Nuclear and Alternative Energy Supply Options for an Environmentally Constrained World

A Long-Term Perspective

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Prepared for the

Nuclear Control Institute's 20th Anniversary Conference
"Nuclear Power and the Spread of Nuclear Weapons:
Can We Have One Without the Other?"

Washington, DC
9 April 2001

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Introduction

Nuclear power is commercial technology that offers the potential for providing electricity with zero emissions of air pollutants and greenhouse gases. Despite this promise, the nuclear power industry is stagnating. Most energy projections show that, although some new capacity will be added (primarily in Asia) there will be little or no net growth or even a decline in nuclear generating capacity worldwide over the next two decades (Williams, 2000).

Nuclear power faces four serious challenges: costs that are typically higher than for alternatives; concerns about reactor safety; the lack of significant progress in dealing with radioactive waste disposal; and the the nuclear weapons connection to nuclear power. The recent World Energy Assessment (WEA, 2000)[1] reached judgments that there are good prospects for addressing the reactor safety challenge satisfactorily, and that the waste disposal problem can probably be solved technically—though it will be difficult to convince publics that the problem is soluble. No judgment was reached on the cost challenge ("the proof is in the pudding"). And the WEA expressed skepticism regarding the prospects for coping effectively with the nuclear weapons connection to nuclear power. This skepticism is rooted in the formidable extent of the challenge of separating the peaceful atom from the military atom—especially at the high levels of nuclear power development needed to "make a dent" in climate change mitigation, as an alternative to continued reliance on fossil fuels over the longer term.

The Climate Change Mitigation Challenge Under IS92a

The climate change challenge is forcing policymakers to take a long-term (century-scale) perspective in energy planning—because of the likelihood that radical technological change for energy is needed to deal effectively with climate change and the fact that 50 years or more are needed to transform fundamentally the energy system (Grübler, 1998).

The IS92a global energy scenario (see Table 1) of the Intergovernmental Panel on Climate Change (IPCC, 1994), often referred to as a "business-as-usual"(BAU) scenario representing a plausible course for global energy under a public policy that gives no consideration to climate change concerns, has been widely used as a framework for understanding the climate change challenge. IS92a also provides a useful framework for understanding energy-related risks other than climate change—such as the nuclear weapons connection to nuclear power, and land use and other challenges posed by renewable energy options.

Under IS92a: CO_2 emissions from fossil fuel burning increase from 6.2 GtC in 1997 to 19.8 GtC in 2100; cumulative CO_2 emissions in the 21st century amount to 1340 GtC, and the atmospheric CO_2 level increases from the present 365 ppmv to 700 ppmv by 2100.

Although there are many uncertainties regarding the potential impacts of such a rise of CO_2 in the atmosphere, the impacts are likely to be severe (Holdren and Smith, 2000), suggesting the importance of exploring whether it would be feasible to evolve an energy system for which CO_2 emissions are such that the atmosphere could be stabilized at 550 ppmv (double the pre-industrial level) or even 450 ppmv of CO_2. Stabilizing the atmosphere at 550 ppmv would require reducing cumulative emissions, 2000-2100, by more than 500 GtC relative to IS92a and evolving an energy system emitting no more than about 5 GtC by 2100. Stabilizing at 450 ppmv would

Table 1: Global Energy: Actual 1997 + IS92a Projection for 2100		
	Actual, 1997[a]	IPCC's IS92a projection for 2100[b]
Electricity Generation (TWh/y)		
Coal	4,818	15,480
Oil	1,244	531
Natural gas	2,246	915
Synthetic liquids/gases from coal	-	3,017
Byproduct of H_2 from coal w/CO_2 storage	-	-
Hydroelectric	2,574	7,660
Wind	192	20,405
Photovoltaic		
Biomass		1,381
Nuclear	2,266	18,695
Subtotal	13,340	68,084
CO_2 emissions, power sector (GtC/y)	1.9	4.9
Fuels Used Directly (EJ/y, HHV basis)		
Coal	43.2	132.7
Oil	142.7	94.6
Natural gas	63.0	37.3
Synthetic liquids/gases from coal	0	276.5
Synthetic liquids/gases from biomass	0	126.5
Subtotal	248.9	667.7
CO_2 emissions, fuels used directly (GtC/y)	4.3	14.9
Primary energy requirements (EJ/y, HHV basis)		
Coal	97.9	718
Oil	156.9	100
Natural gas	88.5	47
Biomass	-	205
Total CO_2 emissions (GtC/y)	6.2	19.8

[a] Global data for 1997 are from EIA (2001).

[b] IS92a is the reference ("Business As Usual") global energy scenario of the Intergovernmental Panel on Climate Change (IPCC, 1994).

require reducing cumulative emissions, 2000-2100, by more than 850 GtC relative to IS92a and evolving an energy system emitting about 3 GtC by 2100 (Wigley, Richels, and Edmonds, 1996; Hoffert *et al*., 1998).

The climate change mitigation challenge can be illuminated by examining details of the IS92a projection (see Box A). Under IS92a, the historical trend toward electrification of the energy economy continues—with the electricity share of secondary energy consumption increasing to 28% in 2100 (nearly double the current share). Yet the power sector's share of CO_2 emissions decline, from 1/3 in 1997 to ¼ in 2100 at the global level (see Figure 1).

The declining share of emissions from the power sector arises in part because of the expectation of growing contributions from non-carbon supplies—to 71% in 2100[2] up from 38% in 1997.[3] Another important reason is an increase in the carbon intensity of fuels used directly in the latter half of the century as a result of the expected peaking of global conventional oil and natural gas production before the middle of this century (see Box A).

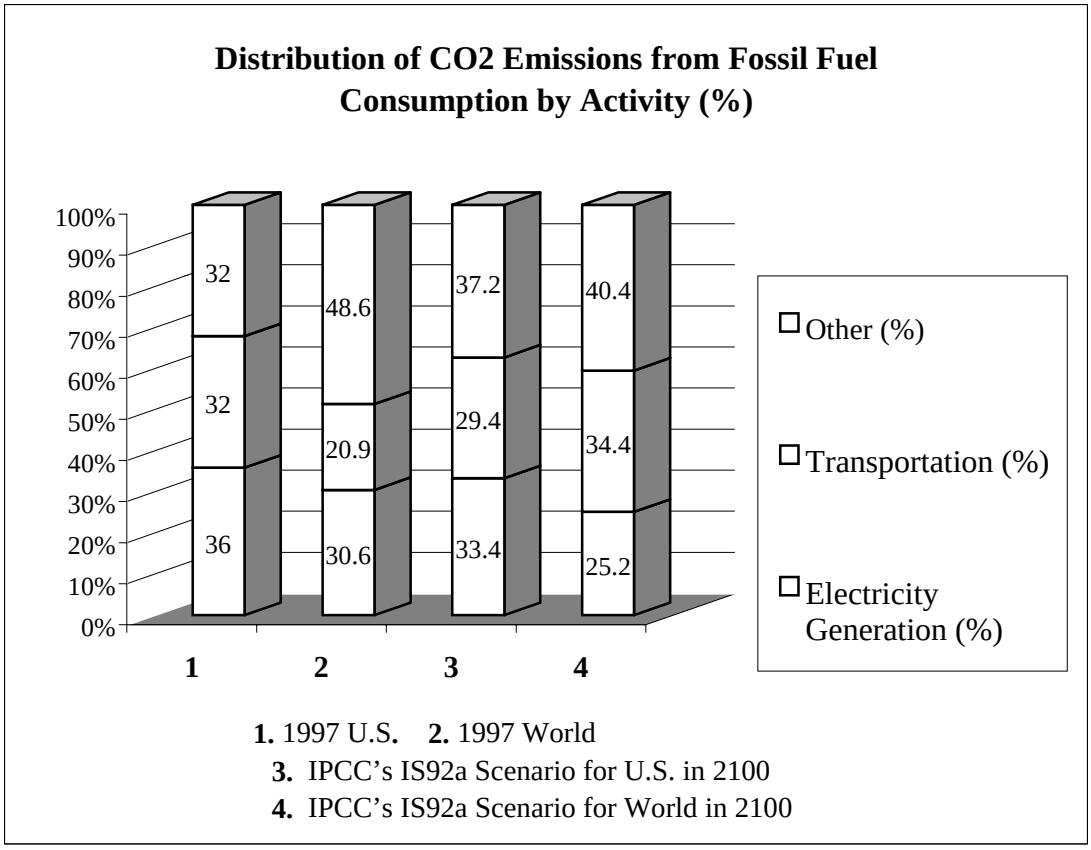

Figure 1: Distribution of CO_2 Emissions from Fossil Fuel Burning by Activity

Emissions are presented for the United States (bars 1 and 3) and for the world (bars 2 and 4), as well as actual data for 1997 [bars 1 and 2—from EIA (2001)] and IS92a projections for 2100 (bars 3 and 4).

Nuclear Power in Climate Change Mitigation and Associated Nuclear Weapons Risks

Under IS92a nuclear capacity grows from 350 GW_e in 1997 to 2,700 GW_e in 2100. Even with this substantial capacity growth, the nuclear contribution to climate change mitigation is relatively modest. If nuclear power in IS92a were entirely replaced by coal, CO_2 emissions in 2100 would be 24 GtC/year, about 20% more than in IS92a.

Nuclear power could potentially play a larger role in climate change mitigation—e.g., by increasing nuclear capacity at the end of the century to 4,900 GW_e, enough to displace *all* coal power. If such a nuclear-intensive variant of IS92a were to be realized, CO_2 emissions in 2100 would be 16 GtC/year, about 20% less than for IS92a. For this scenario nuclear power plants would have to be built at an average rate[4] of 85-90 GW_e per year during the century.

At the high level of nuclear power development in this nuclear-intensive variant of IS92a, the nuclear weapons link to nuclear power (the risks of both nuclear weapons proliferation by nation states and terrorists acquiring nuclear weaponry) would come into sharp focus.

Consider first the case where uranium resource constraints force a shift sometime during the

Box A: The IS92a Scenario for Global Energy

Under IS92a, global population grows from 5.9 billion in 1997 to 11.3 billion in 2100, global GDP grows at an average rate of 2.2%/year (so that GDP per capita grows 5-fold in the 21st century), while primary energy grows about 1% per year more slowly (approximately the historical rate of decline in energy intensity).

