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Major Roles for Fossil Fuels in an Environmentally Constrained World

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Introduction

Radical innovations for energy technology will be required during the early decades of this century in order to deal effectively with the challenges of:

- climate change associated with the atmospheric buildup of greenhouse gases in conjunction with fossil fuel production and use,
- energy supply insecurity concerns associated with the concentration of remaining low-cost oil resources in the politically volatile Middle East, and
- the environmental damages caused by air pollution—especially damages to human health from small particle (< 2.5 µ) air pollution arising both from direct emissions of small particles and from the formation of small sulfate and nitrate particles in the atmosphere from gaseous precursor emissions of SO_2 and NO_x.

Conventional wisdom holds that addressing such problems effectively requires phasing out fossil fuels in favor of renewables or other non-carbon-based primary energy sources. This paper argues that:

- despite key roles that will be paid by renewables, there is also a compelling need for super-clean and climate-friendly fossil energy in an environmentally constrained world;
- a super-clean, climate-friendly fossil energy system is within grasp and can probably be realized with technologies that can be widely available within 10-20 years time.

Paradoxically, perhaps the most compelling reason for not abandoning fossil fuels in favor of renewables is that a climate-friendly variant of fossil energy that involves its decarbonization and geological sequestration of the separated CO_2 seems to be key to achieving, at low incremental cost, deep reductions in CO_2 emissions worldwide in addressing climate challenge. A good place to begin understanding why this is so is to examine some of the dimensions of the climate change challenge.

Formulating Targets for Energy Technological Innovation to Mitigate Climate Change

Consider IS92a, a long-term global energy scenario constructed by the Intergovernmental Panel on Climate Change as a plausible representation of a Business-As-Usual (BAU) global energy future in which climate-change concerns are given no consideration in shaping the course of the energy system. Some details of the scenario are presented in Box 1, Table 1, and Figure 1. Two features of IS92a relevant to climate change are noteworthy.

First, annual global CO_2 emissions increase from 6.2 gigatonnes of carbon per year (6.2 GtC/y) in 1997 to 13.2 GtC/y in 2050 and 19.8 GtC/y in 2100 (see Table 1); and cumulative emissions, 1990-2100, amount to 1500 GtC.

The cumulative emissions, 1990-2100, that characterize IS92a are consistent with stabilizing the atmospheric CO_2 level at about three times the pre-industrial level. In contrast, consider that in order to stabilize the atmospheric CO_2 concentration at 550 ppmv or 450 ppmv, cumulative emissions in this period would have to be 1050 or 725 GtC, respectively (see Figure 2)—so that, relative to IS92a, reductions of 450 GtC or 775 GtC would be required, respectively. By the end of the century annual emissions would have to be reduced to about 5 GtC/y (1/4 of the IS92a level) to stabilize CO_2 in the atmosphere at 550 ppmv or to 2-3 GtC/y to stabilize at 450 ppmv.

Box 1: The IS92a Scenario for Global Energy

Under IS92a, global population grows from 5.9 billion in 1997 to 11.3 billion in 2100, global gross domestic product grows at an average rate of 2.2%/y (so that GDP per capita grows fivefold in the 21st century), while primary energy grows about 1%/y more slowly, approximately the historical rate of decline in energy intensity (so that primary energy use per capita doubles in the 21st century).

The trend toward electrification of the global energy economy continues under IS92a, with per capita electricity generation growing to 6,000 kWh in 2100 (about one-half the 1997 U.S. rate), up from 2,300 kWh in 1997. Under IS92a, direct use of fuels (in applications other than for electricity generation) grows much more slowly: direct secondary fuel use per capita grows less than 40% (to 59 GJ in 2100, about ¼ of the 1997 U.S. rate, up from 42 GJ in 1997).

Because of an expected peaking of global conventional oil and natural gas production before mid-century,* unconventional energy sources will be needed to provide fuels used directly. IS92a projects large roles for both coal- and biomass-derived synthetic fuels under business-as-usual conditions—with synthetics (69% derived from coal and 31% from biomass) accounting for 3/4 of both liquid and gaseous fuels by 2100. Despite a projected large role for biomass (205 EJ/y by 2100, see Table 1), which has a carbon intensity of zero, the average carbon intensity of fuels used directly in 2100 is about 30% higher than in 1997.

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* Although there is no imminent danger of running out of conventional oil and gas, it is expected that productive capacity will not increase after about ½ of remaining exploitable conventional resources have been used up, in large part as a result of the tendency to exploit the largest fields first.

Planners in various government agencies around the world are beginning to consider 550 ppmv as a target for policy planning. Though such a level would require a sharp departure from BAU in energy planning, this target is not necessarily consistent with the objective of the Framework Convention on Climate Change, which is "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." Oppenheimer, points out, for example, a major benefit of stabilizing at 450 ppmv instead of 550 ppmv: some especially sensitive ecosystems, including the coral reefs, may be lost entirely with CO_2 stabilization at 550 ppmv but would be saved at 450 ppmv.[i] It seems that a prudent approach would be to aim for stabilization at 450 ppmv—especially if such a goal could be realized at acceptable costs.

Second, consider that primary energy supplies can be divided into two categories: those that are used for electricity generation in stationary power plants and those that provide gasoline and other energy carriers that are used directly in transportation, buildings, and factories. At present energy supplies used for electricity generation account for less than 31% of total CO_2 emissions, and under IS92a this percentage declines to 29% in 2050 and 25% in 2100, even though electricity generation is projected to grow much faster than total energy (electricity up 5.1-fold, 1997-2100, compared to a 3.8-fold increase for total energy—see Table 1 and Figure 2). The declining share of emissions from the power sector arises in part because of the expectation that the contributions from noncarbon supplies will grow to 71 percent in 2100,[ii] up from 38 percent in 1997.[iii] Another important reason is an increase in the carbon intensity of the fuels used directly in the latter half of the century as a result of the expected peaking of conventional oil and natural gas production before the middle of this century (see Box 1).

The carbon intensity of power generation could plausibly be reduced much more during this century than is projected in IS92a. In recent papers[iv] the author shows that renewables, mainly in the forms of central-station wind power and distributed grid-connected PV power, have good prospects for becoming broadly competitive during the next two decades, and that over the longer term, when used in conjunction with compressed air energy storage (CAES), these technologies in combination could meet most global electricity needs. Especially promising is the outlook for "baseload"wind/CAES power systems that would make it possible to exploit cost-effectively via long, high-voltage transmission lines the huge, high-quality wind resources that are remote from major electricity markets in many parts of the world.

But even if the power sector were to be completely decarbonized in this century, with 100% of electricity provided by renewables by 2100, say, CO_2 emissions would still be problematic at 15 GtC/y by 2100 (see Table 1). Without fundamental breakthroughs that can provide low-cost electrical storage at small scales (e.g., batteries), the scope for expanding electricity's share of total energy beyond that projected in IS92a is limited. Likewise the scope for further gains in energy efficiency improvement relative to IS92a is limited (average global per capita energy use in 2100 is 35% of that in the United States in 1997). Thus, in a climate-constrained world, major efforts will be needed to decarbonize fuels used directly as well as electricity.

Outlook for Renewable Energy in Markets That Use Fuels Directly

Biofuels, H_2 derived electrolytically from water using wind and photovoltaic power sources, and H_2 derived from water via complex solar heat-driven thermochemical cycles are the leading carbon-free or carbon-neutral candidate renewable energy technologies that might be deployed in markets that use fuels directly.

Biofuels

Modern clean liquid and gaseous fuels derived from biomass will certainly come to play significant roles in markets that use fuels directly. And biomass can become a major energy option in land-rich countries, as Brazil is already demonstrating with its world leadership role in advancing cane-derived ethanol and other bioenergy options. But biomass by itself cannot come close to solving the "fuels used directly" problem. Analysis carried out for the World Energy Assessment concluded that the practical global potential for biomass production for energy (residues plus plantation biomass) over the long term is 100-300 EJ/y.[v] This analysis suggests that the biomass energy option offers only modest potential to improve upon IS92a in terms of greenhouse gas emissions from energy over the longer term, because that scenario already involves, for 2050, the use of 128 EJ/y of biomass (compared to 655 EJ/y of fossil fuels) and, for 2100, 205 EJ/y (compared to 865 EJ/y of fossil fuels)—see Table 1.

Hydrogen as an energy carrier

In recent years interest in H_2 as an energy carrier has grown rapidly. This interest reflects both the benefits it offers for air-quality, climate change, and energy supply security, and the rapid progress being made with fuel cells, for which H_2 is the natural energy carrier.

In combustion applications, H_2 can be burned as a fuel for cooking, for providing low-temperature heat (such as for space and heating of water), and for providing high-temperature heat for industrial processes.[vi] The only air pollutants arising from H_2 combustion are oxides of nitrogen (NO_x), which can be controlled to very low levels by lean-burn combustion, steam or water injection, or catalytic combustion techniques.

Perhaps the most important market opportunity for H_2 is in fuel cells, because H_2 is the natural fuel for that use. In fuel cell applications, even NO_x emissions would be negligible, so that H_2 fuel cells would be characterized by zero emissions of both air pollutants and greenhouse gases. The prospects are good that during the next decade or so fuel cells will be commercialized both for stationary power and combined heat and power applications and for mobile applications. Fuel cell buses will soon be commercialized in various countries, and an intense race is underway among all the world's major automakers to commercialize fuel cell cars.[vii] H_2 fuel cell cars would be less costly to own and operate than fuel cell cars provided with gasoline or methanol fuel that is converted onboard to a H_2-rich fuel that the fuel cell can use. Breakthroughs are not needed in H_2 storage before H_2 fuel cell cars can be commercialized, because fuel-efficient fuel cell cars can be redesigned to accommodate commercially available compressed gaseous H_2 storage. The prospects for successfully launching H_2 fuel cell cars in the market during the second decade of this century are also good.[viii]

Electrolytic H_2

Many believe that the H_2 economy will be based on the use of renewable electricity to break water into H_2 and O_2 via electrolysis. The powerful appeal of a vision based on this energy production strategy along with fuel cells to consume the H_2 so produced is that the entire energy production and use system would be entirely free of air pollutant and greenhouse gas emissions.

