma} + NLC \quad 2025 \leq t \leq 2050$$

Eq. 14

GC	The specific energy cost of a technology in time t
NLC	Non-ETL part of the specific energy cost of a technology in time t
ILC	The Initial cost that assumes learning
CC	The Cumulative Production (Learning -by-Doing)
KS	The Knowledge Stock (represents Learning -by-Searching)
β	The learning by doing elasticity
γ, γ_1	Learning by searching elasticities

Figure C-20 elaborates on the above relations¹⁸.

¹⁸ Actually this figure should have been three dimensional with KS as the second independent variable but for simplicity this cost reduction is shown with a dotted line.

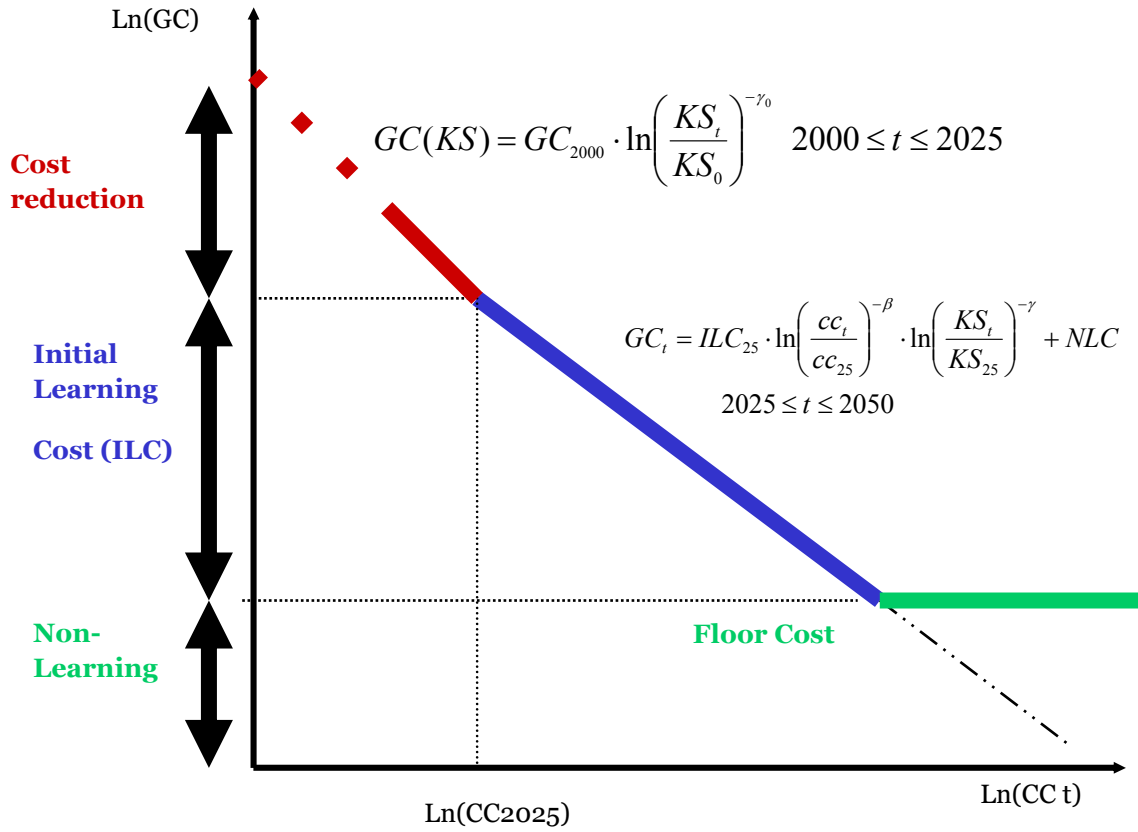


Figure C-20: Illustration of the endogenized experience curve costs reduction. There is a cost component that assumes learning by searching starting from GC2000 and going to the cost valid in TECHPOL in 2025, i.e., GC2025. Then, the TFLC applies until we reach the floor cost. Afterwards, the cost remains constant to the level of floor cost.

In the following we present the more relevant model equations for the transportation sector as the full model is described in the Appendix. Firstly, a general equation of the transportation demand is established where a set of technologies compete to satisfy the demand:

$$\sum_j X_{j,t} = DM_t \quad \text{Eq. 15}$$

Where:

j The technology index

t Time period index

X Activity of given technology for vehicles, i.e., in billion v-km

DM Overall demand for transportation using personal vehicles in billion V-km

Next, the demand for transportation by hydrogen fuel cell vehicles is matched with the amount of hydrogen produced (Eq. 16). The fuels and the costs related to hydrogen production or the non-hydrogen fuelled vehicles are also balanced and defined elsewhere.

$$\begin{aligned}
\sum_{gen} X_{gen,t} / eff_{gen} &= \sum_{tran} X_{tran,t} \\
\sum_{tran} X_{tran,t} / eff_{tran} &= \sum_{dis} X_{dis,t} \\
\sum_{dis} X_{dis,t} / eff_{dis} &= \sum_j X_{j,t} / eff_{j,t}
\end{aligned}
\tag{Eq. 16}$$

Where:

X Activity of given technology (for hydrogen technologies: amount of GJ of hydrogen delivered)

gen – hydrogen generation,

tran – transmission of hydrogen,

dis – distribution of hydrogen

j The vehicle range is limited to hydrogen fuelled fuel cell vehicles

eff efficiency (for hydrogen technologies [GJ-H₂/GJinput], for vehicles [MJ/v-km])

The learning part of the costs, defined by the ILC_j parameter is specific for each type of vehicle, hydrogen generation, and transmission & distribution technology. The non-learning and the learning part is specified in equations (17) and (18) respectively, for each technology j.

$$CNL_t = CRF_j \cdot \frac{INV_j}{AM_j} + Fix_{j,t} + Var_{j,t} + Fuel_{g,t}
\tag{Eq. 17}$$

Where:

CNL Non-EEC cost indicating index

CRF Capital recovery factor

INV Specific Investment costs

AM annual load factor (either in 1000 km per year or fraction of the year the plant is in operation)

Fix	Fixed operations and maintenance costs
Var	Variable operations and maintenance costs
Fuel	Costs related to the fuel including efficiency
ILC	The part of the specific investment costs that learns

$$ILC_{j,t} = CRF_j \cdot \frac{LINV_j}{AM_j} \quad \text{Eq. 18}$$

Lastly, the energy system cost (**Z**) that is part of the overall objective function combines the two costs components related to learning and refers to the vehicle and fuel allocation modules (Eq. 19). $X_{j,t}$ is the activity of technology **j**, time period **t** and **dr** the discount rate.

$$Z = \sum_{j,t} \left[X_{j,t} \cdot CNL_{j,t} + X_{j,t} \cdot ILC_{j,t} \cdot \left(\frac{CC_{jg,t}}{CC_{j,0}} \right)^{-b_j} \right] \cdot (1 + dr)^{-\Delta t} \quad (1) \quad \text{Eq. 19}$$

Indicators

The MERGE formulation presented before can also describe a set of indicators expressing the benefits of enhanced RD&D support for technologies with endogenous learning. The indicators specify the gains induced from the global sales of these technologies, as well as the attendant reduction in the marginal costs of carbon control per € spent for RD&D, changes in economic growth by region along with the improved environmental and resource performance associated for the carbon scenarios to be analyzed.

Technology Data and R&D Scenarios

The TECHPOL-EURO-2000 data has been the main source of the information summarizes in the tables below. The fuel cost is excluded (with exception of nuclear) as the resource cost is endogenous to the model specification. The database defines cost and other data for the year 2000, 2025 and 2050. Values in the between years are defined by interpolation.

Table C-26: Technologies for electric and non-electric

Source: TECHPOL-EURO2000 and own estimates for a discount rate of 5%. The initial learning cost used in the model is defined as the cost difference between the cost in the year 2000 and the floor cost.

Technology	Description	Year	For GC see below	Carbon Emissions kg C/kWh	Initial Learning m/kWh	c _{peo} T/kWh	LBDR %	LBSR %
Electric	Technologies							
HYDRO	Hydro & renewables	2000		0				
NUC	Initial nuclear	2000		0				
GAS-R	Initial gas fired	2000		0.1443				
OIL-R	Initial oil fired	2000		0.2094				
COAL-R	Initial coal fired	2000		0.2533				
GAS-N	Adv. combined cycle	2000		0.0935				
GAS-A	Gas-FC & CCS	2020		0	12	0.12	0.06	0.05
COAL-N	Pulverized Coal	2000		0.1955				
COAL-A	Coal-FC & CCS	2020		0.0068	17	0.2	0.05	0.05
IGCC	IGCC	2000		0.024				
IGCC-A	IGCC & CCS	2020		0	12	0.22	0.06	0.05
SPV	Solar PV	2000		0	70	0.01	0.16	0.1
WND	Wind	2000		0	30	0.75	0.12	0.06
NNU	New Nuclear	2020		0	8	0.6	0.06	0.05
HFC	Hydrogen fuel cell	2020		0	19	0.6	0.15	0.08
Non-Electric	technologies							
			US\$/GJ	tons C/GJ				
CLDU	Coal direct use	2000	2.5	0.0241				
OIL1-OIL10	Oil categories	2000	3-5.2	0.0199				
GAS1-GAS10	Gas categories	2000	2-4.2	0.0137				
SYNF	Synthetic fuels	2000	8.33	0.04				
RNEW	Renewables	2000	6	0				

NEB -HC	Ren.Back-stop	2020	14	0	8	1	0.1	0.1

Table C-27: Technologies for road transport in MERGE

	<i>GC2000</i>	<i>GC2025</i>	<i>GC2050</i>	<i>GC-floor</i>	<i>Eff-2000</i>	<i>Eff-2025</i>	<i>Eff-2050</i>
	<i>m/kWh</i>	<i>m/kWh</i>	<i>m/kWh</i>	<i>m/kWh</i>	<i>%</i>	<i>%</i>	<i>%</i>
HYDRO	60	54	48	48	100	100	100
NUC	45	35	36	36	33	33	33
NNU	50	40	30	25	45	45	45
GAS-R	14.5	11.8	12.7	12.7			
OIL-R	13.5	12.7	11.8	11.8			
COAL-R	19.9	18.3	17.2	17.22			
GAS-N	8.9	8	7	6	55	59	62
GAS-A	14	11	10	8	47.6	54.1	57.4
COAL-N	20	18	15.9	12	44	48	50
COAL-A	30.9	25	18.6	14.3	35.2	40.1	42.4
IGCC	27.5	25.1	22.7	16	45	49	51
IGCC-A	35	30.6	24.8	18	37.9	43.5	45.2
SPV	180	100	65	43.9	100	100	100
WND	43.8	35.9	31.5	27.6	100	100	100
HFC	200	50	15	10	49	61	62

Source: TECHPOL-EURO2000 and own estimates.

Efficiency is defined in 1000 Vehicle-km per GJ; Purchase price in € per car, e.g., I2000; Fixed operation & maintenance cost in € per 1000 v-km, e.g., FIX2000; Life time is 10 years; Discount rate 5%; and 17500 kilometers is the average traveling per year.

<i>Road Transport</i>	<i>START</i>	<i>I2000</i>	<i>I2025</i>	<i>I2050</i>	<i>I-Floor</i>	<i>PR</i>	<i>LBS</i>
<i>Technology</i>	<i>year</i>	<i>€/CAR</i>	<i>€/CAR</i>	<i>€/CAR</i>	<i>€/CAR</i>	<i>-</i>	<i>-</i>
Conventional Gasoline/Diesel-ICE	2000	17700	18900	18900	18900	0	0
Hybrid gasoline-electric	2000	21000	21000	21000	21000	0	0
Compressed natural gas	2000	20400	19000	19000	19000	0.05	0.1
H2-FC-Pipeline	2015	90000	29000	25000	22000	0.05	0.1

H2-FC Liquid	2015	90000	28380	22920	20000	0.1	0.1
H2-ICE	2015	90000	28380	22920	20000	0.1	0.1
Methanol FC	2010	25013	19822	19379	18000	0.05	0.05
Electric	2015	43994	30177	26723	25000	0.1	0.1
	Eff2000	Eff2025	Eff2050	FIX2000	FIX2025	Fix2050	
	kvkm/GJ	kvkm/GJ	kvkm/GJ	€/kvkm	€/kvkm	€/kvkm	
Conventional Gasoline/Diesel-ICE	0.33	0.47	0.52	23.58	24.56	25.21	
Hybrid gasoline-electric	0.3	0.33	0.35	25	25	25	
Compressed natural gas	0.56	0.6	0.76	29.28	26.21	25.4	
H2-FC-Pipeline	0.9	0.99	1	30	30	30	
H2-FC Liquid	1	1.2	1.43	28.3	28.3	14.1	
H2-ICE	1	1.2	1.43	24	24	14.1	
Methanol FC	0.26	0.47	0.52	35.37	28.3	23.58	
Electric	1.18	1.32	1.57	11.79	11.79	11.79	

Table C-28: Processes for H2 production in MERGE-ETL

Source: TECHPOL-EURO2000 and own estimates for Methanol.

Cost data exclude the cost of feedstock; Starting year 2015; Life 20 years (for Pipelines 40 years) Discount rate of 5%; Availability factors of 85% to 90% (for Solar H2 26%)

<i>Technology</i>	<i>GC00</i>	<i>GC2025</i>	<i>GC2050</i>	<i>GC-floor</i>	<i>Input</i> <i>/Output</i>	<i>eff2000</i>	<i>eff2025</i>	<i>eff2050</i>	<i>PR</i>	<i>LBS</i>
	<i>\$/GJ</i>	<i>\$/GJ</i>	<i>\$/GJ</i>	<i>\$/GJ</i>	<i>GJe/GJH2</i>				-	-
Gas to H2	1.47	1.38	1.1	1	0	0.74	0.78	0.81	0.1	0.07
Gas 2 H & CCS	2.51	2.28	1.94	1.5	0	0.62	0.68	0.73	0.1	0.07
Coal to H2	4.7	4.3	4	3	0	0.59	0.6	0.6	0.1	0.05
Coal 2 H & CCS	5.76	5.23	4.79	4	0	0.5	0.52	0.54	0.1	0.05
Biomass to H2	5	4.4	4	3	0	0.72	0.72	0.72	0.1	0.05
Biomass2H & CCS	6	5.3	4.8	4	0	0.6	0.63	0.65	0.1	0.05
Biomass to methanol	9.8	8.5	8	6	0	0.57	0.57	0.57	0.1	0.05
Biomass 2M&CCS	11.56	10	9	7	0	0.5	0.5	0.5	0.1	0.05
Solar 2H2	66	41.3	29.5	15	0	1	1	1	0.1	0.1
Nuclear 2 H2	43.5	30.3	20.5	18	0	0.5	0.5	0.5	0.1	0.1

Electrolysis 2 H2	3.3	3	2.5	2	0	0.7	0.75	0.8	0.1	0.1
T&D Pipeline	3.1	3	3	2.5	0.01	1	1	1	0.07	0.05
T&D Liquefied H2	7.4	7	6.5	5	0.33	1	1	1	0.07	0.05

Table C-29: Annual R&D and Knowledge Stock for the R&D Outlook

<i>Annual R&D Outlook in million €/yr</i>									
YEAR	2000	2005	2010	2015	2020	2025	2030	2040	2050
HYD	224	236	302	375	447	520	596	754	871
NUC	2126	2288	2388	2502	2564	2595	2593	2509	2333
NND	815	958	1123	1302	1469	1646	1820	2173	2574
LCT	116	134	159	189	216	243	269	312	335
CCT	903	899	1125	1415	1488	1492	1415	946	633
PFC	194	300	375	458	541	626	712	890	1084
ICG	131	172	205	244	281	319	356	428	492
OCT	672	438	226	13	15	16	17	19	21
OGC	171	179	225	282	340	401	466	596	702
GCT	399	419	441	441	389	285	123	114	79
GGT	1375	1143	1414	1709	1926	2052	2050	1800	1724
CHP	516	551	644	751	839	918	988	1087	1125
SHY	16	22	27	32	38	43	47	55	60
WNO	45	58	101	167	256	372	516	870	1256
WND	285	302	382	446	517	586	650	754	916
SPP	95	144	190	245	304	368	438	592	770
SPV	917	994	1213	1482	1751	2032	2325	2911	3449
BF2	533	431	449	443	534	640	753	986	1194
BGT	153	177	224	279	337	400	467	616	794
FC	923	1194	1710	2285	2725	3124	3523	4298	5118
GSR	117	254	406	394	265	310	352	382	330
CPO	47	102	118	137	152	165	175	168	126
OPO	23	52	82	119	145	169	184	175	122
CGF	94	205	312	445	562	688	783	822	628
BPY	23	48	67	91	116	142	167	187	163
BGF	47	106	168	236	302	365	424	456	366
SMR	12	27	44	66	85	105	128	145	120
SHT	12	27	45	70	93	121	153	269	422
NHT	12	23	41	73	127	227	412	1123	2046
WEG	47	107	130	158	187	207	238	275	332
HTND	12	28	59	105	163	247	337	569	803
HSTOR	23	60	128	212	304	416	560	897	1262
CrCONV	4730	5025	5625	6261	7214	8057	8849	9980	10151
HYBE	407	480	586	716	846	960	1074	1282	1440
ESTOR	23	64	102	143	187	224	259	298	314
PsCOMB	75	185	255	379	582	865	1168	1789	2276
PRCOMB	31	68	119	142	213	277	366	546	662
SEQ	72	76	86	134	207	289	379	557	545
UNK	0	0	108	256	553	1062	1844	4880	10654

TOTAL	16418	17977	21404	25198	29280	33573	37976	47509	58293
YEAR	2000	2005	2010	2015	2020	2025	2030	2040	2050
HYD	8600	7678	7190	7131	7414	7961	8725	10786	13045
NUC	49368	48074	47841	48155	48773	49446	50014	50389	49540
NND	17873	17758	18536	19923	21773	23989	26497	32100	38510
LCT	4009	3672	3517	3521	3654	3879	4173	4866	5546
CCT	20385	19679	19917	21291	23095	24635	25625	24722	20143
PFC	3952	4354	4934	5744	6747	7904	9188	12036	15250
ICG	4078	3866	3861	4023	4319	4718	5198	6309	7524
OCT	17497	16173	13934	11241	8763	6850	5375	3363	2175
OGC	3688	3625	3741	4069	4584	5254	6062	7982	10086
GCT	11678	10172	9838	9616	9305	8687	7578	5499	4050
GGT	25707	25238	25448	26901	29157	31642	33791	35546	35522
CHP	10215	10271	10702	11493	12537	13720	14970	17383	19352
SHY	539	502	502	525	566	623	686	826	961
WNO	415	552	801	1251	1963	2992	4390	8387	13843
WND	5008	5246	5645	6275	7072	8004	9023	11120	13482
SPP	2614	2636	2817	3190	3738	4446	5300	7398	10006
SPV	21987	21219	21522	22882	25156	28167	31805	40443	50168
BF2	8827	8681	8725	8775	9046	9708	10721	13552	17039
BGT	3206	3271	3461	3842	4396	5101	5943	7990	10547
FC	18162	18258	20945	25523	31322	37689	44421	58513	73245
GSR	575	1385	2629	3849	4424	4747	5194	6118	6543
CPO	230	555	935	1311	1676	2020	2338	2790	2842
OPO	114	278	531	887	1296	1732	2147	2752	2823
CGF	461	1111	2077	3389	4958	6730	8587	11765	12883
BPY	114	273	480	741	1055	1412	1804	2547	2950
BGF	230	560	1081	1788	2632	3581	4587	6366	7112
SMR	58	140	276	471	716	995	1308	1903	2206
SHT	58	140	279	490	759	1085	1474	2637	4437
NHT	58	134	255	470	841	1500	2696	8067	18093
WEG	230	561	980	1422	1894	2365	2853	3796	4754
HTND	58	141	319	637	1125	1835	2781	5423	8929
HSTOR	114	288	684	1335	2250	3423	4925	9021	14332
CrCONV	53121	63558	73605	84184	96100	109348	123288	150459	171676
HYBE	3261	4612	6031	7674	9536	11525	13580	17737	21695
ESTOR	288	439	731	1140	1650	2230	2837	3981	4863
PsCOMB	215	908	1731	2828	4452	6848	10040	18299	27717
PRCOMB	71	323	695	1139	1718	2468	3405	5846	8471
SEQ	217	649	852	1176	1713	2485	3478	6019	8196
UNK	0	0	286	1105	2814	6057	11616	34829	85943

C.2.5 Dynamic Energy System Optimisation Model for Europe: MARKAL

[H. Rösler, K. Smekens, G. Martinus (ECN)]

Introduction

This chapter describes the activities and the outcomes of the model development work done with the Western European MARKAL model for the Cascade-Mints Part I project. This work took place more or less in parallel with the scenario analysis in Part II of the project. The technology data and technology chains options are resulting and delivered from WP1.5, referred to as (Krewitt, 2004).

In WP1.5 DLR has made an extensive analysis of the hydrogen technologies: the end use in stationary and mobile applications, production and transport and distribution options, documented in (Krewitt, 2004). In this chapter, the focus is on explaining how the data from (Krewitt, 2004) have been used for modelling hydrogen in the MARKAL model. Not all data has been repeated, but rather some specific problems related to the optimisation and perfect foresight character of the model are described, together with the solutions applied.

Hydrogen modelling in MARKAL – Western Europe

In a model of the present day energy system of Western Europe, the role of hydrogen is small but existent. It is used, not as an energy vector, but rather as feedstock for the process industry. Therefore, the MARKAL model for Western Europe developed at ECN contained a set of rather simple hydrogen energy chains, incorporating a number of production technologies, and end-use mainly in the process industry. As the model contains a detailed description of the transport sector, some end-use applications there are also foreseen.

The resulting system of hydrogen chains is shown in Figure C-21. The use of hydrogen as a feedstock is determined by the demand for end-products from the processes involved, and thus in most cases proves to be the major source for demand for hydrogen. Of the other applications, the three stationary applications (in industry, households, and the tertiary sector) basically use hydrogen as a replacement fuel for natural gas. In the transport sector, hydrogen does not serve as replacement fuel in existing technologies, but requires the development of new technologies and the related new manufacturing industry.

The focus on the use of hydrogen in the process industry serves as a justification for sidestepping a detailed description of the transport and handling of hydrogen. For the application by industry, these are of small importance as the production and consumption of hydrogen generally occur in close proximity. This also holds for use via the mix-in in the natural gas network, so that only for the application in the transport sector accounting for the infrastructure is necessary. The costs associated with the build-up and use of the

infrastructure were included through including delivery costs for hydrogen use by transport technologies, under the simplified assumption that these costs would be approximately equal to those for conventional fuels in case of large-scale deployment of hydrogen in the transport sector.

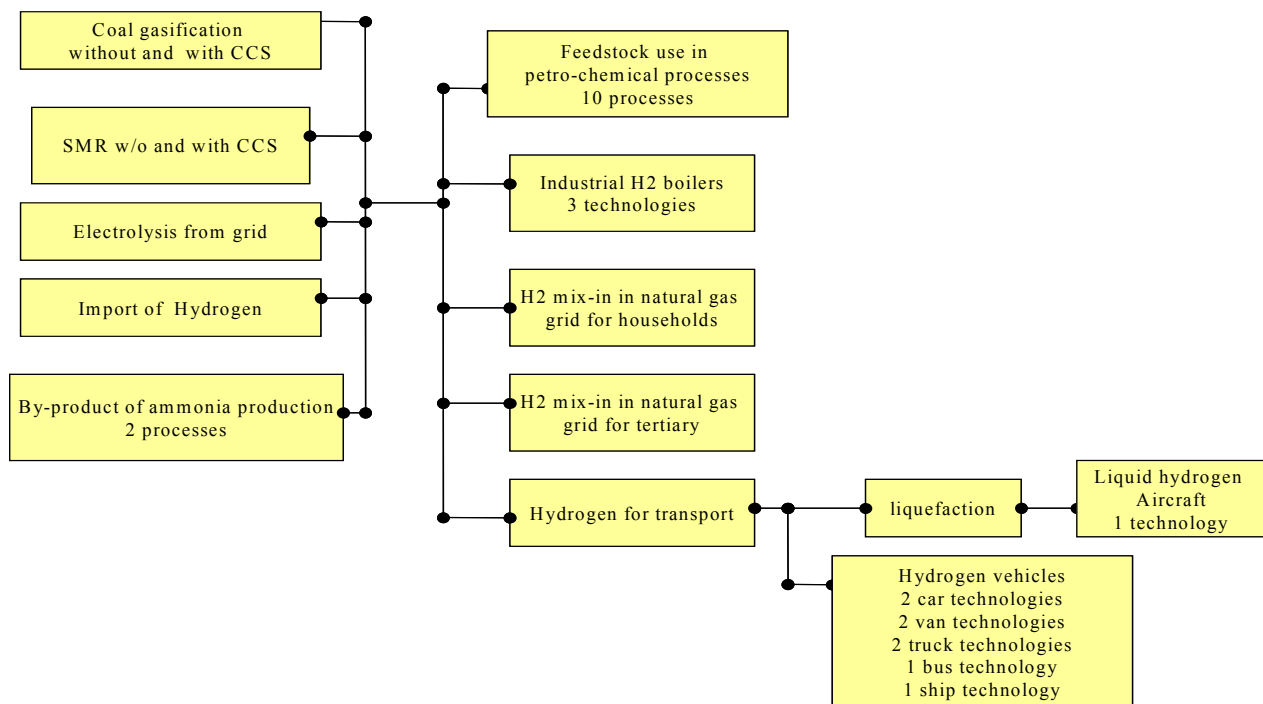


Figure C-21 Overview of existing hydrogen chains in the MARKAL model (SMR=Steam Methane Reforming, CCS =CO₂ capture and storage)

Within the existing model, a proper analysis of the transition towards a hydrogen economy is hardly possible. While on the one hand, a number of production and consumption technologies are clearly missing, on the other hand detailed description of hydrogen handling between production and consumption is clearly required. Production occurs on a large and local scale level for gaseous H₂, although production can be followed by liquefaction. H₂ produced by renewables is directly linked to liquefaction and further distribution of liquid H₂. Transportation and distribution of H₂ occurs through pipelines or trucks without or with temporary storage. Stationary end use taps directly from a H₂ grid whereas mobile applications are serviced by filling stations. The stationary end use technologies follow the demand pattern of the sector to which they belong, e.g. residential fuel cell systems will deliver electricity and heat fitted on these residential demand patterns as existing in the MARKAL model.

Hydrogen production and liquefaction

As mentioned above, the existing and mainly feedstock oriented modelling of hydrogen in the model included a number of production options. These were described with limited detail, and constrained to those technologies that play a role in present day hydrogen production. Aside from production of hydrogen

through electrolysis, SMR and coal gasification, these included by-product hydrogen generation as well as import of hydrogen directly from a unspecified source outside the Western European region.

In modelling the transition towards a hydrogen economy, the by-product generation will be of limited importance, as the amount of hydrogen produced from this is restrained by the use of the main product. Therefore, in current modelling efforts, it is retained as it was. A similar situation exists for the import of hydrogen, which according to the existing estimates is limited to 500 PJ per annum. Its costs vary from an initial value of 12.5 €/GJ to in the long run 25 €/GJ at the border, making it supposedly rather expensive as compared to local production. Both the by-product hydrogen and the imported hydrogen are mostly used in petrochemical processes.

The inclusion of new production technologies from the modellers' perspective is to improve on the existing description. In the framework of the Cascade Mints project the extension is based on (Krewitt, 2004) resulting in the selection of production technologies shown in Table C-18.

Table C-30 Overview of hydrogen production technologies, with decomposition in key technologies

	Electrolysis	Steam turbine	Fuel cell	SMR ¹⁾	CCS ²⁾	Gasifier
Electrolysis based systems						
Small electrolyser, local	*					
Large electrolyser	*					
PEM based			*			
HTS -SOFC based ³⁾			*			
Natural gas based systems						
SMR small, local ¹⁾				*		
SMR large ¹⁾				*		
Direct solar MR ¹⁾						
SMR small with CCS ^{1, 2)}				*	*	
SMR large with CCS ^{1, 2)}				*	*	
Direct solar MR with CCS ^{1, 2)}					*	
Solid fuel based systems						
ICG ⁴⁾		*				*
Biomass gasification						*
ICG with CCS ^{2,4)}		*			*	*
Biomass gasification with CCS ²⁾					*	*
ICG HSMR ^{1,4)}		*				*

¹⁾ (S)MR = (Steam) Methane Reforming

²⁾ HTS = High Temperature Steam

³⁾ CCS = Carbon Capture and Sequestration

⁴⁾ ICG = Integrated Coal Gasification

The table shows both the production technologies included in the model, in the rows, as well as the key technologies underlying these technologies in the columns. The use of clustering for endogenous learning technologies in the ECN MARKAL model has been described on several occasions, for example in (Seebregts et al, 1999) and also for this project in Chapter C.1.1. The formalism is based on the fact that technologies can improve on their cost through increased deployment. This is generally called 'learning-by-doing', reflecting

that as a technology is used more and more, its manufacturers will improve on the production process. In the end the result will be lower production costs, and hence improved competitiveness for the learning technology.

In the MARKAL model the learning is done on the level of key components, rather than on the level of individual technologies. This is illustrated by the technologies in Table C-16 where instead of the IGC hydrogen production plant its components being a gasifier and steam turbine are the learning technologies. These components are shared by some of the other hydrogen production technologies, and possibly even by technologies in other sectors. The set of all technologies sharing a learning component is called a cluster, whence the use of the term 'learning in clusters' for this formalism.

The costs of a technology with learning components is proportional to the costs of the key components that make up the technology, plus optionally some additional non-learning part. The non-learning part may stand for 'Balance of System' costs, or for some other parts of the technology. As for the learning part of the costs, due to the investment in the particular clustered technology, the costs of the key technology defining the cluster decrease according to a learning-by-doing principle. Through the clustering, the investment costs in the other technologies in the cluster also decrease. Thus, with learning in clusters it is possible to describe technological spill-over effects, in the form of cost decreases as reflection of sharing experience among related technologies, even between technologies in different sectors.

Another feature exhibited by the entries in the table is the distinction between small scale and large-scale production options. Such a distinction is closely related to the locality of the production process. Whereas small-scale applications are used in a decentralised fashion, the large-scale applications are centralised plants, requiring a more extensive transport and distribution network. In an analysis of the transition towards a hydrogen economy, this distinction will prove essential, as large scale applications can only be viable once there is sufficient density of hydrogen demand.

Finally, the technologies in Table C-16 are only a selection of the full optional set of technologies, as given in (Krewitt, 2004). Other options, such as biological and thermo-chemical cycles, have been excluded because of the highly speculative nature of such technologies. In a bottom-up model such as MARKAL, it is essential that there is sufficient information on the technologies included, to warrant a fair comparison of the respective technologies. Speculative technologies currently are extremely expensive, and there is no estimate of the costs at market introduction. The exclusion is justified by the observation that the only way in which such technologies could enter the market is when their costs are comparative with those of more conventional technologies, and the decrease to such a level is unlikely barring extreme investments in R&D. One exception to this may be direct photo-electrolysis, as it is closely connected to an existing technology, solar PV. As there might be learning spill-over between electricity producing and direct hydrogen producing solar PV, such a technology might prove of future importance.

Electrolysis

Besides the well-established alkaline water electrolysis, a high-temperature steam electrolysis using a Solid Oxide Fuel Cell technology is implemented in the model. Expected efficiency increases of 10% as well as significant cost decreases of the alkaline electrolyzers made that two versions in time are implemented. Proton Exchange Membrane Electrolyzers are not implemented due to lack of sufficient data.

Methane reforming

Three methane reformers are implemented, two state of the art plants based on steam methane reforming (SMR) and one future solar methane reformer. Efficiency improvements of both large and small scale SMR are expected to be limited, so unlike electrolyzers, only one version is implemented.

Coal gasification

Hydrogen production from coal is modelled in three technologies. First of all there is the state of the art Integrated Coal Gasification (ICG). From 2020 also an ICG with CO₂ capture facility is available. Finally, significant improvement of membrane technologies could lead to the competitiveness of Hydrogen Separation Membrane Reactors (HSMR). However according to (Krewitt, 2005) the cost data given are indicative targets which are still very uncertain.

The coal gasification plants all three have electricity as a by-product. Therefore in contrast with the other hydrogen production technologies these plants have been modelled as power plants.

Biomass gasification

From the common information database (Krewitt, 2004) the 2000 version biomass gasification plant has been implemented in the MARKAL model, as well as the 2030 version, which has been equipped with a CO₂ capture component. The 2030 plant has a significant efficiency improvement and an investment cost reduction of more than 65%.

Partial Oil oxidation

One partial oxidation plant for heavy oil has been implemented. Limited improvements on technical and economical level do not make it essential to implement the more enhanced technologies.

Hydrogen liquefaction

Liquefaction of hydrogen may prove interesting in the initial stage of the transition to a hydrogen economy, when transport of liquefied hydrogen has benefits over transport of gaseous hydrogen due to the higher energy density of the liquefied hydrogen. Moreover, even on longer timescales liquefaction might see some application as long-distance transport modus, similar to the current role for liquefied natural gas (LNG). On the backside of liquefaction stand the energy consumption and the complexity of the liquefaction process.

The energy needed for liquefaction is supposed to be mainly electricity to drive the compressors. H₂ liquefaction has been implemented in the MARKAL model in line with (Krewitt, 2004). In the model, the liquefaction is included as a transformation step between the production and transport of hydrogen. The liquefaction may be combined with gasification later on in the chain, for example in the liquid-to-gas filling station.

Transport and distribution

When the focus shifts from feedstock application of hydrogen towards use as an energy vector, a detailed treatment of transport and handling is essential, as production and consumption no longer are spatially closely connected.

Transportation of H₂ by ship is not considered because this is more appropriate for intercontinental transport of H₂. Since MARKAL covers only Western Europe, this falls outside the model and is supposed to be included in the H₂ import option.

Again, the model extensions are based on data provided in (Krewitt, 2004), except where indicated.

Mix-in in the natural gas network

One of the simplest modes of transport of hydrogen is the mixing of hydrogen in the natural gas network. It is likely to remain the most cost-effective mode of transport for a long time, but for hydrogen as energy vector it is not likely to be very relevant. Technologies for separating the hydrogen from the natural gas are still highly speculative and as explained above cannot be included in the model. Thus, the hydrogen transported still can only be used in mixed form, and in effects is only used to lower the carbon content of end-use natural gas. The description of this mode of transport is retained from the previous model version.

Hydrogen trailers¹⁹

At the onset of a hydrogen economy, the transport of hydrogen by means of trailers is thought to play a crucial role. While demand is still relatively diffuse, the economies of scale for production technologies may be such that central production is most cost-effective. As the build-up of a network infrastructure will take time, and the demand should be sufficiently dense to warrant the investments in pipeline infrastructure, trailer transport may fill the niche.

Hydrogen may be transported in trailers either in gaseous form, or as liquefied hydrogen. On the one hand, liquefied hydrogen has relatively high investment costs, due to the need for a more expensive storage vessel. On the other hand, the considerably higher energy density of liquefied hydrogen makes the costs per GJ transported much lower than for gaseous hydrogen. A final analysis of the relative competitiveness will also

¹⁹ In this section, the data used is described in more detail, as it has not been provided in (Krewitt, 2004).

include the pre- and post-processing steps required for each of these two options, as well as the role the technology can play in a transition.

Two types of trailers for H₂ are considered, one for gaseous and one for liquid H₂. The main differences lie in the cost structure and in the amount of H₂ transported, as specified in Table C-19.

Table C-31 Overview of H₂ trailer data

		Liquid H ₂ trailer	Gaseous H ₂ trailer
Investment cost	[k€/truck]	516	196
Of which for storage vessel	[k€/truck]	400	80
Fixed O&M cost	[k€/truck]	51.5	51.5
Fuel consumption	[l/km]	34.7	34.7
	[GJ/km]	124.6	124.6
Lifetime	[yr]	10	10
Load	[GJ_H ₂ /truck]	404.4	30.0

Aside from the distinction between liquefied hydrogen and gaseous hydrogen, there is a distinction in the average trip distance. Such a distinction is made to account for the locality of the production option; a local production option can only have local distribution, while a central large-scale production option can have both long distance transport as well as a combination of long distance and small distance. The technical parameterisation for a long distance (LD) and short distance (SD) truck differs somewhat, mostly due to different round-trip distances, and the average annual utilization and annual mileage, see

Table C-20. Such differences will impact on the relative competitiveness of local versus central hydrogen production options.

Short distance is assumed to be 100 km (single) or 200 km for a round trip, long distance is 800 km single way (1600 km for a round trip). An SD truck has a useful yearly kilometrage of 48,000 km, an LD truck one of 115,000 km. This corresponds with 240 and 71 return trips respectively. The activity unit of the trucks is GJ H₂ transported annually, or the load capacity multiplied with the number of trips. The actual annual distance driven is 66,000 km for SD and 121,000 km for LD (utilization factors of 0.73 and 0.95).

Table C-32. Overview of distance dependent H₂ trailer data

		Short distance (SD)	Long distance (LD)
Annual activity			
Liquid H ₂	[GJ Liquid H ₂ /yr/truck]	97056	28712
Gaseous H ₂	[GJ Gaseous H ₂ /yr/truck]	7200	2130
Fuel consumption per GJ hydrogen			
Liquid H ₂	[GJ diesel/GJ Liquid H ₂]	0.0085	0.0525
Gaseous H ₂	[GJ diesel/GJ Gaseous H ₂]	0.1142	0.7079
Fuel consumption per truck	[GJ H ₂ transported/yr/truck]	2822.4	1507.8

Pipelines

As a direct competitor to the transport of hydrogen via trucks, pipeline systems have to be included in any model of a future hydrogen system. Unfortunately, inclusion of such technologies in MARKAL is non-trivial

due to the high number of independent parameters that characterise pipeline technologies. There is at least one dimension too many as the investments in pipelines depend on distance, capacity (diameter) as well as flow. This means that additional assumptions need to be made in order to approximate this transportation option.

Given the distinction between de-central and central hydrogen production, there are at least two scales at which the pipeline infrastructure will be implemented. Local pipeline networks may serve to distribute hydrogen from local production to local use. They may however also serve as the end-point distribution network for long-range transport of hydrogen, be it from large-scale pipelines or long distance trucks. The investment costs for large-scale pipelines are higher than for small-scale pipelines, but the costs per unit of energy are obviously smaller.

Filling stations

One of the major end-uses of hydrogen can be the application in transportation technologies, particularly passenger cars. Hence, it is important to include filling stations in the hydrogen infrastructure description. These should reflect the use of hydrogen, and in particular the states in which hydrogen is used, so that at least two types should be included, delivering either liquid or gaseous hydrogen. Including a possible conversion in the station, a total of four options in this respect is found, but given the high costs of small-scale liquefaction, only three are in the end included in the model (gas-to-gas, liquid-to-gas, and liquid-to-liquid).

Aside from the state of the hydrogen, the size of the filling station is a distinguishing feature. Here, again the problem of unit size of installations in the standard MARKAL implementation occurs. When simply defining different technologies for say three size classes, the model will simply choose the cheapest option. When the largest is the cheapest, this choice may prove problematic particularly for the initial phases of the transition. This unfavourable optimisation formalism may be overcome by defining a single “average” filling station, but this would disregard the available detailed data and the possible storage technology spill-over between the types.

It can be argued that by using a single station size inside the model, one foregoes to address the relative competitiveness of the various sizes of filling stations, and hence ignores benefits of scale. This is only partially the case, as the full description of filling station infrastructure has to address the issue of utilization. In the initial phase of the transition to a hydrogen economy, the density of demand will be relatively low, resulting in reduced utilization of (particularly large) filling stations. But as this parameter is external to the model, it has to be provided on beforehand and this in general is given irrespective of the actual demand level. This tends to bias the system towards large-scale installations.

H2 storage

H2 storage recipients are modelled in MARKAL for both stationary applications as well as mobile (fuel tanks) and for liquid as well as gaseous H2. Stationary storage includes the necessary working storage capacity in filling stations as well as large scale temporary storage in built vessels or in underground caverns.

Currently, small-scale storage is modelled as part of hydrogen vehicles and the size of the tank is dependent on the vehicle type. It ranges from 0.5 GJ for small cars to 0.8 GJ for light duty vehicles and 1900 GJ for inland ships. For a few types of vehicles (buses and trucks) no data was available about the storage tank size, hence the storage costs are still included in the technology costs and their storage by consequence not clustered.

Furthermore, bulk storage can be modelled for both liquid as well as gaseous hydrogen. As all of these are representations for storage in tanks, the learning in clusters formalisms in principle can be used to describe spill-over between the various applications of such storage tanks. However, based on data from (Krewitt, 2004) such clustering does not occur for liquid storage technologies, where a clear distinction between small-scale and large-scale applications remains.

Storage of gaseous hydrogen storage in underground caverns, similar to that of natural gas, in principle is possible. It is included in the MARKAL model, although there are some open issues to be solved. For the model, these issues in the end all boil down to the physical potential for such options. It is two-fold problem, as not only the overall potential is important, and may be quite limited given the physical properties of hydrogen, but also the locality of the storage facility may limit the use of underground storage.

Table C-33 Liquid H2 storage capacities

	Storage tank local on site	Small filling stations	Medium filling stations	Large filling stations	City cars	Medium cars	Large cars	Vans/light duty vehicles	L H2 trailers
[GJ]	360	240	500	1000	0.5	0.6	0.6	0.8	404.4

Table C-34 Gaseous H2 storage capacities

Stationary storage tank à 25000 €/GJ					Storage tank à 3000 €/GJ				
	On site storage	Small filling stations	Medium filling stations	Large filling stations	City cars	Medium cars	Large cars	Vans/light duty vehicles	G H2 trailers
[GJ]	252	4.56	9	18	0.5	0.6	0.6	0.8	30.0

Hydrogen end-use

New H2 technologies have been introduced in the end-use sectors (residential and tertiary, industry and transport). No other changes in sectors have been introduced, i.e. the existing demand patterns were kept as

they were and the new H₂ technologies compete with the other existing model technologies to satisfy this demand.

Use of hydrogen in the built environment

The built environment spans the residential sector and the tertiary sector (commercial and services). From the technological point of view the applications are quite similar. The fuel cell will be used to provide electricity and heat, and two magnitudes are distinguished: single-unit (single family dwelling or single company) or multi-unit (apartment building, or large-scale commercial building), as these two classes of end-use are already incorporated in the MARKAL model. The integration of a fuel cell technology for either of these applications in the existing description of these sectors is depicted in Figure C-22.

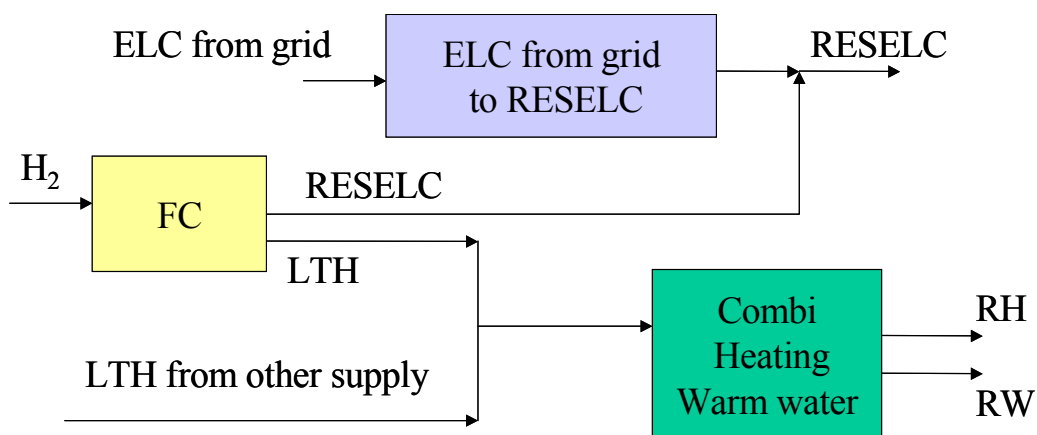


Figure C-22 Modelling of fuel cell technologies in the built environment. For the tertiary sector, the combi heating transforms only into heat

As MARKAL in origin is designed as a model for the power sector, the description of the demand for electricity is generally more detailed than the demand for heat. As a consequence, technologies that have electricity as an output are necessarily electricity-driven technologies, in that the output of electricity defines the use of the technology as the demand for example for heat has too little detail for an adequate definition of the electricity output. Thus, in the model the low temperature heat (LTH) is treated as a by-product. The final use of this heat, indicated by the green box in Figure C-22, differs between the residential and the tertiary sector. Whereas the first has both demand for space heat (RH in the figure) or warm water (RW), the latter has only demand for spatial heating.

In implementing the fuel cells for the built environment, no detailed distinction between types of fuel cell is made (e.g., distinguishing between solid oxide fuel cells (SOFC) or proton exchange membrane fuel cells (PEMFC)). The introduction of hydrogen is likely to span a period of some fifty years, introducing quite some uncertainty on the developments for the individual technologies. The final ‘winner’ may be some as yet not envisaged crossover between current technologies (in terms of energy model relevant parameters, that is).

Furthermore, it is likely that experience in one fuel cell application (e.g. transport use) may lead to advances in other applications, even if the actually used technologies differ somewhat. Finally, a very detailed description of hydrogen technologies would introduce an imbalance between these technologies and the other, competing technologies such as the fossil fuel based technologies.

An important issue to address when implementing hydrogen in the built environment is to make sure that existing bounds for fuel mixes in these sectors do not hinder the introduction of hydrogen. In the end-use sectors fuel shares have a lower and upper bound starting from the 2000 value and using a ratio per decade onwards. This ensures that fuels have a considerable growth potential but also that fuels cannot disappear from one decade to another. The combination of the lower bounds of all fuels may lock out any hydrogen use if the sum of these bounds approximates the demand level. Therefore, these bounds may need to be revised in order to create the necessary market share opening for hydrogen deployment.

Finally, for the built environment already in the previous model version some use of hydrogen was possible, as the mix-in of hydrogen in the natural gas network was already modelled. This option is retained in the implementation of a more extensive description of the hydrogen system, and it may play a substantial role in the transition. Currently, separation of the hydrogen after transport via the gas network is not modelled, because of a lack of data, and therefore once the hydrogen is mixed into the network, no further modelling is necessary.

The use of hydrogen in industry

Prior to the implementation of the detailed description for a hydrogen economy, the modelling of the industry sector already contained three dedicated hydrogen technologies. There were three hydrogen boiler technologies, reflecting that in some industrial areas surplus hydrogen in some cases is currently competitive with fossil fuel. This was accounted for by the inclusion of a low and high temperature steam boiler for the large industry and a low temperature steam boiler for the small industry, and of course these technologies are retained in the redesign of the model.

Aside from the use of hydrogen as energy carrier, the existing model contained a description of the use of hydrogen as feedstock in specific industrial processes, mainly in the petrochemical domain, mostly refinery processes such as hydro-crackers. Again, this use of hydrogen is retained, but its impact on the transition to a hydrogen economy will be quite limited, as such processes do not use hydrogen as an energy input.

Finally, there is the potential application of fuel cell technologies in industry to provide heat and power. For such applications, the technologies are rather similar to the application in the built environment, and from the methodological point of view there is hardly a difference. Of course, the process scale will be different, and given the specific need for high temperature steam in industry, two systems are be modelled. For each of these, the representation of the modelling is similar to that shown in Figure C-22 although the steam output now occurs on a high or lower temperature level..

Hydrogen use in the transport sector

When considering the transition to a hydrogen economy, the transport sector as currently modelled in MARKAL has quite some room for detailed introduction of hydrogen technologies. Sub-sectors are included as separate demand classes, such as passenger transport and freight transport. Fixed modal splits are assumed, as the distribution between public and private transport obviously is not based on economic grounds only. For the private passenger transport, an even more detailed definition at the level of drive cycle (city, regional, interregional) has been introduced as part of the Cascade-Mints project work for MARKAL.

In the implementation of the hydrogen system, hydrogen fuel cell applications are expected to play a role in most forms of transport. For road transport, vehicles with internal combustion engines (ICE) similar to Otto engines can use hydrogen, losing the benefit of the higher fuel cell efficiency, but retaining the low emissions at the tail pipe. Such technologies can play a role particularly in the onset of a transition. Most technologies will use gaseous hydrogen, but unlike the stationary end-use applications in the mobile application it is not uniquely so. Liquid hydrogen can be used for the larger vehicle (large cars, vans, buses, trucks and ships), both for the fuel cell and the ICE vehicles.

From the technological point of view, it is clear that the fuel cell technologies for mobile applications will differ substantially from those used in the stationary applications. The requirements for mobile technologies are obviously different. Nevertheless, in modelling some hydrogen system spill-over options between mobile and stationary applications will be assumed. The aim is to reflect that advancement in one sector will lead to knowledge that will stimulate advancement in the other, due to similarities on a conceptual level.

C.2.6 Computable General Equilibrium Models: PACE-T(H₂)

[by S. Jokisch (ZEW)]

This report focuses on the Technology Scenario analysis developed in Part 1 of the Cascade Mints project. The aim of the analysis is to investigate the prospects of a hydrogen economy.

Our analysis is based on the dynamic computable general equilibrium (CGE) model PACE-T(H₂) which is an extended version of the PACE-T CGE model developed in Boeters, Böhringer and Löschel (2004). The current version of the PACE-T(H₂) model features two regions: Europe (including the EU-15, Norway, Switzerland and Iceland) and the rest of the world. The sectoral disaggregation of the economy distinguishes between nine sectors (transport, energy intensive production, five energy sectors, the rest of production, and an aggregated savings good). The model is set up as a fully dynamic model with optimal savings and investment decisions of the representative household who maximises the present value of his lifetime utility given his intertemporal budget constraint. Period length is chosen to be 10 years with the model horizon extending from 2000 to 2080²⁰. International trade is modelled in the Armington fashion (Armington,

²⁰ Simulation results are reported up to year 2050. The additional periods between 2060 and 2080 account for the terminal condition of the model.

1969) where goods produced in different countries are treated as imperfect substitutes with their import shares depending on their relative prices. The international crude oil market is homogenised so that every country either imports or exports crude oil.

All essential functions in the model are of the nested constant elasticity of substitution type. Production of commodities in each region is captured by aggregate production functions which characterise technology through substitution possibilities between various inputs (capital, labour, energy, non-energy, intermediate inputs). Domestic demand is composed of final demand of private and public consumers and intermediate demand from other sectors. Final demand of the representative agent is given as a constant elasticity of substitution composite of transport services, heating services and an aggregate of other consumption commodities which combines consumption of an energy aggregate with a non-energy consumption bundle.

The main focus of PACE-T(H2) is on passenger transport. The model therefore implements passenger cars as a separate stock of automobile capital. Thereby, it is assumed that households do not consume cars as such but transport services that are produced with various inputs. The value of these services is mainly composed of capital services of the automobile stock present in the respective economy, fuel and expenditures for operation and maintenance (O&M). Passenger cars are modelled as durable consumption goods where car lifetime is assumed to be 14 years for all cars. The model distinguishes between three different size classes for cars. These are small, medium and large cars which are powered by either a conventional technology or by hydrogen.

In close analogy to passenger cars, we introduce – as one extension of the original model – micro heating systems as a second durable good at the household level. It is assumed that the representative household consumes heating services from a quasi fixed stock of heating installations which are fuel-based but also might become hydrogen-based in the future.

In order to solve the model, the following equilibrium conditions have to hold: (i) zero profit conditions for all production sectors (under the assumption of perfect competition), (ii) market clearance on all markets (perfectly adjusting prices) and (iii) exhaustion of the representative consumer's budget through consumption purchases.

The baseline path from 2000 to 2050 in PACE-T(H2) which is the base for all policy simulations includes all key assumptions of a dynamic model:

- Fully flexible output and factor prices and perfectly competitive markets,
- Labour force productivity increases at an exogenous growth rate (Harrod-neutral technological progress),
- In each region, a representative consumer maximises the present value of lifetime utility subject to (i) an intertemporal balance of payments constraint, (ii) the constraint that output per period is either consumed (incl. intermediate demand and exports) or invested, and (iii) the equation of motion for the capital stock, i.e. capital stocks evolve through depreciation and new investment,
- Agents have an infinite horizon, and their expectations are forward looking and rational. To approximate an infinite horizon model with a finite horizon model we assume that the representative

consumer purchases capital in the model's post-horizon period at a price which is consistent with steady-state equilibrium growth (terminal condition).

In order to represent hydrogen economy configurations the original PACE-T model was extended in several ways. These extensions on the one hand refer to the implementation of hydrogen end-use technologies and on the other hand on hydrogen production technologies.

The most important hydrogen application within PACE-T(H₂) is passenger cars that are powered by hydrogen. Thus we introduce a separate automobile capital stock for hydrogen cars. Consumers in the model are assumed to choose between transportation services that are a composite of services from fossil fuel and hydrogen powered cars. The major difficulty in the calibration of the demand function is the lack of detailed empirical data on hydrogen car demand. One possibility would be to assume that transportation services from hydrogen and conventional cars are perfect substitutes. As a consequence, households would simply choose the cheaper technology and the more expensive technology would be withdrawn from the market. In order to prevent such a development, we chose an alternative way. Precisely, we assume conventional and hydrogen cars to be close to perfect substitutes, i.e. services from fuel and hydrogen powered cars enter the transport service aggregate with finite but very high substitution elasticity. Consequently, an increase in the user costs of fossil fuel based transport services leads to an increase in the demand for hydrogen cars. Such a formulation also takes into account further factors affecting car demand, like e.g. noise or driving properties, which may restrain hydrogen cars from being perfect substitutes to conventional cars.

A major advantage of our approach is that hydrogen penetration is endogenous in consumer demand. Thus it is not only possible to analyze the macroeconomic effects of the introduction of hydrogen in passenger transport but also the effects of different technology and/or policy assumptions on hydrogen penetration in consumer's demand. The magnitude of hydrogen penetration in passenger transport is mainly determined by the cost difference between lifetime (user) costs of conventional and hydrogen cars. Total automobile costs are calculated as the sum of purchase and utilisation costs for both hydrogen and conventional cars over their lifetime where utilisation costs are further de-composed into fuel costs and other costs. The value of the cost difference between conventional and hydrogen cars highly depends on whether taxes for conventional fuel are taken into account or not. The comparison of net costs allows determining when hydrogen cars become competitive. This is essential for the welfare implications of introducing hydrogen cars. Gross car costs, calculated from the car and fuel prices including fuel taxes, are important for the consumer's choice between transportation services from fuel or hydrogen powered cars.

Another possible hydrogen application introduced in our model is micro heating systems that might become hydrogen based in the future. As already stated above, we introduce such heating installations as durable consumption good at the household level. The implementation was done in close accordance to passenger cars, i.e. consumers in the model are assumed to choose between heating services that are a composite of services from fossil fuel-based and hydrogen-based installations. Again we assume that the substitution elasticity between these two alternatives is finite but allows for a high degree of substitution.

Of course, the use of hydrogen as fuel input in passenger transport or heating systems demands a hydrogen production technology. The model therefore features a separate sector for hydrogen production which is

characterised by fixed input shares for the various inputs. Thereby it is assumed that the hydrogen production technology not only covers all costs of the different hydrogen production technologies reached from energy system models per se but also the numerous distribution and storage technologies (like filling stations, pipelines and trucks). The aggregate hydrogen production technology in PACE-T(H₂) is characterised by the average costs of hydrogen production calculated as the sum of costs for investment, fuel inputs and operation and maintenance for the various production, distribution and storage technologies. Consequently, the inputs into the aggregate production technology and thus the costs for hydrogen change over time due to the different mix of hydrogen technologies.

Finally, PACE-T(H₂) assumes that the international import-export structure of hydrogen and conventional cars is the same. Consequently, if a country is producing and exporting conventional cars at present, the assumption is made that this country will also produce and export hydrogen cars in the future.

A more detailed description of the PACE-T(H₂) model and the extensions to represent hydrogen economy configurations is given in the Cascade Mints Deliverable D1.7 (Jokisch and Koschel, 2007).

C.2.7 Stochastic World Energy Models: PROMETHEUS

[by N. Kouvaritakis and V. Panos (ICCS-NTUA)]

PROMETHEUS is a self-contained world energy model consisting of a set of stochastic equations developed with assistance from the 5th Framework Programme of DG Research (SAPIENT project). In the context of CASCADE MINTS project, PROMETHEUS has been extended in order to contain stochastic relations for all the main quantities concerning the hydrogen economy. Naturally, compared to detailed deterministic models, these are represented in reduced form, but specific effort was made to retain the key structural elements, as these are the main vehicles through which stochastic dependence of the impacts of possible scenarios can be established.

Econometric methods were used to the extent possible, in order to provide an element of objectivity or at least neutrality. However, in case of unsuitable or non-available time series information, which is necessary for fitting econometric relations, the stochastic parameters required for the construction and running of the module were provided from other sources directly from specific expertise.

In assessing and filtering uncertainty estimates concerning hydrogen economy related technological developments, a substantial role was played by the reviews carried out during the construction of the common information database. Where it was proved difficult to obtain such scientific probabilistic information, informal Delphi-type consultations were used as last resort. Even though such approaches are rather unsatisfactory, because they tend to introduce a dose of subjective judgement, it should be noted that it is preferable to utilise them rather than assume relationships to be deterministic especially since the cases which can be treated neither by statistical methods nor by scientific assessments are likely to be the ones carrying the highest degree of uncertainty.

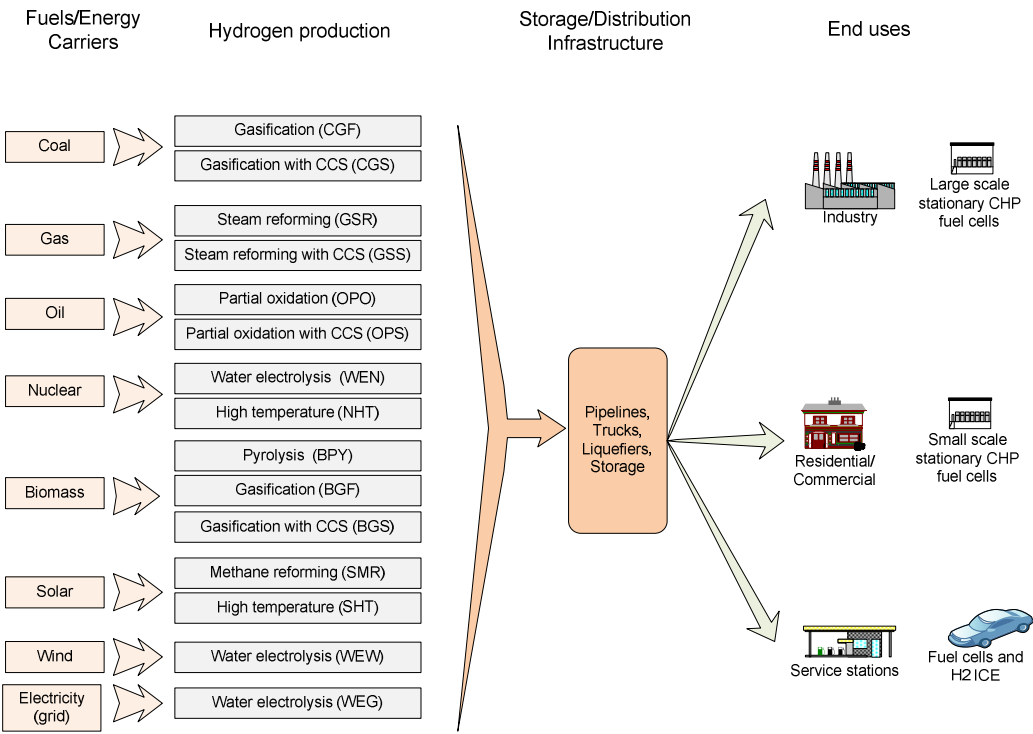
It should be noted that in the context of the CASCADE MINTS project, the equations of the model were quadrupled (from 2500 in SAPIENTIA to almost 10000 in CASCADE MINTS) as a result of the extensive improvements of the model. This chapter presents an overview of the extensions of the PROMETHEUS model. In section 1 the hydrogen module, representing the hydrogen economy in the model, is presented. Section 2 includes an overview of other extensions/improvements made in the model, which are not directly linked with the hydrogen economy but were necessary since they correct and enhance crucial parts of the model. Finally, section 3 presents the technology dynamics implementation in the model, with particular emphasis on the stochastic characteristics of the learning parameters.

Hydrogen economy characterisation

The hydrogen module of PROMETHEUS model incorporates a large number of technologies for hydrogen production, distribution and end use. In order to describe more accurately some key technologies, such as fuel cells, these technologies are included in the model on component-by-component basis. The characterisation of the technologies and their components was based on the common information base of the CASCADE MINTS project.

This section presents an overview of the hydrogen related technologies included in the model. In those cases where an interaction of the hydrogen energy system with the rest of the energy system takes place, a short description of this interaction is given. Figure C-23, presents in summary, the hydrogen module in PROMETHEUS. The discussion in this section will start from the hydrogen end-use technologies, will proceed to the infrastructure network and will finish with hydrogen production.

Figure C-23: Overview of the hydrogen economy as represented in PROMETHEUS



Hydrogen end use technologies

The major end uses of hydrogen in PROMETHEUS are for vehicle propulsion and for production of steam or heat and electricity. In this sense, hydrogen is introduced as an energy carrier in the road transport sector, in industry and in the residential/commercial sectors. The discussion will start with the mobile applications of hydrogen in road transport and then it will proceed to the stationary applications.

Mobile applications (Road Transport sector)

In order to represent a hydrogen powered vehicle in PROMETHEUS, its primary components (engine, onboard storage, and onboard reformer) should be characterised and defined. This approach is followed in the model not only for hydrogen powered vehicles but also for the rest of the vehicle types.

Two kinds of vehicle propulsion engines that use hydrogen are included in PROMETHEUS: fuel cells and internal combustion engines. The fuel cell engine is further differentiated into stack and system components. Moreover, the stacks and systems themselves are varying depending on the fuel used in the fuel cell cars (hydrogen or gasoline). On the other hand, the internal combustion engines technically are not different from the internal combustion engines that are used today in oil-powered vehicles. However, in the common information database they display different economic performance, so it was decided to include them as a different technology in the model.

For automotive on-board hydrogen storage, two options are included in the model: hydrogen in liquid form and hydrogen in gaseous form. These two options compete in the model, since each of them needs its own specific infrastructure to support it.

Onboard gasoline reformers are also included in PROMETHEUS, in order to allow for onboard hydrogen production. These reformers are used in the fuel cell vehicles, bypassing in this way the need for hydrogen distribution infrastructure.

In total, in PROMETHEUS the hydrogen related technologies for mobile applications are two types of fuel cell stacks, two types of fuel cell systems, two types of on board hydrogen storage, one type of onboard reformer and a hydrogen IC engine. All these result in eight different hydrogen related technologies in road transport. These components are combined together to define five new vehicle types in the model:

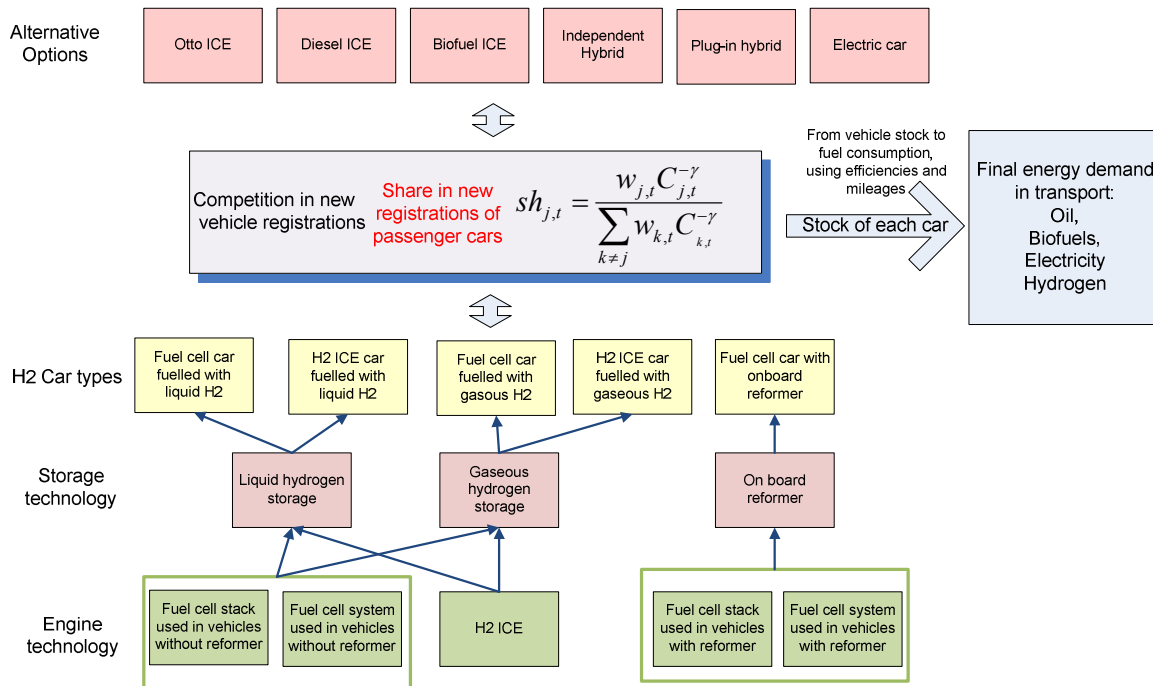
- Fuel cell cars powered with liquid hydrogen
- Fuel cell cars powered with gaseous hydrogen
- Fuel cell cars with on-board reformer powered with gasoline
- Internal combustion engine cars fuelled with liquid hydrogen
- Internal combustion engine cars fuelled with gaseous hydrogen

The hydrogen powered cars compete with the rest of the car types that are included in the model (otto, diesel, biodiesel ICE, hybrid, plug-in hybrid, electric). The decision is based on the cost per vehicle kilometre of each car type. In each year, the increased transport activity generates the need for new vehicle registrations and the different vehicle types are competing to gain share in the new market. The shares are determined by using a Weibull function:

$$sh_{j,t} = \frac{w_{j,t} C_{j,t}^{-\gamma}}{\sum_{k \neq j} w_{k,t} C_{k,t}^{-\gamma}}, (1)$$

where $C_{j,t}$ is the cost per vehicle kilometre of car j in year t , w is a weight representing the relative maturity of the technology and influencing the share of each technology and it is used for calibration purposes and γ represents conditions that influence the investment decisions (such as acceptability of new technologies in the sector). The new cars are added to the existing stock. From the car stock, and by applying efficiencies and annual average mileages, the fuel consumption can be determined. The representation of hydrogen in road transport is given in Figure C-24. The figure shows the hydrogen related technologies considered in the model for vehicle propulsion and onboard storage/reformer, and how they are combined together in order to define the hydrogen powered cars.

Figure C-24: Representation of hydrogen in road transport and competition with other options



Stationary applications (Industry, Residential/Commercial sectors)

In PROMETHEUS hydrogen is also used for the combined production of heat and electricity. The fuel cell CHP plants are distinguished according to their size and the fuel that they use. Small scale stationary fuel cell CHP plants (1-5Kw) are used in the residential/commercial sectors, while fuel cell CHP plants of a size of up to 300Kw are used for the combined production of low enthalpy steam and electricity in the industrial sectors. Regarding the fuel that they use, two types are considered, one which is fuelled directly with hydrogen and one which uses natural gas and onsite steam reforming. For a more accurate characterisation of the fuel cell CHP plants, the fuel cell stacks, the fuel cell systems and the onsite reformers are defined individually. In total, six hydrogen related technologies are considered for stationary applications in the residential/commercial and industrial sectors:

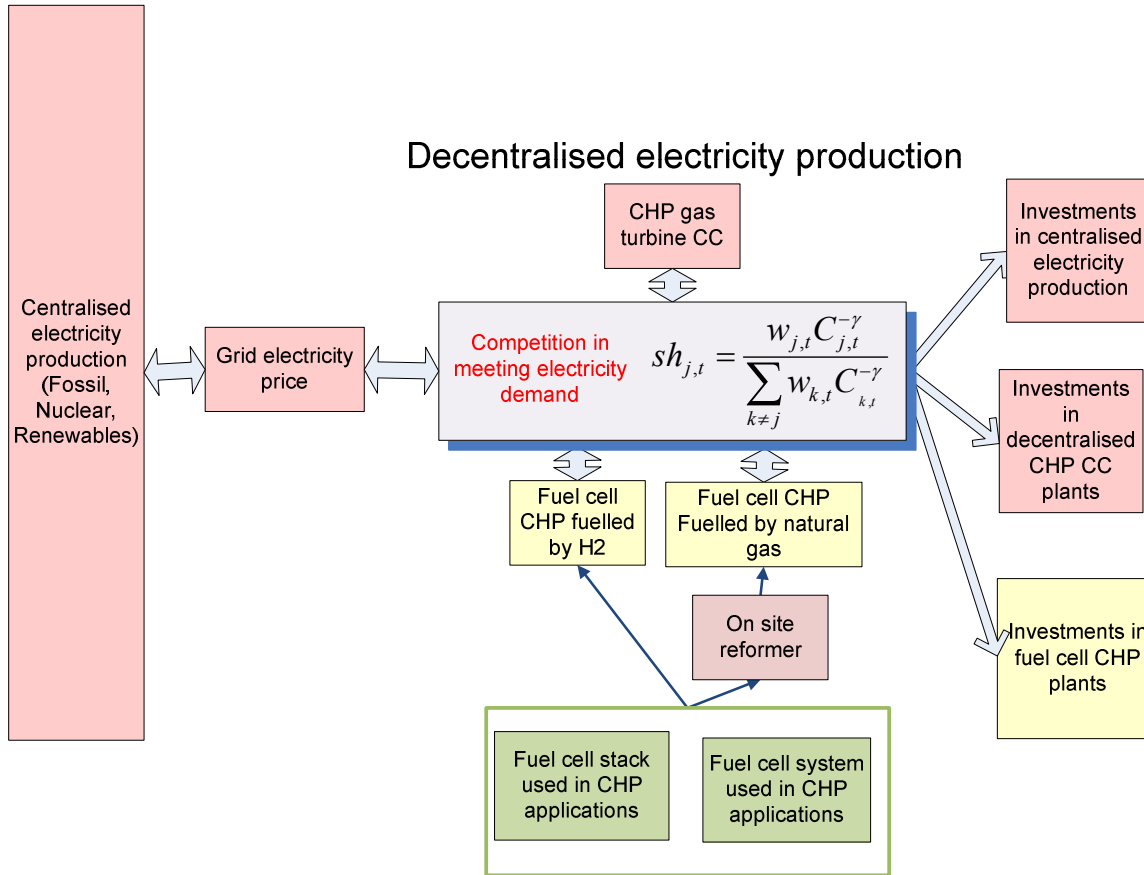
- Fuel cell stacks and fuel cell systems for small scale CHP
- Fuel cell stacks and fuel cell systems for large scale CHP
- Onsite natural gas reformers

PROMETHEUS includes also CHP plants that operate with natural gas and are based on gas turbine combined cycle technology for combined heat and power production. All types of CHP plants (either fuel cells or not) are introduced in the competitive market for decentralised electricity production. The consumer decision is based on the competitiveness of the electricity production cost from a CHP plant (after subtracting the value of steam/heat) and the grid electricity price. Each year the increased electricity demand generates the need for new investments for electricity production. In the decentralised market, the different types of CHP plants are competing to gain share over the grid electricity. The shares are calculated using a Weibull function:

$$sh_{j,t} = \frac{w_{j,t} C_{j,t}^{-\gamma}}{\sum_{k \neq j} w_{k,t} C_{k,t}^{-\gamma}}, \text{ which is similar to the one used in the competition of vehicles in road transport sector.}$$

The new investments in CHP plants are added to the already installed capacity. Electricity produced by CHP is subtracted from the electricity demand of the sector and the remainder has to be covered by the centralised electricity production. Moreover, their steam or heat production is subtracted from the non-electric fuel consumption of the sector, using the average efficiency of a boiler (that is powered with the same fuel) for the conversion. Figure C-25 presents an overview of the representation of hydrogen use in industrial/residential/commercial sectors.

Figure C-25: Representation of stationary hydrogen applications and competition with other options



Hydrogen storage, transportation and delivery infrastructure

PROMETHEUS implements the “Reference case for hydrogen distribution” as it was described in chapter B.1.3 of the final technical report. As a result, a large number of technologies for hydrogen distribution and storage have been introduced in the model, many of them defined on component-by-component basis:

- Turnpike pipelines of a large scale diameter, which serve as storage medium and load balancing tool. The pipeline is connected with hydrogen production facilities and they actually constitute a large national and international network.
- High pressure transmission pipeline, connecting the turnpike pipelines and the production facilities with the residential/commercial urban areas.
- Medium pressure urban ring pipelines as distribution backbones to ensure higher availability of supply.
- Service stations connection lines, which connect the service stations to the ring.
- Low pressure pipelines, which connect households/stores/offices with the backbone ring.
- High pressure transmission pipeline, connecting the turnpike pipelines and the production facilities with the industrial areas.

- Trucks for delivering gaseous hydrogen to rural and urban areas.
- Trucks for delivering liquid hydrogen to rural and urban areas.
- Liquefiers for hydrogen liquefaction.
- Centralised liquid hydrogen storage facilities.
- Service stations delivering gaseous or liquid hydrogen to vehicles.

In order to introduce a form of clustering in the learning of pipelines, their capital costs are functions of their distance and diameter of the form of:

$$C_{j,t} = e^{(A_t + \alpha \cdot \ln(diam_j) + \beta \cdot \ln(length_j))}$$

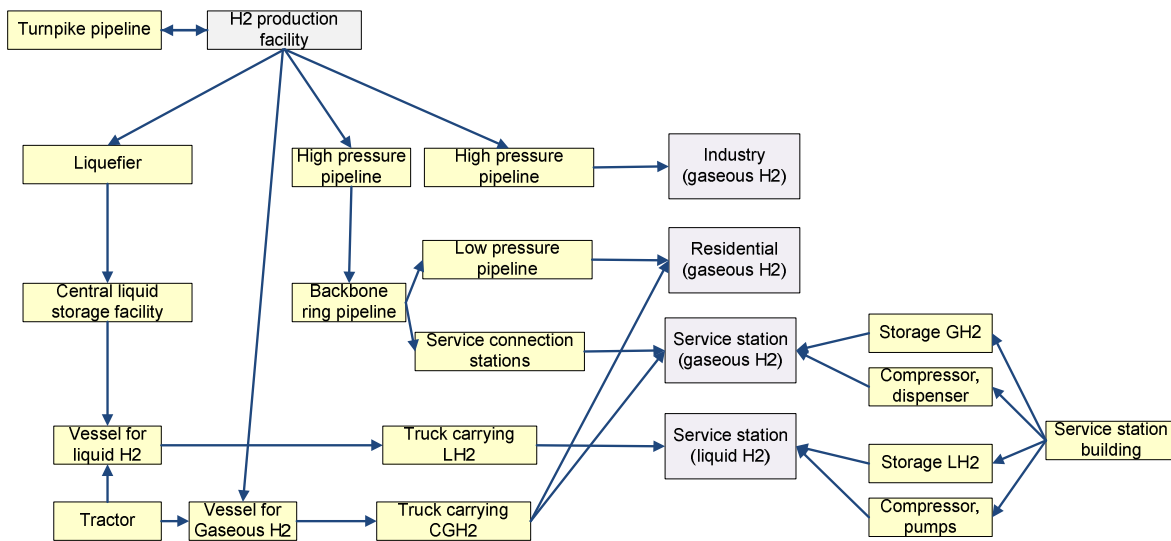
where the elasticities A_t , α and β are common to all pipeline types and A_t is common to all pipelines. A_t is a scaling factor representing fix investment costs and it is independent of diameter and length. Also it encapsulates technical progress in hydrogen pipelines. The parameters were estimated simultaneously by three stage least squares using data from the common information base. However, it should be noted that these parameters are considered to be deterministic and not stochastic in the model.

The trucks that are carrying hydrogen to the final consumers are split in the tractor itself and in the storage vessel. The tractor is considered to be the same either the truck is carrying liquid or gaseous hydrogen. The trailers with the hydrogen storage vessels that store hydrogen in either gaseous or liquid form are treated as separate technologies.

The service stations are split into distinct parts in the model: the storage equipment, the specialised equipment for hydrogen dispensing (dispensers, compressors, pumps, etc) and the rest of the service station installation. In order to introduce some clustering in the learning of hydrogen storage equipment, the progress of the storage facility of a service station is linked to the progress of the storage equipment on a truck.

In total 16 different technologies/components for representing the hydrogen infrastructure are included in the model. The following figure summarises the above discussion.

Figure C-26: Overview of the hydrogen infrastructure representation in PROMETHEUS (yellow represents the infrastructure technologies)



Hydrogen production

PROMETHEUS has been equipped with an enhanced portfolio of hydrogen production technologies, as a result of the work performed in the common information base of the CASCADE MINTS project. The model has been extended to include 18 hydrogen production options, compared to 9 options in the SAPIENTIA project (Table C-23).

Table C-35: Hydrogen production options in PROMETHEUS

Gas	Gas steam reforming
	Gas steam reforming with CCS
Coal	Coal partial oxidation
	Coal partial oxidation with CCS
	Coal gasification
	Coal gasification with CCS
Oil	Oil partial oxidation
	Oil partial oxidation with CCS
Biomass	Small scale biomass gasification
	Large scale biomass gasification
	Large scale biomass gasification with CCS
	Biomass pyrolysis
Solar	Solar methane reforming
	Solar high temperature thermochemical cycle
Nuclear	Water electrolysis from dedicated nuclear plant
	Nuclear high temperature thermochemical cycle
Wind	Water electrolysis from dedicated wind plant
Electricity (Grid)	Water electrolysis from electricity grid

The above technologies compete in order to satisfy the hydrogen demand. The investment decision is based on the production cost from each technology. In each year the model determines the required new investments, by taking into account scrapping, and then calculates the shares of the production technologies (using a Weibull function similar to the one used in transport sector) in the new investments.

Long term average cost pricing is applied for the production cost of hydrogen. The consumer price also includes overheads for the storage and distribution of hydrogen plus any taxes.

Other improvements in PROMETHEUS model

This section describes other enhancements in the PROMETHEUS model, which have been done in the context of the CASCADE MINTS project. Some of these extensions do not directly relate to the hydrogen economy but they are considered to be necessary since they improve important parts of the model and enable a more accurate evaluation of the implication of hydrogen penetration in the energy system.

Geographical extension of the model to include the new European Union member states

Until CASCADE MINTS, the PROMETHEUS model covered three world regions: EU-15 plus Norway and Switzerland, rest of OECD (which includes USA, Japan, Canada, Australia and New Zealand) and the rest of the world. After the expansion of the European Union in May 2004 and in January 2007, EU-15 is not any more a valid indicator for the European Union. It was deemed necessary to introduce in the model explicitly another region, which includes the new European Union member states. The option to introduce another region than expanding the current EU-15 region was chosen due to the different economic growth patterns pertaining to the new member states. In this sense, the differences between the developed EU-15 members and the developing new member states are kept in the model, enabling separate probabilistic assessments on the members of the European Union themselves. The new region is called “NMS-12”, and currently in the model the “Europe” region refers to EU-27 plus Norway plus Switzerland.

The introduction of a fourth region into the model required the modification of the older “Rest of the World” region, since the new member states were belonged to this region. This resulted in re-estimation of the “Rest of the World” region and, of course, estimation of new equations for the NMS-12. The latter required the collection of long time series covering GDP, population, fuel prices, final consumption, etc. The main sources for these time series were the Eurostat New Cronos database and the Enerdata databases. For road transport statistics, the International Road Federation (IRF) database was also used. The estimation technique used was the ordinary least squares method.

Extensions in the transport module of PROMETHEUS

In view of the importance of road transport for hydrogen prospects a major re-design and re-estimation of the transport module of PROMETHEUS has taken place during the CASCADE MINTS project. New car types have been introduced in the model: apart from the hydrogen powered cars the available options now include biodiesel internal combustion engine cars and plug-in hybrids.. In total, the model now includes 11 different car types: 5 hydrogen powered, 2 conventional internal combustion engines (gasoline and diesel), 1 using biodiesel, 2 types of hybrid and 1 type of pure electric car.

In addition the logic of the module was re-designed. During this process new reduced form stochastic equations were estimated, replacing previous ones. In the current version, the model first determines the total car stock that is necessary to satisfy the increased transport activity, by using a stochastic equation of GDP and average fuel price for road transport. It then calculates the new registrations required meeting the increased demand by taking into account the scrapping. The eleven vehicle types compete in the new vehicle market. The shares are calculated using the Weibull function described in the previous section. The new registrations of each car type are added to the remaining (after scrapping) stock and fuel consumption is calculated using efficiencies and average mileages.

Cost-supply curves for biomass

Until the CASCADE MINTS project, the price of biomass for electricity, hydrogen and biofuel production was exogenous to the model. Apart from the fact that this assumption violated the logic of the model, in many cases it has also led to unrealistic results, i.e. the biomass price was too low and independent from the primary consumption. Given the importance of biomass for hydrogen production, and of course for biofuels production in transport, it was deemed necessary to include a cost supply curve for biomass in a reduced form. In constructing the supply curve, a number of studies were taken into account including:

- The potential of biomass energy under four land use scenarios (2004), Monique Hoogwijk, André Faaij, Bert de Vries, Wim Turkenburg
- IPCC Climate change 2001 mitigation, Chapter 3: Technological and Economic Potential of Greenhouse Gas Emissions Reduction, W.R. Moomaw (USA), J.R. Moreira (Brazil)
- Global bioenergy potentials through 2050, G. Fischer, L. Schrattenholzer, Journal of Biomass and Bioenergy vol.20 pp151-159
- Global biomass energy potential, J.R. Moreira
- VLEEM II, Monograph on Biomass, Frey, Lako, Pittermann, Pospischil, Reisinger, 2004
- Global biomass fuel resources, M. Parikka, Biomass and Bioenergy vol. 27 pp613-620, 2004
- A quick scan of global bio-energy potentials to 2050, E. Smeets, A. Faaij, I. Lewandowski, March 2004 ISBN 90-393-3909-0
- Evaluation of bioenergy potential with a multi-regional global-land-use-and-energy model, H. Yamamoto, J. Fujino, K. Yamaji, Biomass and Bioenergy vol.21 pp185-203
- Biofuels and bioenergy scenarios, Final report of VIEWLS WP5 modelling studies, A. Wakker, R. Egging, E. Thuijl, X. Tilburg, E. Deurwaarder, T. Lange, G. Berndes, J. Hausson
- How much bioenergy can Europe produce without harming the environment? EEA report No7/2006, T. Wiesenhal, A. Mourelatou, Jan-Erik Petersen, P. Taylor, ISBN: 92-9167-849-X
- Assessment of the potential biomass supply in Europe using a resource-focused approach, K. Ericsson, L. Nielsen, Biomass and Bioenergy, vol. 30 pp1-15

- Outlooks on selected agriculture variables for the 2005 State of the Environment and the Outlook Report, EuroCARE, 2004

The above studies include technical and economic potential of biomass, while some of them also estimate cost supply curves. However, their estimates for the biomass potential vary significantly, implying that a high uncertainty surrounds this topic. Although for a deterministic model this would present a problem of choice, in PROMETHEUS, where the main objective is to measure the uncertainty, the variation of the estimates in the above studies proved to be very useful for determining the stochastic characteristics of the biomass supply curve. Using econometric techniques the following reduced form stochastic equations for the biomass cost supply curve were fitted for each region j :

$$Tpot_{j,t} = Tpot_{j,t-1} \cdot (1 + gr_{j,t}) \cdot \left(\frac{pop_{j,t} / p_t}{pop_{j,t-1} / p_{t-1}} \right)^{\alpha_j} \cdot \left(\frac{(gdp_{j,t} / pop_{j,t}) / (g_{j,t} / p_{j,t})}{(gdp_{j,t-1} / pop_{j,t-1}) / (g_{j,t-1} / p_{j,t-1})} \right)^{\beta_j}$$

$$\ln \left(\frac{Epot_{j,t}}{Tpot_{j,t}} \right) = \ln \left(\frac{1}{1 + e^{\kappa_j (avprice_{j,t} - \mu_j)}} \right) + \varepsilon_t$$

$$bmsprice_{j,t} = bmsprice_{j,t-1} \cdot \left(\frac{primarybms_{j,t-1} / avTpot_{j,t-1}}{primarybms_{j,t-2} / avTpot_{j,t-2}} \right)^{0.8 \cdot \varphi_j} \cdot \left(\frac{primarybms_{j,t-1} / avEpot_{j,t-1}}{primarybms_{j,t-2} / avEpot_{j,t-2}} \right)^{0.2 \cdot \varphi_j} \cdot \left(\frac{primarybms_{j,t-1}}{avEpot_{j,t-1}} \right)^2 \Bigg)^{0.5}$$

In the above equations Tpot is the technical potential of biomass, gr is a random variable determining the increase in the technical potential, pop is the population, p is a benchmark population, gdp is the GDP and g is a benchmark for GDP, Epot is the technical potential, avprice is the six-year moving average of biomass price, bmsprice is the biomass price, primarybms is the primary production of biomass, avTpot is the six-year moving average of the technical potential, avEpot is the six-year moving average of the economic potential and φ is the sensitivity elasticity of price in increases in the primary production. GDP and population are used to derive a proxy for labour costs that constitute an important part of production costs.

It should be noted that the above equations calculate the marginal cost of biomass, since there is no actual biomass market. Therefore they are used more as a constraint to the penetration of biomass in the energy system rather than equations calculating the biomass price.

Cost-supply curves for CO₂ sequestration

The importance of CO₂ capture for electricity and hydrogen production raises the issue of the cost of CO₂ storage. The CO₂ storage sites are considered to be depletable resources, thus a cost-supply curve is necessary as the quantities of the CO₂ that is captured every year are increased. Using marginal storage cost curves provided by the IPTS, exponential cost-supply curves were estimated for each region in the form: $\ln(C_t) = \ln(\alpha \cdot e^{CCO2_{t-1} \cdot \beta}) + \varepsilon_t$, where C_t is the unit storage cost in €/tnCO₂ and CCO₂t is the cumulative CO₂ captured until the year t. The parameters α and β were estimated for each PROMETHEUS region, using the IPTS data.

Cost-supply curves for uranium

Before CASCADE MINTS in PROMETHEUS the price of fuel for nuclear reactors was considered to be exogenous to the model, deterministic in the nature and also it was kept constant throughout the projection period. Apart from the fact that keeping a deterministic variable in a stochastic model violates the model logic, the assumption of keeping constant the price for the whole projection period is not valid: recently, after a long period of almost constant prices, the prices have doubled (although still the fuel costs constitute a small part of the total production cost of a nuclear plant). It was, therefore, deemed necessary to endogenise the nuclear fuel price in the model, by estimating a cost supply curve.

The implementation of such curve required long time series for the nuclear fuel price and for nuclear production. The major source for prices was the Ux Consulting Company (<http://www.uxc.com/index.aspx>) which maintains a database of long time series for the costs and prices of extracted, converted and enriched uranium products. Moreover, the World Nuclear Association report “The new economics of nuclear power” was used in order to analyse and represent in the model a reduced form of the uranium fuel cycle from extraction to the input of the nuclear reactor.

A set of stochastic equations were estimated, representing the fuel cycle in a reduced form. The first equation calculates the extraction cost of U₃O₈ as a function of oil price and nuclear based electricity and hydrogen production. The higher the oil price and/or the production the higher the cost of U₃O₈ is. The second stochastic equation calculates the price of converting U₃O₈ as a function of U₃O₈ price and the gas price (which is assumed to be the dominant fuel used for conversion). The third stochastic equation calculates the cost of enrichment services as a function of the oil price. The sum of all these costs is the price of fuel in the nuclear reactor.

$$priceU3O8_t = priceU3O8_{t-1} \cdot oilprice_t^\alpha \cdot e^{\beta \cdot \sum_{k=1}^4 \gamma_k \cdot \left(\frac{Qnuc_{t-k}}{Qnuc_{t-k-1}} - 1 \right)} \cdot e^{\varepsilon_t}$$

$$priceConv_t = priceConv_{t-1} \cdot e^c \cdot \left(\frac{priceU3O8_t}{priceU3O8_{t-1}} \right)^\delta \cdot \prod_{k=1}^3 \left(\frac{gasprice_t}{gasprice_{t-1}} \right)^{\mu \cdot \theta_k} \cdot e^{\varepsilon_t}$$

$$priceEnrich_t = priceEnrich_{t-1} \cdot \prod_{k=1}^4 \left(\frac{oilprice_{t-k+1}}{oilprice_{t-k-1}} \right)^{\sigma \cdot \omega_k} \cdot e^{\varepsilon_t}$$

$$pricenuc_t = (8 \cdot priceU3O8_t + 7 \cdot priceConv_t + 4.8 \cdot priceEnrich_t + 240) / 81.21$$

Intermittent renewable sources economic potentials

One major limitation in PROMETHEUS model, until the CASCADE MINTS project, was the absence of any kind of constraint in the penetration of intermittent renewable energy sources due to the depletion of the available sites. By not constraining the penetration of renewables for electricity and hydrogen production, in cases of strong climate policy unrealistic results were often obtained. In the context of CASCADE MINTS, and in view of the importance of renewable energy sources in the future, the model has been equipped with

cost-supply curves for the electricity and hydrogen production from hydro, wind and solar. The supply curve operates on the utilisation of the plant and it is used in the investment decision mechanism. The main idea is that when the penetration is low the investments are placed in sites with high utilisation rates. As the penetration increases and the sites are being exploited, the investments are built on sites with gradually lower utilisation rates. A logistic function is used as a supply curve, which reduces the utilisation rate of a new plant based on the electricity or hydrogen production of this type of plants so far. In this way the production cost from this plant is increased, which in turn has a negative effect on the investment decision.

$$util_{j,t} = \left(\frac{0.95}{1 + e^{\alpha \cdot Q_t - \beta}} + 0.05 + \varepsilon_t \right) \cdot u_{j,t}$$

The logistic function is of the form of $util_{j,t} = \left(\frac{0.95}{1 + e^{\alpha \cdot Q_t - \beta}} + 0.05 + \varepsilon_t \right) \cdot u_{j,t}$, where $u_{j,t}$ is the theoretical (maximum) utilisation rate of the plant j , and $util_{j,t}$ is the actual utilisation rate as the production Q_t increases. The parameters α and β have been estimated for each PROMETHEUS region using data from the following studies, while ε_t is the error of regression:

- Hydropower & Dams, 2001. World Atlas & Industry Guide, Aqua-Media International, UK.
- Hydropower potential and development activities, A. Bartle, Energy Policy vol.30 pp 1231-1239
- On the global and regional potential of renewable energy sources, M. Hoogwijk, 2004
- Worldwide offshore wind potential and European projects, T. Ackermann, R. Leutz, J. Hobohm, 2001 IEEE

Hydrogen taxation in road transport

In order to include the possibility of a future hydrogen taxation in the road transport, PROMETHEUS has been equipped with a logistic function in the form of $h2tax_t = \frac{gasoline\_tax_t}{1 + e^{\alpha \cdot (shconv_t / shh2_t - \beta)}}$, which increases the tax in hydrogen as the share of hydrogen cars in total stock increases. This function applies to each region separately. At the beginning the tax is zero and gradually approaches the tax of gasoline. The parameters α and β have been estimated for each region separately, using a Delphi procedure.

Stochastic mechanism for R&D allocation in energy technologies

In the SAPIENT project, where PROMETHEUS was initially constructed, the R&D was an exogenous variable. In SAPIENTIA, the annual public and private R&D expenditures to energy technologies became a stochastic variable depending on the cost of energy and the GDP growth. In the context of CASCADE MINTS, the allocation of annual public and private R&D also became a stochastic variable, increasing in this way the uncertainty in the R&D expenditures. Based on the R&D database of the CASCADE MINTS project, and on the R&D outlook, stochastic equations for the share of each technology in total annual R&D expenditures were estimated.

Introduction of infrastructure and social network effects in the decision mechanisms of the model

The nature of hydrogen end use technologies is such that they can successfully penetrate only if the associated infrastructure is developed in parallel. In addition, consumer decisions are also guided by mimetism and social networking effects.

Since the main objective of CASCADE MINTS part I project is to evaluate the prospects of the hydrogen economy, PROMETHEUS has been equipped with a decision mechanism in order to simulate the above social and infrastructure network effects in consumer decisions. The mechanism is introduced in a reduced form logistic function, which increases the weight w in the Weibull function, which determines the share of the technology in new investments, as the penetration of the specific technology increases. This mechanism has been introduced for the hydrogen powered cars, for the stationary fuel cell applications and electric vehicles (including plug-in hybrids). The criterion for measurement of the penetration of a technology, is the ratio of the current useful energy produced from this technology to the theoretical upper bound of the useful energy that can be produced if this specific technology was the only available option to the consumer.

Introduction of stochastic real interest rates in the decision mechanisms of the model

In order to represent more fully the uncertainty in the decision mechanisms for new investments, the discount rates used are not any more deterministic. In the previous PROMETHEUS versions, the discount rates used was 8% for the power plants and 17.5% for passenger cars, which were kept constant throughout the projection period.

In the context of CASCADE MINTS project, it was decided to alter this by including into the decision the uncertainty of future long term interest rates that provide a low risk placement alternative. For this purpose, reduced form stochastic relations were estimated, linking the interest rates with the world GDP growth. In this way, the discount rate is formed using an unknown and random part, the interest rate, and a constant known part.

Introduction of pre-mature replacement

A major limitation of the PROMETHEUS version prior to the CASCADE MINTS project was the absence of the possibility to replace existing equipment if the continued utilisation of this equipment became un-economic. In previous PROMETHEUS versions, the installed equipment was replaced only at the end of its technical lifetime. The main implication of this logic was the slow renewal of the equipment stock. This constituted a major limitation especially for the power generation sector and in the context of effective climate policy, since it meant that the possibilities for abatement were underestimated.

In the new version of PROMETHEUS it is assumed that if a plant is no longer cost-effective any more (due to, for example, high fuel prices) this plant is removed from the park. The pre-mature replacement is formulated as a logistic function, which increases the annual scrapping rate of a given plant by comparing its variable

cost to the total production cost of its competitors (assuming that the competitors have the same utilisation rate of the given plant). The general algebraic formulation is:

$$prescr_{i,t} = 1 - \frac{VOM_{i,t}^{-g}}{h_{i,t} \sum_{j \neq i} TOTCOST_{j,t}^{-g} + VOM_{i,t}^{-g}},$$

where $prescr_{i,t}$ is the pre-mature replacement factor, $VOM_{i,t}$

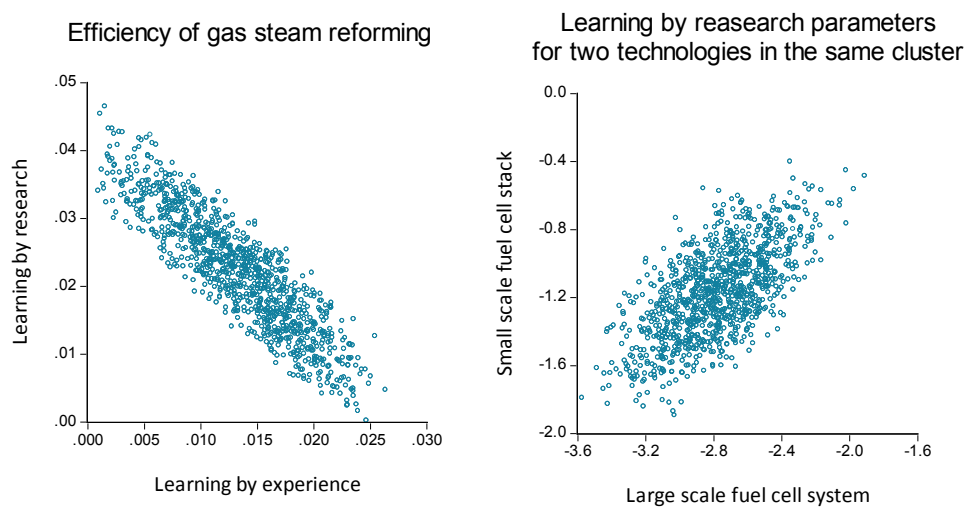
is the variable (including fuel) cost of technology i and $TOTCOST_j$ is the total production cost of technology j for the same utilisation rate as technology i. Factor h_i is used for scaling purposes.

Technology dynamics

PROMETHEUS incorporates endogenous learning (both by research and by experience) for all hydrogen related technologies in the form of two factor learning curves as they have been described in chapter C.1.2 of the report. PROMETHEUS, being a stochastic model, it treats the learning parameters as random variables, which implies that the stochastic characteristics of the parameters play a crucial role in determining the uncertainties surrounding the learning characteristics. In particular they may influence the uncertainty surrounding the efficacy of R&D effort. For this purpose, during the estimation of the two factor learning curve equations, particular attention was given in order to ensure both statistical fit and sufficient robustness.

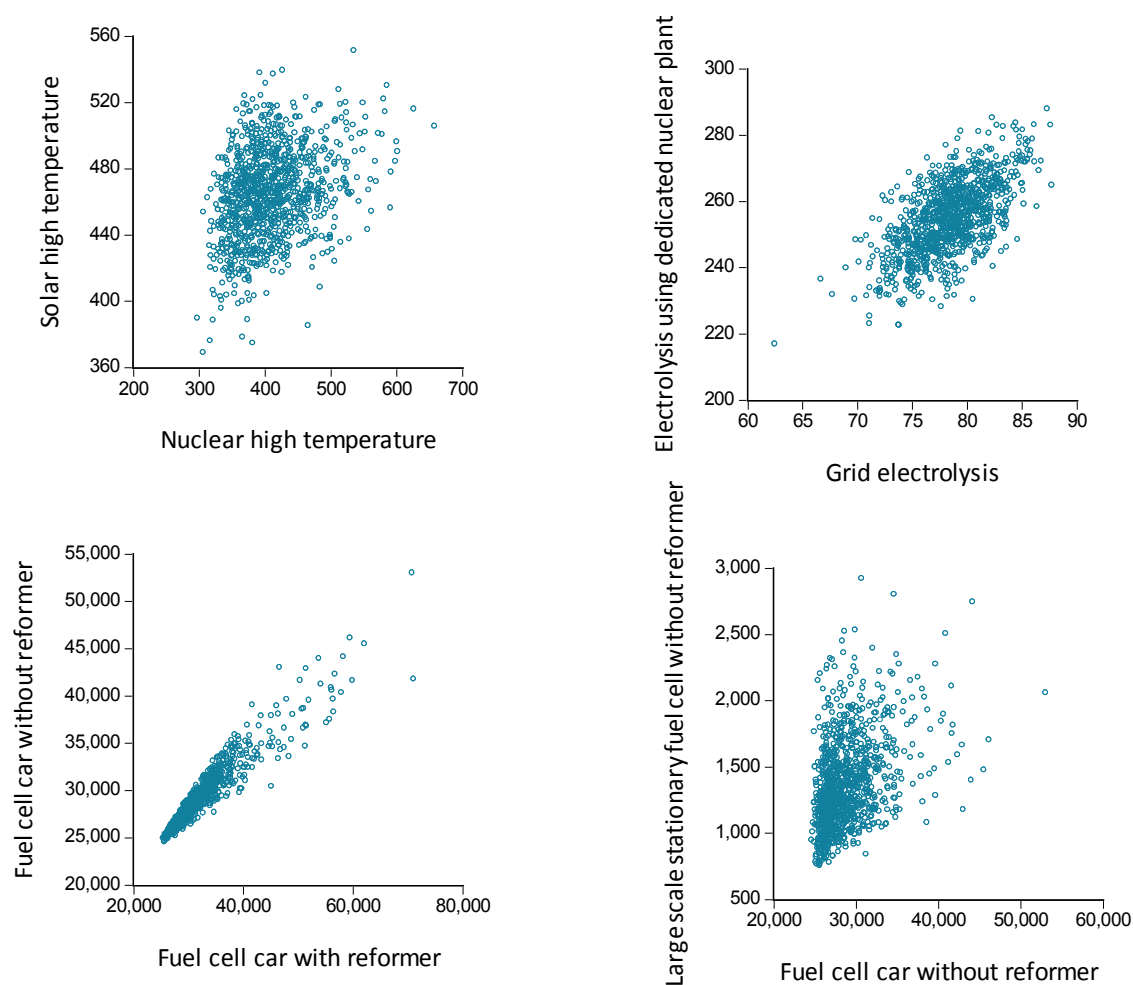
Looking at the joint distributions of the learning parameters within a single technology, learning by experience and learning by research estimates are strongly and negatively correlated. This tends to reduce variability of learning, since in the cases where one parameter is large the other has significant probabilities to be small. Also, learning parameter estimates of the same type for different technologies within the same cluster tend to be positively correlated, which implies some uniformity in the stochastic behaviour of the whole cluster. Learning parameters also tend to be positively correlated when the same type of learning coefficient is considered (either learning by doing or learning by research) (see Figure C-27)

Figure C-27: Joint distributions of learning parameters



Covariance in learning parameters is one of the reasons for producing covariance in technology prospects. This mechanism operates in a variety of ways that they cannot be easily summarised. For example a positive covariance between two learning by research parameters will turn to produce a positive covariance for improvements only if the R&D directed towards them displays a similar time profile and is effectively statistically correlated. In fact a host of other considerations all of them subject to risk (and positive or negative covariance) will also tend to play a role in shaping stochastic patterns for technology improvement. These will include the degree of clustering as well as the type of condition that may favour a particular option as opposed to another. Such effects are transmitted primarily through learning by doing parameters but can be modified to the extent that technical limits to improvement are reached at varying speeds.

Figure C-28: Scatter graphs of the capital costs of selected technologies in 2050 (for cars the cost is €05/vehicle, for hydrogen production technologies the cost is €05/Nm3/d, for electricity production technologies the cost is €05/Kw)



The scattergrams above demonstrate the stochastic dependence of the capital cost of some technologies as they emerge from PROMETHEUS results for the year 2050. The technologies chosen are characterised by some technological affinity. For example the solar high temperature thermochemical cycle and the nuclear high temperature thermochemical cycle are partly based on kindred thermochemical cycle processes

involving separation at stages characterised by varying temperatures. They also both depend on the availability of an effective Zn/O₂ separation technique. On the other hand, it is clear that the scale of the application is different in the two cases. Likewise the nuclear based process also depends on the resolution of problems associated with more direct use of reactor heat and successful demonstration of new design concepts. Such uncertainties are obviously not shared by the solar process. This goes some way in explaining the variability in the cost performance of nuclear high temperature and its relative independence from the eventual performance of solar high temperature (see Figure C-28)

D. Model based analysis of Hydrogen Economy Prospects

D.1 Common Assumptions

D.1.1 Macro-economic and world price assumptions

[by P. Criqui and S. Mima (LEPII-EPE)]

Overview

The Reference projection adopts exogenous forecasts for population and economic growth in the different world regions and it makes consistent assumptions for the availability of fossil energy resources and for the costs and performances of future technologies. Reference projections to 2050 have been made with *POLES model* extended with adequate mechanisms for representing hydrogen economy.

This report presents the common set of assumptions used in this study, concerning GDP, POP and oil and gas reserves.

Key assumptions in the Cascade study

Key economic assumptions

Using the POLES model 2005 Reference case assumptions, the outlook for the world economy can be summarised as follows in the Table D-1:

- World GDP growth will be sustained all along the current decade with an average 3.9 %pa growth; it will however slowdown in the following twenty years to 2.9 %pa and to 2.2% during 2030/2050.

- In all the industrialised regions, of Europe, North America and Pacific, economic growth will be brought down to annual growth rates of about 2 %pa after 2010 and 1.4% after 2030.
- While China, India and the Rest of Asia are the fastest growing regions in the current decade, they will also experience a slowdown after 2010; this slowdown is particularly noticeable in China and is connected to the evolution of demography and to the rapid ageing of population.
- Largely due to high oil and gas price, the Middle East region turns to be the fastest growing region of the world in the 2010-2050 period.

Table D-1 : GDP growth by region (GDP measured in Purchasing Power Parity)

	G\$95					Annual % change		
	2001	2010	2020	2030	2050	2001/10	2010/30	2030/50
World	42224	59524	81559	105930	164090	3.9%	2.9%	2.2%
Europe	10312	12660	15900	19079	25194	2.3%	2.1%	1.4%
North America	10003	13225	16432	19843	26887	3.2%	2.0%	1.5%
Jap-Australasia	3583	4497	5474	6558	8731	2.6%	1.9%	1.4%
CIS	1463	2164	3041	3860	5488	4.4%	2.9%	1.8%
Latin America	3410	4474	6210	8145	12658	3.1%	3.0%	2.2%
Middle East	978	1353	1981	2842	5908	3.7%	3.8%	3.7%
Africa	1664	2244	3106	4177	8795	3.4%	3.2%	3.8%
India	2763	4847	7980	11531	20367	6.4%	4.4%	2.9%
China	4805	9107	13766	18914	30626	7.4%	3.7%	2.4%
Other Asia	3242	4952	7669	10981	19435	4.8%	4.1%	2.9%

Source : POLES 2005

Table D-2 illustrates the consequences of these differentiated dynamics in terms of convergence of per capita GDP while using the European situation as a bench mark. It shows a convergence amongst the industrialised regions, but still more clearly the continuation of the catch-up process in Asia: when expressed in Purchasing Power Parity, the current per capita GDP is about 20 % of the European level in China and the Rest of Asia, 15 % in India; in 2050 it will have increased to 52 % of the European level in China, 30 % in India and the Rest of Asia.

Table D-2 : Per capita GDP convergence

Europe = 100	2001	2010	2020	2030	2050
World	39	41	41	42	43
Europe	100	100	100	100	100
North America	180	182	166	156	141
Jap-Australasia	130	132	128	129	132
CIS	30	37	43	47	54
Latin America	37	36	36	37	39
Middle East	33	31	30	31	37
Africa	12	11	10	9	11
India	15	20	23	26	31
China	22	32	37	42	52
Other Asia	19	21	23	25	28

World fossil fuel reserves and resources

The assumptions about oil and gas resources are critical because present market behaviour and a series of recent studies suggest that access to supplies to meet future increase in demand may be difficult. The Institut

Français du Pétrole (IFP) reviewed the assumptions concerning Ultimate Recoverable Resources²¹, discoveries, reserves and cumulative production and recovery rates.

Any energy outlook for the long-term has to deal with the possibility of “peak oil” and “peak gas” that some geologists expect soon. The consequent increase in prices may profoundly influence the development of competing energy technologies and reshape the future energy system. Cascade gives special attention to the evaluation of oil and gas resources. In broad terms, the logic used in POLES in order to model oil and gas supply and price is based on the following sequence:

- The Ultimate Recoverable Resources (URR) is derived from the USGS estimates, but are modified over the projection period in order to account for the impact of increasing recovery rates (which are assumed to be dependent on the oil and gas prices).
- Discoveries depend on the drilling effort (also oil and gas price dependent) and the reserves are equal to the total discoveries minus the past cumulative production.
- For all regions except the Gulf, the production depends on a price dependent “reserve on production” or R/P ratio.
- The international prices depends, in the case of oil on the world R/P ratio (including non conventional oil), and for gas on regional R/P ratios as well as of an indexation term to the oil price.

In this process, the driving exogenous hypothesis is related to the URR estimate at the beginning of the simulation. The uncertainty concerning this set of hypotheses is quite high as testifies the long-lasting controversy between ‘optimists’ and ‘pessimists’ concerning oil and gas resources. In order to produce the CASCADE Reference projection, the core assumptions are based on the US Geological Survey's median estimation for oil and for gas in each producing region (i.e. 50% probability of occurrence). This results in oil recoverable resources of around 2600 billion barrels at the beginning of the simulation, as illustrated in Table D-3.