The trend toward electricification of the global energy economy continues under IS92a, with per capita electricity generation growing to ~ 6,000 kWh per capita by 2100 (about ½ the use rate in the United States in 1997), up from ~ 2,300 kWh per capita in 1997. Under IS92a, direct use of fuels (use in applications other than for electricity generation) grows much more slowly: direct secondary fuel use per capita grows less than 40% [to 59 GJ per capita in 2100 (about ¼ of the use rate in the United States in 1997), up from 42 GJ per capita in 1997].

Because of an expected peaking of global production of conventional oil and natural gas during the second quarter of this century,[5] unconventional energy sources will be needed to provide fuels used directly. IS92a projects large roles for both coal- and biomass-derived synthetic fuels under BAU conditions—with synthetics (69% derived from coal and 31% from biomass) accounting for ¾ of liquid fuels and ¾ of gaseous fuels by 2100. Despite a projected relatively 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.

second half of this century to conventional plutonium breeder reactors so that such reactors are in wide use by 2100, along with fuel reprocessing and plutonium recycling. Each 1-GW_e power plant under such circumstances would discharge in its spent fuel 10^3 kilograms of plutonium each year that would be recovered via reprocessing and used in fresh fuel. The amount of plutonium circulating in global commerce would be about 5 million kilograms per year. The nuclear weapons link to nuclear power in this scenario is apparent from the fact that the amount of plutonium needed to make a nuclear weapon is less than 10 kilograms.

Because of the daunting institutional challenges associated with preventing significant quantities of this plutonium from being diverted to weapons purposes, attempts are being made to design technologies for which the energy benefits of the plutonium economy might be exploited without the risks implicit in the conventional plutonium economy.

One set of such technologies is metal-cooled fast reactors for which plutonium is never separated from fission products (Filin *et al*.,1999; Hill *et al*.,1999; Lopatkin and Orlov, 1999; Orlov *et al*., 1999; Zrodnikov *et al*., 1999). Although the system would be designed so that plutonium would never be fully separated from spent fuel, such systems would provide their operators with extensive knowledge, experience, and facilities for chemical processing of intensely radioactive spent fuel, which could provide the basis for moving quickly to separating plutonium for a weapons program, should a decision be made to do so (Williams, 2000).

A modest-scale (100-MW_e), compact[6] version with a lifetime (15-year) sealed core has been proposed for developing-country applications as a way to avoid such proliferation capacity-building (Hill *et al*., 1999). The system is intended to be "proliferation-resistant" in that the reactor core would be sealed so that individual fuel assemblies could not be removed. The entire sealed core

would be delivered as a unit to the power plant site and returned to the factory at the end of its useful life. However, the reactor core would contain 2.5 tonnes of plutonium, so that high security would have to be provided to deter theft of sealed reactor cores during transport to (as well as from) deployment sites. If such a technology were to catch on, providing adequate security would be a daunting challenge. Suppose ½ of the 4,900 GW_e of nuclear capacity in 2100 in the nuclear-intensive scenario discussed above were based on such reactors and that this capacity were built up at a linear rate beginning in 2040. During the period 2040-2100 the average deployment rate would be about 1000 reactors per year.[7]

If uranium could be extracted from seawater at competitive cost (Charpak and Garwin, 1998; Nobukawa *et al*., 1994), a shift to a plutonium economy might be avoided altogether, making possible continued reliance on once-through nuclear fuel cycles that are inherently more proliferation-resistant than fuel cycles that involve plutonium recycling. But with a large number of nuclear plants proliferation concerns would still be considerable. Feiveson (2000) has described a future in which the 100 MW_e pebble bed modular reactor (PBMR) operated on a once-through fuel cycle becomes the norm in a nuclear-power-intensive energy future. He envisions that 500 t SWU/y enrichment plants would deployed, each serving about 24 such reactors.[8] About 2000 such enrichment plants would be needed to support 4,900 GW_e of nuclear capacity. Assuming a critical mass of 15 kg, the enrichment requirement would be 3.4 t SWU per bomb, so that each enrichment plant would have the capacity to make about 150 bombs per year from natural uranium. More troubling still is that, for the 8% enriched uranium prepared for the PBMR, 84% of the enrichment required to make 90%-enriched uranium for a bomb has already been carried out, so that, starting with 8% enriched uranium, a 500 t SWU/y enrichment plant could make 875 bombs per year. Feiveson (2000) concludes:

> "So, the bottom line? Lots of enriched uranium too close to bomb quality, lots of separation plants, lots of incentive for innovation to make isotope separation cheaper and quicker. To me this is an unsettling prospect."

Largely as a result of being involved recently in a major review of advanced fossil and nuclear energy technologies and in the process becoming sensitised to the shortcomings of alternative "proliferation-resistant" nuclear reactor and fuel cycle technologies (Williams, 2000), the author is coming to the view that the nuclear weapons connection to nuclear power cannot be made acceptably low at levels of nuclear power development high enough to "make a dent" in addressing the climate change mitigation challenge unless all sensitive facilities—enrichment plants, reactors, reprocessing plants, fuel fabrication plants—are clustered in large, heavily guarded nuclear parks that are maintained under international control to reduce proliferation and diversion risks. There is no doubt that the "nuclear park" concept is technically feasible and would reduce proliferation and diversion dangers substantially. Much more questionable, however, is whether it is politically realistic to expect all the world's countries to place a major component of electricity supply under international control—and to agree on the administrative arrangements for doing so. Acceptance of international controls would be especially difficult for those countries that are world leaders in nuclear technology development and deployment and that see nuclear power as offering energy autarky.

But the question remains as to whether it is worthwhile to evolve nuclear power to such high levels of development as a climate change mitigation strategy. To answer this question one must know the prospects for the alternatives to nuclear power in a greenhouse gas emissions-constrained world. In what follows the prospects for some leading supply alternatives to nuclear energy for mitigating the climate change challenge in the power sector are first discussed. This is followed by a discussion of the major options for reducing CO_2 emissions for fuels used directly, which account for 3/4 of CO_2 emissions in 2100 under IS92a.

Alternatives for Achieving Deep Reductions of CO_2 Emissions in Power Generation

The major options that are alternatives to nuclear fission for decarbonizing the power sector are thermonuclear fusion, hydroelectric power, the "new" renewables (mainly wind and photovoltaic power) and decarbonized fossil fuels—each of which will be discussed in turn.

Thermonuclear Fusion

Fusion technology could provide CO_2 emissions-free electricity and might potentially be more proliferation-resistant than fission technology, but commercialization of fusion technology is not expected before the middle of the century (PCAST Energy R&D Panel, 1997). However, if nuclear fusion could be brought to commercial readiness in 50 years its market prospects would be quite uncertain, because it would face much stiffer competition than nuclear fission faces today—as will be apparent below.

Hydroelectric Power

Hydroelectricity accounted for 19% of global electricity generation 1997 (see Table 1). Hydroelectric power is a fully established renewable electric technology; the technical and economic potentials for expansion are and 5 ½ and 3 times the 1997 generation rate (Rogner, 2000); in IS92a, the economic potential is fully exploited by 2100 (see Table 1). Although large hydropower projects are coming under increasing attack on environmental grounds (Rogner, 2000), the future of climate-change mitigation does not depend sensitively on future environmental constraints on hydropower. If hydropower expansion were limited to plants already under construction and the deficit were made up entirely by coal power, CO_2 emissions in 2100 would be only 5% more than in IS92a.

New Renewables

Among new renewables, the focus here is on wind and photovoltaic (PV) power and on how use of appropriate electric storage technology could facilitate high levels of electric grid penetration by these intermittent renewables.

Coping with intermittency. The intermittency of wind and PV power is often viewed as a constraint on electric grid penetration. However, high reliability of power for grid systems can be assured despite this intermittency for grid penetration levels up to 10%-30% without new electric storage technology, if a substantial fraction of the capacity on the grid is accounted for by gas turbines and/or combined cycles and/or hydroelectric power supplies that can provide effective

backup to these intermittent renewables (Kelly and Weinberg, 1993). But without electrical storage, much lower penetrations of intermittent renewables are feasible if the grid backup capacity is mainly in the form of nuclear or supercritical fossil steam plants, which cannot respond quickly to changing load conditions and for which idle capacity costs are high. This implies that nuclear and intermittent renewables represent competitive rather than complementary power technologies in grid applications.

To achieve higher levels of electric grid penetration, electric storage is needed. Intermittent renewables can provide either load-following or baseload outputs if coupled to suitable electric storage. Fortunately, technological breakthroughs are not needed because costs of commercially available compressed air energy storage (CAES) technology are attractive (Shainker *et al*., 1993). CAES is well-matched to intermittent renewables, because costs are much lower than for all other electrical storage technologies with about a day of storage (see Table 2),[9] as would typically be needed to make load-following or baseload power from intermittent renewables. CAES requires suitable geology: bedded or domed salt formations that can be solution mined, mined spaces in hard rock, or porous media (aquifers or depleted natural gas fields). About 85% of the U.S. area has one or more suitable geologies for CAES (EPRI, 1993).

Wind power. Around 1980 the first modern grid-connected wind turbines were installed. By 1990 about 2 GW_e of grid-connected wind power was in operation worldwide. In 1999 installed wind capacity worldwide was about 14 GW_e, and wind accounted for 0.2% of total global electricity generation. Globally, wind power capacity for electric grid-connected applications has been growing 27%/y - 33%/y since 1994 (Turkenburg, 2000).

For the United States, the estimated *practically* exploitable potential for wind power is 10,000 TWh/year (see Table 3), about three times the total US electricity generation rate in 1997. At the global level, Grubb and Meyer (1993) estimated that the practically exploitable *onshore* potential is 53,000 TWh/y, whereas a World Energy Council study (WEC, 1994) estimated the potential to be 20,000 TWh/y; the author's estimate is 43,000 TWh/y,[10] which is more than the electricity generation rate in 2100 from fossil fuels plus nuclear power under IS92a (see Table 1).

