



# Hydrogen from coal gasification: An economical pathway to a sustainable energy future

Gary J. Stiegel<sup>a,\*</sup>, Massood Ramezan<sup>b,1</sup>

<sup>a</sup>U.S. Department of Energy, National Energy Technology Center, P.O. Box 10940, Pittsburgh, PA 15236, United States

<sup>b</sup>Science Applications International Corporation, P.O. Box 10940, Pittsburgh, PA 15236, United States

Received 28 May 2004; received in revised form 18 May 2005; accepted 22 May 2005

Available online 11 August 2005

## Abstract

Although hydrogen is the most abundant element in the universe, it does not occur naturally in large quantities or high concentrations on Earth. Hydrogen must be produced from other compounds such as fossil fuels, biomass, or water and is therefore considered an energy carrier like electricity. Gasification of carbonaceous, hydrogen-containing fuels is an effective method of *thermal* hydrogen production and is considered to be a key technology in the transition to a hydrogen economy. However, for gasification to play a major role during the transition period, capital and operating cost must be reduced and reliability and performance must be improved.

Analyses show that hydrogen produced from coal-based gasification can be competitive with production from natural gas provided the cost of natural gas remains above \$4/10<sup>6</sup> Btu and the high reliability of gasification-based processes can be demonstrated. But for coal to be considered in a carbon-constrained environment, the cost of natural gas would have to be greater than \$5.50/10<sup>6</sup> Btu. The development of advanced technologies, however, offers the potential for significant reductions in capital costs, improved thermal efficiencies, and increased reliability. If these advanced technologies are capable of achieving their goals, the cost of producing hydrogen from coal could be reduced by 25–50%, even with the capture and sequestration of CO<sub>2</sub>. With these reductions, the cost of natural gas would have to be less than \$2.50/10<sup>6</sup> Btu to compete, a scenario that is very unlikely to occur in the future. This potential cost reduction provides considerable impetus for continuing research and development in the production of hydrogen from coal.

© 2005 Elsevier B.V. All rights reserved.

*Keywords:* Hydrogen; Coal; Gasification; Economics

## 1. Introduction

Hydrogen (H<sub>2</sub>) is the most common element in the environment — at about 18 atomic %. However, due to its low mass density, this converts into less than 1% by weight, placing hydrogen 9th in order of occur-

\* Corresponding author. Fax: +1 412 386 4822.

E-mail addresses: [gary.stiegel@netl.doe.gov](mailto:gary.stiegel@netl.doe.gov) (G.J. Stiegel), [massood.ramezan@sa.netl.doe.gov](mailto:massood.ramezan@sa.netl.doe.gov) (M. Ramezan).

<sup>1</sup> Fax: +1 412 386 4516.

rence by weight. Hydrogen does not occur to any significant extent on the Earth in elemental form. It is mostly present in water and hydrocarbons. For example, water contains about 12 wt.% H<sub>2</sub>, coal about 4–6 wt.%, natural gas about 25 wt.%, and gasoline about 12 wt.%.

Hydrogen is being considered worldwide as a future, environmentally benign replacement for gasoline, diesel fuel, heating oil, natural gas, and other fuels in both the transportation and non-transportation sectors. Hydrogen is a versatile *secondary* energy carrier that can be produced from a variety of widely available *primary* energy sources, including coal, natural gas, biomass, wastes (Kim, 2003), solar, wind, or nuclear power. Hydrogen can be subsequently utilized at high conversion efficiency with essentially zero emissions. A future energy infrastructure based on hydrogen has long been proposed as an ideal long-term solution to energy-related environmental and supply security problems (Bockris, 2002; Ogden, 2003). Hydrogen holds the potential to provide a clean, reliable, and affordable energy supply that can enhance America's, as well as the world's, economy, environment, and security. Because of the absence of carbon, no carbon oxides are produced during the combustion of hydrogen; rather, the only product is water.

Despite these compelling benefits, the realization of a hydrogen economy faces many challenges. Unlike the viable infrastructure for gasoline and natural gas, no large-scale supporting infrastructure currently exists for hydrogen distribution, and the construction of one will require major capital investments. Interest in hydrogen grew in Europe after World War I, and the first use of the phrase "hydrogen economy" is attributed to General Motors engineers in 1970 (Dunn, 2002). Although, Goltsov and Veziroglu (2002) report that the words "hydrogen economy" were first introduced by J. O'M Bockris in 1971. More recently, many worldwide activities have described the transition to hydrogen as a future fuel of choice (see for example, Barreto et al., 2003). Elam et al. (2003) and Collot (2003) describe the International Energy Agency's Hydrogen Program and its research and development activities.

Although hydrogen production, storage, and delivery technologies are currently in commercial use by the chemical and refining industries around

the world, existing hydrogen storage and conversion technologies are still too costly for widespread use in energy applications. Finally, existing energy policies do not promote consideration of the external environmental and security costs of energy that would encourage wider use of hydrogen. Developing hydrogen as a realistic energy option will necessitate an unprecedented level of sustained and coordinated activities by a diverse group of stakeholders.

## 2. Hydrogen production today

Although it is the most abundant element in the universe, hydrogen does not naturally exist in large quantities or high concentrations on the Earth — it must be produced from other compounds such as fossil fuels, water, biomass, etc. Hydrogen, usually mixed with other gaseous compounds, has long been produced in large commercial quantities. Total U.S. production of hydrogen is now about 9 million metric tons per year, which is about one-half of the world's total production.

A variety of technologies have been and continue to be developed for the production of hydrogen: Some of these include:

1. Thermochemical reforming of hydrocarbons with steam at elevated temperatures.
2. Partial oxidation of fossil fuels such as residual oil, coal, or their derivatives (e.g., Shell Gasification Process; ChevronTexaco Partial Oxidation Process).
3. Reaction of steam with hot coal-derived or petroleum-derived coke to generate a producer gas or low-energy content synthesis gas.
4. Distillation (pyrolysis) of coal (e.g., coke ovens whereby the product gas contains 45–55 vol.% hydrogen, which was the basis of the former "town gas" industry).
5. Fluid-bed gasification of coal with lime addition to absorb carbon dioxide (CO<sub>2</sub> Acceptor Process).
6. Thermal cracking, pyrolysis, or decomposition of hydrocarbons (typically, natural gas) or ammonia (ammonia is a very effective hydrogen carrier, but has disadvantages).
7. Electrolysis of conductive water.

8. Other methods, such as reactions between highly electronegative metals (e.g., sodium) and water, reactions between certain oxides (e.g.,  $V_2O_3$ ) and water, or the reaction of certain hydrides (e.g.,  $CaH_2$ ) with water.

Conte et al. (2001) describes state-of-the-art technologies for hydrogen production and offers recommendation to accelerate the pace for widespread introduction of the hydrogen economy.

Hydrogen must be generated using other primary energy sources. Nearly 50% of the hydrogen produced worldwide is derived from natural gas, primarily via steam methane reforming. As shown in Fig. 1, the remaining hydrogen is produced from oil (30%), most of which is consumed in hydroprocessing applications in petroleum refineries, from coal (19%) primarily for the manufacture of ammonia, with the remaining 4% via water electrolysis. In the United States, only about 1% of primary energy use and 5% of natural gas use currently goes toward hydrogen production. Hydrogen produced in the United States is consumed in a variety of application markets. These include: 49% for the manufacture of ammonia ( $NH_3$ ) for use as a refrigerant and as a fertilizer; 37% for petroleum refining, 8% for methanol production, and about 6% for miscellaneous smaller-volume uses (Kroschwitz, 1995).

Within the United States, only a small portion of the hydrogen produced today is used as an energy carrier, most notably by the National Aeronautics and Space Administration for space launch vehicles.

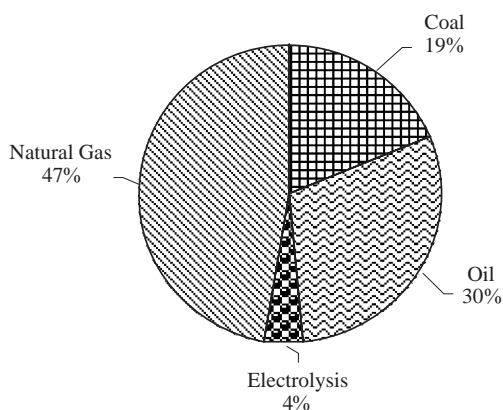


Fig. 1. Feedstock contribution to hydrogen production.

### 3. Future hydrogen requirements and production options

Once applications for hydrogen as an energy carrier have become well-established, the United States will require much more hydrogen than it now produces. An estimated 40 million tons of hydrogen will be required annually to fuel about 25 million fuel-cell powered cars, or to provide electricity to about 25 million homes. Each of the following centralized hydrogen production methods scenarios could produce 40 million tons per year of hydrogen:

- Coal/biomass gasification plants: 140 plants-each similar to today's large coal-fired plants
- Nuclear water splitting: 100 nuclear plants making only hydrogen
- Oil and natural gas refinery: 20 plants, each the size of a small oil refinery, using oil and natural gas in multi-fuel gasifiers and reformers.