²¹ The core assumptions used in POLES for the URR, for instance in WETO-2030, are based on the USGS median estimates for oil and for gas in each producing region (i.e. 50% probability of occurrence)

Table D-3: Oil development and supply, Reference

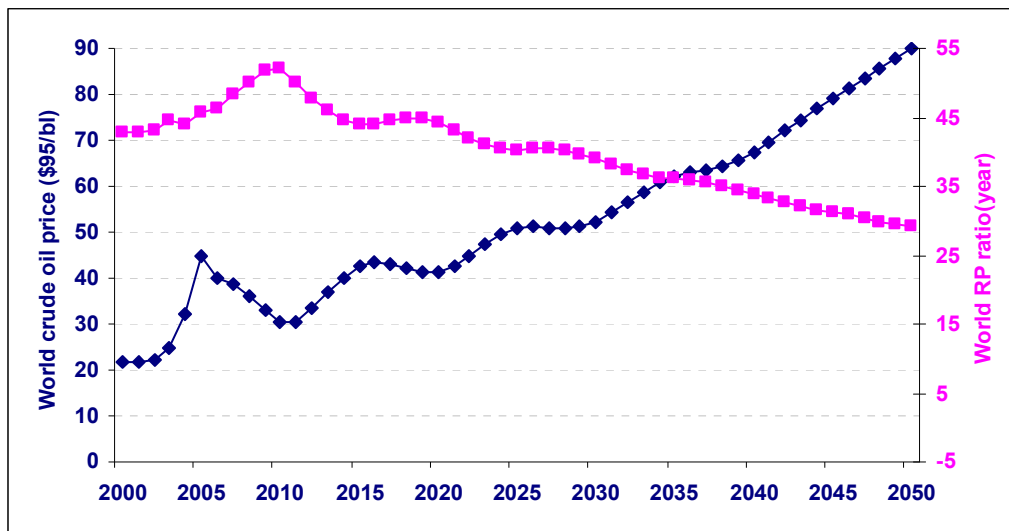
OIL	1990	2001	2010	2020	2030	2040	2050
ULTIMATE RECOVERABLE RESOURCES (thousand mb)							
OECD	417	451	502	533	559	586	618
Non OPEC	996	1231	1360	1440	1509	1582	1667
OPEC of which	1468	1384	1520	1596	1655	1715	1787
Gulf	1052	998	1087	1133	1167	1199	1238
World	2464	2615	2880	3036	3164	3297	3454
OIL RESERVES (thousand mb)							
OECD	66	66	45	26	21	18	14
Non OPEC	309	336	304	257	212	175	140
OPEC of which	659	778	831	856	788	656	497
Gulf	592	624	664	690	646	548	422
World Conventional	967	1115	1135	1112	1000	831	637
Non Conventional	48	48	247	281	366	437	467
Total	1016	1163	1381	1393	1366	1268	1104
OIL PRODUCTION (mbd)							
OECD	18	17	17	13	11	10	8
Non OPEC	38	42	51	47	38	31	25
OPEC of which	24	30	18	32	43	48	49
Gulf	15	18	9	20	30	37	39
World non conventional	1	1	4	8	16	25	32
Total	63	73	73	87	97	104	106
OIL CONSUMPTION (mbd)							
OECD of which	35	42	36	35	34	32	29
N.America	17	21	18	18	18	17	15
Eur25	12	14	12	12	12	11	9
Latin America	5	7	6	8	9	10	11
Asia of which	7	15	19	27	32	37	39
China	2	5	6	8	8	9	9
Other	13	15	17	22	26	30	32
World	60	78	77	92	102	109	111
WORLD OIL PRICE and R/P RATIO							
World crude oil price	27	22	30	41	52	68	90
World RP ratio (year)	49	43	52	44	39	34	29

NB: price expressed in \$95

The table also illustrates the increase in URR resulting from the improvement in technologies and recovery rates. This increase is induced partly by autonomous technological progress and partly by oil price increases. In 2050, the URR for world conventional oil end up at quite a high level of 3 378 Gbl, for an average recovery rate of about 40%.

When combined with the increase in non-conventional reserves, the increase in recovery rates limits the decline in total reserves between 2010 and 2050. However, as the production level is steadily increasing during the projection period, the world R/P ratio decreases from 43 years today to 24 years. This is the key driving force for the increase in oil price. Figure D-1 illustrates the links between the oil R/P ratio and price dynamics: in the short run the R/P is increasing, causing, together with some loosening in the capacity constraints, a certain decline in oil price, while the decreasing trend in R/P is the fundamental cause of the price rise in the long term.

Figure D-1 : World crude oil price and R/P ratio in the Reference Case



Source : POLES Cascade Reference

As far as gas is concerned the resource growth due to technological progress in recovery is much less pronounced than in the case of oil as the initial recovery rate is much higher (around 80 %) and the improvement limited. The increase in resources and in discoveries allows however for the world reserves to slightly increase until 2020 and decrease steadily after that. While R/P ratio strongly decreases in every region, as shown in Table D-4.

Table D-4: Gas development and supply, Reference Case

Gas	1990	2001	2010	2020	2030	2040	2050
ULTIMATE RECOVERABLE RESOURCES (Trillion m3)							
OECD of which	77	78	83	87	90	93	98
N.America	51	51	55	58	60	62	65
Eur25	10	11	12	13	13	14	14
CIS	111	111	117	122	127	132	136
Middle East	82	104	110	115	119	123	128
Asia	8	8	9	9	9	9	10
Other	67	69	74	77	79	82	85
World	345	371	394	410	424	440	457
GAS RESERVES (Trillion mm3)							
OECD of which	15	18	20	17	13	11	8
N.America	7	7	6	4	2	1	0
Eur25	4	4	3	2	1	1	1
CIS	59	56	60	62	62	62	61
Middle East	37	57	89	95	94	87	75
Asia	2	3	3	3	3	2	2
Other	22	30	41	34	25	17	11
World	136	164	212	211	198	179	157
GAS PRODUCTION (Billion m3)							
OECD of which	774	987	1181	1088	861	888	825
N.America	567	677	835	717	506	566	485
Eur25	192	228	214	168	122	97	85
CIS	704	662	643	878	944	1026	1064
Middle East	94	219	381	940	1373	1642	1964
Asia	110	201	604	436	426	356	263
Other	187	283	811	1089	1200	944	750
World	1869	2353	3620	4431	4804	4855	4865
GAS CONSUMPTION (Billion mm3)							
OECD of which	882	1167	1693	1814	1730	1560	1482
N.America	552	649	1028	1069	1009	883	814
Eur25	295	436	551	590	545	516	504
CIS	618	541	550	586	571	528	452
Latin America	79	130	221	334	384	390	346
Asia of which	81	189	590	979	1308	1395	1378
China	13	28	131	232	312	293	255
Other	202	311	566	718	811	983	1206
World	1862	2339	3620	4431	4804	4855	4865
Gas prices (\$95/boe)							
American market	10.9	21.1	23.2	34.3	45.6	62.2	90.8
European and African market	15.2	17.1	19.3	31.6	43.0	58.8	82.6
Asian market	20.6	22.5	33.3	35.7	44.1	60.1	83.8
RP ratio							
N. American market	22	19	13	11	10	7	6
European market		97	100	64	53	44	38
Asian market	67	58	27	29	22	19	16

Energy Technologies in the Cascade Reference

Technological change is critical to the management of strong constraints on resources and on emissions. In this project it is particularly essential to visualize technological breakthroughs and radical innovations. The Cascade Reference incorporate new energy technology portfolios, including:

- i. Hydrogen production through chemical, thermo-chemical or electrical routes
- ii. Carbon capture and storage options as add-ons to plants burning fossil fuel to make electricity or hydrogen
- iii. Distributed electricity production, with or without cogeneration, from fossil fuel, renewable energy or hydrogen

iv. very low emission vehicles with new power systems and carrier concepts, including cars powered by electricity or hydrogen

v. Low and very low energy buildings with significantly improved thermal performances (meaning a reduction by a factor of 2 to 4 from the consumption of present buildings in each region); these can even be “positive energy buildings” when photovoltaic systems are integrated into the design

Projections of the economic, physical and environmental performance have been organised in a database TECHPOL(see Table D-5)

Table D-5 : Energy technologies considered in the POLES model

1. Large scale power generation

1	Conventional, large-size hydroelectricity	HYD
2	Conventional Light-Water nuclear Reactor	NUC
3	New Nuclear Design	NND
4	Pressurised coal supercritical	PFC
5	Pressurised coal supercritical with sequestration	PSS
6	Integrated Coal Gasification with Combined Cycle	ICG
7	Integrated Coal Gasification with Combined Cycle with sequestration	ICS
8	Advanced Thermodynamic Cycle (coal powered)	ATC
9	Lignite-powered Conventional Thermal	LCT
10	Coal-powered Conventional Thermal	CCT
11	Oil-powered Conventional Thermal	OCT
12	Gas-powered Conventional Thermal	GCT
13	Gas-powered turbine	GGT
14	Oil-powered Gas Turbine in Combined Cycle	OGC
15	Gas-powered Gas Turbine in Combined Cycle	GGC
16	Gas-powered Gas Turbine in Combined Cycle with sequestration	GGs

2. New and renewables

1	Small Hydro Power plants (<10 MWe)	SHY
2	Wind power plants for network electricity production according to wind resources	WND (WN1, WN2, WN3)
3	Offshore Wind power plants	WNO (WO1, WO2)
4	Solar Power Plants (thermal technologies for network electricity production)	SPP
5	Low Temperature Solar systems in residential sector	LTS
6	Biofuels, conventional technologies (woodfuels, elec. from wastes, biofuels)	BF1, BF2, BF3
7	Biomass gasification for electricity production in GT	BGT

3. Distributed electricity

1	Combined Heat and Power (small to medium-size cogeneration in industry)	CHP
2	Stationary Fuel Cells with natural gas	GFC
3	Stationary Fuel Cells with hydrogen	HFC
4	Decentralised building integrated PV systems with network connection	DPV
5	PV systems for Decentralised rural electrification in DCs	RPV

4. Hydrogen production

1	Hydrogen from Gas Steam Reforming	GSR
2	Hydrogen from Gas Steam Reforming with CCS	GSS
3	Solar Methane Reforming	SMR
4	Hydrogen from Heavy Fuel Oil Partial Oxidation	OPO
5	Hydrogen from Coal GASification	CGA
6	Hydrogen from Coal Gasification with CCS	CGS
7	Hydrogen from Biomass GASification	BGA
8	Hydrogen from Biomass Gasification with CCS	BGS
9	Biomass PYrolysis	BPY
10	Hydrogen from Solar thermal High-temperature Thermolysis	SHT
11	Hydrogen from Nuclear thermal High-temperature Thermolysis	NHT
12	Hydrogen from Water Electrolysis dedicated Nuclear power plant	WEN
13	Hydrogen from Water Electrolysis dedicated Wind power plant	WEW
14	Hydrogen from Water Electrolysis baseload electricity from Grid	WEG

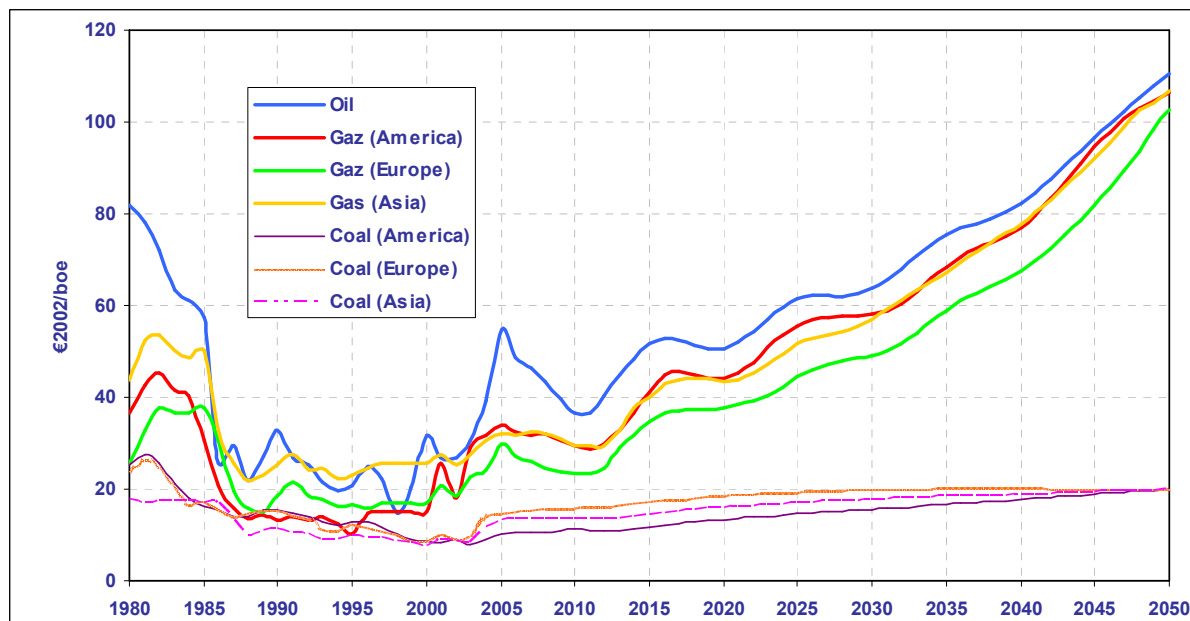
5. Vehicles

1	Conventional	CONV
2	Hybrid	HYBV
3	Electric	ELEV
4	Gas fuel cell vehicle	GFCV
5	Hydrogen fuel cell vehicle	HFCV
6	Hydrogen conventional	THYV

The primary energy prices outlook

The primary energy prices produced in the CASCADE Reference are illustrated in the Figure D-2, they reflect a situation in which no strong supply constraints are supposed to be felt at least in the period to 2020.

Figure D-2: Primary energy prices in the Reference scenario



Source : POLES Cascade Reference

The decline of the oil price to 37 €/2002/boe until 2010 reflects a situation of relatively abundant supply due to competition among key producers and a slow down of some geopolitical tensions. After that date, when the production of the Gulf and OPEC regions has to expand more rapidly to keep pace with world demand, the oil price increases regularly and attains 110 €/2002/boe in 2050, a level that is nearly the double of the one reached in 2005, under particularly tense supply conditions.

These changes reflect the built-in dynamic processes in the model: in the short run, oil prices depend on changes in global oil demand and on the productive capacities of the Gulf countries, considered as the "swing producers" in the oil market. In the longer run, oil prices are likely to be influenced to a greater extent by the "fundamentals", i. e. the relative dynamics of oil demand and of available reserves, which is measured by the variations in the R/P ratio.

While the oil market is fairly integrated at a global level ("one great pool"), this is not the case for gas and coal, the markets of which still show a strong regional basis. The main reason for these regional differentiations is the high transportation cost of gas and coal, relative to their production cost. Although the development of LNG transport facilities will introduce some degree of trade-off between the regional gas

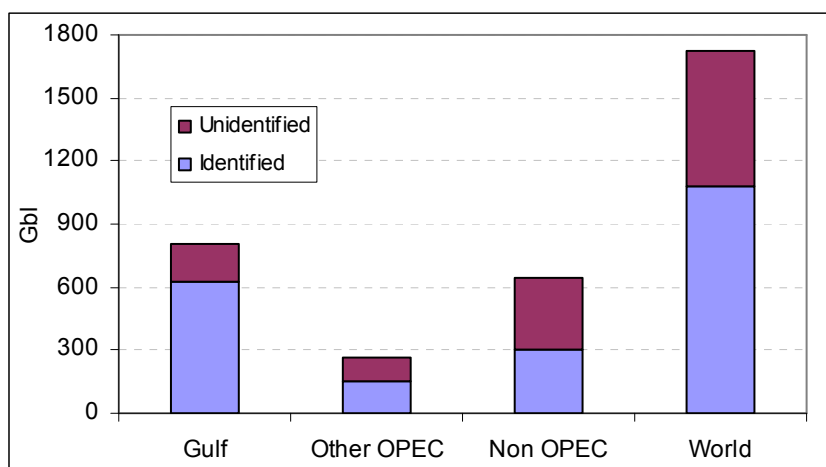
market, the price differentials are not expected to fully disappear over the next 50 years under the Reference assumptions for energy prices.

For gas, the R/P ratio in 2000, is significantly different from one region to the other, from about 19 years in the American market to nearly 100 years for the European market (see above Table D-4). The decline in R/P ratio explains the rise in gas prices in the projection and some extent the hierarchy in price levels as the latter indeed depends of the structure of supply of each market. At the beginning the Asian market with the highest proportion of LNG supply has the highest price level and the American market which is mostly continental the lowest, while Europe is in an intermediate position for both features. At the end of the period the impact of the R/P on the hierarchy of the price levels seems more important. So the highest price is attained at the American market, followed by Asian and at the end by the European market.

In a very different profile, coal prices on the three markets converge at the end of the period at a level of 20 €/t, about one sixth of the oil price.

Cumulative production of oil today is around 900 Gbl. The assumption of the WETO-H2 study is that there are 1 700 Gbl remaining, of which almost 1 100 Gbl has been discovered. Of these 1 700 Gbl, about 1 000 Gbl (including identified and unidentified resources) are in OPEC countries. The remaining recoverable resources represent 60 years of present production of conventional oil (Figure D-3).

Figure D-3: Remaining oil resources²², key regions



The POLES oil and gas module simulates technological progress in exploration and production of oil and gas. Progress has been rapid since the seventies, in particular through spill over from information and communication technologies. The main impact is to improve the success of exploratory drilling and to increase recovery rates across the world. The POLES model simulates improved recovery by linking the Ultimate Recoverable Resources (URR) directly to the contemporary recovery rate.

²² Remaining resources as of 2005

Figure D-4: Ultimate Recoverable Resources, cumulative discoveries and production

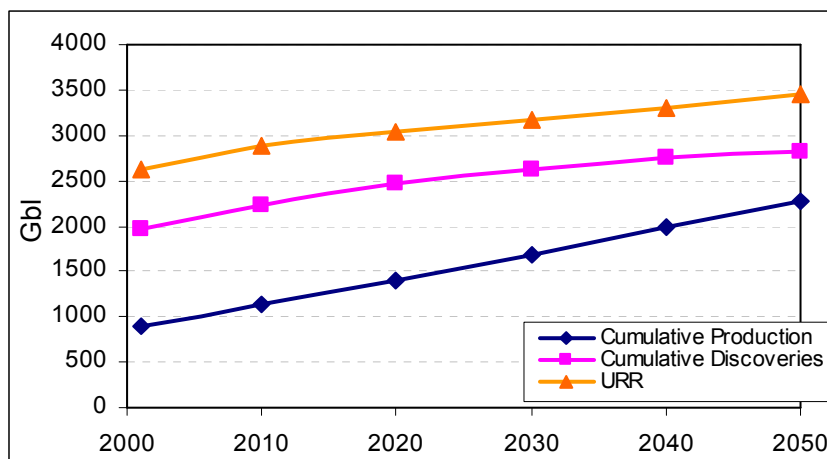


Figure D-4 presents the results of the simulation of the discovery and production of oil. The volume of Ultimately Recoverable Resources increases in the period because of improved recovery rates; cumulative discoveries depend on the exploration effort. The development of reserves is visible in the Figure, because reserves are the difference between total cumulative discoveries and cumulative production. This process of reserve development and extension explains how total Ultimate Recoverable Resources estimated by the USGS are extended from 2 600 Gbl today to nearly 3 500 Gbl in 2050; this has an important influence on the supply and demand balance for oil to 2050.

D.1.2 Technological prospects to 2050

[by P. Menanteau (LEPII-EPE)]

Introduction

Following the description of the common information database carried out in the chapter B.2.2 of this report, the present chapter presents technological prospects to 2050 for the main categories of technologies that are described in the database. The aim of this section is not to present and comment in details all the information that is in the database but point out and comment the main evolutions that are assumed up to the year 2050. Power generation, centralised or decentralised, carbon capture technologies, hydrogen production and transport technologies are successively described in this section.

Power generation

Centralised power generation

Four conventional (steam) fossil fuelled power plants are represented in the database (lignite, coal, fuel, natural gas). The overnight investment costs are similar for the four technologies, in the range from 800 to

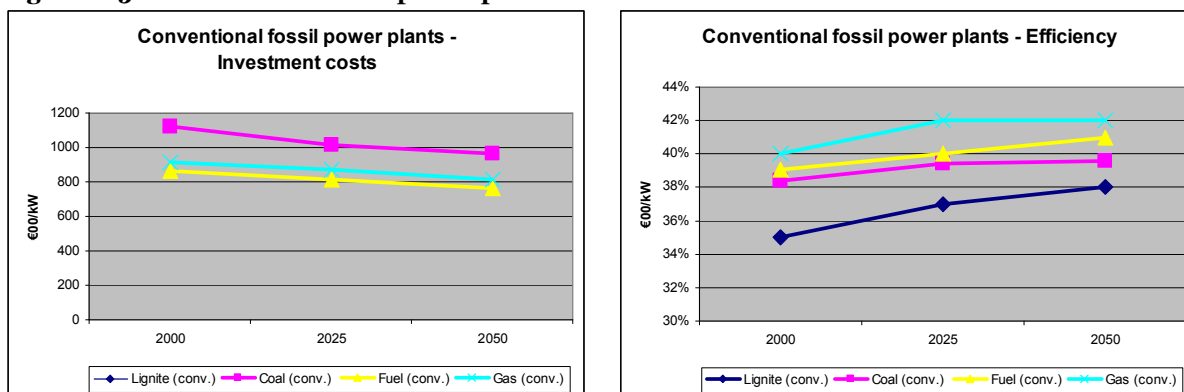
1200 €/kW with a slight advantage for natural gas and fuel that necessitate less handling and storage devices and also less de-pollution systems (Figure D-5).

Limited technical progress is expected on these technologies that are considered as mature. In the long term the overnight investment costs might go down to 800 – 1000 €/kW.

As efficiency depends on the quality of the fuel, it is higher for natural gas and lower for coal and lignite. Again efficiency is not expected to increase much because of the maturity of the technology and the predictable shift of R&D focus from conventional to "advanced" technologies such as supercritical pulverized plants for coal and combined cycle gas turbines for gas.

Only fuels of lower quality might still be used in conventional power plants which would lead to a slight increase in efficiency.

Figure D-5 : Conventional fossil power plants



Source : TECHPOL

These technologies have to be present in the database because they represent a significant share of installed capacity in some countries. Their importance is expected to decrease strongly in the forthcoming years as they will progressively be replaced by more efficient and cleaner technologies such as supercritical pulverized coal, IGCCs and combustion turbines.

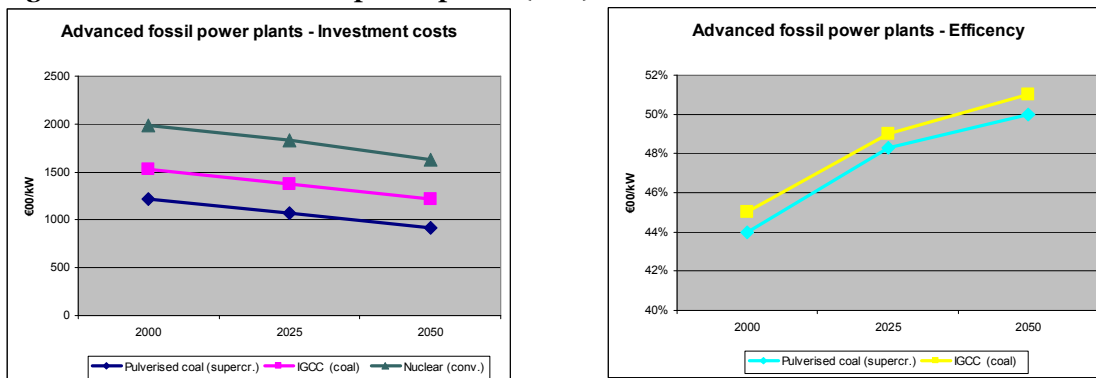
Advanced coal technologies are much more efficient than conventional ones. Present efficiencies for both super critical pulverized coal plants and IGCCs are above 45% and could reach 50% in the long term. Overnight investment costs of supercritical plants and IGCCs are much more important than cost of conventional plants. Given the expected technical progress these costs should decrease to similar levels for supercritical plants in the long term (900 €/kW). Present and future costs of IGCCs are much more uncertain. According to these assumptions, IGCCs production costs would remain higher than production costs of supercritical (and ultra supercritical in the long term) coal power plants except in very favorable case.

Despite higher investment costs, supercritical plants are already competitive with conventional coal power plants. The difference in production costs will increase as the gap in efficiency will widen, supercritical plants being clearly the reference technology for coal power plants in 2025.

Overnight investment cost of nuclear power plants is a debated issue. Investment costs seem indeed quite different according to American, Japan or French experience, whether expected or actual plants are considered. The investment costs that are considered in the database take into account these uncertainties. They do not necessarily reflect the low costs suggested by nuclear industry for forthcoming nuclear reactors but an average that takes into account real experience with construction of nuclear plants. As a consequence, present overnight investment costs are estimated to be close to 2000 €/kW with expected price decrease down to 1600 €/kW in the long term (Figure D-6).

Estimating investment costs (and efficiency, and availability and O&M costs) for revolutionary nuclear reactors concepts is even more difficult as no estimations of costs have been published yet. In the absence of information we have considered that costs would be much higher in present and immediate future (2025) compared to conventional nuclear plants. However we have estimated that generation IV nuclear reactors would be competitive with conventional nuclear plants in the long term (2050), as expected by Gen IV Forum.

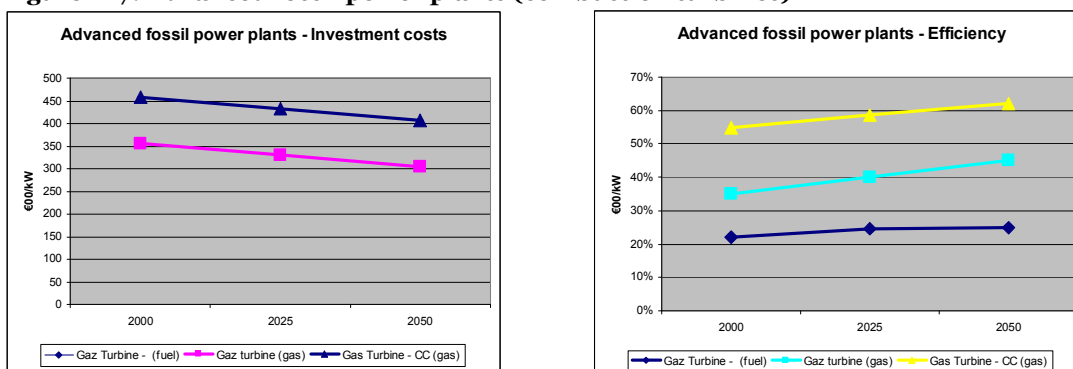
Figure D-6 : Advanced fossil power plants (coal) and nuclear



Source : TECHPOL

As far as combustion turbines are concerned, investment costs are much lower compared to supercritical and even conventional power plants. Efficiencies are higher and progression is still expected with maximum value of 60% being reached in the long term for gas turbines with combined cycles. Simple cycle turbines are less expensive but their efficiency is largely less favorable. It also tends to decrease sharply at partial loads

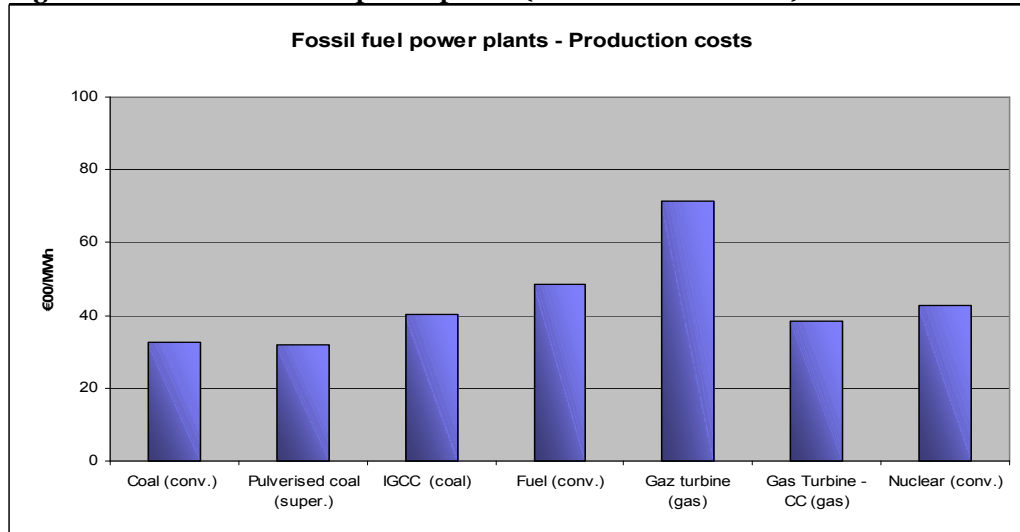
Figure D-7: Advanced fossil power plants (combustion turbines)



Source : TECHPOL

With the existing assumptions about energy prices in TECHPOL (no carbon value), the production costs for fossil fuel power plants are in a range between 30 and 40€/MWh for steam cycle coal power plants and combustion gas turbines (Figure D-8). Production costs of nuclear plants is slightly higher 40 €/kW and comparable to IGCCs but with much greater uncertainties for the latter given the still limited experience recorded on this new technology. Simple cycle combustion turbines because of their lower efficiency (compared to combined cycles) and higher fuel costs should only be used for peak power production.

Figure D-8: Advanced fossil power plants (combustion turbines) - 2000



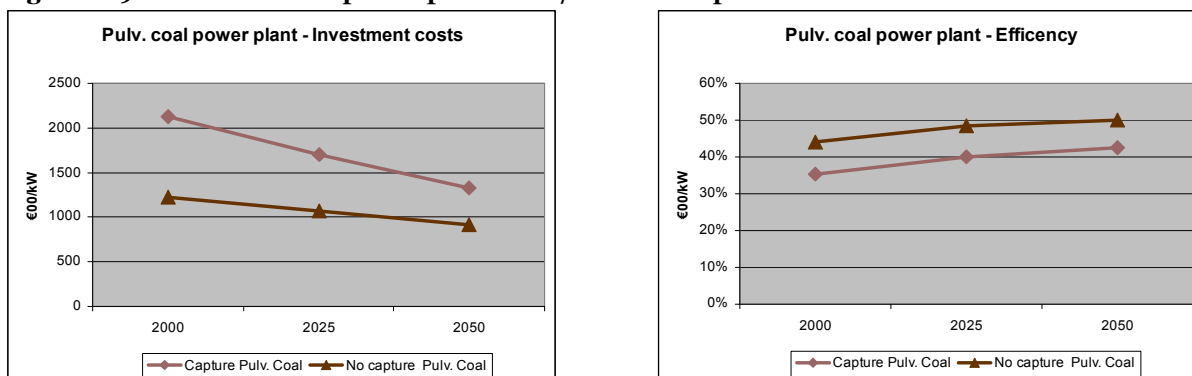
Source : TECHPOL

Fossil power plants with carbon capture

Carbon capture is considered for three important fossil fuelled power plants : pulverized coal, combustion turbine with CC and IGCCs.

Additional investment cost for coal steam cycle is very significant in the initial period (post combustion capture) but it is divided by a factor of two in the long term : from 900 €/kW down to 400 €/kW. Efficiency of plants with carbon capture increases with a similar profile as plants without carbon capture (Figure D-9).

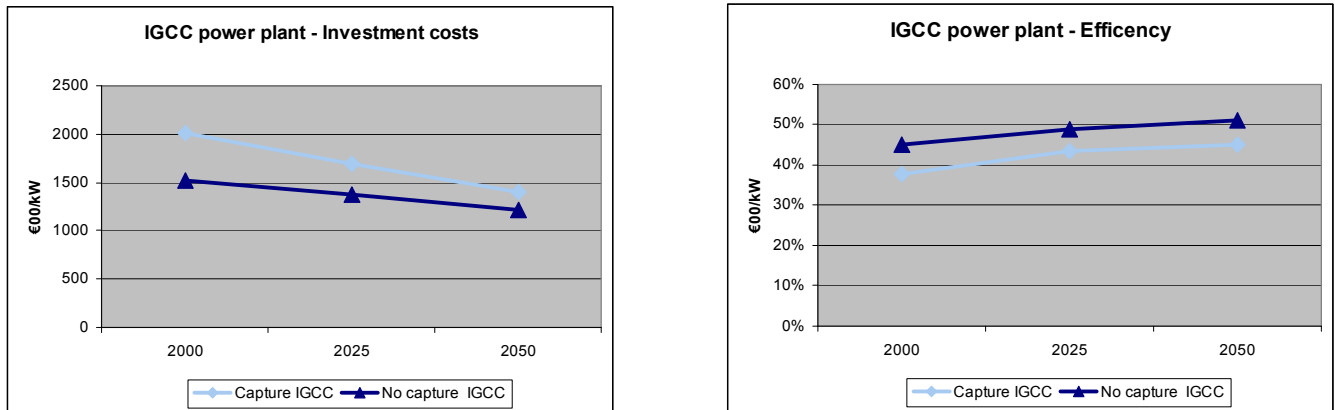
Figure D-9: Pulverised coal power plants w-w/o carbon capture



Source : TECHPOL

Because the technology is different (pre-combustion capture), the additional investment cost for IGCCs is lower and technical progress is also expected to reduce the gap in the long term, from 500 €/kW in 2000 down to 300 €/kW in 2050 (Figure D-10).

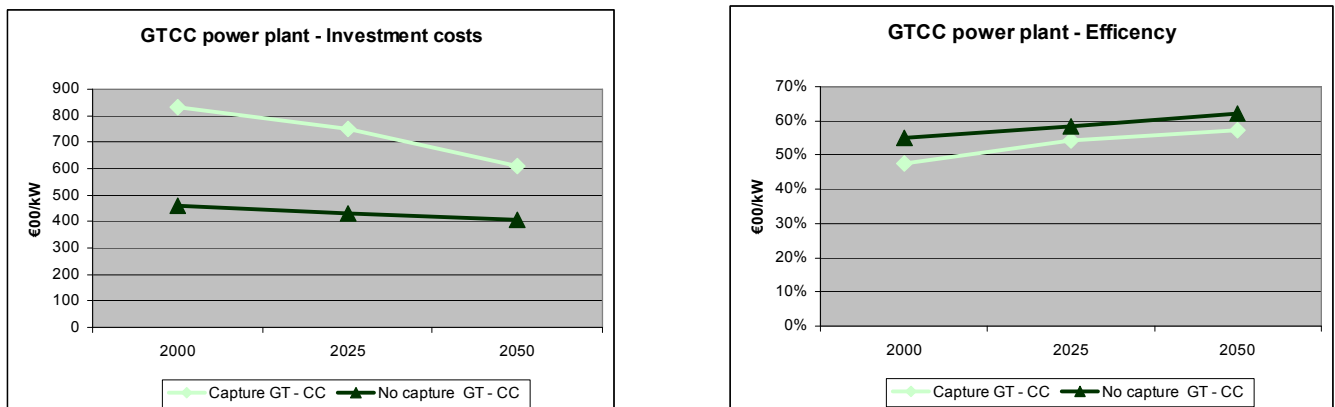
Figure D-10: IGCC w-w/o carbon capture



Source : TECHPOL

As for pulverised coal, the technology of carbon capture used with combustion turbines (post-combustion) implies high additional investment costs (400 €/kW) with almost a doubling of investment for GTCC. This additional cost is supposed to decrease significantly in the long term. Again, efficiency of plants with carbon capture is following the same profile as plants without carbon capture taking into account a slight recovering in the period.

Figure D-11: GTCC w-w/o carbon capture

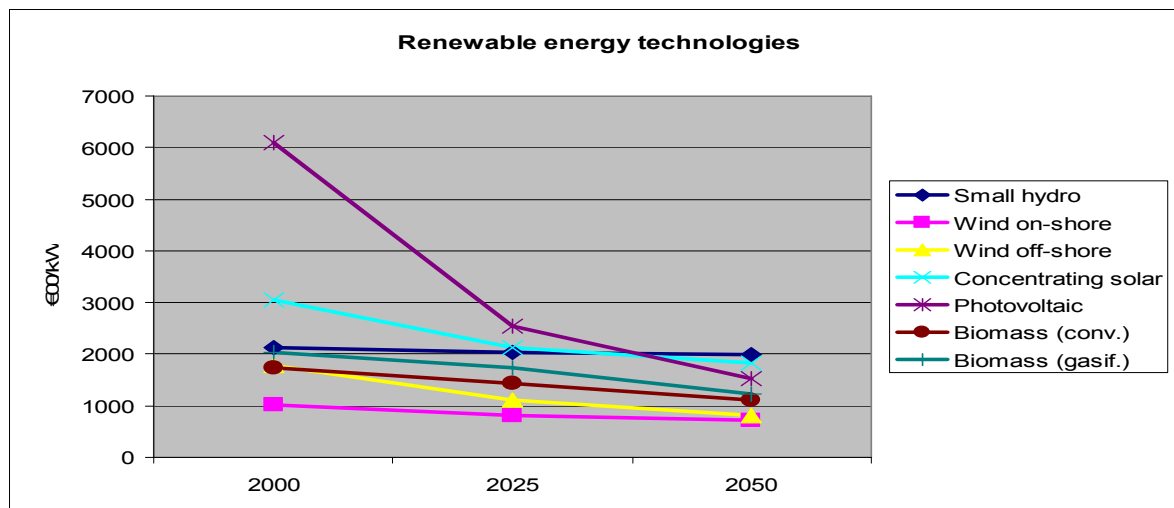


Source : TECHPOL

Decentralised / renewable power plants

A significant decrease of overnight investment costs is expected for renewable energy technologies on the period 2000-50, in particular for those technologies that are today still immature ie., wind off-shore, biomass gasification, concentrating solar and most of all, photovoltaics (Figure D-12). Conversely, the cost of small hydro and to a lesser extend, on-shore wind power, should not change much even in the long term.

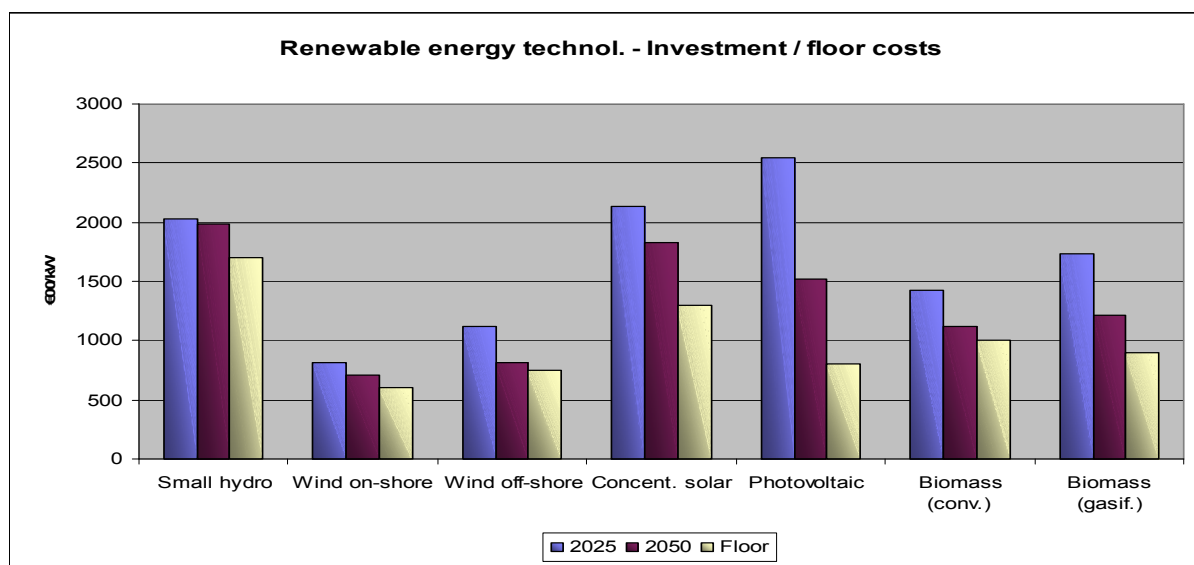
Figure D-12: Renewable energy technologies - Investment costs



Source : TECHPOL

No information is available in the literature about floor costs that are considered as very long term investment costs ie not different from investment costs in 2050. Floor costs have been provided by considering the life cycle of the technology. The more mature the technology is the closer the investment cost in 2050 is to the floor cost. On the contrary the investment cost of a technology that has still not reached maturity in 2050 will be distant from the floor cost (Figure D-13).

Figure D-13: Renewable energy technologies – Investment / floor costs

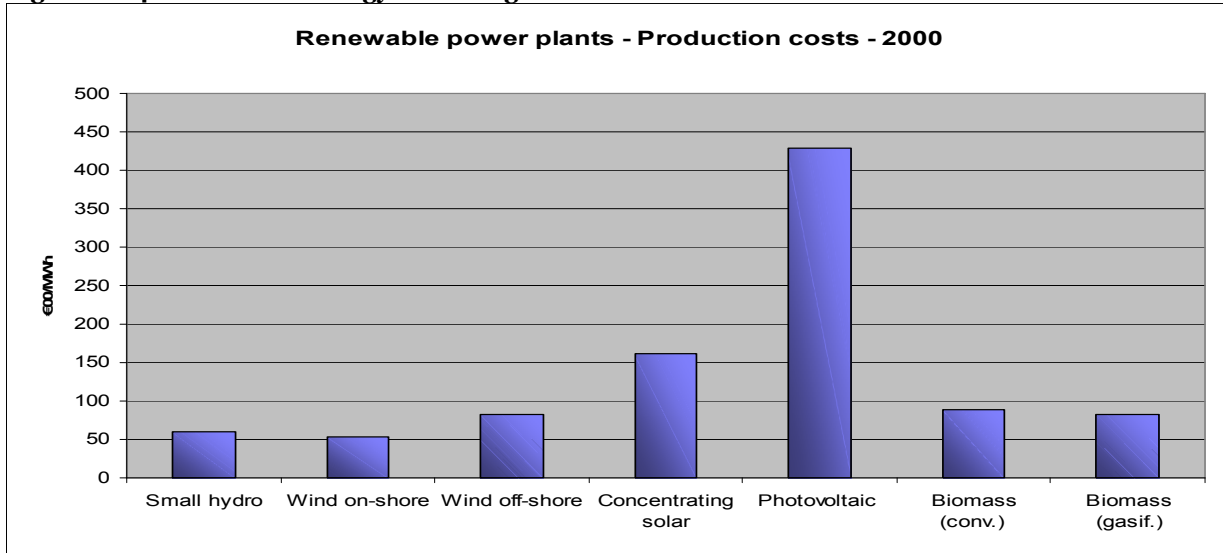


Source : TECHPOL

The range of production costs is very large (50 – 430 €/MWh) in 2000 (Figure D-14) but it should narrow to 40 – 100 €/MWh in 2050. Dynamic of cost decrease will probably continue on wind power albeit at a lower rhythm for on-shore sites. As far as biomass is concerned, technical progress is also expected in particular with gasification but scheduled increase in biomass price could limit the impact of reduction on

investment costs. Despite huge progress in the last 20 years PV is still far from being competitive with conventional power and most of renewable production technologies. Cost decrease and perspectives of competitiveness will largely depend on the possibility to continue on passed learning curves in the next 30-40 years. For concentrating solar power, a reduction of 30% in investment and production costs is expected in the medium term (2025) but still uncertain in the longer term.

Figure D-14: Renewable energy technologies - Production costs

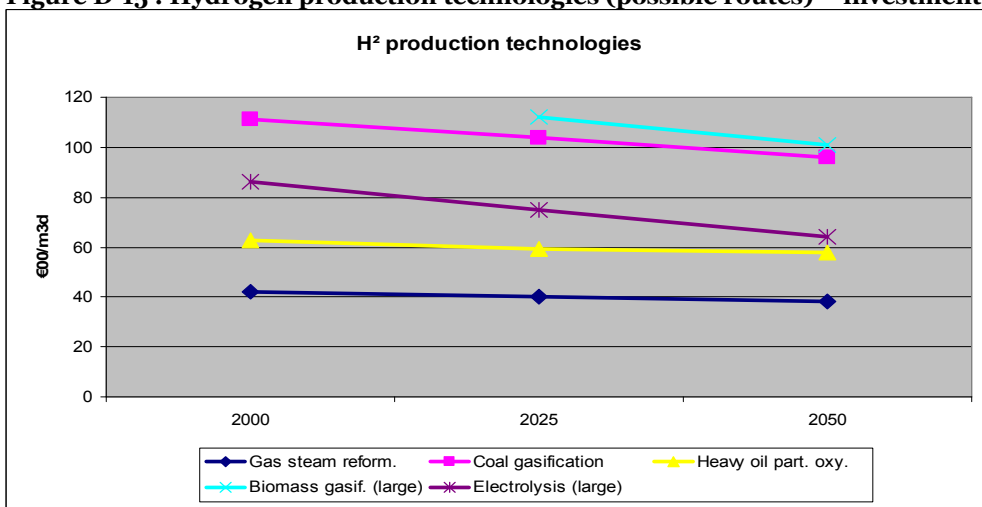


Source : TECHPOL

Hydrogen production

Different routes for the production of hydrogen are considered in the database (Figure D-15) using fossil or nuclear fuels (natural gas reforming or solar methane reforming, coal gasification, heavy fuel partial oxidation, nuclear HT thermochemical cycle), renewable fuels (biomass gasification or pyrolysis, solar HT thermochemical cycle) or electricity (electrolysis using electricity from grid or from dedicated power plants).

Figure D-15 : Hydrogen production technologies (possible routes) – investment costs



Source : TECHPOL

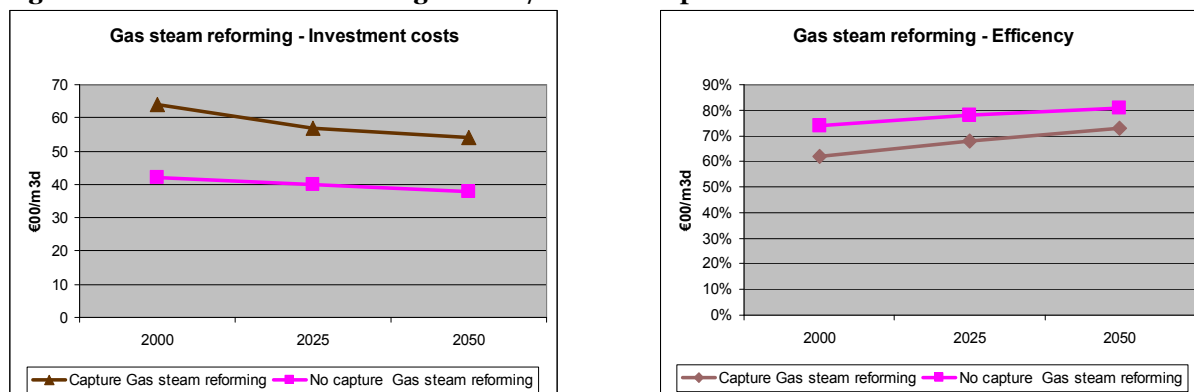
Some routes correspond to almost mature technology on which limited potential for further cost decrease is expected (gas reforming). For other technologies (electrolysis), there are still opportunities of continued progress and cost decrease until 2025 and beyond. Hydrogen production from coal gasification is also an established technology with perspectives of cost decrease. Because of the early development stage, cost estimates and perspectives related to biomass gasification are much more uncertain. The assumptions used in the database reflect average estimates of future costs (2025) which may be considered as not over optimistic.

Some information have also been reported in the database about technologies that are considered as futuristic options, ie thermochemical cycles. Suggesting long term and floor costs for these prospective technologies was difficult as no real reliable technical and economic data are available. As a consequence, the data provided should be considered at best as rough provisional estimations and often as target costs.

According to the assumptions used on energy prices in the database (which may be different from the energy prices simulated by the energy models) the present production costs of hydrogen are in a range of 7.0 – 8.0 €/GJ for gas steam reforming and coal gasification. They are much higher for electrolysis. In the future the order of merit will change because of expected price increase of natural gas. Biomass and coal become the cheaper options (coal is much cheaper in absence of carbon taxes). The cost of hydrogen production from electrolysis depends to a great extend on the price of electricity considered.

The addition of carbon capture technologies does not impact the investment cost as much as it does for power production because pre-combustion is possible and less expensive than post combustion technology. For gas steam reforming, the introduction of carbon capture raises the investment cost by 50% in the year 2000 but only one-third in 2050. Similarly the loss in efficiency is less important compared to electricity production from 12% down to 8% in 2050 (Figure D-16).

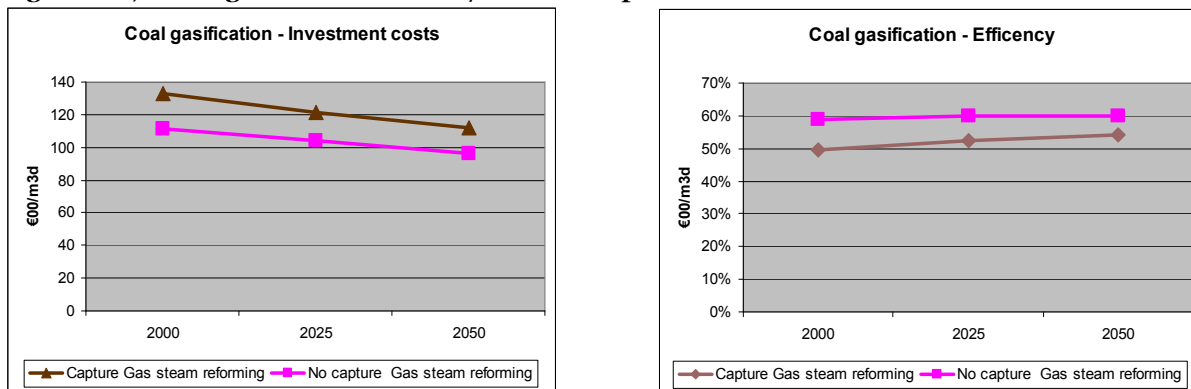
Figure D-16 : Gas steam reforming – w – w/o carbon capture



Source : TECHPOL

As for gas steam reforming, the additional cost of carbon capture is limited for coal gasification. In 2050, the overcost stays below 15%. Similarly, the loss of efficiency decreases from 9 to 6% in the end of the period (Figure D-17)

Figure D-17 : Coal gasification – w – w/o carbon capture

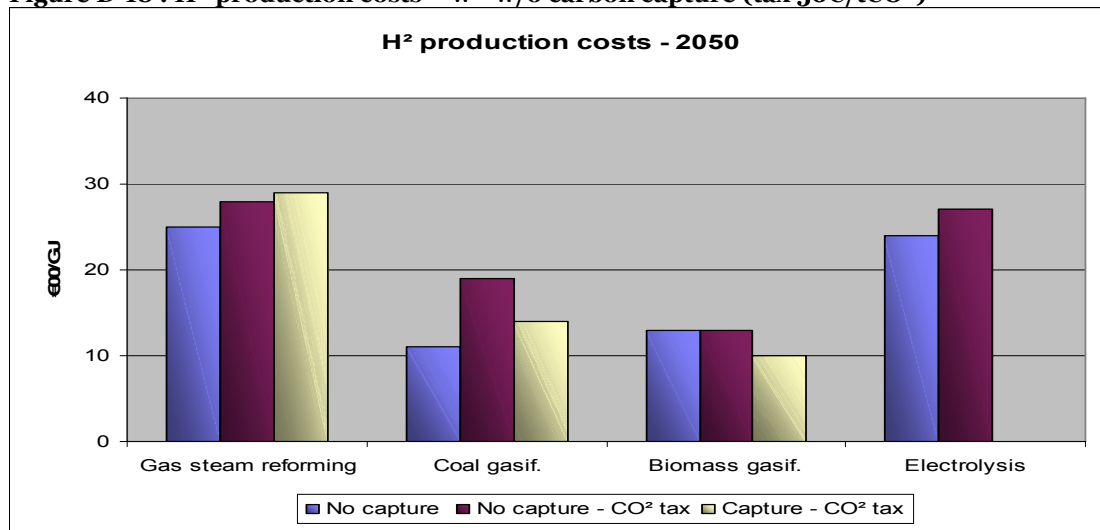


Source : TECHPOL

With the data on costs and performance of the H₂ technologies as described above and our assumption on future energy prices, the merit order for H₂ production is modified in 2050 compared to 2000. Coal and biomass gasification are the less expensive production routes. Because of the gas price increase, gas steam reforming becomes much more costly. Water electrolysis is not competitive with the assumed electricity prices, except if a dedicated nuclear reactor is considered.

The introduction of a carbon tax (50 €/tCO₂) does not change radically this result. Coal and biomass gasification remain the cheapest options, but as it is carbon free, biomass technology becomes less expensive. The addition of carbon capture has a positive impact on both technology but biomass remains less expensive with our (favourable) assumptions on biomass price.

Figure D-18 : H₂ production costs – w –w/o carbon capture (tax 50€/tCO₂)



Source : TECHPOL

Transport technologies

Five different motorisations are considered in the database : conventional internal combustion engine vehicles, pure electric vehicles, hybrid vehicles, hydrogen powered internal combustion engine vehicles and fuel cell hybrid vehicles fuelled with hydrogen (gaseous or liquid) or gasoline.

For fuel cell vehicles, very fast technical progress is considered. Extremely high costs in the year 2000 reflect the experimental status of the technology and the lack of industrial development. The costs in the year 2050 are target prices which take into account expected innovations combined with learning effect (standardised products). Optimistically we have considered that a big part of the price decrease could be reached until 2025 given the rhythm of price decrease recorded in the past years.

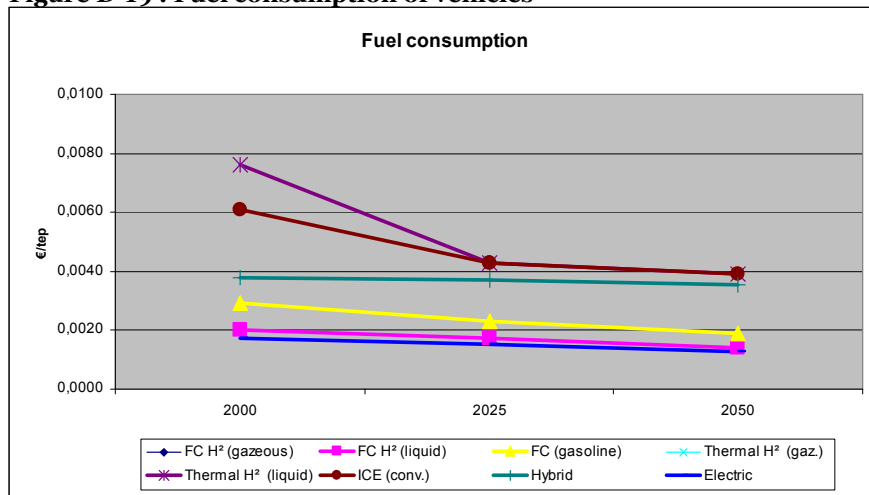
Table D-6 : Fuel cell vehicles – Engine costs (2000 – 2050)

Fuel cell H ²		2000	2025	2050
Stack cost	€/kW	1500	38	24
FC system/engine cost	€/kW	35500	38	24
Total engine cost	€/kW	37000	76	48
Fuel cell H ² (liquid)		2000	2025	2050
Stack cost	€/kW	1500	38	24
FC system/engine cost	€/kW	35500	38	24
Total engine cost	€/kW	37000	76	48
Fuel cell (gasoline)		2000	2025	2050
Stack cost	€/kW	2100	150	42
FC system/engine cost	€/kW	35500	38	24
Total engine cost	€/kW	37600	188	66

Source : TECHPOL

The fuel consumption of the different motorisation are assumed to evolve as indicated on Figure D-19. Important progress on efficiency is expected on internal combustion engines with the generalization of hybrid vehicles. Improvement of efficiency is also expected on fuel cell and electric vehicles with sustained progress beyond 2025.

Figure D-19 : Fuel consumption of vehicles

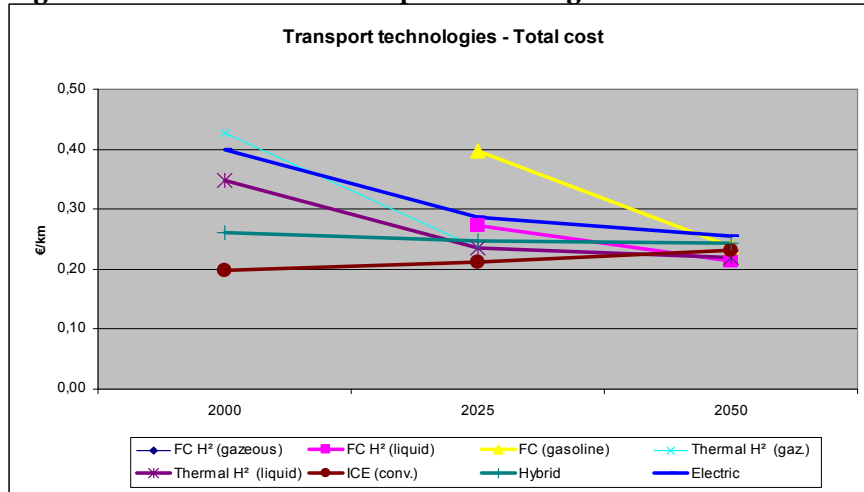


Source : TECHPOL

In Figure D-20, total cost of use for the different transportation technologies is presented for the period 2000-50. Fuel cell vehicle costs which are much higher are not included in the graph in the year 2000. In 2050, the total costs of the vehicles considered are in a close range (without carbon tax). Given the favourable assumptions used, fuel cell vehicles are nearly cost effective in 2025 and the cheapest option in 2050. Cost

and performance of hybrid vehicles (engine cost and fuel efficiency) and above all of internal combustion engine vehicles does not decrease enough to compensate the assumed increase in fuel prices. Electric vehicles are slightly more expensive than the other options but not significantly. As for hybrid vehicles, this may largely depend on the assumptions used in TECHPOL about the future electricity prices.

Figure D-20 : Total cost of transport technologies



Source : TECHPOL

D.1.3 R&D Outlook

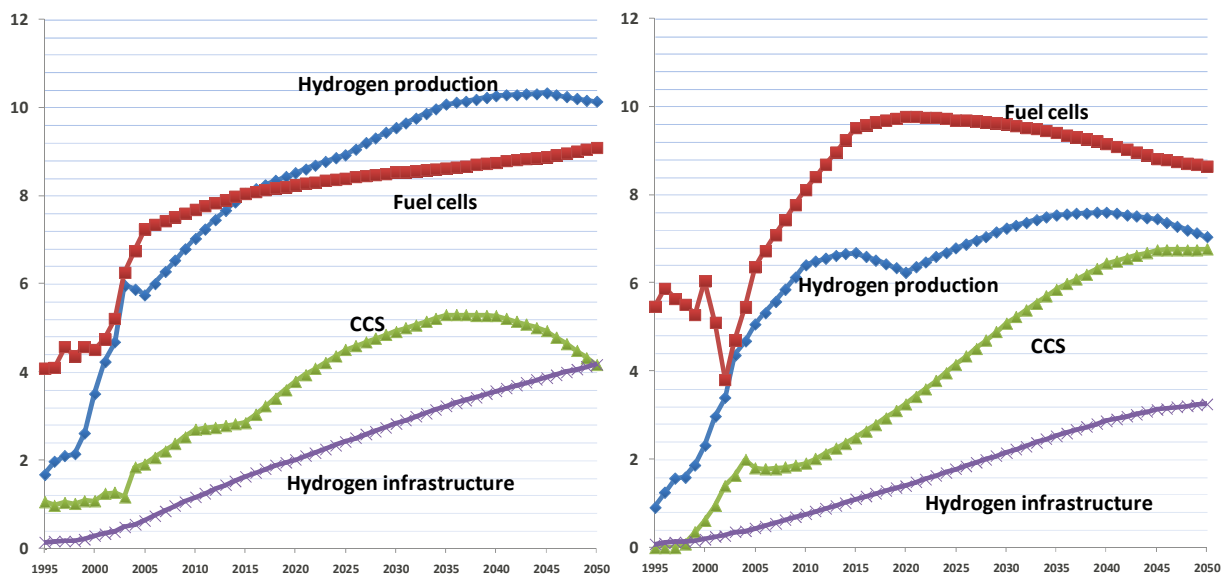
[by N. Kouvaritakis and V. Panos (ICCS-NTUA)]

The use of two factor learning curves requires the availability of information on capacities (for learning by experience) and R&D (for learning by research) for each hydrogen related technology. Although most models generate values for capacity/technology take-up endogenously, very few include endogenous mechanisms for determining R&D expenditures on hydrogen technologies. For this purpose, it was necessary to elaborate an outlook for R&D effort directed to different technological options, to be used as common assumptions for the construction of the baseline scenarios of the different models. This Outlook is based on past trends, recent changes in emphasis and perspective analysis based on judgement. It does not intend to be the result of rigorous modelling logic. On the other hand, effort was devoted to maintain some consistency in order to allow a clear picture on a probable direction of future R&D to emerge.

Inevitably, predicting the future size and direction of R&D is a highly speculative activity, especially for such a long-term period, however every effort has been made here to adequately present the underlying assumptions and causal mechanisms that are expected to drive the projected developments in the energy technology system. The baseline projections presented below are based on critical socioeconomic and geopolitical assumptions which indicate that the recent economic downturn -which was followed by slackening markets as world GDP and with it electricity generation growth slowed down- will be reversed, that globalization will continue, that primary energy resources will become relatively less abundant, that concerns with security of energy supply shall remain and that dealing with climate change will retain its place at the top of the environmental and political agenda.

The current chapter focuses on the R&D directed to hydrogen related technologies and to CO₂ capture and sequestration options. The reasons for this grouping are twofold: a) the realisation that if hydrogen is to fulfil its environmental potential on the demand side, low carbon or carbon free methods of producing it have to be developed and b) the technological affinity of some hydrogen production methods with separation technologies (gas separation). Looking at Figure D-21, which presents the shares of hydrogen and CCS related technologies, it can be seen a shift in the public R&D expenditures from fuel cells and CCS to hydrogen production and infrastructure technologies. This shift occurs when fuel cells and CCS research reach its maturity. This happens in 2015 for fuel cells and in 2035 for CCS technologies. In these periods, the public sector turns its interest to new hydrogen production technologies (such as hydrogen production from high temperature thermochemical cycle) and to new hydrogen infrastructure options (such as compact on-board hydrogen storage). These shifts are mainly attributed to the fact that the character of the research supported by the public sector is mainly pioneering, i.e. exploring new possibilities rather than improving products to increase profits. On the other hand, the research of the private sector (and in particular the automobile industry) is mainly focused on fuel cells during the whole horizon to 2050, although signs of “saturation” occur after 2015. However, fuel cells more or less maintain their share in the annual private energy related R&D expenditures, due to two reasons: either as an offensive stance from the side of manufacturers (i.e. creating new markets for these technologies) or as a defensive stance in order to ensure that in case of success of a particular option a company would not lose market share by failure to diversify.

Figure D-21: % Shares in total GERD(left chart) and BERD(right chart) of hydrogen related technologies and CCS



Concerning CCS technologies, the private sector follows the same patterns as the public sector, i.e. it reduces their share in annual R&D expenditures after 2040, although not so rapidly as in the public sector. Finally, the reduction in business R&D directed to hydrogen production that occurs at around 2020, is attributed to the fact that until that time research is focused mostly on steam reforming and coal gasification technologies, but as climate policy concerns accentuate, research is shifted to biomass gasification and to nuclear high temperatures thermochemical cycles.

On average, the contribution of the private sector in R&D expenditures is forecast to be around 70% for fuel cells, 64% for the hydrogen production technologies, 63% for hydrogen infrastructure options and 70% for CCS technologies. Under this perspective, the shares of the R&D in hydrogen related technologies in total annual energy related R&D expenditures reflect in some way the trends of the private sector (see Figure D-22 below).

Figure D-22: % share of hydrogen technologies and CCS in total energy related R&D expenditures

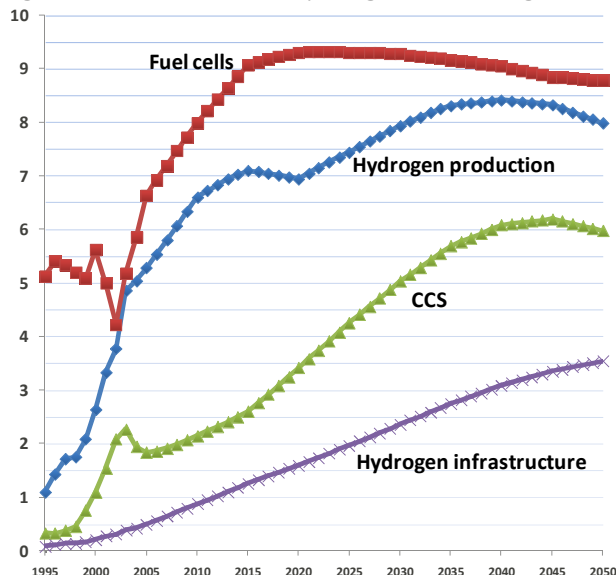


Figure D-23: % Shares of H₂ Production Options in Total Energy Related R&D for H₂ Production

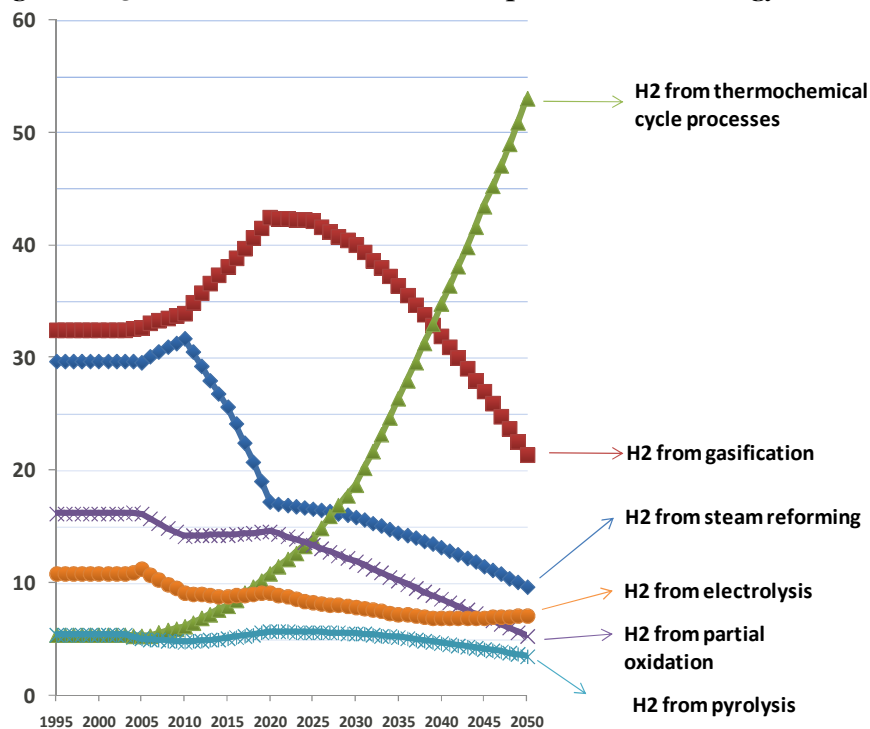
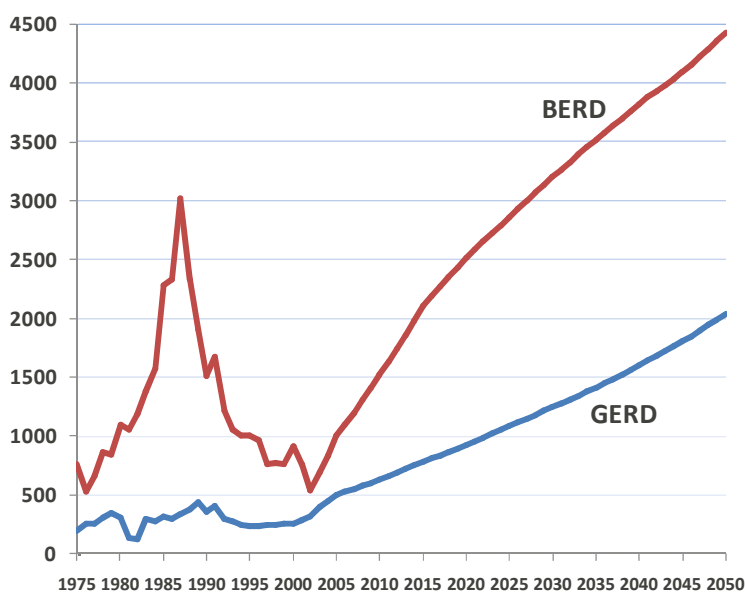


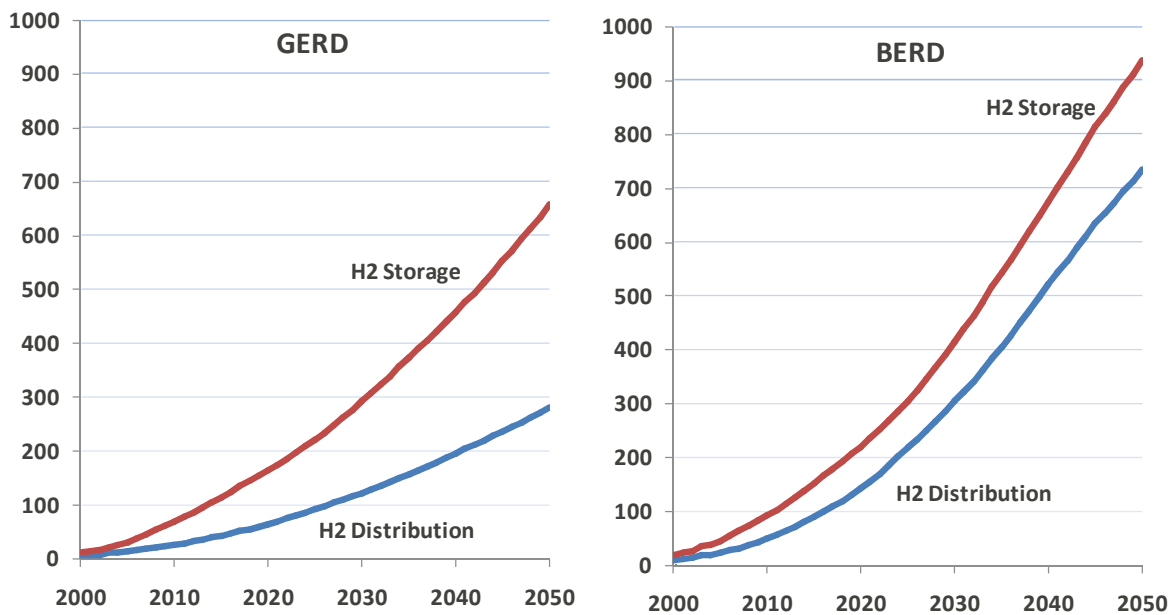
Figure D-23 presents in detail the allocation of the R&D directed to the different hydrogen production options, by showing the share of the R&D for each option in total annual R&D expenditures in hydrogen production technologies. Two main periods can be distinguished on the graph. The first is the period to 2010, where around 2/3 of the R&D directed to hydrogen production supports the research on coal gasification and steam reforming. The second period is the period 2010-2030, where the interest in steam reforming options recedes, and the interest in gasification turns to biomass gasification instead of coal. Finally the third period is from 2030 to 2050, where the research is mainly focused on hydrogen production from high temperature thermochemical cycles. These periods correspond to the timeline at when a technology becomes mature and ready for large scale utilisation. Thus, until 2010 the dominant option for hydrogen production is the currently very mature technology of steam reforming. Research is also supported for coal gasification, mainly because this technology is considered to be one of the main options for hydrogen production as well as is expected emergence for electricity production. From 2010-2030, gas steam reforming becomes mature and, in conjunction with its relatively limited prospects for further improvement, the funding of further research in this technology starts to be reduced. Biomass gasification research starts attracting R&D funding at that time, increasing in this way the share of R&D spent in options for hydrogen production from gasification. However, after 2030, gasification technologies almost reach their potential improvement (as it emerges from the corresponding perspective analysis), thus research is focused on the more futuristic options, such as the nuclear high temperatures thermochemical cycle process. The rest of the available options for hydrogen production (electrolysis, partial oxidation and pyrolysis) do attract a significant share in total R&D expenditures for hydrogen production technologies, due to their limited prospects for future improvements, in conjunction with their high production costs which constraints them to a low penetration into the hydrogen production sector. Some interest is maintained in the longer term in the form of hedging and in the case of electrolysis because of prospects in decentralised hydrogen production and dedicated power plants.

Figure D-24: Government energy R&D (GERD) and business energy R&D (BERD) on Fuel cells (M€05)



Looking in more detail at the R&D directed to fuel cells technologies (Figure D-24) the outlook projects a reversal of the past trends both for government and business energy related R&D. Although GERD was almost constant at around 300 million €05 until 2000 and BERD has constantly declined between 1987 and 2000, the outlook projects a continuous increase in GERD for the next 45 years at an average rate of 3.2% per year, and a continuous increase in BERD at almost the similar rate (3.3% per year). This reversal of the past trends is attributed to the increasing interest of the automobile industry for fuel cell vehicles, which has already resulted in an increase in the annual expenditures directed to fuel cells in the last five years (2000-2005).

Figure D-25: Government energy R&D (GERD) and business energy R&D (BERD) on H2 infrastructure

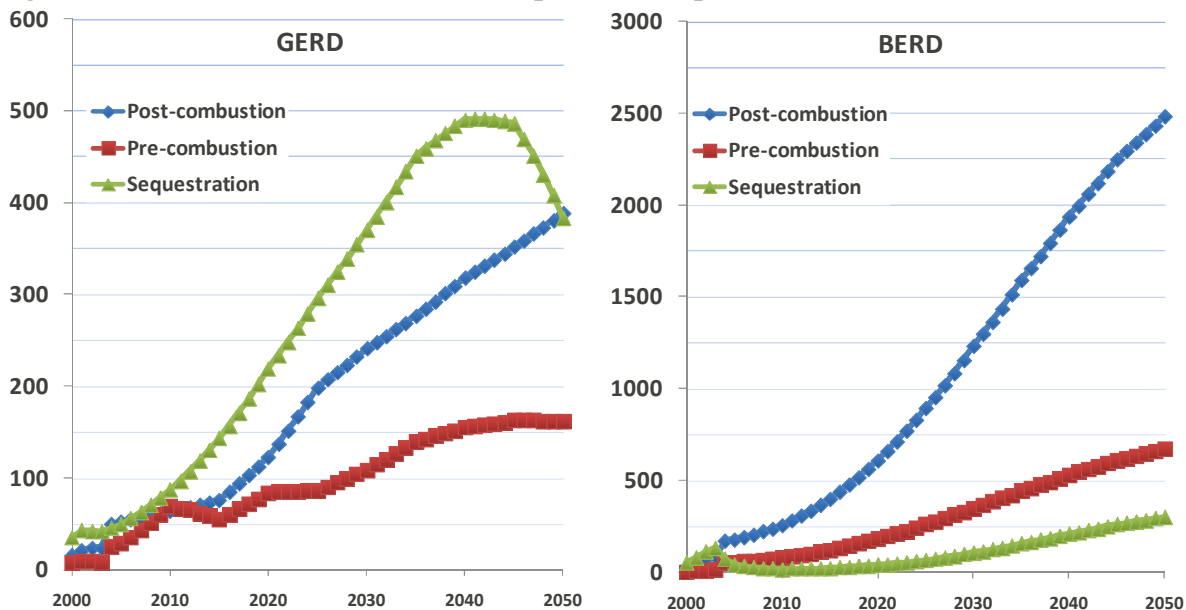


Concerning hydrogen distribution and storage technologies, it should be noted that hydrogen storage technologies receive the highest share both in GERD and BERD annual expenditures. This is due to the fact that hydrogen storage (and particularly on-board storage) has more potential for further improvement than the already mature distribution (pipelines and trucks). The private sector share in hydrogen infrastructure annual R&D expenditures is around 63%. (see Figure D-25).

CCS provides important prospects in a carbon constrained world because it enables continue use of fossil fuel resources. Figure D-26 below, presents the annual private and public R&D expenditures to the main CCS options (pre-combustion and post-combustion carbon capture) as well as to CO₂ sequestration. The share of each CO₂ capture option reflects its prospects of improvement (as established in the technology perspective analysis). Thus, since post-combustion presents more prospects for further improvement, it receives higher share in R&D expenditures than pre-combustion CO₂ capture. R&D on CO₂ storage is used in order to reduce the leakage rates (by supporting the exploration of new sites and by improvement storage technologies/methods). Since the CO₂ storage technologies do not have a lot of prospects for improvement and profit, it is unlikely that the private sector will support research on them. The research is funded by governments, which as stated before its main purpose is to support new experimental technologies for future

use. Establishing the means of safe and efficient CO₂ sequestration can be viewed as a pre-acquisitive enabling all CO₂ capture technologies and falls naturally in the public domain. However, as these technologies become already mature by 2040, the funding of their further development is being reduced.

Figure D-26: BERD and GERD on carbon capture and sequestration (in M€05)



D.2 Baseline Scenarios

D.2.1 Baseline Scenarios developed using different deterministic models

D.2.1.1 POLES

[by P Criqui and S Mima (LEPII-EPE)]

Overview

In the framework of the Cascade study, LEPII-EPE team has elaborated a new reference projection of the world energy system to 2050. This scenario will be used as reference point for the construction of the “Technology Story” scenarios.

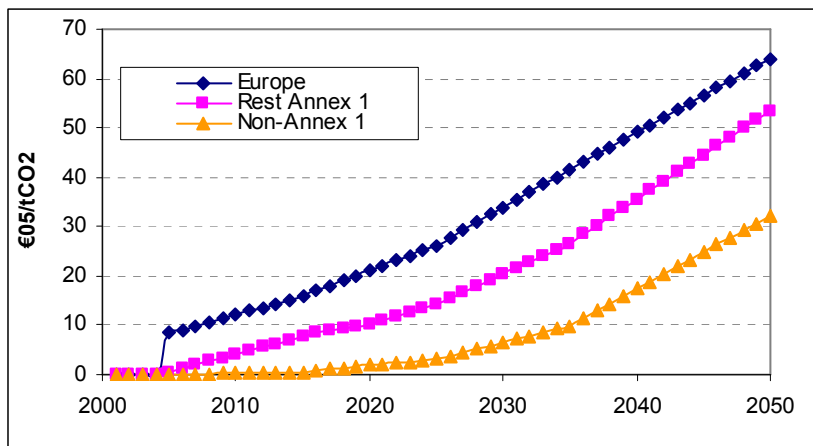
Reference projections to 2050 have been made with *POLES model* extended with adequate mechanisms for representing hydrogen economy.

This report first presents the common set of assumptions used in this study, then the results of the Reference projection with particular attention addressed to hydrogen economy and carbon capture and sequestration.

The Cascade reference scenario incorporate (Figure D-21) a regularly increasing Carbon value, rising for Europe from 12 €/tCO₂ in 2010, to 33 in 2030 and 64 in 2050. The other regions follow a similar path with a

time-lag in the carbon value of less than ten years for the Rest of OECD compared to Europe and of more than ten years for the Rest of the World compared to the Rest of OECD

Figure D-27 : Carbon values in the world regions according to SAPIENTIA DELPHI



Source: SAPIENTIA ICCS Delphi study

The world energy system

The world energy system that results from this analysis reveals the significant structural changes needed to accommodate the constraints on resource and emissions. Table D-7 lists the main results that reveal the structural consequences of these constraints. In summary, the principal outcomes of the Cascade reference case are:

The world primary energy consumption is projected to reach 21 Gtoe in 2050, more than doubling its current level, while population is likely to increase only by a factor of 1.4, and world GDP by a factor of 3.9. This means that average per capita energy consumption will increase from the current 1.6 to 2.4 toe/cap in 2050, while the average energy intensity of world GDP will continue to decrease significantly, from 236 to 128 toe/k\$95.

This projection thus relies, on the one hand on a relatively abundant energy supply, and on the other hand on a continuous increase in the average efficiency of energy use and conversion : in 2050 the world will use a lot more energy, but also a lot more efficiently, with an average -1.2 %pa energy efficiency improvement over the period.

In the CASCADE Reference Case, the 1.5 %pa increase in world energy consumption between 2001 and 2050 is due to the increases in population and per capita GDP (respectively +0.7 % and +2.8 %pa) and to the decrease in energy intensity (-1 %pa, in rounded figures). CO₂ emissions increase at 1.2 %pa, at a lower pace than primary energy consumption.

In 2050, coal is projected to be the most important source of energy at world level, with more than one quart of total primary supply, followed very nearly by oil qui remain at 24 % of total primary supply. Gas is likely

to experience the highest growth rate (+1.5 %pa) after coal (+1.7 %pa). The share of natural gas in the total primary production increases steadily from 20% in 2001 to 27% in 2020 and decrease encore after that date to 20% in 2050. The share of coal increases steadily up to 2030 from 24% to 27% but it decreases after that date, attaining 26 % in 2050.

Wind and solar mark an increase of 10 %pa, but given their low level at the beginning of the period, their share in the total primary production remains very limited (4 %) at the end of the period.

Table D-7: Key indicators and world primary energy supply, Reference

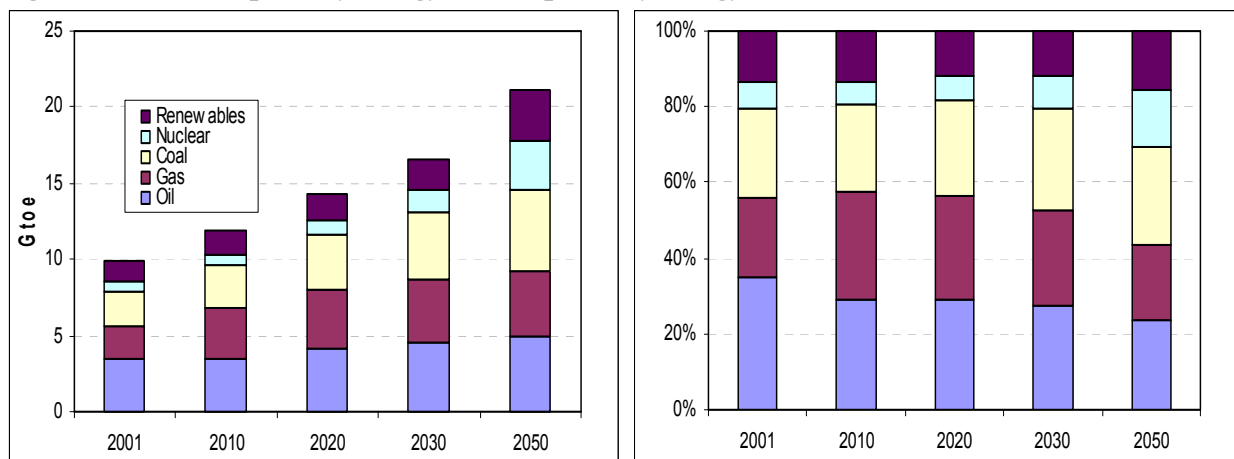
	2001	2010	2020	2030	2050	y.a.gr 2001/50
Key Indicators						
Population (Millions)	6112.9	6791.7	7496.5	8081.9	8863.7	0.7%
GDP (G\$95)	42223.9	59523.8	81558.6	105930.3	164089.8	2.8%
Per capita GDP (\$95/cap)	6907.4	8764.2	10879.6	13107.1	18512.6	2.0%
Gross Inland Cons/GDP (toe/M\$95)	236	200.2	175.1	156.5	128	-1.2%
Gross Inland Cons/capita (toe/cap)	1.6	1.8	1.9	2.1	2.4	0.8%
Electricity Cons/capita (kWh/cap)	2074	2580	3117	3735	5349	1.9%
Transport fuels per capita (toe/cap)	0.8	0.7	0.7	0.8	0.7	-0.2%
CO2 emissions/capita (tCO2/cap)	3.9	4.1	4.6	4.9	4.8	0.4%
CO2 Emissions (MtCO2)	23580	27896	34343	39371	42438	1.2%
Primary Production (Mtoe)	10230	12053	14443	16752	21265	1.5%
Coal, lignite	2408	2719	3578	4413	5408	1.6%
Oil	3711	3598	4279	4753	5202	0.7%
Natural gas	2094	3413	3953	4183	4201	1.4%
Nuclear	671	743	910	1426	3180	3.2%
Hydro, geothermal	232	274	314	351	420	1.2%
Biomass and wastes	1106	1283	1337	1444	2006	1.2%
Wind, solar	7	22	73	182	846	10.0%
World Oil Price in \$95/b	21.9	30.1	41.6	52.2	90.6	2.9%

Primary energy consumption

World primary energy consumption increases steadily, but with different paces according energy sources. Up to 2030 fossil fuels represent 80% of the total consumption with nearly 1/3 for each fuel. After that their share falls to 71% in favour of renewables (16%) and the nuclear (13%). Biomass and waste play the most important role in the renewables production.

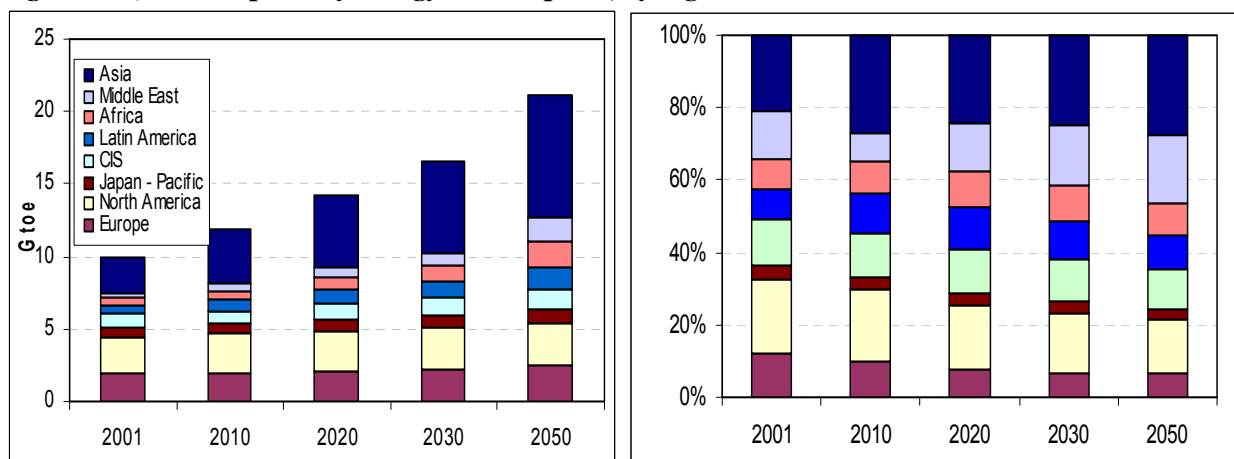
Another important feature of the primary consumption is the increasing role of coal which becomes the most important fuel (26%) in 2050 moving oil in the second place (24 %). The role of the natural gas increase considerably up to 2020 representing 27 % of the total primary consumption, which means the second place after oil, and decreases in the end of the simulation period at the same level as now (20%).

Figure D-28: World primary energy consumption, by energy source



By 2050, the energy consumption of today's industrialised countries (including the CIS countries) will increase by a factor of 1.4; in the developing world, consumption will increase by a factor of 3.5. Shortly after 2010, the consumption of the developing countries exceeds that of the present industrialised countries. The present group of developing countries consumes nearly two-thirds of world energy in 2050 (Figure D-23).

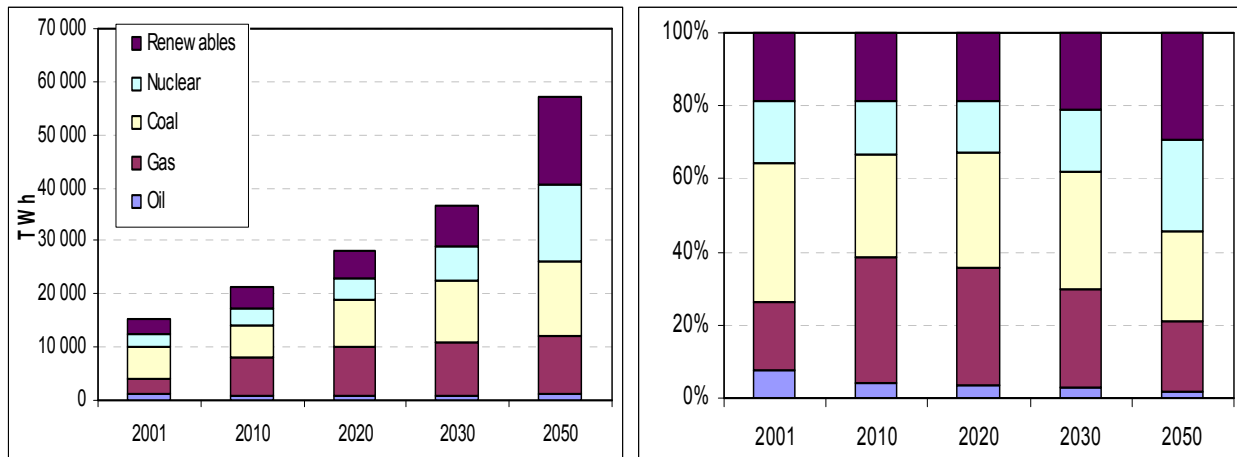
Figure D-29: World primary energy consumption, by region



The development of electricity

The generation of electricity in the world increases nearly four-fold from 15 500 TWh/year today to 57 500 TWh/year by 2050 (Figure D-24). The share of thermal generation increases up to 81% until 2020 because other sources cannot match the growth in demand. Generation from nuclear and hydro sources increases only slowly; generation from renewable resources grows strongly, exceeding 17%/yr in 2050 for wind and solar, but from a low base it cannot match demand growth in volume. After 2020 nuclear electricity increases rapidly representing 22%/yr. As result by 2050 the share of fossil-based electricity falls to 45%. This is significant structural change for a Reference case.

Figure D-30: World electricity production



Within the thermal generation, advanced technologies progressively gain the lion's share. In 2050, more than 80% of coal-based power generation is from advanced coal technologies and 70% of gas-based electricity is from combined cycle or cogeneration; oil almost disappears from the electricity sector (Table D-8).

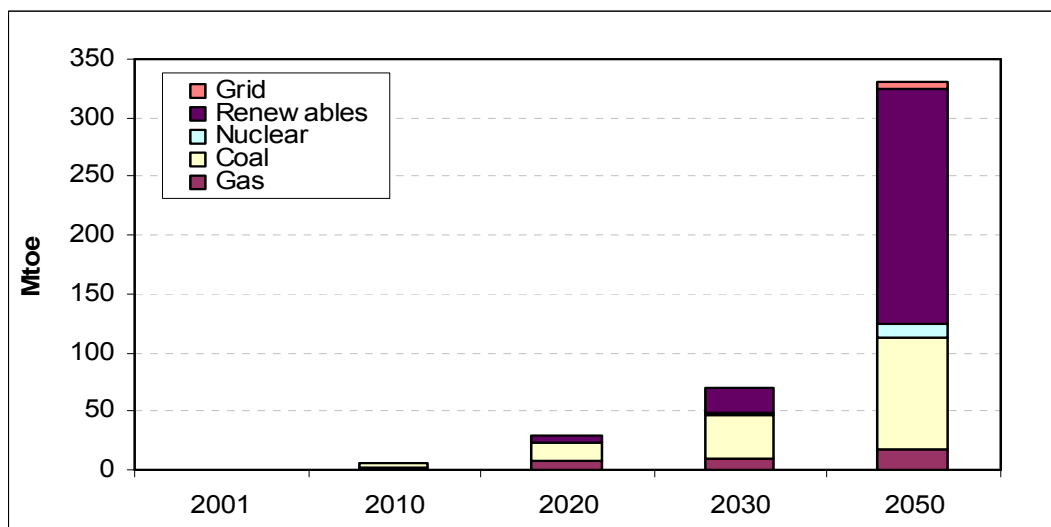
Table D-8: World electricity production

	2001	2010	2020	2030	2050	Annual % change		
						2001/10	2010/30	2030/50
Electricity Generation (TWh)	15468	21224	28373	36689	58407	3.6%	2.8%	2.4%
Thermal	10074	14689	19969	24213	28681	4.3%	2.5%	0.9%
of which:								
Coal	5848	5890	8999	11726	14032	0.1%	3.5%	0.9%
Gas	2934	7316	9120	9910	11022	10.7%	1.5%	0.5%
Biomass and wastes	155	567	877	1599	2619	15.5%	5.3%	2.5%
Nuclear	2653	3137	3954	6294	14390	1.9%	3.5%	4.2%
Hydro+Geoth	2703	3185	3653	4082	4887	1.8%	1.2%	0.9%
Solar	1	10	49	112	1778	24.9%	13.0%	14.8%
Wind	37	204	741	1925	7581	21.0%	11.9%	7.1%
Hydrogen	0	1	7	63	1090	na	26.1%	15.3%

Hydrogen production and carbon capture and storage

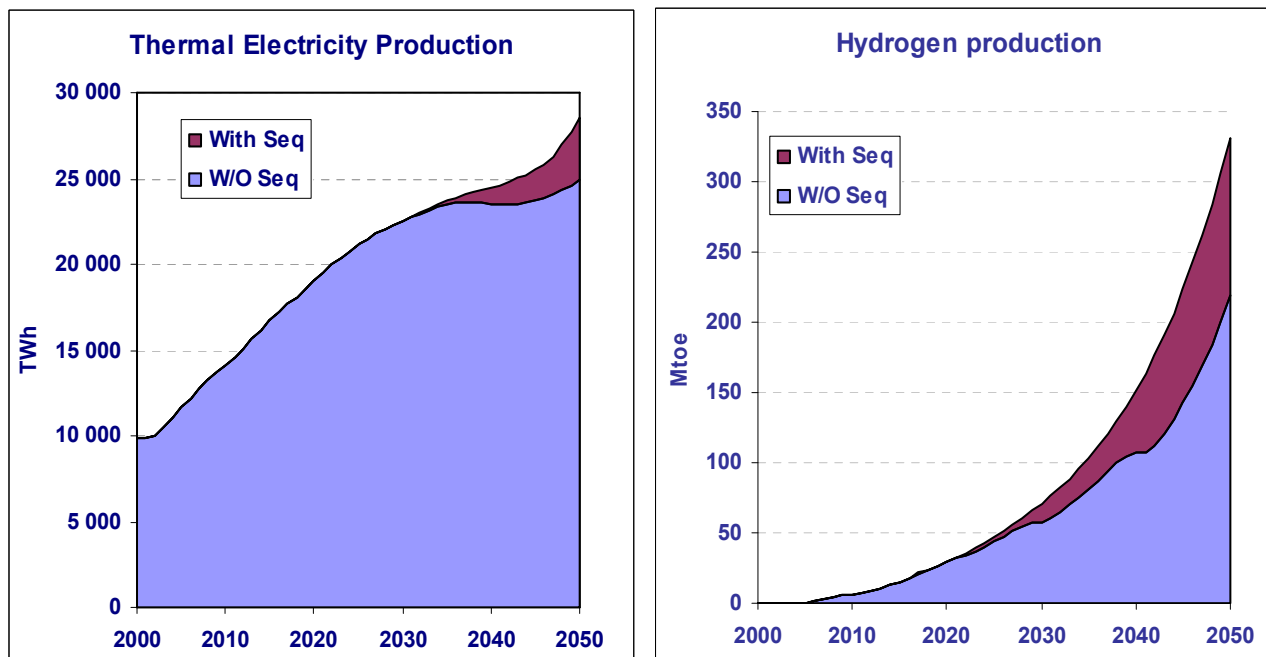
In the Cascade Reference, there is little production of hydrogen, 318 Mtoe in 2050, representing only 2.4 % of the total final energy consumption - equivalent to 8% of final electricity consumption. As illustrated in Figure D-25, production is mostly from non-fossil fuels, primarily from renewable sources and nuclear. The production from steam reforming of natural gas is limited by high prices and is generally more costly than hydrogen from coal gasification.

Figure D-31: Hydrogen energy production by technology



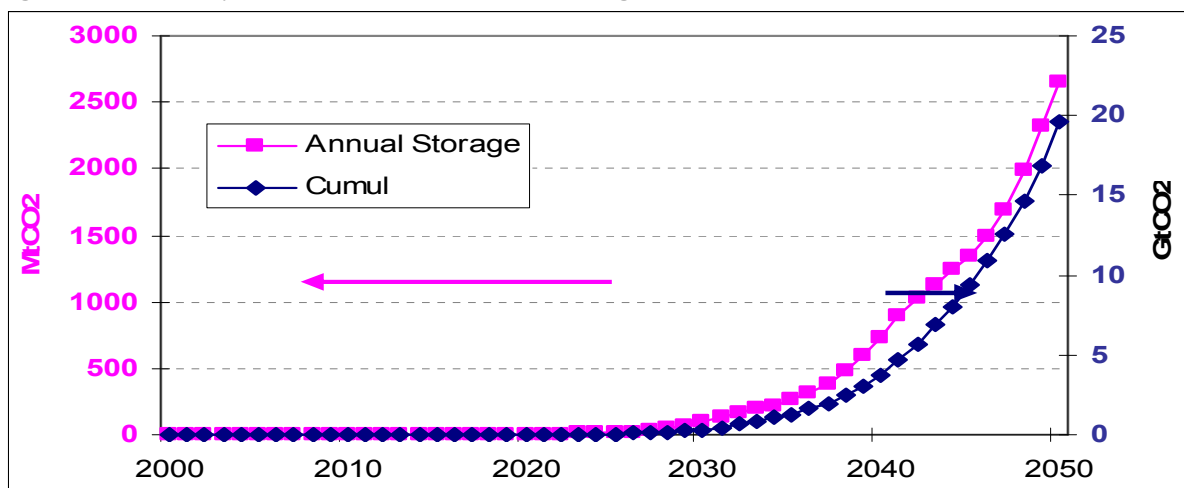
In 2050, 12% of electricity generation and 27 % of hydrogen production comes from plants equipped with carbon capture and storage. Figure D-26 shows that CCS only develops after 2035, when the carbon value in Non-Annex 1 countries is around 10 €/tCO₂ and when technological progress has reduced the cost of storage.

Figure D-32: Carbon capture and storage in thermal electricity and hydrogen production



In 2050, 2.6 Gt of carbon dioxide are captured and stored; this is 5.8% of the gross emissions in that year. In this relatively low carbon constraint case, the cumulative volume stored up to 2050 is 19 Gt (Figure D-27), which is slightly less than one year of current emissions.

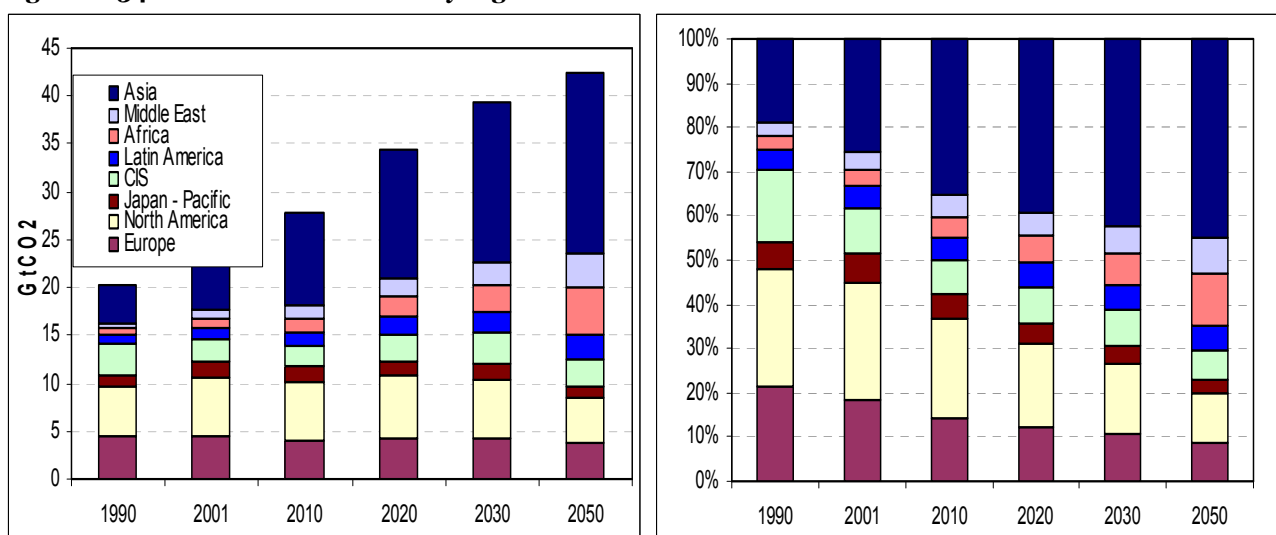
Figure D-33: Yearly and total cumulative CO₂ storage



CO₂ emissions

World CO₂ emissions in the cascade reference double in 2050 in comparison with 1990 (see Figure D-28). The CO₂ emissions of Annex B countries increase slowly from the 1990 level of 14.2 Gt to 15.4 Gt in 2030; they then fall to 12.7 Gt in 2050. This behaviour can be explained by slow population growth, the high price of energy and to the implementation of moderate climate policies. In the same time the increase in non-Annex B regions is dramatic; emissions are 5.9 Gt in 1990 but catch up with Annex B countries in 2010. By 2050, the emissions from non-Annex B countries are 30.3 Gt and amount to two thirds of the world total. This situation translate the fact that the developing world needs a lot of energy that price rises can only partly contain and the price-induced shift to coal increases the carbon intensity.

Figure D-34: World CO₂ emissions by region



Source : POLES Cascade Reference

Conclusion

The Cascade Reference projection describes a continuation of existing economic and technological trends, including short-term constraints on the development of oil and gas production and moderate climate policies for which it is assumed that Europe keeps the lead.

World energy consumption

The total energy consumption in the world is expected to increase to 21 Gtoe per year in 2050, from the current 10 Gtoe per year. Fossil fuels provide 70% of this total (coal 26%, oil 24%, natural gas 20%) and non-fossil sources 30%; the non-fossil share is divided almost equally between renewable (16%) and nuclear energy (13%).

Energy efficiency improvement

The size of the world economy in 2050 is four times as large as now, but world energy consumption only increases by a factor of 2.1. The significant improvement in energy efficiency arises partly from autonomous technological or structural changes in the economy, partly from energy efficiency policies and partly from the effects of much higher energy prices.

Dominant role of developing regions in the energy consumption

Energy demand grows strongly in the developing regions of the world, where basic energy needs are at present hardly satisfied. The consumption in these countries overtakes that of the industrialised world shortly after 2010 and accounts for two thirds of the world total in 2050.

Oil and gas production profiles

Conventional oil production levels off after 2025 at around 80 Mbl/d. The profile forms a plateau rather than the “peak” that is much discussed today. Non-conventional oils provide the increase in total liquids, to about 106 Mbl/d in 2050. Natural gas shows a similar pattern, with a delay of almost ten years.

Oil and gas prices

The prices of oil and natural gas on the international market increase steadily, and reach 110 \$/bl for oil and 100 \$/boe for gas in 2050. The high prices mostly reflect the increasing resource scarcity.

Electricity: the comeback of coal, the take-off of renewable sources and the revival of nuclear energy

The growth in electricity consumption keeps pace with economic growth and in 2050, total electricity production is 3.7 times greater than today. Coal returns as an important source of electricity and is increasingly converted using new advanced technologies. The price of coal is expected to reach about 20 \$/ton in 2050. The rapid increase of renewable sources and nuclear energy begins after 2020 and is massive

after 2030; it implies a rapid deployment of new energy technologies, from large offshore wind farms to “Generation 4” nuclear power plants .

CO₂ emissions

The larger use of non-fossil energy sources to some extent compensates for the comeback of coal in terms of CO₂ emissions, which increase nearly proportionally to the total energy consumption. The resulting emission profile corresponds to a concentration of CO₂ in the atmospheric between 900 to 1000 ppmv in 2050. This value far exceeds what is considered today as an acceptable range for stabilisation of the concentration.

A1 WORLD : Energy Balance Summary, Reference Case

	2001	2010	2020	2030	2050	Annual % change		
						2001/10	2010/30	2030/50
Key Indicators								
Population (Millions)	6113	6792	7496	8082	8864	1.2%	0.9%	0.5%
GDP (G\$95)	42224	59524	81559	105930	164090	3.9%	2.9%	2.2%
Per capita GDP (\$95/cap)	6907	8764	10880	13107	18513	2.7%	2.0%	1.7%
Gross Inland Cons/GDP (toe/M\$95)	236	200	175	156	128	-1.8%	-1.2%	-1.0%
Gross Inland Cons/capita (toe/cap)	1.6	1.8	1.9	2.1	2.4	0.8%	0.8%	0.7%
Electricity Cons/capita (kWh/cap)	2074	2580	3117	3735	5349	2.5%	1.9%	1.8%
Transport fuels per capita (toe/cap)	0.8	0.7	0.7	0.8	0.7	-1.4%	0.2%	0.0%
CO2 emissions/capita (tCO2/cap)	3.9	4.1	4.6	4.9	4.8	0.7%	0.9%	-0.1%
% of renewables in Gross Inland Cons	13.5	13.2	12.1	11.9	15.5	-0.2%	-0.5%	1.3%
% of renewables in electricity	18.7	18.7	18.7	21.0	28.9	0.0%	0.6%	1.6%
Primary Production (Mtoe)	10230	12053	14443	16752	21265	1.8%	1.7%	1.2%
Coal, lignite	2408	2719	3578	4413	5408	1.4%	2.5%	1.0%
Oil	3711	3598	4279	4753	5202	-0.3%	1.4%	0.5%
Natural gas	2094	3413	3953	4183	4201	5.6%	1.0%	0.0%
Nuclear	671	743	910	1426	3180	1.1%	3.3%	4.1%
Hydro, geothermal	232	274	314	351	420	1.8%	1.2%	0.9%
Biomass and wastes	1106	1283	1337	1444	2006	1.7%	0.6%	1.7%
Wind, solar	7	22	73	182	846	13.4%	11.0%	8.0%
Gross Inland Consumption (Mtoe)	9955	11917	14282	16573	21069	2.0%	1.7%	1.2%
Coal, lignite	2352	2719	3578	4413	5408	1.6%	2.5%	1.0%
Oil	3504	3460	4114	4570	5002	-0.1%	1.4%	0.5%
Natural gas	2082	3413	3953	4183	4201	5.6%	1.0%	0.0%
Biomass and wastes	1106	1283	1337	1444	2006	1.7%	0.6%	1.7%
Others	910	1042	1301	1962	4451	1.5%	3.2%	4.2%
Final Consumption (Mtoe)	6932	8144	9664	11027	13387	1.8%	1.5%	1.0%
<i>by source</i>								
Coal, lignite	511	1061	1392	1687	2162	8.5%	2.3%	1.2%
Oil	2940	3097	3683	4136	4500	0.6%	1.5%	0.4%
Natural gas	1133	1334	1508	1582	1441	1.8%	0.9%	-0.5%
Electricity	1090	1507	2009	2596	4078	3.7%	2.8%	2.3%
Biomass and wastes	1009	890	793	717	787	-1.4%	-1.1%	0.5%
Heat	249	250	252	253	257	0.1%	0.1%	0.1%
Hydrogen	0	5	26	56	163	na	12.7%	5.5%
<i>by sector</i>								
Industry	2470	3029	3478	3805	3992	2.3%	1.1%	0.2%
Transport	1715	1723	1994	2236	2663	0.0%	1.3%	0.9%
Household, Service, Agriculture	2747	3392	4192	4986	6731	2.4%	1.9%	1.5%
Electricity Generation (TWh)	15468	21224	28373	36689	58407	3.6%	2.8%	2.4%
Thermal	10074	14689	19969	24213	28681	4.3%	2.5%	0.9%
<i>of which:</i>								
Coal	5848	5890	8999	11726	14032	0.1%	3.5%	0.9%
Gas	2934	7316	9120	9910	11022	10.7%	1.5%	0.5%
Biomass and wastes	155	567	877	1599	2619	15.5%	5.3%	2.5%
Nuclear	2653	3137	3954	6294	14390	1.9%	3.5%	4.2%
Hydro+Geoth	2703	3185	3653	4082	4887	1.8%	1.2%	0.9%
Solar	1	10	49	112	1778	24.9%	13.0%	14.8%
Wind	37	204	741	1925	7581	21.0%	11.9%	7.1%
Hydrogen	0	1	7	63	1090	na	26.1%	15.3%
Hydrogen Production (Mtoe)	0.0	5.8	29.7	70.6	329.3	na	13.3%	8.0%
<i>of which:</i>								
Coal	0.0	2.2	13.4	32.5	76.7	na	14.5%	4.4%
Gas	0.0	2.5	7.0	9.4	17.1	na	6.9%	3.0%
Renewables	0.0	0.2	1.2	3.9	57.4	na	16.8%	14.3%
Nuclear	0.0	0.0	0.3	1.0	12.3	na	16.0%	13.6%
Electricity	0.0	0.1	0.3	0.9	6.0	na	14.5%	10.1%
CO2 Emissions (MtCO2)	23580	27896	34343	39371	42438	1.9%	1.7%	0.4%
<i>of which:</i>								
Electricity generation	8873	9336	11741	13395	13161	0.6%	1.8%	-0.1%
Industry	4176	5753	6603	7123	6552	3.6%	1.1%	-0.4%
Transport	5043	4923	5567	6071	6646	-0.3%	1.1%	0.5%
Household, Service, Agriculture	3184	4864	6755	8384	11136	4.8%	2.8%	1.4%
CO2 Sequestration (Mt CO2)	0.0	0.0	1.5	105.8	2649.4	na	na	17.5%

D.2.1.2 PRIMES

[by N. Kouvaritakis, V. Panos and P. Capros (ICCS-NTUA)]

This section describes the baseline scenario of the PRIMES-H2 model, which reflects median developments for key drivers affecting hydrogen penetration in Europe as established for the baseline of the whole project. These include demographic and economic activity projections, assumptions for future climate policy intensity, technological improvement and internationally traded fuel prices.

The analysis in this section concentrates mainly on the prospects of hydrogen economy. Developments in the rest of the energy system are discussed in connection to their impact on the evolution of the hydrogen supply and demand system.

Drivers and constraints to the European energy system development

The baseline implies that the population in EU-27 remains virtually unchanged between 2005 and 2050. This broad stability results from modest growth in the early part of the forecast underpinned by increased fertility in some member states. In the longer term the dynamics of the aging of the population prevails and decline occurs. This is particularly the case for some countries including the new member states, where the present structural of age cohorts implies an acceleration of decline in the absence of a major shift in fertility rates. Table D-9, shows the population growth in EU-15, in the new member states that joined EU in May 2004 (NMS-12) and in EU-27.

