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Assessment of Alternative Hydrogen Pathways: Natural Gas and Biomass

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Abstract

Achieving large-scale changes to develop a sustained hydrogen economy requires a large amount of planning and cooperation at national and international levels alike. ECS developed a long-term hydrogen-based scenario (B1-H2) of the global energy system to examine the future perspectives of fuel cells (Barreto *et al.*, 2002). That earlier study, done with the collaboration and support of the Tokyo Electric Power Company (TEPCO), illustrated the key role of hydrogen towards a clean and sustainable energy future. In an affluent, low-population-growth, equity and sustainability-oriented world, hydrogen technologies experience substantial but plausible performance and costs improvements and diffuse extensively. Fuel cells and other hydrogen-using technologies play a major role in a transformation towards a more flexible, less vulnerable, distributed energy system that meets energy needs in a cleaner, more efficient and cost-effective way. This profound structural transformation of the global energy system brings substantial improvements in energy intensity and an accelerated decarbonization of the energy mix, resulting in relatively low climate impacts.

In order to understand the future potential of hydrogen, in this report we compare the two main hydrogen production alternatives from natural gas and biomass as identified in the above-mentioned (B1-H_2) scenario in more detail. The first alternative, steam reforming of natural gas, is a well-established technology and the most common and current method to produce hydrogen (Ogden, 1999a). The second technology, biomass gasification, is still in its infancy. A small number of demonstration facilities are in place. Many issues still have to be addressed before the technology can be expected to reach an adequate technical performance and hence become economically competitive (Milne *et al.*, 2002). Nevertheless, biomass-based systems are a very promising option for ensuring the sustainability of a future hydrogen-supply system.

The report includes a comparative analysis of both systems and their potential for carbon mitigation via CO_2 capture and sequestration. Estimates of the hydrogen costs for alternative production chains are presented, and the competitiveness of the systems under alternative CO_2 taxes are analyzed. Both technologies appear as economically attractive and environmentally compatible options for shaping a sustainable hydrogen economy and contributing to the mitigation of greenhouse gas emissions in the long term.

Acknowledgments

About the Authors

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Assessment of alternative hydrogen pathways: Natural gas and biomass

Atsutoshi Makihira, Leonardo Barreto, and Keywan Riahi

1. Introduction

In earlier work within the collaborative study with the Tokyo Electric Power Company (TEPCO) on examining future perspectives for fuel cells, a long-term hydrogen-based scenario of the global energy system has been developed (Barreto *et al.*, 2002). The scenario, labeled as B1-H_2, illustrated the key role of hydrogen in a long-term transition towards a clean and sustainable energy future. In an affluent, low-population-growth, equity and sustainability-oriented B1-H_2 world, hydrogen technologies experience substantial but plausible performance and costs improvements and diffuse extensively. Fuel cells and other hydrogen-using technologies play a major role in a transformation towards a more flexible, less vulnerable, distributed energy system that meets energy needs in a cleaner, more efficient and cost-effective way. This profound structural transformation of the global energy system brings substantial improvements in energy intensity and an accelerated decarbonization of the energy mix, resulting in relatively low climate impacts.

Clearly, a number of considerable technological, institutional, political and social obstacles stay in the way of a transition towards a sustainable hydrogen-based energy system. Given the large inertia of the energy system and its current "lock-in" to a fossil-based regime, it is difficult for alternative resources and technologies to penetrate and if they do, the conformation (and replacement) of energy technology regimes can proceed only gradually.

Achieving the large-scale changes that a sustainable hydrogen economy necessitates, would require considerable and sustained efforts in a number of areas and the involvement of many different social actors at national and international levels alike. A combination of government measures and business activities would be necessary to stimulate the growth of the hydrogen energy industry, the commercialization of the technologies and the deployment of the corresponding infrastructure. Together with other activities, international collaboration on Research, Development, Demonstration and Deployment (RD3) are necessary for a successful development of hydrogen technologies and their introduction into the marketplace. International collaboration on RD3 could contribute to share costs and risks of R&D and demonstration projects, identify and exploit niche market opportunities and implement buy-down strategies to ensure that these technologies will move along their learning curves. Cooperation could

also facilitate technology transfer and access to attractive markets, and key issues for speeding up the global deployment of a cluster of hydrogen technologies.

Public-private partnerships would be an important part of these efforts. They could be particularly useful in exploring business opportunities for hydrogen technologies and exploiting synergies between different market segments. However, the short-term-profit orientation of industrial partners would most likely drive joint government-industry RD3 projects to address only short- or medium-term issues. There remains, however, a gap in the long-term RD3 challenges that must be tackled to ensure that a sustainable global hydrogen economy materializes and its potential long-term benefits can be reaped. Specifically, R&D portfolios should be articulated with the long-term goals. Governments could play a central role in filling such gaps.

The global hydrogen production system in the B1-H_2 scenario is initially fossil-based but progressively shifts towards renewable sources. At the global level, hydrogen is produced with a diversified mix of technologies. Steam reforming of natural gas and gasification of biomass play the leading roles. For the most part of the time horizon (the year 2100), steam reforming holds the largest share of supply. In the last decades of the 21st century, however, the rapidly increasing production from biomass becomes the most important supply source at the global scale. Significant contributions are also made by solar thermal technologies and, to a lower extent, by coal gasification, with the latter operating as a transition technology. Nuclear high-temperature reactors and electrolysis play marginal roles, but they constitute important complementary options.

In order to understand the future potential of hydrogen, in this report we compare the two main hydrogen production alternatives from natural gas and biomass identified in the B1-H_2 scenario in more detail. The first alternative, steam reforming of natural gas, is a well-established technology and the most common current method to produce hydrogen (Ogden, 1999a). The second technology, biomass gasification, is still in its infancy. Currently, only a small number of demonstration facilities are in place and many issues must still be addressed before the technology can be expected to reach an adequate technical performance and hence become economically competitive (Milne *et al.*, 2002). Nevertheless, biomass-based systems are a very promising option for ensuring the sustainability of a future hydrogen-supply system.

Concerns about climate change and other energy-related environmental impacts suggest that it is important to explore alternatives of energy production, conversion and use with a low release of carbon to the atmosphere. Therefore in this report, the CO_2 emissions of both systems, steam reforming and biomass-based, are estimated and their possibilities for carbon separation and sequestration examined. Steam reforming of natural gas turns out to be well suited for carbon removal and sequestration. Biomass gasification systems can also be configured to allow separation of CO_2 and its subsequent capture, which, if biomass is produced in a sustainable way, can offer possibilities for net removal of carbon from the atmosphere (Obersteiner *et al.,* 2001).

The comparison presented in this report assesses the economic cost and benefits of both systems and estimates their CO_2 emissions, including emissions during hydrogen production and transportation and incorporating CO_2 separation, transport and sequestration. Both technologies appear as economically attractive and environmentally

compatible options for shaping a sustainable hydrogen economy and contributing to the mitigation of greenhouse gas emissions in the long term.

The report's structure is as follows. Section 2 presents descriptions of the components for a hydrogen supply system based on natural gas and biomass. The assumptions of the selected hydrogen energy systems and the results of the comparative assessment of the two hydrogen production systems with regards to their costs, performance and their economics for carbon abatement are presented in Section 3. Finally, Section 4 concludes.

2. Alternative hydrogen pathways

A hydrogen-based energy system, the so-called "hydrogen economy" is regarded as one of the alternative energy supply options, which, while providing high-quality energy services, could make a substantial contribution to greenhouse gas mitigation. This carbon emission mitigation is achieved in two ways. First, the introduction of highly efficient hydrogen-based end-use technologies, such as fuel cells, would help to reduce final energy use. Second, hydrogen can be produced from carbon-free primary resources and from carbon-rich ones in combination with carbon separation and long-term sequestration (Ogden, 1999a). In this section, general descriptions of the components in alternative hydrogen pathways from natural gas and biomass are presented. Specific assumptions for the assessment are given in detail in Section 3.

2.1. Hydrogen production technologies

2.1.1. Steam reforming of natural gas

Steam methane reforming (SMR) is a well-established commercial process and is the most common method currently used to produce large quantities of hydrogen. As SMR is currently the most competitive hydrogen production option, this technology could be key to the successful introduction of hydrogen as an energy carrier. With natural gas as an abundant primary-energy resource (Nakićenović *et al*., 2000), SMR-based hydrogen production systems could stimulate the diffusion of hydrogen into the current fossil-fuel-based energy supply system and provide the transition to an eventual renewable-based hydrogen supply.

The SMR process consists of three major steps; steam reforming, water-gas shift reaction, and hydrogen purification. In a first step, the reforming reaction takes place between natural gas (i.e., methane) and steam over a nickel catalyst in a reformer at temperatures in the range of 800 to 1000ºC. A simplified schematic flow diagram for a typical steam reforming process is shown in Figure 1. The required heat for the chemical reaction is provided by the combustion of a fraction of the incoming natural gas (the feedstock) with process waste gas from the hydrogen purification system, which also reduces carbon emission from the reformer exhaust gas. The gaseous products of the reforming reaction consist mainly of a mixture of hydrogen and carbon monoxide (CO), also known as a syngas. In a subsequent water-gas shift reaction process, steam reacts with the CO forming additional hydrogen and CO_2. Small

amounts of CO, methane and water remain in the produced gas mixture. In a final step, hydrogen is purified by pressure swing adsorption (PSA) systems. The required purity of hydrogen depends on the application. For example, if the hydrogen is used for proton exchange membrane fuel cell (PEMFC) vehicles, high purities of hydrogen are desirable. Since PSA systems can purify hydrogen up to 99.999 percent with low energy costs, more recently, hydrogen producers generally prefer PSA systems to chemical or physical absorption systems which require significant energy input to regenerate the absorbing solvent for lower purity (95 to 98 percent) of hydrogen (Ogden, 1999b).
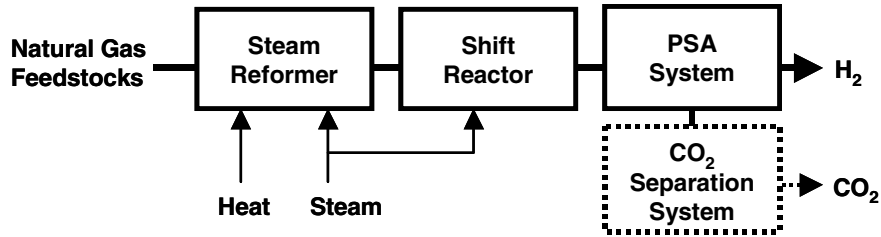

Figure 1: A schematic diagram of natural gas steam reforming (SMR).

