Design of a European sustainable hydrogen model

Model structure and data sources

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Abstract
This report presents a modelling tool to evaluate the performance of presently proposed hydrogen technology chains, including the stages of production, infrastructure and end-use, in a range of future worlds. The employed modelling methodology allows for analysing the impact of different trajectories of global price and availability of fossil fuels and the impact of varying levels of ambition regarding climate change control. Moreover, it enables studying the hydrogen technology performance improvements required to compete with alternative technology chains involving fuels and electricity that do not use hydrogen as main energy carrier.

The report summarises the challenges in exploring the perspective for hydrogen technology chains, and describes the essentials of the model tool that was chosen and further developed for this project, including relevant data specifications. Finally, It also discusses our implementation priorities and challenges for further development.

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1. Introduction

This report has been published in partial fulfilment of the requirements for the project 'The feasibility of the hydrogen economy as a function of developments in global energy markets and climate change policies', funded by the ACTS Sustainable Hydrogen Programme of the Netherlands Organisation of Scientific Research (NWO).

The objective of this project is to evaluate the performance of presently proposed hydrogen technology chains, including the stages of production, infrastructure and end-use, in a range of future worlds. The employed modelling methodology allows for analysing the impact of different trajectories of global price and availability of fossil fuels and the impact of varying levels of ambition regarding climate change control. Moreover, it enables studying the hydrogen technology performance improvements required to compete with alternative technology chains involving fuels and electricity that do not use hydrogen as main energy carrier.

In order to inspect the impacts of global energy markets and climate change policies on the feasibility of establishing a hydrogen economy, 'feasibility' ought to be defined. We describe our definition of 'feasibility' in the first chapter of this report. In Chapter 1 we also assess how one should go about evaluating the impact of global energy markets and climate policies on the development of our energy system. In Chapter 2 we justify our choice for using the energy system model TIAM-ECN for the purpose of this project. In Chapters 3 and 4 the characteristics and structure of the TIAM-ECN model are described in detail. In these chapters we also explain why we focused on the passenger car sector only. A detailed description of cost and performance data for hydrogen production and distribution technologies used in TIAM-ECN is given in Chapter 5. In Chapter 6 we present our assumptions regarding performance and costs of hydrogen cars as well as for all main competing passenger cars.

2. Assessing the feasibility of a European sustainable hydrogen economy

2.1 How to define a feasible European sustainable hydrogen economy?

What do we mean by a hydrogen economy?

The hydrogen economy has become an accepted term for an energy system innovation that strongly depends on hydrogen as key energy carrier. Many system studies of the hydrogen economy, however, deal almost exclusively with the technological, rather than economic features of such a system. Additionally, a number of the studies that do focus on economic factors suggest that the hydrogen economy might not be economically feasible, not unless under favourable conditions are assumed for the hydrogen technology cost reductions (IEA, 2005; NRC, 2004; Barreto et al., 2003). This economic angle partially explains the position of hydrogen technologies in key global scenario studies for the medium term (up to 2030) such as the IEA World Energy Outlook (IEA, 2008b), where hydrogen is hardly mentioned. However, the main reason for the exclusion of hydrogen in these studies is even more related to the short time frame; even the protagonists for hydrogen energy systems are hesitant to suggest a major role for hydrogen up to 2030 and rather focus on the role they consider achievable by 2050, a horizon common for long run studies. The IEA Energy Technology Perspectives, the long term equivalent of the medium term World Energy Outlook, accordingly assumes a much larger share of hydrogen in end-use by 2050, particularly in the OECD transportation sector (IEA, 2008a). Nevertheless, the structure of the hydrogen economy as depicted in many long-run energy system studies varies widely in terms of major primary energy sources, key conversion technologies and dominant infrastructural choices (McDowall and Eames, 2007; Ros, 2007). In fact, one could argue, that the high degree of interpretive flexibility in defining a hydrogen economy is one of main reasons for its rhetorical power in popular conceptions of hydrogen as panacea for a wide array of social ills attached to energy use.[1] The only common feature defining a hydrogen economy seems to be that the hydrogen share of energy flows in some part of the potential chains from primary energy conversion to end use becomes significant in the long run. Usually, fuel cell vehicles and/or hydrogen as a storage medium for renewable electricity play a major role, but opinions on likely primary energy resources, conversion routes and infrastructural choices vary widely. For the purpose of this study we will therefore define a hydrogen economy as an energy system, where hydrogen accounts for a significant percentage (say 10%) of total final energy use in the system by the year 2050, exclusive of hydrogen flows produced and used as feedstock within the gates of large petrochemical complexes.

What do we mean by a sustainable hydrogen economy?

The concept of sustainability has a long and complicated history. Generally, the concept combines elements of social, environmental and economic goals. Each conceptual element can in turn be defined in complicated ways and measured in a wide array of sustainability indicators. This report is not intended to dwell on the voluminous literature on the concept of sustainability and the appropriate indicators. For the purpose of this study we will use just two basic measures to monitor the sustainability of the European energy systems considered, one referring to climate change (as a proxy for environment) and one referring to energy security (as a proxy for social goals). The first sustainability indicator we will use is the rate of decarbonisation and it is measured as the average annual percentage of European CO_2-emission reduction in the period up to 2050. The second sustainability indicator we will use is the rate of energy securitization and it is measured as the reduction in the annual share of net European energy imports of total

[1] Two widely cited authors in this respect are Amory Lovins and Jeremy Rifkin. See Rifkin (2002) and Lovins (2004).

primary energy use in the period up to 2050. If both these indicators are significantly positive, then we consider that Europe is on the road towards a sustainable hydrogen economy.

What do we mean by a feasible sustainable hydrogen economy?
We have not yet discussed the economic dimension of sustainability. We consider a hydrogen economy feasible only if the choice for hydrogen technologies is economically justified, i.e. hydrogen technologies would be the preferred option of energy producers and consumers when evaluating decisions from a purely economic perspective. This economic analysis needs to therefore consider not only the costs related to hydrogen, but also those of the competing, alternative technologies. In fact, the basic reason for developing a European sustainable hydrogen model in this study is the hypothesis, that a European hydrogen economy is only feasible given specific worldwide trajectories of technology unit costs, fossil fuel prices and CO_2-emission prices. Of course, economic feasibility presupposes technological feasibility, but if certain energy system configurations are only technologically feasible but economically unwise, than it would seem rash to talk of a feasible hydrogen economy.

2.2 How to evaluate the competitive position of hydrogen?

The dynamic nature of economic competition in the energy sector
When energy producers and consumers make investment decisions today, they are already confronted by wide brackets of uncertainties concerning the economic parameters they need to predict. However, generally, they can be assured of the initial investment costs per unit of output and it is therefore mainly the development of variable economic parameters they have to worry about; at least fuel costs, emission prices, interest rates, changes in subsidy or regulatory regimes and price levels of outputs can have crucial impacts on the economic performance of a technology. Also, when dealing with investment choices over the long term, it is not only variable costs that change, but also the investment costs become uncertain. In fact, strong opinions about the feasibility of the hydrogen economy, or any other type of future energy system, are often based on optimistic opinions about the future investment costs of specific technological options such as fuel cells. Proponents of specific technological options however often forget that competing technologies are not at a stand-still, but are also evolving. Worse, technologies that arrive late on the competitive stage are forced to compete with existing technologies on unequal footing, since prior arrivals will compete on the basis of variable costs only, because their sunken investments do no long matter. This makes it difficult to make statements about the feasibility of the hydrogen economy just based on a static comparison of alternative technological options at some future date. To draw plausible conclusions about the feasibility of a sustainable hydrogen economy a system wide evaluation of options over time is crucial.

The driving forces of technological learning, fossil fuel depletion and climate change policy
The development of the unit costs of energy technology over time is often captured by the concept of technological learning. The idea behind the concept of technological learning curves is that increasing cumulative installed production capacity of a particular technology, in a competitive market environment, leads to constant improvement of cost performance. The more units of a particular technology installed the lower the cost level at which each unit delivers its output. This performance improvement can presumably be described in terms of a power function that describes the development of unit costs as a function of, for example, cumulative installed capacity or production. Plotting a power function along a double-logarithmic scale makes the curve linear with a decreasing slope equal in value to a learning index. Empirical studies usually report on the progress ratio of a particular technology, which is defined as the equivalent of 1 minus the learning index. To observe a progress ratio of 90% thus means that a doubling of cumulative capacity has led to a cost reduction of 10% per unit of capacity or production. Most empirical studies estimate progress ratios in the range between 75% and 95%, with an average slightly above 80 % (Dutton and Thomas, 1984. See also MacDonald and

Schrattenholzer, 2001). While that may not seem so impressive in light of the high costs for hydrogen technologies today, one should realise, that such improvements should be viewed in relation with competing fossil fuels alternatives that are unlikely to experience any further considerable cost reductions related to learning and which may be subject to fuel price escalation caused by depletion effects. Moreover, successful global climate change will tilt the economic balance even further towards sustainable energy carrier choices (e.g. hydrogen, electricity, if emissions related to the conversion are abated), because rising CO_2-prices will make direct use of fossil fuels less competitive. How divergent developments of technological learning, fossil fuel price escalation and climate change policy could interact in such a way, that a sustainable hydrogen economy would be the optimal energy system choice in Europe, is the key strategic question that we wish to explore systematically in the European sustainable hydrogen model to be designed.

Providing a consistent accounting framework for European energy system development
Hydrogen technologies may become competitive throughout the energy system, i.e hydrogen production could be based on all major primary energy sources and used across all major end-use sectors. Hydrogen options will therefore compete with a wide range of technologies throughout the energy system. Evaluating the feasibility of a sustainable hydrogen economy therefore requires keeping track of simultaneous developments throughout the European energy system. Moreover, the benefits of hydrogen must be evaluated at the system level, because hydrogen may lead to significant conversion efficiency losses in some part of the system, but significant conversion efficiency gains in another part of the system. The hydrogen chain from natural gas reforming to fuel cell vehicles provides a simple example. When multiple and interconnected hydrogen chains characterise energy system configurations, the final efficiency consequences are not so easy to estimate consistently.[2] A consistent accounting framework for European energy system developments thus requires a comprehensive and integrated systems model for the European energy sector. Such system models are already widely used in European energy scenario analysis for policy design and the exploration of R&D roadmaps for specific technologies.

Developing a vision on the feasibility of a European sustainable hydrogen economy
The European Sustainable Hydrogen Model makes it possible to develop a vision on the feasibility of a European sustainable hydrogen economy, based on a quantitative evaluation of alternative pathways to such an energy system. Such a vision provides insights concerning the combination of driving forces (technological development, fossil fuel price escalation, climate change policies) that may be necessary for making a sustainable hydrogen economy in Europe feasible. It should be clear that the model results depend on exogenously generated assumptions about these driving forces and it therefore rather answers questions of a 'what if' nature instead of projecting or forecasting developments. The driving forces of the model are specified exogenously and the model analysis determines what combination of driving forces and technological futures would make a European sustainable hydrogen economy feasible. The vision to be supported by the model results concerns the required quantitative role of each factor in alternative scenarios and the consequences this has for hydrogen R&D trajectories and climate change policies. A key hypothesis for the study is that the feasibility of a sustainable hydrogen economy is strongly correlated with high fossil fuel prices in combination with high carbon prices. From the technological side of things it is assumed that transport sector will be of key importance for the success or failure of hydrogen technologies Model results allow statements about required progress rates in for hydrogen technologies, under different global fossil fuel market conditions and climate change policy measures.

2 Not surprisingly, some argue that system-level energy efficiency is the greatest barrier to development of the hydrogen economy (see Bossel, 2006 or Page and Krumdieck, 2008) while others argue the other way around. It all depends on specific assumptions about system level configuration of the hydrogen economy.

2.3 How to incorporate global driving forces into the model analysis?

The necessity of using a European energy systems model in a global context
The focus of the model will be on hydrogen and Europe. However, as discussed earlier, the future of a sustainable hydrogen economy depends to a large extent on performance improvement of hydrogen technologies (technological learning), the rate of fossil fuel price escalation (depletion effects) and the level of carbon prices (global climate change policies). These driving forces are not determined exclusively by European energy sector changes, but are strongly dependent on global energy sector developments. It is unlikely that Europe is willing and able to promote the transition to a sustainable hydrogen economy independent of energy sector transitions elsewhere. Therefore, it is important to consider the analytical sources for specification of alternative trajectories of these exogenous global driving forces. This is what we mean by emphasizing the need for using the model in a global context.

Development of separate Global Fossil Fuel Depletion model
The present European energy system is to a large extent dependent on imported fossil fuels and the transition towards alternative energy system regimes will be driven strongly by global fossil fuel market developments. Although fossil fuel prices are introduced exogenously in the proposed European Sustainable Hydrogen Model, they will be analyzed in detail in a separate economic model of global fossil fuel markets that forms part of this project and is presently developed by the Institute of Environmental Studies of the Vrije Universiteit. This Global Fossil Fuel Depletion model will be used interactively with the proposed Global Sustainable Hydrogen Model. In contrast to the technological hydrogen details at the European level characterizing the European Sustainable Hydrogen Model, this model will concentrate on the theoretical foundation of resource economics and the empirical data on fossil fuel depletion to produce alternative scenarios of fossil fuel price developments.

Incorporating assumptions on carbon price developments
Europe has been a global frontrunner in climate change policies. The establishment of the European emission trading system constitutes a remarkable policy innovation that allows a transparent market for CO_2-emission rights and a uniform CO_2-price across a large segment of the European energy sector. There are, however, large uncertainties about the gradual expansion of this market to other sectors and to other global regions. In the face of these major uncertainties no generally accepted forecasts for potential global CO_2-price trajectories exist. We will therefore analyse the impact of CO_2 prices by simple parametric sensitivity analysis. Proposed CO_s-price trajectories will be based on qualitative arguments regarding the expansion and speed of implementation needed in Europe, while also taking into account explicit assumptions about the global expansion of regional carbon pricing initiatives, related to assumptions concerning final long term targets, and how these global developments may affect the European carbon price developments in the future.

Technological learning for hydrogen technologies
The third major driving force affecting the feasibility of the hydrogen economy is the potential for cost reduction across the full range of hydrogen technologies, from production to end-use including infrastructure (transportation, distribution, storage). Again this development is characterised by a global dimension, because obviously the scope for expanding the scale of hydrogen use is not limited to Europe. In fact, it is unlikely that the choice for hydrogen routes would be a singular European choice. Perhaps, Europe may act as a frontrunner in the transition to a hydrogen economy, but ultimately a successful transition will have an important global dimension. This topic of technological learning at the global scale has been the major research objective of another, on-going NWO-ACTS project implemented by ECN Policy Studies.

This project aims at the formulation of support mechanisms for technological learning of hydrogen-based applications and includes a major empirical study on technological learning curves for hydrogen. The results of this project will form the basic starting point for incorporation of technological development estimates into the model analysis.[3]

[3] The first results of this project concern observed cost reductions in hydrogen production technologies such as steam methane reforming and electrolysis and have been published in (Schoots et al., 2008).

3. Choice of energy systems model

3.1 Building on existing experience on energy systems models

Choice for bottom-up, technologically-oriented energy systems optimization model

Since there are already many models available for analysing energy system transitions in the long run, there is no need to build a new model from scratch. The basic idea is to adopt an existing, in-house model and modify it adequately for the purpose of this study.

Energy systems models are generally divided into two broad generic categories: bottom-up models with detailed representation of technologies and top-down models with detailed representation of economic sectors. From the economic perspective, the first type of model can be viewed as a partial equilibrium model for the energy sector in isolation. In such a model macro-economic feedbacks from the energy sector affecting performance and growth of other economic sectors are disregarded. The second type of model can be viewed as a general equilibrium model with energy as a key factor of production. In such a model representation of energy technology is highly aggregated and technological developments within the energy sector are disregarded. These two approaches are sometimes combined (e.g. Messner and Schrattenholzer, 2000; Turton, 2008) to give additional insights on economy/technology, but the focus is also then mainly on one of the approaches (usually on the bottom-up characteristics).

The model chosen for the present study is a bottom-up, technology-oriented model, since the study is supposed to address problems of technological choice within the energy sector rather than macro-economic performance and impacts of the sector. The structure of such bottom-up models is usually based on a reference network of energy flows between process nodes representing specific technological production, conversion, transmission and distribution and end-use technologies. Each node in the network is characterised by a set of economic and technological parameters describing the performance of specific processes and the nodes and flows may also be linked to each other through user defined relations and constraints. The other key input data refer to the energy demand levels per end-use category that the energy system is required to satisfy. The network model functions as a set of quantitative restrictions under which an objective function, usually a discounted stream of total system costs, must be minimised. To function as a partial equilibrium model, energy demand levels are made dependent on the energy price levels, which in turn result from specific technological choices. The results of the model specify the configuration of investments in (and use of) energy technologies over time that minimizes total discounted system costs while satisfying specified energy demand curves. The solution algorithm for such models is usually based on methods of linear programming or variations thereof.