Wind electricity costs have fallen sharply since the early 1980s. Currently, the unsubsidized cost is as low as 4 ¢/kWh where there are high-quality (Class 6) winds or 5 – 6 ¢/kWh in regions with moderate-quality (Class 4) winds (see Table 4)—significantly less than the cost of electricity from a new nuclear plant (see Table 5). In light of expected continuing technological improvements, wind electricity costs are projected to be less than 4 ¢/kWh by 2020 in regions with moderate-quality winds (see Table 4)—comparable to electricity costs for coal integrated gasifier combined cycle (IGCC) and natural gas combined cycle (CC) power plants (see Table 5).

The cost of electricity for a large baseload wind/CAES power system with a 90% capacity factor (i.e., the average system output would be 90% of peak output) would be only about 0.7 ¢/kWh more than the cost of electricity from simple wind farms at wind power costs projected for 2020 in regions with moderate-quality winds (see Table 4).[11] At 4.4 ¢/kWh, the cost of such power would be much less than for baseload power either from nuclear power or from natural gas or coal power with decarbonization/CO_2 sequestration technologies (see Table 5).

Table 2: Capital Costs for Electrical Storage[a] *(1997 Dollars)*				
Technology	Component Cost		Total Cost ($/kW)	
	Discharge capacity ($/kW)	Storage ($/kWh)	2 hours	20 hours
Compressed Air				
Large (350 MW)	350	1	350	370
Small (50 MW)	450	2	450	490
Above Ground (16 MW)	500	20	540	900
Conventional Pumped Hydro	900	10	920	1,100
Battery (target, 10 MW)				
Lead acid	120	170	460	3,500
Advanced	120	100	320	2,100
Flywheel (target, 100 MW)	150	300	750	6,200
Superconducting Magnetic Storage (target, 100 MW)	120	300	720	6,100
Supercapacitors (target)	120	3,600	7,300	72,000

[a] Source: PCAST Panel on International Cooperation in Energy Research, Development, Demonstration, and Deployment (1999) and based on a presentation by Robert B. Schainker (Electric Power Research Institute) to the PCAST Energy R&D Panel, 14 July 1997.

Most good wind resources are in regions remote from major electricity markets (Grubb and Meyer, 1993).[12] However, large-scale exploitation of these remote resources would be feasible by constructing large (multi-GW_e) wind farms coupled to CAES units to produce baseload wind/CAES power that could be transmitted at acceptable transmission cost to markets as distant as thousands of kilometers from generation sites via high capacity (GW_e-scale) transmission lines operated at high capacity factors (Cavallo, 1995; Lew *et al*., 1998).

A concern about wind power is its land-use intensity. But suppose wind power were developed by 2100 to the extent of the author's estimate of practically exploitable wind power—some 43,000 TWh/y or enough to provide almost 2/3 of total global electricity projected for 2100 under IS92a (see Table 1). The land area occupied by wind farms would amount to ~ 1.4% of the land area of the inhabited continents. Three considerations are helpful in thinking about using this much land. First, only 5-10% of the land on which wind turbines are deployed is actually used for wind turbines and their foundations, access roads, electrical substations, and other infrastructure; most of the land is usable for other purposes such as growing crops and ranching, as long as the visual impact of the turbines is tolerated Second, people in the remote areas where most wind resources are concentrated are likely to be less concerned than people in densely populated areas about aesthetic impacts of large wind farms, if wilderness areas are avoided. And third, to the extent that remote wind farms would be concentrated in farming/ranching regions (as would be the case in the United States—see Table 3), the income from wind farm royalties would be a major supplement to farming/ranching income—in the United States typically offering income per acre that is greater than net income from farming.[13]

Photovoltaic power. Although PV costs have fallen substantially since the mid-1970s, electric generation costs for central-station PV power plants in areas with good insolation at present are several times wind generation costs in regions with good wind resources. However, PV power offers major advantages over wind power and other renewables in that small PV systems can be sited near users—e.g., on residential building rooftops, commercial building facades, and roofs of parking garages—where the power is worth much more than in central-station power plants.

Table 3: Estimated Recoverable Wind Resources and Projected Costs by Wind Power Class in the US			
Region	**Class 4** *(5.6 m/s < V_{ave} < 6.0 m/s, 10 m)* *P = 400-500 W/m^2 @ 50 m*	**Class 5** *(6.0 m/s < V_{ave} < 6.4 m/s, 10 m)* *P = 500-600 W/m^2 @ 50 m*	**Class 6** *(6.4 m/s < V_{ave} < 7.0 m/s, 10m)* *P = 600-800 W/m^2 @ 50 m*
US	9,200 TWh/y	690 TWh/y	490 TWh/y
Great Plains[a]	8,900 TWh/y	570 TWh/y	420 TWh/y

[a] Potential based on U.S. land areas estimated by Elliott *et al.* (1991) as available for wind farms in amounts 0.415. 0.028, and 0.017 million km^2 for wind power classes 4, 5, and $\geq$ 6, respectively; estimates assume excluding: all wilderness and urban areas, 50% of forest lands, 30% of farm lands, and 10% of barren and range lands. The net power generation potential is estimated for 100 m hub height with year 2030-vintage technology (1412, 1566, and 1797 kWh/m^2/y, for wind power classes 4, 5, and 6, respectively (EPRI/OUT, 1997) and for wind turbine spacings of 5 rotor diameters across the wind and 10 rotor diameters downwind.

Such decentralized generation is feasible because a PV system requires no system operators, causes no pollution, is not noisy, and has costs per kWh that are not especially sensitive to scale

Already PV is the least-costly means of providing electricity to households with modest demand levels at sites remote from electric grids, including rural households in developing countries (Cabraal *et al.*, 1996). PV systems for grid-connected applications are not yet competitive, but installed costs for grid-connected residential rooftop applications have been falling sharply [from \$17/W_{ac} in 1984, to \$9/W_{ac} in 1992 and \$6/W_{ac} in 1996 (PCAST Energy R&D Panel, 1997)]. For thin-film residential PV systems, installed costs are expected to reach \$3/W_{ac} during 2005-2010; at this cost level PV systems on rooftops of new houses are expected to be fully cost-effective for U.S. consumers in several regions where net metering is allowed[14] and where PV systems are financed with home mortgages (Payne, Duke, and Williams, 2001). The potential residential rooftop PV market in the United States under these conditions is estimated to be as much as 40 GW_e for installed costs of \$3/W_{ac} (Marney *et al.*, 1997).

Major future gains are expected for PV performance, energy payback,[15] and cost. An assessment carried out jointly for the Electric Power Research Institute and the US Department of Energy projects that between 2005 and 2030 system efficiencies for thin-film PV will reach nearly 14% (up from 6 – 8% at present) and system costs for central-station applications will decline to less than \$1/W_{ac} (EPRI/OUT, 1997).[16] Realizing such gains would enable PV to compete in many markets throughout the world.

Although the economic prospects for PV in central-station power markets are quite uncertain, it is likely that PV will become widely competitive in distributed grid-connected markets. It is not unrealistic to expect that PV could ultimately be deployed at an average global per capita rate of the order of 1 kW_{ac}, which would require a collector area of about 7 m^2 per capita near users in areas characterized by average insolation.[17]

Electricity generation in 2100 at the global level could plausibly be based entirely on renewables[18] if at that time: (*i*) total generation is at the rate projected under IS92a (68,000 TWh/y—see Table 1), (*ii*) wind power is generated at the rate of the author's estimate of the

practically achievable long-term potential (43,000 TWh/y); (*iii*) hydropower and biomass power are produced at the

Table 4: Projected Electricity Cost for Wind Electricity[a]

	1997		2000		2005		2010		2020		2030	
Wind												
Wind farm capacity (*MW*)	25		37.5		50		50		50		50	
Installed capital cost (*$/kW*)	1000		750		720		675		655		635	
Wind power class[b]	4	6	4	6	4	6	4	6	4	6	4	6
Average capacity factor (%)	26.2	35.5	30.2	40.4	35.1	45.3	36.2	46.4	37.6	47.9	38.3	48.7
Generation cost (*¢/kWh*)												
Capital	6.54	4.82	4.26	3.18	3.51	2.72	3.19	2.49	2.99	2.34	2.84	2.23
O&M	1.18	0.87	0.93	0.70	0.57	0.44	0.57	0.44	0.57	0.45	0.57	0.45
Overhaul/replacement	0.21	0.15	0.16	0.12	0.08	0.06	0.10	0.08	0.07	0.05	0.06	0.05
Royalties to landowners	0.24	0.18	0.17	0.12	0.11	0.08	0.10	0.08	0.09	0.07	0.09	0.07
Total	8.17	6.02	5.52	4.12	4.27	3.31	3.96	3.09	3.71	2.91	3.56	2.80

[a] Source: Based on EPRI/OUT (1997), with an assumed annual capital charge rate of 15%.

[b] Classes 6 and 4 represent "high-quality" (6.4 to 7.0 m/s average wind speed at 10 m) and "moderate-quality" (5.6 to 6.0 m/s average wind speed at 10 m) wind resources, respectively.

rates projected for IS92a (9,000 TWh/y total—see Table 1), and (*iv*) the rest of the needed power (16,000 TWh/y) is provided by distributed PV power—which would require deployment of 0.8 kW_{ac} of PV capacity per capita in areas of average insolation.[19]

Decarbonized Fossil Fuels

Conventional wisdom is that avoiding CO_2 emissions from fossil fuel use requires abandoning fossil fuels. This is not so. Feasible technologies and strategies exist that make it possible to extract most of the energy contained in fossil fuels while simultaneously recovering the carbon in fossil fuels as CO_2 and preventing its release to the atmosphere. The issues involved concern the capacity, security, and cost of alternative CO_2 disposal options and the costs of separating the CO_2 from fossil energy systems and preparing it for disposal.

Outlook for CO_2 disposal. The options for CO_2 disposal include CO_2 storage in both the deep ocean and porous geological media. Although ocean disposal has received the most attention, environmental concerns and other large uncertainties in its prospects have led to a shift of focus in recent years to geological (underground) storage of CO_2—in depleted oil and natural gas fields, in uneconomic coal beds, and in deep saline aquifers (Williams, 2000; Bachu, 2001).

CO_2 injection for enhanced recovery of hydrocarbons might become profitable foci of initial efforts to sequester CO_2 (Williams, 2000).

