HYDROGEN PRODUCTION FROM COAL AND COAL BED METHANE, USING BYPRODUCT CO_2 FOR ENHANCED METHANE RECOVERY, WITH CO_2 SEQUESTRATION IN THE COAL BED

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Abstract

Rapid advances being made in proton exchange membrane fuel cell technology for transportation and stationary combined heat and power market applications are creating renewed interest in hydrogen, the preferred fuel for these fuel cells. A promising strategy for providing the needed hydrogen in countries such as China that are coal- and coal-bed-methane-rich but poorly endowed with conventional hydrocarbon resources would be to produce hydrogen from coal and coal bed methane, using the low-cost CO_2 generated as a byproduct of hydrogen production to stimulate the recovery of methane from deep beds of unminable coal—a promising new technique recently advanced for recovering coal bed methane. While awaiting the arrival of fuel cells for major commercial applications, hydrogen so produced might be used in the manufacture of ammonia for fertilizer, as a less costly option for hydrogen manufacture than making it from only coal with modern coal gasification technology, as is being done at some new plants in China. Moreover, the production of hydrogen in this manner from coal plus coal bed methane would lead to low levels of lifecycle CO_2 emissions, because the CO_2 injected into the coal bed for methane recovery would remain sequestered there. This strategy stands out as a promising major option for using coal with low local and global environmental impacts.

Background

There are substantial activities in the United States, Europe, and Japan aimed at accelerating the commercialization of the proton exchange membrane (PEM) fuel cell (FC) for both stationary distributed combined heat and power (CHP) generation in residential and commercial buildings (as an alternative to central station power generation) (Dunnison and Wilson, 1994; A.D. Little, 1995) and for transportation applications (as an alternative to the internal combustion engine) (Kircher et al., 1994; Mark et al. 1994; Williams, 1993, 1994). For these applications, the PEM FC offers primary energy savings as a result of energy efficiency gains, zero or near-zero local air pollution without the need for end-of-pipe pollution control technologies, the opportunity to diversify the fuel supplies for the transport sector, and the potential for realizing deep reductions in greenhouse gas emissions without large increases in the costs of energy services. For distributed CHP and transit bus applications, the technology will be commercially available before the year 2000 (Prater, 1996). Car manufacturers in Europe, Japan, and the United States are seeking to develop and commercialize FC cars for the much larger automotive markets, with automobile market entry targeted for the period 2005-2010—see Box A.

If ongoing efforts to commercialize the PEM FC are successful, fossil fuels could play far greater roles in a greenhouse-emissions-constrained world than if only conventional fossil-fuel conversion technologies were available, because:

(*i*)   the PEM FC "prefers" to be supplied with hydrogen (H_2) fuel,[1]

(*ii*)   their commercialization could spur a shift to an energy economy in which H_2 would be derived primarily from carbonaceous feedstocks[2] and the byproduct CO_2 could be isolated from the atmosphere at low incremental cost,[3] and

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[1]   All fuel cells use as fuel H_2 that is produced either at the point of use or at a centralized facility and delivered to the user by pipeline or other means. The PEM fuel cell operates at such a low temperature (~ 80 °C) that point-of-use fuel processing of a conventional liquid or gaseous fuel to produce a H_2-rich gas suitable for fuel cell use is relatively inefficient because little if any "waste heat" from the fuel cell is available for fuel processing, in contrast to the situation with high-temperature fuel cells (e.g., solid oxide or molten carbonate fuel cells).

[2] H_2 is manufactured thermochemically from carbonaceous feedstocks through processes that begin with the production of synthesis gas, a gaseous mixture consisting mainly of CO and H_2 . [Synthesis gas can be produced from natural gas by steam reforming or from coal, oil, or municipal solid waste by oxygen-blown gasification or from biomass using either oxygen-blown or indirectly heated gasifiers (Williams et al., 1995a, 1995b)]. Next the synthesis gas is reacted with steam ($H_2O_{(g)}$), thereby converting the CO and $H_2O_{(g)}$ into H_2 and CO_2. The H_2 is then readily separated by chemical or physical gas separation techniques from the resulting gaseous mixture that consists mainly of CO_2 and H_2 .

H₂ produced in this manner will be far cheaper than H_2 derived electrolytically from water using any electricity source (Williams, 1998a; Williams and Wells, 1997), except where off-peak hydroelectric power (for which the capital charge is zero in the electricity price paid by the H_2 producer) is available. (Supplies of off-peak hydroelectric power are adequate for serving only niche markets.) A large cost advantage for thermochemically-derived H_2 over electrolytic H_2 is maintained even when the costs of sequestering the CO_2 separated out at the H_2 production plant are taken into account (Williams, 1998a).

[3]   In producing H_2 from a carbonaceous feedstock, a concentrated stream of CO_2 accounting for most of the carbon in the feedstock can be generated as a byproduct and stored in isolation from the atmosphere with low overall penalties on the H_2 production cost (Blok et al., 1997; Williams, 1998a).

(iii)   there are large underground reservoirs in which CO_2 could be securely isolated from the atmosphere.[4]

Although H_2 is the fuel of choice for use with the PEM FC, a H_2 fuel infrastructure is not yet in place. Accordingly, for many applications the PEM FC will be introduced into the market using the existing hydrocarbon (HC) fuel infrastructures, with conversion of the HC fuel into a H_2-rich gas suitable for fuel cell use at the point of use—e.g., onsite reforming of natural gas for CHP applications, and liquid HC fuel processing onboard a car (Mitchell *et al.*, 1995)—a strategy being pursued by two US automakers (see Box A). These are likely to be only transitional strategies, however, because of the preference of the PEM FC for H_2 fueling. If the FC car is successfully launched in the market with a liquid HC fuel, the automotive system would generate internal market pressures to shift to H_2 derived from carbonaceous feedstocks, as soon as the H_2 infrastructure could be put into place, as a result of the higher first cost, higher maintenance cost, and lower fuel economy of the gasoline FC car relative to the H_2 FC car (Ogden *et al.*, 1997; Williams, 1998b).

Coal-rich countries that are not well endowed with petroleum resources and that do not yet have extensive HC fuel infrastructures in place (e.g., China) have the opportunity to "leapfrog" directly to H_2 fuel cell technology, obviating the need for the costly HC-fueled FC transition technology (Williams, 1998c).

The present paper discusses H_2 production from coal and methane recovered from deep coal beds, using the byproduct CO_2 for enhanced coal bed methane (CBM) recovery, with sequestration of the injected CO_2 in these beds. This strategy seems to be well suited to the production of H_2 for FC applications in countries such as China that have substantial coal and CBM resources but limited petroleum resources (Williams, 1998c). Initially, while awaiting the introduction of FC technology, the H_2 so produced might be used in the manufacture of ammonia for fertilizer.

CBM Resources and Current CBM Recovery Technology

Coal beds are both source rocks and reservoir rocks for large quantities of methane-rich gas. This gas is typically produced throughout the burial history of the coal in volumes ranging from 150 to 200 normal cubic meters (Nm^3) per tonne of coal, as a result of biogenic and thermogenic processes whereby plant material is progressively converted into coal (Rice *et al.*, 1993). Because coal is a microporous solid with large internal surface areas (tens to hundreds of square meters of per gram of coal), large quantities of methane (CH_4) produced this way will remained trapped in the coal bed, adsorbed on coal surfaces. The large micropore surface areas and the close proximity of CH_4 molecules adsorbed on the internal surfaces (approaching liquid densities) of these micropores make high gas storage densities possible even though the porosity associated with the macropores of the system of natural fractures is low—in the range 1-5% (Rogers, 1994). A good coal bed in the San Juan or Warrior Basin in the United States holds two or three times as much gas as the same volume of a sandstone reservoir of like depth having 25% porosity and 30% water saturation (Kuuskraa and Brandenburg, 1989). In general, gas content increases with increasing coal rank; typically lignites contain very little

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[4]   There is increasing confidence in the scientific community that the capacity of underground storage reservoirs (depleted oil and gas fields, deep saline aquifers, and deep coal beds) for storing CO_2 securely for long periods of time is very large, suggesting that a fuel cell energy strategy based on the use of fossil fuel-derived H_2 could make feasible major roles for fossil fuels in a severely greenhouse-gas emissions-constrained world (see the Appendix).

Box A: Progress in Developing Motor Vehicles Powered by PEM Fuel Cells

1993	Clinton Administration announces Partnership for a New Generation of Vehicles (PNGV) with U.S. automakers, aimed at introducing by 2004 production-ready prototypes of "cars of the future" that will be three times as fuel efficient as today's cars but will maintain size and performance and cost no more to own and drive
1993	Ballard Power Systems of Vancouver (Canada) introduces proof-of-concept H_2 PEM fuel cell bus (with compressed H_2 storage)
1995	Daimler-Benz introduces NECAR I, a H_2 PEM fuel cell test van (with Ballard fuel cell, compressed H_2 storage)
1995	Ballard demonstrates H_2 PEM fuel cell bus suitable for commercial use (with compressed H_2 storage)
1995	Mazda demonstrates a H_2 PEM fuel cell golf cart (with compressed H_2 storage)
1996	Daimler-Benz introduces NECAR II, a prototype passenger van equipped with a compact H_2–powered fuel cell system (power density of 1 kW_e/liter, 0.7 kW_e/kg for the fuel cell stack) developed jointly with Ballard (with compressed H_2 storage)
1996	Toyota introduces prototype PEM H_2 fuel cell car (with metal hydride storage)
1996-97	Ballard sells several H_2 PEM fuel cell buses to cities of Chicago and Vancouver
1997	Ballard and Daimler-Benz form joint venture with $320 million planned investment to develop PEM fuel cell cars, with commercialization targeted for 2005 timeframe
1997	Daimler-Benz introduces NECAR III, a prototype small fuel cell passenger car [with onboard methanol (MeOH) reformer]
1997	Toyota introduces prototype fuel cell passenger car (with onboard MeOH reformer)
1997	Ford joins Daimler-Benz & Ballard in joint venture to commercialize fuel cell cars, bringing planned pooled investment total to $420 million; fuel cell power trains for cars targeted for commercialization in 2004
1998	GM announces it will develop production-ready prototype fuel cell cars by 2004
1998	Chrysler announces it will develop production-ready prototype fuel cell cars by 2004 (with onboard gasoline partial oxidation systems)
1998	Mobil Corporation and Ford Motor Company form a strategic alliance to develop a hydrocarbon fuel processor for use in fuel cell vehicles
1998	Mazda joins automotive fuel cell alliance with Ballard, Daimler-Benz, and Ford

gas, while high-rank coals (e.g., medium- or low-volatile bituminous coals, semianthracite, or anthracite) can contain up to 30 Nm^3/tonne. Medium-volatile or higher rank coals may have generated more methane than they can store, resulting in the expulsion of the excess methane to the atmosphere or into adjacent reservoirs (e.g., trapped under a caprock above the coal bed). The amount of gas that can be stored in a particular coal as a function of reservoir pressure at a constant temperature is commonly determined from a sorption isotherm (Rice et al., 1993). Figure 1 presents an idealized coal-bed gas sorption isotherm, showing the relationship between gas content and reservoir pressure. The heavy solid line indicates the maximum amount of gas that can be stored at a given reservoir pressure—e.g., 17 Nm^3 per tonne (17 cc/gr) of coal at 10 MPa (100 bar).[5]

Worldwide CBM resources are estimated to be 85-262 trillion Nm^3 (Rice et al., 1993); the corresponding energy value is 3,400-10,400 EJ (assuming the gas is entirely CH_4 with a HHV of 39.7 MJ/Nm^3), equivalent to 0.3 to 0.9 times the mean estimate of remaining recoverable conventional natural gas resources worldwide (Masters et al., 1994). In China, CBM resources are estimated to be 30-35 trillion Nm^3 (1200-1400 EJ) at depths less than 2000 m (Rice et al., 1993; Sun and Huang, 1995); another estimate (Murray, 1996) is that the upper limit of the total CBM in place in China is 75 trillion Nm^3 (3000 EJ). For comparison, total fossil fuel consumption in China was 30 EJ in 1990, and the mean estimate of the remaining recoverable conventional natural gas resources in the United States is about 700 EJ (Masters et al., 1994). The fraction of the CBM resource that can be recovered economically depends on both the quality and accessibility of the resource and the recovery technology employed.