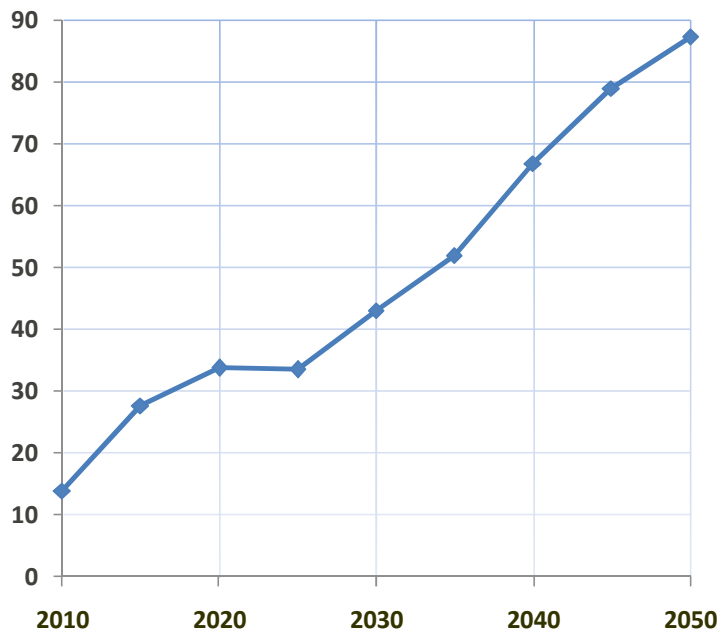
According to the baseline scenario for EU-15 growth in per capita income to 2030 is broadly consistent with long term growth experienced in the last 25 years.. In the longer term a slight deceleration is assumed reflecting the slower growth of population of working age. The per capita income in new member states is assumed to converge steadily, albeit slowly, to the EU-15 mean. In 1992 it represented 35%, by the time of accession it stood at 43%, while in 2030 it is projected to be 60% and reach 77% in 2050. The European economy progressively changes its structure as sectors with higher value added develop more rapidly than sectors with heavy intensiveness with respect to energy and materials. Table D-9 shows the average annual growth rate of GDP per capita in EU-15, in the new member states that joined the EU in May 2004 (NMS-12) and in EU-27.

Table D-9: Population and GDP per capita (in ppp) average annual growth rate in the baseline scenario [%]

	1990-2000	2000-2010	2010-2030	2030-2050	2005-2050
Population					
EU-15	0.35	0.42	0.12	-0.04	0.09
New member states	-0.17	-0.29	-0.46	-0.72	-0.55
EU-27	0.24	0.27	0.01	-0.16	-0.03
GDP per capita					
EU-15	1.79	1.63	1.85	1.33	1.65
New member states	1.09	4.08	2.90	2.59	2.88
EU-27	1.78	1.95	2.01	1.52	1.84

The CASCADE MINTS common assumptions cover climate policy intensity (see chapter D.1). The EU is assumed to lead the effort worldwide which implies that it experiences the higher effective carbon values. It is assumed that beyond 2025 climate policy intensity accelerates in response to tougher climate targets and covering progressively all emitting activities. The level of carbon value in EU-27 is shown in Figure D-29.

Figure D-35: Carbon value in €2005/tn of CO₂ in the baseline scenario for EU-27



Hydrogen penetration in the energy system

In addition to the strong climate policy, the baseline assumes fiscal support (partial exemption from taxation for zero emission vehicles in response to urban pollution problems. Apart from these blanket environmental initiatives, the baseline does not incorporate any specific measures to promote hydrogen as an alternative for the energy system: market forces and technological development alone are assumed to drive the penetration of hydrogen in the transport sector and in the decentralised electricity and heat production. In this sense, the main aim of the baseline scenario is to examine the limitations in the evolution of the hydrogen economy, when this evolution is supposed to be based on the continuation of the policies and measures of the past.

Hydrogen in the road transport sector

The baseline scenario suggests a slowdown in the growth of road transport activity due to a declining population and saturation effects concerning human mobility. Figure D-30, shows the car ownership per capita in EU-15 and in the new member states that joined the EU in May 2004 (NMS-12), as well as the average annual growth rate of passenger cars stock. In EU-15, saturation effects in car ownership become particularly pronounced after 2020. Car ownership in new member states is currently around the middle of the penetration curve with ownership increasing rapidly. The first real signs of saturation will occur after

2030, when ownership rate would have gone above 500 cars per thousand inhabitants compared to 625 cars per thousand inhabitants in EU-15. These saturation effects imply a marked deceleration of the growth in vehicle stocks broadly in line with secular developments until virtual stagnation is reached after 2035. The combination of decelerating stock growth and present vehicle scrapping rates would normally result in virtually stable new registrations around the present levels. However, as per capita incomes increase the average vehicle life declines and as a result scrapping accelerates resulting in a growth of around 37% (2005 to 2050) in new passenger cars registrations. This growth is an important factor for vehicle stock renovation and the potential for the introduction of new technologies, especially in the latter years.

Figure D-36: Car ownership per 1000 inhabitants (left chart) and annual growth rate of cars stock (right chart)

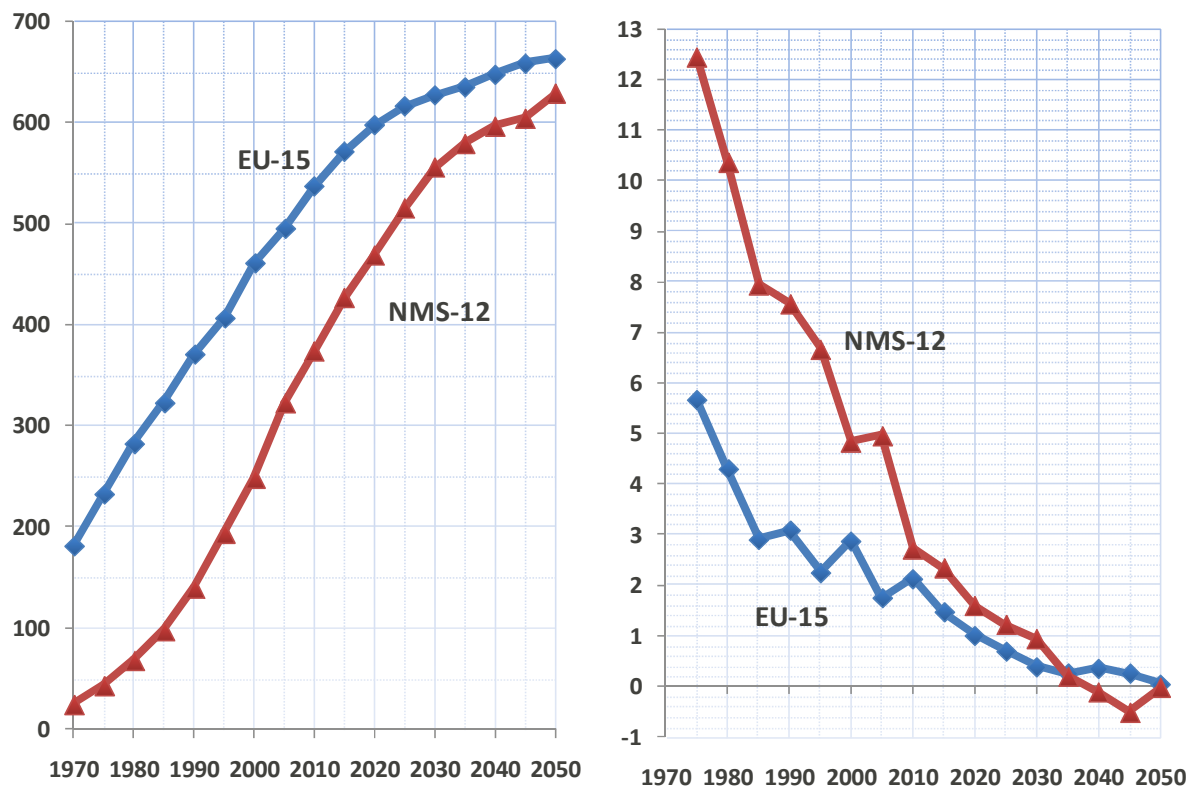


Table D-10, presents an overview of the cost per kilometre of the passenger car technologies. The cost includes annualised acquisition costs, fixed operating and maintenance costs and fuel cost (including taxes). Diesel engine cars are currently the most cost effective option especially when long annual distance travelled is considered (in the table the benchmark is 15000 km per year). This cost advantage explains to a large extent the gradual “dieselisation” of the European vehicle stock that has occurred in the last twenty years. This technological option retains the overall advantage until 2035 even though oil prices rise and the taxation on diesel is harmonised with gasoline. However in the course of the projection this advantage is steadily eroded vis-a-vis just about all other automotive options. Hybrid cars with onboard generation have been introduced in the market during the last seven years and sales have picked up recently. According to the calculations in the table, the cost of this technology at the moment stands at 8.3% above the cost of gasoline

Otto powered vehicles. This differential is projected to be reduced steadily and be eliminated towards the late 2030's. On the other hand, plug-in hybrids (currently a less mature option) are around 27% more costly than gasoline cars. Improvements in battery costs after 2020 mean that this differential would be constantly eroded despite increasing electricity prices due to higher carbon values. This option, however, together with the pure electric car option is not expected to become fully competitive even at 2050 horizon.

Hydrogen powered internal combustion engines can in theory be used even today at a cost no more than 19% higher than conventional gasoline vehicles, despite the additional onboard storage cost (but assuming that hydrogen is not taxed). Naturally the lack of hydrogen production and distribution infrastructure impedes the introduction in the market. This technology is projected to increase its attractiveness and attain gasoline ICE costs by 2030. According to PRIMES-H2 baseline assumptions the large scale introduction of hydrogen in the automotive sector would trigger a gradual increase in taxation for this vector leading to an increase in overall costs for this option after 2035. Fuel cells, which provide the biggest opportunities for transforming the passenger car stock, are currently prohibitively expensive and unlikely to become other than a niche option before 2025.

Table D-10: Vehicle kilometre cost in cents €05/km in the baseline scenario

	2005	2010	2020	2030	2040	2050
Gasoline ICE	38.5	41.2	41.2	41.2	42.1	43.0
Diesel ICE	37.0	38.6	39.7	40.1	41.1	42.2
Hybrid	41.7	43.3	42.4	41.9	42.1	42.4
Plug-in hybrid	49.4	51.7	49.5	47.0	46.1	45.3
Electric car	56.5	60.2	56.3	50.9	48.6	46.4
H2 ICE	45.7	45.2	42.8	41.1	41.0	42.5
Fuel cells	2392.9	717.8	76.4	48.5	44.6	42.1
Fuel cells on board reformer	2884.6	948.4	117.1	68.1	54.9	47.4

Towards the end of the projection period and assuming the development of a hydrogen production and distribution infrastructure, fuel cells become genuine competitors of conventional vehicles. This holds despite the assumed increase in hydrogen taxation, because of the very high efficiency of fuel cell powered engines. Assuming the existence of a hydrogen distribution infrastructure, fuel cell vehicles with onboard reformers are not attractive even as a transitional option.

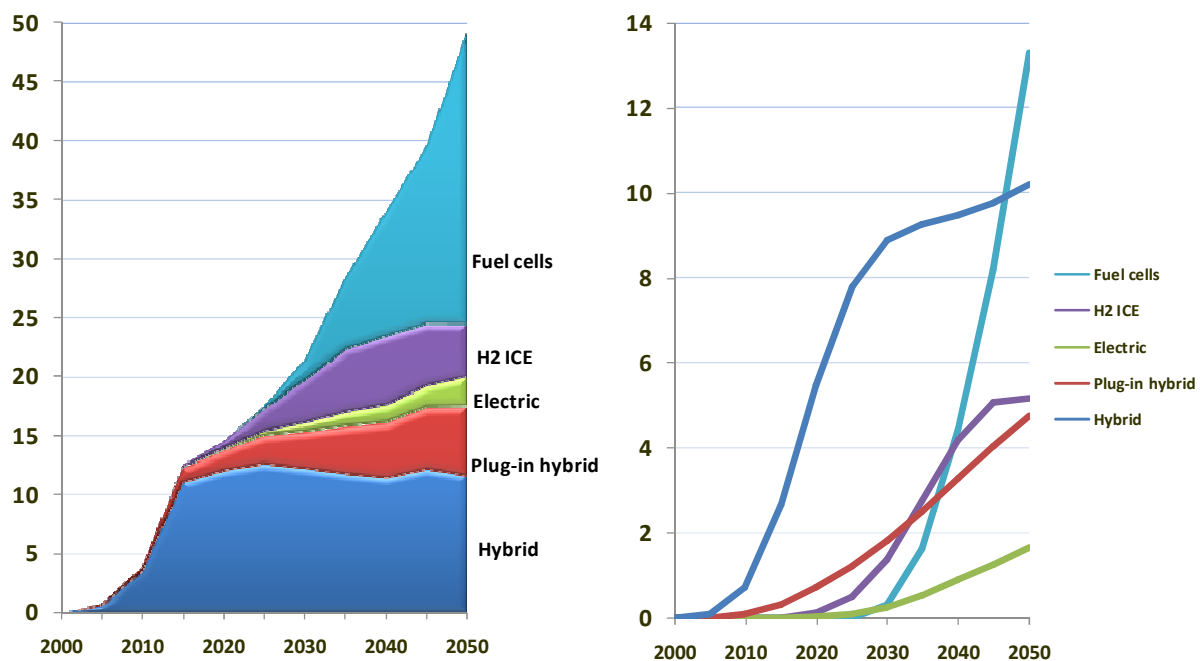
Figure D-31 shows the share of non-conventional passenger cars in the new registrations and in passenger cars stock. In the medium term internal combustion engine cars dominate new registrations, maintaining an 80% market share in 2030. By that time, hybrids (including plug-ins) obtain 15% of the market, while hydrogen internal combustion engine cars, despite the cost attractiveness, are restricted to around 5% due to the still limited hydrogen production and distribution infrastructure. Hydrogen ICE cars constitute the key driver for the development of such infrastructure in the period between 2025 and 2030 and thus pave the way for the introduction of fuel cell vehicles beyond that. The last decade of the outlook is characterised by a rapid transformation of the road transport sector mainly driven by the take-off in fuel cell vehicle sales. During this decade fuel cell stacks and systems and onboard storage are sufficiently cheap as to be comparable to conventionally powered cars. With the development of hydrogen distribution infrastructure

on a large scale, fuel cells reach 25% of new sales by 2050. After the introduction of fuel cells, conventional vehicle market shares start declining rapidly, while the other new vehicle options stabilise in market share.

The chart on the right hand side of Figure D-31, shows the shares of the different vehicle options in total vehicle stock. The projection can be divided into three principle stages:

- The period to 2020, where all erosion to the dominance of conventional vehicles is only challenged by the penetration of hybrids (predominantly independent with only a gradual introduction of plug-ins).
- The period from 2020 to 2035 is characterised by transition with many options essentially competing but a relatively erosion of conventional vehicle dominance. Hydrogen is introduced in ICE vehicles first, fuel cells make their appearance, while hybrids start saturating.
- The period 2035 to 2050 sees the rapid introduction of fuel cells accompanied by tapering-off in the stock of H₂ ICE vehicles. The lags in vehicle turnover (survival of older vintages) mean that although by the end of the projection horizon fuel cells account for one quarter of total registrations, their share in the vehicle population is still 13% but experiencing take-off.

Figure D-37: % share in new registrations (left chart) and in passenger car stock (right chart) in EU-27



Hydrogen for heat and power production

Apart from the uses in the transport sector the main technological option considered as a candidate for market penetration in the PRIMES-H₂ model is decentralised heat and power production in the form of fuel cell CHP systems. These have applications in small scale heat and power productions in both industry and residential/commercial sector. They characterised by very high efficiencies but their relative attractiveness depends on both stack/system costs (which according to the perspective analysis are expected to be

considerably higher than for mobile applications) and the cost of obtaining heat and especially power from alternative sources.

Table D-11: Summary results for stationary fuel cells prospects

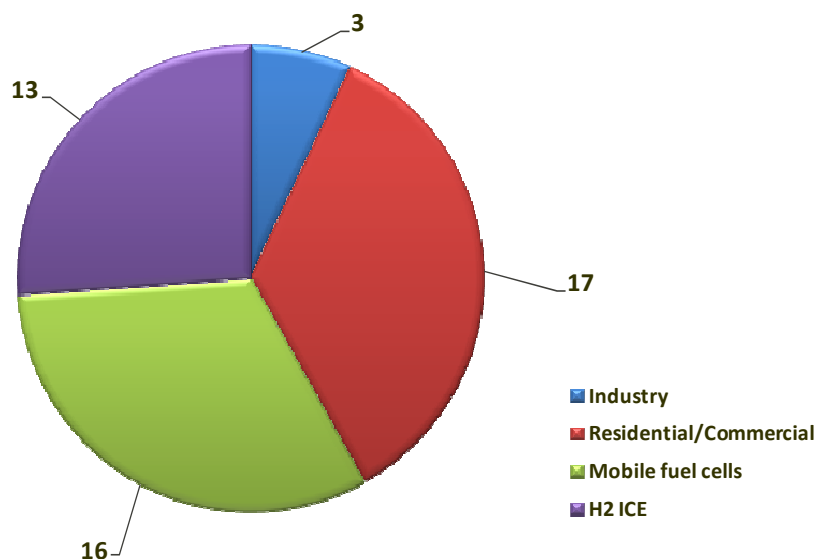
	2005	2020	2030	2040	2050
Industry					
Electricity production cost relative to electricity price *	7.88	1.91	1.33	1.10	0.90
% Electricity from fuel cells in electricity demand	0.00	0.15	1.01	1.96	2.21
% Steam from fuel cells in steam demand	0.00	0.06	0.44	1.01	1.32
Residential/Commercial					
Electricity production cost relative to electricity price *	10.51	2.74	1.63	1.17	0.79
% Electricity from fuel cells in electricity demand	0.00	0.00	0.07	0.49	2.33
% Heat from fuel cells in heat demand	0.00	0.01	0.13	1.00	5.36
* The value of heat/steam is deducted from the electricity cost					

Table D-11 summarises the evolution of the cost effectiveness and penetration of fuel cells in the industrial and residential/commercial sectors. As was the case for mobile fuel cells, full cost effectiveness is achieved after 2040. It is particularly marked in the residential/commercial sector, where according to the perspective analysis although small scale stationary fuel cell technologies start by being considerably costlier than large scale ones but exhibit greater potential for ultimate improvements. Residential/commercial applications are also favoured by very high retail prices of fossil fuels rendering the value of the heat (a negative cost in CHP comparisons) greater.

Although fuel cells in industry start penetrating before 2030 and become attractive towards the end of the projection period, the turnover of the steam raising equipment stock is slow among other things because of stagnant industrial demand for process heat. Turnover is also particularly slow in the buildings sector and fuel cells do not make any significant impact before 2040. However, the rapid improvement in the performance in the final years of the projection together with the expansion of urban distribution networks results in a situation of fairly rapid take-off.

The low penetration of stationary fuel cells does not mean that in terms of hydrogen demanded they are insignificant. Figure D-32 below summarises the main categories of demand for hydrogen for 2050. Transport accounts for about 60%. Within transport demand for hydrogen to fuel internal combustion engines absorbs around 45% of hydrogen requirements despite their relatively smaller importance within the hydrogen powered vehicle stock (28%). This is obviously due to the much higher efficiency of fuel cell vehicles (in 2050, 1.4 kg.o.e. per 100 km instead of 3.9 kg.o.e. for hydrogen ICE). Stationary fuel cells account for the remainder 40% of the European hydrogen market in 2050. The overwhelming bulk of this demand will occur in small scale stationary applications in the residential/commercial sector with important implications for infrastructure needs to distribute hydrogen in towns and cities (see the following section).

Figure D-38: Hydrogen demand (in Mtoe) in EU-27 in 2050



Hydrogen supply: infrastructure and production

Infrastructure development

According to the PRIMES-H₂ baseline the dominant form of transportation infrastructure for hydrogen distribution will be pipeline intensive. This is due to the cost-effectiveness of pipeline options compared to other distribution forms as long as demand is sufficient to justify their construction. In fact, the mode of hydrogen introduction in Europe as simulated by PRIMES implies the appearance of hydrogen demand and distribution networks initially in areas of high population and energy demand density (big conurbations) and gradually spreads into areas of lesser intensity. This pattern is consistent with cost effective expansion of infrastructure and can also be justified by the greater environmental pressure characterising densely population areas that could favour the early introduction of hydrogen as an energy vector even before it has become competitive with more conventional alternatives. The characterisation of the pipeline system in the baseline follows broadly the reference system developed in section D.1.3.

Table D-12: Baseline scenario evolution of pipelines system in km

	2020	2025	2030	2035	2040	2045	2050
Turnpike pipelines	98	401	1109	2448	4426	6534	9736
Industry connection pipelines	10	37	69	123	244	374	428
High pressure pipelines	68	277	766	1691	3058	4514	6726
Medium pressure pipelines (ring)	55	226	625	1380	2495	3683	5487
Low pressure pipelines	85	542	2373	8110	22143	48631	139973
Service station connection pipelines	85	368	1088	2409	4089	5483	6422

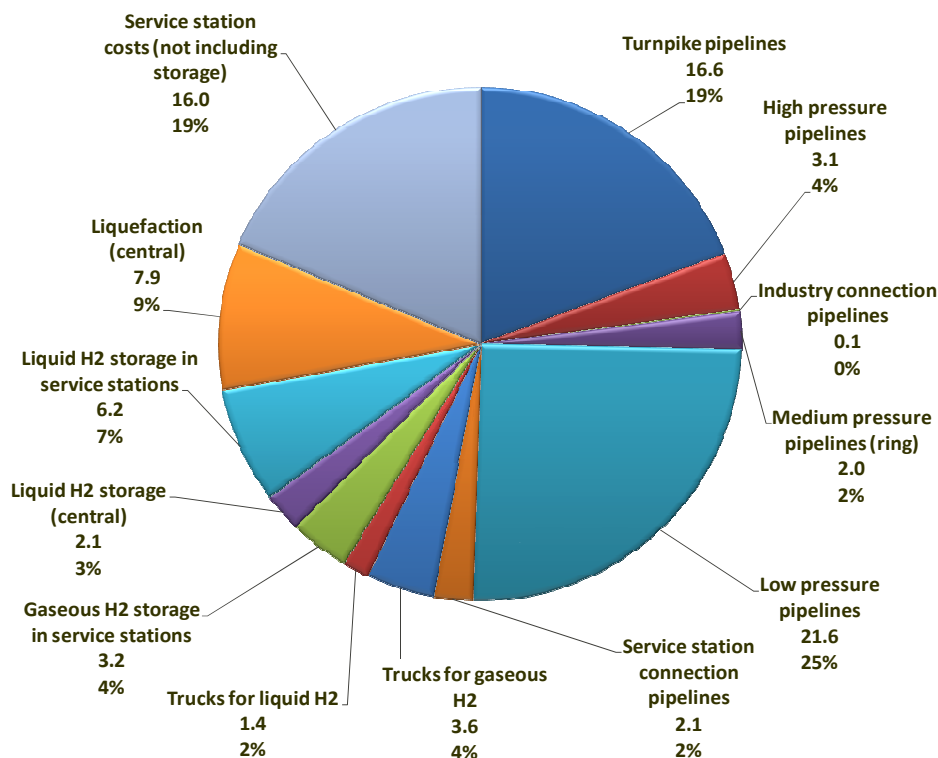
Turnpike pipelines connect the different production plants and additionally act as buffer storage. They represent a good measure for the overall pipeline system expansion. Connections to industrial uses do not follow the pattern of rapid expansion beyond 2040, because of the sluggish demand growth of large scale stationary fuel cells (see the previous section “Hydrogen for heat and power production”). On the other hand, this period experiences very rapid expansion of medium pressure pipelines (reflecting the increasing

number of cities supply of hydrogen) and especially low pressure pipelines supplying households in line with the increased take-up of small scale stationary fuel cells for residential/commercial applications. The service station connection pipelines see a rapid increase in the earlier periods with the introduction of H₂ ICE vehicles. Beyond 2035 they expand more slowly than the overall pipeline system because of increases in utilisation rates following the spread of hydrogen for road transport as well as because of the introduction of fuel cell vehicles that require almost 40% of the hydrogen consumed by the H₂ ICE vehicle variety. The expansion of the pipeline system is supplemented by an increase in the use of trucks to reach remoter rural areas or other areas that are not connected to the grid. This is especially true with regard to rural hydrogen service stations.

The pipeline network expansion as described above is projected to cover around 12.5% of the geographical area of EU-27 and reach approximately 22% of consumers in 2050. This broadly implies that given baseline assumptions on key drivers in 2050 the European energy system still be at relatively early stages of transition to a hydrogen economy.

The length of the different types of pipeline is a poor indicator of real infrastructural requirements because the different types of pipeline (diameters and pressures) are characterised by very different costs. In addition, pipelines are not the only type of infrastructure required to meet the demand as it emerges in the baseline. Notably the baseline requires the construction of liquid storage facilities, liquefaction units, as well as hydrogen carrying trucks and specialised service stations. Figure D-33 below presents the baseline cumulative infrastructure investments to 2050 by infrastructure type.

Figure D-39: Required infrastructure for hydrogen storage and distribution in EU-27 in 2050 (billion €05, and shares in total infrastructure expenditures)



According to the projection total cumulative infrastructure investments will amount to 86 billion €05. This figure may seem somewhat low, especially compared to the cumulative sales of other hydrogen related equipment (e.g. fuel cell system and hydrogen production plants). This is directly linked to the pattern of gradual geographical expansion of the system that characterises the baseline. As mentioned earlier this pattern is economical in terms of infrastructure.

Pipelines represent the bulk of this infrastructure investment (around 52%). Almost half of this pipeline investment is directed at providing a low pressure system for residential/commercial uses. Storage accounts for 14% of the investments primarily for liquid facilities of different scales (on-board is not included). Six percent of the investment goes on hydrogen carrying trucks, the bulk taking the form of gaseous H₂ transportation. Liquefaction accounts for 9% while specialised equipment (compressors, dispensers, pumps) for service stations take-up around 11%.

Hydrogen production

The baseline scenario implies a final demand for hydrogen equivalent to around 50 Mtoe (about 17.5 Mtn of H₂) in 2050. The main options for satisfying this demand include fossil fuel based technologies (with and without carbon capture and sequestration), biomass based options, dedicated renewable configurations and nuclear power including the more futuristic high temperature thermochemical cycle.

The high carbon values in the last two decades of the projection (90€05 per tonne of CO₂ in 2050) mean that hydrogen demand appears at a time when fossil options without CCS are uncompetitive. They make very minor contributions in hydrogen production (mostly gas steam reforming due to the earlier adoption of this technology as a transition production mode). Solar high temperature suffers from the high capital costs projected. Electrolysis from the grid is disadvantaged by the high electricity prices where dedicated wind based electrolysis is prohibitively expensive due to its capital intensiveness and low utilisation rates. Gas steam reforming and oil partial oxidation with CCS are disadvantaged by high feedstock costs. All the other options in Table D-13 below effectively constitute viable alternatives for producing hydrogen in the context of the baseline.

Table D-13: % Share in hydrogen production and production costs in EU-27 in 2050

	Share in production %	Production cost in €05/toe
No CCS	25.0	
Fossil fuels	4.0	
<i>Solar methane reforming</i>	<i>0.2</i>	<i>1732</i>
<i>Gas steam reforming</i>	<i>2.5</i>	<i>1541</i>
<i>Coal gasification</i>	<i>0.2</i>	<i>1135</i>
<i>Oil partial oxidation</i>	<i>1.1</i>	<i>1519</i>
Non-fossil energy sources	21.0	
<i>Solar high temperature thermochemical cycle</i>	<i>0.1</i>	<i>1703</i>
<i>Electrolysis from grid</i>	<i>0.8</i>	<i>1575</i>
<i>Dedicated wind turbine for electrolysis</i>	<i>0.4</i>	<i>1663</i>
<i>Dedicated nuclear power plant for electrolysis</i>	<i>6.8</i>	<i>955</i>
<i>Nuclear high temperature thermochemical cycle</i>	<i>9.1</i>	<i>692</i>
<i>Biomass pyrolysis</i>	<i>2.1</i>	<i>936</i>
<i>Biomass gasification with steam reforming</i>	<i>1.7</i>	<i>774</i>
CCS	75.0	
<i>Gas steam reforming</i>	<i>0.4</i>	<i>1708</i>
<i>Coal gasification</i>	<i>59.6</i>	<i>739</i>
<i>Oil partial oxidation</i>	<i>0.3</i>	<i>1639</i>
<i>Biomass gasification with steam reforming</i>	<i>14.6</i>	<i>650</i>

The cheapest option for producing hydrogen is through biomass gasification with steam reforming. The late introduction and therefore immature character of this technology means that despite its cost advantage it only gains 14.6% of total production in 2050. Even less mature, the nuclear high temperature thermochemical cycle is projected to be able to produce hydrogen at only 7% higher cost and gains a share of 9% by 2050. Nuclear power combined with electrolysis provides another 6.4% (this option is clearly available even today). Hydrogen supply is dominated by coal gasification options with CCS because they offer at the same time a relatively low cost and intermediate maturity in the sense that coal gasification and CCS are projected to penetrate the power generation market at earlier stages of the projection (especially after 2015). Coal gasification accounts for just under 60% of hydrogen production.

Conclusions

From the above discussion some general conclusions can be drawn:

- Given the basic assumptions on drivers that characterise the baseline scenario the 2050 horizon is too short a period for a transformation of the European energy system towards a hydrogen economy. Before 2030, virtually no hydrogen for any use is registered. Only in the last decade before 2050, hydrogen start making significant inroads and hydrogen infrastructure expands. This development still constitutes an early transition (by 2050 hydrogen reaches less than a quarter of the EU population).

- It is clear that an earlier introduction of hydrogen as an important energy vector in the European system would require faster technological developments in hydrogen technologies and additional policies and measures to promote hydrogen use by providing extra motivation for switching.
- The transport sector displays the highest possibilities for hydrogen penetration with fuel cells experiencing the highest penetration rates. The early appearance of hydrogen internal combustion engine cars lead the developments in hydrogen supply and distribution infrastructure, but they cannot by themselves transform the transport sector and ultimately they compete with fuel cells.
- The major obstacle that fuel cell cars face is the continuous improvement in internal combustion engine cars. This implies that the future success of a hydrogen economy depends on technological developments, with the reduction of fuel cells stack and systems costs being the key technological improvement.
- Fuel cell applications in the heat and power sectors are likely to lag behind the developments in the road transport sector. This is due to the wider competition that they face from the broader portfolio of electricity production technologies, in contrast to the road transport sector where the main competitors of fuel cells are the internal combustion engines cars either fuelled with oil or hydrogen.
- In the presence of vigorous climate policy in Europe, hydrogen supply is dominated by coal based sources with CO₂ capture and sequestration (around 60%). Nuclear (especially high temperature thermo chemical cycles) is also likely to play an important role (around 10%). Biomass is projected to take around 16.4%.
- The late introduction of hydrogen notwithstanding, because the hydrogen economy broadly implies substituting energy use for technology even in the modest prospects of baseline translate into large markets for new technological equipment.

Table D-14: Cumulative outlays on hydrogen related technologies in billion €05 in EU-27

	2020	2025	2030	2035	2040	2045	2050
Fuel cells	1	5	13	38	85	151	245
<i>Mobile fuel cells stacks</i>	0	0	3	13	34	62	101
<i>Mobile fuel cells systems</i>	0	0	3	14	36	67	112
<i>Stationary fuel cells stacks</i>	0	1	2	2	4	5	7
<i>Stationary fuel cells systems</i>	1	3	5	8	12	17	25
Storage and distribution	2	6	18	39	70	107	156
<i>Onboard storage passenger cars</i>	1	3	7	16	30	49	70
<i>Pipelines</i>	0	1	3	8	15	25	45
<i>Hydrogen storage</i>	0	1	2	4	7	10	11
<i>Trucks</i>	0	0	1	2	3	4	5
<i>Liquefaction</i>	0	0	1	3	5	7	8
<i>Other infrastructure</i>	0	1	3	6	10	14	16
Production	0	0	1	3	6	10	15
<i>Gasification based production</i>	0	0	1	2	4	7	10
<i>Nuclear based production</i>	0	0	0	1	2	3	5
<i>Other sources of production</i>	0	0	0	0	0	0	1
Total	3	12	32	80	162	268	417

D.2.1.3 MARKAL

[by H. Rösler (ECN)]

This section describes the analysis of the Baseline scenario using the Western European MARKAL model.

Assumptions

Since the background and main assumptions of the Baseline are extensively described in section D.3.1, only a short outline of the world oil prices and the assumed European coal and gas prices are given Table D-9 and Table D-10

Table D-15 Fuel price assumption for Western Europe [\$2005/boe]

\$2005/boe	2000	2010	2020	2030	2040	2050
Oil	27	37	49	61	78	97
Gas (Europe)	19	24	37	49	61	73
Coal (Europe)	10	12	15	18	21	23

Table D-16 CO₂ emission taxation path [€2000/ton CO₂]

€2000/ton CO ₂	2010	2020	2030	2040	2050	>2050
	16	28	44	64	78	85

Results

In this section the main results of the Baseline scenarios are described. The most important result in view of this study is that under the baseline assumptions hydrogen will neither penetrate in the transport nor in the built environment. Hydrogen will be used for the conversion from HTU oil into biodiesel, however, this is not within the scope of the project. To study the impact of hydrogen penetration in the technology scenarios on the energy system, primary energy consumption, electricity production, transportation fuel mix and CO₂ emissions prospect under the baseline assumption will be presented.

Primary energy consumption

In the period 2000-2050 the total primary energy consumption will increase with 40% and the mix will be considerably different from the current situation. First of all the use of oil will decrease. While in 2000, 40% of the total primary use could be ascribed to oil or derived products, by 2050 the share of oil is below the 10% due to the assumed CO₂ tax and the exhaustion of oil reserves. The largest part of the increased consumption will be by coal and nuclear energy that both double. But renewable energy will also increase and renewable energy sources will reach a 34% share of the total primary energy consumption (calculated using the substitution principle). Biomass will be the renewable source used most and in 2050 the use of biomass will be triple the amount it was in 2000. However, also other renewable options like wind and solar will gain a

larger share. Remarkable is that despite the strongly increasing gas prices, the consumption of gas increases in the period 2000-2020, after which it stabilizes.

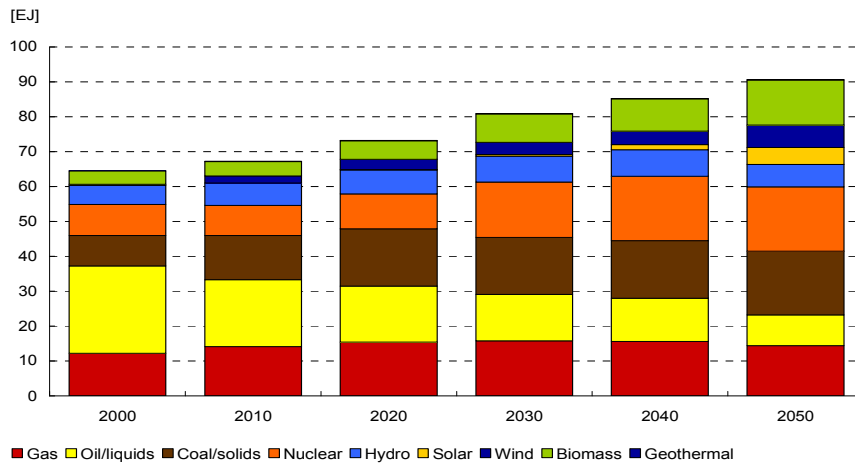


Figure D-40 Primary energy consumption

Electricity production and transport fuel consumption

Although a complete analysis could be done for all demand sectors, this section focuses on energy consumption in the power and transportation sector since one of the main goals of the analysis is to study the penetration of hydrogen in the transport sector under certain demand push and supply pull assumptions.

From Figure D-30 (a) it can be seen that the total electricity production will double in the period 2000-2050. Since the primary energy consumption increases no more than 40% in the same period, it can be concluded that an electrification of the energy system will take place. The increased use of coal and nuclear becomes even more clear in the power sector as seen in primary energy consumption above. By 2050 coal plants and nuclear power plants will both produce 30 % of the total electricity consumption. All the electricity produced from coal in 2050 is used in coal gasification plants with SOFC. Biomass use in the power sector is rather limited.

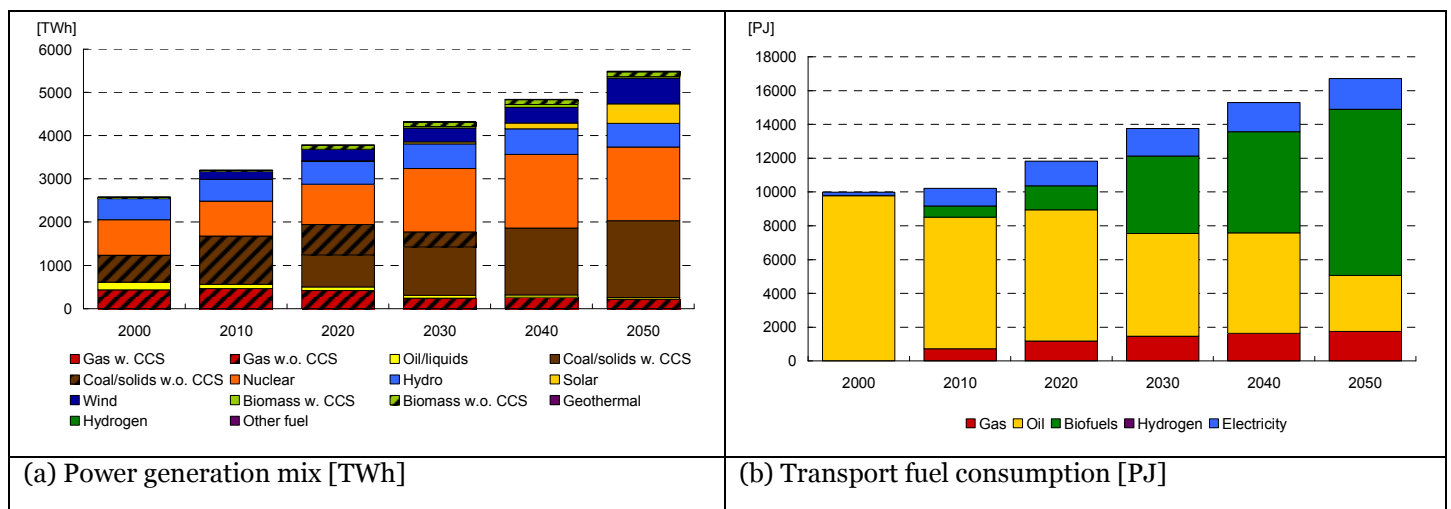


Figure D-41 Power generation mix and transport fuel consumption in Baseline

On the other hand the use of biomass in the transport sector increases almost exponentially under the increasing oil prices and carbon tax reaching a 60% in 2050, see Figure D-30 (b). In Figure D-30 (b) the category 'oil' covers all non-renewable liquid transport fuels like gasoline, conventional diesel and kerosene. However, by 2050 the use of gasoline will be small compared to the use of conventional diesel and biodiesel. Not only will all trucks use diesel, but 90% of all passenger cars and 80% of the buses will be diesel driven. The other 20% of the bus stock will have electric engines, these are all city buses. The increasing penetration of electric buses partly induces the increase of electricity use in the transport sector, the rest of increase due to switch of the complete van stock to electricity. The higher efficiency use of diesel and electricity engines leads to the moderate growth consumption between 2000 and 2010.

CO₂ emissions

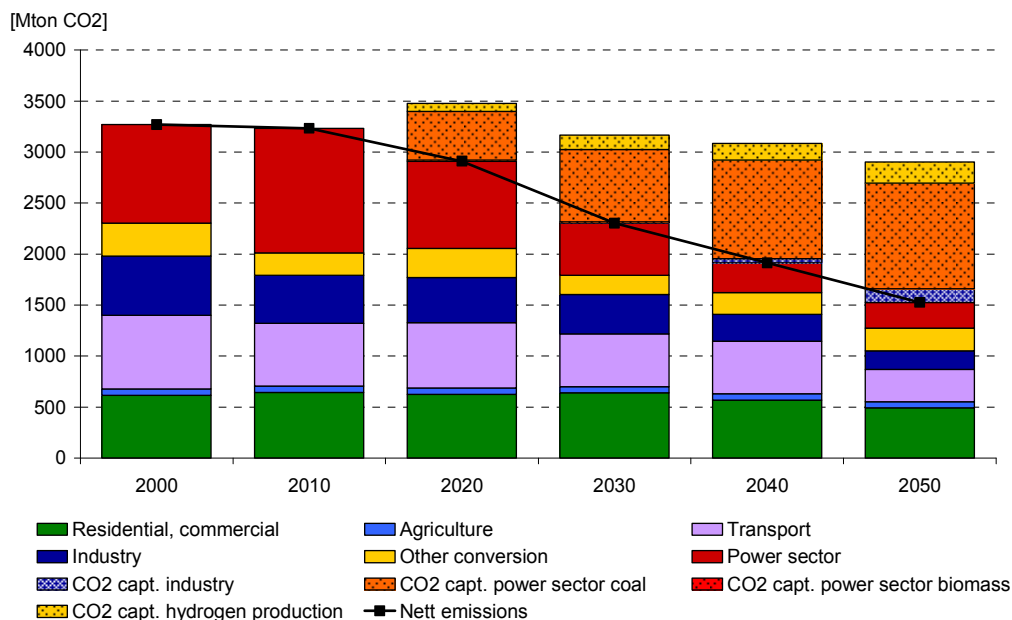


Figure D-42 CO₂ emissions level

Under the applied CO₂ tax the total emissions in 2050 will be less than half of those in 2000. The highest reduction potentials are in the power sector, industry and transport sector which will reduce their CO₂ emissions to respectively 26%, 32% 44% of the 2000 level. This is mainly due to an increase of CO₂ capture and storage. Most CO₂ is captured in the power sector, however, the CO₂ can also be captured easily when producing hydrogen from coal. The hydrogen is mainly used for the production of biodiesel from HTU oil. In 2050, 1375 Mton CO₂ will be stored per year.

Conclusions

Under the assumed fuel prices and CO₂ tax:

- Hydrogen will not penetrate in the transport sector or in the built environment.
- Coal, nuclear and biomass will become the most important energy sources. Other renewable energy sources as wind and solar will also have a growing importance.
- Electricity use will become more important and will take an increasing share of the final energy demand.
- Biofuels will be the main transport fuel by 2050 with a share of 60% of the total fuel use.
- The total CO₂ emissions in 2050 will be half of those in 2000.

D.2.1.4 MESSAGE

[by G. Totschnig and I. Keppo (IIASA)]

This study is based on the assumptions of the MESSAGE-B2 scenario. The extensions to the model code as described in C.2 have also been included, and a fuel tax of 0.5 euro2000/liter gasoline equivalent (15.6 euro/GJ) is assumed for all transportation fuels, including hydrogen. Further, a carbon tax is included in the definition of the baseline scenario (see Table D-17) according to the SAPIENTIA Delphi expert opinion poll.

Table D-17. Carbon tax assumptions, according to the SAPIENTIA Delphi expert opinion poll.

	Euro2000/tC										
	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Europe	0	50	74	118	179	250	349	349	349	349	349
Rest of OECD	0	27	45	81	134	201	297	297	297	297	297
Rest of World	0	5	13	33	69	122	220	220	220	220	220

For the baseline and technological scenario analysis, the newly developed 2FLC version of MESSAGE was used in operation mode 4 (see C.2.3.2). This means that R&D spending is exogenously given and that the model uses the 2FL equations to calculate the costs (and other parameters) of the learning technologies according to the exogenously given R&D spending and the achieved cumulative installed capacity. The R&D spending is taken from the R&D outlook (see Table C-25 in chapter C.2.3.2)).

The MESSAGE study of the hydrogen economy is focused on the use of hydrogen in passenger transport, hydrogen production, and the importance of learning in spillovers among technologies with similarities. See

Table C-21 in C.2.3.1 for the MESSAGE implementation of the learning spillovers. The MESSAGE model used is very detailed for the whole energy system, from resource extraction and conversion to final energy. The technology descriptions of the end-use sectors are rather stylized because of their diversity. An exception is the transport sector which was completely renewed and modeled in great detail for the CASCADE Mints project, as described in C.2.3.1.

Recent studies have reported that passenger transport is the most important sector for the hydrogen economy. For example, the International Energy Agency (2005) report, “Prospects for hydrogen and fuel cells,” states that, in its scenario with the highest hydrogen penetration, 97% of the hydrogen is used for transport in 2050.

MESSAGE baseline scenario results

In Figure D-43 a result of the baseline scenario for global passenger car transport is given. This baseline scenario shows that gasoline hybrid cars start replacing gasoline cars in 2010, whereas hydrogen fuel cell cars make their market entry in 2050 and dominate the market with a more than 90% share from 2080. Ethanol hybrid cars and natural gas hybrid cars have a small market share between 2040 and 2080.

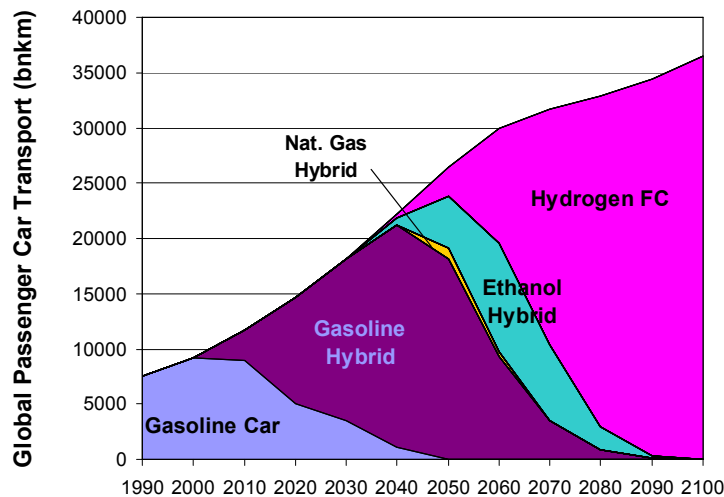


Figure D-43. Global passenger car transport.

Figure D-43 shows that the assumed passenger transport demand increases by a factor of 4.9 from 7,500 to 36,500 billion kilometers. On the other hand, energy consumption trends look different (see Figure D-44).

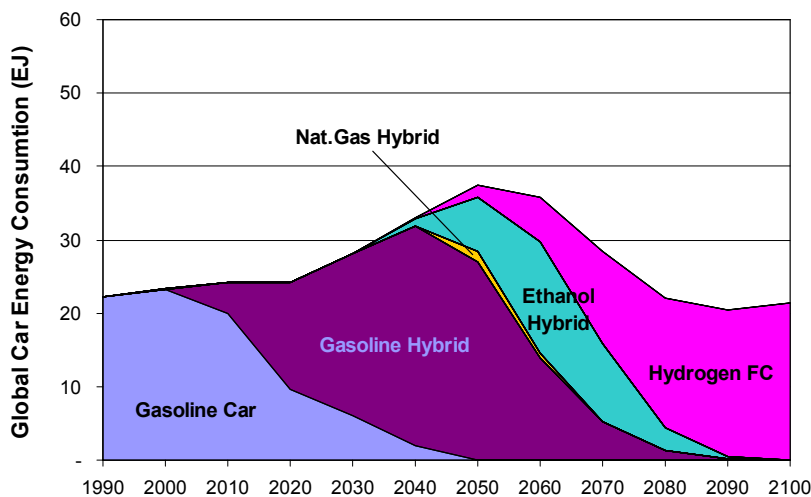


Figure D-44. Global energy consumption in the passenger car transport sector.

Despite the growing demand for passenger car transport, the efficiencies of hybrid and fuel cell cars lead to a reduction in energy consumption in the passenger car sector from 22.2 EJ in 1990 to 21.4 EJ 2100.

In Figure D-45 global CO₂ emissions are given for the ground transport sector and for the global economy as a whole.

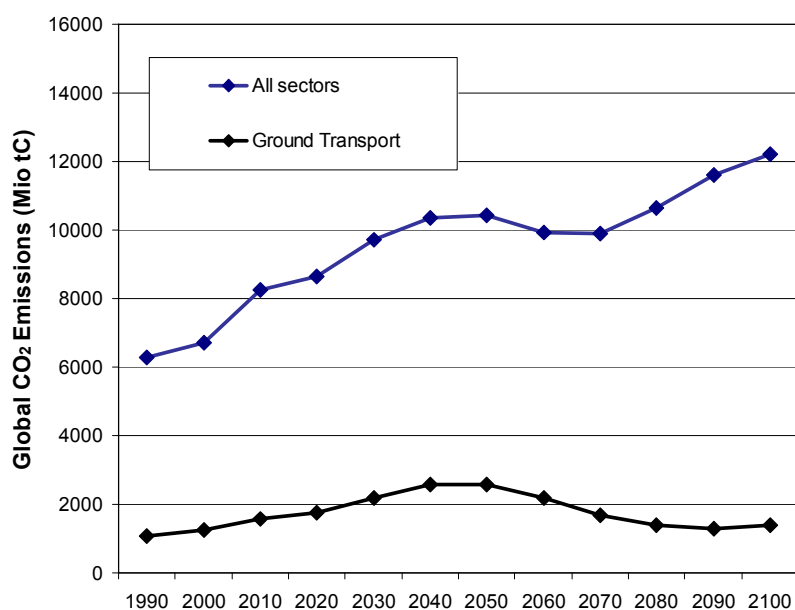


Figure D-45. Global CO₂ emissions for the baseline scenario.

The ground transport curve includes all transport CO₂ emissions except for those from air transport. It therefore includes passenger car and ground freight transport. It is not assumed that fuel cells and hybrids are introduced into freight transport. After 2050 a shift occurs from oil products to natural gas and bio fuels in freight transport. This shift, in combination with the success of fuel cells in passenger car transport, leads to a stabilization of CO₂ emissions from ground transport at around 1.4 GtC in 2100 (from 1.1 GtC in 1990 and 2.5 GtC in 2050).

In Table D-18 the global shares of hydrogen passenger vehicles in all passenger vehicles are given.

Table D-18. Share of H₂, ICE , and FC cars in all passenger cars.

	1990	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
H2 ICE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
H2 FC	0%	0%	0%	0%	0%	2%	10%	35%	67%	91%	99%	100%
H2 ICE+FC	0%	0%	0%	0%	0%	2%	10%	35%	67%	91%	99%	100%

The behavior of learning technologies in the baseline scenario:

As described in the description of the MESSAGE model extensions (see C.2.3), two-factor learning is modeled with clusters and spillovers and using subcomponents. In total, the model includes 17 2FL technologies and 3 technologies with a 2FLC subcomponent. As clustering and subcomponents are used extensively, the technological progress of these 20 technologies depends on 9 independently learning clusters or standalone (sub)technologies, which are: vehicle fuel cell components, vehicle hybrid system, vehicle hydrogen storage, vehicle reformer, stationary reformer for hydrogen production, stationary fuel cell, electrolyzer, gasifier, and biomass handling.

To investigate the learning behavior of the model, these 9 independently learning components will be analyzed. See, for example, Figure D-46 and Figure D-47.

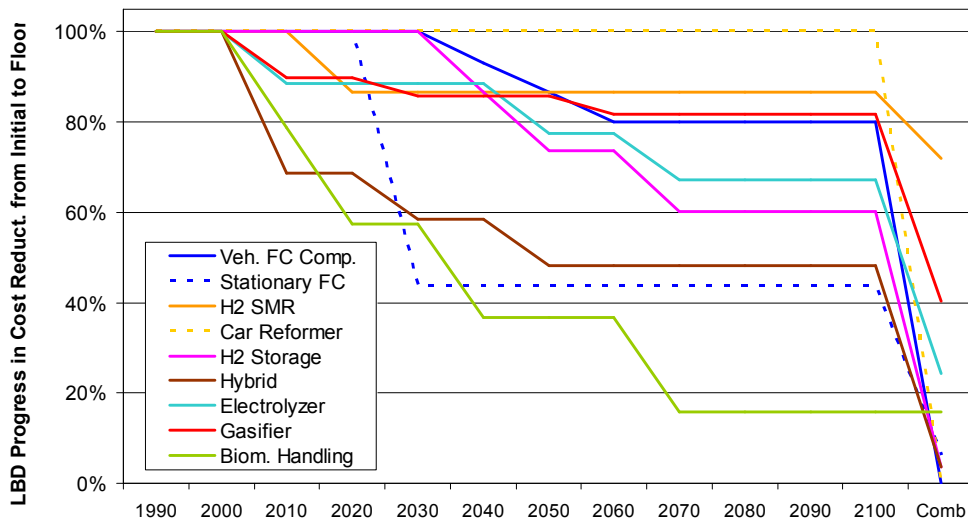


Figure D-46. Cost reduction for the key learning technologies as achieved in this baseline run by LBD only. The data right of 2100 is labeled “Comb,” meaning that this represents the cost in 2100 as achieved through combined effect of R&D spending and learning by doing. 100% indicates the initial cost in 2000 and 0% the floor costs.

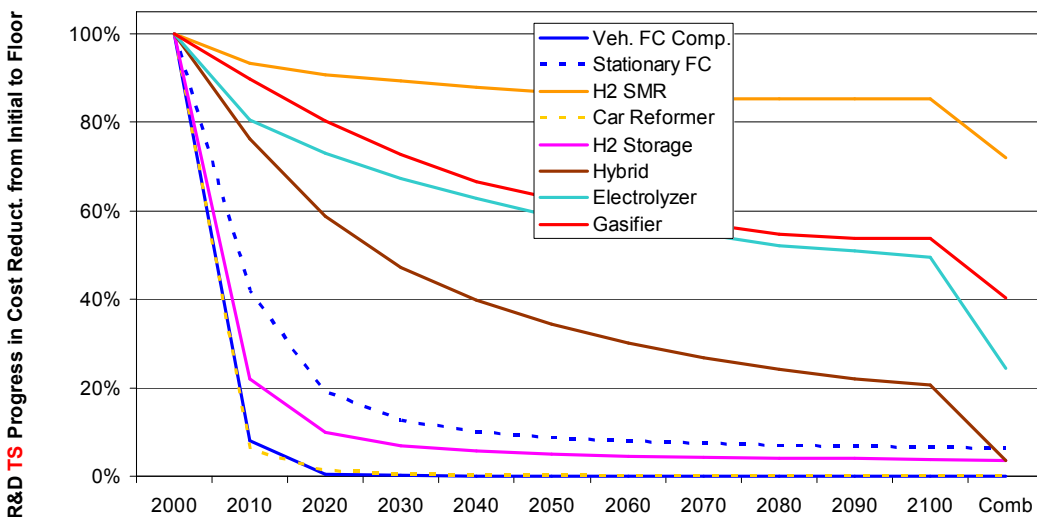


Figure D-47. Here the cost reduction due to R&D spending only of the key 2FL technologies are given. The data right of 2100 is labeled “Comb,” meaning that this represents the cost in 2100 as achieved through combined effect of R&D spending and learning by doing. 100% indicates the initial cost in 2000 and 0% the floor costs.

Figure D-46 depicts the cost reductions due to LBD. These cost reductions do not include the effect of R&D spending. Only the data to the right of 2100, which are labeled “Comb,” represent the cost in 2100 due to R&D spending and learning by doing. The values are calculated in percentage terms using the following formula:

$$\text{Progress in \%} = (\text{Cost}(t) - \text{Floor}) / (\text{InitialCostIn2000} - \text{Floor})$$

Thus, 100% means that costs are still at the initial level and 0% indicates floor costs. Similarly, Figure D-47 shows the cost reductions due to R&D spending and does not include the cost reductions of learning by doing. Only the data to the right of 2100, which are labeled “Comb,” represent the cost in 2100 due to R&D spending and learning by doing.

It can be seen that the cost reductions are stepwise in Figure D-46 and continuous in Figure D-47. The reason for this difference is that in the baseline scenario the R&D spending is exogenously given and the cost reductions are included in the model as exogenous time series. The learning-by-doing cost reductions, however, are a result of the endogenous optimization of the mixed integer (stepwise) formulation of the learning curves (see C.2.3.2, Mode 4).

It can be seen from Figure D-46 and Figure D-47 that the vehicle fuel cell components achieve most of their cost reductions from R&D and not from learning by doing. Mobile hydrogen storage and hybrids also learn more strongly from R&D than LBD. Steam methane reforming (H₂ SMR) learns by a similar extent through learning by doing. This different learning performance is primarily a consequence of the specific definition of the 2FLC; but it is also due to the optimization results. Since steam methane reforming (SMR) is not used much in the baseline run, there is not a great deal of LBD for this technology.

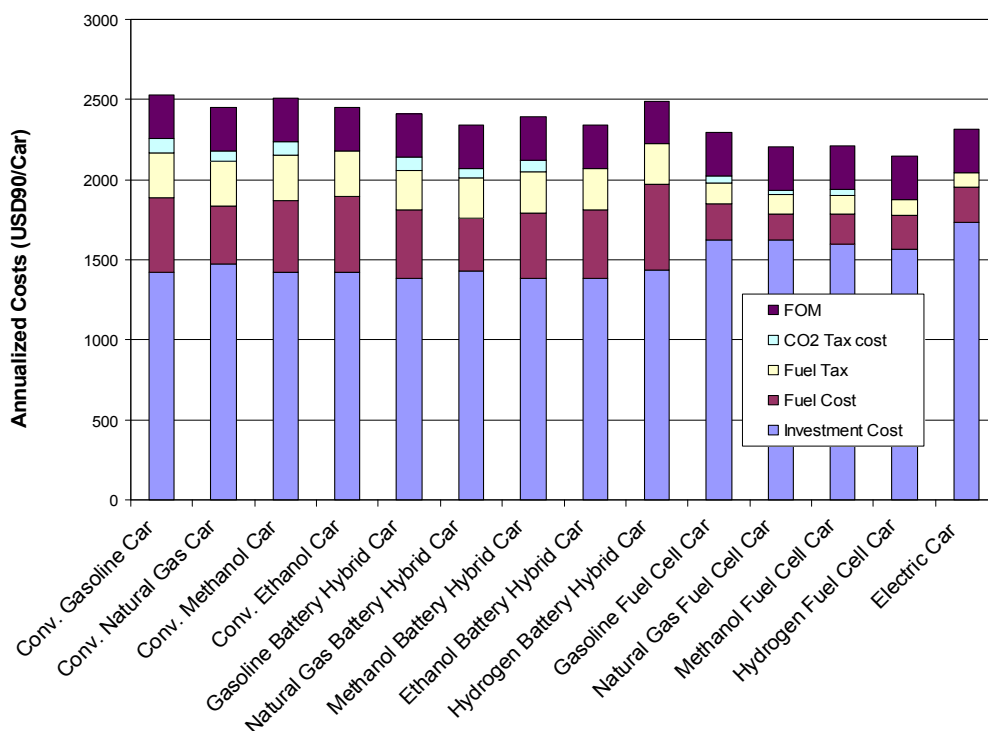


Figure D-48. Annualized costs of passenger car technologies in 2100 after 2FL learning. The different cost contributions are shown.

In Figure D-48 the annualized costs are shown for different passenger car types. It is evident that the efficient fuel cell and electric cars are less affected by the fuel tax because of their low fuel consumption. Similarly do the CO₂ tax and the fuel price have a stronger effect on inefficient cars. The fuel cell car has the lowest annualized cost in 2100, but not the lowest annualized investment costs.

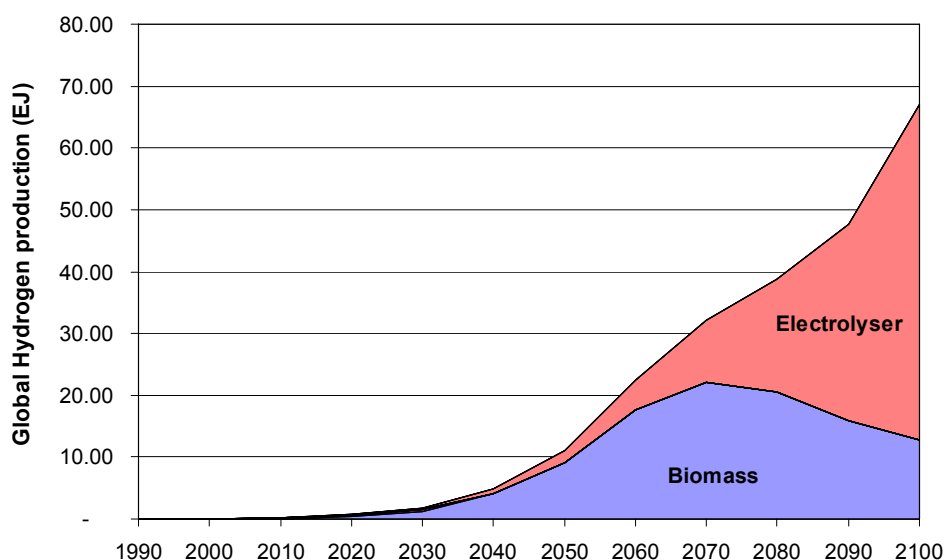


Figure D-49. Global hydrogen production.

The hydrogen production options used are given in Figure D-49. The production of H₂ from electrolysis is mainly carried out using nuclear energy; this assumes that there are no limits on nuclear energy use.

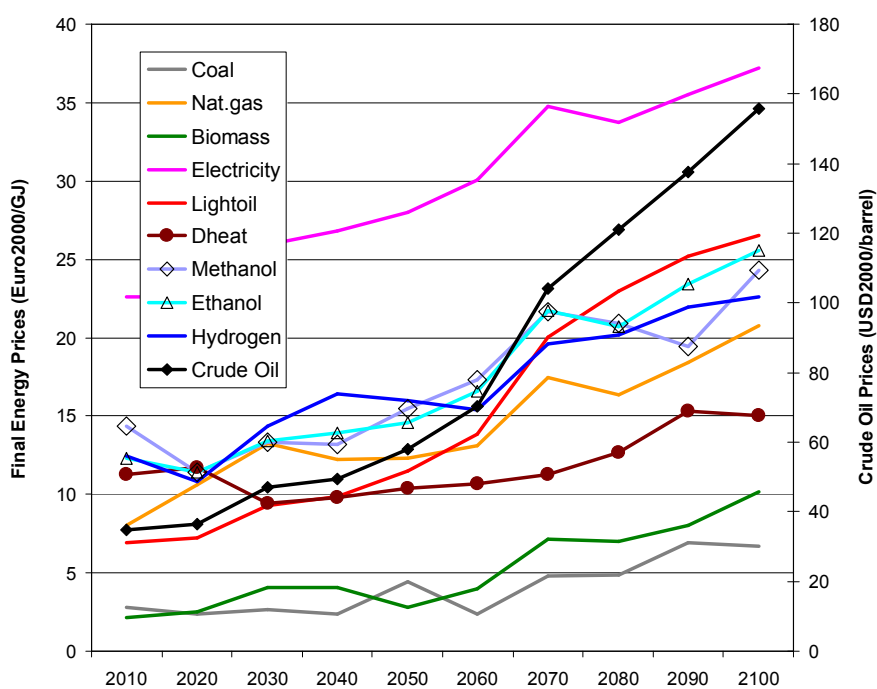


Figure D-50. Global energy prices.

In Figure D-50 the endogenous final energy prices from the baseline run are shown. The final energy prices (shadow prices of the MESSAGE model) for hydrogen do not rise as steeply as light oil prices.

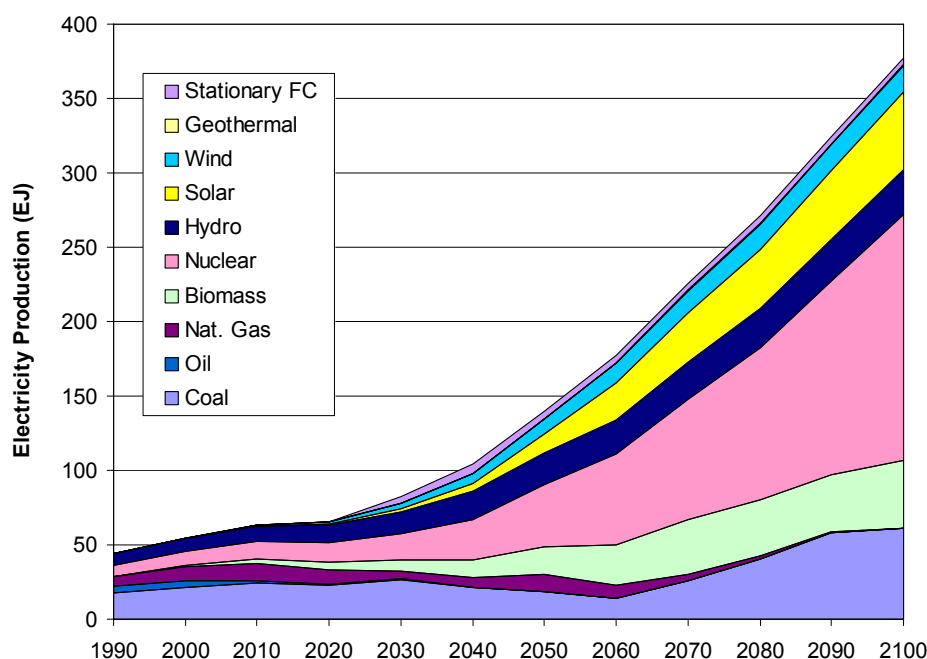


Figure D-51. Global electricity production including electricity for the grid and for H2 production.

In Figure D-51 global electricity production is shown for the baseline run. Large stationary natural gas fuel cell combined-heat-and-power plants are producing at a rather constant output of 4–7 EJ, starting in 2030. In 2100, 38% of the electricity from nuclear energy is used to produce hydrogen.

Table D-19. Global electricity production shares.

	1990	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Coal	40%	39%	39%	35%	32%	20%	13%	8%	11%	15%	18%	16%
Oil	11%	8%	3%	1%	0%	0%	0%	0%	0%	0%	0%	0%
Nat. Gas	14%	17%	18%	15%	7%	7%	8%	5%	2%	1%	0%	0%
Biomass	1%	1%	4%	8%	9%	11%	13%	16%	16%	14%	12%	12%
Nuclear	16%	17%	19%	20%	21%	26%	30%	34%	36%	38%	40%	44%
Hydro	18%	17%	16%	18%	18%	18%	15%	13%	11%	10%	9%	8%
Solar	0%	0%	0%	1%	3%	5%	9%	14%	15%	15%	14%	14%
Wind	0%	0%	1%	3%	4%	7%	7%	7%	7%	6%	6%	5%
Geothermal	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Stat. Fuel Cell	0.0%	0.0%	0.0%	0.0%	5.6%	6.4%	3.8%	3.0%	2.1%	2.1%	1.5%	1.2%
Share of Nuclear												
Nuclear-Grid	100%	100%	99%	98%	99%	97%	94%	90%	85%	79%	71%	62%
Nuclear-H2	0%	0%	1%	2%	1%	3%	6%	10%	15%	21%	29%	38%

The results in Figure D-52 showing the district heat supply are similar. Three different CHP sources are listed. The two fuel cell combined-heat-and-power plant types are shown separately. All other MESSAGE combined-heat-and-power sources are denoted by “CHP.” The contribution of large stationary fuel cell combined-heat-and-power plants using natural gas as fuel is rather constant at about 2.4–3.7 EJ.

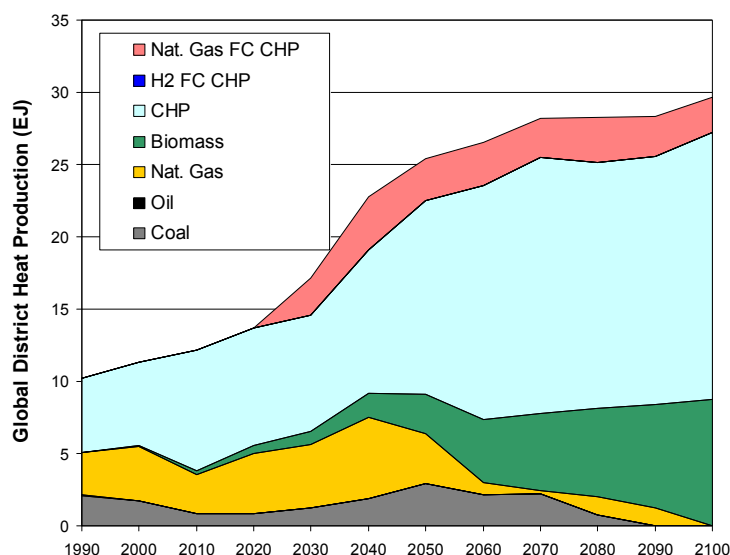


Figure D-52. Global district heating supply.

Table D-20. Global district heating supply.

	1990	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Coal	20%	15%	7%	6%	7%	8%	11%	8%	8%	3%	0%	0%
Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nat. Gas	29%	33%	22%	30%	26%	25%	14%	3%	1%	5%	5%	0%
Biomass	0%	1%	2%	4%	6%	7%	10%	16%	19%	22%	25%	29%
CHP	50%	51%	69%	59%	47%	44%	53%	61%	63%	60%	61%	62%
H2 FC CHP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nat. Gas FC CHP	0.0%	0.0%	0.0%	0.0%	15.0%	16.3%	11.6%	11.2%	9.5%	11.0%	9.8%	8.2%

Figure D-53 shows the global final energy demand. The share of hydrogen in the final energy supply is about 6% in 2100. As, however, fuel cell cars are about 3 times more efficient than conventional cars, the fact that this 6% share replaces a considerably larger share of conventional fuels has to be taken into account.

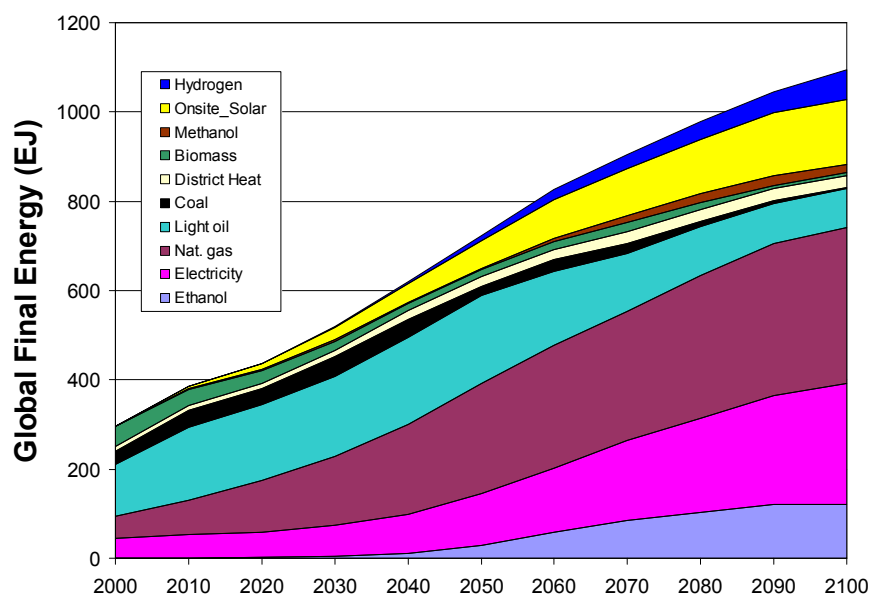


Figure D-53. Global final energy supply.

Table D-21. Global final energy shares.

	1990	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Ethanol	0%	0%	0%	0%	1%	2%	4%	7%	9%	11%	12%	11%
Electricity	13%	15%	14%	13%	13%	14%	16%	17%	20%	22%	23%	25%
Nat. gas	15%	17%	20%	27%	30%	33%	34%	33%	32%	33%	32%	32%
District Heat	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	2%	3%
Light oil	41%	39%	42%	39%	35%	31%	27%	20%	14%	11%	9%	8%
Coal	13%	10%	10%	8%	9%	6%	3%	3%	3%	1%	1%	0%
Biomass	16%	15%	9%	6%	4%	3%	2%	2%	2%	2%	1%	1%
Methanol	0%	0%	1%	1%	1%	0%	0%	1%	2%	2%	2%	1%
Onsite_Solar	0%	0%	1%	3%	5%	7%	9%	11%	12%	12%	13%	13%
Hydrogen	0.0%	0.0%	0.1%	0.2%	0.3%	0.8%	1.5%	2.7%	3.6%	4.0%	4.5%	6.1%

D.2.1.5 MERGE-ETL

[by S. Kypreos (PSI)]

In order to define the policy free reference scenario and to explain the consequence of the overlying policy assumptions of our analysis, we describe first the main characteristics of our baseline scenario, as quantified with the MERGE-ETL model.

The baseline scenario used for CASCADE-MINTS (CM) includes a climate policy in all regions, which was defined using a Delphi method among the participants of the SAPIENTIA project. This policy is incorporated as a time-dependent CO₂ tax in all regions. In this scenario, the EU leads the world climate abatement followed by lesser efforts in other industrialized regions. Developing regions undertake abatement efforts only after industrialized regions become active and their efforts are smaller than those in industrialized regions. Also, the baseline scenario presented here has been constructed using two key inputs: a) the common assumptions within the project regarding the Outlook for R&D effort directed to different technological options and b) the technology cost reduction defined in TECHPOL-EURO 2000 database. Applying Eq. 14 and considering the Outlook RD&D, new technologies develop and reach maturity to the cost levels described in the database of the project for the years 2025 and 2050. This calibration is the main challenge in the formulation of MERGE.

In conclusion: the time-series for RD&D spending by technology and the technology database created by the partners of the Cascade-Mints project are the key inputs needed to establish the storylines and the technology dynamics analyses foreseen in the project. The key underlying project assumption is that the Outlook R&D spending (Table C-29) is sufficient to induce the technical and economic performance described in the TECHPOL database as summarized by Table C-26, Table C-27, Table C-28.

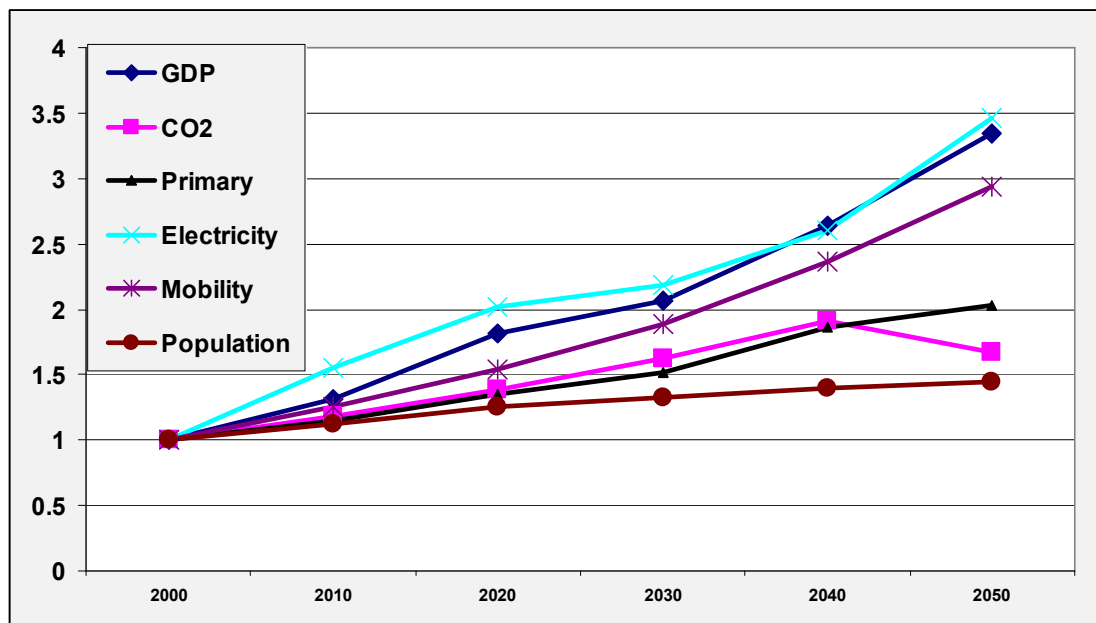


Figure D-54: Baseline indices relative to the year 2000.

The BASELINE estimates in MERGE correspond to the B2 world, i.e., the IIASA special scenario generated for the IPCC. In this scenario there is a significant growth assumed to take place in a world where the different regions converge in the long term to the same income per capita and the same energy use and emissions. Thus, there is more growth and emissions anticipated for the now less developed countries in relation with the industrialized countries. Figure D-54 lists the development of some key indices describing the scenario.

The economic growth is such that the overall development is more than a factor of 3.5 above the present economic output. Population is around 8.7 billion inhabitants by the year 2050 while the significant decoupling between energy use and economic growth results to an increase by only 2 times above the present energy use. Further more, the carbon emissions are increased by a factor of 2 while the CO₂-equivalent concentration is reaching levels of 550-600 ppmv by the middle of the 21st century. Electricity is substituting for fuels and assumes similar growth levels as GDP. Figure D-55 shows the energy use by fuel in this scenario. Oil and gas are deplete-able resources and their price increases such that coal, nuclear and renewables take over high shares in the energy markets.

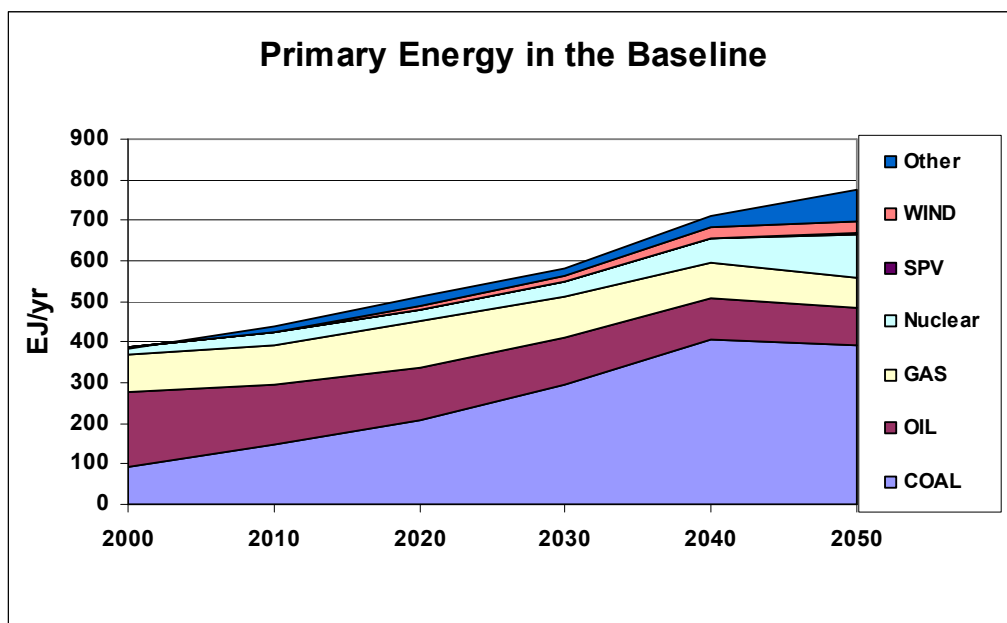


Figure D-55: Global Primary energy by fuel in the baseline between 2000 and 2050

By the year 2050, primary energy consumption reaches about 780 EJ, i.e. approximately doubles when compared with year-2000 levels. Although non-fossil energy resources increase their contribution significantly, fossil fuels still dominate the primary energy mix during the first half of the 21st century. Specifically, the use of coal significantly increases while gas remains less important and the share of oil becomes lower with time. Coal consumption is basically driven for electricity generation. Nuclear energy experiences a revival and its contribution grows significantly. Renewable energy use also expands dynamically during the 2000-2050 period.

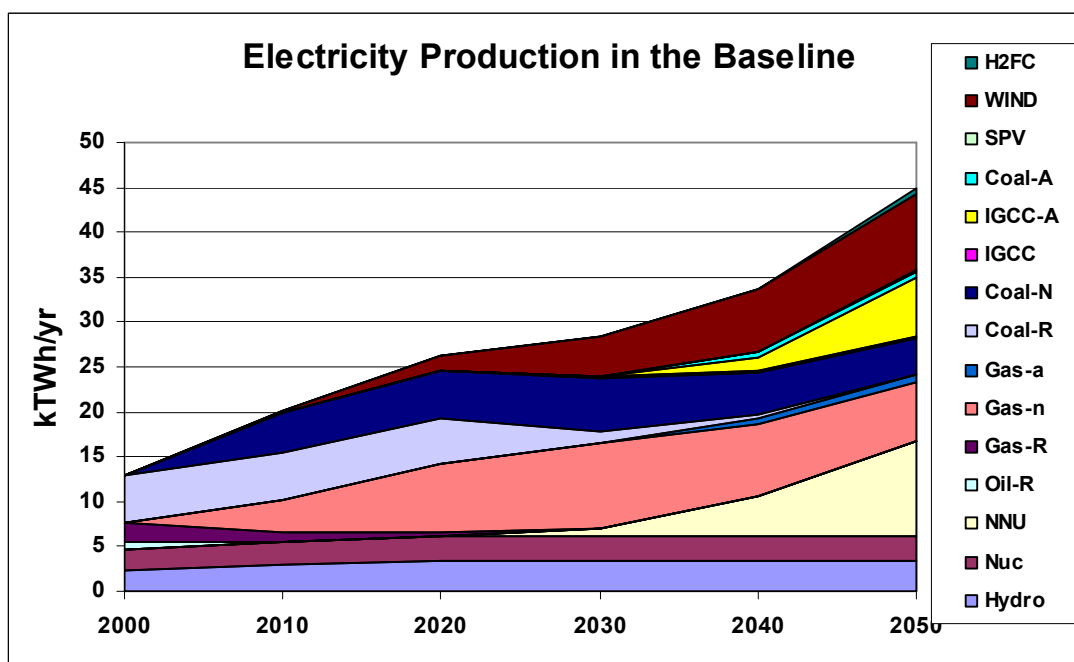


Figure D-56: World electricity generation by fuel in the baseline between the years 2000 and 2050.

Figure D-56 presents the global electricity generation mix by technology in the baseline scenario. Electricity generation increases substantially, reaching 3.5 times its levels in the year 2000. Electricity is gaining importance as key energy in the final energy markets while coal, nuclear and wind energy are the main input fuels for electricity production. As mentioned before, in this scenario coal-based power plants still experience a substantial growth but after the year 2025 the growth rate becomes negative. Moreover, in the new coal-based fraction of the electricity mix after 2025, a gradual transition occurs from conventional coal-fired plants towards more efficient and clean Integrated Gasification Combined Cycle (IGCC) plants with CCS technology. The contribution of natural gas increases, driven by the growth of highly efficient combined-cycle gas turbines and then lowers again. Nuclear power plants also experience a substantial increase along this 50-year period with improved conventional nuclear designs (inherently safe and more efficient advanced new reactor designs). Nuclear energy becomes by the end of the time horizon the first technology in power generation followed by coal, gas and wind. The reduced growth in power generation in the 20ies is explained by the high carbon taxes imposed on the global level.

Figure D-57 presents the technology mix in the global passenger car sector. While conventional and advanced internal combustion engines (ICE) based on oil products still dominate the passenger car mix to a large extent, during a first half of the 21st century, in the second half, their absolute number starts decreasing. Hybrid vehicles gradually gain some market shares first, followed by ICE burning hydrogen that experiences a dynamic growth accounting for about 22% of passenger car mobility in the year 2050. Electric vehicles (EV) and fuel-cell vehicles are locked out in the baseline

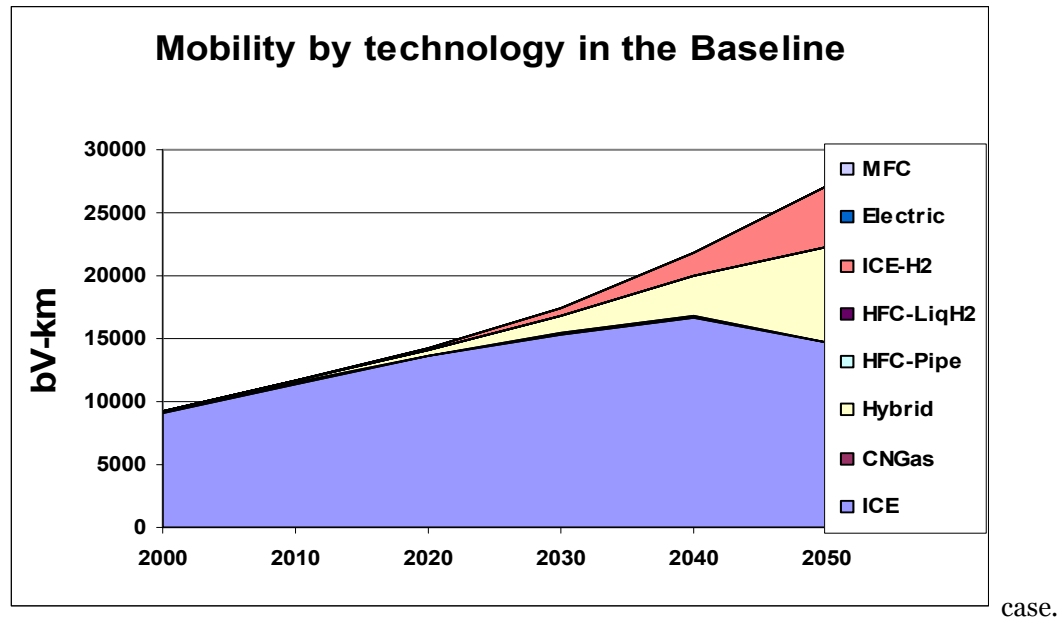


Figure D-57: World use of passenger cars (in billion vehicle-km travelled) for the baseline scenario between the years 2000 and 2050.

Figure D-58 presents the global CO₂ emissions in the baseline scenario by region. Under the influence of increasingly stringent climate-change policies around the world, CO₂ emissions still grow linearly with time. By the year 2040, the annual CO₂ emissions are approximately 12.2 Gigatons of carbon (GtC), which

represents about a doubling relative to their levels of the year 2000. Afterwards the emission level falls-back to 10.5 GtC/yr. The bulk of emissions growth comes from developing regions and, specifically, developing ASIA and the rest of the world (RoW). CO2 emissions in currently industrialized regions, where the most stringent carbon price signals are imposed, decline in the long term.

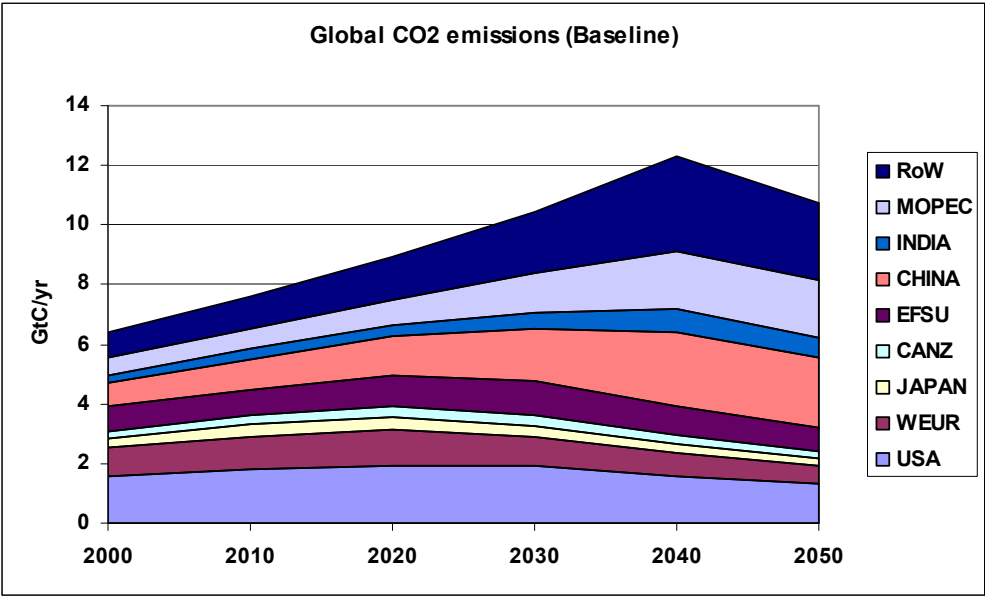


Figure D-58: Global CO2 emissions by region in the baseline scenario.

Figure D-59 depicts the atmospheric concentrations of CO2, CH4 and N2O and other GHGs for the period 2000 to 2050 as computed with MERGE. In the baseline scenario, the atmospheric concentration of CO2 reaches approximately 550 parts per million in volume (ppmv) in the year 2050 while the overall CO2-equivalent concentration reaches the levels of 600 ppmv with increasing trends.

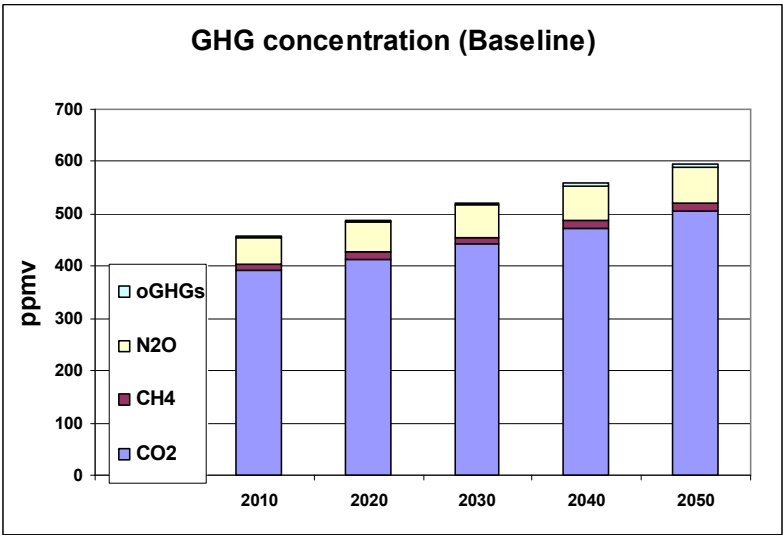


Figure D-59: Atmospheric concentration of three greenhouse gases (CO2, CH4 , N2O and other GHGs) in the baseline scenario. Notice that the assumed tax is applied only on carbon emissions.

Figure D-60 presents the global, post-industrial, average temperature change in the baseline scenario. The temperature change for the year 2000 is assumed to be 0.65 °C. Under this scenario, the global temperature change reaches about 2° C in 2060 with increasing trends. It must be emphasized that huge uncertainties exists on this estimate, related to climate sensitivity, radiative forcing of aerosols and the simplified formulation of the climate sub-model used, among others.

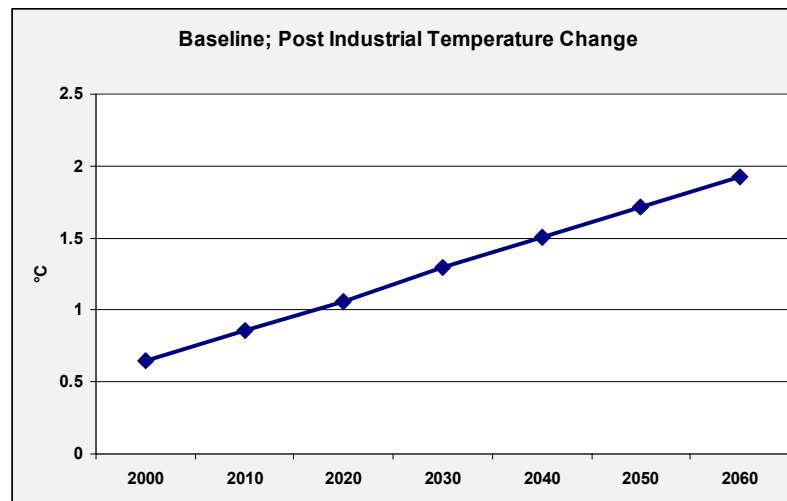


Figure D-60: Post Industrial global annual-average temperature change in the baseline scenario.

D.2.1.6 PACE-T-H2

[by S. Jokisch (ZEW)]

The baseline development in PACE-T(H2) is principally calibrated on the GTAP5 database (GTAP, 2002). In a first step, the model assumes a uniform steady state growth path where the growth rate is set to 2.3% and the interest rate is 5%. Afterwards, PACE-T(H2) is recalibrated to the European Commission's business-as-usual assumptions on non-uniform growth rates for GDP as well as projections on fossil fuel production and use (the latter determining the carbon emissions) (European Commission, 2003). Autonomous energy efficiency improvement (AEEI) factors are employed which scale energy demand functions in order to match GDP forecasts with the energy production and consumption projections.

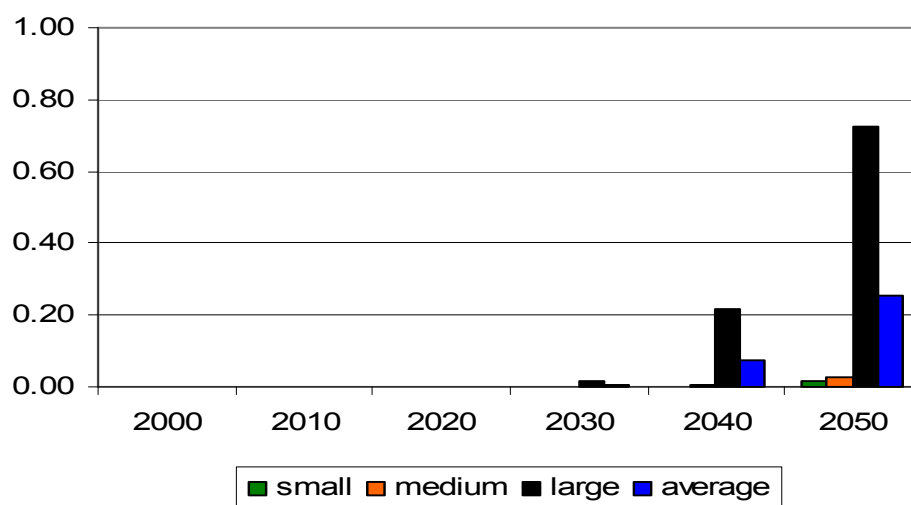
In addition to this top-down approach, the model needs further input data on conventional and hydrogen end-use technologies as well as on hydrogen production, distribution and storage technologies. This bottom-up data is mainly calculated from the output of the energy-system model MARKAL provided by ECN. We adopt the overall size of the conventional car categories (small, medium, large) from MARKAL and compute conventional car costs as weighted averages of diesel and gasoline cars. Annual fuel expenses in Euro per car are derived by multiplying fuel costs per litre by average fuel input (in litre) per car per year. Fuel costs are discounted and aggregated over the car's lifetime. Consumer fuel prices consist of net prices plus fuel taxes.

Fuel taxes in Europe are set to 0.50 Euro per litre and are assumed to be constant over time. The remaining costs that are incurred during the vehicles' lifetimes are subsumed under "other costs". They consist of O&M costs as well as costs for the delivery of fuel. Technology costs for hydrogen cars are calculated similar to conventional cars. We however adopt the information on hydrogen fuel cell cars from the TECHPOL database in order to reach hydrogen car costs, fuel consumption and other costs expressed relative to conventional car costs. Again, we make similar calculations to reach investment, fuel and other costs for the heating applications at the household level. In order to reach the cost development for the aggregate hydrogen production technology in PACE-T(H₂), we calculate average costs for hydrogen production, distribution and storage based on the activities of the various hydrogen technologies in the MARKAL scenario output. Consequently, hydrogen in the baseline scenario is produced from central coal gasification and gas steam reforming. The distribution of hydrogen is done mainly via local pipeline networks and trailers. Assuming average cost pricing and no taxes on hydrogen, the derived production costs are directly used to generate hydrogen car fuel costs.

Finally, we calibrate the model to the exogenous oil price path of the POLES model and implement the baseline carbon taxes of the SAPENTIA project.

Given the cost developments of conventional and hydrogen technologies, we reach hydrogen penetration rates in overall new cars as shown in Figure D-61.

Figure D-61: Hydrogen penetration rates in new cars (baseline)



Obviously, hydrogen cars do not penetrate before 2030. This finding of course reflects the large cost disadvantage of hydrogen cars in the years before 2030. Even if hydrogen car costs decrease immensely in the coming decades, this decrease will not be enough to make hydrogen cars competitive in the baseline without further policy interventions. As soon as the lifetime costs of hydrogen cars come fairly close to those of their conventional counterparts or even fall short off those, conventional cars are more and more substituted by hydrogen cars. Consequently, hydrogen penetration in 2030 is 1.4% in the large car segment while it is still zero for small and medium cars. From 2040 onwards, hydrogen cars start to penetrate in the

small and medium size classes, too. Thus in 2050 penetration rates amount to 1.5% for small cars, 2.5% for medium cars and 72.7% for large cars. On average, 25.6% of overall new cars in 2050 will be powered by hydrogen.

On first sight it might seem surprising that there is such a large share of hydrogen cars in the large car segment. The reason for this development is threefold. First, due to their much higher fuel consumption large cars are hurt relatively more by the assumed increase in oil prices over time in the baseline compared to their small and medium counterparts. Second, large cars face a higher fuel tax burden. Third, the imposed carbon tax in the baseline also leads to higher expenditures for large cars associated with the higher fuel consumption. Since fuel consumption of hydrogen cars is much lower than that of conventional cars, fuel expenditures over a hydrogen car's lifetime are much lower compared to gasoline/diesel cars. Large cars become relatively cheaper for the consumer than small or medium cars and therefore reveal larger hydrogen penetration.

Note that in none of the considered baseline and policy scenarios hydrogen penetrates the micro heating installations at household level. The reason for this is that – according to the available data – costs of hydrogen based heating systems do not decrease sufficiently but stay on a relatively high level compared to fossil fuel based heating installations. We therefore abstain from any explanations on these stationary uses.

D.2.2 Stochastic Evaluation of Hydrogen Economy Prospects using PROMETHEUS

[by N. Kouvaritakis and V. Panos (ICCS-NTUA)]

The discussion in D.2.1 concerns the analysis of hydrogen prospects in a deterministic context. This is a case irrespective of the model logic (simulation, myopic optimisation, perfect foresight). Using such models uncertainties can be explored in the form of contrasting scenarios. Such exploration, however, is not systematic in that it makes no attempt at evaluating the likelihood of different occurrences: it explores possibilities but not probabilities.

The main objective of this chapter is to perform a stochastic evaluation of hydrogen economy prospects. It proceeds with a systematic evaluation of the risks (and opportunities) facing the evolution of the hydrogen economy in an attempt to make an assessment as to how likely different paths towards it are. In this way risks that are specific to hydrogen technology evolution are confronted with an exhaustive range of risks associated with other key elements of the energy system including uncertainties due to lack of precise knowledge of the system itself.

The basic output of PROMETHEUS is a data set of Monte Carlo simulations containing values for all the variables in the model. This constitutes an extensive set of information containing the equivalent of the distillation of a very large number of alternative scenarios involving alternative assumptions about activity levels and structures, resource availabilities, prices, policy stances on various issues (notably the climate change issue) and crucially technological developments while considering at the same time the fact of the

imperfection of the modelling itself (omitted variables that can generate considerable “noise”, measurement problems etc.). It therefore provides a large set of probable visions of the hydrogen economy both in terms of the extent to which it may transform the energy system but also alternative paths for an eventual transition. In addition it enables the probabilistic evaluation of these alternatives thus adding an extra dimension to scenario analysis. Wherever it is thought analytically important specific attention is given to issues of covariance (the dependence of the variability of one variable on the variability of another). The key addition provided to the overall analysis in CASCADE-MINTS is to give a probabilistic dimension to the results discussed in D.2.1 and this chapter emphasises this aspect. On the other hand, the notion of probability, by adding another dimension to results, increases considerably the complexity of the presentation. Though considerable effort has been devoted in choosing meaningful thresholds to be evaluated it is inevitable that occasionally the presentation that follows appears rather indirect.

The general structure of the chapter is to proceed to the extent that is possible from the general to the specific. It begins with an evaluation of the main drivers influencing world energy system development (section 1) then proceeds to discuss broad implications on primary and final energy needs (section 2). Given the importance of technological developments for hydrogen prospects section 3 specifically addresses technology dynamics. Section 4 looks at the penetration of hydrogen related technologies within the different energy consuming sectors, while section 5 draws the hydrogen balance and examines the possibilities for hydrogen production, distribution and costs.

Drivers and constraints to world development

This section performs a brief uncertainty analysis on the main drivers influencing world energy system development namely, population growth, economic activity, oil and gas reserves and climate policy.

Population trends

World population is expected to increase in the next 50 years (Table D-22) ²³, but at lower rates compared to the period 1971-2000. It is unlikely to observe a higher average annual growth rate in the period 2005-2050 than the historical one in all regions.

Moreover, a deceleration in the period 2030-2050 is expected; the probability that world population will grow faster in that period compared to 2005-2030 is almost nil.

²³ In PROMETHEUS the “EU-15” region consists of EU-15 members plus Norway and Switzerland. The “NMS-12” region includes the European countries joined the European Union after May 2004. The “Rest of OECD” region includes the USA, Canada, Japan and Australia. The EU-27 region, also referred as “Europe”, is the aggregate region including all EU-15 and NMS-12 countries. Finally the “Developing countries” region consists of all countries not including in “EU-27” and “Rest of OECD” regions.

This deceleration which in PROMETHEUS analysis takes the form of low probabilities of attaining historical growth, is predicated on secular trends (evident over a number of years) suggesting an aging of the world population and a natural decline in fertility rates in the less developed regions.

Table D-22: Summary statistics for population average annual growth rate in the period 2005-2050 [%]
2005 -2050

	EU-27	EU-15	NMS-12	Rest of OECD	Developing countries	World
Mean	-0.03	0.09	-0.57	0.41	0.89	0.80
Median	-0.03	0.09	-0.57	0.41	0.89	0.80
Std. Dev	0.11	0.12	0.27	0.15	0.20	0.18
Lower 5%	-0.22	-0.12	-1.01	0.14	0.56	0.50
Upper 5%	0.14	0.26	-0.12	0.65	1.22	1.09
<i>Historical of 1970-2005 [%]</i>	<i>0.32</i>	<i>0.34</i>	<i>0.23</i>	<i>0.95</i>	<i>1.83</i>	<i>1.61</i>
<i>Probability to exceed historical [%]</i>	<i>0.10</i>	<i>0.98</i>	<i>0.49</i>	<i>0.10</i>	<i>0.00</i>	<i>0.00</i>

It should be noted that PROMETHEUS mean values for Europe are consistent with the UN medium fertility population projections (“UN World Population Prospects: The 2006 Revision”)

Economic activity

A decrease in the average annual growth rate of GDP per capita for the developed world, compared to the observed growth in 1971-2005, is expected. On the other hand in the Less Developed Countries a rapid increase is expected (Table D-23).

The probability that the average annual growth rate in GDP per capita in the developed world for the period 2005-2050 will be higher than the historical observed is 10% (Europe 26%, Rest of OECD 7%).

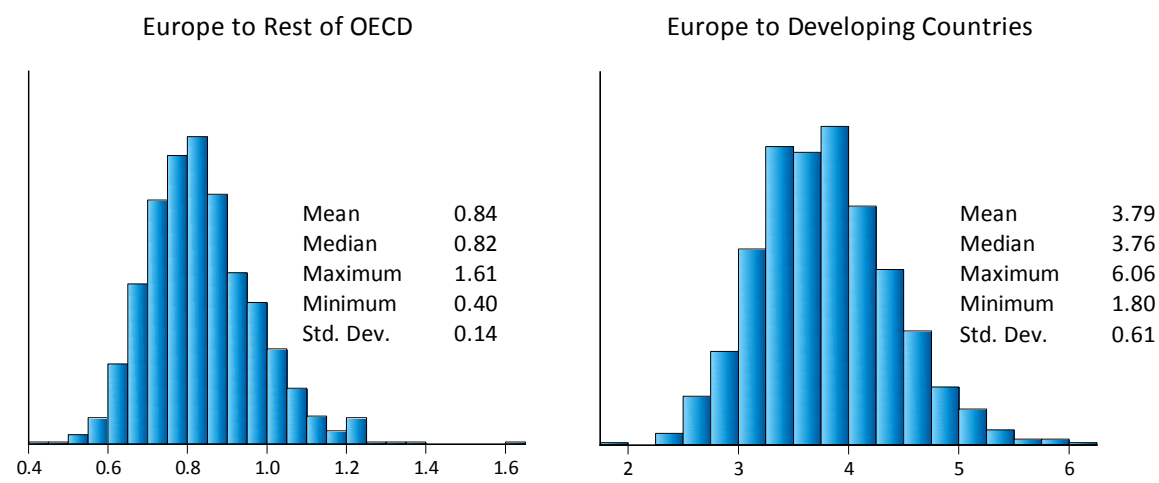
Table D-23: Summary statistics for GDP per capita average annual growth rate in the period 2005-2050 [%]
2005 -2050

	EU-27	EU-15	NMS-12	Rest of OECD	Developed countries	Developing Countries	World
Mean	1.81	1.62	2.83	1.36	1.59	2.48	1.88
Median	1.82	1.63	2.82	1.35	1.56	2.48	1.87
Std. Dev	0.37	0.38	0.47	0.56	0.46	0.33	0.33
Lower 5%	1.20	1.00	2.07	0.48	0.84	1.91	1.34
Upper 5%	2.40	2.24	3.60	2.29	2.35	3.00	2.43
<i>Historical of 1970-2005 [%]</i>	<i>2.06</i>	<i>2.01</i>	<i>2.37</i>	<i>2.18</i>	<i>2.18</i>	<i>2.83</i>	<i>1.92</i>
<i>Probability to exceed historical [%]</i>	<i>25.59</i>	<i>14.75</i>	<i>83.50</i>	<i>7.32</i>	<i>9.77</i>	<i>13.87</i>	<i>44.92</i>

Figure D-62, presents the distributions of the ratios of GDP per capita in Europe and Developing countries and the Rest of OECD respectively. The analysis suggests that Developing countries are gradually converging to Europe but are unlikely to reach the European GDP per capita even in 2050. The probability that the GDP per capita in Europe would be more than 5 times the per capita income of Developing countries (the value for

2005) is only 3.2% implying a low probability of divergence. However, the probability that the GDP per capita in Developing countries will be higher in 2050 than the GDP per capita in Europe in 2005 is 0%.

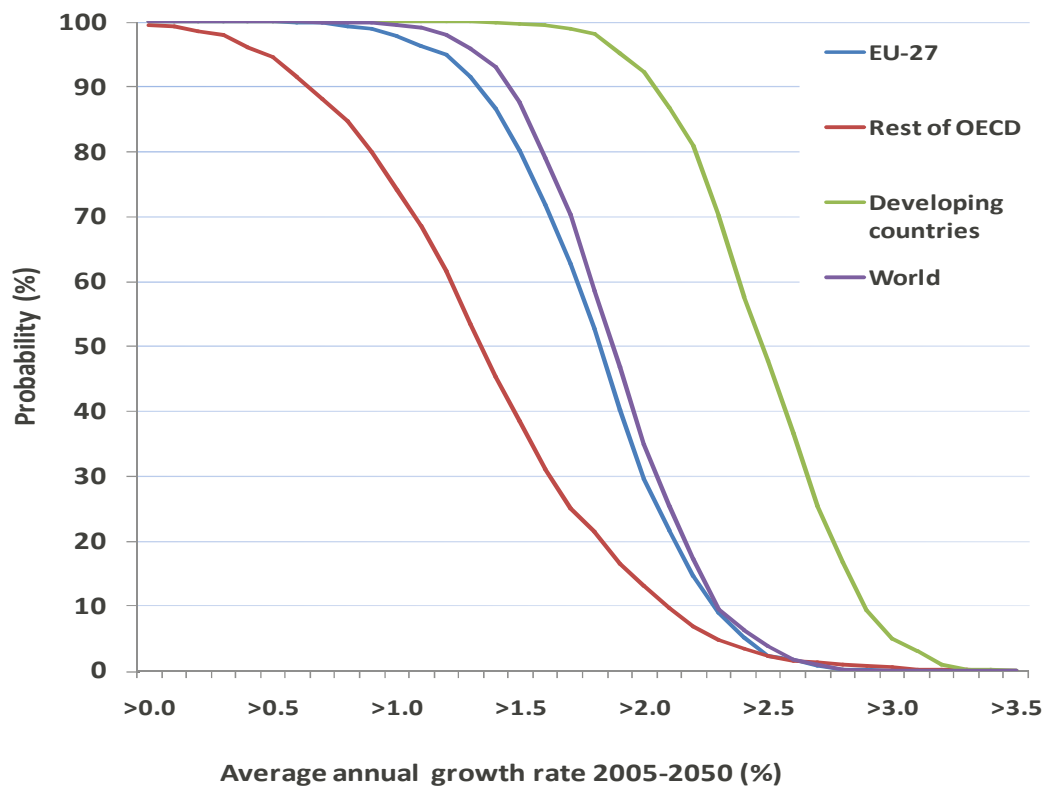
Figure D-62: Distribution of the ratios of the GDP per capita in Europe and in the other regions in 2050



Comparing Europe with North America, Japan and Australasia, the probability that Europe will develop at a slower rate than these countries is 11.1%. On the other hand, there is also an 88% probability that the GDP per capita in Europe will still be lower than the average for these countries in 2050.