### 4. Hydrogen production from natural gas

Approximately 80% of the hydrogen produced worldwide is derived from natural gas and petroleum. Commercial hydrogen production plants can be built utilizing steam-methane reforming (SMR), steam/oxygen reforming (SMR/ $O_2R$ ), and auto-thermal reforming (ATR) technology with natural gas, LPG, or naphtha feedstocks. Partial oxidation (POX) technology can be utilized with natural gas, naphtha, or heavy hydrocarbon feedstocks.

The basic processing steps common to both SMR and ATR are:

- Natural gas compression;
- Natural gas purification (i.e., sulfur removal);
- Catalytic steam reforming of methane to hydrogen and carbon monoxide (CO);
- Water-gas shift to convert CO to  $CO_2$  and additional hydrogen;
- Hydrogen gas purification.

The difference between SMR and ATR is how heat is provided to activate the endothermic steam reforming reaction. In SMR, the catalyst is contained in tubes heated by an external burner. In ATR, a portion

of the natural gas is burned to raise the temperature of the process gas before it contacts the catalyst.

Reforming is a mature technology, and the cost of hydrogen is sensitive to the cost of the feedstock. For natural gas as the feedstock, the capital cost of a large SMR producing 100 million scfd is in the range of \$0.65–\$0.80/scfd of hydrogen with thermal efficiencies in excess of 70% HHV. The relationship between the cost of hydrogen produced from natural gas in an SMR with a capital cost of \$0.70/scfd and the price of natural gas is given by the following equation (Gray and Tomlinson, 2002):

$$\text{Hydrogen Cost } (\$/10^6\text{Btu}) = 1.27 * \text{Natural Gas Price } (\$/10^6\text{Btu}) + 0.985. \quad (1)$$

At a natural gas price of \$4.00/10<sup>6</sup>Btu, using Eq. (1), the hydrogen cost would be about \$6/10<sup>6</sup>Btu.

## 5. Gasification technology overview

As mentioned previously, hydrogen can be delivered to customers or future distribution centers either as gaseous or liquid hydrogen or as a high hydrogen-containing reformable liquid hydrocarbon and gasification is poised to do both. Gasification offers industry the opportunity to develop unique combinations of advanced technologies that offer low cost, reliable, and highly efficient options for meeting a whole host of market applications. Gasification-based systems are capable of utilizing all carbon-based feedstocks, including coal, petroleum coke, biomass, municipal and hazardous wastes, etc., and is the only advanced power generation technology capable of coproducing a wide variety of commodity and premium products to meet future market requirements. Gasification-based systems are the most efficient and environmentally friendly technologies for the production of low-cost electricity and other products and can be readily adapted for concentrating and sequestering CO<sub>2</sub> (Rafia-Brown et al., 2002). Lin et al. (2002) provides a detailed description of hydrogen production from coal.

Gasification-based process options are depicted in the schematic diagram in Fig. 2. In the process, carbon-based feedstocks are converted in the gasifier in the presence of steam and oxygen at high temperatures and moderate pressure to synthesis gas, a mix-

ture of carbon monoxide and hydrogen. The chemistry of gasification is quite complex and involves many chemical reactions. In the initial stages of gasification, the rising temperature of the feedstock in the gasifier initiates devolatilization of the feedstock and the breaking of weaker chemical bonds to yield tars, oils, phenols, and hydrocarbon gases. These products generally react further to form H<sub>2</sub>, CO, and CO<sub>2</sub>. The fixed carbon that remains after devolatilization is reacted with oxygen (O<sub>2</sub>), steam, CO<sub>2</sub>, and H<sub>2</sub> to further contribute to the final gas mixture. The water-gas shift reaction alters the H<sub>2</sub>/CO ratio in the final mixture but does not greatly impact the heating value of the synthesis gas. Methane formation via two methanation reactions is favored by high pressures and low temperatures and is thus important in lower-temperature gasification systems. Methane formation is a highly exothermic reaction that does not consume oxygen and therefore increases the efficiency of gasification and the final heating value of the synthesis gas. Overall, about 70% of the feed fuel's heating value is associated with the CO and H<sub>2</sub> components of the gas but can be higher depending upon the gasifier type.

Depending on the gasification technology employed, significant quantities of water (H<sub>2</sub>O), CO<sub>2</sub>, and methane (CH<sub>4</sub>) can be present in the synthesis gas as well as several minor and trace components (Higman and van der Burgt, 2003). Under the sub-stoichiometric-reducing conditions of the gasifier, most of the fuel's sulfur converts to hydrogen sulfide (H<sub>2</sub>S), but some (3–10%) also converts to carbonyl sulfide (COS). Nitrogen bound with the fuel generally converts to gaseous nitrogen (N<sub>2</sub>), but some ammonia and a small amount of hydrogen cyanide (HCN) are also formed. Most of the chlorine content of the fuel is converted to hydrogen chloride (HCl) gas and some particulate-phase chlorides. Trace elements associated with both organic and inorganic components of the feedstock, such as mercury and arsenic, are released during gasification and partition between the different ash fractions (e.g., fly ash, bottom ash, slag) and gaseous emissions. The particular chemical species and physical forms of condensed-phase and vapor-phase trace elements are functions of gasifier design and operating conditions. The synthesis gas must be cleaned of these minor and trace components to predetermined levels consistent with further downstream

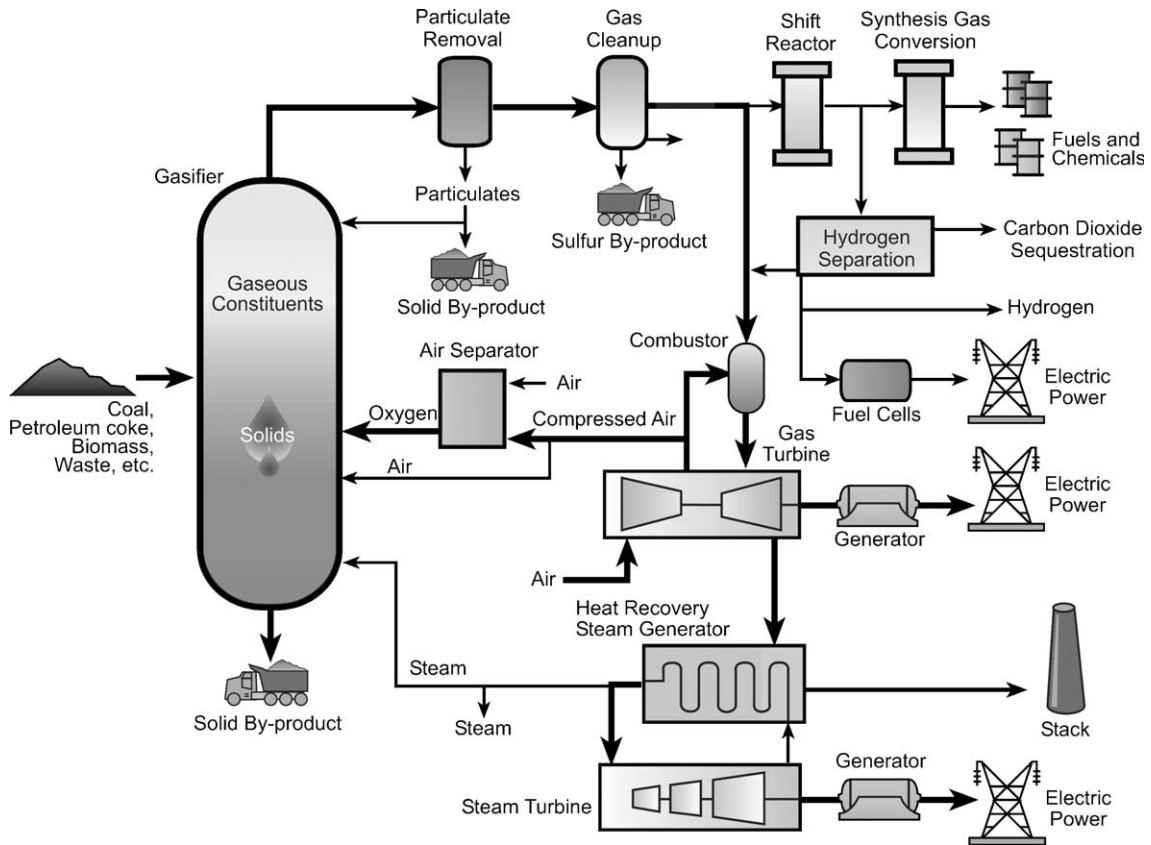


Fig. 2. Gasification-based energy conversion options.

processing. To clean the synthesis gas, chemical and physical solvents such as methyl diethanolamine (MDEA), methanol, etc. operating at near ambient temperatures or lower are employed. The selection of the technology for gas cleanup, (e.g., Selexol™, Rectisol™, etc.), is dependent on the purity requirements of downstream operations.