There are about 74 enhanced oil recovery (EOR) projects worldwide, mostly (66) in the United States, where in 2000 oil production via EOR accounted for 4% of total US 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,[20] but 5 million tonnes per year comes from anthropogenic waste CO_2 sources (Stevens, Kuuskraa, and Gale, 2000).

Another option is CO_2 injection for enhanced recovery of methane from beds of unminable coal.

Table 5: Electricity Generation Costs for Baseload Nuclear, Natural Gas CC and Coal IGCC Power Plants

	Nuclear[a]	Natural Gas CC[b]		Coal IGCC[b]	
CO_2 sequestered?	-	No	Yes	No	Yes
Efficiency (%)	-	54.0	45.7	45.9	36.1
Emission rate (gr C/kWh)	0	90	15.7	184	23.9
CO_2 disposal rate (gr C/kWh)	-	-	91	-	210
Capital cost ($/kW$_e$)	1,700 – 3,100	416	907	1,114	1,514
Generation cost (¢/kWh)					
Capital[c]	3.64 – 6.64	0.89	1.94	2.38	3.24
Operation and maintenance	1.40	0.24	0.52	0.64	0.86
Fuel	0.54	2.27[d]	2.68[d]	0.73[d]	0.93[d]
CO_2 disposal (at $5/t CO_2[e])	-	-	0.17	-	0.39
Total	5.58 – 8.58	3.40	5.31	3.75	5.42
Generation cost (¢/kWh) with $104/tC carbon tax[f]	5.58 – 8.58	4.34	5.47	5.67	5.67

[a] A recent survey by country indicates that installed costs for new light water reactors range from $1,700 - $3,100 per kW$_e$ (Paffenbarger and Bertel, 1998). It is assumed that fuel and operation and maintenance (O&M) costs are, respectively, 0.54 and 1.40 ¢/kWh—average values for US nuclear plants in 1998 (Williams, 2000).

[b] Costs for 400 MW$_e$ natural gas combined cycle (CC) and coal integrated gasifier/combined cycle (IGCC) power plants—based on GE gas turbine/steam turbine CCs with steam-cooled gas turbine blades (technology recently commercialized for natural gas CCs). The calculations presented are from Chapter 8 (Advanced Energy Supply Technologies) of the World Energy Assessment (WEA, 2000); based on analyses by Dale Simbeck, SFA Pacific: engineering and contingencies are 10% of process capital equipment costs; general facilities are 10% of process capital equipment costs; annual operation and maintenance cost = 4% of the capital cost. For the CO_2 sequestration cases, costs are included for the capital, O&M, and energy penalties associated with compressing the separated CO_2 to 135 bar to make it ready for CO_2 disposal; CO_2 disposal costs are indicated separately.

[c] Assuming that: the annual capital charge rate is 15% and the average plant capacity factor is 80%.

[d] For natural gas and coal at $3.40/GJ and $0.93/GJ, respectively—the average prices projected for U.S. electric generators in 2020 by the U.S. Energy Information Administration (EIA, 2000).

[e] The disposal cost = cost for the pipeline carrying the CO_2 to the disposal site + cost for the disposal wells for injecting the CO_2 into a suitable geological formation + cost for associated surface facilities at the disposal site. For 400 MW$_e$ natural gas CC and coal IGCC plants a disposal cost of $5/tCO2 is a typical cost for CO_2 disposal at a sites that are respectively 50 km and 80 km from the power plant where the CO_2 is recovered.

[f] With this carbon tax, the coal IGCC electricity cost is the same without and with CO_2 sequestration.

Large amounts of methane are trapped in the pore spaces of many coals. Injection of CO_2 into such coals can sometimes lead to efficient methane recovery because typically CO_2 is twice as adsorbing on coal as is CH_4; it can therefore efficiently displace the CH_4 adsorbed on the coal (Gunter *et al*., 1997). As CO_2 moves through the reservoir it displaces CH_4; the limited experience to date indicates that very little of the injected CO_2 shows up in the production well until most of the CH_4 has been produced (Gunter *et al*., 1997), so that 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 are unminable.[21] Unlike EOR, enhanced recovery of CBM via CO_2 injection is not commercially

established technology, although one U.S. CBM producer has been carrying out a commercial pilot project in the San Juan Basin since 1996 (Stevens *et al.*, 2000).

Sequestration of CO_2 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, Cantle, and Boutkan, 1992; Summerfield *et al*., 1993). One estimate of the prospective global sequestering capacity of such reservoirs[22] is 100 and 400 GtC for oil and gas fields, respectively (Hendriks, 1994); 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 (IPCC, 1996). The range of estimates is wide because reservoir properties vary greatly in suitability for storage, and because oil and gas recovery may have altered the formations and affected reservoir integrity.

Deep saline aquifers are much more widely available than oil or gas fields. Such aquifers are present in all sedimentary basins, the total area of which amounts to 70 million km^2 (2/3 onshore and 1/3 offshore)—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 (Hitchon *et al.*, 1999; Bachu and Gunter, 1999; Bachu, 2001). To achieve high storage densities, CO_2 should be stored at supercritical pressures,[23] which typically requires storage at depths greater than 800 m.[24] The aquifers at such depths are typically saline[25] and not effectively connected to the much shallower (depths less than ~ 300 m) freshwater aquifers used by people.

Up until a few years ago it was generally thought that closed aquifers with structural traps would be required for effective storage. The potential global sequestering capacity in such traps is relatively limited—about 50 GtC (Hendriks, 1994), equivalent to less than 10 years of global CO_2 production from burning fossil fuel at the current rate. However, a growing body of knowledge (Bachu, Gunter, and Perkins, 1994; Holloway, 1996) 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 aquifer boundaries that it either never reaches the boundaries, or if it does, the leakage rate would be sufficiently slow as to be of little consequence with regard to climate change, because of the extraordinarily slow rates of CO_2 migration in such reservoirs (typically of the order of 1 cm/year)—a phenomenon called "hydrodynamic trapping" of CO_2 (Bachu, Gunter, and Perkins, 1994). For large aquifers, the CO_2 will eventually dissolve in the water ("dissolution trapping" of CO_2). For 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) (Gunter, Perkins, and McCann, 1993).

If structural traps are not required for effective storage, potential aquifer storage capacity might be huge; estimates range from 2,700 GtC (Omerod, 1994) to 13,000 GtC (Hendriks, 1994). For comparison, estimated remaining recoverable fossil fuel resources (excluding methane hydrates) contain 6,000 - 7,000 GtC (Rogner, 2000).

There is a growing base of experience with CO_2 disposal in aquifers. One large project being carried out by Statoil involves recovering the CO_2 contaminant in natural gas from the Sleipner Vest offshore natural gas field in Norway gas at a rate of 1 million tonnes of CO_2/year and its injection into and sequestration in a nearly aquifer under the North Sea (Kaarstad, 1992). A

prospective large aquifer disposal project expected to commence within 10 years will involve recovery of more than 100 million tonnes/year (equivalent to 0.5% 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).

There is also a rapidly growing number of smaller acid gas disposal projects. In Alberta there are 31 such projects that involve recovery of CO_2 along with H_2S from natural gas fields and injection of these acid gases (characterized by a wide range of relative concentrations) underground for storage, in aquifers as well as in depleted oil and gas fields. Underground disposal of CO_2/H_2S is pursued in these projects as a less costly strategy for responding to sulfur air emission regulations than the alternative of recovering H_2S from the natural gas and converting it to elemental sulfur (Longworth, Dunn, and Semchuck, 1995; Wichert and Royan, 1997).

The long history of 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 in the scientific community that long-term sequestration of a significant fraction of the next several hundred years of global CO_2 production from human activities might be feasible (Holloway, 1996; Socolow, 1997; PCAST Energy R&D Panel, 1997).

Public acceptability issues are paramount. Fuel decarbonisation with CO_2 sequestration is unfamiliar to most people as a strategy for dealing with climate change. The scientific community has a major responsibility to inform the public debates on the various issues relating to safety and environmental impacts. Much can be learned from both natural events (Holloway, 1997) and from the extensive historical experience with use of CO_2 injection for enhanced oil recovery and with underground gas storage (Gunter, Chalaturnyk, and Scott, 1999).

More research, field testing, modelling, and monitoring are needed to narrow the uncertainties relating to CO_2 storage in geological media.

Outlook for CO_2 capture in power generation. Large central-station coal-fired power plants are likely to be early targets of efforts to recover CO_2 associated with fossil fuel consumption and prevent its release to the atmosphere by disposing of it in geological formations or otherwise (Williams, 2000). For such systems, the cost of fuel decarbonization plus CO_2 disposal in a geological reservoir is made up of costs for:

- separating out a relatively pure stream of CO_2 from the fossil energy system,
- compressing CO_2 to a dense (supercritical) state for pipeline transport to the disposal site,
- the CO_2 pipeline and associated rights of way,
- the wells for injecting the CO_2 into disposal reservoirs and associated surface facilities.

Most decarbonization studies have focused on recovering CO_2 from flue gases of fossil fuel power plants. Costs for separation and disposal are dominated by the cost of separating out the CO_2 from flue gases—which is high because the CO_2 concentration is low (~ 12%) and its partial pressure is low (0.12 bar). At such low CO_2 partial pressure, CO_2 recovery is typically achieved by reacting 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 plant, the generation cost would be 60% higher than the cost without CO_2 recovery (Williams, 2000). A superior approach involves recovering CO_2 instead before combustion (so that the CO_2 is undiluted by nitrogen from air) in a coal integrated gasifier/combined cycle (IGCC) power plant.

The coal IGCC is commercial technology that makes it possible to convert coal to electricity at much higher efficiency (~ 46%) than with conventional coal steam-electric technology (35-36% for new plants or 33% for average US plants in use) with air pollutant emission levels comparable to emissions for natural gas combined cycles and environmental damage cost levels associated with such emissions that are about 1/10 those for coal steam-electric plants equipped with best available control technologies (Williams, 2000). Even without taken credit for the environmental benefits offered by coal IGCC technology, generation costs are approaching costs for conventional coal steam-electric plants equipped with flue gas desulfurization.[26] And decarbonization/CO_2 sequestration costs are much less than for coal steam-electric technology.