Figure D-63 shows the cumulative distribution of the average annual growth rate of the GDP per capita in all three regions and in the world. These results are consistent with a general trend of diminishing marginal productivity of capital, labour and knowledge.

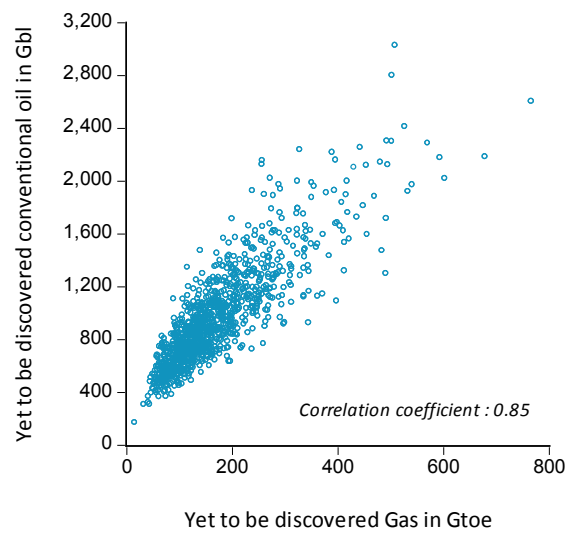
Figure D-63: Cumulative distribution of GDP per capita average annual growth rate in the period 2005-2050



World oil and gas reserves and supply

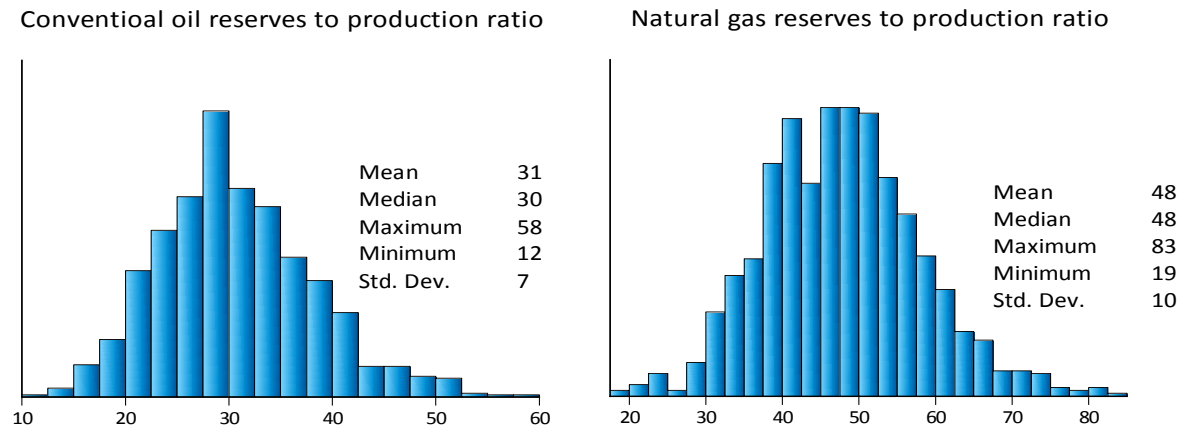
High uncertainty surrounds the amount of oil and gas that is yet to be discovered. This uncertainty has been incorporated into PROMETHEUS. Using studies conducted by USGS, stochastic analysis has been carried out in order to obtain distributions for the yet to be discovered oil and gas at the starting year of simulation. The two variables are not statistically independent i.e. there is a considerable amount of correlation between the unknown quantities of gas and oil due to geological factors (uncertainties on hydrocarbon formation and retention in sedimentary basis) (Figure D-64). In each Monte Carlo experiment, PROMETHEUS begins from a different state of the world regarding these variables. The rate of discovery as well as the rate of recovery is endogenous in PROMETHEUS depending on fuel prices and subject to their own specific uncertainties. For gas it is also assumed that often oil is sought and gas is found.

Figure D-64: Scatter graph of the yet to be discovered conventional oil and gas in the starting year of PROMETHEUS simulations



In 2005 the oil R/P ratio was 40 years up from 23.5 in 1977 (the year of its lowest historical value). According to PROMETHEUS results the probability of exceeding the 1977 figure in 2050 is 84%, while the probability of exceeding the 2005 value is only 11%. Gas R/P ratios have been more or less steadily increasing in the last 30 years from around 57 to around 63 years. The probability of exceeding present R/P ratios in 2050 is only 11%. Figure D-65 presents the distribution of conventional oil and gas reserves to production ratios in 2050.

Figure D-65: Distribution of fossil fuels world reserves to production ratio in 2050



Non-conventional oil is expected to increase its share in the world oil production in 2050 as it compensates for the continuous decline in non-Gulf oil production (Table D-24). There is a 5% probability that 61% of world oil production in 2050 comes from non-conventional oil. The importance of non-conventional oil raises issues related to CO2 emitted during the recovery and processing of non-conventional oil, which are not taken into account by models.

Table D-24: Share of conventional and non conventional oil in total oil production (%)

	2005		2030		2050	
	Conventional Oil	Non-conventional	Conventional Oil	Non-conventional	Conventional Oil	Non-conventional
Mean	98.8	1.2	77.5	22.5	54.9	45.1
Median	-	-	78.3	21.7	53.9	46.1
Std. Dev	-	-	4.3	4.3	11.0	11.0
Lower 5%	-	-	69.5	17.6	38.8	28.1
Upper 5%	-	-	82.4	30.5	71.9	61.2

International fuel prices

The PROMETHEUS baseline projects high oil and gas price means in 2050 (Table D-25), 120 €/bbl for oil and 102 €/bbl for gas. Looking at the uncertainty in price evolution, by taking the ratios of the standard deviation to mean, it can be observed that in the more distant year the uncertainty is much higher. To aid the analysis, some probabilities for oil, gas and coal are given below, which are supplementary to lower and upper quantiles presented in the table:

- The probability that the oil price will exceed 100 €/bbl in 2050 is 65%; the probability that the oil price will be less than it was in 2005 is only 2%.
- The probability that the gas price will exceed the 100 €/bbl is 46%; the probability to be lower than it was in 2005 is nil.
- The probability that the coal price will be higher than 20 €/bbl (approximately 100 €/tn) is 20%. The probability that coal prices will be lower than they were 2005 is 30%.

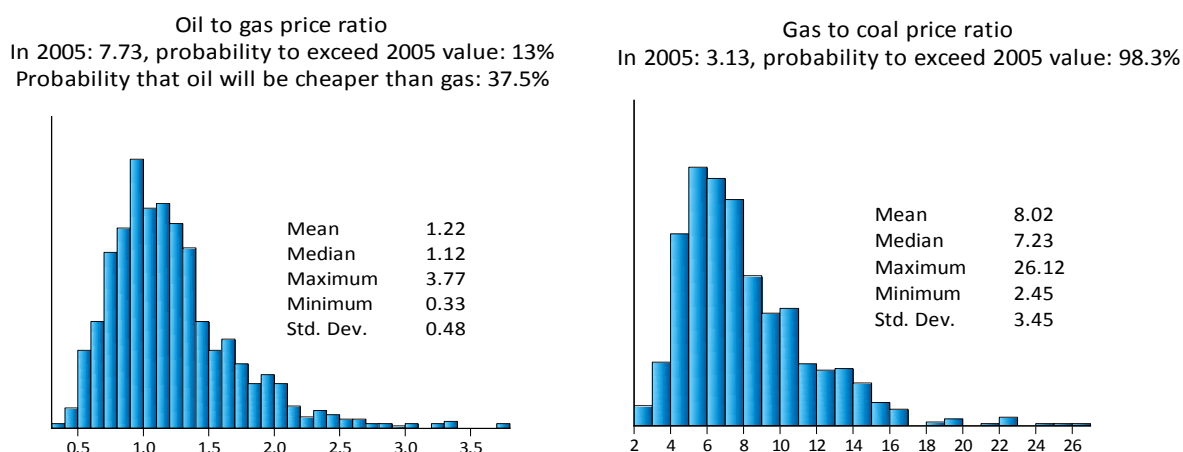
Table D-25: Summary statistics for international fossil fuel prices in €/bbl per barrel of oil equivalent

	2005			2030			2050		
	Oil	Gas	Coal	Oil	Gas	Coal	Oil	Gas	Coal
Mean	57	33	11	72	55	13	121	103	15
Median	-	-	-	70	53	12	113	96	14
Std. Dev	-	-	-	19	14	3	44	39	8
Lower 5%	-	-	-	47	36	8	65	56	7
Upper 5%	-	-	-	108	81	19	208	177	30
<i>Probability to be lower than 2005</i>	-	-	-	21.4%	2.7%	28.1%	2.0%	0.0%	29.8%
<i>Probability to exceed 100€/boe(*)</i>	-	-	-	9.3%	0.8%	2.5%	64.6%	45.8%	19.8%

* 100€/boe for oil and gas, 20€/boe for coal

Figure D-66 presents the distributions of oil to gas price ratio and the gas price to coal price ratio. According to distributions, the probability that the gas price is more expensive than oil in 2050 is 63%. Moreover, the probability that the oil price to gas price ratio will exceed the 2005 ratio is 13%. Regarding the gas price to coal price ratio the probability to exceed the 2005 ratio is 98%.

Figure D-66: International prices ratios (oil to gas and gas to coal) in 2050



Deterministic analysis is ill suited to address directly security of supply issues and must resort to indirect measures such as import dependence and fuel diversification in order to assess security implications. It is clear however that a high import dependence does not necessary imply a deterioration in security since a lot will depend on the stability and reliability of the exporting region. Furthermore in a world of potentially abundant resources even dependence on insecure sources could represent a relatively minor risk if alternative and more secure sources can be activated within a reasonable time frame. Likewise poor fuel diversification does not always represent a security issue when it implies concentration on relatively secure alternatives. It is clear that the notion of risk (probability of damage) is central to security of supply considerations and the more directly it is addressed the more appropriate the analysis becomes.

PROMETHEUS is capable of carrying the analysis forward and addresses risk issues by providing analytical answers to questions of the type: what is the probability that dependence on an insecure source will exceed a given threshold at some point in the future? Or more appropriately: what is the probability that an imported fuel price or total fuel costs increase by more than an elevated (and damaging) rate in any three-year period?

PROMETHEUS is capable of addressing such questions by synthesising risks associated with World and regional fuel demand growth, geological uncertainties regarding the extent and geographical distribution of undiscovered resources (together with their interrelations) and the risk of supply disruptions expressed in terms of random reductions of productive capacity especially in the less stable regions of the World. Geological uncertainties are mostly measured using expert assessments and notably reports of the US Geological Survey. For risks disruptions of a “political” nature historical evidence is used under the neutral assumption (which is not invalidated by statistical tests) that such risks have not exhibited statistically significant increases or diminutions over several decades.

The measure of security of supply presented here is the maximum increase in oil and gas price average in any 3-year period of the forecast horizon (Table D-26). According to PROMETHEUS results, there is a 79% probability that the maximum oil and gas average price in any 3-year period in the next 50 years will be higher than the price increase observed in the oil crisis period 1978-81 (Iranian revolution and Iran-Iraq war); the price increase in that period was around 45 €/05/bl.

Table D-26: Maximum increase in oil and gas price average in any 3-year period in the next 50 years

	€05/boe
Mean	66
Median	59
Std. Dev	27
Lower 5%	32
Upper 5%	122
<i>Increase in 1979-81</i>	<i>45</i>
<i>Probability to exceed this increase</i>	<i>79%</i>

The above results indicate that there are significant probabilities to observe international fossil fuel prices that are considerably higher than the levels of today. Gas is expected to be an expensive fuel in the future and there is a considerable probability that it will be more expensive than oil. Sharp increases in oil and gas prices in any 3-year period are very likely to happen in the next 50 years and there is a noteworthy probability to be higher than in period '78-81.

Climate policy

Assuming no policy response in the PROMETHEUS baseline would be equivalent to stating that there is no probability of such policy anywhere in the World for the next 50 years. Such an assumption alters the PROMETHEUS results from “maximum likelihood” to conditional distributions. The intensity of climate policy is endogenous in PROMETHEUS and is assumed to adapt albeit uncertainly and with considerable lags to climate change signals.

Since no truly scientific expertise regarding the timing, extent, nature and probability of climate policies is really available, it was decided to resort to a Delphi type methodology (among SAPIENTIA project partners) in order to derive the essential input. In terms of the methodology, the climate policy effort is measured through the introduction of an implicit carbon value (reflecting a carbon tax or the price of the permit in an emission quotas trading system) which instead of focusing on imposition of international targets and associated climate regime, concentrates on the impacts of emission reduction policies on technology development, independently of distributional impacts associated with allocation of emission targets/permits. The alternative options, such as the introduction of a given emission profile at the regional or global level or the use of a GHG emission constraint would render model implementation much more complex and the policy definition highly dependent on the Baseline and its attributes. Assuming a target that is met would also violate the basic logic of PROMETHEUS, which must allow for failure to meet the given target.

The climate policy scenario adopted assumes that the EU leads the world climate abatement effort, followed by lesser efforts in other industrialized regions. Developing regions undertake abatement efforts only after industrialized regions do and their efforts are smaller or equal to those in industrialized regions.

Table D-27 presents the summary statistics of the average carbon value in all regions for the period 2005-2050. The average carbon value has been calculated by taking into account the effective carbon value in each region weighted by CO₂ emissions. According to PROMETHEUS, the joint probability that Developing countries and Rest of OECD will not exercise a climate policy in the whole period 2005-2050 is 5%.

Table D-27: Summary statistics of the average carbon value for the period 2005-2050 in €/t of CO₂

	Europe	Rest of OECD	Developing countries	World
Mean	49	31	13	18
Median	47	27	8	13
Std. Dev	24	21	15	14
Lower 5%	16	3	0	4
Upper 5%	92	73	44	47

Energy consumption

In the present section the emphasis is given on the probabilistic assessment of the main endogenous variables, which are grouped in terms of primary consumption and final consumption. In view of the importance of the road transport sector for the prospects of the hydrogen economy it is treated in somewhat greater detail.

Primary consumption

Table D-28 presents the summary statistics for the average annual growth rates for total primary consumption and energy intensity indicator in each region and in the world for the period 2005-2050. It should be noted that traditional biomass consumption has not been taken into account in the calculation of total primary consumption. At the global level, the average annual growth rate of total primary consumption is expected to gradually slow down in the next 50 years. The historical observed average annual growth rate for the period 1971-2005 has 13% probability to be exceeded in the period 2005-2050.

In the developed world, there is small probability that the average annual growth rate of total primary consumption will exceed the one observed in history (1971-2005). Although naturally energy consumption in Developing countries grows on average much faster, a slowdown is also evident in this region since the probability to exceed their historical average annual growth rate is around 2.7%. This results from improvements in efficiency, continuing structural change and de-materialisation of production, the gradual introduction of effective climate policies (especially in Europe) and of course the slowdown in economic growth which, as discussed in the previous section, is expected with particularly high probabilities.

The different regional dynamics in primary consumption result in a reduction of the share of the developed world in total primary consumption from its 2005 levels. Although in 2005 the share of the developed world was higher than the Developing countries (around 51%), in 2050 the probability that the developed world will still have the highest share is zero. Moreover, the probability that the share of Developing countries in total primary consumption will be higher than 2/3 is 95%, while the probability to be more than 3/4 is 44%.

The above implies high probabilities of virtual Developing countries dominance of the world energy system in 2050.

In all regions energy intensity improvements are expected and the probability that over the whole period energy intensity will deteriorate is assessed at zero. In fact PROMETHEUS projects faster improvements in Europe compared to the rest of OECD (a reversal of trends observed in the period 1971-2005). The probability of Europe performing better than the Rest of OECD over the whole forecast period is estimated at 68%. The main reason for this reversal is the probability of a much higher climate policy intensity in Europe.

Regarding primary consumption by energy source at the world level, the following can be noted:

- Despite rising carbon values, coal consumption is expected to increase faster than oil and gas. There are three main reasons explaining this result. The first is the high oil and gas prices. The second is that China and India have large coal resources and according to PROMETHEUS results and in view of development requirements it is unlikely that they will desist from their exploitation in view of paucity of large scale alternative energy sources. The final reason is the high likelihood of cost effective coal based CO₂ capture technologies for electricity and hydrogen production.
- Natural gas progressively is turned into an expensive energy form due to increasing scarcity resulting in higher prices.
- In sharp contrast to the rapid increase in coal, oil consumption decreases in the developed countries. This is due to higher prices, as a result of the reduction in the non-Gulf conventional oil production and the penetration of the more expensive non-conventional oil, coupled with saturation effects in the transport sector (slow down in the increase of car ownership, lower utilisation rates and competition from non conventional transport modes). In the developing world there is a small increase resulting from large scale motorisation and despite loss of share of oil in non-transport sectors due to very high prices.

Table D-28: Summary statistics for primary consumption, shares in world consumption and energy intensity

Europe

	% Average annual growth rate of primary consumption (2005-2050)					% Share in world consumption in 2050	% average annual growth in energy intensity
	Total	Coal	Oil	Gas	Other [1]		
Mean	0.16	0.80	-0.55	-0.63	1.13	9.1	-1.54
Median	0.15	0.85	-0.55	-0.61	1.11	9.1	-1.54
Std. Dev	0.30	0.69	0.32	0.52	0.43	1.4	0.18
Lower 5%	-0.31	-0.32	-1.08	-1.51	0.47	6.9	-1.84
Upper 5%	0.64	1.87	-0.03	0.16	1.84	11.5	-1.26
<i>Historical of 1971-2005</i>	<i>1.00</i>	<i>-0.99</i>	<i>0.05</i>	<i>4.08</i>	<i>6.43</i>	<i>18.6</i>	<i>-1.32</i>
<i>Probability to exceed historical</i>	<i>0.49</i>	<i>98.93</i>	<i>3.22</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>9.28</i>

Rest of OECD

	% Average annual growth rate of primary consumption (2005-2050)					% Share in world consumption in 2050	% average annual growth in energy intensity
	Total	Coal	Oil	Gas	Other [1]		
Mean	0.25	-0.26	-0.91	0.05	2.41	16.8	-1.45
Median	0.22	-0.15	-0.94	0.07	2.34	16.5	-1.46
Std. Dev	0.47	1.15	0.51	0.63	0.71	3.2	0.19
Lower 5%	-0.45	-2.22	-1.71	-1.00	1.35	12.3	-1.76
Upper 5%	1.11	1.47	-0.02	0.99	3.64	22.4	-1.12
<i>Historical of 1971-2005</i>	<i>1.39</i>	<i>2.18</i>	<i>0.82</i>	<i>0.61</i>	<i>5.81</i>	<i>32.5</i>	<i>-1.68</i>
<i>Probability to exceed historical</i>	<i>1.86</i>	<i>0.59</i>	<i>0.10</i>	<i>18.65</i>	<i>0.00</i>	<i>0.29</i>	<i>88.96</i>

Developing countries

	% Average annual growth rate of primary consumption (2005-2050)					% Share in world consumption in 2050	% average annual growth in energy intensity
	Total	Coal	Oil	Gas	Other [1]		
Mean	2.72	2.54	1.51	2.99	5.57	74.1	-0.54
Median	2.71	2.73	1.50	3.01	5.51	74.4	-0.54
Std. Dev	0.39	0.82	0.44	0.52	0.77	4.1	0.23
Lower 5%	2.05	0.91	0.83	2.10	4.40	66.9	-0.92
Upper 5%	3.36	3.55	2.24	3.79	6.90	80.2	-0.18
<i>Historical of 1971-2005</i>	<i>3.51</i>	<i>3.46</i>	<i>3.34</i>	<i>3.29</i>	<i>6.85</i>	<i>48.9</i>	<i>-1.13</i>
<i>Probability to exceed historical</i>	<i>2.73</i>	<i>7.42</i>	<i>0.00</i>	<i>29.20</i>	<i>5.86</i>	<i>100.00</i>	<i>99.41</i>

World

	% Average annual growth rate of primary consumption (2005-2050)					% average annual growth in energy intensity
	Total	Coal	Oil	Gas	Other [1]	
Mean	1.78	1.95	0.64	1.57	3.63	-0.80
Median	1.77	2.12	0.63	1.59	3.59	-0.80
Std. Dev	0.33	0.72	0.34	0.38	0.66	0.19
Lower 5%	1.24	0.55	0.10	0.90	2.59	-1.10
Upper 5%	2.32	2.84	1.21	2.15	4.78	-0.51
<i>Historical of 1971-2005</i>	<i>2.14</i>	<i>2.19</i>	<i>1.59</i>	<i>2.09</i>	<i>6.85</i>	<i>-1.35</i>
<i>Probability to exceed historical</i>	<i>13.09</i>	<i>44.04</i>	<i>0.59</i>	<i>7.42</i>	<i>0.00</i>	<i>99.90</i>

Final energy consumption

The most striking feature of the stochastic outlook concerning final demand is the high probability of electricity intensiveness in all the regions of the world. This development is underpinned by several factors that act separately but produce the same cumulative result:

- The secular increase in electrical appliances in the residential/commercial sector. This is of course particularly pronounced in the developing world where the rate of ownership of such appliances is currently low and has considerable scope for expansion as incomes grow.
- Structural change in industry favouring lighter and more electricity consuming sectors rather than the process heat intensive ones. The effects of this structural are further magnified by continuing substitution towards electrical processes within the energy intensive sectors.
- The resilience of electricity costs in the phase of increasing fuel costs and even climate policy induced penalties. Such resilience stems from the capital and technology intensive character of the electricity industry implying the moderation of cost increases through continuing technical progress. The emergence and improvement of carbon free technologies, as well as carbon capture and sequestration, plays a key role in absorbing some of the cost effects of emission constraints.

Table D-29: % Shares of electricity consumption in industrial and residential/commercial demand, and share of steam and heat in final consumption in 2050

	Europe			Rest of OECD			Developing Countries			World		
	electricity in industry	electricity in residential/ commercial	steam & heat in final cons.	electricity in industry	electricity in residential/ commercial	steam & heat in final cons.	electricity in industry	electricity in residential/ commercial	steam & heat in final cons.	electricity in industry	electricity in residential/ commercial	steam & heat in final cons.
Mean	41	56	31	44	60	29	35	42	42	36	46	39
Median	41	56	31	44	60	28	34	42	42	35	46	39
Std. Dev	6	6	4	13	6	5	11	8	7	8	7	6
Lower 5%	32	47	25	21	50	21	19	28	30	23	35	29
Upper 5%	50	66	37	65	69	38	55	56	54	51	57	48
In 2005	24	33	50	22	45	42	19	31	56	20	35	50
Probability to exceed 2005	99.9%	100.0%	0.0%	94.3%	99.8%	2.0%	95.5%	90.3%	1.9%	98.5%	95.6%	2.2%
Probability to exceed 50% in 2050	5.2%	84.0%	0.0%	29.8%	96.2%	0.1%	10.2%	16.1%	12.5%	6.5%	30.1%	2.2%

* Commercial energy only

Table D-29 summarises the probabilities for electrification in the different regions. Further penetration is most assured in the residential/commercial sectors of already developed economies with very large probabilities of electricity contributing more than half the energy needs for these sectors by the end of the projection horizon. Further electrification of industrial final energy demand is also highly likely even in developing countries.

The prospects for the share of steam and heat in final energy are closely related to the above developments. Such uses currently account for almost 50% of final energy demand worldwide. According to PROMETHEUS results, the probability of maintaining such dominance by 2050 is little over 2%. In developing countries it is somewhat higher at 12.5% representing the possibilities of a shift of process steam activities in such regions

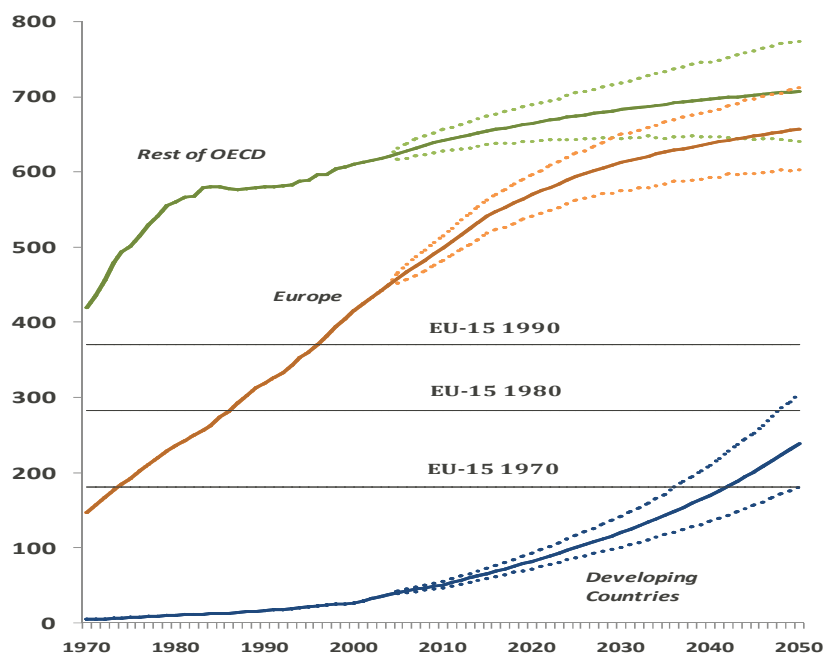
due to lower prices. The low likelihood of steam and heat dominance in the world energy system ultimately limits the potential for hydrogen penetration in the form of combined heat and power.

It is widely recognised that the road transport sector is likely to become the key entry point for an eventual large scale introduction of fuel cells leading to a hydrogen-based energy system. This sector is currently dominated by oil use and has been experiencing considerable growth even after the price increases of the 1970's that show a reversal of other trends in energy intensity. In fact year after year the number of vehicles, both commercial and private, is steadily increasing in almost every country in the world. It is widely acknowledge that if this situation continuous in the long term it could lead to serious problems of sustainability in terms of the environment, congestion, health and resource depletion.

Considerable uncertainties surround the long term evolution of passenger car fleets. The study of such uncertainties has concentrated on two main issues:

- Saturation levels in car ownerships in developed regions of the world.
- The patterns of mobility growth accompanying economic growth in currently less developed regions of the world

Figure D-67: Car ownership per capita (dotted lines represent five percentiles) in number of vehicles per thousand inhabitants



Of the three broad regions identified in the current analysis the Rest of OECD region, which is dominated by North America, displays the most pronounced signs of maturity. Car ownership per capita in this region has been increasing sharply until around 1980 but reached a plateau at around 580 vehicles per thousand inhabitants (v.p.t.) between 1980 and 1995. Since 1995 it has grown very modestly and is currently standing at around 620 v.p.t.. The PROMETHEUS projection implies, on average, a gradual slowdown of this growth

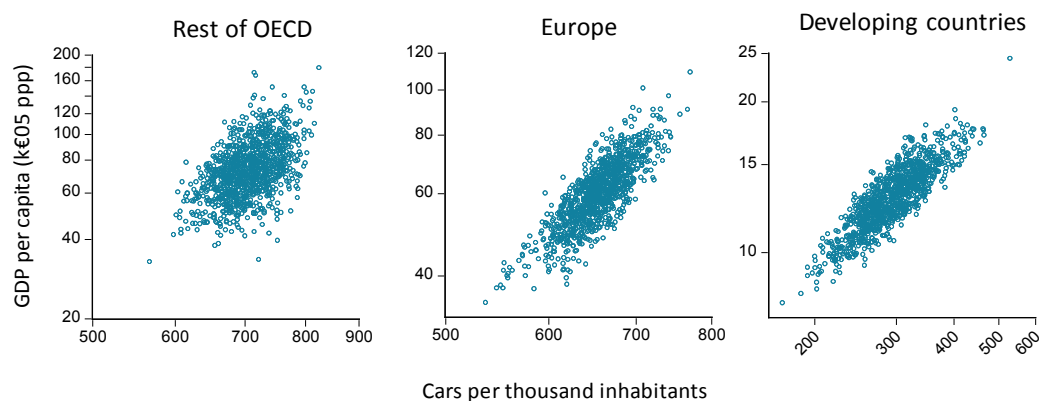
reaching the mean value of 707 v.p.t. in 2050. It also suggests a probability of around 2% of declining from present levels.

On the other hand, car ownership per capita in Europe has been growing at a vigorous pace with few signs of saturation. It currently stands at 73% of the Rest of OECD level. According to the projection it will continue growing strongly until around 2015 mostly due to the impact of rapid motorisation in the new member states of the EU. Beyond that date, on average, a slowdown will set in. By 2050 there is an 87% probability that car ownership per capita in Europe will be higher than it is today in the Rest of OECD and a 12% probability that it will be higher even when ownership levels in the latter region for 2050 are considered.

The developing world is currently experiencing what could be termed as a take-off in car ownership, suggesting similar patterns as those experienced in developed countries several decades ago. According to the projection, average figures will still be growing exponentially at the end of the horizon. The probability of ownership rates reaching European levels in 2050 is close to nil. On the other hand, in order to put the projection into perspective it is important to note that it implies a 95% probability of exceeding the rates experienced in EU-15 in 1970 and a 11% probability of exceeding the equivalent figure of 1980. Considering that even in those years the EU-15 was already highly motorised, it becomes apparent that the projection implies very high probabilities of a private car based road transport for the world, the main uncertainty remaining only on the timing of the different phases of development.

Car ownership per capita is obviously closely related to income per capita. Figure D-68 gives scattergrams on a logarithmic scale for the main regions considered in the analysis. It is worth noting that the relation appears to be looser for the Rest of OECD region that displays signs of saturation early in the projection.

Figure D-68: Scatter graphs of GDP per capita and car ownership in 2050

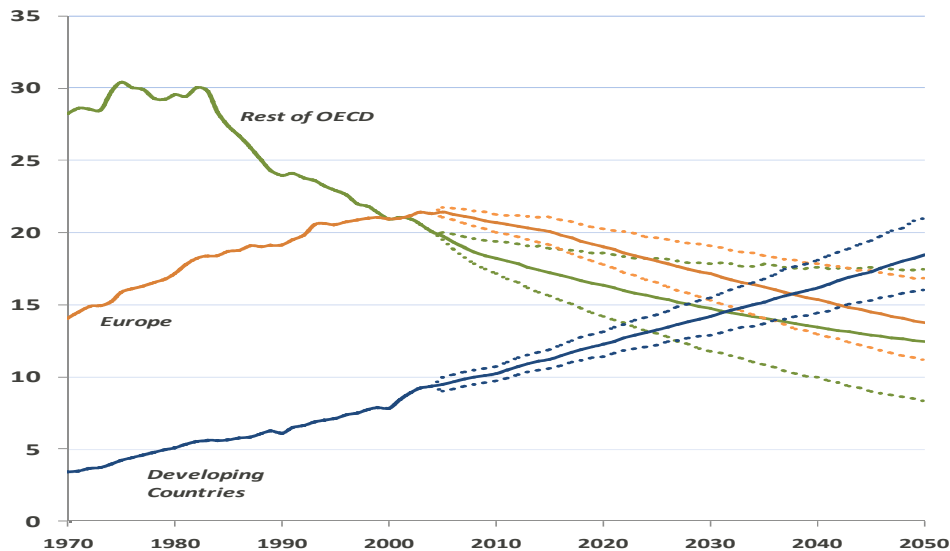


The close relationship between income and car ownership suggests a more refined way of looking at relative maturity by netting out income effects and considering the intensity of vehicle ownership in GDP. The measure chosen is number of vehicles per million Euro of GDP (in €05).

Figure D-69 presents the historical evolution and the probabilistic projection of this index for the three regions under consideration. The general pattern is that at initial stages in car ownership penetration the

index rises (the marginal propensity to use income for acquiring and maintaining vehicles is greater than one). As the level of motorisation increases and vehicles stop being “luxury” goods the index flattens out and quickly turns down. The Rest of OECD region seems to have reached the flattening out phase at around 30 cars per million euro of GDP by the mid seventies and has started decreasing from the mid eighties onwards. The decline has been precipitous until 1990 but has slowdown afterwards.

Figure D-69: Number of cars per million €05 of GDP (dotted lines represent five percentiles)



During the period from 1970 to 1990 the index for Europe has been increasing steadily. After that date it has flattened out considerably, crossing the Rest of OECD index at around 21 cars per million euro of GDP. In fact, Europe is showing signs of the onset of maturity at a level that is considerably lower than the 30 cars million euro of GDP that characterised the evolution of the Rest of OECD. On average, the outlook suggests that the EU index will start declining slowly from 2010 onwards, while remaining above the Rest of OECD index. The probability that it will exceed the latter in 2030 is around 96%, while it is 77% in 2050.

The index for developing countries has been rising from very low levels all along the historical period under consideration. The probability that it will reach 21 cars per million euro of GDP (the point at which the index for Europe stabilised) by 2050 is only 5%. This means that the projection horizon is too short for a strong likelihood of saturation worldwide to emerge.

Considering the probability distributions discussed above, together with the probability distribution for population, produces the following picture for world passenger vehicles stock.

Table D-30: World passenger vehicles in 2050

	Probability to exceed given levels								
	2005	95%	90%	80%	60%	40%	20%	10%	5%
# of cars (billion)	0.72	2.1	2.2	2.4	2.6	2.7	3.0	3.1	3.3

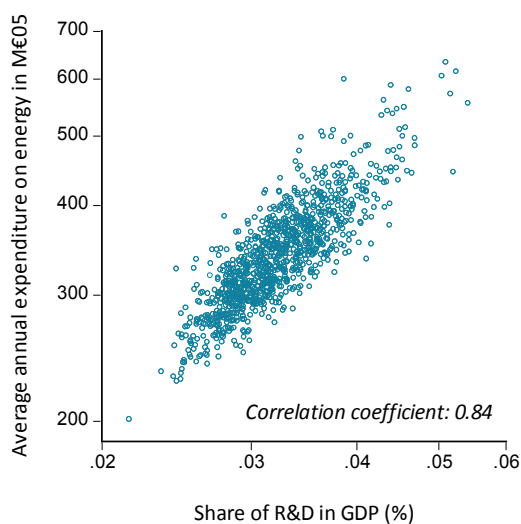
The probability of more than tripling the number of vehicles between 2005 and 2050 is 93.5% and more than quadrupling is 25%. This suggests a huge potential market with a high degree of certainty. By 2025 the probability that more than half the vehicles in circulation will be in developing countries is estimated at 50%.

Technology improvements

The PROMETHEUS stochastic model is equipped with technology dynamics mechanisms in the form of two factor learning curves making improvement a function of experience and research. The parameters of these equations in PROMETHEUS are jointly distributed random variables (they co-vary). Technical progress is also subject to independent random variation.

Apart from these random elements of the technology dynamics mechanisms the PROMETHEUS outlook also incorporates uncertainties regarding the size and direction of R&D, which are endogenous to the model. By analysing historical observations on R&D on energy technologies relations have been established, linking R&D to economic factors and particularly measures of energy cost. These relations are reflected in the outlook. Figure D-70 presents in the form of a scatter graph the PROMETHEUS experiments on total world outlays on energy and the R&D directed at the PROMETHEUS technologies as a percentage of GDP. The mean value over the whole period is 0.033% which is close to the values of recent years. However, it is clear from the graph that variation in this percentage is dominated by the variation in energy cost.

Figure D-70: Scatter graph of cumulative annual R&D expenditures (as shares of GDP) and average annual energy outlays in 2005-2050 (logarithmic scale)

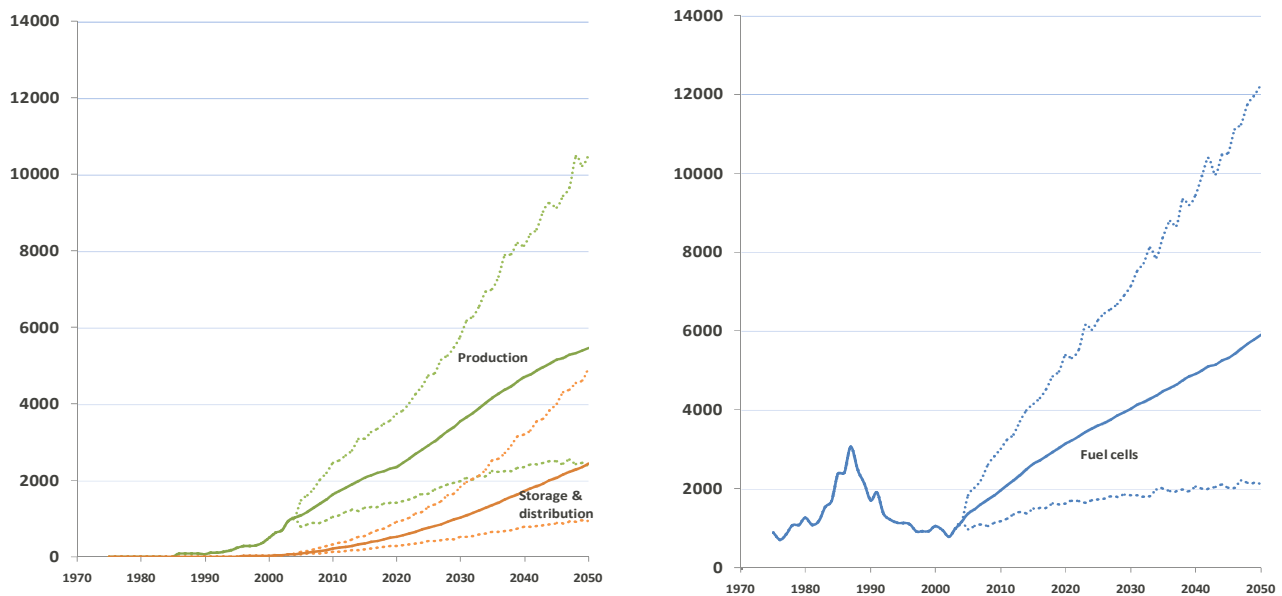


During the period between 1985 and 1995 there has been considerable R&D interest in fuel cell related technologies (see Figure D-71). In recent years there seems to be a revival in interest from the private sector. According to the PROEMETHEUS outlook there is a 76% probability that outlays directed to fuel cells in the period 2005-2020 will exceed those of the period 1980-2000. Beyond 2020 there is a slight deceleration on

average. The variation, however, is very large and rising to the end of the period and contributes to the variation in the technical and economic performance of fuel cells that is discussed below.

R&D on production technologies, which has known a considerable revival in interest in recent years, is projected a slowdown on average in the period to 2020, but pick up again between 2020 and 2030 as during that period (on average) the prospects of large scale applications of hydrogen will become brighter.

Figure D-71: Annual R&D expenditures in million €05 in hydrogen related technologies (dotted lines represent five percentiles)



R&D on infrastructural technologies (pipelines, on-board and centralised storage, liquefiers, gasifiers, etc) is likely to pick up in the further lag as needs start evolving. R&D on the supply side (production and infrastructure) is not characterised by the high expectations of return that characterises R&D on fuel cells. The variation projected for the former in a sense reflects the variation of the latter since the development of supply is a prerequisite for the materialisation of the success of the fuel cells. Over the whole period 2005-2050 there is a 55% probability that R&D on fuel cells will be lower than R&D on the other technologies characterising the hydrogen economy. Given the relatively low returns for the latter, it can be reasonably assumed that a larger share will be undertaken by public bodies in an effort to provide a solid basis for the diffusion of fuel cells.

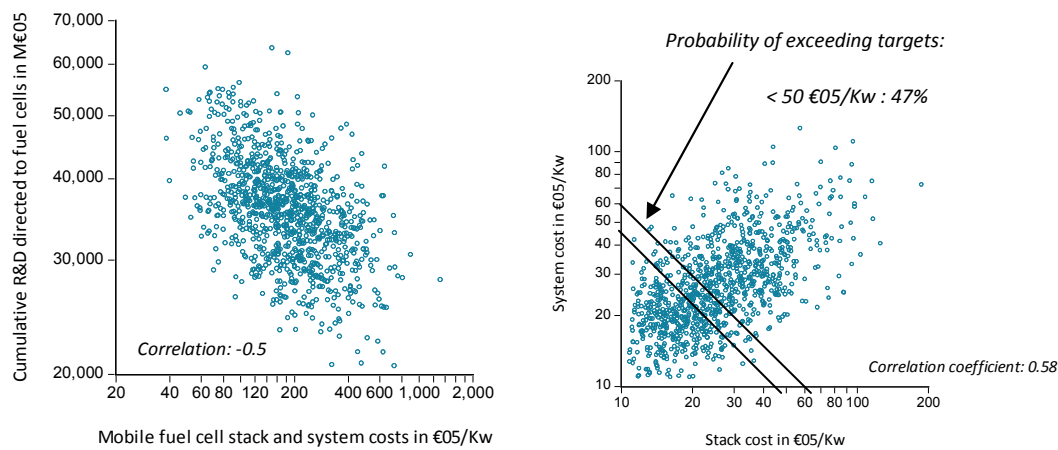
According to the PROMETHEUS projections the crucial technologies for the introduction of hydrogen are those related to mobile applications for the road transport sector. There are two distinct categories of these technologies identified in the model:

- Stacks consisting of cells including electrodes and a proton conducting membrane pressed between them that acts as an electrolyte and sheets separated by bipolar plates with integrated gas flow channels.

- Other supplementary systems including a stack cooling system, a cathode air supply compressor, sensors and control valves and ancillary components such as an electronic controller, a start-up battery, electrical equipment, safety equipment and system packaging.

Both these technology clusters are subject to considerable improvement, which will indeed be necessary if fuel cell vehicles are to become competitive at all. According to the outlook R&D will be directed towards both but success in each one of them is not completely statistically dependent on success of the other. The right hand side graph on Figure D-72 presents the results concerning the costs of the two clusters for 2050. According to Freund E. (CO₂ Sequestration. 1st European Hydrogen Energy Conference, 2003) in order to compete with existing automotive propulsion systems, fuel cell systems for vehicle application will have to reach costs between 50 and 65 €/kW with a lifetime of 3,000 to 5,000 hours. These targets are also plotted in the graph in order to map the area that is consistent with meeting them.

Figure D-72: Scatter graph between cumulative R&D expenditures and cost improvement of mobile fuel cells in 2020 (left graph) and Scatter graph between stack cost and system cost of mobile fuel cells in 2050(right graph)



The graph also gives an indication for the large variation in the relative success of the combined system. A large part of this variation can be attributed to uncertainties on the R&D that is specifically directed to fuel cells. This is particularly true in the earlier years of the projection, where variation is even wider (possibilities for complete failure to produce a breakthrough). The left hand side of Figure D-72 gives an indication of the joint distribution of cumulative R&D between 2005 and 2020 and the cost of mobile fuel cell stacks + system costs in 2020.

Figure D-73: Probability that the mobile fuel cell stack and system costs will be lower than certain levels

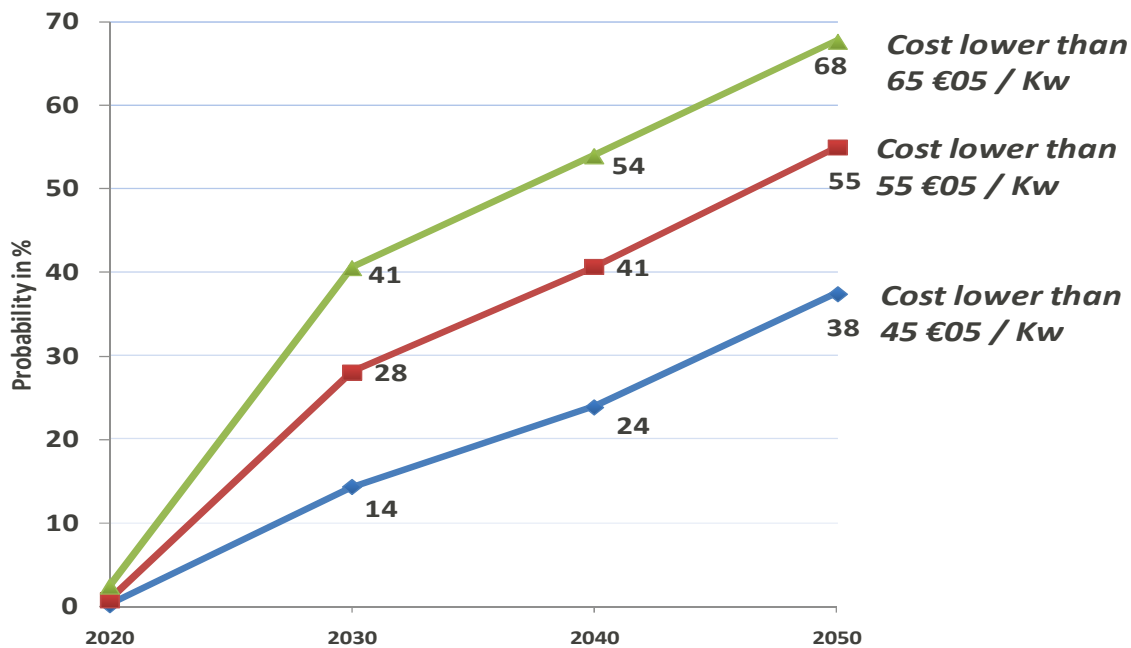


Figure D-73 provides an indication of PROMETHEUS results concerning the time profile of probabilities of reaching different success benchmarks for mobile fuel cell costs. Three benchmarks have been chosen:

- Benchmark 1: 65 €/Kw broadly corresponding to the stage at which fuel cells start being considered as an option beyond strict niche markets.
- Benchmark 2: 55 €/Kw corresponding to a stage where take-off becomes a possibility, especially for large annual mileages.
- Benchmark 3: 45 €/Kw broadly corresponding to a cost below which fuel cells could easily make major inroads into the road transport market.

The implications of the PROMETHEUS outlook are that:

- By 2020 technical progress in fuel cells is unlikely to occur to a sufficient degree to allow introduction of fuel cells in anything but niche markets. Even benchmark 1 can be reached with only a 2.5% probability.
- By 2030 the likelihood of different success levels improves markedly. This is particularly so for the modest breakthrough implied by benchmark 1, which registers more than 40% probability of being achieved.
- In 2040 there is a more than even probability of technological success of some sort with more than 40% chance that it will be substantial (benchmark 2).
- By 2050 there is a two-in-three probability that mobile fuel cells will be a valid choice in road transport and a more than even chance that there will be genuinely competitive. On the other hand the probability of a big breakthrough will still be less

than 40%. Even at this late stage there is nearly 20% probability of what can be construed to represent a complete technical failure (costs above 80€05/Kw).

Table D-31 presents some details for the technical-economic evolution of the hydrogen related technologies that have figured prominently in scenario results within the CASCADE MINTS project. In general the technological attributes that experience the most pronounced improvements are also those that display the biggest variability. These technologies are often the most prospective in character with non negligible probabilities for relative technical failure. Mobile fuel cells are subject to the biggest uncertainty that has been discussed at some length above. Stationary fuel cell costs (both stack and system) also have large variances. A notable feature of these technologies is that the fixed operating and maintenance costs also display equivalent variation. On board hydrogen storage cost variability is likely to affect the variability of cost performance of hydrogen internal combustion engine cars as storage represents the main additional cost for such vehicles. The variability in efficiencies for mobile hydrogen applications is relatively small and for stationary applications almost insignificant.

For hydrogen production technical options the nuclear high temperature thermochemical cycle displays the highest variability (especially in terms of fixed operating and maintenance costs). This technology is based on the yet unproven new nuclear designs that are not expected to appear before 2020 and their use for hydrogen production is subject to additional variability. Most of this variability is founded on lack of knowledge today rather than uncertainties surrounding R&D or other economic factors. Biomass gasification with CCS also displays uncertainty especially with regard to capital costs (in 2050 the standard deviation represents almost 10% of capital cost). The other main production options coal gasification and particularly gas steam reforming are subject to much smaller uncertainties but at the same time tend to improve less.

Table D-31: Summary statistics for the improvement in the performance of selected hydrogen related technologies (costs are given in €05)

		2020					2050				
	Unit	Mean	Median	Std. Dev	Lower 5%	Upper 5%	Mean	Median	Std. Dev	Lower 5%	Upper 5%
Coal gasification with CCS											
Capital cost	€/M3d	209	208	11	194	230	190	189	12	174	213
Fixed O&M costs	€/M3d/y	9.3	9.3	0.1	9.1	9.5	8.1	8.1	0.2	7.8	8.4
Efficiency	%	53.2%	53.2%	0.2%	52.8%	53.6%	54.1%	54.1%	0.2%	53.7%	54.5%
Biomass gasification with CCS											
Capital cost	€/M3d	250	247	18	223	286	230	227	21	201	268
Fixed O&M costs	€/M3d/y	8.9	8.9	0.3	8.4	9.3	7.8	7.8	0.4	7.1	8.4
Efficiency	%	64.1%	64.1%	0.3%	63.6%	64.5%	64.9%	64.9%	0.3%	64.4%	65.4%
Nuclear High Temperature Thermochemical Cycles											
Capital cost	€/M3d	1126	1128	51.0	1038	1205	413	403	54.5	340	518
Fixed O&M costs	€/M3d/y	20.8	20.8	2.9	16.4	25.8	5.9	5.7	1.7	3.5	9.1
Efficiency	%	41.0%	40.9%	0.7%	39.9%	42.2%	52.0%	51.8%	2.9%	47.4%	57.0%
Gas steam reforming without CCS											
Capital cost	€/M3d	56	56	0.6	55	57	52	52	0.7	51	53
Fixed O&M costs	€/M3d/y	1.01	1.01	0.01	1.00	1.02	0.87	0.87	0.03	0.83	0.92
Efficiency	%	77.1%	77.0%	0.8%	75.8%	78.5%	81.0%	81.0%	0.9%	79.5%	82.6%
Fuel cell vehicles											
Stack cost	€/kW	84	70	53	26	191	30	25	17	13	62
FC System/engine cost	€/kW	129	106	89	40	309	30	26	15	14	58
On board hydrogen storage cost	€/kgH2	101	101	9	88	117	62	62	7	51	74
Fuel input	kgr/100km	0.61	0.61	0.01	0.59	0.63	0.49	0.49	0.03	0.45	0.54
Maintenance cost	€/yr	456	456	18	425	486	265	264	31	215	317
Hydrogen internal combustion engine vehicles											
Hydrogen storage capacity	kg	13	13	0.4	12	14	11	11	0.4	10	12
Engine cost	€/kW	33	33	0.0	33	33	35	35	0.0	35	35
On board hydrogen storage cost	€/kgH2	80	80	7	69	93	49	49	6	41	59
Fuel input	kgr/100km	1.59	1.59	0.04	1.53	1.66	1.36	1.36	0.04	1.30	1.44
Maintenance cost	€/yr	544	544	7.1	532	555	439	439	7.9	426	452
Small stationary fuel cells (1-5Kw)											
Stack cost	€/kW	494	483	116	326	709	223	215	59	142	331
System cost	€/kW	2006	1947	493	1291	2906	894	842	285	540	1426
Stack lifetime	Years	8	8	0.8	7	10	10	10	1.0	9	12
System lifetime	Years	19	19	0.0	19	19	20	20	0.0	20	20
Fixed O&M costs	€/kW/y	106	103	26	67	152	23	21	8	12	38
Overall fuel efficiency	%	90.5%	90.5%	0.9%	89.0%	91.9%	93.0%	93.0%	0.9%	91.5%	94.6%
Electrical efficiency	%	33.2%	33.2%	0.4%	32.5%	33.9%	36.0%	36.0%	0.6%	35.0%	37.1%
Thermal efficiency	%	57.3%	57.3%	0.8%	55.9%	58.7%	57.0%	57.0%	1.0%	55.4%	58.6%
Large stationary fuel cells (5 - 250 Kw)											
Stack cost	€/kW	714	699	169	471	1023	316	308	66	224	439
System cost	€/kW	2175	2107	508	1427	3091	994	944	290	627	1533
Stack lifetime	Years	8	8	0.8	7	10	10	10	1.0	9	12
System lifetime	Years	19	19	0.0	19	19	20	20	0.0	20	20
Fixed O&M costs	€/kW/y	122	119	29	79	173	26	25	9	15	43
Overall fuel efficiency	%	90.5%	90.5%	0.9%	89.0%	91.9%	93.0%	93.0%	0.9%	91.5%	94.6%
Electrical efficiency	%	59.0%	59.0%	1.4%	56.6%	61.4%	62.0%	62.0%	1.4%	59.6%	64.2%
Thermal efficiency	%	31.5%	31.6%	1.5%	29.1%	33.8%	31.0%	31.0%	1.4%	28.6%	33.3%

Penetration of hydrogen technologies

Road transport

Before proceeding with the stochastic assessment of the contribution of hydrogen technologies in the energy system, some broad considerations concerning competing technologies must be taken. With regard to the road transport sector that constitutes the key point of entry for hydrogen technologies a special issue concerning taxation arises: it is widely accepted that during early stages of the introduction of a new technology fuel taxation on an equal footing with conventional technologies would stunt its prospects and prevent further development. If the technology starts penetrating by substituting fuels that are taxed this

would naturally create a shortfall in government revenues. This is particularly the case for regions in the world like Europe where fuel taxation (especially for road transport fuels) is heavy. It is therefore natural that in cases of success of a new energy vector, taxation for it would be introduced at least gradually. The extent and speed of this adjustment will depend on policy stances (the pay-off between the promotion of a clean technology and loss of tax revenue). For the transport sector PROMETHEUS takes this development into account by the incorporation of stochastic relations linking taxation to the part that new technologies attain within the vehicle stock. The effect of this mechanism is that the competitiveness of new options is reduced in cases where they tend to succeed subject to uncertainties surrounding policy stances. With regard to fuel cell vehicles this effect is relatively minor due to the very high efficiency that characterises them. On the other hand, with regard to hydrogen internal combustion engine cars it could have some importance.

Table D-32 gives a stochastic assessment of the cost performance of the different vehicle types in 2050. For the sake of simplicity the probability of lowest cost per vehicle kilometre is used as an index without any consideration of gradation (how much cheaper the cheapest option is).

Table D-32: Cost performance of vehicle types in 2050
% Probability that a given option has lowest cost per vehicle km for 15000km/yr

Car type	Europe		Rest of OECD		Rest of the World	
	2030	2050	2030	2050	2030	2050
Conventional	97.4	80.6	100.0	79.4	100.0	78.4
Hybrids/Electric	0.0	4.2	0.0	0.9	0.0	0.7
H2 ICE	2.2	2.8	0.0	10.4	0.0	5.8
Fuel cells	0.4	12.4	0.0	9.4	0.0	15.1

% Probability that a given option has lowest cost per vehicle km for 25000km/yr

Car type	Europe		Rest of OECD		Rest of the World	
	2030	2050	2030	2050	2030	2050
Conventional	92.7	72.9	100.0	78.2	100.0	71.2
Hybrids/Electric	0.0	5.3	0.0	0.0	0.0	0.0
H2 ICE	3.4	1.9	0.0	6.1	0.0	2.9
Fuel cells	3.9	19.9	0.0	15.7	0.0	25.9

Fuel cell vehicles are characterised by high acquisition costs and low running costs. Therefore it is reasonable to expect that their performance improves as annual vehicle use increases. In 2030 conventional cars almost certainly remain the most cost-effective option in the rest of OECD and in the rest of the world whereas there is a small probability that hydrogen powered cars (ICE in the 15000km per year case and both ICE and fuel cells in the 25000km case) dominate in terms of cost effectiveness. The reason for this early emergence of these probabilities is the high taxation of transport fuels in Europe, which, given the low penetration of hydrogen that is most probably attained at this date, provide an opportunity for a cost advantage.

By 2050 there are distinct probabilities for cost effectiveness of fuel cell vehicles throughout the world and particularly in the developing countries where hydrogen cost are likely to be lower. Hydrogen ICE chances for competitiveness are better if a low mileage is considered. With the exception of Europe (where there is around 5% probability), there is little chance that hybrid or fuel electric cars will dominate. However, even by that

date according to PROMETHEUS there is more than 70% probability that conventional vehicles, especially diesel powered ones, will remain the most cost-effective option despite the big probabilities for high petroleum prices.

The relative cost of different options is an important factor for the penetration of technologies but it is by no means the sole factor. Key among factors determining the structural vehicle stock are:

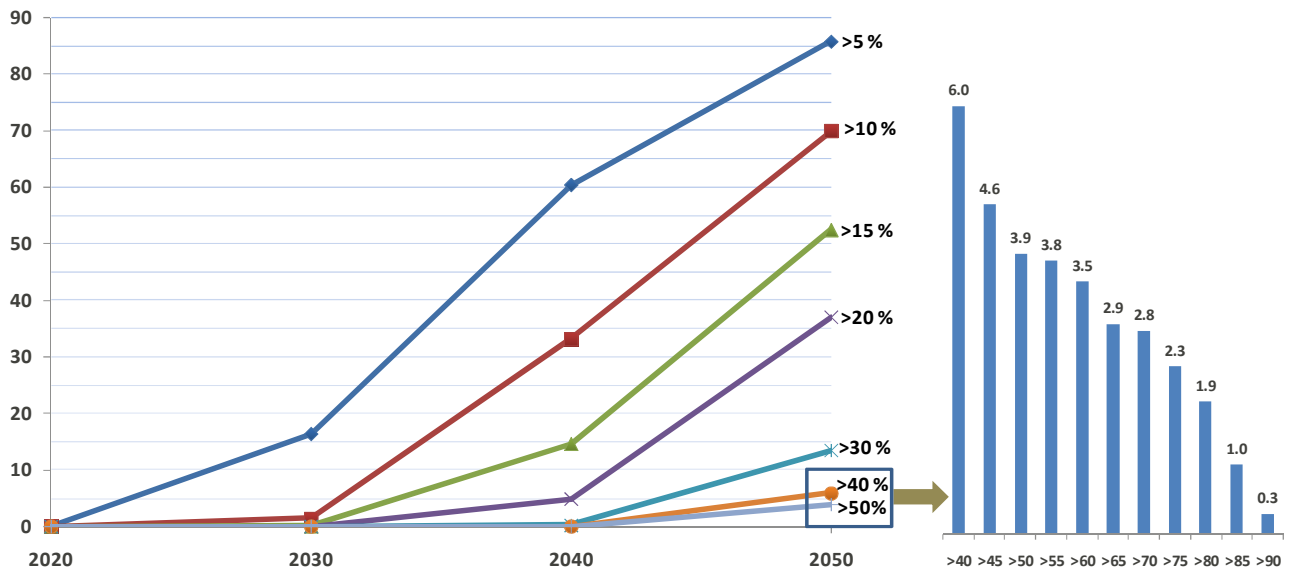
- The vehicle stock turnover. Unlike stationary equipment that are characterised by very long technical lifetimes, vehicles have shorter average lives (typically around 14 years for private vehicles and even shorter for commercial vehicles). However, even such shorter lifetimes mean that in the absence of accelerated withdraw many older generation vehicles persist over several decades.
- The development of infrastructure. Hydrogen vehicles (but also to a lesser extent plug-in electric vehicles) presuppose the existence of production, transportation, storage and distribution network to supply energy to the final consumer. In the case of hydrogen this is likely to be particularly capital intensive involving a very gradual geographical expansion starting with densely populated areas and overtime moving to more sparsely populated ones. The fact that availability may not be universal at the early stages could prove in itself a major barrier to the large scale introduction of hydrogen for road transport.
- In addition to these technical considerations other effects that can be broadly labelled as social networking effects can also an important role especially with regard to radically novel technologies. Key among these considerations are consumer acceptance and mimetism (the propensity of consumers to copy each other's behaviour).

Table D-33: Summary statistics of the share of fuel cell vehicles in vehicle stock in 2050 (%)

Probabilities to exceed certain shares % share of fuel cells in vehicle stock				
Probability	Europe	Rest of OECD	Developing Countries	World
95%	2	1	1	1
80%	6	4	3	4
50%	14	11	8	10
20%	24	20	15	17
5%	40	30	21	24

Table D-33 gives an indication of the likelihood of penetration of mobile fuel cells in the vehicle stock of different regions in 2050. The median value for the world is around 10%. In Europe this figure is somewhat higher because of the higher likelihood of heavy taxation for conventional vehicles and the geographical compactness of demand that is likely to lead to an earlier development of infrastructure. According to these results there is a 20% probability that less than one in twenty five vehicles in circulation will be fuel cell powered. At the other end there is around 5% probability that one in four vehicles will be based on this technology. In Europe its share could exceed 40% with a 5% probability suggesting a process of radical transformation of the vehicle stock.

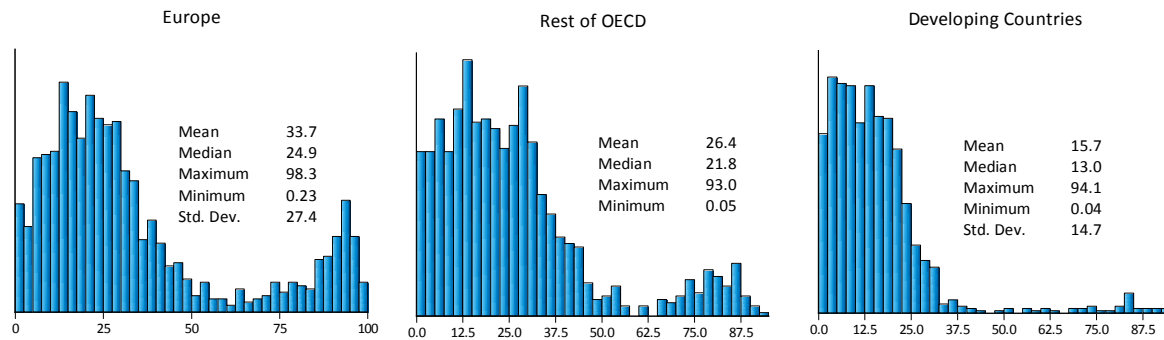
Figure D-74: % Probability that the share of fuel cell vehicles in new registrations will exceed certain levels worldwide in 2050



Way before vehicle stocks are transformed radical change will have to occur in new vehicle registrations. Figure D-74 provides a time profile for the probabilities of attaining different shares in new registrations worldwide. It is worth noting that in 2020 such probabilities are virtually zero with only about 15% probability that one in twenty new vehicles will be fuel cell powered in 2030. The probability for low shares (between 5 and 10%) increases sharply between 2030 and 2040 but it is only in the last decade of the outlook that any noticeable probabilities for fuel cell domination occur (4% probability that the share of fuel cell vehicles will exceed 50%).

The tales of the probability distributions of shares of fuel cells in new registrations present particular interest. Figure D-75 below presents the distributions for the year 2050. Their most striking feature is an element of bimodality that characterises them: a probability trough around or just above 50% with a resurgence of probability densities for higher shares. This phenomenon is primarily due to the social network effects discussed above: in some cases technological success is combined with accelerated social acceptance thus snowballing into very high penetration rates. This upper hump is particularly noticeable in Europe where it accounts for around 20% i.e. there is one in five chance for radical and seemingly irreversible transformation of road transport towards hydrogen.

Figure D-75: % Share of fuel cell vehicles in new registrations in 2050



By contrast the probability density for penetration rates of between 0 and 20% is almost uniform suggesting normal simultaneous competition between different road transport options. In Europe the probabilities for very low shares are very small due to assumptions on the likelihood of proactive policies encouraging diversification in transport.

Stationary applications

PROMETHEUS identifies the following hydrogen based stationary applications:

- Generic large scale fuel cells (5-250 KWe) with and without onsite gas steam reforming for industrial applications
- Generic small scale fuel cells (1-5 KWe) with and without onsite gas steam reforming for residential/commercial applications

Reformers are assumed to use natural gas, while application without reformer are assumed to use centrally produced hydrogen distributed either via a pipeline network or by tanker trucks. A general finding in the CASCADE MINTS project, which is confirmed by PROMETHEUS results, is that the introduction of stationary applications will lag behind mobile uses. According to PROMETHEUS results there is a probability of less than 5% that fuel cells will contribute more than 1% of energy requirements in industry, while the equivalent figure in the residential/commercial sector is less than 1/2 percent. For this reason the stochastic evaluation of stationary application prospects will concentrate on the year 2050, when distinct possibilities of meaningful contributions exist.

Table D-34 summarises the results for the different regions of the world in 2050. Since stationary fuel cell applications are assumed to take the form of CHP, both electricity and heat are considered in obtaining shares. In adding different energy forms approximate useful energy conversion coefficients have been utilised.

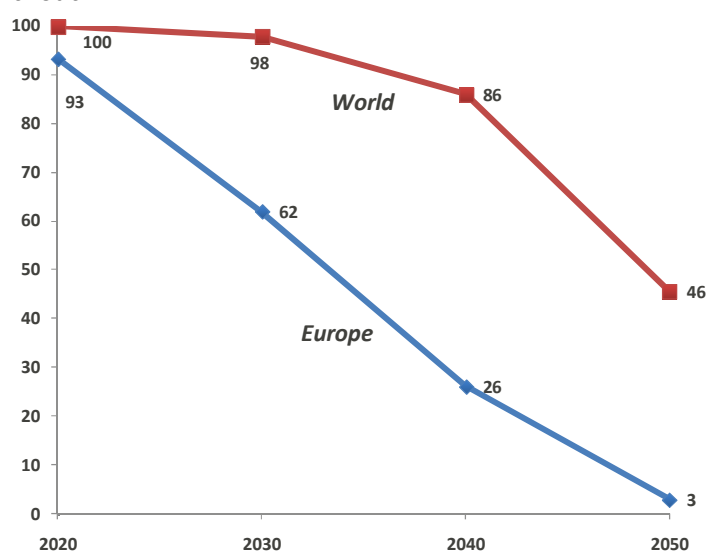
Table D-34: Summary statistics of the share of fuel cells in energy requirements in 2050 (%)

% Share of energy from fuel cells in final energy needs in industry					% Share of energy from fuel cells in final energy needs in residential/commercial sectors				
Probability to exceed share	Europe	Rest of OECD	Developing Countries	World	Probability to exceed share	Europe	Rest of OECD	Developing Countries	World
95%	1	0	0	0	95%	1	0	0	0
90%	1	0	0	1	90%	1	1	0	0
80%	2	1	1	1	80%	2	1	0	1
70%	3	1	1	1	70%	3	2	0	1
60%	4	1	1	1	60%	4	2	0	1
50%	4	1	1	2	50%	5	3	0	2
40%	5	1	1	2	40%	7	4	0	2
30%	7	2	2	2	30%	11	6	0	3
20%	9	3	2	3	20%	13	8	0	4
10%	13	6	3	5	10%	15	10	1	5
5%	16	9	4	7	5%	16	11	3	8

A general remark on the prospects of stationary applications is that even by 2050 the probability of fuel cells making major inroads in the heat and power market are very low indeed. This result is partly due to the fact that even in cases where the technical-economic performance of the technology improves to the extent to make it very cost effective vis-a-vis its competitors, this development in general occurs in the final years of the horizon and the slower turnover of equipment in these markets means that there is not sufficient time for radical transformation. The probability profiles for large scale and small scale fuel cells are very similar primarily due to the close correlation in technological progress for both. On the other hand, there is considerable diversity in prospects depending on region. In Europe the probability of the cost of energy from hydrogen based CHP being lower than alternatives for producing heat or purchasing power is much greater than it is in developing countries. This is primarily due to the high likelihood of a strong climate policy in Europe.

Another area where there is wide differentiation between Europe and the rest of the world is in the use of fuel cell installations with reformers. Reformers offer the opportunity for an early introduction of fuel cell technologies because they do not depend on the existence of the hydrogen production and distribution infrastructure. For mobile applications the cost of the reformer is very high and the role is limited even at the early stages of fuel cell introduction. For stationary applications, and assuming that natural gas feedstock costs are sufficiently low, the avoidance of pipeline and storage costs could prove a major advantage.

Figure D-76: % Probability that the number of stationary fuel cells with reformer exceeds the number without



The likelihood of fuel cells with reformer exceeding installations without is high in the early stages (2020-2030) in Europe but declines rapidly thereafter especially in view of the development of the distribution infrastructure. On the other hand, in the rest of the world and particularly in some of the developing regions, natural gas prices are sufficiently low to ensure that reformers remain a valid option by 2040 and beyond (see Figure D-76).

Hydrogen balance (supply and costs)

The previous chapter has concentrated on the contribution of hydrogen related technologies to final energy needs. In this chapter we adopt the point of view of hydrogen to be supplied in order to meet requirements. The distinction is important because hydrogen is used in technologies with widely varying efficiencies (for example very high ones for large scale fuel cells and low efficiencies for internal combustion engine applications). Furthermore the type of application can have important implications for infrastructure requirements (e.g. high infrastructure intensiveness for centralised distribution to households).

PROMETHEUS results suggest mean requirements of just under 600Mtoe for the world and just under 90Mtoe for Europe. However, the probability distribution for both is highly skewed i.e. the median values are lower, the mode smallest still and there are non negligible probabilities for considerably higher values (see first line of Table D-35). On average the road transport sector accounts for two thirds of demand worldwide and 40% in Europe. Hydrogen ICE cars, though taking a much smaller share of the vehicle fleet, account on average for a larger share in hydrogen requirements because of the much lower efficiency that characterises them. Despite the relatively low likelihood of fuel cells making large contributions to energy requirements of the residential/commercial sector (see Table D-34 above), in terms of hydrogen requirements such uses can be important because of the size of overall requirements in this sector. This is particularly the case in Europe where the probabilities of high effective carbon values are larger: in such situations consumers may be left

with few cost effective alternatives for satisfying their demand for heat (electricity from the grid and fuel cells assuming that both can be produced primarily by carbon free technologies). It is noticeable that there is a 5% probability that the residential/commercial sector in Europe will account for close to 64% of hydrogen needs (see Table D-35).

According to the PROMETHEUS outlook, on average more than 85% of worldwide hydrogen requirements will be met by centralised hydrogen production. The figure for Europe is higher (more than 90%) because of higher average natural gas prices. There is, however, a probability of 5% that on-site production worldwide will exceed 30% of total production. The bulk of decentralised production according to PROMETHEUS results takes the form of natural gas steam reforming. This technology appears to be particularly reserved for decentralised applications and is unlikely to contribute more than 10% of total hydrogen need in its centralised form.

Coal gasification is the leading technological option to producing hydrogen in both Europe and the world at large. There is a 50% probability that hydrogen from coal gasification will be produced in facilities equipped with CCS worldwide. This probability is 95% for Europe reflecting the high chances for a strong climate policy. Biomass gasification with steam reforming is another technology that registers a high mean in PROMETHEUS results. In particular, facilities utilising this technology, in conjunction with CCS, capture 10% of hydrogen production worldwide by 2050. For such technologies the effective carbon value constitutes a negative cost. The distribution of its penetration worldwide is highly skewed: the median is less than 4%, there is a 5% probability that it makes no contribution at all, but also an 8% probability that it will produce more than one third of all hydrogen required. Another technology of a highly speculative nature that emerges in some PROMETHEUS experiments with moderately large shares is the nuclear high temperature thermochemical cycle. According to PROMETHEUS there is a 10% probability that it makes virtually no contribution (less than 1%) to worldwide supplies. On the other hand, there is a 13% probability that it may contribute more than one tenth. This wide spread is consistent with the technological uncertainties surrounding this option. Renewables other than biomass have a very low likelihood of making more than niche contributions. Wind power can only produce hydrogen with an electrolyser added on and adequate buffers for storing the hydrogen. It thus becomes very capital intensive and this combined with the intermittent character of the energy source and relatively low availabilities, results in high production costs. Solar high temperature thermochemical cycle is also costly but there are distinct probabilities of sufficient improvement in the longer term making it potentially attractive beyond the 2050 horizon.

Table D-35: Summary statistics of the hydrogen balance in 2050

Hydrogen balance in 2050										
	World					Europe				
	Mean	Median	Std. Dev.	Lower 5%	Upper 5%	Mean	Median	Std. Dev.	Lower 5%	Upper 5%
Hydrogen consumption (Mtoe)	584	480	380	276	1127	87	70	53	28	197
Industry	82	57	85	15	221	18	13	17	2	56
Residential/Commercial	150	94	198	13	432	39	29	30	4	92
Transport	352	329	130	214	567	30	27	13	15	55
Mobile fuel cells	136	121	97	15	298	14	13	10	2	33
Hydrogen ICE cars	216	202	75	141	330	16	14	10	4	33
Hydrogen production (Mtoe)	584	480	380	276	1127	87	70	53	28	197
On site steam reforming	83	63	69	15	213	7	6	5	2	17
Centralised production	501	405	354	246	995	80	61	51	25	188
Gas steam reforming	23	22	11	7	43	2	2	1	0	4
with CCS	6	3	6	1	17	0	0	0	0	1
Solar methane reforming	1	1	1	0	3	0	0	0	0	0
Coal gasification	292	256	170	146	524	46	36	29	15	106
with CCS	162	119	182	23	437	43	33	30	10	105
Oil partial oxidation	14	13	8	5	28	2	2	1	0	4
with CCS	6	4	6	1	16	1	1	1	0	3
Biomass pyrolysis	15	13	9	6	29	1	1	1	0	3
Biomass gasification with steam reforming	84	33	140	9	335	16	8	18	1	57
with CCS	73	19	142	1	326	14	6	19	0	56
Nuclear high temperature therm. Cycle	42	20	84	2	148	7	3	10	0	28
Dedicated nuclear plant for electrolysis	17	11	23	3	48	4	3	5	1	14
Solar high temperature therm. Cycle	1	0	1	0	2	0	0	0	0	1
Electrolysis from grid	9	7	10	2	25	1	0	1	0	3
Dedicated wind turbine for electrolysis	2	1	3	0	6	0	0	1	0	2
Shares in hydrogen consumption (%)										
Industry	12.8	12.1	5.8	4.6	23.1	19.2	18.5	8.9	5.7	34.3
Residential/Commercial	20.6	19.7	11.9	4.2	41.4	39.7	40.4	15.5	14.3	63.8
Transport	66.6	67.3	14.6	41.6	89.0	41.0	38.7	16.6	19.5	71.7
Mobile fuel cells	23.4	23.4	11.9	3.9	42.7	18.4	16.6	10.8	3.2	39.6
Hydrogen ICE cars	43.3	41.5	16.3	19.9	73.8	22.7	18.1	16.2	4.6	56.3
Shares in hydrogen production (%)										
Fossil fuels without CCS	47.2	47.7	23.1	8.6	80.6	19.7	15.7	15.2	2.8	51.0
Gas steam reforming	18.1	17.0	9.2	5.1	35.1	12.1	10.8	7.6	2.5	26.0
Onsite	14.3	12.5	8.4	3.7	29.9	9.6	8.4	6.3	2.0	22.0
Centralised	3.8	3.3	2.7	0.4	8.8	2.4	2.1	1.7	0.1	5.8
Solar methane reforming	0.2	0.2	0.1	0.1	0.5	0.2	0.2	0.1	0.1	0.4
Coal gasification	27.0	24.8	19.6	0.5	61.0	6.4	1.2	10.0	0.0	28.4
Oil partial oxidation	1.9	1.6	1.5	0.1	4.9	1.0	0.7	1.0	0.0	3.1
Non Fossil fuels	15.0	13.8	6.8	6.4	28.4	16.7	15.0	8.4	6.4	33.1
Biomass pyrolysis	2.9	2.6	1.5	0.9	5.9	2.0	1.5	1.6	0.3	5.3
Biomass gasification with steam reforming	2.2	1.9	1.4	0.4	4.8	2.5	1.4	2.8	0.3	8.1
Nuclear high temperature therm. Cycle	5.4	4.1	4.8	0.7	14.0	6.3	4.4	5.8	0.8	17.4
Dedicated nuclear plant for electrolysis	2.6	2.3	1.5	0.8	5.5	4.5	3.9	2.6	1.5	9.6
Solar high temperature therm. Cycle	0.1	0.1	0.1	0.0	0.3	0.2	0.1	0.2	0.0	0.5
Electrolysis from grid	1.5	1.4	0.8	0.5	3.0	0.8	0.7	0.5	0.2	1.7
Dedicated wind turbine for electrolysis	0.3	0.2	0.2	0.1	0.7	0.4	0.4	0.3	0.1	1.1
Facilities with CCS	37.8	36.4	23.1	7.1	76.2	63.6	66.6	16.2	33.4	85.6
Gas steam reforming	1.0	0.6	1.0	0.2	3.1	0.4	0.4	0.2	0.1	0.8
Coal gasification	26.1	25.7	15.3	6.0	52.9	48.0	48.2	13.2	24.7	69.8
Oil partial oxidation	1.0	0.8	0.8	0.2	2.6	1.4	1.2	0.9	0.4	3.4
Biomass gasification with steam reforming	9.7	3.9	13.1	0.1	38.7	13.7	9.2	14.5	0.3	43.2
Shares in hydrogen production by energy form (%)										
Coal	53.0	52.9	12.4	32.4	73.1	54.4	55.1	12.5	33.4	73.8
Gas	19.3	18.3	9.2	6.3	36.2	12.7	11.3	7.8	2.8	26.9
Oil	2.9	2.7	1.7	0.7	6.0	2.5	2.2	1.4	0.6	5.1
Biomass	14.8	10.3	12.1	4.3	41.9	18.2	14.5	13.5	3.4	45.6
Nuclear fuel *	8.0	6.6	5.9	1.6	18.8	10.8	8.5	7.8	2.5	26.3
Electricity (grid)	1.5	1.4	0.8	0.5	3.0	0.8	0.7	0.5	0.2	1.7
Solar	0.1	0.1	0.1	0.0	0.3	0.2	0.1	0.2	0.0	0.5
Wind	0.3	0.2	0.2	0.1	0.7	0.4	0.4	0.3	0.1	1.1

* includes dedicated nuclear power plant for electrolysis and nuclear high temperature thermochemical cycle

Total hydrogen production can be viewed as a crude measure for the transformation of the energy system towards a hydrogen economy (it is crude because it gives no indication of the part of different types of energy requirement that is met by this new energy vector). At this stage it is worth attempting a probabilistic assessment of the main models participating in the CASCADE MINTS project with respect to this measure. According to the graphs in Figure D-77, the baselines of the two world models (MESSAGE and POLES) are very close to the mode of the distribution. Likewise the MARKAL baseline is situated near the mode of distribution for Europe, while POLES predicts very close to the median and PRIMES is situated between the two. The mean values as evaluated by PROMETHEUS are considerably higher than the model predictions. This is because they are influenced by the relatively small possibilities of major technico-economic breakthroughs, which the deterministic models naturally do not consider. On the other hand, none of the baseline predictions can be considered as an outlier: this is reassuring in terms of robustness of the results obtained across the project. At the same time it is not really surprising, given the attempt made to homogenise the technological database and assumptions on key drivers.

Figure D-77: Distribution of the centralised hydrogen production in 2050 (Mtoe)

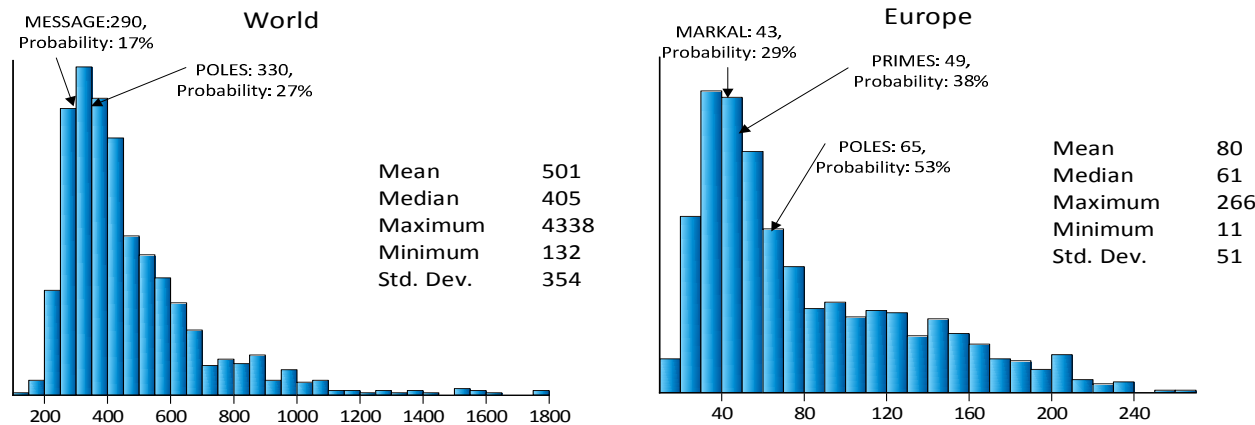
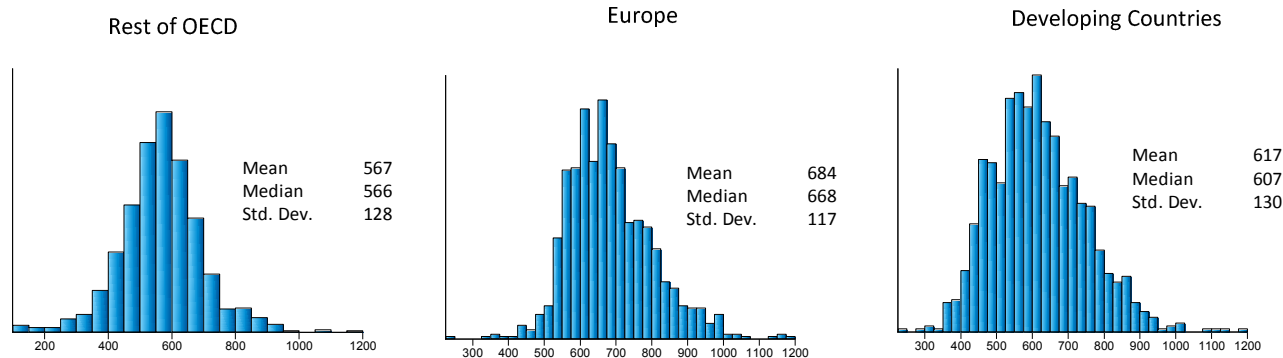


Figure D-78 presents the distribution of average hydrogen production cost in the different regions. A striking feature of these distributions is the similarity in terms of mean and standard deviation, as well as in terms of the general shape even over the less probable values. This is despite the fact that different pathways and intensities of climate policy have been assumed for the different regions.

Figure D-78: Distribution of the hydrogen production cost in the three regions in 2050 (€05/toe)



A general observation encountered with PROMETHEUS work in particular but also with other models is that the relation between cost of producing hydrogen and effective carbon values is far from being straightforward. Figure D-79 illustrates this point by taking the Rest of OECD region as an example. By careful consideration of this scattergram it can be noted that:

- For effective carbon values that are zero or close to zero hydrogen production costs tend to vary independently.
- For carbon values between 20 and 80 €/tn of CO₂ the relation seems to be broadly positive but less and less pronounced as the higher end of the range is approached.
- For values above 80 €/tn of CO₂ there are even appears to be some indication of reversal to a negative relation. This is due initially to decoupling as a result of large scale introduction of hydrogen free production technologies and CCS. The trend is intensified once biomass with CCS is considered, because in such cases the carbon value becomes a negative production cost.
- In any case the tendencies discussed above are far from being systematic and production costs display a lot of independent variation all along the possibilities space but particularly in the zone around 120 to 150 €/tn of CO₂.

Figure D-79: Relative importance of effective carbon value variability for hydrogen production cost variability (Rest of OECD, 2050)

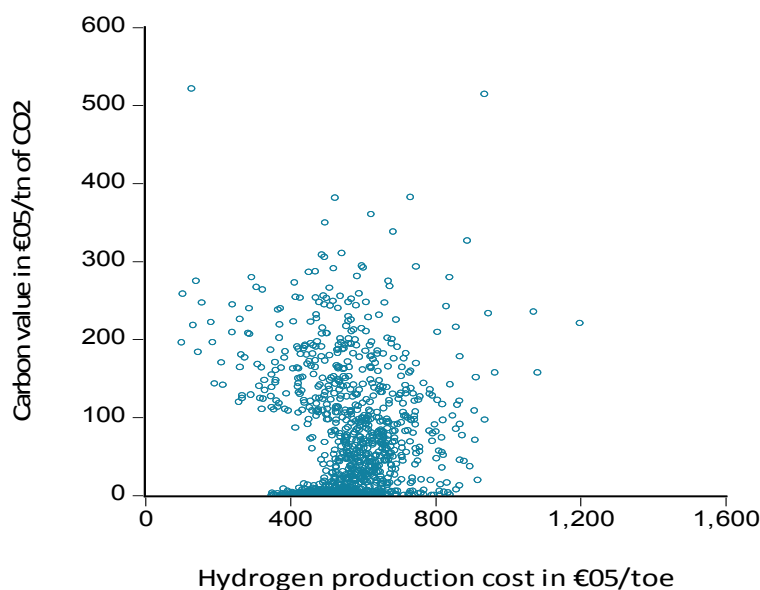


Figure D-78 dealt with the distribution of hydrogen production costs at the plant gate. However, before hydrogen can be used the cost of transport, distribution and storage must be added. Such costs for hydrogen are far from negligible but they vary depending on consumer class and the type of infrastructure involved. In order to provide a probabilistic indication of relative competitiveness of hydrogen at the consumption point Figure D-80 presents the evolution of the likelihood that delivered hydrogen will be less costly than its main

competitor fuel at the point of consumption in Europe. The competing fuel chosen for industry and the residential/commercial sector is natural gas delivered to the energy consumer facility, while for transport gasoline at the pump is used for the comparison. Taxes have been excluded in order to avoid considerations of the likelihood of differential taxation that would eventually cloud the issue of competitiveness of hydrogen. The first market where hydrogen is likely to become competitive is for small scale heat and power in industry. Already by the second half of 2020's there is more than one in four probability that hydrogen can be delivered at a lower cost than natural gas. Already by early 2030's this probability exceeds 50% and by 2040's stands at 70%. The cost of hydrogen at the pump has only a 10% probability of being lower than the cost of gasoline (excluding tax) in 2030. Thereafter it increases relatively rapidly reaching 50% by 2040 and 70% by 2050. Due to high transportation and distribution costs the delivered hydrogen cost to the residential/commercial sector is almost completely unlikely to be lower than natural gas in 2030 and there is less than a 15% probability that the situation is reversed by 2040. On the other hand towards the end of the final decade of the outlook the chances become even. The evolution of these probabilities has more to do with the likelihood of high fossil fuel prices in the longer term than the possibilities for cheap hydrogen production and distribution. It should be noted that the cost of delivered hydrogen is far from being an appropriate indication of the cost effectiveness of hydrogen use, which will depend primarily on the improvements on hydrogen end use technologies (see section "Penetration of hydrogen technologies").

Figure D-80: Probability of delivered hydrogen costing less than alternative fuel (excluding taxes) in Europe

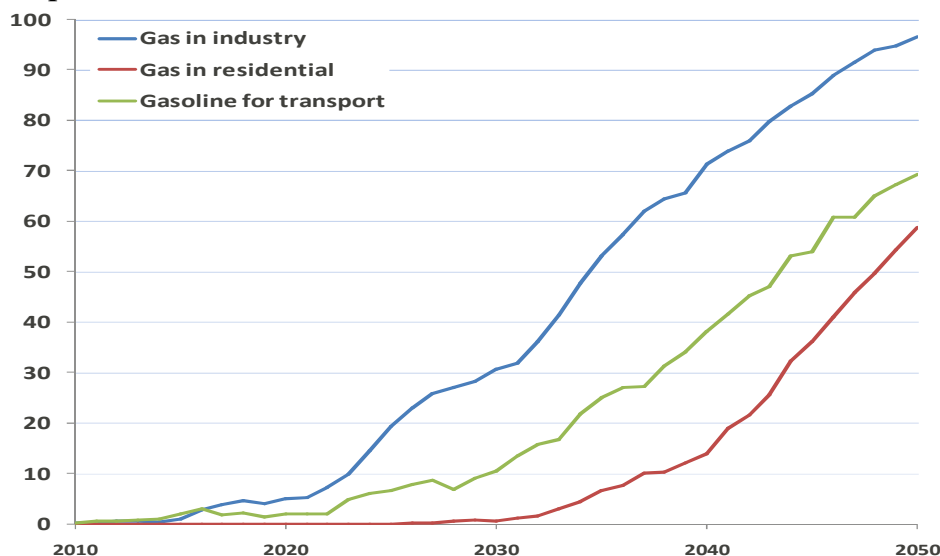
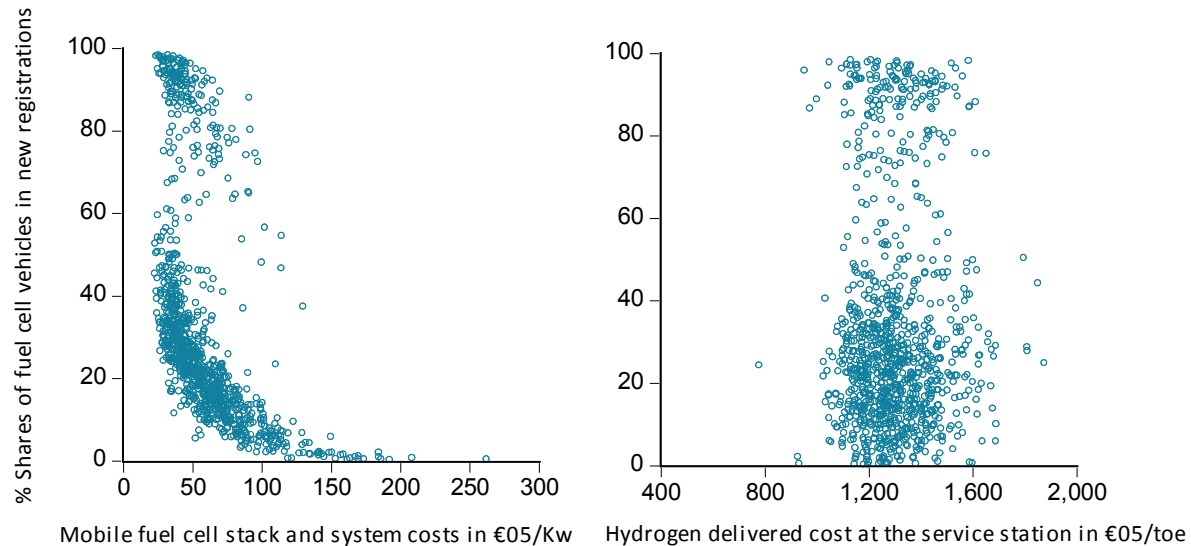


Figure D-81 illustrates clearly this latter point by concentrating on the share of fuel cell vehicles in European new registrations for 2050 (also covered in Figure D-75). The cluster of points representing probability density on the upper left hand corner of the graph on the left corresponds to the cases of major breakthrough, which is also illustrated as the second mode in the distribution in Figure D-75). For fuel and stack costs below 40€/05/Kw the probability of large fuel cell penetration diminishes rapidly, while there is a very small likelihood of significant penetration for costs of more than 100€/05/Kw. On the other hand, it is clear by looking at the graph on the right of Figure D-81 that the penetration of fuel cells in the new vehicle market is

statistically independent from the cost of delivered hydrogen. The strong pattern of the first graph goes a long way in explaining the lack of pattern on the right.

Figure D-81: Relative importance of hydrogen production cost variability for hydrogen penetration variability (Europe, 2050)



D.3 Technological Scenario analysis using the different models

D.3.1 Introduction to Technology Stories

In this section we describe the global picture of technology development, which is the common background of the models from Europe and around the world being used in Cascade Mints Part 1 and the basis of the technology stories. The specific details of the different storylines are given below after the common baseline assumptions. The population projections and the economic growth figures are based on the SRES B2 scenario.

The common baseline assumptions

The population reaches about 10 billion by 2100. Income per capita grows at an intermediate rate to reach about US\$12,000 by 2050. It is a world with economic catch-up and massive infrastructural developments, particularly in the developing countries of today. In the energy area, this implies development of large sources of primary energy, integrated electricity grids, and energy gas pipelines. Economic development is associated with: 1) high rates of capital turnover; 2) generous investment in research and innovations, infrastructures, education, cultural values, and social security for the less privileged; and 3) an amplification of the current tendencies toward stronger environmental awareness. The world is more and more urbanized, and humanity is increasingly concentrated in large urban corridors and mega-settlement patterns. Current

examples would be the Tokyo–Osaka corridor, the Ruhr cluster in Europe, the eastern seaboard of the United States, and many of the main mega-cities in the developing parts of the world ranging from New Delhi and Beijing to Mexico City and Sao Paolo. The technology stories depict a world that tries to address the main challenges to the global energy system, to provide affordable and reliable energy services for most of the global population, and to protect the environment at all scales from global to local. For the first time, humanity is in a position to irreversibly interfere in the planet’s processes, from the ecosphere to climate change. Natural disasters, new scientific findings, political changes, and increasing incomes drive the political will to act against climate change, and a paradigm shift occurs toward massive decarbonization. As a market-based policy measure, a carbon tax is implemented. Table D-36 lists the baseline assumptions.

Table D-36. Baseline carbon tax assumptions. These assumptions are based on the SAPIENTIA Delphi expert opinion poll.

	Euro2000/tC										
	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Europe	0	50	74	118	179	250	349	349	349	349	349
Rest of OECD	0	27	45	81	134	201	297	297	297	297	297
Rest of World	0	5	13	33	69	122	220	220	220	220	220

The hydrogen and electricity technologies (also called hydricity technologies; see Nakicenovic et al., 2005) offer future energy systems with zero carbon emissions, provided that both electricity and hydrogen are produced: 1) from hydrocarbons with carbon capture and storage; or 2) from other sources of energy such as nuclear and new renewables. A transition toward a hydrogen and electricity age is consistent not only with the historical evolution of the global energy system but also with a pervasive decarbonization of energy, from exclusive dependence on carbon-intensive energy sources and carriers, such as coal and biomass, toward liquids, electricity, and energy gases. Energy gases have an especially important role, as they offer the possibility of grid-oriented and very convenient energy carriers, ranging from syngases to methane and hydrogen. They complement electricity as the other grid-oriented and also very convenient energy carrier. A further shift toward energy gases, electricity, and the hydricity age is consistent with the increasing quality and flexibility of energy carriers, higher security, and better environmental protection. It is also consistent with an increasing share of grid-oriented energy carriers reaching the consumer today in the more affluent parts of the world, primarily as natural gas and electricity. Depending on the local circumstances, the energy conversion to hydrogen is either central, with higher infrastructure investments providing more economic and environmentally benign structures, or more decentralized conversion, distribution, and energy end-use patterns.

The technology stories scenarios

The storylines mainly consider the OECD and fast-growing Asian regions. As these regions are technology leaders, policy there influences technology development.

1. Demand-pull storylines:

a) “Breakthrough in fuel cells” storyline. Considering the importance of the automotive industry, technological leadership in fuel cell technologies is considered a key part of industrial competitiveness by

OECD governments. Even though big improvements are still needed in fuel cell technology, and even though industry is investing considerable funding in technology development, governments dedicate massive R&D funding to breakthroughs in areas that are known inhibitors of high-volume production of fuel cell vehicles. Between 2008 and 2015, there is enormous investment in research that focuses on new fuel cell designs using low cost materials, on the durability of these new fuel cell systems, and on on-board storage systems. These efforts lead to mass production starting around 2020. As a result, the wholesale costs of the fuel cell components (system + stack) of a car in 2025 reduce from about 190 USD2000/kW in the baseline story to about 40 USD2000/kW. Focused research is also directed to high-efficiency, low-emission decentralized power generation using stationary fuel cell combined-heat-and-power plants. In 2025 investment costs are down to 250 USD2000/kW compared with 1,500 USD2000/kW in the baseline story.

b) “Urban air pollution measures” storyline. Increasing high urbanization at a global scale leads to air-pollution-related health problems, especially in the fast-growing developing regions and large urban clusters. The expansion of the European Union accelerates the growth in road freight transport. Goods are produced at the cost-optimal location and transported to the demand centers. Technological research and development is the same as in the “Breakthrough in fuel cells” storyline but in this storyline, growing private incomes lead to a public willingness to act against increasing air pollution and particulate matter. Instead of requiring certain emission standards, a more market-based approach is chosen. From 2025 onwards, fuel tax is increased by 0.5 euro2000/liter gasoline equivalent (15.6 euro/GJ) for all fuels except the “emission-free” fuels, hydrogen, and electricity, which are completely exempt from fuel tax.

c) “Strong climate policy” storyline. This storyline differs from the “Urban air pollution measures” storyline in terms of stronger actions being taken against global warming. A series of natural disasters, including unprecedented strong rainfalls, storms, floods, heat waves, and droughts, increases the costs and the public awareness of climate change. Natural disasters, new scientific findings, and political changes lead to an increasing willingness to avoid excessive global warming through strong coordinated global and local actions. As a market-based measure, carbon taxes are introduced globally. Carbon taxes increase in the course of time because of more and more evidence of climate change, the dangers of irreversible climate change, and evidence for positive feedbacks, such as thawing of permafrost and methane hydride release from a warming ocean. Europe plays a leading role in taking action against climate change.

Table D-37. Global Carbon Tax in the “Strong climate policy” story.

	Euro2000/tC										
	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Europe	0	99	149	236	358	501	698	698	698	698	698
Rest of OECD	0	54	89	161	269	403	593	593	593	593	593
Rest of World	0	10	25	65	137	243	441	441	441	441	441

2. Supply-push storylines:

a) “Breakthrough in hydrogen production” storyline. In this storyline, the political framework sets out clear support for the hydrogen economy at an early stage. In 2015 issues such as safety regulations, infrastructure development, and policy support are agreed upon for the OECD regions and provide a stable

business environment for long-term investments. As a result hydrogen production is larger scale and more centralized, compared to the baseline. More R&D is focused on hydrogen production, with a special emphasis on reducing the costs of hydrogen production from renewable energy sources. As a result the hydrogen production costs in 2025–2030 in this storyline are about 20–30% lower, compared with the baseline.

b) “Subsidy of hydrogen infrastructure” storyline. This storyline has the same hydrogen production cost reductions as the “Breakthrough in hydrogen production” storyline. Facing problems in energy security, urban pollution, and global warming, governments decide to develop the hydrogen infrastructure as a public service. A hydrogen infrastructure R&D program in 2010–2015 addresses issues such as exploratory research on new concepts for hydrogen delivery, optimal hydrogen infrastructure layout and implementation, storage requirements, hydrogen purity, and pipeline materials. The infrastructure is developed until 2020, and storage, transport, and distribution are supplied free of charge. In Europe the discussed EC Directive COM(2001) 547 is implemented, which requires that at least 5% of vehicles to 2020 be hydrogen vehicles. For this purpose, full area coverage is achieved by upgrading 15–20% of all refueling stations to supply hydrogen. This H₂ infrastructure enables hydrogen to be substituted for up to 15% of today’s conventional fuels in 2020.

c) “Strong climate policy” storyline. This storyline is based on the “Subsidy of hydrogen infrastructure” storyline but, as in the “Strong climate policy” storyline in 1c, natural disasters, new scientific findings, and political changes lead to a strong climate policy, which is implemented through a carbon tax with a tax rate that varies according to region (See Table D-37).

3. “Combined policy” storyline. This is a storyline that is very optimistic in terms of developments in favor of hydrogen. It is a combination of the developments of the “Strong climate policy” storylines 1.c and 2.c. and assumes: 1) massive R&D investments into fuel cell research; 2) strong actions against urban air pollution leading to an additional fuel tax on conventional fuels of 15.6 euro/GJ with exemptions for hydrogen and electricity; 3) early establishment of the political framework to support the hydrogen economy; 4) increased R&D investments into hydrogen production options; 5) hydrogen infrastructure being developed as a public service; and 6) strong action against climate change through a variable regional carbon tax (See Table D-37).

D.3.2 Analytical results using different models

D.3.2.1 POLES

[by S. Mima (LEPII-EPE)]

Overview

POLES has been extended and radically re-designed so as to describe all possible configurations of a hydrogen economy. This includes all demand categories where fuel cells can be used as well as the different

options producing hydrogen from different primary sources. Because of the analytical description of the whole energy system and the adequate mechanisms of representing the hydrogen economy, POLES is a very useful tool to perform technological scenario analysis in order to explore under what conditions and to what extent the hydrogen economy may materialize.

If the reference represents an equilibrated assessment of technological perspectives concerning hydrogen related technologies both on the demand and the supply side equivalent to a “consensus view”, a much more optimistic view can be formed by “Technology story” type scenarios, which have been constructed primarily by assuming favorable trajectories for the technical and economic characteristics of hydrogen related technologies (both on the demand and supply side). Such scenarios have been based on a careful and unbiased examination of prospects as they appear to experts today.

Once POLES has been equipped with adequate mechanisms for representing the hydrogen economy it is used to explore under what conditions and to what extent it may materialize.

A Reference representing either a median, “conventional wisdom” or “Business-as-usual” (pessimistic case) is developed to serve as a benchmark against which alternative and more optimistic scenarios have been examined.

Such scenarios have been constructed primarily by assuming favorable trajectories for the technical and economic characteristics of hydrogen related technologies first on the demand, secondly on supply side and at last on a combined case. Such scenarios are based on a careful examination of prospects as they appear to TECHPOLES database constructed by CASCADE MINST experts.

Description of scenarios

Discussions between partners made clear that both breakthroughs in the hydrogen technologies and demand pulls are required to establish a hydrogen economy. In the effort to explore the future (which is inherently uncertain) scenarios are designed to explore possible future configurations by describing hypothetical sequences of events that could develop over a period of time. Each scenario is accompanied by a storyline, which covers the prevailing driving forces that shape that future.

That's why, three types of scenarios have been selected : demand pull, supply push and combined cases. Demand pull cases are constructed on assumptions that concern the increase of the hydrogen demand. Whereas the supply push cases make assumptions on decrease of the hydrogen production, transport and distribution costs. The combined case links technology assumptions with climate policy uncertainties.

3 demand pull scenarios have been identified :

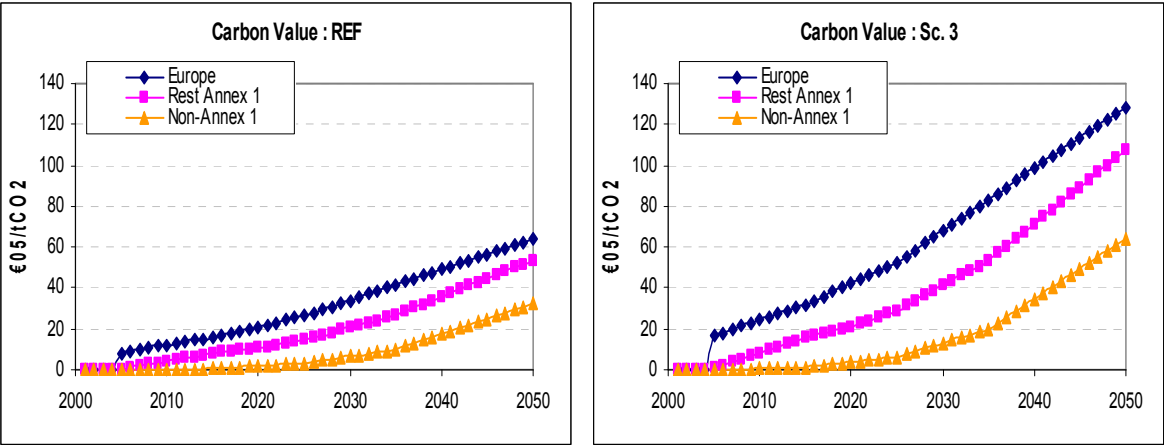
Scenario 1.a : Breakthrough in fuel cells (setting all technical and economic parameters to their technical limits as defined in the technology perspectives analysis).

Scenario 1.b : S 1.a + worldwide increase in the tax on fossil fuels for road transport of the order of 0.5€/lt from 2025 and onwards.

Scenario 1.c : S 1.a + doubling the baseline climate policy worldwide from 2010 and onwards.

Assuming some breakthroughs in fuel cells (S 1.a) may be translated in the model through reducing fuel cell cost close to the floor cost from 2025 to 2050. The demand for hydrogen can be encouraged also through subventions on purchase cost of FCVH, for example lets assume that a support of 5000 €/vehicle may be granted by the governments desirous to reduce transport emissions. This measure makes fuel cells vehicles really competitive in comparison with conventional ones. Another way to promote the use of hydrogen can be the instauration of a tax on local pollution, as for example the increase of + 50% on existing tax on gasoline and diesel except CO2 taxes. The third scenario integrates the assumptions of S 1.a and S 1.b and doubles the baseline climate policy worldwide from 2010 and onwards, as it is presented in the following figure :

Figure D-82 : Carbon value in the reference and carbon constraint case



In the hydrogen **supply side** three other scenarios have been taken into account :
The scenario S 2.a assumes cheap H2 production, by setting all production technologies technical and economic parameters to their limits from 2025 onwards.

The scenario S 2.b count not only in improvements in the hydrogen production costs but also on subsidising (100%) all hydrogen distribution and storage infrastructure.

The scenario S 2.c integrates assumptions of the scenarios S 2.a and S 2.b as those of doubling the baseline climate policy worldwide from 2010 and onwards.

The technological advancements and lessons learned through these 6 technology story scenarios is integrated to S 3 in order to understand the complex interactions between components, systems costs, environmental impacts, societal impacts, and system trade offs. Identifying and analyzing these interactions results in well-integrated and optimized hydrogen and fuel cell systems.

Table D-44 summarizes the main characteristics of the described scenarios.

Table D-38 : Summary of the Scenario assumptions and their translation into modelling inputs

1. Demand pull				2.a.	2.b.	2.c.	3
1.a.	Breakthrough in fuel cells (reducing their cost to close to floor cost)	2025-50	2025-50				2025-50
	HFC	160 €/kW	160 €/kW				160 €/kW
	GFC	175 €/kW	175 €/kW				175 €/kW
	HFCV	20000 €/veh	20000 €/veh				20000 €/veh
	GFCV	21000 €/veh	21000 €/veh				21000 €/veh
	THYV	18000 €/veh	18000 €/veh				18000 €/veh
1.b.	1.a.+ worldwide increase in the tax on fossil fuels for road transport	2025-2050	2025-2050				2025-2050
	• tax on fossil fuels for road transport	0.5€00/lt from 2025 and onwards	0.5€00/lt from 2025 and onwards				0.5€00/lt from 2025 and onwards
1.c.	1.a. + 1.b. + climate policy		Doubling the baseline climate policy worldwide from 2010 and onwards				Doubling the baseline climate policy worldwide from 2010 and onwards
2. Supply push							
2.a.	Cheap H2 production, by setting all production technologies technical and economic parameters to their limits from 2025 onwards	2025-50	2025-50	2025-50	2025-50	2025-50	2025-50
	Cheap biomass gasification with CCS +	111 €/M3d	111 €/M3d	111 €/M3d	111 €/M3d	111 €/M3d	111 €/M3d
	Cheap Coal gasification with CCS +	111 €/M3d	111 €/M3d	111 €/M3d	111 €/M3d	111 €/M3d	111 €/M3d
	Cheap electrolyser (WEG) +	60 €/M3d	60 €/M3d	60 €/M3d	60 €/M3d	60 €/M3d	60 €/M3d
	Cheap 4th generation nuclear (WEN) +	190 €/M3d	190 €/M3d	190 €/M3d	190 €/M3d	190 €/M3d	190 €/M3d
	Breakthrough in wind offshore (WEW) +	150 €/M3d	150 €/M3d	150 €/M3d	150 €/M3d	150 €/M3d	150 €/M3d
	Cheap electricity prod by WNO (flor investment cost)	815 €/kW	815 €/kW	815 €/kW	815 €/kW	815 €/kW	815 €/kW
	Cheap high temperature thermochemical cycle process (NHT) +	300 €/M3d	300 €/M3d	300 €/M3d	300 €/M3d	300 €/M3d	300 €/M3d
	Cheap high temperature thermochemical cycle process (SHT) +	350 €/M3d	350 €/M3d	350 €/M3d	350 €/M3d	350 €/M3d	350 €/M3d
2.b.	2.a. + subsidise (100%) all hydrogen distribution and storage infrastructure						
	Technology trend TRHD				-0.047	-0.047	-0.047
	CHHNC				0.4	0.4	0.4
	DHLNC				100 €/toe	100 €/toe	100 €/toe
	DHMNC				75 €/toe	75 €/toe	75 €/toe
	DHHNC				50 €/toe	50 €/toe	50 €/toe
2.c.	2.a + 2.b. + climate policy					Doubling the baseline climate policy worldwide from 2010 and onwards	
3. Combined case							
3	1.c + 2.c						

Analysis of the scenarios

In this part will be analyzed the results of the simulation of 7 technological scenarios and comparisons between them, aiming to put in evidence the driving elements which may extend the hydrogen economy.