Choice for MARKAL-TIMES model family

An important choice criterion is that the model should be widely applied in international policy studies. This makes it possible to build on existing experience and software. Moreover, it will help to disseminate the results of the study among the broad circle of policy practitioners that are already familiar with the basic features of this type of model. The model chosen for this study, TIAM-ECN, belongs to the MARKAL-TIMES model family. The term family indicates that there are a wide range of models available that are essentially similar in structure and function and dependent on shared model generators. Moreover, the MARKAL-TIMES model family allows the use of dedicated software for the pre-processing (input preparation) and post-processing (output interpretation) stages of model analysis. The core specification of MARKAL-TIMES models is based on a source code written using GAMS modelling software. The available software allows easily implemented modifications in network structure and data.

3.2 Survey of MARKAL-TIMES model family

History of MARKAL-TIMES model development

The use of bottom-up, technologically detailed models for energy systems analysis started in Europe in the early 1980's on three fronts: sponsored by IIASA in Laxenburg, Austria (MESSAGE model, Agnew et al., 1978), sponsored by the EU in Brussels (EFOM model, Van der Voort, 1982), and sponsored by the IEA in Paris (MARKAL model, Rath-Nagel and Stocks, 1982). All of these three models are still heavily featured today, albeit all of them in a considerably more eloquent form than decades ago.

The MARKAL model, in many ways the origin of the modelling platform to be used in this study, has survived the decades most adequately by constant improvement and adaptation. The model is still used by the IEA to back up the conclusions of its flagship publication Energy Technology Perspectives (IEA, 2008a) with quantitative details. It has an active users community organised through a cost-sharing IEA implementing agreement under the acronym ETSAP (Energy Technology Systems Analysis Program).[4] ECN has been actively involved in the development of MARKAL from the beginning and has a long experience with widely divergent applications of MARKAL models (Okken et al., 1994; Ybema et al., 1997; Gielen et al., 2000; Kram et al., 2001, Smekens et al., 2003; Martinus et al., 2005). The acronym MARKAL stands for MARKet ALlocation and symbolizes the intention of the MARKAL model to simulate the market for energy technologies. The TIMES model is an evolved version of MARKAL which offers extended flexibility and functionality and integrates characteristics of another seminar energy system modelling platform, EFOM. In fact, the acronym TIMES stands for **T**he **I**ntegrated MARKAL-**E**FOM **S**ystem, thus reflecting the intentions to combine features of the MARKAL and EFOM models. TIAM (Loulou and Labriet, 2008; Loulou, 2008) represents the latest expansion of the model family, this time in terms of spatial scope. Although there are global applications of the MARKAL model (Rafaj and Kypreos, 2007, EIA, 2003, Gielen and Podkanski, 2005), TIAM is the first global, integrated assessment application of the TIMES model, as well as the first model in the MARKAL-TIMES family that includes a module for climate change assessment as well as a number of other characteristics that enable it to function as an integrated assessment tool for climate change analysis. The acronym TIAM stands for **T**IMES **I**ntegrated **A**ssessment **M**odel.

Local, national, regional and global model implementations

The models of the MARKAL-TIMES family have been applied at vastly different geographical scales, from a single city to the whole world. National applications for specific countries are however by far most numerous. The reasons are primarily of a practical nature: energy statistics are usually most consistent and detailed at the national level and energy policies are usually most prominent and relevant also at this level. It should also be stressed that there are essentially two very different ways in which to expand the geographical domain of application: by coupling an array of models at a lower scale explicitly or by formulating a new model at a higher level of aggregation. If we use the example of an EU model: in the first type of model EU results are simply the sum of national results, but in the second type of model national results are no longer distinguishable and EU results are generated directly. The first type of model is equivalent to coupling the existing networks of national energy flows through international energy trade flows. In the second type of model a completely new network is designed in which intra-European energy trade is no longer discernable.

4 For comprehensive information about the development and application of models in the MARKAL-TIMES model family consult the ETSAP website: www.etsap.org

3.3 The TIAM model as point of departure

Three basic possibilities for building a European Sustainable Energy model

As a point of departure for building a European Sustainable Energy we could build on existing models in the MARKAL-TIMES family in three ways: by coupling national models, by using a pan-European stand-alone model (Blesl et al., 2010) or by using a global model with Europe as one or more key regions. The approach chosen for this study is the last one. Although this choice is partially based on the availability of the TIAM-ECN model, coupling a large array of national models would also be infeasible within the resources of this project and would provide an overshoot of national detail that would hardly contribute to the purpose of the study. Choosing for an isolated pan-Europe, stand-alone model would involve starting from scratch because an up-to-date version of such a model is presently not available at ECN. We have therefore chosen to taken the TIAM global model as point of departure. This has the advantage of starting with a model that is already highly aggregate and which allows expansion to interregional interactions at a global scale at a later date.

Definition of Europe and preference for geopolitical scope of model

In a geographical sense (taking the Urals, Caspian Sea and Black Sea as borders) Europe contains some 50 sovereign states including a few partially located in Europe such as Turkey and Kazakhstan and half a dozen minor sovereign nations such as Andorra and Liechtenstein. Geopolitically, these nations can be conveniently divided into three geopolitical blocks with different socio-political regimes: Western Europe (the former EU-15 including Norway and Switzerland), Eastern Europe (EU enlargement nations of Central Europe plus former Yugoslavia) and Former Soviet Union (EU enlargement nations of the Baltic plus European Russia, Belarus, Ukraine and Moldova plus Caucasian republics). In the present TIAM model these blocks form separate regions with the Former Soviet Union including, for example, the Asian part of Russia. For the purpose of this project we will include the Western and Eastern European blocks of countries. This implies that to present figures for the EU-27 proper we will have to correct for exclusion of the Baltic States and inclusion of former Yugoslavia, Albania, Norway, Switzerland and Iceland. Such corrections will be minor and can be applied for reasons of geopolitical consistency in the post-processing stage without affecting major conclusions.

4. Structure of the TIAM-ECN global energy systems model

In the first section of this chapter we will briefly introduce the modelling platform used in this study, TIAM-ECN. Since our geographical focus in this study is Europe, we will further adjust this global model by limiting its spatial scope. This, in turn, has also some modelling implications, which will be further elaborated on in the second section of this chapter.

4.1 TIAM-ECN model, the basics

TIAM is a technology-rich, bottom-up systems engineering model, described in detail in Loulou and Labriet, 2008 and Loulou, 2008. This linear optimization model describes the development of the global energy system, covering the full energy chain from resource extraction to the final end use of energy. The time covered time frame is long, typically about 100 years and the regional disaggregation separates the world into 15 geographical areas. Our slightly altered version of the model, TIAM-ECN, keeps all the main characteristics of the original model, while also including several modifications and simplifications. Most of the changes made relate to altered input data, additional growth and decline constraints, as well as more aggregated sectorial and technological detail.

The decision criterion of the model is to minimize the total discounted costs over the full time horizon and summed across the geographical regions. The main cost components represented are investment and operation and maintenance costs, while also cost elements such as tax and subsidy costs, decommissioning costs and costs of demand reductions (resulting from the elastic demands) are included. The prices of tradable fuels are endogenous in the global model, but can be given also exogenously, if, for example, it is considered that the chosen modelling methodology leads to different prices than what could be realistically expected or if the global framework is abandoned in favour of a more restricted regional description (i.e. if the model is optimised only for chosen regions).

The database associated with TIAM is extensive and includes hundreds of technologies for a number of supply and end-use sectors. The demands, defined based on the exogenously defined developments of the chosen demand drivers, are modelled using price elasticities, so that the original demands are adjusted to price changes. Figure 4.1 shows a simplified sketch of the original TIAM reference energy system. In addition to energy flows and conversion technologies, also environmental variables such as greenhouse gas emissions related to energy processes are modelled. Compared to the figure, TIAM-ECN has been simplified by removing the OPEC/Non-OPEC.

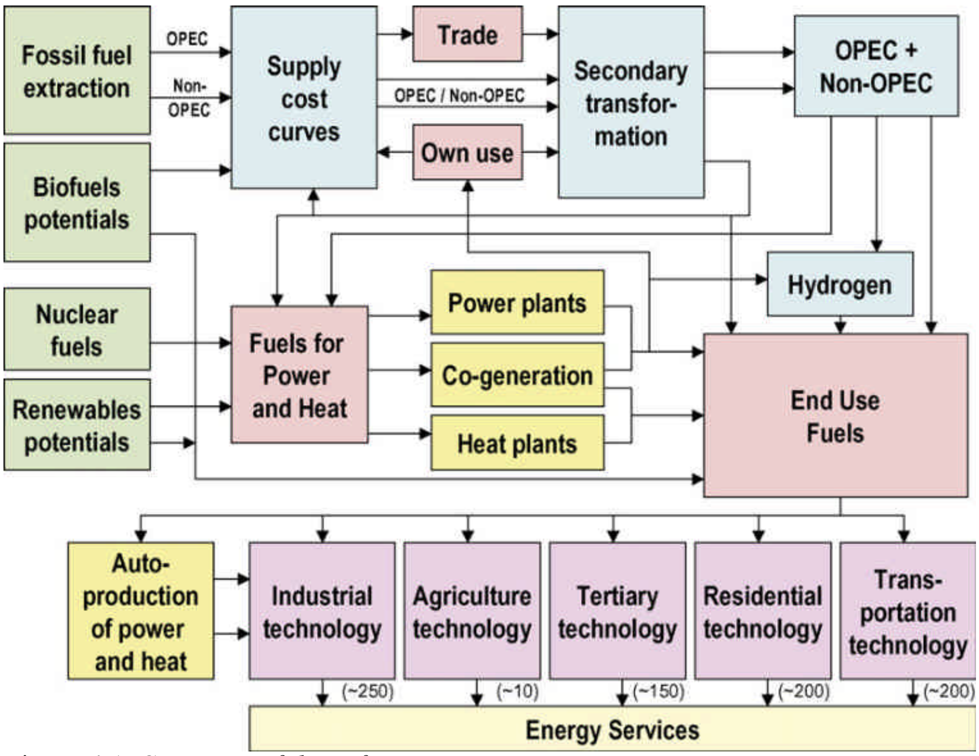


Figure 4.1 *Structure of the reference energy system*
Source: Syri et al., 2008.

In the following subsections we will briefly describe the setup of the model, individual sectors as well as other aspects of the model. Here we roughly divided our presentation into the following subsections: 1) end-use demands and their drivers, 2) energy conversion and trade, 3) energy resources and 4) emissions and climate. Due to the very large extent of the model, we will not be exhaustive, but rather offer a summary of the structure and rationale of the model. A more complete description of TIAM, including the basic mathematical formulation, can be found in Loulou and Labriet, 2008 and Loulou, 2008. The underlying model generator, TIMES, is fully documented in Loulou et al, 2005.

End-use demands and their drivers
TIAM-ECN is essentially a demand driven model; there are all in all over 40 demand categories in transport, agricultural, commercial, residential and industrial sectors and all of these demands need to be fulfilled in each region and at each point in time. The rest of the model mainly then describes how these demands should be fulfilled in a cost optimal manner, while simultaneously taking into account all the other constraints (related to e.g. environmental ambitions, resource depletion or speed of technology diffusion).

Each of the demand categories is linked to a specific, exogenously defined driver (or, in some cases, drivers), which determines the demand projection for that particular demand category. More formally, the demands are defined as:

$$D(t) = D_0 \cdot Driver(t)^{X(t)}$$

Where $D(t)$ is the demand in period t, D_0 is the demand during reference year, $Driver(t)$ is the indexed value of the driver, compared to the reference year and $X(t)$ is the value of the decoupling parameter, which shows how strongly the demand follows the developments of the driver. Different regions may use a different driver for the same demand category (for example, use of refrigerators may be driven by average household income in the developing world and by number of households in the developed world). Also, the demand specific decoupling parameter is region and time specific, thus allowing us to show both, regional differences in the strength of the coupling as well as gradual reductions in the coupling as time passes by.

The exogenously defined drivers that are used to define the individual demands are population, total GDP, number of households and sectorial GDP. Some demands are driven by drivers that can be derived from the four that were given exogenously, i.e. GDP per capita or GDP per household.

In general, most of the relevant demand categories are explicitly modelled in the residential and commercial sector. Demands need to be fulfilled, for example, for space heating and cooling, lighting, cooking, hot water heating and a number of other specific demands. For a full list, see Loulou and Labriet, 2008. Industrial sector is more complex, with the given demands in different industrial sectors linking to a mix of more detailed services, such as steam, process heat, machine drive, electrolytic service, other, and feedstock. Since our focus in this paper is on transport, we will not go into further details concerning the disaggregation of demands in the end-use sectors, and will instead concentrate on the transport sector alone.

There are ten transport demand categories in TIAM-ECN, covering road, rail, water and air transport. These include both passenger and freight transport, as well as domestic transport and transport that crosses national (and regional) borders. The original TIAM model had even more explicitly defined demand categories, fourteen. We have aggregated some of them, for example, combining the demand for light duty vehicle transport with passenger cars and aggregating the demand for two and three wheelers into a demand for small vehicles. We have also aggregated some demand categories for freight, combining the demand for commercial, medium and heavy trucks. Rail transport for passengers is assumed to include transport by trains, trams as well as by subways.

The demand for road transport, for both passengers and freight, is expressed in vehicle kilometres per year. The other demand categories are expressed in energy units, i.e. as annual energy service demand for a given transport category. This also has the disadvantage that energy reduction due to switching to more efficient end-use technologies can't be modelled explicitly. Possibilities for fuel switch are also rather limited for these modes of transport. Energy savings through the use of more efficient technologies are, however, implicitly modelled by implementing own price elasticities for the demands. Since this is more of a 'black box approach' for demand reductions, we can't distinguish between more efficient end-use solutions and reduction due to behavioural change, however. In this study the focus will be on road transport, and especially the role hydrogen could play for passenger cars, and we will therefore leave the non-road demand categories unchanged. Aviation, rail and transport by water could, however, be an interesting topic for a follow up study. Table 4.1 summarizes our demand categories and their drivers.

Table 4.1 *Transport demand categories in TIAM-ECN*

Demand category	*Unit*	*Driver of demand*
Passenger car demand	Bveh-km	GDP per capita
Small vehicles demand	Bveh-km	Population
Bus demand	Bveh-km	Population
Truck demand	Bveh-km	GDP
Rail-Freight	PJ	GDP
Rail-Passengers	PJ	Population
Domestic Internal Navigation	PJ	GDP
International Navigation	PJ	GDP
Domestic Aviation	PJ	GDP
International Aviation	PJ	GDP

The demands derived as describe above are the so called reference demands used in the model The model can be run using these fixed demands, while the model then gives as a result the cost optimal supply decisions for fulfilling the demands. However, TIAM can also be run as a partial equilibrium model, with each demand having a predetermined, constant own price elasticity. If the model is run in this mode, the original demands and corresponding equilibrium prices of the demands for the reference case are used as the reference prices. A modified scenario (with, e.g. an emission constraint) will use this reference point and given elasticity parameters to determine the demand changes that follow from the altered scenario setup. An added climate constraint, for example, would make it more expensive to deliver the energy services required, thus increasing their prices and leading to demand reductions (compared to the reference case). A complete description, including the mathematical formulation, can be found in Loulou and Labriet, 2008 and Loulou, 2008.

Energy conversion and trade

As often is the case with bottom-up models, the conversion sector of TIAM is modelled in detail. The power sector includes all existing technologies (with some aggregation), as well as number of technologies that are expected to become available in the future. For example, a distinction made between distributed and centralized production, onshore and offshore wind power, nuclear reactor types (light water reactor, pebble bed reactor) and different coal power plant technologies (two based on fluidized bed boilers, pulverized coal plant, oxygen and air blown IGCCs, and most of these are available with or without carbon capture and storage).

In addition to power sector, there is also a sizeable number of technologies in the secondary transformation sector. These technologies convert primary energy resources into energy carriers that can be used in the end-use sectors; e.g. heat, coke, town gas, hydrogen and ethanol production.

Trade can be defined for any commodities desired, including emissions. It is also possible to model trade as a global market, as bilateral between two regions or any combinations in between these extremes. Costs and constraints can also be freely attached to the trade activities.

Energy resources

TIAM-ECN includes a full description of both fossil and renewable energy resources. Depending on the resource, energy sources may still be divided to further subcategories, costs and potentials for each being separately defined. We have altered the data and structure of the original TIAM slightly and the following description therefore differs from that of Loulou and Labriet, 2008.

For oil resources we distinguish between heavy oil, oil sand and shale oil resources. We furthermore differentiate between located reserves, new discoveries and reserve growth for heavy fuel oil, and include several cost categories for the first two of these. We determine these potentials as cumulative, regional amounts of the resource available, but also impose further constraints on the growth and decline with which the level extraction can change.

Natural gas resources are modelled similarly to oil resources; existing resources, new discoveries and resource growth are modelled (with several cost steps for the existing resources), as are also some unconventional gas resources (e.g. coal bed methane and aquifer gas).