CBM is recovered commercially in the United States, mostly in the San Juan Basin of New Mexico and Colorado and the Black Warrior Basin of Alabama and Mississippi (McCabe et al., 1993). U.S. CBM production grew rapidly from about 1.1 billion Nm^3 [40 billion standard cubic feet (bscf)[6]] in 1988, to 9.4 billion Nm^3 (350 bscf) in 1991 (McCabe et al., 1993), to 25.5 billion Nm^3 (950 bscf) in 1996 (private communication from Karl Schultz, US EPA, 27 June 1997), when CBM production accounted for about 6% of total US natural gas production.[7]

Current practice is to depressurize the coal bed (usually by pumping water out of the reservoir), which leads to desorption of the gas from the micropores of the coal matrix, its diffusion through the coal matrix to macrofractures in the coal called "cleats," and its flow through the cleats to the wellbore for recovery (see Figure 2). The process is simple and effective but slow and inefficient (Gunter et al., 1997). There is typically a significant time lag (days to months) between the beginning of the dewatering process and the time when substantial gas recovery rates are realized (see Figure 3).

Using CO_2 Injection for CBM Recovery and the Coal Bed for CO_2 Sequestration

An alternative approach to CBM recovery that holds forth the prospect of being more efficient than present technology involves injecting a gas in the CBM reservoir; CO_2 is especially promising as a candidate gas for injection because it is twice as adsorbing on coal as is CH_4; it can therefore efficiently displace the CH_4 adsorbed on the coal (Gunter et al., 1997). CO_2 injection makes it possible to maintain

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[5]   A hydrostatic pressure of 100 bar is found at a depth of 870 meters in areas characterized by the average hydrostatic geopressure gradient.

[6]   The scf is evaluated at 14.696 psia (0.101352 MPa) and 60 °F (288.56 K); 1 scf = 0.02685 Nm^3.

[7]   Only 30 bscf of the CBM recovered in 1996 (3%) was associated with coal mining operations.

reservoir pressure and produce CH_4 gas quickly. As CO_2 moves through the reservoir it displaces CH_4. The limited experience to date indicates that very little of the injected CO_2 shows up in the production well until most of the CH_4 has been produced (Gunter *et al.*, 1997), so that the prospects for permanent sequestration of the injected CO_2 appear to be good.[8]

Of course, CO_2 sequestration in the coal bed would prevent subsequent mining of the coal. However, deep or otherwise unminable coal beds for which coal mining is uneconomic might prove to be attractive for CBM recovery and CO_2 sequestration. The CH_4 content of coals tends to increase with depth, both because the higher formation pressures are beneficial as a driving force for gas production, and because more gas can be adsorbed in the micopores of coals as the pressure increases—see Figure 1 (Rogers, 1994). Thus deep coal beds can contain especially large amounts of CH_4. In the United States, more than 2/3 of the 2.3 trillion Nm^3 of CBM in the Piceance Basin (McFall *et al.*, 1986) and approximately ½ of the 0.6-0.9 trillion Nm^3 of CBM in Menefee coal in the San Juan Basin are below 1500 m (Crist *et al.*, 1990). Moreover, deep or otherwise unminable coals are common in many parts of the world (Kuuskraa and Wyman, 1993). For example, 90% of the nearly six trillion tonnes of U.S. coal resources deposited at depths less than 1800 m is unminable with current technology, either because the coal is too deep, the seams are too thin, or mining would be unsafe (Byrer and Guthrie, 1998). But data on resources deeper than about 1500 m are sparse because such resources are of little interest for coal mining (Rogers, 1994), and, in the CBM community, conventional wisdom is that such deep coals will have extremely low permeabilities and thus would be unproductive. However, Kuuskraa and Wyman (1993) have argued that early estimates of low permeability for deep coals might be overly pessimistic and that under favorable geological conditions (such as low stress and dry coals) CH_4 recovery from deep coals might turn out to be a productive option.

An hypothesis advanced by Gunter, which remains to be verified by experience, is that with CO_2 injection it will often be feasible to recover about 90% of the CBM in place in a homogeneous coal seam, irrespective of the reservoir permeability, down to permeabilities of about 1 millidarcy,[9] a relatively low permeability (private communication, Bill Gunter, March 1998). In contrast, with conventional CBM recovery technology the recovered fraction over a typical project lifetime increases with reservoir permeability (Kuuskraa and Boyer, 1993).[10] Thus the gain relative to conventional recovery technology would tend to be greater for reservoirs with low permeabilities.

There has been a modest amount of field experience with this new technology. Amoco conducted a pilot test of CO_2 injection for CBM recovery in the San Juan Basin in Colorado in December 1993; this was followed by another San Juan Basin CO_2 pilot project conducted by Meridian (now Burlington

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[8]   If all the world's estimated 85 to 262 trillion Nm^3 CBM resources could be exploited by CO_2 injection with sequestration of the injected CO_2, the global CO_2 sequestration potential would be 170 to 524 trillion Nm^3 or 90 to 280 GtC. However, some of these CBM resources may not be suitable for recovery via CO_2 injection, and some will be associated with minable coal resources, for which permanent CO_2 sequestration would probably not be considered.

[9]   The permeability is a measure of the ability of a gas to flow through the reservoir as a result of the structure and interconnection of the pore spaces. Permeability is measured in millidarcies. One millidarcy = 10^{-15} m^2. Permeabilities of coal beds range from 0.1 (or less) to 100 (or more) millidarcies.

[10]   In a recent CBM reservoir modeling exercise for a 12 m thick coal bed, Kuuskraa and Boyer (1993) estimated that recovery efficiency would increase from 39% to 63% and to 81%, as the permeability increases from 1 to 5 and to 25 millidarcies, for CBM wells operated over a 20-year period using conventional CBM recovery technology.

Resources) in 1995; the performance results of these two pilots have not been released (Gunter *et al.*, 1997). In the spring of 1998 a project with many participants and backers[11] was launched to test this CBM recovery technique in Canada's Alberta Basin, under the auspices of the Alberta Research Council; the project will involve, by the end of 1998, an assessment of coal seams in the Mannville geological formation, simulated injection of CO_2 into these beds, a field trial with a single well, and an evaluation of the process; this activity will be followed by an expanded pilot project with continuous injection of CO_2 into five wells and methane recovery.

Although the recovery of CBM via CO_2 injection into deep coal beds is not yet commercial, the technology could be commercialized in 5-10 years if there is sufficient market interest.

Key to the viability of this approach to CBM recovery is having a low-cost source of CO_2 at the prospective CBM recovery site. One potential source of cheap CO_2 is at plants that produce H_2 from a carbonaceous feedstock, where CO_2 is produced in a relatively pure stream as a byproduct of H_2 manufacture.[12] Thus locating plants that produce H_2 from coal and/or natural gas near CBM reservoirs could provide low-cost CO_2 for CBM recovery.

An Opportunity for Launching a CBM Industry in China Using Byproduct CO_2 at NH_3 Plants

China is well-positioned to launch an industry that produces CBM via CO_2 injection. It has large CBM resources and produces large quantities of low-cost CO_2 as a byproduct of making H_2 from coal as an intermediate product in the manufacture of ammonia (NH_3) for fertilizer and other applications. Because of the scarcity of its resources of conventional natural gas (the feedstock from which most of the world's NH_3 supplies are derived), most of the NH_3 China produces is derived from coal.[13] Moreover, China is building up a capacity to make NH_3 for fertilizer from coal using modern gasification technology.[14] China has in operation, under construction, or on order, 25-30 modern,

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[11] Backers and participants include Sproule Associates, Ltd., Gulf Canada Resources, Burlington Resources, Suncor Energy, Canadian Fracmaster, TransAlta Utilities, EPCOR Utilities, the Canadian Association of Petroleum Producers, Air Liquide Canada, the U.S. Department of Energy, Environment Canada, the Geological Survey of Canada, and the Greenhouse Gas Research Programme of the International Energy Agency.

[12] At H_2 production plants byproduct CO_2 is available in the amount 29.7 kgC per GJ of H_2 (0.71 kmol CO_2 per kmol H_2) when H_2 is produced from coal and 10.7 kgC per GJ when H_2 (0.25 kmol CO_2 per kmol H_2) is produced from methane (Williams, 1998a).

[13] In 1990 70% of China's NH_3 production was based on the gasification of some 37 million tonnes of coal (Li *et al.*, 1990).

[14] NH_3 is produced via the Haber process by combining (at a pressure in the range 130 to 680 atmospheres) nitrogen (N_2) and H_2 in the presence of an appropriate catalyst, according to:

$$N_2 + 3H_2 \rightarrow 2NH_3.$$
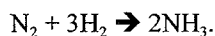
NH_3 can be made from coal, producing the needed H_2 via oxygen-blown coal gasification. Both the oxygen (O_2) needed for coal gasification and the N_2 needed for the Haber process can be obtained by air liquefaction. An oxygen-blown gasifier produces from coal at high efficiency "synthesis gas," a gaseous mixture consisting mainly of carbon monoxide (CO) and H_2. The CO in this synthesis gas is then reacted with steam in so-called "water-gas shift reactors," producing more H_2 plus CO_2. The net effect of gasification and shifting is thus to produce a gaseous mixture consisting mainly of H_2 and CO_2. Various commercial technologies are available for separating the H_2 (with up to 99.999% purity) from the CO_2 in the resulting gaseous mixture. For modern plants the H_2 produced this

oxygen-blown gasifiers; many are for gasifying coal and nearly all are for chemical process applications—mostly for NH_3 production.[15] Chinese interest in such technology arises because nitrogen fertilizer demand is growing[16] and much of the existing coal-based NH_3 production involves small, inefficient, and polluting plants,[17] many of which are likely to be replaced with larger, cleaner, and more cost-competitive plants. The modern coal gasification technology now being introduced could be used to make H_2 for fuel cell applications when fuel cells are established in China's markets.

When NH_3 is produced from coal, the byproduct CO_2 generation rate is about one kmol of CO_2 per kmol of NH_3. The CO_2 potentially available for CBM recovery depends on the fertilizer produced. If the desired product is ammonium nitrate (NH_4NO_3), all the CO_2 is available. If instead the product is urea (NH_2CONH_2), about half the CO_2 is needed for urea manufacture. [18] In either case excess CO_2 could be used for stimulating CH_4 recovery from deep beds of unminable coal, if such beds were located nearby. China should consider locating near prospective CBM recovery sites new plants for making NH_3 from coal and using the low-cost byproduct CO_2 for stimulating the production of CBM.

Here the results of modeling CBM recovery and use in conjunction with NH_3 manufacture from coal are described. It is assumed that NH_3 plants are located near sites with deep unminable coal deposits containing CBM, so that byproduct CO_2 can be used for stimulating CBM recovery, with sequestering of the injected CO_2 in the coal bed. Two alternative CBM uses are considered:

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way would have an energy content greater than 60% of the energy content of the coal (efficiency based on higher heating values) from which it is derived (Williams *et al.*, 1995a, 1995b).

[15]   Some 22 Texaco gasifiers are operating, under construction, or on order in China: 5 coal gasifiers (2 for NH_3 production and 3 for the production of town gas, methanol, and acetic acid) are already in operation and 9 more will go on line for NH_3 production between 1998 and 2004; in addition 6 gasifiers have been built for producing NH_3 from residual fuel oil, and 2 other gasifiers have been built to produce oxo chemcals (alcohols and aldehydes) from residual fuel oil and heavy crude oil. In addition, about six Shell gasifiers and at least one Lurgi gasifier are being used to produce NH_3 from coal.

[16]   The production of NH_3 is projected to increase from 22.5 million tonnes in 1990 to 37.8 million tonnes in 2020 (Li *et al.*, 1995). Fertilizer demand is not expected to grow more rapidly than this because China already uses fertilizer at a high rate—some 148 kg/hectare/year, compared to a world average of 54 kg/hectare/year.

[17]   In 1990 18.7% of total NH_3 production in China was accounted for by large, relatively efficient plants that use natural gas or oil as feedstocks; most of the rest of the ammonia production was accounted for by much less efficient medium-scale and small-scale plants that use coal (Li *et al.*, 1995).

[18]   When NH_3 is used as a feedstock to produce urea for fertilizer, the CO_2 is first reacted with NH_3 to form ammonium carbamate:

$$NH_3 + \tfrac{1}{2} CO_2 \rightarrow \tfrac{1}{2} NH_4COONH_2;$$
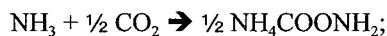
then the ammonium carbamate is dehydrated to form urea (NH_2CONH_2):

$$NH_4COONH_2 \rightarrow NH_2CONH_2 + H_2O.$$

Because only about half of the available CO_2 is needed for the production of urea, the excess CO_2 could be used to stimulate CBM recovery from deep coal beds as an alternative to venting this CO_2 to the atmosphere, as is typically done today at urea plants.

