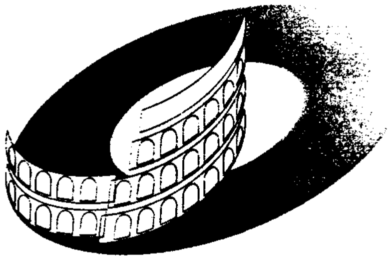

International Symposium

Towards Zero Emissions

The Challenge for Hydrocarbons

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International Symposium

Towards Zero Emissions

The Challenge for Hydrocarbons

The limited availability of natural resources, a still rapidly rising world population combined with overall economic growth will be stretching the Earth's carrying capacity beyond its limit, unless a suitable strategy is set in place. This scenario renders the concept of Zero Emissions all the more relevant, stressing as it does that the problem of environmental pollution cannot be effectively solved simply by reducing the production of wastes.

In practical terms Zero Emissions can be conceived along similar lines to already establish corporate programs aiming to achieve zero accidents. Although no one claims that accidents are never going to occur, unless a clear objective is established, systems will not evolve in that direction.

The target of Zero Emissions is therefore to move towards achieving the highest possible level of material productivity and energy efficiency.

Considering how the hydrocarbon industry could become ever more engaged in applying the concept of Zero Emissions, and what in practice this means, can therefore play an important role in defining an appropriate innovation policy, and promoting long term corporate competitiveness.

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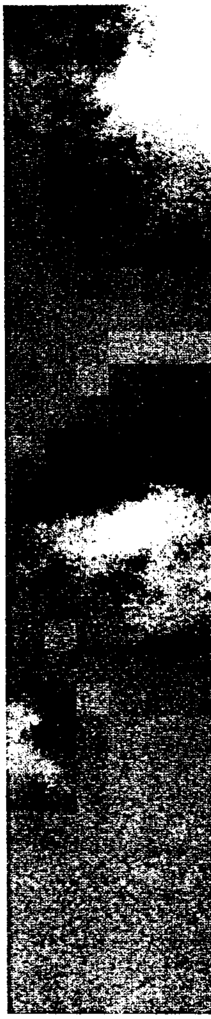

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THE FUTURE OF ZERO EMISSIONS

CLOSING SESSION

"TOWARD ZERO EMISSIONS FOR COAL: ROLES FOR INORGANIC MEMBRANES"

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There are good prospects that advanced inorganic membrane technologies will make it feasible to produce hydrogen (H_2) from coal, typically at a cost lower than the cost of making H_2 from any other feedstock. Such a development, considered together with: (i) growing concerns about air pollution and climate change, (ii) parallel technological developments relating to fuel cells for transportation, and (iii) the growing scientific confidence that opportunities for underground storage of carbon dioxide (CO_2) are vast, have profound implications for energy, environmental, and climate change policy worldwide. As will be argued here, these factors considered together provide a good basis for thinking that H_2 derived from abundant sources of coal could come to play major roles as an energy carrier for both transportation and stationary power generation with near-zero emissions of both air pollutants and greenhouse gases. This outlook indicates the importance of pursuing research and development activities aimed at bringing this advanced H_2 production and related systems technologies to market.

Advanced membrane technologies would probably make it possible to reduce substantially the capital cost of making H_2 from any carbonaceous feedstock and to transform the conversion process from one that requires substantial external electricity inputs into one that produces significant quantities of byproduct electricity. These improvements in conversion technology will tend to make feedstock costs more prominent in the overall H_2 production economics and to favor low-cost feedstocks such as coal.

This paper explores these issues. It begins by highlighting relative cost trends for coal and natural gas. It then turns to a discussion of air pollution and climate concerns as drivers in a quest for zero or near zero emission technologies for fossil energy conversion. This is followed by discussions of the prospects: (i) for achieving zero or near zero air pollution emissions in transportation using H_2 fuel cell vehicles, and (ii) for extending the zero or near zero emission technology quest to CO_2 emissions as well. The latter involves showing that the cost of disposal in geological reservoirs is modest for the CO_2 generated as a byproduct of H_2 production, and then discussing why scientists are beginning to believe that the potential for secure CO_2 sequestration in such reservoirs is vast. Then calculations are presented showing the potential for producing H_2 at low cost from coal using advanced ceramic membranes. And finally, it is pointed out that there are several alternative advanced inorganic membrane technologies offering reasonably good prospects for making H_2 at low cost that warrant intensive R&D aimed at their commercialization.

Trends in Coal and Natural Gas Prices.

Substantial productivity gains are being made in the coal industry, as illustrated for coal produced in both United States (see figure 1) and Australia (see figure 2). Such gains can be expected in other regions as well, after ongoing energy-sector market reforms are put into place around the world. The impact of such productivity gains on coal prices in relation to natural gas prices for electric generators in the United States is illustrated in figure 3, which shows that the average coal price has fallen in real terms by a factor of two since the early 1980s. Over the next two decades a 20% rise in the price of natural gas and a further 30% drop in the price of coal are expected (EIA, 1998a), leading to a price ratio that grows to 3 1/2 from 2 today. As will be shown, this feedstock price advantage for coal might make it feasible with advanced membrane technologies to produce H_2 from coal at a cost that is comparable to the natural gas price. This prospect together with considerations of the global abundance of coal resources compared to conventional oil and gas resources (IPCC, 1996) and of demand factors favoring the introduction of H_2 as an energy carrier, could change the outlook for coal, transforming it from its present status as a dirty energy source, the use of which countries evolve away from as they develop (most growth in the demand for coal at present is expected to be in China - see table 1), into an attractive option for providing abundant clean energy.

A Zero Emissions Imperative?

The risk of climate change is generally regarded as the most daunting challenge posed by burning fossil fuels and is leading to growing interest in advancing various zero or near-zero greenhouse gas-emitting energy technologies (PCAST Energy R&D Panel, 1997; PCAST ICERD[3] Panel, 1999). Recent scientific findings relating to the health impacts of air pollution suggest that health impacts of air pollution might also be serious enough to warrant a quest for zero or near-zero emissions technology for air pollutants as well.

The health impacts of uncontrolled pollution emissions from fuel burning in developing countries is probably the most pressing environmental problem the world faces today, and coal is responsible for much of these air pollution damages. Consider China. There coal, the dirtiest fossil fuel, is widely used and its use is expected to grow rapidly in the decades immediately ahead (see table 1), and effective pollution controls are not in wide use. A recent World Bank study (World Bank, 1997) assessing the costs of local/regional air pollution damages in China (mainly from coal) estimated total costs to be about $ 48 billion in 1995 (7% of GDP), including impacts of acid deposition as well as health effects from outdoor and indoor air pollution. The study found that the dominant cost was associated with the health impacts of air pollution on urban residents, some $ 32 billion in 1995 (5% of GDP). Moreover, the Bank projected that under "business-as-usual" conditions (with a 2.7-fold increase in coal consumption, 1995-2020) health damages to urban residents would increase to $ 98 billion by 2020, at current income levels, or $ 390 billion (13% of GDP) with adjustment for growth in income. (The estimated cost of health impacts increases with income because the World Bank estimated costs on the basis of the "willingness to pay" principle). If these costs were assigned to the fuels that cause the damage, the costs per GJ of fuel would tend to be greater than the market fuel prices. The health damage cost estimates are so high by 2020 that the value of carbon from fossil fuel consumption in China in 2020 (when CO_2 emissions from fossil fuel burning are expected to be 1.9 GtC, compared to 0.7 GtC in 1996) would have to be ~ $ 200/tC for climate change to be as important in strictly economic terms as the health impacts of air pollution on urban residents.

Estimated health damage costs for China are high in large part because of the relatively low levels of pollution control. However, even in countries with relatively high levels of pollution control, health damage costs can be high. Recent studies carried out for the ExternE Program of the European Commission aimed at quantifying the external social costs of pollution under typical European conditions found that these costs are dominated by health impacts and estimated that the costs of health impacts due to fine particle air pollution are especially high [Rabl and Dreicer (1999); Spadaro and Rabl (1998); Spadaro et al. (1998)]. In these studies both median estimates of costs and geometric standard deviations were developed. For aggregated morbidity and mortality, a geometric standard deviation of about 4 was found in these studies, so that the 68% confidence interval for costs is the range 1/4 to 4 times the median cost (Rabl and Spadaro, 1999). These economic calculations reflect recent epidemiological studies indicating that: (i) serious chronic health effects (especially life-shortening) are strongly correlated with fine particles ($PM_{2.5}$ particles, with diameters less than 2.5 microns) in the air which can penetrate deeply into the lungs, and (ii) the dose-response functions for health impacts are approximately linear, with no evidence of a threshold (Pope et al., 1995; Wilson and Spengler, 1996). Most fine particle air pollution is caused by fossil fuel burning - both direct emissions of fine particles and sulfate and nitrate particles formed in the atmosphere from gaseous emissions of SO_2 and NOx. The latter tend to dominate estimated health costs for power plants, while direct fine particle emissions tend to dominate health impacts of automobiles, especially in urban areas.

For coal power plants equipped with best-available pollution control technologies and various power plant sittings, the median estimate of the health impacts cost has been estimated to be comparable to or greater than the direct cost of electricity production (compare tables 2 and 3). Most of the high cost is associated with chronic life shortening from long-term exposure to fine particulates. Even though the life-shortening is typically only a few months, the exposed population is large (because fine particles can often be transported long distances from where they are emitted), and, in high-income countries, the "willingness to pay" to avoid such health damages is high. The economic significance of the estimated health impacts costs presented in table 2 can be appreciated by supposing that the economic cost of climate change is the same and deriving from this assumption the price of avoided CO_2 emissions that would bring about this equality. For the typical power plant siting case shown in table 2, the cost of avoided CO_2 emissions for typical new steam-electric plants would have to be about $ 200/tC to make climate change an issue of economic importance equal to that for air pollution emissions. Similarly, very high equivalent avoided CO_2 emissions costs are associated with the findings of these ExtrernE studies for automotive air pollution[1]. Of course, these cost estimates are specific to European conditions. In general, costs would vary with the size of the exposed populations (e.g., costs would be lower in regions with lower population densities); moreover, the "willingness to pay", and hence health cost levels, increase with per capita income levels.