For coal the main distinction is made between hard coal and brown coal and also for these the located resources and new discoveries are given separately.

The modelling of renewable resources differs from what is described above; these resources are not limited by their cumulative use, but by annual potentials that change in time. Also for these sources we assume growth constraints, which are meant to represent bottle necks that limit the pace of the expansion of the technologies. A number of cost steps is also assumed for most of the renewable resources.

Emissions and climate
TIAM-ECN includes in principle all sources of the main greenhouse gases, i.e. CO_2, CH_4 and N_2O, but currently excludes emissions of pollutants, such as SO_x and NO_x. Energy related greenhouse gases are modelled endogenously, whereas non-energy related greenhouse gases are included as exogenously given emission paths. The latter are based on assumptions concerning their underlying drivers and mitigation technologies are available for some of these non-energy related emissions. For example, mitigation options are available for N_2O emissions from nitric and adipic acid production, as well as for CH_4 emissions from landfills and manure. For some sources, such as CO_2 emissions from land use change, CH_4 emissions from enteric fermentation, rice production and waste water, as well as N_2O emissions from agriculture, only exogenous emission paths are given without availability of mitigation technology. Emissions that affect our climate, but which are not directly included in TIAM, are represented through an exogenous forcing component in the model's climate module (for a description of the module, see Syri et al., 2008). Our modelling runs exclude the impact of aerosols and we assume that the forcing effect of all the remaining non-modelled forcing agents reduces linearly from today's values to a level of 0.1 W/m^2 by 2100.

A large number of mitigation options are modelled for the energy sector. The main clusters of alternatives are: 1) CO_2 reduction in the carbon intensity of fuels (such as a switch from coal to gas, or from fossil fuels to renewables or nuclear), 2) reduction technologies in energy consumption (including more efficient conversion techniques on the supply side and demand reductions at the end-use level), and 3) add-on reduction technologies (such as CCS, or CH_4 emission reduction opportunities in oil, gas and coal production). These climate change mitigation options emerge mainly from TIAM's detailed description of the energy system. As CO_2 emission constraints are implemented, the energy sources with low carbon content become more competitive, as do technologies that require less fuel input to provide the same energy service (and therefore in relative terms produce lower emission levels). A climate constraint will also increase the price of energy services, which leads to a lowered overall demand.

Assumptions regarding the respective potentials of carbon-free or low-carbon fuels, as well as the range of available efficiency improvements, may limit the use of these options. As mitigation options they are also limited by their baseline use: if a carbon-free option is assumed to have a large potential, but this potential is almost completely used already in the baseline scenario, its potential for mitigation is low. CCS is available in the power sector, for synthetic fuel production (including H_2 generation from coal and natural gas, as well as methanol and Fischer-Tropsch liquids from coal), and (stylistically and only up to a limited potential) for upstream fossil fuel supply processes. A large number of storage options are included for the captured CO_2. There are a number of combinations available between CO_2 capture technologies and coal and natural gas based power plants. CCS as applied to the combustion of biofuels is currently not included in our model: while this technology offers a promising possibility for 'negative' emissions, it remains to be seen to what extent it can be applied given possible logistical and spatial constraints. If the technology does, however, become commercially feasible, it could offer increased flexibility for reducing emissions rapidly, if needed.

4.2 Adjustments for the TIAM-ECN, Europe

Europe is the geographical focus of this study on sustainable hydrogen economy. in the spatial definition of Europe, or European Union, does not, however match with any single region in TIAM-ECN. The countries of Europe are spread between three TIAM regions; Western Europe, Eastern Europe and Former Soviet Union. These regions also include areas such as the Asian part of Russia and therefore combining these three regions would not coincide with the definition of Europe either. Since disaggregating and re-aggregating countries into a separate region 'Europe' would require considerable efforts for e.g. calibration we will instead approximate Europe by combining the regions Western Europe and Eastern Europe. This definition is not too far off from the current EU and might be even closer to the EU in 2050 than what a region combining current EU countries would be.

By reducing TIAM-ECN to only two regions instead of the usual fifteen, the trade flows are no longer an endogenous model result. Due to this the original trade options between different regions will now be replaced by import and export technologies in the two European regions, with a single 'rest of the world' trade region representing the omitted regions. Trade between Eastern European and Western European regions will still be endogenously modelled.

As a consequence of not modelling the interregional trade endogenously, global commodity prices are no longer determined endogenously. In the full TIAM-ECN model the trade supply curve is endogenously constructed and it determines the availability of tradable commodities at a given price. Similarly, an implicit price-demand curve is constructed and these two curves together determine equilibrium and the corresponding trade flows, resource extraction etc. Since the detailed information concerning the global supply and demand curves is no longer available, the global trade supply curve for Europe can't be constructed endogenously. Therefore exogenously defined commodity prices for imports will be used. The obvious options for defining the exogenously defined attributes for the imports are to 1) using a fixed price, 2) using a fixed upper limit of imports per commodity and 3) constructing a rough supply curve from the equilibriums quantities and prices of runs done using the full global model.

Some testing needs to be done in order to determine the level of detail that needs to be put into the trade modelling at this point of the development. At a later stage of this project the European TIAM-ECN will be soft linked to a global oil supply model, which allows us to iterate the models in order to reach the equilibrium prices and quantities.

In addition to the changes to the trade flows, a number of other model adjustments need to be done to adequately reflect the characteristics of a hydrogen transition. Of these perhaps most important are the update of the hydrogen technologies and infrastructures and the review and revision of the available data for passenger cars. A full description of this is given in Chapters 6 and 7.

5. Design features of European Sustainable Hydrogen Model

5.1 Main building blocks and key technologies

The main building blocks in the technological architecture of hydrogen futures

Surveys of hydrogen scenarios, visions and roadmaps have noted that the technological architecture of hydrogen futures is built on a limited number of key building blocks (McDowall and Eames, 2006; Ros et al., 2007). The key building blocks usually named are central hydrogen production plants; hydrogen transportation and distribution infrastructure (including storage), stationary applications in the built environment and mobile applications in the transportation sector. Different combinations of dominant production technologies and end-use applications are likely to lead to fundamentally different architectures for hydrogen futures. For instance, reliance on central hydrogen production together with fuel cell cars would necessitate a dedicated hydrogen transportation and distribution system, while reliance on decentralized hydrogen production together with micro-cogeneration of heat and power avoids the need for a dedicated hydrogen transportation and distribution. Although the choice between building blocks is interdependent, there are still a wide variety of architectures possible.

We will build our model assuming that of the building blocks states above the transport sector is most critical, that is, we assume that hydrogen economy will not feasible without hydrogen penetrating in the transport sector. We therefore pay especially much attention to the production, transport and distribution as well as end use of hydrogen especially geared towards the transport sector. Use of hydrogen in the other sectors may also be important for creating the necessary scale factors, or offering niche markets for early introduction of hydrogen technologies. We do, however, assume other sectors to have a more supplementary role and will use a more stylistic modelling for these sectors.

Evaluating the optimal mix of hydrogen and electricity in energy transitions

Both hydrogen and electricity may play an increasingly important role in the transition towards a sustainable energy system. More particularly, both of them have been mentioned as possible replacements for oil products in the transport sector, the sector where future seems currently still rather unclear, in terms of economically and technically feasible options. To evaluate the competitive positions of alternative technological architectures for the hydrogen economy it is not sufficient to look at the main building blocks for the hydrogen economy in isolation, but together with its competing options, especially electricity. Central hydrogen production competes with central power production, hydrogen infrastructure competes with electricity infrastructure and fuel cell cars compete with plug-in electric vehicles.

In general terms, electricity can be viewed as the incumbent energy carrier that will not be replaced directly by hydrogen in most of its current uses; for motive power in industrial processes, for lighting in the built environment and for domestic appliances in households. Moreover, electricity is in a good position to conquer new markets in transportation and heat, when fossil fuel products become increasingly scarce and expensive. But hydrogen could also have some distinct advantages over electricity. As long as central power plants remain largely dependent upon fossil fuels, hydrogen may be viewed as an unavoidable by-product of the need to capture and storage CO_2 in a carbon constrained world. Thus it may acquire a cost advantage over electricity if it can be transported and distributed sufficiently cheap to highly efficient end-uses such as fuel cell cars. Moreover, once fossil fuel power plants with CCS (carbon capture and storage) become too expensive and the share of renewable power increases, hydrogen may gain an advantage because a hydrogen infrastructure, including storage of hydrogen, may be better able to deal with the intermittent nature of renewable power than electricity. Because electricity is already well represented in the existing model structure of TIAM, there is no need to expand the model substantially in this respect. However, some structural adaptations may be required to better represent the transmission infrastructures and the potential expansion needs related to the infrastructure.

Potential evolution of incumbent fossil fuel regime

The expanding role of hydrogen and electricity in future energy transitions is intimately tied to developments in the incumbent fossil fuel regime. First of all, it is unlikely that natural gas and liquid fuels will disappear in the period up to 2050. The performance of today's key technologies such as fossil fuel power stations, internal combustion engines and domestic heat generators will also improve over time, even if at ever slowing speed. Advanced technologies like coal gasification for power generation, hybrid electric cars or natural gas-based micro heat and power may, however, prolong the lifetime and nature of the fossil fuel regime and slow the penetration of hydrogen options considerably. Secondly, the gradual substitution of fossil fuels by carbon free energy carriers can be advantageous for an expanding role of either hydrogen or electricity, depending on relative performance of key technologies and on the level of fossil fuel and CO_2-prices.

Performance improvement of fossil-fuel based advanced options often does not necessitate the introduction of new technological processes into the model. Performance improvements can be modelled by differentiating the associated efficiency and cost parameters over time. In some cases, however, introduction of new technologies may be helpful, especially when the inputs or outputs of the novel technology differ from the conventional one or when the introduction of the new technology creates a clear point of discontinuity is performance characteristics (e.g. introduction of fuel cells for fossil fuels). Furthermore, explicit modelling of novel technologies can be useful for describing the a typical mix of conventional and advanced technologies, determined by the speed of diffusion for new technologies as well as competitive forces included within the modelled system. This could, for example, be the case when conventional cars are gradually being replaced by hybrid cars.

5.2 Petrochemical hydrogen use and niche markets

There are some elements that would, in all likelihood, be important elements of a successful hydrogen transition that cannot be captured by the modelling set up, which focuses on system wide interactions. Below we briefly discuss two such elements and elaborate on their likely role in a successful transition.

No representation of hydrogen flows within petrochemical complexes

Within the confines of petrochemical complexes hydrogen already plays an important role in hydrocracking and as a feedstock for methanol, ammonia and a range of minor chemical compounds. The demand for hydrogen in the petrochemical industry is steadily increasing, because the output mix of refineries is shifting towards lower-sulphur, lower-aromatics products requiring hydrogenation. Hydrogen in these complexes is produced mainly from steam-reforming of natural gas or it is used in the form of syngas from gasification of petroleum residues. These petrochemical complexes function as local hydrogen economies. Their existing infrastructure and knowledge base is often considered a perfect starting point for expanding the production and use of hydrogen towards new niches. This raises the question of how detailed the representation of such local hydrogen economies in the proposed European Sustainable Hydrogen Model should be. In this respect, it must be pointed out, that these local hydrogen economies are intimately connected to feedstock and fuel production and we do not intend to model such production processes in detail. We will treat most of the petrochemical industry as one technological process with multiple inputs and outputs rather than as a network of separate process steps in which internal hydrogen flows can be distinguished. Nevertheless, it is clear that the experience of the petrochemical industry has been crucial in bringing down the costs of steam-reforming and hydrogen infrastructure and that these technologies will be modelled explicitly when used outside the gates of petrochemical complexes.

No representation of marginal niches for hydrogen technologies
Roadmaps towards the hydrogen economy often point out the crucial role of small niche markets for which hydrogen technology offers substantial early benefits and in which high costs applications have short-term commercial potential. Examples are the use of fuel cells in forklift trucks, military vehicles, luxury yachts and telecom backup power. Forklift trucks have a short action radius and a continuous operation cycle and allow the use of fleet economies of scale in fuelling. Both military vehicles and luxury yachts want to avoid the noise and heat signature of combustion engines for obvious although different reasons. Finally, fuel cells have definite operational and maintenance advantages versus batteries in hostile environments with unreliable grid supply. Using marginal niches to bring down costs in a learning cycle is an important step in the initial stages of commercialisation of hydrogen technology. But they will always remain a marginal feature of a hydrogen economy. Although the specification of the European Sustainable Hydrogen Model allows a time-dependent description of the process of transition towards a hydrogen economy, it will not be designed to capture the role and impact of marginal niches for hydrogen technologies in the short-term. The structure of the model will only describe hydrogen technologies that can potentially grow into significant building blocks for a sustainable hydrogen economy in the long run.

5.3 Representation of demand side

Representation of demand side technologies in the present model
The present version of the TIAM uses levels of end-use demand, in either physical units or as service provided, as exogenous inputs. The focus on end-use functions, rather than final energy use, and the representation of a wide range of demand-side technologies makes it possible to capture explicitly the impact of energy efficiency improvements on the demand side. However, this approach has important consequences for model size and data requirements. The central question of this study concentrates on supply side issues regarding the optimal mix of primary sources and energy carriers. Since the end-use efficiency developments can be intimately connected with choice of energy carrier, however, there is an analytical need to include end-use applications in detail at least for the most promising sector for hydrogen, transport. We will therefore describe this sector in detail, whereas some aggregation of end-use technologies and demands will be done for the residential and commercial sector. The aggregation is considered to be necessary in order to avoid the data collection difficulties and computational consequences of including a large number of non-essential technologies.

Structure of transportation module
For the explicitly modelled transport activities, TIAM-ECN includes both freight as well as passengers transport. Freight can be transported by ship, truck or train. The technologies available for passenger transport include cars, busses, small vehicles, trains and airplanes. For aviation and train transport a distinction is made between domestic and international transport.

The representation of aviation, rail and water transport is rather stylistic; no explicit technology options are included, efficiency improvements are a function of time alone and there is little, if any flexibility allowed for fuel switching (e.g. the fuel mix for a generic international aviation technology will remain practically the same as in the calibration year). Switching to alternative fuels is therefore not possible for these modes of transport. With a growing importance of especially aviation, improvements in the modelling of these transport means is high on the priority list and would offer a good follow-up study for the car transport orientated study at hand.

Road transport, however, is explicitly modelled and there is therefore much more flexibility. The range of cars, trucks, busses and small vehicles included in TIAM-ECN are given in Table 5.1.

Table 5.1 Road transport *technologies included in TIAM-ECN*

Passenger cars	*Trucks*	*Busses*	*Small vehicles*
Diesel car	Diesel truck	Diesel bus	Gasoline small vehicle
Gasoline car	Gasoline truck	Gasoline bus	Diesel small vehicle
Ethanol car	Ethanol truck	Ethanol bus	
LPG car	LPG truck	LPG bus	
NGA car	NGA truck	NGA bus	
Electric car		Electric bus	
Plug-in hybrid car			
Hydrogen car			

Although a wide range of technologies are included for the road transport, the original TIAM model included even more. Some of the reductions are due to aggregation of demand categories, leading naturally to aggregation of end-use technologies. For example, TIAM-ECN model includes one general transport demand for trucks and the related technologies in Table 5.1 all fulfil this demand. The original model, however, had separate demands for commercial, medium and heavy truck transport and correspondingly has a set of technologies for each of the demand categories. Moreover, in the TIAM-ECN model older technologies of the same kind are phased out as new, improved technologies appear in the market. Original TIAM included a 'standard' and an 'advanced' version of many technologies, thus adding detail to the choice between cost and efficiency (e.g. standard gasoline technology is cheaper, but less efficient than the advanced gasoline technology). We instead assume that most of the technical improvements will quickly become common practise for the following generation of the car technology and therefore we assume the efficiency of a given car technology improves over time. In most cases this can be considered a sufficient representation. If, however, the focus is on the competition of the end-use level technologies, additional detail is desirable in order to represent all the factors affecting the competitive situation more accurately. We will do this for passenger cars, by updating the data and distinguishing between standard technologies, advanced technologies as well as hybrid and plug-in hybrid versions of a car using a given energy carrier. Moreover, we will pay extra attention to the modelling of the hydrogen cars, which are the main focus of this project.

Demand-side response to price and cost developments

It is important to represent cost induced demand effects, both relating to efficiency improvements for the end-use devices as well as to behavioral change brought about by the increased prices. This is especially true in light of the focus that has been recently given for demand reductions as perhaps the main tool for mitigating climate change (see e.g. Grübler and Riahi, 2010). Also for this our chosen model has some very useful characteristics. TIAM-ECN has a detailed description of the end-use sector and therefore price induced efficiency improvements, or fuel substitutions, can be endogenously modeled. Furthermore, as was described in chapter three, TIAM-ECN can be run in a mode that implements own price elasticities for the demands, allowing also demand reductions for the services provided.