Once the synthesis gas is sufficiently cleaned, various options exist for its utilization such as the production of electricity via integrated gasification combined cycle (IGCC) or the production of hydrogen and reformable liquid fuels. For hydrogen production, the synthesis gas is routed to the water-gas shift reactor where the CO in the gas is reacted with water over a catalyst to produce additional H<sub>2</sub> and CO<sub>2</sub>. The H<sub>2</sub> and CO<sub>2</sub> are then separated with the hydrogen being used in the gas turbine, highly efficient fuel cells, or distributed for use as a fuel in the transportation sector, while the CO<sub>2</sub> can be sequestered. For the production

of a reformable liquid fuel, the synthesis gas is partially shifted to a predetermined H<sub>2</sub>/CO ratio and then catalytically converted to a saturated hydrocarbon product via conventional Fischer–Tropsch synthesis. The Fischer–Tropsch product can then be shipped to the point of use where it would be catalytically reformed to produce the needed hydrogen. Other reformable liquid fuels such as methanol can also be produced from synthesis gas with the appropriate choice of catalysts and process conditions. Because of its unique process and environmental attributes, gasification is viewed as a key technology in the transition to a hydrogen economy in the United States.

The low-cost production of hydrogen from fossil fuels, and in particular coal, is a key factor that will impact the successful introduction of hydrogen into the transportation and utility energy sector. Advanced technologies for the production of hydrogen will be required to achieve the level of cost

necessary to minimize the impact to the consumer. While natural gas currently represents the primary fossil energy resource for hydrogen production, coal and other solid carbonaceous resources also offer viable options for producing the large quantities of hydrogen that will be required to fuel future world energy needs. For the latter to compete against natural gas, advanced process technologies producing hydrogen with concomitant capture and sequestration of carbon dioxide must be developed and must be cost competitive with alternative production routes.

## 6. Coal-based hydrogen production system costs

Many have estimated the cost of producing hydrogen from coal, but the reported costs vary considerably. The variations in costs are due to different process configurations and process conditions as well as to different assumptions for economic and financial parameters. These differences in cost will be discussed further in a later section. To obtain a consistent set of costs for the production of hydrogen from conventional as well as advanced technologies, both with and without the sequestration option, the U.S. Department of Energy's National Energy Technology Laboratory commissioned a study with Mitretek Systems to investigate the cost of producing hydrogen under various scenarios (Gray and Tomlinson, 2002). For consistency in the analysis, the economic and financial assumptions employed in the study are provided in Table 1. The following seven options for producing hydrogen will be discussed:

- Case 1 Conventional Coal to H<sub>2</sub> (without CO<sub>2</sub> Recovery) — GE (ChevronTexaco) quench gasifier/WGS/Low-Temp. Gas Cleaning/Gas Turbine/Steam Turbine
- Case 2 Conventional Coal to H<sub>2</sub> (with conventional PSA CO<sub>2</sub> Recovery/Sequestration) — Single Train, GE (ChevronTexaco) quench gasifier/WGS/Low-Temp. Gas Cleaning/ Gas Turbine/Steam Turbine/Sequestration
- Case 3 Conventional Coal to H<sub>2</sub> (with Membrane CO<sub>2</sub> Recovery/Sequestration) — Single Train, ConocoPhillips Advanced E-gas gasifier/WGS/

Table 1

Financial and economic assumptions (Gray and Tomlinson, 2002)

Debt/Equity	67/33%
Return on equity	15%
Interest on debt	8%
General inflation	3%
Coal de-escalation below general inflation	1.5%
Plant life	25 years
Depreciation (Double declining balance)	16 years
Federal tax rate	34%
State tax rate	6%
Cost of sequestration of high pressure CO <sub>2</sub>	\$10/ton Carbon
Construction period	3 years
Output in startup year	50%

High-Temp. Gas Cleaning/Gas Turbine/Steam Turbine

- Case 4 Advanced Coal to H<sub>2</sub>/Power (without CO<sub>2</sub> Recovery) — Two train, ConocoPhillips Advanced E-gas gasifier /WGS/Low-Temp. Gas Cleaning/No CO<sub>2</sub> Removal/Gas Turbine/Steam Turbine
- Case 5 Advanced Coal to H<sub>2</sub> (with conventional PSA CO<sub>2</sub> Recovery/Sequestration) — Two train, ConocoPhillips Advanced E-gas gasifier /WGS/Low-Temp. Gas Cleaning/Gas Turbine/Steam Turbine
- Case 6 Advanced Coal to H<sub>2</sub> (with conventional PSA CO<sub>2</sub> Recovery/Sequestration) — Two train, ConocoPhillips Advanced E-gas gasifier /High-Temp. Gas Cleanup/WGS/SOFC/Gas Turbine/Steam Turbine
- Case 7 Advanced Coal to H<sub>2</sub> (with membrane CO<sub>2</sub> Recovery/Sequestration) — Two train, ConocoPhillips Advanced E-gas gasifier /High-Temp. Gas Cleanup (HGCU)/WGS/SOFC/ Gas Turbine/Steam Turbine

In each of the above cases, the selling price of the electricity produced has an impact on the required selling price (RSP) of the hydrogen. In the nonsequestration cases, the cost of electricity is based on the estimated cost of power produced from a General Electric (GE) H frame gas turbine operating in a combined cycle mode with a 15% return on investment. Using cost and performance data from a joint study sponsored by the DOE and EPRI (Buchanan et al., 1998), Gray and Tomlinson (2002) developed the following relationship for the cost of electricity from

Table 2

Summary of hydrogen production costs using conventional and advanced technologies, with and without carbon sequestration (Gray and Tomlinson, 2002)

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Feedstock rate, tons/day	3000	3000	3000	6000	6000	6000	6000
H <sub>2</sub> production, 10 <sup>6</sup> scf/day	131	119	158	149	153	149	150
Net power, MWe	20	27	25	475	358	509	519
Effective thermal efficiency, %	63.8	59	75.5	62.4	56.5	64.5	65.2
Capital cost, \$Million (Y2000)	367	416	425	910	950	1037	1019
RSP of H <sub>2</sub> , \$/10 <sup>6</sup> Btu	6.83	8.18	5.89	5.42	5.64	2.79	2.40
RSP of H <sub>2</sub> , \$/GJ	6.48	7.75	5.58	5.14	5.35	2.65	2.28

Feedstock delivered cost: \$1.26/10<sup>6</sup> Btu.

the H-turbine operating at 90% capacity factor versus the cost of natural gas:

$$\text{RSP of electricity (\$/MWh)} = 6.4 * \text{Natural Gas Price (\$/10}^6\text{Btu)} + 16.6 \quad (2)$$

At a natural gas cost of \$3.75/10<sup>6</sup>Btu used in the study, using Eq. (2), the required selling price of the electricity is \$35.6/MWh. Buchanan et al. (1998) also reported that the additional cost to capture and sequester CO<sub>2</sub> from the H frame gas turbine NGCC plant would be about \$18/MWh. Adding this to the cost of electricity from the base NGCC plant gives a required selling price of \$53.6/MWh. These values are used for the selling price of electricity in the analyses reported here. In addition to the cost of electricity, all cases deliver the hydrogen at about 300 psig and CO<sub>2</sub> at 200 bar; the cost for sequestering this carbon is assumed to be \$10/ton of carbon. In all cases, an Illinois #6 coal was used with a delivered cost of \$1.26/10<sup>6</sup>Btu. A summary

of the results of each of the seven options described above is presented in Table 2.

Cases 1 and 2 represent the processes for producing hydrogen from coal using conventional technologies, both with and without the capture and sequestration of CO<sub>2</sub>. Fig. 3 depicts the process that was used in the analysis. For Case 1, approximately 50% of the CO<sub>2</sub> in the shifted synthesis gas stream to the PSA unit is removed via conventional amine technology and vented so that a combustible tail gas leaves the PSA unit. In Case 2, nearly 87% of the carbon in the coal feed is captured using a two-stage selexol unit and subsequently sequestered. As the results in Table 2 show, the thermal efficiency of the plant is reduced by about 5 efficiency points, primarily due to the added energy required for compression of the CO<sub>2</sub> to 200 bar. This level of compression may be too high; recent studies are now standardizing compression to 2000 psig, which should somewhat improve the overall plant efficiency. The additional capital cost for the added CO<sub>2</sub> removal amounts to about \$50 million.

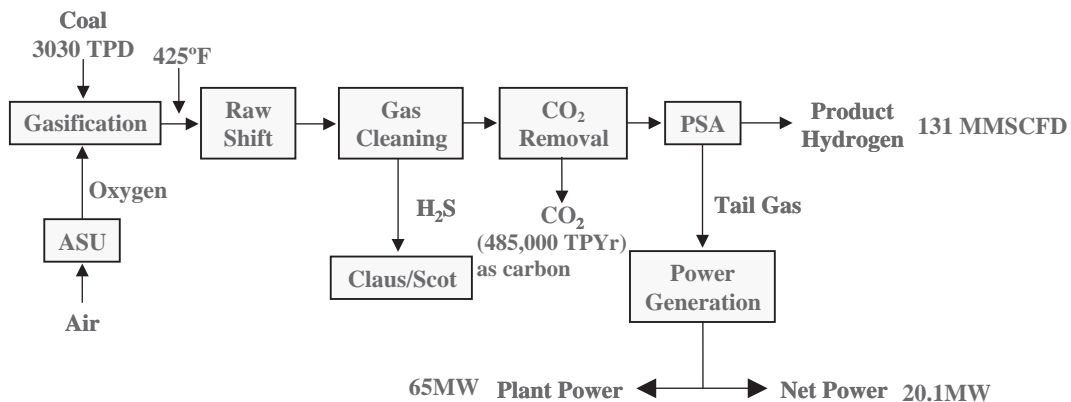


Fig. 3. Production of hydrogen from coal via conventional technologies (Cases 1 and 2).