The persistence of high estimated health impacts costs even for plants in Europe with substantial pollution controls in place arises because there appears to be no threshold below which the pollution levels are safe, and because reductions in emissions achieved via the use of pollution control equipment can be more than offset by the combined effects of the increased pollution

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[1] For gasoline internal combustion engine cars equipped with 3-way catalytic converters, the median estimate of the health impacts cost has been estimated to be ~ 60 ¢/liter of gasoline for urban Paris driving (average exposed population density ~ 7,500/km^2) and ~ 30 ¢/liter for inter-urban driving (Paris to Lyon trip, with average exposed population density ~ 400/km^2) (Spadaro and Rabl, 1998; Spadaro et al., 1998)—costs that are greater than retail gasoline prices (excluding retail taxes); in these cases, the value of CO_2 emissions avoided would have to be about $ 900/tC and $ 400/tC for urban and rural driving conditions, respectively, to make climate change an issue of equal economic importance to health impacts.

arising from increased energy consumption levels and an increased "willingness to pay" for avoiding pollution damages as incomes rise. As a result, the challenge of meeting air-quality goals by continually ratcheting up the required levels of end-of-pipe controls becomes very costly. This approach is costly in part because the cost of reducing emissions by the next increment, tends to increase sharply with the level of emissions reduction. In addition, the continual technological change required to keep up with changing regulatory goals can be very costly when there is not enough time between regulatory changes to recover the cost for the last incremental improvement before the next incremental improvement must be made. To illustrate the dimensions of the challenge of addressing air-quality goals as economies evolve, consider a simple model of a hypothetical "average" developing country that evolves from its "1990 state" in which per capita GDP is $ 2,300 (1990 $, PPP basis—the average for all developing countries in 1990) and there are no air pollutant emission controls in place, to a future state where per capita GDP is 7.2-fold higher, or $ 16,400, the average for OECD countries in 1990. (This could be realized in 100 years with a sustained per capita GDP growth rate of 2% per year). Suppose also that in this period per capita consumption of coal plus oil also increases 7.3-fold, from the actual average level in 1990 for developing countries to the 1990 level for OECD countries. And suppose, for simplicity, that without controls, pollutant emissions increase in proportion to coal plus oil consumption levels. Without pollution controls and taking into account an expected doubling of population in this period, health damage costs would increase about 100-fold (2 x 7.2 x 7.3) in this period (assuming, as economists do, that the "willingness to pay" to avoid pollution damages increases in proportion to per capita GDP). Thus end-of-pipe controls that reduce emissions by 100*(1 – 1/100) = 99% would be required to keep damage costs in dollar terms to a level no greater than in 1990.

The apparent linearity of the dose-response relationship for small particle air pollution and the practical difficulties of achieving high levels of pollution emissions control via the use of end-of-pipe control approaches and continual ratcheting up of levels of mandatory controls in the regulatory process highlight the importance of giving serious attention to the alternative of pursuing entirely new technologies that are characterized by zero or near-zero emissions.

Progress Toward Zero Air Pollutant Emissions in Transportation.

Recognizing the value of a zero emission vehicle (ZEV) technology-forcing policy as a strategy for meeting its air quality goals, the State of California has a policy mandating that 10% of all new cars sold in the State must be ZEVs by the year 2003. Initially, this policy focused on the battery-powered electric car as the zero-emission technology that would be deployed to meet this policy objective. Although efforts to develop this ZEV technology have led to some significant advances (e.g., in electric drive-train technology), the battery-powered electric car is no longer the central focus of ZEV developmental efforts, because the technological challenges of overcoming the problems of long battery recharging times, modest vehicle ranges between recharging, and high costs have proved to be formidable.

But the California ZEV mandate has been catalytic in stimulating industrial interest in the fuel cell car as an alternative technology that offers good prospects for addressing effectively all the shortcomings of the battery-powered ZEV and that might eventually become fully competitive with the gasoline-powered internal combustion engine car (Steinbugler and Williams, 1998).

The fuel cell-powered car has become one of the leading contenders for next-generation cars. Intensive efforts are underway in the automotive industry worldwide to develop fuel cell-powered automobiles; several automakers have set goals to introduce this technology into the automotive market in the period 2004-2010. The successful development and commercialization of the fuel cell car could eventually lead to its becoming a ZEV, because the fuel cell engine "prefers" to be fueled with H_2, and the only byproduct of operating a H_2 fuel cell car is water vapor.

With H_2 fueling, the fuel cost per km for a fuel cell car would typically be less than for a gasoline internal combustion engine car of comparable performance. Although the H_2 might be more costly per unit of energy than gasoline or Diesel fuel - even when using the least-costly commercial H_2 production technology (H_2 derived from natural gas) - the fuel cost per km would typically be less for the fuel cell car, because the H_2 fuel cell car would be 2.5 to 3 times more fuel efficient than a conventional gasoline internal combustion engine car of comparable performance. This efficiency gain arises because, while the efficiency of a internal combustion engine declines with decreasing load [so that the efficiency of driving a car, averaged over all driving conditions, is modest (~ 15%)], the efficiency of a fuel cell increases as the load decreases [so that the efficiency at average part-load conditions is high (~ 50%)].

Because a H_2 fuel infrastructure is not in place and because a new liquid fuel such as methanol can be introduced more easily than a gaseous fuel such as H_2, the fuel cell car may well be introduced using methanol or a liquid hydrocarbon fuel that is converted onboard the car into a H_2-rich gaseous fuel the fuel cell can utilize. However, ultimately, if fuel cell cars are successfully launched in the market, an internal market dynamic would assist a shift to H_2 fueling, because H_2 fuel cell cars will be easier to maintain and less costly to own and operate than liquid-fueled fuel cell cars that require the use of onboard fuel processors (Steinbugler and Williams, 1998).

The strongest competitor for the fuel cell car is likely to be a hybrid internal combustion engine/battery car, which is also capable of high fuel economy, and which, like a fuel cell car, would have an electric drive train. It is too early in the development process to predict the winner in this competition on the basis of estimated direct economic costs for mass-produced vehicles. However, if relative pollutant emission characteristics prove to be a major determinant, the H_2 fuel cell car, a true zero-emission vehicle, could emerge the winner[2], thereby providing the technological basis for wide use of H_2 in the transport sector.

Toward Zero CO_2 Emissions from the Transport Sector.

If the fuel cell car were successfully launched in the market, it would make possible not only near-zero emissions of air pollutants, but also, at relatively low incremental cost, near-zero lifecycle emissions of CO_2 emissions from the H_2 production system.

This prospect arises from the fact that when H_2 is produced from a carbonaceous feedstock a stream of nearly pure CO_2 can be produced as a byproduct-virtually "free". In a world where climate change is not a significant concern this CO_2 would probably be vented to the

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[2] Health costs of air pollutants from hybrids might be significant even with stringent controls. Consider the compression-ignition, direct-injection internal combustion engine/electric hybrid vehicle—the leading competitor to the fuel cell vehicle in the race to develop the "car of the future" under the Partnership for a New Generation of Vehicles (PNGV), a US government/industry-sponsored competition to develop 80 mpg (34 km/liter) cars by 2004 (NRC, 1998). Suppose such hybrid vehicles are developed and can meet the most stringent emissions requirements in the US—the Super-Ultra-Low-Emission Vehicle (SULEV) standard for a rising fraction of vehicles sold in California after 2003. Considering only NOx and PM_{10} SULEV standards (0.012 and 0.006 gr/km, respectively), assuming that 86% of PM_{10} emissions are from $PM_{2.5}$ particles, and valuing health impacts for NOx and $PM_{2.5}$ emissions following Spadaro and Rabl (1998), the median estimate of the health cost would be 1.5 ¢/km (50 ¢/liter of Diesel fuel) for urban driving and 0.13 ¢/km (4.5 ¢/liter) for rural driving; the corresponding value of CO_2 emissions avoided would have to be about $ 700/tC and $ 60/tC, to make climate change an issue of equal economic importance to health impacts, for urban and rural driving conditions, respectively.

mosphere. But in a CO_2-emissions-constrained world, consideration might be given to questering this separated CO_2 (e.g., in an appropriate geological storage reservoir).

the fuel cell car powered by H_2 produced from a fossil fuel with venting of the byproduct CO_2 ere to become the least-costly means of providing automotive services (e.g., if the H_2 fuel cell car nder these conditions were fully competitive with gasoline internal combustion engine cars on lifecycle cost as well as on a fuel cost per km basis), the cost of avoiding CO_2 emissions to the tmosphere would approach the cost of CO_2 disposal, when costs are measured on a $/tC basis. nitially, H_2 is likely to be introduced as an energy carrier for transportation by producing it from atural gas at refueling stations for fuel cell vehicles (Ogden et al., 1998). For such configurations he cost of CO_2 disposal would be prohibitively large, because the costs for the small pipes that would be required for transporting CO_2 from refueling stations to disposal sites would be very high. However, as a H_2 infrastructure grows, it would become feasible over time to expand H_2 production o centralized facilities from which H_2 would be transported by pipelines to refueling stations.

One way that a shift to centralized H_2 production for fuel cell vehicles might take place is in conjunction with the introduction of H_2 manufacture for central-station power generation. A strategy for producing H_2 from coal for use in large (~ 800 MWe) central-station power plants is described below (see Applications of the Ceramic HSD to Central-Station Power Generation). These power plants might be appropriate sites for producing the extra H_2 needed for supporting fuel cell cars that are used in the vicinity. Assuming that the number of cars supported by a power plant is determined by the average ratio of driving to electricity generation in the United States (1.0 km per kWh), enough extra H_2 would be produced at each 800 MW_e power plant to support about 340,000 cars in its vicinity - a number that would require increasing H_2 production about 12% beyond what is required to meet the H_2 needs for the power station[3].

When H_2 is manufactured from coal at such large scales, the byproduct CO_2 is generated at such a high rate (~ 800 tonnes per hour) that CO_2 disposal costs become relatively modest, as is illustrated by the calculation presented in Table 4[4]. There costs are presented for compressing the CO_2 byproduct of H_2 production from near atmospheric pressure to a supercritical state at 110 bar, for transporting the CO_2 by pipeline up to 500 km to a disposal site, and for injecting the CO_2 into a deep saline aquifer where it is sequestered. The cost of disposing of CO_2 in aquifers 500 km from the CO_2 generation site might turn out to be a reasonable estimate of a ceiling cost for CO_2 disposal, at least for the United States, because all thermal power plants in the United States are within 500 km of a geological disposal site (US DOE, 1999)[5], and because

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[3] The H_2 production level needed to support 340,000 fuel cell cars at each 800 MW power plant is about 5 PJ per year, assuming that fuel cell cars are driven 18,000 km per year (the average amount of driving for light-duty vehicles in the United States) and consume H_2 at a rate of 2.22 liters of gasoline-equivalent fuel per 100 km (106 miles per gallon of gasoline-equivalent fuel)—an estimated fuel consumption rate for H_2 fuel cell cars that is consistent with the load characteristics and performance requirements of cars being developed in the United States under the Partnership for a New Generation of Vehicles (Ogden et al., 1998). For comparison, the annual H_2 requirements for fueling an 800 MW_e power plant would be 40 PJ/year (see table 7).

Consider the following "thought experiment" illustrating the potential role in U.S. transportation for coal-derived H_2 produced in conjunction with the manufacture of H_2 from coal for central-station power applications. Imagine that at 1996 activity levels, all coal-fired power plants in the United States were converted to H_2, that extra H_2 was produced at these power plants to support fuel cell cars at a rate of 1 km per kWh, and that the CO_2 generated as a byproduct of producing H_2 from coal was sequestered. Under these conditions, about half of the US fleet of light-duty vehicles would have been supported with coal-derived H_2, US CO_2 emissions would have been 40% less, US oil use would have been 20% less, and US coal use would have been 7.5% more.