5.4 Functional requirements in model design

The model that we formulate according to the characteristics described in this chapter will heavily rely on the original TIAM features described in Chapter 3. This model needs to be able to simulate energy systems that tilt in the direction of, for example, a full electric society, hydrogen economy or fossil fuel regime. More precisely, if sensitivity analysis is conducted, there parameter combinations should exist that cause the model to redirect itself towards another regime. In other words, the model should be flexible in both its inputs (easy to alter) and outputs (model reacts to changes, is not too constrained).

Further requirements relate especially to the variables we have deemed essential for the analysis, namely emission taxes (or climate constraints), fuel prices and security of supply indicators. TIAM offers a good background also for these; it is rather straightforward to add emission constraints or taxes into the model and security of supply indicators can also be calculated from the results - or even given to the model as targets that need to be reached. Fuel prices, especially for imports, are also easily adjustable.

6. Data specification of the European Sustainable Hydrogen Model

In this section of the document we turn our attention to the global energy system model TIAM-ECN. We will first review and document the original structure and data of the TIAM model, before proceeding to describe our vision of how the hydrogen infrastructure, from the production until the final consumer, could be modelled. This process includes not only structural changes, but also the reviewing and, if necessary, updating the relevant data sets. On the end-use side, our focus will be mainly on the transport sector, since we do not consider it likely that a potential 'hydrogen revolution' could start in any other sector.

6.1 Review of the original structure and data for hydrogen chain in TIAM

In this section we document and review the structure and data for the hydrogen, as it is in the TIAM model currently, before we implement our changes. We aim at being fairly thorough in our documentation, so that the meaning and purpose of the changes done later is more apparent.

Structure of hydrogen flows and processes
We start our description from the superstructure of the hydrogen system, including the main building blocks as they are currently in the model and shown below in Figure 6.1. This figure shows the flow of hydrogen through the system, from production to the end-use. The commonly used, or most promising, production technologies are included adequately in the model and the production side is, in general, covered quite well. The representation of hydrogen transport and distribution, however, is very limited, due to the difficulties of adding spatial structures in a model where this dimension is highly aggregated. At the end-use level the focus is mainly on hydrogen use in the transport sector. In the following sections the modelled production, distribution and use of hydrogen will be discussed separately in more detail and the data will be compared against literature sources. Secondary conversion processes related to hydrogen, such as Fischer-Tropsch-diesel and methanol production, are also included in the model, but do not usually play a prominent role in most of the hydrogen scenarios. We will therefore, at this stage, exclude them from the detailed discussion at this stage.

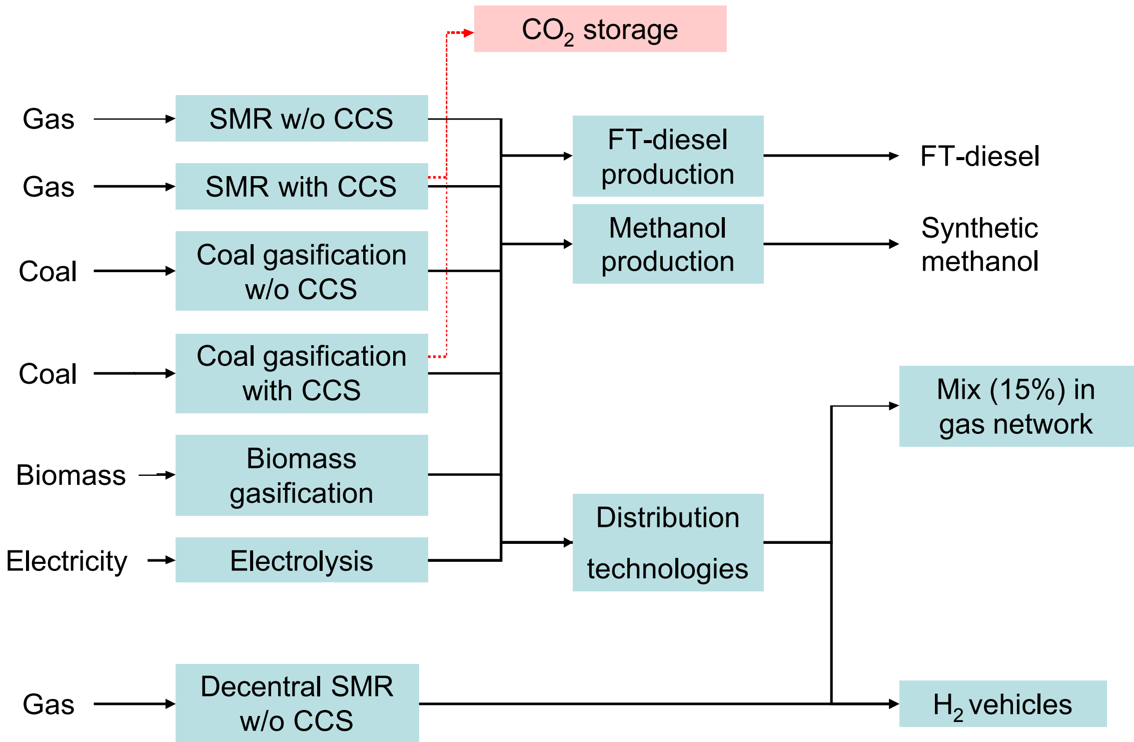


Figure 6.1 *Hydrogen currently modelled in TIAM*

Hydrogen production

As stated above, the existing representation of hydrogen production technologies in TIAM is quite complete. Technologies modelled are steam methane reforming (SMR, uses natural gas), gasification of coal and biomass and finally electrolysis. Detailed descriptions of different technologies are given in Section 6.3.

Table 6.1 lists the original technology data of the model, most of which is unsourced and therefore reflects unknown assumptions in the choice of parameter values. Furthermore, when comparing the TIAM data with (Gül, 2008) and (IEA, 2005), both of which review data from various sources, some general comments can be made. First of all, the technology characteristics in TIAM are assumed to be static, i.e. there are no cost reductions or efficiency improvements expected for the future. Most of the sources listed in (Gül, 2008), (IEA, 2005) and (Krewitt and Schmid, 2005), however, do assume some improvements over time. Moreover, some more specific observations can be made based on the comparison:

- TIAM does not currently include a biomass gasification plant with CO_2 capture. According to IEA, 2005, biomass gasification will only become economical attractive if the CO_2 can be captured, since this would lead to negative emissions and additional credits under a CO_2 control regime.

- Small scale electrolysis is not modelled. This could be an interesting option for the early phase of hydrogen diffusion, when the demand for hydrogen is still low. Furthermore, small scale electrolysis could also contribute for decentralized systems in remote areas where other sources are not easily available.

- Specific investment costs of large and small scale SMR plants are assumed to be similar, i.e. economy of scales is ignored. This is in contrast to assumptions presented in the literature (IEA, 2005 and Krewitt and Schmid, 2005).

- Assumptions concerning the specific investment costs for coal gasification based hydrogen production seem pessimistic in TIAM, when compared to other sources.

- Assumptions concerning the efficiencies for centralized and decentralized SMR, as well as electrolysis, are very optimistic.

- The availability factors for SMR and coal gasification technologies are very high. On the other hand, the availability factor for electrolysis is quite pessimistic. According to sources in [Gül, 2008] coal gasification plants are operational 80-90% of the year, whereas the SMR and electrolysis plants have an availability factor around 90%.

For biomass gasification the sources (Gül, 2008), (NRC, 2004) and (Krewitt and Schmid, 2005) diverge in their assumptions on investment costs and efficiencies. It is unclear whether these differences could be partially explained by different assumptions on whether the costs for biomass handling and drying are included.

Table 6.1 *Technology data for hydrogen production in TIAM*

		Steam methane reforming (SMR)	Steam methane reforming with CO_2 capture	Steam methane reforming - decentralized	Coal gasification	Coal gasification with CO_2 capture	Biomass gasification	Electrolysis
Efficiency	[%]	81	79.6	75	63	61.9	63	80
Gas / coal / biomass use	[PJ/PJ]	1.23	1.23	1.33	1.59	1.59	1.59	
Electricity use	[PJ/PJ]		0.02			0.03		1.25
Availability factor	[%]	95	95	95	95	95	85	85
Investment cost	[mln $\$_{2005}$ / PJ annual]	10	12.5	10	33.5	36	50	30
Fixed O&M cost	[mln $\$_{2005}$ / PJ annual]	0.56	0.56	0.56	1.5	1.74	1.08	0.95
	[% per year of capital]	5.6	4.5	5.6	4.5	4.8		
Variable O&M cost	[mln $\$_{2005}$ / PJ_{out}]			2	0.2	0.22		
Lifetime	[years]	20	20	20	20	20	25	30
Available from	[year]	2005	2020	2005	2005	2020	2008	2005

[1)] In TIAM brown coal as well as hard coal can be used for coal gasification.

Transportation and distribution of hydrogen
Currently transport costs for centrally produced hydrogen (including the costs of refuelling stations) are modelled simply as a variable cost of 2 mln €/PJ. There is therefore no distinction made between transporting hydrogen per pipeline or by truck, nor are there explicit assumptions made on the type of refuelling stations used. Cost for refuelling stations for decentralized production are currently in TIAM modelled as a variable cost of 2 mln €/PJ.

Modelling of the transport and distribution infrastructure is not easy in a model that has very little spatial detail:: in a model like TIAM the geographical distribution of the demand and production cannot be represented in detail, therefore making also the explicit modelling of transport distances impossible. The main parameters for determining transport costs are the distance between production and consumption and the amount of hydrogen that needs to be transported. Using the combination of these two parameters, different hydrogen technologies are optimal for different flow rates and distances (Chang and Ogden, 2008). For small amounts of hydrogen over short distances truck transport of gaseous hydrogen is most economical, while truck transport of liquid hydrogen is more economical for long distance transport. Pipeline transport is, due to high investment costs, only attractive when the flow of hydrogen is high.

Costs for refuelling stations also differ between the transport modes used. Refuelling stations connected to a pipeline system have higher capital costs than refuelling stations that are supplied by trucks, mainly because additional costs for compressing and storage. Moreover, economies of scale are also significant for refuelling stations.

Transport and distribution costs are a significant part of the total hydrogen costs, therefore making it necessary to consider how these costs could be modelled in such a way that the transport costs are represented realistically for the different stages of hydrogen market penetration. Moreover, the modelling of hydrogen distribution should be comparable with the modelling of electricity distribution, for both the level of detail and for including all the necessary cost elements.

End-use of hydrogen
Currently hydrogen is available in TIAM only in the transport sector and its use is limited to passenger cars. Other end use sectors do not include technologies for the use of hydrogen, although the model does allow limited mixing of hydrogen into the natural gas deliveries. For the transport technologies, direct combustion of hydrogen in an internal combustion engine (ICE) as well as hydrogen use in a fuel cell is modelled. For the ICE hydrogen cars also a hybrid version is included in the model. Onboard storage of hydrogen can be in liquid form or by carbon storage. For fuel cell cars, also gaseous hydrogen storage is an option. In the Table below technology data of the hydrogen cars is given.

When comparing the efficiency and cost data of the different hydrogen cars, it can be seen that the fuel cell car with gaseous storage is considered the most economical option. Other studies (IEA, 2009), (Gül, 2008) and (Concawe, 2008) have previously reached the same conclusion and foresee that gaseous storage, combined either with fuel cells or with direct combustion, is the most economic options for hydrogen cars.

Table 6.2 *Technology data for hydrogen cars*

		Combustion liquid storage	Combustion carbon storage	Combustion hybrid liquid storage	Combustion hybrid carbon storage	Fuel cell liquid storage	Fuel cell carbon storage	Fuel cell gaseous storage
Efficiency								
2006	[Bv-km/PJ]	0.37		0.50		0.69		0.74
2020	[Bv-km/PJ]	0.41	0.45	0.52	0.59	0.73	0.78	0.78
Investment cost								
2006	[$\$_{2000}$ / Bv-km annual]	2000		2500		5000		2500
2020	[$\$_{2000}$ / Bv-km annual]	1528	1929	1674	2074	1892	2293	1608
Fixed O&M cost	[$\$_{2000}$ / Bv-km annual]	80	80	80	80	80	80	80
Discount rate								
Lifetime	[years]	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Start	[year]	2006	2020	2006	2020	2006	2020	2006

6.2 Vision on hydrogen economy and description of modelling limitations

Before implementing all possible hydrogen production, distribution and end-use technologies in the model and then letting the model to decide the most cost optimal solution, this section will discuss how *we* think a realistic transition to a hydrogen economy could look like. What are the crucial points and bottlenecks and how well can these be addressed by the model?

Although many countries have their own vision on how hydrogen economy could develop, based on the historical set up of their energy system, domestic availability of resources and their policy preferences, this section will describe a vision on a broader setting, covering some the general stages of a hydrogen transition for Europe as a whole.

Production of hydrogen

One of the main issues for a transition to hydrogen economy is the chicken and egg problem of supply and demand. Production and supply infrastructures will only be built if there is enough demand for hydrogen and, on the other hand, people will opt for hydrogen cars only if hydrogen is easily available. In the initial phase this will be only in urban areas. Although production plants profit significantly from the economies of scales, it is very likely that in the initial phase the more expensive decentralized production plants, on-site at the refuelling stations are preferable. Since the model is not very suitable for explicitly distinguishing scale benefits or for modelling spatial detail, additional constraints will be needed to simulate the earlier diffusion of decentralized production, before centralized production becomes the norm.

Due to the aggregated nature of the model, the preferences for and availability of resources for individual countries in Europe will not be modelled. The most promising production options will be included in the model and the model will decide on the optimal technology portfolio. Some technologies, such as electrolysis and biomass gasification, might be less cost effective in a business as usual scenario, but could become more interesting under certain circumstances, e.g. with increasing fossil fuel prices or with tightening environmental pressure (increasing CO_2 prices).

Transport and distribution of hydrogen

Transport of hydrogen is a crucial part of the complete supply-demand chain. Although this is true for all energy forms, it is especially so for hydrogen, for which a complete new infrastructure needs to be built. Furthermore, the final economical configuration of the infrastructure depends on the volume of the hydrogen flow, the demand density (i.e. hydrogen demand per square kilometre) and on the distance over which hydrogen needs to be transported. Depending on the set up, transport over pipelines, by truck as gas or as liquid might be economically most lucrative. Pipeline transport is considered economically feasible only for large hydrogen flows, whereas truck transport of gaseous hydrogen is the most economic option for smaller amounts of hydrogen, if transported over short distances. Truck transport of liquid hydrogen falls somewhere in between, being the most economic option for long distance transport up to certain level of hydrogen demand.

Since the model applied has aggregated spatial information only, hydrogen demand is seen only as a 'point' demand for the whole region. The regional spread of the demand and local demand densities, as well as transport distances, can therefore not be represented endogenously. Since the flow and distance are important parameters for making decisions on the mode of hydrogen transport, additional assumptions need to be made concerning the average transport distance and demand density in different stages of the transition to hydrogen economy.

End-use of hydrogen
Our focus in this part of the study will be mainly on the use of hydrogen for transport purposes and in particular hydrogen cars. The main reason for this is that transport sector is considered to be the key for the possible emergence of a hydrogen economy. Although demand from other sectors may well support such a transition, they are expected to play a secondary role and not be initiators of a potential hydrogen breakthrough. The restriction to passenger cars is not because we not foresee use of hydrogen for other mobility purposes, but the latter volumes will be rather small compared to passenger cars. Actually there are good prospects for hydrogen busses entering the market, see (NextHyLights, 2011).

Although the development of production and transmission technologies has a sizable influence on determining whether a transition to a hydrogen economy is feasible, at least similar importance can be attached to the development of fuel cells. Although hydrogen can be used in internal combustion engines (ICE), fuel cells are seen as preferable because of their high efficiency performance and currently also the only technology used by car manufacturers. Also developments in storage technologies play an important role for any cars using hydrogen. We describe the assumptions concerning the costs and performance of hydrogen cars and their key components in Section 7.1.

Below we sketch a vision of how the initial and advanced phase of a European hydrogen economy could look like. This vision is formulated on a conceptual level and it does not involve decisions concerning production technologies, a decision that will be taken by the model. This vision also differs from the visions developed in projects such as (Hyways, 2008), in which the individual countries made decisions on specific shares of each production-transport chain. The general views concerning the development of the hydrogen system are, however, in line with each other (i.e. penetration of hydrogen vehicles, truck transport and decentralized production in initial phase and centralized production with pipeline infrastructures in final phase (except for rural areas)). As an example how hydrogen cars can penetrate, the share of hydrogen cars in the total passenger car fleet, for four penetration scenarios from the HyWays study, are given in Figure 6.1. In our study we will investigate how external conditions like developments in global energy markets and climate change policies will influence the penetration of hydrogen cars and as a result show similar curves for a couple of possible scenarios.