Applying the power costs described above, i.e., \$35.6/MWh for nonsequestration case and \$53.6/MWh in the case of carbon sequestration, the required selling price of the hydrogen increases by \$1.40/10<sup>6</sup>Btu due to carbon sequestration, i.e., from about \$6.80/10<sup>6</sup> to \$8.20/10<sup>6</sup>Btu. These costs are comparable to hydrogen produced from natural gas costing \$4.60/10<sup>6</sup> and \$5.70/10<sup>6</sup>Btu, respectively.

Case 3 explores the impact of incorporating advanced technologies into the overall process for the production of hydrogen from coal. Included are the advanced entrained E-Gas gasifier (Bechtel Corporation, 2003), high temperature gas cleanup, and a ceramic membrane operating at 600 °C with a 100 psi pressure drop across the membrane. The membrane performance is based on the porous system being developed by Oak Ridge National Laboratory (Klett et al., 2002). It was assumed that 90% of the synthesis gas is converted to H<sub>2</sub> in the membrane system. The cost of the membrane system was assumed to be equivalent to the cost of the amine and PSA units. The process schematic for this case is shown in Fig. 4. Since all of the hydrogen cannot be recovered via the membrane, the nonpermeate stream containing mostly CO<sub>2</sub> and residual H<sub>2</sub> and CO is combusted with oxygen in a combustor to produce the CO<sub>2</sub> stream for sequestration. Heat from both the H<sub>2</sub> and CO<sub>2</sub> streams is recovered in a heat recovery steam generator (HSRG)

to produce steam for additional power generation. Because of the process's ability to operate at higher temperatures and the absence of the energy requirements associated with the amine absorption process, the efficiency of the process is about 11 efficiency points higher than Case 1 even with the capture and sequestration of carbon. Although the capital cost is higher, as shown in Table 2, the increased amount of hydrogen produced using the advanced technologies ultimately results in a reduction in the RSP of the hydrogen by nearly \$1.00/10<sup>6</sup>Btu even with carbon sequestration. This cost of hydrogen is equivalent to that from natural gas costing about \$3.90/10<sup>6</sup>Btu. This drastic improvement provides the incentive for the continuation of the development of advanced process technologies.

Case 4, shown in Fig. 5, explores the concept of coproducing both hydrogen and power, without carbon sequestration, using a two-train advanced entrained gasification system with conventional gas cleaning and H<sub>2</sub> separation technologies. One train provides gas for hydrogen production while the second feeds the combined cycle plant. In this case, the hydrogen production is slightly more than that from Case 1, but now the process generates a net 475 MWe. The overall thermal efficiency of the process is about the same as that in Case 1. However, the cost of the facility is about 2.8 times that of Case 1, but the RSP

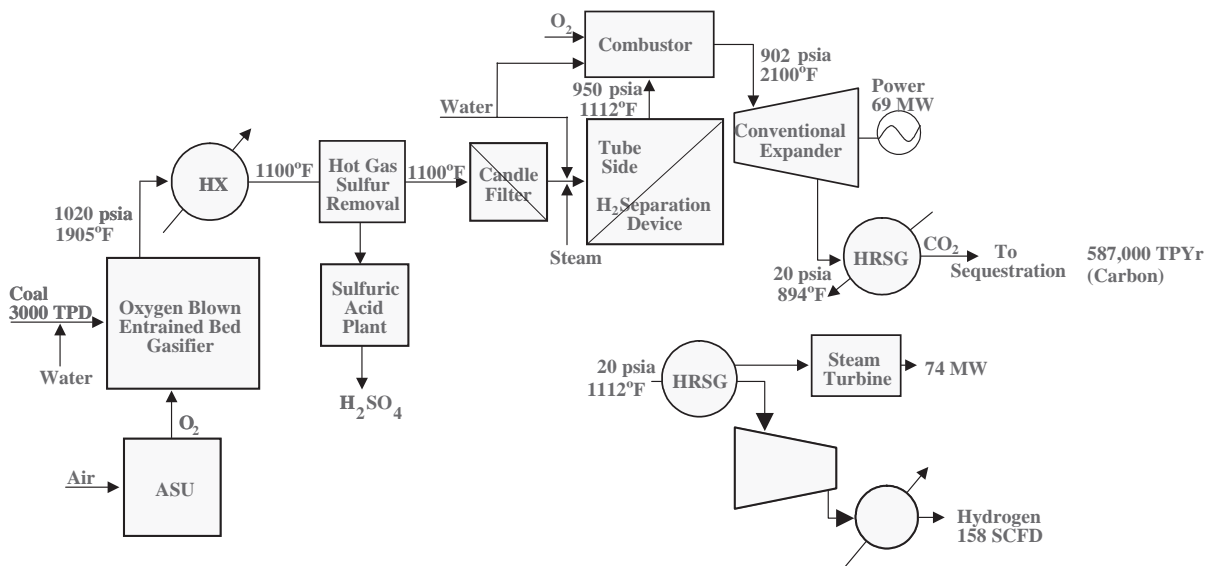


Fig. 4. Production of hydrogen using advanced gasifier, gas cleaning, and membrane technologies (Case 3).



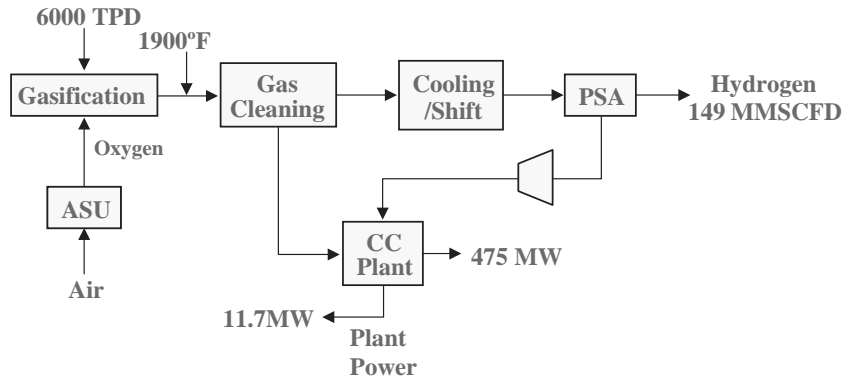


Fig. 5. Coproduction of hydrogen and power from coal (Case 4).

of the hydrogen is approximately 20% less, provided the coproduced power can be sold for \$35.6/MWh. In this case, the cost of hydrogen is sensitive to the price of the electricity sold to the market.

Case 5 (Fig. 6) is similar to Case 4 except that all of the synthesis gas is shifted, the CO<sub>2</sub> is removed, and the hydrogen is produced in much the same way as in Case 2 (see Fig. 3). The tail gas from the PSA unit is compressed and fed to the combined-cycle unit for power generation. Approximately 95% of the carbon is captured and sequestered in this case. Approximately the same quantity of hydrogen is produced as in Case 4; however, the net power production decreases by nearly 125 MWe, primarily due to additional parasitic power required for CO<sub>2</sub> capture and compression. As such, the thermal efficiency of the plant drops by nearly 6 efficiency points compared to Case 4 without CO<sub>2</sub> capture. In this case, the RSP of the hydrogen increases slightly, provided that the power produced can be sold for \$53.6/MWh. If the value of the coproduced electricity is capped at the cost of electricity

from an advanced IGCC plant, i.e., \$46.3/MWh, then the RSP of the hydrogen would increase to about \$6.90/10<sup>6</sup>Btu, similar to that from conventional technologies without CO<sub>2</sub> capture (Case 1).

The remaining two cases, i.e., Cases 6 and 7, represent futuristic processes incorporating solid oxide fuel cells (SOFC) for power generation as well as advanced and conventional technologies. In Case 6, the SOFC topping cycle is used in combination with a conventional PSA unit for H<sub>2</sub> separation. The SOFC is assumed to operate at 2000 °F, 60% efficiency (HHV), convert 85% of the synthesis gas, and cost \$400/kWe. The clean synthesis gas from the high temperature gas cleanup unit is split with a portion being fed to the anode of the SOFC and the remainder being mixed with the effluent from the anode and fed to the water-gas shift reactor. The shifted gas is sent to a conventional system for CO<sub>2</sub> removal (90% of the carbon in the feed) and the remaining gas is sent to a PSA unit for production of hydrogen (Fig. 7). The vitiated air from the cathode

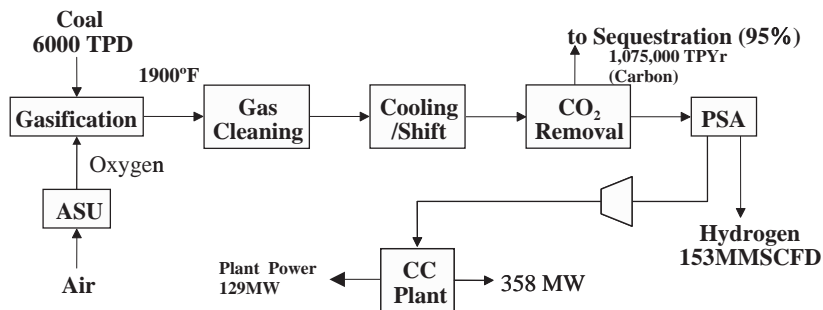


Fig. 6. Coproduction of hydrogen and power from coal (Case 5).