But cost considerations are likely to limit the realization of this vision. Although electrolysis based on use of off-peak hydroelectric power will play a role in launching demonstration fleets of H_2-powered vehicles in the market, electrolytic H_2 is not likely to play substantial roles in the energy economy in the long run, because the total amount of H_2 that can be provided by offpeak hydropower is quite modest in relation to potential demand in a H_2 economy. When the capital charges for power generation are allocated to H_2 production, as would be required at the high H_2 demand levels of a H_2 economy, electrolytic H_2 would be far more costly than H_2 derived from fossil fuels—even if the CO_2 coproduct of making H_2 from fossil fuels is sequestered underground instead of released to the atmosphere and the cost of CO_2 sequestration is reflected in the H_2 price. This judgment will not change with advanced technology. To illustrate, suppose that in the future renewable electricity (e.g., wind power) becomes routinely available at 2.5 ¢/kWh, that electrolytic system efficiencies increase to 88% (up from 74%, HHV, today), and that the capital cost of electrolyzers is reduced 40% relative to today's electrolyzers—all of which are quite plausible for 20 years from now.[ix] Even under these very optimistic assumptions, electrolytic H_2 derived from renewable electricity sources would be twice as costly as H_2 derived from coal with geological sequestration of the separated CO_2, using technologies that are commercially available today.[x]

Thermochemical routes to H_2 production from water

An alternative way to split the water molecule to produce H_2 is by applying heat. Using this process directly requires temperatures of the order of 4,000 ^oC—a level that cannot be accomplished at present because there are no materials that can contain the reactions. Over the years, however, various multiple-step chemical processes have been proposed for making hydrogen from water thermochemically at lower temperatures, for example, using high-temperature solar heat that can be provided with collectors that concentrate sunlight.[xi] In contrast to electrolytic processes, thermochemical processes for hydrogen manufacture are far from being commercially available. The processes are quite capital-intensive and have overall thermal efficiencies for converting heat into H_2 that are typically less than 50%. Here, as in the electrolytic case, the prospects are bleak that thermochemical conversion would ever become economically competitive with fossil fuel-derived hydrogen with CO2 sequestration.[xii]

Decarbonized Fossil Fuels

The making H_2 from fossil fuels with sequestration in geological reservoirs of the CO_2 coproduct of H_2 manufacture as the primary basis for a H_2 economy is a concept that is unfamiliar to most people. Yet the idea is by no means “far out.” Although H_2 is not yet used as an energy carrier, it is widely manufactured for use in the chemical processing and petroleum refining industries; in the United States, about 1% of primary energy use (mostly natural gas) is committed to H_2 manufacture. Moreover, geological disposal of CO_2 is a well-established industrial activity in conjunction with enhanced oil recovery (EOR), as discussed below.

In what follows the fossil energy approach to a H_2 economy is discussed. The section begins with a review of geological CO_2 disposal and ends with a discussion of the prospects for making H_2 from fossil fuels in conjunction with geological disposal of the CO_2 coproduct. In between is a discussion of carbon capture and CO_2 sequestration in fossil fuel power systems—which has been the focus of attention relating to decarbonized fossil energy systems to date.

Outlook for CO_2 disposal

The options for CO_2 disposal include its storage in both deep ocean and porous geological media. Although ocean disposal has received the most attention, environmental concerns and other large uncertainties about its prospects have led to a shift in focus in recent years to geological (underground) storage—in depleted oil and natural gas fields, in uneconomic coal beds, and in deep saline aquifers.[xiii]

CO_2 injection for enhanced recovery of hydrocarbons might become a profitable focus of initial efforts to sequester CO_2.[xiv] There are about 74 enhanced oil recovery projects worldwide, most (sixty-six) in the United States. In 2000 oil production via EOR accounted for 4% of total U.S. oil production, a byproduct of which is the sequestration of 30 million tonnes of CO_2 annually. Most of the injected CO_2 comes from natural reservoirs of CO_2,[xv] but 5 million tonnes per year comes from anthropogenic waste sources.[xvi]

Another option is CO_2 injection for enhanced recovery of methane from beds of coal that cannot be mined.[xvii] Large amounts of methane are trapped in the pore spaces of many coals. Injection of CO_2 into the coals can sometimes lead to efficient methane recovery because typically CO_2 is twice as adsorbing on coal as is methane. Therefore CO_2 can efficiently displace the methane adsorbed on the coal:[xviii] as CO_2 moves through the reservoir, it displaces methane. The limited experience to date indicates that very little of the injected CO_2 shows up in the production wells until most of the methane has been produced,[xix] so that prospects for permanent sequestration of the injected CO_2 appear to be good. Of course, CO_2 sequestration in the coal bed would prevent subsequent mining of the coal. However, large amounts of the coal in the ground cannot be mined.[xx] Unlike EOR, enhanced recovery of coal-bed methane via CO_2 injection is not a commercially established technology, although one U.S. producer of coal-bed methane has been carrying out a commercial pilot project in the San Juan Basin since 1996.[xxi]

CO_2 sequestration in depleted oil and gas fields is probably a secure option if the original pressure of the reservoir is not exceeded.[xxii] One estimate of the prospective global capacity for sequestration in such reservoirs[xxiii] is 100 and 400 GtC for oil and gas fields, respectively;[xxiv] other estimates are as low as 40 and 90 GtC for depleted oil and gas fields, respectively, plus 20 GtC associated with enhanced oil recovery.[xxv] The range of estimates is wide because the suitability of the properties of the reservoirs for storage varies greatly and because oil and gas recovery may have altered the formations and affected the integrity of the reservoirs.

Deep saline aquifers are much more widely available than oil or gas fields. They are present in all sedimentary basins, with a total area of 70 million km^2 (2/3 onshore, 1/3 offshore), equivalent to more than half the 130 million km^2 land area of the inhabited continents. Some sedimentary basins offer better prospects for CO_2 storage than others.[xxvi] To achieve high storage densities, CO_2 should be stored at supercritical pressures,[xxvii] which typically requires storage at depths greater than 800 meters.[xxviii] The aquifers at such depths tend to be saline[xxix] and not effectively connected to the much shallower (depths of < 300 m) freshwater aquifers people use.

Until a few years ago it was generally thought that closed aquifers with structural traps would be required for effective storage. The potential capacity for global sequestering in such traps is relatively limited—about 50 GtC,[xxx] equivalent to less than ten years of global CO_2 production from burning fossil fuels at the current rate. However, a growing body of knowledge indicates that many large, regional-scale open aquifers with good top seals (very low permeability layers) can provide effective storage, if the CO_2 is injected sufficiently far from the boundaries of the aquifers that the CO_2 either never reaches the boundaries or, if it does, leaks at a rate that is sufficiently slow to be of little consequence to climate change.[xxxi] The reason is the extraordinarily slow rates of CO_2 migration in such reservoirs (typically ~ 1 cm/y), a phenomenon called "hydrodynamic trapping" of CO_2.[xxxii] With large aquifers, the CO_2 will eventually dissolve in the water ("dissolution trapping" of CO_2), and with sandstone reservoirs containing certain clay minerals (but not carbonate reservoirs), the CO_2 will, after dissolving in the water, eventually precipitate out as a carbonate mineral ("mineral trapping" of CO_2).[xxxiii]

Notably, aquifers need not be "leak-free" to qualify as "secure" options for CO_2 storage. From a climate-change-mitigation perspective, leakage rates of the order of 0.1%/y should be acceptable; note that if aquifers leaked at this rate on average and if 600 GtC were sequestered during this century, the leakage rate at the end of the century would be only 0.6 GtC/y. Of course, local risks must also be taken into account—e.g., might upward migration of CO_2 that might leak through a caprock fracture lead to leaching of heavy metals into near-surface fresh water aquifers that are used for human consumption? Such potential risks warrant careful study.

If structural traps are not required for effective storage, the potential storage capacity of aquifers might be huge: estimates range from 2,700 [xxxiv] to 13,000 GtC.[xxxv] For comparison, the estimated remaining resources of recoverable fossil fuels (excluding methane hydrates) contain 6,000-7,000 GtC.[xxxvi]

There is a growing base of experience with aquifer disposal. A Statoil project involves recovering the CO_2 contaminant in natural gas from the Sleipner Vest offshore natural gas field in Norway at a rate of 1 million tonnes of CO_2 per year, which it is injecting and sequestering in a nearly aquifer under the North Sea.[xxxvii] A large project that is expected to commence within 10 years will involve annual recovery of more than 100 million tonnes of CO_2 (equivalent to 0.5% of 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) and its disposal in nearby aquifers.[xxxviii]

There are also 31 small acid-gas disposal projects in Alberta that involve recovery of CO_2 along with hydrogen sulfide (H_2S) from natural gas fields and injection of these gases (in a wide range of relative concentrations) into both aquifers and depleted oil and gas fields for storage. These projects are using underground disposal of CO_2/H_2S because this strategy for responding to the regulations governing emissions of sulfur into the air is less costly than the alternative of recovering the H_2S from the natural gas and converting it to elemental sulfur.[xxxix]

The long experience with EOR, the growing body of experience with aquifer disposal, as well as extensive historical experience with underground gas storage are contributing to a growing confidence within the scientific community that long-term sequestration of a significant fraction of global CO_2 production from human activities over the next several hundred years might be feasible,[xl] although more research, field testing, monitoring, and modelling are needed to narrow the uncertainties relating to CO_2 storage in geological media.

Outlook for CO_2 capture in power generation

In recent years many analyses have been carried out with the aim of understanding better the technologies and costs associated with recovery of CO_2 at large central-station fossil fuel power plants and its disposal in geological formations or otherwise.[xli] The activities involved are:

- Separating out a relatively pure stream of CO_2 from the fossil energy system,
- Compressing the CO_2 to a dense state for pipeline transport to the disposal site,
- Constructing the CO_2 pipelines and gaining associated rights of way, and
- Drilling the wells for injecting the CO_2 into disposal reservoirs and constructing associated surface facilities.

Most of such studies have focused on recovering CO_2 from flue gases of fossil fuel power plants. The cost of separating out CO_2 from flue gases dominates the costs of separation and disposal because the CO_2 concentration is low (~ 12% for coal steam-electric plants), as is its partial pressure (0.12 atmosphere). At such a low partial pressure, CO_2 recovery is typically achieved by making it react with amines (chemical solvents) to form a weakly bonded intermediate compound that is heated to recover the CO_2 stream and regenerate the original solvent. If CO_2 were recovered from flue gases of modern coal steam-electric plants, the cost to generate electricity would be 60% higher than without CO_2 recovery.[xlii]

A superior approach involves recovering CO_2 before combustion (so that it is undiluted by nitrogen from the air) in a coal integrated gasifier/combined cycle (IGCC) power plant. The coal IGCC power plant is a commercial technology that makes it possible to convert coal to electricity at a much higher efficiency (about 44%) than with conventional coal steam-electric technology (35-36% for new plants and 33% for average US coal plants in use). Air pollutant emission levels for this technology are comparable to those from natural gas combined cycles; moreover, costs of environmental damage associated with such emissions are about 1/10 of those for coal steam-electric plants equipped with the best available control technologies (see Table 2). Even without taking credit for the environmental benefits offered by coal IGCC power plant technology, the generation costs are approaching those for conventional coal steam-electric plants equipped with flue gas desulfurization.[xliii] Moreover, the costs of decarbonization/CO_2 sequestration are much less than those for coal steam-electric technology.