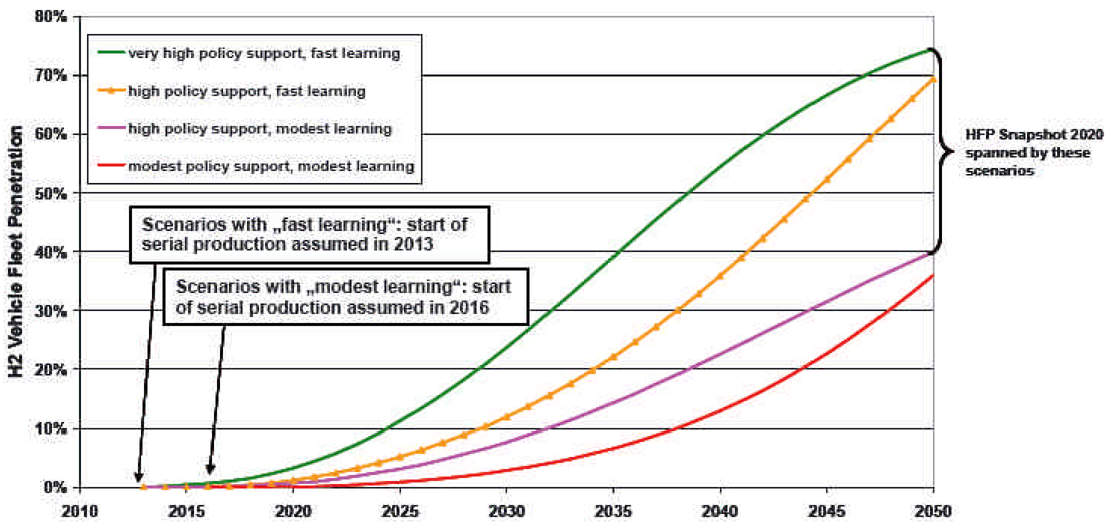


Figure 6.2 *Share of hydrogen cars in different penetration scenarios from HyWays study*
Source: HyWays, 2008.

Initial phase of the hydrogen economy
In the initial phase the demand for hydrogen will be limited and penetration of hydrogen in the transport sector will remain low. In this phase the refuelling stations will be mainly located in urban areas. Currently some EU countries have plans to start the roll out of hydrogen infrastructure in city centres. Hydrogen will be produced decentrally from natural gas or electricity, onsite at the refuelling stations. Furthermore, these stations will be small and able to supply only a small number of cars per day. Later, at the next stage, also some centralized production facilities will be available and hydrogen will be delivered in gaseous form to the refuelling stations using trucks. Transport distances will be still relatively short and the truck trailer will be left behind at refuelling station, thus serving also as a storage vessel for the hydrogen.

Although hydrogen is produced already now in several countries in Europe as by-product from industrial processes, we do not consider this to be the first step in the emergence of a hydrogen economy and will not include such flows within our modelled structures.

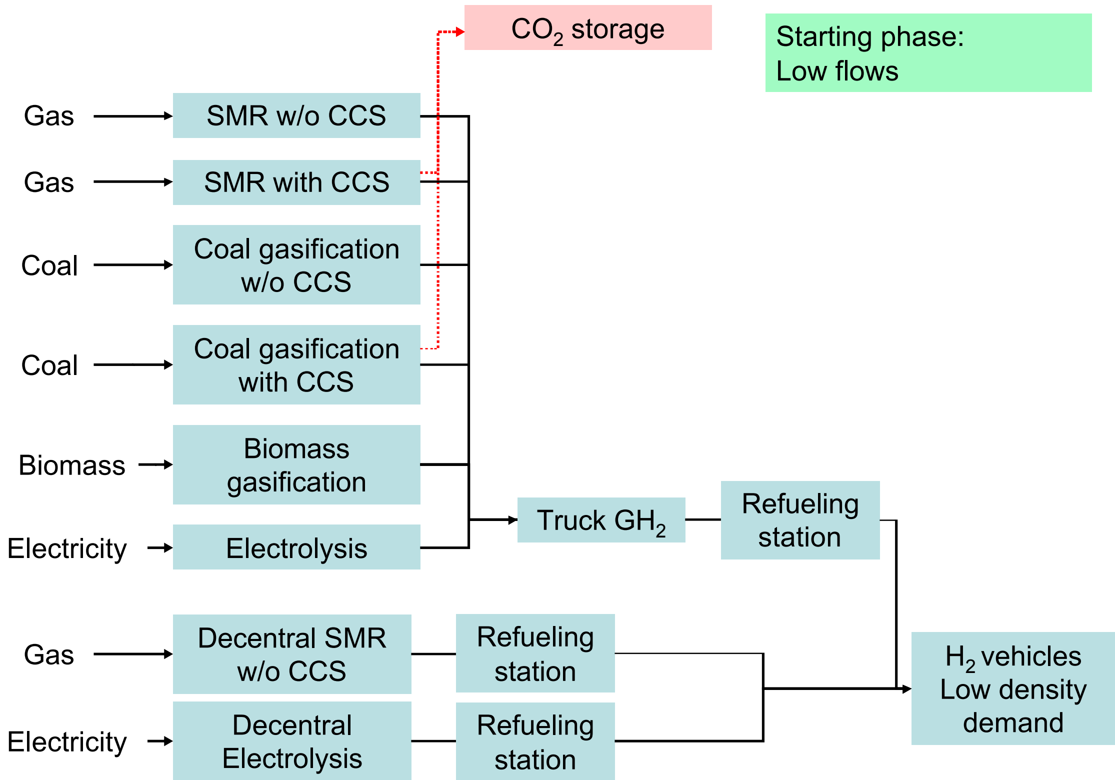


Figure 6.3 *Hydrogen flows in the initial phase of the hydrogen economy*

Advanced phase of the hydrogen economy
In the advanced phase of the hydrogen economy the penetration of hydrogen in the transport sector is expected to be significant. A large fleet of hydrogen driven cars is assumed to be on the roads and a large number of large refuelling stations is needed to supply them. Production will be centralized and will take place at huge, centrally located plants alone. With this high demand density a pipeline infrastructure is the most economic option and an extensive pipeline network will be built up by the time of this phase. Despite the high population density of Europe, there will also remain regions in which the density of hydrogen demand will be much lower. Furthermore, there are also areas where building a pipeline infrastructure is too expensive due to difficult pipe laying conditions. In these (rural) areas the demand for hydrogen will be fulfilled by either decentralized production or by truck transport from the centralized plants. This will, however, constitute only a small share of the total hydrogen demand.

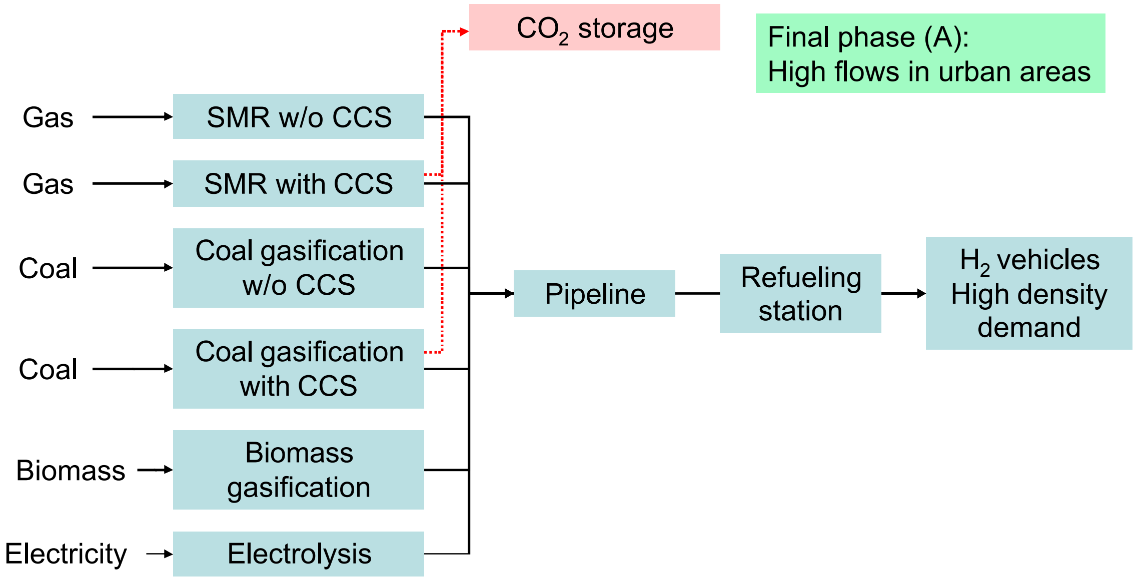


Figure 6.4 *Hydrogen flows in areas with high demand density, the advanced phase of the hydrogen economy*

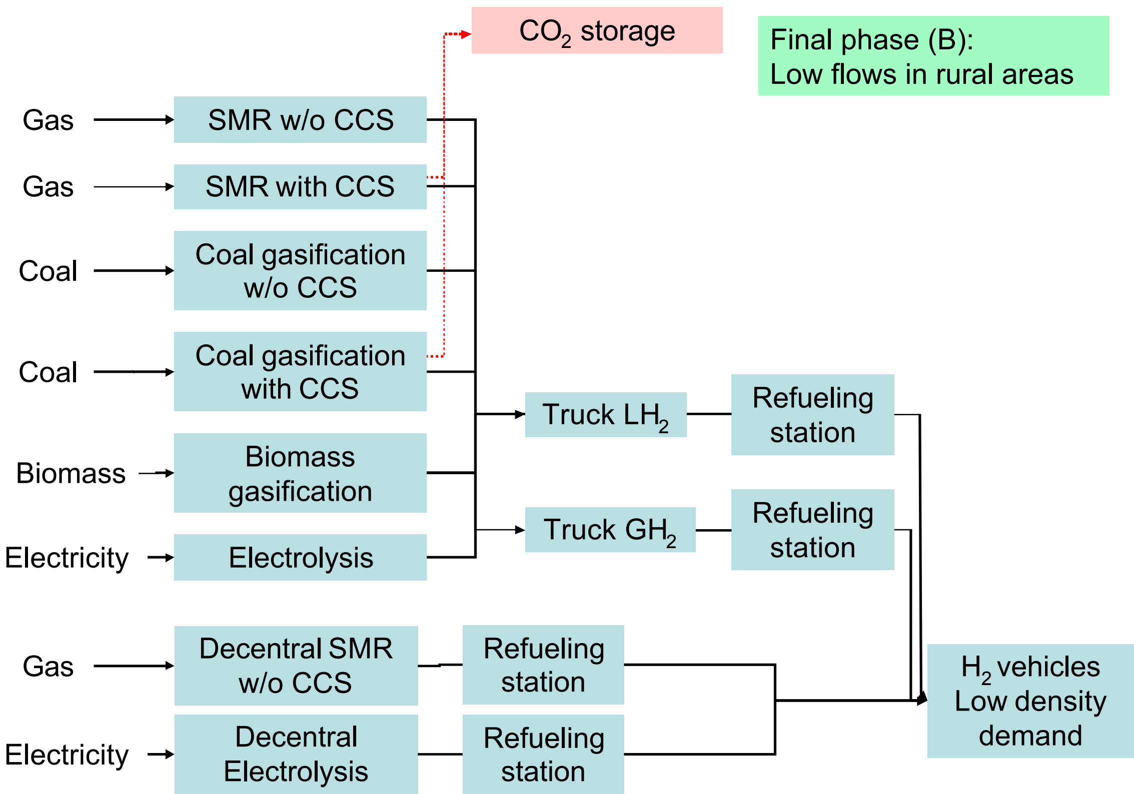


Figure 6.5 *Hydrogen flows in areas with low demand density, the advanced phase of the hydrogen economy*

6.3 Technology data for hydrogen production

Most of the numerical technology data we implement is based on the study 'The Hydrogen Economy' of the American National Research Council and National Academy of Engineering from 2004 (NRC, 2004). This study is very comprehensive, containing data for both technical indicators, such as efficiencies, as well as for economic components of all kinds. It even offers insights on the R&D needs and on the possible improvements of the technologies in the future. Moreover, the scale of the competing technologies documented in the report is similar, thus offering a good basis for comparison. Besides (NRC, 2004) other sources are used for consolidation of the numbers used. An overview and comparison of technology data from different sources can be found in (Gül, 2008) and (IEA, 2005).

All cost data in this report is in Euros in the year 2010 and since the data in the model database are in US dollars in the year 2005 we tried to include also all the costs data in US dollars 2005. If the year of the currency used was not explicitly mentioned in the source, it was assumed that costs are given in the currency of the year of the publication. We use a GDP deflator from IMF to convert cost data from other years to the currency of 2005 and 2010 (http://www.imf.org/external/pubs/ft/weo/2009/01/weodata/index.aspx).

Below we describe the main hydrogen production technologies, all of which we will also include in our modelling framework. We have excluded some technologies that we consider yet to be too far from the commercial stage (e.g. biological production) or which we consider to remain uncompetitive over the studied time frame for other reasons (e.g. we assume that production of hydrogen from natural gas by partial oxidation or auto-thermal reforming are not competitive with steam methane reforming). Finally, we do not include by-product hydrogen flows from other conversion and industrial processes.

6.3.1 Steam methane reforming (SMR)

Centralized production

Steam methane reforming is based on an endothermic reaction of methane and steam. In the first step the methane reacts with steam forming a synthetic gas (syngas) containing hydrogen and carbon monoxide (CO). In the second step the CO and steam react (water-gas shift reaction) yielding carbon dioxide (CO_2) and hydrogen. The final step of steam methane reforming process is the purification of the syngas, in order to have only pure hydrogen in the final output stream.

Since we do not include plant size and other specific characteristics of the plant within the endogenously modelled system, we need to choose a representative plant. For this we base our assumptions on a centralized SMR plant that produces around 50 PJ of hydrogen per year (1.1-1.2 kton hydrogen per day) and includes the pressurization until pipeline pressure of 7.6 MPa (NRC, 2004 Appendix E). Technology data are given in Table 6.3.

The main source we use for our data (NRC 2004) gives, among other indicators, also future numbers for an optimistic scenario (although it is not specified for which year these numbers are estimated to apply). For example, it is estimated that under optimistic assumptions a reduction of 30% in the specific investment cost of a large scale SMR plant can be reached. Assuming a learning by doing rate of 11% (Schoots et al, 2008) a 30% cost reduction would mean that the global cumulative capacity of SMR installations would need to be over 8 times the cumulative capacity installed until now (i.e. there should be more than three doublings of the cumulative global capacity). Since IEA (IEA, 2005) reports only limited potential for improvements in large scale SMR and also (Krewitt and Schmid, 2005) expect costs reduction of mere 5% by 2030, we assume that the estimations in (NRC, 2004) are for the far future, that is 2050 the earliest. If, however, it turns out that this assumption is essential for the results we retrieve with the model, the cost decline path of the technologies can be varied in the context of a sensitivity analysis.

Since the production of H_2 with SMR produces also a pure stream of CO_2, emissions from a SMR plant can be captured quite easily. This is, however, only economically feasible for large, centralized plants. Integrating carbon capture technology to SMR leads to additional investment costs around 20%-25%. These costs result mainly from the compression of the CO_2 and this number does not include the costs for transport and storage of the captured CO_2.

In addition to the natural gas used as feedstock, the SMR process also requires some electricity as input, mainly for the compression of the hydrogen. If also CO_2 capture technology is integrated into the plant, half of all electricity needed is used for compression of the captured CO_2.

Fuel costs are the largest component of the operation and maintenance costs. These costs, however, are calculated endogenously by the model, meaning that only non-fuel O&M costs need to be estimated for the SMR facilities. Based on the literature, it appears that a range of 2-5% of the capital costs is a reasonable estimate for annual fixed O&M costs (Krewitt and Schmid, 2005, NRC, 2004 Appendix E) and around 1% (NRC, 2004 Appendix E) for variable O&M costs.

Decentralized production

Currently most of the hydrogen produced with SMR originates from large scale industrial sites. SMR can, however, be easily scaled down, making it in suitable for decentralized production. Since it is expected that during the early stages of hydrogen diffusion decentralized systems will dominate, this characteristic of the production technology is essential. Decentralized systems are expected to be especially important in the beginning, because initially only small amounts of hydrogen are required and building a complete pipeline infrastructure for hydrogen would be prohibitively expensive and take a long time to construct. Therefore producing hydrogen at local refuelling stations could be the first solution for providing the fuel for hydrogen vehicles.

As a reference plant for small-scale SMR production we use an onsite plant with the capacity to produce annually 0.02 PJ of hydrogen (480 kg H_2 per day. H_2 produced at a pressure of 34 MPa). A refuelling station of this size can supply approximately 700-850 fuel cell vehicles per week (100-122 per day).

The costs per unit of capacity of or output are for a small SMR plant much higher than those of a large plant. The costs given for the decentralized plant in Table 6.3 include also the costs for the refuelling station, i.e. for the compressor, storage and dispenser needed at the station. In addition to being more expensive, small scale steam methane reformers also are less refined technically and, for example, have a lower efficiency than the large units have. Small scale SMR technologies are, however,, expected to have good prospects for costs decreases and efficiency improvements (IEA, 2005).