[4] The calculations presented in table 4 are for a CO_2 removal rate of 706 tonnes/hour, a value appropriate for a H_2 production facility providing fuel for a 800 MW combined cycle power plant that uses a Frame 7H gas turbine (see table 7). If enough extra H_2 were also produced at the facility to support a fleet of 340,000 fuel cell cars, the CO_2 removal rate would be increased to about 800 tonnes per hour, and the costs of CO_2 disposal would be 3-4% less per ton of CO_2 than indicated in table 4, as a result of scale economies for CO_2 pipeline transport.

[5] Of course, not every reservoir will be suitable for disposal of large quantities of CO_2, so that transport distances longer than 500 km might ultimately be needed for some H_2 production plants. However, the incremental cost for transport to a more remote but more favorable disposal site would be modest, because of the scale economies achievable with large pipes. For example, if transport beyond 500 km were via pipes that combine the output of 10 H_2 production plants each generating about 5 Mt CO_2 per year, the incremental cost per 100 km would be $ 3.1 per tC for onshore piping or $ 2.3 per tC for offshore piping (see table 4).

deep aquifer disposal will tend to be the most costly option for disposal. [Unlike the alternative geological disposal options (depleted oil or gas fields or deep beds of unmixable coal), disposal in deep saline aquifers does not provide the opportunity for enhanced oil or natural gas recovery to help defray CO_2 disposal costs.] The calculation presented in table 4 for disposal at 500 km thus suggests that the ceiling cost for CO_2 disposal might well be about $ 50 per tC. If the H_2 produced without CO_2 sequestration could competitively support a fleet of fuel cell cars, a carbon tax of this magnitude would induce the H_2 producer to sequester the separated CO_2. Such a carbon tax would increase the gasoline price faced by competing gasoline internal combustion engine cars by about $ 0.03 per liter.

This calculation suggests that fuel cell cars could be operated on fossil fuel-derived H_2 with near zero air pollutant and greenhouse gas emissions, with only a modest cost penalty for eliminating greenhouse gas emissions. The calculation is for the case where H_2 fuel cell cars (without CO_2 sequestration) are fully competitive with gasoline internal combustion engine cars. At present, fuel cell cars are not competitive, so that the cost of CO_2 emissions avoided by shifting to fuel cell cars would be far greater than the CO_2 disposal cost. Bringing the avoided CO_2 emissions cost down to the CO_2 disposal cost level requires launching fuel cell technology in automotive markets in a sufficiently large number of cars that the technology's cost can be "bought down" to levels where fuel cell cars can compete with gasoline internal combustion engine cars[6]. Also, of course, geological storage capacities must be adequate to make such a strategy for reducing greenhouse gas emissions viable at large scale.

The Outlook for CO_2 Disposal.

Although the deep ocean is the most-discussed option for CO_2 disposal (Herzog et al., 1997), 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 natural gas recovery), in deep coal beds [in conjunction with coal bed methane (CBM) recovery], and in deep saline aquifers.

In the near term, CO_2 injection for enhanced oil recovery (Blunt et al., 1993), for natural gas recovery (Blok et al., 1997), and for enhanced methane recovery from deep coal beds (Byrer and Guthrie, 1998; Gunter et al., 1997; Stevens et al., 1999; Williams, 1999) might become foci of initial efforts to sequester CO_2 in profitable ways.

Sequestration in depleted 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). One estimate of the prospective global sequestering capacity of such 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 100 GtC for oil fields and 400 GtC for natural gas fields (Hendriks, 1994); other estimates of the oil and gas field sequestering capacity

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[6] For a technology amenable to the economies of mass production, costs tend to decline as a function of cumulative production as the technology moves along its learning curve—typically at a cost reduction rate in the range 10 to 30% for each cumulative doubling of production. The level to which costs can ultimately fall is limited by materials costs. For fuel cells, the only inherently very costly material is the noble metal catalyst required to drive the reactions at the electrodes. Recent technological advances have led to reductions in the catalyst loading for the proton exchange membrane (PEM) fuel cells being targeted for automotive applications to levels where catalyst costs will not prevent fuel cell costs from falling to levels where fuel cells can ultimately compete in automotive applications.

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 wide range of estimates of potential storage capacity in depleted oil and gas fields 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. Much of the prospective sequestering capacity will not be available until these fields are nearly depleted of oil and gas.

Deep 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), which typically requires storage at depths greater than about 800 m. 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 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. 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 (Holloway, 1996; Socolow, 1997; PCAST Energy R&D Panel, 1997).

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).

More research, field testing, monitoring, and modeling are needed to narrow the considerable range of uncertainty regarding the regional and global capacities for secure CO_2 storage in alternative geological reservoirs.

The Challenge of Making Hydrogen for Central-Station Power Generation.

Although current H_2 production technology might be adequate to enable H_2 to compete eventually in fuel cell vehicle markets, new H_2 production technology is needed to enable H_2 to become an option for baseload central-station power generation with low avoided CO_2 emissions costs. In contrast to the situation with cars, which operate, under average conditions, at a small fraction of peak engine output and thus at low efficiency for internal combustion engines, baseload stationary power plants typically operate near their rated output. Thus, for baseload stationary power applications the market does not put such a high value on H_2 as it does in automotive markets, where use of the fuel cell leads to a large efficiency gain relative to the internal combustion engine.

A review of conventional H_2 production technology is useful background for understanding the potential for advanced H_2 production technology based on the use of inorganic membranes. The technology for producing H_2 is well established if not mature. Although H_2 is not currently a widely distributed energy carrier, it is routinely produced for applications in the chemical and petroleum refining industries.

The dominant commercial H_2 production technology is via steam reforming of natural gas. Hydrogen can also be made via gasification of any carbonaceous feedstock (Williams et al., 1995a; 1995b), including coal, heavy oils, biomass, or municipal solid waste (Larson et al., 1996), or via electrolysis of water using renewable (e.g., hydro, wind or solar) or other power sources. Until fossil fuel prices are much higher than at present, electrolytic approaches for producing H_2 using renewable electricity sources will be much more costly than making H_2 from natural gas, even when the added costs of CO_2 sequestration are taken into account (Williams, 1998).

The process of making H_2 from natural gas begins with steam reforming of the natural gas to produce synthesis gas [a gaseous mixture consisting mainly of carbon monoxide (CO) and H_2] at a relatively high temperature (~ 900 °C). Assuming natural gas is methane (the main component), the highly endothermic steam reforming process can be represented as:

$$CH_4 + H_2O_{(g)} \rightarrow CO + 3H_2, \qquad \Delta H = +\,206.2\ MJ/kmol. \qquad (1)$$

Reforming is followed by cooling the produced synthesis gas and reacting the contained CO with more steam ("water gas") to produce a H_2-rich gas:

$$CO + H_2O_{(g)} \rightarrow CO_2 + H_2, \qquad \Delta H = -\,41.2\ MJ/kmol. \qquad (2)$$

Because this "water-gas-shift reaction" is slightly exothermic, low temperatures are needed to drive the reaction strongly to the right. Typically the shift reaction is carried out in two stages: first in an adiabatic shift reactor (gases introduced at ~ 350 °C) and then in an isothermal shift reactor at a lower temperature (~ 230 °C). The heat released in the water-gas-shift reaction is almost exactly equal to the latent heat of water:

$$H_2O_{(l)} \rightarrow H_2O_{(g)}, \qquad \Delta H = +\,44.0\ MJ/kmol, \qquad (3)$$

so that the combination of the water-gas-shift reaction and this phase change is approximately autothermic, with little net change in the overall energy balance. Thus, in effect, the energy content of the original CO is "shifted" to H_2 - hence the reaction's name. The summary reaction for the production of H_2 from CH_4 is:

$$CH_4 + 2H_2O_{(g)} \rightarrow CO_2 + 4H_2. \qquad (4)$$

If pressure swing adsorption (PSA) technology is used to separate the H_2 from the gaseous mixture emerging from the shift reactors, H_2 can be provided at high purity. For the summary reaction, the theoretical value of ER, the ratio of the energy content (HHV basis) of the produced H_2 to the energy content of the original methane, is ER= 1.28. This theoretical energy ratio is greater than unity because heat absorbed in steam-reforming reaction is converted into chemical energy. If this heat were provided by burning some extra CH_4 the energy ratio would be less.

A more meaningful index of performance for the conversion process is the overall thermal efficiency η, the ratio of the H_2 energy output to the total fuel input (HHV basis), including the fuel consumed to provide external electricity requirements for the overall process. Taking into account the various parasitic energy requirements yields values of η that are less than ER[7] with commercially available technology. For an energy-efficient, heat-integrated plant design, ER = 0.90 and $\eta = 0.84$ can be achieved with commercially available technology for 99.999% pure H_2 provided at a pressure of 75 bar (Williams et al., 1995a; 1995b).

Hydrogen can be made from coal with commercial technology via a process that begins with oxygen-blown coal gasification. Assuming Illinois No. 6 coal (which can be represented approximately as $CH_{0.8}O_{0.08}$), the coal gasification process can be summarized as:

$$CH_{0.8}O_{0.08} + 0.46\ O_2 \rightarrow CO + 0.4\ H_2, \quad \Delta H = -92.9\ \text{MJ/kmol}, \tag{5}$$

followed by synthesis gas cooling, the water gas shift reaction, and H_2/CO_2 separation, as in the case of natural gas. The overall summary reaction for producing H_2 from coal can be represented as:

$$CH_{0.8}O_{0.08} + 0.46\ O_2 + H_2O_{(g)} \rightarrow CO_2 + 1.4\ H_2. \tag{6}$$

For the summary reaction, the theoretical ER = 0.82. In a practical system that provides 99.999% pure H_2 at 75 bar, ER = 0.77 and $\eta = 0.64$ (Williams et al., 1995a; 1995b).

Conventional H_2 conversion and separation technology is costly in large part because of the high capital costs for heat exchangers associated with the need to cool the synthesis gas to the low temperatures needed for driving the water-gas-shift reaction strongly to the right, and because of the need downstream of the water-gas-shift reactors for capital- and energy-intensive gaseous separation technologies such as pressure swing adsorption.

Advanced inorganic membrane technologies might make it possible to reduce significantly the cost of making H_2 from fossil fuels by substituting membrane reactors for the water-gas-shift reactors and the conventional technologies used to separate the H_2 from CO_2 and other trace gases.

Prospects for Advanced Ceramic Membranes in Hydrogen Manufacture.
A promising class of advanced inorganic membranes is porous ceramic membranes made from Al_2O_3 or another ceramic material that is permeable to the flow of small molecules like H_2 but inhibits the flow of CO_2 and other larger molecules. One version of such a membrane is under development at the Oak Ridge National Laboratory (ORNL), as a variant of a membrane that has long been utilized for uranium enrichment via gaseous diffusion.