With coal IGCC power plant technology, decarbonization/CO_2 sequestration begins with gasification (partial oxidation) of the coal in oxygen (O_2, obtained from an air separation plant) and steam at high pressure and temperature to produce synthesis gas [mostly carbon monoxide (CO) and H_2]. The synthesis gas is cooled and scrubbed to remove pollutants (other than H_2S, the compound formed from sulfur in the coal during gasification) and then passed to water-gas-shift (WGS) reactors equipped with H_2S-tolerant water-gas-shift catalysts. In these units, CO is reacted with steam according to the WGS reaction ($CO + H_2O \rightarrow CO_2 + H_2$).

There are two options for dealing with the shifted synthesis gas (made up mostly of H_2, CO_2, and steam). In one approach, the shifted synthesis gas is cooled to near ambient temperatures, the H_2S is removed using a glycol solvent and converted to elemental sulfur, the steam is condensed out, and the synthesis gas (at this point mostly H_2 and CO_2) is sent to a CO_2 separation unit. There the CO_2 at high concentration and partial pressure is recovered using a physical solvent[xliv] and made ready for disposal by drying and pressurization to 150 atmospheres. The H_2-rich synthesis gas is then burned in a combined cycle power plant. It is assumed here that the separated CO_2 is transported about 100 km by pipeline to a site where it is injected via disposal wells into an appropriate storage medium (such as a deep saline aquifer). This approach entails considerable cost for the sulfur removal processes.

Alternatively, one can prevent the emission of sulfur compounds to the air by instead disposing of the H_2S along with CO_2 (see Figure 3). With this “cosequestration” approach the H_2S and CO_2 are removed simultaneously from the shifted synthesis (using the same physical solvent as with the sulfur removal option) and made ready for disposal by drying and pressurization to 150 atmospheres; the rest of the system is the same as for the sulfur removal case.

Both options are based on commercially available technologies and involve making relatively straightforward modifications to conventional coal IGCC power plants from which CO_2 is vented. The estimated performance and electricity costs for both conventional and these two decarbonized coal IGCC plants are summarized in Table 3.

Consider first the case where the H_2S is removed and converted to elemental sulfur. As indicated by Table 3, such an IGCC plant located about 100 km from the CO_2 disposal site and whose CO_2 emissions per kWh are 92% less than those for a conventional coal IGCC plant would have: (1) a capital cost that is 25% higher than that of a conventional coal IGCC plant; (2) a conversion efficiency that is 6 percentage points less [38.4% (which is still higher than for a new coal steam-electric plant) vs. 44.4%]; and (3) a generation cost that is about 31% higher (5.9 vs. 4.5 ¢/kWh).

For the cosequestration case, the capital charge penalty is reduced from 25% to 12%, and the generation cost penalty is reduced from 31% to 21%. However, at the present time it is not known if cosequestration is a viable option. Although the experience in Alberta with 31 acid gas disposal projects that involve underground disposal of CO_2/H_2S gaseous mixtures suggests that this option might be viable, detailed risk assessments are needed to ascertain whether this cost-saving option would be a safe option in routine practice.

Power generators would not pursue either sequestration option unless it is cost-effective to do so. A carbon tax could provide the needed motivation. As indicated in Table 4, a carbon tax of $80/tC would make sequestration worthwhile for the sulfur removal case, whereas a $53/tC tax would make cosequestration worthwhile. The corresponding generation costs would be 6.1 and 5.5 ¢/kWh, respectively.

Decarbonizing natural gas combined cycle (NGCC) power plants is not nearly so attractive from a cost perspective as for coal IGCC plants. For NGCC plants, pre-combustion options are not less costly than stack-gas CO_2 removal schemes, which are quite costly. As a result, the cost of electricity from decarbonized NGCC and coal IGCC plants comparable, even though, where natural gas is readily available NGCC electricity is typically less costly than coal IGCC electricity when CO_2 is vented. Moreover, the carbon tax needed to induce sequestration for NGCC systems is much higher than for coal IGCC systems (see Table 5). Thus, paradoxically, coal fares better in competition with natural gas for power generation in a carbon-emissions constrained world than in a world where climate change is not a major concern.

Both coal IGCC and NGCC technologies, when decarbonized, would face stiff competition from baseload power systems that involve wind power coupled to compressed air energy storage at wind power costs expected in the ~ 2020 time frame. Of course, in this time frame, costs for decarbonized coal IGCC and NGCC technologies are likely to be less than present costs, so that is not clear would “win”decarbonized power competion at that time.

In contrast to this situation in decarbonized power markets, fossil fuels are likely to be decisive winners in decarbonized energy markets for fuels used directly.

Fossil fuel-derived H_2 for markets that use fuel directly

The manufacture of H_2 from a fossil fuel begins with the conversion of the fossil fuel feedstock into synthesis gas. At present most H_2 is manufactured from natural gas by steam reforming.[xlv] As noted, synthesis gas can be made from coal via gasification (partial oxidation). The manufacture of H_2 from coal using commercial technology is essentially the same as the process described above for decarbonization of coal IGCC power applications, except that at the final stage following the removal of the CO_2, the H_2-rich gas would be purified (up to 99.999% purity) in a pressure swing adsorption unit instead of being burned in a combined cycle power plant. As in the case of coal IGCC technology, there are two sequestration options: one in which the H_2S is first recovered and converted to elemental sulfur, and an alternative “cosequestration” option in which the H_2S is removed from the shifted synthesis gas with the CO_2 and sequestered with it. The co-sequestration option is illustrated in Figure 4.

The process is more capital-intensive for coal than for natural gas, but coal is typically the less costly feedstock. For example, in the United States the average price paid by electricity generators for natural gas in 1997 was 2.1 times the price paid for coal, and this ratio is projected by the US Energy Information Administration to increase to 3.7 times by 2020 (see Tables 3 and 4), which is perhaps as soon as H_2 could be used as an energy carrier in significant markets. Assuming today's technologies and US coal and natural gas prices projected for 2020, H_2 from coal is likely to be less costly than H_2 from natural gas (compare Tables 3 and 4), with or without CO_2 sequestration (compare Tables 3 and 4).

With CO_2 sequestration, the efficiency of making H_2 from coal would be about 70%, and the cost would be $7.2/GJ for the sulfur removal option (29% more than the cost with CO_2 vented) and $6.5/GJ for the cosequestration option (16% more than the cost with CO_2 vented)—for coal prices at $0.93/GJ, the projected average US price for electric generators in 2020. The corresponding carbon taxes needed to induce producers to sequester CO_2 are respectively $50/tC and $29/tC. Advanced technologies based on use of inorganic membranes for separating H_2 from CO_2 and other gases might lead to lower costs for making H_2 from coal.[xlvi]

In terms of energy content, a $6.5/GJ plant-gate cost of H_2 (HHV basis) is equivalent to a gasoline price (LHV basis) of $0.25/liter, which is not much higher than the $0.23/liter average U.S. refinery-gate gasoline price in 2000. If this H_2 were used by fuel cell cars, the cost of the H_2 distribution and refueling system (see Table 4b) would increase the cost seen at the pump by consumers to about $0.54/liter of gasoline equivalent[xlvii]—much higher than the average gasoline pump price in 2000 of $0.30/liter (excluding retail fuel prices). However, because H_2 fuel cell cars are expected to be two to three times as fuel efficient as today's cars with gasoline internal combustion engines, the cost of fuel per mile of driving would be less.[xlviii]

H_2 from coal via gasification might turn out to be the dominant way that H_2 will be produced in a H_2 economy, but the gasification approach will often lead to H_2 production at attractive costs using any low-quality carbonaceous feedstock—including petroleum coke and other refinery residuals, heavy oils and tar sands, and biomass.[xlix] It is noteworthy that several commercial projects have been launched in recent years involving the gasification of petroleum residuals at refineries around the world, in many instances for the coproduction of H_2 and electricity.[l]

Should natural gas-based energy systems be decarbonized?

Table 5 summarizes the carbon taxes needed to induce sequestration for energy systems that would produce H_2 and electricity based on commercially available technologies. Two observations can be made about these results.

First, the carbon tax needed to induce sequestration is far less for H_2 production than for electricity production. This arises because a relatively pure stream of CO_2 can be provided as a coproduct of H_2 manufacture at relatively low incremental cost, whereas the cost of separating out CO_2 is a major component of the total cost in the case of electricity manufacture. This suggests that contrary to conventional wisdom, H_2 producing facilities rather than electricity generating facilities might be early targets for CO_2 sequestration projects. Such early projects need not await the introduction of H_2 as an energy carrier, because there are rapidly growing industrial markets for H_2. In addition to chemical process industry markets where most H_2 is an intermediate product in the manufacture of ammonia fertilizers, demand for H_2 is growing rapidly at petroleum refineries—both because of tightening environmental restrictions on the sulfur content of liquid fuels (H_2 is needed for hydrodesulfurization) and because of secular trend to heavier crude oils, which require upgrading by adding H_2. In the United States, for example, the demand for H_2 at refineries is growing about 10%/y.

Second, the carbon tax needed to induce sequestration for coal-based systems is much less than for natural gas-based systems—a result that arises to a large extent from the fact that in coal systems the CO_2 is available for removal at far higher concentrations and partial pressures than in natural gas systems. This suggests that priority for decarbonization efforts be given to coal energy systems relative to natural gas energy systems.

Resource considerations (see Table 6) suggest further that it might not be necessary to decarbonize natural gas-based systems if a concerted decarbonization effort is carried out for coal systems. Consider that if there were no other remaining fossil fuel resources other than conventional oil and natural gas (the energy content of which is equivalent to 50 to 90 years of total fossil fuel energy consumption at the current global rate—compare Tables 6 and 1), burning them would release to the atmosphere about 400 GtC, which is consistent with stabilizing the atmosphere at near the present level—so that there would be no climate change challenge. Further, if the only remaining fossil fuels were estimated ultimately recoverable conventional oil and gas plus estimated ultimately recoverable non-conventional natural gas resources (the energy content of which is about 3 times the energy content of remaining conventional natural gas) and if these were burned, the CO_2 added to the atmosphere would be consistent with stabilization of the atmospheric CO_2 level at about 500 ppmv.

Natural gas-based energy systems can be designed to emit very low levels of air pollution. Moreover, because methane, the primary constituent of natural gas, has a H/C ratio that is 5 times that for coal, and because natural gas energy conversion systems can be made more energy efficient than coal systems, CO_2 emissions with CO_2 venting are also relatively modest. A state-of-the-art NGCC power plant emits less than 40% as much CO_2 per kWh as a new coal steam-electric plant. And a H_2 fuel cell car (with a gasoline-equivalent fuel economy of 2.9 liters/100 km) operated on natural gas-derived H_2 with venting of the CO_2 coproduct would be characterized by full fuel cycle CO_2 emissions that are less than 30% of those for US average gasoline internal combustion engine cars (10.5 liters/100 km).