Using coal IGCC technology, the process of decarbonization/CO_2 sequestration begins with gasification (partial oxidation) of coal in O_2 (obtained from an air separation plant) at high pressure and temperature to produce synthesis gas (mostly CO and H_2). The synthesis gas so produced is cooled and "scrubbed" to remove pollutants (other than H_2S, the compound formed from the sulfur in the coal during gasification) and then passed to water-gas-shift (WGS) reactors equipped with H_2S-tolerant WGS catalysts. In these units, CO is reacted with steam ($H_2O_{(g)}$) according to the WGS reaction ($CO + H_2O_{(g)} \rightarrow CO_2 + H_2$). The shifted synthesis gas (made up mostly of H_2, CO_2 and $H_2O_{(g)}$) is then cooled to near ambient temperatures, the H_2S is removed using a glycol solvent and converted to elemental sulfur, the $H_2O_{(g)}$ 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[27] and made ready for disposal by drying and pressurization to 135 bar. 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 some 80 km by pipeline to a site where the CO_2 is injected via disposal wells into an appropriate storage medium (e.g., a deep saline aquifer).

This can all be accomplished using commercially available technologies and making relatively straightforward modifications of conventional coal IGCC power plants for which CO_2 is vented. Estimated performance and electricity costs for both conventional and decarbonized coal IGCC plants are summarized in Table 5, which shows that an IGCC plant for which CO_2 emissions per kWh are 87% less than for a conventional IGCC plant would have: (*i*) a capital cost that is 36% higher than for a conventional IGCC plant, (*ii*) a conversion efficiency that is 10 percentage points less (but still higher than the 33% average efficiency for US coal steam-electric plants!), and (*iii*) a generation cost that is about 45% higher, for a plant located about 80 km from the CO_2 disposal site.

A carbon tax somewhat greater than $100/tonne of carbon would be needed to motivate decarbonization/CO_2 sequestration for IGCC technology, but even with such a carbon tax in place the cost of electricity from a decarbonized coal IGCC plant would be less than for a new nuclear plant except in those parts of the world where capital costs are at the very lowest end of the range of costs for new plants (see Table 5).

One reason it is difficult for nuclear power to compete is the high operation and maintenance (O&M) cost for existing light water reactors (see Table 5). Plausibly, new reactor technologies that have a high degree of inherent safety would have lower O&M costs. One such technology that has recently been commercialized is the 1,300 MW_e advanced boiling water reactor (ABWR) developed by GE/Toshiba/Hitachi—an evolutionary light water reactor (one of which has been built and is in operation in Japan) that has been granted design certification in the United States. For the ABWR to be competitive with the decarbonized coal IGCC, its O&M cost would have to be about 30% less than the 1998 average value for the United States.[28] But security measures likely to be enacted to deal with security risks in light of growing concerns about nuclear terrorism will make it difficult to realize low O&M costs.

Still, the prospects are good that baseload wind/CAES power will become less costly than decarbonized coal IGCC power as well as nuclear power and thus would be preferred in a greenhouse gas emissions constrained world wherever substantial wind resources are available. As will be discussed below, the most promising market opportunities for decarbonized fossil fuels are in serving markets for fuels used directly.

Can Deep Reductions of CO_2 Emissions Be Achieved for Fuels Used Directly?

Even if the power sector were to be completely decarbonized by 2100 via deployment of some mix of renewable, nuclear, and decarbonized fossil fuel technologies, CO_2 emissions from fuels used directly (other than for power generation) in 2100 under IS92a would still amount to 15 GtC/y—several times larger than levels required to keep the atmospheric CO_2 concentration at a level in the range 450 to 550 ppmv.

Reducing total global CO_2 emissions by 2100 to about 3 GtC/y would be required to stabilize the atmospheric concentration of CO_2 at 450 ppmv—which can be achieved only if most fuels used directly 2100 under IS92a were provided at zero net CO_2 emissions.

The main options for realizing zero or near-zero emissions from fuels used directly are: (*i*) H_2 produced from fossil fuels with sequestration of the CO_2 coproduct, (*ii*) H_2 produced electrolytically from non-carbon (renewable or nuclear) power sources, (*iii*) H_2 produced by thermochemical splitting of water using heat generated from a non-carbon source (e.g., a high temperature gas cooled reactor or a solar furnace), and (*iv*) biomass fuels. In what follows each of these options is discussed in turn, following an introductory discussion of the prospects for introducing H_2 as a major energy carrier.

Hydrogen as an Energy Carrier

In combustion applications H_2 can be burned as a fuel for cooking, for providing low-temperature heat (e.g., for space and water heating), and for providing high-temperature heat for industrial processes (Ogden and Williams, 1989). The only air pollutant arising from H_2 combustion is NO_x, which can be controlled to very low levels by lean-burn combustion, by steam or water injection, or by catalytic combustion techniques.

But perhaps the most important market opportunity for H_2 would be in fuel cells, because H_2 is the natural fuel for use in fuel cells. 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.

There are good prospects for commercialization of fuel cells for both stationary power and combined heat and power applications and mobile applications during the next decade or so. 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. 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 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 compressed gaseous H_2 storage (current technology); and there are good prospects for successfully launching H_2 fuel cell cars in the market during the second decade of this century (Ogden, Williams, and Larson, 2001).

Hydrogen from Fossil Fuels

Although H_2 is not yet used as an energy carrier, it is widely manufactured for use in the chemical process and petroleum refining industries; in the United States, about 1% of primary energy use (mostly natural gas) is committed to the manufacture of H_2.

The process of making H_2 from a fossil fuel begins with converting the fossil fuel feedstock into synthesis gas. At present most H_2 is manufactured from natural gas by steam reforming.[29]

As noted above, 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 for IGCC power applications except that at the final stage following CO_2 removal the H_2–rich gas would be purified (up to 99.999% purity) in a pressure swing adsorption unit instead of burned in a combined cycle power plant.

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 for natural gas by electricity generators in 1997 was 2.1 times the coal price; this ratio is projected to increase to 3.7 by 2020 (see note d, Table 5), which is perhaps as soon as H_2 could be used as an energy carrier in significant markets. At US prices projected for 2020, H_2 from coal is likely to be less costly than H_2 from natural gas. It is estimated that with near-commercial technology H_2 could be produced at an efficiency of 72% from coal with sequestration of the CO_2 coproduct of H_2 manufacture at cost of $6.4/GJ, for coal priced at $0.93/GJ (see note d, Table 5) and in the presence of a $100/tC carbon tax (Williams, 2001).

This plant-gate H_2 cost is equivalent in terms of energy content to a gasoline price of $0.92/gallon—not much higher than the $0.88/gallon average US refinery-gate gasoline price in 2000. If this H_2 were to be used by fuel cell cars, the cost of the H_2 distribution and refueling system would increase the cost seen "at the pump" by consumers to about $2/gallon of gasoline equivalent (Williams, 2001)—much higher than the average gasoline pump price in 2000 of

$1.14/gallon (excluding retail fuel prices). However, fuel cell cars are expected to be 2-3 times as fuel efficient as gasoline internal combustion engine cars, so that the cost of fuel per mile of driving would be less than for today's cars (Ogden, Williams, and Larson, 2001).

Large-scale geological sequestration of CO_2 would be required if the coal-based H_2 option were to be widely pursued in a greenhouse-gas-emissions-constrained world. If in 2100 all fossil fuels used directly under IS92a except fuels[30] to make iron and steel (assumed to be coal) and to run jet airplanes (assumed to be oil) were replaced by H_2 derived from coal, the amount of H_2 required in 2100 would be 452 EJ/y and the CO_2 sequestration rate would be about 16 GtC/y—2.6 times the total CO_2 emission rate from fossil fuel burning in 1997 (see Table 1).

Consider how the global energy system might evolve to such an intensive level of sequestration. Suppose that by 2010 the initial CO_2 sequestration projects associated with coal conversion involve sequestration at a rate of 8.5 million tonnes of CO_2/y (8.5 times the sequestration rate for the ongoing Sleipner sequestration project in the North Sea). If there were public policy in place aimed at expanding this activity at an accelerated rate of 35% per year until 2025,[31] the incremental annual sequestration capacity added in 2025 would be 770 million tonnes of CO_2 /y (210 million tonnes of C/y). If, after this rapid ramp-up, sequestration were continued at a linear expansion rate of 210 million tC/y, 2025-2100, the year 2100 target rate could be realized. Under this scenario, the total amount of CO_2 sequestered in this century would be about 600 GtC—a large amount, but a quantity significantly less than even pessimistic estimates of the global capacity for secure geological sequestration. To be sure, undertaking such a global activity will require a much better understanding of CO_2 storage and the risks involved than we have at present.

Electrolytic Hydrogen

An alternative to making H_2 from fossil fuels with CO_2 sequestration is to make it by breaking apart water molecules using electricity from either nuclear or renewable electric supply sources.

Consider first making H_2 electrolytically from wind power at the cost projected for Class 6 winds in 2020—some 2.9¢/kWh (see Table 4). A large wind farm providing power at this price coupled to a CAES unit could provide baseload electricity at a relatively modest incremental cost. Such baseload electricity from a remote wind farm in turn could be transported via a high-voltage transmission line at low incremental cost to an urban center where it might be used to make H_2 electrolytically for transport applications. It is estimated that the cost of such baseload electricity delivered 300 km to a "city gate" would be about 4.0¢/kWh.[32] Moreover, by 2020, it is plausible that advanced electrolytic conversion equipment could become widely available, for which the cost of H_2 derived from wind power at 4.0¢/kWh would be ¼ less than with current electrolytic technology; still, the cost of the electrolytic H_2 so produced with advanced electrolytic technology would be 2 ½ times more costly than H_2 produced from coal with CO_2 sequestration using near-commercial technology.[33].