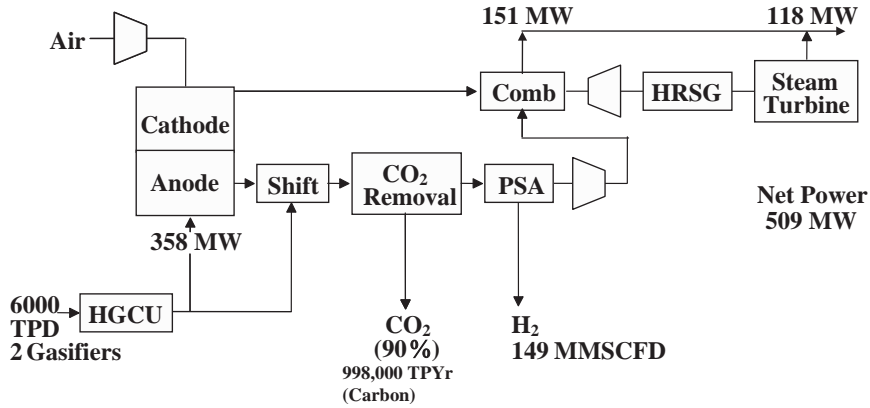


Fig. 7. Production of hydrogen and power with sequestration utilizing solid oxide fuel cells and convention technologies for gas cleaning and hydrogen separation (Case 6).

of the SOFC is fed to the gas turbine of a combined cycle unit along with the tail gas from the PSA unit to produce additional power. Although the capital cost of this process is slightly over \$1 billion, the efficiency of the plant is approximately 65%, even with CO<sub>2</sub> capture and sequestration. Assuming the cost of electricity is \$53.6/MWh, the RSP of the hydrogen would be about \$2.80/10<sup>6</sup>Btu, considerably lower than any case presented thus far. At a cost of \$46.3/MWh, as above, the RSP of the hydrogen increase to \$4.60/10<sup>6</sup>Btu, still substantially lower than any of the other cases.

Finally, in Case 7, the advanced membranes are employed to affect the water-gas shift reaction and separate the hydrogen. The sensible heat is recovered to produce steam and the resulting H<sub>2</sub> is compressed

to 22 atm. The nonpermeate stream is fed to the anode of the SOFC where nearly 400 MWe is produced. The effluent from the anode is sent to a combustor where it is burned with oxygen to produce power in a gas turbine (Fig. 8). The effluent, containing only CO<sub>2</sub> and water, is cooled in a HRSG to produce steam for the steam cycle. The hot vitiated air from the cathode of the SOFC is expanded in a gas turbine and the heat in the effluent is recovered in a HRSG for steam generation. The combined net power output from the fuel cell, gas turbine, and steam turbine is about 520 MWe. Again, the overall thermal efficiency of this plant is estimated to be about 65%. Once again, the use of the advanced H<sub>2</sub> separation membranes yields a significant reduction in the cost of hydrogen, i.e., \$2.40/10<sup>6</sup>Btu vs. \$2.80/10<sup>6</sup>Btu.

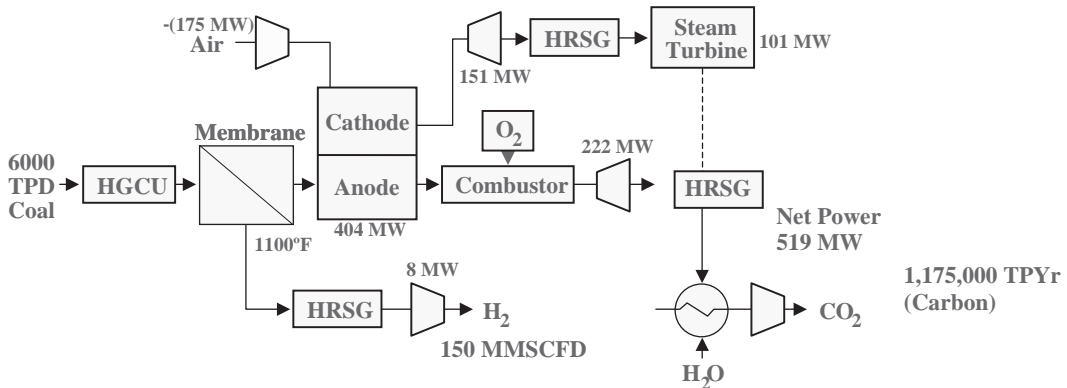


Fig. 8. Production of hydrogen and power with sequestration utilizing solid oxide fuels cells and advanced membranes with sequestration (Case 7).

## 7. Comparison of hydrogen costs from other studies

With the recent heightened interests in hydrogen utilization, a variety of hydrogen production cost estimates have been performed. It should be noted that these different sets of cost estimates may be site-specific and not necessarily based on inter-consistent assumptions. As such, each should be considered independently and comparisons should be made carefully. The results of three studies are presented here to compare the following:

- Comparison of Alternative Coal to Hydrogen Configurations (Table 2)
- Comparison of coal to Hydrogen with and without CO<sub>2</sub> capture (Tables 3 and 4)
- Comparison of Steam–Methane Reforming with Coal Gasification/WGS (Table 5)
- Comparison of Fossil Energy Based Hydrogen Production with Non-Fossil Production (Fig. 9)

Table 2 was discussed in detail in the previous section. The results again indicate the importance of employing advanced H<sub>2</sub>/CO<sub>2</sub> membrane separation technology, as well as lower cost/better performing

gasification technology. Above all, the development and incorporation of SOFC technology into these energy production cycles can have a dramatic impact on system cost.

Table 3 provides a comparison of coal-based hydrogen production from different studies (Klett et al., 2002; Gray and Tomlinson, 2002; Simbeck and Chang, 2002; Ogden, 2003) for cases with and without CO<sub>2</sub> capture. These studies are based on different assumptions and consider different plant sizes. Hence, it is important to normalize the results per unit of hydrogen production. As indicated in Table 3, capital cost of hydrogen production ranges from \$2.8–\$4.2/scfd and \$3.5–\$7.5/scfd for cases with and without CO<sub>2</sub> capture, respectively. The resulting required selling price for H<sub>2</sub> is \$0.77–\$1.62/kg and \$0.93–\$2.64/kg for cases with and without CO<sub>2</sub> capture, respectively. Taking the Gray and Tomlinson (2002) case with CO<sub>2</sub> capture as the base case, it is shown that the hydrogen production cost could vary from –30% to +140% depending on the assumptions employed in the analyses.

Gray and Tomlinson (2002) made an attempt to put the analyses in Table 3 on the same basis. Their results are presented in Table 4. Under this normalized case, the results of 5 studies are much closer

Table 3  
Coal to hydrogen comparisons with and without CO<sub>2</sub> capture

Reference cases	1		2		3	4	5
	No Cap <sup>a</sup>	Cap <sup>b</sup>	No Cap	Cap	No Cap	No Cap	Cap
Construction cost	264	308	271	316	188	–	–
Engineering /Office	26	31	28	33	22	–	–
Contingencies	32	36	45	41	15	–	–
Other	32	37	23	27	33	–	–
Total capital	354	412	367	417	258	731	601
H <sub>2</sub> plant size (MM scfd)	112	114	131	119	62	252	80
Capital (\$/scfd)	3.2	3.6	2.8	3.5	4.2	2.9	7.5
RSP H <sub>2</sub> , \$/MMBtu	HHV	6.91	6.83	8.18	12.06	6.50	19.70
	LHV	8.17	8.07	9.67	14.25	7.68	23.28
RSP H <sub>2</sub> , \$/kg		0.93	0.92	1.10	1.62	0.87	2.64
H <sub>2</sub> cost Above/Below base		–15%	–16%	Base	47%	–21%	140%

1. Klett et al., 2002.
2. Gray and Tomlinson, 2002.
3. Simbeck and Chang, 2002.
4. Ogden, 2003.
5. NREL.

<sup>a</sup> No carbon capture.

<sup>b</sup> Carbon capture.