Conclusions and Implications for Brazil

The following conclusions can be drawn from this analysis:

- In order to stabilize the concentration of CO_2 in the atmosphere at a level no greater than 450-550 ppmv, it will be necessary to decarbonize both the electric power sector and those sectors of the energy economy that use fuels directly.
- Potential CO_2 storage capacity in geological media is probably sufficiently large at the global level to make the option of fossil fuels decarbonization/CO_2 sequestration a major energy option for a GHG-emissions-constrained world.
- In electric power markets, renewables and decarbonized fossil energy systems will be strong competitors, and it is not unrealistic to expect that some combination of central-station wind power and distributed grid-connected PV power will emerge triumphant over decarbonized fossil fuel power systems over the next couple of decades in a carbon-constrained world that values carbon emissions at \$50-\$80/tC.

- In markets that use fuels directly, biofuels can make some important contributions, but supplies potentially available at the global level in the long run are likely to amount to a modest fraction of demand for fuels used directly later in this century.
- To achieve deep reductions in GHG emissions, H_2 will probably have to be introduced as a major energy carrier for use in markets that use fuels directly.
- By a wide margin, the least costly route to providing H_2 in a GHG emissions-constrained world will be from fossil fuels and other carbonaceous feedstocks (including biomass).
- The manufacture of H_2 from coal appears to be more attractive than the manufacture of H_2 from natural gas at natural gas and coal feedstock prices that are likely to be typical by the time H_2 is established as an energy carrier in the market.
- If a concerted effort can be directed to decarbonization strategies for coal, it might not be necessary to decarbonize natural gas energy systems.
- The production of H_2 from water via either electrolytic or complex thermochemical processes will have only very modest roles in providing H_2 unless geological sequestration of CO_2 and alternative approaches keeping fossil CO_2 out of the atmosphere (e.g, storing fossil-energy-derived CO_2 as carbonate rocks[li]) turn out to be a fatally flawed ideas.

Are any of these ideas relevant to Brazil? Not being a Brazilian, I can only speculate. I make the following technical observations:

- The prospect that H_2 will be needed as a major energy carrier in a GHG-emissions constrained world has far-reaching implications for all countries, because it implies that H_2 producing and consuming technologies will be needed throughout the world.
- On the supply side Brazil has such large hydro-electric resources that fueling initial H_2 vehicle demonstration fleets (e.g., small fleets of H_2 fuel cell buses, as is being planned with support from the Global Environment Facility) with H_2 derived electrically from off-peak hydropower offers a good opportunity to “test the waters” of the hydrogen economy. But the electrolytic option cannot cost-effectively be expanded to H_2 production levels beyond what can be supported with off-peak hydroelectric power.
- Additional H_2 supplies might be provided at low cost with commercial technology via gasification of petroleum residuals. For example, the petroleum coke production at three large Brazilian refineries (Betim, Minas Gerais; Cubatao, Sao Paulo; Paulina, Sao Paulo) would be adequate to support 1.2 million H_2 fuel cell cars.
- The coal gasification route to H_2 might not be relevant to Brazil in light of the scarcity and poor quality of Brazilian coals.
- However, H_2 production via gasification of biomass might prove to be important in Brazil, which, blessed with vast land resources, is one of the few countries where large biomass energy plantations might be viable.

At the policy level, an energy future such as the one I have laid out can evolve only in the context of a strong climate-change-mitigation policy that aims for deep reductions in CO_2 emissions. Such a policy would have to eventually involve a relatively high price on carbon emissions (on the basis of the present somewhere in the range \$30/tC to \$80/tC) that arises either from the levy of a carbon tax or the introduction of some form of a cap-and-trade system.

A biomass-rich country (like Brazil) that produces H_2 from biomass would be in a good position to profit from a world-wide cap-and-trade system, because CO_2 in a relatively pure stream can be generated as a coproduct of H_2 manufacture and sequestered underground in geological media at relatively low incremental cost. Because the CO_2 so sequestered was extracted from the atmosphere during photosynthesis, the CO_2 emissions for the H_2 production system would be negative,[lii] thereby putting the biomass H_2 producer in a strong position to sell CO_2 emission rights to other countries.

Acknowledgments

The author thanks the Geraldine R. Dodge Foundation, the Energy Foundation, the W. Alton Jones Foundation, and the David and Lucile Packard Foundation for support in the preparation of this paper.

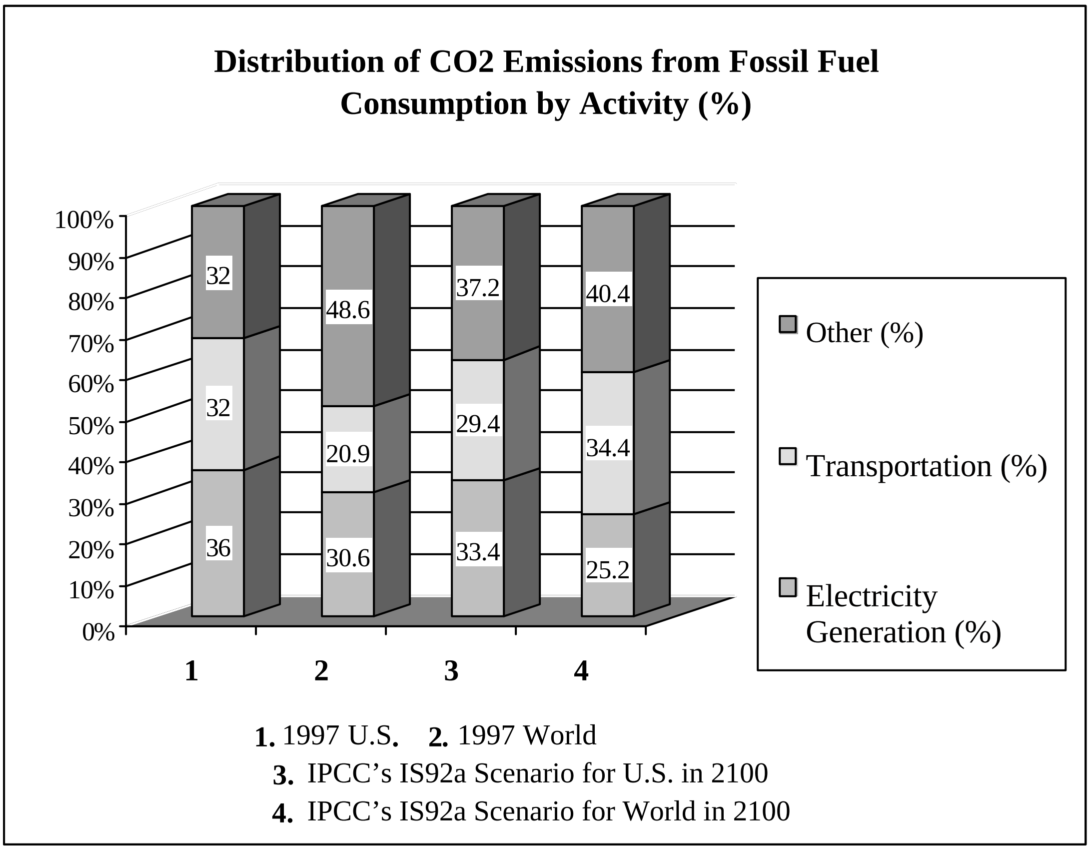

Figure 1: Distribution of CO_2 Emissions from Fossil Fuel Burning by Activity (%)
Sources: Bars 1 and 2: Energy Information Administration, *International Energy Outlook 2001*, DOE/EIA-0484 (2001), U.S. Department of Energy, Washington, D.C., March, 2001. Bars 3 and 4: Intergovernmental Panel on Climate Change, *Climate Change 1994—Radiative Forcing of Climate Change and an Evaluation of the IPCC IS92 Scenarios*, Cambridge University Press, Cambridge and New York, 1994.

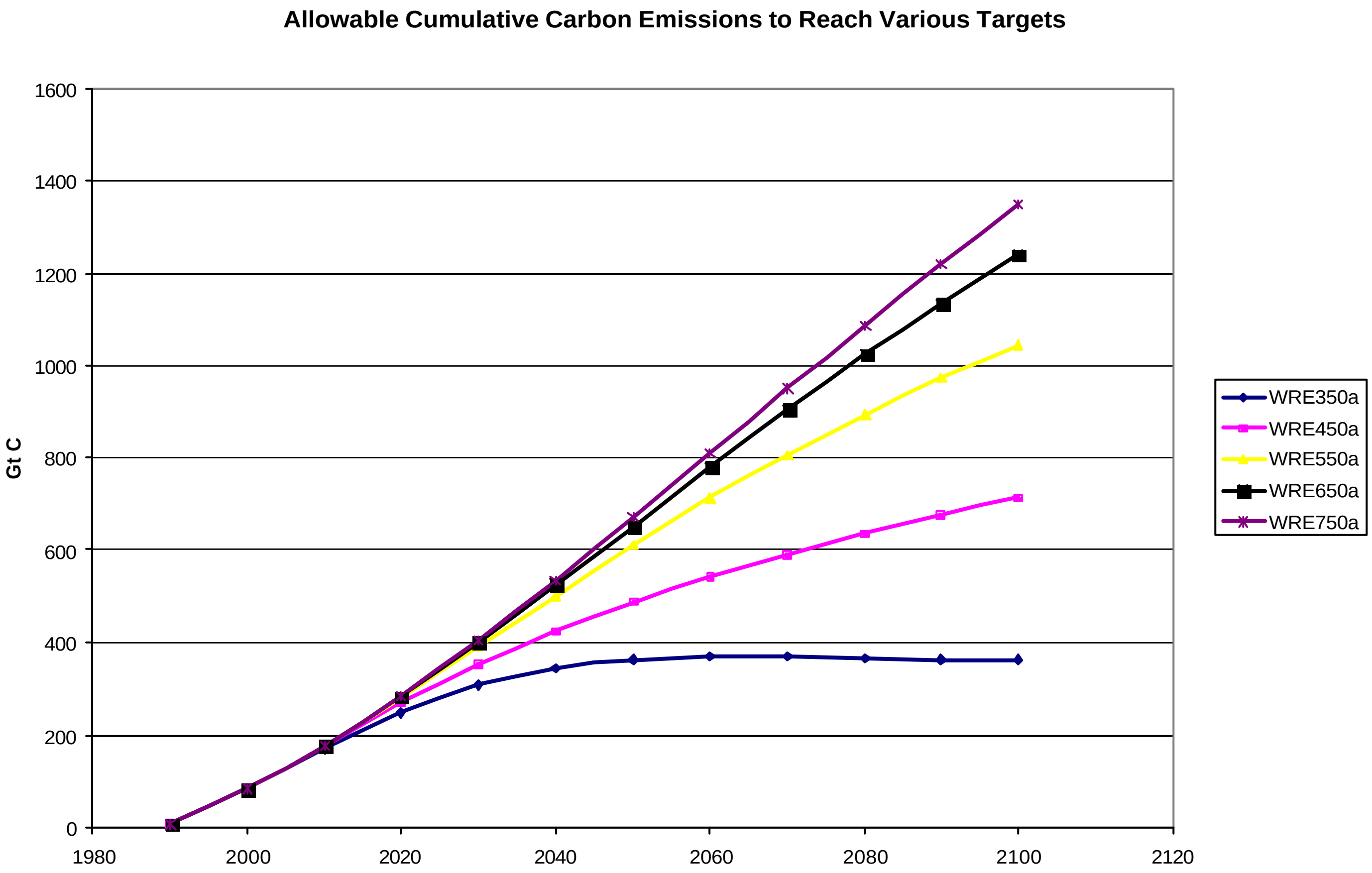

Figure 2: Cumulative CO_2 Emissions, 1990-2100, Consistent with Stabilization of Atmospheric CO_2 at Levels of 350 ppmv to 750 ppmv

These curves are from H. Pitcher, How much must be done to mitigate climate change?, Solar Conference, Washington DC, 23 April 2001 and are based on T. M. L. Wigley, R. Richels, and J. A. Edmonds, “Economic and Environmental Choices in the Stabilization of Atmospheric CO_2 Concentration,” *Nature* **379**: 240-243, 18 January 1996.