SMR facilities have been built in widely varying sizes, and there are significant economies of scale in building SMR reformers (see Section 3.2). However, if small reformers, operating at lower temperatures and pressures than larger plants and manufactured with lower cost-materials, could be built in large enough volumes, their costs could become comparable to those of larger SMR facilities (Ogden, 1999a). A decentralized hydrogen supply system based on small-scale reforming of natural gas would have the advantage of producing hydrogen close to the point of use, benefiting from existing natural gas distribution systems and from the lower costs of transporting natural gas as compared to hydrogen. Some studies (Lovins and Williams, 1999) imply that such small-scale SMR facilities could contribute to overcoming some of the barriers imposed to the introduction of hydrogen by the current lack of a large-scale hydrogen delivery infrastructure.

Eventually, with growing demand for hydrogen, centralized large-scale production plants could enter the market and hydrogen transmission and distribution infrastructure could develop. Besides the benefits from economies of scale, centralized production is necessary to make carbon capture and sequestration economical. For assessing hydrogen pathways combined with a carbon sequestration system, we focus our analysis on large-scale centralized hydrogen production. Carbon separation and sequestration systems will be discussed in detail in Section 2.2.

2.1.2. Biomass gasification

Biomass, such as agricultural and forest residues, urban wood wastes and energy crops, can be used as feedstock for producing hydrogen through thermochemical or biological processes (Milne *et al.*, 2002). Hydrogen would be a promising energy carrier to enable biomass meeting current and future energy needs in an efficient manner. Biomass is an inherently clean feedstock and if it is produced in a sustainable way, it can be carbon-neutral. That is, it can absorb as much carbon dioxide during its growing cycle as it is

produced when it is transformed to final energy. This characteristic makes biomass-based systems an attractive option for offsetting energy-related carbon emissions. If combined with carbon removal and sequestration technologies, a net removal of carbon from the atmosphere can be achieved (Obersteiner *et al.*, 2001).

Biomass-based hydrogen production constitutes one of the promising options for a long-term decarbonized and sustainable hydrogen supply system. However, no processes for hydrogen production from biomass are commercially available today (Zittel and Wurster, 1996). The technologies are still in the R&D or demonstration phase, and a number of technical and economic issues still have to be solved.[1]

Biomass gasification is a thermochemical process in which biomass is converted into gaseous components, from which hydrogen is extracted. A simplified schematic flow diagram for a typical biomass gasification process is shown in Figure 2. In a first step, dried biomass feedstock is fed to a gasifier with steam or oxygen (air) inputs. The gasifier operates at high temperature to produce a gas containing primarily CO, H_2, CH_4, CO_2 and some higher hydrocarbons (syngas). As shown in Figure 2, the gasification step is followed by a similar steam reforming process; a reforming step which converts methane and the higher hydrocarbons in the syngas to hydrogen; a water-gas shift reaction step, which forms additional hydrogen; and a final hydrogen purification step to produce the required purity of hydrogen. The characteristics of the biomass gasification process are also similar to those of coal gasification systems, but the biomass gasifier operates at lower temperatures and has different clean-up requirements (Ogden, 1999a).
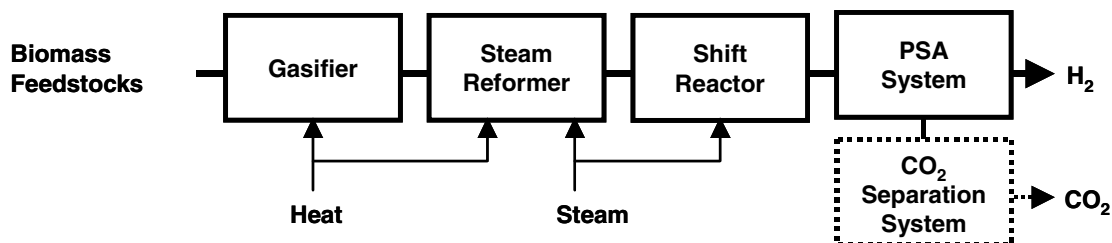

Figure 2: A schematic diagram of biomass gasification.

Technological learning plays an important role in achieving the cost reductions and performance improvements necessary for a technology to become competitive in the marketplace. The stimulation of the learning processes of both natural gas steam reforming and biomass gasification through research, development, demonstration and deployment (RD3) actions would be key to ensuring that they become competitive in the energy markets in the long-run.

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[1] For an overview of R&D activities and needs in biomass-based hydrogen production see Milne *et al.*, (2002). Among other topics, the compatibility of biomass-based hydrogen production systems with different types of fuel cells must be examined more carefully. Since different types of fuel cells have different requirements regarding the purity of the hydrogen, their possibilities for a technically efficient and cost-effective combination with biomass-based systems are different (Amos, 1998a).

Spillovers of learning between different technologies can occur, where related or complementary technologies benefit from the learning processes of each other (Grübler *et al.*, 1999; Gritsevskyi and Nakićenović, 2000). This "technological proximity" may stimulate a collective co-evolution process. Although it is difficult to be certain of their magnitude, one could expect learning spillovers between steam reforming of natural gas and biomass (or coal) gasification technologies, since they have some similar basic processes and components (see Figure 1 and Figure 2). These commonalities could lead to some synergies, with developments in one of them being useful for the other. In other words, their technological learning processes could cross-enhance each other to some extent.

This is important because, as seen in the B1-H_2 scenario results, in the early phase of a "hydrogen economy", steam reforming would most likely dominate hydrogen production. If this indeed occurs, a cluster of related and complementary technologies would likely to emerge and develop. One could then ask the question of how the emergence and possible dominance of such a gas-based technology cluster would affect a future transition to a renewable-based hydrogen supply. Clearly, technologies that are compatible with an existing regime face fewer barriers to diffusion than those that are radically different (Kemp, 1997). Thus, being capable of benefiting from the knowledge and experience accumulation of steam reforming, biomass gasification could play an important role in facilitating such transition.

This compatibility between steam reforming and biomass gasification, added to their inherent advantages, would make them attractive as part of a cluster of technologies whose development may contribute to a cleaner, more flexible, reliable, safe and cost-effective global energy system.

In addition, both technologies could be configured in a way to facilitate the separation of CO_2 at reasonable costs. In combination with carbon removal and sequestration technologies, they could constitute sound options for decarbonizing an emerging hydrogen supply system. Thus, both technologies would be attractive options to both promote hydrogen as an energy carrier and curb greenhouse gas emissions from the energy system.

2.2. CO_2 removal and sequestration

The increasing evidence of anthropogenic interference with the earth's climate system and mounting concerns about possible serious adverse impacts of future global climate change (IPCC, 2001), call for the investigation of alternatives for energy production, conversion and final use with a low release of greenhouse gases to the atmosphere.

Carbon sequestration appears as an option for mitigation greenhouse gas emissions from the global energy system in the long run. Carbon sequestration permits the use of carbon-rich primary-energy sources while reducing their net emissions to the atmosphere. It could be a complement to the long-term decarbonization of the energy supply and efficiency increases in energy extraction, conversion, transportation and end-use. In that sense, carbon sequestration should act as an accompanying measure to the transition towards a sustainable non-fossil-based energy system. Thus, it should

contribute to minimize the impacts of the fossil-based systems that would bridge the transformation of the current global energy system to a sustainable regime.

Combining technologies for hydrogen production from carbon-containing feedstocks, such as natural gas, coal or biomass, with CO_2 removal and long-term storage could be an attractive emissions mitigation option. There are two basic possibilities for carbon sequestration. The first is preventing carbon, produced by human activities, from reaching the atmosphere. The second is removing carbon from the atmosphere (DOE, 1999). We are concerned here mainly with the first alternative. In such a context, carbon removal and sequestration requires the capture, transport and long-term storage of the CO_2 resulting from production of fossil-based or biomass-based energy carriers.

In general, there are two basic alternatives for removal of carbon produced in energy conversion processes. The first option is the capture of CO_2 after energy conversion, for instance, from flue gases after electricity generation. Capturing CO_2 from flue gases appears as a feasible option, particularly for large fossil-based power plants, but it entails significant energy penalties and costs, mainly due to the low concentration of CO_2 in the flue gases. However, novel combustion technologies and/or polygeneration schemes could improve their competitiveness. The second possibility is producing hydrogen-rich synthetic fuels from carbon-rich primary energy carriers and capturing the CO_2 during the process. This is the alternative considered here in relation to hydrogen production by natural gas steam reforming and biomass gasification, the two technologies described above.