Table 6.3 *Technology data for centralized and decentralized SMR plants*

		Steam methane reforming		Steam methane reforming with CO_2 capture		Steam methane reforming decentral	
		2005	2050	2020	2050	2005	2050
Gas use	[PJ/PJ_{H2}]	1.31	1.24	1.39	1.28	1.67	1.43
Electricity use	[PJ/PJ_{H2}]	0.021	0.016	0.05	0.04	0.066	0.05
Availability factor	[%]	98	98	90	90	90	90
Investment cost	[mln $\$_{2005}$ / PJ/yr]	9.7	7.0	12.3	8.4	90.8	47.1
	[mln €$_{2010}$ / PJ/yr]	8.7	6.3	11.0	1.5	81.5	42.3
Fixed O&M cost	[% per year of capital]	5	5	5	5	5	5
Variable O&M cost	[mln $\$_{2005}$ / PJ_{out}]	0.10	0.07	0.14	0.09	1.01	0.52
	[mln €$_{2010}$ / PJ_{out}]	0.09	0.06	0.13	0.08	0.91	0.47
Lifetime	[years]	20	20	20	20	20	20
Available from	[year]	2005		2020		2005	

6.3.2 Hydrogen from coal gasification

A number of gasifier technologies exist for producing hydrogen from coal, although, the processes used are quite similar in general terms. In a gasification plant a mixture of coal, oxygen and steam is converted into a synthetic gas (syngas), which consists of hydrogen, carbon monoxide (CO), carbon dioxide (CO_2) as well as some other gases and particles. This occurs at very high temperature and under a high pressure. After the syngas is cooled down, the other gases and particles are removed from the stream. In the next step the CO in the syngas is shifted to hydrogen and CO_2. In the final step the gas mixture is separated into a hydrogen stream and a high concentration CO_2 stream. Again, it is relatively easy to capture CO_2 from the pure CO_2 stream.

A lot of variation in the performance estimates can be found in the literature. For example, some studies report net production of electricity while others report electricity production from tail gas but also additional electricity consumption/import to produce the required oxygen.

Unlike with SMR technology, hydrogen production with small, decentralized coal gasification units is not considered a viable option due to aspects such as stronger economies of scales and prohibitive costs for distributing coal to decentralized sites.

Table 6.4 presents the technology data we assume for coal gasification technologies. The chosen representative coal gasification technology is of comparable size to the SMR plant described in Table 6.3, producing around 52PJ/yr at a pressure of 7.6 MPa. Additional compression is not needed since the H_2 is already produced at a high pressure.

According to (Schoots et al, 2008) the development of investment costs of coal gasification technologies found in literature does not show a traditional learning effect. More precisely, the data points retrieved from literature form an inconclusive cloud, based on which one can't detect learning, albeit nor lack of learning either. In other words, there is no definite, detectible decrease of specific investment costs with increasing cumulative capacity. We will, however, assume that this will change and the costs will decline in the future due to expected technological developments (see Appendix G of (NRC, 2004for research and development possibilities). We do, however, consider the suggested costs decline of 25% for future technologies in (NRC, 2004) to be very optimistic and assume therefore that these costs can be reached only in the far future (2050).

For the additional CO_2 capture costs (NRC, 2004) reports an increase of 2% for total investment costs, a very low number when compared to other sources. For example, (IEA, 2005) reports additional costs of 5%, whereas according to (Gray and Tomlinson, 2002) the investment costs with CO_2 capture are 13% higher than without it. We use costs the NRC estimated for current technology with CCS, but assume that these costs are reached only in 2020 instead of 2005. 2020 can also be considered to be the year when CO_2 storage might be out of the demonstration phase and be technically feasible on a larger scale.

As mentioned above, literature sources differ in their assumptions concerning the net electricity use of hydrogen production from coal. We assume in this study that part of the electricity needed for oxygen production can be produced form the tail gasses, but still some additional electricity from the grid is also needed.

Table 6.4 *Technology data for coal gasification plants*

		Coal gasification		Coal gasification with CO_2 capture	
		2005	2050	2020	2050
Coal use	[PJ/PJ$_{H2}$]	1.48	1.36	1.48	1.36
Electricity use	[PJ/PJ$_{H2}$]	0.07	0.02	0.11	0.05
Availability factor	[%]	90	90	90	90
Investment cost	[mln \$$_{2005}$ / PJ/yr]	22.6	17.0	23.1	17.5
	[mln €$_{2010}$ / PJ/yr]	20.3	15.3	20.7	15.7
Fixed O&M cost	[mln \$$_{2005}$ / PJ$_{out}$]	5	5	5	5
Variable O&M cost	[mln \$$_{2005}$ / PJ$_{out}$]	0.25	0.19	0.26	0.19
	[mln €$_{2010}$ / PJ$_{out}$]	0.22	0.17	0.23	0.17
Lifetime	[years]	20	20	20	20
Available from	[year]	2005		2020	

6.3.3 Hydrogen from biomass gasification

Although there are a variety of biomass gasifier processes, in general two main approaches are used. The first approach is very similar to the above described coal gasification process: Biomass is gasified, the produced syngas is cooled down and cleaned. The CO present in the syngas is shifted to hydrogen and CO_2 and, as the final step, the hydrogen stream is purified.

The second approach is not very different from the first one, but contains an additional reforming step and operates at lower temperatures. Biomass is gasified, the gas is cleaned up and the steam reformed. And, as in first approach, this is followed by a CO shift and the hydrogen purification.

Although biomass gasification based hydrogen production is not commercial and still in the R&D and demonstration phase, it can profit from recent developments in technologies with which it shares many components, i.e. biomass gasification for electricity production and hydrogen production using coal gasification. Due to the early development stage of biomass based H_2 production technologies, estimations on technology characteristics are partially based on these related technologies. Sources, however, differ significantly in appraisal approaches as well as for the numerical values for the estimated data.

For example, (Krewitt and Schmid, 2005) report data for a production process that includes, in addition to the gasifier, also a steam reforming step. According to (NRC, 2004), this process could be available in the future, but currently only a technology including a gasifier alone would be available. Also, NRC reports lower efficiencies and higher costs than Krewitt and Schmid do for the current state of the technology. For the future, both sources suggest similar values for efficiency,, but the investment costs approximations are quite different. Krewitt and Schmid report costs of € 48/PJ for plants with capacity of less than 1 PJ per year, and € 29/PJ for plants with capacity of more than 1PJ per year. NRC is less optimistic, with costs of € 59/PJ for plant with capacity of 1 PJ/yr. The latter costs, however, include also investments for the biomass handling and drying, whereas it is not known whether these components are included in the data reported by Krewitt and Schmid.

For this study we use the data from (NRC, 2004). One of the main reasons for this is that unlike some other sources, (NRC, 2004) has data for biomass gasification also with CO_2 capture. The investment and also fuel costs for hydrogen production from biomass are much higher than those of other hydrogen production technologies. It is therefore expected that biomass gasification can be economically competitive only if there is a price on CO_2 emissions. Biomass based H_2 production with CO_2 capture could be especially interesting, if the value of CO_2 reductions rises very high: Capturing and storing CO_2 emissions from biomass can effectively lead to ‘negative emissions’, if the area where the biomass was retrieved is reforested, therefore also tying carbon from the atmosphere.

Because it is not very economic to transport biomass with low energy density (per volume or mass unit) for long distances, the regional availability of biomass is assumed to determine the size of the reference biomass gasification plant. In other words, although also the biomass gasification plants are assumed to be centralized, their size is expected to be smaller than that of coal gasification plants. Technology data is given in Table 6.5 and it is based on a midsize hydrogen plant producing 1.05 PJ/yr at a pressure of 7.6 MPa.

Table 6.5 *Technology data for biomass gasification plants*

		Biomass gasification		Biomass gasification with CO_2 capture	
		2005	2050	2020	2050
Biomass use	[PJ/PJ_{H2}]	2.5	1.6	2.5	1.6
Electricity use	[PJ/PJ_{H2}]	0.20	0.10	0.27	0.14
Availability factor	[%]	90	90	90	90
Investment cost	[mln $\$_{2005}$ / PJ/yr]	120.1	58.5	122.9	60.0
	[mln $€_{2010}$ / PJ/yr]	107.8	52.5	110.3	53.9
Fixed O&M cost	[mln $\$_{2005}$ / PJ_{out}]	5	5	5	5
Variable O&M cost	[mln $\$_{2005}$ / PJ_{out}]	0.25	0.19	0.26	0.19
	[mln $€_{2010}$ / PJ_{out}]	0.22	0.17	0.23	0.17
Lifetime	[years]	20	20	20	20
Available from	[year]	2005		2020	

6.3.4 Electrolysis

Centralized electrolysis

In the electrolysis process water is split into hydrogen and oxygen using electricity. Various types of electrolysers exist, differing in the electrolyte used as well as in the pressure and temperature at which the reaction takes place. One of the more established ones is the alkaline electrolyser, a mature technology using alkaline water solutions as an electrolyte and working at low pressures. Another option is the Proton exchange membrane (PEM) electrolyser, which uses a solid acid polymer membrane instead of liquid electrolyte and has therefore a more compact design than the alkaline electrolyser does. Moreover, with PEM electrolyser the hydrogen is produced at a much higher pressure. Finally, there are new, less mature technologies under development that operate under high pressure and/or high temperature, such as the reverse of the solid oxide fuel cell. Some of these technologies have the potential to become a very efficient conversion options.

The data we use for the representative centralized electrolysis plant is based on a midsize facility, producing annually 1.04 PJ of hydrogen, at a pressure level of 7.6 MPa. We do not make distinction between the different types of electrolyte used (i.e. alkaline, PEM and new concept electrolysers), but use a single representative technology for electrolysis. We do, however, indirectly assume the more advanced technologies to develop and reflect this in our choice of parameter values: We use cell efficiency of 75% for the current electrolysis technology, corresponding to a conventional alkaline electrolyser, but increase the efficiency to 85 % for the future technology, representing the new high temperature concepts. The data is given in Table 6.6 and is based on (NRC, 2004).[5]

[5] It’s worth noting that the other main data source of ours, Krewitt and Schmid, 2005, reports rather different investment costs due to different assumptions concerning the specifics of the reference plant.

Decentralized electrolysis
The technology data for decentralized electrolysis is based on a representative plant with the capacity to produce 0.02 PJ of H_2 each year (i.e. 480 kg H_2 per day) at a pressure of 34 MPa. We assume the electrolysers to be located on-site at a refuelling station, supplying 700-850 fuel cell vehicles per week (100-122 per day).

Electrolyser is easily scalable and the size of the plant does not influence its efficiency. Economies of scale, however, do play a role, even if the difference is smaller than that of centralized and decentralized SMR plants. The costs for decentralized electrolysis, given in Table 6.6, also include the costs for compression, storage and dispensing at the refuelling station. Although currently the cost of the electrolyser is dominating, it is anticipated that electrolyser costs will decline significantly in the future while storage costs will experience a more moderate improvement, thus becoming a more significant part of the total investment costs.

Table 6.6 *Technology data for electrolysis plants*

		Electrolysis		Electrolysis decentral	
		2005	2050	2005	2050
Electricity use	[PJ/PJ$_{H2}$]	1.64	1.42	1.64	1.42
Availability factor	[%]	90	90	90	90
Investment cost	[mln $\$_{2005}$ / PJ/yr]	84.1	9.6	124.7	28.2
	[mln €$_{2010}$ / PJ/yr]	75.5	8.6	111.9	25.1
Fixed O&M cost	[mln $\$_{2005}$ / PJ$_{out}$]	5	5	5	5
Variable O&M cost	[mln $\$_{2005}$ / PJ$_{out}$]	0.93	0.11	1.39	0.31
	[mln €$_{2010}$ / PJ$_{out}$]	0.83	0.10	1.25	0.28
Lifetime	[years]	20	20	20	20
Available from	[year]	2005		2005	

6.4 Distribution and dispensing of hydrogen

Distribution and dispensing of hydrogen is, next to production, the other key determinant for the supply side hydrogen costs. The main factors for determining the costs of hydrogen distribution are the transported hydrogen flow and the distance over which the hydrogen needs to be transported (Yang and Ogden, 2008). These two parameters are also essential for determining the most economic means of hydrogen transportation, the main options being pipeline transport or transport by trucks (H_2 having either gaseous or liquid form). The most economic transport option for point-to-point delivery, depending on the volume of hydrogen flow as well as the distance over which it has to be transported, as computed by Yang and Ogden, 2008, is given in Figure 6.6

Hydrogen Flow [kg/day]	25	50	75	100	125	150	175	200	225	250	275	300	325	350	375	400	425	450	475	500
2000	G	G	G	G	G	G	G	G	G	G	G	G	G	L	L	L	L	L	L	L
4000	G	G	G	G	G	G	G	G	G	G	L	L	L	L	L	L	L	L	L	L
6000	G	G	G	G	G	G	G	G	L	L	L	L	L	L	L	L	L	L	L	L
8000	P	G	G	G	G	G	G	G	L	L	L	L	L	L	L	L	L	L	L	L
10000	P	G	G	G	G	G	G	L	L	L	L	L	L	L	L	L	L	L	L	L
12000	P	G	G	G	G	G	L	L	L	L	L	L	L	L	L	L	L	L	L	L
14000	P	P	P	G	G	G	L	L	L	L	L	L	L	L	L	L	L	L	L	L
16000	P	P	P	P	P	L	L	L	L	L	L	L	L	L	L	L	L	L	L	L
18000	P	P	P	P	P	P	L	L	L	L	L	L	L	L	L	L	L	L	L	L
20000	P	P	P	P	P	P	L	L	L	L	L	L	L	L	L	L	L	L	L	L
30000	P	P	P	P	P	P	P	P	P	L	L	L	L	L	L	L	L	L	L	L
40000	P	P	P	P	P	P	P	P	P	P	P	L	L	L	L	L	L	L	L	L
50000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	L	L	L	L	L	L
60000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	L	L	L	L
70000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	L
80000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P
90000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P
100000	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P	P

Figure 6.6 *The most economic transport options for point-to-point delivery, given as a function of volume (vertical axis) and distance [km] (horizontal axis) of the hydrogen transported. [G] stands for truck, H_2 as gas, [L] for truck, H_2 as liquid and [P] for pipeline*

Source: Yang and Ogden, 2008.

As can be seen from the figure, low volumes imply a truck delivery, no matter the distance, whereas with very high flows pipeline delivery is always the most economic choice. Truck delivery in gaseous form holds a relatively small niche and is suitable especially for low volume, short distance transport. This also suggests that this means of transportation could be considered the most likely candidate during the early diffusion phase of the hydrogen transition.

Truck transport of gaseous hydrogen

The energy density of gaseous hydrogen is not very high, meaning that the amount of gaseous hydrogen that can be transported by a single truck is low. The low energy density also leads to a rather high variable cost for a unit of hydrogen, related to e.g. salary of the driver, for this means of transportation. On the other hand, the required investments are lower than with other transport options, making gaseous truck transport economic mainly for low volumes transported over short distances. With this mode of transportation the cost per unit of hydrogen transported is not very dependent on the volume of the hydrogen flow, since this would merely imply a higher number of trucks and drivers. Therefore, if the flow of transported hydrogen is high, other transport options benefiting from the increased volume are likely to be more economic.

Truck transport of liquid hydrogen

Liquefaction of hydrogen increases the energy intensity, and therefore the variable costs of truck based hydrogen transport. However, the investment needs, and therefore the fixed costs, increase considerably due to the costs related to the liquefaction process. Since the main cost component is no longer related to the distance over which the hydrogen is to be transported, transport of liquid hydrogen using trucks is an economically attractive option for long distance transport. Since liquefaction costs decrease with increasing amounts of hydrogen to be liquefied, this transport option competes with pipelines when hydrogen needs to be transported in larger volumes and over longer distances.

Hydrogen transport using pipelines

Hydrogen pipelines have high investment costs, which naturally increase with increasing length of the pipeline. This makes pipelines especially suitable for large hydrogen flows. Also, the larger the flow of the hydrogen is, the longer is the economically lucrative distance for the pipeline transport.

Refuelling station for hydrogen
In addition to determining the costs of the transmission infrastructures, different transport modes also imply different characteristics for storage and compression of hydrogen at the refuelling stations. Moreover, economies of scale play an important role as the unit costs of refuelling stations (i.e. costs per unit of hydrogen dispensed) are highly dependent on their size.

Refuelling stations supplied with gaseous hydrogen by trucks will, in general, be small filling station, since this mode of transport is mainly suitable for low volume flows. The transported hydrogen vessel will be left at the refuelling station and it can then be used as the on-site hydrogen storage. This mode of operation leads to storage costs clearly below those of pipeline refuelling stations of same size.

Trucks with liquid hydrogen will supply several refuelling stations, the number depending on the size of the individual stations. The costs of the stations supplied with this transport options are similar to the ones supplied with gaseous hydrogen by trucks.

The costs of refuelling stations supplied by pipelines are significantly higher than those supplied with liquid hydrogen; storage is cheaper for liquid hydrogen, pumps are also less expensive and electricity use is lower than what is needed for the compressors used with gaseous hydrogen.