Is it plausible that with advanced technology, electrolytic H_2 might one day emerge the economic winner? Unfortunately, no. Even assuming advanced electrolysis technologies the economics of electrolytic H_2 production from any carbon-free electricity source would always be unattractive

unless there are "fatal flaws" associated with the option of sequestering the CO_2 byproduct of making H_2 from fossil fuels. Consider the electricity price required for breakeven. Assuming baseload (90% capacity factor) electricity, the electricity price for a carbon-free source would have to be 0.9 ¢/kWh in order for electrolytic H_2 based on advanced electrolytic technology to be competitive with H_2 produced from coal using near-commercial technology with sequestration of the separated CO_2.[34]

It is unlikely that electricity prices less than 1.0 ¢/kWh will be routinely achievable with either nuclear or renewable electric technologies—at least over the course of the next several decades. Offpeak hydroelectric power prices are typically this low or lower, however, and variable nuclear costs might plausibly eventually become low enough to put nuclear offpeak prices in the targeted range as well. However, offpeak pricing strategies would be appropriate only for the situation where H_2 production is a minor activity relative to electricity generation, so that power generation could shoulder capital and other fixed charges. But in a greenhouse gas emissions-constrained world H_2 is likely to be required in the late 21st century at levels far in excess of the level of power generation,[35] so that fixed charges must be allocated to H_2 production. So, electrolytic H_2 generated via either nuclear or renewable electric sources is not promising economically and neither would be considered as a major energy option in this century unless presently unforeseen flaws in the CO_2 sequestration option were to emerge.

Thermochemical Routes to Hydrogen Production from Water

An alternative way to split the water molecule is by the application of heat to produce H_2. If this were done directly, temperatures of the order of 4000 ^{o}C would be needed—which cannot be accomplished at present because of the absence of materials for containing the reactions. But over the years various multiple-step chemical processes have been proposed for making H_2 from water thermochemically at lower temperatures—using either nuclear heat [(e.g., heat that can be provided by a high-temperature gas-cooled reactor (HTGR) (Yoshida, 1983; Yalçin, 1989)] or high-temperature solar heat that could be provided with collectors that concentrate sunlight (Steinfeld and Palumbo, 2001). In contrast to electrolytic processes, thermochemical processes for H_2 manufacture are far from being commercially available. Here, as in the electrolytic case, the prospects are bleak that thermochemical conversion would *ever* become economically competitive with fossil fuel derived H_2 with CO_2 sequestration.

Such processes have overall thermal efficiencies for converting heat into H_2 that are typically less than 50% (Yoshida, 1983) and tend to be quite capital-intensive. The UT-3 process,[36] an option that has been investigated extensively in Japan, illustrates the challenge facing these technologies. For the most promising configuration of a system for producing H_2 with the UT-3 process, a recent study (Tadokoro *et al.*, 1997) estimated that the overall efficiency of converting nuclear heat into H_2 would be 45% (HHV basis); for this technology the estimated H_2 production cost is $37.5/GJ (see Table 6)—about six times the cost of making H_2 from coal using near-commercial technology with CO_2 sequestration (Williams, 2001).

Table 6: Estimated Cost for Thermochemical H_2 Production from Water Using the UT-3 Process and Nuclear HTGR Heat[a] (*$/GJ, HHV basis*)	
Capital	12.53
Maintenance	2.31
Labor	0.42
Utilities	2.78
HTGR heat	$C_{HTGRheat}/0.449$
Credit for byproduct O_2	- 3.99
Subtotal	$14.05 + C_{HTGRheat}/0.449$
Overhead	$0.1*(14.05 + C_{HTGRheat}/0.449)$
Total production cost	$15.46 + 2.45*C_{HTGRheat}$
Total production cost for $C_{HTGRheat}$ = $9.0/GJ[b]	$37.5

[a] Based on Tadokoro *et al*. (1997), for a system producing 20,000 Nm^3/h of H_2 from water using heat from a high-temperature gas-cooled reactor (HTGR) via the UT-3 process under development in Japan. To facilitate a comparison of the costs presented in Tadokoro *et al*. (1997), however, it is assumed here that the capital charge rate is 15%/y (as for other H_2–production technologies discussed in this pa\per) and that the system operates at an average annual capacity factor of 80% (so that the annual rate of H_2 production = 1.787 million GJ/y). Also, only the most economically attractive option presented in Tadokoro *et al*. (1997)—the option using a membrane for separating H_2 from other gases at a high H_2 recovery rate—is considered here. The results presented here in $ are based on an exchange rate of 101 Yen/$, the average exchange rate for 1995-96.

[b] In Tadokoro *et al*. (1997) it is estimated that HTGR heat is available at 3.8 yen /1000 kcal = $9.0/GJ.

One reason for the high cost is that nuclear heat is expensive, accounting for nearly 60% of total production cost. However, if this heat were "free," the cost of H_2 would still be $15.5/GJ, some 2.4 times the cost of H_2 from coal using near-commercial technology with CO_2 sequestration.

One might hope that in the future more promising thermochemical cycles will be discovered and developed. But the prospects are not bright. Consider going to the other extreme in a limiting cost calculation: setting to zero all costs other than the cost of nuclear heat. Tadokoro *et al*. (1997) estimate that HTGR heat would cost $9.0/GJ (see Table 9); assuming this heat cost and a free conversion technology the production cost for H_2 would be $22/GJ, which is 3.4 times the cost of H_2 from coal with CO_2 sequestration based on near-commercial technology.

Still, one might argue that in the future HTGR heat costs will come down substantially, as would be the case if recent very optimistic projections of capital and generation costs for the Pebble Bed Modular Reactor (PBMR) could be realized; a crude estimate is that the nuclear heat so generated might cost as little as $2.6/GJ.[37] But even at this optimistic heat cost level the contribution of just the nuclear heat to the cost of thermochemical H_2 would be $6.4/GJ, so that all other components of the cost presented in Table 6 would have to be reduced to zero to enable thermochemical H_2 to compete.

In light of its poor economic prospects, thermochemical H_2 would not be considered seriously unless geological sequestration of CO_2 associated with fossil energy-derived H_2 proves to be unworkable for reasons than cannot presently be identified, or in the longer term (more than a century into the future)—when geological storage capacity limits for CO_2 are approached.

Moreover, even if those conditions could be satisfied, nuclear H_2 would have to compete both with electrolytic H_2 derived from PV or wind electricity sources and with H_2 derived thermochemically using high-temperature solar thermal processes.

Biomass Fuels

To the extent that carbon-based fuels can be produced from biomass grown on a sustainable basis, H_2 would not be needed to provide fuels for direct use in a greenhouse-gas-emissions-constrained world, because the growing and use of biomass leads to no net buildup of CO_2 in the atmosphere: the CO_2 released in combustion is balanced by the CO_2 extracted from the atmosphere during photosynthesis. Biomass-derived energy can be provided from residues of agricultural and forest product production and from biomass grown on plantations dedicated to the production of biomass for energy.

Biomass can be converted to fuels used directly for transportation and other applications by various routes, including biological processes to produce ethanol (e.g., from woody biomass via enzymatic hydrolysis—the main focus of the US Department of Energy's biofuels development effort) and the synthesis gas route, for the production of fuels such as methanol, synthetic middle distillates, and dimethyl ether.

The Second Assessment Report of the Intergovernmental Panel on Climate Change (IPCC, 1996) assessed the long-term potential of obtaining biomass from various residue sources and concluded that by the end of this century the primary energy potentially obtainable from residues could potentially amount to up to about 90 EJ/year—slightly more than global natural gas production at present.

The growing of biomass on plantations dedicated to energy could increase biomass energy supplies beyond what could be provided by residues. But bioenergy production is very land-use intensive, requiring about 4 million km^2 (3% of the land of the inhabited continents[38]) for each 100 EJ/year of primary biomass grown[39] to provide additional energy supplies. A detailed review of biomass energy options (Turkenburg, 2000) carried out for the World Energy Assessment (WEA, 2000) concluded that worldwide some 7 to 14 million km^2 of land (5 to 10% of the land area of the inhabited continents) is potentially available for producing biomass for energy purposes—made up of excess agricultural lands, degraded lands, and unproductive lands—without posing major conflict with the use of land for food production. Nevertheless large-scale biomass growing for energy in dedicated plantations is likely to be a contentious activity because of its land-use intensity. Some would argue that it is preferable to encourage the conversion of excess agricultural lands, degraded lands, and unproductive lands to wildlife habitat purposes rather than the growing of biomass for energy—even considering the climate change mitigation and other benefits that biomass plantations could provide.

The analysis carried out for the World Energy Asssessment of bioenergy concluded that the practical global potential for biomass production for energy (residues plus plantation biomass) over the long term is 100 to 300 EJ per year (Turkenburg, 2000). This forecast suggests that the biomass option offers little if any potential to improve upon IS92a in terms of GHG emissions from energy over the longer term, because that scenario already involves use of 205 EJ of biomass primary energy in 2100 (compared to 865 EJ from fossil fuels—see Table 1).

Conclusion

Effectively addressing the major energy challenges will require radical technological change. Energy technologies are needed that are affordable and offer zero or near-zero emissions of both air pollutants and greenhouse gases. Moreover, decades of rapid deployment growth will be needed for new technologies that offer significant promise in addressing these challenges.

Although nuclear power offers the potential for zero emissions for the power sector, it faces strong competition both from both new renewable-electric (mainly wind, photovoltaic) and decarbonized fossil fuel/CO_2 sequestration technologies.

For nuclear power there are reasonably good prospects for addressing reactor safety concerns, technical issues associated with radioactive waste disposal, and perhaps also cost concerns. Still, gaining public acceptance of waste disposal plans is a major challenge. For the longer term, the nuclear weapons connection to nuclear power would move to center stage among concerns about nuclear power if it were developed to the high levels needed to "make a dent" in addressing the climate change challenge. The author is not optimistic about the prospects for achieving adequate proliferation resistance via technical fixes for a world where there is 10-20 times as much nuclear capacity as at present (as would be required if nuclear energy is to play a significant role in climate change mitigation). However, concentrating nuclear technologies in large "nuclear parks" maintained under tight security and international control would probably be an effective response to proliferation concerns in a nuclear-intensive energy future.

For renewables, costs have fallen sharply, and there are good prospects that over the next 1-2 decades wind and PV power will become widely competitive in central-station and distributed grid-connected power markets, respectively. No new technological developments are needed to deal effectively with the intermittency challenge. And overall land requirements would be quite modest for both wind and PV technologies—even for future energy scenarios in which wind and PV come to account for most global electricity generation.

Fossil energy decarbonization/CO_2 sequestration has emerged as a major new competitor in the race to zero emissions for both power generation and markets that use fuels directly. There is growing confidence in the scientific community that up to several thousand GtC in the form of CO_2 can be stored securely in deep geological reservoirs, making it possible to use hundreds of years of fossil fuel supplies with very little release of CO_2 to the atmosphere. To be sure, there remain uncertainties regarding the environmental impacts of geological disposal of CO_2 at large scales, but the uncertainties should be greatly reduced over the course of the next decade.