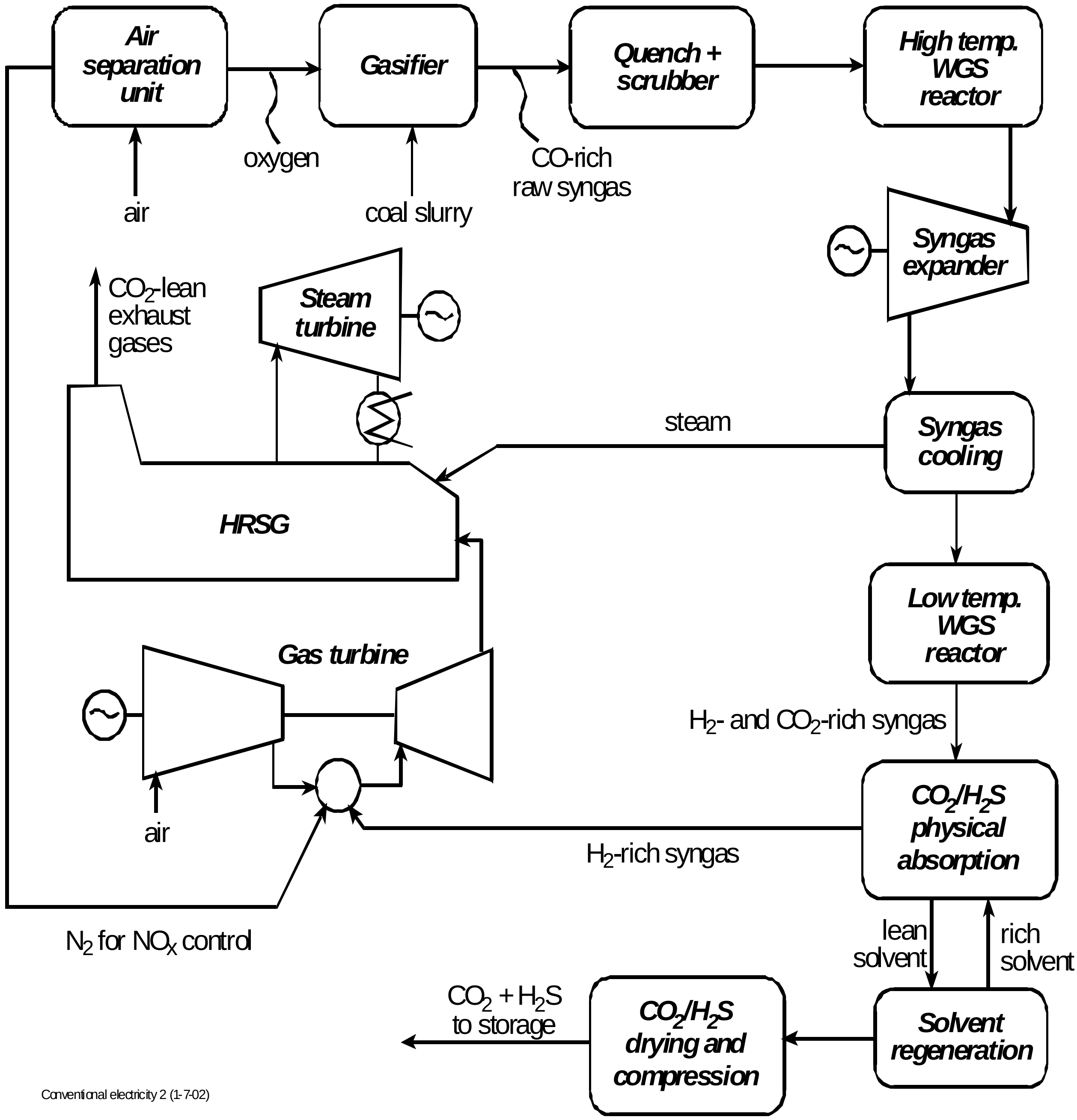

Figure 3: Coal Integrated Gasifier/Combined Cycle Power Plant with Simultaneous Removal of H_2S and CO_2 for Cosequestration

This is a schematic for the system labeled “Electricity only, with CO_2 Coseq.” in Table 3.

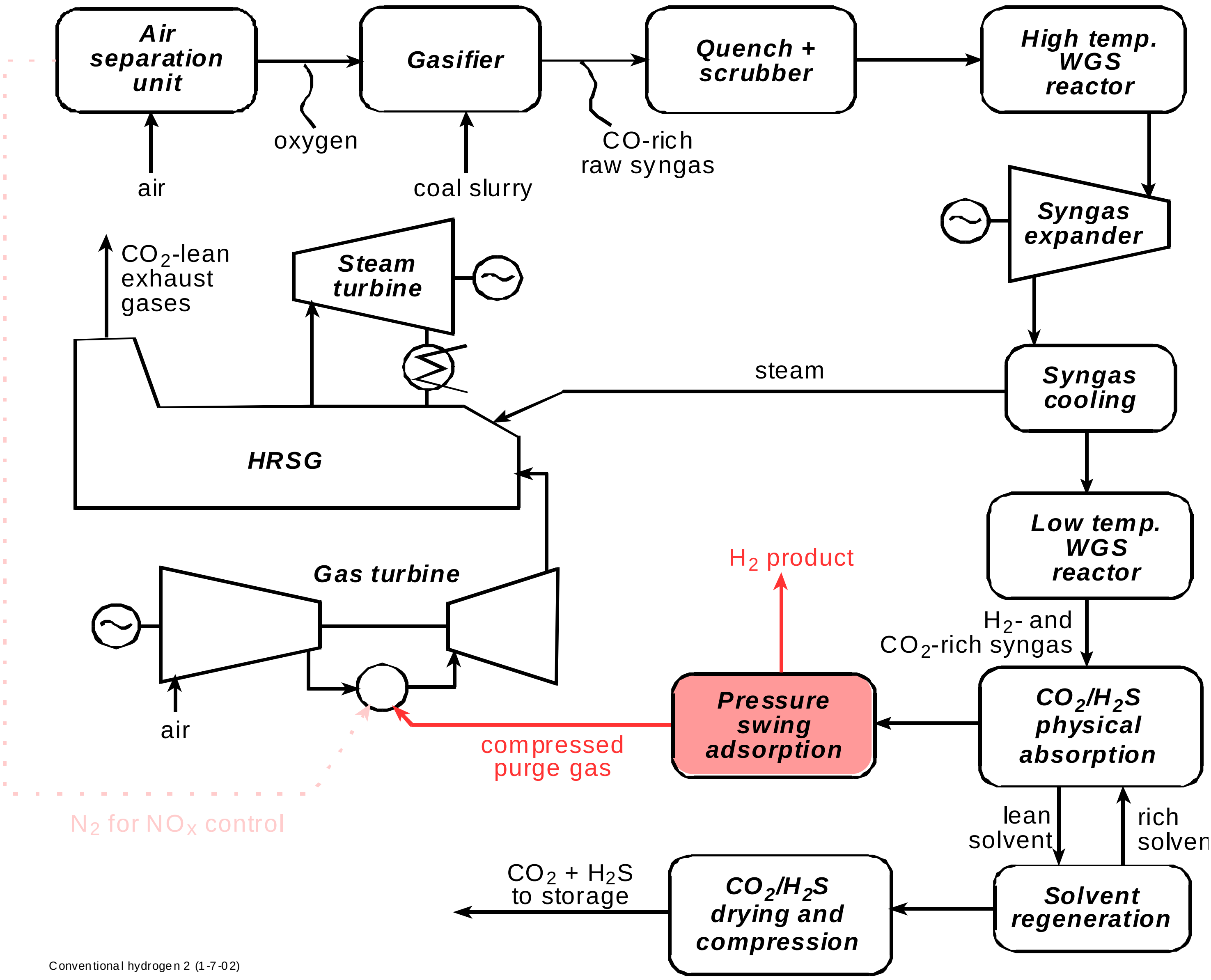

Figure 4: Hydrogen Plus Electricity Production from Coal with Simultaneous Removal of H_2S and CO_2 for Cosequestration
This is a schematic for the system labeled “H_2 + electricity, with CO_2 Coseq.” in Table 3.

Table 1: Global Energy

	Actual	IS92a projection	
	1997	2050	2100
Population (*billlion*)	5.87	10.0	11.3
Electricity generation (*TWh/y*)			
Coal	4,818	11,517	15,480
Oil	1,244	1162	531
Natural gas	2,246	2558	915
Synthetic liquids/gases from coal	-	819	3,017
Hydroelectric	2,574	5,848	7,660
Solar	192	5,838	20,405
Biomass		951	1,381
Nuclear	2,266	8,140	18,695
Subtotal	13,340	36,833	68,084
CO_2 emissions, power sector			
GtC/y	1.9	3.8	4.9
% of total global CO_2 emissions	31	29	25
Fuels used directly (*EJ/y, HHV basis*)			
Coal	43.2	128.9	132.7
Oil	142.7	142.6	94.6
Natural gas	63.0	114.8	37.3
Synthetic liquids/gases from coal	0	68.5	276.5
Synthetic liquids/gases from biomass	0	79.5	126.5
Subtotal	248.9	534.3	667.7
CO_2 emissions, fuels used directly (*GtC/y*)	4.3	9.4	14.9
Primary energy requirements (*EJ/y, HHV basis*)			
Coal	97.9	356.4	718.1
Oil	156.9	155.2	100.0
Natural gas	88.5	143.3	46.7
Biomass	-	128.4	205.2
Hydroelectric power	32.3	58.7	71.7
Solar	-	58.6	191.0
Nuclear power	25.5	81.7	175.0
Total primary energy requirements	401	982	1508
Total CO_2 emissions (*GtC/y*)	6.2	13.2	19.8

Sources: Global data for 1997 are from Energy Information Administration, *International Energy Outlook 2001*, DOE/EIA-0484 (2001), U.S. Department of Energy, Washington, D.C., March 2001. The IS92a projection is the "business as usual" global energy scenario presented in Intergovernmental Panel on Climate Change, *Climate Change 1994—Radiative Forcing of Climate Change and an Evaluation of the IPCC IS92 Scenarios,* Cambridge University Press, Cambridge and New York, 1994. Energy quantities are presented on a higher heating value basis.