Demand pull scenarios

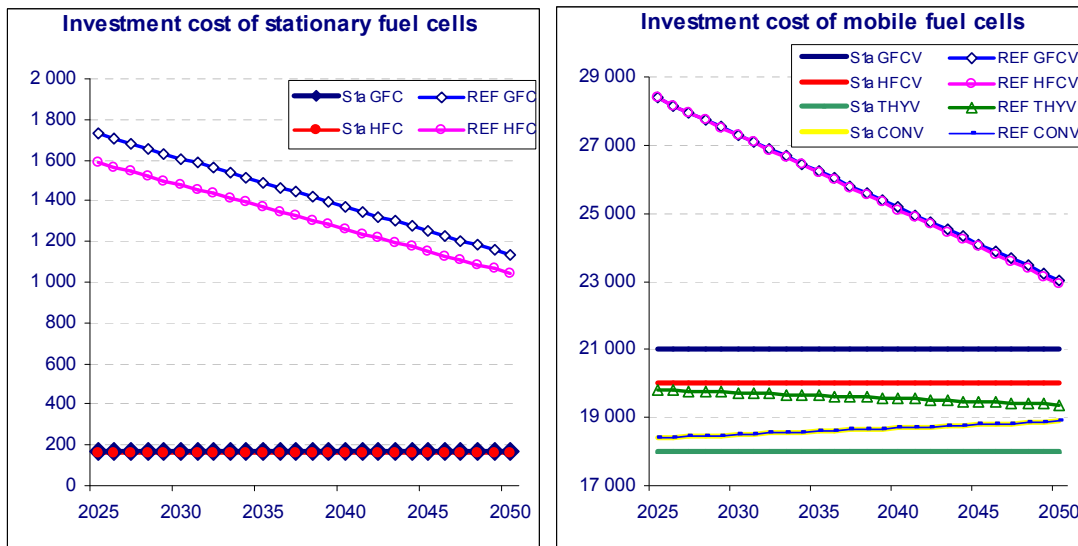
Assumptions on breakthrough in fuel cells, plus worldwide increase in the tax on fossil fuels for road transport from 2025 and onwards combined with doubling the reference climate policy worldwide from 2010 and onwards will be tested separately and in a combined way identifying their impact on hydrogen demand according the two markets : mobile and stationary.

S 1.a : Breakthrough in fuel cells

The first scenario intends to analyze the impact of the breakthrough in fuel cells in the development of the hydrogen economy. The best way was to assume an important reduction of the fuel cell cost close to the floor

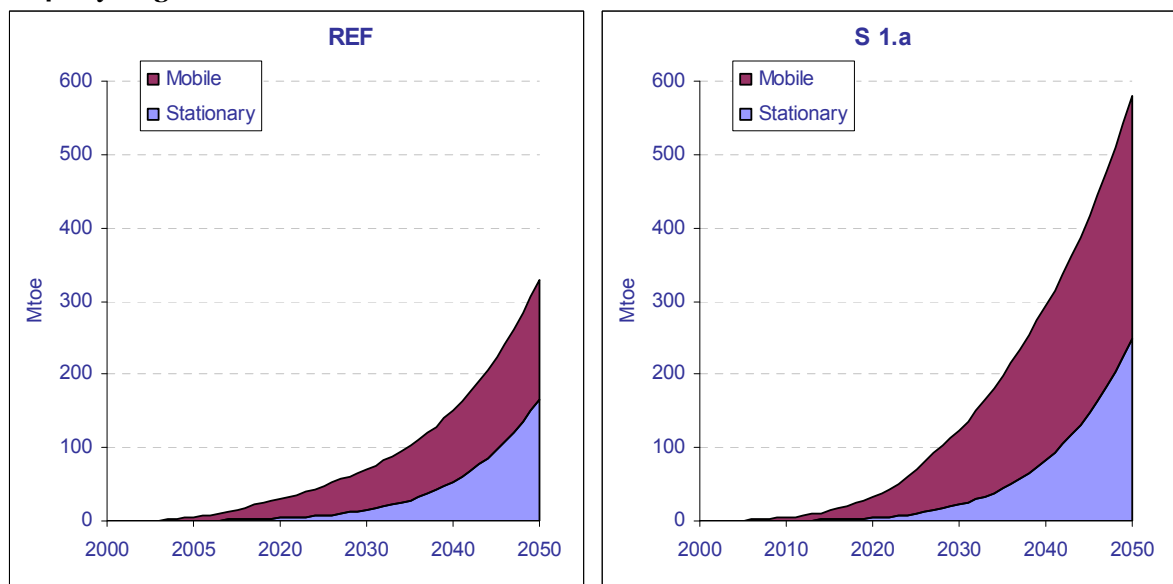
cost from 2025 to 2050 : HFC at 160 €/kW, HFCV at 20000 €/vehicle²⁴. The same thing was assumed for thermique hydrogen vehicles : THYV at 18000 €/vehicle. So, in S 1.a scenario, the stationary fuel cells are 10 times less expensive during the period 2025-2050. On the other hand, despite the breakthrough, fuel cell investment costs in mobile market remain higher than for conventional vehicles.

Figure D-83 : Fuel cell investment cost assumptions



In the S 1.a scenario, total H₂ demand is 1.8 times higher than in REF case. This increase is more important in mobile sector (2 times) than in stationary use (1.5 times).

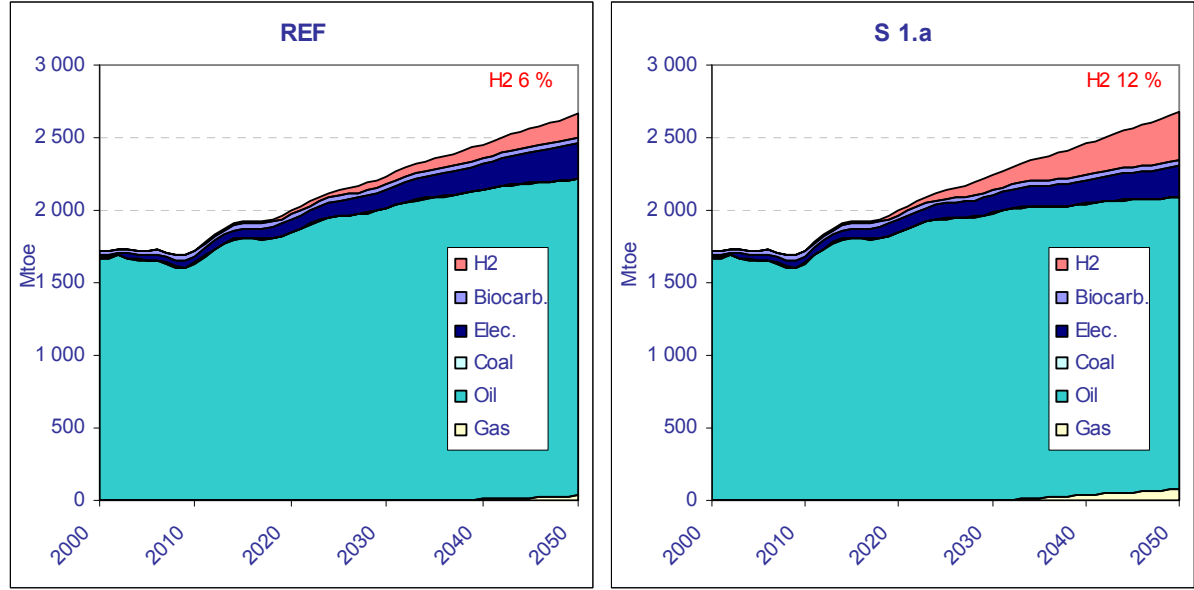
Figure D-84 : Hydrogen markets



²⁴ For comparable reasons it is supposed that GFC cost will be 175 €/kW and GFCV 21 000 €/veh.

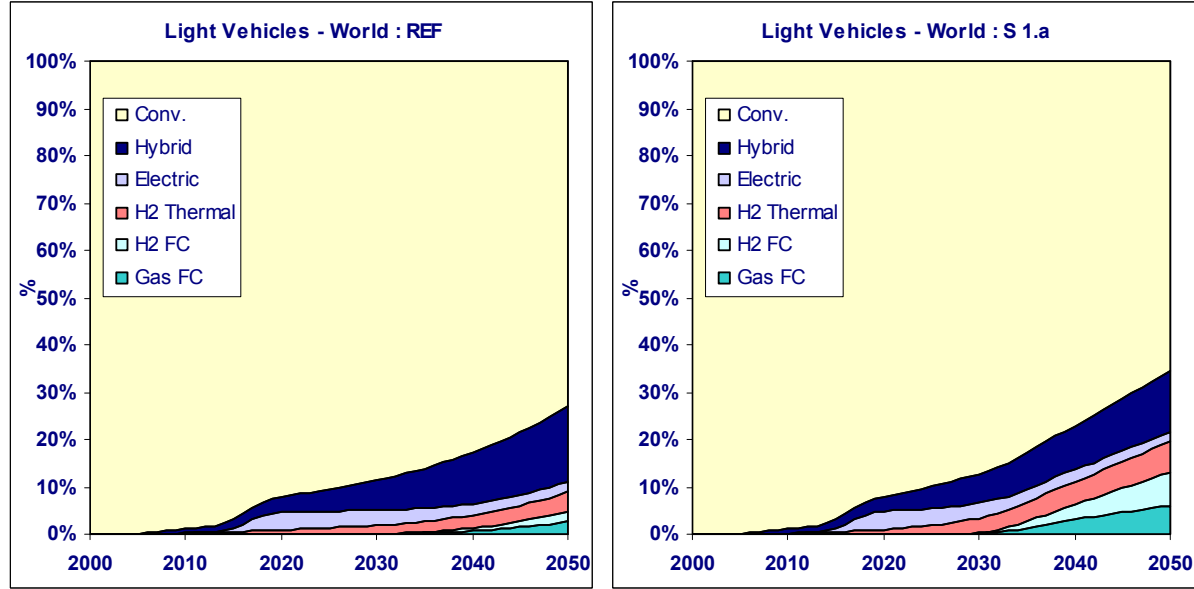
The share of hydrogen use in transport double in S 1.a scenario in comparison with the reference case.

Figure D-85 : The share of Hydrogen in the transport consumption



However, hydrogen vehicles which represent 6% of total light vehicles in the reference case in 2050, represent no more than 14 % in the S 1.a scenario with equally part for fuel cell and thermique hydrogen vehicles.

Figure D-86 : Share of hydrogen vehicles

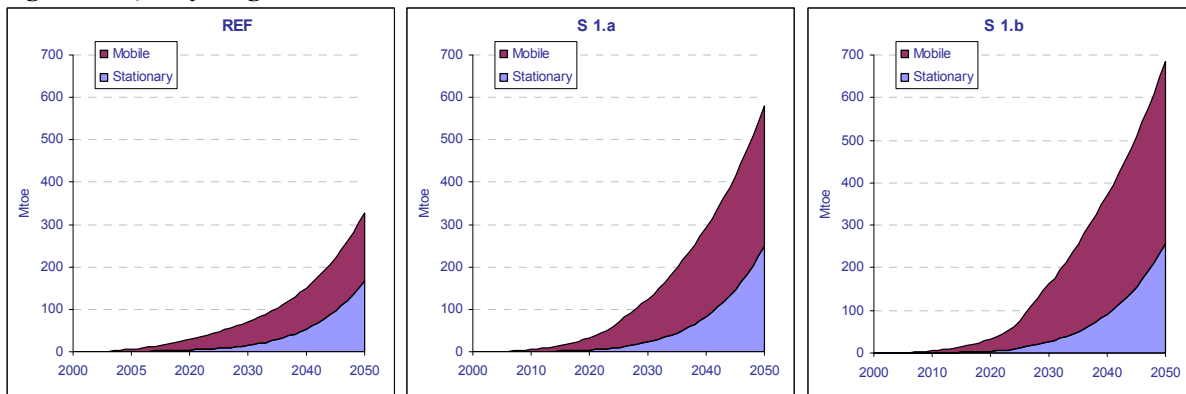


S 1.b : Breakthrough in fuel cells and urban environmental considerations

The scenario S 1.b suppose a combination of the previous scenario with urban environmental considerations. The urban environmental considerations are translated in the scenario through worldwide increase of the tax on fossil fuels for road transport of the order of 0.5€/lt from 2025 and onwards. In absolute term this tax represents important revenue which in its turn can be used to promote the diffusion of hydrogen fuel cell vehicles.

Demand for H₂ in S 1.b is 20 % higher than in S 1.a scenario, from which mobile uses increase 30 %.

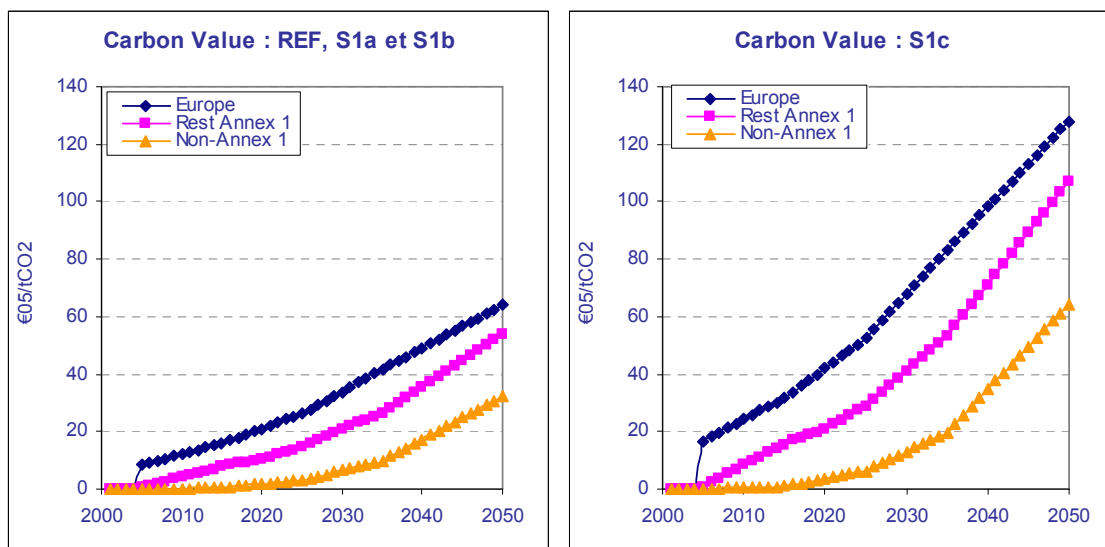
Figure D-87 : Hydrogen markets



S 1.c : Breakthrough in fuel cells, urban environmental considerations and climate policy

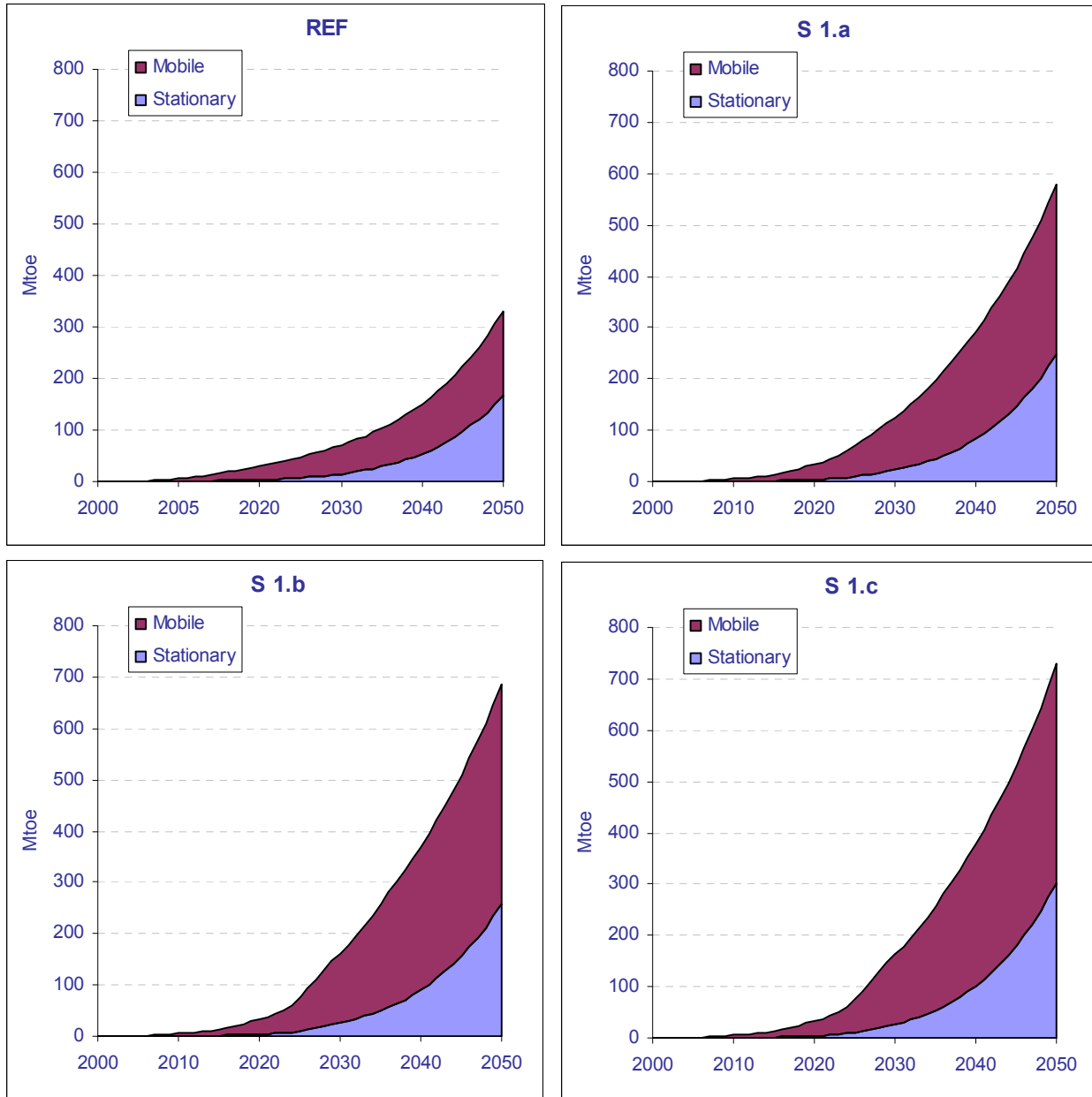
The Carbon Constraint case reflects a state of the world with moderately ambitious climate targets. While the reference, S 1.a and S 1.b scenarios apply climate policy assumptions used SAPIENTIA project, S 1.c apply 2 times assumptions used SAPIENTIA project. Taken together, the assumptions of S 1.b projection and the Carbon Constraint case indicate the major changes to expect in the structure and development of the world energy system in different policy contexts.

Figure D-88 : Carbon value used in the Cascade scenarios



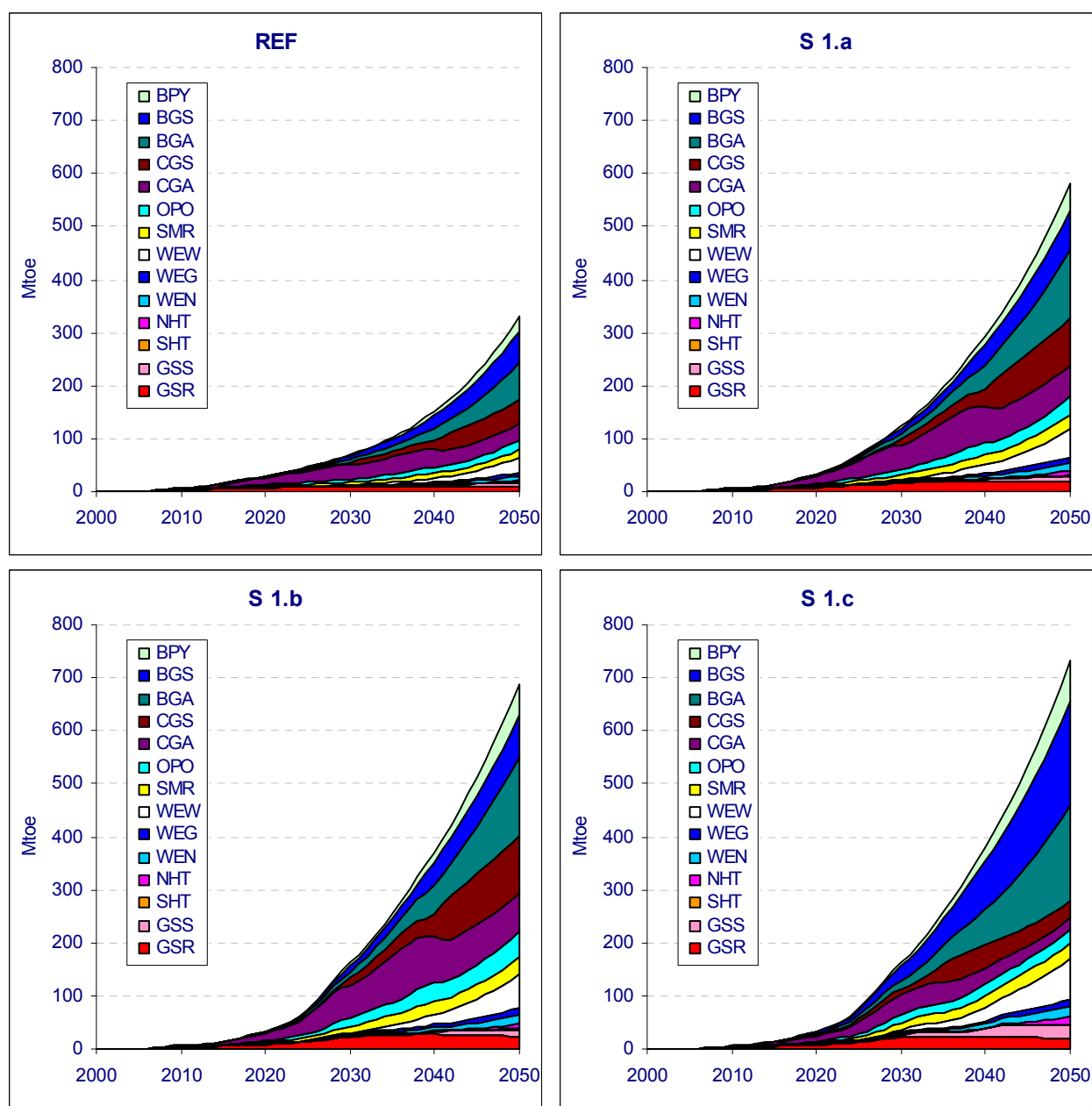
The present projections, with the horizon of 2050, clearly show the consequences of the twin constraints of finite fossil fuel resources and restrictions on greenhouse gas emissions. The image of the world provided by S 1.c makes apparent the need for radical changes to energy systems. Demand for H₂ in S1c is 2.2 times higher than in REF. Mobile uses increase respectively 2.6 times, while stationary uses only 1.8 times.

Figure D-89 : Hydrogen markets



Because of the higher carbon value in the S 1.c scenario, some changes can be identified in the structure of the hydrogen production technologies : in 2050, the role of renewables increase from 51 % in S 1.b to 72 % in S 1.c scenario. Nuclear technology also increase their share from 3 to 5 %. Coal technologies decrease their share from 26 % to 7 %.

Figure D-90 : Hydrogen production mix



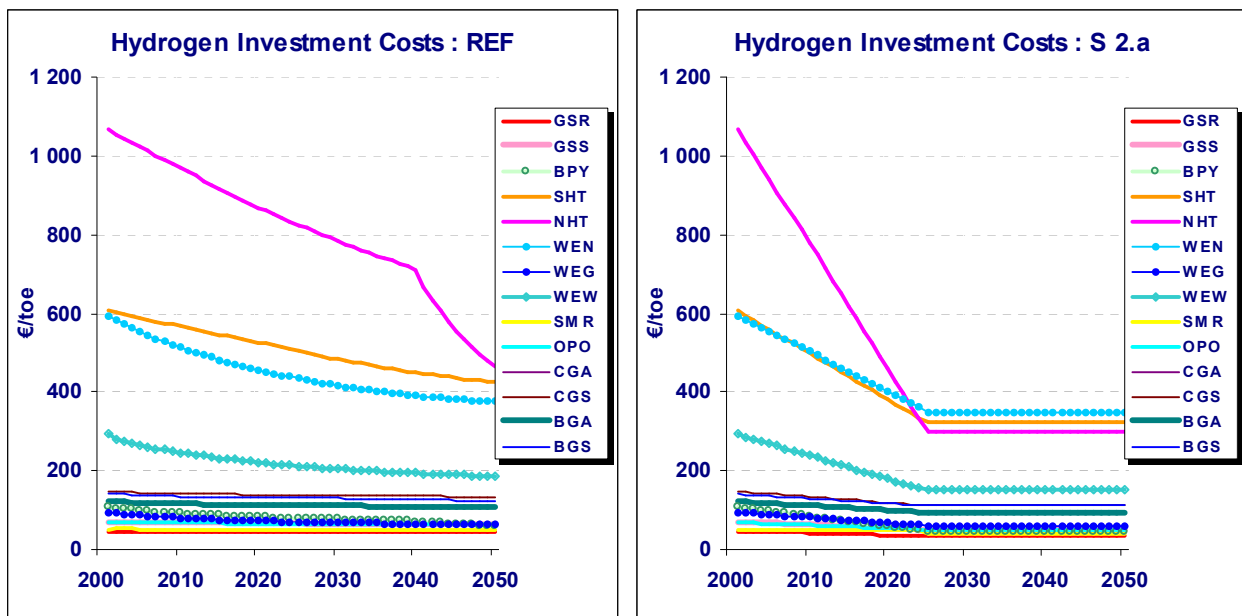
Supply push scenarios

Three other scenarios have been constructed as supply push scenarios. They intend to test the impact of cheap H₂ production investment cost and hydrogen distribution and storage infrastructure on the diffusion of the hydrogen economy. The impacts are calculated separately and combined with climate policies.

S 2.a : cheap H₂ production, by setting all production technologies technical and economic parameters to their limits from 2025 onwards.

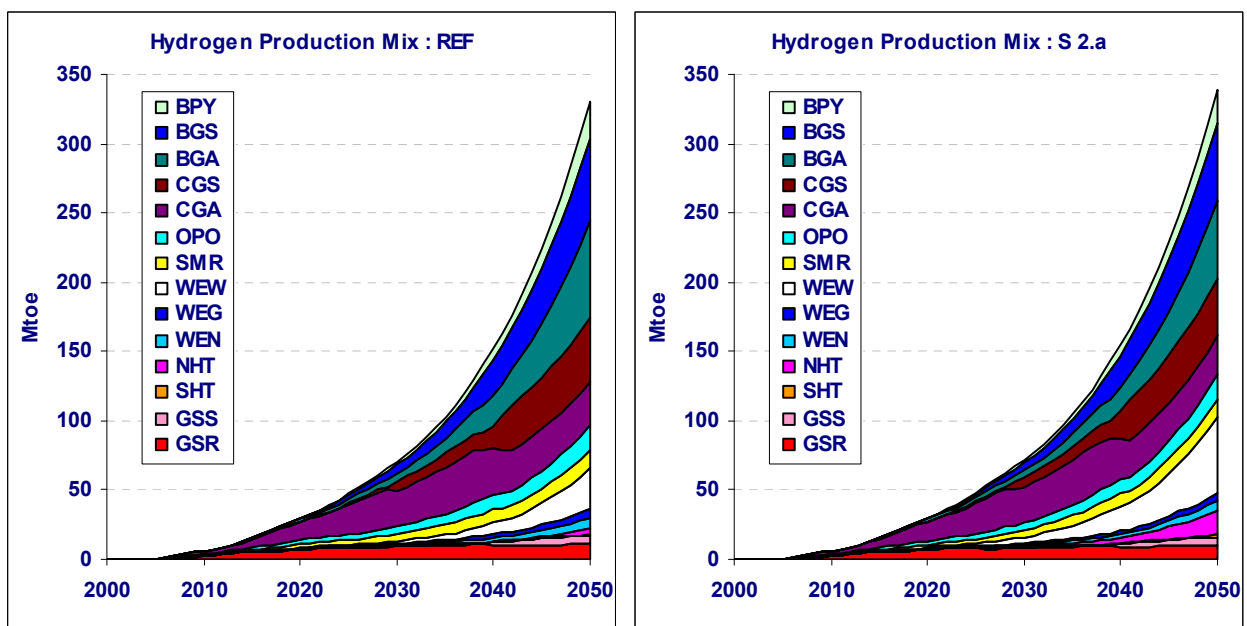
Assumptions on investment costs are presented in the following graph :

Figure D-91 : hydrogen Investment costs



Despite cheaper production cost, demand for H₂ isn't so different from the REF case. The winner technology in this case is WEW which H₂ production is 1.8 times higher in S 2.a than in the reference case in 2050.

Figure D-92 : Hydrogen production mix

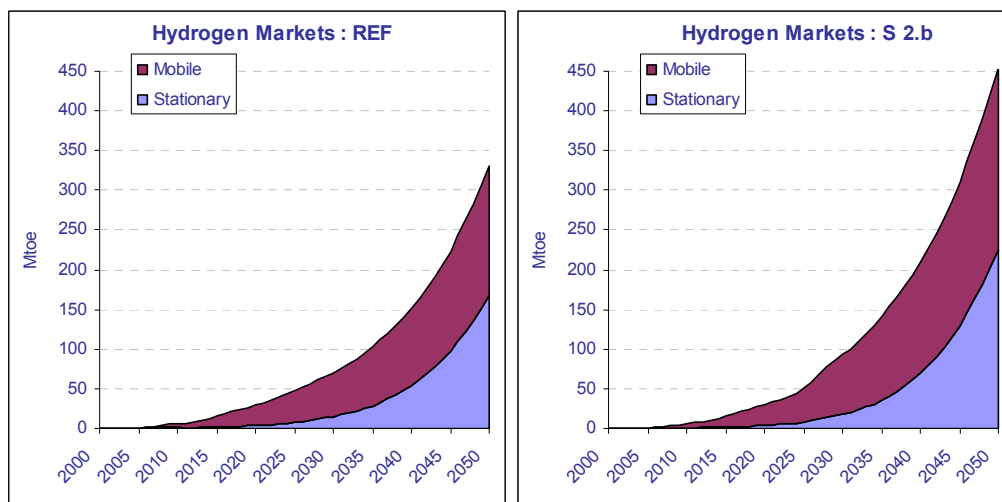


So, all incremental improvements that are expected in the hydrogen production technologies, all the way to 2050, will not change the role of the hydrogen economy.

S2.b : S 2.a + subsidize (100%) all hydrogen distribution and storage infrastructure

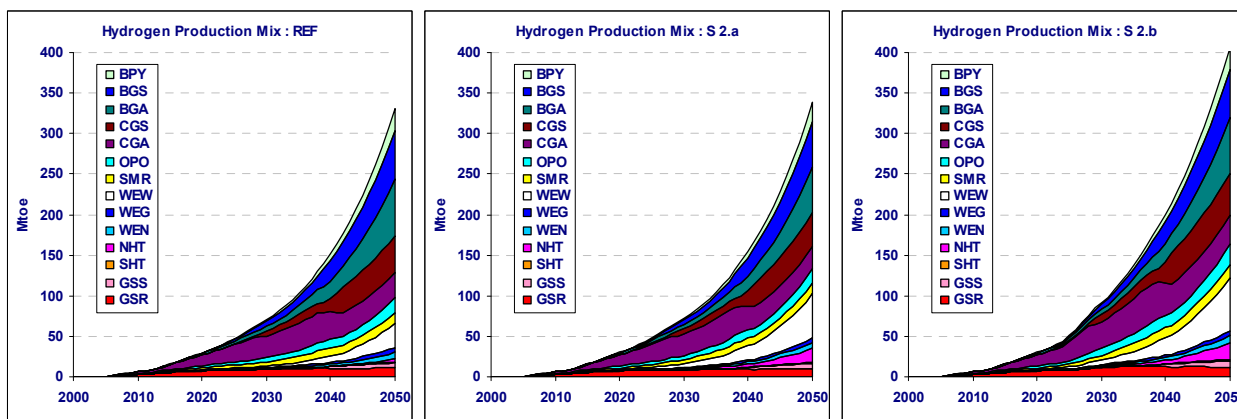
After testing the impact of the reduction of the investment costs of hydrogen production technologies, its important to test also the impact of subsidizing all hydrogen distribution and storage infrastructure on the diffusion of the hydrogen economy. Reducing hydrogen distribution and storage infrastructure expenditures to zero means a reduction of the hydrogen price which have an impact on the demand side : 20 % more H₂ than in S 2.a scenario.

Figure D-93 : Hydrogen markets



The hydrogen mix doesn't change in a significant way.

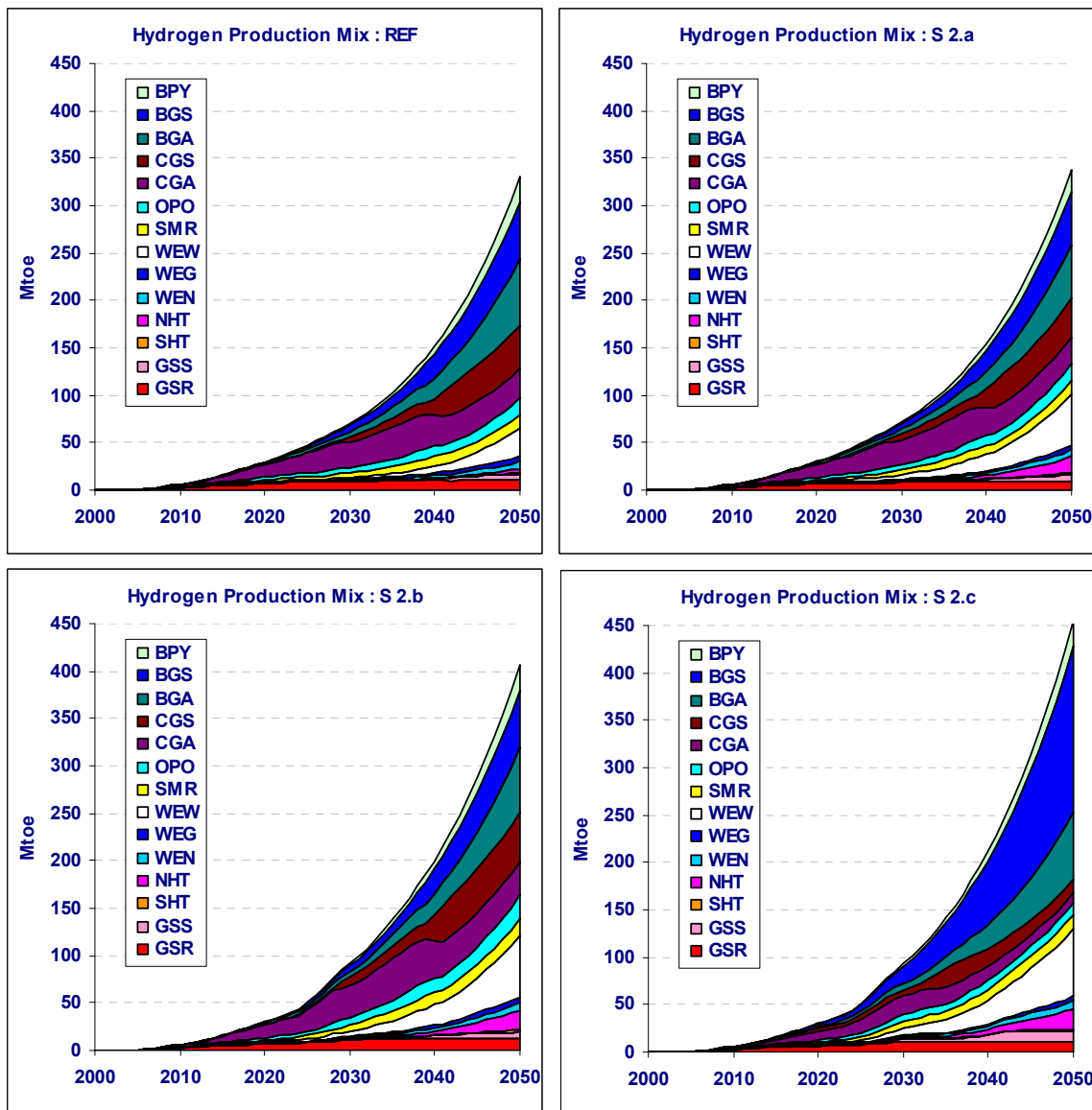
Figure D-94 : Hydrogen production mix in REF, S 2.a and S 2.b scenarios



S 2.c : S 2.b + doubling the baseline climate policy worldwide from 2010 and onwards

The fact that in S 2.c, H₂ production is multiplied by 1.4 in comparison with the REF case, shows that the deployment of hydrogen in the world energy system is compatible with ambitious climate policies. Renewables are technology winners in this case. The role of biomass increase from 47% in the REF case to 60% in the S 2.c case and the role of wind nearly double.

Figure D-95 : Hydrogen production mix



S3, Combined « Technology Story » : S 1.c + S 2.c scenarios

The combined scenario represents the most favorable case in the Cascade project for hydrogen economy development. It is derived from the carbon constraint case, but also assumes a series of technology breakthroughs that significantly increase the cost-effectiveness of hydrogen technologies, in particular in end-use. It is characterized by :

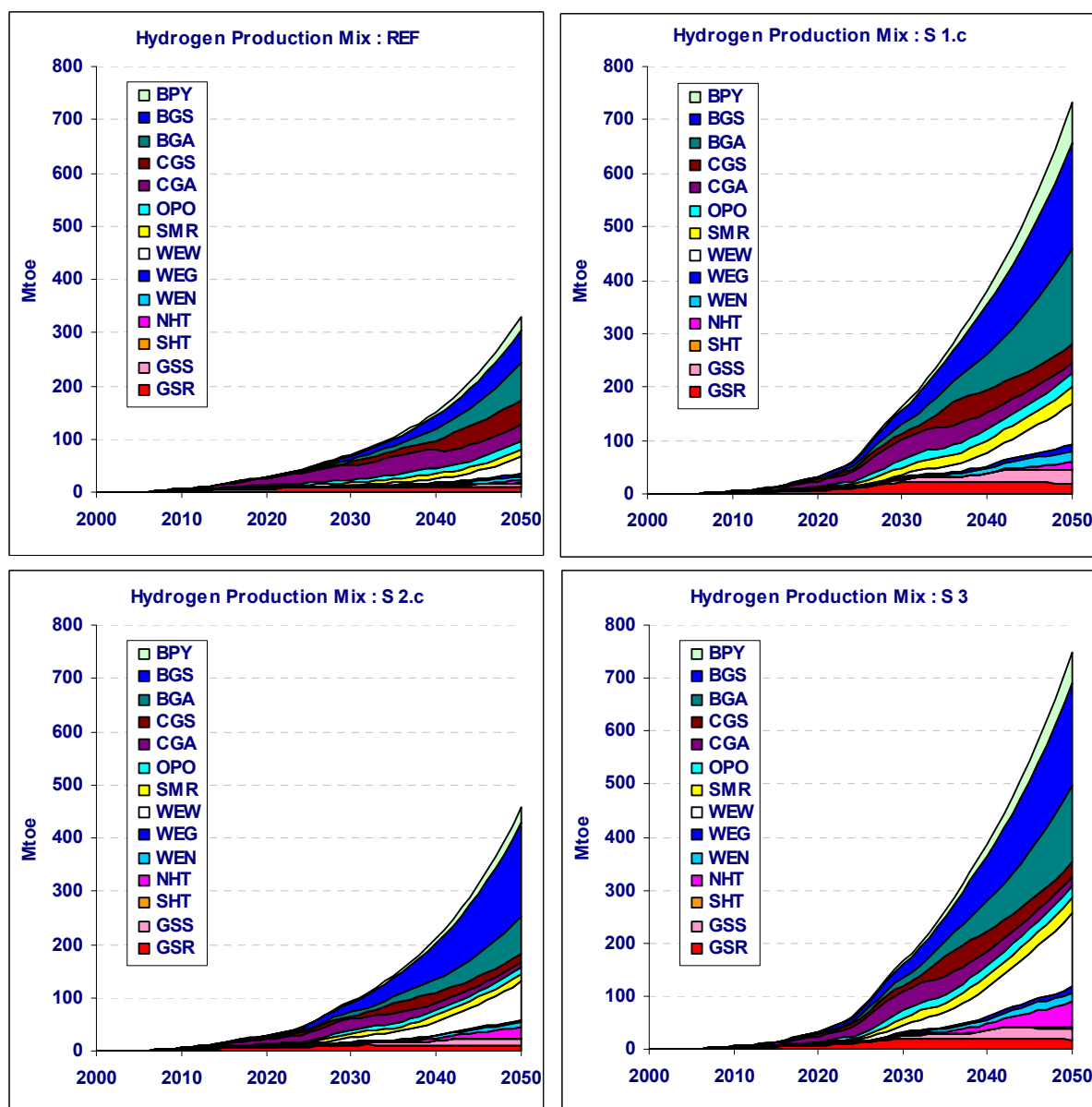
1. Important breakthroughs in fuel cell technologies associated with significant improvements in the production, distribution and storage of hydrogen technologies ;
2. A strong commitment of the society since the beginning of the century to introduce sizeable urban environmental considerations, and

- Important climate policies (doubling the baseline climate policy worldwide from 2010 and onwards).

Hydrogen production and use

The use of hydrogen takes-off after 2030, driven by substantial reductions in the cost of the technologies for producing hydrogen and the demand-pull in the transport sector. From 2030 to 2050, production increases more than four-fold attaining 749 Mtoe. By 2050, hydrogen provides 6% of final energy consumption, compared to 2.5 % in the Reference case. The share of renewable energy in hydrogen production is 58 % and that of nuclear is 6.7 %.

Figure D-96 : Hydrogen production



Around 60% of hydrogen is used in transport. By 2050, the consumption of hydrogen in transport is five times as high as in the Reference case, with a share of almost 60% of the consumption of the sector compared to 8% in the reference case. Hydrogen is used in nearly two thirds of passenger cars and about 56 % of these are powered by fuel cells and 5% are hydrogen internal combustion engines.

Figure D-97 : Hydrogen markets

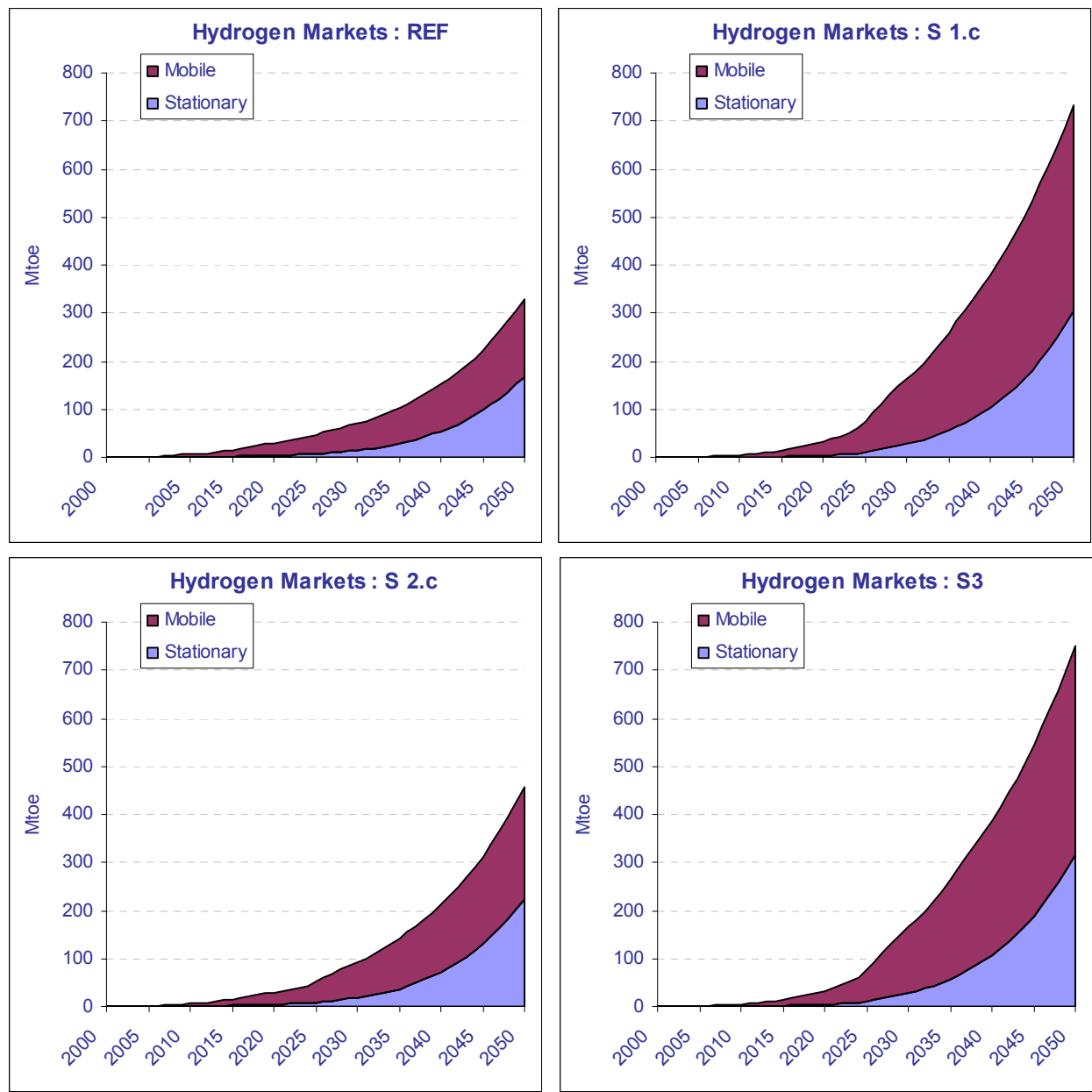
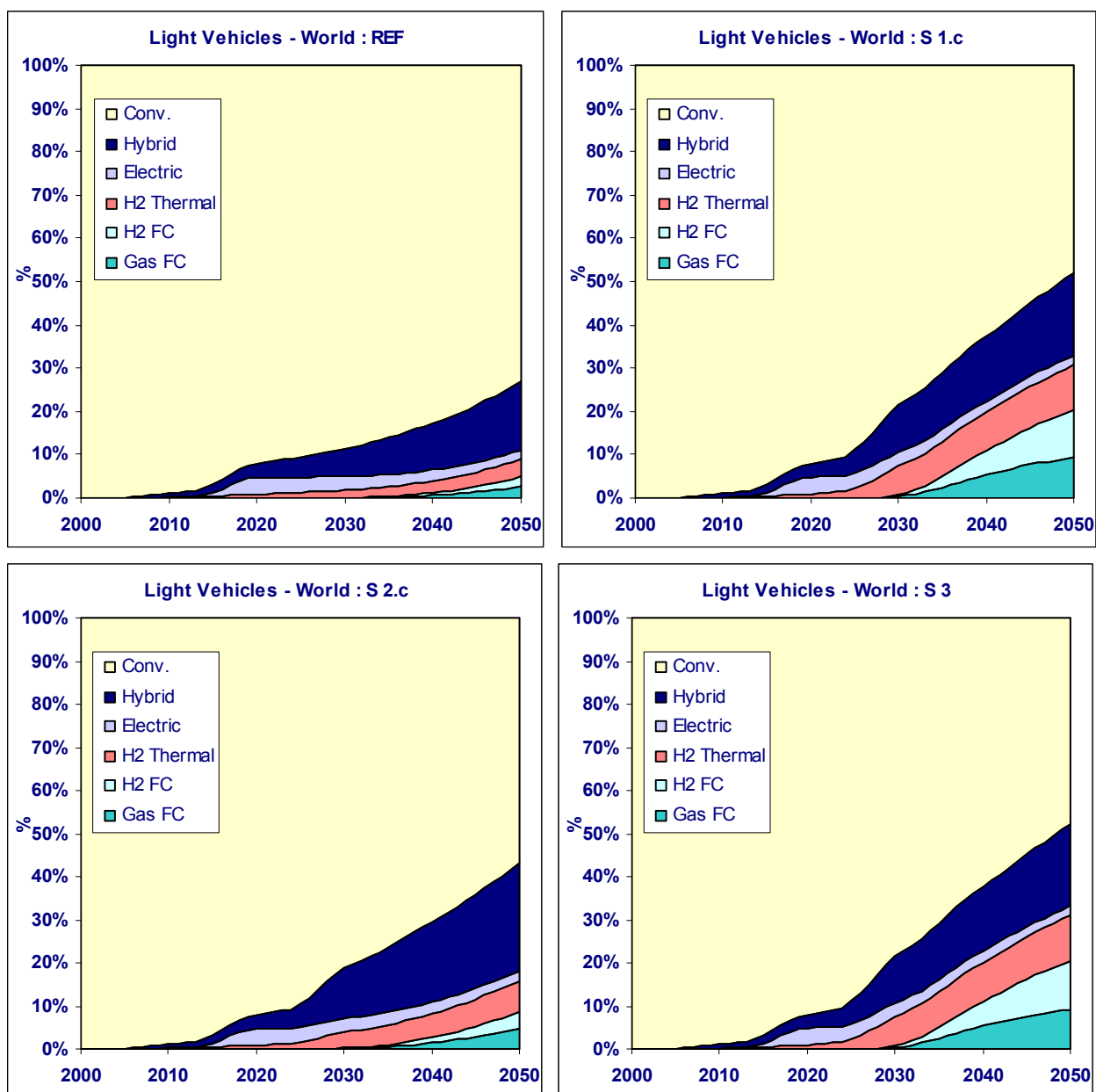


Figure D-98 : S3 - Combined case : share of ZEV



develop a sustainable energy system that relies to the greatest possible extent on renewable energy sources, where both hydrogen and electricity transport energy from producer to consumer. The early support of the European opinion stems from increasing concerns and rising of awareness of the public about the security of energy supply and global climate change. This commitment is successfully coupled with as well as the commercialisation of fully viable types of fuel cells. As a result all technological barriers are eliminated well before the middle of the century, making available the necessary infrastructure and equipment at a competitive cost.

By 2050 hydrogen has penetrated significantly all sectors of economy. The first step to achieve this goal is made by the European Union and national Governments that implement policies and other measures at a

very early stage to raise public awareness and promote the use of hydrogen. In an effort to develop hydrogen related technologies in Europe, policy makers give strong support to research, development and demonstration (RD&D) in the hydrogen field; establish fiscal incentives and other measures to encourage the use of hydrogen-fuelled products; adopt standards and regulations to facilitate the introduction of hydrogen in the energy system; and assist in the development of the necessary infrastructure. Community spending in RD&D increases steadily over the years and public-private partnerships are formed to promote the penetration and use of hydrogen technologies. An effective research policy leads to the development of a range of promising technologies at low costs that either improve existing options or represent new options. Public awareness triggers the demand for hydrogen related products encouraging market-driven private R&D activities, which lead to new products and services.

General comments

The fact that in the S 3 H₂ production more than double in comparison with the REF case shows that the deployment of hydrogen in the world energy system is compatible with important breakthroughs and ambitious climate policies. Demand pull scenarios seems to have a higher impact in the hydrogen economy than supply push ones. However in the best conditions (Sc. 3) the role of hydrogen in the final consumption don't overtake 6% and it represents less than 19% of final electricity consumption.

Table D-39 : Hydrogen production in technology scenarios and its role in total final and electricity consumption

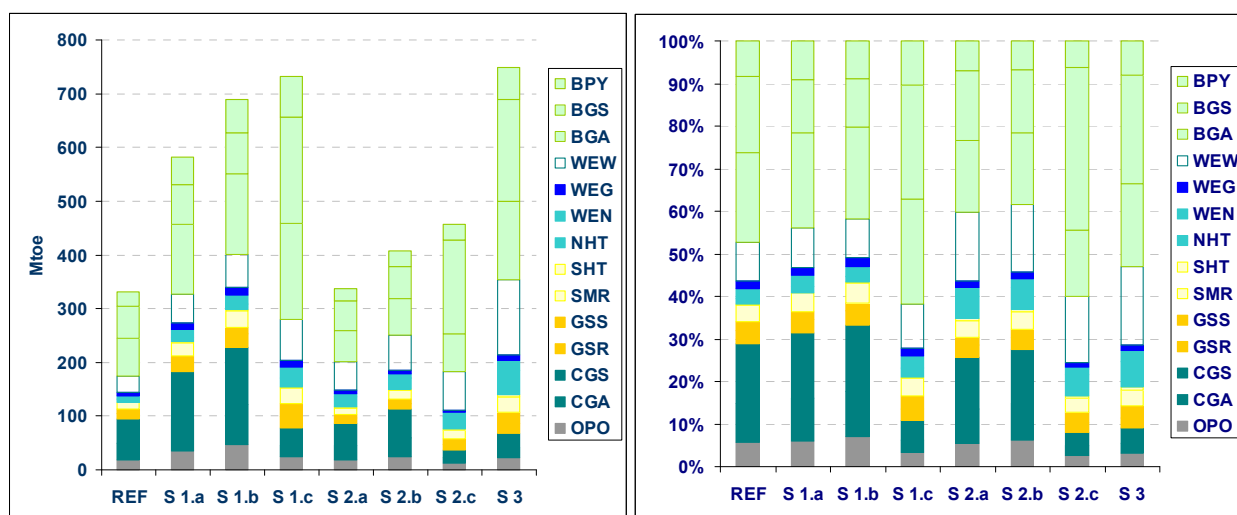
	Hydrogen production in Mtoe	S / REF in times	Ratio of final H ₂ cons in total final cons.	Ratio of final H ₂ cons on final Elec. Cons.
REF	331		2.5%	8.1%
1. Demand pull				
S 1.a	583	1.8	3.4%	11.3%
S 1.b	689	2.1	3.4%	11.1%
S 1.c	732	2.2	3.6%	11.3%
2. Supply push				
S 2.a	338	1.0	3.4%	11.1%
S 2.b	407	1.2	3.4%	11.0%
S 2.c	456	1.4	3.6%	11.2%
3. Combined case				
S3	749	2.3	5.9%	18.7%

Table D-46 summarizes the role of hydrogen in the mobile uses for each scenario.

Table D-40 : Share of ZEV

	REF	S 1.a	S 1.b	S 1.c	S 2.a	S 2.b	S 2.c	S 3
Conv.	73%	65%	49%	48%	73%	58%	57%	48%
Gas FC	3%	6%	9%	9%	3%	5%	5%	9%
H2 FC	2%	7%	11%	11%	2%	4%	4%	11%
H2 Thermal	16%	13%	19%	19%	16%	24%	25%	19%
Hybrid	2%	2%	2%	2%	2%	2%	2%	2%
Electric	4%	7%	11%	10%	4%	7%	7%	11%

Figure D-99 : Hydrogen production mix in technological scenarios in 2050



Biomass provide more than half of H2 production in the S 3 scenario. The role of nuclear increase from 1.6 % in the REF case into 6.7 % in the S 3 scenario. The role of fossils decrease from 24 % to 14% in the S3 scenario.

D.3.2.2 PRIMES

[by N. Kouvaritakis, V. Panos and P. Capros (ICCS-NTUA)]

This section presents a synthesis of the results obtained from the implementation of the CASCADE MINTS technology stories scenarios in the PRIMES-H2 model. The analysis focuses on the prospects of the hydrogen economy under the different assumptions implied by the scenarios. The main conclusions are given at the end of the section.

Implementation of technology stories in PRIMES-H2

The technology stories within the CASCADE MINTS project have been defined in common with the modelling partners of the project and have been implemented with each of the models. They are discussed in D.3.1. However, in order to facilitate readers of this section a summary description is given below.

The technology stories are grouped into two major clusters: a) demand pull technology stories focusing on scenarios that favour the technological developments of hydrogen end use technologies, and b) supply push stories focusing on scenarios that favour hydrogen production and distribution infrastructure. A case combining demand pull with supply push has also been examined. In total seven distinct scenarios were examined, as indicated in the following box:

1. Demand pull scenarios:

1a. Breakthrough in fuel cells (case name: FC): Assuming that all technical and economic parameters of mobile and stationary fuel cells reach their limits as defined in the technology perspective analysis from 2025 onwards.

1b. 1a + Urban air pollution measures (case name: FC+TAX): Corresponds to FC plus increasing the tax on fossil fuels for road transport by 0.5€/lt from 2025 onwards.

1c. 1b + Strong climate policy (case name: FC+TAX+CV): Corresponds to FC+TAX plus doubling the baseline carbon value from 2010 onwards.

2. Supply push scenarios:

2a. Breakthrough in hydrogen production (case name: H2P): Assuming that all technical and economic parameters of all hydrogen production technologies reach their limits as defined in the technology perspective analysis from 2025 onwards.

2b. 2a + Subsidy of hydrogen infrastructure (case name: H2P+INFR): Corresponds to H2P plus free infrastructure for hydrogen distribution and storage.

2c. 2b + Strong climate policy (case name: H2P+INFR+CV): Corresponds to H2P+INFR plus doubling the baseline climate policy

3. Combined case (case name: COMB): Corresponds to 1c and 2b together

Hydrogen prospects under the technology story scenarios

Table D-47 below presents an overview of the penetration of hydrogen in the energy system, by giving the shares of hydrogen based technologies in transport and in electricity and steam production. The table focuses on 2050, as this is the year with the highest hydrogen penetration.

Table D-41: Summary results from the technologies stories for EU-27 in 2050

	% share in passenger cars stock						% in new car registrations	% share in final consumption of industry and residential/commercial		Hydrogen demand (Mtoe)
	Conventional	Hybrid	Plug in hybrid	Electric	H2 ICE	Fuel cells	Fuel cells	Electricity from fuel cells	Steam and heat from fuel cells	
Baseline	64.1	11.1	4.7	1.7	5.2	13.3	24.8	2.2	3.7	49
Demand Pull										
FC	35.1	5.1	2.2	0.8	1.1	55.8	70.0	19.7	26.2	219
FC+TAX	29.5	3.7	2.0	0.9	1.3	62.6	76.9	19.0	25.1	215
FC+TAX+CV	28.1	3.3	2.0	1.0	1.3	64.3	79.0	24.1	31.6	281
Supply push										
H2P	63.5	10.9	4.7	1.6	5.4	13.9	25.6	3.9	6.6	67
H2P+INFR	61.6	10.5	4.5	1.6	7.1	14.8	27.1	10.4	18.2	150
H2P+INFR+CV	59.9	10.0	4.7	1.8	7.5	16.2	29.8	14.8	25.1	206
Combined case	28.0	3.3	1.9	1.0	1.4	64.5	79.1	27.2	34.6	314

Road transport

It is widely accepted that the road transport sector is the key to the success of a transition to a hydrogen economy and the technology stories scenarios address very specifically this sector. In fact the most important development and indeed a prerequisite for the penetration of fuel cells in the road transport sector is the improvement in the technical and economic performance of some key components of fuel cell powered cars (notably stacks, FC systems). Table D-48 below provides a detailed breakdown of the implications of the FC scenario on different cost items.

Table D-42: Cost breakdown of the total cost per vehicle km in c€05

	2005	2020		2030		2040		2050	
		Baseline	FC	Baseline	FC	Baseline	FC	Baseline	FC
Fuel cell cars	2392.9	76.5	48.4	48.5	35.9	44.6	36.0	42.1	35.6
Stack cost	163.8	14.6	4.7	6.5	1.6	5.1	1.6	4.1	1.6
System cost	2185.7	24.2	8.8	6.5	1.6	5.1	1.6	4.1	1.6
Electric engine cost	6.5	4.1	3.4	3.5	2.6	3.0	2.3	2.7	2.2
Total engine cost	2356.1	42.9	16.9	16.5	5.9	13.3	5.6	10.8	5.5
Storage cost (H2)	2.9	1.4	1.4	1.1	1.0	0.9	0.9	0.8	0.8
Storage cost (elec)	2.2	2.5	3.1	2.1	2.6	1.9	2.4	1.8	2.1
Body cost	25.6	24.1	24.1	23.8	23.8	23.8	23.8	23.8	23.8
Maintenance cost	3.5	3.0	1.2	2.6	0.9	2.2	0.9	1.8	0.9
Fuel cost	2.5	2.5	1.7	2.5	1.8	2.5	2.5	3.1	2.5
H2 ICE cars	45.7	42.8	42.8	41.1	42.7	41.0	45.0	42.5	44.4
Total engine cost	4.1	5.2	5.2	5.4	5.5	5.4	5.5	5.4	5.6
Storage cost (H2)	7.1	3.4	3.4	2.3	2.2	2.0	2.0	1.7	1.8
Body cost	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
Maintenance cost	4.2	3.6	3.6	3.4	3.4	3.2	3.2	2.9	3.0
Fuel cost	6.4	6.7	6.7	6.2	7.7	6.7	10.5	8.6	10.2
Gasoline cars	38.5	41.2	41.2	41.2	41.3	42.1	42.2	43.0	43.0
Engine cost	4.1	5.2	5.2	5.6	5.6	5.9	6.0	6.2	6.4
Body cost	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
Maintenance cost	2.9	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.2
Fuel cost	7.6	9.1	9.1	8.8	8.8	9.3	9.3	9.9	9.6
Diesel cars	37.0	39.7	39.7	40.1	40.2	41.1	41.1	42.2	42.1
Engine cost	6.2	7.9	7.9	8.4	8.4	8.8	9.0	9.3	9.6
Body cost	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
Maintenance cost	2.9	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.2
Fuel cost	4.1	5.0	5.0	4.9	4.9	5.4	5.2	6.0	5.6

According to this scenario stack and system costs will represent one third of the baseline values in 2020 and only one quarter from 2030 to 2050. The electric engine cost is downsized to the tune of around 25%, while

electric storage is increased (bigger batteries) to enable smoother operation and longer ranges. Fuel efficiency improves by more than 40%. On the other hand, fuel costs are only 30 to 20 percent lower because PRIMES assumes that taxation of hydrogen increases as its share in road transport increases. In the scenario, this process begins earlier and is accomplished as early as 2040 when hydrogen is taxed at a 100% of the petroleum equivalent (in the baseline, the percentage was 27% in 2040 and 81% in 2050). This higher hydrogen cost influences adversely the economics of hydrogen ICE vehicles that do not benefit from gains in efficiency (they are 55% higher in 2040). Because the technology story is assumed to apply worldwide, the reduction in oil demand leads to lower pressure on oil prices that end-up around 35€/5/bl lower in 2050 (92 instead of 126 €/5/bl according to PROMETHEUS). These lower prices are reflected in the cost performance of conventional vehicles to the tune of around 0.4 eurocents per vehicle kilometre.

The net effect of these developments is that fuel cells become highly competitive vis-a-vis all other options already from around 2025. They end-up gaining around 70% of EU new registrations in 2050, while the share of the vehicle stock stands at around 56% (see Table D-47). This technological push effect appears to be the principal determinant in the penetration of hydrogen in road transport. Additionally taxing conventional fuels adds another 7% in FC share both in terms of stock and new registrations, while the effect of doubling the carbon value produces two percentage points on both. The supply push scenarios, by comparison, have resulted in small changes with regard to fuel cells. This is mainly due to the low importance of hydrogen prices on the total cost of running fuel cell driven cars. The effect is somewhat more marked for hydrogen ICE vehicles, which in the demand pull scenarios fail to penetrate but gain two percentage points over baseline values in the case of infrastructure subsidies. The combined case produces a picture very close to the FC+TAX+CV scenario further underlying the small importance of supply measures in accelerating hydrogen developments.

Heat and power production

Looking at Table D-47, it can be seen that as was the case for the transport sector, the reduction of fuel cell stacks and systems costs is the key for the successful penetration of hydrogen in electricity and steam production. As indicated in the baseline scenario analysis, the stationary fuel cells face wider competition than the mobile fuel cells and lag behind developments in the road transport sector.

More specifically, the reduction of fuel cells stack and system costs increases their share in electricity production from 2.2% to 19.7%. On the other hand, the technological developments in hydrogen production do not succeed in producing a high penetration of stationary fuel cells for electricity production. This is attributed to the fact that the majority of the hydrogen production technologies present few technical possibilities for major improvements. However, a subsidy on hydrogen distribution and supply infrastructure has a significant impact on the penetration of stationary applications (unlike the results obtained for road transport); the share of electricity produced from fuel cells is increased fivefold compared to the baseline scenario. This is due to the fact that the hydrogen distribution and storage costs represent a large fraction in the consumer price for hydrogen. Finally, the introduction of a stronger climate policy favours the

penetration of stationary fuel cells to the extent that key competitors such as natural gas fired CHP become more expensive.

In the combined case 27% of the electricity consumed originates from fuel cells. This is rather low figure reflects the slow stock turnover effects that characterise the heat and power sector. This suggests that in the absence of policies specifically accelerating capital stock turnover the technological developments, subsidies and taxes are not likely to produce an early transformation.

Overall energy consequences

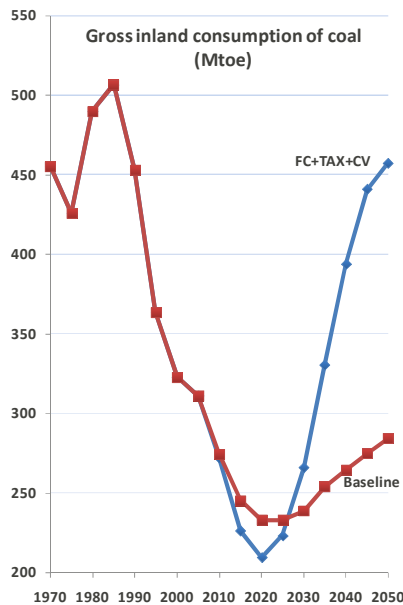
In this section the broader implications of the scenarios in terms of key aggregates of the energy balance is examined. The year 2050 is used for this discussion because it is at the end of the projection period that the maximum impact of the scenarios is obtained.

Table D-43: Technology stories energy balance aggregates in 2050 (% changes from baseline)

	FC	FC+TAX	FC+TAX+CV	H2P	H2P+INFR	H2P+INFR+CV	Combined case
Gross Inland Consumption	-1.1	-2.9	-0.8	0.7	3.7	5.8	0.2
Solids	53.4	51.3	60.9	3.0	25.4	31.4	56.3
Liquids	-15.6	-20.2	-25.4	-0.8	-3.7	-8.1	-26.3
Gas	-16.2	-13.1	-31.9	-2.0	-8.6	-27.4	-34.3
Nuclear	-7.3	-10.1	5.3	4.8	13.6	32.2	20.9
Renewables	-2.5	-3.3	10.9	-0.5	-0.6	12.0	8.2
Final consumption	-4.4	-6.5	-7.3	0.2	1.4	0.5	-6.7
CO2 emissions	-14.6	-17.0	-40.9	-1.7	-4.6	-27.0	-42.2
Change in hydrogen demand (Mtoe)	169.6	166.3	232.1	18.3	101.0	156.7	265.3

The dramatic improvement in the cost and performance of fuel cells (scenario FC) results in reduction in final energy consumption of the order of 4.4%, mostly attributable to the introduction of fuel cell vehicles which are four times more energy efficient than conventional equivalents. Additional taxation of petroleum products leads to a further 2% reduction. On the other hand, doubling the carbon value has a very small effect: this comes as a result of the general feature of the projection where future demand is dominated by electricity and to a lesser extent transportation; mitigation within the electricity sector takes the form of substitution towards non-emitting generation options with relatively small impact on electricity prices; on the other hand, carbon values play a small role in mitigation in the transport sector where taxation in Europe is already very heavy. The effect of the supply push scenarios on final consumption is insignificant with a minor increase registered especially in the scenario involving the free provision of infrastructure services.

The impact of the fuel cell improvement on gross inland consumption is much less marked. This is primarily due to the effects of substitution towards hydrogen in the heat and power sector: substitution in favour of hydrogen does not involve an overall reduction in energy intensity. This is particularly the case because the additional hydrogen in these scenarios is produced from coal-fired CCS facilities, biomass with CCS facilities and nuclear thermochemical cycles which are not characterised by very high conversion efficiencies (in part



due to CO₂ capture). The arguments above are particularly applicable to the supply push scenarios where the energy intensive hydrogen production does not occur in conjunction with increased fuel cell efficiency. The combined case in fact results in static gross inland consumption.

All scenarios have produced high gross inland consumption for coal. This is due to the dominance of coal gasification with CO₂ capture filter in hydrogen production. This also explains why the increase in coal consumption is more pronounced in those scenarios that also involve high carbon values. The figure on the left illustrates this situation by comparing the Baseline scenario with FC+TAX+CV technology story. It is worth noting that the baseline implies a sharp drop in coal consumption up to 2020 with a very modest revival from 2030 to 2050 (mostly due to the introduction of clean coal power generation with

capture).

The initial impact of the higher carbon value in the period from 2010 to 2025 is to suppress further consumption. With hydrogen production picking up beyond 2030 the scenario registers high growth in coal consumption ending-up more than 60% higher than baseline by 2050.

Gross inland consumption of oil is negatively affected in all scenarios especially those that involve specific measures for road transport (example the FC+TAX scenarios). However, the most striking feature of the scenarios is the impact on gas consumption. This impact is closely linked to the use of hydrogen in heat and power generation and the level of carbon value. This is because fuel cells in the heat and power sector replace to a large extent natural gas fired CHP and direct uses of natural gas for heat and steam production. At the same time the options involving natural gas based hydrogen production, and in particular options involving CCS, are not cost effective.

Nuclear power is negatively affected by improvements in fuel cells since the latter encourage decentralised power generation. On the other hand, the technology stories involving hydrogen production improvements all produce an increase in the contribution of nuclear high temperature thermochemical cycle for hydrogen production, because according to the technology perspective analysis this option is characterised by considerable margins for improvements beyond the baseline projection. Nuclear power is also positively affected by scenarios involving high carbon values though the shift occurs mostly in the power generating sector.

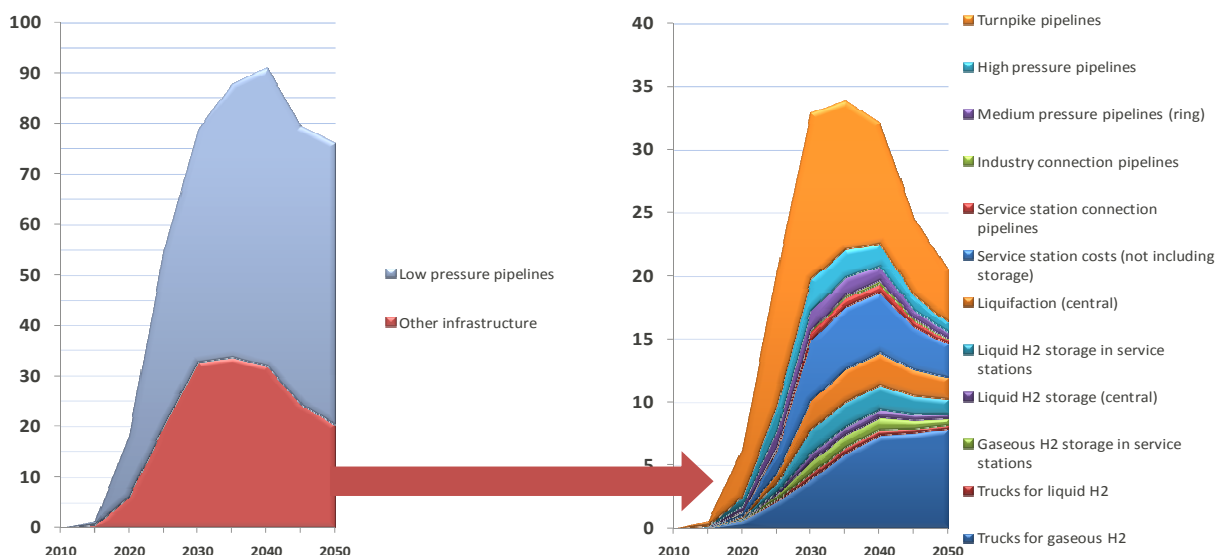
According to the scenario analysis carried out with PRIMES-H2 high carbon values do in general favour the penetration of fuel cells. This is especially pronounced in the CHP applications. This outcome is based on the fact that production of hydrogen in the baseline is dominated by low carbon and carbon free processes making hydrogen impermeable to cost spillovers, while affecting competing options like gas-fired CHP with gas turbines.

As discussed in the section D.2.1.2 the PRIMES baseline does not represent even remotely a transition of the energy system towards a hydrogen economy. On the other hand, most of the scenarios examined in this section reflect in varying degrees greater levels of maturity concerning such a transition. In order to provide some insights on the impact of a more rapid penetration of hydrogen on infrastructure requirements the combined case, which produced the maximum hydrogen use by 2050 (over 300 Mtoe) has been chosen for specific illustration. It must be reminded that this scenario involves both early and dramatic technological improvement as well as strong fiscal incentives (petrol taxes, infrastructure subsidies and very large carbon tax).

The demand aspects of this scenario have been discussed earlier in this section along with all the other scenarios. In this part therefore, the focus is placed on infrastructure and in particular the profile of investment requirements on the different modes for transporting, storing, and distributing hydrogen in the EU-27 region.

Figure D-114 below presents the evolution of investments by major infrastructure category. It should be noted that the figures on the vertical axis refer to investments over a whole 5-year period (5-years is the time interval in the PRIMES model).

Figure D-100: Infrastructure investments in billion €05 in the combined case (values refer to cumulative investments over 5-years terminating at a given date)



Looking at the graph on the left of the figure it is clear that investments peak up very sharply in the period from 2020 to 2030 then reach a plateau between 2030 and 2040 before starting to decline moderately. This decline at the end of the period is an indication that the scenario does indeed represent a more accomplished transition. In fact the total investment figure is maintained high in this latter period only because of the continuing expansion of the low pressure pipeline network supplying users in the residential/commercial sector, which, as discussed in the analysis of the scenarios, is lagging behind road transport in hydrogen penetration. Investments in low pressure pipelines represent around two thirds of total infrastructural investment in the period to 2050. Other types of investment (enlargement on the graph on the right of the figure) peak in the 2025 to 2030 period and then decline sharply after 2040.

The most important category among the latter types is investment in turnpike pipelines connecting hydrogen producing plants and acting as a storage medium in order to balance the hydrogen supply and demand system. These peak in 2025 to 2030 period at over 2.5 billion per year. By the end of the outlook they fall to under one billion per year. This is due to the pattern of hydrogen propagation across the continent: at the beginning low intensity networks are developed in densely populated areas, serving essentially niche markets. During this phase, expansion takes place mostly by the multiplication of such areas. However, as familiarity of consumer with the technology increases expansion of hydrogen consumption takes place increasingly by a more intensive utilisation of existing basic infrastructure (this also explains why the expansion of the low pressure network continuous unabated). On the other hand as the network starts growing into less densely populated areas, this growth is not accompanied by equivalent increases in hydrogen volume and this development eventually puts a break on the geographical expansion of the basic network. Another important category of infrastructure investment consists of trucks for compressed gaseous hydrogen transportation. The constant expansion of hydrogen driven cars not only in densely inhabited areas but also rural areas implies that investment needs for this type of equipment is maintained continuing increasing until the mid '40s. Such investment requirements are also influenced by replacement of scrapped trucks that were introduced in the period of rapid expansion. Investments in service stations reach a plateau of around 1 billion euro per year in 2030. They decline sharply between 2040 and 2045, but are maintained at over 500 million euro per year thereafter.

Table D-44: % shares in hydrogen production in the baseline and combined case scenarios

	% Shares in Baseline	Production Combined
No CCS	25.0	28.8
Fossil fuels	4.0	1.8
<i>Solar methane reforming</i>	0.2	0.1
<i>Gas steam reforming</i>	2.5	1.1
<i>Coal gasification</i>	0.2	0.0
<i>Oil partial oxidation</i>	1.1	0.6
Non-fossil energy sources	21.0	27
<i>Solar high temperature thermochemical cycle</i>	0.1	0.4
<i>Electrolysis from grid</i>	0.8	0.8
<i>Dedicated wind turbine for electrolysis</i>	0.4	0.6
<i>Dedicated nuclear power plant for electrolysis</i>	6.8	7.8
<i>Nuclear high temperature thermochemical cycle</i>	9.1	16.0
<i>Biomass pyrolysis</i>	2.1	0.6
<i>Biomass gasification with steam reforming</i>	1.7	0.8
CCS	75.0	71
<i>Gas steam reforming</i>	0.4	0.4
<i>Coal gasification</i>	59.6	50.8
<i>Oil partial oxidation</i>	0.3	0.5
<i>Biomass gasification with steam reforming</i>	14.6	19.6

Concerning the structure of hydrogen production in the combined case it retains the main features that were encountered in the baseline: it is dominated by coal gasification with CO₂ capture, albeit with a reduced share. The reduction is mostly due to the high carbon value that renders biomass gasification steam reforming incorporating carbon capture particularly attractive (the carbon value for this option represents a negative cost). Interestingly this option is crowding out the other biomass technologies that do not involve CO₂ capture. Another reason for the reduction in the dominance of coal is the big technological improvements assumed in the combined case for the highly speculative nuclear high temperature thermochemical cycle option that increases the share from 9% to 16%.

Conclusions

From the above analysis the following conclusions can be drawn:

- The future success and eventual timing of a hydrogen economy in Europe is highly dependent on technological developments. Key among them is the reduction in costs of fuel cells stacks and systems. Production, storage and distribution technologies are less crucial because they form relatively small parts of the costs and they present fewer technical possibilities for major improvements.
- Automotive applications constitute the key segment for the future of fuel cells. They are likely to experience the highest penetration rates, and lead improvements that can spill over to other applications and carry forward infrastructure development.

- Hydrogen powered internal combustion engine cars are characterised by fewer prospects for technological improvements and their penetration is stunted in cases where fuel cells emerge as a dominant option.
- The major obstacle that mobile fuel cells face is the continuous improvement in internal combustion engine cars. The latter maintain a high share in cases where only hydrogen supply is promoted but they decline sharply in the cases where fuel cells experience a technological breakthrough and are fiscally advantaged.
- Fuel cell applications in the heat and power sectors lag behind developments in the road transport sector, even in cases where they experience equivalent technological improvements. This is because they face wider competition from other options.
- An early transformation of the European energy system towards a hydrogen economy is unlikely even under extremely favourable technological developments in the absence of specific supports. The European transportation sector could be at best in mid transition by 2050, due to lags in vehicle stock turnover. This problem is more accentuated in stationary applications (slower turnover).
- A stronger climate policy favours the introduction of hydrogen but is not decisive. This is particularly reinforced by the fact that the likely availability of many low carbon and carbon free options for hydrogen production.
- In cases of large scale introduction of hydrogen in the energy system, the bulk of investments in infrastructure will take the form of low pressure pipelines supplying consumers in the residential/commercial sector. Most other investments will peak fairly early in the transition and would only account for around one third of cumulative outlays in any case.
- A future hydrogen-based energy system will not necessarily be a less energy intensive system. Gross inland consumption in general will not be greatly affected and will even increase in cases where stationary applications are promoted.

D.3.2.3 MARKAL-EUROPE

Hilke Rösler, ECN Policy Studies.

Introduction

This section describes the analysis of the technology stories using the Western European MARKAL model. Since the background and scenario assumptions of the technology stories are extensively described in section D.3.1 only a short outline of the scenarios is given in Table D-51.

Table D-45 Short description of the technology scenarios

Name	Short description

Demand pull cases	SCEN1A	Baseline + mobile and stationary FC on floor cost from 2030
	SCEN1B	SCEN1A + fuel tax of 0.50 Euro/liter gasoline from 2025
	SCEN1C	SCEN1B + twice the Baseline CO ₂ tax (which gradually increases up to 78 euro/ton CO ₂ in 2050)
Supply push cases	SCEN2A	Baseline + H ₂ production technologies on floor costs from 2030
	SCEN2B	SCEN2A + investments in infrastructure at no cost
	SCEN2C	SCEN2B + twice the Baseline CO ₂ tax
Combined case	SCEN3	Combine cases SCEN1C and SCEN2C

Besides these seven scenarios, three additional technology scenarios are taken into account in the analysis. In these scenarios the assumption that mobile fuel cells will be on their floor costs from 2030 has been omitted and so they can be used to study the effect of taxation of fuels other than hydrogen and a higher general CO₂ tax on the cost development of fuel cells without a breakthrough in mobile fuel cells. As the other assumptions are similar to the common technology scenarios, the description of the additional runs is limited to the data in Table D-52.

Table D-46 Short description of three additional technology scenarios

Name	Short description
SCEN1BV1	Baseline + stationary FC on floor costs + fuel tax of 0.50 euro/liter gasoline
SCEN1CV1	SCEN1BV1 + double CO ₂ tax as in Baseline
SCEN3V1	Combine cases SCEN1CV1 and SCEN2C

Although we tried to implement the assumptions as strictly as possible, some additional remarks have to be made. First of all in the current MARKAL model fuel cells are also modelled in the power sector. Since the coal gasification plant with SOFC is already active in the Baseline scenario as was described in section D.2.1.3, it was decided to not to assume that the costs of fuel cells in the power sector will arrive on their floor cost level from 2025 onwards. Secondly, the cost optimisation character of the MARKAL model implies that a cost effective technology will be used at its maximal potential unless additional constraints are set. For example in the case where floor cost levels are assumed for mobile fuel cells it turned out that the whole car stock will change in one modelling period of 10 years from the conventional mix of gasoline and diesel cars to a completely fuel cell driven car fleet. This is not very likely since not all car owners will switch to fuel cell cars in such a short period of time. Even more importantly, the automobile industry can't adjust their manufacturing capacity in such a short period, and this would not be economically viable. Finally, the build-up of production capacity of fuel cells could also be restrictive to the increase in fuel cell cars. Therefore a growth constraint on the number of cars is modelled. The number of fuel cell cars cannot increase more than 10% per year plus an additional number of 15 million in ten years. This is similar to the prospects for fuel cell cars as indicated by car manufacturers in the Hyways project²⁵.

²⁵ See www.hyways.de.

Hydrogen prospects

This section focuses on the cost development of fuel cells and uptake in different sectors. First the prospects for mobile fuel cells and hydrogen use in the transportation sector will be discussed, followed by the stationary use of fuel cells and hydrogen. Finally, this section describes the impact of both technologies on CO₂ emission reductions.

Mobile fuel cell and hydrogen use for transport

In Figure D-101 the cumulative capacity build-up of mobile fuel cells is given. Three clusters of scenarios can be distinguished.

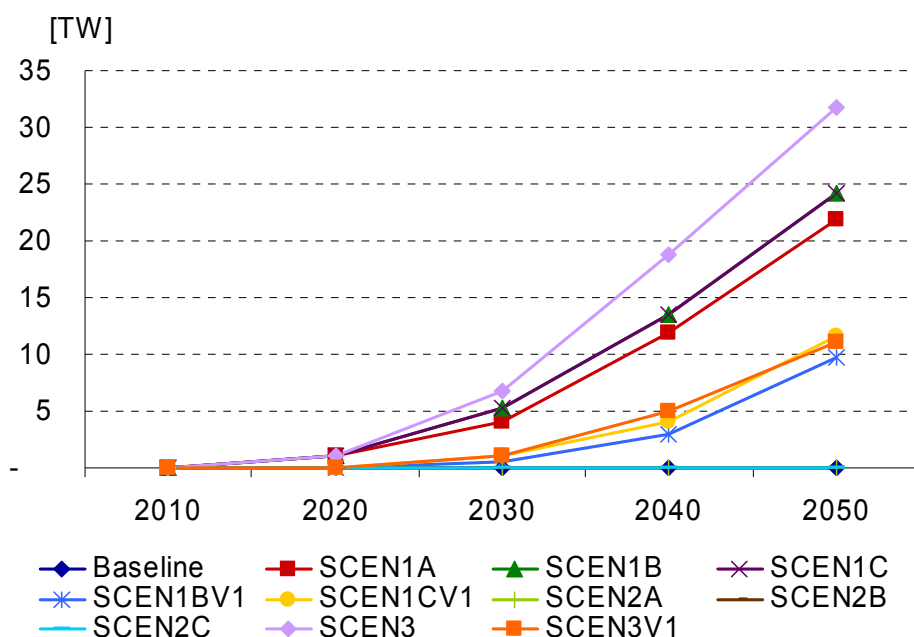


Figure D-101 Cumulative capacity of mobile fuel cells [TW]

Starting from the bottom of the figure, there are the supply push scenarios SCEN2A, SCEN2B and SCEN2C in which the fuel cells will not enter the transport sector at all. So even when the production technologies are on their technical limits and distribution of hydrogen is ‘for free’, this gives not enough incentives to switch to fuel cell driven vehicles. Also under a doubling of the general CO₂ tax (SCEN2C) the systems does not see the use of fuel cell driven vehicles as a competitive option to avoid high cost for CO₂ emissions.

For the second cluster of scenarios (SCEN1BV1, SCEN1CV1 and SCEN3V1), on the other hand, a specific tax on conventional fuels, including biofuels, as in SCEN1BV1 works as a trigger for applying fuel cells in the transport sector. However it is questionable if hydrogen regardless its resource will be free from taxation while biofuels aren’t. Nevertheless, in SCEN1BV1 590 GW of fuel cell capacity is installed in 2030 increasing to 9680 GW in 2050, corresponding to a share of fuel cell driven of 44 %, see Figure D-103. Doubling the CO₂ tax as applied in SCEN1CV1 increases the fuel cell capacity further in 2030 to 1050 GW. It however,

does not shift the introduction of mobile fuel cells to an earlier point in time. Also the supply push in SCEN3V1 cannot achieve this, but it will bring fuel cell trucks and hydrogen ICE cars to the market as can be seen in Table D-53. On the other hand, in 2050 the share of fuel cell cars (Figure D-103) will be lower than in the other two scenarios. In Figure D-102 the cost development of mobile FC is given, reaching a value of 35 Euro/kW in 2050.

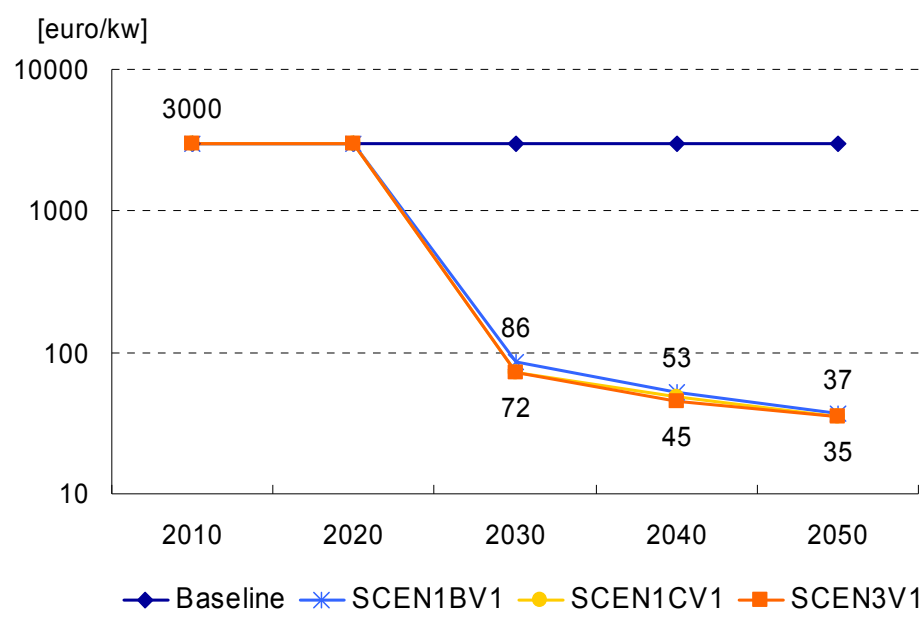


Figure D-102 Cost development of mobile fuel cells system including in scenarios SCEN1BV1, SCEN1CV1 and SCEN3V1 [euro/kW]

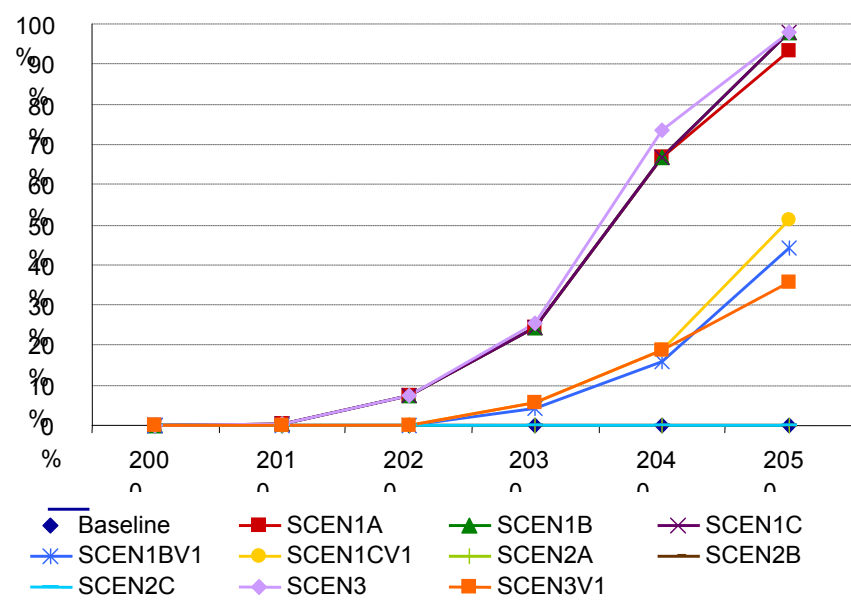


Figure D-103 Share of fuel cell cars in total passenger car stock [%]

The third cluster in Figure D-101 contains the demand pull scenarios and the combined scenario in which the costs of mobile fuel cells reach their floor cost level in 2030. At floor costs level, FC vehicles are competitive and the capacity build-up goes very fast, mostly on account of cars. In 2030 25% of all passenger cars will be FC driven, reaching a 93% share in SCEN1A by 2050 and 98% in the other three scenarios. As can be seen in Figure D-103 fuel cells are already used in cars before 2030. Due to the perfect foresight characteristic of the model it is anticipated that relatively cheap FC will be available in 2030, but the growth constraints prevent a too fast increase of FC cars in a short time, so already in 2010 the model will start building capacity to have a high number of FC cars as soon as cheap FC is available. With a learning by-doing progress ratio of 0.81 the costs corresponding to the cumulative capacities in 2010, 2020 and 2030 are respectively 245, 102 and 58 Euro/kW. So instead of a sudden break through in FC, this should be seen as smooth process, in which the costs decrease faster due to continuously research improvements than it could solely by learning by-doing. Producers of FC as well as car manufacturers are aware of the accelerated cost decrease and start in advance building up their production capacity. Finally, it turned out that the growth constraint is the limiting factor in the period 2010-2040, so this is the maximal penetration for passenger cars due to restrictions on the production of fuel cell and cars.

Besides deployment in passenger cars, fuel cells are, when on their floor cost level, also used for other transport technologies. From 2030 onwards, 80% of all busses are FC driven, see SCEN1A, SCEN1B, SCEN1C and SCEN3 in Table D-53. The other 20% of the busses are full electric and only driving within the cities. Busses are somewhat more likely to switch to fuel cell engines within a 10 year period than passenger cars, because of more governmental influence, bus companies have a better incentive to innovate than private investors.

Differences in the cumulative capacity between SCEN1A and SCEN1B/SCEN1C (Figure D-101) lie in the fact that in SCEN1A there are no fuel cell ships, whereas there are in the other scenarios from 2040 on. So for inland ships, cheap FC are not decisive to change to FC engines unless taxation of fuels other than hydrogen is applied. The fact that FC ships are not used in 2030 (Table D-45) can be explained by efficiency improvements. Finally, the higher deployment of FC in SCEN3 can be explained by the use of FC in trucks which only can compete with conventionally driven trucks when the production and distribution technologies of hydrogen are on their economic limits.

Table D-47 Shares of Fuel cell* and hydrogen driven vehicles in different scenarios**

		2010	2020	2030	2040	2050
H2 ICE cars	SCEN3V1	0%	0%	17%	8%	0%
FC Buses	SCEN1A	0%	0%	80%	80%	80%
	SCEN1B	0%	0%	80%	80%	80%
	SCEN1C	0%	0%	80%	80%	80%
	SCEN3	0%	0%	80%	80%	80%
	SCEN3V1	0%	0%	0%	45%	39%
FC Ship	SCEN1B	0%	0%	0%	39%	100%
	SCEN1C	0%	0%	0%	39%	100%

	SCEN3	0%	0%	64%	100%	100%

*) Share of FC cars is given in Figure D-103

**) In all other scenarios there is no fuel cell penetration in transport sector

In Figure D-104 the fuel use of the transport sector in 2050 is given. As can be seen comparing for example the Baseline and SCEN1BV1, the use of fuel cell cars lowers the total transport fuel consumption. The higher total use of for example scenarios SCEN1 compared to SCEN1V1 is due to lower efficiencies of fuel cell busses than of hybrid diesel busses. Lower efficiencies of fuel cell trucks than diesel trucks explain the higher total use of SCEN3 with respect to SCEN3V1. Furthermore, in SCEN3 biofuels are used in aircrafts.

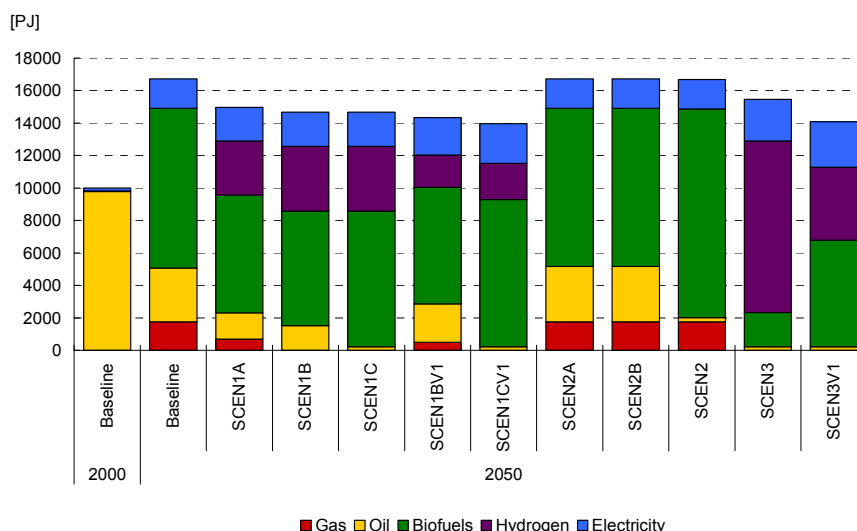


Figure D-104 Fuel use in transport sector [PJ]

Stationary fuel cell use and hydrogen consumption

In all scenarios (including the Baseline) the stationary applications of fuel cells is limited to large scale systems in the power sector. So even when the fuel cell is on its floor cost it is not a sufficiently cheap option to produce electricity or steam for industry or in the built environment. However, one can not immediately conclude that FC will never be an option for these applications since here also the balance of system (BoS) cost can play a crucial role. Therefore an additional run has been done in which also is assumed that the BoS cost are on their economic limits. This run also did not result in large CHP fuel cells system for the industry or small scale end-use in the residential sector. For industry this can be explained by the presence of steam as by-product from other industrial processes and the availability of electricity from the grid. On household scale the lack of FC could be the result from the assumption made that just one learning key-component is used to describe large and small scale fuel cell system. Particularly because in (Menanteau, 2005) for example the floor cost (Euro/kW) of 1-5 kWel systems are assumed half that of a large system of 200-500kWel, which is modelled as the key-component in the model. So instead of using one generic FC for stationary appliances as was suggested in C.1.1, it may have been better to have at least two endogenous learning FC technologies.

In Figure D-105 the share of electricity produced by FC is given. As can be seen in the left and the right figures there are major differences between the scenarios with the normal CO₂ tax (left) and those with twice as high CO₂ taxes (right). Different options such as biomass, gas and coal gasification combined with FC with and without CO₂ capture and storage (CCS) are modelled. However, in all scenarios, except SCEN₃, the only technology used is the integrated coal gasification SOFC with CO₂ capture. In SCEN₃ also a gas fired combined cycle SOFC without CCS and a dedicated biomass combined cycle gasifier with CCS are used. As can be seen from the right figure (Figure D-105) SCEN₃ differs in more ways from the other scenarios. The sudden increase of the share between 2010 and 2020 is due to the fact that CO₂ storage will be available from 2020.

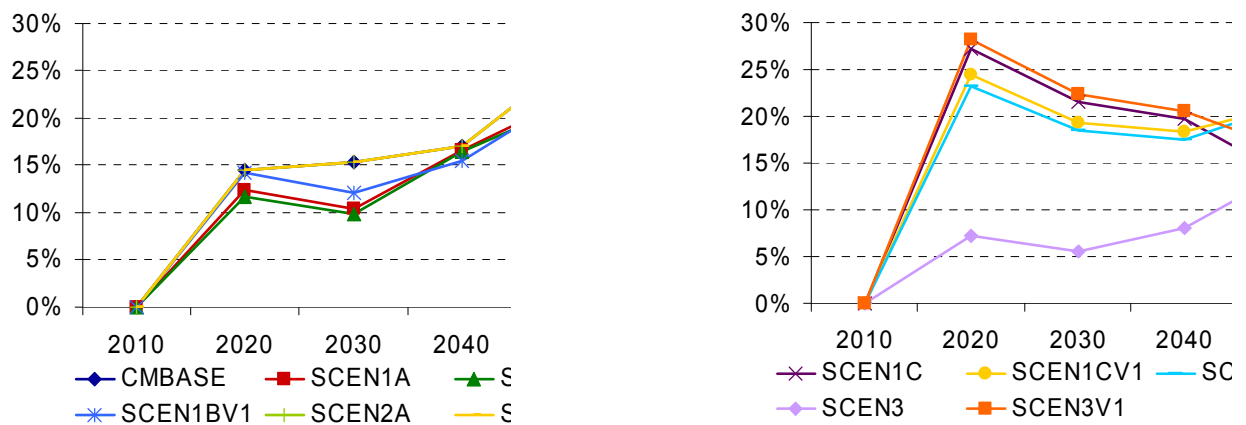


Figure D-105 Share of electricity produced by fuel cell in total electricity production [%]; left graph shows scenarios with baseline CO₂ tax (up to 78 euro/ton CO₂ in 2050) right graph shows scenarios with CO₂ tax up to 156 euro/ton CO₂ in 2050

Fuel cells were treated differently in the power sector than they were for the other stationary appliances. First of all because they were modelled in the existing model before the CASCADE MINTS project started and it was assumed that Balance of system cost were in the non-ETL part of the investment cost already. Moreover, because there is already a substantial contribution of FC for electricity production in the Baseline (see D.2.1.3), it was decided not to set the investment cost towards the floor level in this sector. So the cost curve of these fuel cells is determined by the model endogenously, as presented in Figure D-106 for three scenarios. The lower costs in 2010 in SCEN_{1C} and SCEN₃ with respect to the Baseline are due to investments in a biomass gasifier (without CCS). This is the case in all scenarios with twice the Baseline CO₂ tax. Note that the corresponding electricity production is so small that it is not visible in Figure D-105. Costs around 250 Euro/kW in 2050 are in line with the cost of a 200-5000 kWel FC stack as given in (Menanteau, 2005).

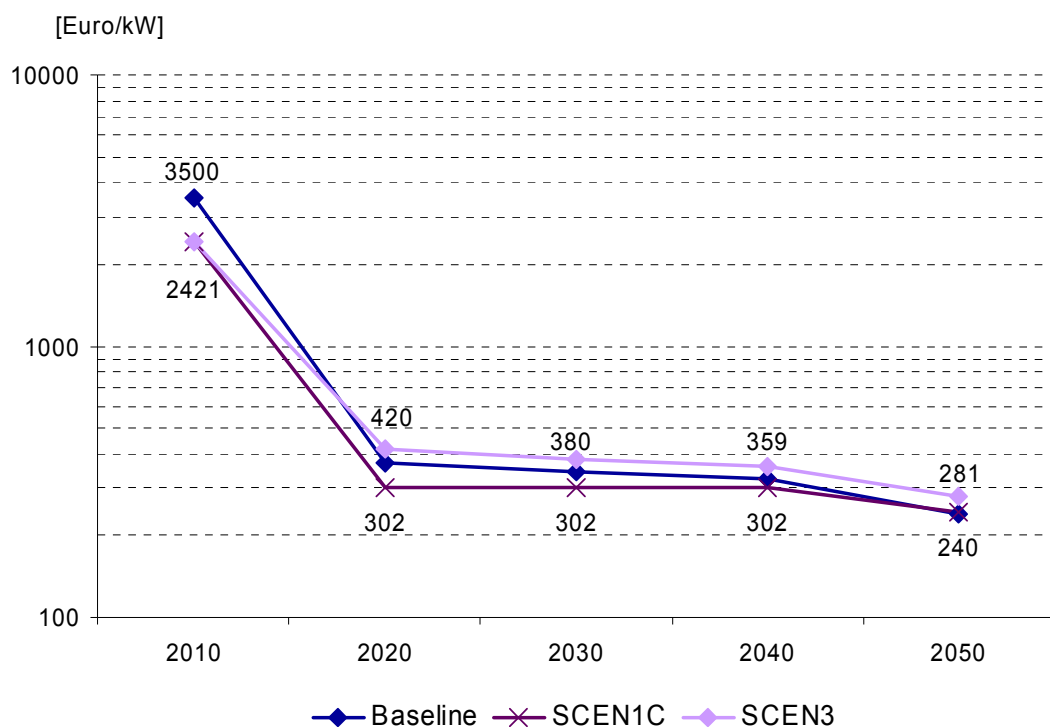


Figure D-106 Cost development of large scale fuel cell (system) used in power sector [Euro/kW]

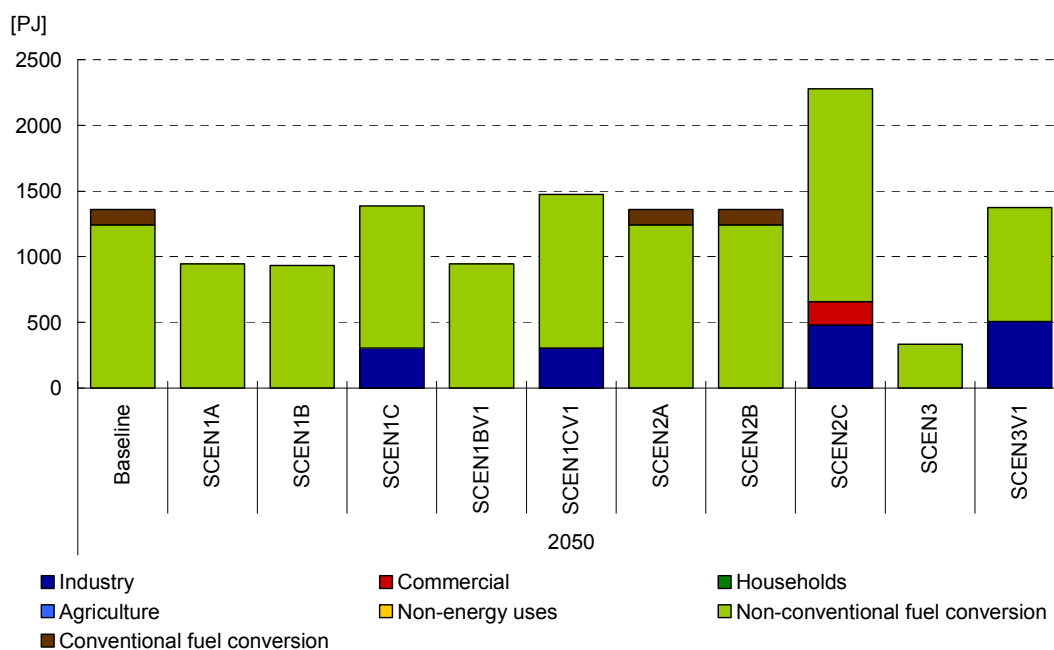


Figure D-107 Hydrogen use (not transport) in 2050 [PJ]

Figure D-107 gives the use of hydrogen in 2050 for all sectors except transport. Most hydrogen is used for the conversion of HTU oil to biodiesel (non-conventional fuel conversion), which of course is related to the amount of biofuels used (Figure D-104). The non-conventional use of hydrogen is used in hydro crackers to produce conventional oil products. As can be seen, under a double CO₂ tax hydrogen will be used in

industrial boilers to produce low temperature heat. In SCEN1C and SCEN1CV1 this is limited to boilers close to hydrogen production facilities in SCEN3 and SCEN3V1 there are also de-central boilers using H₂ from pipeline network since the transport is assumed to be free of charge. Hydrogen use in boilers will not occur before 2050. Under the circumstances that the hydrogen production is on its floor cost, zero investment costs for infrastructure and a double as high CO₂ tax as in the Baseline (SCEN2C) is applied, hydrogen will be mixed in the gas network and used in the commercial sector. On the other hand, when a lot of hydrogen is used in the transport sector (SCEN3 and SCEN3V1) this is not the case. The fact that it is cheaper to use hydrogen in the transport sector than in other sectors is also apparent from the differences in hydrogen for industrial boilers between SCEN3 and SCEN3V1.

Production and distribution

Looking at production and distribution of hydrogen it appears that central large scale coal gasification with CO₂ capture will be the dominating way to produce hydrogen, see Figure D-108. The major part of hydrogen will be transported through a pipeline infrastructure. The latter is less the case for the bulk of stationary hydrogen use since it is assumed that hydro crackers and plants to convert HTU oil into biodiesel are located close to the coal gasifiers. Therefore from now on the focus will be on impact from different scenario assumptions on the production and distribution of hydrogen for transport.

In the demand pull scenarios, in which hydrogen cars will penetrate already in 2010, steam methane reforming will be used in this early stage. The production will be more de-central and on a much smaller scale and transported by a local pipeline network to the filling stations. However, in SCEN3 where demand pull and supply push are combined, the hydrogen will be already in 2010 produced from coal. In this case without CCS since it is assumed that CO₂ storage will not be available before 2020.

In SCEN1C, SCEN1CV1 and SCEN3 with a doubled CO₂ tax also biomass gasification will be used to produce hydrogen (Figure D-108).

Central liquefaction and long distance transport by truck seem to be the favourable option to provide the liquid hydrogen filling stations. Filling stations with liquid hydrogen are only used for busses and ships, which occur in scenarios with FC on their floor costs. This does not imply that liquid hydrogen transported by trucks is only used to supply liquid filling stations. In scenarios SCEN1A, SCEN1BV1 and SCENCV1 the trucks provide also liquid-to-gas filling stations.

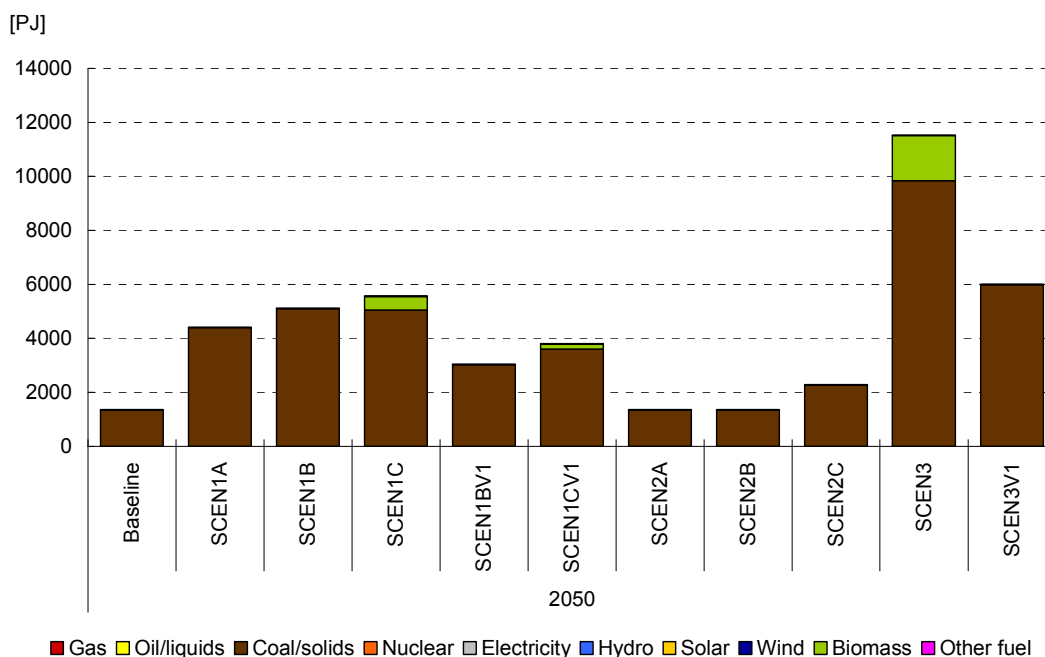


Figure D-108 Hydrogen production mix in 2050[PJ]

CO₂ emissions

This section looks at the contribution of hydrogen to the reduction of CO₂ emissions. In Figure D-109 the CO₂ emissions as well as the CO₂ captured in 2050 are given. As already seen in the Baseline (D.2.1.3) the climate policy implemented reduces the 47% of the 2000 level by 2050. Without assuming more stringent climate policy the penetration of fuel cell cars in scenarios SCEN1A, SCEN1B and SCEN1BV1 will reduce emission in the transport sector with respectively 60%, 80% and 50% with respect to Baseline emissions in 2050. This results in all three scenarios to overall emissions around 40% of the 2000 level. This is a 7% higher reduction than in the Baseline.

To study the reduction of CO₂ emissions due to fuel cells and hydrogen in the scenarios with a twice as high CO₂ a reference case is needed. Such a case is not taken into account in this study. However, since SCEN2C has a double CO₂ tax and only little impact on hydrogen use it could be a good reference scenario and it can be concluded that a doubling of CO₂ leads to a emission level of 31% of the 2000 level. The extra 16% reduction in 2050 with respect to the single CO₂ tax in the Baseline is achieved in the power sector (73% reduction) and transport sector (75% reduction). The use of FC in transport and power sector under this double CO₂ tax (SCEN1C, SCEN1CV1 and SCEN3V1) results in additional reductions of CO₂ emissions of 5% and so the overall emissions will be around 25% of the 2000 level. In SCEN3 the overall emission level will be 20% of that in 2000. The differences between SCEN3 and SCEN3V1 can not directly be assigned to the higher deployment of FC in the transport sector, since both scenarios have zero emissions in transport sector. However, since less biofuels are used less emissions are emitted converting biomass to biofuels and in addition, more biomass is available for the power sector which decreases the emissions in this sector. In SCEN3, this even results in negative emissions from the power sector, because the used biomass takes up more CO₂ emissions than what is emitted by the power sector.