The separation of CO_2 from those hydrogen production processes can be made either in the reformer exhaust gas stream or hydrogen process stream. In the first case, CO_2 is removed from the flue gases resulting from the combustion of feedstock necessary to keep the reforming reaction active. The low concentration of CO_2 in the flue gases, however, makes its separation process difficult and expensive. In the second case, CO_2 is generally captured from the hydrogen process stream in the hydrogen purification step with other impurities such as CH_4, CO, H_2O and N_2. For CO_2 sequestration, separation of pure CO_2 from the gas mixture is required, which can involve some additional equipment and energy input (Ogden, 1999b). In comparison to the first case, the carbon removal could be achieved without incurring excessive energy and costs penalties because of the high concentration of CO_2 in the process stream. This is valid both for the steam reforming and biomass gasification technologies considered here and described above. Nonetheless, in order to facilitate the CO_2 sequestration process and the applications of hydrogen in the fuel cells, high-purity CO_2 and H_2 streams are required. Work is still necessary in devising more economic and efficient ways for separation of these two products.[2]

Several options appear to be possible for the storage of the captured CO_2. These include injection into the deep ocean, depleted natural gas/oil fields or saline aquifers or its use for enhanced oil or gas recovery (in non-depleted fields). Potentials for storage appear

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[2] In this regard, novel concepts can provide promising alternatives. For example, the Sorption Enhanced Reaction Process (SERP), now under development in the U.S. (Hufton *et al.*, 2000) could contribute to significantly increasing the efficiency and purity of hydrogen produced by steam reforming and to decreasing the production costs.

to be very significant, but a deeper scientific understanding of the above mentioned storage possibilities is still lacking. Although CO_2 capture and sequestration technologies exist today (DOE, 1999), a number of issues concerning costs, energy requirements, physical integrity of the reservoirs and associated environmental effects remain unsolved. Those aspects are particularly relevant if the feasibility to dispose of large quantities of CO_2 in the long-term is to be ensured.

2.3.   Transportation of hydrogen and CO_2

Separation of hydrogen and CO_2 in steam-reforming facilities or biomass gasification plants would provide virtually a carbon-free hydrogen production system. However, large facilities appear to be necessary for an economic carbon sequestration process. Thus, there is a trade-off between the size of the hydrogen production plant and the requirement for the transport of feedstocks, hydrogen, and CO_2. Hydrogen can be transported in a number of ways (as compressed gas, liquid or solid metal hydride) depending on quantities and distances. It can be delivered using trucks, railways, pipelines or ships. For long distances and large quantities, transportation as compressed gas using pipelines appears to be the most cost-effective option. However, across the ocean, transportation as liquefied H_2 using ships is more attractive.

Several short hydrogen pipelines are currently in operation in Europe and the US. However, H_2-ready pipelines require special materials (e.g., special types of steel not subject to embrittlement), and it is estimated that they may cost at least 50 percent more than natural-gas pipelines (Amos, 1998b). In addition, compression of hydrogen has to be higher than that of natural gas.[3] There exists also the possibility to inject small quantities of hydrogen into existing natural gas pipelines. In this case, no special modifications are required.

In general, in a world without carbon constraints, it appears more cost-effective to transport the feedstock and produce hydrogen close to the demand centers. With the current and foreseeable cost trends, several of the feedstocks used to produce hydrogen can be transported over long distances cheaper than hydrogen itself (Ogden, 1999a). Long-distance transportation of hydrogen would only make sense if a particular feedstock would be cheap enough in a given world region such that delivering hydrogen to another world region where adequate feedstocks are too expensive or unavailable would still be competitive when hydrogen transportation costs are added.

This would be the case when one is not considering the carbon removal and sequestration process. When considerations regarding CO_2 transport and storage enter the picture, the situation becomes more complicated to assess and may be case-dependent.

Transportation of the captured CO_2 to the storage site can be made either by pipeline or by tanker. Pipeline investment costs will depend on both the distance and the diameter.

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[3] Some studies (Oney *et al*, 1994) suggest that, if pipelines and compressor stations were optimized to transport hydrogen, it could be equally, or even less, expensive to transport hydrogen-rich mixtures at high pressures than natural gas at low pressures.

If CO_2 transport is applied at a large scale, a CO_2 grid could develop that would enjoy substantial economies of scale. Tankers could have a similar layout as those transporting liquefied natural gas, and could be used if transportation across the ocean is required.

When CO_2 transport and storage is considered, the optimal location of hydrogen, production facilities can change. For natural-gas-based systems, for instance, the most attractive option could be to locate hydrogen production facilities with carbon removal at the wellhead in natural gas fields (see e.g., Blok *et al.*, 1997; Williams, 1998), because the CO_2 could be injected directly in the gas reservoir and be used for enhanced gas recovery.

For biomass, the situation is somewhat more complex. Production of hydrogen in large facilities would require solving significant logistic problems for the feedstock supply. On the other hand, producing the hydrogen in small-scale facilities close to demand centers or to biomass plantations will make the collection and transport of the removed CO_2 very complicated and possibly uneconomical.

In the analysis presented below, we examine the cost estimates only at fixed feedstock prices and distances for hydrogen delivery and CO_2 transportation. A detailed discussion of the trade-offs will not be carried out here. Those aspects, however, and the subsequent implications for the configuration of infrastructures for transportation of energy carriers and CO_2 are very relevant and deserve further and detailed examination.

2.4.   Future potential of natural gas and biomass resources

Natural gas and biomass could play an important role as primary sources in a number of alternative future global energy paths (e.g., Nakićenović *et al.,* 1998; SRES, 2000). In this section, we present a general overview of the global reserves and resources of natural gas and the global energy potentials for biomass. For natural gas, this overview is based mainly on Rogner (1997). For biomass, we rely mainly on Fischer and Schrattenholzer (2001).

Natural gas is the least carbon-intensive fossil fuel and, thus, it is regarded as one of the primary sources that could bridge the transition from the current carbon-intensive technological regime towards a more sustainable low-carbon one (Nakićenović *et al.*, 2000). The natural-gas share of the global primary energy supply has been growing in the last decades and currently represents about 25 percent of commercially traded primary energy fuels (BP, 2001).

Worldwide, there are significant gas resources and a substantial potential for new discoveries during the 21st century. Typically, hydrocarbon resources are classified according to their geological certainty and economical recoverability, both dynamically depending on technological progress. Rogner (1997) provides a systematic categorization of occurrences of hydrocarbons in which the author distinguishes

between conventional and unconventional reserves and resources.[4] Table 1 presents his estimates of natural gas occurrences, disaggregated into eight categories for the following four world macroregions:

- The OECD90 region comprises the OECD members in 1990.

- The REF region includes the economies in transition of the Former Soviet Union and Eastern Europe.

- The ASIA region represents the developing countries in the Asian continent.

- The ALM region covers the rest of the world, combining countries in sub-Saharan Africa, Latin America and the Middle East.

According to that estimation, global conventional reserves and resources of natural gas amount to 17 Zetajoules (1 ZJ=10^{21} Joules) and unconventional reserves and resources to 827 ZJ for a total of occurrences of 847 ZJ. For comparison, natural-gas consumption during the period 1860-1990 was 2.4 ZJ and the estimated consumption in the B1-H$_2$ scenario between the years 1990-2100 is 24 ZJ.[5]

Table 1: Eight categories of conventional and unconventional gas reserves, resources and additional occurrences in Zetajoules, ZJ (10^{21} J) for four world macroregions.

	Conventional Reserves and Resources			Unconventional Reserves and Resources					Total
	Proved Reserves	Additional Reserves	Additional Resources	Enhanced Recovery	Recoverable Reserves and Resources		Additional Occurrences		
	I	II	III	IV	V	VI	VII	VIII	
OECD90	0.9	0.8	1.0	0.5	2.2	4.6	6.9	354.0	371
REF	1.7	1.9	2.8	0.9	1.1	2.0	3.0	177.6	191
ASIA	0.3	0.4	0.6	0.2	1.1	1.4	2.1	42.4	49
ALM	2.5	1.5	2.1	0.8	1.3	2.9	4.3	217.6	233
World	5.4	4.7	6.5	2.3	5.7	10.9	16.3	791.6	844

Although the availability of conventional natural gas is limited, unconventional gas resources, i.e., those resources not exploitable with conventional recovery techniques, appear to be massive. They include, among others, coal-bed methane, tight formation gas, gas hydrates (clathrates) and geopressured aquifer gas (Rogner *et al.*, 2001). The largest occurrences appear to be those of gas hydrates and geopressured gas, but they are also the most uncertain, and substantial technological developments would be

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[4] Reserves are defined as those time-dependent occurrences that are measured and technically and economically recoverable. Resources, on the other hand, are geologically less assured and less economically feasible. Conventional occurrences can be measured and recovered with currently available technologies while technologies to quantify and extract unconventional occurrences are not yet mature (Rogner, 1997).

[5] In the B1-H$_2$ scenario quantification, gas resource assumptions are based on Rogner (1997). However, consistent with the defining assumptions of this scenario, conservative assumptions were made concerning its availability. Although both conventional and unconventional occurrences were taken into account, the categories labeled as "additional occurrences" (VII and VIII), for which the highest uncertainty exists and which are not likely to be exploited with the foreseeable technological developments, were not included.

necessary to tap them. The exploitation of unconventional gas resources could guarantee the availability of natural gas well through the 21st century.

From those sources, production of coal-bed methane appears to be the most suitable to be enhanced by means of CO_2 injection. Coal-bed methane production can be a by-product of underground coal mining or it can be undertaken directly for methane production and this is currently practiced in the US (Kuuskraa and Guthrie, 2001). Capturing the methane, which is itself a potent greenhouse gas, can also have additional climate change benefits since it prevents its venting into the atmosphere. CO_2 enhanced coal-bed methane production has been demonstrated in the US and its feasibility for other countries, such as the Netherlands, has been examined (Hamelinck *et al.*, 2002) and the result appears to be promising.