The value of such membranes in separating H_2 from CO_2 and other gases has been recognized for a number years (Johnson and Schulman, 1993), but only recently has the technology been given attention as an advanced technology option for plants that would manufacture H_2 from fossil fuels (Parsons I&TG, 1998). Here the potential performance and economics of a H_2 separation device (HSD) that uses this membrane technology in the production of H_2 from coal are described for HSD applications in central-station power generation, based on a preliminary

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[7] The denominator in the energy ratio ER does not include the fuel required to provide the external electricity needed for the process.

assessment of the technology for making H_2 from coal by the Parsons Infrastructure and Technology Group (Parsons I&TG, 1998).

The process for making H_2 from coal using this new HSD, as described by Parsons I&TG (1998), is illustrated in figure 4. The process begins with oxygen-blown coal gasification to produce a hot, pressurized synthesis gas (1040 °C, 70 bar). Steam is added to the gas to provide the basis for the downstream water-gas-shift reaction and to cool moderately the gas, from which particulate matter in the fly ash is then removed in high-temperature-tolerant ceramic candle filters. The rest of the ash is recovered in the gasifier as slag, which falls into a water bath and is cooled and shattered to become an inert frit.

The filtered hot, pressurized gas (790 °C, 65.5 bar) is then delivered to the HSD, where H_2 is removed from the synthesis gas via the ceramic membrane. Hydrogen separation in the HSD is driven by a large H_2 partial pressure drop across the membrane. In Parsons I&TG (1998) it is argued that the ceramic membrane in a HSD would make it possible to drive the water-gas-shift reaction strongly to the right, even at high temperatures, while simultaneously separating the produced H_2 from CO_2 and other gases, because the membrane removes H_2 from the reactor as it is produced. The recovered H_2 primary product would be cooled and made available at 1.4 bar.

The gases exiting the HSD on the high-pressure side of the membrane contain 5% of the heating value of the original fuel gas in the forms of CO, H_2, and H_2S. This gas is burned catalytically in oxygen[8], water is injected into the combustor and evaporated, and the combustion product/steam mixture is expanded to 1.4 bar, producing byproduct electricity in a turbine expander/generator. About half of the produced electricity is needed for onsite needs; the remainder is available for export. The turbine exhaust gases are cooled, the water is condensed, recovered and recycled, and the SO_2 in the cooled gases is removed in wet limestone forced oxidation flue gas desulfurization (FGD) unit. After sulfur removal, the stream of relatively pure CO_2 at 1.4 bar is available for underground sequestration.

The performance characteristics and H_2 production cost for the system modeled by Parsons TG&I are summarized in table 5. Although ER = 0.75 for this system, a value slightly less than value with conventional technology, the thermal efficiency would be higher than for conventional technology, as a result of the byproduct power generation. Credit for byproduct power can be taken by defining an "effective efficiency" ηeff for producing H_2 from coal as the ratio of the energy content of the produced H_2 to the net coal input, with the net coal input defined as the gross coal input minus the coal consumption avoided by not having to generate the byproduct electricity in a stand-alone power plant. Assuming that this electricity would alternatively be produced at an efficiency $\eta = 0.355$, the efficiency of a modern coal steam-electric plant with flue gas desulfurization (see table 3), the effective efficiency for this technology would be ηeff = 0.914 (see table 5). This is not the appropriate value for making a comparison with the conventional technology presented in table 5, because in the Parsons I&TG design for the HSD involves providing H_2 at a pressure of 1.4 bar compared to 75 bar for the conventional technology. However, if a compressor is added to the Parsons TG&I design, the resulting ηeff = 0.816, which is still much higher than the corresponding ηeff = 0.635 for the conventional technology (see table 5).

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[8] Catalytic combustion is needed because of the low heating value of the gas (0.59 MJ/Nm^3—about 1.5% of the heating value of natural gas).

In the cost comparison shown in table 5 for the HSD and conventional H_2 production technologies, costs for the HSD system are presented in two ways: in parentheses costs are presented for the original Parsons I&TG plant design, which provides H_2 at 1.4 bar. The other set of values includes costs for H_2 compression to 75 bar to make the comparison with conventional technology meaningful. When costs are thus compared on the same basis, the cost per GJ of H_2 is less than 60% of the cost with conventional technology, in a plant that has less than half the output capacity (see table 5).

The ceramic membrane in the HSD is the core technology that makes possible the production of H_2 from coal at low cost. Inorganic membranes are generally more expensive than polymer membranes. For the system considered in table 5 the membrane is expected to cost ~ $ 1,000 per m^2. The total estimated HSD cost per unit area of membrane is much higher, ~ $ 6,000 per m^2 (Parsons I&TG, 1998)—quite a high cost for a material, on a $/$m^2$ basis.
But membrane cost per unit area is not a measure of performance; a useful performance measure is the cost relative to the rate of separating H_2. The Parsons I&TG design is for a HSD that is characterized by a "membrane coefficient" of 192 kW of H_2 per m^2, when the H_2 partial pressure drop across the membrane is from 27.5 to 1.4 bar. Thus the HSD cost relative to the H_2 recovery rate is low, some $ 30 per kW. Thus, despite its importance to the H_2 production process, the HSD contributes only modestly to the system cost. In the system modeled by Parsons I&TG, the HSD capital cost is only about 1/4 as large as the capital cost for the air separation unit (the single most costly item in the system) and is comparable to the capital cost of the flue gas desulfurization unit.

Applications of the Ceramic HSD to Central-Station Power Generation.

In what follows, the analysis of Parsons I&TG (1998) is extended to considerations of using the produced H_2 (at near atmospheric pressure) at the same site for electricity generation in a central-station power plant. Cost estimates for H_2 production for these applications, both without and with sequestration of the separated CO_2, are summarized in table 6 for a plant with an output that is 2.6 times the output of the plant originally designed by Parsons I&TG (see table 5), using the costs for CO_2 disposal developed in table 4.

One candidate technology for making electricity from the produced H_2 is a gas turbine/steam turbine combined cycle power plant. Hydrogen can be burned in combined-cycle power plants originally designed for natural gas use, with relatively modest modifications of the combustor - i.e., no technical breakthroughs are required (Foster Wheeler, 1998).

When the separated CO_2 is sequestered, a combined cycle plant fired with coal-derived H_2 would provide electricity with near-zero lifecycle CO_2 emissions. Emissions of SO_2 and particulates would also be virtually zero, but there would be NOx emissions from "thermal NOx" produced from nitrogen in the air when H_2 is burned at high temperature. However, thermal NOx emissions could be reduced to extremely low levels by injecting steam into the combustor to reduce peak flame temperatures. Steam injection has been used for NOx control with natural gas-fired gas turbines, but with natural gas this NOx emissions control strategy is constrained by the fact that emissions of another pollutant, carbon monoxide, increase rapidly as the ratio of steam-to-fuel injected into the combustor increases; because there is no such constraint for H_2, NOx emissions can be controlled this way to extremely low levels, making the H_2-fueled combined cycle a near-zero-emissions system for both CO_2 and air-pollutant emissions.

Two General Electric (GE) combined cycle systems are considered. One system consists of three 253 MW$_e$ units that use the commercially available Frame 7F gas turbine, for which the LHV efficiency = 55.8%; the other consists of two 400 MW$_e$ units based on the Frame 7H gas turbine for which the LHV efficiency = 60.0%. Estimated performance characteristics and electricity costs for these combined cycles fired with natural gas (NGCC units) and with coal [via coal integrated gasification combined cycle (CIGCC) units], assuming natural gas and coal prices projected for 2020, are presented in table 3.
The Frame 7H involves a higher turbine inlet temperature (1430 °C vs. 1300 °C), a higher pressure ratio (23 vs. 15), and steam cooling instead of air cooling of the gas turbine blades Frame 7H machines are expected to be commercially available for use in NGCC units by the year 2000 and for use in CIGCC units shortly thereafter (Todd and Stoll, 1997). It is assumed that: (i) with H_2 provided at a pressure that is 1.2 times the pressure of the gas turbine combustor the combined cycle efficiency will be the same as when operated on natural gas (LHV basis)[9], and (ii) the unit capital costs and O&M costs with H_2 operation (exclusive of the costs for H_2 compression) are the same as with natural gas operation.

Taking into account the power requirements for H_2 compression, the overall net efficiency of converting coal into electricity (HHV basis) with these combined cycle plants without CO_2 sequestration is in the range 40-42% (see table 7). The electricity requirements for CO_2 compression reduce the overall net electric generating efficiency with CO_2 sequestration to about 93% of its value without sequestration. But even with sequestration electricity generation would require about 10% less coal input per kWh in the Frame 7H case than for a new coal steam-electric plant equipped with flue gas desulfurization (compare tables 7 and 3).

Electricity generation costs for these systems are presented in table 7[10]. Even though the estimated cost of producing H_2 without CO_2 sequestration shown in table 6 is about 10% less than the natural gas price assumed for the systems described in table 3, the estimated cost of electricity generation is about 10% higher with H_2 than with natural gas for the Frame 7F combined cycle and about 15% higher for the Frame 7H[11], because of H_2 compression requirements.

The cost of CO_2 disposal for the case where the CO_2 disposal site is 500 km from the power plant (see table 4) adds about 1 cent per kWh to the electricity cost without CO_2 disposal (see table 7). The total cost penalty for shifting to this near-zero emissions technology is greater than this because the H_2-fired combined cycle without sequestration is not the least-costly option for providing electricity.

A shift to the near-zero emissions H_2 system could be induced by a tax on CO_2 emissions equal to the cost of CO_2 emissions avoided by shifting to the H_2 system. This avoided cost AC (in $ per tC) is given by:

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[9] The HHV of H_2 = 285.8 MJ/kmol. and the LHV = 0.846*HHV.

[10] Assuming coal prices equal to those assumed for conventional power generation systems in table 3.

[11] Although electricity generation from H_2 is less costly for the Frame 7H system than for the Frame 7F system, the cost is greater relative to natural gas for the Frame 7H system than for the Frame 7F system, because H_2 compression requirements are greater for the Frame 7H system with its higher pressure ratio.

$$AC = (C_{HCC} - C_{REF} - AQB_{HCC})/(E_{REF} - E_{HCC}), \qquad (7)$$

where:
C_{HCC} = cost of electricity for the least costly H_2 combined cycle with CO_2 sequestration (in \$/kWh);
C_{REF} = cost of electricity from the "reference" fossil fuel power plant—the least-costly fossil fuel option;
E_{REF} = CO_2 emissions from the reference power plant (in tonnes C per kWh);
E_{HCC} = CO_2 emissions from the H_2 combined cycle system with CO_2 sequestration;
AQB_{HCC} = air quality benefit associated with shifting from the reference to the zero-emission power plant.

In calculating the avoided cost, two questions are key: "What is the reference power system being displaced? And what air quality benefits are being credited to the zero emissions H_2 power system?"