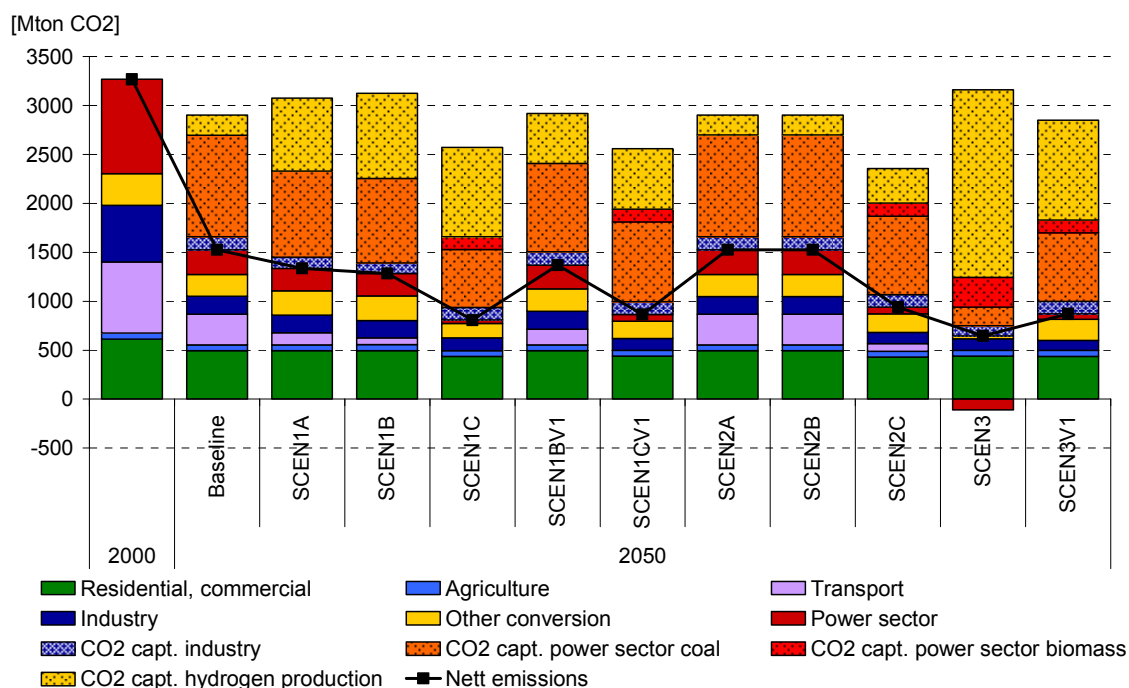


Figure D-109 CO2 emissions and captured CO2 in different sector [Mton CO2]

Although the penetration of hydrogen in the energy system reduces the net CO2 emissions, Figure D-109 also shows that it increases the gross emissions. Increased production of hydrogen will result in more CCS from H2 production, which is much higher than the decrease of CO2 emissions in the transport sector. On the other hand the increase of hydrogen and fuel cells leads to less CCS in the power sector due to reduced use of coal. Instead of coal, solar, wind and nuclear will be used, see Figure D-110. This probably is the result of economically viable CO2 storage and shows that it is cheaper to switch to other sources in the power sector than it is for hydrogen production. It would be interesting to look in future research at the potential and availability of CO2 storage and hydrogen production.

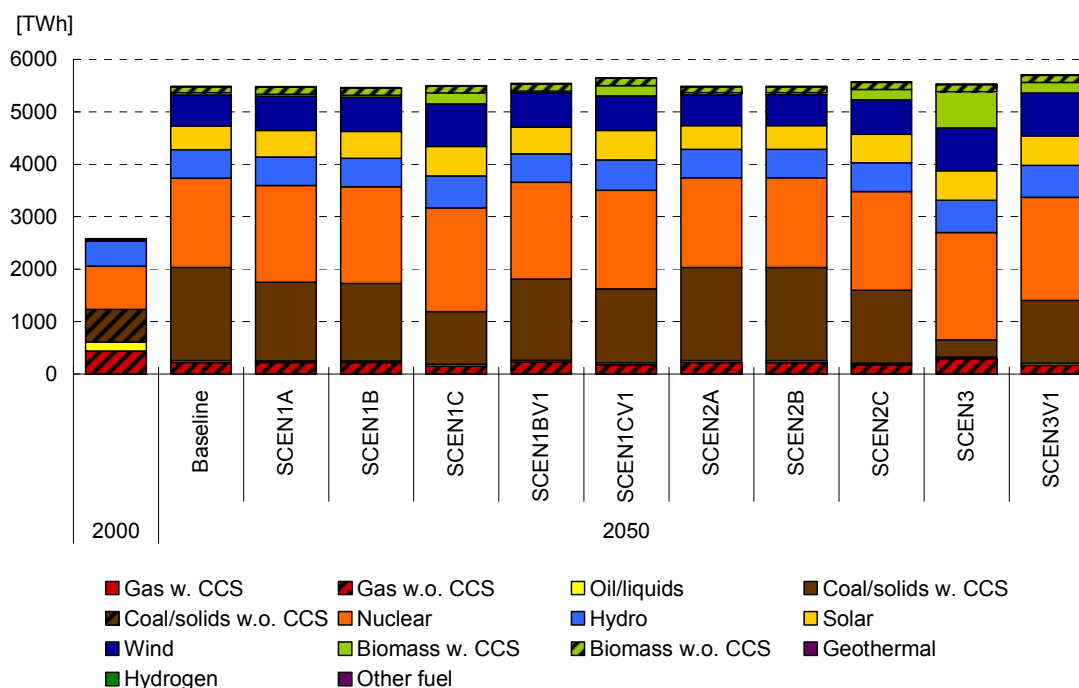


Figure D-110 Electricity mix in 2050 [TWh]

Conclusions

Demand pull

Assuming that the costs of fuel cells reach their floor cost level in 2030 will have a large impact in the transport sector. In the transport sector fuel cell cars and fuel cell buses will penetrate the market and reach a share of 92% by 2050. Additional demand pull policies as taxation of transport fuels other than hydrogen or a doubling of the assumed overall CO₂ tax, cannot increase the share of fuel cell cars in the starting phase since it is already on the maximal penetration due to restrictions on production of fuel cell cars. After 2030, it can make a difference. These additional demand pull measures cause the penetration of fuel cells in inland shipping.

It turned out that without assuming that fuel cells reach their floor cost by 2030, the fuel tax is a driver for penetration of fuel cell cars. This again is strengthened by a higher overall CO₂ tax.

On the other hand, assuming floor cost for stationary fuel cells has no impact at all. The fuel cell system will still be too expensive. Therefore it would be interesting for future work to study also the effect of a stronger decline of the balance of system cost.

Supply push

Assuming that production technologies will reach their floor cost level by 2030 and that investments in infrastructure will be for free, will not lead to the penetration of hydrogen in the transport or built environment. This also is not the case when the overall CO₂ tax is doubled. So a targeted taxation of the transport fuels appears to be more effective than an overall measure.

Combined case

Combining the demand pull and supply push assumptions the picture of the demand pull scenarios is strengthened in the way that more fuel cell vehicles will penetrate in the transport sector. In this case also trucks will be equipped with fuel cell engines.

General conclusions

Hydrogen and fuel cell are most likely to penetrate in the transport sector.

Large scale use of fuel cells in the power sector for instance in coal gasification plants will be competitive already under the Baseline assumptions.

For small scale stationary use the costs of the complete system, including balance of system costs, need a stronger decrease than assumed here, before hydrogen and fuel cells will penetrate in built environment.

The dominating way to produce hydrogen will probably be central large scale coal gasification with CO₂ capture and storage.

Most of the hydrogen will be transported through a pipeline network to the filling station.

The penetration of fuel cell vehicles can contribute to the reduction of CO₂ emissions. However, under the general CO₂ path assumed in this study the additional reduction with respect to the Baseline will be limited to 7%.

D.3.2.4 MESSAGE

[by G. Totschnig and I. Keppo (IIASA)]

For the technological scenario analysis, the R&D spending for each cluster is exogenously defined (see Table C-25 in chapter C.2.3.2) through the R&D outlook. This is the same as for the baseline case and means that the newly developed 2FLC version of MESSAGE was used in operation mode 4 (see C.2.3.2). For the R&D policy scenarios (see D.4.2.4) MESSAGE is run using an endogenous optimization of R&D spending allocation.

1. Demand-pull scenarios

In the following figures the global passenger car transport sector and the energy consumption of this sector are shown for the 3 different demand-pull scenarios.

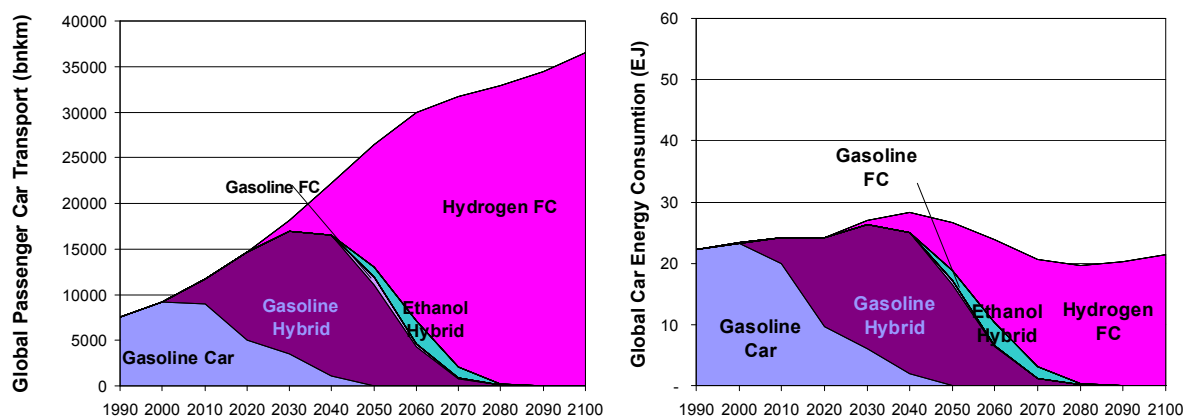


Figure D-111. Global passenger car transport for the “Breakthrough in fuel cells” scenario.

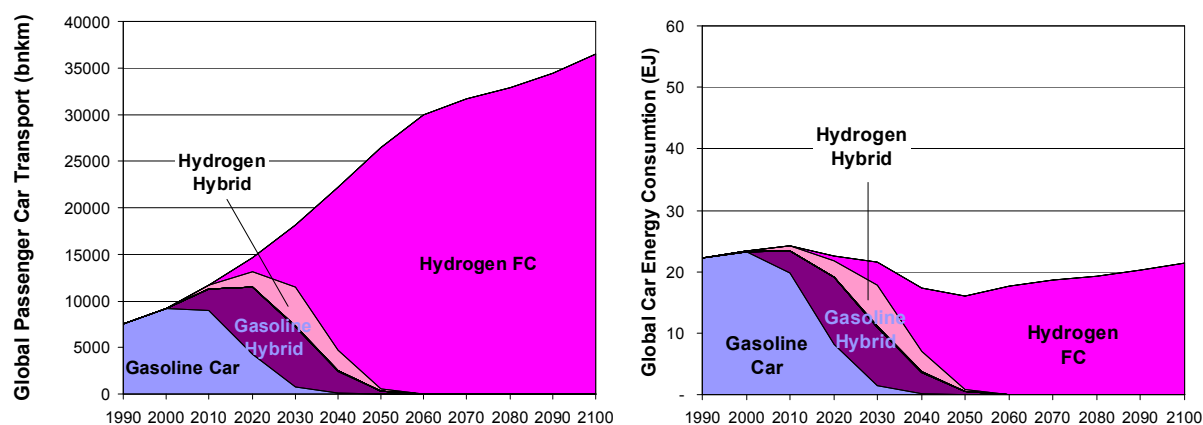


Figure D-112. Global passenger car transport for the “Urban air pollution measures” scenario.

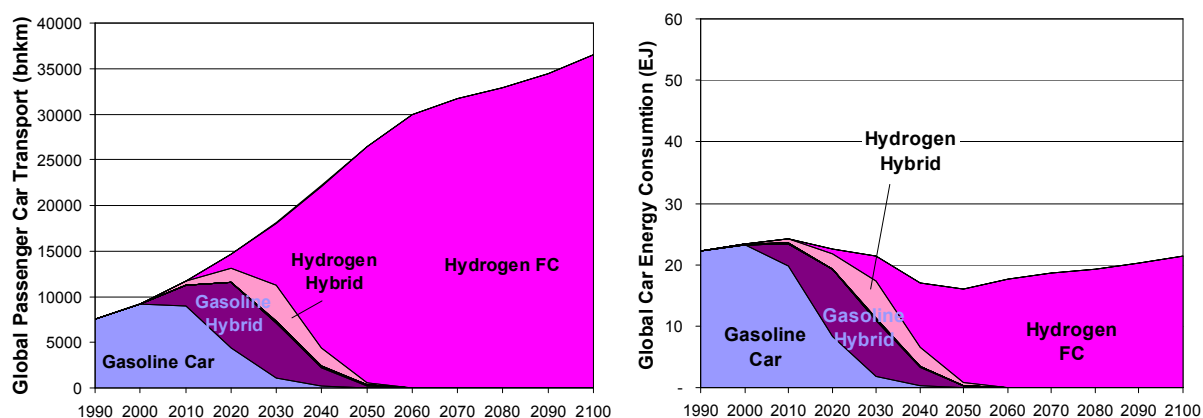


Figure D-113. Global passenger car transport for the “Strong climate policy” demand-pull scenario.

If one compares the baseline scenario (D.2.1.4) with the “Breakthrough in fuel cells” scenario (see Figure D-114) one can see the hydrogen penetration from around 15 years previously. The “Urban air pollution and climate policy” scenarios add another 20 years. In the baseline scenario, the large-scale

introduction of hydrogen cars starts in 2050; for the demand-pull scenario in 2030 and for the “Urban air pollution measures” and “Strong climate policy” scenarios in 2010–2015.

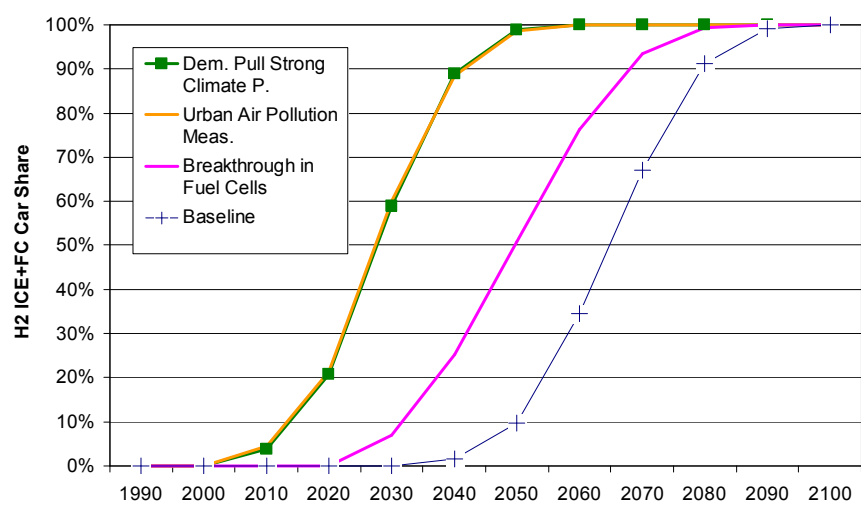


Figure D-114. Shares of hydrogen-fueled vehicles in total passenger vehicle stock. See also Table D-38.

Figure shows the passenger transport results of a scenario that has all the baseline assumptions but additionally assumes an increased fuel tax for all transport fuels except for hydrogen and electricity, which are exempt from the fuel tax. It thus has the same assumptions as the “Urban air pollution” scenario but does not assume any faster learning progress with fuel cells. This scenario achieves the same hydrogen car penetration in passenger transport as the “Urban air pollution” scenario. The fuel tax exemption makes hydrogen an attractive fuel, even for hydrogen hybrid cars, which penetrate the market 25 years before fuel cell cars. Assuming the fuel tax exemption for hydrogen, a breakthrough in fuel cells is no longer needed to achieve early uptake of hydrogen as a passenger transport fuel.

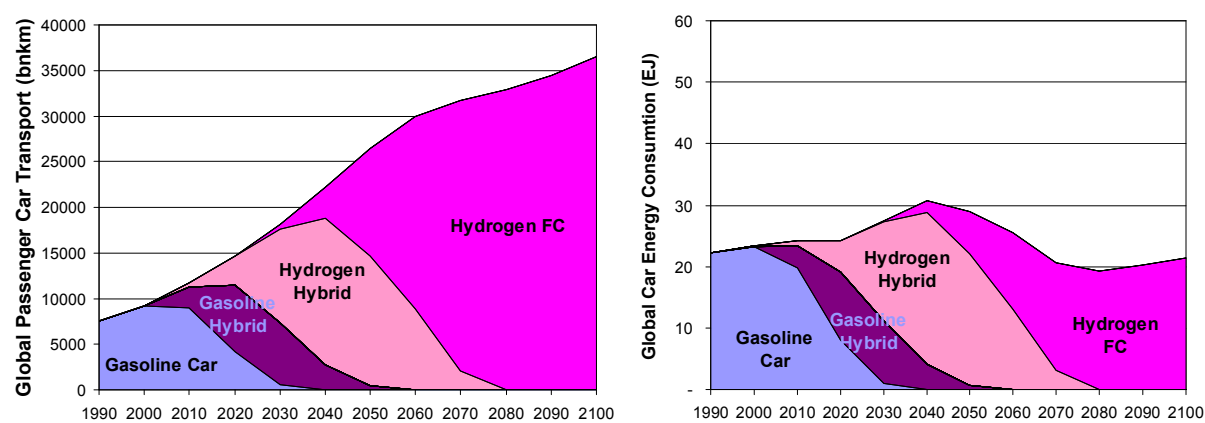


Figure D-115. Global passenger car transport for the “Baseline + fuel tax” scenario.

Table D-48. Shares of H2 fuel cell cars and H2 ICE vehicles in total passenger vehicle stock.

		1990	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Baseline	H2 ICE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	H2 FC	0%	0%	0%	0%	0%	2%	10%	35%	67%	91%	99%	100%
	H2 ICE+FC	0%	0%	0%	0%	0%	2%	10%	35%	67%	91%	99%	100%
Breakthrough in Fuel Cells	H2 ICE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	H2 FC	0%	0%	0%	0%	7%	25%	51%	76%	94%	99%	100%	100%
	H2 ICE+FC	0%	0%	0%	0%	7%	25%	51%	76%	94%	99%	100%	100%
Urban Air Pollution Measures	H2 ICE	0%	0%	5%	11%	23%	10%	1%	0%	0%	0%	0%	0%
	H2 FC	0%	0%	0%	10%	37%	79%	98%	100%	100%	100%	100%	100%
	H2 ICE+FC	0%	0%	5%	22%	60%	89%	99%	100%	100%	100%	100%	100%
Strong Climate Policy	H2 ICE	0%	0%	4%	10%	22%	9%	1%	0%	0%	0%	0%	0%
	H2 FC	0%	0%	0%	11%	37%	80%	98%	100%	100%	100%	100%	100%
	H2 ICE+FC	0%	0%	4%	21%	59%	89%	99%	100%	100%	100%	100%	100%

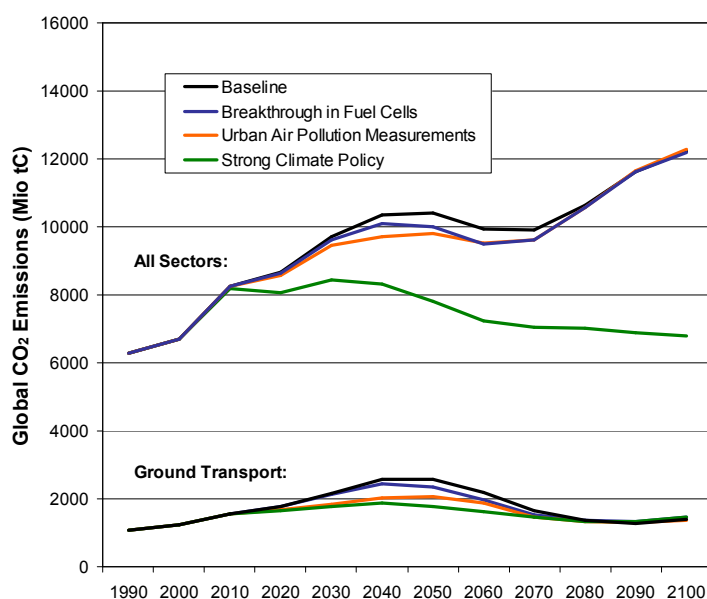


Figure D-116. Global annual CO₂ emissions for the different demand-pull scenarios compared with the baseline.

Figure D-116 shows the global CO₂ emissions from the total economy and from the ground transport sector. In Table D-39 the cumulative CO₂ emissions for 1990–2100 and other impact factors are shown for the different scenarios. In terms of global cumulative emissions from 1990 to 2100 there is only a 2% reduction for the “Breakthrough in fuel cells” or the “Urban air pollution measures” scenarios compared to the baseline scenario. One reason is that even in the baseline scenario, hydrogen cars dominate passenger car transport from 2070 onwards. Thus, the demand-pull scenarios help just in terms of CO₂ emission reductions getting a 20–35 year earlier start. Second, the car transport sector represents only 4% of the total cumulative 1990–2100 emissions (baseline values). If the ground transport CO₂ emissions are taken as a proxy for urban air pollution, then in mid century (2030–2060) the “Breakthrough in fuel cells” scenario leads to a 6% air pollution reduction, the “Urban air pollution” scenario leads to an 18% reduction because of earlier hydrogen penetration in car transport, and the “Strong climate policy” scenario leads to a 26% reduction, because of earlier hydrogen car penetration and a shift to ethanol-

fuelled freight transport. The dependency of the OECD region on oil and gas imports is reduced by all demand-pull scenarios. The highest reduction is 24% achieved by the “Strong climate policy” scenario. The average weighted final energy price is affected only by the “Strong climate policy” scenario with a 6% increase.

Table D-49. Cumulative CO₂ emissions and other impact factors for the different scenarios.

	Baseline	Breakthrough in Fuel Cells	Urban Air Pollution Measures	Strong Climate Policy
Total CO ₂ emissions 1990-2100 (GtC)	1054	1038	1032	822
Ground Transport Co ₂ Emissions 1990-2100 (GtC)	196	190	176	169
Car Transport CO ₂ Emissions 1990-2100 (GtC)	39	33	19	19
Total Emissions (% Change to Baseline)	0%	-2%	-2%	-22%
Ground Transport (% Change to Baseline)	0%	-4%	-10%	-14%
Car Transport (% Change to Baseline)	0%	-17%	-52%	-52%
Change Global Airpollution from Ground Transport in 2030-2060	0%	-6.4%	-17.8%	-25.6%
Change OECD Oil Gas Import Dependency in 2050-2100	0%	-1.7%	-5.2%	-24.1%
Change OECD Average Weighted Final Energy Price 2050-2100	0%	-0.6%	-0.5%	6.0%

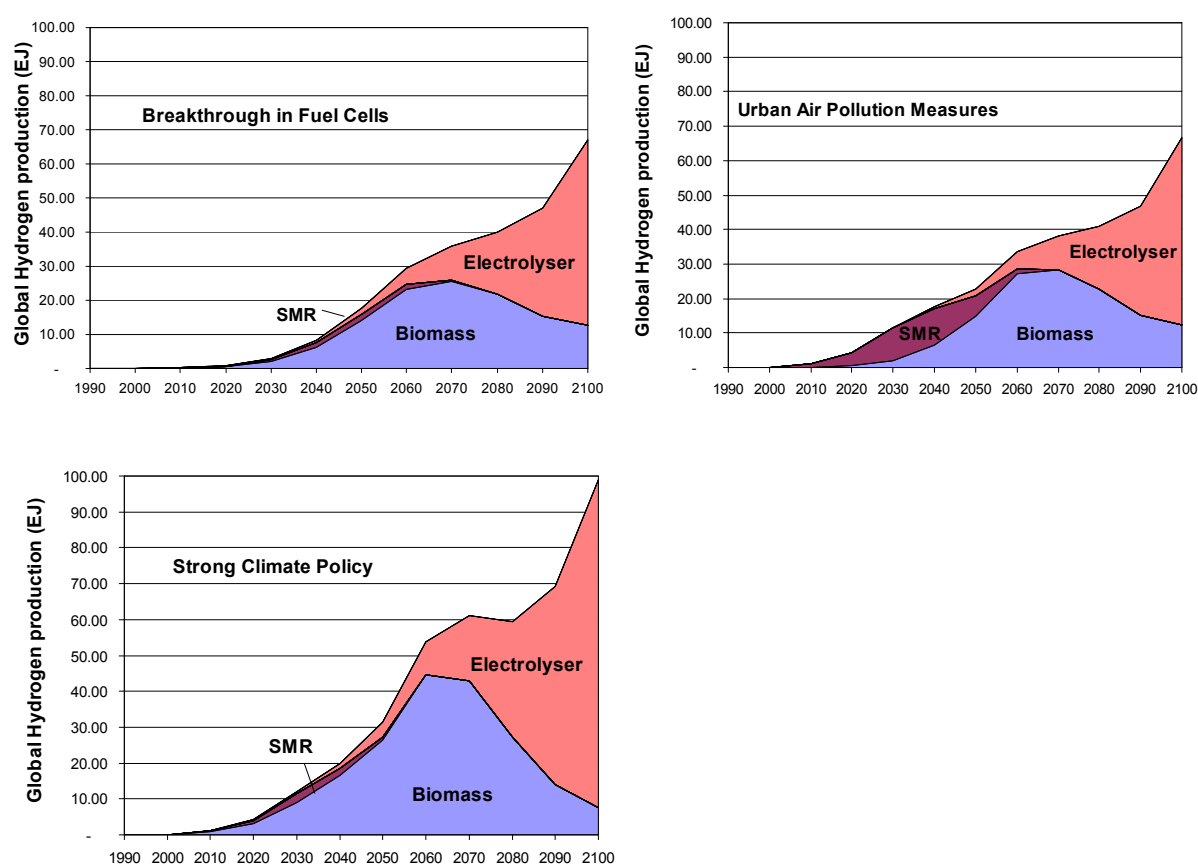


Figure D-117. Hydrogen production for the three demand-pull scenarios.

The “Strong climate policy” demand-pull scenario shows a higher hydrogen demand for heat and power cogeneration in industry.

In Table D-40 the shares of large stationary fuel cell heat-and-power generation in district heat and central power generation are given.

Table D-50. Share of large stationary fuel cell combined-heat-and-power plants in district heat and electricity production.

		1990	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Share in Distric Heat:													
Baseline	Total FC CHP	0%	0%	0%	0%	15%	16%	12%	11%	9%	11%	10%	8%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Breakthrough in Fuel Cells	Total FC CHP	0%	0%	0%	0%	15%	15%	12%	12%	9%	10%	10%	8%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Urban Air Pollution Measures	Total FC CHP	0%	0%	0%	0%	15%	17%	13%	11%	10%	12%	9%	10%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Strong Climate Policy	Total FC CHP	0%	0%	0%	5%	16%	21%	22%	25%	27%	20%	20%	31%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	18%
Share in Electricity Generation:													
Baseline	Total FC CHP	0.0%	0.0%	0.0%	0.0%	6%	6%	3.8%	3.0%	2.1%	2.1%	1.5%	1.2%
	H2-FC CHP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Breakthrough in Fuel Cells	Total FC CHP	0.0%	0.0%	0.0%	0.0%	5.7%	5.9%	4.0%	3.3%	2.1%	2.0%	1.6%	1.1%
	H2-FC CHP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Urban Air Pollution Measures	Total FC CHP	0.0%	0.0%	0.0%	0.0%	5.6%	6.6%	4.3%	3.0%	2.2%	2.3%	1.5%	1.4%
	H2-FC CHP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Strong Climate Policy	Total FC CHP	0.0%	0.0%	0%	2%	5.6%	8.0%	6.5%	6.1%	5.5%	3.8%	3.3%	4.7%
	H2-FC CHP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	2.9%

2. Supply-push scenarios:

In the following figures the global passenger car transport sector and the energy consumption of this sector is shown for the scenarios listed above.

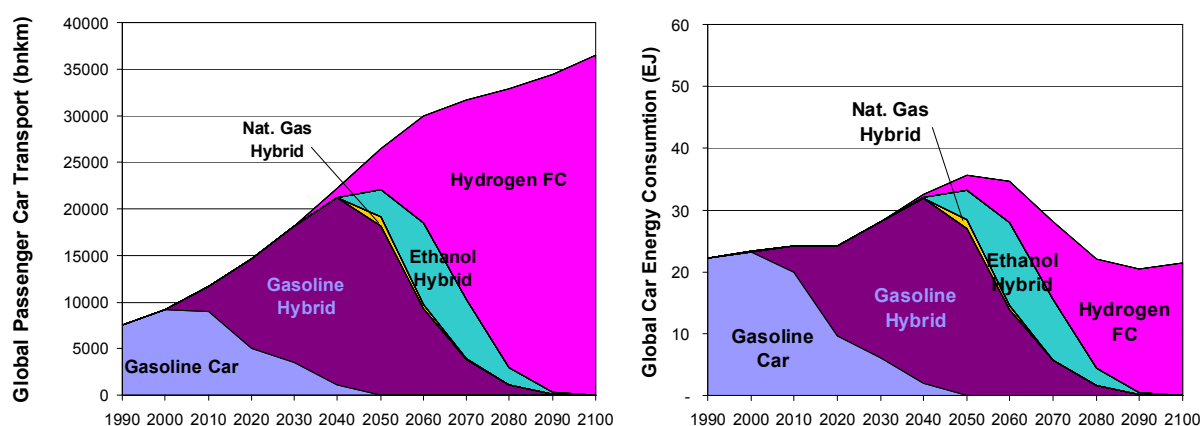


Figure D-118. “Breakthrough in hydrogen production” scenario.

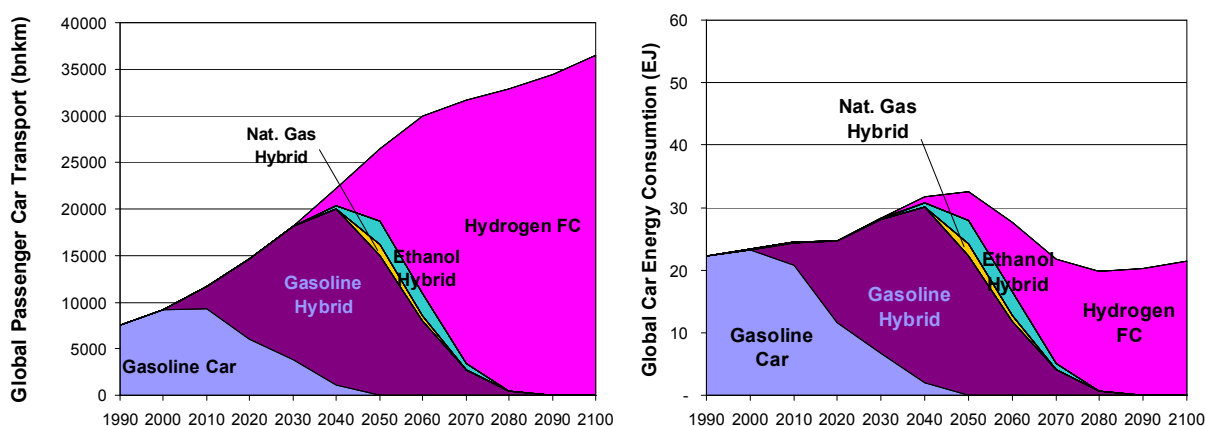


Figure D-119. “Subsidy of hydrogen infrastructure” scenario.

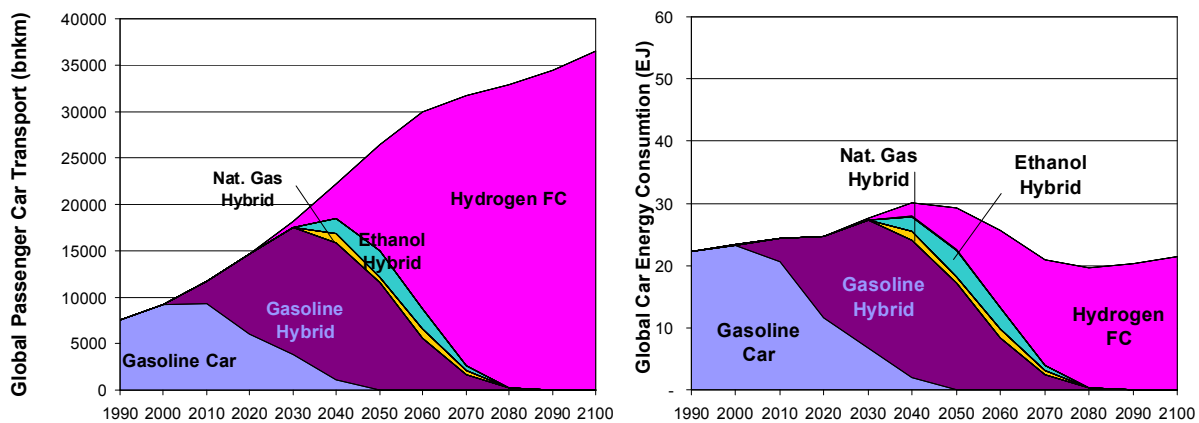


Figure D-120. “Strong climate policy” supply-push scenario.

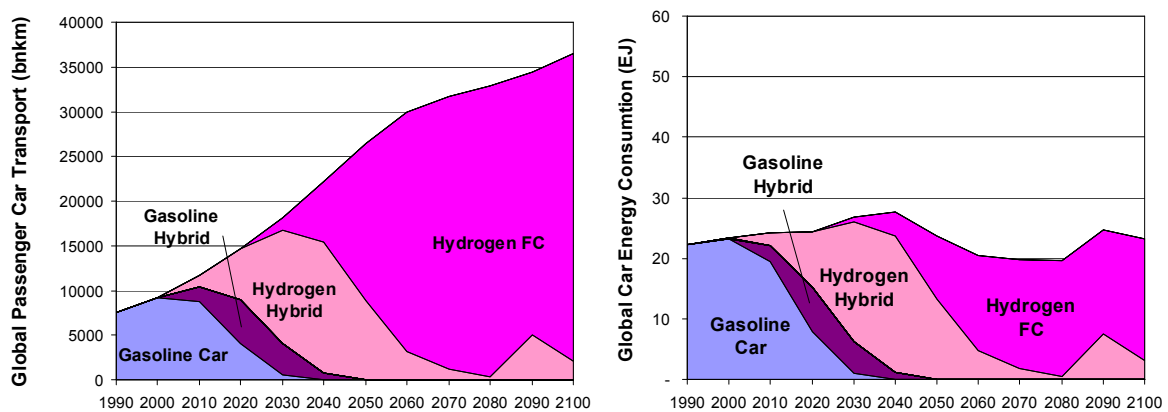


Figure D-121. “Combined” scenario: Combining the assumptions of the demand-pull scenarios and the supply-push scenarios.

In Figure D-122 and Table D-41 the shares of hydrogen-fueled cars in total passenger transport is shown for the scenarios in this chapter. As can be seen, the breakthrough in hydrogen achieves only a 5-year earlier start to hydrogen penetration compared with the baseline. “Subsidizing the hydrogen infrastructure” and the “Strong climate policy” scenarios achieve 5–10 years of earlier hydrogen car penetration. A comparison of these results with the demand-pull scenarios shows that the demand-pull scenarios have a stronger hydrogen penetration effect. This is understandable as the dominant cost factor for the highly efficient fuel cell cars is the fuel cell system and not the fuel cost. The “Combined” scenario combines the assumptions of the demand-pull scenarios and the supply-push scenarios. Figure D-122 shows that the “Combined” scenario achieves a 5-year-earlier hydrogen penetration as compared with the “Urban air pollution measures” demand-pull scenario. The dominant factor for the “Combined” and “Urban air pollution measures” scenarios is the high fuel tax for conventional fuels and the tax exemption for hydrogen and electricity. In the “Combined” scenario the low hydrogen costs, which are a result of the fuel tax exemption for hydrogen and the infrastructure subsidy, make the hydrogen hybrids a close competitor to the hydrogen fuel cell.

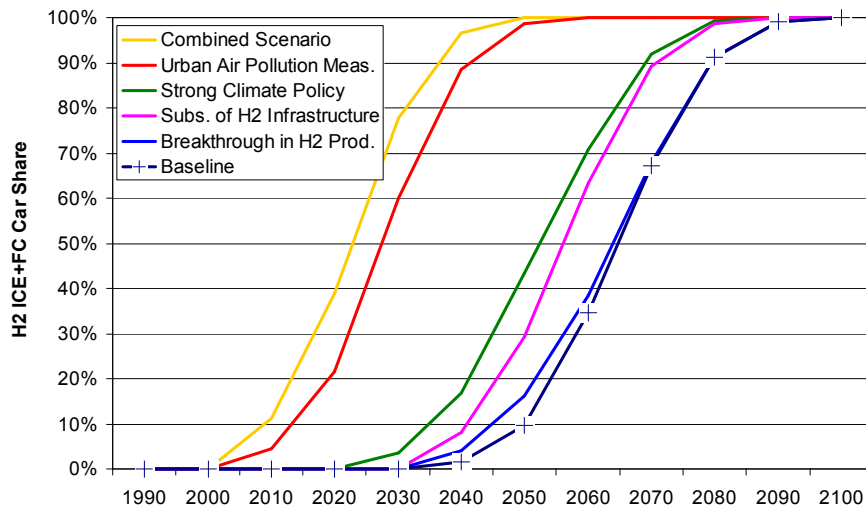


Figure D-122. Share of hydrogen-fueled cars in total cars.

Table D-51. Share of hydrogen-fueled cars of total cars.

		1990	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Baseline	H2 ICE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	H2 FC	0%	0%	0%	0%	0%	2%	10%	35%	67%	91%	99%	100%
	H2 ICE+FC	0%	0%	0%	0%	0%	2%	10%	35%	67%	91%	99%	100%
Breakthrough in H2 prod.	H2 ICE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	H2 FC	0%	0%	0%	0%	0%	4%	16%	38%	68%	91%	99%	100%
	H2 ICE+FC	0%	0%	0%	0%	0%	4%	16%	38%	68%	91%	99%	100%
Subsidy of H2 infrastructure	H2 ICE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	H2 FC	0%	0%	0%	0%	0%	8%	29%	63%	89%	99%	100%	100%
	H2 ICE+FC	0%	0%	0%	0%	0%	8%	29%	63%	89%	99%	100%	100%
Strong Climate Policy	H2 ICE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	H2 FC	0%	0%	0%	0%	4%	17%	43%	71%	92%	99%	100%	100%
	H2 ICE+FC	0%	0%	0%	0%	4%	17%	43%	71%	92%	99%	100%	100%
Combined Scenario	H2 ICE	0%	0%	11%	39%	70%	66%	33%	11%	4%	1%	15%	6%
	H2 FC	0%	0%	0%	0%	8%	30%	67%	89%	96%	99%	85%	94%
	H2 ICE+FC	0%	0%	11%	39%	78%	97%	100%	100%	100%	100%	100%	100%

In Figure D-123 the global CO₂ emissions and in Table D-42 the cumulative CO₂ emissions from 1990 to 2100 and other impact factors are shown for the different scenarios. One can see that the “Subsidy of hydrogen infrastructure” and the “Strong climate policy” supply-push scenarios do have a strong impact on global CO₂ emissions. Subsidizing the hydrogen infrastructure leads to a high use of hydrogen in the end-use sectors and to it replacing natural gas.

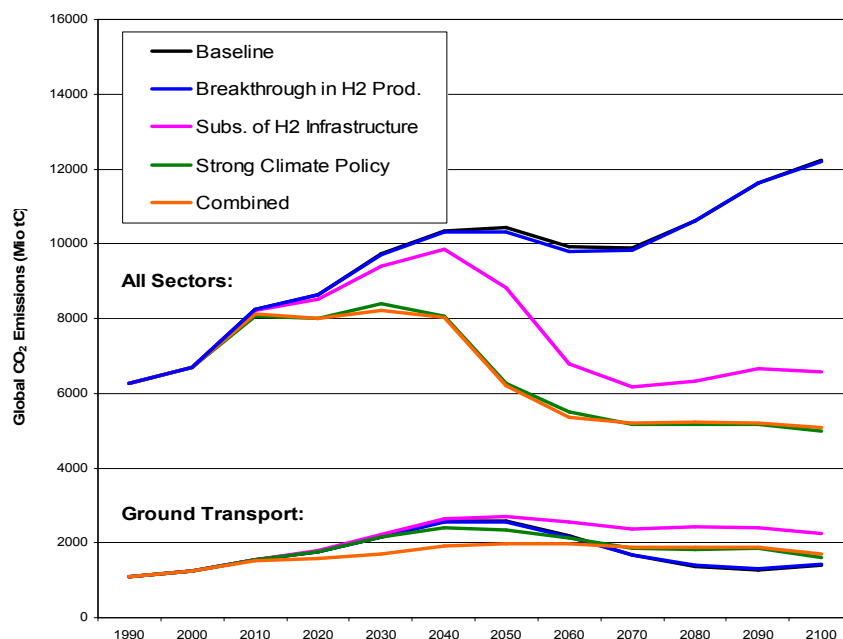


Figure D-123. Global CO₂ emissions.

Table D-52. Cumulative CO₂ emissions and other impact factors for the different scenarios.

	Baseline	Breakthrough in H2 Production	Subs. of H2 Infrastructure	Strong Climate Policy	Combined
Total CO ₂ emissions 1990-2100 (GtC)	1054	1050	838	721	719
Ground Transport Co ₂ Emissions 1990-2100 (GtC)	196	197	236	205	190
Car Transport CO ₂ Emissions 1990-2100 (GtC)	39	40	38	34	16
Total Emissions (% Change to Baseline)	0%	-0.4%	-20%	-32%	-32%
Ground Transport (% Change to Baseline)	0.0%	0.1%	20%	4.3%	-3.3%
Car Transport (% Change to Baseline)	0%	1%	-5%	-13%	-59%
Change Global Airpollution from Ground Transport in 2030-2060	0%	-0.3%	7%	-5%	-20%
Change OECD Oil Gas Import Dependency in 2050-2100	0%	-2%	2%	-26%	-28%
Change OECD Average Weighted Final Energy Price 2050-2100	0%	0.3%	-2.0%	0.7%	0.7%

The CO₂ emissions from ground transport are used as a proxy for the urban air pollution from traffic. The most effective measures for reducing the air pollution from traffic are the demand-pull measures included in the “Combined” scenario, which lead to an early adoption of hydrogen cars and therefore reduce emissions. The second most effective measure is the increased carbon tax, which causes a shift in freight transport away from gasoline toward natural gas. The “Subsidy of hydrogen infrastructure” scenario has an adverse effect on air pollution. The cheap hydrogen replaces natural gas in many sectors and leads to a lower natural gas and oil price. But as hydrogen is not assumed to be a freight transport fuel, the cheaper natural gas and oil reduce the share of ethanol in freight transport and therefore increase transport emissions. The only scenario significantly affecting the average final energy price in the OECD region is the “Subsidy of hydrogen infrastructure” scenario, where a reduction of 2% occurs. The “Combined” scenario and the “Strong climate policy” supply-push scenario show reductions of dependency on oil and gas imports by 26–28%. The dependency on oil and gas imports is calculated as a share of oil and gas imports in total primary energy. Both scenarios include a strong climate policy which increases the share of nuclear energy in electricity production.

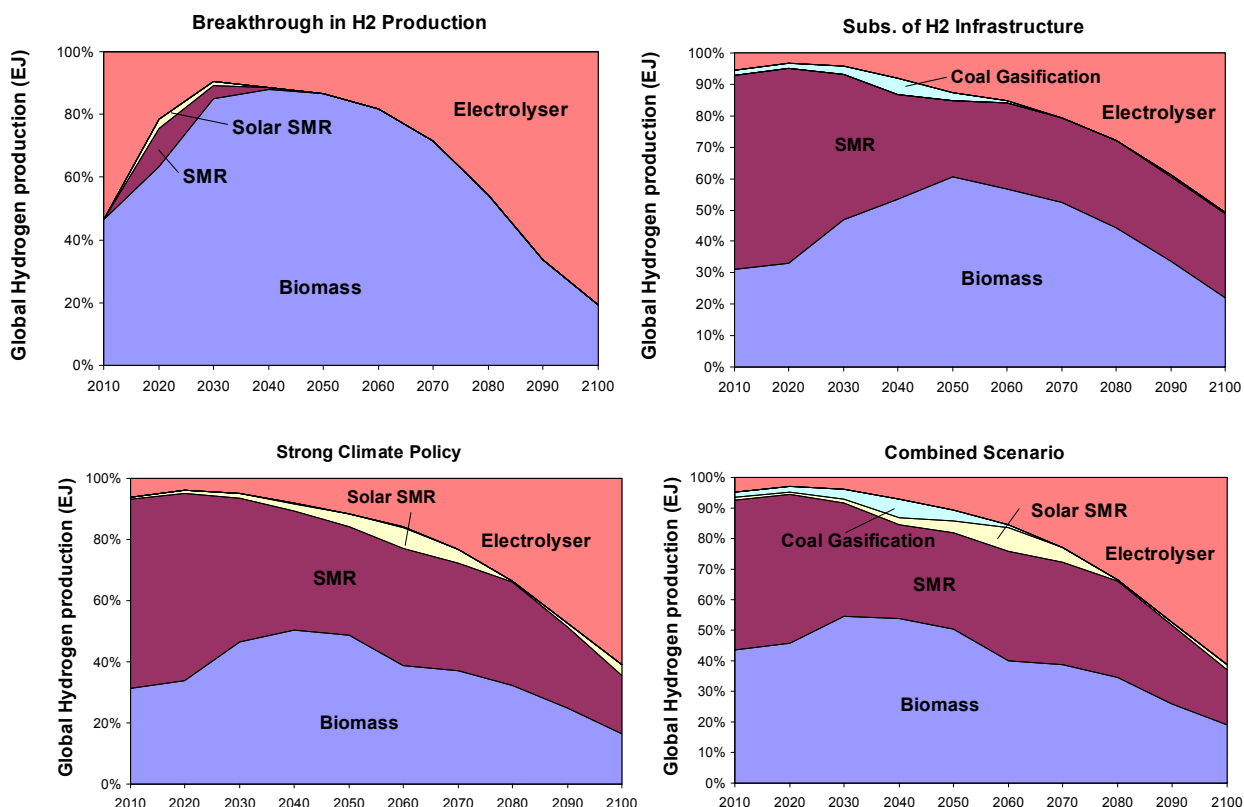


Figure D-124. Shares of the different hydrogen production options.

In Figure D-124 the hydrogen production shares are given. The “Breakthrough in hydrogen production” scenario shows basically the same shares as the baseline. The “Subsidy of hydrogen infrastructure” is part of the definition of the “Subsidy of hydrogen infrastructure,” “Strong climate policy,” and “Combined” scenarios. This subsidy makes it economic first to produce hydrogen from natural gas and then to use the hydrogen in different end-use sectors, instead of using natural gas directly in the end-use sectors. In these three scenarios there is a shift from natural gas to hydrogen use not only in the residential and commercial sector but also in the industrial sector.

Table D-53. Share of stationary fuel cell combined-heat-and-power plants in district heat and electricity production.

		1990	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Share in Distric Heat:													
Baseline	Total FC CHP	0%	0%	0%	0%	15%	16%	12%	11%	9%	11%	10%	8%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Breakth. in H2 Prod.	Total FC CHP	0%	0%	0%	0%	15%	16%	12%	11%	10%	10%	11%	8%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Subs. of H2 Infrastr.	Total FC CHP	0%	0%	0%	0%	2%	15%	18%	24%	35%	37%	51%	49%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	15%	17%
Strong Climate Policy	Total FC CHP	0%	0%	0%	0%	21%	30%	32%	26%	31%	31%	43%	42%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	16%	17%
Combined	Total FC CHP	0%	0%	0%	0%	23%	32%	37%	28%	34%	34%	42%	42%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	16%	17%
Share in Electricity Generation:													
Baseline	Total FC CHP	0%	0%	0%	0%	5.6%	6.4%	3.8%	3.0%	2.1%	2.1%	1.5%	1.2%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Breakth. in H2 Prod.	Total FC CHP	0%	0%	0%	0%	5.6%	6.4%	3.7%	3.0%	2.2%	2.0%	1.7%	1.2%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Subs. of H2 Infrastr.	Total FC CHP	0%	0%	0%	0%	0.7%	4.3%	4.0%	4.3%	5.0%	4.3%	4.6%	3.5%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1.4%	1.3%
Strong Climate Policy	Total FC CHP	0%	0%	0%	0%	6.4%	8.7%	7.5%	4.6%	4.3%	3.4%	3.6%	2.7%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0.4%	1.4%	1.1%
Combined	Total FC CHP	0%	0%	0%	0.1%	7.0%	9.2%	8.4%	5.1%	4.6%	3.7%	3.5%	2.7%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0.3%	1.4%	1.1%

D.3.2.5 MERGE-ETL

[by S. Kypreos (PSI)]

As explained in the introduction, different cases have been analyzed as technology storylines with MERGE-ETL based on exogenous specifications of technological change. In these cases we postulate significant cost reduction and best technical and economic performance for the fuel-cell related technologies as e.g., the specific capital cost that becomes equal to its floor cost by the year 2025.

The input model specifications in MERGE follow the TECHPOL-EURO2000 database assuming that the proposed floor costs are be attained in 2025. The key input to MERGE-ETL is the generating cost (estimated at 5% discount rate) minus the fuel cost that is endogenous in MERGE.

The following seven scenarios described in **Box 1** are to be specified while the assumed economic and technical specifications and policy taxes applied are described below or in section 3 while the results per case are presented and compared below for the year 2050.

Box 1: Definition of technology storylines as given by the project management

(Scenario names are in **bold** letters and appear in the subsequent figures)

1. Demand pull

DP1A Breakthrough in fuel cells (setting all technical and economic parameters to their technical limits as defined in the technology perspectives analysis)

DP1B Corresponds to **DP1A** + Urban **environmental** considerations that result to a worldwide increase in the tax on fossil fuels for road transport of the order of 0.5€/00/lt from 2025 and onwards.

DP1C Corresponds to **DP1B** + doubling the baseline **climate policy** worldwide from 2010 and onwards. (See **Table D-54** with the Carbon-tax below).

2. Supply push

SPA Cheap H2 production: set all production technologies technical and economic parameters to their limits from 2025 onwards.

SPB Corresponds to **SP2a** + **subsidise** by 100% all hydrogen distribution and storage infrastructure

SPC Corresponds to **SP2b** + doubling the baseline **climate policy** worldwide from 2010 and onwards.

3. Combined case

DPSP corresponds to **DP1C** combined with **SP2C**

Table D-54: Carbon values assumed in the case of enhanced mitigation policy in €/t CO₂

	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Europe	0	28.0	42.0	66.7	101.0	141.4	197.1	197.1	197.1	197.1	197.1
ROOECD	0	15.2	25.2	45.6	75.9	113.7	167.6	167.6	167.6	167.6	167.6
ROW	0	2.8	7.1	18.4	38.8	68.7	124.5	124.5	124.5	124.5	124.5

We start with the presentation of some global energy, economic and environmental indicators per storyline and we end-up with the penetration of Hydrogen fuel cells in their stationary and mobile markets. Most of results are presented for the year 2050 but the time evolution is discussed in some cases.

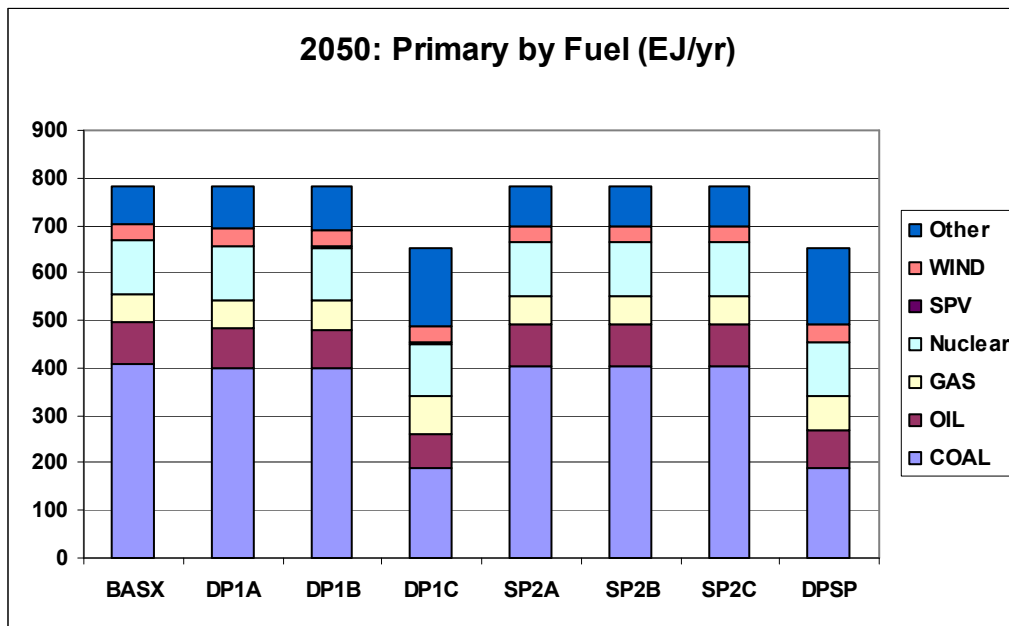


Figure D-125: Global Primary energy by fuel in the 2050

Figure D-125 shows the Primary energy use by fuel in the year 2050 and for all the storylines including the policy free base case. Oil and gas are deplete-able resources such that coal together with nuclear and renewables take over the markets. By the year 2050, primary energy consumption reaches about 780 EJ, but is reduced in the cases with high carbon taxation rates to 660 EJ per year. As an effect of price changes, coal dominates the markets while oil and gas become less important. Nuclear energy and renewables capture 28% of the markets and expand to 48% in the case of high carbon taxes.

Figure D-126 presents the global electricity generation mix by scenario and technology in the year 2050. Electricity production (i.e., 47 kTWh/yr), is reaching 3.5 times its levels in the year 2000, independently of the carbon taxes applied. This means that electricity is always substituting for fossil fuels in the markets. Coal-based power plants and gas still experience a substantial growth and are both introduced with CCS technology. Nuclear power plants and renewables (mainly wind and biomass) becomes by the end of the time horizon, the most important technologies in power generation followed by coal and gas. The most significant difference in the case of an intensive carbon control policy is the substitution of pulverized coal systems with those with CCS options (i.e., Coal-A and IGCC-A). The degree of introducing advanced coal and systems without CCS (i.e., coal-n, gas-n) depends on the intensity of the carbon policy followed. Both gas power station (i.e., with and w/o CCS technology) gain market shares at higher taxes but, this is not true for Coal-n, that is phased out.

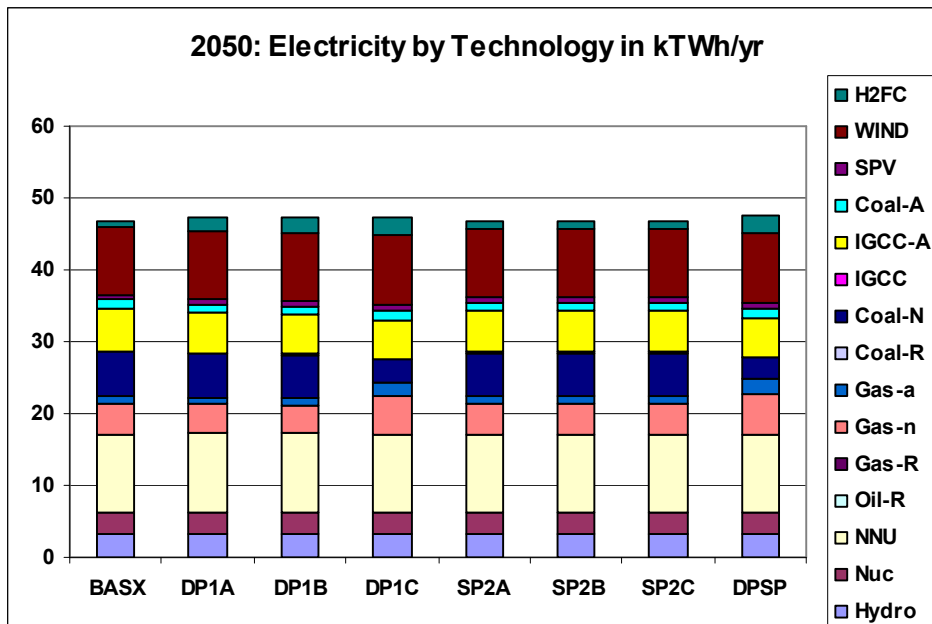


Figure D-126: World electricity generation by fuel in the year 2050. No significant differences are shown between scenarios. New nuclear and renewables (wind) are the most important technologies while coal and gas are installed mainly with CCS facilities as electricity is produced with low carbon emission systems.

Figure D-127 depicts the technology mix in the global passenger car sector, where the beginning of a technology transition takes place. While conventional and advanced internal combustion engines (ICE) satisfy a significant part of demand their absolute number decrease. Hybrid vehicles gradually gain market shares first followed by ICE burning hydrogen that experience a dynamic growth, accounting for about a quarter of passenger car mobility in the year 2050. Then, HFC cars are introduced in the case that the systems reach their technical and economic performance limits in 2025 while local taxes and carbon taxes result to a higher share of cars based on compressed natural gas (CNG) but also of HFC cars. Surprising is the fact that supply push options increase the share of hydrogen ICE cars but not this of HFC cars.

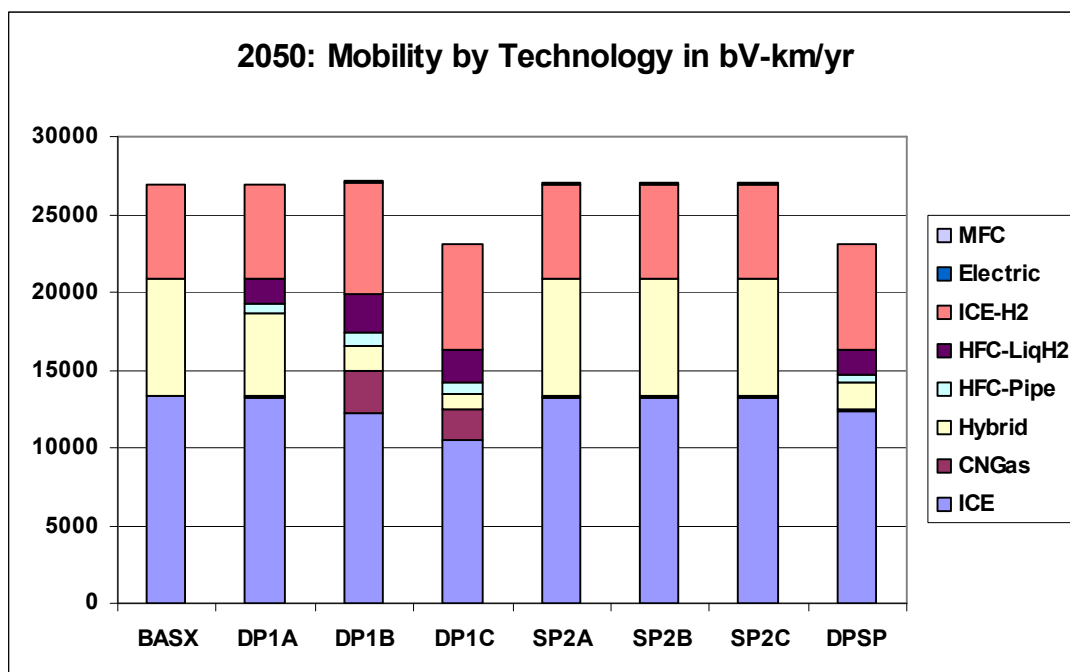


Figure D-127: World use of passenger cars for the technology storylines in the year 2050.

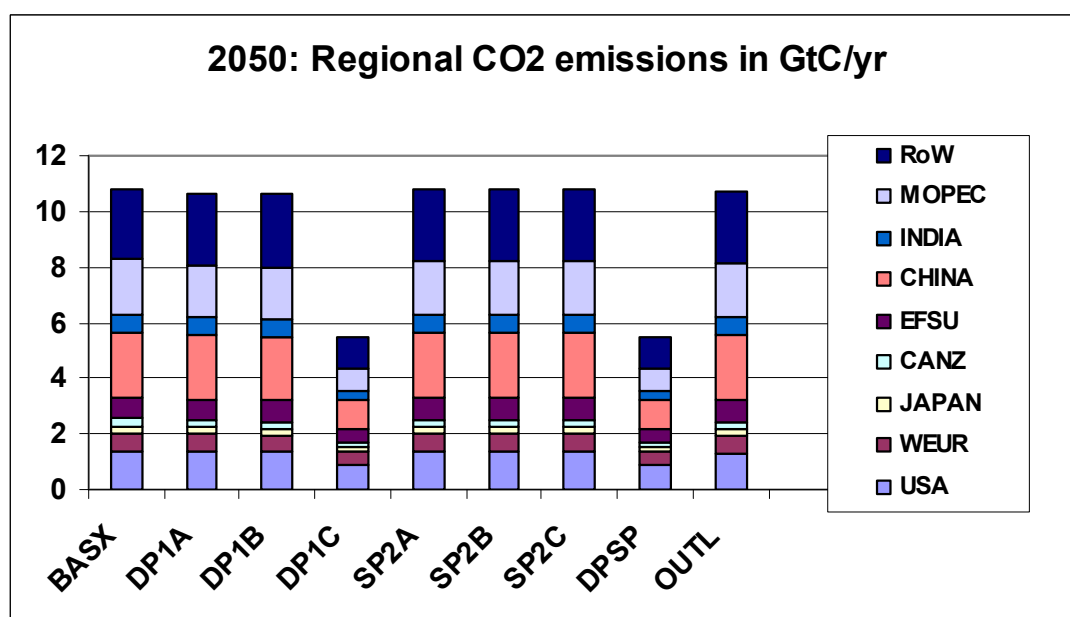


Figure D-128: Global CO2 emissions by region in 2050.

Figure D-128 presents the global CO₂ emissions for the storylines by region. Under the influence of increasingly stringent climate-change policies around the world, CO₂ emissions like in the baseline case reach a maximum of 12 GtC/yr, by the year 2040, but then fall again to around 10.5 GtC/yr by 2050. The intensive carbon policy reduces global emissions to the level of 5.5 GtC/yr. Thus, we conclude that the storylines will not significantly change the developments in terms of climate change, at least for the time horizon of analyses.

The atmospheric concentration given in Figure D-129, of all GHGs for 2050 follows the results of CO₂ emissions reach the levels of 600 ppmv. The difference in the case of an intensive carbon tax is only 50 ppmv the CO₂ equivalent concentration, as it takes time to translate emission reductions to concentration change.

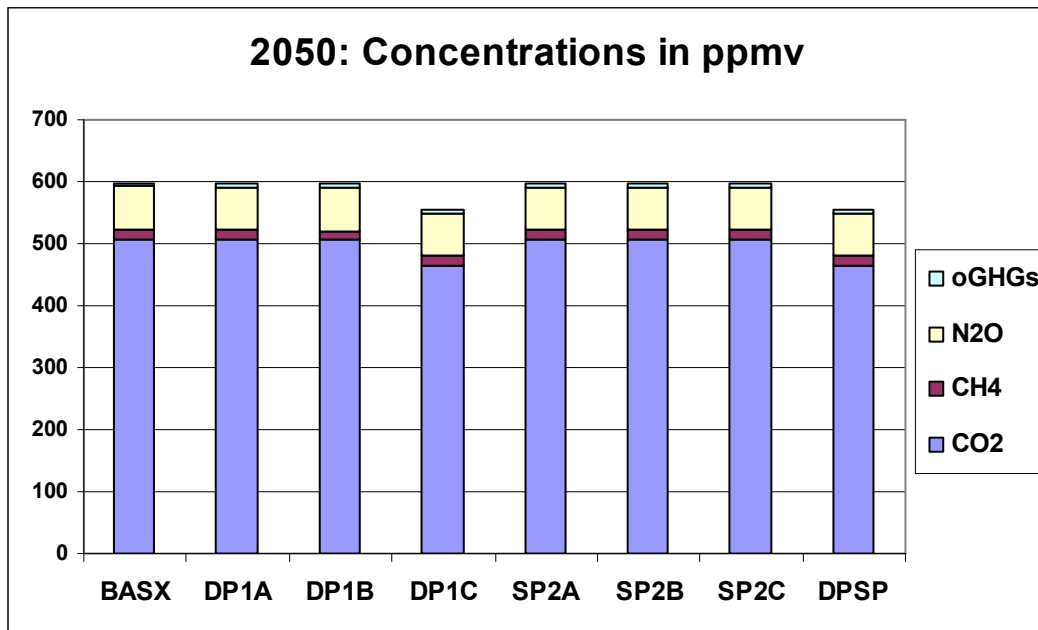


Figure D-129: Atmospheric concentration of three greenhouse gases (CO₂, CH₄, N₂O and other GHGs) in 2050 Notice that the assumed tax is applied only on carbon emissions.

Finally the share of hydrogen fuel cell cars in the overall mobility is given in Figure D-130 together with the share of stationary fuel cells in power generation. We clearly conclude that “demand pull” options that reduce the price of fuel cells are more important than “supply push” options that change the cost of hydrogen production. Also, taxation policy either on the local or global level increases the market shares of HFC. In the case of mobile fuel cells the influence of such policies is more evident.

Thus efficient policies and measures in favor of fuel cells should help to reduce primarily the price of fuel cells as the cost reduction in the production of hydrogen without a simultaneous change of the fuel cell price is not sufficient to render HFC-cars competitive.

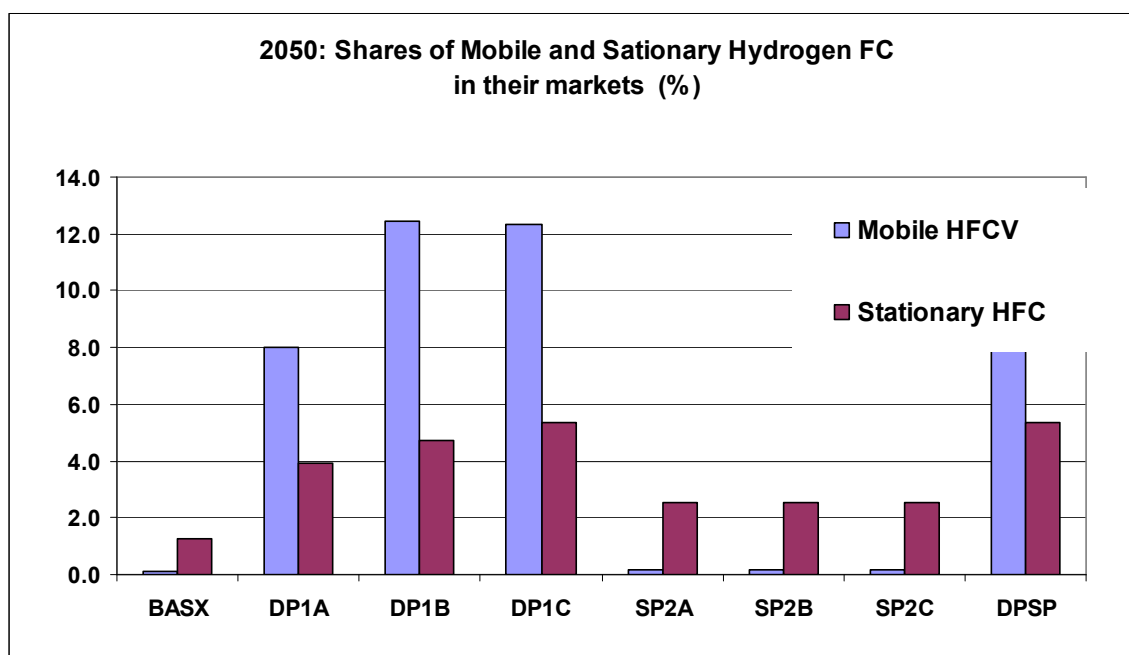


Figure D-130: Market shares of hydrogen fuel cells. In both markets the price of fuel cells is the most relevant factor for their successful diffusion in the markets as the supply-push cases is less successful.

Finally, Figure D-131 presents the GDP development per storyline for the year 2050 and the induced economic losses or gains at that year. The overall economic output increases by more a factor of 3.5, relative to the output in the year 2000, but the differences among scenarios are small and difficult to realize without the help of Figure D-131b. This latter Figure that depicts GDP changes in percent shows that the assumed technological progress in fuel cells has, as expected, has a positive but small feed back to the overall economy.

Only the gasoline tax and/or the carbon tax result to losses above 0.6 percent of the GDP. The direction of the GDP changes relative to the baseline case are easy to explain, as when HFC-technology satisfies demand for energy services at lower costs, the economic output increases while taxation policies will have negative but small impacts (independently of the technology improvement assumed) as the factor energy becomes more expensive. The positive impacts of HFC to the overall economy are not significant but on the contrary, gasoline taxes have a negative impact of 0.35% while the doubling of the climate change intensity results to GDP losses of 0.61%. Under the same tax assumptions the GDP losses are reduced to 0.27 percent when all possible positive developments in the hydrogen fuel cell technology cluster takes place.

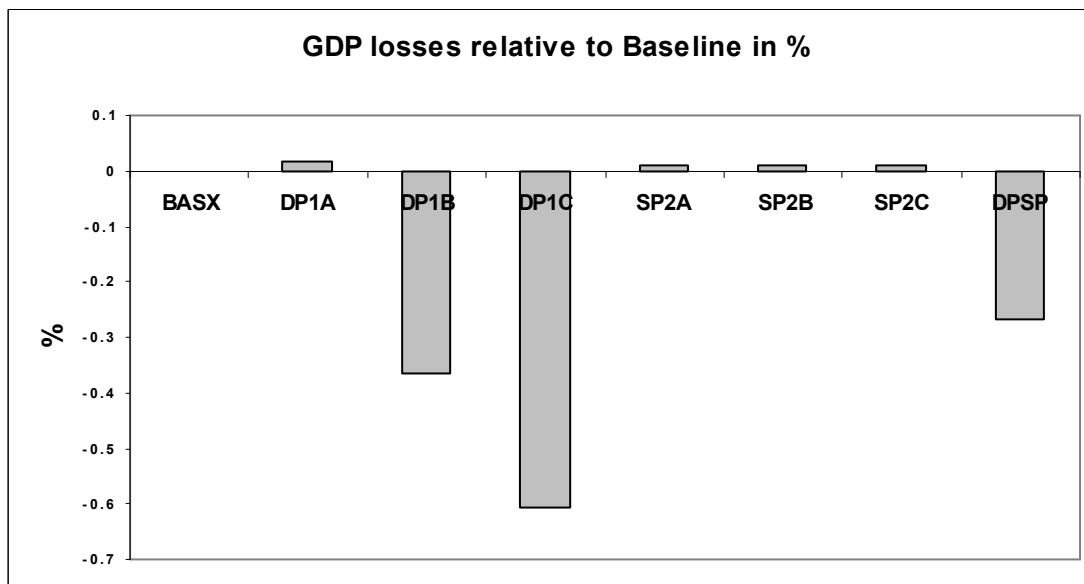
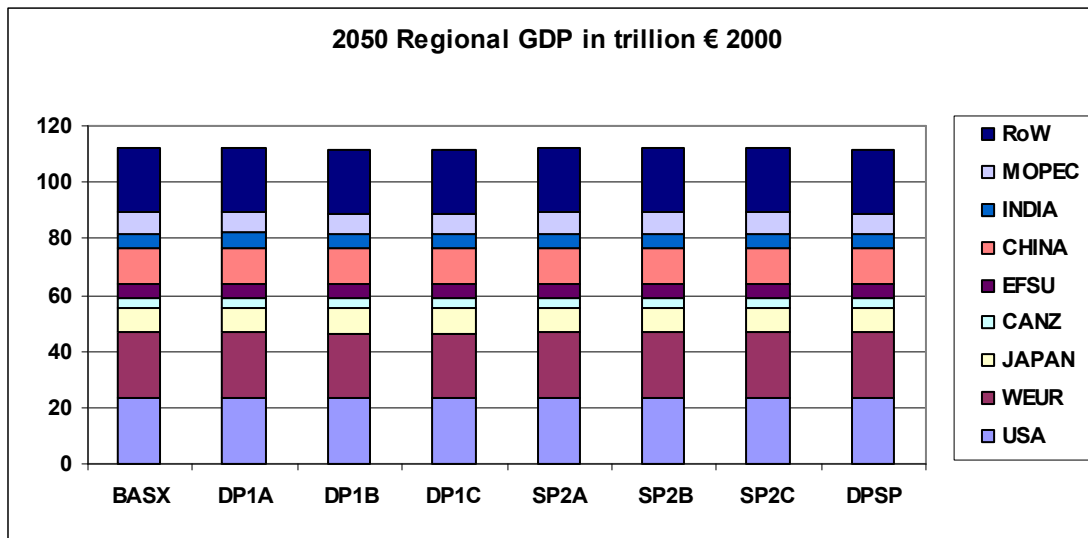


Figure D-131a and Figure D-132b: Economic output by case in 2050. The impacts of improved HFC technology to the overall economy are positive but not significant.

The first results of MERGE implementing the technology stories help to conclude that hydrogen penetrates mostly in the transport sector and that the capital cost reduction of hydrogen fuelled cars is the key factor of success. For hydrogen production, biomass and coal are the dominant supply options but the cost reduction in hydrogen production is not sufficient to render the hydrogen economy competitive without a simultaneous improvement in the price of fuel-cells.

D.3.2.6 PACE-T-H₂

[by S. Jokisch (ZEW)]

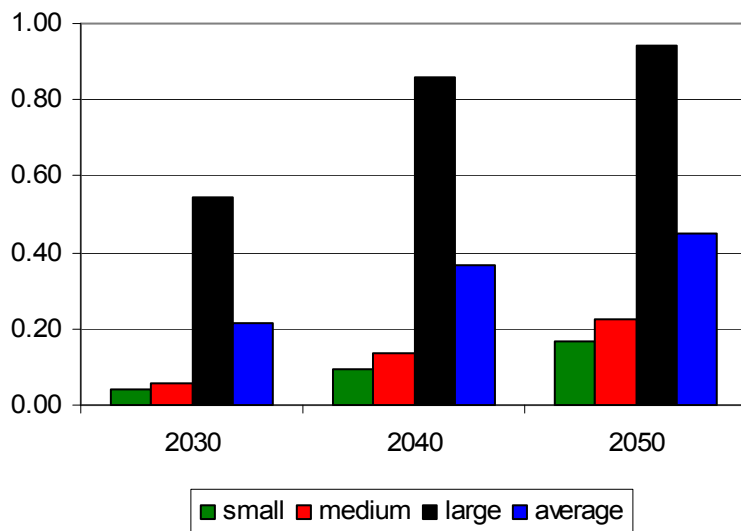
Demand Pull

Scenario 1a: Breakthrough in Fuel Cells

The first scenario analysis concentrates on a breakthrough in fuel cells reached by setting the vehicle costs of hydrogen cars to their floors. Since PACE-T(H₂) implements 10-year periods, we start this technology scenario in year 2030, i.e. vehicle costs are set to their floors from 2030 onwards. The development of hydrogen penetration rates is shown in Figure D-133.

Setting the vehicle costs to their floors has a large impact on hydrogen penetration in the new vehicle fleet. In 2030 the penetration rate of large hydrogen cars increases to 54.3%. There is also a sizeable share of 4.1% in the small car segment and of 5.6% in the medium car segment. In all this means an average hydrogen penetration rate of 21.3%. Over time the figure indicates further increases in hydrogen penetration. The share of hydrogen cars in overall new vehicles in 2050 thus reaches more than 90% for the large car segment, 22.6% for medium cars and 16.9% for small cars. Average hydrogen penetration climbs to 45.1%. Again, the larger hydrogen penetration in the large car segment can be explained by the relative larger cost advantage from the introduction of hydrogen cars compared to medium and small cars.

Figure D-133: Hydrogen penetration rates in new cars (Scenario 1a)

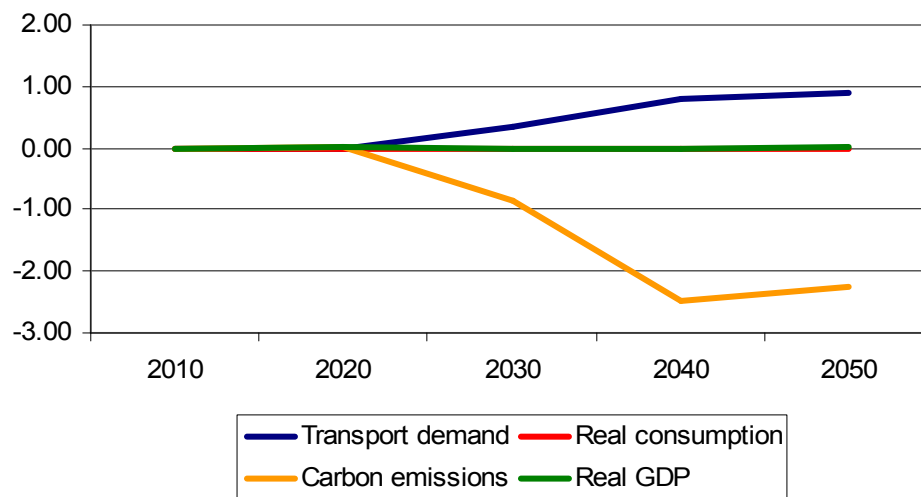


The macroeconomic effects of the breakthrough of fuel cells are shown in Figure D-134. Note that the values express percentage changes relative to the respective year in the baseline. Thus the curves do not describe the macroeconomic variables over time but the multipliers to get the economic variable in the scenario in a

certain period. For example, a value of 0.3% for transport demand in 2030 would indicate that transport demand in year 2030 has increased by 0.3% compared to the respective baseline value in 2030.

Obviously, there are hardly any changes in the macroeconomic variables before 2030. Starting with the assumed decrease in vehicle costs in 2030, transport demand starts to increase. In 2050 it will be almost 1% above the respective baseline value. The reason for increased demand for transportation services are of course the reduced car costs. The latter lead to lower lifetime costs for hydrogen cars and thus to lower costs for transportation services. As a consequence consumer's demand for these services rises. It also becomes obvious from the figure that there is a small negative effect on real consumption in the considered scenario, but the magnitude of this effect is negligible. This is an interesting finding. Real consumption is composed of transportation services and demand for other consumption goods. Given the observed increase in transport demand there is redistribution from other consumption goods to transport demand so that in effect real consumption remains fairly unchanged. The effects of lower vehicle costs on GDP are also more or less negligible.

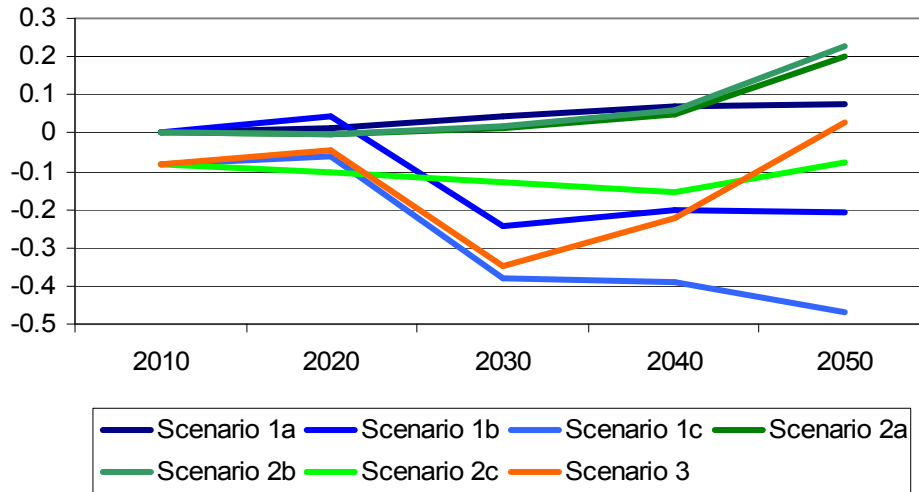
Figure D-134: Macroeconomic indicators Scenario 1a (changes in % relative to baseline)



The increased penetration of hydrogen cars has however sizeable effects on carbon emissions. In 2030, emissions are reduced by almost 1% compared to the baseline. The largest decrease of 2.5% is reached in 2040, and in 2050 carbon emissions are 2.2% below the respective baseline value. The relatively large decline in carbon emissions in 2040 is due to the immense rise in hydrogen penetration for large cars. The savings potential of carbon emissions in the medium and small car segment is much smaller. This explains why the decline in emissions in 2050 is somewhat less pronounced than in the previous period. Furthermore, higher demand for hydrogen transport technologies demands larger production of hydrogen. Since hydrogen is mainly produced by coal and gas inputs there is an additional counterbalancing effect on carbon emissions. Nevertheless, the introduction of non-zero and more fuel efficient emission vehicles outweighs the effects on carbon emissions in the hydrogen production sector and thus leads to a decline in overall emissions.

Figure D-135 plots the effects of the considered scenario (and of other scenarios, see below) on the real wage rate (for fixed labor supply). The changes relative to the baseline are again very small. However, one can see a small positive effect on the wage rate so that in 2050 it exceeds its baseline value by 0.07%. This improvement in the real wage rate mainly stems from the higher demand for passenger transport which, in turn, increases labor demand.

Figure D-135: Real wage rate (changes in % relative to baseline)



Finally, we turn to the welfare implications of the considered scenario. Welfare changes of the different scenarios are measured in this report in Hicksian equivalent variation in income (HEV). Since the underlying utility function is linearly homogeneous, percentage changes in the utility level are equivalent to percentage Hicksian equivalent variations in income. With this convenient cardinalization of utility, percentage HEVs in income are equivalent to percentage changes in real consumption with respect to the baseline.

Table D-55: Social welfare

Scenario	Changes in %
1a	-0.01
1b	-0.12
1c	-0.16
2a	0.01
2b	0.01
2c	-0.03
3	-0.16

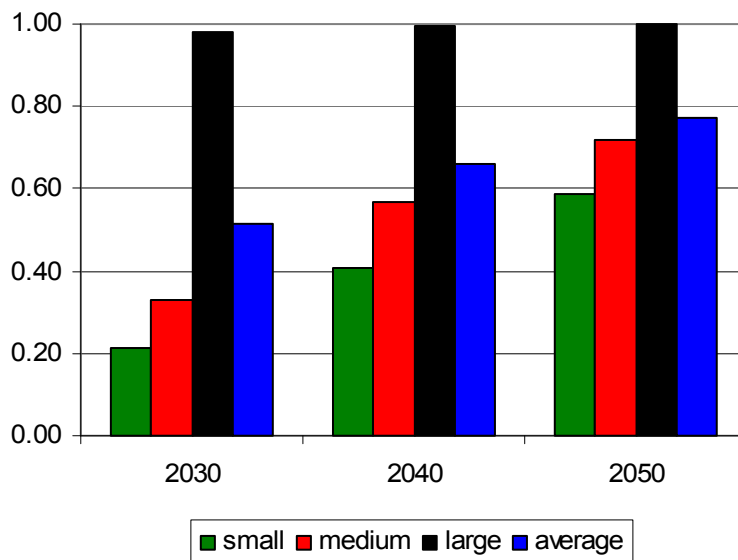
Table D-55 reports the welfare changes of all scenarios analysed in this report. Obviously, Scenario 1a reveals hardly any change in consumer's welfare compared to the baseline. However, as expected from the development of real consumption, social welfare is slightly reduced by 0.01%.

Scenario 1b: Scenario 1a and Environmental Considerations

This scenario combines the breakthrough in fuel cells, analysed in the previous section, with a higher fuel tax. Precisely, we again assume that starting in 2030 hydrogen vehicle costs are set to their floor costs. Additionally, the fuel tax is raised by 0.50 Euro/liter, i.e. by 100%, from 2030 onwards.

The impact of the considered scenario on hydrogen penetration rates is shown in Figure D-136. Not surprisingly, the increase in the fuel tax leads to substitution of the conventional technology by the tax-favoured hydrogen technology. Therefore, hydrogen penetration of large cars immediately rises to 98.1% in 2030 and almost 100% in the years afterwards. But there is also an enormous additional rise in hydrogen penetration in the other two size classes. The share of hydrogen in new small cars is 21.5% in 2030 and 58.9% in 2050, for medium cars the respective shares are 33.1% and 71.8%. Average penetration rates increase to 51.5% in 2030 and 77.1% in 2050, i.e. more than three quarters of all new cars in 2050 will be powered by hydrogen.

Figure D-136: Hydrogen penetration rates in new cars (Scenario 1b)



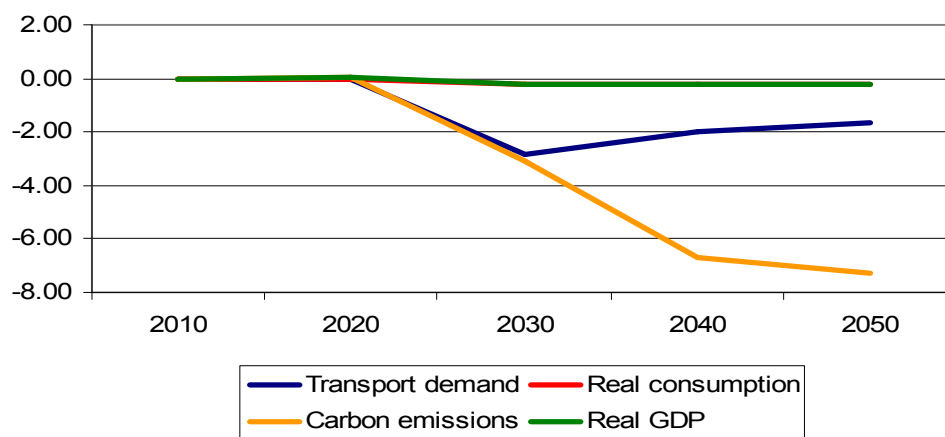
The development of the macroeconomic variables is given in Figure D-137. In contrast to Scenario 1a transport demand is now reduced vis-à-vis the baseline. The reason is of course the higher taxation of fuel for conventional cars which distorts the consumer's decision, lowers his lifetime budget and increases the costs of transport services. In 2030 the decrease in transport demand is largest (-2.8%) since the average share of hydrogen cars is the smallest compared to later periods. After 2030, however, the positive effect on transport demand from the lower vehicle costs starts to counterbalance the negative tax effect so that the change in transport demand is less pronounced (only about -2% in 2040 and 2050). The higher tax burden leads to a

shift from transport demand to consumption of other goods so that real consumption only slightly declines compared to the baseline. This also leads to a small negative effect on real GDP.

From Figure D-137 it becomes obvious that the increase in the fuel tax has a major impact on carbon emissions. Thus in 2030 these are by 3.1% below the respective baseline value and in 2050 the reduction is 7.3%. This means that carbon emissions are reduced much more in comparison to the baseline than in Scenario 1a.

The development of wage rates as shown in Figure D-135 is mainly determined by the demand for transportation services. Consequently, real wage rates decline during the transition by approximately 0.2% compared to the baseline. Finally, as Table D-55 indicates, the raise of the fuel tax leads to reduced consumption demand and thus lower social welfare. However, the effect is relative small (welfare loss of 0.12%).

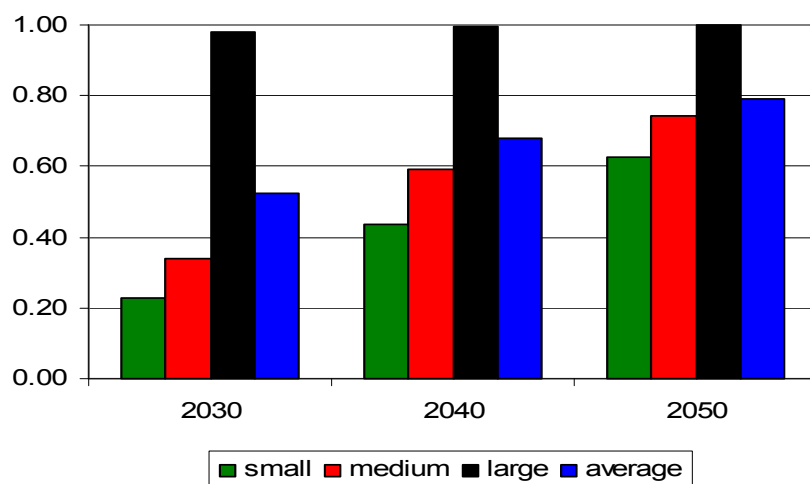
Figure D-137: Macroeconomic indicators Scenario 1b (changes in % relative to baseline)



Scenario 1c: Scenario 1b + Climate Policy

This scenario combines the previous Scenario 1b with an increased carbon value. Besides assuming the breakthrough in fuel cells and the increased fuel tax starting in 2030, the baseline carbon value is doubled already from 2010 onwards. The additional effects of the latter assumption are modest.

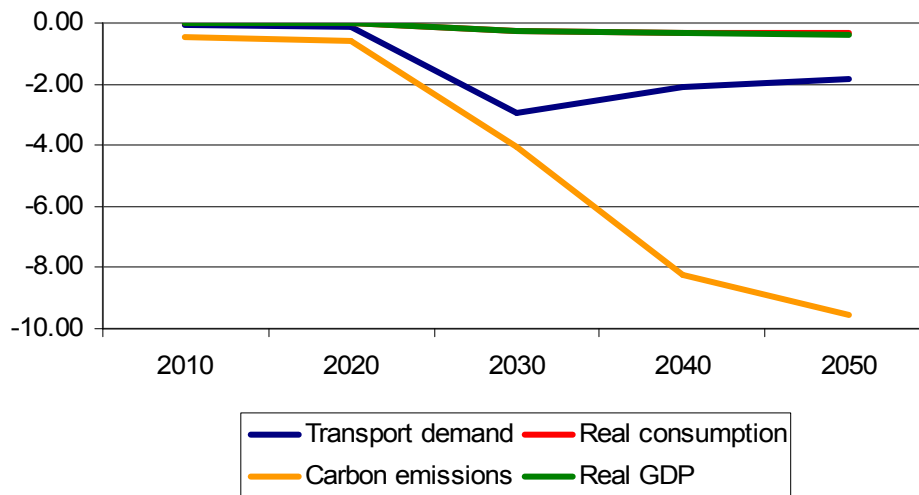
Figure D-138: Hydrogen penetration rates in new cars (Scenario 1c)



Take the development of hydrogen penetration rates shown in Figure D-138. Since in the large car segment, hydrogen penetration was already very high in the previous scenario, there are only very small improvements. However, for the other two size classes hydrogen penetration in the new vehicle fleet further increases. Penetration rates for new small cars increase to 22.6% in 2030 and 62.7% in 2050. In the medium size class the rates rise to 34.1% in 2030 and 74.1% in 2050. On average, hydrogen penetration rates in new cars amount to 52.2% in 2030 and 79.1% in 2050. Why is the additional penetration of hydrogen rather small even if the carbon value is doubled? The explanation on the one hand is the fact that even without assuming an increased carbon value hydrogen penetration is already very high – especially in the large car segment – so that only a smaller amount of non zero emission vehicles (relative to the baseline) are hurt by the higher carbon tax. On the other hand, hydrogen production from mainly fossil fuels itself is also affected by the increased carbon value so that fuel costs for hydrogen cars also rise. And third, one still has to remember that hydrogen vehicle costs exceed those of conventional cars even assuming the breakthrough in fuel cells. Therefore, hydrogen cars are from a macroeconomic point of view not competitive. This of course affects the representative consumer's budget and limits the substitution of conventional vehicles by hydrogen cars.

The macroeconomic effects in Scenario 1c are very similar to the previous scenario, see Figure D-139. Due to the increase in the carbon value from 2010 onwards, transport demand is already reduced in 2010 and 2020 relative to the baseline. The magnitude of this effect is however fairly small. Starting in 2030 the demand for transportation services decreases much more sizeably. Thus in 2030 transport demand is reduced by 2.9% vis-à-vis the baseline; in 2050 the reduction is 1.9%. Again the reason for this development is the combination of the higher fuel tax (from 2030 onwards) with the doubled carbon value. Not surprisingly, real consumption and GDP declines somewhat more than in the previous scenario.

Figure D-139: Macroeconomic indicators Scenario 1c (changes in % relative to baseline)



Of course, the doubling of the carbon tax leads to additional reductions of carbon emissions compared to the baseline. This decline is already remarkable in 2010 and 2020. With the market entry of hydrogen cars and the increase in the fuel tax in 2030, the deviation of carbon emissions from the respective baseline values become much more sizeable. Thus the decrease in carbon emissions in 2030 is now already 4%, and in 2050 emissions will be reduced by almost 10% compared to their baseline level. It is worth mentioning that the additional reductions in carbon emissions not only stem from reduced emissions of cars but also from all other economy-wide emission reductions.

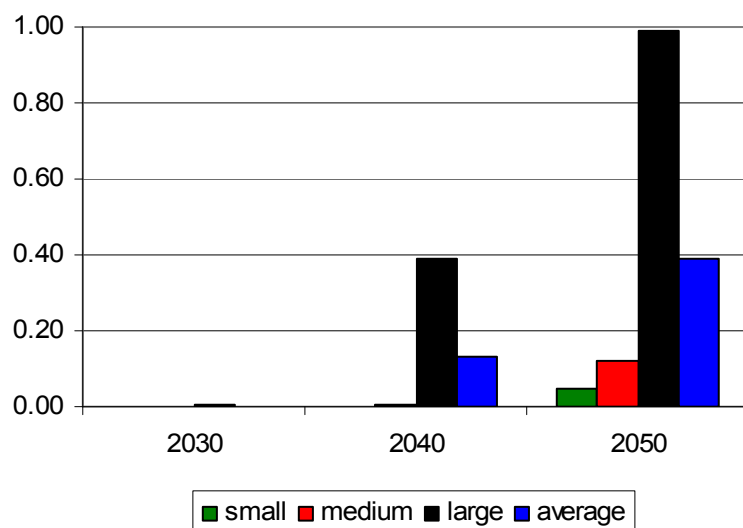
The introduction of the higher carbon value has a negative impact on real wages (see Figure D-135). These are now reduced on the one hand by the lower demand of transport services and on the other hand by reduced demand in other production sectors. Not surprisingly, the doubling of the carbon value leads to additional welfare losses so that social welfare is reduced by 0.16% compared to the baseline.

Supply Push

Scenario 2a: Cheap H₂ Production

The scenarios considered until now concentrated on demand side effects to encourage hydrogen penetration. As the simulation results suggest, all analyzed measures lead to improved hydrogen penetration. The scenarios in this section focus on the supply side of hydrogen. In the first scenario it is assumed that hydrogen is produced cheaply by setting the parameters of hydrogen production technologies to their floors from 2030 onwards.

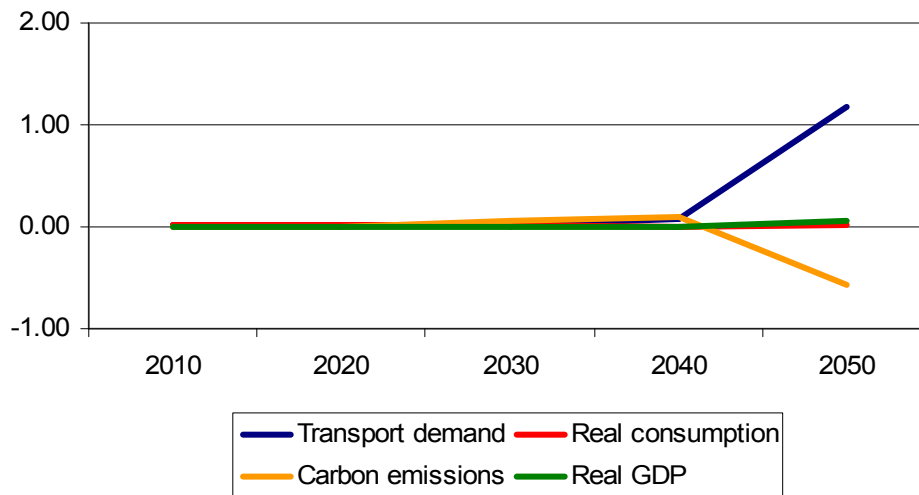
Figure D-140: Hydrogen penetration rates in new cars (Scenario 2a)



A first look at Figure D-140 already makes clear that the effects of a cheaper H₂ production on hydrogen penetration are much smaller than in the scenarios that focused on the demand side. Obviously, hydrogen penetration in 2030 remains unchanged compared to the baseline. In 2040 hydrogen penetration is increased, especially in the large car segment. By 2050, there will be 4.7% small hydrogen cars, 12.1% medium hydrogen cars and 98.7% large hydrogen cars in the new vehicle fleet. On average this is a share of 39.2% of hydrogen cars. This finding supports two major issues. First, the most important drivers for hydrogen penetration are the vehicle costs (i.e. the fix costs). Only if there is a sizeable share of hydrogen cars in the market, cheaper hydrogen production and thus cheaper hydrogen fuel costs become relevant. Second, it is again the large car segment that benefits most from cheaper hydrogen since these cars reveal the highest fuel consumption so that cost savings are largest in this size category.

These findings are also reflected in the development of the macroeconomic variables, see Figure D-141. Any deviations of transport demand, real consumption, GDP and carbon emissions from the baseline are negligible until 2040. Only in 2050 there are sizeable effects. Thus transport demand is increased by 1.2% due to lower hydrogen fuel costs. These cost savings lead to additional resources for the consumer so that consumption demand and thus GDP slightly rise vis-à-vis the baseline. As before, the increased penetration of hydrogen cars leads to reduced carbon emissions by 0.6% in 2050.

Figure D-141: Macroeconomic indicators Scenario 2a (changes in % relative to baseline)



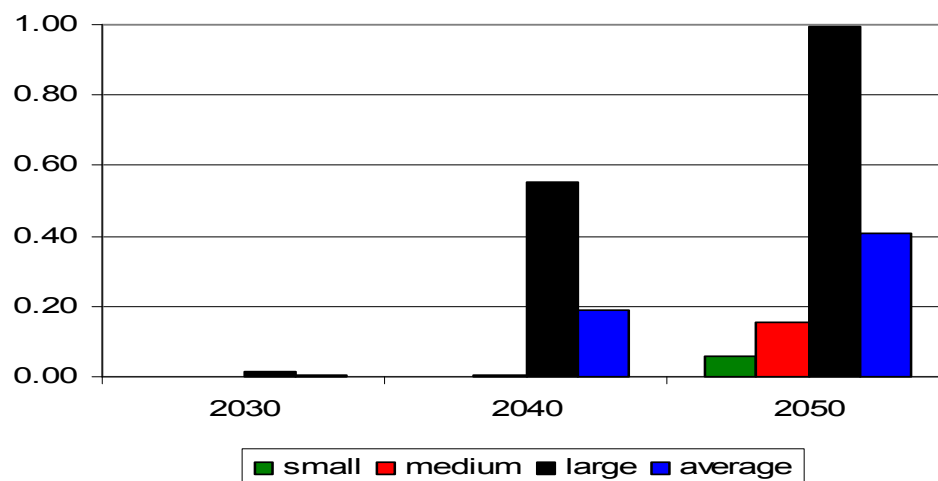
The real wage rate as shown in Figure D-135 behaves very similarly to transport demand and thus slightly improves compared to the baseline. In 2050 the increase is about 0.2% compared to the respective baseline value. Finally, the positive effect on consumption demand leads to small welfare gains of 0.01%.

Scenario 2b: Scenario 2a + 100% Subsidy on H₂ Distribution and Storage Infrastructure

We now turn to a scenario where we assume cheap hydrogen production and additionally subsidize the hydrogen distribution and storage infrastructure by 100%. PACE-T(H₂) doesn't distinguish explicitly between hydrogen production costs on the one hand and hydrogen distribution and storage costs on the other hand. The development of hydrogen fuel costs is calculated as an average of all costs of hydrogen production, distribution and storage technologies. Following these calculations, approximately 30% of hydrogen fuel costs are due to the hydrogen distribution and storage infrastructure. In order to implement this scenario, we therefore assume that 30% of the hydrogen fuel costs are subsidized from 2030 onwards.

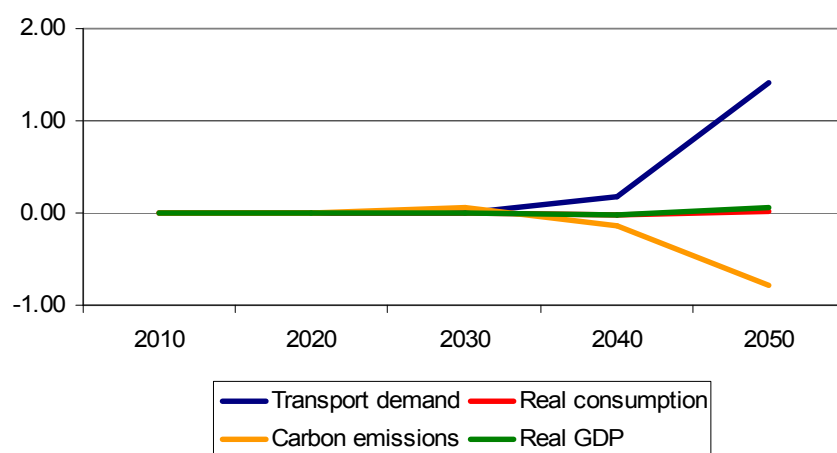
The findings are very similar to the previous scenario. Hydrogen penetration rates (see Figure D-142) in 2030 remain fairly unchanged to the baseline. In 2040 there is an additional rise in penetration rates for large cars to 55.4%. As before, hydrogen penetration in the large car segment in 2050 is almost 100%, in the medium car segment it is 15.7% and in the small car segment 5.8%. The average hydrogen penetration rate in overall new cars increases to 41% in 2050.

Figure D-142: Hydrogen penetration rates in new cars (Scenario 2b)



Due to the larger cost decrease for hydrogen the macroeconomic effects are slightly more pronounced than in the previous scenario. As Figure D-143 indicates, transport demand in the considered scenario is already increased in 2040. In 2050 the deviation from the baseline is 1.4%. The effects on real consumption and GDP are also enforced. However, the changes relative to the baseline are again fairly small. Finally, carbon emissions start to decrease from 2040 onwards. The reduction in 2050 is 0.8% relative to the baseline. The wage rate as shown in Figure D-135 follows more or less the same pattern as in the previous scenario. Now the positive effect is slightly reinforced so that in 2050 the wage rate is somewhat more than 0.2% above the baseline value.

Figure D-143: Macroeconomic indicators Scenario 2b (changes in % relative to baseline)



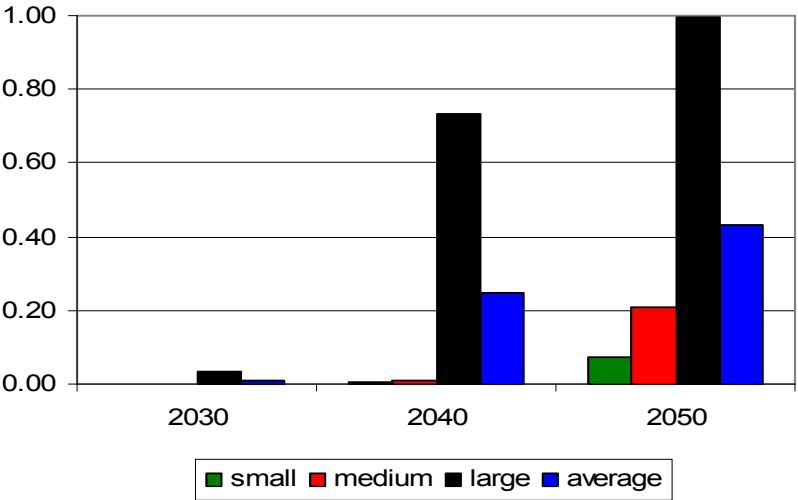
Welfare effects of the considered scenario are almost identical to the previous one. Social welfare is expected to increase by 0.01%.

Alternative Scenario 2b:

In order to get a better valuation of the effects of subsidizing hydrogen fuel costs and their importance on hydrogen penetration, we implemented a further scenario where we assume that hydrogen fuel production is subsidized by 100% (in contrast to the 30% assumed in the previous paragraphs).

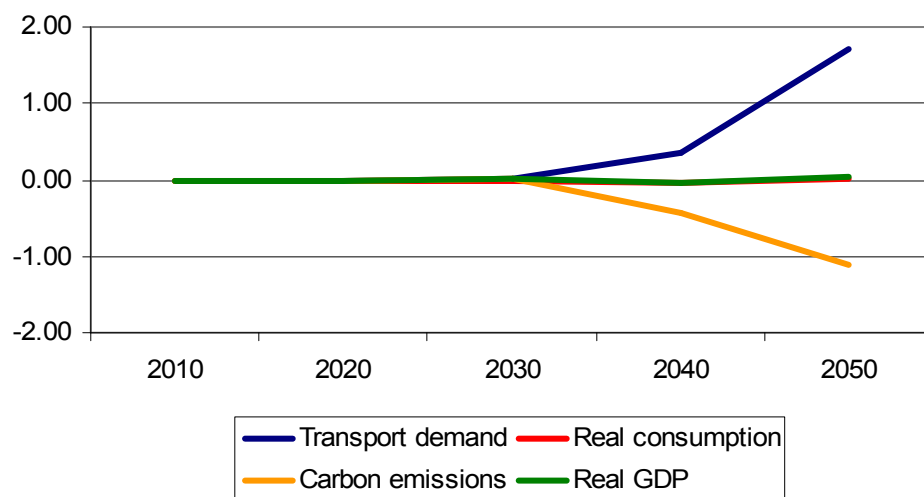
The impact on hydrogen penetration can be seen from Figure D-144. Obviously, hydrogen penetration in the new vehicle fleet already slightly increases in 2030. A major improvement in hydrogen penetration for the large car segment can be observed in 2040. In this period 73.4% of large cars are fueled by hydrogen (in the previous scenario the share amounted to 55.4%). Penetration rates in 2050 will rise to 7.3% for small cars, 21% for medium cars and 99.6% for large cars. The average share of hydrogen cars in the same period increases to 43.4% (compared to 41% in the previous analysis).

Figure D-144: Hydrogen penetration rates in new cars (Alternative Scenario 2b)



It is not surprising that the effects on the macroeconomic variables as shown in Figure D-145 are more or less the same as before. But it is worth mentioning that due to the subsidization of hydrogen production by 100% fuel costs for hydrogen cars become extremely low so that transportation demand is additionally increased. By 2050, the demand for transportation services rises by 1.7% compared to the respective baseline value. Due to the larger penetration of hydrogen cars carbon emissions experience further decrease so that in 2050 these are reduced by 1.1% relative to the baseline.

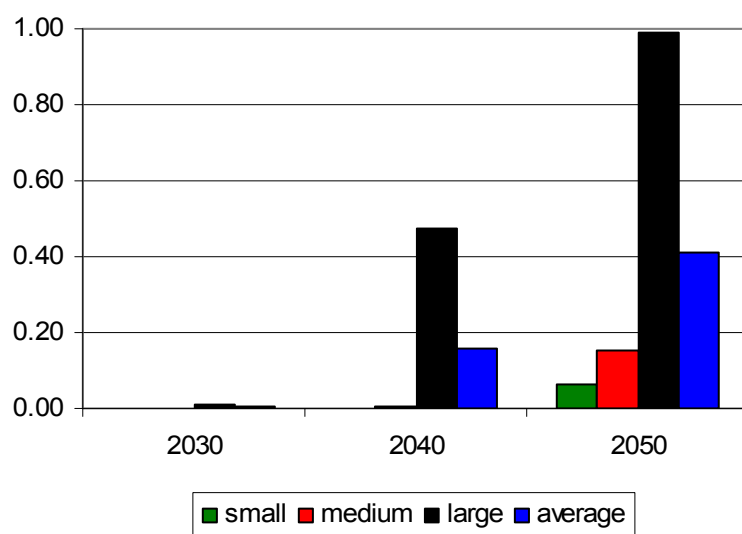
Figure D-145: Macroeconomic indicators Alternative Scenario 2b (changes in % relative to baseline)



Scenario 1c: Scenario 2b + Climate Policy

This scenario combines Scenario 2b with an increased carbon value. Consequently, starting in 2030 hydrogen production is assumed to be cheap and the distribution and storage networks are subsidized by 100%, i.e. hydrogen production costs in the aggregate hydrogen production technology in PACE-T(H₂) are subsidized by 30%. In addition, the assumed carbon value in the baseline is doubled from 2010 onwards.