Biomass currently holds about 10-14 percent of the global primary energy mix, which is equivalent to about 40-55 exajoules per year (EJ/yr). The bulk of biomass consumption occurs in developing countries, where traditional, non-commercial and unsustainable uses of biomass still cover a significant share of the energy needs. However, new technologies for direct biomass applications and conversion to other fuels are being developed. They could "add value" to this traditional energy source, enabling it to supply modern energy services. Biomass gasification for hydrogen production is one of them.

Unlike natural gas, biomass is a renewable resource and, as noted above, when produced and used in a sustainable way it can be carbon-neutral. There is a significant potential for bioenergy applications in the future. However, since biomass is a relatively land-intensive energy source, when estimating bioenergy potentials, other land uses must be taken into account. Fischer and Schrattenholzer (2001) present estimates of global bioenergy potentials up to the year 2050. These estimates are consistent with a scenario of requirements for arable land and agricultural production estimated at IIASA (Fischer *et al.*, 1996) and take into account economic considerations.

The estimates are presented in Table 2, disaggregated for the four macroregions described above. Five bioenergy categories are included, namely crop residues, energy crops, wood from forests and forest residues, animal waste and municipal waste. There is, however, uncertainty as to how the potential can grow over time. This is particularly important for the energy crops and wood from forests categories, where uncertainty about productivity improvements is noticeable. In order to reflect such uncertainty, high and low estimates are presented for these two categories and, consequently, for the total potentials. Global bioenergy potential for the base year (1990) is estimated at 225 EJ, and grows to between 370 EJ and 450 EJ by the year 2050. For comparison, the contribution of biomass to the primary energy mix in the B1-H$_2$ scenario in the year 2050 is 136 EJ.

Table 2: Bioenergy potentials from 1990 to 2050 for the four macroregions in EJ/year. High and low potentials are presented. Source: Fischer and Schrattenholzer, 2001.

	1990	2000	2010	2020	2030	2040	2050
Crop Residues							
OECD90	5.7	6.3	6.6	7.1	7.4	7.8	7.7
REF	2.8	2.8	3.0	3.1	3.2	3.5	3.6
ASIA	5.5	5.4	4.6	3.6	2.7	2.1	1.1
ALM	3.7	4.6	5.7	7.1	8.1	9.3	10.4
World	17.7	19.1	19.9	20.9	21.4	22.7	22.8
Wood from Forests							
OECD90	13.7	14.8-15.3	16-17.4	17.1-19.3	18.3-21.3	19.7-23.8	21-26.3
REF	9.4	9.9-10.4	10.7-11.7	11.5-12.9	12.4-14.4	13.2-16.1	14.2-17.8
ASIA	14.0	15-15.6	16.1-17.5	17.2-19.5	18.3-21.6	19.8-24.0	21.1-26.6
ALM	24.9	26.4-27.4	27.7-30.2	29.4-33.1	31.1-36.4	32.9-40.0	34.9-44.2
World	62.0	66.1-68.7	70.5-76.8	75.2-84.8	80.1-93.7	85.6-103.9	91.2-114.9
Energy Crops							
OECD90	20.0	21.4-22.9	22.6-25.7	24.4-29.3	25.9-33.3	28.3-37.9	30.6-43.5
REF	9.5	9.9-10.7	10.8-12.1	11.5-13.5	12.1-15.0	12.9-16.6	13.5-18.2
ASIA	12.9	13.7-14.2	14.3-15.8	15.5-18.2	16.9-20.6	18.4-23.7	20-26.9
ALM	70.2	71.6-75.4	72.6-81.4	73-87.1	75-95.4	78.8-106.3	84.4-119.5
World	112.6	116.6-123.2	120.3-135	124.4-148.1	129.9-164.3	138.4-184.5	148.5-208.1
Animal Waste							
OECD90	6.9	7.5	8.1	8.5	8.9	9.2	9.3
REF	3.0	3.1	3.3	3.4	3.5	3.6	3.8
ASIA	8.7	10.2	11.7	13.1	14.4	15.5	16.5
ALM	10.2	12.0	14.1	16.6	18.4	19.6	20.5
World	28.8	32.8	37.2	41.6	45.2	47.9	50.1
Municipal Waste							
OECD90	2.5	3.9	5.3	6.8	7.9	8.6	9.3
REF	0.3	0.5	0.9	1.5	2.4	3.5	4.8
ASIA	1.2	2.5	4.9	8.6	13.0	17.9	23.4
ALM	0.7	1.3	2.5	4.8	8.5	13.5	19.5
World	4.7	8.2	13.6	21.7	31.8	43.5	57.0
Total							
OECD90	49.0	53.7-55.9	58.7-63.1	63.9-71.0	68.3-78.9	73.5-87.4	78.1-96.3
REF	25.0	26.4-27.6	28.6-30.9	30.9-34.5	33.6-38.5	36.8-43.4	39.8-48.3
ASIA	42.1	46.5-47.9	51-54.4	57.4-62.8	64.4-72.3	72.3-83.1	80.8-94.5
ALM	109.7	116.2-121.1	122.9-134.2	130.7-148.5	141.1-166.7	154.1-188.7	169.7-214.0
World	225.8	242.8-252.5	261.2-282.6	282.9-316.8	307.4-356.4	336.7-402.6	368.4-453.1

Obviously, the ability of exploiting such a bioenergy potential will depend on a number of actions related to technological progress, economic incentives and institutional developments, among others. Besides technical and economic aspects, the successful application of biomass technologies, particularly at a large scale, presupposes finding solutions to a number of issues that currently prevent biomass from having a more relevant role in meeting energy needs. These include, among others, minimizing associated environmental impacts, development of dedicated fuel supply systems, avoiding conflicts with food production and other land uses, solving logistics-of-supply problems, particularly those related to transport of the feedstock, and overcoming organizational difficulties related to the co-ordination of a large number of actors (Turkenburg *et al.*, 2001).

3. Hydrogen cost and CO_2 emissions

3.1. Specifying a hydrogen supply system

The hydrogen supply system studied in this report consists of hydrogen production, hydrogen transportation and CO_2 sequestration, which includes CO_2 separation, CO_2 transportation and CO_2 storage. Hydrogen end-use applications such as hydrogen fuel cell power plants and hydrogen filling stations for fuel cell vehicles are not included in this assessment. A scheme of the selected hydrogen supply system is given in Figure 3. Hydrogen is produced from natural gas or biomass at a large plant and transported by pipeline to the site for hydrogen end-use application. We assume that CO_2 separation equipment is installed in the hydrogen production plant and that the captured CO_2 is transported by pipeline to the storage site. As we mentioned in the previous section, there are two sources of CO_2 emissions from hydrogen production plants to the atmosphere. One is a concentrated CO_2 stream from the hydrogen purification process and the other is a diluted stream from the reformer stack flue gas. In this report, we are not concerned with carbon removal from the reformer flue gas. From a survey of literature on hydrogen technologies, we estimated total hydrogen costs and CO_2 emissions for the hydrogen pathways considered here. Detailed descriptions and assumptions for each component process are presented in the following subsection.
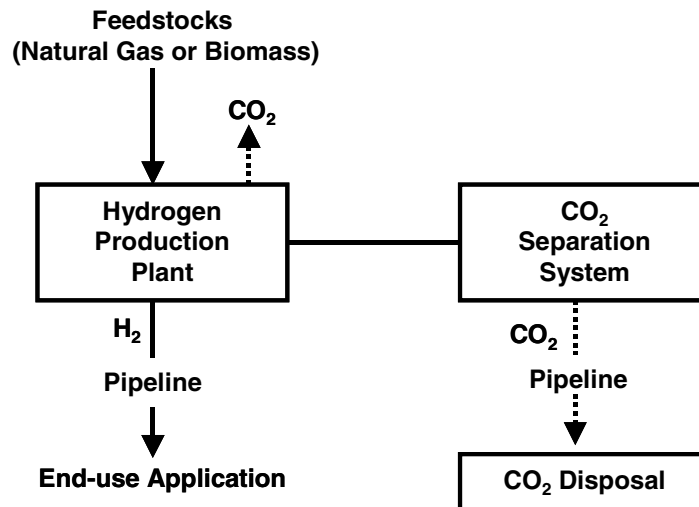

Figure 3: A scheme for the assessment of a hydrogen supply system.

3.2. Assumptions for the assessment

This subsection describes the assumptions for the calculations of hydrogen cost and CO_2 emissions. All energy values in this report are on a higher heating value (HHV) basis. Costs are expressed in US dollars, 1990 prices.

3.2.1. Hydrogen production cost

We calculated current levelized hydrogen production cost from the published literature on economics of steam methane reforming (SMR) and biomass gasification. As for biomass gasification, some different designs of gasifiers are reported. In this assessment, an indirectly heated gasifier developed at the Battelle Columbus Laboratories (BCL) was selected as the representative technology. This system is called indirectly heated because the heat necessary for the endothermic gasification reactions is supplied by sand circulating between the char combustor and the gasifier vessel. This biomass gasification technology is not commercialized yet, but together with other biomass gasification options it has potential to become a cost-effective hydrogen production system (Williams *et al*., 1995; Spath and Mann, 1998; Hamelinck *et al*., 2001).

Three major cost factors (investment, operation and maintenance (O&M) and feedstock cost) contribute to the cost of hydrogen production.[6] Investment and O&M costs obtained from the collected data were converted into levelized values in US dollars per gigajoule of produced hydrogen ($/GJ-$H_2$). An annual discount rate of five percent, a plant lifetime of 20 years and plant utilization factors of 90 percent are assumed and a straightforward annualization method was used for the calculation.