(*i*)　　*Case I*: The CBM is used mainly to produce additional H_2 and thus more NH_3 [Case Ia for ammonium nitrate (NH_4NO_3) production (see Figures 4) and Case Ib for urea (NH_2CONH_2) production (see Figure 5)];

(*ii*)　　*Case II*: All the CBM is used to produce electricity in a gas turbine/steam turbine combined cycle power plant [in conjunction with NH_4NO_3 production from coal in Case IIa and in conjunction with NH_2CONH_2 production from coal in Case IIb)].

Material and energy balances for Cases Ia and IIa are shown in Figures 6 and 7, respectively. In all instances production rates, costs, and CO_2 emission rates are compared to *Base Cases*, in which H_2 and electricity are produced from coal only, with venting of the excess CO_2 generated in H_2 manufacture. For all cases, CBM recovery and use are considered in conjunction with the manufacture of 26 PJ (2.0 billion Nm^3) per year of H_2 from coal for fertilizer applications—an amount of H_2 adequate for producing 920 thousand tonnes of NH_3 per year.

It is assumed that CH_4 is recovered from a 10 m-thick, homogenous coal bed[19] at an average depth of 856 m (the average depth of all CBM wells drilled in the United States in 1990) and that the CH_4 in the bed has a concentration of 15 Nm^3 per tonne of coal. Adopting the "Gunter hypothesis," it is assumed that 90% of the CBM in place is recovered over the facility life. The assumed lifetime CBM recovery rate is 1.78 million Nm^3 per hectare (26.7 million scf per acre)[20] and the assumed land area per well is 65 hectares (160 acres),[21] so that the lifetime CBM recovery per well is 115 million Nm^3 (4.3 billion scf).[22] For a particular well the CBM production profile will vary markedly over time. However, detailed modeling of the CBM recovery profile at each well is not attempted. Rather, each case considered involves a large number of wells, and it is assumed that production can be arranged so that the aggregate output of all wells can be maintained at a relatively constant level over the assumed 25-year life of the CBM recovery facility.

It is assumed that the CO_2 recovered at the H_2 plants at 1.3 bar is compressed to 100 bar and transported by pipeline to the injection sites, that the number of injection wells equals the number of CBM recovery wells, and that the CO_2 injection rate per well is 2.3 tonnes/hour, which is less than the injectivity (maximum injection rate) if the reservoir permeability is greater than about 1 millidarcy.[23] It

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[19]　　For comparison, in the CBM-rich Fruitland Formation of the San Juan Basin coal bed thicknesses are in the range 6 to 24 m (Kuuskraa and Boyer, 1993).

[20]　　For comparison, in the CBM-rich regions of the San Juan Basin the CBM resource in place is in the range 2 to 4 million Nm^3 per hectare (Kuuskraa and Boyer, 1993).

[21]　　With conventional CBM technology this is a typical area per well in the San Juan Basin; in the Warrior Basin, where coal seams are thinner and permeabilities lower, typical areas per well are about half as large. Modeling carried out by Kuuskraa and Boyer (1993) for a 12 m-thick coal seam having a 25 md permeability indicates that increasing the area per well from 65 to 130 hectares would lead, with conventional CBM recovery technology, to a 1/3 increase in the peak production rate and a 90% increase in the 20-year cumulative production rate per well but a reduction of the fraction of gas in place ultimately recovered from 81% to 72%.

[22]　　The corresponding daily average recovery rate is 0.47 million scf per day per well. For comparison, at the end of 1991 there were 1660 CBM wells in the San Juan Basin producing CBM at an average rate of 0.60 million scf per day per well (Kuuskraa and Boyer, 1993).

[23]　　The CO_2 injection rate per well can be compared to the injectivity—the maximum feasible CO_2 injection rate per well. The injectivity depends directly on the thickness of the coal bed and its permeability to the flow of

is assumed that the CO_2 injection wells are evenly distributed in a square array, at the center of which the conversion facility is located. The number of injection wells, assumed to be proportional to the CO_2 injection rate, is 200, 79, 154, and 82 for Cases Ia, Ib, IIa, and IIb, respectively.

Preliminary estimates of the lifecycle costs of the recovered CBM and the H_2 and electricity produced from coal and CBM are developed here.[24]

The estimated costs for the recovered CBM are made up of two components:

(*i*)   *CBM recovery cost estimates* per well developed by Kuuskraa and Boyer (1993)[25] for CBM reservoirs in the San Juan Basin of Colorado, using conventional CBM recovery technology, plus

(*ii*)   *Cost estimates for stimulating CBM recovery with CO_2 injection* [costs for CO_2 compression, transport, and injection, based on previous analyses relating to CO_2 sequestration in depleted natural gas fields (Blok *et al.*, 1997) and aquifers (Hendriks, 1994), modified as appropriate to reflect assumed coal bed reservoir characteristics].

Energy and mass balances for CBM production in Case Ia are presented in Table 1, and the corresponding estimate of the cost of the produced CBM is presented in Table 2. For all the cases considered, the estimated CBM production cost is in the range $2.20-$2.25 per GJ. For comparison, the average U.S. wellhead natural gas price (in 1991$) in 1996 was $1.80 per GJ (EIA, 1997).

CO_2. These parameters can be related by the following heuristic formula used by reservoir engineers (Hendriks, 1994):

$$q_s = 7200 \, \pi \, \rho_r \, kh \, \Delta P / [\, \mu \, \ln \, (r_e/r_w)],$$

where:

q_s = CO_2 injectivity [kg/hour],
ρ_r = CO_2 density under coal bed conditions = 700 kg/m^3 (typical value for supercritical CO_2),
k = permeability of the coal bed [m^2],
h = thickness of coal bed [m],
ΔP = difference between CO_2 pressures at the well bottom and at a long distance from the well [Pa],
μ = viscosity of the CO_2 at the well bottom = 6 x 10^{-5} Pa s (typical value),
r_e = radius of the influence sphere of the injection well [m],
r_w = radius of the injection well [m].

It is assumed that h = 10 m. The CO_2 pressure at the wellhead is about 100 bar. The pressure increases with well depth some 0.092 bar per m (Hendriks, 1994). Thus at the bottom of the well the pressure is 100 + 856*0.092 = 178 bar. It is assumed that the hydrostatic geopressure gradient is 0.0115 MPa/m, so that the presssure in the reservoir at a large distance from the well is 98 bar. Thus ΔP = 80 bar = 8,000,000 Pa. Following Hendriks (1994), it is assumed that ln (r_e/r_w) = 7.5. Thus the injectivity is q_s = 2.81*10^{18}*(k) kg/hour. Equating the injectivity and the assumed injection rate ➔ k = 0.82*10^{-15} m^2 (0.82 millidarcies).

[24]   Costs are estimated assuming a coal price of $1 per GJ, a 10% discount rate, and neglecting taxes/subsidies. All costs are prices presented are in 1991$. Energy quantities are represented on a higher heating value basis.

[25]   Except that the cost for well drilling and completion is assumed to be $249,000 per well—the average for all CBM wells drilled in the United States in 1990, when the average CBM well depth was 856 m and the average cost was $291/m (Pelzet, 1991).

Results for Case I H_2 production analyses are summarized in Table 3 and Figure 8. The amount of H_2 produced by the coal/CBM system is 1.82 times and 1.17 times that produced in the Base Case (which involves the same amount of coal feedstock) for Cases Ia[26] and Ib, respectively. In Case Ia the estimated cost of H_2 produced from CBM is \$4.8 per GJ_{H2} (65% of the cost of H_2 produced from coal in the Base Case), and the average H_2 cost is 16% less than in the Base Case; in Case Ib the cost of CBM-derived H_2 is \$5.8 per GJ_{H2} (higher than in Case IIa because of the much smaller scale of the H_2 plant); in this case the average cost of H_2 is only slightly less than in the Base Case. There is no unique way to assign to subsystems credits for CO_2 sequestered at the system level. Here these credits are assigned to activities associated with CBM production (and thereby to the production of H_2, electricity, and heat from CBM), because all costs associated with CO_2 injection are assigned to CBM production. As a result, the net lifecycle CO_2 emissions for CBM-derived H_2 are negative. CO_2 emissions per GJ associated with H_2 manufacture from coal in Case I are also 1/3 less than in the Base Cases, because it is assumed that CBM rather than coal is used to provide the external electricity and heat needed to make H_2 from coal.[27] The average net emission rate for the entire coal/CBM system of H_2 production is 6.0 kgC/GJ_{H2} (15% of the Base Case emission rate) for Case Ia and 19.0 kgC/GJ_{H2} (50% of the Base Case emission rate) for Case Ib.

Results of the Case II analyses are presented in Table 6. Here CBM production supports 50%-efficient combined cycle plants at 545 MW_e and 279 MW_e, respectively, of which 378 MW_e in Case IIa and 135 MW_e in Case IIb is in excess of onsite electricity needs (for both H_2 production from coal and CBM recovery). For Cases IIa and IIb the estimated cost of electricity produced in CBM-fired combined cycle plants is about 13% less per kWh than the cost of electricity from coal in steam-electric power plants in the Base Cases. Moreover, local air pollutant emissions would be much less, in light of the fact that natural gas-fired combined cycle power plants have the lowest local air pollutant emissions of all fossil fuel thermal-electric power generating technologies. As in the case of CBM-derived H_2, net lifecycle CO_2 emissions for CBM-derived electricity are negative; CO_2 emissions per GJ of H_2 produced from coal in Case II are also 1/3 less than in the Base Cases. The average net emission rates for the entire system of H_2 production from coal plus electricity production from CBM are ¼ as much for Case IIa and ½ as much for Case IIb as in the Base Cases.[28]

Initially, electricity generation might be preferred to H_2 production for use of the CBM, because with H_2 production a large amount of capital equipment downstream of CBM production (e.g., for H_2, NH_3, and nitrogen fertilizer production) would be idled at high cost if there were substantial unexpected reductions in the CBM recovery rate. In contrast, if electricity is produced from CBM and most is exported to the electricity grid, the capital at risk would be much less both because of the low capital intensity of combined cycle power plants and because unexpected shortfalls in CBM recovery could probably be readily compensated for by other underutilized electric generating capacity on the electricity grid. However, once CO_2 injection technology is well-established in the market, CBM use for producing additional H_2 should be considered wherever there is a sufficiently large market for H_2 (e.g., for extra

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[26]   The energy and mass balances and the costs for H_2 production from CBM are presented for Case Ia in Tables 4 and 5, respectively, along with the same parameters for Base Case H_2 production from coal.

[27]   It is assumed that electricity is provided in a 45%-efficient combined cycle and that heat is provided in an 85%-efficient boiler.

[28]   The Base Cases of Table 6 are defined such that the same amounts of H_2 and electricity are produced as are produced in Cases IIa and IIb, but in the Base Cases these are produced from coal without CO_2 sequestration.

NH_3 production in the near term or for FC applications in the longer term), in light of the much lower cost of making H_2 from CBM than from coal.

This analyses indicates not only that there are likely to be large local and global environmental benefits associated with CO_2-stimulated CBM recovery carried out in conjunction with the production of H_2 for ammonia manufacture from coal in China, but also that there are favorable prospects that CBM production carried out in this manner would be economically competitive in serving near-term market needs for H_2 and/or electricity. These findings highlight the importance of developing this CBM recovery technology quickly.

The Potential for H_2 Derived from Coal and CBM for Transportation Applications in China

The demand for transportation services is growing rapidly in China. However, China has only modest oil resources to support its transportation needs; ultimately recoverable conventional oil resources in China are estimated to be about 400 EJ, 4% of the global total (Masters *et al.*, 1994). But China has abundant coal and CBM resources, which might be effectively utilized in providing transportation services if PEM FC vehicles are successfully launched in the market. China is beginning to explore FC options for transportation. In February 1998, China's State Science and Technology Commission (SSTC) issued a request for proposals from international FC companies to work with China in developing a FC transit bus demonstration project in Beijing. The intent is that if this demonstration is successful, it would be followed by commercial production of FC buses in China.

Hydrogen derived from coal plus CBM in the manner described above for NH_3 manufacture (with energy/materials balances similar to those for Case Ia) could support FC vehicle fleets at large scales in China. This point is illustrated by a *gedanken* experiment developed in a companion paper (Williams, 1998c). In this experiment H_2 is so produced in quantities adequate to support a hypothetical future automotive fleet of 350 million H_2 FC cars that are driven 15,000 km (9300 miles) per year and have a fuel use rate of 2.35 liters of gasoline-equivalent per 100 km (100 mpg).[29] For such a fleet (Williams, 1998c): (*i*) the fuel cost per km for typical FC car owners in China would probably not be greater than for owners of gasoline internal combustion engine cars of comparable size and performance; (*ii*) the coal requirements for supporting such a fleet would be only 13% of total coal use in China in 1990; (*iii*) a fleet of this size could be supported for 100 years with just ¼ of China's estimated CBM resources of 35 trillion Nm^3, and (*iv*) the lifecycle CO_2 emissions for H_2 production and use in this system (including the assumed use of coal-derived electricity to operate H_2 compressors at car refueling stations) would amount to only 6% of China's CO_2 emissions in 1990. And local air pollutant emissions of such a vehicle fleet would be zero.