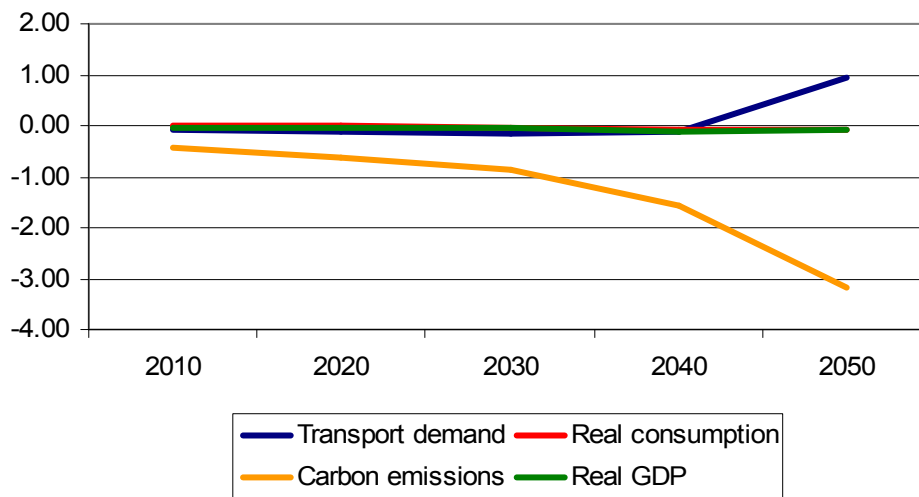
Figure D-146: Hydrogen penetration rates in new cars (Scenario 2c)



As becomes obvious from Figure D-146, hydrogen penetration rates develop almost identical than in the previous scenario. There is however a small exception in 2040. Here hydrogen penetration rates are increased compared to the baseline but somewhat decreased compared to the previous scenario. The reason is that the higher carbon value also affects hydrogen production costs. Since hydrogen becomes more expensive this has a negative impact on hydrogen penetration.

Transport demand again develops very similar to the previous two scenarios. However, Figure D-147 indicates that the increase is slightly dampened. Furthermore, the higher carbon value leads to slightly reduced consumption demand and real GDP compared to the baseline. It is not surprising that the doubling of the carbon value has a major impact on carbon emissions. These are reduced from 2010 onwards vis-à-vis the baseline. The largest change occurs in 2050 when carbon emissions fall short off their respective baseline value by more than 3%.

Figure D-147: Macroeconomic indicators Scenario 2c (changes in % relative to baseline)



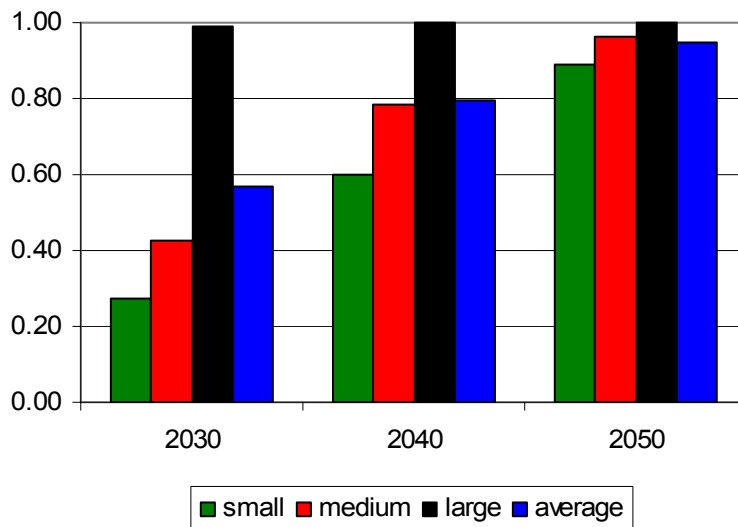
The increase in the carbon value leads to a decline in the real wage rate. In 2040 this decline is about 0.15%. There is however a small improvement until 2050 so that wages in this period are reduced by only 0.07%. Finally, the doubling of the carbon value slightly reduces social welfare by 0.03%.

Scenario 3: Combined Case of Scenarios 1c and 2c

The last scenario combines Scenarios 1c and 2c, i.e. it includes all measures on the demand side and the supply side.

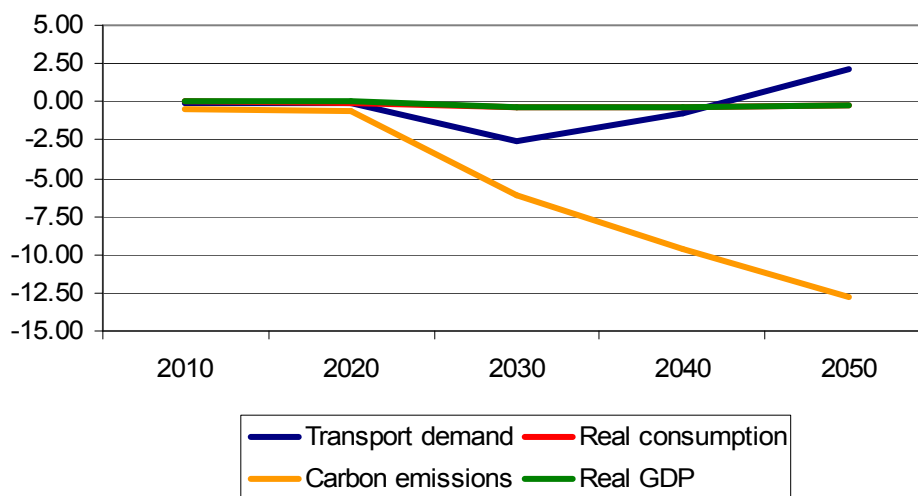
Obviously, this combined scenario reveals the largest effects on hydrogen penetration in the new vehicle fleet, see Figure D-148. Take the year 2030. Penetration rates for small cars are 27.6%, for medium cars 42.8% and for large cars 99.1%. This yields an average hydrogen penetration rate of 57.1%. In 2050 the increase in hydrogen penetration rates is overwhelming. 88.7% of all new small cars are hydrogen cars. The respective values for medium and large cars are 96.1% and 100%. On average 95% of all new cars will be powered by hydrogen.

Figure D-148: Hydrogen penetration rates in new cars (Scenario 3)



The macroeconomic effects as shown in Figure D-149 are a combination of all previously considered scenarios. All deviations from the baseline before 2030 are fairly small. In 2030 transportation demand is reduced by 2.5% compared to the respective baseline value. This negative effect is of course due to the increase in the distorting fuel tax and the doubled carbon value which lowers the consumer's budget and makes transportation services more expensive. Until 2050 the deviations in transport demand from the baseline gradually turn to positive changes. This reflects the cheap vehicle costs from the breakthrough in fuel cells as well as the lowered variable costs from cheap hydrogen production and subsidized distribution and storage networks. Thus transportation demand in 2050 ends up 2.2% above the respective baseline value. GDP and real consumption are slightly negative affected, carbon emissions are reduced the most in this scenario. Starting in 2030 there is a steady decline in emissions. In 2050 emissions will be about 12.5% below the respective baseline value.

Figure D-149: Macroeconomic indicators Scenario 3 (changes in % relative to baseline)



The development of real wages follows again a very similar pattern as transport demand (see Figure **D-135**). While in 2030 wages are by 0.35% below their respective baseline value, the deviations become smaller in later periods and remain fairly unchanged in 2050 compared to the baseline value. The changes in social welfare are identical to Scenario 1c where it was reduced by 0.16%.

Conclusion

All technological scenarios considered here favor the penetration of hydrogen. As the scenario analysis indicates, the most driving force for hydrogen penetration is the cost development of the hydrogen vehicle technology. If vehicle costs of hydrogen cars can be reduced to their floors, there will be a major impact on penetration rates. Our simulation results with the dynamic CGE model PACE-T(H₂) show that this might lead to a share of 21% of hydrogen cars in the new vehicle fleet in 2030 and of 45% in 2050. Assuming additional tax policies, like the doubling of the fuel tax and the carbon tax, favors hydrogen penetration by even more. In this case hydrogen penetration rates could reach 52.2% in 2030 and 79.1% in 2050 in overall new cars.

Supply side considerations reveal only minor effects on hydrogen penetration. Assuming cheap hydrogen production technologies by setting the parameters of the hydrogen production technologies to their floors, leads to unchanged hydrogen penetration rates in 2030 compared to the baseline and to increased rates of 39.2% in 2050. If it is additionally assumed that the hydrogen infrastructure is subsidized by 100% and the carbon value is doubled with respect to the baseline development, hydrogen penetration becomes more pronounced. Thus, in 2050 average hydrogen penetration is 41%.

Combining the demand and supply side scenarios reveals the largest effects on hydrogen penetration. In 2030, the average share of hydrogen cars in new vehicles is expected to be 57.1% and in 2050 95%. This means a substantial change of the existing car market and a positive outlook for the hydrogen technology.

The simulations with the CGE model PACE-T(H₂) also indicate that the promotion of hydrogen cars has only minor effects on the future development of most macroeconomic variables. From an environmental point of view, it is worth noting that the higher penetration of zero emission vehicles (as in the case of hydrogen cars) leads to major reductions in carbon emissions despite the fact that hydrogen is mainly produced from fossil fuels. Thus, the combined scenario of demand side pull shows emissions reductions of 4% in 2030 and almost 10% in 2050 compared to the respective baseline values. Of course, due to the smaller hydrogen penetration in the supply side scenarios, the decline in emissions is lower. Again, the largest effects on carbon emissions are observed for the combined demand and supply side scenarios. Here the simulation results suggest that emissions in 2030 are reduced by more than 6% and in 2050 by almost 13%.

Finally, the effects of the considered scenarios on wages and consumers' welfare are almost negligible.

D.4 R&D Policy Scenarios

D.4.1 Introduction –Definition

The CASCADE MINTS project Part I has insisted on establishing a common specification for a technology dynamics module to be used by the models (see C.1.2). The module is based on the concept of the two factor learning curve explaining technological improvement in terms of R&D expenditure and cumulative experience gained by technology implementation. In fact, according to this concept, R&D is a primary mover for technological change providing initial improvements which lead to additional technology take-up that in turn leads to further improvement via learning by experience. In this sense, learning by experience is a factor magnifying the initial impetus given by research.

Once the models have been equipped with this mechanism and calibrated to approximately reproduce the Baseline scenario they are capable of carrying out R&D policy scenarios. The scenario definitions take the form of large additional (above Baseline) R&D funding addressed at specific clusters of hydrogen economy related technologies or to several clusters at the same time. The choice of combinations is guided to a considerable extent by information arising from the “Technology Story” definition in WP1.5 and the scenario results in WP 1.2. In evaluating the scenarios emphasis is placed on notions of “R&D productivity” in terms of specific objectives, such as technology sales, reduction in energy system costs etc., as well as objectives in the broad domain of sustainable energy systems, such as climate change, air pollution, depletion of resources/energy supply security etc. A limited number of scenarios combining enhanced R&D effort with other policies such as emission constraints or internalisation of external costs through taxation, subsidies on infrastructure are also considered in an attempt to examine how such non- R&D policies may improve R&D productivity in terms of policy objectives or conversely how R&D policies may reduce the cost of attaining given objectives.

CASCADE-MINTS does not pertain to define optimal R&D policies involving allocation of funding to hydrogen economy related options as opposed to other energy technology options, although it is clear that the R&D scenarios open the way for the performance of such analysis at a future date.

The scenarios examined are summarised below:

- o. Stop all baseline R&D expenditures on hydrogen production, infrastructure and fuel cell technologies from 2007 onwards worldwide. The purpose of this scenario is to examine the role of R&D in initiating any progress in hydrogen related technologies.
- 1. Demand side scenarios:
 - 1.1. Tenfold increase of baseline R&D allocations on fuel cells from 2007 to 2015 worldwide. This corresponds to about 207 billion €05 additional R&D expenditures in fuel cells.
 - 1.2. Scenario 1.1 together with additional tax in oil for road transport of the order of 0.5€/lt from 2025 onwards worldwide.

1.3. Scenario 1.2 and using 5% of the tax revenues as additional R&D in fuel cells and hydrogen infrastructure. The additional R&D is allocated according to the share of each technology in total energy related R&D expenditures.

1.4. Scenario 1.3 combined with doubling baseline effective carbon values (see Table D-56)

Table D-56: Carbon value used in the R&D scenarios involving climate policy stronger than the baseline €05/tn of CO₂

	2005 - 2010	2011 - 2020	2021 - 2030	2031 - 2040	2041 - 2050	2051 - 2100
Europe	27	43	72	114	155	214
Rest of OECD	5	17	39	73	122	186
Developing countries	0	1	9	27	68	139

2. Supply side scenarios:

2.1. Tenfold increase in baseline R&D expenditures on hydrogen production options between 2007 and 2015 worldwide. This corresponds to 167 billion €05 of additional R&D expenditures.

2.2. Scenario 2.1 together with additional tax in oil for road transport as in Scenario 1.2

2.3. Scenario 2.2 together with 100% subsidy to all hydrogen distribution and storage infrastructure worldwide

3. Combined case; scenarios 1.4 and 2.3. This scenario, which is naturally both highly unlikely and extremely costly was evaluated to test the limits of policy induced technical change.

D.4.2 Results from each model

D.4.2.1 POLES

[by P. Criqui and S. Mima (LEPII-EPE)]

Overview

Once POLES has been equipped with adequate mechanisms for representing the hydrogen economy it is used to perform R&D scenario analysis in order to explore under what conditions and to what extent the R&D may influence hydrogen economy to materialize.

The Reference case is characterized by a large R&D effort in the direction of Fuel Cells and some hydrogen supply options. So a substantial technical progress concerning Fuel Cells (close to what is being assessed as the technical limits) is identified already in the Reference. Such progress falls short of making hydrogen an indisputable option in the automotive or the heat and power markets in the horizon to 2050. Under such circumstances the efficacy of R&D encounters diminishing returns. Hence, in this report, firstly we have examined the contribution of the R&D already incorporated in the Reference scenario. It is used as a

benchmark against which 9 alternative R&D scenarios has been examined. The purpose is to better quantify the possible role of R&D in making possible or accelerating the introduction of Hydrogen as an important vector in energy balances. For each scenario a change (with respect to the Reference) is provided for every technical and economic characteristic covered by the TFLCs.

Qualitative and quantitative description of scenarios

The scenarios have been proposed by NTUA after discussion and agreement among partners. Four types of scenarios have been selected : Scenario without R&D, demand and supply side scenarios and combined cases. Scenario without R&D case is constructed on assumption of stop of all R&D in hydrogen related technologies from 2007 and onwards. In the demand side 4 cases makes cumulative assumptions on :

- Tenfold increase in R&D expenditure on fuel cells between 2007 and 2015
- Previous scenario together with an increase in the tax on fossil fuels for road transport of the order of 0.5 €/00/lt from 2025 onwards worldwide.
- Previous Scenario using 5% of the tax revenues for R&D on fuel cells and infrastructure (split according to Reference R&D shares)
- Previous Scenario combined with a doubling of Reference effective carbon values

On Supply side three scenarios have been chosen lean on the following assumptions:

- Tenfold increase in R&D expenditure on hydrogen production options between 2007 and 2015
- Previous Scenario together with additional fossil fuels for transport taxation as in Scenario 1.1
- Previous Scenario together with 100% subsidy to all hydrogen distribution and storage infrastructure

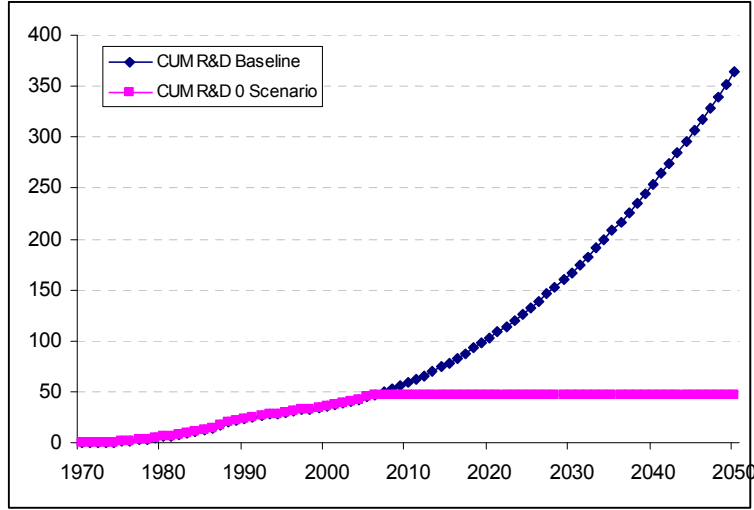
In order to take into account the joined impact of the most important assumptions of the demand and supply side scenarios, at the end is constructed a combined case which suppose a combination the two last the scenarios of the demand and supply side scenarios.

Analysis of the R&D scenarios

Stop all R&D in hydrogen related technologies from 2007 and onwards (R&D o)

One of the ways used to study the role of the learning by searching in the development of the hydrogen economy is the stopping of all R&D expenditures in hydrogen related technologies from 2007 onwards. This means a decrease of 87 % of cumulative R&D in hydrogen related technologies at the end of the period in the R&D o scenario in comparison with Reference case (see Figure D-150).

Figure D-150 : Cumulative R&D in hydrogen related technologies in the Reference and R&D o scenario



The lower level of the cumulative R&D expenditures means a decrease of the learning by doing which in its side is translated in a lower improvement of technology performances in comparison with the reference case (see total learning rate in the Table D-57) impacting the demand of hydrogen and the production capacity. The impact of cutting of the R&D is much more important on fuel cell investment costs then on the performances of the hydrogen production technologies. So, for example, because of the stop of the R&D in the hydrogen production technologies, the investment cost at the end of the period increase 47% for biomass pyrolysis, 10-32 % for water electrolysis technologies and and 2-4% for most other technologies in the R&D o scenario in comparison with the reference case (see Figure D-151). The impact is much more important for HFC (5 times higher in 2050) and HFCV (30 times higher), (see Table D-57).

Figure D-151 : Impact of the stop of the R&D in the investment cost of hydrogen production technologies in 2050

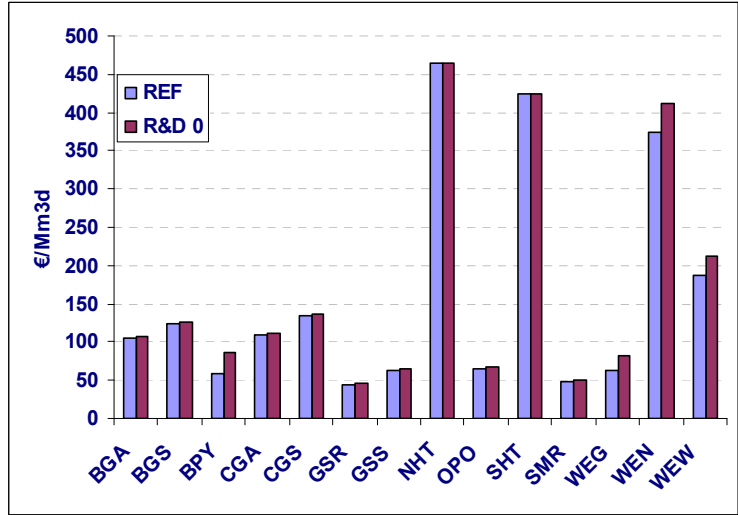
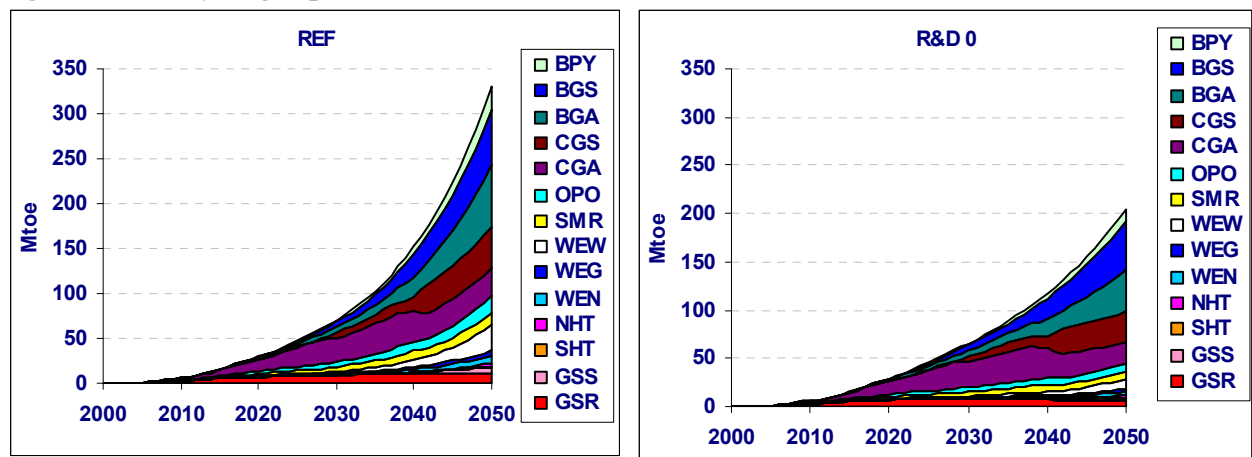


Table D-57 : Investment costs, capacities, variation from reference in 2050 and total learning rate in R&D o scenario

		Investment cost (€/kWe)				Capacities (Mwe)				Var. from Ref in 2050		Total Learning Rate	
		2001	2010	2030	2050	2001	2010	2030	2050	Costs	Capacities	2010-2030	2030-2050
GFC	REF	20520	4077	1294	922	0	109	12576	147 596			15.42%	9.10%
	R&D 0	20520	4865	4823	4784	0	105	5364	44 664	419%	-70%	0.15%	0.26%
HFC	REF	19504	4077	1294	922	0	77	8020	138 226			15.74%	7.93%
	R&D 0	19504	4865	4823	4784	0	75	3923	43 683	419%	-68%	0.15%	0.23%
		Investment cost (€/Mm3d)				Capacities (Mm3d)				Var. from Ref in 2050		Total Learning Rate	
		2001	2010	2030	2050	2001	2010	2030	2050	Costs	Capacities	2010-2030	2030-2050
GSR	REF	46	45	45	44	5	41	131	149			0.77%	3.21%
	R&D 0	46	45	45	45	5	41	114	84	2.2%	-43.4%	0.00%	0.00%
GSS	REF	71	70	66	63	5	3	4	90			18.14%	0.73%
	R&D 0	71	70	66	64	5	3	4	39	1.5%	-56.1%	26.20%	0.82%
CGA	REF	121	116	111	108	52	58	402	437			1.65%	15.21%
	R&D 0	121	116	112	110	52	58	399	325	1.8%	-25.7%	1.25%	-5.51%
CGS	REF	147	142	136	134	52	36	99	710			2.67%	0.61%
	R&D 0	147	142	138	136	52	36	97	476	1.5%	-33.0%	2.09%	0.61%
BPY	REF	107	91	76	59	5	4	28	383			6.07%	6.55%
	R&D 0	107	94	94	87	5	4	24	180	47.0%	-53.0%	0.00%	2.66%
SHT	REF	605	567	484	424	15	10	4	22			-13.66%	5.51%
	R&D 0	642	567	484	424	15	10	4	14	0.0%	-38.3%	-13.63%	7.77%
NHT	REF	1066	969	784	465	6	4	2	62			-22.4%	9.77%
	R&D 0	1174	969	784	464	6	4	2	38	-0.3%	-38.8%	-22.1%	11.29%
WEN	REF	594	512	417	375	6	4	12	110			11.47%	3.32%
	R&D 0	580	516	445	413	6	4	10	50	10.1%	-54.6%	10.23%	3.19%
WEG	REF	94	80	68	62	5	3	12	84			8.54%	3.06%
	R&D 0	94	82	82	82	5	3	9	38	31.8%	-54.5%	0.00%	0.00%
WEW	REF	292	247	205	186	161	112	100	1 473			-220.22%	2.45%
	R&D 0	292	249	225	213	161	112	77	470	14.6%	-68.1%	-21.53%	1.98%
SMR	REF	51	51	49	49	204	150	355	885			2.04%	0.86%
	R&D 0	51	51	51	51	204	150	313	458	4.3%	-48.2%	0.00%	0.00%
OPO	REF	68	67	65	64	52	38	80	265			2.15%	0.55%
	R&D 0	68	67	67	67	52	38	69	114	3.7%	-56.8%	0.00%	0.00%
BGA	REF	122	116	112	105	59	39	86	1 050			3.11%	1.61%
	R&D 0	122	116	114	108	59	39	83	620	2.3%	-41.0%	2.04%	1.76%
BGS	REF	140	134	130	124	59	39	121	863			2.05%	1.72%
	R&D 0	140	134	132	126	59	39	116	732	0.8%	72.9%	1.36%	1.60%
		Investment cost (€/kWe)				Capacities (k*cars)				Var. from Ref in 2050		Total Learning Rate	
		2001	2010	2030	2050	2001	2010	2030	2050	Costs	Capacities	2010-2030	2030-2050
GFCV	REF	4544650	480682	30253	22628	0	0	111	16 920			15.24%	3.93%
	R&D 0	4544650	848673	806873	707260	0	0	0	0	3026%	-100%	-3.67%	-9.35%
HFCV	REF	4541855	502963	28663	22796	0	0	138	14 144			15.88%	3.37%
	R&D 0	4541855	886524	857457	754996	0	0	0	0	3212%	-100%	-2.80%	-10.73%
THYV	REF	25013	21426	20102	19782	0	275	5343	25 233			1.48%	0.71%
	R&D 0	25013	21426	20102	19778	0	275	5343	27 509	-0.02%	9%	1.48%	0.68%

Stopping all R&D in hydrogen related technologies from 2007 onwards means lower hydrogen demand because of the higher fuel cells cost. In these conditions world hydrogen demand in 2050 is 38 % lower than in the reference case. Meanwhile the structure of hydrogen production is not affected significantly. The most important change concern the production of hydrogen with WEW, which is divided by two and its share is reduced from 9% in the reference case to 5 % in the R&D o in 2050.

Figure D-152 : Hydrogen production mix



In terms of the hydrogen markets, H₂ used in the mobile markets in R&D 0 decrease to 87 % of the corresponding level in the reference case and to 38% in the stationary market. The most important decrease in the mobile factor can be explained by the decrease of role of fuel cells in the R&D 0 (see Figure D-154).

Figure D-153 : Hydrogen markets in the reference and R&D 0 scenario

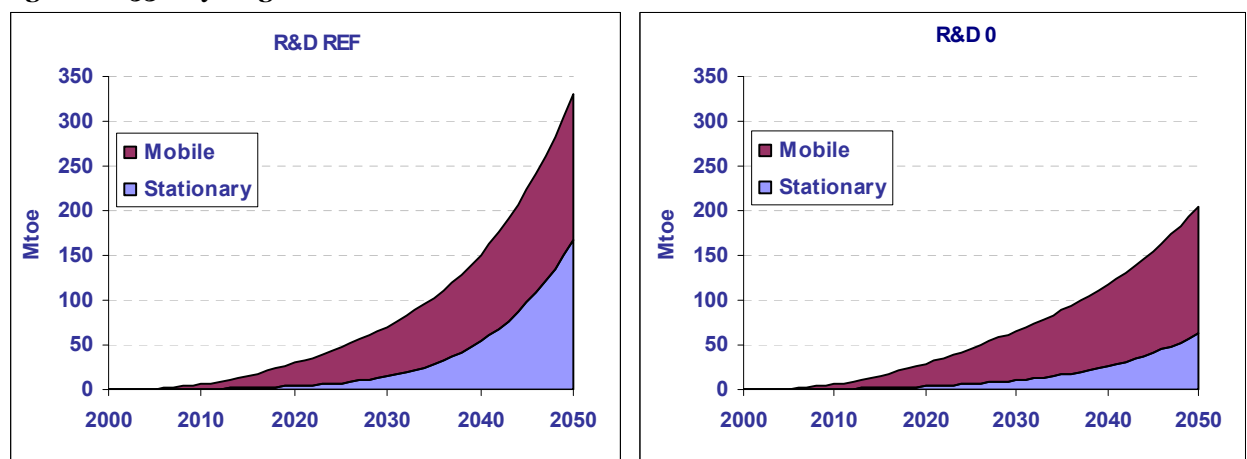
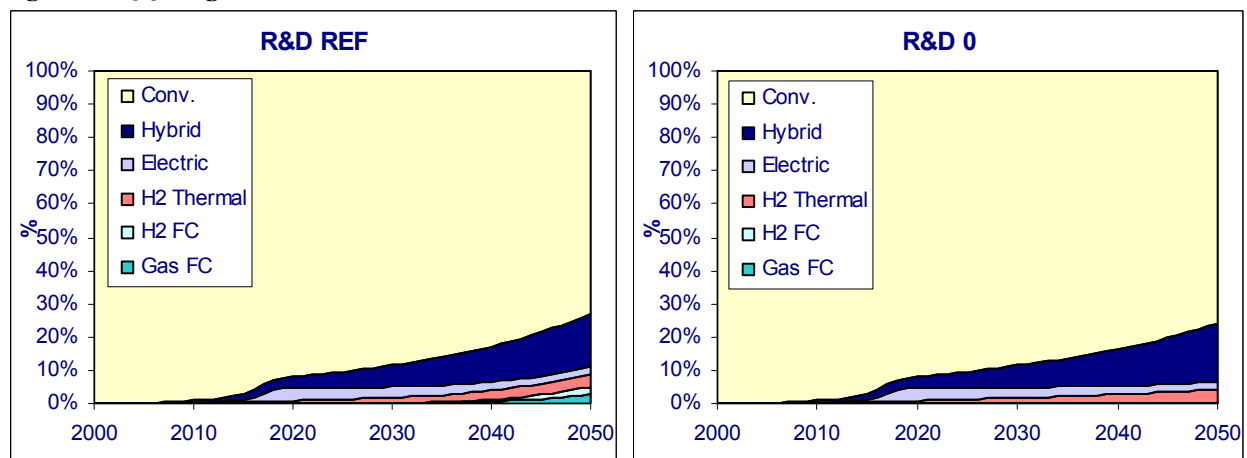


Figure D-154 : Light Vehicles - World



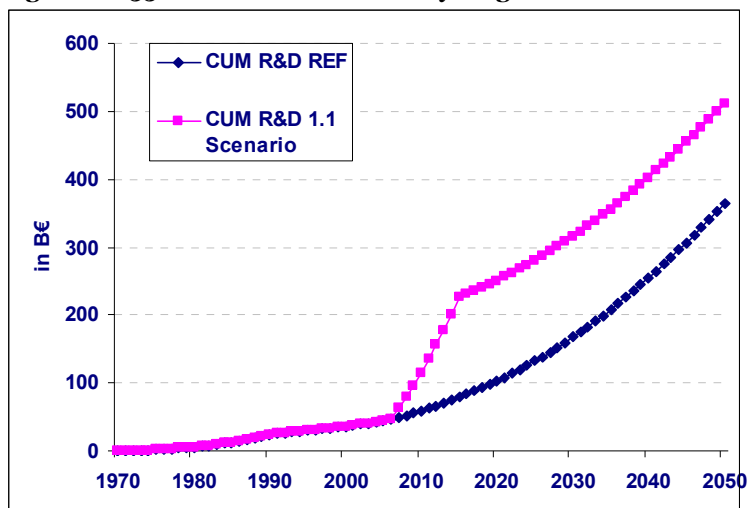
Demand side scenarios

Four scenarios have been selected to study the role of the R&D in the hydrogen demand side. The first scenario assumes an increasing of tenfold of the R&D expenditure on fuel cells between 2007 and 2015. The second scenario adds to this impact an increase in the tax on fossil fuels for road transport of the range of 0.5 €/lt from 2025 onwards worldwide. The third scenario combines the second scenario with the use of 5% of the tax revenues for R&D on fuel cells and infrastructure. The last one adds to the third scenario a doubling of Reference effective carbon values. The aim is the same for all these scenarios : measure the impact of these assumptions on expansion of the hydrogen economy and specially on mobile and stationary hydrogen demand.

Tenfold increase in R&D expenditure on fuel cells between 2007 and 2015 (R&D 1.1)

This scenario intends to analyze the impact of an important increase (10 fold between 2007 and 2015) of the R&D expenditures on fuel cells in the development of the hydrogen economy. Cumulated R&D in hydrogen related technologies in R&D 1.1 scenario becomes 1.4 times higher then in the reference case at the end of the period (Figure D-155).

Figure D-155 : Cumulative R&D in hydrogen related technologies in the reference and R&D 1.1 scenario



Evolution of the investment cost for related hydrogen technologies, their installed capacities and their total learning rates in the scenario R&D 1.1 and the reference case are presented in the following table :

Table D-58 : Investment costs, capacities, variation from reference in 2050 and total learning rate in R&D 1.2 scenario

		Investment cost (€/kWe)				Capacities (Mwe)				Var. from Ref in 2050		Total Learning Rate	
		2001	2010	2030	2050	2001	2010	2030	2050	Costs	Capacities	2001-2030	2030-2050
GFC	REF	20520	4077	1294	922	0	109	12576	147 596			12.14%	9.10%
	R&D 1.1	20520	1566	803	750	0	128	18008	186 389	-18.69%	26.28%	13.78%	2.01%
HFC	REF	19504	4077	1294	922	0	77	8020	138 226			12.28%	7.93%
	R&D 1.1	19504	1566	803	750	0	87	10621	166 772	-18.69%	20.65%	14.03%	1.71%
		Investment cost (€/Mm3d)				Capacities (Mm3d)				Var. from Ref in 2050		Total Learning Rate	
		2001	2010	2030	2050	2001	2010	2030	2050	Costs	Capacities	2010-2030	2030-2050
GSR	REF	46	45	45	44	5	41	131	149			0.60%	3.21%
	R&D 1.1	46	45	45	44	5	41	154	174	0.00%	16.75%	0.57%	3.29%
GSS	REF	71	70	66	63	5	3	4	90			-57.31%	0.73%
	R&D 1.1	71	70	66	63	5	3	5	105	0.00%	17.45%	100.00%	0.72%
CGA	REF	121	116	111	108	52	58	402	437			3.00%	15.21%
	R&D 1.1	121	116	111	108	52	58	470	514	0.01%	17.52%	2.79%	14.12%
CGS	REF	147	142	136	134	52	36	99	710			7.74%	0.61%
	R&D 1.1	147	142	136	134	52	36	116	835	0.00%	17.65%	6.27%	0.61%
BPY	REF	107	91	76	59	5	4	28	383			13.14%	6.55%
	R&D 1.1	107	91	76	58	5	4	34	458	-1.23%	19.45%	11.90%	6.88%
SHT	REF	605	567	484	424	15	10	4	22			-13.25%	5.51%
	R&D 1.1	642	567	484	424	15	10	4	26	0.00%	18.24%	-17.12%	5.01%
NHT	REF	1066	969	784	465	6	4	2	62			-21.02%	9.77%
	R&D 1.1	1174	969	784	466	6	4	2	74	0.08%	18.27%	-29.65%	9.42%
WEN	REF	594	512	417	375	6	4	12	110			26.90%	3.32%
	R&D 1.1	580	512	417	375	6	4	15	130	0.04%	18.42%	21.16%	3.33%
WEG	REF	94	80	68	62	5	3	12	84			22.36%	3.06%
	R&D 1.1	94	80	68	62	5	3	15	100	0.00%	18.17%	18.85%	3.09%
WEW	REF	292	247	205	186	161	112	100	1 473			-67.35%	2.45%
	R&D 1.1	292	247	205	186	161	112	113	1 746	0.00%	18.54%	-100.90%	2.41%
SMR	REF	51	51	49	49	204	150	355	885			4.00%	0.86%
	R&D 1.1	51	51	49	49	204	150	420	1 036	0.00%	17.06%	3.09%	0.87%
OPO	REF	68	67	65	64	52	38	80	265			6.78%	0.55%
	R&D 1.1	68	67	65	64	52	38	96	326	0.00%	23.10%	4.82%	0.54%
BGA	REF	122	116	112	105	59	39	86	1 050			14.62%	1.61%
	R&D 1.1	122	116	112	105	59	39	103	1 245	0.00%	18.54%	10.32%	1.61%
BGS	REF	140	134	130	124	59	39	121	863			6.99%	1.72%
	R&D 1.1	140	134	130	124	59	39	140	899	2.75%	40.87%	5.83%	1.82%
		Investment cost (€/kWe)				Capacities (k*cars)				Var. from Ref in 2050		Total Learning Rate	
		2001	2010	2030	2050	2001	2010	2030	2050	Costs	Capacities	2010-2030	2030-2050
GFCV	REF	4544650	480682	30253	22628	0	0	111	16 920			26.74%	3.93%
	R&D 1.1	4544650	51092	22974	21432	0	0	3966	35 251	-5.28%	108%	22.01%	2.18%
HFCV	REF	4541855	502963	28663	22796	0	0	138	14 144			26.61%	3.37%
	R&D 1.1	4541855	40894	23357	21811	0	0	2523	25 043	-4.32%	77%	22.60%	2.05%
THYV	REF	25013	21426	20102	19782	0	275	5343	25 233			1.00%	0.71%
	R&D 1.1	25013	21426	20106	19789	0	275	5096	23 320	0.04%	-8%	1.01%	0.72%

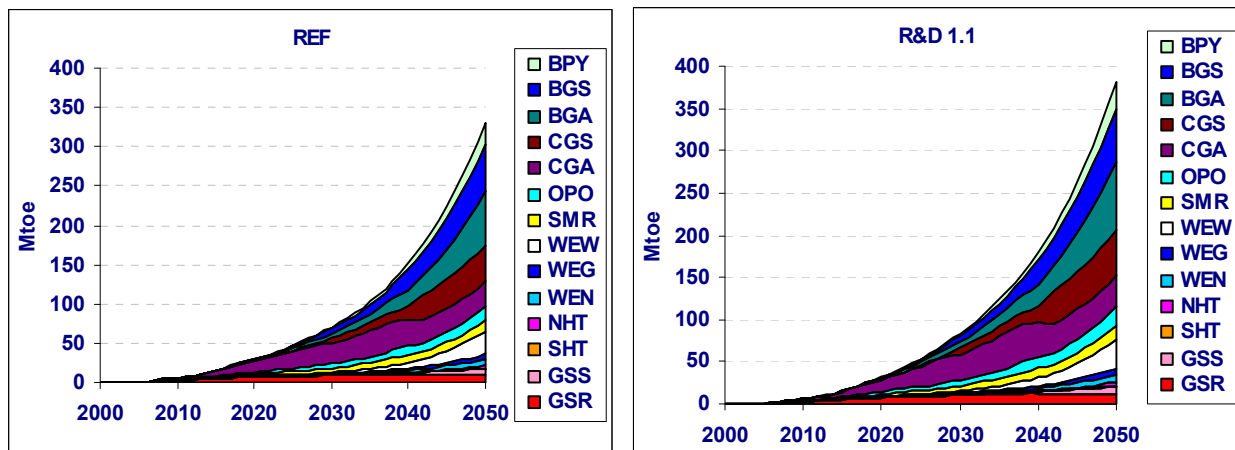
The investment costs of the HFC& GFC decrease 19% in the end of the period in the R&D 1.1 in comparison with the reference case because of the increase of the R&D. Their installed capacities increase respectively 26

and 21% for the same period. However the impact is much important for the first period (2001-2030) where the learning rates are more important then in the reference case.

The important increase of the R&D is less important for HFCV and GFCV technologies in terms of the investment costs (- 4-5%). This can be explained by the fact that the share of the fuel cells in the total vehicle cost is less important then in the stationary use. However the fleets of the HFCV and GFCV vehicles double in comparison with the reference case in 2050. Given that, the most part of learning by research happens during the first decade; learning rates are lower than in the reference case for the periods 2010-2030 and 2030-2050.

In order to balance the increase of the hydrogen demand (+ 16 % in the R&D 1.1 in comparison with the reference case) some increases in the installed capacities happens although the investments costs of the hydrogen production technologies remain constant. So some increase in the learning by doing is identified beginning from 2030 for GSR, GSS, BPY and BGS. However the production mix remains the same as in the reference case.

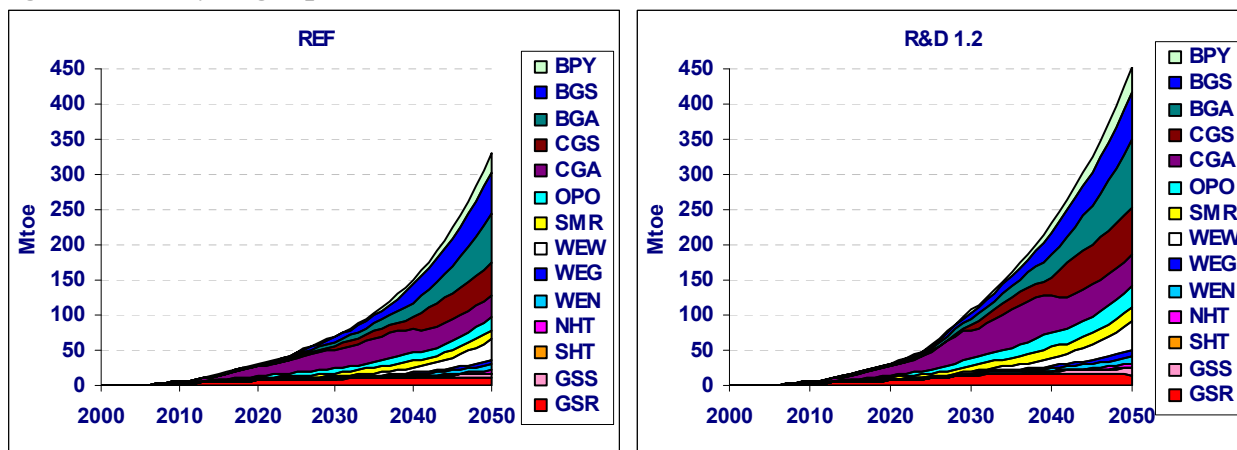
Figure D-156 : Hydrogen production mix



Scenario 1.1 together with an increase in the tax on fossil fuels for road transport of the order of 0.5 €/lt from 2025 onwards worldwide (R&D 1.2)

Increasing the tax on fossil fuels for road transport of the order of 0.5 €/lt decrease their use and improve the competitiveness of hydrogen technologies which the total level in this case is 37 % higher than in the reference case (instead of +16 % in the R&D 1.1 scenario). The increase profits to the increase of the production of all options. Some technologies as BGA, BPY profits more then the others.

Figure D-157 : Hydrogen production mix

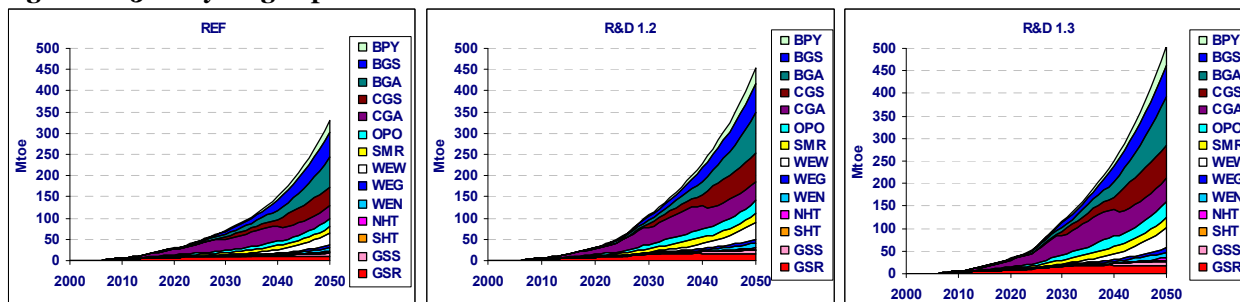


Scenario 1.2 plus using 5% of the tax revenues for R&D on fuel cells and infrastructure (R&D 1.3)

In the third demand side scenario, the urban environmental considerations are translated through two assumptions. Firstly it is maintained the assumption of the R&D 1.2 scenario (an increase in the tax on fossil fuels for road transport of the order of 0.5 €/00/lt from 2025 onwards worldwide). And secondly, given that in absolute terms this tax represents important revenues, it is supposed that 5% of the total amount can be used to promote the diffusion of hydrogen fuel cell vehicles and hydrogen infrastructure.

This situation makes the demand for hydrogen 53% higher than in the reference case instead of +37% in R&D 1.2 case.

Figure D-158 : Hydrogen production mix



Scenario 1.3 combined with a doubling of Reference effective carbon values (R&D 1.4)

The doubling of Reference effective carbon values reflects a state of the world with more ambitious climate targets. Taken together, the R&D 1.3 scenario and higher carbon constraint indicate that hydrogen production increase 69% in comparison with the reference case which is equivalent with an increase of 10 % in comparison with the R&D 1.3 case.

Figure D-159 : Carbon values in REF and R&D 1.4 case

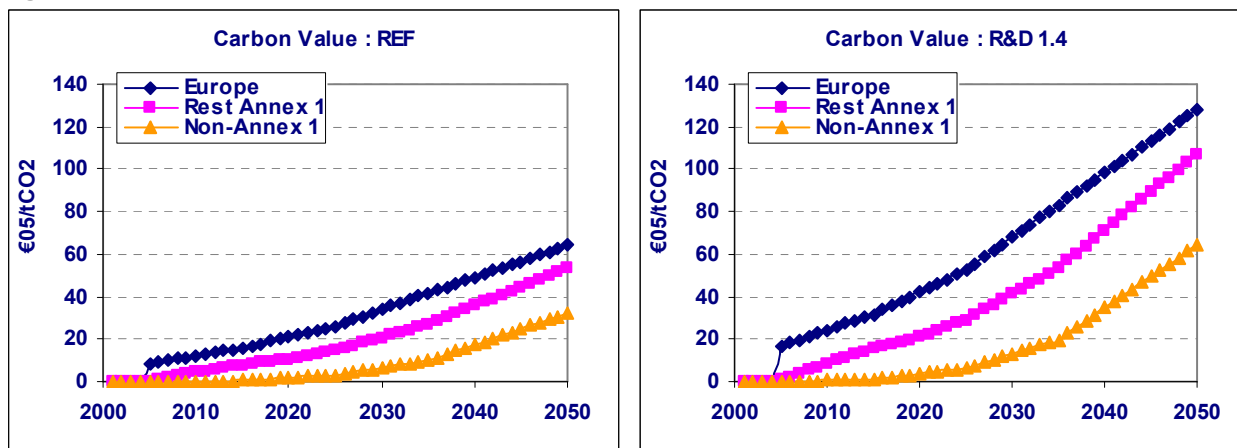
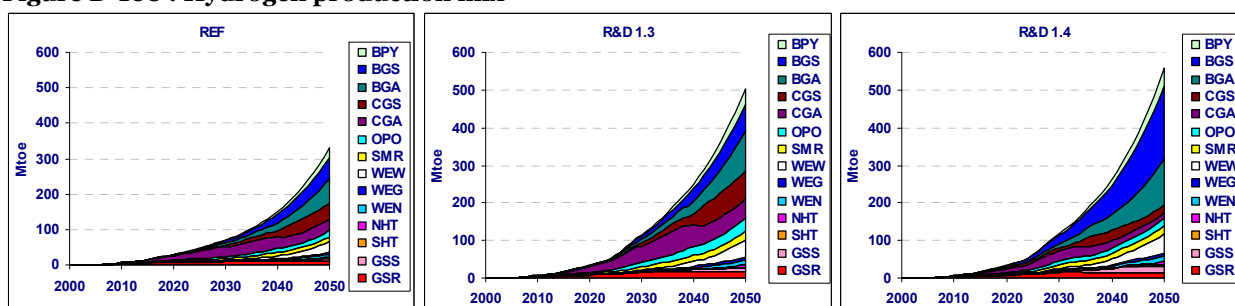


Figure D-160 : Hydrogen production mix



Supply side scenarios

Three scenarios have been selected in the supply side :

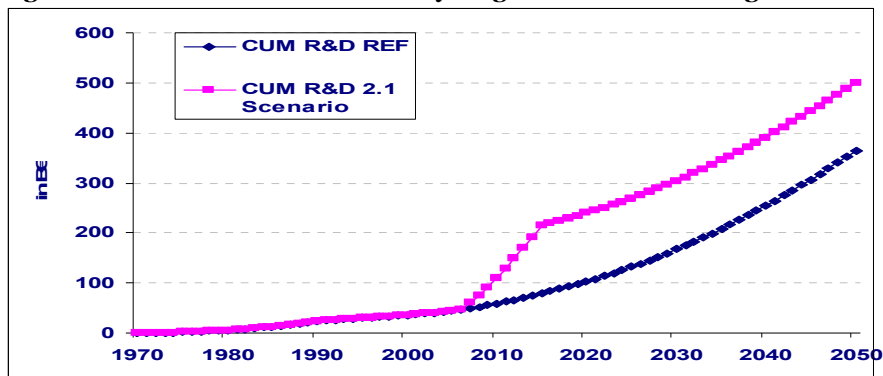
- **R&D 2.1** : Tenfold increase in R&D expenditure on hydrogen production options between 2007 and 2015
- **R&D 2.2** : Previous Scenario together with additional fossil fuels for transport taxation as in Scenario 1.1
- **R&D 2.3** : Previous Scenario together with 100% subsidy to all hydrogen distribution and storage infrastructure

For the R&D scenarios acting on hydrogen economy supply side, the impacts will be analysed in terms of increase of the hydrogen production compared to the reference case.

Tenfold increase in R&D expenditure on hydrogen production options between 2007 and 2015 (R&D 2.1)

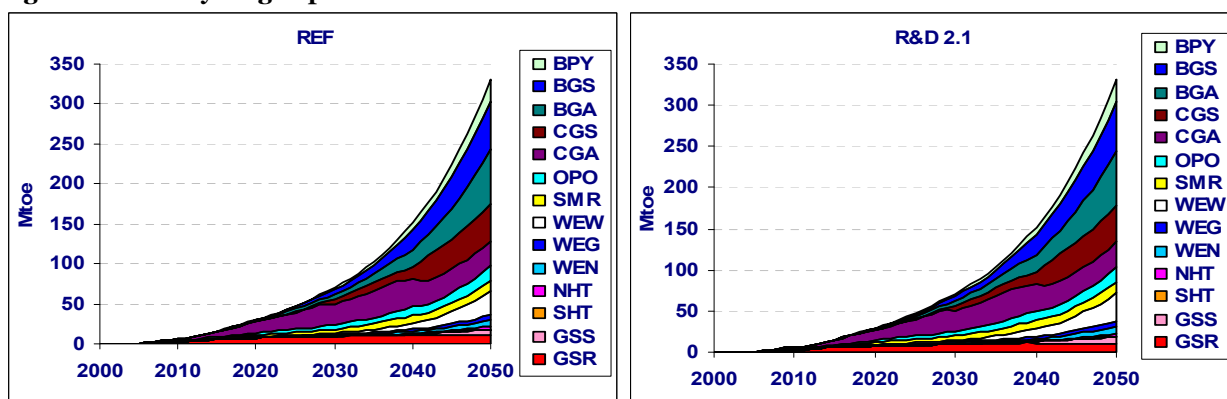
The amount of the cumulated R&D expenditures on the related hydrogen technologies in 2050 in the R&D 2.1 scenario is comparable with that of the R&D 1.2 scenario and is 1.37 times higher than in the reference case.

Figure D-161 : Cumulative R&D in hydrogen related technologies in the reference and R&D 2.1 scenario



However the impact on the hydrogen production technology performances is not as spectacular as for fuel cells. The impact of the increase of the R&D on the production side is insignificant (+ 0.2 % more than in the reference case).

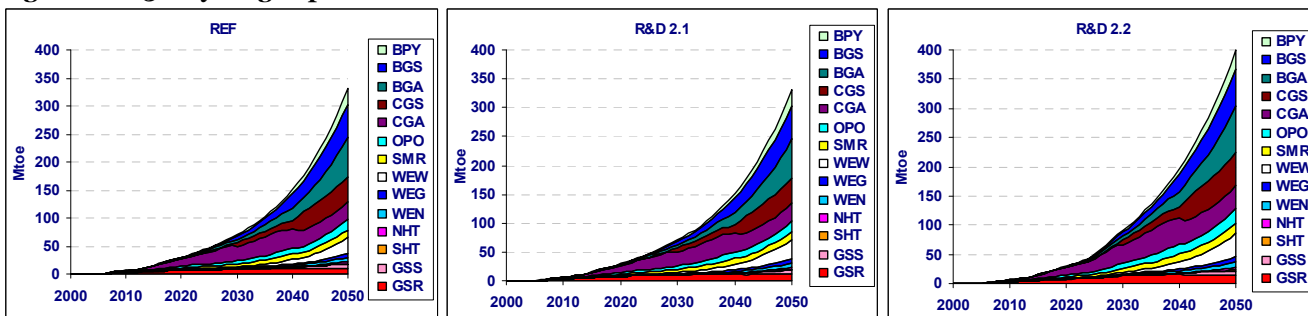
Figure D-162 : Hydrogen production mix



Scenario 2.1 together with additional fossil fuels for transport taxation as in Scenario 1.1(R&D 2.2)

The impact of the additional taxation on fossil fuel for transport is the same as in the R&D 1.1 case. The result is : + 21 % more hydrogen than in the reference and the R&D 2.1 case.

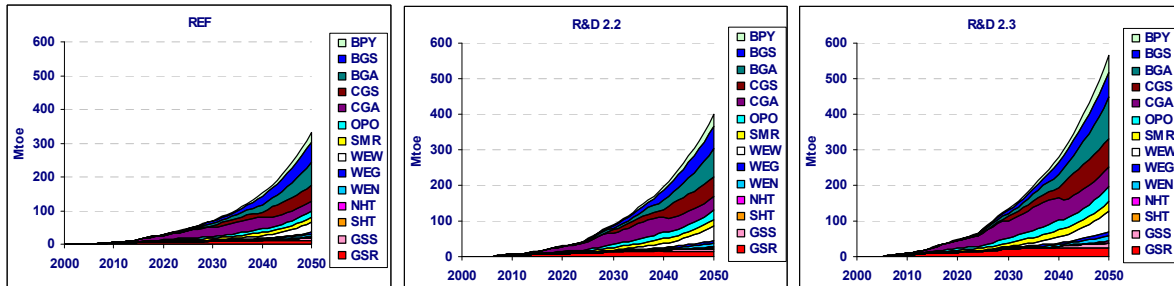
Figure D-163 : Hydrogen production mix



Scenario 2.2 together with 100% subsidy to all hydrogen distribution and storage infrastructure (R&D 2.3)

100% subsidy to all hydrogen distribution and storage infrastructure means zero cost for all hydrogen distribution and storage. In this case hydrogen demand is 71 % more than in the reference case and 42 % more important than in the R&D 2.2 scenario. The use of the additional tax on hydrogen infrastructure seems very interesting for the diffusion of hydrogen.

Figure D-164 : Hydrogen production mix



Combined case (R&D 3)

The combined scenario represents the most favorable case of the R&D scenarios for hydrogen economy development. Given that this scenario suppose tenfold increase in R&D expenditure in all related hydrogen technologies either on fuel cells or in production options between 2007-2015, the cumulated R&D for all hydrogen related technologies is 1.8 times higher than in the reference case at the end of the period (see Figure D-165).

The scenario R&D 3 is derived from combination of the scenario R&D 1.4 and R&D 2.3. This means that the scenario R&D 3 profits also from the impacts of doubling of reference carbon value, increase in the tax on fossil fuels for road transport and the using of the tax revenues for R&D on fuel cells and on hydrogen distribution and storage infrastructure.

The implication of these assumptions on investment costs and installed capacities is presented in the Table D-57.

Figure D-165 : Cumulative R&D in hydrogen related technologies in the reference and R&D 3 scenario

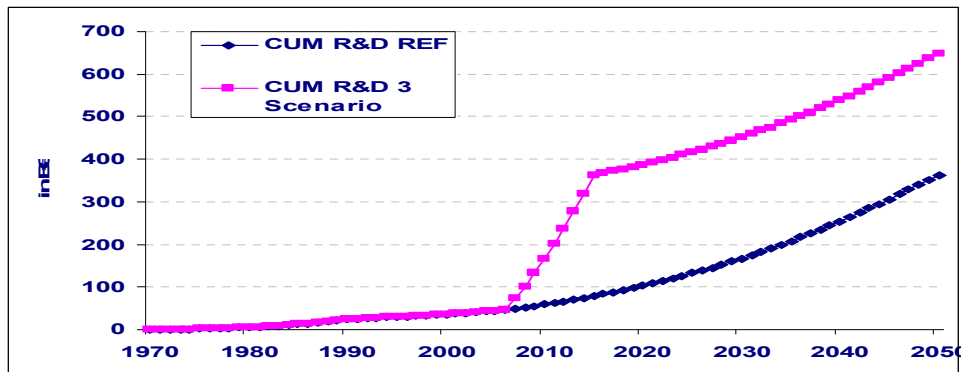


Table D-59 : Investment costs, capacities, variation from reference in 2050 and total learning rate in R&D 3 scenario

		Investment cost (€/kWe)				Capacities (Mwe)				Var. from Ref in 2050		Total Learning Rate	
		2001	2010	2030	2050	2001	2010	2030	2050	Costs	Capacities	2001-2030	2030-2050
GFC	REF	20520	4077	1294	922	0	109	12576	147 596			12.14%	9.10%
	R&D 3	20520	1566	802	749	0	131	18806	178 536	-19%	21%	13.74%	2.08%
HFC	REF	19504	4077	1294	922	0	77	8020	138 226			12.28%	7.93%
	R&D 3	19504	1566	802	749	0	132	23440	362 954	-19%	163%	13.36%	1.71%
		Investment cost (€/Mm3d)				Capacities (Mm3d)				Var. from Ref in 2050		Total Learning Rate	
		2001	2010	2030	2050	2001	2010	2030	2050	Costs	Capacities	2010-2030	2030-2050
GSR	REF	46	45	45	44	5	41	131	149			0.60%	3.21%
	R&D 3	46	45	44	44	5	71	339	343	-1.1%	130.4%	0.71%	10.22%
GSS	REF	71	70	66	63	5	3	4	90			-57.31%	0.73%
	R&D 3	71	70	65	63	5	4	63	422	-0.7%	371.0%	2.44%	1.05%
CGA	REF	121	116	111	108	52	58	402	437			3.00%	15.21%
	R&D 3	121	115	110	108	52	76	507	284	-0.1%	-35.1%	2.85%	-1.91%
CGS	REF	147	142	136	134	52	36	99	710			7.74%	0.61%
	R&D 3	147	141	136	134	52	36	161	493	-0.1%	-30.6%	4.76%	0.86%
BPY	REF	107	91	76	59	5	4	28	383			13.14%	6.55%
	R&D 3	107	81	67	49	5	4	76	993	-16.3%	159.2%	11.45%	7.93%
SHT	REF	605	567	484	424	15	10	4	22			-13.25%	5.51%
	R&D 3	605	567	483	424	15	10	5	51	0.0%	133.4%	-14.02%	3.71%
NHT	REF	1066	969	784	465	6	4	2	62			-21.02%	9.77%
	R&D 3	1066	969	784	430	6	4	2	196	-7.6%	214.6%	-29.78%	9.10%
WEN	REF	594	512	417	375	6	4	12	110			26.90%	3.32%
	R&D 3	594	495	398	365	6	4	35	281	-2.7%	155.9%	14.06%	2.89%
WEG	REF	94	80	68	62	5	3	12	84			22.36%	3.06%
	R&D 3	94	71	59	57	5	4	31	174	-7.8%	105.7%	16.17%	1.31%
WEW	REF	292	247	205	186	161	112	100	1 473			-67.35%	2.45%
	R&D 3	292	234	192	179	161	112	270	4 209	-3.8%	185.7%	42.98%	1.77%
SMR	REF	51	51	49	49	204	150	355	885			4.00%	0.86%
	R&D 3	51	50	48	48	204	159	864	2 346	-1.4%	165.0%	2.54%	0.28%
OPO	REF	68	67	65	64	52	38	80	265			6.78%	0.55%
	R&D 3	68	66	64	64	52	41	224	421	-1.0%	59.0%	2.77%	0.40%
BGA	REF	122	116	112	105	59	39	86	1 050			14.62%	1.61%
	R&D 3	122	115	111	105	59	39	205	2 476	-0.4%	135.8%	5.22%	1.49%
BGS	REF	140	134	130	124	59	39	121	863			6.99%	1.72%
	R&D 3	140	134	129	123	59	39	442	3 173	3.1%	-60.1%	2.82%	1.57%
		Investment cost (€/kWe)				Capacities (k*cars)				Var. from Ref in 2050		Total Learning Rate	
		2001	2010	2030	2050	2001	2010	2030	2050	Costs	Capacities	2010-2030	2030-2050
GFCV	REF	4544650	480682	30253	22628	0	0	111	16 920			26.74%	3.93%
	R&D 3	4544650	50834	22891	21396	0	0	8780	56 536	-5%	234%	21.03%	2.48%
HFCV	REF	4541855	502963	28663	22796	0	0	138	14 144			26.61%	3.37%
	R&D 3	4541855	40779	23297	21755	0	0	6963	47 874	-5%	238%	21.33%	2.43%
THYV	REF	25013	21426	20102	19782	0	275	5343	25 233			1.00%	0.71%
	R&D 3	25013	21202	19988	19691	0	593	17002	53 569	-0.46%	112%	0.96%	0.90%

The R&D 3 scenario impact is translated by an increase of 2.2 times of the hydrogen demand in comparison with the reference case, 1.3 times in comparison with R&D 2.3 case and 3.9 times in comparison with R&D 1.4 scenario.

Figure D-166 : Hydrogen production mix

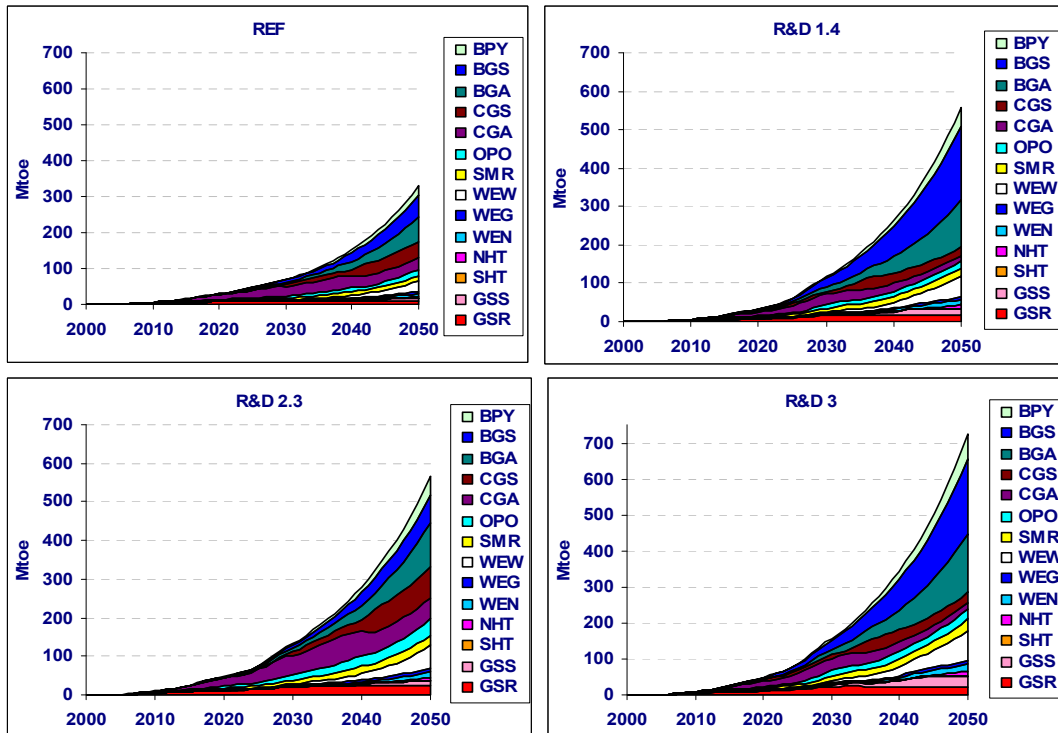
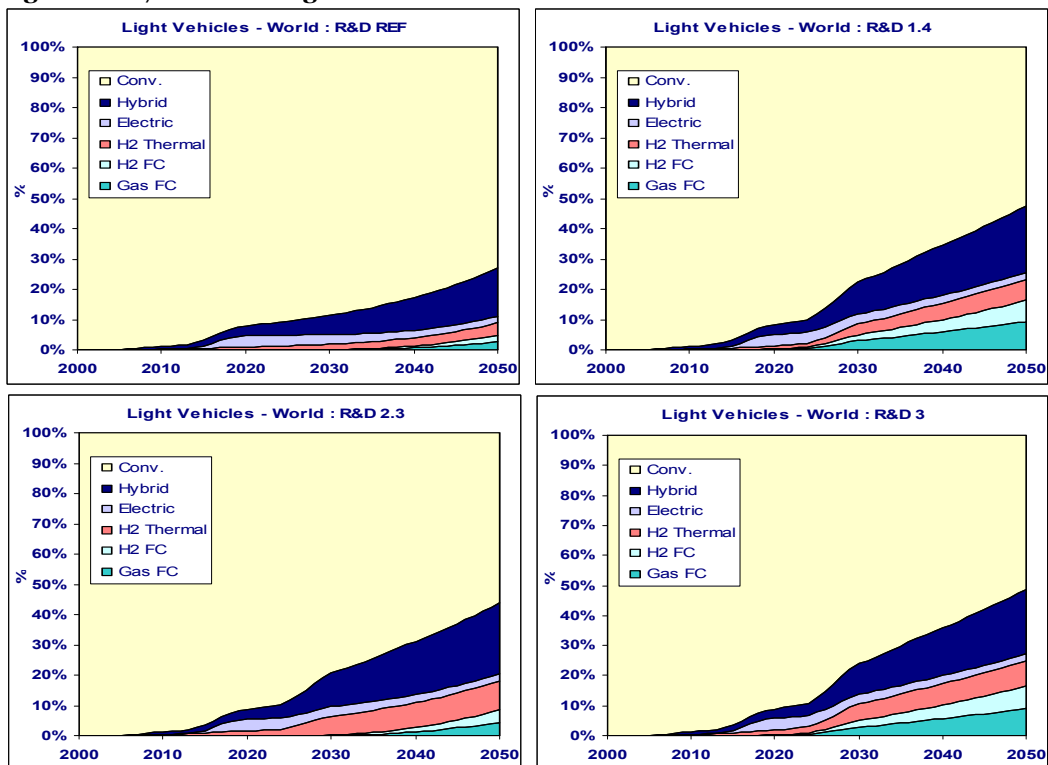


Figure D-167 : Share of light vehicles



In the R&D 3, 16% of the vehicles use hydrogen spread equally in H2 thermal and in FCHV vehicles.

General comments

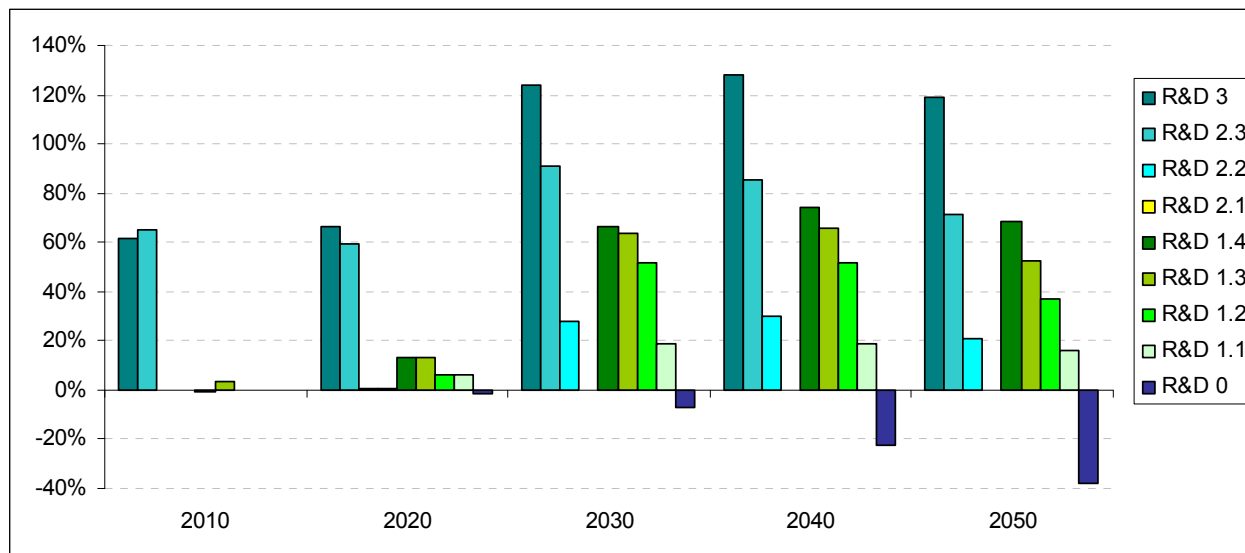
The Figure D-168 presents a summary of the impacts of different R&D scenarios in the world hydrogen production in comparison with the reference case. The negative impact of cutting R&D is noticeable. In 2050 in the R&D 0 scenario, the hydrogen production is 38% lower than in the reference case.

The implication of the demand side scenarios on hydrogen production is nearly 69 % for R&D 1.4 and varies from 16 to 53 % higher for other scenarios. So the impact of doubling the carbon constraint seems much more perceptible than the impact from the increase of the R&D expenditures, or the increase in the tax on fossil fuel. The reason is known: while R&D impact investment costs, efficiencies or O&M costs, carbon tax impact fuel prices and indirectly all decisions concerning the use of hydrogen.

Supply side R&D scenarios, and particularly R&D 2.3 scenario have a higher impact on hydrogen production up to 2040 than demand side scenario, but their impact is lower in 2050. The reason for that are the possibilities for earlier improvements in the hydrogen production technologies than for fuel cell investment costs.

The combined scenario is evidently the most favourable for hydrogen production (nearly 1.2 times higher than in the reference case. The conclusion is that the combination of the policies will have a better effect on the hydrogen economy than separated measures.

Figure D-168 : Summary of R&D scenario impacts on the world hydrogen production in comparison with the reference case



D.4.2.2 PRIMES

[by N. Kouvaritakis, V. Panos and P. Capros (ICCS-NTUA)]

In the context of the CASCADE MINTS project a number of R&D policy scenarios were defined in order to analyse the possible role of R&D on hydrogen related technologies for accelerating their introduction in the

energy system. The scenarios were also designed to examine R&D in the context of other policies specifically aimed at promoting the use of hydrogen. In summary the scenarios were defined as follows:

o. No R&D in hydrogen related technologies from 2007 onwards (case name: No_RD)

1. Demand side scenarios:

1.1. Tenfold increase in R&D expenditures on fuel cells from 2007 to 2015 (case name: D1.1)

1.2. Scenario 1.1 together with additional tax in fuels for road transport of the order of 0.5€/lt from 2025 onwards (case name: D1.2)

1.3. Scenario 1.2 and using 5% of the tax revenues as additional R&D in fuel cells and hydrogen infrastructure (case name D1.3)

1.4. Scenario 1.3 combined with doubling baseline effective carbon values (case name: D1.4)

2. Supply side scenarios:

2.1. Tenfold increase in R&D expenditures on hydrogen production options between 2007 and 2015 (case name: S1.1)

2.2. Scenario 2.1 together with additional tax in fuels for road transport as in Scenario 1.2 (case name: S1.2)

2.3. Scenario 2.2 together with 100% subsidy to all hydrogen distribution and storage infrastructure (case name: S1.3)

3. Combined case; scenarios 1.4 and 2.3 (case name: combined)

PRIMES-H2 is a partial equilibrium model covering in detail the EU. On the other hand, R&D spills over to the whole world and to the extent that learning occurs through experience, the total effect of R&D in improving the technical and economic characteristics must be examined using a world model. For the R&D scenarios examined in this section, the PROMETHEUS model in deterministic mode has been used. PROMETHEUS is equipped with learning mechanisms in the form of two factor learning curves as developed within the CASCADE MINTS project (see C.2.7). The model incorporates the full specification covering capital costs, fixed o&m costs, efficiencies, life duration for both demand and supply technologies. It also deals fully with technology clustering.

The methodology adopted for implementing the R&D scenarios with PRIMES-H2 was to run PROMETHEUS (deterministic) for all above cases and obtain the resulting technical-economic characteristics, introduce them exogenously into PRIMES-H2 and run the latter by adding the other specific policies and measures. It should be noted here that it was assumed that the same policies and measures were applied throughout the world resulting in enhanced learning for the technologies involved.

R&D policy scenarios results

The baseline projection incorporates around 22 billion €05 of worldwide R&D expenditure directed at fuel cells in the period 2007 to 2015. This is assumed to represent a median estimate of likely outlays both from public and private sources. The basic R&D scenario (D1.1) assumes a tenfold increase in R&D of this period, which represents in R&D terms a very large sustained effort and presupposes a strong belief in early success for this technology.

The table below presents the impact of scenario D1.1 on the key technical and economic characteristics of fuel cells and the delivered cost of hydrogen to different market segments. The figures are derived from PROMETHEUS simulation, but refer to European averages as they have been introduced in the PRIMES-H₂ model.

Table D-60: Impact of R&D in fuel cell costs and delivered hydrogen cost in €05

Mobile applications							
		2025			2050		
	unit	Baseline	10x R&D	% change	Baseline	10x R&D	% change
Stack cost	€/kW	57	21	-63%	30	19	-36%
System cost	€/kW	63	28	-55%	30	27	-9%
On board storage cost	€/kgH ²	88	85	-3%	66	65	-1%
On board batteries	€/kWh	343	346	1%	246	245	0%
Maintenance cost	€/yr	418	271	-35%	263	204	-22%
Fuel input	kgr/100km	0.58	0.46	-20%	0.49	0.40	-17%
Cost of running the vehicle	€ cents /km	54	42	-22%	42	40	-5%

Stationary applications (1-5 Kwe)							
		2025			2050		
	unit	Baseline	10x R&D	% change	Baseline	10x R&D	% change
Stack cost	€/kW	392	203	-48%	224	166	-26%
System cost	€/kW	1509	868	-42%	896	799	-11%
Stack lifetime	Years	9	11	25%	10	12	14%
Fixed O&M cost	€/kW _y	72	30	-59%	22	18	-16%
Overall fuel efficiency	%	92	95	3%	94	95	2%
Electrical efficiency	%	34	37	7%	36	38	5%
Thermal efficiency	%	58	58	1%	57	57	-1%
Electricity production cost *	€/MWh	328	218	-34%	140	126	-10%

* the value of heat is subtracted from this figure

Hydrogen delivered cost to							
		2025			2050		
	unit	Baseline	10x R&D	% change	Baseline	10x R&D	% change
Industry	€/toe	853	833	-2%	849	839	-1%
Transport	€/toe	1182	1159	-2%	1140	1129	-1%
Residential/commercial	€/toe	1113	1085	-3%	1066	1054	-1%

A general remark concerning these results is that the impact in 2025 is considerably bigger than in 2050. The main reason for this is that the baseline assumes considerable R&D effort beyond 2015 (around five billion euro per year on average). In this sense the main effect of the R&D scenario is to bring forward improvements.

Stack costs for both mobile and stationary applications are the economic characteristic that registers the biggest improvements as a result of R&D. Large improvements are also registered for operating and maintenance costs and system acquisition costs. On board hydrogen storage is little affected: this is due to the effects of learning by doing that is influenced both by applications on fuel cell vehicles (which increase substantially) and applications on hydrogen ICE vehicles (which in this scenario take much smaller shares). R&D also has a very pronounced effect on the overall efficiency of fuel cell vehicles, while little gain over baseline values is registered for the efficiency of stationary fuel cells (for this application R&D tends to increase the electrical efficiency but overall efficiencies are 94% already in the baseline with little room for further improvement). In terms of competitiveness of fuel cell options it is worth noting that in the R&D scenario the cost per vehicle kilometre for fuel cells is already broadly competitive with conventional equivalents by 2025. In that year, small scale stationary fuel cells for household applications produce electricity at a cost around 20% higher than residential electricity tariffs. By 2050 the R&D scenario implies a highly competitive cost for producing heat and power from such stationary applications assuming heat utilisation rates of around 1500 hours per year.

The impact of the R&D on supply options (hydrogen production, storage and distribution) in terms of reduction of delivered costs of hydrogen is very small, even in 2025. This is mainly due to the poor prospects for improvement of such technologies following the perspective analysis carried out within CASCADE MINTS. On the other hand, one of the findings of the project is that hydrogen costs play a relatively minor role in shaping the prospects for a hydrogen economy (this is particularly the case for mobile applications).

Table D-61: Summary results from R&D policy scenarios

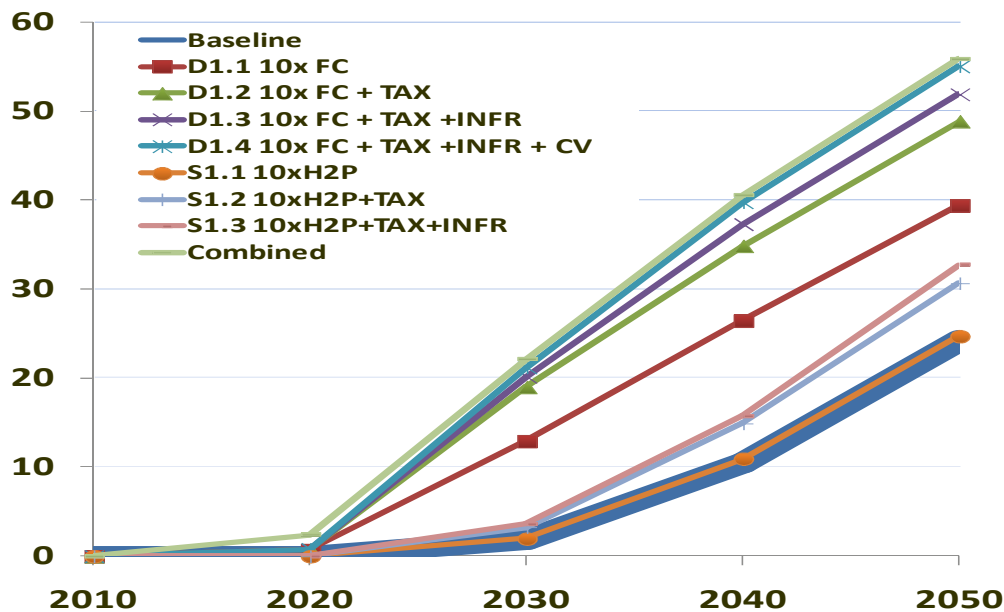
	% share in passenger cars stock						% in new car registrations	% share in final consumption of industry and residential/commercial		Hydrogen demand (Mtoe)
	Conventional	Hybrid	Plug in hybrid	Electric	H2 ICE	Fuel cells	Fuel cells	Electricity from fuel cells	Steam and heat from fuel cells	
Baseline	64.1	11.1	4.7	1.7	5.2	13.3	24.8	2.2	3.7	49.0
Demand side										
D1.1 10xFC	55.4	9.3	4.0	1.4	2.8	27.0	39.4	4.5	6.7	64
D1.2 10xFC+TAX	48.3	7.5	4.3	2.0	3.3	34.5	48.8	4.0	5.6	65
D1.3 10xFC+TAX+INFR	46.8	7.2	4.0	1.9	3.4	36.7	51.9	4.5	6.4	71
D1.4 10xFC+TAX+INFR+CV	44.8	6.6	4.0	2.1	3.6	38.9	55.1	8.0	12.4	116
Supply side										
S1.1 10x H2P	63.8	10.9	4.7	1.7	5.3	13.7	25.1	2.4	4.1	51
S1.2 10x H2P +TAX	58.7	9.5	5.4	2.5	6.4	17.6	30.7	2.0	3.3	53
S1.3 10x H2P+INFR+TAX	56.6	9.1	5.1	2.4	8.1	18.7	32.7	7.1	13.0	120
Combined case	44.2	6.5	4.0	2.0	3.6	39.6	55.8	8.5	13.2	122
No R&D in H2 technologies	75.1	13.7	5.9	2.1	3.2	0.0	0.0	0.0	0.0	10

Fuel cell vehicles become broadly competitive vis-a-vis all other options already from around 2030. They end-up gaining around 40% of EU new registrations in 2050, while the share of the vehicle stock stands at around 27% (see Table D-61). The technological improvement appears to be the principle determinant in the penetration of hydrogen in road transport. Additionally taxing conventional fuels adds another 7.5% in FC share in stock and around 10% in new registrations, while the effect of recycling 5% of tax revenues results in an additional 2% increase both in stock and new registrations. Doubling the carbon value adds another 2-3 percentage points. Given the small improvements obtained from R&D on supply technologies, the S1.1

scenario shows virtually no difference from baseline. The increased penetration in S1.2 and S1.3 are purely due to the additional measures (taxation of conventional fuels and infrastructure subsidy).

Figure D-169 gives the time profile of penetration of fuel cells under the different R&D scenarios. It is worth noting that since the baseline involved a take-off of fuel cell registrations in the last decade of the projection, the most pronounced effect of the scenarios is to bring forward this development. The pure R&D scenario (D1.1) implies an acceleration equivalent to around 12 years, while the supplementary fiscal assistance increases this figure to 17-18 years.

Figure D-169: % Share of fuel cells in new car registrations in baseline (the bold line) and in R&D scenarios



The impact of the R&D scenarios on stationary fuel cells is altogether more modest. As indicated in the baseline scenario analysis, the stationary fuel cells face wider competition than the mobile fuel cells and lag behind developments in the road transport sector. Furthermore, they are subject to a slower equipment turnover and competitiveness arising from the R&D scenarios for this category is reached at a later stage than in the case for road transport. As a result, even in cases D1.4 and in combined case involving extensive subsidisation and high carbon values the fuel cells only contribute around 8% of industrial/residential electricity demand and provide 12 to 13% of the heat and steam needs.

The “no R&D” case implies virtually no improvement in the technical-economic characteristics of hydrogen related technologies and results in a virtually total absence of hydrogen in the European energy balance. The results from this scenario, together with the results obtained in the transport sector from the R&D scenario D1.1, underscore the importance of early R&D intervention for making possible and accelerating an eventual transition to a hydrogen economy.

D.4.2.3 MARKAL-EUROPE

[by H. Rösler (ECN)]

Introduction

This section describes the results of the R&D scenarios carried out for the Cascade Mints project with the Western European MARKAL model. Since two factor learning is not included in the Western European model, this case study differs from the other case studies described in this chapter. However, some things can be said on the effect of R&D on the penetration of fuel cell and hydrogen in the energy system without a full implementation of two factor learning. General idea behind learning by searching is that increased R&D expenditures of fuel cell technologies will lead to lower costs. Since it is presumed that a tenfold increase in expenditures will take place between 2007 and 2015, the initial investment cost at market introduction in the model period 2010 (2006-2015) will be lower than the originally assumed cost of 3000 €/kW. Since it is not known how much lower the system costs will be, three possible values are assumed; 2000 €/kW, 1000 €/kW and 500 €/kW as initial investment cost for the FC system. The scenarios that were studied for these three levels of investment cost are given in Table D-62

Table D-62 Short description of the R&D scenarios

Short description	
Demand pull cases	
11RD2000/1000/500	Lower initial investment cost at market introduction: of respectively 2000, 1000 and 500 €/kW due to increased R&D expenditures.
12RD2000/1000/500	Scenarios 11RD2000/1000/500 + fuel tax of 0.50 €/liter gasoline from 2025 on.
14RD2000/1000/500	Scenarios 12RD2000/1000/500 + twice the Baseline CO ₂ tax (which gradually increases up to 78 €/ton CO ₂)
Combined case	
3RD2000/1000/500	Scenarios 14RD2000/1000/500 + H ₂ production technologies on floor costs from 2030 + investment in infrastructure at no cost

So since learning by searching is not endogenously treated in the model, the case in which 5% of the tax revenues are used for R&D is not considered in this study. The absence of endogenous R&D learning is also partly the reason why the supply side scenarios are not studied. On the other hand it is also not necessary since it turned out in the technology scenarios study (D.3.2.3) that there will be no penetration of hydrogen even in the most optimal situation where production cost are on floor level and hydrogen distribution is subsidized 100%. For the combined case (3RD2000/1000/500) these optimal conditions for the supply side are assumed.

Finally, the focus in this section is on mobile FC rather than on stationary fuel cell, since as it turned out in section D.3.2.3 stationary FC are not penetrating even when their floor cost level is assumed.

Results

The focus of the description of results of the R&D scenarios will be on the penetration and cost development of FC rather than on production, distribution of hydrogen and consequences for CO₂ emissions. Due to the similarities with the results of the technology stories SCEN1BV1, SCEN1CV1 and SCEN3V1 information on these issues can be found in D.3.2.3.

The cumulative capacity build-up of fuel cells and the related cost development are given in Table D-63 and Table D-64. It turns out that initial investment cost of 2000€/kW, 1000€/kW or 500€/kW still are not low enough for the penetration of FC (scenarios 11RD2000/1000/500). When in the next scenario cluster a tax is applied on all transport fuels except hydrogen FC are penetrating. So a fuel tax on conventional fuels is a trigger for penetration of hydrogen in transport sector, but just from 2025 when the tax is imposed. The additional impact on hydrogen penetration of a twice as high CO₂ tax as in the Baseline is limited. Differences between cumulative capacities are due to a shift from smaller FC cars in 12RD2000/1000/500 to larger FC cars in 14RD2000/1000/500 and 3RD2000/1000/500. The total number of FC cars, however, is not changing.

It appears that the initial investment cost is not that important, at least not when the costs are in a range of 500-2000 €/kW. First of all for different FC costs the cumulative capacity build-up is similar. Differences in the initial years are due to the assumption that higher R&D expenditures lead to higher deployment of technology for example due to a higher number of lab test versions, first prototypes for demonstration and pilot projects and may be even first commercial use. Although the starting point on the learning curve is different under different initial investment costs and different initial cumulative capacities at market penetration, the cost development in time is similar. In all scenarios with a penetration of FC a cost level of the fuel cell system of 35 €/kW is reached by 2050. Taking into account also the results of the technology stories SCEN1BV1, SCEN1CV1 and SCEN3V1 (see section D.3.2.3), the idea that capacity build-up and cost development under different costs are similar is strengthened.

Table D-63 Cumulative capacity of mobile fuels cells [GW]

[GW]	2010	2020	2030	2040	2050
Baseline	0.005	0.005	0.005	0.005	0.005
11RD2000	0.019	0.019	0.019	0.019	0.019
11RD1000	0.185	0.185	0.185	0.185	0.185
11RD500	1.810	1.810	1.810	1.810	1.810
12RD2000	0.019	0.019	858	3,565	11,204
12RD1000	0.185	0.185	750	3,460	11,097
12RD500	1.810	1.810	752	3,462	11,099
14RD2000	0.019	0.019	1,050	4,012	11,643
14RD1000	0.185	0.185	1,050	4,013	11,644
14RD500	1.810	1.810	1,052	4,019	11,650
3RD2000	0.019	0.019	1,050	4,934	11,123
3RD1000	0.185	0.185	1,050	4,935	11,123
3RD500	1.810	1.810	1,052	4,936	11,125

Table D-64 Cost development of mobile fuel cell system [€/kW]

[€/kW]	2010	2020	2030	2040	2050
Baseline	3000	3000	3000	3000	3000
11RD2000	2000	2000	2000	2000	2000
11RD1000	1000	1000	1000	1000	1000
11RD500	500	500	500	500	500
12RD2000	2000	1997	77	50	35
12RD1000	1000	1000	80	50	35
12RD500	500	500	80	50	35
14RD2000	2000	1997	72	48	35
14RD1000	1000	1000	72	48	35
14RD500	500	500	72	48	35
3RD2000	2000	1997	72	45	35
3RD1000	1000	1000	72	45	35
3RD500	500	500	72	45	35

Cars are the most likely vehicles for penetration of fuel cells. In those scenarios where FC cars will penetrate, they will on their maximal potential according to the assumed growth constraints as described in D.3.2.3. All other FC vehicles are not economically viable except FC trucks and H₂ driven ICE cars under the assumption that infrastructure is 100% subsidized and the production cost of H₂ are on the level of their floor cost.

Table D-65 Shares of fuel cell or hydrogen driven vehicles in different scenarios*

		2010	2020	2030	2040	2050
FC cars	12RD2000/1000/500	0%	0%	6%	19%	51%
	14RD2000/1000/500	0%	0%	6%	19%	51%
	3RD2000/1000/500	0%	0%	6%	19%	36%
H ₂ ICE cars	3RD2000/1000/500	0%	0%	17%	8%	0%
FC trucks	3RD2000/1000/500	0%	0%	0%	45%	39%

*) In all other scenarios there is no fuel cell penetration in the transport sector

Conclusions

From the R&D scenarios some general conclusions can be drawn:

Initial investment costs of 2000 €/kW, 1000 €/kW or 500€/kW which are lower than the original cost estimate of 3000 €/kW due to increased R&D expenditures, are still not low enough to lead to the penetration of hydrogen in transport sector.

A fuel tax on fuels other than hydrogen in combination with reduced investment costs, works as a trigger for the penetration of hydrogen in the transport sector.

Although the starting point on the learning curve is different in scenarios with different initial investment costs within a range of 500-2000€/kW, the cumulative capacity build-up as well as the cost development in time are similar in these scenarios.

Under the assumption on increase of R&D expenditures and other assumptions taken in the case study, fuel cell cars are only vehicle using fuel cells except in cases where infrastructure and production of hydrogen are on their economical limits their, when FC trucks will also penetrate.

D.4.2.4 MESSAGE

[by G. Totschnig and I. Keppo (IIASA)]

The baseline and technological scenarios shown previously (Baseline, Demand-pull, Supply-push, Combined) use the R&D spending allocation and timing as defined in the R&D outlook (see Table C-25 in C.2.3.2). The amount of R&D spent on each technology and when are predefined. The MESSAGE model was operated in 2FL mode 4 (see C.2.3.2).

For the R&D scenarios the MESSAGE model is instructed to optimize endogenously the allocation of the budget, that is, the model decides endogenously which cluster or technology to spend the R&D on, given a total R&D budget time series. This means that the model is operated in 2FL mode 1 (see C.2.3.2). This is strictly true for the 0.5x R&D and for the 1x R&D scenario. For the 10x FC R&D in 2007–2015 scenario the FC R&D is defined by the exogenously defined 10x FC R&D in 2007–2015 time series, whereas the R&D spending allocation of the other technologies are endogenously optimized. For the 10x H₂ Production R&D in 2007–2015 scenario, the hydrogen production R&D is defined by the exogenously defined 10x H₂ Production R&D in 2007–2015 time series, whereas the R&D spending allocation of the other technologies are endogenously optimized. For the Combined R&D scenario, both the FC and the hydrogen production are exogenously given.

The definition of the scenarios is given in chapter D.4.1

In the following figures the global passenger car transport sector and the energy consumption of this sector is shown for the R&D policy scenarios. Compare all the R&D scenarios below with Figure D-180, which compares the global hydrogen car shares and Table D-66 which compares the CO₂ emissions and other impact factors.

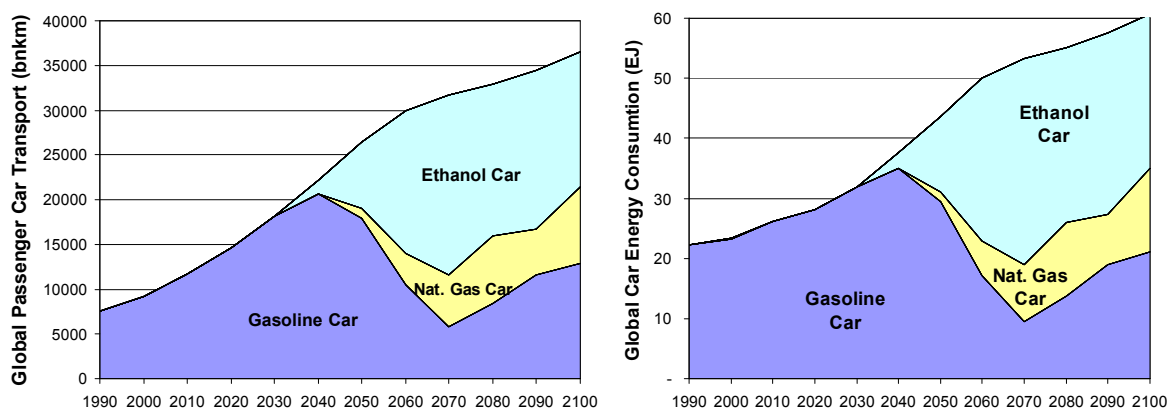


Figure D-170. No R&D spending. Technologies improve only through learning by doing.

In Figure D-170 the results for passenger car transport are given for the No R&D scenario. It is clear that hybrid cars and hydrogen cannot penetrate with only learning by doing and without any R&D.

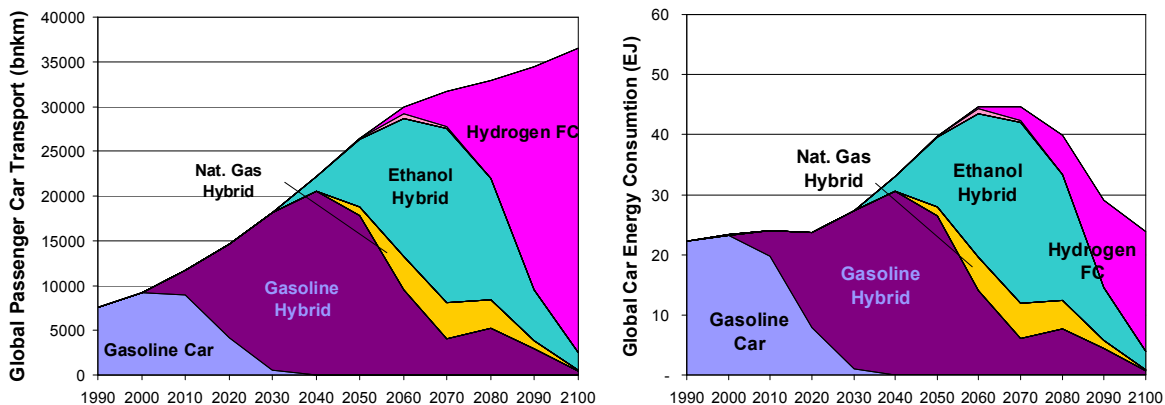


Figure D-171. 0.5x R&D scenario. The total R&D budget is only 50% of that in the baseline in each time period. The R&D allocation is endogenously optimized. The total R&D spent between 2000 and 2050 is 96 billion USD₉₀.

In the 0.5x R&D scenario with only 50% of the baseline R&D, the entry of hydrogen into the market is delayed by 20 years compared to the baseline (see also Figure D-180). The ethanol cars enable climate neutral car transport before the market entry of hydrogen cars.

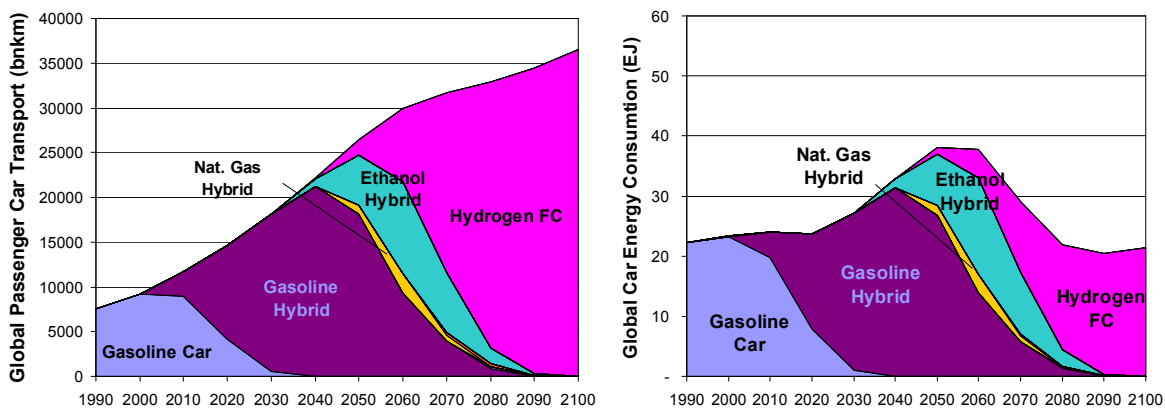


Figure D-172. 1x R&D scenario is defined as the Baseline scenario but with full endogenous two-factor learning optimization of the R&D budget allocation. The total R&D spent between 2000 and 2050 is 192 billion USD₉₀.

The 1x R&D scenario has very similar results to the baseline. The most significant difference is an earlier penetration of gasoline hybrid cars.

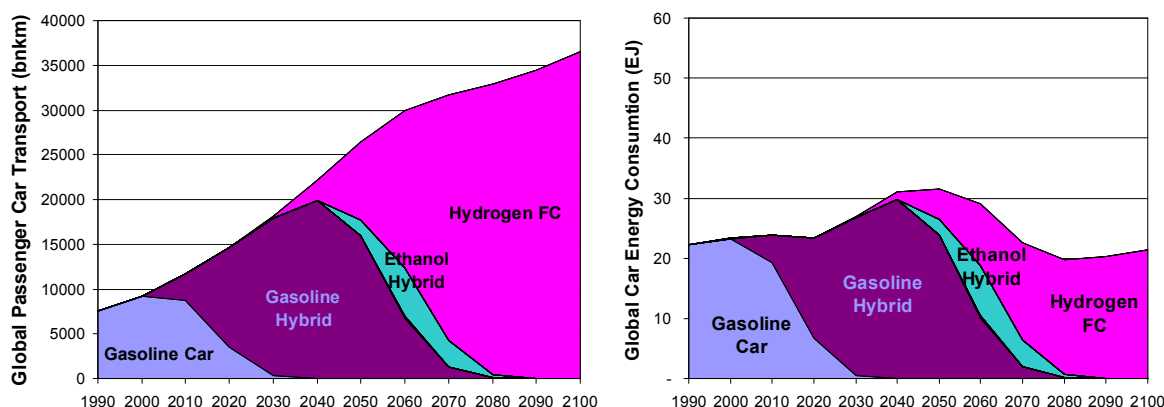


Figure D-173. 10x FC R&D in 2007–2015 scenario assumes a tenfold fuel cell R&D budget between 2007 and 2015 as compared to the baseline. The total R&D spent between 2000 and 2050 is 294 billion USD₉₀.

The 10x FC R&D in 2007–2015 scenario assumes 102 billion USD₉₀ spent on FC between 2007 and 2015. Despite this effort, the market entry of hydrogen FC cars starts only in 2040–2050. The first reason is that, as up to 2030 the gasoline hybrid car cannot be beaten on price (see Figure D-174). Only after 2030 does the increasing price of fuel and of CO₂ lead to hydrogen fuel cell cars being competitive. In this scenario all the fuels are covered by the same fuel tax. The second reason is that even with this R&D boost between 2007 and 2015 the investment costs are still too high for the fuel cell. Only the cumulative R&D up to 2050 brings the investment costs of fuel cell cars into a competitive range (see Figure D-174). The 10x FC R&D between 2007 and 2015 would result in an earlier market entry of hydrogen fuel cell cars if the R&D spending is combined with some other measure to make hydrogen competitive, for example higher CO₂ tax, tax exemption for hydrogen fuel, and infrastructure subsidy.

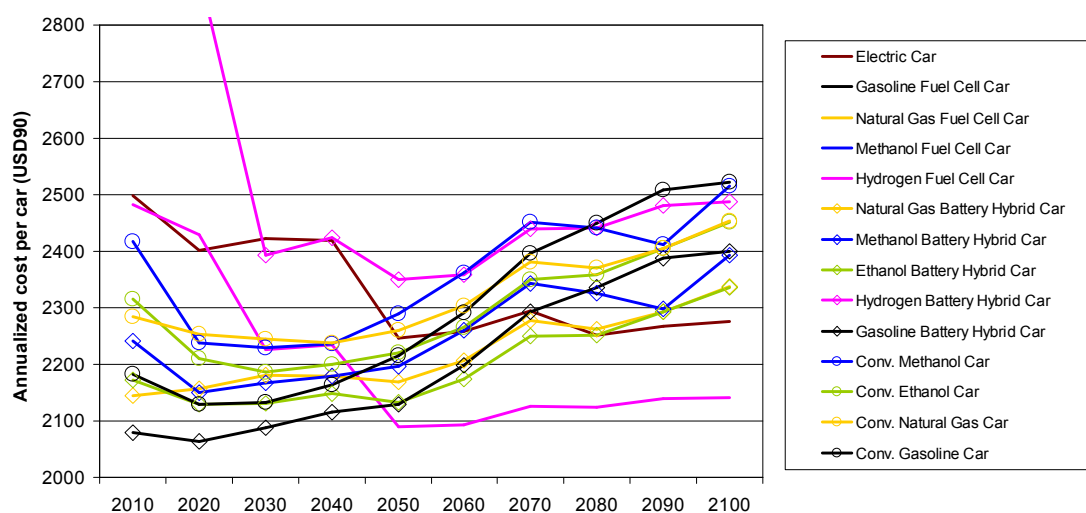


Figure D-174. Annualized costs for the different car types for the 10x FC R&D in the 2007–2015 scenario. The annualized costs included the vehicle cost, fuel cost, fuel tax, CO₂ tax and operation, and maintenance costs. This figure is based on a 5% discount rate, a global average CO₂ tax, a global average car utilization rate, and a global average fuel price.

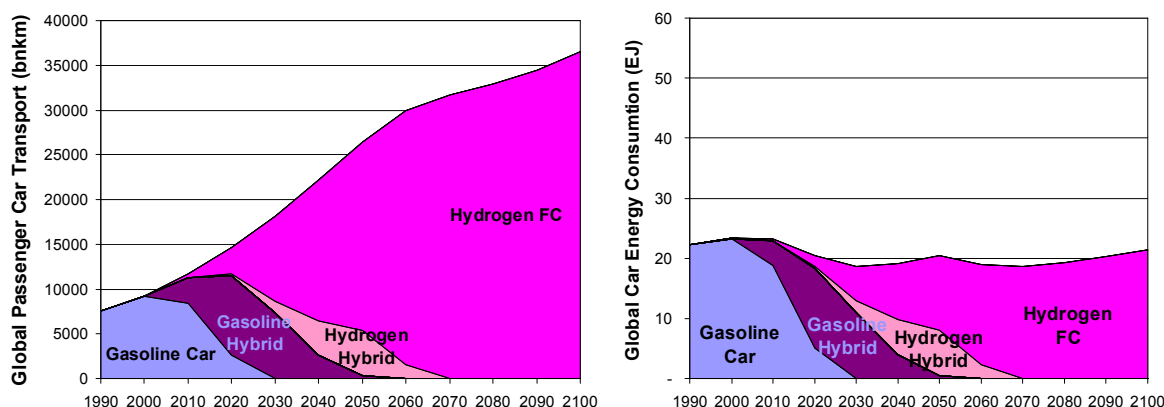


Figure D-175. Tenfold fuel cell R&D budget between 2007 and 2015 and increased fuel tax for all fuels except hydrogen and electricity scenario. Hydrogen and electricity are exempt from fuel tax in this scenario.

The scenario depicted in Figure D-175 assumes that, in addition to the tenfold-increased FC R&D between 2007 and 2015, the fuel tax is increased from a worldwide 0.5 euro2000/Liter to 1.0 euro2000/Liter from 2025 onwards for all fuels except the emission free fuels, hydrogen and electricity, which are completely exempt from fuel tax for all time periods. The fuel tax is the same for the passenger and the freight transport sector. As a result the hydrogen fuel cell vehicle is competitive from 2025 onwards (see Figure D-176).

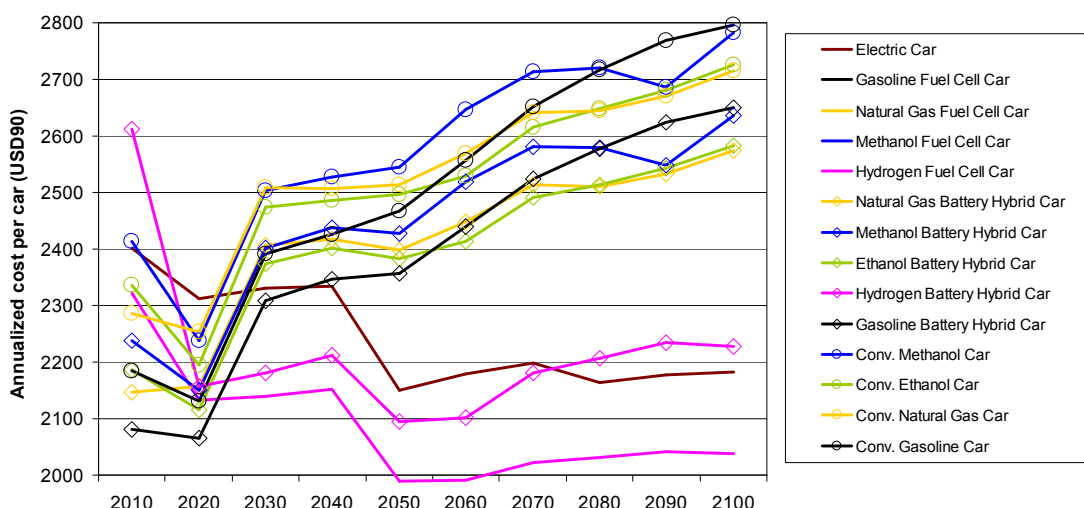


Figure D-176. Annualized costs for different car types for the 10x FC R&D in 2007–2015 with increased fuel tax for all fuels except hydrogen and electricity scenario. The annualized costs include the vehicle cost, fuel cost, fuel tax, CO₂ tax, and operation and maintenance costs.

Figure D-176 shows the effect of the increased fuel tax (from 2025 onwards) and the tax exemption for hydrogen and electricity. Compared to the 10x FC R&D in 2007–2015 scenario, R&D is here invested earlier in hydrogen storage. This considerably lowers the costs of hydrogen cars in 2020 (compare Figure D-174). The figure is based on: 1) a global average CO₂ tax; 2) a global average car utilization rate; and 3) a global average fuel price. As the regions Asia and reforming economies are assumed to have a lower car utilization rate, the high fuel cell investment costs dominate over the high efficiency and low consumption. In these regions, the hydrogen hybrid cars are first to be cost competitive; the hydrogen fuel cell cars become so 15

years later. As Figure D-175 shows the global results, it is a mix of regional trends with low and high car utilization.

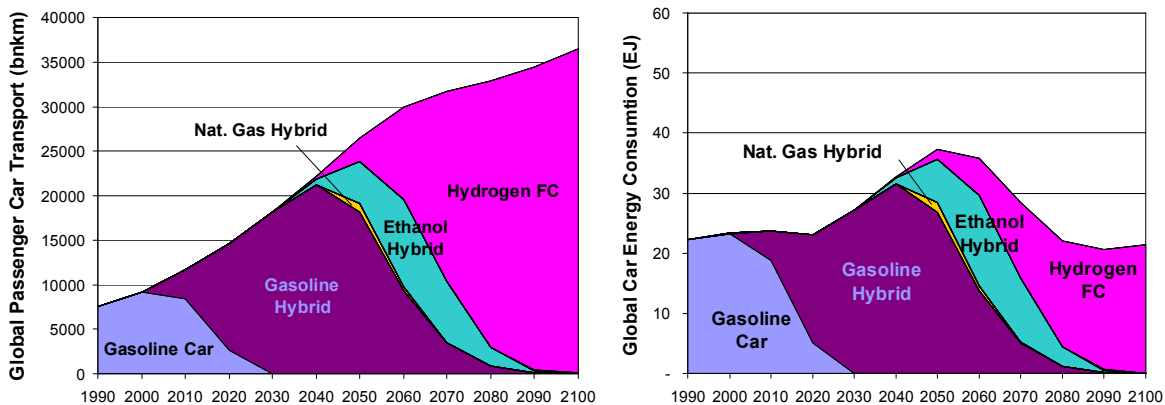


Figure D-177. Tenfold hydrogen production R&D budget between 2007 and 2015 scenario. The total R&D spent between 2000 and 2050 is 235 billion USD90.

The tenfold hydrogen production R&D budget between 2007 and 2015 scenario does not show a great deal of difference from the 1x R&D scenario. In the 1x R&D scenario the possibility of a free R&D spending allocation is used to spend more R&D on hydrogen production at all times than in the scenario showing tenfold hydrogen production R&D budget between 2007 and 2015.

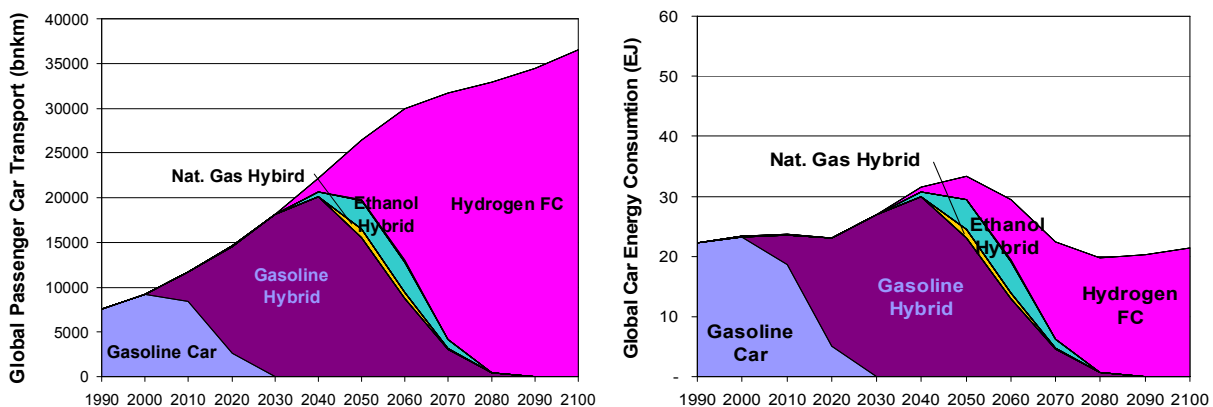


Figure D-178. Tenfold hydrogen production R&D budget between 2007 and 2015 and hydrogen infrastructure subsidy scenario. The delivery of hydrogen from production to the end user is cost free due to a 100% subsidy.