The feedstock costs highly depend on time and place. Biomass feedstock costs particularly differ from country to country. For the simplicity, we assumed the feedstock costs as utility acquisition prices in typical OECD countries for the industry sector, 3.1 $/GJ for natural gas (IEA, 2001) and 3.9 $/GJ for biomass (IEA, 1994) are adopted as representative values.

Figure 4 presents the cost of hydrogen production from steam reforming of natural gas (SMR) and biomass gasification (BCL) plant as a function of hydrogen production capacity. As shown in Figure 4, there is a significant economy of scale for both the SMR and the BCL plant. For the comparative assessment, we considered two sizes of hydrogen production plants, 1 and 10 million standard cubic meter per day (Nm^3/d). The hydrogen capacity of 1 million Nm^3/d can be considered as equal to generating approximately 80 megawatts electricity (MWe) from a hydrogen fuel cell power plant.[7]

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[6] Byproducts (e.g., steam) credits from hydrogen production plant are not included in the production costs of hydrogen.

[7] Assuming a set of sixteen 5 MWe proton exchange membrane fuel cell (PEMFC) power plants (NEDO, 2000).
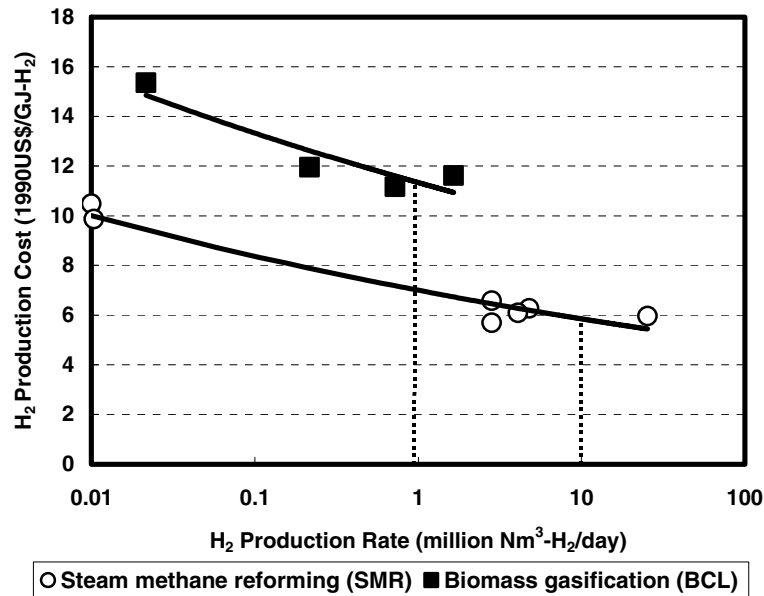
Figure 4: Hydrogen production cost via steam methane reforming of natural gas (SMR) and biomass gasification (BCL). Sources: Basye and Swaminathan, 1997; Berry, 1996; Block *et al.,* 1997; NEDO, 1999; Mann, 1995; Williams, 1998.

3.2.2. Hydrogen transportation cost

It is assumed that hydrogen is compressed at the production site and transported by pipeline to a hydrogen end-use site. The cost of hydrogen storage and delivery to users is not considered. For the calculation, we used the hydrogen pipeline transportation cost data from Amos (1998b) who studied the pipeline transmission cost at various capacities and distances.[8] As expected, the cost of pipeline transportation increases with pipeline length and decreases with the amount of hydrogen transported. In this report, the assumed distance of 200 miles (322 kilometers) between the hydrogen production site and a market is adopted as a representative value. Figure 5 presents the hydrogen transportation cost as a function of hydrogen transportation capacity. Again, the regression equation has been adapted for the calculation to derive the transportation cost at different capacities, 1 and 10 million Nm^3/day.

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[8] The estimated costs for hydrogen transportation include the pipeline cost as well as cost of compressing hydrogen to the pressures required for the transportation.
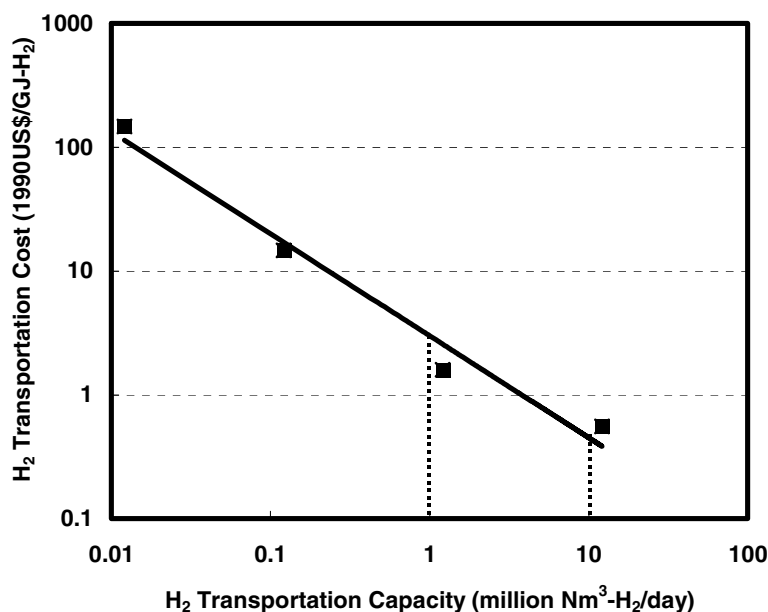
Figure 5: Hydrogen transportation cost as a function of hydrogen capacity at a distance of 200 miles (322 km). Source: Amos, 1998b.

3.2.3. CO_2 separation cost

In this assessment, we assumed that an additional set of pressure swing adsorption (PSA) equipment is installed after the hydrogen purification step to remove CO_2 from the hydrogen plant (i.e., separating CO_2 from process stream gas mixture), for both the SMR and the BCL systems (see Figure 1 and Figure 2).

The additional cost of the PSA system in large SMR plants has been estimated by Ogden (1999b). In the plant design, about 70 percent of the CO_2 in the natural gas feedstock can be removed from the SMR plant. The remaining 30 percent of CO_2 from the steam reformer combustion exhaust gas is emitted into the atmosphere. From the literature, we adopted 11 US dollars per ton of carbon dioxide ($/tCO_2$) as a CO_2 separation cost by additional PSA for both the SMR and the BCL plants.[9] This value is much lower than the capture cost of CO_2 emitted from power plants flue gas estimated to be at least 30 to 50 $/tCO_2$ (IEA, 1999a).[10]

3.2.4. CO_2 transportation cost

The cost of CO_2 transportation (including costs of compressors and of a pipeline to the sequestration point) has been estimated by Skovholt (1993) for a range of CO_2 capacity from 3 to 110 million tCO_2/year. Figure 6 shows the CO_2 transportation cost for a

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[9] Equivalent to 41 $/tC.

[10] Equivalent to 110 to 180 $/tC.

transportation distance of 250 kilometers as a function of CO_2 capacity with a regression line. We have extrapolated Skovholt's results to derive transportation costs at various CO_2 capacities.
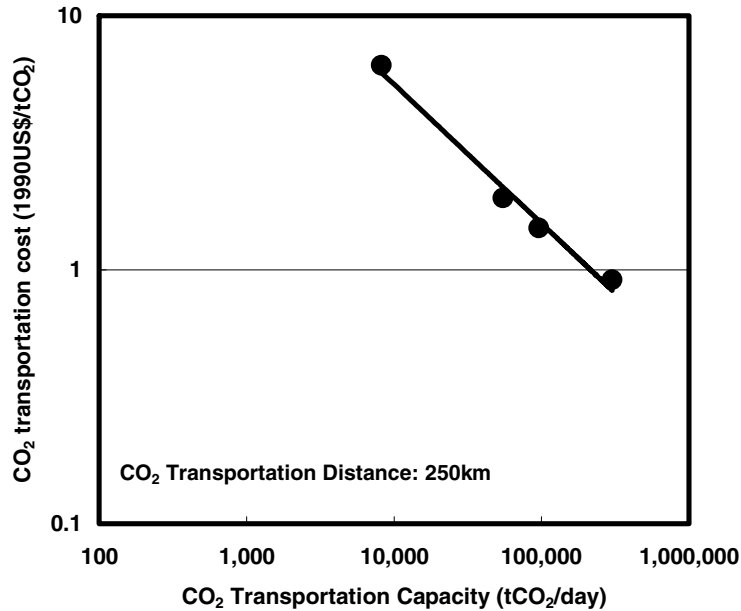

Figure 6: CO_2 transportation cost as a function of CO_2 capacity at a distance of 250 km. Source: Skovholt, 1993.

3.2.5. CO₂ storage cost

We assume that pipeline-transported CO_2 is stored in onshore saline aquifers. CO_2 storage cost of this option is from Hendriks (2000) who calculated costs of 2.5 \$/tCO_2 for storage at a depth of 2 km from the surface.

3.2.6. CO₂ emissions from the systems operation

We have estimated the direct CO_2 emissions from hydrogen production. The values of CO_2 emissions from plant operations of SMR and BCL without CO_2 sequestration are quoted from Williams (1998) as 56 kilograms of carbon dioxide per gigajoule of hydrogen ($kgCO_2/GJ$-H_2 for SMR) and 126 $kgCO_2/GJ$-H_2 (BCL), respectively. With CO_2 separation, it is assumed that 70 percent of the carbon in the feedstock is captured by additional PSA equipment for both SMR and BCL plants. In addition, CO_2 emissions from the use of electric power required for the operation of compressors in hydrogen transportation and CO_2 sequestration are also included in our estimates. The data for electricity required for compression (i.e., energy penalties), expressed in kilowatt hour per gigajoule of hydrogen (kWh/GJ-H_2), are converted into CO_2 emissions by using an

appropriate CO_2 intensity coefficient of power plants.[11] CO_2 emissions from a BCL plant operation, however, are assumed to be completely recovered during the biomass growing cycle, therefore no carbon emissions from BCL system are assumed.