Because of its high population density, China might view buses and two- and three-wheeled vehicles as preferable to automobiles for passenger transportation. This *gedanken* experiment suggests, however, that such alternatives should be preferred because they would cause less congestion and noise or because adoption of the automobile culture would require sacrificing other development goals—not because of concerns about energy resource constraints, local air pollution, or greenhouse gas emissions. Hydrogen derived from coal plus CBM used in FC vehicles could support high levels of transportation services in China, making it possible for China to avoid heavy dependence on petroleum for transportation, potentially at competitive costs, with very little local or global air emissions. Moreover, because it presently has very little HC fuel infrastructures in place for transportation, it has the

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[29]   This is the fuel use rate expected for H_2 FC cars that have the acceleration, hill climbing ability, rolling resistance, aerodynamic drag, and weight characteristics established for cars under the Partnership for a New Generation of Vehicles in the United States (Ogden *et al.*, 1997)].

opportunity to "leapfrog" directly to H_2 FC technology, obviating the need for the costly HC-fueled FC transition technology that is being considered for launching FCs in transportation markets in some industrialized countries.

Conclusion

The recovery of CBM from deep coal beds by injecting CO_2 into the coal bed appears to be a promising technique for CBM recovery if low-cost supplies of CO_2 are readily available. The technique might be especially promising for low-permeability reservoirs. Low-cost CO_2 supplies could be provided by locating at prospective sites for CBM recovery facilities for the production from H_2 from fossil fuels, using the byproduct CO_2 for stimulating CBM recovery.

In countries such as China, where conventional oil and natural gas resources are scarce but coal and CBM resources are abundant, a near-term opportunity for using this technique for CBM recovery would be to site future plants for making NH_3 from coal near deep CBM reservoirs. The CBM so recovered could be used either to produce more H_2 for NH_3 manufacture or to make electricity in combined cycle power plants. In either case the CBM-derived product (H_2 or electricity) would probably be less costly than the corresponding coal-derived product. This same H_2 production strategy could be pursued later at large scales for energy purposes if PEM fuel cells are successfully established in the market. China's CBM resources so exploited along with coal in the production of H_2 appear to adequate to support high levels of transportation energy services based on the use of fuel cell vehicles.

A major ancillary benefit of this strategy is the potential for sequestering substantial quantities of CO_2 in the coal bed, since about 2 carbon atoms will remain as CO_2 adsorbed on the coal for each atom of carbon recovered as methane desorbed from the coal. Exploiting this fact would make it economically feasible in China to provide transportation services with very low lifecycle CO_2 emissions using abundant coal and CBM resources, if low-temperature fuel cells are successfully developed for transportation applications.

Acknowledgments

Appendix: Options for CO_2 Storage

Although disposal in the deep oceans is the most-discussed option for CO_2 disposal,[30] much more research is needed to better understand the security of various ocean disposal schemes and their environmental impacts (Turkenburg, 1992). In recent years increasing attention has been given to geological (underground) storage of CO_2: in depleted oil and natural gas fields (including storage in conjunction with enhanced oil and gas recovery), in deep saline aquifers, and in deep coal beds [in conjunction with coal bed methane (CBM) recovery].

Sequestration in oil and gas fields is generally thought to be a secure option if the original reservoir pressure is not exceeded (van der Burgt et al., 1992; Summerfield et al., 1993). Much of the prospective sequestering capacity will not be available until these fields are nearly depleted of oil and gas. One estimate of the prospective sequestering capacity of depleted oil and gas reservoirs associated with past production plus proven reserves plus estimated undiscovered conventional resources (most of which will be used up during the next century) is about 100 GtC for oil fields and about 400 GtC for natural gas fields (Hendriks, 1994); other estimates of the oil and gas field sequestering capacity are as low as 40 GtC for depleted oil fields plus 20 GtC associated with enhanced oil recovery plus 90 GtC for depleted natural gas fields (IPCC, 1996). (For comparison, global CO_2 emissions from fossil fuel burning totaled 6.0 GtC in 1990.) There is a considerable uncertainty regarding the global sequestering capacity of depleted oil and gas fields and the security of such sequestration. More research and field testing are needed to refine depleted oil and gas field sequestering capacity estimates, because reservoir properties vary greatly in their suitability for storage, and because the recovery of oil and gas from these reservoirs may have altered the formations and affected reservoir integrity. In the near term, CO_2 injection for enhanced oil recovery [which is established technology (Blunt et al., 1993)] and enhanced natural gas recovery (Blok et al., 1997) might become foci of initial efforts to sequester in profitable ways CO_2 recovered in H_2 production. For high-permeability reservoirs, the potential for enhanced production of natural gas with CO_2 injection is quite limited, because a large percentage (~ 80%) of the gas in place is recoverable in primary production; however, enhanced recovery might be significant for low-permeability reservoirs, as is the case when CO_2 is used for methane recovery from deep coal beds (see main text).

Without the benefit of enhanced resource recovery, storage in aquifers will generally be more costly than storage in depleted oil or gas fields. However, deep saline aquifers are much more widely available than oil or gas fields; such aquifers underlie most sedimentary basins, which account for nearly half of the land area of the inhabited continents. To achieve high storage densities, CO_2 should be stored at supercritical pressures (i.e., at pressures in excess of 74 bar). Since the normal hydrostatic geopressure gradient is about 100 bar per km, typically depths of about 800 m or more are desirable for sequestering CO_2 in aquifers. The aquifers at such depths are typically saline and not connected to the much shallower (typically < 300 m) "sweetwater" aquifers used by people.

If aquifer storage is limited to closed aquifers with structural traps, the potential global sequestering capacity is relatively limited, some 50 GtC (Hendriks, 1994), equivalent to less than 10 years of global CO_2 production from fossil fuel burning at the current rate. However, if structural traps

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[30] The deep oceans represent a very large potential sink for anthropogenic CO_2. The ultimate sequestering capacity of the oceans (determined by choosing a nominal allowable change in the average acidity of all ocean water) has been estimated to the in the range 1,000 to 10,000 GtC, the equivalent of 200 to 2,000 years of emissions from fossil fuels (Socolow, 1997). If the injected CO_2 can be incorporated in the general oceanic deep water circulation, a residence time of up to 1,000 years can be anticipated (Socolow, 1997).

are not required for secure storage, the storage capacity of aquifers might be huge–some 14,000 GtC (Hendriks, 1994), equivalent to more than 2,000 years of CO_2 emissions from fossil fuel burning at the current global rate. A growing body of knowledge indicates that many large horizontal open aquifers might provide secure storage if the CO_2 is injected far from the reservoir boundaries (Holloway, 1996). The notion that large horizontal aquifers can provide secure sequestration is a relatively new idea that has led to an increase in confidence that long-term sequestration of a significant fraction of the next several centuries of global CO_2 production from human activities might be feasible (Socolow, 1997; PCAST Energy R&D Panel, 1997).

Good estimates of the aquifer sequestration potential require considerable data gathering for and detailed modeling of specific aquifers. A recent major study carried out under the Joule II Non-Nuclear Energy Research Programme of the European Commission (Holloway, 1996) did a considerable amount of such modeling in an assessment of underground CO_2 storage reservoirs in Europe. This study estimated that the underground storage capacity accessible to the European Union plus Norway (mostly deep aquifers under the North Sea) would be adequate to store more than 200 GtC—storage capacity equivalent to 250 years of CO_2 emissions from all of OECD Europe at the current emission rate.

Experience with aquifer disposal will be provided by two projects involving injection into nearby aquifers of CO_2 separated from natural gas recovered from CO_2-rich gas reservoirs. One is a Statoil project begun in 1996 to recover 1 million tonnes of CO_2 per year from the Sleipner Vest offshore natural gas field in Norway (Kaarstad, 1992). The second, which will commence in about a decade, will involve the recovery of over 100 million tonnes per year (equivalent to about 0.5 percent of total global emissions from fossil fuel burning) from the Natuna natural gas field in the South China Sea (71% of the reservoir gas is CO_2) (IEA, 1996).

CO_2 sequestration in conjunction with CBM recovery is discussed in the main text of this paper.

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Table 1. Energy & Mass Balances for the Production of CBM via Injection into a Deep Coal Bed of CO_2 Produced as a Byproduct of H_2 Manufactured from Coal and CBM, *Case Ia*	
CO_2 injection rate for CBM-derived H_2 production, tCO_2/h[a]	104.9
CO_2 injection rate for coal-derived H_2 production, tCO_2/h[b]	355.3
Total CO_2 injection rate, tCO_2/h (kmol CO_2/h; kgC/GJ_{CBM})	460.2 (10,460; 26.98)
CBM production rate, PJ_{CBM}/y (kmol/h)	36.73 (5,230)
Electricity requirements, 10^6 kWh/y (kWh/GJ_{CBM})	
$\quad CO_2$ compression, 1.3 to 100 bar[d]	287.6 (7.83)
$\quad$ CBM compression, 1 to 30 bar[e]	119.7 (3.26)
Total electricity requirements	407.3 (11.09)

[a]   For H_2 produced at a rate of 21.12 PJ/y from CBM via steam reforming. The sequestration rate is 10.69 kgC/GJ_{H2} (Williams, 1998a), and the CBM gas feedstock required is 1.114 GJ_{CBM} per GJ_{H2} (Williams *et al.*, 1995a, 1995b).

[b]   For H_2 produced at a rate of 25.76 PJ/y from coal via oxygen-blown gasification. The sequestration rate is 29.70 kgC/GJ_{H2} (Williams, 1998a), and the coal feedstock required is 1.292 GJ_{COAL} per GJ_{H2} (Williams *et al.*, 1995a, 1995b).

[c]   Following Gunter et al. (1997) it is assumed that 1 kmol of CBM is recovered for each 2 kmols of CO_2 injected into and sequestered in the deep coal bed from which the CBM is recovered.

[d]   It is assumed that CO_2 recovered from the PSA units @ 1.3 bar is compressed to 100 bar for pipeline transmission and injection into the coal bed, as would be the case for CO_2 injection into depleted natural gas fields (Blok *et al.*, 1997). The electricity required is 78.06 kWh per tonne for compression to 80 bar (the supercritical point is 73.8 bar, 31°C) plus 0.057 kWh/tonne/bar for additional pressure. The pressure has to be sufficiently high to prevent two-phase flow problems during transmission; pressure losses in transmission amount to 0.12 bar/km. The electricity required = 79.19 kWh/tonne CO_2 or 7.83 kWh/GJ_{CBM}.

[e]   It is assumed that CBM is recovered at 1 bar and compressed to 30 bar at the wellhead. The amount of electricity EL_{CBM} required to compress 1 GJ (Q = 920.8 scf) of CH_4 (for which the ratio of specific heats k = 1.315) is
$EL_{CBM} = 7.9795*10^{-4}*Q*(N/nc)*k/(k-1)*[(P2/P1)^{(k-1)/Nk)}-1] = 3.26$ h/GJ_{CBM}, assuming a compressor efficiency nc = 0.85 and N = 4 stages of compression.

Table 2. Estimated Production Cost for CBM Recovered via CO_2 Injection, *Case Ia*	
CO_2 injection rate, tCO_2/h[a]	460.2
CBM production rate, PJ/y[a] (GJ/h)	36.73 (4656)
Capital costs related to CO_2 injection (10^6 $)	
CO_2 compressor[b]	28.16
CO_2 injection wells[c]	49.82
CO_2 pipelines[d]	43.49
Utilities, auxiliaries[e]	30.37
Engineering, administrative support, contingencies, owner costs, fees, profits, startup[f]	75.92
Subtotal	227.76
Capital costs related to CBM recovery (10^6 $)	
Geological/geophysical expenditures, engineering feasibility studies[g]	6.00
CBM production wells[h]	49.82
Well stimulation[i]	16.00
Surface equipment, including gas gathering equipment[j]	24.00
Water disposal[k]	10.00
CBM compressor[l]	13.66
Engineering, administrative support, contingencies, owner costs, fees, profits, startup[f]	59.74
Subtotal	179.22
Total capital cost	406.98
Production cost ($ per GJ_{CBM})	
Capital costs[m]	
Related to CO_2 injection	0.721
Related to CBM recovery	0.563
O&M costs	
Related to CO_2 injection[n]	0.124
CBM wells, gas treatment, water disposal, engineering, general & overhead[o]	0.277
Electricity requirements	
For CO_2 compression[p]	0.225
For CBM compression[p]	0.094
Royalty to resource owner[q]	0.250
Total production cost	2.25

[a]   For the CBM recovery system described in Table 1. It is assumed that all costs of CO_2 disposal downstream of the PSA units at the H_2 production plants, as well as CBM recovery costs and royalties, are levelized over the 25-year life of the CBM recovery system and charged to the cost of CBM. It is assumed that the CBM is recovered from a 130 km² square grid of 200 CBM recovery wells and an equal number of CO_2 injection wells, with the energy conversion facility at the center of the recovery field. It is assumed that the wells are arranged such that aggregate output of all the wells can be maintained at a relatively constant level over the assumed 25-y life of the CBM recovery facility.