The tenfold hydrogen production R&D budget between 2007 and 2015 and hydrogen infrastructure subsidy scenarios results in an approximately 8-year-earlier hydrogen penetration.

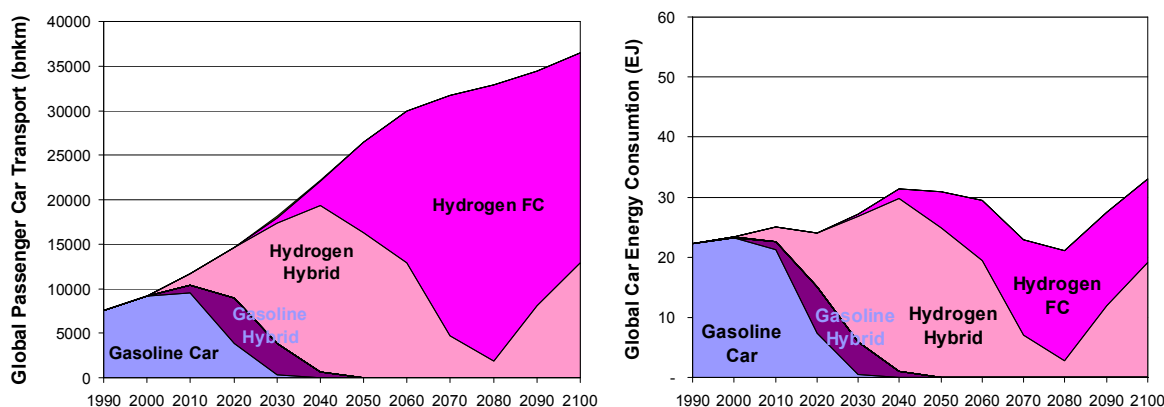


Figure D-179. Combined scenario with tenfold fuel cell and hydrogen production R&D budget between 2007 and 2015, increased fuel tax with hydrogen exempt, infrastructure subsidy, and doubled CO₂ tax.

For all the above global figures it must be borne in mind that they are the sum of the 4 MESSAGE regions used in these scenarios (OECD, Asia, Latin America + Africa + Middle East, reforming economies). The combination of the trends in the 4 regions leads to the depicted global result.

In Figure D-179 the Combined R&D policy scenario is shown. Because of the tax exemption for hydrogen and the infrastructure subsidy, hydrogen becomes inexpensive and makes the less-efficient hydrogen hybrid a close competitor of the hydrogen fuel cell car. In 2050 the cumulative fuel cell R&D lowers the vehicle fuel cell investment costs to a competitive level. However, especially in regions, like Asia, with a low carbon tax and low annual vehicle utilization, hydrogen hybrids stay a close competitor. At the end of the century, hydrogen hybrid cars gain market share in Asia because of the low hydrogen price.

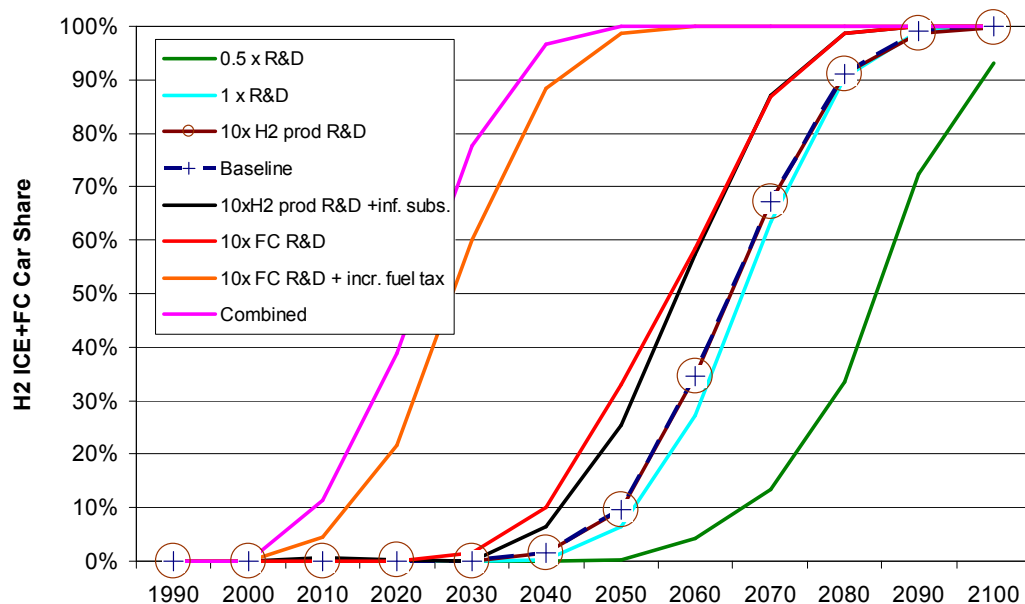


Figure D-180 Global hydrogen car shares. Hydrogen hybrid cars and hydrogen fuel cell cars are included.

In Figure D-180 the hydrogen penetration shares are given. It is clear that the 0.5x R&D scenario leads to a 20-year delay in hydrogen market penetration compared with the baseline. The hydrogen penetration in the baseline scenario (with the exogenous R&D allocation) and the 1x R&D scenario (baseline assumptions with model internal optimization of R&D allocation) are very similar. The No R&D scenario does not use any hydrogen cars. The 10x FC R&D 2007–2015 scenario results in approximately a 10-year-earlier introduction of hydrogen. The timing difference of the hydrogen car market penetration between the “0.5x R&D” and the “10x FC R&D 2007–2015” scenarios is 30 years. The baseline scenario spends 96 billion USD90 more between 2000 and 2050 than the “0.5x R&D” scenario and gains 20 years in terms of earlier hydrogen penetration. The “10x FC R&D 2007–2015” scenario spends 102 billion USD90 more between 2000 and 2050 than the baseline scenario and gains about 10 years in terms of earlier hydrogen penetration. Thus, the R&D spending becomes less effective at higher levels. The 10x FC R&D with increased fuel tax for fossil fuels and exemption for hydrogen leads to a 37-year-earlier hydrogen penetration. The Combined scenario shows a 40-year-earlier market entry of hydrogen vehicles. The early market entry of both scenarios is a result of the high fuel taxes for conventional fuels and by tax exemption for hydrogen. If only baseline assumptions are taken and combined with this changed fuel tax, it will result in the same 37-year-earlier hydrogen penetration (compare Figure in the demand-pull chapter). A difference is that in this baseline with changed fuel tax scenario the hydrogen hybrid cars will initially dominate the market and only later will hydrogen fuel cell cars dominate.

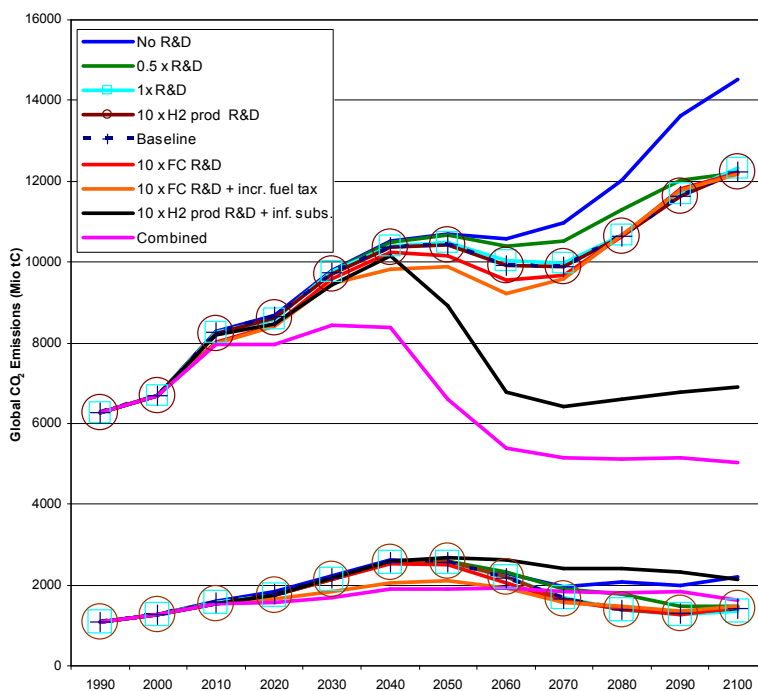


Figure D-181. Global CO₂ emissions for selected R&D scenarios.

From Figure D-181 and Table D-66 it can be seen that insufficient R&D leads to significantly higher CO₂ emissions. The difference is especially remarkable in the car transport sector (49% and 10% increase in cumulative CO₂ emissions from car transport for the No R&D and the 0.5x R&D scenarios, see Table D-66). As CO₂ emissions in the transport sector also accompany local air pollution, one can say that insufficient

R&D funding for hydrogen has a negative effect on local air pollution in the mid-to-end century. As, however, in all the scenarios (except the No R&D scenario) hydrogen vehicles dominate passenger car transport in 2100, the effect of the scenarios compared to the baseline is only a temporary reduction in emissions due to the different timing of the market success of hydrogen cars. Exceptions are the scenarios with hydrogen infrastructure subsidy (“10x H2P +inf. sub.” and “Combined”). As a result of the subsidized hydrogen infrastructure it becomes economic to convert natural gas to hydrogen (including CO₂ sequestration) and to use hydrogen (instead of natural gas) in the industrial, residential, and commercial end-use sectors. This leads to reduced CO₂ emissions. The low hydrogen price also leads to a lower oil and natural gas price on the final energy level and results in a shift from ethanol to natural gas and oil freight transport. Thus, in total ground transport (including freight), the CO₂ emissions go up in these scenarios. Compare also to Table D-66, Figure D-181, and Figure D-182.

Table D-66. Cumulative CO₂ emissions between 1990 and 2100 and other impact factors for different scenarios.

	No R&D	0.5 x R&D	1 x R&D	10x H2 Prod. R&D	10x H2 Prod. R&D+ Inf. Subs.	10x FC R&D	10x FC R&D + incr. fuel tax	Combined
Total CO ₂ emissions 1990-2100 (GtC)	1123	1079	1058	1054	850	1041	1028	725
Ground Transport Co ₂ Emissions 1990-2100 (GtC)	220	206	196	196	234	193	180	186
Car Transport CO ₂ Emissions 1990-2100 (GtC)	59	44	40	39	37	36	19	16
Total Emissions 1990-2100 (% Change to 1xR&D)	6%	2%	0%	0%	-20%	-2%	-3%	-32%
Ground Transport 1990-2100 (% Change to 1xR&D)	13%	5%	0%	0%	20%	-1%	-8%	-5%
Car Transport 1990-2100 (% Change to 1xR&D)	49%	10%	0%	-2%	-6%	-10%	-53%	-59%
Change Global Airpollution from Ground Transport in 2030-2060	2%	2%	0%	0%	7%	-2%	-16%	-21%
Change OECD Oil Gas Import Dependency in 2050-2100	11%	5%	0%	4%	2%	2%	-2%	-27%
Change OECD Average Weighted Final Energy Price 2050-2100	3%	1%	0%	-1%	-4%	-1%	-3%	0%

Global air pollution in the middle of the century is reduced most strongly by an increased fuel tax on fossil fuels (“10x FC+ incr. fuel tax” and Combined R&D policy scenarios) and an increased carbon tax (Combined R&D policy scenario). In terms of the energy security, defined as OECD oil and gas import dependency, no R&D increases the dependency by 10%, while the Combined scenario, which includes a increased carbon tax, reduces the dependency by 27%. The final energy prices are not really affected by the different scenarios.

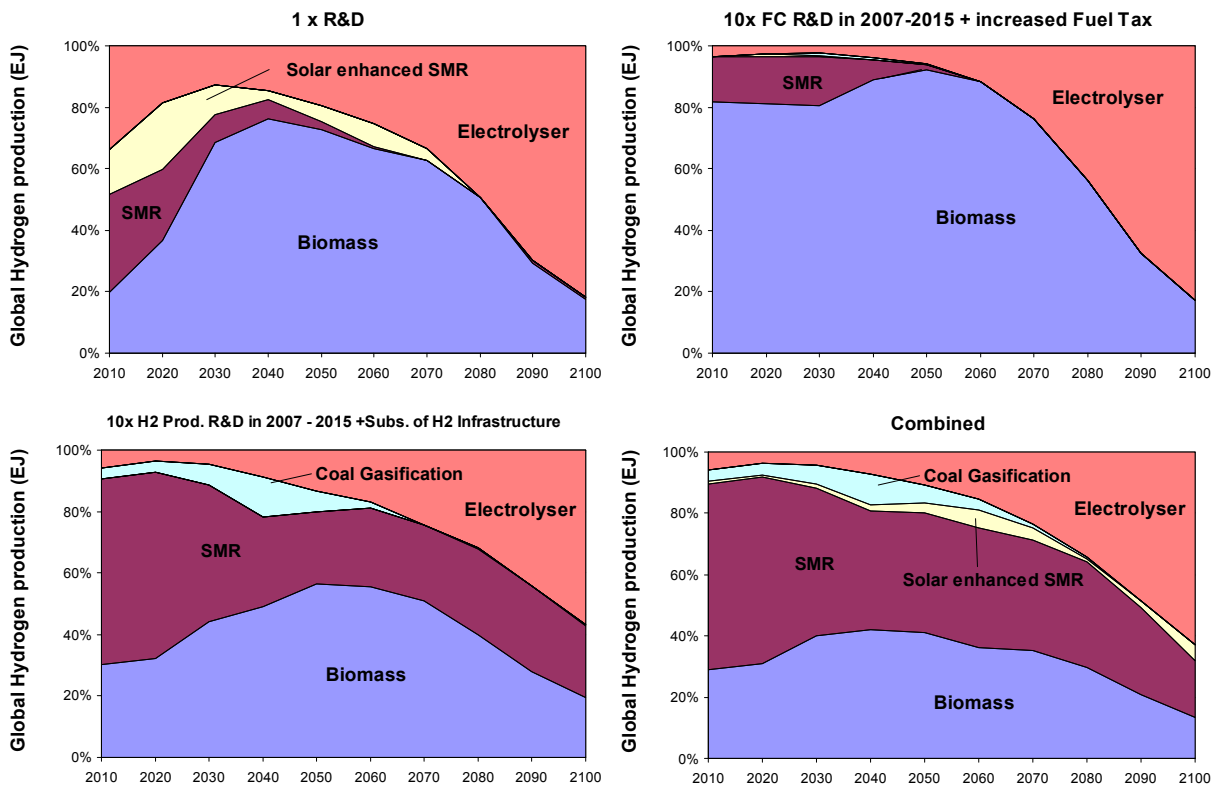


Figure D-182. Hydrogen production shares for 4 different R&D scenarios.

Hydrogen production shares are given in Figure D-182. For the scenarios including the hydrogen infrastructure subsidy, the shift from natural gas end use to natural gas use in hydrogen production can be observed.

Below the endogenous two-factor learning behavior and results are shown and discussed for the “1x R&D” scenario. As defined in the definitions of the 2FLC there is only one common “Fuel cell” R&D spending variable for the “stationary fuel cell” and “mobile fuel cells” clusters, and there is only one common “reformer” R&D spending variable for the “steam methane reformer” (SMR) and “mobile reformer” cluster.

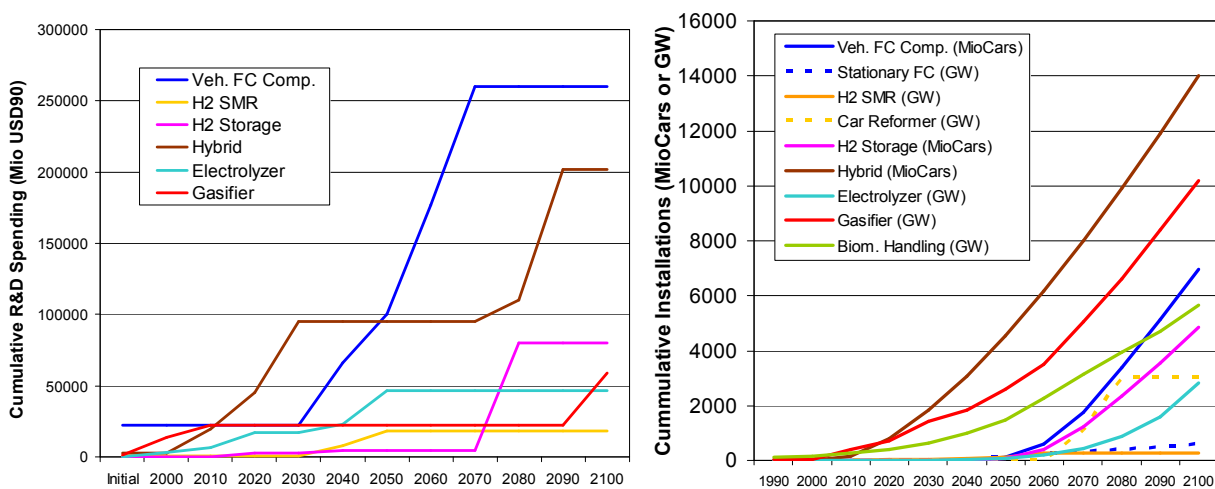


Figure D-183. Cumulative spent R&D and cumulative installed capacity of the different clusters for the “1x R&D” scenario.

The biggest R&D demands are for fuel cells and for hybrids (see also R&D outlook Table C-25 in C.2.3.2). In Figure D-183 the cumulative spent R&D and cumulative installed capacity are shown. The cumulative spent R&D shows flat parts, where the cumulative R&D remains at one of the discrete learning-by-research levels. These curves start off at an initial level (cumulative R&D up to 2000) and increase thereafter. In “1x R&D” and the other R&D scenarios with free R&D allocation it is found that the model first spends the R&D on hybrids until it achieves 95% of the possible cost reduction (the 95% includes the effect of the LBD; see Figure D-185), which occurs when the cumulative R&D spending on hybrids reaches the second level CRD₂ at 95,000 million USD₉₀. In Figure D-183 this level is achieved in 2030. The statement that the R&D is spent first on hybrids seems to contradict the fact that between 2000 and 2020 the model also spends R&D on the vehicle fuel cell component and hydrogen storage. However, the cumulative spent R&D between 2000 and 2020 on vehicle fuel cell and hydrogen storage amounts to only 40 billion USD, whereas 50 billion USD more needs to be spent on hybrids to achieve the CRD₂ level at 95 billion USD by 2020. As the model cannot achieve the second R&D level before 2030 anyway, it spends the remaining R&D in the shared R&D budget for the other important clusters. This is an effect of the discrete learning-by-research levels. The model has to achieve or surpass these levels in order to obtain the cost reductions of these learning levels. It does not obtain any cost reductions for getting halfway to the next level (see C.2.3.2 and Figure D-185). The right-hand figure in Figure D-183 shows the cumulative installed capacities. It is clear that only hybrids, gasifiers, and biomass handling are active up to 2050. Biomass handling and gasifiers are used as subcomponents of biomass and coal power plants.

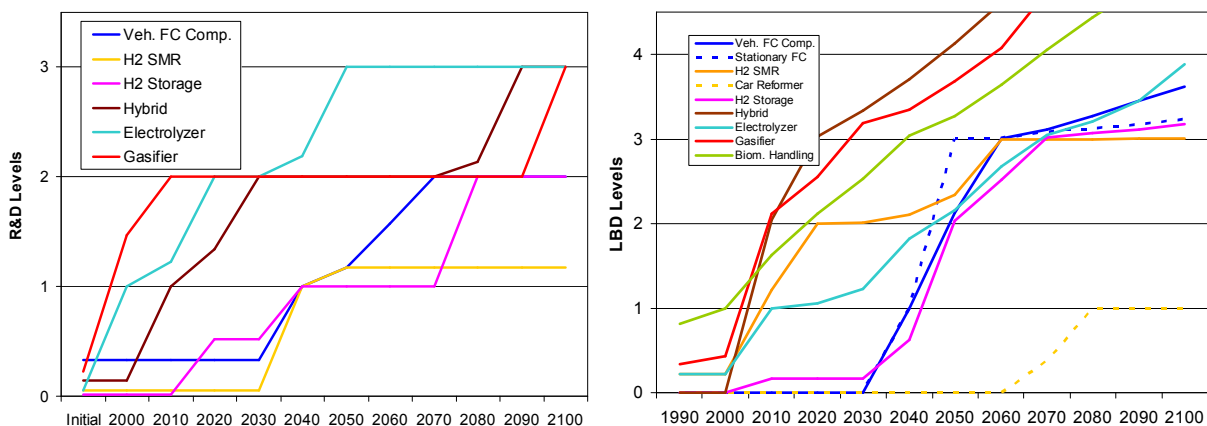


Figure D-184. The progress of the endogenous learning clusters is shown in respect to the achieved learning levels for the “1xR&D” scenario.

In Figure D-184 the progress of learning by research and learning by doing is shown in terms of achieving the respective levels for each cluster. The same data as in Figure D-183 are also depicted in Figure D-184, but the cumulative spent R&D and the cumulative installations are now normalized to the learning levels of each cluster. It is clear from comparing Figure D-183 and Figure D-184 that the first learning-by-research level of H₂ storage (4,691 million USD) is tiny compared with the first learning-by-research level of fuel cells (66,044 million USD). In Figure D-184 both levels are shown as level 1. Learning by research has 3 levels of

cumulative spend R&D (called CRD_i; see guidelines in C.2.3.2) defined for each cluster, and learning by doing has 4 levels of cumulative installed capacity for each cluster (called CCL_j in C.2.3.2).

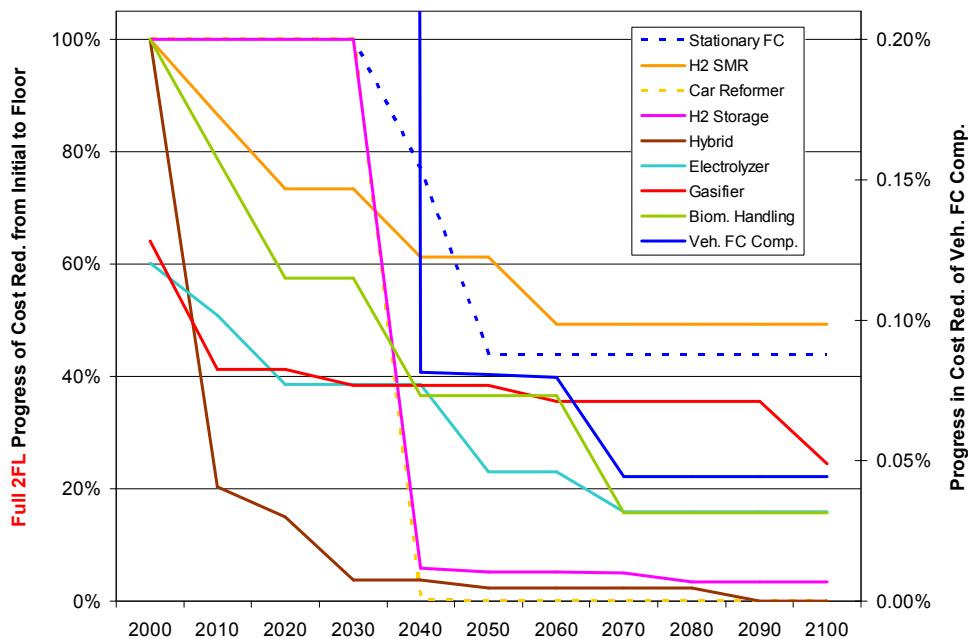


Figure D-185. The cost reductions in the 2FL clusters and standalone technologies are given for the “1x R&D” scenario. The cost reductions are the combined effect of learning by research and learning by doing. 100% indicates the initial cost in 2000 and 0 % the floor costs.

In Figure D-185 the cost reductions due to the achieved learning levels (see Figure D-184) are shown. This figure includes the effects of both learning by doing and learning by research. It is clear that the hybrid subcomponent achieves 96% cost reduction until 2030. The cost reduction curve for the vehicle fuel cells (Veh. FC Comp.) refers to the right axis. All other technologies refer to the left axis. The values of the initial costs and floor costs are given in Table C-22 of chapter C.2.3.2. One can see that steam methane reforming achieves most of its cost reduction from learning by doing whereas fuel cells and hydrogen storage mainly learn from learning by research.

The 2FL analysis of the R&D policy scenarios shows that it is most economic to spend the R&D first on hybrids until 95% of the cost reduction is achieved and then on fuel cells and on other components. Comparing the baseline scenario using exogenously given R&D allocation and the “1x R&D” scenario using endogenous R&D allocation and timing shows that the results very similar (See Figure D-43 in chapter D.2.1.4, Figure D-172, and Figure D-180). The main difference is an earlier and stronger penetration of hybrid vehicles.

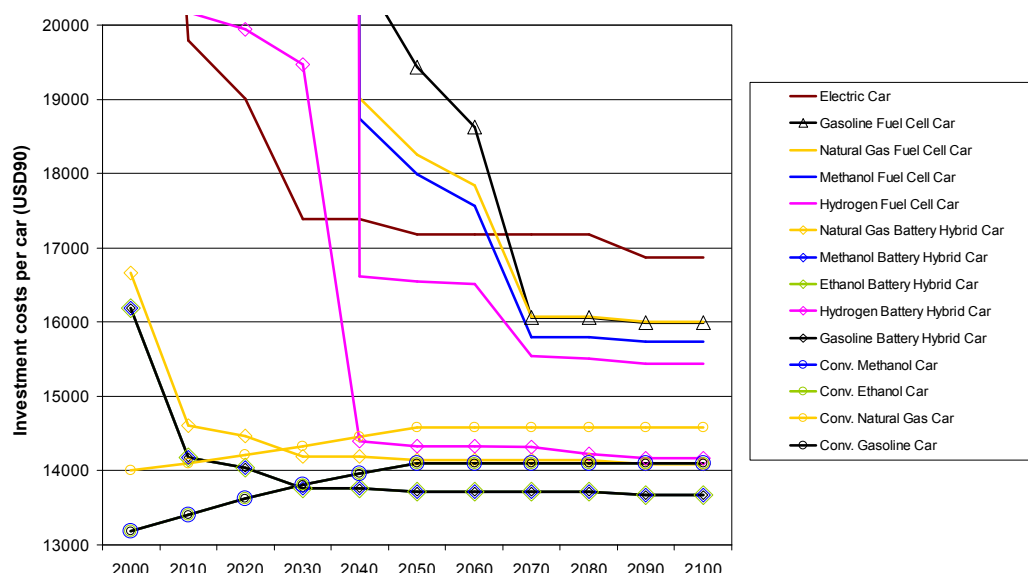


Figure D-186. Investment cost for different car types for the “1x R&D” scenario.

In Figure D-186 the investment cost are given for different car types. This figure is based on the technological progress as shown in Figure D-185.

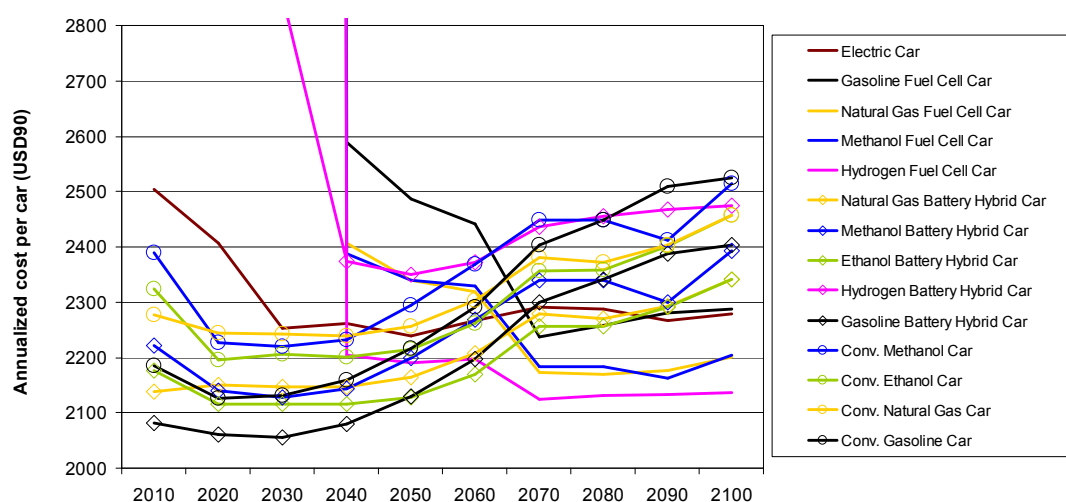


Figure D-187. Development of annualized cost per car for the “1x R&D” scenario. The costs include vehicle cost, fuel cost, fuel tax, and CO₂ tax.

In Figure D-187 the annualized costs per car are given for different passenger car technologies. The figure is based on global averages of vehicle utilization rates, CO₂ tax, fuel prices, and a 5% discount rate. The regional figures vary accordingly. The costs include vehicle investment cost, maintenance costs, fuel cost, fuel tax, and CO₂ tax. The two-factor learning cost, efficiency, and the performance progress of the 2FL car technologies are included in this picture (as depicted in Figure D-185; compare Table C-21 in chapter C.2.3.1). From Figure D-187 it can be seen that, up to 2040, gasoline hybrid cars are the most economic option. Only the rise in oil prices and the increasing CO₂ tax lead to competitiveness in other vehicle technologies. It can also be seen that increasing the fuel cell R&D could shift the market entry of fuel cells by 10 to 20 years. Compare with the breakthrough in fuel cells demand-pull scenario in Figure D-111. For an even earlier start to fuel cell

market success, measures such as tax exemptions for hydrogen, infrastructure subsidies, or increased CO₂ tax are needed.

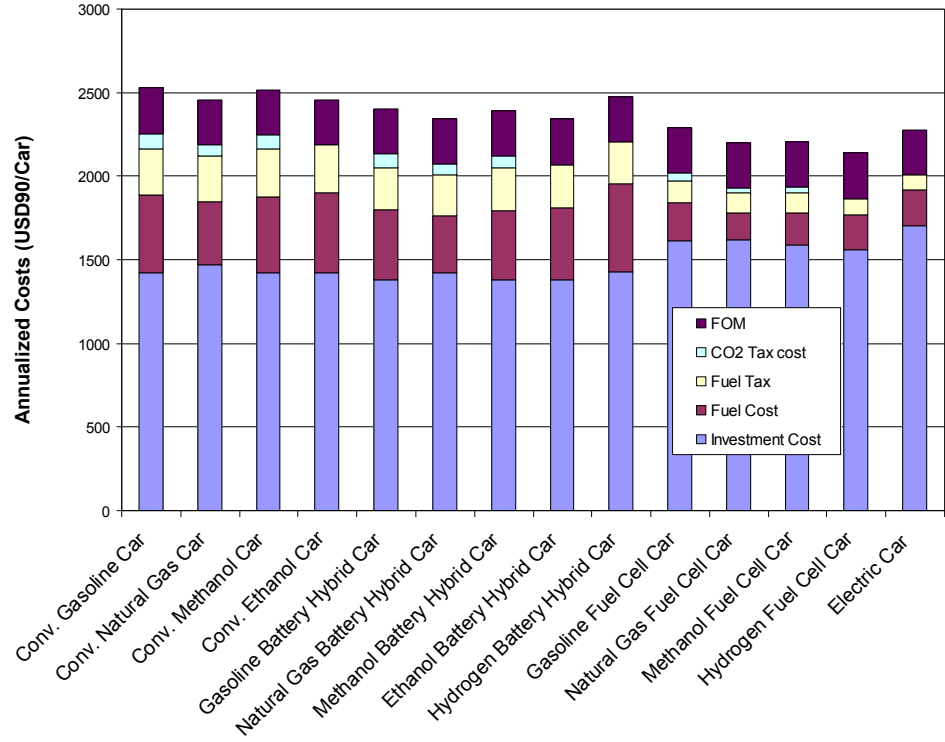


Figure D-188. Contributions to the annualized costs are depicted for different car types for the year 2100 for the “1x R&D” scenario.

In Figure D-188 the total annualized cost is split into the different cost factors. In the “1x R&D” scenario the fuel tax is equal for all fuels. It is clear that the fuel tax and the CO₂ tax have a much stronger cost effect for the less efficient car technologies. For the gasoline hybrid car and the hydrogen hybrid car, the fuel price, fuel tax, and carbon tax contribute to 31% of the annualized costs, whereas for the hydrogen fuel cell they contribute only 14%.

For purposes of comparison, Table D-67 gives the shares of large stationary combined-heat-and-power plants in power and district heat generation.

Table D-67. Share of stationary fuel cell combined-heat-and-power plants in district heat and electricity production.

		1990	2000	2010	2020	2030	2040	2050	2060	2070	2080	2090	2100
Share in Distric Heat:													
Baseline	Total FC CHF	0%	0%	0%	0%	15%	16%	12%	11%	9%	11%	10%	8%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.5 x R&D	Total FC CHF	0%	0%	0%	0%	0%	0%	0%	1%	3%	2%	1%	0%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1 x R&D	Total FC CHF	0%	0%	0%	0%	0%	0%	10%	11%	9%	11%	9%	11%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10x H2 Prod. R&D	Total FC CHF	0%	0%	0%	0%	15%	17%	12%	11%	10%	11%	10%	9%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10x H2 Prod. R&D+	Total FC CHF	0%	0%	0%	0%	0%	2%	8%	16%	28%	35%	44%	41%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	15%	17%
Inf. Subs.	Total FC CHF	0%	0%	44%	38%	27%	18%	16%	17%	12%	11%	11%	6%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10x FC R&D	Total FC CHF	0%	0%	44%	38%	26%	19%	15%	14%	11%	11%	11%	6%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10x FC R&D + incr. fuel tax	Total FC CHF	0%	0%	45%	33%	34%	32%	31%	25%	32%	32%	41%	42%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	16%	17%
Share in Electricity Generation:													
Baseline	Total FC CHF	0%	0%	0%	0%	6%	6%	4%	3%	2%	2%	2%	1%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.5 x R&D	Total FC CHF	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1 x R&D	Total FC CHF	0%	0%	0%	0%	0%	0%	3%	3%	2%	2%	1%	2%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10x H2 Prod. R&D	Total FC CHF	0%	0%	0%	0%	6%	7%	4%	3%	2%	2%	2%	1%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10x H2 Prod. R&D+	Total FC CHF	0%	0%	0%	0%	0%	1%	2%	3%	4%	4%	4%	3%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%
Inf. Subs.	Total FC CHF	0%	0%	19%	18%	10%	7%	5%	5%	3%	2%	2%	1%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10x FC R&D	Total FC CHF	0%	0%	18%	18%	10%	7%	5%	4%	2%	2%	2%	1%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10x FC R&D + incr. fuel tax	Total FC CHF	0%	0%	19%	15%	11%	10%	7%	4%	4%	3%	3%	3%
	H2-FC CHP	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%

Conclusion for the scenarios conducted in CASCADE MINTS Part 1:

In the baseline scenario, hydrogen vehicles make their market entry in 2040 and gain 35% in 2060. Assuming extensive fuel cell R&D spending or a breakthrough in fuel cell performance, the market entry and fuel cell market penetration can be accelerated by about 16 years. The MESSAGE model results indicate that the earliest possible market entry of hydrogen vehicles is in about 2025–2030. Only in around 2030 are the gasoline price and the CO₂ tax rise high enough to make fuel cell cars competitive. The 2030 market entry date is based on optimistic assumptions regarding the possible technological progress and assumes a R&D spending on fuel cells of about 150 billion USD between 2000 and 2030. Insufficient R&D leads to a considerable delay in market entry. In the scenario where the R&D budget is reduced by 50% compared to the Baseline, hydrogen car market entry is delayed by 20 years until 2060. In the R&D policy scenarios only the hydrogen fuel cell cars, but not the hydrogen hybrid cars, gain market shares.

In all R&D policy scenarios with endogenous optimization of budget allocation and timing, the R&D is spent as a first priority on hybrids until 95% of the possible cost reduction is achieved. Then the R&D is spent on fuel cells and on other technologies.

To achieve an even earlier market penetration of hydrogen vehicles, other favorable circumstances have to come into play. The assumptions of the urban air pollution technology story lead to a fuel tax of 1 euro2000/liter gasoline equivalent for all fuels, except hydrogen and electricity, which are exempt from the fuel tax. This measure is very effective and brings hydrogen vehicles into the market from 2010. Depending on the progress in vehicle fuel cells the hydrogen cars would be hydrogen hybrids or hydrogen fuel cell cars.

The doubled carbon tax and subsidizing the hydrogen infrastructure lead to about a market entry that is around 8 years earlier.

Whereas an optimization model will always choose the cheapest option, in real life other decision criteria are important and the cheapest passenger cars have only a very small market share. Assuming that technological progress is as defined in the two-factor learning curves, a fuel cell car with investment cost of less than 17,000 USD90 per car (including a markup factor of 1.74) is possible. With such a price and related performance the fuel cell car would be overpriced by only less than 7% in 2010 and 2020, compared to the gasoline hybrid.

In terms of global cumulative CO₂ emissions, the different scenarios do not have a big impact. Only the scenarios with a doubled CO₂ tax and the scenarios with hydrogen infrastructure subsidy have a strong impact. The infrastructure subsidy makes it economic to produce hydrogen from natural gas und replace the natural gas in industrial, residential, and commercial end use. The CO₂ from the steam methane reforming is captured and stored and leads to a CO₂ emission reduction. The passenger car emissions are reduced to a large extent in all scenarios with hydrogen fuel cell car market penetration.

The scenarios with the hydrogen infrastructure subsidy were also the scenarios with the highest uptake of hydrogen as a fuel for the industrial, residential, and commercial end use. As these diverse and broad sectors are modeled only in a rather stylized way, no detailed conclusions are drawn from these results in these sectors.

The two-factor learning results show a 40% cost reduction for electrolyzers and gasifiers due to learning. The hydrogen in the different scenario is mainly produced from biomass gasification and electricity used in electrolyzers. Steam methane reformers have a market share in the first half of the century and electrolyzers using nuclear power dominate hydrogen production in the second half of the 21st century. Because of the high efficiency of the fuel cell, the hydrogen supply side is not as important to the competitiveness of fuel cell cars as to the fuel cell costs. In the baseline scenario the hydrogen cost and fuel tax contribute only 14% to the annualized fuel cell car cost in 2100. For the gasoline and hydrogen hybrid cars the fuel price, fuel tax and CO₂ tax contribute 31% of the annualized cost.

In the 10x fuel cell R&D scenarios large stationary fuel cell combined heat-and-power cogeneration plants achieve a 19% share in electricity generation in 2010. This share decreases slowly thereafter. The other scenarios show shares of less than 10%.

The success of the hydrogen economy strongly depends on the technological progress of hydrogen fuel cells and on the political framework. The political framework can be supportive for the development of a hydrogen economy via increased R&D investments, early definition of infrastructure policies, defining hydrogen fuel taxation, and security standards.

D.4.2.5 MERGE-ETL

[by S. Kypreos (PSI)]

Technology Dynamics

Box 2: Definition of R&D Scenarios as defined by the project management

(Scenario names are in **bold** letters and appear in the subsequent figures)

RD01 Stop all R&D after 2007 for fuel cells and H₂ related technologies

1. Demand side scenarios

RD11 Tenfold increase in R&D expenditure on fuel cells between 2007 and 2015

RD12 Scenario 1.1 together with an increase in the tax on fossil fuels for road transport of the order of 0.5 €/lt from 2025 onwards worldwide.

RD13 Scenario 1.2 using 5% of the tax revenues for R&D on fuel cells and infrastructure (split according to baseline R&D shares)

RD14 Scenario 1.3 combined with a doubling of baseline effective carbon values

2. Supply side scenarios

RD21 Tenfold increase in R&D expenditure on hydrogen production options between 2007 and 2015

RD22 Scenario 2.1 together with additional fossil fuels for transport taxation as in Scenario 1.1

RD23 Scenario 2.2 together with 100% subsidy to all hydrogen distribution and storage infrastructure

3. Combined 1.4 + 2.3

RD31 Tenfold increase of R&D for cells between 2007, 2015; 0.5 € per lt tax for oil; 100% subsidy of infrastructures; 5% of tax revenue to FC and to infrastructures; and a doubling of baseline effective carbon values

R&D is an important pre-condition for the improvement of H₂ technologies but there are strong signs of diminishing returns. Thus, a considerable amount of R&D scenarios is proposed, as described in **Box 2**,

aiming at testing the R&D efficacy. The following ideas of the Project Management are behind these specifications:

- 1) Scenarios involving a massive and early increase of R&D on selected hydrogen technologies are to be elaborated to contrast them with the reference case of the R&D Outlook.
- 2) Since the R&D outlook already contains a very large R&D effort directed at hydrogen related technologies a scenario could be defined where such effort is substantially reduced. The purpose of this scenario would be to examine the overall importance of R&D in producing adequate technological progress for the initiation of a transformation of the energy system.
- 3) R&D Scenarios are also to be combined with additional climate policy scenarios and with environmental taxes, as in the case of technology storylines.

In order to assess the R&D scenarios with MERGE-ETL we define first the knowledge stock per R&D scenario based on the specific assumptions of Box 2. The knowledge stock is estimated and stored in MERGE assuming a depreciation rate for knowledge of 5% per annum using Eq. 7. As hydrogen fuel cells need significant R&D spending to become mature, the underlying assumption is that the R&D spending described in the Outlook (Table C-29) will induce the technology improvements described in TECHPOL-EURO-2000 for the period of 2025 and 2050. Thus we apply Eq. 14, with learning by searching before 2025, and after 2025 the TFLC for the stock of knowledge that corresponds to each R&D scenario. The model then, defines technology diffusion based on the endogenous treatment of learning.

The section starts with the presentation of some global energy, economic and environmental indicators per R&D scenario and ends with the penetration of hydrogen fuel cells in stationary and mobile markets and the economic impacts.

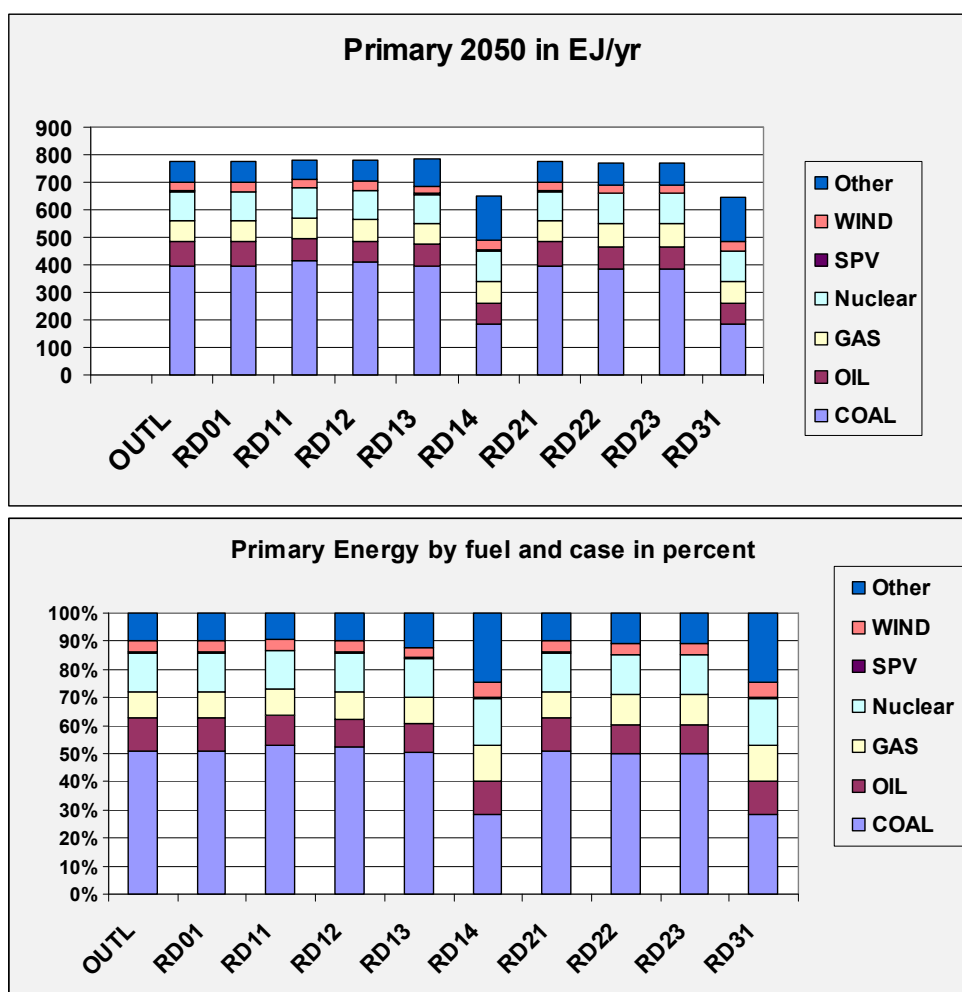


Figure D-189: Global Primary energy by fuel in the 2050

Figure D-189 shows the Primary energy use by fuel in the year 2050 and each R&D scenario. The first column refers to the R&D Outlook case. Again in these cases we realize the same behavior as in the storylines. Oil and gas are exhaustible resources such that coal, nuclear and renewables take over the markets. By the year 2050, primary energy consumption reaches about 780 EJ, with the exception of the cases with double carbon taxation rates demand is reduced to 650 EJ per year and the share of coal falls below 30% (versus 52% in the other cases). Although non-fossil energy resources increase their contribution significantly, fossil fuels still dominate the primary energy mix during the first half of the 21st century. Under a carbon tax we have significant reduction of coal use while renewables and nuclear energy take over. Renewable energy becomes the second important option after coal and expands dynamically during the 2000-2050 period.

Figure D-190 presents the global electricity generation mix by scenario and technology in the year 2050. Again the system behavior is as in the storylines, where electricity generation increases substantially, reaching 3.5 times its levels in the year 2000, even in the cases with intensive carbon policy. The most

significant difference is related to the penetration of HFC which takes place only when externalities are internalized.

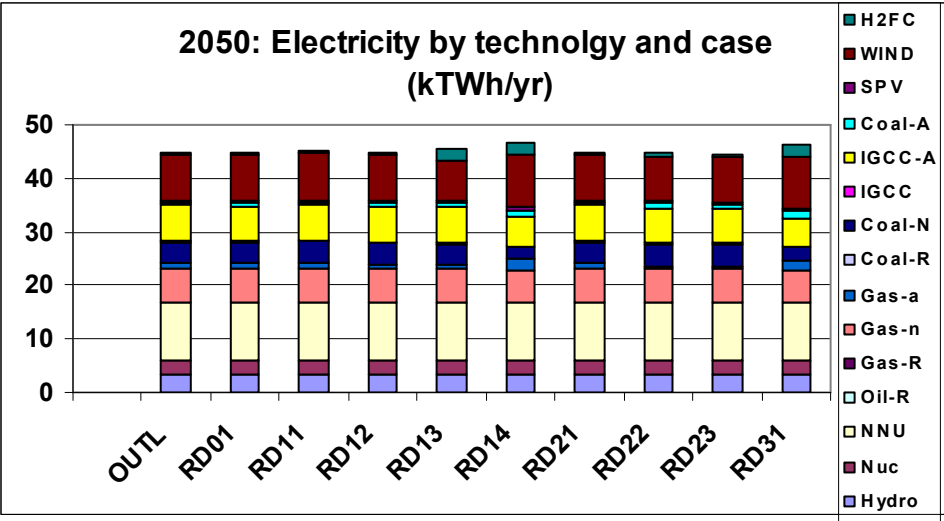


Figure D-190: World electricity generation by fuel in the year 2050. No significant differences are shown. New nuclear and renewables (wind) are the most important technologies while coal and gas are mainly installed with CCS facilities. Hydrogen fuel cell systems appear only when environmental externalities are internalized.

Figure D-191 depicts the technology mix in the global passenger car sector, where conventional and advanced internal combustion engines (ICE) satisfy a significant part of demand but at the end of the time horizon do not expand any more while their absolute number decreases. Hybrid vehicles gradually gain some market shares followed by ICE burning hydrogen. However this is not the case when a tenfold increase in the R&D for fuel cells is introduced and/or local and global externalities are internalized in form of taxes. In that case, hydrogen FC systems start penetrating in significant rates. Surprising is the fact that supply push options increase the share of hydrogen ICE cars but not this of HFC cars as cost reductions above the one given in the baseline for fuel cells are necessary to render them competitive.

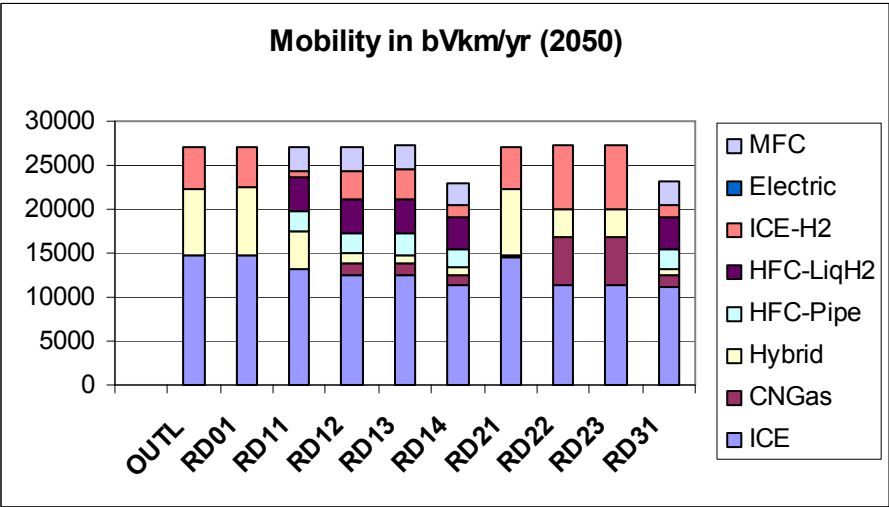


Figure D-191: World use of passenger cars for the technology storylines in the year 2050.

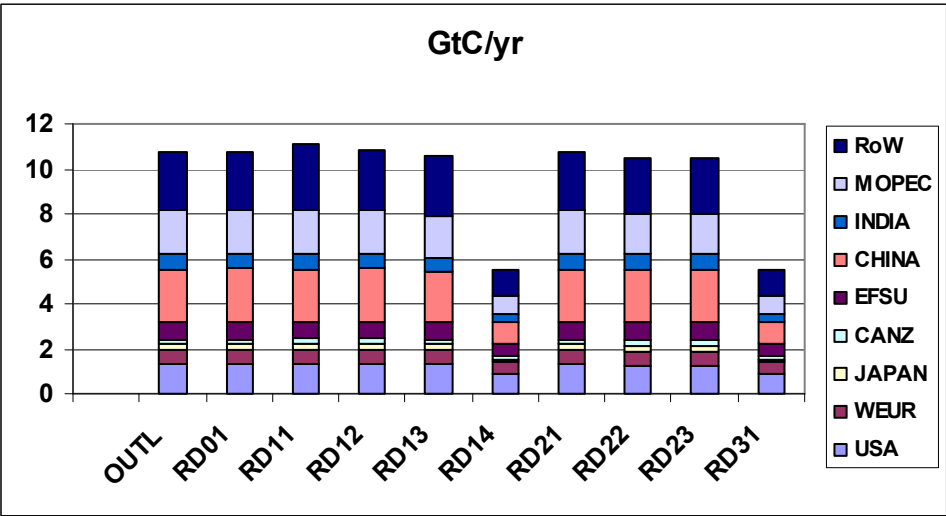


Figure D-192: Global CO2 emissions by region in 2050.

Figure D-192 presents the global CO2 emissions in the R&D scenarios by region where the results show similar trends like in the case of storylines. Similar results are obtained in terms of the atmospheric concentrations of all GHGs for 2050 as results are dictated by the level of carbon tax intensity.

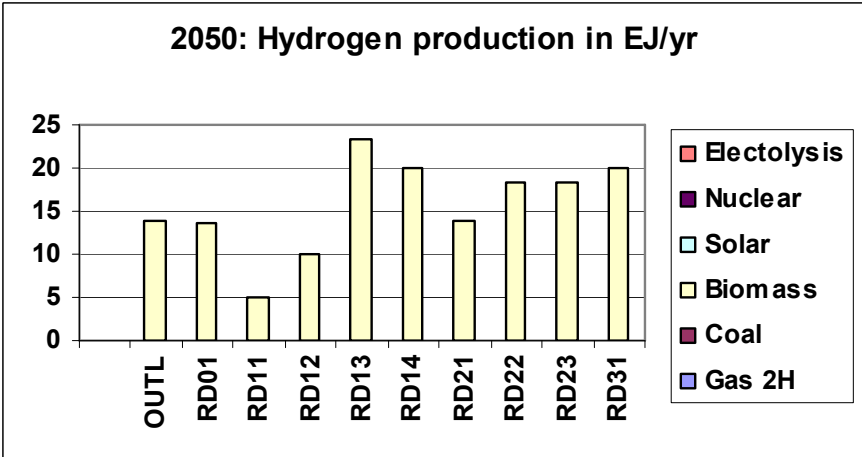


Figure D-193: Hydrogen Production by technology

Figure D-193 depicts the amount of hydrogen generated per case showing that biomass is the contributing technology mainly due to the carbon taxes introduced and the low costs assumed for biomass²⁶.

The share of hydrogen fuel cell in the overall mobility by car is given in the next Figure D-194 together with the share of stationary fuel cells in power generation. We clearly conclude that the cost data specifications for

²⁶ Running the model without carbon taxes we get mostly coal as the primary energy technology to contribute to hydrogen production.

stationary fuel cells are such that their penetration is obtained only when either a carbon or a gasoline tax is applied with minor penetration in the other cases. In the case of mobile fuel cells, the influence of policies is more evident while R&D policies that contribute to “Demand Pull” are more efficient than “Supply Push” policies which are not efficient at all. Important is the conclusion that what matters are policies and measures that either reduce primarily the price of fuel cells (or make the competitors more expensive) while the cost reduction in hydrogen production without a simultaneous change of the fuel cell cost is not sufficient to render HFC-cars competitive. Another important conclusion is that either under the Outlook R&D scenario or in all other scenarios without extra and dedicated R&D hydrogen fuel cells will not penetrate in the markets.

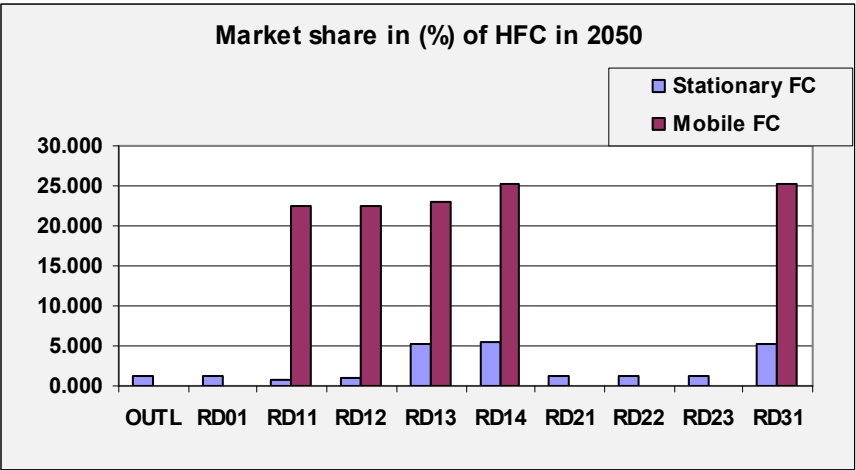


Figure D-194: Market shares of hydrogen fuel cells. In both markets the price of fuel cells makes them competitive

Finally, Figure D-195 presents the GDP development per storyline for the year 2050 and the induced economic losses or gains at that year. The overall economy increases output by more a factor of 3.5 relative to the output in the year 2000 while differences among scenarios due to R&D support for fuel cells are of some importance as shown in Figure D-195b.

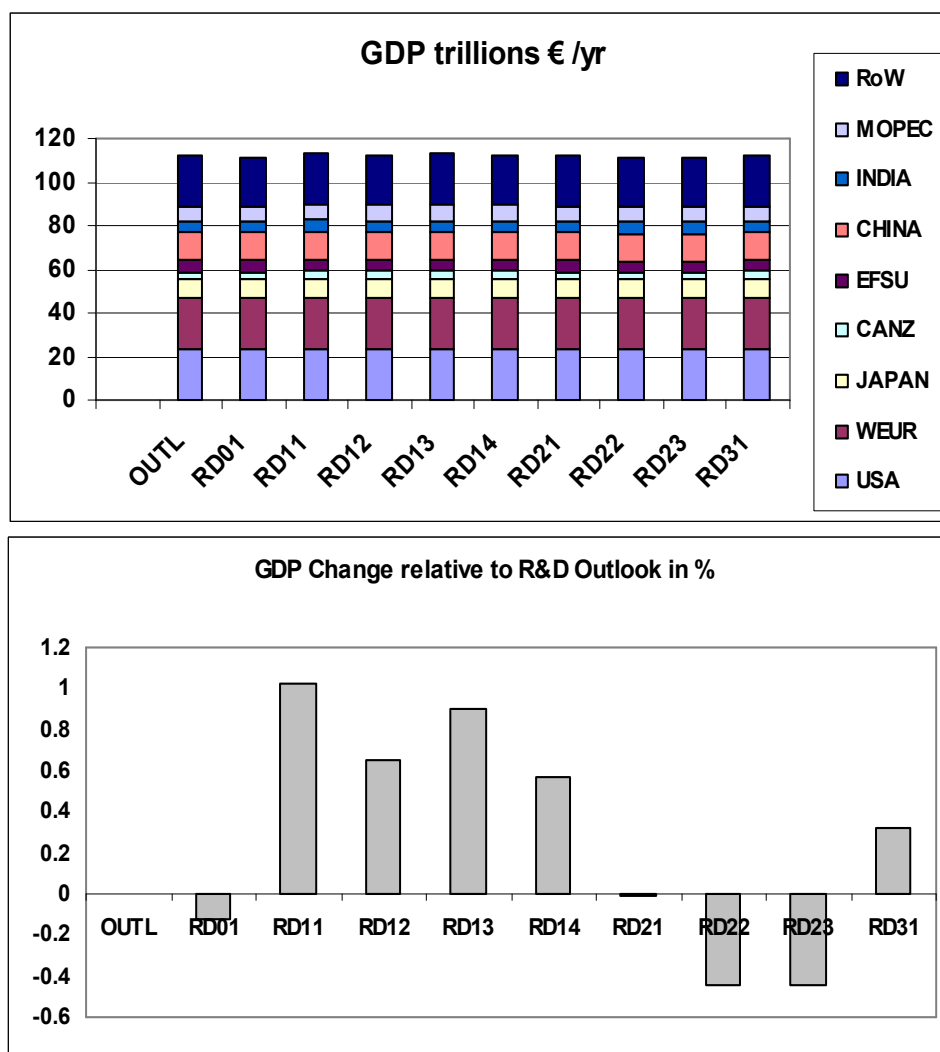


Figure D-195a and Figure D-196b (below): Economic output by case in 2050. The positive impacts of the tenfold R&D increase (i.e., RD11) in favour of HFC are around 1% while externality taxes reduce the benefit by 0.3%. Only when part of the tax revenue is used to support HFC systems and their infra-structures (i.e., RD13) the benefits are significant. R&D support of infra-structures is not efficient.

The Figures explain that the assumed technological progress in fuel cells has, as expected, a positive feed back to the overall economy (as energy becomes a cheaper production factor) and the level of impact is in the order of 1 percent. Notice that the tenfold increased of R&D spending is not taken into consideration to define the net GDP growth but it is in the order of 0.5% of the GDP in the period of 2007-2015, and falls afterwards to 0.05%, while our results refer to 2050. Finally, in the case of a tenfold increased R&D spending combined with gasoline tax and/or a carbon tax the GDP gains are in the order of 0.6 percent. This is not anymore the case when tenfold increased of R&D spending in favor supply technologies takes place where we get minor GDP losses. Notice also that these positive results in terms of economic development are consistent with the penetration of Hydrogen fuel cell systems.

Conclusions

On Model Development

MERGE-ETL includes now an electric and non-electric sector; road transportation; and hydrogen and synthetic fuel production while the energy system is linked to the macro-economic development and reflects the climate change impacts. The formulation of the transportation sectors is general enough such that it can be extended to other end-use sectors while the NLP formulation of LBD and LBS is quite efficient and well working algorithm when solved with CONOPT3.

R&D is either a decision variable or an exogenous scenario parameter such that policy simulations on learning subsidies and/or on R&D spending can be formulated.

Model development has been a quite difficult but successful, in spite that most of the methodology formulated in this project aims at the development of procedures for recursive dynamics models incorporating consumer's behavior algorithms and not for optimization models with perfect foresight like MERGE. Finally, after many efforts and versions developed, the best choice for the purpose of CASCADE-MINTS has been the version described by Figure C-20.

In this case production cost is split in three parts in the case of speculative technologies:

- the first part simulates the influence of dedicated R&D spending in favor of new technologies with LBS being the mechanism inducing cost reduction during the development phase of a technology
- the second part describes the combined effect of LBD and LBS using the TFLC and becomes active when technology begin its commercialization
- Finally, the part of the costs associated with the floor cost.

Each part of the cost assumes a different treatment in the model. The first two parts are non-linear while the third cost component can be expressed with a linear relation. This version of the model reproduces almost the same baselines for the R&D scenarios and the storylines and allows differentiating on the importance of different scenarios on R&D spending.

On Hydrogen Technology Diffusion

As expected, the ETL options reduce significantly the cost of technologies and this of CO₂ mitigation but in real world situations such developments will not take place without dedicated policies and measures, as e.g., learning investments, R&D support, internalization of externalities etc., that helps new and advanced technologies following their learning curves. The present version of the model allows estimating the efficacy of these measures and in quantifying some sustainability indicators.

The project has shown significant chances for the hydrogen economy to emerge as an alternative transportation system, if appropriate policies and measures are going to be followed supporting the system in

the phase of development and consolidation and in the initial phase of its commercialization. These conclusions are somehow optimistic as the underlying assumption in the overall analysis is that dedicated R&D spending for hydrogen fuel cells and hydrogen production technologies and infrastructures will eventually result to costs reductions and efficiency improvements as assumed by the TECHPOL-EURO2000 database.

Even when this development is realized and hydrogen technologies will become matured for commercialization by 2025, there are again policies and measures needed to help hydrogen technologies to become competitive in the long term markets. The conditions of success could be summarized as follows:

- HFC systems are competitive only when their capital cost can be significantly reduced but not when low hydrogen generation/infrastructure cost alone is attained.
- This reduction in HFC price can be first obtained by a dedicated and enhanced R&D (e.g., a tenfold enhancement in relation with the Outlook R&D) or by a policy of enhanced R&D combined with the endogenization of local or global externalities. The best option would be to use part of the tax revenue to support R&D and learning investments in favor of FC technologies. This mechanism will trigger LBD cost reduction and help the technology to become competitive in the markets.
- The penetration of such systems could also have positive overall economic impacts in the order of 1 percentage point of GDP growth.
- Without carbon mitigation policies cheap options of H₂-production are based on fossil fuels but with a carbon tax and/or high oil and gas prices, biomass becomes the preferable technology for hydrogen production.
- HFC cars, hybrids and eventually cars running on bio-fuels are in strong competition and need to model their systems-dynamics well for definite conclusions
- We expect that definite winners depend on specific market conditions based on regional circumstances and policies supporting technology developments and infrastructure build-up.
- Sensitivity and stochastic analyses is needed to verify conclusions
- Whatever the case, one should consider the work presented herein as a starting point towards a more detailed analysis of regionalized markets.

Appendix: Description of MERGE with Transportation and Hydrogen Production

MERGE defines demand for electric and non-electric energy based on a CES production function. The basic idea for MERGE-ETL is to separate the non-electric demand into demands for transportation (TRA) and the rest non-electric demands called, Non-TRA. Demands for transport are covered based on different competing car technologies (and fuels) to satisfy an exogenous set of demands. The market shares (defined as least cost optimization) of the car-types specify their final energy fuel use based on their efficiency (tank to wheel) and the type of primary fuels consumed (resource to tank) to generate the final energy. Electric cars

will increase the demand for electricity while demand for H2 to be consumed by FC cars will be produced in another market of processes that operate with fossil fuels, renewables, nuclear or via electrolysis. These explicit processes for H2 production will add to the primary energy use of the transport sector. The reference demands for mobility will be adjusted based on the income and price elasticity taking into consideration the marginal cost of demands by region and time during the external model loop on Negishi weights that balance inter-temporal trade²⁷. It follows a detailed mathematical description of the optimization problem.

SETS

r	world regions
t	time periods
et	electric technologies
nt	non-electric technologies
dm	demand categories
dmd	demand devices
prc	process converting energy
x	fossil fuel index
trd	index of traded goods
dle	set of electric technologies that decline
dln	set of non-electric technologies that decline
xle	set of electric technologies that expand
xln	set of non-electric technologies that expand
etl	set of electric technologies with learning
ntl	set of non-electric technologies with learning
trl/trn	set of electric technologies with learning/non-learning
tch	all technologies $tch = et \cup nt \cup dmd \cup prc$

Energy related variables

EC(rg,tp)	energy cost - trillion dollars
E(rg,tp)	electric energy
EN(rg,tp)	new electric energy
NREST(rg,tp)	on-electric energy minus transport

²⁷ For partial equilibrium we can apply the NLP relation simultaneously with the external Negishi iterations on weights. The relation

adjusts demands to price changes based on the relation $\frac{D(p_t, y_t)}{D(p_0, y_0)} = \left(\frac{y_t}{y_0}\right)^\alpha \cdot \left(\frac{p_t}{p_0}\right)^{-\sigma}$ with y_0 and p_0 being the output

by region and the price vector of demands for the starting year. Therefore the data needed to introduce partial equilibrium in the transport sector of MERGE include: The price and income elasticity σ and α ; the reference case economic output Y_0 ; and the reference prices P_0 at the starting year, and the new equilibrium points, for each region and time, i.e., the policy related prices P_t and the scenario's economic output Y , both defined based on the solutions of the MERGE model during the Negishi loop.

NTRA(rg,tp)	non-electric energy for transport
N(rg,tp)	non-electric energy
NN(rg,tp)	new non-electric energy
PE(rg,tp,et)	production of electric energy - kTWh
PN(rg,tp,nt)	production of non-electric energy – EJ
XT(rg,tp)	Activity of a transport technology - bvkm/yr
YT(rg,tp)	Cumulative activity of a transport technology - bvkm
XP(rg,tp)	Activity of a process technology (e.g., EJ)
YP(rg,tp)	Cumulative activity of a transport technology - EJ
GASNON(rg,tp)	gas consumed to meet non-electric demands
OILNON(rg,tp)	oil consumed to meet non-electric demand
RSC(rg,tp,x)	undiscovered resources
RSV(rg,tp,x)	proven reserves
RA(rg,tp,x)	reserve additions
GCAP(et,tp)	cumulative installations of electric relative to capo
GCAPN(nt,tp)	cumulative installations, non-electric relative to capon
EINV(et,rg,tp)	new investments in electric
NINV(nt,rg,tp)	new investments in non-electric
CLEV(rg,tp)	carbon emissions level billion tons
EXP(rg,tp,trd)	exports
IMP(rg,tp,trd)	imports
GCARBON(tp)	global carbon per period level
CLEV(rg,tp)	carbon emissions level - billion tons
CUM(rg)	carbon cumulative emission level - billion tons

The MACRO Sub-Model

Positive variables

K(rg,tp)	capital stock
KN(rg,tp)	new capital stock
Y(rg,tp)	production
YN(rg,tp)	new production
C(rg,tp)	consumption - trillion dollars
I(rg,tp)	investment - trillion dollars
NWEL	Negishi welfare
EC(rg,tp)	energy cost - trillion dollars

The ETA Sub-model; the transportation sector

VARIABLES

XE(dmd,rg,tp)	Mobility by technology DMD – 10^9 car-km/yr
YE(dmd,tp)	Accumulated mobility by technology - 10^9 car-km/yr
YEH(tp)	Accumulated mobility by H2 tech. - 10^9 car-km/yr
XH(prc,rg,tp)	H2 or methanol supply by process technology – PJ/yr
YH(prc,tp)	accumulated H2 or methanol supply – PJ/yr
NTRA(rg,tp)	non-electric energy for transport EJ/yr
OILTRA(rg,tp)	oil for transport
GASTRA(rg,tp)	gas for transport
H2TRA(rg,tp)	hydrogen for transport
ETRA(rg,tp)	electricity for transport
BIOTRA(rg,tp)	biofuel for transport
HCOTRA(rg,tp)	coal for H2
RENTRA(rg,tp)	solar for H2
H2NON(tp,rg)	H2 for non-electric non-transport markets
METNON(tp,rg)	methanol for non-electric non-transport markets
NREST(rg,tp,sw)	non-electric other than transport

Equations

DEM(rg,tp)	mobility supply-demand balance - bcarkm
DEC(rg,dmd,tp)	decline constraints dmd - bcarkm
EXPTRA(rg,dmd,tp)	expansion constraints dmd - bcarkm
YDF(dmd,tp)	definition of accumulated supplies - bcarkm
YDFH(tp)	definition of accumulated HFC cars-bcarkm
DemH2(rg,tp)	supply-demand balance for H2 in PJ
DemM(rg,tp)	supply-demand balance for methanol in PJ
DECH2(rg,prc,tp)	declining bounds for H2 production by process
EXPH2(rg,prc,tp)	expansion bounds for H2 production by process
YDFH2(prc,tp)	definition of accumulated supplies of H2 by process
shareh2(tp)	maximum fraction of demand by HFC
sharemet(tp)	maximum fraction of demand by Me-FC

Links to MERGE

NONTRA(rg,tp,sw)	balance the non-electric demands in EJ
BALTALL(rg,tp)	Primary energy balance in transport EJ
BALTOIL(rg,tp)	Primary energy balance oil in transport EJ
BALTGAS(rg,tp)	Primary energy balance gas in transport EJ

BALTH2(rg,tp)	Primary energy balance for hydrogen in transport EJ
BALTE(rg,tp)	Primary energy balance for electricity in transport EJ
BALTB(rg,tp)	Primary energy balance bio-fuels in transport EJ
BNDBIO(tp)	Bounds for total production in EJ
BALTHCO(rg,tp)	Primary energy coal balance of transport EJ
BALTren(rg,tp)	Primary energy renewables balance of transport EJ
TNDBALP(rg,tp)	Balance for T&D of Hydrogen pipeline H2 TNDBALL(rg,tp) Balance for T&D of Hydrogen trucks liquefied H2
TNDBALT(rg,tp)	Balance for T&D of Hydrogen trucks compressed H2

EQUATIONS

Objective: weighted sum of discounted utilities, or Negishi welfare function

NWELD:
$$NWEL = \sum_r w_r \cdot \sum_t udf_{rt} \cdot \log C_{rt}$$

New electric **NEWEELEC:**
$$EN_{r,t+1} = E_{r,t+1} - speed \cdot E_{r,t}$$

speed the speed of adjustment $speed = (1 - depr/100)^{YPP}$, at high depreciation rates of existing capital we need to invest more in new systems.

New non-electric:

NEWNON
$$NN_{r,t+1} = N_{r,t+1} - speed \cdot N_{r,t}$$

Total capital stock

TOTALCAP
$$K_{r,t+1} = KN_{r,t+1} + speed \cdot KN_{r,t}$$

The reallocation of primary production factors over time takes place for only the new capital stock.

NEWPROD
$$YN_{r,t} = (a_{rt} \cdot KN_{rt}^{\rho\alpha} \cdot LN_{rt}^{(1-\alpha)\rho} + b_{rt} \cdot EN_{rt}^{\rho\beta} \cdot NN_{rt}^{(1-\beta)\rho})^{1/\rho}$$

Total Production:

TOTALPRO
$$Y_{r,t+1} = YN_{r,t+1} + speed \cdot Y_{r,t}$$

Consumption: Competing claims on resources include consumption, investment, energy costs and net exports of the composite numéraire good. New is the annual R&D spending (only for the version where R&D is endogenous)

CC:
$$Y_{r,t} = C_{r,t} + I_{r,t} + EC_{r,t} + EXP_{nmr,rt} + R \& D_{rt}$$

Terminal conditions:

TC:
$$I_{r,T} = KN_{r,T} \cdot (grow_{r,T} + 1 - speed_{r,t})$$

grow is the potential growth rate of an economy and

speed the speed of adjustment

New capital

$$\mathbf{NEWCAP:} \quad KN_{r,t+1} = 0.5 * ypp \cdot speed_{rt} \cdot I_{r,t} + 0.5 * ypp \cdot speed_{rt+1} \cdot I_{r,t+1}$$

Trade balance of numéraire

$$\mathbf{TRDBAL:} \quad \sum_r EXP_{rt}^{nmr} = 0.0$$

Non-electric energy is now split to the “rest non-electric” and for transport

$$\mathbf{NONTRA} \quad N_{rt} = NTRA_{rt} + NREST_{rt}$$

N_{rt} is defined in the production function; $NTRA_{rt}$ is the exogenous primary energy use for transport (e.g., for road car transport) adjusted to GDP and price changes while $NREST_{rt}$ is the non-transport and non-electric demand defined in ETA.

Demand balance in transport:

$$\mathbf{DEM} \quad \sum_{dmd} XE_{dmd,rt} \geq D_{rt}$$

Demand D_{rt} is the exogenous baseline demand (in billion car-km per year based on A. Schafer) adjusted to price changes and income during the Negishi loop.

BOT / BGT/BCT/BRNT: Supply balance equations for oil, gas, coal, and renewables for transport demands (as hydrogen, methanol and electricity are secondary fuels they are not balanced as part of NTRA, which is the primary energy use in transport, while the corresponding fossil or renewable energy needed to produced them, is properly balanced. DMD is the set of end use devices, DM the set of demand categories explicitly defined in MERGE, e.g., cars for road transport, in our case. Notice that the formulation of the end use markets is general enough and be extended to all other end-use markets, if desired, by extending the model to the proper input specifications defining demands and competing technologies by market.

$$\begin{aligned} OILTRA_{rt} &= \sum_{DMD \in DM} XE_{DMD,rt} / eta_{DMDrt} \cdot ma_{dmd2oil} \\ GASTRA_{rt} &= \sum_{DMD \in DM} XE_{DMD,rt} / eta_{DMD,rt} \cdot ma_{dmd2gas} + \sum_{PRC} XH_{prc,rt} / eta_{prc,rt} \cdot ma_{GSAS2prc} \\ HCOTRA_{rt} &= \sum_{PRC} XH_{prc,rt} / eta_{prc,rt} \cdot ma_{HCO2prc} \\ BIOTRA_{rt} &= \sum_{PRC} XH_{prc,rt} / eta_{prc,rt} \cdot ma_{BIO2prc} \\ RENTRA_{rt} &= \sum_{PRC} XH_{prc,rt} / eta_{prc,rt} \cdot ma_{REN2prc} \end{aligned}$$

BALTALL Balance of primary energy used in transport

$$NTRA_{rt} = OILTRA_{rt} + GASTRA_{rt} + HCOTRA_{rt} + BIOTRA_{rt} + RENTRA_{rt}$$

BALE Balance of electricity used in transport (demand for electricity)

$$ETRA_{rt} = \sum_{DMD \in DM} XE_{DMD,rt} / eta_{DMD,rt} \cdot ma_{dmd2ele} + \sum_{PRC} XH_{prc,rt} / eta_{prc,rt} \cdot ma_{ele2prc}$$

SUPELEC Definition of electricity demand to supply balance

Electricity produced by different technologies balance electric demands and demand for electric transport and electricity spent for hydrogen production.

$$\sum_e PE_{e,r,t} \geq E_{r,t} + ETRA_{rt}$$

We also define cumulative activities for each transportation technology and process as well as their knowledge stock (i.e., the accumulated but depreciated R&D spending by technology). Also, expansion and declining rates are defined for each technology.

SUPLNON Supply of energy for $NREST_{rt}$ demands

Oil non-electric use, gas non-electric, coal direct use, synthetic fuel, and renewables are perfect substitutes of non-electric demands. One could also define the use of Hydrogen and Methanol to satisfy demands for $NREST_{rt}$ but this option is not followed now.

$$NREST_{rt} = OILNON_{rt} + GASNON_{rt} + PN_{CDU,rt} + PN_{synth,rt} + PN_{renew,rt} + PN_{BDU,rt}$$

DEMH2 Hydrogen supply equals consumption for stationary HFC for production of electricity and for mobile HFC transport.

$$\sum_{prc \in H2} XH_{prc,rt} \cdot eta_{prc,rt} = \sum XE_{DMD,rt} \cdot ma_{dmd2H} / eta_{DMD,rt} + 1000 \cdot hr_{HFC} \cdot PE_{HFC}$$

DEMM Methanol supply equals consumption for MFC for transport

$$\sum_{prc \in M} XH_{prc,rt} \cdot eta_{prc,rt} = \sum XE_{DMD,rt} \cdot ma_{dmd2M} / eta_{DMD,rt}$$

SUPGAS total supply of gas in a region and net imports are greater than consumption for electric and non-electric use and for hydrogen production or for direct transportation.

$$\sum_{gasx} PN_{gasx,rt} + IMP_{gas,rt} - EXP_{gas,rt} \geq \sum_{Gas} hr_{EGas} \cdot PE_{Gas,rt} + GASNON_{rt} + GASTRA_{rt}$$

SUPOIL Oil supply greater than of oil for electric, non-electric use and transport direct use

$$\sum_{oilx} PN_{oilx,rt} + IMP_{oil,rt} - EXP_{oil,rt} \geq \sum_{Oil} hr_{Oil} \cdot PE_{Oil,rt} + OILNON_{rt} + OILTRA_{rt} / \eta_{ref}$$

SUPCOAL Coal supply greater than coal for electricity production, synthetic fuel, hydrogen and for direct use

$$PN_{coal,rt} \geq \sum_{Ecoal} hr_{Ecoal} \cdot PE_{Ecoal,rt} + PN_{synth,rt} / \eta_{synth,rt} + HCOTRA_{rt} + PN_{cldu,rt}$$

SUPBIO Biomass for electricity production, synthetic oil fuel, methanol, hydrogen and direct use

$$PN_{bio,rt} \geq \sum_{Ecoal} hr_{bio} \cdot PE_{bio,rt} + PN_{synth,rt} / \eta_{synth} + BIOTRA_{rt} + PN_{BDU,rt}$$

GFRAC Gas fraction of non-electric energy

$$GASNON_{rt} + GASTR_{rt} + G2H_{rt} \leq 0.5N_{rt}$$

GFRACE gas fraction of electric energy

$$\sum_{EL \subseteq GAS} PE_{EL,rt} \leq gasfr \cdot E_{rt}$$

SYNTH synthetic fuel exports cannot exceed domestic production.

$$EXP_{rt,synth} \leq 0.5N_{synth,rt}$$

GROWTHE cumulative production of electricity,

$$YE_{jt} = YE_{j,t-1} + PE_{jt} \cdot ypp$$

GROWTHN cumulative production of non- electric with learning

$$YN_{jt} = YN_{j,t-1} + PN_{jt} \cdot ypp$$

DECE Declining dynamic adjustment constraints of electric technologies

$$PE_{dle,r,t+1} \geq PE_{dle,r,t} \cdot decfr^{10}$$

DECN Declining dynamic adjustment constraints of non-electric technologies

$$PN_{xln,r,t+1} \geq PN_{dln,r,t} \cdot decfr^{10}$$

EXPP Expanding dynamic adjustment constraints of electric technologies

$$PE_{xle,r,t+1} \cdot nxpf^{10} \geq PE_{dle,r,t} \cdot decfr^{10}$$

NXPP Expansion rate of non-electric technologies

$$PN_{xln,r,t+1} \cdot nxpf^{10} \geq PN_{xln,r,t} \cdot decfr^{10}$$

EXPPETL Diffusion dynamic adjustment constraints of electric technologies with learning

$$PE_{etl,r,t} \leq sf E_{r,t} + er^{10} PE_{etl,r,t-1} + (\sum_r er^{10} PE_{etl,r,t-1}) * gdf$$

sf is a low seed value parameter, Er the energy demand of region r , er the annual expansion rate and gdf a global diffusion factor reflecting regional spill-over effects.

Similar expression is defined for the non-electric technologies:

EXPPNTL expansion rate of non-electric technologies

$$PN_{ntl,r,t} \leq sf \cdot N_{r,t} + er^{10} \cdot PN_{ntl,r,t-1} + \left(\sum_r er^{10} \cdot PN_{ntl,r,t-1} \right) \cdot gdf$$

RSCAV Undiscovered resources available: Changes in the remaining undiscovered resources (RSC) available are defined as a distributed lag-function of reserve additions, RA:

$$RSC_{r,x,t+1} = RSC_{r,x,t} - 5(RA_{r,x,t} + RA_{r,x,t+1})$$

RSVAV Proven reserves available:

Reserves available RSV, are defined as a distributed lag function of reserves additions less production of exhaustible resources.

$$RSV_{r,x,t+1} = RSV_{r,x,t} + 5(RA_{r,x,t} - PN_{r,x,t}) + 5(RA_{r,x,t+1} - PN_{r,x,t+1})$$

RDFLIM Resource depletion limit: additions are a fraction of remaining reserves

$$RA_{r,x,t} = rdf_{x,r} \cdot RSC_{r,x,t}$$

PRVLIM Production-reserve limit: Production is a fraction of proven reserves

$$PN_{r,x,t} = pfr_{x,r} \cdot RSV_{r,x,t}$$

CARLEV carbon emissions level is related to electric, non-electric and transport energy use times the carbon coefficients per unit of energy, adjusted for the trade balance of fuels.

$$CLEV_{r,t} = \sum_e PE_{r,e,t} \cdot ce_{r,e,t} + TRA_{r,t,fuel} \cdot ce_{fuel} + \sum_n PN_{r,n,t} \cdot ce_{r,n,t} + (EXP_{fuel} - IMP_{fuel}) \cdot ce_{fuel}$$

ANC regional annual carbon limit constraint

$$CLEV_{r,t} + (EXP_{crt,t} - IMP_{crt,t}) \leq carlm_{r,t}$$

CUM cumulative emission level

$$CUM_r = \sum_t \left(\sum_e PE_{r,e,t} \cdot ce_{r,e,t} + \sum_n PN_{r,n,t} \cdot ce_{r,n,t} + TRA_{r,t,fuel} \cdot ce_{fuel} + (EXP_{fuel} - IMP_{fuel}) \cdot ce_{fuel} \right)$$

CUMLEV cumulative global carbon constraint $\sum_r CUM_r \leq cumclm$

TRDBAL global trade balance $\sum_r EXP_{trd} - \sum_r IMP_{trd} = 0.0$

CARBSTO cumulative carbon storage less than $MaxSEQ$ (in Gt of Carbon); $frrem_{jrt}$ is the removal fraction of CO2 emissions $ECO2_j$ by technology (e.g., 90%)

$$\sum_{r,t,j \in CCS} ypp_{r,t,j} \cdot (PE_{rtj} \cdot frrem_{jrt} \cdot ECO_{2j} \leq \text{MaxSEQ}$$

COSTNRG

Annual cost of energy in region r, and period t:

- The first line refers is the cost per Km (excluding energy resource cost);
- The second line refers to the electric generation cost, the non-electric resource cost or the non-electric production cost and the cost differential of gas to oil for transport via pipelines;
- The next line is the cost due to sequestration cost for power generation and processes;
- the fourth line refers to cost of processes (excluding fuel cost)
- the last one is the learning part of the cost for all ETL technologies.

$$\begin{aligned} EC_{r,t} = & \sum_j XE_{j,r,t} \cdot CS\_NETL\_Km_{j,r,t} \\ & + \sum_e PE_{r,e,t} \cdot ecst_{r,e,t} + \sum_n PN_{r,n,t} \cdot ncst_{r,n,t} + \sum_{trd} EXP_{trd} \cdot cexp_{trd} + GASNON_{r,t} \cdot ogpd_r + \\ & Cseq \cdot (PE_{rt}^{GAS-A} \cdot frm^{GAS-A} + PE_{rt}^{IGCC-A} \cdot frm^{IGCC-A} + \sum_{PRC} X_{PRC,rt} \cdot Cseq \cdot frm^{prc} \\ & + \sum_{PRC} X_{PRC,rt} \cdot GC_{PRC,rt} + \\ & \sum_{j \in (ETL)} X_{j,r,t} \cdot \left(\frac{ILC_j \cdot CRF}{LF_j} \right) \cdot \left(\frac{CP_{j,t}}{CP_{j,0}} \right)^{-\beta_j} \cdot \left(\frac{KS_{j,t}}{KS_{j,0}} \right)^{-\gamma_j} \end{aligned}$$

The **linear part of the costs** parameters in the model is discussed taking as example the transport sector as similar relations are valid for other sectors. The cost is calculated according to the following equation:

$$CS\_NETL\_Km = \left(\frac{P_{Tech} \cdot CRF + FIXOM_{Tech} + VAROM_{Tech}}{AM_{Tech}} + \frac{F_{Tech}}{E_{Tech}} \right)$$

Where:

CS_NETL_Km	Cost of travelling e.g., part w/o learning [USD/1000v-km]
CRF	Capital recovery factor
P	Vehicle purchase cost that does not undergo learning [USD]
AM	Technology specific annual km travelled (in thousand)
FIXOM	Technology specific annual fixed costs (insurance, road tax)
VAROM	Technology specific annual variable costs associated with travelling of the annual mileage (services, maintenance checks, tires, etc.)
FD	Fuel delivery costs (USD per GJ)
E	Fuel efficiency of a specific technology (1000 v-km/GJ)

D.4.2.6 PROMETHEUS

[by N. Kouvaritakis and V. Panos (ICCS-NTUA)]

The implementation of many future policy scenarios presents a number of conflicts with the very nature of the PROMETHEUS stochastic model: the model assumes that future policies such as fuel taxation, subsidies and climate mitigation are a priori unknown and subject to random variation often in response to a signal (such response also is subject to uncertainty). Likewise technological progress is assumed to be an uncertain process. For these reasons the technology story scenarios and the policy combinations, introduced in chapter D.3.1 and implemented using the deterministic models, were not evaluated by PROMETHEUS.

On the other hand PROMETHEUS is equipped with a very detailed stochastic technology dynamics module, notably linking R&D directed at a great variety of options and technology improvement see C.1.2 and C.2.7. In this way PROMETHEUS is particularly well suited for evaluating the R&D scenarios. In order to reconcile these scenarios with the general notion of PROMETHEUS that future policy is unknown their implementation must be viewed as a conditional evaluation: i.e. how are the probabilistic prospects of hydrogen technologies affected assuming that R&D is increased tenfold. This assumption may be reasonable in the PROMETHEUS context if it implies additional effort in the short term (as is the case with the R&D scenarios that had a horizon to 2015). Apart from the pure R&D scenarios, variants involving additional supportive policies (taxes and subsidies) have been defined within CASCADE MINTS and implemented using the deterministic models. Such variants imply a shorter term additional R&D effort and longer term implementation of the additional policies. Though, as mentioned above, PROMETHEUS is unsuitable for evaluating longer term policies (which in themselves are highly uncertain) it has been thought worthwhile to include some of them in the PROMETHEUS exercises in order to attempt a stochastic evaluation of the relative efficacy of R&D compared to other more direct policies. In the discussion that follows emphasis is placed on the pure R&D scenarios, while the variants are treated in a more summary fashion. Naturally the best use of PROMETHEUS in the context of R&D policy evaluation is to concentrate on the effect of R&D in reducing technological risk and improving the probability of success of different technological options. The discussion, therefore, focuses on probability results.

Table D-66 summarises the results of the R&D scenarios and variants introduced above for the world and the year 2050. The figures in italics represent the upper five percentile (the share that is exceeded with 5% probability). The other figures refer to median shares. It should be reminded here that neither the median nor the percentiles are additive.

According to the results, R&D has a major impact on the prospects of fuel cell vehicles. Their median share in the world vehicle parc more than doubles following the early tenfold increase in R&D. The tax on competing fuels also produces a considerable additional shift and has a particularly marked impact on the upper five percentile. Recycling of the tax to enhance R&D produces another ten point increase in the median but the impact on the upper five percentile is much smaller because under this scenario the shape of the distribution has shifted from right skewness to left skewness as a certain amount of saturation sets in. R&D in production

technologies produces insignificant results, while the additional tax results in a small (compared to the FC R&D case) increase in the share but a large jump in the percentile from 25 to 43 percent. This is mainly due to the fact that the prospects for fuel cells in this scenario remain uncertain (relatively high probabilities of technology failure) while at the same time in cases of success higher prospects are provided by the induced substitution resulting from enhanced competitiveness due to the tax. The provision of free infrastructure leads to big increases for both the median and percentile, while the combined case constitutes effectively a transition of the world road transport towards hydrogen (probability of a share larger than 50%: 89%). Hydrogen ICE vehicle penetration is negatively affected by R&D on fuel cells. However, tax discrimination boosts them sufficiently to neutralise this negative impact. Tax recycling towards R&D also favours slightly H2 ICE vehicles to the extent that the R&D is directed to infrastructure and especially on-board hydrogen storage. The provision of hydrogen infrastructure as a public good (free of charge) has a major impact on H2 ICE vehicles. This impact is particularly noticeable on the upper five percentile, which in the S1.3 scenario stands above a 40% share. This is mainly due to the cases where fuel cells effectively fail and most of the benefit of low delivered hydrogen prices is absorbed by ICE hydrogen applications.

Table D-68: Summary results from R&D scenarios (World, 2050)

Hydrogen penetration index	Baseline	No R&D in H2 related techs	10x R&D in Fuel Cells (FC)	10xR&D in FC & TAX in road transport	10xR&D in FC & TAX & recycling of TAX	10xR&D in H2 production techs	10xR&D in H2 production techs & TAX in road transport	10xR&D in H2 production techs & TAX in road transport & free infr.	Combined case
% Share of fuel cell vehicles in vehicles parc									
Median	9.6	0.0	22.6	35.1	45.1	10.2	14.9	25.7	63.2
Upper 5%	24.0	0.0	43.9	62.3	67.3	25.4	43.1	57.4	72.8
% Share of H2 ICE vehicles in vehicles parc									
Median	4.2	3.1	3.4	5.3	6.1	4.6	6.8	13.4	11.5
Upper 5%	6.4	4.1	5.9	9.6	10.4	7.2	14.8	41.2	19.0
% Share of elec. from fuel cells in final elec. demand *									
Median	1.9	0.1	5.0	6.7	10.6	2.0	2.0	9.4	24.6
Upper 5%	6.5	0.8	18.4	23.7	25.5	7.3	14.0	23.1	33.1
% Share in non-electric final demand**									
Median	1.4	0.1	3.6	4.9	7.3	1.5	1.5	7.0	17.3
Upper 5%	5.4	0.6	15.9	19.3	20.8	6.1	11.3	19.5	25.8
% Share of potential index									
Median	3.7	1.2	5.6	9.0	12.5	4.0	5.7	17.5	26.1
Upper 5%	8.4	1.9	19.9	24.9	26.2	9.3	18.8	34.3	34.9

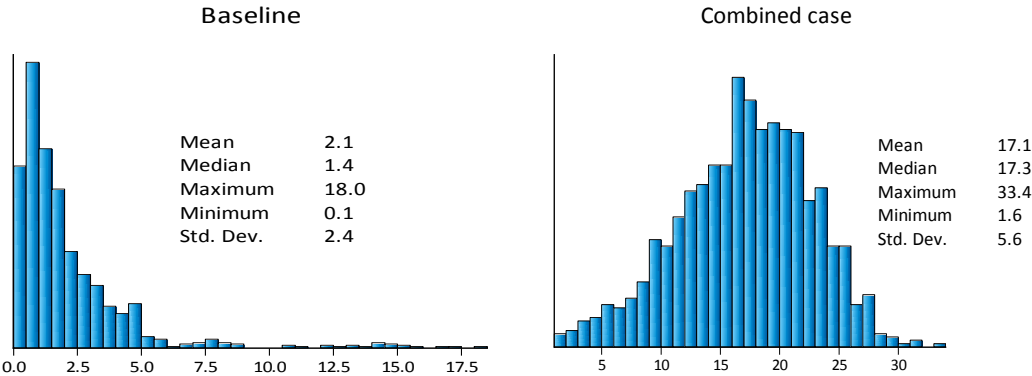
* Final demand in industry, residential and commercial sectors

** Share of heat and steam from fuel cells in non electric final demand in industry, residential and commercial sectors

R&D on fuel cells also affects the prospects of stationary applications, although their penetration in the electricity and heat market is smaller compared to road transport. The tax discrimination in favour of road transport uses of hydrogen spills over to the stationary applications (the upper five percentile shifts from 18 to 24 percent of total electricity production). This is due to improved availability of hydrogen in general. This

effect is particularly marked when the tax is recycled to infrastructure (median shares increase about 1.5 times). Such spill-over effects are particularly pronounced in the cases that do not involve additional R&D for fuel cells. This is especially noticeable in the case involving just the road transport tax, when median values for stationary applications do not shift while the upper percentile almost doubles. The combined case scenario has a very strong impact on median share values for stationary fuel cells (more than tenfold increase from baseline). At the same time, it changes completely the shape of the distribution: when as in the baseline it is positively skewed it becomes negatively skewed for the scenario (see Figure D-197). A distribution of a share shifting in this fashion suggests the beginnings of maturity (and this despite the still relatively low shares).

Figure D-197: Distribution of the share of heat and steam from fuel cells in non electric final consumption (World, 2050)



The discussion above examined the impact of the scenarios on hydrogen prospects in different markets. The heterogeneity of these markets and the very high efficiencies of fuel cells create some problems for an overall aggregation of results. In order to obtain such an overall assessment a special index is used: percent share of potential index. The potential is calculated by hypothetically assuming that all useful energy demand for categories that are susceptible to substitution by hydrogen was met by this energy vector. In this way, the ratio to this potential gives an indication of overall success for the hydrogen economy. It is worth noting that although R&D and the additional measures produce a clear tendency for improvement of the prospects as measured by this index, even in the combined case its median value only stands at 26% with an upper five percentile of around 35%. Measures specifically directed at the road transport sector fare relatively worse than those involving interventions on the infrastructure.

Figure D-198: Probability of hydrogen penetration levels

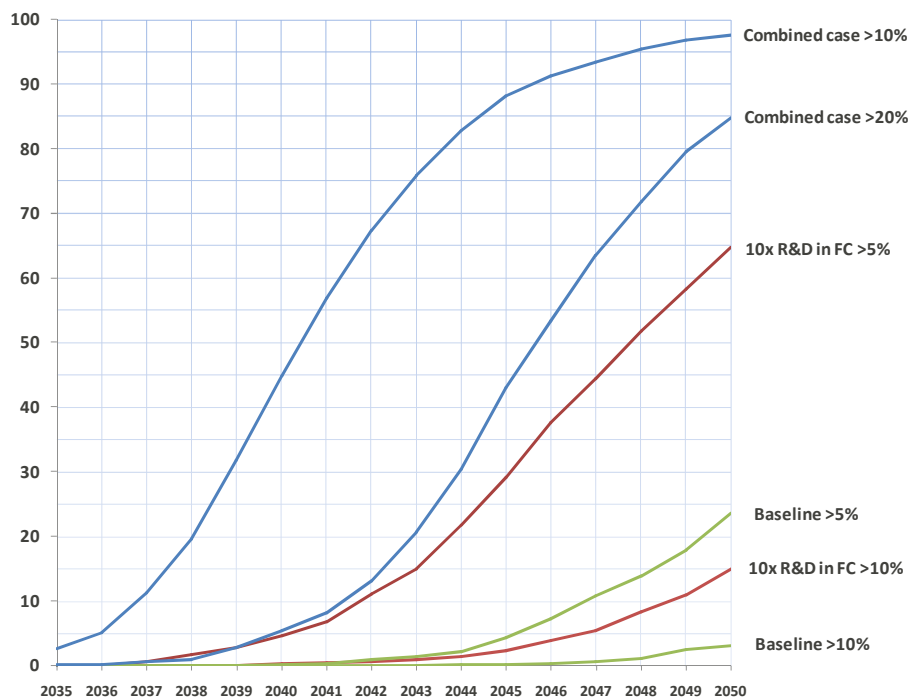


Figure D-198 gives the time profile of probability prospects in terms of the percent share of potential index. The benchmarks examined are the 5 and 10 percent levels for the baseline and tenfold increase in R&D directed to fuel cells scenario, and the 10 and 20 percent levels for the combined case. It is worth noting that probabilities of this index reaching any of these benchmarks for any of the scenarios are very small or virtually zero before 2035. After that date the chances of the index exceeding 10% improve rapidly for the combined scenario (it should be remembered here that these are conditional probabilities, assuming that all the additional policies and measures are in place worldwide; this in itself is a highly unlikely occurrence). In the tenfold increase of R&D in fuel cells case, prospects for exceeding a 5% value improve sharply around 2045 and become more than even by the end of the decade. However, under this scenario the probability of the index exceeding 10% is still only 15%.

An overall examination of Figure D-198 additionally points to another feature that has emerged constantly in the modelling work undertaken in the CASCADE MINTS project and in particular work undertaken using the PROMETHEUS model: the lags involved between R&D action and technological improvement, between the latter and technology take-up and the inertia implied by capital stock turnover mean that the time dimension becomes a key element in the assessment of the prospects for a hydrogen economy. In other words under any scenario, as for example the baseline, prospects tend to improve with time (e.g. the probability that the percent share of potential index will exceed 5% is virtually nil in 2040 but gets close to 20% in 2050). This leads to an alternative way of looking at the impact of scenarios by examining their effect on bringing forward developments.

Figure D-199: Forcing the pace by additional R&D: % share of fuel cell cars in vehicle parc in World

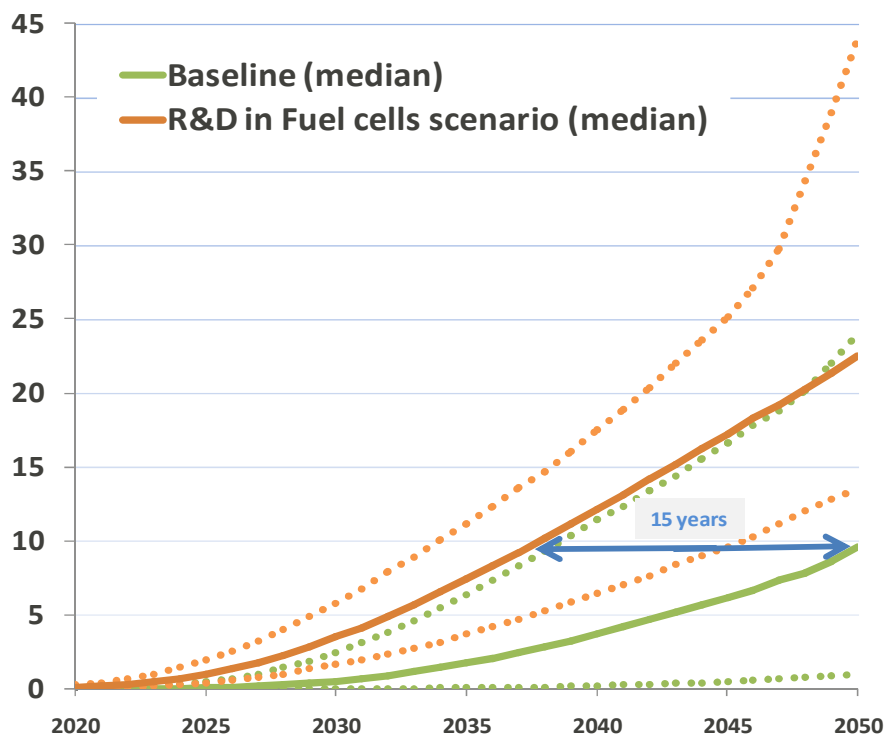


Figure D-199 plots the median value and upper and lower five percentiles of the share of fuel cell cars in the world vehicle parc for the baseline and tenfold increase of R&D in fuel cells scenarios. According to these results the additional R&D of 170 billion €05 directed towards fuel cell technologies brings forward the median penetration rate of 10% (baseline) by about 15 years. On the other hand the probability of exceeding 20% in the R&D scenario is only 5% in the early 40's – which is about the same probability applying for the baseline in the late 40's. These results seem to suggest that R&D can drastically bring forward the more modest developments but given the considerable inertias of the system are less likely to have the same effect on breakthroughs.

In general the scenario involving the tenfold increase in R&D directed to hydrogen production technologies has resulted in trivial variants of the baseline scenario. This is due to the relatively poor prospects for improvement of the technical and economic characteristics of most of these technologies but also to a large extent to the low importance of hydrogen production costs as a constraint for the penetration of hydrogen technologies in the energy system (see Figure D-81: Relative importance of hydrogen production cost variability for hydrogen penetration variability (Europe, 2050) in PROMETHEUS BASELINE SCENARIO)

The no R&D to hydrogen related technologies scenario has naturally resulted in insignificant contributions of hydrogen over the whole period with perhaps the exception of H₂ ICE vehicles the prospects of which depend more on urban pollution policies than on technological improvements. This lack of progress underscores the importance of R&D, and especially R&D on fuel cells at the early stages, in enabling, facilitating and accelerating the introduction of hydrogen technologies.

It is clear from the analysis carried out using PROMETHEUS but also throughout the CASCADE MINTS Part I project that the eventual success of the hydrogen economy hinges on a dramatic improvement in the technical and economic characteristics of fuel cells and such an improvement is highly dependent on adequate R&D effort directed towards the various aspects of this technology. On the other hand, the size and timing of such effort will depend on a host of factors and their interaction, a full analysis of which goes beyond the scope of the CASCADE MINTS project.

On the other hand, PROMETHEUS results can go some way in investigating the role of R&D budget size and the “efficacy” of R&D effort. Before such analysis can proceed a measure of “efficacy” must be devised in a way that it corresponds broadly to the main objectives of the R&D undertaken. On average, in the last 30 years 70% of R&D on fuel cells has been financed by the business sector. The CASCADE MINTS outlook implies broadly the maintenance of this share in the future. Naturally the main motivation of business R&D is the prospects for future sales of technologies. This preoccupation with future sales can be both offensive (i.e. creating new markets for technologies) and defensive (ensuring that in case of success of a particular option a company would not lose market share by failure to diversify). Given the preponderance of such preoccupations it is appropriate to build an R&D “rate-of-return” index combining the discounted future flow of sales and the discounted R&D outlays. The choice of a discount rate poses particular problems especially when R&D decisions are considered. In usual business practice the discount rate utilised depends on returns on risk free alternatives and the amount of risk involved in the particular investment. R&D is usually a very risky investment and would normally be evaluated using a high discount rate. On the other hand, PROMETHEUS is capable of generating risk information. This means that a “reasonable” discount rate can be used for calculating the RoR and subsequently it is possible to examine explicitly risks of failure to reach specific benchmarks associated with the R&R (however defined). This leads to a second problem with this type of analysis: the choice of appropriate benchmarks. In classical investment analysis profits on sales rather than total sales would constitute the benefit component of the RoR calculation. It is very hard to establish what future rates of profit would be appropriate on technologies that do not even have a market at present. In any way a lot will depend on future market structure (the degree of oligopoly). It is clear, however, that the profit rate would normally be a relatively small fraction of sales (say from about 8% to about 25%). In the case of defensive R&D strategies, very low benchmarks become acceptable because the issue is no longer profitability but risk of loss.

For the purposes of the assessment of the efficacy of R&D investment in PROMETHEUS a “normal” discount rate of 6%+a risk free real rate-of-return has been used. The notion of risk free in a stochastic model like PROMETHEUS is very relative; usually long term real interest rates are used for such calculations since they come closest to low risk return on bank deposits. However, even long term real interest rates vary over time and in PROMETHEUS their variation is explicitly taken into account. In this sense, it can be said that the discount rate chosen is, on average, 8% but is subject to random variation. Concerning the benchmarks, PROMETHEUS is capable of producing results for a number of them, but the analysis carried out below concentrates on the values of 6, 10, 20 and 60. Their appropriateness to particular decisions will depend on the decision context and the choice is best left to decision makers. In summary, the RoR index chosen is

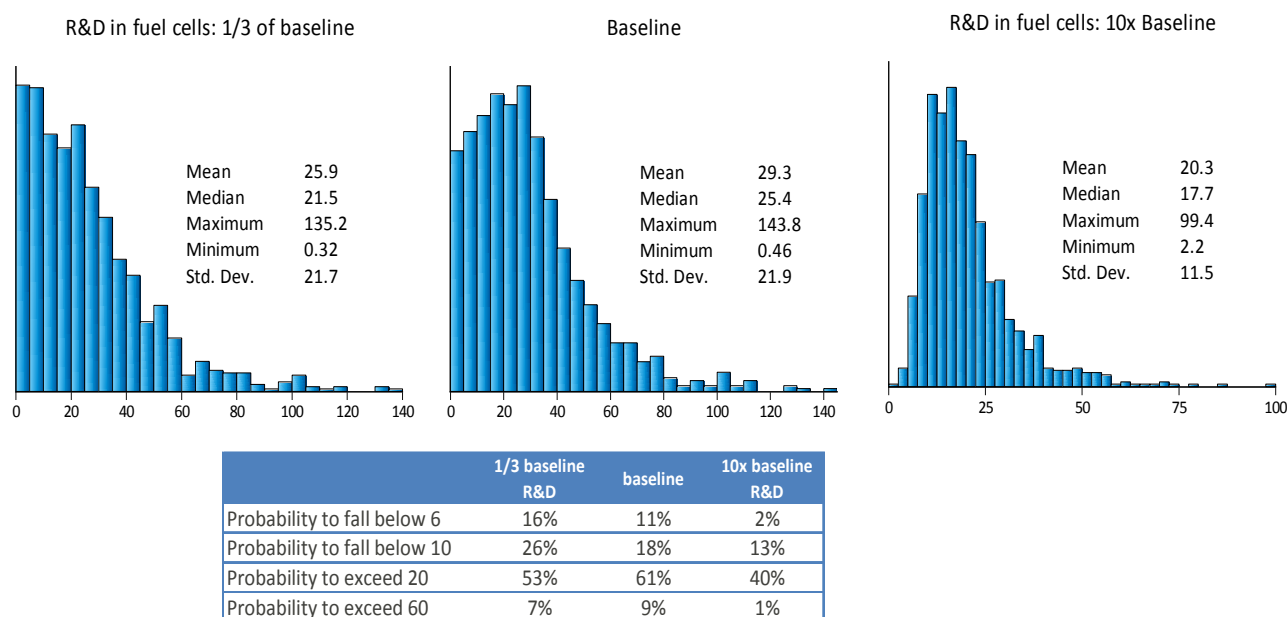
defined as follows:
$$RoR = \frac{\text{Cumulative\_discounted\_sales}_{from 2005 to 2050}}{\text{Cumulative\_discounted\_RD\_outlays}_{from 2005 to 2050}}$$

The baseline scenario naturally incorporated R&D on fuel cells throughout the forecast horizon 2005-2050. In order to carry out the efficacy assessment the D1.1 scenario involving tenfold increase in R&D in fuel cells in the period 2007-2015 used to examine the impact of an increase R&D effort. In order to complete the assessment an additional scenario was evaluated involving a postponement of R&D: it assumes that over the period 2007-2015 R&D on fuel cells will stand at 1/3 of the baseline values.

Figure D-200 summarises the results obtained on the RoR as defined above for all three scenarios. The lower R&D scenario performs worse than the baseline on almost every count: it has lower mean and median RoR and appears to display higher risks of failure with lower probabilities of a breakthrough. This result suggests that postponing efforts is not an effective R&D strategy.

Figure D-200: Effectiveness of R&D in fuel cells

Probability distribution of the ratio of discounted* technology sales and R&D expenditures



* discount rate: Real interest rate + 6%

On the other hand the comparison of the ten times baseline R&D to the baseline scenario produces a more mixed picture. It implies a considerable drop in mean and median RoR (they are even lower than in the low R&D scenario). This would suggest decreasing returns to additional R&D effort. At the same time, the standard deviation of the high R&D scenario is almost half the baseline value. As a result the risk of serious failure is drastically reduced, while even the probability of obtaining no better than a mediocre return (less than 10) is lower (13% instead of 18%). At the other extreme, the probability of very big returns is much

lower. The shapes of the probability density functions (p.d.f.) in Figure D-200 underpin these findings. The low R&D p.d.f. has a mode close to zero and is very heavily skewed to the right. For the baseline the mode shifts close to the mean and median, but the p.d.f. remains markedly skewed to the right. In the high R&D case a second tail at the low end emerges implying much lower probabilities of failure. At the same time the distribution becomes more concentrated around the mean, median and mode, which get closer to each other suggesting a movement towards symmetry.

E. References

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