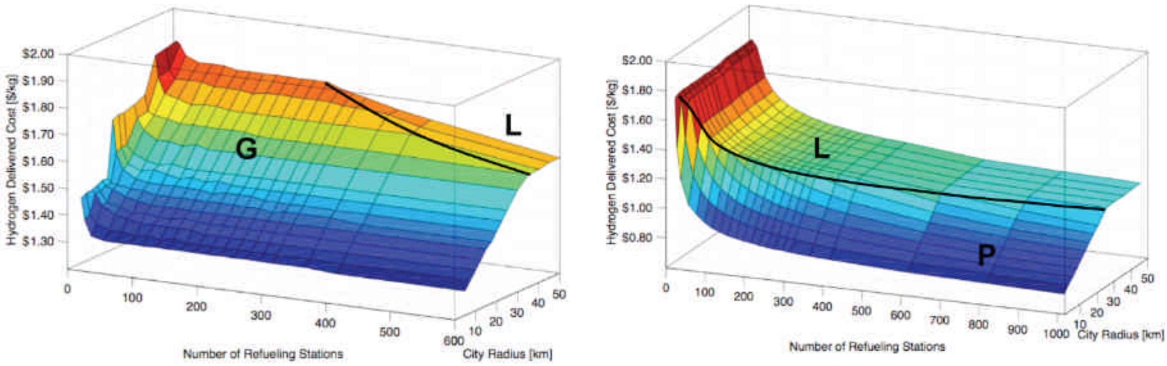
For all three types of refuelling stations the major share of the total costs are related to the costs for land (Yang and Ogden, 2008). With increasing capacity of the refuelling stations the land related costs can be decreased, leading to a significantly lower total cost per unit of hydrogen dispensed.

Lebutsch and Weeda (2011) did a study on the roll-out of hydrogen refuelling infrastructure for the Netherlands, in which they focussed on the distribution of liquefied hydrogen by truck. They assumed that hydrogen refuelling units will be placed at existing, conventional refuelling stations and hydrogen will be sold merely as one of many fuels available. They suggest that there would be an infrastructural cost gap until shortly after 2030. The infrastructural annual cost gap is defined as the difference between the levelised cost of hydrogen and the hydrogen equivalent price of gasoline in a certain year. The hydrogen equivalent price of gasoline is the price that results in equal specific fuel cost (€/km) for gasoline and hydrogen. Moreover, they estimate that this refuelling infrastructure cost gap accounts for some 3-6% of the overall cost gap of infrastructure and vehicles. The annual cost gap for vehicles refers to the cost difference between a fuel cell car and a conventional reference car in a certain year multiplied with the amount of fuel cell car sold.

Cost assumptions for the TIAM-ECN model
Economies of hydrogen transport infrastructures have a strong spatial dimension that can't be explicitly captured by a spatially aggregated model, such as TIAM; relationship between cost and transport distance, spatial distribution of demand density and size of refuelling sites can't be approached from the bottom up perspective most of the model characteristics rely on. We therefore need to make rough assumptions on general trends concerning hydrogen diffusion and then use averaged costs and scenario based transition trajectories. We will mostly rely on the data of Yang and Ogden, 2008.

Figure 6.7 below (from Yang and Ogden, 2008) depicts the hydrogen delivery costs for the most economic mean of hydrogen transport, as a function of the number of refuelling stations and city radius. Values are given for refuelling station capacities of 500kg/day and 1800kg/day. As can be seen, the costs increase with increasing radius of the network, especially if trucks with compressed hydrogen or pipelines are used. Costs initially decrease with increasing number of refuelling stations, but after a certain number of stations, a further increase in the number of stations no longer reduces the unit costs of delivery significantly. The range for hydrogen distribution costs to a network of refuelling stations is given in Table 6.7.[6] Based on the data shown, we assume for our exercise an average transport and dispensing cost of 10.4 $€_{2010}$ (11.5$\$_{2005}$) per GJ of hydrogen transported with a truck as compressed gaseous H_2 and 8.3 $€_{2010}$ (9.2$\$_{2005}$) per GJ for a liquid truck transport of hydrogen. These costs include electricity use for compression or liquefaction of hydrogen and fuel use for the truck, so these energy flows are not modelled explicitly. We also assume these costs to remain constant over time.

For trucks variable costs make up large part of the total costs. For pipelines, however, the costs mainly relate to investments made in pipelines and therefore fixed and not a direct function of the use of the pipeline. We will therefore model pipeline costs as investments in capacity rather than as a variable cost per GJ of hydrogen. The high investment requirements in hydrogen pipelines is often seen as a hurdle for investors to build up the necessary infrastructure network, especially in the initially phase when the utilisation of the network will be lower than in the latter stages of the hydrogen transition.



a) 500 kg/day b) 1800 kg/day

Figure 6.7 *Hydrogen distribution cost to a network of refuelling stations as a function of the number of refuelling stations in the network and the radius of the circular city, with refuelling station capacity of a) 500 kg/day and b) 1800 kg/day*

Source: Yang and Ogden, 2008.

Table 6.7 *Cost range of hydrogen distribution to a network of refuelling stations of 500kg/day and 1800kg/day for compressed and liquid hydrogen trucks and pipeline transport*

	500 kg/day	1800 kg/day	500 kg/day	1800 kg/day
	[$\$_{2005}$/GJ]		[$€_{2010}$/GJ]	
Truck, compressed H2	10-14.2		9-12.8	
Truck, liquid H2	12.3-13.8	8.5-13.5	11-12.4	7.6-12.1
Pipeline		5.4-13.5		4.8-12.1

The costs assumptions for pipelines, so without costs for refuelling stations, given by (NRC, 2004) and (Krewitt and Schmid, 2005), are shown in Table 6.8. Although both assume similar costs per kilometre for a pipeline, the complete costs figures are quite different. The divergence can be explained by the different assumptions concerning the hydrogen flow that is transported through the pipelines and the assumed utilisation rate of the pipeline. The NRC study assumes that 1200 ton hydrogen per day will be transported to about 440 stations, each with a refuelling capacity of 2740 kg/day, so a total capacity of 1667 MW. The capacity of the pipeline network of Krewitt and Schmid, on the other hand, is with less than 216 ton hydrogen per day only 300 MW.

6 Truck delivery in gaseous form is omitted if a refuelling station with 1800 kg/day capacity is used because it will not be the most economic choice, no matter the number of refuelling stations or the size of the city. Same applies for pipeline delivery with a station size of 800 kg/day.

Table 6.8 *Assumptions for pipeline transport of hydrogen by (NRC, 2004) and (Krewitt and Schmid, 2005)*

		NRC, 2004		Krewitt and Schmid, 2006		
		Current situation	'Future optimism'	2000	2015	2050
Pipeline network		600 km, 4 arms of 150 km		600 km, 4 arms of 150 km, diameter 31 cm		
Capacity of network		1200 ton H2/day, 1667 MW		215760 kg H2/day, 300 MW		
Cost of pipeline	[$€_{2010}$/km]	611,686	458,764	580,935	?	?
Transport efficicency	[%]	?	?	94	94	94
Additional cost[1)]	[%]	83	79	36		
Investment cost	[$€_{2010}$/GJ/y]	12.78	9.40	49.98	47.69	43.41
Utilisation factor	[%]	90	90	69	69	69
Fixed O&M costs	[%]	5	5	2.5	2.5	2.5
Variable O&M costs	[$€_{2010}$/GJ]	0.23	0.15	2.87	2.14	1.46
Total costs	[$€_{2010}$/GJ]	3.24	2.47	15.60	14.29	12.52

1) Additional to pipeline costs, i.e. costs for storage at plant, general facilities and permitting, and contingencies.

We will construct our dataset for pipeline costs such that it is comparable and consistent with the data of Yang and Ogden we use for truck transport of. Our reference pipeline network extend to about 600 km, consisting of 4 arms, each arm being a network of 150 km and supplying a city with a radius about 15 km. Each arm is assumed to provide 110 refuelling stations, each having a capacity of 1800 kg/day[7], so a total capacity of 1100MW. For this kind of system Yang and Ogden estimate cost of 7 $€_{2010}$ per GJ of hydrogen transported and distributed. Taking that, and comparing it with the assumed investment and related operational costs of NRC and Krewitt and Schmid, we assume investment costs to start at 17 $€_{2010}$/GJ/yr (18.9$\$_{2005}$) and decrease to 13 $€_{2010}$/GJ/yr (14.5$\$_{2005}$) in 2050. The cost for refuelling station will be modelled as variable cost of 3 $€_{2010}$/GJ.

Table 6.9 *Technology data used for hydrogen transport by pipeline*

Pipeline network		600 km, 4 arms x 150 km, each arm a network with 15 km radius,110 refuelling stations per arm 1100 MW
Transport efficiency	[%]	94
Investment cost	[$€_{2010}$/GJ/y]	17 (currently); 13 (in 2050)
Utilisation factor	[%]	80
Fixed O&M costs	[% of investment]	2.5
Variable O&M costs	[$€_{2010}$/GJ]	3 (mainly related to costs of refuelling stations)

7 According to Yang and Ogden, 15 km is the maximum radius for which pipelines are the most economical transport mode, assuming the network consists of about 110 refuelling stations.

7. Data specification of passenger cars

Transport sector is currently responsible for more than 28% of the European CO_2 emissions. The transition of this end use sector in a more sustainable direction can be expected to play an important role in the ongoing efforts to reduce the climate change impact of mankind. Additionally, this sector is extremely dependent on oil, the fossil fuel that can be expected to start showing signs of depletion already during the next following decades. Due to the critical nature of this sector and the lack of 'easy' substitutes for to current paradigm, the breakthrough of hydrogen is likely to take place in this sector, if anywhere at all. In this section we will describe the structure and data we implement for the main technologies in this key sector.

7.1 Passenger cars

In order to model the competition in the transport sector realistically, not only the data for hydrogen vehicles needs to be updated, but the same has to be done also for all competing passenger cars. Since it was outside the scope of this study to collect up-to-data data ourselves, we rely on data taken from other studies. Since there is no single literature source that would cover all the relevant technological options, we use a number of different sources to put together our own data set. (Concawe, 2008; Grahn et al., 2009; Gül, 2008; Hanschke et al. 2009, Uyterlinde et al., 2008 and IEA, 2009).

Since the costs of electric and hydrogen cars are largely related to the uncertain cost development of the key component for each technology, the battery and the fuel cell respectively, the cost data given below makes a distinction between the costs for batteries, fuel cells and the rest of the vehicle costs.

Table 7.1 presents the costs we use for the different passenger car technologies. Since the cost of batteries is extremely important for electric and hybrid cars, we would like to point out explicitly that the data we use is based on the low estimates of battery costs made by the IEA, 2009. More information on the costs of batteries as a function of battery capacity is given in Section 7.6.

Table 7.1 *Investment costs for passenger cars*

			Rest of car cost [€$_{2010}$]			Size component Battery [kWh]/FC [kW]		Cost component Battery [€/kWh] /FC[€/kW]		Total costs [€$_{2010}$]	
	2005	2010									
Gasoline standard	17000	17000									
Diesel standard	18000	18000									
LPG standard[1]	19000	19000									
		2010	2020	2030	2040	2020	2040	2020	2040	2020	2040
Gasoline advanced		18400	18400	18400	18400					18400	18400
Diesel advanced		19300	19300	19300	19300					19300	19300
CNG[2]		19750	19750	19300	19300					19750	19300
Gasoline hybrid		20200	19750	19750	19750	1	0.5	682	413	20432	19956
Diesel hybrid		21550	21100	20650	20650	1	0.5	682	413	21782	20856
CNG hybrid[2]		21550	21100	20650	20650	1	0.5	682	413	21782	20856
Gasoline plug-in		20650	20200	20200	20200	8	6	512	377	24293	22462
Diesel plug-in		22000	21550	21100	21100	8	6	512	377	25643	23362
Battery electric (200km)		18000	18000	18000	18000	44	36	399	296	35573	28663
H2 ICE hybrid[3]		23500	23000	22500	22500	1	0.5	682	413	23682	22706
H2 FC hybrid[4]		20200	19700	19400	19400	1 / 80	0.5 / 80	682 / 162	413 / 45	33306	23196

1) **L**iquefied **P**etroleum **G**as; LPG
2) **C**ompressed **N**atural **G**as; CNG
3) **I**nternal **C**ombustion **E**ngine; ICE
4) **F**uel **C**ell; FC

Table 7.2 *Fuel consumption of passenger cars [MJ/km]*

		2005	2010			
Gasoline standard		2.7	2.6			
Diesel standard		2.3	2.2			
LPG standard[1]		2.5	2.3			

		2010	2020	2030	2040
Gasoline advanced		2.3	2.1	2	1.9
Diesel advanced		2.1	1.9	1.8	1.7
CNG[2]		2.3	2.1	2	1.9
Gasoline hybrid		1.85	1.7	1.6	1.5
Diesel hybrid		1.7	1.6	1.5	1.48
CNG hybrid[2]		1.85	1.7	1.6	1.5
Gasoline plug-in	gasoline	1.2	1.1	1	0.95
	electricity	0.4	0.38	0.36	0.34
Diesel plug-in	diesel	1.1	1	0.95	0.9
	electricity	0.4	0.38	0.36	0.34
Battery electric (200 km)		0.71	0.7	0.66	0.65
H2 ICE hybrid[3]		1.8	1.6	1.5	1.4
H2 FC hybrid[4]			1.1	1	0.95

1) **L**iquefied **P**etroleum **G**as; LPG.
2) **C**ompressed **N**atural **G**as; CNG.
3) **I**nternal **C**ombustion **E**ngine; ICE.
4) **F**uel **C**ell; FC.

7.2 ‘Standard’ and ‘Advanced’ gasoline and diesel cars

‘Standard’ technologies reflect the current, immediately available technology. However, no cost or efficiency improvements are assumed for these cars and they therefore represent the existing, ‘frozen’ technologies.

‘Advanced’ versions of the diesel and gasoline cars become available from 2010 on. We do not, however, imply any specific advanced/improved technology, but instead use the term ‘Advanced’ as generic indicator for a technology that could be based on, for example, using a DISI engine in a gasoline car instead of PISI engine, stop & go systems, transmission improvements and so forth. We assume that the novel technological advancements lead to efficiency improvements and higher investment costs compared to the standard vehicles. It is further assumed that the fuel economy of the advanced technologies will keep improving further; whereas the costs of these cars are expected to stay at the level of the year of introduction. Our assumptions concerning the relative difference in investment costs between the gasoline and diesel cars are based on the data from IEA, 2009.

For the fuel consumption, our assumptions are combined from Gül, 2008 and Concawe, 2008 for the initial 2010 values and from Gül, 2008 and Hanschke et al., 2009 for the expected future improvements in fuel economy. The estimates we use for future values are also in line with IEA, 2009.

7.3 Compressed Natural Gas (CNG) cars

There is much variety in the cost estimates for CNG cars in the literature and sources do not seem to agree on how CNG costs may relate to the costs of a diesel or gasoline car either. In this study we assume the CNG car to be slightly more expensive than an advanced diesel car is in 2010 and then assume the cost difference to diminish over time.

In terms of fuel efficiency, the CNG car is assumed to require similar amount of fuel as a gasoline car does. Since the CNG car therefore has similar fuel efficiency as, but higher costs than, a gasoline car, the incentives to choose a CNG car over a gasoline car would have to follow from potentially lower fuel cost or from reduced environmental burden (in terms of having lower CO_2 emissions, for example).

7.4 Electric cars

Hybrid vehicles

Many sources make no differences between gasoline and diesel based hybrids and some of those that do assume no cost difference between the cars. On the other hand, the IEA, for example, assumes much higher near term costs for a diesel car hybrid than for gasoline hybrid, the difference apparently relating mainly to their assumptions concerning the costs of an advanced diesel engine. For the long term most sources assume the cost difference between gasoline hybrid and diesel hybrid to decrease considerably, being potentially even smaller than the difference between an advanced gasoline car and an advance diesel car.

The assumption used in this study is that the additional costs of the gasoline hybrid, beyond the costs of a non-hybrid, advanced gasoline car are € 1800 in 2010. These additional costs stem from costs related to electric motor, other power train and vehicle component upgrades. The cost difference is assumed to decrease to € 1350 in 2020 and remain constant after that. The additional battery costs are given as a separate cost component in Table 7.1. For the diesel hybrid we assume the additional costs to be slightly higher, € 2250 in 2010 and € 1800 in 2020. This is done to reflect the higher costs of the advanced diesel engine. It is further assumed that by 2030 the additional costs of the hybrid system, without batteries, are the same for both, gasoline and diesel based hybrid cars. Finally, we assume the CNG hybrid to have similar costs as the diesel hybrid does[8].