Table 2: Emission Rates For And Estimated Costs Of Environmental Damages From Air Pollutant Emissions of Fossil Fuel Power Plants *(Low Valuation for Typical European Conditions)*

	Emission rate (gr/kWh)			Low estimate of costs of environmental damages (¢/kWh)[a]				Environmental damage costs relative to NGCC
Primary air pollutant	SO_2	NO_x	PM_{10}	SO_2	NO_x	PM_{10}	Total	Total
Average U.S. coal steam-electric plant, 1997	6.10[b]	3.47[b]	0.16[c]	1.59	1.39	0.07	3.05	82
New coal steam-electric plant with best available control technology[d]	0.46	0.87	0.15[c]	0.12	0.35	0.06	0.53	14
Coal IGCC plant[e]	0.075	0.082	0.0025	0.020	0.033	0.001	0.054	1.5
NGCC plant[f]	-	0.092	-	-	0.037	-	0.037	1.0

[a] Environmental damage costs from power plant air pollutant emissions are assumed to be ¼ of the median estimates of Rabl and Spadaro (A. Rabl and J.V. Spadaro, Public health impact and implications for the energy system, *Annual Review of Energy and the Environment,* **25**: 601-627, 2000) for typical power plant sitings in Europe. The Rabl and Spadaro calculations were carried out under the European Commission's ExternE Programme. Nearly all the estimated costs of environmental damages are associated with adverse health impacts; the economic values of health impacts were estimated on the basis of the principle of willingness to pay to avoid adverse health effects.) Rabl and Spadaro considered a wide range of pollutants, but the only significant damage costs were from SO_2, NO_x, and PM_{10}, for which their median estimates of damage costs (in $/kg) were $10.44, $16.00, and $17.00, respectively. Damage costs at ¼ of the median estimates of Rabl and Spadaro (equivalent to one standard deviation below the median) were assumed, to put a conservatism into the calculation to reflect the scientific uncertainty.

[b] Average emission rates in 1997 for U.S. coal plants, whose average efficiency was 33.0%

[c] In 1990, PM_{10} emissions from U.S. electric utility coal power plants amounted to 245,000 tonnes when these plants consumed 17.1 EJ of coal, so that the PM_{10} emission rate was 14.34 gr/GJ—the assumed emission rate for all steam-electric cases in this table.

[d] It is assumed: that the new coal steam-electric plant is 35.5% efficient; that the sulfur content of the coal is 454 gr/GJ (1.08% sulfur by weight), the average for U.S. coal power plants in 1997; that SO_2 emissions are reduced 95%, a commercially feasible rate; that the NO_x emission rate is 86 gr/GJ—achievable with advanced low-NO_x burners that will be commercially available shortly;

[e] It is assumed: that the coal integrated gasifier combined cycle (IGCC) plant is 43.8% efficient, based on use of steam-cooled gas turbines; that the emission rates equal the measured values for the Buggenum coal IGCC plant (Netherlands):10.0 and 0.3 gr/GJ of coal, for NO_x and particulates, respectively, as well as 99% sulfur recovery (data presented by Co van Liere, KEMA, at the Gasification Technologies Conference in San Francisco, 17–20 October 1999); and that the sulfuer content of coal is 454 gr/GJ.

[f] It is assumed: that the natural gas combined cycle (NGCC) plant is 54.1% efficient, based on use of steam-cooled gas turbines; that the NO_x emission rate is 9 ppmv (dry volume basis, at 15% O_2), corresponding to an emission rate of 0.092 gr/kWh.

Table 3: Producing Electricity and H_2 from Coal (*conventional technologies, 70 bar*)[a]

	Electricity only,[b] with CO_2:			H_2 + electricity,[c] with CO_2:		
	Vented	Seq.	Coseq.	Vented	Seq.	Coseq.
Coal input rate (MW_{th})	923	1058	1058	1492	1497	1497
CO_2 emission rate	grC/kWh			kgC/GJ_{H2}		
	193.7	15.9	15.9	35.65	2.61	2.61
CO_2 disposal rate ($t\ CO_2/h$)	-	309.7	309.7	-	437.4	437.4
H_2 output rate (MW_{th})	-	-	-	1000	1000	1000
Electric power balance (MW_e)						
Gas turbine output	314.5	335.4	335.5	-	59.6	59.6
Steam turbine output	173.7	178.3	178.3	138.1	101.4	101.4
Syngas expander output	7.0	10.4	10.4	0.0	-	-
Air separation	- 25.2	- 28.8	- 28.8	- 40.6	- 40.8	- 40.8
Extra $_{O2}$ compressor	- 15.4	- 17.5	- 17.5	- 24.7	- 24.8	- 24.9
Gasification auxiliaries	- 8.9	- 10.2	- 10.2	- 14.4	- 14.4	- 14.4
CO_2 compressor (→ *150 bar*)	-	- 25.8	- 25.8	-	- 36.6	- 36.6
Purge compressor for PSA unit	-	-	-	-	- 8.4	- 8.4
N_2 compressor	- 29.8	- 28.9	- 28.9	-	-	-
Other auxiliaries	- 6.0	- 7.3	- 7.3	- 6.2	- 5.1	- 5.1
Net power output	409.9	405.7	405.7	52.2	30.9	30.9
1st law efficiency ($?_{1st}$), HHV basis (%)[d]	44.40	38.35	38.35	70.52	68.86	68.86
Eff. Efficiency ($?_{eff}$) of H_2 production (%)[d]	-	-	-	73.83	70.06	70.06
Plant capacity factor (%)	80	80	80	80	80	80
Capital cost by component ($\$10^6$)						
Coal storage, preparation, handling	36.01	39.61	39.61	50.40	50.52	50.52
Air separation unit	72.12	79.07	79.07	123.87	124.16	124.16
Extra O_2 compressor	15.03	16.18	16.18	20.17	20.22	20.22
Gasifier	85.77	94.35	94.35	120.04	120.33	120.33
Water gas shift reactors	-	26.58	26.58	33.81	33.90	33.9
Glycol H_2S removal	58.15	63.97	-	81.39	81.58	-
Selexol CO_2 or $_{CO2}/H_2S$ removal	-	27.41	27.41	-	34.96	34.96
PSA $_{H2}$ separation	-	-	-	42.91	42.91	42.91
Gas turbine	103.46	109.69	109.69	-	26.86	26.86
HRSG and steam turbine	114.13	116.54	116.54	94.99	74.17	74.17
N_2 compressor	16.54	16.24	16.24	-	-	-
CO_2 drying and compression	-	31.42	31.42	-	44.52	44.52
Subtotal, overnight construction cost	501.2	621.1	557.1	567.6	654.1	572.5
Interest during construction	80.3	99.5	89.3	90.95	104.82	91.75
Total installed cost ($\$10^6$)[e]	581.5	720.6	646.4	658.5	758.9	664.3
Energy production cost by component	Electricity (*¢/kWh*)			H_2 (*$/GJ*)		
Capital (*ACCR = 15%*)	3.04	3.80	3.41	3.92	4.51	3.95
O&M (*4% of “overnight” capital/y*)	0.70	0.87	0.78	0.90	1.04	0.91
Coal input (*@ $0.93/GJ*[f])	0.75	0.87	0.87	1.39	1.39	1.39
CO_2 disposal (*@ $5/t* CO_2)	-	0.38	0.38	-	0.61	0.61
Electricity sales credit[g] (*P_E = electricity price in $/kWh*)	-	-	-	-14.50*P_E	- 8.58*P_E	- 8.58*P_E
Total cost, carbon tax (CT) = $0/tC	4.49	5.92	5.44	5.56	7.16	6.47
Total cost, CT = $28.72/tC[h]	5.05	5.97	5.55	**6.50**	7.19	**6.50**
Total cost, CT = $50.35/tC[i]	5.47	6.00	5.52	**7.21**	**7.21**	6.52
Total cost, CT = $53.43/tC[j]	**5.53**	6.01	**5.53**	7.31	7.22	6.53
Total cost, CT = $80.42/tC[k]	**6.05**	**6.05**	5.57	8.20	7.24	6.55

Notes for Table 3:

[a] Energy balances (HHV basis) and material flows (P. Chiesa, T.G. Kreutz, and R.H. Williams, Techno-economic analysis of hydrogen and/or electricity production from coal with near-zero pollutant and CO_2 emissions using an inorganic hydrogen separation membrane reactor. B: System optimization and comparative analysis, Princeton Environmental Institute, Princeton University, forthcoming) were calculated using GS power generation and chemical process software developed at the Dipartimento di Energetica, Politecnico di Milano, Milan, Italy. All cases involve the Texaco O_2-blown gasifier with quench (@ 70 bar) and high sulfur coal. CO_2 recovery cases involve CO_2 compression to 150 bar for pipeline transport to a sequestration site and disposal @ \$5/t CO_2.

[b] Technology without CO_2 separation/recovery is an IGCC plant with a steam-cooled gas turbine; glycol solvents are used to remove H_2S, which is recovered and converted to elemental sulfur. Technology with CO_2 separation/recovery is the same IGCC unit except that shift reactors are added where steam reacts with CO to form CO_2 and H_2, and Selexol (a glycol solvent) is used to remove simultaneously H_2S and CO_2 from the shifted synthesis gas for codisposal ; 92.7% of coal C is recovered as CO_2 for disposal.

[c] Technology without CO_2 separation/recovery involves: gasifier plus shift reactors; a glycol solvent to remove H_2S, which is recovered and converted to elemental sulfur; pressure-swing-adsorption (PSA) unit to separate out $H_{2;}$ steam turbine fueled by PSA purge gas. For the "sequestration" case, a glycol solvent is used to remove H_2S, which is recovered and converted to elemental sulfur; Selexol is used to remove CO_2 from the shifted synthesis gas for disposal; a pressure-swing-adsorption (PSA) unit is used to purify the $H_{2;}$ a PSA purge gas compressor is used to compress the purge gas for use in a combined cycle providing coproduct power; 92.7% of coal C is recovered as CO_2 for disposal. The "cosequestration" case is similar to the sequestration case, except that sulfur in the form of H_2S is not recovered and converted to elemental sulfur; rather Selexol is used to remove simultaneously H_2S and CO_2 from the shifted synthesis gas for co-disposal.

[d] $?_{1st}$ = (electricity + H_2 output)/(coal input); $?_{eff}$ = (H_2 output)/(coal input – coal saved), where the coal saved is the coal consumption avoided by not having to produce the electricity coproduct in a stand-alone facility. The efficiency of power generation assumed in calculating the coal saved is for the least costly electricity option with zero carbon tax.

[e] The installed capital cost includes interest during construction (assuming a 10% interest rate and a 4-year construction period). Costs for CO_2 separation and compression are included but not the cost of CO_2 disposal (pipeline plus disposal wells and surface facilities), which are treated separately below.