3.2.7. Three alternative cases

For a base case, we selected a hydrogen production plant with a capacity of one million Nm^3/day, a hydrogen transportation distance of 322 kilometers and a CO_2 transportation distance of 250 kilometers. For the comparison between the SMR and BCL systems, we introduced two alternative cases, focusing on hydrogen capacity for SMR and CO_2 transportation distance for BCL. The descriptions of the three cases are shown in Table 3.

Table 3: Three alternative cases with descriptions.

Cases	Descriptions
Base Case (SMR and BCL)	H_2 capacity: 1 million Nm^3/day
	CO_2 transportation distance: 250 km
Case1	H_2 capacity: 10 million Nm^3/day (SMR only)
	CO_2 transportation distance: 250 km
Case2	H_2 capacity: 1 million Nm^3/day
	CO_2 transportation distance: 500 km (BCL only)

As shown in the data ranges in Figure 4, it is estimated that larger plants (more than one million Nm^3/day of hydrogen capacity) could be economically feasible for SMR. In contrast, BCL plants could have a size limitation due to the lack of technology experience so far. For that reason, Case1 includes a hydrogen production capacity of the SMR plant ten times larger than that assumed in the base case. Since the nature of biomass feedstock would restrict the BCL plant location more strictly than that of SMR, Case2 includes a CO_2 transportation distance for BCL that is double of base case In this case, the transportation cost is estimated as double of a baseline cost.

3.3. The results for the base case

We begin with a presentation of the results by discussing the base case. Table 4 summarizes the results of hydrogen cost calculations for the base case. The graphical illustration of disaggregated hydrogen cost for the base case is shown in Figure 7. The difference between the hydrogen cost produced by SMR and BCL is mainly due to the difference of hydrogen plant costs (investment and O&M costs). Under these

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[11] Assuming the electricity required for the operation of compressors is generated from the same feedstock, natural gas combined cycle power plant without CO_2 recovery for SMR and biomass gasification combined cycle power plant without CO_2 recovery for BCL respectively are considered. The estimated direct CO_2 emissions data are quoted from Fujie and Schrattenholzer (1999) as 0.4 $kgCO_2$/kWh for SMR and zero $kgCO_2$/kWh for BCL.

assumptions, the hydrogen costs from natural gas and biomass without CO_2 sequestration are approximately 10 and 14 \$/GJ, respectively. The addition of CO_2 sequestration (including CO_2 separation, transportation and disposal) adds about 15 percent to the overall cost of hydrogen, i.e., 1.6 for SMR and 2.8 \$/GJ for BCL. Comparing these results with results on power plants, this cost increase is less than that of removing CO_2 from flue gas of natural gas combined cycle power plants, which is approximately 50 to 60 percent of electricity generation cost (IEA, 1999b). Although the CO_2 separation system addressed here cannot remove CO_2 from the plant completely[12], the cost of hydrogen from SMR with CO_2 sequestration system is still lower than BCL without CO_2 sequestration and water electrolysis using renewables such as wind and solar.[13]

Table 4: Results of the hydrogen cost analysis for base case.

			SMR (Base case)	BCL (Base case)	Notes
H₂ production	H₂ capacity	million Nm³/day	1	1	1 million Nm³-H₂/day can operate a set of sixteen 5 MW PEM fuel cell power plants (i.e., 80MW) NEDO 2000
	Efficiency	-	0.76	0.53	Average of collected data
	Feedstock cost	\$/GJ-feed	3.1	3.9	Natural gas: IEA, 2001 Biomass: IEA, 1994
	H₂ production cost	\$/GJ-H₂	7.0	11.3	SMR (\$/GJ): 6.9991*(H₂ capacity in 10⁶Nm³/d)^(-0.0777) BCL (\$/GJ): 11.334*(H₂ capacity in 10⁶ Nm³/d)^(-0.0705)
H₂ transportation	Distance	km	322	322	Pipeline transportation including compression of H₂
	H₂ transportation cost	\$/GJ-H₂	3.0	3.0	H₂ transportation cost (\$/GJ): 2.9999*(H₂ capacity in 10⁶Nm³/d)^(-0.8234) Amos, 1998b
CO₂ separation	CO₂ separation cost	\$/tCO₂	11	11	Ogden, 1999b
	CO₂ emission (w/o separation)	kgCO₂/GJ-H₂	56	0	Williams, 1998
	CO₂ separation rate	kgCO₂/GJ-H₂	39	87	70% carbon of feedstock is captured by additional PSA. Williams, 1998
	Separated CO₂	tCO₂/day	503	1,116	
	CO₂ separation cost	\$/GJ-H₂	0.43	0.95	
CO₂ transportation	Distance	km	250	250	Pipeline transportation including compression of CO₂
	CO₂ transportation cost	\$/tCO₂	28	18	CO₂ transportation cost (\$/tCO₂ at 250km): 836.07*(CO₂ capacity in tCO₂/d)^(-0.5481) Skovnolt, 1993
	CO₂ transportation cost	\$/GJ-H₂	1.09	1.56	
CO₂ storage	CO₂ storage cost	\$/tCO₂	2.5	2.5	Onshore saline aquifer at depth of 2 km Hendriks, 2000
	CO₂ storage cost	\$/GJ-H₂	0.10	0.22	
Total cost (without CO₂ sequestration)		\$/GJ-H₂	10.0	14.3	
Total cost (with CO₂ sequestration)		\$/GJ-H₂	11.6	17.1	
Incremental cost of CO₂ sequestration		\$/GJ-H₂	1.6	2.7	

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[12] Note that 30 percent of the carbon in the natural gas feedstock is not captured in this system.

[13] For example, Mann *et al.*, (1998) projected the selling price of hydrogen from a photovoltaic (PV) and wind electrolysis system as over 20 \$/GJ-H₂.
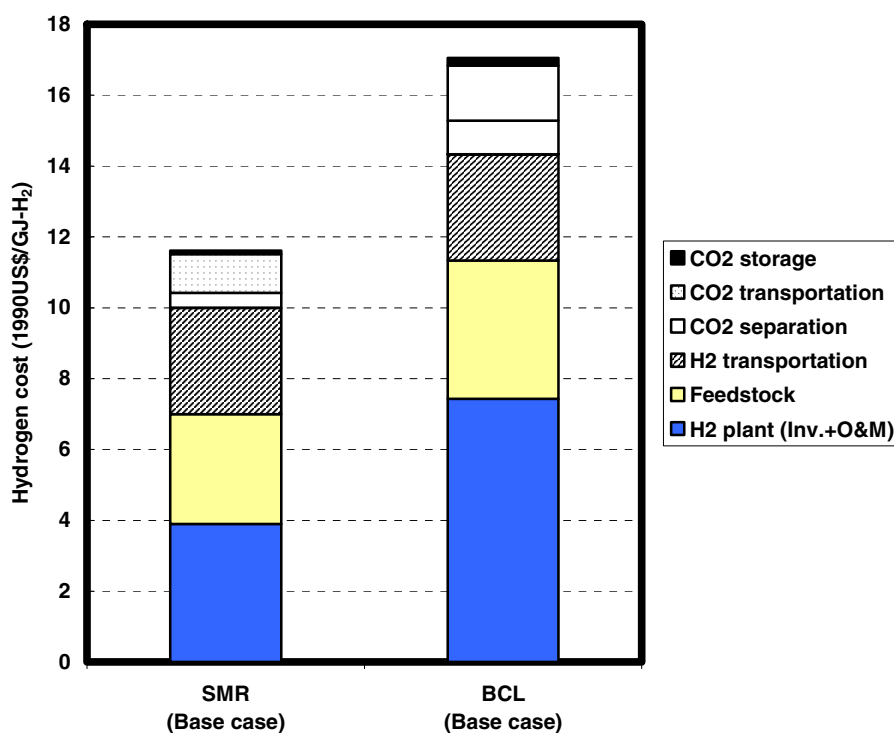
Figure 7: Hydrogen cost from natural gas (SMR) and biomass (BCL) for the base case. Hydrogen production capacity: 1 million Nm^3/day, CO_2 transportation distance: 250km.

Table 5 summarizes the base case results of CO_2 emissions from both SMR and BCL with and without CO_2 sequestration. The graphical illustration of CO_2 emissions is shown in Figure 8. The main contribution to the CO_2 emissions in the SMR systems is from the hydrogen production plant. The contribution of the electricity consumption of the compressor to the total amount of CO_2 emissions is just 0.5 $kgCO_2$/GJ. Because of the operation of the overall SMR plant without CO_2 sequestration, about 60 $kgCO_2$/GJ is emitted from the system. In the SMR plant with CO_2 sequestration, the total amount of CO_2 emissions to the atmosphere decreases to approximately 20 $kgCO_2$/GJ, that is, 65 percent of the total amount of CO_2 emissions is removed.

As mentioned earlier, since the amount of CO_2 emissions from the BCL system is regarded as zero, BCL with CO_2 sequestration system could result in a net CO_2 removal from the atmosphere at a rate of approximately 90 $kgCO_2$/GJ.