By the time sequestration strategies are undertaken (assumed here to be ~ 2020), Frame 7H levels of gas turbine technology should be fully established in the market for natural gas, coal gasification, and H_2 applications. Thus, from table 3, an CIGCC plant based on the Frame 7H gas turbine is assumed for the reference power plant, and, from table 7, a H_2 combined cycle plant based on the Frame 7H gas turbine is assumed to be the least costly system for making electricity from coal-derived H_2.

Even though CIGCC technology can provide electricity with much lower air pollutant emissions than is feasible for pulverized coal steam-electric (PCSE) plants equipped with best available control technologies, the air quality benefits realized in shifting from CIGCC technology to H_2 combined cycle technology can still be significant, because the estimated health costs caused by small particles are so large, and the effects appear to be linear functions of the dose and thus emissions levels (Wilson and Spengler, 1996). Here it is assumed that the CIGCC air pollutant emissions are at levels that were proven in the Coolwater CIGCC demonstration facility in the 1980s (CWCGP and Radian Corp, 1990)[12]. Assuming the valuations of these emissions for typical power plant sittings in Europe presented in table 2, the economic value of avoiding these emissions is AQB_{HCC} = 0.62 ¢/ kWh—about 14% of the health cost of air pollution from a PCSE plant equipped with best available control technology (see table 2).

Thus:
C_{HCC} = \$ 0.0452/kWh (from table 7, for case where CO_2 is disposed of at a site 500 km from the power plant);
C_{REF} = \$ 0.0302/kWh (from table 3, for the Frame 7H-based CIGCC);
E_{REF} = 0.000201 tC/kWh (from table 3);
E_{HCC} = 0;
AQB_{HCC} = \$ 0.0062/kWh,

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[12] Emission rates of 27.1 grams of NOx and 4.0 grams of particulates per GJ of coal are assumed—levels that were proven at the Coolwater CIGCC demonstration project. For SO_2, it is assumed that 99% S recovery is achieved with the CIGCC, since the feasibility of 99% S recovery was also demonstrated at Coolwater. When such technology is used with typical bituminous coal containing 3.3% S from Illinois (EPRI, 1993) in the heart of the U.S. "coal power belt," the SO_2 emission rate would be 25.7 grams per GJ. If coal were burned in a Frame 7H-based CIGCC plant the emission rates per kWh of electricity produced would be 0.21 grams for SO_2, 0.22 grams for NOx, and 0.033 grams for PM_{10}. These emission rates are, respectively, 21%, 11%, and 17% of the SO_2, NOx, and PM_{10} emission rates for PCSE plants equipped with "best available control technologies" (see table 2).

so that the cost of avoiding CO_2 emissions is AC = \$ 44 per tC - which is essentially the same as the CO_2 disposal cost for this case (see table 4).

There are of course many uncertainties underlying this calculation. Especially important are the uncertainties regarding the H_2 production cost - since HSD technology is not a commercial product. Such technological uncertainties are discussed in the next section. In addition, there are uncertainties about the valuation of the air quality benefits offered by an electric generation technology having zero air pollutant emissions. (As noted earlier the 68% confidence interval for costs presented in table 2 is the range 1/4 to 4 times the median cost estimate, and costs can vary substantially with the conditions at the power plant site and its surrounding environment). But even in the extreme case where no credit is taken for the air quality benefits of the zero emissions technology, the cost of avoiding CO_2 emissions would be only \$ 75/tC - a cost that is far below the \$ 200/tC that global change modelists typically assume as the marginal cost for a "backstop" technology that is capable of making major contributions to energy supply with zero or very low emissions of CO_2 (Manne et al., 1995).

Uncertainties Relating to Ceramic Membranes and Alternative Options.
Various technical issues must be resolved before the HSD technology proposed by Parsons I&TG could become a commercial product.

One set of concerns relates to the ceramic candle filters used to clean the synthesis gas before the gas is delivered to the HSD. The reliability of such filters has not yet been proven for the high temperatures assumed in the Parsons TG&I plant design. Moreover, it is inevitable that some particles will escape capture by the membranes. Will such "fugitive" particles damage the HSD? Developers of the ORNL ceramic membrane claim that as long as the particles to not "slag" (i.e., melt), which is possible as they pass over the membrane[13], escaped particles can be periodically cleaned off the membranes; however, the membrane can be degraded if the particles slag and thereby stick to the ceramic membrane (private communication from Rod Judkins, December 1998). The slagging problem can be avoided by choosing coals that will not slag at the operating temperature of the HSD.

The system advanced by Parsons I&TG also requires that the membrane material have the tensile strength to withstand a high-pressure differential (~ 64 bar) across the membrane. If a high total pressure differential poses membrane structural integrity problems, steam might be injected on the H_2 recovery side to equalize total pressures on the two sides of the membrane, while maintaining the high partial pressure differential for H_2. Subsequently, the water could be separated out by condensation as a result of cooling the gaseous mixture.

Perhaps the most fundamental concern about the Parsons I&TG system design relates to water-gas-shift catalysis. In this design, it is assumed that the water-gas-shift reaction will be driven strongly to the right as the H_2 is removed via the membrane and that equilibrium will be quickly established. At sufficiently high temperatures, equilibrium will indeed be established quickly, but whether or not the proposed design operating temperatures are high enough must be verified by kinetic modeling and/or experiment.

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[13] Slagging is possible because the water-gas-shift reaction is exothermic, so that the gas temperature will increase as the gases pass over the membrane if the reactor is insulated—see figure 4.

If it should turn out that catalysis is needed at the proposed operating temperatures, alternatives to the Parson's design will be needed, because there are no commercially available "sour-gas-tolerant" (i.e., tolerant of H_2S) catalysts for the water-gas-shift reaction at these high temperatures. One possibility would be to remove the sulfur (mainly in the form of H_2S) from the synthesis gas before it is delivered to the HSD. But "hot gas" sulfur removal technology is at an embryonic development stage.

Another possibility for dealing with these challenges would be to cool the synthesis gas before it is delivered to the HSD to temperature levels where commercially available "sour-gas-tolerant" water-gas-shift catalysts can be used. Doing so would reduce system efficiency somewhat. However, modest efficiency losses should not result in large economic penalties. One of the effects of an efficiency penalty would be to increase coal costs. But the coal cost penalty would not be significant at the low coal prices assumed for this analysis[14]. The other main effect would be to increase the CO_2 sequestration penalty, because more CO_2 would have to be disposed of per kWh generated. But this penalty would also not be large because the cost of CO_2 disposal accounts for only about 1/5 of the electricity cost (see table 7)[15]. Moreover, operating the system at lower temperatures would make the overall system design less challenging technologically (e.g., gas cleanup would be less challenging) and might even lead to reduced capital or O&M costs for some system components that would help offset the coal cost and CO_2 sequestration penalties arising from operation at lower temperatures.

If technical concerns about the HSD can be resolved satisfactorily with further R&D, it should be feasible to scale up to manufacturing capability relatively quickly, since large-scale manufacturing technology is well established for inorganic ceramic membranes that have been used in gaseous diffusion-based uranium-enrichment technology. (The manufacturing technology for these membranes is currently classified because of this link to uranium enrichment technology, even though the H_2 permeable membranes could not be used for uranium enrichment purposes.)

But all would not be lost if these technological challenges prove to be too formidable to bring this ceramic membrane technology to market. Operation at lower temperatures than those for the Parsons I&TG design increases the technological choices for membranes that can simultaneously drive the water-gas-shift reaction to the right and separate H_2 from CO_2 and other gases.

One set of promising alternative technologies being rapidly developed is metallic membranes. As in the case of ceramic membranes, large reductions in the cost of making H_2 from coal are also expected to be feasible with metallic membranes (D.J. Edlund and M.H. Henry, 1995). Some of these metallic membranes are non-porous. For these, H_2 separation is achieved by exploiting the fact that atomic hydrogen (H) migrates through the metallic crystal lattice when a H_2 partial pressure differential is maintained across the membrane. These non-porous membranes can provide pure H_2. One interesting subgroup is composite

[14] For example, if the overall coal-to-electricity conversion efficiency were reduced to 90% of the 39.2% value for the Frame 7H case presented in table 7, the increased cost of coal would add 0.09 ¢ (less than a 2% increase) to the cost of generating a kWh.

[15] For example, if the overall coal-to-electricity conversion efficiency were reduced to 90% of the 39.2% value for the Frame 7H case presented in table 7, the CO_2 disposal rate for an 821 MW_e plant would increase from 706 to 784 tonnes per hour, but the cost of disposing of a ton of CO_2 would be reduced from $ 43.3 to $ 42.4 per tC (because of the scale economies in CO_2 pipeline transport). The net effect is that the cost for disposing of additional quantities of CO_2 increases the cost of generating a kWh of electricity by 0.08 ¢.

membranes that involve Group V-B body-centered cubic metal (e.g., vanadium) layers (which have high H_2 permeance) coated with thin layers of metals such as palladium[16] (Moss and Dye, 1996; 1997)[17]. A key concern for coal-based H_2 production systems is that that the metallic membranes not be degraded by exposure to H_2S, which will be a major contaminant of coal-derived synthesis gas[18].

Still another potentially important class of membranes for which development is more embryonic is non-porous ceramic membranes that conduct both hydrogen ions and electrons (Balachandran, Guan, and Dorris, 1998). As in the case of nonporous metal membranes, these membranes provide pure H_2.

For H_2 applications involving the proton exchange membrane (PEM) fuel cell (which is being developed for transportation and other H_2 fuel cell applications), the nonporous metallic and ceramic membranes that provide pure H_2 would be probably be preferable to porous ceramic membranes for H_2 production, because the PEM fuel cell is poisoned by carbon monoxide levels in the H_2 product at levels in excess of about 10 ppm.

Can Coal-Based H_2 Technologies Become Backstop Technologies for Climate Change Mitigation?

The near-zero CO_2 emitting energy system described here offers the potential of becoming a "backstop" technology for climate change mitigation purposes. Coal is abundant on a time scale of a few centuries and can be readily delivered to most locations on earth at relatively low costs. If large, open aquifers with good top seals prove to be secure CO_2 storage reservoirs, opportunities for geological storage would also be widely available for centuries. And if fuel cell vehicles and advanced membrane technologies for H_2 production can be successfully developed and deployed, the cost penalties for CO_2 emissions avoided are not likely to be prohibitive when the CO_2 produced as a byproduct of H_2 manufacture is sequestered in such aquifers. Moreover, if credit can be taken for the reduced adverse air pollution impacts of the conventional energy technologies that coal-derived H_2 systems would replace, the cost of avoided CO_2 emissions could approach the CO_2 disposal cost, which is modest.

Where Will the Needed Technological Innovation Take Place?