Table 4

Coal to hydrogen comparisons normalized to standard assumptions and 150 million scfd plant size

	1		2		3	4	5
	No Cap	Cap	No Cap	Cap	No Cap	No Cap	Cap
<i>Normalized cases for 150 million scfd plant size &amp; financial assumptions</i>							
Total capital (million)	447	5133	409	502	523	482	993
Capital (\$/scfd)	3.0	3.4	2.7	3.3	3.5	3.2	6.6
H <sub>2</sub> RSP(a) \$/kg	0.91	1.10	0.90	1.05	1.23	1.01	1.71
H <sub>2</sub> cost Above/Below base	–13%	5%	–14%	Base	17%	–4%	63%
<i>Normalized assumptions used to adjust RSP of H<sub>2</sub></i>							
Hydrogen plant size	150 million scfd						
Power price, \$MWhr	35.6						
Coal cost, \$/ton (b)	29						
Capital cost scaling factor	0.8						
Capital recover factor (c)	12.7%						
Efficiency	No changes made to reference cases efficiencies						

1. Klett et al., 2002.

2. Gray and Tomlinson, 2002.

3. Simbeck and Chang, 2002.

4. Ogden, 2003.

5. NREL.

(a) RSP = Required Selling Price.

(b) Bituminous coal used in all cases, except NREL, who used Wyodak minemouth coal at \$5/ton.

(c) CRF based on 67/33 Debt/Equity ratio, 8% cost of debt, 15% DCF ROR on equity.

— i.e., the selling price of hydrogen is \$0.90–\$1.23/kg and \$1.05–\$1.71/kg for cases with and without CO<sub>2</sub> capture, respectively. Again, taking the Gray and Tomlinson (2002) case with CO<sub>2</sub> capture as the base case, the hydrogen production cost could vary from –14% to +63% depending on the assumptions.

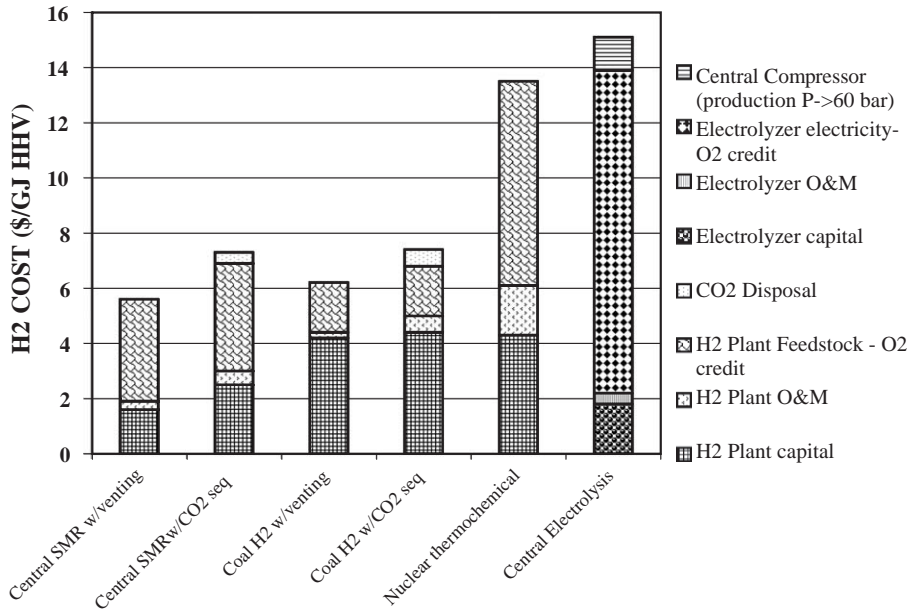
Table 5 compares costs for methane reforming (with and without CO<sub>2</sub> removal) with that of coal gasification-based hydrogen production (with and without CO<sub>2</sub> removal). These results indicate that, for the assumed cost of natural gas and coal, SMR and gasification yield similar H<sub>2</sub> production costs when CO<sub>2</sub> control is not a factor, even though the capital

Table 5

Comparison of hydrogen cost from conventional and advanced plant designs (Klett et al., 2002)

CO <sub>2</sub> Capture Method	Steam-methane reforming		Cleaned synthesis gas by coal gasification		
	None	1-Stage amine	None	2-Stage amine	Inorganic membrane
Plant size (Tons H <sub>2</sub> /Day)	417.8	417.8	312.6	317.8	430.8
Coal feed (Dry Tons/Day)	N/A	N/A	2500	2500	2500
Natural gas feed (10 <sup>6</sup> SCFD)	65.5	60.3	N/A	N/A	N/A
Equivalent thermal efficiency (HHV), %	83.9	78.6	62.3	60.1	80.4
CO <sub>2</sub> Recovered (Tons/Day)	N/A	2609	N/A	6233	6362
% CO <sub>2</sub> recovered	N/A	71	N/A	92	94
Net power output (MWe)	–6	–15	38	12	7
Total plant cost (Million \$, year 2000)	131	142	322	375	360
Cost of H <sub>2</sub>					
(\$/10 <sup>6</sup> Btu HHV)	5.54	5.93	5.71	6.91	5.06
(\$/GJ HHV)	5.25	5.62	5.41	6.55	4.97
(\$/MSCF)	1.8	1.92	1.86	2.25	1.65

Natural Gas Cost=\$3.50/10<sup>6</sup> Btu.Coal Cost=\$1.00/10<sup>6</sup> Btu.



**Current NG, Coal Technologies (2005 Fuel Prices), Future Nuclear, Renewable Technologies**  
 ( $P_{NG} = \$3.1/GJ$ ;  $P_{COAL} = \$1.2/GJ$ ;  $P_{NUC.HEAT} = 1.6 \text{ ¢/kWh}$ ;  $P_{RENEW.ELECT} = 4.0 \text{ ¢/kWh}$ )

Fig. 9. Plant-gate H<sub>2</sub> production costs (Williams, 2003).

cost is 2.5 times larger for the gasification-based process. However, when CO<sub>2</sub> removal is required, SMR shows a decided advantage over gasification coupled to conventional CO<sub>2</sub> control technology. Alternatively, integration of advanced inorganic membrane technology into the gasification cycle is expected to significantly reduce the H<sub>2</sub> production cost and make it less expensive than conventional SMR.

Fig. 9 shows the results from another study (Williams, 2003) that compares costs for the following technologies:

- Advanced electrolysis;
- Complex thermochemical cycles using nuclear heat from a high-temperature gas-cooled reactor: Direct H<sub>2</sub>O dissociation requires  $T \sim 4000 \text{ °C}$ ;
- Steam reforming of natural gas-with underground storage of separated CO<sub>2</sub>; and
- Coal gasification-with underground storage of separated CO<sub>2</sub>.

The results show that large-scale H<sub>2</sub> production from fossil fuel resources, both coal and natural gas,

is likely to be the most viable near-term option to support increased H<sub>2</sub> demand for advanced transportation systems.

The above cases illustrate several key points for hydrogen production from coal. The first is that producing hydrogen from coal using commercially demonstrated technologies is competitive with that produced from natural gas. One of the key impediments to deployment of coal gasification for H<sub>2</sub> production is the lack of demonstrated integration of all process units with high reliability. For applications within a refinery, such a facility must be capable of producing hydrogen >97% of the time. With conventional technologies and a spare gasifier (something that was not included in these studies), such availabilities are possible.

The second key point is the importance of continued R&D to develop new technologies. As shown by the analysis, advanced gasification technologies, lower cost, more efficient gas cleaning processes operating at moderate temperatures, advanced separation membranes, and fuel cells can have a tremendous impact on the economics of producing hydrogen while simultaneously capturing CO<sub>2</sub>. A brief overview of

some of these technologies and their potential impact on cost and efficiency is discussed below.

## 8. Technology issues/needs for gasification-based hydrogen production

As shown by the above results, technology development can play a significant role in the reduction of cost for the production of hydrogen from coal. Developments that improve the performance and reliability of existing gasifier technologies, new gasification concepts, advanced deep cleaning technologies for contaminant removal from synthesis gas, innovative gas separation technologies, and advanced gas turbines and fuel cells are required to realize the projected cost for hydrogen. The discussion below will focus on those technologies required to produce the hydrogen and not technologies for the utilization of hydrogen for power generation or for the sequestration of CO<sub>2</sub>. However, before any of this can be realized, the sequestration of CO<sub>2</sub> must be fully demonstrated, i.e., the projected cost of \$10/ton of carbon sequestered and the permanence of the stored CO<sub>2</sub> through long-term monitoring, measurement, and verification (MMV) must be confirmed, to ensure the continued use of coal in the future energy mix.

### 8.1. Gasification

For the production of hydrogen from coal to play a major role in the future, the reliability and performance of the gasifier is of paramount importance. For such applications, the availability of the gasifier must be >97%. Today, this can be accomplished through the use of a spare gasifier, but at a cost to the plant. What must be demonstrated is single-train availabilities of >97% with high carbon conversion. To achieve this, several areas of the gasifier require attention (Clayton et al., 2002). Feed injectors are considered to be the weakest links in the process for achieving high on-stream factor particularly with slurry-fed systems. A typical injector is reported to last between two to six months; however, a minimum life of 12 months is desired. Computational Fluid Dynamics (CFD) modeling around the injector may help to define the factors that lead to failure. New materials and/or coatings for existing materials are needed to provide protection

from sulfidation and corrosion at high reactor temperatures. Injector life is also highly dependent on whether a dry or wet feed system is used. In a dry feed system, injector life is usually better, possibly due to the absence of large amounts of evaporating water. Although improved life has been reported, operations with dry feed systems at high pressures are problematic in the feed system.