Table 5: CO_2 emissions in the base case.

|			SMR (Base case)	BCL (Base case)	Note
CO_2 intensity (Electricity)		$kgCO_2/kWh$	0.4	0	Fujie and Schrattenholzer, 1999
H_2 production	CO_2 emission	$kgCO_2/GJ-H_2$	56	0	Williams, 1998
H_2 transportation	Energy penalty	$kWh/GJ-H_2$	2.6	2.6	2.6 $kWh/GJ-H_2$ for compressing from 0.1 to 4 MPa. Amos, 1998b
	CO_2 emission	$kgCO_2/GJ-H_2$	1.0	0	
CO_2 separation	Captured CO_2	$kgCO_2/GJ-H_2$	39	88	
	Energy penalty	kWh/tCO_2	100	100	100 kWh/tCO_2 for PSA operation (Ogden, 1999b)
	CO_2 emission	$kgCO_2/GJ-H_2$	1.5	0	
CO_2 transportation and storage	Energy penalty	kWh/tCO_2	114	114	114 kWh/tCO_2 for compressing from 0.1 to 11 MPa. Hendriks, 2000
	CO_2 emission	$kgCO_2/GJ-H_2$	1.8	0	
CO_2 emission (without CO_2 sequestration)		$kgCO_2/GJ-H_2$	58.6	0	
CO_2 emission (with CO_2 sequestration)		$kgCO_2/GJ-H_2$	21.1	-88.4	
Captured CO_2		$kgCO_2/GJ-H_2$	37.5	88.4	
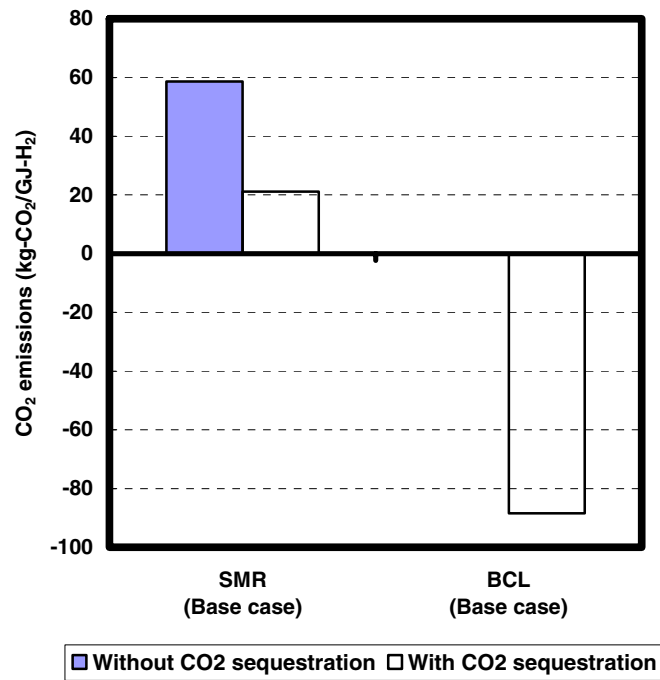
Figure 8: CO_2 emissions from hydrogen production systems for the base case. Hydrogen production capacity: 1 million Nm^3/day, CO_2 transportation distance: 250km.

3.4. Comparative assessment of two alternative cases

3.4.1. Hydrogen cost

In this subsection, we present the results of two alternative cases by comparing them with the base case. Figure 9 compares hydrogen cost and CO_2 emissions for all three cases. Comparing Case1 results for SMR with the base case, overall hydrogen cost in Case1 decreases due to the economy of scale, which particularly affects the hydrogen plant costs and hydrogen and CO_2 transportation costs. The contribution of CO_2 sequestration to the overall cost is smaller. This implies that if CO_2 sequestration is desired, large centralized plants are preferred because the incremental cost of carbon sequestration for small, decentralized hydrogen production plants would be large. Furthermore, for small hydrogen production plants with CO_2 sequestration, another cost, stemming from the need of collecting captured CO_2 from many plants, must be considered. However, if CO_2 sequestration is not necessary and the higher cost of decentralized plants is offset by lower hydrogen transportation cost, a decentralized hydrogen production system could be attractive and competitive with centralized hydrogen production. The values of CO_2 emissions per produced hydrogen are the same in all cases.
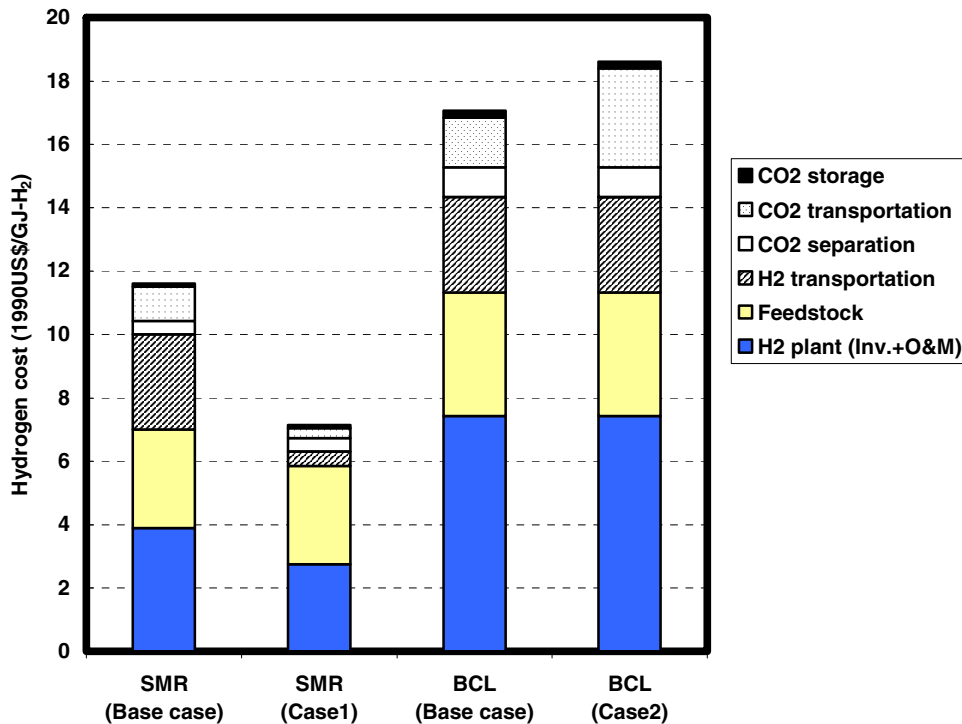

Figure 9: Hydrogen cost from natural gas and biomass for three cases. Base case, hydrogen production capacity: 1 million Nm^3/day, CO_2 transportation distance: 250km. Case1, 10 times the hydrogen production capacity for SMR than the Base case. Case2, double CO_2 transportation distance for BCL than the Base case.

3.4.2. Carbon emission reduction costs

This subsection describes carbon emission reduction costs for three cases. The carbon reduction cost expressed in dollars per tons of carbon abated is calculated by comparing the (higher) cost and (lower) CO_2 emissions of a carbon emission reduction measure with the corresponding values of a reference case. The formula for doing so is defined as follows.

$$C_e = \frac{C_o - C_r}{E_r - E_o}$$

Where

C_e: carbon emission reduction cost ($/tC)

C_o: hydrogen cost ($/GJ)

C_r: reference energy cost ($/GJ)

E_o: carbon emissions (tC/GJ)

E_r: carbon emissions of reference energy (tC/GJ)

Carbon emission reduction costs in alternative cases are presented in Figure 10. For the calculation, the reference cost and CO_2 emission values refer to gasoline. We assumed a gasoline price of 5 $/GJ and a CO_2 emission coefficient of 66 kgCO_2/GJ of gasoline. The retail gasoline price without tax is adapted from an average untaxed retail pump prices for November in 1998 (Metschies, 1998), converted to 1990 prices. The CO_2 emission coefficient of gasoline is quoted from the report from Ministry of the Environment in Japan in 2000 (MOE, 2000).

The cost of the carbon reduction is the lowest in the SMR with CO_2 sequestration (SMR-R) system in Case1 (10 times the hydrogen capacity). This is due to the significant economy of scale assumed for the SMR system. In the Base case, however, the carbon reduction cost for BCL with CO_2 sequestration (BCL-R) system is the lowest. Comparing SMR-R in Base case with Case2 (double CO_2 transportation distance), BCL-R still has lower carbon reduction costs. This implies that BCL with carbon sequestration system could be a better option than SMR with carbon sequestration for carbon mitigation.
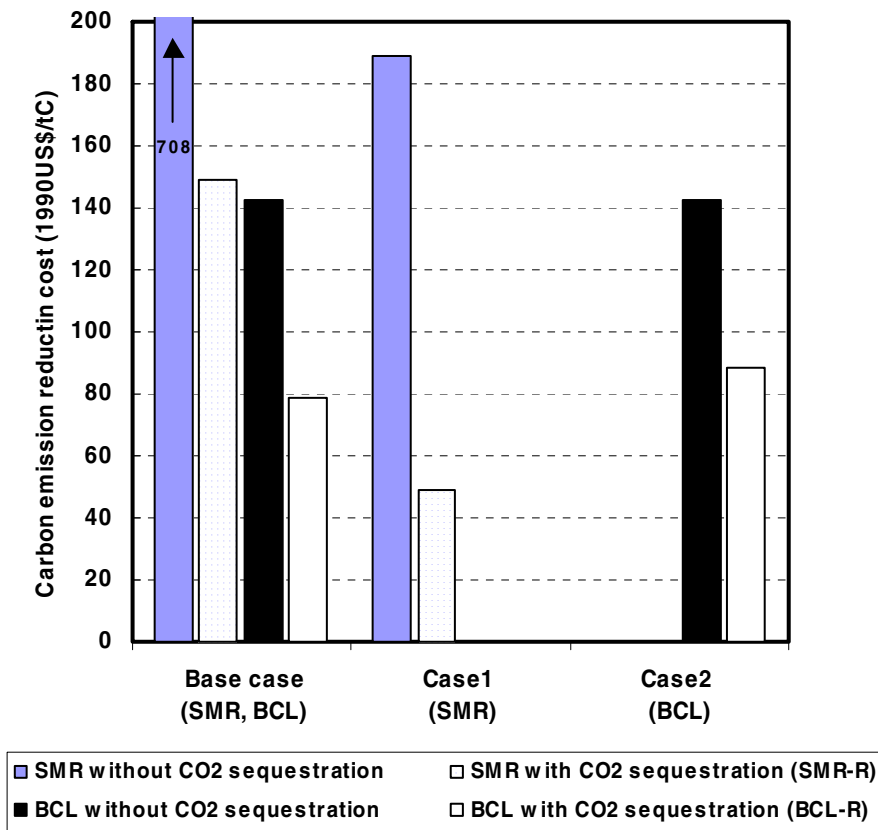
Figure 10: Carbon emission reduction costs for all cases. Base case, hydrogen production capacity: 1 million Nm^3/day, CO_2 transportation distance: 250km. Case1. 10 times the hydrogen production capacity for SMR than the Base case. Case2, double CO_2 transportation distance for BCL than the Base case.