With commercially available technology, coal power plants could be built that are characterized by near-zero emissions of both greenhouse gases and air pollutants and would be cost-competitive with nuclear power.

The largest climate-change-mitigation challenge is posed, not by the power sector, but by transportation and other sectors where fuels are used directly—which account for about 2/3 of global CO_2 emissions at present and probably an even larger fraction in the future under business-as-usual conditions.

The least-costly supply option for achieving deep reductions of CO_2 emissions for fuels used directly is via H_2 production from low-cost and abundant fossil fuel feedstocks (e.g., coal), with sequestration of the separated CO_2. Electrolytic H_2 based on electricity from nuclear or intermittent renewable power sources would be far more costly, even considering advanced technologies. The same is true for H_2 that might be produced from water via thermochemical cycles driven by nuclear heat or heat derived from high-temperature solar concentrating collectors. Such options would be considered seriously only if it turns out that CO_2 sequestration cannot be carried out at large scales. Biofuels will be important but, because of land use constraints, the contributions from biofuels in the long term are not likely to be much higher than the levels projected for 2100 under IS92a.

To sum up, there are plausible combinations of energy supply technologies that would make it possible to address all the major challenges posed by conventional energy. But addressing the challenges effectively in this century would require extraordinarily rapid deployment rates over a period of decades. Such deployment rates are not likely to be realizable under free energy market conditions. Therefore, public policies are called for that would set goals for tackling the challenges, support R&D on promising options for addressing the challenges, create market-launching incentives for radical technologies that offer great promise in realizing the goals, and foster competitive market conditions for widespread deployment after market launch.

Establishing such policies and keeping them in place long enough to make a difference would require a high degree of support among the general public for the targeted technologies. Such policies can endure in democratic societies over the multi-decadal periods needed to keep capacity expansion on track *only if the targeted technologies are not just tolerated but enthusiastically embraced by the general public*.

Opinion polls indicate that of the different clusters of technologies reviewed here, PV and wind power probably have the best prospects for garnering such broad public support.

It is too soon to tell how the public will react to fuel decarbonization/CO_2 sequestration technologies and strategies—which are still largely unfamiliar. The nuclear experience with pubic attitudes regarding radioactive waste disposal is not encouraging. However, CO_2 is not radioactive and would not be harmful as long as leakage rates can be kept low, and there seem to be good prospects for that. One hopeful consideration is that if decarbonization/sequestration were focused on technologies emphasized in this review that offer near-zero emissions of air pollutants as well as CO_2—thereby offering technology as clean as renewable energy technologies—the prospects for getting broad public support would be much better than for the "band aid" approach of removing CO_2 from stack gases of fossil fuel power plants that many regard as environmentally unacceptable. Building broad public support would also be facilitated if renewable energy advocates were to view this cluster of technologies as being complementary rather than competitive in the quest for clean and climate-friendly technology.

It is difficult to imagine how public enthusiasm for nuclear power can be rekindled and sustained for multi-decadal periods. Nuclear power has been around for a long time, during which strong opinions have been developed among the general public. A *sustainable* nuclear power

renaissance is likely only if new nuclear technologies come into the market that are judged by most people to be decisively better than alternative energy technologies. There are technologies such as the PBMR that appear (on paper) to be much better than current nuclear technologies—but renewable and emissions-free fossil energy technologies could become widely available in the same time frame or earlier. Moreover, before undertaking the task of generating enthusiasm for nuclear power, the nuclear industry and interested governments would have to overcome the intense hostility to nuclear power that exists among various groups in many countries.

For the longer term, the nuclear weapons connection to nuclear power may be the real showstopper. Although until recently this issue has not been on most people's radar screens, the terrorist attacks of 11 September 2001 have thrust this issue into the limelight. This new concern would come into even sharper focus in a world with much more nuclear power capacity than at present—perhaps stimulated by a diversion incident or two. The large international nuclear park option would greatly weaken the weapons link and might make most of the general public more comfortable. But would national governments find this option acceptable? So giving up some degree of energy sovereignty would seem to be especially difficult for those countries with substantial nuclear power programs where the decision to "go nuclear" was originally motivated by the perception that nuclear power offered a promising route to energy autarky.

Finally, even if the weapons link to nuclear power could be adequately weakened via deployment in international nuclear parks, there is a risk that public policies and resources committed to resurrecting the nuclear option would weaken efforts to develop and commercialize non-nuclear technologies that could have far greater impact in climate-change mitigation.

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Endnotes

[1] The author was Convening Lead Author for Chapter 8, Advanced Energy Supply Technologies (fossil and nuclear) of the World Energy Assessment (Williams, 2000).

[2] 39% nuclear, 16% hydroelectric, and 45% new renewables.

[3] 45% nuclear, 51% hydroelectric, and 4% new renewables.

[4] Both net new and replacement capacity, assuming linear capacity growth and 40-year plant lives.

[5] Although there is no imminent danger of running out of conventional oil and gas, productive capacity is expected to be constrained after about 1/2 of remaining exploitable conventional resources have been used up—in large part as a result of the tendency to exploit the largest fields first.

[6] The reactor core volume would be less than 7 cubic meters.

[7] The deployment rate would be: 408 reactors per year, 2040-2055; 816 per year (408 net new + 408 refurbished), 2055-2070; 1224 per year (408 net new + 816 refurbished), 2070-2085; and 1632 per year (408 net new + 1224 per year refurbished), 2085-2100.

[8] These reactors require 8%-enriched uranium; the projected fuel burnup is 80,000 MWD/t.

[9] CAES costs are low because they are dominated by the turbomachinery components, and the turbomachinery costs are low because they involve gas turbine technology for which the compressor and expander functions are separated in real time.

[10] The author's estimate of the practically exploitable global wind energy potential is 43,000 TWh/y, obtained as follows. First, the estimate is restricted to wind resources at least as good as Class 4 resources (average wind speed of at least 5.6 m/s at 10 m. Second, the exploitable potential is estimated for 100 m hub height [expected to be routinely exploitable with technology available by 2030 (EPRI/OUT, 1997)]; at this hub height, the estimated net annual electricity generation rate with 2030 technology is 1412, 1566, and 1797 kWh/m^2 of area intercepted by the the rotor, for wind classes 4, 5, and 6, respectively (EPRI/OUT, 1997). Grubb and Meyer (1993) estimate that globally the land areas over which Class 4 and Classes 5+ winds are available are 9.55 million km^2 and 8.35 million km^2, respectively (a total of 14% of the land areas of the inhabited continents). The author adopts these estimates but assumes that for the world, the breakdown between Class 5 and Classes 6+ is the same as for the United States (61.5% for Class 5). Under these assumptions the unrestricted global potential is 429,000 TWh/y (212,000 TWh/y for Class 4 + 126,000 TWh/y for Class 5 + 91,000 TWh for Classes 6 and higher). Following Grubb and Meyer (1993), the author assumes that the practically exploitable potential is 10% of the unrestricted potential.

[11] This calculation [based to a large extent on Cavallo (1995)] is for a 6 GW_e wind farm (with a 36% average capacity factor—as would be appropriate for Class 4 winds and 2020 technology—see Table 4) coupled to a 1.4 GW_e CAES unit (with 20 hours of storage and a heat rate of 4326 kJ/kWh for the expander) operated at a 28% average capacity factor that provides 2 GW_e of baseload power (90% capacity factor). Of this baseload power 78% is provided directly from the wind farm (@ 3.7 ¢/kWh—see Table 4) and 22% from the CAES unit (@ 6.7 ¢/kWh), so that the average cost is 4.4¢/kWh. It is assumed that the expander is fired with natural gas, so that the natural gas

consumed per average kWh provided by the wind/CAES system is 943 kJ/kWh. The CO_2 emission rate for this system is 13 grC/kWh—some 14% of the emission rate for a natural gas combined cycle power plant (see Table 5).

[12] Examples: (*i*) in the United States, over 95% of the high-quality wind resources are concentrated in the 12 states of the Great Plains, which account for only 16% of the US population, and whose land areas (34% of total US land) are occupied mainly by ranchers and farmers; (*ii*) in China, excellent wind resources are available on 83,000 km^2 (0.9% of China's land area) in sparsely populated Inner Mongolia, where the potential production is 1,800 TWh/y (Lew *et al*., 1998)—about twice the thermal electricity generation rate in China in 1998.

[13] For Class 4 winds, U.S. wind power costs are projected to average 4.3 ¢/kWh in 2005 (see Table 4), when the net generation rate per unit area of wind intercepted is expected to be ~ 1300 $kWh/m^2/y$ for 70 m hub heights (EPRI/OUT, 1997). For a wind turbine spacing of 5D across the wind and 10D downwind (D = diameter of wind turbine rotor), the corresponding generation rate per unit of ground area is 20 $kWh/m^2/y$. Assuming that the royalty rate to the landowner is 2.5% of revenues generated (EPRI/OUT, 1997), the royalty amounts to $88/acre/year. For comparison, net U.S. farm income in 1999 was $48 billion, of which $23 billion was direct government payments (Morehart *et al*., 2000); total U.S. farm area in 1999 was 947 million acres (Shapiro, 2000), so that net farm income was $51/acre, of which $24/acre was in the form of direct government payments.

[14] "Net metering" is a policy that allows customers to run their electric meters backward, delivering excess electricity to the grid for credit at retail rates during periods when PV generation exceeds on-site demand. In the United States, 30 states have adopted net metering policies to encourage the deployment of PV systems.

[15] The energy payback (the time required to pay back the energy invested in manufacturing and installing PV systems) must be a small fraction of the system lifetimes (~ 20-25 years) if PV is to make substantial contributions to energy supplies. For current grid-connected rooftop crystalline silicon and thin-film systems, payback times are 4-9 years and 3-4 years, respectively; payback times are projected to fall in less than a decade's time to 3-4 years and 1-2 years for crystalline silicon and thin-film PV systems, respectively (Alsema *et al*., 1998; Turkenburg, 2000).