The cluster of technologies discussed in this paper that would make it possible to provide energy from coal with near-zero emissions at attractive costs would be applicable worldwide. But these technologies would be especially important for coal-rich developing countries such as China—because of rapid expected growth there in the use of coal in conventional power generating systems (see table 1) and the fact that once such systems are put in place they will "lock in" for many decades an "air-polluting capacity" that will be very environmentally damaging.

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[16] The purpose of the thin palladium coatings is both to prevent the formation of an oxide layer on the vanadium surface that inhibits H permeance and to catalyze dissociation of H_2 molecules into H atoms on the feed side and recombination of H atoms into H_2 molecules on the permeate side of the membrane.

[17] Metal costs for these membranes are not limiting. The cost of the metals for a composite metal membrane under development at Los Alamos National Laboratory (Moss and Dye, 1996; 1997) consisting of a 40 μ layer of vanadium coated by a 0.5 μ layer of palladium on each side would cost ~ \$ 200/m². But a typical permeance for such a membrane would be ~ 200 kW of H_2 throughput, so that the cost of metal per unit of H_2 throughput would be trivial (~ \$1/kW of H_2).

[18] Metal membranes made of palladium, nickel, and iron, as examples, undergo rapid irreversible chemical reaction with H_2S that results in a dramatic decrease in membrane permeability and/or physical destruction of the membrane. However, membranes do exist that are H_2S-tolerant. For one such membrane, an alloy made up of 60% palladium and 40% copper, no degradation in H_2 permeance was observed with 350 hours of exposure to H_2S at a level of 1000 ppm and a temperature of 500 °C, and no permanent poisoning by H_2S was found with up to 10% H_2S (D.J. Edlund and M.H. Henry, 1995).

n light of the needs for such environment- and climate-friendly fossil-energy technologies and the ong lead times inherent in the innovation process, there is an urgency to pursue the technological nnovation activities required to convert the technological vision described here into a commercial eality. Unfortunately, under business-as-usual conditions, the industrialized countries are poor heaters for innovation because the demand for coal power systems is stagnant there. In the United tates, for example, electric utilities are planning to add only 4.2 GW of new coal capacity, 1997-010, which corresponds to a capacity growth rate of only 0.10% per year (EIA, 1998a). Moreover, lthough most of the existing coal-generating capacity in the United States will reach the 'nominal" retirement age (~ 40 years) over the next couple of decades, most power companies are lanning to refurbish these old plants and try to extend their useful lives to 60 and even 70 years.

Vhile their rapid coal demand growth makes developing countries prospectively better heaters for innovation, much of the needed technology is under development in the industrialized countries. This situation underscores the need for international collaborative ctivities relating to research, development, demonstration, and deployment in this area involving companies that have the capability to bring these technologies into the marketplace (PCAST ICERD[3] Panel, 1999).

But it will be difficult to bring such technology to market in developing countries without substantial supporting markets in industrialized countries. This dilemma might be resolved if the public health problems caused by the present generation of coal power plants prove to be as large as indicated in table 2. If so, new regulations might be considered that would make it difficult for electric companies to extend the lives of old coal plants, or, alternatively, policymakers might offer new incentives that would make it more attractive to pursue a "scrap-and-build" strategy that would involve replacing old fossil fuel power plants with new clean technologies. Under a policy conducive to a scrap-and-build strategy, the coal-based energy system in industrialized countries might evolve from steam-electric power generation to one where H_2 is produced from coal at the same sites for both stationary power and transportation applications, shifting to H_2 production at the time of normal plant turnover. Such activity could facilitate a transition to coal-derived H_2 in the developing world.

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Table 1.
PROJECTION OF COAL USE AND CO_2 EMISSIONS FROM COAL[a]:

Region	1996			2020			Coal use growth rate (%/y)
	Coal use (EJ/y)	Coal CO_2 emissions (Gt C/y)	Coal emissions as % of global CO_2 emissions	Coal use (EJ/y)	Coal CO_2 emissions (Gt C/y)	Coal emissions as % of global CO_2 emissions	
U.S.	22.0	0.52	9	29.6	0.68	7	1.2
Other Industrial	16.4	0.40	7	12.6	0.35	4	- 1.1
EE/FSU	13.7	0.33	6	9.6	0.23	2	- 1.5
China	29.6	0.68	11	69.2	1.61	16	3.6
India	6.3	0.16	3	10.5	0.27	3	2.2
Other Developing	9.8	0.25	4	14.4	0.37	4	1.6
World	97.9	2.34	39	145.9	3.51	36	1.7

[a] Source: EIA (1999a).

Table 2.
AIR POLLUTANT EMISSIONS AND ESTIMATED HEALTH COSTS FOR POWER PLANTS IN EUROPE EQUIPPED WITH BEST AVAILABLE CONTROL TECHNOLOGIES.

Siting	Unit Health Cost (¢/gr)			Emission Rate (gr/kWh)				Unit Health Cost (¢/kWh)				
				PCSE with FGD			NGCC	PCSE with FGD				NGCC
	SO_2	NOx	PM_{10}	SO_2	NOx	PM_{10}	NOx	SO_2	NOx	PM_{10}	Total	NOx
Typical	1.0	1.6	1.7	1.0	2.0	0.2	0.1[b]	1.0	3.2	0.3	4.5	0.16
Urban	1.6	2.3	5.1	1.0	2.0	0.2	0.1[b]	1.6	4.6	0.5	6.7	0.23
Rural	0.7	1.1	0.5	1.0	2.0	0.2	0.1[b]	0.7	2.2	0.1	3.0	0.11

[a] From Rabl and Dreicer (1999). These calculations were carried out for both pulverized coal steam-electric (PCSE) plants with flue gas desulfurization (FGD) and natural gas combined cycle (NGCC) plants, as part of the European Commission's ExternE Program.

[b] This NOx emission rate, lower than the 0.7 gr/kWh assumed by Rabl and Dreicer (1999), is based on use of commercially available dry low-NOx premix combustion systems. For example, a NGCC using the General Electric (GE) Frame 7F gas turbine so equipped has a rated NOx emission rate of 9 ppmvd (@ 15% O_2) or 0.1 g/kWh.

Table 3.

ELECTRICITY GENERATION WITH ALTERNATIVE CONVENTIONAL FOSSIL FUEL POWER PLANTS[a].

	PCSE Plant with FGD	**CIGCC Plant**		**NGCC Plant**	
GE Gas Turbine Model	-	Frame 7F	Frame 7H	Frame 7F	Frame 7H
Installed Capacity (MW_e)	500	500	400	506	400
Installed Capital Cost ($/kW)	1090	1320	1091	468	445
HHV efficiency (%)	35.5	40.1	43.8	50.2	54.1
Fuel Price ($/GJ)	0.88	0.88	0.88	3.07	3.07
CO_2 Emission Rate (g C/kWh)	248	219	201	98	91
Electric Generation Cost (¢/kWh)					
Capital	1.79	2.17	1.79	0.77	0.73
Fuel	0.89	0.79	0.72	2.20	1.98
Fixed O&M	0.23	0.28	0.30	0.23	0.23
Variable O&M	0.20	0.20	0.21	0.15	0.15
Total	**3.11**	**3.44**	**3.02**	**3.35**	**3.09**

[a] Capital and O&M cost estimates and plant efficiencies are from Todd and Stoll (1997). Electricity costs are calculated assuming an 80% average capacity factor, a 10% discount rate, a 25-year plant life, an annual insurance rate of 0.5%, and neglecting corporate income taxes, so that the annual capital charge rate is 0.1152. Assumed fuel prices are averages projected for U.S. electric generators in 2020 (EIA, 1998a); assumed coal and natural gas carbon levels are 24.42 and 13.6 kgC/GJ, averages for U.S. electric generators in 1996. CIGCC = coal-integrated-gasification combined cycle.

Table 4.

COST OF CO_2 DISPOSAL IN REMOTE AQUIFER[a].

	\$ per ton of CO_2	**\$ per ton of C**
Electricity for Compressor[b]	0.80^*P_v	2.93^*P_v
Compressor[c]	0.71	2.59
Onshore Pipeline[d] for first 100 km	2.85	10.43
Onshore Pipeline[d], 100 to 250 km[e]	2.06	7.57
Pipeline[d] from 250 to 500 km[e]		
Onshore	2.13	7.80
Offshore	1.56	5.72
Wells for Aquifer Disposal[f]		
Onshore	0.45	1.65
Offshore	1.45	5.30
Total Disposal Cost		
Onshore if Disposal site at 250 km	$6.07 + 0.80^*P_v$ (9.54)[g]	$22.26 + 2.93^*P_v$ (35.0)[g]
Onshore if Disposal Site at 500 km	$8.20 + 0.80^*P_v$ (11.8)[g]	$30.07 + 2.93^*P_v$ (43.3)[g]
Offshore if Disposal Site at 500 km	$8.63 + 0.80^*P_v$ (12.3)[g]	$31.64 + 2.93^*P_v$ (45.0)[g]

[a] It is assumed that a relatively pure stream of CO_2 is available for disposal at 1.3 bar and a flow rate of 706 tonnes/h = 4.95 Mt CO_2/y for a single plant (see table 6) with an 80% capacity factor.

[b] The electricity required to compress CO_2 from 1.3 to 80 bar is 78.05 kWh/t; the extra electricity required to compress the CO_2 further to 110 bar is (30 bar)*(0.0567 kWh/bar) = 1.7 kWh/t (Blok et al., 1997); thus total required compressor work is 79.75 kWh/t. It is assumed that electricity costs P_v ¢/kWh.

[c] The compressor capacity CC (in MW) is CC = 0.0798*CRR, where CRR is the CO_2 recovery rate in tonnes of CO_2 per hour. Following Chiesa and Consonni (1999) the total installed cost for CO_2 compressors is assumed to increase from \$ 16.8 million [\$ 12 million (\$ 400/kW) for equipment plus 40% (12% for balance of plant, 18% for engineering and 10% for contingencies)] for 30 MW units to [(\$ 16.8 million)*$(CC/30)^{0.667}$] for other capacities. Thus, for a 10% discount rate, a 25-year plant life, a 0.5% insurance rate, an 80% capacity factor and O&M costs = 3% of the equipment cost/y, the leveled capital plus O&M costs for CO_2 compressors (in \$/t of CO_2) is $COMC = 6.28^*CRR^{-0.333}$.

[d] The cost of CO_2 pipeline transport (\$/t/km of CO_2 transported) is $CCPT = 0.0658^*(ADR)^{-0.5242}$ for onshore pipelines and $CCPT = 0.0476^*(ADR)^{-0.5207}$ for offshore pipelines, where ADR is the annual disposal rate in Mt/y (Holloway et al., 1996), assuming that 1 ECU = 1.25 \$, that the annual charge rate for capital, insurance, plus O&M is 0.1452, and that the annual average capacity factor is 80%.

[e] It is assumed that for the first 100 km the CO_2 transported is the output of a single plant; that for transport from 100 to 250 km, flows totaling 20 Mt/y from 4 plants are combined; that for transport from 250 to 750 km, flows totaling 50 Mt/y from 10 plants are combined.