3.4.3. Carbon taxes

To check the consequences of introducing a carbon value, we analyzed the consequences of assuming a carbon tax in a range between 0 and 500 $ per tons of carbon emitted. To illustrate the effect of such a carbon tax on hydrogen costs, the total carbon emission rate (tC/GJ-H_2) from each system is used. Figure 11 shows the relationship between the hydrogen costs of the BCL and SMR systems and the assumed carbon tax. As illustrated, assumptions on the carbon tax strongly affect the costs of hydrogen systems, and are, hence, an important factor in determining the cost-effectiveness of competing production systems.

Since the hydrogen production from SMR and SMR-R is associated with carbon emissions, their costs increase in line with raising carbon taxes (Figure 11). In contrast, BCL is not influenced by the carbon tax, because it is a zero-emissions technology. If BCL is equipped with CO_2 sequestration systems (BCL-R), it has even negative carbon emissions. Hence, the carbon tax levied on BCL-R is regarded as a cost credit, resulting nominally that hydrogen cost decreases in the case of higher carbon taxes. Quite naturally, biomass-based hydrogen systems with carbon capture and sequestration become increasingly attractive with increasing values of the assumed carbon tax.

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Comparing hydrogen costs of relatively small plants (Base cases) shows that BCL-R becomes an economically attractive option for mitigating CO_2 beyond a carbon tax of 200 \$/tC. However, in the case where a small-scale BCL-R (Case2) has to compete with a ten times larger SMR-R plant (Case1), the threshold-value for the carbon tax (beyond which BCL-R becomes attractive) moves to about 400 \$/tC.
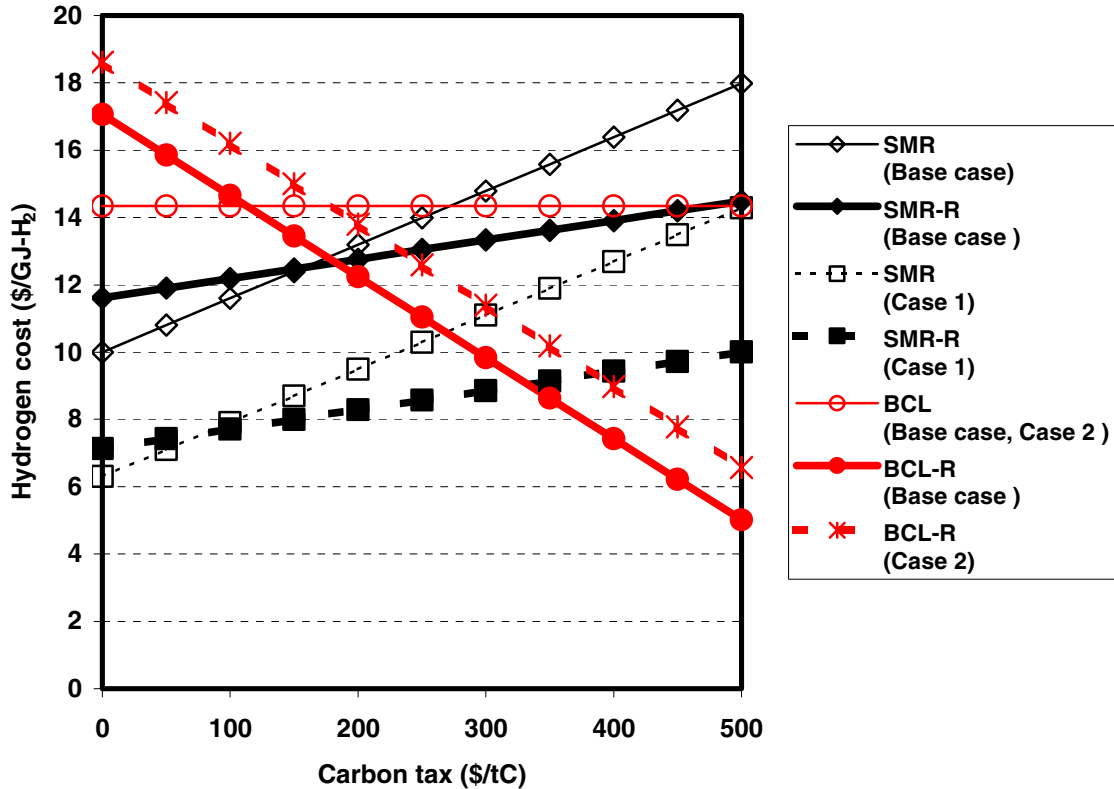

Figure 11: Relationship between hydrogen costs and carbon taxes for SMR and BCL production systems (with and without carbon scrubbing). Base cases: hydrogen production capacity: 1 million Nm^3/day, CO_2 transportation distance: 250km. Case 1: 10 times the hydrogen production capacity for SMR compared to the Base case. Case 2: double CO_2 transportation distance for BCL compared to the Base case.

4. Summary and Conclusions

In previous work we developed a long-term global energy scenario, describing a route for the transition from the present fossil-based energy system to a sustainable hydrogen-based economy (Barreto *et al.*, 2002). By doing so, we identified two main hydrogen production technologies, (1) the steam methane reforming of natural gas and (2) the hydrogen production via biomass gasification, as the most promising options for an environmentally sound hydrogen production at low carbon-intensities. In this report, we took a closer look at these technologies, and made a comparative assessment of the two hydrogen production systems with regards to their costs, performance and their economics for carbon abatement.

At present, large amounts of hydrogen are produced as a feedstock for ammonia and oil refineries via the steam methane reforming of natural gas (SMR), which is the most economically available technology for large amounts of hydrogen production. In contrast, the hydrogen production from biomass (BCL) is a comparatively new and advanced technology, of which just a few demonstration plants exist. The main reason for this is that in comparison to BCL, SMR costs are relatively low: we estimated the delivery costs of hydrogen for an 80 MW (i.e., 1 million Nm^3/day hydrogen capacity for fuel cell power plant) SMR system (including the costs for hydrogen transportation and distribution) at 10 \$/GJ. The costs for a BCL plant with the same size is about 14 \$/GJ. The bulk of the cost difference is due to the high costs of the biomass-gasification facility, compared to the direct use of natural gas for SMR.

An important finding of our analysis is that the costs of both systems benefit significantly from economies of scale, i.e., hydrogen production at lower costs can be achieved at larger scales (plant sizes). This is particularly the case for the steam methane reforming of natural gas, where we estimated a reduction in hydrogen costs by 40 percent to result from increasing the plant size from 80 to 800 MW. In theory, also the BCL technology could benefit in the same way from the economics of scale. In practice, however, the plant size of the BCL is constrained by the logistics involved in handling enormously large flows of fuelwood required for the operation of very large BCL plants. Hence, at present costs, BCL can hardly compete with SMR due to the relatively high costs of the biomass-gasification, and due to the limitation of plant sizes.

The economics of hydrogen production changes considerably when one analyses the costs of SMR and BCL technologies in the context of carbon abatement. Hydrogen production from biomass gasification is a zero-emissions technology (assuming that the feedstock comes from sustainable forest management). If equipped with facilities for carbon capture and sequestration, BCL even permits the production of hydrogen at negative carbon emissions. In contrast, the hydrogen production via SMR leads to carbon emissions, even under the assumption that most of the CO_2 is captured and subsequently disposed of. We analyzed the carbon mitigation costs of the BCL and SMR systems for the case in which hydrogen replaces gasoline in the transport sector. Our analysis shows that, given that hydrogen is produced by 80 MW plants in both cases, BCL is by far the cheaper mitigation option (79 \$/tC compared to 149 \$/tC for SMR). If, as we assume, SMR profits from economies of scale, the mitigation costs of SMR including carbon capture and sequestration may drop to about 49 \$/tC. Most notably, however, our analysis shows that due to the negative emissions of BCL with carbon sequestration, this technology becomes increasingly competitive at increasing carbon values. Comparing hydrogen costs of relatively small plants (80 MW) shows that BCL-R becomes economically attractive option for mitigating CO_2 beyond a carbon tax of 200 \$/tC. If compared to very large centralized SMR facilities, the value moves to about 400 \$/tC, where medium-scale BCL systems become the cheapest option to produce hydrogen.

Given the current high costs of hydrogen production compared to cheap fossil alternatives, and acknowledging the lack of global agreements and efficient institutions for CO_2 abatement, it is unlikely that hydrogen technologies will enter the energy market in the near future. A pervasive and widespread diffusion of hydrogen technologies, as depicted by our "hydrogen-economy" scenario, requires considerable

efforts to further improve technology costs and performance. Strategies to accelerate the market introduction of BCL and SMR should focus on short-term actions to foster the market penetration in the long term. We suggest that these actions should focus on the creation of niche markets, development of demonstration plants, and targeted technology policies and R&D investments.

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