[b]   The estimated compressor cost (for compressing CO_2 from 1.3 to 100 bar) is $61,200/(tonne/h) (Blok *et al.*, 1997).

[c] CO_2 injection wells are assumed to cost the same as CBM recovery wells (see note h).

[d]   The CO_2 pipeline network for transporting the CO_2 from the energy conversion facility to the 200 injection wells is assumed to be laid out in a square array (11.4 km on a side), with neighboring wells 877 m apart. The pipeline network consists of two mains extending from the plant to opposite edges of the array plus 14 pairs of equally spaced side pipelines that branch out from the mains and extend to the other two edges of the array. It is assumed that pipe diameters are reduced as mass flow is diverted to sidelines or wells, such that the CO_2 flow speed is constant throughout the network.

Notes to Table 2, cont.

The CO_2 pipeline cost I_{PIPE} (in $) is (Blok *et al.*, 1997): $I_{PIPE} = 0.56 \times (300 + 1500 \times d^{0.9}) \times L$, where d = diameter (in m), L = length (in m). The optimal diameter is d = 0.5 m for a CO_2 injection rate of 500 t/h; assuming the cross-sectional area is proportional to the flow rate $\rightarrow$ d = 0.5 x $(F/500)^{0.5}$ for a flow rate of F tonnes per hour. Thus the pipeline cost per segment (each of which is 877 m long) is $0.56*\{300 + 1500*[0.5*(F/500)^{0.5}]^{0.9}\}*877 = \$147,336 + 24,089*F^{0.45}$, where F is the flow rate in each pipe segment. Using this formula, the cost for the entire square grid of CO_2 surface piping amounts to \$43.49 million.

e   Assumed to be 25% of other equipment costs, following Williams *et al.* (1995a, 1995b).

f   Assumed to be 50% of direct capital costs.

g   Following the Kuuskraa and Boyer (1993) analysis of CBM recovery in the San Juan Basin, it is assumed that geological and geophysical expenditures and engineering-based feasibility studies cost \$30,000 per CBM recovery well.

h   It is assumed that the average well depth is 856 m [the average for all CBM wells drilled in the United States in 1990 (Petzet, 1991)] and that CBM well costs are same as the average for all CBM wells drilled in the United States in 1990, some \$291 per m (Petzet, 1991), or \$249,000 per well.

i   Following the Kuuskraa and Boyer (1993) analysis of CBM recovery in the San Juan Basin, CBM well stimulation costs amount to \$80,000 per CBM recovery well.

j   Following the Kuuskraa and Boyer (1993) analysis for the San Juan Basin, it is assumed that surface equipment, including gas gathering cost \$120,000 per CBM recovery well.

k   Following the Kuuskraa and Boyer (1993) analysis for the San Juan Basin, it is assumed that water disposal costs \$50,000 per CBM recovery well; this includes costs for water treatment and injection of recovered water into disposal wells.

l   It is assumed that the CBM is recovered at 1 bar and compressed to 30 bar. The CBM compressor capacity Pcm (in kW_e) needed is $Pcm = 7.9795*10^{-4}*Q*(N/nc)*k/(k-1)*[(P2/P1)^{(k-1)/Nk} - 1]$, where Q is the CBM flow rate in scf/h, P2 and P1 are the output and input pressures, respectively, nc is the compressor efficiency, k is the ratio of specific heats, and N is the number of stages of compression. For methane, k = 1.315 and 1 scf = 1086 kJ or 1 GJ = 920.8 scf, so that the flow rate is Q = $4.287*10^6$ scf/h. Assuming that N = 4 and nc = 0.85, the needed capacity Pcm = 15,182 kW_e. It is assumed that compressors cost \$900/kW_e (Williams *et al.*, 1995a, 1995b).

m   Assuming a 10% discount rate plus a 0.5%/y insurance charge for equipment, annual capital charge rates are: 0.110 (25-y project life) for studies, 0.122 for compressors (20-y equipment life), and 0.115 for other capital (25-y equipment life).

n   Assumed to be 3% of capital costs for equipment per year.

o   Adapted from the Kuuskraa and Boyer (1993) analysis of CBM recovery in the San Juan Basin.

p   It is assumed that electricity needs [7.83 kWh/G_{CBM} and 3.26 kWh/GJ_{CBM} for CO_2 and CBM compression, respectively (see Table 1)] are provided by a CBM-fueled combined cycle power plant dedicated to the entire facility that makes H_2 from CBM and coal . Capital costs for power generation are calculated assuming a 10% discount rate, a 25-year plant life, a 0.5%/year insurance charge, and an 80% capacity factor. It is assumed that the installed capital cost is \$413/kW_e, the O&M cost is \$0.0039kWh, and the efficiency is 45%; the total cost of CBM-derived electricity is \$0.0287/kWh. Except for the fuel cost (\$2.25/GJ_{CBM}) and efficiency, these power plant cost parameters are from Stoll and Todd (1997) for a Frame 7FA General Electric combined cycle; the assumed lower efficiency (45% instead of 50.2% for a combined cycle based on the Frame 7FA) is a more appropriate value at the smaller plant size considered here (219 MW_e instead of 506 MW_e for a combined cycle based on the Frame 7FA).

q   Assumed to be 12.5% of direct CBM costs.

Table 3. Alternative Schemes for Producing H₂ for Fertilizer Manufacture

	Base Cases: H_2 from Coal for Fertilizer Manufacture (Base Cases)[a]		Case Ia: H_2 from Coal + CBM for NH_4NO_3 Manufacture (CBM Produced by Injecting into Deep Coal Beds CO_2 Generated in Making H_2)[b]			Case Ib: H_2 from Coal + CBM for Urea Manufacture (CBM Produced by Injecting into Deep Coal Beds CO_2 Generated in Making H_2)[b]		
	NH_4NO_3 Production	Urea Production	H_2 from Coal	H_2 from CBM	H_2 from Coal + CBM	H_2 from Coal	H_2 from CBM	H_2 from Coal + CBM
Coal consumption rate (PJ/y)	42.83		33.28	-	33.28	33.28	-	33.28
CBM consumption rate (PJ/y)	-		8.43	28.30	36.73	8.43	6.00	14.43
H_2 production rate (PJ/y)[c]	25.76		25.76	21.12	46.88	25.76	4.48	30.24
CO_2 available (kgC/GJ)	29.70	15.69	29.70	10.69	21.14	15.69	-3.32	12.87
Use of available CO_2?	Vented to Atmosphere		Injected into Deep Coal Beds to Stimulate Production of CBM					
Coal price ($/GJ)			1.0					
CBM production rate (PJ/y)				36.73			14.43	
CBM production cost ($/GJ)[d]				2.25			2.24	
H_2 production cost ($/GJ)[e]	7.41		7.40	4.81	6.23	7.40	5.84	7.17
CO_2 emission rate (kgC/GJ)[f]	38.62		25.62	-17.97	5.98	25.62	-17.97	19.16

[a] In the Base Cases coal is used both as a feedstock and for providing external electricity (@ 35.5% efficiency) and heat requirements (@ 80% efficiency) in the manufacture of H_2.

[b] In these cases (Case Ia is shown in Figures 4 and 6) 85%-efficient CBM-fired combined cycles are used to provide the external electricity required in H_2 manufacture from both coal and CBM, and coal is used only as a feedstock in the manufacture of H_2 from coal.

[c] Assuming an overall yield of 90%, a H_2 production rate of 1 PJ/y corresponds to an NH_3 production rate of 35,750 tonnes per year.

[d] The CBM production cost is developed in Table 2 for Case Ia, where CO_2 generated in making H_2 from coal is injected into the coal bed at a rate of 29.70 kgC/GJ$_{COAL}$ (NH_4NO_3 fertilizer production case) and the CBM production rate is 36.73 PJ/y; the same procedure is followed for Case Ib.

[e] The costs for producing H_2 pressurized to 300 bar from coal only (Base Case) and from CBM for Case Ia (where the H_2 is used to make NH_4NO_3 fertilizer) are developed in Table 5. The cost of producing H_2 from CBM is much higher for the urea production case because of the scale economy effect at the lower CBM-derived H_2 production rate (4.48 PJ/y vs. 21.12 PJ/y), which arises because with urea production far less CO_2 is available for injection into the coal bed and thus far less CBM can be recovered and converted to H_2.

[f] The CO_2 emissions rates for burning coal and CBM are 23.23 kgC/GJ$_{COAL}$ and 13.57 kg C/GJ$_{CBM}$, respectively. However, because costs associated with CO_2 sequestration are allocated to the cost of CBM production, credit for the CO_2 sequestered in the deep coal bed is assigned to CBM consumption at a rate of 26.98 kg C/GJ, so that the net emissions associated with CBM consumption 13.57 – 26.98 = - 13.41 kgC/GJ$_{CBM}$.

Table 4. Energy and Mass Balances for the Production of H_2 from Coal and CBM, *Case Ia*	H_2 from Coal	H_2 from CBM
Annual H_2 production (PJ/y)	25.76	21.12
Byproduct CO_2 (kgC/GJ_{H2})	29.70	10.69
Feedstock required[a] (GJ/GJ_{H2})	1.292	1.114
Electricity requirements (kWh/GJ_{H2})		
For producing O_2 for the coal gasifier[b]	16.74	-
Lockhopper[c]	0.58	-
PSA recycle compressor[c]	3.87	3.26
Vacuum pump for PSA unit[d]	11.03	3.97
H_2 compression[e]	8.42	8.42
Pumps	0.11	0.05
Total	40.75	15.70
Electricity supplies[f] (kWh/GJ_{H2})		
Waste heat	3.08	2.30
Purge gases	4.95	-
External sources	32.72	13.40
External heat requirements[f] (GJ/GJ_{H2})	0.031	-

[a]   From Table 4 in Williams *et al.* (1995a, 1995b). Does not include process energy.

[b]   Producing a tonne of O_2 at 24.50 bar via air liquefaction requires 480 kWh of electricity, and O_2 requirements for coal gasification are 0.03488 tonnes/GJ_{H2} (Williams *et al.*, 1995a, 1995b), so that 16.74 kWh/GJ_{H2} of electricity is required.

[c]   Electricity needs for the lockhopper, the PSA recycle compressor, and pumps are from Williams *et al.* (1995a, 1995b).

[d]   The electricity required for the vacuum pump for the PSA unit can be calculated as 4.46 kWh/(kmol CO_2 removed) [see footnote c, Table 4 in Williams *et al.* (1995a, 1995b)], which amounts to 11.03 kWh/GJ_{H2} in the case of H_2 from coal and 3.97 kWh/GJ_{H2} in the case of H_2 from CBM.

[e]   The H_2 is recovered from the PSA unit at 20.3 bar. For NH_3 production it is assumed that H_2 must be compressed to 300 bar. The power needed for compression (in kW) is
$Pcm = 7.9795 \times 10^{-4} \times Q \times (N/nc) \times k/(k-1) \times [(P2/P1)^{(k-1)/Nk}-1]$, where Q is the flow in scf/h, N is the number of stages of compression, nc is the compressor efficiency, k is the specific heat ratio, and P2 and P1 are, respectively, the ouput and input pressures. For H_2, 1 scf = 343 kJ or 1 GJ = 10^6 kJ = 2915.45 scf. Thus the electricity required EL_{H2} (in kWh per GJ_{H2}) is $EL_{H2} = 2.3264 \times (N/nc) \times k/(k-1) \times [(P2/P1)^{(k-1)/Nk}-1]$. Assuming nc = 0.85, N = 3, and k = 1.411 for H_2, the electricity required to compress H_2 from 20.3 to 300 bar is 8.42 kWh/GJ_{H2}.

[f]   See Table 4 in Williams *et al.* (1995a, 1995b).