For those gasifiers employing refractories to protect the pressure vessel (e.g., GE (ChevronTexaco), E-gas), new materials must be developed and demonstrated that have a useful life in excess of three years (Leininger, 2002). Depending upon how aggressive the gasifier is operated to achieve the desired level of carbon conversion and the feedstock itself, these liners typically last between six to 18 months. To rebrick these gasifiers typically requires three weeks of downtime and costs between \$1–2 million. If a gasifier must be rebricked at least once per year, the availability is automatically reduced by 5–6 percentage points. Actively cooled gasifiers (e.g., Shell) would mitigate the refractory problem, but less expensive approaches are required.

Thermocouples used to measure the temperature inside the gasification zone are reported to last about 30–45 days. Failure of the thermocouples is due to corrosion resulting from slag penetration into the refractory and stresses caused by temperature cycles. When the thermocouple is lost, the gasifier is typically controlled based on a prior calibration of expected temperature versus the methane content of the exit gas. New instrumentation capable of operating in the gasification environment with an expected lifetime of >1 year is required.

Flexible gasification systems that provide for operation on a variety of available feedstocks such as coal (ranks and blends), waste materials, and biomass would contribute to the versatility of the overall process. For such versatility, an improved understanding of the properties and characteristics of the feedstock and molten slag inside the gasifier is needed. Analytical instrumentation for rapid on-line analyses of the feedstock and for slag flow properties inside the gasifier provide for better process control when processing feedstocks of varying properties.

The gasifier technologies being deployed today were developed many years ago, and therefore only incremental improvements can be made to the overall

technology. To provide any significant improvements, innovative approaches must be explored. The chemical looping concepts being developed by Alstom, GE Global Research (Rizeq et al., 2002), and the Zero Emission Coal Alliance — ZECA (Ziock et al., 2003) offer a new direct route to the production of hydrogen and the capture of CO<sub>2</sub> through the use of solid sorbents. In these concepts, air and coal are fed to the system, and pure streams of H<sub>2</sub> and CO<sub>2</sub> are produced. Multiple reactors are employed with transfer of solids between the beds. For instance, air is fed to one of the reactors where the oxygen is absorbed on an oxygen transport material. This material is transferred to a second bed where the oxygen desorbs and reacts to generate heat for the gasification reactions. Although the technologies are in the very early stages of development and numerous problems associated with the transfer of hot solids between the vessels must be resolved, preliminary studies have shown the potential for significant capital cost reductions and efficiency improvements if the performance goals can be achieved.

### 8.2. *Synthesis gas cleaning technologies*

Current synthesis gas cleaning technologies employ chemical or physical solvents and operate at near ambient temperature or lower. In an IGCC plant, these technologies generally constitute 12–15% of the total capital cost of the plant. Amine-based systems are suitable for meeting today's emission requirements, but they are not capable of achieving future potential regulations nor are they applicable for chemicals production. For the latter, more expensive and energy intensive technologies such as Rectisol must be employed. Industry would like to have technologies that are capable of achieving the performance of a Rectisol unit but at equal or lower cost than an amine system.

Several technologies currently under development have potential for achieving just that (Gardner et al., 2002; Newby et al., 2003; Srinivas and Bebhald, 2003; Gupta et al., 2003) A novel sorbent-based technology utilizing a transport reactor is currently being commissioned in conjunction with a coal gasifier that can achieve sulfur levels as low as 1–5 ppm in the synthesis gas stream while operating at moderate process conditions (i.e., 500–700 °F). Such temperatures are consistent with downstream process applications and obviate

the need for cooling and reheating which impart an efficiency penalty on the system. Integrated operations are necessary to demonstrate the impact of trace contaminants in the coal-derived synthesis gas on the performance and longevity of the sorbent and its regenerability and to evaluate attrition resistance.

Selective catalytic oxidation technologies being developed have the potential for achieving sulfur levels well below 1 ppm while operating at moderate process temperatures. In this approach, a small quantity of oxygen is injected into the synthesis gas stream where it reacts with H<sub>2</sub>S over a catalyst to directly form elemental sulfur. To achieve the desired performance, either the COS in the raw gas stream must be hydrolyzed to H<sub>2</sub>S or a new catalyst must be developed to directly convert COS to elemental sulfur.

Preliminary engineering analyses of these two technologies have shown significant improvements over current commercial technologies. While achieving greater than an order of magnitude reduction in sulfur over amine-based systems and comparable performance to Rectisol, the capital cost of the technology is expected to be reduced by at least \$60–80/kWe compared to amine-based technologies. In addition to the capital cost reduction, there is a concomitant increase in thermal efficiency of 1–2 efficiency points.

For the above two approaches to be commercially attractive at moderate process temperatures, technologies are needed that can remove other trace contaminants at similar process conditions. Technologies for mercury, ammonia, and chloride removal are currently being developed, and testing in conjunction with a coal gasifier is expected within the next year or two.

### 8.3. *Gas separation technologies*

Cost effective and efficient gas separation technologies are vital in any chemical process operation and will impact the overall cost of the system. For the production of hydrogen from coal, gas separation operations occur in two major areas: 1) the separation of oxygen from air for use in the gasifier and 2) the separation of the shifted synthesis gas stream into pure H<sub>2</sub> and CO<sub>2</sub> streams.

Cryogenic technologies are currently employed for the production of oxygen; however this process is very capital and energy intensive. Cryogenic air separation units in an IGCC plant typically constitute 12–15% of

the total plant capital cost and can consume upwards of 10% of the gross power output of the plant. Advanced dense ceramic membranes possessing both ionic and electronic conductance are being developed as a high temperature approach for air separation (Armstrong et al., 2002; Prasad et al., 2003). Preliminary engineering analyses have shown that such approaches have the potential for reducing the capital cost of an IGCC plant by \$75–100/kWe with a corresponding 1–2 point gain in thermal efficiency. Although many challenges exist in material composition and processing to produce defect-free chemically and thermally stable membranes with commercially relevant fluxes, significant progress has been made over the past few years. Integration of the membranes with a gas turbine is critical for achieving the stated performance; however, recent indications are that no critical issues exist with the integration of a gas turbine that cannot be overcome through design modifications. The first commercial offering of these membrane-based technologies is expected to occur near the end of this decade.

Separation of hydrogen from shifted synthesis gas, either derived from coal or natural gas, is a key unit operation of any fossil-energy-based hydrogen production system. Membrane technologies have and are continuing to be explored quite extensively by many. Membranes can usually be divided into either organic or inorganic. Organic membranes appear to have limited applications for coal-based hydrogen production routes because of their extreme sensitivity to process conditions and trace contaminants. Instead, the bulk of the work for hydrogen separation is focused on inorganic membranes.

Inorganic membranes can be further classified as either porous or dense, and the latter can be further subdivided into metallic or solid electrolytes (ceramic). Of the porous membranes being developed, the most promising appears to be one developed by Oak Ridge National Laboratory (ORNL). The above engineering analyses were based on ORNL's membrane. Because of the manufacturing process employed in producing this membrane, the pore size and distribution can be precisely controlled to allow primarily hydrogen to diffuse through the pores, thereby achieving very high separation factors. Although classified by the U.S. government for many years, the membrane technology was recently declassified for hydrogen separation applications; the

manufacturing process, however, still remains classified. The DOE and ORNL are currently initiating an effort to develop a large scale module for performance testing on coal-derived shifted synthesis gas. Dense ceramic solid electrolyte membranes have also been under intense investigation; however, the required operating temperature of the membrane is much too high for applications to coal-based hydrogen production, and hydrogen fluxes have not achieved the level of commercial significance.

Considerable effort has also been devoted to metallic membranes, most of which are based on Palladium (Pd). Although initially thought to be promising, these membranes have been found to be susceptible to degradation from the presence of both sulfur and CO. However, Eltron Research has recently reported metal alloys that have shown very high hydrogen fluxes at temperatures around 400 °C (Roark et al., 2002). In fact, the performance of the material at this stage of development rivals that of the ORNL K25 membrane. The composition of the alloy has not been disclosed pending the filing of a patent application; however, the materials used are not expensive. Again, the stability of these membranes in the presence of trace contaminants from coal must be determined.

Although considerable effort is being devoted to membranes, there needs to be a more diversified approach to hydrogen separation technology development that does not rely solely on the use of membranes. Other novel concepts, for instance, employ chemical solvents and solid sorbents. One of the more promising approaches is the CO<sub>2</sub> hydrate process being developed jointly by Nexant, Inc., Simteche, and Los Alamos National Laboratory (Spencer et al., 2003). In this approach, the shifted synthesis gas is contacted with cold water containing a promoter to form a hydrate which captures CO<sub>2</sub>. The CO<sub>2</sub> is released from the hydrate by the application of heat or reducing pressure. Unlike membrane-based technologies, this approach results in both high pressure H<sub>2</sub> and CO<sub>2</sub> streams.