[f] Assuming disposal in wells for which the injection rate is 2500 tonnes of CO_2 per day (104 t/h). For the total CO_2 disposal rate of 49.5 Mt CO_2/y or 7060 t CO_2/h, 68 wells are needed. Assuming for onshore disposal cost parameters for the Bunter Aquifer in Denmark: the capital cost per well (for initial studies, distribution system, injection wells, management and contingency) = 1.86 MECU = \$ 2.33 million; the annual O&M cost = 2.57% of the capital cost. Assuming for offshore disposal parameters for the Sherwood Sandstone Aquifer in the North Sea: capital cost per well = \$ 5.68 million; annual O&M cost = 7.00% of the capital cost (Holloway et al., 1996). For a 25-year plant life and an insurance cost of 0.5%/year the annual capital charge rate is 0.1152.

[g] The CO_2 disposal cost in parenthesis is for the case where $P_v = P_t$, the cost of generating electricity from coal-derived H_2 using a Frame 7H gas turbine—from table 7.

Table 5.

COMPARSION OF HSD-BASED AND CONVENTIONAL TECHNOLOGIES FOR PRODUCING H_2 FROM COAL[a].

	HSD-Based Technology[a]	Conventional Technology[b]
H_2 Production Capacity (GJ/h)	2187	4790
Net External Power Required (MW)	- 22.9 (- 51.00)	+ 133.33
Energy Ratio	0.751	0.774
Effective Conversion Efficiency[c]	0.816 (0.914)	0.635
H_2 production Cost (\$/GJ)		
Capitald (except H_2 compressor)	1.97[e]	4.01
Capital for H_2 compressor[f]	0.51 (0.00)	
O&M for the H_2 compressor[g]	0.08 (0.00)	
Coal Input[h]	1.17	1.14
External Electricity[i]	- 0.31 (- 0.70)	+ 0.84
Fixed O&M	0.69[j]	1.42
Variable O&M	0.21[j]	0.33
Total	**4.32 (3.14)**	**7.74**

[a] Performance and cost parameters presented here are for applications with venting of the separated CO_2. Costs are calculated assuming a 10% cost of capital and an 80% capacity factor for the plant. Here the output capacity and performance are for the HSD-based system described in Parsons I&TG (1998), except that it is assumed that a 28.1 MW compressor for compressing the H_2 from 1.4 to 75 bar (the pressure of the product gas assumed in the assessment of the conventional technology) is added to the system, so that net byproduct power is reduced from the 51.0 MW estimated in Parsons I&TG (1998) to 51.0 - 28.1 = 22.9 MW. The values given in parentheses in the HSD-based technology case are for a plant providing H_2 at 1.4 bar (i.e., a case with no H_2 compressor).

[b] The conventional technology is discussed in Williams et al. (1995a; 1995b), which is based on Katofsky (1993). The costs for conventional technology have been updated from 1991\$ to 1997\$, the dollar base year for the HSD technology case.

[c] In the calculation of effective efficiency ηeff it is assumed that the electricity exported or imported is produced from coal at an efficiency of 35.5% (the efficiency of a typical new coal steam-electric plant). Thus:

$\eta\ eff = 100*2187/[2187/0.751 - (0.0036\ GJ/kWh)*(22{,}900\ kW)/0.355] = 81.6\%$ with HSD-based technology, and
$\eta\ eff = 100*4790/[4790/0.774 + (0.0036\ GJ/kWh)*(133{,}330\ kW)/0.355] = 63.5\%$ with conventional technology.

[d] Installed capital costs are converted to annualized capital costs assuming an annual capital charge rate of 0.1152 (10% discount rate, 25-year plant life, 0.5%/year insurance rate, taxes neglected).

[e] The overnight construction cost estimated by Parsons I&TG (1998) is \$ 238.0 million. It is assumed that the construction time is 3 years and that payments of capital are made in three equal installments. Interest during construction increases the overnight construction cost by 10.33%, so that the total installed cost is \$ 262.6 million.

[f] The overnight construction cost for the H_2 compressor is \$ 42.1 million (assuming a unit cost of \$ 1300/kW), and the installed cost is \$ 46.5 million. Assuming a 10-year compressor life and an insurance charge of 0.5% per year, the annual capital charge rate is 0.1677 for the H_2 compressor.

[g] The annual O&M cost for the H_2 compressor is assumed to be 3% of the overnight construction cost for the compressor.

[h] For an assumed coal price of \$ 0.88 per GJ, the average price projected for electric generators in the United States in 2020 (EIA, 1998a).

[i] It is assumed that the price of electricity sold or purchased is \$ 0.03 per kWh.

[j] O&M costs as estimated by Parsons I&TG (1998).

Table 6.

PRODUCING H_2 FROM COAL AT LARGE SCALE, USING AN ADVANCED H_2 SEPARATION DEVICE, WITHOUT AND WITH SEQUESTRATION OF THE SEPARATED CO_2 IN A REMOTE DEEP SALINE AQUIFER[a].

H_2 Production Capacity (GJ/h)	5669
Byproduct Power Generation Rate (MW_e)	
Without CO_2 Sequestration	132
With CO_2 Sequestration	76
Energy Ratio	0.751
Effective Conversion Efficiency[b]	
Without CO_2 Sequestration	0.877
With CO_2 Sequestration	0.818
Byproduct CO_2 Generation Rate (tonnes/hour)	706
Cost by Component without CO_2 Sequestration ($/GJ)	
Capital Cost[c]	1.63
Coal Feedstock[d]	1.17
Fixed O&M Costs[e]	0.57
Variable O&M Costs[e]	0.21
Byproduct Credit for Electricity Sales[f]	$- 0.233 * P_v$
Total H_2 Production Cost without CO_2 Sequestration ($/GJ)	$3.58 - 0.233 * P_v$ (2.75)[h]
CO_2 Sequestration Costs[g] ($/GJ)	
Onshore disposal at site 250 km from H_2 plant	$0.76 + 0.099 * P_v$ (1.19)[h]
Onshore disposal at site 500 km from H_2 plant	$1.02 + 0.099 * P_v$ (1.47)[h]
Offshore disposal at site 500 km from H_2 plant	$1.07 + 0.099 * P_v$ (1.52)[h]
Total H_2 Production Cost with CO_2 Sequestration ($/GJ)	
Onshore disposal at site 250 km from H_2 plant	$4.34 - 0.134 * P_v$ (3.76)[h]
Onshore disposal at site 500 km from H_2 plant	$4.60 - 0.134 * P_v$ (3.99)[h]
Offshore disposal at site 500 km from H_2 plant	$4.65 - 0.134 * P_v$ (4.04)[h]

[a] Costs for producing H_2 (HHV basis) at atmospheric pressure without sequestration are based on Parsons I&TG (1998)—see table 5. Costs for sequestration are from table 4. The assumed H_2 production rate is the rate required to support two 400 MW combined cycle plants based on the GE Frame 7H gas turbine (see table 7).

[b] In calculating the effective conversion efficiency, it is assumed that the byproduct power would otherwise have been produced in a CIGG plant based on the Frame 7H gas turbine, for which the HHV efficiency is 43.8% (see table 3). The lower effective conversion efficiency with sequestration arises because in this case 56.3 MW is required to run the CO_2 compressor (assuming compression requirements of 79.75 kWh/ton of CO_2–see table 4).

[c] For an annual capital charge rate of 0.1152 (10% discount rate, 25-year plant life, 0.5%/year insurance rate, taxes neglected) and an 80% capacity factor. It is assumed that the "overnight construction cost" scales with the 0.8 power of the output capacity relative to the case considered by Parsons I&TG (see table 5). Interest during construction increases the required investment by 10.33% relative to the overnight construction cost, assuming a 3-year construction period and those plant payments are made in 3 equal installments.

[d] Assuming a coal price = $ 0.88/GJ [average projected price for U.S. electric generators in 2020 (EIA,1998a)].

[e] Assuming that the fixed O&M cost scales with H_2 production capacity in the same manner as the capital cost and that the variable O&M cost (in $/GJ) is scale independent—see table 5.

[f] It is assumed that the output of the CO_2 turbine expander in excess of H_2 production facility needs is sold at a price P_v (in cents per kWh) in competitive electricity markets.

[g] Costs for CO_2 disposal are from table 4.

[h] The H_2 production cost in parenthesis is for the case where $P_v = P_E$, the cost of generating electricity from coal-derived H_2 using a Frame 7H gas turbine—from table 7.

Table 7.

EFFICIENCY OF CONVERTING COAL INTO ELECTRICITY AND ELECTRICITY COST FOR COMBINED CYCLE POWER PLANTS[a] IN ALTERNATIVE CONFIGURATIONS, FUELED WITH H_2 DERIVED FROM COAL USING HSD TECHNOLOGY.

System Configuration	**With Frame 7F Gas Turbines and:**		**With Frame 7H Gas Turbines and:**	
	CO_2 Venting	**CO_2 Sequestration**	**CO_2 Venting**	**CO_2 Sequestration**
Generating Capacity (MW)	847	790	878	821
Overall Efficiency (%)	39.6	36.9	41.9	39.2
Generation Cost (¢/ kWh)				
Capital[b]	0.77[c]	0.77[c]	0.73[c]	0.73[c]
Fixed O&M	0.23	0.23	0.23	0.23
Variable O&M	0.15	0.15	0.15	0.15
H_2 at 1.4 bar[d]	0.36*(3.58 – 0.233*P_E)/0.472	0.36*(3.58 – 0.233*P_E)/0.472	0.36*(3.58 – 0.233*P_E)/0.508	0.36*(3.58 – 0.233*P_E)/0.508
CO_2 disposal @:				
250 km onshore	-	0.36*(0.76 + 0.099*P_E)/0.472	-	0.36*(0.76 + 0.099*P_E)/0.508
500 km onshore	-	0.36*(1.02 + 0.099*P_E)/0.472	-	0.36*(1.02 + 0.099*P_E)/0.508
500 km offshore	-	0.36*(1.07 + 0.099*P_E)/0.472	-	0.36*(1.07 + 0.099*P_E)/0.508
H_2 compression[e]				
Capital	0.21	0.21	0.23	0.23
O&M	0.03	0.03	0.04	0.04
Electricity	0.0616*P_E	0.0616*P_E	0.0683*P_E	0.0683*P_E
Total Generation Cost P_E	3.69	-	3.57	-
With disposal @:				
250 km onshore	-	4.52	-	4.34
500 km onshore	-	4.71	-	4.52
500 km offshore	-	4.75	-	4.55

[a] Capital and O&M cost estimates (except for H_2 compression costs) and LHV plant efficiencies are assumed to be the same as for NGCC plants offered by GE (see table 3). Two cases are considered: a plant consisting of three 253 MW units using a Frame 7F gas turbine (with a pressure ratio PR = 15); and a plant made up of two 400 MW units based on the Frame 7H gas turbine (with PR = 23)]—technology that is likely to be commercially available by 2000. Combined cycle cost and performance parameters are based on Todd and Stoll (1997).