Table 5. Estimated Production Costs for H_2 Produced from Coal (*Base Case*) and CBM (*Case Ia*)	H_2 from Coal[a,b]	H_2 from CBM[a,c]
H_2 production rate, PJ_{H2}/y (GJ_{H2}/h)	25.76 (3,265)	21.12 (2,677)
Feedstock input rate, PJ/y (GJ/h)	33.28 (4.219)	23.52 (2,982)
Installed equipment cost (10^6 \$)[d]		
Feed preparation[e]	52.00	-
Gasifier[f]	91.86	-
High-temperature gas cooling[g]	86.67	-
Oxygen plant[h]	72.68	-
Sulfur removal[i]	27.74	-
Reformer[j]	-	46.51
Shift reactors[k]	5.68	9.63
PSA recycle compressor[l]	11.37	7.85
PSA unit (with CO_2 removal)[m]	39.30	33.08
Hydrogen compressor[n]	24.74	20.29
Steam turbine cogeneration plant[o]	29.27	11.80
Utilities, auxiliaries[p]	110.33	32.29
Subtotal	551.64	161.45
Contingencies, owner costs, fees, profits, startup[q]	193.07	56.51
Total fixed capital investment (10^6 \$)	744.71	217.96
Working capital (10^6 \$)[r]	55.16	16.15
Land (10^6 \$)[s]	4.77	4.23
Production Cost (\$/GJ_{H2})		
Capital[t]	3.57	1.30
Feedstock[u]	1.29	2.51
Operation and maintenance[v]	1.52	0.62
Purchased electricity[w]	0.99	0.38
Other purchased energy[x]	0.04	-
Total production cost (\$/GJ_{H2})	7.41	4.81

[a]   Costs are for systems operated at 90% capacity factor and having the energy balances presented in Table 4.

[b]   For this Base Case (see Table 3) coal is used for external electricity and heat as well as feedstock in H_2 manufacture.

[c]   For Case Ia in Table 3 (see also Figures 4 and 6) where (*i*) all byproduct CO_2 associated with producing H_2 from coal and CBM is injected into deep coal beds to produce CBM (with the molar production rate of CBM equal to half the molar CO_2 injection rate into the coal beds), (*ii*) the recovered CBM is used both as a feedstock for producing H_2 and to provide the external electricity and heat needs in the production of H_2 from both CBM and coal.

[d]   Capital costs are based on costs developed in Williams *et al.* (1995a, 1995b) for producing H_2 from coal and natural gas at rates of 37.76 PJ/y and 19.09 PJ/y, respectively, adjusted to the production rates in the present analysis using scaling factors for system components presented in Williams *et al.* (1995a, 1995b).

[e]   The capital cost for coal feed preparation is $(25.76/37.76)^{0.7} * 67.96 = \$52.00$ million.

[f]   The capital cost for a Shell oxygen-blown coal gasifier is $(25.76/37.76)^{0.7} * 120.6 = \$91.86$ million.

[g]   The capital cost for high-temperature gas cooling is $(25.76/37.76)^{0.7}*113.27 = \$86.67$ million.

[h]   The capital cost for the O_2 plant is $0.260*(tO2/d)^{0.712}$ million \$. The O_2 requirements for the coal gasifier are 2729 t/d. Thus the capital cost is \$72.68 million.

[i]   The capital cost for sulfur removal is $(25.76/37.76)^{0.7}*36.25 = \$27.74$ million.

[j]   The capital cost for a steam reformer is $(21.12/19.09)^{0.57}*43.91 = \$46.51$ million.

[k]   The capital costs for shift reactors are $(25.76/37.76)^{0.65}*7.28 = \$5.68$ million for coal and $(21.12/19.09)^{0.65}* 9.02 = \$9.63$ million for CBM.

[l]   Based on the PSA recycle compressor electricity needs from Table 4, the compressor capacity needed for the PSA recycle compressor is $[3.87 \text{ kWh/GJ}_{H2})]*(3,265 \text{ GJ/h}) = 12,636 \text{ kW}_e$ for coal and $[3.26 \text{ kWh/GJ}_{H2})]*(2,677 \text{GJ/h}) = 8,727 \text{ kW}_e$ for CBM (Williams et al., 1995a, 1995b). The capital costs for these compressors are \$11.37 million and \$7.85 million for coal and CBM, respectively, assuming a specific cost of $\$900/\text{kW}_e$.

[m]   The capital cost for the Gemini-9 PSA unit (with CO_2 removal) is $(25.76/37.76)^{0.7}*51.39= \$39.30$ million for coal and $(21.12/19.09)^{0.7}*30.82 = \$33.08$ million for CBM.

[n]   The H_2 compressor capacity needed is $(3,265 \text{ GJ/h})*(8.42 \text{ kWh/GJ}_{H2}) = 27,491 \text{ kW}_e$ for coal and $(2,677 \text{ GJ/h})*(8.42 \text{ kWh/GJ}_{H2}) = 22,540 \text{ kW}_e$ for CBM. Assuming that H_2 compressors cost $\$900/\text{kW}_e$ the capital cost is \$24.74 million for coal and \$20.29 million for CBM.

[o]   The capital cost for the steam turbine cogeneration plant is $(25.76/37.76)^{0.626}*37.19 = \$29.27$ million for coal and $(21.12/19.09)^{0.626}*11.08 = \$11.80$ million for CBM.

[p]   Utilities and accessories are assumed to cost 25% of the above equipment costs.

[q]   Contingencies, owner costs, fees, profits, and startup costs are assumed to be 35% of equipment costs.

[r]   The required working capital is assumed to be 10% of the equipment cost.

[s]   Following Williams et al. (1995a, 1995b) land costs are assumed to be $423*(tpd)^{1.147}$ for coal (tpd is the coal feedstock input rate in tonnes per day) and $\$0.18$ per GJ_{CBM}/y for CBM. In the present coal case the coal input rate is $5000*(25.76/37.76) = 3411$ tpd, so that the land cost is \$4.77 million; in the CBM case the land cost is \$4.23 million.

[t]   Assuming a 10% discount rate, equipment lifetimes of 20 years for compressors and 25 years for other equipment, and a 0.5%/year insurance charge rate, the annual capital charge rates are 0.122 for compressors and 0.115 for other equipment. Both working capital and land are non-depreciating assets for which the annual capital charge rate is 0.10.

[u]   Feedstock costs are assumed to be \$1.00/GJ for coal and \$2.25/GJ for CBM (see Table 2).

Notes for Table 5, cont.

^v   Operation and maintenance (O&M) costs are derived as follows from the values presented in Williams *et al.* (1995a, 1995b) for H_2 derived from coal and natural gas in the amounts 37.76 PJ/y and 19.09 PJ/y, respectively. It is assumed: that the cost of labor scales with output [(25.76/37.76)*3.14 = \$2.14 million/y for coal and (21.12/19.09)*1.0 = \$1.11million/y for CBM]; that maintenance is 3% of the installed hardware cost (0.03*551.64 = \$16.55 million/y for coal and 0.03*161.45 = \$4.84 million/y for CBM); that direct overhead is 45% of the labor cost (0.45*2.14 = \$0.96 million/y for coal and 0.45*1.11 = \$0.50 million/y for CBM); that general overhead is 65% of labor + maintenance cost [0.65*(2.14 + 16.55) = \$12.15 million/y for coal and 0.65*(1.11 + 4.84) = \$3.87 million/y for CBM]; and that catalysts and chemicals scale with output (25.76/37.76*10.87 = \$7.42 million/y for coal and 21.12/19.09*2.58 = \$2.85 million/y for CBM). Thus total O&M costs amount to \$39.22 million/y for coal and \$13.17 million/y for CBM.

^w   External electricity needs are 32.72 kWh/JG$_{H2}$ with coal and 13.40 kWh/JG$_{H2}$ with CBM (see Table 4). Capital costs for power generation are calculated assuming a 10% discount rate, a 25-year plant life, a 0.5%/year insurance charge, and a 80% capacity factor. In the coal case, it is assumed that electricity is produced in a 35.5%-efficient 500 MW$_e$ coal steam-electric plant with an installed capital cost of \$963/kW$_e$, an O&M cost of \$0.0045/kWh, and a coal cost of \$1/0/GJ, so that the total cost of coal-derived electricity is \$0.0303/kWh. In the CBM case, it is assumed that electricity is produced in a CBM-fired combined cycle power plant with an installed capital cost of \$413/kW$_e$, an O&M cost of \$0.0039/kWh, an efficiency of 45%, and a CBM cost of \$2.25/GJ, so that the total cost of CBM-derived electricity is \$0.0287/kWh. Except for fuel costs and the assumed combined cycle efficiency, these power plant cost parameters are based on a recent study by General Electric analysts (Stoll and Todd, 1997). The combined cycle plant considered in that study (which involves use of a GE Frame 7FA gas turbine) has a capacity of 506 MW$_e$ and a 50.2% efficiency. The lower 45% efficiency assumed here is a more appropriate value at the smaller plant size considered here (219 MW$_e$).

^x   It is assumed that the external heat required for making H_2 from coal (0.031 GJ/GJ$_{H2}$) is provided by burning coal costing \$1.0/GJ in an 80%-efficient boiler.

o

Table 6. Alternative Schemes for Producing Electricity In Conjunction with the Manufacture of Fertilizer from Coal-Derived H₂

|	Base Cases: H₂ from Coal for Fertilizer Manufacture + Coal Steam-Electric Power[a]		Case IIa: H₂ from Coal for NH₄NO₃ Manufacture + CC CBM Power (CBM Produced by Injecting into Deep Coal Beds CO₂ Generated in Making H₂)[a]	Case IIb: H₂ from Coal for Urea Manufacture + CC CBM Power (CBM Produced by Injecting into Deep Coal Beds CO₂ Generated in Making H₂)[a]
	NH₄NO₃	Urea		
Coal consumption rate (PJ/y)	69.87	52.45	33.28	33.28
CBM use in producing H₂ from coal (PJ/y)	-	-	7.59	7.59
CBM use in external electricity generation (PJ/y)	-	-	20.77	7.39
Rate of producing H₂ from coal (PJ/y)			25.76	25.76
CO₂ available (kgC/GJ$_{H2}$)	29.70	15.69	29.70	15.69
Use of available CO₂?	Vented to Atmosphere		Injected into Deep Coal Beds to Stimulate Production of CBM	
CBM production rate (PJ/y)	-		28.36	14.98
Electricity production rate (TWh/y)	3.509	1.792	3.824	1.958
Rate of electricity export (TWh/y)	2.666	0.949	2.666	0.949
Coal price ($/GJ)			1.0	1.0
CBM production cost ($/GJ)[b]	-	-	2.20	2.23
H₂ production cost ($/GJ)[c]	7.41		7.33	7.33
Electricity production cost (cents/kWh)[d]	3.03		2.65	2.67
CO₂ emissions, H₂ production (kgC/GJ)[e]	38.63		26.06	
CO₂ emissions, electricity generation (grC/kWh)[e]	235.6		- 104.5	
System CO₂ emissions (10⁶ kgC/y)[e]	1623	1218	393	572

a   In the Base Cases coal is used both as feedstock and for providing external electricity (@ 35.5% efficiency) and heat (@ 80% efficiency) requirements in H₂ manufacture. In the other cases (Case IIa is shown in Figure 7) 85%-efficient CBM boilers are used to provide the external heat and 50.2%-efficient CBM-fired combined cycles are used to provide the external electricity required in H₂ manufacture, and coal is used only as a feedstock.

b   The CBM production costs are developed according to the procedure for Case Ia presented in Table 2.

c   For H₂ pressurized to 300 bar. See Table 5 for the Base Case calculation. Costs are somewhat lower for the other cases because the required electricity is provided by CBM combined cycle plants that provide electricity at lower cost than coal steam-electric plants.

d   Assumed installed capital costs [$963/kW$_e$ for coal steam-electric plants and $413/kW$_e$ for CBM combined cycle (CC) plants] and O&M costs ($0.0045/kWh for coal steam-electric plants and $0.0039/kWh for CBM CC plants) are from a recent General Electric study (Stoll and Todd, 1997). Capital charge rates are calculated assuming a 10% discount rate, a 25-year plant life, a 0.5%/year insurance charge, and an 80% capacity factor.