[f] The average coal price for electric generators in the United States in 2020 is projected by the Energy Information Administration to be \$0.93/GJ in 2020 [Energy Information Administration, *Annual Energy Outlook 2001, with Projections Through 2020*. DOE/EIA-0383(2001), US Department of Energy, Washington, DC, 2000].

[g] The value of electricity P_E in the electricity sales credit depends on the carbon tax level; for a given carbon tax level P_E equals the cost of the electricity from the least-costly option.

[h] This is the carbon tax at which H_2 production costs are equal for the CO_2 venting and cosequestration cases.

[i] This is the carbon tax at which H_2 production costs are equal for the CO_2 venting and sequestration (with elemental sulfur recovery) cases.

[j] This is the carbon tax at which electricity production costs are equal for the CO_2 venting and cosequestration cases.

[k] This is the carbon tax at which electricity production costs are equal for the CO_2 venting and sequestration (with elemental sulfur recovery) cases.

Table 4a: Producing H_2 from Natural Gas (*1000 MW_t of 60 bar H_2 Output Capacity*)[a]		
	CO_2 vented	CO_2 sequestered
First law efficiency ($?_{1st}$), HHV basis (*%*)	81	78
CO_2 Emission Rate (*kg C/GJ H_2*)	17.56	2.74
CO_2 Sequestration Rate (*t CO_2 /h*)	-	204
Capital Investment except for CO_2 disposal (*$ million*)		
Equipment and installation subcontracts:		
Reformer	48.65	67.90
Purification	23.65	58.08
CO_2 compression	-	35.67
Other	123.95	174.67
Subtotal	196.25	336.32
Engineering, const. management, commissioning, training	9.13	16.94
Catalysts and chemicals	8.75	9.00
Client's costs	24.00	28.00
Contingency	23.81	39.03
Total installed capital cost	261.94	429.3
Lifecycle cost (*$/GJ*)		
Capital (*excluding CO_2 disposal*)	1.56	2.56
O&M (*except for CO_2 disposal*)	0.24	0.39
CO_2 disposal (*@ $5/t CO_2*)	-	0.28
NG input	4.20	4.36
Total	6.00	7.59
Production cost with a carbon tax (CT) = $107/tC	7.88	7.88

Table 4b: Delivered Cost of H_2 from Natural Gas (*$/GJ*)		
Production cost	6.00	7.59
Central H_2 plant compression from *60 bar* to 1000 psia for storage or pipeline transmission (*$/GJ*)[b]	0.03	0.03
Central H_2 plant buffer storage cost (*$/GJ*), storage capacity = 1/2 day's output of H_2 plant[b]	0.41	0.41
H_2 pipeline distribution system[b]	1.58	1.58
Refueling station[b]	5.61	5.61
Total cost of delivered H_2[c]	$13.6/GJ ($1.97/gge)	$15.2/GJ ($2.20/gge)

[a] Based on a study prepared by Foster Wheeler (Foster Wheeler, *Decarbonization of Fossil Fuels*, Report No. PH2/2, prepared for the Executive Committee of the IEA Greenhouse Gas R&D Programme of the International Energy Agency, March 1996) for Statoil and the IEA GHG Programme except that: the FW results are presented here with all energy quantities expressed on a HHV basis; the annual capital charge rate and system capacity factor are assumed to be 15% and 80%, respectively (compared to 12.4% and 90% in the original FW study), so that the annual H_2 production rate is 25.2 million GJ/year; the CO_2 disposal cost is assumed to be $5/t CO_2 in order to be consistent with the coal-to-H_2 analyses presented in Table A3. For these systems all energy requirements for H_2 production are provided from natural gas. 85% of the CO_2 in the feedstock is recovered, compressed to 112 bar, and transported by pipeline to the disposal site at a disposal rate of 57 kg CO_2/GJ H_2. The natural gas price is assumed to be $3.4/GJ, the average natural gas price projected for U.S. electric generators in 2020 by the Energy Information Administration [Energy Information Administration, *Annual Energy Outlook 2001, with Projections Through 2020.* DOE/EIA-0383(2001), US Department of Energy, Washington, DC, 2000].

[b] Based on Ogden (J.M. Ogden, Prospects for building a hydrogen energy infrastructure, *Annual Review of Energy and the Environment*, **24**: 227-279, 1999) high auto density case (1600 cars/mi^2)—equivalent to ½ the cars in the Los Angeles area being H_2 FCVs; refueling stations dispense H_2 at 345 bar to FCVs at a rate of 10^6 scf/day.

[c] The retail fuel price in $/GJ is presented on a HHV basis; the retail price in $ per gallon of gasoline equivalent energy (gge) is presented on a LHV basis.

Table 5: Carbon Tax Needed to Induce CO_2 Sequestration in the Production of H_2 and Electricity

(*\$/tC*)

Energy Carrier	Feedstock for Producing the Energy Carrier		
	Natural Gas with CO_2 Sequestered	Coal with CO_2[c]	
		Sequestered	Cosequestered
Hydrogen	107[a]	50	29
Electricity	257[b]	80	53

[a] From Table 4a.

[b] Derived from the calculation presented for a NGCC with a flue gas scrubber in Table 8.10, p. 292, in R.H. Williams, Advanced energy supply technologies, Chapter 8, pp. 273-329, in *World Energy Assessment: Energy the Challenge of Sustainability*, 2000 (a study sponsored jointly by the United Nations Development Programme, the United Nations Department of Social and Economic Affairs, and the World Energy Council), published by the Bureau for Development Policy, United Nations Development Programme, New York, 2000.

[c] From Table 3.

Table 6: Estimated Remaining Ultimately Recoverable Conventional Oil and Natural Gas Resources and Unconventional Natural Gas Resources and Their Carbon Contents

	Energy Resources (10^3 *EJ*)			Carbon Content[c] (*GtC*)		
	Low	**Med**	High	Low	**Med**	High
Conventional oil[a]	9.4	**11.1**	13.7	179	**211**	260
Conventional natural gas[a]	8.7	**11.9**	16.5	118	**162**	224
Subtotal	18.1	**23.0**	30.2	297	**373**	484
Non-conventional natural gas[b]		**33.2**			**452**	
Total		**56.2**			**825**	

[a] Conventional oil and natural gas resource estimates are from a 1994 analysis carried out by the US Geological Survey (USGS): C.D. Masters, E.D. Attanasi, and D.H. Root, “World petroleum assessment and analysis,” *Proceedings of the 14th World Petroleum Congress,* Stavanger, Norway. Since this assessment, theUSGS has come out with a new assessment (USGS World Petroleum Assessment 2000), which found that outside the US: undiscovered oil will amount to 110 billion barrels more (12.7 GtC more) than the 1994 estimate; undiscovered natural gas will be 137 billion boe less (11.4 GtC less) than the 1994 estimate; and NGL will be 117 boe more (11.8 GtC more) than the 1994 estimate. Thus the total carbon content of conventional oil and gas resources according to the 2000 USGS survey will be 13 GtC more than for the 1994 USGS estimate.

[b] The estimated ultimately recoverable unconventional natural gas resources are from Table 5.7, p. 149, in H.-H.Rogner, Energy resources, Chapter 5, p. 135-171, in *World Energy Assessment: Energy the Challenge of Sustainability*, 2000 (a study sponsored jointly by the United Nations Development Programme, the United Nations Department of Social and Economic Affairs, and the World Energy Council), published by the Bureau for Development Policy, United Nations Development Programme, New York. Estimated ultimately recoverable natural gas resources amount to 3.5% of the estimated natural gas in place (see Table 5.4, p. 146, in Roger (2000) in the form of coal bed methane (8.6 thousand EJ), tight formation gas (4.2 thousand EJ), gas hydrates (347.5 thousand EJ), and geopressurized gas (599.4 thousand EJ).

[c] Carbon contents are assumed to be 13.6 MtC/EJ for natural gas and 19.0 MtC/EJ for oil.

References and Endnotes

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[i] Michael Oppenheimer, How Much Climate Change Mitigation is Enough?, Princeton Environmental Institute Seminar, November 2001.

[ii] 39% nuclear, 16% hydroelectric, and 45% new renewables.

[iii] 45% nuclear, 51% hydroelectric, and 4% new renewables.

[iv] See R. H. Williams, Nuclear and alternative energy supply options for an environmentally constrained world, in *Nuclear Power and the Spread of Nuclear Weapons: Can We Have One Without the Other?* (a work arising from the 20th Anniversary Conference of the Nuclear Control Institute, 9 April 2001, Washington, DC), to be published by Brassey's; Williams, 2002a; R.H. Williams, Facilitating widespread deployment of wind and photovoltaic technologies, Annual Report of the Energy Foundation, San Francisco, CA, 2002b.

[v] W. Turkenburg, Renewable energy technologies, Chapter 7, pp. 219–272, in *World Energy Assessment: Energy the Challenge of Sustainability*, 2000 (a study sponsored jointly by the United Nations Development Programme, the United Nations Department of Social and Economic Affairs, and the World Energy Council), published by the Bureau for Development Policy, United Nations Development Programme, New York, 2000.

[vi] J. M. Ogden, and R. H. Williams, *Solar Hydrogen: Moving Beyond Fossil Fuels*, World Resources Institute, Washington, D.C., 1989.

[vii] In early 2002 the Bush Administration announced a new Freedom Cooperative Automotive Research (Freedom CAR) program to develop with US automakers both H_2-powered fuel cell cars and the H_2 supply infrastructure to support them.

[viii] J. M. Ogden, R. H. Williams, and E. D. Larson, Toward a hydrogen-based transportation system, draft manuscript, Princeton Environmental Institute, Princeton University, Princeton, New Jersey, May 2001.

[ix] Williams (2002a) (see Endnote iv).

[x] The cost C_{H2} of H_2 ($/GJ, HHV basis) produced via electrolysis can be written [see Williams (2002a), Endnote iii] as:

$$C_{H2} = P_{electrolysis} + (P_E)/(? \text{ x } 0.0036 \text{ GJ/kWh}),$$

where

$P_{electrolysis}$ = the cost of electrolysis ($/GJ, HHV basis)
PE = the cost ($/kWh) of the "electricity feedstock"
? = system efficiency (HHV basis) for converting electricity into H_2

For present day electrolytic technology operated in baseload mode (80% capacity factor) $P_{electrolysis}$ = $6.1/GJ and ? = 0.74, whereas $P_{electrolysis}$ = $3.6/GJ and ? = 0.88 might well be realizable with advanced electrolytic technologies (perhaps 20 years from now). It is not unreasonable to expect that unsubsidized wind power will become (say 20 years from now) as cheap as $0.025/kWh for widely available Class 4 winds and that the corresponding cost of baseload power from a wind/compressed air energy storage system might become as cheap as $0.03/kWh. The corresponding H_2 cost with advanced electrolytic technology would thus be $13/GJ—which is 1.8 to 2.0 times as expensive as H_2 derived from coal based on commercial technology, including the cost of sequestering the separated CO_2 in geological formations (see Table 3).