## 9. Summary

It is envisioned that hydrogen will eventually become a premier energy carrier, reducing U.S.



dependence on imported petroleum, diversifying energy sources, and reducing pollution and greenhouse gas emissions. The hydrogen is expected to be produced in large refineries in industrial areas, power plants, and fueling stations in communities, distributed facilities in rural areas, and on-site at customers' premises. Thermal, electric, and photolytic processes will use fossil fuels, biomass, or water as feedstocks and are expected to release little or no carbon dioxide into the atmosphere.

During the transition to a sustainable hydrogen economy, fossil fuels and in particular coal are expected to be the primary source of this hydrogen. With the projected increase in the cost of natural gas and continued price volatility, coal gasification is expected to be a major supplier of future hydrogen.

As shown by the analyses above, hydrogen from coal could be competitive with that produced from other resources. However, demonstration plants must be built and operated to confirm costs, performance, and process reliability so that risk is sufficiently reduced to secure commercial financing. Even if such demonstrations are successful, hydrogen from coal may only be deployed on a large scale if carbon sequestration is fully demonstrated and verified.

The above analyses also illustrate the importance of developing advanced technologies. If such technology developments achieve their goals, the cost of producing hydrogen from coal will be reduced by an expected 25–50% from current values. These advanced technologies not only have the potential for significantly lower cost, but can also extend the fuel supply for the gasifiers through increase process efficiency. Efficiencies in excess of 60% with carbon capture may be possible. It should be noted that hydrogen from non-fossil-based technology is costly in today's market and significant improvements are required to improve their performance and reduce costs. However, as time goes on, these technologies will become increasingly important. Therefore, it is imperative that research continue in these areas also.

### Acknowledgments

The authors appreciate the information provided by David Gray of Mitretek Systems.

### References

- Armstrong, P.A., Stein, V.E., Bennett, D.L., Foster, E.P., 2002. Ceramic membrane development for oxygen supply to gasification applications. Proceedings of the Gasification Technologies Conference, San Francisco, CA, October.
- Barreto, L., Makihira, A., Riahi, K., 2003. The hydrogen economy in the 21st century: a sustainable development scenario. *International Journal of Hydrogen Energy* 28, 267–284.
- Bechtel Corpotaion, 2003. Gasification Plant Cost and Performance Optimization, Task 1 Topical Report IGCC Plant Cost Optimization, Report prepared for DOE, National Energy Technology Laboratory, August. <http://www.netl.doe.gov/coal/Gasification/projects/systems/docs/rev-40342R01.pdf>.
- Bockris, J.O'M., 2002. The origin of ideas on a hydrogen economy and its solution to the decay of the environment. *International Journal of Hydrogen Energy* 27, 731–740.
- Buchanan, T.L., DeLallo, M.R., Goldstein, H.N., Grubbs, G.W., White, J.S., 1998. Market-based Advanced Coal Power Systems. Final Report. USDOE, Office of Fossil Energy, Contract No. DE-AC01-94FE62747, Pittsburgh, PA. [http://www.netl.doe.gov/coalpower/gasification/pubs/pdf/marketbased\\_systems\\_report.pdf](http://www.netl.doe.gov/coalpower/gasification/pubs/pdf/marketbased_systems_report.pdf).
- Clayton, S.T., Stiegel, G.J., Wimer, J.G., 2002. Gasification Technologies Gasification Markets and Technologies — Present and Future: An Industry Perspective, U.S. Department of Energy Report DOE/FE-0447, Pittsburgh, PA, July. [http://www.netl.doe.gov/coal/Gasification/pubs/pdf/Gasification\\_Technologies.pdf](http://www.netl.doe.gov/coal/Gasification/pubs/pdf/Gasification_Technologies.pdf).
- Collot, A.-G., 2003. Prospects for Hydrogen from Coal. IEA Coal Research, London, UK, ISBN: 92-9029-393-4 (December).
- Conte, M., Iacobazzi, A., Ronchetti, M., Vellone, R., 2001. Hydrogen economy for a sustainable development: state-of-the art and technological perspective. *Journal of Power Sources* 100, 171–187.
- Dunn, S., 2002. Hydrogen futures: toward a sustainable energy system. *International Journal of Hydrogen Energy* 27, 235–264.
- Elam, C., Gregoire Padro, C., Sandrock, G., Luzzi, A., Lindblad, P., Hagen, E., 2003. Realizing the hydrogen future: the international energy agency's effort to advanced hydrogen technologies. *International Journal of Hydrogen Energy* 28, 601–607.
- Gardner, T.H., Berry, D.A., Lyons, K.D., Beer, S.K., Freed, A.D., 2002. Fuel processor integrated H<sub>2</sub>S catalytic partial oxidation technology for sulfur removal in fuel cell power plants. *Fuel* 81, 2157–2166.
- Goltsov, V., Veziroglu, T., 2002. A step on the road to hydrogen civilization. *International Journal of Hydrogen Energy* 27, 719–723.
- Gray, D., Tomlinson, G., 2002. Hydrogen from Coal. Mitretek Technical Paper. July, <http://www.netl.doe.gov/coal/Gasification/pubs/pdf/HYDROGEN%20FROM%20COAL4.pdf>.
- Gupta, P., Raja, J., Fan, L.S., 2003. Novel metal oxide sorbent for hot gas sulfur cleanup. Proceedings of the 20th Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September.
- Higman, C., van der Burgt, M., 2003. Gasification. Elsevier, Amsterdam, Netherlands. 391 pp.

- Kim, H., 2003. A low cost production of hydrogen from carbonaceous wastes. *International Journal of Hydrogen Energy* 28, 1179–1186.
- Klett, M., White, J., Schoff, R., Buchanan, T., 2002. Hydrogen production facilities — plant performance and cost comparisons. Final Report, Parsons Infrastructure and Technology Group Inc., Reading, PA. March <http://www.netl.doe.gov/coal/Gasification/pubs/pdf/FinalCompReport.pdf>.
- Kroschwitz, J.I. (Ed.), 1995. *Kirk–Othmer Encyclopedia of Chemical Technology*, 4th ed. John Wiley and Sons, New York, NY.
- Lin, S., Harada, M., Suzuki, Y., Hatano, H., 2002. Hydrogen production from coal by separating carbon dioxide during gasification. *Fuel* 81, 2079–2085.
- Leininger, T., 2002. Design, fabrication and testing of an infrared radiation pyrometer system for the measurement of gasification reaction chamber temperature. Proceeding of the 19th Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September.
- Newby, R.A., Lau, F.S., Slimane, R.B., Jain, S.C., 2003. Development progress on the SWPC novel gas cleaning process. Proceedings of the 20th Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September.
- Ogden, J.M., 2003. Prospects for large-scale use of hydrogen in our future energy system. Testimony to the Committee on Science, United States House of Representatives, Washington, DC, March 5.
- Prasad, R., Chen, J., Chen, H., Lane, J., White, J., Corpus, J., Schreiber, E., Spero, J., van Hassel, B.A., 2003. Oxygen transport membranes for future IGCC power plants. Proceedings of the 20th Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September.
- Ratafia-Brown, J., Manfredi, L., Hoffmann, J., Ramezan, M., 2002. Major Environmental Aspects of Gasification-Based Power Generation Technologies. U.S. Department of Energy Report. <http://www.netl.doe.gov/coal/Gasification/pubs/pdf/final%20env.pdf>.
- Rizeq, G., Subia, R., West, J., Frydman, A., Zamansky, V., Das, K., 2002. Advanced gasification combustion: bench-scale parametric study. Proceeding of the 19th Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September.
- Roark, S.E., Mackay, R., Sammells, A.F., 2002. Hydrogen separation membranes for VISION 21 energy plants. Proceedings of the 27th International Technical Conference on Coal Utilization and Fuel Systems, Clearwater, FL, March.
- Simbeck, D., Chang, E., 2002. Hydrogen Supply: Cost Estimates for Hydrogen Pathways — Scoping Analysis. Report prepared for National Renewable Energy Laboratory, SFA Pacific, Mountain View, CA. <http://www.nrel.gov/docs/fy03osti/32525.pdf>.
- Spencer, D.F., Tam, S.S., Deppe, G., Currier, R.F., Young, J.S., Anderson, G.K., 2003. Carbon dioxide separation from a high pressure shifted synthesis gas. Proceedings of the 20th Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September.
- Srinivas, G., Bebbard, S., 2003. Direct oxidation for sulfur recovery from syngas streams. Proceedings of the 20th Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September.
- Williams, R.H., 2003. Alternative technologies and strategies for hydrogen production. Workshop on Future Energy Issues — Future Energy Resources National Defense University, Washington, DC, May. 12 pp.
- Ziock, H.-J., Garzon, F.H., Guthrie, G.D., Brosha, E.L., Robison, T.W., Roop, B., Mukundan, R., Smith, B.F., Kramer, A., Lau, F., Lackner, K.S., Nawaz, M., Ruby, J., Anthony, E.J., Wang, J., Johnson, A.A., 2003. Technical progress in the development of zeca zero emissions coal process. Proceeding of the 28th International Technical Conference on Coal Utilization and Fuel Systems, Clearwater, FL.