e   As in Table 3 (footnote f), net lifecycle CO₂ emission rates are 23.23 kgC/GJ$_{COAL}$ and – 13.41 kgC/GJ$_{CBM}$.
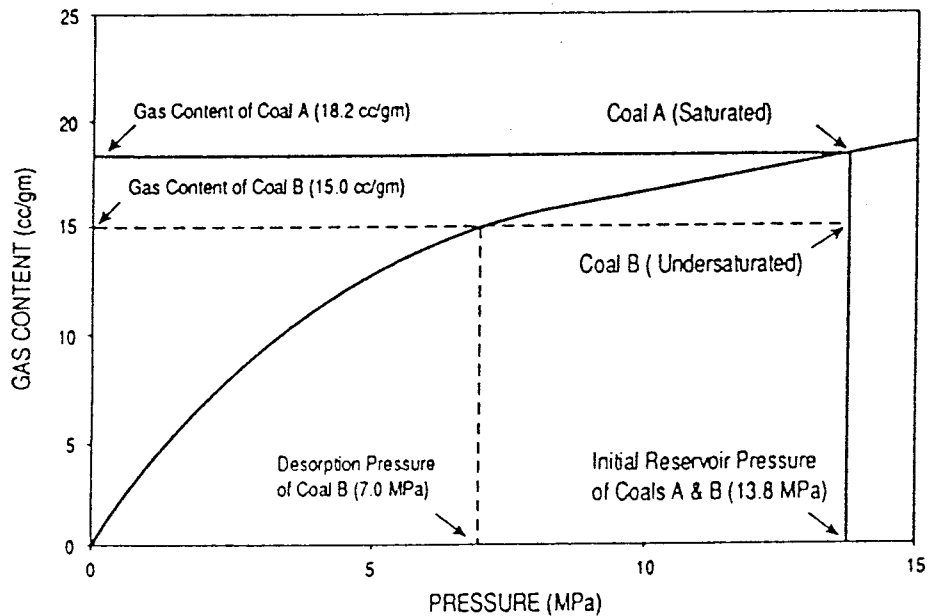
Figure 1: Idealized Coalbed Gas Sorption Isotherm Showing Relationship between Reservoir Pressure and Gas Content for a Saturated Coal (A) and an Unsaturated Coal (B)

This "gas sorption isotherm" indicates the maximum amount of gas that can be stored at a given reservoir pressure. It can be used to understand the gas desorption process associated with the CBM recovery technique that involves reservoir depressurization (e.g. via dewatering). For coal A, which contains 18.2 cm^3 of gas per gram of coal at a reservoir pressure of 13.8 MPa, gas would immediately begin desorbing from the coal matrix when the coal is penetrated by a drill bit and the pore pressure begins to drop. For coal B, which is unsaturated with methane at 15.0 cm^3 per gram and a pressure of 13.8 MPa, gas desorption would not begin until the reservoir pressure is reduced to 7.0 MPa.
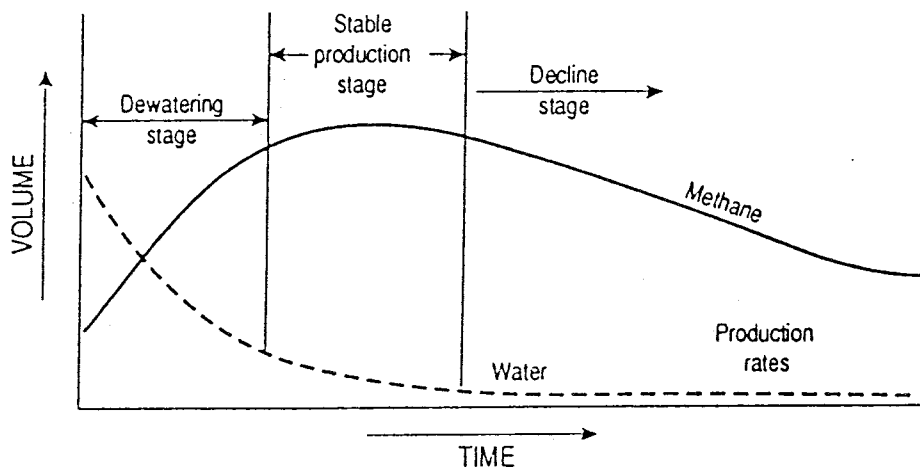
Sources: Rice *et al.* (1993).
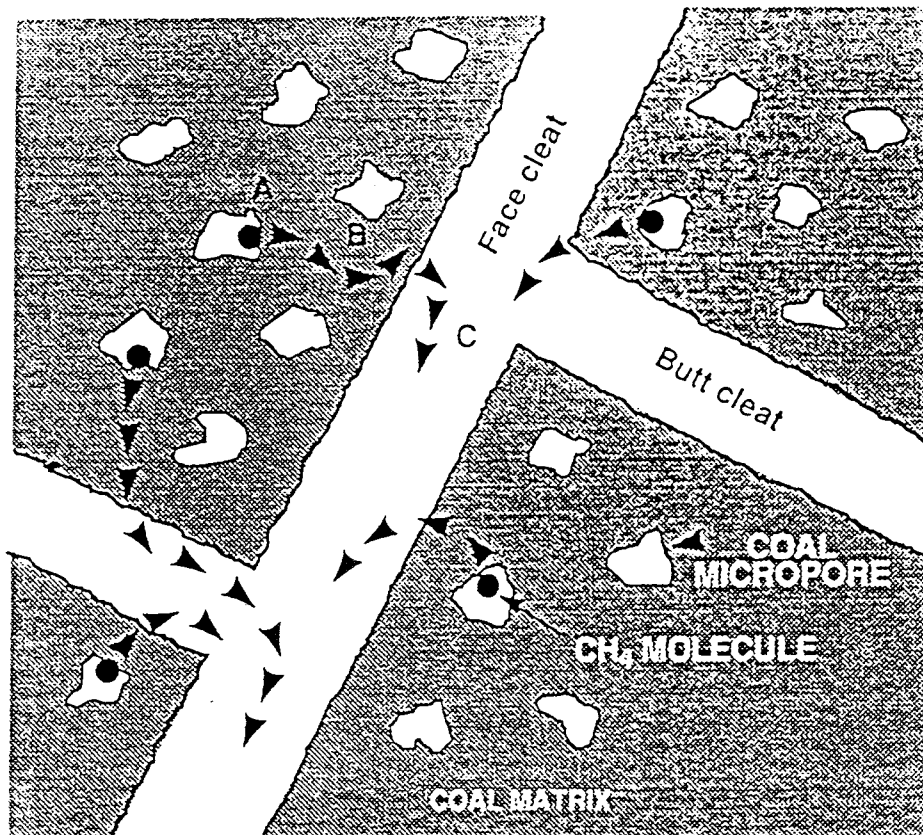
Figure 2: Diagram Showing (A) Desorption of Methane from Micropores in Coal As a Result of Reservoir Depressurization, (B) Diffusion Path of Methane Through the Coal Matrix, and (C) Flow of Methane in Through Fractures in the Coal Bed

Source: Rice *et al.* (1993).

Figure 3: Generalized Production History Showing Volumes of Methane and Water Over Time for a Typical Coalbed Gas Well Based on Reservoir Depressurization
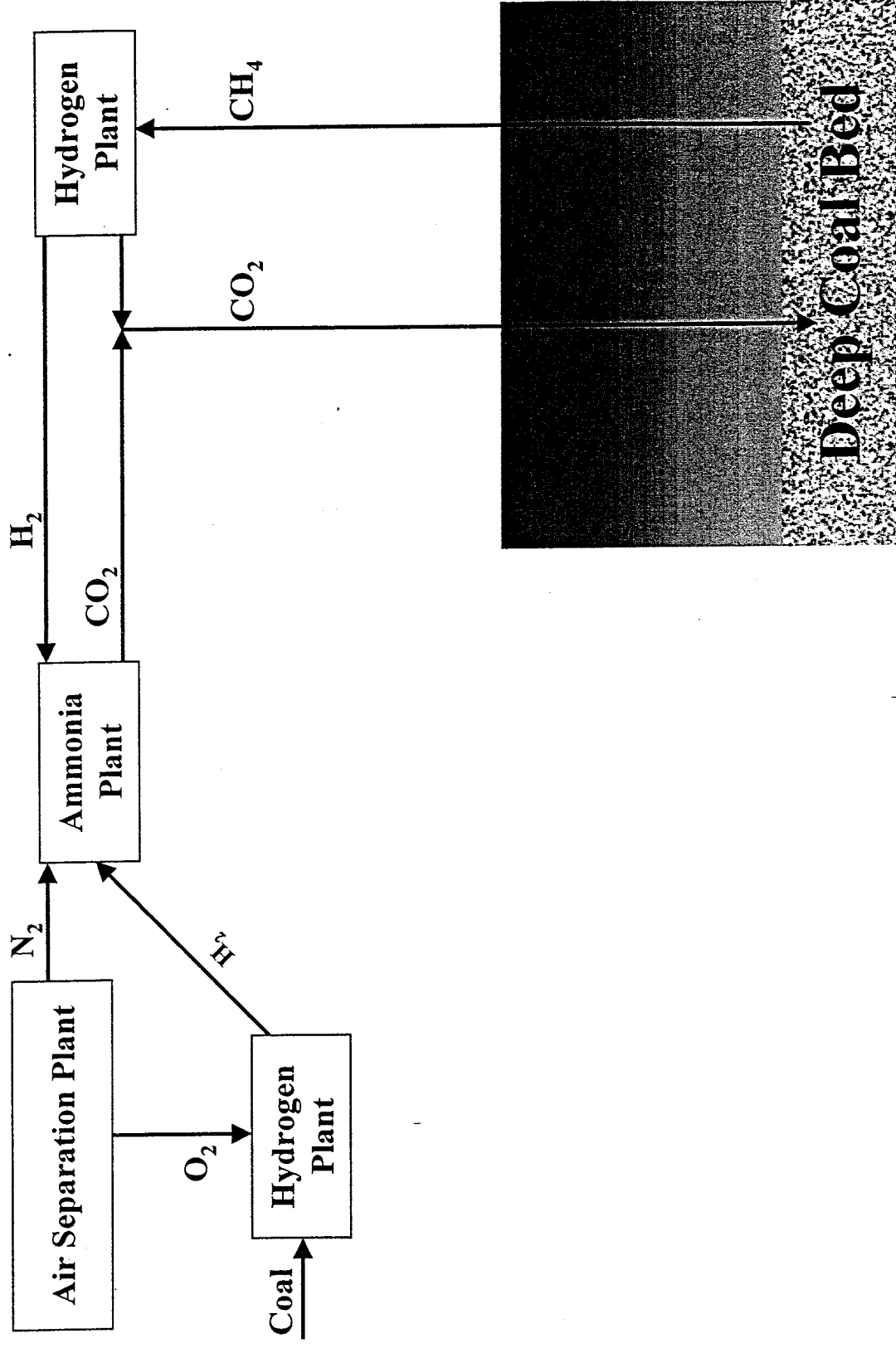
Source: Rice *et al.* (1993).