The literature estimates for efficiency improvements are rather varied and often use different reference technologies. In this study it is assumed that the gasoline hybrid uses some 30 % less fuel in 2010 than a standard gasoline car does in 2005 and by 2040 the consumption is some 44 % below the standard gasoline car in 2005 (and about 20 % below that of the advanced gasoline car in 2040). The hybrid diesel is assumed to have slightly less potential for efficiency improvements, leading to a slower reduction in the fuel use per kilometre driven. By 2040 the gasoline and diesel hybrids are assumed to have very similar fuel consumption. For the CNG we assume similar fuel economy as for the hybrid gasoline car.

Plug-in hybrid cars

As for 'normal' hybrids, also for hybrid plug-in vehicles the data given in the literature sources varies considerably. We assume the additional, non-battery costs of the gasoline plug-in hybrids to be € 2250 above the advanced gasoline car in 2010. The additional cost of € 450 beyond the gasoline hybrid car, is due to, for example, additional costs related to the charger. As for the gasoline hybrid plug-in, we assume also for the diesel hybrid plug-in car an additional cost of € 450 above the costs of a normal diesel hybrid car. Finally, we assume the cost difference between a normal hybrid car and a plug-in hybrid car will remain at this level at least until 2050.

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8 It is, however, worth noting that since the base cost of the normal CNG car is higher than that of a diesel car, the additional hybrid-cost for CNG is assumed to be comparable to a gasoline hybrid, not a diesel hybrid.

Most sources do not give clear data for the fuel efficiencies of plug-in hybrids, with the noted exceptions of Gül, 2008 and IEA, 2009. The efficiencies reported by Gül are slightly more on the optimistic side of the literature, with a total consumption of 1.23 MJ/km of which 0.98 MJ is gasoline and 0.25 MJ/km is electricity in 2010. We assume that on average 50% of the distance is driven using the electromotor, with has an efficiency slightly worse than that of a full electric car. The efficiency of the gasoline engine is assumed to be a little lower than what is assumed for the advanced gasoline car. In practise this means that for 2010 we assume the total energy use per kilometre to be 1.6 MJ of which 1.2MJ gasoline and 0.4MJ is electricity. Our assumptions concerning the efficiency improvements are such that we project the total use to decrease to 1.36MJ per kilometre by 2030, 1.0MJ of this being gasoline and 0.36MJ electricity. These assumptions are in line with the efficiency improvements reported for gasoline plug-in hybrid cars by the IEA: a reduction of fuel use per kilometre of 49% in near term and 54% in long term with respect to the standard gasoline car in 2005. The assumptions for the diesel plug-in hybrids follow the same general logic that was used for gasoline fuelled plug-in cars and our numbers are again relatively close to those of IEA.

Full battery electric cars
The cost for the electric car will, to a great extent, be determined by the cost assumed for the battery. The cost of the battery, in turn, is largely dependent on the size of the battery, which determines the driving range of the vehicle. The driving range, however, is not assumed to have any significant impact on the costs for the rest of the car (i.e. costs excluding the battery costs).)

In terms of the total, non-battery costs of the car, IEA, 2009 indicates savings from removal of ICE engine and fuel system, compensated by additional costs for electric motor and control systems. Gül, 2008, however, reports € 1200 lower rest of the car costs for electric cars when compared to advanced gasoline cars. We will in this study assume costs between these two estimates and use costs that are € 400 below the (rest of) car costs of an advanced gasoline car.

In terms of fuel use, Hanschke, 2009 and Gül, 2008 both report very similar numbers for 2010. However, Hanschke assumes no improvements in fuel economy over time, whereas Gül expects a constant increase in fuel efficiency. We will assume some efficiency improvement over time, but less than suggested by Gül, 2008. Our assumed efficiency improvements with respect to standard 2005 gasoline car are still higher than what IEA, 2009 is reporting, however.

7.5 Hydrogen cars

Hydrogen ICE hybrid cars
Most sources do not give data for ICE hydrogen car; only Gül, 2008 and Concawe, 2008 do this. In general, cost build up of a hydrogen ICE hybrid car does not differ very much from a gasoline hybrid car, the main difference being the more expensive fuel tank in the hydrogen car. The cost estimates for the fuel tank from the two sources range from € 2200 to over € 4400 in 2010. We will assume a cost between the ones found in literature, € 3300, for the fuel tank (assumed to start declining in 2020 and reaching € 2750 in 2030). Besides the fuel tank, we assume the costs of the car to be similar to those of a hybrid gasoline car. The dimensioning of the hydrogen tank is assumed to be such that the driving range of the car is similar than with the other cars and hydrogen is stored at a pressure of 76 MPa.

The efficiency improvements for hydrogen ICE cars reported by Gül are again slightly optimistic and we therefore instead assume similar improvements as we did for the hybrid gasoline cars.

Hydrogen fuel cell hybrid cars

The future costs of a fuel cell car will largely be determined by the cost developments of the fuel cell. Table 7.3 summarizes cost projections for PEM (proton exchange membrane) fuel cells given by (IEA, 2005), (IEA 207), (Gül., 2008) and (McKinsey 2010). The estimates are close to what was discovered by Schoots et al. 2010, who conducted a thorough analysis of the cost elements of PEM fuel cells in 2007 and estimated a specific cost of around € 560/kW for an 80 kW PEMFC stack.

Table 7.3 *Estimates from literature for specific costs of PEMFC stack [$€_{2010}$/kW]*

Source	Stack size	2010	2015	2020	2030	Additional notes
IEA 2004, IEA 2007	80kW	463			70/32	High/low estimates for 2030
McKinsey 2010	Unknown	500	110	43		
Gül 2008	40kW	254				Floor cost of 50 $€_{2010}$/kW

We compile our own projection for the costs of the PEMFC system based on the data above, and show our own projections in Table 7.4 below. The underlying assumption for the capacity of the fuel cell is 80kW. A lower assumption concerning the size would lead to a higher specific cost, and a larger fuel cell stack would imply correspondingly a lower specific cost due to the economies of scale.

Table 7.4 *Specific costs used in this study for the PEMFC system*

	2010	2020	2030	2040
PEMFC stack 80kW [$\$_{2005}$/kW]	550	200	80	50
PEMFC stack 80kW [$€_{2010}$/kW]	494	162	72	45

Schoots et al, 2010 focus on identifying and evaluating the learning by doing effects for PEM fuel cells and, based on the analysis, establish a progress ratio of 79±4%. This estimate can be used to illustrate the underlying diffusion assumptions in our projections: In order for the specific costs to decline from 494 €/kW in 2010 down to 162 €/kW in 2020, the cumulative capacity in 2020 would need to be 32 times the cumulative capacity today.

Currently the lifetime of fuel cells is shorter than the lifetime of a car, meaning that the fuel cell needs to be replaced during the lifetime of the car. This increases the lifetime costs of the car drastically. As previous studies, however, also in this study it is assumed that by the time of the introduction of the FC car the, fuel cell technology has progressed and the lifetime of fuel cells has increased to match the life time of the car.

If the cost of the battery and the fuel cell is excluded, sources generally report car costs comparable to the advanced gasoline car (Gül, 2008) or hybrid gasoline car (Concawe, 2008). This implies that the higher costs of the hydrogen tank are compensated by having only one engine and by other extra costs affiliated with turbo and Euro IV related technologies in a gasoline hybrid car. Following this, we use for the 2010 version of the hydrogen fuel cell car similar total rest of car costs as are used for the gasoline hybrid car.

As with electric cars, both Hanschke, 2009 and Gül, 2008 suggest similar for the fuel use of early FC cars. We assume some further improvements in fuel efficiency, therefore again falling in between Hanschke, 2009 and Gül, 2008, the former of which uses static numbers and latter assumes further, ongoing improvements. Numbers given in IEA, 2009 are in the same range as what we use here.

7.6 Assumptions on batteries

At the moment the economically most critical component of the electric car (and, to a lesser extent, in some hybrid cars) is the battery. The costs related to batteries are currently still high and it remains uncertain whether rapid decrease in the costs can be foreseen. Due to the crucial role of the battery, we will go slightly more into the details regarding the assumptions we will use for the vehicles with an electric engine.

Table 7.5 and Table 7.6 below show the cost development of batteries, as suggested by Gül, 2008 and the IEA, 2009. The floor costs reported by Gül indicate the lowest costs considered possible, when taking into account material costs and components of the battery that can be assumed to be already technically mature and not demonstrate significant potential for cost reductions. When, if ever, this cost level will be reached, depends on the speed with which the technology would be implemented as well as on the learning by doing factor of the technology. IEA, 2009 reports costs development for near term and long term, without specifying more explicitly the years these qualitative terms represent. Economies of scales lower the specific cost per kWh for larger batteries, explaining the cost difference visible in the tables below for the full electric cars and the hybrid cars.

We base our own assumptions concerning the battery cost development on the low cost estimates of the IEA, 2009, shown in Table 7.6 below.

Table 7.5 *Battery costs reported by Gül*

	Size [kWh]	Costs [$€_{2010}$/kWh]	
		Initial	Floor
Plug-in hybrid	8.2	804	346
Battery electric	48	344	254

Table 7.6 *Battery costs reported by the IEA*

	Battery size [kWh]		Costs [$€_{2010}$/kWh][1]			
	Near term	Long term	Near term		Long term	
			Low	Up	Low	Up
	1	0.5	682	898	413	628
Plug-in hybrid	8	6	512	678	377	579
Electric 150 km	33	27	422	556	314	476
Electric 200 km	44	36	399	530	296	453
Electric 400 km	88	72	363	480	269	413

1) We assumed that the costs data in (IEA, 2009) were originally reported in $\$_{2005}$

8. Implementation priorities and future work

In the previous chapters of this document we have described the motivation and background for building a European sustainable hydrogen model, we have then elaborated on the platform, TIAM-ECN, onto which we will construct our model, we have collected and documented the dataset we will use for the model and have in the previous chapter described the construction of the sector most essential to a successful diffusion of hydrogen technologies, i.e. the transport sector. This final section will briefly summarize the final modelling steps, not directly related to data issues alone, that we see as essential additions to the final model. It needs to be mentioned the list of elements below could easily be expanded further, but these chosen developments are considered to be a priority.

8.1 Demand density and transmission infrastructures for hydrogen

Build-up of transmission infrastructures and the spatial distribution of energy demand are very difficult to fully take into account in a model that does not include the necessary spatial information within its endogenously modelled system. Since, however, the volume of hydrogen demand together with the delivery distance largely determine the cost optimal delivery options, a rough proxy approximation for these characteristics is needed.

We will approach the issue from a scenario perspective and implement the qualitative characteristics of the European hydrogen roadmap, defined within the HyWays project (HyWays, 2008). We will therefore assume that first hydrogen will be transported by truck before a full hydrogen pipeline system will be realized and that a certain minimum share of the hydrogen transport will always be by truck. Moreover, a minimum share for decentralized production of hydrogen will be investigated.

8.1.1 Infrastructure of non-hydrogen transport fuels

Currently the representation of infrastructure and infrastructural costs of non-hydrogen transportation fuels is very limited. For conventional transport fuels no cost for transport and distribution of transportation fuels are modelled. For CNG only cost for building up new infrastructural capacity are included in the model. Transport costs for electricity used by private and public transport options are represented by a variable cost of 0.90 $€_{2010}$/GJ.

Since we will incorporate costs for transport and distribution of hydrogen and we want to model a realistic competition between the use of hydrogen and of other transportation fuels, the representation of infrastructural costs of conventional and other alternative fuels should be improved. Especially improving the transport and distribution costs for electricity has a high implementation priority, since widespread electrification of the private transport sector will bring significant investment needs for the extension of the electricity grid and recharging facilities. Due to the rough temporal scale we implement, we will not take into account load balancing issues nor smart grid related developments that may become increasingly important in the future.

8.2 Description of biofuels for transport

Our focus in the model development, and also this report, has been hydrogen and the transport sector. At times we have mentioned also electric cars, since they offer many similar advantages as the H_2 would (e.g. no emissions at the end-use, flexibility in terms of primary energy source, potential for improving security of supply). It is, however, important to take into account a third fuel option for providing sustainable transport services: biofuels. In light of the biofuel targets imposed by the EC, it could even be said that at the moment biofuels are far ahead of hydrogen in terms of diffusing into the private transport sector.

The current representation of biofuels production in the model is limited to ethanol production from energy crops, Fischer Tropsch diesel from solid biomass and conversion of some kind of dummy liquid biofuels commodity to ethanol and methanol. Our implementation priorities will here focus on describing the possible biofuel alternatives in more detail. More specifically, we will implement biofuels production technologies for first generation bio-diesel from oil crops and ethanol from solid biomass. The production of synthetic natural gas (Bio-SNG) from solid biomass that can be used for transportation purpose or electricity production will also be implemented. Finally also the data on potentials of different energy crops and solid biomass will be reviewed and updated if necessary.

8.3 Modelling of technology diffusion

Most energy investments, especially on the supply side, have long lifetimes and high investment costs. This creates inertia into the energy system, historically shown by the rather slow transitions from one energy paradigm into another. Figure 8.1 below demonstrates this, showing historical transition of the global energy system, shown here through the market shares of final energy carriers (Grübler, 2008). As we can see from the figure, the transition from the dominance of one energy carrier to that of another can easily take decades. For example, the relative importance of coal was decreasing since the 1930's, but only around 1960 another fuel, oil, took over the role as the most widely used commercial[9] fuel. Perhaps even more interestingly, despite the ascendance of electricity and natural gas, oil still clearly dominates the energy palette some four decades later.

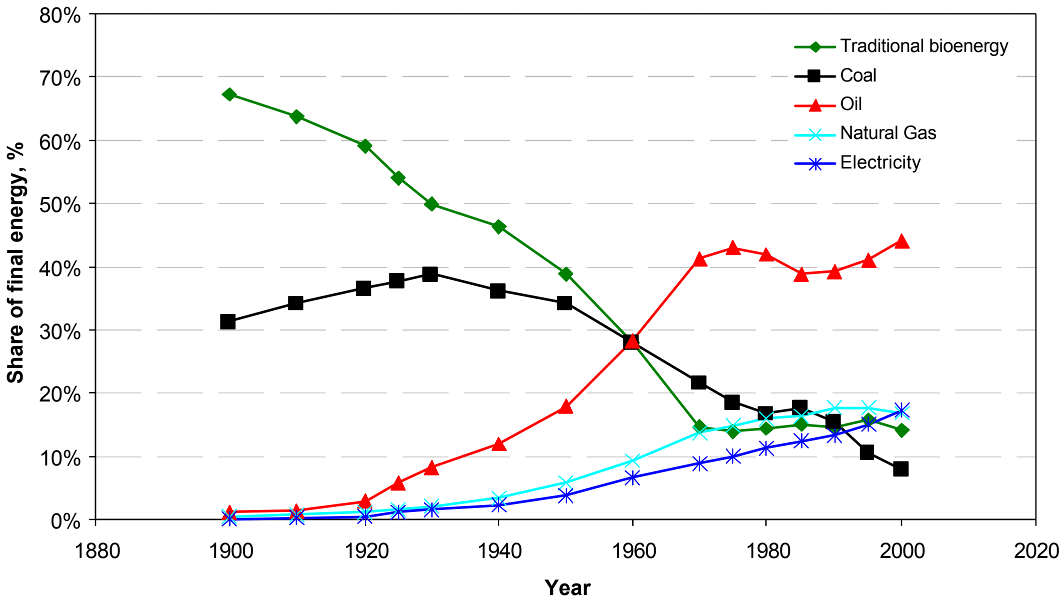

Figure 8.1 *Historical shares of energy carriers for the end use of energy*
Source: Grübler, 2008.[10]

In order to capture some of these effects, we will implement a number of growth and decline restrictions into the model. These constraints will limit the speed of diffusion and therefore help

9 Traditional bioenergy includes energy sources such as wood, dung, crop residues and other biomass, most of which are not considered as commercial energy carriers.
10 Figure here is redrawn by the authors of this report, based on the data provided with the article.

in simulating the real life processes more realistically. We will implement such constraints throughout the model, from the resource level up to the choice for energy carriers at the end use level. At the same time, however, much care needs to go in determining that the established constraints do not artificially block any possible transitions, but merely implement the 'slowness' of these processes, often observed in real life.

8.4 Policy targets and instruments

Implementation of policy targets and instruments is more related to model application than use. Some, such as emission or energy taxes, are rather easy and straightforward to implement, but others, like security of supply or sustainability indicators, require more thought and background work to define the said indicators robustly. Furthermore, the model gives an option to either directly constrain the activity of a given variable or alternatively implement an instrument that should move the results in the desirable direction, but leave the exact activity level for the model to decide. The simplest example of this would be emissions, which can either be capped (leaving the implied marginal price of reductions for the model to decide) or taxed (leaving the emissions levels to be determined by the model). Implementing some of the policy targets and instruments therefore requires some care, so that the results can be interpreted appropriately.

In light of the main policy issues indicated earlier, the policy instruments that need to be implemented include emission taxes and quotas, subsidies for technologies and energy security measures (e.g. import quotas or taxes). The impact of different instrument combinations and fuel price trends will also be studied, in order to give a better idea of what kind of developments could be expected to lead to a successful hydrogen economy in Europe.

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