[b] Assuming a 10% discount rate, a 25-year plant life, and an insurance rate of 0.5% per year, and neglecting corporate income taxes, the annual capital charge rate is 0.1152. The capacity factor is assumed to be 80%.

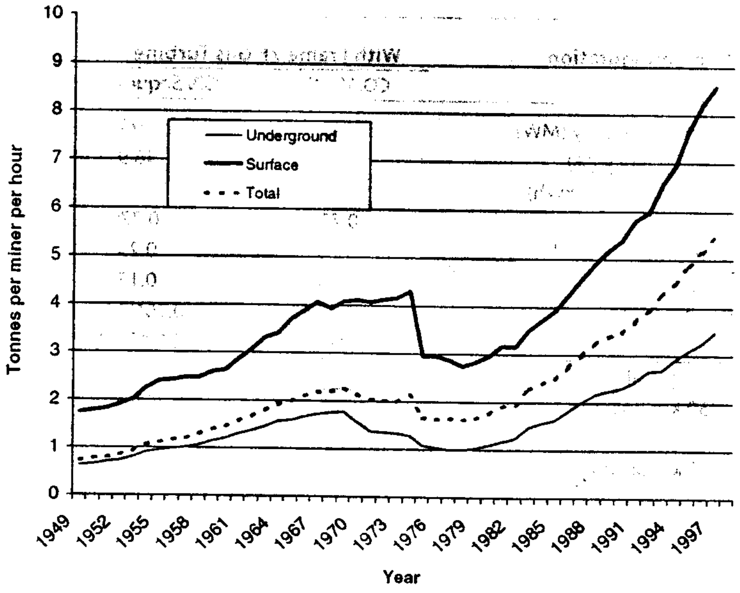
[c] For an installed capital cost of $ 468 ($ 445) per kW with Frame 7F (Frame 7H) gas turbines (see table 3).

[d] For HHV efficiencies of 47.2% (50.8%) for NGCCs with Frame 7F (Frame 7H) gas turbines; the LHV efficiencies are 55.8% and 60.0%, respectively. The cost of H_2 is from table 6, with $P_V = P_E$.

[e] It is assumed that the H_2 at 1.4 bar must be compressed to 1.2 times the gas turbine combustor pressure. The electricity required for H_2 compression (in kWh/GJ of H_2) is $E = 7.8*(N/n_c)*(T_1/T_0)*[(P_2/P_1)^{(0.291/N)} - 1]$, where N = number of compressor stages (assumed to be = 3), T_0 = reference temperature (298 °K), T_1 = temperature of the gas delivered to the compressor (311 °K), n_c = compressor efficiency (assumed to = 0.85). Thus, for the Frame 7F, E = 8.08 kWh/GJ and the required H_2 compressor capacity is (3*253,000 kW)*(0.0036/0.472)*(8.08 kWh/GJ) = 46,775 kW, while for the Frame 7H, E = 9.63 kWh/GJ and the required compressor capacity is (2*400,000 kW)*(0.0036/0.508)*(9.63 kWh/GJ) = 54,595 kW. It is assumed that the overnight construction cost for compressors is $ 1300 per kW, that interest during construction adds 10.33% to the overnight construction cost, and that compressors last 10 years. Thus for a 10% interest rate and an insurance charge of 0.5% per year, the annual capital charge rate for the H_2 compressors is 0.1677. The annual O&M cost for H_2 compressors is assumed to be 3% of the overnight construction cost.

Figure 1.

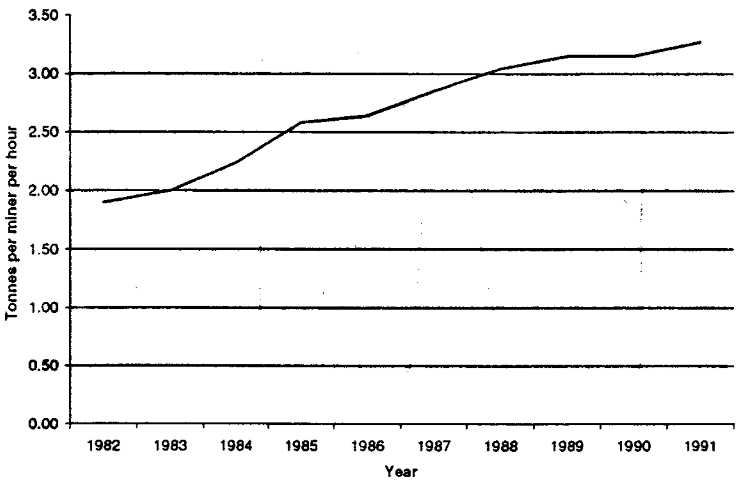
PRODUCTIVITY OF UNDERGROUND, SURFACE, AND ALL COAL MINING IN THE UNITED STATES.



Sources: EIA (1995); EIA (1998b). Except for the period 1970 to 1978, the productivity of coal mining has increased rapidly in the United States—e.g., at average rates of 7.1, 6.2, and 6.6 percent per year, respectively, for underground, surface, and all mines, in the period 1978-1997, as annual coal production increased from 604 to 990 million tonnes per year. Productivity gains were achieved in this period by shutting down smaller, less-efficient mines (the number of operating mines declined from 6600 to 1800 in this period) and by shifting to more efficient mining technologies (e.g., long-wall mining). During the period 1970 to 1978, productivity fell as mine operators adjusted to various new health and safety and environmental laws—notably the Coal Mine Health and Safety Act of 1969, the Clean Water Act of 1977 (which required mine operators to control acid mine drainage), and the Surface Mine Control and Reclamation Act of 1977, as well as many State surface mining and land reclamation laws.

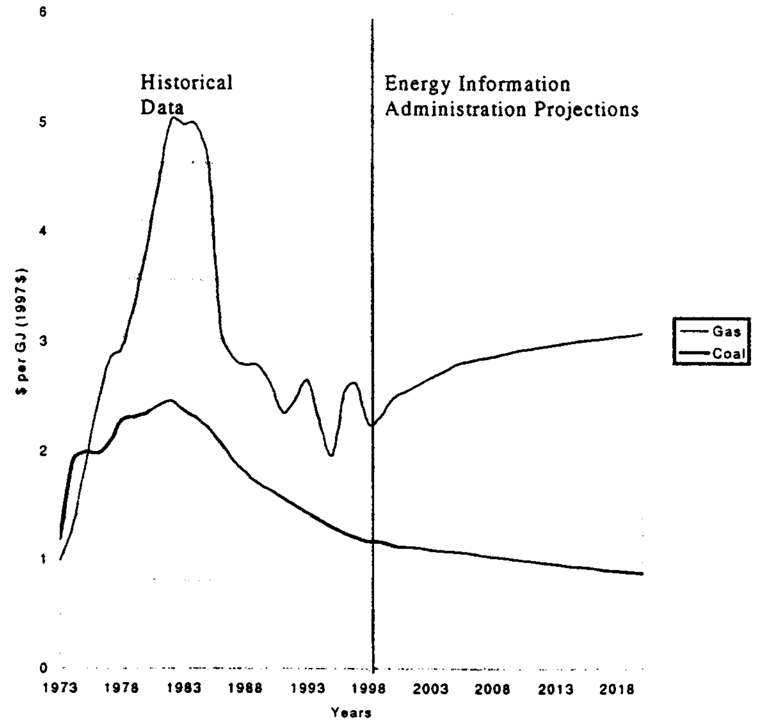
Figure 2.

PRODUCTIVITY OF COAL MINING FOR EXPORT MARKETS IN AUSTRALIA.



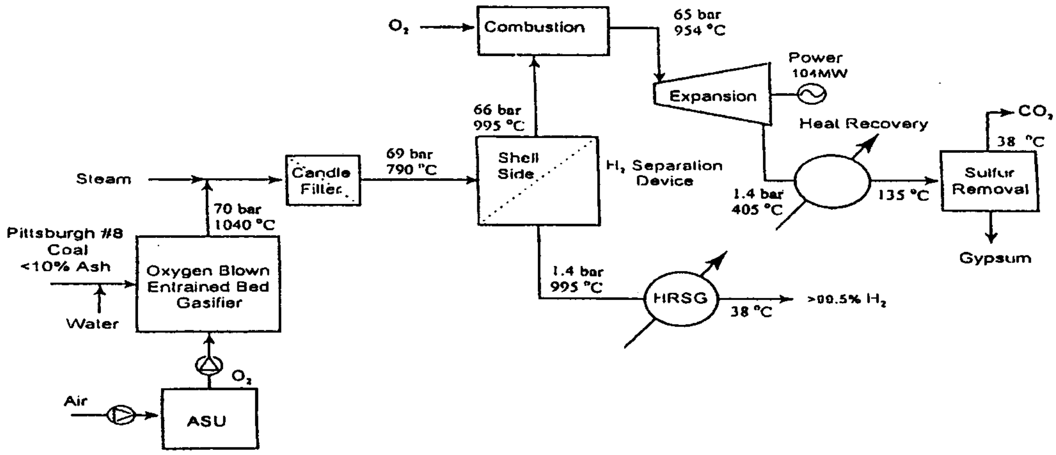
Source: Weatherburn (1994). During the period 1982 to 1991 the productivity of coal mining increased 6.2 percent per year in Australia.

Figure 3.
COAL AND NATURAL GAS PRICES FOR ELECTRIC GENERATORS IN THE UNITED STATES.



Historical prices are from EIA (1999b). Price projections are from EIA (1998a).

Figure 4.
BLOCK DIAGRAM FOR A PLANT THAT WOULD PRODUCE HYDROGEN FROM COAL.



This plant design, proposed by Parsons I&TG (1998), uses an oxygen-blown gasifier to produce synthesis gas from coal. Steam is mixed with the synthesis gas, which is cleaned of particulates using ceramic candle filters. The cleaned synthesis gas is then passed over a ceramic membrane that is permeable to hydrogen but relatively impermeable to other gases. Hydrogen is generated on the feed side of the membrane by reacting carbon monoxide with steam (water-gas-shift reaction). The water-gas-shift reaction is driven to the right as a result of the removal of hydrogen through the membrane as it is produced. The produced H_2 is removed from the permeate side of the membrane at near atmospheric pressure. The residual gas on the high-pressure side of the membrane is mostly CO_2 and H_2O, along with small amounts of hydrogen, unreacted carbon monoxide, and hydrogen sulfide. These residual gases are burned with oxygen in a catalytic combustor, and the combustion-product gases are expanded through a turbine expander to produce electricity. About half of this electricity is needed to meet onsite electrical needs. The rest can be sold as a byproduct of hydrogen production. The exhaust gases from the turbine are cooled, thereby condensing out the water vapor. The sulfur (as sulfur dioxide at this point) is removed in a scrubber, and the relatively dry and clean CO_2 is available for disposal.