Figure 4: Schematic for the Production of H$_2$ from CBM and Coal for Ammonia Manufacture, Using all the CO$_2$ Separated at the H$_2$ Production Plants to Recover CBM, with Sequestration of the Injected CO$_2$ in the Coal Bed (*Case Ia in Table 3*)
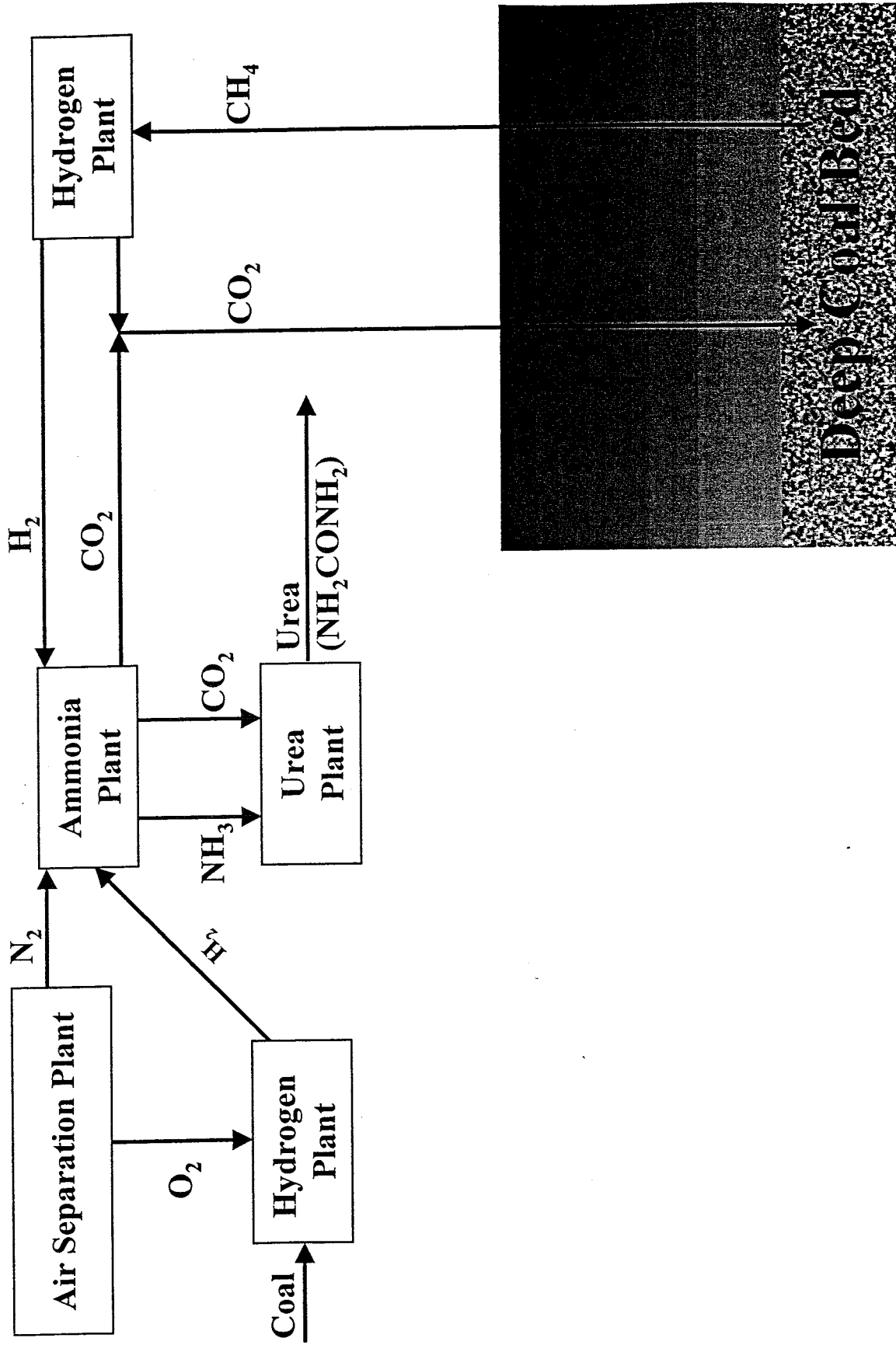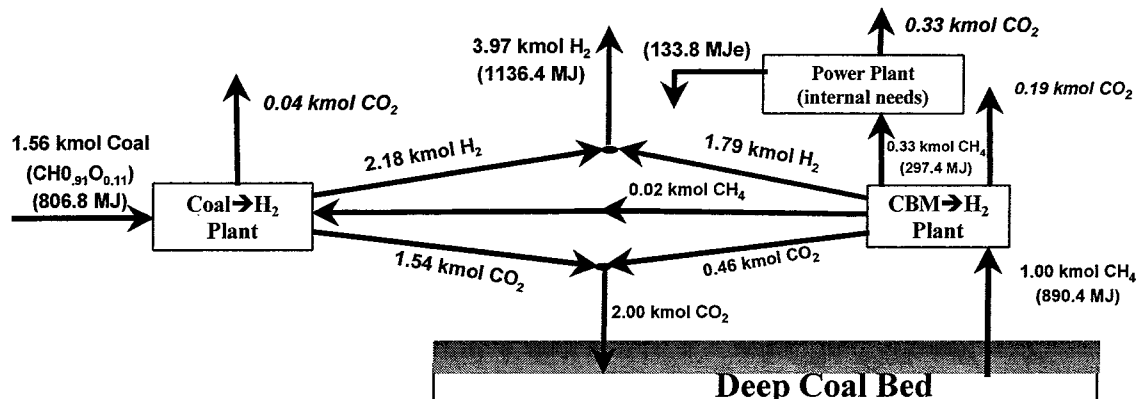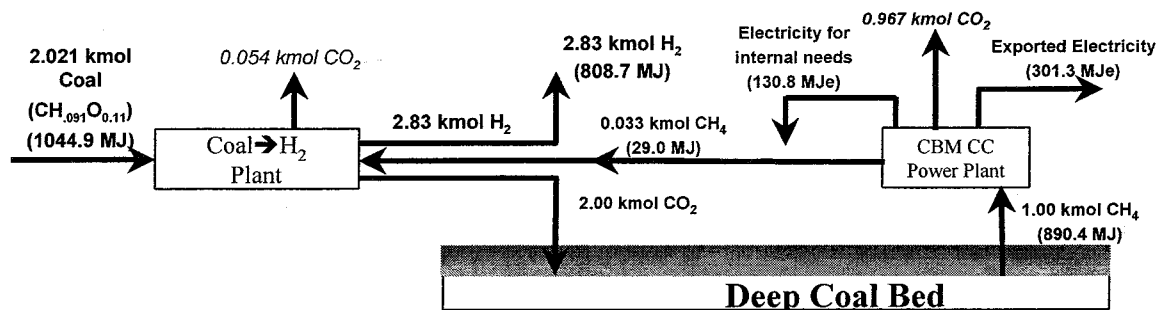
Figure 5: Schematic for the Production of H$_2$ from CBM and Coal for the Manufacture of Ammonia and Urea, Using Byproduct CO$_2$ Separated at the H$_2$ Production Plants in Excess of that Needed for Urea Manufacture to Recover CBM, with Sequestration of the Injected CO$_2$ in the Coal Bed (*Case Ib in Table 3*)

Figure 6 diagram:

1.56 kmol Coal
($CHO_{91}O_{0.11}$)
(806.8 MJ)

Coal→H_2 Plant

0.04 kmol CO_2

3.97 kmol H_2
(1136.4 MJ)

(133.8 MJe)

0.33 kmol CO_2

Power Plant (internal needs)

0.19 kmol CO_2

2.18 kmol H_2

1.79 kmol H_2

0.02 kmol CH_4

0.33 kmol CH_4
(297.4 MJ)

CBM→H_2 Plant

1.54 kmol CO_2

0.46 kmol CO_2

1.00 kmol CH_4
(890.4 MJ)

2.00 kmol CO_2

Deep Coal Bed

Figure 6: **Material and Energy Balances for H_2 Production from Coal and Coal Bed Methane (CBM), Using All the CO_2 Separated at the H_2 Production Plant to Recover CBM, with Sequestration of the Injected CO_2 in the Coal Bed**

For H_2 compressed to 300 bar (as required for NH_3 manufacture). These balances (per kmol of CBM) are for Case Ia in Table 3. The ratio of H_2 from CBM to H_2 from coal is for a 2/1 molar ratio of injected CO_2 to recovered CBM. Some CBM is used to provide the electricity for making H_2 from coal and CBM and for CBM recovery, and to provide the external heat for manufacturing H_2 from coal.

Detailed material balances are indicated only for C (e.g., inputs of O_2 and H_2O are not shown).

Figure 7 diagram:

2.021 kmol Coal
($CH_{091}O_{0.11}$)
(1044.9 MJ)

Coal→H_2 Plant

0.054 kmol CO_2

2.83 kmol H_2
(808.7 MJ)

2.83 kmol H_2

Electricity for internal needs
(130.8 MJe)

0.967 kmol CO_2

Exported Electricity
(301.3 MJe)

0.033 kmol CH_4
(29.0 MJ)

CBM CC Power Plant

2.00 kmol CO_2

1.00 kmol CH_4
(890.4 MJ)

Deep Coal Bed

Figure 7: **Material and Energy Balances for H_2 Production from Coal plus Electricity Generation from CBM in a Combined Cycle Power Plant, Using the CO_2 Separated at the H_2 Production Plant to Recover CBM, with Sequestration of the Injected CO_2 in the Coal Bed**

For H_2 compressed to 300 bar (as required for NH_3 manufacture). These balances (per kmol of CBM) are for Case IIa in Table 6. The ratio of H_2 from coal to electricity from CBM is for a 2/1 molar ratio of injected CO_2 to recovered CBM. Some CBM is used to provide the electricity for making H_2 from coal and for CBM recovery, and to provide the external heat for manufacturing H_2 from coal; the rest is used to make electricity for export from the site.

Detailed material balances are indicated only for C (e.g., inputs of O_2 and H_2O are not shown).
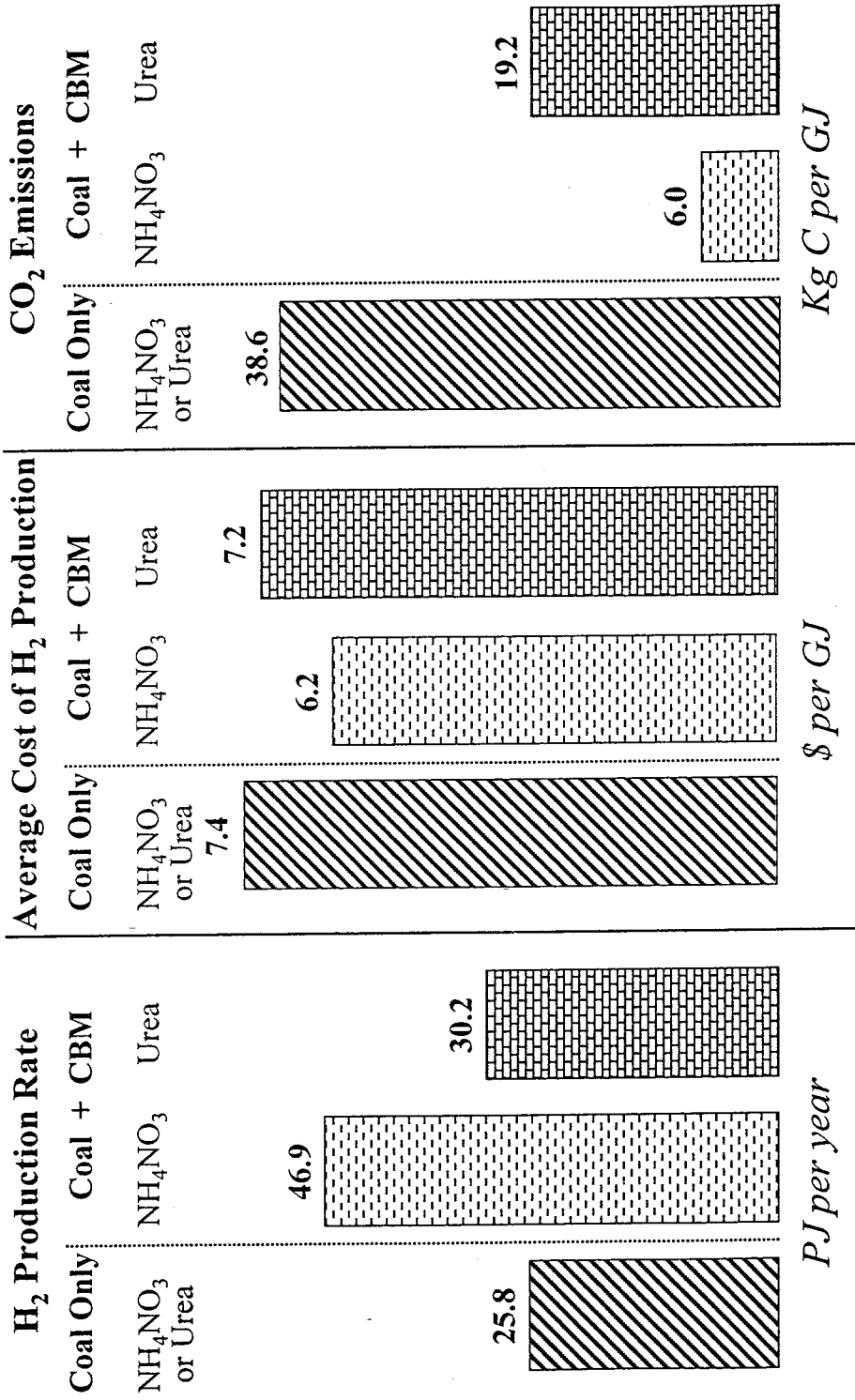
H₂ Production Rate

Coal Only	Coal + CBM
NH₄NO₃ or Urea	NH₄NO₃ Urea

25.8   46.9   30.2

PJ per year

Average Cost of H₂ Production

Coal Only	Coal + CBM
NH₄NO₃ or Urea	NH₄NO₃ Urea

7.4   6.2   7.2

$ per GJ

CO₂ Emissions

Coal Only	Coal + CBM
NH₄NO₃ or Urea	NH₄NO₃ Urea

38.6   6.0   19.2

Kg C per GJ

Figure 8: H₂ Production Levels, H₂ Production Costs, and CO₂ Emissions for Alternative Schemes to Produce H₂ from Coal Plus CBM for NH₃ Manufacture

This figure summarizes the results presented in Table 3.   The bars on the left in each set represent the Base Cases, the middle bars are for Case Ia, and the bars on the right are for Case Ib.