[xi] A. Steinfeld and R. Palumbo, Fuels from sunlight and water, a paper available at www.psi.ch, the website of the Paul Scherrer Institute, Switzerland, 2001.

[xii] Williams (2002a) (see Endnote iv).

[xiii] R.H. Williams, Advanced energy supply technologies, Chapter 8, pp. 273-329, in *World Energy Assessment: Energy the Challenge of Sustainability*, 2000; and S. Bachu, Geological sequestration of anthropogenic CO_2: applicability and current issues, pp. 285-303, in *Geological Perspectives of Global Climate Change,* eds. L. C.

Gerhard, W. E. Harrison, and B. M. Hanson, AAPG Studies in Geology 47, American Association of Petroleum Geologists, Tulsa, Oklahoma, 2001.

[xiv] Williams (2000) (see Endnote xiii).

[xv] Most enhanced oil recovery projects in the United States are in the Permian Basin of Texas. Most of the CO2 for these projects is transported by pipeline from natural reservoirs of CO2 in Colorado, New Mexico, and Wyoming [e.g., via an 800-km pipeline from the M^{c}Elmo Dome (which contains 0.5 Gt of CO_2) in western Colorado].

[xvi] S. H. Stevens, V. A. Kuuskraa, and J. Gale, Sequestration of CO_2 in depleted oil and gas fields: global capacity, costs, and barriers, pp. 278-283, in *Greenhouse Gas Control Technologies: Proceedings of the 5th International Conference on GHG Control Technologies (GHGT-5),* edited by D. J. Williams, R. A. Durie, P. McMullan, C. A. J. Paulson, and A. Y. Smith, CSIRO Publishing, Collingwood, Victoria, Australia, 2000.

[xvii] S. H. Stevens, V. A. Kuuskraa, D. Spector, and P. Riemer, Enhanced coalbed methane recovery using CO_2 injection: worldwide resource and CO_2 injection potential, pp. 175-180, in *Greenhouse Gas Control Technologies: Proceedings of the 4th International Conference on GHG Control Technologies,* edited by B. Eliasson, P. Riemer, and A. Wokaun, Pergamon, Amsterdam, The Netherlands, 1999..

[xviii] W. D. Gunter, T. Gentzix, B. A. Rottenfusser, and R. J. H. Richardson, Deep coalbed methane in Alberta, Canada: a fuel resource with the potential of zero greenhouse emissions, *Energy Conversion and Management* **38**: S217–S222, 1997.

[xix] Gunter et al. (1997) (see Endnote xviii).

[xx] Of the 6 trillion tonnes of U.S. coal resources at depths up to 1,800 meters, 90 percent is cannot be mined with current technology because the coal is too deep, the seams are too thin, or the mining would be unsafe (C. W. Byrer and H. D. Guthrie, Coal deposits: potential geological sink for sequestering CO_2 emissions from power plants, in *Greenhouse Gas Control Technologies: Proceedings of the 4th International Conference on GHG Control Technologies*, pp. 181-187).

[xxi] Stevens, Kuuskraa, and Gale (2000) (see Endnote xvi).

[xxii] M. J. van der Burgt, J. Cantle, and V. K. Boutkan, CO_2 disposal from coal-based IGCCs in depleted gas fields, *Energy Conversion and Management*, **33** (5–8)(1992): 603–610; and I. R. Summerfield, S. H. Goldthorpe, N. Williams, and A. Sheikh, Costs of CO_2 disposal options, in *Proceedings of the International Energy Agency CO_2 Disposal Symposium*, Pergamon, Amsterdam, 1993.

[xxiii] Capacity from past production plus proved reserves plus estimated undiscovered conventional resources.

[xxiv] C. A. Hendriks, *CO_2 Removal from Coal-fired Power Plants*, Ph.D. thesis, Department of Science, Technology, and Society, Utrecht University, Utrecht, Netherlands, 1994.

[xxv] Intergovernmental Panel on Climate Change, Energy supply mitigation options, Chapter 19, in *Climate Change 1995: Impacts, Adaptations and Mitigation of Climate Change: Scientific-Technical Analyses,* Second Assessment Report of the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, 1996.

[xxvi] B. Hitchon, W. D. Gunter, T. Gentzis, and R. Bailey, Sedimentary basins and greenhouse gases: a serendipitous association, *Energy Conversion and Management* **40**: 825–843, 1999; S. Bachu and W. D.Gunter, Storage capacity of CO_2 in geological media in sedimentary basins with application to the Alberta Basin, pp. 195-200, in *Greenhouse Gas Control Technologies: Proceedings of the 4th International Conference on GHG Control Technologies*; and Bachu (2001) (see Endnote xiii).

[xxvii] The critical point for CO_2 is 74 bar and 31 °C.

[xxviii] The hydrostatic pressure gradient is typically about 100 bar per km.

[xxix] Deep aquifers (800 m or more below the surface) tend to be saline because the contained water is fossil water that has been there over sufficient geological time for the water to come into chemical equilibrium with the minerals in the host rock. Dissolved salts typically make the water brackish and often even briny.

[xxx] Hendriks (1994) (see Endnote xxiv).

[xxxi] S. Bachu, W. D. Gunter, and E. H. Perkins, Aquifer disposal of CO_2: hydrodynamic and mineral trapping, *Energy Conversion and Management*, **35**: 269-279, 1994; and S. Holloway, ed., *The Underground Storage of CO_2*, a report prepared for the Joule II Programme (DG XII) of the Commission of the European Communities, Contract No. JOU2 CT92-0031, Brussels, Belgium, February 1996.

[xxxii] Bachu, Gunter, and Perkins (1994) (see Endnote xxxi).

[xxxiii] W. D. Gunter, E. H. Perkins, and T. J. McCann, Aquifer disposal of CO_2-rich gases: reaction design for added capacity, *Energy Conversion and Management*, **34**: 941-948, 1993.

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[xxxv] Hendriks (1994) (see Endnote xxiv).

[xxxvi] H.-H.Rogner, Energy resources, Chapter 5, p. 135-171, in *World Energy Assessment: Energy the Challenge of Sustainability*.

[xxxvii] O. Kaarstad, Emission-free fossil energy from Norway, *Energy Conversion and Management*, **33** (5–8): 781-786, 1992.

[xxxviii] International Energy Agency, CO_2 capture and storage in the Natuna NG Project, *Greenhouse Issues*, **22** : 1, 1996.

[xxxix] H. L. Longworth, G. C. Dunn, and M. Semchuck, Underground disposal of acid gas in Alberta, Canada: regulatory concerns and case histories, SPE 35584, a paper presented at the Gas Technology Conference, Calgary, Alberta, Canada, April 28–May 1, 1996; and E. Wichert and T. Royan, Acid gas injection eliminates sulfur recovery expense, *Oil and Gas Journa* : 67-72, 28 April 1997.

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[xli] Williams (2000) (see Endnote xiii).

[xlii] Williams (2000) (see Endnote xiii).

[xliii] Williams (2000) (see Endnote xiii).

[xliv] At such high partial pressures, use of a physical solvent such as Selexol (dimethyl ether of polyethylene glycol) for CO_2 removal leads to a lower lifecycle cost than for CO_2 removal using amines.

[xlv] Typically the manufacture of H_2 from natural gas begins by reacting steam with the natural gas at a temperature of ~ 900 degrees centigrade to make synthesis gas (mostly CO and H_2). The synthesis gas is then cooled and the CO is reacted with more steam to produce H_2 and CO_2 via the water-gas-shift reaction, so that the overall processing leads to a gaseous mixture consisting mainly of H_2 and CO_2. The H_2 is next separated

from the CO_2 and other gases. Commercial technology can provide H_2 that is 99.999% pure. If a stream of relatively pure CO_2 is desired as a coproduct (to facilitate CO_2 disposal), the cost is somewhat higher than that for the standard practice.

[xlvi] P. Chiesa, T.G. Kreutz, and R.H. Williams, Techno-economic analysis of hydrogen and/or electricity production from coal with near-zero pollutant and CO_2 emissions using an inorganic hydrogen separation membrane reactor. B: System optimization and comparative analysis, Princeton Environmental Institute, Princeton University, forthcoming; R. H. Williams, Toward zero emissions for coal: roles for inorganic membranes, pp. 212-242, in *Proceedings of the International Symposium Toward Zero Emissions: the Challenge for Hydrocarbons*, pp. 212-242, EniTecnologie, Rome, Italy, March, 1999.

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[xlviii] J. Ogden, R.H. Williams, and E.D., Larson, Toward a hydrogen-based transportation system, Princeton Environmental Institute, Princeton University, May 2001, unpublished manuscript.

[xlix] R. H. Williams, E. D. Larson, R. E. Katofsky, and J. Chen, Methanol and hydrogen from biomass for transportation, *Energy for Sustainable Development*, **1** (5): 18-34, 1995.

[l] See Table 8.6, page 283, and Table 8.13, page 298, in Williams (2000) (see Endnote xiii).

[li] If the geological sequestration of CO_2 proves to be a fatally flawed idea (which the author doubts will turn out to be the case), another option for preventing the release of CO_2 to the atmosphere from fossil energy systems would be in the form of solid carbonates, by reacting CO_2 with certain abundant minerals such as forsterite or serpentine in exothermic reactions that are favored under ambient conditions. The reactions are:

$$\tfrac{1}{2}\, Mg_2SiO_4 + CO_2 \rightarrow MgCO_3 + \tfrac{1}{2}\, SiO_2 + 95 \text{ MJ per kmole},$$

for foresterite and:

$$1/3\, Mg_3Si_2O_5(OH)_4 + CO_2 \rightarrow MgCO_3 + 2/3\, SiO_2 + 2/3\, H_2O + 64 \text{ MJ per kmole}$$

for serpentine.

Resources of such minerals are more than what is needed to store as carbonates the carbon in all remaining recoverable fossil fuels. Although about 6 tonnes of mineral (e.g., serpentine) are needed for each tonne of coal processed, the mineral mining costs are low, and overall costs might not be prohibitive; various chemical processes for creating carbonates from CO_2 and serpentine are being investigated (T.M. Yegulalp, K.S. Lackner, and H.J. Ziock, A review of emerging technologies for sustainable use of coal for power generation, *The International Journal of Surface Mining, Reclamation, and Environment,* 2000).

[lii] One estimate [R.H. Wiliams, Fuel decarbonization for fuel cell applications and sequestration of the separated CO_2, pp. 180-222, in *Ecorestructuring,* R.U. Ayres (ed), UN University Press, Tokyo, Japan, 417 pp., 1998] is that the lifecycle emission rate would be – 18.4 kgC/GJ of H_2 produced using an indirectly heated biomass gasifier. Thus, a valuation of negative emissions at $54/tC would generate a credit of $1.0/GJ against the cost of H_2 manufacture.