[16] Very low costs are potentially realizable for thin-film PV technologies in large part because the layer of active PV material (deposited on a glass, steel or other substrate) is typically ~ 1 μ thick (about 1% of the thickness of a human hair), so that overall costs for the active PV materials are low.

[17] Assuming an overall PV efficiency of 13.6% [the average efficiency projected for thin-film PV systems in 2030 (EPRI/OUT, 1997)] or a peak PV output of 136 $Watts/m^2$ (because the peak insolation is (1000 $Watts/m^2$), the required collector area is (1000 Watts)/(136 $Watts/m^2$) = 7.35 m^2.

[18] But the power sector would not necessarily be fossil energy free in such a renewables-intensive electricity future if fossil-fuel-powered CAES units were to be used to enable intermittent renewables to follow load or provide baseload power. Suppose that natural gas is used as fuel in CAES units to back up <u>all</u> wind and PV power at a rate of 1000 kJ/kWh (see end note 11). Assuming wind and PV power are produced in 2100 at rates of 43,000 and 16,000 TWh/y, respectively, the total natural gas required in 2100 would thus be 59 EJ/y and the corresponding CO_2 emission rate would be 0.80 GtC/y. Alternatively CAES units could be powered by H_2 derived from fossil fuels with sequestration of the CO_2 coproduct—in which case the CO_2 emissions from the CAES units would be negligible.

[19] Assuming insolation of 1800 $kWh/m^2/y$ (the average for the United States), a 0.8 kW_{ac} array would produce 1440 kWh/y of electricity. Assuming PV capacity deployment at an average rate of 0.8 kW_{ac}/capita in 2100 and a world population of 11.3 billion at that time, the worldwide PV generation rate in 2100 would be 16,000 TWh/y.

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

[21] Of the 6 trillion tonnes of US coal resources at depths up to 1800 m, 90% is unminable with current technology because the coal is too deep, seams are too thin, or mining would be unsafe (Byrer and Guthrie, 1998).

[22] Capacity from past production + proved reserves + estimated undiscovered conventional resources.

[23] The critical point for CO_2 is 74 bar and 31 ^oC.

[24] Because the hydrostatic pressure gradient is typically about 100 bar per km.

[25] 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 geological time—time sufficient 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.

[26] The installed capital and O&M costs for a new 35.5%-efficient sub-critical coal steam-electric plant with flue gas desulfurization are \$1090/kW_e and 0.43 ¢/kWh, respectively (Williams, 2000), so that for a \$0.93/GJ coal price the generation cost is 3.70 ¢/kWh, assuming a 15% annual capital charge rate and an 80% capacity factor.

[27] At such high partial pressures, a physical solvent such as Selexol (dimethyl ether of polyethylene glycol) is used for CO_2 removal, for which costs are less than with amines.

[28] The overnight construction cost of the ABWR is estimated to be \$1,582/kW_e (NEA, 2000). Assuming a 5-year construction period and 10% real interest rate during construction, the total installed cost is \$1,932/kW_e, so that the annual capital charge is 4.14 c/kWh. Assuming a nuclear fuel cost of 0.54 ¢/kWh, the O&M cost for the ABWR would have to be less than 1.0 ¢/kWh to compete with the decarbonized coal IGCC plant.

[29] Typically the manufacture of H_2 from natural gas begins by reacting steam with natural gas at a temperature ~ 900 ^oC to make synthesis gas ($CH_4 + H_2O_{(g)} \longrightarrow CO + 3H_2$). The synthesis gas is then cooled and reacted with more steam to convert the CO to H_2 and CO_2 via the water-gas-shift reaction, so that overall processing leads to a gaseous mixture consisting mainly of H_2 and CO_2. Then the H_2 is separated from CO_2 and other gases. Commercial technology can provide H_2 that is 99.999% pure. If it is desired to provide a stream of relatively pure CO_2 as a coproduct (for CO_2) the cost is somewhat higher than for standard practice.

[30] It is assumed that by 2100 the only fossil fuels used directly without CO_2 capture and sequestration are coal for iron and steel making and jet fuel for airplane use.

It is assumed that by 2100 iron/steel making is via smelt reduction/near final shape casting (an advanced process now under development that is widely viewed as the technology of choice for the future) with the current OECD mix of iron ore and scrap, so that the coal required is 5.9 GJ/tonne of steel (Worrell, 1995). It is further assumed that the average steel consumption rate per capita for the global population of 11.3 billion is 386 kg (the OECD average rate for 1987). Thus coal use for iron/steel making is 25.8 EJ/y. Assuming a CO_2 emission rate for coal of 25.3 kg/GJ, total emissions from iron and steel making in 2100 are 0.65 GtC/y.

It is assumed that global jet fuel requirements for airplane use in 2100 $GJF_{2100} = (USJF_{1998})*GGDP_{2100}/USGDP_{1998}/(1.007)^{102}$ = 58.8 EJ/y. Here $USJF_{1998}$ = US rate of jet fuel consumption in 1998 (3.59 EJ) (EIA, 2000). $GGDP_{2100}$ = global GDP in 2100 (284.5 trillion 1996 \$, for IS92a). $USGDP_{1998}$ = US GDP in 1998 (8.52 trillion 1996\$). It is assumed that the efficiency of airplanes increases at an average rate of 0.7% per year. [Note that energy efficiency of new production aircraft has improved at a rate of 1-2% per year since the dawn of the jet era. A recent IPCC expert panel projected that a 0.7%/year rate of improvement can be expected, 1997-2050 (Lewis and Niedzwiecki, 1999).] It is further assumed that refineries are 90% efficient in the manufacture of oil products from crude oil so that the total oil required to serve jet fuel markets in 2100 is 58.8/0.9 = 63.3 EJ/y and the corresponding CO_2 emission rate is 1.16 GtC/y.

[31] Any new energy technology launched from a zero base must expand initially at an accelerated pace, with growth rates in the range 30-40% per year, for a period of the order of a couple of decades in order to be able to make major supply contributions later in this century. Such market-launching growth rates characterized nuclear power in its early years [worldwide nuclear power growth averaged 37% per year, 1957-1977 (Williams and Terzian, 1993)], and, as noted, wind power has been expanding at rates near 30% per year since the early 1990s.

[32] It is estimated that for wind power at \$0.029/kWh the cost of baseload wind power (wind farm + CAES) would be \$0.036/kWh for CAES based on storage in salt dome caverns. Transmission of this electricity 300 km via a 1 GW_e HV AC line (including ohmic losses) would bring the city-gate cost of this baseload power to \$0.04/kWh.

[33] The cost of H_2 using *advanced* electrolytic technology [based on Ogden and Nitsch (1993), for a 15% annual capital charge rate and an O&M cost of 4% of the capital cost per year] is $C_{EH} = \$3.59 + P_E/(\eta*0.0036$ GJ per kWh), where $\eta = 0.882$ = efficiency of converting alternating current electricity into H_2 (an overall electrolytic efficiency of 90%, HHV basis, and a rectifier efficiency of 98%), where PE is the electricity price in \$/kWh. Thus, if $P_E = \$0.040$/kWh, $C_{EH} = \$16.2$/GJ.

[34] With a \$100/tC carbon tax the cost of H_2 from coal with CO_2 sequestered based on use of near-commercial technology is \$6.4/GJ (Williams, 2001). Thus the electricity price P_E (in \$/kWh) for carbon-free electricity at which the electrolytic H_2 cost P_{H2} (based on use of advanced electrolytic technology) equals the cost of H_2 from coal with CO_2 sequestered is given by: $P_{H2} = 3.59 + P_E/(0.882*0.0036) = 6.4 \rightarrow P_E = \$0.0089$/kWh. If instead present-day electrolytic technology were used, the breakeven electricity price is determined by: $P_{H2} = 6.12 + P_E/(0.739*0.0036) = 6.4 \rightarrow P_E = \$0.00074$/kWh.

[35] Note in Table 1 that fossil fuels used directly in 2100 under IS92a amount to 541 EJ/y and account for 15 GtC/y of CO_2 emissions. For comparison electricity generation in 2100 amounts to only 245 EJ/y (68,000 TWh/y).

[36] The UT-3 process is based on the following reactions aimed at decomposing water thermochemically:

$$CaO + Br_2 \rightarrow Ca\,Br_2 + \tfrac{1}{2}\,O_2 \text{ (at 700-750 } ^oC)$$
$$CaBr_2 + H_2O \rightarrow CaO + HBr \text{ (at 500-600 } ^oC)$$
$$Fe_3O_4 + 8\,HBr \rightarrow 3\,FeBr_2 + H_2O + Br_2 \text{ (at 200-300 } ^oC)$$
$$3\,FeBr_2 + 4\,H_2O \rightarrow Fe_3O_4 + 6\,HBr + H_2 \text{ (at 550-600 } ^oC)$$

In this series of reactions that take place in multiple vessels, water and heat are consumed, and both H_2 and O_2 are produced; the rest of the chemicals are recycled.

[37] Eskom, the South African electric utility has an effort underway to develop the PBMR, a small modular HTGR (a 1100 MW_e power plant would be made up of ten 110 MW_e modules), for which the targeted (hoped for) installed capital cost is \$1,000/kW_e. If this capital cost target could be reached, the generation cost (assuming a 15% annual capital charge rate and an 80% capacity factor) would be \$0.03/kWh (Taylor, 2001):

Capital	0.0215
Nuclear fuel	0.0047
O&M	0.0030
Decommissioning	0.0010
Total	\$0.0302/kWh

For these cost targets a rough estimate of the cost of nuclear heat is obtained by assuming the PBMR is 43% efficient in converting nuclear heat into electricity and that 40% of the capital cost for electricity generation is for power conversion equipment not needed when the PBMR is used for providing heat for H_2 manufacture. The cost of nuclear heat estimated under these assumptions is thus:

$$0.43*[(\$0.0302/kWh) - 0.40*(\$0.0215/kWh)]/(0.0036\text{ GJ/kWh}) = \$2.58/GJ.$$

It is quite uncertain whether the cost goals set for the PBMR are realizable, because the cost target is very aggressive, and the PBMR is still in the R&D phase of its development.

[38] For comparison, land areas in croplands, forests, and pastures are 15, 41, and 33 million km^2, respectively.

[39] Assuming an average productivity of 12 tonnes/hectare/y and a biomass heating value of 20 GJ/tonne.